FERC - ORDER SETTING VALUES FOR INCENTIVE RATE OF RETURN

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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Before Commissioners: Charles B. Curtis, Chairman;
Don S. Smith, Georgiana Sheldon,
and George R. Hall

Determination of Incentive Rate of Return, Tariff, and Related Issues) Docket No. RM78-12

ORDER NO. 31

ORDER SETTING VALUES FOR INCENTIVE RATE OF RETURN, ESTABLISHING INFLATION ADJUSTMENT AND CHANGE IN SCOPE PROCEDURES, AND DETERMINING APPLICABLE TARIFF PROVISIONS

(Issued: June 8, 1979)

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I. INTRODUCTION

By this Order, the Federal Energy Regulatory Commission (Commission) resolves three complex and interrelated issues concerning the segments 1/ of the Alaska Natural Gas Transportation System (ANGTS) located in the United States: (1) the structure of the initial tariffs to be applied to the transportation of Alaskan gas; (2) the Incentive Rate of Return (IROR) mechanism and the values to be applied to

1/ These segments are on the Alaskan segment and the Eastern leg (Northern Border). The only tariffs currently before the Commission for approval are those filed by Alaskan Northwest Natural Gas Transportation Company on behalf of the Alaskan segment, and by Northern Border Pipeline Company on behalf of the Northern Border segment.

the separate elements of that mechanism; and (3) the rate of return on equity to be applied once the system becomes operational.

A. Scope of Order

This Order is divided into six major sections. Section II is concerned with the Incentive Rate of Return, its rationale and mechanism. The four parts to this section explore and define the incentive concept (Part A), the six IROR parameters (Part B), and the implementation of the incentive mechanism (Part C). Sections III and IV deal with particular adjusting mechanisms which are required for the proper implementation of the Incentive Rate of Return. These are the Adjustments for Inflation (Section III) and Change in Scope mechanisms and procedures (Section IV). Section V provides a general overview of the result of the IROR mechanism. Taken together, these four sections supplement the basic framework for an incentive mechanism, specified in Commission Order No. 17, 2/ which is designed

2/ Federal Energy Regulatory Commission, Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity, Docket No. RM78-12 (Dec. 1, 1978) confirmed, Order No. 17-A (Jan. 12, 1979).

to reward project sponsors for good management and effective control of costs.

The project sponsors' proposed tariffs are addressed in Section VI. The focus of that section is to resolve important issues which affect the risk to be borne by project sponsors in the construction and initial operation of the ANGTS. The relationship between the tariff issues and the IROR mechanism is important.

The last section (Section VII) addresses two procedural issues. These concern the use of the rulemaking process, and the relationship of this rulemaking to other pending proceedings pertinent to certification of the ANGTS. 3/

The resolution of tariff, incentive rate, and rate of return on equity issues for the Alaskan Northwest and Northern Border segments of the ANGTS are embodied in the text of this Order, and implemented though the ordering paragraphs and the terms and conditions.

3/ These proceedings focus upon issues surrounding the building of natural gas facilities which, prior to transporting gas as a part of the ANGTS, will be used to transport Canadian gas. See Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, et al., "Order Consolidating Proceedings, Establishing Procedures, Granting Interventions and Initiating Hearings." (April 20, 1979.)

The project sponsors have earnestly sought that this Order, especially as it relates to the tariff structure, provide assurance to prospective equity investors and lenders. The concern of the sponsors is wellfounded. The Commission fully recognizes that equity investors and lenders will make critical decisions respecting the financing of construction of the ANGTS in reliance on this Order.

The Commission has articulated in great detail its rationale for this Order. Where reasoned alternatives were available, we have provided a thorough analysis of the issues and the basis for our conclusions. This thoroughness provides the investors' best security in relying on this Order.

B. Background

The Prudhoe Bay Field, on the north slope of Alaska, contains the largest single gas reservoir ever discovered on the North American continent. Virtually every estimate exceeds 26 trillion cubic feet of proven, recoverable natural gas reserves. This large deposit of natural gas could supply more than two billion cubic feet of natural gas per day (approximately five percent of the nation's current gas requirements) over a 25-year period.

In recognition of the potential importance of this domestic energy source, Congress passed the Alaska Natural Gas Transportation Act (ANGTA), Pub. L. No. 94-586, 90 Stat. 2903 (1976) (15 U.S.C. SS 719-719m), which authorized the President to recommend a natural gas system to transport Alaskan natural gas to the contiguous lower-48 States. In September of 1977, the President rendered a decision that the Alcan Pipeline Company, because its proposal was environmentally and economically superior to competing proposals, should be granted the certificate to construct the ANGTS. 4/ Congress, by joint resolution, approved and adopted the President's selection in November of that year, H.J. Res. 621, Pub. L. No. 95-158, 91 Stat. 1268 (1977).

The ANGTS will be 4,800 miles in length, orginating on the north slope of Alaska and passing through Canada to the

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4/ Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System (September 1977) [hereinafter cited as Decision]. The present sponsors for the Alaskan segment are the successors to the Alcan Pipeline Company; see, Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, et al., "Order Transferring Conditional Certificate of Public Convenience and Necessity from Alcan Pipeline Company to Alaskan Northwest Natural Gas Transportation Company, Reviewing Relevant Portions of Underlying Partnership Agreement and Granting Intervention," (June 30, 1978). The sponsor for the Eastern Leg Segment is the Northern Border Pipeline Company.

lower-48 states. 5/ This system is expected to deliver about 2.4 billion cubic feet of natural gas per day to markets in the lower-48 States. At the time of the President's Decision the capital costs were estimated at $10.5 to $13.9 billion 6/, which would make the project the largest privately financed project i history. 7/

5/ The ANGTS will be a chilled, buried, natural gas pipeline that will run parallel to the Trans-Alaska Oil Pipeline, to Delta Junction, just south of Fairbanks. From there, it will run parallel to the existing Alcan Highway through southern Alaska and northwestern Canada to Caroline Junction, near Calgary, Alberta. (In addition to transporting Alaskan gas, this section may also carry Canadian gas from the Mackenzie Delta region to the Trans-Canada Pipeline at Empress, Alberta.) At Caroline Junction, the system will divide into two legs: the Eastern Leg (Northern Border pipeline in the United States), which will carry approximately two-thirds of the gas eastward to a point near Chicago, and the Western Leg, which will parallel an existing Pacific Gas Transmission Company pipeline, carrying the remaining one-third from Alberta to California. See Decision at 6-12.

The pipeline system in the U.S. will be built by three major pipeline companies. The Alaska segment, from Prudhoe Bay to the Yukon Border, will be constructed by the Alaskan Northwest Natural Gas Transportation Company. The Western Leg will be built by the Pacific Gas Transmission Company. The Northern Border segment will be built by the Northern Border Pipeline Company.

6/ Decision at 157.

7/ The sponsors state they are unable to provide current cost estimates, which have increased since 1977,

(Footnote continue on next page).

In the course of deciding the issues presented in this Order, the Commission has reviewed an extensive record compiled over the past several years in numerous proceedings. This includes the record developed prior to the President's *Decision* during the lengthy Alaska natural gas hearing in which the Commission first considered project alternatives, 8/ and the *Recommendation* submitted by the Federal Power

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7/ (Footnote cont'd.)

reflecting inflation and changes in original cost estimates as well as changes in project design. Letter of Mr. Rush Moody, Jr., Counsel representing Alaskan Northwest and Northern Border, to Mr. John B. Adger, Jr., Director, Alaskan Gas Project Office, Federal Energy Regulatory Commission (May 3, 1977).

8/ *See*, El Paso Alaska Company, Docket Nos. CP75-96, *et al.*, *Initial Decision on Proposed Alaska Natural Gas Transportation Systems* (Feb. 1, 1977).

On October 1, 1977, pursuant to the provisions of the Department of Energy Organization Act (DOE Act), Pub. L. No. 95-91, 91 Stat. 565 (August 4, 1977), and Executive Order No. 12009, 42 Fed. Reg. 46267 (Sept.15, 1977), the Federal Power Commission ceased to exist and its functions and regulatory responsibilities were transferred to the Secretary of Energy and this Commission, which, as an independent commission within the Department of Energy, was activated on October 1, 1977. The Commission was assigned all relevant authority not granted to it under the DOE Act respecting action concerning the ANGTS. Department of Energy Delegation Order No. 0204-8 (effective Oct. 1, 1977) 42 Fed. Reg. 61491 (Dec. 5, 1977).

Commission to the President prior to the President's Decision. 9/ In addition, there is the record of comments submitted to the President on the Commission's Recommendation, comments on the President's Decision submitted by this Commission and others to the Congress, and the hearings held by Congress pursuant to approving the Decision. Finally, there is the extensive record compiled in this rulemaking, a record which consists of comment submitted to the Commission during the proceedings initiated on May 8, 1977, 10/ six studies or reports dealing with IROR issues, 11/ a special tariff report of the Commission's Alaska Delegate, and comments and reply comments submitted to the Commission pursuant to the April 6, 1979 Notice.

9/ FPC, Recommendation to the President, Alaska Natural Gas Transportation Systems (May 1, 1977) [hereinafter cited as Recommendation].

10/ Federal Energy Regulatory Commission, "Incentive Rate of Return from the Alaska Natural Gas Transportation System" Notice of Proposed Rulemaking, Docket No. RM78-12 (May 8, 1978), 43 Fed. Reg. 20245 (May 11, 1978), revised Sept. 15, 1978.

11/ The reports received were: Alaska Gas Project Office FERC, "Price Indices for Adjusting the Cost Performance Ratio of the Alaska Gas Pipeline: Analysis and Recommendations" (March 29, 1979)[hereinafter cited as Alaska

(Footnote continue on next page).

The Decision was the final product of a process, stipulated by Congress in ANGTA, 12/ that included written comments from Federal officers and agencies, as well as State governors, and certain separate evaluations by the council of Environmental Quality. These comments and reports covered matters such as environmental

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11/ (Footnote cont'd.)

Gas Project Office Report]; J. Hass, "Risk, Return and the IROR Plan: A Report to the Federal Energy Regulatory Commission" (March 1979) [hereinafter cited as Hass Report]; James D. McCullough, Institute for Defense Analysis, "On the Treatment of Risk, and Uncertainty in Determining Change in Scope Allowability and Center Point Establishement in the Alaska Gas Pipeline IROR Mechanism" (March 1979) [hereinafter cited as McCullough Report]; Northwest Alaskan Pipeline Company, "Allowable Cost Estimate Revisions Under the Incentive Rate of Return Procedure (March 3, 1979) [hereinafter cited as Northwest Alaskan, Allowable Cost Estimate Revisions"]; Northwest Alaskan Pipeline Company, "Determining the Project Risk Premium for the Alaska Segment of the Alaska Natural Gas Transportation System" (March 7, 1979) [hereinafter cited as Northwest Alaskan, "Determining Project Risk Premium"]; Northwest Alaskan Pipeline Company, "Recommended Inflation Adjustment Under the Incentive Rate of Return (IROR) Procedure" (March 7, 1979) [hereinafter cited as Northwest Alaska "Recommended Inflation Adjustment"]. All of these reports were served on interested parties of record. See Federal Energy Regulatory Commission, "Determination of Incentive Rate of Return, Tariff and Related Issues For The Alaska Natural Gas Transportation System," Docket No. RM78-12 at 18 n. 24 (mimeo) (April 6, 1979) [hereinafter the April 6 Notice].

12/ ANGTA, Section 6 (15 U.S.C. §719d).

and safety considerations, financing, and the relationship of any decision on the ANGTS to other aspects of national energy policy. These submissions formed an important part of the record from which the President's Decision, with all of its attendant terms and conditions, was developed.

The FPC's Recommendation found that the net national economic benefit (NNEB) was large and positive for any of the three alternatives which the Commission had considered, and it recommended that one of the two overland routes be constructed. 13/ However, several of the July 1, 1977, reports to the President explored the impact of higher-than-anticipated costs on the benefits of the proposed projects. In particular, task forces studying construction delay and cost overruns on the one hand, 14/ and national economic impact on the other, 15/ combined

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13/ Recommendation, Chapter IV. NNEB is defined as "the present value of the benefits derived less the present value of resources employed in undertaking the project." Decision at 174.

14/ Department of the Interior and Department of Transportation, "Alaska Natural Gas Transportation System: White House Task Force Lead Agency Report on Construction Delay and Cost Overruns," (July 1977).

15/ Federal Energy Administration, Department of Commerce, Department of the Interior, Department of Labor, "Working Group: National Economic Impact of Alaskan Natural Gas Transportation Systems," (June 30, 1977).

forces in preparing an evaluation of the effects of cost overrun and schedule delay on NNEB. 16/

The President's Decision responded to the possibility of overruns in two ways. First, an analysis of the potential for cost overruns and time delay for

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16/ This table is included to illustrate the genesis of the President's concern over the impact of cost overruns on the project's NNEB as evaluated at the time of the Decision:

Effect on NNEB of Expected Cost Overrrun and Worst Case Overrun (Billions of 1975 Dolars)

	Discount Rate		
Artic			
Expected Overrun	10.4	3.3	0.9
Worst Case	2.6	-2.2	-3.4
Alcan			
Expected Overrun	12.3	4 8	2.0
Worst Case	6.6	0.7	-1.1
El Paso			
Expected Overrun	10.4	3.9	1.5
Worst Case	7 6	1.8	-0.1

Source: Federal Energy Administration, Department of Commerce, Department of the Interior--U.S. Geological Survey, Department of Transportation, Department of Treasury, Energy Research and Development Administration, "Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas." Table II-13, at 138 (July 1, 1977).

the selected project, as well as discussion of comparisons with the oil pipeline experience, was incorporated in the Report which accompanied the Decision. 17/ From that evaluation came an estimate of cost overruns under expected conditions, or an "expected overrun."

Second was the explicit recognition of the risk that cost overruns could be much different than the President's expected case, and the requirement that a framework be devised to minimize that risk. The framework, provided in the President's Decision, calls for the allocation of the project's risks among its various beneficiaries, and the organization of Federal Government interactions with the project to reduce those risks. 18/

The structure of government involvement includes a series of approvals designed to ensure that appropriate planning and analysis has been completed prior to construction,

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17/ The Report, following page 84 of the Decision, accompanied the Decision to Congress and may be regarded as authoritative legislative history. Midwest Gas Transmission Co. v. FERC, 589 F.2d 603, 611 n.23 (D.C. Cir. 1978).

18/ Decision at 201-205.

and an organization of the government's enforcement responsibilities in a manner which will provide coordinated and efficient action. 19/ It is this framework in its entirety -- reduction of risks as much as possible through appropriate government involvement, and allocation of residual project risks among the project's various beneficiaries -- that will provide the greatest likelihood of obtaining the expected positive benefits of the project.

The President's Decision places a number of requirements on the Commission to implement the framework within which the project is to proceed. One of the most important is to establish a variable or incentive rate of return mechanism to relate the allowed rate of return for equity for this project to the actual capital cost as compared with projected cost. 20/

19/ Reorganization Plan No. 1 of 1979, submitted by the President to the Congress on April 2, 1979 pursuant to the provisions of 5 USCA §901 et seq.

20/ In the words of the Decision, the Commission was to fix "a variable rate of return on equity that will reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above budgeted cost. The variable return shall be set to provide substantial incentive to construct the project without incurring overruns . . ." Decision at 36.

The consideration of the incentive rate of return mechanism and the project company tariffs will further assign appropriate risks to the project sponsors, and will establish the share of the cost overrun risk to be borne by gas consumers. The principal matters which rem in for Commission consideration are consideration of the shipper company tariffs (including pass-through of charges under the tariffs approved herein), 21/ and the costs of processing and conditioning the gas for pipeline entry. The latter of these two matters is the subject of a rulemaking proceeding currently pending before the Commission in Docket No. RM79-19. 22/

21/ The shipper companies have not yet filed their tariffs with the Commission.

22/ Before the Section 7 certification process for the ANGTS facilities is complete, the Commission must also approve (1) the certification cost and schedule estimates, and (2) the financing plans for the project's segments. Procedures for submission and consideration of certification costs and schedule estimates are being completed by the Commission's Alaska Delegate. These estimates could be filed now for the Northern Border and Western Leg segments of the ANGTS. For the Alaskan segment, these estimates must await the resolution of questions as to the maximum allowable operating pressure of that segment, and the proximity of that segment to the existing oil pipeline.

(Footnote continued on next page)

The final or ultimate cost of this project is now unknown; the best that can be done is to specify a probability distribution of possible final cost outcomes. The range of possible costs for a pipeline such as Northern Border is probably very narrow, whereas the range for the Alaska segment, with its inherent uncertainties regarding system design and logistics of construction, is likely to be much broader.

Cost estimates for most large projects tend to increase as more is known about the detailed design of the system. The classic example in this respect is the

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22/ (Footnote cont'd.)

The Commission has noticed for comment (in Northwest Pipeline Co., Docket No. CP78-123, et al.) a report on system design issues (pipe diameter and operating pressure), and the Department of the Interior has expressed its intention to resolve, in the near future, at least provisionally, the proximity question. Financing plans for the "pre-built" portions of Northern Border and Western Leg (i.e., southern segments to be built in advance of the Alaska segment, to transport gas from Canada pending completion of the full system) are presently being considered in a proceeding before the Commission in Northwest Alaskan Pipeline Co., Docket No. CP78-123, et al. Other financing plans will be considered as they are filed.

Trans-Alaska Oil Pipeline System (TAPS). The General Accounting Office (GAO) reports that, from an initial estimate of just over $1 billion at the time it was first planned in 1968, the cost estimates had risen to over $4 billion by May 1974 largely due to more detailed system definition and design, additions to the system size and sophistication, delay costs, and route and design changes. By the time the base control budget was established in early 1975, the cost estimates had grown to over $6 billion. 23/ The GAO reports that this tendency is not restricted to the oil pipeline, but is a common feature in other large projects. 24/

As discussed in considerably more detail in Section II.B.2 (the Center Point), the President's Decision took this tendency into account by allowing for expected overruns from the March 1977 estimates. Further review by the Commission suggests that 1.3 times the March 1977 estimate is a reasonable allow-

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23/ Comptroller General of the U.S., Report to the Congress: Lessons Learned From Constructing the Trans-Alaska Oil Pipeline at 10 (June 15, 1978).

24/ Id. at 19-20.

ance for cost growth after this estimate is corrected for inflation and scope changes. However, as Alaskan Northwest points out, the estimte might well be expected to grow as more is known about the detailed requirements for the project's design.

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 comencement 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 i 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.

The President and the Congress found that adequate assurance of continued project viability, and appropriate completion guarantees from the project's direct beneficiaries, should allow the project to be financed in the private market. The Commission recognizes that, in order to achieve a privately financed project, debt service must be assured in all events once the system is complete. The Commission also recognizes that such assurance requires the approval of appropriate project company pro forma tariff provisions and service agreements, as well as assurance that the shippers who sign the service agreements can pass charges incurred under them through to their customers. The Commission observes that the parties are essentially unanimous in agreeing that assurance of pass-through is necessary.

However, certain mechanical and timing aspects of pass-through, as well as appropriate provisions for pass-through of charges incurred in Canada, of necessity are reserved for future proceedings when all tariffs are before the Commission.

The Commission recognizes the essential role of the project company tariffs with all of their attendant conditions in securing financing for the project. In its comments on the President's Decision, the Commission recognized that the Decision and the Agreement on Principles with Canada 25/ anticipated that these will be cost-of-service tariffs, as opposed to a stated rate, to ensure that revenues available to the project companies are adequate to meet their expenses irrespective of fluctuations in throughput volume or costs. We recognize that funds are to be advanced in reliance upon the regulatory approvals provided in this Order.

The size and potential importance of the ANGTS to U.S. energy supplies has led it to receive special

25/ The Decision incorporated an "Agreement on Principles" between the United States and Canada. Agreement on Principles Applicable to a Northern Natural Gas Pipeline, Decision, Section 7 at 47-83 (Sept. 20, 1977).

regulatory attention and priority. 26/ The Commission has created special administrative arrangements to expedite regulatory decisions and to assure that all necessary administrative resources are devoted to the analysis and resolution of matters in controversy. The Commission reaffirms its commitment to carry out its responsibilities under the President's Decision and ANGTA, as well as its general statutory responsibilities under the Natural Gas Act and the Natural Gas Policy Act as they pertain to this project, with maximum dispatch and full cognizance of the significance of this project for consumers and the nation as a whole. We believe we have provided in this Order the opportunity for the system equity capital suppliers to earn truly generous rates of return if they perform, and for U.S. energy users to obtain valuable natural gas supplies at a reasonable cost.

26/ Both the President and Congress have singled out the ANGTS for special treatment. The most obvious instance is the special legislation incorporated in ANGTA and Congressional approval of the Decision; see also the provisions of Title I of the Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3550 (1978). The Department of Energy, National Energy Plan II (May 7, 1979) designates it as the top priority among potential supplemental sources of natural gas.

II. THE IROR MECHANISM

A. Concept and Structure

1. Concept

The President's Decision requires the use of a "variable" or incentive rate of return to deter cost growth during construction. 27/ The concept expressed in the President's Decision is straightforward: in order to provide an incentive for management to reduce costs, rates of return on equity should be increased if the actual construction costs of the project are controlled so as to be at or below the target estimates. In creating the incentive, the President sought to offer the project sponsors a positive reward for superior cost and schedule control, in a format that is not available under conventional public utility ratemaking practices. 28/

The traditional tool for cost control in natural gas pipeline construction has been regulatory oversight, with its attendant threat to disallow investments imprudently incurred during construction. Under traditional regulation,

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27/ Decision at 36.

28/ The Commission recognizes that additional incentives to control the cost of gas delivered by this project are created by the sponsors' interest in ensuring marketability for the delivered gas and by the need to stay within the pool of funds committed by investors for construction.

before any costs may be disallowed for inclusion in rate base they must be shown to have been imprudently incurred. This approach, resting on hindsight, implies that only those costs attributable to patently unreasonable management action may be disallowed.

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

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

To facilitate future regulation of the project, the IROR will be implemented by an equivalent one-time adjustment to the equity portion of the project's capital costs instead of varying the allowed rate of return on equity. 29/

29/ As explained more fully below, Section II.C., the adjustment is calculated from the discounted present value of the sums of return on equity and return of equity when the appropriate value from the IROR schedule is applied to the equity component of capital cost.

The IROR, then, is designed to complement the disallowance-of-cost mechanism by offering economic rewards for holding down costs. In addition to the standard process of allowing or disallowing costs according to the prudently-incurred standard, project managers will be rewarded for eliminating avoidable costs even though those costs (had they been incurred) might later withstand an allegation that they were not "prudent."

The consumer should be the chief beneficiary of the IROR. Under conventional regulatory practice, consumers may be forced to bear all cost overruns. Consumers traditionally bear not only the return and taxes associated with the additional capital necessary to finance the overruns, but also the depreciation expense associated with the return of that investment. Using IROR, however, the burden of cost overruns will be distributed between consumers and equity investors. While consumers will continue to bear the depreciation expense associated with such prudently incurred investment, they will bear only a portion of the return on the investment to finance such cost overruns. Thus, the IROR should lead to savings in construction costs, which will be divided between lower overall costs to consumers and higher returns to investors. The ultimate effect of applying the IROR will be to provide lower cost natural gas to consumers, with just and reasonable returns to investors.

2. Structure

The IROR mechanism should provide significant incentives to control costs without placing risks on investors that inordinately increase the cost of capital since that cost is ultimately paid by consumers. The IROR mechanism cannot be examined in a vaccuum. Because the mechanism affects risk and the allowed rates of return on equity, it must be related to other factors that affect the rates, such as applicable tariff provisions. While the IROR mechanism must be evaluated in its entirety and not just on a component-by-component basis, the major elements should be examined before evaluating the expected end-result on rates.

The basic elements of the IROR mechanism are the Cost Performance Ratio and the associated IROR schedule of rates of return. The Cost Performance Ratio is the ratio of Actual Capital Costs (derived from the final construction costs) to the Projected Capital Costs (derived from estimated costs at the start of construction). 30/ The Cost Performance Ratio

30/ As explained in more detail below, in Sections III and IV, the ratio is adjusted for both inflation (an adjustment to Actual Costs) and for design and other scope changes (an adjustment to Projected Costs).

measures how well project management has succeeded in controlling the costs of the project. A ratio greater than 1.0 indicates that actual costs are greater than projected or budgeted costs; a ratio less than 1.0 indicates that actual costs are less than projected or budgeted costs.

The IROR schedule specifies an allowed rate of return for each Cost Performance Ratio. With an IROR mechanism, the lower the value of the Cost Performance Ratio, the higher will be the allowed rate of return, and vice-versa. Figure 1 illustrates this concept by showing a hypothetical IROR schedule. The curve in the figure slopes upward to the left, indicating that rates of return increase as actual costs are reduced to, or fall below, targeted costs (that is, the smaller the Cost Performance Ratio, the greater the rate of return.

<u>Figure 1</u>

Hypothetical Incentive
Rate of Return Mechanism

Rate of
Return on
Equity

IROR Schedule

1.0

Cost Performance Ratio

$$= \frac{\text{Actual Capital Costs}}{\text{Projected Capital Costs}}$$

The Projected Capital Costs of the project are based on the Certification Cost Estimates submitted to the Commission for approval prior to the issuance of final certificates of public convenience and necessity. These will be submitted in base-year prices and will not incorporate an allowance for future inflation. In addition to the direct construction costs, an interest or finance charge will be included to create an incentive to minimize delays in construction. Under the Decision, the Certification Cost Estimate must be compared to the earlier cost estimate submitted by the project sponsors in 1977, to see if the new estimate "materially and unreasonably exceeds" the earlier estimate. (Decision at 36-37.)

The Actual Capital Costs of the project are the direct costs of construction determined after two adjustments. First, since Projected Costs are calculated in base-year prices with no allowance for inflation, the Actual Capital Costs must be adjusted downwards (or deflated) to remove the effects of general inflation in the U.S. economy, in order to produce a measure of cost overrun for the project absent the effects of inflation. It is not equitable to penalize investors for their inability to estimate future inflation rates; thus, an inflation adjustment mechanism is specified to remove the effects of economy-wide inflation from Actual Capital Costs. Second, finance or interest charges are added to the direct costs.

Finally, it is unreasonable to penalize the equity investors for certain major events beyond their control that significantly increase construction costs if such events could not reasonably have been anticipated by the project sponsors in preparing their cost estimates. Examples of such events include war, natural disasters, design changes compelled by changes in government laws or regulations, and delays caused by government. Such events are defined as Changes in Scope, and the Projected Capital Costs will be adjusted to reflect these changes. This Order specifies the allowed Change in Scope events, and the procedures for altering the Projected Capital Costs to reflect these changes.

A full specification of the IROR structure must begin with the concept that the IROR schedule is to provide an opportunity for project sponsors to earn a rate of return adequate to attract capital so as to compensate investors for the financial and business risks of the project. 31/ This return would be earned at the expected Cost Performance

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31/ This requirement is fully discussed below; see Section II.B.3 (the Operation Phase Rate).

Ratio. This rate of return is termed the Center Rate of Return (and the associated Cost Performance Ratio is the Center Point). If the realized Cost Performance Ratio is greater than the Center Rate, the IROR will be less than the Center Rate and vice-versa.

By this Order the Commission establishes a value for the Center Rate of Return which should compensate equity investors for the financial and business risks of investing in this project. This will be the sum of an "Operation Phase Rate" and two "risk premiums," a "Project Risk Premium" and an "IROR Risk Premium". The Operation Phase Rate is a rate of return to compensate investors for the risks incurred during the operation of the pipeline after construction is complete.

The Decision contemplates that tariff provisions during operation of the pipeline will be such that the risks during operation will be shared by gas consumers and equity investors. The service interruption provisions of the project tariffs will guarantee debt service once operations commence, but equity will remain at risk. The return on equity will be proportionate to the level of service performed, and for extended total service interruptions the return of equity will also be at risk. The Commission in this Order evaluates the remaining risks borne by investors, and compares them with the risks of investing in conventional lower-48 natural gas pipelines in order to determine a reasonable value for the Operation Phase Rate. This rate of return will be the rate actually used to calculate the transportation charges of the project under the initial tariff approved by the Commission. This rate will also be used to calculate the allowance for equity funds used during construction in determining the rate base of the project. 32/

The Project Risk Premium is to compensate investors for the unusual risks of non-completion, and other risks borne by investors during the construction of the pipeline. It will be added to the Operation Phase Rate. The *Decision* requires that construction risks are to be borne by investors or other project beneficiaries and not by consumers during construction, (*Decision* at 120-21) and that charges to customers may not commence prior to the "completion and commissioning of operation of the system" (*Decision* at 37-38). 33/ In this Order

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32/ While it will be the rate applied to the pro forma tariffs, the Operation Phase Rate may change over time once the pipeline is in operation, to remain comparable with rates of return earned on other investments having similar risks. *See* Section VI.B.8. (Review of Equity Rate of Returns).

33/ *See* Section VI.A.1 (Billing Commencement Date) for an analysis of this phrase.

the Commission evaluates these risks, and establishes values for the Project Risk Premium to compensate equity investors for bearing them.

Because the final costs of construction are unknown, the use of the IROR mechanism introduces uncertainty as to the ultimate rate of return that will be earned by the sponsors. For this reason, a second premium is added to the Operation Phase Rate, an IROR Risk Premium. This will compensate investors for risks created by the use of an IROR mechanism.

The Center Rate of Return is the sum of the Operation Phase Rate, the Project Risk Premium, and the IROR Risk Premium. This will be the rate of return allowed when actual costs (adjusted for inflation) equal expected costs (adjusted for scope changes). For higher values of the Cost Performance Ratio, the Incentive Rate will be reduced; cost growth will result in lower rates of return on equity. The extent of this reduction (or increase, if the Cost Performance Ratio is less than the Center Point) is determined by the Marginal Rate of Return.

The Marginal Rate of Return is an analytical concept used to derive the IROR schedule. It is the rate of return implicitly allowed on incremental investment either above or below base estimates. A low Marginal Rate would mean that the Incentive Rate will decline rapidly as cost increases occur; a high Marginal Rate would mean that the Incentive Rate will decline only slightly as cost increases occur.

The Commission does not intend to use two rates of return, one on projected costs and one on overruns or under-runs. Rather, a single Incentive Rate will be earned on all investment in the project; but this rate will be a weighted average of the Center Rate and the Marginal Rate. By simple mathematics, the averaging process gives more weight to the Marginal Rate as the Cost Performance Ratio increases. Thus, the Marginal Rate plays the major role in determining the incentive to reduce costs. To provide this incentive, the Marginal Rate must be low enough to make an investment in cost increases unattractive.

