Alaska State Legislature
Joint Committee on Natural Gas Pipelines
November 8, 2001, 2 PM

Testimony by Mark S. Sexton, President & CEO
Evergreen Resources, Inc.

1. INTRODUCTION TESTIMONY

Thank you for the invitation to testify before you today. I regret being unable to do so in person, but please believe if it were possible to be with you, I would do so.

Please allow me several minutes to provide you with an overview of my company, Evergreen Resources. Evergreen is a public independent oil and gas company traded on the New York Stock Exchange under the symbol EVG.

We have provided each of you with an information packet on Evergreen, so if you want further information you can refer to them. Our purpose here is not to do a financial or investment presentation, but if any of you wish to invest, we certainly won't object!

Our operations involve extraction of natural gas from coal beds, primarily from our leases in the Raton Basin of southern Colorado. There are other coal bed methane operations in the Lower 48, some larger, and some not as extensive as Evergreen's.

But there are none executed with more care for the environment and for the communities in which we operate. To that point, the Colorado Oil & Gas Commission has recognized us for excellence – in 1996 and in 2000 as Outstanding Operator for Community Relations and in 1997 for Production Enhancement. In May 2001, Governor Tony Knowles gave Evergreen the Environmental Stewardship Award at the Annual Interstate Oil and Gas Compact Commission Meeting in Anchorage.

We have added jobs to a depressed region, bringing prosperity and vitality where previously the Southern Colorado economy was stagnating.

In the following discussion, you will hear the term "coal bed methane". Please understand that coal bed methane is another word for natural gas. They are the same, except in this case, it is natural gas that comes from coal.

Here's a quick look at the concept behind coal bed methane, our prospects in Alaska, and then we'll show you some examples of our work on our Raton Basin properties.

2. POWEPOINT SLIDES

Topics: **What is Coal bed Methane**
Description of Evergreen's Pioneer Unit
Here is what CBM looks like – EVG's Raton Basin

in place ensures that wells are drilled, cemented, completed and produced in a way that maximizes the resource.

As to our exploration plans, we also have shallow gas leases applications, pending with the state.

Evergreen and along with several other parties, applied for shallow gas leases in the vicinity of the Pioneer Unit in February 2000. Pending the granting of these leases, hopefully by the end of this year, Evergreen will negotiate with the successful lessees and then unitize the acreage. If unitization can be established in 2002, then permitting and exploration activities could also begin that year and new wells could be drilled as early as 2003 or 2004.

4. What is your proposed south-central drilling budget for the next 5 years?

Our proposed budget for 2002 is roughly $5 million dollars. If successful, we expect our pace to accelerate prudently each year thereafter, like we have in the Raton Basin. As an illustration, this year, we will drill, complete and place on line 140 wells in the Raton Basin. This requires in excess of $75 million dollars this year alone. To date, Evergreen's investment in the Raton Basin exceeds one quarter of one billion dollars.

5. What is your current assessment of south-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and best cases, please generally describe each case.

Our view of South-Central gas demand calls for a continuation of the slow growth that we have seen for the last 30 years. During that time, yearly demand has slowly climbed from 145 BCF to about 210 BCF, an increase of about two BCF per year. Barring major changes in supplies, consumption, or pricing, we expect this trend to continue.

6. We have heard that "deliverability," the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next ten years. Please discuss what can be done to reduce any deliverability problem.

As proven producing gas reserves dwindle, delivering peak volumes on the coldest winter day becomes more difficult. Short-term solutions include additional compression, recompletion of existing wells, or drilling new wells in established fields could increase peak delivery.

The long-term solution is to develop new gas supplies like coal bed methane.

7. Finally, do you have any recommended state legislation the committee should consider to advance the development of natural gas within the state?

Yes, there is legislation that could advance the development of coal bed natural gas.

You probably noticed that throughout my testimony, that I have prefaced my conversations with the word "IF" as in "if coal bed methane is successful, then this is what it can provide for Alaska". Here, I stress the word "IF". <pause> I am confident that if coal gas can be produced in Alaska, then Evergreen is the company to do it. We have the technical expertise and the state of the art equipment required to make CBM a technical success. So we can get gas out of the ground; whether or not we can do it economically, in many ways, rests with the decisions of the legislators in this room.

Friends of ANWR:

After 15 years of trying to open ANWR, maybe a different strategy is in order.

What is missing in the debate over ANWR - **A viable national energy program that WILL have a effect on reducing US imports with the most amount of States (people) participating.**

All you hear today in Alaska is talk about ANWR. While ANWR will have a benefit for the US, it is doubtful that it would be producing by the end of this decade. Most Americans see little benefit for them, only "rich" Alaskans with their PFD's getting richer while we destroy "their" wilderness.

There is a viable program that should be **included** in the ANWR debate that would have a tremendous benefit for Alaska and more importantly, the rest of the US. Maybe a little "sugar" for the rest of the US will slow or end the resistance in the lower 48 against ANWR, because we know few in Alaska are opposed.

A North Slope gas to liquids (GTL's) program followed by a lower 48 coal based gas to liquids program can work in 38 different states. Think of the support you may get for an Alaska program when there could be jobs, energy production, tax base and valued added industries across the US.

Also, the debate on ANWR does not include a viable way to develop the extensive gas reserves of Alaska, dramatically reduce US dependence on foreign crude and improve the US environment that WILL play to all sides of this very contentious issue.

I have long been a proponent of GTL's as one solution for Alaska's stranded natural gas and lower 48 coal based GTL's as one answer for reducing US dependence on foreign crude imports. It could also help the ANWR issue and GTL's are the ONLY viable option on the horizon that can significantly reduce US dependance on foreign crude oil and products.

If the US wants a National Energy Policy to reduce its dependence on foreign crude oil it can to look to the example of the South African's. South Africa pioneered coal gasification - gas to liquids in the 50's and expanded the program in the 70's when OPEC boycotted the US in order to reduce its imports of foreign crude.

Today with advances in GTL technology, the US can build more efficient gasification - GTL plants for far less than what it cost South Africa.

The Alaskan North Slope contains enough natural gas to make approximately 1 million barrels per day of synthetic fuels that can be transported down the existing crude oil line to Valdez for shipment to the lower 48, still leaving room for development of ANWR.

GTL's from Alaska's North Slope can start the process TODAY, educating American's with the possibilities of GTL's and the real promise of reducing US imports of crude oil and products. Coal based GTL's can produce not only the cleanest motor fuels know to man, the gasification program can also produce electricity as efficiently and environmentally effectively as natural gas.

The US has enough coal reserves in 38 states across the nation to make over 10 million barrels per day of synthetic motor fuels (gasoline and diesel) **for at least 200 years. Now this is a reduction in US imports worth talking about.**

Reliable, Affordable and Environmental Sound Energy for America's Future, GTL's Gas to Liquids. The President's "Energy Policy" with a little kicker.

One solution that can happen TODAY in Alaska and in 38 + states across America in the near future.

GTL technology is proven and cost effective.

A North Slope GTL proposal can result in the US, replacing up to 25% of its "dirty" diesel with this new clean burning fuel.

Fischer-Tropsch (F-T) produced GTL's are odorless, non-toxic and completely biodegradable on land or water according to the US EPA.

Over 36 billion gallons of these ultra clean fuels have been produced in South Africa and other locations around the world.

Alaska can become a major producer of these ultra clean fuels if it so chooses, but it will take tremendous pressure from the people and environmental community to make it happen. Alaska has enough existing natural gas to make upwards of 1 million barrels per day of these ultra clean fuels and enough capacity in the existing oil pipeline to transport these fuels; plus develop ANWR.

America is not as short of clean energy as we are critically short of a comprehensive energy policy that can wean us off foreign crude and products.

It could be that by marrying ANWR with an energy program that can benefit all Americans and physically be located in upwards of 38 States, Alaskan's can finally achieve their goal of developing ANWR.

To learn more about GTL's see our web site at www.angtl.com

Respectively,

Richard Peterson
A friend of ANWR and GTL's for a stronger Alaska and US.

ENSTAR

Natural Gas Company

ALASKA STATE LEGISLATURE

Joint Committee on Natural Gas Pipelines

November 8, 2001

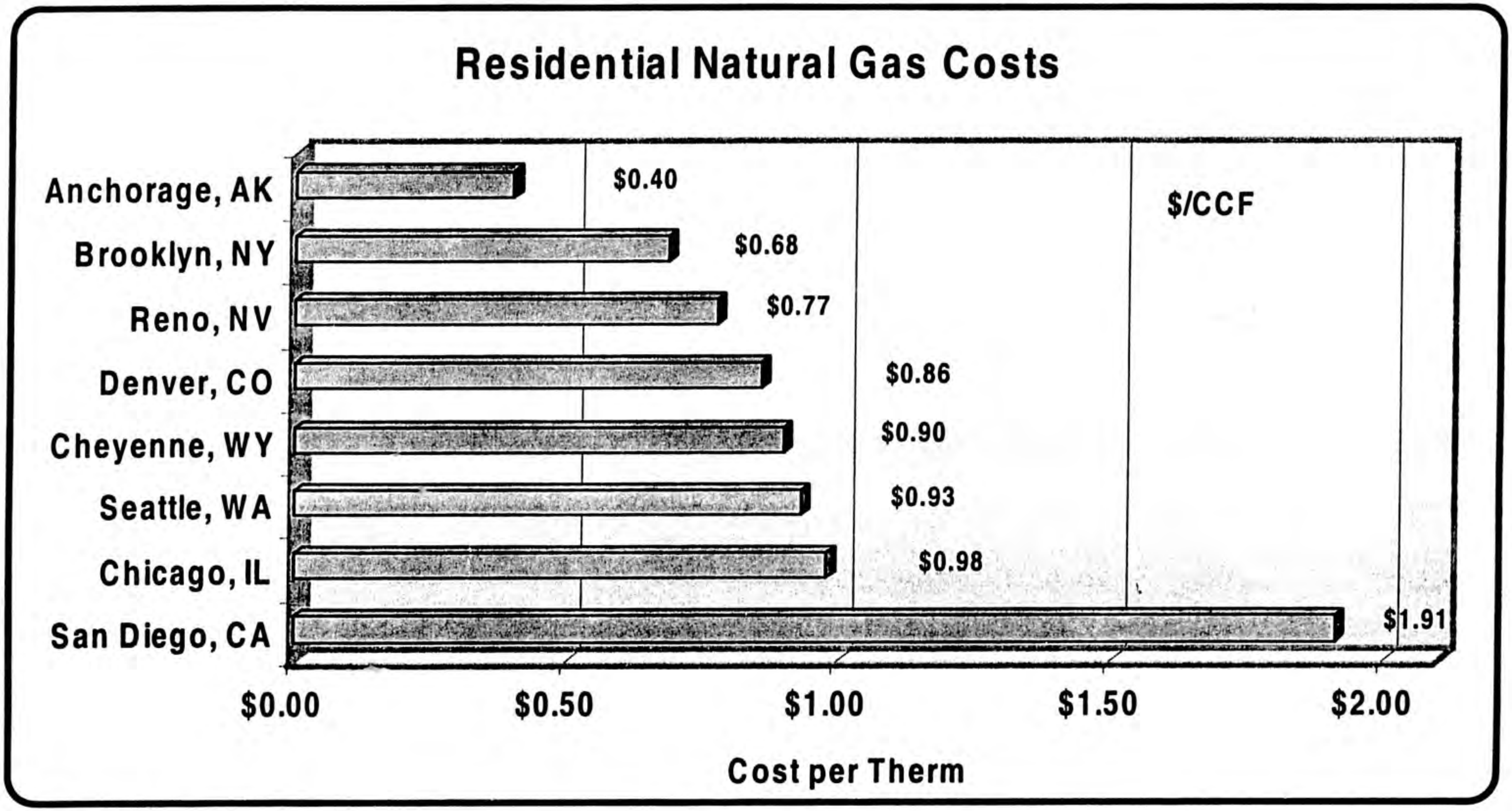
ENSTAR

- Company Overview
- Projected Gas Usage
- South-central demand & deliverability

ENSTAR

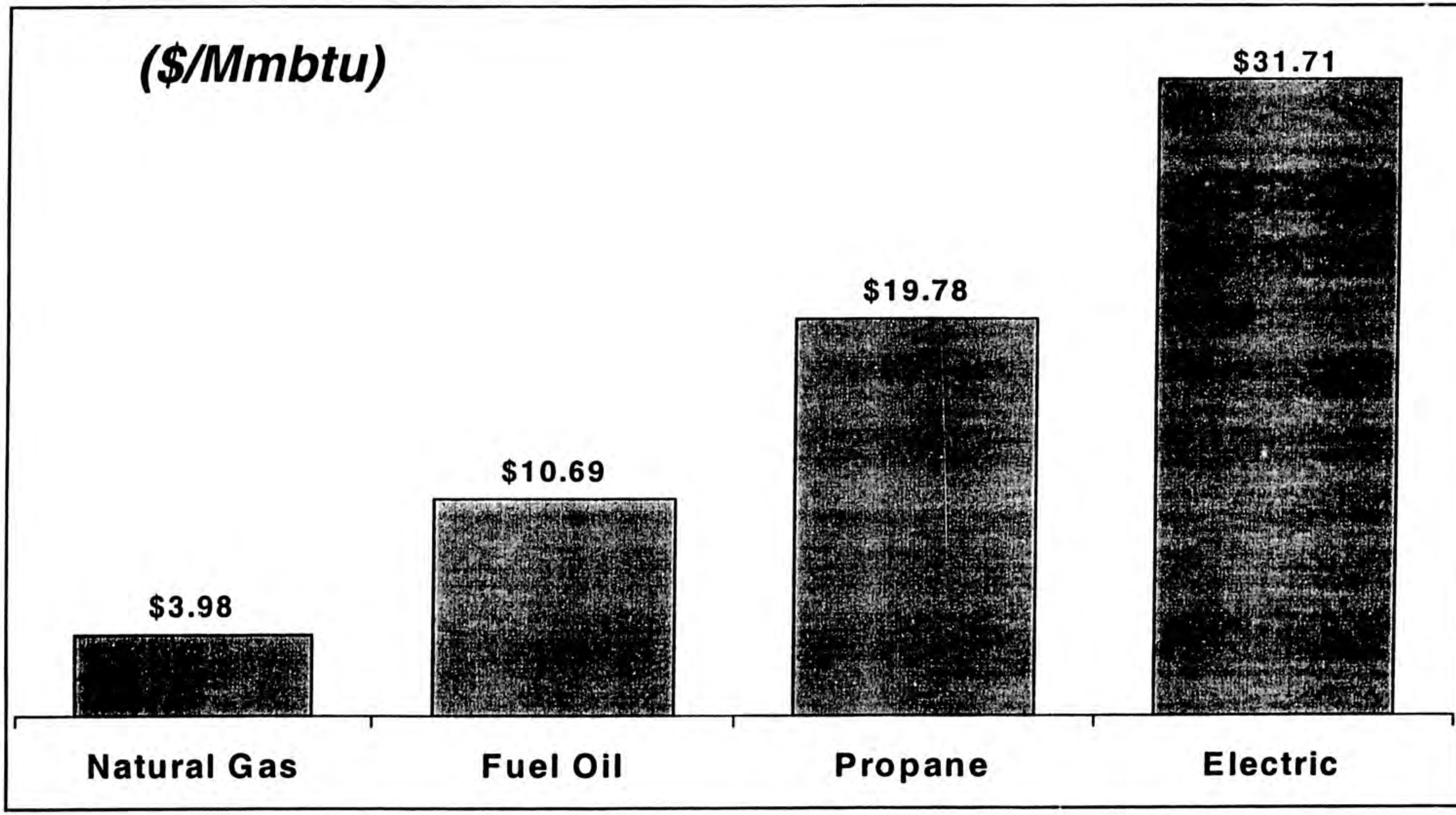
- Local Distribution Company based in Anchorage
- Commenced operation in August 1961
- Currently serve 106,800 customers
- Some of the lowest gas rates in the country
- Highest gas usage per residential customer among investor-owned utilities in U.S.

ENSTAR



ENSTAR

1 CCF is equal to 100,000 BTUs

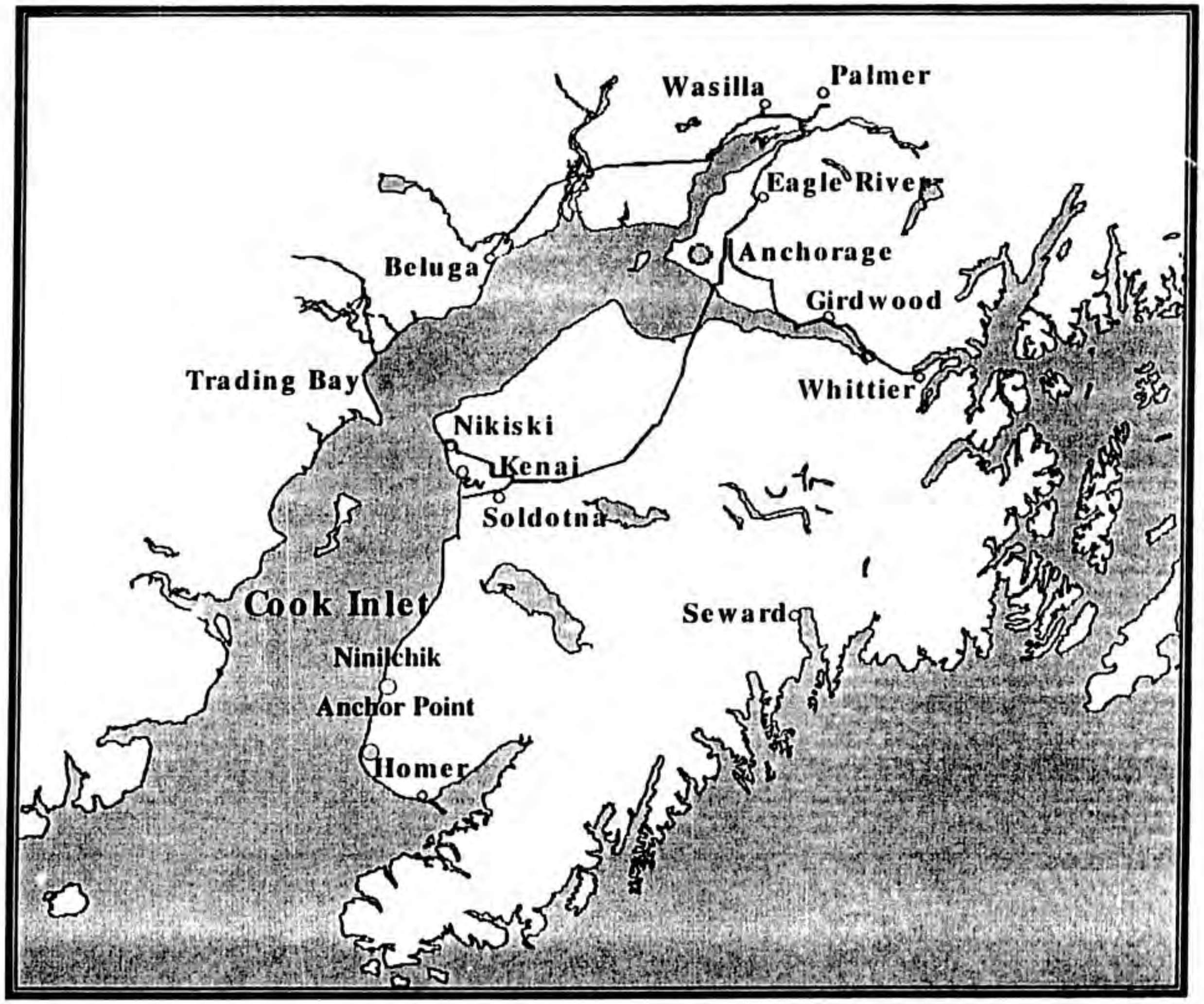


($/Mmbtu)
$3.98
$10.69
$19.78
$31.71
Natural Gas
Fuel Oil
Propane
Electric

Expansion Plans

- Future plans to expand our system to Ninilchik, Anchor Point, and Homer
- ENSTAR owns and operates over 2,700 miles of Distribution and Transmission Pipeline

ENSTAR

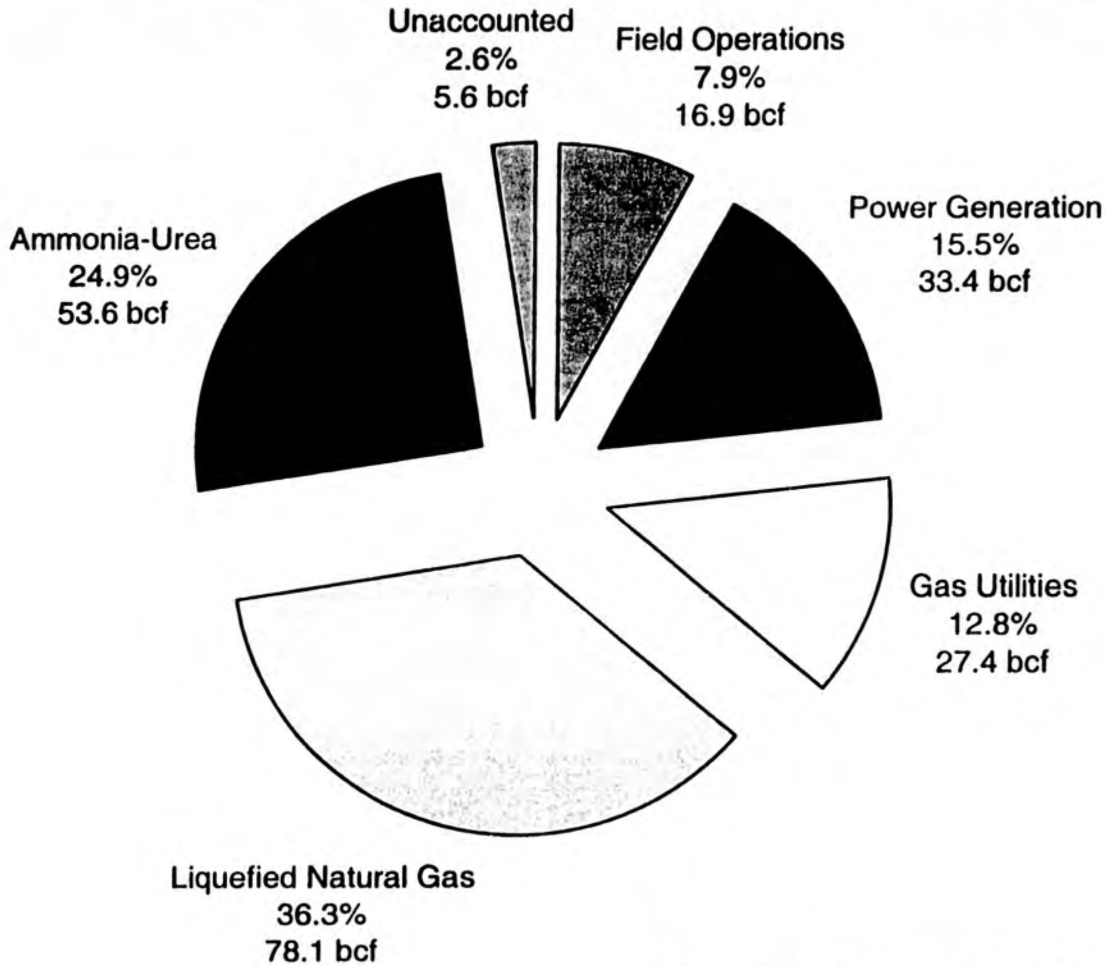

Wasilla
Palmer
Eagle River
Anchorage
Girdwood
Beluga
Trading Bay
Whittier
Nikiski
Kenai
Soldotna
Cook Inlet
Seward
Ninilchik
Anchor Point
Homer

ENSTAR

- Company Overview
- **Projected Gas Usage**
- South-central demand & deliverability

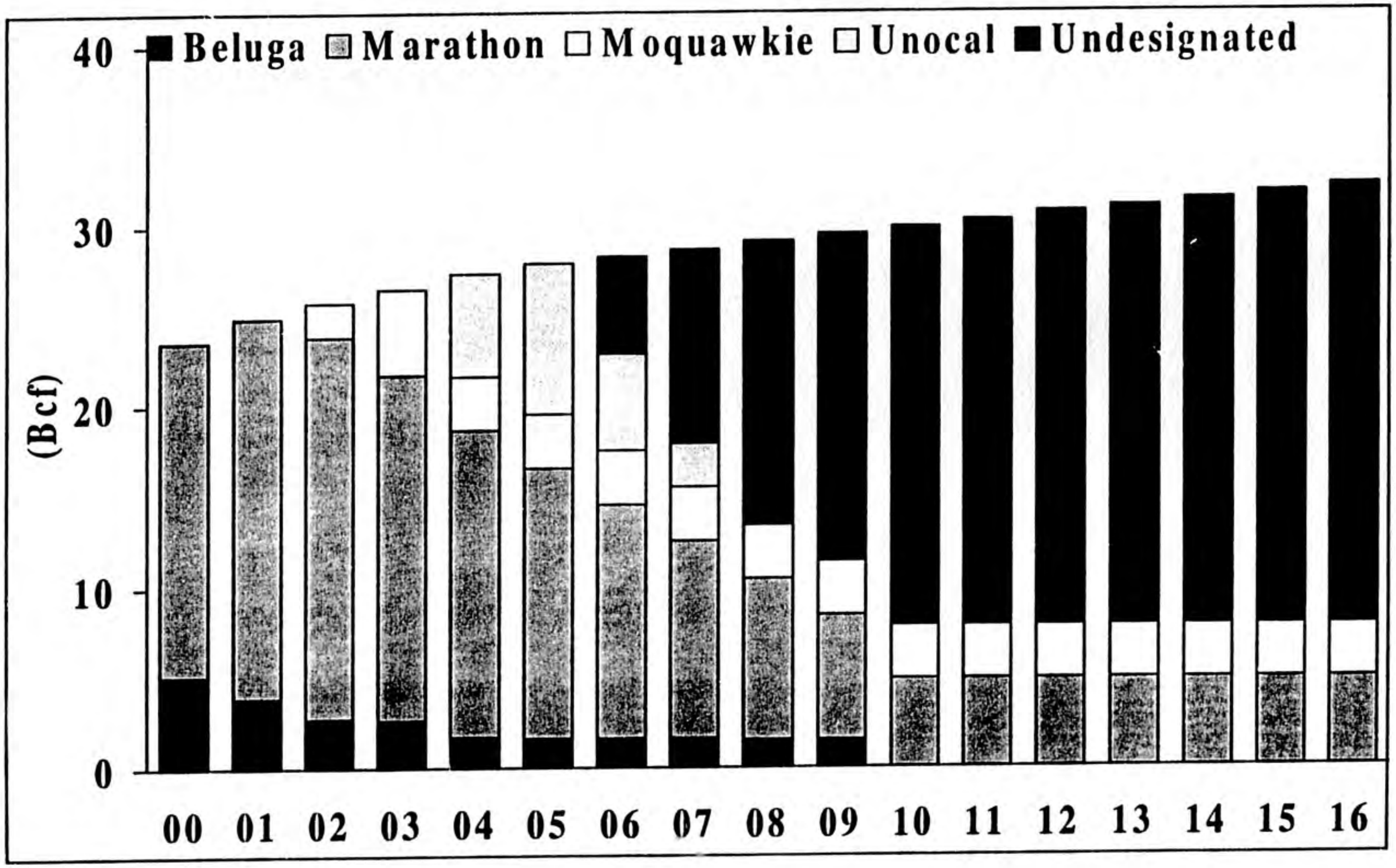
ENSTAR

Cook Inlet Historical Gas Consumption by Type, 1998



ENSTAR

Source: DNR, Division of Oil and Gas, 2001a


Beluga
Marathon
Moquawkie
Unocal
Undesignated
(Bcf)
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ENSTAR

- Gas is purchased under long-term contracts with Marathon, Chevron, ML&P, & Phillips
- Gas is indexed to changes in the price of crude oil
- Gas supply costs passed through to customers
- No take-or-pay liability
- Two new Supply Contracts
  - Moquawkie (Anadarko & Phillips) deliveries start 1/1/02
  - Unocal – deliveries scheduled to start 1/1/04
- Currently talking with producers for future supplies

ENSTAR

- Company Overview
- Projected Gas Usage
- **South-central demand & deliverability**

ENSTAR

[redacted]

- **The Near Term [2001-2008]**
- **The Medium Term [2009-2019]**
- **The Long Term [After 2019]**

ENSTAR

The Near Term [2001-2008]

- By the middle of this decade, it may be become difficult to meet winter peak demands without new discoveries or development of peaking facilities.
- Industrial usage reduction may be needed to meet winter peak demand.
- ENSTAR has entered into new supply contracts at higher prices in an effort to spur exploration and increase reserves.
- ENSTAR's new Gas Supply Contract with Unocal contemplates that gas storage will be developed.

ENSTAR

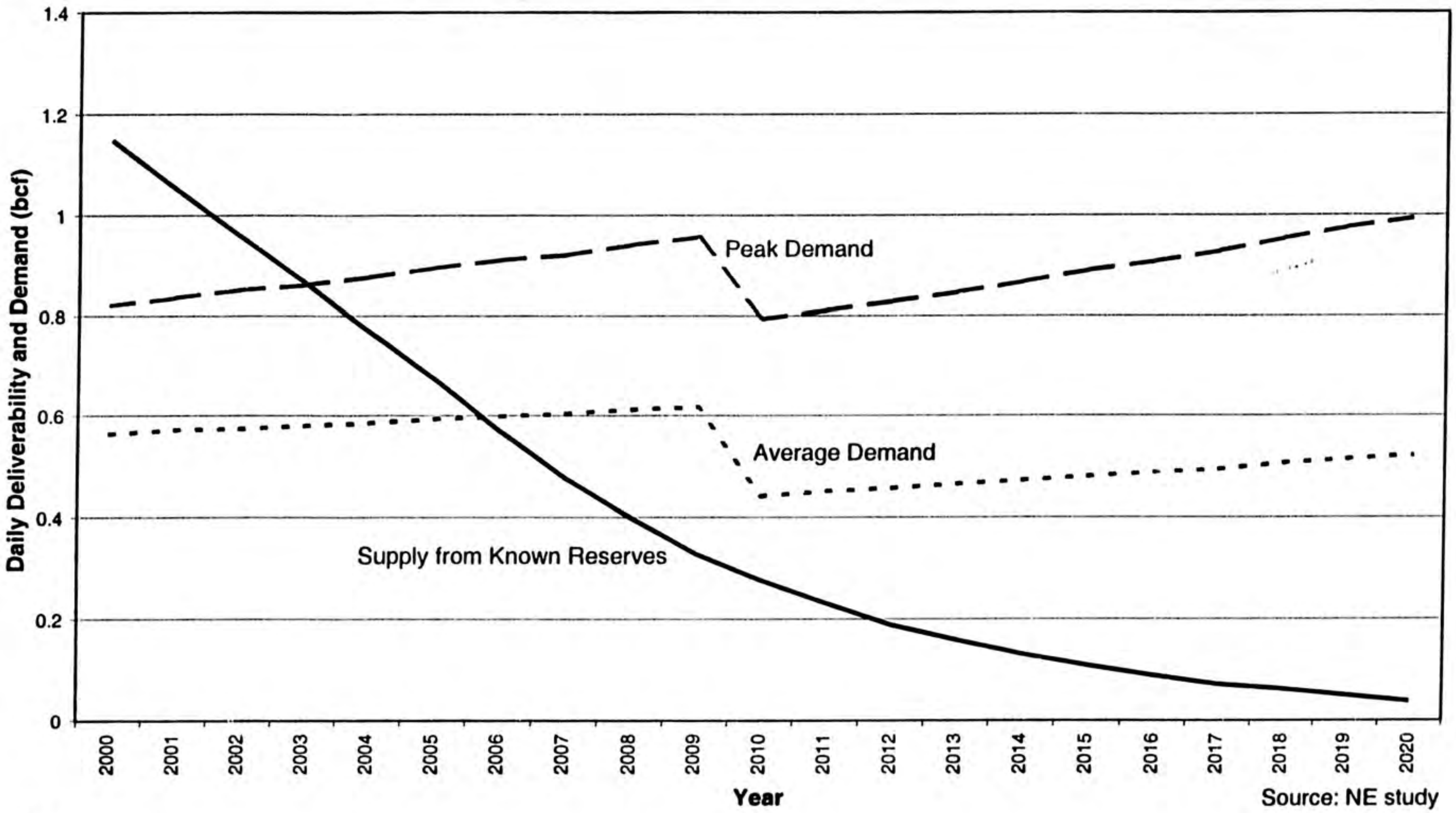
The Medium Term [2009-2019]

- Peak and daily deliverability become more difficult if –
  - Approximately 2 TCF of additional reserves are not added
  - Industrial use continues after 2009
- Federal LNG license may be at risk

ENSTAR

[redacted]

Estimated Deliverability Timeline Assuming that Industrial Use is Reduced by Half in 2010



ENSTAR

The Long Term [After 2019]

- Current natural gas reserves in Cook Inlet will most likely be unable to meet the demand of the Cook Inlet region unless –
  - 2 TCF of reserves are added
  - Industrial use is discontinued after 2009
- After 2020 significant new reserves or North Slope Gas is necessary

ENSTAR

- Cook Inlet natural gas reserves are sufficient to meet residential and commercial needs in the near term. New reserves and/or storage will improve near-term deliverability during peak demand.
- ENSTAR is optimistic about future growth (Ninilchik, Anchor Point, & Homer).
- ENSTAR supports an in-state route for North Slope Gas to ensure access to reliable low cost energy for future generations of Alaskans.

ENSTAR

Natural Gas Company

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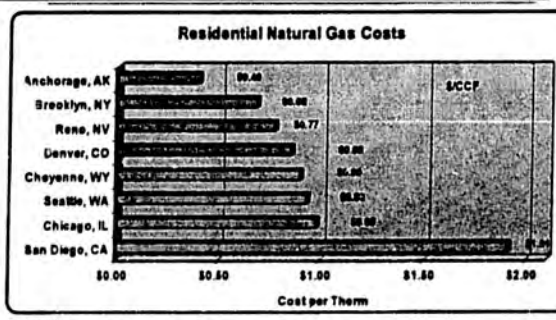
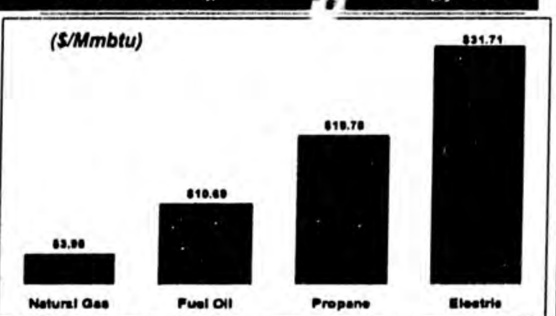
Low Residential Natural Gas Rates



1 CCF is equal to 100,000 BTUs

Lowest Average Residential Energy Costs



ENSTAR Overview

Expansion Plans

- Future plans to expand our system to Ninilchik, Anchor Point, and Homer
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ENSTAR Transmission Pipelines

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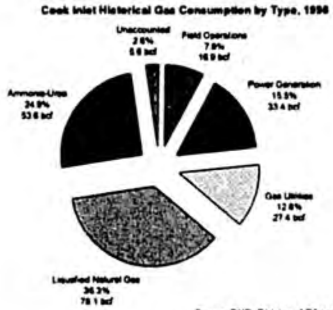
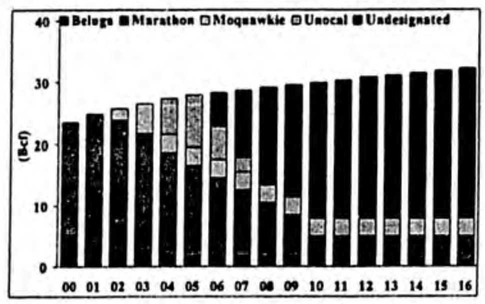
Cook Inlet Consumption



ENSTAR Projected Gas Use



Gas Supply Considerations

- Gas is purchased under long-term contracts with Marathon, Chevron, ML&P, & Phillips
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Demand and Deliverability

- The Near Term [2001-2008]
- The Medium Term [2009-2019]
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Demand and Deliverability

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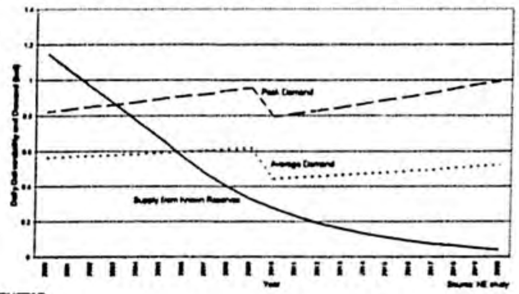
Deliverability

Estimated Deliverability Timeline Assuming that Industrial Use is Reduced by Half in 2010



Demand and Deliverability

The Long Term [After 2019]

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In summary

- Cook Inlet natural gas reserves are sufficient to meet residential and commercial needs in the near term. New reserves and/or storage will improve near-term deliverability during peak demand.
- ENSTAR is optimistic about future growth (Ninilchik, Anchor Point, & Homer).
- ENSTAR supports an in-state route for North Slope Gas to ensure access to reliable low cost energy for future generations of Alaskans.

ENSTAR

Providing Alaskans with safe, clean, economical natural gas for 40 years.

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

TESTIMONY of JOHN ELLWOOD
EXECUTIVE VICE PRESIDENT AND
CHIEF OPERATING OFFICER

FOOTHILLS PIPE LINES LTD.

KENAI, ALASKA NOVEMBER 7-8, 2001

Alaska State Legislature Joint Committee on Natural Gas Pipelines

Mr. Chairman:

Thank you for the invitation to appear before your committee and to report on the progress of the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project.

Foothills appeared before your committee on July 18, August 15 and September 19, 2001. During the earlier appearances we spoke to issues of the ANGTS advantages, Alaska benefits, pipeline access, status of the pipeline and the various permits. The later appearance focused on our position regarding the federal legislation proposed by the Alaska producer group.

Since that time, U.S. Senate hearings on Alaska natural gas were held in Washington and the Alaska Highway Natural Gas Policy Council forwarded its recommendations to the Governor. Foothills appreciates the efforts of policy makers involved in both of these proceedings.

Mr. Chairman, I would like at this time to express our appreciation to you and to the committee for your words and contribution to the US Senate Energy Committee hearings.

Today I would propose to report progress by Foothills on three fronts:

- The Alaska Northwest Natural Gas Transportation Company (ANNGTC) partnership.
- Foothills commercial proposal.
- Work on the pipeline right-of-way.

<u>Alaska Northwest Natural gas Transportation Company (ANNGTC)</u>

We are aware of a lingering concern regarding the so-called withdrawn partners issue and alleged liabilities associated with that issue.

When I appeared before your committee in July of this year, I indicated that Foothills had undertaken discussions to re-enlist the Withdrawn Partners of the ANNGTC.

In our testimony before the US Senate Energy Committee on October 2, 2001, Foothills said:

> "In the initial stages of the Alaska Highway Project, numerous U.S. energy companies were partners in the Alaska Partnership. However, during the decade of the 1980s and the 1990s when the producers of Alaska natural gas were unwilling to commit that gas to Lower 48 markets because of low energy prices,

> all of the U.S. partners withdrew from the Alaska Partnership. Foothills and TransCanada, as the two remaining partners, have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. The negotiations with these companies have been productive and are ongoing"

Last month we followed-up our testimony with a letter expanding on the re-enlistment process.

> " Earlier this month we testified before the Committee on Energy and Natural Resources regarding our efforts to reconstitute the Alaska Northwest Natural Gas Transportation Company (Alaska Partnership) by re-enlisting the withdrawn partners. We are writing today on behalf of TransCanada and Foothills, and, with the authorization of the withdrawn partners – Duke, El Paso, Enron, PG&E Corporation, Sempra and Williams specifically with respect to the re-enlistment process. We are pleased to report that continued progress has been made on the critical issues, including the key principles for re-enlistment by any withdrawn partner who so elects in the Alaska Partnership, for the purpose of constructing the Alaska Natural Gas Transportation System (ANGTS).
>
> We have already scheduled further meetings so that we can continue to work on the details for reconstituting the Alaska Partnership. It is anticipated that all parties will have signed a Memorandum of Understanding (MOU) within the next month. TransCanada, Foothills and the withdrawn partners are committed to eliminating commercial barriers to construction of the ANGTS and in so doing would be prepared to release contingent claims against the Alaska Partnership related to previous investments in the ANGTS as part of a commercial arrangement to ensure a market viable project."

Our negotiations with the withdrawn partners are approaching the final stages and we are confident of meeting our timeline for the successful conclusion of an agreement..

Commercial Proposal

A commercial agreement with the Alaska producers is an important prerequisite to any pipeline project.

Achieving such an agreement has been delayed, in part, because of the withdrawn partnership issue overhanging the project, and because the Alaska North Slope are focused on completing their project feasibility study.

In our October evidence before the US Senate Energy Committee, we said:

> "An important first step towards commercial viability of an Alaska gas pipeline is a commercial agreement between the producers and potential shippers who, in turn, enter into transportation contracts with the owners and operators of the transportation system. In this regard, the Alaska Partnership has pursued discussions with the producers for the last several months. After several

> discussions with the producers over the last year, it has been agreed that we will develop a commercial proposal to present to the producers before the end of the year."

The above referenced October testimony also stated:

> "The next step on our critical path will be to prepare, present to, and negotiate with the producers of Alaska North Slope natural gas a comprehensive commercial proposal for a pipeline project. Based on the progress we have made since the Energy Committee hearings, we are confident that such a proposal will be presented to the producers before the end of the year. As companies with long-standing interest in building and owning an Alaska natural gas pipeline, we have every incentive to reach a commercial arrangement with the producers to develop a viable project. We believe that such an arrangement will be achieved on a timely basis, consistent with the energy needs of the Nation."

With regards to the negotiations with the North Slope Producers, we remain confident that we will reach a commercial arrangement to develop a viable project.

<u>Pipeline Right-of-Way</u>

The Alaska Natural Gas Transportation System from Prudhoe to Alberta is approximately 1,750 miles long.

Access to land is becoming a difficult challenge for all North American pipeline projects. Public lands constitute the majority of the property through which the pipeline will pass.

Foothills is well advanced along the road of securing the pipeline right-of-way. More than 400 miles of right-of-way on federal lands has been acquired. Currently, we are making progress on securing the 200 miles of right-of-way on State lands with the Gas Pipeline Office. Work is under way to assess the information that was previously submitted in an earlier application, and a process to move forward has been identified. With the State right-of-way lease expected to in hand by2003, over 90% of the right-of-way for the project will have been acquired or reserved.

Let's summarize the progress of the Alaska Highway Pipeline project.

1. The United States and Canada have determined that the ANNGTC/Foothills (ANGTS) Alaska Highway Pipeline project is:

    (a) Necessary.
    (b) In the public interest.
    (c) Should be granted a unique fast track status.

2. Foothills and TransCanada have offered to the current holders of the withdrawn partner interests an opportunity to rejoin the Alaska Partnership. Negotiations have been productive and we are well on our way to re-assembling the Alaska Partnership.

3. A commercial arrangement between a coalition of North American pipeline companies and an Alaska natural gas producer group is the next key milestone. We are working towards that end.

    - A commercial arrangement will allow the project to move to the next phase of the project ... "the countdown to construction" phase.

    - A substantial amount of this work has already been completed and more is currently being done "on spec" to further expedite this stage of the project.

4. As I indicated, we have made substantial progress in the area of pipeline right-of-way.

5. In moving forward we will comply with the technical and environmental conditions established by President Carter when he approved our project. In doing so we intend to work with interested stakeholders. Over the coming months we will take steps to establish a consultation process that will enable interested Alaskans to become involved in the project.

6. We are committed to maximizing Alaska benefits consistent with prudent economic efficiencies. The Governor's Policy Council has made reasonable recommendations in this regard.

Ultimately the final decision to construct a pipeline will rest with the gas producers. We remain confident that the long-term demand for and the price of natural gas in the North American markets will support this project.

ANGTL COMPANY
ALASKA NATURAL GAS TO LIQUIDS

November 8, 2001

The Honorable John Torgerson
Chair, Joint Committee On Natural Gas Pipelines
Alaska State Legislature
35477 Kenai Spur Highway, Suite 101A
Soldotna, Alaska 99669

Senator Torgerson:

Thank you for the opportunity to address your committee relating to a GTL project for the North Slope and on issues of gas supply and demand for Cook Inlet natural gas.

I would like to make a few comments about U.S. energy independence in light of the September 11th terrorist attack on the US.

I have long been a proponent of GTL's as one solution for Alaska's stranded natural gas and coal based GTL's as one answer for reducing US dependence on foreign crude imports. Many others are interested in the prospects of GTL's but are waiting for some sign from the Federal and Alaskan Governments that they are willing to support GTL programs.

If the US wants a National Energy Policy to reduce its dependence on foreign crude oil it can to look to the example of the South African's. South Africa pioneered coal gasification - gas to liquids in the 50's and expanded the program in the 70's when OPEC boycotted the US in order to reduce its imports of foreign crude.

Today with advances in GTL technology, the US can build more efficient gasification - GTL plants for far less than what it cost South Africa. The US has enough coal reserves in 38 states across the nation to make over 10 million barrels per day of synthetic motor fuels for over 200 years.

The Alaskan North Slope contains enough natural gas to make a 1 million barrels per day of synthetic fuels that can be transported down the existing crude oil line to Valdez for shipment to the lower 48. Of importance also is that a GTL batching program will

ANGTL's proposal can result in the US, replacing up to 25% of its "dirty" diesel with this new clean burning fuel. The existing crude oil refiners don't want that to happen because it will cost them money.

Each year US refiners cite lack of domestic refining capacity to meet the summer driving needs as justification to raise the price of gasoline and diesel 25¢ to 35¢/gallon. An Alaskan GTL program could end this US refining short fall, resulting in $billions less to the oil companies.

F-T produced GTL's are odorless, non-toxic and completely biodegradable on land or water according to the US EPA. The $3+ million cost to clean up of the diesel spill from the fishing boat Windy Bay in Prince Williams Sound this past August could have been a non event.

Alaska can become a major producer of these ultra clean fuels if it so chooses, but it will take tremendous pressure from the people and environmental community to make it happen. Alaska has enough existing natural gas to make upwards of 1 million barrels per day of these ultra clean fuels and enough capacity in the existing oil pipeline to transport these fuels; plus develop ANWR.

America is not as short of clean energy as we are critically short of a comprehensive energy policy that can wean us off foreign crude and products.

There are many misconceptions about an Alaskan GTL program and about GTL's in general.

Too many BTU's are wasted

Natural gas from the North Slope must be converted into useful energy by some process. Home heating, electric generation, transportation fuels, industrial processes. None are 100% efficient. Most industrial processes, including electric generation are at best 50% efficient. Did you know that the gas turbines used to generate electricity are only about 40% to 50 % efficient.

The truth is that the actual GTL conversion process converts approximately 70% of the natural gas BTU into synthetic fuels. If you capture the "waste" heat for electric generation, the CO2 for enhanced oil recovery and process water to reduce energy consumption, you end up converting more BTU's in the natural gas to useful products.

Of course the finished products from the GTL process are for the most part more valuable than natural gas, certainly from a National Energy Policy point of view.

There is enough Natural Gas on the North Slope for several projects.

The truth is that a 4 BCF/D gas line will need at least 36 TCF. No other project can be financed until gas producers "prove" up additional reserves. While it is easy to say the North Slope contains 50 to 100 TCF of gas reserves, until they are "proven" no other project can be financed and built. A .5 to 1 BCF/D GTL project that can be economically done TODAY still leaves enough gas for a

Gas to liquid plants are very expensive but will produce environmentally superior natural gas based "alternative" fuels for the motor fuels market. It is important to note that GTL's are NOT petroleum based. Compressed natural gas (CNG), is also an "alternative" fuel for use in the motor fuels market. Under existing motor fuels tax schedules, CNG is taxed at a lower rate than petroleum based motor fuels. If GTL's, which are also natural gas based like CNG, are taxed at the same rate as CNG, then the GTL producer will keep up to $13/bbl more of the price collected for its fuel at the pump resulting in a higher net-back to the well head and an acceptable rate of return on the plant investment. This is not additional Federal and State support, it is being taxed at the same rate as other natural gas based alternative motor fuels.

One Major Oil company claims that any form of Federal "subsidy" is unacceptable and sends the wrong signals to the market. This same oil company gladly accepted an exemption to the "wind fall profit tax" for their Alaskan crude to help pay off their "expensive" Alaskan oil line. Are these majors willing to accept subsidies when they help them, but unwilling to allow them if they help others and reduce US dependence on foreign crude oil?

Now I would like to move on the Cook Inlet / Kenai area.

The ANGTL Company is looking at two different GTL programs in the Cook Inlet area. They are for the most part mutually exclusive in that natural gas price and availability will dictate which direction we go.

Some believe that the Cook Inlet area is short on natural gas and the long term outlook is for limited resources and higher natural gas prices well in excess of $2.50 to $3.00 / mcf. Still others believe that the region has vast supplies of natural gas but little or no new market demand for base load supplies to warrant much additional exploration.

In the scenario of abundant gas supply in the Cook Inlet area - $2.00 or under gas prices.

ANGTL has proposed to contract with several Cook Inlet producers to purchase up to 70,000 mcf/d of natural gas (25 bcf/yr) for a minimum of 12 years (300 bcf) and preferably 25 years (640 bcf) to base load a GTL plant built adjacent to the Tesoro and Agrium facilities on the Kenai. Based upon a preliminary engineering study preformed by Dresser Engineering, the estimated plant cost should be in the $250 million dollar range for a 8,500 bbl/d plant. The limiting plant size is the availability of the natural gas feed stock.

The natural gas will be sold to the plant on a net back basis determined by the revenues received from the sale of the different products. As you know the GTL plant produces excess hydrogen and nitrogen, two of the primary feed stocks for the fertilizer plant. The GTL plant plans to will export these feed stocks to the fertilizer plant for incremental ammonia and urea production. Thus potentially lowering the overall cost of the fertilizer plant, improving the economics of the plant and its ability to pay market value for natural gas while competing in an export products market.

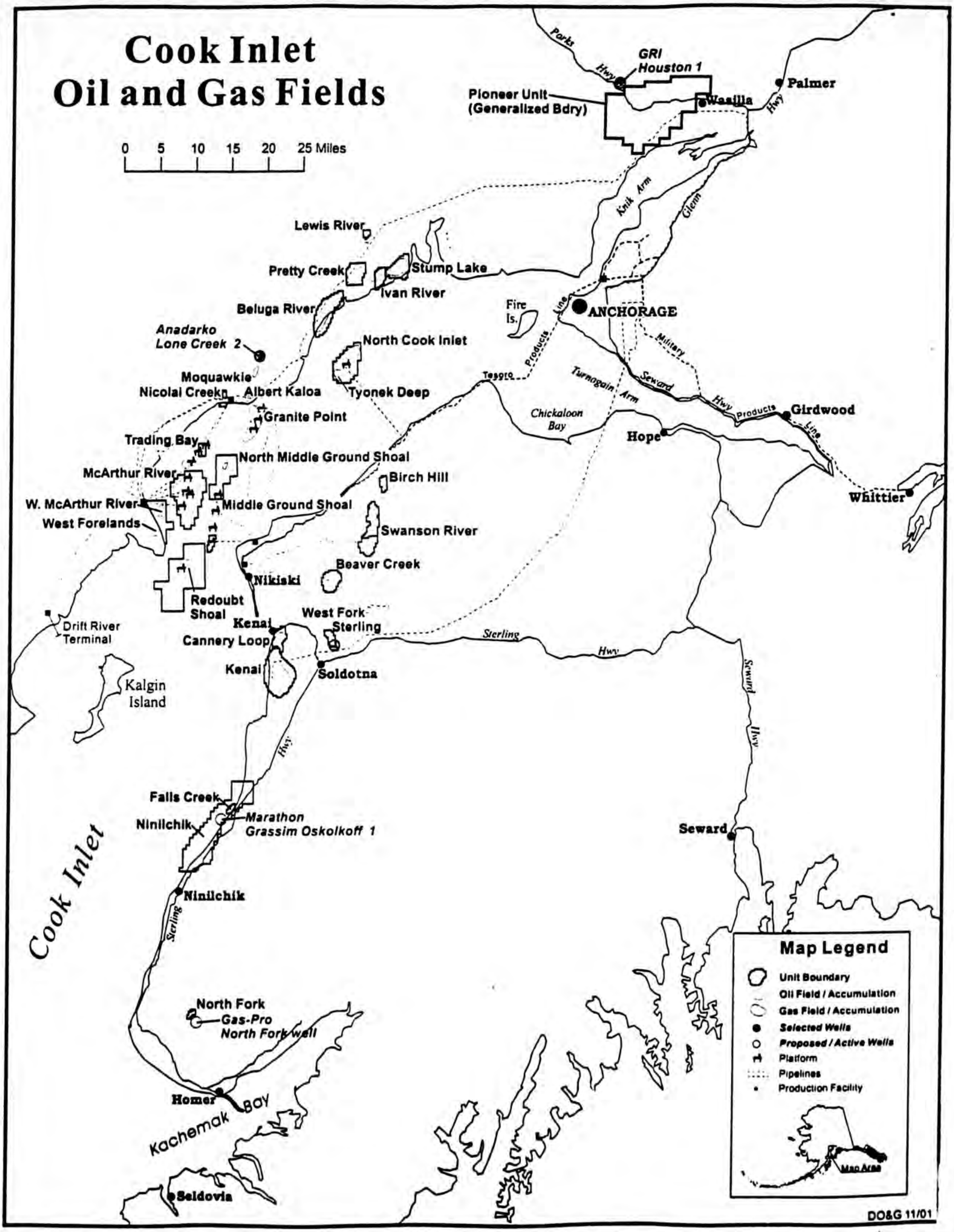
Presentation to the Joint Committee on Natural Gas Pipelines

Bill VanDyke, Petroleum Manager
Tim Ryherd, Geologist
Will Nebesky, Commercial Analyst

Alaska D.N.R. - Division of Oil and Gas
November 8, 2001

Alaska Department of
Natural
Resources

http://www.dog.dnr.state.ak.us/oil/index.htm


Cook Inlet
Oil and Gas Fields
0 5 10 15 20 25 Miles
GRI
Houston 1
Pioneer Unit
(Generalized Bdry)
Wasilla
Palmer
Parks Hwy
Hwy
Knik Arm
Glenn
Lewis River
Pretty Creek
Stump Lake
Ivan River
Beluga River
Anadarko
Lone Creek 2
Fire Is.
ANCHORAGE
North Cook Inlet
Moquawkie
Nicolai Creek
Albert Kaloa
Tyonek Deep
Products Line
Military
Tesoro
Turnagain Arm
Seward
Hwy
Products
Girdwood
Line
Chickaloon Bay
Hope
Granite Point
Trading Bay
North Middle Ground Shoal
McArthur River
Birch Hill
W. McArthur River
Middle Ground Shoal
West Forelands
Swanson River
Whittier
Beaver Creek
Nikiski
Redoubt Shoal
Drift River Terminal
Kenai
West Fork
Sterling
Cannery Loop
Sterling
Hwy
Kenai
Soldotna
Kalgin Island
Seward
Hwy
Hwy
Falls Creek
Ninilchik
Marathon
Grassim Oskolkoff 1
Seward
Ninilchik
Cook Inlet
Sterling
North Fork
Gas-Pro
North Fork well
Homer
Kachemak Bay
Seldovia
Map Legend
Unit Boundary
Oil Field / Accumulation
Gas Field / Accumulation
Selected Wells
Proposed / Active Wells
Platform
Pipelines
Production Facility
Map Area
DO&G 11/01

Cook Inlet Gas Production and Reserves

FIELD NAME	2000 PRODUCTION (BCF)	RESERVES [illegible]
BEAVER CREEK	5	92
BELUGA RIVER	39	[illegible]
IVAN RIVER, STUMP LAKE, PRETTY CREEK, LEWIS RIVER	3	17
KENAI, CANNERY LOOP	18	207
MCARTHUR RIVER	65	[illegible]
NORTH COOK INLET	53	[illegible]
STERLING	0.3	[illegible]
SWANSON RIVER	29 (net)	[illegible]
TRADING BAY	0.1	[illegible]
WEST FORELAND	0	[illegible]
ALL OTHERS	5	[illegible]
TOTAL	[illegible] (net)	[illegible]

WVD
DNR/DO&G
NOV. 8, 2001

Gas Hypothetically Available for Local Utility Use

GAS USER	SCENARIO 1	SCENARIO 2	SCENARIO 3	SCENARIO 4**
	ASSUMED DATES GAS USERS CEASE OPERATIONS			
AGRIUM	2005	2010	2015	2015
LNG	2009	2009	2015	2015
OIL FIELD OPERATIONS	2009	2015	2015	2015
GAS REMAINING FOR UTILITY USE (BCF)	1060	690	-100	900**
YEARS OF SUPPLY FOR UTILITY USE	17	11	0	15

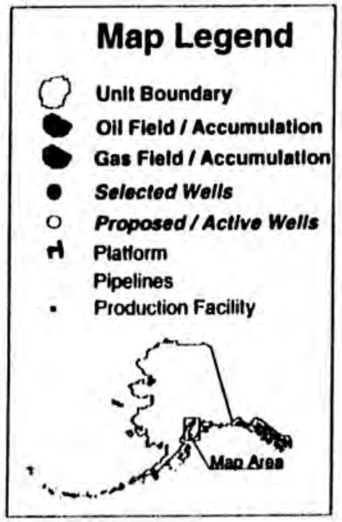
NOTES:

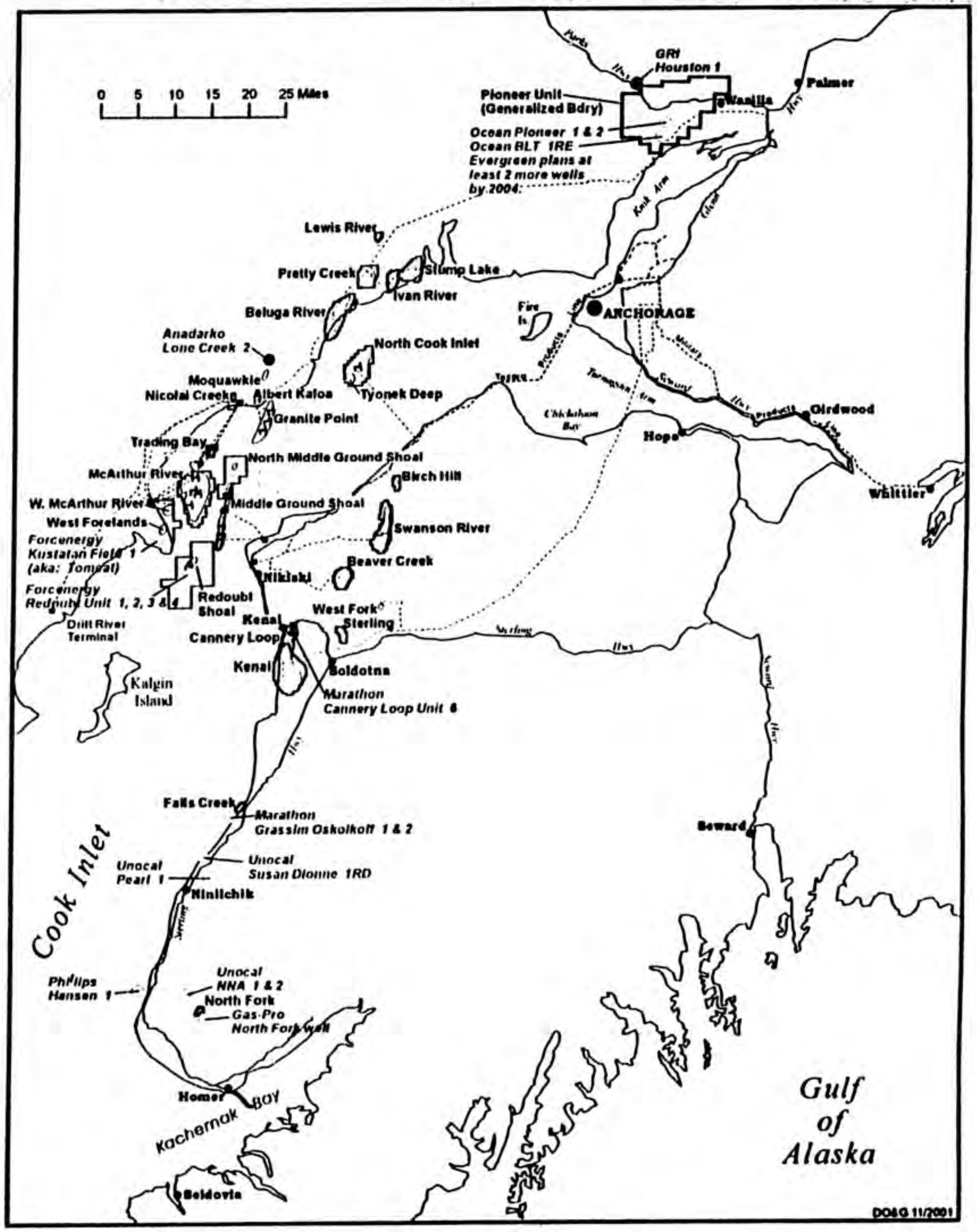
1) THESE SCENARIOS ARE HYPOTHETICAL.
2) ASSUMED SHUT DOWN DATES ARE NOT BASED ON ACTUAL GAS SUPPLY OR ECONOMIC REALITIES.
3) GAS REMAINING FOR UTILITY USE IS BASED ON CURRENT RESERVE AND USE ESTIMATES.
4) YEARS OF UTILITY SUPPLY BASED ON CURRENT UTILITY CONSUMPTION RATES.
5) POTENTIAL FUTURE GAS DELIVERABILITY CONCERNS ARE IGNORED.

****SCENARIO 4 ADDS AN ASSUMED 1000 BCF OF YET-TO-BE DISCOVERED GAS.**

WVD
DNR/DO&G
NOV. 8, 2001

Cook Inlet Activity





tjr 11/2001

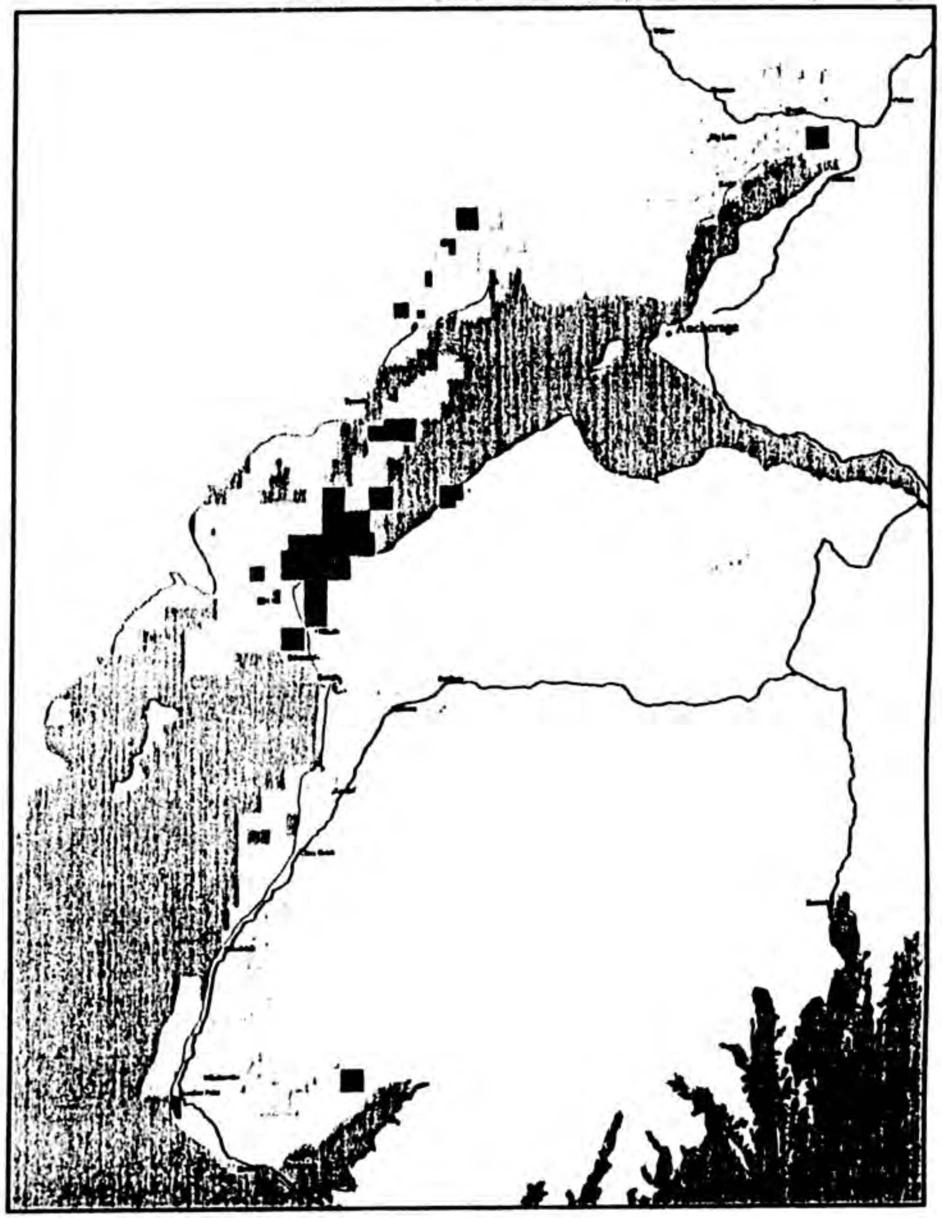
Cook Inlet Exploration Summary – 2001

- Ninilchik Unit and Falls Creek Unit – Marathon (Gas)
  - G.O. #1 well completed as gas well, G.O. #2 well planned
- South Ninilchik Unit and Deep Ck. Unit – Unocal (Gas)
  - Possible State/CIRI joint administration, up to 3 wells planned for 2001-02
- Pretty Ck./Lewis Riv./Ivan Riv. – Unocal (Gas)
  - Re-entered 1 well each in Lewis Riv. and Ivan Riv., drilling P.C.U. #4, new well, in Pretty Ck. field
- Swanson River Unit Gas Satellites Project – Unocal (Gas)
  - Proposal to develop two gas fields north and east of Swanson River oil field on Federal and Native owned lands
- Redoubt Unit – Forest Oil (Oil discovered in 1968 by Pan Am)
  - R.U. #1, #2, & #3 wells completed by Forest, R.U. #4 is planned
  - Field is bigger than originally thought, up to 193 MMBO recoverable reserves
  - Forest has other prospects at Sabre, Corsair, and Valkyrie
- Pioneer Unit – Evergreen Exploration (Coalbed gas, no proven reserves)
  - Formerly operated by Ocean Energy, ownership and operations transferred to Evergreen in mid-2001.
  - 2 production wells & 1 injection well drilled in 1999; committed to drill 6 more wells, at least 1 in each of 2 new areas
- Cosmopolitan Unit – Phillips (Oil discovered in 1967 by Penzoil)
  - Hansen #1 well permitted to drill to bottom location on State lease
- Nikolai Ck. Unit – Aurora Gas (Gas)
  - Production started in Oct., NCU #3 well produces at rate of 2 MMCF/day
- North Fork Unit – Gas Pro (Gas)
  - Project apparently on hold
- Trading Bay Unit/McArthur River Field – Unocal (Oil)
  - T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet

Cook Inlet Areawide 2001
Sale Results

Currently Leased Acreage

Cook Inlet Areawide 2001 Leases



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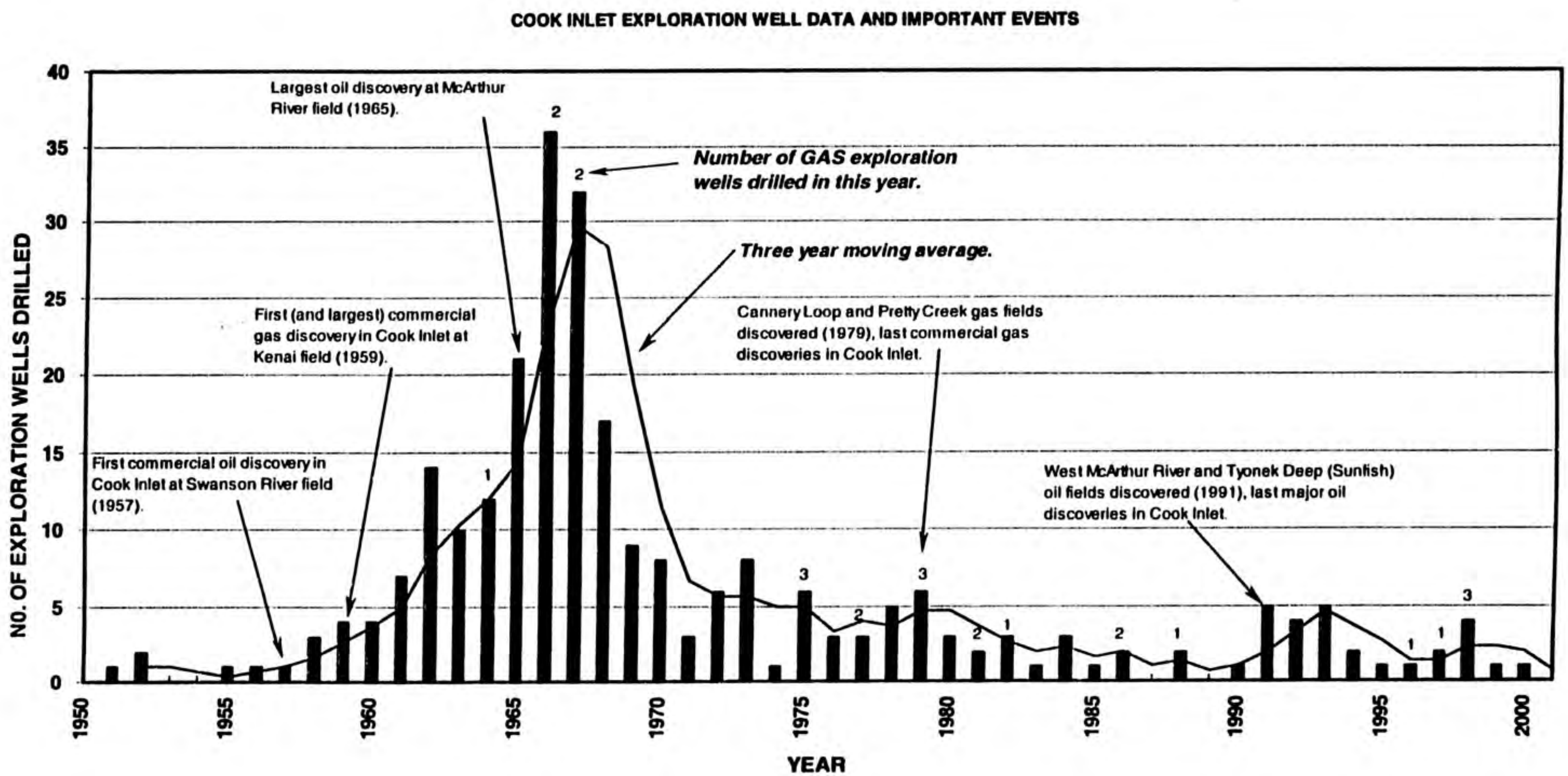
Timeline of Cook Inlet Exploration



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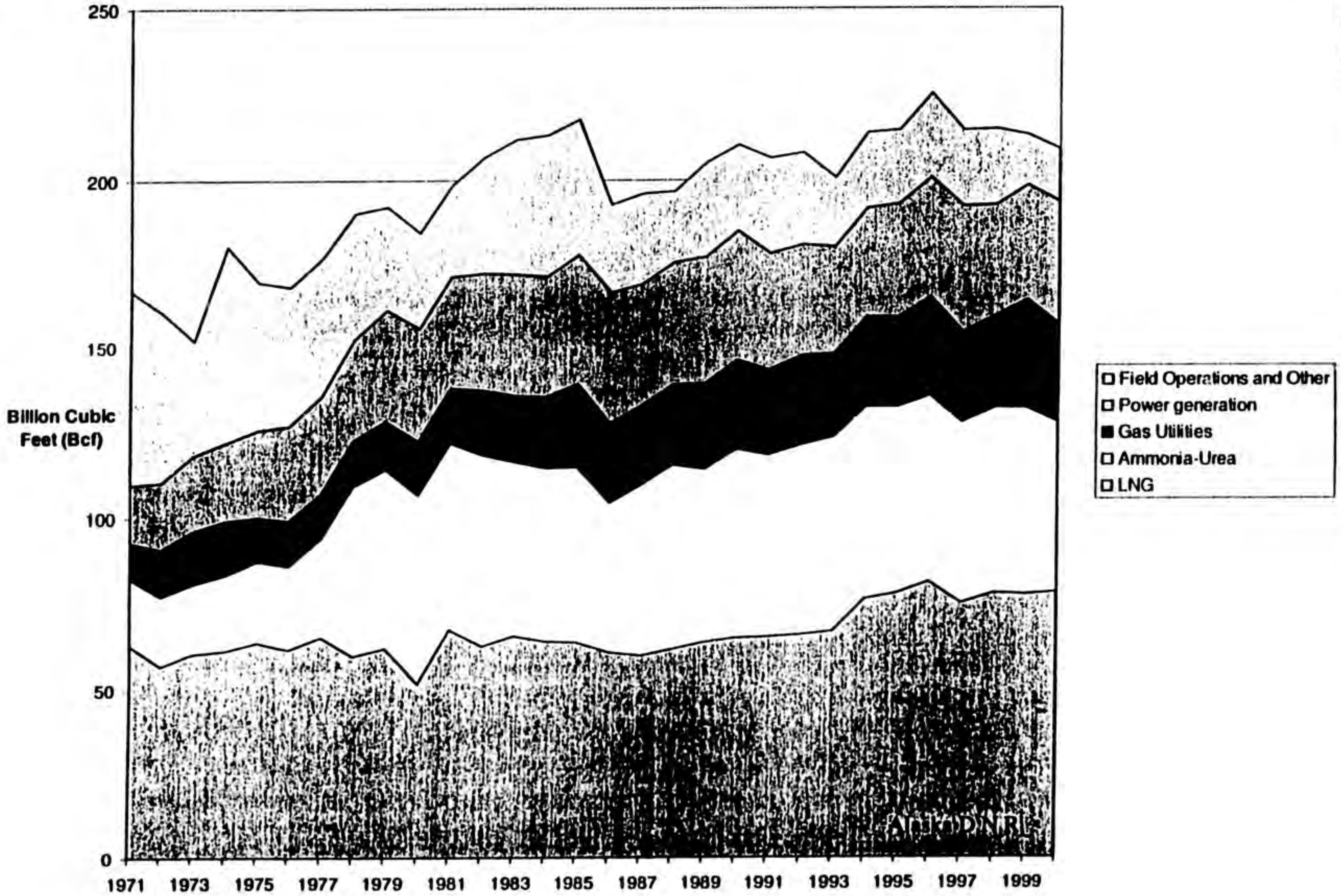
Cook Inlet Gas Exploration History

- 267 oil & gas exploration wells drilled in CI through 2000
  - Of these, 24 were GAS exploration wells
- Of largest 10 CI gas fields (based on current gas reserves), only Cannery Loop (smallest of the 10) was found by exploring FOR gas
- Much of Cook Inlet basin area is underexplored

Outlook and Predictions For Cook Inlet

- Areawide sales make entire area available for exploration and development
- Independents will become an increasing influence
  - More competition for prospects and leases
  - New thinking and inventive technology and business climate
- Independents will drive exploration and development costs lower
  - This may mean less money for the State of Alaska, as well as service companies
- Oil continues to be an elusive target in Cook Inlet
- Conventional gas exploration will extend beyond the core developed areas
- Coalbed gas will continue as an emerging exploration target
  - Viability of this exploration play is yet to be determined

Cook Inlet Historic Gas Consumption by Major Disposition Category 1971 - 2000



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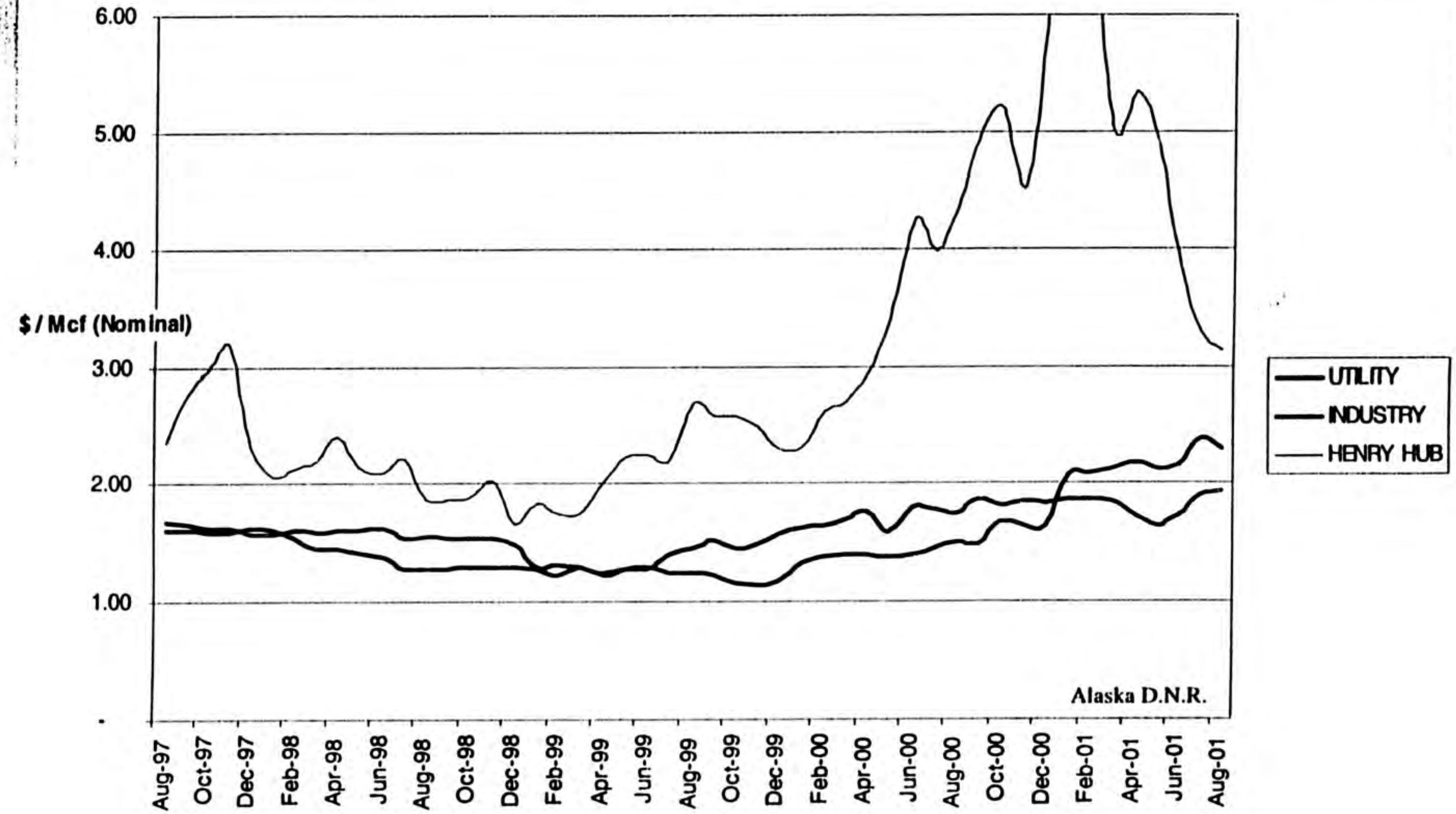
Royalty Value for Natural Gas Utility and Industry Dispositions in Cook Inlet
Versus Henry Hub Spot Price
Aug 1997 - Aug 2001



Utility = Electric and Space Heat.
Industrial = Urea, LNG, and Field Operations.
Henry Hub located at U.S. Gulf of Mexico.

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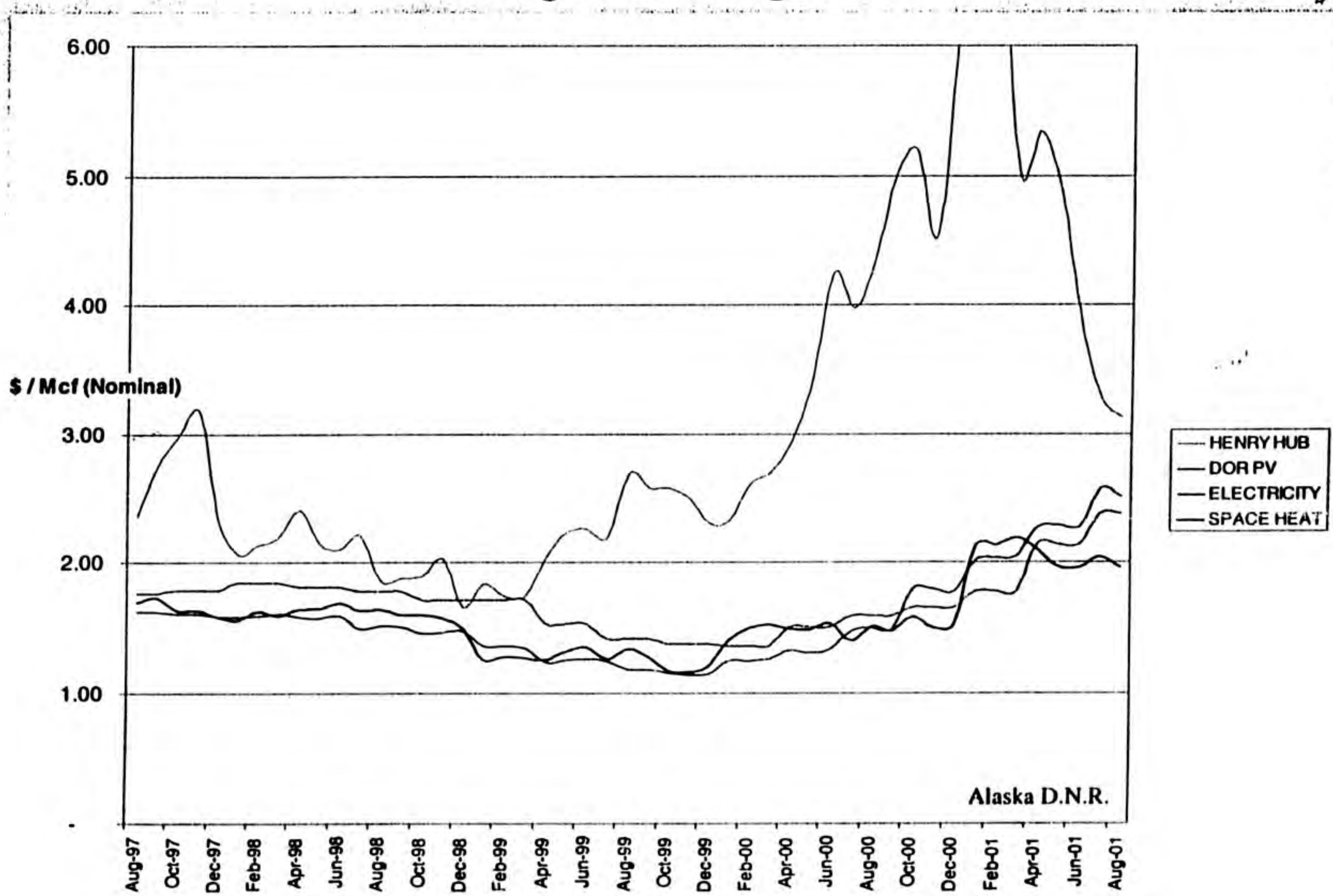
Royalty Value for Electricity and Space Heat Dispositions in Cook Inlet Versus Henry Hub Spot Price Aug 1997 - Aug 2001



Electric = CEA and MLP.
Space Heat = Enstar, Aurora, and Other LDC Direct Sales.
DOR PV for CEA, MLP, and ENSTAR.

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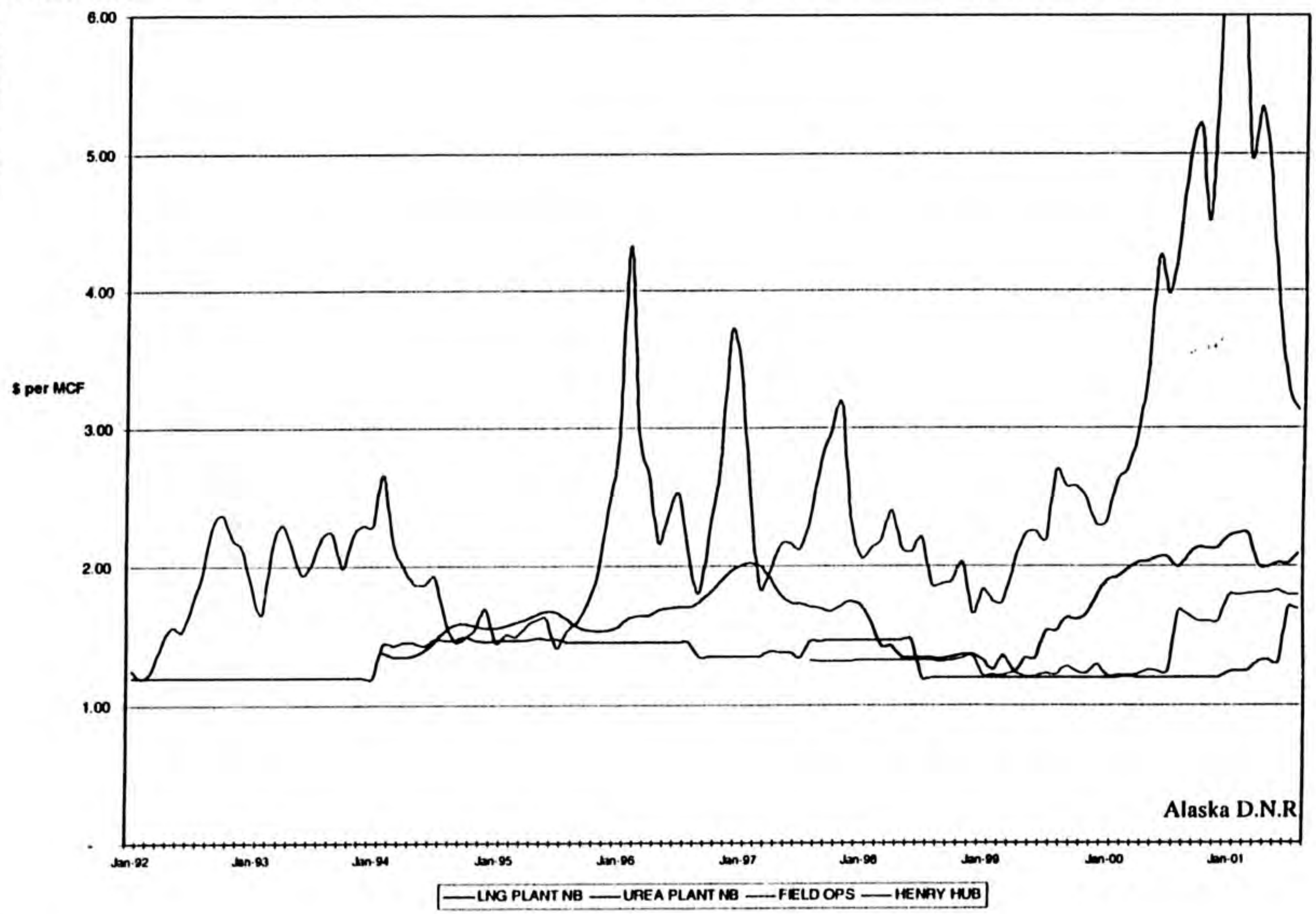
Royalty Values for Urea Plant, LNG and Field Operations Gas Dispositions in Cook Inlet
Versus Henry Hub Spot Price
Jan 1989 - Aug 2001



Note: Royalty Values are Netted Back to the Wellhead.

