

ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILE 8672
1623 SCOMM 62: SENATE SPEC. COMM. ON OIL & GAS, 1989-1990

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I. OVERVIEW

At the January 24, 1989 public conference in Anchorage, Alaska, representatives of the Economic Regulatory Administration ("ERA") of the Department of Energy requested that the parties file certain information. ^{1/} Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest") reasserts its firm conviction that the insufficient record adduced to date compels denial of the Application. Nevertheless, in compliance with ERA's request, the following is herein submitted:

- The factual and legal basis for conditions to be attached to any export authorization that might be issued to Yukon Pacific Corporation ("Yukon Pacific"), together with specific proposed language.

- summary of the issue regarding North Slope gas conditioning facilities for the Alaska Natural Gas Transportation System ("ANGTS") and for Yukon Pacific's proposed export project, including Alaskan Northwest's position.

^{1/} See Tr. 101, 180, 204-205, 219.

II. FACTUAL BASIS FOR IMPOSITION OF PROPOSED CONDITIONS

A. Proved North Slope Gas Reserves Are Inadequate For Two Projects

Alaskan Northwest herein supplements its prior treatment of the issue of whether there exists sufficient proven reserves to support both the Trans-Alaska Gas System ("TAGS") and the ANGTS, ^{2/} and provides recent evidence from State and Federal Government sources to demonstrate that the projects are mutually exclusive as to reserves. ^{3/} The evidence demonstrates conclusively that some 26 trillion cubic feet ("tcf") of proved gas reserves are available for only one major gas transportation system in the same time frame.

Proof of an adequate, well-defined, gas reserve base is an essential prerequisite to obtaining regulatory approval--and the subsequent financing--of construction and operation of a pipeline

^{2/} See the following previously submitted Alaskan Northwest testimony: Motion of March 9, 1988, pp. 47-51, 54-56; (2) Comments, August 24, 1989, p. 9 and Exhibit A; (3) Reply Comments, September 23, 1989, p. 31 and Exhibit G, p. 10-11; (4) Prepared Statement of Vernon T. Jones, January 24, 1989 (pp. 11-13); and (5) Prepared Statement of James T. Jensen, January 24, 1989.

^{3/} There are only three government agencies (one Federal and two State of Alaska) that independently make annual estimates of proved reserves of natural gas in Alaska. The current estimate of each of them is discussed herein. The Bureau of Land Management ("BLM"), cited by Yukon Pacific on January 24, does not produce its own reserve estimates; in Economics of Oil and Gas Production from ANWR for the Determination of Minimum Economic Field Size, by John B. Young and William S. Hauser, BLM, 1968, p. 4, a brief historical reference is made to quantities of "recoverable resources" in the Prudhoe Bay Field, but no reference source is cited.

system. This was an important part of the Federal Energy Regulatory Commission's ("FERC") formal review in 1975 and 1976 of the then three proposed pipeline systems to transport the Prudhoe Bay gas. Detailed analyses and testimony were required from qualified reservoir engineers and other expert witnesses to substantiate the gas reserve base. Subsequently, in the early 1980s, the financial institutions that were considering financing the ANGTS also performed their own, independent analysis using an expert consulting firm to obtain assurance that at least 26 tcf of proved, economically transportable reserves ^{4/} were available at Prudhoe Bay. The key concerns were the magnitude of the proved reserves, the assurance of sustained deliverability for the twenty-five year economic life of the project, and the degree of confidence in the cost of production. Current government forecasts of proved reserves are discussed below:

1. Federal Government Estimate

The Energy Information Administration of the U.S. Department of Energy ("EIA") currently is the only source of nationwide, comprehensive, authoritative proved reserve estimates. Its annual report is the "bible" with respect to U.S. proved reserves, and its most recent edition (as of December 31, 1987) specifies 24.6 tcf of proved reserves of dry natural gas on the

^{4/} Any resource category other than "proved reserves"--such as "undiscovered reserves" or "potential recoverable resources," as cited by Yukon Pacific, Tr. Exhibit I, will not be relied upon by lenders financing a project such as TAGS or ANGTS.

North Slope. 5/

2. Alaska Oil and Gas Conservation Commission ("AOGCC") Estimate

The AOGCC annually publishes its list of proved reserves within the state. Its most recent report (as of January 1, 1988) indicates the following proved, salable North Slope gas reserves for the fields/reservoirs indicated:

AOGCC Estimate of
North Slope Proved Reserves 6/
(Billions of standard cubic feet, dry)

Endicott	798
Kuparuk	634
Prudhoe Bay (Lisburne)	406
Prudhoe Bay (Oil Pool)	<u>20,628</u>
	22,466

All of the fields indicated above are in relatively close proximity to the general Prudhoe Bay complex, and all are connected to the central gas facility. The AOGCC report names

5/ See EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1987 Annual Report (DOE/EIA-0216 (87)), Released October 27, 1988 (Copies of relevant pages attached as Exhibit A.)

6/ See AOGCC, Bulletin, "Estimate of Gas Reserves in Alaska," May 1988, p. 4. Based on a telephone conversation with Mr. Russell Douglas of AOGCC on January 27, 1989, the AOGCC figures were adjusted by subtracting 12% carbon dioxide for the Endicott Field as well as the Prudhoe Bay (Oil Pool) fields in order to obtain true "dry gas" figures comparable to other sources. The figures, as adjusted, shown above include all quantities listed that are on the North Slope except 15 billion cubic feet ("bcf") of proved reserves in the East and South Barrow Fields committed to domestic use in the North Slope Borough. (Copies of relevant pages attached as Exhibit B.)

other potential North Slope gas fields (e.g., Seal Island Area, Colville Delta Area); however, it makes clear that insufficient information is available to warrant assignment of any quantity of reserves--in short, these potential reserves are not something that regulators or the financial community would consider an adequate basis for a multi-billion dollar pipeline system.

3. Alaska Department of Natural Resources Estimate

Another source of proved reserves estimates is the Oil and Gas Division of the Alaska Department of Natural Resources ("ADNR"). Its most recent reserves figures for the North Slope are as follows for three alternative cases (low, middle-range, and high oil/gas prices):

ADNR Estimated Remaining Recoverable Reserves ^{1/}
(Billion cubic feet, dry)

<u>Proven and Developed</u>	<u>Low</u>	<u>Middle</u>	<u>High</u>
Endicott	590	790	1190
Kuparuk	420	570	720
Lisburne Reservoir	790	890	990
Prudhoe Bay Unit	26,000	26,000	26,000
<u>Proven but Undeveloped</u> <u>or Shut In</u>			
Point Thompson and			
Flaxman Island Areas	<u>0</u>	<u>0</u>	<u>5,000</u>
	27,800	28,250	33,900

^{1/} See ADNR, Historical and Projected Oil and Gas Consumption, January 1989, Table 2.1. The figures shown above include all quantities shown for locations on the North Slope except the 15 bcf of proved North Slope reserves committed to the North Slope Borough. (Copies of relevant pages attached as Exhibit C.)

The high-range ADNR estimate is reached only with the inclusion of 5 tcf of gas in the Point Thompson/Flaxman Island areas. In terms of transportability, this field stands in significant contrast to all of the others. Point Thompson/Flaxman Island is about 60 miles distant from the intended gas conditioning site at Prudhoe Bay; it has not been developed; its production characteristics are unknown; and gathering lines have not been installed. In short, it is not in the same "ball park," using ADNR's classifications, as the "proven and developed" reservoirs that currently are tied directly to central gas facilities at Prudhoe Bay. Major additional expenditures would be required to further define the field, develop the gas and transport it to a central conditioning plant.

4. Conclusion

Excluding the Point Thompson/Flaxman Island area gas, the combined EIA, AOGCC, ADNR range of North Slope proved, dry gas reserves is 22.5 to 28.3 tcf. Only with addition of the more costly, less certain Point Thompson/Flaxman Island gas could the total approach 33.9 tcf.

With ANGTS requiring at least 26 tcf of proved reserves, TAGS requiring at least 16 tcf, and additional gas required for production, gathering, conditioning, and compressor station fuel, the two projects obviously are mutually exclusive with respect to

transportable proved reserves in the same general time frame. ^{8/}

B. The Prudhoe Bay Gas is Needed Domestically

Alaskan Northwest has provided a plethora of evidence demonstrating that the proved, economically transportable reserves of North Slope gas will be needed in the lower-48 states by American consumers during Yukon Pacific's proposed period of export, i.e., 1996-2021. Alaskan Northwest demonstrated that the gas would be highly competitive on a free-market basis, without government subsidy, during that period. ^{9/} Alaskan Northwest sees no need to further burden the record with repetition or additional proof.

It is, however, necessary to set the record straight regarding certain Yukon Pacific statements made at the January 24 conference. Yukon Pacific, in attempting to defend the already discredited study by Dames and Moore and Decision Focus, Inc. ("D&M Study"), made numerous factually inaccurate statements concerning the conclusions reached in certain independent studies, as well as the feasibility of cost "levelization," which Alaskan Northwest intends to use. See Tr. 116-135.

At the January 24 conference, Yukon Pacific erroneously

^{8/} See f.n. 3 supra; Young and Hauser, p. 8, reference a study indicating 5.7 tcf are required to operate the Prudhoe Bay field and to provide fuel to operate the oil and gas pipeline systems.

^{9/} See the following: Comments, pp. 7-16; Reply Comments, pp. 25-39; Prepared Statements of January 24, 1989 by (1) Vernon Jones, pp. 3-11, (2) Cuba Wadlington, and (3) James Jensen, pp. 10-12.

stated that studies by the U.S. Department of Energy ("DOE"), the Potential Gas Committee ("PGC"), the United States Geological Service ("USGS") and the Gas Research Institute ("GRI") ". . . agree with the conclusion reached by our study that this [Alaskan North Slope] gas will not be economic, in the Lower 48 States, during the term of our export project." Tr. 92.

Yukon Pacific also asserted that the National Energy Board of Canada ("NEB") had stated: "[t]he year, 2017, under a high oil price is the first time that Canada expects Alaska North Slope gas to reach the Lower 48 states." Tr. 92-93. This representation is false, as discussed below. Yukon Pacific's assertions concerning the PGC and USGS can be readily dismissed by observing that both organizations deal with the magnitude of "undiscovered resources"--not with forecasts of deliverability by any specific dates. Neither organization prepares the natural gas economic supply/demand studies which would be required to reach the conclusion falsely attributed to it by Yukon Pacific.

Alaskan Northwest urges the ERA to disregard all such Yukon Pacific statements not fully proven in the record. Evidence to refute Yukon Pacific's undocumented, erroneous assertions is provided below:

1. GRI Projections

The GRI projects commencement of Alaskan pipeline gas flow in 2007. The basis for this statement is GRI's most recent forecast: 1988 Baseline Projection of U.S. Energy Supply and Demand to 2010, December 1988. The analytical work for this

study was completed before Alaskan Northwest's revised cost figures became available in June 1988. Even with the old, much higher costs, GRI projected ANGTS gas flow in 2007, i.e., squarely within the early part of Yukon Pacific's proposed period of export. This is documented in Exhibit D.

2. DOE Projections

A report entitled An Assessment of the Natural Gas Resource Base of the United States, May 1988, was prepared by the Argonne National Laboratory for DOE's Office of Policy, Planning and Analysis ("DOE/Argonne Report"). It was previously commented upon by Jensen Associates, Inc. See Alaskan Northwest's Comments, Exhibit A, pages 10-11. The report primarily is a survey of the nation's "resource" base, but it also concludes that large potential additions to reserves would be possible at a wellhead price of about \$3.00 per Mcf (1987 dollars). The Jensen comments observe that this implies a city gate price of "at least" \$3.50 in most major U.S. consuming markets. As demonstrated in Cuba Wadlington, Jr.'s Prepared Statement of January 24 (p. 6), Prudhoe Bay gas can be highly competitive in such a market.

3. NEB Projections

Yukon Pacific, at the January 24 conference, baldly misrepresented the contents of the recent study entitled Canadian Energy: Supply and Demand, 1987-2005, September 1988 ("NEB Report"). See Tr. 93.

Upon a diligent search of the NEB Report, no reference to Alaskan gas can be found. The study, in fact, is of Canadian gas, and detailed forecasts extend only to the year 2005--not beyond.

4. Alaskan Northwest's Cost Levelization

In direct contrast to uninformed opinions offered by Yukon Pacific representatives, Tr. 116-135, cost levelization is an approved and tested way to reduce the initial high cost of a "traditional tariff" and thereby ensure that gas is competitive in the marketplace. By analogy, if mortgage payments were not "levelized," virtually no homes would be purchased today in the United States. In 1984, the FERC issued an order to the Northern Border Pipeline Company authorizing use of a levelized tariff for the Eastern Leg of the "prebuilt" portion of the ANGTS. The Commission stated:

We believe . . . [that the levelized cost-of-service tariff] is in the public interest. The overall impact. . . is to make ANGTS 'prebuild' gas more price responsive in the United States markets. In addition [it] will provide rate stability . . . as well as a rate reduction in the near term. ^{10/}

Subsequent to that order, proposed new domestic gas pipeline projects have indicated an intent to use a levelized cost

^{10/} See Northern Border Pipeline Company, Docket No. RP85-25-000, "Order Accepting Certain Tariff Sheets Subject to Conditions," 29 FERC ¶61,303, p.61-629 (1984).

recovery method. ^{11/} Even more important in this proceeding is the fact that both the ANGTS and the proposed TAGS are more like international "mega-projects" than traditional utility rate base expansions, as Mr. Jensen testified at the January 24 conference. See Tr.28-29, 127-128. And no international project, to Alaskan Northwest's knowledge, has ever used the traditional but now outmoded domestic rate base methodology.

The fundamental point is that if gas is priced competitively in the marketplace, whether by levelization or by some other negotiated cost recovery method, it will be purchased. It should be obvious that levelization will not affect all sources of gas equally. Each project or source has a different remaining economic life, each exists at a different point in amortizing its incurred costs, and each has a different mix of wellhead and capital costs. Comparability among projects and sources for the purpose of determining market acceptability can be achieved only by considering prices actually offered to the market. For the ANGTS, it will be a levelized cost.

Yukon Pacific continues to tout its self-commissioned, self-serving D & M Study, which uses self-generated assumptions in discussing domestic need for the gas. In contrast, all of the independently developed forecasts by GRI, the American Gas Association, the Washington Policy and Analysis group, and others indicate a domestic need for the Prudhoe Bay gas by 2010 at the

^{11/} See, for example, Kern River Gas Transmission Company, Docket CP85-552; Mojave Pipeline Company, et al, Docket CP85-437; and Wyoming-California Pipeline Company, Dockets CP87-479/CP87-480.

latest. Accordingly, Yukon Pacific's D & M Study should be disregarded as a clearly faulty, biased work. 12/

5. Conclusion

For the foregoing reasons, Yukon Pacific's discredited assertions respecting the GRI, DOE, PGC, USGS, and NEB projections, as well as the alleged infeasibility of cost levelization must be rejected.

C. Insufficient Information is Available on Yukon Pacific's Proposed Project

Yukon Pacific's Application lacks, inter alia, the following: 13/

--gas purchase contracts--or firm letters of intent--for proved North Slope gas reserves

--gas sales contracts--or firm letters of intent--delineating the volumes of gas to be exported, the export recipients, and the terms and conditions of sale

--gas conditioning arrangements, including cost-sharing procedures and agreements for any joint-use of the Alaska Gas Conditioning Facility ("AGCF") conditionally FERC-certificated to the ANGTS (i.e., a facility which is also

12/ See Alaskan Northwest's Reply Comments, September 23, 1989, Exhibit G, A Critique of Yukon Pacific Corporation's Analysis of the Need for North Slope Natural Gas, by Jensen Associates, for a detailed assessment of the D & M Study.

13/ See Alaskan Northwest's Motion, pp. 25-44, for elaboration.

currently covered by a Corps of Engineers Section 404 permit for wetland construction and use of gravel).

--a complete environmental review of the gas conditioning arrangements, regardless of whether they will require an addition to existing/planned facilities or a new, stand-alone plant.

--specification of cost-sharing arrangements for other facilities (e.g., airfields, construction camps) intended to be used jointly with (and in many cases already permitted to) the ANGTS 14/

--a feasibility study regarding construction of TAGS in the Atigun Pass in addition to the existing oil pipeline, the state highway and the ANGTS. This raises a major cost sharing question in addition to feasibility and safety issues. 15/ Alaskan Northwest placed into the record at the January 24, 1989 conference a letter to the BLM spelling out its grave concerns with, inter alia, the Atigun Pass

14/ See Yukon Pacific, Project Description, December 1986, Section 5.2.15, pp. 113-119. Yukon Pacific, for example, specifically identifies facilities for its use that are currently permitted to the ANGTS.

