

ALASKA LEGISLATURE SPECIAL COMMITTEE / SUBJECT FILES 86/2

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application to the FERC, which were the source of Case A costs. However, care has been taken to assure that the estimates are comparable and have included consistent contingency and risk costs.

Table 2 shows estimates of operating and maintenance costs for the gas conditioning facilities. Although these estimates are approximate, they indicate that there are not sufficient operating cost savings to provide any economic incentive to incur higher capital costs of conditioning facilities in interior Alaska.

In summary, the preferred option is Case A, using the approved 48-inch 1260 psig pipeline system and a single gas conditioning facility at Prudhoe Bay. This option has the lowest cost, presents minimum technical risk, and provides the lowest relative potential for overall project delay. A detailed discussion of the relative features of each case is presented in Section V.

III. BACKGROUND

A. Gas Conditioning Requirements

To facilitate understanding of the data submitted herein, a general technical background description of the requirements for gas conditioning is furnished.

Petroleum as produced from wells in oil or gas fields is seldom suitable for long-distance transportation. In the case of oil, gas must be separated from the liquid because the further treating or conditioning of the gas or oil is most economically done in separate facilities. Produced water, usually quite salty, must be separated from the oil to avoid the cost of transporting the useless brine to the refinery. Natural gas as produced is also usually unsuitable for transportation for more than short distances because the gas is saturated with water vapor and will form hydrates at modest pressures and moderately low temperatures. The gas may contain toxic constituents such as

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Hydrogen Sulfide, inert gases such as Nitrogen and Carbon Dioxide, and heavy hydrocarbons which will condense and form liquid slugs in a gas transmission pipeline. Facilities built to upgrade raw crude oil or natural gas to a transportable condition are almost always located in the field near the wells because of safety, operability, and economic factors. The early removal of water reduces the risk of corrosion and hydrate formation, a cost and safety risk; and the removal of toxic material makes the transportation operation significantly more safe. Both water vapor and Carbon Dioxide can create operational problems, especially when both are present, and are usually removed to some small acceptable level (typical pipeline requirements are no more than 3 volume percent CO₂ and 7 pounds of water per million cubic foot of gas) prior to long-distance transmission. The transport of material such as Water, Nitrogen, or Carbon Dioxide is also usually avoided because these materials have no energy value and their inclusion in the transportation system increases the cost of transporting the energy-bearing portion of the stream. Also, these diluents can cause end user interchangeability problems (flame-outs, yellow-tips) and safety hazards. Gas and oil conditioning is usually performed in or near the producing field as opposed to other processing operations which are usually accomplished as close to the market as possible, such as upgrading or refining of raw petroleum into motor fuel, fuel oil, and petrochemicals. This is because the transportation of relatively benign raw petroleum is safer, less complicated, and less expensive than the transportation of finished or intermediate products which have a higher value and may be more volatile, flammable, and/or toxic.

B. Prudhoe Bay Conditioning Requirements

The wellhead gas at Prudhoe Bay has been sampled and analyzed extensively, and three constituents which pose transportation problems have been found: first, the gas is saturated with water vapor (as is virtually always the case); second, the gas contains about 13 volume percent Carbon Dioxide; and third, the gas is relatively "rich" in

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heavy hydrocarbons such as butane, pentane, hexanes, and other components which will condense into the liquid phase at proposed pipeline pressures and temperatures.

Figure 1A shows the expected chemical composition of the gas to be produced. Figure 1B shows a "phase envelope" diagram for this gas to illustrate the vapor and liquid regions of this mixture at various combinations of temperature and pressure. The portion of the chart marked "two-phase region" illustrates conditions where both gas and liquid exist, and shows that at conditions contemplated in the current Alaska Gas Pipeline (30°F, 1260 psig maximum, and -10°F, 1000 psig minimum), the raw or "unconditioned" gas would exist in two phases. This condition poses an unacceptable pipeline risk because condensation and the formation of liquid "slugs" will cause damage to compressors and could cause unacceptable mechanical forces as the "slugs," with large mass relative to the gas, are forced to turn or traverse large elevation changes. Two-phase flow is a particular problem in mountainous areas, where liquid "slugs" occur erratically, are unpredictable in size and velocity, and cause unacceptable pipeline flow surges and pressure fluctuations. A serious problem could arise if condensed liquid accumulated in a section of pipeline on the slopes of the Brooks Range and created enough additional hydraulic head to increase pipeline pressure to the maximum allowable value. The end result of two-phase flow would be severely restricted gas flow rate in a given pipeline.

For a chilled gas pipeline to be able to transport unconditioned gas in the single phase region, the gas pressure must be maintained at quite high levels. When the gas enters more conventional pipelines and pressure is reduced to 1000 psig or below, the unconditioned gas would revert to the unacceptable two-phase condition unless the gas is heated. To eliminate the two-phase problem, the "hydrocarbon dew point" of the gas must be lowered, i.e., enough of the heavier constituents of the mixture (such as pentane, hexanes and heavier hydrocarbons)

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must be removed so that a single-phase gaseous mixture is obtained which will not partially condense at pipeline conditions. This heavy hydrocarbon removal must be done before the gas enters the lower pressure pipeline.

Figure 1A shows that the Prudhoe Bay gas has a Carbon Dioxide content of nearly 13 percent. This high level of Carbon Dioxide poses two problems in pipeline transportation: first, if water should be allowed to enter the pipeline, corrosive carbonic acid would be formed by the solution of Carbon Dioxide in the water; second, the Carbon Dioxide is of no value at the burner tip, but Carbon Dioxide would take up "transportation space" in the pipeline and requires compression just as does the hydrocarbon gas. To transport 2 billion cubic feet per day of raw Prudhoe Bay hydrocarbon gas, approximately 2.3 billion cubic feet per day of the gas-CO₂ mixture would have to be handled.

The removal of water vapor down to some small level must be accomplished both for corrosion control and to inhibit the formation of hydrates, since conditions suitable for hydrate formation exist at virtually all expected pipeline conditions of temperature and pressure. The produced gas is currently dehydrated to a -40°F water dew point at the separation stations prior to being transported 5-8 miles to the in-field central compressor plant for injection back into the reservoir. For pipeline transportation through the ANGTS, dehydration will continue to be required, and if the gas is subjected to any process which resaturates the gas with water vapor, the gas will again have to be dehydrated before it enters the pipeline.

The preceding discussion describes the technical and economic need to "condition" the Prudhoe Bay gas. Data presented in the remainder of the report will illustrate economic comparisons of various pipeline modes and conditioning facility configurations to meet these requirements.

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VI. CASE STUDIES OF ALTERNATE DESIGNS

Case A (Figure 2A)

A. Objectives

Case A is the current plan and comprises the facilities necessary to prepare gas for entry into a 1260 psig pipeline system for minimum temperature and pressure conditions of -10°F and 1000 psig, respectively.

Carbon Dioxide content of the gas must be reduced to an acceptable economic level. For this case, all conditioning facilities are located at Prudhoe Bay. Pipeline configuration is the 1980 ANNGTC filing.

B. Technical Requirements

Condensation in the pipeline must not take place at -10° and 1000 psig; therefore, enough heavy hydrocarbons must be removed so that the phase envelope of the pipeline gas is adequately below this condition. The process described in the 1978 Parsons Report meets this requirement by removing some of the butane and essentially all of the pentanes and heavier hydrocarbons. Figure 1B illustrates the approximate hydrocarbon dew point curve required. Since no economic uses for light NGLs were assumed to exist, the NGL's removed were either reblended into the product pipeline gas or blended with the effluent Carbon Dioxide stream and used as plant and field fuel.

The gas pipeline specifications require an inlet pressure of 1260 psig and a temperature of 30°F .

C. Facilities Description

The conditioning facilities consist of a refrigeration section to cool the gas and cause heavy hydrocarbons to condense, a CO_2 removal section,

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a fractionation section to separate ~~light~~ hydrocarbons from heavy hydrocarbons so that they may be pumped or compressed as required, pipeline gas compressor facilities to increase the pressure to the pipeline inlet requirement, and gas chilling facilities to cool the pipeline inlet gas to the required pipeline inlet temperature of 30°F.

For comparative purposes, the pipeline facilities for this case are those described for the Prudhoe Bay-Fairbanks (near Fox) section (Mileposts 0.0-455.0) of the July 1980 FERC application by the ANNGTC. In summary, the facilities included in this segment are: (a) the Prudhoe Bay receipt metering station, (b) the four northernmost compressor stations between Prudhoe Bay and Fairbanks proposed for the initial 2.0-2.4 Bcf/day throughput, and 455 miles of 48-inch, 1260 psig buried pipeline.

D. General Discussion of Case

1. Costs: this system has the lowest overall costs.
2. Schedule and Permit Approvals: this system complies with the current schedule and ongoing approval process for the Alaska Segment of the ANGTS; the conditioning facility is essentially as described in the FERC final Environmental Impact Statement.
3. Technical Risks: the systems described in this alternate are all based on commercially proven technologies and the Alaska construction and logistics methods have all been used for facilities at Prudhoe Bay.
4. Personnel Requirements:
 - a. Plant Operations: about 438 personnel will be required to operate and maintain the facility at Prudhoe Bay. Over 50 catering and contract personnel will be employed to provide



services for the Owner employees. Presumably almost all of these personnel will reside in Alaska and work a "7 days on, 7 days off" schedule.

- b. Pipeline Operations: the operational plan described in the FERC application would be followed.

5. Environmental and Resource Requirements

- a. Plant Impacts: In general, the construction environmental impacts will be short-term, and acceptable as described in the EIS. The facility will have minimal liquid effluents and the air emissions will comply with all applicable state and Federal regulations. The blending of Carbon Dioxide into the fuel system will actually reduce NO_x emissions from gas turbines.

Permafrost impacts will be mitigated by the elevated module and pile method used for other facilities at Prudhoe Bay. The increase in manpower, transportation, and logistics resources now used for North Slope activities will be nominally small relative to the current activity.

- b. Pipeline Impacts: all impact information on the Alaska Segment of the ANGTS pertinent to the July 1980 FERC application is public knowledge and is directly applicable to this case.

Case B (Figure 2B)

A. Objectives

The objective of this case was to examine the requirements and costs for a system which utilized the approved 48-inch, 1260 psig chilled pipeline system specifications, with the Carbon Dioxide removal facilities located in interior Alaska in the general vicinity of Fairbanks.

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"Pipeline quality" gas enters the pipeline at the outlet of the interior Alaska facilities.

B. Technical Requirements

As can be seen in Figure 1B, the raw gas must undergo hydrocarbon dew point control prior to entering the chilled 1260 psig pipeline at Prudhoe Bay for vapor-phase transmission to interior Alaska. Transportation economics through the remaining pipeline system south dictate that Carbon Dioxide should be removed in Alaska to pipeline specifications. The gas must be dehydrated, compressed to 1260 psig, and cooled to 30°F following the CO₂ removal process.

C. Facilities Description

At Prudhoe Bay, a "straight" refrigeration system is used to cool the gas and liquify the components which are not transportable in the pipeline. The gas has been dehydrated in the field, so no further water removal is necessary. The recovered NGL is fractionated into pentanes and heavier components which can be transported in TAPS and the lighter material is used for fuel. The gas is compressed to pipeline pressure and chilled to 30° prior to entering the pipeline. The pipeline distance to the interior facilities is assumed to be 455 miles, which would locate the interior facility in the vicinity of Fox. This location is assumed only for the comparative perspective of this report; it appears to be as feasible as any other interior site for comparative purposes.

At the interior plant location, gas must be warmed to about 90°F to avoid hydrate formation in the Carbon Dioxide removal system. The gas is contacted by an aqueous "chemical" solvent to remove CO₂. This type of process must be used to minimize the hydrocarbons absorbed and released with the CO₂, since no means are available to conserve hydrocarbons mixed with CO₂ (such as the field fuel system at Prudhoe Bay). The CO₂-free gas is dehydrated to an acceptable

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water content, compressed to 1260 psig, and chilled to 30°F for entry into the pipeline.

To transport the incremental volume of CO₂, approximately 38,000 horsepower of additional compression and 14,000 tons of additional refrigeration would be distributed among the four pipeline compressor stations between Prudhoe Bay and Fairbanks. Additional metering facilities would be required at Prudhoe Bay and probably at the interior CO₂ removal site, but the costs of these facilities were neglected for purposes of this comparative analysis.

D. General Discussion of Case

1. Costs: the system costs are adversely impacted primarily because of additional investment costs and operating costs resulting from separation of the two gas conditioning functions within the resulting duplication of facilities and manpower. An additional 38,000 horsepower of compression would be required to transport the higher gas volumes to interior Alaska because of the CO₂ content.
2. Schedule and Permit Approvals: the ANGTS project schedule would likely be impacted by the time required for approval of the additional compression facilities. The simultaneous construction of two conditioning facilities in two locations would result in large Alaska construction labor requirements which could impact the schedule.

The FERC EIS does not address two conditioning plant locations constructed and operated simultaneously, and would have to be supplemented with the resulting project delay.

3. Technical Risks: the principal technical risks are the high corrosion potentially associated with transporting gas containing 13 percent CO₂. If water should enter the pipeline from hydrotesting, repairs, or from future tie-ins, and if gas contacts unfrozen

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water, serious corrosion would likely occur. Repairs would probably involve system shutdowns.

A second risk is the operational difficulty of coordinating two facilities which are 455 miles apart, and which must both function effectively and simultaneously to condition the gas.

4. Personnel Requirements:

- a. The facility would require 434 operating, maintenance, and support personnel. Obviously optimum manning could not be achieved with the facilities separated. Some duplication of supervision and maintenance personnel would be required, offset by the lower manpower requirement in interior Alaska.
- b. Construction and operating personnel for the Prudhoe Bay-Fairbanks pipeline segment could increase slightly, but not significantly over Case A. Such changes are considered negligible for purposes of this comparison.

5. Environmental and Resource Requirements: the energy, land use, gravel, and other material resource facilities would exceed those of a single facility; therefore, the environmental impact would undoubtedly be greater. Pipeline compressor stations (north of Fox) would contain more powerful equipment, but environmental impacts and resource requirements over Case A would be minor.

Case C (Figure 2C)

A. Objectives

The objective of this case was to examine the requirements and cost for a system which had all gas conditioning facilities located in interior Alaska (in the general vicinity of Fairbanks). The raw gas would be

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transported to the Interior Alaska site for carbon dioxide removal and hydrocarbon dew point control as required for transport in the system south of the conditioning facility.

B. Technical Requirements

The raw gas from the producer gathering system is at a temperature of about 90°F and has a hydrocarbon dew point of about 88°F; the gathering facilities operate at approximately 600 psig. The concept for this alternative is to apply these gathering system design parameters to the Prudhoe Bay-Fairbanks pipeline segment. This necessitates a low pressure, warm gas pipeline adequately insulated to maintain temperature under cold weather shutdown conditions. Above and below ground pipeline construction modes must be employed to cater to permafrost soil conditions (similar to TAPS).

C. Facilities Description

Two 56-inch insulated pipelines are required to provide the nominal 2 BCF/day flow rate at 675 psig maximum operating pressure. The lines are installed on vertical support members and the configuration would be trapezoidal similar to TAPS to provide for thermal expansion and contraction. A new crossing will likely be required at the Yukon River, since the space for two additional lines, each with a total diameter of 5'8", including insulation, probably does not exist. No design exists for this crossing; the cost, although significant, has not been estimated for this study and is omitted. Heating stations must be provided at the compressor stations to maintain gas temperature above the hydrocarbon dew point. Metering facilities and a heating station are provided at Prudhoe Bay.