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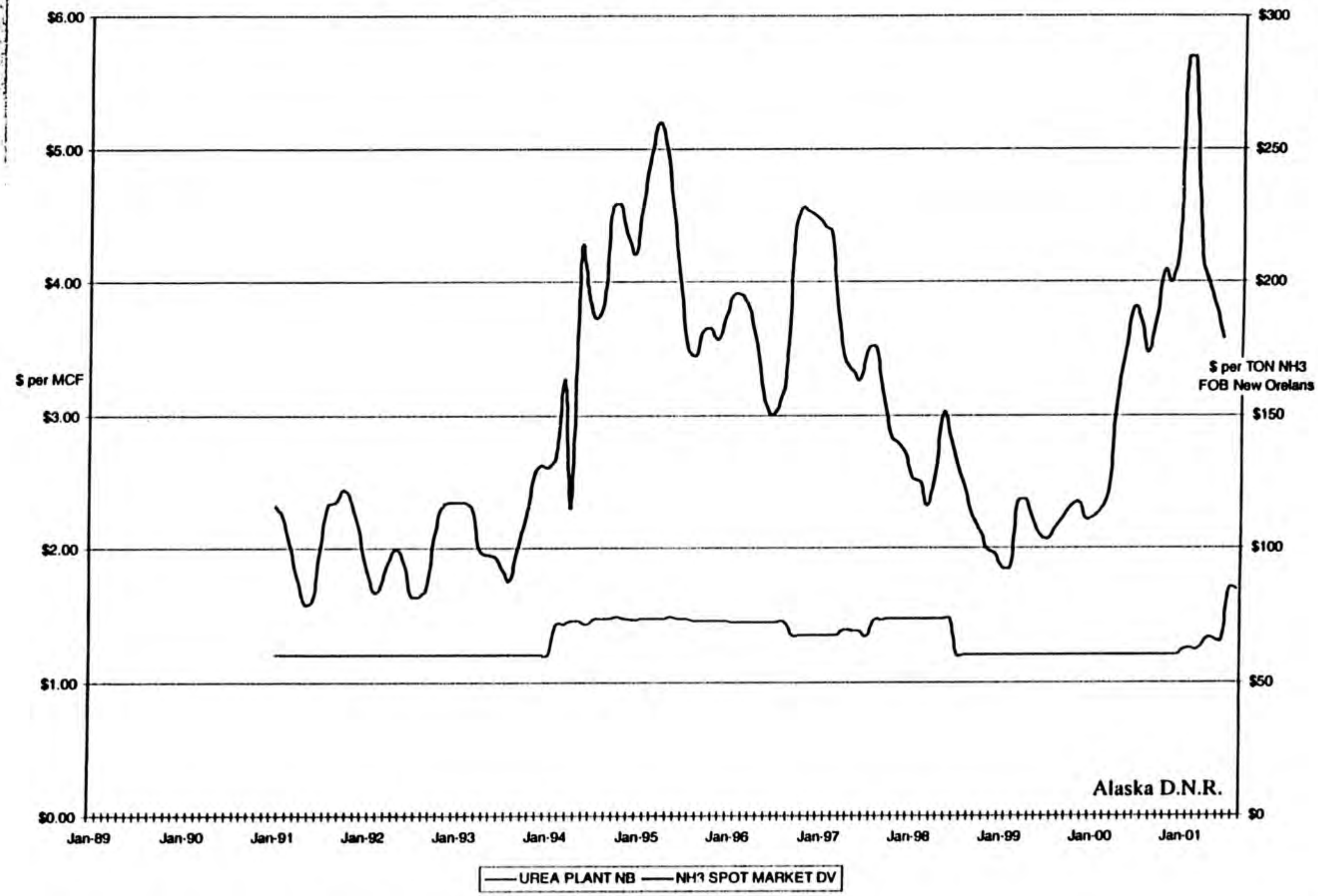
Destination and Royalty Values for Ammonia-Urea Plant Dispositions in Cook Inlet
Jan 1991 - Aug 2001



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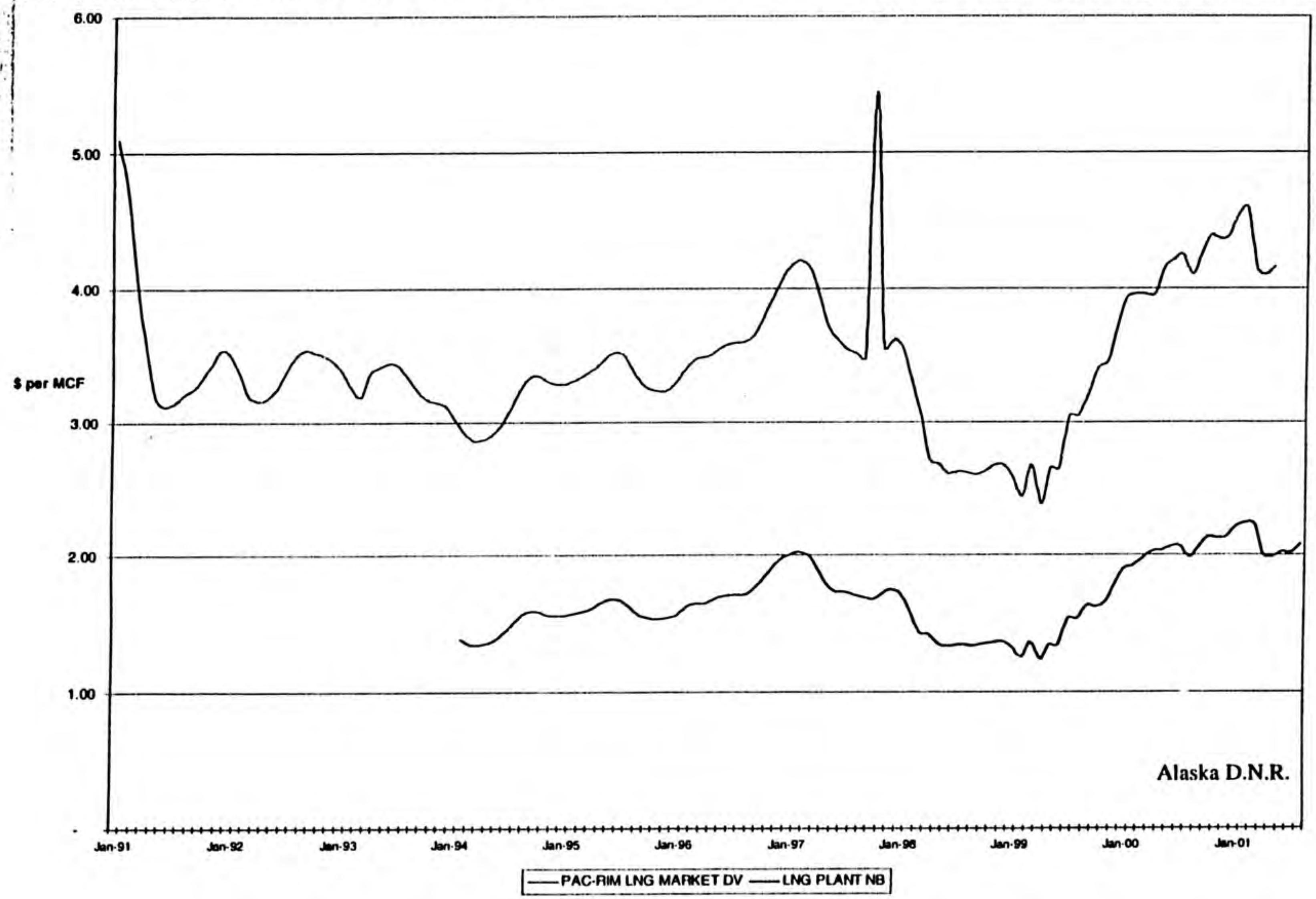
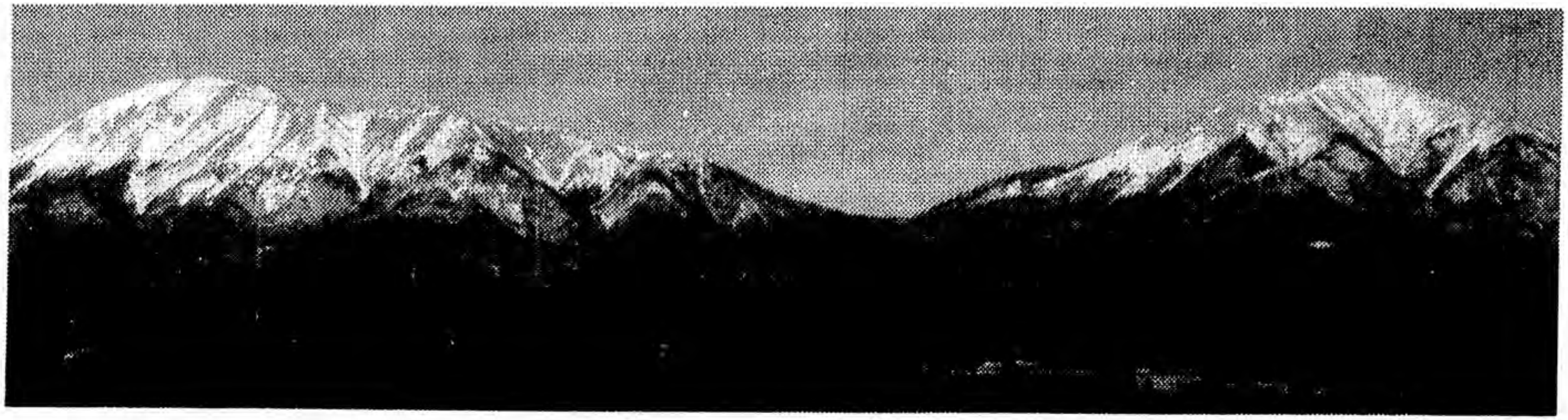
Destination and Royalty Values for LNG Gas Dispositions in Cook Inlet
Jan 1991 - Aug 2001

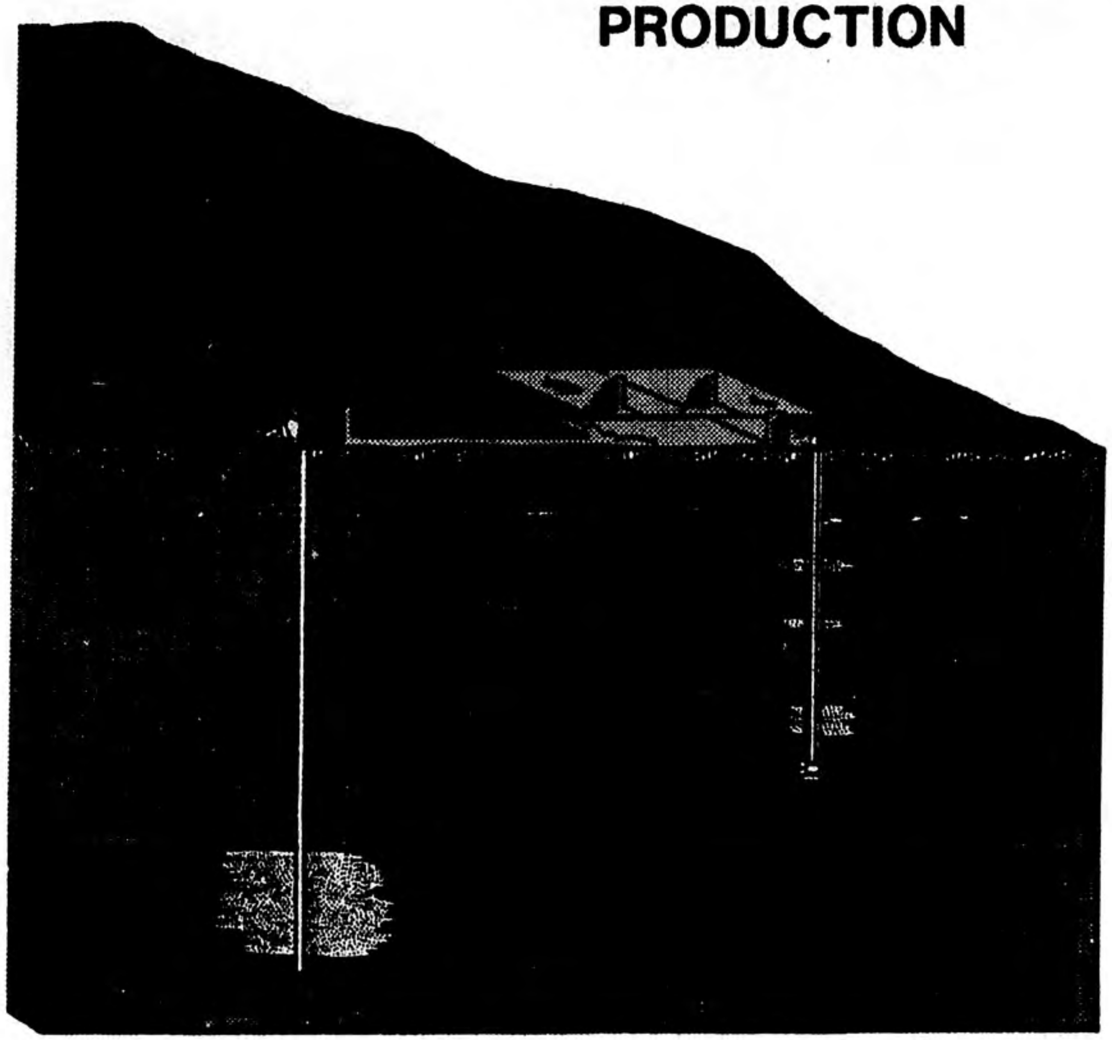




Alaska State Legislature

Joint Committee on Natural Gas Pipelines
November 8, 2001

COALBED METHANE PRODUCTION



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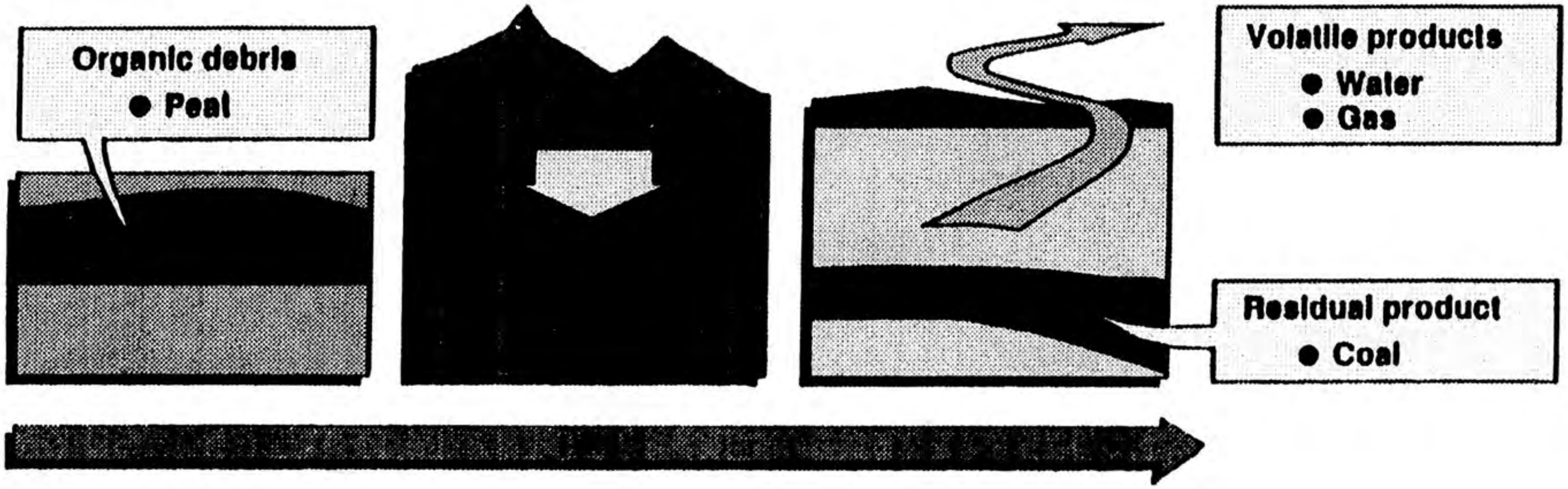
COALIFICATION



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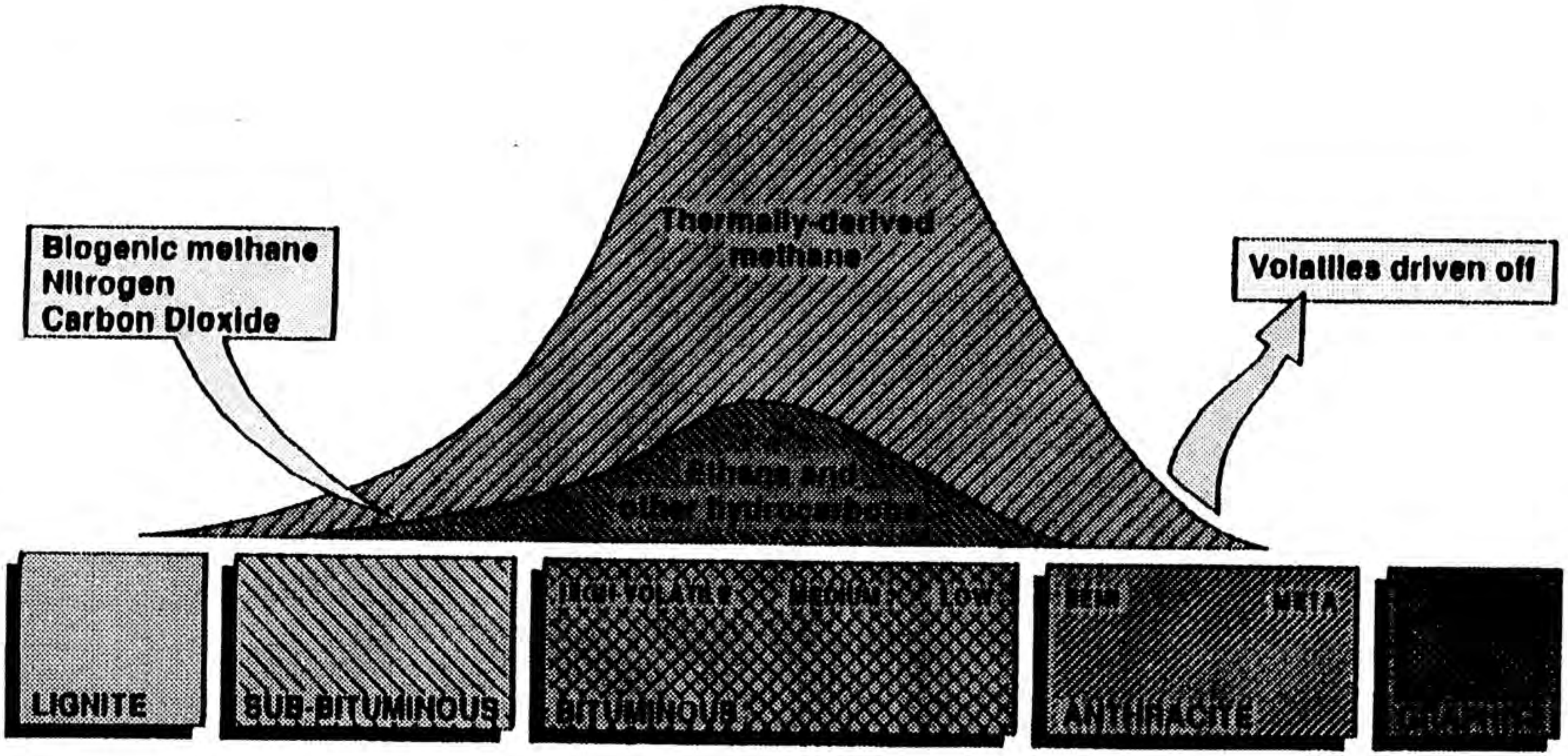
GAS GENERATION IN COAL



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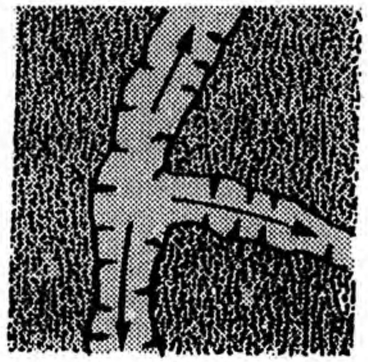
PROCESSES IN THE TRANSPORT OF COALBED METHANE GAS

Desorption from Internal Coal Surfaces

Diffusion Through the Matrix and Micropores



Fluid Flow in the Natural Fracture Network

Increasing Size →

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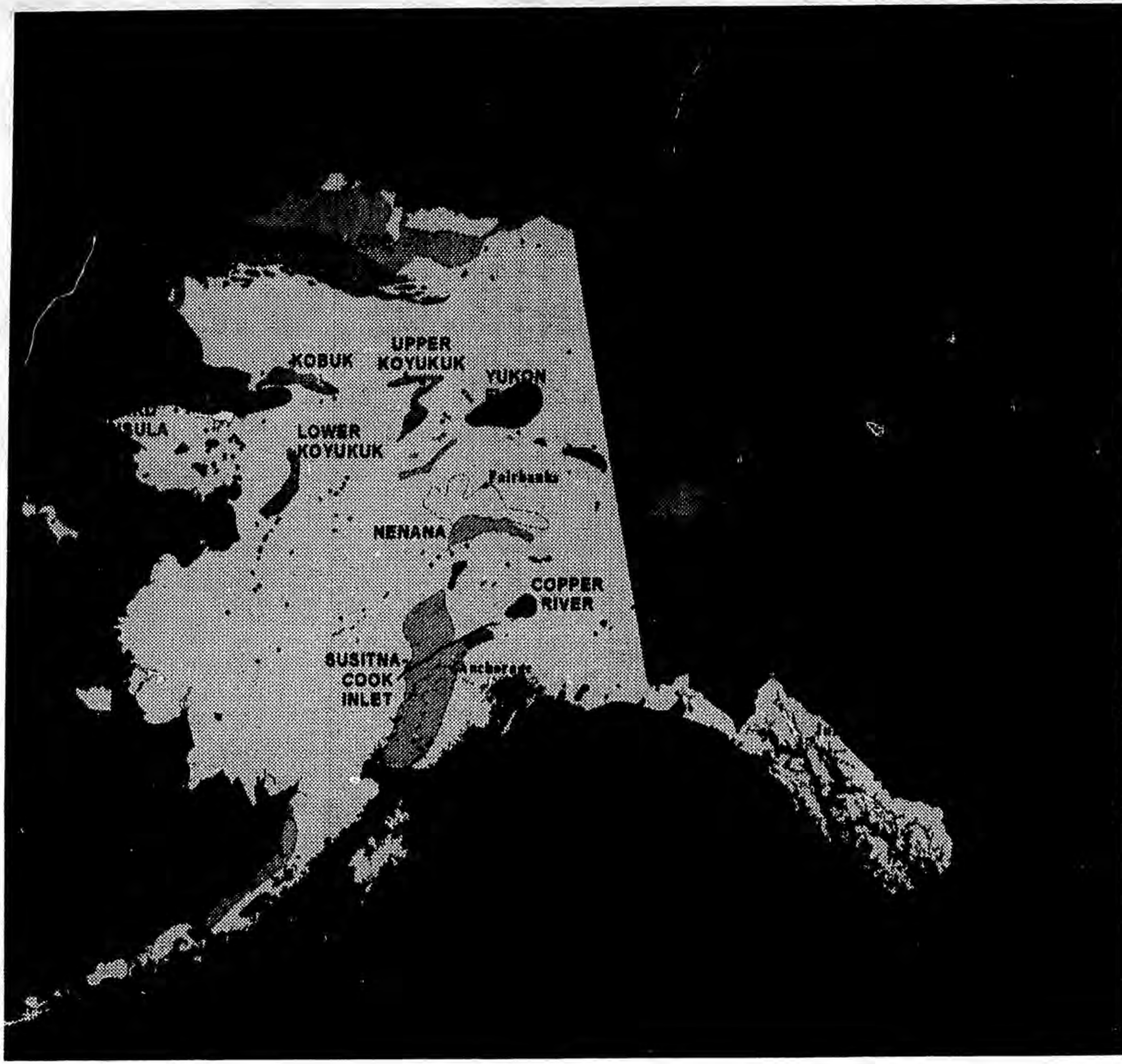

aska has half of
known coal
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A

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Alaska Cook Inlet Basin

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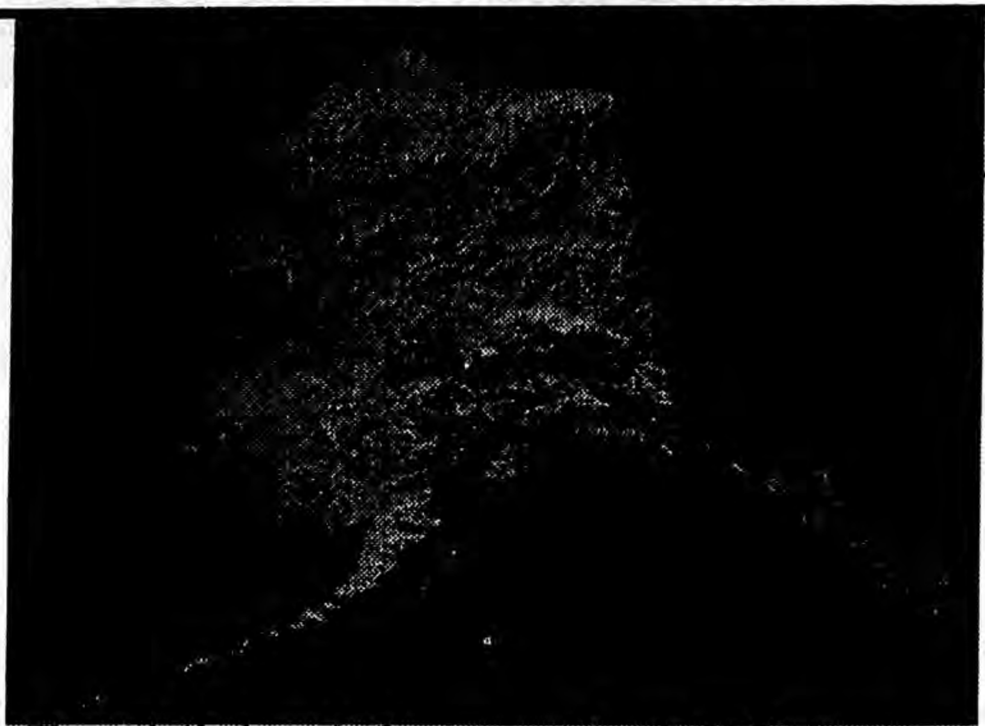

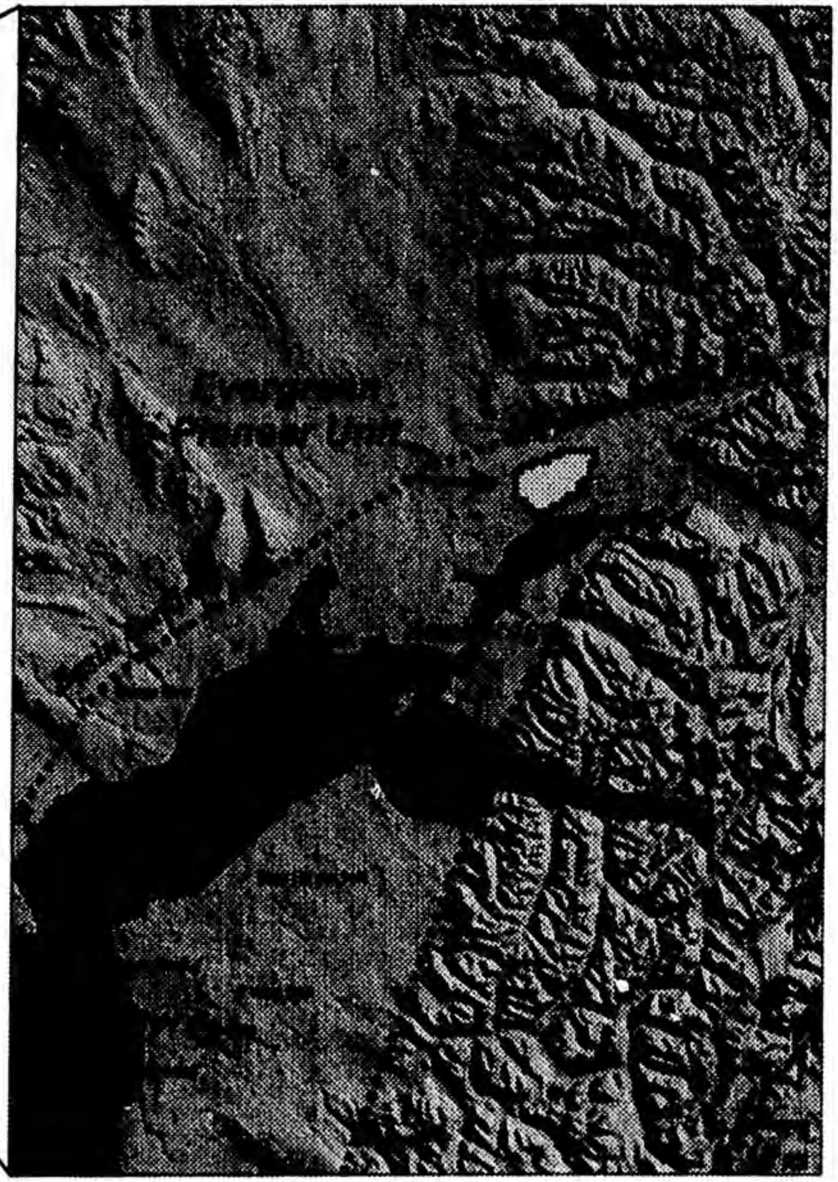

- Established Conventional Gas:
  - Discovered 1957
  - Existing infrastructure
  - Declining gas supply in this region
  - 6.2 Tcf produced to date
- Cook Inlet Basin Resource
  - 1.5 trillion tons coal possible
  - 200 Tcf CBM resource possible
- Evergreen Acquires Pioneer Unit in 2001

Pioneer Unit

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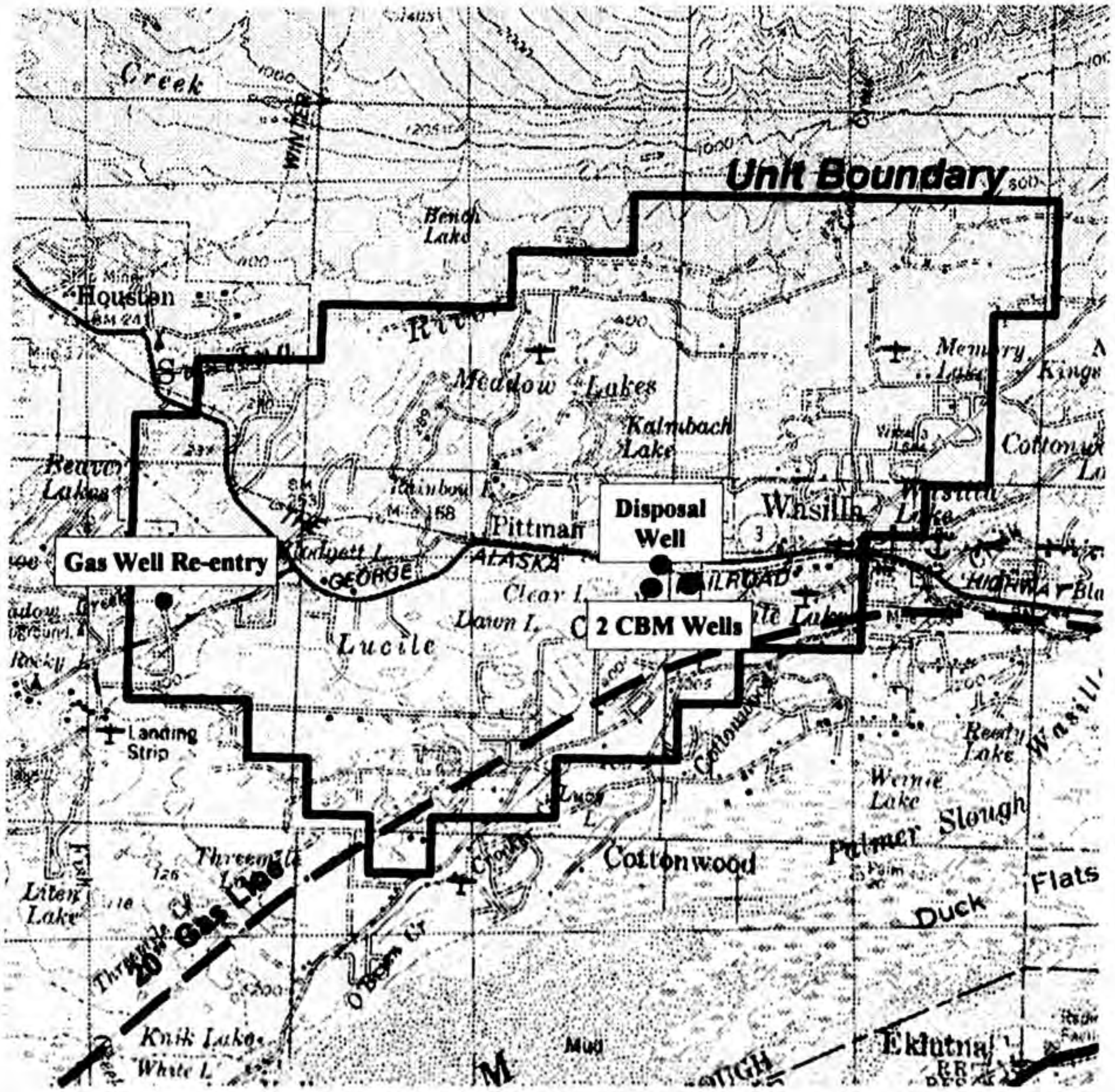

- 48,000 acres
- 100% working interest
- Infrastructure
  - Gas pipeline
- Wells drilled - 2000
  - 2 CBM
  - 1 Water disposal
  - 1 Gas well re-entry
- Future Plans
  - Drill/Complete 6-8 wells in 2002
  - Complete disposal well

Cross Sections

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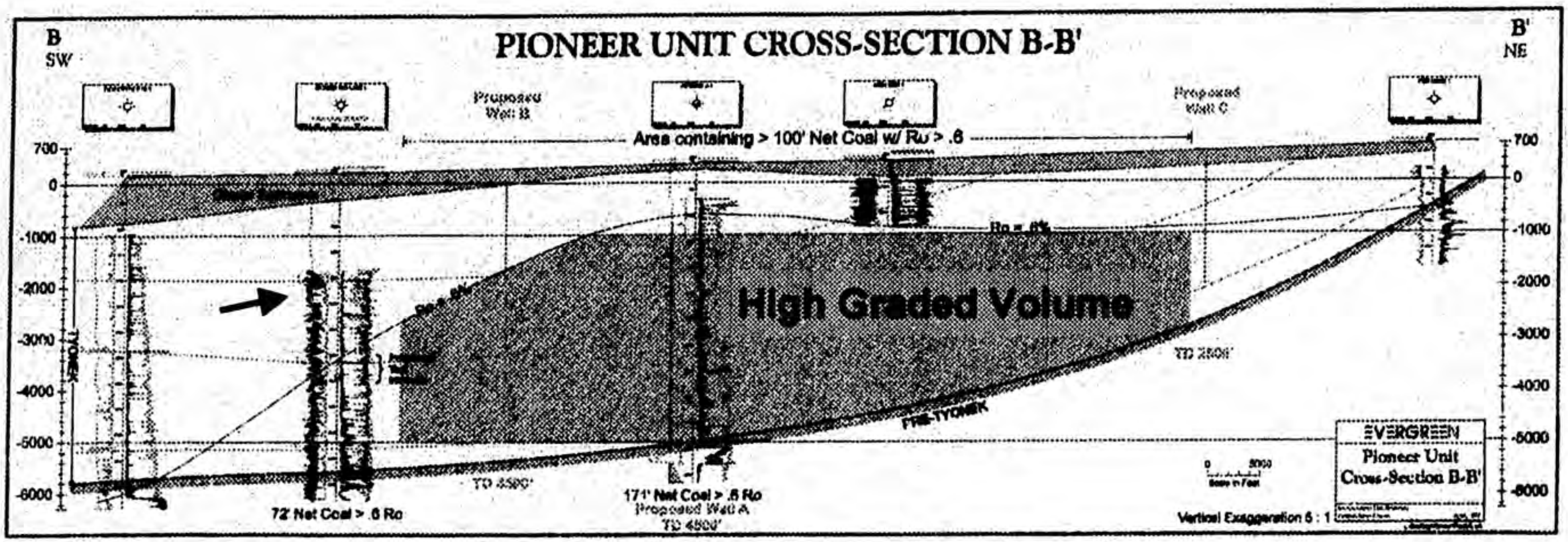

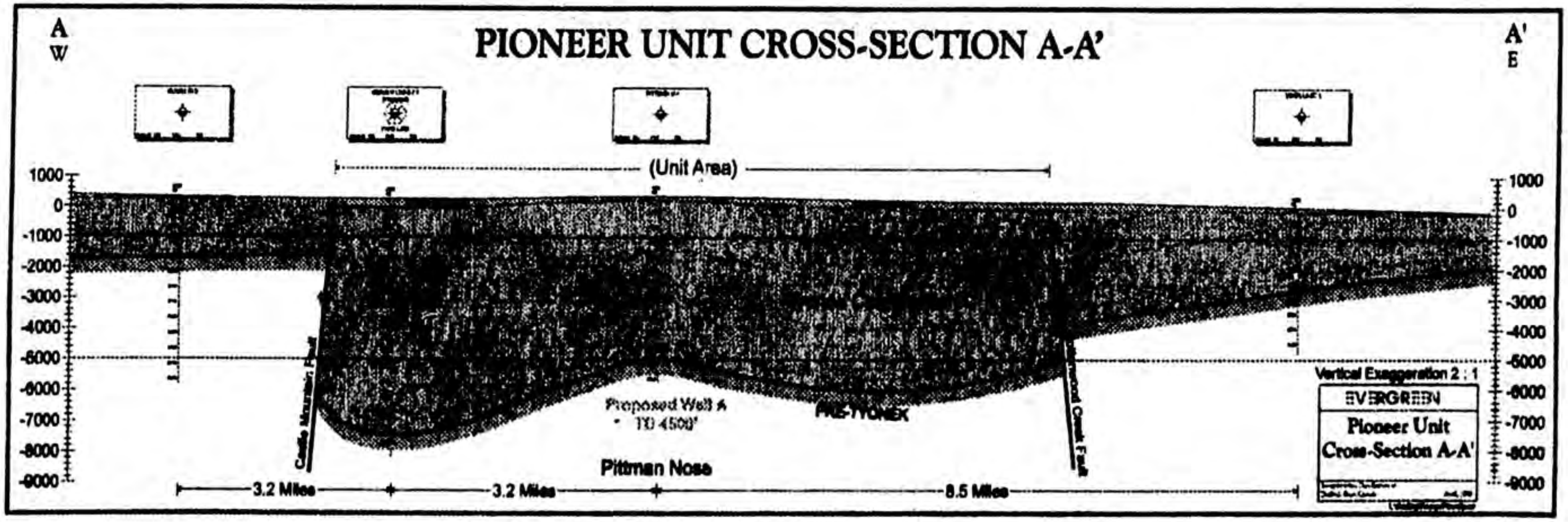

Raton Basin

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U.S. Coalbed Methane Resources

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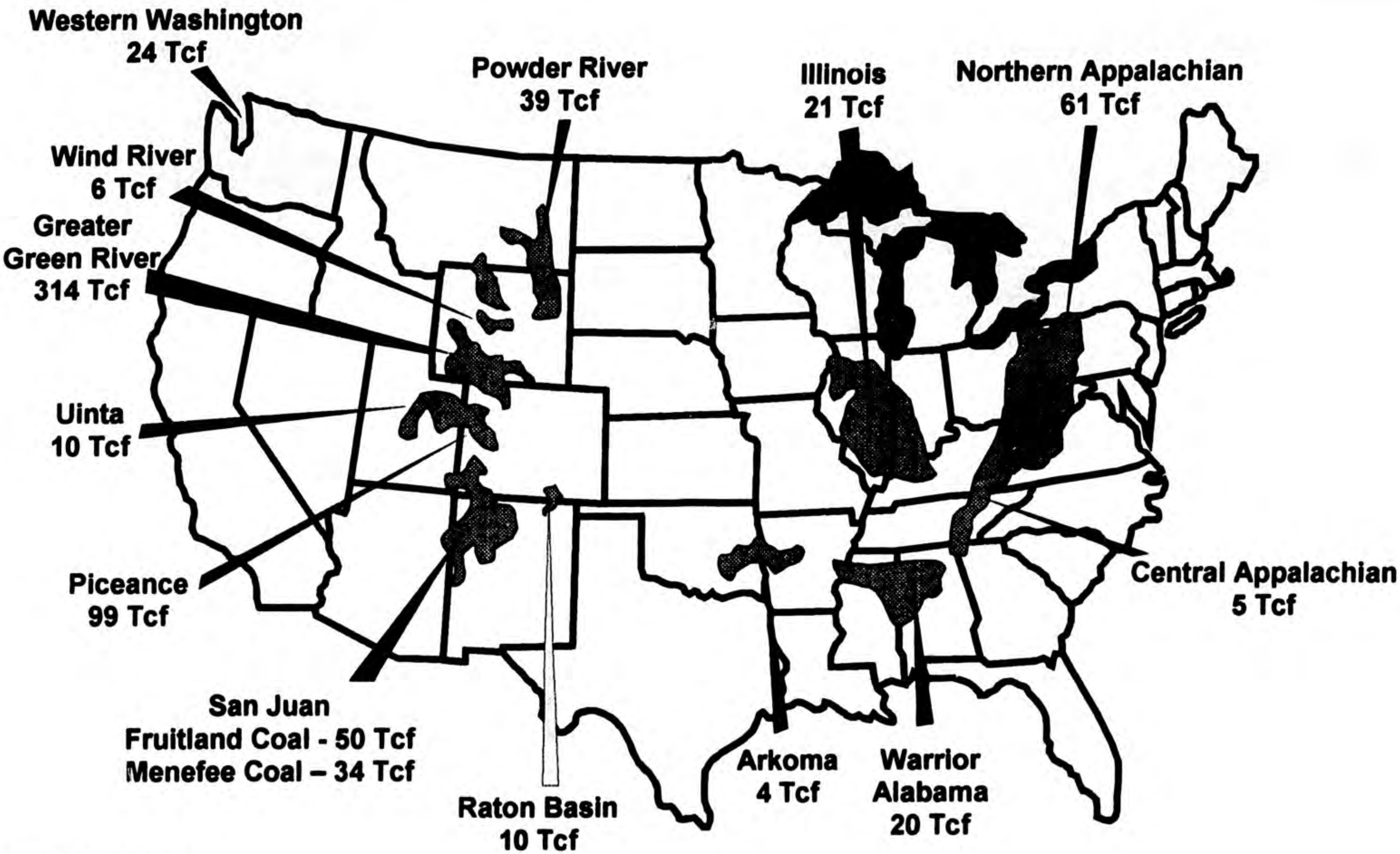

Source: GTI/ICF

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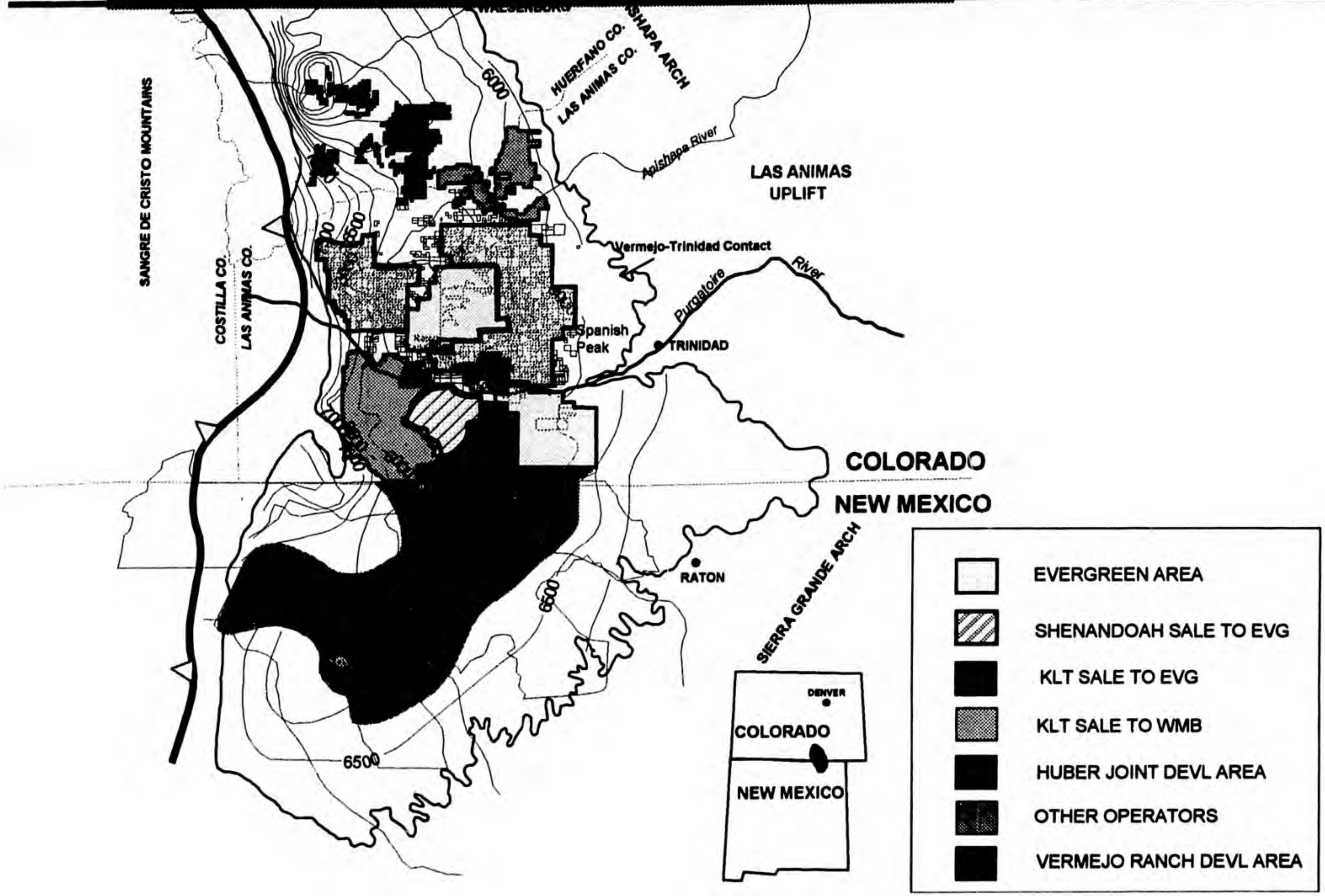

Raton Basin Stratigraphy

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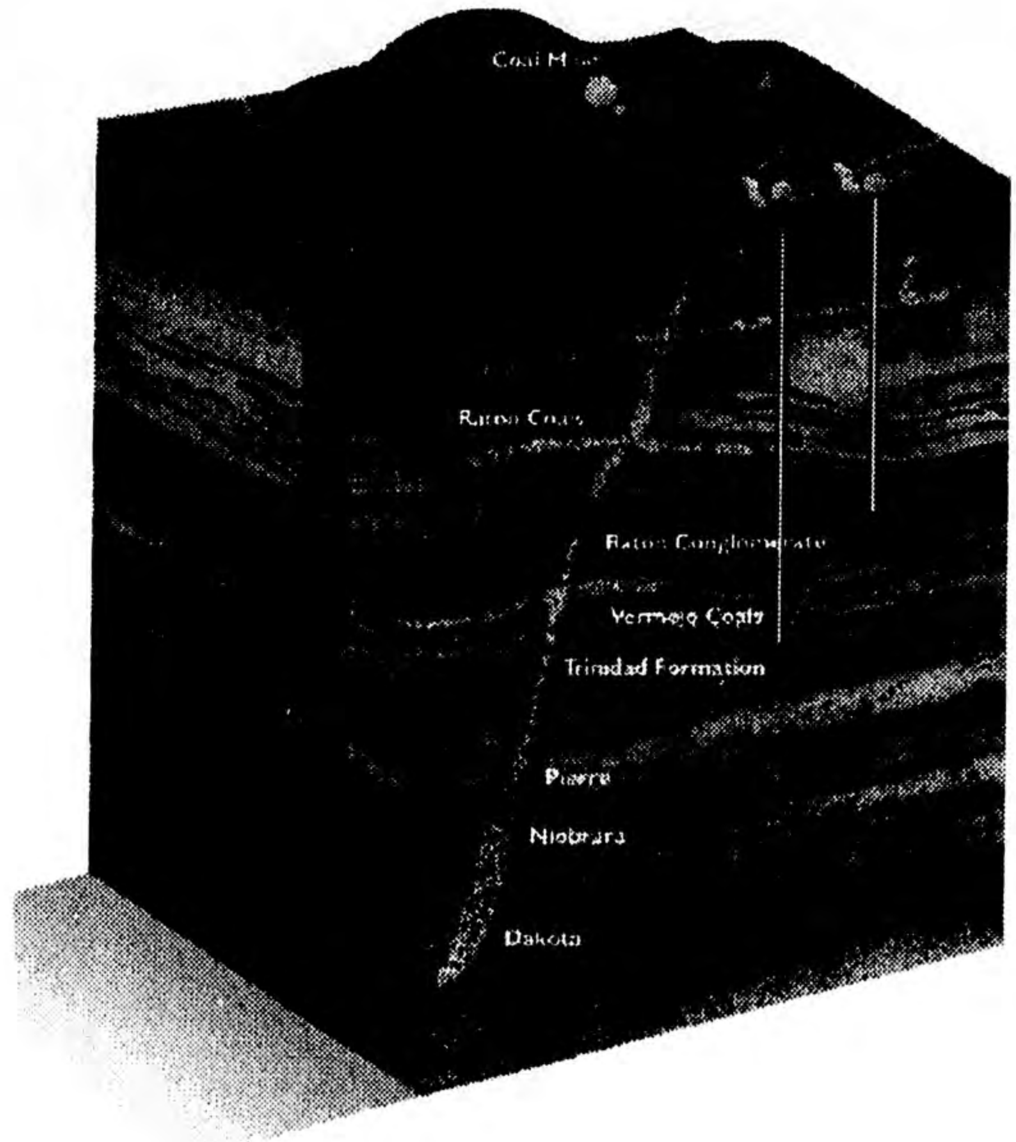
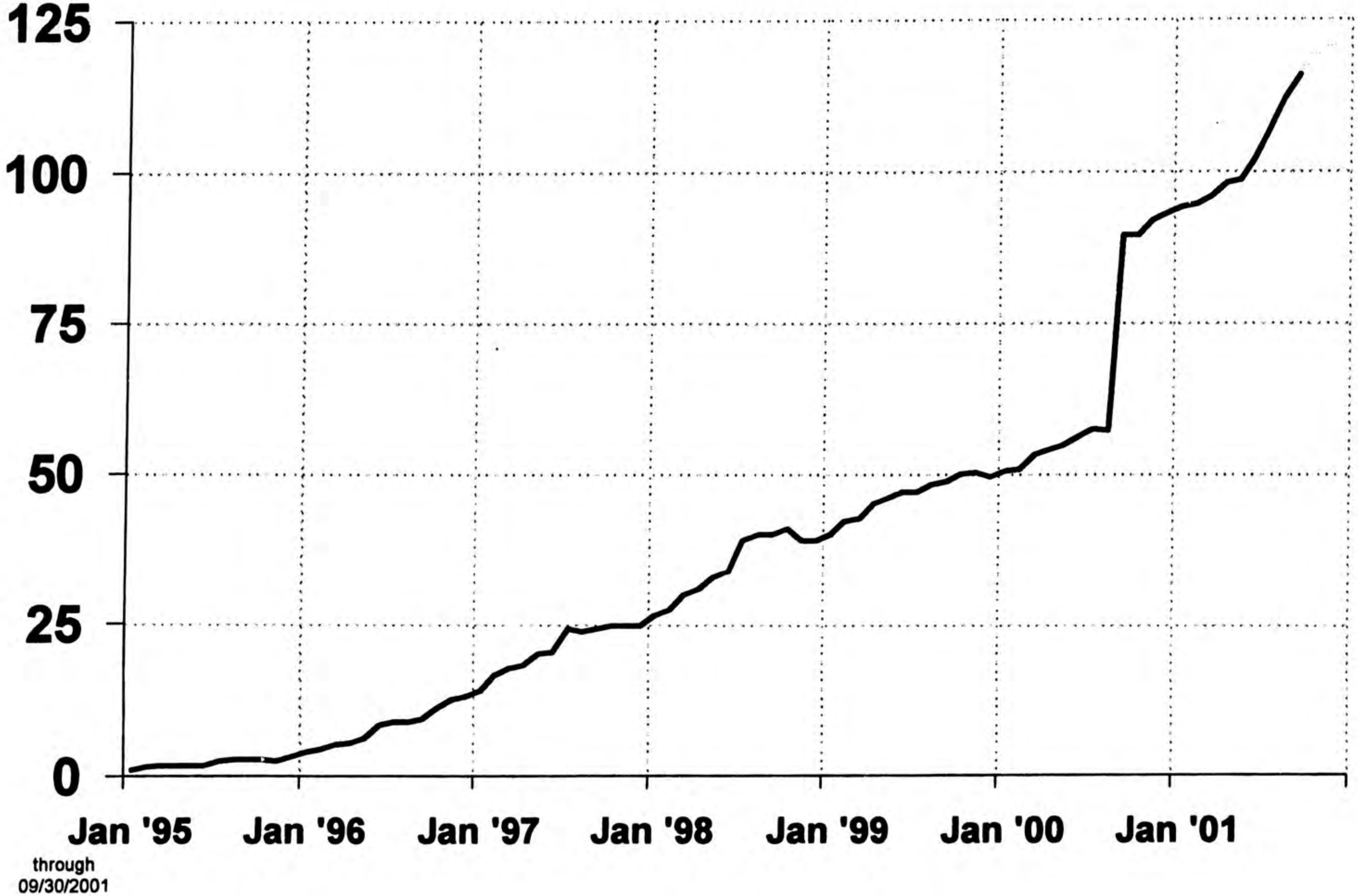


Gross Daily Production

(Million Cubic Feet)



Key Operating Focus

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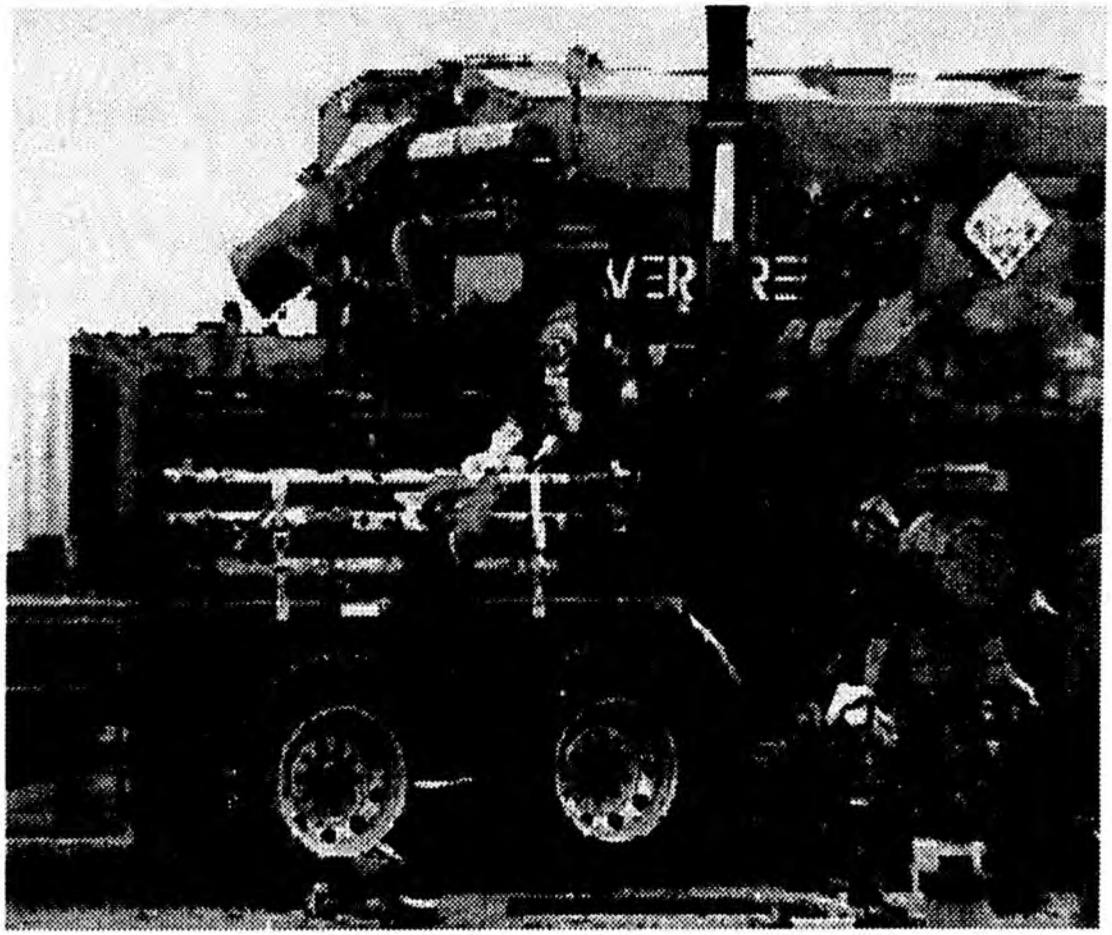
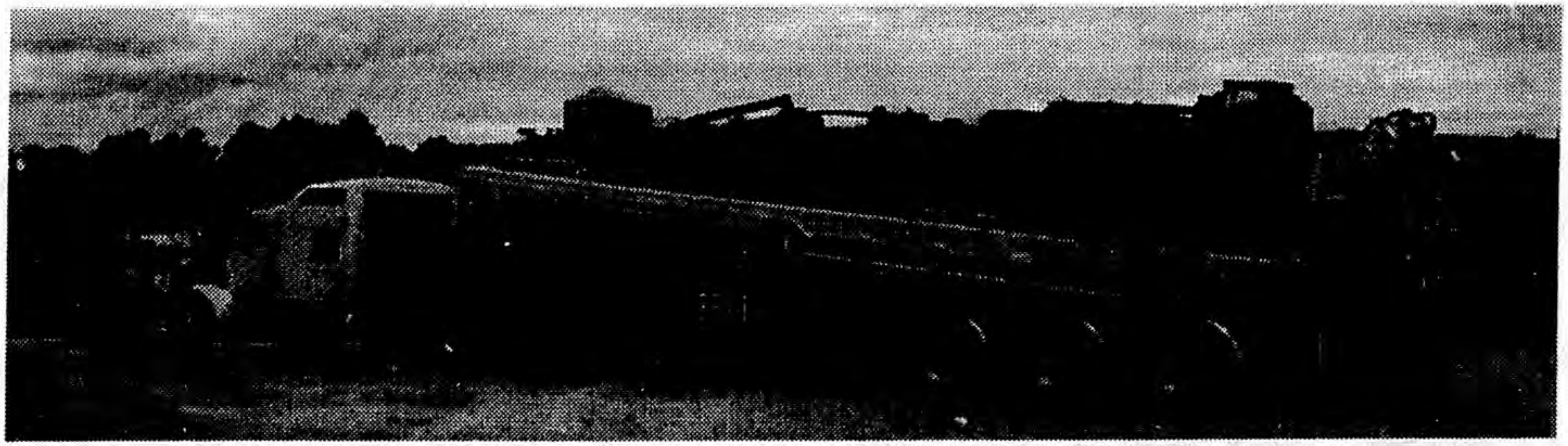
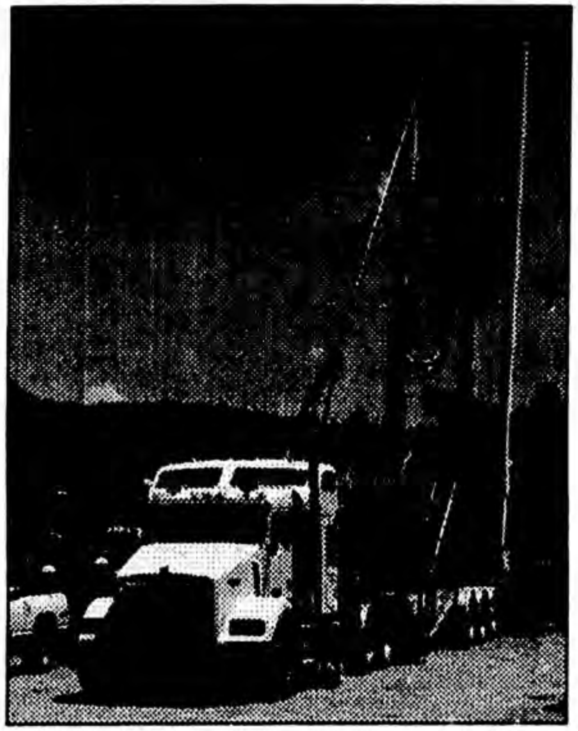
Constant experimentation to improve productivity through new technologies

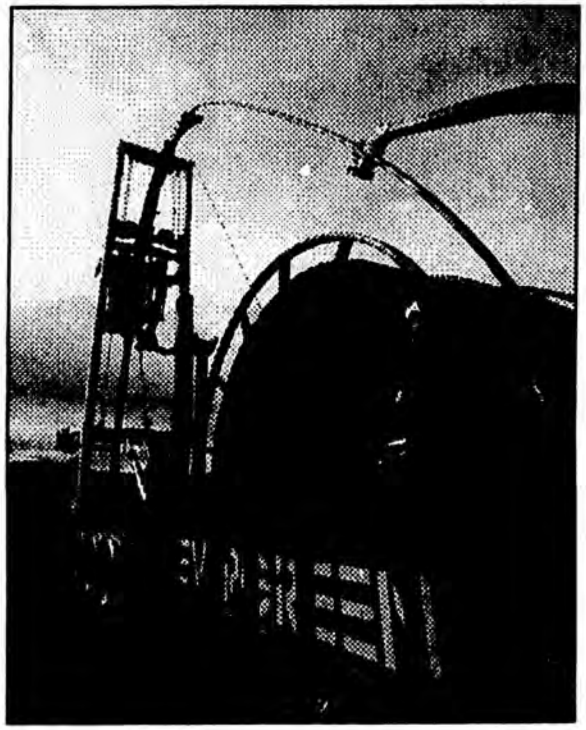
Overall drilling success since 1993: 98%



New Completion Technology







Evergreen Air Drilling Rig

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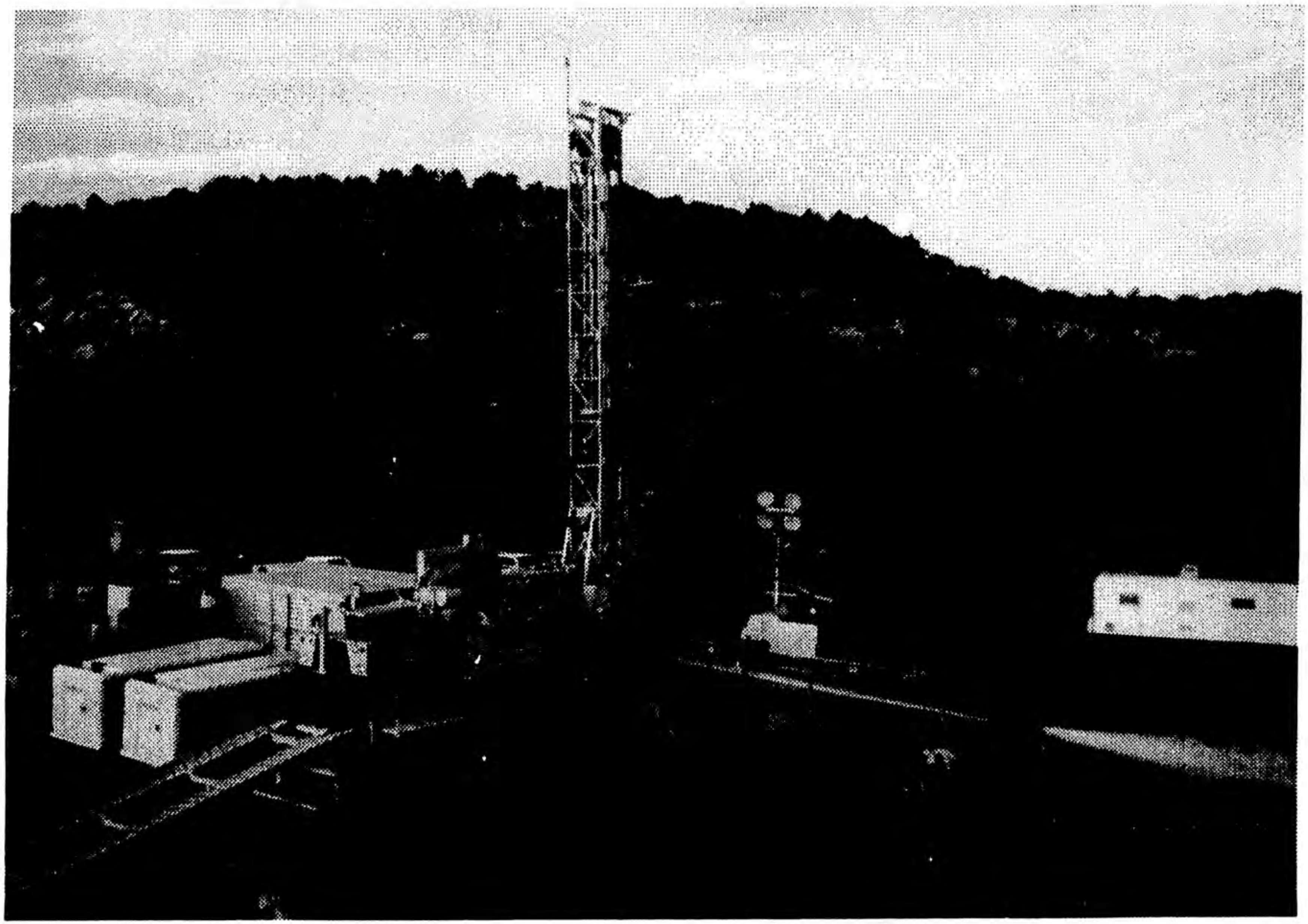

Evergreen Cement Equipment

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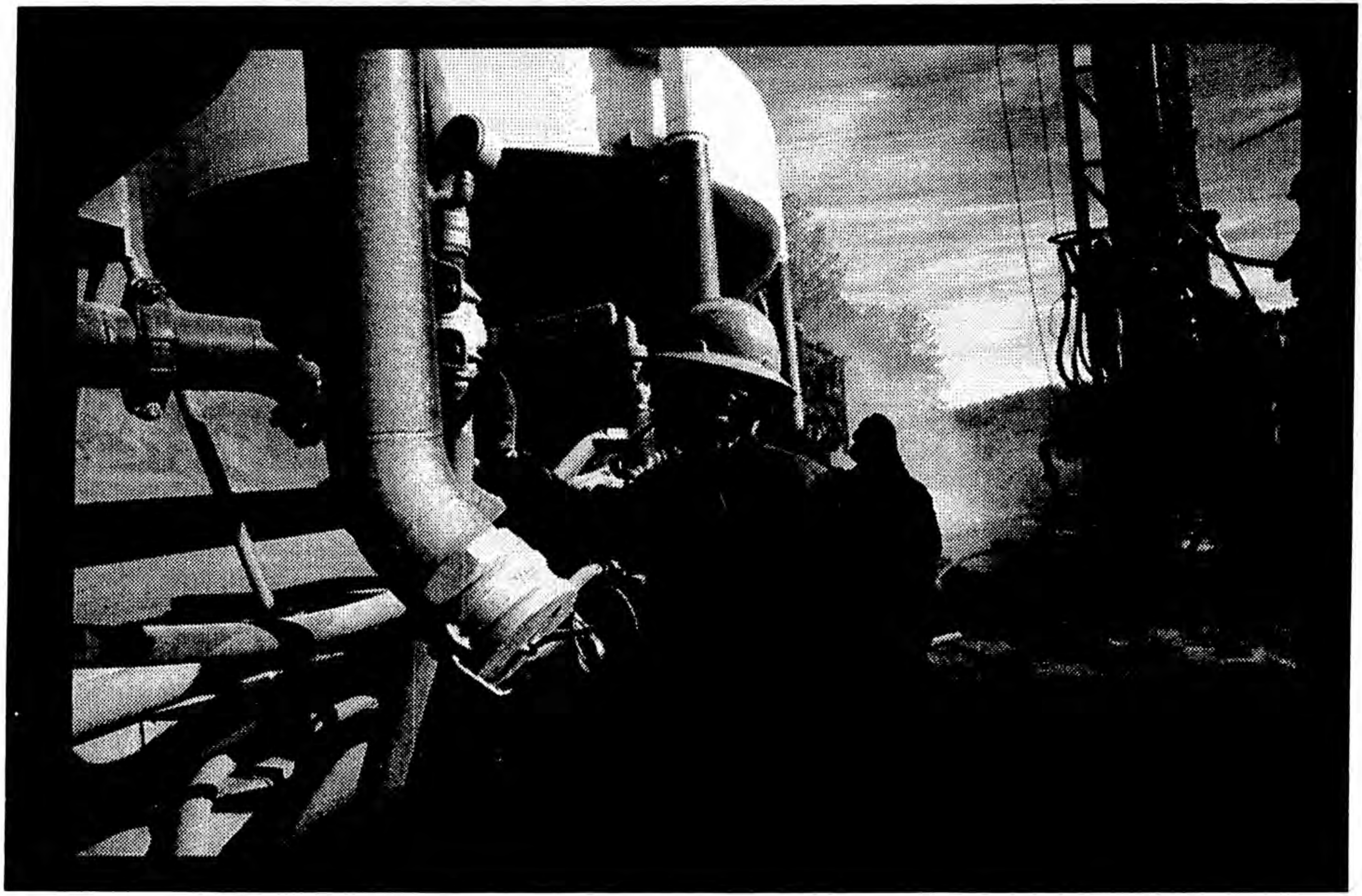

Evergreen Hydraulic Fracture Treatment

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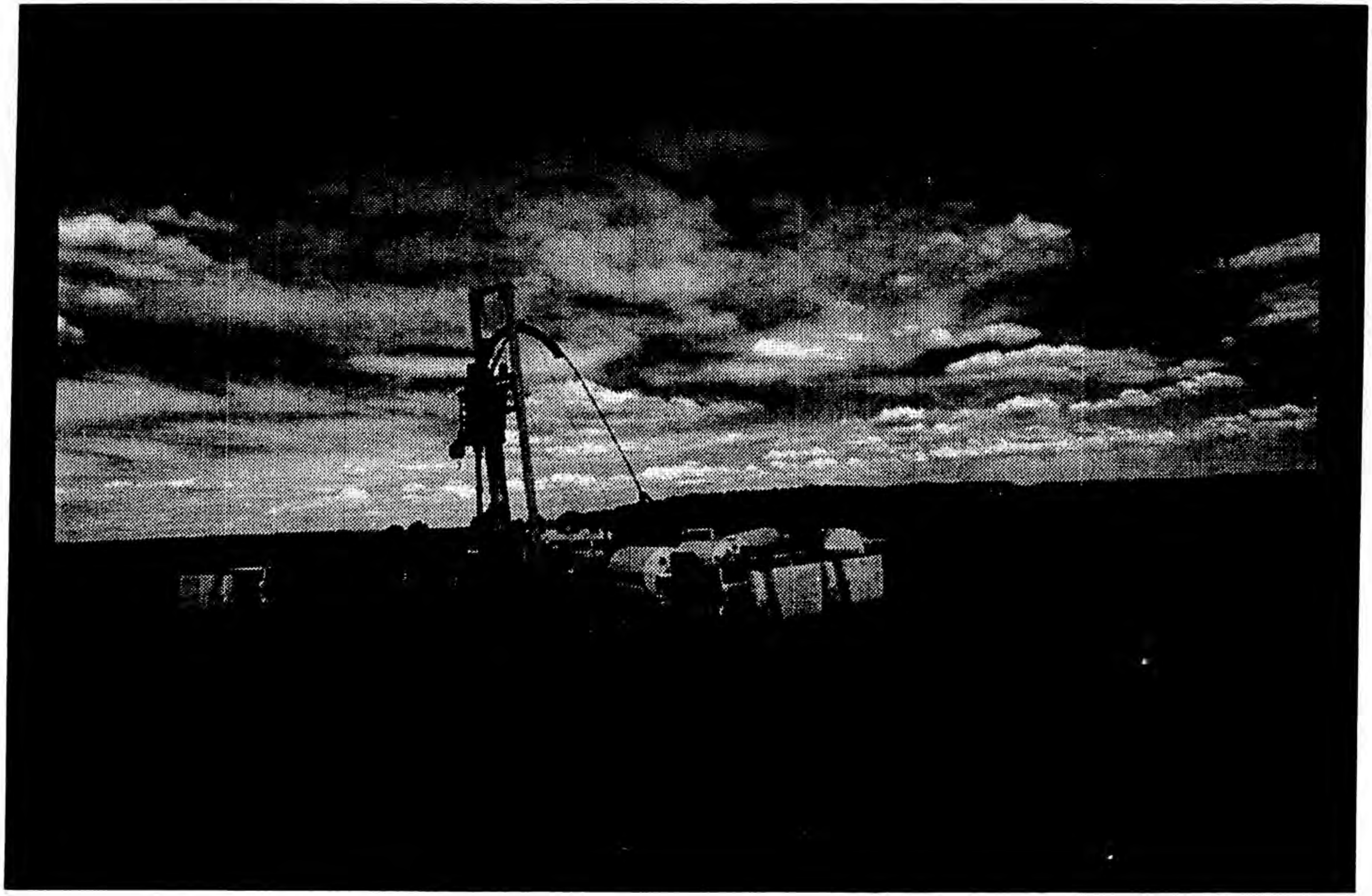

Portable Frac Equipment

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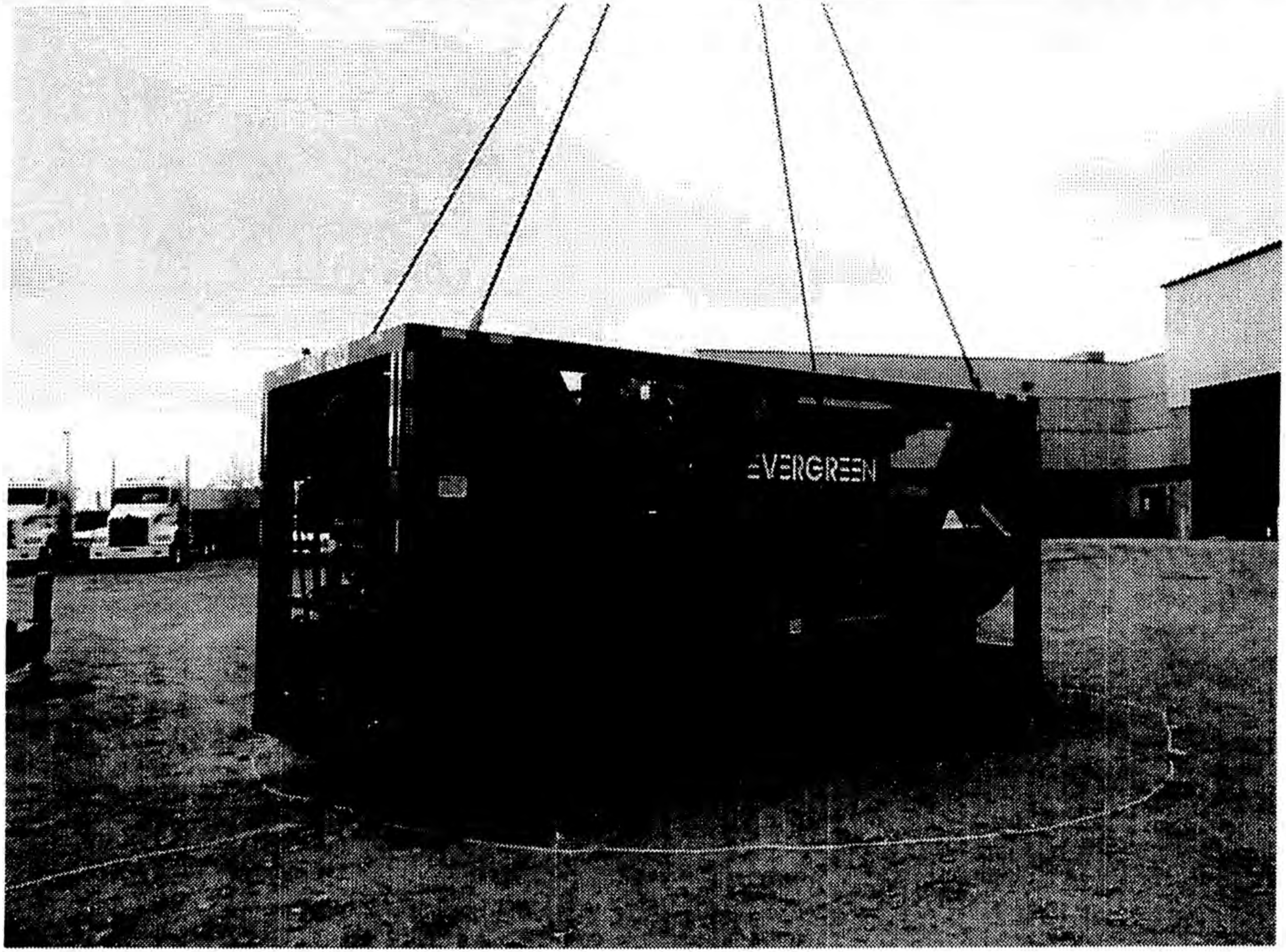
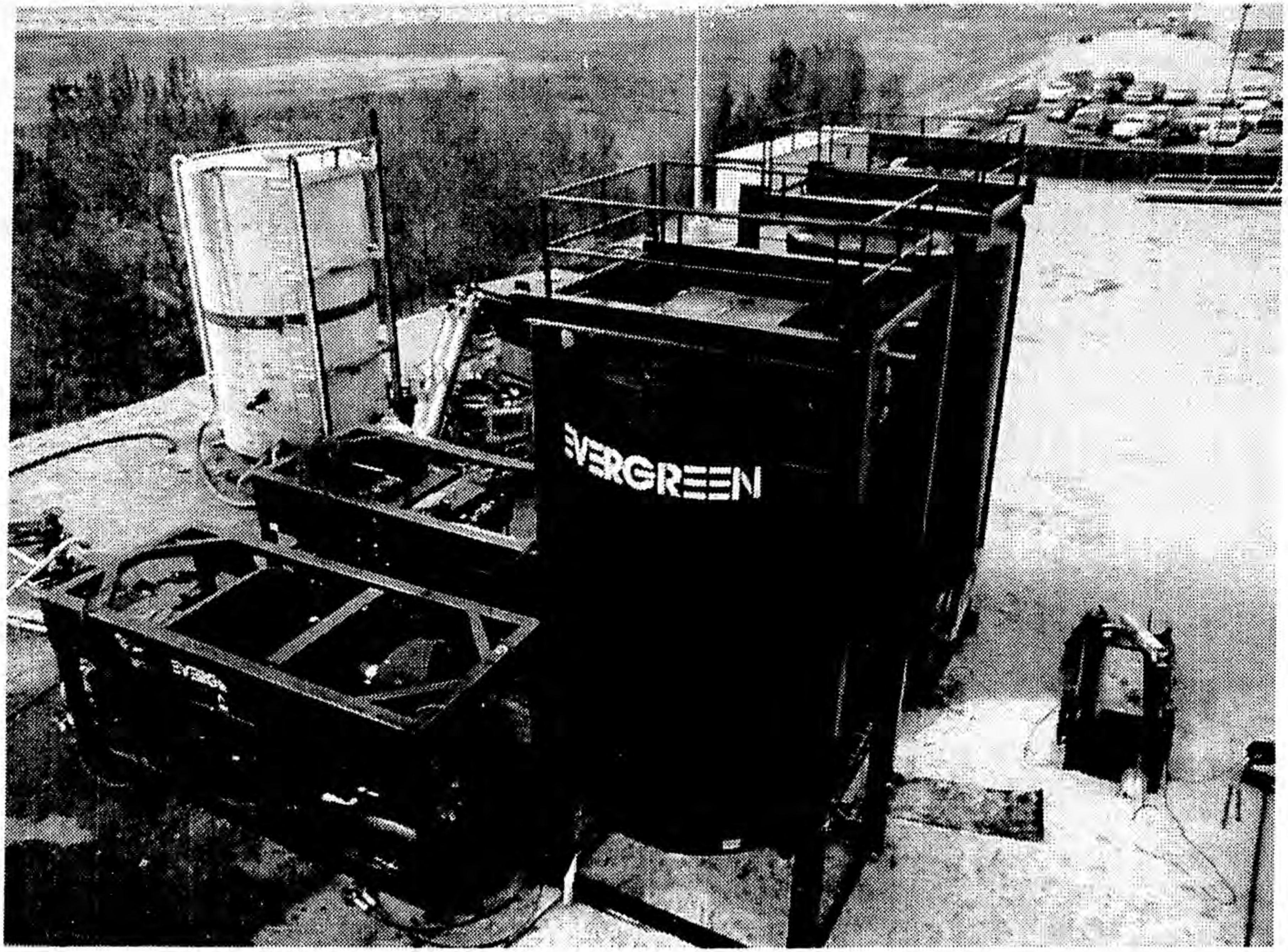


Portable Frac Equipment



Electric Well Pump

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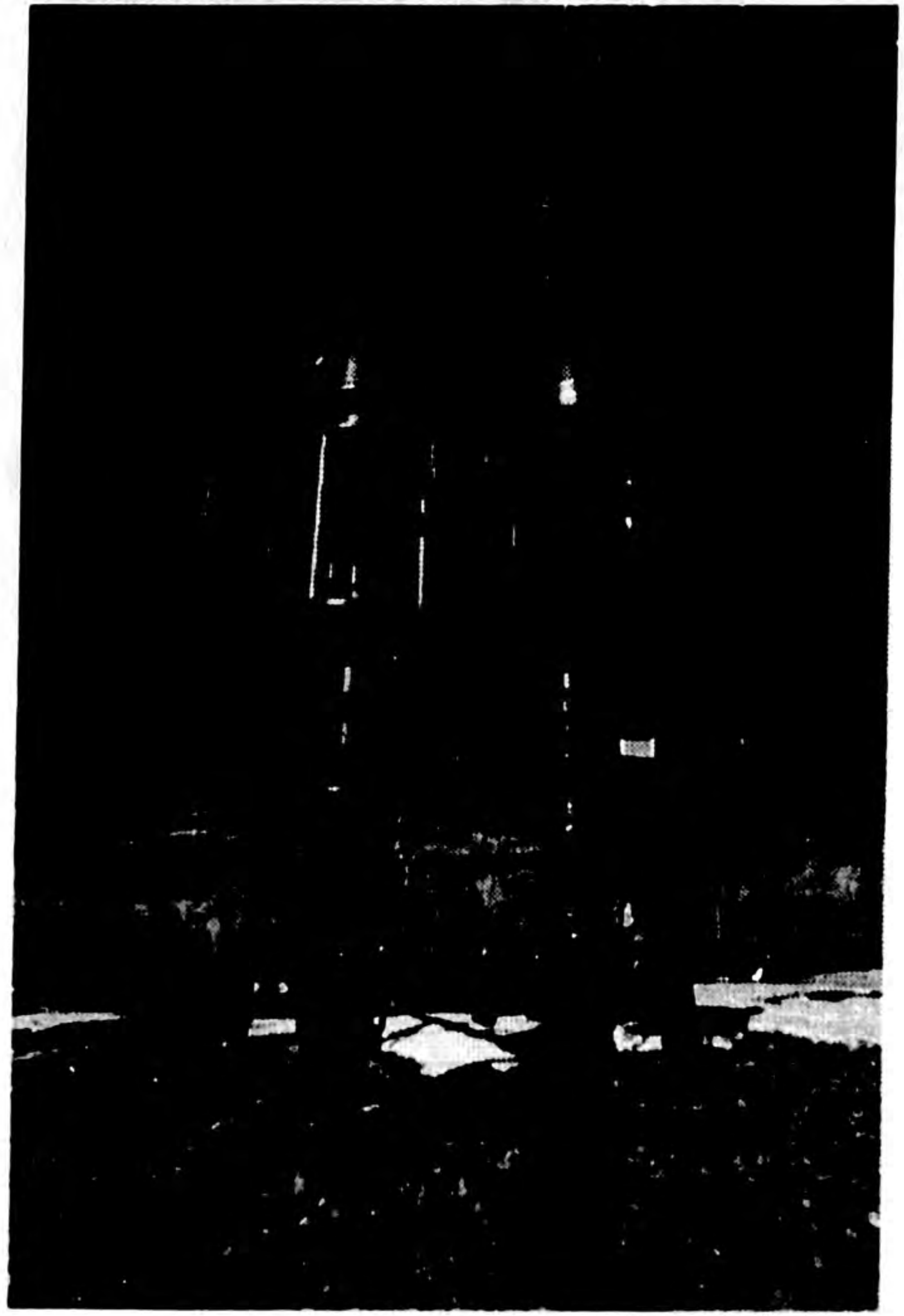

Enclosed Gas Engine and Well Pump

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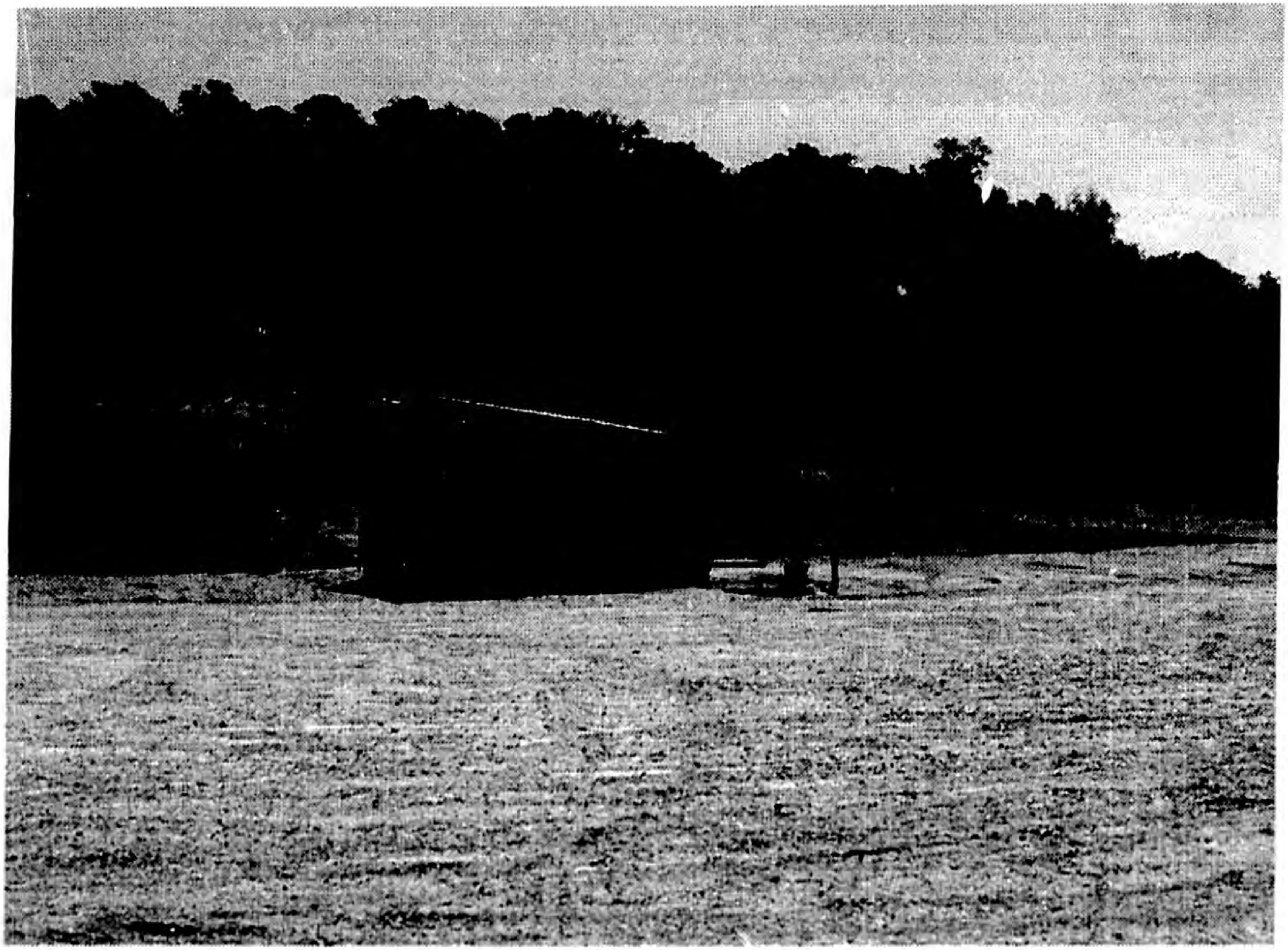

Produced Water-- Evaporation Ponds

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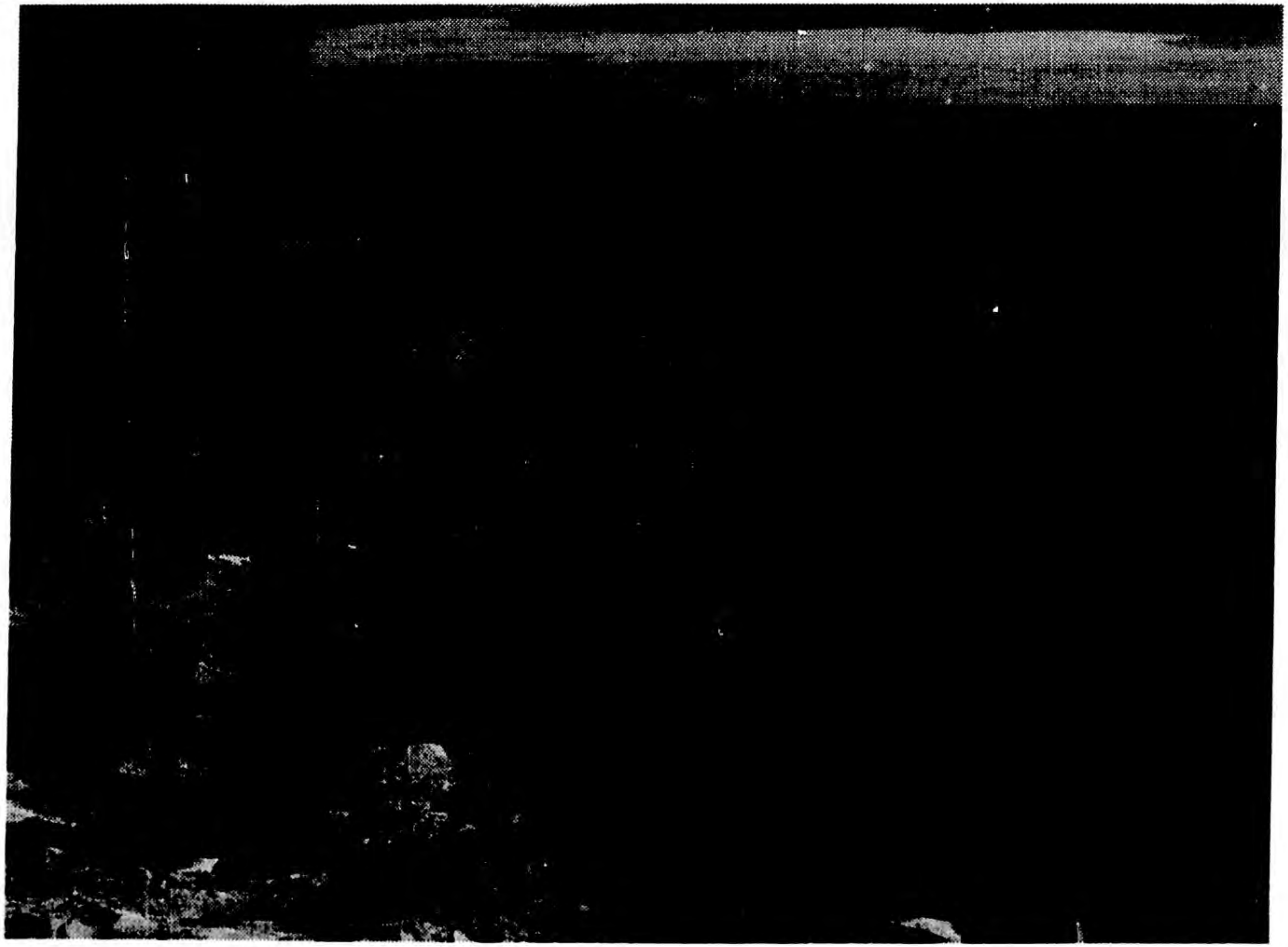
Produced Water-- Erosion Control



Evergreen Pipeline Construction

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Evergreen Compressor Station

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Compressor Noise Reducing Structure

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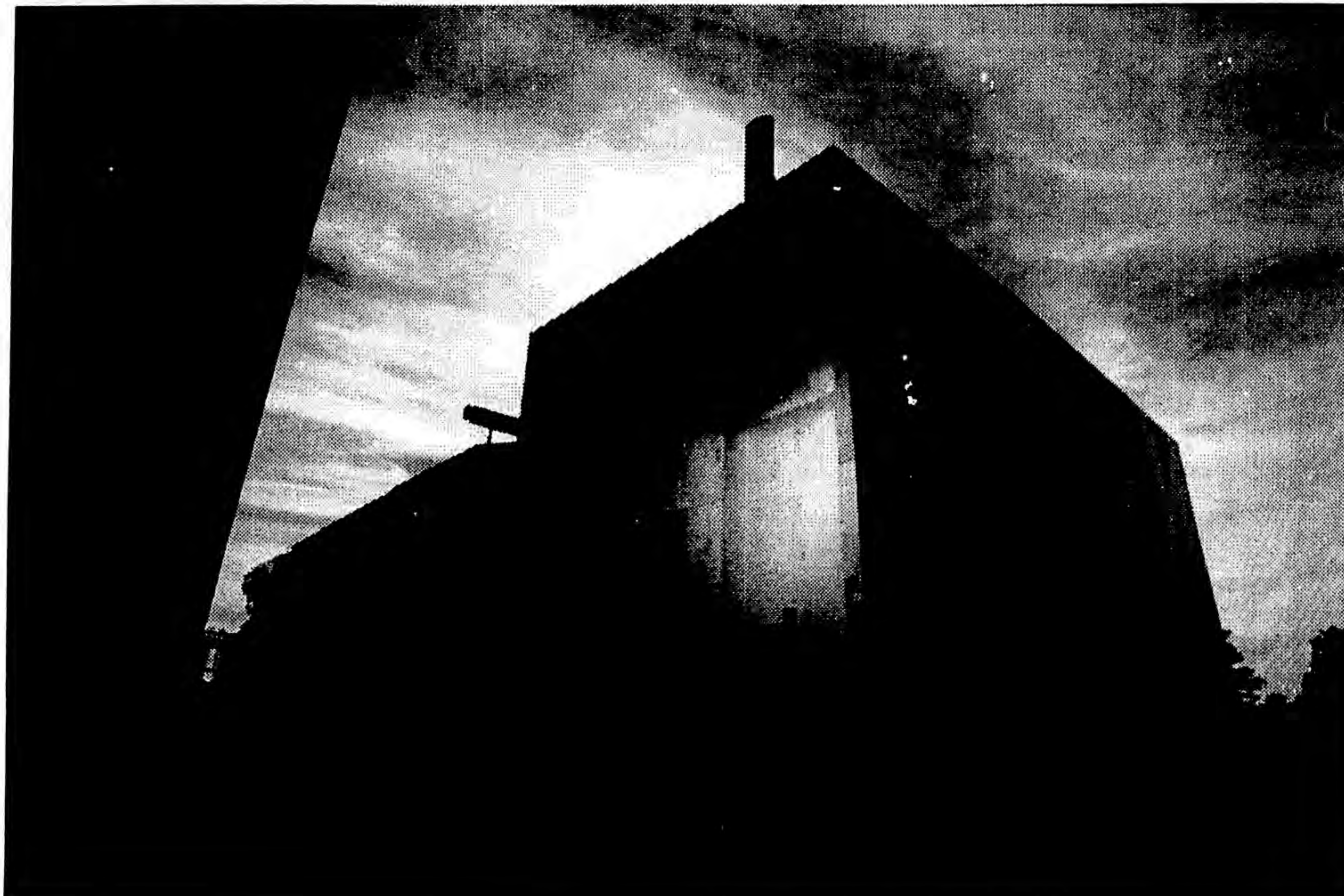


Committee Request: Address these Topics

EVERGREEN

1. Update on Evergreen's Activities
2. Plans for Gas from North Slope
3. Assessment of Reserves & Undiscovered Resources
4. Evergreen budget for next 5 years
5. Assessment of Cook Inlet Gas Demand
6. Deliverability Constraints in Next 10 Years
7. Recommendations for Legislature

Concluding Remarks

EVERGREEN

- Evergreen's and Alaska's Shared Goal:
  Provide Long-Term Natural Gas Supply for Alaskans

- CBM is a long lived resource and provides us the opportunity to make a long term investment in Alaska

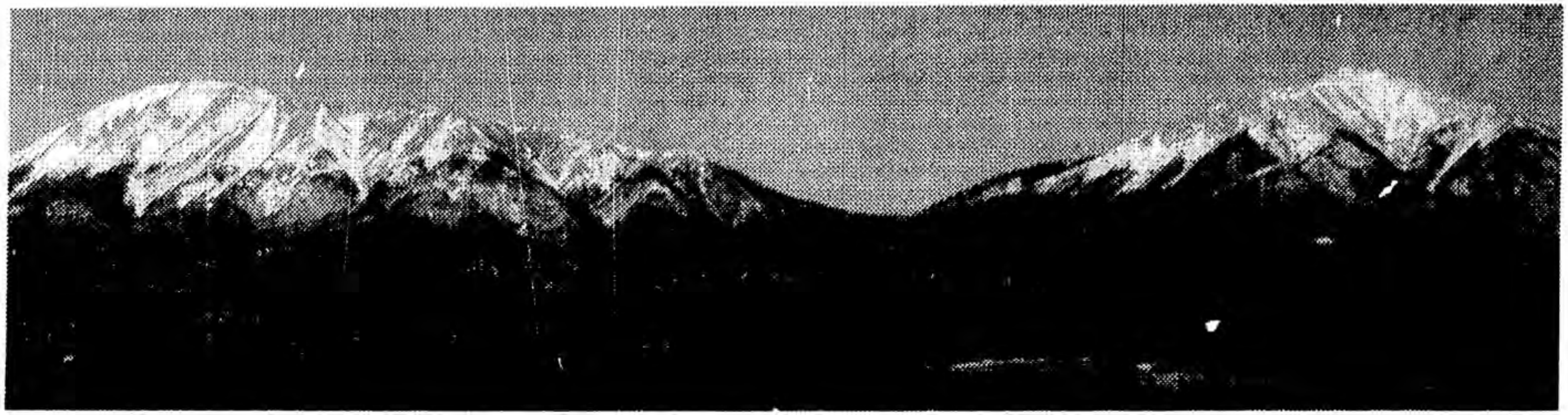
- We support Alaska's gas pipeline efforts to the lower 48

- Above all else, we seek and expect to be contributing citizens of Alaska, providing jobs, environmentally responsible development resulting in a clean energy source. We have done this in the Raton Basin of Colorado, we look forward to replicate that success here.