15/ See Final Environmental Impact Statement for the Proposed Trans-Alaska Gas System ("FEIS"), June 1988, Appendix B. In assessing the compatibility of TAGS with other pipeline systems, BLM's Compatibility Review Team stated: "While a final compatibility determination can be made only after a detailed design has been developed . . . the engineering design solution for two chilled gas pipelines through the [Atigun] pass must be coordinated prior to construction of the first gas pipeline to be built." (p. B-6)

area. 16/ It is Alaskan Northwest's firm position, based on expert engineering and construction advice, that construction of a second gas pipeline in Atigun Pass might be feasible (if at all) only if the construction is accomplished at the same time the first gas pipeline is constructed. Such simultaneous construction raises, in addition to engineering issues, obvious cost-sharing and regulatory issues including possible application of Sections 4, 5, 7 and 16 of the Natural Gas Act ("NGA").

--complete identification of all project participants, including corporate and other affiliations.

--evidence of technical and financial capability to engineer, finance and construct the largest LNG project to date in the world. 17/

III. LEGAL BASIS FOR PROPOSED CONDITIONS

As Alaskan Northwest has previously documented, the failure of Yukon Pacific to present sufficient record evidence in support of its Application compels denial of the requested export application. On the assumption, however, that the ERA may consider issuance of some form of preliminary authorization, the

16/ See Northwest Alaskan Pipeline Company letter (ALO-86-4099) of December 22, 1986, addressed to Mr. Arlan H. Kohl, BLM.

17/ At the January 24, 1989, conference, the Yukon Pacific representative refused to divulge the investment in TAGS to date (estimated by some at less than \$2 million, including all public relations expenditures). See Tr. 209.

breadth of the legal requirements prescribed by the various statutes implicated by the Application requires the attachment of certain protective conditions. Accordingly, Alaskan Northwest provides the following legal analysis in support of such necessary protective conditions.

A. Section 3 of The Natural Gas Act

With respect to any application to export natural gas, Section 3 of the NGA requires the ERA to find, based upon substantial evidence, that the proposed export is in the public interest. Such evidence must include an examination of: the adequacy of gas reserves to support the proposed export; the lack of demand for the export volumes in the lower 48 states; environmental considerations; and claimed benefits (or, at a minimum, absence of harm) to U.S. consumers and ratepayers. See 10 C.F.R. §590.201, et seq.

Evidence has not been adduced to support any asserted claim that the proposed export is in the public interest. In many critical respects, the inability or unwillingness of the TAGS sponsors to provide a more complete record leaves the ERA to discharge its Section 3 review responsibilities in a vacuum. Nevertheless, should the agency be resolved to issue some form of preliminary permit, the parameters of any such authorization are necessarily circumscribed given the absence of the requisite substantial evidence.

Yukon Pacific's failure to provide contracts for the purchase of North Slope reserves and for the resale of exported volumes

has foreclosed any meaningful review of several considerations relevant to the "public interest." Evidence has not been presented identifying the export markets, the terms and conditions of sale, the conditioning and delivery arrangements, and the lack of domestic need for these gas supplies. Accordingly, the impact on the trade deficit, international relations, U.S. energy security and the related economic, environmental and socio-economic consequences cannot be assessed. Issuance of an unconditional export permit simply cannot be defended under the public interest standard.

Accordingly, under the "plenary authority" provided to the ERA under Section 3, a full range of certificate-type conditions must attach to the extent some form of preliminary export authorization is contemplated. See Distrigas Corporation v. F.P.C., 495 F. 2d 1057 (D.C. Cir.), cert. denied, 419 U.S. 834 (1974). ^{18/} These conditions, set forth herein, would include (among others) supplementation of the deficient Application, as well as mandatory conditions which would ensure that, for the life of the project (and in the event of domestic need) the proposed exports would not result in any adverse impact on ANGTS or the incurrence of any additional costs by U.S. consumers and ratepayers. Additionally, continuing oversight authority should

^{18/} See also Delegation Order No. 0204-25, para. (a) (1)-(5), 43 Fed. Reg. 47,769 (Oct. 17, 1978): "In exercising the functions [of determining whether importation or exportation of natural gas is not inconsistent with the public interest], the Administrator may attach such terms and conditions as he shall determine to be necessary to make the import or export not inconsistent with public interest. . . ."

be retained by ERA, e.g., by imposition of a condition permitting the ERA to withhold, modify or suspend the final export authorization as required by the public interest or as necessary to preserve the jurisdictional powers of the ERA and/or FERC.

B. Alaska Natural Gas Transportation Act of 1976 ("ANGTA")

ERA's review responsibilities are compounded and expanded by other statutory provisions, including the ANGTA. These statutory mandates impose on the ERA further restrictions with regard to the permissible scope of any forthcoming export authorization.

The provisions of Sections 9 and 12 of ANGTA define and limit the nature of North Slope exports which may be authorized, with due consideration for the priorities and protections provided to the ANGTS. Specifically, in pertinent part, Section 9 of ANGTA prohibits any federal action which would ". . . prevent or impair in any significant respect the expeditious construction and initial operation" of the ANGTS. Section 12 of the ANGTA requires, as a precondition to any export authorization, a specific finding that a proposed export of Alaskan gas to countries other than Mexico or Canada would not "diminish the total quantity or quality nor increase the total price of energy available to the United States." As detailed below, these congressionally mandated safeguards cannot be enforced in the absence of permit conditions protecting the North Slope reserves relied upon and needed for the successful development of ANGTS.

1. Section 9

Alaskan Northwest has demonstrated, on the record, that available, proved and deliverable North Slope reserves will only justify construction of one project in the time frame envisioned. ^{19/} In any event, however, a proposed protective condition is required regardless of the amount of ultimately available reserves. Until such time as North Slope gas actually begins to flow (whether in interstate or foreign commerce), there can be no assurance, short of the proposed protective condition, that the Section 9 protection--i.e., no impairment of initial ANGTS construction or operation--will be honored. Stated differently, because the North Slope reserve base identified in prior ANGTS-related legislative, executive, and regulatory approvals will form the basis for all underlying financing arrangements necessary for the "initial construction and operation" of the ANGTS, any actual or threatened depletion of such reserves would undermine the economic viability of the ANGTS project.

Other issues are directly implicated, and subject to the ERA's mandatory review by virtue of Section 9 of ANGTA. For example, unless a comprehensive analysis is forthcoming with respect to possible parallel construction of TAGS and ANGTS and possible joint use of the conditionally certificated gas

^{19/} See discussion at Part II.A., supra.

conditioning facility proposed as part of the ANGTS, ^{20/} the requested export authorization cannot issue. Such issues, and other issues which could potentially impact the capital and/or operating costs of the ANGTS, fall directly within the purview of Section 9 and therefore demand mandatory scrutiny.

2. Section 12

As previously documented, the legislative history of Section 12 of ANGTA indicates Congress' intent to permit the export of North Slope reserves only in the context of an exchange resulting in the delivery of an equivalent amount of comparably priced energy to the United States. See, Alaskan Northwest Comments, pp. 23-28. By interposing a specific Section 12 finding--i.e., that a proposed export will not reduce the quantity or quality of domestic energy or increase prices to U.S. consumers--as a prerequisite to any export authorization, Congress clearly contemplated the exportation of North Slope reserves only contemporaneous with importation of thermally equivalent and comparably priced energy supplies.

Nevertheless, apart from whether or not North Slope exports can only be approved in the context of an exchange, the ERA must, at a minimum, find that the proposed export will not require U.S. consumers to suffer curtailments or pay prices for either oil,

^{20/} See Order Amending Conditional Certificate, 18 FERC ¶ 61,002 (1982), incorporating certificate revisions mandated by Waiver of Law, S.J. Res. 115, Pub. L. No. 97-93, 97th Cong. 1st Sess. (1981) and, specifically, inclusion of conditioning plant as part of approved ANGTS.

gas or other alternative supplies where the costs associated therewith will be higher than the cost of Alaskan gas delivered to the lower 48 states during the term of the proposed export. Consequently, consistent with the ERA's own preliminary findings, the Yukon Pacific export proposal may not proceed in the absence of a detailed examination of U.S. demand through the first quarter of the next century. Evidence presented to date on the domestic need issue contains expert forecasts of U.S. domestic need for the North Slope gas by independent organizations, including government agencies, on the one hand, and, at best, a questionable analysis by Yukon Pacific asserting the absence of need on the other. Without a more convincing demonstration that there is no domestic need, the ERA is not equipped to render the necessary Section 12 findings to support an unconditional export permit.

Yukon Pacific makes much of the January 12, 1988 Presidential Finding ("Finding"), going so far as to contend that such finding preempts the ERA from further consideration of the range of issues which otherwise arise under Section 12 of ANGTA. Contrary, however, to the arguments advanced by Yukon Pacific, the Finding is neither project nor reserve specific and, by its own terms, does not attempt to "assess the merits or feasibility of any particular project." Additionally, the Finding includes no determination that the proposed exports are in the public interest, or that adequate reserves exist to support both the TAGS and the ANGTS.

On the contrary, by declaring that any export project "should

not hinder completion of the ANGTS," the President reaffirmed the federal government's long-standing support for the ANGTS. The expansive interpretation urged by Yukon Pacific--i.e., that the Finding relieves the ERA from review responsibilities with regard to issues arising under Section 12 of the ANGTA--was properly rejected by the ERA as reflected in the July 25, 1988 and December 5, 1988 orders. Specific findings, supported by substantial evidence, on issues such as magnitude of reserves, domestic need, and environmental and economic ramifications of parallel construction are prerequisite--under Section 12--to any export permit issued.

C. National Environmental Policy Act of 1969 ("NEPA")

Another obvious impediment to authorization of TAGS concerns the sponsors' failure to provide descriptive data and analysis mandated by the NEPA. At least two interested governmental entities (the Environmental Protection Agency ("EPA") and the FERC), have cited the inadequacy of the June 1988 FEIS for TAGS and, in particular, its failure to address environmental consequences associated with construction and operation of gas conditioning facilities. EPA stated: "the air quality analysis must be deferred to a future NEPA review." ^{21/} And the concerns previously raised by FERC's environmental evaluation branch

^{21/} See letter dated June 13, 1988 from the EPA to BLM, attached as Exhibit B to Alaskan Northwest's Reply Comments.

remain entirely unresolved. ^{22/} BLM, with its FEIS, has in effect passed the buck to ERA.

There is no evident dispute that authorization of the TAGS project constitutes a "major federal action" triggering the full panoply of NEPA requirements. To date, however, the TAGS sponsors have attempted to evade NEPA's manifest intent, at least concerning the admittedly necessary gas conditioning complex at Prudhoe Bay. Short of providing ". . . environmental disclosure sufficiently detailed to aid in the substantive decision whether to proceed with the project in light of its environmental consequences . . ." (Trout Unlimited v. Morton, 509 F.2d 1276, 1282 (9th. Cir. 1974)), the BLM's FEIS contains the unsupported observation that "[l]ittle additional land use impacts would occur [assuming construction of a second major conditioning plant] because the modification from subsistence and undisturbed wilderness to a petroleum complex has already taken place." P. 4-116.

As Alaskan Northwest has demonstrated, the ERA cannot legally or responsibly proceed to decision on the request for an unconditional export authorization so long as the environmental consequences associated with the multi-billion dollar conditioning installation--covering approximately 200 acres of fragile wetlands and requiring the mining of 2 million cubic yards of gravel--remain unaddressed. See Trout Unlimited, supra;

^{22/} See letter dated August 7, 1987 from FERC's Environmental Evaluation Branch to BLM, portions attached as Exhibit D to Alaskan Northwest's Reply Comments.

see also Sierra Club v. Cavanaugh, 447 F. Supp. 427 (D.S.D. 1978)

The standards by which environmental impact statements are to be tested were recently considered in Town of Huntington v. Marsh, 859 F.2d 1134 (2nd Cir. 1988). In Marsh, the court found inadequate the EIS prepared by the Army Corps of Engineers in connection with applications for dumping permits authorizing the disposal of dredged waste in the Long Island Sound. The Corps contended that its EIS properly and sufficiently addressed those environmental issues within the "scope of the project"--i.e., according to the Corps, consideration of the appropriate disposal site. The Court rejected such contention, finding that the " . . . fundamental flaw in the Corps' EIS is its too circumscribed view of the 'project' which is the subject of its impact statement. . . [and its failure] to insure that interrelated projects, the overall effect of which is environmentally significant, not be fractionalized." Id. at 1142. According to the Court, the Council on Environmental Quality ("CEQ") guidelines, promulgated under NEPA and set forth at 40 C.F.R. § 1502, et seq., require all "connected actions"--i.e., actions "closely related such that they are interdependent parts of a larger action and depend on the larger action for their justification" to be encompassed within the FEIS. Id. The applicable test is whether a specific project (or, by analogy, a specific component of a project) has independent utility. Id.

That the TAGS conditioning facility constitutes a "connected action" subject to mandatory FEIS inclusion under Marsh cannot credibly be challenged. The conditioning facility has "no

independent utility" separate and apart from the export project. Its very existence is inextricably tied to the operation and construction of TAGS. Accordingly, unless and until the FEIS is supplemented to include in-depth, comprehensive consideration of the TAGS conditioning installation (i.e., well beyond the few pages of cursory discussion in the FEIS), the requested export permit may not issue.

D. Sections 4, 5, 7 and 16 of the Natural Gas Act

1. Joint-Use of the Alaska Gas Conditioning Facility

President Reagan's proposed Waiver of Law ("Waiver") was submitted to Congress on October 15, 1981, pursuant to Section 8(g) of ANGTA. Shortly thereafter, Congress approved the proposed Waiver by Joint Resolution, and it was signed into law by the President. S.J. Res. 115, Pub. L No. 97-93, 97th Cong. 1st Sess. (1981). As discussed below, the legislative history of the Waiver contemplated not only FERC-required certificate modifications, but also the need for FERC to undertake cost-allocation and rate design review in the event of joint-use of the AGCF.

In pertinent part, the Waiver amends the President's Decision of September 1977, on the ANGTS, to "include the gas conditioning plant [i.e., the AGCF] in the approved transportation system" for the delivery of North Slope gas to the Lower-48 states. Accordingly, by order issued January 4, 1982, 18 FERC ¶61,002 (1982), the FERC amended the conditional certificate issued

December 16, 1977 to reflect inclusion of the gas conditioning plant as part of the "Alaska segment" of the ANGTS.

On May 27, 1977, the FERC issued a Declaratory order in Yukon Pacific Corporation, Docket No. GP87-16-000. Although subject to numerous caveats and qualifications, ^{23/} the Commission nonetheless found--on the record before it--that the Yukon Pacific export proposal did not invoke the Commission's jurisdiction under the NGA. This finding was expressly qualified in recognition of the uncertainties surrounding conditioning arrangements for the proposed export volumes. In the Commission's words:

It is also not clear whether the gas conditioning plant proposed to be used by the TAGS sponsors is the same plant for which the ANGTS sponsors have already received a conditional certificate under Section 7 of the NGA, or whether it is a different and totally unrelated plant. If we had jurisdiction to certificate the project, such factual uncertainties would necessarily mandate an evidentiary hearing before issuance of a certificate could be considered.

39 FERC at p. 61,754 (emphasis added).

And, elsewhere in the same order, the Commission noted:

If Yukon Pacific subsequently decides to utilize Alaskan Northwest's conditionally-certificated AGCF, the matter of Section 7 jurisdiction would have to be re-examined We stress again, that this conclusion [i.e. no Section 7 jurisdiction] is premised on all of the factual predicates discussed above, including the facts regarding the conditioning plant, the configuration of the pipeline, and the sources of the gas.

Id. at pp. 61,757-61,758 (emphasis added).

^{23/} See, e.g., 39 FERC at 61,754 ". . . issuance of a declaratory order does not have finality or the consequences of a certificate [and] . . . determination[s] made today can only be valid within the parameters of the facts and factual predicates before us . . . any material change in those facts could well affect our jurisdiction"

The conditioning arrangements for TAGS exports are no more definitive today than they were in December 1986, when Yukon Pacific's declaratory order petition was originally filed. The TAGS sponsors continue to hedge in their most recent filings, to the extent conditioning plans are even discussed. Clearly, however, as the Commission acknowledged, a host of jurisdictional issues--not heretofore decided by the FERC or the ERA--will immediately come into focus in the event TAGS at some point announces its intention to use the AGCF. Thus, for example, if the jurisdictional AGCF is eventually used by TAGS jointly with Alaskan Northwest, the commingling of Yukon Pacific's export volumes with the ANGTS interstate volumes in the AGCF could subject the entire TAGS pipeline facilities to regulation as an interstate jurisdictional facility under the Natural Gas Act. See California v. Lo-Vaca Gathering Company, 379 U.S. 366 (1965); see also State of Louisiana v. F.P.C., 533 F.2d 1239 (D.C. Cir. 1976), and Louisiana Power and Light Company v. F.P.C., 483 F.2d 623 (5th Cir. 1973), cert. denied 416 U.S. 974 (1974). ^{24/}

^{24/} As documented earlier in these proceedings by Alaskan Northwest, Yukon Pacific's treatment of the gas conditioning issue has been a sorry example of obfuscation and misstatement. First, Yukon Pacific's own President filed an application with the BLM that specified in precise words its intended use of the FERC-certificated AGCF; and Yukon Pacific's own Chairman executed a formal agreement with BLM for preparation of an EIS covering its project, which was specifically described as including gas conditioning. Yukon Pacific then filed with FERC an application for a declaratory order in which it was asserted that the AGCF would not be used and that a separate, stand-alone facility would be built. Thus, there were simultaneously pending before two federal agencies flatly contradictory applications. At the
(Footnote Continued)

The potential joint use of the AGCF also raises cost allocation issues cognizable under Sections 4 and 5 of the NGA, as Congress acknowledged in enacting the Waiver. The Committee report accompanying the recommendation to approve the proposed Waiver addresses the implications of possible joint use of the AGCF, stating:

. . . FERC in determining tariff provisions applicable to the gas conditioning facility for ANGTS purposes will have to decide the proper allocation of costs among various users. The Committee intends that FERC will carefully review all of the allowable costs in the ANGTS proceedings to ensure that only those properly allocated to transportation of the Alaskan natural gas through ANGTS will be included in the ANGTS tariff.