At the interior Alaska plant site, hydrocarbon dew point control facilities, CO₂ removal facilities, compression facilities for 1260 psig, and gas chilling equipment are installed. The functions are similar to those

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required for Case A, except that a chemical solvent CO₂ removal process and subsequent dehydration, as described in Case B, are required. All NGL removed for gas conditioning would be either burned as fuel or pumped into TAPS. Spare fractionation facilities are required, because at this location no NGL emergency injection (during fractionator outages) into the Prudhoe Bay reservoir is feasible.

D. Advantages and Disadvantages

1. **Costs:** the costs of this system are extremely high because of the following:
 - a. Two 455-mile, 56-inch aboveground pipelines are required.
 - b. Plant construction in interior Alaska precludes large modular installations.
 - c. Additional facilities for NGL disposition are required.
 - d. Additional fuel is required for heating and compression on the pipeline.
2. **Schedule and Permit Approvals:** a minimum of two years of delay in the ANGTS schedule would occur because of the radical change in pipeline construction and cost from that envisioned in the FERC filing and other Federal applications. A total pipeline redesign effort would contribute to the delay. The number of pipe mills capable of rolling 56-inch pipe in the quantities required is limited. The additional pipeline construction alone would probably require at least one year more than the current schedule. Re-evaluation of the current right-of-way stipulations and TAPS proximity criteria would likely be required.

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3. **Technical Risks:** the technical risk of transporting raw gas and relying on pipeline heaters to maintain the line above 100°F at all possible flow rates and under all weather conditions in the Arctic is formidable. Additionally, the corrosion risk described in Case B is present, except that at normal operating temperature unfrozen water will exist, making corrosion damage in the CO₂-rich portion of the line inevitable if water enters the line.
4. **Personnel Requirements:**
 - a. Personnel requirements are 362 operating, maintenance, and support personnel required at the Interior Alaska plant site.
 - b. The two aboveground pipelines will require considerably more maintenance and surveillance personnel than would be the case with a single buried line. No estimate has been made of these requirements, because none is believed to be warranted due to the cost and schedule infeasibility of this alternative.
5. **Environmental and Resource Requirements:** the gravel resource requirements will be higher than the buried line cases since more and larger workpads for the pipelines would be necessary. Fuel consumption is higher than other cases because of the heated low pressure line. Construction and operational impacts will be significantly greater than those of a single buried line.

Case D (Figure 2D)

A. Objectives

Case D examines the facilities necessary to compress raw field gas to a 48-inch, 1680-psig, aboveground, warm pipeline system which will handle the gas with no conditioning required at Prudhoe Bay. Carbon

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Dioxide removal and hydrocarbon dew point conditioning facilities are located in interior Alaska to prepare the gas for transmission to a 1260-psig buried, chilled line.

B. Technical Requirements

The raw gas must be compressed to 1680 psig and cooled to about 100°F at Prudhoe Bay. The pipeline gas must not be allowed to cool below about 70°F at the compressor suction pressure of 1450 psig. Aboveground pipeline construction with insulated pipe is required. Gas conditioning to prepare the gas for transport in the chilled 1260 psig pipeline is required at the interior Alaska location.

C. Facilities Description

Facilities for compression of the raw gas to 1680 psig and cooling to about 90°F are required at Prudhoe Bay. The 1680 psig pipeline is insulated and installed aboveground in the same manner as TAPS between Prudhoe Bay and the interior Alaska location. At the interior Alaska site, hydrocarbon dew point control is achieved by chilling the gas, and liquids recovered are fractionated and put into TAPS or used for fuel. Carbon Dioxide removal to pipeline specifications is accomplished in a "chemical" solvent process as in Cases B and C except that the conditioning is accomplished at a pressure adequate to provide entry into the 1260 psi pipeline without compression. The gas must be dehydrated, and chilling to 30°F is required prior to entry into the 1260 psi buried, chilled pipeline.

D. General Discussion of Case

1. Costs: the costs are increased by the use of an aboveground pipeline between Prudhoe Bay and the higher construction costs in interior Alaska.

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2. **Schedule and Permit Approvals:** the change in the pipeline design pressure and revisions to the design and construction method would likely delay the ANGTS schedule by at least one year. The change to an aboveground line would likely require re-evaluation of the current right-of-way stipulations and TAPS proximity criteria.
3. **Technical Risk:** as described in Cases B and C, the major technical risk is the corrosion potential attendant to transport of raw gas containing 13 percent CO₂.
4. **Personnel Requirements:**
 - a. Personnel requirements are 440 operating, maintenance, and support personnel.
 - b. Pipeline personnel requirements would be marginally larger than Case A because of the additional security, inspection, and maintenance for an aboveground pipeline system.
5. **Environmental and Resource Requirements:** the necessity for a large compression facility at Prudhoe Bay as well as a plant in interior Alaska would increase gravel requirements over a single facility case. The installation of a second aboveground pipeline essentially parallel to TAPS would create additional impacts because of the construction mode.

Case E (Figure 2E)

A. Objectives

The objective of this case was to examine the use of a 42-inch 2160 psig chilled, buried pipeline to transport unconditioned raw Prudhoe Bay gas to an interior Alaska gas conditioning site, and conditioning for a 1260 psi pipeline at the interior site.

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B. Technical Requirements

No gas conditioning is required at Prudhoe Bay, although the gas must be compressed to 2160 psi and chilled to 30°F for the buried line. At the interior Alaska site, CO₂ must be removed and hydrocarbon dew point controlled to allow the gas to be transported in the subsequent 1260 psi chilled line and through the Canadian line segments.

C. Facilities Description

The compression equipment at Prudhoe Bay entails about 200,000 horsepower and the gas must be chilled to 30°F prior to entry into the pipeline. At the 2000 psig ^{operating} pressure level, a 42-inch diameter pipeline is adequate to transport the required 2.3 Bcf/day of raw gas. At the interior Alaska site, 455 miles from Prudhoe Bay, hydrocarbon dew point control is achieved by chilling utilizing the available pressure drop in expanders. CO₂ is removed by a chemical process similar to Cases B, C, and D. Gas is dehydrated, recompressed to 1260 psi, and chilled to 30°F for entry into the pipeline system.

D. General Discussion of Case

1. Cost: although a smaller diameter pipeline can be used in this case, costs are somewhat higher than Case A because of the greater pipe wall thickness and the higher working pressure valves, fittings, compressors, coolers, etc. Equipment of the large size and high pressure rating which meets Arctic service requirements would likely require some developmental engineering; while these development costs could be significant, none are included in the estimated cost of this case.
2. Schedule and Permit Approvals: since this pipeline system represents a major scope change from the current plan, new approvals would be required from the FERC, DOI, and the Federal Inspector.

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Questions were raised during regulatory hearings relative to the advisability of operating a 1680 psig pipeline, and similar questions would have to be answered for a 2160 psig line. Such resolutions would result in an ANGTS schedule delay of at least one year and probably more.

3. **Technical Risks:** the transport of gas containing a high concentration of CO₂ would pose the same corrosion risk described in Cases B, C, and D. Pipeline qualification burst tests and/or a decision to utilize crack arrestors would have to be implemented to minimize ductile fracture risk. Large valve and fitting manufacture to the required quality specifications would have a greater risk of schedule delay than more common pressure requirements, and operating risks would be higher due to extensive use of unproven equipment.
4. **Personnel Requirements:**
 - a. Plant personnel requirements are 422 operating, maintenance, and support personnel.
 - b. Pipeline operating requirements would be essentially the same as Case A.
5. **Environmental and Resource Requirements:** The construction of facilities at both Prudhoe Bay and at the interior Alaska site would consume more gravel and other resources than a single site.

V. COMPARISON OF ALTERNATES

A. Costs

Investment costs are summarized on Table 1. The costs (excluding risk) of various alternates involving conditioning facilities at an

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interior Alaska location are estimated to exceed those of the current plan (Case A) by \$617 million (for Case B) to \$7,597 million (for Case C). When "risk" costs for additional contingency to cover serious weather and construction difficulties are added, the current plan is less costly by \$584 million (Case B) to \$7,539 million (Case C). These costs are in 1980 dollars and do not include the escalation to the actual date of expenditure. If the regulatory and design delays inherent as a result of major changes to the design were considered, Case B, the next lowest cost alternative to Case A would involve a minimum of one year of delay for the entire ANGTS, including sections of the line in Canada. This delay cost could exceed \$2 billion for a \$20-billion system at an inflation rate of 10 percent. Cases C, D, and E would undoubtedly involve delays exceeding one year with the commensurate delay costs.

Fuel usage for Case A is estimated to be 10% to 30% lower than the other cases. Case B, the next investment case, would have a fuel cost penalty of about \$23 million per year. This is the result of the necessity for using the less efficient "chemical" CO₂ removal process, the additional pipeline fuel required to transport the CO₂ to the interior conditioning plant location, and the restricted availability of integrated heat conservation options when the hydrocarbon dew point and CO₂ removal facilities are at separate locations.

B. Approvals and Permits

A comparison of the deviations from current temporary certificates and other approvals indicates that Case B is the least changed from the current basis; however, Case B still has two important differences: first, the transportation of up to 300 Mmcf per day of CO₂ with the gas creates compressor station design changes with attendant investment and operating cost increases, and creates a technical concern with respect to corrosion potential. The cost-effectiveness of design changes and higher operating risks to transport valueless CO₂ could

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be challenged during the regulatory approval process. Second, the construction and operation of two conditioning facilities at two locations presents additional environmental impacts over a single installation not addressed in the FEIS. Other cases also have obvious design differences which would delay approvals.

C. Schedule

The overall ANGTS schedule delay implications of the cases which differ from the current design are mentioned in A and B, above. In general, the relative schedule delays are conservatively estimated as follows:

<u>Case</u>	<u>Minimum Delay</u>	<u>Comment</u>
A	None	Current plan
B	1 year	Design changes
C	2 years	Design changes & additional construction time
D	1 year	Design and construction changes
E	1 year	Design and technological scope changes

D. Technical Factors and Risks

All cases except Case A pose the problem of mitigating the potential corrosion risk attendant with transport of high CO₂ gas. This risk is most serious in the "warm" pipeline Cases C and D, because water can exist in the liquid form inside the pipeline at normal operating temperatures.

The cases with major facilities at two locations, Cases B, D, and E pose potential operating coordination problems. Case B is the worst example because the hydrocarbon dew point control is done 455 miles from the CO₂ removal. Operational problems at Prudhoe Bay could adversely affect the operation of the CO₂ removal plant at the interior location. "Early warnings" of impending "upsets," or other problems

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are essential to good plant operations and long distances and decentralized operations make this procedure more difficult. The 455-mile separation of facilities would undoubtedly compound operating difficulties.

Cases C and D require aboveground pipeline operations to be conducted at temperatures above the hydrocarbon dew point. The problems of maintaining warm line temperature during an extended shutdown, and/or the disposal of large quantities of condensed NGL in the pipeline would have to be resolved, and would involve costs not considered in these estimates.

The risk of a ductile fracture incident and the potential for damage would be significantly greater for the aboveground construction. The likelihood of fracture initiation would be increased by the higher exposure to either accidental or deliberate external damage. A propagating fracture could disengage the pipe from the supports and thrust forces caused by the escaping gas could cause relatively long sections of the pipeline to "whip," with resulting damage to the gas pipeline and its supports and possibly to TAPS.

VI. OTHER FACTORS

A. NGL Recovery

As stated previously, the gas from the Prudhoe Bay Sadlerochit reservoir is relatively "rich" in high molecular weight hydrocarbon compounds. These compounds are sometimes extracted from natural gas because their separate end-product values may be greater than their heating value in a natural gas-fuel mixture. The compounds are essentially all those components heavier than methane, such as ethane, propane, isobutane, normal butane, etc. They are sometimes called "NGL" (natural gas liquids), or "LPG" (liquefied petroleum gas consisting of propane and/or butane), or "Natural Gasoline" (usually pentanes and heavier compounds). It was previously pointed out that some of

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the "NGL" hydrocarbons must be removed to enable safe pipeline transportation. After bulk extraction these compounds (pentanes-and-heavier, plus some of the butane) may be separated and the lower vapor pressure liquids shipped with the crude oil and the higher vapor pressure liquids utilized as fuel. The "lighter" NGL components (ethane and propane) are transportable in the gas and can always be extracted if the necessary economic driving force exists (i.e., if their value as separate commodities is sufficiently higher than their heating value sold as "gas" to justify the required investment and operating costs for the extraction and disposition facilities). NGLs may temporarily be used for fuel or temporarily left in the gas, but are never really "lost." They are simply moving to the use which provides the highest economic value. This situation is reasonably analogous to the refining of crude oil into various products such as motor gasoline, jet fuel, or heating oil; the economics of specific product supply/demand balances dictate the product disposition, and that disposition may change from time to time.

B. Alternate Plant Fuels

It has been suggested that the use of Alaska coal should be considered as fuel for ANGTS gas conditioning facilities in order to release more gas for market. The critical factors in addressing this question are security and reliability of supply, economics, and environmental considerations.

The security of a fuel supply which involves another separate business is far more fragile than a fuel supply which is irrevocably tied to the primary operation; for this reason most field petroleum operations utilize their own production for fuel and most gas pipelines utilize their own gas for fuel. The risk of coal shortages due to production or transportation strikes or weather interruption is relatively high. The ANGTS is unlike electrical power grids having alternate power sources where occasional outages of one or more sources may be tolerable. Prudhoe Bay Gas may represent as much as 10 percent of the

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gas supply for the U.S. and is essentially irreplaceable in the event of an interruption. Very serious complications would result from an interruption of this gas supply, and the risks of interruption would increase significantly if the ANGTS operation were dependent on coal.

Economics are a factor when costly long distance transportation of fuel by road or rail is required. Employing the transport gas for fuel provides the lowest cost method of moving fuel from the source to the use. A further economic advantage of using gas for fuel is that it is the best engine fuel for low maintenance costs and long life of the gas and refrigeration compressor drivers.

The environmental problems of a coal-fired steam power plant are well-known: particulate, NO_x , and CO emissions into the air, water usage, and liquid effluent disposal. Whether at Prudhoe Bay or at an interior Alaska location, the construction of a coal-fired power plant which meets today's environmental requirements would pose an economic and schedule burden of serious magnitude. These would be even more serious if the power plant emissions impacted the air quality of a Non-Attainment Area.

It is concluded that the interests of the the system owners and the gas consumers are best served by the use of gas for fuel. This system has the lowest investment, the least risk of interruption, and the least environmental impact.

C. Construction Considerations

The construction mode considered in this study for Prudhoe Bay gas conditioning facilities is that utilized for Prudhoe Bay producing facilities. Large equipment modules weighing up to 2000 tons are constructed in a "lower 48" coastal facility suitable for loading onto sea-going barges. Approximately 75 percent (or more, if possible) of the construction labor manhours would be incurred at the lower 48 site.

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Modules are transported to Prudhoe Bay by barge and crawled to a prepared location. The annual sealifts arrive in Prudhoe Bay in August, and the outdoor construction is completed during August, September, October and November to utilize the better weather. The remaining indoor construction work for hookup, detail finishing, and testing can then be done essentially indoors during the winter. As a result, most of the Prudhoe Bay work is done either outdoors in reasonable weather or indoors during inclement periods.

The Fairbanks work was assumed to be accomplished by packaging the equipment onto small skids which can be transported overland by rail and/or truck to interior Alaska. Because of the size and weight limitations, only a limited amount of packaging can be accomplished prior to shipment. Similar packaging concepts are frequently incorporated into inland facilities in the lower 48. It was assumed that some weather protection can be achieved by air-pressurized enclosures and early construction of buildings. The construction costs are higher in interior Alaska because of several factors: (1) more labor is required in Alaska at higher wage rates, (2) more low-efficiency outside work is required for the land transportable packages, because in most cases enclosures cannot be transported with the equipment and must be built at the site, with increased labor and material costs, (3) full achievement of scale economy is precluded because the transportation constraints require smaller process vessels than may be used in large modules, with the attendant additional piping, valves, instrumentation, foundations, etc., and, (4) schedules become more complex when constrained by interior Alaska weather and transport requirements resulting in increased construction time.

