Cook Inlet Energy Supply Alternatives Study Final Report

Dunmire Consulting Team

Carolyn Dunmire, Dunmire Consulting
Mark Cronshaw, Cronshaw Consulting
Shawn O'Fallon, Integral North America, Inc.
Charlie Sassara, Integral North America, Inc.
Kelly McAndrews, McAndrews Web Design

Prepared for Alaska Natural Gas Development Authority
ANGDA Contract 06-0402
April 14, 2006

Cook Inlet Energy Supply Alternatives Study
Final Report

Dunmire Consulting Team

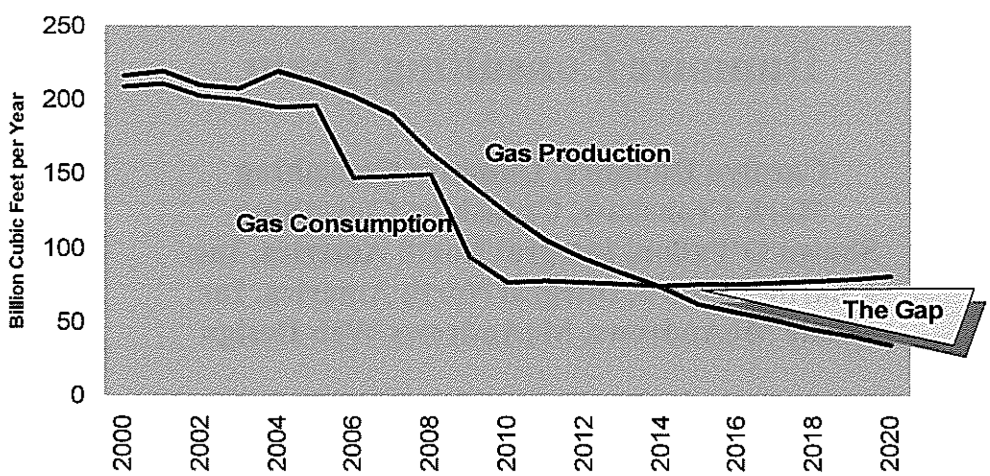
Carolyn Dunmire, Dunmire Consulting
Mark Cronshaw, Cronshaw Consulting
Shawn O'Fallon, Integral North America, Inc.
Charlie Sassara, Integral North America, Inc.
Kelly McAndrews, McAndrews Web Design

Prepared for Alaska Natural Gas Development Authority
ANGDA Contract 06-0402
April 14, 2006

Executive Summary

The Cook Inlet Basin is the source for all of the natural gas produced in south-central Alaska. This gas is used by three out of four Alaskans to heat and light their homes and businesses.[1] Natural gas production from Cook Inlet has been relatively flat since its peak production in 1998. Production forecasts for Cook Inlet show a steep decline starting in about 2007 and depending on future gas demand; shortages are expected 6 to 8 years later. Figure ES-1 illustrates the potential gap or shortage between future gas production and consumption in Cook Inlet.

Figure ES-1 Cook Inlet Natural Gas Production and Consumption



The Alaska Natural Gas Development Authority (ANGDA) commissioned a study to evaluate alternatives for filling the gap. The Cook Inlet Energy Supply Alternatives Study had three objectives:

1) Document the current status of the Cook Inlet energy situation.
2) Identify energy supply alternatives
3) Evaluate alternatives with a consistent framework to determine which options have the best possibility of meeting future energy needs cost-effectively.

The Dunmire Consulting Team (team bios in Appendix A) undertook this study and completed the analysis in February, 2006 using published literature and industry interview sources. The results of this study are summarized in this report.

What are the Alternatives?

The Dunmire Consulting Team evaluated over 20 different energy alternatives. An energy alternative was defined as any action, program, or project that could be implemented to meet Cook Inlet's future natural gas fueled energy demand. Two different types of alternatives were identified: Supply and Demand alternatives. Supply alternatives are those options that increase natural gas production and would use the existing natural gas transportation and delivery infrastructure. Supply alternatives include transporting North Slope gas to Cook Inlet and coal gasification. Demand alternatives generally reduce natural gas consumption by replacing natural gas-fired electric generation with another fuel source or conservation program. In this analysis, demand alternatives include coal-fired electric generation, hydro power and all types of distributed generation (except natural gas-fired generation). Figure ES-2 includes the list of energy alternatives evaluated in the study.

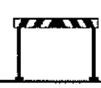
Figure ES-2 Energy Supply Alternatives evaluated for Cook Inlet

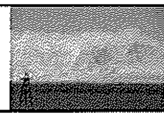
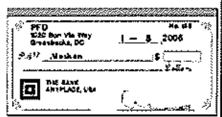
	Alternative	Description
Supply	**Increase Production**	Enhance existing gas production and develop new production in Cook Inlet.
Supply	**Spur Line**	Deliver North Slope gas to Cook Inlet with Spur Line from a main gas line.
Supply	**Bullet Line**	Deliver North Slope gas to Cook Inlet with Bullet Line.
Supply	**Enriched Gas Line**	Deliver North Slope gas to Cook Inlet with methane carrier for liquids line.
Supply	**CBM**	Develop Coal Bed Methane in Susitna Basin.
Supply	**Import LNG**	Import Liquefied Natural Gas from outside to existing Kenai LNG facility.
Supply	**Other Alaska Gas**	Develop and deliver gas from Copper River, Bristol Bay or Nenana Basins.
Supply	**Coal Gasification**	Implement coal gasification such as Agrium's Blue Sky Project.
Demand	**Coal Power**	Replace gas-fired electric generation with coal-fired power (Emma Creek)
Demand	**Hydro Power**	Replace gas-fired electric generation with small-scale hydro power.
Demand	**Wind Power**	Replace gas-fired electric generation with wind power (Fire Island Project).
Demand	**Nuclear Power**	Replace gas-fired electric generation with small-scale nuclear power.
Demand	**Tidal Power**	Replace gas-fired electric generation with tidal power.
Demand	**Gas Conservation**	Implement end-use gas conservation programs (weatherization, efficiency)
Demand	**Electric Conservation**	Implement end-use conservation programs (appliance & light bulb upgrade)
Demand	**Distributed Generation**	Implement small-scale electric generation including cogeneration and fuel cells at point-of-use to displace central gas-fired electric generation.

Evaluation Process

The evaluation process used in this analysis was based on eight evaluation criteria. These criteria were selected to highlight key aspects of each alternative including the amount of energy that would be available, the cost-effectiveness of this energy and other potential impacts to the regional economy and environment. Figure ES-3 describes each of the evaluation criteria and the characteristics of the alternatives that were ranked highest with respect to that criterion.

Figure ES-3 Evaluation Criteria for the Cook Inlet Energy Supply Alternative Study

Evaluation Criterion	Icon	Characteristics
Energy Service		Amount of energy service provided by the alternative annually reported in billion cubic feet of natural gas. Highest ranked alternatives provide level of energy service equivalent or greater than demand.
Prerequisites for Success		What must happen before the alternative can produce energy? Highest ranked alternatives have lowest hurdle to clear.
Start-up Date	**5 years**	Years from present that the alternative starts to deliver energy service. Highest ranked alternatives start immediately.
Investment	**$**	Total capital investment needed by an alternative to deliver energy service. Top alternatives need lowest investment.

Monthly Bill	%	Effect that the alternative will have on residential monthly gas and electric bills. Highest ranked alternatives have potential to lower utility bills.
Uncertainty		Uncertainty associated with level of energy service, start-up date, investment, or operation for the alternative. Highest ranked alternatives have lowest levels of uncertainty.
Environmental		Unmitigated environmental impacts associated with the alternative. Highest ranked alternatives have fewest impacts.
Alaskan Citizens		Potential impacts of the alternative on Alaskan citizens such as increased employment, economic activity, permanent fund as well as efficient development of Alaskan resources. Highest ranked alternatives have potential for large, positive impacts.

Energy service is reported in terms of natural gas – either natural gas produced or natural gas displaced by the alternative in a year during full operation. In some cases, such as hydro power and distributed generation the energy service reported would be the total from several individual projects. Prerequisites for success identifies key activities, projects, or milestones that must be achieved before the alternative could provide energy service. For example, the main gas line transporting North Slope gas to Glennallen must be operating before the Spur Line alternative could delivery gas to Cook Inlet. In this study, uncertainty should not be confused with risk. The uncertainty criterion is a qualitative measure of the probability that the level of energy service, start-up date, capital investment and operating costs will be in the ranges reported. In this analysis, it is assumed that all projects will comply with all environmental regulations and requirements, so the environmental criterion considers unmitigated environmental impacts. The overall impact of an alternative on Alaskan citizens is summarized in the criterion by measuring the impacts on regional job and government revenues. In this study imported technology and fuel are considered to have negative impacts on Alaskan citizens because of the negative economic impacts of imports on an economy.

Top Alternatives

During the evaluation, each of the energy alternatives were evaluated and ranked with respect to each of the eight criteria. This affords decision-makers the opportunity to see which alternatives rank highest under the criterion that is most important to them. A summary of the ranking for each of the evaluation criterion is included in Figure ES 4 through ES-11. Details of the analysis for each alternative with complete references and assumptions are included in Appendix C. In reviewing the rankings for each criterion, some general observations of the results include:

- Near term: Gas Conservation and Increased Production in Cook Inlet would prolong gas supplies and buy time to select long term option and raise investment funds.

- Intermediate term: Coal Gasification could keep industrial facilities operating and provide electric power. Feasibility depends on proving process output and cost-effectiveness with Alaskan coals.

- Long term: Enriched Gas Line may be better investment than Bullet Line. Coal and Wind development strong second.

- Spur Line tops the list if pipeline carrying North Slope gas is built through Alaska.

Figure ES-4 Energy Service – How much energy can the alternative provide annually?

Rank	Alternative	Bcf	Energy Service
	Enriched Gas Line	360	Additional 16.5 million barrels of liquefied petroleum gas LPG
	Bullet Line	360	Pipeline capacity 1 Bcf per day.
	Spur Line	145-220	Depends on pipeline capacity (400-600 million cubic feet/day)
	Increase Production	100-200	Develop 1.4 trillion cubic feet (Tcf) of gas in Cook Inlet. Existing infrastructure can deliver up to 700 million cf/day.
	CBM	100-200	Develop 1 trillion cubic feet of CBM.
	Other Alaska Gas	50-100	Bristol Bay may hold 7 Tcf of gas. Nenana Basin 3-10 Tcf.
	Coal Gasification	40-65	40 Bcf as feedstock. 25 Bcf for 350 MW electric generation.
	Import LNG	40-120	Imported LNG to be used to meet peak winter demand.
	Coal Power	10-15	200 mega-watts (MW) of electric generation.
	Gas Conservation	2.5-5	Reduce expected growth in home and business gas demand.
	Wind Power	2.5-5	50-100 MW of wind generation at Fire Island.
	Electric Conservation	0.5-2.5	Reduce expected growth in electric generation.
	Nuclear Power	0.5-2.5	10-50 MW of nuclear generation at Galena.
	Hydro Power	0.5-2.5	10-50 MW of small-scale run-of-river hydro projects.
	Distributed Generation	0.25-0.50	10 MW of distributed generation (<1 MW per project).
	Tidal Power	0.25-0.50	0.5-10 MW tidal power project.

Figure ES-5 Prerequisites for Success – What must happen before the alternative can be successful?

Rank	Alternative	Prerequisites
	Gas Conservation	Increase residential and commercial gas rates to promote efficiency.
	Increase Production	Higher contract prices for Cook Inlet gas to promote exploration. Affordable pipeline and infrastructure access.
	Electric Conservation	Increase rates. Implement efficiency and education programs.
	Distributed Generation	Affordable & reliable fuel cell projects using non-gas hydrogen source.
	Hydro Power	Access to sufficient electric load and infrastructure.
	Wind Power	Successful large scale wind power demonstration in Alaska.
	Coal Power	Successful demonstration of clean coal technology using Alaskan coal
	Bullet Line	Increased industrial gas demand to 0.5 Bcf per day in Cook Inlet to support project scale and financing.
	Coal Gasification	Successful demonstration of gasification technology with Alaskan coals. Development of coal mine and transport infrastructure.
	Enriched Gas Line	Increased industrial gas demand to 0.5 Bcf per day in Cook Inlet to support project scale and financing. Successful demonstration of methane carrier for liquids pipeline technology on large scale.
	Spur Line	Construction of main line from North Slope to Spur take-off point.
	CBM	Discover and implement commercial production in Susitna Basin.
	Other Alaska Gas	Discover and implement commercial gas production in Bristol Bay, Nenana, or Copper River Basins.
	Import LNG	Access to imported LNG affordable to Cook Inlet consumers.
	Nuclear Power	Successful implementation of small scale nuclear technology and licensing process in US. Proven cost-effective small scale reactor.
	Tidal Power	Successful implementation of commercial-scale projects.

Figure ES-6 Start-up Date – When the alternative start providing energy service?

Rank	Alternative	Start-up Date
0-1 year	Gas Conservation	2006 – Presently occurring because of rate increases.
	Increase Production	2006 – Presently occurring because of higher contract prices.
2–5 years	Electric Conservation	2007 – Implement conservation programs.
	CBM	2008 - Leasing and community standards complete.
	Distributed Generation	2010 - Demonstration projects have been successful.
	Wind Power	2011 - Preliminary permitting and feasibility completed for Fire Island.
	Import LNG	2011– Depends on retrofit starting in 2009.
	Coal Gasification	2011 – Reported start-up date for Agrium Blue Sky project.
6–15 years	Enriched Gas Line	2012
	Bullet Line	2012-2016
	Spur Line	2012 – Depends on completion of main line to Spur take-off.
	Other Alaska Gas	2012 – Bristol Bay leases sold in 2005.
	Hydro Power	2012-2020 Long lead time to complete license application, environmental assessment, and to raise capital investment.
	Coal Power	2008 - Healy Clean Coal Plant restart possible in 18 months. 2014 - Emma Creek project operational.
	Nuclear Power	2012 - Proposed start-up date for Galena project.
	Tidal Power	2020 – Technology currently in experimental phase.

Figure ES-7 Investment – What is the capital investment needed to implement the alternative?

Rank	Alternative	Level of Investment
<$100 million	Hydro Power	$10 - $100 million ($1 to $2 million per MW)
	Tidal Power	$10 - $20 million
	Distributed Generation	$25 - $50 million ($5 million per MW)
$ 100 – 500 million	Gas Conservation	$25 - $100 million
	Import LNG	$70 - $200 million
	Electric Conservation	$50 - $100 million
	Nuclear Power	$75 - $150 million
	Wind Power	$100 - $200 million
	Coal Gasification	$100 - $500 million
$ >500 million	Spur Line	$300 - $500 million $700 - $900 million if main line follows Highway Route.
	Coal Power	$400 - $500 million
	Increase Production	$500 million
	Bullet Line	$3 - $4 billion
	Enriched Gas Line	$4 billion with 2 LPG tankers
	CBM	$1- $5 billion
	Other Alaska Gas	$1- $5 billion

Figure ES-8 Monthly Bill – How much will monthly utility bills change?

Rank	Alternative	Production Costs and Issues
Savings	Gas Conservation	Reduces total monthly bill.
	Electric Conservation	Reduces total monthly bill.
+0-50%	Coal Power	5-10 cents per kilo-watt hour (kWh).
	Wind Power	7-12 cents per kWh.
	Hydro Power	7-15 cents per kWh.
	Spur Line	Gas rates to Cook Inlet would be bounded by Lower 48 prices.
	Distributed Power	5-15 cents per kWh for fuel cells. Lower costs if heat can be used.
	Coal Gasification	Production costs uncertain with Alaskan coals. Power generation could be by-product of fertilizer production.
	Enriched Gas Line	Gas transport costs subsidized by income from LPG exports.
	Nuclear Power	10-20 cents per kWh depending on value of by-products (heat, hydrogen)
	Bullet Line	Cook Inlet consumers could pay substantial share of pipeline cost. Costs could be subsidized by industrial users and LNG exports.
+50-100%	Increase Production	Higher gas prices needed to encourage investment in development. Recent contracts linked to Lower 48 gas prices that have doubled.
	CBM	Higher gas prices needed to encourage investment in development
	Other Alaska Gas	Higher gas prices needed to encourage investment in exploration.
	Tidal Power	11-26 cents per kWh.
	Import LNG	Depends on world market prices of LNG, transport, and operating costs.

Figure ES-9 Uncertainty – How much uncertainty is there in achieving the alternative?

Rank	Alternative	Types of Uncertainties
	Gas Conservation	Persistence, level, and cost-effectiveness of energy savings.
	Electric Conservation	Persistence, level, and cost-effectiveness of energy savings.
	Hydro Power	Cost and availability of electric power.
	Coal Power	Operation of clean coal technology with Alaska coals.
	Wind Power	Availability and level of energy service.
	Bullet Line	Cost over-runs and delays are possible.
	Enriched Gas Line	Cost over-runs and delays are possible. Performance of new dense phase pipeline technology.
	Distributed Power	Operating cost, availability, and efficiency of fuel cells.
	Spur Line	Route, completion date, cost of main line carrying North Slope gas
	Coal Gasification	Efficiency of coal gasification process with Alaskan coals. Transport and cost of coal. Value of gasification products.
	Nuclear Power	Reliability and affordability of small-scale nuclear reactor. Approval of site license in geologically active Alaska.
	Import LNG	Availability and cost of imported LNG.
	Increase Production	Amount of economically recoverable gas in Cook Inlet.
	CBM	Amount of economically recoverable gas in Cook Inlet.
	Other Alaska Gas	Amount of economically recoverable gas in Bristol Bay, Copper River, and Nenana Basins.
	Tidal Power	Availability, cost, and level of energy service in Alaskan conditions

Figure ES-10 Environmental – What are the unmitigated environmental impacts of the alternative?

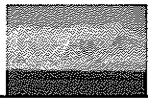
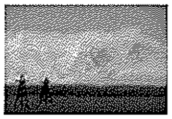
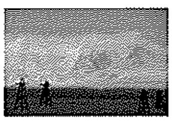
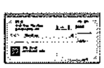
Rank	Alternative	Potential Unmitigated Impacts
	**Gas Conservation**	Net positive environmental impacts. More efficient fuel use.
	Electric Conservation	Net positive environmental impacts.
	Distributed Power	Net positive. No transmission impacts.
	**Spur Line**	Risk of accident. Increased access and travel opportunities provided by right-of-way (ROW) (positive/negative impact)
	Bullet Line	Risk of accident. Increased access provided by ROW.
	Enriched Gas Line	Risk of accident. Increased access provided by ROW.
	Wind Power	Noise. View shed impacts.
	Import LNG	Risk of leaks/spills. Facility emissions, noise, odor.
	Nuclear Power	Risk of accident. Long term land use. Nuclear waste.
	Hydro Power	Aquatic and surface/site impacts.
	Tidal Power	Aquatic impacts. Naval traffic constraints.
	**Increase Production**	Land use. View shed. Wildlife. Waste water into Cook Inlet. Risk of spills/accidents. Remediation of offshore platforms.
	Other Alaska Gas	Loss of undeveloped land. Wildlife. Risk of spills/accidents.
	Coal Gasification	Ash disposal. Facility emissions. Impacts from coal mining.
	Coal Power	Ash disposal, cooling water requirements, increased greenhouse gas emissions. Impacts from coal mining.
	CBM	Produced water disposal. Industrial landscape. Noise.

Figure ES-11 Alaskan Citizens – What are the potential impacts on Alaskan Citizens of the alternative?

Rank	Alternative	Potential Impacts
	**Spur Line**	New jobs, increased State revenues associated with North Slope gas development.
	Enriched Gas Line	New jobs, increased State revenues.
	Bullet Line	New jobs, increased State revenues.
	Increase Production	New jobs. Increased State revenues.
	CBM	New jobs. Increased State revenues.
	Other Alaska Gas	New jobs. Increased State revenues.
	Coal Gasification	New jobs. Retention of industrial operations and jobs.
	**Coal Power**	New jobs. Energy security with development of indigenous energy resource.
	Distributed Power	New job opportunities/industries in remote locations. Imported generation technology (negative impact).
	Hydro Power	Energy security with development of indigenous renewable energy resources.
	Gas Conservation	Money saved on energy bills stays in the economy.
	**Electric Conservation**	Money saved on energy bills stays in the economy. Imported conservation technologies (negative impact)
	Wind Power	Renewable energy resource/energy security. Imported generation technology (negative impact).
	Tidal Power	Renewable energy resource/energy security. Imported generation technology (negative impact).
	Nuclear Power	Imported generation technology (negative impact).
	Import LNG	Imported fuel. Large negative impact on economy.

Cook Inlet Energy Supply Alternatives Study
Final Report

By the Dunmire Consulting Team
P.O. Box 72
Cahone, CO 81320
970-562-4495
dunmire@fone.net

Carolyn Dunmire, Dunmire Consulting
Mark Cronshaw, Cronshaw Consulting
Shawn O'Fallon, Integral North America, Inc.
Charlie Sassara, Integral North America, Inc.
Kelly McAndrews, McAndrews Web Design

Prepared for Alaska Natural Gas Development Authority
ANGDA Contract 06-0402

April 14, 2006

Table of Contents	**Page Number**

INTRODUCTION

There is a business opportunity to serve the energy needs of Cook Inlet residents and industries. One of the challenges is accommodating the diverse interests of all those involved, in the face of risk and uncertainty. One of the goals of this study is to serve as a platform for creating consensus.

