AEROSPACE REPORT NO.
ATR 76(7557)-1

ALASKA NATURAL GAS
TRANSPORTATION SYSTEM

FINAL GEOTECHNIC EVALUATION

ALASKA PIPELINE

Applicant: Alaskan Arctic Gas Pipeline Company

December 1975

THE AEROSPACE CORPORATION

Prepared for BUREAU OF LAND MANAGEMENT
U.S. DEPARTMENT OF THE INTERIOR
Washington, D.C. 20240

Contract No. AA 550-CT6-6

Aerospace Report No.
ATR-76(7557)-1

ALASKA NATURAL GAS TRANSPORTATION SYSTEM
FINAL GEOTECHNIC EVALUATION
ALASKA PIPELINE

Applicant: Alaskan Arctic Gas Pipeline Company

December 1975

Prepared for

Bureau of Land Management
U.S. DEPARTMENT OF THE INTERIOR
Washington, D.C.

Contract No. AA 550-CT6-6

Energy and Transportation Division
THE AEROSPACE CORPORATION
El Segundo, California 90245

FOREWORD

This report contains a Geotechnic Evaluation of the application by the Alaskan Arctic Gas Pipeline Company, designed for transporting natural gas from Prudhoe Bay in Alaska to the Canadian border, herein termed the Alaska Arctic Pipeline. This report is one of four that cover the four portions of the Alaska Natural Gas Transportation System. The reports are as follows:

THIS REPORT	Alaska Arctic Pipeline
	Northern Border Pipeline
	San Francisco Pipeline
	Los Angeles Pipeline

The Geotechnic Evaluation was directed at the identification of those critical factors that affect the integrity of the transportation system and thereby pose a threat to the environment and/or the public safety. This evaluation was conducted by The Aerospace Corporation under Contract AA550-CT6-6 from the Bureau of Land Management (BLM), Department of the Interior (DoI). An earlier version of this set of reports (Aerospace 1975) was published on 15 March 1975 and was among the inputs to the Draft Environmental Impact Statement (DEIS) on the Alaska Natural Gas Transportation System (DoI 1975).

Inputs to this geotechnic evaluation included the Applicants Environmental Report, Application for Certificate of Public Convenience, Alignment Charts, answers to questions posed by DoI, the 15 March Geotechnic

Evaluation report, comments on the 15 March report and on the DEIS, testimony presented during public review of the DEIS, and additional technical data obtained from the Applicant and other sources.

For easy reference, the material contained herein is presented in the order defined by the DoI Environmental Impact Statement outline. Only those topics of the outline that were jointly identified by BLM and The Aerospace Corporation as being pertinent to pipeline integrity are addressed. The table of contents for the report identifies those subjects addressed by the use of asterisks underlining the subjects for the section, subsection, or words in the title of such section or subsection that limit the scope of the input. Each of the outline items discussed was subdivided into the following area: Applicant's submission, analysis of submission, conclusions, and recommendations.

ACKNOWLEDGMENTS

The Aerospace Corporation acknowledges the contributions of R&M Consultants, Anchorage, Alaska, for their technical analysis in relation to construction in the Alaskan environment and particularly permafrost. Appreciation is also expressed to Department of the Interior personnel, especially James Coan, Henry Noldan, and Kenneth Thomas for their overall guidance in conducting this geotechnic evaluation.

In addition, comments from the reviewers of the 15 March 1975 geotechnic evaluation report and the Draft Environmental Impact Statement are acknowledged. These comments along with additional data, much of it provided by Northern Engineering Services Company Limited, has provided the basis for major revisions of many sections in this report.

CONTENTS

CONTENTS (cont.)

CONTENTS (cont.)

CONTENTS (cont.)

CONTENTS (cont.)

CONTENTS (cont.)

HIGHLIGHTS

The thrust of the Geotechnic Evaluation centered on the identification and assessment of pipeline integrity issues that may pose a threat to the environment or public safety. These issues in many cases reflect the worst expected conditions and no attempt has been made to assess the probability of their occurance. The scope was limited to the Applicant's prime route in Alaska. Well-head operations, gas compressor/chilling stations, and related facilities located at Prudhoe Bay were excluded since they were not a part of the application. The system configuration investigated included: 195 miles of pipe crossing coastal plain and approximately 122 rivers with block valves located 15 miles apart. Remote communications for management and control, three maintenance sites, and large landing sites were also included.

The Alaska Arctic Pipeline from Prudhoe Bay across the North Slope of Alaska to the Canadian border is an engineering project involving many challenging problems. Permafrost, with insulating organic cover, requires the use of special techniques during the construction phase to prevent permanent environmental damage and pipeline failures. During pipeline operations, the maintenance of the permafrost would require the gas temperature to be below 32°F. Almost the entire pipeline route crosses perpendicular to natural drainage slopes and rivers. Control of drainage, erosion, and pipeline integrity at river crossings, on slopes, and on flood plains also would require careful consideration during all seasonal changes while the system is in both inactive and active states. All of these problems, while difficult, are well within the realm of engineering feasibility. However, voids in the design data should be filled before construction approval is granted, to ensure that sound engineering practices would be implemented in resolving pipeline integrity issues to insure minimum environmental change.

The discussion of pipeline integrity in this report is arranged in a sequence consistent with the outline of the Environmental Impact Statement to allow proper cross-referencing. Since certain issues may be greater significance than others, an effort has been made to select those critical technical issues requiring more immediate attention. The issues have been sifted from the extensive environmental material and limited final design data submitted by the Applicant.

1. Unchilled Pipe-Thermal Problems

The Applicant states that the buried pipeline may have an inactive period for up to one or more years after construction. The buried pipe will not be flowing gas during this period and will seek the temperature of the surrounding soil.

The main problem with the unchilled pipe is ground settlement in the right-of-way and in the berm. This is attributed to disturbence of the organic layer and the composition of the backfill. Possible accumulation of water in the ditch could induce drainage and erosion problems which may be aleviated but not eliminated with ditch plugs.

Another potential problem is severe berm erosion. Such erosion could compromise the effectivity of the berm as a mitigating measure for bouyancy and frost heave effects.

Methods which can be taken to mitigate these effects include anchoring the pipe, passing chilled air through the pipe during the inactive period, use of surface insulation or berm reinforcement and through the addition of a sacrificial layer to compensate for the berm erosion. In addition plugs can be used which act to arrest the flow of water along the berm in a manner analogous to the use of ditch plugs. (See sections 1.1.1.1.B.2; 1.1.1.6.B.2 and 3.1.1.2.D.1.)

2. Summer Repair and Maintenance Concept Viability Questioned

Since an all-season road to the route site has not been proposed, summer repair and maintenance if not conducted properly, could have a major effect on the environment. The proposed solution is the use of aircraft, air cushion vehicles, and low ground pressure vehicles. The availability of machines is under investigation by the Applicant, but it will be necessary to prove (low footprint) concept feasibility prior to pipeline construction and to conduct field trial demonstrations prior to pipeline operation, to ensure that the summer repair and maintenance procedures are adequate. (See section 1.1.1.1.7.C.3.)

3. Pipeline Mechanical Design Criteria

The comprehensive design criteria formulated by the Applicant permits unconservatively high levels of stress and strain to develop in the pipe under certain combinations of external loadings. These levels are in excess of the express and implicit allowable stress levels described by Part 192, Title 49 of the Code of Federal Regulations.

Measures which can be taken to mitigate this discrepancy between design approach and interpretation of Part 192, Title 49 of the Code of Federal

Regulations, includes increasing the wall thickness of the pipeline, decreasing the operating pressure, or invoking to a greater degree the measures already proposed to reduce geotechnic loads to the pipeline.

4. Frost Heave Effects

Since the gas will be chilled to prevent thawing of the permafrost throughout the regions traversed, the chilled pipe will tend to freeze or refreeze areas with front-susceptible soils. Inadvertant thaw conditions may occur during construction, during prolonged shutdown, or during the up to one or more years which may elapse between construction and establishment of chilled gas flow in the completed pipeline. The consequent frost heave forces are to be mitigated by mounding the backfill trench (surcharge) over the pipe to increase down pressure to above critical levels. The ability to provide sufficient surcharge pressure above the critical level is questioned, particularly as limited by berm height during the inactive period, berm erosion, and river scour considerations. In addition, the accuracy of the methods proposed to determine frost heave rate and, indirectly, berm surcharge requirements, is not defined for the range of soils along the right-of-way, since complete soil surveys have not been accomplished.

In summary, there is uncertainty about the amount of overpressure (surcharge) required to arrest front heave forces because of soil variation, river scour, erosion, and subsidence effects, the latter becoming more pronounced with the unchilled pipe in the ground. A detailed analysis of the worst expected conditions is required by the Applicant to minimize potential frost heave and pipe overstressing hazard.

Measures which can be taken to mitigate frost heave effects include anchoring the pipe, increasing the berm height (surcharge) to add a factor of safety to the analytically determined surcharge requirements, or combinations of these techniques (see sections 2.1.1.3.C.4.e and 1.1.1.1.B.2.).

5. <u>Effect of Mass Wasting on Pipeline Integrity</u>

Although the Applicant has shown a sound understanding of the potential effects of mass wasting on the pipeline integrity, this remains a major design issue. The effects of mass wasting on pipe external loads, particularly in the case of undercut slopes, should be evaluated in detail for the case when pipe may remain inactive and unchilled for one or more seasons, or when the pipe is chilled. The unchilled pipe also introduces a problem of subsidence in the right-of-way, and a change in the drainage pattern with associated berm channeling and ponding. This problem requires carefully planned mitigating measures to minimize the environmental impact.

Measures which can be used to mitigate the effect of mass wasting include erosion control measures, such as avoidance of slopes with marginal stability, drainage control, and slope reconstruction.

In order to be able to assess the mass wasting problem, pipeline movement monitoring equipment should be provided at critical locations along the route (see section 2.1.1.3.C.2.g).

6. <u>Protection of Pipe at River Crossings</u>

During thaw periods, ice dams could form in the river above the chilled pipeline. If such dams were to break, the resulting channeling and bank erosion could significantly affect scour depth and bank profile and perhaps expose the pipe (see section 2.1.1.1.5.B.2). The Applicant stated that the problem of ice jam during the breakup is unlikely because most of the crossings are at braided river sections with low banks. Nonetheless, several channeled rivers (examples: Hulahula, Aichilik Rivers and others) will be crossed and the problem posed by ice jams and deep scouring and bank erosion must be considered (see section 2.1.1.1.5.B.2).

A measure which can be used to mitigate these factors is deep burial at approaches to the river as well as under the channel.

7. Snow Roads and Work Pads

Snow roads and work pads are a point of concern from the aspect of timely availability of large amounts of snow and water through the winter period. Extensive use of snow fences to bank snow along the proposed right-of-way, plus the manufacture of snow (from water), may allow pipeline construction to be started in October. However, the ability to end the construction season by late May is questioned, due to melting and degradation of the snow road at the start of the summer following the construction season. Early melting compounds another problem which consists of the after-effect snow roads on the tundra. While the Applicant performed a series of useful experiments on the feasibility of snow roads, the problems cited above are not yet totally answered for the arctic tundra.

Measures which can be used to mitigate these factors include accelerations of the construction schedule by use of more than three construction spreads, by using low ground pressure vehicles extensively at the end as well as at the beginning of the construction season (see section 1.1.1.6.B.1), or through provision of sufficient all seasons road to support the construction period. (See section 1.1.1.6.B.1.)

8. Leak Detection

The hostile environment and inaccessibility of the pipeline would make small leak detection extremely difficult utilizing current technology. Means should be defined and procedures set for detecting gas leaks under frozen ground with and without thaw layer, under rivers and under ice. A research program directed at remote leak detection systems should be undertaken (see sections 3.1.1.6 and 3.1.1.7).

9. Effect of Leaking Gas

Effect on the environment of the gas leak and gas loss in the case of pipe fracture should be investigated. Assuming the gas trapped between two sets of block valves 15 miles apart were to be released, approximately 180 million scf of gas would be discharged into the atmosphere (see sections 3.1.1.6 and 3.1.1.7).

10. Seismic Monitoring

Seismic instrumentation provided along the pipeline route in the vicinity of Flaxman Island, which has a history of seismic activity, should be considered. If any indication of seismic activity is recorded, the pipeline should be carefully re-inspected for leaks via the leak detection system previously recommended (see section 2.1.1.3.C.1.b.1).

11. Operations, Emergency, and Contingency Incomplete

Procedures should be defined for hydrotesting, including the water/methanol disposal, emergency repairs, and health and safety of the personnel. Operations and emergency and contingency planning are necessary and the Applicant proposes to perform this task as a part of the final design of the pipeline system (see sections 1.1.1.6.D.1, 1.1.1.7.A.1 and 1.1.1.7.C.3).

1 CF gas = X CF LNG

?

GAS LNG

2.3 BCF/DAY → IN 2.1 BCF/DAY → OUT

31 X10[12] CF reserves

2.8 x10[9] CF rawgas BCFD

2.3 x10[9] BCFD Feed Gas

2.1 BCFD LNG

Feed Gas = 1050 - 1150 BTU/FT[3]

CONDITIONING PLANT ? FERC EIS complete?

Fault Crossing 49 CFR 192.317 (is silent)

River X-ing 48" O.K. w/ 49 CFR 192.327

F/G Xing 12" O.K. w/ 49 CFR 192.325 but not APSC

FIG 18 Spacing between TAPS u/g & TAGS

1. DESCRIPTION OF THE PROPOSED ACTION

1.1 ARCTIC GAS PIPELINE PROJECT

1.1.1 Alaska Arctic Pipeline

1.1 1.1 Purpose

B. Function of Related Facilities

2) Temperature Maintenance

****

Applicant's Submission

The Applicant proposes a buried pipeline with the gas chilled to a temperature range between 10^{o} and $30^{o}F$ (alternate value is 5^{o} to $25^{o}F$) to maintain the integrity of the permafrost. Field tests are being conducted in Canada to obtain data both on operating and nonoperating installations of buried pipe.

The Applicant presents test results from the Prudhoe research facility on the permafrost thermal balance associated with different pipe burial construction techniques (Battelle, 1974). Four separate pipeline temperature regimes were tested.

1. Dormant period; prior to pipeline operation.
2. Proof test; simulated proof testing with $41^{o}F$ average air temperature.
3. Pipeline operation; operation with average air temperature of $25^{o}F$.
4. Refrigeration system breakdown; several days shutdown after continuous period of operation with chilled air.

The type of construction and pipe temperature operation regime is shown to alter the thermal behavior in the vicinity of the pipe (in a predictable manner). However, it is stated that this alteration as designed and installed has not affected the integrity of the pipeline-soil system.

In the Applicants answer to DOI question 2, for chilled gas operation of the pipeline, it is assumed that the pipe will be warmer than the soil in winter and cooler in summer, resulting in ground water flow reversal to and from the pipe, thus reducing the hazard of frost bulb growth and frost heave.

In later submittals the Applicant presents data and analysis relating to the temperature of an unchilled pipe buried in permafrost and states that the pipeline may remain inactive (unchilled-no gas flowing) up to a year or more after construction.

Analysis of Submission

The Applicant's submission has addressed the effect of several anticipated pipeline temperature operating regimes on the permafrost thermal behavior. The test results have also reasonably verified the thermal predictive model, thus lending credence to their predictive technique.

The test program could not evaluate the effect of gas temperature reduction along the pipeline as a result of the system pressure drop. The temperature history along the pipeline is treated extensively in 1. 1. 1. 3. A. 2. This temperature drop could be on the order of 22.5°F for a chilled gas inlet temperature of 25°F. This lower gas temperature could result in a net yearly heat flux into the pipe from the surrounding permafrost, rather than a net heat flux into the permafrost, as exhibited in the Prudhoe tests, since the average ground temperature at the pipe midpoint quoted by the Applicant is

1.1.1.1.B.2 (cont.)

28°F in summer and 20°F in winter. Though this may provide greater assurance of maintaining the permafrost in a frozen state, it could increase the impact of frost heave, if the soil under the pipeline is unfrozen or contained liquid water prior to the startup of system operation. This groundwater may well be below 32°F and the worst cases will occur in some river crossings where unfrozen ground may be found. There would be, therefore, areas in the pipe route where the pipe would remain colder than the soil throughout the year, and this condition could be critical because the permafrost zone would be higher along the pipeline route and could interfere with drainage from the upslope side of the pipeline, as discussed in section 2.1.1.3.C.4.e.

The Applicants submission has addressed thermal effects of an unchilled pipe buried in permafrost. (NESC-June 1974) Details of the thermal model and computations of mound subsidence and active layer penetration depth are presented. For the cases considered mound subsidence up to two inches with a tendency to side channel and active layer penetration depth up to five feet are shown. However, mound subsidence, side channeling and penetration depth could be much greater than those given since the analytical model does not consider ponding and water flow along the ditch. Consideration of these factors could increase expected values of mound subsidence, or side channeling and of penetration depth. Of particular concern is active layer penetration below the pipe and excessive mound erosion due to subsidence and side channeling.

1.1.1.1.B.2 (cont.)

Penetration of the active layer below the pipe will introduce bouyant forces and freeze back of a water saturated trench will introduce frost heave forces. The Applicant has proposed (see section 2.1.1.3.4.e and 2.1.1.5.B.2) that these two effects be mitigated by an increase in mound or berm height (surcharge). Mound erosion due to subsidence and side channeling will compromise this mitigating measure. Bouyant forces in excess of those expected may act upward on the berm, forming surface cracks which could be widened and eroded by the ponding and water flow action, this also acts to compromise the proposed mitigating measure.

The Applicant should incorporate the factors of ponding and water flow in his thermal model and determine specific site locations for which the mitigating measure of increased berm height (surcharge) is expected to be effective during the life of the pipeline.

Conclusions

- The Applicant's test program has considered most of the important pipeline temperature influences on the thermal behavior of the permafrost. An area not considered, however, is the ground heaving effect associated with initiation of chilled gas operation with an initial water saturated backfill at some river crossings where unfrozen ground may be found.
- The Applicant has considered the case of the unchilled pipe buried in permafrost but his computations of mound subsidence, mound side channeling and active layer penetration depth do not consider ponding and

1.1.1.1.B.2 (cont.)

water flow along the ditch. The production of "unexpected" bouyant forces could lead to berm cracking. This could be a contributing factor to "excessive" berm erosion caused by ponding and water flow along the ditch. Excessive berm erosion will compromise a primary measure proposed by the Applicant to mitigate the effects of bouyant and frost heave forces. The amount of berm erosion that is excessive (in this context) has yet to be quantified.

Recommendations

(a) The Applicant should conduct additional tests and/or analysis to evaluate the worst case high temperature of the ground at pipeline startup combined with a worst case ground moisture content. The lowest anticipated gas temperature should be used once the test is started and maintained throughout the test to demonstrate the effect of frost heave induced on the pipeline.

(b) The thermal, ground settlement and frost heave effects of an unchilled pipeline should be analyzed including ponding and water flow and results provided to the appropriate regulatory and/or statutory agency(s).

(c) The Applicant should incorporate ponding and water flow in his analytical model and determine specific locations for which the proposed mitigating measure of increased berm height (surcharge) is expected to be an effective method to mitigate bouyant and frost heave effects. In addition, the applicant should quantify "excessive" berm erosion.

1.1.1.1.B.2 (cont.)

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comment of Arctic Gas Applicants to Alaska Natural Gas Transportation System Draft Environment Impact Statement — Part II (Alaska)

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

Northern Engineering Services Company Ltd. (June 1974) Application of Geotechnical Analysis for Canadian Arctic Gas Study, Ltd.

Technical Interchange Meeting (October 26 and 28) Alaskan Arctic Gas Pipeline Company and Department of the Interior-Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.3 Facilities

A. Pipeline Description

1) Length, Diameter, Thickness

****

Applicant's Submission

The Applicant states that the design, construction, testing and operation of the proposed pipeline will be in accordance with the requirements of Part 192 Title 49 of the Code of Federal Regulations, Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standard and such other Federal, State and local rules and regulations as may be applicable, and that the line pipe used in Alaska will be 48 in. diameter by 0.8 in. wall thickness grade X70 steel which will meet or exceed the requirements of: (1) the American Petroleum Institute Specification for High-Test Line Pipe (API Spec 5LX), Nineteenth Edition and/or (2) the American Petroleum Institute Specification for Spiral-Weld Line Pipe (API Spec 5LS), Seventh Edition. The nominal strengths of this pipe are yield strength 70,000 psi and ultimate strength the maximum of 82,000 psi and yield strength +10,000 psi. Further metallurgical requirements are contained in CAGSL Specification 2950-6-6. The environmental report contains brief qualitative discussions of the effects of bouyancy, frost heave, differential settlement and seismicity upon the pipe. The discussion contained in the environmental report has been amplified by Volume III of the Final Report of the Alaskan Arctic Gas Study Company which deals with the pipe stress and displacement phenomena observed in an instrumented test loop of pipe installed at the

1.1.1.3.A.1 (cont.)

Prudhoe Bay research facility. The three volume report, Mechanical Stress Analysis of Buried Pipeline" contains detailed qualitative and quantitative treatments of all types of loadings that will be considered in the pipeline design, and presents a Proposed Design Criteria against which the effects of these loadings will be evaluated.

Analysis of Submission

In order to be assured of an adequate factor of safety against pipe rupture it is necessary to evaluate the magnitude of stresses and strains induced in the pipe from all sources, and to compare these stresses and strains to levels at which the pipe will rupture and/or leak. The Applicant's stress analysis document presents detailed discussions of the various loading conditions, the analytical procedures used to evaluate the effect of these loading conditions on the pipe, and a proposed Design Criteria in which allowable values for pipe stresses and strains are established. Each of these aspects of the Applicant's submission are discussed separately below.

Loading Conditions

The Applicant has identified three classes of loading conditions which affect the pipeline:

1) Design Loading

   a) Gas pressure

   b) Hydrostatic test pressure

   c) Temperature differentials

   d) Pipe weight, hydrostatic test medium weight and jacketing weight

1.1.1.3.A.1 (cont.)

2) Seismic Loadings

3) Geotechnical Loadings

a) Differential soil settlement

b) Differential frost heave

c) Bouyant uplift

d) Overburden loads

e) Soil deformation at field bends

The maximum levels for the design loadings conditions are deterministic and appropriate. The seismic loadings levels have been specified by Dr. N. M. Newmark (March 1974). The conservatism of the levels selected for the geotechnic loadings is not so easily determined. The Applicant states that frost heave, differential settlement and soil deformation at field bends will have very low magnitudes in permafrost and cites the Prudhoe Bay test results; for the reasons cited below these results do not necessarily establish that these loadings are insignificant.

The data presented for the Prudhoe Bay test section show axial force, vertical and horizontal bending moments, and vertical displacements of each 800 foot long test leg for a period covering approximately 15 months. The reported results indicate very low pipe stresses as well as small pipe displacements. However, only small credence may be put in the vertical deflection measurements as presented by the applicant since they were made with transmit rather than a level, were conducted by inexperienced surveyors,

1.1.1.3.A.1 (cont.)

1) A criteria for limiting the maximum levels of longitudinal tensile and compressive stresses for all loading combinations are not provided (e.g., bending induced stresses acting concurrently with temperature, pressure and earthquake), and

2) The criteria for stress intensity* (i.e., the value of the sum of the absolute values of the hoop tension and longitudinal compressive stresses) are so liberal for some loading conditions, that yielding of the pipe is permitted.

Part 192.105 states . . . "additional wall thickness required for concurrent external loads . . . may not be included in computing design pressure." A more specific restatement of Part 192.105 is that additional wall thickness is required only if the stresses resulting from loadings other than internal pressure interact with the pressure induced stresses in such a way that the capability of the pipe to resist the internal pressure without yielding is reduced. The use of the Tresca yield criteria is generally accepted as a reasonably accurate and conservative way by which to determine the proximity to a yielding condition when a material is subjected to a biaxial stress condition. The Tresca criteria

*Phenomena described by the Applicant as stress intensity is more correctly designated "Equivalent Tensile Stress"

1.1.1.3.A.1 (cont.)

were not obtained as part of a conventional, closed loop, level circuit and are admittedly not self consistent.

The strain gage data shows that stresses in the test loop were generally low during the 15 month period, but, since the gages were not installed and/or calibrated until after the pipe was in the ditch the installation stresses were not measured. A check of the cross section constants used in data reduction indicates that the data were for a 0.28 in. wall thickness pipe rather than the 0.8 in. wall pipe scheduled for use. No discussion of the correlation between the two pipe sizes is given.

Analytical Procedures

The Applicant has performed comprehensive preliminary analyses in order to determine the severity of pipe stresses and strains resulting from each of the loading conditions, both separately and in combination. It has been adequately demonstrated that the Applicant possesses sufficient technical expertise and computer codes to perform the required analyses.

Design Criteria

The Applicant has provided a detailed design criteria covering allowable stresses and strains resulting from the application of various combinations of loading conditions. (NESC October 1975) These are summarized in Table 1. This criteria does not meet the requirements of Parts 192.103 and 192.105 Title 49 with regard to the allowable combinations of pressure induced loading and other external loadings in two important respects:

TABLE 1. ARCTIC GAS DESIGN CRITERIA[6]

CASE DESIGNATION	LOADING CONDITIONS: DESIGN: Gas Pressure	Temperature Changes	Self Weight	SEISMIC: Design Earthquake	Maximum Earthquake	GEOTECHNIC: Differential Settlement	Frost Heave	Buoyancy	Overburden	Field Bends	ALLOWABLE VALUES: STRESS (% SMYS[1]): Hoop	Longitudinal Tension	Longitudinal Compression[2]	Intensity[3]	STRAIN (%): Hoop	Longitudinal Tensile	Longitudinal Compressive	STABILITY (% CRITICAL)
A	X										72	-	-	-[5]	-	-	-	-[5]
B	X	X									72	72	18	90	-	-	-[5]	80
C	X	X		X							72	72	28	100	-	-	.4	-
D	X	X			X						72	72	38	110	-	.5	.6	-
E	X	X				X	X	X	X	X	72	-	28	100	-	.5	.6	-
F	X	X		X							72	-	-	-	-	.375	.45	-
G[4]									X		80	-	-	-	-	-	-	-
H[4]										X	-	-	-	-	-	-	.285	-

(1) Specified Minimum Yield Strength
(2) Derived from Stress Intensity Requirement
(3) Hoop Tension Minus Longitudinal Compression
(4) During Construction
(5) Dashed Line Indicates Exceedence of Part 192
(6) "Mechanical Stress Analysis of Buried Pipe, Vol. II Structural Design Criteria," Northern Engineering Services Company, Limited, Calgary, Alberta, September, 1975.

1.1.3.3.A.1 (cont.)

predicts the onset of yielding when the equivalent tensile stress is equal to the material yield stress. Equivalent tensile stress is defined as 1) the maximum of the hoop tension and longitudinal tension stresses when both are positive, or 2) the difference of these stresses if they are of opposite sign. Since the explicitly stated stress criterion in Part 192.105 is expressed as a Design Factor (F) times the stress to cause yielding (SMYS), in the absence of other detrimental loadings the proper allowable value for equivalent tensile stress is the same factor times the equivalent tensile stress at which yielding occurs. Numerically the allowable for equivalent tensile stress is equal to maximum hoop stress. The use of a higher factor for equivalent tensile stress results in allowing the pipeline to operate in a stress state which has a lower factor of safety against yielding than that specified by Part 192.105.

The above interpretation of Parts 192.103 and 192.105 is considered to be the proper one to ensure safe operation of the pipeline. This criterion should be applied directly to all loading conditions and combinations which may reasonably be expected to affect the pipe on a continuing basis. It should be noted that longitudinal compressive stresses resulting from external sources are not detrimental, and consequently will not require increased pipe wall thickness to the pipe capability to resist yielding until they exceed the 14,040 psi longitudinal tension induced by internal gas pressure. A moderate increase in the design factor for combined loading conditions involving very infrequent transient conditions such as earthquakes or abnormal temperature

1.1.3.3.A.1 (cont.)

extremes has precedent in ANSI B31.4 which allows an increase from 0.72 to 0.8 for tensile longitudinal stress. Since a gas pipeline is inherently more hazardous than a liquid filled pipeline, a value of 0.8 SMYS for the stress intensity represents an absolute maximum allowable value for these extreme conditions in Zone 1. Proportioned increases could also be allowed in the other zones.

The Applicant, however, states that the pipe may be analyzed using inelastic theory for strain levels up to 0.006 corresponding to stress levels above the yield stress. Part 192 gives no indication that any stress higher than 0.72 SMYS is acceptable; the strain corresponding to 0.72 SMYS = 0.00168. The Applicant's design criteria exceed this value, as shown above (0.006 strain) allowing for yielding of the pipe at some load conditions.

The use of Part 192 for the basic design requirements must be contingent upon those provisions covering the probable failure modes. A separate discussion of Fracture Toughness is provided in Attachment A to this section.

A factor which cannot be dismissed without note is that API X-70 steel represents the upper limit of permissible yield points for all steels covered by the API specification. As such, it represents the lower limit in the ratio of ultimate strength to yield strength, and in ductility. For example, API X-42 steel has a 22% greater spread between its yield and ultimate strengths than X-70 and a 37% greater elongation capability. The corresponding numbers for X-52 are 8% and 26%. Since the same basic code applies equally to

1.1.1.3.A.1 (cont.)

these steels' yield points, it must be recognized that the actual safety factor against rupture is less for the higher strength alloys. Experience gained with the use of more forgiving steels cannot be taken at full face value for X-70 steel.

Conclusions

- o The Applicant has identified all potential significant sources of loading which may influence the pipeline mechanical design.
- o The Applicant has demonstrated a capability to properly perform engineering analyses to predict the internal stresses and strains resulting from the various loading conditions,
- o The Applicant has not shown conclusively that all geotechnic loadings are insignificant. The results of the Prudhoe Bay test loop cannot be readily extrapolated to show that the entire length of the pipeline segment will be free from significant additional loads and temperature induced displacements. It is a virtual certainty the soil and geologic conditions at some points along the route will be more unfavorable than at the test site, and the test loop did not include any segments with significnat vertical curvature. Further, since instrumentation did not become operative until July 1971 at the time of the simulated hydrostatic test no assessment of construction and initial settlement stresses could be made. All that were measured by the strain gages were the changes in stress occurring after 3 July 1971,

1.1.1.3.A.1 (cont.)

- The design criteria proposed by the Applicant does not meet the implied requirements of Part 192 of Title 49 with respect to the effects if interaction between pressure induced stresses and stresses resulting from other loadings, and with respect to the permissibility of strains beyond those corresponding to a uniaxial tension of 0.72 x SMYS.
- The risk of failure of the pipeline during operation is greater than the level corresponding to a pipeline designed in strict accordance with Part 192 of Title 49.
- Specification of fracture toughness parameters have been accomplished so as to ensure ductile behavior of the API X70 steel at the lowest design temperature.

Recommendations

(a) The Applicant should make a comprehensive analytical determination of the maximum stresses that can exist concurrently with pressure induced stresses during pipeline operation. These analyses should cover thermal stresses for the worst possible combination of installation and operation temperature, stresses associated with worst case frost heave phenomena, the effects of bouyancy and the attendant weighing and/or anchoring, differential settlement for the worst anticipated soil conditions, earthquake induced strain effects, pipeline behavior in regions of soil slippage, and the additive effects of construction induced initial stresses. The results of these studies should be

1.1.1.3.A.1 (cont.)

used in conjunction with an appropriate design criteria to determine pipe wall thickness.

(b) The toughness value specified should be an absolute minimum acceptable toughness of the pipe as well as an average minimum.

(c) The design criteria should be revised to that the maximum stress intensity levels do not exceed 0.72 SMYS for all loading combinations expected to occur during normal operational lifetime. This value may be raised to 0.8 SMYS when the loading combinations include extraordinary loads, such as earthquakes, acting concurrently with the other loadings.

References

Canadian Arctic Gas Pipeline Company (1974), CAGSL Specification 2950-6-6, "Large Diameter Main Line Pipe for Minimum Service Temperature of +250°F and -10°F

Code of Federal Regulations, Part 192, Title 49, "Transportation of Natural and Other Gases by Pipelines: Minimum Federal Regulations

Newmark, N. M., (March 1974) "Seismic Design Criteria for Canadian and Alaskan Arctic Gas Pipeline," Urbana, Illinois, March 1974.

Northern Engineering Services Company Ltd (September 1975), "Mechanical Stress Analysis of Buried Pipeline," Vol. II, "Structural Design Criteria"

1.1.1.3.A.1 (cont.)

Northern Engineering Services Company Ltd (October 1975), "Mechanical Stress Analysis of Buried Pipeline," Vol. I, "Preliminary Design Guidelines" Vol. III, "Theory and Structural Analysis"

Attachment A to Section 1.1.3.3.A.1

FRACTURE TOUGHNESS

Any time steel is used at low temperatures, the possibility of brittle or quasi-brittle fracture must be considered. In a gas pipeline where the decompression speed may be less than the speed of a running crack, there is the possibility of a very small flaw initiating a failure hundreds or thousands of feet long. Because of brittle fracture considerations, conventional safety factors based on operating loads and the static strength of the steel are generally insufficient for safe designs at low temperatures. There must be the additional requirement of some kind of notched strength or, as it is generally termed, toughness. There are a variety of test methods for toughness and a variety of ways of relating the values obtained to satisfactory service. Pipe steels undergo a transition from being very ductile at temperatures near ambient (70°F) to very brittle as the temperature decreases. There are a number of methods for defining the minimum suitable temperature for safe operation and the necessary toughness for safe operation.

The Applicant has proposed the inclusion of a drop weight tear test (DWTT) requirement in the material specification to insure against brittle fracture and a Charpy V notch (CVN) requirement to assure adequate toughness. Critical flaw sizes on the order of 6 in. long were calculated on the basis of the specification requirements. The Applicant has also stated that because the minimum operating temperature is above the fracture propagation transition temperature (FPTT), plane stress conditions rather than plane strain conditions will prevail and plane strain based values of critical flaw size are inappropriate. In actuality, the determination of plane stress or plane strain conditions depends on geometry, strength, and stress. To preclude the possibility of plane strain fractures, the plane strain fracture toughness K_{IC}, should be high enough that the failure stress is higher than the yield strength so that for the pipe thickness, plane stress conditions prevail. After examining the available data, we generally concur with the Applicant's approach. The drop weight tear test requirement should, indeed, insure against brittle fracture, although it in itself does not preclude plane strain fracture. Most persuasive is the Battelle work correlating Charpy V notch energies with fracture initiation. Although most of the tests were conducted on steel pipe of lower strength than X65 and X70 and with thinner walls, the tests that have been made on X65 and X70 line pipe made from controlled rolled plate have given comparable results. The only reservation about the test results is that the tests on thick-walled pipes were made with very high Charpy energy pipe rather than with pipe exhibiting the minimum values allowed by the specification. Additional tests are being planned with low Charpy energy pipe to resolve this question.

Atta. A, 1.1.3.3.A.1 (cont.)

One shortcoming of the material specification is that average values of Charpy energy are specified with no absolute minimum. This would appear to allow use of pipe with virtually no toughness because it came from a heat which displayed minimum average values of material toughness. Since the higher pipe steel properties are due primarily to the processing rather than composition, very low toughness properties in some pipe sections could occur. It would be advisable to put an absolute minimum on the acceptable toughness of the pipe as well as an average minimum.

Although of lower importance at this stage, there is a question on the reliability of the Charpy test to measure the type of fracture toughness that determines critical flaw size. Charpy energy is an indirect measure of crack initiation toughness since propagation energy is also included in the value. So long as the partitioning of initiation and propagation energy is unaffected by processing variables, the correlations developed can be expected to hold. It would be desirable, however, to make at least some direct measurements of fracture toughness (such as crack opening displacement tests) to insure that the relative values do not change.