It has been suggested that weather factors in a central Alaska location would allow more efficient construction. This was not the experience on TAPS. Pump Stations 3 and 4, north of the Atigun Pass, cost essentially the same as Pump Stations 9, and 12 which are in central and southern Alaska.

For Discussion Purpose Only	
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Further, it is felt that the construction mode utilized for Prudhoe Bay has minimized the impact of outdoor bad weather construction by utilizing very large pre-enclosed facilities to mitigate the effects of the harsh climatic conditions on construction labor efficiency. The experience in the complexities of construction by the producers at Prudhoe Bay and by TAPS -- in Alaska and on very large projects -- has illustrated that simplistic approaches to project cost estimates, cost comparison of alternatives, construction planning, and project execution are not adequate. Estimates using only factored Gulf Coast or other lower 48 construction costs may contain very large margins for error.

D. Personnel and Operating Factors

The construction cost estimates assume that a peak of about 800-1000 construction workers would be employed at the Prudhoe Bay location for Case A, and peak labor forces 25 to 50 percent higher in the cases with facilities in interior Alaska. For operations, about the same number of operating positions and employees would exist for Cases A, B, D, and E, since the cases with split facilities would incur some duplication of positions offset by the lower manpower requirement in interior Alaska.

In the cases with facilities in interior Alaska, the savings for operating costs of wages, camps, and catering are offset by the insurance and tax burdens of the higher capital costs.

Pipeline operating costs have not been calculated for this study, but directionally the higher capital cost cases would have higher operating costs. Cases C and D which transport unconditioned gas will undoubtedly have significantly higher pipeline costs because of the corrosion potential and the additional equipment required for heating, slug catching, and liquid disposal.

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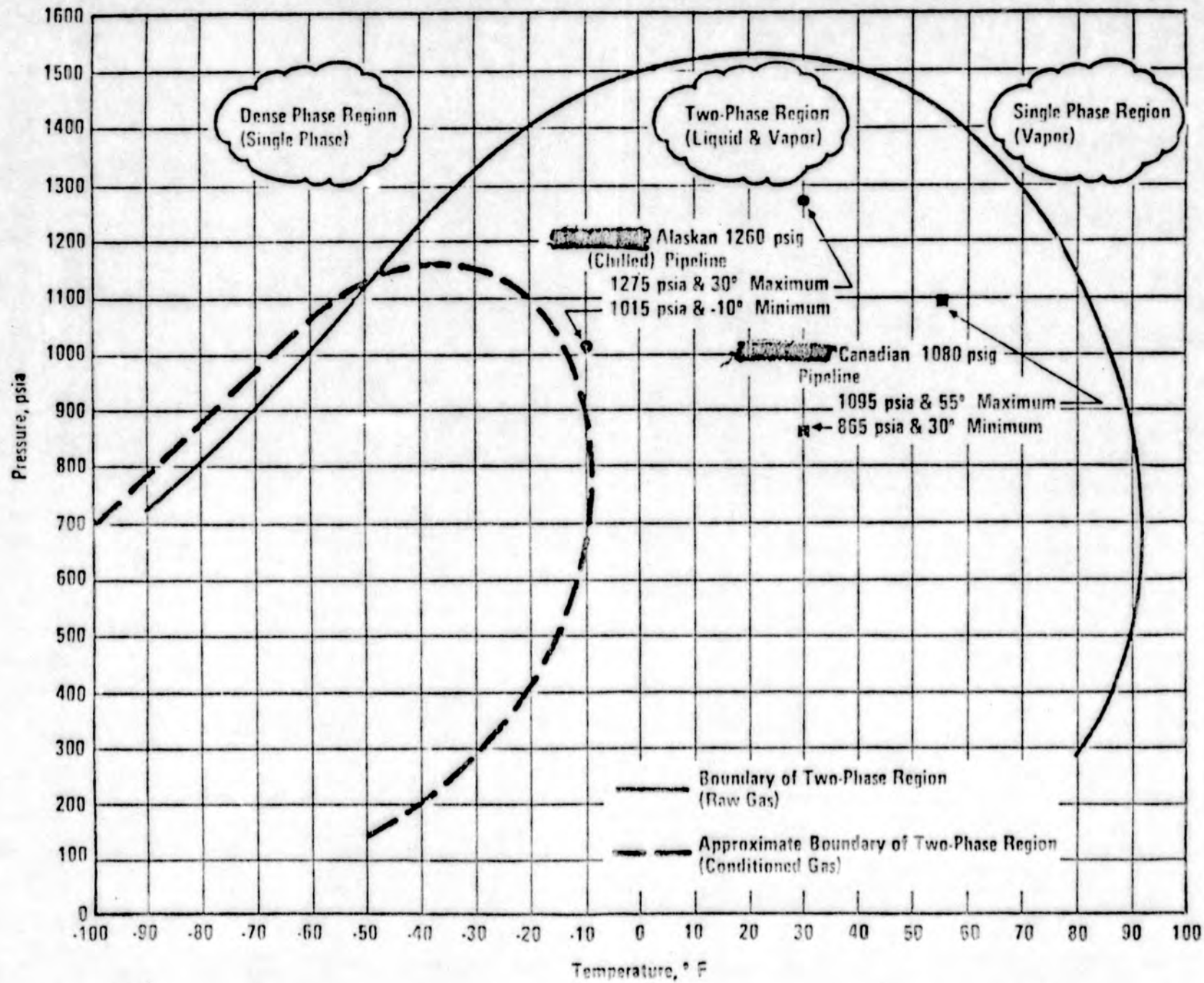
FIGURE 1A

Prudhoe Bay Raw Separator Gas Composition

<u>Component</u>	<u>Mole Percent</u>
Hydrogen Sulfide	(8 ppmv)
Carbon Dioxide	12.63
Nitrogen	0.47
Methane	74.18
Ethane	6.47
Propane	3.48
Isobutane	0.49
Normal Butane	1.17
Isopentane	0.26
Normal Pentane	0.49
Hexanes	0.19
Heptanes	0.12
Octanes	0.04
Nonanes	0.01

Figure 1-B

PHASE ENVELOPE FOR PRUDHOLE BAY (SADLEROGHIT) ASSOCIATED GAS

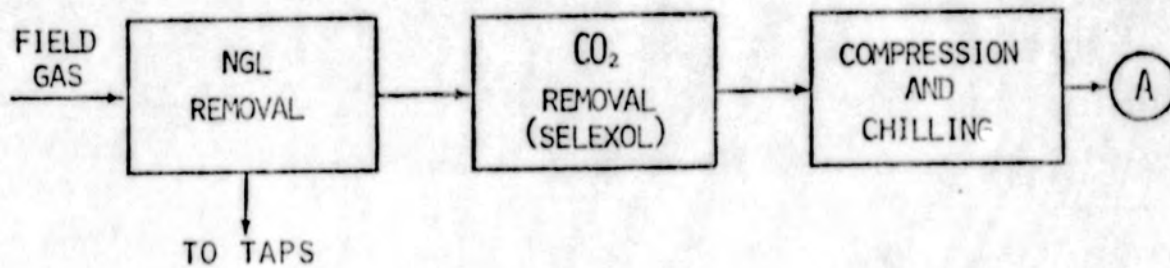


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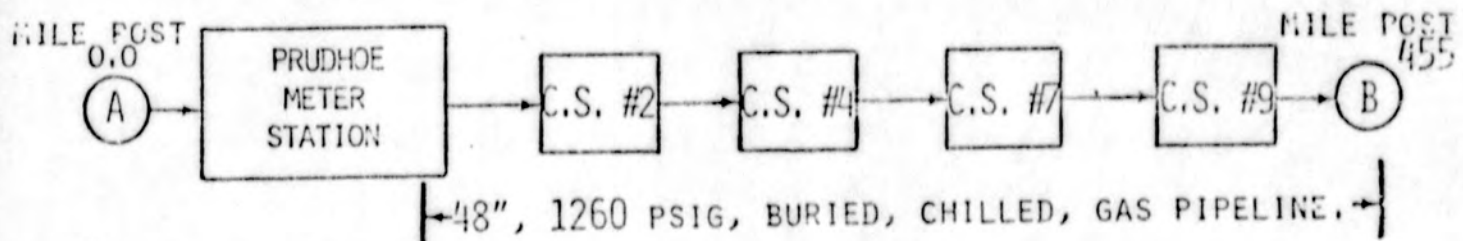
FIGURE 2A

CASE A: ALL GAS CONDITIONING AT PRUDHOE BAY
PRESENT PIPELINE SYSTEM DESIGN

PRUDHOE BAY FACILITIES



PRUDHOE BAY - FAIRBANKS PIPELINE SEGMENT



INTERIOR ALASKA FACILITIES

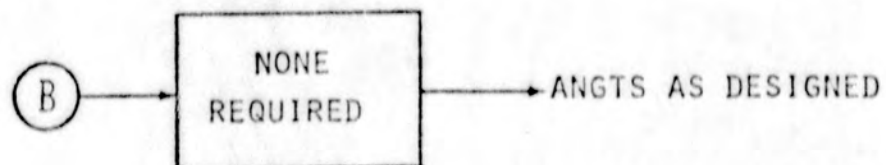
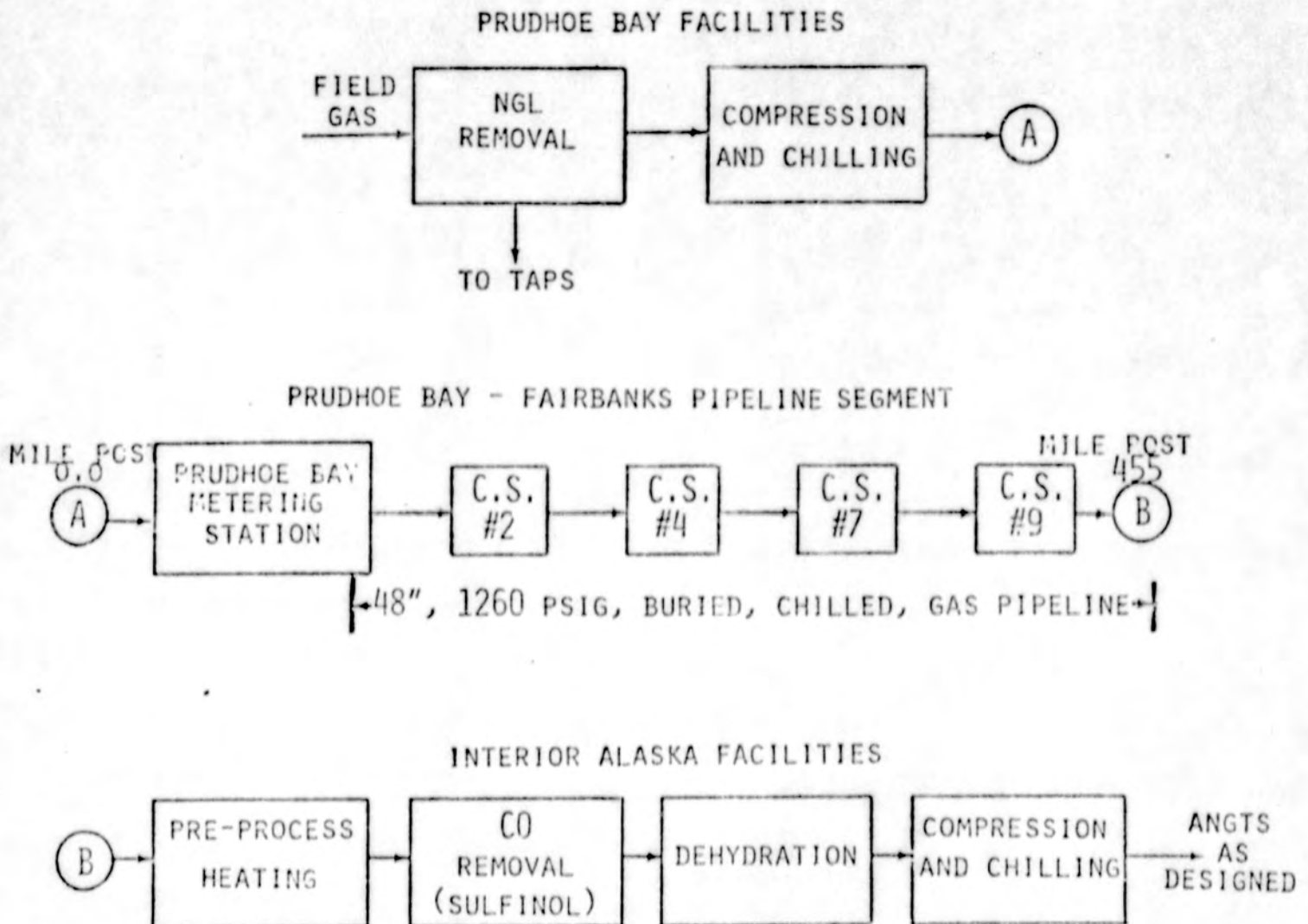