The energy situation in Cook Inlet is bewildering in its level of complexity because it has so many dimensions, including

- A large number of alternative approaches for dealing with the situation
- Many interested parties with different values and motivations (Alaska residents, oil and gas producers, utility companies, pipeline companies, investors, Alaska State government, US Federal government, Canadian government, energy users in the Lower 48, Canada, and Asia)
- Uncertainties (such as cost, timing, energy reserves, environmental impact)

The goals of the Cook Inlet Energy Supply Alternatives Study are:

a. To compare energy alternatives in a consistent manner
b. To present the results in a format understandable for the public.

This study does not attempt to recommend one or more alternatives for implementation. Rather, it establishes a foundation for meaningful discussion of the best alternative(s). That discussion could include consideration of utility functions[i] that represent the relative importance of the many attributes identified in the current framework. The goal of the discussion would be to create agreement about a way forward, with specific actions for specific players.

The evaluation framework has three aspects:

1. a list of alternatives for dealing with the energy situation
2. a list of criteria for evaluating the alternatives
3. a list of stakeholders and their viewpoint of the energy situation.

COOK INLET ENERGY SITUATION

The Cook Inlet Basin is the source for all of the natural gas produced in south-central Alaska. This gas is used by three out of four Alaskans to heat and light their homes and businesses.[2] The major consumers of Cook Inlet's natural gas include:

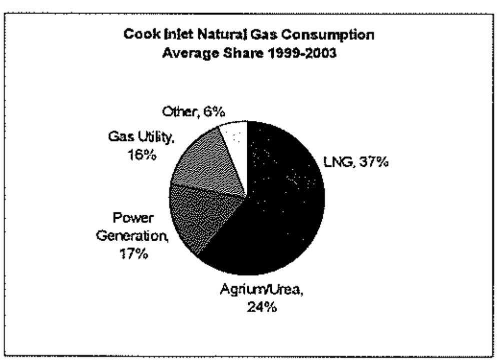


Figure 1: Cook Inlet Gas Consumption

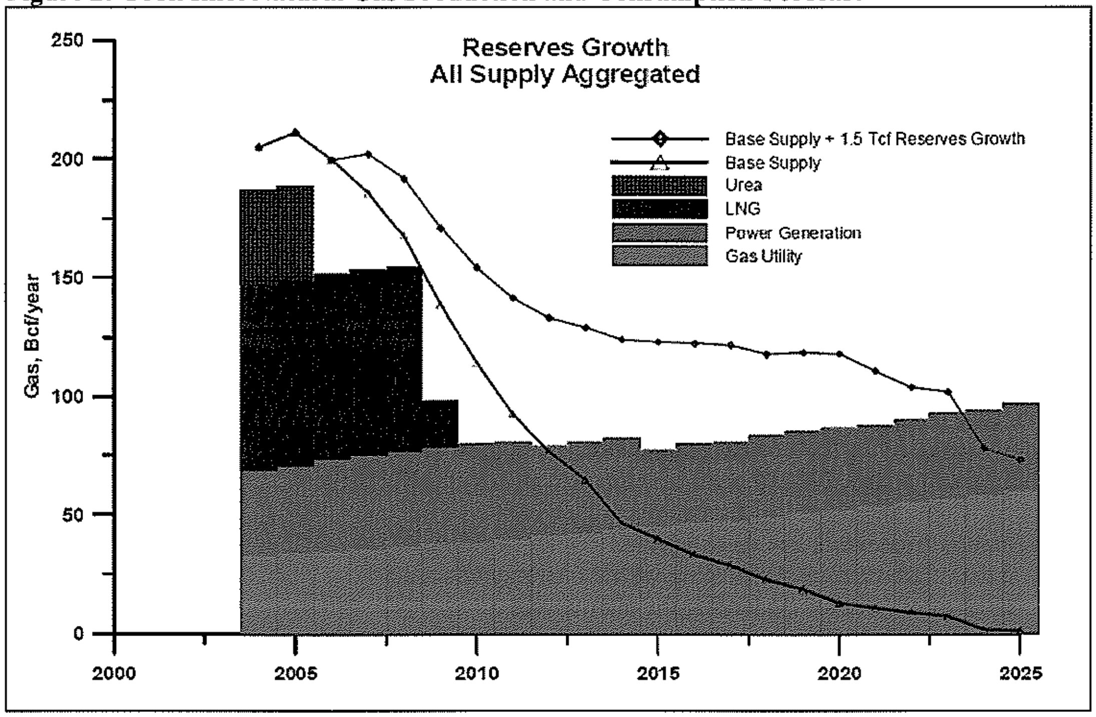
1) Liquefied natural gas (LNG) plant in Nikiski that exports LNG to Asia.
2) Agrium petrochemical/fertilizer plant.
3) Electric utilities including Chugach Electric and Anchorage Municipal Light and Power (ML&P) that burn natural gas to generate electric power.
4) Natural gas utilities including ENSTAR that provide natural gas to commercial and residential customers in greater Anchorage area, Wasilla, and Kenai Peninsula.

---

[i] A utility function is a standard economic tool for representing an individual's preferences and attitudes towards risk. Since preferences are diverse, different people have different utility functions.

The average share of total annual gas consumption for these users is shown in Figure 1.[3] Total natural gas production in Cook Inlet averaged 207 billion cubic feet between 1999 and 2003 with a peak production rate of about 700 million cubic feet per day.[4] Recent predictions by US Department of Energy and the Alaska Division of Oil and Gas have estimated that Cook Inlet's natural gas production will diminish rapidly in the future. Gas shortages are expected as early as 2012 depending on assumptions about industrial use and reserves growth. Cook Inlet natural gas production forecast is illustrated in Figure 2.[5]

Figure 2: Cook Inlet Natural Gas Production and Consumption Forecast



ENERGY ALTERNATIVES

Given the diverse uses of Cook Inlet natural gas, we considered alternatives that could either: a) augment or replace Cook Inlet natural gas or b) substitute for its use as a fuel or feedstock. We grouped the alternatives into two categories: supply alternatives and demand alternatives. Supply alternatives are those options that replace Cook Inlet natural gas with gas from another location or source such as the North Slope or coal-bed methane. Supply alternatives use the existing natural gas infrastructure to transport and deliver the gas to end-users. Demand-side alternatives generally reduce demand for Cook Inlet natural gas through curtailment, conservation, or fuel-switching. Demand alternatives use other infrastructure such as the electric grid or rail road to transport the fuel or energy to end-users. Many of these demand-side alternatives can not individually meet the projected energy service shortfall in Cook Inlet. Therefore, it is likely that a combination of these alternatives would have to be implemented to meet future energy service requirements. A list of the 16 alternatives analyzed in the study is shown Figure 3.

Figure 3: Alternatives Analyzed in the Cook Inlet Energy Supply Study

	Alternative	Description
Supply	**Increase Production**	Enhance existing gas production and develop new production in Cook Inlet.
	Spur Line	Deliver North Slope gas to Cook Inlet with Spur Line from a main gas line.
	Bullet Line	Deliver North Slope gas to Cook Inlet with Bullet Line.
	Enriched Gas Line	Deliver North Slope gas to Cook Inlet with methane carrier for liquids line.
	CBM	Develop Coal Bed Methane in Susitna Basin.
	Import LNG	Import Liquefied Natural Gas from outside to existing Kenai LNG facility.
	Other Alaska Gas	Develop and deliver gas from Copper River, Bristol Bay or Nenana Basins.
	Coal Gasification	Implement coal gasification such as Agrium's Blue Sky Project.
Demand	**Coal Power**	Replace gas-fired electric generation with coal-fired power (Emma Creek)
	Hydro Power	Replace gas-fired electric generation with small-scale hydro power.
	Wind Power	Replace gas-fired electric generation with wind power (Fire Island Project).
	Nuclear Power	Replace gas-fired electric generation with small-scale nuclear power.
	Tidal Power	Replace gas-fired electric generation with tidal power.
	Gas Conservation	Implement end-use gas conservation programs (weatherization, efficiency)
	Electric Conservation	Implement end-use conservation programs (appliance & light bulb upgrade)
	Distributed Generation	Implement small-scale electric generation including cogeneration and fuel cells at point-of-use to displace central gas-fired electric generation.

During the survey of energy alternatives, alternatives that rely on technologies that have not been demonstrated on a commercial scale or that are not expected to be available on a commercial scale until after 2012 were eliminated from further analysis. This eliminated some experimental technologies from the analysis; however, commercial tidal power which has been demonstrated in limited applications in Europe and small-scale nuclear power which is not expected to be implemented until after 2012 but is being considered in Galena, Alaska were included.[6] Small scale fuel-cell technology is included in the analysis as a distributed generation options.

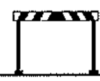
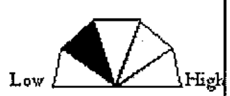
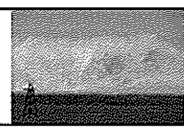
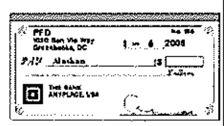
This initial list of alternatives was further refined to eliminate those options that are unlikely to be implemented in the next 10 years such as the Susitna Hydro project. This project was cancelled in the late 1980's because of large investment and environmental impacts. Although there have been some recent efforts by Alaska's Senator Don Young to resurrect this project, it is very unlikely that the Susitna Hydro project would provide energy to Cook Inlet within the next 10 years. Electric generation technologies such as wind-diesel and geothermal which are best used in remote, village power situations are unlikely to be cost-effective in comparison current energy prices in Cook Inlet, and were also eliminated from further study.

For all of the alternatives, the analysis is based on a scale that would best fit existing infrastructure. For example, we assumed that coal-fired generation would be located at the Beluga coal deposit near the existing electric power grid eliminating the need to transport the coal or add significant lengths of transmission lines. We use similar assumptions in estimating the costs of large-scale wind or hydro-power; i.e. that the hydro and wind sites located near the existing power grid would be developed first.

EVALUTION CRITERIA

Each of the 16 alternatives was evaluated with eight different evaluation criteria. The evaluation criteria are designed to reflect a variety of perspectives relevant to energy decisions. The evaluation criteria include quantitative criteria such as energy service, capital investment, start-up date, and monthly bill designed to show the relative size, investment, in-service date, and operating costs for each of the alternatives. There are four qualitative criteria: pre-requisites for success, uncertainty, environmental impacts, and impacts on Alaskans that are designed to show the activities that must be completed and level of uncertainty related to the alternative becoming operational as well as potential unmitigated impacts to the environment and Alaskans. Figure 4 summarizes the evaluation criterion and some of the characteristics of high ranking alternatives.

Figure 4: Evaluation Criteria for Cook Inlet Energy Alternatives Study

Evaluation Criterion	Icon	Characteristics
Energy Service		Amount of energy service provided by the alternative annually reported in billion cubic feet of natural gas. Highest ranked alternatives provide level of energy service equivalent or greater than annual gas demand.
Prerequisites for Success		What must happen before the alternative can produce energy? Highest ranked alternatives have lowest hurdle to clear.
Start-up Date	**5 years**	Years from present that the alternative starts to deliver energy service. Highest ranked alternatives start immediately.
Investment	**$**	Total capital investment needed by an alternative to deliver energy service. Top alternatives need lowest investment.
Monthly Bill	**%**	Effect that the alternative will have on residential monthly gas and electric bills. Highest ranked alternatives have potential to lower utility bills.
Uncertainty		Uncertainty associated with level of energy service, start-up date, investment, or operation for the alternative. Highest ranked alternatives have lowest levels of uncertainty.
Environmental		Unmitigated environmental impacts associated with the alternative. Highest ranked alternatives have fewest impacts.
Alaskan Citizens		Potential impacts of the alternative on Alaskan citizens such as increased employment, economic activity, permanent fund as well as efficient development of Alaskan resources. Highest ranked alternatives have potential for large, positive impacts.

Energy service is reported in terms of natural gas – either natural gas produced or natural gas displaced by the alternative in a year during full operation. In some cases, such as hydro power and distributed generation the energy service reported would be the total from several individual projects. Prerequisites for success identifies key activities, projects, or milestones that must be achieved before the alternative could provide energy service. For example, the main gas line transporting North Slope gas to Glennallen must be operating before the Spur Line alternative could delivery gas to Cook Inlet. In this study, uncertainty should not be confused with risk. The uncertainty criterion is a qualitative measure of the probability that the level of energy service, start-up date, capital investment and operating costs will be in the ranges reported. In this analysis, it is assumed that all projects will comply with all environmental regulations and requirements, so the environmental criterion considers unmitigated environmental impacts. The overall impact of an alternative on Alaskan citizens is summarized in the criterion by measuring the impacts on regional job and government revenues. In this study imported technology and fuel are considered to have negative impacts on Alaskan citizens because of the negative economic impacts of imports on an economy.

EVALUATION METHODOLOGY AND RESULTS

The evaluation methodology draws on concepts from decision analysis and game theory. Decision analysis breaks an issue into three aspects:

1. The set of decisions which must be made, now and in the future
2. Metrics for success i.e., identification of what constitutes a "good" outcome[ii]
3. Uncertainties which affect the outcome but are beyond the control of the decision maker.

Game theory is a tool for analyzing the behavior of multiple agents, each of whose fate depends not only on their own action, but also on actions taken by the others. The evaluation framework presented here is an essential first step for application of these concepts to the decision about which energy alternatives should be pursued to meet future energy needs in Cook Inlet.

The primary goals of the evaluation were to develop a transparent method of comparing the energy alternatives that would be useful to decision-makers and stakeholders unfamiliar with the energy industry. The evaluation results are designed to compare the energy alternatives on a consistent basis and identify those alternatives that are most likely to "rise to the top". These goals presented two major challenges: 1) each of the stakeholders will likely base his or her preference on a different set of criteria; 2) the data available on investment and operating costs, start-up date, and amount of energy service are undetermined and uncertain for most of the alternatives because most of the projects related to the alternatives are in the feasibility analysis stage of development. To overcome these challenges, the evaluation methodology uses eight different evaluation criteria, so that each stakeholder can focus on his or her most important issues. Additionally, the analysis includes criteria that evaluate the uncertainty and prerequisites for success to capture the robustness and level of completion each alternative represents.

During the evaluation process, each alternative was ranked from highest to lowest with respect to each criterion. See Figure 4 for characteristics of highest ranked alternatives for each criterion. There are four quantitative criteria (energy service, start-up date, capital investment, and monthly bill) where the alternatives are ranked by the values for these parameters. For example, for the energy service criterion, the alternatives are ranked by the amount of equivalent natural gas in billion cubic feet that they are reported to provide or produce annually. The alternatives with the largest numbers are ranked highest. The energy service values are based on publicly available documents or published reports. Detailed references and analysis for the evaluation of each alternative is included in Appendix C.

For the qualitative criteria (prerequisites for success, uncertainty, environmental, and impacts on Alaskans), the energy alternatives are grouped into high, medium, or low. This is where the icons help to clarify the ranking. For example, in evaluating the energy alternatives against prerequisites for success, the icon is a hurdle. Those alternatives that must clear the highest hurdle, such as the Spur Line, are ranked lower than alternatives that only have to clear a relatively low hurdle such as Natural Gas Conservation.

For each of the criterion, the energy alternatives are grouped by rank. Although the ranking indicates the relative order for the individual alternatives, the alternatives within the same group

[ii] These are inputs to the utility function. The utility function implicitly captures trade-offs between the success metrics.

should be considered the same rank. For instance, the ranking for energy alternatives under prerequisites for success shows Gas Conservation, Increase Production, Electric Conservation, and Distributed Generation with a low hurdle. Although Gas Conservation is listed at the top, all four of these alternatives are grouped/ranked with low prerequisites for success. See Figures 5 through 12 for a summary of the evaluation results and Appendix C for analysis details.

Figure 5 Energy Service – How much energy can the alternative provide annually?

Rank	Alternative	Bcf	Energy Service
	**Enriched Gas Line**	360	Additional 16.5 million barrels of liquefied petroleum gas LPG
	Bullet Line	360	Pipeline capacity 1 Bcf per day.
	Spur Line	145-220	Depends on pipeline capacity (400-600 million cubic feet/day)
	Increase Production	100-200	Develop 1.4 trillion cubic feet (Tcf) of gas in Cook Inlet. Existing infrastructure can deliver up to 700 million cf/day.
	CBM	100-200	Develop 1 trillion cubic feet of CBM.
	Other Alaska Gas	50-100	Bristol Bay may hold 7 Tcf of gas. Nenana Basin 3-10 Tcf.
	**Coal Gasification**	40-65	40 Bcf as feedstock. 25 Bcf for 350 MW electric generation.
	Import LNG	40-120	Imported LNG to be used to meet peak winter demand.
	Coal Power	10-15	200 mega-watts (MW) of electric generation.
	Gas Conservation	2.5-5	Reduce expected growth in home and business gas demand.
	Wind Power	2.5-5	50-100 MW of wind generation at Fire Island.
	**Electric Conservation**	0.5-2.5	Reduce expected growth in electric generation.
	Nuclear Power	0.5-2.5	10-50 MW of nuclear generation at Galena.
	Hydro Power	0.5-2.5	10-50 MW of small-scale run-of-river hydro projects.
	Distributed Generation	0.25-0.50	10 MW of distributed generation (<1 MW per project).
	Tidal Power	0.25-0.50	0.5-10 MW tidal power project.

Figure 6 Prerequisites for Success –
What must happen before the alternative can be successful?

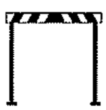
Rank	Alternative	Prerequisites
	**Gas Conservation**	Increase residential and commercial gas rates to promote efficiency.
	Increase Production	Higher contract prices for Cook Inlet gas to promote exploration. Affordable pipeline and infrastructure access.
	Electric Conservation	Increase rates. Implement efficiency and education programs.
	Distributed Generation	Affordable & reliable fuel cell projects using non-gas hydrogen source.
	**Hydro Power**	Access to sufficient electric load and infrastructure.
	Wind Power	Successful large scale wind power demonstration in Alaska.
	Coal Power	Successful demonstration of clean coal technology using Alaskan coal
	Bullet Line	Increased industrial gas demand to 0.5 Bcf per day in Cook Inlet to support project scale and financing.
	Coal Gasification	Successful demonstration of gasification technology with Alaskan coals. Development of coal mine and transport infrastructure.
	Enriched Gas Line	Increased industrial gas demand to 0.5 Bcf per day in Cook Inlet to support project scale and financing. Successful demonstration of methane carrier for liquids pipeline technology on large scale.
	**Spur Line**	Construction of main line from North Slope to Spur take-off point.
	CBM	Discover and implement commercial production in Susitna Basin.
	Other Alaska Gas	Discover and implement commercial gas production in Bristol Bay, Nenana, or Copper River Basins.
	Import LNG	Access to imported LNG affordable to Cook Inlet consumers.
	Nuclear Power	Successful implementation of small scale nuclear technology and licensing process in US. Proven cost-effective small scale reactor.
	Tidal Power	Successful implementation of commercial-scale projects.

Figure 7 Start-up Date – When the alternative start providing energy service?

Rank	Alternative	Start-up Date
0-1 year	Gas Conservation	2006 – Presently occurring because of rate increases.
	Increase Production	2006 – Presently occurring because of higher contract prices.
2–5 years	Electric Conservation	2007 – Implement conservation programs.
	CBM	2008 - Leasing and community standards complete.
	Distributed Generation	2010 - Demonstration projects have been successful.
	Wind Power	2011 - Preliminary permitting and feasibility completed for Fire Island.
	Import LNG	2011– Depends on retrofit starting in 2009.
	Coal Gasification	2011 – Reported start-up date for Agrium Blue Sky project.
6–15 years	Enriched Gas Line	2012
	Bullet Line	2012-2016
	Spur Line	2012 – Depends on completion of main line to Spur take-off.
	Other Alaska Gas	2012 – Bristol Bay leases sold in 2005.
	Hydro Power	2012-2020 Long lead time to complete license application, environmental assessment, and to raise capital investment.
	Coal Power	2008 - Healy Clean Coal Plant restart possible in 18 months. 2014 - Emma Creek project operational.
	Nuclear Power	2012 - Proposed start-up date for Galena project.
	Tidal Power	2020 – Technology currently in experimental phase.

Figure 8 Investment – What is the capital investment needed to implement the alternative?

Rank	Alternative	Level of Investment
<$100 million	Hydro Power	$10 - $100 million ($1 to $2 million per MW)
	Tidal Power	$10 - $20 million
	Distributed Generation	$25 - $50 million ($5 million per MW)
$ 100 – 500 million	Gas Conservation	$25 - $100 million
	Import LNG	$70 - $200 million
	Electric Conservation	$50 - $100 million
	Nuclear Power	$75 - $150 million
	Wind Power	$100 - $200 million
	Coal Gasification	$100 - $500 million
$ >500 million	Spur Line	$300 - $500 million $700 - $900 million if main line follows Highway Route.
	Coal Power	$400 - $500 million
	Increase Production	$500 million
	Bullet Line	$3 - $4 billion
	Enriched Gas Line	$4 billion with 2 LPG tankers
	CBM	$1- $5 billion
	Other Alaska Gas	$1- $5 billion

Figure 9 Monthly Bill – How much will monthly utility bills change?

