USE IN ALASKA OF NORTH SLOPE NATURAL GAS: A SURVEY OF PROSPECTS AND THEIR LIKELY IMPACTS ON AN ALASKA GAS PIPELINE

for the United States General Accounting Office

by Connie C. Barlow

and

Arlon R. Tussing

26 October 1982
(updated March 1, 1983)

ARTA ALASKA Inc.
526 Main Street
Juneau, Alaska 99801

NOTICE

This report was prepared for the General Accounting Office as a result of contract number 3130089 . Neither the General Accounting Office, nor any person acting on behalf of the General Accounting Office makes any warranty or representation, expressed or implied, with respect to accuracy, completeness, or usefulness of the information contained in this report.

TABLE OF CONTENTS

Introduction: The Status of the Alaska Highway Gas Pipeline	1
Potential In-state Use of North Slope Gas: Its National Significance	3
Scope of Inquiry	3
Use of North Slope Gas for Field Operations	4
The Petrochemical Option	8
Potential Use in Alaska of North Slope Gas Liquids	10
Markets for Compressed Natural Gas in Alaska Motor Vehicles	10
North Slope Methane as Fuel for Alaska Homes and Businesses	11
A Forecast of Alaska Fuels Demand for North Slope Methane	18
Conclusion	19
Notes	23
Map	26

INTRODUCTION

THE STATUS OF THE ALASKA HIGHWAY GAS PIPELINE

In April of 1982, Northwest Alaska Pipeline Company announced a two-year delay in its six-year quest to build the "Alaska Natural Gas Transportation System" (ANGTS) from Prudhoe Bay through Canada to the southern 48 states. That announcement, coupled with a widespread belief within the industry that the delay was really "indefinite", spawned a growing skepticism about whether and when the 26 trillion cubic feet (tcf) of proved gas reserves at Prudhoe Bay will become accessible to energy users throughout the United States.

Twenty-six tcf of gas is a substantial amount. The Prudhoe Bay reserves alone could satisfy the nation's entire demand for gas for well over a year, and as of January 1982, they accounted for fully 13 percent of U.S. proved reserves. But until a system is put in place for moving the gas to market, the companies producing oil at Prudhoe Bay will continue to reinject the gas, which is an unavoidable co-product of oil production.

Indefinite delay of the gas pipeline resurrects old questions about the appropriate time and methods for disposing of North Slope gas. The major producers (Exxon, Atlantic Richfield, and Standard Oil of Ohio), along with the State of Alaska, have the biggest stake in those questions. The three companies hold almost all of the leasehold rights, while the State maintains a one-eighth royalty interest, plus the usual taxing powers and development concerns of a sovereign government.

One can be sure that the producers are now re-examining the question of North Slope gas marketing, and that they were doing so long before the ANGTS sponsors formally acknowledged the project's deep problems. The State of Alaska has seized the opportunity as well. State agencies have contracted $370,000 worth of consultant studies on gasline alternatives.[1]

Meanwhile, Governor Hammond appointed a special committee to guide the overall state effort. Co-chaired by two former governors, the committee took a fresh look at an the concept "All-Alaska" pipeline, combined with an LNG terminal in Southcentral Alaska, for marketing the gas. This approach was first promoted in the mid-Seventies by El Paso Natural Gas Company but rejected by President Carter and the Congress in 1977 in favor of the Alaska Highway route.

In the fall of 1982, Committee Co-Chairman Walter Hickel appeared throughout the nation, and on the pages of Business Week (10/25/82), stumping for a reincarnated version of the El Paso scheme. Not surprisingly, when the committee released its findings in January

1983[2], it found such a system to be economically feasible, under its chosen assumptions about world oil prices, engineering costs, and competitive factors. The January report found, however, that "North Slope gas does not have a ready market in the United States in the near term." Consequently, the most crucial difference between the committee's "Trans-Alaska Gas System" (TAGS) and the earlier El Paso plan is the targeted market: The TAGS promoters envision exporting LNG to Japan.

Both the TAGS idea and the defunct El Paso project, however, have captured substantially more support from the business establishment of Anchorage and Southcentral Alaska than ANGTS was ever able to get. The perceived benefits of an "All-Alaska" system that would bring North Slope gas into the state's principal population and industrial center, meant that competing proposals (including the Mackenzie Valley and Alaska Highway systems) suffered an unenthusiastic and often hostile reception from influential Alaskans.

The delay of ANGTS (and the emergence of the TAGS export idea) call for re-examination of public policies on the federal level as well. The Alaska gas pipeline was, after all, important enough to merit Congressional action four times between 1976 and 1982. In light of today's conditions --- a domestic (and Canadian) gas glut with no end in sight, coupled with soaring gas prices that have gone beyond market-clearing levels --- the perceived **need** for Alaska gas is now far from compelling. Present conditions, moreover, nullify some of the basic tenets of the ANGTS sponsors, who assumed that "rolled-in" pricing, supported by a "cushion" of cheap price-controlled gas would make it easy for U.S. markets to absorb the high price of Alaska gas. (See the authors' separate analysis of the difficulties the ANGTS sponsors now face.[3]

These changes mean that it is no longer obvious that the highest and best use for North Slope gas is to bring it into the other states as quickly as possible. Re-examining this basic point raises a host of questions about methods of transport, timing, and how much if any additional effort or assistance the federal government ought to devote to the matter. As part of a larger investigation conducted by the General Accounting Office, this report examines the possibilities for using North Slope gas **within Alaska.**

POTENTIAL IN-STATE USE OF NORTH SLOPE GAS: ITS NATIONAL SIGNIFICANCE

Not surprisingly, the State of Alaska has put a lot of money and effort into examining prospects for in-state use of the gas. During the past decade, public and private bodies within Alaska have zealously explored a handful of schemes for using North Slope gas to promote regional economic development, foremost of which was the as-yet unsuccessful attempt to introduce a "worldscale" petrochemical complex based on natural gas "liquids" (NGL's) from Prudhoe Bay. State agencies also appraised the likely needs of its resident homeowners and industries for gas as a source of thermal energy and electric power.

For these reasons, virtually no uncharted ground remains for the federal government to explore regarding in-state use of Alaska gas. The purpose of this document, rather, is to extract from the existing body of knowledge the data and analyses that can provide insight into two specific questions that are of national scope:

> (1) Is there, perhaps, some way of putting all or most of the gas to productive use within Alaska, thereby eliminating the need to move any of it through transcontinental or trans-oceanic systems?
>
> (2) If, on the other hand, in-state uses are unlikely to provide suitable destinations for all or most of the North Slope reserves, is there a chance that such uses might, nonetheless, be large enough to threaten the viability of ANGTS or a successor project?

Basically then, **federal officials need a ball-park estimate of the scale of in-state** use to be expected. Specificity may be important for state planning purposes, especially from the standpoint of ensuring Alaskans access to the most economical fuel sources, but it is not particularly relevant to questions of national scope.