Forward Looking Statements

This presentation contains forward-looking statements within the meaning of federal securities laws, including forward-looking statements regarding Evergreen's natural gas production and realized natural gas price. These statements are subject to various uncertainties. Actual results could differ materially from these forward-looking statements as a result of variety of risks, including, among others, risks that production estimates are inaccurate or gas prices change significantly. Accordingly, there can be no assurance that actual results will be as projected in the forward-looking statements.

EVERGREEN



Recognized Leader in Coal Bed Methane Technology & Development

EVERGREEN RESOURCES, INC.

COOK INLET NATURAL GAS

The Federal Outer Continental Shelf

John Larson, Geologist

Department of the Interior

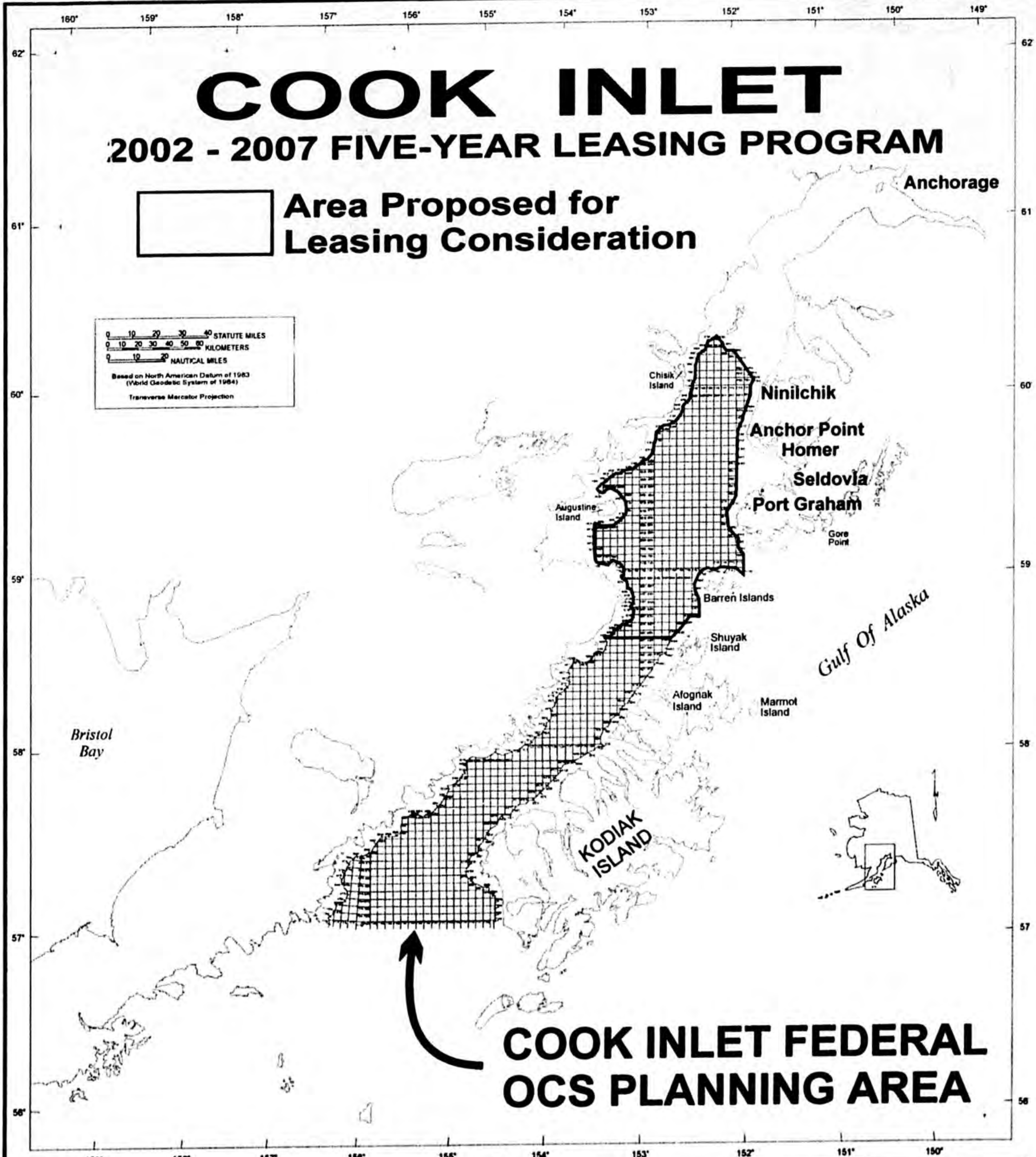
U.S. Minerals Management Service

Alaska State Legislature

Joint Committee on Natural Gas Pipelines

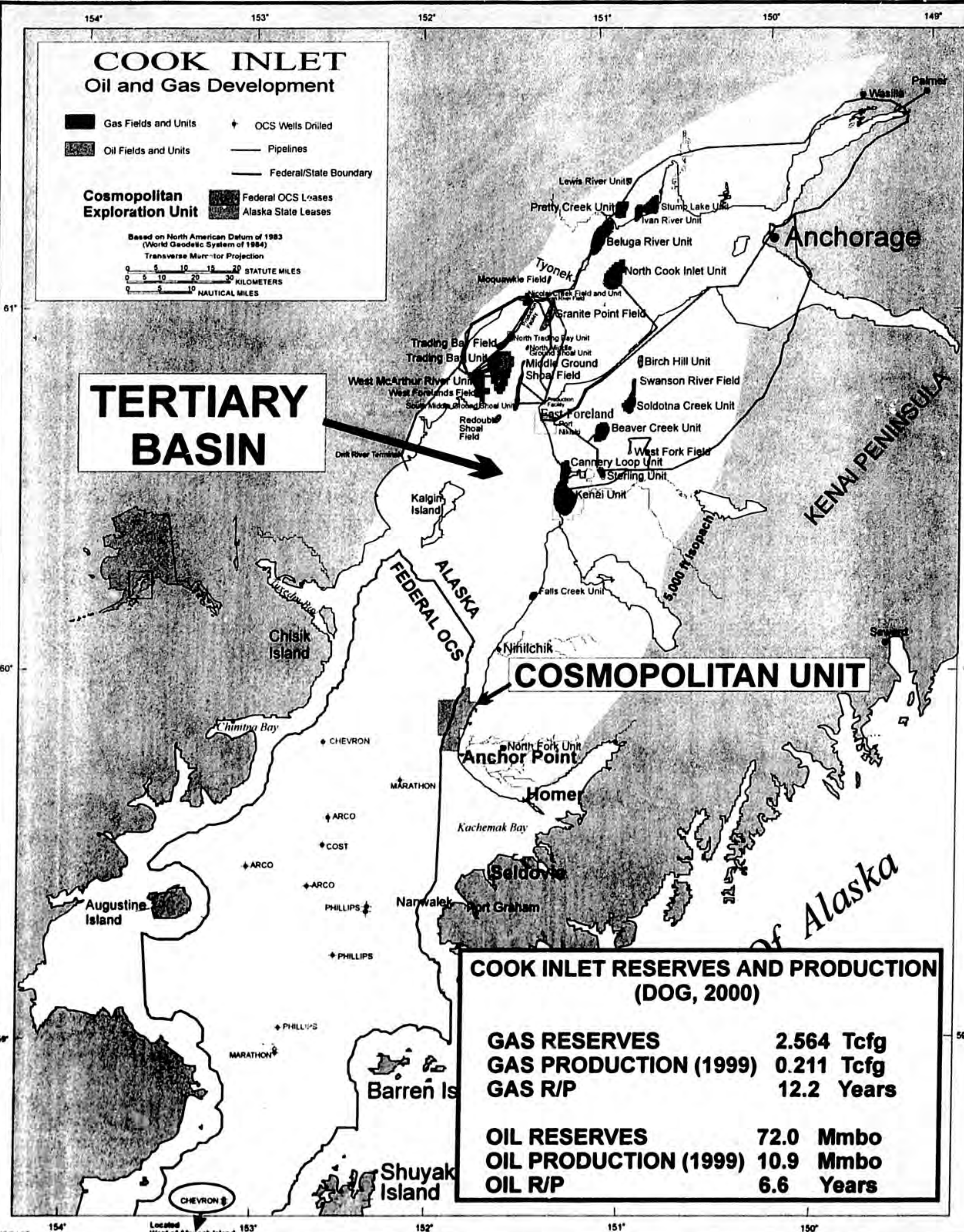
November 07, 2001

MMS U.S. Department of the Interior
Minerals Management Service
Alaska OCS Region

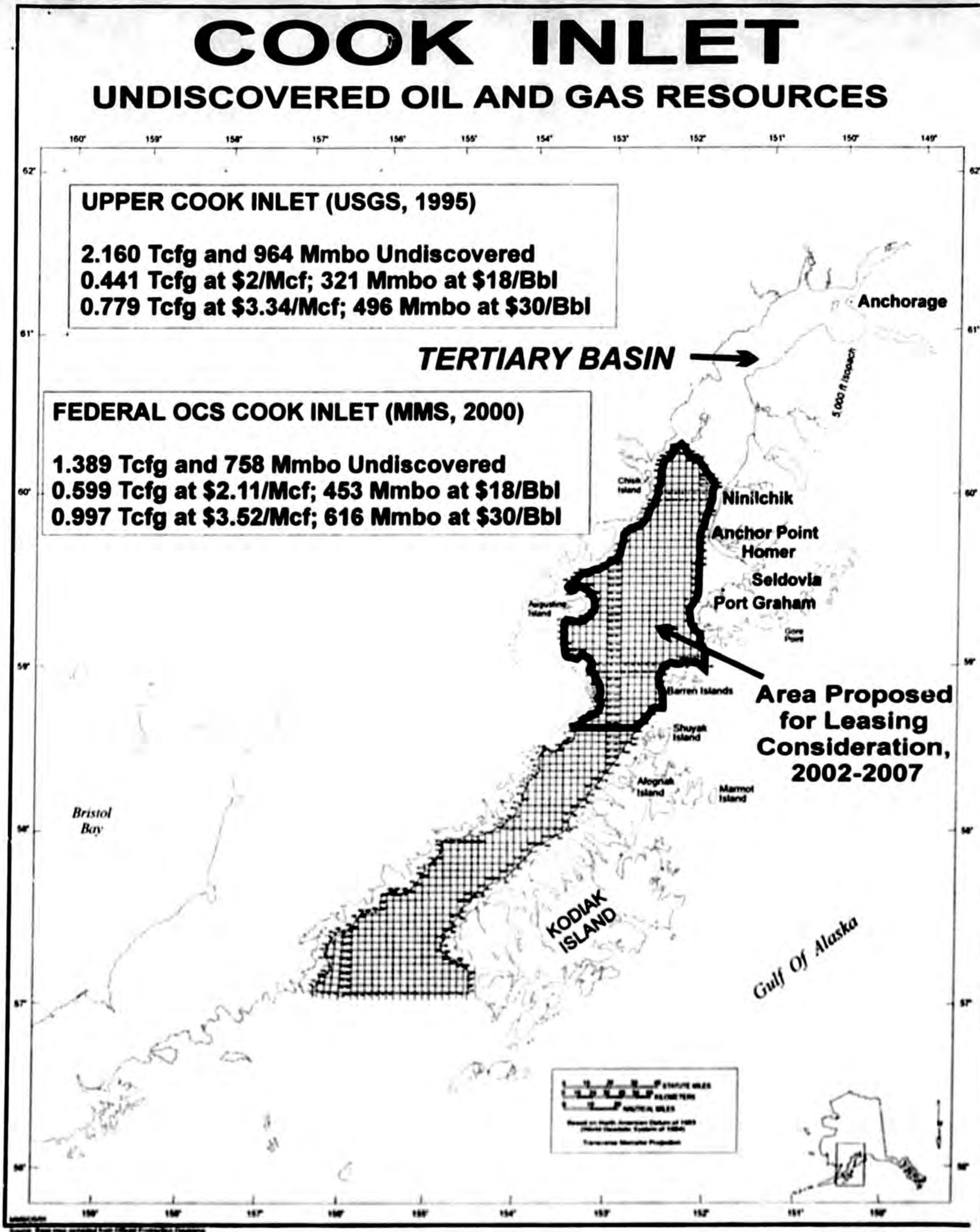


MMS/OS/01
Source: Base map compiled from Official Protraction Diagrams.

MMS U.S. Department of the Interior
Minerals Management Service
Alaska OCS Region



Source: Base map compiled from Official Protraction Diagrams


COOK INLET
UNDISCOVERED OIL AND GAS RESOURCES
UPPER COOK INLET (USGS, 1995)
2.160 Tcfg and 964 Mmbo Undiscovered
0.441 Tcfg at $2/Mcf; 321 Mmbo at $18/Bbl
0.779 Tcfg at $3.34/Mcf; 496 Mmbo at $30/Bbl
TERTIARY BASIN
FEDERAL OCS COOK INLET (MMS, 2000)
1.389 Tcfg and 758 Mmbo Undiscovered
0.599 Tcfg at $2.11/Mcf; 453 Mmbo at $18/Bbl
0.997 Tcfg at $3.52/Mcf; 616 Mmbo at $30/Bbl
Anchorage
5,000 ft isopach
Ninilchik
Anchor Point
Homer
Seldovia
Port Graham
Barren Islands
Shuyak Island
Afognak Island
Marmot Island
Area Proposed for Leasing Consideration, 2002-2007
Bristol Bay
KODIAK ISLAND
Gulf Of Alaska

In Conclusion

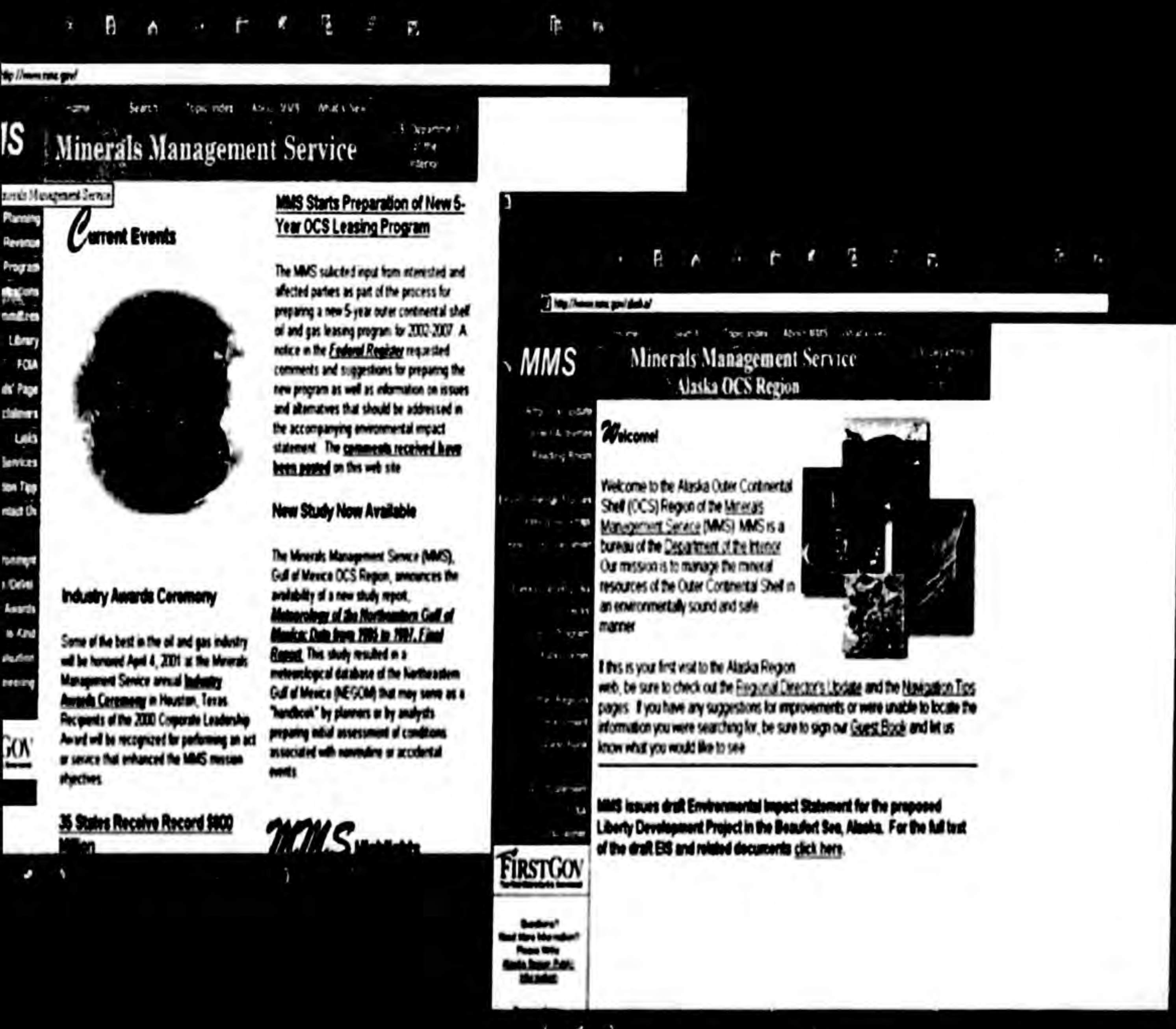
- Cook Inlet basin has significant untapped natural gas resources

- The MMS is proposing two oil and gas lease sales in years 2004 & 2006 for the most promising portion of the Federal OCS part of Cook Inlet basin

For more information

http://www.mms.gov/

http://www.mms.gov/alaska/



ALASKA STATE LEGISLATURE
JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

MEMORANDUM

To:	Members of the Joint Committee on Natural Gas Pipelines
From:	Senator John Torgerson
Re:	Committee correspondence for the hearing on November 7 & 8
Date:	November 7, 2001

Attached, please find a copy of written testimony from invitees who have chosen not to testify in person.

- Chugach Electric Association
- Forest Oil Corporation
- Yukon Pacific Corporation
- Alaska Gasline Port Authority
- Gas-Pro Alaska

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669
Phone: 907-260-3041
Fax: 907-260-3044

CHUGACH ELECTRIC
ASSOCIATION, INC.

GENERAL COUNSELS' OFFICE
PHONE: (907) 762-4790
FAX: (907) 762-4688

November 1, 2001

VIA TELEFAX

Senator John Torgerson
Alaska State Legislature
35477 Kenai Spur Hwy., Ste. 101A
Soldotna, AK 99669

Dear Senator Torgerson:

Thank you for the opportunity to participate in the public hearing set for November 7th and 8th in Kenai on Southcentral natural gas supply issues. While Chugach does not intend to testify, I have enclosed a copy of a document entitled "2001 Ten-Year Natural Gas Fuel Requirements Projection" which summarizes Chugach's anticipated natural gas needs. This document responds to the first topic referenced in your letter of October 22, 2001.

In response to your question about possible expansion plans in the event a natural gas supply is made available from the North Slope, Chugach's needs for fuel are based on electric power loads in Southcentral. To the extent that growth in loads results from the availability of North Slope natural gas in Southcentral Alaska, Chugach would be prepared to expand electric power production and transmission as needed to meet those needs.

As this is a topic in which Chugach is keenly interested, I will be reviewing the testimony submitted by other participants in this hearing. I would also appreciate being placed on any list you maintain of people to keep informed on this and related topics. You can reach me by email at don_edwards@chugachelectric.com or by phone at (907) 762-4637.

Sincerely,

Donald W. Edwards
General Counsel

Enclosure

Chugach Electric Association, Inc.
Asset Management

2001 Ten-Year Natural Gas Fuel Requirements Projections

Attachment 1

Based on 2001 Power Requirements Study, Mid Load Growth Case
Amounts in Thousand MCF's

		FIRM REQUIREMENTS							POTENTIAL ECONOMY SALES		MARATHON TOTALS			TOTAL REQUIREMENTS
Plant →		Beluga Plant		Bernice Lake	Nikiski	IGT	USPS Fuel Cell Plant	AIA Cogen	Beluga Plant	Bernice Lake				
Fuel →	New Contract Source (See Note 2)	Beluga Producers (Pooled (1))	Marathon	Marathon	Marathon	Marathon ENSTAR Transport	Marathon ENSTAR Transport	Marathon ENSTAR Transport	Marathon	Marathon	Firm	Economy Sales	Total Marathon	
Year	(000 MCF) →													(000 MCF)
2001	0	11,378	7,585	441	3,123	59	80	0	2,244	369	11,288	2,613	13,901	25,280
2002	0	11,825	7,965	268	3,626	62	81	0	2,233	367	12,000	2,600	14,600	26,426
2003	0	11,715	7,891	475	3,626	75	81	306	2,233	367	12,455	2,600	15,055	26,769
2004	0	12,056	8,119	601	3,636	78	82	335	2,233	367	12,850	2,600	15,450	27,506
2005	0	12,419	8,360	241	3,626	50	81	334	2,233	367	12,691	2,600	15,291	27,710
2006	0	12,585	8,472	855	3,626	109	82	334	2,256	370	13,477	2,626	16,103	28,687
2007	0	12,754	8,584	905	3,626	130	82	334	2,278	374	13,660	2,652	16,312	29,066
2008	0	12,855	8,651	328	3,636	52	82	335	2,301	378	13,084	2,679	15,762	28,617
2009	4,816	13,536	4,208	515	3,626	63	39	161	2,324	381	8,612	2,706	11,318	29,670
2010	17,045	13,241	0	0	0	0	0	0	0	0	0	0	0	30,286

Notes:

(1) Forecast assumes Soldotna #1 unit is relocated and operational as Nikiski Unit #1 at UNOCAL's Nikiski Refinery by February 15, 2001. Assumed Nikiski site fuel sources: 100% Marathon contract gas.

(2) It is anticipated that Marathon contract vol[illegible] will be depleted by mid-year 2009. The forecast assumes that new contract fuel sources (presently unidentified) will be in place starting in 2009.

FOREST OIL CORPORATION
310 K Street • Suite 700
Anchorage, Alaska 99501
(907) 258-8600 • (907) 258-8601 (Fax)

October 25, 2001

Honorable John Torgerson/Joe Green
Joint Committee on Natural Gas Pipelines
State Capitol, #427
Juneau, AK 99801

Fax: 907-260-3044

Dear Honorable John Torgerson/ Joe Green,

Thank you for the invitation to testify before your committee on natural gas issues concerning the Cook Inlet and Forest Oil Corporation's plans for the near future. Unfortunately, I will be out of state during the hearings, and therefore, will be unable to testify in person. I would be happy to provide written testimony, which I will submit to your office prior to November 5, 2001.

Very truly yours,

Gary E. Carlson
Senior Vice President

GEC/nc

FOREST OIL CORPORATION

310 K Street • Suite 700
Anchorage, Alaska 99501
(907) 258-8600 • (907) 258-8601 (Fax)

November 5, 2001

Senator John Torgerson, Chair Fax: 907-260-3044
Alaska State Legislature Joint Committee on Natural Gas Pipelines
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669

Dear Sirs:

On behalf of Forest Oil Corporation, I appreciate the opportunity to provide testimony to this committee regarding Cook Inlet gas development.

Forest Oil is actively engaged in exploration for gas reserves in the Cook Inlet area, as well as in other areas outside the North Slope of Alaska. Currently our operations and immediate development activities are focused on oil production; however, our strategy includes finding and developing gas reserves in our areas of activity. Forest Oil has defined multiple gas prospects on our leased acreage in the Cook Inlet area. We are interpreting geological and geophysical data, and addressing business issues necessary to develop economic scenarios, which will support exploratory drilling of the prospects.

Forest Oil is also performing regional investigations in other areas under the auspices of exploratory licenses. The result of this work will, hopefully, be to develop leads, which can be more specifically evaluated, with the final result being the development of specific drillable prospects in those regions. Gas prospects are key to these license areas.

Over the next 5 years, Forest Oil forecasts a Cook Inlet drilling budget of $225,000,000 including both development and exploratory drilling – to both oil and gas targets. Because Forest Oil is not currently a commercial natural gas supplier, we rely on public and third party estimates of proven Cook Inlet gas reserves, which place those reserves near 2.5 TCF. Both internal and published estimates of probable reserves from producing areas range from 1.0 to 2.0 TCF. Undiscovered possible reserves may range up to another 1.0 to 2.0 TCF.

The deliverability concerns that have been mentioned are tied to making the appropriate investments "just-in-time" to meet the contract demands; therefore, there could be problems if the fields are not properly managed. The current oil and gas producers in the Inlet are capable and qualified to manage this issue by adding wells or compression, as need be.

Forest Oil has been involved in permitting processes here in Alaska for the last few years and it is not an efficient system. It takes too much time, adds little or no value to the State's interest, and is

Date Modified: 11/5/01
Date Prepared: 11/2/01
nc

\\ANCFLS1\\KCULVERHOUSE\\GEC Docs\\Letter_PublicTestimony_11-5.doc destructive to industry's investment returns. In our opinion, the problem lies in the administration and regulatory agencies. We have not identified any legislative solutions to this problem at this time.

In summary, market access and pricing will drive industry investments in natural gas projects and development opportunities in the Cook Inlet area. Technically, we are convinced that the resources are there to serve the needs of Anchorage and surrounding communities for many years to come. Again, thank you for the opportunity to provide feedback to your committee.

Very truly yours,

Gary E. Carlson

Gary E. Carlson
Senior Vice President

GEC/nc

Date Modified: 11/5/01
Date Prepared: 11/2/01
nc

YUKON
PACIFIC
CORPORATION
TRANS-ALASKA GAS SYSTEM

VIA FACSIMILE

October 31, 2001

Senator John Torgerson
35477 Kenai Spur Hwy., Suite 101A
Soldotna, AK 99669

Dear Senator Torgerson:

Thank you and Representative Green for your invitation to make a presentation during the hearing of the Joint Committee on Natural Gas Pipelines scheduled in Kenai on November 7th and 8th. I respectively decline your invitation since I feel we do not have new information or updates significant enough to justify a presentation.

We are currently implementing a reorganization of Yukon Pacific Corporation and moving our offices. The attached press release provides some particulars regarding our current activity.

Thanks again for your invitation We look forward to working with your committee in the future.

Regards,

Ward Whitmore

Ward Whitmore
Director of Project Development

1400 WEST BENSON BLVD., SUITE 525 • ANCHORAGE, ALASKA 99503 • (907) 265-3100 • FAX (907) 265-3180
Yukon Pacific Corporation is a Business Unit of CSX Corporation

NEWS

CSX
CORPORATION
Corporate Communications
PO Box 85629
Richmond, Virginia 23285-5629
http://www.csx.com

Contact: Robert L. Gould
202-783-8124

WHITMORE TO HEAD UP YUKON PACIFIC

CSX CEO Says Trans-Alaska System Project, "Most Viable" Alternative for North Slope Gas

WASHINGTON, Oct. 31, 2001 – CSX Corporation Chairman & CEO, John W. Snow, announced today that Ward Whitmore, a 12-year veteran of the company's Trans-Alaska Gas System (TAGS) subsidiary, Yukon Pacific Corporation (YPC), has been named director of project development and will direct YPC's day-to-day operations. Additionally, YPC has relocated its former office at 1049 West 5th Ave., to 1400 West Benson Blvd., Suite 525, in Anchorage.

"I'm pleased to have someone with Ward's knowledge and experience directing YPC's activities, particularly at a time during which the company is moving into a new phase of operations," said Snow. "The YPC team has put together a terrific project, one that epitomizes the vision of former Governors Hammond, Hickel and Egan, all of whom saw the need to market Alaska's vast natural gas resource."

He added, "As he moves on to pursue other challenges, all of us at CSX thank Jeff Lowenfels and wish him the best in his future endeavors."

Whitmore, an Anchorage resident since 1989, joined YPC after having held several engineering-related positions with Union Pacific Resources and Phillips Petroleum. He earned a bachelor's of science degree in chemical engineering from the University of Michigan.

Under the TAGS project, natural gas would move via pipeline from the North Slope of Alaska to Valdez, where it would then be refrigerated to produce liquefied natural gas for shipment to Asia. Additionally, natural gas would flow through the interior of Alaska for access by major Alaskan population centers. Currently, YPC holds the major state and federal permits and authorizations for the 800-mile pipeline and liquefaction facility excluding wetland permits, which are presently under development.

- More -

"We believe the Trans-Alaska Gas System project is the most viable alternative to developing North Slope gas and as such will continue to press ahead with its development," said Snow. "An important aspect of the project is the ability to serve multiple markets in today's dynamic world gas market."

Snow added, "The employees of Yukon Pacific are hard at work building upon the engineering and permitting assets already in place and will continue to review a variety of configurations as they move forward with the project."

Commenting further, Snow said, "Recent trends have shown that demand for natural gas will grow rapidly. YPC has made major commitments to develop Alaska's gas and will continue to work cooperatively with the North Slope gas holders, the Governor and the legislature, the Federal government and other parties – all of whom are committed to developing this vast natural resource."

CSX Corporation, based in Richmond, Va., operates the largest rail network in the eastern half of the United States. It also provides intermodal, domestic container shipping and global container terminal operations.

###

CSX's Internet Address: http://www.csx.com

ALASKA GASLINE PORT AUTHORITY
550 West 7th Avenue, Suite 1850
Anchorage, Alaska 99501
(907) 278-7000\ fax:(907) 278-7001
ddengel@ci.valdez.ak.us

November 1, 2001

Senator John Torgerson, Chair
Joint Committee on Natural Gas Pipelines
35477 Kenai Spur Highway, Suite 101A
Soldotna, Alaska 99669

Dear Senator Torgerson,

Thank you for your invitation to speak before your committee next week. At this time the Port Authority does not have anything new to present. We are continuing to work with possible purchasers of Alaska's North Slope natural gas.

The Port Authority will be having its annual meeting later this month. I will let you know what the date has been set. If you would like to attend and speak before the Board you will certainly be welcomed.

Again, thank you for your invitation to speak before your committee. We will keep you apprised of the status of the Port Authority.

Sincerely,

David Dengel
Executive Director

Gas-Pro Alaska LLC

1909 So. Harvard Ave., Tulsa, Oklahoma 74112

Phone (918) 748-8775 ★ Fax (918) 748-8891

Part of the NORTHSTAR *Energy Group*

November 6, 2001

Alaska State Legislature
Joint Committee on Natural Gas Pipelines
Senator John Torgerson, Chairman
Rep. Joe Green, Vice-Chair

Ladies and Gentlemen:

This letter is in response to the Committee's questions regarding Gas-Pro Alaska's plans to develop gas reserves in Cook Inlet. Taking the questions in order:

1) Provide the committee with an update of Gas-Pro's activities related to south-central gas field operations.

Gas-Pro is planning to continue the development of the North Fork Field. Specific activities include rebuilding the NF 41-35 wellhead and conducting a mechanical integrity test of the well and; flow testing the well to demonstrate productivity and quantify proved recoverable reserves. As a separate project, Gas-Pro is still permitting an offset well to the NF 41-35. The offset well is intended to prove up additional gas reserves in the Tyonek and possibly test the oil potential of the deeper Hemlock conglomerate. Gas-Pro is also working to identify and lease other potentially productive structures along the same general trend as North Fork.

2) What, if any, expansion plans are being made in the event that a natural gas supply is made available from the North Slope?

Gas-Pro assumes that a pipeline bringing North Slope gas to the Cook Inlet market would also provide access for Cook Inlet gas to markets in the Lower 48.

3) What is your current assessment of proven developed gas reserves, proven undeveloped gas reserves, and unproven probable gas reserves in the Cook Inlet? What is your current assessment of undiscovered gas resources in the Cook Inlet? What are your current explorations plans within and outside known producing fields in the Cook Inlet?

Gas-Pro's assessments of PDP and PUD gas reserves in the Cook Inlet Basin are based on studies released by the Alaska Department of Natural Resources, the Alaska Oil and

Gas Conservation Commission and GeoQuest (study commissioned by Marathon Oil Company and Phillips Petroleum). Specifically, Proved Developed Producing (PDP) reserves are 2.93 TCF. Proved Undeveloped reserves are 858.9 BCF. Total proved reserves are 3.79 TCF

Gas-Pro has not assessed "unproven probable" reserves in the Cook Inlet Basin but does not disagree with the USGS estimate of 2.3 TCF of reserves *yet to be discovered* in the Cook Inlet Basin. At North Fork alone, Gas-Pro believes at least 220 BCF of recoverable reserves are contained in Beluga and Tyonek reservoirs. Gas-Pro believes that there will be more significant gas discoveries in the Cook Inlet Basin as exploration continues in south-central Alaska.

Gas-Pro is studying other prospects along the North Fork trend. Some of these will require additional seismic to delineate.

4) What is your proposed south-central drilling budget for the next five years?

Gas-Pro anticipates drilling up to 20 wells over the next five years at an estimated cost of $60MM.

5) What is your current assessment of south-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and base cases, please generally describe each case.

Gas-Pro subscribes to projections by the University of Alaska Institute for Social and Economic Research that demand for natural gas in south-central markets will grow at between 1% and 2.5% per year for the foreseeable future. New industry requiring large volumes of natural gas and construction of a new LNG plant, possibly at Homer, would significantly boost demand.

6) We have heard that "deliverability", the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next 10 years. Please discuss what can be done to reduce any deliverability problem.

Gas-Pro's view of the deliverability issue is based on statements by Enstar and others that deliverability shortfalls are anticipated within the next few years barring any significant additions to supply. Gas-Pro believes a potential gas deliverability crunch is looming and that immediate steps should be taken to avert such an event.

It is Gas-Pro's position that the best way to alleviate future gas shortages in the south-central market is to expedite development of known fields such as North Fork and Falls Creek in the southern Cook Inlet Basin by encouraging pipelines such as the one being considered from Kenai to Homer. Additionally, the State should continue to encourage exploration for new reserves on the southern Kenai Peninsula and other under-explored areas of the Cook Inlet Basin

7) Finally, do you have any recommended state legislation the committee should consider to advance the development of natural gas related industry within the state?

Gas-Pro believes that streamlining the permitting process for drilling wells would be very helpful.

Gas-Pro appreciates this opportunity to voice its opinions on the current state of the natural gas industry and its future in south-central Alaska. Please feel free to contact us with any questions at the above numbers.

Sincerely,

J. Lawrence Snead

J. Lawrence Snead
Gas-Pro Alaska LLC

PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Cook Inlet Gas Considerations

Testimony to Joint Committee on Natural Gas Pipelines

By
Scott Jepsen
Manager, Cook Inlet Group

November 8, 2001

Mr. Chairman, for the record, my name is Scott Jepsen. I am employed by Phillips, as the Manager for our Cook Inlet assets. I reside in Anchorage, Alaska. Thank you for giving Phillips an opportunity to provide its perspective on the matters requested in the attachment to your October 22, 2001 letter.

For clarity, my testimony is structured in question and answer format, addressing the 10 questions asked in your letter. These answers also provide our overall perspective on Cook Inlet, as requested in your letter.

1) Provide the committee with an update on Phillips' LNG facility activities and its Cook Inlet gas field operations.

Phillips is the operator of the Beluga River Field and the North Cook Inlet Unit (NCIU). Phillips' interest in the Beluga River Field is 33% and in the NCIU is 100%. The Beluga Field primarily provides gas to the local utility market with some sales of gas to the Agrium urea plant. Total gross yearly production out of Beluga is approximately 38 BCF per year. Gas from the North Cook Inlet Unit is produced from the Tyonek Platform. Currently, 100% of the gas from Tyonek is used to supply the Phillips portion of the feed requirements to the Phillips/Marathon LNG plant. The yearly production from the NCIU is approximately 53 BCF. Phillips' plan for these fields is to maintain deliverability within economic constraints. Phillips also has a 50% interest in the Moquawkie gas field, a small, one well, undeveloped, 1998 discovery on the west side of Cook Inlet near the Beluga River Field.

The Kenai LNG plant is jointly owned by Phillips (70%) and Marathon (30%). Total feed to the plant from Phillips and Marathon is approximately 77 BCF per year. The plant produces on average about 1.5 million tons per annum of liquefied natural gas which is sold to Japanese utilities. Our current plans do not envision any significant changes to the operation of the LNG facility.

2) What is the expected length of time Phillips plans to continue current levels of LNG production under the most recent production estimates from natural gas reserves in the Cook Inlet?

On April 2, 1999, Phillips and Marathon were granted a renewal of the export license for the Kenai LNG plant for the period April, 2004 to March, 2009 by the U.S. Department of Energy, Office of Fossil Fuels. For that renewal, a thorough analysis of reserve adequacy was conducted and substantial hearings were held. The results of that process demonstrated that reserve capacity was sufficient for LNG exports to continue through the approved period. It was also found that export was consistent with the public interest and would not result in a local or regional gas supply shortfall on an annual basis.

Phillips hopes to operate the Kenai LNG plant well past 2009. However, it is premature to determine whether we will seek another extension, but if we do, there will be adequate gas reserves to do so, as well as provide for the state's needs.

3) What, if any, expansion plans are being made in the event that a natural gas supply is made available from the North Slope?

Phillips is focussing its ANS gas commercialization efforts on a pipeline to the Lower 48/Canadian markets.

On the general topic of LNG, we would also note that Phillips has been part of the Alaska North Slope LNG Sponsor Group since its inception in 1999. A detailed review of the Sponsor Group work was given to the Senate Resources committee in April, 2001. That review indicated that the Nikiski area and a pipeline from Prudhoe Bay would provide a technically feasible and permittable LNG plant site/route configuration. However, a cost competitive, economically viable Alaska LNG project has yet to be identified.

4) Do you plan to apply for an extension of your LNG export authorization past 2009 if North Slope gas is not available? Is your answer different if North Slope gas were available?

As mentioned in my previous answer, Phillips would like to extend the operation of its LNG operation past 2009, if the dedicated gas supply available to Phillips and Marathon in Cook Inlet allows us to do so. However, we do not see that an export license extension is necessarily contingent on ANS gas being available in the Cook Inlet area.

5) What is your assessment of the Japanese LNG market?

The East Asian LNG market is fiercely competitive and likely to continue to be so throughout the remainder of the decade. In round numbers, we see about 60 to 75 million metric tons per year of potential new LNG supply chasing after 20 to 40 million metric tons per year of new LNG demand through 2010. As a result, recently we have seen prices for new contracts trending downward and pressure for shorter contract periods.

This reinforces the difficulties that an Alaskan LNG project faces in the East Asian market over the next decade. While the market for new LNG is expected to grow, there is an over abundance of lower cost supply and in smaller increments compared to new LNG that would be delivered from Alaska.

That said, Phillips will continue to monitor and evaluate this situation for possible opportunities for Alaskan LNG.

6) What is your current assessment of proven developed gas reserves, proven undeveloped gas and unproven probable gas reserves in the Cook Inlet? What is your current assessment of undiscovered gas resources in the Cook Inlet?

For competitive reasons, Phillips does not release its internal assessment of reserves for fields or basins. However, we can cite several published reports that provide estimates of Cook Inlet reserves. Schlumberger-Geoquest performed a study for Phillips/Marathon in support of the LNG export license renewal effort. The Schlumberger-Geoquest report estimated that, as of 1/1/98, total remaining proven reserves in Cook Inlet stood at 3.3 TCF (cited in the application to Amend Authorization to Export Liquefied Natural Gas, Department of Energy, Office of Fossil Energy). Adjusting for estimated production volumes since then, 1/1/2001 proven reserves stood at around 2.7 TCF. The USGS has also estimated probable reserves at 1 TCF and possible reserves at 1.4 TCF (as reported in "A Review of Cook Inlet Natural Gas Supply and Demand", Northern Economics, 2001, p.8).

With regard to Phillips' assessment of undiscovered gas resources in Cook Inlet, one has to first step back a bit from the numbers. While the estimate of proven reserves is fairly precise, the assessment of possible or potential reserves is less precise. The only real significance of the USGS estimate is that it indicates we probably have not found everything there is to be found in Cook Inlet. The only way to know for sure is through drilling. Because of the historic overabundance of gas in Cook Inlet, drilling activity targeted at gas has not been as high as it might have been. The supply and demand relationship is starting to turn now, with the extreme supply overabundance relative to demand dropping to a level more comparable to the Lower 48. While some see this as a matter of concern, it is premature to think that the market will not react and fill in the supply opportunities as they arise. From an exploration and production point of view, this is really a time for optimism, not pessimism. Let me explain.

By 1970, gas reserves in Cook Inlet stood at about 8 trillion cubic feet (TCF) and production was about 145 billion cubic feet per year: thus the Reserves to Production ratio (R to P ratio) was about 55 years. As would be expected with such a high ratio, there was little incentive to explore for gas, since it would either be a long time before revenues would be realized for the additional, discovered gas or the gas would have to be sold at inordinately low prices.

Over time, the known Cook Inlet reserves have been slowly consumed. As indicated above, reserves are about 2.7 TCF, consumption is about 215 bcf/yr and the R to P ratio is just under 13 years. Theoretically, this would suggest that developed reserves will be exhausted in about 2014. However, in reality, this is a very normal situation in the natural resource industry. For example, the R to P ratio of the L-48 is about 7 years and it has roughly been at 7-10 years, with a slight decline, for the last 20 years. New resources have been added at about the same level as consumption. The market for gas and the increased demand spurs exploration and development.

In the past, the overabundance of gas supply in Cook Inlet has served as a disincentive for exploration. However, for the first time in about 30 years, a company that finds new gas can actually sell at least some of its potential production at a price that may yield acceptable rates of return.

In fact, Phillips believes we are beginning to see the early signs of a new phase of exploration and discovery. We have seen public announcements showing that gas activity has begun to pick up. Phillips and Anadarko had success in finding gas in the Moquawkie Field. We also note the public announcement that Nikolai Creek No. 3 has been successfully recompleted and that Northstar Energy Group proposes a well to tap the North Fork gas field. Marathon and Unocal are actively exploring throughout the Kenai Peninsula. There is clearly a "renewal" of interest in gas exploration and production in the Cook Inlet area, and the results of that effort are beginning to be seen.

Exploration for oil is also on an 'upswing'. Forrest Oil has made an oil discovery at Redoubt Shoal and Phillips is drilling an oil exploration well near Anchor Point. While these oil fields may not add significant gas reserves, they do provide infrastructure that could lower the economic hurdles for additional exploration and development.

On the price side, Enstar has shown willingness in its more recent contracts to tie gas prices to widely accepted gas indices such as Henry Hub. While Cook Inlet is not connected to the Lower 48, receiving Lower 48 prices or better for Cook Inlet gas makes it easier to evaluate gas plays in Cook Inlet relative to other options available to potential investors.

Beyond these basic observations, there are other reasons for prudent optimism. First, seismic technology has progressed and should significantly improve exploration chance factors. Second, there are more players, some new, in the picture. Besides the historical players such as Unocal, Marathon, Chevron and Phillips, companies such as Northstar Energy, Forrest Oil, Anadarko, Aurora, Crosstimbers, Pelican Hill and Escopeta are investing in the Inlet. Clearly, the more players, the more likely that wells will be drilled and discoveries made.

In looking at Cook Inlet as typical of any large, prolific resource basin, there are a couple of characteristics that are common to all of these types of basins. First there is invariably a distribution of field sizes in basins that have been well explored. Second, there are normally cycles of discoveries based upon technology or play concepts.

I want to first take the topic of field size distribution. We know that, typically, naturally occurring phenomena, like hydrocarbon accumulations are distributed in what is technically defined as a log normal distribution. Simplistically, there should be a few giant fields and an ever increasing number of smaller fields. In Cook Inlet, almost all of the currently known reserves are contained in what industry would consider large or giant gas fields. These are fields with more than 1 TCF of initial reserves. These fields have long been regarded as 'accidental discoveries' made while exploring for oil. There has also been a sprinkling of relatively small discoveries in the 50 BCF or less range, which are an inevitable result of the exploration wells that have been drilled. What are undiscovered are the expected field sizes in between. As the incentive to explore for gas in Cook Inlet increases, there is a high likelihood that explorers will start to find these middle-sized fields. With higher prices and increased infrastructure, many of these fields could be economic and in aggregate, could contain relatively large amounts of gas.

Discovery cycles are also a common characteristic of basins like Cook Inlet. Typically, a number of discoveries are initially made in a basin based upon a particular geologic concept, often followed by a period of few discoveries. Almost invariably, there is a new concept or a new technology that leads to a new round of discoveries. An example of this on the North Slope is the recent successes in NPRA. Although it may seem counter intuitive because of the long history of production in Cook Inlet, Cook Inlet may just be starting to come out of its first phase of discoveries. While many of the obvious targets in Cook Inlet have been drilled and technology will play a part in new exploration concepts, the lack of a market in Cook Inlet has kept operators from drilling some long known play concepts. This is another reason for optimism: there are drill ready prospects already out there.

In public forums, we often hear the concern that the Cook Inlet is "running out of gas". It strikes us that this assertion basically ignores the role that exploration is very likely to play in Cook Inlet. As long as the industry has incentive to drill, we believe the next five to ten years will yield much about the potential of the basin.

7) What are your current exploration plans within and outside known producing fields in the Cook Inlet? What is your proposed Cook Inlet drilling budget for the next five years?

As I mentioned in my response to the last question, Phillips is drilling an oil exploration well near Anchor Point. For proprietary reasons, Phillips does not release its specific exploration plans or strategies. In general, however, we will look at any Cook Inlet drilling opportunity on a case by case basis and determine if it competes with Phillips' world-wide opportunities, including those on the North Slope.

8) What is your current assessment of South-central demand for gas over the next ten to twenty years? If you have pessimistic, optimistic and base cases, please generally describe each case?

The area utilities and the University of Alaska at Anchorage (UAA) generally provide demand forecasts for the South Central Area on an ongoing basis. In general, we do not see any significant variances around their forecasts at this time that would influence our business strategies.

9) We have heard that "deliverability", the ability to meet peak winter demand, may be a problem soon. Please discuss whether you see deliverability constraints in the next ten years. Please discuss what can be done to reduce any deliverability problem.

Gas demand in the Cook Inlet is very seasonal. For a period of a few days to perhaps several weeks in the winter, consumption peaks perhaps 30 – 40 % higher than that for the rest of the year. However, meeting these peak demands is not so much a function of reserves as a function of the capacity of wells and delivery facilities. To meet the peak winter demand, investments must be made that are underutilized at other times of the year. For example, in the Lower-48, Canada and Europe, investments have been made for "peak shaving": facilities specifically designed to supply gas during seasonal high demand. Common types of peak shaving are underground storage in converted reservoirs, LNG storage and facility capacity expansions such as additional compression. Typically, these investments are made by the utilities, which have the ultimate responsibility to meet the peak gas demand of consumers. While such peak shaving facilities are common elsewhere, due to high deliverability, there has been little incentive for them in Cook Inlet.

Phillips believes that the tension of not over-investing, yet still meeting peak demands is something that the marketplace can and will ultimately solve through a variety of strategies. As a practical matter, as has been illustrated in numerous markets around the world, investments by the producers to increase peak deliverability must be balanced with development of true peaking facilities. Further, we understand Enstar has agreements in place with Unocal and Marathon to divert gas supplies to meet local peak requirements, should the need arise. In addition, Phillips is committed to working in support of Enstar's efforts to ensure that the needs of the community during critical periods are met.

10) Finally, do you have any recommended state legislation the committee should consider to advance development of natural gas related industry within the state?

Clearly, more frequent and wider lease sales and expedited permitting is an excellent policy. In addition, State support of increased federal lease sales in the potentially gas prospective lower Cook Inlet would also be appropriate.

Mr. Chairman this concludes my testimony. Thank you for the opportunity to present Phillips' views on Cook Inlet gas. I would be happy to answer any questions you may have.

Agrium

Alaska Cook Inlet Natural Gas Competitiveness

Alaska Joint Committee on Natural Gas Pipelines
November 2001

Chris W. Tworek
Vice President, Supply Management
Agrium Inc.

Agenda

- **The Company**
- **Kenai Nitrogen Operations**
- **World Competitiveness**
- **The Alaskan Situation**
- **Partners in Growth**

Agrium

The Company

- **Agrium is One of World's Largest Fertilizer Manufactures**
  - *14 Production Facilities*
  - *11 million tons*

- **Second Largest Ag. Retailer in N.A.**
  - *226 Outlets*
- **Annual sales exceed US $2.0 Billion**

Agrium

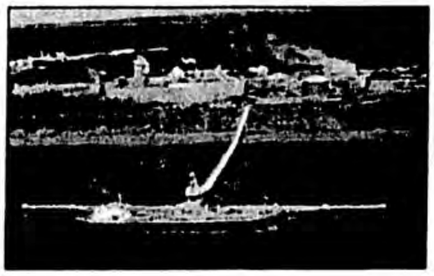
The Company

- **World Scale Facilities**
  - *High Efficient / Low Cost Producer*
  - *Strategically Located Near Key Markets*
  - *Tidewater Access to International Markets*
- **Highly Skilled Workforce**
  - *More Than 5000 Employees World Wide*
- **Committed to Safety & The Environment**

Agrium

Kenai Nitrogen Operations

- **Products**
  - *6% of N.A. Nitrogen Production*
    - Ammonia - 700,000 (net) tons
    - Urea - 1.1 million tons



- **50-55 BCF/yr of Natural Gas Consumption**

- **Employees**
  - *300 Full-Time, Highly Skilled*
  - *30 Contractors on average*

Agrium

Kenai Nitrogen Operations

- **Primary Markets**
  - *Ammonia – Pacific Rim*
  - *Urea – Mexico, South America, Taiwan and Korea*

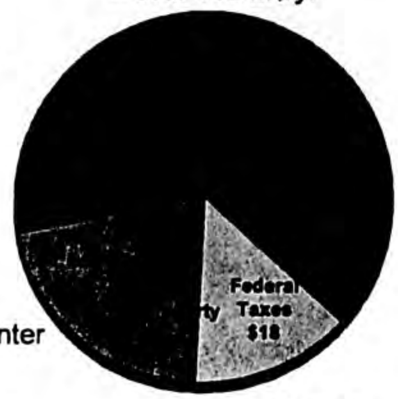
- **Competition**
  - *FSU, South America, Trinidad and Pacific Rim*
  - *Many new plants built in last decade*
  - *World product prices tend to be capped by trapped gas economics*

Agrium

Kenai Nitrogen Operations

- **Community Investments**
  - *Large Local Employer*
    - 300 Highly Skilled Employees
  - *Donations & Sponsorships*
    - Caring for The Kenai
    - United Way
    - Challenger Learning Center
    - Boys & Girls Club, etc.
  - *Commitment to Safety & Environment*

Economic Benefits
– over 130 M$/yr



**Includes Royalties*

Agrium

World Competitiveness

- **Nitrogen is a World Traded Commodity**
  - *Easiest way to monetize & transport gas reserves*
    - $15/t to 50/t ocean freight
- **Recent high N.A. gas prices made N.A. Nitrogen production uneconomic**
  - *N.A. Produces 14% of World's Nitrogen**
    - Up to 50% of N production shut-in at peak
    - U.S. Nitrogen imports doubled
    - Gas producers lost sales for all industrial products

* 20 M tons N - Ammonia, Urea, Nitrate, UAN solutions (2.0 - 2.3 BCF/d natural gas consumption)

Agrium

Importance of Natural Gas

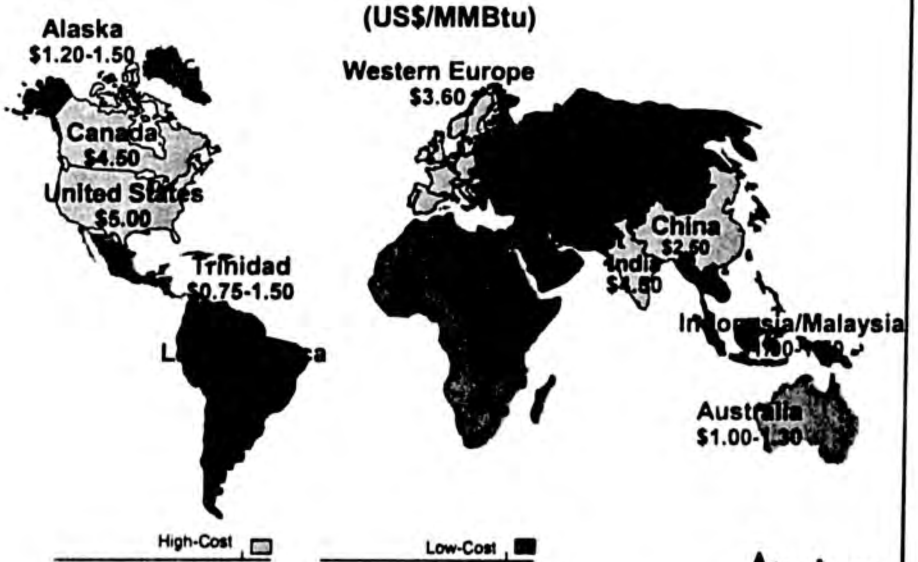
- **Ammonia takes 33.5 MMBTU per ton**
- **Gas is 75 – 90% of ammonia production cost**

	World	Recent Prices	N.A.
Feed (MMBTU/ton)	33.5		33.5
Gas Price ($/MMBTU)	x 1.00		x 5.00
Variable Feed /ton	$34		$168
Cash Conversion /ton	$25		$25
Cash Production /ton	**$59**	**←$100-190→**	**$193**

Agrium

World Industrial Gas Cost Comparison

Projections for 2001
(US$/MMBtu)



Source: CERA, BJ&A, Fertecon, Agrium

Agrium

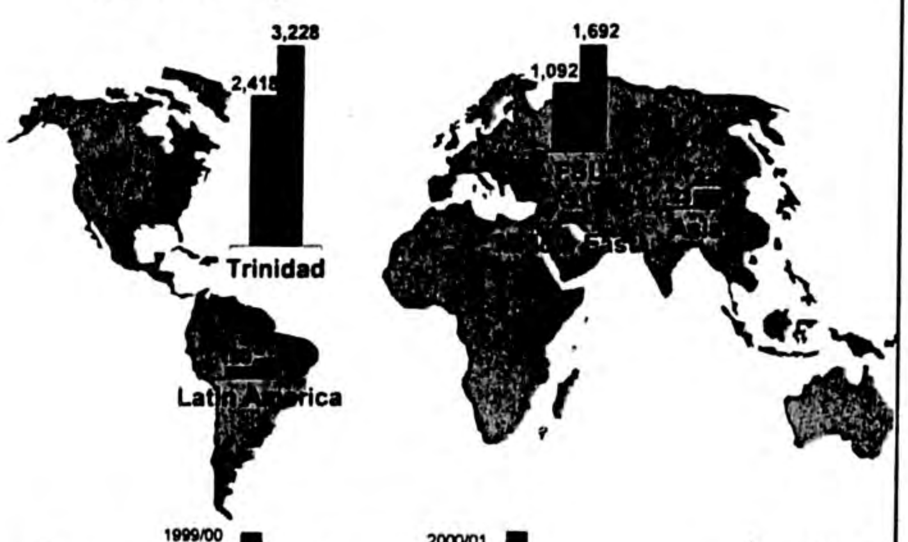
The North America Balance

2001 vs 2000 (Crop Year)	Nitrogen (million st/yr)
Normal Production	**19**
Production reductions	(3)
Increased imports	3
Supply	**19**
Market Demand	18
Inventory Build	**1.0**

Agrium

Major Ammonia Exporters to North America

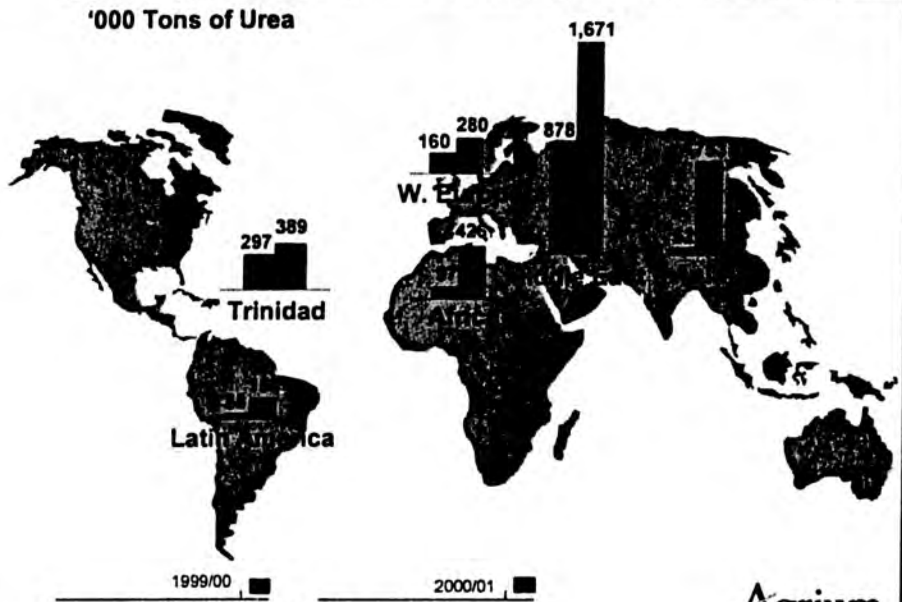
'000 Tons of NH_3



Source: USDC, Statistics Canada

Agrium

Major Urea Exporters to North America



Source: USDC, Statistics Canada

Agrium

Affect of High N.A. 2001 Gas Pricing

- **Plant Shut Downs**
  - *Up to 50% at Peak Gas Pricing*
- **Loss of Market Share**
  - *Imports almost doubled*
- **$ 4-5 gas cannot compete against $1 gas**
  - *Offshore competition won*
  - *Gas Producers lost sales*
    - N was about 0.75 of 3-5 BCF/d industrial demand destruction
    - High prices were not sustained

Agrium

The Alaskan Situation

- **Cook Inlet Products are exported**
  - *Fertilizer and LNG compete globally*
  - *New industries (e.g. gas to liquids) will also have to compete internationally*
  - *Our prices are based on international markets not lower 48*

Source: Green Markets, Blue Johnson

Agrium

The Alaskan Situation

- **Jones Act restricts exports to lower 48**
  - *Act requires U.S. Flag vessels to move products among U.S. ports*
- **Cook Inlet Fertilizer is forced to go off-shore**
  - *No U.S. flag ammonia vessels left*
  - *Urea limited to 1-2 sea going barge*

Agrium

Partners in Growth

- **Expansion Opportunity**
  - *Based On Cook Inlet Advantages:*
    - Close to Pacific Rim markets
    - Good Business Climate & Skilled Workforce
    - World Scale Plant
      - Needs to expand to stay competitive
  - *Agrium uses 50-55 BCF/yr today*
    - Expansion plans add up to 30 BCF/yr
    - Current base supply needs long term extension

Agrium

Partners in Growth

- **Expansion Benefits to Alaska**
  - *Grows Current Local Economic Contribution of $130 M annually*
  - *Increases Sales/Exports*
  - *Expands skilled employment*
  - *Allows Greater Community Investment*
  - *Increases Tax Base*
  - *Encourages Gas Exploration*
  - *Opens Up Other Industries to Export Markets*
- **Must Be Based on Competitiveness**
  - *Reliable and Internationally Competitive Supply of Gas*

Agrium

Partners in Growth

- **Some Possible Solutions**
  - *Spur from Alaska Gas Pipeline is long term advantageous solution*
  - *Cook Inlet has immediate additional gas potential*
    - Anchorage Economic Development Corp Report: 1-3 TCF to be found
    - Coal Bed Methane: 8 – 250 TCF
    - Escopeta: 5-18 TCF

Agrium

Partners in Growth

- **Agrium willing to work with State and Producers to encourage development:**
  - *Pre-investment on appropriate risk/reward:*
    - Pre-bought gas production
    - Infrastructure investment (e.g. pipelines)
    - Exploration and drilling partnerships
  - *Exploration Royalty Relief*
  - *Ongoing royalties based on actual contracts or weighted average sales prices*
  - *Purchase of State Royalty Gas*
  - *North Slope Spur Line*

Agrium

In Closing...

- **Successful partnering will:**
  - *Continue Alaska's development for all sectors*
    - Building Cook Inlet strengthens base for mega projects such as Alaska Pipeline
  - *Contribute to Alaska's export position*
  - *Increase Agrium's annual $130 M plus contribution to local economy*

Agrium

Agrium

November 2001

FRAN ULMER
LIEUTENANT GOVERNOR
STATE OF ALASKA

September 4, 2001

Scott R. Heyworth
PO Box 100531
Anchorage, AK 99510

Dear Scott:

The initiative application for a bill entitled, "The All-Alaskan Gasline Initiative", was submitted to our office for review under AS 15.45.070. The application was forwarded to the Division of Elections for verification of signatures and the Department of Law for review.

Enclosed for your information is the Department of Law's opinion regarding this bill and a copy of the petition statistics report for **01GSLN** as prepared by the Division of Elections.

The Division of Elections has verified that the application does have a sufficient number of sponsors to qualify for circulation of a petition. The Department of Law has concluded that the initiative application does comply with AS 15.45.030 and AS 15.45.040. Consequently, the above referenced initiative application has been certified as being in the proper form under the provisions of AS 15.45.010 through AS 15.45.070, and Article XI of the Alaska Constitution. The official certificate for the application is enclosed.

As Lieutenant Governor and in accordance with AS 15.45.090 (2), it is my duty to prepare an impartial summary for the petition booklets. The following is the suggested petition summary:

Initiative on Gas Pipeline Development Authority

> **This bill would create the Alaska Natural Gas Development Authority (Authority) as a public corporation of the State. The Authority would acquire and condition North Slope natural gas, and construct a pipeline to transport the gas. The Authority's powers would include buying property or taking it by eminent domain, and to issue state tax-exempt revenue bonds. The gasline route would be from Prudhoe Bay to tidewater on Prince William Sound and the spur line from Glennallen to the Southcentral gas distribution grid. The Authority would operate and maintain the gas pipeline, ship the gas, and market the gas.**

P.O. Box 110015 Juneau, Alaska 99811-0015 Phone (907) 465-3520 Fax (907) 465-5400

POLITICAL OPINION SURVEY

IVAN MOORE RESEARCH
TEL: 278-4600
JUNE 23/24, 2001

MUNICIPALITY OF ANCHORAGE ONLY
252 RESPONSES

Hello, my name is ________ and I'm calling for Ivan Moore Research, an Alaska public opinion research firm. We're conducting a public opinion survey that should take about 2 minutes. Your opinions are important to us, and we'd appreciate your participation if that's OK with you, and of course your responses will be completely confidential.

S1. Is this a residential telephone?
IF "YES", CONTINUE...
IF "NO", TERMINATE...

S2. Are you registered to vote in the Municipality of Anchorage?
IF "YES", CONTINUE...
IF "NO", ASK FOR OTHER VOTER...

1. What is your registered party affiliation?

	PARTY AFFILIATION:	
	Count	%
Democrat	48	19.0%
Republican	81	32.3%
Other party/No party	123	48.7%

2. When it comes to politics, do you consider yourself to be a conservative, a moderate or a progressive?

	POLITICAL IDEOLOGY:	
	Count	%
Conservative	99	39.4%
Moderate	108	42.9%
Progressive	45	17.7%

There has been some discussion lately about thetransportation of North Slope natural gas to market. Which of the following two proposals do you support most? A route that travels south from the North Slope to Fairbanks then east along the Alaska Highway to Canada and down to the Lower 48, or a route that follows the Alaska Pipeline corridor south to Valdez where it is converted from gas to liquid natural gas and is shipped out by tanker?

"(The All-Alaskan Gasline Initiative) An Act establishing the Alaska Natural Gas Development Authority, to maximize revenues for Alaska and jobs and gas for Alaskans."

BE IT ENACTED BY THE PEOPLE OF THE STATE OF ALASKA:

*** Section 1. The uncodified law of the State of Alaska is amended by adding a new section to read:**

FINDINGS AND INTENT. (a) The people find that

(1) The Phillips-Marathon liquefaction facility at Nikiski has been supplying Cook Inlet natural gas to Japan and Southcentral Alaska at great profit and without interruption since 1969;

(2) Cook Inlet gas supplies are dwindling rapidly with shortfalls anticipated as early as the winter of 2003;

(3) Alaska's North Slope contains vast proven reserves of natural gas that have been known for at least 25 years but have never been developed;

(4) these gas resources have never been offered for sale, because there has been no way to transport them to market;

(5) multiple markets in North America and Asia have recently expressed an interest in receiving a proposal from Alaska for the purchase of Alaska gas;

(6) if developed, these natural gas resources could represent substantial economic benefits to Alaskans in jobs, state revenue, and gas for Alaska citizens and businesses;

(7) the major North slope leaseholders have competing gas reserves in other parts of the world vying for the same markets, creating a conflict of interest for them in advancing the sales of Alaska gas;

(8) the North slope Producers agreed in 1991 to strand North Slope gas until at least 2005;

(9) given the producer's conflicts of interest and their historic refusal to make North Slope natural gas available it may be necessary to take the gas back;

(10) the permits necessary for an Alaskan gasline project have been pledged to the Alaska Natural Gas Development Authority, operating as a port authority, to facilitate the development of the project;

(e) The authority may not be terminated as long as it has bonds, notes, or other obligations outstanding.

Sec. 41.41.020. Authority governing body. (a) The authority shall be governed by a board of directors consisting of seven members from the general public appointed by the Governor and confirmed by the legislature.

(b) The board shall annually elect a chair, and may elect other officers, from among its members.

Sec. 41.41.030. Term of office. (a) The members of the board shall be appointed for terms of three years, and they may be reappointed.

(b) The terms of the members shall be staggered.

Sec. 41.41.040. Removal and vacancies. (a) The governor may remove a member of the board from office. A removal must be in writing and must state the reason for the removal. A member who is removed may not participate in board business and may not be counted for purposes of establishing a quorum after the member receives written notice of removal. A member who is removed is not entitled to honoraria, per diem, or travel expenses authorized under AS 41.41.060 for work performed after the member receives the written notice of removal.

(b) The governor shall promptly fill a vacancy on the board by appointment. An appointee to a vacancy shall hold office for the balance of the term for which the appointee's predecessor on the board was appointed.

(c) A vacancy on the board does not impair the authority of a quorum of the board to exercise all the powers and perform all the duties of the board.

Sec. 41.41.050. Quorum and voting. Four members of the board constitute a quorum for the transaction of business and the exercise of the powers and duties of the board. Action may be taken only upon the affirmative vote of a majority of the full membership of the board.

Sec. 41.41.060. Compensation of board members; per diem and travel expenses. Members of the board are entitled to per diem and travel expenses authorized for boards and commissions under AS 39.20.180.

Sec. 41.41.070. Authority staff. (a) The board may employ and determine the salary of a chief executive officer.

(b) The chief executive officer may, with the approval of the board, select and employ additional staff as necessary.

Sec. 41.41.130. Tax exemption. The security instruments issued by the authority, the transfer of the security instruments, and the income on the security instruments are exempt from all taxes and assessments in the state.

Sec. 41.41.140. Political activities. The resources of the authority may not be used to finance or influence political activities.

Sec. 41.41.150. Public access to information. (a) Information in the possession of the authority is a public record, except that information that discloses the particulars of the business or affairs of a private enterprise or investor is confidential and is not a public record for purposes of AS 40.25.110 - 40.25.140. Confidential information may be disclosed only for the purposes of an official law enforcement investigation or when its production is required in a court proceeding.

(b) The restrictions of (a) of this section do not prohibit the publication of statistics presented in a manner that prevents the identification of particular reports, items, persons, or enterprises.

Article 2. Powers of the Authority.

Sec. 4141.200. Powers of the authority. In furtherance of its corporate purposes, in addition to its other powers, the authority may

(1) sue and be sued;

(2) adopt a seal;

(3) adopt, amend, and repeal bylaws and regulations;

(4) make and execute contracts and other instruments;

(5) in its own name acquire property, lease, rent, convey, or acquire real and personal property; a project site or part of a project site may be acquired by eminent domain;

(6) acquire natural gas supplies;

(7) issue bonds and otherwise incur indebtedness in accordance with AS 41.41.300 - 41.41.410 in order to pay the cost of a project;

(8) accept gifts, grants, or loans from and enter into contracts or other transactions regarding gifts, grants, or loans with a federal agency or an agency or instrumentality of the state, a municipality, private organization, or other source;

(9) enter into contracts or agreements with a federal agency, agency or instrumentality of the state, municipality, or public or private individual or entity, with respect to the exercise of its powers;

coupons, exchangeable for bonds or bond anticipation notes when these definitive bonds or bond anticipation notes have been executed and are available for delivery.

(e) Bonds or bond anticipation notes may be sold in the manner and on the terms the authority determines.

(f) If an officer whose signature or a facsimile of whose signature appears on a bond, note, or coupon attached to them ceases to be an officer before the delivery of the bond, note, or coupon, the signature or facsimile is valid to the same extent as if the officer had remained in office until delivery.

Sec. 41.41.310. Covenants. In a resolution of the authority authorizing or relating to the issuance of bonds or bond anticipation notes, the authority has power by provisions in the resolution that will constitute covenants of the authority and contracts with the holders of the bonds or bond anticipation notes to

(1) pledge to a payment or purpose all or a part of its revenues to which its right then exists or may thereafter come into existence, and the money derived from the revenues, and the proceeds of bonds or notes;

(2) covenant as to the use and disposition of payments of principal or interest received by the authority on loans or other investments held by the authority;

(3) covenant as to establishment of reserves or sinking funds and the making of provision for and the regulation and disposition of the reserves or sinking funds;

(4) covenant with respect to or against limitations on a right to sell or otherwise dispose of property of any kind;

(5) covenant as to bonds and notes to be issued, and their limitations, terms, and conditions, and as to the custody, application, and disposition of the proceeds of the bonds and notes;

(6) covenant as to the issuance of additional bonds or notes, or as to limitations on the issuance of additional bonds or notes and the incurring of other debts;

(7) covenant as to the payment of the principal of or interest on the bonds or notes, as to the sources and methods of the payment, as to the rank or priority of the bonds or notes with respect to a lien or security, or as to the acceleration of the maturity of the bonds or notes;

(8) for the replacement of lost, stolen, destroyed, or mutilated bonds or notes;

(b) This section does not apply to the issuance by the authority of refunding bonds or to the issuance by the authority of bonds the proceeds of which are intended to be used to refinance the loans held by the authority.

Sec. 41.41.330. Independent financial advisor. In negotiating the private sale of bonds or bond anticipation notes to an underwriter, the authority may retain a financial advisor. A financial advisor retained under this section must be independent from the underwriter.

Sec. 41.41.340. Validity of pledge. (a) The pledge of assets or revenue of the authority to the payment of the principal or interest on an obligation of the authority is valid and binding from the time the pledge is made, and the assets or revenue become immediately subject to the lien of the pledge without physical delivery or further act. The lien of a pledge is valid and binding against all parties having claims in tort, contract, or otherwise against the authority, irrespective of whether those parties have notice of the lien of the pledge.

(b) This section does not prohibit the authority from selling assets subject to a pledge, except that a sale may be restricted by the trust agreement or resolution providing for the issuance of the obligations.

Sec. 41.41.350. Capital reserve funds. (a) For the purpose of securing one or more issues of its obligations, the authority may establish one or more special funds, called "capital reserve funds," and shall pay into those capital reserve funds (1) money appropriated and made available by the state for the purpose of those funds, (2) proceeds of the sale of its obligations, to the extent provided in the resolution or resolutions of the authority authorizing their issuance, and (3) other money that may be made available to the authority for the purposes of those funds from another source. All money held in a capital reserve fund, except as provided in this section, shall, subject to appropriation, be used as required solely for the payment of the principal of obligations or of the sinking fund payments with respect to those obligations; the purchase or redemption of obligations; the payment of interest on obligations; or the payment of a redemption premium required to be paid when those obligations are redeemed before maturity. However, money in a fund may not be withdrawn from that fund at any time in an amount that would reduce the amount of that fund to less than the capital reserve requirement set out in (b) of this section, except for the purpose of making, with respect to those obligations, payment, when due, of principal, interest, redemption premiums, and the sinking fund payments for the payment of which other money of the authority is not available. Income or interest earned by, or resolution, either at law or in equity, may enforce all rights granted hereunder or under the trust agreement or resolution, or under another contract executed by the authority under this chapter, and may enforce and compel the performance of all duties required by this chapter or by the trust agreement or resolution to be performed by the authority or by an officer of it.

Sec. 41.41.370. Negotiable instruments. All obligations and interest coupons attached to them are negotiable instruments under the laws of this state, subject only to applicable provisions for registration.

Sec. 41.41.380. Obligations eligible for investment. Obligations issued under the provisions of this chapter are securities in which all public officers and public bodies of the state and its political subdivisions, all insurance companies, trust companies, banking associations, investment companies, executors, administrators, trustees, and other fiduciaries may properly and legally invest funds, including capital in their control or belonging to them. These obligations may be deposited with a state or municipal officer of an agency or political subdivision of the state for a purpose for which the deposit of bonds, notes, or obligations of the state is authorized by law.

Sec. 41.41.390. Refunding bonds. (a) The authority may provide for the issuance of refunding bonds for the purpose of refunding an obligation then outstanding that has been issued under the provisions of this chapter, including the payment of redemption premium on them and interest accrued or to accrue to the date of redemption of the obligations. The issuance of the bonds, the maturities and other details of them, the rights of the holders of them, and the rights, duties, and obligations of the authority in respect of them are governed by the provisions of this chapter that relate to the issuance of obligations insofar as those provisions may be appropriate.

(b) Refunding bonds may be sold or exchanged for outstanding bonds issued under this chapter, and, if sold, the proceeds may be applied, subject to appropriation and in addition to another authorized purpose, to the purchase, redemption, or payment of the outstanding obligations. Pending the application of the proceeds of refunding bonds, with any other available funds, to the payment of the principal, accrued interest, and redemption premium on the obligations being refunded, and, if so provided or permitted in the resolution authorizing the issuance of the refunding bonds or in the trust agreement securing them, to the payment of any interest on the refunding bonds and expenses in connection with the refunding, the proceeds may be invested in direct obligations of, or obligations the principal of and the interest on which are

Article 6. General Provisions.

Sec. 41.41.900. Tax exemption. All obligations issued under this chapter are declared to be issued by a body corporate and public of the state and for an essential public and governmental purpose, and the obligations, and the interest and income on and from the obligations, and all fees, charges, funds, revenues, income, and other money pledged or available to pay or secure the payment of the obligations, or interest on the obligations, are exempt from state taxation except for transfer, inheritance, and estate taxes.

Sec. 41.41.990. Definitions. In this chapter,

(1)"authority" means the Alaska Natural Gas Development Authority;

(2)"board" means the board of directors of the Alaska Natural Gas Development Authority;

(3)"project" means the gas transmission pipeline, together with all related property and facilities, to extend from the Prudhoe Bay area on the North Slope of Alaska to tidewater at a point on Prince William Sound and the spur line from Glennallen to the Southcentral gas distribution grid, and includes planning, design, and construction of the pipeline and facilities as described in AS 41.41.010(a)(1) - (5).

* Sec. 3. AS 39.25.110(11) is amended by adding a new subparagraph to read:

(G) Alaska Natural Gas Development Authority;

* Sec. 4. AS 39.50.200(b) is amended by adding a new paragraph to read:

(57) the board of directors and chief executive officer of the Alaska Natural Gas Development Authority (AS 41.41.020).

* Sec. 5. The uncodified law of the State of Alaska is amended by adding a new section to read:

DEVELOPMENT OF PROJECT PLAN. Not later than one year after the first meeting of the board of directors of the Alaska Natural Gas Development Authority, the board shall produce a development plan. The development plan must include

(1) estimates of construction costs and timelines;

(2) gas procurement prices;

(3) use of the state's royalty gas;

(4) estimates of revenue to the general fund and the Alaska permanent fund;

(5) a revenue sharing plan with municipal governments;

<u>Department of Revenue testimony</u>

Larry Persily, Deputy Commissioner
Before the Joint Legislative Committee on Natural Gas Pipelines
Nov. 7, 2001 in Kenai

Pursuant to your instructions in Senate Bill 158, the Department of Revenue and its consultants have been working for the past few months compiling a report for the legislature on the merits of state or public ownership and/or financing of a natural gas project. In addition to consulting with experts on debt financing and project financing, we've interviewed more than 30 individuals plus representatives from 10 companies in the oil and gas industry – not just the producers but the large and not-so-large players in the pipeline business. Our list of interviews also has included many Alaskans involved in banking, the oil and gas industry, legislators and business leaders.

Certainly, the Alaskans we interviewed all would like to see a gasline built to create jobs in Alaska, to generate tax revenues to pay for public services, and to promote the economic activity that would come with such a large construction project. Obviously, we don't need a study to tell us that. What we're looking at are the risks to the state – and the benefits – of becoming a member of any partnership that builds and operates the line. And we're looking at how — and what would happen — if the state wanted to raise the hundreds of millions or billions of dollars needed to buy into the project.

Here are some of the questions we're trying to answer:

- What if we sign on as a partner and there are serious cost overruns during construction? What if the partners are all required to pay in more money to cover those overruns? Will the state be able to come up with the money? It's always possible that federal regulators — FERC — may not allow the pipeline owners to recover 100% of the cost of any overruns. Is it smart to commit to some possible unknown expense in the future, given that the state already is running short of cash? Even worse, what if some unforeseen event blocks or stalls completion of the line? Granted, the risk is small judged by the odds of it happening, but the risk does exist. We need to consider that the Constitutional Budget Reserve Fund is at $2.8 billion and falling. We're looking at around $2.5 billion by the end of the fiscal year next June 30, and below $2 billion one year later. The Permanent Fund Earnings Reserve Account, which had $6.1 billion just a couple of years ago, is at $2.7 billion this week after a bad year in stocks while still continuing to pay full dividends.

- After the pipeline is built and the gas is flowing, there are still price risks to the owners of the line. This is the cost of getting the gas to market, and whether the market will be willing to pay that cost in full year after year. Whereas the cost of moving North Slope oil to market is about 25% of the sales price at the refinery, the cost of moving gas to Chicago is closer to 80%. There just isn't that much margin left after paying the transportation tariff on the pipeline. A small swing in the market price for gas could mean a losing year for whomever is carrying the risk. That's the central issue in all this – who takes the price risk that, in any given year, the price for gas in Chicago will not be sufficient to cover the tariff of moving it from Alaska to the Midwest, plus the cost of production, taxes, and a profit? Generally, the gas producers take this risk, but in the case of the Alaska project, because of its size, we expect there may be some sharing of the risk between the producers and pipeline owners. Certainly, if the producers agree to take all the price risk, pipeline ownership could be a good investment for the state, consistent with Permanent Fund earnings on a risk-adjusted basis.

As I said, we expect that the three North Slope producers are hesitant to take all the risk – the risk of construction cost overruns if they build the pipeline and the larger risk that some years the market will not pay enough to cover the $2+ pipeline tariff plus other costs. Even if you lose just a dime on every thousand cubic of gas in a 4 billion cubic foot per day line, that loss could total $400,000 a day, or almost $150 million over a full year.

Of course, the pipeline companies would be happy to build the line if the producers agree to take all the risk – signing "ship-or-pay contracts," committing to pay the pipeline companies a fixed tariff regardless of the market price.

The decision whether to build the gasline, and who will build it, will come down to a deal over who is willing to share how much of the price risk.

- Also thinking about risk, does it make sense for the state, which is already heavily dependent on oil revenues, to take a large investment in gas? Should we instead diversify from the oil and gas sector in generating state revenues?

  It's one thing for a corporation to take a risk that could mean no dividends to shareholders if it goes sour one year. It's another thing for a state to take a risk with providing essential public services. Remember, we expect the Budget Reserve to hit empty in the second half of 2005, and the Permanent Fund earnings reserve has taken a major hit in the stock market.

- Would the state be better off letting someone else take all the risk, and we then would do what we do best – and that is tax the profits?

- Putting aside the risk issues, we next will have to answer the questions: What can the state bring to table as a partner in the project? Would state government involvement actually slow down a commercial operation? Does the state gain anything worthwhile for taking a share of the risk?

In our research and analysis, and our interviews with producers and pipeline companies, here is what we ve learned:

- Project sponsors — be they gas producers or pipeline companies — already have access to all the capi.al they need if they decide to build the project. State involvement just isn't needed for financing.

- State investment doesn't do anything to lessen the financial risks for the other partners, so they don't gain anything from having us as a partner. Project risk is mostly dictated by the marketplace, and the state has no control over that.