Rank	Alternative	Production Costs and Issues
Savings	Gas Conservation	Reduces total monthly bill.
	Electric Conservation	Reduces total monthly bill.
+0-50%	Coal Power	5-10 cents per kilo-watt hour (kWh).
	Wind Power	7-12 cents per kWh.
	Hydro Power	7-15 cents per kWh.
	Spur Line	Gas rates to Cook Inlet would be bounded by Lower 48 prices.
	Distributed Power	5 -15 cents per kWh for fuel cells. Lower costs if heat can be used.
	Coal Gasification	Production costs uncertain with Alaskan coals. Power generation could be by-product of fertilizer production.
	Enriched Gas Line	Gas transport costs subsidized by income from LPG exports.
	Nuclear Power	10-20 cents per kWh depending on value of by-products (heat, hydrogen)
	Bullet Line	Cook Inlet consumers could pay substantial share of pipeline cost. Costs could be subsidized by industrial users and LNG exports.
+50-100%	Increase Production	Higher gas prices needed to encourage investment in development. Recent contracts linked to Lower 48 gas prices that have doubled.
	CBM	Higher gas prices needed to encourage investment in development
	Other Alaska Gas	Higher gas prices needed to encourage investment in exploration.
	Tidal Power	11-26 cents per kWh.
	Import LNG	Depends on world market prices of LNG, transport, and operating costs.

Figure 10 Uncertainty – How much uncertainty is there in achieving the alternative?

Rank	Alternative	Types of Uncertainties
	Gas Conservation	Persistence, level, and cost-effectiveness of energy savings.
	Electric Conservation	Persistence, level, and cost-effectiveness of energy savings.
	Hydro Power	Cost and availability of electric power.
	Coal Power	Operation of clean coal technology with Alaska coals.
	Wind Power	Availability and level of energy service.
	Bullet Line	Cost over-runs and delays are possible.
	Enriched Gas Line	Cost over-runs and delays are possible. Performance of new dense phase pipeline technology.
	Distributed Power	Operating cost, availability, and efficiency of fuel cells.
	Spur Line	Route, completion date, cost of main line carrying North Slope gas
	Coal Gasification	Efficiency of coal gasification process with Alaskan coals. Transport and cost of coal. Value of gasification products.
	Nuclear Power	Reliability and affordability of small-scale nuclear reactor. Approval of site license in geologically active Alaska.
	Import LNG	Availability and cost of imported LNG.
	Increase Production	Amount of economically recoverable gas in Cook Inlet.
	CBM	Amount of economically recoverable gas in Cook Inlet.
	Other Alaska Gas	Amount of economically recoverable gas in Bristol Bay, Copper River, and Nenana Basins.
	Tidal Power	Availability, cost, and level of energy service in Alaskan conditions

Figure 11 Environmental – What are the unmitigated environmental impacts of the alternative?

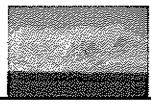
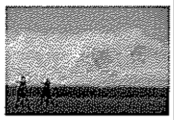
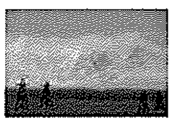
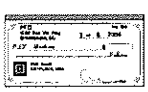
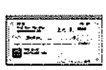
Rank	Alternative	Potential Unmitigated Impacts
	Gas Conservation	Net positive environmental impacts. More efficient fuel use.
	Electric Conservation	Net positive environmental impacts.
	Distributed Power	Net positive. No transmission impacts.
	Spur Line	Risk of accident. Increased access and travel opportunities provided by right-of-way (ROW) (positive/negative impact)
	Bullet Line	Risk of accident. Increased access provided by ROW.
	Enriched Gas Line	Risk of accident. Increased access provided by ROW.
	Wind Power	Noise. View shed impacts.
	Import LNG	Risk of leaks/spills. Facility emissions, noise, odor.
	Nuclear Power	Risk of accident. Long term land use. Nuclear waste.
	Hydro Power	Aquatic and surface/site impacts.
	Tidal Power	Aquatic impacts. Naval traffic constraints.
	Increase Production	Land use. View shed. Wildlife. Waste water into Cook Inlet. Risk of spills/accidents. Remediation of offshore platforms.
	Other Alaska Gas	Loss of undeveloped land. Wildlife. Risk of spills/accidents.
	Coal Gasification	Ash disposal. Facility emissions. Impacts from coal mining.
	Coal Power	Ash disposal, cooling water requirements, increased greenhouse gas emissions. Impacts from coal mining.
	CBM	Produced water disposal. Industrial landscape. Noise.

Figure 12 Alaskan Citizens – What are the potential impacts on Alaskan Citizens of the alternative?

Rank	Alternative	Potential Impacts
	Spur Line	New jobs, increased State revenues associated with North Slope gas development.
	Enriched Gas Line	New jobs, increased State revenues.
	Bullet Line	New jobs, increased State revenues.
	Increase Production	New jobs. Increased State revenues.
	CBM	New jobs. Increased State revenues.
	Other Alaska Gas	New jobs. Increased State revenues.
	Coal Gasification	New jobs. Retention of industrial operations and jobs.
	Coal Power	New jobs. Energy security with development of indigenous energy resource.
	Distributed Power	New job opportunities/industries in remote locations. Imported generation technology (negative impact).
	Hydro Power	Energy security with development of indigenous renewable energy resources.
	Gas Conservation	Money saved on energy bills stays in the economy.
	Electric Conservation	Money saved on energy bills stays in the economy. Imported conservation technologies (negative impact)
	Wind Power	Renewable energy resource/energy security. Imported generation technology (negative impact).
	Tidal Power	Renewable energy resource/energy security. Imported generation technology (negative impact).
	Nuclear Power	Imported generation technology (negative impact).
	Import LNG	Imported fuel. Large negative impact on economy.

STAKEHOLDER ANALYSIS

While the Dunmire Consulting team was not tasked with identifying "the best" energy supply alternative, it is important to understand that the preferred option will depend on an agent's motivations and point of view. Each stakeholder or agent will have a different perspective depending on their role in the decision-making process, their past experience, values, and expectations for future energy service in Cook Inlet. Ultimately, project investors and natural gas producers will need to be convinced that that the energy situation in Cook Inlet is an attractive business opportunity. They may rely on commitments by energy purchasers, and might require concessions by the Alaskan government. Success will depend on timely and cost effective implementation of one or more of the alternatives identified in this work.

We identified stakeholders and their potential motivations using an "integral framework" based on recent research by a variety of psychologists and social researchers.[7] We applied these theories to surveys of individuals and media sources to identify groups of stakeholders and their general motivations. We interviewed several ANGDA Board members, a State regulator, and the head of a local environmental group to better understand their perspective and preferences regarding Cook Inlet energy alternatives. Additionally, we included questions in surveys of energy producers, gas and electric utility staff, as well as state and local government officials to add their conception of "the facts" related to Cook Inlet energy service. "The facts" related to an option depend in part on the perspective, experience, and motivation of the individual reporting them. It is clear that we won't get decision makers to agree on "the facts".

In the Figure 13, some of the stakeholders and agents that could potentially be affected by implementing the Cook Inlet energy alternatives are listed with some of their motivations with respect to potential preferences in the outcome or selection of one of the alternatives.

Figure 13: Stakeholders and their Viewpoints of Cook Inlet Energy Situation

Stakeholder	Viewpoint and Motivations
Alaskan citizens	Identify with Alaska – what is good for the State is good for its citizens. One measure of State's success is the amount of Permanent Fund Distribution check. Generally, comfortable with development of natural resources as major source of economic development and jobs in the State. *A state-wide survey performed by Hellenthal Associates in February 2003 found that two-thirds of respondents preferred bringing North Slope gas to Cook Inlet over exploring for gas in Cook Inlet.*[8]
Cook Inlet Consumers	Presently, more concerned about future availability of natural gas/energy services than paying higher prices to get them. High priority given to preserving high paying oil, gas and utility job in Kenai/Anchorage area.
Community Groups (Churches, civic, environmental groups)	These groups tend to hold a position consistent with their common values and try to negotiate a solution from there. *"We are sick and tired of having the oil companies control our destiny," Jeff Lowenfels – Guerilla session on pipeline*[9]
Energy Industry. Producers, pipeline companies, utilities, Agrium, LNG plant.	Motivated by profit and providing energy service. *"The good news is that we've finally been able to negotiate supply for that period of serious uncertainty between now and .... When we might see North Slope Gas". Tony Izzo, president and CEO of Enstar told an Anchorage Chamber of Commerce audience on Nov 14.*[10] *"We don't see any problem selling as much gas as we can find". Scott Pfoff, President and CEO, Aurora Gas, LLC.*[11]
Investors, Banks.	Motivated by profit. Do not like to hold risk. Generally, require some risk mitigation to participate in a deal.
Federal Government	Motivated by energy security in the lower 48 States. An $18 billion in loan guarantee has been offered for larger pipeline projects to the Midwest.

Foreign Governments Canada, Asia, Japan	Asia and Japan -Motivated to secure low cost and reliable sources of natural gas. Canada – Motivated to increase access to gas from Mackenzie Delta and other remote basins as well as to improve natural gas infrastructure.
State Government	The State's economic development depends on developing natural resources. Long term and short term perspectives can be in conflict. It can be difficult to secure public support to forego short term gains for long term benefits. North Slope gas development is an "epic decision" equivalent to the decision for Statehood. *"This is not a Democrat or Republican issue," Harris said. "This is a state of Alaska issue, and the ramifications of doing it wrong could be huge." John Harris Rep Speaker of House*[12]

CONCLUSIONS

During the evaluation, each of the energy alternatives were evaluated and ranked with respect to each of the eight criteria. This affords decision-makers the opportunity to see which alternatives rank highest under the criterion that is most important to them. For example, if it is important to a stakeholder that the alternative is operating before 2010, then conservation, increased production, and distributed generation rank highest with respect to start-up date.

In reviewing the rankings for each criterion, some general observations of the results include:

- Near term: Gas Conservation and Increased Production in Cook Inlet would prolong gas supplies and buy time to select long term option and raise investment funds.
- Intermediate term: Coal Gasification could keep industrial facilities operating and provide electric power. Feasibility depends on proving process output and cost-effectiveness with Alaskan coals.
- Long term: Enriched Gas Line may be better investment than Bullet Line. Coal and Wind development strong second.
- Spur Line tops the list if pipeline carrying North Slope gas is built through Alaska.

It is important to note that some of the options with the lowest capital investment provide the least amount of energy service. Therefore, a combination of alternatives may be required to fill the energy service gap. For instance, the Fire Island wind power project (100 MW) and the a new coal-fired power plant (200 MW) would both have to be built and operating to replace the electric power generated with natural gas for the City of Anchorage. To keep the industrial facilities at the Agrium fertilizer plant without Cook Inlet gas will require operating, a significant coal gasification project. This would facilitate opening the Beluga coal mine which could then result in an additional coal-fired power plant near Beluga and the electric grid inter-tie. This power plant could serve to replace the existing natural gas-fired generators at Beluga as well as provide power to the proposed Pebble Mine. There are many alternatives which are complimentary or build on each other as more infrastructure is developed to serve a new energy source such as coal. In all cases, gas and electric conservation would help to slow energy demand growth and prolong dwindling gas supplies. This would help buy time to secure other energy alternatives.

APPENDIX A

Dunmire Consulting Team
P.O. Box 72 Cahone Colorado • 970-562-4495 • dunmire@fone.net
Cronshaw Consulting Boulder Colorado
Integral North America, Inc. Anchorage, Alaska

Dunmire Consulting – Coordinated study and analysis. Developed analysis plan, created Cook Inlet Background website, conducted analysis of all alternatives. Created final report.
Carolyn Dunmire has over 20 years experience analyzing the environmental impacts of the energy industry. She created a computer simulation to estimate the cost of sulfur dioxide allowances for the Clean Air Act, created a computer analysis tool to estimate environmental externalities for all types of power generation resources in New York, and analyzed mitigation options for reducing greenhouse gas emissions internationally. Her most recent projects have focused on renewable energy in Alaska. Ms. Dunmire identified and analyzed renewable energy options for remote rural villages in Lake and Peninsula Borough in southwestern Alaska. This study is being used to design and fund rural energy projects such as wind-diesel hybrid systems. These results were presented at the Alaska Rural Energy Conference in September 2005 and are available at: http://www.uaf.edu/aetdl/2005Presentations.html, the full study is available at www. lakeandpen.com Economic Development: "Technical Assistance to Fisheries Impacted Communities.pdf."

Cronshaw Consulting developed evaluation framework and analyzed pipeline options.
Mark Cronshaw, PhD has 25 years experience in economic and analytical analysis of the energy industry including tariff and capital cost analyses for the Alaskan Natural Gas Transportation System and business case development illustrating benefits from incremental oil/NGL sales and WPT relief for Prudhoe Bay for ARCO in the early 1980's. Presently, Dr. Cronshaw applies his original work on strategic behavior in dynamic systems to valuation of new gas pipeline services and traffic analyses for relieving congestion on a transcontinental communications network.

Integral North America conducted survey and stakeholder analysis for the study.
Integral North America (INA) Consulting is a firm located in Anchorage Alaska and dedicated to the healthy and constructive development of individuals, leaders and organizations. Using subjective and adaptive elements of organizational culture, teamwork and leadership in developing frames of reference and thought, procedures, organizational structures and behaviors to create quantifiably exceptional outcomes.
Charlie Sassara Co-founder. A life long Alaskan with 25 years of management, business development, project start-up and leadership experience. 14 years experience working Alaska Native (Regional and Village) Corporations in developing and managing complex infrastructure and O&M projects throughout Alaska, the western United States (US) and Hawaii. Has direct and extensive experience in developing projects and unique teaming agreements, with many in cross-cultural circumstances.
Shawn O'Fallon, Co- founder. 20 years of management and leadership experience. Development of survey methodologies to better understand beliefs, assumptions and worldviews of individuals and groups to better design and utilize methods of presentation that allow for participation and decision making unencumbered by unconscious hot and cold buttons.

APPENDIX B
WEBSITE SUMMARY

Welcome to Alaska Natural Gas Development Authority's

Cook Inlet Energy Alternatives Background Information Site

This site presents information on the history, production, and consumption of natural gas in Cook Inlet. It also outlines several energy alternatives that could be used to replace or supplement the Cook Inlet natural gas energy resource. After clicking on the maps below you may explore further by passing your cursor over numerous active links on each map.

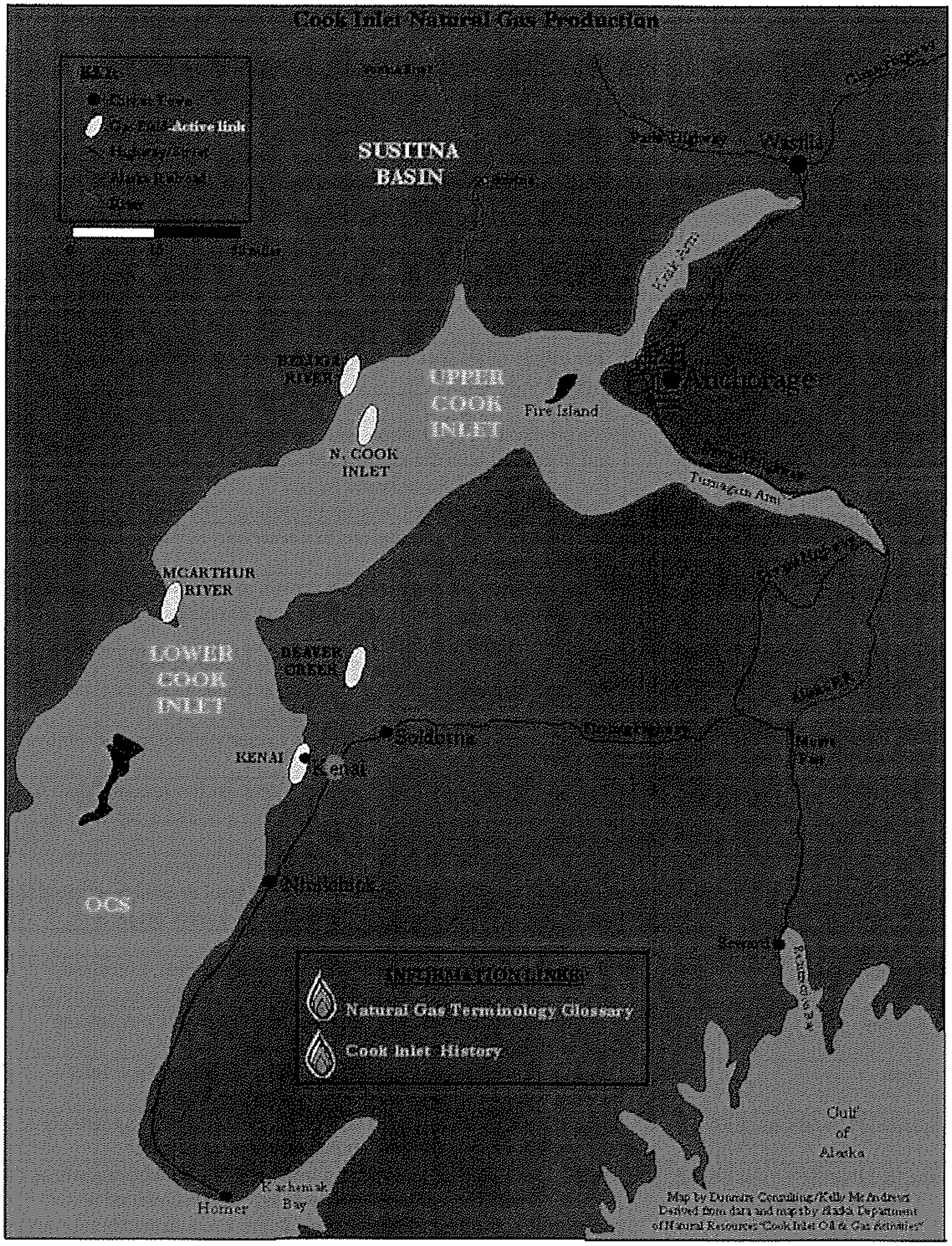
Map A – includes information on the geology and geography of Cook Inlet Basin, natural gas reserves in Cook Inlet, history of natural gas production in Cook Inlet, and natural gas terms.

Map B – presents information on natural gas production in Cook Inlet as well as natural gas infrastructure including pipelines, gas storage, the Agrium fertilizer plant, and the Kenai LNG facility. Map B also includes information about natural gas consumption as well as a base case forecast for production and consumption of Cook Inlet gas.

Map C – outlines some of the alternative energy sources to Cook Inlet natural gas including:

- Spur line or bullet line carrying North Slope Gas to Cook Inlet
- Wind power at Fire Island
- Coal bed methane development
- Energy conservation
- Hydro electric production
- Beluga coal gasification
- Industrial curtailment
- Increased gas storage
- Propane and natural gas liquids development
- LNG import

MAP A


Cook Inlet Natural Gas Production
Active link
SUSITNA
BASIN
Wasilla
Anchorage
Fire Island
UPPER
COOK
INLET
N. COOK
INLET
Turnagain Arm
MCARTHUR
RIVER
LOWER
COOK
INLET
KENAI
Kenai
Soldotna
OCS
Seward
INFORMATION LINKS
Natural Gas Terminology Glossary
Cook Inlet History
Gulf
of
Alaska
Homer
Kachemak
Bay

MAP A - **NATURAL GAS TERMS**

Natural gas is primarily methane (CH_4) trapped porous rocks deep underground. In Cook Inlet, natural gas is usually found at depths between 5000 and 7000 feet. Normally, the gas comes to the surface with natural pressure. The natural gas must be cleaned (sulfur, water, and other compounds removed) before it is transported by pipeline to end-users. An odorant is added to the gas before it is delivered to residences and commercial buildings.

Measures of Natural Gas

(cf) cubic foot	Volume of natural gas that would fit into a basketball.
(ccf) 100 cubic feet	One hundred cubic feet.
(mcf) 1000 cubic feet	One thousand cubic feet.
(MMcf) 1,000,000 cubic feet	One million cubic feet. Peak production rate from Cook Inlet is about 700 MMcf per day.
(Bcf) 1,000,000,000 cubic feet	One billion cubic feet. Annual gas production in Cook Inlet is about 200 Bcf.
(Tcf) 1,000,000,000,000 cubic feet	One trillion cubic feet. Estimate remaining reserves in Cook Inlet amount to 2 Tcf.

