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FERC Conditionally Approves Construction of Portion of Western Leg of ANGTS

On 1/11/80 the FERC approved construction of the first 160 miles of the Western Leg segment of the Alaska Natural Gas Transportation System between Kingsgate, British Columbia and Stanfield, Oregon, just below the Washington-Oregon border. At the same time, the Commission decided that it would issue separate decisions with respect to the remainder of the Western Leg and the Eastern Leg segments now consolidated in the Northwest Alaskan Pipeline Co. proceeding (CP78-123 et al.). The Commission decided to approve early construction of the initial 160 miles of the Western Leg in order to, among other things, facilitiate financing for the remainder of the project and spread the demand for labor and capital over a longer period of time, thus lessening their costs.

Background

On 6/7/78 the FERC conditionally authorized Northwest Alaskan to import a total of 1.04 Bcf of Canadian gas from Pan-Alberta Gas Ltd. over an initial contract term of six years, subject to extension for up to six additional years (subsequently extended to a primary term of 12 years) at the border price established under Canadian law. The import total includes 800,000 Mcf/d to be received at Monchy, Saskatchewan (for the Eastern Leg) and 240,000 Mcf/d to be received at Kingsgate (for the Western Leg). Subsequently, two sets of applications relating to the Western and Eastern Leg segments were filed in regard to the "prebuilding" of the project. Specifically, Northwest Alaskan (CP79-59) applied to sell up to 240,000 Mcf/d of Alberta gas to Pacific Interstate Transmission Co. for ultimate delivery (less fuel and line loss) to markets in Southern California. Related applications were filed by Pacific Gas Transmission Co. (CP79-60), Northwest Pipeline Corp. (CP79-56), El Paso Natural Gas Co. (CP79-57) and Pacific Interstate (CP79-58) to accomplish delivery of this gas from the international boundary near Kingsgate to the Arizona-California border. Subsequently, applications were filed for the Eastern Leg from Monchy to Dwight, Illinois.

Thereafter, the Commission consolidated all of the applications and divided the proceeding into three phases. Phase I was designed to examine the relationship between the prebuild project and implementation of the ANGTS; Phase II to examin generally the merits of the prebuild project; and Phase III to evaluate proposals to import Canadian gas which may be competitive with the prebuild proposal. Phase II was subsequently divided again for separate consideration of the Western and Eastern Legs. The initial decision procedure was then waived for each of the phases.

Initial briefs were filed with respect to the Western Leg by various parties. The FERC Staff and the California Public Utilities Commission opposed prebuilding only a portion of the Western Leg to Stanfield, Oregon so as to transport primarily the Pan-Alberta volumes. Instead, they preferred constructing the entire Western Leg to Antioch, California as contemplated in the President's Decision approving the Alcan-Foothills ANGTS (which suggested that prebuilding of certain ANGTS facilities might be appropriate). The entire Western Leg project, as approved by the President, would involve construction of 341 miles of 36-inch pipeline looping in the PGT system from Kingsgate to Malin, Oregon and some 143 miles of 36-inch pipeline looping on the PG&E system between Malin and Antioch. South of Antioch up to 104 miles of 36-inch pipeline looping on the PG&E system will be required. However, the only ANGTS facilities involved in the sponsors' proposal, on the other hand, would be the initial 160 miles of 36-inch looping along the PGT system from Kingsgate to Stanfield, Oregon. After that, the sponsors' proposal deviates from the Western Leg route designated in the President's Decision. Specifically,

the system of Northwest Pipeline Corp. would be augmented by installation of 350 miles of pipeline looping from Stanfield to Burley, Idaho, and certain segments of El Paso's San Juan Triangle facilities would be augmented.

The Staff emphasized that only 16% of the Western Leg of the ANGTS would be prebuild under the sponsors' proposal. The majority of the facilities proposed and costs therefor would involve substantial augmentation of non-ANGTS facilities of Northwest and El Paso and would not be used to transport the anticipated volumes of Alaskan gas. The remaining 84% of the Western Leg ANGTS would be required to be built to transport Alaskan gas. Staff and the California PUC urged that the sponsors' proposal be rejected and that construction be exclusively along the Western Leg ANGTS designated in the President's Decision. This, Staff argued, would be more economical; provide greater additional capacity at a lesser cost to the California consumer; and would provide additional benefits of more gas from other Canadian sources, while minimizing environmental effects. The California PUC stressed that the project's proposal "could saddle the ratepayers with a depreciation life as short as six years with no possibility of revision after Alaskan gas begins to flow." Moreover, California PUC added, it involves unnecessary facilities and could actually cause displacement from California of less expensive gas. 1/

The Staff and California PUC also argued that any export permit issued by the NEB for less than the volume proposed to be imported would bring the project "into question." The Staff stressed that the Western Leg proposal is "critically dependent" on the NEB granting a license to export 240,000 Mcf/d for a firm 12 years. "Any reduction in either the daily volumes or the term of the license vitally affects the economics of the sponsors' proposals and would require reopening the record should the sponsors continue to seek Commission approval of their proposed facilities." The California PUC urged the Commission to determine that the Canadian export permits would be sufficient before any prebuilding can commence.

Subsequently, the NEB authorized new exports of gas to the U.S. totalling 3.75 Tcf through 12/31/87. The NEB approved the full amount of exports applied for by 10 companies in the first five years (1980-1984), but approved lesser amounts through 1987. As a result, the NEB approved exports of 1.8 Bcf by Pan-Alberta instead of the total of 4.9 Bcf as sought. (See REPORT NOS. 1209, pp19-21; 1233, pp3-4; 1238, pp1-2; 1239, pp8-11; 1242, p10.)

FERC Order

With respect to routing of the Western Leg, the FERC could not choose between the sponsors' proposal and the alternative favored by the Staff and California PUC. First, the Commission noted, the sponsors stated in their brief that their proposal is unworkable without changes in the recent export decision of the NEB and suggested approval subject to a change in the NEB decision. The Commission concluded that such a condition, as well as outright rejection, would be inappropriate, and it will hold most of the applications for the sponsors' proposal in abeyance pending further advice on any modification of the NEB decision or the sponsors' proposal.

1/ In Report No. 1239, p10, it was stated that the CPUC urged that the Western Leg be rejected. Inadvertently omitted, however, was the CPUC's further suggestion that the prebuild application be refiled to include construction along the Western Leg ANGTS as designated in the President's Decision.

However, the Commission observed that partial looping of the Kingsgate to Stanfield segment is common to both alternative routing proposals, and is also the "pacing item" for beginning deliveries in the fall of 1980. "The Commission believes that acceptance of some risks are in order given the urgent national priority of the ANGTS in both the U.S. and Canada. Thus, the Commission believes that it must find an acceptable basis for certificating a portion of the ANGTS project now." Accordingly, the Commission concluded that the public convenience and necessity requires approving the partial looping proposed for the Kingsgate to Stanfield segment of the PGT system based on the NEB's export license, and the expectation that Alaskan volumes will be flowing through those facilities before expiration of that license. With about 10% of the country's proven domestic gas reserves located at Prudhoe Bay, and national expediting legislation in place in both countries, "the Commission believes that certification of these facilities now is not an unreasonable exposure for PGT's customers. On the contrary, this country will obtain a timely addition to its natural gas supplies from the new export license just granted."

The Commission also approved provision of the transportation service through existing facilities of Northwest and El Paso to Pacific Interstate Transmission Co. for the 1980-1981 heating season under FERC-approved tariffs in existence at that time. "The Commission is confident that any additional transportation and facilities proposals growing out of any further consideration by th NEB will have been developed and submitted for timely consideration and approval prior to the end of that period."

While approving portion of the Western Leg facilities, the FERC found the record in Phase I concerning the benefits of prebuilding "disappointingly vague." For example, the Commission explained, there is no conclusive evidence indicating that prebuilding will expedite completion of th entire ANGTS or assure financing for the remainder of the system. "With or without prebuilding, the evidence indicates that Alaskan gas will not begin to flow through the ANGTS until at least 1984." The Commission noted that addition of Albertan gas into the system will reduce the unit cost of service for the Alaskan gas, prebuilding will get the ANGTS project started sooner, and it will spread the demand for labor and capital over a longer period of tim , thus lessening the likelihood of increased labor and material costs and cc truction delay costs due to increased demand. Also, the Commission added, prebuilding will facilitate, although not assure, financing of the remainder of the project. Based on these factors, the Commission concluded that prebuilding will produce "some tangible benefits to the remainder of the ANGTS."

The Commission rejected a recommendation by the Staff that satisfactory commitments for debt and equity financing for the entire ANGTS be in place before commencement of construction of the prebuild facilities so as to protect consumers of Canadian gas from paying excessive charges if prebuilding is not economically justified on a stand-alone basis (Alberta volumes only) and the ANGTS is not completed. In support, the Commission said, the Staff conducted an economic study which concluded that the Western Leg would not be viable on a stand-alone basis and that if the entire ANGTS were not completed, SoCal's customers would pay excessive charges for Alberta gas. While taking issue with the Staff's study, the sponsors conceded that their proposal would not be viable on a stand-alone basis if the NEB decision is not modified.

The Commission concluded that while noncompletion is always a possibility, it is convinced that the entire ANGTS will be completed. First, the Commission explained, about 10% of the country's known domestic reserves are located at Prudhoe Bay, expediting legislation is in place in both countries, and a signed agreement

committing them to implementation exists. Moreover, the price for the gas is reasonable when compared to alternative fuels and there are sufficient economic benefits so as to justify approval. Hence, there is no need for the specific condition recommended by the Staff since adoption would delay the flow of Canadian gas from Alberta for one to two years and could also eliminate or reduce the benefits associated with prebuilding. This conclusion, the Commission added, is premised upon the price for the prebuild volumes being determined in a manner consistent with other Canadian gas exports.

On the question of gas supply, the Commission noted the sponsors' contention that Pan-Alberta has sufficient gas reserves under contract to provide Northwest Alaskan with 1.04 Bcf/d over a 12-year period. The Staff, on the other hand, contended that because Pan-Alberta might be the source of supply for another project designed to extend Canada's gas system eastward from Montreal to the Maritime Provinces, Pan-Alberta cannot demonstrate sufficient supplies under contract for both projects. Accordingly, Staff urged that any certificate be conditioned upon a showing by Pan-Alberta that there are sufficient deliverable volumes to satisfy both projects for the life of the prebuild facilities. The Commission concluded that Pan-Alberta's gas supply is adequate to support its contracts with Northwest Alaskan, and approval of the prebuild project will stimulate exploration and make more reserves available to Pan-Alberta. However, the Commission observed, it is reasonable to assume that Canada will not authorize any export for Pan-Alberta unless all domestic requirements can be met. Hence, there is no need for the condition suggested by the Staff.

Turning to rate and tariff matters, the Commission first rejected PGT's proposal that the costs associated with the additional partial looping and compression on its system be recovered from Pacific Interstate over the term of the latter's export authorization for Canadian gas, and that Pacific Interstate bear an allocated portion of the costs of the facilities which are considered to be used to serve all PGT's customers. PGT also proposed to carry this tariff treatment forward to Alaskan gas once it begins to flow. In all authorizations to date, the Commission said, costs and volumes associated with additional services proposed by PGT to PG&E were rolled in with other costs and volumes for the purposes of determining the rates for service to PG&E and Northwest Pipeline under PGT's cost of service tariff. All facilities, whether compression or pipeline looping, were deemed to be totally integrated and used for all services rendered by PGT.

In determining the proper tariff treatment here, the Commission decided to focus on the characteristics of the service to be performed by PGT. First, the Commission said, the transportation by PGT for Pacific Interstate is similar to services it now performs for Northwest Pipeline and PG&E. None of the characteristics of the proposed service for Pacific Interstate are different from those of the existing services. All services are firm and none are seasonal or peaking in nature. The transportation of all gas through PGT's system is and will continue to be a conventional transportation arrangement. Furthermore, the Commission continued, the additional facilities will be operationally integrated with PGT's existing facilities. Both the existing, partially looped facilities and the additional looping and compression facilities will be used for all services. Furthermore, the Commission found it significant that the additional facilities are a prebuild portion of facilities necessary to transport Alaskan gas whose beneficiaries will also be Northwest and PG&E. Hence, it would make little sense to separate the costs and volumes associated with the transportation of gas from Alaska and for Pacific Interstate on the one hand from costs and volumes associated with transportation of gas for PG&E and Northwest on the other hand, as PGT proposes.

The FERC conceded that facilities required for this project and completion of the Western Leg are more costly than existing facilities which have been substantially depreciated, and the effect of rolled-in tariff treatment will be to increase the rates for PGT's services to Northwest and PG&E. However, in the past, both have received cost benefits under the cost of service tariff from the depreciated existing facilities and will continue to receive them in the future along with all PGT's customers. Moreover, PG&E and Northwest have derived significant benefits from the cheap expansibility of the existing pipeline in the form of reduced rates with each increment of additional throughput added to its system. Nevertheless, limits of this cheap expansibility of the existing line have now been reached. "The Commission sees no reason why the existing customers should now have what amounts to a priority for rate and tariff purposes on the existing pipeline, a priority which results from PGT's departure from the rolled-in treatment accorded additional compression and pipeline looping facilities in the past, coupled with complete insulation from the costs associated with the additional facilities." While a goal of regulation is to match costs incurred with benefits received to specific consumers, the Commission added, there are times when this is "not worth the administrative costs and inconvenience, and this is one of those occasions. The rolled-in tariff and financing approach will make PG&E customers pay more now in order to pay less later, but it has the advantage of making the PGT looping proposed as part of this proceeding supportable based on currently authorized exports of Canadian gas. We hope that the project sponsors are successful in obtaining additional volumes of gas exports; however, more than two years after approval of the ANGTS by the President and the Congress, the time has come to take the first step toward implementation of this massive project."

However, the Commission added, if after further NEB action on the gas exports, the three principally affected parties -- PGT, Pacific Interstate and the California PUC -- are able to agree on tariff and financing proposals superior to the rolled-in approach, the Commission will be prepared to reconsider its decision on that issue.

On other matters, the Commission (1) concluded that no changes to the depreciation provisions of PGT's cost of service tariff need be made -- because the Canadian export authorizations issued to PGT's supplier, all of which expire before 1992, continue to be a valid measure of the useful life of the PGT system; (2) declined to modify PGT's existing rate of return -- because that is not properly a subject of concern in this certificate proceeding; and (3) reaffirmed an earlier conclusion that a resale restriction in the Northwest Alaskan/Pan-Alberta contracts authorizing the latter to terminal sales if the former resells exported Alberta gas in the U.S. to any purchaser not a partner in ANGTS does not violate a provision of the ANGTA which requires, among other things, that nonowner shippers be afforded equal access to the pipeline -- because such provision seeks to protect shippers of gas -- in particular, nonowner suppliers -- and does not protect the purchasers of gas who are the only ones subject to the contract restriction.

D.C. Circuit Holds that Regulatory Agency Member Not Disqualified from Rulemaking Proceeding Without Showing of "Unalterably Closed Mind" on Critical Issues

On 12/27/79 the U.S. Court of Appeals for the D.C. Circuit reversed a decision of U.S. District Court of the District of Columbia which upheld a petition by the Association of National Advertisers, Inc. et al. prohibiting Michael Pertschuk, Chairman of the Federal Trade Commission, from participating in a pending rulemaking concerning children's advertising on TV on the ground he had prejudged issues involved therein. The D.C. Circuit concluded that "an agency member may be disqualified from such a proceeding only when there is a clear and convincing showing that he has an unalterably closed mind on matters critical to the disposition of the rulemaking." In so holding, the Court agreed with arguments of the FTC and seven other federal regulatory agencies, including the FERC, that the lower court's decision would have "a potentially chilling effect on otherwise legitimate public discussion of important regulatory policy questions and hamper the policymaking process." 1/

In the lower court case, the National Advertisers charged that Mr. Pertschuk made public statements concerning regulation of childern's advertising that demonstrated prejudgment of specific factual issues sufficient to preclude his ability to serve as an impartial arbiter. The Chairman had made several public comments about children's susceptibility to advertising and about how the FTC might reach the conclusion that such advertising is "deceptive." Later, the FTC began a rulemaking proceeding to consider certain restrictions on advertising directed to children. The lower court first noted that the FTC rulemaking is governed by the Magnuson-Moss Act, which imposed additional procedures -- including trial-type hearings in some cases -- on conventional notice and comment rulemaking. For that reason, the lower court applied the strict disqualification test applicable to adjudication -- as specified in the D.C. Circuit's decision in Cinderella Career and Finishing Schools, Inc. v. FTC, 425 F.2d 583 -- i.e., whether "a disinterested observer may conclude that [the agency member] has in some measure adjudged the facts as well as the law of a particular case in advance of hearing it."

In seeking rehearing before the D.C. Circuit, the FTC argued that the standard for disqualification of an administrative decisionmaker in an adjudication -- relied on by the lower court -- differs from the standard in rulemakings, and that, under any disqualification standard, Chairman Pertschuk could not be found to have prejudged issues in contravention of due process. In an amici curiae brief filed by the FERC and six other regulatory agencies, the "critical distinctions" between rulemaking and adjudication were also stressed. Rulemaking, they declared, is "different in concept, and different in procedures." By definition, they explained, rulemaking is the process for developing an agency statement of a general or particular applicability and future effect designed to implement, interpret or prescribe law or policy. This process is typically concerned with broad policy considerations rather than review of individual conduct. And this conceptual distinction, which is clearest in cases of informal rulemaking where there are no hearing requirements, remains valid no matter what the particular procedural format. "The mere presence of hearings, for example, ought not to convert what is really a rulemaking into adjudication."

1/ On 1/7/80 Chairman Pertschuk withdrew from the case because his involvement may strengthen supporters of legislation to bar the FTC from issuing a rule to restrict TV commercials aimed at children.

The regulatory agencies called attention to the D.C. Circuit's holding in another case that rulemaking "is not to be shackled, in the absence of clear and specific Congressional requirement, by importation of formalities developed for the adjudicatory process and basically unsuited for policy rulemaking." They urged that the adjudicatory concept of disqualification employed by the lower court is one of those "formalities developed for the adjudicatory process and basically unsuited for policy rulemaking. . . . The Cinderella concept -- that a member must be disqualified if he or she 'has in some measure' prejudged the facts or law -- simply does not blend with the rulemaking process."

The regulatory agencies further observed that a rulemaking proceeding begins with a notice of proposed rulemaking, a document which "inevitably shows that the agency 'has in some measure' prejudged issues." As a practical matter, they continued, such notice normally reflects a substantial step along the way from an idea to a final rule. In important rulemakings, moreover, the idea will have been closely examined by Staff experts and agency members themselves. Drafts of the notice and accompanying statements may well have been rewritten after direct consultation with and upon instructions from agency members. The more important the rulemaking, the closer the personal involvement of the agency member is likely to be. "Devoting that kind of attention to major policymaking questions is, after all, just what the agency member is suppose to be doing."

However, the regulatory agencies continued, if the Cinderella test is to go beyond adjudication into rulemaking, "there is an obvious anomaly." On the one hand, the agency is not suppose to give the appearance that it has in some measure adjudged the facts as well as the law of the proceeding. But at the same time, it is also suppose to issue a notice which inherently reflects at least a preliminary judgment -- often formed after considerable thought -- about the very subject matter of the controversy. "We think it apparent that a literal application of the Cinderella test is wholly unsuited for the rulemaking process."