At the present time crack arrest behavior of line pipe made from controlled rolled steels cannot be reliability predicted. The Applicant recognizes this and proposes to use mechanical reinforcement at intervals along the pipelines as a mitigating measure to arrest cracks. In addition, the Applicant states that he has conducted successful tests demonstrating that

Atta. A, 1.1.3.3.A.1 (cont.)

reinforcement bands around the circumference of the pipe will arrest a running crack.

References

Alaskan Arctic Gas Pipeline Co. (24 March 1975), Docket Nos. CP74-239 and CP74-240, Vol. I, Prepared Direct Testimony and Exhibits of Alaskan Arctic Gas Pipeline Company before the Federal Power Commission. Pg 16

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Battelle Columbus Laboratories (October 10, 1975) "Final Report on Examination of Critical Flaw Size Predictions and Fracture Propagation Transition Temperatures in Experimental Arctic Line Pipe" by Wilkowsky, G.M. et al.

Canadian Arctic Gas Pipeline Company (1974), CAGSL Specification 2950-6-6, "Large Diameter Main Line Pipe for Minimum Service Temperature of +250°F and -10°F."

J. F. Keifner, W. A. Maxey, R. J. Eiber, and A. R. Duffy (1973), "Failure Stress Level of Flaws in Pressurized Cylinders," Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536.

W. A. Maxey (November 1974), "Fracture Initiation, Propagation and Arrest," 5th Symposium on Line Pipe Research.

Atta. A, 1.1.3.3.A.1 (cont.)

R. J. Podlasek and R. J. Eiber (1974), "Predicting the Fracture Initiation Transition Temperature in High Toughness, Low Transition Temperature Line Pipe with the COD Test," Trans. ASME, J. Engr. Matls. & Tech., pp. 330-334.

Technical Interchange Meeting (October 27 and 28, 1975) Alaska Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.3 Facilities

A. Pipeline Description

2) Operating Pressure and Temperature
****

Applicant's Submission

In the Application for a Certificate of Public Convenience and Necessity, exhibit G-II, the Applicant presents the formulation and required data used to determine the normal operating temperatures and pressures of the flowing gas, as well as compressor and chilling station requirements. In exhibit G, the Applicant presents flow diagrams which give the predicted pipeline pressure drops and compressor suction gas temperature for maximum daily capability for average summer and winter conditions. Flow diagrams are provided for each of the first five years of operation. No flow diagrams are provided for the peak design flow rate of 4.5 BSCFD.

Analysis of Submission

The formulae used by the Applicant are the industry standards for computation of natural gas pipeline transmission system pressures and temperatures. The physical quantity to be calculated is the gas pressure drop along the pipeline. This requires an adequate determination of the pipe friction factor (or transmission factor). The Applicant employs the method recommended by the Institute for Gas Technology (IGT) for determination of the transmission factor. This method requires the value of the effective pipe roughness. The Applicant, as stated in exhibit G-II, uses a value of 0.0003.

1.1.1.3.A.2 (cont.)

This corresponds to values in general use for very smooth steel pipes, and is reasonable for gas pipelines which are internally coated with corrosion-resistant epoxy. An alternate method of obtaining the transmission factor is to use the empirically obtained "Panhandle B" transmission factor equation (which is based on actual pipeline data correlations) as was done in the Battelle Laboratories (1974) study performed for the Northwest Project Study Group. Under the flow conditions appropriate for the Alaska pipeline, the transmission factor predicted by the two methods are comparable. The pressure drops given in exhibit G (flow diagrams) thus appear reasonable. The Aerospace Corporation checked the results by performing a calculation for the winter-operating year 3 case, which has a flow rate of 2.274 BSCFD (standard). The Aerospace Corporation calculated pressure drop along the pipeline from pipeline entrance to station CA-05 (first compressor station across the Alaska-Canada border into Canada) is 383 psi, while the Applicant's is a comparable 375 psi. The difference in calculated values is not significant.

The gas temperature drop along the pipeline is a function of the pressure drop. With the gas being initially chilled to near the in-depth ground temperatures, the temperature drop along the line is mainly due to nonideal gas behavior. For the case of no heat transfer between the pipe and its surrounding soil, the total enthalpy of the gas would be constant. Since the gas flow Mach number is small, the static enthalpy of the gas is nearly the same as the total enthalpy and is approximately constant. If the gas were an ideal

1.1.1.3.A.2 (cont.)

gas, its temperature would then be constant along the pipe. However, the gas is not ideal and has a nonzero positive Joule-Thompson coefficient $\left(\partial T/\partial p\Big|_h\right)$, so that the temperature drops as the pressure drops along the pipe. For the 2.274 BSCFD throughput case mentioned above, the Joule-Thompson effect alone (neglecting heat transfer to the soil) would decrease the temperature by about 22.5°F. Heat transfer between the pipe and the surrounding soil would reduce this gas temperature drop, for an initial gas temperature of 25°F or less.

The Applicant uses acceptable standard methods (including heat transfer to the soil) for calculating the gas temperature profile along the pipe. Using these methods, calculations made by The Aerospace Corporation indicate a gas temperature at entrance to compressor station CA-05 of 13°F, 8°, and 5°F for an initial gas temperature of 25°F and ground temperatures (at pipe center-line depth) of 28°F, 20°F, and 15°, respectively, with a 2.274 BSCFD flow rate. For an initial gas temperature of 5°F at pipe inlet, the downstream temperatures are 5°F, 0°F, -3°F for mean in-depth ground temperatures of 28°F, 20°F, and 15°F, respectively. From exhibit G-II, the average summer in-depth ground temperature is 28°F, and the average winter is 19-20°F, with the minimum average monthly temperature being 15-17°F. For an inlet gas temperature of 25°F and average winter conditions, the Applicant calculates a compressor suction temperature of 9°F, which is comparable to the 8°F calculated by The Aerospace Corporation.

1.1.1.3.A.2 (cont.)

The temperature results are based on the Applicant's tabulated values of the Joule-Thompson coefficient. These are obtained from calculations using natural gas compressibility factors determined according to AGA procedures, using the Prudhoe Bay gas composition. Battelle Laboratories, in its study, calculates temperature drops for specific cases. A gas enthalpy-pressure-temperature correlation was used in the Battelle calculations. Battelle's estimates for temperature drops, and hence the conclusions, appear to be too pessimistic and are not consistent with results obtained using the Applicant's tabulated values of the Joule-Thompson coefficient (which are reasonable) and midpipe depth soil temperatures. Part of the discrepancy is due to Battelle's using a soil temperature of $0^{\circ}F$. (For a ground temperature of $0^{\circ}F$, a flow rate of 2.25 BSCFD, and a gas inlet temperature of $25^{\circ}F$, the downstream gas temperature at inlet to station CA-05 is calculated by The Aerospace Corporation to be $-4^{\circ}F$.) The Applicant's temperature results appear reasonable.

The Applicant does not provide any flow diagrams for the peak flow rate of 4.5 BSCFD, and thus no indicated calculation of pressure drop is provided. However, in the Applicant's reply to DOI question 24, he states that the compressor station discharge temperature (after chilling) would be $11^{\circ}F$ which would result in a gas temperature of $0^{\circ}F$ at arrival to the next station. Four additional compressor stations are contemplated, with an average distance between stations of approximately 45 miles. Aerospace Corporation calculations of pressure drop between these stations showed a

1.1.1.3.A.2 (cont.)

pressure drop of 292 psi. With a gas temperature of 11°F at each upstream segment of pipe, a downstream gas temperature of 2.5°F and -2°F was calculated for average summer and winter in-depth ground temperatures of 28°F and 20°F. For a ground temperature of 15°F, the downstream gas temperature at the end of a 45-mile-long segment is -3°F. Thus, the Applicant's downstream temperature of 0°F is reasonable, although perhaps a trifle optimistic.

The Applicant does not present any considerations of gas overpressure due to valve closure. Therefore, gas surge calculations were performed by The Aerospace Corporation for the maximum flow rate anticipated for the Arctic Gas Pipeline, 4.5 BSCFD. A peak overpressure of 46 psi is predicted. (For a flow rate of 2.5 BSCFD, a peak overpressure of 26 psi occurs.)

Rapid closure of a valve results in a compression (pressure) wave that propagates upstream away from the valve. An increase in pressure is created which stops the flow. For virtually instantaneous valve shut-off, the overpressure remains at its peak value until the pressure wave is reflected from an upstream obstacle (such as the pipe entrance or another closed valve) and propagates back to the valve. Placement of gas shut-off valves every 15 miles is contemplated. If the first valve downstream of the pipe entrance is rapidly closed, for instance, the reflected wave arrives back at the valve in 160 seconds, relieving the overpressure and causing the decrease in pressure. This condition lasts for another 160 seconds, until another wave

1.1.1.3.A.2 (cont.)

has traveled upstream to the entrance, and back to the valve, when again an overpressure occurs which is less than the original peak value of 46 psi due to fluid friction and pipe losses.

The magnitude of the peak overpressure is independent of the location of the closed valve. The duration of the peak overpressure is approximately 10.8(x) seconds, where (x) is the distance in miles from the valve to the nearest upstream obstacle, such as the pipeline entrance, a compressor station, or another closed valve. If the valve is closed slowly but closure is complete in a time less than 10.8(x) seconds after initiation of valve closing, the same peak overpressure occurs, but the duration is shorter. If complete valve closure takes longer than 10.8(x) seconds, the peak overpressure is decreased. The amount of the decrease depends on the time history of the closing process.

The Aerospace gas flow pressure and temperature, and surge overpressure calculations are shown in the attachment to this section.

Conclusions

- The Applicant's methodology and required inputs for calculating the operating gas pressures and temperatures along the pipeline are appropriate although only average summer and winter soil temperatures are used and this approximation will cause differences in gas temperatures throughout the pipeline. The projected results for the first five years of operation indicated on the Applicant's flow diagrams

1.1.1.3.A.2 (cont.)

in exhibit G appear to be reasonable. However, no flow diagrams are presented for the 4.5 BSCFD throughput case. No results are presented, except that the Applicant states in his response to DOI question 24 that the downstream compressor station inlet temperature would be $0^{o}F$ for an upstream station discharge gas temperature of $11^{o}F$. (Four compressor stations, approximately 45 miles apart, would be added to accommodate the higher throughput.) The Applicant's temperature drop result was checked by Aerospace and results were in agreement.

- The Applicant does not present any considerations of gas surge overpressure due to valve closing, as during emergency shutdown procedures. Nevertheless, the peak overpressure that could occur, 46 psi, is not large relative to the initial gas pressure at the pipeline entrance. This overpressure, if included in determining the pipe design safety factor, would reduce the steady-state operating pressure by only 2.5 percent. Alternatively, should the maximum operating pressure remain at 1680 psig, the safety factor would be equivalently reduced or pipe thickness would be proportionately increased. Minimization of gas loss and gas leak safety hazards would appear to present a strong argument for closing the emergency valves as quickly as feasible, rather than purposely slowing down valve closure time so as to reduce surge overpressure.

1.1.1.3.A.2 (cont.)

Recommendations

(a) The Applicant should provide flow diagrams for summer and winter operation for a nominal 4.5 BSCFD (standard) throughput.

(b) All upstream valves between the location of the emergency (leak, pipe fracture, etc.) and at least the nearest upstream compressor station should be simultaneously closed at rapidly as possible during emergency shutdown. The Applicant should consider the loads induced by valve closure in the pipeline thickness determination under 1.1.1.3.A.1, recommendation (a).

Reference

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

1.1.1.3.A.2 (cont.)

Attachment to Section 1.1.1.3.A.2

OPERATING PRESSURES AND TEMPERATURES

The equations and terminology used by the Applicant and given in exhibit G-II, which are the standard ones in the industry, were also employed by The Aerospace Corporation.

1. Pressure loss from pipe inlet to inlet to CA-05 for $Q_b = 2.274 \times 10^9$ (2.274 BSCFD).

$$P_2^2 = P_1^2 - C_e - \left(\frac{Q_b P_b}{38.774\, d^{2.5}\, Z_b T_b F}\right)^2 GLT_{12}\, Z_{12}$$

Since N_R is greater than N_{R_t},

$$F = 4 \log_{10}\left(\frac{3.7\, d}{k}\right) = 4 \log_{10} \frac{3.7\,(46.6)}{0.0003} = 23.2$$

$$C_e = 0.0375\, \frac{G \Delta h\, P_{12}^2}{Z_{12}\, T_{12}} = \frac{(0.0375)\,(0.665)\,(100)}{(0.65)\,475}\, \frac{2}{3}\, \frac{1695^3 - 1320^3}{1695^2 - 1320^2} = 3 \times 10^4$$

Therefore,

$$P_2^2 = 1695^2 - 3 \times 10^4 - \left[\frac{2.274 \times 10^9\,(14.73)}{38.774\,(46.4)^{2.5}\,(520)\,(23.2)}\right]^2$$

$$(0.67)(224)(475)(0.67)$$

Attachment, 1. 1. 1. 3. A. 2 (cont.)

$$P_2 = 1312 \text{ psia} \quad , \quad P_1 - P_2 = 383 \text{ psi}$$

2. Gas temperature at inlet to CA-05 for $Q_b = 2.274$ BSCFD.

Take $K = 1$, which is appropriate based on the range of frozen ground conductivities given in exhibit G-II:

$$T_2 = T_a + (T_1 - T_a)\, e^{-A}$$

$$T_a = T_g - \frac{(P_1 - P_2)\, J_{12}}{A} - \frac{\Delta h}{jAC_{P_{12}}}$$

$$A = 5280 \frac{2\pi}{\cos h^{-1} \left(\frac{2Z}{D}\right)} \frac{KL}{m\, C_{P_{12}}}$$

$$= \frac{5280\ (6.28)}{\cos h^{-1} \left[\frac{2(41)}{4}\right]} \frac{(1)\ (224)}{\left[\frac{(0.051)\ 2.214 \times 10^9}{24}\right]\ (1)}$$

$$= 0.93$$

$$(P_1 - P_2)\, J_{12} = (383)(0.055) = 21$$

$$\frac{\Delta h}{jAC_{P_{12}}} = \frac{100}{(778)(0.93)(1)} = 0.14$$

For $T_g = T_{ground} = 28^oF,\ 20^oF,\ 15^oF$, then

$T_a = 5^oF,\ -3^oF,\ -8^oF$, respectively

Attachment, 1.1.1.3.A.2 (cont.)

Then, for $T_1 = 25^oF$,

$T_2 = 13^oF,\ 8^oF,\ 5^oF$, respectively

For $T_1 = 5^oF$,

$T_2 = 5^oF,\ 0^oF,\ -3^oF$, respectively

3. $Q_b = 4.5$ BSCFD (L = 45).

P_2: Since $P_1^2 - P_2^2 - C_e \propto Q_b^2 L$ and $C_e \ll P_1^2 - P_2^2$,

$$\frac{\left(P_1^2 - P_2^2\right)_{Q_b = 4.5}}{\left(P_1^2 - P_2^2\right)_{Q_b = 2.274}} = \left(\frac{4.5}{2.274}\right)^2 \frac{45}{224} = 0.79,$$

$$P_2^2 = 1695^2 - 0.79\,(1695^2 - 1320^2)$$

Therefore,

$P_2 = 1403$ psia, $P_1 - P_2 = 292$ psi

T_2: $A \propto L/Q_b$

Therefore,

$$A = \frac{45}{224}\,\frac{2.274}{4.5}\,(0.93) = 0.095$$

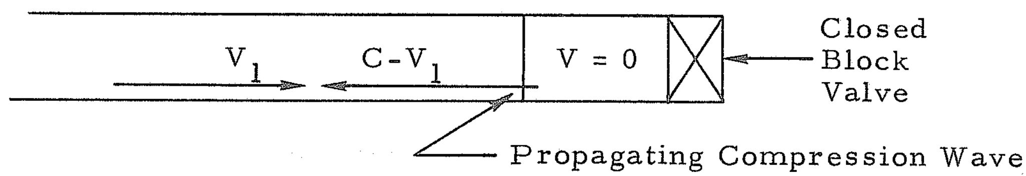
For $T_g = 28^oF,\ 20^oF,\ 15^oF$, then,

with $T_1 = 11^oF$,

$T_2 = -2^oF,\ -2.5^oF,\ -3^oF$, respectively

Attachment, 1. 1. 1. 3. A. 2 (cont.)

4. Gas surge peak overpressure (Q_b = 4.5 BSCFD).



Valve closure initiates a shock wave traveling at velocity C relative to the undisturbed gas. The overpressure due to valve closure is the pressure increase across this compression wave.

$$\Delta P = mC = \frac{P_b Q_b}{g\ RT_b\ Z_b \frac{\pi}{4} d^2} C$$

$$C = \sqrt{\gamma,\ RT,\ Z,\ g} = \left((1.29) \frac{1544}{19.25} (4.75)(0.62)(32.2) \right)^{1/2}$$

$$= 985 \text{ ft/sec}$$

Therefore,

$$\Delta P = \frac{(14.7)\ (4.5 \times 10^9)/(24)\ (3600)}{(32.2)\ \frac{1544}{19.25}\ (520)\ (1)\ \frac{3.14}{4}\ 4}\ (985)$$

$$= 46 \text{ psi}$$

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.3 Facilities

C. Description and Operating Characteristics of Plants, Compressor Stations, and Related Facilities

1) Treatment, Measurement, and Compression

****

Applicant's Submission

For the initial period covered by this submittal, building up to a flow of 2.24 BSCFD, there are no provisions for compressor facilities in Alaska with exception of the Prudhoe Bay station.

Four maintenance station locations are identified as sites for future expansion into compressor stations, if deliveries increase to 4.5 BSCFD. A gravel-padded area is planned for these maintenance sites so that required building and equipment to be added for such conversion could be accommodated. In a later submittal, the Applicant stated that each compressor site is 1200 x 900 feet or approximately 25 acres. A separate environmental impact assessment would be made prior to such action.

The four future compressor stations would be similar in design, and a typical station description is given. The submittal identifies the additional buildings for housing operating equipment and ancillaries needing weather protection. At each site, it is proposed to install a single nominal 27,500 or 30,000 HP gas turbine driver and centrifugal gas compresor to recompress the pipeline gas flow from suction pressure to 1680 psig. The suction side

1.1.1.3.C.1 (cont.)

of each compressor would include gas scrubbers to protect against particulate ingestion such as condensed liquids or dirt. The compressors would be equipped with surge controls. The gas turbine drive units operating on air and natural gas bled from the pipline would have an intake air anti-icing system in addition to filters and equipped with intake and exhaust silencers.

As gas-turbine-driven (17,000 HP) refrigeration system using propane as a refrigerant would be installed to cool the recompressed delivery gas to sub-freezing temperatures. This is done in order to maintain the perma-frost temperature levels along the buried pipeline. The propane, contained in a closed loop, would extract the heat of (mainline gas) compression using surface heat exchangers referred to as "gas chillers" by the Applicant. The major equipment items would all be housed, except for the air-cooled propane condensers (not to be confused with the above-mentioned chillers) and the propane receiver. The submission states that the stations would be operated by remote automatic control from the Gas Control Center. While all prime movers (turbines) would be natural-gas-powered, the on-site turbine generators for electrical power could switch to standby liquid fuels in emergencies. All buildings housing equipment containing natural gas or propane would contain gas leakage detectors, flame detectors, alarm signal systems (at Gas Control Center), automatic shutdown capability, and inert gas fire-fighting systems. During an emergency shutdown, 3750 MSCF of

1.1.1.3.C.1 (cont.)

natural gas within the station block valving would be vented to atmosphere. Emergency venting of propane would be accomplished automatically upon detection of fire within the propane compressor building. However, the pressurized propane would not be vented to atmosphere; instead, it would go to a closed-flare system.

Design equations, data on likely gas composition and properties and related information dealing with compressor station equipment sizing analyses to support the information given are contained in exhibit G of the submission. Impurity levels are given in a supplement to the submission, and other information which states that formations of liquid hydrocarbons is highly unlikely are also provided.

Clarification of certain information contained in the submittal is provided in response to DOI question 24. Basically, the Applicant states that specifications are as yet preliminary. Analyses have been carried to the point of assessing and assuring availability of major equipment items using conventional state-of-the-art technology. Equipment selection, including possibly multiple units at a compressor station, would be made on the basis of providing lowest cost service at the optimum volume. The stations would be designed to operate unattended.

Matters regarding operating safety in the question response provide some new information. Sensors are planned for protection of compressors from

1.1.1.3.C.1 (cont.)

excessive vibration and bearing temperatures, and also there would be isolation valves for the pressurized propane in the refrigeration system, if a fire should occur. Emergency battery power is planned and manual operation of certain emergency valves has been considered.

There is one measurement station planned for Prudhoe Bay, and another would be located in Canada. Multiple meter runs, including a spare would be provided and housed in buildings. Gas composition measurements would be made. Decisions concerning equipment types will be finalized as part of the final design process. Gas water content and other contaminant levels would be kept within the limits specified which are stated to be commensurate with good pipeline practice.

Analysis of Submission

The compressor station description is typical for gas pipeline transport systems, except for the propane refrigeration system needed to protect the permafrost by chilling the pipeline flow.

All proposed compressor facilities should be designed, constructed, and operated in compliance with Part 192, Subpart D, Title 49, Code of Federal Regulations, "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards." Facilities construction should also be in accord with OSHA requirements. In a later submittal, the Applicant stated that he will comply with all appropriate rules and regulations.

1.1.1.3.C.1 (cont.)

The trend in modern pipeline systems is toward a single large gas-turbine-driven centrifugal unit. The use of single large compressors at each station may be defended from an economic standpoint. Process industry experience has shown that trouble-free operation of gas compressors is obtainable with the use of diagnostic monitors such as vibration, temperature, and proximity sensors, to prevent damage by warning of changes in the condition of rotating machinery (Wett, 1973; Jackson, 1974). One paper noted, however, that it may not be desirable to depend entirely upon a single large piece of rotating equipment for each train. Expected downtime required for routine maintenance and availability of units during the first five operating years was given for the Prudhoe Bay compressor facilities. Descriptions of these facilities show eight compressors in the first stage train.

The basis used to establish compressor power requirements is conventional. A crosscheck of the Applicant's submission shows that a 30,000 CHP compressor (80 percent polytropic efficiency) is capable of handling 4.5 BSCFD of gas having the Prudhoe Bay composition (85.11 vol. % CH_4, exhibit G-II) with a repressurization approach 325 psi to an outlet of 1695 psia.

The fact that the Applicant stated the need for anti-icing equipment on turbine intake air is noteworthy. Problems with turbine operations in the North Slope region owing to the lack of proper attention to this detail have been reported (Stenson, 1972). The low temperatures have contributed to

1.1.1.3.C.1 (cont.)

ice fog formation (especially in the vicinity of a water vapor source such as engine exhaust), and other weather difficulties. Turbine damage (air compressor), power losses, and frequent shutdowns have resulted.

Several questions appear with regard to operating safety of the refrigeration system. The Applicant's statements indicate how the propane would be handled in case of a fire. Propane venting to atmosphere must be avoided because the vapors are denser than air. It is not practical to prevent total leakage in normal operations, and, in the event of a fire, the risk of encountering a serious leakage situation within a building is greatly enhanced, and thus the danger of a severe accident resulting is also enhanced. It is understandable that the Applicant should consider propane as a likely refrigerant, as it is probably the most economical readily available fluid.

Conclusions

- Considering the facts that no compressor stations are included in the initial request and extensive lead time is involved before expansion is anticipated, a satisfactory amount of general information has been supplied.

1.1.1.3.C.1 (cont.)

Recommendations

(a) Future design data submitted to the appropriate regulatory and/or statutory agency(s), for approval of compressor status should include capability for uninterrupted gas flow during maintenance operations or during single compressor failures. The remote location of these compressor stations in a rugged environment focus the attention on high reliability of controls and on safety devices.

(b) The Applicant should examine the safety aspects and industry experience involving the use of propane as a chilling fluid versus other non-flammable refrigerant alternates.

(c) A unique feature of buried natural gas pipeline transport systems in permafrost is represented by the need to chill compressed gas. Part 192, Title 49, Code of Federal Regulations dealing with compressor station design safety overlook such refrigeration facilities. This code must be revised.

References

Alaskan Arctic Gas Pipeline Company (November 15, 1974), Supplement to Application-Docket No. CP74-239.

Alaskan Arctic Gas Pipeline Company (January 30, 1975), Formation of Hydrocarbon Liquids in the Pipeline - Response to FPC/DOI Oral Question.

1.1.1.3.C.1 (cont.)

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments to the Alaskan Natural Gas Transportation System Draft Environmental Impact Statement-Part II (Alaska)

Jackson, C., "Care in Installing, Maintaining Rotating Equipment Keeps Big Methanol Plant on Line," The Oil and Gas Journal, December 23, 1974.

Stenson, D. R., "Air Filtration Experience, Arctic Applications," SOLAR Divison International Harvester Company for Presentation at Gas Turbine Conference, San Francisco, California, March 26-30, 1972.

Watt, T., "Compressor Monitoring Protects Oelfins Plant's Reliability," The Oil and Gas Journal, September 10, 1973, p. 120.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.6 Construction Procedures

B. Unique Pipeline Construction Techniques

1) Ditching and Snow Roads

****

Applicant's Submission

The Applicant proposes to use conventional pipeline construction techniques whenever possible. The Applicant indicates that 75 percent of the length would be excavated by a wheel-type ditching machine and that blasting may be required in certain types of ground. The Applicant has conducted a ditcher testing program in frozen silts during the winters of 1972-73 and 1973-74, at Churchill, Manitoba on special heavy-duty wheeled ditching equipment designed for arctic service.

In a later submittal, the Applicant states that these tests using special heavy duty teeth show encouraging results. Ditching machines used were new generation prototype machines weighing approximately 200,000 pounds and having total power of approximately 1100 hp. These tests have also been conducted in hard shales.

Further development of new teeth and machines is being conducted. This work is directed toward development of equipment that will have greater productivity in excavating permafrost. Larger ditching machines being pursued weigh 350,000 pounds and have a total power of 3500 hp.

The Applicant proposes to substitute a snow pad over the right-of-way in lieu of the usual work bed. Snow roads are also proposed for the construction road infra-structure used to transport men, supplies, material,

1.1.1.6.B.1 (cont.)

and equipment from the coastal sites to the maintenance camps, along the right-of-way and to and from the borrow pits. Approximately 195 miles of right-of-way (90 feet wide) and 200 miles of infra-structure (30 feet wide) are required.

Feasibility of snow roads for heavy traffic was investigated by the Applicant in the NESC Inuvik test program (1975). Snow roads were prepared by building up thin layers of snow, consolidated layer by layer with water. Snow utilized for these tests included that derived from natural ground cover, from harvests off the top of a frozen lake, and from snow manufactured from water using comerically available snow making machines. The Applicant further states in a later submittal that snow for the roads and right-of-way along the prime route in Alaska will be derived from these sources plus derived by controlled snow drifting using fences as described in CREEL. In a further submittal, the Applicant states that high production snow making equipment is under development and will be tested the winter of 1975.

In the applications Environmental Report (Tab F) the proposed construction schedule shows snow and ice roads construction starting in early September and terminating in late December. Grading is shown beginning in early November and terminating in late December. In the schedule, snow fence erection would take place in September and snow road construction would begin in October. These roads and right-of-way would support pipeline construction which is scheduled to begin on 1 October and terminate 31 May (212 calendar days).

1.1.1.6.B.1 (cont.)

In a later submittal, the Applicant recognizes that early winter natural snow cover may be insufficient to provide the roads and right-of-way required to support the construction schedule, and in that eventuality proposes to initiate early winter construction with roads and right-of-way initially constructed of manufactured snow and of snow packs formed by snow fences. The Applicant has estimated water requirements for each of the proposed construction spreads, D, A and B. The data provided by the Applicant is summarized in Table 1. As can be seen from the table, two cases have been considered and total snow road and pad requirements are estimated to lie between 2,283,000 barrels (318 acre-feet) and 3,600,000 barrels (500 acre-feet) of water. The Applicant further states that this water requirement would be in October and November.

The Applicant identifies additional requirements for water for Construction Spread A in his response to DoI question 41, and states that the majority of the lakes in the vicinity of the pipeline right-of-way are shallow, do not appear to contain fish population and probably freeze solid at some time during the winter. In addition, the Applicant notes that of the rivers crossed by the pipeline in spread A, only the Tamayarik and the Okerokovic were flowing at the point of crossing in early November 1973. In addition, the Applicant notes that flow rates were recorded at the Sadlerochit Springs, approximately six miles upstream of the pipeline crossing and at the Hula Hula River about three miles downstream of the crossing.

The Applicant further states that water field surveys will be conducted prior to construction, that information obtained from these surveys

TABLE 1. WATER REQUIRED TO MANUFACTURE SNOW ROAD AND SNOW RIGHT-OF-WAY

CASE	SPREAD MP TO MP STAGING	D 0 to 65 PRUDHOE BAY	A 65 to 130 CAMDEN BAY to MP 100 to CA 02	B 130 to 195 DEMARKATION BAY to MP 190 to CA 04	TOTALS
I	ROADS (MILES) R.O.W. (MILES) WATER (BARRELS)	10 10 530,000	31 10 971,000	22 10 782,000	63 30 2,283,000
II	ROADS (MILES) R.O.W. (MILES) WATER (BARRELS)	20 20 1,060,000	34 20 1,354,000	26 20 1,186,000	80 60 3,600,000

Note: To manufacture snow for a road 30 feet wide and 18 inches deep, with a density of 0.5 grams/cc requires 21,000 barrels of water per mile of road

Note: To manufacture snow for a right-of-way (R.O.W.) 90 feet wide and 9 inches deep, requires 32,000 barrels per mile of right-of-way.

Note: 1,000,000 barrels of water is equivalent to 129 acre-feet of water.

1.1.1.6.B.1 (cont.)

will be used to develop an environmentally acceptable water withdrawal program, and that the sources from which the water requirements will be obtained and the amount to be taken from each source will be developed after this survey is complete.

Analysis of Submission

The arctic region with its sub-freezing temperatures requires methods that deviate from the more usual gas pipeline construction techniques, specifically:

1. Ditching in large expanses of permafrost
2. Use of snow for roads and right-of-way work pad

The Applicant states that his testing programs on ditching equipment are progressing, but does not state the degree of reliability and maintainability that ditching equipment has or is expected to experience in use in the arctic environment.

Previous ditching tests performed in frozen gravel for the hot oil pipeline indicated that in the case of frozen gravels, equipment wear was extreme and excavation rate were very low. The Applicant states that development of larger, more powerful ditching machines with special heavy duty teeth that will have greater productivity in excavating permafrost are being sponsored. This work should be continued.

The Applicant plans to use snow for roads and right-of-way work pads. Practices for construction and use of the snow roads is defined by the results of testing done by NESC at Inuvik, Northwest Canada. The

1.1.1.6.B.1 (cont.)

construction schedule is stated to be from October 1 to May 31. The Applicant recognizes that sufficient snowcover may not be available to support the early winter portion of this construction schedule and proposes to manufacture snow from water to meet snow road and pad requirements in October and November. Water requirements are presented for manufacture of snow roads and pad for the early months for all construction spreads (Table 2) and water requirements to meet other construction needs defined as ditch flooding, camp requirements, hydrostatic test were presented for construction spread A (Table 1). The Applicant states that a preconstruction survey of water sources and a water withdrawal plan that is environmentally acceptable will be formulated as part of the final design phase.

In the Inuvik tests, it appears that roads with a Rammsonde hardness of 450 or greater could withstand heavy equipment traffic provided ice capping on bends and slopes as well as repair and maintenance was continually provided. An effective repair method used was to lay down a mixture of sawdust or chips and freeze it into place by application of water. However, in a later disclosure the Applicant states that this repair method will not be used along the North Slope. An alternative repair method has not been proposed by the Applicant.

The Applicant examined the effect of a snow road upon the underlying vegetation in the Inuvik tests. The effect on the vegetation, as determined after the spring that, appeared negligible; however, the site

TABLE 2. WATER REQUIREMENTS (BARRELS) FOR CONSTRUCTION SPREAD A

USAGE	NOV.	DEC.	JAN.	FEB.	MAR.	APR.
1. Snow and Ice Roads	340,000	340,000	340,000			
2. Ditch Flooding			21,000	21,000	21,000	6,000
3. Camp Requirements	20,000	15,000	55,000	55,000	55,000	10,000
4. Hydrostatic Testing			40,000			
Monthly Requirement	350,000	355,000	456,000	76,000	76,000	16,000
Daily Requirement	11,700	11,500	14,700	2,700	2,700	500
Estimated Maximum Daily Withdrawal Rate	15,000	15,000	20,000	5,000	5,000	5,000

selected for the tests did not represent windswept tundra and the difference should be evaluated by the Applicant.

More information on the survival of arctic vegetation under snow roads is given in the "Environmental Impact Assessment" of the Canadian Environmental Board regarding the Alaska to Alberta pipeline. For roads built according to the best practice, the organic mat (peat) was preserved, although compressed 25 percent, the thaw increased in the first year by 65 percent, and plant recovery was 10 percent.

Another source of information on the effect of snow roads on vegetation may be obtained from the Battelle report on Prudhoe Bay test site in which various lanes of unprepared snow surface (11 to 19 inch snow cover) were subjected to a single pass or multiple passes of heavy equipment such as the Caterpillar D-9 tractor. The tests have shown that the resulting compression of the low density hoarfrost above the vegetation flattens and breaks standing dead or live vascular and cryptogamic vegetation. The thaw depth was not affected after one year, but biomass and plant productivity were adversely affected which may result in a long term alteration of the environment.

The Applicant has recognized that a portion of the total snow road and snow right-of-way requirements may be satisfied using manufactured snow. The Applicant has stated that testing of high production snow making machines will proceed in the winter of 1975. The Applicant has presented (potential) water requirements for roads manufactured completely from manufactured snow for all construction spreads, and has provided a partial listing of additional water requirements. In addition, the Applicant has stated that a complete water withdrawal plan will be developed based on a survey to be completed sometime prior to construction.

An estimate of the water requirement for construction spreads D, A and B is shown in Table 3. As can be seen from the Table a light snowfall year approximately 5,319,000 barrels (710 acre-feet) could be required. The Applicant should immediately develop a water withdrawal plan to demonstrate that such an amount of water is available.

In addition, independent of the amount of snowfall, the use of snow roads for heavy traffic during the month of May may be marginal. The report of the Muskeg Research Institute on the use of lumber roads in Richard Island during spring thaw led to the conclusion that the traffic halt is a combination of exposed tundra, thickness of snow, etc., but that as a guide air temperature of 10-20°F with bright sunlight and light winds appears to be the limit. From the NESCL report on geothermal analysis, air temperatures in the northern coastal zone in May were between a maximum of 28.4°F and a minimum of 16.8°F. It would be prudent, therefore, to not count on any heavy traffic on snow roads in May to avoid local destruction of the tundra. The Applicant should develop a construction concept which provides an alternative to the use of snow roads at the end of the construction season.

TABLE 3. CONSTRUCTION WATER REQUIREMENTS (ESTIMATED

		Construction Spread	
	D	A	B
o Road and Pad Requirements			
Manufactured (miles)	20	41	32
Normal (miles)	110	101	104
Total (miles)	130	144	136
o Water Requirements			
1. Manufactured (bbls)	530,000	971,000	782,000
Normal (bbls)	790,000	720,000	740,000
Subtotal (bbls)	1,320,000	1,691,000	1,522,000
2. Ditch Flooding (bbls)	69,000	69,000	69,000
3. Camp (bbls)	210,000	210,000	210,000
4. Hydrostatic Testing (bbls)	40,000	40,000	40,000
Subtotal (bbls)	1,639,000	2,010,000	1,680,000
TOTAL (bbls)		5,319,000	

In addition to the water availability issue, there is the question of water transportation to the road and pad sites. In snow road construction and trafficability tests conducted at Norman Wells NWT (CAGS - 1974), three various trucks were used to haul water. The larger truck, which was finally used to complete the job, was equipped with its own pump and drew water directly from Bosworth Creek at a temperature of 32°F. This truck was a FWD, six-wheel drive tank truck, with a capacity of 3,700 gallons (880 barrels), and weighed 65,000 pounds.