FIGURE 2B

CASE B: CO₂ REMOVAL IN INTERIOR ALASKA

ADDITIONAL PIPELINE COMPRESSION
 TO TRANSPORT 13% CO₂ TO FAIRBANKS



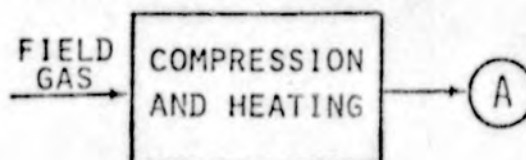
DATE

DEC 22 1980

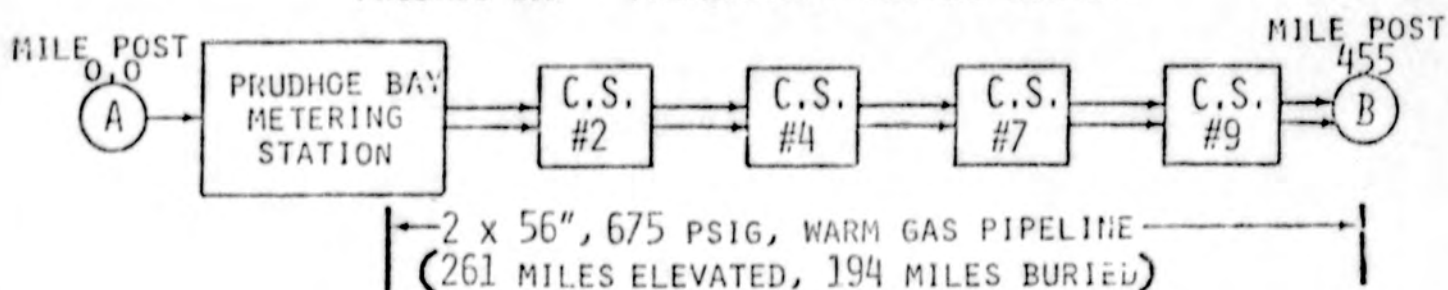
FIGURE 2C

CASE C: ALL GAS CONDITIONING IN INTERIOR ALASKA
LOW PRESSURE, WARM GAS PIPELINE TO FAIRBANKS

PRUDHOE BAY FACILITIES



PRUDHOE BAY - FAIRBANKS PIPELINE SEGMENT



INTERIOR ALASKA FACILITIES

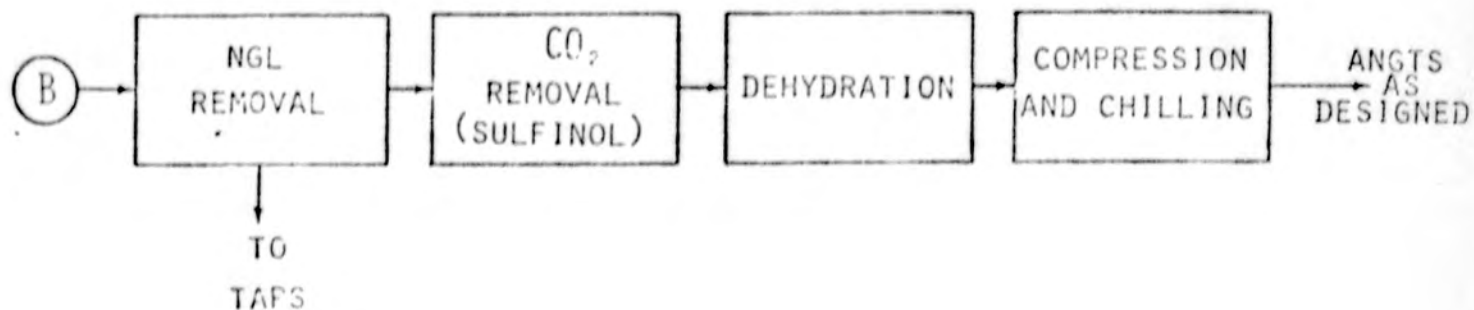


FIGURE 2D

CASE D: ALL GAS CONDITIONING IN INTERIOR ALASKA
HIGH PRESSURE WARM GAS PIPELINE

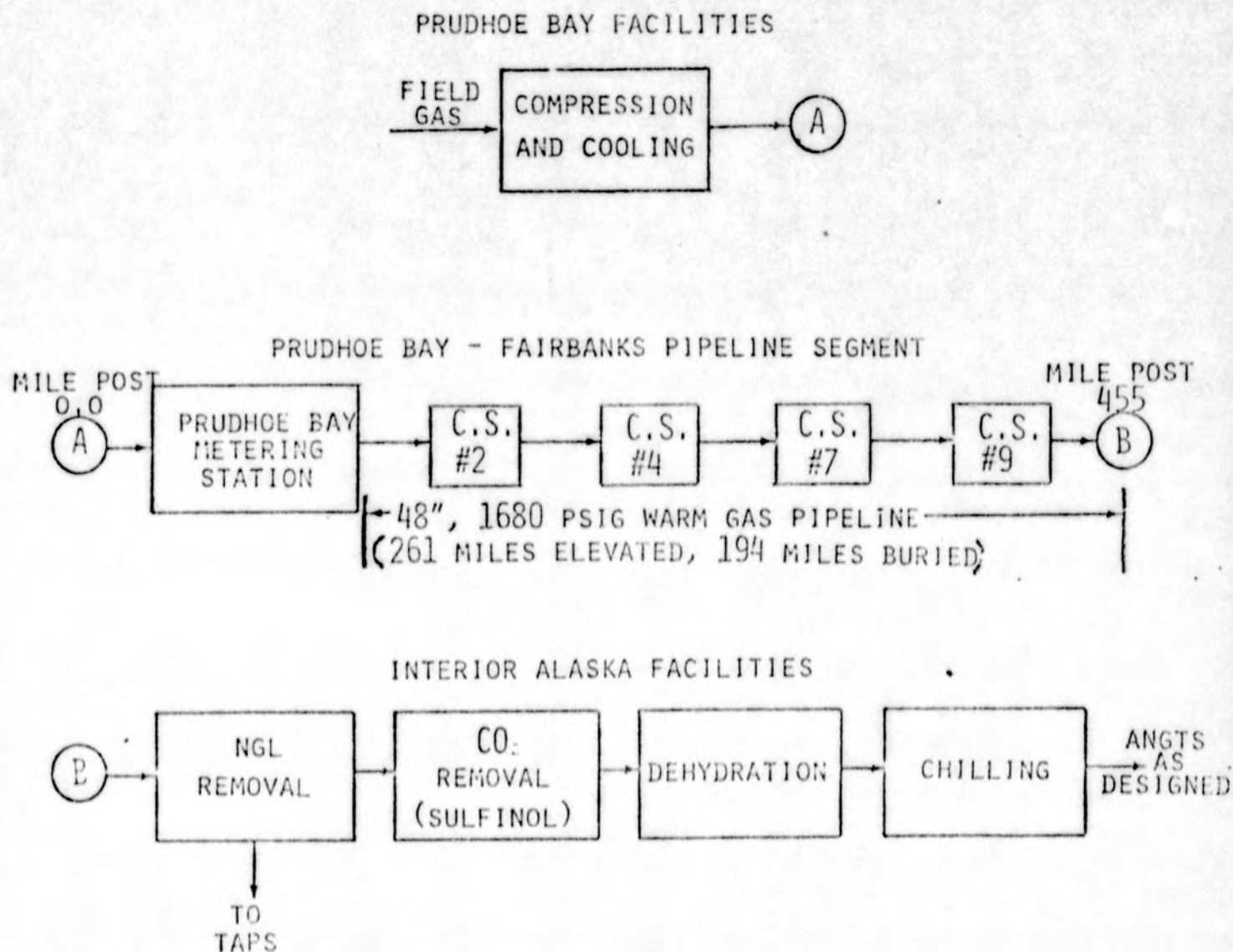


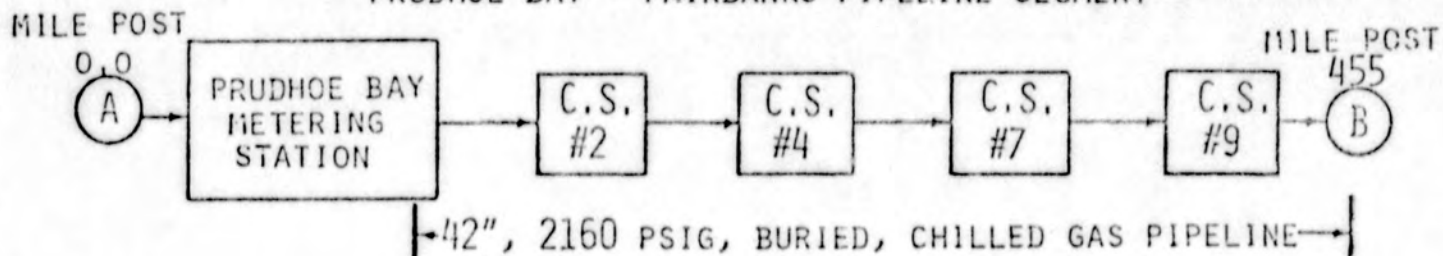
FIGURE 2E

CASE E: ALL GAS CONDITIONING IN INTERIOR ALASKA
HIGH PRESSURE CHILLED GAS PIPELINE

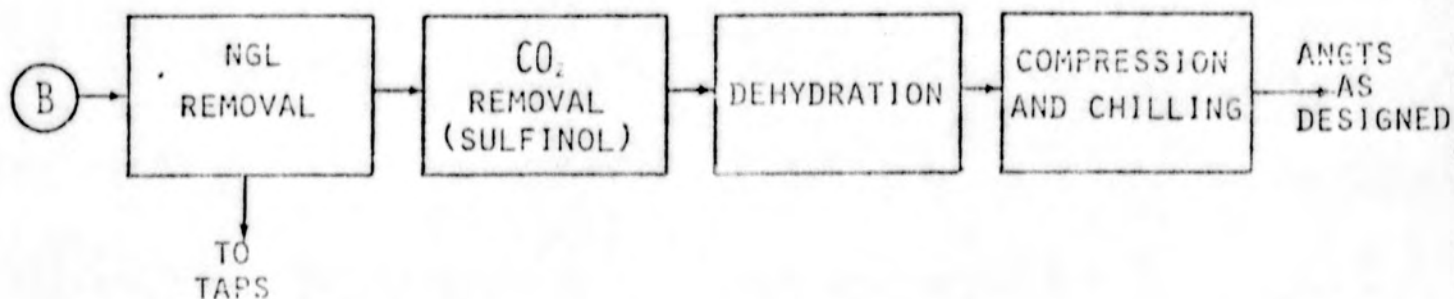
PRUDHOE BAY FACILITIES



PRUDHOE BAY - FAIRBANKS PIPELINE SEGMENT



INTERIOR ALASKA FACILITIES



DATE

DEC 22 1980

TABLE 1

Summary of Estimated Investment Costs and Fuel Consumption

	Cases				
	A	B	C	D	E
<u>Investment Costs, \$ Million (1980)</u>					
Prudhoe Bay Facilities	2300	1100	-	360	585
Pipeline Segment (455 miles)	5250	5317	11717	6214	5495
Interior Alaska Facilities	-	1740	3430	3025	2945
	-----	-----	-----	-----	-----
Subtotal Investments	7550	8167	15147	9599	9231
Risk Costs - Prudhoe Bay	230	110	-	36	59
Risk Costs - Interior	-	87	172	151	147
	-----	-----	-----	-----	-----
Subtotal Risk Costs	230	191	172	187	206
	-----	-----	-----	-----	-----
Grand Total Investment Costs	7780	8364	15319	9786	9437
<u>Fuel Consumed, Billion Btu/day</u>					
Prudhoe Bay Facilities	93	66	-	43	59
Pipeline Segment	15	19	18	19	12
Interior Alaska	-	55	102	68	66
	-----	-----	-----	-----	-----
Total	108	140	120	130	137
<u>Estimated Fuel Value, \$ Million (1980) Per Year¹</u>					
Total	74	97	83	90	94

¹ Based on current (July 1980) NGPA allowed field gas price for Alaska. Does not include costs of transportation to interior Alaska other than pipeline fuel, in Cases B, C, D, and E.

TABLE 2

Summary of Estimated Operating and Maintenance Costs and
Manpower Requirements for Alaska Gas Conditioning Facilities

	<u>Cases</u>				
	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>
<u>Operating Costs, \$ Million (1980) Per Year</u>					
Operations Labor ¹	19.0	18.3	14.9	18.6	17.4
Maintenance Labor ¹	31.6	29.3	23.4	28.4	28.3
Maintenance Materials	45.1	47.1	45.1	46.0	46.2
Chemicals and Supplies	1.9	2.0	1.9	1.9	2.0
Camps and Catering	8.9	5.4	-	2.7	2.7
Taxes and Insurance ²	46.0	55.0	69.0	68.0	71.0
Overhead Above Field Level	21.2	22.3	21.2	21.8	22.0
Total	173.7	179.4	175.5	187.4	189.6
<u>Total Field Personnel Employed</u>					
	438	434	362	440	422

¹ Prudhoe Bay costs based on 12-hour shifts working "seven and seven" schedule. Interior Alaska costs based on 8-hour shift without camp, catering, or travel expense.

² Based on 2 percent of total investment cost.

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

January 10, 1980

CONDITIONING PLANT
(GASLINE)

FOSTER REPORT NO. 1243 - p8

D.C. Circuit Dismisses Complaint by Earth Resources Co. and State of Alaska Against FERC Order Approving Design and System Capacity of Alaskan Segment of ANGTS

On 1/3/80 the U.S. Court of Appeals for the D.C. Circuit dismissed complaints filed on 10/5/79 by Earth Resources Co. and the State of Alaska et al. seeking reversal of the FERC's order of 8/6/79 granting application of Alaskan Northwest Natural Gas Transportation Co. (CP78-123 et al.) to approve the design specifications set forth in the President's Decision of September 1977 for the Alaskan segment of the Alaska Highway Pipeline Project. The Court concluded that it does not have jurisdiction to rule on these complaints because the Alaskan Natural Gas Transportation Act prevents review of the Commission's decision for reasonableness or substantial support on the record. Earth Resources Co. of Alaska v. FERC, No. 79-2191 and State of Alaska et al. v. FERC, No. 79-2193.

Specifications for Canadian portions of the ANGTS were adopted by the NEB in February 1978. Over objections of the U.S. Government which favored a 48-inch, 1680 psig system, the NEB prescribed a 48-inch, 1260 psig system from the Alaskan-Yukon border to Whitehorse (as proposed by the project sponsors) and selected a 56-inch, 1080 psig system for the segment from Whitehorse, Yukon to Caroline, Alberta to accommodate reserves from the Mackenzie Delta region (which may be attached to the ANGTS via construction of the so-called Dempster lateral).

In its request that the Commission approve the design specifications in the President's Decision, Alaskan Northwest said it had considered various alternatives and concluded that the system as originally proposed by Alcan Pipeline -- 48-inch with a pressure of 1260 psig -- is the best economic selection for delivery of volumes up to 3.4 Bcf/d. There has been no new evidence, Alaskan Northwest observed, showing that that level of expansibility above the expected 2.0 Bcf/d delivery rate from presently proven reserves is inadequate.

In its 8/6/79 order granting Alaskan Northwest's application, the Commission stated that the President had decided that the diameter of the pipeline will be 48 inches, and created "a predisposition" in favor of the 1260 psig system by his statement that the approved facilities were those included in the Alcan proposal -- which involved operations of a pipeline at a maximum pressure of 1260 psig. Furthermore, the Commission noted, the President also said that the capacity of the system should be adequate for an average daily throughput of up to 2.4 Bcf/d and up to 3.2 Bcf/d with increased compression. Such requirements, the Commission observed, would be satisfied by a combination 48-inch pipe and 1260 psig pressure.

The FERC emphasized the importance of the operating pressure because of its relationship to the ability of the gas stream to carry natural gas liquids. In this connection, the Commission noted concern by the State of Alaska and Earth Resources about the ability of the gas stream to carry gas liquids in view of the state's desire to preserve the option of developing a world-class petrochemical industry. Alaska emphasized that an operating pressure of 1260 psig -- in conjunction with other factors such as the standard for carbon dioxide content and the type of process used for its removal -- could preclude development of a petrochemical industry in Alaska. The state also questioned the location of a conditioning facility at Prudhoe Bay, contending that alternative sites should be given serious consideration.

The Commission, however, stated that it preferred to consider the complex liquids carrying issue in the context of deciding the carbon dioxide standard in the RM78-12 rulemaking proceeding (involving incentive rate of return for the project). Moreover, the Commission added, consideration of that issue in this proceeding

would result in delay of the project because it is an essential predicate to refining the design of the system which, in turn, has a direct bearing on the sponsors' ability to prepare detailed cost estimates and obtain financing. "Thus, a delay in determining the pressure could have serious and wide-ranging consequences in delaying the entire project." (See REPORT NOS. 1146, pp9-11; 1156, pp15-16; 1199, pp32-33; 1231, pp11-12; 1240, App. p39.)

In its decision, the D.C. Circuit asserted that this case "reflects exactly the sort of time-consuming challenge that Congress designed ANGTA to prevent during the approval and construction of the Alaska Natural Gas Pipeline. The order challenged here is nothing but a routine step in the process of issuing a certificate for construction of the pipeline. It is clearly within the Commission's statutory authority and offers no basis for a challenge on due process grounds. . . . In order to accept jurisdiction and step in to overturn this action of the Commission, we would have to ignore the ANGTA in precisely the type of situation where it most compellingly applied. This would produce exactly the result the Congress tried to prevent."

More specifically, the Court explained, the ANGTA prevents a review of agency decisions on the pipeline system for reasonableness or substantial support on the record. Instead, "the courts are strictly limited to reviewing claims of denial of constitutional rights, or action in excess of statutory jurisdiction, authority, or limitations, or action short of statutory right."