- Alaska already has a significant future income risk in the energy sector. Why would people want to compound the situation by making a large, discretionary investment in energy? An executive said by investing in a project that will not be cash-flow positive for a numbeı of years, the state is depriving its citizens of the present-income value of its limited investment capital.

- Although some may believe the state would gain a "seat at the table" as a partner in the pipeline, we wouldn't really gain any more information than we would be able to get on our own — especially through the Federal Energy Regulatory Commission, which would regulate the pipeline tariff, and through the state's own regulatory agencies. We couldn't use confidential, proprietary information from the table against companies in tax cases, and we couldn't use the information to out maneuver our partners in gas marketing opportunities.

- As a partner, the state might face the political temptation to meddle in the business operation.

  As one pipeline company said, quite bluntly, the state would need to recognize that board discussions are open, frank, and confidential. Decisions would need to be made for the best interest of the project, not necessarily the state. Decisions of and debate of the joint venture board cannot be shared publicly. This might not be compatible with state ownership.

  Another executive explained that a seat at the table is a fine political concept, but the state's participation likely will hurt the viability of the project. The decision-making process of the state on the joint venture governing board likely will be influenced by political, not business, concerns and will be slow. Management of any joint venture is, by its very nature, very difficult. A governmental entity will only increase the complexity because governments are not accustomed to making quick, unemotional decisions.

- The state already can regulate much of the operations of the line through right-of-way permits and regulatory oversight functions.

- Being a partner could put the state into a conflict of interest situation. What would be more important to the state – running the line at maximum profit, or following new, perhaps costly environmental or safety or regulatory rules?

- And, a final, should the state own a piece of a project in a foreign country?

If the state decided to go ahead and take the risk as a partner in the project, where would we get our share of the cash to buy into the gasline?

Under existing federal law, the state or any other public entity could not issue tax-exempt debt except for a very small portion of the project. Only those facilities available for public use, such as a dock or highway or distribution hub available for all users, would qualify under federal law for tax-exempt financing. Everything else would be financed with taxable bonds.

Federal law does allow the state to issue a limited amount of tax-exempt debt for private-activity uses, but that currently is set at $187.5 million a year, and is used in full by AHFC, AIDEA, the student loan corporation and others.

Congress could change the tax laws as it has for other projects, but without a change in federal law, tax-free bonds do not appear to be possible for raising the state's share of buying into the project. The same restriction likely would apply to a port authority or other, similar public corporation or agency.

Another issue is that we don't believe the state could issue general obligation bonds for this project. State ownership in the gasline likely would fail to meet the required standard of a capital improvement or public improvement.

But if we could issue GO bonds for our investment in the pipeline — assuming the state wants to preserve its existing AA credit rating — a conservative estimate of our debt capacity would allow us to commit no more than 5% to 8% of our general fund revenue stream to debt payments. That's been the state's target for years, and it has served us well in maintaining a good credit agency. At a limit of 8% of general fund revenue, the state could issue somewhere around $200 million to $300 million in 10- or 15-year bonds over the next six years. Those numbers are based on the state's current fiscal situation, meaning the budget gap. If the state were to adopt new revenue sources, be it taxes or using some Permanent Fund earnings, we would have the capacity to issue significantly more debt by the end of the decade.

But also keep in mind that that any estimate of Alaska's bonding capacity today does not yet account for bonds under consideration, such as the new DEC seafood lab, deferred maintenance on public buildings, schools and harbors. The gasline would have to compete with all those other needs for GO debt.

The state or another public entity could issue revenue bonds, pledging the future revenue from the gasline to pay back the debt. But there are some problems here, too.

- One, if the state backed the revenue bonds with a moral obligation, we'd have to use tax money or Permanent Fund earnings if gasline revenues were insufficient in any given year to cover debt service. If we sold the bolds based solely on the gasline revenue — with no other assets or income at risk — we'd probably have to pay much higher interest rates to borrow that money. Much higher than what the producers or pipeline companies would have to pay on their own debt.

- Two, the state would be at risk if the gas flow or revenue stream were disrupted. We would no longer have the revenue to pay back the debt.

- Three, even with pledging future gasline revenues, the state still couldn't match the excellent credit rating and lower interest rates that companies such as Exxon and BP could get. For example, looking at taxable bonds, the difference between Exxon's AAA rating and the state's AA rating — if we could maintain that grade — would be $20 million in interest payments in the first year on a $10 billion debt.

- Four, we don't believe 100% project financing is feasible for this project for any governmental entity. Regardless of what the port authority is told by its lawyers and financial advisers, our research indicates it is close to impossible to obtain 100% debt financing for a project operated by a government entity with no experience in such projects and with just a single source of revenue to repay the debt. The answer might be different if the producers were willing to absolutely guarantee a high enough price for a high enough volume of gas for a long enough period of time to pay back the debt, but if they're going to take all the risk why would they want to work through the state or a port authority when they could issue their own debt at a lower cost?

One other comment I want to make is that back in 1978 the pipeline companies were encouraging state investment in the project. Federal law back then prohibited oil and gas producers from owning a pipeline, so that source of funding was not available. The project was estimated to cost $20 billion or more, and that was more than the pipeline companies could afford. Simply put, they needed the state. But the law has changed and the producers can own the line. And the financial strength of many of the companies involved has grown. And the cost is much lower. No one really needs us any more.

These are our preliminary findings and thoughts to date, and could change as we continue with our work. Our final report will be delivered in January, and we would be happy to give you an update next month at your convenience.

ALASKA HIGHWAY NATURAL GAS POLICY COUNCIL

REPORT TO THE GOVERNOR

EXECUTIVE SUMMARY

NOVEMBER 30, 2001

Efforts to Develop North Slope Gas Have a Long History

For almost 30 years – since oil was first discovered on the North Slope – oil and gas companies and Alaskans have been working on ways to market large gas reserves on the slope.

1970

In 1970, the Arctic Gas consortium, mainly U.S. pipeline companies and large gas utilities, proposed a land pipeline east from Prudhoe Bay, crossing what is now the coastal plain of the Arctic National Wildlife Refuge, to Canada's Mackenzie Delta. The pipeline would then run south along the Mackenzie River Valley to connect to the existing U.S. and Canadian pipeline grid.

1974

In 1974, El Paso Natural Gas proposed an "all-Alaska" pipeline across the state to a proposed liquefied natural gas (LNG) plant in southern Alaska. El Paso wanted to ship LNG to the U.S. West Coast.

1976

In 1976, Congress passed the Alaska Natural Gas Transportation Act (ANGTA), designating a special process for a Presidential Finding to select a pipeline route, and for expedited permitting.

1977

In 1977 the Canadian government decided against the Arctic Gas plan, citing unsettled Native land claims along the Mackenzie River route of the pipeline as the main reason.

A second consortium formed to build a pipeline on an alternate route parallel to the oil pipeline to the Fairbanks area, then southeast along the Alaska Highway into B.C. and Alberta. This group included Canadian as well as U.S. companies.

In 1977 President Jimmy Carter approved the Alaska Highway route as the approved corridor for a North Slope gas pipeline. Canada followed suit with similar legislation, and the "Alaska Highway" route was given official blessing by both the U.S. and Canadian governments. It was designated the Alaska Natural Gas Transportation System (ANGTS).

Through the late 1970s and early 1980s, partners in the ANGTS group spent hundreds of millions of dollars on engineering, environmental work and permits.

1982

In 1982, plans to build the ANGTS were suspended when the project partners were unable to agree on a financing plan, given the high costs of the project.

Concerned that Alaska North Slope gas would be "stranded," two former Alaska governors, Walter Hickel and William Egan, and several Alaska businessmen formed Yukon Pacific Corp. to resurrect El Paso's idea for a pipeline across Alaska to an LNG plant. Unlike El Paso, Hickel envisioned shipping the LNG to Asia. For almost a decade, Hickel and Yukon Pacific were the only promoters of an Alaska gas project.

1992

In 1992, North Slope producers decided to take a new look at a trans-Alaska gas pipeline and an LNG export project. A joint study team was formed by the major gas owners, ARCO, BP and Exxon.

1995

In 1995, after tens of millions of dollars were expended in new studies, the joint study team was disbanded. The companies pursued gas marketing individually. ARCO continued to investigate LNG exports, while Exxon concentrated on its new gas-to-liquids technology as a possible way to market North Slope gas.

1998

In 1998, the Alaska Legislature passed the Stranded Gas Act, establishing a framework for negotiation of special fiscal terms for an LNG export project.

1999

In 1999, ARCO formed a proposed "sponsor group" of itself, Phillips Petroleum, Foothills Pipelines, Marubeni Corp. and Yukon Pacific. Yukon Pacific eventually withdrew from the group and BP joined it. After the BP-ARCO merger, Phillips assumed ARCO's share of the project. This group is still at work, focusing now on finding synergies between an LNG project and the proposed all-land pipeline to the lower 48.

2000

In 2000, the three North Slope producers, BP, ExxonMobil and Phillips (heir to ARCO Alaska), formed a joint group to study pipeline routes to the lower 48. Their work, expected to cost about $100 million, is still underway.

2001

In January 2001, Governor Knowles formed the Alaska Highway Natural Gas Policy Council. He directed the 28-member Council to engage Alaskans and develop recommendations for promoting a natural gas pipeline project that maximizes benefits to all Alaskans.

In 2001, Foothills Pipelines owned by TransCanada and Westcoast Energy and six former members of the ANGTS consortium, subsidiaries of Duke Energy, El Paso, Enron, PG&E Corp., Sempra Energy and Williams Energy, announced they would reform the consortium and present a plan for a pipeline to the North Slope producers.

In 2001, Congress is again revisiting possible legislative changes that would speed construction of an Alaska gas pipeline. North Slope producers have proposed legislation that would set up a new procedure for permitting a gas pipeline. The State of Alaska has proposed modifications of the existing Alaska Natural Gas Transportation Act, which endorses a "southern" or Alaska Highway pipeline route.

A Letter from Governor Knowles

November 30, 2001

Dear Alaskan,

The time is right to bring Alaska's North Slope gas to market. American consumers are demanding affordable, environmentally friendly energy and our state has the resources to deliver. A gasline project will provide good jobs for Alaskans, affordable energy for our communities and revenues to pay for vital services.

That is why last January I formed the Alaska Highway Natural Gas Policy Council and asked 28 distinguished Alaskans to examine how the state can promote a gasline project that maximizes benefits to Alaska. I asked the Council to go out and talk to project proponents, natural gas experts, and – most importantly – Alaskans. I encouraged them to ask the tough questions.

The Policy Council's work exceeded expectation. The Council held comprehensive workshops to examine the issues surrounding gasline development. They heard from Alaskans during public hearings held in Fairbanks, Kenai, Anchorage, Tok, Barrow, Juneau and Valdez. Finally the members worked through a subcommittee process that culminated in a series of thorough and useful recommendations.

I am proud to receive this report. The Council's recommendations will be extremely helpful to me and my Administration as we continue to advocate for an Alaska Highway natural gas pipeline.

I thank the Council members for their exceptional hard work and dedication. This report will no doubt serve as a guide to Alaskans as we work together to make a highway gasline project a reality.

Sincerely,

Tony Knowles

Tony Knowles
Governor

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Note to readers:
This is the Executive Summary of the Alaska Highway Natural Gas Policy Council Report to the Governor. For more detailed information, please see the Council's complete report. To obtain a copy of the report, please call (907) 269-7450 or visit www.gov.state.ak.us/gascouncil.

Introduction: A Report to Alaskans

Through the spring, summer and fall of 2001 several hundred Alaskans met in community meetings around the state to advise our state's leaders on important issues involving natural gas policy and the construction of a natural gas pipeline from the North Slope to the lower 48.

The advice and information contributed in these meetings were distilled by 28 Alaskans – business, labor and local government leaders, legislators and state officials – appointed by the governor to the Alaska Highway Natural Gas Policy Council. The results of those efforts are the recommendations in this report.

Based on the advice received during these meetings from Alaskans as well as industry, expert consultants and state officials, the Council believes:

• **Arctic gas is critical to the nation's energy and economic security.** Despite the extreme volatility in natural gas prices, long-term market trends continue to point to a strengthening in natural gas prices along with future shortages of domestic gas supplies and deliverability. Our nation has a strategic energy security need to develop North American energy instead of relying on increased imports of oil and gas from foreign sources.

• **A southern pipeline route through Alaska's Interior, the "Alaska Highway" route, will best serve the nation's and Alaska's interests.** The Council believes the apparent cost advantages of an alternative northern "offshore" pipeline route are illusory because of construction challenges and probable environmental permitting delays posed by the difficult offshore Arctic ice-pack environment.

• **The Council believes a pipeline could be economic and attractive to certain investors, assuming a long-term price of $3 per thousand cubic feet (mcf) flat real prices.** The Council believes there is an urgency to make the project move forward so that the projected long-term gap in North American supply is met by North American natural gas rather than supply imported from uncertain sources overseas.

Alaska Gas is Critical to the Nation's Energy and Economic Security

A paramount consideration is the importance to the security of the United States of natural gas delivered through a secure, buried pipeline from Alaska and Arctic Canada. Our nation is too dependent on oil imported from unstable and even unfriendly foreign nations. Increasingly, natural gas is being looked to as a substitute for oil.

Gas is also clean-burning, an important consideration in meeting the nation's goals for clean air.

Our nation faces a long-term shortage of natural gas, all experts agree. The regions which now produce gas cannot meet the projected long-term growth, and it is unlikely that other areas being explored, such as the U.S. Gulf of Mexico or Canada's eastern offshore provinces or western provinces, will meet all of those needs. Natural gas from many of the other sources in North America tends to have a faster rate of decline, while North Slope gas can be produced at constant production rates for a longer period of time, a distinct advantage for consumers who want surety of long-term supply. Arctic gas from Alaska and Canada can meet those needs.

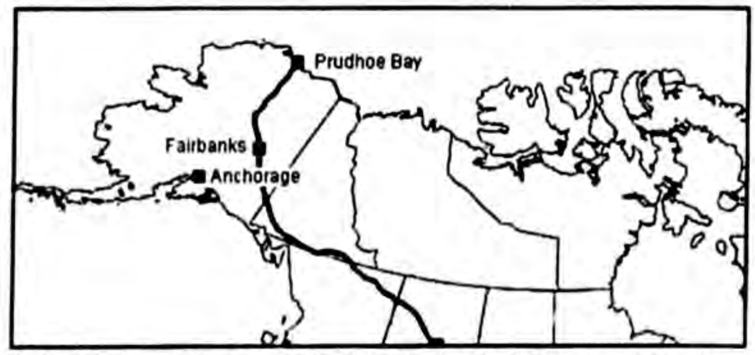
Despite the extreme volatility of lower 48 gas prices over the last 18 months, most experts agree that by the latter years of this decade gas prices over the long term will be set by the cost of imported liquefied natural gas (LNG). This is expected to be between $3 and $3.50 per thousand cubic feet (mcf). It is this and not the current price gyrations that will determine the viability of the pipeline project.

Alaska gas is also economically important to the nation. Four billion cubic feet of gas, and potentially 6 billion cubic feet, can be delivered daily through an Alaska gas pipeline at an affordable price that will boost the economies of North America. Four billion cubic feet delivered daily will represent over 5 percent of the nation's estimated gas demand of 75 billion cubic feet per day at the end of this decade, a supply large enough to dampen or prevent future price spikes. Lower 48 consumers will benefit from a gasline delivering Arctic gas.

The Council toured the Phillips Alaska LNG Plant in May.

During construction, the pipeline will provide considerable jobs in construction, manufacturing and transportation to the nation's workforce, creating a payroll in excess of a billion dollars a year. The cumulative, long-term effect of bringing North Slope gas to market is estimated at 160,000 American jobs and a several billion dollar addition to our gross domestic product. At a time when our nation faces economic uncertainties, this project is of vital national importance.

A Southern Pipeline Route Will Avoid Delays and Speed Delivery of Alaska Gas



An Alaska Highway gas pipeline would travel from Prudhoe Bay to Fairbanks, and then along the Alaska Highway to Alberta to connect with the North American pipeline grid.

It is the Council's belief that a "southern," all-land pipeline route through Alaska's Interior and following the existing Alaska Highway will deliver gas earlier and at less cost to consumers than a "northern," offshore pipeline. A northern route would rely on construction technologies never attempted, at that scale, in a difficult Arctic offshore environment. Because of these challenges, the Council believes there will be no cost savings for the northern route. Summer icepack movements will challenge summer construction, and ice gouging of the ocean floor and ice ridges in winter months pose a very difficult year-round operating environment. In addition, several Alaska Native groups and environmental organizations have voiced strong opposition to the northern route but have expressed support in working with the state and industry on southern route permitting. There will be a lengthy delay in permitting – if permits are ever obtained – for a northern offshore route under the Beaufort Sea ice.

A Gas Pipeline Will Strengthen and Diversify the State's Economy

As for its importance to Alaska, we find that this project, when constructed, will strengthen and diversify our economy by creating a new natural gas exploration and production industry on the North Slope, which will help extend the life of our existing oil fields. This will result in new revenues to the state, shrinking a projected future fiscal gap.

A gas pipeline will encourage the manufacturing in Alaska of products made from gas, similar to the way Cook Inlet gas led to local manufacturing of products such as fertilizer.

While the Council believes North Slope gas may someday be exported to Asia and the U.S. West Coast through a liquefied natural gas plant in southern Alaska, an all-land pipeline to the lower 48 appears more economically feasible as an initial project.

A gas pipeline could also bring clean, affordable energy to many Alaskan communities now dependent on fuel oil. Gas could also be brought to southern Alaska to meet future demands for gas in the Cook Inlet area, potentially extending the life of the industrial plants and making a larger LNG export plant possible.

Unless new significant gas reserves are developed, a shortfall in natural gas deliverability for peak winter demand is predicted for Southcentral Alaska by 2006-08. This shortfall in gas supply in Anchorage and the Cook Inlet area can be offset only by more expensive sources of natural gas or alternative fuels. In future years, the deliverability shortage will be more pronounced. North Slope gas can provide a long-term stable supply source to the main population center of Alaska.

Although there will be fewer construction jobs than the trans-Alaska oil pipeline in the 1970s, many Alaskans will find good employment. The project will stimulate training which will strengthen the skills of our workforce.


The Governor greets Barrow residents before the Council's hearing at the North Slope Borough Assembly Chambers.

A Southern, "Highway" Pipeline Route is Needed for Many of These Benefits

For many of these benefits to be realized, however, the pipeline will have to be built along a route through Interior Alaska and to the lower 48 through the Yukon Territory, the so-called "Alaska Highway" route. In our meetings around Alaska, we found Alaskans united in support of a southern route, with no public support from Alaskan communities for an alternative offshore, or northern, route that is also being studied by the North Slope producers.

An important consideration is how ownership of a gas pipeline is structured. First, the North Slope producers may wish to build, and own, the pipeline. Secondly, a consortium of pipeline, or gas transmission, companies could build and own the pipeline. In this case, producers would sign contracts with the pipeline companies for transportation of gas. A third option is a combination of one or more producers and pipeline companies in a consortium. A fourth possibility is for the Alaskan segment of the pipeline to be financed and owned by a vehicle such as a public authority. This authority would finance its share of a pipeline through access to capital markets much as pipeline companies would do. This vehicle could bring possible tax advantages, such as exemption from payment of State and Federal income tax.

There are advantages with each form of ownership. An advantage of producing companies doing the project is that they would be able to finance part of the project themselves. This could lower financing costs. Independent pipeline companies would look more to capital markets, but an advantage for the state is that these companies, which are in the transportation business, are typically more open to expanding the system to ship gas discovered in the future. (Producing companies traditionally build only enough capacity to meet their own requirements.) Additionally, pipelines in the lower 48 owned by pipeline companies sometimes ship gas at lower costs than pipelines owned by producers. A consortium that combines producing and pipeline companies might have the advantages of both forms of ownership.

The Council believes ownership of the Alaskan segment of the pipeline and construction of in-state gas distribution infrastructure by a public authority is an interesting idea that merits further study, as long as financing is drawn from private capital markets. There are some very significant challenges involved but the tax advantages mentioned earlier might make this vehicle an option in the event that the producers or gas transmission companies elect not to proceed with the project. The public authority vehicle may be applicable for smaller parts of the in-state gas infrastructure, such as spur lines off the main pipeline. This could be one way energy costs for Alaska consumers could be lowered.

The Gas Policy Council tours the BP Gas-to-Liquids test facility construction site in Nikiski:
(l-r, back row): Jack Roderick, Debra Ceffalio, Pat Pourchot, Rep. Mike Chenault, Tom Boedeker, Charles Coulson, John Ringstad, Angela Sorrentina, Barry Babyak, Jim Sampson, Tom Maloney.
(l-r, front row): Ken Freeman, Frank Brown, Michael Hurley, George Findling, Grace Schaible, Steve Fortune, Shane O'Leary.

Important Policy Issues Considered by the Council

Following seven Council hearings around the state and meetings of the five committees, 61 recommendations for State policy were developed, with supporting conclusions. They were adopted unanimously by the Alaska Highway Natural Gas Policy Council.

Some highlights among these recommendations include:

• The State should not invest directly in a gas pipeline project unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms. However, a public financing vehicle, such as a public authority, could play an important role in financing segments of the pipeline because of possible tax exemptions.

• The State's option to take its royalty gas in-kind must be retained. Sales of royalty gas to companies other than producers will foster competition, leading to greater values and more benefits to residents.

• Alaska must have a role in the review and approval of tariffs (transportation costs) and other charges affecting transportation of gas from the North Slope to Alaska communities. The Council recommends either Congress give the state Regulatory Commission of Alaska authority over intra-state gas issues similar to the State's authority over intra-state shipment of crude oil through the TAPS oil pipeline, or a joint board be created between the state's regulatory commission and the Federal Energy Regulatory Commission.

• The State should complete a thorough study of various approaches to in-state natural gas pricing of in-kind royalty gas.

• Several policy clarifications are necessary to enhance the value of the State's one-eighth royalty share of gas production, including basing value on actual market transactions rather than a formula (at least initially), and including sales of natural gas liquids in reported values.

• The southern, or Alaska Highway route is the environmentally preferred route.

• As allowed by North Slope oil and gas leases and existing statutes, the State should keep some of its royalty gas "in-value" by allowing the producers to market the gas and pay the State royalty payments. To increase natural gas marketing competition, however, the State should keep some of its royalty share of gas "in-kind" and allow third parties such as natural gas trading firms to market the gas to consumers.

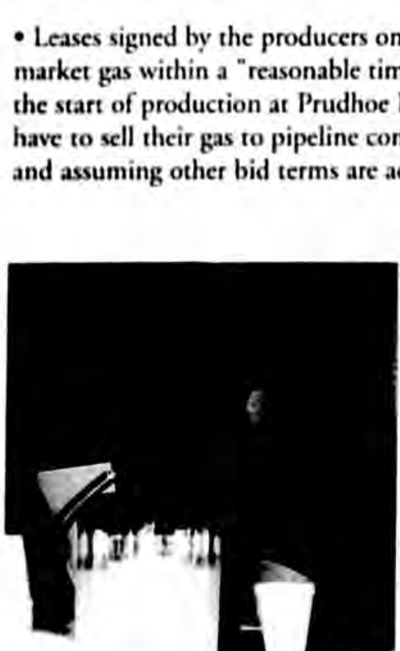
• The experience with the Trans-Alaska Pipeline System must be drawn on. State and federal agencies must be adequately funded to perform the necessary oversight of pipeline construction and operation. Processes for effective public involvement need to be implemented.

• Training for Alaskans should be encouraged, and funded if necessary, to realize an important goal of using the opportunity of a large construction project to strengthen the skills of Alaskan workers.

• An important conclusion by the Council is that a connection for gas offtake on a high-pressure pipeline will be costly. Taps should be at strategic locations, or "hubs", along the pipeline, from which natural gas and natural gas liquids such as propane and butane could be supplied for local and regional distribution, and electricity could be generated and distributed. To meet clean energy needs in Fairbanks, Anchorage and other communities, spur gas pipelines could be constructed.

• Leases signed by the producers on the North Slope legally stipulate an implied covenant to market gas within a "reasonable time" and at a "reasonable price." It is assumed that 25 years since the start of production at Prudhoe Bay meets the reasonable time stipulation. Producers will thus have to sell their gas to pipeline companies or third parties if a "reasonable price" offer is made, and assuming other bid terms are acceptable.

• The State should ensure a southern or Alaska Highway route is mandated in any proposed federal gasline legislation and that Alaska's needs are appropriately addressed in the legislation. The Council supports modifications to modernize the Alaska National Gas Transportation Act and believes such modifications would be beneficial to an Alaska gasline project.



Carl Marrs addresses the audience at the Council's Barrow hearing.

ABOUT NATURAL GAS:

What is natural gas?

Natural gas, crude oil and gasoline are hydrocarbons, a mixture of molecules composed of hydrogen and carbon atoms. The simplest hydrocarbon has one carbon atom with four hydrogen atoms stuck to it, CH_4 methane, the fuel Cook Inlet residents use. Methane, ethane, propane, butane and pentane, which are typically in natural gas as it is produced, have relatively simpler hydrocarbon molecules compared to crude oil or gasoline, which are a mixture of bigger and more complicated hydrogen-carbon molecules.

What are natural gas liquids?

What we usually refer to as natural gas is predominantly methane, which is used mostly as fuel, but can also be used to make fertilizer and other products when the molecules are separated or "cracked." Methane is called "dry" gas, because at normal temperature and pressure, it remains in a vapor form. Ethane, propane, butane and pentane are referred to as natural gas liquids (NGLs) because they are often in liquid form at higher pressure or lower temperature. They are typically separated from the methane and sold separately. Wet gas is more valuable than dry gas because it contains more Btu value per given volume.

What is liquefied natural gas?

Liquefied natural gas, or LNG, is dry natural gas (mostly methane) that is chilled to extremely low temperatures so that it becomes a liquid that can be shipped in a tank, on a ship or even by truck or train. An LNG plant near Kenai now ships liquefied gas from Cook Inlet area fields to customers in Japan.

Natural Gas Policy Council Hearings: Alaskans Speak Out

In addition to meeting with industry experts and project proponents, the members of the Alaska Highway Natural Gas Policy Council traveled to seven communities across the state to talk to Alaskans about the proposed gasline project.

Fairbanks Residents Advocate for Local Access to Gas

The public hearing process began in April with a meeting held at the Fairbanks Chena River Convention Center. Over 200 Interior residents attended, including city officials, labor and business representatives and native leaders.

A common theme throughout the evening's testimony was the need to bring natural gas to Fairbanks for residential and commercial use. Many residents also expressed enthusiasm for the pipeline's potential to be an enormous economic boost to the region.

Steve Ginnis, president of the Tanana Chiefs Conference, spoke about the importance of native village involvement. Ginnis told the Council that because the highway route will cross Native lands, it is important that Native villages be represented on the planning committees. The villages also need access to the gas to reduce energy costs and improve living conditions.

Several business leaders also testified. "We do plan on building the next pipeline," said Bert Bell, President of the Association of General Contractors of Alaska. But Bell reminded Council members that the pipeline's labor needs must be known soon so training programs for Alaskans can begin.

Peninsula Residents Promote In-state Gas Use

In May, the Gas Policy Council saw the industrial uses of natural gas firsthand when they traveled to Kenai and toured the BP Gas-to-Liquids test facility, the Agrium fertilizer plant and the Phillips LNG plant. After the tours, the Council held a public meeting to hear from Peninsula residents. Kenai residents expressed their strong desire to bring North Slope natural gas to the Cook Inlet region to fuel existing industry and create new economic opportunities.

Speaking on behalf of the Cook Inlet Pipeline Terminus Group, Mike Navarre told the Council "seventy percent of the state's population lives along the corridor a pipeline would follow to Cook Inlet. It's the economic base of the state. An economy needs room to grow, and there is ample space for development in Nikiski, the Mat-Su area and along the Railbelt to Fairbanks," Navarre said.

John Williams, Kenai city mayor, spoke about the importance of using Alaska gas in-state. He urged the Council to propose changes in state law that would require as much gas as possible be processed in Alaska. BP's gas-to-liquids test facility in Kenai demonstrates the potential for gas to be used as a feedstock, Williams said.

Kenai Mayor John Williams testifies at a Council hearing.

Anchorage Residents Highlight Need for Gas to Cook Inlet

While the testimony at the Anchorage hearing was broad and varied, one theme emerged. Anchorage businesses and residents want to ensure that Cook Inlet has access to natural gas.

Tony Izzo, president and CEO of Enstar Natural Gas, told the Council that Anchorage has "one of the best gas utilities in the country, with new high-tech systems, 400 miles of pipelines and 2,400 miles of distribution lines." While Enstar has contracts pending to meet all its supply needs to 2006 and some of its needs to 2017, beyond that there are long-term supply concerns.

Steve Cleary, speaking on behalf of the Alaska Public Interest Research Group, said his members' concerns were those of consumers and utilities in the region. "In the next decade our members will need a reliable source of gas, and we think it must be North Slope gas."

Tok Residents Contemplate Impacts of Gasline

At a June hearing, residents of Tok expressed support for a natural gas pipeline route through their community to Canada, though they were leery of the possible impacts to their small community.

Most residents supported local access to the gas pipeline that could run through their community, but some pointed out that there will be costs associated with natural gas access, such as the cost of tapping the pipeline and building local distribution lines to several hundred widely scattered homes in the Tok community. Tok resident John Portscheller worried that the region could loose its rural character if the pipeline leads to development of local infrastructure and stimulates formation of a regional municipal government.

There were also comments about local hire for the project. One resident stressed the importance of hiring people from the local communities, not just residents of the state.

Overwhelming Opposition to the Northern Route Heard in Barrow

In July, the Council traveled to Barrow to listen to residents of the North Slope. Local government and village leaders told the Council emphatically that they will support a natural gas pipeline, only if it follows a southern route.

Speaking on behalf of the Alaska Eskimo Whaling Commission, Charlie Neakok, vice president of the Barrow Whaling Captain's Association said: "The Alaska Eskimo Whaling Commission is prepared to work cooperatively with the gas producers" if they bring the pipeline down the highway. "However, the AEWC and the whaling captains of all 10 whaling villages will oppose, absolutely, any attempt to build a gas pipeline through our Beaufort Sea."


In Barrow, the Council heard testimony about the importance of subsistence hunting in the Beaufort Sea. Here, former mayor Ben Nageak addresses the group.

Marie Carroll Adams of the Arctic Slope Native Association spoke about new research indicating subsistence foods help natives stay healthy. "We're finding out from recent studies that native people cannot live without subsistence food. It's killing us to eat non-native foods, and we need to protect those resources that keep us alive," Adams said.

Southeast Alaska Looks to Play a Role in Gasline Construction

At an August hearing in Juneau, residents of Southeast Alaska expressed enthusiasm for participating in the development of a gasline project.

Loren Gerhard, executive director of the Southeast Conference, told the Council that Southeast communities hope to play a role in gasline construction through logistics support. He pointed out that Haines, Skagway and Juneau are all well positioned to support gas pipeline construction.

Robert Venables, economic director of the City of Haines, told the Council that in addition to providing support services, Haines can be a site for manufacturing LNG for shipment to Southeast communities and possibly to Pacific export markets. There is a relatively short distance for a "spur" pipeline connection between Haines and the larger trunk pipeline.

Environmental advocates also attended the Juneau hearing to voice their opposition to a northern route. Sue Schrader of the Alaska Conservation Alliance, testified to her organization's strong opposition to the "over-the-top" route. "This route has the greatest potential for environmental impacts and will be vigorously opposed by the state and national environmental communities," Schrader said.

Valdez Residents Back Gasline to Prince William Sound

In August, the Council traveled to Valdez for its last public hearing and heard an in-depth presentation from the Alaska Gasline Port Authority outlining its proposal to use its tax-exempt status to develop natural gas. The Port Authority explained their economic model which shows a two-project "Y" line, a gasline to the lower 48 with a spur to an LNG facility in Valdez, to be viable.

Many Valdez residents spoke in favor of the Port Authority concept and in favor of bringing gas to Valdez. City manager Dave Dengel reminded the Council to look out for all Alaskans. He said that adding an LNG leg to the project will provide more benefits and opportunities to Alaskans.

Valdez Mayor Bert Cottle urged the Council to move forward with a gasline project that will bring inexpensive energy and economic opportunities to Alaskans.

Alaska Highway Natural Gas Policy Council Meetings

March 1
First full Council meeting,
Anchorage

March 23
Council workshop,
Anchorage

April 5
Council workshop,
Anchorage

April 18
Public hearing,
Fairbanks

May 17
Public hearing,
Kenai

May 24
Public hearing,
Anchorage

June 14
Public hearing,
Tok

July 19
Public hearing,
Barrow

August 2
Public hearing,
Juneau

August 23
Public hearing,
Valdez

September 7
Full Council meeting,
Anchorage

September 25
Full Council meeting,
Anchorage

October 31
Full Council meeting,
Anchorage

November 30
Report presented to Governor,
Anchorage

Alaska Hire/Buy/Build
Mike Navarre, Chair

Members
Jerry Hood, Rhonda Boyles, Jake Adams, Peg Tileston

Committee examined the following topics
- Use of the Alaska labor pool by contractors and subcontractors
- Use of Alaska businesses
- Training and readiness of Alaskans for jobs on a gas project
- Socio-economic impacts

Committee Meetings
- April 5, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage

Recommendation:
The committee believes Alaska residents and contractors should be employed on a gasline project when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.

Recommendation:
The committee believes that Alaska hire language, similar to language from the BP/ARCO Merger "Charter Commitment," should be sought for the Alaska Highway natural gas pipeline and facilities. *(Note: see full report for charter language.)* It should be specifically stated that the quarterly report to the Department of Labor should include all contractors and subcontractors of the company or sponsor.

Recommendation:
The committee believes additional funding should be made available for vocational education training and should be coordinated with existing workforce training efforts now underway. Additionally, efforts should be increased to notify interested Alaskans of training opportunities available.

Recommendation:
The committee believes every effort should be made to ensure that needed gas production facilities are constructed at sites in Alaska.

Recommendation:
The committee recommends the state's Department of Community and Economic Development undertake a study to determine the socio-economic impacts of the gas pipeline along the Alaska Highway route. The Department has already begun implementation of this recommendation. *(See full report for a draft "scope of work" for this study.)* We recommend the scope of the study also be expanded to include impacts to local governments.

"We do plan on building the next pipeline. We need to compare pipeline construction needs to our current workforce needs."

Bert Bell, President, Association of General Contractors of Alaska, Fairbanks hearing

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Conclusions and Narrative:
The committee held several hearings regarding the constitutionality of local hire laws. The record in Alaska on local hire litigation is not encouraging. We believe it will be difficult to construct local hire legislation that will withstand challenges under the U.S. and Alaska Constitutions (equal protection and privileges and immunities clauses). Additionally, a successful Alaska hire provision is complicated by the national and international scope of the project. Voluntary, cooperative efforts with industry seem to hold the most promise and should be pursued.

The number of jobs will be significant and will exceed the available capacity of Alaskan workers. The committee heard testimony that there is already a crisis situation being created because of the aging workforce in the oil industry, without factoring in the effect of a large-scale project like the gasline. There are coordinated efforts already underway, by industry, unions, native and tribal organizations, the Denali Commission, the University of Alaska and state agencies to address the training of Alaskan workers, and those efforts will require additional funding. The Alaska Human Resources Investment Council has developed a white paper that details a comprehensive approach to workforce training.

In addition to assuring labor stability, a project labor agreement will facilitate the further ramping up of union training programs, bringing more Alaskans into apprenticeship and skill upgrade programs. An ancillary benefit of the PLA is the legality of geographic preference provisions of collective bargaining agreements.

"Alaska workers and businesses are better positioned today than ever before to take advantage of the economic opportunities that the construction and operation of a gas pipeline would create."

Allen Todd, General Counsel, Doyon Limited, Fairbanks hearing

Committee members heard testimony from rural residents along the pipeline route expressing interest in job opportunities. We believe that issue is best addressed through notification, to interested Alaskans, of available training and through registering of interested workers and their skills. Construction training in rural Alaska has increased to an unprecedented level in the past two years through initiatives such as the Alaska Works Partnership, various labor organization programs, and the Denali Training Fund and other efforts funded by the Denali Commission. Continued support of these initiatives, which have resulted in training and employment of hundreds of rural Alaskans in construction, is essential if residents of communities along the pipeline and in areas of the state suffering economic dislocation due to fisheries problems, are to share in the economic benefits of the project. The Department of Community and Economic Development is already working with Native nonprofits to create accurate job banks, focusing on rural areas and villages.

The committee also obtained information regarding module related jobs for gas treatment facilities and compressors. The opportunity is tremendous and construction of modules at Alaskan sites should be vigorously pursued. It is estimated that the module related jobs and opportunities will be bigger than the Alpine, Northstar, Badami and MIX projects combined.

Council Co-Chair Jim Sampson talks with construction workers at the BP Gas-to-Liquids test facility.

Mike Navarre discusses local hire issues at the Kenai public hearing.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

BP/ARCO merger charter commitment: An agreement between the State of Alaska and British Petroleum regarding the State's nonobjection to BP's acquisition of Atlantic Richfield Corp. In the charter BP agreed to a variety of actions, including steps to train and employ Alaska workers and to build facilities in the state when possible.

Alaska Human Resources Investment Council: A private/public advisory council that sets policies and makes recommendations on training and vocational education. The council's policies guide allocation of approximately $80 million in federal training funds that come to Alaska annually.

Project Labor Agreement: A collective bargaining agreement between a developer or project owner and construction trade unions establishing the terms and conditions of employment on a specific project, and to which all contractors utilized by the owner will be signatory.

Alaska Works Partnership: A construction and maintenance training program conducted by Alaska building trades unions in partnership with rural communities and development entities.

Modules: Components of oil and gas (or minerals) processing facilities that are built at a construction site and moved to a remote oil field, or mine.

Alpine, Northstar, Badami, MIX projects: Large oil and gas module projects built in Alaska in recent years.

Access for In-State Gas Use and Future Opportunities
Ken Thompson, Chair

Members
Carl Marrs (vice chair), Rhonda Boyles, Al Adams, Brian Davies, Jim Jansen, Jerry Hood, Bob Penney, Jack Roderick, Lee Gorsuch, Jeff Feldman, George Ahmaogak, Bill Corbus

Committee examined the following topics
- Supply/demand for in-state natural gas
- Best practices valuation/netback pricing methodology to facilitate in-state gas use
- Ensuring fair and transparent access rules to natural gas for Alaskan customers
- Benefits of natura' ıs development to rural Alaska and to communities along the pipeline
- Future options over 50 years for projects utilizing: gas-to-liquids (GTL), liquefied natural gas (LNG), natural gas liquids (NGL), petrochemical feedstock, fertilizer, etc. for in-state use or for export to markets in Asia or the West Coast
- Promotion or attraction of investment for in-state distribution and value-added processing
- Assess costs and benefits of the State taking delivery of its royalty share vs. taking royalty payments; review other states' policies for best practices

Committee Meetings
- April 5, 2001, Anchorage
- May 24, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage
- October 16, 2001, Anchorage
- October 26, 2001, Anchorage

Goal #1: Assess current supply/demand for in-state natural gas use and assess potential demand for expansion of current use as well as conceptual new uses.

Recommendation:
A long-term clean energy plan and vision needs to be developed for Alaska, providing for substantially increased use of natural gas for residential and industrial use and for power generation.

Recommendation:
The State should take a long-term, broad and strategic view of its entire natural gas resources. This should include areas on the North Slope, including non-producing areas, Interior basins and in south Alaska. There is a significant potential gas resource base in Alaska much larger than the 35 tcf proven natural gas reserves in existing fields on the North Slope.

Recommendation:
The State of Alaska should undertake more intensive, updated geologic and geophysical studies of the natural gas potential of current non-producing areas, including Interior and Southcentral Alaska basins. This should include a more thorough assessment of basin geology and natural gas generation and migration utilizing the most modern technology tools, as well as a more thorough assessment of the producible methane gas potential from coal seams within Alaska. In recent years new tools, such as satellite imagery and soil sampling techniques, have been developed. Another gas resource that should be assessed is gas from gas hydrates on the North Slope and in Interior basins, which are very sizeable and could be developed in future decades as technology advances.

Recommendation:
The State should evaluate incentives and policies to spur the exploration by private companies for natural gas, to better delineate the natural gas resources not only on the North Slope but elsewhere throughout the state. Strategies and plans should be implemented to attract additional companies interested in natural gas exploration who now utilize new technologies, to the North Slope, Cook Inlet, the Interior basins and elsewhere in the state.

Recommendation:
A major gas pipeline should traverse Alaska if the State is to fully exploit its longer-term resource from all basins over 50-plus years and also to gain access to future multiple markets over the long-term. In addition such a pipeline could ensure long-term, reasonably priced supplies of energy to the Railbelt and other areas of the state, thereby encouraging economic development.

Recommendation:
The State should facilitate favorable policies and incentives to encourage development by the private sector of a broader natural gas infrastructure within the state that meets the long-term clean energy demand of Alaskans at reasonable market prices.

Goal #2: Assess how natural gas or natural gas products can meet the clean and economical energy needs of communities along the pipeline route and in rural Alaska.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing fuel switching in certain Interior and rural communities from diesel to cleaner burning propane to provide information for the likelihood of economic natural gas "hub" propane processing facilities.

Recommendation:
The State should sponsor a comprehensive economic and environmental study of assessing broader electrical power distribution to certain Interior and rural communities to provide information for the likelihood of economic power generation plants near natural gas "hub" offtake points.

Recommendation:
The State should encourage private investors to initiate an economic study of creating one or more gas "hubs" for gas distribution, natural gas liquid processing, and/or power generation near Fairbanks, with a spur line to Anchorage and other "hub" locations that could distribute to Valdez and Southeast Alaska cities. This would foster a broader clean energy natural gas, propane and electrical distribution system within Alaska once a pipeline is endorsed across Alaska.

"My message to you is do everything possible to use as much of the raw product in-state; in our homes, in our cars...and in the many, many products we can create."

Kenai Mayor John Williams, Kenai hearing

Goal #3: Assess the costs or benefits of the State taking its royalty share "in-kind" for facilitation of in-state access and use.

Recommendation:
The State should retain its right to take its royalty share of gas on the North Slope "in-kind" or "in-value." This flexibility creates competition to maximize wellhead value for the State by either the producers or other firms such as energy trading companies interested in marketing the State's share of gas. The producers have requested a long-term commitment by the State and are asking the State to decide up front to take either "in-kind" or "in-value." The Council

Lt. Governor Fran Ulmer talks with Soldotna City Manager Tom Boedeker and State Rep. Mike Chenault. The residents of Kenai expressed to the Council the importance of future access to North Slope gas for the Peninsula.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Basin: A term usually referring to a region of sedimentary rocks ("sedimentary basins") that have potential for oil and gas discoveries. The "Cook Inlet Basin," for example, refers to the region, not just the offshore producing fields of Cook Inlet.

Natural gas generation and migration: Geologic terms referring to the creation of hydrocarbon fluids in underground rocks and the "migration" (movement) of the fluids into trapping mechanisms, potential reservoirs, in underground rocks.

Methane gas from coal seams: Methane (the main component of natural gas) is a common emission from coal seams. It is a safety hazard in coal mines, for example.

Gas hydrates: Methane (gas) that is frozen as a solid phase in rocks, such as in the permafrost of the North Slope. As pressure is decreased and temperature increased, gas is released from the hydrate. Gas is not now commercially produced from hydrates, but research on their potential is under way.

Railbelt: A term referring to the state's major population areas of Southcentral and Interior Alaska that are served by the Alaska Railroad and other surface transportation infrastructure.

Propane: One of the natural gas liquids associated with gas production. It is sold as a pressurized liquid for fuel, and also has other uses.

Spur line: Informal term for a smaller pipeline connecting to a larger pipeline. For example, a pipeline connecting Anchorage, or Valdez, to a large-diameter pipeline along the Alaska Highway route is being referred to as a "spur" pipeline. The idea is that smaller "spur" pipelines would be built after the main, larger, pipeline is in operation.

feels the flexibility to switch on six months notice is very important, creates marketing competition, and ultimately maximizes resource value. The State should not negotiate away its right to take its royalty share of gas "in-value" or "in-kind."

Recommendation:
The State could maximize the value of its natural gas royalty resource with a mixed portfolio of "in-value" and "in-kind" sales, with in-kind royalty marketed by energy trading companies such as Duke Energy, Enron, Williams Energy or major companies like them. The State should put its royalty "in-kind" gas out for bid and seek bids from multiple parties for contract terms and price. Such contracts should ask for a "floor price" equal to or exceeding the average netback wellhead price achieved by the three major producers or from "in-value" sales as "insurance" that the energy trading companies are working in their marketing to beat the producers' gas sales realization.

Recommendation:
When there are out-of-state sales using an energy trading company, the energy trading company will reserve the capacity and the liability associated with that capacity, and that liability will not fall back on the State.

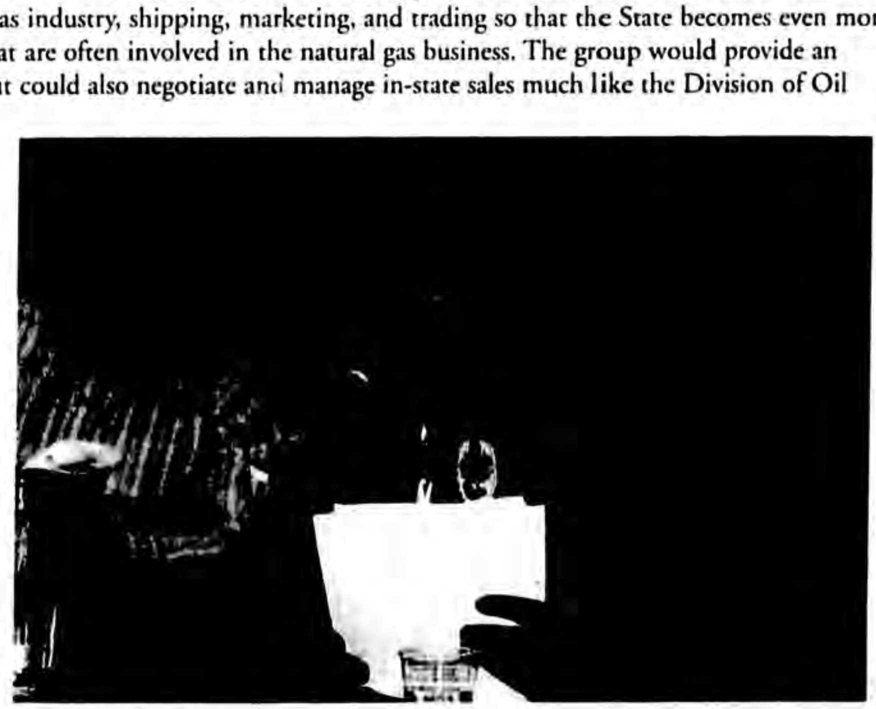
Recommendation:
The State may choose to direct market some portion of its gas to in-state consumers using State staff, but it is recommended that sales to customers in outside markets be handled by professional energy trading firms, considering the complexity of and rapid change in those markets. This would also allow those firms to absorb the risk of nominating pipeline capacity and buying hedging instruments to lessen risk on pricing of contracts.

Recommendation:
By keeping some portion of its royalty share of natural gas "in-kind," the State may be able to make some contract deals with consumers in-state at more favorable terms than the producers, as the State might realize added dollar benefits through jobs and corporate taxation of value-added processing such as natural gas liquids processing, petrochemical manufacturing, power generation, etc. that may not otherwise be economically viable to entrepreneurs within the state. However, there should not be a subsidy in sales of royalty-in-kind gas. The State should receive a netback price for royalty gas equal to or greater than the market-based "netback value" of gas on the North Slope.

Recommendation:
To the extent practical, the State of Alaska should enforce its "higher of " clauses on natural gas royalty as this could add value and ensure producers work hard in their marketing to obtain the best value in their sales of natural gas. When the State elects to take any share of its royalty gas "in-value," existing lease terms and statutes allow the State to receive royalty payments and production taxes on the "higher of" actual proceeds or market value. Other states, as well as the U.S. Minerals Management Service, are aggressive in ensuring all producers pay this "higher of" price for royalty and relevant taxes and receive such payments from the same producers that produce on the North Slope.

Recommendation:
Because of the complexities of the natural gas industry and the differences with the oil industry, the State should form a Natural Gas Services Group with people experienced in the natural gas industry, shipping, marketing, and trading so that the State becomes even more sophisticated in understanding deals and transactions that are often involved in the natural gas business. The group would provide an oversight function on sales of royalty gas out-of-state, but could also negotiate and manage in-state sales much like the Division of Oil and Gas now manages sales of royalty oil.

Recommendation:
For more cost effective development of in-state gas infrastructure resulting in more economical transportation of state royalty gas within the state, the State should encourage entities to examine the port authority concept of tax advantaged financing for a gas "hub," spur lines, and other distribution facilities.



Howard Mermelstein testifies at the Council's first public hearing in Fairbanks.

'A key component of the Alaska gasline must be how the rest of the state is going to benefit from North Slope natural gas."

Dave Dengel, City Manager, City of Valdez

Goal #4: Determine the "best practices" for methodologies to achieve transparency in netback pricing valuation at the wellhead and transportation to assure fair and favorable pricing for in-state gas business creation and expansion as well as for taxation and royalty calculations.

Recommendation:
The State should keep a natural gas price netback valuation methodology based on actual sales proceeds, or sales contracts, and not change to a formula linked to average prices in gas trading hubs or some other general formula at least for the first several years of major gas sales. The State's right under lease terms and statutes to obtain actual realized prices for its gas and natural gas liquids should not be negotiated away.

Recommendation:
With the growing natural gas liquids (NGLs) business in the U.S., the State should keep a natural gas liquids price netback of gas-line liquids based on actual sales proceeds, or sale contracts, of the liquids and no accept a value for the liquids based on a Btu adjusted basis of the gas stream unless there is clearly a higher value obtained by Btu-based sale. The State should be very sophisticated in its assessment and knowledge of the business of NGLs, as revenues from NGL sales will be a substantial part of revenues from the overall gas stream.

Recommendation:
Alaska statutes should be reviewed and updated to require information on sales spot transactions, sales contracts, actual transportation costs, and other information be made known to the State, much as statutes in Texas and other locations provide for. When updating these statutes the process should be clarified in a way that assesses the "lessons learned" on the Alaska oil valuation disputes and provides for more timely resolution of any differences in valuation.

Recommendation:
Alaska statutes should be reviewed and updated to require information on "affiliated sales" by producers be made known to the State, much as statutes in Texas and other locations provide for.

Goal #5: Recommend policies that assure clear and transparent rules for access to natural gas into and out of the gas pipeline for Alaska businesses and customers.

Recommendation:
The State must develop a clear and sophisticated understanding of the "open season" rules governing access to a contract carrier pipeline and devise strategies to facilitate access to the pipeline for firms exploring for or developing new gas discoveries on the North Slope or Interior basins.

Recommendation:
The State should incorporate in any federal legislation the right to gas access in-state. This right is provided in ANGTA 'but is not provided in the producers' recently proposed federal legislation.

Recommendation:
The State should first seek federal legislation that gives the Regulatory Commission of Alaska (RCA) authority to set tariffs for the transportation of intra-state gas used in-state similar to that authority given to the RCA for tariff review on the TAPS oil line. The state RCA should review applications for pipeline access within the state to ensure fairness in pre-determined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Royalty share of gas: The State of Alaska, as landowner, receives a royalty, or share, of production. At Prudhoe Bay the leases provide for a one-eighth (12.5 percent) share. Oil and gas leases issued more recently provide for one sixth (16 percent) and sometimes one-fifth (20 percent) royalties.

In-kind, in-value: Under the terms of its leases, the State can take its royalty "in-value," allowing the producers to sell the oil or gas and pay the State cash. The State also has the option to take the royalty "in-kind," (physically taking control of the oil or gas). In this case the State sells the royalty oil or gas to another party. The practice is for the party buying the "in-kind" royalty oil or gas to arrange for transportation. When the State is paid "in-value" by the producers, they must transport the royalty oil or gas.

Floor price: A minimum price in a contract.

Average netback wellhead price:
"Wellhead price" is the value of the oil or gas at the well in the producing field. In Alaska it is determined by subtracting transportation costs from market sales prices. An "average" netback price is the weighted average of the netback prices reported by several leaseowners in a field, which can vary because leaseowners usually sell their oil or gas to different customers.

Energy trading company: A company, or division within a company, that buys gas or oil from producers and sells to others. Energy trading has developed into a large, complex, sophisticated business in recent years.

Capacity: Physical space in a pipeline. A producer typically buys "capacity" in a pipeline to ship gas, for example.

Council member Ken Thompson addresses the group at the Fairbanks public hearing.

Recommendation:
Failing to achieve RCA obtaining sole authority in-state, the State should seek through federal legislation the creation of a joint board between the Regulatory Commission of Alaska and the Federal Energy Regulatory Commission (FERC) that would have authority to set tariffs for the transportation of intra-state gas used in-state. This joint board should participate in review of applications for pipeline access within the State to ensure fairness in predetermined fees and terms based on reasonable rates of return for investors who ship to in-state consumers.

Recommendation:
Alaska should consider including a "fairness" clause in the granting of State right-of-way approvals across state lands to guarantee fair access, similar to provisions developed by Texas for pipeline rights-of-way approved across state lands. Such a clause will give the State valuable leverage in negotiating fair access rules. The clause could also provide an avenue for appeal to the RCA in the event of disputes.

Recommendation:
The State should complete a thorough socio-economic study of various approaches to in-state natural gas pricing of in-kind royalty gas.

One approach is that the sales price of in-kind royalty gas or gas liquids to in-state users, whether private or State, be based on the market netback price of gas on the North Slope (which is determined by subtracting actual pipeline transportation costs from actual realized market sales prices in the lower 48 or other outside markets) adjusted for intra-state tariffs actually incurred for the transportation of the gas to the in-state access point, or hub, and then transportation costs to the consumer with allowance for a reasonable rate of return on investment. Price of gas or gas liquids to in-state users should not be based on comparisons with alternative fuels, such as diesel. Providing that the intra-state tariff is determined on a prorated basis and not the "postage stamp" methodology, this policy will create a supply of reasonably priced, clean energy for communities in Interior Alaska, and ultimately Southcentral Alaska if a spur line is built. These more affordable natural gas prices would be passed along to consumers who purchase from a regulated utility but may not be passed along to consumers who purchase from a non-regulated company. A problem with this approach is that the State receives a potentially lower netback value than if the price is determined through competition with other fuels. This may favor the consumers in that area at the cost of lower State revenues. On the other hand, such an approach could mean more affordable natural gas to a large number of customers who purchase from regulated utilities, potentially enhancing economic development and quality of life for businesses and consumers.

Another approach is that the sales price of in-kind royalty gas or gas liquids to in-state users should be based on being competitive with the pricing of alternative fuels, as that may create higher netback prices resulting in higher royalty and tax revenues to the State. This would potentially increase the revenue received by the State but would not significantly lower the costs of consumers using this in-kind gas or gas liquids. However sellers other than the State could compete for these higher netback markets and so drive the price down well below the alternative fuels.

Goal #6: Assess pipeline sizing and the pipeline "contracted volumes" structure for growth of in-state use and/or potential future export markets to Asia and the West Coast, or expansion of deliveries to the lower 48.

Recommendation:
The State should investigate ways of working with pipeline transmission companies as investors to build in excess capacity, to provide space for transporting new gas that will be discovered on the North Slope or Interior basins.

Recommendation:
The State should evaluate innovations in using part of its "in-kind" royalty share in contract sales to energy trading companies who can bid for shipping capacity which then may be used in a creative way in the future to ship gas from new discoveries while the State elects at the time of new discoveries to change and sell the originally nominated royalty gas volumes "in-value."

Recommendation:
The State should seek an order by FERC, or federal legislation, for periodic open-season nomination periods, to allow for additional capacity to be built for new gas, when triggered by requests from existing or potential producers, transporters, shippers, customers or the State.

Goal #7: Evaluate conceptual options for future value-added projects during the 50-year life of gas reserves for in-state use and/or export to Asia and the U.S. West Coast.

Recommendation:
No one can rule out with certainty the viability of value-added processing of natural gas in Alaska over the next 50 years. Alaska should have a natural gas pipeline that allows this option to remain open. The previous recommendations regarding access, reasonable tariff and pricing, and capacity expansion will keep these options open.

Recommendation:
Gas and gas product markets are highly cyclical in price and somewhat cyclical in demand, and somewhat regional in nature; thus the State should facilitate a pipeline option that will allow access to multiple markets in the future.

Recommendation:
As markets change, the State should take a proactive role in encouraging investors to consider the possibilities for liquefied natural gas (LNG), gas-to-liquids (GTL), expanded uses of natural gas liquids (NGLs such as propane, butane) and downstream processing such as petrochemicals.

Goal #8: Determine strategies to promote and attract investment for in-state distribution and value-added processing.

Recommendation:
The State should develop and periodically update a formal marketing plan to attract investors in Alaska who may be interested in in-state gas distribution or development of value-added industries. Assisting with this could be an additional function of a new Natural Gas Services Group within the Department of Natural Resources.

Please see full report for this committee's complete recommendations and conclusions.

Gas Policy Council Co-Chair Frank Brown talks with Fairbanks residents at a public hearing reception held at the Chena River Convention Center.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Nominating pipeline capacity: When a producer "nominates," or proposes, to ship oil and gas through the pipeline. Pipeline companies usually have specific periods in which they accept such nominations.

Value-added processing: When "value" is added to a raw resource, such as oil or gas, by processing, refining or manufacturing it into another product, such as fuel, fertilizer or a petrochemical product. Since value-added processing or manufacturing is capital and often labor intensive, it brings new investments, jobs and tax bases into a region. Examples are plants making fertilizer and LNG near Kenai, and fuel refineries near Kenai, Fairbanks and Valdez.

Gas "hub": A connection to a gas pipeline where gas can be taken off. Gas is often bought and sold at hubs.

"Best practices" methodologies: Best procedures, best methods.

"Transparency": Clarity in terms and conditions; easily understood.

"Netback pricing valuation": Determining a local value, for pricing purposes, of gas or oil by subtracting transportation (pipeline) costs from destination markets where the gas or oil is sold.

"Realized prices": Prices actually achieved in market sales (i.e. not value established through a formula).

Natural gas liquids: Components of natural gas other than methane, such as ethane, butane, propane and pentane. These are valuable, and are usually sold separately from the methane, which is used mainly as fuel.

Btu: British thermal unit, a common unit for measuring energy content.

State Pipeline Ownership and Tax Structure
Bill Corbus, Chair

Members
Dave Rose, Ron Duncan, Grace Schaible,
Mike Navarre, Ed Rasmuson, Mike O'Connor, Ken Thompson

Committee examined the following topics
- State promotion and facilitation of project financing – State ownership
- Evaluation of State tax structure

Committee Meetings
- April 5, 2001, Anchorage
- May 24, 2001, Anchorage
- July 11, 2001, Anchorage
- August 13, 2001, Anchorage
- September 21, 2001, Anchorage
- October 3, 2001, Anchorage

Recommendation:
The committee believes the pipeline is economically feasible for certain investors and should be undertaken with private financing. We recommend against direct State investment unless there is clear evidence of economic benefits to Alaska that cannot be achieved through other regulatory or political mechanisms.

Recommendation:
The committee encourages exploration of creative financial structures to facilitate all or part of a gas pipeline and/or in-state gas infrastructure, provided such entities finance their activities through private markets.

Recommendation:
The committee recognizes that State tax policy is one of several tools that could play a role in influencing pipeline development, but reserves a decision. It is premature to decide how to use this tool until there is more definition of a project and the nature of its ownership.

"A project of this value can help improve community infrastructure. It's not unrealistic to think that better schools, transportation and health care can be a result of a project like the gas pipeline."
Steve Ginnis, President, Tanana Chiefs Conference, Fairbanks hearing

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Conclusions:
- When the committee began its work early in 2001, there appeared to be certain problems that could be resolved by partial State ownership in a gas pipeline, and that it could be an important advantage for Alaska. However, through the process of gathering information and holding meetings, the committee has determined that most if not all of these could be resolved through other means, other tools the State has at its disposal. For example, access to and from a pipeline can be facilitated through the state Regulatory Commission of Alaska working with the Federal Energy Regulatory Commission, and through stipulations in a right-of-way lease across State lands.

- The committee believes a natural gas pipeline from Alaska would be a good investment, but there are other, equally good investment opportunities for public funds that entail less risk. The State has a policy of diversifying investment of its assets (the Permanent Fund is an example) to reduce risk.

- From information gathered during hearings, the committee has concluded that, absent majority or total ownership of a natural gas pipeline, an ownership interest gives the State no right to capacity in the pipeline. Capacity in a contract carrier pipeline is obtained through the nomination process during an "open season."

- The committee is not persuaded that partial ownership of the pipeline raises any conflict of interests for the State (i.e. a State "ownership" interest vs. a State responsibility to regulate the pipeline) that cannot be resolved.

- The committee investigated alternative sources of financing, including the Permanent Fund, Constitutional Budget Reserve and the ability of various public authorities to issue revenue bonds. The committee believes that private sector companies can raise needed funds based on adequate coverage and financing reserves. State participation would not enhance the acquisition of funds, would not necessarily guarantee lower financing costs and might unduly interfere with a straightforward private sector funding. The State's participation would include a vote on a tariff but its interest would not be proportionately large and it would not guarantee a desired outcome.

Council member Ron Duncan confers with Governor Knowles on State ownership issues.

• Absent a compelling public interest for partial State ownership, ownership of the pipeline is best left to private industry, and to firms which are experienced in oil and gas and the pipeline business.

• The committee suggests that Alaskan-owned businesses, such as Alaska Native corporations, have the opportunity to invest in a natural gas pipeline project.

• Regarding alternative financing mechanisms, the committee has been told by the producers' group that an investment in a gas pipeline might not meet the rate-of-return criteria for the producing companies. If so, alternative financing mechanisms, such as through a public authority, might facilitate others, such as pipeline transmission companies, becoming involved. A public authority may have advantages in terms of exemption from federal income tax, or jurisdiction by the Federal Energy Regulatory Commission.

• Regarding tax policy, the producers are seeking simplification and clarity in natural gas tax and royalty administration.

• The Gas Policy Council itself has endorsed the governor's proposals for federal tax incentives, such as accelerated depreciation, an investment tax credit and a gas price volatility protection mechanism, a tax credit that becomes effective if prices fall below a certain point. The committee reaffirms this endorsement.

• The committee feels that if a viable proposal for a pipeline is put forward and the producers do not respond in a reasonable period of time, the State should use the tools that it has available to facilitate the project moving forward.

• The committee recommends finding a mechanism for a "contract" between the State and a sponsor of a gas pipeline project that would encourage a State fiscal policy as well as a stable State revenue policy. While there are legal limits to the Legislature's ability to guarantee future tax policy, such a contract would carry an important moral commitment, and would be worthy of consideration for an Alaska Highway gas pipeline.

• Different forms of pipeline ownership will affect the interests, and incentives, of the parties involved. Overall, the State has an interest in keeping costs of a pipeline down, and transportation tariffs lower, to maximize State revenues. (State revenues are based on the "wellhead" values of gas on the North Slope, after transportation.) If the producers build the pipeline, they will have an interest in maximizing production revenues, similar to the State, but will have less interest in keeping tariffs low because they are also pipeline owners. If an independent pipeline company consortium owns the pipeline, the producers' interests will be only in maximizing production revenues. In that scenario, the producers' interests would be aligned with the State's in seeking low tariffs for transportation of gas.

Bill Corbus, Brian Davies, Peg Tileston and Charlie Cole participate in the Barrow hearing.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Regulatory Commission of Alaska (RCA): The state regulatory commission that has authority to set rates and make decisions affecting intra-state pipelines. RCA also regulates telecommunications and public utilities in the electricity, water, sewer and solid waste fields.

Federal Energy Regulatory Commission (FERC): The federal regulatory commission that has authority to set rates and make decisions affecting interstate shipments of natural gas, as well as telecommunications and electricity.

Contract carrier pipeline: A pipeline (usually gas) that has volumes committed for shipment. Pipeline owners design capacity to handle the volumes contracted for. Unlike common carrier pipelines (usually oil), owners of gas who have not contracted for pipeline capacity have no guarantee their gas will be shipped.

Alternative financing mechanisms, such as a public authority: Public-owned entities like authorities are formed to carry out specific tasks, and are usually tax-exempt. Alaska's International Airport Authority is an example. The proposed Alaska Gasline Port Authority is another.

Environmental Considerations
Peg Tileston, Chair

Members
Brian Davies (vice chair), Esther Wunnicke, Lee Gorsuch, Grace Schaible

Committee examined the following topics
- Key environmental issues, both natural and human, associated with the construction of a natural gas pipeline.
- Recommendations for policies and procedures necessary to ensure that the design, construction and operation of the natural gas pipeline will proceed in an environmentally sound manner.
- Potential environmental benefits of a natural gas pipeline.

Committee Meetings
- April 5, 2001, Anchorage
- August 2, 2001, Juneau
- September 25, 2001, Anchorage

Recommendation:
Endorse the Alaska Highway gas pipeline route as the environmentally preferred pipeline route that minimizes the potential adverse environmental effects and maximizes potential environmental benefits to Alaska.

An Alaska Highway route would limit the gasline to an existing corridor, minimizing impacts to the environment as well as to fish and wildlife. It would also allow Alaska communities access to a cleaner, more efficient fuel. In addition, a highway route following the TAPS line would make oversight of both lines more efficient and effective. At hearings of the Gas Policy Council, Alaskans voiced overwhelming support for the environmentally preferred southern route.

A rigorous environmental review should be required. There are three approaches to this. The most expeditious approach but the one most susceptible to challenge is to meet the requirements of Section 5, subsection III of the President's Decision relating to the Alaska Natural Gas Transportation System which anticipated the development and public review of detailed plans to protect the environment using the best of current science and technology. The two other approaches are either a supplemental environmental impact statement (EIS) building on the ANGTS EIS or a full EIS done in an expedited manner using information from the ANGTS EIS. The outcome of any process should spell out for public review the alternatives associated with the highway route, the environmental pros and cons associated with them, and mitigation measures that should be taken to avoid or minimize adverse impacts.

Any frontier route would require a "start from scratch" approach, including collection and analysis of physical, biological and social data and determination of required technology.

Recommendation:
Adequately fund and staff a natural gas pipeline office that is housed in one place to facilitate communication, coordination and cooperation among all affected state, federal and Canadian agencies.

Lack of timely and complete communication among agencies can have severe consequences on any project, but can be particularly difficult in one of this size. A facilitated review of the JPO operation by all the involved agencies to note procedural changes they might recommend to improve effectiveness and efficiency would be beneficial. Acquiring personnel with the necessary technical and scientific expertise may be difficult for both federal and state agencies when competing with industry, which will be hiring for the same positions and will have considerably higher salary scales. Every effort should also be made to include the considerable number of borough and local agencies concerned with the various project alternatives, along with Alaska Native corporations, tribes, and villages that will be affected by a pipeline right-of-way (ROW).

Recommendation:
Recommend that the Gas Pipeline Office (GPO) conduct a thorough review of "lessons learned" from TAPS design, construction and operation. This review should include public comment and public participation. Use "lessons learned" to develop procedures for t[illegible] gas pipeline that ensure past mistakes are avoided and successes repeated.

A natural gas pipeline following the TAPS/Alaska Highway corridor will have many environmental concerns similar to those of the earlier project. Certain differences need to be identified and addressed, such as the effect of a buried, chilled pipeline crossing beneath streams, geologic and hydrologic data for areas where TAPS is not buried, and design and operational differences between a low-pressure, hot oil line and a high-pressure, cold gas line. In addition, Canadian and other high-latitude gas pipelines should be studied for lessons learned.

Recommendation:
Establish an open and available data and information process for the public, agencies and industry.

Frustration and suspicion take hold when individuals, organizations and communities are unable to get information on issues of concern in a timely and appropriate manner. Such a process should start at the beginning of the project and make available all non-proprietary material. Meaningful involvement by affected communities is important. Effort should be made to include all stakeholders, not just decision-makers. Websites, e-mail addresses and information repositories, such as local libraries and borough offices should be used to disseminate information. A central site, preferably the Alaska Resource Library & Information Services (ARLIS), should be used as effectively as possible and adequately funded. An information clearinghouse such as the Exxon Valdez Oil Spill Library (which is now consolidated in ARLIS) could be an appropriate approach.

Recommendation:
Establish mandatory training for all personnel involved with the gas pipeline project.

Timely, appropriate and sufficient training is vital for all personnel associated with a major project. Such training should start with applicable federal, state, and local laws and regulations, agency mandates and responsibilities, enforcement options and penalties for noncompliance, best practices and appropriate technologies. Government and industry should coordinate to ensure commensurate levels of training for the public and private sectors, including all contractors and subcontractors. Sessions to update personnel as the project progresses should be included, along with required orientation for those joining it.

"We strongly oppose all proposed natural gaslines from Alaska's North Slope that invade frontier wilderness ecosystems with new routes and new infrastructure."

Sue Schrader, environmental advocate, Juneau hearing

Recommendation:
The state should take a long term view of the gas pipeline to minimize environmental concerns.

In view of the likely long life of this project, the state should encourage a long-term view be taken in design, construction, operation and maintenance in order to mitigate environmental risks over the entire life of the project.

Department of Natural Resources Commissioner Pat Pourchot discusses the role of his department in the pipeline permit review process.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

Trans-Alaska Pipeline System: The formal name of the trans-Alaska oil pipeline, also informally referred to as the "Alyeska" pipeline. TAPS is operated by Alyeska Pipeline Service Co. but is owned by North Slope oil and gas producing companies plus Amerada Hess and Williams.

Joint Pipeline Office: A central office established by State and federal agencies responsible for pipeline oversight and regulation. Federal and State agency staffs with similar responsibilities work together, improving coordination and efficiency.

ABOUT NATURAL GAS:
What is "Gas-to-Liquids?"
Gas-to-liquids, or GTL, refers to a chemical conversion technology developed in the 1920s that converts natural gas into a liquid product from which environmentally "clean" refined products, such as diesel, can be made. A great deal of highly guarded research is now focused on improving GTL technologies so commercial plants can be developed economically. BP has a pilot GTL facility in Nikiski.

Why is natural gas a clean fuel?
Natural gas (methane) is the cleanest fuel because it has the fewest number of carbon atoms compared with hydrogen atoms relative to other fossil fuels and far fewer contaminants too, such as sulfur, nitrogen compounds, and heavy metals. Oil or coal have more carbon atoms. When burned, the carbon combines with oxygen in the air and becomes carbon dioxide, a gas suspected as the main contributor to global warming. The hydrogen combines with oxygen in the air and becomes water vapor. Because methane molecules have fewer carbon atoms than other fuels, less carbon dioxide is emitted when methane is burned.

> "Our tribal council supports responsible development of natural gas – as long as it's not done through our ocean."
>
> *Patsy Aamodt, President, Native Village of Barrow, Barrow hearing*

Patsy Aamodt, President of the Native Village of Barrow, testifies to the Council.

Recommendation:
A records management system for compiling and maintaining complete and updated documentation should be in place at the beginning of the project and maintained and updated throughout the life of the pipeline in accordance with professional document control standards. The State must have copies of all documents.

The TAPS experience has shown that older engineering drawings, including "as-builts" and documents confirming original facility configurations and placements, have not always been readily accessible by pipeline managers and regulators when needed. Establishing a professionally designed and maintained document control system will help to ensure that accurate records from every phase of pipeline development remain rapidly retrievable under unforeseen future circumstances. Recent advances in technology will undoubtedly aid this process.

Recommendation:
Assure that effective and adequate monitoring and enforcement systems are in place at the start of the project and continue throughout the life of the pipeline.

Adequate funding will be needed to ensure that a sufficient number of appropriately trained agency personnel are available for monitoring and enforcement throughout pipeline construction and operation. Agency personnel without a working knowledge of pipeline construction, operation, and maintenance will have little credibility with their industry counterparts. Training of agency personnel associated with all aspects of the pipeline should be integral to the project. Such training should emphasize the prevention and early detection of problems, and understanding of regulations, codes and penalties. Enforcement of regulations and codes is essential but will not occur without trained personnel who are actually available on site.

Recommendation:
Direct the GPO to establish a comprehensive citizen's involvement plan. This effort may include the creation of a citizen advisory council with representatives from communities affected by construction of the pipeline.

A determined effort should be made to aggressively involve and engage affected communities during the planning and construction phase through a coordinated federal/state effort. If necessary as determined by the federal/state plan, a citizen advisory council should be formed and adequately funded to receive and evaluate information and respond to pertinent issues. If established, the council would also evaluate their role following construction of the pipeline.

The public involvement process should also include a full review, including stakeholder involvement, of proposed federal grant and state lease right-of-way provisions and stipulations.

Recommendation:
Provisions should be incorporated into ROW lease agreements to ensure that adequate dismantling, removal and restoration (DR&R) funding will be available for the Alaska segment of the natural gas pipeline.

The actual DR&R provisions will depend on ownership of the pipeline and should take into consideration the true long life of the asset.

Recommendation:
Perform a full security review and develop a comprehensive and detailed security plan early enough to influence the pipeline design and alignment process.

Heightened security concerns throughout the United States should be reflected in the engineering design and alignment of the natural gas pipeline, which will be a significant part of America's domestic energy supply. Any aspect of the design of pipeline facilities and structures that would be particularly vulnerable to sabotage, such as compressor stations, bridge crossings and above-ground valve housings, should receive attention from a security standpoint early in the design process, and not as an afterthought. This concern applies also to the alignment, which may preser. opportunities for modifications or adjustments that will minimize the potential for harm.

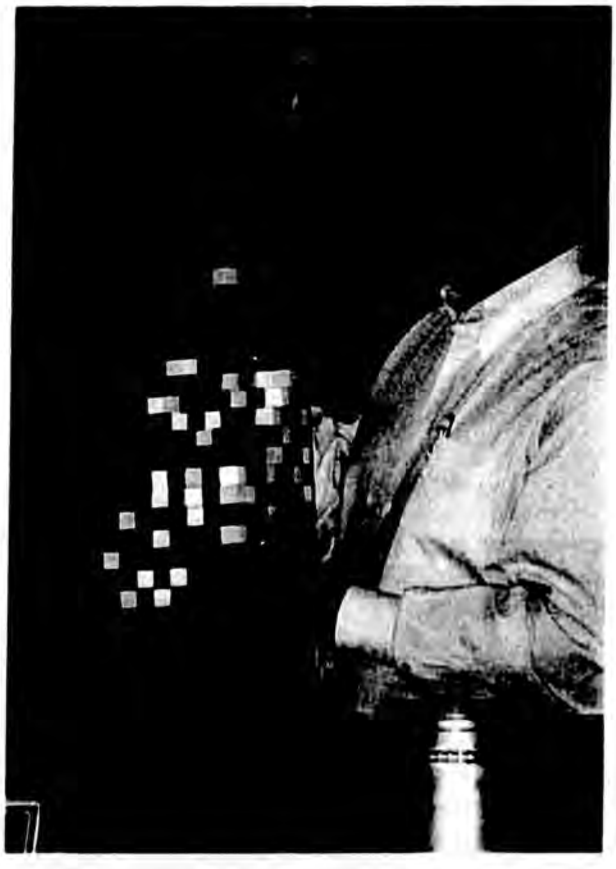
Recommendation:
Continue to ensure that environmental scientists and permitting specialists work side-by-side with design engineers and construction planners from the earliest stages of the project through to its completion.

It is essential that environmental safeguards be built into the design of the project, not added as an afterthought to satisfy regulatory requirements and stipulations. Preliminary engineering design products will be used to support major permit applications with long lead times and must contain fully integrated environmental features at that early stage. This can best be accomplished if environmental and permitting specialists work on the same teams and in the same facilities as the engineers.

Recommendation:
The State of Alaska ROW lease should require long-term environmental surveillance and monitoring, and annual reporting. This function should continue throughout the life of the pipeline.

Recommendation:
The GPO, in cooperation with the federal government, should continue to coordinate the trans-boundary aspects of construction, operation and maintenance of a gasline, including operations control and emergency response.

Although it may cross land belonging to two nations, the gas pipeline will be a single integrated system. Emergencies, whether structural, operational or environmental, will not respect the international boundary. The U.S. and Canada must establish integrated control protocols that can regulate the pressure and flow of gas through the pipeline as a single system and thus respond quickly and effectively to emergencies. This will require open communications, shared data, and a close working relationship between personnel of both nations. The State should look to other international pipelines, particularly between Canada and the United States, for models in handling the trans-border oversight aspects of construction, operation and maintenance.



Steve Arbelovsky of Phillips explains to the Council the properties of liquid natural gas.

ABOUT NATURAL GAS:
How much gas do we have?
Alaska's North Slope is estimated to hold about 35 trillion cubic feet (tcf) of proven natural gas reserves. Twenty-six tcf of this is in the gas cap of the large Prudhoe Bay oil field. The remainder is mostly in the undeveloped Point Thomson gas field east of Prudhoe Bay, and in other oil fields on the Slope.

Geologists think there could be as much as 100 tcf, or more, of gas that can be discovered and commercially produced on the Slope, and more gas in unexplored areas of Interior Alaska.

Until recently, exploration on the North Slope was for oil. However, gas was discovered during the course of that exploration. Companies are now exploring exclusively for gas, and geologists are confident more will be found.

What competitive advantages does Alaska have in marketing its gas?
The large gas reserves on the North Slope are proven by drilling and ready to produce. In other places, like Canada's Mackenzie Delta and the U.S. Gulf of Mexico deep offshore, more exploration and development must be done to prove reserves. The North Slope gas reserves are a certainty, and are the largest proven undeveloped gas resource in America.

Alaska will also be a dependable and secure source of long-term supply for the nation. Gas from the Canadian Arctic could also fill some of this need. The alternative to a gasline is more dependence on imported liquefied natural gas (LNG) from uncertain and possibly unfriendly foreign sources.

Federal/International Action
Charlie Cole, Chair

Members
Esther Wunnicke, Bob Penney, Jon Rubini, Jeff Feldman, George Wuerch

Committee examined the following topics
- Federal permitting/access
- Federal agency lead
- Canadian permitting/access
- Other contractual considerations
- Domestic markets – competing sources/sharing of the market
- Canadian national and territorial relations

Committee Meetings
- May 24, 2001, Anchorage
- August 2, 2001, Juneau
- September 7, 2001, Anchorage
- September 25, 2001, Anchorage

Members of the Gas Policy Council were extensively involved in decisions on State policy and in the development of proposed legislative changes. A substantial product of the Federal/International Action Committee were recommendations for changes to federal law to address key concerns of the State of Alaska in the development of a natural gas pipeline.

The committee supports modifications to modernize ANGTA and believes such modifications would be beneficial to an Alaska gasline project. The committee endorsed 10 key policy goals that should be included in any new gasline legislation.

The 10 policy goals developed to guide drafting of the legislation were debated by the full Council and ratified in concept by a majority of its members on September 25, 2001. Several changes were made as a result of points raised by Council members during the September 25 debate.

If Congress moves forward with new legislation as suggested by the producers, a principal concern of the Council is that Congress should take steps early to reaffirm the southern, or Alaska Highway, route as the sanctioned route for a natural gas pipeline, as a previous Congress did in 1977 when it ratified the President's choice of the southern route under the Alaska Natural Gas Transportation Act. Such a step would focus the attention of industry and federal agencies on regulatory and permit approvals for a project along this route.

This committee also notes that a southern route provides several advantages over other alternatives. Among these is use of the pipeline corridor for other purposes, including the possibility of constructing a railroad or other utilities over time. In addition, a southern route could facilitate access to highly mineralized areas which are located in close proximity.

A second concern of the Council was the probability that with a new initiative in Congress, an Alaska gas pipeline would be subject to Federal Energy Regulatory Commission jurisdiction on issues important to Alaska without a defined role for the state with the FERC. Such issues would include tariffs on intra-state shipment of gas, and access to and from a pipeline. The proposal for a joint board that would give the Regulatory Commission of Alaska joint jurisdiction with FERC on issues affecting Alaska grew out of this concern.

Other concerns of the Council involved provisions to encourage hiring of residents of Alaska for a gas pipeline project, and the hiring of Alaskan Natives.

"Alaska resources should be developed to benefit Alaskans."

Robert Wilkinson, CEO, Copper Valley Electric Association

It was recognized by the Council that the pipeline project will be substantial and that, for all practical purposes, qualified Alaskan workers wishing to work on the project will be employed. Still, an explicit encouragement to hire locally will be a strong inducement for companies and unions to train Alaskans for pipeline-related construction and operating jobs. The skills developed in the Alaskan workforce as a result of training and employment will thus be a lasting legacy of the project.

The Council also considered the importance of pipeline access and the need for future open seasons to facilitate pipeline access for new discoveries. Failure to provide for additional capacity either at startup or through future open seasons could create a "monopoly" on pipeline capacity, discouraging exploration by non-owners. Any new gasline legislation must address this issue to protect the interests of the State of Alaska.

Other policy points guiding development of proposed legislation are detailed later in this report. The committee recognizes the governor's strong advocacy of the 10 principles, as reflected in his recent testimony before the Senate Committee on Energy and Natural Resources and in other forums. It would appear that the State's policy position is well understood by decision makers in Congress and the Federal Executive Branch.

With this in mind, the committee believes that it would be useful for the State Administration to continue its efforts with the commercial parties to develop a market driven solution to transport Alaska natural gas to market via the Alaska Highway route.

Close coordination and communication between the State, the North Slope producers and the pipeline companies could facilitate the establishment of a consortium of companies with the financial capability to build the pipeline.

In our opinion, current discussions among the parties concerning economic feasibility and reestablishment of the previous pipeline partnership underscore the need for such coordination at this time.

Background on Canadian Relations

First Nations

The Kaska First Nations located in Northern British Columbia and the Yukon continue to negotiate land claims and self-government agreements with the Government of Canada and the Province of British Columbia. While these negotiations are expected to continue for the foreseeable future, speculation is that when the time is right, the Kaska will be open to a side agreement on any proposed pipeline running through their territory.

The eight First Nations who have land claims along the proposed route of the Mackenzie Valley pipeline have been negotiating with producers since late spring of 2001. Early in October of 2001, seven of the eight groups came to an agreement on ownership sharing of any pipeline built through their territories. This agreement would grant 30% ownership to the First Nations Bands. The eighth, the De Cho, refuse to sign the agreement. While the Minister of Indian Affairs and Northern Development has been quoted as saying that one Band cannot hold a veto over any project, the De Cho believe that they have the right to refuse construction on lands they claim.

Position of the Government of Canada on Arctic Gas Production and Transportation

The Government of Canada has affirmed that in relation to this project, all departments and agencies will maintain route and project neutrality. In the spring of 2001, the Prime Minister set

Governor Knowles, Mayor Boyles and Charlie Cole listen to testimony at the Fairbanks public hearing. Interior residents expressed their strong need for access to natural gas.

TERMINOLOGY GUIDE:
Definitions of terms used in this section

ANGTA: Alaska Natural Gas Transportation Act, passed by Congress in 1976, which designated the Alaska Highway route for a North Slope pipeline and selected a consortium led by Northwest Energy, of Utah, to build the pipeline. (Foothills Pipelines now owns rights to the system.)

ANGTS: The Alaska Natural Gas Transportation System is the formal name for the Alaska Highway pipeline project approved by Congress in 1977.

North Slope gas producers: Companies that own rights to produce gas. Major Alaska gas producers are BP, ExxonMobil and Phillips. The State owns 1/8 royalty.

Tariffs: Charges, or fees, charged by pipeline owners to firms or entities shipping natural gas.

Intra-state: Referring to shipments within one state, as opposed to interstate shipments from one state to another.

First Nations: Term under Canadian law for Native American groups.

Gas liquids: Valuable components of the natural gas stream, such as ethane, butane and propane.

Petrochemicals: Industrial products made from hydrocarbon (gas or oil) feedstock.

ABOUT NATURAL GAS:
Why is gas in demand?
Mainly because of its clean-burning characteristics, a major advantage in meeting clean-air requirements, and because gas-fired turbines for electricity generation have improved in efficiency, with sharply lowered costs. In the long-term, demand for gas used to generate electricity is expected to grow, although demand for gas for industrial and home-heating will also continue to grow.

up a Cabinet reference group to study the current state of Canada's energy policy. The main issue of study was whether to express a preference for one route over another. A number of Cabinet Ministers expressed support for either the "over-the-top" route or a two-pipeline route with the construction of the Mackenzie Valley line happening first. After careful consideration of all available information and a careful review of the regulatory implications of each option, the Cabinet reference group recommended to the Prime Minister that the original position of route and project neutrality be maintained.

Provincial and Territorial Positions
Of the four non-federal jurisdictions involved in the issue, only the Yukon Territory is firmly supporting the Alaska Highway route. While they have not been overly aggressive in the past, they intend to become more aggressive in promoting the route with the Canadian Federal Government. The Yukon Government has commissioned an economic study of the benefits to Canada of constructing and operating the Alaska Highway route and it is expected that this study will be released to the public in January of 2002.

The Northwest Territories is aggressively promoting the Mackenzie Valley line either in conjunction with an "over-the-top" segment or as a stand-alone line. Assuming the latter is chosen by producers, the Northwest Territories is demanding that this line be built before an Alaska Highway gasline. They are very active with the Federal Government asking for financial incentives to ensure the line's construction.

The other two jurisdictions involved, British Columbia and Alberta, have remained route and project neutral. Premier Klein of Alberta has said that regardless of what line is built, he will not allow a "bullet line" to cross his province. He demands that Albertans share in the long term economic prosperity created by a line to the lower United States. Principally, he is referring to gas liquids and would like to see the petrochemical industry in his province benefit from them.

While it would seem logical for the Government of British Columbia to be supportive of the Alaska Highway route, this government has only been in power since June 2001 and this issue has yet to be critically examined by the Premier and his Cabinet.

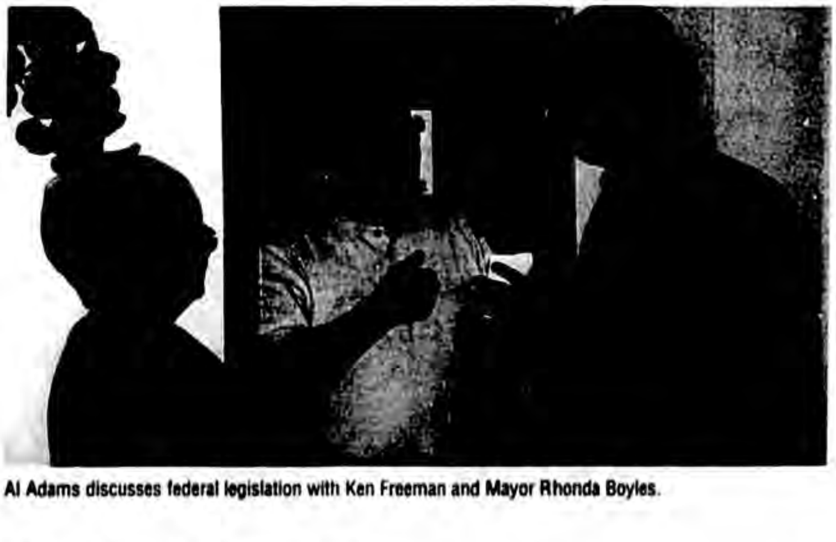
Recommendations:
The committee endorsed 10 key policy goals that should be given consideration in any new federal gasline legislation. The 10 principles and corresponding legislative provisions are outlined below.

Key Principles
• Find that the Alaska Highway natural gas pipeline is in the national interest.
• Mandate the already permitted Alaska Highway route as the preferred route.
• Provide opportunities for new pipeline participants, such as existing producers, pipeline companies, and major Alaska companies.

Corresponding Legislative Provisions
• The 1976 Alaska Natural Gas Transportation Act (ANGTA) that established a process selecting the ANGTS project following the Trans-Alaska Pipeline and the Alaska Highway through Canada to the lower 48 should be the framework for any new gasline legislation.
• The legislation should provide for updating and modernizing the process provided in ANGTA for the expeditious environmental review and approval of a pipeline application for the Alaska Highway route.
• A finding that an Alaska Highway route would make an important long-term contribution to the nation's energy supplies and independence.
• A finding that an Alaska Highway route would have less potential environmental impacts and related delays in construction.

Key Principles
• Provide a mechanism for Alaska communities and businesses to obtain access to natural gas from the pipeline.

Corresponding Legislative Provisions
• FERC should require the project sponsor to demonstrate how the sponsor plans to meet reasonable projections of in-state local consumption needs, including the needs of Fairbanks, Cook Inlet, and rural Alaska. In addition, the sponsor should allow for possible future construction of a pipeline to tidewater for the export of LNG.



Al Adams discusses federal legislation with Ken Freeman and Mayor Rhonda Boyles.

• The Regulatory Commission of Alaska should have concurrent jurisdiction with FERC to set just and reasonable rates for the shipment of natural gas over the Alaska section of the gasline for in-state users.
• The Regulatory Commission of Alaska should have exclusive jurisdiction to set just and reasonable rates for any lateral pipeline connected to the Alaska section of the gasline that serves in-state users.

Key Principles
• Provide access to the pipeline for new natural gas discoveries that will keep Alaska's oil and gas industry healthy through new leasing, exploration and production.