SCOPE OF INQUIRY

In 1974, the State of Alaska amended its royalty hydrocarbons statute (AS 38.05.183) to require periodic appraisals of "intrastate domestic and industrial needs" for state royalty oil and gas. The law grew out of the legislature's fear that unless state energy managers routinely reviewed the **long term** supply and demand outlook, piecemeal commitment of publicly-owned hydrocarbons to outside purchasers might ultimately deprive Alaskans and Alaska enterprises of access to essential state resources.

Since enactment of the law, the question of what constitutes an "in-state" use has remained fuzzy. But for the purposes of this report, it is not too difficult to come up with a workable definition. **In this study, we will limit "in-state" use to those activities which would (1) utilize the gas right on the North Slope for oilfield operations, including enhanced recovery of oil, (2) process it into a non-fuel commodity (such as petrochemicals) destined for markets outside of the state boundaries, or (3) actually consume the gas within Alaska for a variety of energy applications.**

What this definition excludes are in-state facilities that would process North Slope gas into a form suitable for export as a **fuel commodity**. This report, therefore, will not consider the potential for using North Slope gas to produce LNG or alcohol fuels. These systems are, rather, means of circumventing the need for fixed pipelines by chilling the vapors or altering the chemistry so that gas can be shipped by tanker in a liquid state.

One other definitional problem arises with respect to North Slope gas. The "associated" gas that is stripped from crude oil during production activities contains not only methane, but heavier hydrocarbons too. Ethane and propane components of natural gas liquids (or NGL's) cannot be shipped through TAPS because they tend to vaporize in a heated oil line. They can move through a high-pressure gas pipeline like ANGTS, or in a separate gas-liquids pipeline. **We shall, therefore, include in-state use of NGL's in the present survey.**

USE OF NORTH SLOPE GAS FOR OILFIELD OPERATIONS

It takes energy to produce energy at Prudhoe Bay. Oil must be gathered, the vapors, water, and impurities separated, and the TAPS pump stations fueled. The current program of gas-reinjection requires fuel to run the compressors, while the waterflood facilities under construction will add to fuel demand. Finally, a gas pipeline and conditioning plant would, if built, require energy resources.

Not surprisingly, practically all of the stationary (as opposed to vehicular) equipment on the North Slope now rely on produced gas. And it makes sense for the operators to continue to use gas for field fuel as long as it has a lower value per unit of energy than oil sold at the wellhead. At a November 1982 wellhead price for Prudhoe Bay oil of about $20 per barrel, the wellhead value of gas would have to exceed $3.50 per million btu (mmbtu) before it was economic to substitute oil in field operations. There is little question that gas will continue to be a cheaper fuel to burn on the North Slope --- especially if no gas transportation system is in place.

Studies completed in anticipation of ANGTS[4] calculated that field-fuel requirements of oil-related activities at Prudhoe Bay (including raw gas consumed in TAPS pump stations #1 through 4 north of the Brooks Range divide) would consume about 11 percent of the energy value of the produced gas and gas liquids and about 12.5 percent on a volumetric basis. If the remaining gas is to be marketed off the North Slope, the "conditioning" process would consume another 4 percent of the total energy value and 9 percent of the volume. In addition, if construction of a gas pipeline were to make gas available to TAPS pump stations nos. 5 through 9, the current throughput of 1.6 million barrels per day implies use of an additional 33 million cubic feet (mmcf) per day or pipeline-quality gas. The total would thus amount to about 16 percent of the energy and 22.5 percent of the volume of produced raw gas from Prudhoe Bay. Table 1 sets out these balances.

Table 1: NORTH SLOPE GAS AVAILABLE FOR EXPORT

	VOLUME million cubic feet per day (mmcf/d)	**ENERGY** billion btu per day (gross)
Produced (raw) gas	**2,700**	**2,849**
Less: field fuel and TAPS pump stations #1-4	(336)	(309)
Less: gas-conditioning plant fuel	(248)	(113)
Less: TAPS pump stations #6-9	(33)	(38)
Pipeline-quality gas available for shipment	**2,083**	**2,389**

Source: C. C. Barlow, Natural Gas Conditioning and Pipeline Design. Juneau: ARTA Inc. for the Alaska Department of Natural Resources, 1980. p. 33. Also, Frank Fisher, Alyeska Pipeline Service Co., telephone communication to Barlow, 20 December, 1982.

The producing companies expect this rate of field-fuel use to continue throughout the period of oil production.[5] Considering the fuel needs of the gas conditioning plant as well, field activities would consume about 5.7 tcf of the initial recoverable reserves, leaving only

20.6 tcf for export out of the original 26.3 tcf of recoverable reserves in the Prudhoe Bay Field. Taking into account the fuel requirements for gas reinjection before an export system is in place, the total energy loss would be even greater.

> **Thus, field operations by themselves account for a significant in-state fuel demand for North Slope gas --- more than one-fifth of the available resource.**

These requirements have been generally known ever since the ANGTS project was first conceived, and the sponsors, therefore, have had a pretty good idea of how field fuel requirements would affect project feasibility. The big unknown with respect to field demand for North Slope gas has turned, instead, on questions about the amount of gas that might be needed for enhanced oil recovery.

Immediately following the 1977 Presidential and Congressional approvals of the Alaska Highway route and its sponsor, the biggest question regarding enhanced oil recovery was whether the anticipated completion date for ANGTS would mean that gas would be removed from the field too soon and at too great a daily rate. In the early years of oil production, gas reinjection was the only means for maintaining reservoir pressure, which is essential for maximum oil recovery. In 1977, reservoir dynamics were still largely speculative and nobody was certain whether and when a waterflood facility would be ready and able to replace gas as the chosen repressuring agent.

In late 1982, with a waterflood facility under construction and after five years of oil production (yielding a far more certain understanding of the sensitivities of hydrocarbon recovery to field operating conditions), those fears are gone. In fact, if there is any oil-related concern about gas off-take today, it is that gas reinjection might be prolonged so far as to endanger ultimate oil recovery. Too much gas thrust back into the gas cap could spread unevenly, "fingering" down into the oil zone below the gas and folding back on itself, thereby separating a portion of the oil from the main body of liquids.

This particular concern does not carry much weight among the producers and the State's petroleum managers. Even if the engineering outlook did change for the worse, it is likely that the State of Alaska, with its one-eighth ownership interest, would relax its laws pertaining to gas flaring if prolonged gas reinjection endangered its royalty and tax revenues.

Reinjection into the gas cap, field-fuel requirements, and flaring are not the only local prospects for gas disposal and use on the North Slope. The producers are now looking at ways to use gas for "tertiary" oil recovery --- that is, techniques for increasing the proportion of original oil-in-place retrievable from the reservoir that go beyond gas reinjection (which repressurizes the gas cap above the oil zone) and beyond waterflood (which boosts the pressure that the water layer exerts on the oil from below). One approach is to alter the composition of the gas so that it will become "miscible" with oil and can be injected directly into the oil zone.