Furthermore, the regulatory agencies stressed, the extension of the Cinderella approach to rulemaking would have a "chilling effect on the public expression of views about important subjects. From a policy standpoint, we believe that the law ought to recognize and accommodate this important informational aspect of an agency's work. The rules should encouurage -- not deter -- agency members from speaking out openly on the very kinds of broad policy questions likely to lie at heart of the most significant rulemakings."

The regulatory agencies also emphasized the affirmative duty that they have to report and inform the public on issues involving the industries they regulate. The FERC, for example, is authorized to publish and make available to state commissions and municipalities information about matters investigated under the Natural Gas Act and the Federal Power Act. "These responsibilities reflect the public's legitimate interest in knowing how agency members think about important policy questions. We think it vital that these considerations not be subordinated to a notion drawn from adjudication (where this informational role is far less important) that there is something wrong with an agency member telling the public his or her preliminary views about a pending issue. Just as legislators may approach their tasks with preliminary views -- the typical Congressional hearing opens with a statement reflecting substantial prejudgment about the problem -- so may agency members."

While arguing for the inapplicability of strict adjudicatory standard of the Cinderella case to rulemaking, the agencies recognized that the need for some kind of a standard to deal with extraordinary situations. Accordingly, they suggested a standard which would allow disqualification in any kind of rulemaking only when there has been "a clear and convincing showing that the agency member has an unalterably closed mind on matters critical to the disposition of the proceeding. This formulation would ensure that any agency member who cannot meaningfully fulfill his or her responsibility under the [Administrative Procedure Act] would be disqualified."

The D.C. Circuit first held that the FTC proceeding was rulemaking notwithstanding the additional procedures required by the Magnuson-Moss Act. The Court stressed that it never intended the Cinderella rule to apply to a rulemaking procedure such as the one under review here. "Legislative facts adduced in rulemaking partake of agency expertise, prediction and risk assessment." In the Cinderella case, the Court noted, it was able to "cleave fact from law" in deciding whether particular factual issues had been prejudged. "In the rulemaking context, however, the factual component of the policy decision is not easily assessed in terms of an empirically verifiable condition. Rulemaking involves the kind of issues 'where a month of experience will be worth a year of hearings' Application of Cinderella's strict law-fact dichotomy would necessarily limit the ability of administrators to discuss policy questions. The legitimate function of a policymaker, unlike an adjudicator, demands interchange and discussion about important issues. We must not impose judicial roles upon administrators when they perform functions very different from those of judges."

Furthermore, the D.C. Circuit continued, the Cinderella view of a neutral and detached adjudicator "is simply an inapposite role model for an administrator who must translate broad statutory commands into concrete social policies. If an agency official is to be effective, he must engage in debate and discussion about the policy matters before him. As this Court has recognized before, 'informal contacts between agencies and the public are the 'bread and butter' of the process of administration.'" The Court concluded that a Commissioner should be disqualified "only when there has been a clear and convincing showing that the agency member has an unalterably closed mind on matters critical to the disposition of the proceeding." In this case, the Court said, Chairman Pertschuk's remarks, considered as a whole, represent discussion "and perhaps advocacy, of the legal theory that might support exercise of the Commission's jurisdiction over children's advertising. The mere discussion of policy or advocacy on a legal question, however, is not sufficient to disqualify and administrator."

The Court's decision was signed by Circuit Judge Tamm. Circuit Judge Leventhal (prior to his recent death) concurred in a separate statement. Circuit Judge MacKinnon dissented on the ground, among others, that the "unalterably closed mind" standard is improper here because of the adjudicatory overtones of the Magnuson-Moss Act. Moreover, he stated that the "closed mind" test is so overly strict as to make it practically impossible to prove.

Fourth Circuit Refers Certain Issues in Case Involving Gas Shortage on Transco's System to FERC

On 1/8/80 the U.S. Court of Appeals for the Fourth Circuit granted a motion by Transcontinental Gas Pipe Line Corp. that it hold in abeyance review of an award of $23.8 million in damages by a North Carolina federal district court as a result of curtailments to certain customers, and refer to the FERC certain underlying issues involving, among others, the reasons for shortages on Transco's system. The Court, however, refused to vacate the lower court's judgment. CF Industries, Inc. and Farmers Chemical Association, Inc. v. Transcontinental Gas Pipe Line Corp., Nos. 79-1359 and 79-1366.

This case arose out of civil damage suit filed against Transco by CF Industries and Farmers in connection with the curtailment on Transco's system beginning in 1971. On 2/16/79 a jury in the North Carolina court awarded $23.8 million in damages to CF and to Farmers based on Transco's liability in contract, negligence and promissory estoppel. Earlier, the lower court twice refused Transco's appeal that certain issues raised in the case falling within the expertise of the FERC and which have an impact upon its regulatory responsibility be referred to the Commission.

On 2/28/79 Transco filed a petition (TC79-8) requesting the Commission to (1) institute a proceeding into circumstances which resulted in the gas shortage on its pipeline system, the effects of its gas tariff curtailment provisions and service agreements and Commission orders, rules and regulations, and the effect on the Commission's ability to carry out its responsibilities by the damage award; and (2) issue a declaratory order holding, among other things, that the shortage on Transco's system was caused by factors beyond its control, Transco reacted thereto in good faith and in a prudent manner, its curtailment tariff provisions and service agreements are in compliance with Commission rules and regulations (and therefore represent a defense to any claims for damages), and that any such award would constitute an undue preference and discrimination under the Natural Gas Act and adversely affect the Commission's ability to fairly allocate supplies available to Transco.

On 8/17/79, the Commission (1) agreed that a proceeding should be instituted on the effects of Transco's gas curtailment provisions and service agreements and Commission orders, rules and regulations, including whether any undue preference or advantage is involved with the award of damages; and (2) granted that portion of the request for a declaratory order holding that Transco's curtailment tariff provisions and service agreements are in compliance with Commission rules and regulations. The Commission denied Transco's request for a proceeding and declaratory order in all other respects.

In subsequent applications for rehearing by Transco, INGAA and others, it was argued that the Commission must inquire into the facts and circumstances of the shortage on Transco's system in order to determine whether it properly carried out its gas acquisition, transportation, inventory or sales activities. This same issue, it was noted, is also involved in other cases where pipelines are being sued.

Transco also filed a petition in the Fourth Circuit for review of the damage award, in which it requested the Court to refer the underlying issues involving the shortage on its system to the Commission. In an amicus curiae brief, the FERC asserted that the Court should vacate the lower court's judgment and remand with instructions to refer issues subject to the Commission's primary jurisdiction --

i.e., concerning the interpretation and effect of the certificate, tariffs and service agreements, and orders, rules and regulations as they affect the litigation. However, the Court should not direct the referral of the question of ultimate liability in the damage action, including whether compliance with Transco's tariff provisions is a complete defense to any claims for damages for breach of contract -- because "that responsibility belongs to the courts." (See REPORT NOS. 1224, pp16-18; 1231, pp22-25.)

In its decision, the Fourth Circuit agreed with a conclusion reached by the Fifth Circuit in a 1976 case involving a similar controversy that deference to the primary jurisdiction of the Commission is particularly appropriate in the complex area of natural gas curtailment. The Fourth Circuit quoted the Fifth Circuit's decision that "referral is particularly appropriate. While the Federal Power Commission's jurisdiction is somewhat limited, the Natural Gas Act, as interpreted by the courts, has provided the Commission with the statutory basis for pervasive regulation of the curtailment question . . . . The Commission is presently involved in resolving issues which have a direct impact on similar litigation involving curtailment plans. The advisability of invoking primary jurisdiction is greatest when the issue is already before the agency . . . . The Commission, moreover, is reviewing in some detail the facts and circumstances that resulted in the present shortage in order to determine what is a fair, equitable, permanent curtailment plan. Indeed, this court has already stated in a similar action that referral to the FPC is preferred.'"

The Fourth Circuit also noted that in one of its own prior cases it "recognized the unique expertise of the Commission . . . ." In that case, the Court said, it found the Commission to be "'a far more appropriate body than a district court'" to make a determination requiring a balancing of conflicting needs and interests of all consumers of the gas supplier involved.

However, the Fourth Circuit agreed with the FERC's position that the Commission does not have authority to adjudicate ultimate liability in the pending damage action since this responsibility rests solely on the Court, and that any inquiry by the Commission into the effect of a damage award against Transco on the Commission's ability to carry out its responsibilities, including allocation of Transco's gas supplies, would be premature and speculative at this point.

The Fourth Circuit concluded that the Commission has the authority under the Natural Gas Act to investigate the causes of a gas shortage on any particular pipeline system, and such an investigation and determination "would be appropriate and helpful in the pending litigation." But the Court decided not to approve the suggestion of the Commission and Transco that the lower court's judgment be vacated and the case remanded with instructions to refer the specified issues to the Commission for the exercise of its primary jurisdiction, with the lower court proceeding stayed pending final Commission action. Instead, the Fourth Circuit decided that the appeals pending with respect to the lower district court action should be held in abeyance and that certain facts and issues be referred to the Commission for its determination and decision, after which the Court would consider the appeals and determine the proper procedure.

Specifically, the Court directed the Commission to consider (1) the facts and circumstances resulting in the shortage on Transco's system that allegedly resulted in the loss claim by CF Industries and Farmers; (2) the meaning and interpretation of Transco's gas tariff curtailment provisions and service agreements and of Commission orders, rules and regulations relating to curtailments in the event of shortage, and the effect of such provisions on Transco's

responsibility to its customers; (3) whether undue preference or advantage is created by the damage award and what administrative action, if any, should be taken; (4) the meaning and effect of Transco's contracts and related certificates authorizing service to distributor customers; and (5) any other findings the Commission deems appropriate and relevant.

* * * * *

On 1/17/80 FERC Administrative Law Judge Steven M. Charno granted a motion by Transco that the procedural schedule in the investigation (TC79-8) ordered by the Commission's 8/17/79 order on the effects of Transco's gas curtailments and service agreements and Commission orders, rules and regulations be suspended pending Commission action in response to the Fourth Circuit's decision described above. In support, Transco noted that the issues referred to the Commission by the Court are broader than, and in conflict with, issues which the Commission set for hearing in its 8/17/79 order. Hence, the procedural schedule should be suspended to prevent potentially wasteful effort by the parties until the Commission has acted with respect to the Court's referral order.

Supreme Court Asked to Review Conflicting Decisions of D.C. Circuit and Fifth Circuit Ruling on Commission's Power to Impose a 30-Day Timing Requirement on Advance Payments Covered by Order No. 465

During the past month, petitions for writ of certiorari were filed in the U.S. Supreme Court by Tennessee Gas Pipeline Co. and the FERC to review conflicting decisions by the D.C. Circuit and the Fifth Circuit in regard to the Commission's power to impose a 30-day timing requirement on producer expenditure on advance payments received under Order No. 465 in determining whether such advances are "reasonable and appropriate" for rate base treatment. The FERC requested review of the Fifth Circuit's decision only if the Supreme Court grants Tennessee's petition for certiorari to review the D.C. Circuit's decision. Tennessee Gas Pipeline Co. v. FERC (No. 79-962) and FERC v. United Gas Pipe Line Co. (No. 79-1055).

First, on 12/19/79, Tennessee Gas Pipeline Co. asked the Supreme Court to review a D.C. Circuit decision issued 6/20/79 (Tennessee Gas Pipeline Co. v. FERC, No. 77-1496) which, among other things, remanded FPC Opinion Nos. 769 and 769-A denying inclusion of some $100 million of front-end advance payments made by Tennessee (RP73-113) to producers under agreements executed in 1973. In that year, the Commission's advance payment program was governed by Order No. 465 which required merely that advances be "reasonable and appropriate" in order to qualify for rate base treatment. Subsequently, in Order No. 499 governing the advance payment program during the years 1974 and 1975, the Commission clarified that advances must be expended by producers within a "reasonable time" after inclusion thereof in the pipeline's rate base. In Opinion No. 769 (issued 7/9/76), the Commission ruled for the first time that advance payments not expended by producers within 30 days are "presumptively extravagant" and hence not "reasonable and appropriate" for inclusion in the advancing pipeline's rate base. While conceding that Order No. 465 did not contain any timing requirement, the Commission declared that the "reasonable and appropriate" standard was consistent with well-established principles of regulatory law that "extravagant or unnecessary costs cannot be passed along to customers through rates." Further, the Commission stated, "it has not been suggested by Tennessee that a producer in the conduct of its own business would borrow money and pay interest thereon far in excess of the time it is needed. Nor do we think Tennessee could make such a showing. We find, therefore, that front-end advance payments are presumptively extravagant." In Opinion No. 769-A (issued 5/31/77), the Commission denied that application of a timing standard to advances under Order No. 465 constituted retroactive ratemaking since the

"reasonable and appropriate" standard, which pervaded all of the advance payment rulemaking orders, "necessarily covered such unnecessary and extravagant costs as those resulting from front-end advances."

On appeal, the D.C. Circuit partly affirmed and partly remanded Opinion Nos. 769 and 769-A, as well as FPC orders in two other cases which similarly applied a 30-day standard in disallowing rate base inclusion of advance payments by Transcontinental Gas Pipe Line Corp. and Michigan Wisconsin Pipe Line Co. pursuant to both Order Nos. 465 and 499. The Court concluded that the Commission correctly rejected the pipelines' position that the front-end advances were dictated by "good faith business judgments" given the competitive conditions at the time and hence were "reasonable and appropriate" for purposes of inclusion in the rate base. The Court said the pipelines had the burden of demonstrating affirmative evidence in favor of "extended" front-end advances, especially in view of the traditional "used and useful" public utility concept on which the Commission has consistently relied. At the same time, the Court held that the Commission's 30-day rule focused too narrowly on a line-of-credit approach and, as a result, the Commission "failed to evaluate fully and fairly the reasonableness of the protective mechanisms adopted by particular pipelines to fulfill their obligation of vigilance in the consumers' interest." The Fifth Circuit accordingly remanded the cases for a more extensive and flexible inquiry into the reasonableness of attempts to protect ratepayers from excessive costs. On 10/31/79 the Court denied rehearing and suggestions for rehearing en banc. (See REPORT NO. 1214, pp18-21.)

The D.C. Circuit's decision was issued two days prior to a Fifth Circuit decision (United Gas Pipe Line Co. v. FERC, No. 78-1091) which overturned Opinion Nos. 815 and 815-A denying rate base inclusion of some $24 million of advance payments by United Gas Pipe Line (RP74-20, RP74-83) under Order Nos. 465 and 499 because the advance payments had not been expended by the recipient producers within 30 days. The Fifth Circuit reversed the Commission's denial of rate base treatment for advance payments governed by Order No. 465. As applied to these payments, the Court said the 30-day standard "arbitrarily imposes a new dimension and a new restraint . . . . The law will not tolerate this sort of after-the-fact, in fact retroactive, imposition of standards." In regard to the advances covered by Order No. 499, the Fifth Circuit reversed and remanded the Commission's application of the 30-day rule as "unreasonably harsh." The "relatively vague" timing guideline imposed in Order No. 499, the Court said, did not constitute sufficient notice to pipelines that all advances should be made on a 30-day installment basis. On 8/8/79 the Court denied FERC's petition for rehearing. (See REPORT NO. 1217, pp16-17.)

In still another case, the Seventh Circuit on 1/5/79 reversed and remanded an FPC order of 6/3/77 which applied the 30-day rule in denying rate base treatment for front-end advance payments by Natural Gas Pipeline Co. of America (RP73-110). Natural's advances were all made pursuant to Order No. 499. The Seventh Circuit held that imposition of the 30-day standard represented a retroactive modification of Order No. 499, which merely required that advances must be expended within a "reasonable time" after their inclusion in a pipeline's rate base.

In seeking Supreme Court review of the D.C. Circuit's decision of 6/20/79, Tennessee contended that the Court's holding regarding Order No. 465 advances conflicted directly with the Fifth Circuit's decision in the United case described above. Further, the D.C. Circuit's rationale that imposition of an implicit timing requirement is not impermissible retroactive rulemaking conflicts with the Seventh Circuit's decision in the Natural Gas Pipeline case dealing with Order No. 499 advances. Proper resolution of this conflict is of "critical importance" to the

natural gas industry, Tennessee declared, since it involves the ultimate disposition of substantial Order No. 465 advance payments made by interstate pipelines generally. In this regard, Tennessee noted that nearly 99% of the $. 5 billion total committed by interstate pipelines under the advance payments program represented front-end advances of the type involved in this case. Moreover, Tennessee added, even though the advance payment program has now been terminated prospectively as to new agreements, the problem is of continuing importance to the administration of jurisdictional rate increases filed under advance payment contracts which remain in effect.

The second petition for certiorari was filed on 1/5/80 by the Solicitor General, on behalf of th FERC, to review the Fifth Circuit's decision in the United case with respect to advances under Order No. 465. (The petition does not request review of the Fifth Circuit's remand of the Commission's disallowance of front-end advances under Order No. 499.) The FERC asked that its petition for certiorari be granted only if the Supreme Court grants review of the D.C. Circuit's decision in the Tennessee case. The Commission noted the direct conflict between the Fifth Circuit and D.C. Circuit decisions respecting the Commission's power to impose a timing requirement on Order No. 465 advances. However, while the FERC agrees with the D.C. Circuit's holding on this issue, it does not advocate Supreme Court review of the interpretation of Order No. 465, which "governs only contracts executed in 1973 under a terminated experimental program." Consequently, the FERC intends to oppose the petition for writ of certiorari in the Tennessee case (No. 79-962). However, if the Supreme Court grants Tennessee's petition for review in that case, it should also grant review in the United case "so that the interpretation of Order No. 465 will be uniform for pipelines and consumers throughout the country."

Tenneco, FERC, INGAA File Complaints and Requests for Injunctive Relief Enjoining Enforcement of Louisiana Statute on Intrastate Purchasers' Right of First Refusal

During the past several weeks, Tenneco, Inc., the FERC and the Interstate Natural Gas Association of America (INGAA) have filed complaints for declaratory judgment and injunctive relief with the U.S. District Court for the Middle District of Louisiana (Civil Action Nos. 80-17 et al.) in regard to a recently enacted Louisiana statute, effective 9/7/79, which provided Louisiana intrastate purchasers of natural gas with a right of first refusal for all natural gas not committed or dedicated to interstate commerce prior to 9/7/79 effective date of that statute. 1/

The Louisiana Act (No. 732) amended the state's Natural Resources and Energy Act of 1973 to require that "producer-sellers" of natural gas not committed or dedicated to interstate commerce prior to 9/7/79 obtain a state certificate of public convenience and necessity before allowing the introduction of such gas into any interstate pipeline system. The Act further requires producer-sellers to make a bona fide offer to sell such gas to intrastate natural gas transporters before committing the supply to interstate commerce. Noncompliance with the Act is not excused by contractual obligations, and criminal penalties are set forth for violations. Interim regulations implementing the Act were promulgated on 10/28/79 by the Louisiana State Conservation Commission.

1/ The District Court originally set a 1/18/79 date for a hearing on the preliminary injunction request, but this date was extended indefinitely by request of the State of Louisiana.

In its complaint and request for a preliminary injunction, Tenneco asserted, among other things, that the Act "has had a chilling effect on the willingness of sellers to contract for sale in interstate commerce." Tenneco cited eight contracts which it has entered into with producers since the enactment date of the legislation but for which no deliveries have commenced owing to the requirements of the Louisiana statute. Moreover, Tenneco stated that the requirements of the Act have hampered its efforts to negotiate further contracts and thereby limited its ability to fulfill the natural gas requirements of its customers.