Though the President's Decision contemplated that the allowed rate of return would be variable, the Commission has previously recognized that an unusually high or low rate of return allowed over the 25-year (or longer) operating life of the pipeline could create complications for both future Commission regulation of the pipeline and future financing of expansions or additions. 34/ Consequently, the Commission

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34/ See Order No. 17 (Docket No. RM78-12) (Dec. 1, 1978); see also Notice of Proposed Rulemaking, Docket No. RM78-12 (May 8, 1978); Revised Notice of Proposed Rulemaking, Docket No. RM78-12 (Sept. 15, 1978).

introduced the concept of a one-time adjustment to rate base that would have the same effect as varying the allowed rate of return over the operating life of the pipeline. The one-time adjustment is based on the principle that the same level of profitability can be achieved by allowing the Incentive Rate to be earned on a normal, unadjusted rate base, or by allowing the Operation Phase Rate to be earned on an appropriately adjusted rate base. By adjusting the rate base the same effect can be achieved as varying the allowed rate of return.

The one-time adjustment to the equity investment in the rate base of the project will be made shortly after the operation of the pipeline commences. Thereafter the Operation Phase Rate will be earned on the adjusted rate base. The size of the adjustment to the equity investment in the rate base will be derived from standard discounted cash-flow analyses. The one-time adjustment is such that the present worth of the return on equity and return of equity over the operating life of the pipeline (based on the Operation Phase Rate) is equivalent to the present worth of the returns from applying the Incentive Rate to the normal, unadjusted rate base.

B. Components

1. The Cost Performance Ratio

The basic concept of the Cost Performance Ratio was described above. This section provides a more specific description of its determination and use.

The Cost Performance Ratio is used to measure the degree of cost growth or reduction from the projected costs of the project. It is also used to measure the success of project management in reducing or controlling costs of construction. The measurement of cost growth or the success of management in reducing costs must take into account the following four factors:

(1) Cost growth due to general inflation within the economy can not be reduced or controlled by management and should not be included in the measurement of management's performance in reducing costs.

(2) Cost growth due to an extension of the construction schedule is as important as an increase in direct construction costs and should be included in the measurement of management's cost control performance. A longer construction schedule adds finance or interest charges to total costs, and these will be paid by the gas consumer.

(3) Certain major events may occur which could not have been anticipated by management, the cost impact of which are largely beyond the control of management, and which substantially increase costs. The impact of these events should not be included in the measurement of management's performance in controlling costs.

(4) The measurement of cost growth should be as simple and as uncomplicated as possible to avoid controversy about its use, and thereby avoid major administrative burdens on the Commission, the Federal Inspector, and the project management in implementing the IROR mechanism.

The measurement of cost growth established by the Commission in this Order (the Cost Performance Ratio) meets these four criteria. The Cost Performance Ratio is simply the ratio of actual costs to projected costs: Cost Performance Ratio equals the Deflated Actual Capital Costs divided by the Projected Capital Costs.

The Deflated Actual Capital Costs for the project will be calculated in three steps. First, the direct construction costs (labor, materials, services, etc.) actually incurred in the construction of the project will be totaled for each quarter. 35/

Second, these quarterly expenditures will be deflated back to base-year prices by the use of a composite inflation index. This index is discussed in greater detail below in Section III. This index is designed to remove the effect of general inflation on those construction costs.

Finally, an interest charge or finance charge will be added to the total direct costs of the project. This charge, hereafter referred to as the Finance Charge, will be based on a Real Rate of Return. 36/ Since the effect of inflation has been removed from the calculation of direct costs, the rate of interest or return on equity used to calculate the Finance Charge will be a "real" rate with the effect

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35/ In their initial comments, the project sponsors request the Commission to clarify when a particular expenditure will be deemed to have occurred since this is important for the inflation adjustment mechanism (Joint Comments at Tab. 2, p. 11). The Commission agrees with the sponsors that an expenditure for materials or services should be deemed to have occurred when the actual payment for those materials or services is made.

36/ This Finance Charge was referred to as an allowance for funds used during construction (AFUDC) in the Notice of April 6.

of inflation also removed. Actual market rates of interest in our economy today reflect or compensate investors for their expectations about future rates of inflation since inflation reduces the worth of their return from the investment.

The Projected Capital Costs (the denominator of the Cost Performance Ratio) will be calculated in four steps. First, the direct costs included in the Certification Cost Estimate, to be submitted to the Commission prior to the receipt of a final certificate of public convenience and necessity, will be divided into quarters depending on when they are expected to be incurred. Since these costs are already calculated from base-year prices, no adjustment for inflation is required.

Between the time the Certification Cost Estimate is prepared and the time when the final design and cost estimate is submitted to the Federal Inspector, 37/ certain changes in design or schedule may occur. The second step will be to adjust the Certification Cost Estimate to reflect these changes in design or schedule. 38/

37/ This final submission is mandated by the President's Decision. Decision at 29.

38/ Prices, however, will not be changed from those that prevailed in the base year for cost estimation.

After construction begins, certain events may occur which the Commission defines to be Changes in Scope for the project. (For a more complete description of these events, see Section IV.) Direct costs in the Certification Estimate will, in the third step, be adjusted to reflect the impact of these Changes in Scope should they occur.

Finally, a Finance Charge will be added to the adjusted direct costs using the Real Rate of Return to obtain the Projected Capital Costs.

The Commission believes that the ratio of these two measures of capital costs (Deflated Actual Capital Costs and Projected Capital Costs) provides the best practical measure of cost growth or overruns to be used to determine the extent of the project management's success in controlling costs. This Cost Performance Ratio meets the four criteria discussed above.

The Commission believes that it is important to include some type of interest charge or finance charge in the calculation of the Cost Performance Ratio since these charges are just as much a cost to consumers as is the cost of steel, labor, valves, etc. However, the Finance Charge should be calculated from a "real" or inflation-free rate of return. Calculation of such a real rate return is inherently imprecise. The "real" rate is derived by subtracting an estimate of the rate of future inflation expected by current investors from current market rates of interest and rates of return.

The Commission estimates the Real Rate to be 5 percent. This estimate is based on the following assumptions: (1) 25 percent equity capitalization earning a 14 percent return (a rate of return generally representative of current rates required by equity investors); (2) 75 percent debt capitalization earning an 11 percent interest rate (a rate generally representative of current rates of interest, for example the prime rate); and (3) an investor expectation of a long term inflation rate of 7 percent (a rate representative of recent rates of inflation in the U.S. economy). The Real Rate can then be derived from:

$$\begin{aligned}&(0.25)(14\% - 7\%) + (0.75)(11\% - 7\%)\\&= (0.25)(7\%) + (0.75)(4\%)\\&= 1.75\% + 3\%\\&= 5\% \text{ (rounded)}\end{aligned}$$

The project sponsors, with almost no justification, propose instead a rate of 1 percent. Though we are not confident that 5 percent is precisely the correct number, we are certain that 1 percent is too low.

A second criticism by the sponsors, put forward as a footnote, concerns the "cut off" date for accrual of the Finance Charge. 39/ The intent of this footnote is unclear, but it shows a misunderstanding of the relationship between the accrual of the Finance Charge in calculating the Cost Performance Ratio, the accrual of AFUDC in the rate base of each pipeline segment, and the billing commencement date. The distinction between these concepts is important, and any confusion must be dispelled. Accrual of a Finance Charge in the Actual Capital Costs, and thus in the numerator of the Cost Performance Ratio, will cease for each segment of the project (Alaska or Northern Border) when construction of that segment has been completed even if, for whatever reason, another segment is not complete. The intent of this provision is to avoid penalizing investors in one segment for delay in another segment or in the start-up of gas production. 40/

39/ Joint Comments at 21 n. 12.

40/ The Commission Staff in their comments propose a variation on this approach which would add the "real" Finance Charge no longer being accrued in the Cost Performance Ratio of a completed segment, to the Cost Performance Ratio of those segments not completed, including if possible segments in Canada. (Initial Staff Comments at 48) This idea has some theoretical appeal since it would require the late segments to to bear an even greater Finance Charge in the Cost Performance Ratio, and thus give the investors

(Footnote continued on next page).

This procedure for including a Finance Charge derived from the Real Rate of Return in the Cost Performance Ratio of each segment must not be confused with Commission procedures for the inclusion of AFUDC in the actual rate base of each segment. Inclusion of AFUDC in the actual rate base will be calculated from rates of interest actually incurred during construction on project debt and the rate of return on equity allowed for purposes of calculating AFUDC. Accrual of AFUDC in the rate base of each segment will continue until billing under the full cost-of-service provisions of the tariff commences. For a more complete discussion of the billing commencement date, see Section VI.A.1.

40/ (Footnote cont'd.)

even greater incentive to complete construction. However, insofar as we would be obliged to further compensate investors for the additional risk this requirement would add, we do not believe its additional incentive benefits outweigh the additional costs that further compensation may impose on customers.

2. The Center Point

The Center Point Cost Performance Ratio should represent the best current estimate of the actual costs of the project, including any cost overruns relative to the Certification Cost Estimate approved by the Commission. 41/ This ratio has two significant functions.

First, if the Certification Cost Estimate, including likely cost overruns, "materially and unreasonably exceeds" the March, 1977 cost estimate filed by the project sponsor with the Federal Power Commission, then the Commission must carry out the mandate in the President's Decision to review the project and determine whether a certificate of public convenience and necessity should be granted. 41a/ In this review, both the Certification Cost Estimate and the Center Point Cost Performance Ratio are highly significant. The Certification Cost Estimate is important because it indicates, when compared with the March, 1977 estimate and after making proper allowances for price inflation, the growth in the projected costs as a result of the study and work on this project between March, 1977 and the preparation

41/ In statistical terms the Center Point is obtained by adding together each possible level of the Cost Performance Ratio multiplied by the probability of that Cost Performance Ratio occurring.

41a/ Decision at 36.

of the Certification Estimate.

The Center Point Cost Performance Ratio is important to this review because it also may have changed as a result of the study and work on the project. The Certification Cost Estimate will likely have grown from March, 1977 as a result of detailed planning and design, but the expected cost overrun associated with that estimate may have been altered, and hopefully reduced, by that planning and design. Thus, the Commission believes that the Center Point Cost Performance Ratio must be a part of the comparison of the Certification Cost Estimate with the March 1977 estimate since that review should consider whether or not the expectation of cost overrun has changed from that associated with the March 1977 cost estimates.

Second, the Center Point Ratio is important because it is the target outcome of the project. For example, a Center Point of 1.2 would indicate that a further 20 percent increase in costs is expected from the Certification Estimate, and that this would be the target for IROR purposes. The President's Decision envisioned that the Certification Cost Estimate would be used as the "basis for fixing a variable rate of return on equity that would reward the applicant for project completion under budgeted cost and penalize the applicant for project completion above the budget cost." 42/ The Commission, therefore, after having determined that the Certification Cost Estimate does not unreasonably exceed the 1977 estimate, must select from all the possible outcomes a target Cost Performance Ratio to use as the Center Point in structuring the IROR schedule.

Common observation as well as historical and statistical studies 43/ of many different types of large projects have revealed a tendency for the estimates of total cost-to-completion to increase as a project moves over time from initial conception to completion. In the early stages of a project this growth often reflects the study required to turn an idea into a detailed set of plans and specifications. In the process of research, evaluation, planning, and budgeting, natural initial optimism is tempered by more realistic appraisals; and in the usual case, unperceived complexities are discovered and the difficulty of the required tasks becomes better understood.

42/ Decision at 37.

43/ See, e.g., W. Mead, G. W. Rogers, & R. Z. Smith, Transporting Natural Gas from the Arctic: The Alternative Systems, 89-94 (1977).

It would have been unrealistic had the President's Decision used the project sponsors' cost estimate in March 1977 as the basis for evaluating the economics of the project. Instead, the Decision factored in cost growth estimates of approximately 30 percent for the Alaska segment and 10 percent for the Northern Border segment, in the evaluations leading to approval of the project. 44/ The estimates that cost growth in excess

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44/ The President's Decision contains two estimates of the extent of likely cost overruns in Alaska. The Report accompanying the Decision states that "[o]verall, it has been estimated that cost overruns of 30 percent or more should be expected in Alaska and Canada. . ." Decision at 150. The table of capital cost estimates on p. 157 of the Report, however, shows a 24 percent cost increase from the Base Case estimate in current or inflated dollars for Alaska. For Northern Border, the expected overrun is 10 percent. All of these estimates include finance charges or an allowance for funds used during construction derived from market rates of interest and rates of return on equity. The State of New York in its initial comments (p. 5) points out that the estimates of cost overruns in the Decision do not include an adjustment for inflation and route changes or other changes in scope. These points, however, do not mean that to the extent the Commission excuses cost increases resulting from design changes or change in scope events, the expected overruns should be less than estimated in the Decision. Inflation is fully accounted for in the Decision by the use of constant 1975 prices; moreover we cannot presume that the Decision considered change in scope variables in estimating costs for a given system.

of 30 percent for Alaska and 10 percent for Northern Border were not likely to occur were one basis for the finding that the project was in the public interest.

Several implications follow. Looking at the project at the time of submission of the Certification Estimate with the benefit of two or more years of intensive study, evaluation, planning, programming, and budgeting by the sponsors, it would be surprising if the new estimate did not reveal some cost-growth compared to the March, 1977 estimate, even allowing for price inflation. This would be a natural phenomenon reflecting, at a minimum, a better understanding and perspective on the project. 45/

Another implication is that after two or more years of work on this project, the Certification Cost Estimate should be a more accurate estimate of what the actual cost of the project will be upon its completion than the cost estimate made in 1977. It would be surprising to realize as large an

45/ The comments by the project sponsors list a number of reasons why they now expect the Certification Estimate to exceed the March 1977 estimate: (1) cost of restoring Alyeska work camps; (2) cost of restructuring Alyeska communications system; (3) higher estimate of costs to obtain Governmental approvals; and (4) greater project management expenses. Joint Comments at 11-15.

amount of cost growth from the Certification Estimate as the expected amount of cost growth from the 1977 estimates. 46/

Because the Certification Cost Estimate will be the basis of the Commission's certification proceeding and the cornerstone of the allowed rate of return for this project, it is vital that the Commission have the most accurate and realistic set of cost estimates that can be obtained. There is need to deter both overly optimistic projections which might be offered in the hope that they would promote final certification of the project, and overly pessimistic projections which provide a large margin for error in cost estimates or an implicit allowance for large cost increases. The latter type of estimate would vitiate the intended motivational aspects of the IROR and could result in unreasonably high rates of return.

Considering that a 30 percent allowance for cost growth on the Alaska segment and 10 percent on Northern Border were allowed for in the President's Decision, it is unlikely that, on the sole basis that estimated costs had increased by 30

46/ The project sponsors, however, seem to expect as much cost growth from Certification Estimate as did the President from the March 1977 estimate. Joint Comments at 31. They argue that a 30 percent increase is likely from the Alaskan Certification Estimate and 20 % for Northern Border.

percent for the Alaska segment and 10 percent for Northern Border, the Commission could make a negative finding concerning the public interest of the project. On the other hand, if there were to be a substantial increase in the Certification Estimate over the March 1977 estimate without a substantial decrease in the expected cost overrun from the Certification Estimate, it would seem to follow that either the initial cost estimates used in the 1977 evaluation were badly mistaken or the nature of the project had changed considerably. In either situation the Commission would need to take these developments into consideration in connection with its certification responsibilities. 47/

The Commission has embodied these considerations in a procedure for determining the Center Point. It is contained in Condition No. 12 of the attached Terms and Conditions. The Incentive Rate of Return is based solely on the Certification Cost Estimate. However, in determining the value of the Center Point Cost Performance Ratio, the Commission will take into consideration the relationship between the Certification Cost Estimate and the March 1977

47/ In this connection, the Commission notes with concern the sponsors' comments regarding cost growth cited in footnotes 45 and 46, *supra*.

estimate, i.e., the cost growth between these two estimates during the intervening period. If a substantial amount of cost growth had already occurred, it would seem in accord with the basic thrust of the Presidential Decision to assume that most of the projected 30 percent cost growth had already occurred and that it would be unreasonable to expect a sizable amount of cost growth in the future. Conversely, should the two estimates show very little cost growth in the intervening period, it would seem reasonable to expect that most of the 30 percent cost growth envisioned in the Presidential Decision would occur in the future. 48/

The formula in Condition No. 12 expresses this concept mathematically. For example, if the Certification Cost Estimate were to exceed the March 1977 estimate for the Alaska segment by 20 percent, then in accord with the President's Decision, the Center Point would be set so as

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48/ In response to earlier concern by the project sponsors, the Commission, in Order No. 17, made it clear that the Certification Estimate will be the basis for the IROR mechanism. Order No. 17, "Order Attaching Incentive Rate of Return Conditions to Certificates of Public Convenience and Necessity," Docket No. RM78-12 (Dec. 1, 1978). The Projected Capital Costs will be derived from the Certification Estimate. However, the Commission believes that it must consider the Decision's findings concerning likely overruns in choosing a Center Point.

to anticipate a further 10 percent cost growth between the time of the Certification Cost Estimate and completion of the project. 49/ To cite another hypothetical example, were the Certification Cost Estimate to exactly equal the March 1977 estimate then the formula would imply that the Center Point should be 1.3, which would provide for the 30 percent cost growth the Presidential Decision estimated would take place.

Of course, it may be that the project had so changed in nature and scope that the two cost estimates could be linked in the process of setting the Center Point. If this were so, the project sponsors should so inform the Commission and provide a detailed explanation of the nature of the changes which had caused the discontinuity in the project so that the Commission could have this information in conjunction with the certification function as well as for establishing a Center Point.

49/ In all cases allowance should be made for inflation so that the comparisons involve calculation of real growth, *i.e.*, growth in resource requirements and not prices.

In the absence of an assertion of a major change in the basic nature of the project from that assumed in the Decision, the Commission will relate its determination of the Center Point to the cost growth that has taken place during the last two years. The mathematical relationship for the Alaska segment will be: Center Point = 1.3 x (March 1977 estimate in base year prices + Finance Charge)/ (Certification Cost Estimate + Finance Charge). For the Northern Border segment the relationship will be: Center Point = 1.1 x (March, 1977 estimate in base year prices + Finance Charge) / (Certification Cost Estimate + Finance Charge). Base-year prices are those used in preparing the Certification Estimate, and the Finance Charge is calculated from the Real Rate of Return defined below. 50/

In their comments on the Commission's April 6 notice, where the above procedure for determining the Center Point was proposed, the project sponsors criticize this proposal as basing the IROR mechanism on the March 1977 estimates submitted to this Commission and the President. As we stated in Order No. 17, the Commission does not intend to

50/ The Commission Staff in its initial comments (pages 58 and 60) supports this procedure and puts forth a number of the arguments given here advocating this procedure.

base the IROR mechanism on the March 1977 estimates. The attached terms and conditions clearly state that the Projected Capital Costs and the Cost Performance Ratio will be based on the Certification Estimates to be submitted to the Commission sometime in the future.

The Commission must have some basis, however, for determining the Center Point of the IROR schedule. The only information available to us now about the likely cost growth or the ultimate costs of the project including overruns are the conclusions reached in the President's Decision based on the March 1977 estimates. Those conclusions were based upon reasoned comparisons between the cost estimates of the competing projects, actual experience in the Alyeska System, the Recommendation submitted to the President by this Commission, and a number of intragency task force studies and numerous other information sources. Using this information, the Commission has established the above procedure to determine the Center Point.

The Commission, however, anticipates that additional information will be made available to us by the project sponsors about the expected ultimate cost of the project at the time they submit the certification cost estimates. If this information is substantially different from that relied upon by the President in reaching his conclusions about cost growth, then the Commission would have to reconsider the issue of where the Center Point should be set. 51/ In such a situation the Commission would envision setting the Center Point as part of its overall review of Project costs using a procedure such as that set out below.

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 for setting the Center Point is no longer applicable, then the sponsors, as part of their respective submissions of certification cost estimates, 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, including a

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51/ The project sponsors in their comments seem to advocate that the Commission now set a Center Point of 1.3 for Alaska and 1.2 for Northern Border based on the certification cost estimates which have not yet been submitted to us. The Commission has no factual basis or evidence to support such a determination. Since the Decision is the best estimate of the cost of the project available to us, the procedure or formula described above is the only method we can justify for setting the Center Point until such as time the project sponsors may provide us with additional evidence.

detailed explanation of why the Certification Cost Estimate has changed from the March, 1977 estimate. The Commission will later specify certain cost formats which the sponsors shall follow in submitting their Certification Estimates in order to allow the Commission to better assess the reason for the change in costs. (See Condition 8 of the attached terms and conditions). This information will assist the Commission in determining if the Certification Estimates materially and unreasonably exceed the March 1977 estimates as required by 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. In other words, the sponsors must demonstrate that the project is still in the public interest given the changes in the project since the Decision.

(3) The cost increases or cost overruns above the Certification Estimates that may reasonably be expected to occur. The sponsors should explain what eventualities or contingencies are provided for in the Certification Estimates and the contingencies for which no costs have been included. As part of the

Certification Estimate, the sponsors should provide an analysis of the events that could cause cost increases from the Certification Estimate, the likelihood of these events, and their impact on costs. 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. 52/ The sponsors' analysis of the potential for cost increases from the Certification Estimate will then be used by the Commission in determining the Center Point. If a convincing case is made that the potential for cost increases beyond the Certification Estimate is substantial, then a reasonable value for the Center Point may be substantially greater than one. In any event, the Commission considers it unlikely that the Center Point would be less than one if the Certification Estimate is based on normal or probable conditions.

52/ Since the Certification Estimate will be revised as a result of design changes and other events prior to the Final Design, and for a limited number of Change in Scope events after the final design (see Section IV), the analysis of cost overruns should distinguish between events that are covered by the Change in Scope mechanism and those that are not.

3. The Operation Phase Rate

The Operation Phase Rate of return on equity is that rate which will compensate equity investors for the risks incurred during the actual operation of the pipeline. This rate will be used to calculate transportation charges pursuant to the tariff approved by the Commission after the one-time adjustment to the rate base. 53/

By way of background, the Commission notes that the natural gas transmission industry has had limited experience with project financing; the most expensive projects undertaken have been in the $500 million to $1.5 billion range. However, the ANGTS project is unique in that no other project of this magnitude and character has been undertaken.

53/ This rate will also be used to determine the equity component of the Allowance For Funds Used During Construction in the rate base of the project. Originally in Order No. 17, the Commission required that the AFUDC rate would be the Operation Phase Rate plus the Project Risk Premium. However, the methodology for determining the Project Risk Premium proposed by the project sponsor required knowing the AFUDC rate before calculating the Project Risk Premium. In order to solve this dilemma, the Commission now requires the use of the Operation Phase Rate to calculate AFUDC. However, as a compensating adjustment, the Project Risk Premium, and thus the Center Rate, have been increased from what they would have been assuming the higher AFUDC rate. See Section II.B.4., discussing the Project Risk Premium.

The Commission has adopted a general approach for determining the Operation Phase Rate. First, an estimate was made of the range of rates of return that appears reasonable, considering current financial market conditions and the risks of investing in conventional lower-48 natural gas pipelines. Second, the Commission has compared the operating risks of the Alaskan gas pipeline with the risks normally encountered during operation of conventional pipelines. Based on this comparison of risks, the Commission has determined that the Operation Phase Rate should be within the range of rates that is reasonable for conventional pipelines. 54/

A survey of rate cases (mostly settlements) during the years 1977, 1978, and early 1979, discloses that the rates of return allowed for lower-48 natural gas pipelines have been between 10.68 percent and 15.0 percent. The majority of returns fell within the narrower range of 12 to 14 percent. This survey is the point of departure for our analysis.

54/ Order No. 17 provides that the Operation Phase Rate shall be set by the Commission "within the general range of rates of return for other pipelines with similar operating risks" (Terms and Conditions, No. 12).

Apart from simply reviewing values allowed in the past, there are a number of alternative approaches used by financial analysts for estimating rates of return for utility rate-setting purposes. Without attempting to select a preferred approach from the array of methodological options, the Commission has examined three procedures to see what each implies as an appropriate reference value for lower-48 pipelines. No procedure can precisely determine a just and reasonable rate of return. Therefore, the Commission must exercise its judgment after reviewing the relevant information in order to determine an appropriate value for the Operation Phase Rate.

The general standards for establishing a just and reasonable return on common equity were set forth by the Supreme Court:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. 55/

55/ FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

At the outset, it is readily acknowledged that assembling samples of enterprises "with corresponding risks" is a formidable task. It is difficult to specify risk measures that are both conceptually valid and also work. For this reason, virtually all methods used for recommending allowed rates of return share the weakness of relying on data for entities that may not be precisely comparable in risk.

The often-used "comparable earnings approach" examines rates of return on common equity earned in other businesses or industries with risks comparable to those of the natural gas pipeline industry. In their comments, Alaskan Northwest and Northern Border provided information as to returns earned by industry groups for the years 1973-1978. Looking at the average rate of return for all industries combined over the six-year period, the range has been approximately 11.7 to 15.4 percent. 56/

56/ Joint Comments, Tab 1. Data for natural gas utilities show returns in the range of 11.9-16.2 percent.

Another popular technique is the familiar "discounted cash flow" approach. This method attempts to determine the investors' required rate of return by estimating their expected return (dividends and capital appreciation) on the market price of common stock. The application of the discounted cash flow approach to the ANGTS indicates that the investors' required rate of return for natural gas pipeline companies is somewhere in the range of 14 to 16 percent. 57/

57/ Based on recent years' data for Moody's Natural Gas Transmission Company Average, it appears reasonable that investors might expect return on book equity to be 15-16 percent and dividend payout ratios to be 40-50 percent. (*See* Moody's Public Utility Manual at a16 (1978). Using growth from retained earnings as a proxy for growth in dividends, such data implies an expected growth in dividends of 7.5 to 9.6 percent. (Growth from retained earnings equals return on book equity times the retention rate, or 15 to 16 percent multiplied by 1 minus 40 to 50 percent). Combined with the average dividend yield of 6.7 percent for the first quarter of 1979, a range of 14.2 to 16.3 percent is produced. Since the market-to-book ratio of Moody's Natural Gas Transmission Company Average in recent years has fluctuated around 1.0, there is reason to believe that this calculated range is reasonable insofar as it approximates the earned returns on book equity in recent years.

Sponsors' consultant, also using a discounted cash flow approach, arrived at a range of 15.7 to 16.7 percent. (Joint Comments, Tab A.) In our judgment, this selection of a 9 to 10 percent expected growth in dividends is biased on the high side because of an incomplete and inadequate implementation of this approach. For example, we note the absence of historical book value growth rates for Moody's Natural Gas Transmission Company

(Footnote continued on next page).

The third approach examined by the Commission involves estimating the difference in return that equity investors require over the rate of interest prevailing on bonds. Since market-determined rates of interest are widely available and accepted as meaningful, a measure of the differential between equity return and prevailing interest rates using this information is practical and provides a plausible guide to the equity investors' required return.

Based on the proposition that over long periods an equilibrium is established between investors' earned returns and their required returns, one way to determine a differential between equity and debt returns is to observe the difference between returns realized on riskless investments (such as U.S. Government bonds) and returns realized on investments in common stock, namely, dividends

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57/ (Footnote cont'd).

Average even after . e sponsors' favorable comments concerning the merit in using them to smooth fluctuations in earnings and to provide a longer term view of potential growth. (Joint Comments at Tab A.) Using the least-squares growth rate in average book value of 8.4 percent for the 1968-1977 period, we can derive an estimate of 15.1 percent for the investor's required return. Furthermore, the assumption of a dividend payout ratio as high as 60 percent in the analysis of the expected dividend growth rate was completely unsupported.

and capital appreciation. Using U.S. Treasury bond interst rates as the riskless rate measure, the equity differential has averaged between 5 and 6 percent over lengthy historical periods. 58/ Thus, adding these equity differentials to current Treasury bond interest rates of about 9 percent produces a required equity return in the range of 14 to 15 percent. 59/

58/ Ibbotson & Sinquefeld, "Stocks, Bonds, Bills and Inflation: Year by Year Historical Returns (1926-74)." Jnl. Bus. (Jan 1976); "Stocks, Bonds, Bills and Inflation: The Past (1926-1976) and the Future (1977-2000)," The Financial Analysts Research Foundation, 1977; see also, Levy "Stocks, Bonds, Bills and Inflation Over 52 Years," Jnl. Portfolio Mngt. at 18-19 (Summer 1978).

59/ Implicit in Hass' analysis of an Operation Phase Rate is a current required return of 15.7 percent for diversified natural gas transmission companies (a "riskless" rate of 9 percent plus an equity "risk premium" of 6.7 percent). See Hass Report at 16-20.

Sponsors' consultant employed the capital asset pricing model, a variant of the risk premium approach, and arrived at a rate of return of 17.33 percent for conventional lower-48 pipeline companies. (Joint Comments, Tab A.) Incorporated in this analysis was a market risk premium of 8.5 percent. The support for a required premium of this magnitude, however, was largely undocumented and unpersuasive. Substituting the 5 to 6 percent premium cited above, the result is a range of 13.9 to 14.9 percent. (Riskless Rate plus Beta times Market Risk Premium or 9.0 percent plus 0.98 times 5 to 6 percent.)

In summary, the Commission's recently allowed rates of return for lower-48 natural gas pipelines have generally fallen within the range of 12-14 percent. In addition, data for recent earned rates of return on common equity and two methods for estimating investors' required rates of return for lower-48 pipelines yield the following ranges:

Estimation Approach	Range of Rates
Comparable Earnings	12 to 15%
Discounted Cash Flow	14 to 16%
Equity Risk Premium	14 to 15%

Given this range of estimates, the Commission must exercise its judgment in determining the reference value for lower-48 pipelines. On balance, the Commission believes that under current market conditions a rate of return in the range of 12 to 15 percent is appropriate to use as a basis for setting the Operation Phase Rate for the ANGTS.

To use this range as a guide for setting the Operation Phase Rate, the Commission must assess how the risk exposure of investors in the ANGTS project during operation compares to the risk-exposure of pipeline investors in the lower-48 states. The Commission believes that the greatest risks faced by investors in the ANGTS will occur during the construction phase. 60/ The risk exposure the Commission is

60/ The Project Risk Premium is intended to compensate investors for these risks. See Section II.B.4 (Project Risk Premium).

is attempting to evaluate here concerns the relative risks of the ANGTS and lower-48 pipelines during the operational phase. To compare risks, we first examine why the Alaska project may have greater operating risks than lower-48 pipelines, then examine why risks during operation may be less than those faced by other pipelines. Finally, we weigh and balance the various factors.

Operating aspects of the Alaska project that may be regarded as more risky than operating conditions for lower-48 pipelines are the following:

Arctic operating environment. The project in Alaska will be operating in a harsh environment. The ANGTS could experience problems such as thaw settlement or frost heave affecting the reliability of operations. Innovative techniques such as gas refrigeration will have to be used because of the environment. Environmental restrictions, remote locations, and severe climate may affect the ability to repair the pipeline in the event of a service interruption.

High pressure pipeline. The project will be operating at higher pressure than is conventional. Although the Commission does not expect the higher pressure to affect operating reliability, confirmation will only come through operating experience.

High cost gas. Because of relatively high transportation costs, the gas transported through this system will be expensive compared to other sources of supply. Large cost overruns or partial service interruptions could result in even greater costs per unit of gas. Though the tariff approved by the Commission will allow for rates to recover the full cost of service once service commences (with the exception of equity charges in the event of service interruptions), difficulties in marketing the gas or in collecting the allowed revenues could conceivably occur.