The Court rejected the complainants' claim that the FERC violated due process by deciding the pressure issue in isolation from related issues such as carbon dioxide content and conditioning plant design, thereby foreclosing options and rendering any future hearing on the related issues meaningless. In order to invoke the due process guarantee of a hearing, the Court said, "one must show that a government action infringes upon a liberty or property interest." And if the complaint concerns administrative action, due process hearing requirements apply only to adjudicatory proceedings which concern particular effects on an individual or a small group of persons. "Complaints have met neither prerequisite." First, the Court explained, they really do not assert any damage from the FERC action to the environment, to existing property interests or to any liberty interests. The most they can point to is a possible impairment of Alaskan development which they -- "but not necessarily everyone" -- favor. Moreover, the desire of Alaska to develop a petrochemical industry which is alleged to be frustrated by the Commission's order "is far removed from the sort of legitimate claim to entitlement necessary to demonstrate a liberty or property interest." To put the matter in broader perspective, the Court stressed, the Commission's decision on the pressure issue "is a prospective, legislative resolution of a general policy issue, by rulemaking, which in contrast to an adjudication does not give rise to the usual due process rights associated with a hearing. Therefore, complaints have not stated a valid due process objection to the Commission's actions." Instead, they actually attack the Commission's decision to proceed on an issue-by-issue basis which goes to the reasonableness of the Commission's exercise of its discretion. Hence, the Court has no jurisdiction under ANGTA to review.

Next, the D.C. Circuit answered the complainants' further argument that the Commission's order approving the design specifications was not issued within the normal framework of Section 7(c) certificate applications and it thereby exceeded statutory limitations. Northwest did not apply for a certificate, they argued, but only an order on particular issues and the Commission did not require the usual detailed supporting exhibits. These objections, the Court concluded, "fly in the face of the ANGTA," which authorized the Commission to issue a certificate

"forthwith." The Court reiterated that the procedures adopted to that end by the Commission were within its discretion and beyond jurisdiction to review. "Whether the FERC has fully considered factors and alternatives bearing on public necessity and convenience is an issue going to reasonableness and the substantiality of support for the order; this type of issue, ANGTA expressly forecloses for consideration." For the same reason, the Court added, it cannot review the claim that the Commission improperly accorded a presumption to the 1260 psig pressure level based on the President's Decision. The statutory preclusion of the Court's review of these issues "is crystal clear."

Finally, the D.C. Circuit rejected the contention that the FERC was required to prepare an environmental impact statement in accordance with the National Environmental Policy Act. First, the Court observed, Congress set forth in the ANGTA "specific and far-reaching restrictions on judicial review of the decisions related to the pipeline system." Specifically, the Act provided that Congressional ratification of the President's pipeline system decision will be conclusive as to the legal and factual sufficiency of the EIS submitted by the President with respect to the approved system. "This provision goes on to state that no court has jurisdiction to consider the sufficiency of such statements under NEPA. The effect of this section is place review in the Congress instead of the courts. By ratifying the President's 1977 decision, Congress has approved the EISs for the pipeline system."

The Court noted that in an attempt to avoid the force of the Act's preclusion of judicial review on NEPA questions, the complainants argued that if the Commission permitted another pressure for the pipeline, a different location for the conditioning plant would have been permitted as desired by Alaska. In effect, it was suggested that the FERC decided the issue of a conditioning plant location without preparing a final EIS; and since the conditioning plant is outside the scope of the pipeline system approved in the President's Decision, the Act's limited review provisions do not apply. The problem with this theory, the Court said, is that the issue of conditioning plant location was not a subject of the application and the order under review here, and the Commission did not take any major federal action on the conditioning plant. Instead, it took an entirely different action which happens to affect future consideration of the conditioning plant issue. The actual decision of the Commission that the complainants claim is a violation of NEPA is the pipeline pressure decision which is shielded from judicial review as regards the adequacy of the EIS.

Furthermore, the Court added, to require a separate EIS for the pipeline pressure issue would delay eventual construction by months and perhaps years. "The inter-relationship between issues, which is the foundation of the complainants' argument, could make the delay even longer. . . . Such concerns underly the Commission's decision to proceed with separate issues and Congress' decision to shield the decisionmaking process from judicial review when constitutionally permissible." Even with provisions of the ANGTA to expedite pipeline construction, the Court noted, it has already taken two years since the President's Decision for the Commission to approve a pressure level, and final certificates and commencement of construction are still further in the future. "In this light, if there is any shortcoming in the Commission proceedings, it is certainly not in a lack of deliberation or in denial of time and opportunity for interested parties to express their views."

The Court's decision was signed by Circuit Judge Wilkey for the panel completed by Circuit Judges Robb and Mikva.

FERC Orders Northern Border Pipeline to Refile Certification Cost Estimates for Pre-build ANGTS Facilities

On 1/4/80 the FERC granted a motion filed on 11/29/79 by the Staff for an order directing Northern Border Pipeline Co. to refile certification cost estimates for the prebuilding of the Eastern Leg of the Alaska Highway Pipeline Project. The Commission agreed with the Staff that more detail is required to conform Northern Border's cost estimate with the cost format criteria previously established by the Commission in a procedural order issued 9/6/79.

In September 1977 the President approved the Alcan-Foothills proposal to construct the ANGTS. The decision included a condition requiring the FERC to review certification cost estimates filed by the sponsors to determine whether they materially and unreasonably exceed the estimates filed with the Commission in March 1977. The Commission then established specific requirements for review of cost estimates as part of the final certification process for the ANGTS in Order No. 31 (RM78-12) issued 6/8/79. Also, the Commission fixed values for the Incentive Rate of Return mechanism to be applied to the Alaskan and Northern Border segments for the purpose of controlling construction cost overruns and decided most tariff issues for the same two segments. The Commission directed that certification cost and schedule estimates must be filed, according to cost estimate formats approved by the Commission, to determine if they materially and unreasonably exceed comparable capital cost estimates filed by Alcan. In its 9/6/79 order, the Commission set out procedures for the submission and examination of cost estimates by Northern Border (and Pacific Gas Transmission Co.). Specifically, the Commission adopted cost estimate formats recommended by the Alaskan Delegate and decided that its review thereof for the prebuild facilities would proceed concurrently with the ongoing adjudicatory proceeding (Northwest Alaskan Pipeline Co., CP78-123 et al.). The Commission observed that pursuant to Order No. 31, it must determine a Center Point for the IROR mechanism. Also Northern Border sponsors may request a change in the Center Point value and file necessary material and support thereof.

On 11/29/79 the FERC Staff filed a motion requesting, among other things, that the Commission reject Northern Border's certification cost estimates, and require refiling thereof in compliance with the 9/6/79 order or pursuant to an alternative format suggested by Staff.

In support, the Staff argued that Northern Border's filing should be rejected because it does not permit a comparison of the March 1977 estimate as required by the President's Decision nor highlight reasons for changes which were to be solicited by the Alaskan Delegate's formats. Contrary to the express purpose of these formats, the Staff said, it is not possible to determine from Northern Border's filing the reasons for, among other things, changes in design and revised estimates of labor productivity. This is so, Staff explained, because Northern Border did not recast the March 1977 estimate into the formats of the certification cost estimate but instead started with the certification cost estimate and recast it into a two-year construction program instead of a one-year construction program. "Thus, rather than showing any increases in the quantities of resources required or any changes that are due to design modifications or changes in expected productivity rates, the proffered filing merely reflects the difference in cost that is due to Northern Border's decision to follow an accelerated construction schedule."

The Staff also suggested an alternative format whereby Northern would apply inflation indices to "bottom line" 1975 total dollar costs to produce a 1979 dollar figure for that estimate.

Finally, Staff objected to Northern Border's suggestion that it will use a formula specified in Order No. 31 for its Center Point determination and not seek a change thereof assuming the Commission does not make any changes to its entire cost estimate filing. Any election regarding a change in Center Point, Staff said, must be made when the certification cost estimate is filed. Hence, if the FERC directs refiling, Northern Border should also be ordered to make its election at that time. In a subsequent response in opposition to Staff's motion, Northern Border emphasized that the description "March 1977 estimate" is a misnomer as applied to it since Northern Border itself did not prepare or file any cost estimate at that time. What was filed in March 1977, Northern Border said, was an Alcan estimate. At that time, Northern Border explained, it was an integral part of the Arctic Gas Project and was in an adversary competitive position with Alcan. In March 1977, Alcan "adopted" Northern Border and made it an integral part of its proposal as the Lower 48 Eastern Leg. Cost estimates then presented by Alcan included an estimate for Northern Border which was not new at that time but had been the same cost estimate filed in May 1976 in the El Paso Alaska case and was based on 7/1/75 dollars.

As to Staff's contention that certain of its exhibits lack sufficient detail, Northern Border argued that Staff previously agreed at a conference on 9/21/79 that the exhibits were acceptable. However, Northern Border stated that workpapers to support these exhibits are available.

In its order, the Commission agreed with the Staff that Northern Border's filings did not provide sufficient documentation for analysis. The Commission noted that its cost criteria require that all cost estimates be explained in full detail. Specifically, the March 1977 cost estimates must be presented in such a manner as to show derivation of the original estimates by labor and material categories, and also 1975 costs are to be shown. Then the 1977 estimate must be recast into a Work Breakdown Structure format of the certification cost estimate and, in as many exhibits as needed, information for each WBS element is to be provided down to the lowest level. As to the certification cost estimate, the Commission continued, its criteria require (also in as many exhibits as are needed) details for each estimate at the lowest level of WBS as appropriate for a "thorough understanding of the composition and derivation of the estimate." The comparison of the two estimates should contain an explanation of all variances.

The FERC recognized that a March 1977 cost estimate for Northern Border's prebuild portion of the ANGTS does not exist per se and that analytical techniques must be used to derive such a value. However, the Commission emphasized that the derived estimate must correspond as nearly as possible to one which would have been made in 1977 if the Northern Border prebuild portion had been considered then. The Commission noted Staff's objections to the fact that Northern Border did not recast the March 1977 estimate into the formats of the certification cost estimate but instead started with the construction cost estimate and recast it into a two-year construction program instead of a one-year construction program. The Commission concluded that a one-year construction schedule should be assumed in the preparation of the 1977 estimate and that for purposes of preparing the studies, the two estimates should reflect a consistent set of assumptions as to the design of facilities. For example, the same size compressor stations and measurement stations should be assumed for both estimates. Design changes for pipe type and the number of communication system sites are to be considered as design changes.

The Commission directed Northern Border to prepare a new March 1977 estimate using assumptions of the 1979 certification estimate to derive the estimate where no known design changes are involved.

In response to Staff's request for clarification of Order Nos. 31 and 31-B to require Northern Border to make any election to change its Center Point at the time of filing its certification cost estimate, the Commission noted that it gave the project sponsors two choices as to how the Center Point would be determined. The first was to use a formula based on a comparison of the certification cost estimate and the estimates in the President's Decision. Under the second, the sponsors could request a Center Point without reference to the formula if a major change occurred in the project resulting in a total estimated cost which would exceed the estimates in the Decision. This request was to be included in the certification cost estimate submission.

Accordingly, the Commission said, if Northern Border does not choose to use the Center Point formula it has approved, it may elect to assess the likelihood of abnormal events that could increase costs and determine the impact thereof on costs. And this information should be submitted as part of Northern Border's certification cost estimate. Accordingly, if Northern Border desires to request a change in its Center Point, it should make this selection at the time of filing the required revisions to its March 1977 estimate herein.

The Commission directed the Law Judge to establish a schedule for filing answering and rebuttal testimony and a date for hearing on Northern Border's revised filings and methodology. 1/

Distributors and Pipelines Differ on Proposed Policy Regarding Distributor Access to OCS Gas

On 1/7/80 a public hearing was held on a proposed FERC rulemaking (RM80-11) to adopt a statement of policy with respect to distributor access to Outer Continental Shelf gas. Pipeline and distributor spokesmen differed on various aspects of the proposed rulemaking, particularly as to whether the Commission has the authority to direct unwilling interstate pipelines to transport distributor OCS gas.

This rulemaking was initiated pursuant to Section 603 of the Outer Continental Shelf Lands Act Amendments of 1978 which directed the FERC to publish a statement of policy -- within one year from enactment if possible -- to encourage expanded participation by local distribution companies in OCS lease acquisition and natural gas development through facilitating transportation of distributor-owned gas from OCS leases to distributor service areas. Section 603 also directed that the statement of policy set forth standards to be applied in considering certificate applications for such transportation, identify conditions which may be attached to such certificates, and specify criteria or requirements for determining whether an application of a local distribution company qualifies under the statement of policy.

The proposed rulemaking sets out procedures and standards to govern interstate pipeline transportation of "eligible OCS natural gas" (produced either from a lease entered into after 4/20/77 or from an interest acquired prior to the date of the final rule in a pre-4/20/77 lease) to an "eligible recipient" (a regulated distributor) from an "eligible OCS producer" (a regulated distributor, a producing affiliate of such distributor, or a joint venture in which either participates).

1/ On 1/10/80 Law Judge Lotis directed that direct, answering and rebuttal evidence be submitted on 1/15, 2/1 and 2/13/80, respectively, and that the hearing commence on 2/25/80.

CONDITIONING PLANT
(GAS/LUE)

EXXON COMPANY, U.S.A.

1800 AVENUE OF THE STARS • LOS ANGELES, CALIFORNIA 90067 (213) 552-5400

PRODUCTION DEPARTMENT
WESTERN DIVISION

January 21, 1980

Heating Values Used in
Parsons Study Report

Ms. Connie Barlow
811 Basin
Juneau, Alaska 99801

As you requested in the meeting in Houston on January 14, attached are the heating values used in the September, 1978 Parsons Study Report. As the footnote on the attached table indicates, these heating values are from the 1972 edition of the Gas Processors Suppliers Association Engineering Data Book.

If you have any questions, or we can be of additional assistance, please call.

Very truly yours,



James L. Shanks, Jr.
Division Gas Engineer

GJM:ae
Attachment

HEATING VALUES₁ USED IN PARSONS STUDY REPORT
(Btu/SCF)

	<u>LHV</u>	<u>HHV</u>
C ₁	909.1	1009.7
C ₂	1617.8	1768.8
C ₃	2316.1	2517.4
iC ₄	3001.1	3252.7
nC ₄	3010.4	3262.1
iC ₅	3698.3	4000.3
nC ₅	3707.5	4009.5
C ₆	4403.7	4756.1
C ₇	5100.2	5502.9
C ₈	5796.7	6249.7
C ₉ +	6493.3	6996.6
H ₂ S	588.0	637.0

1. Heating values are from the Engineering Data Book of the Gas Processors Suppliers Association (1972).

GJM:ae
1-16-80
nv

4-4

GAS PLANT LIQUIDS
POTENTIAL, RECOVERED, AND DISPOSITION
PRUDHOE BAY GAS CONDITIONING PLANT

File 163
Liquids
OR GAS
CONDITIONING PLANT

Product	Potential In Inlet Gas MB/D	Components Recovered as Liquid Feed in the Conditioning Plant(1)		Commercial Liquid Products from Fractionator Train					Components in Sales Gas	
		% of Inlet	MB/D	Total(2) MB/D	Disposition				Residue Gas MB/D	Total MB/D
					Cond. Plt. Fuel MB/D	Field Fuel MB/D	Crude Oil MB/D	Sales Gas MB/D		
Ethane	111.4	20	22.8	-	-	-	-	-	56.5	58.1 <i>✓ 75% = 43</i>
Propane	61.8	77	47.5	52.4 (16)	14.0 (21)	14.1 (82)	0	24.3 (23)	1.1	23.3 <i>✓</i>
I-Butane	10.3	93	9.6	} 31.2 (12)	} 0	} 0	} 0	} 31.2	0.2	9.4
N-Butane	23.7	95	22.5						0.3	21.9
Pentane plus	27.3	99	26.9	28.6 (10)	0	0	28.6	0	0.2	1.0
TOTAL	234.5		129.3	112.2	14.0	14.1	28.6	55.5	58.3 (2)	113.7 (29)

- (1) Feed to fractionator train: Liquid from low temperature separator plus liquid from local fuel fractionator. Not a commercial product - contains about 13% methane which is not included in these volumes.
- (2) There are three commercial products produced: Propane, mixed-butaness, and pentane-plus (natural gasoline). These commercial products are not pure components; for example, the propane product contains some ethane which accounts for more ethane in the total sales gas than is indicated by adding the numbers shown on this table.