Corresponding Legislative Provisions
• FERC should require the project to establish reasonable plans and procedures, including additional open seasons if necessary, for the expansion of the Alaska section of the gasline as new fields of natural gas are developed on the North Slope and throughout Alaska.
• FERC should be authorized to order expansions of the gasline in the future under reasonable, non-discriminatory terms.

Key Principles
• Provide for Alaska hire and Alaska Native hire.
• Provide for the use of Alaska businesses.

Corresponding Legislative Provisions
• To the extent allowed by law, Alaska residents and contractors should be employed when they are available and qualified. In turn, contractors should be encouraged to employ and train Alaska residents.
• Recruitment should be accomplished primarily by advertising in-state and using Alaska's job service organizations to notify the Alaskan public.
• The project sponsors must, whenever feasible, enter into construction contracts with Alaska firms and fabricate modules in Alaska.
• The gasline sponsors should be required to enter into an agreement to provide for pre-employment recruitment, on-the-job training and employment of Alaska Natives.

Key Principles
• Provide for a project labor agreement for the construction and maintenance of the pipeline, and for worker training.

Corresponding Legislative Provisions
• The project labor agreement should require all contractors and employees to agree to a total ban on strikes, lock-outs and other disruptive activities for the life of the agreement.
• The agreement should be designed to ensure a steady supply of skilled labor and a contractually binding means of resolving worker grievances.

Key Principles
• Provide a priority for the use of American and Canadian steel.

Corresponding Legislative Provisions
• Only steel manufactured or produced in the U.S. or Canada should be used in the construction of the Alaska section of the gasline unless its use is inconsistent with the public interest or the cost is unreasonable. Factors to be considered in evaluating the public interest should include quality, availability and delivery times.

Key Principles
• Provide for economic incentives to give investors in ANGTS additional levels of confidence.

Corresponding Legislative Provisions
• Accelerated depreciation on gasline investments.
• An investment tax credit for an approved ANGTS project.
• A tax credit for producing gas from the Alaska North Slope tied to a price floor.

ABOUT NATURAL GAS:
What are we doing with the North Slope gas?
Produced gas in the Prudhoe Bay field is reinjected to conserve it and help produce more oil, as well as to fuel production facilities. Gas, oil and water come out of the ground together and must be separated. The separated gas is injected back into the underground reservoir to maintain pressure, which drives the oil to the surface. Some natural gas liquids, pentane, hexane, and so on, are mixed with crude oil being shipped through the TAPS pipeline and then sold, while other NGLs are mixed with other molecules, like CO2, ethane and propane, and reinjected into the ground to enhance oil recovery.

Who are Alaska's main competitors?
It is assumed that gas from other areas of the U.S. and Canada are not really long-term competitors with Alaska because ultimately all North American gas will be needed to meet demand. Alaska's short-term competitor is thought to be imported liquefied natural gas and gas from Canada, because if an Alaska gas project is delayed, small LNG import projects and continued development in Canada could incrementally fill market gaps that Alaska gas could have filled.

Council Members

The Co-Chairs

Frank Brown
Before retiring in 1999, Frank Brown was a senior vice president for ARCO Alaska, where he was responsible for the Kuparuk Field and the initial development of the Alpine Field.

Prior to his Alaska assignment, Brown was president of both the Thums Long Beach Company and ARCO Long Beach Company. The companies were in a risk sharing joint venture with the State of California to produce and market the State's oil and gas in the Long Beach Unit. Currently, Brown is a director of Grey Wolf, Inc., a provider of land drilling services. He is also president of Fairweather International, a consulting company focusing on Alaska North Slope opportunities.

Brown graduated from Louisiana Tech University. He has served on the Anchorage Opera Board and has been actively involved in numerous United Way campaigns.

Jim Sampson
Jim Sampson served two terms as mayor of the Fairbanks North Star Borough from 1991 to 1997 and was the State of Alaska commissioner of labor from 1986 to 1990. Sampson is currently chair of the Alaska Permanent Fund Corporation Board of Trustees and is a director with the Alaska State AFL-CIO and Alaska Works Partnership, a firm committed to training Alaskans for jobs in the construction industry.

Sampson is a 42-year resident of Alaska. He has served on the Board of Directors of the Alaska Housing Finance Corporation and as chairman of the Alaska Labor Relations Agency and Workers' Compensation Board.

The Executive Committee

Charlie Cole
Charlie Cole has had a long and distinguished career in Alaska. He began practicing law in Alaska in 1954 and has kept his private practice ever since. From December 1990 to January 1994, Cole served as the State's Attorney General under then Governor Walter Hickel. As Alaska's top attorney, he negotiated the settlement of the Exxon Valdez lawsuit on behalf of the state and its residents.

In recent years Cole has served on numerous boards and task forces, giving much of his time to help solve the policy issues facing Alaska. He recently participated in Governor Knowles' subsistence summit and has served on two other subsistence task forces.

Cole earned a B.A. and a J.D. degree from Stanford University. He had a distinguished career in minor league baseball.

William Corbus
William Corbus is president and general manage of Alaska Electric Light and Power, an investor-owned electric utility providing electric service to the City and B rough of Juneau.

Corbus has served on the Alaska State Pension Investment Board and currently sits on the board of First National Bank of Anchorage. His civic involvement has included work with the Juneau Boy Scout Council, Juneau Hospice and Homecare and Catholic Community Service.

Corbus was an officer in the United States Navy and served in Vietnam. He earned a degree in industrial engineering from Stanford University and a Master of Business Administration from Dartmouth College. He is also a registered electrical engineer.

Mike Navarre

Mike Navarre served in the Alaska State Legislature for over 10 years, where his leadership positions included finance committee chair (1991-92) and house majority leader (1989-90). He was later elected as mayor of the Kenai Peninsula Borough.

Navarre is currently the president of ZAN, Incorporated, a company that owns and operates nine Arby's Roast Beef Restaurants in Alaska. He also serves as the chair of the State of Alaska Royalty Oil and Gas Advisory Board and as president of the Boy's and Girl's Clubs of the Kenai Peninsula. He is a member of the Kenai, Soldotna and Nikiski Chambers of Commerce and is on the Nature Conservancy Board.

Navarre is a graduate of Eastern Washington University.

Ken Thompson

Ken Thompson is president of Pacific Rim Leadership Development, an Anchorage company that provides management and leadership consulting services to corporations, churches and nonprofit organizations.

Prior to his current position, Thompson spent 26 years with ARCO in positions ranging from president of ARCO's Exploration and Production Research and Technology Center to president of ARCO Alaska, Inc. Thompson also worked as an ARCO executive vice president, responsible for the company's global natural gas marketing and gas operating companies in Alaska, California, Indonesia, China, Singapore, Malaysia and Thailand.

Thompson sits on the boards of Alaska Airlines and Alaska Air Group. He is involved in community service through organizations such as United Way and the Anchorage Museum Foundation. He serves on the Board of Trustees for Alaska Pacific University.

Peg Tileston

Peg Tileston is president of Tileston and Associates, an Anchorage research and information retrieval business. Tileston is also chair and co-founder of Alaska Common Ground, an organization seeking consensus on public policy issues in Alaska. She is a board member of the Alaska Conservation Foundation and was appointed to the Governor's Alaska Oil and Gas Policy Council in 1996.

Tileston served 15 years on the Alaska Water Resources Board and 10 years on the Chugach Electric Association Board. She was the co-founder of Trustees for Alaska, an environmental public interest law organization.

Tileston is a graduate of Earlham College. She has been widely recognized for her community involvement and was named a woman of achievement by the YWCA in 1997.

Council Members

Al Adams

Al Adams served nine years in the Alaska State House of Representatives and 10 years in the Alaska State Senate. His distinguished legislative career included eight years as chair of the House Finance Committee and six years on the Senate Finance Committee. Adams retired from legislative service in 2001 and is currently the manager of economic development for the North Slope Borough mayor's office.

Adams' business experience includes serving as president of Kikiktagruk Inupiat Corporation and executive vice president of Nana Regional Corporation. He also served on the Alaska Native Claims Appeals Board.

Adams, a life-long Alaskan born in Kotzebue, graduated from Mt. Edgecumbe High School and the University of Alaska, Fairbanks.

Jacob Adams

Jacob Adams has been the president of Arctic Slope Regional Corporation (ASRC) since 1983. As president, Adams has led the corporation through a period of intensive diversification and remarkable growth.

Adams began his career with ASRC in 1971 when he was elected to the company's first Board of Directors. He has served on the board ever since.

When he was only 21, Adams won election to the Barrow City Council. When the North Slope Borough was organized in 1972, he was elected to its first assembly. Adams was later appointed to succeed the late Eben Hopson as mayor. Adams served on the assembly until 2000.

Adams, a successful whaling captain, helped form the Alaska Eskimo Whaling Commission.

George Ahmaogak, Sr.

George Ahmaogak, Sr. is currently serving his fourth term as North Slope Borough mayor. He first held the office from 1984-1990 and was elected again in 1993. During his tenure as mayor, Ahmaogak has spearheaded a variety of innovative initiatives including the Mayor's Jobs Program which provides employment opportunities to local Barrow residents while allowing them to maintain their subsistence lifestyle.

Prior to his first term as mayor, Ahmaogak was president of the Ukpeagvik Inupiat Corporation, the village corporation for Barrow. He has also served as the head of Piquniq Management Corporation. Later Ahmaogak was elected to the board of Arctic Slope Regional Corporation.

Ahmaogak is a successful whaling captain and a graduate of Mt. Edgecumbe High School in Sitka.

Rhonda Boyles

Rhonda Boyles was elected Fairbanks North Star Borough mayor in October 2000. A businesswoman and restaurateur, Boyles has been a leader in the Fairbanks community for over 25 years.

Boyles has served as director of the Greater Fairbanks Chamber of Commerce and sat on the Board of Directors of the Alaska State Chamber of Commerce. Her service has been honored by the University of Alaska, Fairbanks, who named her business leader of the year in 1999.

Throughout her career Boyles has taken a special interest in higher education, serving on a variety of boards including the University of Alaska College of Fellows, the University of Alaska Statewide Vocational and Technical Education Advisory Council and the Tanana Valley Campus Council.

Brian Davies

Brian Davies was involved with BP's development and operation of the North Slope oil fields, particularly Prudhoe Bay, for almost 23 years. Before coming to Alaska in 1971, Davies worked as a geologist and a petroleum engineer in the Southern North Sea, Abu Dhabi and Colombia.

Davies retired from BP in 1994 and is currently a part-time consultant. He is also involved with several Anchorage nonprofit organizations including the Anchorage Symphony Orchestra, Anchorage Museum, Alaska World Affairs Council and The Nature Conservancy of Alaska.

Davies grew up in Herefordshire, England and went to Trinity College, Dublin where he graduated with a degree in geology.

Ronald Duncan

Ronald Duncan is a founding member of GCI and has been the company's president and CEO since 1989. Duncan is a board member and past chairman of the Anchorage Economic Development Corporation and is current chairman of the Alaska Science and Technology Foundation. Prior to starting GCI, Duncan founded Alaskavision, an Alaska-based cable television company, and was a partner at Lyall Associates, a management and economic consulting firm. He has also served as an assistant director at the Johns Hopkins University Center for Metropolitan Planning and Research and as a special assistant to Congressman John Dow.

Duncan received a bachelor's degree in economics from Johns Hopkins University and a master's of business administration from Harvard Business School.

Jeffrey Feldman

Jeffrey Feldman is a partner in the Anchorage law firm Feldman and Orlansky. Prior to entering private practice, Feldman served as an assistant public defender for the Alaska Public Defender Agency and as a law clerk to Justice Edmond Burke of the Alaska Supreme Court.

Feldman has held a variety of professional appointments, including chairman of the Alaska Commission on Judicial Conduct and member of the Governor's Task Force on Civil Liability Reform.

Feldman obtained a B.A. and a J.D. degree from Northeastern University. In 1998, Feldman was awarded the Alaska Bar Association Professionalism Award and he twice received the United States District Court for the District of Alaska Public Service Award. In 1993, he received the ACLU Public Service Award.

Lee Gorsuch

Lee Gorsuch has been chancellor of the University of Alaska Anchorage since 1994. As chancellor, he oversees five colleges and schools on the Anchorage campus, the extended college campuses and the statewide delivery of education programs to the military.

From 1976 to 1994, Gorsuch led the Institute of Social and Economic Research (ISER). Later he served as the dean of the School of Public Affairs at UAA.

Gorsuch earned his undergraduate and graduate degrees in economics and community development from the University of Missouri at Columbia. He is a former president of both the Anchorage School Board and the Alaska Association of School Boards. Currently he serves on the board of Commonwealth North and the Nature Conservancy of Alaska.

Jerry Hood

As the leader of Alaska's Teamsters Union, Jerry Hood administers the collective bargaining needs of some 7,000 Alaskans. He was named secretary-treasurer of Teamsters Local 959 in February 1994 and has been elected to that position three times. Hood chairs the Union's Executive Board, the Alaska Teamster-Employer Welfare Trust and the Alaska Teamster-Employer Pension Trust. Hood also serves as special assistant on energy to the General President of the International Brotherhood of Teamsters James P. Hoffa.

Hood, who has long been active in civic and community affairs, is a member of the Anchorage Chamber of Commerce, Commonwealth North and the Resource Development Council. He also serves on the Board of Directors and Executive Committee of Arctic Power.

Jim Jansen

Jim Jansen is the president and CEO of Lynden Inc., an Alaskan transportation company.

Raised in the town of Lynden, Washington, Jansen grew up in the trucking and construction business. He served as a heavy equipment operator in the Navy and completed a tour of duty in Vietnam. Jansen came to Alaska in 1967 and worked hauling copper ore at Kennicott. Jansen joined Lynden full time in 1970, becoming president and CEO in 1983.

Jansen holds a degree in business administration from Central Washington College. He is a 12,000 hour commercial pilot, an assistant hunting guide and avid fisherman. He serves as a director of Wells Fargo Bank and is a past board member of the Special Olympics World Winter Games.

Carl Marrs

Carl Marrs has been with CIRI for more than 28 years, serving in a variety of positions before becoming president and CEO. A respected Alaska business leader, Marrs has repeatedly been named one of the top 25 most powerful Alaskans by the Alaska Journal of Commerce. He was also recently given the 2001 Alaska Federation of Natives Citizen of the Year Award.

Marrs currently sits on the boards of the Fiscal Policy Council of Alaska, Alaska Railroad Corporation, and Alaska Communications Systems Group, Inc. He is the president of the Association of ANCSA Regional Corporations Presidents/CEOs, Inc., a member of the Alaska SeaLife Center Board of Governors, a trustee of Alaska Pacific University and a member of the Anchorage Daily News Board of Advisors.

Mike O'Connor

Mike O'Connor has over 25 years management experience in oil and gas related construction projects. He is president of Peak Oilfield Service Company, an Alaskan-based general contractor that specializes in oilfield construction, rig moves, pipe fabrication, heavy hauling and equipment maintenance. O'Connor also oversees Precision Power Company and Peak's other subsidiaries.

O'Connor is active in the community, serving as a campaign coordinator for the United Way of Anchorage and a board member of the Alaska Support Industry Alliance. He has also volunteered for the Alaska Special Olympics and the 2001 World Winter Games.

O'Connor holds a bachelor's degree in civil engineering from Ohio State University and is a certified professional engineer.

Bob Penney

Bob Penney is the owner of Penco Properties, an Anchorage-based real estate brokerage company specializing in real estate development and property management. His development experience includes single and multi-family residential projects, commercial properties, retail buildings and land development in five western states.

Penney has a long history of community involvement in Alaska. His service has included work with the Anchorage Economic Development Corporation and Alaska Regional Hospital Board of Trustees. Penney is a past president of the Anchorage Chamber of Commerce and helped found the Resource Development Council.

A lifelong sport fisherman, Penney is the founder of the Kenai River Sportfishing Association and the Kenai River Classic. He was recently appointed to the North Pacific Fisheries Management Council.

Edward Rasmuson

Edward Rasmuson is a third generation Alaskan who began his career at National Bank of Alaska in 1956 as a summer employee. After graduating from Harvard University, he joined the bank full time and achieved successive promotions as the manager of several branches and later vice president. In 1974 he became president and in 1985 was appointed chairman of the board. Currently he is chairman of Wells Fargo Bank Alaska.

Rasmuson was a member of the University of Alaska Board of Regents for 14 years and is a past president of the Rotary Club and the Boy Scouts of Alaska, Western Council. He currently serves on committees at the University of Alaska Foundation, Alaska Pacific University and Providence Hospital.

Jack Roderick

Jack Roderick has had a long and varied career as a resource developer, public policy maker and writer. A resident of Alaska since before statehood, Roderick founded many small oil and resource-related businesses, including Alaska Exploration Corporation, Petroleum Publications and Alaska Industry magazine. As a consultant to Alyeska Pipeline Services Company during the early 1970s, Roderick assisted the company in settling Native land claims. Roderick was Greater Anchorage Borough mayor from 1972 to 1975 and later was deputy commissioner of the Alaska Department of Natural Resources.

A graduate of Yale University, Roderick also received an M.A. from Harvard University and a J.D. from the University of Washington. His book, *Crude Dreams: Oil and Politics in Alaska,* was published by Epicenter Press.

Dave Rose

Dave Rose is chairman and founder of Alaska Permanent Capital Management Company, the first major money management firm in Alaska designed to serve Alaska institutional investors. Before forming his own firm, Rose served ten years as the first executive director of the Alaska Permanent Fund Corporation. His professional career also includes leading the Alaska Municipal Bond Bank and revitalizing the Alaska Industrial Development and Export Authority.

Rose was the first chairman of the Anchorage Municipal Assembly and has received numerous awards for his dedication to public service. He currently serves as vice chair of the Alaska Pacific University Foundation and as a member of the Anchorage Concert Association Endowment. Rose earned an accounting degree from Queens College and an MBA from Syracuse University.

Jonathan Rubini

Jonathan Rubini is the managing partner of Foster Pepper Rubini & Reeves LLC, an Alaska law firm. He focuses his practice on public finance and general corporate law. Rubini is also currently chairman and chief executive officer of JL Properties, Inc., an Anchorage-based real estate development and management firm.

Rubini's past professional experience includes working as a partner with the firm Birch, Horton, Bittner & Cherot. He also served as a law clerk to Justice Allen T. Compton of the Alaska Supreme Court and as an assistant attorney general for the State of Alaska.

Rubini earned a B.A. from Brown University and a J.D. from Boalt Hall School of Law, University of California, Berkeley.

Grace Schaible

Grace Schaible is a retired attorney and a respected civic leader. During her time in private practice, Schaible was known for accepting pro bono cases. In 1987, she became the first woman to hold the office of Alaska Attorney General.

Schaible is a past chair of the Alaska Permanent Fund Corporation Board of Trustees and a former member of the University of Alaska Board of Regents. She has served on the Fairbanks Chamber of Commerce Board and as president of the University of Alaska Foundation. In 2000, Schaible was honored by the State Chamber of Commerce for her life-long contributions to Alaska.

Schaible graduated from the University of Alaska Fairbanks and earned a law degree from Yale University.

George Wuerch

George Wuerch was elected mayor of Anchorage in May 2000. Prior to taking office, he served on the Anchorage Municipal Assembly for five years.

Wuerch served as an officer in the U.S. Marine Corps for 20 years. After retiring from the Marines he became manager of governmental affairs for the Northwest Alaskan Gasline. In 1984 he moved to Alaska to become founder and president of Fluor Daniel Alaska Engineering. Later he joined Alyeska Pipeline Service Company as a vice president.

Wuerch holds a degree in engineering technology from Oregon State University and a master's degree from the U.S. Naval Postgraduate School. His community involvement has included service as chairman of the Anchorage Chamber of Commerce and chairman of the United Way Campaign.

Esther Wunnicke

Attorney Esther Wunnicke began her distinguished career in public service as an assistant attorney general for the State of Alaska. In 1983, Wunnicke was appointed commissioner of the Department of Natural Resources. Wunnicke's federal service in Alaska has included work with the Federal Field Committee, the Federal-State Land Use Planning Commission and the Department of Interior Mineral Management Service.

Since retiring from the Department of Natural Resources in 1986, Wunnicke has served on the State Commission on Human Rights, the Oil and Gas Policy Council and the Alaska Rural Governance and Empowerment Commission.

In 1991 Wunnicke and a group of citizens formed Alaska Common Ground, a forum for Alaska citizens to address long-term public policy issues.

Ex-Officio Members of the Alaska Highway Natural Gas Policy Council

Fran Ulmer, Lieutenant Governor, State of Alaska
Rick Halford, President, Alaska State Senate
Brian Porter, Speaker, Alaska State House of Representatives
Georgianna Lincoln, Senator, Alaska State Senate
Ethan Berkowitz, Minority Leader, Alaska State House of Representatives
Bruce Botelho, Attorney General, Department of Law
Michele Brown, Commissioner, Department of Environmental Conservation
Wilson Condon, Commissioner, Department of Revenue
Ed Flanagan, Commissioner, Department of Labor and Workforce Development
Patrick Galvin, Director, Division of Governmental Coordination
John Katz, Director of State/Federal Relations, Office of the Governor
Joseph Perkins, Commissioner, Department of Transportation and Public Facilities
Pat Pourchot, Commissioner, Department of Natural Resources
Frank Rue, Commissioner, Department of Fish and Game
Deborah Sedwick, Commissioner, Department of Community and Economic Development

Staff to the Council:
Ken Freeman, Executive Director
Debra Ceffalio, Communications Coordinator
Erika McConnell, Project Assistant

From the Co-Chairs

Dear Alaskan,

It has been an honor to co-chair the Alaska Highway Natural Gas Policy Council, a diverse group of distinguished and knowledgeable Alaskans. All 28 Council members deserve recognition for the long hours and hard work they dedicated to this effort.

We would like to thank Governor Knowles for the opportunity to serve on this Council. By giving Alaskans a meaningful opportunity to discuss the issues surrounding natural gas development, the Council has helped create a growing momentum and excitement for an Alaska gasline project.

We were impressed with the thoughtful testimony we received from the many Alaskans, project proponents and industry experts who made presentations to our group. Alaska is fortunate to have so many knowledgeable people working to develop our natural gas resources. We'd also like to thank the mayors, civic leaders and others who so graciously welcomed the Gas Policy Council into their communities.

Finally, we'd like to thank the staff of the Governor's office and other departments for their work, as well as the many legislators who worked with us along the way. A special thank you to Lieutenant Governor Ulmer and members of the Governor's Gas Cabinet for their dedication to this project.

From top: Barrow dancers welcome the Council to the North Slope; the Council staff reviews final meeting documents; Co-chairs Jim Sampson and Frank Brown participate in the Fairbanks hearing with Governor Knowles.

One key theme emerged during our work – the importance of unity. Alaskans prosper when Alaskans work together. We urge the Administration, Legislature and congressional delegation to continue to work together to ensure that Alaska's needs are put first as we develop our gas resources.

Sincerely,

Frank M Brown

Frank Brown
Co-Chair

James A Sampson

Jim Sampson
Co-Chair

In Memoriam

Rosemarie Maher, 1947-2001

In July, the Council mourned the passing of Council member Rosemarie Maher, a beloved friend and respected colleague.

Rosemarie was the president and chief executive officer of Doyon Ltd. Maher had served on the board of the Interior Native corporation from 1979 until she was named president in January 2000. She replaced Morris Thompson who retired from Doyon in December 1999. She also served as co-chair of the Alaska Federation of Natives from 1997-2000 and on the Alaska Board of Game during the late 1980s and early 1990s.

Maher was born in a canvas tent at a fish camp on the Nabesna River in 1947. She grew up in Northway and learned the traditions of the Upper Tanana Athabaskans. Maher is remembered as a woman who could move easily between the corporate and village life. She was a respected leader who cared deeply for the people she served. She will be missed by many in Alaska.

This publication was released by the Office of the Governor, produced at a cost of $2.76 per copy to inform Alaskans about gasline issues and printed in Anchorage, Alaska. This publication can be made available in other forms. Contact the Office of the Governor at (907) 269-7450 or TDD (907)465-3489 to make arrangements.

Alaska Natural Gas In-State Demand Study
ASP 2001-1000-2650

Prepared on Behalf of the Alaska Department of Natural Resources

Volume 1: Technical Report

David E. Dismukes, Ph.D.

With Contributions from:

Dmitry V. Mesyanzhinov, Ph.D.
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Report Prepared by the Collaboration of:

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and

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Baton Rouge, Louisiana

January 23, 2002

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Executive Summary

The purpose of this report is to examine the future natural gas demand of Alaska communities and businesses. The study was prepared in a manner that provides quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. The major results of our study can be summarized as follows.

- We developed a baseline forecast which assumes a business as usual environment over the forecast period. Alaska prices were assumed to be constant, in real dollars, over the forecast period, while income was assumed to be increasing at a real annual average rate of a half-percent per year. (Chapter 4, page 25)

- Baseline residential natural gas demand is expected to grow at an average rate of 1.8 percent per year to 2020. Over the next ten years, residential baseline demand will increase by 3.5 Bcf per year, and will increase by 7.9 Bcf by 2020. (Chapter 4, Table 4.1)

- Baseline commercial natural gas demand is expected to grow at an annual average rate of 1 percent per year to 2020. Over the next ten years, commercial baseline demand will increase by 3.3 Bcf, and will increase by 6.3 Bcf by 2020. (Chapter 4, Table 4.2)

- The baseline forecast estimates moderate to flat growth of industrial natural gas usage. Over the forecast period, industrial baseline demand will increase at an annual average rate of approximately half a percent. Industrial demand will increase by 4.0 Bcf by the year 2010, and by 8.0 Bcf by 2020. (Chapter 4, Table 4.3)

- Electric utility demand for natural gas will increase by 0.7 percent per year to 2020. Electric utility demand will increase by 1.4 Bcf by the year 2010, and by 5.1 Bcf by 2020. (Chapter 4, Table 4.4)

- Total baseline natural gas usage is forecasted to grow at an annual average rate of little under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. (Chapter 4, Table 4.5)

Summary of Baseline Forecast

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,851,818	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Note: Baseline forecast excludes natural gas dispositions to the Kenai LNG Plant. See discussion in Chapters 2 and 7.

- The baseline forecast developed in this study was subjected to a number of sensitivity analyses to determine the impact of changes in economic assumptions on natural gas usage. (Chapter 5, page 37)

- Under the high price/high income scenario, prices and income were expected to increase at a rate of one percent per year in real dollars. Under the low price scenario, prices were assumed to decrease at a real rate of one percent per year. Under the low income scenario, income was assumed to be constant in real dollars over the forecast period. (Chapter 5, page 37)

- Changes in price assumptions had larger influences on the baseline forecast than changes in income assumptions. (Chapter 5, Figure 5.2)

- Under a low price forecast, total in-state natural gas usage would grow at a 0.05 percent rate higher than under the baseline forecast. The low price forecast assumes that prices will fall by an annual rate of one percent during the forecast period. The baseline forecast, on the other hand, assumes constant prices. (Chapter 5, Figure 5.1)

Summary of Forecast Sensitivities

High Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

- After examining a range of expanded service opportunities through the state, the largest concentrations of new service opportunities are in the South Central and Interior regions of the state. There are approximately 2.2 Bcf of expanded service opportunities in South Central region and 4.3 Bcf of expanded service opportunities in the Interior. (Chapter 6, Table 6.6)

- There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of Internet server farms and a major petrochemical industry. Both are energy-intensive industries. (Chapter 7)

- It would take the addition of a relatively large Internet facility (i.e., about a one million square foot facility) to impact total in-state usage. We estimate that a high power density, million square foot server farm could use up to 4.3 Bcf per year. (Chapter 7, Table 7.1)

- A major petrochemical facility, on the other hand, could have a more meaningful impact. Based upon statistics from typical world class facilities on the Gulf of Mexico, a 619 ton per year ethylene facility could use as much as 27 Bcf per year. (Chapter 7, Table 7.3)

- All generating units in the state were examined to identify facilities those that could potentially shift their primary fuel to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior section of the state. There are approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Annual natural gas usage would be about 15 Bcf per year if all of the eligible facilities were to switch fuels. (Chapter 8, Tables 8.1 and 8.4)

- There is a supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the marginal costs of existing generating units. This new generation could account for about 12.5 Bcf of natural gas usage per year. However, prior studies of power markets performed on behalf of the Regulatory Commission of Alaska, have noted that Alaska does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. (Chapter 8, Tables 8.10 and 8.11)

- Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. We examined a number of major concentrations of potential gas usage, and modeled the typical costs of supplying natural gas to these potential applications. These results included:

- ***New Service to the Interior:*** Positive opportunities for natural gas service exist based on our initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent. (Chapter 9, page 120)

- ***Fuel Switching:*** Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated. (Chapter 9, page 124)

- ***Gas by Wire:*** There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014. (Chapter 9, page 128)

- ***Expanded Service to the Southcentral:*** Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage, 30-to-40 Bcf per year, currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area. (Chapter 9, page 131)

CHAPTER 1: INTRODUCTION

1.1: Research Overview

The purpose of this report is to examine the future natural gas demand and supply for Alaska communities and businesses. The study was prepared in a manner that provides a host of quantitative information about natural gas usage to assist the Alaska Department of Natural Resources, as well as other important stakeholder groups, in evaluating the possibilities of meeting certain Alaska energy needs through Alaska North Slope (ANS) gas. Our study considers a number of opportunities including expanding natural gas service to retail customers, increased gas-fired power generation alternatives, and the addition of new industries to the Alaska economy.

A number of demand models have been developed throughout the course of this report. The primary set of models estimate customer class specific natural gas usage. These models have been developed to understand the important empirical determinants of natural gas demand, as well as forecasting potential in-state usage under a number of different economic scenarios.

The report uses a geographic information system (GIS) approach for identifying new regional sources of natural gas usage. Our GIS model identifies existing and potential sources of natural gas usage, and maps those locations to existing and future infrastructure development. Volumes by location and region are developed from this approach. Throughout the course of our report, we will define Alaska regions as identified below in Figure 1.1. These regions include: the Far North, the Interior, the Southwest, the Southcentral, and the South Eastern portions of the state.

Our GIS analysis was comprised of two approaches. First, we examine total regional in-state possibilities for expanded natural gas service regardless of distance and economics. This approach essentially defines the outer boundary of potential new natural gas usage in the state. Second, we examine the possibilities of expanding natural gas service within two major natural gas infrastructure systems: the existing local distribution networks in place in Alaska, and the proposed Alaska Highway Route (AHR).

Figure 1.1: Definition of Alaska Regions

We also examine the possibilities of new sources of natural gas usage. These include new natural gas power generation possibilities as well as a number of new commercial and industrial opportunities. The power generation options we consider can be broken into two classes. First, we estimate the opportunities for fuel switching at existing utility and non-utility fuel oil and diesel fired generation facilities. Second, we examine the possibilities of a "gas-by-wire" application where a larger central station power generation facility is located in close proximity to the AHR. Power generated from the gas-fired facility would then be moved by high voltage transmission lines to nearby communities.

We also analyze the possibilities of adding new energy intensive industries to the Alaska economy. These include: the development of an internet server farm; the possibilities of a new petrochemical facility in the state; as well as expansion of existing LNG and ammonia-urea production.

Lastly, no analysis of in-state demand would be complete without examining the cost implications of supplying natural gas to these identified possibilities. In a later chapter of our report, we examine the costs associated with stepping natural gas down from the high pressure AHR transmission line to potential regional natural gas usage applications.

1.2: Organization of Report

This report is organized into a total of ten chapters, three technical appendices, and a bibliography. The technical appendices and bibliography associated with this report are included in Volume 2.

The first chapter is this introduction that gives an overview of the report and its organization.

The second chapter of our report provides an overview of recent Alaska natural gas market trends. This chapter is a general overview over the past several years. A more detailed analysis, over a longer time period, can be found in Appendix 1 (Volume 2).

The third chapter of our report provides a general discussion of demand modeling and the techniques typically employed in this type of research. For those readers less interested in these technical details, this chapter of the report can be skipped without loss of context. For those readers looking for greater detail on natural gas demand modeling, Appendix 2 (Volume 2) has been provided for that purpose.

The fourth chapter of our report provides our baseline forecast of natural gas usage by major customer class: residential, commercial, industrial, and power generation. This chapter highlights the results of our forecast, with little discussion of our actual model and its statistical results. Those readers looking for greater empirical detail, in terms of the statistical models and their results, should refer to Appendix 3 (Volume 2).

The fifth chapter of our report subjects our baseline forecasts to a number of different assumptions about economic conditions in Alaska and how they could impact in-state natural gas usage.

The sixth chapter of our report examines new retail service opportunities for natural gas. This chapter highlights our GIS approach and maps out new usage opportunities on a regional and geographic proximity basis.

The seventh chapter of our report examines new natural gas opportunities through additions of new industries to the Alaska economy. This chapter provides some estimates of potential natural gas usage by the previously discussed internet server farm and the development of a new major petrochemical facility. We also consider expanded opportunities for natural gas usage at existing Alaska industries. In particular, expanded usage at existing LNG and urea production facilities.

The eighth chapter of our report examines new opportunities for natural gas fired power generation. This chapter identifies fuel switching applications, and potential natural gas usage volumes that could result from a shift in primary fuel at certain power generation stations and locations. We also examine a gas-by-wire application in this chapter of our report.

The ninth chapter of our report examines the cost of supplying natural gas to a number of the opportunities identified in the earlier chapters of our report. Our primary emphasis has been on the new service opportunities in relatively concentrated areas, in addition to power generation applications.

The tenth chapter of our report presents our overall conclusions. Also included with this report, in Volume 2, is an exhaustive bibliography of the leading articles in natural gas industry supply and demand modeling.

CHAPTER 2: RECENT TRENDS IN ALASKA'S RETAIL NATURAL GAS MARKETS

This chapter of our report will examine some of the more recent trends associated with the major natural gas consuming sectors in Alaska. A more detailed, longer run historical analysis has been presented in Appendix 1.

2.1: Data Used in the Analysis of Alaska Natural Gas Usage

The following discussion, as well as the models that we will develop in subsequent chapters, utilizes data from the EIA 176 database published by the U.S. Department of Energy, Energy Information Administration (EIA). This database is developed and maintained from annual survey information collected by the EIA under EIA Form 176. All major interstate natural gas pipeline companies, intrastate natural gas pipeline companies, investor and municipally owned natural gas distributors, underground natural gas storage operators, synthetic natural gas plant operators, among other providers of natural gas service, are required to complete this form. The completion of this report is mandatory under the Federal Energy Administration Act of 1974.

For a typical LDC, the EIA Form 176 requirements include annual reporting on the disposition of all gas flows over the company's system. This includes accounting for all gas sales, prices (average revenues), and customers for residential, commercial, industrial, and any other retail customer class. In addition, LDCs must report any transportation services (and volumes) for non-core customers. Thus, if a commercial or industrial customer is within the city gate, but receives gas from a third party, the LDC is required to report the volumes it transports to these customers even though the LDC is only providing transportation services.

In the information reported for Alaska natural gas companies, two LDCs filed information on sales, customers, and transportation volumes. The majority of their disposition was associated with traditional retail sales (i.e., residential, commercial, industrial, etc.). However, starting in 1992, Enstar began reporting transportation volumes for one industrial customer.[1] In 1995, the Company began reporting transportation volumes for commercial customers as well. Since 1995, the number of non-core commercial customers for Enstar has grown significantly. In 1995, there were 62 commercial customers receiving transportation service only from Enstar. This increased to 187 in 1996; 401 in 1997; and 768 in 1998. By 1999, this number has grown to 883 commercial customers taking only transportation service.

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[1]In such a situation, if an LDC is transporting gas on behalf of a customer within the city gate, then that customer is being served by a competitive third party, presumable a competitive retail natural gas marketer. Thus, identifying transportation customers within an LDC's service can give some indication of the degree of competition within that particular area.

Other companies with pipeline assets are also required to report transportation and sales volumes even if they are not an LDC. According to the data included in the EIA 176 database, there were 6 non-LDCs reporting either transportation and/or direct sales. These included Arco Alaska, Inc., Chevron USA, Marathon Oil Company, Phillips Alaska Natural Gas Company, Ukpeaqvik Artic Slope, and Union Oil Company of California (UNOCAL). In 1999, these companies, collectively, served 11 commercial customers, of which 2 were transportation customers alone. In the same year, these companies collectively served 9 industrial customers. Enstar provided transportation service to three industrial customers.

The EIA database that we used in our historic trends analysis, as well as in the development of our forecasting models, excludes information from other natural gas uses that are reported separately to the DOE. These include field uses of natural gas in oil and gas production, internal company use of natural gas, pumping and compressor station use of natural gas, and liquefied natural gas (LNG). None of these gas usage activities are included in the commercial and industrial series analyzed in this chapter, nor were these natural gas uses included in commercial or industrial forecasting models. Gas Dispositions to the Kenai LNG Plant are excluded from the EIA data series because the LNG it is exported and not considered as an in-state requirement. However, the role of LNG in Southcentral Alaska is important since it accounts for close to 36 percent of total gas dispositions in the Cook Inlet area (see discussion in Chapters 7 and 9).

In addition to usage and price information included in the EIA Form 176, we compiled additional information to supplement the data we would use to specify our demand equation. This includes energy price information for alternative fuels such as diesel, fuel oil, and electricity. This information was also collected from the US Department of Energy, and is published every year in the Annual Energy Report. We also collected employment and state gross product information from the US Department of Commerce, Bureau of Economic Analysis (BEA).

2.2: Recent Trends in Retail Natural Gas Prices

Over the past several years, most Alaska customer classes have experienced price decreases for natural gas service. These trends have been presented in Figure 2.1. In this figure, customer class retail prices are measured as average revenues (expressed in non-inflation adjusted, money-of-the-day dollars).

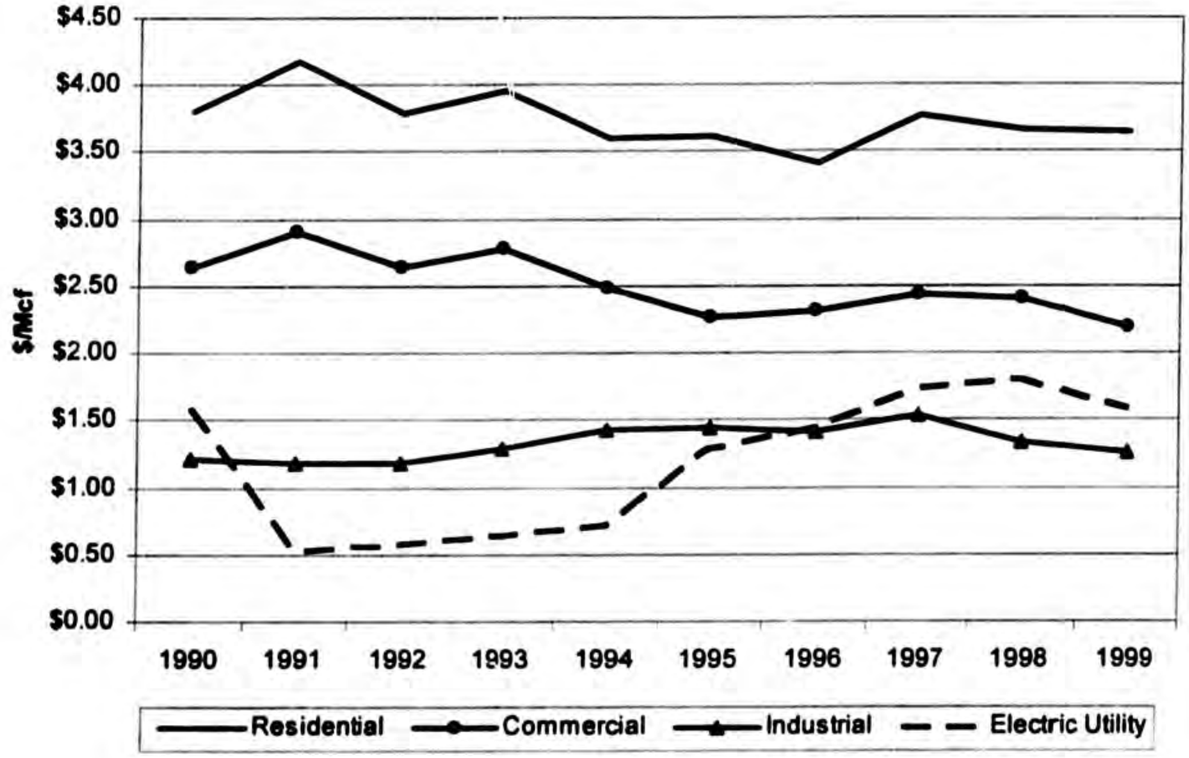

Figure 2.1: Recent Trends in Alaska Natural Gas Prices by Sector

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

As seen from the figure, residential rates tend to be the highest of all Alaska customer classes. Commercial rates are the next highest, with the differential between commercial and residential rates falling by close to 50 cents per Mcf over the past decade. Since 1990, the relative ranking of prices for electric utilities and industrial customers has shifted. Prior to 1996, electric utilities generally paid less on a Mcf basis for natural gas service than industrial customers. This changed in 1996, with electric utilities paying slightly higher rates. Since electric utilities in Alaska tend to sign longer term fuel agreements, this shift could reflect different contract terms and conditions.

Natural gas retail prices are usually composed of two parts: the base rate and the purchased gas acquisition (PGA) rate. The base rate covers the cost of providing service and return on, and of, investment for the local distribution company. The PGA, on the other hand, is the cost of obtaining natural gas, which is a pass-along to end-users. The different between the total retail rate and the PGA can be thought of as the cost of providing non-fuel related service. Figure 2.2 presents the relative changes of residential retail prices and PGA adjustments for Enstar, the state's largest natural gas local distribution company.

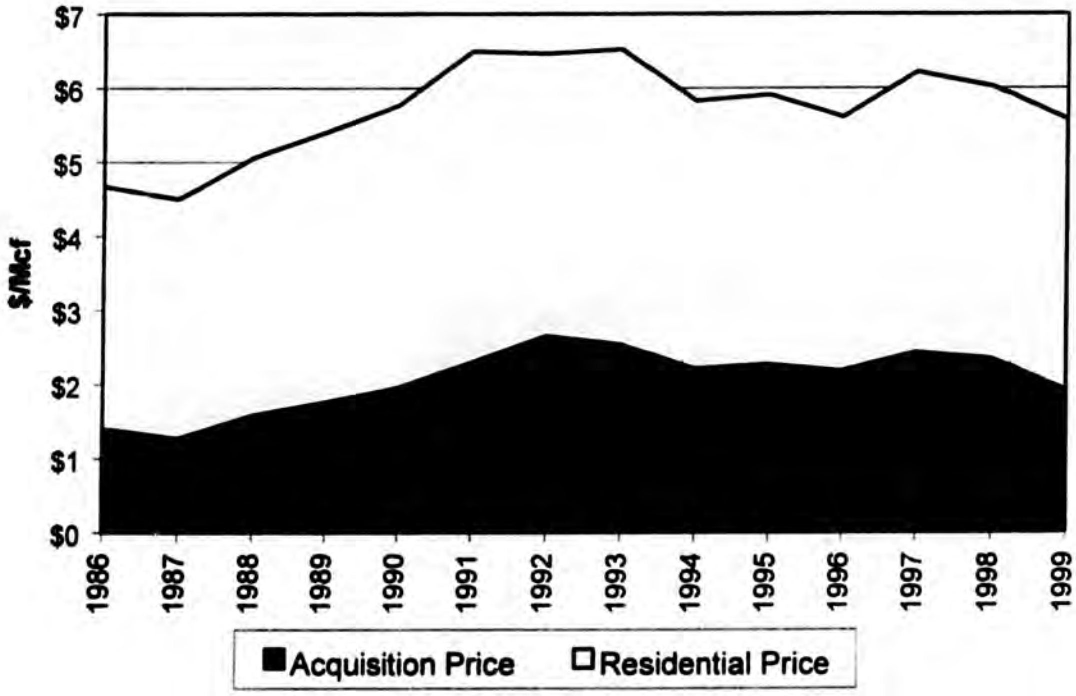

Figure 2.2: Residential Retail Rates and Gas Acquisition Costs -- Enstar

Source: U.S. Department of Energy, EIA Form 176.

As seen in Figure 2.2, retail prices have, in general, followed shifts in gas acquisition charges paid by LDCs. The lower area highlighted in the figure represents the acquisition cost of the LDC, while the higher area represents the total residential price. The difference between these two areas represents the non-fuel distribution charges associated with the residential rate, which has been relatively stable at an average of $1.50 per Mcf over the past five years.

A comparable analysis has been provided in Figure 2.3. This figure compares residential markups,[2] commercial markups, and the differentials between gas acquisition charges and wellhead prices. All three series tend to move in the same direction indicated that most of the recent trends in retail rates are driven by the cost of gas that is incurred by LDCs. The graph presented in Figure 2.3 compares relative price markups for Enstar.

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[2]Residential mark-ups are defined as the residential retail price less the overall system gas acquisition cost. Commercial mark-ups are simply the commercial retail price less the same gas acquisition cost.

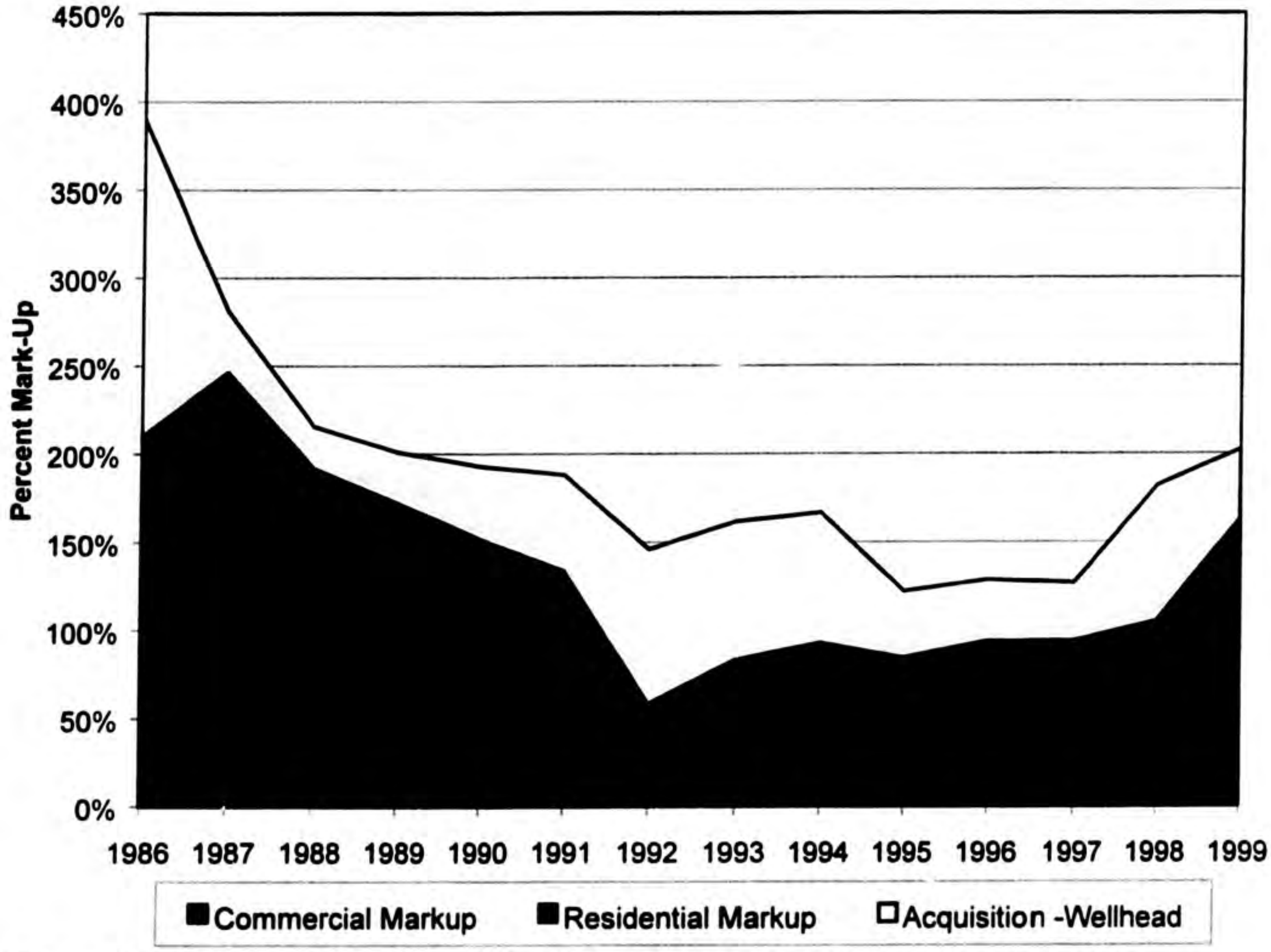

Figure 2.3: Comparison of Residential, Commercial, and Wellhead to PGA Markups – Enstar

Source: U.S. Department of Energy, EIA Form 176.

2.3: Recent Trends in Natural Gas Customer Growth

Over the past 10 years, residential natural gas customer growth has been relatively strong. Figure 2.4 presents annual number of residential and commercial customers while Figure 2.5 presents the annual number of industrial customers. Residential customer growth over the past decade has averaged at an annual rate of about 2.5 percent, while commercial customers have grown at an annual average rate of 1.3 percent. Industrial customer growth has been very limited, and over the past decade has hovered between 8 and 11 customers.

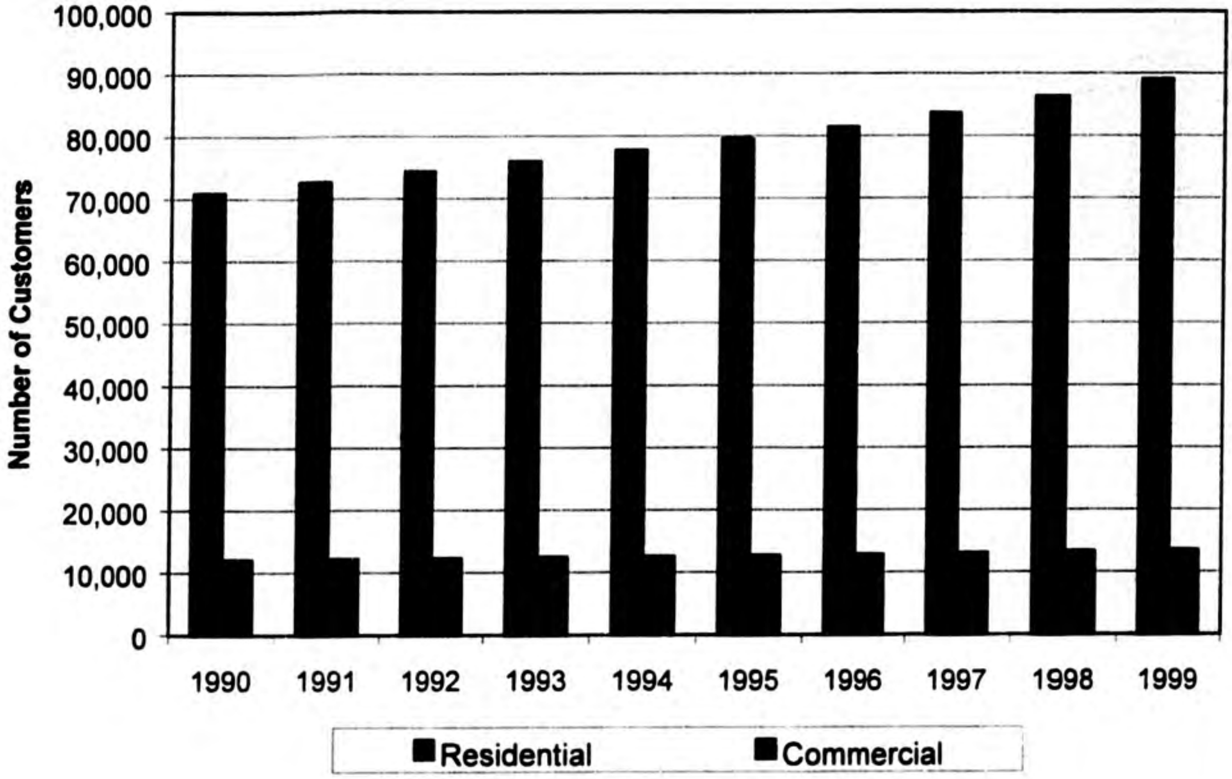

Figure 2.4: Annual Number of Residential and Commercial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

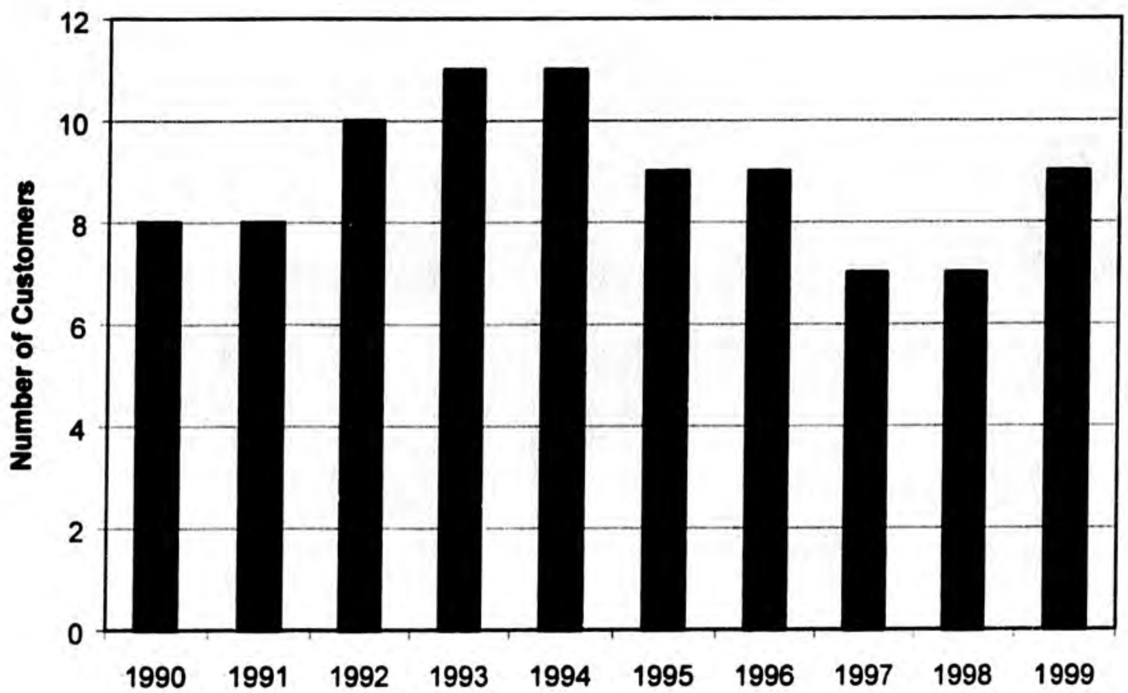

Figure 2.5: Annual Number of Industrial Customers

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual.*

2.4: Recent Trends in Natural Gas Usage

Industrial customers are the largest users of Alaska natural gas. Total industrial natural gas usage averaged around 73 Bcf annually during the past decade. Usage for these customers took a decided dip between 1996 and 1998, but has rebounded since that time. The same trend is noticeable for electric utility customers of natural gas who averaged about 30 Bcf per year over the past decade. Both customer classes have tended to have relatively flat usage growth throughout the 1990s.

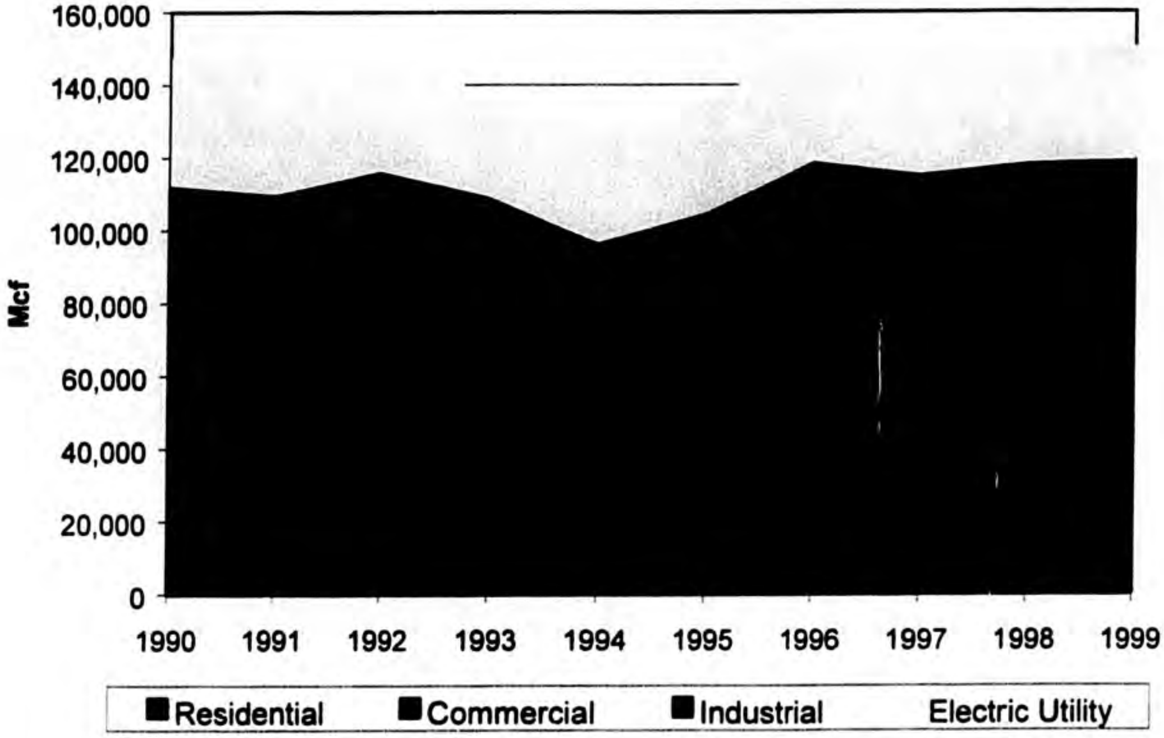

Figure 2.6: Recent Trends in Alaska Natural Gas Usage (Annual Mcf)

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Residential and commercial customers, have both smaller, and more stable usage patterns than their larger industrial and electric utility counterparts. Over the past decade, residential usage has grown by an annual average rate of 2.8 percent, while commercial usage has grown by 2.7 percent over the same time period. In recent times, usage for residential customers has averaged around 15 Bcf per year, while commercial usage has averaged about 24 Bcf per year.

Figure 2.7 presents recent trends in residential average usage. As noted in earlier graphs, residential customer growth has been relatively steady and consistent over the past decade. Usage, on the other hand, has moved sporadically. In some years usage has been up dramatically, like the 12 percent increase in 1998-1999, while in other years it has fallen, like the 6.3 percent decrease in 1996-1997. As a consequence, average usage has tended to move in fits and spurts.

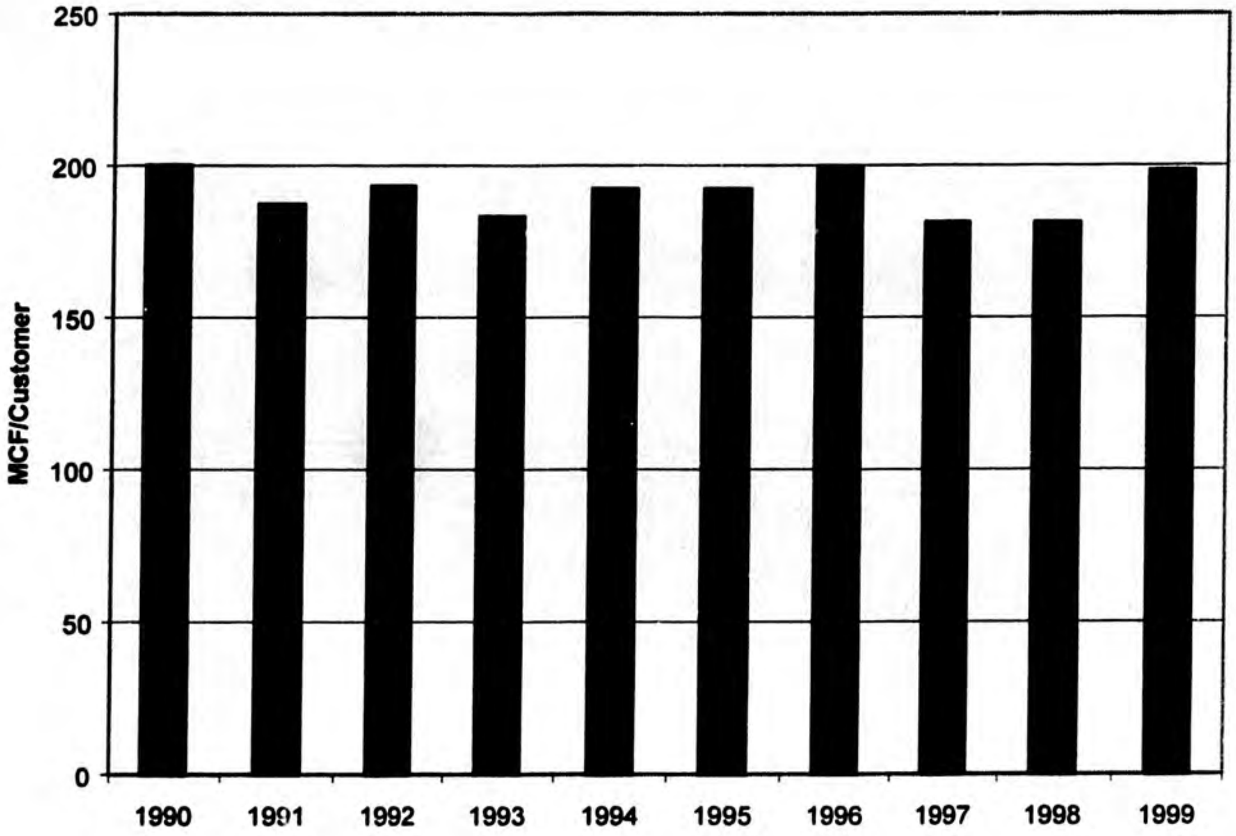

Figure 2.7: Residential Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

Figure 2.8 presents average usage for commercial customers. Unlike the recent trends with residential customers, commercial customers have exhibit more stable average usage growth over the past decade. Average usage for commercial customers has grown at an average rate of about 1.4 percent over the past 10 years.

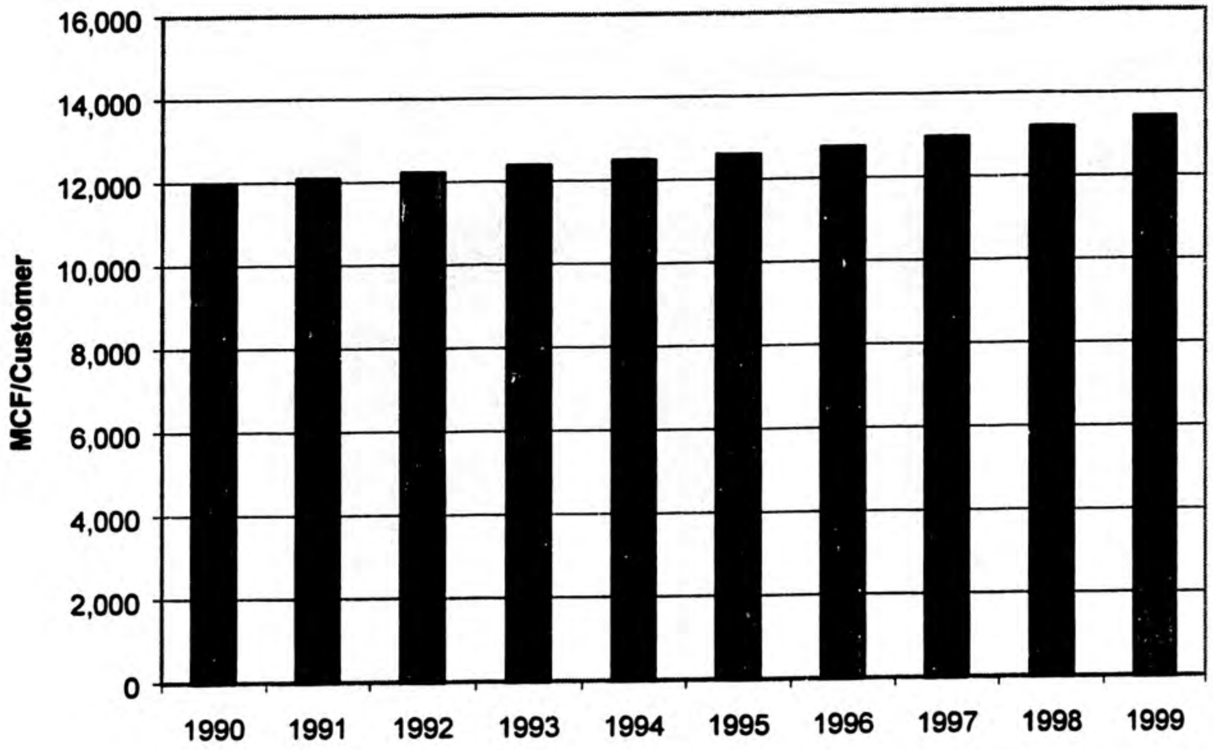

Figure 2.8: Commercial Average Usage

Source: US Department of Energy, Energy Information Administration. *Natural Gas Annual*

CHAPTER 3: REVIEW OF DEMAND AND SUPPLY MODELING LITERATURE

This chapter of our report presents an overview of general issues associated with demand modeling, an overview of various different approaches to modeling natural gas demand, as well as an overview of the methods that we will employ in the development of our baseline natural gas demand models.

For the more general reader, this chapter of the report can be skipped without loss of context of the overall study. For those readers looking for additional detail on the modeling of natural gas demand, Appendix 2 was prepared for this purpose.

3.1: General Issues in Modeling Demand

Modeling natural gas demand and supply in local, regional, and national markets is important for a number of reasons. These models give researchers and other market observers information about the structure and composition of demand and supply. Futhermore, the results of these models inform researchers about the magnitude of future demand and its sensitivity to key determinants such as energy prices and income. This information is used to understand:

- Past trends and the determinants of realized demand and supply;
- The responsiveness of demand and supply to changes in its important determinants; and
- Future demand and supply under different assumptions about future scenarios.

From its most basic perspective, the relationships of demand and supply can be summarized as:

- Demand is a function of prices, income, and tastes and preferences; and
- Supply is a function of input factor prices, technology, and other factors.

Transforming these theoretical relationships into measurable statistical equations is difficult. The way empirical data is measured may not conform with the structure implied by theory. For instance, theory suggests that the quantity demanded is a function of prices and other important variables. Yet the "appropriate" prices may not be readily available or easily generated. Furthermore, in many energy pricing situations, prices are set in a multitude of different manners (i.e, average rates, two-part tariffs, increasing block rates, decreasing block rates, time of day and seasonal pricing, etc.) Data measurement problems in terms of definition, sampling, and aggregation complicate model specification and statistical estimation.

Most quantitative analyses of supply and demand are broken into two types: cross sectional and time series. Cross sectional models typically examine causal relationships across a collection of variables over a fixed period of time. As suggested by the nomenclature, time series models focus on time dependency.

Cross sectional models are used to examine existing determinants of either supply and demand. These models are structural in nature since they attempt to flush out causality and typicially employ many different determinants of demand or supply as independent (explanatory) variables. Thus, a model of the industrial demand for energy, could consider a number of different explanatory factors that include economic characteristics (i.e., relative energy prices, output levels, etc.) and technical characteristics of the facilities (i.e., number of boilers, fuel switching abilities, heat to power ratios, etc.).

Cross sectional models provide useful information on the relative statistical importance of these variables at a given period of time but are less useful in estimating how relationships change over time. Thus, their ability to serve as a springboard for forecasting is limited. In addition, these types of approaches usually require detailed disaggregate information (usually at the firm or production or consumption unit level), that can be difficult to acquire, particularly for independent research.

Time series models, on the other hand, are more useful in examining the dynamic determinants of demand or supply. The advantage of time series models is that they can convey information about how supply or demand relationships have varied historically, and where particular "structural breaks" in certain trends have occurred. These models are equally useful as a starting point for forecasting since most forecasts are developed from historical trend relationships. Their disadvantage is that data availability usually limits the range of the determinants measuring the supply or demand relationship.

Another consideration in time series models is that they can be developed in two different fashions. The first is traditionally referred to as a "structural econometric" approach while the second is commonly referred to more generally as a "time series" approach.[1] The structural econometric approach is concerned with the estimation of relationships suggested by economic theory across time. For instance, in demand analysis we might look at the relationship of energy demand relative to prices, income, weather, and other relevant variables. Such models serve two purposes. First, they allow economic hypotheses to be tested

[1]A seminal text on the econometric analysis of time series is Andrew Harvey. (1991) *The Econometric Analysis of Time Series*. Second Edition. Cambridge, Massachusetts: The MIT Press.

empirically.[2] Second, they provide a framework for making rational and consistent predictions (i.e., forecasting).

Pure time series approaches, on the other hand, are more generalized trend analyses based on statistical extrapolation techniques rather than theoretic relationships. Traditional time series analysis forecasts the time path of a variable with models that explicitly contain stochastic components to measure their dynamic relationships.[3] Difference equations, such as moving averages of either the error term, the dependent variable, or both, are at the core of these types of approaches. Uncovering the dynamic path of a series improves forecasts since the measurable components of the series can be extrapolated into the future.

There is a third modeling option known as cross-sectional/time series models. These approaches, as the name suggests, merge these two approaches to maximize the relative benefits, and minimize their relative shortcomings. The problem is that, in many instances, pooled cross sectional approaches require relatively advanced statistical techniques, as well as being very data intensive.

Another important question in measuring either supply or demand relationships is the determination of which of the two general approaches should be facilitated. In many instances, this is usually done by purpose of the study as well as the practical limitations of the data. If a researcher is interested in examining the price elasticity of the residential demand for natural gas, then a cross sectional analysis of account-specific information would be a useful approach. However, many researchers outside of natural gas local distribution companies usually have limited or no access to this type of information. The US Department of Energy, however, does report aggregate information by customer class across time, thus some type of time series approach may be more readily facilitated.

Lastly, determining the appropriateness of a particular model is an important specification issue. Often, applied modeling can emphasize goodness of fit of a particular model to the expense of all other considerations. However, more balanced consideration should include such factors as:

- *Consistency with theory.* Ensuring the quantitative estimates of model parameters exhibit mathematical signs and magnitudes consistent with economic theory (i.e., negative price elasticities and positive income elasticities).

- *Consistency with goals.* Obviously specifying and measuring time series models can be more important for forecasting goals, while cross sectional models can be more important for research

[2] *Ibid.*, 1.

[3] Walter Enders. (1995). *Applied Econometric Time Series.* New York: John Wiley and Sons, Inc.

questions related to the relative importance of structural determinants.

- *Parsimony*. Ensuring that models that are not overly specified and are straightforward.

- *Robustness*. Ensuring that models are not overly dependent upon unique specifications or time periods under consideration.

The modeling of supply and demand for natural gas builds on a broad arena of industry-based energy modeling. Natural gas supply modeling, for instance, is conditioned by a number of earlier studies in petroleum supply modeling. Natural gas demand modeling is heavily linked to the electric power industry.

The study of natural gas supply and demand also is linked to technical-engineering models, sociological models, economic models, and hybrid models that employ varying combinations of these factors. Econometric analysis, as opposed to time series approaches, has dominated much of the supply and demand modeling literature. The preference for these econometric approaches is probably to be expected. First, econometric approaches are useful in explaining the changes in natural gas disposition that result from general changes in the industry—particularly, the response to shifts in price and the general degree of price volatility in the industry since the early 1970s.

Second, while data measurement and implementation is still a challenge in the analysis of energy demand and supply, accessibility of the information has improved considerably. Reporting requirements and data collection developed at the U.S. Department of Energy gives researchers a consistent source of information to examine and corroborate existing studies in the energy industry. With the advent of the internet, the electronic availability of the information enhances the ability to concentrated important efforts in understanding empirical relationships rather than collecting basic information on industry disposition and trends.

Third, over the past twenty years, econometric approaches have become more accessible to industry practitioners as software packages have reduced the programming work needed to do the earlier models by an exceptional order of magnitude. Today, many readily available statistical packages can estimate either supply or demand models in matter of seconds. The reduction in computational difficulty has helped facilitate the development of a large body of analysis related to important energy relationships.

3.2: Empirical Studies of Natural Gas Demand

One of the pioneering authors in demand modeling, for many sectors that go beyond just energy demand modeling, is Hendrick S. Houthakker. His studies in energy demand modeling were extensive, and provided some of the first insights into the importance many structural determinants of energy demand. His work is still commonly cited in principal textbooks of microeconomic theory.[4] Houthakker's work in energy demand modeling, developed in the early 1950s, was a basis for his broader work in overall demand modeling.[5]

On the more practical side, there is a considerable amount of work in natural gas demand modeling that rests outside the traditional academic literature. This work is associated with the modeling conducted within the process of regulated natural gas distribution companies, commonly referred to as local distribution companies or LDCs. These LDCs use forecasting models for internal planning process in meeting supply (commodity) and capacity (transportation and storage) needs.[6]

Many of the theoretic developments of natural gas demand modeling have come from the academic literature. A good portion of this analysis has focused on residential, and to a lesser degree commercial, demand for natural gas. These models are primarily econometric in nature since the purpose of many are to get accurate estimates of price, income, and weather related sensitivities of natural gas demand.

Another practical consideration in reviewing the literature on natural gas modeling is its relationship with its sister energy industry, electricity. A number of the earliest works in energy demand concentrated in the area of electricity (i.e., Houthakker) and not natural gas. It seems likely that one of the initial reasons for more comprehensive development of demand modeling in the electricity industry is associated with its greater degree of data availability. Thus, any survey of natural gas demand modeling will have to include some references to the development in the power industry as well.

There are a number of surveys in the literature dedicated to natural gas and energy demand modeling in general. One of the earliest and most comprehensive surveys of energy demand modeling was prepared by Douglas R. Bohi for the Electric Power Research Institute (EPRI).[7] While the overall

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[4] Hendrick S. Houthakker and Lester D. Taylor. (1966). *Consumer Demand in the United States, 1929-1970*. Cambridge: Harvard University Press.

[5] For instance see: Hendrick S. Houthakker. (1951), "Some Calculations of Electricity Consumption in Great Britain." *Journal of the Royal Statistical Society*. Series A, 114, Part III, 351-71.

[6] A general primer on the role of natural gas demand forecasting and how it relates to overall LDC planning can be found in: Charles Goldman, et al. (1993). *Primer on Gas Integrated Resource Planning*. Berkeley, California: Lawrence Berkeley Laboratories.

[7] Douglas R. Bohi. *Price Elasticities of Demand for Energy: Evaluating the Estimates.* Palo Alto: Electric Power Research Institute.

purpose of the study was to examine price elasticities, the study is an excellent overview of demand modeling since price elasticities are usually outputs derived from an overall analysis of demand determinants. An update to this study was prepared in 1984 by Bohi and Zimmerman.[8]

A more recent study, which emphasizes the development of the literature in residential energy demand modeling, was presented by Reinhard Madlener.[9] In the survey, Madlener attempts to update the earlier Bohi work, as well as breaking the existing econometric literature into a number of useful different categories. These include studies associated with log-linear functional forms, transcendental logarithmic (translog) functional forms, qualitative choice models (also know as discrete choice models), household production theory (end-use modeling), and pooled time series-cross sectional models.

Madlener presents a table associated with each of these types of models. This table has been replicated, with additional comments and analysis, in Appendix Table A.2.1. The following discussion provides a brief overview of the literature along the lines developed by Madlener. A more detailed discussion of each of the general demand modeling methods is provided in Appendix 2.

3.2.1: Log-Linear and Double Log Models: The typical log-linear and double log models are relatively straightforward and tend to be the model of choice, particularly for industry practitioners. The benefit of the log-linear and double log form is that coefficients can easily be translated into elasticities. In the double log form, the parameter for price is interpreted as the price elasticity of demand, while the parameter estimate for income can be interpreted as the income elasticity of demand.

3.2.2: Transcendental Logarithmic (Translog) Models: Translog models became popular in the 1970s with the advent of the Christensen, et al. (1973) approach of estimating industrial production, and later with cost functions and consumer-utility functions.[10] This approach was applied to the electric power

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[8]Douglas R. Bohi and Martin B. Zimmerman. (1984). "An Update on Econometric Studies of Energy Demand Behavior." *Annual Review of Energy*. 9: 105-54. The Bohi and Zimmerman (1984) elasticity estimates vary considerably but two general conclusions emerge. First, price elasticities for residential tend to be under 1.0. Two, elasticities are higher (in absolute value) as the analysis moves residential to commercial, to industrial customers. Elasticities increase in absolute value since larger customers tend to have more fuel substitution opportunities.

[9]Reinhard Madlener. (1996). Econometric Analysis of Residential Energy Demand: A Survey. *Journal of Energy Literature*. 2:3-32.

[10]Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1973) "Transcendental Logarithmic Production Frontiers." *The Review of Economics and Statistics*. 55:28-45. Laurits Christensen, Dale Jorgenson, and Lawrence Lau. (1975) "Transcendental Logarithmic Utility Functions." *The American Economic Review* 65: 367-83.

industry in 1976, and has become commonplace for a considerable amount of the energy economics research.[11]

The translog specification is a quadratic function with its elements expressed in terms of their natural logarithm. This specification is a second order approximation around a given point for the Cobb-Douglas production function. The Cobb-Douglas production function allows declining marginal products for all inputs, and also assumes that opportunities exist to substitute inputs in production without gaining or losing output.

The advantage of the translog approach is that it provides some structure on the assumed production/utility function under investigation. The parameters associated with the own and cross-price terms provide estimates of own and cross-price elasticities of demand. In additional, the translog approach allows for a more flexible functional form that enables empirical validation of utility-function properties. For example, while the Cobb Douglas function imposes unitary elasticity of substitution among inputs, the translog enables the data to determine the degree of input substitutability. In general, this flexible functional form enables the data to determine if the assumed functional form is correct, and imposes fewer a-priori restrictions on model specification.

The approach, however, is not without its potential problems. First, translog models require a significant amount of information, which can be difficult to attain. Second, these models can be relatively difficult to apply and interpret. This has led many practitioners to steer clear of these approaches. Third, the parameter estimates in many instances do not tend to be robust or stable, and can lead to some erroneous results. Last, the model tends to lend itself better to cross-sectional analyses, and, as a result, is not a very useful tool for forecasting.

3.2.3: Qualitative Choice and End Use Models: Most demand models prior to the early to mid 1970s, and even to this day, use continuous variables to measure energy consumption. There are equally interesting empirical applications, however, that examine not how much of a particular resource is utilized, but whether or not that resource is utilized at all. Such approaches are discrete in nature and have led to the development of qualitative choice, or discrete choice models of energy usage.

Discrete choice models are those in which the dependent variable is a discrete variable. The simplest application is one where the dependent variable is a binary choice variable that represents a simple positive or negative response. The dependent variable takes the value 1 if the choice is made, and 0 if the choice is not made. Independent variables are then used to estimate parameters influencing that choice.

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[11] Laurits Christensen and William Greene. (1976). "Economies of Scale in U.S. Electric Power Generation." *Journal of Political Economy*. 84 (4): 655-76.

Discrete choice models can be powerful tools to examine individual customer choice behavior and the factors influencing those decisions. Sensitivities, developed through the calculation of odds ratio statistics, can then be derived. These odds ratio statistics give some indication on how the probability of making a particular discrete energy consumption decision change as the independent variables change. In some natural gas and energy end use applications, these models provide interesting information on appliance usage and potential changes in penetration rates resulting from shifts in natural gas prices.

These qualitative based models, however, usually require specific and relatively comprehensive end use information. Typically, data used in these types of analyses are from individual consumer surveys. Thus, such empirical approaches are limited, if customer, or decision making unit information is not available. In addition, these types of models can tend to be more static in nature making it difficult to use for long forecasting and trend analysis.

3.3: Methods and Data Used to Develop the Baseline Demand Model

As noted above, there are a number of empirical modeling techniques that have been facilitated in the literature. However, one of the most common and successful approaches for examining natural gas demand are the log-linear and double log models first developed in the 1960s. Our baseline models of natural gas demand are based upon those approaches. There are a number of advantages associated with the traditional double-log models. These include:

- They are straightforward approaches that are parsimonious and easier to implement;

- They are general models that are applicable to a wide range of data;

- In the absence of detailed, account specific survey data, these models serve as the best approach for fitting demand curves for the broad customer classes we are examining (i.e., residential, commercial, and industrial);

- The majority of the past academic and trade literature has been based upon these approaches; and

- These approaches have the advantage of providing considerable descriptive information in addition for being good tools for developing forecasts.

This study has developed baseline models for each major consuming sector in Alaska's natural gas markets. These include residential, commercial, industrial, and electric utility.

In looking at natural gas demand, the goal was to find a consistent source of information that was documentable and widely accepted as authoritative. Based upon our past experience, we have found that the information provided by the Department of Energy, Energy Information Administration (EIA) provides the most comprehensive, and documentable source of information for natural gas usage. This information is compiled annual by the EIA in EIA Form 176. A discussion of EIA Form 176, and the data collected in this annual survey.

The descriptive statistics for all the variables that were utilized in the baseline demand models are presented in Table 3.1.

Table 3.1: Descriptive Statistics for Baseline Model Dataset (1986 – 1999)

Variable Name	Number of Observations	Mean	Standard Deviation	Minimum	Maximum
Residential NG Usage, Mcf/yr	14	14,364,367	1,561,998	12,090,998	17,633,864
Commercial NG Usage, Mcf/yr	14	23,010,401	3,015,288	20,002,655	27,667,159
Industrial NG Usage, Mcf/yr	14	70,717,120	7,004,328	59,341,410	80,937,950
Electric Utilities NG Usage, Mcf/yr	15	31,306,872	2,323,032	28,024,737	35,569,901
Number of Residential Customers	14	75,892	7,242	65,953	88,924
Number of Commercial Customers	14	12,290	643	11,243	13,409
Number of Industrial Customers	14	9.29	1.77	7.00	13.00
Average Revenue from Residential Customers (1999 $/Mcf)	14	4.20	0.42	3.58	4.88
Average Revenue from Commercial Customers (1999 $/Mcf)	14	2.91	0.45	2.18	3.51
Average Revenue from Industrial Customers (1999 $/Mcf)	14	1.38	0.16	0.99	1.58
Heating Degree Days at Fairbanks (Base 65 degrees F.)	14	13,605	802	12,244	15,142
Per Capita Income (1999 $)	14	27,383	713	25,966	28,629
Manufacturing Gross State Product (1999 $ MM)	14	1,226	199	684	1,457

Data Sources:	***Variables***
EIA-176 "Annual Gas Supply and Disposition Report", 1986-1999	Usage, number of customers, and average revenue for all customer classes except electric utilities.
EIA Electric Power Annual, 1986-2000	Industrial NG Usage
NOAA National Climatic Data Center website	Heating Degree Days
BEA website	Per Capita Income and Gross State Product

CHAPTER 4: BASELINE IN-STATE NATURAL GAS DEMAND FORECASTS

The results from our baseline in-state natural gas demand models are summarized in this chapter of the report. A more detailed description of the statistical models used in this forecast is presented in Appendix 3.

Our baseline in-state natural gas demand forecasts are developed under a set of "business as usual" assumptions. We have forecast in-state natural gas demand for each major customer class to the year 2020 under the assumption that trends over the past five years will be maintained into the forecast period. In the following chapter of our report, we will examine the sensitivities of these forecasts to changes in the underlying assumptions associated with these past trends.

We use a three-fold approach to forecast baseline natural gas demand. First, we estimate econometric time-series models. Natural gas usage in each major sector (residential, commercial, industrial and electric power generation) is the dependent variable to be explained. Explanatory variables include personal income, gross state product, prices, weather, and other important determinants of natural gas demand. The magnitude of these impacts (i.e., elasticities) and their statistical properties are presented in Appendix 3.

Second, we estimate traditional time series trend models. The time series approach extrapolates the underlying trend in natural gas usage over time for each sector. This approach is useful because it is simple to apply and straight forward to interpret. The detailed statistical results, along with a discussion of each of these types of methods, are also presented in Appendix 3.

Third, we average the results of the separate econometric and time-series trend models described above to form a combined forecast. This approach helps pick up the peaks, valleys, and underlying trends in data and is a useful tool for forecasting. The forecast information from each of these approaches has been provided in tables in this chapter of our report. The detailed results from each of the approaches, and their related statistical output, have been provided in Appendix 3.

4.1: Residential Baseline Forecast

The results from our residential in-state demand model are presented in Table 4.1.

Table 4.1: Residential Baseline Demand Forecast (2000-2020)

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1986	12,090,998	12,198,225		12,198,225
1987	12,256,280	12,499,708	12,406,056	12,452,882
1988	12,529,140	12,808,641	12,540,566	12,674,604
1989	13,588,767	13,125,210	13,655,173	13,390,191
1990	14,164,886	13,449,602	14,151,008	13,800,305
1991	13,561,759	13,782,013	13,445,474	13,613,744
1992	14,349,944	14,122,639	14,537,644	14,330,141
1993	13,857,568	14,471,683	13,585,834	14,028,759
1994	14,895,199	14,829,354	14,873,428	14,851,391
1995	15,230,778	15,195,865	14,947,440	15,071,653
1996	16,179,216	15,571,435	15,908,103	15,739,769
1997	15,146,116	15,956,287	15,415,471	15,685,879
1998	15,616,617	16,350,651	15,926,681	16,138,666
1999	17,633,864	16,754,761	17,594,905	17,174,833
2000	--	17,168,859	17,867,599	17,518,229
2001	--	17,593,192	18,087,424	17,840,308
2002	--	18,028,012	18,310,890	18,169,451
2003	--	18,473,578	18,537,190	18,505,384
2004	--	18,930,157	18,766,257	18,848,207
2005	--	19,398,021	18,998,187	19,198,104
2006	--	19,877,448	19,232,955	19,555,201
2007	--	20,368,724	19,470,649	19,919,686
2008	--	20,872,142	19,711,255	20,291,698
2009	--	21,388,002	19,954,860	20,671,431
2010	--	21,916,612	20,201,450	21,059,031
2011	--	22,458,286	20,451,117	21,454,701
2012	--	23,013,349	20,703,866	21,858,607
2013	--	23,582,129	20,959,711	22,270,920
2014	--	24,164,967	21,218,750	22,691,858
2015	--	24,762,210	21,480,954	23,121,582
2016	--	25,374,215	21,746,434	23,560,325
2017	--	26,001,345	22,015,159	24,008,252
2018	--	26,643,974	22,287,242	24,465,608
2019	--	27,302,487	22,562,653	24,932,570
2020	--	27,977,274	22,841,498	25,409,386
Root Mean Square Error		0.01753		

The results from our in-state residential demand forecast show relatively healthy growth in natural gas usage from the existing residential customer base in Alaska. Overall, we forecast that natural gas demand will grow at an annual average rate of about 1.8 to 1.9 percent per year, under baseline conditions, until 2020. Baseline conditions included a half percent increase per year in per capita income and zero percent increase in real retail residential natural gas prices. In the next chapter of our report, we examine the sensitivity of this forecast to changes in those underlying assumptions.

Under our baseline forecast, residential in-state natural gas usage will grow from a 1999 level of 17 Bcf to 25 Bcf by the year 2020. A graph of this longer run trend is presented below in Figure 4.1

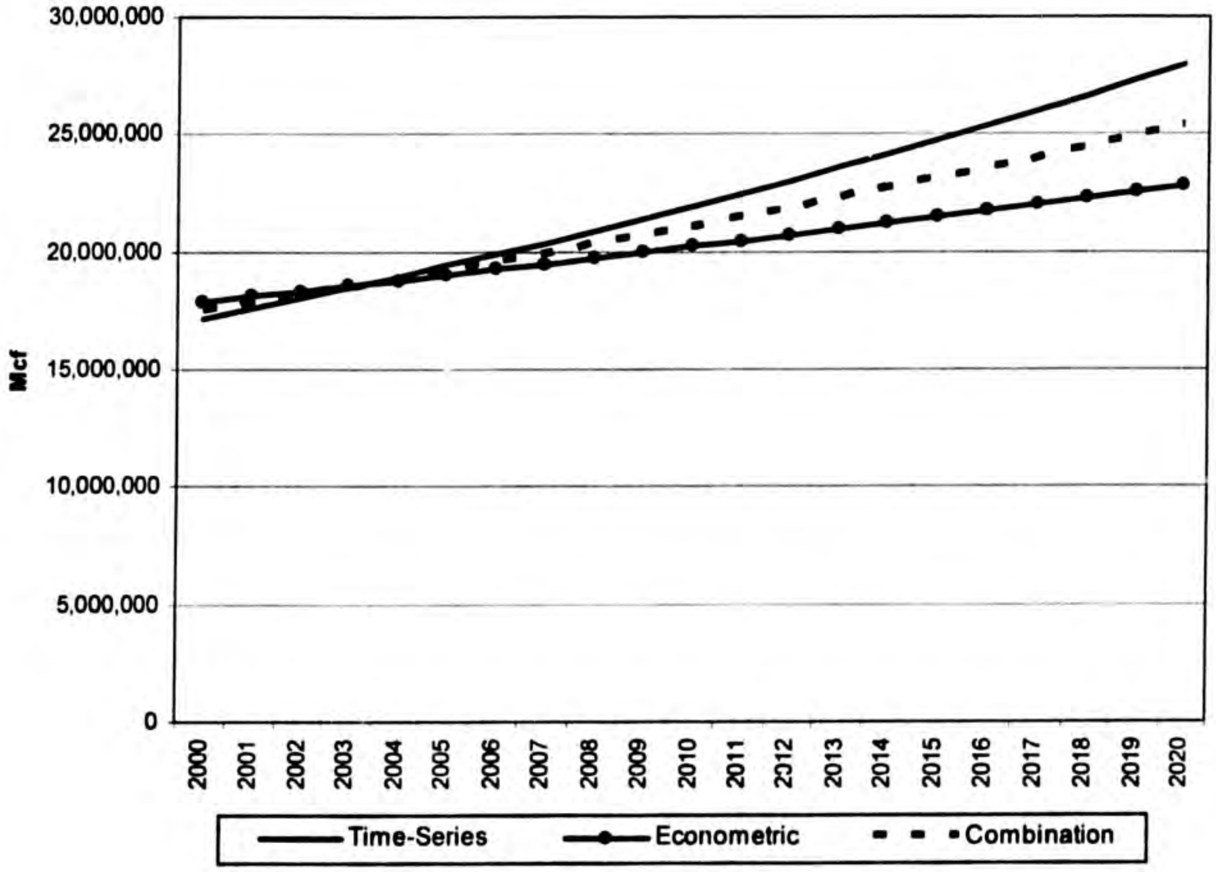

Figure 4.1: Residential Baseline Demand Forecast (2000-2020)

4.2: Commercial Baseline Forecast

Our commercial in-state demand forecast is presented in Table 4.2. A graph of these longer run trends is presented in Figure 4.2. Under business as usual conditions, we forecast long-term commercial natural gas usage to grow at a relatively moderate pace. The average annual rate of growth over the forecast period varies from a high of 1.7 percent in the 2003-2004 time period, to around 1.0 percent or less for the period 2010 onwards.