In November 1982, the three major leaseholders at Prudhoe Bay announced plans for a $100 million enhanced-oil recovery project, using gas and gas liquids. This pilot project for "miscible enriched gas displacement" would affect only about 2 percent of the entire producing area. The companies plan to take a small portion of the produced gas stream (which is about 74 percent methane by volume and 13 percent carbon-dioxide) and enrich it with the heavier NGL components. The enriched gas, containing only 42 percent methane, would be able to mix freely with oil at the high pressures that exist deep within the oil zone.

If the pilot project proves feasible and if the oil reservoir responds favorably, the practice could become more widespread. In theory, the entire gas stream could be turned into a miscible fluid by chemically combining the methane molecules to form heavier gas liquids. This approach has been advocated by engineering staff at the University of Alaska as an alternative to a gas-export project.[6]

An even more profitable use for otherwise unmarketable North Slope gas may be for the extraction of heavy oil by steam-injection or fire-flood. One known heavy-oil formation on the North Slope may turn out to hold two or three times as much oil-in-place as the Prudhoe Bay field, but in the absence of nearly free energy for "thermally enhanced recovery", it may never be economic to produce.

Interest in the use of North Slope gas and gas liquids for enhanced oil recovery is not surprising, now that the ANGTS project is more-or-less officially on hold. It is also not surprising that some business and political leaders in Alaska are voicing fears that an expanded miscible injection program might undermine a gas export scheme (which would generate more construction activity). Nevertheless, it is important to remember that the escalation in interest is largely pragmatic. Absent ANGTS, the gas has at best a zero wellhead value (and quite possibly a negative value because of the costs of reinjection), and any field use that could put gas on the positive side of the ledger is, therefore, attractive.

> **Thus, when the waterflood facility begins operations in mid-1984, North Slope gas will no longer be an essential resource for enhanced oil recovery. Modified into a miscible stream, however, it may still offer some additional value in oil recovery, which may be an attractive option if an export system proves infeasible.**

THE PETROCHEMICAL OPTION[7]

The prospects for converting North Slope hydrocarbons into petrochemicals for export into world markets captured far more industry and state government attention than any of the other possible in-state uses. Petrochemical manufacturing was, in fact, the state government's most vigorously pursued program for economic development between 1977 and 1981.

During the first two years of the petrochemical rage, the State targeted North Slope crude oil as the raw material. It even sold the bulk of its crude-oil royalties to Alaska Petrochemical Company (Alpetco) on long-term contract. Although oil sales began almost immediately, continued deliveries hinged on construction of a petrochemical plant at tidewater somewhere in Southcentral Alaska. A year after the contract was signed, the State agreed to a change in scope requested by Alpetco. The proposed petrochemical plant was replaced by plans for a fuels refinery. The sponsoring firms even adopted a new name, Alaska Oil Company. But the refinery never materialized and the State is still trying to collect around $60 million in alleged underpayments for royalty oil purchased before the deal fell through.

Meanwhile, interest shifted to North Slope gas as a feedstock for petrochemicals. More specifically, the State hoped to entice credible businesses (it had, after all, learned something from the Alpetco debacle) to build a "world-scale" plant, using North Slope NGL's as feedstock. Alaska's royalty share of liquids (primarily ethane) would, however, have been insufficient for a plant yield of ethylene and ethylene-derivatives in the range of a billion pounds per year; so the State considered swapping most or all of its North Slope royalty methane for NGL's owned by the North Slope producers.

This prompted some concern, primarily within the legislature, that homeowners and electric utilities within the state would be denied an attractive form of energy if the petrochemical concept and the gas swap ever materialized. In 1980, a legislative committee sought proposals for evaluating such in-state needs, and allocated $150,000 for the project. A study contract was never issued, however, mostly because the perpetual issue of state oil taxes heated up once again and legislative budget priorities shifted.

Finally in 1981, proponents of an NGL's-based petrochemical industry experienced a major setback. In exchange for an option to purchase Alaska's share of North Slope liquids, a consortium of companies led by Dow Chemical and Shell Oil Company (Dow-Shell) devoted over $5 million dollars of their own money and employee time to a detailed feasibility study. Dow-Shell concluded that the outlook for an ethane-based facility was favorable, but with a crucial hedge. The ten-volume study pronounced an ethylene complex "economically feasible **under the right conditions**" (emphasis added). Because construction costs in Alaska were estimated at 1.7 to 2.1 times those of the U.S. Gulf Coast, the study concluded that project feasibility depended on "a favorable Alaska ethane feedstock cost relationship to that of the U.S. Gulf Coast". Dow-Shell thereby officially stated what many analysts both inside and outside of state government had suspected for a long time: Alaska is a poor place to manufacture petrochemicals unless it can offer an exceptional bargain on the gas feedstocks.

Alaska politics demanded that state leaders be advocates and promoters of economic development --- seemingly the bigger the better. But it was equally unfashionable to jump on the bandwagon of a project that required an overt state subsidy. The Dow-Shell report, therefore, crushed further discussion (at least for a while) of an NGL's-based petrochemical industry. Although world market conditions make the petrochemcial option even less realistic today (with state-subsidized plants in many countries already in deep trouble), the TAGS proposal for a combined gas and gas-liquids pipeline has given petrochemical enthusiasts in Alaska a new platform. Use of North Slope gas for petrochemicals manufacturing is, therefore, likely to remain a political issue in Alaska; but it merits little, if any, national attention.

Conceivably, North Slope methane could be turned into methanol, ammonia, and urea. An ammonia/urea plant has been processing a small portion of Cook Inlet methane for many years. But if world markets could accomodate more methane-based petrochemicals from Alaska, it is hard to understand why Southcentral Alaska isn't already supporting a bigger industry --- especially since Cook Inlet gas owners still reckon with a chronic oversupply of gas and a limited world market for LNG. More specifically, a September 1982 report prepared for the U.S. Maritime Administration (ICF Inc., "Alaska Natural Gas Development, An Economic Assessment of Marine Systems") concludes that North Slope gas entirely processed into ammonia and urea would in 1985 surpass worldwide demand for additional sources by twenty times. Moreover, the study suggests that OPEC nations still flaring surplus gas (Saudi Arabia alone flared 1.4 tcf of natural gas in 1980[8]) "appear capable of under-cutting market prices at will."

Overall then, nobody within Alaska ever seriously considered or promoted construction of a second ammonia-urea plant for use of North Slope methane. Alaskans and the Dow-Shell group, instead, devoted their full attention to the opportunities posed by the enormous volumes of NGL's available at Prudhoe Bay --- opportunities which, in the context of Alaska's remoteness and climate, offer very little real prospect for industrial expansion.

In summary, development of a big petrochemical operation in Alaska that would consume a sizeable share of North Slope gas or gas liquids is not a realistic possibility.