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

(1)

	(1) INLET GAS		(2) LTS FEED (INLET GAS & SELEXOL REGENERATOR OVHD)		(3) LTS VAPOR		(4) LTS LIQS (DeC ₂ FEED)	
	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>
C1	74.00	-	72.20	-	76.88	-	19.90	-
C2	6.53	111.4	6.35	114.3	5.59	91.5	14.80	21.9
C3	3.52	61.8	3.66	67.9	1.95	32.8	22.87	34.9
iC4	0.50	10.3	0.50	11.0	0.14	2.8	4.53	8.2
nC4	1.18	23.7	1.18	25.0	0.24	4.6	11.64	20.3
iC5	0.27	6.2	0.26	6.3	0.02	0.5	2.88	5.8
nC5	0.49	11.4	0.48	11.6	0.03	0.6	5.46	11.0
C6	0.19	5.1	0.18	5.1	-	0.1	2.21	5.0
C7	0.12	3.2	0.11	3.3	-	-	1.38	3.2
C8	0.04	1.2	0.04	1.2	-	-	0.50	1.2
C9	0.01	0.2	0.01	0.2	-	-	0.07	0.2
H ₂ S	0.00	-	0.00	-	-	-	-	-
CO ₂	12.68	-	14.57	-	14.65	-	13.72	-
N ₂	0.47	-	0.46	-	.50	-	0.02	-
TOTAL	<u>100.0</u>	<u>234.5</u>	<u>100.00</u>	<u>245.9</u>	<u>100.00</u>	<u>132.9</u>	<u>100.00</u>	<u>111.7</u>
MMSCFD	2686		2836		2578		233	
BTU/CF	1055		1036		939		2117	
PSIA	576		565		540		495	
°F	98		96		18		86	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

	(5) DeC ₂ OVHD TO FIELD LEVEL		(6) DeC ₂ BTMS		(7) SELEXOL ABSORBER FEED		(8) SELEXOL ABSORBER OVMD	
	%	MB/D	%	MB/D	%	MB/D	%	MB/D
C ₁	42.33	-	0.00	-	76.88	-	94.28	-
C ₂	28.13	20.0	2.98	2.4	5.59	91.5	4.47	56.5
C ₃	0.41	0.3	42.57	35.3	1.95	32.8	0.08	1.1
iC ₄	-	-	8.55	8.4	0.14	2.8	0.01	0.2
nC ₄	-	-	22.02	20.9	0.24	4.6	0.02	0.3
iC ₅	-	-	5.48	6.0	0.02	0.5	-	0.1
nC ₅	-	-	10.42	11.4	0.03	0.6	0.01	0.1
C ₆	-	-	4.23	5.2	-	0.1	-	-
C ₇	-	-	2.65	3.4	-	-	-	-
C ₈	-	-	0.96	1.3	-	-	-	-
C ₉	-	-	0.13	.2	-	-	-	-
H ₂ S	.01	-	-	-	-	-	-	-
CO ₂	29.08	-	-	-	14.65	-	0.50	-
N ₂	.04	-	-	-	0.50	-	0.62	-
TOTAL	100.00	20.3	100.00	94.6	100.00	132.9	100.00	58.3
MMSCFD	112		127		2578		1994	
BTU/CF	935		3174		939		1035	
PSIA	545		480		540		530	
°F	2		249		18		86	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

	(9) SELEXOL ABSORBER BTMS		(10) SELEXOL REGENERATOR OVHD		(11) SELEXOL FLASH VAPOR		(12) LFF FEED	
	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>
C ₁	15.53	-	39.99	-	19.66	-	1.30	-
C ₂	9.85	39.3	3.07	2.9	15.32	19.0	8.61	13.0
C ₃	8.40	34.5	6.32	6.2	7.58	9.7	10.18	15.8
iC ₄	0.67	3.3	0.60	0.7	0.38	0.6	0.74	1.4
nC ₄	1.22	5.7	1.04	1.2	0.57	0.8	1.26	2.2
iC ₅	0.25	1.4	0.10	0.1	0.03	0.1	0.11	0.2
nC ₅	0.42	2.3	0.13	0.2	0.04	0.1	0.14	0.3
C ₆	0.11	0.7	0.01	-	-	-	0.02	-
C ₇	0.07	0.4	0.01	-	-	-	-	-
C ₈	0.02	0.1	-	-	-	-	-	-
C ₉	-	-	-	-	-	-	-	-
H ₂ S	0.01	-	0.01	-	-	-	-	-
CO ₂	63.42	-	48.44	-	56.41	-	77.65	-
N ₂	0.02	-	0.27	-	0.01	-	-	-
TOTAL	<u>100.00</u>	<u>87.7</u>	<u>100.00</u>	<u>11.3</u>	<u>100.00</u>	<u>30.3</u>	<u>100.00</u>	<u>33.0</u>
MMSCFD	628		150		196		238	
BTU/CF	642		681		694		498	
PSIA	540		565		75		350	
°F	19		79		13		131	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

	(13) LFF OVHD		(14) LFF BTMS		(15) DeC ₃ FEED (DeC ₂ , BTMS & LFF BTMS)		(16) DeC ₃ OVHD (PROPANE)	
	%	MB/D	%	MB/D	%	MB/D	%	MB/D
C ₁	1.46	-	-	-	-	-	-	-
C ₂	9.04	12.1	5.17	0.9	3.35	3.3	6.41	3.3
C ₃	2.29	3.2	74.16	12.6	47.96	48.0	91.58	47.9
iC ₄	-	-	6.74	1.4	8.24	9.8	1.44	0.9
nC ₄	-	-	11.45	2.2	20.21	23.2	0.56	0.3
iC ₅	-	-	0.98	0.2	4.71	6.3	-	-
nC ₅	-	-	1.29	0.3	8.86	11.7	-	-
C ₆	-	-	0.14	-	3.54	5.3	-	-
C ₇	-	-	0.03	-	2.21	3.4	-	-
C ₈	-	-	-	-	0.80	1.3	-	-
C ₉	-	-	-	-	0.11	0.2	-	-
H ₂ S	-	-	-	-	-	-	-	-
CO ₂	87.21	-	0.03	-	0.01	-	0.01	-
N ₂	-	-	-	-	-	-	-	-
TOTAL	100.00	15.3	100.00	17.7	100.00	112.2	100.00	52.4
MMSCFD	212		26		153		80	
BTU/CF	232		2651		3085		2484	
PSIA	325		340		220		200	
°F	-4		156		175		90	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

	(17) DeC ₃ BTMS (DeC ₄ FEED)		(18) DeC ₄ OVHD (Butanes)		(19) DeC ₄ BTM (Pentanes - Plus)		(21) PROPANE TO LOCAL FUEL	
	%	MB/D	%	MB/D	%	MB/D	%	MB/D
C ₁	-	-	-	-	-	-	-	-
C ₂	-	-	-	-	-	-	6.41	0.9
C ₃	0.10	-	0.18	-	-	-	91.58	12.8
iC ₄	15.70	8.9	27.72	8.9	0.17	-	1.44	0.2
nC ₄	41.78	22.8	69.58	21.4	5.84	1.4	0.56	0.1
iC ₅	9.89	6.3	2.15	0.8	19.89	5.5	-	-
nC ₅	18.59	11.7	.38	0.1	42.13	11.5	-	-
C ₆	7.41	5.3	-	-	17.00	5.3	-	-
C ₇	4.63	3.4	-	-	10.62	3.4	-	-
C ₈	1.67	1.3	-	-	3.84	1.3	-	-
C ₉	0.22	0.2	-	-	0.52	0.2	-	-
H ₂ S	-	-	-	-	-	-	-	-
CO ₂	-	-	-	-	-	-	-	-
N ₂	-	-	-	-	-	-	-	-
TOTAL	100.00	59.8	100.00	31.2	100.00	28.6	100.00	14.0
MMSCFD	73		41		32		21	
BTU/CF	3745		3277		4350		2484	
PSIA	75		60		70		640	
°F	161		90		90		90	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

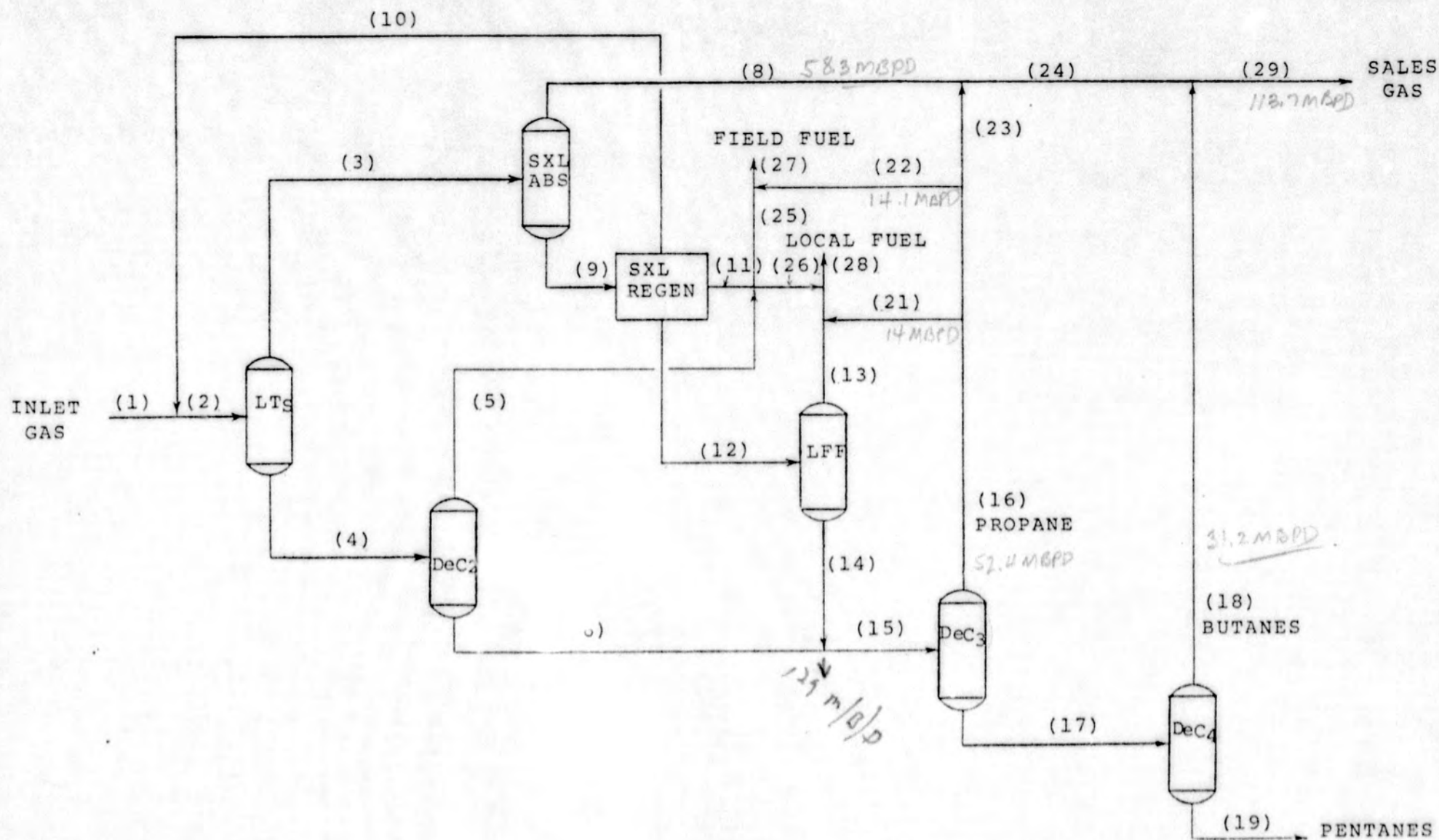
	(22) PROPANE TO FIELD FUEL		(23) PROPANE TO SALES GAS		(24) SALES GAS WITH PROPANE		(25) SELEXOL FLASH VAPOR TO FIELD FUEL	
	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>	<u>%</u>	<u>MB/D</u>
C 1	-	-	-	-	92.56	-	19.66	-
C 2	6.41	0.9	6.41	1.5	4.50	58.1	15.32	17.6
C 3	91.58	12.9	91.58	22.2	1.75	23.3	7.58	9.0
iC 4	1.44	0.2	1.44	0.4	0.04	0.6	0.37	0.5
nC 4	0.56	0.1	0.56	0.2	0.03	0.5	0.56	0.8
iC 5	-	-	-	-	0.01	0.1	0.04	0.1
nC 5	-	-	-	-	0.01	0.1	0.05	0.1
C 6	-	-	-	-	-	-	-	-
C 7	-	-	-	-	-	-	-	-
C 8	-	-	-	-	-	-	-	-
C 9	-	-	-	-	-	-	-	-
H ₂ S	-	-	-	-	-	-	-	-
CO ₂	-	-	-	-	0.49	-	56.41	-
N ₂	-	-	-	-	0.61	-	0.01	-
TOTAL	<u>100.0</u>	<u>14.1</u>	<u>100.00</u>	<u>24.3</u>	<u>100.00</u>	<u>82.6</u>	<u>100.00</u>	<u>28.0</u>
MMSCFD	22		37		2032		181	
BTU/CF	2484		2484		1061		694	
PSIA	640		640		525		520	
°F	90		90		75		208	

PRUDHOE BAY CONDITIONING PLANT
MAXIMUM FUEL CASE STREAM COMPOSITIONS

(7)

	(26) SELEXOL FLASH VAPOR TO LOCAL FUEL		(27) FIELD FUEL		(28) LOCAL FUEL		(29) SALES GAS W/ PROPANE & BUTANES	
	%	MB/D	%	MB/D	%	MB/D	%	MB/D
C ₁	19.65	-	37.74	-	2.42	-	90.72	-
C ₂	15.30	1.4	16.24	41.1	9.18	14.5	4.41	58.1
C ₃	7.59	0.7	8.84	23.0	10.31	16.7	1.72	23.3
iC ₄	0.37	-	0.27	0.8	0.51	0.3	0.59	9.4
nC ₄	0.55	0.1	0.33	1.0	0.08	0.1	1.41	21.9
iC ₅	0.06	-	0.02	0.1	-	-	0.05	0.8
nC ₅	0.06	-	0.03	0.1	-	-	0.01	0.2
C ₆	-	-	-	-	-	-	-	-
C ₇	-	-	-	-	-	-	-	-
C ₈	-	-	-	-	-	-	-	-
C ₉	-	-	-	-	-	-	-	-
H ₂ S	-	-	-	-	-	-	-	-
CO ₂	56.43	-	36.40	-	77.85	-	0.49	-
N ₂	-	-	0.13	-	-	-	0.60	-
TOTAL	100.00	2.3	100.00	66.1	100.00	31.6	100.00	113.8
MMSCFD	15		398		248		2071	
BTU-CF	695		912		454		1106	
PSIA	515		520					
°F	90		81					

PRUDHOE BAY SALES GAS CONDITIONING PLANT
MAXIMUM FUEL CASE (DeC₂ OVHD TO FIELD FUEL)



VARIOUS PRUDHOE BAY CONDITIONED GAS COMPOSITIONS
(Mole Percent)