The use of such equipment to support snow road construction from October through December would require that it exist in a low ground pressure configuration, be equipped with suitable water extraction and application equipment, and be insulated with/or heated to preclude in situ freezing of the water load. The Applicant should describe the equipment to be used to support snow road construction.

Conclusions

- Additional development of ditching and blasting techniques is required. The Applicant's development work in this area should be continued.
- In the eventuality of a light snow year, snow will be manufactured to provide that portion of the snow road and pad provided to support a construction start of 1 October. This will require a large water supply. A water withdrawal plan has not been developed by the Applicant.

1.1.1.6.B.1 (cont.)

- The nature and special characteristics of the water tankers that would be used for snow road and pad construction have not been defined. These tankers are anticipated to require a low ground pressure configuration and to be insulated and/or heated to preclude in situ freezing of the water during transportation from the extraction point to the road/pad site.
- The use of snow roads and pads for heavy traffic during the month of May is considered marginal. Combinations of sunlight, air temperatures, and wind speed prevalent during this month may lead to thawed soft surfaces. Traffic under these conditions may be harmful to the underlying vegetation.
- The entire problem of constructing a pipeline in the hostile environment of the North Slope of Alaska within the time frame of approximately five months must be addressed, providing for all contingencies and demonstrating ability to complete the project and successfully establish chilled gas flow after the pipeline is inactive for a summer thaw.

Recommendations

(a) The Applicant should provide a detailed plan for developing ditching and blasting techniques appropriate for ditching in frozen gravels and other stubborn permafrost areas.

(b) The Applicant should provide a Snow Road and Pad Construction Plan. This Plan shall include design criteria, anticipated water requirements and a description of all equipment and

1.1.1.6.B.1 (cont.)

vehicles required to support road and pad construction in a light and normal snowfall year. This Plan should be provided to the appropriate statutory and/or regulatory agency(s) for review and approval.

(c) The Applicant shall provide a Water Requirements and Availability Plan. This Plan shall include a statement of total water requirements for snow road and pads, and all other requirements for all construction spreads. Water sources and withdrawal rates shall be identified. The equipment to be used to transport water without environmental impact shall be identified. This Plan shall be provided to the appropriate regulatory and statutory agency(s) prior to issuance of permits.

(d) The Applicant should provide test data substantiating the feasibility of wheel-type ditching equipment for use in permafrost, particularly in frozen sand or gravel. In a later disclosure, the Applicant stated that new vehicles with improved wheel teeth materials are under development. This work should be continued.

1.1.1.6.B.1 (cont.)

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comment of Arctic Gas Applicants to Draft Environmental Impact Statement for the Alaska Natural Gas Transportation System-Part 11 (Alaska).

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Battele Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

Battelle Columbus Laboratories, 1972, "Prudhoe Bay Test Facility Over-snow Vehicle Impact Studies."

Canadian Arctic Gas Study Ltd. (April 8, 1973) Snow Road Construction and Trafficability Tests Norman Wells Northwest Territory.

Cold Regions Research and Engineering Laboratory (May 1972) Special Report 172 Literature Survey of Cold Weather Construction Practices by Havers, J. A. and Morgan, R. M.

Cold Regions Research and Engineering Laboratory (January 1975) Accumulating Snow to Augment The Fresh Water Supply at Barrow Alaska by Slaughter, C. W. et al.

1.1.1.6.B.1 (cont.)

Environmental Protection Board (Canada), (September 1974) Environmental Impact Assessment of the Gas Pipeline from Alaska to Alberta, Volume 4.

Muskeg Research Institute (May 1973), "Factors Affecting Use of Winter Roads during Spring Thaw," A Report to Arctic Petroleum Operators Association, University of New Brunswick.

Northern Engineering Services Company, Ltd. (June 1974) Application of Geotechnical Analysis for Canadian Arctic Gas Study Ltd.

Northern Engineering Services Company, Ltd. (December 1974) Application of Geothermal Analysis Appendix B-1F Graphical Representation of Climate Along the Pipeline.

Northern Engineering Services Company, Ltd. (March 1975) Drainage and Erosion Control Measures Description and Proposed Design Principles.

Northern Engineering Services Company, Ltd. (June 1975) Inuvik Snow Road Construction, Testing and Environmental Assessment 1973-1974 Inuvik, Northwest Territories, Canada.

Technical Interchange Meeting (October 27 and 28) Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.6 Construction Procedures

B. Unique Pipeline Construction Techniques

2) Backfill and Bedding
****

Applicant's Submission

The procedures which the Applicant intends to follow with respect to backfill and bedding are as follows: The topsoil and organic material will be used according to good pipeline practice to provide a uniform support for the pipe in cases where ditch bottom is irregular. Native backfill will be replaced in the ditch and covered with the previously removed topsoil and organic matter both directly over the ditch and with some side overlap. Where appropriate, Applicant intends to replace select backfill in the ditch in place of exceedingly ice rich soil. Borrow required will be obtained from borrow sites located on the project strip maps and alignment sheets. Reassessment of these locations is continually underway. Typical borrow pit development plans have been shown in the back-up document "Pipeline Related Borrow Studies" which was submitted in answer to DOI question 19. In addition the Applicant presented revegetation specifications for all disturbed areas along the prime route. Also, Battelle conducted a test program on backfill, and the reports are provided in response to DOI question 25.

Analysis of Submission

The Applicant recognizes the need for pipe protection for rough ditch conditions. He has specified the use of a bedding of processed spoil or borrow material, where the bottom is rough or uneven. Criteria for this bedding and the conditions requiring such criteria should be developed by the Applicant.

The Applicant does not state that he would completely comply with all of the Battelle recommendations to preclude subsidence and ponding when high ice content backfill materials are utilized. To remedy the subsidence and ponding problems, the use of supplemental borrow, 50 percent overfill, and side overlap over the ditch are cited by Battelle; such side overlap would be required to prevent thaw depressions and to impede ambient thermal inputs into the ditch walls. In a later disclosure, the Applicant stated that bedding material will be used to provide a uniform support for the pipe and that where appropriate he will replace ice-rich soil with selected backfill. The topsoil and organic material will be removed and preserved to cover the berm over the pipe. The practicality of this procedure should be demonstrated before the pipeline design is finalized. The Applicant should also ensure that sufficient compacting of the backfill is done to minimize ground subsidence during spring and summer. This, however, does not solve the problem of differential subsidence due to voids and ponding as the backfill settles. The Applicant presented in the NESCL report, "Pipeline Related Borrow Studies," (1974) the location of four borrow sites in the Alaskan part part of the pipeline, their potential yield and the pipeline borrow requirements. It appears that the pipeline requirements should be amply satisfied.

1.1.1.6.B.2 (cont.)

A plan for rehabilitation of the borrow sites to mitigate the environmental impact was provided by the Applicant. (See section 3.1.1.2.B.1)

Pipeline sections will be delivered to the field already coated with corrosion protective coatings, except in the area of the ends which must be welded. These areas would be coated in the field after the welding operation is completed. The Applicant has not provided any criteria for the inspection of the individual lengths of pipe for damage prior to incorporation into the pipeline, nor has he provided criteria for inspection of the pipeline prior to and subsequent to other required operations.

The pipe sections and protective coatings (internal and external) may be damaged during any phase of construction and inspections would be required at each step to preclude damaged sections from being included in the pipeline and to permit identification of damage and corrective measures to be taken.

Conclusions

- The results of the Applicant's backfill test program pointing to the need for supplemental borrow, 50 percent overfill, and side overlap appear valid and should be instituted.
- Bedding criteria are required to assure uniform loads on the pipeline.
- Inspection criteria are required prior and subsequent to each operation.

1.1.1.6.B.2 (cont.)

Recommendations

(a) The Applicant should identify not only the quantity of sources, but also the quality and suitability of material, particularly in areas where existing ice-rich soil is to be replaced with borrow for control of subsidence. Mixing processes and restoration plans should be included.

(b) The Applicant should provide criteria for bedding material to be used to support the pipe to prevent the introduction of local stresses in the pipeline. This should include criteria for trench conditions which require the use of bedding material.

(c) The Applicant should provide inspection cirteria for the pipe, welds, and coatings for all stages of construction from pipeline stringing through lowering-in and backfilling. This should include repair and inspection procedures for damaged areas.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to The Aerospace Corporation Geotechnic Evaluation 15 March 1975.

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

Northern Engineering Services Company, Ltd., (1974) Pipeline Related Borrow Studies.

Northern Engineering Services Company, Ltd., (September 1975) Preliminary Pipeline Revegatation Specifications For Areas North of 10^{o}

****

Applicant Submission

Compressor stations would not be built in the first five years of the pipeline operation, and the construction of compressor stations would be the subject of a separate application. Permanent buildings would be placed on granular pads of sufficient thickness to prevent degradation of the permafrost.

"The Applicant submitted NESCL thermal studies on the time history of soil temperature under 5-ft gravel pads. In the two cases considered by the Applicant and pertaining to the Alaskan Coastal environment, the depth of the active layer below the pad was less than that outside of it and the subsidence cuased by compression of surface peat was small."

Analysis of Submission

Possible approaches for maintenance of the permafrost are providing (1) either ventilation space between the structure and the ground surface, (2) a ventilation duct system, or (3) a thick gravel pad. The Applicant has not provided any analysis to show that a gravel pad would be an acceptable solution for a steady-state heat input into the ground from the operation of heat-generating equipment and the heated building itself. In making any

1.1.1.6.C.2 (cont.)

analysis, the radiant heat collected by the exterior walls of the building and conducted to the ground must be added to any internally generated heat. It appears, however, that this proposal is incompatible with maintenance of the permafrost and methods, such as air-cooled or refrigerated pad, pile driven into permafrost with adfreeze provisions, or the thermopiles may be required. In a later submittal the Applicant stated that those informations would be obtained as part of the final design phase.

The topography and geology of the sites are discussed in section 2 of the environmental report. Foundation systems for the building facilities, workpads, roads, airfield, and communication would all require design for permafrost and soil conditions quite similar to those now existing at Prudhoe Bay. While utilization of similar foundation concepts may be appropriate for these sites, the design analysis for specific foundation units should be based on appropriately selected parameters. Sufficient justification for selection of such design parameters, including detailed subsurface soils information, is required for each site.

In particular, the proposed location of the second compressor station CA-02-MP 83.0 may not be optimum. The location is questionable, since it is within the ice-rich silt-mantled deposit with the possibility of high thermal sensitivity and potentially unstable massive ice. A single test hole, AG 546, has been placed adjacent to the proposed site and disclosed highly ice-rich material to the full depth of the 20-foot boring. A second boring, AG 545, placed approximately one mile west of the site in a lower lying old outwash

1.1.1.6.C.2 (cont.)

deposit, encountered 15 feet of well graded gravel. Problems associated with these foundation conditions range from high sensitivity to thermal erosion and degradation to unacceptable creep or strains for moderate loading on piles placed in the massive ice and ice-rich soils. The potential for headward gulley advancement toward the proposed station site, particularly in view of the imposed construction activity, should be evaluated, since any such erosion could extend into the site within a short period of time.

Based on the single test hole (AG 546 results), it appears that the outwash deposit could provide significantly better foundation and site development conditions than those that exist at the presently proposed compressor station site.

The Applicant's proposed Compressor Station CA-03-M.P. 129.2 would be located in the transition area between the Arctic Foothills Province and the Eastern Arctic Coastal Plain Province. The station site would lie approximately one half mile west of the Jago River, situated on a fossil flood plain generally containing up to several feet of silty sand overlying well graded sandy gravels.

The Applicant's test hole AG 567 was placed adjacent to the proposed site, encountering silty sand to a depth of 2.5 feet continuing through sandy gravel to the depth of the boring, which was terminated at 17 feet below ground surface. The soil data indicated relatively high moisture contents for the frozen sandy gravel. Presence of thawed ground is not expected in

1.1.1.6.C.2 (cont.)

this soil unit, except possibly adjacent to shallow drainages or the river bluff.

Foundation conditions for this soil unit are expected to be good; however, the high moisture contents noted for the underlying frozen gravel indicate that thaw settlement strains must be considered if thermal degradation extends down to this material. The airfield is shown to be located in the thicker ice rich silt mantle terrain unit and, as such, would be built on poorer foundation materials.

Compressor Station No. CA-04 would be located in the Eastern Arctic Coastal Plain Province, approximately 3.5 miles east of the Kongakut River. The site would be situated on an alluvial fan deposite typically containing thin silt cover overlying silty-to-clean sand and gravel having relatively low ice contents. Permafrost is essentially continuous.

Topographic relief at this projected site is characterized by mildly north sloping ground and numerous minor drainages. The Applicant's test hole AG 573 was placed at the compressor station site and tended to confirm the above generalized terrain unit description. The test hole indicated the presence of a poorly graded sand gravel to the depth of the boring, which was terminated at 7.0 feet below ground surface. This boring depth is inadequate

1.1.1.6.C.2 (cont.)

for defining the range of possible foundation soil conditions that may apply to the site and further exploration information is needed in order to identify foundation requirements.

The location of facilities on specific terrain units would be nearly identical to those for Compressor Station No. CA-03 and the general comments made for that station apply equally as well to this proposed site.

Conclusions

- o Insufficient subsurface soil information exists to determine adequacy of preliminary sites. Detailed site studies are lacking for the compressor stations and airfields. The variability of the soil requires deep bore hole data at the exact locations. The Applicant states that these data are to be provided as part of the final design phase.

- o The particular location of CA-02-M.P. 83.0 is open to question, because a bore hole one mile west of the proposed site indicates the presence of more stable soil.
- o The proposed construction of compressor site foundations is not clear. Placing the buildings directly on the gravel pad would lead to long-term degradation of the permafrost.

Recommendations

(a) The Applicant should conduct a detailed site study for each compressor site and airfield along with possible alternates. Included therein should be all the appropriate parameters, such as subsurface soils and drainage properties. In a later submittal, the Applicant states these data will be provided as part of the final design phase.

1.1.1.6.C.2 (cont.)

(b) The Applicant should provide a detailed design analysis for his compressor station foundations to ensure permafrost maintenance.

References

Northern Engineering Service Co Ltd (June 1974) Application of Geotechnical Analysis for Canadian Arctic Gas Study Ltd.

Technical Interchange Meeting (October 27 and 28, 1975) "Alaskan Arctic Gas Pipeline Company and Department of the Interior" Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.6 Construction Procedures

D. Testing Procedure

1) Hydrostatic Testing
****

Applicant's Submission

Field testing would consist of hydrostatic proof pressure testing. The procedures would be conducted according to detailed specifications developed prior to start of the testing program in conformance with applicable codes. Proof pressure testing of a line segment would be conducted after construction and backfilling of a line segment. No gas testing or warm water testing (response to question 39) is planned; instead, a solution of water containing methanol as a freeze depressant is currently being considered. The concentration of methanol has been indicated as 26 percent consistent with a minimum expected subsurface temperature of $0^{o}F$.

Water sources and requirements were covered in response to DOI question 41. Details concerning withdrawal rates are being deferred pending the results of field surveys prior to construction. Methanol requirements have been estimated at 640,000 Imperial gallons.

Operations relating to filling the pipeline are covered in response to DOI question 40. In the relatively flat terrain, test section lengths of three miles are planned. The test fluid would be mixed before entering the first test section and moved from section to section as construction proceeds. Reserve fluid for about two miles of pipeline would be prepared. Approximately 55,600 barrels of solution would be needed to fill five miles of 48-inch pipe.

1.1.1.6.D.1 (cont.)

In the event of an accidental spill of test media containing methanol, it would be allowed to pond. The suction pumps would then be used to recover as much of the spill as practicable, and would be stored in bladder-type storage tanks.

In a later submittal the Applicant states that a failure during the testing operation would result in a localized saturation of the ditch backfill downslope from the point of failure and adjacent to the nearest ditch plug. The amount of ponding is dependant upon the leakage rate and the time elapsed between occurrence and correction. The pipe is expected to be full of test fluid on the downslope direction and the pipe immersed in a pond of test fluid is not expected to become buoyant.

In the case of a gravel backfill the backfill will not be affected by the methanol solution. In the case of a fine grained soil backfill local saturation with a water methanol solution will break down the soil to form a viscous slurry.

This saturated and thawed backfill (slurry) will be removed from the ditch to within about one foot of the top of the pipe and will be replaced with granular material to ground surface. The methanol solution saturated material will be spread in borrow areas or other approved sites, where it will stabilize as the methanol evaporates.

Although some methanol backfill will remain around and over the pipe, it will consolidate under the weight of the granular backfill and the concentration will gradually diminish. This material may not freeze back initially, but it will be at a temperature below the freezing point of water.

1.1.1.6.D.1 (cont.)

Thus, the adjacent soil beyond the area affected will freeze back and the unfrozen portion will not significantly inhibit the formation of the frost bulb.

The Applicant states that effects of dilute solutions of methanol have been tested on a few of the plant species in Canada at the Inuvik Test Area (Northwest Territories). These studies have shown that a diluted water and methanol solution applied during winter does not detectably affect shrub-tundra vegetation. In a later submittal, the Applicant also states that studies are underway to determine the effects of a full methanol spill on arctic vegetation. Results are not available at this time.

After completion of a test and transfer of fluid to the next section, methanol would be used to dehydrate the pipeline.

Analysis of Submission

Hydrostatic testing represents the usual method of proof testing a pipeline in the field. The main purpose is to prove that the components would withstand worst case internal static pressures without rupture or leakage. Conversely, an indirect purpose of such tests (before commitment to service) is to induce failure of structural material of insufficient strength due to previously undetected manufacturing flaws (such as cracks or occlusions), flaws occurring in transit, or fabrication faults (such as weak weld joints).

Consideration must be given to proper procedural details to assure success. This is measured in terms of ability to perform the test while in compliance with specific sections of cited safety regulations. Proper specification of test pressures, selection of appropriate test fluids,

1.1.1.6.D.1 (cont.)

avoidance of overpressurization, ability to detect failures and make necessary repairs, handle spills and leaks, provide for appropriate safety precautions on the part of test personnel, assure satisfactory removal and waste disposal of test fluids, are examples of items requiring definition.

Federal standards and safety regulations pertaining to gas transportation pipeline systems hydrotesting include Department of Transportation Regulations, 49 CFR, Part 192, "Transportation of Natural and Other Gas by Pipelines: Minimum Federal Safety Standards." The Applicant states these regulations will be complied with.

In the case of the Alaska Arctic Pipeline construction, a problem area involves selection of a satisfactory test fluid. The preferred hydrostatic test medium for pipelines is normally water, sometimes containing small amounts of nontoxic corrosion inhibitors and leak detectors in the form of odorants or dyes. In certain situations, the fluid which is to be pumped through the completed pipeline is used, or other substitutes are employed. The prevailing subfreezing weather conditions in the North Slope Alaska region necessitate selection of a test medium with a lower freezing point than water. DOT 49 CFR, Part 192 allows the use of air, natural gas, or inert gas testing but does not mention methanol solutions. DOT 49 CFR, Part 192, "Transportation of Liquids by Pipeline," does indicate the use of methanol and other anti-freeze fluids where frost conditions prevail.

Operations relating to conducting the pressure tests for pressure proofing and leakage determination, and activities relating to safe operations involving the handling and use of methanol have not been discussed by the Applicant.

1.1.1.6.D.1 (cont.)

The Applicant proposes to dilute the methanol to a one percent solution prior to dispersal and presents the results of studies that indicate forest tundra is not affected. Similar studies for vegetation typical of the Alaskan North slope should be provided by the Applicant. In addition, the results of studies on full strength methanol spills should also be provided. The Applicant states that only the strength study is in progress.

Since the pipeline is buried during hydrotest, leakage will cause a rapid local thaw. The Applicant recognizes this and proposes to replace fined grained thawed soil (described as a viscous slurry) with gravel backfill to within one foot from the surface. The Applicant does not discuss the influence of a test medium leak upon the sides and bottom of the trench, or upon the characteristics and effectivity of the bedding material. It is essential that the hydrostatic pressure be monitored closely during the initial phase of the test so that leaks are immediately discovered and the test pressure removed before extensive local thaw occurs.

The Applicant has stated that the test pressure will be 1.2 times the operating pressure. It will be held for a twelve hour period and that leaks will be visually detected by walking the trench. No special methods are proposed to detect these leaks. The Applicant should specify the size leak that can be visually detected particularly in view of the Applicant's comments regarding formation of a viscous slurry in fine grained soils.

Methanol in undiluted form is a flammable, toxic liquid. It is completely miscible with water, so that handling and fire hazards diminish with water dilution. However, prior to dilution, methanol is known to

1.1.1.6.D.1 (cont.)

produce blindness through ingestion or narcosis through inhalation. The threshold limit value for vapir inhalation by workers under repeated exposure is 200 ppm. The flash point of methanol is 52°F and the auto-ignition temperature is 878°F. Avoidance of the need for a worker to enter a vapor-filled line has been overlooked. Should such an eventuality occur, provisions for the use of proper breathing apparatus would be necessary.

The Applicant has not defined an allowable level of water contamination in the methanol rinse liquid.

Conclusions

- The use of methanol as a freezing point depressant in a water solution for hydrostatic testing appears reasonable, provided proper handling procedures are followed.
- The development of a leak during hydrotesting will require replacement of saturated backfill (fine grained soil). The need to strip the sides and bottom of the trench and to replace the bedding material has not been addressed by the Applicant.
- The size of the leak that is detected by visual inspection of the trench has not been defined by the Applicant. This is essential in view of the discussion presented on the effect of a water methanol solution on fine grained soils.
- Methanol will be used to dehydrate the pipeline. The Applicant is assessing the impact of full strength methanol spills upon vegetation

1.1.1.6.D.1 (cont.)

in ongoing studies, but has not indicated what dilution is permissible in reuse of the rinsing fluid.

Recommendations

(a) The Applicant should propose a detailed hydrotest procedure as per recommendation (b) of section 1.1.1.3.A.1.

(b) The Applicant should develop appropriate handling procedures and personnel safety practices, taking into consideration the toxic nature of methanol vapors.

(c) The Applicant should quantify the leak size that can be detected visually during hydrotest and the size leak that can be detected by pressure gages.

(d) The Applicant should prepare a contingency plan for handling leaks and spills of the hydrotest fluid. The plan should indicate the potential damage to the soils along the right-of-way, measures that would be taken to minimize the potential for spills, and detailed restoration methods that would be used when spills occur. This plan should be submitted to the appropriate regulatory and/or statutory agency(s) for approval prior to construction.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975). Comments of Arctic Gas Applicants to Draft Environmental Impact Statement for the Alaska Natural Gas Transportation System - Part II (Alaska).

Northern Engineering Services Co., Ltd., (March 1975), The Effects of Winter Methanol Spills on Forest-Tundra Vegetation.

1.1.1.6.D.1 (cont.)

Technical Interchange Meeting (October 27 and 28) Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.6 Construction Procedures

D. Testing Procedure

2) Water Quality
****

Applicant's Submission

The Applicant has stated that the hydrotesting solution will be diluted before disposal. Residual solutions would not exceed one-percent methanol concentration. The diluted solution would be disposed of by controlled spray dispersal onto snow surfaces or land so as to prevent undue flooding, erosion, or siltation. Final selection of the disposal technique is stated to be dependent on an assessment of environmental considerations.

Preliminary studies have shown that high concentrations of methanol are not harmful to vegetation, and work in the laboratory has indicated that fry or arctic char and grayling were not adversely affected by concentrations of less than one-percent solution of methanol even with exposure of up to a week.

Tests conducted near Inuvik, N.W.T.,[*] have shown that winter application of a water/methanol solution does not detectably affect shrub tundra vegetation. The release of test fluids onto land is not anticipated to have any adverse effect on terrestrial or riparian vegetation.

---

[*]Northwest Territory, Canada.

1.1.1.6.D.2 (cont.)

Analysis of Submission

The Applicant states that residual solutions to be discharged will not exceed one-percent methanol. The studies and laboratory efforts mentioned by the Applicant refer to forest tundra vegetation rather than vegetation typical of the Alaskan north slope.

Conclusions

- o Considering the fact that the methanol would be reused, the disposal question does not appear to present a serious problem.
- o The only fluid requiring disposal would be material recovered from leaks and spillage.

Recommendations

(a) The Applicant should perform studies involving winter application of a water/methanol solution to vegetation typical of this Alaskan north slope.

References

Technical Interchange Meeting (October 27 and 28) Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

Northern Engineering Services Company, Ltd., (March 1975), The Effects of Winter Methanol Spills on Forest-Tundra Vegetation.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

A. Technical and Operational Feasibility

1) Valves, Controls, and Pipeline
****

Applicant's Submission

The operations and maintenance planning of the Applicant is based on the use of automatic, unattended equipment at the measurement and maintenance stations, communication sites, and mainline block valves. A communication system extending along the entire length of the pipeline would provide voice services, data transmission for the supervisory control systems, and maintenance information related to equipment performance. Tentatively, a terrestrial microwave communication system has been selected, with five primary communication sites, located at Prudhoe Bay and near the four maintenance station sites, and four repeater communication sites located between each primary site. The system would link the Applicant's Field Operating Headquarters at Prudhoe Bay with the Gas Control Center in southern Canada. In a later submittal, the Applicant stated that satellite communications and control were also under consideration. Such a system would be augmented by a mobile radio system. The frequency of the mobile radio system would be 150 mHz and the frequency of the satellite communication in the gega Hertz range. In addition, the Applicant states that the aurora borealis is not expected to degrade or interrupt the satellite link.

1.1.1.7.A.1 (cont.)

Mainline full-opening block valves would be placed at the beginning of the pipeline, at each maintenance station, and along the pipeline at approximate 15-mile intervals. The valves would have automatic controls to shut them off when a rate of change of pressure is sensed that indicates a break in the pipeline. Applicant also refers to manual operation of these valves and the inclusion of the necessary blowdown valves and stacks.

Scraper trap assemblies would be located at the maintenance sites. A description of components and operation is provided.

If compressor units were to be installed at the maintenance stations in the future, they too would be designed for automatic operation. Discharge pressure and temperature set points and unit start-stop would be controlled remotely or locally. Stations would be self-protecting, with safety devices to shut down the station under hazardous conditions. The initial pipeline design would allow the compressor stations to be connected and activated with no significant interruption of gas delivery.

Analysis of Submission

The Applicant has not mentioned any installation of pressure-limiting or pressure-relieving devices. The gas supplies should provide pressure-relieving devices upstream of the delivery point to protect the pipeline. Future compressor stations should also provide for pressure-relief protection of the pipeline. Such devices are an important feature in maintaining pipeline integrity and should be discussed.

1.1.1.7.A.1 (cont.)

There is no reference to odorizing gas service lines in the maintenance (and later compressor) stations. Since these sites would occasionally be occupied by personnel, it would seem prudent to odorize the gas, despite provision of hazardous gas detection equipment. In a later submittal, the Applicant stated that design specifications for control equipment and automatic block valves will be provided during the final design phase.

The scraper trap assemblies will be at ambient, relatively high temperatures during the summer months. The Applicant should present any test data or available analysis relative to heat flow back to the pipeline possibly causing local thawing of the permafrost. A similar question applies to the block valves and vents also extending to the surface.

Conclusions

- The Applicant has presented a general overview and concept definition for the pipeline valving, ground communication and control system, and appurtenances. In a later submittal the Applicant states that equipment design specifications, piping, and electrical diagrams, and the operation and maintenance plan will be provided during final design.
- An additional item needing concept definition is the option of satellite communications and control. The reliability of satellite communications under arctic conditions has not been considered.
- A significant problem requiring treatment is the foundations supporting valve systems.

1.1.1.7.A.1 (cont.)

- The many natural gas transmission lines in the lower 48 states that operate automatically, unattended, by remote control, with few major mishaps, attest to the feasibility of the Applicant's operational concept. However, the North Slope environment is far more fragile than that heretofore experienced in the lower 48 states. It is incumbent, therefore, that design details be carefully scrutinized to ensure their capability to meet the environmental stresses imposed, and that all foreseeable conditions have been considered.

Recommendations

(a) Plans should be defined for protection of the pipeline from over-pressure, both in the initial stages and when the compressor stations are activated.

(b) Data or analysis should be presented regarding heat soakback from exposed piping, such as from the scraper trap assemblies and main-line block valves.

(c) This Applicant should provide concept definition for the satellite communications and control option, with emphasis on reliability of operation under arctic aurora borealis conditions.

(d) The Applicant should submit criteria for valve supporting systems (foundations) to the appropriate regulatory and/or statutory agency(s).

1.1.1.7.A.1 (cont.)

References

Technical Interchange Meeting (October 27 & 28) Alaskan Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

Northern Engineering Services Company, Ltd., (November 1975) Letter from NESC to Aerospace Corporation.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

A. Technical and Operational Feasibility

2) Process and Treatment Description

****

Applicant's Submission

The pipeline system does not provide for any processing or treatment of the flowing gas. The product accepted at Prudhoe Bay for transportation through the pipeline would only be subjected to pressure and temperature changes resulting from frictional losses and heat transfer with the pipe wall. In the event that the flow rate were to be increased beyond the 2250 MMCFD value, additional compression/refrigeration equipment would be required along the pipeline. The Applicant has also discussed acceptable composition of the gas to be transmitted in the pipeline. The Applicant states in supplement one (Tariff) to the submission that up to 20 grains of sulphur are acceptable for gas entering the pipeline. The implication on the environment of using this high sulphur content fuel in future compressor stations is considered by the Applicant. In addition, the Applicant further states that although individual sources could contain these levels, that gas mixtures being transported would be maintained at the 2 to 3 grains of sulphur level. In addition, Applicant has stated that liquid hydrocarbons are not likely to form in the pipeline for nominal gas compositions.

Analysis of Submission

The Prudhoe Bay raw gas contains relatively high concentrations of carbon dioxide and sulfur, which must be substantially reduced at the

1.1.1.7.A.2 (cont.)

processing/compression station (not part of the pipeline system) before delivery to the pipeline (see section 1.1.1.3.C.1). The Applicant has considered the consequences of improper processing of the gas including the formation of liquid and solid phases and has considered the consequences of fueling compressor/chilling equipment by pipeline gas, with up to 20 grains of sulphur, and has considered the impact of oxides of sulphur upon the vegetation (see section 3.1.1.1.B).

Conclusions

- No processing or treatment of the gas along the pipeline would be provided for, nor should it be necessary if the composition of the transported gas mixture is adequately controlled.
- Later addition of compression/refrigeration equipment would require some processing equipment, e.g., gas scrubbers to protect the compressor units.

Recommendations

(a) None

References

Alaskan Arctic Gas Pipeline Company (November 15, 1974) Supplement to Application - Docket No. CP74-239.

Alaskan Arctic Gas Pipeline Company (January 3, 1975), Formation of Hydrocarbon Liquids in the Pipeline - Response to FPC/DOI Oral Question.

1.1.1.7.A.2 (cont.)

Technical Interchange Meeting (October 27 & 28, 1975), Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaska) of the Draft Environmental Impact Statement of the Department of Interior Regarding the Alaska Natural Gas Transportation System.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

A. Technical and Operational Feasibility

3) Testing and Startup

****

Applicant's Submission

The initial hydrotest proceudre for the pipeline is described and evaluated in section 1.1.1.6.D. This section is specific to the immediate steps preceding inititation of gas transmission.

The Applicant has provided a brief description of the startup sequence. The Measurement Station at Prudhoe Bay would be commissioned first; all facilities and instrumentation necessary to measure operating parameters would be tested for accuracy and performance after installation. Piping in the Measurement Station would be pruged with nitrogen to eliminate all air.

The mainline purge would be accomplished in sections, using a pig to prevent mixing of the gas and air, and the natural gas system for maintenance station facilities would be pruged and activated. All station water handling facilities would be tested to assure correct chemical treatment and filtration. The emergency shutdown systems would be tested. The maintenance station facilities initially would be manned until the system has been approved for unmanned operation.

Analysis of Submission

The description of the startup procedure does not, of course, take the place of a detailed, step-by-step startup plan that would have to be prepared

1.1.1.7.A.3 (cont.)

later. Consideration of the procedures involved indicate that, in general, they are similar to those used in commissioning natural gas lines in the lower 48 states. This also applies to the startup of future compressor stations. However, there are a few unique conditions on the North Slope that would require some additional care in executing the pipeline startup sequence.

Since the present plan proposes commencement operation of the pipeline in the summer months, it would be necessary to control the startup activity and associated traffic along the route to avoid damage to the terrain. Inasmuch as the activity involves personnel rather than heavy equipment, most of the transportation would probably be via aircraft, with minimum impact on the environment. Another caution is that all purging of the mainline must be done using chilled gas. Whether the slug of nitrogen gas usually placed ahead of the purge pig would require cooling would depend upon its size and a thermal analysis of its effect on pipeline temperature.

Conclusions

o A preliminary description of the checkout and startup procedure has been supplied. In a later submission, Applicant stated that a complete plan would be provided as part of the final design procedure.

Recommendations

None

1.1.1.7.A.3 (cont.)

Reference

Technical Interchange Meeting (October 27 & 28, 1975) Alaskan Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

B. Maintenance Procedures

1) Corrosion Prevention
****

Applicant's Submission

Corrosion control was based on the use of both coating and cathodic protection systems. Two basic external coating systems were described, either of which would be used on different segments of the pipeline. One projected technique is to apply a continuous line travel tape coating over-the-ditch with an unbonded outerwarp or a bonded polyethylene rock shield material. The alternative approach is to use pipe precoated with a fusion bond epoxy and then field coat the girth welds with either polyethylene tape, or shrink sleeves, or direct application of epoxy material equivalent to the precoat. Full encirclement holiday detectors would be used to check the integrity of the coating. The entire length of the line will be checked prior to lowering-in of the pipeline.

The cathodic protection system would comprise an impressed DC current source and ground bed installations at or near each maintenance station, test leads at approximately one-mile intervals, and galvanic anodes where specially required. The type of ground bed construction to be used would depend upon the particular conditions at each site following detailed testing. Cable trenches would be 24 to 30 inches in depth and up to two feet in width. Energizing would be accomplished as soon as practicable following construction of the pipeline section.

1.1.1.7.B.1 (cont.)

All portions of the ground bed and cable system will be below surface and the surface conditions will be restored in accordance with approved clean-up followed by restoration procedures.

Internal corrosion would be controlled by an internal coating applied at the mill. Routine monitoring of internal corrosion would be undertaken by use of corrosion-rate monitoring probes. Corrosion of pipe, valves, irregular shaped fittings, and vessels exposed to the atmosphere would be controlled by protecting them with a suitable paint system and/or a polyethylene wrapping.

Analysis of Submission

The external coating systems mentioned cover generic classes that are acceptable for buried pipe service, however, specific materials in each of the classes can have widely different properties. No specifications for materials were given and no application procedures were provided. Surface cleaning and priming methods, the approved temperature of application, and the thickness of coating, should be provided to determine the adequacy of the coating to be furnished. Title 49 CFR 192.461, which covers coatings, was not mentioned.

A cathodic protection system was generalized in connection with mainline construction procedures. There were no design details as to type, location of rectifiers, cabling and anode beds, location of test leads, or the use of galvanic anodes. The pertinent Title 49 reference was not given. However, the Applicant has provided basic or conceptual design approaches that will serve as the framework for their detailed

1.1.1.7.B.1 (cont.)

design, using a study by Ebasco Services, Inc., dated December 1974, entitled "Cathodic Protection System for the Arctic Gas Pipeline."

The Applicant stated that galvanic anodes will provide corrosion control at river crossings.

The Applicant stated that the pipe will be internally coated with an epoxy which should avoid internal corrosion. The Applicant will also control the dewpoint of the incoming gas to prevent condensation in the system. He also stated that specifications and procedures for both internal and external coating systems will be provided prior to the final design of the pipeline.

<u>Conclusions</u>

o Corrosion control using coatings was not treated in detail by the Applicant. However, through Ebasco Services he provided a detailed cathodic protection plan. He did not reference relevant parts of the OPS codes. The Applicant did not provide monitoring procedures for corrosion protective measures but stated that specifications and procedures will be established and made available in his final design. If these procedures are not adequate, pipeline integrity will be affected.