Reserve Terms[13]

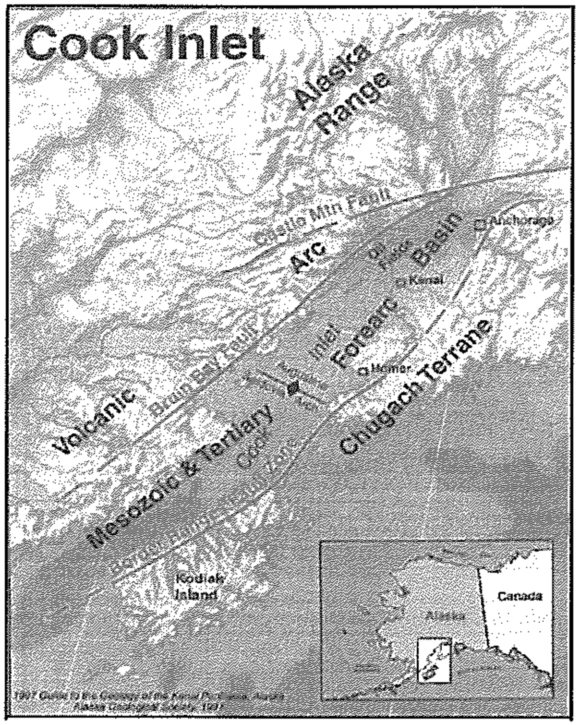
Associated gas	Gas produced in association with oil, or from a gas cap overlying and in contact with the crude oil in the reservoir.
Gas Field	The general area encompassed by one or more oil or gas reservoirs or pools that are located on a single geologic feature.
Gas-in-place (GIP)	The total amount of natural gas in a reservoir including recoverable and unrecoverable reserves.
Probable reserves	Those reserves which are not yet proven but which are estimated to have a better than 50% chance of being technically and economically producible.
Proven reserves	Those reserves are virtually certain to be technically and economically producible based on the available evidence (i.e. having a better than 90% chance of being produced).
Recoverable reserves	That proportion of the oil and/gas in a reservoir that can be removed using available techniques.
Reservoir	The underground formation where oil and gas has accumulated. It consists of a porous rock to hold the oil or gas, and a cap rock that prevents its escape
Unit	Joint operation of several leases, usually for economic or conservation reasons. Frequently a whole pool or field is unitized to prevent unnecessary drilling and conduct recovery projects

Contract and Other Terms

Henry Hub	A pipeline interchange, located in Vermilion Parish, Louisiana, which serves as the delivery point of natural gas futures contracts.
MMcf/day	Million cubic feet per day. Peak gas production in Cook Inlet is about 700 MMcf/day.
Bcf/year	Billion cubic feet per year. Total gas production in Cook Inlet amounts to about 200 Bcf/year.
Liquefied Natural Gas (LNG)	Natural gas which has been liquefied by reducing its temperature to minus 260 degrees Fahrenheit at atmospheric pressure.
Liquefied Petroleum Gas (LPG)	A gas containing certain specific hydrocarbons which are gaseous under normal atmospheric conditions but can be liquefied under moderate pressure at normal temperatures. Propane and butane are the principal examples.
Producer	Any party owning, controlling, managing, or leasing any gas well and/or party who produces in any manner natural gas by taking it from the earth or waters.

MAP A - COOK INLET BASIN

The Cook Inlet Basin is the source for the natural gas used by three out of four Alaskans to heat and light their homes and businesses.[14] Recent forecasts of natural gas production in Cook Inlet Basin predict future gas shortages as these gas reserves are depleted.



Cook Inlet Basin Geology

Geologically, Cook Inlet Basin is defined by three major faults: Bruin Bay fault to the west, Castle Mountain fault to the north, and the Border Ranges Fault zone to the east. See Figure A-1. The Basin is about 250 miles long and 60 miles wide with about half of the land area under the waters of Cook Inlet. All of the commercial natural gas and oil production has occurred in the 9,000 square mile area north of the Augustine-Seldovia Arch and south of the Castle Mountain fault.[15]

Cook Inlet Basin Geography

Cook Inlet Basin lies between the Alaska Range and the Kenai Mountains. It includes the north-eastern coast of the Alaska Peninsula, Anchorage Bowl, Knik Arm, and the western half of the Kenai Peninsula including the towns of Kenai and Homer. Rivers from the south and eastern-side of the Alaska Range as well as from the western side of the Kenai Mountains drain into Cook Inlet including the Susitna and Kenai rivers.

Figure A-1: Geologic Boundaries of Cook Inlet Basin.
Source: U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South-Central Alaska Natural Gas Study. June 2004.

Susitna Basin: Includes the Pioneer Unit (group of leases currently held by Burlington Resources) located west of Wasilla that are targeting coal-bed methane.

Upper Cook Inlet: Includes the North Cook Inlet and Beluga River fields that together produced half of Cook Inlet's total natural gas production in 2003.[16]

Lower Cook Inlet: Includes McArthur River, Beaver Creek, and Kenai fields some of the oldest producing fields in Cook Inlet. While these older fields are experiencing reduced production levels, new developments such as Ninilchik field have kept total production in this sub-basin consistent.

Outer Continental Shelf (OCS): This sub-basin has yet to report any commercial discoveries. A lease sale held in May 2004 by the U.S. Minerals Management Service received no bids. The next lease sale is scheduled for May 2007 if there is sufficient interest.[17]

MAP A - COOK INLET HISTORY – NATURAL GAS

The history of exploration and production of natural gas and oil in Cook Inlet extends over 150 years. Russian explorers exploited oil seeps on the west side of Cook Inlet in the 1880's. Yet, because of more accessible oil and gas reserves outside Alaska, commercial production of oil and gas in Cook Inlet did not begin until the mid-twentieth century. However, Cook Inlet oil and gas has been noted as a key factor in Alaska achieving statehood because Alaskans could prove energy self-sufficiency.

Natural gas in Cook Inlet was discovered during oil exploration in the 1950's and 1960's. Over the past 75 year, only 24 of the 267 exploration wells drilled in Cook Inlet were natural gas exploration wells. Commercial natural gas production began in 1961 at the Kenai field. Since then, more than 9 trillion cubic feet of natural gas have been produced in Cook Inlet Basin

Cook Inlet Natural Gas Development Timeline[18]

1788	Captain Cook visits Cook Inlet.
1853	Oil seeps on Iniskin Peninsula are discovered by Russian explorers.
1880's	Oil found at Oil Bay at 700 feet. Produces 50 barrels per day.

1950 – 1956	Richfield Oil begins seismic exploration on the Kenai Peninsula in the National Moose Range (now Kenai National Wildlife Refuge) using horses to haul equipment because motorized vehicles are not allowed in the refuge.
1957	Swanson River oil field discovered by ARCO.
1959	Kenai natural gas field discovered by Unocal and Marathon Oil Company.
1959	Alaska becomes the 49th State.
1959	State of Alaska holds first oil and gas lease sale in Cook Inlet Basin.
1961	Kenai natural gas field begins production. Natural gas pipeline from Kenai to Anchorage constructed. Sterling natural gas field discovered by Marathon.
1962	Gas turbine begins to generate electricity in Anchorage. Beluga River natural gas field discovered.
1964	North Cook Inlet offshore natural gas field discovered. Exploration well blows out and escaping gas burns for 13 months.
1967	Beaver Creek natural gas field discovered.
1968	Unocal starts production at a ammonia-urea plant at Nikiski using Cook Inlet gas as feedstock.
1969	Liquefied Natural Gas (LNG) plant begins operations and exports first shipment of LNG to Japan.
1978	Ammonia and urea plant doubles in size to become the West Coast's largest fertilizer supplier and exporter.
1979	Cannery Loop natural gas field discovered by Unocal and Marathon. Pretty Creek natural gas field discovered on West side of Cook Inlet.
1984	Gas utility pipeline built by Enstar carries gas from Beluga field to Wasilla.
1987	T/V Glacier Bay tanker spills 159,000 gallons of crude oil at Nikiski. Steelhead Platform explodes causing million of dollars in damage. No lives lost.
1989	Exxon Valdez runs aground in Prince William Sound spilling 232,000 barrels of crude oil. Sections of Cook Inlet's shoreline are affected by the spill.
1993	Two larger LNG tankers are put into service to replace original tankers from 1969.
1999	Sterling gas field begins production.

2001	Experimental gas-to-liquids facility developed by British Petroleum begins operation.
2002	Construction begins on Kenai-Kachemak Pipeline.

2003	Gas storage operations begin at Swanson River field.
2004	• Agrium files dispute to gain access to Cook Inlet Gas Gathering System (CIGGS) a private pipeline owned by Marathon and Unocal/Chevron. • Coalbed methane exploration begins in Susitna Basin. Further leasing halted because of surface-owner concerns. • U.S. DOE study predicts Cook Inlet gas production will decline and known reserves could be depleted by 2012. • Kenai-Kachemak Pipeline begins operation carrying gas from new fields in Ninilchik.
2005	• Largest gas producers are Conoco/Phillips, Marathon, and Unocal with several small companies producing natural gas in Cook Inlet. • Chevron purchases Unocal. • CIGGS dispute resolved in short term. • Happy Valley gas field begins production. Largest recent gas field discovery for Unocal with reserves estimated at 100 billion cubic feet. • Negotiations between the "Big-3" North Slope oil producers (British Petroleum, Conoco/Philips, ExxonMobile) and the State of Alaska (Governor's office) begin in earnest on the terms for constructing a pipeline to carry North Slope gas to Cook Inlet and Lower 48.
2006	Agrium fertilizer plant scheduled for shutdown because of high natural gas prices.
2009	LNG export license at Nikiski facility expires. License renewal not expected.

MAP A - COOK INLET FIELDS AND RESERVES

Natural gas was discovered in Cook Inlet during oil exploration in the 1950s and 1960s. The majority of Cook Inlet's proven gas reserves are classified by geologists as non-associated biogenic gas that has no genetic relationship to the origin and distribution of oil. Normally, natural gas is "associated" with or found with oil deposits.

According to the US Department of Energy (DOE) in a recent report on gas reserves in South-central Alaska, 95 percent of Cook Inlet gas produced today was discovered before 1970 during oil exploration.[19] New gas resources in Cook Inlet are likely to come from biogenic gas in stratigraphic or combination traps Stratigraphic traps typically account for 50% or more of the ultimate production of gas in basins elsewhere. As of 2004, no gas exploration had occurred in stratigraphic traps in Cook Inlet.

The reason that Cook Inlet has been overlooked is because when companies started to discover significant oil and gas reserves in Cook Inlet, discoveries were also made on Alaska's North Slope. By comparison, Cook Inlet was small and isolated. State incentives to develop these "stranded" resources encouraged three companies (Marathon, ConocoPhillips, and Unocal/Chevron) to develop Cook Inlet's oil and gas fields. These companies also invested in an oil refinery, liquefied natural gas export facility, and petrochemical plant.

Cook Inlet Natural Gas Production - Fields

The majority of the natural gas produced in Cook Inlet is from four large fields:

- **Beluga River**: Owned equally by ConocoPhillips, ChevronTexaco, and Municipality of Anchorage. Gas from Beluga River field is used primarily to generate electricity.

- **North Cook Inlet**: Owned by ConocoPhillips who uses the gas at its Kenai Liquefied Natural Gas (LNG) facility. Most of the LNG is exported to Japan, though a small share is trucked to Fairbanks to serve residential and commercial customers

- **McArthur River:** Owned by Marathon Oil, Corp. and Unocal/Chevron. McArthur River field produces gas used at the Agrium petrochemical facility that makes ammonia, urea, and fertilizer for export.

- **Kenai:** Owned by Marathon and produces gas used at the Kenai LNG facility.

How much natural gas is left Cook Inlet Basin?

Most recent estimates of the amount of natural gas left in Cook Inlet are in the range of 2 trillion cubic feet. The Alaska Division of Oil and Gas (DOG) who makes annual estimates of remaining "proven reserves" found that there is 2.087 trillion cubic feet of natural gas in proven reserves in Cook Inlet as of January 1, 2004. At current consumption rates, these reserves will last about another 9 years.

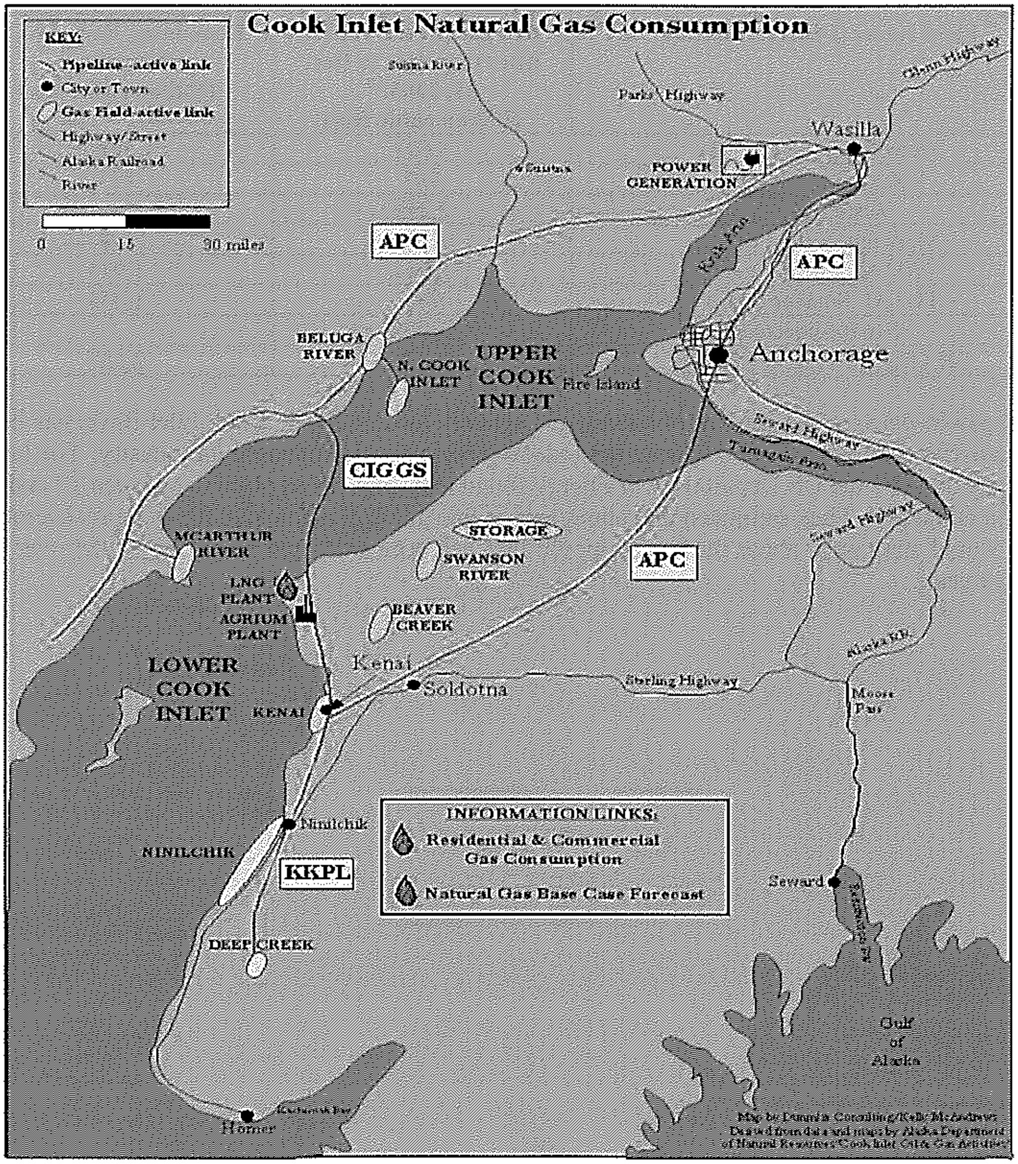
Figure A-2 shows the cumulative production and the remaining recoverable reserves as estimated by DOG.

Figure A-2: Natural Gas Reserve Estimates for Cook Inlet Fields

Field Name (Discovery Date)	Total gas produced from discovery date to Dec. 31, 2003.[20] (Billion cubic feet)	Remaining Recoverable Reserves.[21] (Billion cubic feet)
North Cook Inlet (1962)	1,621	597
Beluga River (1962)	847	423
Kenai (1959)	2,246	182
McArthur River (1955)	1,220	168
TOTAL Large Fields	5,934	1,034
TOTAL Smaller Fields	711	1,053
Gas Re-injected	2,902	
GRAND TOTAL as of 12/04	**9,547**	**2,087**

Total gas-in-place or the amount of natural gas actually located inside Cook Inlet Basin has been estimated by a variety of experts from the federal government and petroleum industry. The latest estimate done by the US Department of Energy found that total gas in place to between 13 and 17 trillion cubic feet. They estimated that about half of this gas (8.5 tcf) would likely be recoverable. This would amount to about the same amount that has been extracted from Cook Inlet over the past 30 years.

MAP B


Cook Inlet Natural Gas Consumption
KEY:
Pipeline - active link
City or Town
Gas Field-active link
Highway/Street
Alaska Railroad
River
0
15
30 miles
Parks Highway
Glenn Highway
Wasilla
POWER GENERATION
APC
APC
Anchorage
BELUGA RIVER
N. COOK INLET
UPPER COOK INLET
Fire Island
Seward Highway
CIGGS
STORAGE
MCARTHUR RIVER
SWANSON RIVER
APC
LNG PLANT
AGRIUM PLANT
BEAVER CREEK
Kenai
LOWER COOK INLET
KENAI
Soldotna
Sterling Highway
Moose Pass
INFORMATION LINKS:
Residential & Commercial Gas Consumption
Natural Gas Base Case Forecast
Ninilchik
NINILCHIK
KKPL
Seward
DEEP CREEK
Gulf of Alaska
Homer

MAP B – GAS PIPELINES IN COOK INLET

One of the major barriers to natural gas production in the Cook Inlet has been establishing a gas pipeline infrastructure and negotiating carrier terms. Since Cook Inlet is a remote area lacking even a road system in most places, gas pipelines and infrastructure have been costly and difficult to build. Despite these difficulties there about 500 route miles of natural gas pipeline connecting Cook Inlet's onshore and offshore gas fields to industrial consumers on the Kenai Peninsula, as well as electric generators, commercial, and residential consumers from Homer, Kenai, Anchorage, and the Mat-Su valley.

There are three main pipeline systems in Cook Inlet:
1)Alaska Pipeline Company (APC) system
2) Cook Inlet Gas Gathering System (CIGGS
3) Kenai Kachemak Pipeline (KKPL)

ENSTAR/Alaska Pipeline Company (APC)
The Alaska Pipeline Company (APC) owned by Enstar Natural Gas Company operates the pipeline network that delivers Cook Inlet gas to Anchorage and other regional communities as well as transports natural gas for the major industrial users and electric generators.
The APC pipelines are shown in blue Figure B-4.[22]

Construction on this pipeline network began in the 1960's with the line from Kenai to Anchorage. The most recently constructed pipelines connect the west side of Cook Inlet (Tyonek) to Anchorage.

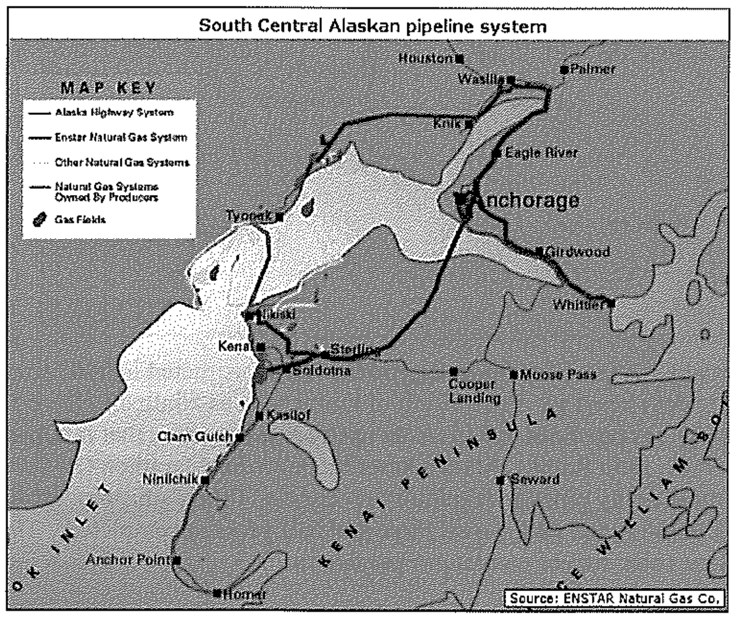
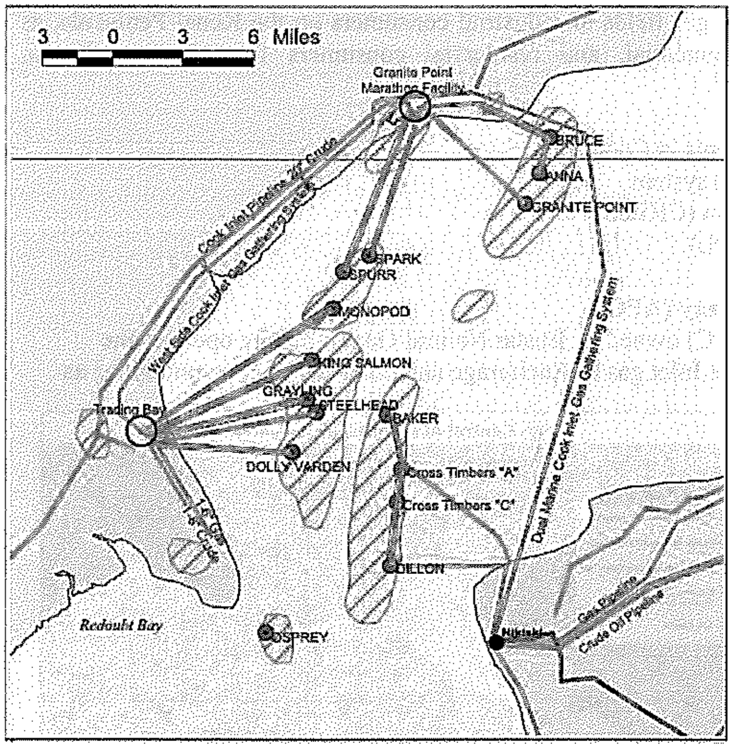


Figure B-4. ENSTAR/APC PipelineNetwork.
Source: ENSTAR Natural Gas[23]

Cook Inlet Gas Gathering System (CIGGS)
This privately owned pipeline system was built in the early 1970's by Marathon Oil Corp and Unocal/Chevron to bring gas from offshore wells in the North Cook Inlet field to facilities and pipelines on the Kenai Peninsula. Recently, access to CIGGS has come under regulatory review. As a private pipeline system built before the Alaska Right-of-Way Leasing Act, CIGGS was exempt from common carrier provisions. In early 2004, Agrium, the owner of the fertilizer plant in Nikiski, complained to the Regulatory Commission of Alaska (RCA) that lack of access to CIGGS was deterring development of natural gas fields on the west side on Cook Inlet. See Figure B-5 for map of CIGGS.[24]

Later in 2004, Aurora Gas a relatively new and small producer participated in a second petition to RCA for access to CIGGS to carry gas from its fields on the west side of Cook Inlet to consumers in Nikiski.