Low equity capitalization. The proportion of equity in the capitalization of the pipeline is expected to be approximately 25 percent, in contrast to an industry average of about 50 percent. In the absence of other considerations, the higher degree of leverage increases the risks to equity investors should there be a diminution of revenues because the fixed costs of the project, including debt service must be paid prior to any return to equity. 61/

61/ Leverage should not be evaluated alone; it must be considered along with other factors of which the most important is the cost-of-service tariff which largely reduces the risk associated with a high proportion of equity investment.

There are also very significant risk-reducing features of this proposal. The most important are:

Cost-of-service form of tariff. By this Order, the project is granted a cost-of-service form of tariff instead of the conventional fixed-rate form. The cost-of-service tariff allows the project to charge rates adequate to recover its full cost of service, even if costs or throughput change over time, without the need for first filing a new rate schedule or obtaining this Commission's approval. In contrast to the fixed-rate tariff, changes in costs or throughput volumes are reflected immediately in the pipeline's rates, rather than after some period required for processing a rate-change application.

The commitment to allow a cost-of-service tariff is a major factor that offsets much of the risk exposure of investors in the ANGTS. The cost-of-service mechanism greatly reduces the risk of inability to earn an allowed return due to increases in cost or reduction in volumes. 62/

62/ Some risk that estimated throughput volumes may not be attained continues to exist. For example, as discussed more fully in the section on tariffs, the segment may be unable to transport the contract quantities because of a pipeline operating problem. If the diminution of service over a one month period amounts to more than 10 percent of contract throughput, the return on equity

(Footnote continued on next page).

With respect to the proposed capitalization, sponsors' consultant urges that the Commission continue to acknowledge the risk increasing effects of financial leverage by allowing a higher equity return for the "thinner" equity of the project. However, we feel that there is much merit in the Staff's argument that the cost-of-service and service interruption provisions in the tariff largely offset the financial risks associated with debt financing. Considering the risks associated with the relative proportions of debt to equity in the capital structure, we believe that the cost of service tariff provisions offset the high degree of leverage proposed by the sponsors and consequently, we feel that ANGTS will face lower financial risks than would conventional pipelines with the same equity capitalization but without the cost of service tariff.

62/ (Footnote cont'd).

will be proportionately reduced. Provision is made for possible makeup transportation at a later date. If all service is interrupted for more than 30 days (a most unlikely event), the return of equity may also be forfeited if the Commission finds that the cause of the interruption was within the project sponsors' control.

Tracking of costs by shippers. In order to further assure that revenues are adequate to cover the cost of service of the project, the Commission's policy will be to allow automatic tracking of Alaska gas transportation costs in the tariffs of gas shippers who are interstate pipelines under our jurisdication. The exact form or nature of the tracking mechanism must await specific applications from shippers to modify or amend their tariffs and may differ from shipper to shipper.

Large reserves-to-production ratio. The reserves of gas at Prudhoe Bay are very large (at least 26 trillion cubic feet) and can supply gas for the pipeline at a rate of 2.4 billion cubic feet per day for at least 20 years without exhausting the reserves. This reserve-to-production ratio is much larger than for most other natural gas pipelines and provides assurance that gas supply will be adequate to allow the full recovery of capital investment in the project. Thus, as compared to most pipelines that have reserve commitments that generate significant risk-exposure, the ANGTS is in an enviable position.

Rolled-in pricing. In order to reduce marketing risks for this relatively high cost gas, the Congress, as part of the Natural Gas Policy Act, directed that the transportation cost and wellhead price for this gas will be "rolled-in" or averaged with cheaper sources of supply and sold to higher priority users. Thus, even if this gas is more expensive than some other sources of supply, potential problems of marketability are reduced since shippers are assured that they will not have to market this gas separately from other sources of supply.

Weighing all the risk-increasing and the risk-reducing factors, the Commission concludes that the risk exposure of ANGTS investors during the operation phase of the Alaska segment of the project will be somewhat higher than the risk-exposure of investors in the typical or average lower-48 pipeline. Thus, the Commission believes that an allowed Operation Phase Rate near the upper end of the range of rates discussed previously for lower-48 pipelines (12 to 15 percent) is reasonable for the Alaska segment of the project. The Commission selects 14 percent as the Operation Phase Rate for the Alaska segment. 63/

63/ Sponsors' asserted that the implementation of the comparable earnings approach confirmed the reasonableness of a previously deduced 18% return on common equity for the ANGTS project (as opposed to typical lower-48 pipelines). (Joint Comments at Tab A.) They initially contended, without adequate support, that the ANGTS project should be viewed as a relatively risky enterprise during its operation. This unsubstantiated position presumably underlies the 18% return recommendation. They then attempt to further justify this recommendation merely by noting that the 18% value falls in the upper deciles of the earned returns on common equity for over four thousand

(Footnote continued on next page).

63/ (Footnote cont'd).

publicly held corporations. The apparent rationale here is that risk and earned returns on common equity are directly related. The sponsors nowhere establish, however, that high earned returns on common equity are necessarily associated with high risk.

Hass recommended 14.4% as the Operation Phase rate for the Alaska segment and 12.5% for the Northern Border segment, Hass Report at 20, while Staff contended that 11.5% and 10.5 percent, respectively, are more appropriate. Initial Comments of the Commission Staff on Company Tariffs and Incentive Rate of Return, Docket No. RM78-12 at 76-77 (May 4, 1979). [Hereinafter Staff Initial Comments]. Both took the position that investors, primarily because of the cost-of-service tariff, would perceive the ANGTS project as being a less risky investment than investments in lower-48 pipelines. However, while Hass' analysis enables one to see the steps leading to his conclusion, Staff's analysis is wholly subjective and no attempt is made to justify the current appropriateness of a 13% allowed return for conventional pipeline companies or how Staff's risk analysis led it to conclude that 10.5 - 11.5 percent is a reasonable range for the ANGTS project. Although the Commission recognizes the risk reducing nature of many of the issues discussed by Staff, we believe that Staff's qualitative analysis does not give sufficient consideration to how the uncertainties associated with the ANGTS project will impact on investors' required returns.

Staff attempted to confirm the reasonableness of its recommendation by duplicating, with some adjustments, the type of risk premium approach employed by Hass. We believe, however, that Staff's version of the Hass approach is flawed in several respects. For example, the 12.9% figure that Staff used as representative of allowed return for natural gas pipelines in 1975 was not shown to be equal to the investors' required return. Furthermore, for the risk premium approach to have any validity, investors' required returns for debt and equity securities must be compared during the same time period. Staff, however, relates this 12.9% figure to a current riskless rate rather than the riskless rate

(Footnote continued on next page).

The Commission also concludes that the operation phase risk exposure of investors in the Northern Border segment is lower than the risk exposure of investors in the Alaska segment. The environmental and other risk-increasing factors pertinent to the Alaska segment are not as important here. The major risk imposed on investors by the tariff is that the return on equity or the return of equity may be reduced because of service interruptions.

The Northern Border system will be located in an area which is geologically more stable and readily accessible for any repair work which might be required. Along most

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63/ (Footnote cont'd).

prevailing in 1975, as Hass did. Finally, Staff's downward adjustment of its derived 3.9% equity risk premium for the alleged lower risks of the ANGTS project by the same absolute percentage points as reflected in Hass' analysis, rather than by the same relative percentage, is questionable.

Hass also suggested the use of a rate indexed to interest rates, rather than a fixed-rate. Given current uncertainties with regard to inflation and capital market developments, there is undoubtedly some merit to such a proposal, as evidenced by the increasing use of variable or "floating" interest rates for long-term debt instruments. The Commission is aware that certain portions of the financial community are becoming more interested in the concept of indexing. At this point, however, the Commission does not believe that such a mechanism is necessary. Should the project sponsors discover that such a mechanism would facilitate project financing, the sponsors are certainly free to petition the Commission to impose such a condition.

of Northern Border's route, it will traverse areas which are already served by one or more of the major pipeline systems in the lower-48 transmission network. We believe that because of its location, the operating problems of the Northern Border segment will not be significantly greater than for other lower-48 pipelines. Consequently, the cost-of-service tariff, tracking provisions, and rolled-in pricing reduce the risks of this segment below that of the Alaska segment. The Commission finds, therefore, that 13 percent is a reasonable Operation Phase Rate for the Northern Border segment.

4. Project Risk Premium

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. A key feature of the President's Decision is its emphasis that this risk of non-completion shall be borne by equity investors and other beneficiaries of the project, such as the State of Alaska or the producers at Prudhoe Bay, rather than by gas consumers or the general public through government loan guarantees. 64/ Consequently, the Decision states that charges may be levied on consumers only after the "completion and commissioning of operation of the system." 65/ If the project is abandoned prior to the initiation of service, investors cannot expect to recover their investment through charges on gas consumers.

The sponsors of the Alaskan segment presented a basic approach or methodology for determining these values of the Project Risk Premium in a paper submitted to the Alaskan Delegate on March 7, 1979, and distributed to all

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64/ Decision at 124.

65/ Decision at 38.

interested parties. 66/ The Commission adopts the general methodology earlier used by the project sponsors, but disagrees with certain key parameter values. 67/ Use of more appropriate values results in a Commission estimate of the Project Risk Premium substantially lower than the sponsors' estimate. 68/

First, the Commission has assumed a seven-year schedule of testing and construction, beginning in 1978 and ending in 1984, instead of the longer eight-year schedule assumed by the project sponsors. Even a seven-year schedule is significantly greater in length than the schedule that was presented to the President and the Congress as part of the March 1977 cost estimate. That estimate was based on a construction schedule that would be essentially complete by

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66/ A similar but more elaborate methodology was proposed by Hass, Hass Report at 20-40.

67/ Since the project sponsors in their comments make no reference to this methodology nor comment on the Commission's use of this approach, it is not clear whether they still advocate this approach.

68/ The April 6 Notice identified four issues the Commission believes are important in determining the Project Risk Premium and invited comments on these issues. Based on a review of these comments, the Commission has altered its view of the Project Risk Premium in a number of significant respects.

the end of 1981, with some additional work on compressor stations in 1982.

Second, the Commission has based its calculations on the assumption that there is at least a 67 percent chance that the current sponsors will be able to complete the system. In their paper, the sponsors assumed only a 30 to 40 percent probability of completing the system. The Commission's utilization of 67 percent by no means indicates its belief that the odds for completion of the project are two out of three. However, the Commission also cannot accept the sponsors' representation of a one out of three probability of project completion. The assumption chosen here merely makes certain that the Project Risk Premium compensates for a reasonable estimate of non-completion risk. 69/ The Commission believes that the low probability of success assumed by the sponsors contradicts the assurances given to the President and the Congress, at the time of the President's Decision, that this project could be privately financed under the conditions imposed by the Decision. Consequently, the Commission cannot accept the sponsors' assumptions, and does not believe that it is reasonable to allow a large Project Risk Premium on the basis that it is needed to compensate investors for an assumed small chance of successful completion.

Third, in calculating the Project Risk Premium the Commission makes no provision for the possibility that the

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69/ The Commission notes, in this regard, that comments on the reasonableness of the assumptions concerning the probability of project abandonment and construction schedules were sought from the sponsors in the Notice of Proposed Rulemaking (at 26). None were forthcoming.

sponsors could recover part of their investment through charges on existing customers in the event of abandonment. The Commission believes that the President's Decision did not contemplate such charges, and that plans and present decisions should be made on the assumption that cost recovery from rate-paying consumers will not be allowed in case of abandonment. The Commission recognizes, however, that substantial tax savings could accrue to investors in the event of abandonment. The lost investment is a loss for tax purposes and would reduce the tax payments of the project sponsors by an amount approximately equal to one-half of the investment. 70/

Fourth, the project sponsors' paper and the Commission's April 6 Notice assumed substantially different values for the rate of return used to calculate the allowance for the funds used during construction (AFUDC) included as part of the "risk adjusted rate base." 71/ The project sponsors

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70/ The only exception would be if a partner did not have a taxable income larger than the lost investment. Even in this event, loss carry forward provisions would allow the loss to be deducted from past and future income.

71/ The equity AFUDC rate is conceptually quite different from the actual rate the Commission will allow for determining AFUDC and it is used only to derive the theoretical construct of the "risk adjusted rate base".

proposed 15 percent, while the Notice proposed a lower rate of 9.5 percent. 72/ The Commission stated in the Notice that the risk of non-completion was essentially the only risk faced by investors during construction, and that this was compensated for by the "risk adjusted rate base" and the resulting Project Risk Premium. Under this concept, an equity AFUDC rate for calculating the "risk adjusted rate base" should be very low and incorporate no explicit compensation for risk. The Commission used 9.5 percent, which is comparable to the rate obtainable on low risk government securities.

72/ Staff's arguments in their initial comments recommending a 4.5 percent after-tax risk free equity AFUDC rate in calculating the risk adjusted rate base are not persuasive. Staff Initial Comments at 80. Staff is confused by the fact that the equity investors in the Alaska gas project are themselves likely to be corporations (the sponsor companies) rather than individual stockholders and thus must pay the corporate profits tax on any interest income at a rate of approximately 50 percent. Staff's argument is that a low risk alternative to an equity investment in the Alaska gas project would be an investment in government bonds from which the interest income would be subject to the corporate profits tax rate. This is misleading since the sponsoring companies can best be thought of as intermediaries for their own stockholders. The choice to a stockholder in a sponsor company is to invest in the Alaska project indirectly through the sponsor company or to invest in a low risk government security. From the perspective of a stockholder in a sponsor company, the interest income and the return on equity are both on the same tax basis (after corporate tax but prior to the personal income tax) and are in fact comparable.

The project sponsors, on the other hand, asserted that the methodology for calculating the Project Risk Premium only explicitly compensated for the extraordinary risk of non-completion for this project, and that any compensation for the normal risks of building a pipeline, including a competitive pre-decision risk, must be incorporated in the value of the AFUDC equity rate. 73/ The Commission has been persuaded by these arguments and has used an equity AFUDC rate to calculate the "risk adjusted rate base" that is equal to the Operation Phase Rate of 14 percent.

Based primarily on the project sponsors' methodology, and using most of the same parameter values, with one important exception, the Commission has calculated a

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73/ One particular risk for which this higher value of the equity AFUDC rate compensates is the risk incurred during competitive proceedings before this Commission. The Commission regards this risk as one of the normal risks of the pipeline business, for which the normal rate of return allowed regulated gas pipelines, and thus the Operation Phase Rate for this project, provides compensation. Thus, the Commission's calculation of the "risk adjusted rate base," and the Project Risk Premium, in this Order does not explicitly consider the probability of abandonment prior to the Decision and the issuance of the conditional certificates of public convenience and necessity in December 1977. In their initial comments, both the State of New York and the Upper Tanana Development Corporation argued against a higher Project Risk Premium to compensate for this risk, and no party argued for it.

Project Risk Premium of 2.0 percentage points for the Alaska segment. 74/

74/ The time profile of equity investment is taken from the response of the sponsor to an interrogatory from the Alaskan Delegate (dated May 3, 1979) which was served on all parties. As stated earlier, the probability of successful completion is assumed to be approximately 67 percent, making the chance of abandonment approximately one-in-three. The equity AFUDC rate used to calculate the "risk adjusted" and normal rate base is the Operation Phase Rate of 14 percent.

The calculations necessary to derive the Project Risk Premium for the Alaskan segment discussed herein are as follows:

	1978	1979	1980	1981	1982	1983	1984
Equity Investment (% of total)	9.0	5.3	5.3	20.1	27.5	20.1	12.7
Normal Rate Base (RBN) (14.0 % AFUDC rate)	10.26	17.74	26.26	52.85	91.60	127.34	159.64
Risk of Abandonment	.06	.12	.12	.05	.03	.01	.005
Risk Adjusted Rate Base (RBA) (14.0 % AFUDC rate)	10.63	19.66	31.00	59.23	100.89	138.88	173.42

Project Risk Premium = .1931 (173.42/159.64 - 1) = .0167

Applying a higher equity AFUDC rate (e.g., 14 percent vs 13 percent) to the RBA/RBN ratio results in a lower Project Risk Premium, other factors being equal. Under the conditions

(Footnote continued on next page.)

For the Northern Border segment, the construction p risks are considerably less than for the Alaska segment. Essentially, Northern Border will be of conventional pipe design, traversing areas where natural gas pipelines have previously been constructed. Thus, the likelihood of proj abandonment during construction due to extreme cost overru is virtually non-existent.

The required expenditures on pipeline design, engineeri and testing for Northern Border are of a lower magnitude relative to total costs than for the Alaskan segment. Hence, if Northern Border had to be abandoned during the early stage of pipeline design and engineering, the lost investment relative to total cost would be less than for Alaska.

74/ (Footnote cont'd)

above, as an example: Project Risk Premium at 14% = 1.67; at 13% = 1.87. As indicated above, the fact that the Commission specifies a lower AFUDC Rate than contemplated in Order No. 17, results in a higher Project Risk Premium and a higher Center Rate. The premium of 1.67% would be fair compensation for the risk-neutral investor who was willing to accept a fair gamble in the narrow statistical sense. The Commission, however, believes that the premium must be higher to compensate risk averse in estors and has selected a value of 2.0%. For more informa on about the methodology, see Northwest Alaskan, "Determ ng Project Risk Premium," cited at n.11 above.

The Northern Border segment also has the potential for transporting gas from two sources of supply, Western Canada as well as Alaska. Because of the possibility of "pre-building" most of Northern Border to carry Canadian gas in advance of Alaskan gas, the risk of abandonment of Northern Border will be obviated sooner than the risk of abandonment of the Alaska segment.

Weighing all of these factors, the Commission concludes that the appropriate Project Risk Premium for the Northern Border segment is 1.5 percent.

5. IROR Risk Premium

The IROR Risk Premium is to compensate equity investors for the risks introduced by the variability in the allowed rate of return created by the IROR mechanism. The IROR Risk Premium, when added to the Operation Phase Rate and the Project Risk Premium, yields the Center Rate. 75/

The IROR Risk Premium compensates for the various uncertainties attendant to implementing a new regulatory mechanism. For example, since the Inflation Adjustment and Change in Scope mechanisms established in this Order have no prior history, some uncertainty exists regarding their implementation and their effects on the return that will finally be realized by investors in this project. As is discussed more fully in Section III, the composite inflation index required by the Commission may over or underestimate the actual inflationary experience

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75/ In order for the ANGTS to obtain private equity financing, the IROR schedule must be designed in such a way that the statistical concept of the expected discounted stream of revenues (i.e. depreciation and return on equity) is at least equal to the expected discounted equity investment. Because of the design of the IROR schedule, the discounted expected returns to equity investors will exactly equal the expected equity investment if the Center Rate equals the cost of equity capital to the project, given the risks of the project.

of the project during construction. This creates additional uncertainty about the final outcome of the IROR mechanism. This uncertainty is the major reason why the Commission has decided to increase the IROR Risk Premium for Alaska from the 0.5 percent proposed in the April 6 Notice to the figure, established in this Order, of 1.5 percent. Similarly, the IROR Risk Premium for Northern Border has been increased from 0.25 percent to 0.5 percent.

Suppliers of very large sums of equity capital are likely to be risk averse. If presented two investments, both of which have the same average expected rate of return but one has a wide range of possible outcomes and one has a smaller range, most investors would prefer the latter. This would be true even if possible positive returns balance possible negative returns. Most investors prefer relative certainty to variability; therefore variable rates of return have to be higher than relatively sure rates of return.

Adoption of an IROR schedule confronts investors with a variable allowed rate of return in the form of a schedule of rates depending on cost control performance, rather than the single allowed rate of return as provided in the usual situation for public utility investment. Moreover, while in the usual utility investment, actual or realized rates of return may vary from allowed rates of return due to unanticipated inflation, demand shifts, or other economic changes, this project could have more variance due to the inflation and Change in Scope adjustments. Thus, an IROR Risk Premium is necessary to attract private equity investment in the project as compensation to investors for the risk created by the variable allowed rate of return.

There is no clear basis for determining the trade-off between a single allowed rate of return and a schedule, but the Commission in its judgment has concluded that a 1.5 percent IROR Risk Premium is appropriate for the Alaskan segment and that a 0.5 percent IROR Risk Premium is appropriate for the Northern Border segment. 76/ These figures, when added to the Non-Incentive Rate, yield Center Rates of 17.5 percent and 15.0 percent, for the Alaskan and Northern Border segments, respectively.

76/ Hass concludes that ". . . the IROR Risk Premium does not need to be very high and could be set to zero with justification." Hass Report at 42. Project sponsors, on the other hand, have expressed a concern that uncertainties associated with the IROR mechanism compound the already formidable task of arranging private financing for the project.

The State of Alaska has argued in its comments that the IROR Risk Premium is unnecessary and inconsistent with the rationale presented for it by the Commission. It states that the expected rate of return, in the statistical sense, can never be less than the Non-Incentive Rate (that is, the sum of the Operation Phase Rate and the Project Risk Rate) and will probably exceed the Non-Incentive Rate. It concludes that there is no downside risk inherent in the IROR mechanism and that even a schedule which embodied no IROR Risk Premium would offer investors a schedule of returns which are higher than necessary to induce equity investment in the project.

The Commission is not persuaded by these arguments because they fail to address the fundamental issue of the variability of the earned rate of return relative to the Center Rate. The actual Cost Performance Ratio, and thus the Incentive Rate which will be achieved, is by no means known with certainty. By definition, there is some probability of a Cost Performance Ratio in excess of the Center Point. Therefore, investors face the possibility of receiving a rate of return less than the Center Rate, even though the expected rate of return (by the narrow statistical definition) may be in excess of the Non-Incentive Rate.

The IROR mechanism does confront investors with downside risk, and thus, a reasonable IROR Risk Premium is appropriate. 77/

The Commission Staff has proposed that no IROR Risk Premium should be incorporated into the IROR schedule. They assert that upside variance in returns (i.e., the contribution to that variance due to returns above the expected

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77/ In addition, the Commission does not agree with the State of Alaska that an IROR schedule which embodied a zero IROR Risk Premium would offer investors higher returns than necessary. Although it is true, as the State of Alaska notes, that the statistical concept of the expected rate of return is likely to exceed the Center Rate, rational investors are not likely to base their investment decisions on the expected rate of return, per se. The expected rate of return is a weighted average of all possible rates of return, using as weights the assumed probabilities of each rate of return being received. Such a procedure does not take into consideration the different levels of investment associated with different allowed rates of investment return. A rate of return in excess of the Center Rate would be received on a smaller rate base than a rate of return which is less than the Center Rate. Thus, the dollar amount of gain, in an opportunity cost sense, from achieving a Cost Performance Ratio less than the Center Point by a certain percentage would be smaller than the dollar amount of loss resulting from achieving a Cost Performance Ratio in excess of the Center Point by the same percentage. In order to induce investment in the project, the expected discounted dollar amount of return to investors from the project must be at least equal to the expected discounted dollar amount of incremental investment. As was shown in the April 6 Notice, a zero IROR Risk Premium would produce an expected discounted return just equal to the investment.

level) is a desirable feature to investors. They contend that since the upside variance due to the IROR mechanism is proportionally much greater than the downside variance (i.e., the contribution to total variance due to returns below the expected level), no IROR Risk Premium is needed.

This approach for assessing risk is one with which the Commission has had no previous experience. Even if the ratio of good or upside variance to bad or downside variance is a useful measure of risk, the Commission is uncertain as to how it should be employed in determining the IROR Risk Premium. While the Staff's approach is interesting, it is not sufficiently developed to constitute a reliable basis for Commission action.

In sum, in light of those attributes of the rate of return mechanism for this project that could produce a variance between actual and allowed rates of return greater than the variance usually observed in regulated situations, it is appropriate to establish a special IROR Risk Premium. The Commission's judgment is that on the basis of an overall assessment of the project, 1.5 percent is reasonable for Alaska and 0.5 percent is reasonable for the Northern Border.

6. Marginal Rate

a. Definition

The Marginal Rate is the return on the incremental dollar invested in moving from one Cost Performance Ratio to another. Alternatively, it can be thought of as the rate of return allowed on cost overruns or the rate of return enjoyed if costs can be reduced. However, as previously discussed in Section I, a single Incentive Rate will be earned on all investments in the project. The marginal rate is merely an analytical device for determining, in part, what the rate of return will be depending on cost performance.

This order establishes an overall schedule of rates of return called the IROR schedule, but implicit in any schedule is one or more Marginal Rates of Return. To illustrate this relationship between the overall IROR schedule and the Marginal Rate, consider the following abbreviated IROR schedule where the marginal rate is constant at 8 percent. When the marginal rate is applied to the additional equity investment, the average rate of return on equity (IROR) is reduced.

Equity Share of Capital Costs	Cost Performance Ratio	IROR
$ 1.2 million	1.2	18.29
1.3 million	1.3	17.50
1.4 million	1.4	16.82

Assume that the Cost Performance Ratio of 1.3 has already been reached shortly before project completion and the equity share of these costs is $1.3 million. But in order to complete the project, additional funds equal to 10 percent of projected costs must be expended. The equity share of this increase is $100,000. This increases the Cost Performance Ratio to 1.4. Because of this increase in costs, the IROR is reduced from 17.50 percent to 16.82 percent. This reduction occurs because the Marginal Rate implicit in this schedule is 8 percent and the equity investor will only earn an 8 percent return on his $100,000 investment. 78/ Conversely, if the project sponsor can find some way to reduce construction costs so as to reduce the Cost Performance Ratio from 1.4 to 1.3, then the equity

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78/ The IROR for the Cost Performance Ratio of 1.4, i.e, 16.82 %, can be calculated as the weighted average of the 17.50 % return allowed for the 1.3 Cost Performance Ratio and the 8 % Marginal Rate earned on the $100,000 increase in costs.

The weights in the average are the share of the total investment earning each of the two rates of return.

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\begin{aligned}
& (1.3/1.4) \times (17.50\ \%) + (0.1/1.4) \times (8.0\ \%) \\
= & (0.92\ \%) \times (17.50\ \%) + (0.071) \times (8.0\ \%) \\
= & 16.25\ \% + 0.57\ \% \\
= & 16.82\ \%
\end{aligned}
$$

Again, however, there is only one overall rate of return, in this case 16.82 %.

investor will have avoided investing $100,000 at the low Marginal Rate of 8 percent.

b. Impact of the Marginal Rate

The Marginal Rate plays three important roles in the IROR mechanism:

(1) Incentive to reduce costs. Because the Marginal Rate is the implicit rate of return allowed on all equity to finance increases in costs, this rate primarily determines the incentives to reduce costs created by the IROR. If the cost of capital is more than the allowed return, investors have a strong incentive to avoid making that investment. In addition to any other incentives already in existence, the Marginal Rate will create an incentive to reduce costs if the Marginal Rate is set below the cost of capital. 79/

79/ In their joint initial comments, the sponsors argue that the fundamental incentive to reduce or control costs is the need to remain within the pool of funds committed to the project. (Joint Comments at 36.) We agree that this financial restriction will create a powerful and practical incentive. Marginal Rate is designed to discourage the expenditure of funds which exceed the cost estimates upon which the project was certificated. This is a separate and distinct issue from that raised by the sponsors of whether the funds will be available to finance will be available to finance cost overruns. The President's Decision is clear that the IROR must be constructed so as to create "substantial incentives" to reduce costs. The Commission, to meet this requirement, must consider the implicit Marginal Rate in the IROR schedule and compare it with the cost of equity capital for this project.

(2) Slope of IROR schedule. The Marginal Rat determines the steepness of the IROR curve. A low margin Rate will mean that the Incentive Rate will decline more r as cost overruns occur. A high Marginal Rate will mean th the Incentive Rate will decline slowly as cost increases oc From another perspective, a low Marginal Rate creates great risk or uncertainty about the final outcome since the range or variability of rates is large. A high Marginal Rate creates little or no variability, and provides a substantial likelihood that even if there is substantial cost growth relative to the projected costs the earned rate will be close to the Center Rate.

(3) Floor of the IROR schedule. If a constant Marginal Rate is used, the Marginal Rate then becomes the floor on the IROR schedule. Since the Marginal Rate is effectively the rate allowed on all cost increases, the Incentive Rate can never be reduced below the level of the Marginal Rate no matter how large the Cost Performance Ratio becomes.

(c) Alternative Marginal Rates

In the Commission's April 6, 1977 Notice, in the comments received pursuant to this Notice, and in comments received in the earlier rulemakings dealing with the IROR, a number of different methodologies or approaches have been advocated for determining the Marginal Rate. The fundamental principle in choosing a Marginal Rate is that it should be less than the cost of equity capital. However, the comments demonstrate considerable controversy about the appropriate measure of the cost of capital and how much less the Marginal Rate must be. Here, we will review briefly the alternative approaches suggested to the Commission and discuss their merits. The Commission, however, must exercise its best judgment and choose a reasonable value from the various values presented in the comments.

The highest value for the Marginal Rate has been advocated by the project sponsors, Northern Border and Northwest Alaska. That rate is 12 percent. Their argument is that the Marginal Rate only needs to be slightly less than the "rate potential investors will require to accept the Project's risks," or, in other words, only slightly less than the Operation Phase Rate plus the Project Risk Premium. (Initial Comments, page 30). This order specifies that rate to be 16.0% for the Alaska segment and 14.5% for Northern Border.

The Commission, however, believes that there are three compelling reasons why the Marginal Rate must be substantially less than the Operation Phase Rate plus the Project Risk Premium to create a significant incentive. First, the risk of an investment in this project is reduced substantially as the project nears completion. 80/ In fact, an investment just prior to completion has avoided all of the construction phase risks and is only confronted with the operation phase risks. Even adopting the sponsors' argument that the Marginal Rate need only be slightly less than the rate required to compensate for the risks of the project, the relevant rate is the Operation Phase Rate. This Order specifies an Operation Phase Rate of 14.0 percent for Alaska and 13.0 percent for Northern Border.

Second, the Commission believes that the incentive to reduce costs increases as the difference between the Marginal Rate and the rate that would otherwise be adequate compensation for the risks of investment increases. A Marginal Rate only slightly less than the Operation Phase Rate will only create a slight incentive to avoid overruns. In order to create a substantial incentive, the Marginal

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80/ See, e.g., Northwest Alaskan, "Determination Project Risk Premium" at 39.

Rate must be substantially less than the Operation Phase Rate. 81/

Third, the Commission believes that it may be appropriate in determining the Marginal Rate to examine the cost of the funds used to make the equity investment in the project. If the equity investor can borrow a substantial portion of the funds to make the investment, then the average cost of funds could be much less than the Operation Phase Rate. In the Commission's September 15, 1978, Revised Notice of Proposed Rulemaking (at page 45), an example was presented where equity investors could borrow 60 percent of the funds to make an equity investment in the Alaska gas project. This produced a weighted cost of capital funds of about 8 percent. 82/

The lowest value of the Marginal Rate was advocated in the comments by the Staff. The Staff argued that a zero Marginal Rate was appropriate by analogy to the proposed

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81/ See, Initial Comments of the People of the State of California and the Public Utilities Commission of the State of California at 3 (May 4, 1979) which, for a similar reason, advocated a Marginal Rate of 5 %.