<u>Recommendations</u>

(a) The Applicant should provide detailed designs and specifications for the cathodic protection system and submit them to the appropriate regulatory and/or statutory agency(s) for evaluation and

1.1.1.7.B.1 (cont.)

approval during the final design phase.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Department of Transportation (October 1973), "Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards," Office of Pipeline Safety, Title 49 CFR, Part 192, October 1, 1973.

Ebasco Services Inc (June 1974) Cathodic Protection Operation and Maintenance Procedure for Canadian Arctic Gas Study Ltd.

Ebasco Services, Inc (December 1974) Cathodic Protection System For The Arctic Gas Study Company and Canadian Arctic Gas Study: Ltd.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

B. Maintenance Procedures

2) Corrosion Control Monitoring
****

Applicant's Submission

Routine monitoring of internal corrosion of the line may be undertaken with the use of corrosion measurement probes. Inspection and painting of all above-ground surfaces, followed by repairs as required, would be part of the regular maintenance program. Line patrols would include inspection of all monitoring systems. Maintenance and inspection programs will be developed after the pipeline and equipment have been installed.

Testing and surveillance of the cathodic protection system will be provided in accordance with referenced Ebasco Services, Inc., studies dated June 1974 and December 1974.

Preliminary specifications for coating materials and mill application have been revised. Specifications for field handling, installation, inspection and repair are in preparation.

Analysis of Submission

The Applicant did not specifically describe a corrosion control monitoring plan in his Environmental Report. He will monitor his cathodic protection systems in accordance with referenced Ebasco Services studies. The specifications for monitoring coating are still in draft form and are not published.

1.1.1.7.B.2 (cont.)

Conclusions

o The Applicant has stated that monitoring the pipeline for corrosion will be accomplished by adherence to their applications for coatings, and to Ebasco Services' recommendation for monitoring and maintenance of cathodic protection systems.

Recommendations

(a) The Applicant should furnish a corrosion monitoring plan to the appropriate regulatory and/or statutory agency(s) for evaluation and approval.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Department of Transportation (October 1973), "Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards," Office of Pipeline Safety, Title 49 CFR, Part 192, October 1, 1973.

Ebasco Services Inc (June 1974) Cathodic Protection Operation and Maintenance Procedure for Canadian Arctic Gas Study Ltd.

Ebasco Services, Inc (December 1974) Cathodic Protection System For The Arctic Gas Study Company and Canadian Arctic Gas Study: Ltd.

1.1.1.7 Operational, Maintenance, and Emergency Procedures

C. Emergency Features and Procedures Feasibility

1) Design Features for Geological, Meteorological, and Man-Induced Hazards

Applicant's Submission

The construction approaches proposed by the Applicant to satisfy the more obvious geotechnic requirements, e.g., slope instability and seismicity, are evaluated in other sections of this report. This discussion covers several design measures that can mitigate the effects of abnormal or hazardous pipeline conditions.

Mainline block valves would have automatic controls to close them in the event of a pipeline break, thus limiting the amount of gas released to the atmosphere. Emergency shutdown and fire extinguishing systems would be installed in meter and maintenance facilities, and future compressor buildings. Major mechanical equipment would be self-protecting, with automatic shutdown and venting in the event of unsafe operating conditions, such as excessive vibration or high bearing temperature.

Passing reference is made to pipeline mileposts. Since the pipeline route is in an area of little human activity, other than Applicant's employees, the need to alert the public to the existence of the pipeline is less critical than in more populated areas.

1.1.1.7.C.1 (cont.)

The corrosion prevention measures, viz., pipeline coating and cathodic protection, should essentially eliminate this source of pipeline failure. Likewise, control of the water dewpoint and corrosive contaminants should effectively prevent internal corrosion.

Analysis of Submission

There are a few additional design features not mentioned by the Applicant. One is lightning protection for buildings and other above-ground facilities. Pressure limiting or relief devices should be included in the pipeline system. All facilities, including mainline valves, should be fenced, more for protection against animal damage than any human activity.

While the Applicant is correct in citing the remote location as a reason that the pipeline is unlikely to be disturbed by the public, it is necessary nevertheless to mark the center line of the pipeline. Once the pipe is buried and revegetation established, it would be difficult to discern the pipeline route, especially in winter, when the line is covered with snow. Care must be taken to prevent heavy vehicular traffic over the pipeline during maintenance operations, and for this reason pipeline marking would be required.

Conclusions

o Most of the necessary design features have been covered in this preliminary phase. However, protection from overpressure, lightning, and vehicular traffic over the pipeline has not been addressed.

1.1.1.7.C.1 (cont.)

Recommendations

(a) The Applicant should furnish measures to protect the pipeline from overpressure as per recommendation (a) of section 1.1.1.7.A.1.

(b) Applicant should furnish a plan for marking the pipeline route, and as he stated, in a later submittal, that a plan would be provided as part of the final design.

(c) The Applicant should provide lightning protection for buildings and other above-ground facilities in accordance with ANSI C5.1. Lightning Protection Code (1968).

Reference

Technical Interchange Meeting (October 27 and 28, 1975), Alaskan Arctic Gas Pipeline Company and Department of Interior, Calgary, Alberta, Canada.

1.1.1.7 Operational, Maintenance, and Emergency Procedures

C. Emergency Features and Procedures

2) Shutdown and Venting

****

Applicant's Submission

Emergency shutdown procedures would be developed later as a part of the operating procedures. During the initial period of pipeline operation, prior to installation of the compressors, shutdown would be limited to failure of the pipeline. In this situation, automatic controls on the main-line blockvalves would close the adjacent valves to isolate the break and limit the escape of gas. Shutdown of meter or maintenance (compressor) stations would be effected automatically upon the detection of fire or hazardous concentrations of gas, with all gas within the station vented to the atmosphere. In a later disclosure, the Applicant stated that procedures will be developed during the final design stage.

Analysis of Submission

An evaluation of both emergency and routine shutdown procedures cannot be accomplished until equipment and piping have been defined and an operating/maintenance manual written.

Conclusions

o Applicant has furnished general design criteria for the shutdown equipment and has stated that a shutdown and venting plan will be provided as part of the final design phase.

Recommendations

(a) Applicant should furnish an operating/maintenance manual covering shutdown procedures. The Applicant stated this plan will be provided as part of the final design phase.

1.1.1.7.C.2 (cont.)

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975)
Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluations, 15 March 1975.

Technical Interchange Meeting (October 27 and 28, 1975), Alaskan Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

C. Emergency Features and Procedures

3) Emergency Contingency Procedures

****

Applicant's Submission

Applicant states that a contingency and emergency plan will be prepared and ready for use prior to operation of the pipeline but not as part of the submissions for the Application for a Certificate of Public Convenience and Necessity nor for the Application for a Right-of-Way Permit.

Therefore, neither contingency plans nor emergency procedures have been prepared as yet, but general considerations and main courses of action are presented in the Environmental Report and in response to questions of the DoI/FPC Environmental Team. Contingency plans would be developed for each section of the pipeline containing the manpower, materials, and equipment needed to effect major line repairs and the sequential steps for their utilization. As an example, there would be a Mainline Break Repair Plan, a part of the Operating Manual, which would consider the location, type of terrain, and weather conditions to be encountered. It would preplan methods of repair and include an estimate of time required for the operation. Other information in the plan would include (1) the location of equipment storage areas and their contents: (2) recommended methods of transportation and routing considering

1.1.1.7.C.3 (cont.)

seasonal and environmental constraints, (3) assignment of supervisory and repair personnel, and (4) notification and reporting requirements.

General considerations and sequence of events in repairing a line break are presented in the Environmental Report, while specific procedures in the case of a break during the winter months are given in the Applicant's response to DOI question 20 and, for the summer season, in the response to DOI question 5. Inasmuch as most environmental damage would result in transporting men, materials, and equipment to the break site, the Applicant's description of repair activities focusses on the transportation vehicles available and how they could be employed.

There would be, of course, emergency conditions other than those on the pipeline itself. For example, the response to question 15 covers the case of personnel that might become lost during the winter months while operating or maintaining the pipeline.

The best of contingency plans are of limited usefulness if personnel are unfamiliar with their contents and implementation. Thus, the Applicant states that operations and maintenance personnel would be continually updated on contingency measures through scheduled training programs and practice drills requiring response to simulated specific emergency situations.

Analysis of Submission

Although the difficulties attendant to pipeline repairs during the winter and summer months have been addressed, there may be periods during the spring and fall seasons that could pose even more severe maintenance problems. Many streams overflow immediately following the thaw periods, which usually begin in mid-May. The heaviest snows occur in the fall. However, probably the most important consideration is that the surface organic layer is particulary susceptible to damage when a thin ice layer covers the ground. In a later disclosure, the Applicant provided a document, "Preliminary Report of Work and Transportation Equipment for Canadian Arctic Gas Study, Operation and Maintenance," which presents planning charts for pipeline repair and lists equipment which could be used. The possibility of using an air cushion barge towed by low ground pressure trucks is one of the viable options judging from the report of the National Research Council of Canada, "Proceedings of the Symposium on Heavy Transportation in the Application of Air Cushion Technology," Technical Report 5174, June 1974. If this or another option is selected by the Applicant, development and exploratory tests with proper equipment should be conducted under various arctic conditions as a proof of the concept before the start of pipe construction.

The destructive effect on the tundra of summer off-road traffic of heavy equipment was studied by the Muskeg Research Institute in Canada and others and the conclusions reached there were that multi passes of heavy equipment destroy the vegetation with a very slow rate of regrowth and the possibility of thermokrast development. This further emphasizes the need for the Applicant to consider the use of special non-tracked equipment with low ground pressure for any of his summer operation.

1.1.1.7.C.3 (cont.)

In describing projected repair procedure during the summer period, the Applicant does not address the consequences of the excavation on subsequent soil conditions on the ditch affecting pipeline integrity. These problems, regarding local thawing, flooding, and subsequent refreezing, should be detailed.

Movement of heavy equipment for summer repairs would be carried out by air cushion vehicles to be based either in Prudhoe Bay or Canada and this requires prior "proof of concept" development and demonstration.

The Applicant also emphasizes use of helicopters and short takeoff/landing (STOL) aircraft for both routine and emergency maintenance, but he does not indicate the number or type of such aircraft he would base at Prudhoe Bay. Two pilots and two flight engineers are assigned to Operations Headquarters, which may be indicative of the quantity of aircraft. Some discussion is needed of (1) the number and size of aircraft, (2) load capability, (3) airborne ambulance facilities mentioned, and (4) the availability of additional aircraft for charter in case of a major emergency.

An emergency condition that the Applicant has not mentioned is a failure in the producer's refrigeration equipment or compressor station.

Conclusions

- The Applicant has covered many aspects of this subject in several submittals and additional studies on Operation and Maintenance are in progress. The information from these additional studies is required before the pipeline design is finalized.

1.1.1.7.C.3 (cont.)

Recommendations

(a) The Applicant should consider the effect of summer pipeline excavation and in a later submittal the Applicant proposed mitigating measures to reduce potential hazards of ablation and subsidence.

(b) Air cushion vehicles, low ground pressure vehicles, and type and number of aircraft required for summer repair should be presented in detail. Precautions that might be employed during periods in which the ground is covered by a thin ice or a thin thawed layer should be discussed.

(c) An evaluation should be performed on line break detection equipment and on detection of small gas leaks.

(d) A contingency plan and emergency procedures for the pipeline system, including the time required for repairs, should be prepared and presented for the appropriate regulatory and/or statutory agency(s) for approval at least one year prior to pipeline operations.

References

Canadian Arctic Gas Study Ltd (July 14, 1975) Special Work and Transportation Equipment for Use During Operations and Maintenance of the Arctic Gas Pipeline System.

Cold Regions Research and Engineering Laboratory (November 1974) "Effects of SK-5 Air Cushion Vehicle Operations on Organic Terrains after Two and Three Years," Gunars Abele, David M. Atwood and Larry D. Gould.

1.1.1.7.C.3 (cont.)

Eggleton, Peter L. and Laframboise, Jacques, "Field Evaluation of Tower Air Cushion Rafts," Transport Canada, January 1974.

J.E. Rymes Engineering, Ltd., (October 1975) Preliminary Report Work and Transportation Equipment for Canadian Arctic Gas Study Limited Operation and Maintenance Calgary, Alberta.

Muskeg Research Institute, University of New Brunswick, Alur 1971-72, "Analysis of Disturbance Effects of Operations of Off-Road Vehicles on Tundra." by Radforth, J.R.

Muskeg Research Institute (Alur-72-73-12) "Immediate Effects of Wheeled Vehicle Traffic on Tundra During the Summer," University of New Brunswick.

Muskeg Research Institute, University of New Brunswick, "Long Term Effects of Summer Traffic by Tracked Vehicles on Tundra." by Radforth, J.R.

Muskeg Research Institute (May 1973), "Factors Affecting Use of Winter Roads During Spring Thaw," A Report to Arctic Petroluem Operators Association.

National Research Council Canada, November 1973, "Air Cushion Technology in Canada 1973."

National Research Council Canada (June 1974) Proceeding of the Symposium on Heavy Transportation in the Application of Air Cushion Technology Ottawa, Ontario.

1. DESCRIPTION OF THE PROPOSED ACTION

1.1.1.7 Operational, Maintenance, and Emergency Procedures

C. Emergency Features and Procedures

4) Precipitates and Condensates
****

Applicant's Submission

In DOI question 24 (second series) regarding gas composition, it is stated that the criteria for acceptance of gas for transmission would include: (1) a maximum water content such that water, water solutions, or hydrates would not accumulate on the pipe surfaces, (2) hydrocarbon liquids not forming in the gas to the extent that pipeline operations would be impaired, and (3) other contaminants (assumed to include particulates and sulfur compounds) within limits commensurate with good pipeline practices. In a later submittal, Applicant has defined limits on impurities and has provided data in hydrocarbon dewpoints. In addition, Applicant has stated that an internal coating shall be provided for internal corrosion control. (Section 1.1.1.7.B.2)

In a preceding discussion of meter station design, Applicant states that drains and a liquid collector will be provided on the inlet header.

Analysis of Submission

The primary effect of water condensation is internal pipeline corrosion. Small quantities of carbon dioxide and hydrogen sulfide may normally be present in the pipeline gas; and the Applicant has specified the maximum allowable content of these components. In the presence of condensed water, acidic solutions can be formed that are corrosive to the steel pipe. The primary method of internal corrosion control is therefore

1.1.1.7.C.4 (cont.)

based on avoiding the possibility of water vapor condensation in the pipeline system by specifying a maximum water dewpoint and/or providing an internal coating for corrosion control. The Applicant is proposing to use both methods.

Conclusions

o The Applicant indicates an understanding of the condensate problem.

Recommendations

(a) None.

Reference

Technical Interchange Meeting (October 27 and 28 1975), Alaskan Arctic Gas Pipeline Company and Department of Interior, Calgary, Alberta Canada.

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1 ARCTIC GAS PIPELINE PROJECT

2.1.1 Alaska Arctic Pipeline

2.1.1.2 Topography

D. Steepness and/or Angles of Slopes Traversed
****

Applicant's Submission

The Applicant states that over 90 percent of the slopes traversed by the pipeline are less than 3^{o}, and that 56 slopes are between 3^{o} and 9^{o}. He concludes that the slopes of less than 3^{o} can be regarded as stable. He states that the remaining slopes are steeper and require careful field and office studies to determine the potential instability and corrective action. In general, three categories of mass movement (landslides) generated on unstable slopes were recognized by McRoberts and Morgenstern (1972): solifluction, skin flows, and bimodal flows. These modes are discussed by the Applicant as well as general methods used for slope stabilization. Extensive discussion on slope stability is presented in the report of Northern Engineering Service Company attached to the answer to DOI question 24.

The Applicant mentions soil creep as an insignificant factor within the lifetime of the pipeline, but also as a factor that could call for special design.

Analysis of Submission

The purpose of describing the terrain which the pipeline will traverse is to recognize any special problems that could exist due to the steepness of the slopes and/or the direction of the pipeline relative to the slopes.

2.1.1.2.D (cont.)

Implications of stability of slopes less than 3° cannot be supported. Segments of the alignment have surfacial deposits containing significant massive ice with little mineral soil. With disturbance and thermal degradation, these slopes may become unstable, even though they are less than 3°. Solifluction and creep may also occur on very gentle slopes during the thaw season.

For those slopes exceeding 3°, the Applicant does not present an evaluation of the critical slopes in detail, nor does he present specific slope stabilizing methods for specific critical slopes, although a list of slopes with some indication of stability was presented in the abovementioned report of Northern Engineering Services Company. The thaw consolidation model described by the Applicant to predict the range of slope instability requires specific characteristics of the soil and "typical" soil properties may not represent a specific case study. While there is a good general correspondence between the terrain units shown and the bore hole data, there are large gaps between a number of the bore holes. Between 130 and 175 mileposts there are no holes at all. This represents a 45-mile segment, or approximately 23 percent of the alignment in which no ground truthing has yet been attempted.

The Applicant proposes the trenching and burial of the pipeline in the 1978-79 winter. Delays in the construction of the Canadian pipeline would result in the Alaska Arctic Pipeline being buried and inactive for a year or longer, as stated by the Applicant in a later disclosure. Unchilled pipe

2.1.1.2.D (cont.)

buried in the permafrost will introduce additional thermal problems affecting slope stability.

Conclusions

- o The Applicant has not provided adequate information along the pipeline route to determine the significance of the slopes encountered, nor specified design modifications or construction precautions required for slopes of less than maximum stability.
- o The Applicant has not considered the effect of pipeline inactivity or pipeline startup at different seasons on slope stability.

Recommendations

(a) The Applicant should develop allowable loads criteria for each unavoidable landslide bench traversed by the proposed pipeline with supporting analysis. These criteria should be provided to the appropriate regulatory and/or statutory agency(s) for review.

(b) The Applicant should identify all slide areas, and all such areas (active or dormant) should be avoided. For any slide area that cannot be avoided, stabilizing procedures and mitigating measures should be investigated. Blasting on slide areas should also be avoided, particularly in areas where unfrozen subsoil may exist.

(c) The Applicant should restore surface drainage which will be affected by the pipe inactivity period along the pipeline route to pre-construction conditions except that, wherever closed depressions existed on a bench, these depressions would be regarded to permit runoff of the surface

2.1.1.2.D (cont.)

water over the edge of the slope. In a later disclosure, the Applicant confirmed his intention to follow the recommendation.

(d) Applicant should determine conditions created by possibility of the inactive pipeline buried for one or two seasons, as well as by pipeline flowing chilled gas, together with proposed stabilization methods.

(e) The Applicant should measure solifluction and creep displacement by field observation. The Applicant should also describe in detail measures that will be taken to control such displacements.

(f) The Applicant should estimate maximum differential settlement due to solifluction, creep, seismic activity or other factor and use these criteria in the determination of pipeline wall thickness in accordance with recommendations in section 1.1.1.3.A.1.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Geotechnic Evaluation 15 March 1975.

McRoberts, E. C. and Morgenstern, N. R., (November 1973) "The Stability of Thawing Slopes," Department of Civil Engineering, University of Alberta, Edmonton, Canada

McRoberts, E. C. and Morgenstern, N. R., (November 1974) "Stability of Slopes in Frozen Soil, Mackensie Valley," Vol. 11, No. 4, Canadian Geotechnical Journal, pp. 447-469.

2.1.1.2.D (cont.)

Northern Engineering Services Co., Ltd., (December 1974), "Interim Report (Draft), Slope Stability in Permafrost Terrain," Calgary, Canada.

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.2 Topography

E. General Drainage Characteristics

2) Geomorphic Description of Major River Channels, Flood Plain, and Other Related Features

Applicant's Submission

General physiography of river crossings in Canada and some Alaskan crossings is extensively treated in two separate volumes (Northern Engineering Services, 1974) attached to the answer to DOI question 7. This report discusses river regimes, methods for computing scour depth, pipeline anchoring, bank erosion and stability, and related subjects. The crossing of the Sagavanirktok River in Alaska is described in some detail, and a measure of the erodibility of floor plains and river channels is provided in the alignment sheets.

Dimensions of watercourses are given for 12 Alaskan rivers, partial dimensions for an additional 10.

The response to DOI question 33 discusses qualitatively the depth of pipeline burial beneath active and dry meanders.

Analysis of Submission

The treatment of river regimes given in Northern Engineering Services (1974) is useful as a general construction guide. It is not clear to what extent the guide is applicable (except for the discussion of the Sagavanirktok River) to the North Slope river crossings in Alaska, nor to what extent the Applicant proposes to utilize it.

2.1.1.2.E.2 (cont.)

The most important question regarding the geomorphology of river crossings is that of bank erosion and bed scour. Lesser considerations involve siltation and effects of aufeis and borrow pits. These questions are discussed in general terms by the Applicant, but he has not addressed himself to specific instances of river crossing, deferring such studies to the construction phase of the project. For example, large, thick aufeis deposits can exist year-round in this latitude. These deposits can be located anywhere on the floodplain and cause serious changes in the river regime.

Conclusions

o The Applicant's statement is adequate in its compilation of background material, in his awareness of the environmental needs involved in river crossings, and of the technology required to meet them. It is deficient, however, in failing to present a thorough analysis of specific river crossings and specific measures applicable to individual crossings.

Recommendations

(a) The Applicant provided data on major rivers in Volume V, "Reference Book of Water Crossings," by NESCL. The data indicate the need for pipe buried up to 11 feet although scour depth calculations were not yet performed. It is recommended that pipe depth burial be verified after scour depth is analyzed.

(b) Aufëis and ice jamming require detailed studies and analysis. Data from the preconstruction reconnaissance should be sub- by the Applicant.

2.1.1.2.E.2 (cont.)

References

Northern Engineering Services Co., Ltd., (December 1974), "Reference Book of Water Crossings, Volume I - Hydrology," Calgary, Canada.

Northern Engineering Services Co., Ltd., (October 1974), "Reference Book of Water Crossings, Volume II - River Crossing Design," Calgary, Canada.

Northern Engineering Services Co., Ltd., (February 1975), "Reference Book of Water Crossings, Volume V - Preliminary Designs of Selected River Crossings Alaskan Coastal Route," Calgary, Canada.

Northern Engineering Services Co., Ltd., (March 1975), "Reference Book of Water Crossings, Volume VII - Supplemental Hydrology," Calgary, Canada.

Alaskan Arctic Gas Pipeline Company (28 October 1975), "Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Geotechnical Evaluation 15 March 1975."

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.3 Geologic

C. Geologic Hazards

1) Seismicity (Earthquakes)

b) Historic Earthquakes

(1) Severity

****

Applicant's Submission

In this discussion of seismic hazards, the Applicant draws considerably upon a report by Newmark (1974) which gives design criteria for two levels of earthquake magnitude (probable and maximum). The Applicant proposes to use the Design Maximum Earthquake as his design criterion. Applicant adopts the magnitude 5.5 (M5.5) Richter Scale, proposed for this area by the USGS (Page, 1972) and provided maps of strain release and earthquake epicenters.

The response to DOI question 23, in remarking that no seismograph station is considered for this route, states that criteria for design of pipeline have taken into account the probable magnitude of any seismic event. The response to DOI question 25 states that special design features may be used for areas of seismic activity.

The Applicant notes that no active faults have been recognized in the Alaskan portion of the pipeline (primary route). If faults were to be encountered during construction, the Applicant proposes to minimize the risk of pipe breakage by suitable trenching methods.

2.1.1.3.C.1.b.1 (cont.)

Analysis of Submission

From the fact that this section of pipeline would lie in an area of low seismic risk, it appears that the Applicant's selection of source material is judicious and generally adequate. The only exception to this may be the area in the vicinity of Flaxman Island, which has an historic record of seismic disturbance above the M5 level. The Applicant does not correlate the seismic accelerations and displacement with the stresses imposed on the pipe. Effect of seismic disturbance on the pipe safety should be evaluated, both in summer and winter conditions.

Conclusions

- o The major deficiency in the Applicant's discussion of seismicity is his failure to provide a relation between seismic data presented and specifications for a seismic design, however limited the requirement may be.
- o The Applicant does not supply an historic record of seismic events in this area, except for the statement of Newark (1974) that no M5 or greater earthquake has occurred in the period 1899-1970. In view of the meager information available, this is not considered a serious omission.
- o A contingency plan should be provided to check and reestablish pipeline integrity of this seismic activity.

2.1.1.3.C.1.b.1 (cont.)

Recommendations

(a) The Applicant should develop loads criteria for the pipeline design per recommendation (a) of section 1.1.1.3.A.1 to withstand earthquakes of M5.5 considering all above ground construction. Criteria should treat trench and backfill requirements to prevent instability from potential liquefaction, specifying a maximum acceleration in g and a duration above a minimum acceleration level, such as 0.1g specified by Newmark (1974). If data are available, an estimate should be made (see, for example, Howell, 1973) of the Average Regional Seismic Hazard Index.

(b) The Applicant should consider installing seismic instrumentation in the vicinity of Flaxman Island, considered the most likely center of seismic activity along the route. In a later disclosure, the Applicant stated that this will be dealt with in the final design.

(c) A detailed discussion should be presented of the special design features for areas of seismic activity mentioned in response to DOI question 25. The N.M. Newmark report (1974) quoted by the Applicant provides only seismic design criteria which should be translated into pipeline design features.

(d) The Applicant should provide a contingency plan for checking and re-establishing pipeline integrity after seismic activity. In a later disclosure, the Applicant stated that this will be covered in the final design.

2.1.1.3.C.1.b.1 (cont.)

References

Howell, B. F., Jr. (1973), "Average Regional Seismic Hazard Index (ARSHI) in the United States," from "Geology, Seismicity, and Environmental Impact," Moran, D. E., Slosson, S. E., Stone, R. O., and Yelverton, C. A., Eds. Association of Engineering Geologists, Spec. Pub. (October 1973), University Publishers, Los Angeles, California.

Newmark, N. (March, 1974), "Seismic Design Criteria for Canadian Arctic Gas Pipeline and Alaska Arctic Pipeline."

Page, R. A., Boore, D. M., Loyner, W. B., Coulter, H. W. (1972), "Ground Motion Values for Use in the Seismic Design of the Trans-Alaska Pipeline System," Geol. Survey Circ. 672, USGS, US DoI, Washington, D. C.

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

1. Seismicity (Earthquakes)

b) Historic Earthquakes

(3) Areas Susceptible to Liquefaction
****

Applicant's Submission

The Applicant's review of the historic data available on Alaskan earthquakes notes that north of L 67°N no earthquakes greater than M5, Richter Scale, have been detected (Stevens, 1974). Since the only ground susceptible to liquefaction by seismic energy is that which consists of loose, fine, uniform sands, in conjunction with a high water table, only one short section of the pipeline route is appraised as a liquefaction hazard. In this section, additional pipe weighting is to be provided at a river crossing; elsewhere, the shallowness of thawing is said to limit the extent of soil liquefaction.

In discussing depth of pipe burial, Applicant states that where potentially buoyant areas are crossed, the minimum depth of cover could be increased to four feet, to reduce the effects of bouyancy.

Analysis of Submission

The Applicant has identified only one short section of the pipeline route as subject to liquefaction. The ability to define these areas at this time depends upon the thoroughness of his soil sampling program and/or the uniformity of the soil along the pipeline route. A high water table is one

2.1.1.3.C.1.b.3 (cont.)

of the conditions which the applicant defines as necessary to provide a liquefaction susceptible area. The introduction of the pipeline with the ice ball surrounding the pipe could very well change the drainage characteristics in the upslope side of the pipe and provide the moisture content required to make other areas susceptible to liquefaction. In particular, excess pore pressure generated by thawing, subsurface flow gradients, and other means although below liquefaction level may also produce instability and must be considered in the mass wasting study."

During the construction phase, 100 percent of the route would be sampled and areas other than presently defined could be discovered and require anchoring. Criteria for evaluating samples of frozen soil excavated during construction are required to enable the identification of other liquefaction susceptible areas.

Conclusions

o To establish the hazard of seismic liquefaction, the whole pipeline route should be explored and the now existing gap of 45 miles (between Mileposts 130 and 175) should be provided with boring data, particularly around major streams and rivers.

Recommendations

(a) The Applicant should consider that some loose, fine, uniform sands or other liquifiable-type soils may obtain the necessary water content under the location of the pipeline and the changes in drainage which may

2.1.1.3.C.1.b.3 (cont.)

be induced. The Applicant should review his data with some projection of the worst case moisture content, and define those areas which are considered to be subject to thixotropic liquefaction.

(b) The Applicant should provide criteria for the identification of thixotropic liquefaction susceptible areas during the construction phase, along with procedures for selecting and implementing appropriate anchoring methods.

Reference

Stevens, A.E. and Milne, W.G. (1974), "A Study of Seismic Risk Near Pipeline Corridors in Northwestern Canada and Eastern Alaska," Can. J. Earth Sci., 11, p. 147.

2.1.1.3 Geology

C. Geologic Hazards

2) Mass Wasting

d) Possible Effects of Trenching and Machinery on Weak or Slide Prone Areas

Applicant's Submission

The Applicant discusses effects of trenching and machinery on slopes with emphasis on slope stabilization. It is asserted that all slopes to be cut would be carefully analyzed and slope stabilization schemes applied as necessary. A method of analysis by McRoberts (1974) is proposed. Some cuts would be allowed to slough and heal naturally. Five slope stabilization methods are cited, to be applied as local conditions dictate. In slope cuts filling techniques using snow or water would be used as much as possible. Access roads would be subject to the same general considerations as trench and right-of-way, as far as slope effects are concerned.

Analysis of Submission

The Applicant's approach to evaluating slopes, slope stabilization, and protection of cuts appears to be adequate as far as they are developed. The problem of slope stabilization after pipe burial is of importance particularly in cases where the pipe cuts across the slope. According to the NESCL report, "Slope Stability in Permafrost Terrain," there are 19 slopes exceeding 3^{o} which will be cut across by the pipeline. Methods of stabilizing

2.1.1.3.C.2.d (cont.)

of steep cut slopes are various and those are described in the above-mentioned report and in the Applicant's answer to DOI question 15. A detailed evaluation of the cut slopes if any are made and the proposed method of their stabilization is required.

With reference to access roads cutting across the slopes, the Applicant stated in a later disclosure that the roads with level surfaces will be built above the slope with ice or snow fill.

Conclusions

o The Applicant has not provided details of constraints on construction for gentle slopes subject to soil creep and solifluction, or steep slopes at river crossings. Such excavations could encounter ice-rich soil where thaw would result, accelerating mass wasting and stream siltation, with possible undermining of pipe.

Recommendations

(a) The Applicant should identify all potentially unstable slopes affected by construction with a determination of the factor of safety by the McRoberts Method and the Applicant indicated that this will be done during the final design.

(b) The Applicant should reevaluate the method of restoring slopes by natural sloughing processes, including an examination of slopes where this method has been applied, reporting any instances of excess erosion or degradation of cover. All slopes to be so treated should

2.1.1.3.C.2.d (cont.)

be identified by location, soil type, and evidence should be provided that excess thaw will not occur. Insulation as an erosion deterrent on cut slopes should also be considered. The Applicant indicated in a later disclosure that this will be done if required.

(c) The Applicant should make a similar reevaluation of the use of snow or ice fill, reporting on damage incurred by the melting of such fill.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation 15 March 1975.

McRoberts, E.C. and Morganstern, N.R. (1973), "The Stability of Thawing Slopes," Department of Civil Engineering, University of Alberta, Edmonton.

g) Possible Effects on Pipeline
****

Applicant's Submission

The Applicant discusses various forms of mass movement which may occur in saturated, thawing soils. These are solifluction, creep in the thawed active zone, and large- or small-scale slumping, particularly in the ice wedge polygon terrain.

Solifluction, which is a slow gravitational downslope movement of saturated unfrozen soil over a surface of frozen materials, would be widespread along the pipe route. Areas of intense solifluction would be avoided by appropriate route location.

Creep of unfrozen or thawing slopes is considered to be insignificant in the lifetime of the pipeline, and detailed analysis is not required. On the other hand, creep of frozen slopes and deep-seated failures would be possible types of pipeline failure, and as far as possible the route selection would avoid areas where failures of this type would occur.

The mass movements along the slopes with ice-rich soils would be subject to thaw consolidation, which the Applicant discusses in the section on soil solifluction or liquefaction. The thaw consolidation analysis is performed in the answer to question 3. This phenomenon would be

2.1.1.3.C.2.g (cont.)

manifested in a shallow skin flow at the proposed pipe crossing of the Katakturuk River, as described in the answer to DOI question 27. As a result of this landslide, the Applicant decided to change the location of the crossing originally proposed to one a few hundred feet downstream, where gravel outcrops along the bank. A detailed discussion of mass wasting phenomena with suggested analytical treatment of skin flows is also identified in that answer. Means of soil stabilization are discussed.

Another form of mass wasting is ground differential settlement, which may be caused by thermal regression of permafrost along the proposed right-of-way, by thermal regression of permafrost around the pipeline remaining unchilled for one year or more, by loss of ground support due to erosion, and by compression of the supporting soil under the weight of the pipe and backfill. In general, the Applicant does not consider the differential settlement to be a problem, as stated in answer to DOI question 3, since the depth of burial of the pipe would be such that thaw would generally not penetrate below the top of the pipe.

Analysis of Submission

The Applicant reviews extensively but qualitatively the problem of mass wasting and stabilization methods. It is obviously an area of concern, particularly in view of the lack of experience with large-diameter pipes buried in permafrost. The fact is recognized that removal of the organic mat in the right-of-way would upset the delicate heat balance in the permafrost. The removal of this insulating layer would increase the depth of thawing, and in

2.1.1.3.C.2.g (cont.)

ice-rich, fine-grain-clay-type soils with low permeability and poor drainage would increase the water pore pressure, releasing an excess of water in the trench. Thus, conditions conducive to landslides and skin flows would be created.

The landslide which occurred at Katakturuk River at the crossing site originally selected by the Applicant indicates a need for a detailed review of the prime route in order to identify other potential problem areas that could result in pipe failure.

At present, the projected pipe is sized for hoop stress only, with the assumption that any external loads that may be superimposed would produce stresses which would be small, compared to the principal stress. Such an assumption would be of primary importance to the pipeline integrity and should be verified analytically, at least in the near-worst locations where pipe movement caused by mass wasting would be expected. What would occur if the settlement should not be uniform in a given location and a section of the pipe should be displaced by this amount is not stated. No assessment of the degree of nonuniformity that would be safe from a pipe integrity standpoint is made.

Another problem that should be considered is the thermal conditions associated with inactive versus active phase of buried pipeline. The Applicant has stated that "During the inactive period (after construction and prior to operation) differential settlement within the chilled gas portion of the pipeline may result." When the pipe remains inactive over a year or longer, the active layer would then extend to a greater depth. The Applicant's latest disclosure indicated that the increase in the active layer depth may not be great. Calculations performed by NESCL for unchilled pipe in the ground for two years and presented in the report "Application of Geothermal Analysis" have shown that in most cases the 32° isotherm will be near the top of the pipe. However, the berm above the pipe will be subject to settlement and at the edge of the right-of-way there will be a tendency for channeling which will most probably induce drainage problems and ponding. Appropriate preventive measures should be planned by the Applicant to mitigate this problem.

With the startup and operation of the chilled pipe, the active layer above the pipe will be reduced, as shown by the Applicant in answer to DoI question 4. The problem then is frost heave and its effect on pipe integrity, particularly if the pipe is started in summer.