POTENTIAL USE IN ALASKA OF NORTH SLOPE GAS LIQUIDS

In 1980, Alaskans consumed 190,000 barrels of propane, or "bottle gas", which is an important fuel for cooking (and to some extent heating) in the rural areas of Alaska. Of that, 120,000 barrels came from two in-state suppliers. Crude oil producers in Cook Inlet's Swanson River Field stripped about 50,000 barrels of propane out of the associated gas stream. The Tesoro oil refinery, also in Cook Inlet, sold about 70,000 barrels to local distributors. The remaining 60,000 barrels were imported.[9]

It is doubtful that North Slope gas liquids would prove more attractive in the existing bottle-gas industry than Cook Inlet supplies or even imported propane. Certainly, until ANGTS or a successor pipeline is built, Prudhoe Bay gas liquids will remain on the North Slope, to be either reinjected or burned as field fuel. Because an ethane-based petrochemical plant does not appear viable in Alaska, there is little basis for a "gas liquids" pipeline from the North Slope. Even if and when ANGTS or a successor project is built, installing a stripping plant purely for local or even statewide use of propane may prove infeasible.

From a national standpoint, it makes little sense to investigate potential in-state use of North Slope gas liquids in any greater detail. Ralph M. Parsons Company (September 1978 Study Report: Sales Gas Conditioning Facilities at Prudhoe Bay Alaska) calculated that North Slope gas production (less field fuel and conditioning requirements) would yield about 34,000 barrels of propane daily. If North Slope propane were to take the place of propane imports at current levels of Alaska consumption, less than .5 percent of the propane content of the ANGTS gas stream would be affected. **Even if the entire in-state demand for propane was furnished from the North Slope, it currently would account for only 1.5 percent of the available supply.**

MARKETS FOR COMPRESSED NATURAL GAS (CNG) IN ALASKA MOTOR VEHICLES

One potential use for natural gas in Alaska is as motor vehicle fuel. Compressed Natural Gas (CNG) can be burned in ordinary automobile and truck engines after installation of a conversion unit that costs $1000 to $2000. Energy-cost comparisons with gasoline can be very favorable. In Anchorage, for example, the natural-gas equivalent of a gallon of motor gasoline costs less than 25 cents, at the gas distributor's commercial rate. CNG-powered vehicles have been used for decades in Italy's Po Valley, and are becoming numerous in other areas with relatively low-cost natural gas, most notably Alberta and New Zealand. Many gas distributors throughout the United States power their own trucks with CNG.[10]

Because of the conversion expense, the large space in the vehicle occupied by the CNG equipment, and the lack of filling stations, CNG conversions in Alaska will likely be limited to fleet use, and would constitute a negligible dent in the available supply of North Slope gas.

NORTH SLOPE METHANE AS FUEL FOR ALASKA HOMES AND BUSINESSES

Geographic Considerations. When considering possible use of North Slope methane as a source of energy for Alaskan households and commerical and industrial enterprises, one needs to look no further than the "Railbelt". (See the attached map.) The Alaska Railroad joins the state's two largest cities within this north-south corridor; indeed, until 1972 when a road was completed, the railroad provided the only direct north-south connection. Three-fourths of all Alaskans are Railbelt residents. The rest of the state's population is scattered in relatively small communities outside of the Railbelt, while those that reside in even the major towns of the Southeast Panhandle are barred by mountain, glacier, and sea from pipeline access to any North Slope gas.

A "statewide" system of gas pipelines to serve a population about equal to that of Oklahoma City (roughly 400,000), yet spread across inhospitable terrain comparable in breadth to the span between California and Florida, is ludicrous. Nevertheless, because Alaskans have clustered in the Railbelt, much of the "statewide" need can be served by attending to the needs of this one particular region. In 1981, for example, the Railbelt accounted for 86 percent of the electricity consumed statewide.

Interfuel Competition. In evaluating how much North Slope methane might be consumed in the Railbelt for fuel or electric power generation, one must examine the availability and relative attractiveness of other energy sources. The primary contenders for shares of the Railbelt energy market, in addition to North Slope gas, are local coal, hydroelectricity, imported and locally refined oil products, and gas produced in Cook Inlet.

It is hard to imagine a situation in which **any** North Slope gas would absolutely be **needed** in the Railbelt. Local coal deposits provided most of the southern Railbelt's electricity until Cook Inlet gas came onstream in the Sixties. Even though coal consumption throughout the Railbelt as a whole peaked in 1967, coal is still the most important fuel for electric utilities in the Fairbanks area. There, coal furnishes virtually all of the power consumed on the two military bases and the University of Alaska campus, and most of the power generated by the area's two big civilian utilities.

The biggest plant was built in 1967 by Golden Valley Electric Association (serving the greater Fairbanks area). The "mine-mouth" location, 110 miles south of Fairbanks, allows GVEA to purchase coal at only $1.16 per mmbtu. A second plant was planned, but never made it beyond the blueprints, because of air quality constraints (in the vicinity of Mount McKinley National Park), reduced demand, availability of surplus power from military bases, and anticipated access to hydropower developed by the State.

The Nenana coal resources are far from depleted; the only real limit on production is lack of demand. In addition, state leaders have been courting foreign interests for potential development of the even more extensive deposits of Beluga coal across Cook Inlet from Anchorage. An export project might provide sufficient economies so that Beluga coal would be available at a reasonable price for utilities in the southern Railbelt.

Meanwhile, state government is considering a multi-billion dollar program for hydroelectricity. In 1982 the Alaska Legislature appropriated $18 million to initiate construction of the Bradley Lake project in Southcentral Alaska (with an estimated total cost of $500 million). A far bigger project is on the drawing boards. Construction of two dams on the Upper Susitna River, at a cost exceeding $5 billion, could provide over twice as much power (6200 GWh) as the whole Railbelt consumed in 1981 (2700 GWh). With world oil prices and state petrodollars on the decline, however, and the Energy Crisis over, we expect the enthusiasm for big hydroelectric projects to diminish substantially.

With respect to competition between North Slope gas and refined oil products, it is almost beyond comprehension to think of a situation in which sufficient petroleum would be **physically** unavailable to meet virtually all energy needs within Alaska. Currently, No. 2 fuel oil sells in the Railbelt for almost $7.00 per mmbtu --- far above the price of coal or Cook Inlet gas, and even above conventional estimates of the Fairbanks price of North Slope gas delivered through ANGTS, which assume buyers will pay the NGPA-regulated ceiling at the wellhead.[11]

The world price of oil, and hence the price to Railbelt consumers, is already on the decline, however. Elsewhere[12] we have predicted that oil prices will continue to drop --- perhaps as far as they climbed during the 1970's. Nevertheless, it is pointless here to speculate on future prices in Alaska for coal, hydroelectricity, and fuel oil. This is because **the most formidable competitor that North Slope gas will have to face is likely to be Cook Inlet gas,** which already furnishes 88 percent of the electric power generated in the southern Railbelt and heats 60 percent of the households.[13]

North Slope Versus Cook Inlet Gas. Because of Prudhoe Bay's energy wealth, gas resources in Cook Inlet are often overlooked. But the Kenai Field in Cook Inlet ranks among the ten richest gas fields in the entire nation. The area-wide 3.6 tcf of gas could continue to supply local utilities at present rates of consumption for 75 years. Even if the full capacity of the existing LNG and ammonia-urea plants is accomodated (which were established and owned by the gas producers only because available gas supplies were far in excess of local needs), the reserves would last for about 23 more years.