Sen. Rep. 97-272, accompanying S.J. Res. 115, pp. 33-34.

Thus, because TAGS exports may ultimately be processed and conditioned through the AGCF, FERC's Sections 4, 5 and 7 authority is directly implicated. Pending resolution of these cost allocation (and certificate) issues--i.e., by requiring TAGS to specify, once and for all, proposed conditioning arrangements and directing referral to the FERC in the event joint use of the AGCF is contemplated--there can be no assurance that U.S.

(Footnote Continued)

January 24 hearing, Yukon Pacific's attempt to shield from agency scrutiny its fatal "Achille heel" was once again evident. The gas was to be conditioned in an "add on" facility, but it would be someone else's facility. See Tr. 196-200. As pointed out, however, the courts have made clear that ownership of a facility is not relevant to applicability of NEPA. And, moreover, if gas commingling occurs in such an "add on" to the AGCF, the entire jurisdictional issue is open. If an entirely new, stand-alone facility is built to process only TAGS gas, such facility is equally a "connected action" to the export project, and NEPA requires completion of the EIS for such "stand-alone" facility. Even an add-on facility would require substantial additional facilities and could have a significant cumulative environmental effect. This requires an assessment as to whether such expansion of existing facilities requires reopening the NEPA process.

consumers and ratepayers will not eventually subsidize the costs of any such conditioning and processing. The regulatory hiatus created by TAGS' noncommittal posture respecting conditioning arrangements must not result in deviation from the long-standing rate-making principle (endorsed by Congress in connection with the Waiver) requiring the assignment and allocation of costs to those customers on whose behalf such costs are incurred. See, e.g., Colorado Interstate Gas Co. v. F.P.C., 324 U.S. 581, 591 (1945) (upholding the principle that "beneficiaries of entire project [must] share equitably in the cost"). Accordingly, at a minimum, the ERA must attach appropriate protective conditions to any export authorization requiring, as necessary, final FERC determinations on jurisdictional and rate issues under Sections 4, 5, 7 and 16 of the NGA if the AGCF is ultimately used by TAGS.

2. Atigun Pass Facilities & Other Joint-Use Issues

As discussed, supra, several factual engineering and construction issues arise in connection with TAGS' proposed construction of pipeline facilities through the Atigun Pass. The proposed routing of TAGS in this area coincides with the routing of the conditionally approved ANGTS. Accordingly, given the engineering impracticability of sequential construction of large diameter pipeline facilities through the Atigun Pass, ^{25/} either simultaneous construction of both TAGS and ANGTS, or rerouting of one or the other, may be required. Consequently, should TAGS

^{25/} See factual discussion Part II. C., supra.

undertake construction of proposed facilities prior to initial construction and operation of ANGTS, forced simultaneous construction by TAGS of conditionally-certificated ANGTS facilities through the Atigun Pass may be required in order to ensure compliance with Section 9 of ANGTA. Any such construction would invoke the Commission's Section 7 authority requiring TAGS to first obtain a certificate of public convenience and necessity. Likewise, to the extent that authorization of TAGS forces rerouting of the conditionally certificated ANGTS facilities (assuming, arguendo, that such rerouting may be ordered consistent with Section 9 and 12 of ANGTA), an amendment to the ANGTS conditional certificate would be necessary to reflect (and provide authorization for) any such routing deviation.

Finally, cost allocation issues are posed by the proposed joint use by TAGS of ancillary facilities located between Prudhoe Bay and Delta Junction that are to be used by ANGTS (and in many cases are already permitted to ANGTS). Thus, joint use of airstrips, construction camp sites, material sites, communication facilities, erosion control structures, access roads and the like by TAGS and ANGTS must be carefully analyzed (prior to any export authorization) to ensure that U.S. consumers and ratepayers bear none of the costs associated with TAGS.

IV. PROPOSED CONDITIONS

In light of the deficiencies associated with the Application, protective conditions must attach to any ERA authorization issued

to ensure that the mandates of the NGA, the ANGTA, and NEPA are not contravened. Thus, if the ERA is resolved to issue some form of preliminary authorization, the following conditions, inter alia, must be imposed:

1. The authorization granted herein is conditional and will not become final except by a subsequent order of ERA. In order to obtain a final export authorization, Yukon Pacific must file and serve upon all parties of record, the following information:
 - (a) gas purchase, sales and transportation contracts, or firm letters of intent, setting forth the gas reserves proposed to be purchased, transported and resold;
 - (b) qualified reservoir engineering studies, by producing field, including proven reserves and daily and annual deliverability studies for the reserves relied upon by TAGS;
 - (c) definitive siting, engineering and design data; gas conditioning specifications; and cost and ownership information on proposed conditioning facilities;
 - (d) proposed definitive design, engineering and construction plans for Atigun pass demonstrating feasibility of such construction and measures to be taken to preclude rerouting the ANGTS, including any simultaneous construction of TAGS and ANGTS facilities, together with any proposed cost-sharing arrangements;
 - (e) identification of all other proposed joint-use facilities and proposed cost-sharing arrangements; and
 - (f) a definitive analysis of the net national economic benefits of the proposed exports.
2. No final authorization shall issue until such time as the ERA evaluates all supplemental data required by Condition 1 above, and concludes that:
 - (a) the Application satisfies the "public interest" under Section 3 of the Natural Gas Act, 15 U.S.C. Sec. 717b;
 - (b) no further actions are required under the provisions of the National Environmental Policy Act of 1969, 42 U.S.C. 4231, et seq., with respect to the export application;
 - (c) consistent with the requirements of Sections 3, 4, 5, 7 and 16 of the Natural Gas Act, 15 U.S.C. Sec. 717, et seq., the Federal Energy Regulatory Commission has rendered all

final necessary determinations within the scope of its jurisdiction over the proposed TAGS project pursuant to Sections 3, 4, 5, 7 and 16 of the Natural Gas Act; and

(d) consistent with Sections 9 and 12 of the Alaska Natural Gas Transportation Act, 15 U.S.C. Sec. 719g and 719j, authorization of the proposed export will not, during the term of the authorization, compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System nor otherwise prevent or impair in any significant respect the expeditious construction and operation of that system; and that authorization of the proposed export will not, during the term of the authorization, operate to diminish the total quantity or quality or increase the total price of energy available to the United States.

3. Any final export authorization is subject to suspension, modification, or revocation upon the demonstration to the Economic Regulatory Administration, or any successor entity, of a reasonable likelihood that continuation of the authorized exports is no longer consistent with the findings made pursuant to Condition 2 above.

V. CONCLUSION

The ERA cannot proceed to decision on the merits of the Application without due regard for the review responsibilities imposed by the NGA, ANGTA, and NEPA. Together, these statutes require, at a minimum, that any export authorization granted to Yukon Pacific be grounded on specific findings supported by substantial evidence.

The requisite findings essential to ERA's deliberations include that: (i) the TAGS Application fully complies with all NEPA requirements; (ii) no domestic need will arise during the term of the proposed export; (iii) permitting of TAGS will not compel a change in the general routing of ANGTS or otherwise prevent or impair in any significant respect the expeditious construction and operation of the ANGTS; (iv) permitting of TAGS

will not diminish the total quantity or quality or increase the total price of energy available to the U.S.; and, (v) FERC's jurisdiction under Section 3, 4, 5, 7 and 16 is not invoked by the Application.

On the record established to date, these requisite findings cannot be made, and the Application should be denied. Alaskan Northwest, nevertheless provides, in response to ERA's request, proposed conditions (in Part IV, supra) to attach to any conditional authorization which may be contemplated.

Alaskan Northwest expressly reserves the right to propose additional conditions as may be necessary following the submission by Yukon Pacific of information in further support of the TAGS project.

Respectfully submitted,



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General Counsel

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February 7, 1989

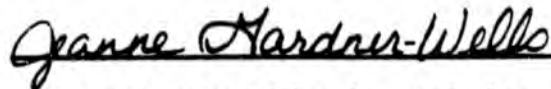
VERIFICATION

William J. Moses, being first duly sworn, deposes and says that he is General Counsel of Northwest Alaskan Pipeline Company, operating partner of the Alaskan Northwest Natural Gas Transportation Company, and that as such he is authorized to sign and verify the foregoing document; that he has read said document and is familiar with the contents thereof; and that the matters and things set forth therein are true and correct to the best of his information, knowledge and belief.



William J. Moses

SUBSCRIBED AND SWORN TO before me this 7th day of February, 1989.



Notary Public in and for
the District of Columbia

Jeanne Gardner-Wells
Notary Public, District of Columbia
My Commission Expires Jan. 12, 1993

CERTIFICATE OF SERVICE

I hereby certify that I have on this day, pursuant to Section 590.107 of the regulations, served the foregoing document upon the ERA, the Applicant, and the parties appearing on the official service list by first-class mail, postage prepaid.

Dated at Washington, D.C. this 7th day of February, 1989.

A handwritten signature in dark ink, appearing to read 'W. J. Moses', is written over a horizontal line.

William J. Moses

EXHIBIT A



DOE/EIA-0216(87)
Distribution Category UC-98

U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves

1987 Annual Report

Energy Information Administration
Office of Oil and Gas
U.S. Department of Energy
Washington, DC 20585

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4. National and State Natural Gas Statistics

Natural Gas Proved Reserves

Table 8 presents the estimated proved reserves, reserve changes, and production of natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions. Total proved reserves of natural gas, wet after lease separation, were 196,428 billion cubic feet, a decrease of 4,681 billion cubic feet or 2.3 percent lower than reported in 1986. This decrease brings total U.S. proved reserves of natural gas to the lowest level since the EIA's initial estimate for year-end 1976. Total proved reserves of natural gas, wet after lease separation, in the lower 48 States decreased 3.0 percent (5,041 billion cubic feet) in 1987. Total wet natural gas production increased 3.1 percent (503 billion cubic feet) during 1987 as a result of higher demand. Total discoveries from new fields, new reservoirs in old fields, and extensions decreased by 19.6 percent (1,834 billion cubic feet). Extensions showed a particularly sharp drop (24.2 percent) to 4,818 billion cubic feet.

The estimated proved reserves of nonassociated natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions are presented in Table 9. Proved reserves of nonassociated natural gas in the United States declined by 3,293 billion cubic feet (2.3 percent) to 138,239 billion cubic feet in 1987. Production of nonassociated gas increased by 4.6 percent (595 billion cubic feet). Total discoveries from new fields, new reservoirs in old fields, and extensions decreased significantly by 19.3 percent (1,606 billion cubic feet) in 1987. The most important factor in the lower 48 States total discoveries was a decline in field extensions of 23.7 percent to 4,276 billion cubic feet. Much of this decline was in the Federal Offshore where extension drilling was not as successful as in the previous year.

Table 10 presents the estimated proved reserves of associated-dissolved natural gas, wet after lease separation, as of December 31, 1987, by selected States and State subdivisions. Proved reserves of associated-dissolved natural gas in the United States declined by 2.3 percent to 58,189 billion cubic feet while production fell by 2.7 percent. Proved reserves of associated-dissolved natural gas in the lower 48 States declined 4.3 percent to 27,457 billion cubic feet while production declined 3.5 percent.

Estimates of proved natural gas reserves on a dry basis are shown in Table 11. During 1987, proved reserves of dry natural gas declined 4,375 billion cubic feet, or more than 2.3 percent. This decrease brings total U.S. proved dry gas reserves to the lowest level since the EIA's initial estimate

for year-end 1976. Alaskan proved reserves of dry natural gas increased by 561 billion cubic feet or 1.7 percent. U. S. proved reserves of dry natural gas in the lower 48 States, however, decreased by 3.1 percent (4,936 billion cubic feet) in 1987. Production of dry natural gas was up 3.2 percent to 16,114 billion cubic feet for the year. Total discoveries of dry gas reserves were down 19.7 percent to 7,175 billion cubic feet in 1987, the lowest discovery level during the 1977 through 1987 period. New field discoveries were roughly flat at 1,089 billion cubic feet, but still 57.1 percent lower than the 1977 through 1986 annual average of 2,539 billion cubic feet. Both extensions (4,587 billion cubic feet) and new reservoirs discovered in old fields (1,499 billion cubic feet) were substantially down in 1987.

The volumetric difference between the estimates reported in Tables 11 and 8 is the result of the removal of natural gas liquids at natural gas processing plants. The methodology used to adjust for plant liquids production is described in Appendix B. All natural gas reserves data in this report exclude natural gas held in underground storage.

Alaskan North Slope Natural Gas Reserves

Background

There has been an ongoing economic reassessment by the companies involved of the Alaskan North Slope gas resources for several years. In 1987, the two major Alaskan operating companies agreed that, given the current outlook and economic conditions, only gas that was marketable on the North Slope could be classified as proved reserves. Current economic conditions include uncertainties that exist with respect to a transportation system or other marketing alternatives for the gas. However, the downward revisions to proved reserves on the Alaskan North Slope reported in 1987 and prior years by the operating companies have not been accepted by EIA and are not reflected in the proved reserve estimates presented for 1987. Therefore, as in past years, EIA proved reserves of dry natural gas include some 24.6 trillion cubic feet located on the Alaskan North Slope that do not, at present, have a market.

Proposed plans for exploitation of the natural gas are still being formulated, but a market does not currently exist for the bulk of these reserves. However, produced natural gas currently creates and will continue to create a positive net cash flow from stripped liquids and as fuel for field operations and the Trans-Alaska Pipeline. The gas also has value

Table 11. Estimated Total Dry Natural Gas Proved Reserves, Reserves Changes, and Production, 1987
(Billion Cubic Feet, Dry, at 14.73 psia and 60° Fahrenheit)

State and Subdivision	Published Proved Reserves 12/31/86	Changes in Reserves During 1987							Proved Reserves 12/31/87
		Net Adjustments (+,-)	Revision Increases (+)	Revision Decreases (-)	Extensions (+)	New Field Discoveries (+)	New Reservoir Discoveries In Old Fields (+)	Production (-)	
Alaska	32,664	202	718	67	45	12	0	349	33,225
Lower 48 States	188,922	1,986	18,809	14,164	4,642	1,077	1,499	16,785	183,986
Alabama Onshore	951	-154	161	57	39	0	2	100	842
Arkansas	1,992	26	215	229	93	0	29	129	1,997
California	3,928	-69	315	136	44	1	2	345	3,740
Coastal Region Onshore	255	-14	34	15	2	0	0	24	238
Los Angeles Basin Onshore	142	9	21	9	2	0	0	17	148
San Joaquin Basin Onshore	3,277	-63	246	102	33	1	2	292	3,102
State Offshore	254	-1	14	10	7	0	0	12	252
Colorado	3,027	-77	340	268	71	7	1	159	2,942
Florida	49	7	0	0	0	0	0	7	49
Kansas	10,509	239	245	147	76	8	1	437	10,494
Kentucky	841	68	65	17	10	0	0	58	909
Louisiana	12,930	156	1,655	1,414	414	16	298	1,625	12,430
North	2,515	-13	247	259	127	1	4	316	2,306
South Onshore	9,103	-121	1,270	1,005	272	6	277	1,109	8,693
State Offshore	1,312	290	138	150	15	9	17	200	1,431
Michigan	1,139	35	160	157	257	90	57	130	1,451
Mississippi	1,300	5	153	96	32	1	3	178	1,220
Montana	803	-25	57	16	2	0	1	42	780
New Mexico	11,808	-76	1,123	650	131	1	11	728	11,620
East	2,694	185	524	222	71	0	11	382	2,881
West	9,114	-261	599	428	60	1	0	346	8,739
New York	457*	-11	3	17	0	1	0	23*	410
North Dakota	541	-3	83	64	5	2	1	57	508
Ohio	1,420	-260	45	35	12	0	4	117	1,069
Oklahoma	16,685	559	2,251	2,047	823	11	242	1,813	16,711
Pennsylvania	1,560	164	109	195	137	0	0	128	1,647
Texas	40,574	438	4,477	4,009	1,326	177	245	4,517	38,711
RRC District 1	913	-7	74	62	9	1	14	130	812
RRC District 2 Onshore	2,180	320	300	280	58	20	24	349	2,273
RRC District 3 Onshore	3,753	-5	518	349	146	119	19	569	3,632
RRC District 4 Onshore	8,274	5	1,127	1,599	701	11	129	1,158	7,490
RRC District 5	2,141	31	151	112	79	0	0	171	2,119
RRC District 6	4,854	68	366	269	47	5	6	395	4,882
RRC District 7B	684	96	59	58	16	0	6	106	697
RRC District 7C	2,721	137	244	192	22	5	13	242	2,708
RRC District 8	7,333	-120	634	308	62	7	24	633	6,999
RRC District 8A	845	72	72	44	2	0	0	71	876
RRC District 9	868	-7	118	68	35	0	0	112	834
RRC District 10	5,276	-129	742	572	108	4	4	471	4,962
State Offshore	732	-23	72	96	41	5	6	110	627
Utah	1,895	-45	281	144	12	5	3	60	1,847
Virginia	253	2	5	8	15	0	0	19	248
West Virginia	2,148	154	137	134	92	0	13	188	2,242
Wyoming	9,756	38	771	425	318	5	16	456	10,023
Federal Offshore ¹	34,223	-27	4,154	3,998	632	752	557	4,462	31,931
Pacific (California)	1,325	163	53	49	6	0	0	46	1,452
Gulf of Mexico (Louisiana) ¹	25,454	-314	2,547	2,770	489	701	386	3,213	23,260
Gulf of Mexico (Texas)	7,444	124	1,554	1,079	157	51	171	1,203	7,219
Miscellaneous ²	133	-78	4	1	1	0	13	7	65
U.S. Total	191,598	1,986	17,527	14,231	4,867	1,989	1,499	16,114	187,211

¹ Includes State and Federal offshore Alabama

² Includes Arizona, Illinois, Indiana, Maryland, Missouri, Nebraska, Oregon, South Dakota, and Tennessee

* Indicates that the estimate is associated with a sampling error (95 percent confidence interval) which exceeds 20 percent of the estimated value.