The depth of burial of the pipe with respect to the expected 32°F isotherm is important with regard to mass wasting. The depth of the undisturbed active layer would vary, according to the Applicant's data, from one to three feet along the route. Removal of the organic mat would increase the depth of the active layer across the right-of-way, with the exception of the layer in the vicinity of the pipe, when it would be chilled with the flowing gas. The minimum depth of cover specified by the Applicant (from the top of the pipe to the original ground surface) would be 2.5 feet. The top of the pipe would be an average of four feet below the original ground surface,

2.1.1.3.C.2.g (cont.)

according to the answers to DoI questions 4 and 6. The depth of the active layer above the chilled pipe and over the right-of-way is also calculated by the Applicant in answer to DoI question 4, at certain assumed pipe and ground temperatures. The calculation shows an active layer of 1.8 feet over the right-of-way and 0.4 feet over the pipe. One would expect that over the right-of-way denuded of the organic mat the thickness of the active layer would be greater than that of the undisturbed ground, particularly during the period when the pipe remains unchilled. Fissures which may form over the berm during freeze-up will collect ice and snow during subsequent thaw periods may lead to severe berm erosion and drainage problems. The Applicant stated in his later disclosure that he intends to pre-strip the organic mat and replace the topsoil and organic material above the backfill to preserve some of the insulating properties of the organic mat. Consequently, calculations should be performed in which the active layer is close to the three feet quoted and then compare this factor with the proposed pipe burial depth. The depth of burial should be quantitatively specified for a few near-worst locations, rather than to be quoted in terms of "minimum" or "average." The Applicant stated in his later disclosure that his calculations were performed on higher than average temperatures; nevertheless, the inactive pipe conditions require careful reassessment to prevent thaw settlement and subsidence.

Typical problems associated with unchilled pipelines in permafrost will occur. Conventional backfill material and procedures will result in relatively high soil permeabilities around and above the pipe. Any pipe laid on longitudinal gradient would probably result in induced subsurface water flow beneath

2.1.1.3.C.2.g (cont.)

the pipe at the pipe-undisturbed soil interface or the backfill-undisturbed soil interface. The end result over one summer could be severe thermal erosion. This could result in undetected voids or pockets forming beneath the pipe which may result in stress concentrations in the pipe. These pockets or voids may fill with water. This thermal erosion could also result in thaw depths several feet beneath the pipe.

Frozen surcharges and frozen backfill placed during winter construction would be highly susceptible to consolidation and densification during warmer months. Expected magnitude of overburden stress would need to be related to placement conditions.

If low density backfill is permitted, depth of frost penetration must be reevaluated. Large voids and continuous air passages would cause significantly deeper frost penetration beneath the pipe. A "pseudo" active layer may come into being, that is somewhat thicker than the natural active layer in that initial pipe chilling or startup will result in the highest thermal gradients in the pipe and the soil surrounding the pipe.

In well drained unfrozen areas containing primarily non-frost susceptible soil conditions, startup should not result in any major problems, assuming appropriate arctic construction techniques and quality control are employed during pipeline installation.

In permafrost areas where the integrity of the frozen soil has been maintained, whether through the use of insulation or some other means, startup should not result in major problems assuming the precautions mentioned earlier are heeded during construction.

"The potential for major problems will be in areas where the pipe is laid in frost susceptible soil, in permafrost that has thermally degraded

2.1.1.3.C.2.g (cont.)

during warm climatic periods (i.e., the summer months) and/or any saturated (riverbottom) soils or soils subject to water influx."

"The thermal studies on the depth of the active layer under the right-of-way with an unchilled pipe and under gravel pads were performed by NESCL. However, the studies assumed certain average backfill and soil properties, soil compressibility, etc., which may not be representative of the entire Alaskan right-of-way condition. It is certain that ground settlement, erosion and drainage problems will be aggravated with unchilled pipe and that appropriate preventive mitigating measures should be considered in the pipeline final design.

One of the locations which should be explored in detail lies in the Arctic Coastal Plain between mileposts 4 and 7, and is representative of typical conditions within this province. Here, the line crosses terrain units containing approximately 1.8 miles of Arctic Coastal Plain sediments and 0.9 miles of former oriented lake sediments and closely skirts 0.3 miles of an oriented thaw lake shore. The Arctic Coastal Plain sediments commonly contain 10 to 15 feet of ice-rich silty sands which overlie sandy gravels, some of which are silty and have varying ice content. Ice wedges are characteristic, as are small ponds and swamps. The moisture content of the soils is generally high.

The closest drill hole locations to this proposed site are at approximately 1.5 and 7.85 miles. In order to assess the soil characteristics, it is necessary to extrapolate the drill hole data presented. These data appear to be

2.1.1.3.C.2.g (cont.)

satisfactory for a broad overview, but the variability of the soils make specific judgments somewhat tenuous. In addition, thaw bulbs exist under some of the lakes, and without more detailed information it is difficult to assess the significance of this unfrozen condition on the proposed pipeline. Surface water is present in almost all areas. This water would be ponded or intercepted by the pipe ditch or diverted by the berm above the ditch. Diversion of drainage would be feasible in a few areas, but ponds would develop in others. These ponds would tend to accelerate melting, even if flow were to be prevented.

Several phenomena occurring in such an environment could affect pipeline integrity. The thaw areas exist in soil which would be conducive to formation of a frost bulb and frost heave with a chilled pipe. Poor drainage of the soil could lead to local ponding, which would aggravate the condition, and an unchilled pipe could lead to backfill erosion and pipe buoyancy.

The backfill material would be ice-rich, and thawing would cause subsidence, changing the pattern of surface water flow and increasing the possibility of erosion in the pipe right-of-way. In a later disclosure, the Applicant stated that in exceedingly high ice content soils native backfill will be used with caution and that select backfill will be imported.

2.1.1.3.C.2.g (cont.)

Conclusions

- o The Applicant has displayed a good understanding of the mass wasting problems and has presented an extensive qualitative description of the various aspects of this phenomenon, analytical methods available, and stabilization methods known.
- o A detailed review of the route is needed to identify potential mass wasting areas. For those areas, quantitative analyses are needed to determine (1) the depth of pipe burial, (2) location of 32° isotherm, (3) drainage requirements, (4) mass wasting hazards and their effect on pipe integrity, and (5) appropriate stabilization methods.

Recommendations

(a) The Applicant should identify potential mass waste areas along the prime route and perform a detailed analysis of mass wasting hazards and their effect on pipe integrity. The Applicant stated in his later disclosure that this task constitutes the final design of the pipeline system.

(b) The Applicant should determine external loads imparted by mass wasting on the pipeline for all areas considered to be a potential hazard and incorporate in pipe thickness determination per 1.1.1.3.A.1, recommendation (a).

(c) The Applicant should determine the magnitude of thaw settlement and ponding with particular emphasis on ice-rich low permeability

2.1.1.3.C.2.g (cont.)

areas where imported select backfill is utilized with the unchilled pipe left for a year or more.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Northern Engineering Services Co., Ltd., (March 1975) "Drainage and Erosion Control Measures Description and Proposal Design Principles."

Northern Engineering Services Co., Ltd., (June 1974) Application of Geotechnical Analysis for Canadian Arctic Gas Study Ltd.

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazard

4) Permafrost

d) Physical Characteristics (Shear Strength, Density)
****

Applicant's Submission

A substantial amount of data is provided on the thermal and physical properties of permafrost. Most of the data are presented in the Northern Engineering Service Co., Ltd (1974) attachment to the answer to DoI question 24. The data include values of coefficient of consolidation; permeability of various soils and thawed backfill; and frozen and thawed soil conductivities.

Analysis of Submission

The properties of permafrost must necessarily be known in order to assess the behavior of the buried pipe. Specifically, (1) permeability, (2) consolidation coefficient, (3) density, (4) sheer strength, and (5) conductivity of both thawed and frozen soils along the pipeline route are required.

Permeability defines the ability of soils to drain off water, and low permeability is indicative of poor drainage and easy accumulation of excess water. For silty sands, the permeability is on the order of 1×10^{-3} cm/sec to 1×10^{-5} cm/sec, while for silts and clays it varies between 1×10^{-5} to 1×10^{-7} cm/sec. Kachadoorian and Ferrians (1973) predict a possibility of mass movement on slopes with high water content and permeability of less than 1×10^{-5} cm/sec.

2.1.1.3.C.4.d (cont.)

The coefficient of thaw consolidation defines the rate by which water may be squeezed out of the thawing surface overlying the advancing thaw interface. The smaller the coefficient and the higher the rate of thaw, the greater the tendency of the soil to move toward a semi-liquid slurry condition. This is of particular importance on slopes where a drastic reduction in soil shear strength associated high liquefaction could initiate mass movement. The Northern Engineering Service Co. report mentioned above quotes the coefficient of consolidation data for silty sands at 1×10^{-1} to 1×10^{-2} cm/sec, and for clays as 1×10^{-2} and 1×10^{-3} cm/sec.

The densities of permafrost vary as a function of soil composition, compaction, and moisture content. Penner, et al. (1973) quote densities of various soils and various moisture content, and the values lie between 90 and 140 lb/ft^3. Slurries with high water content and high densities produce high buoyancy on immersed pipe. For example, in a slurry with density of 110 lb/ft, the net buoyancy of the pipe would be approximately 900 lb per foot of pipe length. Such situations may be uncommon, but they point out the need for careful assessment of the negative buoyancy provisions.

Data on thaw interface shear strength of permafrost soils are limited. Means of increasing shear strength are discussed in the NESCL report, "Slope Stability in Permafrost Terrain." Some laboratory data on fine inorganic silt soil obtained by Thomson and Labacz (1973), with varying overburden, indicate values of 0.4 to 0.8 kg/cm^2.

2.1.1.3.C.4.d (cont.)

Strength properties for insitu soils along the alignment should be determined. A change in the overburden normal stress "has relatively small effect on shear strength when compared with the effect of moisture content and excess pore pressure development. Other factors needing consideration include evaluation of in-situ stress increases resulting from combined effects of meltwater generation and surficial infiltration as well as subsurface flow. Any increase in the moisture content of saturated soils can decrease slope stability."

The soils identified by the Applicant's bore hole records cover nearly the full range of possible classification and water content, and, hence, a range of physical properties. However, the number of bore holes is limited, and a substantial length of pipe route (up to 40 miles) has no bore hole data given. There is a need for such data, particularly for soils on slopes, at river approaches, under rivers, and at proposed compressor station sites.

Conclusions

- The Applicant provided a substantial amount of data on permafrost physical properties. However, data on shear strength of unfrozen soils and on frozen-unfrozen soil interface are limited.
- There are insufficient bore hole data along the proposed pipeline route, and this information should be added for proper assessment of pipeline integrity.

2.1.1.3.C.4.d (cont.)

Recommendations

(a) The Applicant should provide shear strength data on unfrozen soils and soil interfaces for assessment of mass wasting hazard and external loads on the pipe to be used in analysis of recommendations (a) and (b) of section 2.1.1.3.C.2.g.

(b) The Applicant should provide comprehensive bore hole data along the pipeline route, particularly for slopes, river approaches, under rivers, and at compressor stations.

References:

Kachadoorian, R. and Ferrians, O. (1973), "Permafrost-Related Engineering Geology Problems Posed by the TransAlaskan Pipeline," National Academy of Science, 2nd Permafrost Conference, 1973.

Northern Engineering Services Co., Ltd. (Dec 1974), "Interim Report - Slope Stability in Permafrost Terrain," prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd., Calgary, Canada.

Penner, E., Johnson, G.H., and Goodrich, L.E. (1973), "Thermal Conductivity Laboratory Studies of Some MacKenzie Highway Soils," National Research Council of Canada.

Thomson, S. and Labacz, E.F. (1973), "Shear Strength at a Thaw Interface," National Academy of Science, 2nd Permafrost Conference, 1973.

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.3 Geology

C. Geologic Hazards

4) Permafrost

e) Frost Heave

****

Applicant's Submission

Frost heave is caused by volume differential between frozen and unfrozen water and by the buildup of segregated ice or ice lenses. The potential for frost heave arises when three conditions are satisfied: (1) freezing temperatures, (2) frost-susceptible soils, and (3) source of water. With a chilled pipe, there would be a tendency for the pore water to migrate toward the advancing freezing front to form an ice lens.

The frost heave problem, in answers to DoI questions 2 and 6, is categorized as follows: (1) heaving in the active layer across the right-of-way, (2) heaving caused by freezing of unfrozen groundwater in permafrost soils, and (3) heaving in unfrozen ground, such as underwater bodies that do not naturally freeze each year.

Frost heaving in the active layer should not affect pipe integrity because the maximum depth of the active layer along the right-of-way is three feet and the top of the pipe will be an average of four feet below the surface. Consequently, the chilled pipeline would not dominate the freezing in the active layer, and the conclusion presented in the answer to DoI question 4 is that pipe integrity would not be affected by heaving in the active layer.

2.1.1.3.C.4.e (cont.)

The problem of heaving caused by unfrozen groundwater in the permafrost is discussed in the answer to DoI question 1. Since the pipe would be colder than the surrounding medium in summer and warmer in winter, the unfrozen water would tend to migrate toward the pipe in summer and away from it for the rest of the year. This would mitigate significant ice buildup around the pipe. Also, the rate at which water would migrate through permafrost along the route would be extremely low because of very low permeability of frozen soil (ranging from 10^{-9} to 10^{-15} cm/sec). It is, therefore, considered that ice heave in these conditions does not constitute a problem.

The problem of heaving in unfrozen ground under rivers is discussed in answers to DoI questions 2 and 26. The formation of a frost bulb around the pipe is estimated, with no groundwater flow and low rate of water flow in terms of erosion potential caused by interruption of subsurface flow. The conclusion is reached that, if the restriction of subsurface or surface water flow should represent a real problem, remedial steps would be taken, such as insulating the pipe or burying it deeper to minimize the effects. Also, any drained lakes with a potential of pingo formation would be avoided.

Analytical methods would be used to predict heaving pressurers due to ice segregation. It is stated that heaving of the pipeline could be prevented by applying surcharge pressurers greater than computed maximum heaving pressure. The analyses would consider the geothermal aspect of the 32° isotherm advance, soil properties of the frost-susceptible soils with high

2.1.1.3.C.4.e (cont.)

water content, and stress analysis of the pipe from differential heaving in adjacent sections.

Experimental data obtained from Prudhoe Bay of four buried sections of 48-inch pipe over a period of 1.5 years would be used in the analysis, where applicable.

<u>Analysis of Submission</u>

The Applicant has expressed proper concern for the potential detrimental effect of frost heave on the proposed buried pipeline. However, statements identifying procedures to be utilized in assessing and mitigating frost heave effects are presented only in terms of general concepts. The full consequences and required design conservatism have not yet been defined.

Examples of specific points where frost heave could occur along the proposed pipeline route should include all thaw lakes, beaded drainages, possible taliks, as well as any areas with frost-susceptible soils, which might thaw during construction, or prolonged shutdown and then refreeze. Under these conditions, the pipeline would be uniformly buried with native backfill placed back over the pipe. In passing through a thawed section, the pipe would be constrained at both frozen end sections but would be subjected to frost heave effects along the thawed length when refrigeration by gas throughput begins. The development of the 32-degree isotherm and consequent frost heave forces could induce significant pipe stress changes and deformation. This condition is considered to be quite critical in terms of demonstrating the design adequacy of the frozen bury mode.

2.1.1.3.C.4.e (cont.)

Information provided by the Applicant does not yet identify either the range or tolerance in allowable pipe stresses relating to deformation. Those stresses associated with frost heave effects must be included in the evaluation of pipe stresses. While the potential reduction in frost heave due to minimizing ice segregation by surcharging procedures would obviously be beneficial, detailed information on the feasibility and justification of this consideration is required. The effect of buoyancy and the fact that all natural backfill material would be disturbed should also be considered particularly if granular bedding and padding materials were not to be utilized. The Applicant stated in a later disclosure that all the relevant factors related to the properties of the backfill, including pipe buoyancy, are being considered.

The frost heaving in the active layer may not pose a problem if the pipe were to be buried below the active layer. However, it should be kept in mind that in the right-of-way the depth of the active layer would be greater than that of the undisturbed ground and this should be considered when defining the burial depth.

The effect of increasing surcharge pressure on the heave magnitude is dramatic, according to the Applicant. The ability to provide sufficient surcharge pressure is questioned. The limit of ditch depth or overfilled berm is quickly reached. The reverse effect when the surcharge is removed, for instance by river erosion, must be considered. According to the Applicant's latest disclosure and the NESCL interim report on frost heave,

2.1.1.3.C.4.e (cont.)

Vols. I and II, experimental data have shown that frost heave can be at least partially arrested with overburden pressure. The question still remains of how accurate will be the prediction of frost heave rate for varying properties of the soil along the right-of-way and, hence, whether the proposed five feet of surcharge is sufficient, considering the uncertainty in defining soil conditions and properties, and considering possible erosion of the surcharge and subsidence with unchilled pipe. Deeper pipe burial will not necessarily provide an increase in pressure on the freezing front. The "arching" phenomenon that occurs in ditches of this type (particularly a straight wall trench) precludes a linear increase in overburden pressure due only to deeper burial"

Conclusions

o The Applicant is well aware of frost heave problems and means at his disposal to mitigate them. However, there is an uncertainty about the amount of overpressure (surcharge) required to arrest frost heave because of soil variation, river scour, erosion and subsidence, the latter becoming more pronounced with the unchilled pipe in the ground. A detailed review of near-worst but realistic conditions is required to minimize potential frost heave hazard and pipe overstressing.

Recommendations

(a) The Applicant should evaluate the ground temperature profile for all conditions of flow and for all seasons of operation/non-operation to

2.1.1.3.C.4.e (cont.)

determine the optimum pipe burial depth to minimize effects of the active layer.

(b) The Applicant should assume worst case ground moisture conditions and determine the external frost heave loads imposed on the pipe, first, for inclusion in the pipeline thickness determination per recommendation (a) of section 1.1.1.3.A.1, and, second, in the chilled gas effects study per recommendations (b) of section 1.1.1.1.B.2.

Reference

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility)," Columbus, Ohio.

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Northern Engineering Services Company, Ltd., (March 1975) "Interim Report on Frost Effects Study," Volumes I and II.

2.1.1.5 Water Resources

B. Surface Waters

2) Principal Streams in Basins - River Crossings

****

Applicant Submission

The pipeline would cross 120 streams, of which 22 are rivers of reasonable size. The list of the streams is given, as well as the depth and flow data (where available) of the major rivers. Further characteristics of larger rivers, such as active flood plains and major channel width, depth, and summer and winter flow rates (most are riverbed-frozen during the winter) are quoted in answer to DoI question 8. Data on major riverbed slopes are presented in answer to DoI question 5. The streams can be divided into single channel, (which are mostly stable except when excessive meandering may lead to channel shift), split channel, and braided sub-channels, the latter two being unstable and subject to lateral migration. The hazard of lateral migration of a sub-channel stream lies in the difficulty in predicting rates of bank erosion when the river shifts and/or in defining location of pipeline sag points outside of possible shift areas. The most troublesome season in which damage to the pipeline crossing could occur would be during the spring breakup, when intense flooding and heavy frontal rainfall can occur. The floods would dissipate themselves quickly in steep rough channels and could be more destructive than any other flow event. Such flows sometimes reach alluvial fans in the Canning River region Northern Engineering

2.1.1.5.B.2 (cont.)

Services Co. (1974) (Appendix A). This problem is recognized, and need for further assessment is indicated in the answer to DoI question 30. In a later disclosure, the Applicant stated that the pipeline will be designed considering potential scour, lateral migration, negative buoyancy requirements, river training, etc.

The proposed approach to river crossing is to bring the pipe below the anticipated potential scour depth. No above-ground crossings are being planned. The crossings would be made perpendicular to the principal flow direction between the foothills and where the distributing channels would fall out.

The effect of chilled pipeline crossing unfrozen ground below a river is examined in answers to DoI questions 2 and 5. Cases are examined for the growth of frost bulbs around the pipe in rivers with small winter flow and in rivers frozen to the riverbed. The conclusion is reached that in either case there would be no adverse effect on the river flow, on riverbed stability, or on the pipeline integrity.

The river crossing would present a hazard to the pipeline due to the possibility of exposing it to hydraulic and abrasive force of the stream flow because of deep, local scour, general bed degradation, erosion of a riverbank beyond the sag point, and erosion in the flood plain area. The protection of the pipe against this hazard would be by deep burial beyond the scour depth, optimal location of the sag point, and provision of negative buoyancy

2.1.1.5.B.2 (cont.)

on river crossing pipe segments. In some cases, the potential for scour, erosion or channel relocation would be so large that deeper burial is prohibitive from economical or environmental considerations, and pipe protection must be provided by means of bank armoring and/or river training.

The provisions for negative pipe buoyancy in certain delineated areas are quoted in the Applicant's report, and the various design means to achieve this buoyancy are discussed in Northern Engineering Services Co. (1974) (Appendix B).

Analysis of Submission

The problems associated with pipeline river crossing could affect both the pipeline and the environment. General criteria for river engineering considering the various factors are presented by T. Blench, "Mobile Bed Fluviology," 1969. The goal of the pipeline construction is to maintain it buried at the approach to and under the river at all foreseeable conditions. In this, river scouring, channeling, bank erosion, flood plain erosion must be considered. The environment could be affected by the pipeline construction precipitating mass wasting on some of the slopes, riverbed degradation, and formation of ice bulbs around the chilled pipe in the unfrozen ground below the riverbed. It is also known that considerable frozen ground exists within active flood plains. Thus, the problem is not merely one of creating frost bulbs, but also thawing and differential movement.

2.1.1.5.B.2 (cont.)

These problems are addressed by the Applicant in a qualitative way with the exception of frost bulb growth, which was calculated for a given set of conditions. However, the vertically asymmetrical growth of the frost bulbs around the pipe in frost susceptible soils could result in an upward shifting of the pipe from its original position. This problem should be examined for specific stream crossings where the frost bulb growth rate would be greater and determine the addition stresses in the pipe resulting from it. The Applicant stated in his later disclosure that the problem areas, if they exist, will be identified during detailed field investigations as a part of the final design.

Coarse grained materials such as those - beneath most streams and rivers on the Alaskan coastal plain" would only be considered non-frost susceptible if they were free of water, i.e., the reason they are normally considered NFS is because they exhibit lower frost heave characteristics. If these types of soil lie beneath rivers and streams, their very nature would dictate that they normally be continually saturated. For this case there would always be a ready and ample source of water available for freezing and frost heave. The normally stratified nature of the stream deposits dictates that detailed subsurface exploration be accomplished.

Statements are made about the pipe burial depth below streams being greater to avoid the scour problem, but no data are given. Interpretation of figures attached to the answer to DoI question 2 of 7 December 1974 leads to a

2.1.1.5.B.2 (cont.)

burial depth of five feet (between the original riverbed level and the top of the pipe). This may not be sufficient, since calculations performed in Northern Engineering Services Co. (1974) (Appendix B) show, for a typical braided river, scour depth of 12 feet, and for a single channel river scour depth of 13 feet. In a preliminary survey of the areas, R&M Engineering (1972) considered the possibility of significant scour depth resulting from local summer channeling below the normal stream bed elevation. More detailed review of the scour depth and pipe burial depth under streams with potential scour hazard is necessary. It is possible, as pointed out in Northern Engineering Services Co. (1974) (Appendix B), that in some cases the burial depth would be prohibitive and, in those cases, the pipe could need additional protection.

The negative buoyancy provisions, while discussed, are not quantitatively defined and it can only be inferred that they would be between five and 20 percent. A more detailed review is required of the magnitude of negative buoyancy provided as a function of the terrain crossed. In a later disclosure, the Applicant stated that 20 percent negative buoyancy is more than adequate and that any reduction in this value will be a matter of final design.

To obtain a better understanding of the local problems at stream crossings, it would be necessary to examine data from a few critical river crossings. Flooding conditions during late summer should be considered.

The crossing of the Canning River is one such example. The pipeline prime route crosses the river normal to its flow at the beginning of a

2.1.1.5.B.2 (cont.)

large, braided flood plane. Bore holes A6 518 and A6 538 indicate sparse ground covering with 1- to 1.5-foot active layer with sand or silty gravels and high moisture content (at the 2-foot depth) of 70 percent. The west bank of the river at the location of bore hole A6 518 is abrupt, 8 feet high, and the whole area is a fossil flood plain with an ice-rich silty-to-fine sand topstratum crisscrossed with large polygonal features 30 to 70 feet in diameter. These features suggest the presence of highly frost-susceptible soils with large quantities of segregated ice (R&M Engineering, 1972) and 15 feet of highly frost-susceptible silt.

The pipeline integrity may be affected in this area by extensive scouring, bank flood erosion, and solifluction.

The Canning River flow in the summer months is maintained by a high precipitation in the Franklin Mountains, and a mean runoff of 2 cf/sec, square mile with a peak of 50 cf/sec, square mile, resulting in large flood areas.

These conditions indicate the need for careful analysis of pipe burial depth and the negative buoyancy provision, to prevent vertical and/or lateral displacement of the pipe in case of channeling or flood erosion.

A second example is the Sadlerochit River, which is fed similarly to the Canning River, with heavy mountain precipitation and a summer runoff. It is a heavily braided river with the pipeline crossing normal to the river. Bore holes A6 560 and A6 561 in the river vicinity indicate

2.1.1.5.B.2 (cont.)

light peat cover, one-foot active layer, beneath which is gravelly sand or organic silty clays of low plasticity containing up to 21 percent moisture. The fossile flood plain is ice-rich silty-to-clean sand and gravel. Surficial indicators suggest the presence of highly frost-susceptible soils with significant quantities of ice, both massive and interstitial (Taylor, 1972).

Since the pipe would cross the braided section of the river, the summer hazard of large inundated areas is even more pronounced than in the previous case, and, therefore, the length of the weighted pipe for negative buoyancy and the depth of burial to avoid pipe exposure under the most adverse conditions require substantiation under worst case assumptions.

A crossing of an unfrozen channeled stream, such as Sadlerochit Spring or others, should also require detailed review, because of the possibility of frost bulbs forming around the buried, chilled pipeline in the unfrozen ground below the stream bed. Calculations performed at $32^{\circ}F$ temperature differential between the pipe and the surrounding permafrost indicated that the maximum rate of freeze would depend on the soil-water content. A growth of this frost bulb caused by water migration toward the cold zone is presented by the Applicant in answer to DoI question 2 of 7 December 1974. The Applicant shows that at 18 percent soil-water content some obstruction of the stream flow starts to occur already after 12 months, and this obstruction is further increased by growing size of the bulbs and possible frost heaving. The hazard to the pipe would lie in the possibility of heavy riverbed erosion and aufies formation.

2.1.1.5.B.2 (cont.)

Conclusions

- o The Applicant presented an adequate review of problems associated with river crossings. However, more details should be given regarding the depth of pipe burial under braided and channeled rivers to avoid the scour problem. The proposed method of control and location should be identified. Flood plain criteria should be stated and compatibility of the pipeline with the criteria adopted with the lateral erosion risk zone should be shown.
- o Possible pipe displacement caused by frost bulb growth under the rivers merits examination and assessment of external stresses imposed on the pipe.
- o Details on the negative buoyancy provisions of the pipe when crossing critical terrains are needed.

Recommendations

(a) The Applicant should provide detail design at all river crossings with supporting analyses to show that depth of burial and negative buoyancy provisions are compatible with worse case assumptions. In a later disclosure, the Applicant stated that this task is a part of the final design of the pipeline. The designs should be submitted to the appropriate regulatory and statutory agency(s) for review and approval.

(b) The Applicant should provide for review and approval flood plain criteria and demonstrate that the pipeline design is in conformance with these criteria. Details of pipe negative buoyancy provisions

2.1.1.5.B.2 (cont.)

as functions of the terrain crossed should be provided and substantiated by analysis.

(c) The Applicant should specify the design flood used and substantiate his choice with analysis of risk for the projected pipeline life versus cost of increased safety.

<u>References</u>

Alaskan Arctic Gas Pipeline Company, (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation 15 March 1975.

Lachenbruch, A.H., (1959) "Periodic Heat Flow in a Stratified Medium with Application to Permafrost Problems," Geological Survey Bulletin 1083-A.

Northern Engineering Services Co., Ltd. (Dec. 1974), "Interim Report - Slope Stability in Permafrost Terrain," prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd., Calgary, Canada.

Taylor, R.S., (1972) "Engineering Geological Reconnaissance of Three Potential Routes for a Gas Pipeline from Prudhoe Bay to the Canadian/ U.S. Border".

2. DESCRIPTION OF THE EXISTING ENVIRONMENT

2.1.1.10 Sociological Factors

D. Environmental Noise Level
****

Applicant's Proposal

The Applicant has not described the background noise level along the projected pipeline route under "Construction Plans and Procedures."

Analysis of Submission

The pipeline would traverse mainly open land where the noise level is that associated primarily with nature. For the most part, the noise level could be characterized as low.

Conclusions

- The existing environment poses no special problems to pipeline construction.

Recommendations

None.

3. ENVIRONMENTAL IMPACTS OF THE PROPOSED PROJECTS

3.1 ARCTIC GAS PIPELINE PROJECT

3.1.1 Alaska Arctic Pipeline

3.1.1.1 Climate

A. Air Quality Change
****

Applicant's Submission

The Applicant states that during the construction phase equipment exhaust emissions will be high locally and that compressor stations are planned for future installation when flow rates are in excess of 250 MCF. The compressors are fueled with pipeline gas.

The Applicant also states that the influence of compressor station exhaust upon air quality will be minimal. At full load conditions when the ambient temperature is 77°F, the 30,000 hp stations with refrigeration will produce approximately 5315 standard cubic feet per second of exhaust gas. Of this quantity, 3.9% will be water vapour, 2.1% carbon dioxide, 77.5% nitrogen, and 16.5% will be oxygen. At an ambient temperature of -40°F, the total exhaust gases will increase to approximately 5690 standard cubic feet per second and the percentage of each component will be slightly changed.

In addition to the primary exhaust components listed above, small quantities of nitrogen oxides, sulphur oxides, carbon monoxide, and unburned hydrocarbons will be produced.

The data provided by the Applicant is summarized in Table 1, Ambient Air Quality Standards For The State of Alaska and in Table 2, Sulfur Dioxide, Carbon Monoxide and Nitrogen Dioxide Concentration Levels

TABLE 1. AMBIENT AIR QUALITY STANDARDS FOR THE STATE OF ALASKA

	AVERAGE CONCENTRATIONS (PARTS PER MILLION)				
COMPOUND	ANNUAL ARITHMETIC MEAN	24 HOUR(1) AVERAGE	3 HOUR(1) AVERAGE	8 HOUR(1) AVERAGE	1 HOUR(1) AVERAGE
SULPHUR DIOXIDE ($S10_2$)	0.03	0.14	0.50	----	----
CARBON MONOXIDE (CO)	----	----	----	9.0	34.0
NITROGEN DIOXIDE ($N10_2$)	0.05	----	----	----	----

NOTE (1) NOT TO BE EXCEEDED MORE THAN ONCE A YEAR.

TABLE 2. SULFUR DIOXIDE, CARBON MONOXIDE AND NITROGEN DIOXIDE CONCENTRATION LEVELS
Compresser Exhaust - Lichen Damage - Air Quality Standards

COMPOUND	CONCENTRATION (PARTS PER MILLION)							
	EXHAUST				LICHEN DAMAGE[8]			AIR QUALITY STANDARDS
	STACK HEIGHT		GROUND LEVEL[4]		NONE	CHRONIC	ACUTE	
	20g	2g[1]	20g	2g				
SULFUR DIOXIDE (SiO_2)	6.0	0.60	0.005 to 0.008	0.0005 to (5) 0.0008	0.002	0.006	0.030	0.030 to 0.50
CARBON MONOXIDE (CO)	10-50[2]		0.08 to (6) 0.13		---	---	---	9.0 to 34.0
NITROGEN OXIDES (NO_x)	105[3]		0.08 to (7) 0.13		---	---	---	0.05
HYDROCARBONS UNBURNED	Negligible		----		---	---	---	---

Notes:
(1) grains per 100 cubic feet - Sulfur content pipeline gas
(2) Minimum value (compressor at full load and peak efficieny)
(3) Average range is 59 to 130 parts per million stated to be primarily NO_2
(4) Western Research & Development Ltd., August, 1965. "An Evaluation of The Air Quality Changes Associated with Construction of a Pipeline Through the Mackenzie Valley"
(5) Stated to be 6.0 Percent (20g) or 0.60 Percent (2g) of NO_x Values (Note 7)
(6) Stated to be identical to NO_x Value (Note 7)
(8) Sidey, Peter, 1975. "Discussion of the Response of Lichens to Atmospheric Sulfur Dioxide with Special Reference to Those of the Mackenzie Valley, Canada"
(9) State of Alaska Air Quality Standards - Range of Values given in Table One.

3.1.1.1.A (cont.)

- Compressor Exhaust - Lichen Damage - Air Quality Standards.

At stack height the sulphur oxides will consist primarily of sulphur dioxide with a small percentage of sulphur trioxide. The quantities of sulphur oxides in the exhaust gases will depend directly upon the quantities of sulphur in the fuel gas. Section 12 of the Application (Tariff) specifies that the gas shall contain not more than 20 grains of total sulphur per 100 cubic feet. However, the gas in both the Mackenzie Delta and Prudhoe Bay contain only negligible amounts of sulphur. Assuming the maximum limit in the gas specification, the exhaust gas would have a sulphur dioxide content at approximately 6 parts per million. With less than 2 grains sulphur per 100 standard cubic feet, the sulphur content of the exhaust gas will be less than 0.6 parts per million at stack level.

Carbon monoxide in the exhaust gases is a product of an incomplete combustion. The quantity will depend largely on the efficiency of the turbine and the load conditions. At full load, the turbines are most efficient and will produce quantities of carbon monoxide ranging between ten and fifty parts per million. At reduced loads, the quantities will increase.

The oxides of nitrogen will be present in quantities ranging between 59 parts per million and 130 parts per million, depending on the type of turbine, and will consist primarily of nitric oxide, with a small percentage of nitrogen dioxide. The nitric oxide rapidly oxidizes to nitrogen dioxide in the atmosphere. The average concentration from a given station will contain in the order of 105 parts per million nitrogen oxides.

Unburned hydrocarbons in the exhaust gases are also a product of an

3.1.1.1.A (cont.)

incomplete combustion. They will be present only in negligible amounts.

At ground level concentrations of nitrogen dioxide and sulphur dioxide shown in Table 2 are for neutral and inversion atmospheric conditions on a calm day downwind of the compressor stations. The maximum calculated concentrations of nitrogen dioxide during plume trapping conditions are .01 ppm at a wind speed of one mph, .05 ppm at a wind speed of 5 mph and .09 ppm at a wind speed of 10 mph. The maximum calculated concentration of nitrogen dioxide during calm conditions is .13 ppm.

The maximum calculated concentrations of sulphur dioxide in the ambient air at ground level are approximately six percent of the concentrations of nitrogen dioxide, assuming the maximum specification limit of 20 grains sulphur per 100 standard cubic feet. This quantity of sulphur, although an extreme maximum, results in calculated levels which are below the limits stated in the regulations (Table 1). A more probable sulphur content of less than 2 grains per 100 standard cubic feet results in the ground level concentrations being less than .6 percent of the quantities shown for nitrogen dioxide.

The maximum calculated concentrations of carbon monoxide are approximately the same as the concentrations shown for nitrogen dioxide. However, the allowable limits are approximately 60 times higher and therefore, the concentrations are well below the allowable limits.

The Applicant states that lichens are generally minor components of plant communities on the Arctic Coastal Plain. They could therefore play

3.1.1.1.A (cont.)

only a minor role in the diet of any caribou that may happen to winter on the Coastal Plain.

Research published by the Applicant (Hettinger and Janz, 1974, Vegetation and Soils of North-eastern Alaska, Biological Report Series Vol. 21) shows that the genus "Cladonia" is extremely rare naturally on the north slope of Alaska.

Quantitative data from communities on the Coastal Plain indicate a relatively low percentage of the total cover is composed of lichen. Some stands, particularly those in wet sedge meadows have no significant lichen cover at all. The only areas which support relatively high lichen cover are those with an extremely irregular microtopography (greater than 1 meter) due to frost heave (usually reticulately patterned ground) and those on xeric, well drained slopes above river valleys. Though limited in a real extent, the first condition is the only one of importance near the prime route since most of the other terrain types occur further inland towards the Foothills.