Even these measures tend to understate the potential gas supply in Cook Inlet. **Proved** reserves (or "identified economically recoverable reserves", in the terminology of Alaska's Oil and Gas Conservation Commission) constitute only that fraction of the resource base which producers have had a commercial incentive to thoroughly explore. This kind of exploration is expensive and, absent credible near-term market prospects, there is no reason for the lease owners to spend the money. Cook Inlet gas, after all, is mostly "non-associated" gas that exists apart from any oil. And unlike Prudhoe Bay, where the oil producers could not help but prove up the gas resources when going after the crude oil, Cook Inlet leaseholders will require a far more certain market outlet before sinking additional cash into test wells. A good example of their reticence is the fact that California gas companies sponsoring the ailing Pacific-Alaska LNG project had to invest their own money in gas exploration and reserve delineation in Cook Inlet.

Nobody, therefore, knows the volume of gas that resides in even known reservoirs just outside the bounds of what qualifies as "proved", but unpublished estimates in the industry tend to be in the 5 to 10 tcf range. A 1981 U.S. Geological Survey report (Circular 860, Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States) estimates 5.2 tcf as the mean for undiscovered recoverable reserves in Cook Inlet. That amount, in addition to the volume of gas already known to exist, would boost Cook Inlet reserves to a third of the size of those at Prudhoe Bay.

> **The sheer volume of Cook Inlet gas, coupled with the fact that it already has undercut coal and oil in Railbelt power and space-heating markets, makes it the most formidable competitor for North Slope gas.**

In 1980, natural gas accounted for 70 percent of all electricity generated in the Railbelt. Natural gas also cornered 55 percent of the region's home-heating market. All of this gas came from Cook Inlet wells, and none of it was marketed outside of the southern Railbelt.[14]

Gas owes its spectacular success as an energy commodity to its abundance, proximity, and extremely favorable prices. The current average price of Cook Inlet natural gas delivered to Railbelt electric utilities is $0.86 per mmbtu. This price compares to mid-1982 purchases by electric utilities in other U.S. cities that ranged from $3.50 to over $5.00 per mmbtu.[15] Anchorage consumers now enjoy electricity rates that rank among the lowest in the nation, while Anchorage's favorable rates for household purchases of gas are unmatched.

In addition to cheap supplies, the Anchorage gas distributor enjoys a luxury that few other American utilities can boast. Instead of having to invest in costly oil-fired peaking plants or gas storage facilities, Cook Inlet gas producers adjust their deliveries to fluctuating needs. For example, about three times more gas was delivered to the Anchorage distributor in December than in August. This supply flexibility is especially important in Alaska where seasonal temperatures vary markedly and there are few large industries that might be enticed into "interruptible" contracts.

The reason Alaskans can obtain gas at such bargain rates is that it is still sold under long-term contracts negotiated before the OPEC-induced price flare-ups. But even when those contracts expire, Anchorage gas and electric utilities may continue to enjoy a buyer's market --- that is, if the utilities recognize their powers --- simply because the opportunities for selling the gas to anybody else are so limited.

Until quite recently, Alaska leaders worried that the planned export scheme of Pacific-Alaska LNG would trigger higher prices for local sales of gas. Indeed, this assumption was basic to the State's most recent studies on Railbelt energy needs.[16] But the LNG project is now on the verge of collapse, as are just about all of the high-cost "supplemental" gas projects that arose during the supply crunch of the last decade. Accordingly, there is a good chance that Cook Inlet gas will be available for local consumption for many years to come and that the scale of supply compared to demand will continue to endow local buyers with a most favorable bargaining stance.

Because our assessment of likely Cook Inlet availability and price differs markedly from the assumptions used in State-sponsored studies that are the cornerstone of current energy planning activities, the conclusions drawn from those studies are largely useless here.[17] Specifically, we do not agree with the Battelle conclusion that the supply of Cook Inlet gas to local markets "could become a major problem as early as 1990, and almost certainly after the year 2000."

We also disagree with Battelle's estimate of a 6.6 percent average annual increase in real prices for Cook Inlet gas, on the grounds that world oil prices have almost certainly peaked out already and that a gas buyer's market will continue in the area.[18]

But even if Cook Inlet prices escalate enormously, it is difficult to think of a situation in which those prices would be higher than the price of North Slope gas delivered into the Railbelt. From the standpoint of transportation costs, Cook Inlet gas carries an obvious advantage. It is only 80 miles from the region's major population center, whereas North Slope gas must travel 450 miles to reach even the northern bounds of the region and another 350 miles to get to Anchorage. Moreover, those first 450 miles traverse one of the world's harshest climates and remotest terrains.

Despite twenty years of Cook Inlet production, nobody has yet found it profitable to put in a 350-mile gas pipeline to Fairbanks. Given that historical record, it makes little sense to probe the details of building a small diameter, 450-mile pipeline to serve Fairbanks with North Slope gas. **The only way that North Slope gas would be an attractive fuel in even the northern Railbelt would be if local transport were part of a far bigger system that "conditioned" and carried the bulk of North Slope gas to markets outside of Alaska.** Even then, recent estimates of the portion of the ANGTS tariff that a Fairbanks purchaser would pay, puts North Slope gas at about $3.80 per mmbtu (1982 dollars), even if the wellhead price were **zero.**[20]

The State of Alaska has, nevertheless, contracted with Ebasco Services, Inc. to probe the cost and engineering details of building a small-diameter gas pipeline or a high capacity electrical transmission line from the North Slope to Fairbanks. Whatever the quantitative results of the study, there exist some overriding qualitative obstacles. Foremost are the transportation-mileage observations noted above (that argue against either locally-scaled delivery systems for North Slope gas or electricity generated on the North Slope) and the pre-filed ANGTS tariff which portends even more onerous charges for a gas pipeline scaled to in-state needs.

Overall, the only way that North Slope gas could offset the transportation advantage of Cook Inlet gas would be if it made up for the difference through reduced wellhead charges. Although some analysts still assume that the wellhead price **ceiling** for North Slope gas set out by the Natural Gas Policy Act of 1978 (NGPA) will determine the actual price, it is fairly safe to conclude that under today's market conditions and those likely to prevail tomorrow, the North Slope producers would feel lucky to get any positive price at the wellhead. Gone are the days when gas companies expected to pay and producers expected to get $1.45 in 1977 dollars (and $2.32 in mid-1982 dollars) for North Slope gas. Gone also are the days when those same companies quibbled over whether conditioning costs should be added onto or incorporated within the regulated ceiling.

Nevertheless, even if a Fairbanks utility could acquire gas at Prudhoe Bay for next to nothing, the delivered price may not be a whole lot less than the going rate for Cook Inlet gas. For, as mentioned above, Cook Inlet is still a buyer's market and is likely to remain one for quite some time. About a third of all gas produced in the Inlet in 1981 was reinjected, and much of this reinjection was in excess of pressure-maintenance requirements.