Note: The production estimates in this table are based on data reported on Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves", and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production". They may differ from the official Energy Information Administration production data for natural gas for 1987 contained in the *Natural Gas Annual 1987*, DOE/EIA-0131(87).

Source: Form EIA-23, "Annual Survey of Domestic Oil and Gas Reserves", and Form EIA-64A, "Annual Report of the Origin of Natural Gas Liquids Production".



Jackup Rig in Cook Inlet, Alaska.

by increasing the recovery of crude oil through reinjection for pressure maintenance and tertiary recovery operations. There is no question about the technical and low cost producibility of the associated-dissolved gas through the wellhead. For example, in the giant Prudhoe Bay Field, most of the gas could be produced through wells that have already been drilled.

Definitional Aspects

The EIA reviewed the situation within the context of definitional differences used to describe the classification of natural gas reserves located in fields on the North Slope of Alaska. The majority of these volumes continue to be included in the 1987 estimates of proved reserves presented in this report. With respect to the EIA proved reserves definition, it is worth noting that the following language provided significant latitude to allow for the positions taken by the operating companies and EIA.

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

...It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved.

To quote BP America in its annual shareholder report for 1987, "This reserve revision is not the result of a technical reevaluation, rather, it is because the production of Alaskan gas is contingent upon the construction of transportation facilities or development of other marketing alternatives" [27].

EIA remains in agreement with the companies involved that the eventual production of all the natural gas reserves on the Alaskan North Slope is contingent upon construction of transportation facilities or development of other marketing alternatives except for natural gas used in local operations and miscellaneous sales. There are significant economic uncertainties concerning this gas. However, given the current economic production of North Slope gas, EIA chose to retain it as proved reserves.

The primary reason for the position of including these reserves taken by EIA is definitional; however, EIA also believes that the natural gas in question will be marketed sometime in the future. The EIA will continue to carefully review the status of North Slope natural gas reserves, annually.

Natural Gas Reserves in Nonproducing Reservoirs

Like crude oil, not all proved reserves of natural gas were contained in reservoirs that were producing. Reserves in nonproducing reservoirs are defined as those in reservoirs that did not have production during the entire final quarter of 1987. Proved natural gas reserves, wet after lease separation, of 30,897 billion cubic feet were reported in nonproducing reservoirs as shown in Table 12. This was a decrease of 5.8 percent from 1986. Of these reserves, approximately 45.4 percent were located in the Gulf of Mexico Federal Offshore. These proved reserves were reported by Category I and II operators only. These two categories of operators accounted for about 91 percent of the estimated total natural gas production, wet after lease separation. The reasons for the nonproducing status of these proved reserves have not been collected by EIA since 1981. However, previous surveys indicated that most of the wells or reservoirs were not producing for operational reasons. These operational reasons included waiting on workovers, drilling additional development or replacement wells, installing production or pipeline facilities, and awaiting depletion of other zones or reservoirs before recompletion in reservoirs not open to production.

Lease Separator: A lease separator is a facility installed at the surface for the purpose of (a) separating gases from produced crude oil and water at the temperature and pressure conditions of the separator, and/or (b) separating gases from that portion of the produced natural gas stream which liquefies at the temperature and pressure conditions of the separator.

Natural Gas: A mixture of hydrocarbon compounds and small quantities of various nonhydrocarbons existing in the gaseous phase or in solution with crude oil in natural underground reservoirs at reservoir conditions. The principal hydrocarbons normally contained in the mixture are methane, ethane, propane, butane, and pentanes. Typical nonhydrocarbon gases which may be present in reservoir natural gas are water vapor, carbon dioxide, helium, hydrogen sulfide, and nitrogen. Under reservoir conditions, natural gas and the liquefiable portions occur either in a single gaseous phase in the reservoir or in solution with crude oil, and are not distinguishable at the time as separate substances. (See Natural Gas, Natural Gas, Nonassociated and Natural Gas, Associated-Dissolved)

Natural Gas, Associated-Dissolved: The combined volume of natural gas which occurs in crude oil reservoirs either as free gas (associated) or as gas in solution with crude oil (dissolved).

Natural Gas, "Dry": The actual or calculated volumes of natural gas which remain after:

1. The liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and
2. Any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable.

Natural Gas, Nonassociated: Natural gas not in contact with significant quantities of crude oil in a reservoir.

Natural Gas Liquids: Those hydrocarbons in natural gas which are separated from the gas through the processes of absorption, condensation, adsorption, or other methods in gas processing or cycling plants. Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as condensate, natural gasoline, or liquefied petroleum gases. Where hydrocarbon components lighter than propane are recovered as liquids, these components are included with natural gas liquids.

Natural Gas Processing Plant: A facility designed to recover natural gas liquids from a stream of natural gas which may or may not have passed through lease separators and/or field separation facilities. Another function of the facility is to control the quality of the processed natural gas stream. Cycling plants are considered natural gas processing plants.

Natural Gas, Wet After Lease Separation: The volume of natural gas remaining after removal of lease condensate in lease and/or field separation facilities, if any, and after exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable. Natural gas liquids may be recovered from volumes of natural gas, wet after lease separation, at natural gas processing plants. (See Lease Condensate, Lease Separator, and Field Separation Facility)

Net Adjustments: The quantity which preserves an exact annual reserves balance within each State or State subdivision of the following form:

Published Proved Reserves at End of Previous Report Year
+ Net Adjustments
+ Revision Increases
- Revision Decreases
+ Extensions
+ New Field Discoveries
+ New Reservoir Discoveries in Old Fields
- Report Year Production
= Published Proved Reserves at End of Report Year

These net adjustments are the yearly changes in the published reserve estimates that cannot be attributed to the estimates for other reserve change categories because of the survey and statistical estimation methods employed. For example, variations as a result of changes in the operator frame, different random samples or imputations for missing or unreported reserve changes, could contribute to net adjustments.

Net Reserve Additions: Consist of net adjustments, net revisions, extensions to old reservoirs, new reservoir discoveries in old fields, and new field discoveries.

Net Revisions: (See Revisions)

New Field: A field discovered during the report year.

New Field Discoveries: The volumes of proved reserves of crude oil, natural gas and/or natural gas liquids discovered in new fields during the report year.

New Reservoir: A reservoir discovered during the report year.

New Reservoir Discoveries in Old Fields: The volumes of proved reserves of crude oil, natural gas, and/or natural gas liquids discovered during the report year in new reservoir(s) located in old fields.

Nonproducing Reservoirs: Reservoirs in which proved liquid or gaseous hydrocarbon reserves have been identified, but which did not produce during the last 3 months of the report year regardless of the availability and/or operation of production, gathering, or transportation facilities.

Volumes of crude oil placed in underground storage are not to be considered proved reserves.

Reserves of crude oil which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

Estimates of proved crude oil reserves do not include the following: (1) oil that may become available from known reservoirs but is reported separately as "indicated additional reserves"; (2) natural gas liquids (including lease condensate); (3) oil, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (4) oil that may occur in undrilled prospects; and (5) oil that may be recovered from oil shales, coal, gilsonite, and other such sources. It is not necessary that production, gathering or transportation facilities be installed or operative for a reservoir to be considered proved.

Proved Reserves of Lease Condensate: Proved reserves of lease condensate as of December 31 of the report year are the volumes of lease condensate expected to be recovered in future years in conjunction with the production of proved reserves of natural gas as of December 31 of the report year, based on the recovery efficiency of lease and/or field separation facilities installed as of December 31 of the report year. (See Lease Condensate and Proved Reserves of Natural Gas).

Proved Reserves of Natural Gas: Proved reserves of natural gas as of December 31 of the report year are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Reservoirs are considered proved if economic producibility is supported by actual production or conclusive formation test (drill stem or wire line), or if economic producibility is supported by core analyses and/or electric or other log interpretations.

The area of a gas reservoir considered proved includes: (1) that portion delineated by drilling and defined by gas-oil and/or gas-water contacts, if any; and (2) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons is considered to be the lower proved limit of the reservoir.

Volumes of natural gas placed in underground storage are not to be considered proved reserves.

For natural gas, wet after lease separation, an appropriate reduction in the reservoir gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

For dry natural gas, an appropriate reduction in the gas volume has been made to cover the removal of the liquefiable portions of the gas in lease and/or field separation facilities, and in natural gas processing plants, and the exclusion of nonhydrocarbon gases where they occur in sufficient quantity to render the gas unmarketable.

It is not necessary that production, gathering, or transportation facilities be installed or operative for a reservoir to be considered proved. It is to be assumed that compression will be initiated if and when economically justified.

Proved Reserves of Natural Gas Liquids: Proved reserves of natural gas liquids as of December 31 of the report year are those volumes of natural gas liquids (including lease condensate) demonstrated with reasonable certainty to be separable in the future from proved natural gas reserves, under existing economic and operating conditions.

Report Year: The calendar year to which data reported in this publication pertain.

Reserves: (See Proved Reserves)

Reserves Changes: Positive and negative revisions, extensions, new reservoir discoveries in old fields, and new field discoveries, which occurred during the report year.

Reservoir: A porous and permeable underground formation containing an individual and separate natural accumulation of producible hydrocarbons (oil and/or gas) which is confined by impermeable rock or water barriers and is characterized by a single natural pressure system.

Revisions: Changes to prior year-end proved reserves estimates, either positive or negative, resulting from new information other than an increase in proved acreage (extension). Revisions include increases of proved reserves associated with the installation of improved recovery techniques or equipment. They also include correction of prior report year arithmetical or clerical errors and adjustments to prior year-end production volumes to the extent that these alter reported prior year reserves estimates.

Royalty (Including Overriding Royalty) Interests: These interests entitle their owner(s) to a share of the mineral production from a property or to a share of the proceeds



William W. Barnwell, Commissioner

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

3001 PORCUPINE DRIVE

ANCHORAGE, ALASKA 99501

Steve Cowper, Governor



C. V. Chatterton, Commissioner
Chairman of Commission

Lennie C. Smith, Commissioner

BULLETIN

MAY 1988

ADMINISTRATIVE APPROVAL NO. 145-A.32

Administrative Approval No. 145-A.32 was issued on April 4, 1988 to ARCO Alaska, Inc approving flaring of up to 12.5MMSCF of gas at Flow Station #2, Prudhoe Bay, while making tie-ins to the gas coolers. Flaring is to be held to a minimum, shall be metered, and is subject to AS 43.55.020(e).

ADMINISTRATIVE APPROVAL NO. 145-A.33

Administrative Approval No. 145-A.33 was issued April 22, 1988 to ARCO Alaska, Inc approving flaring of up to 28MMSCF of gas at Flow Station #2, Prudhoe Bay, during repair of common lines from drill sites 3, 9 and 7. Flaring is to be held to a minimum, shall be metered, and is subject to AS 43.55.020(e).

ADMINISTRATIVE APPROVAL NO. 232.1

Administrative Approval No. 232.1 was issued on April 7, 1988 to Standard Alaska Production Company approving exceptions to Conservation Order No. 202, Rule 9(b), for sections 1, 3, 7, 9, 10 and 35 in the Duck Island Unit. Although these sections are currently outside the areal gas cap limit, the approval does not preclude wells drilled in these sections from future use as SOC monitoring wells.

Note: Page 4, only, Attached

ESTIMATE OF GAS RESERVES IN ALASKA

Reserves (BSCF)
January 1, 1988

<u>Non-Associated Gas by Field</u>		<u>Associated Gas by Field</u>		<u>Shut-in Gas by Field</u>	
Beaver Creek	177	Beaver Creek	1	Albert Kalos	**
Beluga River	604	Endicott	907	Birch Hill	11
Cannery Loop (Kenai)	300	Granite Point	15	East Umiat	**
East Barrow	8	Katalla	*	Falls Creek	13
Kenai	463	Kuparuk River	634	Ivan River	26
Lewis River	18	McArthur River	25	Kavik	**
McArthur River	600	Middle Ground Shoal	7	Kerik	**
North Cook Inlet	680	Prudhoe Bay,		Moquawkie	**
Pretty Creek	25	Lisburne Oil Pool	406	Nicolai Creek	3
South Barrow	7	Prudhoe Bay,		North Fork	12
Trading Bay	29	Prudhoe Oil Pool	23,441 ***	Sterling	23
Total	2,911	Redoubt Shoal	*	Stump Lake	**
		Swanson River	250	West Foreland	20
		Trading Bay	2	West Fork	6
		Umiat	*	Total	174
		Unnamed Field Pt. Thompson			
		Unit Area	*		
		Unnamed Field Seal Island Area	*		
		Unnamed Field Colville Delta			
		Area	*		
		Total	25,688		

One major addition to Alaskan gas reserves was realized in 1987. The Cannery Loop Unit was under development and slated for 1988 production. Alaskan gas reserves stands at approximately 29 trillion standard cubic feet.

* Insufficient data available for determination of oil reserves in these fields therefore no associated gas reserves may be assigned.

** Reservoir extent as yet undetermined for these reservoirs and lack of operator commitment to produce the gas precludes assignment of reserves.

*** Includes CO₂ at approximately 12% concentration.

STATE OF ALASKA

**HISTORICAL AND PROJECTED
OIL AND GAS CONSUMPTION**

**Steve Cowper
Governor**

**Lennie Gorsuch
Commissioner
Department of Natural Resources**

January 1989

**Prepared for the First Session
Sixteenth Alaska Legislature**

Note: Pages 1-2, 5-7, 11-13, 33-35,
ONLY, ATTACHED

EXECUTIVE SUMMARY

This report compares estimates of the quantity of available Alaskan oil and natural gas reserves with estimates of how much oil (refined products) and gas Alaska will consume in the 15 year period between 1988 and 2002. A revised supply and demand report is issued each year to comply with AS 38.05.183(d), which states:

"(d) Oil or gas taken in kind by the state as its royalty share may not be sold or otherwise disposed of for export from the state until the commissioner determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs. The commissioner shall make public, in writing, the specific findings and reasons on which his determination is based and shall, within 10 days of the convening of a regular session of the legislature, submit a report showing the immediate and long-range domestic and industrial needs of the state for oil and gas and an analysis of how these needs are to be met."

Chapter 1 describes the state's royalty oil program and reviews pending federal legislation which might affect prices of state royalty oil.

Chapter 2 lists high, middle and low estimates of oil and gas reserves, and their respective royalty shares. High estimates assume increasing oil prices and additional enhanced oil recovery efforts, whereas middle and low estimates assume relatively stable oil prices. The lower figures, therefore, are prudent values for long range policy considerations. The middle range oil estimate is 6.8 billion barrels of oil, yielding an 850 million barrel state royalty share. Of this royalty share, 99.0% is attributable to reserves on the North Slope. The middle range estimate of gas is 32.1 trillion cubic feet. The state's share is 3.9 trillion cubic feet. Again, 90.9% of the gas will come from North Slope reserves.

The chapter includes production estimates for a 25 year period. North Slope oil production has peaked at about 2.3 million barrels per day and is expected to begin declining in the next year or two to about 435 thousand barrels per day by the year 2003.

Chapter 3 presents historical data on production and consumption of Alaska oil and gas. Fuel consumption between 1977 and 1988 grew by an average of 9.5% per year from 0.7 to 2.0 billion gallons, while gas consumption in the same period grew an average of 7.5% per year from 205 to 388 billion cubic feet.

Chapter 4 reveals forecasts of expected in-state oil and gas consumption from 1989 to 2003. Alaska will probably consume about 24 billion gallons of fuels and 3.9 trillion cubic feet of gas during that period. Consumption growth rates are forecast to be considerably lower than they have been until now; and between 1989 and 2003, estimated annual growth in consumption will be 1% for both oil and gas.