Figure B-5 Cook Inlet Gathering System (CIGGS)
Source: Minerals Management Service.[25]



The RCA ruled in September 2005, that the CIGGS must submit to regulation under the terms of the Act. The settlement terms negotiated by CIGGS and the petitioners guarantees that a minimum of 40 million cubic feet per day of capacity will be available.[26]

The RCA set an initial tariff rate of 15.2 cents per thousand cubic feet shipped through CIGGS. The final tariff rate will be calculated using a rate base valued at the owner's original cost to build CIGGS.

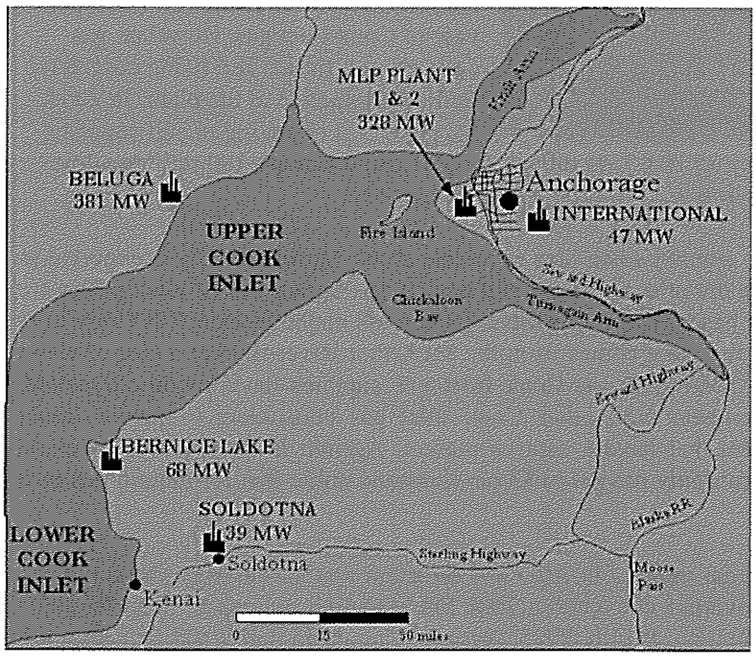
Kenai Kachemak Pipe Line (KKPL)

The KKPL is owned by Marathon Oil Corp (60%) and Unocal/Chevron. This 33-mile pipeline was constructed in 2003 to carry natural gas from the newly developed gas fields south of Kenai such as Ninilchik, Deep Creek, and Happy Valley to existing gas pipelines. KKPL is an open access pipeline that is subject to regulatory oversight by the RCA. John Barnes, Alaska Asset Manager for Marathon Oil Corporation notes that this was the most costly pipeline regulatory process in Alaska's history, costing 15% of the total project ($25 million) and taking over three and half years to complete.[27] The KKPL transported 15 million cubic feet of natural gas per day in 2003.

MAP B – POWER GENERATION

About one-sixth of Cook Inlet's natural gas production is burned in power plants to generate electricity for homes, businesses, and industrial operations. Currently, there is about 800 megawatts (MW) of gas-fired generation in Cook Inlet using about 35 billion cubic feet (Bcf) per year. The location of these power plants is shown in Figure B-8.

Figure B-8 Natural Gas-fired Power Plants in Cook Inlet[28]

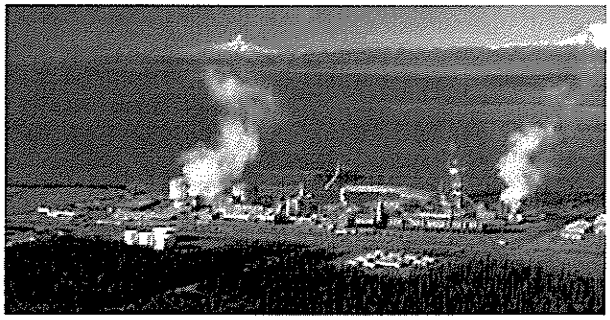


These five power plants generate about three-quarters of all the electricity for south central Alaska.[29] Anchorage Municipal Light and Power (MLP) owns and operates two of these plants totaling 328 MW. MLP purchased a share of the Beluga River gas field and has a secure gas supply for these plants through 2017.[30]

The other three power plants are owned and operated by Chugach Electric Association (CEA), a member owned electric cooperative and the largest utility in Alaska. CEA currently uses about 25 Bcf of natural gas per year supplied by contracts with four suppliers.[31] This supply is expected to last until 2009. Average cost of gas to CEA and MLP from the Beluga River field is $2.60 per thousand cubic feet.[32]

With relatively secure gas supplies, MLP and CEA have been able to keep electricity rates stable at about 12 cents per kWh for residential and commercial customers. Demand for natural gas for power generation is expected to grow at rate less than 1 percent per year.[33] Additionally, there is sufficient electric generating capacity to serve this region until 2014.[34] This means that until new gas supplies are needed in 2009 by CEA, electric rates and supply should remain relatively stable.

Map B – Agrium Fertilizer Plant



The second largest consumer of Cook Inlet natural gas is the anhydrous ammonia and urea manufacturing facility owned by Agrium, Inc. This facility which began production in 1968 can consume 54 billion cubic feet (Bcf) per year of Cook Inlet gas. However, gas delivery constraints and rising costs have limited production at the plant. In 2004, the plant was operating at half capacity and annual consumption was only 25 Bcf.[35] At full capacity, Agrium can use 140 million cubic feet per day. Minimum consumption is 80 million cubic feet per day.

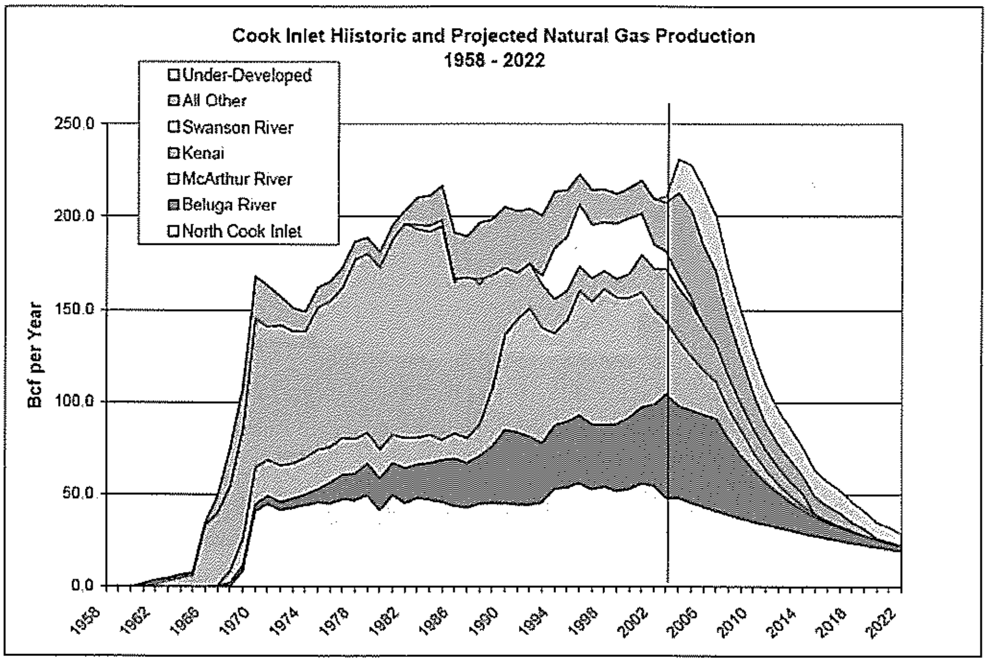
The great majority of anhydrous ammonia and urea produced at the Agrium facility is exported to Asia.[36] Agrium is constrained on the price it can pay for natural gas because its product prices are set by world markets. The plant has stayed competitive because its major feedstock is Cook Inlet natural gas. Most of the gas for the plant comes from the McArthur River field at a cost of about $1.20 per thousand cubic feet.[37] However, as Cook Inlet gas supplies have become depleted, Agrium has been forced to compete with other Cook Inlet gas consumers to secure future supplies. Unlike other consumers that have a captive market, Agrium is constrained by world market prices for fertilizer and can only pay up to $3 per thousand cubic feet for natural gas or it won't be profitable.

Agrium's contracts for low cost gas expired in 2005 and the plant was scheduled to be shutdown in November 2005. Alaska's governor convened a Task Force to find options to keep the plant and its 180 high paying jobs operating. In July 2005, Agrium announced that it had secured a gas contract that would keep the plant operational through November 2006. While the details of the contract were not released, Agrium had made an offer of $3.00 per thousand cubic feet with potential for higher prices paid if higher fertilizer prices supported it.[38]

MAP B – COOK INLET ANNUAL PRODUCTION OF NATURAL GAS

Gas production in Cook Inlet has been in the range of 200 billion cubic feet (Bcf) per year since 1980.[39] Historic and projected natural gas production for Cook Inlet is shown in Figure B1. This familiar figure shows the past and expected trends of production levels from each major unit in Cook Inlet. A unit is a group of leases that are operated together.

Figure B1: Cook Inlet Historic and Project Natural Gas Production.



Source: Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report.

Detailed production levels by unit are shown in Figure B2. This figure also shows the estimated remaining recoverable reserves. It is interesting to note that some of the oldest and highest producing units such as McArthur River and Kenai have 10 years or less of operating reserves.

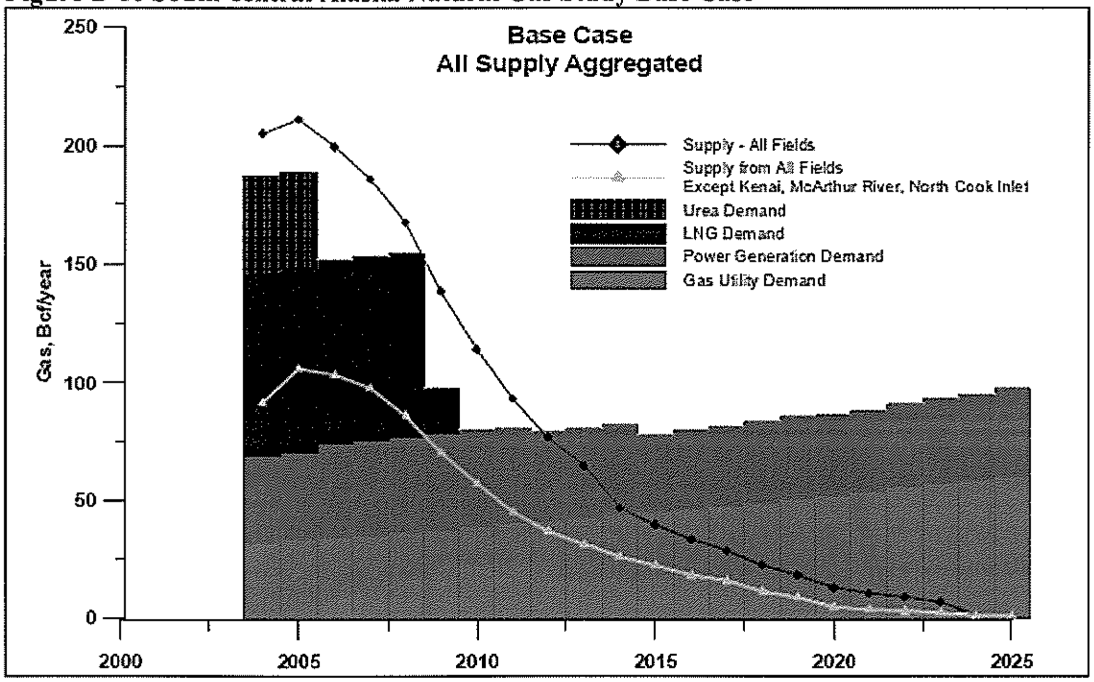
Figure B2 - Natural Gas Production by Major Unit – Cook Inlet[40]

Unit (Operator)	**Net Production in 2003 (Bcf)**	**Estimated Remaining Recoverable Reserves as of Jan 1, 2004 (Bcf)**
Beaver Creek (Marathon)	8	75
Beluga River (ConocoPhillips)	56	423
Kenai (Marathon)	29	182
McArthur River (Unocal/Chevron)	39	168
Ninilchik (Marathon)	3	100
North Cook Inlet (ConocoPhillips)	48	597
Swanson River (Unocal/Chevron)	9	10
All other units	16	532
Total	**208**	**2,087.5**

MAP B – BASE CASE FORECAST FOR COOK INLET NATURAL GAS

The most recent assessment of Cook Inlet's natural gas supply and demand was completed in 2004.[41] Results for the Base Case are show in Figure B-10.

Figure B-10 South-central Alaska Natural Gas Study Base Case



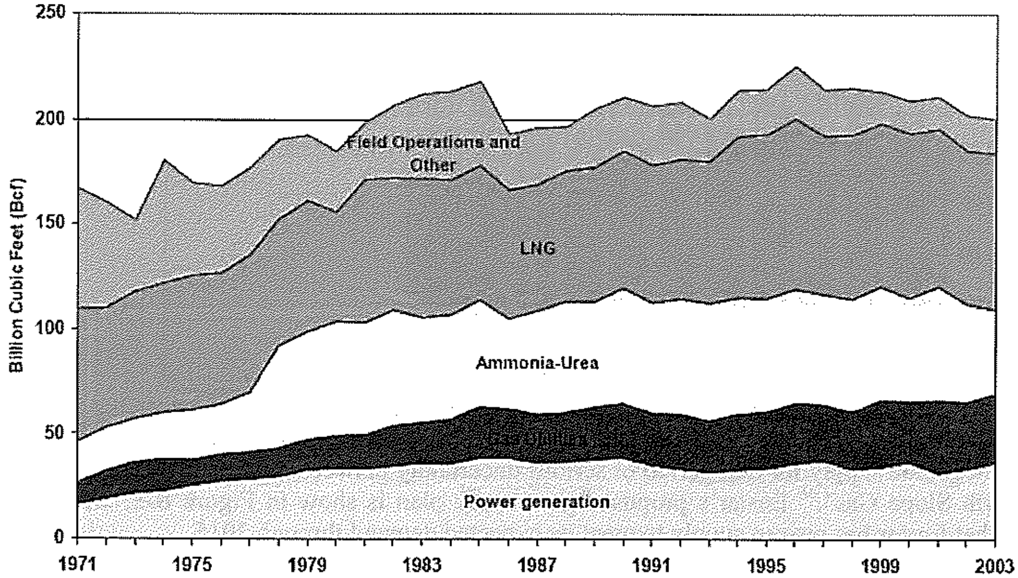
Source: US DOE. South Central Alaska Natural Gas Study. Final Report.

The Base Case uses the assumptions that supply will be limited to proven reserves and that the two largest gas consumers (Agrium Urea/Fertilizer plant and LNG facility) will cease production in 2006 and 2009, respectively. Under this scenario natural gas supply is expected to drop dramatically between 2005 and 2015. Gas supply shortages would start in 2012. If additional reserves of 1.5 trillion cubic feet are included, gas supply shortages are not expected until after 2020. Recent analysis by the Alaska Division of Oil and Gas increased the level of proven reserves for Cook Inlet by more than 0.250 trillion cubic feet between 2003 and 2004.[42] Given the uncertainty of Cook Inlet gas reserve estimates, additional reserves are feasible.

MAP B –RESIDENTIAL AND COMMERCIAL GAS CONSUMPTION

Enstar Natural Gas Company provides natural gas service to over 300,000 homes and businesses in south-central Alaska. Total consumption of Cook Inlet by these consumers averaged 32.2 billion cubic feet per year between 1999 and 2003, amounting to 15.5 percent of total consumption.[43] Figure B-6 illustrates Cook Inlet gas consumption by consumer type for the past 30 years.

Figure B-6: Cook Inlet Gas Consumption



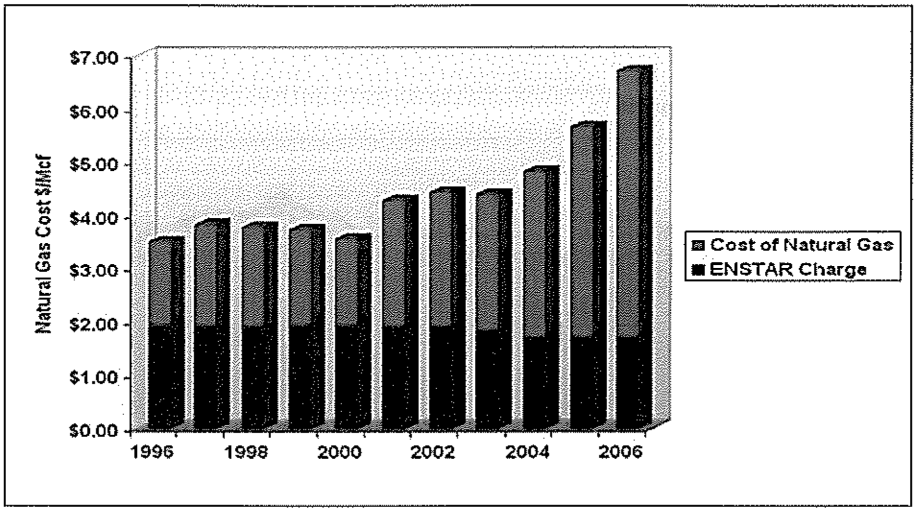
Source: Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.

Residential gas consumption is predicted to grow at an annual average rate of 1.8 percent over the next 15 years. Commercial gas consumption is expected to grow a bit slower at 1 percent per year to 2020.[44] However, natural gas consumption in these sectors may not grow as quickly as expected because of recent rate hikes by Enstar.

Until recently, Enstar customers enjoyed the lowest natural gas rates in the US. Yet, in order to secure future gas supplies to meet this growing demand, Enstar entered into gas supply agreements that link prices paid to Cook Inlet producers to prices in the Lower 48. This arrangement is intended to increase prices paid for Cook Inlet gas and encourage producers to invest in more exploration and production. Otherwise, producer investment may go elsewhere such as Wyoming or New Mexico where higher prices and greater returns are possible. The Regulatory Commission of Alaska (RCA) approved the first gas sales agreement between Enstar and Unocal/Chevron with these pricing provisions with the justification that it would stimulate new development in Cook Inlet. An agreement in late 2005 between Enstar and Marathon Oil Corporation with a similar pricing arrangement is under review by RCA.

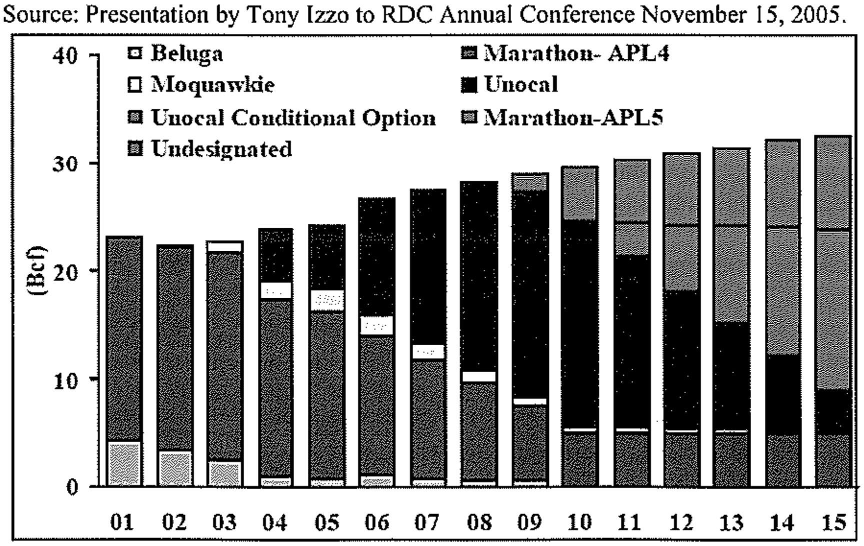
This new pricing arrangement has greatly increased residential and commercial rates for Enstar customers. Figure B-7 illustrates residential rates for the past 10 years. While Enstar's charges have stayed near $2.00 per thousand cubic feet ($/Mcf), the cost of natural gas and residential rates have more than doubled during that time.[45]

Figure B-7 Enstar Residential Rates
Source: http://www.Enstarnaturalgas.com/CompanyInfo/rate_info.htm



Apparently, Enstar's strategy to secure future gas supplies by paying higher prices has worked. According to Tony Izzo, president and CEO of Enstar, "The good news is that we've finally been able to negotiate supply for that period of serious uncertainty between now and....when we might see North Slope Gas".[46] Enstar's proposed gas supply plan is show in Figure B-8.[47] This plan shows that Enstar has proven supply to meet its expected demand through 2015.