A buyer's market for Cook Inlet gas is particularly likely under those circumstances that would make an export scheme for North Slope gas infeasible. Cook Inlet gas also suffers enormous cost obstacles for out-of-state shipment. The very technological and worldwide supply conditions that make it difficult to market North Slope gas will, likewise, discourage interest in Cook Inlet gas. It is not, therefore, out of line to expect Cook Inlet wellhead prices to remain far less than prices that will prevail in gas producing areas to the south.[21]

If ANGTS or a similar system were built, is it likely that North Slope gas could then undercut Cook Inlet supplies for a share of Railbelt energy markets? That question is best answered separately for spaceheating and power generation and for northern versus southern Railbelt consumers.

With respect to spaceheating markets, it is almost certain that North Slope gas carried into the northern Railbelt by ANGTS would be far too expensive to deliver into the southern Railbelt via a small-diameter spur pipeline. For the same reason, however, North Slope gas would probably hold the advantage over Cook Inlet gas in Fairbanks. Sales of Cook Inlet gas in the northern Railbelt would require that somebody install a system to carry it north --- an event that has not yet occurred despite twenty years of availability and remarkably cheap wellhead prices.

Moreover, ANGTS will come into being only if North Slope gas can be delivered to consumers in the Midwest at prices --- over the life of the project, at least --- competitive with residual oil. And if that is the case, a Fairbanks gas utility should be able to obtain supplies at a far lower rate, and one that can undercut local prices for fuel oil. Many residents may still choose to burn wood[22], but of the nonrenewable energy resources, North Slope gas would be the clear winner in the more densely populated areas. Nevertheless, due to residential sprawl and the fact that users would have to bear the costs of conversion, it is probably safe to assume that gas sales in the northern Railbelt will satisfy no more than half of the region's household and commercial thermal demands. Even after twenty years of gas deliveries in Anchorage, for example, only 60 percent of all households are hooked into gas.

Sale of North Slope gas to Railbelt electric utilities is far less promising. The biggest stumbling block is the fact that within a year or two, power generated from Cook Inlet gas will have penetrated even the northern Railbelt, via an electrical intertie that connects Fairbanks utilities with Anchorage power supplies.

In addition to meeting immediate needs for power pooling, the $130 million intertie now under construction is scaled to accomodate the enormous load of Susitna River hydroelectricity, if that multi-billion dollar project is actually built. What the intertie means now, however, is that within a short time, Fairbanks utilities will be capable of meeting energy demands in the Northern Railbelt by using power generated in Anchorage. More specifically, Cook Inlet gas will be able to capture whatever portion of the Fairbanks electric-power market is not constrained by already-installed commitments. One of the arguments in favor of state-funding of the Intertie was that it would make cheap Cook Inlet gas "accessible" to consumers in the northern Railbelt.

Although the State has substantial cash and political capital invested in analysis and promotion of the Susitna dams, this effort is likely to meet with no more success than the State's ambition to foster a big petrochemical industry. If Susitna is dumped, the Intertie will be available for shipping power in either direction and from any source.

Consequently, if and when North Slope gas becomes available, it will have to back out power generated from Cook Inlet gas (or perhaps even Susitna hydroelectricity) that is transmitted throughout the Railbelt. Unless the price of gas **delivered** out of ANGTS at a tap near Fairbanks is substantially less than the **wellhead** price of gas in Cook Inlet (an unlikely prospect), penetration into the southern Railbelt is out of the question.

Penetration of electricity markets in even the **northern** Railbelt may not be as easy as one might first suspect. The conditions under which Railbelt utilities will be responsible for continued amortization of the fixed costs of the State-funded Intertie are not yet established. However, it is clear that substantial conversion of utilities in the Fairbanks region to North Slope gas would seriously interrupt those payments. Either the State will have to accept a loss, or the power transmitted on a pooling basis for emergencies and peakshaving will bear tremendous costs. Considering "sunk" costs, then, the cost of continuing deliveries to the northern Railbelt of power from gas-fired plants in Cook Inlet, may be next to nothing.

A FORECAST OF ALASKA FUELS DEMAND FOR NORTH SLOPE METHANE

On balance then, the maximum level for in-state fuels utilization of North Slope gas that we believe is reasonably plausible relects the following assumptions:

(1) No North Slope gas will be consumed by energy users in Alaska's most populous region (the Railbelt) until ANGTS or a similar gas-export system is installed.

(2) Even with ANGTS, North Slope gas will not be able to penetrate either space-heating or electric power markets in the **southern** Railbelt.

(3) With respect to in-state fuels utilization, the main market for North Slope gas that is likely to develop entails perhaps half of the residential and commercial space-heating load in the northern Railbelt. It is also plausible that North Slope gas would take over the civilian and military power generation markets in the northern Railbelt. Finally, it is conceivable that CNG could capture some share of the motor-vehicle fuels market. Again, these developments are possible only upon completion of ANGTS or a successor export-oriented pipeline.

For the purposes of this study, a forecasting approach that avoids niggling specificity offers the greatest insights. In the quantitative analyses that follow, we have therefore attempted to arrive at a good ball-park estimate (and to reveal the sensitivies of key assumptions) regarding future in-state fuels demand for North Slope gas.

In a 1977 report, Doyon, Ltd., the Native Regional Corporation in the interior of Alaska, projected that if ANGTS was completed as originally scheduled, the Fairbanks region in 1988 could support 11.5 billion cubic feet (bcf) in annual gas sales (2.2 bcf residential, 1.7 bcf commercial, and 7.5 bcf for military and nonmilitary electric power). By 2008, total sales could rise to 18.1 bcf per year. Battelle Pacific Northwest Laboratories, in a 1981 report prepared for the State of Alaska, forecast that completion of the Railbelt electrical Intertie would induce about 3.4 bcf of additional sales of **Cook Inlet** gas in order to satisfy gas-based power demands by utilities in the Northern Railbelt.[23]

Another useful calculation takes the existing population of Fairbanks and the existing power generation, and translates it into potential gas sales. If gas were to penetrate 50 percent of the space-heating market (which is a little less than the current penetration of Cook Inlet gas in Anchorage, a mature gas market) and with a population less than one-third the size of the Anchorage area, today's commercial and residential space-heating market in Fairbanks would consume a little less than 8 bcf per year. If the entire region's power requirements were also based on North Slope gas (operating at efficiencies on a par with Anchorage utilities), military and civilian utilities combined would burn around 7 bcf per year. The total power and space-heating demand would, therefore, be about 15 bcf per year. This is within the same ballpark as Doyon's 2008 forecast of 18 bcf.

Annual demand of, say, 20 bcf per year would amount to only 2.75 percent of the gas throughput planned for ANGTS. Even if the population in the northern Railbelt were to double, the in-state fuels demand for North Slope gas would hardly be noticeable.