Commercial natural gas usage is forecast to grow from a 1999 level of 28 Bcf to a 2020 forecast level of 35 Bcf. This forecast assumes zero percent real changes in commercial natural gas prices and a half percent annual increase in per capita income. Deviations from this forecast assumption, and its implications for commercial natural gas usage, will be considered in the following chapter.

Table 4.2: Commercial Baseline Demand Forecast (2000-2020)

Date	Actual Data (Mcf)	Predicted Time Series (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	20,874,011	20,872,099		20,872,099
1987	20,224,143	21,459,238		21,459,238
1988	20,842,041	20,808,703	20,952,886	20,880,795
1989	21,738,412	21,424,696	21,111,727	21,268,211
1990	21,621,850	22,320,431	21,608,730	21,964,580
1991	20,897,429	22,203,516	20,147,636	21,175,576
1992	21,299,274	21,477,732	20,996,129	21,236,931
1993	20,002,655	21,877,606	20,617,698	21,247,652
1994	20,697,859	20,580,149	22,079,885	21,330,017
1995	24,978,977	21,272,817	24,597,540	22,935,179
1996	27,314,942	25,553,385	27,507,854	26,530,620
1997	26,908,231	27,892,388	27,310,569	27,601,479
1998	27,078,631	27,486,776	25,963,527	26,725,151
1999	27,667,159	27,655,530	27,727,955	27,691,742
2000	--	28,242,988	28,890,145	28,566,567
2001	--	28,818,167	28,999,111	28,908,639
2002	--	29,392,686	29,012,758	29,202,722
2003	--	29,966,545	29,338,263	29,652,404
2004	--	30,539,746	29,796,778	30,168,262
2005	--	31,112,288	30,016,438	30,564,363
2006	--	31,684,173	29,997,933	30,841,053
2007	--	32,255,402	29,832,200	31,043,801
2008	--	32,825,975	29,696,295	31,261,135
2009	--	33,395,893	29,666,724	31,531,308
2010	--	33,965,156	29,738,479	31,851,818
2011	--	34,533,766	29,843,132	32,188,449
2012	--	35,101,723	29,920,323	32,511,023
2013	--	35,669,028	29,946,149	32,807,588
2014	--	36,235,682	29,937,088	33,086,385
2015	--	36,801,685	29,923,989	33,362,837
2016	--	37,367,038	29,929,179	33,648,108
2017	--	37,931,743	29,955,787	33,943,765
2018	--	38,495,799	29,993,163	34,244,481
2019	--	39,059,207	30,028,044	34,543,626
2020	--	39,621,969	30,053,513	34,837,741
Root Mean Square Error		0.04907		

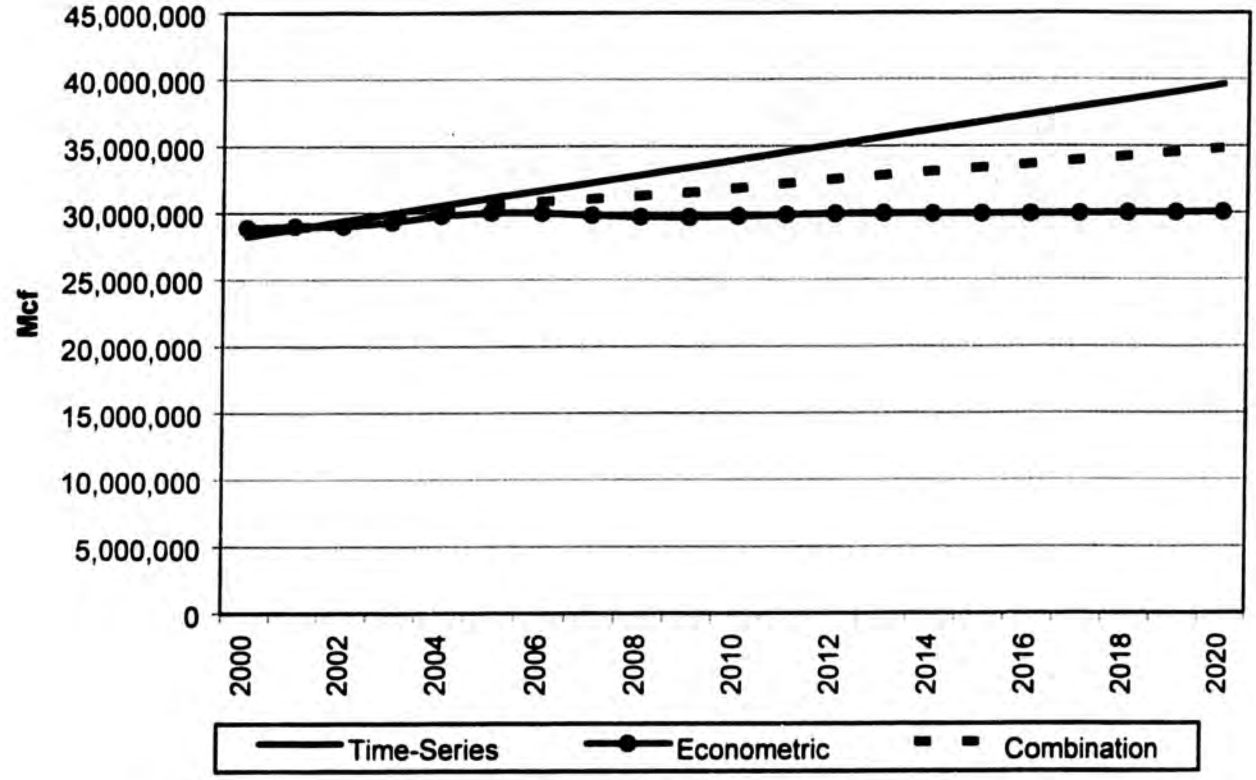

Figure 4.2: Commercial Baseline Demand Forecast (2000-2020)

4.3: Industrial Baseline Forecast

The results from the industrial in-state demand forecast are presented in Table 4.3. A graph of these longer run trends is presented in Figure 4.3. Our forecast assumes no greater than average growth in either the number of industrial customers, or their average usage. In addition, the baseline forecast assumes that current economic conditions and prices will hold relatively stable.

The average annual rate of growth for industrial natural gas usage over the forecast period is half of one percent. Industrial natural gas usage is forecast to grow from a 1999 level of 74 Bcf to a 2020 forecast level of 81 Bcf.

Given the relatively limited historic growth of industrial customers and usage, our forecast for future use is somewhat limited. We anticipate relatively constant growth, under baseline conditions, for industrial consumption. The addition of new industrial customers, however, could impact this forecast. In later chapters of this report, we examine the addition of new industries to Alaska and their implications for industrial and large volume customer usage. Sensitivities to our baseline forecast are also considered in the subsequent chapter.

Table 4.3: Industrial Baseline Demand Forecast (2000-2020)

Date	[illegible] (Mcf)	Predicted [illegible] (Mcf)	Predicted Econometric (Mcf)	Predicted Combination (Mcf)
1986	60,438,785	65,983,516	60,953,186	63,468,351
1987	67,467,489	66,711,763	70,090,074	68,400,918
1988	67,804,860	67,440,010	68,568,283	68,004,146
1989	59,341,410	68,168,256	73,723,646	70,945,951
1990	76,849,333	68,896,503	73,991,984	71,444,243
1991	75,637,177	69,624,750	74,064,575	71,844,662
1992	80,937,950	70,352,997	70,766,558	70,559,778
1993	75,794,979	71,081,244	69,802,135	70,441,689
1994	61,404,028	71,809,491	67,148,789	69,479,140
1995	64,977,342	72,537,737	71,056,370	71,797,053
1996	75,616,070	73,265,984	70,741,268	72,003,626
1997	73,599,299	73,994,231	71,538,235	72,766,233
1998	75,946,906	74,722,478	73,864,793	74,293,635
1999	74,224,056	75,450,725	70,231,772	72,841,248
2000	--	76,178,972	70,298,379	73,238,676
2001	--	76,907,218	70,365,044	73,636,131
2002	--	77,635,465	70,431,784	74,033,625
2003	--	78,363,712	70,498,588	74,431,150
2004	--	79,091,959	70,565,442	74,828,701
2005	--	79,820,206	70,632,373	75,226,290
2006	--	80,548,453	70,699,354	75,623,904
2007	--	81,276,699	70,766,412	76,021,556
2008	--	82,004,946	70,833,520	76,419,233
2009	--	82,733,193	70,900,705	76,816,949
2010	--	83,461,440	70,967,941	77,214,690
2011	--	84,189,687	71,035,253	77,612,470
2012	--	84,917,933	71,102,616	78,010,275
2013	--	85,646,180	71,170,057	78,408,118
2014	--	86,374,427	71,237,547	78,805,987
2015	--	87,102,674	71,305,116	79,203,895
2016	--	87,830,921	71,372,748	79,601,835
2017	--	88,559,168	71,440,431	79,999,800
2018	--	89,287,414	71,508,192	80,397,803
2019	--	90,015,661	71,576,003	80,795,832
2020	--	90,743,908	71,643,893	81,193,900
Root Mean Square Error		0.10026		

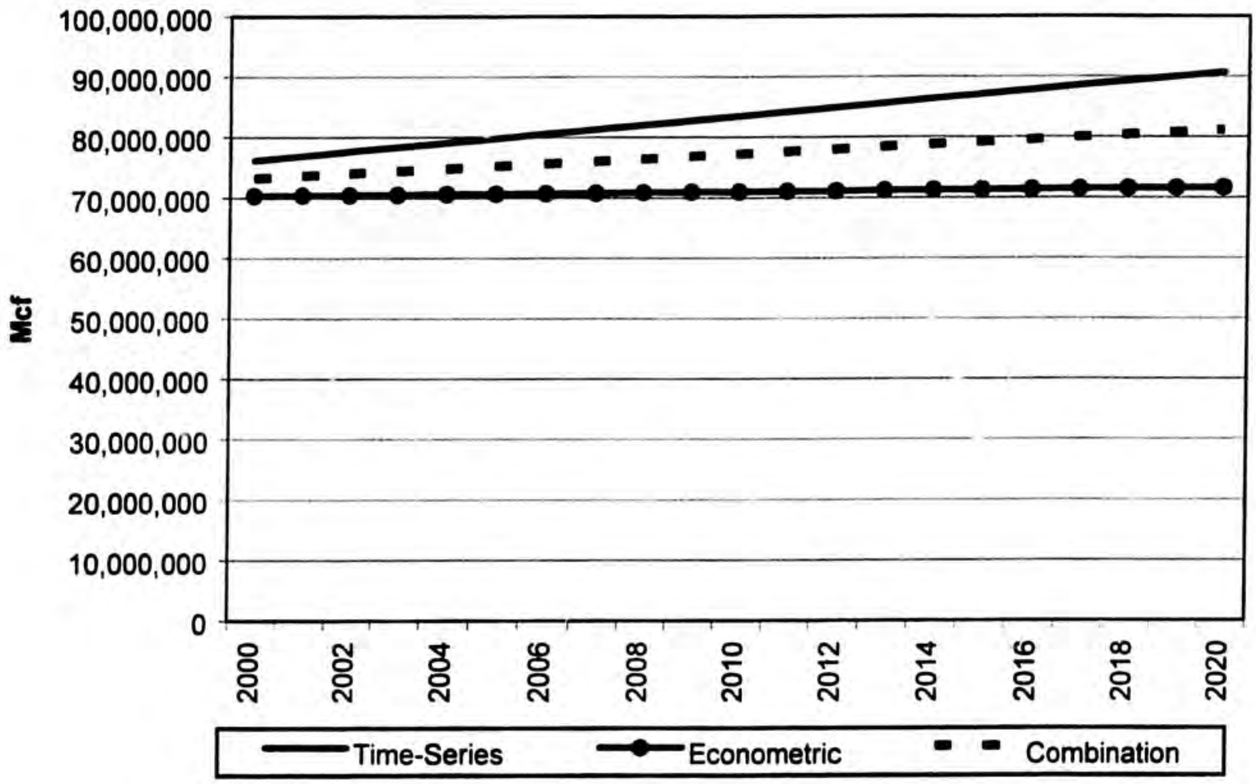

Figure 4.3: Industrial Baseline Demand Forecast (2000-2020)

4.4: Electric Utility Baseline Forecast

Our electric utility demand model was prepared in a manner different from than the other customer classes. First, we developed a long run trend forecast of power generation for Alaska's electric utilities. Second, we used the long run average trend for the gas-fired portion of the fuel mix to determine what proportion of that generation would come from gas-fired units. Third, we utilized the long run trend in power plant heat rates to estimate the future operating efficiency of total in-state power generation. This efficiency rating allows us to estimate the amount of natural gas that would be used for power generation under business as usual conditions. The forecast assumes that no new power generation facilities will be brought on line during the forecast period.

The results from the baseline electric utility demand forecast can be found in Table 4.4 while a graph of forecast electric utility natural gas usage has been provided in Figure 4.4. Baseline forecast electric utility usage is anticipated to grow from a level of 31 Bcf in 1999 to 41 Bcf by the year 2020. Sensitivities to this forecast are also considered in the following chapter of this report.

Table 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

Date	Actual Data (MCF)	Predicted Time-Series (Mcf)
1986	34,409,000	33,670,793
1987	30,530,000	31,234,619
1988	30,841,000	31,418,047
1989	32,746,000	32,312,018
1990	34,366,142	33,549,084
1991	31,329,758	32,470,899
1992	28,953,390	31,259,209
1993	28,024,737	27,867,045
1994	29,047,703	28,129,752
1995	29,808,627	28,661,334
1996	31,154,273	29,541,429
1997	33,509,748	31,362,521
1998	28,784,955	30,332,479
1999	30,527,841	32,409,397
2000	--	35,656,886
2001	--	32,949,652
2002	--	33,655,948
2003	--	34,119,758
2004	--	34,899,977
2005	--	35,406,497
2006	--	35,330,693
2007	--	35,813,699
2008	--	36,248,792
2009	--	36,677,751
2010	--	37,031,714
2011	--	37,353,364
2012	--	37,759,602
2013	--	38,149,476
2014	--	38,529,726
2015	--	38,899,627
2016	--	39,272,923
2017	--	39,657,179
2018	--	40,036,768
2019	--	40,414,176
2020	--	40,790,982

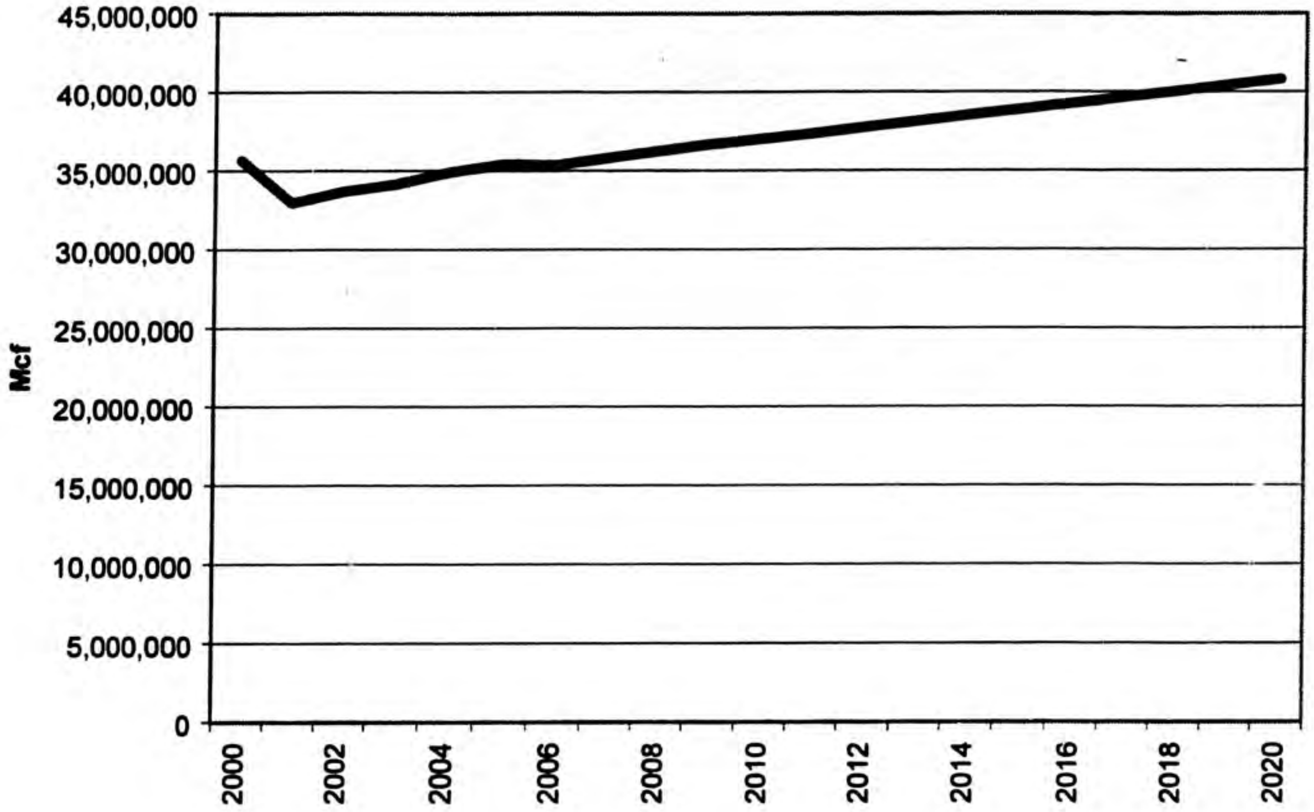

Figure 4.4: Electric Utility Baseline Demand Forecast (2000-2020)

4.5: Total Forecast Baseline In-State Demand

The aggregation of our baseline forecasts for each customer class can be summed to analyze total in-state demand until 2020 under business as usual conditions. The total baseline forecast is developed from our combination forecast. Total in-state, baseline usage, is presented in Table 4.5, while Figure 4.6 presents a graphical representation of annual baseline usage levels.

We anticipate that baseline forecast natural gas usage over the forecast period will grow by 27 Bcf. Residential customers will account for 24 percent of this growth, commercial customers will account for 22 percent of this growth, industrial customers will account for 22 percent of this growth, and electricity utilities will account for 32 percent of this growth. Sensitivities to the overall baseline forecast, and total forecast use by the year 2020, are explored in the next chapter of our report.

Table 4.5: Total In-State Baseline Demand Forecast (2000-2020)

[illegible]	Actual Data (Mcf)	Baseline (Mcf)
1986	127,812,794	130,209,467
1987	130,477,912	133,547,658
1988	132,017,041	132,977,591
1989	127,414,589	137,916,372
1990	147,002,211	140,758,213
1991	141,426,123	139,104,881
1992	145,540,558	137,386,059
1993	137,679,939	133,585,145
1994	126,044,789	133,790,300
1995	134,995,724	138,465,219
1996	150,264,501	143,815,443
1997	149,163,394	147,416,112
1998	147,427,109	147,489,931
1999	150,052,920	150,117,221
2000	--	154,980,358
2001	--	153,334,730
2002	--	155,061,745
2003	--	156,708,696
2004	--	158,745,146
2005	--	160,395,253
2006	--	161,350,851
2007	--	162,798,743
2008	--	164,220,859
2009	--	165,697,439
2010	--	167,157,253
2011	--	168,608,985
2012	--	170,139,507
2013	--	171,636,103
2014	--	173,113,957
2015	--	174,587,941
2016	--	176,083,191
2017	--	177,608,996
2018	--	179,144,660
2019	--	180,686,203
2020	--	182,232,010

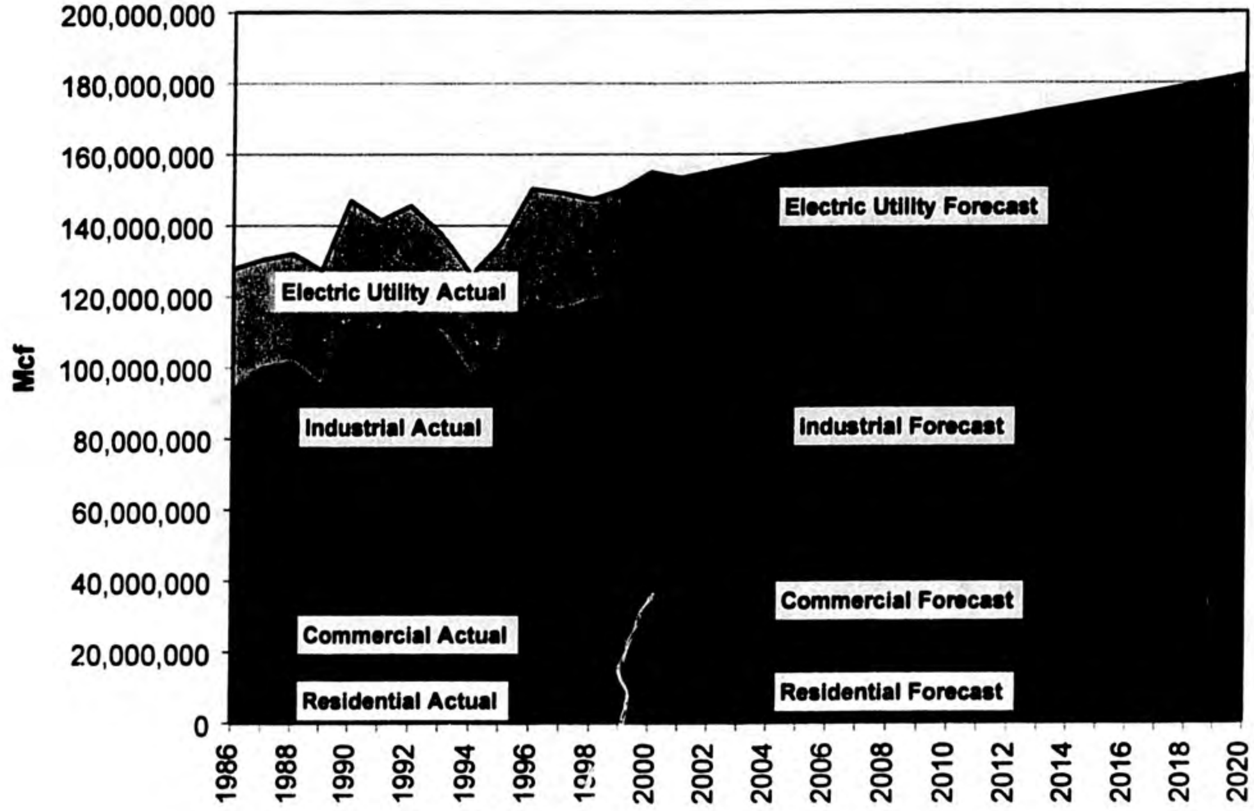

Figure 4.5: Total In-State Natural Gas Usage, Baseline Forecast (2000-2020)

CHAPTER 5: SENSITIVITY ANALYSIS OF BASELINE FORECAST

Our sensitivity analyses consisted of examining potential variations to our baseline forecast under varying economic assumptions. We examined two different scenario categories that could impact customer class natural gas usage: changes in prices; and changes in income. Specifically, each customer class baseline forecast was subject to the following scenarios:

(1) High Price Scenario: customer class natural gas prices were assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period.

(2) Low Price Scenario: customer class natural gas prices were assumed to decrease at an annual average rate of one percent, in real dollars, over the forecast period.

(3) High Income Scenario: state personal income was assumed to increase at an annual average rate of one percent, in real dollars, over the forecast period. Gross state manufacturing product, the income proxy used for our industrial models, is assumed to increase by one percent per year as well.

(4) Low Income Scenario: state personal income was assumed to grow at an average annual rate of zero percent, in real dollars, over the forecast period. Gross state manufacturing product was also assumes to be constant in real dollars.

Our baseline assumptions are comparable to estimates prepared by the University of Alaska's Institute for Economic and Social Research (ISER). The most recent ISER base case forecast anticipates statewide average personal income growth of around one percent until the year 2020. Low personal income growth scenarios used in the ISER models utilize a 0.62 percent average annual growth rate, while the high personal income growth scenario is 2.13.[1]

5.1: Residential Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that residential natural gas usage will increase from an annual level of approximately 17.5 Bcf in 2000 to a level of 21 Bcf in 2010. The increase at the end of the forecast period, 2020, is anticipated to be 25.4 Bcf. The total increase in residential natural gas usage over the ten year period is anticipated to be 3.5 Bcf and 7.9 Bcf for the twenty year period. This represents approximately a 20 percent increase over the ten year period

[1]Scott Goldsmith. *Economic Projects for Alaska and the Southern Railbelt: 2000-2025.* Anchorage: Institute of Social and Economic Research, October 3, 2001. Pages 2, 47, and 65.

and 45 percent increase over the twenty year period. The annual average rate of growth under the baseline forecast is 1.8 percent.

As noted earlier, we subjected each of our customer class forecasts to a number of sensitivities to measure the potential shift in usage that could result from either price or income swings. A comparison of the forecast residential usage levels under our various price scenarios are in Table 5.1.

Under our high natural gas price scenario, we estimate lower levels of residential natural gas usage (holding other variables constant). Under a high natural gas price scenario, residential annual natural gas usage will grow from a level of 17.5 Bcf in 2000 to a level of 20.7 Bcf in 2010 to a level of 24.7 Bcf in 2020.

Total residential usage during the forecast period is anticipated to grow at a slower rate than the baseline forecast. Overall, we anticipate a 1.7 percent annual average rate of growth if the longer run price decrease trend is dampened. Over a 10 year period (2000-2010) we anticipate residential natural gas usage to grow by 3.2 Bcf, and by 7.2 Bcf over the twenty year long run forecast period (2000-2020). This represents an 18.4 percent and 41.2 percent increase over the short run (2000-2010) and long run (2000-2020) forecast periods, respectively.

We also examined a scenario where natural gas prices fell at a greater rate than our baseline forecast. Under our low natural gas price scenario, there would be slightly greater residential natural gas usage. Under our low price scenario, we anticipate residential natural gas usage to grow at an annual average rate of 2 percent. During the short run period, this usage would grow by approximately 3.9 Bcf, and by 8.6 Bcf over the long run horizon.

Table 5.1: Forecast Residential Natural Gas Usage Under Different Price Scenarios

[illegible]	[illegible]	[illegible]	[illegible]
2000	17,518,229	17,500,093	17,536,585
2001	17,840,308	17,794,479	17,886,835
2002	18,169,451	18,095,331	18,244,930
2003	18,505,384	18,402,367	18,610,612
2004	18,848,207	18,715,675	18,983,999
2005	19,198,104	19,035,431	19,365,289
2006	19,555,201	19,361,751	19,754,627
2007	19,919,686	19,694,810	20,152,221
2008	20,291,698	20,034,739	20,558,223
2009	20,671,431	20,381,722	20,972,847
2010	21,059,031	20,735,890	21,396,261
2011	21,454,701	21,097,441	21,828,684
2012	21,858,607	21,466,526	22,270,300
2013	22,270,920	21,843,304	22,721,302
2014	22,691,858	22,227,984	23,181,928
2015	23,121,582	22,620,716	23,652,356
2016	23,560,325	23,021,717	24,132,845
2017	24,008,252	23,431,145	24,623,578
2018	24,465,608	23,849,231	25,124,821
2019	24,932,570	24,276,139	25,636,776
2020	25,409,386	24,712,105	26,159,711
Ten Year Increase	3,540,802	3,235,797	3,859,676
Twenty Year Increase	7,891,157	7,212,012	8,623,126

If state personal income were to increase above its past five year rates, we see significant opportunities for residential natural gas usage growth. Under our high income assumption, residential natural gas usage will increase from a level of 17.6 Bcf in 2000 to 21.9 Bcf in 2010 to 27.3 Bcf in 2020. This represents a 24.7 percent increase over the short run forecast period, and a 55.5 percent increase over the longer run forecast period. Under the high income scenario, residential natural gas usage would be approximately 1.9 Bcf above the long run baseline estimated growth levels. However, some caution should be given to these results. In order for these usage levels to be obtained, economic growth would have to remain uncharacteristically high over the entire forecast period.

The implication of low-income growth on residential natural gas usage over the different forecast periods is summarized in Table 5.2. Under the low-income assumptions, we anticipate much lower levels of natural gas usage. The average annual rate of growth during the forecast period would be approximately 1.6 percent. Total usage over the short run period (10 years) would increase by 2.8 Bcf, and by 6.3 Bcf over the long run forecast horizon.

The residential usage levels associated with different income levels are in Table 5.2.

Table 5.2: Forecast Residential Natural Gas Usage Under Different Income Scenarios

Year	Residential Base Case (Mcf)	Residential High Income Case (Mcf)	Residential Low Income Case (Mcf)
2000	17,518,229	17,584,947	17,451,674
2001	17,840,308	17,975,876	17,706,062
2002	18,169,451	18,376,091	17,966,365
2003	18,505,384	18,785,358	18,232,270
2004	18,848,207	19,203,831	18,503,889
2005	19,198,104	19,631,736	18,781,361
2006	19,555,201	20,069,301	19,064,823
2007	19,919,686	20,516,715	19,354,420
2008	20,291,698	20,974,220	19,650,301
2009	20,671,431	21,442,059	19,952,614
2010	21,059,031	21,920,440	20,261,517
2011	21,454,701	22,409,617	20,577,167
2012	21,858,607	22,909,852	20,899,726
2013	22,270,920	23,421,367	21,229,362
2014	22,691,858	23,944,434	21,566,245
2015	23,121,582	24,479,334	21,910,548
2016	23,560,325	25,026,305	22,262,453
2017	24,008,252	25,585,635	22,622,141
2018	24,465,608	26,157,632	22,989,802
2019	24,932,570	26,742,544	23,365,628
2020	25,409,386	27,340,683	23,749,813
Ten Year Increase	3,540,802	4,335,493	2,809,844
Twenty Year Increase	7,891,157	9,755,736	6,298,140

5.2: Commercial Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that commercial natural gas usage will increase from an annual level of approximately 28.6 Bcf (2000) to 31.9 Bcf (2010) to 34.8 Bcf (2020). The total increase in commercial natural gas usage over this period is 3.3 Bcf (2000-2010) and 6.3 Bcf. Over the long run forecast period, we anticipate annual average growth to be one percent. This is consistent with historic trends when one out-lying year (1994-1995) is excluded from analysis.

Under our high price scenario, we estimate much lower levels of commercial natural gas usage. Our high commercial natural gas price scenario forecasts annual use to grow from a level of 28.5 Bcf in 2000 to 29.6 Bcf in 2010 and 30.7 Bcf in 2020. The annual average rate of growth during the period is less than one half percent. Total commercial usage over the forecast period, under our high natural gas price assumption, will grow by 1.1 Bcf over the short run forecast period (2000-2010) and by 2.2 Bcf over the longer run forecast period (2000-2020). For the year 2010, this would represent a 3.9 percent increase in commercial natural gas usage over the short run period and a 7.8 percent increase over the longer run period. Under our high price assumption, usage would be approximately 2.2 Bcf below the baseline short run forecast estimate and 4 Bcf over the longer run forecast period. The changes associated with each of our different price scenario forecasts are presented in Table 5.3.

Table 5.3: Forecast Commercial Natural Gas Usage Under Different Price Scenarios

Year	Commercial Base Case (Mcf)	Commercial High Price Case (Mcf)	Commercial Low Price Case (Mcf)
2000	28,566,567	28,451,442	28,683,799
2001	28,908,639	28,602,525	29,224,552
2002	29,202,722	28,671,009	29,760,330
2003	29,652,404	28,890,366	30,464,513
2004	30,168,262	29,170,069	31,249,292
2005	30,564,363	29,336,492	31,915,682
2006	30,841,053	29,395,288	32,457,978
2007	31,043,801	29,392,036	32,921,074
2008	31,261,135	29,407,258	33,402,273
2009	31,531,308	29,473,177	33,946,905
2010	31,851,818	29,585,393	34,555,030
2011	32,188,449	29,713,250	35,188,542
2012	32,511,023	29,831,304	35,811,692
2013	32,807,588	29,930,419	36,408,946
2014	33,086,385	30,018,098	36,989,250
2015	33,362,837	30,107,039	37,571,398
2016	33,648,108	30,205,861	38,169,861
2017	33,943,765	30,315,356	38,787,369
2018	34,244,481	30,431,127	39,417,553
2019	34,543,626	30,548,081	40,051,786
2020	34,837,741	30,663,720	40,685,286
Ten Year Increase	3,285,251	1,133,951	5,871,231
Twenty Year Increase	6,271,174	2,212,278	12,001,487

Under our low price forecast, commercial natural gas usage would increase considerably given this class' strong price sensitivity (i.e., price elasticity of demand). The average annual rate of growth under our low price scenario is well over 1.5 percent per year. Over the short run forecast period, commercial usage will grow by 5.9 Bcf and almost 12 Bcf over the longer run forecast period.

Table 5.4: Forecast Commercial Natural Gas Usage Under Different Income Scenarios

[illegible]	[illegible]	[illegible]	[illegible]
2000	28,566,567	28,576,984	28,532,498
2001	28,908,639	28,929,557	29,150,269
2002	29,202,722	29,234,126	29,474,563
2003	29,652,404	29,694,762	29,803,121
2004	30,168,262	30,222,057	30,103,978
2005	30,564,363	30,629,414	30,387,626
2006	30,841,053	30,916,930	30,668,380
2007	31,043,801	31,130,068	30,951,703
2008	31,261,135	31,357,778	31,237,019
2009	31,531,308	31,638,622	31,522,587
2010	31,851,818	31,970,191	31,807,560
2011	32,188,449	32,318,083	32,091,903
2012	32,511,023	32,651,874	32,375,815
2013	32,807,588	32,959,461	32,659,420
2014	33,086,385	33,249,113	32,942,736
2015	33,362,837	33,536,403	33,225,744
2016	33,648,108	33,832,619	33,508,427
2017	33,943,765	34,139,374	33,790,782
2018	34,244,481	34,451,290	34,072,809
2019	34,543,626	34,761,652	34,354,512
2020	34,837,741	35,066,944	34,635,893
Ten Year Increase	3,285,251	3,393,207	3,275,062
Twenty Year Increase	6,271,174	6,489,961	6,103,395

Table 5.4 presents our forecast sensitivity analysis for changes in commercial usage resulting from different assumptions of future economic activity. Higher sustained economic growth in the state could result in the growth of commercial natural gas usage, holding other factors constant. As seen in the table, under a high income scenario, commercial natural gas usage would increase by 22.7 percent over the long run forecast period and by approximately 22.4 percent under a low income scenario.

5.3: Industrial Baseline Forecast Sensitivity

Under our baseline forecast, we anticipate that industrial natural gas usage will grow at a relatively slow pace. Customer growth and usage in this class has been relatively constant over the recent past, and without the addition of new industries, it seems unlikely that there would be a significant relative shift in industrial usage. However, despite the relatively low percent growth for industrial use, it is a meaningful amount in absolute levels.

Table 5.5: Forecast Industrial Natural Gas Usage Under Different Price Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Price Case (Mcf)	Industrial Low Price Case (Mcf)
2000	73,238,676	73,197,507	73,280,303
2001	73,636,131	73,553,767	73,719,514
2002	74,033,625	73,910,037	74,158,897
2003	74,431,150	74,266,303	74,598,436
2004	74,828,701	74,622,570	75,038,129
2005	75,226,290	74,978,844	75,477,994
2006	75,623,904	75,335,110	75,918,010
2007	76,021,556	75,691,388	76,358,194
2008	76,419,233	76,047,661	76,798,539
2009	76,816,949	76,403,938	77,239,049
2010	77,214,690	76,760,215	77,679,715
2011	77,612,470	77,116,500	78,120,555
2012	78,010,275	77,472,776	78,561,547
2013	78,408,118	77,829,065	79,002,711
2014	78,805,987	78,185,348	79,444,037
2015	79,203,895	78,541,636	79,885,529
2016	79,601,835	78,897,930	80,327,188
2017	79,999,800	79,254,219	80,769,008
2018	80,397,803	79,610,512	81,210,997
2019	80,795,832	79,966,805	81,653,146
2020	81,193,900	80,323,106	82,095,472
Ten Year Increase	3,976,015	3,562,708	4,399,411
Twenty Year Increase	7,955,225	7,125,599	8,815,169

Under our baseline forecast, we anticipate industrial usage to grow around 1 percent per year. For the short run forecast period (2000-2010), this would entail about a 5.4 percent increase or 4 Bcf. Over the long run forecast period we anticipate baseline growth of about 8 Bcf – or about an 11 percent increase. If prices increase, we forecast industrial natural gas usage growth would decrease slightly. Alternatively, should prices decrease, industrial natural gas usage would increase slightly.

We also considered the impact of changing economic conditions on industrial usage patterns in Alaska. Under most income scenarios, there are limited shifts in industrial usage over both the short run and longer run forecasting horizon. Given the relatively steady baseline forecast, changes in our differing income assumptions (as well as price) typically result in level shifts in usage.

Table 5.6: Forecast Industrial Natural Gas Usage Under Different Income Scenarios

Year	Industrial Base Case (Mcf)	Industrial High Income Case (Mcf)	Industrial Low Income Case (Mcf)
2000	73,238,676	73,271,847	73,205,369
2001	73,636,131	73,702,568	73,569,492
2002	74,033,625	74,133,416	73,933,615
2003	74,431,150	74,564,396	74,297,739
2004	74,828,701	74,995,497	74,661,862
2005	75,226,290	75,426,724	75,025,986
2006	75,623,904	75,858,085	75,390,109
2007	76,021,556	76,289,566	75,754,232
2008	76,419,233	76,721,175	76,118,356
2009	76,816,949	77,152,918	76,482,479
2010	77,214,690	77,584,783	76,846,603
2011	77,612,470	78,016,776	77,210,726
2012	78,010,275	78,448,903	77,574,849
2013	78,408,118	78,881,154	77,938,973
2014	78,805,987	79,313,533	78,303,096
2015	79,203,895	79,746,048	78,667,220
2016	79,601,835	80,178,686	79,031,343
2017	79,999,800	80,611,453	79,395,467
2018	80,397,803	81,044,357	79,759,590
2019	80,795,832	81,477,384	80,123,713
2020	81,193,900	81,910,542	80,487,837
Ten Year Increase	3,976,015	4,312,935	3,641,234
Twenty Year Increase	7,955,225	8,638,695	7,282,468

5.4: Electric Utility Baseline Forecast Sensitivity

We also examined a number of different scenarios for power generation. Our sensitivity analysis of power generation differed somewhat from the analysis done for retail natural gas usage for residential, commercial, and industrial customers. Our sensitivities were based upon changes that our economic drivers (price, income) had on electricity usage. From there we forecast the changes associated with gas fired power generation, and natural gas usage.

Table 5.7: Forecast Electric Utility Natural Gas Usage Under Different Price Scenarios

Year	Estimated Utility Base Case (Mcf)	Estimated Utility High Price Case (Mcf)	Estimated Utility Low Price Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	32,125,910	33,773,393
2002	33,655,948	32,814,549	34,497,347
2003	34,119,758	33,266,764	34,972,752
2004	34,899,977	34,027,477	35,772,476
2005	35,406,497	34,521,334	36,291,659
2006	35,330,693	34,447,426	36,213,961
2007	35,813,699	34,918,357	36,709,042
2008	36,248,792	35,342,572	37,155,012
2009	36,677,751	35,760,807	37,594,694
2010	37,031,714	36,105,921	37,957,507
2011	37,353,364	36,419,530	38,287,198
2012	37,759,602	36,815,612	38,703,592
2013	38,149,476	37,195,739	39,103,213
2014	38,529,726	37,566,483	39,492,969
2015	38,899,627	37,927,136	39,872,118
2016	39,272,923	38,291,100	40,254,746
2017	39,657,179	38,665,750	40,648,609
2018	40,036,768	39,035,849	41,037,687
2019	40,414,176	39,403,821	41,424,530
2020	40,790,982	39,771,208	41,810,757
Ten Year Increase	1,374,828	536,020	2,387,606
Twenty Year Increase	5,134,096	4,201,307	6,240,856

Table 5.7 presents the results from our electric utility baseline demand sensitivity analysis for changes in retail electricity prices. Under our baseline scenario, we

anticipate electric generation demand for natural gas to grow during the short run forecast period at approximately 3.9 percent. Over the longer run, we forecast generation use of natural gas to grow by about 14.4 percent.

If retail electricity prices increase by one percent, in real dollars, per year, we anticipate a slowing of electricity demand, and as a result, natural gas fired generation. The short run increase in power generation usage of natural gas falls to 1.51 percent under our high price scenario, and to 11.8 percent over the longer run forecast period.

Under a low retail electricity price scenario, we see moderate growth in the amount of natural gas fired generation. Over the short run period, this increase is about 6.7 percent, while over the longer run there is approximately at 17.5 percent increase in natural gas demanded by electric generators.

We have also examined the potential changes in natural gas fired power generation from shifts in our underlying economic output assumptions. If state income were to grow by one percent, in real dollars, per year, we forecast a relatively significant amount of gas fired power generation. Gas usage by power generation increase by about 14.5 percent over a ten year period, and 26.1 percent over the longer forecast period, assuming relatively strong economic growth.

Alternatively, if economic growth were to proceed on a relatively flat pace, we see power generation dipping in the short run, but rebounding slightly over the long run forecast period. In the short run, we forecast natural gas usage to fall by about 6.3 percent. Gas usage by power generation would increase over the longer run, but at a very moderate rate (3.2 percent).

Table 5.8: Forecast Electric Utility Natural Gas Usage Under Different Income Scenarios

Year	Estimated Utility Base Case (Mcf)	Estimated Utility High Income Case (Mcf)	Estimated Utility Low Income Case (Mcf)
2000	35,656,886	35,569,901	35,569,901
2001	32,949,652	36,244,617	29,654,687
2002	33,655,948	37,021,543	30,290,353
2003	34,119,758	37,531,734	30,707,782
2004	34,899,977	38,389,974	31,409,979
2005	35,406,497	38,947,146	31,865,847
2006	35,330,693	38,863,763	31,797,624
2007	35,813,699	39,395,069	32,232,329
2008	36,248,792	39,873,671	32,623,913
2009	36,677,751	40,345,526	33,009,975
2010	37,031,714	40,734,885	33,328,543
2011	37,353,364	41,088,701	33,618,028
2012	37,759,602	41,535,562	33,983,642
2013	38,149,476	41,964,424	34,334,529
2014	38,529,726	42,382,699	34,676,754
2015	38,899,627	42,789,590	35,009,664
2016	39,272,923	43,200,216	35,345,631
2017	39,657,179	43,622,897	35,691,462
2018	40,036,768	44,040,445	36,033,091
2019	40,414,176	44,455,593	36,372,758
2020	40,790,982	44,870,081	36,711,884
Ten Year Increase	1,374,828	5,164,984	-2,241,358
Twenty Year Increase	5,134,096	9,300,180	1,141,983

5.5: Total Usage Baseline Forecast Sensitivity

Under our baseline forecast, we estimate that total natural gas usage will increase from an annual level of approximately 155 Bcf (2000) to 182 Bcf (2020). The total increase in total natural gas usage over this period is 27 Bcf. For the year 2020, this increase represents a 17.6 percent increase from its 1999 levels under our baseline forecast.

If natural gas prices were to increase at an annual average rate of one percent, we estimate much lower levels of total natural gas usage. Our high price case estimates annual use to grow from a level of 155 Bcf in 2000 to a level of 175 Bcf in 2020. Total usage over the forecast period, under our high natural gas price assumption, will grow by 20.8 Bcf over the forecast period. For the year 2020, this would represent a 13.4 percent increase in total natural gas usage. Under our high price assumption, usage would be approximately 6.5 Bcf below the baseline estimate.

If natural gas prices were to decrease at an annual average rate of one percent over the forecast period, we estimate higher total natural gas usage. Our low price forecast for total natural gas usage is 155 Bcf in 2000, and grows to a level of 191 Bcf by the year 2020. This represents an increase of 35.6 Bcf over 2000 total usage levels – or a 23 percent increase. Under our low price scenario, total natural gas usage will be approximately 8.4 Bcf above its baseline level.

Table 5.9: Forecast In-State Natural Gas Usage Under Different Price Scenarios

Year	Estimated Total Base Case (Mcf)	Estimated Total High Price Case (Mcf)	Estimated Total Low Price Case (Mcf)
2000	154,980,358	154,718,943	155,070,588
2001	153,334,730	152,076,681	154,604,295
2002	155,061,745	153,490,926	156,661,503
2003	156,708,696	154,825,800	158,646,312
2004	158,745,146	156,535,791	161,043,895
2005	160,395,253	157,872,101	163,050,624
2006	161,350,851	158,539,575	164,344,576
2007	162,798,743	159,696,591	166,140,531
2008	164,220,859	160,832,230	167,914,047
2009	165,697,439	162,019,644	169,753,495
2010	167,157,253	163,187,419	171,588,512
2011	168,608,985	164,346,721	173,424,979
2012	170,139,507	165,586,218	175,347,131
2013	171,636,103	166,798,526	177,236,172
2014	173,113,957	167,997,914	179,108,184
2015	174,587,941	169,196,528	180,981,401
2016	176,083,191	170,416,609	182,884,641
2017	177,608,996	171,666,470	184,828,565
2018	179,144,660	172,926,720	186,791,058
2019	180,686,203	174,194,8[illegible]	188,766,237
2020	182,232,010	175,470,138	190,751,225
Ten Year Increase	12,176,895	8,468,477	16,517,924
Twenty Year Increase	27,251,652	20,751,195	35,680,637

If state personal income were to increase at one percent per year, we forecast opportunities for total natural gas usage growth. Under our high income assumption, total natural gas usage will increase from a level of 155 Bcf in 2000 to 189 Bcf in 2020. This represents a 22.1 percent increase over the forecast period. Under the high income scenario, total natural gas usage would be approximately 6.9 Bcf above the baseline estimated growth levels.

If state personal income were to remain constant over the forecast period, total natural gas usage growth would grow by about 6.4 Bcf less than the baseline estimate. Under our low income assumption, total natural gas usage will grow from a level of 155 Bcf in 2000 to 176 Bcf in 2020. This represents a 13.5 percent increase over the forecast period.

Table 5.10: Forecast In-State Natural Gas Usage Under Different Income Scenarios

Year	Estimated Total Base Case (Mcf)	Estimated Total High Income Case (Mcf)	Estimated Total Low Income Case (Mcf)
2000	154,980,358	155,003,678	154,759,441
2001	153,334,730	156,852,618	150,080,509
2002	155,061,745	158,765,176	151,664,896
2003	156,708,696	160,576,250	153,040,912
2004	158,745,146	162,811,359	154,679,708
2005	160,395,253	164,635,020	156,060,819
2006	161,350,851	165,708,078	156,920,937
2007	162,798,743	167,331,417	158,292,685
2008	164,220,859	168,926,844	159,629,589
2009	165,697,439	170,579,124	160,967,656
2010	167,157,253	172,210,299	162,244,222
2011	168,608,985	173,833,176	163,497,824
2012	170,139,507	175,546,192	164,834,032
2013	171,636,103	177,226,405	166,162,283
2014	173,113,957	178,889,779	167,488,831
2015	174,587,941	180,551,375	168,813,176
2016	176,083,191	182,237,825	170,147,855
2017	177,608,996	183,959,360	171,499,851
2018	179,144,660	185,693,724	172,855,292
2019	180,686,203	187,437,174	174,216,611
2020	182,232,010	189,188,250	175,585,427
Ten Year Increase	12,176,895	17,206,621	7,484,781
Twenty Year Increase	27,251,652	34,184,572	20,825,986

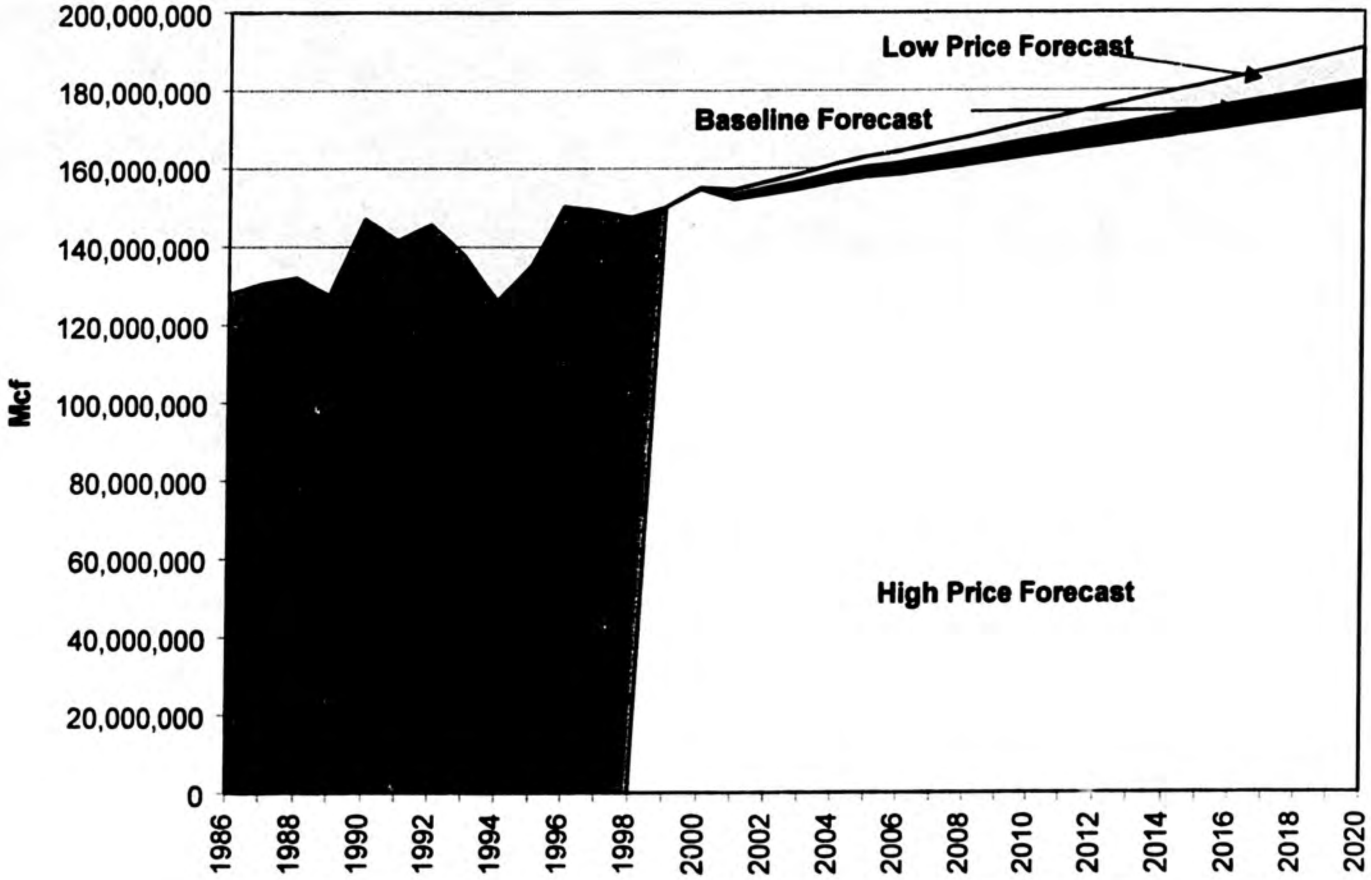

Figure 5.1: Forecast In-State Natural Gas Usage Under Different Price Scenarios

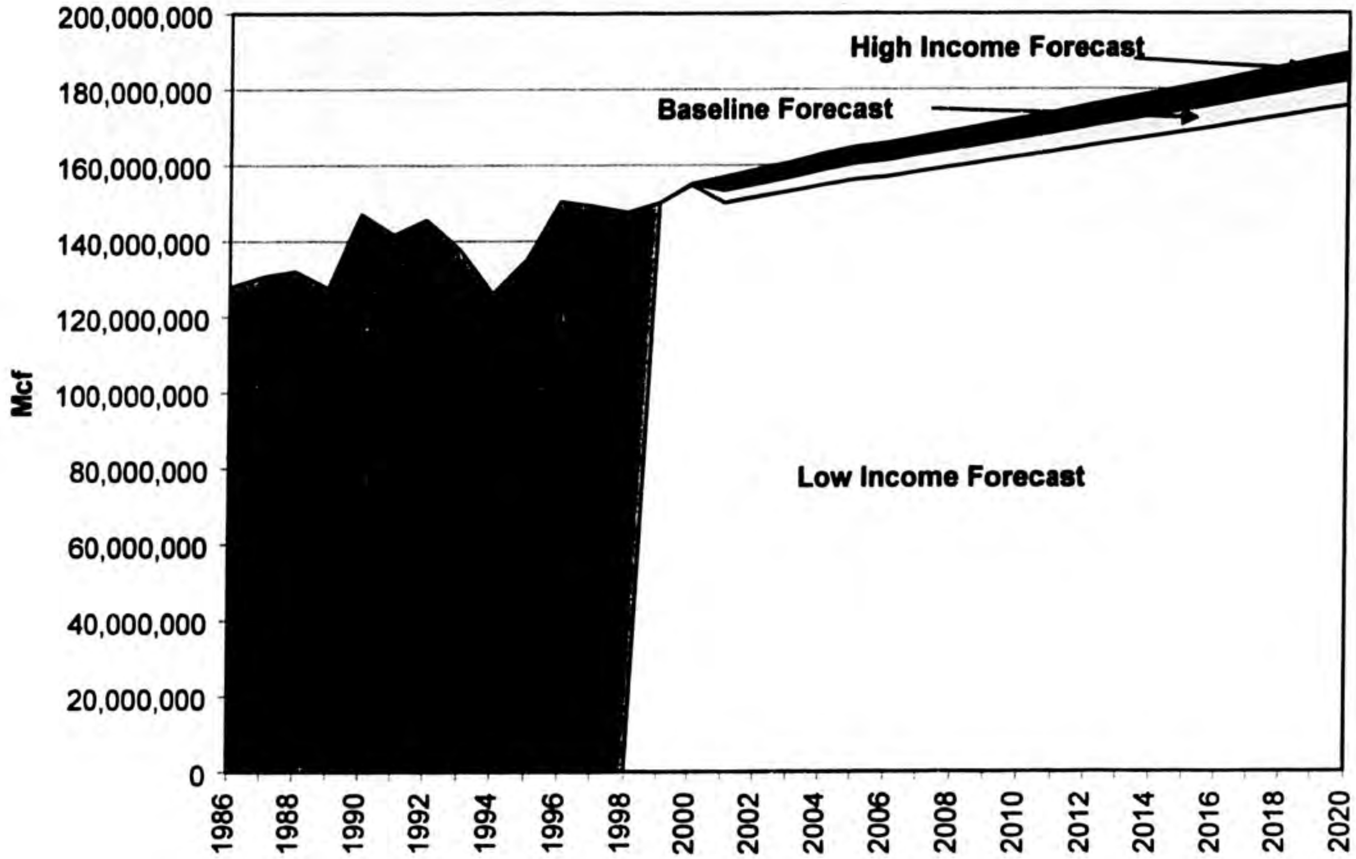

Figure 5.2: Forecast In-State Natural Gas Usage Under Different Income Scenarios

5.6: Conclusions

The sensitivity analysis for the baseline forecast was developed to examine a range of gas usage levels that could be realized under differing economic conditions. The main factor influencing these potential shifts in usage are the income and price elasticities of demand that have been estimated for each customer class. Overall, price impacts tend to have greater implications for usage relative to income impacts. This is particularly true for commercial customers that can exhibit price elasticities of –0.8 in the short run and –1.8 in the long run.

Sensitivity ranges (i.e, high, low) for price and income were developed from a fixed range over longer run 10 year averages. A given symmetrical range around this historic averages were developed for comparison purposes. The approach is similar to that developed by ISER in its Alaska forecast. However, our ranges are admittedly smaller, and more conservation than some of the outer ranges considered in the ISER analyses. Our sensitivity analysis is designed to answer a "what if" question, i.e., explore changes in the dependent variable due to lower or higher levels of the independent variables. In that sense, the levels of the independent variables represent not so much a "forecasted" values, but rather certain discrete levels, which, in our view, correspond to a qualitative label of "high" and "low".

There are a number of other sensitivities to in-state usage that can be considered. These sensitivities include examining the implications of shifts in natural gas usage of large individual users. Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. Combined, these facilities account for close to 130 Bcf per year in natural gas usage. Expansions or closure of these facilities could have significant implications for in-state usage. The role that these facilities play in determining in-state usage trends is examined in greater detail in Chapter 7.

CHAPTER 6: EXPANDED RESIDENTIAL SERVICE

6.1: Regional Analysis of Expanded Residential Service Opportunities

In terms of the residential market, we examined two potential opportunities for increased natural gas usage:

(1) Expanding coverage of natural gas service to those remote areas that currently have no existing or proposed gas service.

(2) Increasing natural gas market penetration rates in areas that already have gas service.

In order to analyze these potential opportunities we used a geographic information system (GIS) to combine demographic geo-referenced information with information on existing and proposed natural gas service areas. This approach allowed us to establish a spatial framework for residential natural gas service in Alaska, which is required for the analysis.

According the 2000 U.S. Census of Population and Housing, Alaska has a population of 580 thousand people, which make up 205 thousand households. Approximately two thirds of the population reside in the Southcentral region. The Interior and the Southeast region account for 11 percent each, while the Far North region has only 4 percent. Anchorage, located in the Southcentral region, is the only large city in the state, it alone accounts for 45 percent of the total Alaskan population. Together, the cities of Juneau and Fairbanks, with populations of about 30,000 each, account for 10 percent of statewide population.

Figure 6.1 shows the geographic distribution of settlements within Alaska according to size. The distribution of population in the state is very uneven, with majority of the population concentrated in three major urban clusters: Anchorage; Juneau; and Fairbanks. The size of the dots in Figure 6.1 represents the size of the settlements throughout the state. Very small dots, for instance, represent settlements with less than 500 households (conventionally, population is measured in number of people; however, we are using number of households because a household represents a gas service customer). As can be seen on the map, Alaska has three major areas with population greater than 4,500 households: Juneau in the Southeast, Anchorage in the Southcentral area, and Fairbanks in Interior Alaska. There are a considerable number of settlements in Alaska with fewer than 500 households.

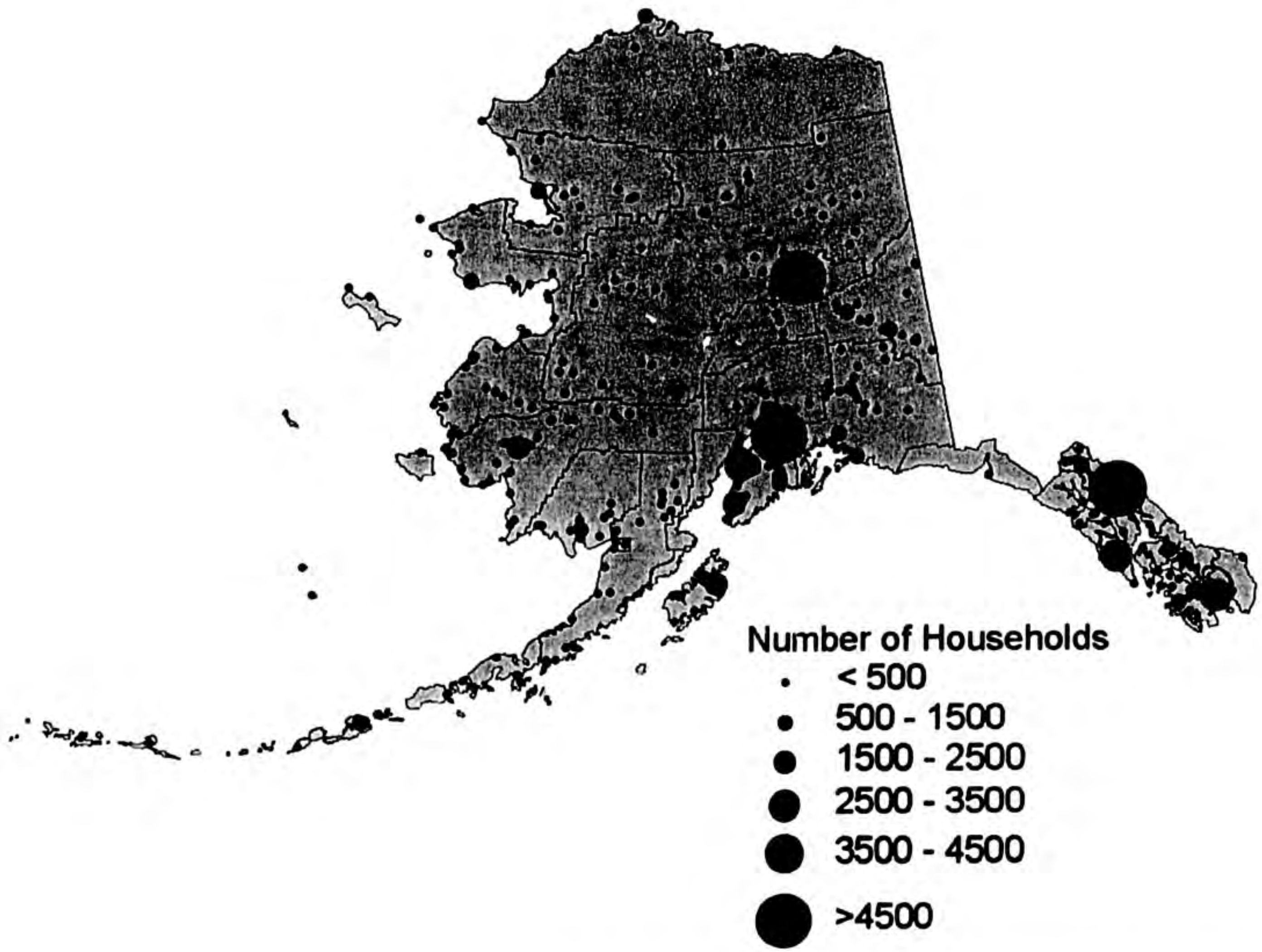

Figure 6.1 Geographical Distribution of Settlements in Alaska

Our next step after identifying settlement distributions and locations throughout the state was to identify those settlements that are currently being served by natural gas distribution systems. In addition to identifying current systems, we also identified those areas that have plans for future services. This information was collected from the Regulatory Commission of Alaska (RCA). The settlements with existing or proposed natural gas services are provided in Table 6.1. The geographic distribution of these settlements and their gas service status is presented in Figure 6.2.

Table 6.1 Settlements with Existing or Proposed Natural Gas Service

Community	Region	NG Provider	Population	Households
Angoon	Southeast	AIGC	572	184
Cordova	Southcentral	AIGC	2,454	958
Craig	Southeast	AIGC	1,397	523
Haines	Southeast	AIGC	1,811	752
Juneau	Southeast	AIGC	30,711	11,543
Kake	Southeast	AIGC	710	246
Ketchikan	Southeast	AIGC	7,922	3,197
Klawock	Southeast	AIGC	854	313
Klukwan	Southeast	AIGC	139	44
Kodiak	Southwest	AIGC	6,334	1,996
Metlakatla	Southeast	AIGC	1,375	469
Petersburg	Southeast	AIGC	3,224	1,240
Sitka	Southeast	AIGC	8,835	3,278
Skagway	Southeast	AIGC	862	401
Valdez	Southcentral	AIGC	4,036	1,494
Wrangell	Southeast	AIGC	2,308	907
Yakutat	Southeast	AIGC	680	261
Barrow	Far North	BUECI	4,581	1,371
Anchorage	Southcentral	ENSTAR	260,283	94,822
Big Lake	Southcentral	ENSTAR	2,635	971
Houston	Southcentral	ENSTAR	1,202	445
Kenai	Southcentral	ENSTAR	6,942	2,622
Nikiski	Southcentral	ENSTAR	4,327	1,514
Palmer	Southcentral	ENSTAR	4,533	1,472
Soldotna	Southcentral	ENSTAR	3,759	1,465
Sterling	Southcentral	ENSTAR	4,705	1,676
Wasilla	Southcentral	ENSTAR	5,469	1,979
Whittier	Southcentral	ENSTAR	182	86
Fairbanks	Interior	FNG	30,224	11,075
Prudhoe Bay	Far North	NORGASCO	5	1

Source: Regulatory Commission of Alaska and 2000 U.S. Census of Population and Housing.
AIGC = Alaska Interstate Gas Company.
BUECI = Barrow Utilities & Electric Cooperative, Incorporated.
FNG = Fairbanks Natural Gas, LLC.
Note: Not all the settlements receive residential gas service. AIGC is planning to provide gas service.

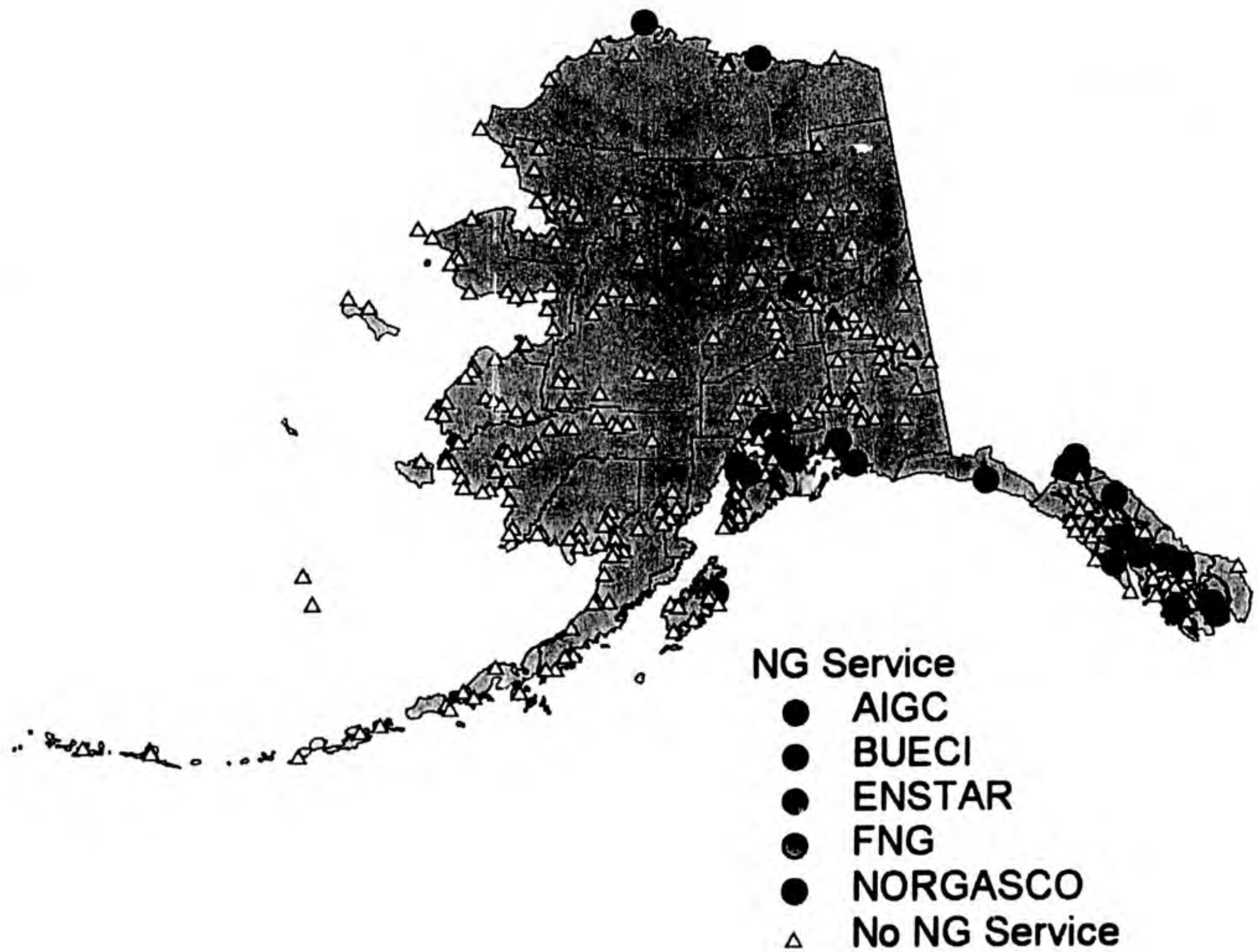

Figure 6.2: Geographical Distribution of Natural Gas Service in Alaska

Figure 6.2 shows that there are a large number of settlements that are currently not listed as having gas service. Areas covered by existing or proposed systems are restricted to Southcentral and Southeastern Alaska. Based upon publicly available information, there are other small pockets in northern Alaska and one in Interior Alaska.

Table 6.2 shows the distribution of Alaska population and households. The top portion of the table presents the numbers for each of the series, while the bottom half of the table shows the relative distribution. An important statistic reported in this table is that 30 percent of Alaska's population and 28 percent of its households are not being served by natural gas.

Table 6.2 Distribution of Alaska Population and Households by Existing or Proposed Natural Gas Service

NG Utility	Population	Households
No NG service	176,272	57,262
AIGC	74,224	27,806
BUECI	4,581	1,371
ENSTAR	294,037	107,052
FNG	30,224	11,075
NORGASCO	5	1
AK Total	579,343	204,567
NG Utility	**Population**	**Households**
No NG service	30.4%	28.0%
AIGC	12.8%	13.6%
BUECI	0.8%	0.7%
ENSTAR	50.8%	52.3%
FNG	5.2%	5.4%
NORGASCO	0.0%	0.0%

Alternatively, some 72 percent of Alaska's households currently reside in places with natural gas service. As seen in Table 6.3, 52 percent of all households in Alaska live within the Enstar's service zone. Enstar, the state's largest local distribution company (LDC), provides natural gas to residential and commercial customers in Anchorage, Big Lake, Chugiak, Eagle River, Eklutna, Girdwood, Houston, Kenai, Knik, Nikiski, Palmer, Peters Creek, Soldotna, Sterling, Wasilla, and Whittier. Enstar contemplates expanding gas distribution service to Ninilchik, Anchor Point, Homer and other lower Kenai Peninsula communities.

Table 6.3: Proposed Kenai Kachemak Pipeline Project

Community	Region	NG Planned Provider	Population	Households
Anchor Pt	Southcentral	ENSTAR	1,845	711
Clam Gulch	Southcentral	ENSTAR	173	67
Homer	Southcentral	ENSTAR	3,946	1,599
Kasilof	Southcentral	ENSTAR	471	180
Ninilchik	Southcentral	ENSTAR	772	320

Unocal Alaska and Marathon Oil Company have formed the Kenai Kachmak Pipeline, LLC and recently announced an open season for a 58-mile gas transmission pipeline between Kenai and Anchor Point near the southern end of the Kenai Peninsula. The KKPL initially would transport gas from new fields currently under exploration in the southern Kenai Peninsula into the existing pipeline distribution system operated by Enstar and Kenai-Nikiski Pipeline. Enstar eventually may construct a distribution segment between Anchor Point and Homer. The KKPL is expected to begin operation in 2004. Pipeline capacity is still unknown and will depend on exploration success. When all phases are completed, gas service could become available to the communities of Ninilchik, Anchor Point, Clam Gulch, Kasilof, and Homer. Collectively these southern Kenai Peninsula communities contain approximately 2,900 occupied households, representing about a three-percent addition to the existing 105,000 Enstar customer base. This would imply about 500 to 600 million cubic feet per year of potential residential gas service, not including commercial and electric power generation potential.

Alaska Interstate Gas Company (AICG) has proposed to develop a gas service, which would serve places containing 14 percent of all Alaska households, primarily in Southeast. According to the RCA 2000 Annual Report, AIGC was scheduled to begin serving Juneau, Ketchikan, and Sitka on July 1, 2001; Cordova, Craig, Klawock, Kodiak, Petersburg, Valdez, and Wrangell by July 1, 2005; and Angoon, Haines, Kake, Klukwan, Metlakatla, Skagway, and Yakutat by July 1, 2010. However it is important to point out that, except for Valdez, these relatively small and remote communities are located apart from the road- or rail-connected energy belt and apart from known natural gas reserves or gas transmission lines.

Table 6.4 examines the distribution of settlement size and number of households with and without natural gas service. According to the information available to our study, there are some 297 settlements with fewer than 500 households that do not have access to natural gas service. The total number of households that live in these small, non-gas service areas is approximately 25,000. There are 26 settlements in Alaska that range between 500 and 2,400 households that do not have access to natural gas service. These places account for approximately 29,000 households. There is one settlement in Alaska that has a total of 4,100 households that is currently listed as not having access to natural gas service. This is an area around the campus of University of Alaska at Fairbanks, a census designated place (CDP), College, located just outside the corporate limits of Fairbanks.

Table 6.4: Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households		
Settlement Size (000 households)	With NG Service	Without NG Service	All	With NG Service	Without NG Service	All
<0.5	10	287	297	2,450	24,599	27,049
0.5-1.4	10	19	29	11,153	15,199	26,352
1.5-2.4	4	7	11	7,165	13,360	20,525
2.5-3.4	3	0	3	9,097	0	9,097
3.5-4.4	0	1	1	0	4,104	4,104
> 4.5	3	0	3	117,440	0	117,440
All	30	314	344	147,305	57,262	204,567

Table 6.5. Cumulative Distribution of Alaska Households by Settlement Size and Existing or Proposed Natural Gas Service

	Number of Places			Number of Households			Percent w/o Gas Service	
Settlement Size (000 households)	With NG	Without NG	All	With NG	Without NG	All	Settlements	Households
<0.5	10	287	297	2,450	24,599	27,049	96.6%	90.9%
<1.5	20	306	326	13,603	39,798	53,401	93.9%	74.5%
<2.5	24	313	337	20,768	53,158	73,926	92.9%	71.9%
<3.5	27	313	340	29,865	53,158	83,023	92.1%	64.0%
<4.5	27	314	341	29,865	57,262	87,127	92.1%	65.7%
All	30	314	344	147,305	57,262	204,567	91.3%	28.0%

The next step in our analysis was to estimate the amount of natural gas that could be used if the identified unserved areas of Alaska were offered access to natural gas service. This estimate has been provided in Table 6.6. Our analysis of new potential residential in-state demand has been conducted in a "boundary" fashion. That is, we have identified the outer range of new residential growth possibilities. The outer range is estimated assuming that every household will use natural gas at current average consumption rate. The first two lines in Table 6.6 identify existing residential consumption and customers. Line 3 through line 5 estimate those households that currently have access to natural gas service, or have plans for service in the near future.

Line 6 and line 7, however, estimate those households that either do not have access to natural gas service or do not utilize their ability to access natural gas service. Line 7 divided by line 2, therefore, would give the current percent of customers not taking natural gas service (not shown). Lines 8 through 11 estimate natural gas usage (based on the observed average consumption per customer) for the various types of residential households: those with natural gas service; those with proposed natural gas service; and potential usage for those that currently do not have residential natural gas service.

Line 10 shows the potential residential gas usage levels in areas without access to natural gas if service were extended to these areas. The largest concentration of these volumes, seen as a percentage in the far right hand columns, is in the Southcentral region of Alaska. Nearly 50 percent of expanded service usage volumes could come from this region. The next two largest opportunities for regional development appear to be in the Southwest region (21 percent) and the Interior region (19 percent).

We also conducted a number of additional analyses that estimated potential residential usage if the penetration rates of existing, proposed, and potential regions were expanded to 100 percent. This estimate would reflect the maximum coverage of gas usage in Alaska if all households were served. These estimates have been provided on line 12 through line 16. Line 14, for instance, estimates total gas usage if existing and proposed regions expanded their penetration rates to 100 percent.

Table 6.6: Summary Analysis of Potential Residential In-State Natural Gas Usage

Line No.	Calculation by Line No.		Levels						Percents of Total					
			Far North	Interior	South Central	South East	South West	Total	Far North	Interior	South Central	South East	South West	Total
1	EIA	1999 Residential NG Consumption (Mcf)	215,126	0	17,418,738	0	0	17,633,864	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
2	EIA	1999 Number of Residential Customers	1,109	0	87,815	0	0	88,924	1.2%	0.0%	98.8%	0.0%	0.0%	100.0%
3	RCA, Census	Number of Households with Existing (as of 12/31/1999) Access to NG	1,371	11,075	107,052	0	0	119,498	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
4	RCA, Census	Number of Households with Proposed Access to NG (AIGS service area) [a]	0	0	2,452	23,358	1,996	27,806	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
5	3 + 4	Number of Households with Existing or Proposed Access to NG	1,371	11,075	109,504	23,358	1,996	147,304	0.9%	7.5%	74.3%	15.9%	1.4%	100.0%
6	RCA, Census	Number of Households without Existing or Proposed Access to NG	4,550	11,456	27,101	1,794	12,361	57,262	7.9%	20.0%	47.3%	3.1%	21.6%	100.0%
7	5 - 2	Number of Households not Using Existing Access to NG	262	11,075	19,237	0	0	30,574	0.9%	36.2%	62.9%	0.0%	0.0%	100.0%
8	4 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas with Proposed Access to NG (MCF)	0	0	398,972	3,446,776	294,536	4,140,284	0.0%	0.0%	9.6%	83.2%	7.1%	100.0%
9	1 + 8	Expected Residential NG Consumption in Areas with Existing or Proposed Access to NG (Mcf)	215,126	0	17,817,710	3,446,776	294,536	21,774,148	1.0%	0.0%	81.8%	15.8%	1.4%	100.0%
10	6 x [1 / 2] x [2 / 3]	Expected Residential NG Consumption in Areas without Existing or Proposed Access to NG (Mcf)	713,948	1,690,482	4,409,681	264,728	1,824,026	8,902,866	8.0%	19.0%	49.5%	3.0%	20.5%	100.0%
11	9 + 10	Expected Residential NG Consumption in Alaska Assuming Universal Access to NG (Mcf)	929,074	1,690,482	22,227,391	3,711,504	2,118,562	30,677,013	3.0%	5.5%	72.5%	12.1%	6.9%	100.0%
12	3 x [1 / 2]	Potential Residential NG Consumption in Areas with Existing Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,234,536	0	0	23,696,657	1.1%	9.3%	89.6%	0.0%	0.0%	100.0%
13	4 x [1 / 2]	Potential Residential NG Consumption in Areas with Proposed Access to NG Assuming 100% Market Saturation (Mcf)	0	0	486,372	4,631,891	395,807	5,514,070	0.0%	0.0%	8.8%	84.0%	7.2%	100.0%
14	12 + 13	Potential Residential NG Consumption in Areas with Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	265,949	2,196,173	21,720,907	4,631,891	395,807	29,210,727	0.9%	7.5%	74.4%	15.9%	1.4%	100.0%
15	6 x [1 / 2]	Potential Residential NG Consumption in Areas without Existing or Proposed Access to NG Assuming 100% Market Saturation (Mcf)	882,618	2,271,725	5,375,679	355,750	2,451,186	11,336,958	7.8%	20.0%	47.4%	3.1%	21.6%	100.0%
16	14 + 15	Potential Residential NG Consumption in Alaska Assuming Universal Access and 100% Market Saturation (Mcf)	1,148,567	4,467,897	27,096,586	4,987,642	2,846,993	40,547,685	2.8%	11.0%	66.8%	12.3%	7.0%	100.0%

[a] Places with households include Cordova and Valdez (Southcentral); Angoon, Craig, Haines, Juneau, Kake, Ketchikan, Klawock, Klukwan, Metlakatla, Petersburg, Sitka, Wrangell and Yakutat (Southeast); and Kodiak (Southwest).

Currently, the Southcentral region dominates both the total number of households with access to natural gas service, and, as a result, total residential natural gas usage. Table 6.6, line 3 shows that this region currently accounts for close to 90 percent of all households with access to natural gas service. Line 4, however, reveals that new (proposed) service opportunities are being created in other regions. These new expansion plans are primarily in the Southeastern region (84 percent of new service proposed for this area).

Another focus of the analysis is to identify households in existing natural gas service areas that do not receive service. Overall, Alaska has an approximate residential natural gas service penetration rate of 80 percent, while the Southcentral region has a somewhat higher average residential penetration rate of 82 percent. We have identified some 11,075 households in the Interior region that are within a defined natural gas utility service area. This region includes the Fairbanks North Star Borough and is examined in greater detail at the end of this chapter.

Lines 8 through 11 of Table 6.6 estimates the natural gas usage associated with households in different Alaska regions. A large portion of the estimated natural gas usage is in the Southcentral region. In addition to identifying the existing distribution of regional natural gas usage, we have also identified new opportunities for natural gas service volumes that are presented on line 10. We have identified a potential for 8.9 Bcf if service were expanded to unserved areas of Alaska. This increased usage assumes that the currently unserved areas achieve a penetration rate comparable to the state-wide average.

As indicated above, close to 50 percent of our identified new sources of expanded residential natural gas usage are located in the Southcentral region. Approximately 40 percent of those potential expanded service usage is in the Interior (19.0 percent) and Southwest (20.5 percent) regions of the state. The remaining new expanded service usage opportunities are in the Far North (8 percent) and Southeast (3 percent) regions. Line 11 sums the existing gas usage and the new potential expansions, to estimate a new in-state residential natural gas usage level based upon 1999 average usage trends and levels.

The analysis also considers opportunities for expanding gas usage in areas that currently have natural gas service coverage through increasing the market penetration rates. Line 12 and line 13, for instance, estimate the levels of gas usage that could occur in existing and proposed service areas if service penetration rates were increased from their existing levels to 100 percent. These opportunities from service expansion have been summed on line 14. We estimate approximately 7.4 (29.2-21.8) Bcf of additional usage opportunities if service penetration levels were increased to their maximum.

Approximately 74 percent of the expanded service opportunities are located in Southcentral Alaska. Close to 16 percent of the expanded service opportunities are located in Southeast Alaska. The total service expansion opportunities are much less in the remaining areas, primarily because these areas currently have no to little service to expand upon.

Line 15 examines new residential usage opportunities in currently unserved areas from a different perspective. Here, we estimate total usage opportunities if service were expanded in these regions, and penetration rates reached 100 percent. This estimate, therefore, is higher than that presented in line 10. We estimate the possibility of 11.3 Bcf of increased residential usage in currently unserved areas if 100 percent penetration rates were achieved.

Line 14 and line 15 can be compared to examine new residential natural gas usage opportunities in existing areas (line 14) with new growth opportunities in unserved areas (line 15). Both estimates assume 100 percent penetration, so the comparison, as well as the sum (line 16), represent the boundary, or outermost opportunities for expanded residential natural gas usage. Comparing lines 14 and 15, we see that increasing market penetration rates in areas with existing or proposed service (7.5 Bcf per year) yields slightly less additional consumption than expanding service into the unserved regions (8.9 Bcf per year).

We have presented three figures to try to simply the analysis presented in Table 6.6. Figure 6.3 presents a pie chart showing the break-out of the estimated usage potentials in unserved areas, versus the estimated usage in existing LDC service territories for the state. Usage in unserved areas would represent approximately 29 percent of the total (or 8.9 Bcf per year). The remaining usage is associated with areas that already have natural gas service opportunities. This figure is based upon the estimates that assumed new areas will achieve penetration rates comparable to the statewide average.

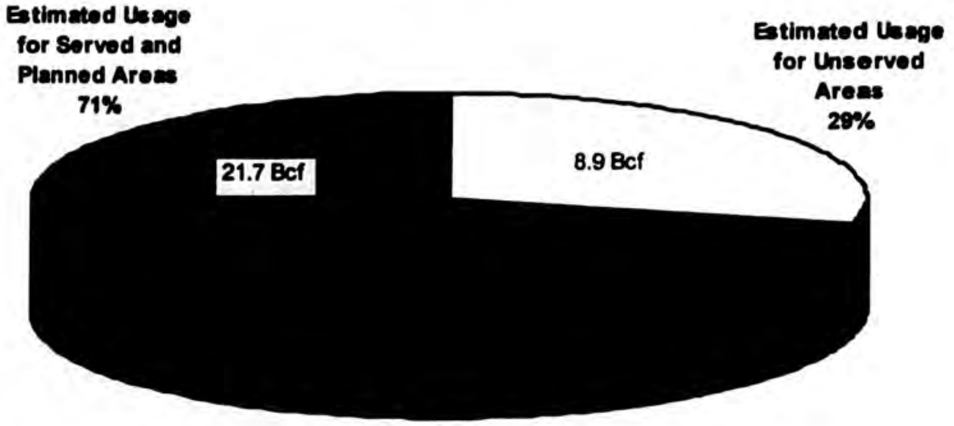

Figure 6.3: Estimated Usage in Served and Unserved Areas Assuming Statewide Average Penetration Rates

Figure 6.4 is a similar representation, but shows total usage, and percentages, assuming 100 percent penetration of both unserved and served areas. Of the maximum total residential usage potential, usage in unserved areas represents about 28 percent of total, or 11.3 Bcf. Usage in areas currently served by LDCs increases to 29.2 Bcf, or 72 percent of total.

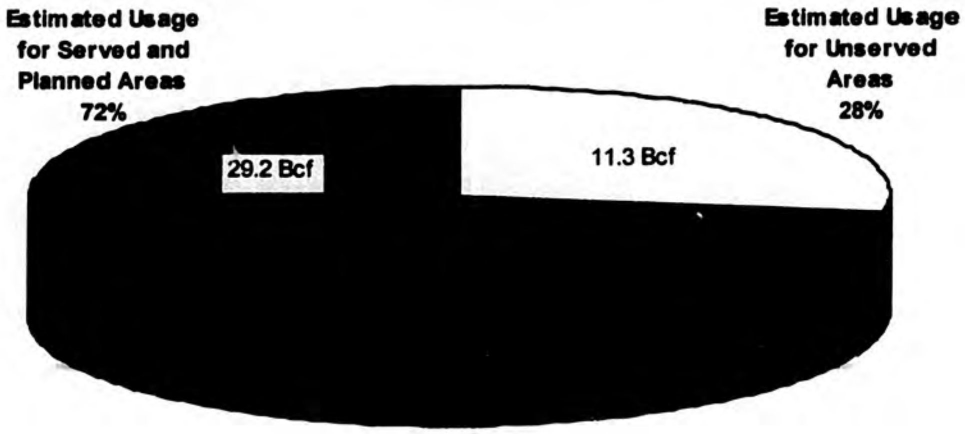

Figure 6.4: Estimated Usage in Served and Unserved Areas Assuming 100 Percent Penetration Rates

The last figure (Figure 6.5) we have presented compares the estimated usage in unserved areas with the estimated usage from expanding the statewide average penetration level from roughly 80 to 100 percent. As seen in the figure, the percentages and levels are roughly the same. Estimated usage in unserved areas could be approximately 8.9 Bcf while usage from expansion of current LDC penetration rates is 7.4 Bcf.