As further support for its complaint and request for a preliminary injunction, Tenneco contended that the Act (1) unconstitutionally discriminates against interstate commerce by creating an undue preference for intrastate purchasers; (2) constitutes a prohibited burden on interstate commerce in violation of the Commerce Clause of the U.S. Constitution; (3) conflicts with federal statutes and is hence void under the Supremacy Clause of the U.S. Constitution; and (4) contradicts the responsibilities of the FERC in the exercise of its jurisdiction under the Natural Gas Act and the NGPA.

The FERC, in its complaint in intervention, also asserted that the Louisiana statute violates the Commerce and Supremacy Clauses of the U.S. Constitution and conflicts with the FERC's exclusive jurisdiction over interstate pipeline transactions. Additionally, FERC cited the deleterious effect the Act will have on future additional gas supplies for the interstate market. "At a minimum," FERC's complaint stated, "this provision will delay the attachment of new gas supplies . . . at the worst, it will reduce the new gas supplies available to the interstate pipelines to the extent that intrastate purchasers exercise their right to purchase such gas."

INGAA also cited the above arguments of Tennessee and FERC in support of its complaint and request for declaratory judgment and injunctive relief. Additionally, the complaint stated that the Louisiana Act, in depriving member companies of INGAA of their freedom to contract with whomever they choose, violates those companies' rights under the provisions of the 14th Amendment of the U.S. Constitution.

FERC Law Judge Finds Violations of Natural Gas Act by National Fuel Companies

On 1/11/80 FERC Law Judge George P. Lewnes issued an initial decision finding that National Fuel Gas Supply Corp. and National Gas Storage Corp. violated the Natural Gas Act and the U.S. Criminal Code in connection with certain construction activities related to development of storage fields in western New York. Judge Lewnes recommended that the violations be referred to the Department of Justice for criminal prosecution.

This proceeding was initiated by the FERC on 12/19/77 in response to a complaint by Fair Environmental Deals for United People (CP77-590) directed to activities of the National Fuel Companies (or their predecessors-in-interest) around Allegany County, New York from January 1975 through July 1977. These activities related, in part, to a long-term storage project whereby National Fuel Supply (CP77-492 et al.) proposes to abandon, and National Gas Storage proposes to acquire, three separate storage fields -- West Independence, East Independence and Beech Hill -- located in Allegany County. After further development, the three fields would be connected via 17.7 miles of new pipeline to National Fuel Supply's interstate transmission system in Potter County, Pennsylvania. The proposed project, estimated to cost nearly $50 million over a three-year period, would enable long-term storage service by National Gas Storage to six nonaffiliated utility customers in aggregate amounts increasing to 22 Bcf by 1980. By order dated 2/1/77, the FPC scheduled hearings on the proposed project to consider various unresolved questions, including environmental impact, rate level and rate form, conditions (if any) to be attached to construction of the proposed facilities, financing, and the impact on existing customers of the National Fuel Companies of developing storage facilities to serve six offsystem distributors. The Commission subsequently consolidated applications by Transcontinental Gas Pipe Line Corp., Columbia Gas Transmission Co. and Tennessee Gas Pipeline Co. to transport storage injection and withdrawal volumes for the six distributor customers. In June 1979, the Commission approved construction of a portion of the facilities.

Specifically, FEDUP -- which described itself as a "nonprofit, unincorporated public benefit association" representing residents in the immediate vicinity of the challenged activities -- asserted that the National Fuel Companies had unlawfully constructed facilities in the Beech Hill, West Independence and East Independence areas for transportation and storage of interstate gas in violation of the Natural Gas Act; had provided false information to the Commission for the purpose of unlawfully evading jurisdiction over reworking of 13 wells at the West Independence Field (CP76-364); and had provided false information in various maps submitted to the Commission. (See REPORT NOS. 1127, pp29-31; 1136, pp30-31.)

In his initial decision, Judge Lewnes stated that the National Fuel Companies violated the Natural Gas Act by substantially installing compressor units at the West Independence Field two months before Commission approval; reworking 21 wells at the Beech Hill Field without authorization; and commencing installation of compressor facilities at the Beech Hill Field. He also found that the companies violated the U.S. Criminal Code by providing false information in a map of the West Independence storage pool.

Most of these violations, he said, involved the installation of facilities and reworking of wells for the storage facilities before the necessary Commission authorization had been given. He stated that the companies' self-imposed time schedule for completing the storage facilities was the principal motivating force for the violations. "The substantial evidence . . . forces the conclusion that these illegal actions were not merely apparent willful and knowing violations, but rather were deliberate and result-oriented."

In support of his conclusion, Judge Lewnes observed, among other things, that the Commission had set the storage proposal for hearing and, on a number of occasions, specifically denied requests by the companies for temporary authorization for portions of the construction. Nevertheless, the companies illegally commenced portions of the project without authorization.

With respect to the violations of the Natural Gas Act, Judge Lewnes noted the Commission's policy that if any illegal action appears to have been taken willfully and knowingly, it would refer the case to the Department of Justice. "The character of every act depends upon the circumstances in which it was done. Here, there is nothing in the factual circumstances as would militate against a referral."

As noted, the Law Judge found a violation of the U.S. Criminal Code by the National Fuel Companies by virtue of their providing false information to the Commission in a map of the West Independence storage pool. He said that the motive for this falsification was the companies' need for a storage permit from the New York State Department of Environmental Conservation prior to development of the storage facility. The New York agency requires that an applicant hold 75% of the storage rights under the land inside the pool boundary before a permit will be issued. The record shows, he said, that the company engaged in a "knowing and willful falsification" in drawing a false boundary of the storage pool on the map submitted to the Commission.

In urging that this violation also be referred to the Justice Department, Judge Lewnes noted that there is no discretionary authority vested in an agency to determine whether to transmit evidence of an apparent violation of a federal statute of general applicability (the U.S. Criminal Code). Hence, "it is obligatory on the part of the Commission to transmit the evidence adduced and the related findings and conclusions to the Attorney General . . . ."

Finally, the Law Judge stated that the violations (except with respect to the map) "were undertaken with the prior willful and knowing authorization of Mr. John A. Comet," former President of the National Fuel Companies. In this connection, Judge Lewnes stated that the inquiry here should not be limited to whether there has been a corporate violation. "Obviously, merely pursuing a corporate entity as opposed to individual corporate officers for a statutory violation is of little consequence. Monetary fines paid by a corporate body for illegal undertakings of its officers in the corporate name does not provide a deterring desideratum. The courts have recognized this and where appropriate, have permitted the prosecution of an officer or employee of a corporation for illegal acts done on behalf of a corporate employer."

FERC Approves Settlement Filed by Reversionary Mineral Interest Owners to Resolve Pricing Issues Raised by Southland Royalty-Type Sales

On 1/17/80 the FERC approved a settlement offer submitted by four reversionary mineral interest owners -- Dore Corp. (CI76-315 and CS76-639), Sullivan-Wells Co. (CI76-316 and CS76-460), Briercrest Oil Co. (CI76-396 and CS76-762) and Fort Worth National Bank et al. (CI76-587) -- to resolve a number of Southland Royalty-type cases currently pending before the Fifth Circuit on judicial review. 1/

The above producers were lessors under various 50-year oil and gas leases which expired during the first half of 1976. At that time, mineral interest rights in nine wells reverted to the lessors. The reversionary interest owners were ordered by the FPC on 3/12/76 and 7/6/76 to continue -- pending the outcome of litigation in the Southland Royalty case involving the question of continued dedication of gas to interstate commerce following expiration of 50-year leases -- the jurisdictional sales made by large producer lessees to interstate pipeline purchasers prior to expiration of the leases in question. These sales were made b the previous lessees at rates of 18.0¢ or 23.5¢. The Commission included protective provisions specifying that continued deliveries by the reversionary mineral interest owners during the interim period until resolution of the Southland Royalty case would be without prejudice to their position regarding the dedication status of the gas involved. Subsequently, the FPC denied applications filed by three of the mineral interest owners for small producer certificates to sell the subject gas at 130% of the national new gas rate set in Opinion No. 699-H. The Commission held, among other things, that the reversionary owners were bound to the rates charged by their respective large producer predecessors.

A total of six petitions were filed by the several mineral interest owners in the Fifth Circuit (Dore Corp. and Sullivan-Wells Co. et al. v. FERC, Nos. 76-2428 et al.) for review of the above described orders requiring continued interstate deliveries and prescribing rates for these deliveries. The Court ordered these proceedings held in abeyance until the final outcome of the Southland Royalty litigation (which was decided by the Supreme Court on 5/31/78). More recently, proceedings before the Fifth Circuit have been further deferred pending settlement discussions between the mineral interest owners, certain other producers, purchasers of the gas involved, and the FERC Staff. (See REPORT NO. 1240, App. p12.)

The settlement offer -- filed 12/7/79 by the four reversionary mineral interest owners -- provides for (1) continuation of sales to the interstate buyers currently receiving the gas under interim protective orders; (2) collection in the future of the maximum lawful price applicable to small producer replacement contracts under Section 104 of the NGPA (or the maximum lawful price under Sections 102, 103, 107 and 108 for any gas qualifying for these prices); (3) retention of all sums collected in the past pursuant to interim protective orders up to the applicable small producer replacement contract rates for the time periods involved (67.6¢/Mcf from 7/27/76 until 1/1/77, 68.9¢/Mcf until 1/1/78, 70.1¢/Mcf until 12/1/78, 77.1¢/MMBtu until 1/1/79, and thereafter as adjusted for inflation in accordance with regulations under the NGPA), subject to adjustment for Btu, taxes, and gathering allowance where applicable; and (4) withdrawal of petitions for review presently pending in the Fifth Circuit. (See REPORT NO. 1239, pp13-15.)

1/ Since the records in these proceedings have not been filed with the Court, the Commission retains jurisdiction to consider the settlement offer.

The Commission cited the Tenth Circuit's decision issued 4/23/79 in Getty Oil Co. v. FERC (No. 77-1993) as relevant to the situation here. In that decision, the Court reversed the Commission denial's of rate increases to new gas ceilings sought by Getty under the "rollover" contract policy on the ground that the underlying 1967 contract had not run its full primary term -- which, the Commission ruled, was a necessary condition to qualify sales under a new contract for "rollover" treatment -- but rather had terminated prematurely upon triggering of a pressure clause. The Tenth Circuit held that rejection of Getty's rate increases was based on a new interpretation of the Commission's contract replacement policy which should not have been applied retroactively to Getty whose contract expired prior to issuance of Opinion No. 770-A due to circumstances beyond the parties' control. (See REPORT NO. 1208, pp22-23.)

Specifically, the Commission declared "The normal expiration of the lease agreements in the instant case prior to the issuance of Opinion No. 770-A fits into the general category of cases covered by the Getty court decision. The expiration of the leases was beyond the control of either the seller or the buyer to the gas sales contract, and thus the seller upon executing a new contract was entitled to 'rollover' treatment."

Industrial Gas Users Protest Transco's Interruption of Transportation Under Order No. 533 Program

On 1/3/80 the FERC issued notice of separate complaints filed 12/20/79 by two groups of high priority industrial gas users -- Cerro Wire & Cable Co. et al. (CP80-153) and American Bakeries Co. et al. (CP80-184) -- with respect to Transcontinental Gas Pipe Line Corp.'s interruption of transportation of direct purchase gas under the Order No. 533 program. 1/

According to the complaints, Transco advised in early December that it would terminate Order No. 533 transportation service on 12/17/79 for a period of 30 to 90 days because of insufficient mainline capacity to render this and other higher priority services. As a result, the complaints charged, the industrial users here involved have been compelled to incur additional expense to replace their "self-help" direct purchase gas, while Transco is "forcing" additional gas on its customers that will be used in large part as low priority boiler fuel. Further, the

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1/ Cerro Wire & Cable (CP79-309), together with six other industrial buyers, previously petitioned the FERC on 5/2/79 to issue an expedited declaratory order respecting their eligibility to a two-year extension of certain Order No. 533 transportation service provided by Transco (CP77-240). The petition stated that Transco had refused to seek authorization to extend this service both because the supply in question appeared to be available for purchase by the pipeline itself absent the Order No. 533 arrangements, and because the seven industrial buyers would not suffer any curtailment of natural gas deliveries from their distributor supplier until at least the end of the 1979 summer season. Cerro Wire & Cable et al. cited a sworn affidavit by producers of the subject supply indicating unwillingness to make sales to an interstate pipeline. Hence, since the gas will not be available to Transco, the industrial buyers contended they are eligible to receive a two-year extension of transportation service under the Order No. 533 direct purchase program. Subsequently, Cerro Wire & Cable et al. withdrew their petition for a declaratory order following Transco's agreement to request a two-year extension of transportation service (CP77-240). This extension was granted by order dated 10/31/79. (See REPORT NO. 1210, pp28-29.)

complaints continued, wells dedicated to the industrial buyers are in danger of being shut in, with resultant damage to the reservoirs, loss of production and, in the case of wells facing water encroachment, a permanent loss of reserves. Transco's actions were also said to constitute a severe, perhaps "crippling" blow to the entire Order No. 533 direct purchase program.

Cerro Wire & Cable et al. contended that Transco's interruption of transportation constitutes (or will soon constitute) an unauthorized abandonment of certificated service. American Bakeries et al. noted that Order No. 533 transportation certificates contemplate interruptions "of an absolutely necessary, short-term nature." Here, however, "Transco -- in a period of relatively warm weather -- is cutting off high priority load to empty storage and in effect force the use of natural gas for low priority boiler fuel." Such interruption may constitute an "unlawful abandonment." Both complaints cited a D.C. Circuit decision in 1976 (Reynolds Metals Co. v. FPC, 534 F.2d 379) holding that a 62% reduction in volumes transported to an industrial customer represented a partial abandonment requiring authorization under Section 7(b) of the Natural Gas Act.

Cerro Wire & Cable et al. and American Bakeries et al. requested the FERC to call an immediate conference for the purpose of requiring Transco to explain in detail the reasons for its interruption of transportation service, to determine whether this interruption comports with the public convenience and necessity, and to reinstate the presently interrupted service pending such determination.

On 1/10/80 Transco moved for summary dismissal of the complaints. Transco stressed that Order No. 533 transportation service is subject to interruption pursuant to contractual arrangements among Transco, end users and end users' distributor-suppliers. Consequently, Transco is not violating any contractual or certificate obligations by interrupting these interruptible services. Moreover, Transco noted, Order No. 533 transportation makes use of temporarily unused pipeline capacity built for -- and dedicated to - serving Transco's commitments to long-term firm service customers. Transco is now required to interrupt these services because its mainline capacity is fully used to render other service obligations of a higher priority. 1/ Under these circumstances, it is "utterly absurd" to suggest that such interruption constitutes an "unlawful abandonment."

Transco also disputed that the D.C. Circuit's decision in Reynolds Metals supports the complainants' position. That decision, Transco stated, involved a permanent reduction in firm service. By contrast, the situation here involves a reduction in interruptible transportation service which will continue only as long as Transco's mainline capacity is fully utilized by other services.

1/ An attachment to Transco's filing indicated that the pipeline's mainline capacity is expected to remain fully utilized until mid-March to meet firm service requests of its resale, direct industrial and firm transportation customers, as well as requests for storage withdrawals under Rate Schedule WSS. In addition, Transco expects utilization of its mainline cpaacity on most days to render interruptible delivery obligations from the Washington Storage Field, or to eliminate an existing temporary imbalance between nominations and withdrawls of storage gas.

Even assuming that the above interruptions in Order No. 533 transportation service were found to violate contractual or certificate obligations, Transco said the requested emergency relief would still be unwarranted because the distributors serving the complainant end users have advised that adequate supplies are available for these customers Hence, there is no threat that any of the industrial users' plants will be forced to shut down for lack of gas supply. Further, Transco noted, in early September it advised all end users, distributors and producers involved in Order No. 533 transactions that mainline capacity limitations were anticipated "on a significant number of days during the 1979-1980 winter season," and that interruption of Order No. 533 interruptible transportation services would be required. This early notification, on its face, "undercuts . . . any claim of dire emergency" except "that brought on by complainants' own failure to give proper attention to Transco's notice."

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More recently, on 1/15/80, the Commission granted Transco's request (CP80-55) to amend 19 certificates for transportation of Order No. 533 direct purchase gas so as to eliminate end-use restrictions. This action was consistent with Order No. 52 (RM80-1), issued 10/5/79, which adopted an interim rule removing conditions on transportation of Order No. 533 gas prohibiting the buyer from using any interstate supplies for other than high priority feedstock or process requirements. The Commission concluded that this end-use limitation placed Order No. 533 customers at a disadvantage in light of the drop in curtailment levels and was contrary to the national need to promote displacement of fuel oil. Accordingly, the interim rule provided that industrial customers may receive natural gas for low priority uses without jeopardizing their right to purchase direct sale gas under Order No. 533. (See REPORT NOS. 1230, pp10-11; 1237, pp16-18.)

Transco requested amendment of the 19 transportation certificates only through the period ending 5/31/80. In support of this limitation, Transco stated that interstate pipelines now have parity of access to onshore supplies and that improvement in the interstate supply situation has substantially mitigated or eliminated the threat of curtailment to high priority industrial uses.

Two of the 19 certificates covered by Transco's application to amend involve transportation for certain of the industrial customers joining in the American Bakeries et al. complaint described above.

FERC Determines Equity Rate of Return of 12.5 Percent for Consolidated Gas Supply and Arkansas Louisiana

On 1/11/80 the FERC issued Opinion Nos. 70 and 71 deciding rate of return and certain other issues in rate proceedings of Consolidated Gas Supply Corp. (RP78-52 and RP79-22) and Arkansas Louisiana Gas Co. (RP77-54 et al.).

In Opinion No. 70, the Commission approved a common equity rate of return of 12.5% for Consolidated Supply in two separate cases covering the period 7/1/78 to the present. Based on the capital structure of Consolidated Supply's parent -- Consolidated Natural Gas Co. -- in the two cases (reflecting a common equity ratio of 53.8% in RP78-52 and 56.1% in RP79-22), this determination resulted in overall rates of return of 10.19% and 10.34%.

The FERC Opinion affirmed the results reached by Administrative Law Judge Stephen L. Grossman in an initial decision issued 7/3/79, although modified some of the details of that decision. (See REPORT NO. 1216, pp19-20.) Among other things, the Commission agreed with the Law Judge in rejecting the company's equity return recommendations in the range of 14.5% to 15.5% because of reliance on studies which examined only the cost of equity of Consolidated Natural and failed to adjust for the lower business risk of Consolidated Supply. Consolidated Natural (through subsidiaries other than Consolidated Supply), the Commission noted, is actively engaged in gas exploration and other production activities involving large capital expenditures and higher risk than traditional utility activities. Consolidated Supply engages in natural gas transmission and distribution, as well as some exploration and development. However, since Consolidated Supply recovers most of its exploration and development expenses on a cost of service basis through tariffs charged to customers for transmission and distribution services, it faces "significantly less risk" with respect to production activities than nonpipeline producers unable to automatically passthrough their production costs in this manner. Further, the Commission added, there is no basis for the contention that Consolidated Supply's customers have benefitted substantially from Consolidated Natural's production activities and hence should bear the risk of these activities through the subsidiary's allowed rate of return. Consolidated Natural is fully compensated for the risks of its production activities through rates charged to Consolidated Supply for gas, the Commission declared. Hence, Consolidated Supply is "properly viewed" as similar in risk to a natural gas pipeline engaged in gas transmission and sale.