> **Considering both electrical and spaceheating needs, therefore, the maximum plausible forecast of in-state fuels demand for North Slope methane (1) is contingent upon construction of ANGTS or a successor pipeline, (2) suggests that only the northern Railbelt would receive North Slope gas, and (3) would account for perhaps 3 percent of the anticipated throughput of ANGTS during the early, most vulnerable years of the project, increasing thereafter in proportion with population growth in the region.**

CONCLUSIONS

The only in-state demands for North Slope gas that are independent of the proposed Alaska Natural Gas Transportation System (or a successor project) are various field operations, especially those attendant to crude-oil production. Not only are field uses the most certain, they are by far the greatest. Perhaps one-fifth of the recoverable gas reserves at Prudhoe Bay will be needed for fuel requirements by the petroleum industry on the North Slope.

In addition, an as-yet unknown volume of methane and gas liquids may prove to be of some worth for enhanced oil recovery, through processes (such as miscible flood or gas-fired steam injection) that are more complicated than simple gas-reinjection, but which offer greater benefits. Nevertheless, it is unlikely that there would be much interest in any of these activities if completion of a gas-export system were certain and promised producers a higher wellhead value.

Of the gas volumes that remain, it is not likely that any will be diverted into petrochemicals manufacturing within Alaska. What's more, if such an industry were to develop, it would almost certainly use ethane and perhaps propane as feedstock rather than methane, which is the key component of "natural gas" and the targeted commodity for shipment through ANGTS.

The only other in-state destination for the NGL components of North Slope gas would be the "bottle gas" industry, which pressurizes and packages propane for use in rural portions of the State. This use, however, would barely make a dent in the available supplies of gas liquids produced on the North Slope. The market for compressed natural gas (CNG) could conceivably amount to as much as 10 percent of the Fairbanks demand for motor fuels, but such an offtake level is insignificant in the context of anticipated North Slope production levels.

Finally, demand for North Slope gas by Alaska households and businesses will be limited to the 3/4 of Alaska's population that lives in the Railbelt, and it will only arise if ANGTS or a similar export pipeline is built. Moreover, the maximum plausible scenario of Railbelt demand, shown in Table 2, implies that price considerations would restrict marketing to the northern, less populated, section of the Railbelt. During the early, most economically vulnerable years of ANGTS operations, in-state fuel demand for North Slope gas would not be likely to exceed 3 or 4 percent of the planned pipeline throughput.

Table 2: MAXIMUM PLAUSIBLE FORECAST OF INSTATE USE PRUDHOE BAY NATURAL GAS, circa 1990-1995

(million cubic feet per day)

Key Assumptions	Field Fuel	Petro-chemi-cals	S.Rail-belt	N.Railbelt- Heat-ing	N.Railbelt- Elec-tricity	TOTAL
Interstate gas transport system **does** exist	617	0	0	20-60	20-60	657-737
Interstate gas transport system **does not** exist	336	0	0	0	0	336

Overall then, fuel requirements in the Prudhoe Bay field and for operation of TAPS account for the only substantial in-state use of North Slope gas. These uses as currently anticipated will consume about a fifth of the recoverable gas resource. The biggest unknown is the amount of gas that will become valuable on the North Slope for enhanced recovery of crude oil. Nevertheless, it is unlikely that producers would opt for this approach if and when a viable export system takes shape that promises a greater wellhead return.

The **national** significance of these conclusions is two-fold:

> (1) **If an export project proves viable, it is very unlikely that in-state demand for gas — whether for petrochemical production, fuels use, or enhanced oil recovery — would substantially diminish the volume industry and government planners now consider to be the available supply. In-state use, on its own, would therefore pose no threat to the continuing viability of such a system.**
>
> (2) **Foreseeable in-state uses, (with the possible exception of gas-driven techniques for enhanced oil recovery soon to be tested), will be too insubstantial to even begin to take the place of export-oriented projects for disposal of North Slope gas.**

The range of uncertainties regarding all potential in-state uses, whether in the oil field or elsewhere, becomes almost trivial when compared to the far greater uncertainties about future gas discoveries.

The Prudhoe Bay gas reserves (now totalling 26.3 tcf) are not the only reserves known or believed to exist on the North Slope. Already in 1982, the oil companies had announced plans to develop the Endicott Field in the Beaufort Sea, estimating its natural-gas production at about 250 mmcf per day.

In September 1982, the oil industry paid $2 billion for leasehold rights offshore in the Beaufort Sea. The U.S. Department of the Interior estimates that those leases (the Diapir Field) may contain 14.8 tcf of gas and 2.8 billion barrels of oil.[24] The Department also estimates gas reserves in the as-yet-unleased Barrow Arch section of the Beaufort Sea at 4.2 tcf of gas and .9 billion barrels of oil. Moreover, 100 tcf is not an uncommon view of the ultimate amount of gas that awaits discovery in the North Slope region.[25]

If gas is found in the Diapir Field and in the Barrow Arch in quantities that prove the Interior Department's predictions correct, the amount of gas available for shipment from the North Slope would increase by 72 percent. And if the forecasts of 100 tcf of gas are valid, there is yet to be found on the North Slope almost four times as much gas as Prudhoe Bay has to offer.

> The amount of North Slope gas that may be required for in-state needs is several orders of magnitude less than the possible amount of gas that may still await discovery in northern Alaska.

NOTES

1. Booz, Allen, & Hamilton, Inc. is studying "alternatives to the Alaska Highway Gas Pipeline", with final reports due in early 1983. Ebasco Services, Inc. is to assess the feasibility of bringing gas to Fairbanks (Alaska's second biggest city) **absent** the ANGTS pipeline. Specifically, the contractor will examine the feasibility of a small-diameter gas pipeline and of burning gas on the North Slope and transmitting the generated electricity instead.

2. The Governor's Economic Committee. Trans-Alaska Gas System: Economics of an Alternative for North Slope Gas, January 1983

3. Arlon R. Tussing and Connie C. Barlow, "The Struggle for an Alaska Gas Pipeline: What Went Wrong?" for the U.S. General Accounting Office, November 1982.

4. Ralph M. Parsons Company, "September 1978 Study Report: Sales Gas Conditioning Facility at Prudhoe Bay, Alaska", Volume I.

5. Russell Douglass, Petroleum Reservoir Engineer, Alaska Oil & Gas Conservation Commission, telephone communication to Barlow 11/9/82.

6. Michael J. Economides and Russell D. Osterman, "Options for North Slope Gas Utilization" Fairbanks: University of Alaska for the Alaska Department of Commerce and Economic Development, Division of Energy & Power Development, April 1982.

7. For an overview of the outlook for petrochemicals development in Alaska, see A. R. Tussing and L. S. Kramer, Hydrocarbons Processing: An Introduction to Fuels Refining and Petrochemicals for Alaskans (Anchorage: University of Alaska Institute of Social and Economic Research, 1981)

8. International Energy Agency, Natural Gas Prospects to 2000, 1982. (page 70)

9. L. S. Kramer, R. B. Williams, and G. K. Gregg Erickson, "In-state Use Study for Propane and Butane". Juneau: Kramer Associates for the Alaska Department of Natural Resources, October 1981.