Compressor station CA-04 east of the Kongakut River is the only one that may be near communities containing a relatively high lichen cover.

Sulphur dioxide levels associated with lichen damage are also presented in Table 2. The Applicant states that the maximum calculated quantity of sulphur dioxide which is expected at ground level from Applicant's emissions is less than .0008 parts per million, based on using a fuel gas containing less than 2 grains sulphur per 100 standard cubic feet. This concentration is well below those levels considered to be harmful to lichens.

3.1.1.1.A (cont.)

The Applicant states that manufacturer studies are continuing to reduce particular oxides of nitrogen in the turbine exhausts by improving combustion chamber and fuel nozzel design. Steam or water injection also has been considered for this purpose, but this method requires a large continuous supply of demineralized water and is not considered practical for Arctic applications.

As regard ice fog, the Applicant states the quantity of water vapour in the station exhaust gases will probably be enough to form ice fog provided atmospheric conditions are right. For ice fog to form, large quantities of water vapour, along with temperatures below -22°F are required. Between temperatures of -22°F and -40°F, an abundance of nuclei are also required for the ice particles formation. Below -40°F, the formation of ice particles is spontaneous and does not require the aid of nuclei.

In areas where ice fog is a problem, such as Fairbanks, Alaska, there is an abundance of unburned hydrocarbons and particulate matter in the atmosphere which originate from automobile exhausts and several coal burning plants in the area. With natural gas as the turbine fuel, if no other contaminants are present in the atmosphere, it is possible that not enough nuclei will be present to form ice fog at temperatures above -40°F. This appears to be the case with existing compressor stations in western Canada where ice fogs are not common during these temperatures.

At temperatures below -40°F, the density and thickness of the ice fog layer will be dependent on the terrain and the degree of stability of the

3.1.1.1.A (cont.)

atmosphere. It is possible that even during temperatures below -40°F, the density of the ice fog will not be high enough to seriously limit visibility.

In addition, the Applicant states that during the startup, during normal unit shutdown for maintenance, or in the event of a mainline break, quantities of natural gas will be expelled to the atmosphere. The low density of natural gas causes it to rise rapidly, thereby making the effects of mainline breaks and ground level air quality only temporary in nature.

<u>Analysis of Submission</u>

The Applicant has not provided an estimate of exhaust pollutants to be released in the atmosphere during the construction phase. The Applicant should provide these data.

The Applicant has provided a discussion of components of compressor station exhaust, expected ground level concentration of sulphur or dioxide and nitrogen dioxide down wind from a compressor station for various assumed atmospheric and terrain conditions, and has provided comments on ice fog formations.

As can be seen from Table 2, maximum expected ground level concentration of sulphur dioxide (to 0.008) are well within the air quality standards of the State of Alaska, even at the level of 20 grains of sulphur in the pipeline gas.

In addition, maximum expected ground level concentrations of sulphur dioxide (to 0.0008) are well below lichen damage thresholds for compressor stations burning pipeline gas with 2 grains of sulphur, but range in the

3.1.1.1.A (cont.)

chronic to acute lichen damage level for pipeline gas containing 20 grains of sulphur.

This is not of immediate importance. Compressor stations will not become operational for up to five years (estimated) after pipeline construction is completed, and the concentration (ground level) computations, even though preliminary in nature, indicate that Alaskan Air Quality Standards are exceeded only on a local basis, and only under a selected set of meteorological conditions. Prior to initiation of compressor station operations, the Applicant should prepare complete ground level concentration computations for sulphur dioxide for pipeline gas sulphur levels to 20 grains. In addition, the Ambient Air Quality Standards for The State of Alaska should be reviewed to determine if provisions shall be made to preclude lichen damage. It is anticipated that additional lichen research would be required prior to instituting such a change to the Ambient Air Quality Standards.

As also can be seen from Table 2, maximum ground level concentration of nitrogen dioxide can also exceed Ambient Air Quality Standards (Table One). This is not of immediate importance for the reasons mentioned previously. Prior to initiation of compressor station operations, the Applicant should prepare complete ground level concentration computations for nitrogen dioxide for the actual gas turbines to be used for this application.

Again from Table Two, concentrations of carbon monoxide and unburned hydrocarbons are at acceptable levels.

A significant problem relative to pipeline integrity is that associated

3.1.1.1.A (cont.)

with ice fog. The compressor turbines would emit large amounts of water vapor. At sub-freezing temperatures this water vapor could transform into ice fog. The same compressor turbines would require large amounts of air for combustion. Ingestion of ice fog by the compressor turbine could cause turbine blade failure with attendant loss of gas delivery, unless preventative measures were to be taken. The Applicant discussed the ice fog condition and indicates an anti-icing system will be incorporated into his (future) compressors (see section 1.1.1.3.C.1).

Conclusions

- Sulphur dioxide, nitrogen dioxide and carbon monoxide concentration levels expected in the construction area have not been defined.

- Sulphur dioxide concentration at ground level downwind of a (future) compressor station will not exceed Ambient Air Quality Standards, burning pipeline gas with sulphur content to 20 grains per 100 cubic feet.

- Sulphur dioxide concentration at ground level downwind of a (future) compressor station will not exceed lichen damage threshold valve (0.002 ppm) burning pipeline gas with sulphur content to 2 grains per 100 cubic feet; but may exceed threshold (0.002 ppm) when burning pipeline gas with 20 grains of sulphur per 100 cubic feet.

- Nitrogen dioxide concentration at ground level downwind of a (future) compressor station may exceed The State of Alaska Air Quality Standards on a local basis under selected meteorological conditions.

3.1.1.1.A (cont.)

Additional study is required to quantify the full extent of these conditions.

- o Carbon monoxide and unburned hydrocarbons concentration levels at stack height are within the Ambient Air Quality Standards for The State of Alaska.

- o An air quality change related to pipeline integrity is the possible creation of ice fog at the compressor stations. Positive means of precluding damage to compressor turbine blades through ingestion of ice fog is required. The Applicant appears to recognize the problem, and his final design should reflect provisions for dealing with this problem.

<u>Recommendations</u>

(a) The Applicant should provide estimates (average) of sulphur dioxide, nitrogen dioxide and carbon monoxide levels to be reached along the right-of-way during construction. Construction schedules should be adjusted to insure these levels are within the Ambient Air Quality Standards of The State of Alaska.

(b) Prior to (future) compressor station operations, the Applicant should quantify the nature and duration of meteorological conditions for which ground level concentrations of sulphur dioxide are expected to exceed lichen damage levels.

(c) Prior to (future) compressor station operations, the Applicant should

3.1.1.1.A (cont.)

quantify the nature and duration of meteorological conditions for which ground level concentrations of nitrogen dioxide are expected to exceed Ambient Air Quality Standards of the State of Alaska.

(d) The Applicant should provide the design measures necessary to preclude ice fog ingestion into compressor turbines during all phases of remote, unattended operation. The Applicant should support his proposed design with test data that verify the design feasibility during operation under continuous ice fog conditions.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaska) of The Draft Environmental Impact Statement of The Department of Interior Regarding the Alaska Natural Gas Transportation System.

Alaskan Arctic Gas Pipeline Company (November 15, 1974) Supplement to Submittal - Docket No. CP74-239.

Environmental Protection Agency (July 1974) Assessment of The Applicability of Automotive Emission Control Technology to Stationary Engines, EPA-650/2-74-051.

Technical Interchange Meeting (October 27 & 28, 1975) Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

3.1.1.2 Topography

A. Development of Erosion Hazard

1) Pipeline Right-of-Way

****

Applicant's Submission

The Applicant presents seven factors controlling water erosion and discusses countermeasures. The overall plan is to minimize interference with natural drainage patterns until revegetation is effective. The Applicant discusses the case of control measures, such as (1) mound breaks, with suitable diversion dikes and ditches, (2) plugs on downslope sides, (3) riprap to control gullying, (4) ditch plugs, and (5) grading of slope cuts with breakers, crossberms, terraces, and diversion ditches as required.

Other topics discussed are the stability of frozen slopes in terms of creep and deep-seated failure, and differential settlement in terms of thaw, erosion, and compaction.

Considerable material on erosion is presented by the Applicant's alignment sheets, photomosaic strip maps giving such information as the preferred type of control measure (based on soil type and slope) and spacings of mound breaks.

In addition, the Applicant presents specifications for a general revegetation plan. In this plan, the initial seed and fertilizer application is planned to occur during the winter construction phase. A tracked

3.1.1.2.A.1 (cont.)

vehicle containing seed and fertilizer and equipped with cyclone seeders will follow behind the equipment, closing the ditch, spreading seed and fertilizer over the backfill mound and right-of-way. It will be necessary to seed areas subject to erosion by run-off and settlement of the backfill mound in the late spring using helicopters, but the ground based winter seeding will ensure a more uniform seed and fertilizer application over most of the right-of-way. Winter seeding will also take advantage of the numerous micro-habitats formed by the frozen backfill and of the moisture provided by early spring snow melt. Studies established at Tuktoyaktuk in the winter of 1974-1975 have demonstrated that winter seeding has no apparent adverse effects on germination or seedling establishment.

Areas having a high erosion potential will receive site specific treatment by ground crews flown in by helicopter the spring following construction. These crews, including both engineering and revegetation personnel, will have visited each of these sites prior to construction and drawn up detailed reclamation and erosion control plans. In addition to seed and fertilizer applications, revegetation measures include sod replacement, erosion control mats, insulated seed mats, mulches and stem cuttings. These techniques are well known and have proven useful in temperate areas and should provide additional protection against erosion in northern regions. Field studies are continuing to evaluate their effectiveness for erosion control in Arctic and sub-Arctic regions. In addition, the Applicant presented data from analyses by NESCL on the thermal effect of an unchilled pipe left in the ground for 2 years on the right-of-way and work pad active layer and settlement.

Analysis of Submission

The Applicant's treatment of erosion hazards and controls is extensive. However, since no specific criteria are presented, there are many opportunities for error.

The Applicant claims that control measures would be designed to minimize disturbance to the existing hydrological regime. It is assured, in view of the worst possible orientation of the pipeline with respect to the numerous drainages of this section, that significant modifications of the existing hydrological regime could occur, regardless of the construction method or season of construction. Countless opportunities exist for cross-drainages to be diverted parallel to the pipeline and for thaw degradation ponding situations to develop.

The Applicant discusses the effects of the interruption of water flow in the active layer on side slopes, due to intrusion of the ice ball around the pipe into the active layer and the tendency of water to be impounded on the upslope side of the pipe. Mitigating measures are discussed; however, no criteria are presented for maintaining runoff velocities below erosive velocities. Overfill of berm required to compensate for snow and ice content aggravates the problem and necessitates more comprehensive criteria.

Permafrost over the pipeline would be 1.5 feet higher over the pipe than over the rest of the adjoining slope. During spring thaw and fall freeze, there would be a time, therefore, when the permafrost along the pipeline would intersect the surface, while the upslope and downslope contiguous area has thawed to a depth of one to 1.5 feet. During spring, the quantity of moisture in the soil and above ground would be high. Although mound breaks would be provided, they would be blocked by localized aufeis and heavy drifted snow, which would precipitate erosive velocities and channelization outside the

3.1.1.2.A.1 (cont.)

mound breaks. The improper handling of this problem could clearly modify surface drainage, induce local mass wasting adjacent to and downslope of the pipeline. Severe erosion downslope of the pipeline would be progressive and could threaten pipeline integrity if a landslide were induced. The erosion hazard will be further aggravated by the unchilled pipe because of possible subsidence and change in drainage pattern.

The Applicant performed thermal studies on the soil temperature in the right-of-way and under gravel pads (see section 1.1.1.6.B.1 and section 1.1.1.6.C.2). It was shown that under certain assumptions the active layer depth never went below the pipe and that under 5-ft gravel pads it was less than normal. Settlement of berm above the pipe and of the gravel pad was also calculated and shown to be small.

It is, nevertheless, to be expected that the settlement and drainage phenomena with the unchilled pipe will present a greater problem than anticipated by the Applicant due to factors such as: flow of water in the ditch interface and water ponding between ditchplugs, cracking of the berm and its accelerated erosion, channeling on the side of the berm. It would be prudent for the Applicant to review the mitigating measures to forestall some of these problems.

The main emphasis of erosion control measures must be directed toward the control of surface runoff. The excavation of the permafrost and the presence of the pipeline would not present the optimum conditions for the establishment of revegetation. The Applicant presents some data in

3.1.1.2.A.1 (cont.)

Battelle (Volume IV) on revegetation tests. Some success was achieved in optimum areas but, in areas where gravel was concentrated at the surface or settling caused a concentration of gravel, the revegetation was not established even in the second year. Further extensive information on revegetation programs was provided by the Applicant in the Preliminary Pipeline Revegetation Specifications for areas North of 60°. In the experimental work described there, it was found that native grasses such as Polar grass and Bluejoint were most successful in the third year in terms of row cover, biomass production and flowering, but that they are not commercial seed sources of either species, and other agronomic varieties (red fescues and Nugget Kentucky Bluegrass) may be considered as successful alternatives until native lichens and mosses are reestablished. However, the Applicant does not present any criteria from these tests to guide his revegetation program. The Applicant will need to establish such criteria and other erosion control methods would be necessitated to span the two-or-three-year interval required to establish revegetation."

<u>Conclusions</u>

o The Applicant discusses all of the applicable erosion control methods; however, success in utilizing these methods depends upon the criteria used for the selection of control methods for each case.

3.1.1.2.A.1 (cont.)

Recommendations

(a) The Applicant should develop criteria for submittal to the appropriate regulator and/or statutory agency(s) for review and approval, which will allow areas with a high potential for accelerated erosion to be defined on a detailed basis and in a manner suitable for portrayal on construction drawings. These criteria should provide methods for the calculation of required quantities of backfill, mound breaks, culverts, ditch plugs, borrow, and other control and restoration measures. Criteria should consider soil type, including thermal state and moisture content, topography, climate, hydrology, construction mode, and grading geometry. The various specific control measures should be formalized to the point of standardization, such that they can be specified to apply, with appropriate modifications for local conditions, to any section of the pipeline.

(b) The Applicant should provide specific criteria to restore any river banks that have been breached for crossing, and to protect them from excessive erosion.

(c) The Applicant should take measures to ensure that surplus spoil is not disposed indiscriminately on right-of-way with an undisturbed vegetative cover required as an erosion control.

(d) The Applicant should provide more information on creep and deep-seated failure in frozen soil, where he states that substantial field investigation is called for. Specifically, a survey should be made

3.1.1.2.A.1 (cont.)

in the field of potential sites for each type of failure, the soil creep measured, and the deep-seated failure potential evaluated by the methods described in the Applicant's Submission.

(e) The Applicant stated in a later disclosure that topsoil and the organic material will be removed and then replaced on the top of the backfill. Also, statements were made for ground fertilization and seeding grass as an interim vegetation cover. The Applicant should provide a more comprehensive plan for post-construction revegetation program.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

Northern Engineering Services Company, Ltd., (September-1975) Preliminary Pipeline Revegetation Specifications for areas North of 60°.

Northern Engineering Services Company, Ltd., (June 1974) Application of Geotechnic Analyses for Canadian Arctic Gas Study, Ltd.

3.1.1.2 Topography

A. Development of Erosion Hazard

2) Borrow Areas
****

Applicant's Submission

The Applicant proposes to obtain borrow materials from pits in river flood plains shown on the alignment sheets. These borrow sites will be developed at least 2000 feet from the pipeline itself. Mining of borrow will not take place in the channels of the active floodplain but rather to shallow depth in gravel bars and other areas of the floodplain which do not have flowing water. The siltation due to borrow operations in active floodplains is not expected to occur owing to special design criteria which have been developed; for example, a berm will be constructed around the entire borrow pit, thereby preventing any silt from reaching the actively flowing watercourse. In addition, borrow sites in the Sagavanirktok, Kadleroshilik, Tamayariak, Jago, Aichilik, and Clarence Rivers will definitely be located at least 2000 feet from the pipeline.

Typical borrow pit development plans are shown in the document "Pipe-line Related Borrow Studies" which was submitted in answer to Question 19 of the Federal Power Commission request for supplemental information. Mining plans for each individual borrow site will be done during final design. Where flood plains are not available other areas would be used. Restoration of borrow pits would be performed by grading, contouring, reseeding, and application of fertilizer.

Analysis of Submission

Some borrow areas would be upstream of the pipeline, and the pipeling integrity will rely to some degree on the success of the Applicant's measures to control erosion in these areas.

3.1.1.2.A.2 (cont.)

Disposal of waste or spoil material is not discussed. Such material could be generated in all or most cuts or during ditching. Disposal is difficult in treeless regions.

Conclusions

- o The borrow pits are remote from the main rivers and the pipeline.
- o Complete analysis of disposal of spoil and rehabilitation of borrow pits should be provided by the Applicant.

Recommendations

(a) The Applicant should review the location of the borrow pits and show that erosion resulting from them would not threaten pipeline integrity.

(b) The Applicant should provide a plan for disposal of waste or spoil materials and for borrow pit rehabilitation.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaska) of the Draft Environmental Impact Statement of the Department of Interior Regarding the Alaska Natural Gas Transportation System.

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation 15 March 1975.

Northern Engineering Services Co Ltd (1974) Pipeline Related Borrow Studies.

3.1.1.2 Topography

B. Inducement of Landslides and Rockfalls During Construction by Blasting and Trenching

Applicant's Submission

As discussed in section 2.1.1.2.D, 90 percent of the slopes traversed are less than 3°, and most of the remainder are between 3° and 9°. The Applicant proposes to use special ditching equipment for trenching in frozen soil during the Alaskan winter construction period. Blasting may also be used in certain soils.

Analysis of Submission

If the development of suitable ditching equipment is successful (see section 1.1.1.6.B), there should be no inducement of landslides or rockfalls during the construction period in the frozen materials.

Even if blasting would be required, the relatively mild slopes and the nature of the frozen soils make it extremely unlikely that landslides would be induced. Blasting could, however, result in slumping, soil fall, or snow avalanches along steep slopes and steep river banks. Battelle (1964) (Volume 1) states that blasting techniques investigated to date have been found unsuitable for ditching in permafrost.

Conclusions

- The key to the feasibility of the Applicant's submission rests on the successful development of suitable ditching equipment.
- Unique techniques and precautions may be required for blasting in permafrost.

3.1.1.2.B (cont.)

Recommendations

(a) Recommendations (a) and (d) of section 1.1.1.6.B.1 should be implemented.

(b) The applicant should identify areas along the pipeline route which, when subjected to blasting groundshocks, may be susceptible to slumping or soil fall and slopes which may be susceptible to avalanches. The Applicant should specify the special precautions to be taken when blasting is required in these areas. In a later disclosure, the Applicant has stated that there are no known areas along the Prime Route that are susceptible to blast-induced slope failures or avalanches. The Applicant should identify areas where the need for blasting is anticipated and evaluate the stability of these areas to substantiate his statement.

References

Battelle Columbus Laboratories (June 1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region," Final Report, Volume I.

Alaskan Arctic Gas Pipeline Company (October 28, 1975), "Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnical Evaluation," 15 March 1975.

3.1.1.3 Geology

B. Destruction of Permafrost in the Applicable Areas
****

Applicant's Submission

The Applicant proposes to operate the pipeline at temperatures below freezing to maintain the pipeline and the soil contiguous thereto in a permafrost condition. The Applicant has conducted tests on lengths of pipe, buried as he proposed, and data have been obtained for the non-operating and emergency shutdown modes.

The Applicant has stated that the pipeline may remain inactive for up to one or more years after construction, and while it would be desirable to begin chilled operation immediately following winter construction, the Applicant's designs are not founded on this assumption. The Applicant has conducted geothermal calculations on the required depth of pipe burial for an unchilled pipe. (NESC - December 1974). These calculations were undertaken using two consecutive years of warmer than average temperatures during the thaw season. It was found that for a pipeline buried at the depth of 4.0 feet below original grade, and average backfill properties, that thaw proceeded to about the top of an unchilled pipe. It was noted that backfill with low water contents could thaw to greater depths. In this case however, the amount of settlement and potential for instability is less than in higher ice content permafrost soils because the native backfill reflects the properties of parent material and is itself thaw-stable.

3.1.1.3.B (cont.)

In addition, the Applicant states that some surface water will infiltrate into the backfill, but that the infiltrated water will freeze in site due to the low ambient temperature of the soil, thereby providing a latent heat barrier. The latent heat barrier will serve to retard deepening of the active layer over the thaw season. In Alaska, the top of the pipe will be 1 to 1-1/2 feet below the top of the surrounding permafrost table.

With regard to effect of water migration within the backfill materials, the rate of movement will be limited by both the permeability of the frozen backfill materials and the slope of the ditch. Much of the Alaskan portion of the coastal route is in flat to relatively flat terrain, and potential for significant movement of water along the pipeline ditch is small. On slopes such as river crossings, ditch plugs will be provided to prevent continuous flow along the pipeline.

It is also stated that in an area of very cold permafrost such as the Alaskan North Slope, the gas is being chilled primarily to prevent (warm gas) thawing of frozen soil rather than being chilled to freeze wet soil.

Analysis of Submission

The Applicant has not considered conditions as they could exist when the pipe would be installed in the ditch through startup and stabilization of the pipeline temperature. The thermal path from the surface through the ditch containing the pipeline would be considerably altered from the conditions that prevailed prior to laying the pipe and the transition from the construction to operation has not been adequately studied. The Applicant should perform this analysis. This is discussed in section 1.1.1.1.B.2.

3.1.1.3.B (cont.)

The Applicant has considered the case of the unchilled pipeline, and has stated that thaw depths would be greater than indicated by the current analyses, for extreme rather than average backfill thermal properties. In addition, surface water infiltration is mentioned and stated to freeze. This freezing can cause berm cracking which contributes to berm erosion. The implications of this are discussed in sections 1.1.1.1.B.2 and 1.1.1.6.B.2.

The snow roads and pads proposed (see section 1.1.1.6.B.1) may not preclude damage or destruction of the underlying vegetation. The effect of winter roads on vegetation in the Arctic environment was studied by Battelle, Muskeg Research Institute, and others. It appears that some damage to the underlying vegetation is inevitable for a road with multi passes of heavy equipment. This damage can be minimised with sufficient snow thickness and with the start of traffic and its termination timed to the weather conditions. Methods for assessing damage to, and criteria for repair of, the terrain should be developed by the Applicant.

Conclusions

- Operation of the chilled pipeline at temperatures below freezing will maintain the soil in a permafrost condition.
- The Applicant has not considered thermal stabilization of the pipeline for the installation and start-up period. This is discussed in section 1.1.1.1.B.2.
- The Applicant has considered the case of the unchilled pipeline in a disturbed (ditch plus backfill) permafrost soil. This is discussed in section 1.1.1.1.B.2.

3.1.1.3.B (cont.)

- The Applicant has considered damage to the terrain and vegetation during the use of snow road and snow pad. This is discussed in section 1.1.1.6.B.1.

Recommendation

(a) The Applicant should develop criteria to specify the gas temperature (maximum) that will be permitted on a temporary basis, to accommodate the eventuality of "Gas Chiller Failure". These criteria shall be submitted to the appropriate regulatory and/or statutory agency(s) for review.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaskan) of The Draft Environmental Impact Statement of The Department of The Interior Regarding the Alaska Natural Gas Transportation Systems.

Battelle Columbus Laboratories (1972),"Prudhoe Bay Test Facility Oversnow Vehicle Impact Studies."

Muskeg Research Institute (August 1972), "Inspection of Winter Roads at Mallik and Taglu," University of New Brunswick.

Northern Engineering Services Company Ltd. (June 1974), Application of Geotechnical Analysis for Canadian Arctic Gas Study Ltd.

3.1.1.3 Geology

C. Effects on Slope Stability
****

Applicant's Submission

In general, slopes less than 3° are considered stable, and no special measures are anticipated to control mass movement on such slopes. In answer to DoI question 3, it is stated that ice-rich native soil would be used as backfill, since any consolidation of backfill would not affect the pipe, which will be secured in the permafrost.

Slopes greater than 3° may be subject to instability, but less than 10 percent of the slopes traversed are in that category. The table attached to the answer to question 3 lists 56 such slopes. The steepest slopes are over 9°.

The slope failures may be shallow or deep-seated. The shallow slope failures, associated with the mass movement in the active layer, are not considered a hazard to the pipe integrity. The deep-seated slope failures involving soil movement at a depth greater than eight to 10 feet would present the greatest threat to pipe integrity. An analytical method to predict where such failures could occur is not available; consequently, a close inspection of aerial photographs and site inspection is required to assess the general slope and ground condition. Similarity between the slopes which displayed instability and the other slopes inspected by the Applicant will be regarded as one of the criteria for identifying potentially unstable terrain.

3.1.1.3.C (cont.)

An analytical method is presented for assessment of mass movement caused by thaw consolidation in the thawing active layer. This method is described in the Applicant's report and in more detail in the Appendix attached to the answer to question 24, "Slope Stability in Permafrost Terrain," by Northern Engineering Service Co., Ltd. (1974). The analysis is based on the one-dimensional model of Morgenstern and Nixon (1971), in which two important parameters are the thaw consolidation ratio (R) and the coefficient of consolidation (C_V). Where the values of R are low in a thawing soil, no excess water pore pressures would be generated and the slopes would be generally stable. If the values of R are high, the effective shear stress level of the soil approaches zero, and mass movement on the slope would be likely to occur. Although this method is conservative in that it neglects the two-dimensional stability effect of the soil, there are possible combinations of soil type and ice conditions such that the method of analysis is not conservative. In ice-rich, low permeability soils, the simple linear thaw-consolidation model formulated by Morgenstern and Nixon (1971) is not conservative and underestimates the magnitude of the excess pore pressures generated in thawing soil (NESCL interim report, "Slope Stability in Permafrost Terrain," 1974).

"Excess pore pressures can be generated by processes other than thaw-consolidation. Cyclic loading (associated with earthquakes) generates excess pressure even after a few cycles and although liquefaction in the true sense of the word may not occur, slope failure may be initiated in marginally stable areas. Also, surface ponding and/or infiltration may lead to subsurface flow gradients which could cause unacceptable excess pore pressure to develop."

The removal of vegetation on the slopes has two negative effects: It increases the rate and depth of thaw, which may lead to instability, and the mass balance is affected, such that stable slopes could become unstable due to changes in evapo-transpiration rate along (see answer to question 23).

The various means of slope stabilization are discussed in the answer to DoI question 24. In answer to DoI question 15, sketches are presented showing potential means of protection of slopes undercut by pipeline construction.

Analysis of Submission

Slope instability is one of two major hazards of the buried pipeline that merits careful evaluation, and this was recognized by the Applicant. The problems connected with steeper slopes in permafrost, the means of slope stabilization, the effect of construction, and the analytical tools available are extensively discussed by the Applicant. However, the descriptive material is of general nature and is not applied to specific slopes along the pipeline route.

The generalized statement that slopes less than 3° are stable may not be true. Such slopes, when composed of liquefiable solids, would be susceptible to skin flow within the thawed active layer in the event of liquefication. Slope failure would also be induced by stream or gully

3.1.1.3.C (cont.)

erosion, resulting in undercutting and localized oversteepening of the adjacent flatter slopes. All slopes exceeding 3^{o} are subject to the same hazard, and, in addition, they could be subject to static instability discussed by the Applicant.

Flow intercepted by ditch plugs should be properly diverted so as to avoid creating erosion or icing problems. As stated by the Applicant, the pipe ditch can be expected to intercept groundwater flowing in the active zone. On slopes where permeable bedding and padding material is used in the pipe ditch, the intercepted groundwater could, before initial throughput and subsequent ground freezing, readily flow through the ditch padding and bedding. Before initial throughput, this groundwater flow would tend to thaw the natural permafrost surrounding the bedding and padding. As the permafrost thawed, it could be progressively eroded, creating voids around the bottom and sides of the pipe, which could cause differential pipe settlement or movement. Once initiated, the progressive erosion may continue after pipeline operation, despite the cold pipe. On the other hand, if the natural permafrost was not erodible after thawing, the intercepted flowing ground water could create a thaw bulb around the pipe. The thaw bulb may freeze back after throughput begins; however, it could continue to grow even after permafrost was established. Because the pipe is not necessarily buried in thaw-stable material, the developing thaw bulb could lead to slope instability. Both possibilities could be avoided by eliminating the flow of intercepted

3.1.1.3.C (cont.)

groundwater through the padding and bedding where thaw-unstable materials lie below the pipe.

The use of trench drains to control drainage along the right-of-way slopes in thaw-unstable permafrost could prove unsuccessful. Aggravated thermal degradation, due to both the occurrence of the trench drains themselves and the flow of drainage water within them, would tend to render the drains inoperative through the effects of thaw settlement on the trench drains; the drains could completely sink into the thawing permafrost. In general, wherever drainage facilities constructed on thaw-unstable permafrost can cause thermal degradation, the resulting disturbance can lead to ineffective operation of the drainage facilities.

In the analysis of shallow or deep-seated slope failures, criteria should be developed as to the degree of slope movement which is critical to pipe integrity. In that analysis, the angle between the pipeline and the slope would be important. Pipeline running perpendicular to the slope (or undercutting the slope) would be more damaging to the slope stability with higher external loads imposed on the pipe than at other relative angles. To provide more detailed data, all slopes should be categorized with respect to the mass wasting hazard, relative angle to the pipeline, and external loads imposed on the pipe in chilled or nonchilled condition. Representative slopes of each category should be analyzed and method of slope stabilization, if necessary, described.

3.1.1.3.C (cont.)

Three specific examples of slopes with various angles between the pipeline and the slope are discussed below.

In the foothill area, one of the steeper slopes reviewed ($4.5-5^{o}$) is situated approximately four miles east of the Katakturuk River. The pipeline runs parallel to the slope. It crosses ice-rich silty and organic soils probably overlying old morainal deposits of till. Thawing of these soils would result in a great loss of volume and the generation of large quantities of water. If this water were allowed to form ponds it would tend to accelerate melting; if it were allowed to flow, precautions would have to be taken to prevent the rapid erosion which would otherwise take place. Additionally, due to the interception of water from the active layer and from the numerous small streams, care would have to be taken to avoid concentration of flow and consequent thermal degradation and erosion of the soil and the formation of icings in the winter. The slope is projected to be located in smoothly rounded silt-manteled sloping regions, composed of thick (up to 50 feet) eolian (silt) and colluvial (organic silt) deposits with many inclusions of ice. The moisture content for samples recovered below the active layer varies from 40 to 90 percent. Due to sample unreliability, the actual moisture content experienced in construction could be significantly greater.

The removal of the organic mat for pipe burial would, as mentioned above, upset the heat equilibrium of the slope. With unchilled pipe, the thaw depth would increase and excess pore pressure may be generated during

3. 1. 1. 3. C (cont.)

the thaw of fine-grained soils. Excess pore pressure would occur if water were to be released at a rate exceeding the discharge of capacity of the soil. As a result of this, the effective shear strength of the soil would be reduced with probable initiation of skin flows. The skin flow, which may be below pipe level, would cause a vertical movement of the pipe and, depending on the magnitude of the mass movement, pipe stresses could be substantially increased. This vertical movement of the pipe would be further aggravated by reduction of the negative buoyancy of the pipe, because of water excess in the pipe trench. The slope flow may vary from inches/year to feet/year, depending on the soil condition and the disturbance introduced by pipeline construction. A more detailed assessment should be made by the Applicant from analyses of these data.

Another slope in the foothill zone, which was selected for review, lies approximately four miles west of the Egaksrak River. It is a low angle slope ($1/3^{\circ}$ to 2°) and was selected because the pipeline direction is 45° to the slope. The slope is a part of an alluvial fan underlain by deep silting to clean sands and gravel sands. The bottom of the slope merges with the fossil flood plain with less than five feet of ice-rich silting to fine sand topstratum. Mass movement which could occur for the reasons mentioned before would cause vertical and lateral displacement of the pipe, although the lower angle of the slope would mitigate this movement.

3.1.1.3.C (cont.)

The third type of slope which merits examinations is the slope running perpendicularly to the pipeline in the alluvial fan. The sample is situated approximately four miles east of the Turner River near the Canadian Border. This zone is characterized by gently rolling terrain cut by broad, very gently sloping flood plains and alluvial fans which become the predominate features east of the Aichilik River at mile 150. The soils in the floodplains and alluvial fans are comprised primarily of gravels, although the drill hole data indicate the presence of isolated pockets of ice-rich fine grained soil. Silty surficial deposits generally less than five feet thick are commonly associated with the alluvial fans and the "fossil" floodplains. Permafrost is essentially continuous. A thin active layer consists of inorganic silts and clayey silts with low plasticity. Moisture content (from bore hole data) varied from low in grained soils to 200 percent in fine grained soil. The general characteristics of the terrain are similar to the previous slope (alluvial fans with low gradients, $1/3^{\circ}$ to 2°). Erosion is not expected to be a problem in these gravels, except at river crossings or where subjected to flooding. Thawing could, however, initiate problems. Because of a lower specific heat and a greater depths than fine-grained soils under similar circumstances. Settlement could be large enough to be a problem, and the loss of fines through piping could accentuate problems or cause siltation. While no massive ice was observed in the drill holes, an important fact is that massive ice (wedges) has been observed in gravels in the Arctic.

3.1.1.3.C (cont.)

A skin flow initiated by the surface disturbance associated with the right-of-way and trench would cause lateral pipe displacement which would be particularly hazardous if the displacement were to involve several sections of pipe length of a magnitude resulting in unsafe pipe bend curvature. The probable failure would be in the weld area with possible pipe deformation.

<u>Conclusions</u>

- o The Applicant presented a comprehensive description of slope stability problems, including analytical models which could be used to assess active layer mass wasting and means of slope stabilization.
- o The description is general and does not address specific slopes in the prime route (except for providing a list of steeper slopes), nor does it categorize the slopes as to their mass wasting hazard. Such information is required for finalization of design and assessment of pipeline integrity. Such assessment cannot be based on conceptual design, but only on detailed geotechnical data. The Applicant stated in a later disclosure that analyses of slopes as mentioned above can only be undertaken during the final design studies.
- o The statement that all slopes below 3^{o} are stable and that shallow failures will not affect pipe integrity should be re-examined and supported by more data on slopes crossed and external pipe loads expected from mass wasting. In a later disclosure, the Applicant agreed that low angle slopes in lobate frontal regions of bimodal flows may be unstable

3.1.1.3.C (cont.)

and stated that this type of slope instability can be easily arrested. The Applicant presented various methods for stabilizing of bimodal flows but the long term performance of such methods is as yet unknown.

o It is necessary also to examine the problem of slope stability for chilled as well as non-chilled pipeline, in case the pipe remains inactive after construction for one or two years. The Applicant stated in a later disclosure that his analysis of slope instability ignored in essence the thermal influence of a chilled pipe, and that the design of permafrost slopes and ditch backfill assumes a non-chilled pipe where appropriate. In the determination of methods adopted for slope stabilization of an unchilled pipe, primary consideration should be given to the pipe integrity and any mass wasting should be controlled to not exceed the threshold of allowable pipe movement. The slope stability criteria so developed should also be verified for a chilled pipe. The Applicant stated in a later disclosure that incremental loads from slope movements must be considered but that the loading will only occur in deep-seated creep movements that result in shear failure along deep-seated slip surface. The Applicant has a field program under way on investigation of deep-seated creep movement in natural permafrost slopes.

Recommendations

(a) All slopes should be categorized with respect to their potential instability, relative angle with respect to the pipeline, and mass wasting hazard.

3.1.1.3.C (cont.)

Slope stability analysis should cover the case of chilled and non-chilled gas.

(b) Typical slopes from each of the categories should be selected for detailed review. External loads on the pipe resulting from mass wasting should be established and slope stabilization method (if required) should be defined.

(c) The Applicant should determine the degree of slope movement that can be expected and establish criteria for including loads resulting from this factor into the pipeline thickness determination in accordance with recommendations in section 1.1.1.3.A.1.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments on Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation 15 March 1975.