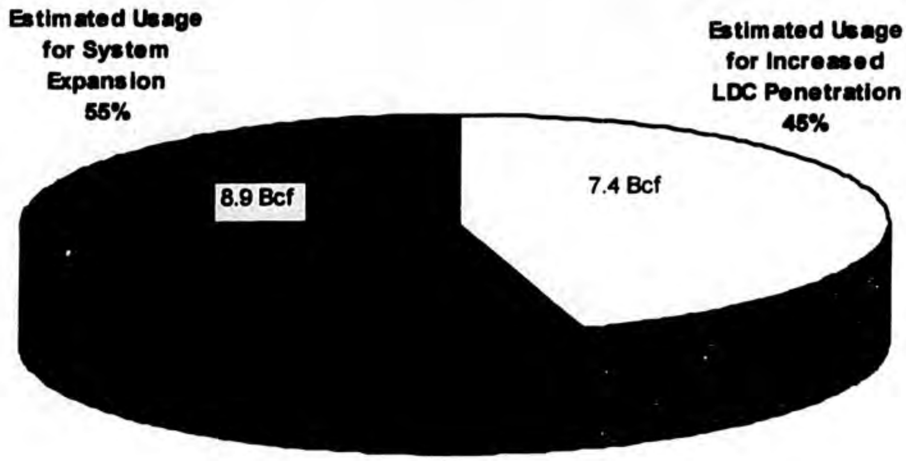

Figure 6.5: Comparison of Estimated Usage in Unserved Areas versus Increased Penetration Rates in Existing LDC Areas

The results of our detailed analysis reveal some interesting insights into new residential natural gas usage opportunities. Our analysis supports the two major conclusions:

(1) On a regional basis, Southcentral Alaska has the largest opportunities for expanding residential natural gas service beyond its current LDC service areas;

(2) On a statewide basis, potential growth in residential natural gas usage associated with increasing the penetration rates of existing local distribution systems almost equals potential growth associated with extending the service into remote areas.

6.2: Residential Proximity Analysis to Existing and Proposed Natural Gas Infrastructure

We also conducted an alternative analysis that examined the possibilities of expanding natural gas service to customers living within proximity to existing and proposed natural gas infrastructure of the state. The two sets of natural gas infrastructure that we examined included:

(1) Expansions to the existing natural gas utilities (LDCs);

(2) Service expansion opportunities in geographic proximity to the Alaska natural gas transportation pipeline.

In both cases, for any given area, physical proximity to sources of natural gas infrastructure becomes a critical factor in determining costs of the provision of natural gas. Our geographic proximity analysis proceeded along the following lines:

1. We used the geographic boundary files developed by the U.S. Census Bureau to produce a map of Alaskan settlements (cities, towns, villages, census designated places, etc.) in their administrative (or census-designated) boundaries.

2. We used the newly released STF1 file for Alaska from the 2000 U.S. Census of Population and Housing to identify the number of occupied households in each settlement.

3. We used information contained in the 2000 Annual Report of the Alaska Regulatory Commission to identify settlements with either existing or proposed natural gas service. As a result, we have classified all the settlement in Alaska as either having existing or proposed natural service (EPNGS) or as not having existing or proposed service (NOEPNG). These areas have been presented earlier in Figure 6.2.

4. For every EPNGS settlement we created four proximity zones in five-mile increments. For instance, a five-mile proximity zone is created by extending administrative borders of a settlement outward by five miles. A 10-mile zone, however, covers a territory around a settlement that is between 5 and 10 miles of its existing geographic definition. Thus, adding up the opportunities in each five-mile increment will result in the cumulative total new natural gas usage opportunities.

5. When buffers in each distance range had multiple EPNGS settlements, we merged each of these settlements into a single proximity zone. Given the concentration of many existing service areas, we created four proximity zones for Alaska. Thus, a five-mile Alaska zone covers all the territory

within five miles of the EPNGS area. These concentrations have been presented in Figure 6.6. The upper left hand side of this figure shows the state-wide concentrations. The upper right hand side is a zoomed-in view of the northern Alaska concentrations, while the lower part of the figure provides a zoomed-in view of the southern Alaska region.

6. Following the description of the proposed Alaska Highway Route (AHR) for the natural gas transportation pipeline, we developed a digital boundary for the proposed pipeline route (this region will be labeled "AHR").[1]

7. Similar to the procedure described above for EPNGS buffers, we developed four proximity zones in the increment of five miles around the AHR. These boundaries have been presented in Figure 6.7.

8. We overlaid boundaries of NOEPNGS settlements separately with EPNGS zones and with AHR zones. Thus, every NOEPNGS settlement was classified according to proximity (within 5 miles, within 10 miles, within 15 miles, within 20 miles, and beyond 20 miles) to the examined natural gas infrastructure.

9. Finally, we aggregated the number of occupied households living in NOEPNGS settlements by region and by proximity to sources of natural gas supply. Tables 6.7, 6.8, and 6.9 present the results of our analysis. We have also estimated usage associated with these household estimates and have presented them in Tables 6.10 and 6.11.

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[1]For purposes of our analysis, the AHR includes spurs into the Southcentral region. These spurs, and our mapping of the AHR, is based upon the presentation provided by Alaska DNR Commissioner Pat Pourchot which is available on the Alaska Highway Natural Gas Council homepage: www.gov.state.ak.us/gascouncil

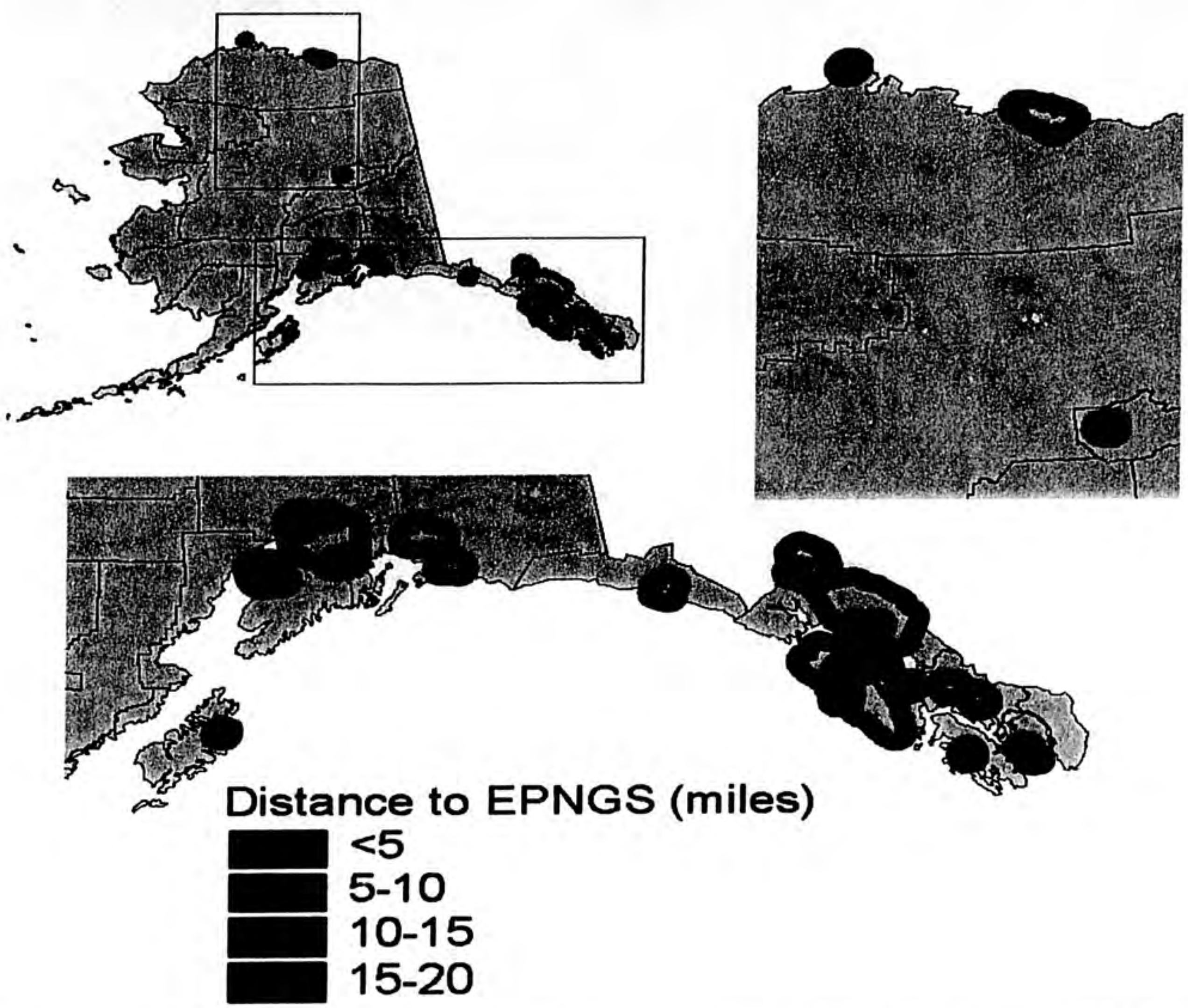

Figure 6.6: Proximity Zones around Existing and Proposed Natural Gas Systems in Alaska (EPNGS)

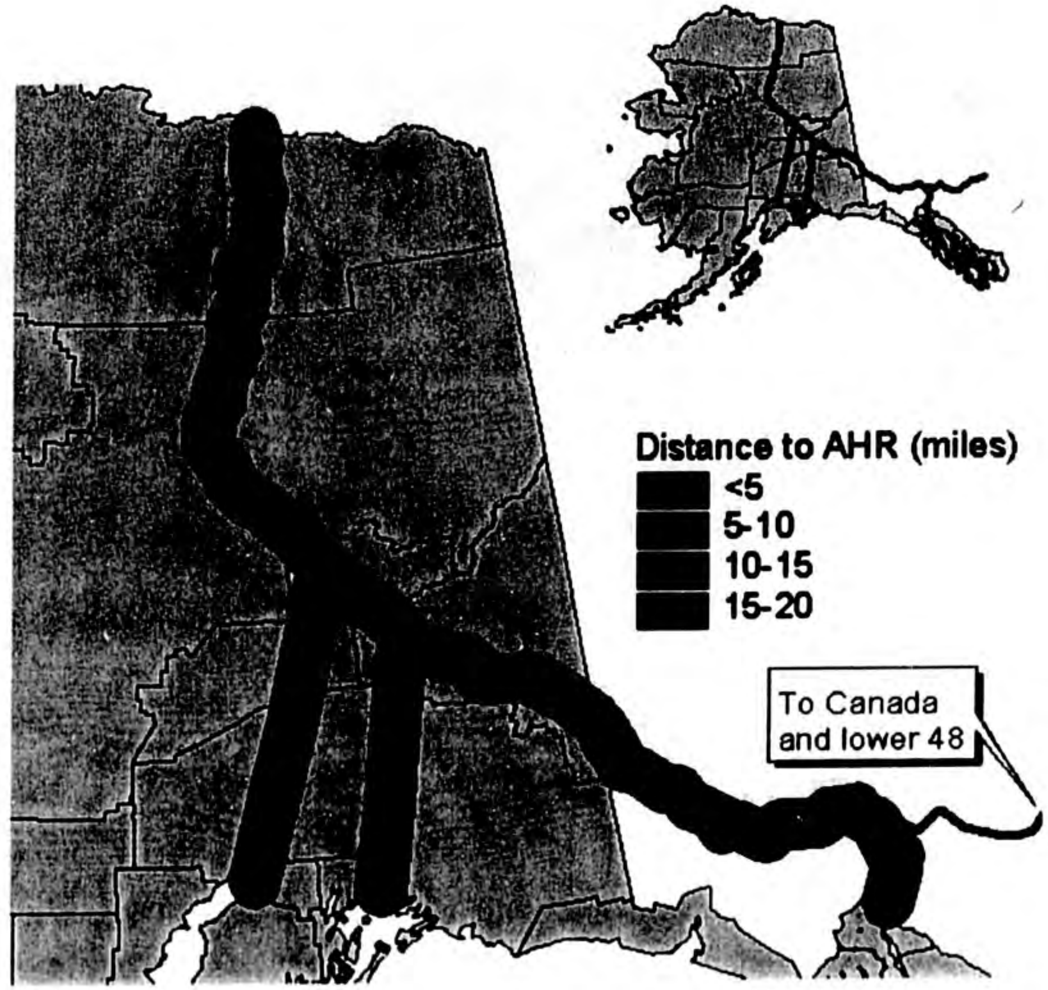

Figure 6.7: Proximity Zones Areas Around the Proposed Alaska Highway Route (AHR)

Table 6.7 reports the number of households in settlements without natural gas service (NOEPNGS), while Table 6.8 shows the frequency distribution of households within each region and for Alaska as a whole. In both tables, statistics for the proximity zones close to existing natural gas systems (EPNGS) are provided in the columns while the statistics for proximity zones close to Alaska Highway Route (AHR) are presented in the rows. These tables should be read in a cumulative and not incremental fashion.

For instance, Table 6.7 shows that in the lower most corner of the table, there are 57,262 households (intersection of "Row Total" and "Column Total") living in settlements that have no existing or proposed natural gas service. Of that amount, some 26,220 households do not live within 20 miles of either an existing natural gas distribution system (EPNGS) or the Alaska Highway Route (AHR) pipeline. These households (26,220) amount to some 45.8 percent of total non-served Alaska households. Thus, close to half of the households in Alaska reside within settlements that are not within 20 miles of neither the proposed major transportation route, nor an existing local distribution system.

On the other extreme, we have provided estimates of those households that are close to existing LDC systems and the AHR. Consider the bottom most section of Table 6.7 that has the Alaska totals. In the upper row (within 5 miles) we estimate that there are 10,325 households that are in settlements that are within both 5 miles of existing LDC systems (EPNGS) and the proposed highway route (AHR). Thus, some 18 percent of the non-served households reside in settlements that are within 5 miles of both the existing LDC systems and the AHR. The percentage can be found in the same cell on Table 6.8

We can also examine the geographic distribution of households within areas served by LDC systems and AHR separately. Consider the same section of Table 6.7 (the Alaska total section). We find that there are 11,934 households that are in settlements within 10 miles of the AHR and within 5 miles of an existing LDC system, representing 20.8 percent of the total unserved households in Alaska (Table 6.7 for cumulative percent). Moving to the right hand side of this section of bottom of Table 6.7 we find that there are 12,490 households that reside within 5 miles of the AHR and within 20 miles of an existing LDC system. This represents 21.8 percent of the unserved households (Table 6.7).

Table 6.9 presents summary of the major mileage categories and the households that fall into the proximity zones we have identified. Estimates for each region are provided in this table. In addition, to the right of the Alaska total is the sum of the households in the combined Interior and Southcentral regions.

We conclude from the geographic proximity analysis that approximately 19,000 occupied households, representing the potential for 3.8 Bcf per year of natural gas usage, are located within 20 miles of the proposed AHR and an existing gas service area. These households are located primarily in the Southcentral and Interior regions and represent about one-third of all occupied households, statewide that currently are not served by natural gas distribution systems.

Table 6.7: Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region	Distance to AHR	Distance to EPNGS Settlements: Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Far North	Within 5 miles	0	0	0	0	13	13
	Within 10 miles	0	0	0	0	13	13
	Within 15 miles	0	0	0	0	13	13
	Within 20 miles	0	0	0	0	25	25
	Beyond 20 miles	0	0	0	0	4,525	4,525
	Column Total	0	0	0	0	4,550	4,550
Interior	Within 5 miles	5,555	5,732	7,403	7,720	1,761	9,481
	Within 10 miles	5,555	5,732	7,403	7,939	1,761	9,700
	Within 15 miles	5,555	5,732	7,403	7,939	1,787	9,726
	Within 20 miles	5,555	5,732	7,403	7,939	1,822	9,761
	Beyond 20 miles	0	0	0	0	1,695	1,695
	Column Total	5,555	5,732	7,403	7,939	3,517	11,456
South Central	Within 5 miles	4,770	4,770	4,770	4,770	1,400	6,170
	Within 10 miles	6,379	6,417	6,417	6,417	1,409	7,826
	Within 15 miles	9,259	9,297	9,297	9,297	1,771	11,068
	Within 20 miles	11,162	11,219	11,219	11,219	2,150	13,369
	Beyond 20 miles	4,849	5,474	5,561	5,778	7,954	13,732
	Column Total	16,011	16,693	16,780	16,997	10,104	27,101
South East	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	19	19	19	19	0	19
	Beyond 20 miles	434	590	926	1,160	615	1,775
	Column Total	453	609	945	1,179	615	1,794
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	743	817	841	930	11,431	12,361
	Column Total	743	817	841	930	11,431	12,361
Alaska Total	Within 5 miles	10,325	10,502	12,173	12,490	3,174	15,664
	Within 10 miles	11,934	12,149	13,820	14,356	3,183	17,539
	Within 15 miles	14,814	15,029	16,700	17,236	3,571	20,807
	Within 20 miles	16,736	16,970	18,641	19,177	3,997	23,174
	Beyond 20 miles	6,026	6,881	7,328	7,868	26,220	34,088
	Column Total	22,762	23,851	25,969	27,045	30,217	57,262

Table 6.8: Relative Frequency Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.3%	0.3%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.5%	0.5%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	99.5%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	48.5%	50.0%	64.6%	67.4%	15.4%	82.8%
	Within 10 miles	48.5%	50.0%	64.6%	69.3%	15.4%	84.7%
	Within 15 miles	48.5%	50.0%	64.6%	69.3%	15.6%	84.9%
	Within 20 miles	48.5%	50.0%	64.6%	69.3%	15.9%	85.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	14.8%	
	Column Total	48.5%	50.0%	64.6%	69.3%		100.0%
South Central	Within 5 miles	17.6%	17.6%	17.6%	17.6%	5.2%	22.8%
	Within 10 miles	23.5%	23.7%	23.7%	23.7%	5.2%	28.9%
	Within 15 miles	34.2%	34.3%	34.3%	34.3%	6.5%	40.8%
	Within 20 miles	41.2%	41.4%	41.4%	41.4%	7.9%	49.3%
	Beyond 20 miles	17.9%	20.2%	20.5%	21.3%	29.3%	
	Column Total	59.1%	61.6%	61.9%	62.7%		100.0%
South East	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Beyond 20 miles	24.2%	32.9%	51.6%	64.7%	34.3%	
	Column Total	25.3%	33.9%	52.7%	65.7%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	6.0%	6.6%	6.8%	7.5%	92.5%	
	Column Total	6.0%	6.6%	6.8%	7.5%		100.0%
Alaska Total	Within 5 miles	18.0%	18.3%	21.3%	21.8%	5.5%	27.4%
	Within 10 miles	20.8%	21.2%	24.1%	25.1%	5.6%	30.6%
	Within 15 miles	25.9%	26.2%	29.2%	30.1%	6.2%	36.3%
	Within 20 miles	29.2%	29.6%	32.6%	33.5%	7.0%	40.5%
	Beyond 20 miles	10.5%	12.0%	12.8%	13.7%	45.8%	
	Column Total	39.8%	41.7%	45.4%	47.2%		100.0%

Table 6.9: Summary of Distribution of Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	5,555	16,011	453	743	22,762	21,566
Within 5 miles of AHR	13	9,481	6,170	0	0	15,664	15,651
Within 5 miles of EPNGS and AHR	0	5,555	4,770	0	0	10,325	10,325
Within 10 miles of EPNGS	0	5,732	16,693	609	817	23,851	22,425
Within 10 miles of AHR	13	9,700	7,826	0	0	17,539	17,526
Within 10 miles of EPNGS and AHR	0	5,732	6,417	0	0	12,149	12,419
Within 15 miles of EPNGS	0	7,403	16,780	945	841	25,969	24,183
Within 15 miles of AHR	13	9,726	11,068	0	0	20,807	20,794
Within 15 miles of EPNGS and AHR	0	7,403	9,297	0	0	16,700	16,700
Within 20 miles of EPNGS	0	7,939	16,997	1,179	930	27,045	24,936
Within 20 miles of AHR	25	9,761	13,369	19	0	23,174	23,130
Within 20 miles of EPNGS and AHR	0	7,939	11,219	19	0	19,177	19,518
Beyond 20 miles of both EPNGS and AHR	4,525	1,695	7,954	615	11,431	26,220	9,649

Table 6.10: Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
Region	Distance to AHR						
	Within 5 miles	0	0	0	0	2,578	2,578
	Within 10 miles	0	0	0	0	2,578	2,578
	Within 15 miles	0	0	0	0	2,578	2,578
	Within 20 miles	0	0	0	0	4,958	4,958
Far	Beyond 20 miles	0	0	0	0	897,308	897,308
North	Column Total	0	0	0	0	902,265	902,265
	Within 5 miles	1,101,557	1,136,656	1,468,015	1,530,876	349,206	1,880,082
	Within 10 miles	1,101,557	1,136,656	1,468,015	1,574,304	349,206	1,923,510
	Within 15 miles	1,101,557	1,136,656	1,468,015	1,574,304	354,362	1,928,666
	Within 20 miles	1,101,557	1,136,656	1,468,015	1,574,304	361,303	1,935,606
	Beyond 20 miles	0	0	0	0	336,119	336,119
Interior	Column Total	1,101,557	1,136,656	1,468,015	1,574,304	697,421	2,271,725
	Within 5 miles	945,891	945,891	945,891	945,891	277,620	1,223,511
	Within 10 miles	1,264,956	1,272,491	1,272,491	1,272,491	279,405	1,551,896
	Within 15 miles	1,836,060	1,843,595	1,843,595	1,843,595	351,189	2,194,784
	Within 20 miles	2,213,425	2,224,728	2,224,728	2,224,728	426,345	2,651,073
South	Beyond 20 miles	961,557	1,085,494	1,102,746	1,145,777	1,577,278	2,723,056
Central	Column Total	3,174,981	3,310,222	3,327,474	3,370,505	2,003,623	5,374,128
	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	3,768	3,768	3,768	3,768	0	3,768
South	Beyond 20 miles	86,062	116,997	183,626	230,028	121,955	351,983
East	Column Total	89,830	120,765	187,394	233,796	121,955	355,750
	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
South	Beyond 20 miles	147,337	162,011	166,770	184,419	2,266,767	2,451,186
West	Column Total	147,337	162,011	166,770	184,419	2,266,767	2,451,186
	Within 5 miles	2,047,448	2,082,547	2,413,906	2,476,767	629,404	3,106,171
	Within 10 miles	2,366,512	2,409,147	2,740,506	2,846,795	631,189	3,477,984
	Within 15 miles	2,937,616	2,980,251	3,311,610	3,417,899	708,129	4,126,028
	Within 20 miles	3,318,749	3,365,151	3,696,510	3,802,799	792,605	4,595,404
Alaska	Beyond 20 miles	1,194,956	1,364,502	1,453,142	1,560,224	5,199,426	6,759,650
Total	Column Total	4,513,705	4,729,653	5,149,653	5,363,024	5,992,031	11,355,055

Table 6.11: Summary of Potential Natural Gas Usage by Alaskan Households without Existing or Proposed Access to Natural Gas Service by Proximity to Potential Sources of Natural Gas Supply, Mcf

	Far North	Interior	South Central	South East	South West	Alaska Total	Interior and South Central
Within 5 miles of EPNGS	0	1,101,557	3,174,981	89,830	147,337	4,513,705	4,276,538
Within 5 miles of AHR	2,578	1,880,082	1,223,511	0	0	3,106,171	3,103,593
Within 10 miles of EPNGS	0	1,136,656	3,310,222	120,765	162,011	4,729,653	4,446,878
Within 10 miles of AHR	2,578	1,923,510	1,551,896	0	0	3,477,984	3,475,406
Within 15 miles of EPNGS	0	1,468,015	3,327,474	187,394	166,770	5,149,653	4,795,489
Within 15 miles of AHR	2,578	1,928,666	2,194,784	0	0	4,126,028	4,123,450
Within 20 miles of EPNGS	0	1,574,304	3,370,505	233,796	184,419	5,363,024	4,944,809
Within 20 miles of AHR	4,958	1,935,606	2,651,073	3,768	0	4,595,404	4,586,679
Beyond 20 miles of both EPNGS and AHR	897,308	336,119	1,577,278	121,955	2,266,767	5,199,426	1,913,397

6.3: Gas Opportunities in the Interior Region

One of the nearest concentrations of potential gas usage in Alaska is in the Interior section of the state. Table 6.7 shows that of the 15,664 unserved households in the state, some 5,555 (35 percent) are in the Interior region. Over 50 percent of all the unserved households in the state that are within 10 miles of the proposed AHR project are in the Interior region of the state. Some 41 percent of all households in the state living within 20 miles of both types of infrastructure (distribution and proposed transmission) are in the Interior region.[2] We explore the degree of residential geographic concentration, and its implications for potential gas demand in this section.

<u>6.3.1: Overview of the Greater Fairbanks Region:</u> The Fairbanks North Star Borough (FNSB) encompasses nearly 7,500 square miles of interior Alaska near the confluence of the Tanana and Chena Rivers and is located in the proximity of the Alaska Highway route for the proposed gas pipeline. As seen in Table 6.12, Borough population was 82,840 in 2001. Some 53,300 people reside in the ten communities and two military bases in the NSB region. The remaining 29,500 FNSB inhabitants reside in unincorporated places in the greater Fairbanks North Star Borough area. The City of Fairbanks, with a population of 30,224 is Alaska's second largest community and the Borough hub. College, a separate community located three miles northwest of Fairbanks, is the location of the University of Alaska at Fairbanks and includes an additional 11,400 residents.

The greater FNSB area has been inhabited by Koyukon Athabascans for thousands of years. During the gold rush era of the 1890s, Fairbanks began a steamboat landing. The University of Alaska Fairbanks was established in 1915. Eielson Air Force Base, established during Worth War II, is 26 miles south of Fairbanks, near the City of North Pole (1,570 population) and accounts for an additional 5,400 Borough residents. The area continued to grow with construction of the Alcan Highway and with the Trans-Alaska oil pipeline.

The FNSB contains 29,800 occupied housing units plus an additional 3,500 vacant or seasonal dwellings. Approximately one third of these are located in unincorporated places. Average occupied household size in the borough is 2.68, down from 2.70 in 1990.

Average temperatures in the greater FNSB range from –22 degrees Fahrenheit during winter to 72 degrees Fahrenheit during summer. Seasonal extremes can far exceed these this temperate range. According to the Stone and Webster *Railbelt Intertie Reconnaissance Study* (1989, Intertie Study), heating degree days in the Fairbanks area are approximately 40 percent greater than

[2]There are 7,939 unserved households in the Interior region compared to a state-wide total 19,777. See Table 6.1 for details.

Anchorage. The average occupied household would consume approximately 235 Mcf of natural gas per year.[3]

[3]Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study*, 1989.

Table 6.12: Fairbanks North Star Borough Population and Housing Characteristics, 2000-2001

		Population			Housing Units				Average Household Size[2]
					Occupied	Vacant		Total	
Item		In Occ HHs	In Group Qs	Total		Total	Seasonal		
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	College	10,651	751	11,402	4,104	397	54	4,501	2.60
2	Ester	1,600	80	1,680	727	87	22	814	2.20
3	Fairbanks[1]	28,325	1,899	30,224	11,075	1,282	121	12,357	2.56
4	Fox	300	-	300	119	40	2	159	2.52
5	Harding Lake	216	-	216	98	391	371	489	2.20
6	Moose Creek	541	1	542	223	57	-	280	2.43
7	North Pole	1,561	9	1,570	605	48	1	653	2.58
8	Pleasant Valley	623	-	623	219	27	13	246	2.84
9	Salcha	854	-	854	317	71	36	388	2.69
10	Two Rivers	482	-	482	177	15	7	192	2.72
11	Subtotal	45,153	2,740	47,893	17,664	2,415	627	20,079	2.56
12	Eileson AFB	5,090	310	5,400	1,448	83	-	1,531	3.52
13	Subtotal	50,243	3,050	53,293	19,112	2,498	627	21,610	2.63
14	Unincorporated	29,517	30	29,547	10,665	1,016	366	11,681	2.77
15	Fairbanks NSB	79,760	3,080	82,840	29,777	3,514	993	33,291	2.68
16	Fairbanks NSB (1990)	74,139	3,581	77,720	26,693	5,130	-na-	31,823	2.70

[1] Includes Fort Wainwright.

[2] Equal to ratio of population in occupied households (a) to occupied housing units (d).

<u>6.3.2: Residential Sector Gas Usage</u>: Residential space heating is accomplished primarily with fuel oil. Electricity, and to a lesser extent, coal and wood, provide only modest baseload space heating requirements.[4] The high incidence of population in unincorporated places, and general lack of population density in the FNSB, is a barrier to widespread gas utility service throughout the area. The authors and expert reviewers of the 1989 Intertie Study determined that a subset equal to 38 percent of the Borough, representing the areas of Fairbanks, North Pole, Farmers Loop, and Beaver Loop comprise the "gas service area" that may be economically served by a gas utility.[5] The number of households in the Fairbanks North Star borough gas service area in 2001 is estimated to be approximately 11,300.

Fairbanks Natural Gas, LLC has operated as a local distribution company for residential and commercial natural gas service in the city of Fairbanks since 1998. Gas from the Enstar system is liquefied in a small facility near Wasilla and transported by cryogenic tanker trailers to its local distribution pipeline system in Fairbanks. As shown in Table 6.13, the residential and commercial natural gas customer base has expanded from 50 in 1999 to 300 in 2001. Average gas usage per customer is about 560 Mcf per year. Retail prices varied from $6.29 to $7.59 per Mcf, depending on customer class and volume of gas usage. The average retail price of gas was $7.19 over the three-year period, 1999-2001.

Table 6.13: Fairbanks Natural Gas, LLC Customers and Gas Usage, 1998-2002

	Customers				Gas Usage			
	Residential	Commercial		Total	Total	Average	Receipts	Price
Year		Large	Small		Mcf/Year	Mcf/Year	$/Year	$/ Mcf
1998				18	3,511	195.1	$ 24,555	$ 6.99
1999				50	29,684	593.7	203,906	6.87
2000				130	73,418	564.8	497,304	6.77
2001	152	10	205	367	157,776	429.9	1,179,208	7.47
2002[a]					275,000		2,400,000	8.73
					Average (1999-2001)	529.4		$ 7.21

The 1989 Intertie Study projected households to grow on average 2 percent annually from the year 2000 to 2010. The statewide annual average household growth used for base case projections by the Institute of Social and Economic Research (2001)[6] is 1.19 percent during the period 2000-2009. The upper range of growth assumes a set of optimistic conditions such as an increase in the real price of ANS Crude, development of ANWR, and the construction of the gas

[4]U.S. Department of Energy, Energy Information Administration. *Residential Energy Consumption Survey.*

[5]Ibid, Vol. 10.

[6]Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025,* October ,2001.

pipeline, among other large projects. While the success of the other events is not assured, the construction of the gas pipeline is a necessary condition for the delivery of ANS gas to Fairbanks. Given its location on the pipeline route, Fairbanks is assumed to grow at the forecasted statewide rate of 1.5 percent through 2009. At this rate, occupied households in the gas service area would grow to 12,558 in 2009 (Table 6.14).

The 1989 Intertie Study used historical residential gas usage in Anchorage, adjusted for 40 percent more heating degree-days, to forecast average annual residential gas utility usage in Fairbanks. This forecast was based on the demand for each existing fuel source and an assumed gas market penetration factor. In turn, this penetration rate is driven largely by the difference between the price of natural gas and its substitutes. As shown in Table 6.14, the penetration rate used for the Fairbanks gas service area residential sector varies from 25 percent to 83 percent. The high penetration rate is based on the assumption that the price of gas will be half that of fuel oil, per million BTUs. This rate is lower than Enstar's experience in the Southcentral region, which is ranges from 90 percent, 95 percent, and 98 percent for electricity, fuel oil and propane substitutes, respectively.

Table 6.14: Summary of Potential Natural Gas Usage in the Fairbanks North Star Borough Area by Sector in 2009

Line No.		Formula		Low	Medium	High
1	**Residential Sector**					
2	Projected Total Occupied HHs in 2009[1]		33,048			
3	Proportion of HHs in Gas Service Area[2]		38.0%			
4	Number of HHs in Gas Service Area		12,558			
5	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
6	Number of HHs Obtaining Gas Service	Line 4 x Line 5		3,140	6,279	10,423
7	Average Annual Household Gas Usage (Mcf/Yr)[2]		235			
8	**Potential Residential Gas Usage in 2009 (Bcf/Yr)**	(Line 6 x Line 7)/1,000,000		**0.7**	**1.5**	**2.4**
9	**Commercial Sector**					
10	FNSB Commercial Space in 1997 (Million Sq Ft)[3]		18.5			
11	Non-Residential Commercial Space to be Heated (Million Sq Ft)[3]		13.3			
12	Projected Non-Res Commercial Space in 2009 (Million Sq Ft)		15.9			
13	Average Commercial Gas Usage (Mcf per Square Foot)[2]		206			
14	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
15	**Potential Commercial Gas Usage in 2009 (Bcf/Yr)**	(Line 12 x Line 13 x Line 14)/ 1,000		**0.8**	**1.6**	**2.7**
24	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 8 and 15)		**1.6**	**3.1**	**5.2**

Table Notes:

1 Annual average growth is assumed to equal to 1.5% based on the analysis in Institute for Social and Economic Research, *Economic Projections: Alaska and the Southern Railbelt 2000-2025*, October 2001.

2 83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study*, 1989.

3 Special tabulation by Carl McManus, Deputy Appraiser for FNSB (1997).

It is important to remember that a key factor in energy mode switch is recovery of upfront investment cost of heating system conversion to the alternate fuel. The rule-of-thumb for gas utilities' market planning is that if a customer can recoup their cost of conversion within three years then the penetration rate will be over 95 percent, at increments of 30 percent to 35 percent each year over a three to five year period.[7] Although wood heat is not exactly homogenous with thermostat-controlled central heating furnaces, they serve the same ultimate purpose. The 1989 Intertie Study concluded that only 10 percent of all the residences currently burning wood in the greater Fairbanks gas service area would switch to natural gas.

As shown in Table 6.14, potential residential gas usage for space heating and projected in 2009 in the greater Fairbanks area varies from between 0.7 to 2.4 Bcf per year, depending on the rate of gas service penetration. By comparison current gas usage for space heating in the Enstar system in Southcentral is approximately 36 Bcf.[8]

6.3.3: Commercial Sector Gas Usage: The potential for gas consumption by commercial users in the FNSB, such as office buildings and hospitals is summarized in Table 6.14. Commercial energy consumption of gas is assumed to depend on the amount of commercial square footage in use. In 1997, Fairbanks North Star Borough has 18.5 million commercial square feet on their tax roles.[9] Of that total, 13.3 million square feet represent nonresidential space to be heated. The 1989 Intertie Study assumed that commercial building square footage would increase in step with increases in population. This rate will cause commercial, heated square footage to grow to approximately 15.9 million square feet by 2009 and require between 0.8 and 2.7 Bcf per year, depending on the rate of gas service penetration (Table 6.14).

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[7]Communication between ADNR and Dan Dieckgraeff of Enstar, July 1997.

[8]This figure is for residential and commercial usage only. DOE reported total retail sales by Enstar for 1999 is 45.6 Bcf (includes some direct served utility and industrial usage). Gas usage for the region, including the Agrium plant, LNG production, other utility generation, and lease use of natural gas is 213 Bcf.

[9]Special tabulation provided to ADNR by Carl McManus, Deputy Appraiser for FNSB, (1997).

CHAPTER 7: NEW AND EXISTING INDUSTRIAL USAGE OPPORTUNITIES

This chapter investigates the natural gas requirements for new and existing industries in Alaska's economy. The two new industries that we examined included the addition of a major Internet server facility as well as a major petrochemical facility. We also consider the possibilities for expanded natural gas use in the LNG plant operated by Phillips and Marathon and the ammonia-urea plant, recently acquired from Unocal by Agrium, Inc., both located near Kenai, Alaska.

7.1: New Natural Gas Usage Opportunities: Internet Server Facility

Data centers, also referred to as "server farms" or "dot-com hotels" are buildings that house computer equipment to support information and communication systems.[1] It is commonly recognized that these data centers have energy usage requirements that are generally higher than most residential or commercial buildings. The exact usage levels of the facilities, however, are much disputed given how new this sector is to the economy, as well as some common misunderstandings about the energy requirements of the different types and sizes of these facilities.

A recently released report prepared at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratories, has offered a number of new insights into these facilities and their energy usage levels. One of the considerable contributions of this study has been to define a set of common metrics upon which to estimate Internet server energy usage. A brief digression on these matrices is helpful in terms of understanding how we estimated the potential energy needs of a new Internet facility in Alaska. This discussion will focus on the power requirements of the new facilities. Later, these power requirements will be translated into new natural gas usage opportunities.

Power requirements in data centers are commonly referred to as the "power density" of the facility as measured in watts per square foot (W/sq.ft). What is commonly not clarified is exactly what square feet of an internet server facility is the most relevant. Data centers, for instance, can vary considerable in both size and composition.

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[1]This chapter of our report borrows heavily from recently completed research conducted at the University of California, Berkeley and the Lawrence Berkeley Livermore (LBL) Laboratory. This recent research provides an excellent analysis of Internet server farm energy requirements and debunks many recent estimates showing considerable energy demand growth from Internet facilities. This chapter of our report will refrain from repeated citations, however, the reader is encouraged to review the following report for analysis and energy usage estimates that we have used to estimate new Internet natural gas usage opportunities: Jennifer D. Mitchell-Jackson. *Energy Needs in an Internet Economy: A Closer Look at Data Centers*. M.S. Thesis. University of California, Berkeley, 2001.

A data center, like many commercial establishments, can be characterized by its gross floor space. Multiplying this gross floor space by a given power density factor can lead overestimates of power requirements for these facilities. In order to get an accurate representation of these uses, data center building compositions need to be disaggregated into its component parts. Understanding the uses and decomposition of an Internet server facility highlights the need for two important distinctions:

> ***Computer power density:*** the power drawn by the computer equipment divided by the central computer room floor area; and
>
> ***Building power density:*** the total facility power requirements divided by the building gross square feet.

The recent LBL study found that close examination of these characteristics are important since energy usage at these facilities is often overstated due to the usable size of a given facility and the utilization of the equipment within a given relevant space. The LBL study, using actual data from Internet facilities and building information found that actual power density for a typical facility was much less than commonly accepted estimates. For the facility under investigation in the LBL study, researchers found that actual power requirements were 1.4 MWs compared to the "misinformed forecast" of 7.5 MW.[2]

Our analysis uses the LBL ranges of computer floor power densities to estimate ranges of potential power and gas requirements for a typical facility. In addition to three potential power density factors, we used a range of computer floor sizes (in square feet) to estimate the potential total energy requirements. Our analysis assumes that all new Internet power requirements will be generated with natural gas fired generators. Thus, our estimates are an outer boundary of the potential gas usage that could result from a new internet facility.

Lastly, our analysis assumes that power requirements will be generated on-site. We examine three different types of small-scale power generation technologies: a small gas turbine; a reciprocating engine; and a fuel cell. Various heat rate assumptions were used to convert power requirements to natural gas usage requirements. The summary results from our findings are presented in Table 7.1

[2]The misinformed forecast took total design power density and multiplied this by total building square feet. Thus size and utilization were overestimated.

Table 7.1: Summary of Internet Server Power and Gas Usage

		Gas Turbine		Reciprocating Engine		Fuel Cell	
Facility Size, Power Density	Generator Capacity (kW)	Annual Generation (kWh)	Annual Gas Usage (Mcf)	Annual Generation (kWh)	Annual Gas Usage (Mcf)	Annual Generation (kWh)	Annual Gas Usage (Mcf)
Small Facility, Low Power Density	420	3,495,240	34,952	3,495,240	45,438	3,495,240	20,971
Small Facility, Medium Power Density	720	5,991,840	59,918	5,991,840	77,894	5,991,840	35,951
Small Facility, High Power Density	1,020	8,488,440	84,884	8,488,440	110,350	8,488,440	50,931
Medium Facility, Low Power Density	1,050	8,738,100	87,381	8,738,100	113,595	8,738,100	52,429
Medium Facility, Medium Power Density	1,800	14,979,600	149,796	14,979,600	194,735	14,979,600	89,878
Medium Facility, High Power Density	2,550	21,221,100	212,211	21,221,100	275,874	21,221,100	127,327
Large Facility, Low Power Density	1,680	13,980,960	139,810	13,980,960	181,752	13,980,960	83,886
Large Facility, Medium Power Density	2,880	23,967,360	239,674	23,967,360	311,576	23,967,360	143,804
Large Facility, High Power Density	4,080	33,953,760	339,538	33,953,760	441,399	33,953,760	203,723

The Internet facility usages presented in Table 7.1 are comparable to a recently announced Internet server farm that is considering development in Alaska. Netricity, L.L.C. has proposed to develop an Internet server farm that would provide web-hosting services and be connected to clients and users by the fiber optic system that runs the length of the trans-Alaska crude pipeline.[3] According to the proposal, the $1 billion facility would house 500,000 Internet servers in a one billion square foot building, with gas usage of approximately 120 MMcf/d. The facility would generate approximately 400 MW of electricity. Assuming that all of this electricity is used on site, this level of power usage (400 watts per square foot) is considerably higher than the high power density example illustrated above (85 watts per square foot).[4]

7.2: New Natural Gas Usage Opportunities: Petrochemical Facility

The potential gas usage opportunities associated with new petrochemical industries in Alaska is the subject of this section. In part, this analysis was stimulated by the opportunities that are currently being explored by Williams Energy Company. In a presentation before the Alaska Highway Natural Gas Policy Council, Williams announced that it was initiating a study of the petrochemical opportunities within the state. One potential option that has been discussed is the development of a project producing ethylene and propylene.

The Williams proposal is based upon a facility that would use over one Bcf/d of natural gas. The plant would take ethane from the natural gas stream to crack ethylene. The ethylene, in turn, is used to develop polyethylene pellets, which would be shipped by rail to Anchorage or Seward for tanker shipment to global markets. Most of the residual gas (methane) would be re-injected back into the natural gas pipeline serving the facility. The plant would employ close to 350 full time personnel and a potential payroll of $18 million per year, with as much as $15 million a year paid to the Alaska Railroad for transportation services.[5] This petrochemical facility opportunity, according to company spokespeople, is still under investigation.

Almost all ethylene produced is consumed as feedstock for manufacturing other petrochemicals. Although some ethylene is shipped across the oceans in large quantities, the preference is usually to ship first-generation products such as polyethylene, or ethyl benzene.[6] The economics for the production of ethylene depends to a large extent on the prices for feedstocks and co-products and transportation charges. In the U.S., the feedstocks of choice have been the

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[3] *Petroleum News Alaska*, Volume 7, Number 101-1, August 1, 2001

[4] The Netricity proposal is not clear on exactly what square feet are being presented in its overall proposed project size. As noted earlier, power density is higher when concentrated on core computer room density.

[5] Kay Cashman. "Williams Wants To Operate Gasline. *Petroleum News Alaska*. (December 2, 2001): 11.

[6] *Kirk-Othmer Encyclopedia of Chemical Technology*. Fourth Edition, Volume 9. New York: John Wiley and Sons: 908.

lighter feeds of ethane and propane. Approximately 70 percent of U.S. ethylene production is from ethane, propane, and butane. Ethane feed generally gives the lowest cost of production and the lowest capital investment relative to other feedstocks.[7] Cheaper alternative feedstocks, in some instances, can offset this advantage.

In the U.S., the Gulf Coast produces and consumes the majority of the ethylene production. In fact, six of the 10 largest plants in the U.S. are in Texas and Louisiana. These plants are served by an extensive system of pipelines connecting the production and consuming plants. Currently operational U.S. ethylene plants, their locations, and typical feedstocks are provided in Table 7.2. These facilities are provided in the annual International Survey of Ethylene From Steam Crackers, *Oil and Gas Journal*, April 2001.

[7] *Ibid.*, 910.

Table 7.2: Major Ethylene Facilities in the U.S.

Facility	Location	Total Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity is Based				
			Ethane	Propane	Butane	Naphtha	Other
BP	Chocolate Bayou, TX	1,451,000	50%	35%		15%	
Chevron Phillips Chemical Co	Cedar Bayou, TX	794,000	30%	20%	25%	25%	
Chevron Phillips Chemical Co	Port Arthur, TX	794,000	70%	30%			
Chevron Phillips Chemical Co	Sweeny, TX	181,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	318,000	100%				
Chevron Phillips Chemical Co	Sweeny, TX	680,000	80%	20%			
Chevron Phillips Chemical Co	Sweeny, TX	907,000	38%	37%	25%		
Condea Vista Co	Westlake, LA	447,000	100%				
Dow Chemical Co	Freeport, TX	590,000	50%	50%			
Dow Chemical Co	Freeport, TX	950,000	10%	70%		20%	
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%			
Dow Chemical Co	Plaquemine, LA	680,000	20%	30%		50%	
Dow Chemical Co	Seadrift, TX	440,000	100%				
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%	
Dow Chemical Co	Taft, LA	410,000	25%	25%		50%	
Dow Chemical Co	Texas City, TX	680,000	95%	5%			
DuPont	Orange, TX	590,000	100%				
Eastman Chemical Co	Longview, TX	684,000	25%	67%	7%	1%	
Equistar Chemical Co	Channelview, TX	875,000	5%			95%	
Equistar Chemicals, LP	Chocolate Bayou, TX	875,000	5%			95%	
Equistar Chemicals, LP	Clinton, IO	544,000				100%	
Equistar Chemicals, LP	Corpus Christi, TX	476,000	80%	20%			
Equistar Chemicals, LP	Lake Charles, LA	771,000	10%	30%		60%	
Equistar Chemicals, LP	LaPorte, TX	385,000	80%	20%			
Equistar Chemicals, LP	Morris, IL	789,000	60%	20%		20%	
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%			
ExxonMobil Chemical Co	Baytown, TX	882,000					
ExxonMobil Chemical Co	Beaumont, TX	1,890,000	50%	15%	35%		
ExxonMobil Chemical Co	Houston, TX	816,000	90%	10%			
Formosa Plastics Corp	Point Comfort, TX	356,000	33%	33%		34%	
Hunstman Corp	Odessa, TX	714,000					
Hunstman Corp	Port Arthur, TX	230,000				60%	40%
Hunstman Corp	Port Neches, TX	551,000					
Javelina Co	Corpus Christi, TX	136,000					
Shell Chemicals Ltd	Deer Park, TX	151,000	15%		5%	50%	30%
Shell Chemicals Ltd	Norco, LA	952,000	45%	5%	5%	45%	
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%
Sunoco Inc	Marcus Hook, PA	225,000	50%	50%			
Westlake Petrochemicals Corp	Calvert City, KY	181,000		100%			
Westlake Petrochemicals Corp	Sulphur, LA	590,000	65%	35%			
Westlake Petrochemicals Corp	Sulphur, LA	436,000	100%				
Williams Energy Services	Geismar, LA	567,000	90%	10%			

Estimating the amount of natural gas used by a typical petrochemical facility like an ethylene plant is a very complicated process. These plants, which are constructed at what is referred to as "world class scale," can amount to billions of dollars of investment. Thus, prior to development, a substantial amount of work is conducted in optimizing plant design, including the use of feedstocks. Critical to this analysis is the liquids composition of the ANS gas stream, which is under the producers' control and would be influenced by requirements for gas cycling for EOR as well as by relative prices for various components in the gas stream.

While large ethylene plants can use a significant amount of natural gas, it is important to keep in mind that only the ethane, propanes, and butanes of the gas are actually used for production. One of the byproducts of the cracking process is methane – often referred to as residual gas. In some instances, this unused methane can actually be injected back into the natural gas pipeline.[8]

Given the myriad number of variables associated with estimating natural gas use at a "typical" ethylene plant, we have opted to use a "comparable facilities" approach to estimating potential natural gas usage at facilities located in Louisiana. These facilities and their typical annual natural gas consumption are presented in Table 7.3. These facilitates are all of "world class scale." In addition, one of these facilities is an ethylene and propylene facility owned and operated by Williams Energy.

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[8]It is common industry practice to refer to ethylene "crackers" when referring to the production process of converting ethane to ethylene. However, this is a misnomer. Ethylene is not cracked by rather is a product of the cracking process. For a straightforward description of the ethylene production process, see Donald L. Burdick and William L. Leffler. *Petrochemicals in Non-Technical Language*. Houston, Pennwell Books: 1990.

Table 7.3: Typical Gas Usage at Major Ethylene Facilities in Louisiana

Facility	Location	Total Nameplate Capacity (TPY)	Typical Feedstock or Feedstock Mixture on Which Listed Capacity is Based: Ethane	Propane	Butane	Naptha	Other	Gas Usage MMcf	Gas Usage MMcf/d	Gas Usage (Mcf/TPY)
Condea Vista Co	Westlake, LA	447,000	100%					3,528	9.67	7.89
Dow Chemical Co	Plaquemine, LA	500,000	80%	20%						
Dow Chemical Co**	Plaquemine, LA	680,000	20%	30%		50%		50,000	136.99	42.37
Dow Chemical Co	Taft, LA	590,000	25%	25%		50%				
Dow Chemical Co**	Taft, LA	410,000	25%	25%		50%		7,908	21.67	19.29
ExxonMobil Chemical Co	Baton Rouge, LA	550,000	80%	20%				20,020	54.85	36.40
Shell Chemicals Ltd	Norco, LA	626,000	5%			35%	60%	13,540	37.10	21.63
Williams Energy Services	Geismar, LA	567,000	90%	10%				6,200	16.99	10.93

** *Combined Plant Totals*

7.3: Expanding Natural Gas Usage at Existing Industrial Facilities

Currently, there are two significant industrial users of natural gas in Alaska: the LNG facility owned by Phillips and Marathon in Kenai, and the Agrium, Inc. ammonia-urea facility, located in neighboring Nikiski. A graph of the historic natural gas consumption for each industrial facility is presented in Figure 7.1.

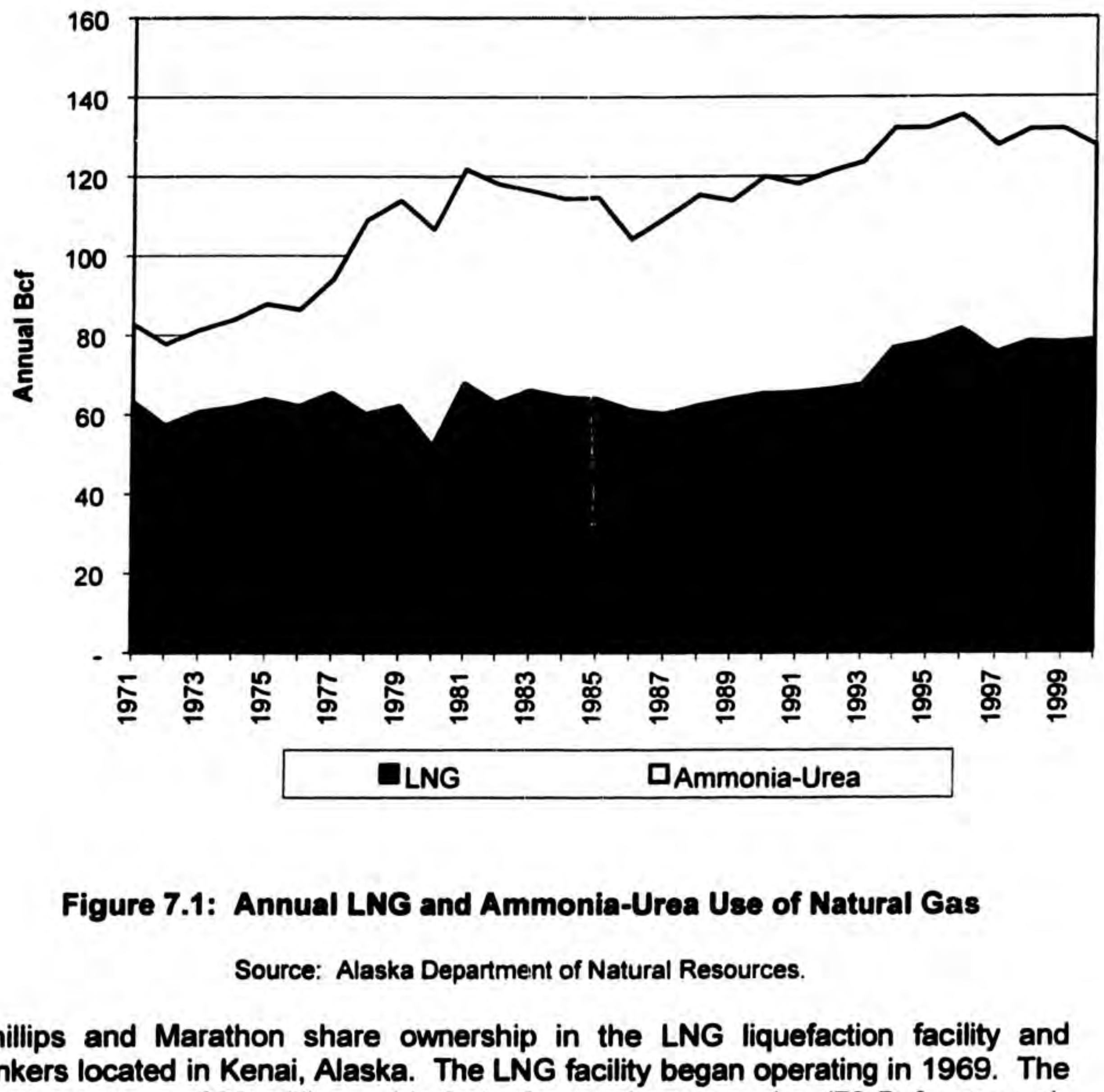

Figure 7.1: Annual LNG and Ammonia-Urea Use of Natural Gas

Source: Alaska Department of Natural Resources.

Phillips and Marathon share ownership in the LNG liquefaction facility and tankers located in Kenai, Alaska. The LNG facility began operating in 1969. The plant consumes 220 million cubic feet of natural gas per day (78 Bcf per year). The facility produces about 1.5 million metric tons of high-methane LNG per year. The LNG is sold to Tokyo Electric and Tokyo Gas companies. Today, the Phillips-Marathon LNG plant supplies approximately one percent of Japan's LNG consumption. The Kenai plant is a baseload LNG facility. Most other U.S. commercial LNG plants are peak saving operations, meaning small LNG plants typically located near utilities. Peak-shaving LNG plants liquefy and store gas delivered by pipeline at low demand periods for later use during peak periods. Baseload plants like the Phillips-Marathon plant in Kenai serve markets that are located far away from sufficient supplies to enable economic deliveries by pipeline. As seen in Figure 7.1, the use of natural gas at the LNG facility has been relatively constant since 1996. Given the steady, long term nature of these contracts, this relatively steady use of natural gas is not unexpected.

The economics of LNG are complicated and dependent upon a number of factors, not the least of which is forecasting the demand for LNG in Asian and world markets, as well as the direction of cost trends in other competing areas around the world. There have been a number of studies of expanded LNG production opportunities in Alaska over the past several years. Developing an alternative to these comprehensive studies was beyond the scope of this study.

However, we have examined the trends in past LNG natural gas usage over the past several years to see if few additional production opportunities exist. As we noted above, the trends in gas usage are relatively stable, and outside year-to-year variations, we see little opportunities to expand production beyond its current levels. Currently, the Kenai LNG facility is operating slightly below its all-time high level of usage of natural gas of 81 Bcf that occurred in 1996. In 2000, LNG uses of natural gas were at 78.5 Bcf, so conceivably, there may be an additional 2.8 Bcf of additional usage at the facility.

We have also examined the potential use of natural gas by the state's other large industrial natural gas user: The Agrium ammonia-urea plant in Southcentral Alaska. This plant produces anhydrous ammonia (NH_3) and urea fertilizer based on technology dating back to the 1960s. Plant output capacity is approximately two million tons per year, divided roughly between ammonia and urea. Natural gas (methane) is combined with nitrogen at high temperatures to produce NH_3 plus carbon dioxide and sulfur by-products. NH_3 is the feedstock for many other products, including nitrogen-based urea fertilizer. Ammonia is sold in separate markets and is an intermediate product used to make urea. Sometimes the relative price of urea is low. In such cases, it many be profitable to intensify ammonia production and reduce or completely halt urea production. Nearly all plant output is exported to markets in Southeast Asia, primarily Thailand.

Based upon information included in the Manufacturing and Industrial Plant Database (MIPD), published by The HIS Energy Group, at about 49 Bcf per year, the Agrium plant currently operates at about 80 percent of capacity. The high point for natural gas usage for the facility, as seen in Figure 7.1, was in 1996 when the facility used about 56 Bcf for that year. The facility consumed less natural gas from year to year since 1993. Hence, there appear to be short run opportunities for increased gas usage of up to 7.2 Bcf per year.

In a recent article published by *Petroleum News Alaska*, Agrium noted that they were interested in expanding its Cook Inlet operations, which could translate into additional annual usage of 30 Bcf per year.[9] Chris Tworek, Vice President of Supply for Agrium noted that, in order for the facility to expand production, its natural gas input prices would have to be competitive with global prices, which range between 75 cents to $1.00 per MMBtu. The potential for Agrium to increase natural gas usage by 30 Bcf per year is unlikely to occur a prices prevailing in the Cook Inlet Basin today but should be considered in a long run forecast of new industrial uses of natural gas in Alaska.

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[9]Kristen Nelson. "Agrium Would Like to Grow Cook Inlet Operation." *Petroleum News Alaska*. (November 25, 2001): A14.

CHAPTER 8: NEW POWER GENERATION OPPORTUNITIES

The Alaska power system can be segregated into three categories: (1) interconnected utilities in the Railbelt; (2) small, isolated, non-interconnected utilities in the Bush; and (3) mid-size, non-interconnected utilities like Kodiak Electric Association and Copper Valley Electric Association, Inc.

The Alaska Systems Coordinating Council (ASCC) provides oversight and coordination of statewide electric utility operations for reliability purposes. The ASCC is comprised of 17 electric utilities, three state agencies, and a federal agency. Nine ASCC members are interconnected in the railbelt region to serve the Anchorage Bowl, Fairbanks area, and the Kenai Peninsula. These members account for approximately 75 percent of the utility generating capacity in Alaska.

The ASCC notes that, "the Alaska electric system is truly isolated and does not have a transmission grid as normally defined." The transmission systems that do exist are commonly referred to as "isolated radial single lines." There is no connection with transmission grids outside of Alaska. Many of the transmission system issues associated with the lower 48 simply do not exist in Alaska.[1]

Power transmission interties on the northern and southern ends of the railbelt system between Fairbanks and Kenai Peninsula improve reliability by providing a second set of transmission links between Healy and Fairbanks in the north and between Anchorage and the Kenai Peninsula to the south. The Northern Intertie route selection process is complete and construction plans are finalized. This line will be constructed for 230 kilovolts (kV), but operated at 138 in the near term. The line is expected to be fully operational within three years. The Southern Intertie route selection process, including its associated environmental impact statement and findings, is underway.

The majority of Alaska's 250 rural towns and villages are not interconnected. The rural town and village power systems typically rely on a single local diesel or fuel oil generating plant. For these areas of the state, power cost and generator reliability (as opposed to transmission reliability) are of the greatest importance. According to the ASCC, maintenance programs, system upgrades, and applying new small-scale power generation technologies are a high priority.

One of the more recent investigations of the potential for new power generation in Alaska, as well as increasing the efficiency of existing power generation stations, was conducted by CH2M Hill in a report prepared for the Regulatory

[1]These include issues associated with interconnection rules and costs, transmission governance and pricing, long term transmission planning for wholesale competition, and the development of Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).

Commission of Alaska (RCA) and the Alaska Legislature.[2] This report, hereafter referred to as the CH2M Hill report, is a comprehensive examination of electric restructuring issues, how they relate to Alaska's power industry, and the potential costs and benefits of moving forward with greater competition. The study notes that "...there is no restructuring model in existence today that would work in rural Alaska among the villages and cities that are not interconnected to the Railbelt system."

The report offers three alternative pathways for the future development of Alaska's power system:

(1) The State can "fix the potholes" in its current system;

(2) The State can choose a scenario that focuses on rapidly "commoditizing kilowatts" in an effort to capture wholesale power market benefits; or

(3) The State can choose a course of "controlled evolution," transitioning the current regulated system into a more competitive and diverse marketplace.

The empirical analysis conducted in the CH2M Hill report included a "least cost dispatch" model for the state's railbelt utilities. Least cost multi-area dispatch models are common tools that are used in the lower 48 to examine the efficiency opportunities for coordinated least cost dispatch of power generation facilities. The approach, in its most simple form, stacks each generator by the least cost generation facility to its most expensive. The intersection of demand to this least-cost developed supply curve represents the amount of power generation that would be dispatched to the market, as well as the market clearing price for power.

While the CH2M Hill report findings were modestly in favor of moving forward with a limited form of competition in Alaska, the RCA Staff was somewhat more critical of the idea. In comments attached to Order 7 in Docket Number R-97-10, the Commission Staff recommended that "... the gains from restructuring appear to be modest, while risks are potentially considerable. Accordingly, Staff recommends that no policy action be taken at this time to restructure Alaska's Railbelt utility system."[3]

With regards to the costs of moving forward with restructuring, the Staff comments noted that:

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[2]Karl Robago, Tom Feiler, Floyd Damron, and Deanana Gamle. *Study of Electric Utility Restructuring in Alaska.* Report to the Alaska Public Utilities Commission and the Alaska State Legislature. June 30, 1999.

[3]Comments of the RCA Staff, Attachment to Order No. 7, Docket R-97-10, *In the Matter of Regulations Defining the Future Market Structure of Alaska's Electric Industry.* June 22, 2001.

> The Railbelt at present does not appear to have the infrastructure – either in diversity of generator ownership, or in transmission redundancy – to support robust competition. The presence of long-term fuel supply contracts may predetermine competitive outcomes if retail competition is introduced in the near term. It appears that Alaska has little gain, and potentially much to lose, by any quick movement to retail competition. The next five to ten years will see resolution of a number of important issues that will profoundly affect the economics of electricity production in the Railbelt.[4]

The issue of electric restructuring is important to the future in-state opportunities for increased gas consumption. In the lower 48, the advent of wholesale and retail competition has resulted in an explosion of new merchant power plant construction. These merchant facilities are typical simple cycle (CT) or combined-cycle[5] (CC) gas generating units. According to a U.S. Department of Energy study, about 50 percent of the future growth in natural gas demand will come from serving the fuel requirements of the power generation facilities.[6]

However, there are a number of factors that dampen the possibilities that Alaska could experience an explosion in new gas fired generation resulting from competition. The RCA Staff raise a number of important issues with regards to both competition and the need for new power generation. Some of the factors that limit the possibilities of competition and new competitive power generation include:

- Large reserve capacity margins that considerably delay when new units to the Railbelt need to be added;
- Utilities that are primarily customer-owned; and
- The prevalence of long term wholesale electricity and fuel contracts.[7]

Referencing an earlier Black and Veatch study on power generation in Alaska, the RCA Staff notes that the State does not have a forecast power generation capacity addition need until the year 2014.[8]

Given the RCA Staff comments and our own analysis of past power demand trends in Alaska, we have limited our analysis of new potential gas generation to

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[4] Commission Staff Comments at 2.

[5] A combined cycle generator is one that includes initial-stage turbine generation with a heat recovery unit for additional generation to enhance overall power generation efficiency.

[6] US Department of Energy, Annual Energy Outlook to 2020. Washington: Energy Information Administration, Table A.13.

[7] Commission Staff Comments at 10.

[8] Commission Staff Comments at 11, referencing the Black and Veatch Power Pooling Study at 5-1 conducted on the behalf of the RCA, 1998.

two sources: first, fuel switching by the Bush utilities and larger non-interconnected systems in Alaska; and second, a new power generation facility located in close proximity to the proposed Alaska Highway Route (AHR). We will assume that the AHR example could be translated into a "gas by wire" application, where power generated from this facility could be moved to neighboring areas to displace existing on-site power generation.

8.1: Fuel Switching Opportunities for Bush and Larger Non-Interconnected Systems

Our analysis of fuel switching opportunities for power generation facilities is similar to that in our residential geographic proximity analysis. There is, however, a difference in how the power plant information is referenced to geographic locations. Due to the unavailability of specific geo-referencing information on many of the smaller power generating units, we aggregated generators (oil and diesel) by ZIP codes and used the U.S. Census-developed SIP code digital boundaries in the overlay procedures. Figure 8.1 maps all power generation facilities in Alaska based upon this method, while Figure 8.2 highlights those facilities that are currently being fired by fuel oil or diesel fuel. The quantitative results of the proximity analysis have been presented in Tables 8.1, 8.2, and 8.3 (capacity by region). The natural gas usage associated with switching these units are provided in Table 8.4 and 8.5.

The geographic distribution of oil and diesel fired generators are different from those conducted earlier for residential customers. In particular, 34.2 percent of the potential fuel switching generating capacity is located within five miles of the proposed AHR (see Table 8.2). Some 202 MWs of capacity are located in the Interior section, 12.9 MWs of capacity is located within the Southcentral region, and 2.5 MWs are located in the Southeastern region (see Table 8.1).

The largest opportunities for fuel switching through power generation are in the interior region – primarily in Fairbanks. Some 96 percent of the capacity available for fuel switching is located in this region, and within 5 miles of the AHR.

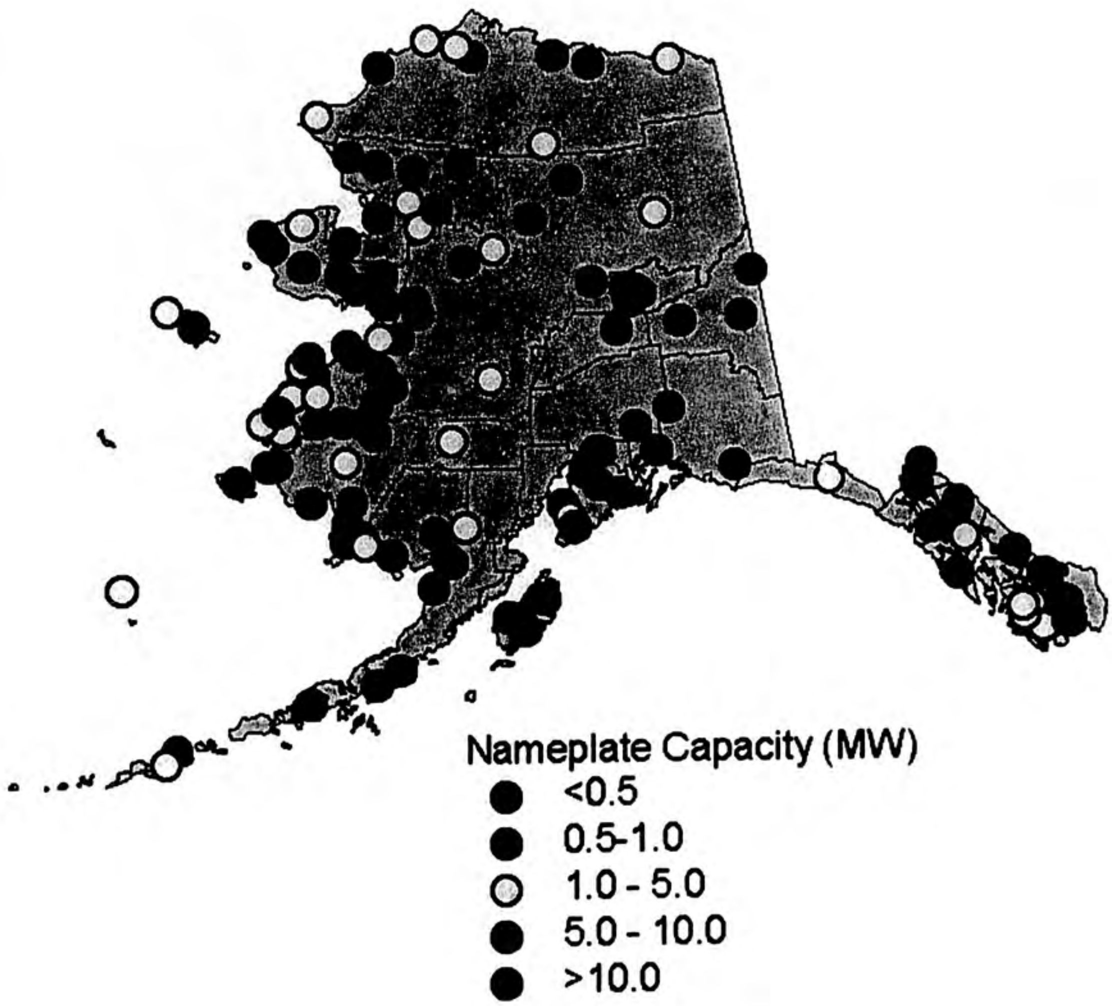

Figure 8.1: Total Power Generation Capacity by Location

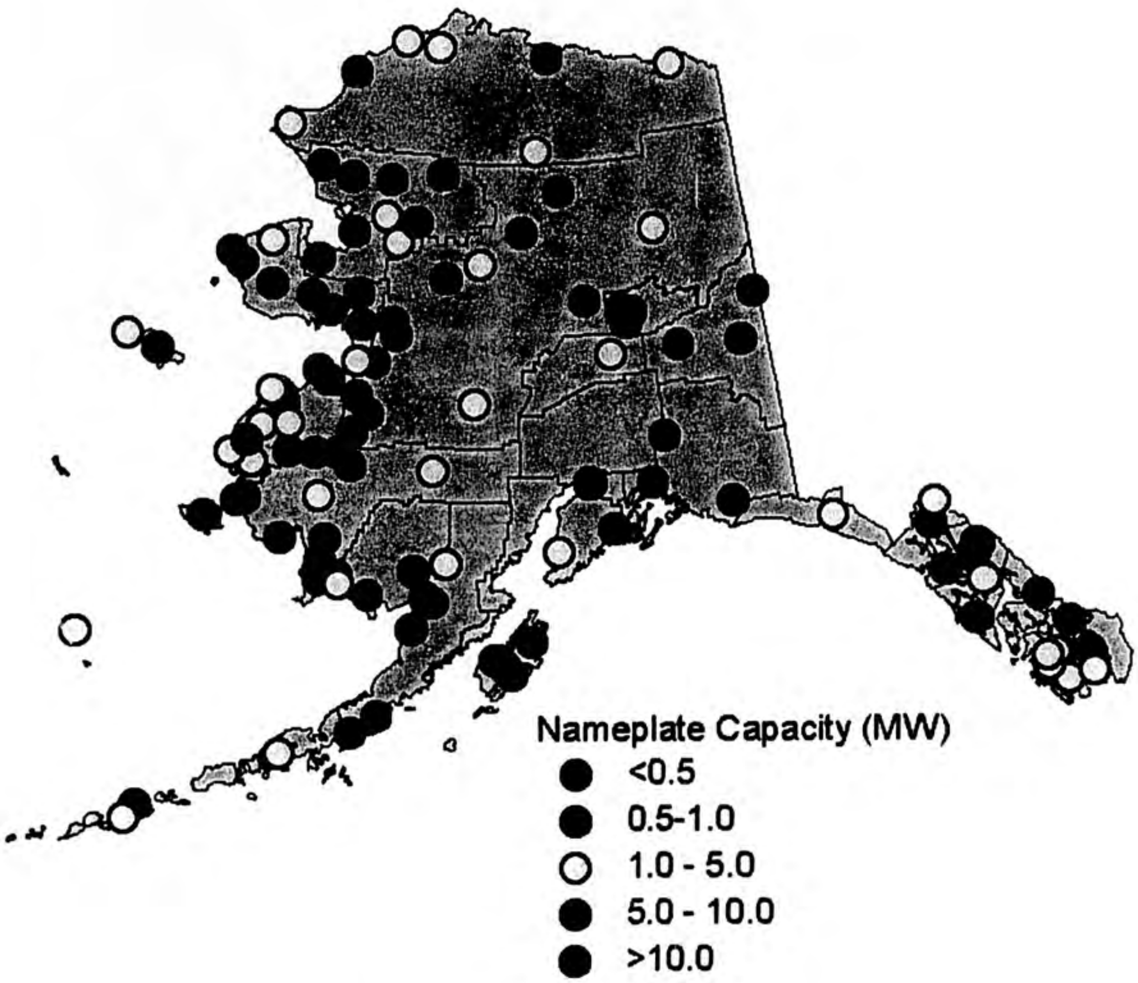

Figure 8.2: Oil and Diesel Fired Generation Capacity by Location

Table 8.1: Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	760	760
	Beyond 20 miles	0	0	0	0	48,228	48,228
	Total	0	0	0	0	48,988	48,988
Interior	Within 5 miles	0	0	192,900	192,900	9,275	202,175
	Within 10 miles	0	0	192,900	192,900	9,275	202,175
	Within 15 miles	0	0	192,900	192,900	9,275	202,175
	Within 20 miles	0	0	192,900	192,900	9,275	202,175
	Beyond 20 miles	0	0	0	0	9,294	9,294
	Total	0	0	192,900	192,900	18,569	211,469
South Central	Within 5 miles	0	0	0	2,536	10,456	12,992
	Within 10 miles	0	0	10,102	15,138	10,456	25,594
	Within 15 miles	0	0	10,102	15,138	10,456	25,594
	Within 20 miles	0	0	10,102	15,138	48,366	63,504
	Beyond 20 miles	0	10,403	10,403	10,403	12,600	23,003
	Total	0	10,403	20,505	25,541	60,966	86,507
South East	Within 5 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 10 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 15 miles	2,500	2,500	2,500	2,500	0	2,500
	Within 20 miles	2,500	2,500	11,130	11,130	0	11,130
	Beyond 20 miles	97,600	136,058	162,178	166,008	3,586	169,594
	Total	100,100	138,558	173,308	177,138	3,586	180,724
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	28,775	29,205	78,755	107,960
	Total	0	0	28,775	29,205	78,755	107,960
Alaska Total	Within 5 miles	2,500	2,500	195,400	197,936	19,731	217,667
	Within 10 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 15 miles	2,500	2,500	205,502	210,538	19,731	230,269
	Within 20 miles	2,500	2,500	214,132	219,168	58,401	277,569
	Beyond 20 miles	97,600	146,461	201,356	205,616	152,463	358,079
	Total	100,100	148,961	415,488	424,784	210,864	635,648

Table 8.2: Relative Frequency Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (Percent of Total)

		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	1.6%	1.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	98.4%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 10 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 15 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Within 20 miles	0.0%	0.0%	91.2%	91.2%	4.4%	95.6%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	4.4%	
	Column Total	0.0%	0.0%	91.2%	91.2%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	2.9%	12.1%	15.0%
	Within 10 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 15 miles	0.0%	0.0%	11.7%	17.5%	12.1%	29.6%
	Within 20 miles	0.0%	0.0%	11.7%	17.5%	55.9%	73.4%
	Beyond 20 miles	0.0%	12.0%	12.0%	12.0%	14.6%	
	Column Total	0.0%	12.0%	23.7%	29.5%		100.0%
South East	Within 5 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 10 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 15 miles	1.4%	1.4%	1.4%	1.4%	0.0%	1.4%
	Within 20 miles	1.4%	1.4%	6.2%	6.2%	0.0%	6.2%
	Beyond 20 miles	54.0%	75.3%	89.7%	91.9%	2.0%	
	Column Total	55.4%	76.7%	95.9%	98.0%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	26.7%	27.1%	72.9%	
	Column Total	0.0%	0.0%	26.7%	27.1%		100.0%
Alaska Total	Within 5 miles	0.4%	0.4%	30.7%	31.1%	3.1%	34.2%
	Within 10 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 15 miles	0.4%	0.4%	32.3%	33.1%	3.1%	36.2%
	Within 20 miles	0.4%	0.4%	33.7%	34.5%	9.2%	43.7%
	Beyond 20 miles	15.4%	23.0%	31.7%	32.3%	24.0%	
	Column Total	15.7%	23.4%	65.4%	66.8%		100.0%

Table 8.3: Summary of Distribution of Oil and Diesel Fired Power Generation Capacity by Proximity to Potential Sources of Natural Gas Supply (kW Capacity)

	Far North	Interior	Southcentral	Southeast	Southwest	Alaska
Within 5 miles of EPNGS	0	0	0	100,100	0	100,100
Within 5 miles of AHR	0	202,175	12,992	2,500	0	217,667
Within 10 miles of EPNGS	0	0	10,403	138,558	0	148,961
Within 10 miles of AHR	0	**202,175**	25,594	2,500	0	230,269
Within 15 miles of EPNGS	0	192,900	20,505	173,308	28,775	415,488
Within 15 miles of AHR	0	202,175	25,594	2,500	0	230,269
Within 20 miles of EPNGS	0	192,900	25,541	177,138	29,205	424,784
Within 20 miles of AHR	760	202,175	63,504	11,130	0	277,569
Beyond 20 miles of both	48,228	9,294	12,600	3,586	78,755	152,463

Tables 8.4, 8.5, and 8.6 present the gas usage associated with each of the power generation facilities identified in earlier capacity tables. As presented in the bottom right hand corner of Table 8.4, the total increase in gas usage, associated with switching power generation fuels, is 32.8 Bcf per year. The majority of the new gas usage opportunity rests within the Interior section of Alaska, primarily Fairbanks (30.28 Bcf).

Table 8.4: Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Total
	Distance to AHR						
Far North	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	95	95
	Beyond 20 miles	0	0	0	0	4,348	4,348
	Total	0	0	0	0	4,443	4,443
Interior	Within 5 miles	0	0	28,896	28,896	1,388	30,284
	Within 10 miles	0	0	28,896	28,896	1,388	30,284
	Within 15 miles	0	0	28,896	28,896	1,388	30,284
	Within 20 miles	0	0	28,896	28,896	1,388	30,284
	Beyond 20 miles	0	0	0	0	1,185	1,185
	Total	0	0	28,896	28,896	2,574	31,469
South Central	Within 5 miles	0	0	0	565	1,666	2,231
	Within 10 miles	0	0	1,670	2,732	1,666	4,398
	Within 15 miles	0	0	1,670	2,732	1,666	4,398
	Within 20 miles	0	0	1,670	2,732	6,398	9,130
	Beyond 20 miles	0	1,488	1,488	1,488	2,103	3,592
	Total	0	1,488	3,158	4,220	8,502	12,722
South East	Within 5 miles	285	285	285	285	0	285
	Within 10 miles	285	285	285	285	0	285
	Within 15 miles	285	285	285	285	0	285
	Within 20 miles	285	285	1,315	1,315	0	1,315
	Beyond 20 miles	14,207	19,582	23,444	23,947	407	24,354
	Total	14,492	19,867	24,759	25,262	407	25,669
South West	Within 5 miles	0	0	0	0	0	0
	Within 10 miles	0	0	0	0	0	0
	Within 15 miles	0	0	0	0	0	0
	Within 20 miles	0	0	0	0	0	0
	Beyond 20 miles	0	0	5,161	5,215	10,140	15,355
	Total	0	0	5,161	5,215	10,140	15,355
Alaska Total	Within 5 miles	285	285	29,181	29,746	3,054	32,800
	Within 10 miles	285	285	30,850	31,912	3,054	34,967
	Within 15 miles	285	285	30,850	31,912	3,054	34,967
	Within 20 miles	285	285	31,880	32,942	7,881	40,823
	Beyond 20 miles	14,207	21,071	30,094	30,650	18,184	48,834
	Total	14,492	21,355	61,974	63,592	26,065	89,657

Table 8.5: Relative Frequency Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (Percent of Total)

Region		Distance to EPNGS Settlements					
		Within 5 miles	Within 10 miles	Within 15 miles	Within 20 miles	Beyond 20 miles	Row Total
	Distance to AHR						
Far North	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	2.1%	2.1%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	97.9%	
	Column Total	0.0%	0.0%	0.0%	0.0%		100.0%
Interior	Within 5 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 10 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 15 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Within 20 miles	0.0%	0.0%	91.8%	91.8%	4.4%	96.2%
	Beyond 20 miles	0.0%	0.0%	0.0%	0.0%	3.8%	
	Column Total	0.0%	0.0%	91.8%	91.8%		100.0%
South Central	Within 5 miles	0.0%	0.0%	0.0%	4.4%	13.1%	17.5%
	Within 10 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 15 miles	0.0%	0.0%	13.1%	21.5%	13.1%	34.6%
	Within 20 miles	0.0%	0.0%	13.1%	21.5%	50.3%	71.8%
	Beyond 20 miles	0.0%	11.7%	11.7%	11.7%	16.5%	
	Column Total	0.0%	11.7%	24.8%	33.2%		100.0%
South East	Within 5 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 10 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 15 miles	1.1%	1.1%	1.1%	1.1%	0.0%	1.1%
	Within 20 miles	1.1%	1.1%	5.1%	5.1%	0.0%	5.1%
	Beyond 20 miles	55.3%	76.3%	91.3%	93.3%	1.6%	
	Column Total	56.5%	77.4%	96.5%	98.4%		100.0%
South West	Within 5 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 10 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 15 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Within 20 miles	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Beyond 20 miles	0.0%	0.0%	33.6%	34.0%	66.0%	
	Column Total	0.0%	0.0%	33.6%	34.0%		100.0%
Alaska Total	Within 5 miles	0.3%	0.3%	32.5%	33.2%	3.4%	36.6%
	Within 10 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 15 miles	0.3%	0.3%	34.4%	35.6%	3.4%	39.0%
	Within 20 miles	0.3%	0.3%	35.6%	36.7%	8.8%	45.5%
	Beyond 20 miles	15.8%	23.5%	33.6%	34.2%	20.3%	
	Column Total	16.2%	23.8%	69.1%	70.9%		100.0%

Table 8.6: Summary of Usage Distribution of Potential Gas Usage of Oil and Diesel Fired Generation Units by Proximity to Sources of Natural Gas Supply (MMcf)

	Far North	Interior	South Central	South East	South West	Alaska
Within 5 miles of EPNGS	0	0	0	14,492	0	14,492
Within 5 miles of AHR	0	30,284	2,231	285	0	32,800
Within 10 miles of EPNGS	0	0	1,488	19,867	0	21,355
Within 10 miles of AHR	0	30,284	4,398	285	0	34,967
Within 15 miles of EPNGS	0	28,896	3,158	24,759	5,161	61,974
Within 15 miles of AHR	0	30,284	4,398	285	0	34,967
Within 20 miles of EPNGS	0	28,896	4,220	25,262	5,215	63,592
Within 20 miles of AHR	95	30,284	9,130	1,315	0	40,823
Beyond 20 miles of both	4,348	1,185	2,103	407	10,140	18,184

8.2: Electric Power Generation in the Interior

The electric power sector in Fairbanks has the potential for the largest use of ANS gas in the area. This sector includes Golden Valley Electric Association (GVEA), Aurora Energy, the University of Alaska Fairbanks, Ft Wainwright and Eielson AFB. The power plants for these facilities generate electricity from coal and fuel oil. GVEA is the largest power generator in the region. It operates two 60-megawatt oil-fired plants in North Pole plus several smaller, sub-station facilities. Golden Valley operates a coal-fired plant in Healy and owns partial interest in the Bradley Lake Hydro-electric facility.[9] Utility managers responded to a 1997 DNR survey regarding the potential for conversion to natural gas. The results of the survey are summarized in Table 8.7.

[9]GVEA obtained the electric customers and a diesel-fired combustion turbine from Fairbanks Municipal Utility System in 1997. Aurora Energy LLP (wholly owned by Usibelli Coal Mines (UCM)) was formed which took over Fairbanks Municipal Utility System's coal burning plant. GVEA contracted with Aurora Energy to purchase all electrical energy generated from these units. GVEA also purchases power directly from Chugach Electric Association, Inc. and Municipal Light and Power in Anchorage.

Table 8.7: Fairbanks North Star Borough Electric Power Survey

	Coal					Fuel Oil				
			Rate of Gas Consumption After Conversion					Rate of Gas Consumption After Conversion		
	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low	Average Price Paid	Max Price for Conversion to Gas	Average	Seasonal Peak	Seasonal Low
	$/Ton	$/MmBtu	Mmcf/d	Mmcf/d	Mmcf/d	$/Gallon	$ per MmBtu	Mmcf/d	Mmcf/d	Mmcf/d
FMUS[1]	$44	$2.50	5	5	5	$0.71	$2.50	0.1	n/a	n/a
GVEA	$23.40	$1.50	7	7	7	$0.45	$2.50	12	14	10
FT. Wainwright	$46.22	$3.00	7.8	11.6	3.6	n/a	n/a	n/a	n/a	n/a
Eielson AFB	n/a	$3.60	6.4	12.8	5.01	n/a	n/a	n/a	n/a	n/a
UAF	$44	$2.82	2.5	3.2	0.5	$0.89	$6.34	0.14	1	0

[1] The Fairbanks Municipal Utility System assets were acquired by GVEA and Aurora Power in 1999.

In general, utility managers were receptive to a natural gas alternative to the low BTU coal. Several utility managers expressed a preference for having a choice among fuel feedstock. However, even if inexpensive, base-load natural gas were available on a sustainable basis, 100 percent plant conversion would be unlikely because of the high upfront investment, long-term contractual commitments with existing fuel suppliers, and the desirability of multiple fuel systems. Respondents indicated the maximum natural gas price that would compete with existing fuels and permit conversion ranges between $1.50 and $3.60 per MmBtu. An initial estimate of potential conversions based upon this survey, at different penetration rates for the year 2009, has been provided in Table 8.8

Table 8.8: Potential Natural Gas Usage for Power Generation in the Fairbanks North Star Borough in 2009

Line No		Formula		Low	Medium	High
1	**Electric Power - Civilian**[1]					
2	Projected Maximum Electricity Load (Bcf per Year)		10.3			
3	Penetration Rate in 2009[2]			25.0%	50.0%	83.0%
4	**Potential Civilian Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 2 x Line 3		**2.6**	**5.2**	**8.6**
5	**Electric Power - Military**[2]					
6	Projected Maximum Electricity Load (Bcf per Year)		2.7			
7	Penetration Rate in 2009[3]			25.0%	50.0%	83.0%
8	**Potential Military Electric Power Gas Usage in 2009 (Bcf/Yr)**	Line 6 x Line 7		**0.7**	**1.3**	**2.2**
9	**TOTAL FNSB AREA (Bcf per Year)**	Sum (Lines 4 & 8)		**3.3**	**6.5**	**10.8**
Table Notes:						
1	83% based on Stone and Webster Engineering Corporation. *Railbelt Intertie Reconnaissance Study*, 1989.					
2	We assume that, at most, 50% of military electric power requirements would be available for gas-fired generation.					
3	Golden Valley Electric Association, Aurora Energy, and the University of Alaska Fairbanks.					

Based on the results of this ADNR survey and other information, an alternative estimate of potential annual natural gas demand for electric power generation was prepared in Table 8.9. The results indicate that natural gas consumption for civilian electric power requirements could be approximately 9.3 Bcf per year. Military power requirements, which are served primarily with coal-fired generation, would be an additional 5.6 Bcf per year. The daily swings for heating use were assumed to be 2 ½ times the average usage rates, which is approximately the same as the maximum deliverability swings experienced in the Enstar system.

Table 8.9: Fairbanks Area Electric Power Plants and Estimated Natural Gas Usage[1]

	Golden Valley Electric Association	Aurora Energy, LLP	University of Alaska Fairbanks	Military[2]	Total
Coal Consumption					
Tons per Year	170,000	130,000	60,000	360,000	720,000
Million Btus per Year[3]	2,516,000	1,924,000	888,000	5,328,000	10,656,000
Oil Consumption					
Gallons per Year (x1000)	28,000		280		28,280
Million Btus per year[4]	3,948,000		39,480		3,987,480
Coal and Oil Combined Total MMBTUs	6,464,000	1,924,000	927,480	5,328,000	14,643,480
Natural Gas equivalent (Bcf per Year)	6.5	1.9	0.9	2.7	12.0
Non-Military			9.3		

[1] Estimated from published 1995 statistics, responses to a utility survey conducted by DNR in 1997 and private conversations with utility managers.
[2] Estimates, include Fort Wainwright and Eielson Air Force Base.
[3] Based on conversion: 1 ton of coal = 14.8 million Btus.
[4] Based on conversion: 1 gallon of heating oil = 141,000 Btus. Note that oil-fired power generation is highly variable.
[5] We assume that 50% of military power requirements would be available for gas-fired generation.

These above estimates are build on the maintained assumption that the cost of gas delivered to the power plants and the cost of furnace and generator system conversion to natural gas, would be competitive with other energy alternatives.

8.3: Gas by Wire Application

We also examine a new gas fired power generation facility near Fairbanks close to the AHR. In effect, we relocate regional gas-fired power generation to Fairbanks and distribute power *by wire* to communities in the Interior Region. For this analysis, we assumed a new 250 MW facility, at an installed cost of $750/kW. This facility was assumed to be operating at a heat rate of 6,000 BTUs per kWh generated. A power plant's heat rate measures its thermal efficiency in terms of the amount of BTUs of energy used to produce one kWh. The results of the analysis are presented in Table 8.10 below.

The results from the preliminary analysis are encouraging. Table 8.10 presents three different generation cost analyses based upon different fuel cost assumptions. We have examined new generation costs from a range taken by the three larger railbelt utilities with gas-fired generation. The top of the table includes the operating and cost assumptions used in the analysis. The bottom portion of the table presents two different cost estimates: total dispatch costs and total levelized costs.

Total dispatch costs are essentially the average variable costs of a generation facility and in most instances under economic (or least cost) dispatch, will dictate the order in which a power generation facility is run. Total levelized costs, on the other hand, are the total costs of the facility, including capital, expressed in per kWh term.[10] These costs are presented at the bottom of Table 8.10 and in all instances are relatively competitive from an absolute level.

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[10]An annual carrying factor has been developed to estimate the return on and of the capital investment as well as any associated taxes.