82/ This figure is derived from:

(share of equity) x (equity rate of return)
+ (share of debt) x (after-tax cost of debt)
= (0.4) x (13 %) + (0.6) x (5 %) = 8.2 %

tariff provisions that would reduce equity return in the event of a service interruption. Since the return on equity is reduced proportionately to the reduction in throughput resulting from a service interruption, the return on equity per thousand cubic feet (Mcf) of throughput would be constant 83/ This provision provides an incentive for sponsors to minimize or reduce service interruptions. The Staff argues that the same incentive should be provided to sponsors to reduce construction costs. A zero Marginal Rate would effectively keep the total dollar equity return constant for all levels of cost overruns or underruns and thus all levels of equity investment.

Though this analogy with the service interruption provision of the tariff is interesting, the Commission believes that the circumstances surrounding the two situations are quite different. In setting the Marginal Rate, the primary criterion is to reduce the equity return on cost increases to a level less than what equity can earn in other investments of similar risk. This same criterion is not relevant for the service interruption tariff provision. The

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83/ The reduction in equity return only occurs if the service interruption reduces throughput to less than 90 % of the contracted quantities.

Commission believes that a zero Marginal Rate would be unnecessarily below the rate of return necessary to create a substantial incentive to avoid cost overruns.

The project sponsors, in their initial comments, argue that a low Marginal Rate may well prevent the project from obtaining both equity and debt financing (Initial Comments, Tab 4, pp. 7-8, and pp. 18-21). The Commission believes that the IROR schedule will prevent equity financing only if potential investors perceive such a high probability of large cost overruns that the IROR mechanism would result in a low average rate of return. The Marginal Rate has been set at a relatively high level in part to assure that the Incentive Rate -- the rate that the project will actually earn -- will decline only gradually as actual costs exceed projected costs. As will be discussed in the later section dealing with the overall impacts of the IROR mechanism, the allowed rate of return for the project is competitive with other project investments in the gas industry and the economy in general. If investors perceive a high probability of such large overruns that the realized rate of return will be low, then it would seem to follow that the projected costs and estimates of cost overruns have grown to such an extent since the President's Decision that the construction of this project may not still be in the public interest.

The project sponsors list three reasons why a low equity return may prevent debt financing even if equity financing is available. 84/ All of these reasons are only relevant if there is a significant probability that large cost overruns will reduce the Incentive Rate to a low level. The project sponsors however, fail to mention what the Commission considers to be the greatest deterrent to the attraction of debt capital for this project, the threat of such a large amount of cost growth that the economic viability of the

84/ Initial Comments, Tab 4, at 7. These reasons are:

(1) The project must offer an equity return high enough to attract completion capital from investors who did not participate in the initial financing. The Commission's response is that the original investors may have to sacrifice some of their return in order to make the project attractive to new investors in the event of large overruns or else face the loss of their investment due to abandonment. A similar argument was made by the State of California in its initial comments (p. 3).

(2) Debt amortization schedules may require that the debt principal payments be funded in part from the equity returns. The Commission notes that the IROR mechanism does not interfere with the return of equity through depreciation but only reduces the return on equity. It would seem to be very unlikely that debt amortization would exceed the total depreciation expense for the project.

(3) Debt investors will consider debt coverage ratios in their decision to invest and the IROR may reduce these ratios. The Commission believes that the cost of service tariff for this project reduces the importance of conventional measures of debt coverage.

project would threaten the security of the debt investor. The IROR mechanism requires the project sponsors and other equity investors to suffer a low rate of return only if large cost overruns occur. If the equity investor is willing to go ahead with the project, then he must be confident that the cost estimates for the project are accurate and large cost overruns will not occur. The existence of equity investment, then, should assure the debt investors that large cost overruns will not occur. Thus the debt investment should be secure.

The Commission, in choosing a Marginal Rate, must balance the requirement in the Decision that the IROR mechanism provide "substantial incentives" with the need to attract equity and debt financing. The Commission has set a relatively high Marginal Rate. An 8 percent Marginal Rate will not lower the levels of the Incentive Rates unless very large cost overruns occur. However, we believe that an 8 percent Marginal Rate is sufficiently below the rates of return that equity investors could earn elsewhere so as to provide a significant incentive for superior cost control. 85/

85/ The State of New York suggests that the Marginal Rate should be reduced for large values of the Cost Performance Ratio, but does not explain what specific benefit would result from this proposal. Comments of the Public Service Commission of the State of New York on Proposed Values for Incentive Rate of Return, Change of Scope and Inflation Adjustment and Tariff Issues, Docket No. RM78-12 at 6 (May 4, 1979). During this and the previous rulemakings dealing with the IROR mechanism, the Commission has examined a number of proposals for a non-constant Marginal Rate. Upon close re-examination of this issue, the Commission fails to see any significant benefits that would result from a non-constant Marginal Rate.

7. Synopsis of Components

The following table presents the determined values for the IROR parameters:

Parameter	Segment: Alaskan	Segment: Northern Border
Center Point 86/	1.30	1.10
Operation Phase Rate	14.00	13.00
Project Risk Premium	2.00	1.50
IROR Risk Premium	2.00	.50
Center Rate	17.50	15.00
Marginal Rate	8.00	8.00
Equity AFUDC Rate	14.00	13.00

With these values the entire range of the IROR schedule can be calculated. 87/ The result of the calculation is produced below in tabular form:

86/ These values for the Center Point are used only for illustration. The values for this component for each of the segments will be determined at a later date. See section II.B.2.

87/ The formulas by which the calculation would be made gives any Cost Performance Ratio (A) would be:

(1) For Alaska: $R = [(17.5)(1.3) + 8(A - 1.3)]/A = 8 + 12.35/A$

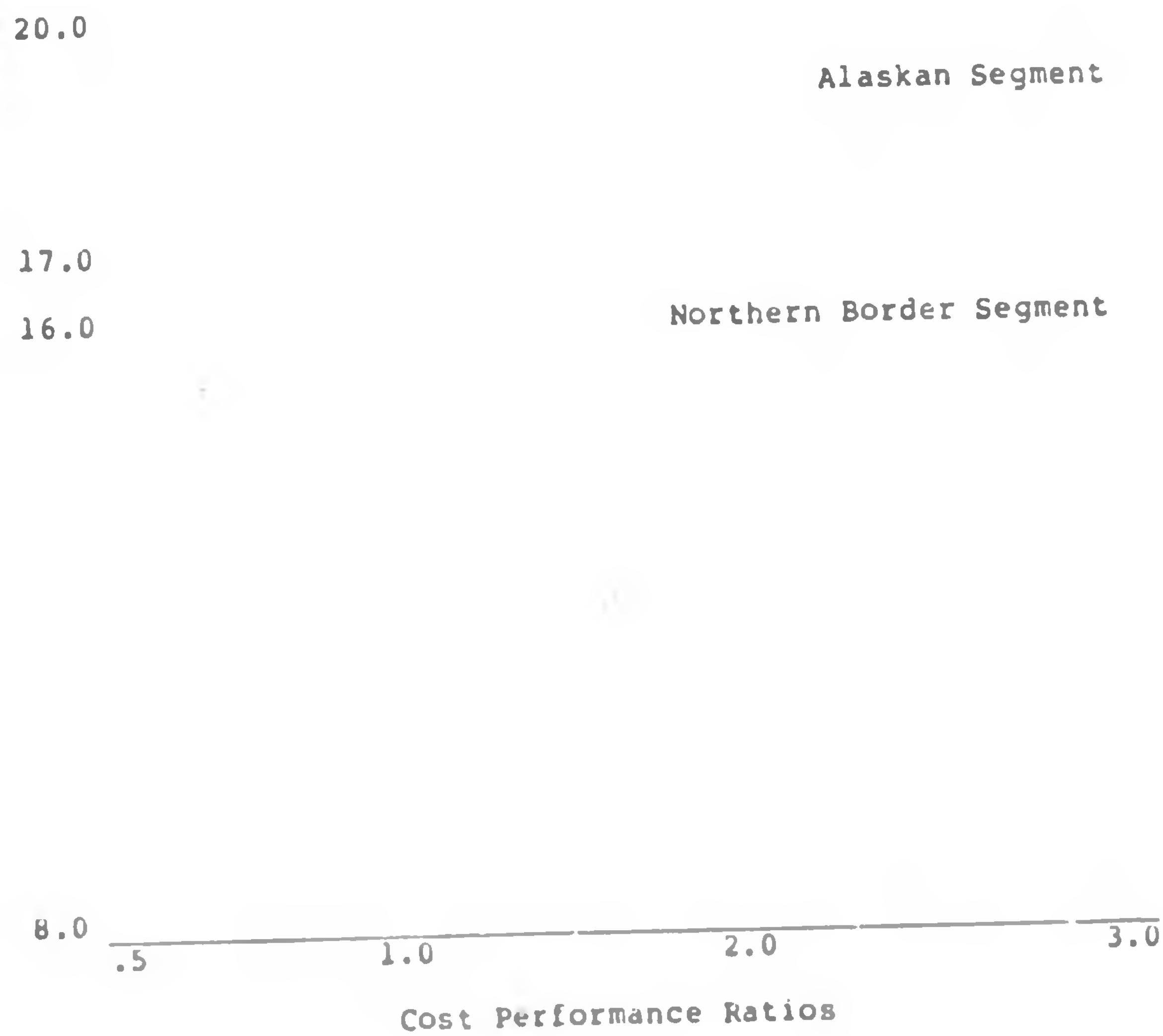
(2) For Northern Border: $R = [(15.00)(1.1) + 8(A - 1.1)]/A = 8 + 7.7/A$

Where: R = the incentive rate of return

INCENTIVE RATE OF RETURN

Cost Performance Ratio	Alaska	Northern Border
0.8	23.44	17.62
0.9	21.72	16.56
1.0	20.35	15.70
1.1	19.23	15.00
1.2	18.29	14.42
1.3	17.50	13.92
1.4	16.82	13.50
1.5	16.23	13.13
1.6	15.72	12.81
1.7	15.26	12.53
1.8	14.86	12.28
1.9	14.50	12.05
2.0	14.17	11.85
2.1	13.88	11.67
2.2	13.61	11.35
2.3	13.37	11.35
2.4	13.15	11.21
2.5	12.94	11.08
2.6	12.75	10.96
2.7	12.57	10.85
2.8	12.41	10.75

[GRAPH]


20.0
Alaskan Segment
17.0
16.0
Northern Border Segment
8.0
.5
1.0
2.0
3.0
Cost Performance Ratios

C. <u>One-Time Adjustment to Rate Base</u>

Order No. 17 specifies a procedure for determining a one-time adjustment to the rate base of the project, in lieu of using the Incentive Rate during the operating life of the project. This section reviews the rationale for this procedure, and describes how the one-time adjustment will be calculated, including examples. Also, this section discusses certain accounting, ratemaking, and tariff implications of the one-time adjustment that were not included in Order No. 17.

The preceding analysis of the IROR mechanism is based on the premise that the Incentive Rate would be applied to the actual equity component of the project's rate base to determine the cost of service. However, Order No. 17 requires an alternative but equivalent procedure. Instead of applying the Incentive Rate to a normal rate base, the Operation Phase Rate will be applied to an adjusted rate base. The adjustment to the capital structure and rate base will be such that the present worth of the future income or cash flow to equity investors will be the same as would result from using the Incentive Rate and an unadjusted rate base. The one-time adjustment would be amortized with the annual amortization charge included in the cost of service and the Operation Phase Rate would be earned on the unamortized portion of the one-time adjustment.

The Commission has adopted the one-time adjustment approach for two reasons. First, the use of a one-time adjustment simplifies the determination of just and reasonable rates of return in the future, because the risks attached to the construction phase, including the risk of the IROR mechanism itself, are already recognized in the adjusted capital structure and rate base. By compensating for these risks through an adjustment to the project's rate base, future rate of return determinations need only address project risks and financial market conditions at the time of determination, not those risks associated with the construction of the project which took place in the past.

The second reason is to simplify future financing for, and rate determinations on, expansions or looping of the ANGTS. The risks of participation in this project prior to and during construction are significantly different from the risks associated with project investments made in the future when in an operational phase. 88/ The IROR mechanism is a concept

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88/ The project sponsors have already provided some recognition of the changing nature of project risks as the project progresses with the discount schedule for late entry which was made part of their Partnership Agreement. The Commission endorsed that concept in approving the relevant portion of the Partnership Agreement, by Order of June 30, 1978, in Docket No. CP78-123 (at pp. 7-11), and seeks to reinforce it with the rate base adjustment methodology.

developed to recognize the project sponsors' performance in the initial construction phase only, and the resulting adjustment should not affect the return on future investment in an expansion of that project. The one-time adjustment ensures this result without the need for separate return determinations for investments made in the ANGTS at different times.

The Commission believes that the adjustment should be the present value of expected future cash flows 89/ resulting from the application of the difference between the Incentive Rate of Return and the Operation Phase Rate as applied to the equity-supplied capital of the system. 90/ Table illustrates how to calculate the one-time adjustment that

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89/ The expected cash flow includes both the return on and the return of the one-time adjustment. The one-time adjustment is, in effect, additional equity provided to the project as a result of the performance of the sponsors during construction.

90/ Some of the comments argue that uncertainties about the future operation of the pipeline will make the present value of the return of equity and the return to equity uncertain, and thus make the precise size of the one-time adjustment uncertain. The Commission agrees that it is impossible to predict with certainty such things as throughput, tax rates, operation costs, or ultimate capacity. However, the type of cost-of-service tariff that this Commission is likely to approve will provide a high degree of certainty as to the return of equity and the return to equity over the life of the project, once the size of the equity investment and the allowed rate of return have been finalized.

is equivalent to an Incentive Rate of 17 percent when the Operation Phase Rate is 14 percent. Instead of earning a 17.5 percent return on the unadjusted equity investment in the project, the investor will earn a 14 percent return on a larger adjusted equity investment. Based on the assumption that the equity investment in the project will be reduced on a straight line basis over a 25-year period, Table 1 shows that the one-time adjustment should equal 18.3 percent of the original investment. 91/

Table 2 shows the one-time adjustment to the equity investment that results for each possible value of the Incentive Rate for both the Alaska segment and Northern Border. In the case of the Alaska segment, a Cost Performance Ratio less than 2.1 will result in an Incentive Rate greater than the Operation Phase Rate (14 percent), and thus in a positive one-time adjustment. For Cost Performance Ratios greater than approximately 2.1, the Incentive Rate will be less than the Operation Phase Rate, and the one-time adjustment will be negative.

91/ Using a 14 percent discount rate, the present worth of the return of and return on equity resulting from a 17.5 percent rate of return on an unadjusted equity investment of $100.00 is the same as the present worth of the return of and return on equity resulting from a 14 percent rate of return on an adjusted equity investment of $118.13.

TABLE 1

Example of One-Time Adjustment Calculation

Assumptions:
- Operation Phase Rate - 14%
- Incentive Rate - 17.5
- Equity Investment - $100
- Depreciation Period - 25 years

Year	Return of equity	Return * on equity	Total	Discounted Total (14% discount rate)
1	$4.00	$17.50	$21.50	$18.86
2	4.00	16.80	20.80	16.00
3	4.00	16.10	20.10	13.57
4	4.00	15.40	19.40	11.49
5	4.00	14.70	18.70	9.71
6	4.00	14.00	18.00	8.20
7	4.00	13.30	17.30	6.91
8	4.00	12.60	16.60	5.82
9	4.00	11.90	15.90	4.89
10	4.00	11.20	15.20	4.10
11	4.00	10.50	14.50	3.43
12	4.00	9.80	13.80	2.86
13	4.00	9.10	13.10	2.39
14	4.00	8.40	12.40	1.98
15	4.00	7.70	11.70	1.64
16	4.00	7.00	11.00	1.35
17	4.00	6.30	10.30	1.11
18	4.00	5.60	9.60	0.91
19	4.00	4.90	8.90	0.74
20	4.00	4.20	8.20	0.60
21	4.00	3.50	7.50	0.48
22	4.00	2.80	6.80	0.38
23	4.00	2.10	6.10	0.30
24	4.00	1.40	5.40	0.23
25	4.00	0.70	4.70	0.18
Total	$100.00	$227.50	$327.50	$118.13

One-Time Adjustment = $18.13

* Computed on remaining balance of one-time adjustment as of January 1 of each year.

TABLE 2

One-Time Adjustment as Percent of Equity Investment

	Alaska		Northern Border	
Cost Performance Ratio	Incentive Rate	One-Time Adjustment % (14% Discount Rate)	Incentive Rate	One-Time Adjustment % (13% Discount Rate
0.8	23.44	48.38	17.62	25.15
0.9	21.72	40.00	16.56	19.33
1.0	20.35	32.89	15.70	14.68
1.1	19.23	27.07	15.00	10.87
1.2	18.29	22.23	14.42	7.70
1.3	17.50	18.13	13.92	5.02
1.4	16.82	14.61	13.50	2.72
1.5	16.23	11.57	13.13	0.73
1.6	15.72	8.90	12.81	-1.02
1.7	15.26	6.55	12.53	-2.56
1.8	14.86	4.46	12.28	-3.93
1.9	14.50	2.59	12.05	-5.15
2.0	14.17	0.91	11.85	-6.25
2.1	13.88	-0.62	11.67	-7.25
2.2	13.61	-2.00	11.50	-8.15
2.3	13.37	-3.26	11.35	-8.98
2.4	13.15	-4.42	11.21	-9.74
2.5	12.94	-5.49	11.08	-10.44
2.6	12.75	-6.47	10.96	-11.02
2.7	12.57	-7.38	10.85	-11.68
2.8	12.41	-8.23	10.75	-12.23

For accounting purposes, the one-time adjustment can be actually recorded as an adjustment to the original cost of plant in the accounting records of the project. This one-time adjustment could be entered into just one of the plant accounts specified by the Commission's Uniform System of Accounts or spread over a number of the plant accounts. Since the tariff of the project relies on the cost of plant as recorded according to Uniform System of Accounts, the one-time adjustment would be incorporated into the rate base of the project for ratemaking purposes. Thus, application of the provisions of the tariff to the project's rate base as specified by the adjusted account(s) would then yield the appropriate revenue streams.

The Commission rejects this approach for a number of reasons. First, it could result in a distorted picture of the actual earnings of the project. To record the adjustment as an increase in the original cost of the plant would be contrary to generally accepted accounting principles, since it would not be in accord with the cost concept of asset accounting. Also, it would violate the original cost concept of regulatory accounting. Other problems might arise in the future if there was a significant change in the project plant, such as an extraordinary retirement or replacement of a significant component of the project plant. If the original cost of this component also included some part of the one-time adjustment, special recognition of this fact must be given in order to ensure continued recognition of the impact of the IROR on rates of return.

The Commission proposes instead to record the one-time adjustment as a memorandum entry in the project's accounts to be used for ratemaking purposes only. The purpose of the one-time adjustment is to reward or penalize the project sponsors for their performance during the construction phase of the project, and to compensate the investors for unusual risks involved in building a project of such magnitude. Under this proposal, the one-time adjustment would be treated as a matter of rates and rate of return on a given investment, not an adjustment of that investment.

The use of the memorandum entry concept will require modification of the tariffs to include a schedule of the one-time adjustment and its amortization over the project's life. Also, the definition of rate base will be changed to include the average remaining balance of the IROR one-time adjustment, and the definition of the components of cost of service will include the scheduled amortization of the IROR one-time adjustment for the tariff computation period. Finally, the equity in the project to be used for the rate determination will include the unamortized one-time adjustment as an adjustment to book equity. 92/

92/ The one-time adjustment to rate base is a means of obtaining a desired result in an uncomplicated manner. The Commission realizes that there are many variables in the ratemaking process which will affect the results of any method used to implement the IROR. The Commission believes that the one-time adjustment, amortized over the life of the project, will result in the closest approximation of the desired results, and any differences will be minimal when reviewed over time.

III. ADJUSTING FOR INFLATION

The Commission believes that it is not reasonable to penalize project sponsors for cost increases resulting from general inflation in the nation's economy. As proposed in our Notice of April 6, the Commission will adjust the Actual Capital Costs to eliminate the effect of general inflation before calculating the Cost Performance Ratio and the IROR.

Extensive research has been done on this subject, and there is substantial information in the record on the appropriate inflation adjustment procedure. Both the Alaskan Delegate and the project sponsors have prepared papers on the inflation adjustment mechanism, and the comments received pursuant to the Commission's Notice of April 6 discuss the inflation adjustment mechanism in considerable detail.

The Commission has evaluated potential inflation adjustment mechanisms against four criteria. These are: (1) the accuracy with which the mechanism would adjust the actual costs of construction for general inflation in the nation's economy; (2) the extent to which it would provide incentives to reduce construction costs; (3) the burden on the Government and the sponsors of administering the inflation adjustment mechanism; and (4) the attendant risk and uncertainty to investors and lenders. Different proposals rank differently when judged by these criteria individually. The Commission must balance the conflicts or differences to arrive at the best possible solution under all of these criteria.

The Commission's proposal for an inflation adjustment mechanism has been criticized (for different reasons) by both the sponsors and the Commission's Staff in their comments. While the Commission has made some modifications in response to the technical criticisms of the sponsors, the Commission still believes that the proposal in the Notice achieves the best balanc nong the four goals.

The Commission's inflation adjustment mechanism has the following major features:

- A hybrid or composite index of construction costs for this project will be constructed.

- This index will be used to deflate Actual Capital Costs back to base year price levels for comparison with the Projected Capital Costs, also in base year prices.

- The composite index will be a weighted average of 42 indices currently available from the Government or other recognized sources.

- Each of the 42 indices will measure the price increase for one category of construction costs (e.g., valves, line pipe, welders, cement, and so forth).

- o The weights to construct the average will change from quarter to quarter and will be based on the proportion of that cost category in the total costs for the project as taken from the estimates in the Certification Cost Estimate. (For example, if valves amount to 15 percent of total costs for a particular period, valves would be given a weight of 15 percent in the composite i[illegible]. for that period.)

- o Weights to be used for any construction occurring after the end of the estimated construction period would be those weights used for the last year of construction in the estimated schedule.

This inflation adjustment mechanism is based in large part on the proposal made by the project sponsors in a paper submitted to the Alaskan Delegate on March 7 and later distributed to all other interested parties. 93/ In their comments on the April 6 Notice, the project sponsors are critical of the

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93/ Northwest Alaskan, "Recommended Inflation Adjustment."

Commission's deviation from their proposal. The Commission's major reason for deviating from the sponsor's proposal is that the proposal would not adequately realize the goals of creating incentives to reduce costs and of limiting administrative burdens. The Commission's procedure results in some attendant uncertainty about the final outcome of the IROR mechanism or, in other words, uncertainty about the realized rate of return. As discussed in Section II.B.5. on the IROR Risk Premium, this is one reason why the Commission has increased the IROR Premium.

The first difference between the mechanism specified in this Order and that proposed by the sponsors is the weights to construct the composite index. The sponsors advocate using the actual costs incurred in each category during construction to determine the weights, while the Commission's procedure is to use the estimate of costs in each category found in the Certification Cost Estimate. There are two major advantages to using estimated costs rather than actual costs to derive the weights.

First, the use of actual costs as weights does not give any incentive to substitute low-cost items in one cost category for high-cost items in another category since the weights would be adjusted to offset this change. Using fixed weights based on estimated costs gives the sponsors a greater incentive to substitute low for high-cost items whenever possible, and thus to achieve a lower Cost Performance Ratio (and a higher IROR).

Second, the determination of the weights prior to the start of construction as part of the certification process means that there will be one less issue or potential controversy to resolve during construction. In general, the project sponsors have emphasized the need to resolve all IROR parameters as soon as possible.

The use of actual costs to determine weights could result in a more accurate measure of inflation for each cost category than using estimated cost weights. However, we believe the overall accuracy of the estimates will be good, since any underestimation of inflation for one of the 40 or more categories will probably be offset by an overestimation in another category. Also, any inaccuracies are just as likely to benefit the project sponsors by overestimating inflation as to harm the sponsors by underestimating inflation.

The second and more important difference between the sponsor's proposal and the Commission's mechanism is in the use of actual prices paid as a measure of inflation. The sponsors argue that no existing index accurately measures their likely inflationary experience for steel prices and wage rates for labor. Though there is merit to this argument, the Commission cannot reconcile the use of actual prices to measure inflation with the requirement in the Decision that the IROR mechanism must provide "substantial incentives" to reduce costs. Labor costs and steel costs will likely account for more than 75 percent of the total costs of this project. By using actual prices paid to measure inflation for these two cost categories, the Commission would in effect be eliminating any extra incentive created by the IROR mechanism 94/ for the sponsors to negotiate for lower wage rates or lower steel prices.

We do not believe that the use of existing indices for these two cost categories creates an inordinate amount of risk for the sponsors. Prices for all steel products generally follow the same price trends, and labor rates in all parts of the country for all skill categories also generally increase together. We do not deny that there may be some divergence in growth rates, but the sponsors are just as likely to benefit from differences as to be penalized.

As we stated in the April 6 Notice, the Commission expects that the Certification Cost Estimate will incorporate a premium for labor rates or steel prices if it can be shown that wages or steel prices for this project can be expected to be higher than other wage rates or steel prices incurred in other major construction projects in the lower-48 states.

94/ There may be other powerful incentives to bargain for lower wages and prices, but the IROR mechanism would not add to them in this case.

Labor prices in Alaska will be higher than in the lower-48, and prices of 48-inch pipe exceed the prices for 36-inch pipe (the largest diamater for which price indexes are available). 95/ However, there is no evidence that future increases in Alaska labor rates or future changes in prices for 48-inch steel would be greater than increases in other wage rates or other steel prices. In fact, there is at least some probability that increases will be smaller and that the sponsors will benefit from the inflation adjustment mechanism required by this Order. 96/

95/ In estimating the prices for labor or steel to be used in the Certification Cost Estimate, we believe that a reasonable procedure would be to estimate the premium (in percentage terms) that will have to be paid for Alaskan labor or 48-inch pipe above lower-48 prices for labor or 36-inch pipe during actual construction. These premiums should then be added to the base year prices for lower-48 labor or 36-inch steel pipe to determine base-year prices for Alaskan labor or 48-inch pipe. The Trans-Alaska Oil Pipeline experience could provide a starting point for determining the premium for labor.

96/ The sponsors argue that incorporating premiums for Alaskan labor or 48-inch pipe in their cost estimates will put them at a competitive disadvantage in their negotiations with labor unions or pipe manufacturers. Joint Comments at Tab 2, p. 10. Even if there was no IROR mechanism, and thus no inflation adjustment mechanism, the Commission would still expect the Certification Estimates to contain the best estimates possible for labor rates and steel pipe prices, including any premiums that the sponsors expect to pay over other more common labor rates or prices. Even assuming, arguendo, that the sponsors are correct, the argument would seem to apply with even more force to the situation where wage and price increases could be passed through to ratepayers by means of an inflation adjustment mechanism with no adverse impact on earnings.

The sponsors also object to the Commission's requirement to use the weights for the last scheduled period of construction to deflate costs during any period of schedule overrun. This may introduce some error, but again, the sponsors are just as likely to benefit as to be harmed. It is doubtful that any inaccuracies as a result of this arrangement could be substantial. The types and quantities of labor and material used during any period of schedule overrun should be similar to the types and quantities estimated to be us for the last period of the planned construction schedule. 97/

97/ The Commission Staff in their initial comments (pp.45-47) argue for a method of adjusting for inflation that would impose a much more severe penalty for schedule delay than would the Commission's mechanism. The Staff would not only use the same weights in the schedule overrun as used in the last scheduled period, but would also use the same values for the cost indices. In other words, there would be no adjustment for any inflation that occurred duri.. the schedule overrun period. This proposal would result in an unneccessarily severe penalty for schedule delay. The true cost of schedule delay is measured by the time value of money, interest charges, or discount rates. The sponsors will be penalized for this cost since the Finance Charge will continue to be added to the Actual Capital Costs, thus increasing the Cost Performance Ratio and lowering the IROR. However, the increased costs due simply to inflation can not be considered an increase in the real costs of the project. In money terms, the costs have increased due to inflation, but then so have all other prices as well as the incomes of gas consumers. Since incomes are likely to increase in step with inflation, consumers are not really worse off simply because inflation has increased construction costs.

In their initial comments, the sponsors raise some technical issues concerning a few of the price indices proposed by the Commission in the Notice of April 6. Upon review, the Commission finds the sponsor's criticisms to be valid and the table of price indices included in Condition No. 18 has been modified to correct these errors.

IV. CHANGE IN SCOPE

A. Mechanism

The Change in Scope mechanism is an essential part of the overall Incentive Rate of Return mechanism. Its purpose is to protect the project sponsors against reductions in their rate of return caused by major events that drastically increase the cost of the project.

In formulating the Change in Scope mechanism the Commission had four goals in mind. 98/ The first was to avoid dilution of the incentive to reduce costs. The second was to limit the administrative burden of implementing the Change in Scope mechanism. The third was to develop clear and unambiguous rules, in order to minimize controversy and disagreement over when a Change in Scope event had occurred. The final goal was to avoid inadvertent, perverse incentives that might have a capricious effect on the project.

To best achieve and balance these four goals, the Commission proposed a Change in Scope mechanism that would only adjust the target cost for cost increases

98/ See April 6 Notice at 43-45 (mimeo).

resulting from four events. If any of these four events occur the Projected Capital Cost of the project will be altered prior to determining the Cost Performance Ratio. The events are (1) wars, (2) any disaster declared by the President of the United States pursuant to the Disaster Relief Act of 1974, Pub. L. 93-288, 88 Stat. 143, (3) major design changes compelled by changes in Federal or State laws or regulations applicable to natural gas pipelines enacted or adopted subsequent to the Federal Inspector's approval of the Final Design of the pipeline, and (4) major changes in pipeline routing or capacity ordered by Federal or State Governments for the ANGTS from that approved by the Federal Inspector in the Final Design of the pipeline. For the reasons stated below, this Order adds a fifth Change in Scope event: 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.

The Staff's comments seek clarification as to the nature and consequences of design changes and cost estimate revisions that occur subsequent to approval of the Certification Cost Estimate but prior to the approval of the Final Design. This concern is also reflected in many of the comments of the project sponsors. These comments raise an important point which must be clarified at the outset.

The Change in Scope mechanism set forth above applies solely to changes that occur subsequent to the approval of the Final Design. Changes that occur subsequent to that date will be governed by the Change in Scope mechanism set forth in Condition No. 10, as implemented through the Change in Scope procedure set forth in Condition No. 11. Changes that occur prior to approval of the Final Design are governed by Condition No. 9. Such changes, for instance, could include design changes generated by new technology or further study by the project sponsors.

Condition No. 9 provides a strong incentive, and wide latitude, for the project sponsors to consider seriously and study intensively all of the problems and risks that they will confront, and to evaluate, propose and justify any design changes that they deem necessary and appropriate, including all of the cost consequences of such proposed changes. If properly justified as desirable changes in design that cause real changes in cost, those cost changes will then be reflected in revisions to the Certification Cost Estimate and the Projected Capital Costs (but not in the Center Point).