The Commission also agreed with the Law Judge that the zone of reasonableness is in the range of 12% to 14% for determining a return on equity for Consolidated Supply. This range, the Commission said, is indicated by final Commission orders fixing equity returns for pipelines since 1977, and is confirmed by other evidence in the record respecting long-term public utility bond yields and composite equity earnings by U.S. industry.

In arriving at a specific equity allowance for Consolidated Supply, the FERC made a separate determination in each case, thereby rejecting the Law Judge's single determination for the two consecutive periods. In both cases, however, the Commission reached the same result. In RP78-52 (applicable to rates which were in effect from 7/1/78 through 6/30/79), the Commission concluded that Consolidated Supply should be allowed 12.5% on common equity -- toward the lower end of the zone of reasonableness -- because of a thicker than average equity ratio and reduced business risks brought about by improvement in the company's gas supply and total gas sales. As a further consideration, the Commission noted that Consolidated Supply plans a reduced construction budget, so that there is no need

for a higher rate of return due to capital requirements which might strain the company's financial resources. In RP79-22 (applicable to rates which went into effect on 7/1/79), the Commission held that the impact of increasing interest rates and bond yields was offset by the continued increase in Consolidated Natural's equity ratio. Consequently, the Commission adopted the same 12.5% return on equity found reasonable in the prior docket.

In Opinion No. 71, the FERC similarly approved a common equity rate of return of 12.5% for Arkansas Louisiana Gas Co. This was somewhat lower than the common equity allowance of 12.75% determined by Administrative Law Judge Isaac Benkin in an initial decision issued 4/26/79. The Commission concluded that the Law Judge gave insufficient consideration to Arkla's relatively high equity ratio of 54%, which served to reduce the company's financial risk. In addition, the Commission disagreed with Judge Benkin's reference to Arkla's need for additional capital to support ongoing exploration and development of gas reserves in the Deep Anadarko Basin. The Commission said Arkla's gas exploration and production operations apparently will be carried out by its affiliate, Arkla Exploration Co. However, even if this were not the case, any gas reserves produced in the future presumably will be sold to Arkla's customers at NGPA prices. Since the new gas prices established by the NGPA are "adequate to compensate producers for the costs and risks associated with producer operations, including the cost of acquiring capital," the Commission did not consider "an increment to Arkla's otherwise reasonable rate of return for pipeline operations to compensate for the cost of capital employed in its production operations . . . to be reasonable or necessary." Accordingly, the Commission declined to allow a higher rate of return in this proceeding as a result of Arkla's possible need for additional capital to undertake gas exploration activities in the Deep Anadarko Basin.

At the same time, the Commission agreed with Judge Benkin's conclusions regarding the inadequacies of the evidence presented by both the company and Staff. Arkla submitted a DCF market-oriented analysis and comparable earnings evidence to support its requested equity rate of return of 15.32%. The Staff recommended an equity allowance of 11.5% on the basis of a comparable earnings study. The Commission said the company's DCF presentation must be rejected because it related to Arkla's overall consolidated activities, with no attempt to separate the risks associated with the company's utility and nonutility operations. However, the Commission declared, the rate of return to be determined in this proceeding should reflect only the risks of Arkla's natural gas pipeline operations. The Commission found Arkla's comparable earnings presentation to be similarly defective in focusing on a group of integrated gas companies which, like Arkla, engage in retail gas distribution and gas exploration and production operations in addition to natural gas transmission. "The result, again, is a potential distortion in the assessment of risk associated with Arkla's natural gas pipeline operations." The Commission also faulted Staff's comparable earnings study of major Class A and B pipelines for failure to demonstrate that risks of this group are representative of those attributable to Arkla's pipeline operations.

A further issue decided by the Commission in both Opinion Nos. 70 and 71 involves the treatment of gains realized by the two pipelines on long-term debt reacquired before maturity at a purchase price below face value. In each case, the Commission adhered to the policy established in 1970 in Opinion No. 583 (re Manufacturers Light & Heat Co.) which held that all gains realized from the reacquisition of debt securities, irrespective of the date reacquired, must be amortized over the remaining life of the reacquired securities, and that the total amortized amount attributable to the test year must be applied to reduce the utility's cost of long-term debt. Arkla contended that no gain on reacquired debt should be

considered for ratemaking purposes, while Consolidated argued that any adjustment to debt cost should reflect only the gain on debt reacquired after 1/1/74 (the effective date of amended Commission regulations prescribing accounting and reporting treatment for gain on reacquired debt) and that application of the policy in Manufacturers would constitute retroactive ratemaking.

The FERC denied any retroactivity involved in application of the Manufacturers policy since there is no alteration of Commission approved rates for past periods. Rather, "debt reacquisitions prior to the test year are examined only for the purpose of determining the amount of gain allocable to th test year. Gain from reacquisitions which is allocable to periods prior to the test year is not recaptured as a credit against the test year cost of debt. Although past financial transactions of the company prior to the test year are examined (just as past financings are used whenever the embedded cost of debt is calculated), it is solely for the purpose of calculating cost of debt for the test year."

* * * * *

A few days previously, on 1/9/80, the FERC denied rehearing of Opinion No. 68, issued 11/19/79, which affirmed an initial decision determining a common equity rate of return of 12.73% for Kansas-Nebraska Natural Gas Co. (RP78-10). The initial decision concluded that neither the company nor the Staff had presented evidence which supported their specific equity return recommendations of 14.5% and 12.25%, respectively. Consequently, while noting continuing inflationary pressures on the cost of capital and the probability of a continuing long-term downward trend in the company's gas reserves, the Law Judge found no reason to change the common equity rate of return of 12.73% approved in Kansas-Nebraska's most recent rate case (RP77-5). 1/

Application of the 12.73% equity allowance to the settlement capitalization in the RP78-10 proceeding -- 40.5% long-term debt, 7.3% preferred stock and 50.8% common equity -- resulted in an overall rate of return of 10.51%.

In denying rehearing of Opinion No. 68, the Commission rejected Kansas-Nebraska's contention that it had ignored changes in interest rates and inflation since 1976, and had ignored prior Commission precedent. "The Commission is aware of inflation and interest rates, but Kansas-Nebraska has not met its burden to show with specificity how these general market conditions support either a rate of return in the very high range for which it argues, or a complete overhaul of rate of return analysis for the gas industry as a whole." In short, the Commission was unconvinced by Kansas-Nebraska's arguments absent a "nexus between generalized proof and the company's own situation," or a substantial showing that precedent should not be followed.

1/ This equity allowance was part of a rate settlement in the RP77-5 proceeding, which was approved by order dated 7/20/77.

ERA Grants Northern Project to Import Canadian SNG by Displacement at Base Import Price of $3.45 per MMBtu

On 1/15/80 the ERA issued Opinion No. 13 granting an application by Northern Natural Gas Co. (78-002-NG) to import about 10 Bcf annually of Canadian SNG by displacement from Union Gas Co. Ltd. over a five-year period beginning in the 1979-1980 heating season at a base price of $3.45/MMBtu, equal to the current authorized Canadian border price, plus storage charges. Opinion No. 13 was issued on rehearing of Opinion No. 5 (issued 3/8/79) which denied Northern's application to import the Canadian SNG at a cost during the first year (1978-1979) of $3.86/MMBtu escalating to $5.33/MMBtu by the fifth year. In Opinion No. 5, the ERA concluded that the import price was too high and Northern failed to demonstrate significant regional or national need for the SNG supply. In Opinion No. 13, the ERA found that the projected composite import price of $4.01/MMBtu for the 1979-1980 heating season (based upon the current border price of $3.45/MMBtu) compares favorably with the cost of primary alternate fuels in Northern's service area, and the SNG is needed in part to displace fuel oil and thereby reduce U.S. dependence on imported oil.

In December 1977, Northern contracted with Union Gas to purchase volumes equivalent to the aggregate Btu content of SNG which Union had previously contracted to purchase from Petrosar Ltd. The SNG is produced at Petrosar's petrochemical-refinery complex near Sarnia, Ontario using Canadian crude oil as feedstock. Deliveries to Northern -- up to 75,000 Mcf -- were to be made only in winter months (November through March), and Union would store SNG volumes received from Petrosar for Northern's account during the remaining months of each year. It was proposed that deliveries be accomplished through displacement of natural gas volumes to TransCanada PipeLines Ltd. at the Michigan-Ontario border near St. Clair, Michigan for further delivery and sale to Union. On days when Northern requested SNG from Union, TransCanada would reduce its deliveries to Union, and Great Lakes would deliver equivalent volumes by displacement to Northern at existing points of interconnection.

In its application, Northern estimated the average cost of the above supply at $3.86/Mcf (U.S.) during the first year, increasing to $5.33/Mcf in 1982-1983. This rate included both the SNG purchase cost and the cost of the storage service to be rendered by Union. The SNG purchase rate would be determined by formula geared in part to Petrosar's feedstock cost. The storage rates would include a monthly demand charge of $2.25/Mcf multiplied by the difference between the daily contract demand (75,000 Mcf) and the average daily level of deliveries under the Petrosar contract to Union during each month, plus commodity charges of 4.5¢/Mcf for all volumes injected into storage and 4.0¢/Mcf for all volumes withdrawn from storage. No charge was proposed by either Great Lakes or TransCanada for delivery of gas by displacement to Northern.

In Opinion No. 5, the ERA stated that the $3.86/Mcf first year cost projected by Northern is sharply higher than the price applicable to domestic new natural gas under Section 102 of the Natural Gas Policy Act ($2.06 as of November 1978). ERA further noted that (1) the proposed import price exceeded the then current authorized border rate of $2.16/MMBtu, and (2) Union offered the SNG to Canadian distributors at a price lower than the price offered to Northern but received no firm offers. As a further reason for denial, ERA held that Northern did not adequately demonstrate a regional need for the subject gas. ERA made clear that denial of Northern's import application was without prejudice in that Northern was free to restructure its project in a manner likely to satisfy criteria set forth in this and prior ERA import decisions.

In its subsequent application for rehearing, Northern stated that as a result of ERA's decision that the cost of the SNG import was too high, it agreed with Union to "a substantially lower price . . . which is demonstrably equitable to U.S. consumers." Specifically, the price to be paid to Union will be the Canadian border export price ($2.30/MMBtu effective 5/1/79), plus 56¢/MMBtu as a storage charge which will remain constant throughout the four-year life of the contract. The 56¢ component is a negotiated charge for storage services to be performed by Union for Northern.

On 5/2/79 the ERA granted rehearing of Opinion No. 5 on the ground that the restructured project may meet the criteria set forth in that Opinion. 1/ (See REPORT NOS. 1149, pp31-32; 1194, pp23-24; 1200, pp18-20; 1204, pp21-23; 1208, pp21-22.)

In Opinion No. 13, the ERA first noted that the base price of $3.45/MMBtu is equal to the current border price established by the Canadian National Energy Board for gas exported to the U.S. designed to equal the substitution value of Canadian imports of foreign crude oil. Previously, the ERA said the DOE has recognized that imported natural gas can have a certain commodity value in excess of normal costs of production, delivery and markup; this has been the case with natural gas imported from Canada since 1974. Moreover, both the U.S. and Canada have recognized that the commodity price established for export sales of gas will not only reflect substitution cost for foreign crude oils imported into Canada, but should be generally competitive with the alternate fuels with which it is competing in the respective service areas.

In order to test this latter point, the ERA contacted energy officials in the 10 states served by Northern to obtain the most current information on wholesale price and type of fuel which competes predominantly with natural gas. That survey, the ERA said, showed that No. 2 fuel oil and propane are the primary alternate fuels in six states, with virtually no No. 6 fuel oil being used therein. No. 2 fuel is a primary alternate fuel in three of the remmaining states, with residual fuel oil used in substantial (although secondary) volumes. The State of Michigan reported Nos. 4, 5 and 6 residual fuel oil as being the primary alternate energy source. The ERA noted that average wholesale prices for No. 2 fuel oil ranged from $4.96 to $7.75/MMBtu; propane varied between $4.20 and $5.08/MMBtu; and residual fuel oil sold for $3.22 to $3.66/MMBtu.

The ERA concluded that while the projected composite import price of the SNG here involved for the 1979-1980 heating season of $4.01/MMBtu is somewhat in excess of the price of the residual fuel oils in the 10-state service area, the proposed composite price compares favorably with the range of prices in which the current primary alternate fuel in the service area -- No. 2 fuel oil -- is selling.

1/ A proceeding in the FERC (CP78-237) is also going forward with respect to rates for sales and storage of the imported SNG. On 9/27/79 Northern submitted a stipulation whereby it agreed to (1) recover through its PGA rate filings the gas purchase costs based on the Canadian border export price, and (2) include in its commodity rate for jurisdictional market area sales (until the effective date of its next general rate increase) a surcharge of $0.0092/Mcf, effective 10/27/79, to recover that portion of the cost applicable to storage service rendered by Union. In subsequent comments, the Staff and others generally supported the stipulation, although the Staff recommended that it be rejected without prejudice to a later filing after the ERA determines whether to permit the import. Alternatively, the Staff would accept the stipulation subject to a different method of computing the storage charge. (See REPORT NO. 1236, pp29-30.)

The ERA authorized import of the SNG at the base price of $3.45/MMBtu, subject to further reivew and authorization for any increase. "A blanket approval of any future change in the Canadian border price for exported natural gas would be inappropriate; accordingly, the composite import price approved here must be reviewed anew if the border price is raised during the term of the import project."

Next, Opinion No. 13 discussed the $0.56/MMBtu charge separately negotiated for specific storage services to be performed by Union for Northern. Northern contended that the current average on-system storage cost incurred to store gas in its company-owned fields is in the range of $0.55 to $0.60/MMBtu -- although no such storage is available for additional supplies. Northern also emphasized that its cost of obtaining lease storage services from other companies would range from $0.90 to $1.10/MMBtu. Hence, while the $0.56 storage fee does not represent Union's cost to store the gas, it is a negotiated price which is consistent with, if not more favorable than, alternative storage services available to Northern.

The ERA stated that as a matter of policy, it will not approve a higher price negotiated by commercial firms where a general commodity-based border price for imported gas is established by the supplying country and approved by the U.S. However, exceptions will be made where the foreign supplier is providing a "special service that is distinct and separate from services which are a normal aspect of production, processing and delivery . . . which would therefore normally be covered in the commodity export price." In this case, the ERA said, Northern adequately demonstrated that the storage service being provided by Northern "is a distinct and separate service that is not ordinarily provided to importers of Canadian gas." First, ERA said, Northern will have the advantage of being able to withdraw the gas supply only during the peak winter months which requires that the SNG be stored during the summer months. "This is a unique service that is not ordinarily covered in the commodity export price." Second, Northern demonstrated that these same storage services would not be obtained in the U.S. at a lower cost.

However, the ERA stressed, Northern did not show that the price proposed to be paid to Union is consistent with its actual costs, and is in fact higher than Union charges its Canadian customers for storage services. Based on such charges, the ERA calculated that the charge to Northern for storing the SNG here involved could be as low as $0.19/Mcf when assessed against the maximum yearly contractual deliveries of 10 Bcf. Furthermore, the ERA added, there is a question of the proper treatment of interest charges which Union incurs on carrying costs associated with storing the SNG which it does not incur for existing storage customers in Canada. Northern proposed to calculate this interest factor on an average unit cost of $4.70 for each Mcf of SNG held in storage. Hence, interest would be determined on the acquisition cost of a single, isolated supply of gas -- the SNG Union purchases from Petrosar -- as opposed to the average acquisition cost of the full supply of gas purchased and placed in storage, despite the standard practice in both countries of computing interest on the average acquisition cost of all gas available for service supply.

The ERA could find "no compeling reason . . . in this case to warrant deviation from this standard." Therefore, the ERA said it will approve a separate storage service charge only on condition that it is the sum of (1) the direct storage costs calculated in accordance with Union's rate schedule applicable to its Canadian customers; and (2) a working capital allowance based on the cost of carrying the volumes of gas held in storage for this project, the average cost of gas acquired by Union for its overall system supply, and the prime bank lending rates prevailing in Ontario, Canada. Opinion No. 13 set forth a specific formula for calculating this working capital allowance.

ERA Cites Uncertainty Over Available Natural Gas Supply in Extending Period for Final Decision on Temporary Exemptions for Powerplants from the Natural Gas Use Prohibitions Under Fuel Use Act

On 1/2/80 the ERA issued notice of an extension of time to 2/15/80 for issuance of final orders respecting temporary public interest exemptions from the natural gas use restrictions of Section 301 of the Powerplant and Industrial Fuel Use Act. ERA cited uncertainty over additional natural gas supplies (due in part to the success of its exemption program and other federal programs) as the chief reason for the extension.

Section 301 of the Fuel Use Act prohibits with certain limited exceptions the use of natural gas as a primary fuel in any powerplant. However, the Act also provided DOE with discretionary authority under Section 311 to exempt certain uses of natural gas. Last April, ERA exercised its authority under that section to formulate a Special Rule establishing procedures to govern applications for temporary public interest exemptions for up to five years from the Section 301 prohibitions on natural gas use. The Special Rule was proposed as a response to the then anticipated shortages of middle distillate fuel oil, given the availability of additional supplies of natural gas at that time. (See REPORT NO. 1204, pp1-2.)

Subsequently, ERA issued notice on 5/11/79 and 6/1/79 of petitions for public interest exemptions filed by some 60 electric utility companies with respect to use of natural gas in several hundred units at over 150 generating stations, and set forth proposed orders granting special exemptions for two years (subject to extension for one to three years). The proposed orders stated that the use of natural gas is preferred over petroleum to the extent that the near-term choice of fuel is limited to these two sources, and that expanded use of natural gas in the powerplants involved would help to reduce U.S. demand for imported petroleum products, protect the nation from the effects of any oil shortages and "cushion the impact of increasing world oil prices." Under Section 701(c)(3) of the Fuel Use Act, ERA has six months after a 45-day public comment period to issue a final decision on petitions for exemptions. The applicable six-month periods would have expired on 12/22/79 and 1/6/80 absent the present extension.

As noted, ERA cited concern over the availability of additional gas supplies as a main reason for its failure to act expeditiously on the exemption petitions. Specifically, ERA declared, additional natural gas supplies are less certain at the present time than at the beginning of 1979 when the Special Rule was first proposed. "This is in large part due to the success of this and other programs over the past several months to displace as much petroleum as possible with available supplies of natural gas." Further, ERA noted some question whether the collective demand for natural gas by users of middle distillates and residual fuel oil with a sulfur content of 0.5% which have already been granted public interest exemptions, or have applications for such exemptions pending, exceeds the available supply.

In view of this uncertainty, ERA said it has thus far processed applications only for those powerplants which will displace middle distillate or residual fuel oil with a sulfur content no higher than 0.5%. No action has yet been taken on other applications, pending completion of an analysis to determine whether the granting of public interest exemptions for powerplants burning residual fuel oil of greater than 0.5% sulfur will jeopardize the ability of powerplants burning lower sulfur residual oil or middle distillates to displace them with natural gas.

ERA invited written comments through 1/30/80 to assist in this analysis. Views are particularly requested on the appropriate scope of the Special Rule in light of natural gas supplies for the foreseeable future, and on what (if any) sulfur levels should be considered in reviewing petitions to use natural gas displacement of residual fuel oil.