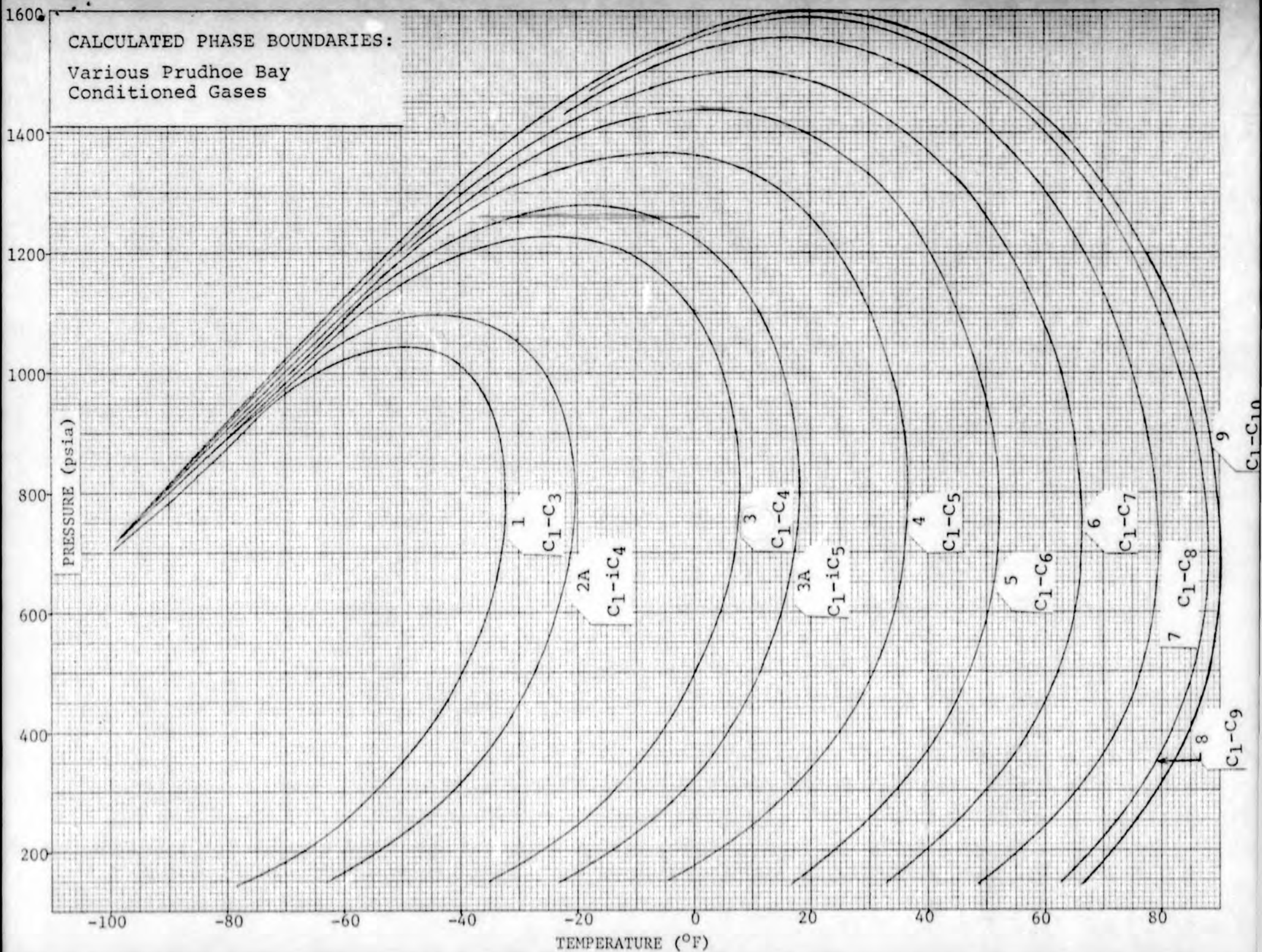
Component	Unconditioned Separator Off-Gas	1 C ₁ -C ₃	2A C ₁ -iC ₄	3 C ₁ -C ₄	3A C ₁ -iC ₅	4 C ₁ -C ₅	5 C ₁ -C ₆	6 C ₁ -C ₇	7 C ₁ -C ₈	8 C ₁ -C ₉	9 C ₁ -C ₁₀
N ₂	0.484	0.564	0.561	0.554	0.553	0.551	0.550	0.549	0.549	0.549	0.549
CO ₂	12.659	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
C ₁	74.706	87.053	86.594	85.554	85.341	84.964	84.818	84.742	84.695	84.679	84.676
C ₂	6.428	7.491	7.451	7.362	7.343	7.311	7.299	7.292	7.288	7.287	7.287
C ₃	3.340	3.892	3.872	3.826	3.815	3.799	3.793	3.789	3.787	3.786	3.786
i-C ₄	0.450	---	0.522	0.515	0.514	0.512	0.511	0.511	0.510	0.510	0.510
n-C ₄	1.038	---	---	1.189	1.186	1.181	1.179	1.178	1.177	1.177	1.177
i-C ₅	0.217	---	---	---	0.248	0.247	0.247	0.246	0.246	0.246	0.246
n-C ₅	0.383	---	---	---	---	0.435	0.435	0.434	0.434	0.434	0.434
C ₆	0.148	---	---	---	---	---	0.168	0.168	0.168	0.168	0.168
C ₇	0.081	---	---	---	---	---	---	0.091	0.092	0.092	0.092
C ₈	0.047	---	---	---	---	---	---	---	0.054	0.054	0.054
C ₉	0.016	---	---	---	---	---	---	---	---	0.018	0.018
C ₁₀	0.003	---	---	---	---	---	---	---	---	---	0.003
Mol. Wt.	22.7	18.5	18.7	19.2	19.3	19.5	19.7	19.8	19.8	19.8	19.9
Heating Value* (Btu/cf)	1027	1095	1106	1131	1138	1150	1156	1160	1163	1164	1164

*Gross, Wet, Actual @ 60°F., 14.73 psia

5/5/78

CALCULATED PHASE BOUNDARIES:

Various Prudhoe Bay
Conditioned Gases



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

ARLON R. TUSSING & ASSOCIATES, INC. / 2720 Rainier Bank Tower / Seattle, Washington 98101 / (206) 447-0321

December 3, 1979

Mr. Ray Booth
Assistant Manager
Natural Gas Department
Exxon Company USA
800 Bell Street
Houston, Texas 77001

Dear Mr. Booth:

You are undoubtedly aware of the recent preoccupation of the public and of state officials in Alaska with the availability of natural gas liquids from Prudhoe Bay for industrial use within the state. Unfortunately, most of the current deliberation and debate on this question is taking place without a real understanding of the technical and economic tradeoffs.

The Alaska Department of Natural Resources has engaged Arlon R. Tussing and Associates, Inc. to write a report explaining to state officials, legislators, and the public what the technical and economic relationships are among the choice of gas pipeline pressure, location and technology of the gas conditioning plant, choice of field and pipeline fuel, and the availability and cost of natural gas liquids for use at different locations in Alaska. Our challenge is to reduce a number of extremely complex economic and engineering issues to a form in which non-specialists can deal with them intelligently.

Our investigation has now proceeded about as far as it can on the basis of published materials, because many of the available documents fail to set out clearly the assumptions upon which their scientific and engineering judgments are made. The following is a list of the questions we have so far been unable to resolve. Our biggest need from you with respect to these questions is to know what assumptions underlie your company's judgment (and that of the others) about the ability of pipeline systems of various pressures to transport different hydrocarbon mixtures.

Mr. Ray Booth
Exxon Company, USA
December 3, 1979

Page Two

We do not know how well these issues can be resolved by correspondence or by telephone, but Connie C. Barlow (who has principal responsibility for this project) and/or I would be willing to travel to a place and at a time of your convenience, in order to discuss them in depth. Ms. Barlow will be calling you toward the end of this week to explore how we ought to proceed.

Your help will be greatly appreciated.

Sincerely,

Arlon R. Tussing

ART/bas

Enclosure

cc Connie Barlow
Robert Maynard
Mary Halloran

QUESTIONS FOR THE PRODUCERS

Question #1:

With respect to determining the actual volumes of methane and gas liquids that will become available for shipment ...

(a) What is the expected composition and daily production rate of total raw gas (less whatever is reinjected to maintain reservoir pressures)? How much uncertainty accompanies anybody's best guesses about this matter?

(b) How is the daily production rate and composition expected to change through time, particularly when oil production begins to drop off? (Specifically, is there a significant difference in composition of solution gas versus gas cap gas, and is the ratio of produced volumes of solution and gas cap gas affected by time?)

(c) Of these produced hydrocarbons how much of each will be consumed to meet North Slope total fuel requirements? How will field fuel requirements change through time as oil production and transportation drop?

(d) Hence, what volumes of methane, ethane, propane, butane, and pentanes+ will actually be available through time for delivery to some transportation system?

Question #2:

Concerning upset conditions in the gasline ...

(a) For each pipeline pressure specification under consideration (1080 psig in Canada and 1260, 1440, and 1680 psig in Alaska), what temperature and pressure

combinations constitute "upset" conditions, "normal minimum operating" conditions, or whatever terminology you use to signify the most troubling conditions (from the standpoint of condensation) that gas may encounter during the journey south?

(b) Are the phase characteristics of probable gas mixtures such that the temperature and pressure combinations of most concern represent the lowest temperature and the lowest pressure likely to be encountered?

(c) At least in the documents we have seen, there appears to be some difference of opinion on the answer to the above questions. For example, I believe Exxon has indicated that a 0 degree F upset temperature is appropriate in Alaska, and 30 degree F for the sections south of Whitehorse, while Sohio lists -10 degrees and +42 degrees respectively. With regard to pressure, Sohio appears to assume that a 1680 psig line will have a 1300 psia upset while Arco assumes a 1200 psia upset. What might be the reasons behind these differences of opinion (e.g. compressor spacing, which compressor station is assumed out, duration of outage, immediacy of response in reducing throughput, normal station outlet temperature of the gas, ambient air or ground temperature, etc.)?

Question #3:

With respect to the ability of IAPS to carry gas liquids ...

(a) What is the lowest IAPS inlet temperature that might safely be considered? What are the physical considerations that determine this (i.e. what worst case assumptions about ambient air temperature and

duration do you make with regard to TAPS shutdown or pump station outage?) Are there absolute physical limitations on the minimum inlet temperature, or is it primarily an economic matter of the costs and aggravation of frequent pigging?

(b) Approximately how much would it cost to add chilling facilities to bring the inlet temperature down to the level indicated above?

(c) Are light hydrocarbons such as butane and pentane useful in reducing oil pipeline viscosity and friction, thereby increasing throughput capabilities with existing equipment? Would one part of additional butane, therefore, require leaving behind maybe less than one part of heavier hydrocarbons if the line were already functioning at capacity? Given the likely timing of gas production for sale, and given the likely oil production scenario, is it a realistic prospect that throughput limitations of the line and pump stations might make it impossible to ship butanes and pentanes separate from the raw gas unless oil shipments are cut back?

(d) What volumes of oil production for each year of field operation should one assume when trying to ascertain TAPS throughput capabilities? To your knowledge, did the other parties commenting on the ability of TAPS to carry light hydrocarbons assume similar production schedules?

(e) Given the oil production scenario noted above and the volume of butanes and pentanes implied in your answer to question 1(c), how much butane and pentane could be transported through TAPS, (noting time as a

variable) at the minimum inlet temperature you have specified in your answer to question 3(a) at the existing TAPS inlet temperature?

(f) Currently, what (if anything) is being done at Valdez to ensure that oil shipped through TAPS (at 140 degrees F and 14.7 psia) meets tanker and lower 48 storage specifications for vapor pressure? How would those activities change if the TAPS inlet temperature were lowered to the point mentioned in your answer to question 3(a)?

Questions #4:

Concerning North Slope Field Fuel requirements ...

(a) Given the likely oil and gas production schedules you have indicated previously, how will the required amounts of field fuel change through time?

(b) What are the physical and economic principles that limit flexibility in choosing the BTU content, dew-point, and overall composition of field fuel? (e.g., the need to ensure a certain level of precision in combustion characteristics, dewpoint limitations imposed by exposure to ambient air temperatures en route, BTU specifications of existing equipment and the cost of changing or expanding that range.)

Miscellaneous questions ...

- When you speak of BTU's do you mean gross or net BTU's? When calculating the BTU values of various compositions of gases, what assumptions do you use with respect to the BTU content per mcf and per

barrel for each hydrocarbon type (C_1 through C_5)
What phase diagrams to you use for the following
pure substances: C_1 , C_2 , C_3 , C_4 , C_5 , CO_2 , H_2O ?

- How does the addition of CO_2 affect the dewpoint characteristics of any particular gas composition, assuming that the composition of the hydrocarbon portion of the mixture remains unchanged?
- On a very approximate basis, how much more money would it cost to isolate most of the produced ethane from the CO_2 rich stream during the conditioning process? Does this represent, say, the added cost of using a Sulfinol or similar process with required dehydration facilities? What other options are available?
- Has anybody done any work yet on the added cost of transporting a gas of 13% CO_2 compared to the cost of transporting a 1% or 3% mixture, holding the pipeline operating pressure constant?
- General questions on the effect of CO_2 content on the hazards of carbonic acid and hydrate corrosion and erosion at the pipeline operating pressures and temperatures under consideration.

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

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



THE STANDARD OIL COMPANY

MIDLAND BUILDING, CLEVELAND, OHIO, 44115

January 23, 1980

Ms. Connie C. Barlow
Arlon R. Tussing & Associates, Inc.
811 Basin
Juneau, Alaska 99801.

Prudhoe Bay Gas Sales

Dear Ms. Barlow:

In reply to the questionnaire attached to Arlon Tussing's letter of December 3, 1979 to Mr. Paul Phillips, attached is Sohio's response.

Many of the answers, particularly those to question #1, draw on data derived from the Parsons Study of September, 1978. While this is the best data we have, we would emphatically point out that the Parsons design is by no means definitive. The main objectives of the Parsons study were to get some idea of the cost and lead time of constructing a gas conditioning plant that would enable an assumed set of pipeline specifications to be met. Time did not permit adequate optimization of the plant design, and perhaps more important, overall optimization of the conditioning plant/pipeline system was not considered. The validity of Parsons' results should be viewed in this context.

We hope the attached answers are helpful to your effort, and will be happy to try to answer any queries you may have.

Very truly yours,

A handwritten signature in cursive script, appearing to read "D. J. Pritchard".

D. J. Pritchard

DJP:ejh

Question #1:

With respect to determining the actual volumes of methane and gas liquids that will become available for shipment ...

(a) What is the expected composition and daily production rate of total raw gas (less whatever is reinjected to maintain reservoir pressures)? How much uncertainty accompanies anybody's best guesses about this matter?

(b) How is the daily production rate and composition expected to change through time, particularly when oil production begins to drop off? (Specifically, is there a significant difference in composition of solution gas versus gas cap gas, and is the ratio of produced volumes of solution and gas cap gas affected by time?)

(c) Of these produced hydrocarbons how much of each will be consumed to meet North Slope total fuel requirements? How will field fuel requirements change through time as oil production and transportation drop?

(d) Hence, what volumes of methane, ethane, propane, butane, and pentanes+ will actually be available through time for delivery to some transportation system?

RESPONSE #1

(a) An expected composition of produced gas in the early years of gas sales (taken from the Parsons Report) is given on table 1. The raw gas production rate used in the Parsons Report is 2.8 BCFD, although the current conservation order limits this production rate to 2.7 BCFD.

(b) It is expected that the initial gas production rate can be maintained for about 25 years. Gas composition will initially get leaner with time. At lower reservoir pressures in the latter stages of depletion this process can reverse itself, and the gas will tend to become richer and approach its initial composition. It is impossible to predict produced gas compositions at different times with any certainty.

Nevertheless, to give a feel for the gas compositions expected later in the field life, it is estimated that the ethane and propane contents will drop to minima of about 5.5% and 2.5% respectively.