During the period between approval of the Certification Cost Estimate and approval of the Final Design, major permits or approvals from government agencies may be granted, including terms and conditions attached thereto. Thus, the sponsors can incorporate the effect of these terms and conditions in their final design and cost estimates. If the granting of the major permits takes longer than anticipated in the Certification Cost Estimate, thus delaying the final design, the Commission expects that the final design cost estimate will incorporate the effect of such delay, both in direct costs, in schedule, and in the projected allowance for funds used during construction. (The final construction schedule should also contain a schedule for the issuance of government permits during construction.) The Commission's goal is that, at the time of approval of the Final Design, all possible uncertainties surrounding the pipeline, whether the result of governmental permitting processes or inherent technical problems, will have been resolved to the maximum extent possible. Once the Final Des[illegible] and cost estimate revisions have been approved, he project sponsors will be expected to build the pipeline, following that Final Design and construction plan, without significant deviation.

In sum, design changes prior to approval of the Final Design can be proposed by either the project sponsors or the Federal Inspector (through the process of the Inspector's review and approval of the Final Design). The Inspector's determination will be final (subject only to applicable judicial review), with respect to both changes in the design itself as well as cost revisions resulting from such changes. The Federal Inspector will make these determinations pursuant to such procedures as he may adopt. The Inspector will advise the Commission of his determinations, but they will not be subject to administrative review by the Commission.

Once the final design has been approved, however, the energies of the project sponsors, the Federal Inspector and the Commission should be devoted, to the maximum extent possible, to the expeditious construction of the pipeline system. By then, the project sponsors will have had ample opportunity to fully consider and evaluate all of the risks and problems inherent in the project, including the attendant cost implications. Thus, as of that point in time, all subsequent IROR cost changes will be governed by the much more restrictive provisions set forth in Conditions No. 10 and 11.

The Upper Tanana Development Corporation, while generally approving the concept of a limited scope change mechanism, proposes in its comments that "socio-economic expenditures" should be allowable as a fifth category of Change in Scope events. 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.

The project sponsors, in their comments, urge a substantially expanded range of events that would qualify as Changes in Scope. In particular, they urge inclusion of:

> "(1) Changes caused by government requirements, delays in government approvals, and reimbursement for government oversight.
>
> "(2) Standard force majeure conditions such as acts of God, earthquakes, abnormal weather, terrorism, sabotage, riots and civil disturbances, and embargos, strikes, work stoppages and slowdowns.
>
> "(3) Field conditions not ascertainable at the time of final design.
>
> "(4) Right-of-way acquisition where rights of eminent domain may not exist."

The Change in Scope mechanism must be examined in its proper context. First of all (unlike the scope change concept in the normal government contract context), it applies solely to determining the rate of return, and not the rate base itself. For instance, in the event of a small flood, fire, or landslide, etc., in which the project sponsors prudently incur unanticipated costs, those costs will be fully recoverable through inclusion in the rate base. All that is at issue here is the effect of such an occurrence on the allowed rate of return.

In this regard, the Commission is faced with a basic choice of alternatives. One alternative is to adopt the very broad range of eligible scope changes proposed by the sponsors, and to take account of that generous and protective approach by adopting a less generous Center Rate and Center Point. The other alternative is to impose a higher degree of risk on the sponsors, by restricting the range of scope changes, and to reflect that higher risk in determining the Center Rate of Return and the Center Point. We have chosen the latter course. 99/ Our reasons for that choice can best be explained through

99/ As discussed previously, this is policy reflected in the IROP Risk Premium; see Section II.B.5.

illustratives discussion of the project sponsors' proposed alternative.

We start with "abnormal weather." Arctic weather can be brutal. 100/ The project sponsors know that it is brutal; that is a risk that they can and must evaluate in planning the cost of the project, and it is a risk for which they are being compensated in their rate of return. Scope change applications and controversies in the context of the Alaska pipeline project would plunge the sponsors and the Federal Inspector into potentially endless inquiries into comparative temperatures, wind/chill factors, and thaw conditions (for which historic weather data may or may not be available), measured in terms of consecutive days of such weather, at particular geographic locations, over the past 20, 50 or 100 years, with commensurate time and motion studies of the effects of abnormally brutal weather (versus normally brutal weather) on labor productivity. This is precisely the diversion of engineering, scientific and legal time, expertise and expense that the Commission seeks to avoid. The

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100/ See, e.g., J. London, To Build a Fire; R. Service, "The Cremation of Sam McGee."

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. Some of these events can be influenced to at least some extent by the sponsors; others cannot, but steps can be taken to cope with their effects. With respect to truly catastrophic events which cannot reasonably be factored into cost planning, such as a war, or a severe earthquake or tsunami, etc., the Change in Scope mechanism affords protection of the rate of return.

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

Similarly, right-of-way acquisition is a problem that the project sponsors can and should evaluate when preparing their Certification Cost Estimate (including the Center Point).

Finally, regarding "changes caused by government," the Change in Scope mechanism does in fact provide rate of return protection with respect to major design changes compelled by changes in government laws or regulations applicable to gas pipelines, and with respect to government ordered major changes in the (Alaska segment) pipeline routing or capacity. During the course of construction, it is probably inevitable that the Federal Inspector will require, and the project sponsors will themselves propose, numerous minor changes in design or routing, or even capacity. Again, this is an eventuality that the project sponsors should consider in preparing their Certification Cost Estimate, and one that the Commission itself has considered in setting the Center Rate and Center Point procedure. When such minor changes are determined to be either necessary or desirable, the energies of all concerned ought to be devoted to making those changes, unencumbered by diversions into the processing of scope change applications.

B. Provision for Delay

In their comments, the project sponsors also take the Commission to task for failing to fulfill an "unconditional assurance with regard to delays caused by the government." 101/ In response to the valid aspect of that criticism, the Commission has added a fifth Change in Scope event.

101/ Joint Comments at 20-22.

Most permits and certificates will be issued prior to approval of the Final Design. To the extent that delays occur in the issuance of those certificates or permits -- and regardless of the cause of those delays -- the project sponsors will have ample opportunity to seek appropriate adjustments in the Projected Capital Cost up to and at the time of approval of the Final Design. That procedure was discussed above.

Some permits, however, will not be applied for or granted until during the construction period. The Commission expects that a detailed timetable for application and issuance of the necessary permits will be established and agreed to by the project sponsors and government agencies, including State agencies as necessary and appropriate, as part of approval of the Final Design and Cost Estimates. 102/

Commission representatives have had extensive discussions with representatives of other government agencies regarding their permitting processes and the importance of timely issuance of permits, particularly during the

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102/ Such a timetable, and establishing responsibility for adherence to that timetable, is within the contemplation of § 202(b) of Reorganization Plan No. 1 of 1979, transmitted by the President to the Congress on April 2, 1979.

construction period. Those agencies have been uniformly responsive to requirements for adhering to a permitting timetable. However, any agency's ability to adhere to the agreed schedule is directly related to the timely filing of all relevant applicant information by the project sponsors.

It is the Commission's expectation that all applications will be timely filed and all permits timely granted. If receipt of a permit is delayed because an application was not timely filed, or if the case for issuing the permit is not adequately set out, then the resulting increase in costs (and in Cost Performance Ratio) is a consequence of action (or inaction) by the project sponsors and should count against them. If, on the other hand, issuance of a permit during construction is delayed by the permitting agency, which fails to process the application to a conclusion, and the cost consequences of such action (or inaction) are significant, then some adjustment is appropriate. This Order revises the April 6 Notice by providing the Federal Inspector with discretion to treat as an allowable scope change event, government failure to take action toward issuing a required government permit, if such delay has significant cost consequences. Under no circumstances, however, shall a government denial of a permit or certificate be construed as a Change in Scope event, unless such denial is subsequently reversed by a court on review; this provisions is directed solely to delay in processing of applications, and not to denial of the permit sought.

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.)

C. Procedure

When the project sponsors believe that a Change in Scope event (as defined above) has occurred, the project sponsors shall submit to the Federal Inspector both an explanation of the alleged Change in Scope and an estimate of the increase in Projected Capital Costs for the project. The Federal Inspector will evaluate the information submitted, and determine whether the event qualifies as a Change in Scope event and, if so, the appropriate adjustment to the Projected Capital Cost.

The Commission intends for the Federal Inspector to act on each Change in Scope case as expeditiously as possible after the alleged Change in Scope has occurred, pursuant to whatever appropriate procedural regulations the Inspector may promulgate. The Federal Inspector's decision will constitute final agency action, subject to applicable judicial review but not subject to review by the Commission. This procedure is designed to ensure prompt resolution of all Change in Scope issues.

The Staff's comments seek clarification of these procedures, on several points. First, the Staff suggests the possibility of the Federal Inspector, or some third party, seeking to obtain a reduction in the Projected Capital

Costs. Such a reduction presumably would be premised on potential - and sizable - construction cost savings that might emanate from (a) a war, (b) a natural disaster, (c) involuntary major design changes after the final design is approved, or (d) major changes in pipeline routing or capacity after the final design is approved. While the hypothetical symmetry of the Staff's suggestion is not devoid of surface appeal, we do not readily perceive how any of the above enumerated events could significantly reduce the total cost of the project. Moreover, even if a major change in design, routing or capacity could in fact significantly reduce the total cost, we would not want to discourage such changes by reducing the rate of return if such a change is implemented. Accordingly, and in order to preclude hypothetical uncertanties in this aspect of the IROR formula, we are limiting the Change in Scope procedure to changes submitted by the project sponsors.

Second, the Staff inquires as to whether interested parties, including the Staff, will be afforded an opportunity to participate in the Change in Scope proceedings before the Federal Inspector, and finally, whether the Inspector's decision could be appealed to the Commission.

The Change in Scope procedure is premised on Reorganization Plan No. 1 of 1979, as submitted by the President to the Congress on April 2, 1979. Section 102 of the Plan transfers to the jurisdiction of the Federal Inspector "[s]uch enforcement functions of . . . the Federal Energy Regulatory Commission related to compliance with: the certificates of public convenience and necessity, issued under Section 7 of the Natural Gas Act . . . ." By incorporating the Change in Scope Mechanism and Procedure into conditions attached to the project sponsors' certificates, it is the Commission's intent and purpose to transfer to the Fede al Inspector the jurisdiction to enforce and implement those conditions, by transferring to the Inspector's jurisdiction the authority to make the Change in Scope determinations. The Commission and the Inspector may, in the future, seek to further clarify the precise boundaries of their respective jurisdiction, on this or othe matters, through means of an interagency agreement, as authorized by the last sentence of section 202 of the Reorganization Plan:

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

While the Commission would have no objection to -- indeed, would welcome -- the opportunity for its Staff and other interested parties to participate in the Federal Inspector's deliberative processes, the Inspector should have the latitude to determine, in whatever appropriate procedural regulations the Inspector may promulgate, the nature and extent (if any) of such participation.

While it would not be implausible for the Commission to retain the power to make the Change in Scope determinations itself, the worst possible procedure would be for both the Inspector and the Commission to participate in that decisionmaking through seriatum adminirtrative deliberations. ANGTA and the President's Decision mandate expedition in decisionmaking, and the project sponsors and their lenders and investors are entitled to receive the promptest possible determinations consistent with applicable requirements of due process. The Federal Inspector and his staff will be located at the scene of the pipeline, monitoring its construction on a full time, day-to-day basis. They will be in the best position to render prompt determinations of Change in Scope events and adjustments. Those determinations should be final, subject only to judicial review.

Finally, as indicated in the preceding section of this Order, the above described procedures will also be generally applicable to the Federal Inspector's approval of design changes, including resultant revisions in the Certification Cost E. .imate, pursuant to the Inspector's approval of the Final Design.

V. END RESULTS

In responding to the Commission's proposal for an Incentive Rate of Return mechanism, the project sponsors have emphasized that, individual parameters aside, it is the end result which is all important: "[t]he end result. . . [should be] the final determination of an equitable, practical, and definitive IROR mechanism which will not prohibit financing." 103/ The Commission believes that the IROR mechanism and values established by this Order will in fact increase the prospects of obtaining private project financing. It remains the responsibility of the project sponsors to convince potential debt and equity investors of their ability to complete the project within a range of construction costs at which the average rate of return

103/ Joint Comments of Alaskan Northwest Natural Gas Transportation Co., and Northern Border Pipeline Co. at 7 (Docket No. RM78-12) (May 4, 1979) [hereinafter cited as Joint Comments]; see also Joint Comments at 6-7, 26-27, 30; Alaska Northwest Natural Gas Transportation Co., "Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range" (Docket No. RM78-12) (Feb. 15, 1979).

is comparable to that which could be earned in alternative investment opportunities of comparable risk. 104/

As noted in the Introduction section of this Order, the Decision was written against a backdrop of concern for the impact of cost overruns on the economic benefits of ANGTS. In response to that concern, the President imposed a framework for project implementation designed to insure that the project would be of economic benefit to the nation. The IROR mechanism and values established by this Order play their role in that framework by providing ". . .substantial incentives to construct the project without incurring overruns." 105/

In evaluating the project's economic benefits to the nation, the President found that ". . .Alcan's direct costs could increase almost 124 percent over the cost overrun case before it would become socially

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104/ In this vein, the Commission recognizes that not even Federal government debt instruments are completely free of uncertainty, and were the project sponsors to be able to find investments which were totally free of uncertainty and ambiguity, the Commission expects that the rates of return on those investments would be a mere fraction of those contained in this Order.

105/ Decision at 37.

uneconomic;. . ." 106/ The project sponsors have insisted that they not be exposed to the risk of earning less than 13 percent on equity. 107/ As Table 3 shows, rates of return less than 13 percent will not be r ached until costs overrun the March 1977 estimates in the Decision by 140 percent in Alaska and 60 percent for Northern Border. 108/ Such large overruns approach the levels at which the analysis in the President's Decision suggests that the economics of the entire project should be reviewed.

If the project sponsors believe that the probability of earning less than 13 percent on equity is substantial, the procedure for setting the Center Point allows the project sponsors to argue for a different Center Point

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106/ Decision at 180. The "Alcan" system referred to here is the precurser of the system proposed by the sponsors and now referred to as the ANGTS. See June 30 order.

107/ Joint Comments at 8.

108/ Note that the measurement of overruns excludes the effects of inflation, design changes prior to the final design, and certain changes in scope for the project.

and thus a different IROR schedule. The project sponsors may offer such arguments at the time they present their Certification Cost Estimates. Until such information or evidence concerning the ultimate costs of the project are presented, the Commission cannot conclude that the IROR mechanism required in this Order creates a significant probability that the Incentive Rate will be less than the 13 percent floor requested by the sponsors.

Comparative IROR Schedule Proposed

	Commission		Project Sponsors		Staff	
	Alaska	N. Border	Alaska	N. Border	Alaska	N. Border
Center Rate (%)	17.5	15.0	18.0	17.0	12.5	11.0
Center Point	1.3 1/	1.1 1/	1.3 2/	1.2 2/	1.3	1.1
Marginal Rate (%)	8.0	8.0	12.0	12.0	0	0

Cost Performance Ratio	Incentive Rate of Return (%)					
0.8	23.4	17.6	21.8	19.5	20.3	15.1
0.9	21.7	16.6	20.7	18.7	18.1	13.4
1.0	20.4	15.7	19.8	18.0	16.3	12.1
1.1	19.2	15.0	19.0	17.5	14.8	11.0
1.2	18.3	14.4	18.5	17.0	13.5	10.1
1.3	17.5	13.9	18.0	16.6	12.5	9.3
1.4	16.8	13.5	17.6	16.3	11.6	8.6
1.5	16.2	13.1	17.2	16.0	10.8	8.1
1.6	15.7	12.8	16.9	15.8	10.2	7.6
1.7	15.3	12.5	16.6	15.5	9.6	7.1
1.8	14.9	12.3	16.3	15.3	9.0	6.7
1.9	14.5	12.1	16.1	15.2	8.6	6.4
2.0	14.2	11.9	15.9	15.0	8.1	6.1
2.1	13.9	11.7	15.7	14.9	7.7	5.8
2.2	13.6	11.5	15.5	14.7	7.4	5.5
2.3	13.4	11.3	15.4	14.6	7.1	5.3
2.4	13.2	11.2	15.3	14.5	6.8	5.0
2.5	12.9	11.1	15.1	14.6	6.5	4.8
2.6	12.8	11.0	15.0	14.3	6.3	4.7
2.7	12.6	10.9	14.9	14.2	6.0	4.5
2.8	12.4	10.8	14.8	14.1	5.8	4.3

1/ These values are based on March 1977 cost estimates. They will be revised late upon the Certificate Cost Estimates if appropriate.

2/ Project sponsors propose that the Commission set these values now.

TABLE 3

The sponsors have requested a floor of 13 percent on the Incentive Rate. They argue that the IROR mu't be within a "zone of reasonableness." 109/

In deciding rates of return, the Commission must balance the need to protect the consumer from unreasonably high rates while maintaining the financial

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109/ Alaskan Northwest Natural Gas Co., "Petition for Expedited Rulemaking and Issuance of Final Order Establishing Rate of Return Range" (Docket No. RM78-12) (Feb. 15, 1979). In arguing for a "zone of reasonableness," Alaskan Northwest directs our attention to the standards of FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944). Presumably the sponsors have in mind the following passage:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that "regulation does not insure that the business shall produce net revenues.". . . But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. (320 U.S. at 603)(citations omitted)

integrity of the project and providing the investors an adequate return on investment. The Commission believes that this classic balancing test must be applied to the IROR in a manner consistent with the mandate of the President's Decision to establish an incentive to control costs. While the Commission must consider the financial integrity of the project, this consideration is tempered in light of the purpose of the incentive; the result must be just and reasonable and must not be confiscatory.

The IROR mechanism, with its inflation adjustment and scope change procedures, strikes the required balance. As advocated by the sponsors, the mechanism does have a *de facto* floor; this is the practical consequence of the Marginal Rate. More importantly, however, the IROR schedule provides, over the range of reasonable Cost Performance Ratios, a rate of return equal or greater to that advocated by the sponsors. This is the practical result of applying an average incentive rate over the range of Cost Performance Ratios. Given this result, the mechanism provided here cannot be considered either unjust or unreasonable; it certainly cannot be construed as confiscatory. Investors, if they perform, are afforded ample opportunity to earn generous rates of return, while consumers will be able to obtain the natural gas they need at an acceptable price.

VI. Tariff Issues

This section of the Order addresses the proposed tariffs submitted by the project sponsors for the Alaskan and Northern Border segments of ANGTS. 110/ The Commission will accept the tariffs, subject to conditions described herein. The Commission shares the project sponsors' assessment of the importance and relevance of the tariffs. The tariffs are indeed the "economic lifeline" of the project. There must therefore be a degree of certainty for project sponsors and potential financers adequate to ensure that there will be a flow of revenues sufficient to service debt and pay all other current expenses once billing has been allowed to commence. The mechanisms for providing this assurance are described in the tariffs themselves and the Commission's considerations herein.

The Commission will resolve in this Order four tariff issues identified by the Alaskan Delegate as affecting the risk to be borne by project sponsors. The Commission will also decide in this Order certain other tariff issues that have been identified in the

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110/ The proposed tariffs were filed on March 12, 1979, pursuant to the Commission's Order set forth in "Notice of Delegate Report and Order Directing Tariff Filing", Docket No. RM78-12 (February 22, 1979) [hereinafter Delegate's Report].

comments of parties and by the Commission's own analysis of the proposed tariffs. 111/

Not all tariff issues are to be decided in this rulemaking. The Commission reaffirms the April 6, 1979 Notice that reserved for resolution in a separate proceeding the issue of the depreciation rate to be used to calculate the cost of service for "pre-delivery" of Canadian gas transported through the Northern Border pipeline (Notice at 60-61). Further, the Commission will defer to the proceedings in Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, *et al.*, the question of whether, and to what extent, there should be any apportionment of costs of Northern Border's "pre-delivery" facilities between deliveries of "Canadian bubble" gas and future deliveries of Alaskan gas. The Commission views these issues to be more closely related to the questions to be decided in that certificate proceeding; hence, that proceeding is the more appropriate forum for their resolution.

111/ The Alaskan Delegate provided notice of these issues in letters addressed to the project sponsors. Those letters were dated April 20, 1979 and April 27, 1979. Copies of each were sent to all parties of record in this docket as well as in Northwest Alaskan Pipeline Company, Docket Nos. CP78-123, *et al.*

Another issue that will not be resolved here concerns specific mechanism(s) for shipper tracking. 112/ A tracking mechanism involves questions of the timing of any flow-through of charges, the necessity of being assured that there will be a matching of costs and revenues, and recognition that appropriate tracking mechanisms for individual shippers may vary because rate designs and rate forms will differ among shippers. Thus, appropriate flow-through arrangements can only be properly addressed when the individual shipper tariffs are filed with the Commission.

Although it would be premature to specify appropriate methods at this time, the Commission can state, however, that it is in basic agreement with the concept that any amounts paid ANGTS under a tariff approved by this Commission will be allowed to be included in the rates

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112/ The Commission has previously addressed this issue. By motion dated April 18, 1979, Alaskan Northwest and Northern Border requested reconsideration of the Notice of Proposed Rulemaking in this docket. Specifically, petitioners requested that the Commission "provide for inclusion in [Docket No. RM78-12] of issues relating to shipper company recovery of all amounts paid under the Alaskan Northwest and Northern Border tariffs." (Motion at 2.)

By order dated April 27, 1979, the Commission denied the motion but indicated that parties would not be precluded from commenting on the flow-through issue or from the filing of *pro forma* tariffs by the shippers. Parties filed comments on this issue but *pro forma* shipper tariffs were not filed.

of those shippers that are interstate gas pipeline companies, subject to appropriate reconciliation of all other aspects of ratemaking to ensure that there is no overcollection of costs attributable to the tracking arrangements themselves. Interstate gas pipeline companies shipping through the ANGTS system will be expected to pay all charges properly due to ANGTS. Any such amounts paid ANGTS will be allowed to be included in the rates of those shippers that are interstate gas pipeline companies. Allowance of those amounts will require that there is a matching of costs and revenues in order that overcollection or undercollection of fixed costs of the shipper company does not occur. 113/

113/ The possibility of overcollection (or undercollection) of fixed costs arises because the commodity charges included in interstate pipeline rates typically recover certain of the fixed costs. For example, under the _United_ 25/75 cost apportionment approach 75 percent of the fixed costs of a shipper would be assigned to the commodity rates of the shipper. The _unit amount_ of fixed costs to be recovered would be determined in a rate proceeding on the basis of the projected costs and throughput of the pipeline for the test period. As Alaskan gas begins to flow through the shipper's pipeline, it will recover the unit fixed costs included in the effective rates. Should the Alaska natural gas volumes not have been included in the billing determinants underlying the "base" charges, the result could be an over recovery of fixed costs, i.e., the fixed costs would be recovered by greater billing determinants than had been used to develop rates. The Commission will require assurance that any mechanism used to flow-through ANGTS costs will not result in this or a comparable situation.

The Commission also defers to a later date the resolution of the question of the permissible level of CO_2 that is to be contained in the gas. 114/ This issue was addressed in the comments of both the State of Alaska and Sohio Natural Resources Company. 115/ The permissible level of CO_2 is a significant issue that involves an evaluation of the impact of the different CO_2 levels on capital and operating costs. However, because of the absence of adequate data available on this record to enable complete evaluation of this issue, the Commission recently requested the parties to file additional information on this matter. 116/ The evaluation of the data filed in response to that request has not yet been completed. The Commission will, therefore, issue a separate order on this issue rather than withhold issuance of its disposition of the other issues raised in this rulemaking. An order establishing the CO_2 quality

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114/ Questions concerning other quality standards are discussed at Section VI.B.5.

115/ Initial Comments of the State of Alaska at 6-7 (Docket No. RM78-12) (May 4, 1979); Comments of Sohio Natural Resources Company on Notice of Proposed Rulemaking Issued April 6, 1979, at 2 (Docket No. RM78-12) (May 7, 1979).

116/ Order Requesting Further Submission of Data, Views, and Comments (Docket Nos. RM78-12 and RM79-19) (issued May 16, 1979).

standard(s) will be issued as soon as the Commission can complete its evaluation of the additional material.

Finally, the Commission will decide in Docket No. RM79-19 the issue of cost responsibility for processing Prudhoe Bay gas to pipeline quality standards. The Notice of Proposed Rulemaking in Docket No. RM79-19 specified that the cost responsibility issue would be decided in that docket. 117/ The record being compiled in that rulemaking will provide the Commission with the information necessary to resolve the issue. Accordingly, the Commission will defer decision on those portions of the tariff that affect this issue. After the issue is resolved in Docket No. RM79-19, a supplementary order in this proceeding will be issued to reflect that resolution in the tariffs of the project sponsors.

117/ Federal Energy Regulatory Commission, "Treatment of Certain Production-Related Costs for Natural Gas to be Sold and Transported through the Alaska Natural Gas Transportation System: Notice of Proposed Rulemaking and Statement of Policy" (Docket No. RM79-19) (issued Feb. 2, 1979).

A. Issues Identified by the Alaskan Delegate

The four major tariff issues identified by the Alaskan Delegate are: (1 determination of the date on which the project sponsors will be permitted to commence billing their shipper-customers; (2) whether an interim rate should be imposed during the initial build-up phase of the project; (3) the extent to which the effect of a service interruption should be shared by the project sponsors as well as by shippers and consumers; and (4) the billing procedure to be used to levy charges for transportation services. 118/

1. Billing Commencement Date

At issue here is the appropriate interpretation of the President's Decision and the setting of the billing commencement date. The Alaskan and Northern Border segments of the system will be project financed, which means their debt will primarily be secured by the revenues they collect. Commencement of the collection of those revenues is triggered by the commencement of billing, and is, therefore, important to an assessment of project

118/ Report of the Alaskan Delegate on Tariff and Operation Phase Rate Issues 6-7, accompanying Notice of Delegate Report and Order Directing Tariff Filing (Docket No. RM78-12) (issued Feb. 22, 1979).

risk. The sooner billing can commence, the less risky the project will appear to potential investors.

The third finance condition in the President's Decision prohibits any payments by the purchaser or ultimate consumer of Prudhoe Bay gas "prior to completion and commissioning of operation of the system". 119/

Definition of this phrase does not appear in ANGTA, the President's Decision, the Natural Gas Act, or the Commission's Regulations. The Report of the Alaskan Delegate, however, offers four possible interpretations of when billing might commence:

1. Charges begin when all segments of the pipeline are complete and gas is being transported.
2. Charges begin when all segments are capable of rendering service, even if no gas is flowing.

119/ The third finance condition provides:

> 3. Neither the successful applicant nor any purchaser of Alaska gas for transportation through the system of the successful applicant shall be allowed to make use of any tariff by which or any other agreement by which the purchaser or ultimate consumer of Prudhoe Bay natural gas is compelled to pay a fee, surcharge, or other payment in relation to the Alaska natural gas transportation system at any time prior to completion and commissioning of operation of the system. Decision at 37-38.

3. Charges begin for each segment when it is complete and capable of rendering service.

4. Charges begin at a date certain.

The proposed tariff of Alaskan Northwest provides that "completion and commissioning" shall occur when the "Company's pipeline is capable of rendering service even if, for whatever reason, gas is not being delivered to, or transported through Company's pipeline system." (Section 1.10 of the General Terms and Conditions.) The tariff of Northern Border contains an identical provision (Section 1.10 of the General Terms and Conditions). Both tariffs would thus prescribe a billing commencement date that follows the third definition suggested by the Alaskan Delegate.

The project sponsors assert in their joint comments that the billing commencement date contemplated in the respective tariffs is both consistent with the President's Decision and promotes financing of the system. The sponsors argue initially that neither the Decision nor its accompanying Report address the specific question of the initiation of billing once a segment has been completed. 120/ Considering that argument, together with the requirement that the project must be privately

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120/ Joint Comments at 48.

financed, the sponsors contend that the Commission must be presumed to have been given broad discretion in approving or fashioning conditions that would encourage private financing. Private financing can best be achieved, according to the sponsors, through Commission assurance that the billing commencement date for one segment will not be tied to the billing commencement date for another segment. 121/

Staff, on the other hand, relies on the President's Decision and accompanying Report to contest the billing commencement date set forth in the tariffs. 122/ Staff argues that in designating different companies to construct and operate different portions of the system, the President was fully aware of the distinction between the "system" and "portions" thereof. According to Staff, the President maintained that distinction in the third finance condition, which precludes any fee, surcharge, or other payment in relation to the ANGTS

121/ Id. at 49-50, 52-55.

122/ Staff, Initial Comments at 6-9. Staff also cites to the Initial Decision in El Paso Alaska Company, to the effect that until a company begins to provide service a "natural gas company" does not exist within the meaning of the Natural Gas Act and, consequently, no effect can be given to a tariff provision of a company that has not yet attained jurisdictional status. Id. at 6. The Commission finds it unnecessary to address this question in light of the determinations made here.

before completion and commissioning of operation of the system.

The Public Service Commission of the State of New York also challenges the tariff provisions defining the billing commencement date. While New York has no objection to "appropriate" billing should Northern Border "pre-build" all or a portion of its pipeline to transport Canadian gas, New York advocates billing consumers only for actual services rendered. 123/

In reaching its conclusion, the Commission has considered these arguments as well as the requirements of the President's *Decision*, its legislative history 124/, and the impact of alternative resolutions upon the financeability of the project.

123/ New York, Initial Comments at 6-7.

124/ The relevant legislative history accompanying the President's *Decision* consists of the *Report Accompanying the Decision*, as well as the House and Senate Reports to H.J. Res. 621 (P.L. 95-158, 91 Stat. 1268), which approved the *Decision*. The Congressional debates on H.J. Res. 621 do not focus on when billing should commence.

The Commission's resolution of the billing commencement date begins with the Commission's interpretation of the phrase "completion and commissioning of operation of the system." The Commission believes that the Decision is precise concerning the definition of the term "system." The Decision both refers to the system in its entirety and to the various segments in the United States and Canada that comprise the system. 125/ Thus, when the Decision uses the term "system," it is clear that the reference is to the entire system including all segments in the United States and Canada. The Commission concurs with Staff on their definition of the term "system."

However, neither the Decision nor the legislative history provides similar certainty in defining the phrase "completion and commissioning of operation." Thus, in specifying a billing commencement date, the Commission has had to consider the broad goals of ANGTA, principles of public

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125/ For example, the Decision defines the system as an overland pipeline from Prudhoe Bay, Alaska, through Canada, to the Midwest and Western sections of the continguous United States (Decision at 6). Also, the Decision defines each of the separate segments and specifies the companies to own and operate each segment.

utility regulation as well as the objectives of this project as identified in the Decision.

Specifically, the Commission has considered the need to (1) equitably treat all parties including the project companies, their investors, the shippers and owners of the gas, and gas consumers; (2) provide incentives to avoid delay both in the completion of construction of all segments and in the start-up of gas production; and (3) reduce the ultimate cost to consumers. Billing commencement at the time when all segments are complete, tested and proved capable of operation satisfies these goals better than the other alternatives posited by the Alaskan Delegate and discussed by the Staff, the sponsors, and other parties.