Table 8.10: Total Dispatch and Levelized Cost for Gas By Wire Application

General Plant Cost and Operating Assumptions			
Capacity Factor	0.95	Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000	Annual Carrying Cost	$22,414,158
Heat Rate	6,000	Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	700	Deprecation, Years	30
Capacity (kW)	250,000	Rate of Return	10.16%
Total Installed Cost	175,000,000	Taxes	38.71%
Capital Cost; $/kW/Yr	23		

New Plant at MPL Gas Cost		New Plant at CEA Gas Cost		New Plant at GVEA Gas Cost	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00	Transportation Charge ($/MCF)	$0.00
Cost of Gas	$1.86	Cost of Gas	$1.27	Cost of Gas	$3.18
Total Annual Gas Cost	$23,218,380	Total Annual Gas Cost	$15,828,444	Total Annual Gas Cost	$39,711,544
Average Variable Fuel Cost	$0.01116	Average Variable Fuel Cost	$0.00761	Average Variable Fuel Cost	$0.01909
Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500	Average Variable O&M Cost	$0.00500
Total Dispatch Cost	$0.01616	Total Dispatch Cost	$0.01261	Total Dispatch Cost	$0.02409
Total Levelized Cost	$0.02693	Total Levelized Cost	$0.02338	Total Levelized Cost	$0.03486

Next, we compare the dispatch cost of the hypothetical, new generation facility with other railbelt utility generation facilities. The objective our our analysis is to explore how well the new gas-by-wire application compares with existing generating units from the standpoint of dispatch costs. In short run hourly power markets, generation facilities are dispatched according to short run marginal costs. This least cost dispatch ranks facilities from the lowest marginal cost to the highest marginal costs. Low cost units are typically run first, with higher cost units being dispatched up to the point where all demand is met.

Unit dispatch costs are usually comprised of average variable fuel costs as well as average variable operation & maintenance (O&M) costs. Unit dispatch costs, on a per MWh basis, are the sum of these two costs. The railbelt generation facilities, and their operating and cost characteristics, are presented in Table 8.11, with summaries given at the bottom for the Railbelt as a whole and the three major Southcentral electric utilities. The results for the new gas-by-wire applications are also shown at the bottom of Table 8.11. The results indicate that existing gas-fired generation in Alaska is relatively inefficient compared to a new gas-by-wire application. Heat rates, (or the thermal efficiency) of existing Railbelt gas fired generation ranges from 13,000 Btus/kWh to almost 16,000 Btus per kWh. New combined cycle generation typical generate at efficiencies of around 6,000 Btus per kWh. In making a comparison between these efficiencies, lower heat rates entail more efficient units. In other words, a lower heat rate entails that a unit uses less energy to make one kWh of electricity.

The new gas-by-wire application is competitive with many of these existing generation resources currently being dispatched in the railbelt utility system. In most every instance, the new gas-by-wire application beats existing gas-fired generation in the region.

A note of caution is in order at this juncture. We have concluded that under limited, short-run conditions, the new gas-by-wire application is more efficient and cost-effective than existing power generation. However, these estimates do not include the costs associated with supplying (transporting) the natural gas to the new gas-by-wire application, nor do they include any new power transmission costs associated with moving the electrical output from this facility. The costs of supplying natural gas to this potential application, as well as several others identified in earlier chapters of our report, are explored in Chapter 9. Our subsequent analysis will show that the new transportation (gas and power) infrastructure costs of putting this facility into service would shift the dispatch cost into the $28.42/Mwh to $36.34/MWh range.

Table 8.11: Railbelt Utility Generation Facilities Dispatch Cost Relative to Gas by Wire Application

Plant	Company	Fuel Type	Capacity (MW)	Maximum Capacity Factor	Generation & Availability Adjustment	Fuel Cost ($/MMBTU)	Heat Rate (BTU/kWh)	Generation Amount (kWh)	Fuel Costs ($/MWh)	Non-Fuel O&M ($/MWh)	Dispatch Cost ($/MWh)
MLP Plant 1, Unit 1	MLP	Gas	16.8	97%	16	$1.86	14,590	142,752,960	$27.14	$2.00	$29.14
MLP Plant 1, Unit 2	MLP	Gas	16.8	97%	16	$1.86	13,980	142,752,960	$26.00	$2.00	$28.00
MLP Plant 1, Unit 3	MLP	Gas	19.5	97%	19	$1.86	14,371	165,695,400	$26.73	$2.00	$28.73
MLP Plant 1, Unit 4	MLP	Gas	34.1	97%	33	$1.86	17,324	289,754,520	$32.22	$2.00	$34.22
MLP Plant 2, Unit 5	MLP	Gas	38.4	97%	37	$1.86	10,106	326,292,480	$18.80	$2.00	$20.80
MLP Plant 2, Unit 7/6	MLP	Gas	109.5	97%	106	$1.86	8,527	930,443,400	$15.86	$2.00	$17.86
MLP Plant 2, Unit 8	MLP	Gas	87.6	97%	85	$1.86	11,577	744,354,720	$21.53	$2.00	$23.53
Beluga Unit 1	CEA	Gas	16.7	93%	16	$1.17	16,924	136,051,560	$19.80	$2.00	$21.80
Beluga Unit 2	CEA	Gas	16.7	98%	16	$1.17	17,320	143,366,160	$20.26	$2.00	$22.26
Beluga Unit 3	CEA	Gas	66.9	96%	64	$1.17	12,288	562,602,240	$14.38	$2.00	$16.38
Beluga Unit 5	CEA	Gas	71.0	97%	69	$1.17	12,537	603,301,200	$14.67	$2.00	$16.67
Beluga Unit 6	CEA	Gas	74.0	90%	67	$1.17	12,743	583,416,000	$14.91	$2.00	$16.91
Beluga Unit 7	CEA	Gas	74.0	95%	70	$1.17	13,172	615,828,000	$15.41	$2.00	$17.41
Beluga Unit 6-8	CEA	Gas	101.5	90%	91	$1.17	9,372	800,226,000	$10.97	$2.00	$12.97
Beluga Unit 7-8	CEA	Gas	101.5	90%	91	$1.17	9,149	800,226,000	$10.70	$2.00	$12.70
Bernice Lake 2	CEA	Gas	19.0	100%	19	$1.38	14,817	166,440,000	$20.45	$2.00	$22.45
Bernice Lake 3	CEA	Gas	28.0	93%	26	$1.38	13,512	228,110,400	$18.65	$2.00	$20.65
Bernice Lake 4	CEA	Gas	28.0	95%	27	$1.38	13,715	233,016,000	$18.93	$2.00	$20.93
International 1	CEA	Gas	15.0	90%	14	$1.38	15,992	118,260,000	$22.07	$2.00	$24.07
International 2	CEA	Gas	15.0	90%	14	$1.38	17,384	118,260,000	$23.99	$2.00	$25.99
International 3	CEA	Gas	19.0	89%	17	$1.38	15,030	148,131,600	$20.74	$2.00	$22.74
Soldotna 1	CEA	Gas	39.0	99%	39	$1.38	11,401	338,223,600	$15.73	$2.00	$17.73
Chena 6	GVEA	HAGO	29.0	95%	28	$3.40	12,256	241,338,000	$41.67	$0.30	$41.97
Zehnder EMD 5	GVEA	HAGO	2.6	99%	3	$3.21	25,679	22,548,240	$82.43	$8.24	$90.67
Zehnder EMD 6	GVEA	HAGO	2.6	99%	3	$3.21	27,679	22,548,240	$88.85	$8.24	$97.09
Zehnder GT 1	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
Zehnder GT 2	GVEA	HAGO	18.0	99%	18	$3.21	14,560	156,103,200	$46.74	$5.37	$52.11
North Pole 1	GVEA	HAGO	56.7	95%	54	$3.00	9,751	471,857,400	$29.25	$4.80	$34.05
North Pole 2	GVEA	HAGO	59.3	92%	55	$3.00	9,154	477,910,560	$27.46	$4.80	$32.26
Healy 1	GVEA	Coal	25.0	91%	23	$1.36	13,995	199,290,000	$19.03	$11.20	$30.23
Healy D 1	GVEA	HAGO	2.6	95%	2	$3.21	11,451	21,637,200	$36.76	$8.24	$45.00
Bradley Lake -- GVEA	GVEA	Hydro	15.2	40%	6	$0.00	1	52,887,974	$0.00	$2.16	$2.16
Bradley Lake -- HEA	GVEA	Hydro	10.8	43%	5	$0.00	1	41,138,397	$0.00	$2.16	$2.16
Bradley Lake -- ML&P	MLP	Hydro	23.3	44%	10	$0.00	1	90,332,078	$0.00	$2.16	$2.16
Ekultna	MLP	Hydro	21.3	40%	9	$0.00	1	74,944,936	$0.00	$2.16	$2.16
Bradley -- Chugash	CEA	Hydro	40.7	42%	17	$0.00	1	151,283,658	$0.00	$2.16	$2.16
Ekultna Chugash	CEA	Hydro	18.7	37%	7	$0.00	1	61,318,108	$0.00	$2.16	$2.16
Cooper Lake 1	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Cooper Lake 2	CEA	Hydro	8.6	33%	3	$0.00	1	24,529,402	$0.00	$0.21	$0.21
Railbelt Average				[illegible]		$1.61	11,152				$24.69
MLP Average -- All Generation				[illegible]		$1.45	10,863				$20.73
CEA Average -- All Generation				82%		[illegible]	[illegible]				$15.60
GVEA Average -- All Generation				[illegible]		$2.44	[illegible]				$43.82
MLP Average -- Gas Only				97%		$1.86	[illegible]				$26.94
CEA Average -- Gas Only				[illegible]		$1.27	[illegible]				$19.44
GVEA Average -- Gas Only				97%		$3.18	[illegible]				[illegible]
New Gas-By Wire Application -- MLP Gas Cost				[illegible]		$1.86	[illegible]				$15.16
New Gas-By Wire Application -- CEA Gas Cost				[illegible]		$1.27	[illegible]				$12.61
New Gas-By Wire Application -- GVEA Gas Cost				[illegible]		[illegible]	[illegible]				[illegible]

CHAPTER 9: COST ESTIMATES OF SUPPLYING NATURAL GAS TO NEW OR EXPANDED SERVICE OPPORTUNITIES

9.1: Introduction

In the earlier chapters of our report, we identified a number of new opportunities for increased in-state natural gas usage. The objective of this chapter is to explore a number of these narrowly defined opportunities. In particular, we examine the cost side of the picture: what it would take to provide ANS gas energy services to in-state users. This refers primarily to the infrastructure requirements for providing energy services connected with the ANS gasline to various locations throughout the state. While many of these opportunities are important, many were spread throughout remote regions of the state and were of relatively small volumes. In these instances, the infrastructure requirements to serve these areas would be substantial and swamp the benefits of fuel switching.

There are a number of important issues conditioning the supply of natural gas to new usage opportunities throughout the state. These include:

- Relatively small demand volumes spread over remote areas;
- Distance between AHR and community;
- Required new investments to take high pressure and high Btu gas from the AHR pipeline; and
- Climate and environmental considerations.

Despite these challenges, earlier chapters of our analysis did identify a number of concentrated opportunities for increased in-state usage that warrant further investigation. These concentrated opportunities include:

(1) Natural gas usage for residential and commercial customers in the Interior region (Fairbanks);

(2) Power plant fuel switching in the Interior region (Fairbanks);

(3) Gas-fired central station generation with electricity being transmitted to the Interior region (gas-by-wire to Fairbanks); and

(4) Expanded gas usage from the existing LDC system in Southcentral region (Cook Inlet).

In the following subsections, we estimate the cost of supplying these regions/applications with ANS gas. These estimates are preliminary. Our analysis has attempted to use the best available information to estimate the cost of supplying each of these opportunities. As most Alaskans are aware, the costs of developing major infrastructure projects in the state are heavily influenced by geography and climate. Any final conclusions about these infrastructure costs should be subject to a detailed engineering and environmental impact analysis.

9.2: Supplying ANS Gas to the Interior for Residential and Commercial Use

As noted in Chapter 6, there appears to be significant and relatively concentrated opportunities for natural gas usage in the Interior section of the state, primarily in the Fairbanks region. Our earlier analysis identifies close to 2 Bcf of potential residential use, and 2.1 Bcf of commercial use,[1] in this region. In order to supply natural gas to these areas, a number of new infrastructure investments would have to be made. The major infrastructure investments that we modeled included:

(1) Tap and meter station off the AHR pipeline that would reduce gas pressure and remove natural gas liquids for retail quality gas.

(2) Pipeline transportation investments to move the AHR gas from the major pipeline to the city gate.

(3) Distribution system investments including mains and lines to serve the local communities with new gas service.

In addition to the capital investments to supply ANS gas to the region, there are also ongoing administrative and general (A&G) and operation and maintenance (O&M) expenses associated with each of the investments described above. Lastly, commodity cost of gas will also have to be added to the cost of providing service to derive an estimated system average retail rate for serving these new sources of usage.

A number of our gas transportation and distribution assumptions are based upon an earlier conducted study by Stone and Webster (S&W) Engineering. This study examined the natural gas transportation and distribution costs of moving gas from the Cook Inlet to Fairbanks.[2] Meter station/processing costs have come from industry sources. Costs from the earlier S&W study were inflated to 2000 dollars. Transportation costs from the ANS Conditioning plant to the Fairbanks metering station, were based upon an assumed value that encompasses a range of prior studies on this issue.

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[1]This assumes 100 percent commercial penetration.

[2]Stone and Webster Engineering. *Estimated Cost and Environmental Impacts of a Natural Gas Pipeline System Linking Fairbanks with Cook Inlet Area.* Prepared for Alaska Power Authority. Jan. 1989.

Costs for each of the applications we consider in this section were first standardized in order to "price-out" each application. For instance, applications were identified by customers, distance (miles), and volumes. Total transmission costs were estimated from typical transmission costs on a per mile basis, from industry sources.[3] These costs were then multiplied by the mileage in each application. Distribution costs from the S&W study were inflated., and standardized on a per customer basis. The number of customers in each application was then applied to this distribution cost per customer. Capital costs for transmission and distribution were estimated based upon a 10.1 percent allowed return on investment, taxes, and straight-line depreciation for an assumed 30-year life for the assets.

Transmission, meter station, and distribution O&M costs were standardized to a cost per volume figure, and based upon typical gas company costs per Mcf. Volumes utilized by each application were then multiplied by these O&M costs per Mcf to derive total annual O&M costs. Lastly, gas acquisition costs were taken from the 1999 reported value for Enstar.

The next step in our cost analysis was to develop an average rate for each of these unbundled costs (i.e., meter/step down costs, transmission, distribution). Each of the total cost estimates discussed above were divided by total projected volumes to serve as a proxy for an average tariff rate. Our supply analysis of retail gas to the Fairbanks/Interior region is presented in Table 9.1.

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[3]We compared our estimated transmission pipeline costs per mile to those published by Oil and Gas Journal in its annual pipeline economics survey. Our estimated costs per mile ($826,000/mile) were well within the range of costs provided for land-based projects, which ranged from a low of $820,000 per mile to a high of $925,000 per mile for 16 inch pipe. See *Oil and Gas Journal*, Pipeline Economics Survey, Volume 99.36: (September 3, 2001), 76

Table 9.1: Estimated System Delivered Cost for Interior (Fairbanks) Region

Fairbanks System Cost per Mcf	
Transportation – ANS Conditioning Plant to Fairbanks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0307
Levelized Transportation Cost	$0.0307
Levelized Distribution Costs	$1.2538
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$3.9646
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	**$5.8746**

Table 9.1 presents the summary results and the estimated system average retail rate for providing retail gas service to the Fairbanks/Interior region. Our modeled distribution system includes 2.27 Bcf of residential annual gas usage (11,075 customers) and 2.1 Bcf of commercial usage (1,291 customers)[4] under 80 percent penetration of potential regional natural gas load.

Our estimated average retail rates assume that the entire load will shift from its existing fuel source to natural gas. For residential customers, the major fuel switching opportunities include using natural gas for space and water heating. Table 9.2 provides a general examination of the potential savings associated with moving consumption from current fuel sources to natural gas. Annual Btu loads and household expenditures are provided and come from the most recent US Department of Energy Residential Energy Consumption Survey (RECS) for households living in areas with greater than 7,000 heating degree days (HDDs).

[4]Assumes 10,300 square feet per typical commercial establishment from the U.S. Department of Energy, Energy Information Administration, *Commercial Buildings Energy Consumption Survey.*

Table 9.2: Estimated Total Bills for Residential Space and Water Heating by Fuel Type – Interior Region

	Annual Average MMBtu per Household	Natural Gas Cost Per Household	Fuel Oil Cost Per Household	Electricity Cost Per Household	LPG Cost Per Household	Kerosene Cost Per Household
Space Heating	158.01	$928	$1,149	$1,222	$2,245	$738
Water Heating	39.20	$230	$285	$303	$557	$183
Total	197.21	$1,159	$1,434	$1,525	$2,802	$921

Table 9.2 examines the cost of new gas service versus other primary fuels used for space and water heating. Fuel oil is the predominant fuel for residential space and water heating, followed by electricity. There is about a 20 percent discount by moving from fuel oil to natural gas. There is a 27 percent discount by moving from electricity to natural gas for the typical household total bill. Total annual savings would be approximately $275 for households switching from fuel oil to natural gas.

Obviously, there would be conversion costs associated with natural gas furnace and appliance replacement. The rows in Table 9.3 provide various fixed levels of potential investments for furnace and appliance switching. Simple pay backs, based upon estimated annual savings from shifting current primary fuels to natural gas, are presented in each of the columns. As seen in Table 9.3, it would take about 3.6 years to pay off a $1,000 of space and water heating conversions/replacements for customers switching from fuel oil to natural gas.

Table 9.3: Simple Pay-Backs for Fixed Conversion Costs – Interior Region (Number of Years)

Fuel Switching Costs	Natural Gas Vs Fuel Oil	Natural Gas Vs Electricity	Natural Gas Vs LPG	Natural Gas Vs Kerosene
$100	0.4	0.3	0.1	-0.5
$250	0.9	0.7	0.2	-1.3
$500	1.8	1.4	0.3	-2.6
$750	2.7	2.0	0.5	-3.9
$1,000	3.6	2.7	0.6	-5.3
$1,200	4.4	3.3	0.7	-6.3

Our conclusions, based upon this very general cost analysis, are that serving natural gas to these communities may be possible. Some industry sources we consulted during the course of this investigation noted that savings in the 10 to 20 percent range are usually considered important in getting residential and small commercial customers to switch. Our estimated savings, under the reasonable optimistic scenario (i.e., 80 percent penetration rate), are around 20 percent for switching from fuel oil to natural gas and about 24 percent for switching from electricity to natural gas. However, these savings are based upon generalized cost assumptions of serving new areas and should be viewed as such.

9.3: Supplying ANS Gas to the Interior for Power Plant Fuel Switching

As noted in Chapter 8, there are a number of fuel switching opportunities for power plants in the Interior region. From our GIS analysis, we identified close to 200 MWs of power generation capacity that utilizes fuel oil or diesel as a primary fuel. These plants, and their operating characteristics and costs, are presented in Table 9.4. This table identifies each unit, the date it was placed into service, its current age, its prime mover by technology, primary fuel, and heat rate (i.e., amount of Btus required to generation one kWh of electricity.)

Table 9.4: Possible Fuel Switching Interior Power Plants

Utility Name	Plant Name	Unit	Capacity (kW)	Prime Mover	Primary Fuel	In Service Year	Plant Age	Estimated Heat Rate	Average Variable Cost per kWh
Alaska Power Co	Tok	3A	1,320	IC	FO2	1999	2	13,000	$0.0677
Alaska Power Co	Tok	4A	1,135	IC	FO2	1989	12	15,000	$0.0782
Alaska Power Co	Tok	5A	1,140	IC	FO2	1996	5	13,000	$0.0677
Alaska Power Co	Tok	7	1,250	IC	FO2	1984	17	15,000	$0.0782
Alaska Power Co	Tok	8	440	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Tok	9	930	IC	FO2	1985	16	15,000	$0.0782
Alaska Power Co	Dot Lake	1	125	IC	FO2	1990	11	13,000	$0.0677
Alaska Power Co	Chistochina	1	100	IC	FO1	1991	10	13,000	$0.0677
Alaska Power Co	Chistochina	2B	85	IC	FO1	1999	2	13,000	$0.0677
Alaska Power Co	Mentasta	1A	60	IC	FO2	1993	8	13,000	$0.0677
Alaska Power Co	Mentasta	2	100	IC	FO2	1992	9	13,000	$0.0677
Alaska Power Co	Mentasta	3A	90	IC	FO2	1996	5	13,000	$0.0677
Golden Valley Elec Assn Inc	Chena	6	23,100	GT	FO2	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	1	64,700	GT	FO4	1976	25	18,000	$0.0938
Golden Valley Elec Assn Inc	North Pole	2	64,700	GT	FO4	1977	24	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	5	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	6	2,600	IC	FO2	1970	31	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT1	17,600	GT	FO2	1971	30	18,000	$0.0938
Golden Valley Elec Assn Inc	Fairbanks	GT2	17,600	GT	FO2	1972	29	18,000	$0.0938
Golden Valley Elec Assn Inc	Healy	IC1	2,500	IC	FO2	1967	34	28,500	$0.1485

IC = Internal Combustion

GT = Combustion Turbine

The analysis of power plant fuel switching costs is similar to the preceding analysis of Interior region retail service opportunities. The results have been presented in Table 9.5. First, we estimated the costs of serving these facilities with natural gas. Total transportation costs were developed in a fashion similar to that for the Interior section. Transmission costs were developed on a per mile basis, distribution costs were assumed to incur only half of the capital investment per customer as traditional residential and commercial customers, step-down and meter station costs were also included. Annual transmission and distribution O&M were taken from the estimated utilized earlier.

All costs were then rolled into an overall estimated tariff (average) rate. This rate can be thought of as a delivered rate of gas since it includes the commodity portion of the gas costs in addition to the transportation amount. Commodity gas costs were based upon the 1999 annual gas costs of $1.74 per Mcf. The column entitled "fuel savings" estimates the total cost savings on a per kWh basis associated with shifting fuel from fuel oil to natural gas. For most generating units, the annual average savings ranges from four-tenths to nine-tenths of a cent.

The second cost we examined included the capital expenditures required to convert these facilities to natural gas. These costs range between $2 to $5 per installed kW of capacity. The column entitled "total conversion costs" provides these estimates. These costs were then converted to a per kWh basis and backed out of the gross savings discussed above. The column entitled "net fuel savings" includes the capital expenditures associated with putting in fuel conversion equipment. Total annual average savings range from 0.87 cents per kWh to 0.36 cents per kWh (i.e., less than one cent per kWh).

These savings, multiplied by the average annual generation level for each facility, yields a total annual savings per facility. This is presented in the column entitled "total net savings." Total per facility savings range from a high of $2.8 million per year, to a low of $1,800 per year. However, the savings are based upon estimates that pipeline infrastructure is laid to the region for converting all eligible power applications. Hence, these figures cannot be taken individually per facility. The estimates are on a per facility basis assuming the infrastructure costs are spread across the volumes for eligible applications. Dropping one or two facilities, for instance, would drive up gas transmission and distribution rates, and effect the economics of fuel conversion for the remaining applications.

Table 9.5: Potential Savings from Fuel Switching Power Plants in the Interior Region

Utility Name	Plant Name	Unit	Capacity (kW)	Estimated Heat Rate	Current Fuel Cost ($/kWh)	Gas Fuel Cost ($/kWh)	Gas Transport ($/Mcf)	Gas Fuel Cost with Transport ($/kWh)	Fuel Savings ($/kWh)	Total Conversion Cost	Net Savings ($/kWh)	Total Net Savings
APC	Tok	3A	1,320	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$6,600	$0.00364	$40,019
APC	Tok	4A	1,135	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$5,675	$0.00430	$40,577
APC	Tok	5A	1,140	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$5,700	$0.00364	$34,562
APC	Tok	7	1,250	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$6,250	$0.00430	$44,689
APC	Tok	8	440	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$2,200	$0.00430	$15,730
APC	Tok	9	930	15,000	$0.07815	$0.02610	$3.14355	$0.07325	$0.00490	$4,650	$0.00430	$33,248
APC	Dot Lake	1	125	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$625	$0.00364	$3,790
APC	Chistochina	1	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Chistochina	2B	85	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$425	$0.00364	$2,577
APC	Mentasta	1A	60	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$300	$0.00364	$1,819
APC	Mentasta	2	100	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$500	$0.00364	$3,032
APC	Mentasta	3A	90	13,000	$0.06773	$0.02262	$3.14355	$0.06349	$0.00424	$450	$0.00364	$2,729
GVEA	Chena	6	23,100	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$115,500	$0.00528	$1,014,118
GVEA	North Pole	1	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	North Pole	2	64,700	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$323,500	$0.00528	$2,840,409
GVEA	Fairbanks	5	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	6	2,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$13,000	$0.00528	$114,143
GVEA	Fairbanks	GT1	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Fairbanks	GT2	17,600	18,000	$0.09378	$0.03132	$3.14355	$0.08790	$0.00588	$88,000	$0.00528	$772,662
GVEA	Healy	IC1	2,500	28,500	$0.14849	$0.04959	$3.14355	$0.13918	$0.00930	$12,500	$0.00870	$181,067
Total												$8,875,417

The analysis presented in Table 9.5 is based upon generalized assumptions about plant operating characteristics. In order to determine the outer possibilities for gas usage at these facilities an average operating capacity factor of 95 percent was assumed. This level may be unrealistically high. Table 9.6, however, presents a range of different cost savings and fuel usage at various different average capacity utilization factors.

Table 9.6: Cost Savings from Fuel Switching Under Different Average Capacity Factor Assumptions.

Capacity Factor	Gas Usage (Mcf)	Savings Per kWh Low	Savings Per kWh High	Total Savings
95%	30,284,049	0.00360	0.00870	8,875,417
75%	23,908,460	0.00350	0.00850	6,794,093
50%	15,938,973	0.00310	0.00820	4,192,437
25%	7,969,487	0.02000	0.00700	1,590,781

<u>9.3.1: Gas By Wire Application – Power to the Interior</u>: Another potential new gas usage opportunity that we identified in an earlier chapter of our report was a gas by wire application. This application includes placing a central station power generation facility close to the AHR step-down meter station near Fairbanks (say), then transmitting the electricity (fueled by natural gas) to the Interior region of the state. The advantages of this opportunity include generating electricity with a more efficient, state of the art natural gas fired power generation facility. In addition, some gas distribution costs, which have been the more expensive costs associated with moving ANS gas to local communities, can by avoided.

The disadvantages of the gas by wire application is that, without substantial growth in electricity demand, the addition of new power generation facilities prior to 2014 could displace existing plants. The remaining costs associated with these displaced units would have to be recovered. Since most utilities in Alaska are publicly owned, ratepayers and shareholders are in the same group. Developing creative policies for recovering these costs would be needed.

Our gas by wire application considers the cost of transportation from ANS to the tap location near the AHR pipeline. We also include meter station and tap costs, as well as a small amount of transportation costs (we assume facility is located within one mile). In addition, we examined the cost of moving power from the generation facility, located in close proximity to the AHR, to the Interior region.

We have assumed that a 345 kV power transmission line would be developed to move gas from the power plant to the Interior section. Substation costs at the plant, and at the distribution system, are also included. The results from our analysis are presented in Table 9.7.

Once the costs of transportation (gas and power) are included in the total cost of dispatching new gas fired electricity, the new power application becomes less attractive. The total dispatch cost increases from between 50 percent to almost 100 percent depending upon the fuel cost assumptions examined.

At \$28.41/MWh, the gas-by-wire dispatch costs under the MPL fuel cost assumption is higher than the average gas generation dispatch cost for MPL (\$26.04/MWh, see Table 8.8 in Chapter 8). At \$24.86/MWh, the gas-by-wire dispatch costs under the CEA fuel cost assumption is considerably higher than the average gas-fired CEA generation cost of \$15.60/MWh. However, even at \$36.34/MWh the gas-by-wire dispatch cost is competitive with the average gas fired generation cost of GVEA which is estimated to be \$43.62/MWh.

We would conclude that, given the relatively higher cost in the GVEA region, there may be some potential applications for a gas-by-wire application that moved electricity into the interior. A more detailed study on power and gas transmission costs, however, would be necessary to draw definitive conclusions.

Table 9.7: Gas By Wire Application, Dispatch and Levelized Cost with Power and Gas Transmission

General Plant Cost and Operating Assumptions			
Capacity Factor	95%	Annual Carrying Factor	12.81%
Total Annual Generation	2,080,500,000	Annual Carrying Cost	$22,414,158
Heat Rate	6,000	Total Capital Cost/kWh	$0.01077
Installed Capacity Cost ($/kW)	$700		
Capacity (kW)	250,000	Deprecation, Years	30
Total Installed Cost	$175,000,000	Rate of Return	10.2%
Capital Cost; $/kW/Yr	$23.33	Taxes	38.7%

New Plant at MPL Gas Cost		New Plant at CEA Gas Cost		New Plant at GVEA Gas Cost	
Commodity Charge ($/MCF)	$1.86	Commodity Charge ($/MCF)	$1.27	Commodity Charge ($/MCF)	$3.18
Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06	Transportation Charge ($/MCF)	$1.06
Cost of Gas	$2.92	Cost of Gas	$2.33	Cost of Gas	$4.24
Total Annual Gas Cost	$36,474,010	Total Annual Gas Cost	$29,084,074	Total Annual Gas Cost	$52,967,174
Average Variable Fuel Cost ($/kWh)	$0.01753	Average Variable Fuel Cost ($/kWh)	$0.01398	Average Variable Fuel Cost ($/kWh)	$0.02546
Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500	Average Variable O&M Cost ($/kWh)	$0.00500
Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588	Transmission Rate ($/kWh)	$0.00588
Total Dispatch Cost ($/kWh)	$0.02842	Total Dispatch Cost ($/kWh)	$0.02486	Total Dispatch Cost ($/kWh)	$0.03634
Total Levelized Cost ($/kWh)	$0.03919	Total Levelized Cost ($/kWh)	$0.03564	Total Levelized Cost ($/kWh)	$0.04712

9.4: ANS Gas Opportunities in the Southcentral Region

9.4.1: The Natural Gas Supply and Demand Balance in the Cook Inlet Basin: Cook Inlet has been an active oil and gas basin since the discovery of the Swanson River Field in 1957. By the late 1960s nine major oil or gas fields containing nine trillion cubic feet (TCU) of gas had been discovered in the Cook Inlet Basin.[5] Two gas-feed industrial plants and a gas pipeline transmission system linking the Kenai Peninsula to Anchorage were fully operational by 1969.

In June of 1972, the Alaska Oil and Gas Conservation Commission passed a gas conservation order that required gas producers to minimize gas flaring. Over the intervening 25 years, the Cook Inlet Basin was able to deliver gas in quantities equal to or greater than the total usage among all customer classes. The Phillips-Marathon LNG plant and the Unocal Ammonia-Urea plant enjoyed an abundance of inexpensive baseload gas. Their investments in gas production facilities and pipeline infrastructure enhanced deliverability and lowered gas costs for residential and commercial users in Southcentral Alaska. Historic gas consumption by major customer classification is shown for the period 1971 through 2000 in Figure 9.1. Over the past five years, industrial users consumed approximately two-thirds of total gas dispositions. Residential and commercial users account for the other one-third.

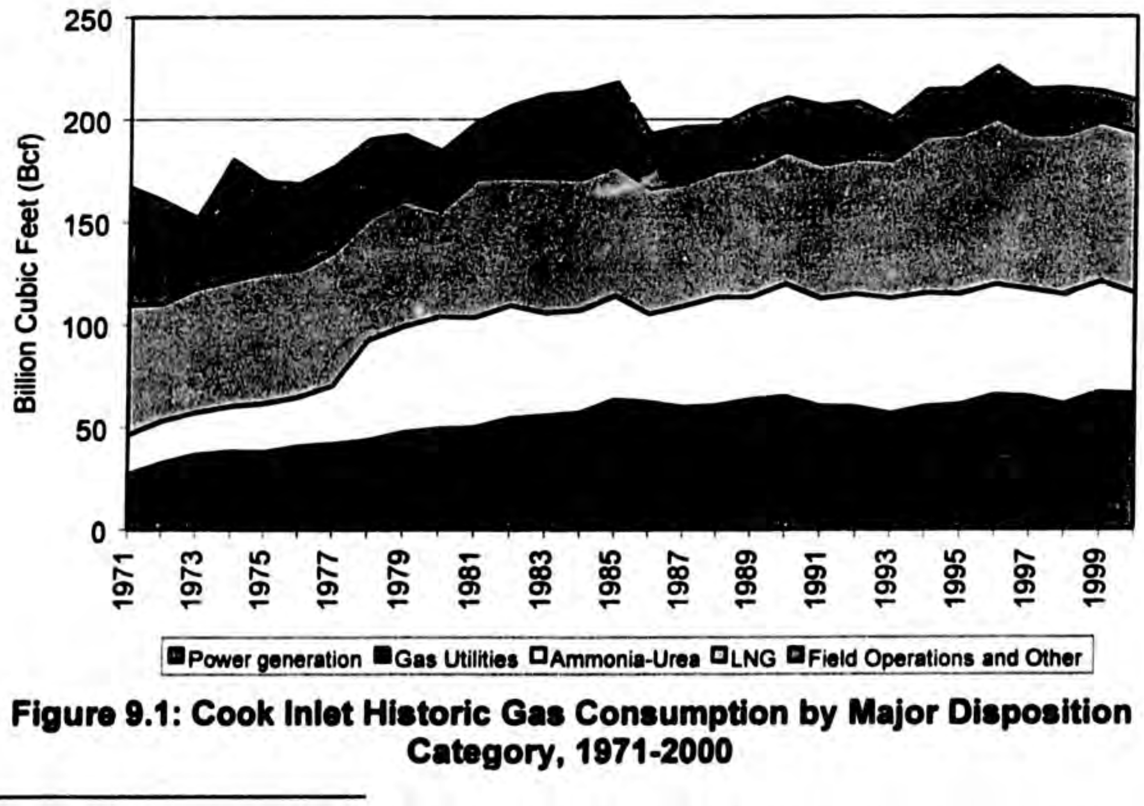

Figure 9.1: Cook Inlet Historic Gas Consumption by Major Disposition Category, 1971-2000

[5]Including Swanson River oil field and the Kenai (2.467 Tcf), North Cook Inlet (2.337 Tcf), McArthur River (1.377 Tcf), and Beluga (1.257 Tcf), plus several smaller gas fields.

December 1996 marked the end of the era of excess gas supply in the Cook Inlet Basin. At that time, Phillips and Marathon filed an application with the U.S. Department of Energy to renew and extend their license to export LNG to Japan. Coincidentally, a deep, winter cold snap in the Southcentral region and a compressor failure on the Steelhead platform resulted in abrupt but short-term gas curtailments to industrial plants. While the reasons and responsibilities for the industrial curtailments were disputed, the event itself signaled a transition to a new era of potential deliverability shortfall under extreme conditions of peak gas demand.[6] In April 1999 the DOE extended the Phillips-Marathon license to export until April 2009 but only after a protracted debate over existing and potential reserves estimates in the basin.[7] Estimates of booked reserves in the Cook Inlet Basin from the Alaska Department of Natural Resources currently stand at about 2.148 Tcf of natural gas.[8]

The debate over the Cook Inlet Basin gas supply and demand balance surfaced again in connection with a gas supply-purchase agreement between Unocal and Enstar, submitted to the Regulatory Commission of Alaska (RCA) in November 2000 The contractual agreement, approved with modifications by the RCA in October 2001, contains several provisions that fueled debate among stakeholders, including competing gas producers and consumer groups.[9]

For example, the agreement stipulates a pricing mechanism that links the wholesale gas price for Unocal deliveries to the daily average price of Henry Hub natural gas futures.[10] Indexing local gas prices to world commodity prices is, in itself not new to the Cook Inlet Basin. Numerous Cook Inlet gas supply agreements are indexed to world oil prices and to spot prices for fertilizer. This Unocal-Enstar pricing mechanism is unique because it is tied directly to a dominant Lower-48 *gas price marker*, the Henry Hub futures price. The pricing mechanism stipulates a three-year moving average for ". . . contract[s] traded

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[6]Gas curtailments were confined to industrial plants and occurred over a period of several days beginning on December 31, 1996. A subsequent legal dispute among gas producers over actions and responsibilities surrounding these curtailments has been settled. Phillips-Marathon and Unocal have gas exchange agreements in place to provide for orderly curtailments to industrial plants in the event that peak system-wide demand exceeds deliverability.

[7]Office of Fossil energy, *Order Extending Authorization to Export Liquified natural Gas From Alaska*, (Washington DC: U.S. Department of Energy, DOE/FE Opinion and Norder No. 1473), April 2, 1999.

[8]DNR, Division of Oil and Gas, *Historic and Projected Oil and Gas Consumption, 2000 Annual Report*, p. 13, 2000.

[9]Regulatory Commission of Alaska, *Order Conditionally Approving TA 117-4 (Gas Sales Agreement) and Requiring Filing*, (Docket No. U-01-7, Order No. 8), October 25, 2001.

[10]Also, it gives Unocal a first right of refusal to supply gas to meet Enstar undesignated supply for up to 450 Bcf. No explicit time limitations were placed on the contract even though RCA's Public Advocacy Staff recommended a nine year contract term. In its final order, the RCA left open the possibility of revisiting the terms of the contract once the 450 Bcf limitation was reached.

during the immediately previous thirty-six month period ended each September 30th of the year prior to the year for which the price is calculated" and a price floor equal to $2.75 per Mcf adjusted for changes in inflation.[11] Unocal is expected to begin making deliveries to the Enstar system under this agreement in 2004.

Figure 9.2 illustrates how the Unocal-Enstar pricing mechanism would work based on *back-casting* a three-year moving average of the monthly Henry Hub spot price during the historic period starting in December 1994.[12] Figure 9.2 compares Unocal-Enstar mechanism with the Alaska Department of Revenue Prevailing Value (DORPV).[13] Several points are noteworthy.

First, the DORPV exhibits an upward trend of approximately seven-tenths of a cent per year over the seven-year historic period. This upward trend is more pronounced after January 2000. Second, the long-term trend for the three year moving average of Henry Hub price is approximately twice that of the DORPV. Third, the 36-month moving average of Henry Hub spot price is on average $0.69 per Mcf higher than the DORPV over the same historic period. This difference becomes more pronounced after September 1998. Fourth, the price floor would have been in effect during much of the historic period, raising gas prices another $0.40 per Mcf, on average. The back-casting results indicate that the Unocal-Enstar price mechanism would have generated higher gas prices than those observed in the recent past in the Cook Inlet Basin.

Figure 9.2 also projects the Henry Hub price and the Unocal-Enstar pricing mechanism based on U.S. Department of Energy, Energy Information Administration forecast of domestic gas prices.[14] Although dispositions under the Unocal-Enstar agreement are not expected to occur until 2004, the pricing provisions in this agreement signal a discrete change in local gas prices at the wholesale level – one that could be interpreted as a response to a prevailing local condition of excess demand for gas. Unocal and Enstar have suggested in testimony to the RCA that higher gas prices are necessary to stimulate exploration.[15]

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[11] *Gas Sales Agreement Between Union Oil Company Of California and Alaska Pipeline Company*, November 2000, p. 21-4. Note, the inflation adjustment is one half of the rate of inflation, measured as the Gross Domestic Product Implicit Price Deflator from the quarter ended June 2001.

[12] Note that the Unocal-Enstar mechanism would adjust once a year, rather than continuously, as reflected in the monthly data in Exhibit 2.

[13] The DORPV is based on a weighted average of gas dispositions to local utilities providing gas and electricity service.

[14] Energy Information Administration. Annual Energy Outlook 2002, Table 14, (Washington DC: U.S. Department of energy), December 2001. Note, the EIA forecast is for average Lower-48 wellhead price. 17 cents per mcf was added to the EIA estimate to approximate the Henry Hub price, based on the historic difference between Henry Hub and EIA estimate for average wellhead price.

[15] *Submittal of Union Oil Company of California's Prefiled Reply Testimony of Daniel B. Thomas, Patrick J. Coughlin and Richard F. Strickland Ph.D,PE.*; *Reply Testimony of Richard F. Barnes*; and *Reply testimony of Daniel M. Dieckgraeff*, Docket No. U-01-007, (July 27, 2001).

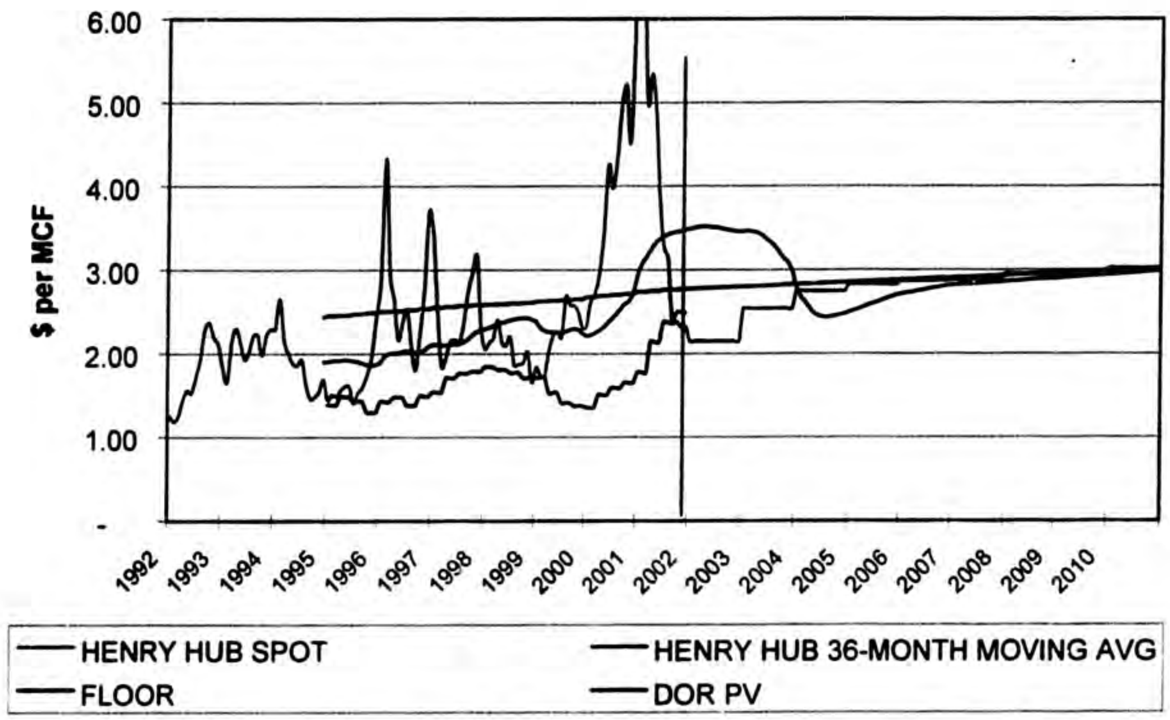

Figure 9.2: Henry Hub 36-Month Moving Average with UNOCAL-ENSTAR Price Floor
Henry Hub Spot Price and DOR Prevailing Value and Backcast: Jan 1992 - Dec 2001 and Forecast: Jan 2002 - 2010

Higher wholesale gas prices have mixed implications. They are expected to stimulate more exploration and lead to new gas discoveries. But also, they raise costs for industrial uses that depend on low-cost gas in order to compete in global markets. While the outcome of expected higher local gas prices is still uncertain, an aggressive program of oil and gas exploration in Cook Inlet was evident in 2001, as shown in Table 9.8. The implications of stepped up exploration for the gas demand-supply balance in the Cook Inlet Basin are illustrated in Figure 9.3 and Figure 9.4.

Assume that relative energy prices remain stable and the demand for Cook Inlet gas, including gas dispositions for LNG Exports, continues to grow at the steady pace outlined in the baseline forecast of Chapter 4. Assume further that production from the existing 2.148 Tcf reserves base continues along reasonable rates of decline for various producing fields. If no new discoveries of gas are forthcoming, then annual deliverability shortfalls can be expected by 2004 or 2005. One Tcf of reserves appreciation would provide a four-to-five year buffer and forestall annual deliverability shortfalls until around 2009.

In addition to one Tcf of added reserves, assume further that the license to export LNG to Japan is not extended beyond April 2009. This situation is illustrated in Figure 9.4. The abrupt fall in demand after 2009 reflects closure of the LNG plant. Here, annual deliverability shortfalls would not occur until after 2015.

These examples suggest that, while gas reserves for utility dispositions are relatively secure, industrial users of Cook Inlet gas have some exposure to the prospect of gas deliverability shortfalls, even when reasonable reserves additions are taken into account. Thus, over the long run, additional gas reserves beyond 1 Tcf will be required to provide continued gas service to industrial users in the Cook Inlet Basin.

Table 9.8: Cook Inlet Oil and Gas Exploration Activity, 2001

Unit or Project	Companies	Description
Ninilchik and Falls Creek	Marathon	G.O. #1 well completed as gas well, G.O. #2 well planned.
Pretty Creek Lewis River Ivan River	Unocal	Re-entered one well each in Lewis River and Ivan River; drilling P.C.U. #4, new well, in Pretty Creek Field.
South Ninilchik and Deep Creek	Unocal	Up to three wells planned on State and CIRI lands in 2001-02.
Swanson River Unit Gas Satellites Project	Unocal	Proposal to develop two gas fields north and east of Swanson River oil field on Federal and Native owned lands.
Redoubt	Forest Oil (discovered in 1968 by Pan Am)	R.U. #1, #2, & #3 wells completed by Forest; R.U. #4 is planned. Up to 193 MMBO recoverable reserves. Forest has other prospects at Sabre, Corsair, and Valkyrie.
Pioneer (Coalbed gas, no proven reserves)	Evergreen Exploration	Formerly operated by Ocean Energy, ownership and operations transferred to Evergreen in mid-2001. Two production wells and one injection well drilled in 1999; Evergreen is committed to drill six more wells, at least one in each of two new areas.
Cosmopolitan	Phillips (discovered in 1967 by Penzoil)	Hansen #1 well permitted to drill to bottom location on State lease.
Nikolai Creek	Aurora Gas	Production started in October; NCU #3 well produces at rate of 2 MMCF per day.
North Fork	Gas Pro	Project apparently on hold.
Trading Bay Unit/McArthur River Field (Oil)	Unocal	T.B.U. #K-13 came on production at 7,100 BOPD, highest rate of any well in Cook Inlet.

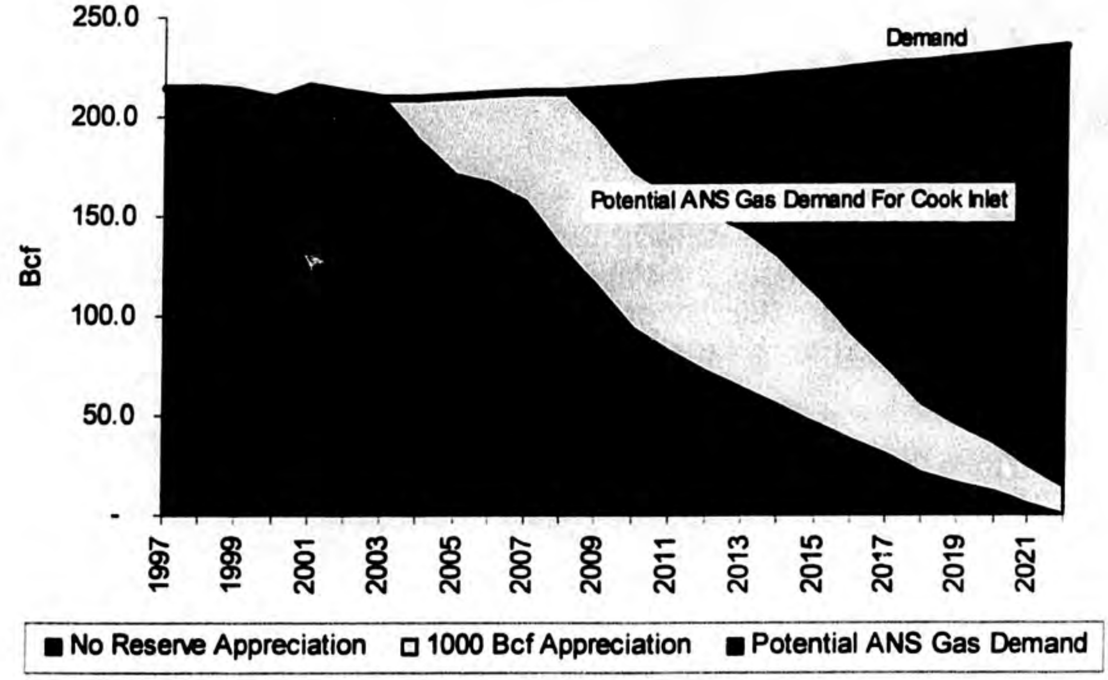

Figure 9.3: Projected Cook Inlet Supply and Demand Typical Production Scenario with 1 Tcf Reserve Appreciation

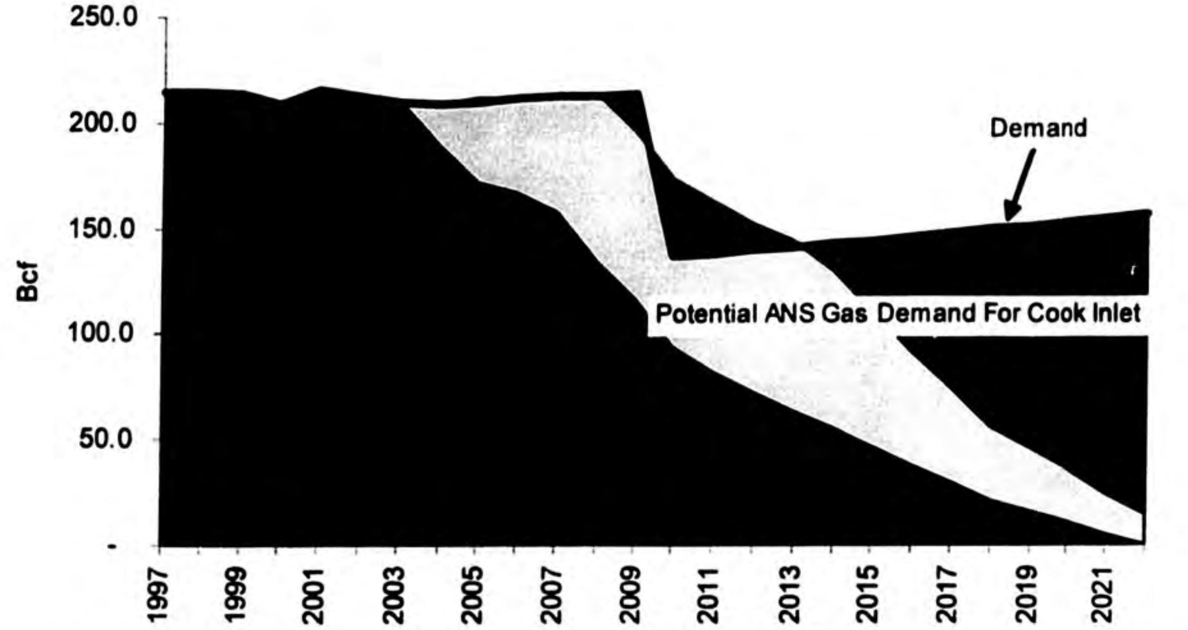

Figure 9.4: Projected Cook Inlet Supply and Demand LNG Export License Renewal Denied

9.4.2: Retail Opportunities in the Southcentral Region: First, consider the implications for expanded gas usage for the Southcentral region, similar to that for the Interior region. We modeled a standardized system to serve the region's *new* natural gas usage. (We assume existing baseline consumption is supplied from existing sources in the Cook Inlet Basin.) The new system is comprised of 11,219 new remote residential customers and 2.2 Bcf of additional annual natural gas usage.

We examined two different opportunities for transporting the natural gas to the region. Our approach is to assume that a lateral spur pipeline from the AHR pipeline is constructed and considered part of the overall pipeline system for pricing purposes. This could entail some spreading of the costs of the system if a zonal based transportation tariff for the region were developed.[16]

We also modeled a system where the cost of the lateral spur was completely recovered from the Southcentral region and no other costs were spread to other out-of-region customers. The overall system average rates are presented in Table 9.9. If the cost of this spur is not spread across some broader region and are allocated only incremental expansion of new residential customer usage, the per-unit cost of moving ANS gas into the region would be prohibitive.

Table 9.9: Estimated System Average Retail Rate for Southcentral/Cook Inlet Region With Entire Spur Transportation Costs

Cook Inlet System – Separate Spur System Cost per MCF	
Transportation – ANS Conditioning Plant to Fbks Meter Station	$1.0000
Levelized Meter/Step-Down Capital Cost	$0.0477
Levelized Transportation Cost	$13.2203
Levelized Distribution Costs	$2.3655
Transportation Meter Station O&M	$0.0545
Transportation O&M	$0.1091
Distribution O&M	$1.4857
Total T&D Cost	$18.2828
Commodity Cost	$1.9100
Total Delivered Cost (Average Retail Rate)	$20.1928

[16] For example, to serve Interior Region gas-by-wire or expanded Interior Region residential and commercial usage. Our analysis showed that if the realized transportation rate was reduced by about $1.25 per Mcf, average retail rates would be around $7.27 per Mcf.

The analysis presented above, is based on small, incremental gas service applications. As expected, many of the applications, given their limited volumes, either generate small, or negative net benefits. However, if volumes were increased, the large fixed costs associated with gas transportation, would decline on a per-unit basis to levels that may compete with alternative energy sources.

9.4.3: ANS Gas as a Means to Meet a Potential Supply/Demand Imbalance in the Southcentral Region: As noted earlier, one area of potential interest to DNR has been associated with supplying the Southcentral region with gas from the ANS given concerns about the availability of future supplies for the region. The RCA also appears to be concerned with this issue as well. In its recent Order conditionally approving Enstar's Gas Sales Agreement (GSA), the Commission noted:

> Natural gas reserves, while plentiful in the past, are declining. It is predicted that the known natural gas reserves in Cook Inlet will be exhausted by 2012. Exploration for new sources of gas in Cook Inlet has not kept pace with other areas. There is also concern that the older fields in the Cook Inlet will be unable to deliver natural gas at the rates required. The ability to meet peak demand may also be affected by the lack of gas storage facilities. Exploration and development of new natural gas sources takes many years and requires that exploration companies act years before reserves are exhausted by customer demand. [Regulatory Commission of Alaska. Order Number 8, Docket Number U-01-7, at 5.]

Given the preceding analysis of fixed and variables costs for gas step-down, transmission, and distribution, we consider the impact of greater throughput on the per transmission and delivered costs.

Table 9.10 presents estimates of the transportation costs associated with two different spur lines from Fairbanks to the Southcentral region: a 16-inch pipeline and a 20-inch pipeline. Discrete transportation/usage volumes are presented in the left hand column, while estimated levelized rates are presented for each volume level, for each type of pipeline. In order to put these volumes into perspective, the second and third columns of the table relate these volumes to total system, and Southcentral 1999 sales.

Table 9.10: Estimated Levelized Transmission Costs (Fairbanks to Southcentral) Under Different Volume Scenarios

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	21.9%	4.9%	$ 2.9412	$ 3.6378
20	43.8%	9.8%	$ 1.4706	$ 1.8189
30	65.7%	14.8%	$ 0.9804	$ 1.2126
40	87.6%	19.7%	$ 0.7353	$ 0.9095
50	109.4%	24.6%	$ 0.5882	$ 0.7276
60	131.3%	29.5%	$ 0.4902	$ 0.6063
70	153.2%	34.4%	$ 0.4202	$ 0.5197
80	175.1%	39.4%	$ 0.3676	$ 0.4547
90	197.0%	44.3%	$ 0.3268	$ 0.4042
100	218.9%	49.2%	$ 0.2941	$ 0.3638

**/1 Sales volumes are for retail customers only and do not include volumes that may be direct served.*

**/2 Enstar retail with Urea plant 1999 volumes of 53.9 Bcf, LNG volumes of 77.95 Bcf, and and gas generation volumes of 34.57 Bcf.*

**/3 Assumes 16 inch pipe at a cost of $826,018 per mile at 278 miles*

**/4 Assumes 20 inch pipe at a cost of $1.02 million per mile at 278 miles. 20 Inch pipe assumes a 45 million increase from total estimated cost (for 16 inch pipe) provided in S&W Study inflated to 2001 dollars.*

As seen from the table, in order to get the overall costs down to the $1/Mcf threshold, a 16-inch system would need to have volumes of around 30 Bcf and a 20-inch system would need to move volumes in the order of 40 Bcf per year. The 30 Bcf level is approximately 14.8 percent of estimated Southcentral 1999 sales volumes, while 40 Bcf is approximately 19.7 percent of total regional 1999 sales.

While increasing usage volumes can reduce the unit costs associated with transporting natural gas to the Southcentral region, it will not to lower distribution charges. One opportunity, however, may be to incorporate the higher than average costs associated with serving these new customers into the existing Enstar distribution system costs. In effect, existing Enstar customers would subsidize the excess costs of expanding the current system to include the potential remote areas.

Based upon our estimates, the average non-gas related distribution costs for Enstar are approximately $1.55 per Mcf. This estimate comes from taking the Company's 1999 average retail rate and subtracting the total annual average gas acquisition cost. We estimate that taking the excess cost of the new system and averaging them into the combined distribution system costs and volumes yields a subsidy of approximately 3.8 cents per Mcf. However, we would note, while not large in magnitude, this type of cost-shifting policy would have to be deemed in the public interest, and approved, by the RCA.

Figure 9.5 graphs the various different estimated transportation costs for each modeled system under different volumetric assumptions.

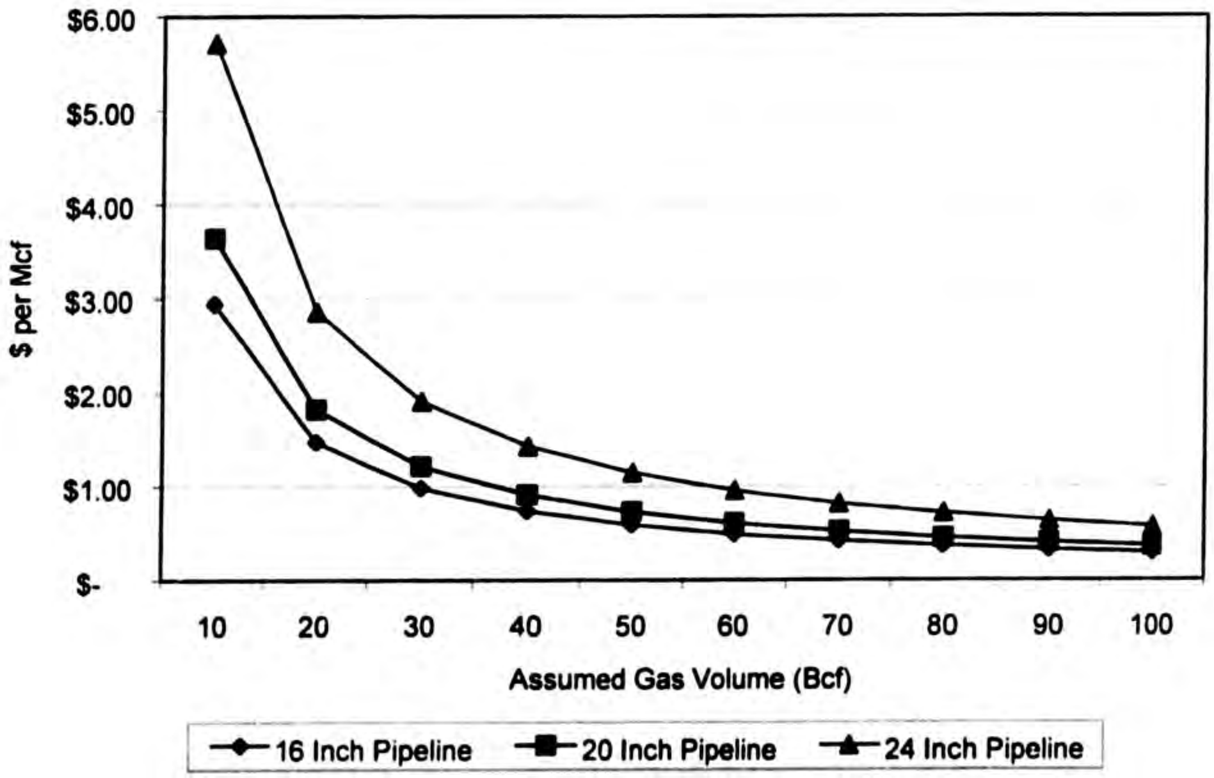

Figure 9.5: Estimate Pipeline Transportation Costs Under Different Volumetric Assumptions

Table 9.11 combines a number of the analyses discussed above for the 16-inch pipeline example. We have estimated total costs associated with providing service into the Southcentral region from a tap located near Fairbanks. Total transmission and distribution costs have been included. Distribution costs, in our example, are from the Enstar system, and include the subsidized portion (i.e., the 3.8 cents per Mcf) of serving the new 2.2 Bcf level of usage associated with remote residential customers. Table 9.11 presents cost estimates for a number of discrete volumes moved over the hypothetical transportation system.

The costs of moving gas, while more economic, are still relatively high relative to 1999 Enstar average rates. However, even with the higher transportation costs, average rates for this hypothetical new system still are below the national average for residential retail customers. The new system yields estimated rates that are between 17 percent to 33 percent below national averages, depending upon the volumes assumed. Even with the pipeline addition, and its increased costs, Alaskans still have the opportunity to pay rates below the national average. Again, we would offer some caution on the numbers. Until detailed engineering studies could be completed, no definitive conclusions can be attained.

Table 9.11: Analysis of Estimated Average Rates – Pipeline System from Fairbanks to Southcentral

Assuming 30 Bcf/y Volumes – 18 Inch System		Assuming 60 Bcf/y Volumes – 18 Inch System	
Transportation -- ANS to Meter Station	$ 1.0000	Transportation -- ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.9804	Levelized Transportation Cost	$ 0.4902
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.8044	Total T&D Cost	$ 3.3142
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.7144	Total Delivered Cost	$ 5.2242
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***56.1%***	***Percent Change***	***42.7%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-17.1%***	***Alaska ANS Rate Relative to US Average***	***-28.1%***

Assuming 80 Bcf/y Volumes – 18 Inch System		Assuming 100 Bcf/y Volumes – 18 Inch System	
Transportation -- ANS to Meter Station	$ 1.0000	Transportation -- ANS to Meter Station	$ 1.0000
Levelized Meter/Step-Down Capital Cost	$ 0.0674	Levelized Meter/Step-Down Capital Cost	$ 0.0674
Levelized Transportation Cost	$ 0.3676	Levelized Transportation Cost	$ 0.2941
Transportation Meter Station O&M	$ 0.0545	Transportation Meter Station O&M	$ 0.0545
Transportation O&M	$ 0.1091	Transportation O&M	$ 0.1091
Distribution System Unit Cost	$ 1.5930	Distribution System Unit Cost	$ 1.5930
Total T&D Cost	$ 3.1916	Total T&D Cost	$ 3.1181
Commodity Cost */1	$ 1.9100	Commodity Cost */1	$ 1.9100
Total Delivered Cost	$ 5.1016	Total Delivered Cost	$ 5.0281
Enstar 1999 Residential Average Revenue	$ 3.6602	Enstar 1999 Residential Average Revenue	$ 3.6602
Percent Change	***39.4%***	***Percent Change***	***37.4%***
US Residential Average Rate (1999)	$ 6.6900	US Residential Average Rate (1999)	$ 6.6900
Alaska ANS Rate Relative to US Average	***-31.1%***	***Alaska ANS Rate Relative to US Average***	***-33.1%***

Our preliminary findings indicate that the levelized cost of a 16-to-20 inch spur pipeline linking Southcentral with the ANS gas pipeline at Fairbanks could be competitive with energy alternatives (such as fuel oil or LNG imports into Cook Inlet) if annual throughput exceeds 30-to-40 Bcf per year. For example, a 20-inch spur pipeline operating at an average of 40 Bcf per year for 30 years would imply meter-station step-down charges and levelized transmission charges of approximately $1.00 per Mcf (excluding the toll to Fairbanks, as well as local distribution and gas commodity charges). In order to be competitive, the spur pipeline would be required to serve a segment of the existing Southcentral customer base now served by local gas reserves in the Cook Inlet Basin. This result could be favorably influence by scale economies resulting from:

- Sharing spur pipeline transmission charges over a wider customer base along the energy belt;
- Higher rates of penetration than those observed among Southcentral users within the existing ENSTAR system;
- System-wide averaging of distribution charges; and
- Baseline growth in all customer classes including industrial users and expanded gas service.

9.5: Conclusions

When viewed individually, few applications for supplying ANS gas for in-state usage "pencil-out." Savings from fuel switching are relatively small. There is no substantial need for new power generation until the year 2014. Opportunities for new industry and businesses, like the internet server farm and a new petrochemical facility, are speculative, at best.

One application that warrants further consideration is natural gas delivery into Interior region communities that are in proximity to the proposed AHR pipeline. Our initial results indicate that, on a stand-alone basis, sufficient concentration of residential and commercial space-heating demand exists in the greater Fairbanks area to enable local natural gas distribution to compete with fuel oil and other spacing-heating energy alternatives. When taken in combination with a lateral spur pipeline into Southcentral, the economics of providing gas service to Interior communities for space heating, electric power generation and industrial applications could improve.

Moving gas to the Southcentral region is highly dependent upon future reserve development in the Cook Inlet Basin. Study results indicate that, in order to be competitive, spur line throughput must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage – 30 to 40 Bcf per year –

currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The declining rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30 to 40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

The decision of supplying ANS gas to Alaska communities should be left to the market. If reserves fall low enough in currently served regions, prices will have to increase to ration demand.[17] Once prices increase, signals will be sent to the market for the development of either new resources, or new means to bring other resources (i.e., ANS gas) to the region.

Higher prices, while signaling the market about important energy development opportunities, can also serve to send signals to critical, energy-intensive Alaskan industries to move elsewhere. In effect, a cycle is set up whereby higher prices are needed to stimulate infrastructure development, but these prices, in turn, discourage industrial development and retention, which in turn, shift the relative economics of infrastructure development. Reserves and infrastructure development on the supply side typically occur in discrete, lumpy amounts and are often not well balanced with demand. This raises project risk and adds to the challenges faced by resource-development and resource-consuming industries.

[17]The same would hold true for regions that are currently not served with natural gas. If prices for their current energy alternatives increase high enough, then opportunities for moving new energy resources in the region increase.

CHAPTER 10: CONCLUSIONS

The purpose of this report has been to examine opportunities for in-state natural gas usage in Alaska. As noted at the onset of this report, the approach taken to examine these opportunities was based upon the analysis of:

- Existing in-state demand and the development of a forecast to the year 2020.
- Forecast assumptions to determine how in-state demand could shift as a result of changing economic conditions.
- New service opportunities in remote and currently unserved areas of Alaska.
- New potential industries and their impact on in-state gas usage.
- Fuel switching opportunities for oil-fired generators as well as an examination of a central power generation station gas-by-wire application.
- The potential costs of supplying new usage opportunities with natural gas service.

The general findings from the analysis can be summarized as follows.

10.1: Baseline Forecast

Under the baseline forecast, retail natural gas usage is expected to show slow, but consistent, growth through the year 2020. Total usage will grow at an annual average rate of slightly under one percent. Residential customers will account for 28.5 percent of this growth, commercial customers will account for 22.7 percent of this growth, industrial customers will account for 28.9 percent of this growth, and electricity utilities will account for 19 percent of this growth. Table 10.1 presents a summary of the baseline usage levels for each major customer class.

Table 10.1: Summary of Baseline Forecast

Date	Residential (Mcf)	Commercial (Mcf)	Industrial (Mcf)	Electric Utility (Mcf)	Total (Mcf)
2000	17,518,229	28,566,567	73,238,676	35,656,886	154,980,358
2005	19,198,104	30,564,363	75,226,290	35,406,497	160,395,253
2010	21,059,031	31,531,308	77,214,690	37,031,714	166,836,744
2015	23,121,582	33,362,837	79,203,895	38,899,627	174,587,941
2020	25,409,386	34,837,741	81,193,900	40,790,982	182,232,010
10 Year Increase	3,540,802	2,964,742	3,976,015	1,374,828	11,856,386
20 Year Increase	7,891,157	6,271,174	7,955,225	5,134,096	27,251,652

Original Source Table: Chapter 4: Tables 4.1, 4.2, 4.3, and 4.4.

10.2: Sensitivity Analysis

Shifts in prices and income can have important impacts on natural gas usage. The impact that shifts in prices can have on usage is relatively more important than income. Under a high price scenario, total in-state annual average growth rates are reduced to about 0.75 percent, while under a low price scenario, annual average growth rates for total in-state usage are increased to 1.05 percent per year. Under a high-income scenario, we anticipate that total in-state usage will increase by an annual average rate of one percent. Under a low-income scenario, total in-state usage will grow by only three-quarters of a percent per year. When compounded over a period of ten-to-twenty years, these impacts could be significant; they range from about 8 to 36 Bcf of incremental gas consumption over baseline levels across all sectors. The sensitivity analysis indicates that gas consumption in 2020 is likely to be between 5 and 20 percent greater than in 2000, depending on future price and income levels. A summary of the various sensitivities has been presented in Table 10.2.

Table 10.2: Summary of Forecast Sensitivities

High Price Forecast Summary

2000	17,500,093	28,451,442	73,197,507	35,569,901	154,718,943
2005	19,035,431	29,336,492	74,978,844	34,521,334	157,872,101
2010	20,735,890	29,585,393	76,760,215	36,105,921	163,187,419
2015	22,620,716	30,107,039	78,541,636	37,927,136	169,196,528
2020	24,712,105	30,663,720	80,323,106	39,771,208	175,470,138
10 Year Increase	3,235,797	1,133,951	3,562,708	536,020	8,468,477
20 Year Increase	7,212,012	2,212,278	7,125,599	4,201,307	20,751,195

High Income Forecast Summary

2000	17,584,947	28,576,984	73,271,847	35,569,901	155,003,678
2005	19,631,736	30,629,414	75,426,724	38,947,146	164,635,020
2010	21,920,440	31,970,191	77,584,783	40,734,885	172,210,299
2015	24,479,334	33,536,403	79,746,048	42,789,590	180,551,375
2020	27,340,683	35,066,944	81,910,542	44,870,081	189,188,250
10 Year Increase	4,335,493	3,393,207	4,312,935	5,164,984	17,206,621
20 Year Increase	9,755,736	6,489,961	8,638,695	9,300,180	34,184,572

Low Price Forecast Summary

2000	17,536,585	28,683,799	73,280,303	35,569,901	155,070,588
2005	19,365,289	31,915,682	75,477,994	36,291,659	163,050,624
2010	21,396,261	34,555,030	77,679,715	37,957,507	171,588,512
2015	23,652,356	37,571,398	79,885,529	39,872,118	180,981,401
2020	26,159,711	40,685,286	82,095,472	41,810,757	190,751,225
10 Year Increase	3,859,676	5,871,231	4,399,411	2,387,606	16,517,924
20 Year Increase	8,623,126	12,001,487	8,815,169	6,240,856	35,680,637

Low Income Forecast Summary

2000	17,451,674	28,532,498	73,205,369	35,569,901	154,759,441
2005	18,781,361	30,387,626	75,025,986	31,865,847	156,060,819
2010	20,261,517	31,807,560	76,846,603	33,328,543	162,244,222
2015	21,910,548	33,225,744	78,667,220	35,009,664	168,813,176
2020	23,749,813	34,635,893	80,487,837	36,711,884	175,585,427
10 Year Increase	2,809,844	3,275,062	3,641,234	-2,241,358	7,484,781
20 Year Increase	6,298,140	6,103,395	7,282,468	1,141,983	20,825,986

10.3: Expanded Service Opportunities

Our analysis also examines the opportunities for expanded service in areas that currently do not have natural gas service. We examined statewide total usage opportunities by region, as well as new service opportunities in areas that are near (within 20 miles) the proposed AHR and existing LDC infrastructure.

After considering a range of expanded service opportunities throughout the state, the largest concentrations of new service opportunities appear to be in the Southcentral and Interior regions. There are also opportunities for increasing natural gas usage within the existing service territories for the Southcentral region LDCs (primarily Enstar). Increasing existing penetration levels by 10 percent results in almost as much expanded usage as moving into new service areas. However, existing average penetration rates of around 80 percent are already high and unlikely to increase under relative prices prevailing today.

A summary of these expanded opportunities is provided in Table 10.3. We have assumed that these service expansion opportunities will be phased in over time with full service opportunities being realized in 2020.[1] Table 10.3 also shows the potential gas demand-supply imbalance in the Cook Inlet Basin. While this does not reflect expanded service, per se, it illustrates the quantity of existing gas usage in Southcentral that may not be met from existing reserves in the Cook Inlet Basin (again, assuming relative energy prices in the future are consistent with levels observed today).

Table 10.3: Summary of Expanded Service Opportunities

2000	154,980,358	0	0	0	154,980,358
2005	160,395,253	556,182	0	1,078,526	162,029,961
2010	166,836,744	1,112,364	41,325,000	2,157,052	188,020,160
2015	174,587,941	1,668,546	111,161,000	3,235,578	220,817,065
2020	182,232,010	2,224,728	195,256,000	4,314,104	299,931,842

Original Source: Table 6.9

[1]The realization of these service opportunities are assumed to increase cumulatively by about 25 percent each year starting in 2005.

10.4: New Industries

There are opportunities for expanding natural gas usage by the addition of new industries. The two that were highlighted for investigation in this study included the addition of internet server farms and a major petrochemical industry. Both are energy-intensive industries. However, the addition of a typical facility for a large internet facility would have a small impact on total in-state usage. A major petrochemical facility, on the other hand, could have a more meaningful impact. A summary of these new industry opportunities has been presented in Table 10.4. We have assumed that the internet facility opportunities will be realized in full by 2005. The petrochemical opportunities are assumed to be realized after the operation of the proposed AHR gasline is completed and enter the forecast in 2010.

Two urea plant usage opportunities are presented. The first assumes a relatively constant utilization at the existing facility but at levels that are near previous historic peaks (about 7.2 Bcf above 2000 levels). The second provides the usage levels from a potential plant expansion discussed in Chapter 7.

Two estimates for LNG usage are also presented. The first estimate presents relatively constant levels of gas usage. The second estimate reflects the outer range of potential gas usage that was discussed in Chapter 7 (i.e., about 2.8 Bcf per year of additional gas consumption).

Table 10.4: Summary of New Industry Opportunities

Date	Baseline Total (Mcf)	Internet Server (Mcf)	Petrochemical Facility (Mcf)	Ammonia Urea Incremental (Mcf)	Ammonia Urea Expanded (Mcf)	Existing LNG (Mcf)	Incremental LNG (Mcf)	New Total (Mcf)
2000	154,980,358	0	0	7,224,195	0	78,533,532	0	240,738,084
2005	160,395,253	4,355,910	0	7,224,195	0	78,533,532	0	250,508,890
2010	166,836,744	4,355,910	27,853,333	7,224,195	15,000,000	78,533,532	2,873,468	302,677,181
2015	174,587,941	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	325,428,379
2020	182,232,010	4,355,910	27,853,333	7,224,195	30,000,000	78,533,532	2,873,468	333,072,448

Original Source: Table 7.1, 7.3

10.5: Fuel Switching

We examined all generating units in the state to identify facilities that could potentially shift their primary fuels to natural gas. Fuel oil and diesel facilities were the most attractive candidates. The highest concentration of these facilities were located in the Interior region of the state. There is approximately 200 MWs of capacity in this region that could shift from fuel oil to natural gas. Fuel switching opportunities would comprise a considerable source of new gas consumption. The reason for this is twofold. First, in total, the 200 MWs of capacity is of a relatively meaningful size. Second, many of these facilities are older, with heat rates that are greater (i.e., less efficient) than many new technologies. Hence, a greater amount of gas usage per every kWh generated. A summary of these fuel switching opportunities has been provided in Table 10.5. The table assumes that these fuel switching opportunities will not be realized until the proposed gasline is in operation.

Table 10.5: Summary of Fuel Switching Opportunities

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	15,938,973	182,775,717
2015	174,587,941	15,938,973	190,526,914
2020	182,232,010	15,938,973	198,170,983

Original Source: Table 8.4 and Table 9.6

10.6: Gas by Wire

There is a considerable supply side efficiency opportunity for new central station gas fired generation. The economics of a 250 MW combined cycle facility stack up favorably with the dispatch costs of existing generating units. However, the state does not have a potential capacity need until the year 2014. If a new generating unit were to be added prior to that time, older generation could be displaced. The displacement of this older generation could result in stranded costs that would have to be recovered. The public ownership of these facilities raises important questions about potential cost recovery since the traditional separation between ratepayers and shareholders does not exist. Given the higher efficiency of a new power station, gas usage associated with this power generation facility would be considerable but less than fuel switching at existing power facilities discuss above.

A summary of the gas-by-wire gas usage has been presented in Table 10.6. In this table, natural gas usage from new power generation is not expected to increase until 2015, given that Alaska will probably not have need for a new generation facility until the prior year.

Table 10.6: Summary of Gas by Wire Application

Date	Baseline Total (Mcf)	New Gas Generation (Mcf)	New Total (Mcf)
2000	154,980,358	0	154,980,358
2005	160,395,253	0	160,395,253
2010	166,836,744	0	166,836,744
2015	174,587,941	12,483,000	187,070,941
2020	182,232,010	12,483,000	194,715,010

Original Source: Table 8.7

10.7: Supplying Gas to New Usage Opportunities

Supplying natural gas to concentrated opportunities for new in-state usage would require significant infrastructure investments. These investments include taps and meter stations to the main AHR gas pipeline, transportation capital costs for pipelines to the city gate, and capital costs to lay distribution mains and service connections.

We examined a number of major concentrations of potential gas usage, and modeled the typical costs of supplying natural gas to these potential applications. These results included:

New Service to the Interior: Positive opportunities for natural gas service from initial analysis. This option warrants further study. Estimated household energy savings of shifting from fuel oil to natural gas were about 20 percent, while savings associated with shifting from electricity to natural gas were approximately 24 percent.

Gas by Wire: There are competitive opportunities for new power generation. However, as noted earlier, the need for a major new power generation resource is questionable until the year 2014.

Expanded Service to the Southcentral: Study results indicate that, in order to be competitive, throughput on a lateral spur line connecting Southcentral must achieve volumes beyond levels that correspond to various individual and incremental gas usage applications considered in this study. Some portion of gas usage -- 30-to-40 Bcf per year – currently supplied by producing fields in the Cook Inlet Basin would be required to generate sufficient economies of scale. The decline rates of existing Cook Inlet fields, combined with the steady progression of demand in the Southcentral and Interior regions suggest that, even with the near-term discovery of one Tcf of additional Cook Inlet reserves, a supply shortfall of 30-to-40 Bcf or more per year is likely to occur sometime between 2009 and 2015. Thus, a lateral spur pipeline that delivers gas into the Southcentral region could provide a long-term, economic solution to the supply-demand imbalance projected for this area.

Fuel Switching: Small, but positive economic opportunities for switching fuel oil fired power plants to natural gas in the Interior region. Net fuel savings ranged between a third to a fifth of a cent per kWh generated.

10.8: Summary of Baseline Forecast, Potential New Usage Opportunities, and Total In-State Demand

Based upon our analysis, there are some 107 Bcf of new usage opportunities in Alaska by the year 2020. This represents about 41 percent of baseline forecast in-state use in 2020.[2] Figure 10.1 presents each of these opportunities relative to the baseline forecast, while Figure 10.2 presents a pie chart breaking out the relative contribution each application has to total new usage opportunities.

This estimate is based on the assumption that all of the new usage opportunities are developed: Southcentral residential usage; Interior retail usage; internet facility development, petrochemical facility development; fuel switching opportunities; high utilization LNG and urea plant use; urea plant expansions; and gas by wire application. As noted in Chapter 9, the economics of supplying natural gas to many of these opportunities on an individual basis will not be competitive. The best opportunities for attaining these new usage levels may be from bundling a number of applications.

[2]Baseline includes existing LNG usage. New usage opportunities represent 58 percent of non-LNG baseline (i.e., residential, commercial, industrial, and electric utility).

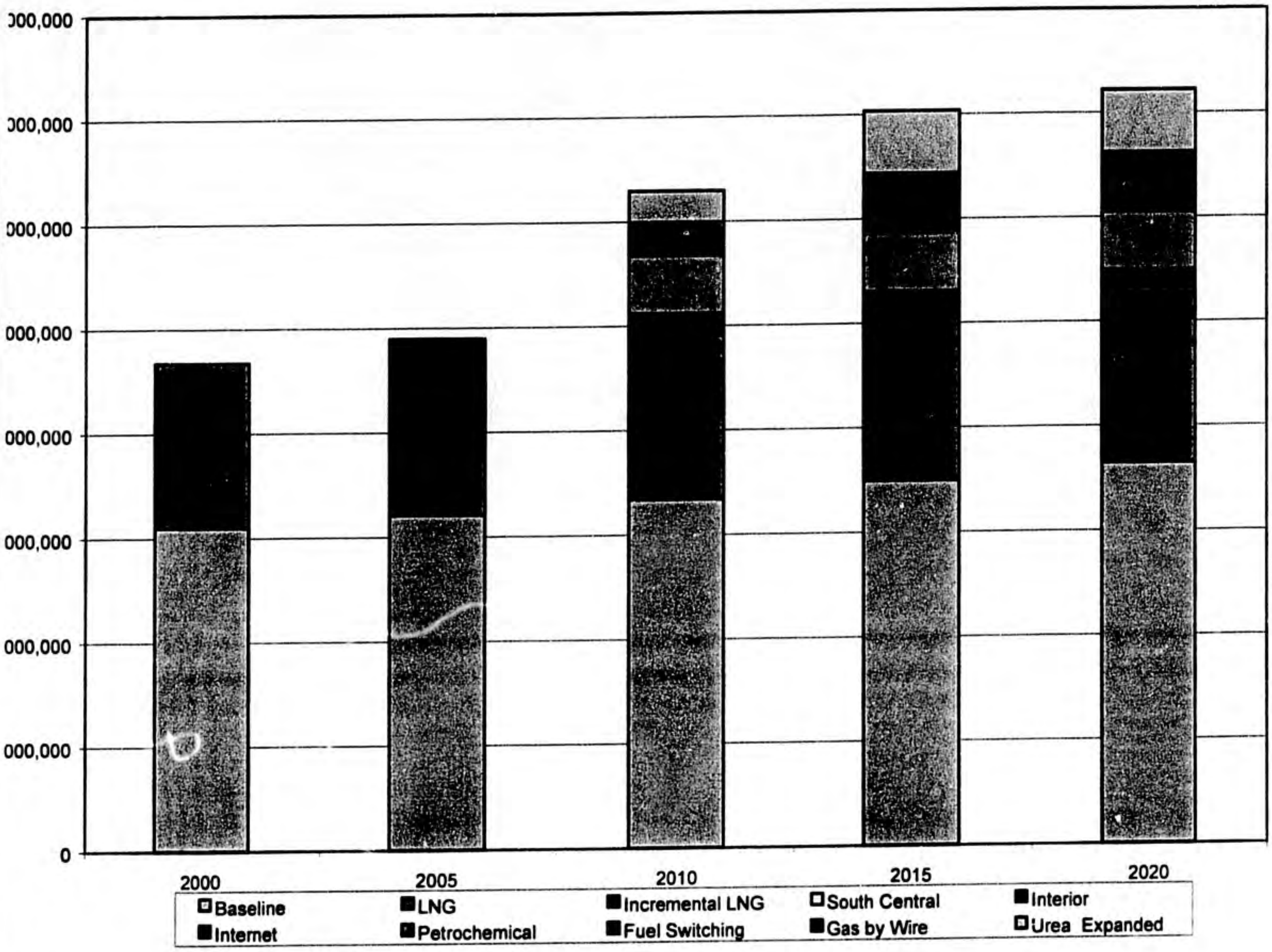

Figure 10.1: Summary of Baseline Forecast and New Usage Opportunities

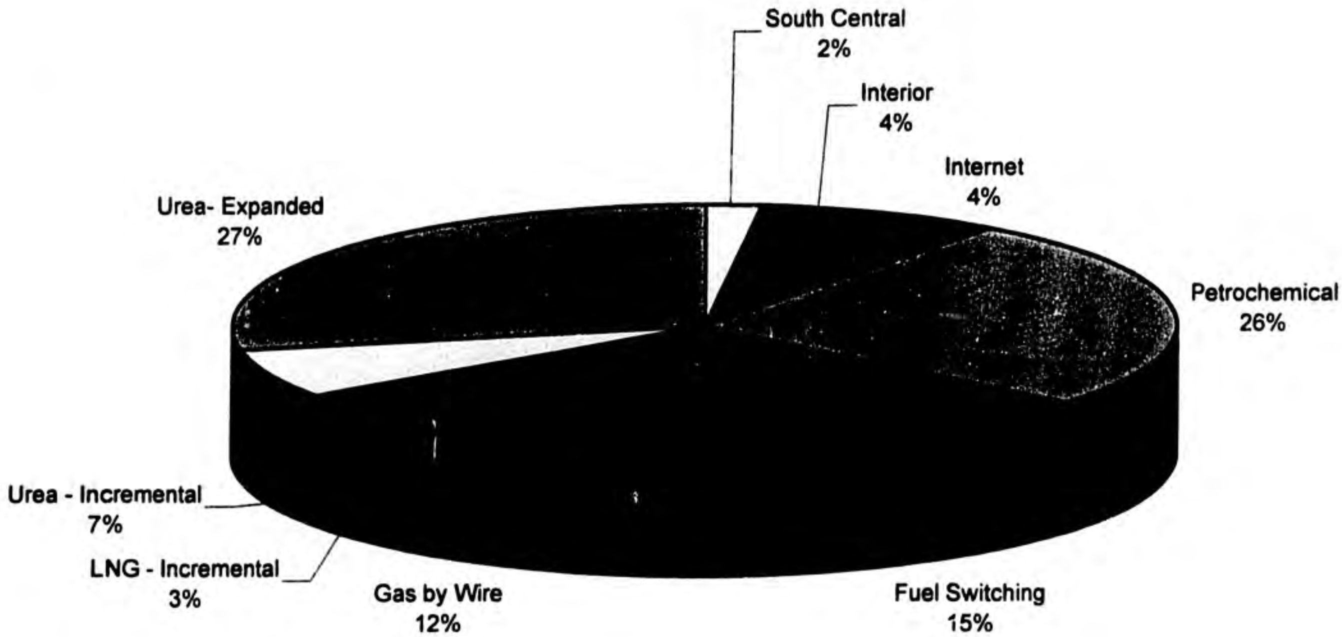

Figure 10.2: Percent Contributions, by Application, for New Usage Opportunities by 2020

As noted in Chapter 9, one of the largest potential concentrations of usage for ANS gas could be in the Southcentral region of the state. Realizing these usage levels, however, will be a function of future natural gas resource additions in the region. If these fail to materialize, then a substantial portion of Southcentral usage could be met with gas supplies from the North Slope. In order for these supplies to come close to being economical, volumes of some 30 to 40 Bcf will have to be served from outside the region. Figure 10.3 shows how potential Southcentral usage, resulting from a regional supply short-fall, would compare to all the other new applications discussed in this report.

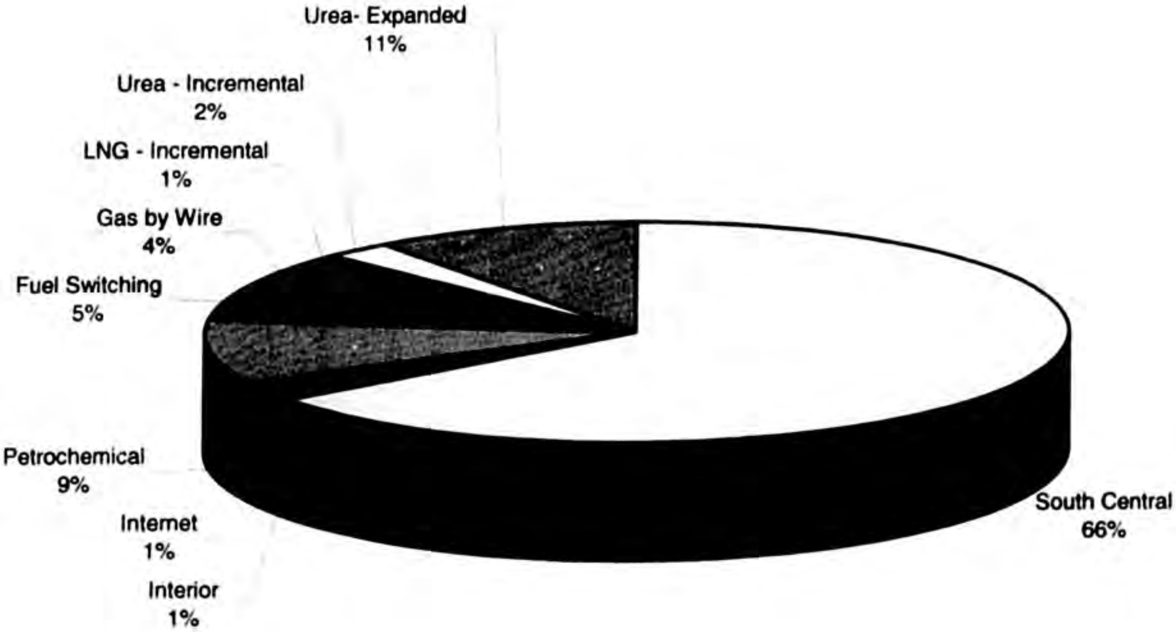

Figure 10.3: Southcentral Usage Relative to New Service Opportunities in 2020