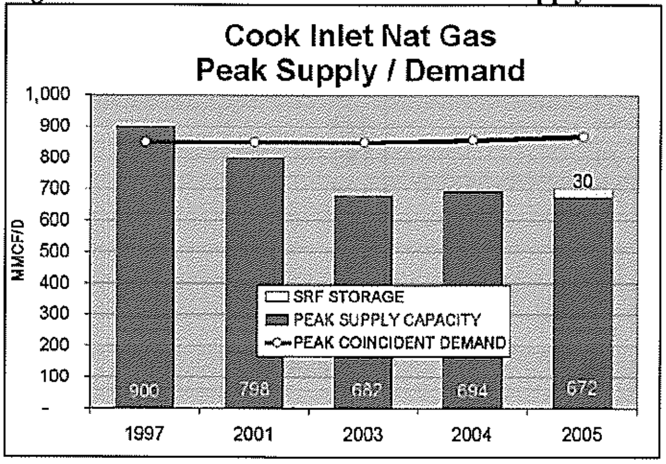
Figure B-8 Enstar's Proposal Gas Supply in Billion Cubic Feet (Bcf)
Source: Presentation by Tony Izzo to RDC Annual Conference November 15, 2005.



MAP B – NATURAL GAS DELIVERABILITY AND STORAGE

The ability of the Cook Inlet natural gas system to deliver sufficient gas flows to meet peak demand is likely to result in near term supply shortages. Presently, the Cook Inlet natural gas system has a peak supply capacity of 740 million cubic feet per day (MMcf/day)[48]. Average demand for Cook Inlet gas is 330 MMcf/day. However, during the winter, demand can more than double to 900 MMcf/day.[49] Figure B-9 illustrates the potential gas shortfall during peak demand.

Figure B-9 - Cook Inlet Natural Gas Peak Supply and Demand[50]



Currently, this supply shortfall is made up by curtailing industrial customers. In early 2006, the Agrium fertilizer plant was forced to shutdown because of an extended cold snap when natural gas was diverted to heat homes and businesses.[51] During this time, the gas delivery system could not even deliver the minimum amount of gas (80 MMcf/day) needed to operate the Agrium plant at reduced capacity.

Plans to alleviate the delivery problem include increasing gas storage facilities in the system. The Swanson River Field (SRF) gas storage facility uses a depleted underground reservoir structure to hold gas produced during non-peak periods. The SRF reservoir can be tapped during peak demand to provide an additional 30 MMcf/day to the system. Unocal/Chevron who owns and operates the SRF has proposed to expand the SRF storage facility.[52] Historically, large volumes of natural gas have been imported to the now depleted SRF to maintain reservoir pressure for oil production. Unocal/Chevron proposes to use the same pipeline infrastructure to support gas storage operations.

The first gas storage lease was approved in October 2005 by Alaska Department of Natural Resources for Unocal/Chevron's Pretty Creek field.[53] Under the terms of the lease, the State will collect royalties on 10 percent of the gas drawn from Pretty Creek reservoir, in proportion with the amount of as-yet unproduced "native" gas remaining in the reservoir. Marathon Oil Corporation applied for a gas storage lease for part of the Kenai field in early 2006.[54]

MAP B - COOK INLET GAS PRODUCTION

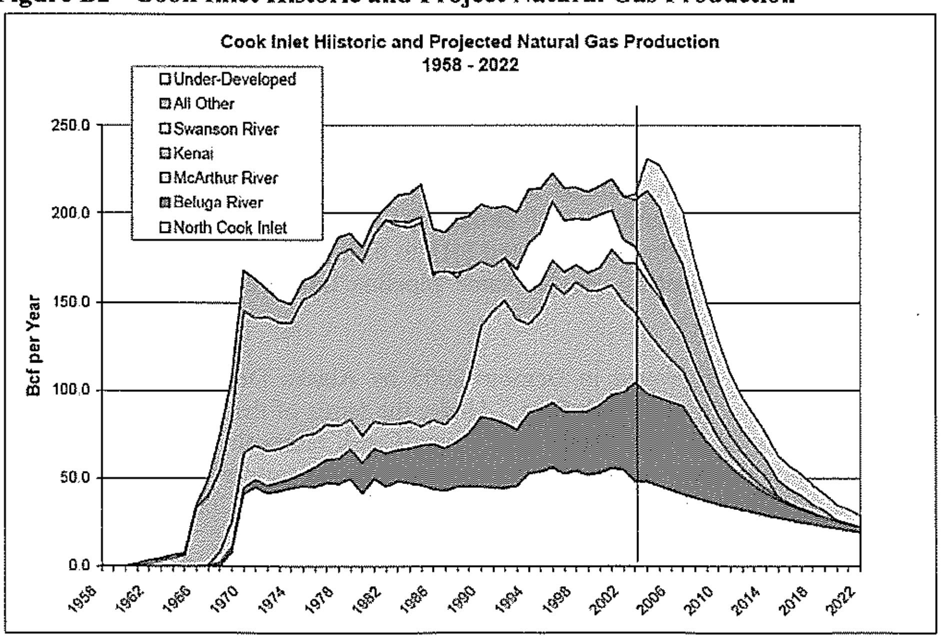
Gas production in Cook Inlet has been about 200 billion cubic feet (Bcf) per year since 1980.[55] Net production peaked in 1996 at 223 Bcf and has since dropped to just over 200 Bcf in 2003. Detailed production by unit is shown in Figure B1. A unit is a group of leases that are operated together.

Figure B1 - Natural Gas Production by Major Unit – Cook Inlet[56]

Unit (Operator)	Net Production in 2003 (Bcf)	Estimated Remaining Recoverable Reserves as of 1/1/2004 (Bcf)
Beaver Creek (Marathon)	8	75
Beluga River (ConocoPhillips)	56	423
Kenai (Marathon)	29	182
McArthur River (Unocal/Chevron)	39	168
Ninilchik (Marathon)	3	100
North Cook Inlet (ConocoPhillips)	48	597
Swanson River (Unocal/Chevron)	9	10
All other units	16	532
Total	**208**	**2,087.5**

Figure B1 also shows the estimated remaining recoverable reserves. It is interesting to note that some of the oldest and highest producing units such as Beluga River and North Cook Inlet have 10 years or less of reserves if production rates stay the same. Historic and projected production for Cook Inlet is shown in Figure B2.

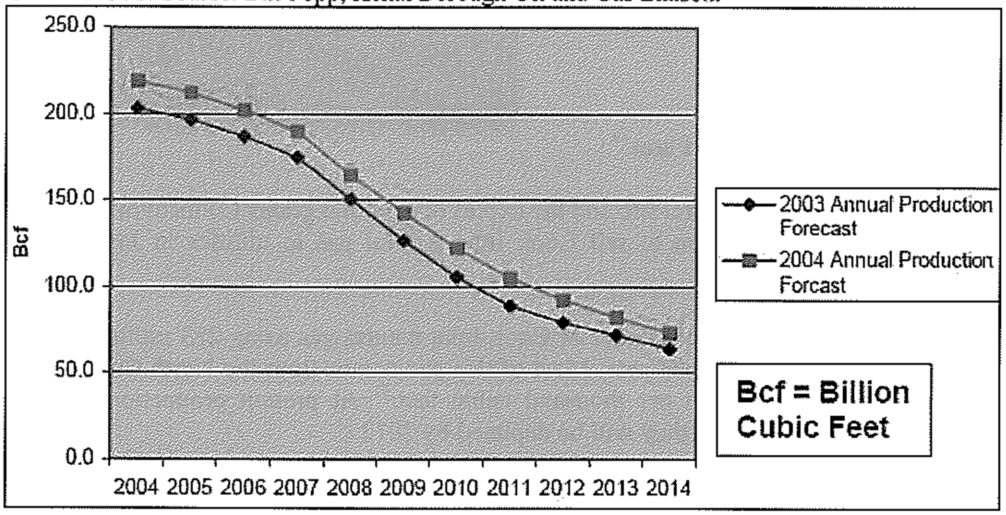
Figure B2 - Cook Inlet Historic and Project Natural Gas Production



Source: Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report.

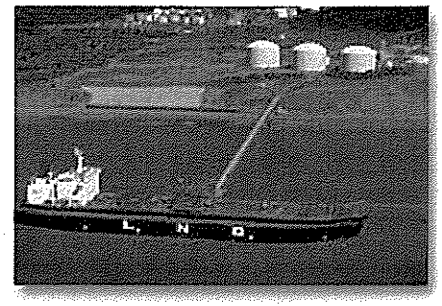
The Alaska Division of Oil and Gas (DOG) makes regular forecast of natural gas production from Cook Inlet. It is interesting to compare the annual production forecasts by DOG for 2003 and 2004. Although DOG was able to prove larger reserves in 2004, the annual production trend remains the same with a sharp downward trend. Figure B-3 illustrates this trend:

Figure B-3: Annual Production Forecast for Cook Inlet Natural Gas by Alaska Division of Oil and Gas. Source: Bill Popp, Kenai Borough Oil and Gas Liaison.[57]



MAP B – KENAI LIQUEFIED NATURAL GAS (LNG) PLANT

When it was first operational in 1969, the Kenai LNG plant was the world's largest LNG project. After almost 40 years of operation and several enlargements, it is presently one of the smallest operational LNG facilities producing about 1.7 million tons of LNG annually.[58]



Kenai LNG Plant[59]

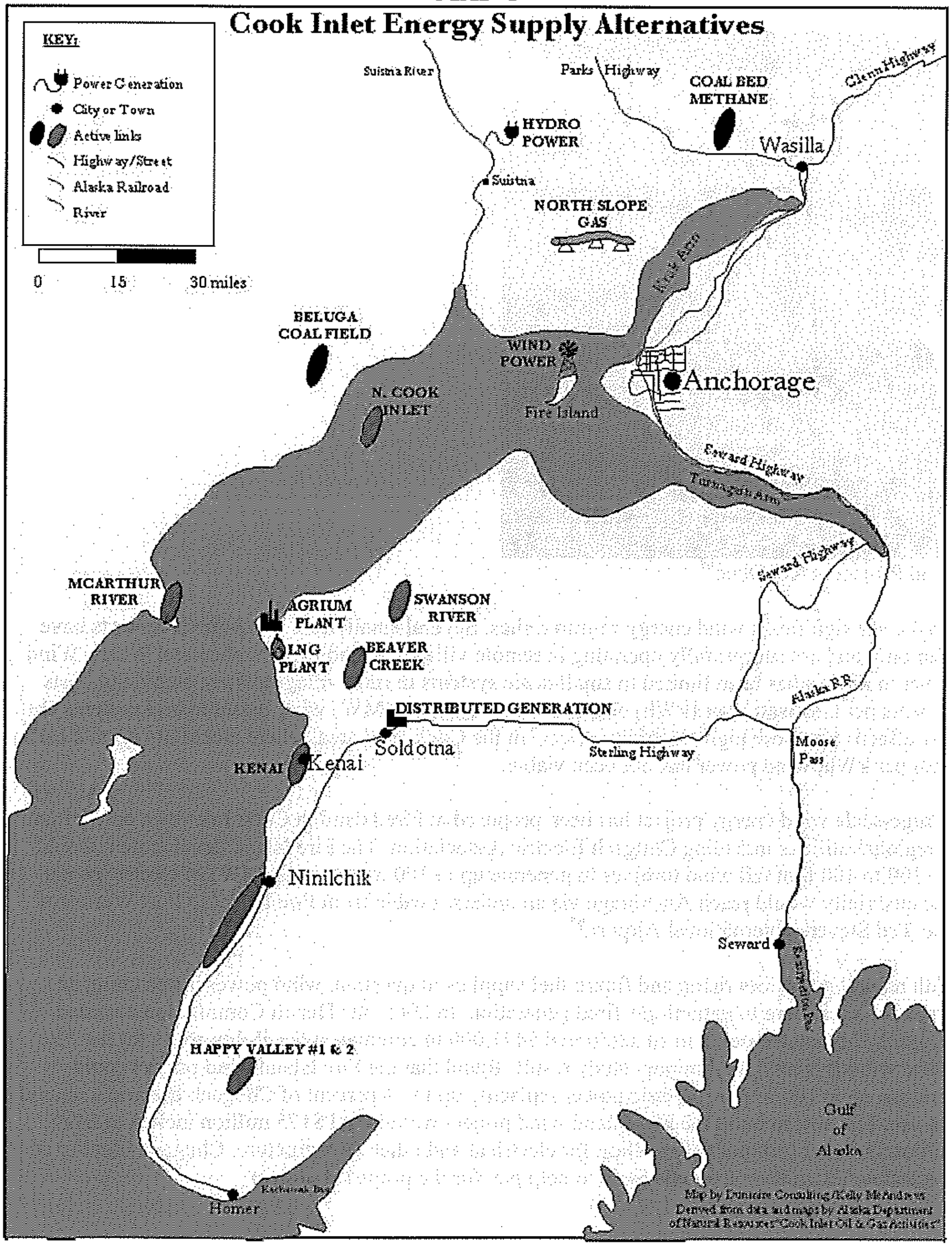
The plant is nearing the end of its useful life and the export license that grants ConocoPhillips and Marathon Oil Corporation permission to sell Cook Inlet natural gas to utilities in Japan will expire in 2009.[60]

The Kenai LNG plant is the largest consumer of Cook Inlet natural gas using 213 million cubic feet per day or 78 billion cubic feet per year. Most of this gas comes from the North Cook Inlet and Kenai fields at a cost of $1.50 per thousand cubic feet.[61] At present production levels, forecasts for these reserves show that they will be depleted by 2012.

In addition to exporting LNG to Japan, the Kenai facility also provides natural gas to the Fairbanks area. The LNG is transported by truck from Kenai to Fairbanks where it is stored until needed by Fairbanks Natural Gas (FNG) customers. At this time, the stored liquid is converted back to natural gas and delivered by pipeline to homes and businesses.[62]

No future plans for the Kenai LNG facility have been announced, however, several options for the facility have been analyzed including: updating and expanding the plant to handle larger volumes of North Slope gas, adding a regasification facility to use this plant to import LNG to Cook Inlet, and using the LNG facility as a storage facility that can provide gas during peak demand.[63]

MAP C


Cook Inlet Energy Supply Alternatives
KEY:
Power Generation
City or Town
Active links
Highway/Street
Alaska Railroad
River
0
15
30 miles
Susitna River
Parks Highway
COAL BED METHANE
Glenn Highway
HYDRO POWER
Wasilla
Susitna
NORTH SLOPE GAS
Knik Arm
BELUGA COAL FIELD
WIND POWER
Anchorage
N. COOK INLET
Fire Island
Seward Highway
Turnagain Arm
Seward Highway
MCARTHUR RIVER
AGRIUM PLANT
SWANSON RIVER
LNG PLANT
BEAVER CREEK
Alaska RR
DISTRIBUTED GENERATION
Soldotna
Sterling Highway
Moose Pass
KENAI
Kenai
Ninilchik
Seward
HAPPY VALLEY #1 & 2
Gulf of Alaska
Homer

MAP C - WIND POWER

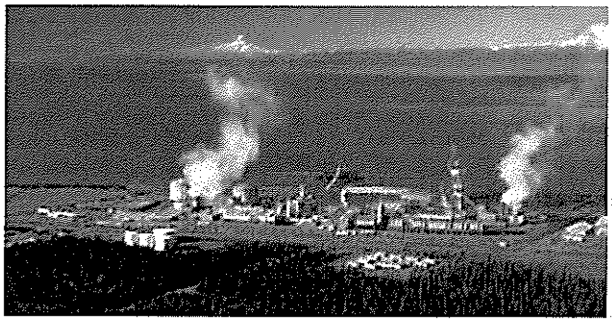
Wind Project at Kotzebue[64]

Alaska has significant wind energy resource sites. Several small-scale wind-diesel projects have been built and are successfully operating in remote villages including Kotzebue and Wales. Wind power in Alaska has been limited to small-scale systems in rural villages where electricity costs 25 cents per kilo-watt hour (kWh) or more. Small-scale (<1 MW) wind-diesel hybrid systems are cost-effective at these high electricity prices. In the Cook Inlet area, where electricity costs 8 to10 cents per kWh, wind power has not been viable.

A large-scale wind energy project has been proposed at Fire Island in Cook Inlet by a consortium of regional utilities including Chugach Electric Association. The Fire Island development would use 300 to 400 foot tall wind turbines to generate up to 100 mega-watts (MW) of electric power. The electricity would reach Anchorage via an undersea cable from Fire Island to Port Woronzof near Ted Stevens International Airport.[65]

With natural gas prices rising and future fuel supplies in question, wind power is becoming an attractive alternative to natural-gas fired generation. In 2005, the Denali Commission awarded Chugach Electric Association an additional $471,000 to complete a feasibility study for the Fire Island wind project.[66] Preliminary study results found that the Fire Island wind project could generate up to 100 MW of electric power replacing up to 14 percent of Chugach Electric's natural gas use. The cost to build the Fire Island wind project would total $175 million including $135 million for wind turbines, $40 million for electrical and other infrastructure. Chugach Electric is requesting $20 million from the State to help pay for the proposed project.

MAP C -AGRIUM PLANT



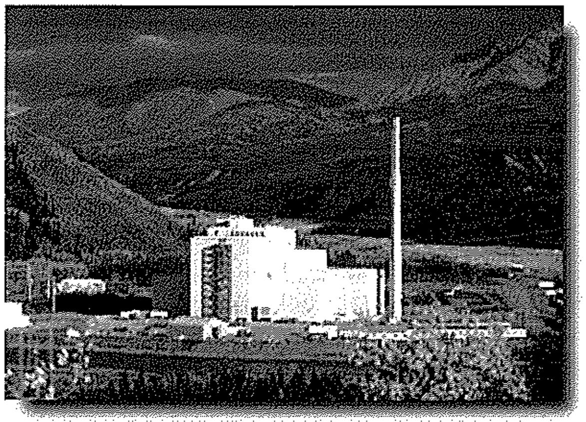
The second largest consumer of Cook Inlet natural gas is the anhydrous ammonia and urea manufacturing facility owned by Agrium, Inc. This facility which began production in 1968 consists of two ammonia plants and two urea plants. At full operation, facility can produce about 1.4 million tons of product and consume 54 billion cubic feet (Bcf) per year of Cook Inlet gas. However, gas delivery constraints and rising costs have limited production at the plant. In 2004, the plant was operating at half capacity and annual consumption was only 25 Bcf.[67]

The great majority of anhydrous ammonia and urea produced at the Agrium facility is exported to Asia.[68] Agrium is constrained on the price it can pay for natural gas because its product prices are set by world markets. The plant has stayed competitive because its major feedstock is Cook Inlet natural gas. Most of the gas for the plant comes from the McArthur River field at a cost of about $1.20 per thousand cubic feet.[69] Agrium's contracts for low cost gas expired in 2005 and the plant was scheduled to be shutdown in November 2005. Alaska's governor convened a Task Force to find options to keep the plant and its 180 high paying jobs operating. In July 2005, Agrium announced that it had secured a gas contract that would keep the plant operational through November 2006. While the details of the contract were not released, Agrium had made an offer of $3.00 per thousand cubic feet with potential for higher prices paid if higher fertilizer prices supported it.[70]

Construction of a new coal gasification facility that would supply the Agrium fertilizer plant in Nikiski with feedstock for its ammonium hydroxide and urea processes and generate 350 mega-watts (MW) of electric power. The project proposed by Agrium, Inc is called Blue Sky[71]. The coal gasification facility would be located at the existing Agrium facility and use coal from the existing Usibelli coal mine in Healy or from the proposed Beluga coal mine across Cook Inlet from Nikiski.

Coal gasification produces hydrogen and carbon monoxide from the high temperature combination of coal and oxygen. The hydrogen and carbon monoxide are further processed to become the feedstock for Agrium's anhydrous ammonia and urea production lines. Other by-products such as carbon dioxide could be used for enhanced oil and gas recovery. This process also has the potential to generate up to 350 MW of electric power. The facility will use 100 MW and the remainder could be sold into the Railbelt grid or provide power to the proposed Pebble Mine on the west side of Cook Inlet near Iliamna.

MAP C - BELUGA COAL FIELD



Healy Clean Coal Project[72]

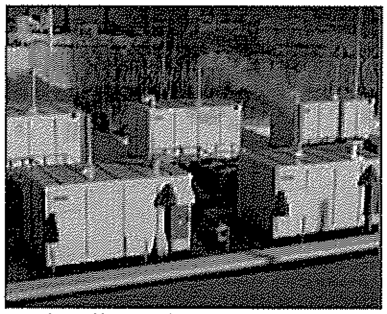
Alaska has abundant coal resources. In south central Alaska, there is a coal mine near Healy operated by the Usibelli family company and a new coal mine proposed at the Beluga coal field.