FERC Releases Final Draft Rule to Govern Applications for Special Relief Rates Under NGPA; On-the-Record Panel Discussion Scheduled for February 11 Before the Commission to Explore Specific Issues

On 1/16/80 the FERC issued a draft final rule (RM79-67) establishing procedures to govern applications for special relief from maximum permissible ceiling prices under Section 104, 106 and 109 of the NGPA. Written comments are invited on the draft rule by 2/1/80. In addition, an on-the-record panel discussion before the Commission has been scheduled for 2/11/80 to permit exploration of specific issues with persons representing various points of view.

The draft final rule would essentially adopt the same regulatory framework set forth in a proposed rulemaking issued last August. Under this framework, different procedures would apply to the grant of special relief where (1) operation and maintenance costs of continued production from an existing well cannot be recovered if gas from the well is sold at the applicable maximum lawful price, and (2) additional planned investment necessary for continued production or reservoir development will not be made if the producer were held to the applicable maximum lawful price. A public hearing on the proposed rule was held before an FERC Staff panel on 9/26/79, and written comments were submitted by 21 interested parties. (See REPORT NO. 1229, pp12-17.

The draft final rule would incorporate various modifications and clarifications in response to the comments. However, the draft order would continue to exclude "sunk" costs from DCF and other cost computations on which special relief rates would be based. This exclusion of "sunk" was widely opposed by producer parties.

The Commission indicated that four major issues concerning the special relief rulemaking proposal had emerged in the course of deliberations, and that further public comments are requested on these issues.

The four issues relate to: (1) whether any limits should be placed on special relief rates granted by the Director of the Office of Pipeline and Producer Regulation or by the Commission (and, if so, at what levels); (2) whether producers should be allowed to switch from a special relief rate to another incentive rate under the NGPA, or whether such switching should be limited; (3) what procedures should be used for reviewing initially proposed special relief rates on the basis of actual expenditures; and (4) whether a fixed or indexed rate of return should be adopted for planned investment projects.

As noted, the Commission will convene an on-the-record panel discussion on 2/11/80 to explore the above issues. The draft rule has been chosen by the Commission as a vehicle for experimenting with use of the panel discussion technique to obtain public input. Commissioner Hall has been designated to select a panel of representatives with different points of view. Requests to participate in the discussion should be submitted by 2/1/80. Persons wishing to participate should attempt to group themselves on the basis of commonality of interests or provide information that would help in structuring a panel discussion. In addition, Commissioner Hall has been authorized to request the participation of persons whose views may not otherwise be represented but who are not filing written comments. Each

participant in the discussion may present a "very" brief prepared statement on the specified issues and will be asked to respond to questions from the Commission and from other panelists.

The draft final rule will be summarized in a subsequent REPORT.

FERC Schedules Prehearing Conference for February 28 on Proposal by Mobil Oil to Build Own Plant to Process Gas Currently Delivered to Getty Oil for Processing

On 1/14/80 the FERC consolidated -- and scheduled a prehearing conference for 2/28/80 -- applications by Mobil Oil Corp. (CI78-497 et al.), American Petrofina Co. of Texas, Joseph I. O'Neal, Jr. and Walter Duncan et al. to abandon their sales of casinghead gas produced from the Reincke and Von Roeder Fields, Borden County, Texas to the East Vealmoor gas processing plant in Howard County, Texas owned by Getty Oil Co., which delivers the residue gas to El Paso Natural Gas Co.

The producers' behind-the-plant percentage-type sales contracts with Getty have terminated (although the gas is still being delivered to Getty for processing) and Mobil now proposes to build its own gas processing plant to handle the volumes for direct sale to El Paso near the same delivery point used by Getty. The four producers and El Paso have agreed to new contracts covering the proposed direct sale of gas to El Paso.

In support, Mobil stressed that its plant will have a lower fuel consumption rate than Getty's plant, which will result in delivery of an additional 95,000 MMBtu per year to El Paso. Mobil also contended that additional competition in the processing industry in this area could stimulate further economic activities which would benefit the public.

In a petition to intervene and request for hearing, Getty responded that the proposed new plant of Mobil will remove about 12% of the input of the Getty plant, which will substantially reduce its economic life, cause premature abandonment, and will constitute an unnecessary duplication of facilities. Furthermore, Getty said, Mobil has no existing arrangements, plants or gathering facilities which would enable it to continue these interstate gas deliveries if the Getty plant fails. Also, Getty stressed, Mobil may intend to justify a higher price for its gas through the abandonment procedure. Getty added that the proposed new plant may not be economically feasible and the fuel efficiencies of both plants would be reduced if either operates at less than capacity.

In its order, the Commission concluded that a hearing should be held to determine whether the proposed abandonments are in the public interest.

Energy Information Administration Reports Only Slight Increase in U.S. Energy Consumption During First Three Quarters of 1979

On 1/4/80 the Energy Information Administration released the second in a new report series entitled "Quarterly Energy Indicators" which revealed that U.S. energy consumption (stated in equivalent amounts of crude oil) during the first three quarters of 1979 was 0.3% higher than during the same period of 1978. Consumption in the third quarter of 1979 averaged 33.9 million b/d or 2.4% lower than consumption during the third quarter of 1978.

The publication contains summary statistics on U.S. energy consumption, production and net imports during the third quarter of 1978 and the first three quarters of 1979, plus information on total energy consumption and shares of energy consumption by fuel type and major economic sector from 1973 through the third quarter of 1979. The first in this new report series was released by EIA on 1/15/79. (See REPORT NO. 1194, p36.)

During the first three quarters of 1979, the EIA report showed: (1) domestic energy production averaged 4.2% more than the same period of 1978 (natural gas production decreased by 3.4%); (2) net imports were 6.3% lower; and (3) natural gas consumption remained about the same. In the third quarter of 1979, gas consumption decreased 1.5% compared with the third quarter 1978 rate.

The natural gas share of total U.S. energy consumption -- expressed in terms of 12-month moving averages of annual rates -- declined from 30.2% in 1973 to 27.3% in 1976, 26.0% in 1977, 25.5% in 1978 and 25.1% in the first three quarters of 1979.

California PUC Terminates Long-Standing Proceeding to Determine Whether Certain California Gas Producers Should Be Regulated as Public Utilities

On 12/18/79 the California Public Utilities Commission terminated, effective 1/17/80, a show cause proceeding instituted in 1976 to determine whether California gas producers supplying Pacific Gas & Electric Co. should be regulated as public utilities. The PUC cited enactment of the Natural Gas Policy Act of 1978 as the prime reason for its determination that "the public interest will not be adversely affected if this proceeding is discontinued without prejudice to its being reopened at a later time should circumstances so require."

The show cause proceeding stems from a CPUC order dated 7/1/75 which granted PG&E a $36.4 million interim rate increase needed to offset increased costs (from 45¢ to 75¢/Mcf) for purchases of California gas. However, because of the lack of "meaningful evidence" regarding California wellhead production costs, the CPUC simultaneously directed its Legal Division to prepare an order to show cause to be served on all California gas producers serving PG&E. PG&E was also warned against further renegotiation of gas contracts during pendency of the proceeding. The show cause order was issued on 5/18/76, and subsequent orders prohibited PG&E from including any price escalation clauses which would provide for a higher price prior to 6/30/80 in renegotiated contracts. (See REPORT NO. 1010, pp23-24.)

No hearings were ever held in the proceeding.

FERC —

Comments of AK. of Response to Draft Sys. design inquiry

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November 17, 1978

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

Dear John:

Enclosed are the State of Alaska's comments on the draft report in the system design inquiry. I enclose five copies, but should you need more, please let me know.

Sincerely yours,

Robert H. Loeffler

RHL/kc
Enclosures

cc: All Parties Receiving
Draft "System Design Inquiry" Report

FERC

COMMENTS
OF THE STATE OF ALASKA
IN RESPONSE TO
DRAFT SYSTEM DESIGN INQUIRY

The State of Alaska offers the following comments in response to the September 27, 1978 draft report of the Commission's Alaska Gas Project Office in its system design inquiry ("Draft Report"). The work of the Gas Pipeline Office displayed in the draft report is exceedingly useful but further inquiry is necessary. Alaska believes the further inquiry should occur in a hearing context and in the near future. Conversely, Alaska does not believe that the Commission now has the legal or factual foundation to issue an order establishing the system pressure. Alaska's comments will concentrate on the points that call for additional exploration or revised analysis in the near future.

1) One overall assumption, Alaska believes, colors the analysis. The report seems to assume a netback theory, i.e., that the price of the gas is free to rise to "absorb" any operating cost savings a higher pressure line would engender. The Gas Pipeline Office apparently believes that any decrease in transportation costs would automatically accure to the benefit of producers, not consumers. (See, e.g., Draft Report, p. 58).

Whatever the state of affairs previously, the case after passage of the Natural Gas Policy Act of 1978 is different. Section 109 of the Act establishes a ceiling

price for Prudhoe Bay unit gas. No one knows now whether that will be the ceiling price in fact or if a lower price will be all that purchasers of the gas are willing to pay. In either case, a contractual price will be established and that price will be what the producers receive for Prudhoe unit gas. Since the contracts are likely to be completed well before system design is settled, any reduction of operating costs due to higher pressure will not result in higher prices to producers.

For reserves beyond the control 2.0 bcfd, it is not clear what the pricing constraints will be. No one with sound mental health will predict what the ultimate effect of the "incremental pricing" rules mandated by NGPA will be. Even if a netback analysis is correct, producers would receive no more than the legislatively determined ceiling prices even if the cost of competing fuels were higher. Consumers would receive the benefit of greater gas supplies, both directly and indirectly (via industry). Thus, to the extent a netback theory means that higher prices to producers -- limited always by the ceiling prices of the NGPA -- might stimulate the development of new Alaska supplies and encourage conservation, those consequences should be perceived as benefits, not as detriments.

2) The Report also does not perceive any benefits to gas consumers from the added NGL's carrying capacity of higher (than 1200 psig) pressure lines. (Draft Report, p. 59). The Report reveals that the clear difference among

the various pressure systems in terms of the NGL carrying capacity is that a 1440 or 1680 psig line can carry a higher percentage (i.e. greater amounts) of butane. If the butane is left in the gas stream, its presence will raise the BTU value of the gas. Higher pressure operation would result then in the delivery of higher heating value gas. Gas consumers would receive a direct, valuable benefit: higher heating value than they would otherwise receive because of the presence of natural gas liquids not used for petrochemicals. In a sense, the overall quantity of gas delivered, measured in caloric terms, could be increased with higher pressure operation. So, while higher pressure operation offers the promise of lower transportation costs and greater efficiency with higher throughputs, it also may deliver to gas consumers the immediate benefit of higher gas supplies measured in terms of the heating value of the delivered gas. The gas contracts will shed light on this question but there is no present basis for assuming that butane will be stripped and separately sold.

3) One further aspect of the butane question deserves further thought. The Draft Report indicates that those quantities of butane not injected into the gas stream could be transported in the oil line. But the limiting factor is vapor pressure requirements in California. (Draft Report, pp. 15-16, 17). While existing vapor pressure requirements may not be insurmountable, tighter vapor restrictions by California to protect or improve the troublesome air quality of Southern California would prevent an economic

disposition of the butane that could not be transported in the gas line. A higher pressure line reduces or avoids tying disposition of these hydrocarbons to Southern California air quality.

4) The draft report notes that the removal of very high quantities of CO_2, as required by a one percent CO_2 standard, has the effect of reducing the NGL carrying capability of the gas stream and states that the savings on gas conditioning costs from leaving the CO_2 in the gas is more than offset by reduced transportation efficiency (Draft Report, p. 11). Alaska does not believe the latter conclusion is justified. The question of the appropriate CO_2 standard has never been addressed and examined adequately. The recent Parson's study of the conditioning plant suggests that it is cost effective to go to a less restrictive CO_2 standard. A three percent standard would save ten percent of the capital cost of the conditioning plant and could result in a reduction of the cost of service to the consumer by noticeable amounts. At the presentation of the conditioning study to FERC, representatives of ARCO have also suggested that the whole question of CO_2 removal should be re-examined. The State of Alaska believes that at least a three percent CO_2 standard is indicated. Whether this issue is properly explored as part of the system size inquiry, or during the hearings on system facilities applications is not clear, but at least the issue deserves greater investigation because of the possible consequences on reducing the overall cost of this system.

5) Alaska agrees with the comments herein of Atlantic Richfield. Alaska joins those comments in urging a 1440 psig system. As stated above, the additional NGL's carried by a 1440 system could result in immediate benefits to consumers. Moreover, a 1440 system has the promise of more efficient, lower cost operation as higher throughputs occur. Alaska believes the relatively small additional costs are a worthwhile premium for its future. Alaska does not perceive the necessary testing as favoring a 1260 psig have over a 1440 psig design, especially given the absence of solid evidence about the testing that ccurred and that must occur.

6) A historical reference will show how inverted the pressure question has become and why a 1440 line should not delay the project. During the FPC comparative hearing, Artic Gas and El Paso each proposed a 1680 psig line. Only Northwest, when it made its belated entry, proposed 1260 psig with a later increase to 1440. Everyone conceded that a line anywhere above approximately 1000 psig was a new undertaking, but the higher pressure of the El Paso and Arctic lines was not a significant issue although almost everything else was in that hotly contested hearing. A 1680 psig design was not regarded as calling for unusual testing delays or technological advances. Given the support of the Arctic Gas consortium and El Paso, a 1680 psig design represented the choice of a substantial part of the American natural gas pipelines.

The finding of Judge Litt confirms these facts:

> "Arctic Gas, El Paso and Alcan all propose to operate their pipeline systems at maximum pressures substantially in excess of levels currently in use in the industry. Nothing in the record suggests that these higher operating pressures cannot be achieved with pipe adequately designed for the purpose. This is not to say, however, that Alcan can reliably and economically achieve its suggested performance at 1440 psig with pipe ostensibly selected to operate at a maximum pressure of 1250 psig. It is found that the operating design pressures are logical extensions of existing pipeline operations and can be achieved here by those applicants making proposals to operate at the higher pressure." Initial Decision, El Paso Alaska Company, Dockets CP75-96, et al. (February 1, 1977).

If the President's choice had been otherwise, we doubt that any time would now be spent on the appropriateness of a 1680 design. It is true Northwest was selected but that does not change the critical fact that any pressure substantually above 1000 psig is an advance in existing technology. There is no convincing evidence in the Draft Report of the differentials in technology, if any, required for a 1260, a 1440, or a 1680 psig design. Thus, testing a 1440 system may not be significantly different than testing a 1260 system. This is what Exxon's comments state based on their actual experience with the Arctic Gas tests. (Draft Report, p. 17). Alaska suspects that there may be no actual differentials, but, in fact, the degree of technological advance is relatively the same for each as is the testing required. Similarly, the report does not adequately investigate whether there are differences in risks of cost overrun and delay with a 1440 or 1680 line. A risk assessment

is called for rather than reliance on theory. Choice of a 1440 psig design thus may not be radical but nearly as conservative a choice as the novel choice of 1260 psig.

7) We have seen that the operating assumption of the comparative hearing was that a 1680 line was acceptable and could be proven within the necessary construction timetables. There is record material about the testing requirements for the 1680 line which may not have been adequately mined to date. Nonetheless, Alaska recognizes Northwests' historic reluctance to venture above 1260 psig. What Alaska suggests, therefore, is that the Commission carefully examine the 1440 line.*/ The focus of the investigation revealed in the draft report has been on the comparative merits of the 1680 versus the 1260 lines. As indicated above, the 1440 line has considerable merit both in the early and later years of operation. Alaska believes this investigation could be conducted now on a hearing record in advance of the facilities' applications. Alaska does not believe, based on its

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*/ It has recently come to Alaska's attention that it may be possible to achieve operating pressures approaching 1440 psig by relaxation of the "design factor" for the pipe Northwest proposes to use from .72 to .8. See 49 C.F.R. 192.111. This would not be a substantial change because the "relaxation" is only to the established Canadian standard. A waiver request would have to be presented to the Office of Pipeline Safety but a good case could be made that safety concerns would be satisfied by the relaxed design factor based on the record in Canada. This avenue is worthy of further investigation.

advisors, that the critical constraint or either the financing or planning of the pipeline is a question of system pressure. It is well known to all that gas contracts are a more critical element and that the apparently fragile nature of the gas pipeline financing is due at least as much to externalities to the project as to the project itself.**/

CONCLUSION

Alaska believes very much in the wisdom of proper advance planning for the future. While the Northwest 1260 proposal may appear to be an adequate compromise, based on the lowered expectations of the present, it would very well be less than optimally designed given the potential of Alaskan reserves. The costs of later adding capacity to the gas line are substantial and suggest the advantages of building extra capacity now as an insurance policy.

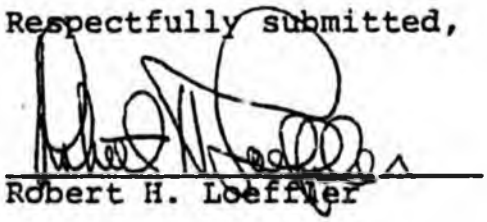
This is the decision reached by the President:

> "overall, considering the art of construction, inflationary impacts, and environmental impacts, the ultimate cost to consumers of providing capacity for increased gas throughout would be much lower if the capacity is provided initially by increasing the diameter or working pressure of the pipe, than if it is provided later by adding compressor horsepower or looping the pipeline." (Decision and Report to the Congress on the Alaska Natural Gas Transportation System, p. 194.)

**/ Alaska believes that it is better to decide the pressure question at a hearing in the near future than to leave the question to be resolved when the applications for the final authorization for these facilities are submitted, perhaps a year or so from now. By then any realistic possibility of increasing system pressure will be foreclosed by the argument that it is too late then to undertake the necessary evaluation and analysis.

For these reasons, Alaska suggests an investigation on the record of what appears to be the obvious advantages of a 1440 psig pipeline and deferral of any order establishing the pipeline's pressure until the completion of such a hearing.

Respectfully submitted,



Robert H. Loeffler

Attorney
for the
State of Alaska

November 17, 1978

FERC-

3/16/79

NOTICE OF

APPLICATION

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

FERC

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

NOTICE OF APPLICATION

(March 16, 1979)

Take notice th t on March 2, 1979, Alaskan Northwest Natural Gas Transportation Company (the Partnership)1/, P.O. Box 1526, Salt Lake City, Utah 84110, filed in Docket No. CP78-123, et al., an application pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA), the Natural Gas Act, the Decision and Report to Congress on the Alaska Natural Gas Transportation System as ratified by Congress (President's Decision) and the Commission's order vacating prior proceeding and issuing conditional certificate of public convenience and necessity, issued December 16, 1977, for an order approving the design specifications and initial system capacity of the Alaskan segment of the Alaska Highway Pipeline Project, all as more fully set forth in the application which is on file with the Commission and open to public inspection.

The President' Decision described the facilities necessary for the construction and initial operation of the system as follows:

1/ The application indicates that the Partnership is successor to Alcan Pipeline Company (Alcan) which filed its application with the Federal Power Commission (FPC) for authorization to construct a 42-inch pipeline in Alaska to be designed and operated at a maximum working pressure of 1260 psig. This proposal was amended to provide additional expansibility by increasing the pipeline diameter to 48 inches at the same design pressure, it is said.