Morgenstern and Nixon (1971), "One-Dimensional Consolidation of Thawing Soils," C. Geot. Journal, 10, pp. 558-565.

Northern Engineering Services Co., Ltd. (December 1974), "Interim Report - Slope Stability in Permafrost Terrain," prepared for Alaskan Arctic Gas Co Ltd and Canadian Arctic Gas Co Ltd

3.1.1.6 Effects of Leaks on Vegatation and Wildlife
3.1.1.7 **************************************

Applicant's Submission

Pipeline rupture could cause temporary adverse localized impacts on vegetation, water and air quality, wildlife and aesthetic attributes. The Applicant states that repair and maintenance programs would alleviate the major long-term impacts associated with this type of accident.

Accidental leakage of gas under stream crossings would be of no significance to fish in the vicinity of or downstream of any leak. Escaping methane would diffuse into the atmosphere because it is not highly soluble in water. The only exception to this would be if escaping methane were trapped under ice. The Applicant concludes that the chances of this occurring in such locations as to represent a hazard to fish population are remote.

Pipeline emergencies requiring heavy construction vehicle access could cause vegetation mat compaction and localized surface damage. However, some Battelle tests have not shown significant tundra mat surface changes. Implementation of revegetation programs and practices is indicated to be under consideration.

The secondary effects of pipeline failure are studied through consideration of the potential for fires and the effects of fires. Generally, tundra fires remove all of the litter and some of the peat, but only char the cottongrass tussocks where this community type is dominant. Some woody species and lichens are consumed, while most mosses are scorched and killed. The effects of tundra fires in the Inuvik area, N.W.T. were reported by Wein and Bliss (1973). Due to the lower-standing biomass and cold, frequently very wet soils, fires in tundra areas are considered much less damaging and usually are of much less extent than in forested areas farther south.

Recovery from fires in tundra areas is rapid, except for lichens, complete recovery generally requiring two to three years. Cottongrass (Eriophorum sp.) and Labrador tea (Ledum palustre sp. decubens) show the most regrowth in the first year. Liverword (Marchantia polymorpha) is often an important soil solonizer in some localized wet areas. Fire often stimulates the growth of the cottongrass (Eriophorum sp.) and bluejoint grass (Calamagrostis canadensis).

Analysis of Submission

The impacts of leaks on vegetation and wildlife are of two types, non-persistent damage, which results only in temporary effects that can be rectified, and persistent damage, which is manifested by an irreversible ecological change in either vegetation, or wildlife population, habits, or habitat. These effects may be due to accidental low-level or undetected gas leakage during operation.

The Applicant, in examining the effects of normal operation and maintenance of the pipeline, does not consider the fact that natural gas composition is not entirely methane but includes also some species with higher molecular weight than air. Differential diffusion of underground (permafrost) leakage could cause local temporary oxygen starvation, but persistent damage would not be expected if the leakage is detected and the necessary repairs effected quickly. A matter that becomes pertinent to accidental leakage loss effects upon the environment is rapid detection, in order to prevent the possibility of persistent damage. The Applicant does not discuss methods for detecting losses due to leaks.

Environmental Protection Agency studies have indicated that an important source of damage to wildlife and vegetation from hydrocarbons is attributable to the presence of ethylene. This is not discussed by the Applicant. Whereas the Applicant discusses the effects of leakage under stream crossings on fish, no mention is made of leakage effects on terrestrial wildlife.

The most catastrophic problem would be pipe rupture. The effect of pipeline rupture on wildlife and vegetation is not discussed by the Applicant, other than the general statement that pipeline rupture could cause temporary adverse localized impacts on vegetation, water and air quality, wildlife and aesthetic attributes. Any major gas leak, if it occurs, is associated usually with spontaneous flaming of the gas at some altitude above the ground at which flammable air/gas mixture is formed. The damaging effect of the heat input from the flame to the vegetation cover will depend on the intensity and duration of the fire, on the moisture content of the vegetation, on the type of vegetation, but if a damage occurs it will be usually confined to the upper 0.5 cm of the tundra ("Environmental Impact Assessment" by Canadian Environmental Protection Board) and should not result in a major environmental impact. No mitigating measures other than prompt maintenance and repair were offered. The Applicant does not specify the probability of such a catastrophic event.

The Applicant does note the secondary effects of pipeline failure, as presented above. Control would presumably be accomplished by isolation of the line section and allowing gas to vent to the atmosphere. In such an instance, depending upon the reaction time, system average pressure and temperature, and assuming a 15-mile distance between the isolation valves, approximately 4500 tons of gas could be released.

Conclusions

- The Applicant has discussed effects of leaks on vegetation and wildlife in a qualitative manner but has not determined the magnitude of leakage required for specific types of damage or, conversely the threshold level below which damage would be negligible.

Recommendations

(a) The Applicant should establish a threshold level of leakage (if any), which would not cause damage to vegetation and wildlife.

(b) The Applicant should show that his leakage detection method(s) would be capable of locating leaks of the

3.1.1.6 and 3.1.1.7 (cont.)

magnitude defined by the Applicant in recommendation (a) above. A research program aimed at sensors and methods suitable for the inaccessible North Slope, and applicable to an internal pig or overflying airplane, should be conducted.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaska) of the Draft Environmental Impact Statement of the Department of the Interior Regarding the Alaska Natural Gas Transportation System.

3.1.1.10 Sociological Factors (Construction and Operation)

C. Environmental Noise Levels
****

Applicant's Submission

The noise level from each compressor station to be built in the future, as shown in section on Future Plans, is estimated at 50 dbA units at 2000 feet from the station boundary.

Compressor noise simulation tests were performed at a sound level of 71 to 90 db at 1/8 of a mile. (Note: 71 db with A weighted was 65 dbA, which was higher than the anticipated noise of future compressors equipped with silencers.) The objective of these tests was to determine the effect of future compressor stations on arctic wildlife. Disturbance to some of the species was noted with only a minor response by caribou, but snow geese were more sensitive.

Comparing estimated noise levels with criteria for nonaircraft noise sources measured outdoors, they could be classified at distances greater than 1000 feet from the station as "normally acceptable" for daytime residential areas. This operational noise level presents no problems with future installations.

It was stated by the Applicant that the noise connected with construction activities on the pipeline will be insignificant from an environmental point of view. Any impacts on wildlife will be temporary because of the short duration of construction time. It was also stated that all noise criteria will be completed well before pipeline construction.

3.1.1.10.C (cont.)

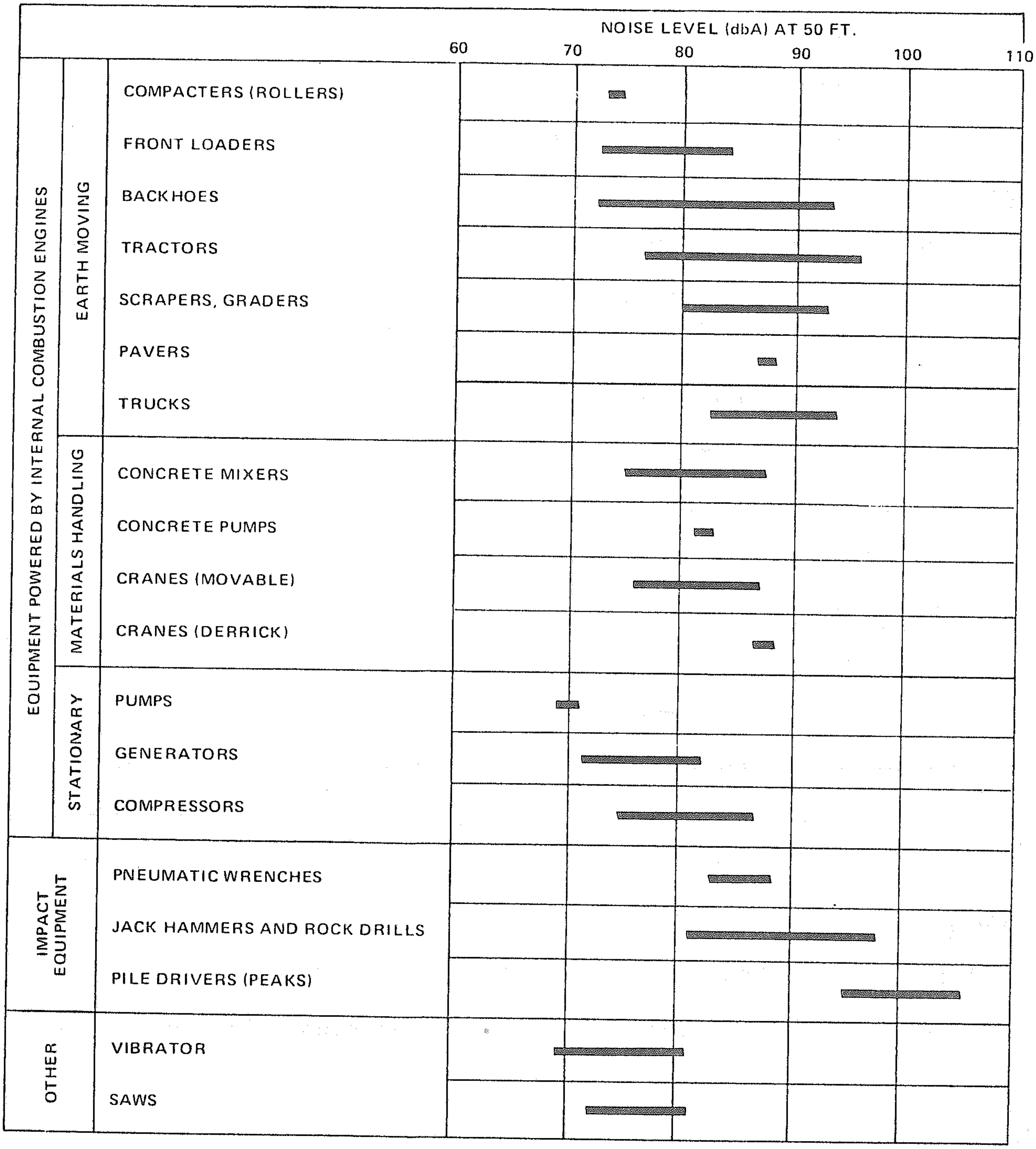
It was pointed out that the State of Alaska has no regulations regarding environmental noise and has adopted no standards for permissible noise levels along the route corridor. However, construction worker noise exposure will be governed by Alaskan Department of Labor and Occupational Safety and Health Act (OSHA).

Analysis of Submission

There are at present no noise regulations applicable to stationary gas turbines, since the former NEMA Standards became inactive, and new industry standards are being prepared by the American National Standards Institute. The noise generated at compressor stations can be attenuated by the use of silencing equipment.

The construction noise and its effect on the environment may be underestimated by the Applicant. Figure 1 shows some typical construction equipment noise ranges. Construction would take place in an environment with very low background noise. It would involve movement of people, heavy equipment, trenching, blasting and drilling, pipe laying and backfilling.

There would also be a noise from occasional operational blowdown as a routine checkout or in an emergency. The Applicant has developed additional preliminary criteria for station equipment which limits noise level to 50 dbA at 1000 feet from the station boundaries, as shown in the "Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Geotechnical Evaluation."



NOTE: BASED ON LIMITED AVAILABLE DATA SAMPLES

Figure 1. Construction Equipment Noise Ranges

3.1.1.10.C (cont.)

Operational noise may affect pipeline integrity and this facet of the Applicant's proposal was not discussed.

Conclusions

- o The noise abatement problems, in general, are recognized. Procedures to control noise levels for construction workers will be provided in accordance with Alaskan Department of Labor and OSHA codes.
- o The maximum station operational noise was established at 50 dbA at 1000 feet from the station boundaries.
- o There is a possibility that long-term noise and vibration may adversely affect the adfreeze strength of piles supporting the buildings and equipment.

Recommendations

(a) Evaluation should be made to establish any adverse effect of vibration due to noise on the adfreeze strength of piles supporting the buildings and equipment. If control measures are required, these should be defined and provided in their final design.

References

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnical Evaluation 15 March 1975.

Environmental Protection Agency (1971) Noise from Construction Equipment and Operations, Building Equipment, and Home Appliances PB 206-717.

4. MITIGATING MEASURES IN THE PROPOSED ACTION

4.1 Arctic Gas Pipeline Project

4.1.1 Alaska Arctic Pipeline

4.1.1.3 Safety and Emergency Measures to be Implemented

****

Applicant's Submission

Strict adherence of the Applicant to requirements and guidelines of DOT and other regulations, with inspection and enforcement by government agencies, will go far toward ensuring the safety of personnel during construction, operation, and maintenance of the Alaska Arctic Pipeline System. An important aspect of safety, particularly in the arctic, is the availability of a reliable communications system for coordination, supervision, information exchanged, reporting of accidents, and obtaining aid. The Applicant's proposed dedicated system, i.e., a system with communication channels assigned exclusively to one service, should provide the necessary communication services. Tentatively, a terrestrial microwave system is proposed for long-distance transmission of voice, and a mobile radio system would be used for short-range communication between crews working and moving along the right-of-way.

One of the first and fundamental approaches toward achieving a good safety record is the implementation of a training program for personnel. During construction, workers would receive training regarding safe procedures when working in arctic conditions. Arctic survival techniques would be presented, with emphasis on the minimum requirements under the most severe conditions. Safety training of operating personnel would be initiated at the time of their employment and continue throughout their services with

4.1.1.3 (cont.)

the company. With coordination by a safety supervisor, the training program would cover such topics as survival and first aid, gas handling and on-the-job safety, personal safety equipment, station equipment and controls, and fire fighting.

Provisions for fire protection are important because of the presence of combustible natural gas, as well as auxiliary liquid fuel supplies. Again, the basis of the fire protection program is the training of construction, operations, and maintenance personnel in fire prevention and fire fighting. Protection against possible natural gas fires would be accomplished by the use of emergency automatic shutdown equipment and automatic fire extinguishing systems. Along the pipeline, maintenance crews would always be provided with portable fire extinguishing equipment. At all airstrips and helipads, wheeled dry chemical fire extinguishers would be provided.

Propane is required during construction for pipeline heating and for applying insulating tape over the pipe. No propane would be required after construction until installation of the future compressors, at which time a propane refrigeration system would be needed for compressed gas chilling. Propane is carried in transportable cylinders, which will be stored at stockpile sites and hauled by sled along the construction line. The requirements of the National Fire Protection Association would be adhered to, and employees handling propane cylinders would receive practical instruction by experts on the subject.

4.1.1.3 (cont.)

Several liquid fuels would also be required during pipeline construction and operation, viz., diesel oil, motor gasoline, and aviation gasoline. During construction, a dedicated diked area would be provided at each stockpile site, and diked compounds would also be constructed around permanent fuel storage tanks.

Acids and explosives would be stored in compliance with applicable federal, state, and local codes. Explosives would be stored and guarded to avoid inadvertent detonation or misappropriation, and used only by qualified personnel.

To minimize the consequences of lost vehicles and aircraft during the winter season, this equipment would carry automatic radio locator equipment in addition to normal mobile radio links to the pipeline communication system. Landing aids would be provided for aircraft to facilitate safe landing under adverse conditions.

Analysis of Submission

One aspect of safety that should have been included is the use of pressure-limiting and relief devices to prevent over-pressure in the line. Another detail relates to the design of the gas alarm system, particularly when compressor units are installed. It will be important to examine the gas sampling points in the system; fires and explosions have occurred because local gas accumulations built up without detection by the gas alarm unit.

4.1.1.3 (cont.)

Particular attention should be paid to the unique conditions in the pipeline area and how they impact emergency provisions. For example, outdoor equipment must be capable of operation with gloved hands. Emergency lights, particularly the portable type, should be readily available because of the long periods of darkness. Transportation equipment must receive careful maintenance with particular emphasis on winterizing provisions to assure reliable operation at low temperatures. Items such as mainline block valves must be capable of operation in the winter environment of snow and cold, and they must be marked for easy location after a heavy snowfall.

Conclusions

o Safety measures for this project are principally directed toward personnel associated with the pipeline because of the absence of other human habitation in the area. While this fact might appear to alleviate the safety problem, the inhospitable environment is more than counterbalancing, requiring constant vigilance, planning, and training to safeguard employee and contractor personnel. In a later submittal the Applicant stated that a Safety and Emergency plan would be provided as part of the final design phase.

Recommendations

(a) The Applicant should provide a detailed Safety and Emergency plan, including a description of the safety training program and safety equipment for buildings, sites, vehicles, aircraft, and personnel. In a later submittal, Applicant states such a plan will be provided as part of the final design phase.

4.1.1.3 (cont.)

Reference

Technical Interchange Meeting (October 27 & 28, 1975), Alaskan Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

4.1.3.5 Recommendations
****

All of the recommendations that appear in this report are repeated in this section. The recommendations are divided into three categories: primary, secondary, and tertiary, which are designed by the letters P, S, and T, respectively, that appear before the discussion of each recommendation. These three categories are defined as follows:

Primary (P)	-	Items that are critical to the integrity and safe operation of the pipeline.
Secondary (S)	-	Items that are essential to adequate design and operation of the pipeline, but which do not entail a direct question of pipeline integrity.
Tertiary (T)	-	Items that should be provided for completeness, but which may be of a less critical nature.

For easy reference, the section numbers for each recommendation are shown in parentheses.

1. (P) The Applicant should conduct additional tests and/or analysis to evaluate the worst case high temperature of the ground at pipeline startup combined with a worst case ground moisture content. The lowest anticipated gas temperature should be used once the test is started and maintained throughout the test to demonstrate the effect of frost heave induced on the pipeline. (1.1.1.B.2)

4.1.3.5 (cont.)

2. (P) The thermal, ground settlement and frost heave effects of an unchilled pipeline should be analyzed including ponding and water flow and results provided to the appropriate regulatory and/or statutory agency(s). (1.1.1.1.B.2)

3. (P) The Applicant should incorporate ponding and water flow in his analytical model and determine specific locations for which the proposed mitigating measure of increased berm height (surcharge) is expected to be an effective method to mitigate and frost heave effects. (1.1.1.1.B.2)

4. (P) The Applicant should make a comprehensive analytical determination of the maximum stresses that can exist concurrently with pressure induced stresses during pipeline operation. These analyses should cover thermal stresses for the worst possible combination of installation and operation temperature, stresses associated with worst case frost heave phenomena, the effects of buoyancy and the attendant weighing and/or anchoring differential settlement for the worst anticipated soil conditions, earthquake induced strain effects, pipeline behavior in regions of soil slippage, and the additive effects of construction induced initial stresses. The results of these studies should be used in conjunction with an appropriate design criteria to determine pipe wall thickness. (1.1.1.3.A.1)

4.1.3.5 (cont.)

5. (S) The toughness value specified should be an absolute minimum acceptable toughness of the pipe as well as an average minimum. (1.1.1.3.A.1)

6. (P) The design criteria should be revised so that the maximum stress intensity levels do not exceed 0.72 SMYS for all loading combinations expected to occur during normal operational lifetime. This value may be raised to 0.8 SMYS when the loading combinations include extraordinary loads, such as earthquakes, acting concurrently with the other loadings. (1.1.1.3.A.1)

7. (T) The Applicant should provide flow diagrams for summer and winter operation for a nominal 4.5 BSCFD (standard) throughput. (1.1.1.3.A.2)

8. (T) All upstream valves between the location of the emergency (leak, pipe fracture, etc.) and at least the nearest upstream compressor station should be simultaneously closed at rapidly as possible during emergency shutdown. The Applicant should consider the loads induced by valve closure in the pipeline thickness determination under 1.1.1.3.A.1, recommendation (a). (1.1.1.3.A.2)

9. (T) Future design data submitted to the appropriate regulatory and/ or statutory agency(s), for approval of compressor stations should include capability for uninterrupted gas flow during maintenance operations or during single compressor failures. The remote location of these compressor stations in a rugged

4.1.3.5 (cont.)

environment focus the attention on high reliability of controls and on safety devices. (1.1.1.3.C.1)

10. (T) The Applicant should examine the safety aspects and industry experience involving the use of propane as a chilling fluid versus other non-flammable refrigerant alternates. (1.1.1.3.C.1)

11. (P) A unique feature of buried natural gas pipeline transport systems in permafrost is represented by the need to chill compressed gas. Part 192, Title 49, Code of Federal Regulations dealing with compressor station design safety overlook such refrigeration facilities. This code must be revised. (1.1.1.3.C.1)

12. (P) The Applicant should provide a detailed plan for developing ditching and blasting techniques appropriate for ditching in frozen gravels and other stubborn permafrost areas. (1.1.1.6.B.1)

13. (P) The Applicant should provide a Snow Road and Pad Construction Plan. This Plan shall include design criteria, anticipated water requirements and a description of all equipment and vehicles required to support road and pad construction in a light and normal snowfall year. This Plan should be provided to the appropriate statutory and/or regulatory agency(s) for review and approval. (1.1.1.6.B.1)

4.1.3.5 (cont.)

14. (P) The Applicant shall provide a Water Requirements and Availability Plan. This Plan shall include a statement of total water requirements for snow road and pads, and all other requirements for all construction spreads. Water sources and withdrawal rates shall be identified. The equipment to be used to transport water without environmental impact shall be identified. This Plan shall be provided to the appropriate regulatory and statutory agency(s) prior to issuance of permits. (1.1.1.6.B.1)

15. (P) The Applicant should provide test data substantiating the feasibility of wheel-type ditching equipment for use in permafrost, particularly in frozen sand or gravel. In a later disclosure the Applicant stated that new vehicles with improved wheel teeth materials are under development. This work should be continued. (1.1.1.6.B.1)

16. (P) The Applicant should provide a construction plan specifying in detail the entire operation. This should include detailed schedules based on material in hand, rather than promised deliveries. The project should not commence until all critical elements of the pipeline have been delivered to the construction site. (1.1.1.6.B.1)

4.1.3.5 (cont.)

17. (P) The Applicant should identify not only the quantity of sources, but also the quality and suitability of material, particularly in areas where existing ice-rich soil is to be replaced with borrow for control of subsidence. Mixing processes and restoration plans should be included. (1.1.1.6.B.2)

18. (P) The Applicant should provide criteria for bedding material to be used to support the pipe to prevent the introduction of local stresses in the pipeline. This should include criteria for trench conditions which require the use of bedding material. (1.1.1.6.B.2)

19. (P) The Applicant should provide inspection criteria for the pipe, welds, and coatings for all stages of construction from pipeline stringing through lowering-in and backfilling. This should include repair and inspection procedures for damaged areas. (1.1.1.6.B.2)

20. (T) The Applicant should conduct a detailed site study for each compressor site and airfield along with possible alternates. Included therein should be all the appropriate parameters, such as subsurface soils and drainage properties. In a later submittal, the Applicant states these data will be provided as part of the final design phase. (1.1.1.6.C.2)

4.1.3.5 (cont.)

21. (S) The Applicant should provide a detailed design analysis for his compressor station foundations to ensure permafrost maintenance. (1.1.1.6.C.2)

22. (P) The Applicant should propose a detailed hydrotest procedure as per recommendation (b) of section 1.1.1.3.A.1. (1.1.1.6.D.1)

23. (P) The Applicant should develop appropriate handling procedures and personnel safety practices, taking into consideration the toxic nature of methanol vapors. (1.1.1.6.D.1)

24. (P) The Applicant should quantify the leak size that can be detected visually during hydrotest and the size leak that can be detected by pressure gages. (1.1.1.6.D.1)

25. (P) The Applicant should prepare a contingency plan for handling leaks and spills of the hydrotest fluid. The plan should indicate the potential damage to the soils along the right-of-way, measures that would be taken to minimize the potential for spills, and detailed restoration methods that would be used when spills occur. This plan should be submitted to the appropriate regulatory and/or statutory agency(s) for approval prior to construction. (1.1.1.6.D.1)

26. (P) The Applicant should perform studies involving winter application of a water/methanol solution to vegetation typical of this Alaskan north Slope. (1.1.1.6.D.2)

4.1.3.5 (cont.)

27. (P) Plans should be defined for protection of the pipeline from over-pressure, both in the initial stages and when the compressor stations are activated. (1.1.1.7.A.1)

28. (P) Data or analysis should be presented regarding heat soakback from exposed piping, such as from the scraper trap assemblies and mainline block valves. (1.1.1.7.A.1)

29. (P) This Applicant should provide concept definition for the satellite communications and control option, with emphasis on reliability of operation under arctic aurora borealis conditions. (1.1.1.7.A.1)

30. (P) The Applicant should submit criteria for valve supporting systems (foundations) to the appropriate regulatory and/or statutory agency(s). (1.1.1.7.A.1)

31. (P) The Applicant should provide detailed designs and specifications for the cathodic protection system and submit them to the appropriate regulatory and/or statutory agency(s) for evaluation and approval during the final design phase. (1.1.1.7.B.1)

32. (P) The Applicant should furnish a corrosion monitoring plan to the appropriate regulatory and/or statutory agency(s) for evaluation and approval. (1.1.1.7.B.2)

4.1.3.5 (cont.)

33. (P) The Applicant should furnish measures to protect the pipeline from overpressure as per recommendation (a) of section 1.1.1.7.A.1. (1.1.1.7.C.1)

34. (S) Applicant should furnish a plan for marking the pipeline route, and as he stated, in a later submittal, that a plan would be provided as part of the final design. (1.1.1.7.C.1)

35. (S) The Applicant should provide lightning protection for buildings and other above-ground facilities in accordance with ANSI-C5.1. Lightning Protection Code (1968). (1.1.1.7.C.1)

36. (P) Applicant should furnish an operating/maintenance manual covering shutdown procedures. The Applicant stated th is plan will be provided as part of the final design phase. (1.1.1.7.C.2)

37. (P) The Applicant should consider the effort of summer pipeline excavation and in a later submittal, the Applicant proposed mitigating measures to reduce potential hazards of ablation and subsidence. (1.1.1.7.C.3)

38. (P) Air cushion vehicles, low ground pressure vehicles and type and number of aircraft required for summer repair should be presented in detail. Precautions that might be employed during periods in which the ground is covered by a thin ice or a thin thawed layer should be discussed. (1.1.1.7.C.3)

39. (P) An evaluation should be performed on line break detection equipment and on detection of small gas leaks. (1.1.1.7.C.3)

4.1.3.5 (cont.)

40. (P) A contingency plan and emergency procedures for the pipeline system, including the time required for repairs, should be prepared and presented for the appropriate regulatory and/or statutory agency(s) for approval at least one year prior to pipeline operations. (1.1.1.7.C.3)

41. (P) The Applicant should develop allowable loads criteria for each unavoidable landslide bench traversed by the proposed pipeline with supporting analysis. These criteria should be provided to the appropriate regulatory and/or statutory agency(s) for review. (2.1.1.2.D).

42. (P) The Applicant should identify all slide areas, and all such areas (active or dormant) should be avoided. For any slide area that cannot be avoided, stabilizing procedures and mitigating measures should be investigated. Blasting on slide areas should also be avoided, particularly in areas where unfrozen subsoil may exist. (2.1.1.2.D)

43. (P) The Applicant should restore surface drainage which will be affected by the pipe inactivity period along the pipeline route to pre-construction conditions, except that, wherever closed depressions existed on a bench, these depressions would be regarded to permit runoff of the surface water over the edge of the slope. In a later disclosure, the Applicant confirmed his intention to follow the recommendation. (2.1.1.2.D)

4.1.3.5 (cont.)

44. (P) Applicant should determine in detail conditions created by possibility of the inactive pipeline buried for one or two seasons, as well as by pipeline flowing chilled gas, together with proposed stabilization methods. (2.1.1.2.D)

45. (P) The Applicant should measure solifluction and creep displacement by field observation. The Applicant should also describe in detail measures that will be taken to control such displacements. (2.1.1.2.D)

46. (P) The Applicant should estimate maximum differential settlement due to solifluction, creep, seismic activity or other factor and use these criteria in the determination of pipeline wall thickness in accordance with recommendations in section 1.1.1.3.A.1. (2.1.1.2.D)

47. (P) The Applicant provided data on major rivers in Volume V, "Reference Book of Water Crossings," by NESCL. The data indicate the need for pipe buried up to 11 feet although scour depth calculations were not yet performed. It is recommended that pipe depth burial be verified after scour depth is analyzed. (2.1.1.2.E.2)

48. (P) Aufeis and ice jamming require detailed studies and analysis. Data from the preconstruction reconnaissance should be substantiated by the Applicant. (2.1.1.2.E.2)

4.1.3.5 (cont.)

49. (P) The Applicant should develop loads criteria for the pipeline design per recommendation (a) of section 1.1.1.3.A.1 to withstand earthquakes of M5.5 considering all above ground construction. Criteria should treat trench and backfill requirements to prevent instability from potential liquefaction, specifying a maximum acceleration in g and a duration above a minimum acceleration level, such as 0.1g specified by Newmark (1974). If data are available, an estimate should be made (see, for example, Howell, 1973) of the Average Regional Seismic Hazard Index. (2.1.1.3.C.1.b.1)

50. (S) The Applicant should consider installing seismic instrumentation in the vicinity of Flaxman Island, considered the most likely center of seismic activity along the route. In a later disclosure, the Applicant stated that this will be dealt with in the final design. (2.1.1.3.C.1.b.1)

51. (P) A detailed discussion should be presented of the special design features for areas of seismic activity mentioned in response to DoI question 25. The N.M. Newmark report (1974) quoted by the Applicant provides only seismic design criteria which should be translated into pipeline design features. (2.1.1.3.C.1.b.1)

52. (P) The Applicant should provide a contingency plan for checking and reestablishing pipeline integrity after seismic activity. In a later disclosure, the Applicant stated that this will be covered in the final design. (2.1.1.3.C.1.b.1)

4.1.3.5 (cont.)

53. (P) The Applicant should consider that some loose, fine, uniform sands or other liquifiable-type soils may obtain the necessary water content under the location of the pipeline and the changes in drainage which may be induced. The Applicant should review his data with some projection of the worst case moisture content, and define those areas which are considered to be subject to thixotropic liquefaction. (2.1.1.3.C.1.b.3)

54. (P) The Applicant should provide criteria for the identification of thixotropic liquefaction susceptible areas during the construction phase, along with procedures for selecting and implementing appropriate anchoring methods. (2.1.1.3.C.1.b.3)

55. (P) The Applicant should identify all potentially unstable slopes affected by construction with a determination of the factor of safety by the McRoberts Method and the Applicant indicated that this will be done during the final design. (2.1.1.3.C.2.d)

56. (P) The Applicant should reevaluate the method of restoring slopes by natural sloughing processes, including an examination of slopes where this method has been applied, reporting any instances of excess erosion or degradation of cover. All slopes to be so treated should be identified by location, soil type, and evidence should be provided that excess thaw will not occur. Insulation as an erosion deterrent on cut slopes should also be considered. The Applicant indicated in a later disclosure that

4.1.3.5 (cont.)

this will be done if required. The Applicant should make a similar reevaluation of the use of snow or ice fill, reporting on damage incurred by the melting of such fill. (2.1.1.3.C.2.4)

57. (P) The Applicant should identify potential mass waste areas along the prime route and perform a detailed analysis of mass wasting hazards and their effect on pipe integrity. The Applicant stated in his later disclosure that this task constitutes the final design of the pipeline system. (2.1.1.3.C.2.g)

58. (P) The Applicant should determine external loads imparted by mass wasting on the pipeline for all areas considered to be a potential hazard and incorporate in pipe thickness determination per 1.1.1.3.A.1, recommendation (a). (2.1.1.3.C.2.S)

59. (P) The Applicant should determine the magnitude of thaw settlement and ponding with particular emphasis on ice-rich low permeability areas where imported select backfill is utilized with the unchilled pipe left for a year or more. (2.1.1.3.C.2.9)

60. (P) The Applicant should provide shear strength data on unfrozen soils and soil interfaces for assessment of mass wasting hazard and external loads on the pipe to be used in analysis of recommendations (a) and (b) of section 2.1.1.3.C.2.g. (2.1.1.3.C.4.d)

61. (P) The Applicant should provide comprehensive bore hole data along the pipeline route, particularly for slopes, river approaches, under rivers, and at compressor stations. (2.1.1.3.C.4.d)

4.1.3.5 (cont.)

62. (P) The Applicant should evaluate the ground temperature profile for all conditions of flow and for all seasons or operation/non-operation to determine the optimum pipe burial depth to minimize effects of the activa layer. (2.1.1.3.C.4.e)

63. (P) The Applicant should assume worst case ground moisture conditions and determine the external frost heave loads imposed on the pipe, first, for inclusion in the pipeline thickness determination per recommendation (a) of section 1.1.1.3.A.1, and, second, in the chilled gas effects study per recommendations (b) of section 1.1.1.1.B.2. (2.1.1.3.C.4.e)

64. (P) The Applicant should provide detail design at all river crossings with supporting analyses to show that depth of burial and negative buoyancy provisions are compatible with worst case assumptions. In a later disclosure, theApplicant stated that this task is a part of the final design of the pipeline. These designs should be submitted to the appropriate regulatory and statutory agency(s) for review and approval. (2.1.1.5.B.2)

67. (S) The Applicant should provide the design measures necessary to preclude ice fog ingestion into compressor turbines during all phases of remote, unattended operation. The Applicant should support his proposed design with test data that verify the design feasibility during operation under continuous ice fog conditions. (3.1.1.1.A)

4.1.3.5 (cont.)

68. (S) The Applicant should provide estimates (average) of sulphur dioxide, nitrogen dioxide, and carbon monoxide levels to be the right-of-way during construction. Construction schedules should be adjusted to insure these levels are within the Ambient Air Quality Standards of the State of Alaska. (3.1.1.1.A)

69. (S) Prior to (future) compressor stations operation, the Applicant should quantify the nature and duration of meterological conditions for which ground level concentrations of sulphur dioxide are expected to exceed lichen damage levels. (3.1.1.1.A)

70. (S) Prior to (future) compressor station operation the Applicant should quantify the nature and duration of meterological conditions for which ground level concentrations of nitrogen dioxide are expected to exceed Ambient Air Quality Standards for the State of Alaska. (3.1.1.1.A)

71. (P) The Applicant should develop criteria for submittal to the appropriate regulatory and/or statutory agency(s) for review and approval, which will allow areas with a high potential for accelerated erosion to be defined on a detailed basis and in a manner suitable for portrayal on construction drawings. These criteria should provide methods for the calculation of required quantities of backfill, mound breaks, culverts, ditch plugs, borrow, and other control and restoration measures. Criteria should consider soil type, including thermal state and moisture content,

4.1.3.5 (cont.)

topography, climate, hydrology, construction mode, and grading geometry. The various specific control measures should be formalized to the point of standardization, such that they can be specified to apply, with appropriate modifications for conditions, to any section of the pipeline. (3.1.1.2.A.1)

72. (P) The Applicant should provide specific criteria to restore any river banks that have been breached for crossing, and to protect them from excessive erosion. (3.1.1.2.A.1)

73. (S) The Applicant should take measures to ensure that surplus spoil is not disposed indiscriminately on right-of-way with an undisturbed vegetative cover required as an erosion control. (3.1.1.2.A.1)

74. (P) The Applicant should provide more information on creep and deep-seated failure in frozen soil, where he states that substantial field investigation is called for. Specifically, a survey s should be made in the field of potential sites for each type of failure, the soil creep measured, and the deep-seated failure potential evaluated by the methods described in the Applicant's Submission. (3.1.1.2.A.1)

75. (P) The Applicant stated in a later disclosure that topsoil and the organic material will be removed and then replaced on the top of the backfill. Also, statements were made for ground fertilization and seeding grass as an interim vegetation cover.

4.1.3.5 (cont.)