Coal power in Alaska has had very limited success. The Healy Clean Coal Project located near the Usibelli coal mine, was completed in 1998 at a cost of $297 million. Most of this funding came from federal grants and AIDEA/State bonds. This plant is a mine mouth plant, 50 MW in size. The Healy Clean Coal Project has been shutdown since testing was completed in 1999.[73]

The Healy plant recently made headlines as an on-going dispute between the owner Alaska Industrial Development and Export Authority (AIDEA) and the operator Golden Valley Electric Association (GVEA) went to State court. AIDEA is suing GVEA for damages related to non-operation of the plant. The entire dispute relates back to the demonstration testing completed from January 1988 through December 1999. GVEA claims the test results showed that the plant could not be operated safely or reliably. AIDEA claims that with relatively modest investment this plant could be operational. The recent Energy Policy Act includes an $80 million loan for refurbishment of the Healy Clean Coal Project.

The lack of transport infrastructure as well as coal characteristics make mine mouth plants the most feasible arrangement for Alaska. Presently, the only infrastructure suitable for coal transport is the Alaska Railroad and a barge loading facility in Seward which is used to export Usibelli coal to Korea. The coal at the Usibelli mine and at the Beluga coal field have a high moisture content meaning that for every four tons of coal shipped, one ton is water.[74] The Usibelli coal mine near Healy has the added challenge for mine mouth plants of being 15 miles from Denali National Park. The means that the power plant must meet the most stringent air quality standards to protect air quality in the national park, adding extra cost for air pollution control. Placing a mine mouth plant near the proposed Beluga coal field has similar issues as it is located near Lake Clark National Park and Preserve.

MAP C - DISTRIBUTED GENERATION



Fuel Cell Installation at USPS Office in Anchorage[75]

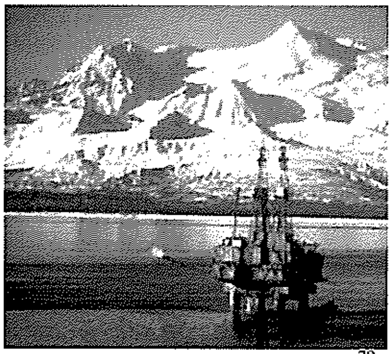
Providing electric power in a place as remote and sparsely populated as Alaska can be expensive and difficult. Distributed generation or generating power at the end-user's location can be a cost-effective strategy for meeting Alaska's relatively small and dispersed loads. Some analysts would consider the majority of Alaska's generation distributed because a good share of electricity in some communities (Valdez, Homer) is co-generated at industrial facilities. While there are a variety of reasons for using distributed generation, the major ones are to avoid large electric power transmission costs from a central facility to remote load or to improve or expand electric service in a region distant from centralized power stations.

Alaska is a leader in operating and testing fuel cell systems. Fuel cells produce electricity through an electrochemical reaction using hydrogen rather than using fuel combustion and a generator set. Fuel cells are relatively compact and self-contained requiring little maintenance or fuel delivery so they are an ideal technology for distributed generation. University of Alaska Fairbanks has become a leader in fuel cell technology testing because of the relatively large number fuel cells in use in the State.[76] One of largest fuel cell projects was operated by Chugach Electric at the US Postal Service facility at Ted Stevens International Airport and the one of the first fuel cells to use propane as a hydrogen source is operating at Exit Glacier Visitor Center in Kenai Fjords National Park near Seward.

Chugach Electric Association and the US Postal Service (USPS) worked together to create a deal the provided the USPS office located at Ted Stevens International Airport with 5.5 years of premium electric service and free heat using fuel cells. Chugach Electric received $1million in prepayment for the electricity and funding from other partners to cover the cost of 6 fuels cells (200 kilo-watts kW each) and an experimental control system that enabled grid connection. The project was 1 MW in size and used natural gas as a methane source. Total cost for the project was $5.5 million.[77] The project proved to be successful, however, it was not profitable for Chugach Electric to operate the fuel cells and they were removed in August 2004.[78]

The 5 kW fuel cell operating at Exit Glacier was installed in August 2003. Unfortunately, this first unit was damaged during shipment and had to be replaced. The new unit was installed in 2004 and has been operating successfully since then.

MAP C -INCREASING GAS PRODUCTION IN COOK INLET



Offshore Platform in Cook Inlet[79]

Natural gas production from Cook Inlet fields can be increased by:

A. Developing new production from discoveries in new fields or in different formations at existing fields.
B. Increasing production from existing fields by implementing enhanced recovery technologies.
C. Developing Coal Bed Methane (CBM) resources.

Alternative A: Develop New Production

The potential for natural gas production in Cook Inlet is vast and uncertain. Gas was discovered during oil exploration in the 1950s and 1960s. According to the US Department of Energy (DOE) in a recent report on gas reserves in South central Alaska, 95 percent of Cook Inlet gas produced today was discovered before 1970 during oil exploration. Currently, Cook Inlet Basin is considered to be "lightly explored". In fact, it was the late 1990's before the first exploration specifically for natural gas occurred.

Total gas-in-place or the amount of natural gas actually located inside Cook Inlet Basin has been estimated by a variety of experts from the federal government and petroleum industry. The latest estimate done by the US Department of Energy found that total natural gas-in-place in Cook Inlet to be about 17 trillion cubic feet. They estimated that about half of that gas could be recovered from Cook Inlet gas fields (8.5 trillion cubic feet about the same amount that has been extracted from Cook Inlet over the past 30 years).[80]. Some of these anticipated discoveries have been made and are producing gas:

- Aurora Gas, LLC made some significant discoveries on the west side of Cook Inlet in 2005. Aurora's general approach is to rework existing well originally drilled for oil production.[81] Production at Three Mile Creek field started in August at a rate of 4 million cubic feet per day. Wells in Aurora's Moquawkie field are producing about 5.5 million cubic feet per day. In the Lone Creek field, Aurora has drilled some highly productive gas wells with production levels in the range of 15 to 20 million cubic feet per day.

- Marathon Oil Corporation, the largest gas producer in Cook Inlet expanded its production in Cook Inlet with three newly discovered fields: Cannery Loop, Ninilchik, and Kasilof. All three fields are located on the west side of the Kenai Peninsula. Cannery Loop has the distinction of being the only gas field discovered while searching specifically for natural gas. Between 1988 and 2003, the Cannery Loop unit produced over 110 billion cubic feet.[82] At Ninilchik field, discovered in 2002, Marathon is producing about 40 million cubic feet per day from eight wells. Marathon's newest discovery at Kasilof, involved drilling a 17,000-foot extended reach well from on-shore. Marathon has plans to drill up to a dozen new wells in these fields during 2006.[83]

Alternative B: Enhance existing production
New technology is enabling producers to revive existing fields whose production has dropped off because of depletion or other problems. Just as in oil production, gas producers rely on gas pressure to move the product from underground to the surface. As they remove gas from the field, the pressure in the formation drops and production of gas (or oil) is reduced. Additionally, application of better geologic data gathering techniques, such as three-dimensional seismic technology, is improving the understanding of Cook Inlet's geology and allowing producers to more efficiently explore or expand existing fields.

In the West Fork field, Marathon applied 3D seismic technology "to breathe new life into an older field. West Fork is a good example of the kind of drilling that is necessary to assess and fully realize the resource potential of South central Alaska." John Barnes, Alaska Unit Leader for Marathon Oil Corp.[84] West Fork field produced gas from 1978 through the early 1990's. Marathon used 3D seismic technology to support deeper drilling in a field extension at West Fork and found gas flowing at rates up to 6 million cubic feet per day in 2005.

Marathon implemented a proprietary technology to revive production levels at some of its large Cook Inlet fields including Kenai. Historically, Kenai field was one of the top producing fields in Cook Inlet. When production levels began declining in the late 1990's, Marathon developed two new zones at Kenai using a new completion technology called "EXCAPE". "The result is that the field is still producing at high levels, and there is potential for even more development in the field" according to John Barnes.[85]

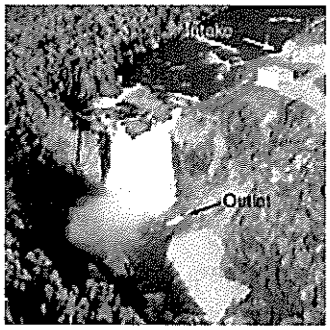
Reworking existing fields can be much less expensive than new development because producers can use existing infrastructure such a roads, drilling pads and pipelines. Also, producers can usually avoid the additional expense and paperwork related to gaining permission and compliance for accessing undeveloped land. Land access is becoming a major barrier to Cook Inlet oil and gas development because much of it is occurring on the west side of the Kenai Peninsula and can be in conflict with community and wildlife land uses.

Coal Bed Methane Development
In addition to oil and gas reserves, Cook Inlet holds significant coal reserves. Methane gas (the major component of natural gas) can be trapped inside the pores of the coal and is recovered by relieving the pressure in the coal seams. Usually this is done by drilling into the coal formation, fracturing the rock, and pumping out the water in the formation. After the well is "de-watered", the methane gas migrates out of the coal and up to the surface.

Estimates of producible coal bed methane reserves in Cook Inlet range from 7 to 12 trillion cubic feet.[86] The first exploratory well for coal bed methane was drilled in the Susitna Basin in 1998. Since then several companies have drilled a half dozen test wells. No commercial gas production has been announced from these efforts.

Community opposition to coal bed methane exploration in the Mat-Su valley led to a State moratorium on shallow gas leasing. Local residents, especially land owners that do not control the subsurface mineral rights, are concerned that coal bed methane development will damage their property and the surrounding areas. In December 2004, the State adopted standards for shallow gas development based on land owner comments.[87] These standards establish setbacks from residences, noise limits, disclosure of fracturing materials, negotiating surface use agreements, pipeline design, public access, removal of facilities, and rehabilitation of impacted lands.

MAP C – HYDRO POWER



Tazimina Hydro Project

Alaska holds the one-third of undeveloped hydro power sites in the US.[88] Although, Alaska has made significant investment in hydropower and now has more than 50 hydro projects supplying about 14 percent of the State's electricity, there is potential for much more hydropower.

Most of the existing hydropower projects in Alaska are less than 10 megawatts (MW) in size. The majority of these projects are located in Southeast serving isolated towns and villages that are not connected to outside electric grid. Most of these projects would be classified as run-of-river, built without dams. Some projects may include diversion works to channel the water through the turbines, but the water returns to the river. Large-scale dams and hydropower projects such as the cancelled Susitna Hydro project (1600 MW) are unlikely to be built in Cook Inlet even with natural gas shortages because of environmental issues and financing difficulties.

Hydropower in Alaska faces several challenges including matching the generator for a potential hydropower site to the electric load and infrastructure that it will serve. Sufficient electric loads must be served by the hydro project or it will not be cost-effective. For example, the Tazimina River Hydroelectric Plant located on the Alaska Peninsula has the potential to produce 6 million kilo-watt (kWh) per year. The plant is currently producing 2.6 million kWh per year on average because there is insufficient transmission infrastructure to send the electricity to other villages or industrial loads.[89]

Another challenge for hydropower in Alaska is the seasonable variability of stream flow and salmon runs that affect the availability of hydropower. During winter freeze up, hydropower is not available to meet electric demand. Hydro project design must consider harsh environmental conditions and may have to be removable to accommodate spawning salmon or other wildlife needs.

MAP C -LNG PLANT

Kenai LNG Plant[90]

The Kenai LNG plant is the largest consumer of Cook Inlet natural gas using 213 million cubic feet per day or 78 billion cubic feet per year. Most of this gas comes from the North Cook Inlet and Kenai fields at a cost of $1.50 per thousand cubic feet.[91] At present production levels, forecasts for these reserves show that they will be depleted by 2012.

In 1969, the Kenai LNG plant was the world's largest LNG project. After almost 40 years of operation and several enlargements, it is presently one of the smallest operational LNG facilities producing about 1.7 million tons of LNG annually.[92] The plant is nearing the end of its useful life and the export license that grants ConocoPhillips and Marathon Oil Corporation permission to sell Cook Inlet natural gas to utilities in Japan will expire in 2009.[93]

In addition to exporting LNG to Japan, the Kenai facility also provides natural gas to the Fairbanks area. The LNG is transported by truck from Kenai to Fairbanks where it is stored until needed by Fairbanks Natural Gas (FNG) customers. At this time, the stored liquid is converted back to natural gas and delivered by pipeline to homes and businesses

One option for bringing natural gas to Cook Inlet would be to convert this existing facility into a Receiving and Regasification Terminal. The terminal would be sized to receive and store LNG imported from world markets and provide up to 200 million cubic feet per day to the Cook Inlet natural gas pipeline system for delivery to homes and businesses during peak winter demand. Estimated annual energy service is 73 billion cubic feet (Bcf) for an investment of $62.5 million.[94]

MAP C -NORTH SLOPE GAS

There are three alternatives for delivering North Slope gas to Cook Inlet:

1. Spur Line
2. Bullet Line
3. Enriched Gas Line.

SPUR LINE

Deliver North Slope gas to Cook Inlet with a Spur Line.

Build a 24" diameter 143 mile pipeline from Glennallen to Palmer to flow 400 to 600 million cubic feet per day (MMCFD) of gas. [iii] This would be a spur line from a main gas pipeline delivering North Slope gas to the lower 48. There are two alternative possibilities for the main line: (a) an All Alaskan line[95] to an LNG plant at Anderson Bay (near Valdez), or (b) a line from the North Slope to Delta Junction and across Canada to existing pipelines in Alberta or to the lower 48. A spur line based on the Canadian main line would require an additional link between Delta Junction and Glennallen.[96] Total flow on the main line would be between 2 and 6 billion cubic feet per day (BCFD).

The success of the spur line depends on whether or not a main line for North Slope gas is constructed. In turn, this depends on the resolution of two huge opposing forces: availability of vast North Slope gas reserves, and the massive capital cost required for construction of either an All Alaskan project or a project across Canada. The anticipated price of gas in the lower 48 will determine whether the capital cost can be justified. In October 2004 the U.S. Congress passed the Alaska Gas Pipeline Act which offers loan guarantees for 80% of the cost of a pipeline up to $18 billon, which reduces the risk to investors.[120]

The required rate of return for the project may be lowered by means of a public entity such as ANGDA, which may be entitled to issue tax-free debt instruments. This may make it easier to raise the huge amount of capital required.

Besides the financing hurdle, either of the main line projects will require approval by the U.S. Federal Energy Regulatory Commission, or the Canadian project will require approval from the Canadian National Energy Board.[97] So approval of the Canadian project depends on substantial international cooperation.[119]

BULLET LINE

Deliver North Slope gas to Cook Inlet with Bullet Line.

Build a 30" pipeline from the North Slope to Nikiski flowing 1 billion cubic feet per day. The line would follow the TAPS from Prudhoe Bay to pump station 7. There are two possible routes[118] south from pump station 7: either via Glennallen to Palmer (600 miles), or via the Susitna valley (509 miles).

There is uncertainty about whether a mainline gas project via Canada or Anderson Bay will occur. The bullet line is an alternative method for delivering North Slope gas to Cook Inlet, which does not rely on either of these projects.

[iii] It is also possible to build a spur line from Fairbanks along the Parks highway to connect with Enstar's Mat-Su system. See "Gas Spur Line – Parks or Glenn?" 23 Nov. 2005 Mary Odden, Copper Valley Bi-Weekly

The price of delivered gas would be high if based solely on demand in Cook Inlet. New industrial demand for gas in Cook Inlet, perhaps for additional LNG exports, will result in lower prices due to economies of scale in the pipeline.

ENRICHED GAS LINE

Enriched gas small pipeline (EGSP) to Nikiski.

Build 1 billion cubic feet per day 24" diameter "dense phase" pipeline from Prudhoe to Nikiski that uses methane as a carrier for other hydrocarbons: ethane, propane, butane and heavier. The other hydrocarbons are extracted at Nikiski. About 45,000 bpd of LPG is available for use in coastal communities and export; ethane and butane+ are used as a feedstock at Nikiski; methane is available for use in Cook Inlet. LPG exports subsidize the cost of methane delivered to Cook Inlet.

The enriched gas small pipeline is an alternative to the bullet line. Like the bullet line, it is an alternative to either of the mainline proposals. However, it has a smaller diameter than the bullet line (24" instead of 30"), and the 1 BCFD flow will include 45,000 barrels of propane. The pipeline will operate at a relatively high pressure of 2500 psi, which enables the smaller diameter and ensures that liquid (propane/butane) will not separate out from the gas. Export of LPG will subsidize the cost of gas delivered to Cook Inlet.

APPENDIX C
EVALUATION RESULTS

Supply Alternative: Increase Production
Supply Alternative: Spur Line
Supply Alternative: Bullet Line
Supply Alternative: Enriched Gas Line
Supply Alternative: Coal Bed Methane (CBM)
Supply Alternative: Import LNG
Supply Alternative: Other Alaska Gas
Supply Alternative: Coal Gasification
Demand Alternative: Coal Power
Demand Alternative: Hydro Power
Demand Alternative: Wind Power
Demand Alternative: Nuclear Power
Demand Alternative: Tidal Power
Demand Alternative: Gas Conservation
Demand Alternative: Electric Conservation
Demand Alternative: Distributed Generation

Supply Alternative: INCREASE PRODUCTION

Increase conventional natural gas production in Cook Inlet.

Natural gas production from Cook Inlet fields can be increased by:

D. Developing new production from discoveries in new fields or in different formations at existing fields.
E. Increasing production from existing fields by implementing enhanced recovery technologies.

Some of the policies and actions that could be used to encourage new or enhanced production in Cook Inlet include:

1. Increased potential revenues to producers with:
    a. Higher gas prices – Enstar has led this effort by entering into new contracts with its suppliers that tie prices paid for Cook Inlet gas to Lower 48 prices. This price link is designed to make Cook Inlet as attractive for exploration and production investment as other places in the U.S.
    b. Demand pricing – Seasonal pricing or price based on volume delivered would better link peak demand and production. Premium pricing for peak volumes would enable producers to gain the resources needed to improve production and infrastructure to meet peak demand.
    c. Reduced royalties/taxes on gas production – Concessions by the State of Alaska and other landowners that reduce payments by the producers to governments increase net revenues.
2. Facilitate access to markets:
    a. One of the complaints by smaller, independent producers in Cook Inlet is that all of the gas produced is sold through long term contracts. There is no "spot market" or short term contract sales. Recently, these producers protested a new contract between Enstar and Marathon for long term gas sales and requested that they be allowed to supply 10% of the gas volume.[98]
3. Reduce regulatory barriers – in addition to price and market barriers, regulatory barriers have limited gas production in Cook Inlet. Producers have noted the following regulatory barriers:
    a. Permitting requirements: paperwork and reporting can be excessive. John Barnes, of Marathon Oil Corporation found that the between 40 and 60 permits, permissions, plans, and reports are required to drill on various Cook Inlet lands.[99] Alaska Division of Oil and Gas has created a new leasing system that is designed reduce paperwork and license costs.[100]
    b. Land access – Oil and gas reserves in Cook Inlet are underneath State, federal, Native, and privately owned lands. Access to these lands can be blocked or limited by surface owner stipulations.
    c. Environmental regulations – Producers in Cook Inlet have not been required to meet zero discharge wastewater regulations like producers in the rest of the US. US EPA is reviewing current practices and emissions in Cook Inlet and may change this exception.
4. Develop Infrastructure - One of the largest barriers to development in Cook Inlet is its remote location and lack of roads, landings, or pipelines that facilitate drilling and production.
    a. Pipeline access – there is a limited network of gas pipelines around and across Cook Inlet. Access to these privately owned pipelines has been under negotiation and review by Alaska's regulatory agencies. Recent resolution of a dispute over access to the Cook Inlet Gas Gathering System (CIGGS) which crosses Cook

Inlet will help alleviate this problem in the short term. Long term access and tariffs have yet to be negotiated.

b. Roads and other transportation infrastructure – Most of the new oil and gas fields in Cook Inlet can only be accessed by boat or airplane. Existing fields on the Kenai Peninsula have a limited road network, but swampy conditions throughout the region make transportation difficult and expensive.
c. Offshore exploration in Cook Inlet is hindered by the lack of a "jack-up rig" in the region.

BACKGROUND

The potential of increasing natural gas production in Cook Inlet in amounts required to meet forecasted demand hinges on two major uncertainties:

- Is there recoverable gas in the amounts needed?
- What incentive is needed to encourage exploration and production of this potential gas resource?

Based on existing gas production in Cook Inlet basin, there is a fair understanding of the costs and difficulties of locating, developing, and producing natural gas there. What is unknown is whether the extensive reserves needed to meet future demand exist and if they can be developed at costs that will be competitive with other options.

The only recent comprehensive study on the Cook Inlet Basin, "South Central Alaska Natural Gas Study" by DOE's Arctic Energy Office speculates that Cook Inlet basin holds somewhere between 13 and 17 trillion cubic feet (TCF) of natural gas.[101] They estimate that half of this gas (8.5 TCF) could be developed at an investment of $5 to $6 billion over the next 20 years. Recent discoveries in Cook Inlet support their findings but investment in exploration and development is not occurring at the rate expected to locate and develop large fields.

How much natural gas is left Cook Inlet Basin?