Chapter 5 compares estimates of state reserves and future production with estimates of future consumption. The comparison shows that Alaska's total supply of oil and gas will be greater than in-state consumption for the next 15 years.

The supply and demand projections in this report are accurate only if their underlying assumptions approximate future events. The demand side of the equation is probabilistic because in-state consumption will be influenced by economic and population growth which in turn will be influenced in a large part by world energy and natural resource prices. For example, development of a new southcentral hydroelectric project (other than Bradley Lake) or a coal-fired electric generation project could dramatically affect the in-state demand for natural gas, particularly after the late 1990s. Future expansion of the natural gas, ammonia-urea or petrochemical export market would similarly affect in-state natural gas availability, as well as prices.

The supply side of the equation is also probabilistic. The middle range estimates of oil and gas reserves, 6.8 billion barrels and 32.1 trillion cubic feet, respectively, are likely outcomes, though the timing of a gas pipeline from the North Slope remains very uncertain and the development of certain proven oil and gas fields beyond the Prudhoe Bay - Kuparuk infrastructure appears unfeasible at today's oil prices. Estimates of undiscovered resources are highly speculative and are not relevant to this projection. Even if these undiscovered resources exist (which they may not), there is no guarantee that they will be discovered or developed in time (or if ever) to assure long-run continuity. For the most part, major oil and gas firms will search for and develop reserves in response to world market conditions, not because of surplus or deficit conditions in Alaska's relatively small intrastate market. In summary,

1 See Appendix D for discussion of statutory definitions.

reasonable assumptions about Alaska's existing oil and gas reserves and future consumption indicate that not only are current reserves more than adequate to meet the demands of Alaskans for the next 15 years, but that significant quantities are surplus to requirements and therefore are available for export from the state.

CHAPTER 2

RESERVE ESTIMATES AND ROYALTY SHARE

Introduction

This chapter discusses estimates of oil and gas reserves in the state and the state's royalty share of these reserves. The reserve estimates have been developed for three different cases. The specific royalty terms of individual oil and gas lease contracts were used to calculate the state's royalty share of the respective reserves in each field. The low range estimates assume falling oil and gas prices and/or poorer-than-predicted reservoir performance. The high range estimates assume rising oil and gas prices and/or better-than-predicted reservoir performance. The middle range estimates assume relatively stable oil and gas prices and predicted reservoir performance.

The estimated reserves and royalty share for oil and gas are shown in Table 2.1. The estimates have been developed separately for Cook Inlet and the North Slope, as different information sources were used for each category. In addition to categorizing reserves by region, reserves are sub-categorized as either "proven and developed" or "proven but undeveloped or shut-in." These sub-categories distinguish those volumes of oil and gas which are readily marketable from those which need additional investment in facilities and transportation systems which will delay bringing the reserves on line.

Oil reserves as of January 1, 1989 are 6.80 billion barrels. For comparison, the U. S. Department of Energy estimate for January 1, 1988 was 7.38 billion barrels; the Table 2.1 figure extrapolated back to January 1, 1988 is 7.45 billion barrels.

Cook Inlet

Considerable historical and subsurface information is available about the oil and gas reserves and potential in the Cook Inlet area. While there has been a renewed interest in Cook Inlet exploration and remedial field work, it is not anticipated that significant new reserves will be added in the near future. Recent changes in working interest ownership of several Cook Inlet gas fields will likely result in development of these currently shut-in fields. The reserves are assumed to remain constant for low, middle and high range estimates. Cook Inlet reserves account for about 1.8% of the low, 1.2% of the middle, and 0.8% of

the high estimates of statewide total oil and gas reserves.

North Slope

Oil and gas reserve estimates shown in Table 2.1 are for currently leased state lands. North Slope oil is produced from the Sadlerochit and the Lisburne reservoirs in the Prudhoe Bay Unit, the Kuparuk River reservoir in the Kuparuk River Unit, and the Endicott reservoir in the Duck Island Unit. Production from the Kuparuk River reservoir in the Milne Point Unit was shut-in January 1987 and remains shut-in.

Additional enhanced oil recovery operations at Prudhoe Bay Unit, over and above those already planned, recovery of additional gas condensate and gas liquids from the Sadlerochit and Lisburne gas caps and enhanced oil recovery from the Kuparuk and Lisburne reservoirs represent an oil resource (versus oil reserves) of about two billion additional barrels of liquids which may or may not be economically recoverable sometime in the future. The economics of enhanced oil recovery operations are extremely sensitive to incremental capital costs, changing markets and expected wellhead crude oil prices. Systematic recovery of liquids from the Sadlerochit and Lisburne gas caps (and absent major gas sales, simultaneous reinjection of the dry gas back into the reservoirs) would require additional investment by the respective gas cap owners. Depending on the nature of the liquids recovered and intended for sale, the owners of the Trans-Alaska Pipeline System (TAPS) may also have to invest in additional infrastructure, as well as retrofit existing pipeline, storage and shipping facilities to ship these gas liquids. In the fall of 1988, the three major gas owners in the Prudhoe Bay Unit (ARCO, Exxon and BP America) announced that a major new gas project they were reviewing (called "Super Spike") did not appear to be economically feasible at that time.

Installation of the world's largest central gas facility at Prudhoe Bay in 1986 is designed to recover gas liquids and gas condensate from the produced gas stream and it is a major step in establishing the infrastructure that will be needed to proceed with any future large-scale gas sales or expanded gas cycling or liquid recovery project.

TABLE 2.1

[1] As of 1/1/09. Alaska Oil and Gas Conservation Commission, "Estimate of Oil Reserves in Alaska" and "Estimate of Gas Reserves in Alaska", adjusted for 1980 production.
 [2] As of 1/1/09. William Van Dyke.
 [3] Oil and gas condensate.
 [4] Reduced for CH₂ content relative to 1980 report; not reduced for future in-field fuel use.
 21.12.19/00

The currently configured plant will recover propane, butane and heavier hydrocarbon liquids from the produced gas stream and it could be modified to recover ethane. Significant volumes of these three products could be shipped through TAPS if the pipeline system and the storage and loading facilities at Valdez were modified. However, until a long term market can be identified for some or all of these three products, no major new gas liquids project will go forward.

The possibility for conversion of any of the above mentioned resources to the proven reserves category and the timing of that conversion must be viewed with extreme caution at this time. However, because billions of barrels of oil will remain in the ground at the Prudhoe Bay and Kuparuk River Units after completion of primary and secondary oil recovery operations, sufficient economic incentives to develop additional economic means of enhanced oil recovery will exist well into the future. For instance, in the Prudhoe Bay Unit Sadlerochit Reservoir, some 12 billion barrels of oil will remain in place if the current ultimate recovery estimate of 10.8 billion barrels holds true. The original ultimate recovery estimate of 9.6 billion barrels has slowly increased to the current 10.8 billion barrel level - hopefully, new enhanced oil recovery technologies, increased infill drilling and horizontal drilling advances can increase the 10.8 billion barrel figure even further. New techniques of using the gas liquids in the reservoir gas caps could also add significantly to the ultimate recovery figure.

Various North Slope leaseholders continue to experiment with techniques to economically produce the vast amounts of "heavy," low gravity oil held in the shallow Tertiary and Cretaceous age sands primarily located west of Prudhoe Bay field. Technology and equipment already exist to produce these types of oil deposits in more temperate, less costly operating and marketing climates. However, permafrost considerations, surface-related permitting, construction and operating constraints, and the projected wellhead price of the produced oil to date have combined to stymie any commercial development of these relatively shallow (but very large) resources. One major pilot production project has been completed by ARCO in the Kuparuk River Unit and laboratory research continues in an effort to improve project performance and economics. ARCO has applied for permits to conduct a second major "West Sak" pilot production project

in the Kuparuk River Unit. A larger well spacing pattern will be used relative to the first pilot and various well bore completion techniques will again be tested in an attempt to improve individual oil well production rates. A water flood will also be conducted to test the influence of the wider well spacing on oil recovery and well performance.

Conoco has received approval to drill two test wells in Milne Point Unit to test the extensive shallow oil sands in that unit. Conoco has also applied to continue the suspension of production at Milne Point Unit through 1989. Shut-in production in Milne Point Unit comes from the deeper Kuparuk Formation.

Technology exists to produce in the range of 300,000 bpd of oil from the shallow north slope oil sands, but current economics do not appear to favor full-scale development. In the Kuparuk River Unit, the Kuparuk River reservoir owners and the West Sak reservoir owners need to approve a facilities-sharing agreement because it will greatly reduce the future West Sak development costs. As Kuparuk oil production facilities become underused and available in the 1990s, it is anticipated that the West Sak reservoir can be brought on line to fill them. Development of the West Sak reserves will also require drilling many hundreds of additional wells and the construction of many more drillsites and pipelines. If and when Milne Point Unit resumes production, the unit's two groups of owners might share facilities in a similar way.

Tables 2.2 and 2.3 list production forecasts for some of the fields listed in Table 2.1. Figure 2.1 graphically portrays these estimates. North Slope oil production is expected to decline in 1989. The decline will begin earlier and will be more gradual than earlier forecasts indicated. Oil production from state-owned lands will decline through the 1990s.

Currently, natural gas is not exported from the North Slope. Both the Alaska Natural Gas Transportation System (ANGTS) and the Trans-Alaska Gasline System (TAGS) are proposed means of moving North Slope gas to market. To date, neither project has secured financing or a guaranteed market. The continued volatility and uncertainty in prices for oil and gas, the relatively abundant worldwide supplies of natural gas, and the sheer magnitude and cost of the proposed pipeline projects combine to make the prospective purchasers of the gas, the financial institu-

tions, and the projects' sponsors all very cautious at this time. Efforts to secure markets for the gas are continuing. However, start up of the ANGTS or TAGS project cannot be expected until financing for one or both projects is arranged, and financing likely will not be finalized until long-term sales agreements for the gas are guaranteed. In addition, the owners of the gas (primarily ARCO, Exxon and BP America) have not agreed to sell the gas to either pipeline company or any of the potential end users. In addition, pending legislation in Congress which would open ANWR to exploration and development would prohibit the construction of pipelines eastward through designated wilderness areas adjacent to the U. S. - Canada border.

During 1988 Esso Resources Canada and Shell Canada applied to the Canadian National Energy Board for permission to export gas from the Canadian Beaufort Sea and MacKenzie River Delta to the United States. This project, while it would be in direct competition with Alaskan North Slope gas for potential U. S. markets, might be an incentive to re-evaluate the once-proposed gas line from Prudhoe Bay east across the Arctic National Wildlife Refuge to the Canadian MacKenzie River Delta area. Such a pipeline probably would be much cheaper to build than either ANGTS or TAGS. At this time no estimates of transportation costs are available for this type of proposal.

Several noteworthy oil and gas related events occurred in 1988. Production at the Milne Point Unit remained suspended. All the facilities have been left in place so that production can be restarted. Conoco, the unit operator, stated that oil prices were not high enough in 1988 to resume day-to-day operations. Conoco also stated that oil prices must be in the 18 to 22 dollar per barrel range for Milne Point field to produce at a profit. On the brighter side, the Endicott field (Duck Island Unit) in the Beaufort Sea completed its first year of operation. Rates are expected to average 100,000 bpd through 1991, then decline.

During 1988 the 8,000th tanker load of oil was shipped from Valdez terminal. Over 6 billion barrels of oil have been shipped from Valdez since 1977.

Standard Alaska Production Company proposes to develop the Niakuk reservoir, located about one mile offshore in the Beaufort Sea just north of Prudhoe Bay. Standard estimates that the reser-

voir could produce up to 20,000 bpd of oil beginning in 1992 if development plans are approved in a timely manner. The proposal includes a 6,600 foot ground fill causeway which state and federal agencies are now reviewing. The U. S. Army Corps of Engineers has issued a preliminary finding that the causeway is unacceptable as proposed. Standard may have to substantially modify the project to gain approval or the project may not be approved at all.

In early 1988, Alaska became the number one oil producing state in the nation. However, with the recent decline in production at Prudhoe Bay, Texas has again regained the number one producing spot. During October 1988, Texas and Alaska averaged 2.065 and 2.000 million barrels per day of oil, respectively. Alaska continues to supply almost 25 percent of the nation's domestic oil supply. Figure 2.2 compares Alaska's oil production with that of other major oil producing countries. Figure 2.3 compares Alaska's projected oil production with that of the lower 48 states. In February Kuparuk River Field set an in-field production record of 322,000 bpd. Field average for 1988 probably will be 280,000 bpd.

The current 1.45 million bpd crude oil production rate at Prudhoe Bay (an additional 0.1 million bpd of gas condensate and liquids are also produced) is expected to continue its slow decline in 1989. The actual rate of the decline will be influenced by the level of infill development drilling, rate of development of the West End and P Pad areas of the field, scheduling of well workovers and equipment repairs, water and miscible gas injection rates, and the capabilities of the installed and to-be-installed gas handling facilities. The Prudhoe Bay owners have approved the construction of GHX-1, a major new gas handling expansion project. The project is designed to boost the amount of gas that can be produced, handled and reinjected from about 3.5 billion cubic feet per day to just over 5 billion cubic feet per day. Bottlenecks in gas processing facilities and insufficient gas compressor capacity are causing a gas overload in the field production facilities. Oil production rates are being cut back because the gas processing facilities cannot handle all the gas associated with the higher oil rates. The oil production rate in 1989 is not expected to reach the allowed annual average 1.5 million barrels per day. Start up of the GHX-1 facilities in the fall of 1990 will alleviate some of the gas overload. The producers are already studying a second project,

GHX-2, which would be designed to boost the gas handling capacity in the field to about 7.5 billion cubic feet per day.

Start-up of the GHX-1 project (and the potential for the GHX-2 project) will help slow the decline of oil production at Prudhoe Bay. If additional gas handling facilities are not installed, the decline will be much more rapid than currently anticipated. In relative terms, more and more gas will be produced along with each barrel of oil as oil production continues over the years. If this additional gas cannot be processed and reinjected, the oil production rate will have to be cut back even further.

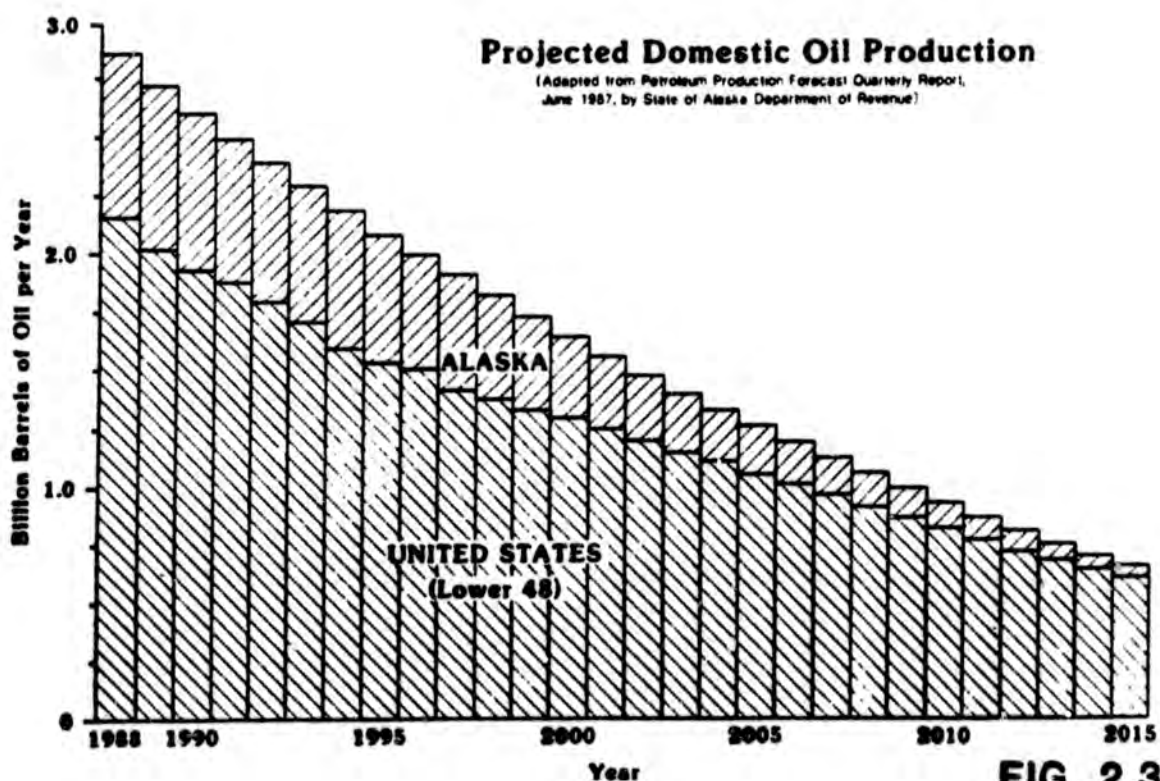


FIG. 2.3

CHAPTER 3

HISTORICAL OIL AND GAS PRODUCTION AND CONSUMPTION

Oil Production

All Alaska oil is produced from Cook Inlet and the North Slope. Cook Inlet fields began production in the late 1950s and peaked by 1970; some of the fields are now near depletion. The region has produced a cumulative total of 1.1 billion barrels of crude oil, but for the last ten years, annual production has fallen from 56 million barrels in 1977 to 16 million barrels in 1988. Prudhoe Bay began commercial production when the Trans-Alaska Pipeline System (TAPS) opened in 1977. Since then the region has produced 6.6 billion barrels of crude oil. Production from this region is expected to peak in 1988 at 706 million barrels per year. Regional and state production data are presented in Table 3.1 and Figure 3.1.