> "...The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in March 8, 1977. If any modifications to those facilities are required by the Agreement on Principles between the U.S. and Canada, those modified facilities will also be entitled to the expedited authorization process in Section 9." (p. 13)
>
> "The gas transportation system will utilize a 48-inch diameter pipeline from Prudhoe Bay to James River, Alberta." (p. 13)
>
> "Peak-day capacity utilizing nine compressor stations will be 2.6 bcfd, with an average daily volume of 2.4 bcfd. By installation of intermediate compressor stations, the system could be increased to 3.4 bcfd peak capacity, with an average day capacity of 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station." (p. 17)

The Partnership summarizes its position as follows:

The Partnership requests an order from the Commission approving the design specification for the 48-inch pipeline with a maximum working pressure of 1260 psig and compressor station size and spacing for an initial capacity of 2.0 to 2.4 Bcfd expandable by the addition of intermediate compressor stations to an average daily volume of 3.2 Bcfd. This proposal is the same as was submitted to the Federal Power Commission in March, 1977.

The modification of facilities resulting from implementation of the Agreement on Principles did not affect the Alaskan segment of the project. The pipeline design in Canada commencing at the Alaska/Yukon border and continuing 260 miles to Whitehorse, Yukon, is a 48-inch pipeline with a maximum design pressure of 1260 psig; therefore, any increase in pressure of the Alaskan segment must consider the effect on the Canadian section of the project.

There are two reasons that the pressure for the Alaskan segment of the system might be increased. First is the expection that the volumes of gas available from new reserves (other than the presently proven reserves in the Prudhoe Bay Unit) with as reasonable period of time after deliveries commence is high enough that a higher pressure system might result in lower transportation costs over the life of the project. Second is the desirability of carrying

larger quantities of hydrocarbon liquids in the gaseous phase by increasing the design pressure. The State of Alaska has made available to the Partnership a recent proposal by Earth Resources Company of Alaska to move the location of the conditioning plant from Prudhoe Bay to Fairbanks, Alaska. To avoid building any conditioning facility at Prudhoe Bay the pressure of the pipeline system from Prudhoe Bay to Fairbanks would be increased to 1680 psig which, it is claimed, would accommodate all hydrocarbon liquids. At Fairbanks the plant would not only condition the gas for further transportation by removing carbon dioxide and sufficient hydrocarbon liquids to meet the requirements of the design pressure of 1260 psig to be utilized thereafter in Alaska and in a portion of the Yukon, Canada, but also would remove from the stream most of the ethane and all heavier hydrocarbons. These hydrocarbons would either be utilized within the state, such as for petrochemical development, or delivered by a new pipeline system to tidewater (Cook Inlet) for delivery to U.S. or foreign markets. The State of Alaska has requested that the Partnership delay its filing originally planned for February 1, 1979, in order to address the feasibility of this proposal. ...

The Partnership has concluded and will show herein that the proposed system is the best economic selection for delivery volumes up to 3.4 Bcfd and that there is no new evidence that this expansibility above the expected 2.0 Bcfd to be delivered from the presently proven reserves is inadequate.

As to liquid hydrocarbon carrying capacity the following conclusions are pertinent: (1) the pipeline design at 1260 psig can transport all of the ethane and propane that is available from the conditioning plant. The ethane would be the raw material for any in-state petrochemical development; therefore, the system design permits complete flexibility for ethane extraction in the future to meet the State of Alaska needs, (2) the increase in hydrocarbon liquids, primarily butane, that can be transported in the pipeline by increasing the pressure is about 5-11 thousand barrels per day and is a small volume in relation to the total oil and gas energy to be delivered which has alternative beneficial uses on the North Slope of Alaska, and (3) the increased volume of liquids that could be transported must be extracted in Alaska since the design pressure as approved by appropriate regulatory authorities in the first Canadian section is 1260 psig.

The Partnership has analyzed the proposal by Earth Resources Company of Alaska and has concluded that the necessary result of this proposal will render the primary pipeline project infeasible and, therefore, it should not be given further consideration.

In reviewing the design pressure decision the Partnership states that it has considered the following alternatives to the proposed system:

1. A 48-inch pipeline design for a maximum working pressure of 1400 psig. This system would result from the increase in the pipeline safety code requirement of 72 percent of the calculated design pressure to 80 percent. This alternative would require a change in the pipeline safety code or a waiver by the Department of Transportation. A portion of the system which follows the Haul Road would require a double waiver that the Department of Transportation has indicated would not be granted.

2. A 48-inch pipeline with a maximum working pressure of 1440 psig.

3. A 48-inch pipeline with a maximum working pressure of 1680 psig.

It is indicated that the present proposed system provides capacity equivalent to any of the competitive proposals which were considered by the Commission and the President and that the Partnership is not aware of any changes in circumstances or new additional gas reserve potential which would require reconsideration of the ultimate capacity to be provided by the pipeline system within Alaska.

Accordingly, the Partnership requests that the Commission issue an order accepting the design specifications for the system selected by the President for a 48-inch pipeline with the maximum working pressure of 1260 psig providing an initial system capacity of 2.0 to 2.4 Bcfd with expansibility by the addition of intermediate compressor stations up to 3.2 Bcfd for the Alaskan segment of the Alaska Highway Pipeline Project.

Any person desiring to be heard or to make any protest with reference to said application should on or before April 5,1979, file with the Federal Energy Regulatory Commission, Washington, D.C. 20426, a petition to intervene or a protest in accordance with the requirements of the Commission's Rules of Practice and Procedure (18 CFR 1.8 or 1.10) and the Regulations under the Natural Gas Act (18 CFR 157.10). All protests filed with the Commission will be considered by it in determining the appropriate action to be taken but will not serve to make the protestants parties to the proceeding.

Any person wishing to become a party to a proceeding or to participate as a party in any hearing therein must file a petition to intervene in accordance with the Commission's Rules. All persons who have heretofore filed need not file again.

Kenneth F. Plumb
Secretary

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Alaskan Northwest Natural Gas)
Transportation Company)

Docket CP78-123, et al

APPLICATION OF ALASKAN NORTHWEST
NATURAL GAS TRANSPORTATION COMPANY
FOR AN ORDER APPROVING THE DESIGN SPECIFICATIONS
AND INITIAL SYSTEM CAPACITY OF THE ALASKAN SEGMENT
OF THE ALASKA HIGHWAY PIPELINE PROJECT

Alaskan Northwest Natural Gas Transportation Company (the Partnership)[1/] pursuant to the Alaska Natural Gas Transportation Act of 1976 (ANGTA), the Natural Gas Act, the Decision and Report to Congress on the Alaska Natural Gas Transportation System as ratified by Congress (President's Decision) and the Commission's Order Vacating prior Proceeding and Issuing Conditional Certificate of Public Convenience and Necessity issued December 16, 1977, hereby applies for an order approving the design specifications and initial system capacity of the Alaskan segment of the Alaska Highway Pipeline Project.

In support thereof the Partnership would show as follows:

I

Background

The President's Decision issued by the President of the United States on September 22, 1977, and approved by Congress on November 22, 1977,[2/] described the facilities necessary for the construction and initial operation of the system. This identification of facilities was required in Section 7(a)(4) of ANGTA. The President's Decision provided that:

1/ The Partnership is successor to Alcan Pipeline Company. Alcan filed its application with the Federal Power Commission on July 9, 1976, for a 42-inch pipeline in Alaska to be designed and operated at a maximum working pressure of 1260 psig. This proposal was amended on March 8, 1977, to provide additional expansibility by increasing the pipeline diameter to 48 inches at the same design pressure.

2/ Public Law 95-158, 91 Stat. 1268.

"... The facilities which are to be covered are those in the U.S. which are adequate for a throughput of up to 2.4 bcfd and are included in the revised Alcan filing submitted to the Federal Power Commission (FPC) in March 8, 1977. If any modifications to those facilities are required by the Agreement on Principles between the U.S. and Canada, those modified facilities will also be entitled to the expedited authorization process in Section 9." (p. 13)

"The gas transportation system will utilize a 48-inch diameter pipeline from Prudhoe Bay to James River, Alberta." (p. 13)

"Peak-day capacity utilizing nine compressor stations will be 2.6 bcfd, with an average daily volume of 2.4 bcfd. By installation of intermediate compressor stations, the system could be increased to 3.4 bcfd peak capacity, with an average day capacity of 3.2 bcfd. The system capacity could be further increased by addition to the compressor horsepower at each station." (p. 17)

The President's Decision, therefore, adopts the system as proposed by the Partnership subject only to the changes which might result from the implementation of the Agreement on Principles between U.S. and Canada. The Agreement between the United States and Canada on Principles applicable to the Northern Natural Gas Pipeline (Agreement on Principles) provided that a technical study group would be established by the governments for the purpose of testing and evaluating various combinations of pressure and diameter "which would achieve safety, reliability and economic efficiency for operation of the Pipeline" (Section 10). The Agreement on Principles also provided that the decision on pipeline specifications would remain the responsibility of appropriate regulatory authorities.

U.S. and Canadian government technical representatives met in order to carry out the obligations of the Agreement. The final results of these discussions are reflected in the Statement of Position Regarding Selection of Pipe for the Whitehorse, Yukon, to Caroline, Alberta, Segment of the Foothills Pipeline System issued by the National Energy Board of Canada (NEB) on February 17, 1978. The NEB provided that an increase in the design pressur to 1680 psig would require thorough testing

estimated by the Canadian companies to delay the project up to two years. Therefore, the NEB did not change the design specifications for the pipeline segment from the Alaska/Yukon border to Whitehorse from the proposed 48-inch, 1260 psig system and selected a 56-inch, 1080 psig for the segment from Whitehorse, Yukon, to Caroline, Alberta, to accommodate reserves from the MacKenzie Delta region of Canada.

In order to resolve the design specifications for the Alaskan segment of the project the Director of the Alaska Gas Project Office of FERC (the Delegate) issued a report on September 27, 1978, and requested comments from the interested parties. Thereafter, the Delegate provided a period for reply comments and held an on-the-record conference among commenting parties on December 15, 1978. At the conclusion of the conference, the Delegate requested the Partnership to examine what would be involved in increasing the system pressure and whether such an increase is necessary or desirable. The Partnership has completed its review and also at the request of the Delegate, has met with several of the interested parties to present the conclusions of this review. The Partnership is now filing this Application for an order from the Commission to resolve the design specifications for the Alaskan segment of the project.

II

Summary of the Partnership's Position

The Partnership requests an order from the Commission approving the design specifications for the 48-inch pipeline with a maximum working pressure of 1260 psig and compressor station size and spacing for an initial capacity of 2.0 to 2.4 Bcfd expandable by the addition of intermediate compressor stations to an average daily volume of 3.2 Bcfd. This proposal is the same as was submitted to the Federal Power Commission in March, 1977.

The modification of facilities resulting from implementation of the Agreement on Principles did not affect the Alaskan segment of the project. The pipeline design in Canada commencing at the Alaska/Yukon border and continuing 260 miles to Whitehorse, Yukon, is a 48-inch pipeline with a maximum design pressure of 1260 psig, therefore, any increase in pressure of the Alaskan segment must consider the effect on the Canadian section of the project.

There are two reasons that the pressure for the Alaskan segment of the system might be increased. First is the expectation that the volumes of gas available from new reserves (other than

the presently proven reserves in the Prudhoe Bay Unit) within as reasonable period of time after deliveries commence is high enough that a higher pressure system might result in lower transportation costs over the life of the project. Second is the desirability of carrying larger quantities of hydrocarbon liquids in the gaseous phase by increasing the design pressure. The State of Alaska has made available to the Partnership a recent proposal by Earth Resources Company of Alaska to move the location of the conditioning plant from Prudhoe Bay to Fairbanks, Alaska. To avoid building any conditioning facility at Prudhoe Bay the pressure of the pipeline system from Prudhoe Bay to Fairbanks would be increased to 1680 psig which, it is claimed, would accommodate all hydrocarbon liquids. At Fairbanks the plant would not only condition the gas for further transportation by removing carbon dioxide and sufficient hydrocarbon liquids to meet the requirements of the design pressure of 1260 psig to be utilized thereafter in Alaska and in a portion of the Yukon, Canada, but also would remove from the stream most of the ethane and all heavier hydrocarbons. These hydrocarbons would either be utilized within the state, such as for petrochemical development, or delivered by a new pipeline system to tidewater (Cook Inlet) for delivery to U.S. or foreign markets. The State of Alaska has requested that the Partnership delay its filing originally planned for February 1, 1979, in order to address the feasibility of this proposal.3/

The Partnership has concluded and will show herein that the proposed system is the best economic selection for delivery volumes up to 3.4 Bcfd and that there is no new evidence that this expansibility above the expected 2.0 Bcfd to be delivered from the presently proven reserves is inadequate.

As to liquid hydrocarbon carrying capacity the following conclusions are pertinent: (1) the pipeline design at 1260 psig can transport all of the ethane and propane that is available from the conditioning plant. The ethane would be the raw material for any in-state petrochemical development, therefore, the system design permits complete flexibility for ethane extraction in the future to meet the State of Alaska needs, (2) the increase in hydrocarbon liquids, primarily butane, that can be transported in the pipeline by increasing the pressure is about 5-11 thousand barrels per day and is a small volume in relation to the total oil and gas energy to be delivered which has alternative beneficial uses on the North Slope of Alaska, and (3) the increased volume of

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3/ The State of Alaska has also requested that consideration be given to reducing the cost of the conditioning plant and increasing the hydrocarbon liquid carrying capacity by increasing the allowable carbon dioxide content of the gas. The increase in hydrocarbon liquid carrying capacity is in direct proportion to the increase in carbon dioxide content, subject to fuel balance changes in the plant. Even considering fuel mix changes the liquid increase is relatively minor. This matter is unrelated to the decision of selection of the design pressure and is therefore better left to contractual negotiations between the shippers, producers and State of Alaska which should be occurring in the near future.

liquids that could be transported must be extracted in Alaska since the design pressure as approved by appropriate regulatory authorities in the first Canadian section is 1260 psig.

The Partnership has analyzed the proposal by Earth Resources Company of Alaska and has concluded that the necessary result of this proposal will render the primary pipeline project infeasible and, therefore, it should not be given further consideration.

III

Alternatives Considered

In reviewing the design pressure decision the Partnership has considered the following alternatives to the proposed system:

1. A 48-inch pipeline design for a maximum working pressure of 1400 psig. This system would result from the increase in the pipeline safety code requirement of 72% of the calculated design pressure to 80%. This alternative would require a change in the pipeline safety code or a waiver by the Department of Transportation. A portion of the system which follows the Haul Road would require a double waiver that the Department of Transportation has indicated would not be granted.

2. A 48-inch pipeline with a maximum working pressure of 1440 psig

3. A 48-inch pipeline with a maximum working pressure of 1680 psig.

In considering these alternatives it is helpful to review the proposals of the three projects which were heard by this Commission and ultimately provided the basis for the selection by the President. The Arctic Gas proposal was for a 48-inch pipeline and a maximum working pressure of 1680 psig. The Arctic Gas System, however, contemplated volumes of 2.25 Bcfd from Alaska and 2.25 Bcfd from the MacKenzie Delta region of Canada. Although the MacKenzie Delta reserves did not materialize as expected, Arctic Gas proposed a minimum of 1.25 Bcfd initially increasing to 2.25 Bcfd in the fifth year of operation from the MacKenzie Delta. Therefore, the Arctic Gas project always contemplated total volumes of 3.5 to 4.5 Bcfd.[4/] The El Paso

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4/ Even though the Alaskan segment (195 miles) of the Arctic Gas project would carry only Alaskan gas the higher pressure syster was selected in order to minimize the number of compressor stations in the Arctic National Wildlife Range.

project proposed a 42-inch pipeline with a maximum working pressure of 1680 psig for volumes of 2.4 to 3.2 Bcfd. The original Alcan proposal contemplated a 42-inch pipeline in Alaska with a maximum working pressure of 1260 psig for initial volumes of 2.4 Bcfd. In order to provide additional expansibility this system was amended to provide for a 48-inch pipeline at the same design pressure for the same initial volume.

These comparisons are significant to show that the present proposed system provides capacity equivalent to any of the competitive proposals which were considered by the Commission and the President. As the Partnership will show, it is not aware of any changes in circumstances or new additional gas reserve potential which would require reconsideration of the ultimate capacity to be provided by the pipeline system within Alaska.

IV

Optimum Design Pressure

In order to select the optimum economic design pressure it is necessary to determine the transportation cost of service at various volume levels and then to analyze the most likely initial volume with a final judgment as to the appropriate expansibility.

A common method for making economic comparisons between various pipeline systems is a graphical analysis as shown on Exhibits Z-4 and Z-5. This type of analysis permits inclusion of all of the variables which affect the cost of transporting natural gas into one common measure, that is, the cost of service per million Btu. These variables include system pressure, compressor station spacing, compressor station size and operation costs, including fuel. Exhibit Z-4 has been prepared based upon capital costs in 1975 dollars as filed with the Commission and adjusted for varying design specifications. A fuel cost of $2.00 per million Btu has been assumed. This fuel cost in 1975 dollars may be high in light of the wellhead price established for the Prudhoe Bay field in the Natural Gas Policy Act of 1978 depending upon action by the Commission to establish regulations concerning the treatment of gathering, processing and compression charges prior to entering the pipeline system. The effect of a lower fuel cost is to increase the volume to be transported at the lowest cost of service for any design pressure. Even though the capital costs are based on 1975 dollars and hence not reflective of current costs, the relative difference in cost of service is still valid for comparison of each system.

Several conclusions are pertinent from this comparison. The minimum cost of service for a 48-inch, 1680 psig system is at a volume of 4.0 to 4.5 Bcfd which is compatible with the original Arctic Gas project proposal. The optimum volume or minimum cost of service for the 48-inch, 1260 psig system proposed by the Partnership is 3.0 to 3.5 Bcfd and is consistent with the Partnership's proposal for ultimately eighteen compressor stations in Alaska for an average daily volume of 3.2 Bcfd. The optimum volume or a minimum cost of service for a 48-inch, 1440 psig system is 3.5 to 4.0 Bcfd. Finally, the point at which the 48-inch, 1260 psig system is equivalent in cost of service to the 48-inch, 1440 psig system is approximately 3.4 Bcfd. Therefore, the 48-inch, 1260 psig system would deliver gas at a lower cost up to this volume.

Exhibit Z-5 has been prepared to show a comparison between a 42-inch, 1680 psig system (El Paso proposed a system of this size and pressure) and the 48-inch, 1260 psig system. This comparison shows that the transportation cost of service is approximately the same with either of these systems throughout the range of volumes transported.

The Partnership concludes that the proposed system without consideration of potential delays is the best economic selection for the Alaskan segment up to a volume of approximately 3.4 Bcfd.

The expected through-put volume is the prime consideration in assessing the expected transportation cost and thereby making the final judgment concerning the system design specifications. The State of Alaska, through its Department of Natural Resources, approved the proposed Producer Operating Plan for Prudhoe Bay in June, 1977. Under the Plan the delivery rate after processing would be 2.0 Bcfd. Providing a pipeline connection to Alaska will undoubtedly result in additional exploration and development and provide substantial additional gas reserves over the life of the project. The timing of these reserves additions is critical to the judgment concerning spare capacity that should be provided in the initial pipeline system.5/ The President's Decision concluded that:

5/ There is no limit to the capacity that can be provided if the pipeline is looped in the future with an additional, integrated pipeline. The issue here is the capacity that can be added with additional compression only.