10. CNG Fuel Systems Ltd., Natural Gas Auto Fuel. Calgary, 1982.

11. Battelle Pacific Northwest Laboratories, "Railbelt Electric Power Alternatives Study: Fossil Fuel Availability and Price Forecasts", for the Office of the Governor, State of Alaska, March 1982.

12. Arlon R. Tussing, "An OPEC Obituary", in The Public Interest, Winter 1983. Also, "Reflections on the End of the OPEC Era", in Alaska Review of Social and Economic Conditions, December 1982.

13. Battelle Pacific Northwest Laboratories, "Railbelt Electric Power Alternatives Study: Evaluation of Railbelt Electric Energy Plans", for the Office of the Governor, State of Alaska, February 1982. (page 7.68)

14. Alaska Department of Commerce & Economic Development, "State of Alaska Long Term Energy Plan", 1982. (page II-E.2)

15. Energy User News, November 1, 1982.

16. Battelle, loc cit.

17. The one exception is a report by Gregg K. Erickson, "Natural Gas and Electric Power: Alternatives for the Railbelt", prepared for the Alaska Legislature in March 1981. We share Mr. Erickson's judgment about future availabilities of Cook Inlet gas.

18. See A. R. Tussing & G. K. Erickson, Alaska Energy Planning Studies. A review of three consultant studies submitted to Alaska state agencies in fiscal-year 1982. Office of the Governor, Department of Policy Development and Planning, November 1982. In December 1982, the Anchorage gas-distribution utility (Enstar) announced the purchase of additional reserves of Cook Inlet gas at an initial price of $2.32 per mmbtu --- almost one dollar less than the regulated ceiling price. The actual purchase price will be indexed to oil prices, promising even lower levels in the future.

19. Battelle, op cit, page iv.

20. Battelle, op cit, page vii.

21. See note 18 regarding the December 1982 Enstar purchase. Even though this gas-purchase price seems low by national standards, the likely condition of worldwide gas markets and Cook Inlet markets in particular could set the stage for even better bargains in future transactions.

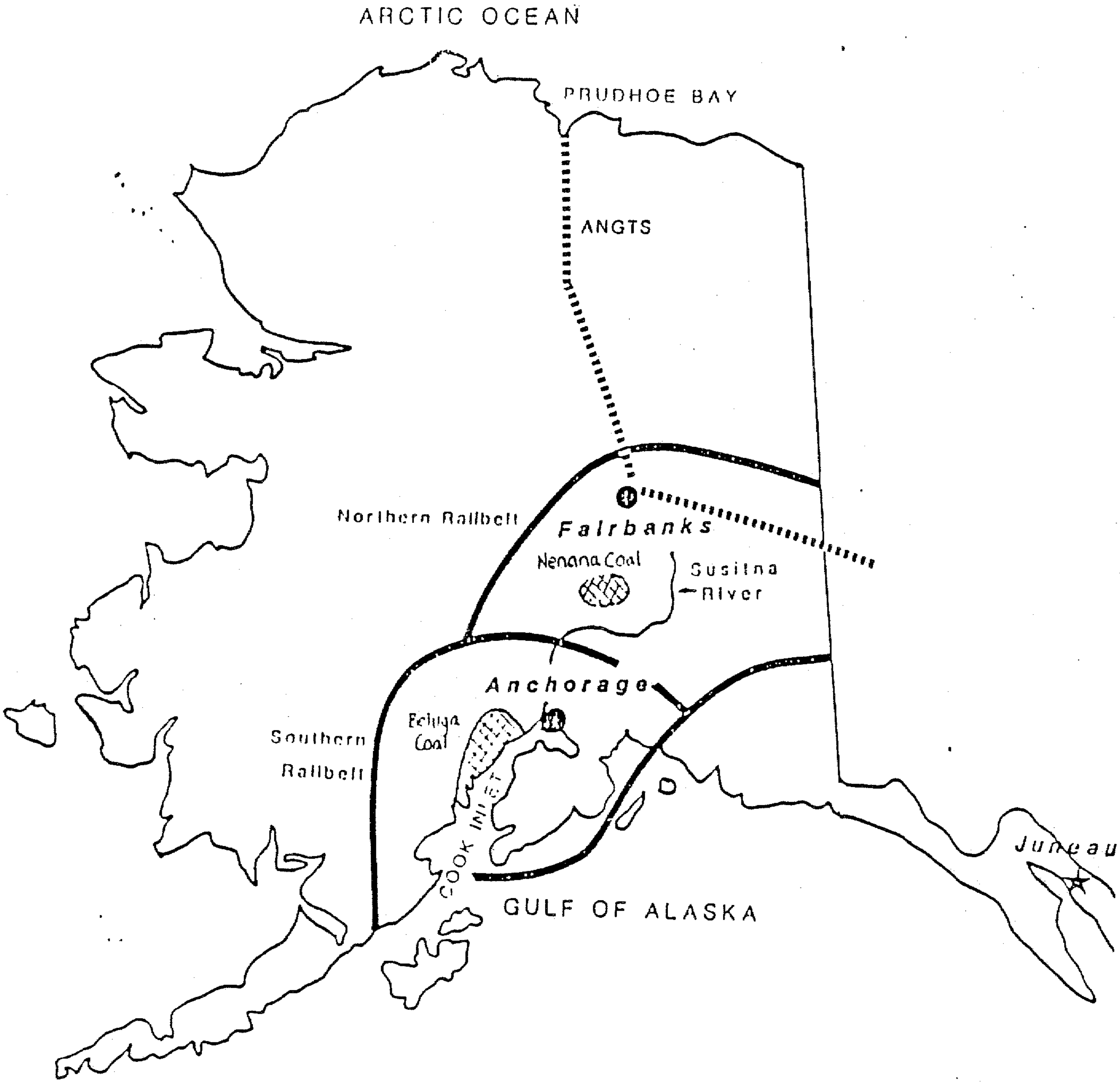
22. In 1981, 23 percent of all households in Anchorage used wood as a secondary heating source, while nearly 15 percent of the homes in outlying areas used wood as the primary heating source. (Alaska Department of Commerce & Economic Development, "State of Alaska Long Term Energy Plan", 1982, page II-16.)

23. Battelle Pacific Northwest Laboratories, "Cook Inlet Natural Gas: Future Availability and Price Forecasts", for the Office of the Governor, State of Alaska, February 1981.

24. U.S. Department of the Interior, "Secretarial Issue Document for Tentative Proposed Final 5-year OCS Leasing Program", March 1982.

25. Testimony of Secretary Edwards, U.S. Department of Energy, at the 1981 Congressional "waiver" hearings.

ENERGY RESOURCES OF THE ALASKA RAILBELT



Adapted from: National Economic Research Associates, Inc., "An Economic Analysis of the Proposed Extension of the Phillips-Marathon LNG Contract with Tokyo Gas and Tokyo Electric," May 1982.