Oil Consumption

All the oil consumed in Alaska is consumed as refined fuels, some of which is refined in-state and some of which is imported. Though no data source satisfactorily reports how much fuel is refined in state nor how much is imported, Department of Revenue (DOR) reports of fuel sales for 1977 to 1988 indicate how much fuel is consumed in state. Data quality from 1977 to about 1984 are unconfirmed, but data from 1985 to 1988 are considered good. Throughout the 11 year reporting period, consumption goes from 750 million gallons per year to 1,961 million gallons per year. Fuel sale data are reported in Table 3.2 and Figure 3.2.

Gas Production

As with oil production, virtually all of Alaska's natural gas is produced from Cook Inlet and the North Slope immediately adjacent to the Prudhoe Bay Unit complex. Production from two small gas fields near Barrow is the only exception. Cook Inlet produces both casinghead and dry gas from a mix of oil fields, gas fields and oil fields with gas caps. Gas production from this region began in the late 1950s and peaked between 1982 and 1984. Cumulative production is 3.4 trillion cubic feet, net of injection, including the 191 billion cubic feet produced in 1988.

North Slope gas production is a by-product of oil field development. The only market for the gas is as fuel for field and pipeline operations and consequently, operators inject 80% of the gas back

into the reservoirs. A cumulative 1 trillion cubic feet, net of injection, have been produced, including 209 billion cubic feet produced in 1988. Table 3.3 and Figure 3.3 show state and regional gas production from 1971 to 1988.

Gas Consumption

The Cook Inlet region's major natural gas feature is its pipeline connections to local markets which this past year consumed 171 billion cubic feet, net of injection. The major users were: LNG, 31% of net production; ammonia-urea production, 20%; electricity generation, 19%; and gas utilities, 13%. An additional 20 Bcf were consumed in field operations.

In contrast to the Cook Inlet region, the North Slope region produces an immense amount of casinghead gas but, as mentioned above, the only market for this gas is as fuel for the oil production facilities. Field operations consumed most of the 1988 net North Slope production (150 billion cubic feet) and an additional 18 billion cubic feet were sold to TAPS. Table 3.4 and Figure 3.4 show state and regional gas consumption data from 1971 to 1987. It is interesting to note that, in 1987 and 1988, field operations alone in the Prudhoe Bay region consumed more gas than total commercial use in Cook Inlet.

APPENDIX C

DEFINITIONS OF STATUTORY TERMS

AS 38.05.183 states that oil and gas taken in-kind as the state's royalty share of production may not be sold or otherwise disposed of for export from the state until the Commissioner of Natural Resources determines that the royalty-in-kind oil or gas is surplus to the present and projected intrastate domestic and industrial needs for oil and gas.

The statute contains several key terms whose meaning must be resolved before an estimate can be made of oil and gas surplus to the state's needs. These key terms are: 1) "oil and gas," 2) "export," 3) "present," 4) "projected," 5) "domestic," 6) "industrial," 7) "intrastate," and 8) "how these needs are to be met." Each key term affects the size of the estimated demand for oil and gas in Alaska and consequently, the size of the projected surplus or deficit. The meaning of each term is discussed below.

"OIL AND GAS"

Crude oil and natural gas are fluids containing hydrocarbon compounds produced from naturally occurring petroleum deposits. Typical crude oil contains several hundred chemical compounds. The lightest of these are gases at normal temperatures and pressure, described as "natural gas." These light fractions of the crude oil stream include both hydrocarbon and non-hydrocarbon gases, such as water, carbon dioxide, hydrogen sulfide, helium, or nitrogen. The principal hydrocarbons are methane (CH₄), ethane (C₂H₆), propane (C₃H₈), butanes (C₄H₁₀), and pentanes (C₅H₁₂). The gaseous component found most often and in largest volumes is, typically, methane. Heavier fractions of the crude stream are usually liquids. If a given hydrocarbon fraction is gaseous at reservoir temperatures and pressures, but is recoverable by condensation (cooling and pressure reduction), absorption, or other means, it is classified by the American Gas Association (AGA) as a natural gas liquid (NGL)². Natural gas liquids include ethane if ethane is recovered from the gas stream as a liquid. A related term is liquefied petroleum gas (LPG), composed of hydrocarbons which liquefy under moderate pressure under normal tempera-

tures. LPG usually refers to propane and butane. A second related term is condensate, which refers to LPG plus heavier NGL component (natural gasoline). The lightest hydrocarbon fraction is methane, which is almost never recovered as a liquid, and which makes up the bulk of pipeline gas. If a natural gas stream contains few hydrocarbons which are commercially recoverable as liquids, it is considered "dry gas" or "lean gas." The distinction between "wet" and "dry" is usually a legal one, which varies from state to state. "Crude oil" usually means the non-gaseous portion of the crude oil stream.

Natural gas may occur in reservoirs which are predominately gas-bearing or in reservoirs in which the gas is in contact with petroleum liquids. Non-associated gas is natural gas from a reservoir where the gas is neither in contact with nor dissolved in crude oil. Associated gas occurs in contact with crude oil, but is not dissolved in it. A gas cap on a crude oil reservoir is a typical example of associated gas. Dissolved gas is dissolved in petroleum liquids and is produced along with them. Dissolved and associated gases are usually good sources of NGL while non-associated gases are often "dry."

The distinction between natural gas and its NGL components is important to a study of the supply and demand of royalty oil and gas because natural gas liquids have a multitude of uses when separated from the gas stream. For example, propane is both produced in Alaska and sold in Alaska as bottled gas for residential, commercial, and limited transportation uses, while butane is used for blending in gasoline and military jet fuel and as a refinery fuel. In addition, Marathon Oil uses LPG to enrich crude oil at its Trading Bay facility. It ships the combined fluids to the Drift River terminal for export³. Potential uses for NGL also include the enriching ("spiking") of pipeline gas and crop drying. Several years ago the Dow-Shell Petrochemical Group and Exxon studied the feasibility of utilizing the NGL contained in Prudhoe Bay natural gas as the basis for an Alaska petrochemicals industry. Since the state has the option of considering NGL separate-

2 Definitions vary with process.

3 Kramer, L., Williams, B., Erickson, G., In-State Use Study for Propane and Butane. Prepared for the Department of Natural Resources by Kramer Associates, Juneau, October 1981.

ly from the gas stream, two definitions of natural gas consumption and reserves are possible. One of these would consider natural gas liquids as part of the gas stream. The second definition would treat the markets for LPG and ethane separately from those for gas. This requires a separate estimate of LPG consumption and gas liquids reserves. In this report, demand for LPG and ethane is estimated separately from that for gas; however, no separate estimate is made of gas liquids reserves.

"EXPORT"

Taken in context, this term appears to mean the direct physical shipment of oil and gas out of the state. However, when one considers the fact that much of Alaska's industrial use of oil and gas is processed directly for export markets, the meaning of export versus "intrastate" is not so obvious. For example, it appears that processing of gas into another product, e.g., anhydrous ammonia, would probably be an "industrial" use rather than "export" of gas, even though the ammonia is mostly exported. Liquefaction to change the phase of the gas is a less obvious case. The liquefaction of natural gas is considered a transportation process in this report. Still more troublesome is the use of gas and oil for transportation related to export. Is the gas and oil consumed in TAPS pipeline pump stations, for example, an "industrial" use in state? Or is it really "export" of that energy, since it is consumed in the exporting process? There is no reason why the state may not be approached in the future to commit royalty oil and gas to quasi-export uses. Indeed, ALPETCO (later, Alaska Oil Company) made a top dollar offer for royalty oil ultimately destined (as petrochemical products) for out-of-state markets. Though they made the offer, they did not make payments in full. Also, the state once committed royalty gas to the El Paso gas pipeline proposal for export of Prudhoe Bay gas, which involved liquefaction. Neither proposal was clearly for in-state industrial use. In this report, industrial demand is treated with multiple definitions as outlined later in the chapter to show how different definitions of "export" affect the estimate of total consumption in Alaska.

"PRESENT"

The problem here is that the term "present" may mean "latest year" consumption, "average recent year" consumption, "weather-adjusted" consumption, or "worst case" consumption. In the residential and commercial sector particularly, each

definition gives a somewhat different answer because of the variability of weather.

The "worst case" consumption calculation can result in considerably higher gas consumption than the most recent year, if the most recent year happens to have been a relatively warm one. While it is not correct forecasting procedure to make long run forecasts of intrastate residential consumption of natural gas which assume worst case forecasts for every year, it may be prudent in practice to reserve part of the the State's gas and oil supply for bad weather. For forecasting, variability of weather makes the picking of a starting value for consumption somewhat tricky. In this report, Rail Belt consumption is based on average weather years. For the remainder of the state, trended per capita consumption is used, which approximates average weather conditions.

"PROJECTED"

This is a very difficult concept, since many different projections of consumption would be possible even if it were possible to agree on a single concept defining consumption. Rates of economic development, population growth, and relative energy prices are key features of any consumption forecast, but assumptions concerning any of these variables are necessarily controversial. This report describes a range of possible consumption figures under precisely articulated definitions of consumption and varying paces of economic, population, and fuel price growth.

"DOMESTIC"

Domestic consumption appears to mean Alaska residential consumption. As we saw above under the subheading "present", it is not at all obvious which definition of domestic consumption is the most appropriate, even when the identity of the customer is not in dispute. Some multifamily residential use may be described as "commercial", obscuring the definition of the customer and causing forecasting problems for natural gas. The definition of "domestic" considered in this report includes multifamily residential in "residential" or "domestic" use.

"INDUSTRIAL"

As described above, "industrial" energy use has a number of potential definitions. Since one intent of giving in-state industrial needs priority over export uses of royalty oil and gas seems to be encourage in-state economic activity,⁴ a day-to-day working definition of this industrial priority is

⁴ However, see the short discussion of legislative intent beginning on page 9 of Kramer, Williams and Erickson, op.cit. That study raises many of the issues regarding surplus gas and oil discussed in this report.

that the royalty reserves be committed to the market which has the largest potential economic impact in Alaska. For forecasting purposes, however, it is difficult to say which markets will prove to be of the most economic benefit to the state. As a compromise, we will adopt four alternative definitions of "industrial" in this study.

The four alternative definitions of industrial use of oil and gas used in this report are outlined below, beginning with the most restrictive and moving to the most liberal.

DEFINITION 1: Industrial use consists of any consumption of natural gas, petroleum, or their products in combustion (except that required to export oil or gas); or the chemical transformation of natural gas, petroleum, or their products into refined products for local markets. This definition explicitly excludes the exported products from refineries, as well as uses which merely change the physical form of the product (gas conditioning or liquefaction) for export, or which move the product to an export market (pipeline fuel, fuel used on lease, shrinkage, injection, vented and flared gas).

DEFINITION 2: Industrial use consists of any consumption of natural gas, petroleum, or their products in combustion (except in oil and gas production and transportation); or the chemical transformation of natural gas, petroleum, or their products into refined products. This definition counts feedstocks for petrochemical plants and refineries as industrial consumption. It also counts energy consumed by an LNG facility as industrial consumption. It excludes the feedstocks of LNG plants; and fuel consumption by conditioning plants, pump stations, fuel used on lease, shrinkage, injection and flared gas.

DEFINITION 3: Industrial use consists of any consumption of natural gas, crude oil, or their products in combustion (except in oil and gas transport and extraction) or their chemical transformation into refined products. This definition permits the feedstocks of refineries to be counted as industrial consumption. It excludes fuels used in pump stations, in conditioning plants, fuel used on lease, and gas shrinkage, injection, or venting.

DEFINITION 4: Industrial use consists of any use of natural gas, crude oil, or their products in combustion, or their transformation into chemically different products. This definition permits feedstocks of refineries to be counted as industrial

consumption, as well as energy consumption in conditioning plants and pump stations. It excludes injected gas, which is ultimately recoverable for other uses, and LNG processing, which is considered an export. Definition 4 will be used for the purposes of this report.

None of the four definitions treats industrial use (including transportation) to include gas injected to enhance oil recovery, since in theory this gas remains part of the ultimately recoverable gas reserves of the state. Thus, it is not "consumed."

"INTRASTATE"

It is unclear what is meant by intrastate consumption. Some uses, such as combustion of oil and gas products in fixed capital facilities in Alaska, are reasonably easy to categorize as intrastate. There are several uses in transportation which are not obviously within Alaska. These categories include the fuel burned in marine vessels such as cargo vessels, ferries, and fishing boats, and fuel burned in international interstate air travel. There are multiple ways to approach the definition of this consumption. The first is a sales definition: the fuel used in transportation which is sold in Alaska. The second approach is to base consumption on fuel used in Alaska or related to Alaska's economy and population, regardless of the point of sale. This results in three logical definitions, described below:

DEFINITION 1: Intrastate consumption in transportation includes all sales of fuels to motor vehicles, airplanes, and vessels in Alaska, including bonded fuels. It excludes fuel consumed by motor vessels which was purchased in other states, and fuel consumed by airlines between Alaska locations unless the fuel was sold in Alaska. It also excludes out of state military fuel purchases.

DEFINITION 2: Intrastate consumption includes fuel consumed by motor vessels, airlines, and vehicles engaged in Alaskan economic activity. It includes use of fuel by American fishing boats in Alaskan waters regardless of where the fuel was purchased, use of fuel purchased in Washington State by Alaska State ferries, and fuel consumed by ships and aircraft involved in Alaska trade. It excludes sales to aircraft on international flights (bonded and unbonded), but includes military out of state purchases.

DEFINITION 3: The final definition is a compromise between the first two. It includes all fuel purchased within the state, plus military uses, but

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1988 GRI Baseline Projection of U.S. Energy
Supply and Demand to 2010

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December 1988

Foreword

This report summarizes the 1988 GRI Baseline Projection of U.S. Energy Supply and Demand, which has been adopted as a major input to the planning cycle leading to the development of Gas Research Institute's (GRI) 1990 research and development program. The baseline projection represents the GRI planning outlook for the economic and energy supply and demand situation to the year 2010. The 1988 projection was developed independently by GRI using publicly available data and a framework of commercially available models that GRI has modified over several years. It is not derived from the views of GRI member companies.

Strategic planning of GRI's R&D program requires an appreciation of the outlook for national energy supply and demand and an estimate of the role that natural gas will play within that outlook. Another key element in GRI's R&D program planning is an assessment of the benefit that would accrue from the successful development of each individual research project being evaluated for funding. The development of a consistent framework that establishes a likely projection of future energy supply and demand is critical to this assessment process. The framework that forms the scenario and data base for these planning decisions is called the baseline projection. The baseline projection supports the strategic planning of the GRI R&D program--the selection of

• NOTE - Page 98, only,
Attached

significant after 1995. Throughout the entire projection period, resource depletion accounts for about two-thirds of the growth in wellhead prices, and the other factors account for the remainder.

Alaska Natural Gas Via ANGTS

- o The Alaska natural gas transportation system (ANGTS) is assumed to begin operation in 2007 at a throughput of 0.7 quad per year. In 2010, its throughput is expanded to 1.2 quads per year.
- o The fixed price component of ANGTS deliveries is based upon the cost estimates of the pipeline consortium in 1982. Because of competitive pressures, the wellhead price for ANGTS gas is held fixed at \$1.00 per MMBtu (1987\$) until the total price of ANGTS gas delivered to the lower-48 equals the Canadian border price. Thereafter, the wellhead price of ANGTS gas increases as the ANGTS price tracks the Canadian border price.
- o Recently, the principal sponsors of ANGTS have reevaluated the capital costs. This analysis has reduced the capital costs for ANGTS by almost 45 percent. This would mean that ANGTS gas could be competitive with lower-48 wellhead prices in the 1988 GRI Baseline Projection when it is introduced in 2007.

Pipeline Imports

- o Real prices for pipeline imports at the border are set on a competitive basis with lower-48 wellhead prices. Prices vary, however, depending upon the point of competition. If the border export point is a producing region in Canada, then the import price is determined by the marginal wellhead gas price. If the export point is a consuming region, then the import price is determined by the regional citygate

STATEMENT OF JAMES T. JENSEN

IN THE MATTER OF

**YUKON PACIFIC CORPORATION
ERA DOCKET NO. 87-68-LNG**

on behalf of

ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION CO.

**JENSEN ASSOCIATES, INC.
Boston, Massachusetts**

PREPARED STATEMENT OF JAMES T. JENSEN
ON BEHALF OF
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

IN THE MATTER OF
YUKON PACIFIC CORPORATION
ERA DOCKET NO. 87-68-LNG

Public Conference
January 24, 1989
Anchorage, Alaska

Prepared by
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JENSEN ASSOCIATES, INC.