Prior to commissioning the system for operation, all pipeline segments must be been tested and proved to be capable of operation. The Commission will rely upon the Federal Inspector to certify that the system is capable of performing the services for which it was certificated. In establishing this billing commencement date, the Commission limits the rate to be charged before initiation of service to a "Minimum Bill." The Minimum Bill shall be equal to actual operation and maintenance expenses, current taxes, plus debt service including interest and scheduled retirement, if the Federal Inspector certifies that the system is capable of performing the service even though no gas has been tendered for transportation. The

Commission concludes that this is a reasonable and fair burden to place on the various parties. First, sponsors have control over the coordination of the construction schedules of the various segments. Shippers or consumers should not be asked to bear the cost of poor coordination in the construction of the entire system. 126/ Once the system is complete, however, it would be unfair to impose a further burden on the project sponsors who are only the transporters of the gas for the shippers and who depend on shippers to tender gas to them. The Minimum Bill (equal to actual operation and maintenance expenses, current taxes, plus interest and scheduled retirement of debt) will allow the project companies to pass this portion of the total cost to the shippers. The mechanism and timing of the flow-through of the Minimum Bill is specifically reserved until such time as the proposed shipper tariffs are presented to the Commission. 127/

Finally, the Commission concludes that the specification of the date for billing commencement strikes the necessary balance between various costs to be borne by the consumer and risks to be borne by project sponsors.

This provision reduces the risk borne by investors in the project, especially debt holders, and this reduction in risk

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126/ The Commission's choice of billing commencement date is not inconsistent with our earlier interpretation of the President's Decision in Alcan Pipeline Company, Docket Nos. CP78-123, et al., "Order Dismissing Petition for Declaratory Order" (March 24, 1978). In that order the Commission stated that the Decision precludes the shifting of the risk of non-completion to gas consumers. Once the system has been constructed and is capable of rendering service, that risk will have passed. It is at just that point that we have allowed charges to commence.

should facilitate the private financing of the project and thus the expeditious construction of this important source of natural gas. Also, this reduction of risks will tend to reduce both the rates of interest and rates of return necessary to attract private debt and equity investors. 128/ Interest charges and return on equity is a major portion of the cost of service for this pipeline. A lowering of such costs of financing could mean a substantial savings to consumers. 129/ The Minimum Bill will provide for debt service and thus reduce the finance charges to be borne by consumers (AFUDC) when service commences. 130/

This choice of a billing commencement date does create the possibility of the project companies billing shippers during a period when transportation service has not commenced. However, the Commission concludes that a long delay in the initiation of service after completion and commissioning is very unlikely. Incentives created by this definition of billing commencement, and the various controls and oversight authority granted to the Federal Inspector encourage coordination and timely commencement of service. First, insofar as most shippers are also going to be sponsors with an equity interest

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128/ See, El Paso Alaska Company, Docket Nos. CP75-96, et al., Tr. at 29,620.

129/ See, New York, Initial Comments at 1.

130/ See, El Paso Alaska Company, Docket Nos. CP75-96, et al., Tr. at 35,514.

in the project, it would obviously be to their benefit to have the gas flowing at an early date rather than deferring cash flow to be realized from their equity share of the project. Thus, the Minimum Bill, which provides no return of or on equity, creates a cash flow incentive for the sponsors to consummate, in a timely manner, the necessary agreements with the gas producers and the transporter, as well as any new arrangements that may be required with the shippers' customers.

Additionally, it would appear to be in the producers' best interest to have producer-shipper contracts finalized at an early date and the conditioning plant ready when the system is prepared to transport gas. This is because of the expected flow of revenues to be realized by the producers from the sale of the gas and also because of the long-range planning required for efficient reservoir management of the Prudhoe Bay field.

Based upon the previous analysis and reasoning, the Commission concludes that the project companies may commence billing after the entire system is completed and tested for service. Tested for service does not require that the line be packed. The Commission's resolution also appears to be harmonious with the approach previously taken by the National Energy Board of Canada (NEB). The NEB uses the terminology "leave to open" as the regulatory event which signifies the NEB's judgment that construction has been completed, the facility has been tested and is ready for service. It is noteworthy that the Foothills' proposed tariff provides that billing may commence only after all nine segments in Canada have been completed and commissioned for operatio... 131/

During the period between completion of the entire system and actual transportation of gas, the Minimum Bill will equal the actual operation and maintenance expenses, current taxes, and amounts necessary to service debt, including interest and scheduled retirement of debt. This level of reduced billing will continue until gas is tendered for transportation and service commences. Upon the initial transportation of gas by the system, the project sponsors will then be allowed to charge an interim rate. The next section of this Order specifies the level and duration of the interim rate.

131/ Foothills Pipelines (Yukon) Ltd., Gas Transportation Tariff, Sheet No. 201, filed April 1, 1979 (Section (1)(1.4), General Terms and Conditions):

> The term "Billing Commencement Date" shall mean the date when all Canadian Segments required in the transportation of that U.S. Gas have been completed and commissioned for operations. . .

The continuation of regulatory consultations as provided for in Section 9 of the Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline may result in a closer coordination of billing commencement in the U.S. and Canada.

2. Interim Rate

We have determined that charges should be permitted only after all segments of the system are completed and capable of rendering service. Next to be addressed are the related questions of the level of the charges to be initially imposed. At issue is whether the tariffs should provide for fixed, reduced charges during the initial operating period of the system or, alternatively, for full cost-of-service charges. For the reasons discussed below, the Commission will require that the tariffs provide for an interim rate scheme, which includes both a Minimum Bill to cover current expenses and debt service, and a fixed unit-rate to be applied to the actual gas throughput during the first year of operation or until the design throughput is attained. The rationale for requiring the interim rate scheme is that it recognizes that at the commencement of billing, either the gas throughput may be less than the design capacity, or the pipeline start-up and testing procedures may be completed prior to the ability of the shippers to tender gas for transportation.

During the proceedings in El Paso Alaska Company, Docket Nos. CP75-96, et al., two interim rate proposals were advanced. The first was a phasing proposal in which some portion of depreciation expense and return on rate base would have been deferred until full throughput capacity was reached. The second proposal would have imposed a fixed reduced unit charge on the smaller initial volumes, with those revenues credited against the construction work in progress account. That reduced charge would have lasted for no more than one year.

The second proposal was endorsed by the Administrative Law Judge in his initial decision in El Paso Alaska Company. 132/ The President's Decision does not discuss the issue. The FPC's Comments on the Decision suggest, however, that an interim rate should be given consideration. 133/

The proposed tariffs of Northern Border and Alaskan Northwest each provide that billing would commence at the full cost-of-service charges. Although the project sponsors acknowledge that an interim rate provision can be incorporated into the tariffs, they are of the view that an interim rate would produce no material changes in the charges that would otherwise be collected under the tariffs. That view is based on the project sponsors assumption that beginning with the initial billing commencement date, their respective segments of ANGTS will be used essentially at their full design capacity.

132/ El Paso Alaska Co., Docket Nos. CP75-96, et al., "Initial Decision on Proposed Alaska Natural Gas Transportation Systems," at 409 (Feb. 1, 1977).

133/ Comments at 63.

The Commission, however, will require an interim rate because there are no assurances about the level of throughput that will be achieved during the initial period of operation. 134/ This is true particularly in light of the fact that charges will be permitted to commence upon completion and commissioning of operations. Because of the sheer size and complexity of this project it is reasonable to expect that the system may not be able to attain its design capacity throughput during the initial months of operation. Any throughput below the design capacity would result in higher unit charges to gas consumers if charges to the shippers were based upon the full cost-of-service computations.

To guard against that event, the Commission will require that an interim rate structure be established to be effective commencing upon completion and commissioning of operation, 135/ and terminating on the earlier of the first year of operation or upon attainment of design capacity throughput, whichever occurs earlier. 136/ The level of that interim rate is to be

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134/ *See Decision* at 145-47.

135/ It must be made clear that this discussion pertains only to the methodology of the interim rate itself. The timing of the flow-through by the shippers of any charges resulting from the interim rate and the actual mechanics of the flow-through are not addressed in this order.

136/ *See* discussion in Section VI.A.1 (Billing Commencement).

computed on the basis of the projected cost-of-service for the first twelve months of operation divided by the system's design capacity throughput. The interim rate is to be a fixed unit charge (i.e., dollars per dekatherm) and is to be applied to the actual quantities of gas delivered through the system. The interim charge so computed will be effective commencing with the initial delivery of gas through the system. During the interim rate period, the expenses and revenues experienced by the transporter should be treated as "earnings and expenses during construction" and AFUDC should continue to be recorded in accordance with 18 C.F.R., Part 201, Gas Plant Instructions 3(17) and 3(18).

The Commission recognizes, however, that -- for some unknown and unforeseeable occurrence -- there could be a lapse between the time of completion and commissioning of operation of the system and the time when gas deliveries commence. As previously explained, 137/ such an event is unlikely because there are adequate incentives placed upon the transporters, shippers, and producers to commence gas deliveries at an early date. If, however, there were a delay in gas deliveries, no revenues would be generated from

137/ See Section VI.A.1. (Billing Commencement).

the interim rate described above. Additionally, if the quantity of initial gas flow were very small, the revenues might not be adequate to service debt and cover current expenses. The Commission will, therefore, permit the transporters to collect, as a "Minimum Bill," charges equal to actual operation and maintenance expenses, actual current taxes, and actual amounts necessary to service debt. It is the Commission's opinion that the tariffs should provide for a "Minimum Bill" as an aid in obtaining financing for this project.

The Commission also recognizes that a portion of the cost of service may have to be capitalized to the extent that costs exceed revenues. On balance, however, the interim rate adopted here appears preferable. It attains a reasonable balance between the need to obtain financing and protection for the consumers against excessive transportation charges during the system's start-up and testing period. Any capitalization of costs in excess of revenues would effectively be spread on a pro-rata basis to all shippers utilizing the system. An interim rate would also likely reduce the burden on those shippers utilizing the system to transport relatively small volumes of gas. Additionally, such a rate would tend to reduce inequities that may occur as a result of, possibly, different, higher charges imposed on shippers that initially use the system as compared to those that later use the system.

The type of interim rate prescribed by the Commission will operate as an incentive to the transporters to maximize the throughput because the revenues recouped from this type of rate will be increased as throughput is increased. The Commission's formula for developing an interim rate should also encourage early utilization of the system because the unit charge would be lower during this period as compared to full cost of service charges. The interim rate adopted by the Commission is also superior to alternatives proposed in the comments of parties and Staff. Further, the Commission's interim rate fully considers the concerns expressed by the project sponsors in their comments on an interim rate.

Staff supports the interim rate concept. 138/ The essential difference between the recommendation of Staff and the interim rate adopted by the Commission is that Staff would compute the interim rate based on the projected full cost of service for the first year of operation divided by the aggregate of the maximum annual contract entitlements.

The Commission is not persuaded that the result of dividing costs by maximum contract entitlements will achieve adequate protection against a high level of transportation

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138/ Staff Initial Comments at 25-28.

charges during the initial months of operation of the system. It is not known at this time the extent to which the capacity of the system will be contracted for during those initial months of operation. That is one of the reasons underlying the Commission's determination that the interim rate prescribed here provides a significant measure of consumer protection without impairing the financeability of the project.

The interim rate adopted here also appears superior to the proposal of the Public Service Commission of the State of New York. New York argues neither for nor against adoption of an interim rate at this time. It suggests, rather, that a final determination on this matter be postponed to the future. 139/ Postponement can be achieved, according to New York, if the Commission were to provide that an interim rate would be prescribed if circumstances at the start-up date so warrant. To assess those circumstances New York proposes that the sponsors would be required, by a date set by the Commission, to file data about the expected level of initial operation. 140/

139/ New York, Initial Comments at 7.

140/ Id.

The Commission believes that its determination herein is more appropriate. In the Commission's view, the project sponsors and the financial community need a determination, at this time, about whether an interim rate will be required. Further, the interim rate prescribed here is sufficiently flexible so that the level of the rate will automatically adjust to the initial level of operation.

The Commission prescribed interim rate will also satisfy the concerns expressed by the State of California. California states that it has no basis for proposing implementation of a "complex" interim rate approach in the early months of operation. 141/ The interim rate described above is not complex. It strikes the necessary balance between protecting consumer interests during the initial months of operation of the system and the requirements for a revenue flow for the project sponsors.

141/ California, Initial Comments at 5.

The State of Alaska did not comment on the interim rate *per se*. Rather, Alaska's comments were directed to whether an attempt should be made to levelize the costs over the life of the project. Alaska, Reply Comments at 5-6. The interim rate issue that is addressed by the Commission should not be confused with any attempt to levelize costs over the whole life of the project. Rather, the interim rate is intended to guard against excessive transportation charges during the initial period of operation of the system.

California also cautions that the Commission should assure itself that the design capacity throughput will be achieved within a short period after the gas begins flowing. 142/ As stated above, this Commission does not have any assurances at this time about the number of months that will be required for the system to reach its design capacity. For this reason, the Commission will require the implementation of the interim rate described above, the effect of which will be that the average charge for gas transported through the system during the initial period of operation will not be excessively high.

Finally, the interim rate adopted here will provide the project sponsors with the assurances they sought. The sponsors state that they do not deny that an interim rate can be incorporated into the project tariffs provided that the interim rate expires on a date certain. 143/ The interim rate that the Commission will impose will expire, as indicated, upon the attainment of design capacity throughput or the end of the first year of operation, whichever occurs earlier. The Commission has also provided resolution of this issue at this time so that, as the sponsors argued,

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142/ Id.

143/ Joint Comments at Tab 3, Pt. 2 at 7.

their ability to arrange timely financing for the project would not be impeded. The interim rate structure provided for here should be an aid in securing financing for the project. Further, should the project sponsors prove correct in their assumption, that the system will be used to its then-available capacity once operations begin, the revenues generated by the interim rate will equ te to the full cost-of-service.

3. Service Interruption

The third issue identified by the Alaskan Delegate involves whether equity investors of either the Northern Border or Alaskan Northwest segment should be subject to a reduced return on equity if that segment is unable to fulfill its contract obligation to transport Alaska gas. Both the Administrative Law Judge in El Paso Alaska Company and the FPC in its Recommendation to the President endorsed such a provision.

Section 5 of Rate Schedule T-1 of each proposed tariff adopts the concept and provides for a reduction in charges should the pipeline be unable to accept and transport the contract gas tendered to it. The tariff provision reducing the charges to shippers would be applicable, however, only in those instances when the reduction in service for any one month was greater than 10 percent. 144/ In that event the adjustment to the monthly bill would reduce the return on equity and associated taxes. That reduction would be proportional to the percentage of volumes tendered but not transported. If the transporter is able subsequently to

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144/ Any failure by the pipeline to accept less than 100% but more than 90% of the gas tendered by a shipper would be accounted for in the Make-Up Gas provision of the respective tariffs. This gas -- referred to as "No Billing Adjustment Gas" -- would be transported in subsequent months at no added charge to the shipper.

transport the volumes of gas to which a billing adjustment had previously been applied, the charge for that "Make-up Gas" transportation would be computed by using the same billing adjustment (i.e., the same $/Dekatherms). In summary, the tariffs have the effect of reducing charges to the shipper if the pipeline is unable to operate at 90 percent of the contracted transportation level, but permits the pipeline to recoup any such billing credits by transporting volumes in excess of the contract level in subsequent months.

Commission Staff argues that the service interruption provision of each of the proposed tariffs is inadequate. Staff contends that, under the proposed tariff arrangement the possibility exists that ultimate consumers may not receive gas because of the failure of one transporter to perform. Those consumers, however, would still be required to pay (1) the full costs of service of those segments able to perform; (2) a portion of the costs of that segment responsible for the service interruption; and (3) depending on the terms of the gas purchase contracts between producers and shippers (e.g., "take-or-pay clauses"), some or all of the shipper's contract obligation.

To recognize this potential burden on consumers, Staff argues that a premium must be placed on performance. Staff, therefore, proposes that the tariff provide both a proportional reduction in return on equity for minor interruptions and a total cessation of recovery of equity investment for interruptions of 60 percent or more of the contract quantities.

In Staff's view the loss of equity investment is compatible with the President's Decision. The Report accompanying the Decision is said to establish that equity investment is to be placed at risk in all circumstances, including service interruption, and should interruption occur, only debt service would be maintained (see Report at 100-101).

There is no dispute about the necessity for a tariff provision that reduces the return on equity for service interruptions, and such a provision must be included in the tariff. The Commission views this tariff provision as striking a necessary and appropriate balance between the need to provide an incentive for maintaining uninterrupted service and yet realistically appraise the operating character of the pipeline. 145/ A reduction in charges to

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145/ The Commission recognizes also the balancing of transporter/shipper interest provided through the "Tender Deficiency" provision under Section 3.1 of Rate Schedule OT-1, which permits the shippers to make up any deficiencies in the volumes of gas tendered for transportation during the same month in which the tender deficiency occurred or in the next following month.

shippers would provide an economic incentive for the project sponsors to maintain uninterrupted service to the maximum extent possible. The provision would simultaneously recognize that a pipeline cannot transport 100 percent of its contract gas every day. It would thus afford some measure of operating flexibility to the transporter through use of the 90 percent billing adjustment "ratchet" without any apparent long-term operating or economic hardship on the shippers.

As proposed by the project sponsors, another feature of the 90 percent billing adjustment ratchet is that there would be no limit imposed on the time available to transport the make-up volumes. Staff objects to that provision, arguing that the period for transporting make-up volumes should be limited to one year. According to Staff, the make-up volumes can be obtained only from "storage, reinjection, improved field deliverability or new discoveries." Each of these sources of increased gas supply will impose additional costs on shippers and producers. In such circumstances, Staff argues, the transporters should not be entitled to an unlimited make-up period because it would be contrary to the intent of a Minimum Bill provision and would also shift risks of interruption to the consumer.

Contrary to Staff's argument, the Commission concludes that a time limit for transporting make-up volumes should not be included in either of the tariffs. If the transportation of make-up gas has no time limitations, a transporter will be required to discharge all obligations under the make-up gas provision of Rate Schedule T-1 before a charge can be assessed pursuant to Rate Schedule OT-1. The make-up gas provision of the Rate Schedule T-1 is to the consumer's benefit since the OT-1 charge would be higner than the make-up gas charge for "Billing Adjustment Gas" (i.e., gas which had been tendered but not transported, and for which an adjustment had been provided, equal to a proportional reduction in return on equity and associated taxes). Further, a transporter operating under an indefinite make-up period will be under a continuing obligation to ship "no billing adjustment gas" which had previously been tendered by a shipper A shipper is not charged for the transport of this gas, because no credit was received by the shipper at the time these volumes were tendered but not transported.

Consumers may also benefit from an indefinite make-up period. To the extent that make-up gas can be transported at a lower charge than other volumes of Prudhoe Bay gas, the lower costs and increased volumes would lower the average cost of all gas. That possibility would be cut off, however, were a one-year limit imposed on transporting make-up gas.

Finally, the Commission disagrees that the indefinite make-up period now provided in the pro forma tariffs will not put a premium on performance. Transporters are not likely to delay the transportation of make-up gas, because such delay prevents recovery of the return on equity. Thus, any make-up provision is self-enforcing. Further, since there is a time value of money, the indefinite make-up provisions of the tariffs might provide a continuing incentive for transporters to perform make-up activities as quickly as possible, so that revenues will be forthcoming for their use sooner rather than later. That continuing obligation would not exist, however, if after one year from the service interruption the transporter, although permanently losing a portion of the return on equity, was also discharged from his make-up obligation and could charge at the then current transportation rates.

For the reasons set forth above, the Commission therefore approves the *pro forma* tariff provisions regarding the reduction in return on equity. Except for the period of time permitted to transport make-up volumes, there is unanimous agreement among participants that such a tariff provision is both fair and necessary.

There is substantial disagreement among participants, however, about whether there should be a loss of equity investment for major service interruptions. As discussed above, Staff would require a permanent reduction in the return of equity whenever transporters fail to transport 60 percent or more of their contract volumes. Tariff provisions similar to that proposed by Staff were discussed in the initial decision in El Paso Alaska Company 146/ and in the FPC's Recommendation. 147/

The Commission has carefully examined this issue and concludes that in the event of an extended, total service interruption, the public convenience and necessity may require a reduction of, not only the return on equity, but also a disallowance of the return of equity. A tariff provision of this nature was before the President 148/ and complies with the conditions under which private financing was expected to occur:

> 1. The equity investment in the project would be placed at risk under all circumstances and the budgeted equity investment be considered the first funds spent. The rate of return on equity would compensate sponsors for bearing this risk.
>
> * * *
>
> 4. Provision of debt service in the event of service interruption would be borne by consumers through a tariff that becomes effective only after service commences. 149/

Unlike the Staff's proposal to reduce charges whenever the level of gas throughput falls below 60 percent of contract amounts, the reduction in charges described below will

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146/ Docket Nos. CP75-96, et al., Initial Decision at 404 (Feb. 1, 1977).

147/ Recommendation at XII, 43.

148/ The private financing model discussed in the Recommendation would have reduced debt service.

149/ Recommendation at XII, 43.

become effective only in the event of an extended total cessation of service. As already discussed, the 90 percent billing adjustment ratchet for any service diminution below 90 percent of tendered gas will reduce charges to eliminate return on equity. However, once the transporters wholly fail to provide any service, it is appropriate that return of equity be subject to forfeiture.

The provision adopted here will be activated only in the event of the failure of the Alaskan segment or Northern Border segment to transport tendered volumes, and only when there is a total cessation of service for thirty consecutive calendar days. The provision would apply prospectively from the thirty-first day of service interruption, and would continue until such time as gas is again transported. Further, this provision will apply solely to that segment directly responsible for the service interruption. 150/ Specifically, the Commission will require that commencing with the thirty-first day of total service interruption, that portion of the transporters' charges attributable to equity costs (that

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150/ For example, if the Alaskan segment of the system were inoperable but the Northern Border segment were operational, no adjustment would be made to the charges by Northern Border. Likewise, if one or more of the Canadian segments of the system were inoperable but the Alaskan segment and the Northern Border segment were operational, no adjustment would be made to the charges by either Alaskan Northwest or Northern Border.

portion of depreciation expense not necessary for debt service and associated taxes) shall be collected, subject to refund. Under no circumstance would debt service be impaired.

A Commission hearing will be convened as soon as practicable after the end of the first month of total cessation of service. At that time, the transporter will be provided the opportunity to demonstrate that the extremity of the circumstances surrounding the service interruption warrants retention of equity costs by the transporter. If the transporter can demonstrate that the failure to provide service was beyond the control of prudent management, the revenues collected subject to refund will be retained by the transporter. If such a showing is not made, the revenues collected subject to refund must be returned to the shippers together with appropriate interest.

While the Commission recognizes that consumers will be required to pay a portion of the transportation charges during the period that the Commission is considering whether equity costs should be refunded, that period should not be long. The ANGTA mandate to expedite will continue in force. The continued collection of equity costs by the transporter may also assist it in having revenues available to make necessary, and perhaps expensive, repairs to restore service.

Consumers, on the other hand, will have the assurance that refunds, with interest, will be provided should the transporter fail to demonstrate that the total cessation of service was not the result of management imprudence.

In that event, fairness requires that the appropriate transportation charge only recover actual operation and maintenance expenses, current taxes, and debt service. This reduced level of charges would continue until service is restored.

This procedure provides the assurance to investors that debt service will be covered in all events as was contemplated in the President's Decision. 151/ It also provides that shippers and consumers would not bear equity costs when management is unable to demonstrate that events surrounding the service interruption justify the retention of such equity costs by the transporter.

151/ Decision at 100-101.

4. Billing Procedure

The selection of the period and method to calculate shippers' transportation charges is the fourth issue affecting risk allocation for the Northern Border and Alaskan segments of the ANGTS project. 152/ According to the Alaskan Delegate, two alternative procedures were presented during the hearings in El Paso Alaska Company, Docket No. CP75-96, et al.

> The first would be to estimate the cost of service of the pipeline over a future six month period and then fix a constant monthly charge to recover this estimated six month cost of service. In the event that the estimate deviated from the actual cost of service, any accumulated undercharge would be added to, or any overcharge subtracted from the charge levied over the following six month period.
>
> The second approach . . . would be to simply bill shippers monthly for the actual costs of service incurred during the previous month. . . . This could result in charges changing from month to month but would avoid any overcharging or undercharging. (Delegate's Report at 13)

The Initial Decision in that proceeding recommended adoption of the six-month billing procedure. 153/ The Presiding Judge found that the six-month billing affected only the timing of recovery of the charged rates and, therefore, no adequate justification had been presented

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152/ See Delegate Report at 13.

153/ Initial decision at 407-408.

for rejecting the proposal. He further postulated, however, that the monthly billing procedure would have also been acceptable. 154/

Each of the proposed tariffs before the Commission provides for a six-month billing procedure (see Section 6.8 of the General Terms and Conditions of the tariffs of Northern Border Pipeline and Alaskan Northwest Natural Gas Transportation Company). Commission approval of each of the tariff provisions is urged by the project sponsors as providing a mechanism to permit shipper tariff tracking provisions with transportation costs attributable to ANGTS. The proposal is also tentatively supported by New York. 155/

Staff acknowledges that the six-month billing procedure is neither unfair nor illegal. Staff contends, however, that billing shippers for the previous month's actual costs provides certain advantages: (1) it would simplify the tariff by eliminating the surcharges and carrying charges which occur with a six-month billing procedure; (2) it would reduce billing controversies regarding methods of estimation; and (3) it would simplify review of transporters' rates.

154/ Id.

155/ New York, Initial Comment, at 8.

Initially, the Commission agrees that the project sponsors' proposed method of billing is neither illegal nor unfair. Each transporter will determine monthly the difference between its actual cost of service and the total charges collected. That difference will be accounted for in the transporter's working capital allowance in rate base and, therefore, carrying charges will be recovered by the transporter when there have been undercollections or by the shipper when there have been overcollections.

Moreover, while Staff's arguments in favor of a monthly billing procedure are credible, the Commission finds that on balance the six-month billing procedure will be adopted. Although cost-of-service billing is typically done on an actual basis, a six-month billing procedure here would provide the transporter with a relatively stable flow of revenues. It would also enable the shippers to more accurately estimate their revenue requirements for the immediate future. 156/

The six-month billing procedure would also benefit the consumer by reducing the possibility of wide variations in monthly transportation charges. Such variations

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156/ This feature may have significance in the Commission's consideration of the mechanics of flow through of the systems' charges by the shippers. The question of shipper tracking is discussed above. See Introduction to Section VI.

could be a result of the planned maintenance and scheduled down time proposed in the tariffs. Section 1.14 of the General Terms and Conditions of the Alaskan Northwest tariff and section 1.15 of the General Terms and Conditions of the Northern Border tariff show how the planned maintenance and scheduled down-time factors vary from month to month for the pipelines. Notwithstanding those monthly down-time variances, the January-June billing period contemplates effective operating days 157/ that are essentially identical to the effective operating days for the July-December billing period. Thus, the proposed six-month billing period -- which uses an estimating and subsequent balancing approach -- would tend to level off the monthly bills, and would appear to be consistent with and a desirable accompaniment to the planned operation of the pipeline.

The Commission will permit the billing procedures proposed by the transporters. However, the proposal to compute working capital allowance on the accumulated differences between the estimated cost-of-service and the

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157/ Effective operating days are determined by multiplying calendar days for each month by the corresponding maintenance and down time factor. Effective operating days should translate, essentially, into relative volume throughput in each month.

actual cost-of-service will not be approved. Rather, carrying charges on such differences will be permitted in a[illegible]dance with the Commission's Regulations. This approach is the normal treatment for similar amounts.

B. Other Tariff Issues

As noted at the outset of this discussion, several tariff issues have been identified through the comment procedure of this rulemaking, and as a result of the Commission's analysis of the proposed tariffs. Those issues are considered below.

1. Availability of Transportation Services

The Alaska Natural Gas Transportation Act states at Section 13(a) that "no person seeking to transport natural gas in the Alaska natural gas system shall be prevented from doing so or be discriminated against in the terms and conditions of service on the basis of the degree of ownership, or lack thereof, of the Alaska natural gas transportation system." A question has arisen about whether the availability clauses of the *pro forma* tariffs (§ 1 of Rate Schedule T-1 and § 1 of Rate Schedule OT-1) comply with this provision of ANGTA.

The *pro forma* tariffs each indicate that services will be available to any shipper under its service agreement. The tariffs do not specifically indicate, however, whether a service agreement will be available on a non-discriminatory basis. It is thus possible that the availability provisions of the *pro forma* tariffs do not comply with Section 13(a) of ANGTA.

In their joint comments, Alaskan Northwest and Northern Border state that the intent of each of the tariff provisions was not to deny access to any person seeking to transport natural gas. 158/ Rather, the intent was to recognize that each transporter is a contract carrier.

Staff expresses its belief that the availability provisions were not intended to deny access to the pipeline but suggests that as now drafted the tariff provisions are ambiguous. Staff, therefore, proposes alternative language. 159/ For Rate Schedule T-1, Staff proposes:

> 1. Availability
>
> This Rate Schedule is available to any person desiring service as provided for by Section 13(a) of the Alaskan Natural Gas Transportation Act of 1976 after execution of a service agreement with the Company.

And for Rate Schedule OT-1, Staff further proposes:

> 1. Availability
>
> This Rate Schedule is available to any Shipper that is receiving service and has executed a service agreement under Rate Schedule T-1.

The Commission has reviewed the proposed changes offered by Staff. These changes better reflect the intention that the services should be made available on a nondiscriminatory basis. The proposed changes of Staff

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158/ Joint Comments, Tab 3, Pt. 2 at 1-2.

159/ Staff Initial Comments at 42-43.

should be substituted for the availability provisions now contained in each of the pro forma tariffs.

2. Cost Allocation

Several cost allocation issues have been raised by the filing of the transporters' tariffs and the comments thereon. The central issues to be decided are:

a) Should costs be allocated to various shippers on the basis of the relative volume units (Mcf) transported through the system or, alternatively, on the basis of relative energy units (Dekatherms) transported through the system?

b) Should Alaskan Northwest's system be segregated into two zones for rate purposes, or should the costs be composited and allocated to various shippers on the basis of the number of miles of system used by each shipper?

The determination of each of these issues has a greater impact upon the State of Alaska than any other party. The issues are created, in the first instance, by the expected delivery of Prudhoe Bay gas within Alaska. As Alaska stated in its initial comments:

> Alaska has been pursuing and evaluating proposal to utilize natural gas liquids from Prudhoe Bay in Alaska as a feedstock for a new petrochemical facility. 160/

160/ Alaska, Initial Comments at 7; see also Alaska, Initial Comments at 10.