The Applicant should provide a more comprehensive plan for post-construction revegetation program. (3.1.1.2.A.1)

76. (S) The Applicant should review the location of the borrow pits and show that erosion resulting from them would not threaten pipeline integrity. (3.1.1.2.A.2)

77. (S) The Applicant should provide a plan for disposal of waste or spoil materials and for borrow pit rehabilitation. (3.1.1.2.A.2)

78. (S) The Applicant should identify areas along the pipeline route which, when subjected to blasting groundshocks, may be susceptible to slumping or soil fall and slopes which may be susceptible to avalanches. The Applicant should specify the special precautions to be taken when blasting is required in these areas. The Applicant should identify areas where the need for blasting is anticipated and evaluate the stability of these areas to substantiate his statement. (3.1.1.2.B)

79. (P) The Applicant should develop criteria to specify the gas temperature (maximum) that will be permitted on a temporary basis to accommodate the eventuality of Gas Chilled Failure. These criteria shall be submitted to the appropriate regulatory and/or statutory agency(s) for review and approval. (3.1.1.3.B)

80. (P) All slopes should be categorized with respect to their potential instability, relative angle with respect to the pipeline, and mass wasting hazard. Slope stability analysis should cover the case of chilled and non-chilled gas. (3.1.1.3.C)

4.1.3.5 (cont.)

81. (P) Typical slopes from each of the categories should be selected for detailed review. External loads on the pipe resulting from mass wasting should be established and slope stabilization method (if required) should be defined. (3.1.1.3.C)

82. (P) The Applicant should determine the degree of slope movement that can be expected and establish criteria for including loads resulting from this factor into the pipeline thickness determination in accordance with recommendations in section 1.1.1.3.A.1. (3.1.1.3.C)

83. (S) The Applicant should establish a threshold level of leakage which would not cause damage to vegetation and wildlife. (3.1.1.6 and 3.1.1.7)

84. (S) The Applicant should show that his leakage detection method(s) would be capable of locating leaks of the magnitude defined by the Applicant in recommendation 83. A research program aimed at sensors and methods suitable for the inaccessible North Slope, should be conducted. (3.1.1.6 and 3.1.1.7)

85. (P) Evaluation should be made to establish any adverse effect of vibration due to noise on the adfreeze strength of piles supporting the buildings and equipment. If control measures are required, these should be defined and provided in their final design. (3.1.1.10.C)

4.1.3.5 (cont.)

86. (P) The Applicant should provide a detailed safety and emergency plan, including a description of the safety training program and safety equipment for buildings, sites, vehicles, aircraft, and personnel. In a later submittal, Applicant states such a plan will be provided as part of the final design phase. (4.1.1.3)

87. (P) The pipeline design should attempt to consider all possible forces that could damage the pipeline and provide sufficient strength to withstand the combined effect of these forces per recommendations in section 1.1.1.3.A.1. (5.1.1.3)

88. (P) The Applicant should develop a comprehensive health and safety plan for both the construction and operations phases. This plan should be submitted to the appropriate regulatory and/or statutory agencys for review and approval. In a later submittal, the Applicant states that such a plan will be provided as part of the final design phase. (6.1.1.1)

89. (S) The Applicants should present an evaluation of the potential damages resulting from natural catastrophe or man-caused accidents, with particular regard to the pipeline system and location. The fire and toxic hazards of gas near the ground in the case of pipe rupture should be evaluated by the Applicant. (7.1.1.1)

4.1.3.5 (cont.)

90. (T) The Applicant should consider increasing the 220 yard distance criteria in 49 CFR 192.179 used to establish the class zones. A closer spacing of the block valves within each class should also be considered by the Applicant. (7.1.1.1)

5. ADVERSE EFFECTS WHICH CANNOT BE AVOIDED SHOULD THE PROPOSAL BE IMPLEMENTED

5.1 ARCTIC GAS PIPELINE PROJECT

5.1.1 Alaska Arctic Pipeline

5.1.1.3 Impact in Relation to Pipeline Integrity

****

Applicant's Submission

The Applicant has provided basic data that can be used to estimate probability of pipeline rupture. Statistics on the frequency of pipeline ruptures in the United States are shown in the following table.

*INCIDENTS OF RUPTURES IN THE OPERATION OF GAS TRANSMISSION LINES, 1970-72

(36-Inch Diameter & Larger)

	1970	1971	1972	Total	Average
Miles in Service	12,191	13,136	13,201	38,520	12,846
Ruptures	1	2	0	3	1
Ruptures per 1000 Miles	0.082	0.152	-	-	0.077

*Battelle - May 1973

In addition, reports obtained from three major Canadian gas transmission systems operating approximately 7,000 miles of 30-inch to 42-inch pipeline for a period of 17 years show a total of 10 ruptures, equating to a probability of 0.084 ruptures per year per 1,000 miles. This compares favorably with the average value of 0.077 ruptures per 1000 miles as shown in the table since the Battelle statistics indicated that the cause of approximately half of all reported ruptures has been

5.1.1.3 (cont.)

outside force and particularly equipment operated by outside parties and that the incidence of rupture is lower in uninhabited areas.

The Applicant further states the above statistics are believed to be conservative as applied to the Alaskan pipeline because damage by outside forces is less probable due to the relative lack of activity in this area.

The Applicant states spring and summer seasons are the periods when damage probability will be greatest, and repairs most difficult. Rivers, slopes and the right-of-way will be patrolled, during these seasons, at more frequent intervals. All indications of unsatisfactory conditions will be closely investigated and repaired, either permanently or temporarily until a permanent repair can be accomplished at less risk to the environment. Winter is not expected to present any unusual pipeline repair conditions, and the rupture incidence probability is expected to be significantly lower during this season.

Rupture incidents will require immediate and efficient repair methods and adequate equipment must be readily accessible to any location. The Applicant's Mainline Break Repair Plan (a part of the Operating Manual) will consider the types of terrain, locations, and weather conditions which will be encountered. It will pre-plan methods of repair, materials, equipment required, and will include an estimate of time duration for a major line repair.

5.1.1.3 (cont.)

Maintenance plans have at all times been formulated to recognize terrain sensitivities with particular reference to permafrost. The use of heavy equipment will be avoided by doing temporary or emergency maintenance with light LGP vehicles or airborne equipment during the terrain-sensitive periods of spring and summer. Permanent repair and heavier type of maintenance work will be done when the ground is frozen and when snow roads can be used. The experience gained during construction will be analyzed closely and used to further improve existing plans.

In addition, of the few failures which have occurred on large diameter lines in southern regions, the majority have been short in length, i.e., tens or hundreds of feet. The Applicant assumes that line breaks, if they occur, will be consistent with this historic pattern.

Analysis of Submission

Based on the average statistics of 0.084 ruptures per 1000 miles per year. The proposed portion of the pipeline along the prime route in Alaska (195 miles) might experience

$$0.084 \times \frac{195}{1000} = 0.016$$ breaks per year or approximately one break every 61 years.

The Applicant has proposed to implement safety and emergency procedures to reduce the hazard from a rupture of the pipeline. The pipeline design incorporates automatic features and block valves at 15-mile intervals to limit the volume of gas which would escape should the pipeline rupture.

5.1.1.3 (cont.)

The pipeline is along an uninhabited or low population density route. Any gas vented due to pipeline rupture is much lighter than air (at all temperatures of gas and air that would exist on this proposed project) and, therefore, the gas would rise rapidly and would not produce a cloud near the ground hazardous to life. This is discussed at greater length in section 7.1.1.1.

Conclusions

o Because there are unknowns and unpredictable events, there remains a small but finite probability that the pipeline would rupture. To reduce the probability of this element to the smallest possible value, the Applicant should implement a program of pipeline marking, surveillance, and public education.

Recommendations

(a) The pipeline design should attempt to consider all possible forces that could damage the pipeline and provide sufficient strength to withstand the combined effect of these forces per recommendations in section 1.1.1.3.A.1.

Reference

Alaskan Arctic Gas Pipeline Company (October 28, 1975), Comments of Alaskan Arctic Gas Pipeline Company Relative to Part III (Canada) of The Draft Environmental Impact Statement of The Department of Interior regarding the Alaska Natural Gas Transportation System.

5.1.1.3 (cont.)

Battelle Institute (May 1973) Reportable Incidents for Natural Gas Transmission and Gathering Lines, 1970 through 1972.

6. RELATIONSHIP BETWEEN LOCAL SHORT-TERM USE OF THE ENVIRONMENT AND MAINTENANCE AND ENHANCEMENT OF LONG-TERM PRODUCTIVITY

6.1 ARCTIC GAS PIPELINE PROJECT

6.1.1 Alaska Arctic Pipeline

6.1.1.1 Risks to Health and Safety

****

Applicant's Submission

Inasmuch as there is no indigenous population along the Applicant's proposed route, and very few people in the entire area, health and safety risks apply principally to personnel associated with the construction and operation of the pipeline.

The principal federal guides to health and safety are: Code of Federal Regulations, Title 29, Chapter XVII Part 1910 (Occupational Safety and Health Standards), and Part 1926 (Safety and Health Regulations for Construction). These documents cover such pertinent topics as (1) personal protective equipment, (2) general environmental controls including sanitation and temporary labor camps, (3) medical and first aid, (4) hazardous materials, (5) materials handling and storage, and (6) machinery and machine guarding.

Prevention is obviously the most desirable way of mitigating the health and safety problem. The Applicant has indicated the important features of such a prevention program, including physical and psychological screening of potential workers, a safety training program, provision of personal and station safety equipment, etc. In addition to preventive measures, first-aid/medical facilities and personnel would be provided in the event of sickness or injury at Prudhoe Bay.

In a later submittal, the Applicant stated injured or ill workers will be evacuated by IFR (Instrument Flight Rules) equipped helicopters or small turbine fixed-wing aircraft such as the Twin Otter during conditions of low ceiling and poor visibility.

The Applicant has presented published data for the entire construction industry to estimate the number of disabling injuries that would be expected during the construction period of the pipeline. He also includes 1972 American Gas Association safety data from natural gas transmission companies, to arrive at the probability of fatal and disabling injuries during the operational period of the pipeline.

Analysis of Submission

Some additional injury data are available from the American Gas Association report used by the Applicant. The gas utility industry as a whole ranked 19th in frequency rate of disabling injuries among 41 major industries and 16th in severity rate. Transmission companies ranked below the gas industry average in the frequency rate (5.88 versus 8.38 disabling injuries per 1,000,000 man-hours) but above in the severity rate (762.3 versus 534.9 days lost per 1,000,000 man-hours).[1] According to 1973 data,[2] there were a total of two employee and 33 non-employee fatalities for the gas utility industry, of which one employee fatality and one non-employee fatality was attributed to the transmission sector.

The transmission industry safety record given above and in the Applicant's proposal pertains to activities primarily in the contiguous United States.

[1] "The Gas Industry - 1972 Disabling Injury Experience," American Gas Association, Catalog No. J00443, 1973.

[2] "Sixth Annual Report of the Secretary of Transportation on the Administration of the Natural Gas Pipeline Safety Act of 1968 - Calendar Year 1973," United States Department of Transportation, 1974.

6.1.1.1 (cont.)

The harsh natural environment and construction working conditions impose unusual stresses and hazards which must be considered. For example, extended periods of construction work in subzero weather and darkness, in relative isolation, would be expected to increase the incidence of injuries and psychological illnesses compared to more benign conditions encountered in the lower 48 states.

It is convenient to divide the problem into the (relatively) short-term construction phase and the much longer operations and maintenance period. The former comprises three stages from pre-construction, small group activities, through construction of logistical sites, to actual laying of pipeline. Manpower would increase correspondingly, with three groups or spreads involved in the final pipe emplacement operations, each spread consisting of about 800 men working 12 hours per day, seven days a week. By contrast, normal operation and maintenance of the completed pipeline would require about 40 people, operating out of Prudhoe Bay on a five-day work week.

Apart from the sheer differences in numbers of men involved in the two phases, there are other factors which would tend to make the construction period more demanding on health service facilities. Many of the workers would be new to the arctic region and the unique hazards that such an environment imposes, as, for example, frostbite. Long hours of work would tend to increase the incidence of accidental injuries, as would the use of new types of construction equipment and techniques. Conversely, communicable diseases may be less of a problem than in the normal population, since workers would undergo a pre-employment physical and a routine immunization program.

The operations and maintenance phase of pipeline operation should, in general, be more conducive to the health and safety of the employees. Personnel would probably be more experienced in arctic operations, work on a less strenuous schedule, and perform more routine tasks. An exception would be the case of emergency repairs, when seldom-used equipment and procedures would be exercised under, possibly, extreme environmental conditions in the presence of fire or explosive hazards.

A particular concern is how health and safety measures would be supervised, coordinated, and controlled during the construction phase, inasmuch as the Applicant has indicated that much of the responsibility would be placed upon the individual contractors. As with other aspects of the project, government approval and inspection are mandatory prior to, and during, the construction and operation of the pipeline.

Conclusions

- It is reasonable to expect that the frequency rate of injuries would be higher for the proposed pipeline than previous industry statistics indicate, due to the isolated location and climatic extremes. However, the very fact that both the Applicant and government officials are aware of the problem and will institute extraordinary precautions should tend

6.1.1.1 (cont.)

to mitigate the problem. Further, by the time construction gets underway, there may be an available supply of personnel who have had considerable arctic experience working on other Alaskan projects.

Recommendations

(a) The Applicant should develop a comprehensive health and safety plan for both the construction and operations phases. This plan should be submitted to the appropriate regulatory and/or statutory agencys for review and approval. In a later submittal, the Applicant states that such a plan will be provided as part of the final design phase.

Reference

Alaskan Arctic Gas Pipeline Co. (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company Relative to Part II (Alaska) of The Draft Environmental Impact Statement of The Department of Interior Regarding the Alaska Natural Gas Transportation System.

Technical Interchange Meeting (October 27 & 28, 1975), Alaskan Arctic Gas Pipeline Company and Department of the Interior, Calgary, Alberta, Canada.

7. IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF RESOURCES IF THE PROPOSED ACTION SHOULD BE IMPLEMENTED

7.1 ARCTIC GAS PIPELINE PROJECT

7.1.1 Alaska Arctic Pipeline

7.1.1.1 Damages from Natural Catastrophe or Man-Caused Accidents

****

Applicant's Submission

There are several potential modes of environmental damage that could result from natural or man-caused incidents. Probably the major concern is the consequence of pipeline rupture. Design and protective measures would be employed, in order to minimize fatigue and failure potential. A most important measure taken to mitigate the possibility of a major pipeline accident is the prevention of warm gas transmission. This is designed to prevent permafrost degradation and subsequent stresses that might be imposed in the pipeline due to excessive movement.

Pipeline failures have occurred because of corrosion or a material failure. The test and inspection program that would be implemented during construction of the pipeline, and the application of cathodic protection, make a failure from these causes unlikely. Thorough training of personnel, constant monitoring of pipeline performance parameters, and routine route surveillance should minimize the possibility of man-caused accidents, especially since there will be little, if any, other human activity along the route.

In the event that pipeline rupture were to occur, natural gas would be released to the atmosphere. Most of this gas would quickly rise and

7.1.1.1 (cont.)

dissipate, as the main constituents are lighter than air even at extreme temperature differentials. Minor quantities of the heavier components may settle along the ground depending upon local meteorological conditions. Automatic activation of the mainline block valves with loss in pressure would isolate the break area. Nevertheless, there would be a sudden release of a large quantity of high-pressure gas. Ignition of the gas may occur. There could also be an upheaval of a ten to several hundreds of feet pipeline and crown.

Such a failure could elicit temporary adverse localized impacts on vegetation (physical destruction and/or fire) water and air quality (combustion products), wildlife (noise, fire) and easthetic attributes. Localized heating of the permafrost would occur in the event of a fire.

The possibility of tundra fires, either as a result of pipeline failure, aircraft or vehicle accidents, or other man-caused incidents, has been considered. Generally, tundra fires remove all of the litter and some of the peat but only char the cottongrass tussocks where this community type is dominant. Due to the lower standing biomass and the cold and frequently very wet soils, fires in tundra areas are considered much less damaging, and usually of much less extent, than in forested areas further south. Recovery from fires in tundra areas is rapid, except for lichens, complete recovery generally requiring two to three years.

In the event of a major pipeline emergency, the need for rapid access to the pipeline would require controlled vehicular passage over unprepared

7.1.1.1 (cont.)

surfaces to move heavy equipment to the location. This is recognized by the applicant and is discussed in section 1.1.7.C.3.

Another area of concern is the consequence of a fuel spill. Two potentials for accident spills exist: (1) leaks during unloading and stockpiling along the coast, and (2) spills on land during construction, and to a lesser degree during operation of the pipeline. In the case of the gas pipeline, any leaks or spills would be in the range of a few barrels or less. Prevention and cleanup are the two measures to mitigate any harmful environmental effects. All operating personnel would be oriented, trained, and motivated to prevent accidental leakage.

Analysis of Submission

The effect of minor gas leaks has been addressed in sections 3.1.3.6 and 7. This discussion covers the consequences of a major pipeline break.

The natural catastrophes that could threaten the integrity of the pipeline, with the potential for pipeline rupture, include earthquakes, floods, landslides, subsidence, and forest fires. Man-caused accidents could arise from material failure, corrosion, or construction defects; incorrect maintenance or repair procedures; or damage by outside parties. The latter was the major cause (58%) of reportable leaks in gas transmission lines in 1973.

An example of the damaging effects of a natural disaster, the Los Angeles earthquake in February 1971, caused over 50 separate transmission line breaks. Greatest damage was sustained by a 16-inch line, but breaks

7.1.1.1 (cont.)

occurred in both larger and smaller lines. Many breaks could be repaired, but abandoned lines were measured in miles. Fortunately, none of the gas ignited and there were no injuries or fatalities.

There are several available examples of failures in compressor stations. One in Ozona, Texas, in March 1973 resulted in line rupture, fire, and explosions, requiring complete replacement of the station. Operating pressure was 950 psig. Gas escaped from a 3/4-inch valve and was ignited by an unknown source, which led to subsequent ruptures of larger lines. An air supply was found to be closed, making all pneumatic valve actuators inoperative. Again, fortunately, there were no injuries. A somewhat similar incident occurred at a compressor station on the Kenai Peninsula in Alaska in January 1972. Gas leakage at three points in a new compressor module ignited and exploded. The station was automatically shut down. There was general damage to the control systems but none to the prime movers. In this case, three employees and two service engineers from the compressor supplier were injured, one of whom required a foot amputation.

The consequences of a pipeline rupture depend upon a variety of factors, including size of the rupture, local conditions of terrain and weather, and proximity to ignition sources and human habitation. There would obviously be a release of large quantities of natural gas even with proper closure of the isolating mainline block valves. There may be considerable disruption of the trench area and additional damage to the pipeline,

7.1.1.1 (cont.)

but these effects are secondary to the potential hazard from the escaping gas. The expansion of the high-pressure gas will result in considerable cooling and density increase.

Even Methane, which constitutes about 90% by volume of the gas, could reach a density greater than that of air, resulting in buildup of dangerous concentrations near the ground. Initially, prior to expansion, the high-pressure gas is very dense (about 60 times as dense as air). A break in a pipeline containing high-pressure gas could cause further pipe damage, upheaval, and cratering. The rapid release of the high-pressure gas causes a large degree of expansion and cooling. While the gas is expanding, its temperature could attain theoretical values of less than $-200^{\circ}F$, and specific densities greater than one (i.e., it would be heavier than air). Furthermore, as the gas expands and cools the dew point may be reached, causing condensation to begin, thereby producing a heavier-than-air liquid particle aerosol. Since data are not provided on the amount or size of solid particulates expected in the gas (other than it be below levels which are injurious to pipelines or may interfere with gas transmission), the possibility of forming a solid particulate aerosol cannot be evaluated. The formation of an aerosol would tend to increase the lifetime of the low-lying cloud of heavy gas that could occur from a pipeline break.

The probability of ignition of a heavy gas cloud depends on its flammability and its extent, as well as the availability of a source of ignition. The gas will remain heavier than air at temperatures below about $-130^{\circ}F$,

7.1.1.1 (cont.)

so that the initial gas, as it expands over the ground, could sufficiently warm up within several hundres feet of the pipe, and start to rise. As the heavy gas flows over the ground and rises, its heat transfer to the now cooler ground and air around it decreases, causing a further increase in the gas cloud radius. The lower and upper flammability limits of gas in air are 4 to 14%, by volume, at standard conditions. At lower temperatures the range decreases (the lower limit rises and the upper decreases). However, the possibility for ignition of the heavy gas cloud would still remain. The area that could be damaged, should ignition of the gas cloud occur, would depend on the size of the cloud.

The size of the heavy gas cloud on the ground is dependent on the wind, terrain, and meteorological conditions in the area and the amount of gas released. Consider the case of automatically actuated block values every 15 miles apart, a 48-inch O.D. pipe, a gas pressure of 1680 psig, and assuming that this 15-mile extent of gas escapes, then approximately 180 MSCF of gas is lost. A significant portion of this gas could lie along the ground for hundreds of feet for long lengths of time. Examples where gas explosions occurred up to one hour after pipe failure are given in National Transportation Safety Board Reports, NTSB PAR 73-4 and NTSB Report 74-3. Unfortunately, no estimates are provided as to the time interval between shutoff of the gas supply and the explosions. In another case (NTSB Report dated July 1, 1971), an explosion from a 14-inch, 780 psi pipeline in a residential area near Houston destroyed 13 houses that

7.1.1.1 (cont.)

ranged from 24 to 250 feet away, with partial damage occurring out to 600 feet. This gives some indication of the distance over which damage is possible should ignition occur.

Modeling the expansion of the escaping gas from a ruptured pipeline as an isentropic expansion results in a final gas temperature at ambient pressure of only $20^{\circ}F$ lower for a 1500 psi pipeline than for a 1000 psi pipeline, so that both would produce heavy gas clouds upon rupture. (An isentropic rather than a Joule-Thomson expansion is more appropriate.) Although the initial expansion is near adiabatic, it is supersonic and not at near-constant static enthalpy. The isentropic expansion gives some indications of the danger distances expected with high pressure gas pipelines, although the higher pressures and sizes of the Alaskan project would indicate even larger danger distances.

The Nuclear Regulatory Commission (NRC) has made a danger radius estimate of 5.6 miles under adverse meterological conditions. This estimate is of necessity very conservative (for instance, it neglects the very important aspects of ground and air to gas heat transfer which diminishes the danger radius). The safety standards imposed on nuclear power plants are justifiably strict, and NRC wishes to be notified if any pipeline passes within 10 miles of a present or proposed nuclear power plant. Of particular concern to them is the possibility that, due to the local topographical and meteorological conditions in the vicinity of a pipe rupture, some of the escaped gas could be funneled down a channel or valley and thus create a much greater

7.1.1.1 (cont.)

danger distance than that which would prevail over flat terrain. This possibility should also be investigated wherever the pipeline is in the vicinity of industrial complexes which possess added dangers of secondary explosions, and also in relation to residential areas.

While the 5.6-mile danger distance stated by NRC would appear overly conservative for general use, the 200 yards danger distance which is in Federal Regulation 49 CFR 192 could certainly be exceeded. Because of the apparent lack of experience by industry with gas pipelines of the diameter, length and pressures of the Alaskan project, and because of the large uncertainties in danger distance estimates, a conservative approach to the potential danger due to pipeline rupture seems wise. An increase in the 220-yard distance criteria used in 49 CFR 192.179 to establish the class zones should be considered. A closer spacing of the block valves within each class should also be considered.

It should be noted that the incidence of pipeline failure with resulting gas ignition is not large. Aside from man-caused ignition, the most probable cause would be an arc from a power line by electro-static discharge and, to a much lesser degree, ignition by lightning. The damage potential depends upon the quantity of gas released prior to ignition but could include destruction of pipeline system equipment, nearby electric power lines, structures, wildlife, and human life. Grassland fires or local forest fires might be initiated, causing secondary damage.

7.1.1.1 (cont.)

During maintenance operations, there is a possibility of pipeline damage. The pipeline center line should be clearly marked, so that crews would not accidentally traverse the pipeline with heavy equipment during either summer or winter maintenance operations.

Conclusions

- o A pipeline rupture will release at least 180 MSCF of gas to the atmosphere. This gas released from a rupture may or may not ignite immediately. Accident reports contain instances where ignition was delayed up to one hour after the leak occurred. The resultant explosion has created damage from 24 to 250 feet, with partial damage reported to 600 feet.
- o Damage radius in the event of a rupture and explosion of the 48 inch high pressure has not been defined by the applicant.

Recommendations

(a) The Applicants should present an evaluation of the potential damages resulting from natural catastrophe or man-caused accidents, with particular regard to the pipeline system and location. The fire and toxic hazards of gas near the ground in the case of pipe rupture should be evaluated by the Applicant.

(b) The Applicant should consider increasing the 220 yard distance criteria in 49 CFR 192.179 used to establish the class zones. A closer spacing of the block valves within each class should also be considered by the Applicant.

7.1.1.1 (cont.)

References

National Transportation Safety Board, NTSB Report PAR 73-4.

National Transportation Safety Board, NTSB Report PAR 74-3.

National Transportation Safety Board, NTSB Report dated July 1, 1971.

U.S. Nuclear Regulatory Commission Response (October 30, 1975) to a Letter Requesting Comment on DEIS for Alaska Natural Gas Transportation System, dated July 25, 1975.

BIBLIOGRAPHY

The Aerospace Corporation (15 March 1975) Arctic Gas Pipeline Project Alaska Arctic Pipeline Geotechnic Evaluation Report No. ATR-75(7496)-1.

Alaskan Arctic Gas Pipeline Company (November 15, 1974), Supplement to Application-Docket No. CP74-239.

Alaskan Arctic Gas Pipeline Company (January 30, 1975), Formation of Hydrocarbon Liquids in the Pipeline - Response to FPC/DOI Oral Question.

Alaskan Arctic Gas Pipeline Co. (21 March 1975) Docket Nos. CP74-239 and CP74-240 Volume 1, Prepared Direct Testimony and Exhibits of Alaskan Arctic Gas Pipeline Company Before the Federal Power Commission.

Alaskan Arctic Gas Pipeline Co. (October 28, 1975). Comments of Arctic Gas Applicants to Draft Environmental Impact Statement for The Alaska Natural Gas Transportation System-Part II (Alaska).

Alaskan Arctic Gas Pipeline Co. (October 28, 1975) Comment of Arctic Gas Applicants to Draft Environmental Impact Statement for the Alaska Natural Gas Transportation System-Part VI (Alternatives).

Alaskan Arctic Gas Pipeline Company (October 28, 1975) Comments of Alaskan Arctic Gas Pipeline Company to Aerospace Corporation Geotechnic Evaluation, 15 March 1975.

American National Standards Institute Code for Pressure Piping (1974) B 31.4 Liquid Petroleum Transportation Piping Systems.

American National Standards Institute Code For Pressure Piping (1975) B 31.8 Gas Transmission and Distribution Piping Systems.

Barsom, J.M. and Rolfe, S.T., (1970) "Correlations Between K_{IC} and Charpy v - Notch Test Results in the Transition-Temperature Range, Impact Testing of Metals, ASTM STP 466."

Battelle Columbus Laboratories, 1972, "Prudhoe Bay Test Facility Over-snow Vehicle Impact Studies."

Battelle Columbus Laboratories (June 1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region," Final Report, Volume I.

Battelle Columbus Laboratories (1974), "Engineering and Environmental Factors Related to the Design, Construction, and Operation of a Natural Gas Pipeline in the Arctic Region (Based on the Prudhoe Bay, Alaska, Research Facility," Columbus, Ohio.

Burdekin, F.M. and Dawes, M.G. (May 1971) "Practical Use of Linear Elastic and Yielding Fracture Mechanics with Particular Reference to Pressure Vessels," Conference on Practical Applications of Fracture Mechanics to Pressure Vessel Technology, Institution of Mechanical Engineers.

Canadian Arctic Gas Pipeline Company (1974), CAGSL Specification 2950-6-6, "Large Diameter Main Line Pipe for Minimum Service Temperature of $+250^{o}$ and $-10^{o}F$".

Canadian Arctic Gas Study Ltd (April 8, 1973) Trafficability Tests Norman Wells Northwest Territory.

Canadian Arctic Gas Study Ltd (July 14, 1975) Special Work and Transportation Equipment for Use During Operations and Maintenance of the Arctic Gas Pipeline System.

Cold Regions Research and Engineering Laboratory (January 1975) Accumulating Snow to Augment the Fresh Water Supply at Barrow, Alaska, by Slaughter, C.W., et al.

Cold Regions Research and Engineering Laboratory (May 1972) Special Report 172 - Literature Survey of Cold Weather Construction Practices by Havers, J.A. and Morgan, R.M.

Cold Regions Research and Engineering Laboratory (November 1974) "Effects of SK-5 Air Cushion Vehicle Operations on Organic Terrains After Two and Three Years," Gunars Abele, David M. Atwood and Larry D. Gould.

Cotton, H.C., Denkam, J.B. and Doble, K.R. "How to Conduct COD Tests and Utilize the Results in Practice."

Department of Transportation (October 1973), "Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards," Office of Pipeline Safety, Title 49 CFR, Part 192, October 1, 1973.

Ebasco Services Inc (June 1974) Cathodic Protection Operation and Maintenance Procedure for Canadian Arctic Gas Study Ltd.

Ebasco Services, Inc (December 1974) Cathodic Protection System For the Arctic Gas Study Company and Canadian Arctic Gas Study. Ltd.

Eggleton, Peter L. and Laframboise, Jacques, "Field Evaluation of Tower Air Cushion Rafts," Transport Canada, January 1974.

Environmental Protection Agency (1971) Noise from Construction Equipment and Operations, Building Equipment, and Home Appliances PB 206-717.

Environmental Protection Board (Canada), (September 1974) Environmental Impact Assessment of the Gas Pipeline from Alaska to Alberta, Volume 4.

"The Gas Industry (1973) - 1972 Disabling Injury Experience," American Gas Association, Catalog No. J00443.

Howell, B.F., Jr. (October 1973) "Average Regional Seismic Hazard Index (ARSHI) in the United States," et al, Special Publication "Geology, Seismicity, and Environmental Impact," Editors Moran, D.E., Association of Engineering Geologists, University Publishers, Los Angeles, California.

Kachadoorian, R. and Ferrians, O. (1973), "Permafrost-Related Engineering Geology Problems Posed by the TransAlaskan Pipeline," National Academy of Science, 2nd Permafrost Conference, 1973.

Keifner, J.F. Maxey, W.A., Eiber, R.J. and Duffy, A.R. (1973) "Failure Stress Level of Flaws in Pressurized Cylinders," Progress in Flaw Growth and Fracture Toughness Testing, ASTM STP 536.

Lachenbruch, A. H., (1959) "Periodic Heat Flow in a Stratified Medium with Application to Permafrost Problems," Geological Survey Bulletin 1083-A.

Maxey, W. A. (November 1974), "Fracture Initiation, Propagation and Arrest," 5th Symposium on Line Pipe Research.

McRoberts, E. C. and Morgenstern, N. R. Stability of Slopes in Frozen Soil, Mackensie Valley-Volume II, No. 4 November 1974 Canadian Geotechnical Journal pp 447-469.

Morgenstern and Nixon (1971), "One-Dimensional Consolidation of Thawing Soils," Canadian Geological Journal, 10, pp. 558-565.

Muskeg Research Institute, University of New Brunswick, Alur 1971-72, "Analysis of Disturbance Effects of Operations of Off-Road Vehicles on Tundra." by Radforth, J. R.

Muskeg Research Institute (Alur-72-73-12) "Immediate Effects of Wheeled Vehicle Traffic on Tundra During the Summer," University of New Brunswick.

Muskeg Research Institute, University of New Brunswick, "Long Term Effects of Summer Traffic by Tracked Vehicles on Tundra." by Radforth, J. R.

Muskeg Research Institute (May 1973), "Factors Affecting Use of Winter Roads During Spring Thaw," A Report to Arctic Petroluem Operators Association.

BIBLIOGRAPHY (cont.)

National Research Council Canada (June 1974) Proceeding of the Symposium on Heavy Transportation in the Application of Air Cushion Technology, Ottawa, Ontario.

National Research Council Canada, (November 1973), "Air Cushion Technology in Canada 1973."

Newmark, N. (March 1974), "Seismic Design Criteria for Canadian Arctic Gas Pipeline and Alaska Arctic Pipeline."

Northern Engineering Services Co., Ltd. (June 1974) Application of Geotechnical Analysis for Canadian Arctic Gas Study Ltd.

Northern Engineering Services Co., Ltd., (July 1974) Pipeline Related Borrow Studies.

Northern Engineering Services Co., Ltd., (October 1974), "Reference Book of Water Crossings, Volume II - River Crossing Design," Calgary, Canada.

Northern Engineering Services Co., Ltd. (December 1974) Application of Geotechnical Analysis Appendix B-11 Graphical Representation of Climate Along The Pipeline.

Northern Engineering Services Co., Ltd., (December 1974), "Reference Book of Water Crossings, Volume I - Hydrology," Calgary, Canada.

Northern Engineering Services Co., Ltd. (December 1974), "Interim Report Slope Stability in Permafrost Terrain," prepared for Alaskan Arctic Gas Co., Ltd., and Canadian Arctic Gas Co., Ltd. Calgary, Canada.

Northern Engineering Services Co., Ltd. (February 1975), "Reference Book of Water Crossings, Volume V - Preliminary Designs of Selected River Crossings Alaskan Coastal Route," Calgary, Canada.

Northern Engineering Services Co., Ltd., (March 1975), "Reference Book of Water Crossings, Volume Vii-Supplemental Hydrology," Calgary, Canada.

Northern Engineering Services Co., Ltd. (March 1975) Drainage and Erosion Control Measures Description and Proposed Design Principles.

Northern Engineering Services Co., Ltd., (March 1975), The Effects of Winter Methanol Spills on Forest-Tundra Vegetation.

Northern Engineering Services Co., Ltd., (June 1975) Inuvik Snow Road Construction, Testing and Environmental Assessment 1973-1974 Inuvik, Northwest Territories, Canada.

Northern Engineering Services Co., Ltd., (September 1975), "Mechanical Stress Analysis of Buried Pipeline," Vol. II, "Structural Design Criteria."

Northern Engineering Services Co., Ltd., (October 1975), "Mechanical Stress Analysis of Buried Pipeline," Vol. I, "Preliminary Design Guidelines."

Northern Engineering Services Co., Ltd., (October 1975), "Mechanical Stress Analysis of Buried Pipeline," Vol. III, "Theory and Structural Analysis."

Page, R. A., Boore, D. M., Loyner, W. B., Coulter, H. W. (1972), Motion Values for Use in the Seismic Design of the Trans-Alaska Pipeline System," Geol. Survey Circ. 672, USGS, US DoI, Washington.

Podlasek, R. J. and Eiber, R. J., (1974), "Predicting The Fracture Initiation Transition Temperature in High Toughness, Low Transition Temperature Line Pipe with the COD Test," Trans. Asme, J. Engr. Matls & Tech., pp. 330-334.

Penner, E., Johnson, G. H., and Goodrich, L.E. (1973), "Thermal Conductivity Laboratory Studies of Some MacKenzie Highway Soils," National Research Council of Canada.

J. E. Rymes Engineering, Ltd., (October 1975) Preliminary Report Work and Transportation Equipment for Canadian Arctic Gas Study Limited Operation and Maintenance, Calgary, Alberta.

Stevens, A. E. and Milne, W. G. (1974), " A Study of Seismic Risk Near Pipeline Corridors in Northwestern Canada and Eastern Alaska," Can. J. Earth Sci., 11, p. 147.

Taylor, R. S., "Engineering Geological Reconnaissance of Three Potential Routes for a Gas Pipeline from Prudhoe Bay to the Canadian/U. S. Border," 1972.

Technical Interchange Meeting (October 27 and 28) Alaskan Arctic Gas Pipeline Company and Department of Interior - Calgary, Alberta, Canada.

Thompson, S. and Labacz, E. F. (1973), "Shear Strength at a Thaw Interface," National Academy of Science, 2nd Permafrost Conference, 1973.

U. S. Department of the Interior (June 1975) Alaska Natural Gas Transportation System Draft Environmental Impact Statement Part II-Alaska.