Introduction

James T. Jensen, President of Jensen Associates, Inc., an independent energy economics consulting firm, has been asked by Alaskan Northwest Transportation Company to provide an independent judgment on two issues pertinent to the application by Yukon Pacific Corporation (Yukon Pacific) to export Alaskan gas to Japan. These issues are the following:

- (1) Are there sufficient proved and economically transportable gas reserves on the North Slope to warrant construction of two major large-diameter pipeline systems in the same time frame?
- (2) Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries in the years ahead?

This statement addresses those issues.

Overview Implications of the Yukon Pacific Application for ANGTS

The decision which the Economic Regulatory Administration (ERA) is being called upon to make in this application is without precedent in the U.S. or international gas experience. The decision will inevitably have a major influence on the way in which the pipeline infrastructure ultimately develops for transporting natural gas from Alaska's North Slope to market. The major risk inherent in this decision is that the size and quality of the proved reserves on the North Slope are not adequate to support the construction of two independent transportation infrastructures for Pacific and U.S. gas markets. In such a case the award of this application to Yukon Pacific runs the risk of prejudicing the ultimate construction of a transportation link between North Slope gas and Lower 48 states markets. Further development of the North Slope gas resources could then become dependent on energy market developments in the Asian countries rather than on those in the United States. The public interest implications of ERA's decision in this matter are thus long-term and strategic in nature.

The natural gas industry in the United States is the oldest and most mature gas industry in the world. Most of the pipeline infrastructure on which the transportation of gas from the

producing regions to markets depends was in place by the early 1950's. With the movement to market-responsive pricing and open transportation, gas in the Lower 48 states is approaching commodity status.

From a U.S. gas industry perspective, therefore, it may be difficult at first to recognize that the policy decision we are discussing in this proceeding, in fact, bears far greater resemblance to the decisions which are being addressed today in countries such as Norway or Nigeria, than it does to any gas policy issue that the United States has ever had to face. For Norway and Nigeria, as with many countries throughout the world, proved reserves of natural gas far exceed any foreseeable local market, and the prospect of developing "mega-projects" to export the gas to other markets is under active discussion. Similarly for Prudhoe Bay gas, local markets on the North Slope are virtually non-existent and it requires a "mega-project" to "export" the gas to any reasonably sized consuming region. This includes not only the international markets of the Pacific Rim countries, but also "export" to the Lower 48 states.

There are two very significant differences between the decision we are discussing today and that which other potential gas exporters face. First, the remoteness of Prudhoe Bay from markets and the very high costs of Arctic construction virtually guarantee that any transportation infrastructure will be one of the most expensive private sector energy projects in the world. It thus forces the project to take maximum advantage of economies of scale and minimize the costs of field development, gathering and treatment if it is to have any hope of economic viability. And second, because the infrastructure of the TAGS and ANGTS systems is so different, there is little prospect that the two systems will provide substantial mutual economic support for one another. Norway's North Sea pipeline grid system to the Continent, in contrast, does not foreclose the possibility of future shipments to the U.K. nor does it make it difficult to "piggyback" a U.S.-oriented LNG project onto the grid as Norway has just announced. And Nigeria's proposed LNG liquefaction facility at Bonny similarly does not preclude shipments to either Europe or the U.S.

The requirement that the infrastructure be largely duplicated for both TAGS and ANGTS together with other key issues discussed below, however, may effectively force the ERA to make an either/or choice between the two projects.

Specific Issues in Delivering Alaskan Gas Economically to the Lower 48 States

A critical element of the ANGTS project and presumably also of the TAGS system is the issue of minimizing the costs of transporting Alaska gas from the wellhead to market. In general, there are three areas in which project planners can address this issue. They are by:

- o taking advantage of economies of scale in constructing pipeline facilities to minimize costs;
- o minimizing the costs of finding, developing and gathering gas; and
- o reducing the costs of financing to the lowest extent possible.

In pipelining, economies of scale are a significant factor since substantial savings can be achieved through the use of larger diameter pipe if flows warrant. In effect, capacity increases much more rapidly with increasing diameters than does pipeline investment.

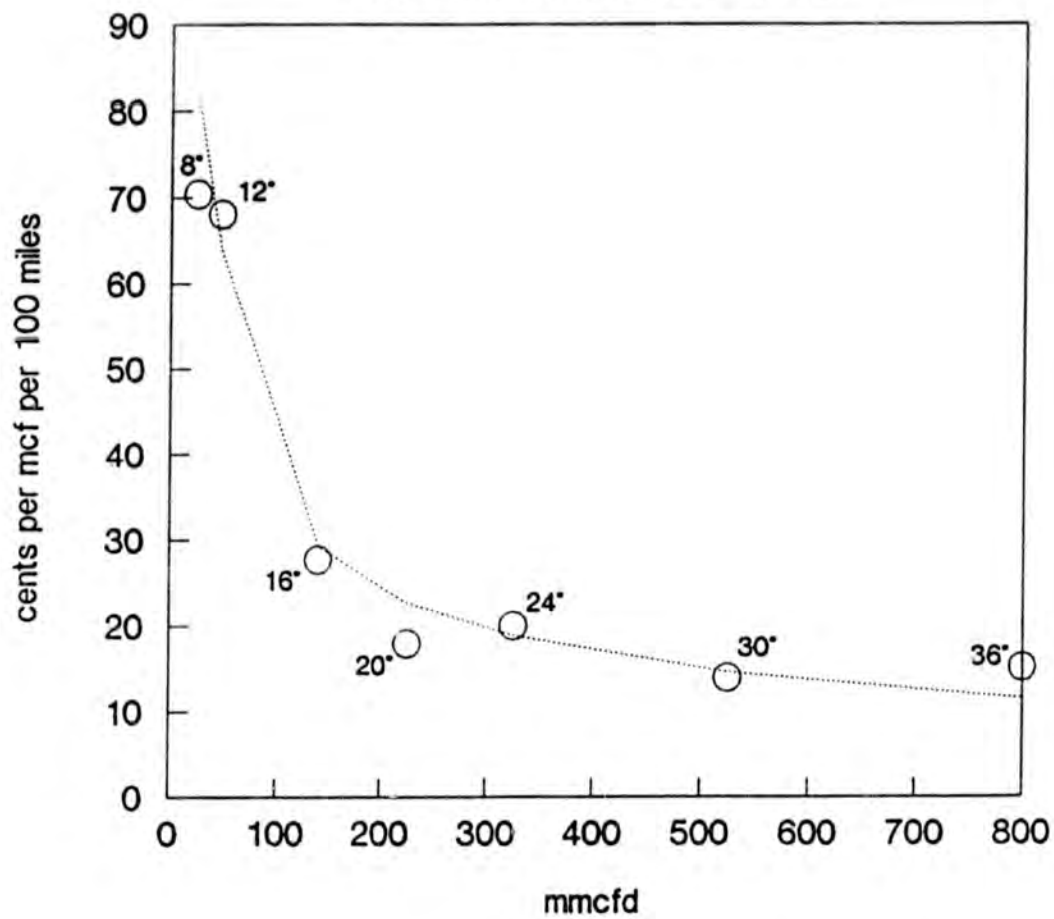
Figure 1 shows the effect of pipeline diameter and thus throughput on the costs of moving gas per 100 miles of pipeline. It is based on onshore pipeline investment costs for 1987 as reported in the Oil and Gas Journal. Alaska pipeline investment costs for Arctic terrain will be much higher. (In order to minimize pipelining costs within Alaska, the ANGTS has resorted to an even larger pipe size with commensurately higher throughputs than is shown in Figure 1.) As a result of its use of a 36 inch pipe diameter pipeline, the TAGS LNG project, at its ultimate design level would be more than twice the size of the largest existing LNG project anywhere in the world.

Issue One: Are there sufficient proved and economically transportable gas reserves for two major pipeline systems in the same time frame?

Because of the size of the ANGTS and TAGS projects, they each require the commitment of very large quantities of proved reserves

FIGURE 1

Cost Of Service As A Function Of
Pipeline Capacity
At 100 % Load Factor



○ Derived From 1987 Costs

if they are to be financeable. The ANGTS project has always assumed that it will require the entire 26 TCF of Prudhoe Bay Sadlerochit reserves if it is to be viable. And even the 16 TCF of reserves which the TAGS project requires represents more than 50% of all reserves remaining on existing contracts from the six countries exporting to Japan, Korea, and Taiwan combined.

This raises the major question as to whether enough relatively low cost, quality proved reserves exist on the North Slope to finance both projects. The final financing will be subjected to very close scrutiny by the lending agencies to assure them that the projects will be economic. This will undoubtedly require both an economic feasibility study with guarantees of wellhead prices in the form of contracts or other binding assurances of gas cost, as well as concrete evidence that there are sufficient proved reserves to guarantee that the pipeline will remain full. For such a feasibility study, vague promises of the potential of discovered but undeveloped reserves or resources will be inadequate. The lending institutions will want to be assured of the costs of the gas as well as its physical availability.

The mining industry uses the term "highgrading" to describe the process of taking out the richest and thus most profitable portion of the ore body first. Basing the development of any gas transportation infrastructure on those reserves which are the least expensive to develop and gather is a form of "highgrading" and will benefit the project which is first able to utilize Prudhoe Bay gas.

It is here that the great concern about the quality of the reserves which will be available after Prudhoe Bay becomes important. Prudhoe Bay is the fifth largest accumulation of natural gas ever discovered in the world outside the Soviet Union and the Middle East. Its reserves are proved in every sense of the word, and much of the costly field facilities which would be required to deliver it to the pipeline inlet are already in place. Gathering lines, some gas compression, and even a portion of the gas processing facilities required to make the gas of pipelineable quality have already been built. The economics of the further gas reserves which would be needed to support a second pipeline are largely unknown. Even the highly regarded Point Thompson gas condensate discovery near Flaxman Island has not been developed sufficiently to warrant inclusion in the proved reserves category of either the U.S. Energy Information Administration or the Alaska Oil and Gas Conservation Commission. Thus the ultimate cost of its gas is largely unknown at this point and could be high.

The experience of several overseas projects and their concern with the development costs associated with particular reserves is instructive. The first example is in Pakistan. The Sui gas field in that country would rank as the world's sixth largest outside the Soviet Union and the Middle East. It has been the basis for the development of the gas industry in that country. The World Bank uses Pakistan to illustrate one of its contentions regarding gas development economics in an Energy Department Paper. In the paper it says of Pakistan:

In Pakistan, the large volumes of gas production and economies of scale in production and transmission lead to low supply costs. The marginal cost for different gas fields are presented in Table (sic) 4. Pakistan has a relatively mature gas industry, and the production to reserve ratio as been increasing. It is now producing from its lower cost fields. As demand increases and supply from these fields fall, the more expensive fields will come under operation.⁽¹⁾

The accompanying Figure 4 is included here as Figure 2.

It is the risk of forcing ANGTS to rely on fields which may be much more expensive to develop than Prudhoe Bay which is the major concern here. Other examples of this sort of concern are readily available.

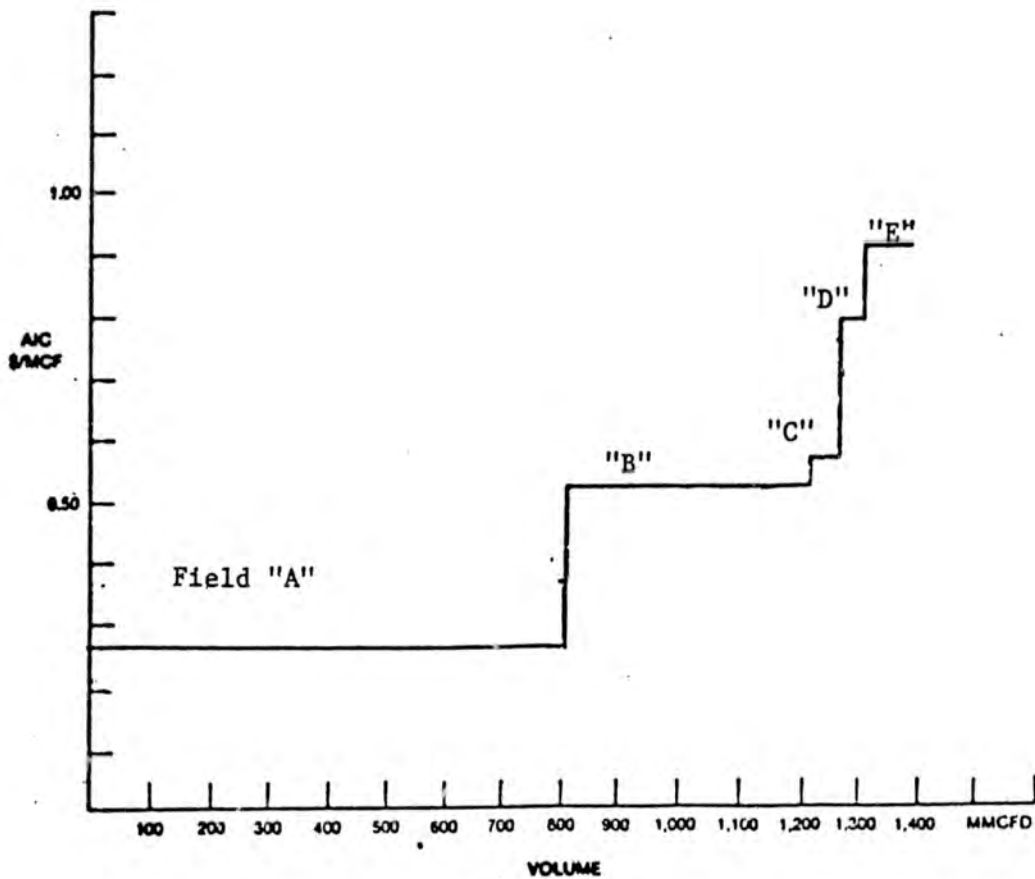
Both Norway and Nigeria are actively exploring new projects to bring LNG to European and/or U. S. markets. In both cases recent press releases have indicated that gas cost minimization has been aggressively pursued to try to make the project feasible.

Norway was widely reported to be trying to develop its northernmost fields in the Troms area of the North Cape for an LNG project. The recent announcement of a contract for U.S. markets indicates instead that they have tried to cut costs by "piggybacking" on the existing Statpipe system out of the Statfjord field farther south. In announcing the contract, R. Gerald Bennett of Enron was reported as saying,

⁽¹⁾ "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, DC, pages 15-16.

FIGURE 2

THE AVERAGE COST OF GAS BY FIELD IN PAKISTAN



Source: "Marginal Cost of Natural Gas in Developing Countries: Concepts and Applications" Energy Department Paper No. 10, August 1983, The World Bank Energy Department, Washington, D.C., page 16.

About the economics of the Norwegian LNG, Bennett said the Norwegians are looking at a site next to an existing LNG facility at Karsto, north of Bergen for the liquefaction plant. The supply will come from uncommitted gas reserves in several large North Sea fields and transmission capacity is available in existing pipelines. The Norwegians have already invested a significant amount to develop the gas fields and believe they can add the liquefaction facilities on an incremental cost basis.⁽²⁾

Nigeria, too, in its efforts to minimize costs, has been highly selective of the gas reserves which would be committed to its proposed LNG scheme. An article in the Petroleum Economist describes the process as follows:

These fields [earlier named as Soku, Bomu, Oshi, Idu, Uberta, Obagi, and Ibewa], located just north of the plant site, are all non-associated gasfields, so the costs of compressing associated gas will be avoided. Shell says production costs will be relatively low because the gas is of good quality and because only shallow drilling will be required. The project as envisioned at present will only require some 130 billion cubic meters out of Nigeria's proven and probable reserves - mostly discovered by accident in the course of oil exploration - of 2600 bcm.⁽³⁾

Both economies of scale and "highgrading" will have an important bearing on the costs of financing. If the financial community sees that a future ANGTS project has been modified, eliminating much of the benefits of economies of scale and/or subjected to "highgrading," it is unlikely to readily embrace such a project except at significantly higher financing costs.

⁽²⁾ Natural Gas Intelligence, December 19, 1988, page 1.

⁽³⁾ Petroleum Economist, March 1988, page 92.

Thus, the economic assumptions incorporated into the ANGTS project by itself should not be assumed to be readily transferrable to a modified project that at some future date attempts to make use of North Slope gas reserves other than those in the Prudhoe Bay field.

In summary, there is no evidence that sufficient proved and economically transportable gas reserves on the North Slope exist to warrant construction of two major transportation systems in essentially the same time frame.

Issue Two: Will the currently proved Prudhoe Bay gas reserves be needed more by the United States or the Pacific Rim countries?

The present period in the U.S. gas industry is a particularly difficult time for ERA to make a critical decision regarding the future need for Alaskan gas in the Lower 48 states. The U.S. has experienced a long-term period of gas surplus -- the gas "bubble" or "sausage" as it has been termed for several years. Wellhead spot gas prices have recently been in the \$1.25 - \$1.50 per million cubic feet range. Thus, from the current perspective of the beginning of 1989, the Lower 48 states may not "need" gas whose sponsors quote a tariff of \$3.05 delivered to market.