> "The certain increase in supply from an Alaska gas project is estimated to be 0.7 tcf per year (2.0 bcfd) by 1985. By 1990, a volume greater than 0.9 tcf (2.4 bcfd) might be produced." (p. 90)

Extensive analysis of the proven reserves and deliverability as well as the potential supply was done as part of the FPC proceedings prior to the President's selection. The result of this analysis was expressed by the FPC in its Recommendations to the President dated May 1, 1977, wherein it concluded:

> "... Thus, we find the system should be designed to carry initially 2.0 to 2.5 Bcfd, and be capable of expansion to an additional 1.0-1.5 Bcfd..." (p. I-17)

Utilizing the State approved volume of 2.0 Bcfd, such action taken after the FPC recommendation, the addition of 1.0-1.5 Bcfd of expansibility would result in a total capacity of 3.0-3.5 Bcfd. The proposed ultimate capacity of 3.2 Bcfd for the 48-inch, 1260 psig system is completely consistent with this recommendation.

Subsequent to the FPC recommendation a Report of the Working Group on Supply, Demand and Energy Policy Impacts of Alaska Gas was prepared by several Federal agencies and submitted to the President on July 1, 1977, as part of system selection process. This report estimated that expected additions by 1985 to proved gas reserves in the Prudhoe Bay structure would add deliverability of 0.3 Bcfd (p. 19). The same report contained general estimates of other potential North Slope reserves by three independent groups and concluded that the North Slope is judged to contain major potential reserves (p. 22). The report, however, cautioned that the estimates were not prepared to be used as a basis for pipeline design since exploratory drilling away from Prudhoe Bay is sparse or lacking. The State of Alaska also submitted potential reserve estimates indicating a range of deliverability including the Prudhoe Bay Unit from 2.0 to 4.2 Bcfd with a median of 2.8 Bcfd. These expectations are consistent with the FPC recommendation.

The Partnership is not aware of any developments which would change these prior views and hence urges the Commission to continue to adopt its prior recommendation that the ultimate capacity of the proposed system is adequate.

V

Hydrocarbon Liquids

The State of Alaska has urged consideration of a higher pressure system as a potential advantage to be able to transport a greater volume of hydrocarbon liquids for possible extraction and benefit to the State through development of a petrochemical industry in Alaska. The proposed system can transport all of the material which would be used as a petrochemical raw material that can be made available at Prudhoe Bay and, therefore, does not offer any impediment to the State's present or future plans. The recommended raw material for a petrochemical plant is ethane and the proposed pipeline system can transport all of the ethane or propane that could be available in the gas stream from Prudhoe Bay.

Further, the Partnership believes that the most economic way of selling liquid hydrocarbons, if not used within the State, is by leaving these hydrocarbons in the gas stream and thereby achieving the greatest value for the State.

A higher pressure system would be able to carry some greater volumes of heavier hydrocarbons, primarily butane.[6/] However, these liquids are not useful in a petrochemical plant nor can they be transported in the Yukon, Canada, section of the line which is designed at 1260 psig. Therefore, it is best to retain these liquids on the North Slope for use as fuel, blending with the oil or reinjected into the reservoir.

The Partnership, as requested by the State of Alaska, has analyzed the impact of moving the conditioning plant from Prudhoe Bay to Fairbanks, Alaska. The Partnership has determined that if most of the ethane and all heavier hydrocarbons were removed at Fairbanks the total deliverable energy through the project would be reduced by 20% to 25%. This substantial reduction would render the project infeasible. First, the transportation costs would increase in about the same proportion, thereby jeopardizing the marketability of the remaining gas. Second, the volumes of gas would become small enough that potential purchasers would not be willing to undertake the substantial risks of this project for the supply to be made available.

6/ The increase is about five to eight thousand barrels per day at 1440 psig and eleven thousand barrels per day at 1680 psig which is less than 5% of the total liquid volumes in the raw gas.

The hydrocarbon liquids that would be extracted at Fairbanks, Alaska, as suggested by Earth Resources Company of Alaska would be about 168,000 barrels per day. In contrast, a world scale ethylene plant producing about one billion pounds of ethylene per year requires less than 30,000 barrels per day of ethane. Therefore, even assuming that petrochemical development is feasible there would be over 138,000 barrels per day (less plant fuel) of ethane and other hydrocarbons to transport to tidewater and market.7/ It simply does not make economic sense to extract a substantial portion of the stream to be sold as liquids by other means out of the State of Alaska. The most efficient way for the State to receive the highest value for its product that is not retained for use in the State is to keep it in the gas volumes to be sold through the Alaska Highway Pipeline Project.

The Partnership recommends that the selection of the 48-inch, 1260 psig system should not be revised due to hydrocarbon liquid considerations and that no further consideration should be given to moving the location of the conditioning plant to Fairbanks, Alaska.

VI

Financing Considerations

The selection of design pressure is not only contingent upon the ultimate capacity and transportation costs as analyzed in this application but also the resulting effect on project financability. The President's Decision requires that the Alaska Natural Gas Transportation System be privately financed. The Natural Gas Policy Act of 1978, recently passed by Congress, contains provisions which will assist in accomplishing the private financing of the project. Other matters remain to be resolved including: (1) issues of an incentive rate of return, as presently being addressed in the proceeding in Docket No. RM78-12; (2) approval of the cost of service tariff; and (3) the financial participation of each of the project beneficiaries including the project sponsors, the State of Alaska, major equipment suppliers and the producers. Resolution of these matters represents formidable financing tasks to be undertaken in the immediate future.

7/ Both Bonner & Moore (report dated January 23, 1978, prepared for the State of Alaska on the Utilization of Royalty Gas) and Earth Resources have stated that the feasibility of a petrochemical plant is only possible if all of the hydrocarbon liquids are extracted in order to reduce the unit cost of extraction even though only a small volume is needed for the petrochemical plant feedstock.

Recognizing this financing challenge, the Partnership believes that the imposition of a technological and cost-overrun risk, by increasing the pressure level of the system beyond the point which lenders believe is reasonable, will jeopardize an already difficult financing task. The reduction of volume if all hydrocarbon liquids are extracted would also jeopardize project financing. Imposition of these substantial additional risks is unnecessary since the potential benefits do not appear to outweigh the economic disadvantages, even without consideration of the added burden of financing difficulties. The position, from a financing viewpoint, has been described in the letter from Mr. Michael Stanfield, Vice President of Loeb, Rhoades, Hornblower & Company (Exhibit Z-6 attached hereto).

VII

Meetings With Interested Parties

The operating partner of the Partnership (Northwest Alaskan Pipeline Company) has met with certain of the parties interested in this decision. Meetings were held with representatives of the State of Alaska, Atlantic Richfield Company and the Department of Transportation. The information and conclusions described in this Application were reviewed with each party. No questions arose or new information which alters the Partnership's conclusions as to the appropriate design specifications.

VIII

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

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

Jack D. Bachman, Esquire
General Counsel
Northwest Alaskan Pipeline Company
P. O. Box 1526
Salt Lake City, Utah 84110

Rush Moody, Jr., Esquire
Akin, Gump, Hauer & Feld
1155 15th Street, N.W.
Washington, D.C. 20005

WHEREFORE, the Partnership respectfully requests that the Commission issue an order accepting the design specifications for the system selected by the President for a 48-inch pipeline with the maximum working pressure of 1260 psig providing an initial system capacity of 2.0 to 2.4 Bcfd with expansibility by the addition of intermediate compressor stations up to 3.2 Bcfd for the Alaskan segment of the Alaska Highway Pipeline Project. The Partnership urges the Commission to approve the order requested herein as soon as possible in order to avoid delay and eliminate uncertainty so that the Partnership may proceed with the steps necessary to finance and construct the system. The Commission has already recognized the importance of such expeditious action in its comments on the President's Decision where it stated that:

> "... Expeditious resolution of the pipe selection is of great importance to the Commission because final certification cannot proceed in its absence." (p. 64)

Respectfully submitted,

Darrell B. MacKay

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY, THE PARTNERSHIP

NORTHWEST ALASKAN PIPELINE COMPANY

VERIFICATION

THE DISTRICT OF COLUMBIA §

I, DARRELL B. MacKAY, being first duly sworn on his oath, deposes and says:

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

Darrell B. MacKay

Subscribed and sworn to before me this 2nd day of March, 1979.

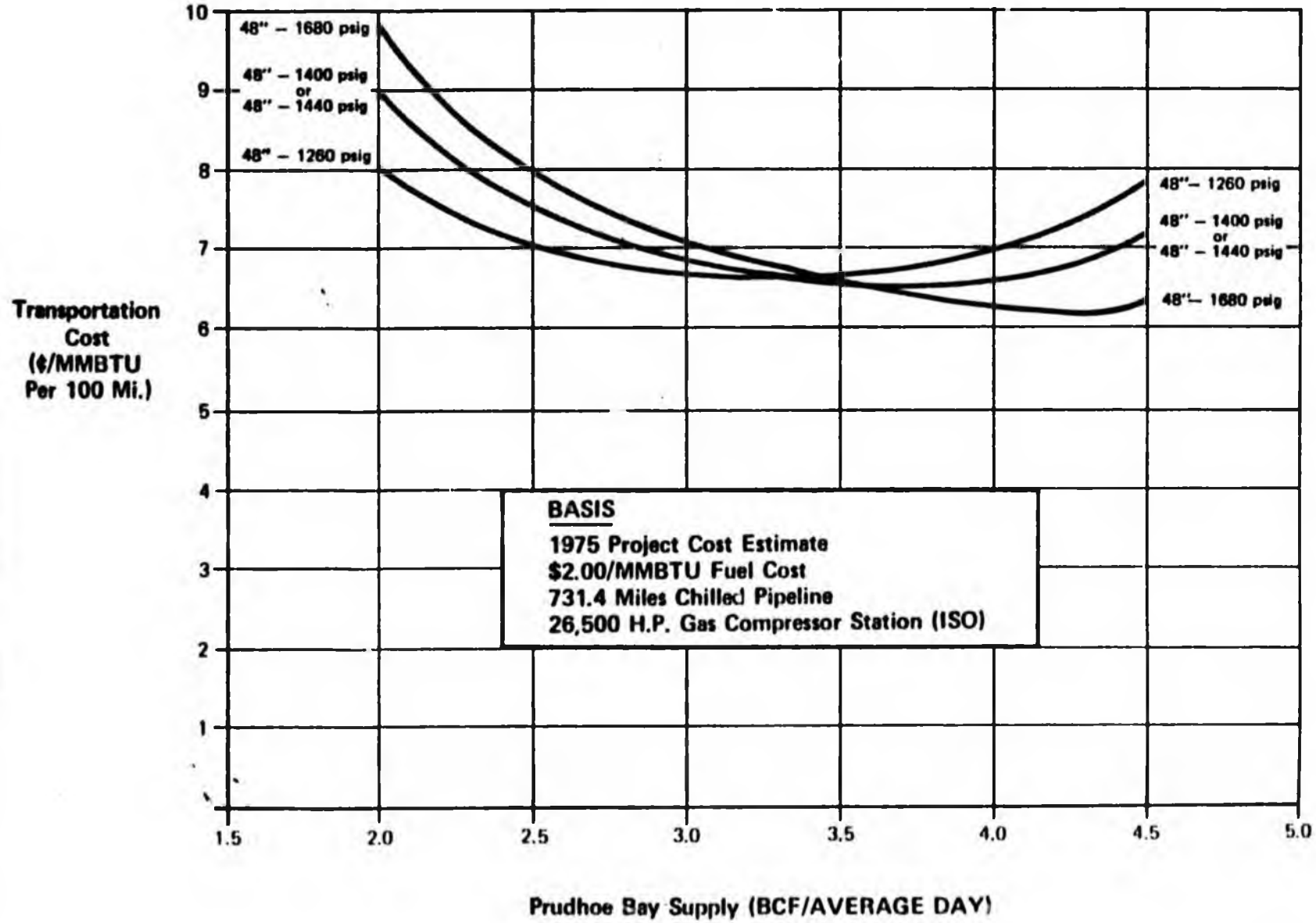
Notary Public

My Commission Expires:
MY COMMISSION EXPIRES JAN. 1, 1984

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

EXHIBIT Z–4

TRANSPORTATION COST CURVES

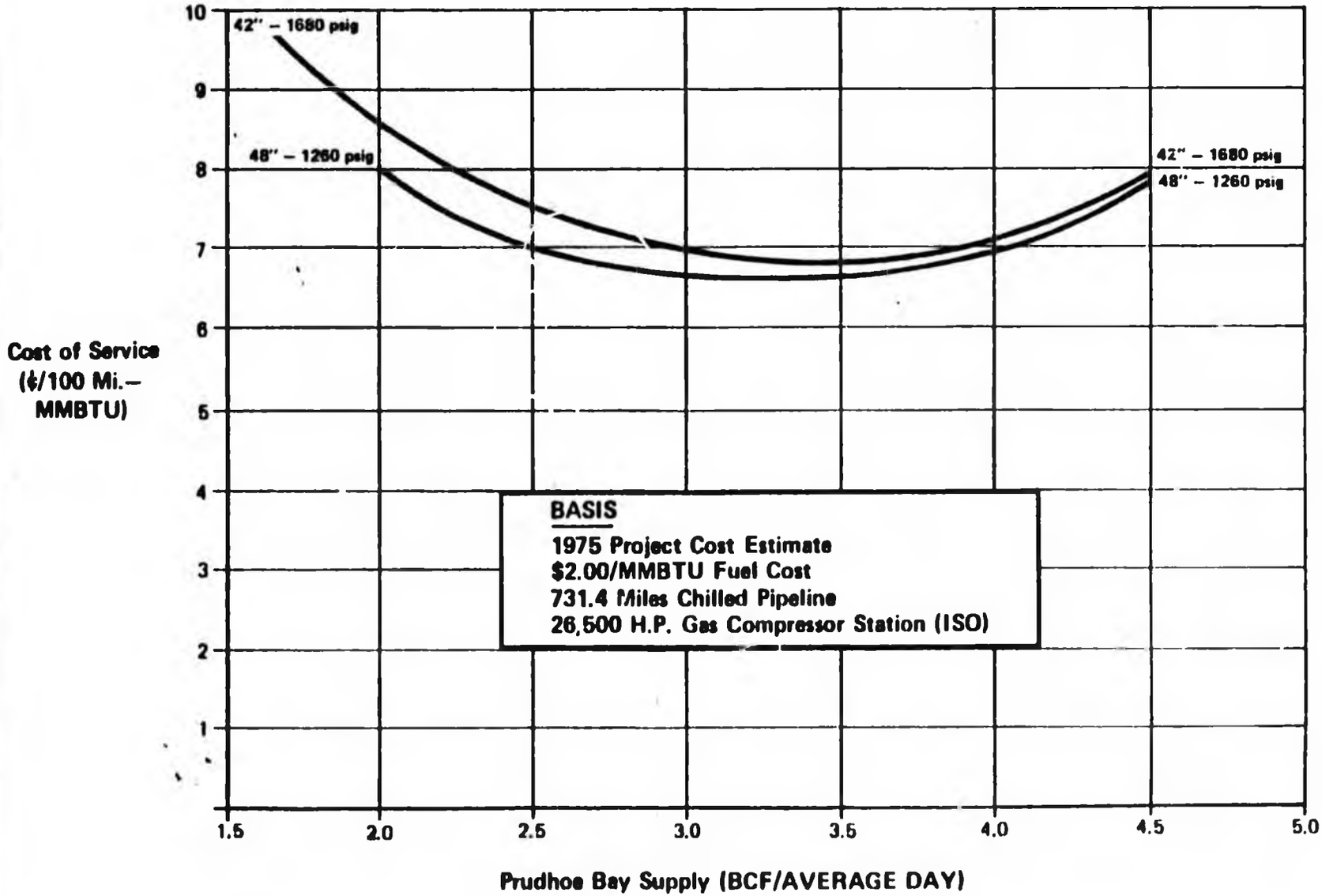


ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

EXHIBIT Z-5

TRANSPORTATION COST CURVES

for 42" and 48" ALTERNATIVES



Loeb Rhoades Hornblower

Loeb Rhoades Hornblower & Co.
60 Broad Street
New York, NY 10004 (212) 785 7400

EXHIBIT Z-6

July 5, 1978

Mr. James W. Allen
Vice President - Finance
Northwest Alaskan Pipeline Company
Post Office Box 1526
Salt Lake City, Utah 84110

Dear Jim:

I would like to respond to your questions regarding the effect higher pressures might have on the financing of the Alaska Gas Project. As you know, throughout the proceedings we have felt that if sufficient conventionality is maintained, the Project could be financed on a project financing basis. This viewpoint has been premised on the Project obtaining the two basic fundamentals of project financing - technical feasibility and economic viability.

I understand that various parties are suggesting that Alaskan Northwest should consider redesigning to a higher pressure (such as 1680 psi). If the fundamental financing structure is changed so that ironclad guarantees from other parties are made available for the Project's debt, then such a redesign is possible. However, if the Project is to be project-financed in a manner consistent with the President's Decision and Report, a substantially different design scenario is highly unlikely to be accommodated by project financing. Let me explain why with references to the fundamentals discussed above.

"Technical feasibility", in lenders' minds, may be paraphrased as "proven technology". Lenders loan money at commercial borrowing rates not at entrepreneurial risk rates. Accordingly, they do not take technological risk. The following examples illustrate the technological step out associated with 1680 psi:

1. The commonly used operating pressures for gas transmission lines does not exceed about 1200 psi worldwide,

2. A major project recently built in Iran was planned at higher pressures, but was redesigned and built at 1100 psi. I understand that the lower design was used due to the fear of ductile fracture. Such risk is compounded in the Alaskan climate

3. Currently no large diameter transmission lines operate at 1680 psi.

4. Exxon and Shell are currently building a line in the North Sea which will operate initially at 2160 psi; however, this line is a blow-down line (decreasing pressures without compression) which operates above 0° C. and which was not project financed.

Additionally, the Canadian participants in the Alaska Gas Project have been profoundly opposed to higher pressures from the outset. The burden of trying to convince lenders to the Alaska segment to assume a technological risk that the equity participants in Canada will not accept is not practical. Lenders will not step substantially into untried technological territory in a project financing of this magnitude.

Let me now turn to the economics of the Project. Lenders and equity holders must view the Project on the basis of the currently proven reserves, not on the basis of projected reserves. Additionally, the cost of service effect of additional capacity availability without additional throughput will endanger the economics of the Project. Lenders will recognize that the current design plan is consistent with both the FERC (at that time, FPC) and U.S.G.S. recommendations.

This Project currently is burdened with all too many unknowns and variables. To add the risk associated with possible excess capacity to the Project will further complicate financing.

Further, one must consider the equity holders' position. The equity holders are currently subject to a reduction in the return on the equity component of the capitalization in the event of service interruption or throughput declines. If the perceived fear of interruption is higher under the higher pressure case, then the chances of equity holders taking the same degree of risk at 1680 psi as at 1260 psi is small. In other words, absent some sharing of risk by consumers and FERC, I question the enthusiasm equity partners will indicate towards investing in the higher pressure system.

In conclusion, I would like to make a general comment. Over the life of this Project, we have strived to imaginatively structure the financing to provide for private financing. However, lenders

will only take a limited amount of risk, and we cannot expect the lending community to break from traditional rules to finance this Project. I urge you to strongly indicate our concern that a substantial technological jump cannot be achieved in the Proje t if private financing, as currently planned, is to be achieved.

Sincerely yours,

MICHAEL R. STANFIELD
Vice President
LOEB RHOADES, HORNBLOWER & CO.