The Commission agrees with the statements included in Alaska's initial comments to the effect that the Alaskan Northwest portion of ANGTS is not contemplated to be a "dual-phase transportation facility" and that Alaskan Northwest's tariff is "constructed on the assumption that there would not be a separate transport of liquids." 161/ It is the Commission's understanding that all of the fluids moving through the Alaskan Northwest pipeline will be in a gaseous state. There will be no droplets, slugs, or phases (or any portion of the fluid to which any similar term can properly be applied) in the pipeline whic[illegible] be in liquid form.

What must be considered, however, is that certain portions of the gaseous stream being transported are liquefiable in a hydrocarbon extraction plant. It seems apparent from Alaska's statements that it intends to extract, or cause to be extracted, certain liquefiable hydrocarbons from the total gas stream passing from Prudhoe Bay through the State of Alaska. The central question that must be addressed is how should transportation costs be allocated to any "off-take" of gas within

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161/ Id. at 7 (statement attributed to Alaskan Northwest).

Alaska 162/ if the composition of the gas is changed by changed by extraction operations occuring after the gas has entered ANGTS. 163/ Alaska states in its reply comments:

> The cost allocation methodology is of no great consequence because whatever the cost allocation methodology, the bottom line will be that the entire cost of service is recovered. 164/

Alaska goes on to state:

> There is no question that Alaska must be charged a just and reasonable rate for its shipment. 165/

The Commission agrees with the latter statement but cannot accept the former assertion. The tariffs must provide a mechanism for allocating ANGTS's costs that gives proper recognition to the planned utilization of the project and the attendant cost responsibility. The consequence of an improper cost allocation method would be that certain shippers would be effectively subsidizing the operations of other shippers. Furthermore, it is important that guidance be given to the potential users of Alaskan gas so that they may evaluate their participation in this project.

162/ See Alaska, Initial Comments at 8-9 for detailed discussion of "Off-Take" considerations and legal requirement to permit in-state withdrawal of royalty gas.

163/ The determination of this question does not require the establishment of a "separate liquids rate," which was suggested as a possibility by Alaska.

164/ Alaska, Reply Comments at 4.

165/ Id.

For the reasons explained below, the Commission determines that energy units (Dekatherms) rather than volume units (Mcf) should be used as the basic allocation units for apportioning Alaskan Northwest's cost-of-service. Additionally, the Commission will require that distance (miles) be factored into the cost allocation procedures. Finally, the Commission will require that Northern Border's cost-of-service also be allocated on a Dekatherm-mile basis.

Consideration of the essential purpose of ANGTS and certain elementary chemical facts is basic to properly resolving the issue of cost allocation. The ANGTS is being constructed as a transportation system to deliver energy to Alaska and the contiguous forty-eight States. The value of the system to most of the gas consumers is the amount of energy that will be made available through the system. Various industrial customers could benefit more by extracting certain of the constituents from the gas stream because of the chemical and physical properties peculiar to those constituents. Therefore, the value of the ANGTS to certain industrial customers is derived more from the discrete chemical and physical properties of the components that can be extracted from the gas stream rather than from the heat energy value of the total gas stream being transported.

Products that normally would be removed in a hydrocarbon extraction process (ethane, propane, butanes and pentanes-plus) have a higher heat value per unit of volume than the principal constituent remaining after processing (methane). 166/ This is obvious from the following:

Gas Component	Heating Value (Dekatherms per Mcf)
Methane	1.0
Ethane	1.8
Propane	2.5
Butanes	3.3
Pentanes-plus	5.0+

Based upon the information presented in the proceedings before the FPC involving the competitive applications to construct an Alaska gas transportation system, 167/ the gas available at a gas processing and conditioning plant could have the following composition of hydrocarbons:

Gas Component	Percent 168/
Methane	85.1
Ethane	7.8
Propane	4.0
Butanes	1.2
Pentanes-plus	0.2

166/ Substantial amounts of methane could also be required in a fertilizer manufacturing complex.

167/ Docket Nos. CP75-96, *et al*.

168/ Docket No. CP75-96, *et al*., transcript at 19,496 (testimony of Exxon Corp.). Percentages do not add to 100% because carbon dioxide and nitrogen, which do not have any heating value, have been omitted.

The gas leaving Prudhoe Bay is sufficiently rich in liquefiable hydrocarbons (ethane and heavier hydrocarbons) to make extraction somewhere on ANGTS attractive. Alaska indicates that it may be economical to extract certain of the hydrocarbons within the State of Alaska. 169/ It is quite obvious from comparing the heating value of the various gas components with the indicated composition of gas leaving Prudhoe Bay, that removal of all or any portion of the components other than methane would significantly affect the heating value of the remaining gas stream. For example, the gas stream after processing at a hydrocarbon extraction plant could essentially have the following hydrocarbon composition:

Gas Component	Percent 170/
Methane	93.5
Ethane	3.0
Propane	1.0
Butanes	0.5
Pentanes-plus	0

The heating value of gas leaving a hydrocarbon extraction plant with the above illustrative composition would have a heating value of approximately 1054 Btu per cubic foot (1.054 Dekatherms/Mcf). The gas leaving Prudhoe Bay with the composition shown at page 195

169/ Alaska, Initial Comments at 7.

170/ As before, the percentages do not add to 100% because of the omission of carbon dioxide and nitrogen.

would have a heating value of 1148 Btu per cubic foot. The extraction operation depicted by this example results in a loss in heating value of 94 Btu per cubic foot, or eight percent.

The implied results of any extraction operation that removes any "heavy" hydrocarbons (ethane, propane, etc.) are quite clear. Those customers purchasing gas downstream from the extraction operation must purchase greater volumes of processed gas to produce the same amount of heat energy that lesser volumes of unprocessed gas would produce. The type of extraction operations described above would effectively deprive other gas consumers of useable amounts of heat energy. As has been shown, the magnitude of deprivation of usable heat energy is not in proportion to volumes of liquefiable components removed in the extraction operation but is related to the heating value of the components removed. Therefore, allocation of the ANGTS costs on a volumetric basis would not be proper if extraction operations change the composition of the gas received into the system.

Recognizing the potential that some processing of Alaska gas to remove liquefiable hydrocarbons will likely occur at some place along the ANGTS, 171/ the Commission

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171/ See, e.g., Alaska, Initial Comments; see also proposed gas purchase contract between Northern Natural Gas Company and Exxon Corporation filed with the Commission May 2[illegible], 1979.

decided to address the cost allocation issue in that context in this Order. 172/ The Commission's goal is to require a cost allocation method that most equitably apportions ANGTS costs to all shippers. Failure to resolve the issue at this time would result in uncertainties of cost allocation and could result in the institution of another proceeding to deal with the issue.

This Commission does not know what form or to what extent extraction operations may eventually be conducted along the ANGTS, either in Alaska or at other locations. If the State of Alaska, or others, conduct hydrocarbon extraction operations similar to those illustrated above, equity and sound regulatory policy require that ANGTS costs be allocated on a heat energy or thermal (Dekatherm) basis rather than a volumetric basis. To guard against any inequitable apportionment of ANGTS costs which

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172/ The Commission is also aware that cost allocation may be sensitive to the carbon dioxide content of the gas being transported. If gas were injected into the pipeline with a carbon dioxide content above that now contemplated by Alaskan Northwest's Tariff (1%), the system would have a greater capacity to transport liquefiable hydrocarbons. The system would then, however, be transporting a larger quantity of inert gases.

The Commission also recognizes that resolution of the cost allocation issue could impact the economic considerations of the carbon dioxide issue. Interested parties are invited to address this interrelationship in their reply comments on this issue pursuant to the Notice issued May 16, 1979, in this docket.

could be attendant with a volumetric cost allocation approach, the Commission will require that the costs of Alaskan Northwest and Northern Border be allocated on a ermal (Dekatherm) basis.

The Commission's determination to require that ANGTS costs be allocated on a heat energy (Dekatherm) basis rather than a volumetric (Mcf) basis is not reached based on an extensive review of incremental costs of transporting liquefiable hydrocarbons. Rather, the Commission views the heat energy basis as the most equitable method of allocating costs incurred by this system in rendering the services permitted under the <u>pro forma</u> tariffs. It may be argued, for example, that there is no substantial increase in the cost of transporting the various constituents of natural gas. What must be considered, however, is that the tariffs now proposed by the transporters are for the transportation of a common supply of natural gas. 173/ There are no announced plans for any shipper to tender discrete hydrocarbons or other gases for movement through the system. Therefore, any upstream off-take of liquefiable hydrocarbons would effectively mean that shippers with delivery points downstream of the extraction operations would have to contract for the delivery of a greater volume of gas to produce the same amount of heat energy that a

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173/ Joint Comments Tab 3, Pt. 2 at 4-5.

lesser volume of unprocessed gas would produce. This feature is the basis for the Commission determination that energy units rather than volume units should serve as the basic cost allocation unit for the ANGTS.

Having determined that energy units (Dekatherm) rather than volume units (Mcf) should be used for cost allocation, the "zones versus mileage" issue must be decided. Three of the most commonly used methods of allocating an interstate gas pipeline's cost-of-service to sales and services performed in different geographical areas are (a) zone-gate method, (b) system-wide method, and (c) Mcf-mile or Dekatherm-mile method.

The zone-gate method allocates costs attributed to the first upstream zone between sales and services performed in that zone and sales and services performed in all downstream zones. The costs incurred in the second upstream zone, together with costs allocated to that zone from the first upstream zone, are composited and allocated between sales and services performed in the second upstream zone and sales and services performed in all zones downstream of that zone. The process is continued, sequentially, for all zones, resulting in the last downstream zone being assigned all costs incurred within that zone plus costs allocated to that zone from all upstream zones. This Commission has approved the zone-gate method in the past for a very limited number of interstate gas pipelines based upon the peculiar circumstances surrounding their operations and expansion. 174/ This method would typically allocate more costs to downstream customers than other methods.

The system-wide method of cost allocation makes no distinction between the geographical locations where sales and services are performed. This method has been approved by the Commission for those pipelines whose diverse sources of gas supplies and whose operations are of such an integrated nature as to effectively reduce or greatly minimize any differences in the cost of providing sales and services in different geographical locations. 175/

The most commonly used cost allocation method for long-distance interstate gas pipelines is the Mcf-mile or Dekatherm-mile method. This method is premised on two essential principles: (1) the pipeline is a system designed to provide sales and services over a long distance, and (2) the costs of providing sales and services vary in relation to distance or the length of the system required to provide the particular sales or services.

174/ See, e.g. United Gas Pipe Line Company, Docket No. G-9547, 25 FPC 26 (Jan. 4, 1961).

175/ See, e.g., Consolidated Gas Supply Corporation, Opinion No. 819 (Aug. 12, 1977).

Alaskan Northwest proposes to allocate costs between its proposed two zones essentially on a zone-gate method. For the reasons set forth below, the Commission does not approve Alaskan Northwest's proposed zone-gate approach but will require that Alaskan Northwest's total cost-of-service be allocated on an energy-distance basis (Dekatherm-miles) between any gas delivered in Alaska and gas delivered to the Foothills system at the Alaska-Yukon border. There are not sufficient reasons at this time supporting the establishment of rate zones on any basis (zone-gate or otherwise) within the State of Alaska. Separate rate zones are normally supported by recognizing that precise allocation of costs cannot be made for a large number of delivery points over a relatively short distance, and by recognizing the administrative advantage (for both the seller and purchasers) of billing a particular customer or group of customers at the same rate for as much gas as possible. 176/ The gas delivery points in Alaska will likely be small in number; 177/ therefore, no administrative advantages

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176/ The feature recognizes the intergrated nature of many distributor customer who have multiple gas receipt points.

177/ Alaska, Reply Comments at 3.

of separate rate zones are apparent. Additionally, it is reasonable to expect that proper cost responsibility can be ascertained for each gas delivery point in Alaska under the Dekatherm-miles basis. In summary, the circumstances of Alaskan Northwest do not conform to criteria historically utilized by the Commission for establishing zones.

The justifications offered by Alaskan Northwest for establishing two rate zones within the State of Alaska are generally as follows: 178/

(1) The cost of providing transportation service for gas delivered in Alaska can be more accurately ascertained by attributing the costs incurred within each zone to the shippers using the facilities in each zone;

(2) Alaskan Northwest will likely provide two categories of transportation service: gas transported for use in Alaska, and gas that completely transits the state;

(3) Substantial variations are expected in costs associated with the northern and southern portions of the Alaskan pipeline, with the portion north of

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178/ "Responses to Data Requests by Alaskan Northwest and Northern Border" in response to a letter from the Commission's Director of the Alaska Gas Project Office, dated April 20, 1979; Joint Comments, Tab A, Pt. 2.

Delta Junction being the highest cost in terms of investment per mile or investment per unit of capacity.

The Commission is not persuaded that Alaskan Northwest's proposed zones will result in an equitable distribution of costs. Alaskan Northwest's suggestion that its proposed method of cost allocation may produce more accurate results is not totally convincing, because as Alaskan Northwest indicates, even under its proposed method, certain types of costs are not directly assignable to each zone and will have to be allocated. The company has proposed that such costs be assigned to each zone "in proportion to plant in service or the levels of contract service," without showing that the method would result in a fair and proper distribution of costs.

More important, however, is the fact that Alaskan Northwest's proposed cost allocation method does not adequately recognize the conditions under which the system will be designed, constructed and operated. During at least the initial operation of the system, it is anticipated that Alaska's share of gas will be shipped to the contiguous forty-eight States. Capacity will be provided for Alaskan royalty gas in not only the northern portion of Alaskan Northwest's pipeline but also in the southern portion. The extent to which Alaska may continue to utilize the southern portion of the system will obviously depend upon how much of its royalty gas entitlement it chooses to "off-take" from the northern portion of Alaskan Northwest's pipeline. 179/ Alaska could very well choose to continue to ship a portion of its royalty gas through the southern portion of Alaskan Northwest's pipeline, either for use within the portion of the state south of Delta Junction 180/ or for shipment to the Alaska-Yukon border for delivery into the Foothills system.

Alaskan Northwest's characterization of two categories of transportation service is not adopted. The transportation services are essentially the same. Any differences in the services pertain only to the portion of the system (miles) used to provide the services, and the cost allocation method required by the Commission is intended to fully compensate for any such differences.

Differences in the costs of constructing and operating the northern portion versus the southern portion of the Alaskan Northwest pipeline do not, in themselves, require the establishment of zones. The higher costs of the northern portion (in terms of investment per mile or investment per unit of capacity) results from the planned long-term operation of ANGTS, and not because of discrete considerations relative to any "off-take" of gas by Alaska. Alaskan Northwest's proposed zones would likely mean higher cost

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179/ See Alaska, Initial Comments at 8-9.

180/ Delta Junction is the point selected by Alaskan Northwest as the division between the two proposed zones.

assignment to Alaska over the long-term than would a distance-of-transportation allocation method. The likely results of Alaskan Northwest's proposed cost allocation method have not been justified.

Weighing all of the considerations, it is the Commission's judgment that Alaskan Northwest's proposed zone-gate method of cost allocation should not be approved. The Commission concludes that the most equitable procedure for allocating Alaskan Northwest's cost-of-service is embodied in an energy-distance basis (i.e., Dekatherm-miles), without the establishment of separate rate zones.

Northern Border proposes to allocate costs on an Mcf-mile basis. The Commission adopts the distance-weighing portion of Northern Border's proposal (i.e., miles), but, for the reasons already explained with respect to the effects of any hydrocarbon extraction operations, will require that energy units (Dekatherms) rather than volume units (Mcf) be used as the basic allocation unit. The Commission is not aware of any extraction operation plans on the Northern Border system. If gas entering and leaving the Northern Border system is not processed and remains of the same chemical composition, it would not matter whether volume units or energy units were used for cost allocation, because the results would be the same. However, the cost allocation method required by the Commission puts all parties on notice of the economic context in which any contemplated extraction operations must be evaluated.

As a final point on cost allocation, it must be made clear that the Commission views the cost allocation requirements for the Alaskan Northwest and Northern Border segments of ANGTS to be quite distinct from the cost allocation requirements for the Foothills system. The Commission's determination that Alaskan Northwest's and Northern Border's costs-of-service should be allocated on an energy-distance basis (Dekatherm-miles) is dictated by the fact that there will likely be some extraction of various components of Prudhoe Bay gas. Even with extraction operations occuring in Alaska, the gas delivered to the Foothills system at the Alaska-Yukon border would probably have a higher heating value than any gas originating in the Mackenzie Delta area and introduced into the ANGTS at Whitehorse, Yukon Territory. The same heating value disparity could also be attendant with any other gas originating in other areas of Canada and introduced into the Foothills system. The reverse could also conceivably occur if gas input in Canada had a heating value higher than Alaska gas delivered at the Alaska-Yukon border.

In any event, the Agreement Between the United States of America and Canada on Principles Applicable to a Northern Gas Pipeline (Agreement on Principles) has a firm mechanism established to give full recognition to any difference in the composition and quality of gas received by the system. 181/ If Canadian gas entered the pipeline system with a heating value less than the heating value of Alaska gas entering the pipeline system at the Alaska/Yukon border, the Agreement on Principles requires that any dilution in the heating value of Alaska gas would be fully recognized in the allocation of Foothills' cost-of-service and in gas deliveries. This adjustment would be necessary so that a disproportionate share of Foothills' cost-of-service would not be imposed on the American consumers. Specifically, the Agreement on Principles provides in pertinent part:

> It is agreed that the following principles will apply for purposes of cost allocation used in determining the cost of service applicable to each shipper on the Pipeline in Canada:
>
> a) The Pipeline in Canada and the Dempster Line will be divided into zones as set forth in Annex II. Except for fuel and except for Zone 11 (the Dawson-Whitehorse portion of the Dempster Line), the cost of service to each shipper in each zone will be determined on the basis of volumes as set forth in transportation contracts. The volumes used to assign these costs will reflect the original BTU content of Alaskan gas for U.S. shippers and Northern Canadian gas for Canadian shippers, and will make allowance for the change in heat content as the result of commingling. Each shipper will provide volumes for line losses and line pack in proportion to the contracted

181/ *Decision* at 47-66.

> volumes transported in the zone. Each shipper will provide fuel requirements in relation to the volume of his gas being carried and to the content of the gas as it affects fuel consumption. 182/

The Commission's determination with respect to cost allocation for the Alaskan Northwest and Northern Border segments of the ANGTS does not in any way change the interpretations, or the application thereof, of the cost allocation methods defined and agreed to by the United States and Canada. The cost allocation procedures set forth in the Agreement on Principles for the Foothills segment are required because of the potential dilution of Alaska gas caused by commingling of that gas and Canadian gas that will likely have a lower heating value. While the cost allocation procedures required by the Commission for the Alaskan Northwest and Northern Border segments of ANGTS are necessary to properly allocate costs to any extraction operations that may be conducted on those two segments, it is the Commission's understanding that no extraction operations will be conducted on any ANGTS gas in transit through Canada. If any extraction operations were conducted, however, the allocation of Foothills' cost-of-service should fully account for any such operations.

182/ Id. at 57-58.

3. Accounting and Rate Treatment for Line Pack

The Staff's initial comments raised an issue related to line pack. The issue is succinctly described in the Staff's example:

> Suppose shippers A & B initially hold title to 100% of the line pack worth $10,000,000. Each files a rate application with the Commission to include $5,000,000 in rate base to recover carrying charges (return & taxes) on their line pack investment. Three months later, Shipper C, a new user of the system, begins transporting gas, and is assigned one-third of the existing line pack. Shipper C files a rate case and claims $3.3 million in rate base attributable to line pack. Unless Shippers A & B voluntarily reduce rates under Section 4 of the Act, the Commission, under current law would be required to approve the rate treatment sought by Shipper C without legal right to automatically lower the rates of Shippers A and B. 1/ Thus consumers would bear carrying charges on $13.3 million in total jurisdictional rate bases when the aggregate line pack investment is only $10 million.
>
> 1/ The Commission's only recourse would be to establish an investigation under Section 5 of the Natural Gas Act and order any resulting rate reduction to become effective prospectively after hearing. The hearing may involve a lengthy inquiry into all aspects of the Shippers' costs of service. 183/

The Staff's initial comments suggested two different approaches for handling the costs of line pack:

> . . . Either require ANGTS sponsors to pay 'rent' or carrying charges on line pack used by the system (these carrying charges would then be an operating expense for the pipeline and recoverable through the cost of service tariff) or require ANGTS shippers to automatically 'track' changes in line pack. 184/

183/ Staff, Initial Comments at 28-29.

184/ Id. at 29.

The reply comments of Northern Border and Alaskan Northwest assert that this issue should not be considered in this rulemaking. Instead, the project sponsors argue the matter should be decided in the proceeding that addresses the shipper tracking issue. 185/

Shippers will incur substantial costs in providing natural gas for line pack in order for their gas to be transported through the ANGTS. It is important that the shippers be able to recover the costs actually incurred. Therefore, any method for recovery should provide for adjustment when a shipper's line pack obligation changes (either increases or decreases) with attendant changes in cost. Staff has presented an alternative which would have the transporters compensate the individual shippers for the carrying costs on their separate line pack contributions and recover the amounts through the transportation tariffs. This would have the advantage of facilitating recovery of the actual costs borne by the shippers, but it would impose an unnecessary added cost recovery burden upon the transporters.

In the discussion on tracking of costs by shippers, the Commission expressed a receptiveness to proposals for automatic flow-through of ANGTS charges for shippers subject to the Commission's jurisdiction, provided such shippers make an appropriate showing that the flow-through

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185/ Joint Reply Comments at 38.

mechanism will result in a matching of costs and revenues. The mechanism could also provide for recovery of actual costs attributable to line pack. 186/ The Commission will, therefore, defer the specification of any particular recovery mechanism pending receipt of the ANGTS cost flow-through proposals by individual shippers based upon their particular circumstances. Such proposals should include methods for recovery of line pack costs that will reflect actual cost incurrence based upon actual line pack obligations.

4. Lateral Line Policy

The *pro forma* tariff of Alaskan Northwest contains the following provision:

> Company will construct, operate and maintain lateral delivery lines on a nondiscriminatory basis and render related service under an appropriate Rate Schedule. Nothing in this policy statement shall require Company to file an application for a certificate of public convenience and necessity under Section 7(c) of the Natural Gas Act. . . . (Section 19.2 of the General Terms and Conditions)

By letter dated April 27, 1979, the Director of the Commission's Alaska Gas Project Office requested Alaskan Northwest to explain this provision. The primary concern was that the proposed tariff language could be interpreted as establishing a waiver of Alaskan Northwest's obligation to file for a certificate of public convenience and necessity if lateral delivery lines were constructed.

186/ *See* Section VI, Introduction.

The joint reply comments of Alaskan Northwest and Northern Border responded to the inquiry, indicating that the referenced language was only intended to clarify that Alaskan Northwest was under no obligation to file for a § 7(c) application at the request of a shipper or other party. If the company were to choose to construct lateral delivery lines, the comments assure the Commission that appropriate certificates of public convenience and necessity would first be sought. 187/

The Commission accepts the explanation set forth in the comments of the project sponsors. In order to avoid any subsequent confusion or controversy however, Alaskan Northwest should revise its tariff in accordance with the explanation provided in the comments and accepted by the Commission.

5. Certain Quality Standards Other Than CO_2 Content

The Commission indicated at the outset of this discussion of tariff issues that it would defer resolution of the issue of the permissible level of CO_2 content in the gas stream. Other issues related to quality standards can, however, now be addressed.

Questions have been raised by Sohio related to the quality standards for water content and sulfur (hydrogen sulfide, mercaptan sulfur, and total sulfur). Sohio contends that the tariff standards are excessive and

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187/ Joint Reply Comment at 51.

not justified. Further, Sohio objects to the water quality standard being stated on a volume basis (pounds per Mcf) rather than on a dew-point temperature basis (degrees Fahrenheit), and the mercaptan sulfur standard being stated on a mass basis (grains per 100 cubic feet of gas) rather than a volume basis (parts per million). 188/ The quality standards stated in the *pro forma* tariffs are the standards that have been known to the parties for the past several years, and no other quality standards have been advanced and supported by any party.

The joint reply comments of Alaskan Northwest and Northern Border state:

> The project company tariffs have proposed stringent quality requirements because we believe it the obligation of the ANGTS project to provide the lowest possible reasonable cost of transportation. If producers such as Sohio have a proposal which would be consistent with the public interest which would demonstrate some benefit to the consuming public by relaxation of ANGTS quality standards, certainly Alaskan Northwest and Northern Border would be willing to consider such a proposal. 189/

The exact quality standards required for gas to be transported through ANGTS will, of course, depend upon the final design of the system. Absent a showing that the quality standards stated in the *pro forma* tariffs are not compatible with the approved final design of ANGTS,

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188/ Sohio, Initial Comments at 1-3.

189/ Joint Reply Comments at 22.

the Commission has no basis for ordering different standards. Accordingly, the water and sulfur standards proposed by the transporters will be permitted to be included in the tariffs subject to any revisions that may be required to comport with the final pipeline system design.

6. Modification of Article 4 of the Service Agreement

Article 4 of the service agreement of each *pro forma* tariff contains language that has generated comments from the Staff and the States of Alaska and California. Article 4 in each agreement obligates a shipper to make payments to a transporter in accordance with the tariff "Rate Schedules, the General Terms and Conditions and the other applicable provisions of [the] Agreement".

The State of Alaska is concerned that there is no express recognition in Article 4 that a shipper's obligation to pay is qualified by the adjustments set forth in Section 5 of Rate Schedule T-1. Alaska, therefore, proposes that each service agreement be modified to state that the obligation of a shipper to pay is subject to the adjustments provided in Section 5 of Rate Schedule T-1 of each tariff. 190/

190/ Alask[illegible] Initial Comments at 9-10.

The reply comments of the project sponsors indicate that Section 5 billing adjustments are recognized in the service agreements because of the reference in each agreement to "Rate Schedules." The sponsors state that Article 4 of each agreement is neither intended to override nor qualify in any way the billing adjustments provided in Section 5 of Rate Schedule T-1. 191/

If the Commission determines, however, that explicit reference should be given to the relationship between the two provisions, then the project sponsors agree with Alaska that the relationship should be recognized in Article 4 of each service agreement. However, the sponsors disagree with Alaska about where the modification should appear.

The modification proposed by the State of Alaska provides:

> Shipper shall make payments to company in accordance with the rate schedules, the general terms and conditions and the other applicable terms and provisions of this agreement. Shippers obligation to pay its allocable share of company's cost of service shall be absolute and unconditional under any and all circumstances (subject only to the adjustments expressly provided for in Section 5 of Rate Schedule T-1). . . . 192/

191/ Joint Reply Comments at 32-35.

192/ Alaska, Initial Comments at Attachment B.

The project sponsors' alternative states:

> Shipper shall make payments to Company in accordance with the Rate Schedules (including Section 5 of Rate Schedule T-1), the General Terms and Conditions, and the other applicable terms and provisions of this Agreement. 193/

The sponsors argue that their proposed alternative is preferable. In their view, the language proposed by Alaska will not recognize that a shipper's payment obligation can be affected by tariff provisions other than Section 5. They cite Section 6 of the General Terms and Conditions -- which also addresses billing and payment matters -- as an example of a tariff provision that also affects a shipper's payment obligation. 194/

The Commission views modifications of the type proposed by Alaska to be beneficial when ambiguities can be clarified and possible disputes thereby avoided. On that basis, it appears appropriate to provide express recognition of the relationship between Article 4 of the service agreement and Section 5 of Rate Schedule T-1. However, because the method of clarification proposed by Alaska may itself create ambiguities, the alternative modification proposed by the project sponsors will be accepted.

193/ Joint Reply Comments at 33.

194/ Joint Reply Comments at 33.

Staff also voices concern with Article 4. Staff argues that Article 4 is duplicative of other provisions in the pro forma tariffs, e.g. § 6.3 of the General Terms and Conditions. Staff further argues that Article 4 should expressly release a shipper from his obligation to pay if there is a willful refusal on the part of a transporter to perform. 195/

The project sponsors respond that Article 4 is necessary to explicitly recognize that the obligation of a shipper to pay will be absolute and unconditional. The sponsors assert that the provision was insisted upon by the sponsors' financial advisors as a means of aiding the financing of the project.

Staff may be correct that Article 4 is duplicative of other provisions in the tariff. However, when that is the sole objection and there is no contention that Article 4 is contradictory of other tariff provisions or that it creates ambiguities, then the Commission is not inclined to order the deletion of the provision in the circumstances presented here. To the extent that Article 4 will aid the financing of the project and is merely duplicative of other provisions, the Commission will permit its retention in the tariffs.

195/ Staff Initial Comments at 17-19.

The sponsors also respond to the proposal of Staff that a release of payment obligations should occur if there is a willful refusal to transport gas. The sponsors argue that explicit recognition of a willful refusal to perform will not affect the reliability of service, since it is unlikely that a willful refusal would occur. That is so, according to the sponsors, because there could be private actions for damages and there is already included in the tariffs a provision that reduces the return on equity should a transporter fail to accept tendered gas. Finally, should there be a willful refusal to perform, the sponsors assert that the Commission can institute an investigation and issue a remedial order, if necessary. 196/

Although the Commission agrees that shippers should not be subject to a payment obligation where there is a willful refusal by a transporter to perform, the Commission cannot endorse the proposal of Staff. In the Commission's analysis, the unlikelihood of a willful refusal, together with the potential problems that may result from adoption of Staff's proposal, adequately argue against the proposal.

As stated by the project sponsors, the likelihood is small that transporters would willfully refuse

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196/ Joint Reply comments at 34-35.

to perform. More importantly, however, the prospective definition of a "willful" failure to perform, and an appropriate remedy, is difficult, if not impossible.

In light of these considerations, the Commission is of the view that the better course of action would be to recognize that any shipper contending there was a willful failure to perform can seek appropriate relief through the Commission.

The State of California argues that Article 4 of the service agreement should not be construed to limit the Commission's authority to review recovery of equity investment in the event of project failure after operations commence. 197/ The Commission's review obligations under the Natural Gas Act, however, shall continue. California's concerns, therefore, are unnecessary.

7. Failure to Deliver Gas

Another issue identified by Staff concerns whether equity costs should be reduced because of a failure by a transporter to deliver gas, rather than a failure to take receipt of tendered gas. Staff argues that the shippers should be given "explicit protection against diversion or loss of gas supply after it enters the control of transporters." 198/

197/ California, Initial Comments at 6.

198/ Staff, Initial Comments at 17.

In their reply comments the project sponsors contend that this provision is unnecessary. They assert that no gas will knowingly be accepted that cannot be delivered. Further, the sponsors argue that a billing adjustment keyed to gas receipt rather than gas delivery would be easier to administer. If the billing adjustment were keyed to gas deliveries rather than gas receipts, the sponsors itemize three considerations that would complicate billing adjustments: "(i) the possibility of multiple delivery points, (ii) variations in fuel use and losses, and (iii) variations in seasonal capacity." 199/

The Commission agrees with the project sponsors. The billing adjustment procedure for failure to accept tendered gas presents a relatively simple approach to protect the shipper, and any modifications to the tariff that complicate that mechanism are not desirable. That factor, taken together with the unlikelihood that the transporters would accept gas when there is an anticipation that it cannot be delivered, is sufficient reason to reject Staff's proposal.