However, the proposed TAGS start-up date is 1996. By that time, at present rates of gas consumption, the U.S. will have consumed a volume of gas equivalent to 79% of our present Lower 48 proved reserves. By then, whether or not we are in surplus will be dependent on the effectiveness of the industry in exploring and developing our remaining gas resource base, not on current perceptions of the bubble.

There are strong indications that the gas bubble period is ending. Within the industry, gas producers are beginning to reactivate plans for future imports of LNG to the Lower 48 states. Increasingly, U.S. gas consumers are looking to Canada as an incremental source of supply, and Canadian gas imports have been steadily rising. Moreover, an interest in long-term contracting is emerging within domestic gas circles. In effect, there are numerous industry "signals" indicating that the U.S. gas market is tightening and that the period of gas surplus is over.

As gas markets move from surplus to more balanced and perhaps even "tight" gas supply/demand conditions, ERA's decision is

particularly difficult given the uncertainties of gas pricing of the coming years. Wellhead pricing under the surplus conditions of recent years has reflected the abundance of gas relative to domestic demand levels and resulted in gas-to-gas pricing competition. In a more balanced gas environment, however, wellhead pricing will be affected by other factors, such as the world price of oil, the availability and price of other energy sources including coal, the level of Canadian gas exports to the U.S., etc.

In addition, U.S. gas pricing is undergoing a major restructuring because of changes taking place under Federal Energy Regulatory Commission Order Nos. 436 and 500 designed to open up the domestic pipeline network to open-access transportation. At this time, the gas industry is in the midst of a major transition in which historical service obligations and merchant functions of gas pipelines are being shifted to gas distribution companies and even directly to gas users. This fundamental restructuring of pipeline rates is far from complete or settled. Gas markets are and will continue to be affected by developments in transportation rate design, but precisely how is difficult to predict since the mechanisms for implementing the new rate structures are still being formulated. For example, the new gas pricing environment will be characterized by such new rate factors as gas inventory charges, standby reserve charges and other, potentially yet unnamed, factors reflecting the unbundling of gas services historically grouped together in a single gas price. But exactly how these new rate features will affect gas pricing in specific regional markets remains to be seen.

There is little evidence that Asian markets need the Prudhoe Bay gas supply any more than we do at present. Table 1 summarizes the committed or accessible gas reserves available to U.S. and Asian markets. The "accessible" exportable surpluses shown in the table are selected from those countries which are the most obvious trading partners for the market in question. It is apparent from the table that the domestic gas reserves, plus contract commitments, plus market-oriented exportable surpluses, provide for substantially greater coverage for Asian markets than do the comparable reserves for U.S. markets. The total (excluding any North Slope commitments) provides 53.3 years coverage for the Asian market versus 10.1 years for U.S. markets. Addition of the North Slope proved reserves to the Asian market would increase its already substantial coverage of its consumption by nearly 13 years. For the U.S., however, addition of the North Slope proved reserves to its relatively much larger market has a much more modest effect.

From this viewpoint, the U.S. has a much more pressing "need" for North Slope gas than Asian markets.

And while the reserves committed or accessible to Asian markets have been increasing at the rate of 6.4 trillion cubic feet (tcf) per year since 1977, they have been decreasing at the rate of 2.1 tcf per year in the U.S.

In summary, the weight of this evidence is that the proved gas reserves at Prudhoe Bay are much more likely to be needed by the United States in the years ahead than they are by Japan, Korea, and Taiwan.

Should the Yukon Pacific Application Be Denied?

The fundamental issue in this application, in our view, is whether the Yukon Pacific project can go forward as designed without foreclosing important energy options for the U.S. as we approach the turn of the century. If this application is approved, it is possible that just when the TAGS project is under way, the ANGTS option is likely to be an economically attractive, necessary supply source for domestic markets. However, a decision now by ERA may preclude the ANGTS possibility forever, given the potential insufficiency of alternative Alaskan reserves to meet domestic market demands and the deleterious impact the TAGS project may have on the economic viability of ANGTS. Thus, it would appear that the burden of proof that the TAGS project does not preempt the U.S. option should rest with the applicant. Absent credible evidence from Yukon Pacific to the contrary, this application should be denied.

TABLE 1
PROVED RESERVES COMMITTED OR ACCESSIBLE
TO U.S. OR PACIFIC GAS IMPORT MARKETS¹

(Tcf 12/31/86)

	<u>Japan</u>	<u>Korea</u>	<u>Taiwan</u>	<u>Total Pacific</u>	<u>U.S.</u>
Committed to Domestic Markets	1.1	--	0.9	2.0	139.3 ²
Committed on Import Contract ³					
Alaska (Cook Inlet)	0.2	--	--	0.2	--
Abu Dhabi	1.1	--	--	1.1	--
Australia	6.1	--	--	6.1	--
Brunei	1.8	--	--	1.8	--
Indonesia	10.2	2.0	1.5	13.7	--
Malaysia	5.1	--	--	5.1	--
Canada	--	--	--	--	20.1
Mexico	--	--	--	--	<u>1.6</u>
Remaining Contract Volumes	24.5	2.0	1.5	28.0	21.7
Accessible Exportable Surpluses					
Australia				26.8	--
Brunei/Malaysia				31.9	--
Indonesia				15.5	--
Canada ⁴				--	7.7
Mexico ⁵				--	<u>0</u>
Subtotal Surpluses				74.2	7.7
North Slope Proved Reserves					
Yukon Pacific Request				16.0	--
ANGTS Project				--	25.0
Surplus				<u>9.0</u>	--
Subtotal North Slope Proved Reserves				<u>25.0</u>	<u>25.0</u>
Total Above				<u>129.0</u>	<u>193.7</u>
Consumption 1986 (adjusted) ⁶				1.95	16.7
Ratio Accessible Reserves to Consumption (ex North Slope)				53.3	10.1
(with North Slope)				66.2	11.6

FOOTNOTE PAGE FOR TABLE 1

- 1 Source of estimates: Based on the supporting detail for Oil and Gas Journal article by James T. Jensen, June 6, 1988, page 38.
- 2 In Jensen Associates, Inc.'s definition, all U.S. domestic proved reserves are "Committed to Domestic Markets" except those expressly allocated to Frontier, Deferred, Committed to Export, or Marginal. North Slope reserves are treated as "Frontier."
- 3 Remaining commitments to end of contract.
- 4 With the abandonment of the surplus test in 1987, Canadian exportable surpluses could rise rapidly reflecting higher depletion rates for proved reserves. This estimate assumes that the Canadian practice of requiring 20-year contracts will be retained and thus the 7.7 tcf is surplus to 20 years of existing contract coverage.
- 5 Mexico ceased exporting to the U.S. in 1984. "Committed to Export" shows volumes remaining on contract. Given current Mexican policy of retaining gas for use at home, exportable surplus is assumed to be zero.
- 6 Total Pacific consumption for 1986 is for Japan and Taiwan. Korea had no consumption at that time; however, Asian volumes have been increased to accommodate new LNG projects starting up between 1986 and 1990.

QUALIFICATIONS OF JENSEN ASSOCIATES, INC.

Jensen Associates, Inc. is a consulting firm specializing in planning and economics for oil and natural gas. We are best known for our experience in North American natural gas markets. Our work in this area covers a broad range of evaluations of demand by sector and by region, supply, pricing considerations, and regulatory and political developments. Some examples of studies we have done for clients will give an idea of the range of our experience.

Retainers

We have a number of retainers with clients in both Canada and the United States with an ongoing interest in North American natural gas markets. They include companies involved in gas distribution, transmission and production, and generally focus on issues of demand, supply, price and regulation.

Market Assessments

JAI was the marketability consultant for the Alaskan Natural Gas Transmission System consortium from 1978 to 1981.

We are called on from time to time to do market studies for major gas supply expansion schemes. Among our studies in recent years are two U.S. East Coast LNG import project evaluations as well as two significant Canadian export pipeline expansion proposals. The feasibility of these projects was dependent upon estimates of market volumes and prices.

International Gas Trade and LNG

JAI has been active in international gas studies, such as LNG developments, for example. We were the contractor for the Office of Technology Assessment of the U.S. Congress on "Imported LNG Projects, Supply and Consumption" -- a policy study undertaken in late 1979. An approach which we used in that study to classify world gas reserves as a basis for international trade was utilized by the IEA in its 1982 study entitled "Natural Gas, Prospects to 2000." We have continued to utilize this approach in papers and speeches since that time. These have included speeches before the Oxford Energy Seminar, the Energy Policy Foundation of Norway and the gas trade summary speeches at the 1984 Gastech Conference in Amsterdam, and the 1986 Conference in Hamburg. The most recent examples of these papers on gas trade are a

paper for the Society of Petroleum Engineers and an article in the Oil and Gas Journal.

Over the past ten years, we have undertaken more than a dozen LNG project studies involving sources in Algeria, Indonesia, Qatar, Norway and Trinidad, and markets in the U.S., Canada, Japan and Taiwan.

We assisted one of the major purchasers of Soviet gas in its anticipated arbitration of its contract with the U.S.S.R. We also undertook a study for one of the major oil companies of the outlook for gas markets in Europe and the influence of Soviet gas export policy on that market.

Supply Evaluations

JAI regularly monitors North American gas supply as a part of our general market monitoring efforts. We were the prime contractors to the Office of Technology Assessment of the U.S. Congress in a study entitled "Understanding Natural Gas Supply in the U.S." Periodically, we undertake specific supply studies for clients. An example of this type of analysis would be a study of the supply position of a pipeline as a means of reassuring an LDC purchaser about the quality of the pipeline's long-term supply position.

Pricing and Contracting

Price forecasts for specific client decisions are frequent assignments for JAI. As examples, we have recently undertaken forecasts of natural gas prices for two different electric utilities, including the logic of price formation as it would influence their operations. Several other recent studies required that we develop escalation clauses that will operate effectively in the new era of market-responsive pricing and volatile energy price formation.

Policy

We are frequently called upon by clients to critique policy proposals by regulatory bodies such as the Federal Energy Regulatory Commission. In Canada, we were selected by the Government's Pipeline Review Panel to assist them in their analysis as to how Canada should move towards open transportation and market-responsive pricing. Our specific assignment was to assist the panel in understanding how the U.S. had approached the problem and what features of the U.S. approach Canada should adopt or avoid.

We were actively involved for Canadian clients in evaluating the alternatives to the earlier Canadian single border pricing policy for exports to the United States. We concluded at an early point that variations on the two-part rate design were a preferred option for Canadian policy. We later assisted several clients in testimony

before the U.S. Federal Energy Regulatory Commission when they sought approval of such a pricing formula for their export contracts.

Strategy/Structure

Some of our projects focus on the question of changing industry structure and the strategy which a company should follow in trying to adapt to change. A major example of such a study was one which we recently undertook for a large interstate pipeline system. The company gas marketing activities had been reorganized upon the recommendation of an organizational consultant. We were asked to provide a second opinion on the organization structure, focusing especially on the likely changes in the market and the organizational effect they would have on demands on company marketing activities. We concluded that certain functions would be required of the company in the future but had not been considered because they were not now part of the present market environment. We recommended changes by which the company could respond to the challenges it would face in the future.

Other

Our experience is both North American and international and includes both oil and gas. We have not included in this listing of projects some of our oil-related work. However, our oil-related work gives us the background to judge oil prices and to determine the interaction between oil market developments and natural gas markets.

JAMES T. JENSEN

Mr. Jensen is President of Jensen Associates, Inc., a firm of consulting energy economists in Boston, Massachusetts. He has a degree in chemical engineering from the Massachusetts Institute of Technology and an MBA from Harvard Business School. For eighteen years prior to his establishment of Jensen Associates, Inc., Mr. Jensen was a Senior Staff Member of Arthur D. Little, Inc. Throughout his career, he has concentrated on petroleum, natural gas, and energy economics and their applications to the management of energy-oriented organizations. His major interests have been in the fields of energy planning, economics, and forecasting, and in investment and feasibility decisions in the energy industries.

He has broad experience in international petroleum and natural gas markets and the impact of governmental intervention on their behavior. His clients have included governments of both producing and consuming countries, as well as private and government energy companies and energy consumers.

Analysis of markets, pricing and interfuel competition have formed a major part of his work. He regularly provides his clients with an interpretation of the political, economic and market forces which determine the prices of oil and gas. Through the use of computer models of interfuel competition which have been developed by Jensen Associates, he frequently provides assessments of the likely impact which energy price changes will have on the relative market share for oil and gas, both by sector and by region. He has undertaken natural gas marketing studies for clients throughout the world and has been responsible for oil marketing strategy studies for companies and for governments.

Issues surrounding energy supply form another important element of his work. These include supply forecasts and long-term crude oil acquisition strategy studies for refiner marketers. He has developed an approach for classifying world gas reserves as a basis for world gas trade which is commonly quoted by others.

Investment feasibility has been an important part of his assignments. These have included refinery expansion projects, transportation facilities, petrochemical plants, and liquefied natural gas proposals for projects in Europe, Latin America, North Africa and the Far East, as well as the United States. For corporate clients he has undertaken merger and acquisition, and company organization studies.

James T. Jensen

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He is recognized for his expertise in natural gas supply, demand, regulation and pricing both in the United States and internationally. He has testified on natural gas issues before Senate and House Congressional Committees, before the Federal Energy Regulatory Commission and its predecessor, the Federal Power Commission, as well as many state regulatory agencies.

Mr. Jensen has written extensively on oil and gas matters. His recent papers include *Evolution of Market-responsive Pricing for Natural Gas in the U.S. and Its Effect on Gas Trade* (1986); *World Gas Reserves and Availability* (1986); *Factors Affecting Gas-based Industrial Development* (1985); *Natural Gas Deregulation and the Clash of Cultures* (1984); *Factors Involved in the Present Oil and Natural Gas Market Instability* (1984); and *Oil's Next Ten Years: "It Won't be Dull"* (1983).

Mr. Jensen has been a regular visiting faculty member of the Oxford Energy Seminar at St. Catherine's College, Oxford. He has also lectured on energy topics at other seminars conducted at Harvard, M.I.T., Northwestern and Oxford. He is a frequent speaker at U.S. and international energy meetings.

Mr. Jensen is a member of the American Petroleum Institute, the Society of Petroleum Engineers, American Chemical Society, Boston Economic Club, and the National Association of Petroleum Investment Analysts.



ALASKA SEGMENT

ALASKA NATURAL GAS TRANSPORTATION SYSTEM

Alaskan Northwest Natural Gas
Transportation Company

YUKON PACIFIC CORPORATION
(ERA DOCKET NO. 87-68-LNG)

VERNON T. JONES, CHAIRMAN
ALASKAN NORTHWEST
NATURAL GAS TRANSPORTATION CO.

JANUARY 24, 1989

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
ECONOMIC REGULATORY ADMINISTRATION

PREPARED STATEMENT OF
VERNON T. JONES, CHAIRMAN, OF BOARD OF PARTNERS
ALASKAN NORTHWEST NATURAL GAS TRANSPORTATION COMPANY

AT PUBLIC CONFERENCE, JANUARY 24, 1989
ANCHORAGE, ALASKA
ERA DOCKET NO. 87-68-LNG (YUKON PACIFIC CORPORATION)

I. INTRODUCTION

I am Vernon T. Jones, making this statement as Chairman of the Board of Partners of Alaskan Northwest Natural Gas Transportation Company ("Alaskan Northwest"), the consortium of natural gas companies designated by a Presidential decision and approved by the U.S. Congress to design, construct, and operate the Alaskan segment of the Alaska Natural Gas Transportation System ("ANGTS"). For the record, I am also the President and a Director of The Williams Companies, Inc., the parent firm of Northwest Alaskan Pipeline Company, the entity designated by Alaskan Northwest as its agent and operating partner.

The U.S. sponsors of the ANGTS have invested about \$ 1.5 billion to date in design, preliminary engineering, satisfying

government requirements, and construction planning for the Alaskan segment of the ANGTS. ^{1/} We made this expenditure in good faith, based on a framework of federal law, including explicit Congressional and Executive commitments to an overland transportation system to bring gas to the lower-48 states and the availability of at least the 26 trillion cubic feet of proved Prudhoe Bay gas reserves for this purpose.

We remain dedicated to bringing this gas to the lower-48 market at the earliest feasible date when the gas can be sold at market clearing-prices. That date is approaching much faster than is generally realized, which I will elaborate upon.

For a variety of reasons, which I will briefly summarize, issuance of an unqualified export license, as requested by Yukon Pacific Corporation ("Yukon Pacific"), would not be in the public interest. If, however, the Economic Regulatory Administration ("ERA") chooses to issue some sort of limited authorization, we strongly believe that the specific conditions we proposed earlier in this proceeding must be imposed to avoid substantially jeopardizing the availability of the proved Prudhoe Bay gas reserves and their delivery by an overland pipeline system to American consumers.

^{1/} The \$1.43 billion of investment (as of 12/31/88) is just for the Alaskan segment (i.e., the pipeline in Alaska and the North Slope conditioning plant), including interest and allowance for use of funds during construction. It does not include expenditures on the planned or already constructed and operating portions of the ANGTS in Canada and the lower-48 states. The currently operating sections comprise about one-third of the total mileage of the ANGTS.