CERTIFICATE OF SERVICE

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

Dated at Washington, D.C. this 2nd day of March, 1979.

Darrell B. MacKay

FERC –
Pipeline Design
+ Capacity –
Comments of
AK
4/15/79

FERC

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE STATE OF ALASKA

The State of Alaska ("Alaska") offers the following limited comments on the Delegate's Report on pipeline size and operating pressure for the Alaska segment of the Alaska Natural Gas Transportation System. Alaska adopts its comments filed April 5, 1979, as amplified and modified below.

Alaska recognizes, and appreciates, the Commission's concern for expeditious resolution of the issues surrounding the Northwest project. To a significant degree, Alaska shares the desire of the Commission for rapid decision making. For example, although Alaska had different views on the incentive rate of return than the Commission adopted, Alaska recognizes that the issues -- for the most part -- were matters of judgment and policy, ones that even if Alaska had had more time to comment, the final decisions were still within the Commission's discretion.

But in some areas quick and summary resolution is not compatible with either fairness or accuracy. Although a rulemaking proceeding can swiftly clear away non-contested areas, or resolve matters that will always be, in the last resort, subjects of the Commission's discretion, it simply cannot paper over serious questions of fact. When, during comments on rulemaking, a serious and substantial question of fact arises, the Commission cannot choose the assertions it wishes to believe. Not only will wishing not make it so, but also Commission policy and judgment will most probably not be realized in fact. One such question of fact arose during the comments on the CO2 standard concerning lower-48 practices. The actual practice in the lower-48 not only affected the allocation of costs between the Project and the producers, but also influences the Commission policy not to burden on lower-48 consumers with unnecessary costs.*/

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*/ For example, to the extent that CO2 is 'removed' from LNG storage in the lower-48, the removal at Prudhoe Bay is simply an extra cost that may be borne by lower-48 consumers.

One other factual problem which also is of the same nature has arisen in this proceeding, relating to liquids carriage and the location of the conditioning plant.

Alaska has consistently taken the position that one of its prime concerns, and a concern of significance to the Commission, is preserving the option of maximum liquids transportation. And, related to this is the primary concern of both the Commission and Alaska that the entire system, both the conditioning plant and the pipeline, be constructed in the most efficient and least expensive manner practicable.

Unfortunately, a major component of the entire system's cost has not been adequately considered by the Commission. As a result, this Commission lacks complete information on not only a key feature in the design of the entire system, but also a major component of the financing cost of the entire project, and of the quality of the gas and gas liquids that could be made available not only to Alaska but lower-48 consumers as well.

In addition, lack of detailed information has severely hampered Alaska in deciding whether, to what degree, and on what conditions it will actively support this Project. Alaska even has a problem in deciding what it could trade-off if such trade-offs became necessary, because of confusion in the record and elsewhere as to what is practically available to all parties.

For these reasons, and in light of the Delegate's comments in his report on liquids' questions, Alaska wishes to present here an outline of its understanding of the "facts" of liquids' transportation, and some of the questions it has, and asks the Commission or other parties to correct on the record any mis-impressions Alaska may be under.

Alaska understands that a 1260, 48", 1% CO2 line could, as a practical matter, transport all the ethane, all the propane, and up to 25% (9,000 bbl/day) of the butane that could potentially be made available from Prudhoe Bay Unit.*/ Alaska also understands that raising the CO2 content of the pipeline will not significantly increase the liquids' carriage of the line, except insofar as more mcf's overall are transported.

With regard to liquids, however, the question is whether the maximum amount of liquids will be made available at the inlet

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*/ Alaska understands that the chart attached as Exhibit B to our reply comments, which show a greater amount of butane being able to be transported, is, as a practical matter, impossible to obtain because some pentanes plus will remain with the sales gass, lowering the available capacity for other liquids.

to the pipeline. This is primarily due to: (1) the need for field and local fuel; (2) the need to supply TAPS with fuel; and (3) the process used to strip CO2 from the raw gas.

The Parsons design plans to condition the gas in a two-stage process. First, the gas will be chilled to -30°, which will drop out most of the butane, most of the pentane, about 60% of the propane, and very little of the ethane. The second stage is the removal of the CO2. The process chosen by Parsons is the SELEXOL CO2 removal process, which is a physical absorption system. One effect of this system is that 1/3 of the available ethane will be stripped along with the CO2 and, to the extent CO2 is not put in the pipeline, that ethane is lost to downstream use.

After stripping the CO2, the conditioned gas has a severely reduced liquids' ratio: ethane is reduced from 6.48% to 4.47% (with the remaining ethane mixed up with the CO2); propane is reduced from 3.48% to .08%, and butane is reduced from 1.66% to .03%.

At this point there are possible reblendings of the stripped propane and butane back into the conditioned gas before it enters the pipeline. This does not apply, however, to the lost ethane, which follow the extracted CO2.

Under the Parsons primary blending plan, 40 MMSCFD with a BTU content of 858 will go to TAPS, 399.4 MMSCFD with a BTU content of 825 will go for field fuel, and 192 MMSCFD with a BTU content of 475 will be used for local turbine fuel, and 56.7 MMSCFD with a BUT content of 212 will be used for local heater fuel. Except for TAPS fuel, the primary source of the field and local fuel will be the CO2/ethane stream, spiked as necessary with propane to reach the higher BTU requirements as necessary. Butane apparently is unacceptable for spiking pruposes, primarily because of surging.

Because of the need to spike the CO2/ethane stream to variously higher BTU contents, under half of the available propane will be injected into the sales gas stream. (24,270 bbl/day out of an available 52,350 bbl/day).

Although a rise to a 3% CO2 level would increase the propane in the pipeline gas by about 15,000 bbl/day, the amount of ethane would stay about the same, and the amount of butane would decrease (because more propane would take up the available space).

The major remaining problem is disposition of the butane. Since butane will not be used for field or local fuel, the only remaining place for butane is: (1) pipeline gas, (2) TAPS; or (3) reinjection. One problem with a 1260, 48" line is that even with the reduced amount of propane made available, at least 15%

of the butane cannot be placed in the gas pipeline. But in order for the butane to be transported through the TAPS line, the oil must be cooled substantially to meet the vapor pressure requirements of both the TAPS line and California. This requires field costs of approximately $60 million, along with additional costs in TAPS for the increased wax-buildup and other problems.

Therefore, it appears to Alaska that if present plans progress, the option of liquids' transportation sufficient to make a petrochemical industry feasible even if the option were more attractive in the future than now is severely, if not fatally, hampered. The selection of a physical, rather than chemical, absorption process is one problem. A chemical process could make available all the ethane, not just 66%; however, a chemical process, Alaska has been informed, requires 10-15% more fuel, is more expensive, and will have some adverse effects in meeting the field and local fuel problems. Although the field is designed to take alternatives to the proposed fuel stream, even if, say, methane is used, the present CO2 process would have to be completely changed to recover all the ethane.*/

Second, even if the conditioning plant could provide the line with all it could handle, most of the butane would be lost to the gas stream. Further, a substantial portion of butane is lost under any scenario for blending of the liquids.

Third, the location of a conditioning plant is also an issue; the material to be submitted by Earth Resources (i.e., the Litwin Study), indicates that substantial savings may be possible by locating the conditioning plant at Fairbanks and building a higher pressure line from Prudhoe to Fairbanks. Although Alaska recognizes that there would be added costs as well, and that it may be that when all problems are considered, including such things as field fuel, CO2 disposal, the accuracy and applicability of the Litwin study, etc., a conditioning plant at Fairbanks is infeasible, Alaska is not satisfied that the matter has even been addressed in any rigorous manner, although it hopes that it will be either here or in the environmental analysis to be conducted.

If there is to be any possibility that Alaska will participate in pipeline financing, the action must not only be economically attractive, but also politically and popularly attractive to the citizens of the state. One of the hopes of a major segment of the Alaska citizenry is the possibility of a major liquids'

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*/ This is not to say that the Commission has jurisdiction over the plant but only to suggest a total system approach is lacking.

extraction and petrochemical facility in the Interior. In addition, although the present prevailing wisdom is that a petrochemical facility based upon the gas stream is economically infeasible, no one can predict the petrochemical future in the next 10 years, much less over the major portion of this pipeline's life.

Alaska believes that, where possible, the option of future liquids' transportation sufficient to support a petrochemical industry be kept open. Unfortunately, given both this Commission's present speed-up and the piecemeal resolution process, an overall resolution of all the competing problems if the present course continues is highly improbable.

Alaska would suggest that where problems like this arise, the Commission either hold hearings on particular factual matters where a factual conflict appears on the record; conduct an independent investigation to ascertain the correct answer; or devise some means of resolving the conflict rather than arbitrarily picking or choosing. Second, Alaska would also suggest that the Commission consider on the record matters which may not be directly before it in a narrow sense, since everything the Commission does impacts upon many other matters, such as financing and liquids, so that parties may have a complete understanding of where they stand and can make changes based both upon that understanding and upon an assurance that the Commission has considered their particular problems in some detail.

Finally, with regard to a final order on pressure and size, Alaska, without answers as to the relative expense of a conditioning plant at Fairbanks, the trade-offs of the costs of a higher pressure line, higher CO2 content, alternative CO2 removal systems, and other matters, cannot take an unconditional position. Neither, Alaska believes, can the Commission.

Respectfully submitted,

Robert H. Loeffler

MORRISON & FOERSTER
1025 Connecticut Avenue, N. W.
Washington, D. C. 20036

Attorney
for the
State of Alaska

VERIFICATION

DISTRICT OF COLUMBIA: ss

Robert H. Loeffler, being first duly sworn, deposes and says that he is an attorney for the State of Alaska, that he is authorized to execute, verify and file this document for, on behalf and in the name of said State; and, that he has examined the statements set forth herein and that the same are true and correct to the best of his knowledge, information and belief.

Robert H. Loeffler

SUBSCRIBED AND SWORN TO
before me this 2nd day
of July, 1979.

Notary Public

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties included on the service list in this proceeding in accordance with the requirements of Section 1.17 of the Rules of Practice and Procedure.

Dated at Washington, D. C. this 2nd day of July, 1979.

Robert H. Loeffler

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF THE STATE OF ALASKA ON THE DESIGN SPECIFICATIONS AND INITIAL SYSTEM CAPACITY OF THE ALASKAN SEGMENT OF THE ALASKA HIGHWAY PIPELINE PROJECT

The State of Alaska ("Alaska") offers the following comments on the application of Alaskan Northwest Natural Gas Transportation Company ("the Partnership") for an order establishing the size and pressure of the Alaskan segment of the Alaska Highway Pipeline Project. The application, which was placed on public notice March 16, 1979, seeks an order establishing a maximum working pressure of 1260 psig and a size of 48-inches for the Alaskan segment.

As both the application and notice of application properly state, Alaska has been closely concerned with the possibilities for productive use within Alaska of natural gas liquids from the North Slope. This concern reaches not only the liquids' carrying capacity of the line, but also the location of the conditioning plant as it is affected by size and pressure considerations. And, Alaska has always favored the common sense approach of planning now for the future so that the line as built will be able to carry additional gas reserves should they become available. Alaska has worked closely with the Partnership to resolve these issues without foreclosing any realistic opportunities that would favor the utilization of liquids in Alaska.

As part of this effort, Alaska requested of the Partnership confirmation of the statement in the application that the proposed pipeline can transport all the ethane and propane that could be available in the gas stream from Prudhoe Bay. A copy of Alaska's request is Exhibit "A" hereto. The Partnership promptly responded by letter of its Vice President, Regulatory, Environmental and Civic Affairs. A copy of the response is Exhibit "B" hereto. Alaska requests

that the exchange of correspondence be brought to the Commission's attention when it acts upon the application.1/

Alaska has reviewed the application and associated material and has made the following assumptions as to the scope of the Order requested by the partnership.

Based on the representations of the Partnership stated in Exhibit "B," Alaska is presently satisfied that its concerns with liquids' carriage do not conflict with the entry of the requested order establishing size and pressure. If, in the future, other professional data should become available to Alaska which seriously conflicts with the representations in Exhibit B, Alaska then would have to consider whether to seek an appropriate procedure for the satisfactory resolution of the conflict. Alaska does not seek such a procedure now and does not expect to seek one in the future.

Alaska also shares what it believes is the operating assumption of all concerned: that the conditioning plant will be located at Prudhoe Bay. Alaska believes that all recognize that this matter will not be settled until gas sales contracts are negotiated and the Commission releases an Environmental Impact Statement concerning the alternative locations and configurations of the conditioning plant. If the contracts or the Environmental Impact Statement (or both) should establish that a place other than Prudhoe Bay is the most desirable site for the conditioning plant, or that a different configuration for the plant is more desirable, the Commission would have to ensure that the most desirable alternative were pursued. As part of this effort, the Commission might have to reconsider its pressure decision, at least with respect to the segment between Prudhoe Bay and the preferred site for the conditioning plant.

Alaska also understands that the matter of a minimum Btu requirement for pipeline quality gas will not be considered or established by the Commission in acting upon this application. This may fall within the omnibus tariff proceeding, the gas sales process, or, conceivably, elsewhere.

1/ The Alaska Gas Pipeline Office has conducted an informal inquiry on size and pressure questions. Alaska, among other parties, filed comments and participated in a conference that the Office called upon the subject. The Office also issued a draft report on this subject on September 27, 1978. Alaska recommends that the materials assembled in this inquiry be made a part of the official record of this proceeding.

Finally, Alaska is concerned with the CO_2 standard to be established for transportation of the North Slope gas. Alaska assumes that this matter also is not within the scope of an order establishing size and pressure, but will be resolved in the contracts, in the tariff proceeding, or in an entirely separate proceeding devoted to this question. In its reply comments in RM79-19, Alaska has urged a more liberal CO_2 carriage standard and a specific inquiry devoted to the question of the proper CO_2 standard. Alaska renews this suggestion and urges that it be pursued separately and apart from the conditioning cost proceeding.

Based on the stated assumptions as to the scope of the requested order, Alaska supports the application of the Partnership for an order establishing size and pressure.2/

Respectfully submitted,

Robert H. Loeffler

ISHAM, LINCOLN & BEALE
Suite 701
1050 Seventeenth Street, N.W.
Washington, D.C. 20036

Attorney
for the
State of Alaska

April 5, 1979

2/ Alaska respectfully requests that it be advised should any of these assumptions be incorrect so that it may then consider whether another procedure is indicated to protect its interests.

EXHIBIT "A"

ISHAM, LINCOLN & BEALE
COUNSELORS AT LAW

1050 17th STREET, N.W. SEVENTH FLOOR
WASHINGTON, D.C. 20036

TELEPHONE 202-833-9730

CHICAGO OFFICE
ONE FIRST NATIONAL PLAZA
FORTY-SECOND FLOOR
CHICAGO, ILLINOIS 60603
TELEPHONE 312-782-7500
TELEX: 2-5260

March 23, 1979

Darrell B. MacKay
Vice President
Northwest Alaskan Pipeline Company
Suite 901
1801 K Street, N.W.
Washington, D.C. 20036

Dear Darrell:

The Application of Alaskan Northwest Natural Gas Transportation Company for an Order Approving the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline Project states that the 1260, 48" line could carry all the ethane and propane, and most of the butanes, that could be made available from the Prudhoe Bay Gas Stream, whether or not the conditioning plant made those amounts available. Application, 9. As you are aware, the amount of liquids able to be transported past Fairbanks is of vital concern to the State. Assuming this to be the case, then many of the State's concerns about the pressure and size of the line are alleviated, for the focus is then shifted to the amount of gas liquids that the conditioning plant will inject into the sales gas stream.

Unfortunately, beyond conclusory statements and summaries, there is no information in any public record which would allow an independent evaluation of your assessment of the liquids question. Since the matter is of vital concern to the State, we request that you make available to us sufficient detailed information which would allow an independent evaluation by a qualified engineer or other professional of the accuracy of your assessment.

Since the matter is of public concern to the State, we intend to make both the independent evaluation and your information a matter of public record.

Thank you for your consideration in this matter.

Sincerely yours,

Robert H. Loeffler

RHL/kc

Attorney

NORTHWEST ALASKAN PIPELINE COMPANY

1801 K Street, N.W.
Washington, D.C. 20036
(202) 466-5850

March 27, 1979
RECA 79-1065

Robert H. Loeffler, Esq.
Isham, Lincoln & Beale
1050 17th Street, N.W.
Suite 701
Washington, D.C. 20036

Dear Bob:

The purpose of this letter is to respond to your request of March 23, 1979, for additional documentation concerning the statement in the Application of Alaskan Northwest Natural Gas Transportation Company for an Order Approving the Design Specifications and Initial System Capacity of the Alaskan Segment of the Alaska Highway Pipeline Project that

> "... the proposed pipeline system can transport all of the ethane and propane that could be available in the gas stream from Prudhoe Bay." (p. 9)

Attached are two exhibits which show the basis for this conclusion. Exhibit I summarizes the volume of liquids which would be transported in the pipeline at a design pressure of 1260 psig without regard to the conditioning plant process. Column (b) shows the gas composition at the point in the field where the oil and gas are separated. This composition was taken from the September, 1978 study report "Sales Gas Conditioning Facilities, Prudhoe Bay, Alaska" by the Ralph M. Parsons Company. Column (c) shows the barrels per day of ethane and heavier hydrocarbon liquids that would be contained in a total volume of raw gas of 2.8 Bcf per day. These calculations are determined from standard densities for each component. The volume of 2.8 Bcf per day is the approximate field production required to deliver 2.0 Bcf per day of conditioned gas in accordance with the Operating Plan approved by the State in June, 1977. Column (d) shows the quantities of liquids that would have to be removed to accommodate the hydrocarbon dew point specifications of -10°F at 1000 psia for the design pressure of 1260 psig. The basis of these calculations is described in connection with Exhibit II. It is important to

note that these volumes are determined without regard to equilibrium calculations related to a specific process. In actual practice some amount of ethane and propane would be removed and some amount of pentanes and heavier components would remain in the gas. This variation does not detract from the conclusion that the pipeline system at 1260 psig could transport all ethane and propane that is available in the raw gas. Column (e) is the difference between Columns (c) and (d) and shows the quantity of liquids that are available for fuel at Prudhoe Bay, for extraction at any point along the pipeline system in Alaska or for retention in the gas stream.

Exhibit II shows the phase envelope for a gas composition based on reducing the carbon dioxide content and removing the liquids shown in Column (d) of Exhibit I but retaining all of the ethane and propane in the pipeline gas stream. As described previously, this composition will be affected by the process utilized to condition the gas. For example, some amount of ethane and propane will be removed from the raw gas and consumed as local fuel irrespective of the gas conditioning process method actually employed. Any such reduction in ethane and/or propane content of the sales gas allows some additional butanes to be carried in the gas pipeline without exceeding the hydrocarbon dew point specification. However, this illustration shows the theoretical maximum amount of ethane and propane that could be made available to the pipeline. It can be seen that this mixture meets the required hydrocarbon dew point specification of -10°F, 1000 psia required to prevent retrograde condensation in the transmission system. A similar phase envelope for a similar mixture was previously submitted by EXXON to FERC April 3, 1978 (Figure 2, Curve 2 of the EXXON response).

We believe that the enclosed information is sufficient for an independent evaluation of these figures by a qualified engineer. I would like to reiterate as stated in our Application that since the recommended raw materials for a petrochemical plant are ethane and propane we are not inhibiting the State's flexibility to develop a petrochemical industry, at any time,