199/ Joint Reply Comments at 30-31.

8. Review of Equity Rate of Return

After completion and commissioning of operation, the rate of return on equity allowed by the Commission is termed the Operation Phase Rate. The value of this rate should be comparable to rates of return allowed for other pipelines with similar operating risks. Once in operation this rate should be altered to reflect any changes in rates allowed for other pipelines with similar risks or if risk factors for this project change. The issue first raised in the letter to the project sponsors from the Director of Alaska Gas Project Office (April 27, 1979) is what procedure should be used to review this rate of return and determine if a change is reasonable.

The Staff's initial comments argue that the Operation Phase Rate should automatically be adjusted through a formula tied to changes in capitalization. 200/ Though capitalization is an important factor in determining rates of return, this procedure would ignore other equally important factors such as overall changes in required rates of return in the nation's economy due to changes in inflationary expectations or changes in risk factors. 201/

200/ Staff, Initial Comments at 36-41.

201/ At the time of the submission of a financing plan the Commission will also review the proposed capitalization over the life of the project.

The project sponsors argue that the only review of the Operation Phase Rate should be by Commission action under Section 5 of the Natural Gas Act. 202/ The disadvantage of this approach is that the burden of proof would be placed upon the Commission and any redetermination of rate of return would have prospective effect only.

A third approach, discussed in more detail in Section II.B.3, is suggested in a paper prepared for the Alaska Gas Project Office by Professor Jerome Hass. 203/ This approach would tie or index the Operation Phase Rate to interest rates. As interest rates change, the Operation Phase Rate would adjust automatically. Though interest rates are an important guide to equity rates of return, this indexing would still not adjust for many other important factors affecting rates of return. Thus, an additional review of some sort would be necessary in addition to this formula which would tie the Operation Phase Rate to interest rates.

After evaluating the above three approaches, the Commission has determined that a periodic rate of return review is a superior approach. On a periodic basis, the project companies shall submit a Section 4 application

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202/ Joint Initial Comments, Tab 3, Pt. 3.

203/ Hass Report at 14-16.

which shall justify the appropriate Operation Phase Rate to be applied during that prospective period. A portion of revenues collected during the period prior to a Commission determination of the appropriate rate of return for that period will be subject to refund pending a final disposition of the rate of return issue. The revenues subject to refund will be only those attributable to the rate of return on equity and associated taxes.

Though the Commission has determined that the tariffs shall provide for a periodic rate of return review, the Commission will not specify at this time the length of the period but will defer that decision to the final project certification proceeding after the submittal of a financing plan. The financing plan may contain information that is relevant to this determination. 204/

The Commission's disposition of this issue reflects a reasoned balancing of consumer protection and financing considerations. In their analysis of this issue, the project sponsors argued that three principles are critical in any future review of the Operation Phase Rate:

204/ A relevant precedent is the three-year review required in purchased gas adjustment clauses. A similar period does not seem unreasonable for this cost-of-service tariff but a final decision will not be made at this time.

(a) All matters affecting the rate should be considered not just capitalization as suggested by Staff.

(b) Any review must be limited to the Operation Phase Rate without express or implied review or reconsideration of the tariff or service agreement.

(c) Any review must not result in impairment of the project economics which formed the basis for investment.

The Commission agrees that any future review should generally abide by these principles, and that it should conduct its review specifically subject to (a) and (b). It is the Commission's intention that during any future rate of return review the proper impact of all matters that affect the return on equity would be considered. Further, it is the Commission's intention that any review of the Operation Phase Rate would be limited to establishing the proper level of that rate.

The Commission determination here to require review of the project's Operation Phase Rate is not a new concept. 205/ The review procedure should in no way "result in impairment of the project economics which the basis for the investment," because there 10 inference or intent in the review of the Operation Phase Rate to disallow from the project's cost of service any actual and proper expenses. 206/

205/ See, e.g., Southern Energy Company, Docket No. CP71-264, "Order Amending Prior Order" (February 13, 1978). In that case, the event that "triggered" a rate of return review was any change in equity capitalization in excess of two and one-half percentage points.

206/ While this Order sets out the Commission's position on matters which can currently be resolved, other details of regulatory oversight remain to be determined. For example, review of certain cost of service expenditures are of this nature. In this regard, the Commission may benefit from Canadian resolution of this common regulatory problem. As previously indicated, the Commission has conducted regulatory consultations with the NEB pursuant to Section 9 of the Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline. (See, Incentive Rate of Return for the Alaska Natural Gas Transportation System, Docket No. RM78-12, Revised Notice of Proposed Rulemaking, 5 n.1a (Sept. 15, 1978) (Erratum Notice, Oct. 6, 1978). The NEB is currently proposing that estimates of certain costs, such as operation and maintenance expenses, be submitted annually for review and approval prior to being incorporated in the transportation charge. (See, National Energy Board of Canada's "Proposed Method for the Regulation of the Tolls and Tariffs of the Foothills Pipeline," 7-8 (issued April 18, 1979)).

Pending further consideration of this matter, the Commission presently contemplates utilizing auditing procedures to determine proper accounting classification of costs in accordance with the requirements of

(Footnote continued on next page)

9. Certain Issues Raised by California

California questioned whether a payment delinquency charge under Section 6.4 of the tariffs would be computed at 125 percent of the interest rate applicable to delinquencies but any repayments to the shippers would be at 100 percent of the same interest rate. 207/ Alaskan Northwest and Northern Border answered in their reply comments that "the shipper would recover, with interest, any amounts paid to the transporter, including the penalty interest itself if the non-payment is excused by order or otherwise." 208/ No other party commented on the provision. The Commission accepts the clarification offered by the transporters.

206/ (Footnote cont'd).

the Uniform System of Accounts. General instruction (2)(e) thereof prescribes that only just and reasonable amounts may be included in the accounts. This audit effort, coupled with the Commission's remedial powers under the Natural Gas Act, may be sufficient to satisfy the requirement that all costs, including operation and maintenance expenses, be prudently incurred.

207/ California, Initial Comments at 7.

208/ Joint Reply Comments at 48 (emphasis in original).

Two other issues raised by California relate to whether the operation and maintenance expenses and company use gas claimed by the transporters will be subject to audit and verification. 209/ The Commission has addressed this matter in the lengthy footnote above, note 206, *supra*, and will not reiterate its reasoning here.

209/ California, Initial Comments at 6-7.

VII. PROCEDURAL MATTERS

This section considers certain procedural issues which have been raised in the course of this rulemaking. These include the relationship of this rulemaking to proceedings now underway to consider issues on construction of the Northern Border segment, the rationale for use of rulemaking procedures, and future Commission action under this Order.

A. Relation to Pre-Building

The purpose of this rulemaking is to (1) resolve outstanding issues concerning the Incentive Rate of Return mechanism for the Alaskan and Northern Border segments of ANGTS, and (2) resolve certain issues attendant to the Commission's approval of the tariffs submitted by Alaskan Northwest and Northern Border pursuant to the Commission's Order of February 22, 1979.

In Order No. 17, the Commission specified certain terms and conditions on a finding that both the Alaskan Northwest and Northern Border projects should be subject to an IROR mechanism. The Commission recognized that the specific values to be included in the IROR mechanism would be established in future proceedings.

By Order of February 22, 1979, the Commission required that the sponsors of the Alaskan and Northern Border segments of the ANGTS file proposed tariffs, to facilitate a thorough evaluation of risk for financing purposes. The Alaskan Delegate's Report attached to the that Order recognized the possibility that certain of the southern segments of the ANGTS may be "pre-built" to transport Alberta gas, as well as the possibility that "charges may begin for these segments in advance of completion of the other segments." On March 12, 1979, Alaskan Northwest and Northern Border filed pro forma tariffs, pursuant to the Commission's Order. The tariff filed by Alaskan Northwest would apply to the transportation of Alaskan natural gas, whereas the Northern Border tariff would initially apply to the transportation of Canadian gas (if made available by the Canadian Government through approval of applications presently before the National Energy Board of Canada), and would undoubtedly require some modification once the transportation of Alaskan gas commenced.

The April 6 Notice indicated that the Commission would address each of the issues presented by the two filed tariffs with the exception that the depreciation rate reflected in Northern Border's tariff would be reserved for separate consideration in the "pre-build" proceeding in Docket Nos. CP78-123, et al. The Notice recognized the relationship between the depreciation rate and the financing of the prebuild facilities. In its initial comments, Staff raises questions regarding the pre-building of certain Northern Border facilities to transport Canadian "bubble" gas. More particularly, Staff questions the need for the particular facilities contemplated, and raises a question as to whether the construction of temporarily excessive capacity or unnecessary facilities constitutes a fee or surcharge in violation of the President's Decision.

This rulemaking is not the appropriate place to determine the nature and size of facilities to transport Canadian gas. That is an issue to be addressed in Docket Nos. CP78-123, et al. The facilities authorized in that proceeding will have to be found to be necessary and required by the public interest. The depreciation rate found appropriate in Docket Nos. CP78-123, et al., will apply until modified by the Commission. In this rulemaking, we establish the tariff provisions applicable to the transportation of Alaskan and Canadian gas. While the issue of whether Canadian gas will be transported through certain "pre-build" facilities is still pending before both the NEB and this Commission, it is clear that before Alaskan gas can be transported through the Northern Border facilities the project sponsors will be required to show that the tariff provisions approved herein are appropriate for the transportation of Alaskan gas.

B. Rulemaking Procedures

This proceeding implements certain financial conditions stipulated in the President's Decision, and is necessary for, and related to, the construction and initial operation of the transportation system approved by the President's Decision. The proceeding, therefore, comes within the scope of the Alaska Natural Gas Transportation Act (ANGTA) (15 U.S.C. §§ 719-719m). For this reason, it is incumbent upon the Commission to proceed as expeditiously as possible.

Section 403(c) of the Department of Energy Organization Act (DOE Act) authorizes the Commission to utilize rulemaking procedures to establish rates and charges under the Natural Gas Act. The setting of the incentive rate, as well as the consideration of pro forma tariffs for the ANGTS, is an establishment of a "rate or charge" within Section 7 of the Natural Gas Act and, per force, Section 403(c) of the DOE Act. Rulemaking provides, in this instance, an expeditious procedure for resolving the issues. Accordingly, in performing its functions under ANGTA, pursuant to ANGTA's mandate for expedition, the Commission chose the rulemaking process authorized by Section 403(c) of the DOE Act.

We recognize that Section 403(c) is not without some limits. On its face, it requires "full consideration of the issues and an opportunity for interested persons to present their views." While this proceeding has been the focal point of numerous rounds of comments, reply comments and special studies, we recognize that the issues are both serious and complex. For that reason, the Commission is staying the effective date of this Order for a period of 60 days, to afford interested parties the opportunity to apply for rehearing. Such applications must be filed within 30 days of the date of issuance of this Order.

The Commission Finds:

(1) For the reasons set forth above, the Commission finds it necessary and appropriate and in the public interest, in administering the Natural Gas Act and the Alaska Natural Gas Transportation Act, to adopt and incorporate into the conditional certificates of public convenience and necessity issued by the Order of December 16, 1977 (Docket Nos. CP78-123, et al.), the terms and conditions set forth in the attachment to this Order.

(2) For the reasons set forth above, the Commission finds it necessary and appropriate and in the public interest, in administering the Natural Gas Act and the Alaska Natural Gas Transportation Act, to require the tariffs under which Alaskan Northwest Natural Gas Transportation Company and the Northern Border Pipeline Company will render service to conform to the conditions and requirements set forth and discussed above in this Order.

The Commission Orders:

(A) The terms and conditions set forth in the attachment to this Order shall be incorporated into the conditional certificates of public convenience and necessity issued by the Commission on December 16, 1977 in Docket Nos. CP78-123, et al., to become effective 60 days from the date of issuance of this Order. These terms and conditions supplement and supersede the terms and conditions incorporated in the conditional certificates by the Commission's Order No. 17, issued in this Docket on December 1, 1978.

(B) No later than twelve months prior to initiating service, Alaskan Northwest Natural Gas Transportation Company and Northern Border Pipeline Company shall submit for Commission approval, tariffs modified to conform with the requirements set forth in this Order. This ordering paragraph number (2) shall become effective 60 days from the date of issuance of this Order.

(C) Parties to Docket No. RM78-12 may file petitions for rehearing of this Order within 30 days of the date of issuance of this Order, pursuant to the procedures set forth in section 1.34 of the Commission's Rules of Practice and Procedure.

(Department of Energy Organization Act, Pub. L. No. 95-91, 91 Stat. 565, E.O. 12009, 42 Fed. Reg. 46267 (Sept. 15, 1977); Natural Gas Act, 15 US §§ 717, et seq.; Alaska Natural Gas Transportation Act, 15 USC § 719(g); President's Decision and Report to Congress on the Alaska Natural Gas Transportation System, H.J. Res. 621, Pub. L. No. 95-158, 91 Stat. 1268 (1977).)

By the Commission.

INITIALS

CHAIRMAN CBC 6-8-79

Secretary SMITH DSS

COMMR SHELDON GHS 6/8/79

COMMR HOLDEN

COMMR HALL [illegible] 6/8/79

AGO 886219

Determination of Incentive)
Rate of Return, Tariff,) Docket No. RM78-12
and Related Issues)

Chairman Curtis, concurring,

Although I am willing to accept the vote of the majority, I want to note my preference for a marginal rate of 6% coupled with an 18% center rate. Because a marginal rate of 6% would exert greater incentive for cost containment than would result from an 8% marginal rate, I believe it is appropriate to account for this effect by a one-half point adjustment to the risk premium factor, thus yielding a center rate of 18%.

The IROR scheme adopted by the Commission would allow a lower rate of return as construction costs increase thereby creating an incentive to control costs during construction. The marginal rate represents the incentive portion of the IROR mechanism and is an important determinant of the overall rate of return on equity. I am concerned that the marginal rate of 8% selected by the Commission may provide too little incentive to control construction costs.

With an 18% center rate and a 6% marginal rate, the resulting IROR schedule would allow higher rates of return than the majority's schedule for a cost performance ratio of 1.3 to one of 1.6, (or for about 30% above the center point) for cost performance ratios greater than 1.6, this schedule would yield lower rates of return on equity. If there is true expectation that the pipeline can be constructed within a cost performance ratio of 1.6, I would think the sponsors would prefer the higher returns.

Notwithstanding my preference for this alternative, I recognize that the question is one of judgment and have determined to abide by the determination of my colleagues on this matter, recognizing that the issue may be represented to the Commission in the course of the rehearing procedure set out in the rule.

Charles B. Curtis

Charles B. Curtis
Chairman

Comparison of Two Combinations
of Center Rates and Marginal Rates
in the IROR Schedule for
the Alaskan Segment of the Pipeline

Cost Performance Ratio	Allowed Rates of Return on Equity 1/		
	For a 17.5% Center Rate and an 8.0% Marginal Rate	For an 18% Center Rate and a 6% Marginal Rate	Column (2) minus Column (1)
	(1)	(2)	(3)
1.0	20.35%	21.60%	1.25%
1.1	19.23	20.18	.95
1.2	18.29	19.00	.71
1.3	17.50	18.00	.50
1.4	16.82	17.14	.32
1.5	16.23	16.40	.17
1.6	15.72	15.75	.03
1.7	15.26	15.18	-.08
1.8	14.86	14.67	-.19
1.9	14.50	14.21	-.29
2.0	14.17	13.80	-.37
2.1	13.88	13.43	-.45
2.2	13.61	13.09	-.52
2.3	13.37	12.78	-.59
2.4	13.15	12.50	-.65
2.5	12.94	12.24	-.70

1/ Assumes a 1.3 CPR as the center point.

Terms and Conditions

1. Applicability

The Incentive Rate of Return (IROR) will apply to two of the three segments of the Alaskan Natural Gas Transportation System within the United States, as defined in the President's Decision and Report to Congress on the Alaska Natural Gas Transportation System (referred to hereinafter as the Decision). These segments are: (1) the portion of the system within the State of Alaska, and (2) the portion of the system from the United States/Canadian border near Monchy in the Province of Saskatchewan to a point near Dwight in the State of Illinois. In the following terms and conditions, the term "pipeline" refers to each of these two segments, and all terms and conditions herein apply to each.

2. Cost Performance Ratio

As required by the second finance term and condition of the Decision (at page 36), the rate of return on equity during the operating period of the pipeline will be increased if the pipeline is completed under projected cost and reduced if the pipeline is completed over projected cost. The relationship between projected cost and completed cost will be determined by a Cost Performance Ratio. The Cost Performance Ratio is the ratio of the Deflated Actual Capital Costs (see Condition 3, below) to the Projected Capital Costs (see Condition 4, below).

3. Deflated Actual Capital Costs

The Deflated Actual Capital Costs will be determined at the start of operations as the sum of direct construction costs actually incurred in the construction of the pipeline after conversion into base-year prices (see Condition 5 below) plus a Finance Charge calculated from the Real Rate of Return (see Condition 6 below). The Finance Charge will be calculated quarterly, based on the Deflated Actual Capital Cost incurred prior to the beginning of the quarter. When a segment (see Condition 1, above) is completed and tested, accrual of the Finance Charge and any other costs in the Deflated Actual Capital Costs will cease for that segment.

4. Projected Capital Costs

The Projected Capital Costs will be determined at the start of operations as the sum of direct construction costs included in the Certification Cost and Schedule Estimate approved by the Commission pursuant to Condition 7, below, and after any adjustments for Changes in Scope (see

Condition 10, below) or resulting from design changes prior to the Final Design (see Condition 9, below) plus a Finance Charge calculated from the Real Rate of Return (see Condition 6, below). The Finance Charge will be calculated quarterly, based on the Projected Capital Costs estimated to be incurred prior to the beginning of the quarter.

5. Inflation Adjustment

The direct construction costs actually incurred, excluding interest during construction, will be deflated to base-year prices, where the base year will be that used in calculating the Certification Cost Estimate. The inflation index will be a composite index calculated as a weighted average of existing published indices or price data. The attached schedule (see Condition 18 below) contains the categories of cost to be used and the index or prices to be used for each category. When the project sponsors submit their Certification Cost Estimate, all projected costs will be divided into each of the cost categories for each year or quarter. The proportion of total costs in that year or quarter for each cost category will be used as the weight for that cost category. For any construction that occurs beyond the projected construction schedule for the project, the weights specified for the last year of the projected construction period will be the weights used.

6. Real Rate of Return

The Real Rate of Return to be used to calculate the Finance Charge included in the Projected Capital Costs and the Deflated Actual Capital Costs shall be five percent (5%). The Real Rate of Return shall only be used in determining the Cost Performance Ratio in the IROR mechanism, and will not be used to calculate the allowance for funds used during construction (AFUDC) included in the rate base for cost of service.

7. Certification Cost and Schedule Estimate

Pursuant to the second finance condition in the Decision, the applicant for a certificate of public convenience and necessity for the pipeline shall submit to the Commission a Certification Cost and Schedule Estimate, adjusted to reflect any design changes resulting from the Agreement on Principles with Canada and any addendum thereto, for comparison with the capital cost estimates filed by Alcan with the Federal Power Commission on March 8, 1977. This estimate will include costs actually incurred prior to submission of the estimate. This Certification

Cost and Schedule Estimate will be submitted in 1978 or 1979 base-year prices and with costs set forth according to formats to be specified by the Commission (see Condition 8, below). The March 1977, cost estimate referred to in the second finance term and condition in the Decision must also be resubmitted in the same format, and recalculated in the same base-year prices for comparability with the certification estimate. An explanation of any significant differences between the March 1977 estimate, and the Certification Cost and Schedule Estimate, must be provided. The date of the base-year period for submitting costs may be determined by the applicant. With these estimates, the applicant shall also provide a Construction Plan and Pipeline Design which show the techniques and procedures the applicant proposes to use in constructing the pipeline, and provide a detailed description of the pipeline as it will appear when completed.

8. Cost Estimate Format

All cost estimates shall be submitted to the Commission according to a Cost Estimate Format to be determined by the Commission. Prior to submittal of the Certification Cost and Schedule Estimate, the applicant may submit to the Commission a proposal for the Cost Estimate Format. The

Cost Estimate Format will specify the functional categories or components into which the total cost estimate must be divided, according to the time period in which the costs are estimated to occur. The breakdown of costs shall be in sufficient detail such that the Commission may compare the various cost estimates and determine the reasonableness of any changes.

9. Final Design

After the submission to and acceptance of the Final Design by the Federal Inspector as required by the Decision, the Certification Cost and Schedule Estimate will be altered to reflect changes in quantities or types of materials, labor, and services, and changes in project development or construction schedule and construction techniques, resulting from changes in design or schedule (including changes in the time necessary to obtain the required government approvals and permits) between the time the Certification Cost Estimate was prepared and the approval of the Final Design. Prices of labor, materials, or services used in the Certification Estimate will not be altered unless the Final Design requires a type of labor or material input not assumed to be used in the Certification Estimate. In that event, base year prices for that new type of input will be used to the extent practicable.

The project sponsors shall submit the revised Certification Estimate, including both an explanation of the alleged design or schedule change and an estimate of the change in costs or schedule, to the Federal Inspector. The Federal Inspector will approve or disapprove the inclusion in Projected Capital Costs of such changes in cost or schedule, pursuant to procedures to be determined by the Inspector, and his decision will be final. The Federal Inspector will promptly notify the Commission of his determinations, including an explanation of the respective changes in design and schedule, and the resultant changes in costs.

10. Change in Scope Mechanism

The Change in Scope Mechanism is applicable to changes caused by events that occur subsequent to the date on which the Federal Inspector approves the Final Design. The Projected Capital Costs shall be increased in an amount equal to the amount of cost increases attributable to Change in Scope events beyond the control of the project sponsors. Such Change in Scope events shall be limited to (1) wars, (2) any disaster declared by the President of the United

States pursuant to the Disaster Relief Act of 1974, Pub. L. No. 93-288, 88 Stat. 143, (3) major design changes compelled by changes in Federal or State laws or regulations applicable to natural gas pipelines enacted or adopted subsequent to the Federal Inspector's approval of the Final Design of the pipeline, (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. To the maximum extent practicable, cost increases attributable to Change in Scope events shall be calculated based upon the assumptions and parameters used to calculate the Certification Cost Estimate.

11. Change in Scope Procedure

Whenever the project sponsors believe a Change in Scope event (as defined above) has occurred, the project sponsors shall submit to the Federal Inspector an explanation of the alleged Change in Scope and an estimate of the increase in

Projected Capital Costs for the project. The Federal Inspector will approve or disapprove the inclusion of such increases in Projected Capital Costs, pursuant to procedures to be determined by the Inspector, and his decision will be final. The Federal Inspector will promptly notify the Commission of his determinations, including an explanation of the Change in Scope events and the resultant changes in costs.

12. Center Point

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

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.

The base-year prices shall be those utilized in the preparation of the Certification Cost Estimate. For purposes of this condition, the March 1977 estimate and the Certification Cost Estimate shall include a Finance Charge calculated from the Real Rate of Return (see Condition 6, above).

At the time the Certification Cost Estimate is submitted to the Commission (see Condition 7 above), the Commission will consider adjustments to the value of the Center Point derived from the above formulas if a showing is made that unanticipated developments have altered the basic nature and scope of the project from that assumed in the preparation of the March 1977 estimate. If the project sponsors believe that a major change in the project has occurred, the sponsors, as part of their submission of a Certification Cost Estimate, should present: (a) the nature of the changes in the project subsequent to the President's Decision, including a detailed explanation of why the Certification Cost Estimate has changed from the March 1977 estimate; (b) the nature or benefit to the nation and to gas consumers of construction of the project in light of the revised cost estimates; and (c) the cost increases or cost overruns above the Certification Cost Estimate that may occur, including explanation and analysis of the contingencies for which costs have and have not been included, the likelihood of such contingencies occurring, and their respective impact on costs.

13. Operation Phase Rate

The Operation Phase Rate is the rate of return on equity that will be allowed after the pipeline is in operation and after the one-time adjustment to the rate base has been made made. The Operation Phase Rate initially shall be 14 percent (14%) for the Alaska segment and 13 percent (13%) for the Northern Border segment.

14. IROR Formula

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 (see Condition 2, above) and CP is the Center Point (see Condition 12, above).

15. Financing Plan

The financing plan submitted pursuant to the Commission's Regulations (18 CFR 157.14(a)(14)[1978]) as part of the application for a certificate of public convenience and necessity under Section 7 of the Natural Gas Act shall describe how the applicant proposes to finance the estimated cost of the project and any overruns, and in particular the proportions of debt and equity financing to be used. If the actual proportions of debt and equity used to finance the project deviate significantly from the financing plan submitted to, and approved by, the Commission, the Commission reserves the right to alter these terms and conditions.

16. Cost of Service Calculations

The allowed rate of return on equity used to calculate cost of service during operation of the pipeline will be the Operation Phase Rate defined above in Condition 13. The rate used to calculate the equity portion of the allowance for funds used during construction shall be the Operation Phase Rate defined above in Condition 13. The rate base will include an allowance for funds used during construction, and will also include the one-time adjustment calculated pursuant to Condition 17 less the cumulative amortization thereof. The cost of service for the pipeline shall include amortization of the one-time adjustment on a straight-line basis over the project life. An amount equal to the one-time adjustment net of related accumulated provisions for amortization will be considered as common equity in the rate of return calculation.

17. Adjustment to Rate Base

Upon completion of construction and initial operation of the pipeline, a one-time adjustment to the rate base will be calculated in three steps. First, for each year in the assumed 25-year operating life of the pipeline, a revenue stream for equity will be derived assuming that the equity investment including AFUDC in the pipeline at the start of operation is fully recovered by depreciation over a 25-year period in equal annual installments at the end of each year, and that an annual return on equity is derived by applying the Incentive Rate to the depreciated equity investment at the beginning of each year. Second, the present worth of this revenue stream will be calculated using a discount rate equal to the Operation Phase Rate specified in Condition 13 above. Third, the difference between this present worth sum and the equity investment including equity AFUDC at the start of operations will be added to the rate base of the project and the equity investment. If the difference is negative, the rate base and the equity investment will be reduced by the difference.

Within six months after condition and testing of the pipeline, the one-time adjustment and a schedule of amortization of the adjustment must be submitted for approval by the Commission. If the Commission reduces the one-time adjustment, the excess in transportation charges incurred during the intervening period will be subtracted from the one-time adjustment. Similarly, any shortfall will be added to the one-time adjustment.

18. Cost Categories and Index/Prices

Cost Category	Index or Price	Source
1. Labor		Engineering News Record
a. Welders and Helpers	Ironworkers Structural and Reinforcing	
b. Operators and Oilers	Motor Graders	
c. Drillers and Power Men	Skilled Laborer	
d. Pipe Fitter	Steamfitter	
e. Carpenters	Carpenters	
f. Electricians	Electricians	
g. Truck Drivers	Truck Drivers, Teamsters, for Dump, rear, over 4 cylinders	
h. Station Mechanics	Skilled Labor	
i. Other Skilled Labor	Skilled Labor	
j. Other Unskilled Labor	Common Labor	
2. Salaried Employees	Executive Compensation Survey for Similarly Skilled Personnel Categories	Bureau of Labor Statistics and American Management Association

Cost Category	Index or Price	Source
3. Line Pipe	36" Line Pipe F.O.B. McKeesport, Pennsylvania	U.S. Steel
4. Gas Turbine Compressor Sets and Auxiliary Equipment	Gas Compressor (Centrifugal Uncooled)	PPI 11410105
5. Gas Refrigeration Systems and Auxiliary Equipment	Pumps, Compressors and Equipment	PPI 1141
6. Generation Systems	Generators and Generator Sets	PPI 117302
7. Supervisory Control and Data Acquisition Instrumentation and Metering Communications and Other Electrical Equipment	Electrical Machinery	PPI 117
8. Valves, Flanges and Fittings	Valves and Fittings	PPI 114901
9. Pipe Insulation and Coating	Plastic Resins and Materials	PPI 006

Cost Category	Index or Price	Source
10. Building and Utilities Including Building Systems (e.g., HVAC, Water, Sewage)	Construction Materials	PPI, Special Commodity Groupings
11. Cement Not Used for Building	Portland Cement	PPI 1322013114
12. Miscellaneous Fabricated Metal Products	Fabricated Metal Products	PPI, Special Commodity Groupings
13. Other Miscellaneous Materials	Construction Materials	PPI, Special Commodity Groupings
14. Air Transportation		Interim Financial Results of Certified Air Carriers (CAB)
a. Passenger	Average Revenue per Passenger Mile Flown in U.S.	
b. Air Cargo	Average Revenue per Ton Mile Flown in U.S.	
15. Surface Transportation		Transportation Statistics in the U.S. (ICC)
a. Water	Average Revenue per Ton Mile Shipped by Water in the U.S.	

Cost Category	Index or Price	Source
b. Rail	Average Revenue per Ton Mile Shipped by Pail in the U.S.	
c. Truck	Average Revenue per Ton Mile Shipped by Truck in the U.S.	
d. Bus	Average Revenue per Ton Mile Shipped by Bus in the U.S.	
16. Facilities		
a. Government Owned	Department of Commerce Composite Index	Table S-11 of Survey of Current Business
b. Food Supplies	Processed Foods	PPI, Special Commodity Grouping
c. Other	CPI --All Items--U.S.	Bureau of Labor Statistics
d. Leased Facilities	Department of Commerce Composite Index	Table S-11 of Survey of Current Business
17. Crawler Type Tractors	Tractors, other than Farm, Crawler type, Diesel 260 Net Engine HP and Over	PPI 11280217

Cost Category	Index or Price	Source
18. Other Heavy Construction Equipment	Construction Machinery and Equipment	PPI 112
19. Transportation Equipment	Transportation Equipment	PPI 14
20. Miscellaneous Construction Machinery and Equipment	Construction Machinery and Equipment	PPI 112
21. Diesel Fuel	Diesel to Commercial Customers: Pacific	PPI 0573030108
22. Other Petroleum, Oil and Lubricants	Petroleum Products Refined	PPI 057
23. Other Miscellaneous Consumables (e.g., explosives, tires, welding rods, etc.)	Industrial Commodities, less Fuel and Power	PPI, Special Commodity Grouping
24. State, Municipal and Native and Private Land	Farm Real Estate Developments Index	Average Value Per Acre by State, U.S. Department of Agriculture
25. Purchased Field Data	CPI--All Items--U.S.	Bureau of Labor Statistics

NOTE:

PPI: Producer Price Index--Source Bureau of Labor Statistics--Available Monthly.

Engineering News Record: Simple 20 City Average-

-Available Quarterly.

CPI--Consumer Price Index: Available Monthly from Bureau of Labor Statistics.

U.S. Steel Line Pipe price is a list price available on request; actual selling price may be different.

American Management Association Executive Compensation Survey is available once a year; Linear interpolation for quarterly estimates.

Interim Financial Results of Air Carriers available quarterly from the Civil Aeronautics Board (CAB).

Transportation Statistics in the U.S. published by the Interstate Commerce Commission (ICC).

Farm Real Estate Index: Source U.S. Department of Agriculture--Available Semi-annually; Linear Interpolation for quarterly estimates.