- (c) The Parsons Report analyses a maximum and a minimum fuel requirements case, and addresses the requirements for various components to meet these fuel demands under the Parsons design and the assumed raw gas composition. Field fuel estimates are further discussed in the response to question 4.
- (d) This question has not been addressed except under the maximum and minimum fuel cases in the Parsons Report. The availability of sales volumes of various components in these two cases is given in table 2.

Question #2:

Concerning upset conditions in the gasline ...

(a) For each pipeline pressure specification under consideration (1080 psig in Canada and 1260, 1440, and 1680 psig in Alaska), what temperature and pressure combinations constitute "upset" conditions, "normal minimum operating" conditions, or whatever terminology you use to signify the most troubling conditions (from the standpoint of condensation) that gas may encounter during the journey south?

(b) Are the phase characteristics of probable gas mixtures such that the temperature and pressure combinations of most concern represent the lowest temperature and the lowest pressure likely to be encountered?

(c) At least in the documents we have seen, there appears to be some difference of opinion on the answer to the above questions. For example, I believe Exxon has indicated that a 0 degree F upset temperature is appropriate in Alaska, and 30 degree F for the sections south of Whitehorse, while Sohio lists -10 degrees and +42 degrees respectively. With regard to pressure, Sohio appears to assume that a 1680 psig line will have a 1300 psia upset while Arco assumes a 1200 psia upset. What might be the reasons behind these differences of opinion (e.g. compressor spacing, which compressor station is assumed out, duration of outage, immediacy of response in reducing throughput, normal station outlet temperature of the gas, ambient air or ground temperature, etc.)?

RESPONSE #2

(a)(b)&(c) This is a question that can only be definitively answered by the pipeline operators after some design work has been done. The definition of "upset conditions" depends on:

- Pipeline operating pressure (remembering that 1260 psia etc., are maximum pressures).

- Pipeline operating temperature
- Compression ratio and compressor station spacing
- Soil temperatures and heat transfer
- Definition of what constitutes an "upset" (e.g. one compressor station shutdown for one month in mid-winter). This is dependent on the degree of backup and sparing in the pipeline design.

It is suspected that the designs of neither the Canadian section nor the Alaskan section (for 1260 psia) are sufficiently advanced for the pipeline operators to have defined their upset conditions. The 1440 psia and 1680 psia proposed Alaskan designs are even less likely to have been evaluated with any precision.

In view of the above, projections to date on upset conditions are rough estimates, based in some part on Alcan's data. In this context the noted variances of 100 psi and 10°F or so between the various companies are not out of line.

We believe that an upset pressure of 200-400 psi below the maximum operating pressure is a reasonable educated guess. The difference between maximum operating pressure and upset pressure would tend to be wider at higher maximum operating pressures.

An upset operating temperature in the range 0°F to -10°F seems reasonable to us for permafrost areas (for practical matters, North of Whitehorse) and around 20 to 30°F south of Whitehorse. Note that the 42°F quoted as Sohio's Canadian upset temperature presumes that heaters will be installed at the critical Canadian compressor station #3; and that in the absence of such heaters we quoted 32°F. It is not known whether it is planned to install the necessary heaters.

The dew point specifications set out in the initial tariff filings of the pipeline sponsors are set out below:

<u>Alaskan Northwest</u>	<u>Foothills (converted from original metric)</u>	
	<u>North of 60°N</u>	<u>South of 60°N</u>
-5°F @ 800 psia	-4°F @ 800 psia	
-10°F @ 1000 psia	-9°F @ 1000 psia	15°F @ 800 psia
-18°F @ 1100 psia	-18°F @ 1100 psia	

Presumably these dew points represent something close to the sponsors' worst case or upset conditions.

It is generally true that the conditions of concern represent the lowest pressure and lowest temperatures.

With respect to the ability of IAPS to carry gas liquids ...

(a) What is the lowest IAPS inlet temperature that might safely be considered? What are the physical considerations that determine this (i.e. what worst case assumptions about ambient air temperature and

duration do you make with regard to IAPS shutdown or pump station outage?) Are there absolute physical limitations on the minimum inlet temperature, or is it primarily an economic matter of the costs and aggravation of frequent pigging?

(b) Approximately how much would it cost to add chilling facilities to bring the inlet temperature down to the level indicated above?

(c) Are light hydrocarbons such as butane and pentane useful in reducing oil pipeline viscosity and friction, thereby increasing throughput capabilities with existing equipment? Would one part of additional butane, therefore, require leaving behind maybe less than one part of heavier hydrocarbons if the line were already functioning at capacity? Given the likely timing of gas production for sale, and given the likely oil production scenario, is it a realistic prospect that throughput limitations of the line and pump stations might make it impossible to ship butanes and pentanes separated from the raw gas unless oil shipments are cut back?

(d) What volumes of oil production for each year of field operation should one assume when trying to ascertain IAPS throughput capabilities? To your knowledge, did the other parties commenting on the ability of IAPS to carry light hydrocarbons assume similar production schedules?

(e) Given the oil production scenario noted above and the volume of butanes and pentanes implied in your answer to question 1(d), how much butane and pentane could be transported through TAPS, (noting time as a variable) at the minimum inlet temperature you have specified in your answer to question 3(a) at the existing TAPS inlet temperature?

(f) Currently, what (if anything) is being done at Valdez to ensure that oil shipped through TAPS (at 140 degrees F and 14.7 psia) meets tanker and lower 48 storage specifications for vapor pressure? How would those activities change if the TAPS inlet temperature were lowered to the point mentioned in your answer to question 3(a)?

RESPONSE #3

Having recognized the importance of the type of questions posed in 3, Sohio commenced a study earlier this year to determine the NGL carrying capacity of the oil transportation system. This study is due to be completed in early 1980, and the responses below give an indication of the results to date.

- (a) There is a TALS temperature in the region of about 100-105° below which wax begins to form. The pipeline has been operated at lower temperatures (e.g. during startup) but it is believed that two factors will act to set the minimum inlet temperature for NGL blending purposes at around 100°F.
- At the current inlet temperature of about 140°F, the oil cools during its passage through TAPS. However, TAPS pressure/temperature analyses predict that under high throughput summer operation, at an inlet temperature of 100-110°F, there is little or no cooling. At 100°F the oil actually gains temperature in certain pipeline sections and emerges at Valdez at essentially the same temperature as it left the North Slope. Clearly there is no benefit in cooling an oil NGL mix on the North Slope for stabilization, only to have the mixture subsequently warm up again.
 - Various downstream jurisdictions impose vapor pressure limitations on hydrocarbons stored in floating roof tanks. The climates of the downstream locations, combined with their vapor pressure limitations suggest that cooling on the North Slope below about 100°F would achieve no practical benefit.

(b) The cost of crude cooling facilities to cool to 1.5 MMBD of crude to about 110°F was estimated in the Parson's Study to be about \$60 MM (1978 terms).

(c) Light hydrocarbons do indeed reduce viscosity. However, cooling the oil to accommodate light hydrocarbons tends to increase viscosity.

Given:

- the likely timing of gas sales (1985 or 1986 at the earliest).
- the likely onset of Prudhoe Bay oil decline in the same time frame.
- the flexibility of increasing TAPS throughput by injection of Drag Reductor Additive.
- the downstream vapor pressure constraints.

It is unlikely that NGL blending and/or oil production will be constrained by TAPS capacity, and if it is it will only be for a period of a year or so.

(d) Expected oil production volumes are shown on Fig 1 (attached). We believe this production profile does not drastically conflict with the views of other Prudhoe Bay Unit owners.

(e) Our present opinion is that the pentanes plus can be accommodated in the crude oil stream for much of the field life, since the vapor pressure characteristics of the pentanes plus/crude oil mix are little different from crude oil by itself. Some butanes may be mixed with the oil during early high throughput years.

(f) Vapor pressure control does not currently take place at Valdez. To control vapor pressure at this point would be a massive undertaking for the following reasons:

- The oil stream to be handled is large.
- Limited space is available for additional facilities in the terminal area.
- Sufficient storage would be required to accumulate cargo sized batches of the NGL's products.
- A fleet of Jones Act NGL tankers would have to be assembled to ship the NGL's for market, probably on the Gulf Coast.

Questions #4:

Concerning North Slope Field Fuel requirements ...

(a) Given the likely oil and gas production schedules you have indicated previously, how will the required amounts of field fuel change through time?

(b) What are the physical and economic principles that limit flexibility in choosing the BTU content, dew-point, and overall composition of field fuel? (e.g., the need to ensure a certain level of precision in combustion characteristics, dewpoint limitations imposed by exposure to ambient air temperatures en route, BTU specifications of existing equipment and the cost of changing or expanding that range.)

RESPONSE #4

(a) Fig. 2 (attached) gives a perspective of field fuel usage with time. The figure is scaled in billions of BTU/Day, which is equivalent to MCFD of 1000 net BTU/SCF gas.

The figure portrays a range. The lower curve is derived from an in-house study made in early 1979; this study was conducted primarily for other purposes and the fuel gas estimates being a secondary objective were not determined rigorously. The upper curve starts with the maximum fuel demand from the Parsons Report and is somewhat arbitrarily declined similar to the lower curve.

Fuel gas estimates at this stage are necessarily coarse:

- Timing and scope of major PB oil production facilities have not been finalized.
- Facility requirements during the oil decline phase cannot be determined at this point.
- No account has been taken of possible enhanced/tertiary oil recovery at Prudhoe Bay.

(b) BTU content of fuel is determined by the specification of the existing equipment at about 900 BTU/SCF $\pm$ 10%. Future equipment can in principle be tailored to the fuel available, subject to the constraints discussed in the remainder of this response.

The dewpoint of a fuel is dictated by the lowest temperature expected to be encountered by that fuel. This temperature is, in turn, dictated by the distance of the fuel user from the fuel source, pipeline size and insulation, etc. In principle, a field fuel system can be designed to cater for a high dewpoint by installation of heating systems, adequate insulation, circulating systems (for shutdown periods) adequate scrubbers (to catch liquid slugs) etc. However, such a system would obviously cost more than a simple system and would also run contrary to operational preferences for simplicity and reliability.

Composition is dictated primarily by the need to meet the conflicting requirements of heating value and dewpoint. An additional constraint for turbine fuel is that of flame stability, which is impaired by higher CO₂ contents. The 75% CO₂ local turbine fuel in the Parson's Report is felt to be close to this limit.

Other considerations for field fuel systems are simplicity, reliability and economics. Ideally there would be one quality of field fuel supplied through one cost effective system from several backup sources which can readily furnish fuel under any likely operating mode. The existing system comes close to meeting these criteria.

Simplicity, reliability and economics go hand in hand. A simple system is likely to be reliable. Reliability will reduce costly outages and enhance economics. It must be stressed that any field fuel system must be capable of sustaining oil production during periods when the gas conditioning plant or gas pipeline are shut down.

Miscellaneous questions ...

- When you speak of BTU's do you mean gross or net BTU's? When calculating the BTU values of various compositions of gases, what assumptions do you use with respect to the BTU content per mcf and per barrel for each hydrocarbon type (C_1 through C_5) What phase diagrams do you use for the following pure substances: C_1 , C_2 , C_3 , C_4 , C_5 , CO_2 , H_2O ?

RESPONSE

In general one uses net BTU's (lower heating values) when discussing fuel usage, whereas gross BTU's (higher heating values) are used for sales streams in line with FERC and industry practice. The Parsons Report is consistent in this respect, and in some places quotes both.

BTU values are taken from the BTU tabulation in the API Technical Data Book, 3rd Edition. Phase diagrams for the Parsons Report were calculated based on Parsons modified version of the Soave Redlich Kwong method.

It was recognized that the high proportions of CO_2 in most of the streams cast doubt on the validity of Parsons' equilibrium constants, and various field gas and liquid samples were taken at Prudhoe Bay in an attempt to determine these constants experimentally. Revised constants were used and while these were the best data available, doubt remains as to their accuracy.

- How does the addition of CO_2 affect the dewpoint characteristics of any particular gas composition, assuming that the composition of the hydrocarbon portion of the mixture remains unchanged?

RESPONSE

Under the pressures, temperatures and compositions contemplated, increased CO_2 content will tend to reduce the dewpoint slightly.

- On a very approximate basis, how much more money would it cost to isolate most of the produced ethane from the CO₂ rich stream during the conditioning process? Does this represent, say, the added cost of using a Sulfinol or similar process with required dehydration facilities? What other options are available?

RESPONSE

This has not been addressed by Sohio. However, there are three reasons why there is no simple answer to this question:

- Any plant design is likely to be complex, especially in the finely tuned areas which are peripheral to the main process.
- The answer would depend on what is meant by "most" of the ethane.
- Depending on the motive for removing the ethane, the same objective may be achieved in another manner.

One could speculate that any such ethane removal may well cost less than a sulfinol plus dehydration process. This speculation is based simply on the observation that sulfinol would require dehydrating a 2BCFD stream whereas the CO₂ rich stream at approximately 400 MMCFD is considerably smaller.

- Has anybody done any work yet on the added cost of transporting a gas of 13% CO₂ compared to the cost of transporting a 1% or 3% mixture, holding the pipeline operating pressure constant?

RESPONSE

Northwest Alaskan Pipeline has done such a study, dated February, 1979, simultaneously with a Supplementary Report to the Parsons Study. The Northwest Study and the Parsons Supplementary Study compared the effects of 3% and 13% CO₂ on respectively, the pipeline and the conditioning plant. Two cases were presented for each of the higher CO₂ contents, one of which aimed at BTU equivalency of the sales stream with the 1% Parsons base case, while the other aimed at volumetric equivalency with the 1% base case.

Northwest chose to compare only the volumetric equivalency cases in their analysis, a choice which we have criticized. Since the primary objective of the venture is to deliver BTU's to the U.S. consumer, it makes sense to us to compare alternate cases on the basis of BTU parity. This latter approach also makes more economic sense since over the range in question (2.0-2.3 BCFD) the cost per MCF of transporting gas through the pipeline system is declining.

- General questions on the effect of CO₂ content on the hazards of carbonic acid and hydrate corrosion and erosion at the pipeline operating pressures and temperatures under consideration.

RESPONSE

Neither CO₂ corrosion nor hydrate formation can occur in the absence of free water. Gas containing CO₂ can be and is safely pipelined in the U.S.; the breadth of CO₂ contents currently being pipelined range from nominal amounts to almost pure CO₂.

The requirement that free water be absent is reflected in the stringency of anticipated pipeline dewpoint specifications in the range of -40°F.

TABLE 1

ANTICIPATED PRODUCED GAS COMPOSITION

<u>Component</u>	<u>Vol%</u>
CO ₂	12.6
N ₂	0.5
C ₁	74.2
C ₂	6.5
C ₃	3.5
C ₄	1.6
C ₅	<u>1.1</u>
	100.0

TABLE 2

PRODUCT DISPOSITION

(MBD except C₁ in MMSCFD)

Parsons Maximum Fuel Case

<u>Component</u>	<u>Supply</u>	<u>Taps and Field Fuel</u>	<u>GCP Fuel</u>	<u>Sales Volumes</u>
C ₁	2077	184	6	1887
C ₂	116	43	15	58
C ₃	63	23	16	24
C ₄	35	2	1	32
C ₅₊	28	-	-	28

Parsons Minimum Fuel Case

<u>Component</u>	<u>Supply</u>	<u>Taps and Field Fuel</u>	<u>GCP Fuel</u>	<u>Reinjection</u>	<u>Sales Volumes</u>
C ₁	1936	54	17	1	1864
C ₂	107	16	18	4	69
C ₃	60	17	10	1	32
C ₄	33	1	1	-	31
C ₅₊	27	-	-	-	27

FIGURE 1

ESTIMATED PRUDHOE BAY OIL PRODUCTION PROFILE