The most recent estimates of the amount of natural gas left in Cook Inlet are in the range of 2 trillion cubic feet. The Alaska Division of Oil and Gas (DOG) who makes annual estimates of remaining "proven reserves" found that there is 2.087 trillion cubic feet of natural gas in proven reserves in Cook Inlet as of January 1, 2004. This total estimate is higher than the previous year even though there was about 0.200 trillion cubic feet of gas produced during 2003. DOG included "reserve additions" because it was able to prove more reserves in Cook Inlet in 2003 with better geological data and analysis techniques.

Alternative A: Develop New Production

The potential for natural gas production in Cook Inlet is vast and uncertain. Gas was discovered during oil exploration in the 1950s and 1960s. According to the US Department of Energy (DOE) in a recent report on gas reserves in South-central Alaska, 95 percent of the gas produced in Cook Inlet today was discovered before 1970 during oil exploration. Currently, Cook Inlet Basin is considered to be "lightly explored". In fact, it was the late 1990's before the first exploration specifically for natural gas occurred.

The majority of Cook Inlet's proven gas reserves are classified by geologists as non-associated biogenic gas that has no genetic relationship to the origin and distribution of oil. "Therefore, it is not realistic to conclude that exploration based on oil prospects will necessarily lead to a true evaluation of the basin's gas potential."[102] New gas resources in Cook Inlet are likely to come from biogenic gas in stratigraphic or combination traps Stratigraphic traps typically account for

50% or more of the ultimate production of gas in basins elsewhere. As of 2004, no gas exploration had occurred in stratigraphic traps in Cook Inlet.

The reason that Cook Inlet has been overlooked is because when companies started to find significant oil and gas resources in Cook Inlet, discoveries were also made on the North Slope. By comparison, Cook Inlet was small and isolated, and the attention of most industry players was diverted to North Slope oil. However, state incentives to develop Cook Inlet's "stranded" gas resource encouraged three companies (Marathon, ConocoPhillips, and Unocal/Chevron) to develop Cook Inlet's oil and gas fields. These companies also invested in several industrial facilities that consume or export large quantities of Cook Inlet oil and gas including an oil refinery, liquefied natural gas export facility, and petrochemical plant.

Total gas-in-place or the amount of natural gas actually located inside Cook Inlet Basin has been estimated by a variety of experts from the federal government and petroleum industry. The latest estimate done by the US Department of Energy found that total natural gas-in-place in Cook Inlet to be about 17 trillion cubic feet. They estimated that about half of that gas could be recovered from Cook Inlet gas fields (8.5 trillion cubic feet about the same amount that has been extracted from Cook Inlet over the past 30 years).[103].

Some of these anticipated discoveries have been made and are producing gas:

- Aurora Gas, LLC made some significant discoveries on the west side of Cook Inlet in 2005. Aurora's general approach is to rework existing well originally drilled for oil production. Aurora sells about 10 percent of Cook Inlet's total gas production (average of 550 million cubic feet per day).[104] Production at Three Mile Creek field started in August at a rate of 4 million cubic feet per day. Wells in Aurora's Moquawkie field are producing about 5.5 million cubic feet per day. In the Lone Creek field, Aurora has drilled some highly productive gas wells with production levels in the range of 15 to 20 million cubic feet per day.

- Marathon Oil Corporation, the largest gas producer in Cook Inlet expanded its production in Cook Inlet with three newly discovered fields: Cannery Loop, Ninilchik, and Kasilof. All three fields are located on the west side of the Kenai Peninsula. Cannery Loop has the distinction of being the only gas field discovered while searching specifically for natural gas. Between 1988 and 2003, the Cannery Loop Unit produced over 110 billion cubic feet.[105] At Ninilchik field, discovered in 2002, Marathon is producing about 40 million cubic feet per day from eight wells. Marathon's newest discovery at Kasilof, involved drilling a 17,000-foot extended reach well under the waters of Cook Inlet from shore. Marathon has plans to drill up to a dozen new wells in these fields during 2006.[106]

Alternative B: Enhance existing production

New technology is enabling producers to revive existing fields whose production has dropped off because of depletion or other problems. Just as in oil production, gas producers rely on gas pressure to move the product from to the surface. As they remove gas from the field, the pressure in the formation drops and production of gas (or oil) is reduced. Additionally, application of better geologic data gathering techniques, such as three-dimensional seismic technology, is improving the understanding of Cook Inlet's geology and allowing producers to more efficiently explore or expand existing fields.

In the West Fork field, Marathon applied 3D seismic technology "to breathe new life into an older field. West Fork is a good example of the kind of drilling that is necessary to assess and fully realize the resource potential of South-central Alaska." John Barnes, Alaska Unit Leader for

Marathon Oil Corp.[107] West Fork field produced gas from 1978 through the early 1990's. Marathon used 3D seismic technology to support deeper drilling in a field extension at West Fork and found gas flowing at rates up to 6 million cubic feet per day in 2005.

Marathon implemented a proprietary technology to revive production levels at some of its large Cook Inlet fields including Kenai. Historically, Kenai field was one of the top producing fields in Cook Inlet. When production levels began declining in the late 1990's, Marathon developed two new zones at Kenai using a new completion technology called "EXCAPE". "The result is that the field is still producing at high levels, and there is potential for even more development in the field" according to John Barnes.[108]

Reworking existing fields can be much less expensive than new development because producers can use existing infrastructure such a roads, drilling pads and pipelines. Also, producers can usually avoid the additional expense and paperwork related to gaining permission and compliance for accessing undeveloped land. Land access is becoming a major barrier to Cook Inlet oil and gas development because much of it is occurring on the west side of the Kenai Peninsula and can be in conflict with community and wildlife land uses.

EVALUATION RESULTS

Energy Service

Estimated reserves and existing pipeline infrastructure can support energy service of 300 bcf per day. This infrastructure can also support a peak load of 700 million cubic feet per day, however, new storage capacity is needed to sustain this peak flow for an extended period. We conservatively estimate energy service from new discoveries to be in the range of 100 to 200 billion cubic feet per year from a potential resource of 1.4 trillion cubic feet.

Prerequisites for Success – These include:

- Discovery and development of major new fields.
- Incentives to attractive investment to Cook Inlet Basin including higher gas contract prices, royalty concessions, favorable contract terms, spot market, risk sharing.
- Improved infrastructure and guaranteed pipeline access.

Start-up Date

New gas is coming on-line everyday, however lead-time from leasing, discovery, drilling, production, and transport (gathering and pipeline) can be 3 to 5 years or more for offshore development. Limited drilling and construction season in Cook Inlet extends duration of development timeline.

Investment

This DOE study found that[109]:

- 1.4 trillion cubic feet of gas might be developed through 2025 at a cost of 35 cents per thousand cubic feet for an investment of $500 million which is consistent with the level of energy service that we are estimating.
- 13 to 17 trillion cubic feet of gas has yet to be discovered. If half could be developed, the investment would be in the range of $5 to $6 billion, at a cost from $0.40 to $0.75 per thousand cubic feet. These costs assume primarily on-shore development and would be higher if development is primarily off-shore.

- Additional investment in infrastructure and pipelines will also be needed. Marathon and Unocal/Chevron recently completed a 33-mile pipeline from Kenai to Kachemak for an investment of $25.4 million.[110]

Residential Monthly Bill Impacts

Enstar's residential natural gas rates in 2006 are $6.70 per thousand cubic feet (mcf).[111] Recent contract between Enstar and Marathon for gas delivery through 2015 link gas prices to Henry Hub prices in the Lower 48. The price is determined by a 36 or 12-month lag to these prices. Therefore, we can predict future gas costs for Enstar based on current Henry Hub prices. In late 2005, Henry Hub prices exceeded $15 per mcf, so we can expect residential gas rates to double in the near term, though this contract is currently under review by Alaska State regulators.

Uncertainties

Major uncertainties include:

- The amount of recoverable natural gas in Cook Inlet Basin is very uncertain.
- The cost of discovering, developing, producing, and transporting the gas to market is somewhat uncertain. This is information from existing field development on these costs, however, future costs will depend on where the natural gas is located (onshore or offshore).

Environmental Considerations

Potential unmitigated environmental impacts include:

- Development in relatively pristine areas such as Kenai National Wildlife Refuge and the west side of Cook Inlet.
- Unregulated waste water discharge into Cook Inlet under regulatory exception.
- Off-shore development – Spill risks, marine traffic disruption, viewshed interruption, and dismantlement, removal, and remediation of offshore platforms at the end of their useful life.

Impacts on Alaskans

Potential impacts on Alaskan include:

- Government revenues from Cook Inlet production (prevailing value - $2.82 per mcf). Property tax and other revenues to state and local government. Oil and gas industry largest source of revenue for Kenai Borough.
- Employment – Oil and gas industry brings local high paying jobs to Kenai Peninsula. Industrial jobs at LNG and Agrium plant are also high paying.
- Low cost natural gas from Cook Inlet has stimulated economic development throughout Kenai Peninsula and Anchorage. Future development and continued production from existing industrial facilities unlikely without low cost natural gas.

Supply Alternative: SPUR LINE

Deliver North Slope gas to Cook Inlet with a Spur Line.

Build a 24" diameter 143 mile pipeline from Glennallen to Palmer to flow 400 to 600 million cubic feet per day (MMCFD) of gas[iv] This would be a spur line from a main gas pipeline delivering North Slope gas to the lower 48. There are two alternative possibilities for the main line: (a) an All Alaskan line[112] to an LNG plant at Anderson Bay (near Valdez), or (b) a line from the North Slope to Delta Junction and across Canada to existing pipelines in Alberta or to the lower 48. A spur line based on the Canadian main line would require an additional link between Delta Junction and Glennallen.[113] Total flow on the main line would be between 2 and 6 billion cubic feet per day (BCFD).

BACKGROUND

The success of the spur line depends on whether or not a main line for North Slope gas is constructed. In turn, this depends on the resolution of two opposing forces: availability of vast North Slope gas reserves, and the massive capital cost required for construction of either an All Alaskan project or a project across Canada (Highway Project). The anticipated price of gas in the Lower 48 will determine whether the capital cost can be justified. In October 2004 the U.S. Congress passed the Alaska Gas Pipeline Act which offers loan guarantees for 80% of the cost of a pipeline up to $18 billon, which reduces the risk to investors.[114]

The required rate of return for the project may be lowered by means of a public entity such as ANGDA, which may be entitled to issue tax-free debt instruments. This may make it easier to raise the large amount of capital required.

Besides the financing hurdle, either of the main line projects will require approval by the U.S. Federal Energy Regulatory Commission, and the Canadian project will require approval from the Canadian National Energy Board.[115] Approval of the Canadian project depends on substantial international cooperation.[116]

EVALUATION RESULTS

Energy Service

The spur line would flow about an annual average of about 500 MMCFD for at least 20 years.[117] Flow rates would be higher during the winter and lower in the summer. This fluctuation would require coordination with other shippers on the main line, since increased flows to Cook Inlet would reduce the availability of gas for other customers. This would amount to between 145 and 220 billion cubic feet per year.

Prerequisite for Success

A North Slope gas main line must be built for this alternative to succeed. Without a main line, the Spur Line does not have a source of gas. The construction cost for the All Alaskan main line and associated LNG facilities has been estimated as $12.7 billion ($2004). [118] Construction cost estimates for the Canadian routed pipeline range from[119] $20 billion ($2001) to $24 billion ($2005) [120] The actual construction costs, accounting for inflation and interest accrued during construction may be twice as large.

[iv] It is also possible to build a spur line from Fairbanks along the Parks highway to connect with Enstar's Mat-Su system. See "Gas Spur Line – Parks or Glenn?" 23 Nov. 2005 Mary Odden, Copper Valley Bi-Weekly

Start-up Date

The main line projects could begin to flow gas in 2012 to 2016.[121] It might be possible to initiate gas flow through the Spur Line before completion of a main line project.

Investment

Capital cost estimates for the Spur Line from Glennallen to Palmer range from $0.3 billion to $0.5 billion ($2005)[122] A Spur Line for the Canadian main line would require an additional link from Delta Junction to Glennallen at an estimated cost of $0.4 billion ($2005).[123]

Residential Monthly Bill Impacts

The impact on the monthly bill of Cook Inlet customers will be relatively low. Any North Slope gas that is delivered to the Lower 48 (or other markets) must compete with other gas. So the netback value of gas in Alaska will be bounded above by the price of other gas supplies in the Lower 48 minus the cost of transportation from Alaska.

Uncertainties

There is substantial uncertainty about whether a main line will be built, because of the huge capital cost. The motivation for a main line is the huge amount of proven gas reserves on the North Slope, namely 35 trillion cubic feet (TCF).[124] However, a consortium of producers and pipeline companies walked away from a similar project in the early 1980's (after spending about $600 million) due to the uncertainty about project economics. Similarly, in 2002 the North Slope producers decided that a 4.5 BCFD pipeline project was uneconomical.[125]

Environmental Considerations

The main line and Spur Line will require rights of way, some of which parallel the Trans Alaska Pipeline System. The pipeline right-of-way could create a travel corridor giving people access to remote area previously undisturbed. This could have positive and negative impacts – locals may consider a new travel corridor a benefit while people who want to preserve remote, and pristine areas may consider increased access a detriment. There is some risk of accidents due to leaks from the pipelines and/or LNG plant and tankers

Impacts on Alaskans

Gas from the Spur Line would replace dwindling supplies of gas in the Cook Inlet. In addition, the State would benefit from employment associated with construction and operation of the main line and Spur Line, and could realize revenue from severance tax, property tax and income tax associated with the flow of North Slope gas.

Supply Alternative: BULLET LINE

Deliver North Slope gas to Cook Inlet with Bullet Line.

Build a 30" pipeline from the North Slope to Nikiski flowing 1 billion cubic feet per day. The line would follow the TAPS from Prudhoe Bay to Pump Station 7. There are two possible routes south from Pump Station 7: either via Glennallen to Palmer (600 miles), or via the Susitna valley (509 miles). [126]

BACKGROUND

There is uncertainty about whether a main line gas project via Canada or Anderson Bay will occur. The Bullet Line is an alternative method for delivering North Slope gas to Cook Inlet, which does not rely on either of these projects.

The price of delivered gas would be high if based solely on demand in Cook Inlet. New industrial demand for gas in Cook Inlet, perhaps for additional LNG exports, will result in lower prices due to economies of scale in the pipeline.

EVALUATION RESULTS

Energy Service

The bullet line would flow 1 BCFD.[127] This corresponds to about 360 billion cubic feet per year.

Prerequisite for Success

Additional industrial use of gas must be developed, since local demand in Cook Inlet is about 0.5 BCFD. The project would not be economical without this additional industrial demand. Financing must be obtained for the Bullet Line, based solely on Cook Inlet gas demand. The project may have to compete for labor and materials with a Canadian Mackenzie Delta pipeline project.

Start-up Date

The pipeline can be operational in the 2012 to 2016 timeframe.[128]

Investment

The estimated capital cost of the Bullet Line is $3 to $4.3 billion ($2004).[129] The actual cost accounting for inflation and interest accrued during construction will be substantially higher.

Residential Monthly Bill Impacts

There could be a medium impact on monthly gas bills. There will only be a limited capacity for export of gas from Cook Inlet, due to the relatively small size of the bullet line compared to a main line project. So the moderating impact of price linkage with external markets will not be as strong. Cook Inlet consumers will have to pay a substantial share of the cost of the Bullet Line.

Uncertainties

There may be cost over-runs and delays in project completion. (The construction cost of the oil pipeline was nine times the original estimate.)

Environmental Considerations

The Bullet Line will require rights of way, some of which parallel the Trans Alaska Pipeline System. The Susitna route crosses the Minto Flats State Game Refuge. Access to Nikiski will be by an undersea crossing of Cook Inlet. The pipeline right-of-way will create a travel corridor giving people access to remote area previously undisturbed. This could have positive and negative impacts – locals may consider a new travel corridor a benefit while people who want to preserve remote, and pristine areas may consider increased access a detriment. There is some risk of accidents due to leaks from the pipelines and/or LNG plant and tankers. There is some risk of accidents due to pipeline leaks.

Impacts on Alaskans

Gas from the Bullet Line would replace dwindling supplies of gas in the Cook Inlet. In addition, the state would benefit from employment associated with construction and operation of the pipeline, and could realize royalty income plus revenue from severance tax, property tax and income tax associated with the flow of North Slope gas. Royalty and severance tax income would not be as large as with a larger volume main line project.

Supply Alternative: ENRICHED GAS LINE

Enriched gas small pipeline (EGSP) to Nikiski.

Build 1 billion cubic feet per day 24" diameter "dense phase" pipeline from Prudhoe to Nikiski that uses methane as a carrier for other hydrocarbons: ethane, propane, butane and heavier. The other hydrocarbons are extracted at Nikiski. About 45,000 barrels per day (bpd) of LPG is available for use in coastal communities and export; ethane and butane are used as a feedstock at Nikiski; methane is available for use in Cook Inlet. LPG exports subsidize the cost of methane delivered to Cook Inlet.

BACKGROUND

The enriched gas small pipeline is an alternative to the Bullet Line. Like the Bullet Line, it is an alternative to either of the main line proposals. However, it has a smaller diameter than the Bullet Line (24" instead of 30"), and the 1 BCFD flow will include 45,000 barrels of propane. The pipeline will operate at a relatively high pressure of 2500 pounds per square inch (psi), which enables the smaller diameter and ensures that liquid (propane/butane) will not separate out from the gas. Export of LPG will subsidize the cost of gas delivered to Cook Inlet.

EVALUATION RESULTS

Energy Service

The dense phase line would flow 1 BCFD which corresponds to about 360 billion cubic feet per year of natural gas. The line will also deliver 45,000 barrels per day of LPG for use in coastal communities and export.[130]

Prerequisite for Success

Additional industrial use of gas must be developed, since local demand in Cook Inlet is about 0.5 BCFD. Federal approval may be required for the export of LPG. Financing must be obtained for the dense phase line. The project may have to compete for labor and materials with a Canadian Mackenzie Delta project.

Start-up Date

The pipeline can be operational by about 2012.

Investment

The estimated capital cost of the project, including 2 foreign-built LPG tankers, is $4 billion ($2005).[131] The actual cost accounting for inflation and interest accrued during construction will be substantially higher.

Residential Monthly Bill Impacts

There could be a low/medium impact on monthly gas bills. There will only be a limited capacity for export of gas from Cook Inlet, due to the relatively small size of the dense phase line compared to a main line project. So the moderating impact of price linkage with external markets will not be as strong. LPG exports could subsidize gas delivered to Cook Inlet.

Uncertainties

There may be cost over-runs and delays in project completion. (The construction cost of the oil pipeline was nine times the original estimate.) Dense phase pipeline technology is not as well-known.

Environmental Considerations

The pipeline will require rights of way, some of which parallel the Trans Alaska Pipeline System. The route crosses the Minto Flats State Game Refuge. Access to Nikiski will be by an undersea crossing of Cook Inlet. The pipeline right-of-way will create a travel corridor giving people access to remote area previously undisturbed. This could have positive and negative impacts – locals may consider a new travel corridor a benefit while people who want to preserve remote, and pristine areas may consider increased access a detriment. There is some risk of accidents due to leaks from the pipelines and/or LNG plant and tankers. There is some risk of accidents due to pipeline leaks.

Impacts on Alaskans

Gas from the dense phase line would replace dwindling supplies of gas in the Cook Inlet. In addition, the state would benefit from employment associated with construction and operation of the pipeline, and could realize royalty income plus revenue from severance tax, property tax and income tax associated with the flow of North Slope gas. Royalty and severance tax income would larger than for the Bullet Line, due to sales of ethane, propane and butane.

Supply Alternative: CBM
Develop Coal Bed Methane (CBM) reserves in Susitna Basin.

BACKGROUND

In addition to oil and gas reserves, Cook Inlet holds significant coal reserves. Methane gas (the major component of natural gas) can be trapped inside the pores of the coal and is recovered by relieving the pressure in the coal seams. Usually this is done by drilling into the coal formation, fracturing the rock, and pumping out the water in the formation. After the well is "de-watered", the methane gas migrates out of the coal and up to the surface.

Estimates of producible coal bed methane reserves in Cook Inlet range from 7 to 12 trillion cubic feet (TCF).[132] The first exploratory well for coal bed methane was drilled in the Susitna Basin in 1998. Since then several companies have drilled a half dozen test wells. No commercial gas production has been announced from these efforts.

Community opposition to coal bed methane exploration in the Mat-Su valley led to a State moratorium on shallow gas leasing. Local residents, especially land owners that do not control subsurface mineral rights, are concerned that coal bed methane development will damage their property and the surrounding areas. In December 2004, the State adopted standards for shallow gas development based on land owner comments.[133] These standards establish setbacks from residences, noise limits, disclosure of fracturing materials, negotiating surface use agreements, pipeline design, public access, removal of facilities, and rehabilitation of impacted lands.

EVALUATION RESULTS

Energy Service

Producible reserves for CBM in Cook Inlet have been estimated from 7 to 12 TCF. However, leasing, land use, and infrastructure limitations could restrict production. We conservatively estimate total production in the near to medium term in the 1 to 2 TCF range with annual production between 100 to 200 BCF.

Prerequisite for Success

The main hurdle for CBM development in Cook Inlet has been community opposition. Recently adopted leasing standards have alleviated some of these concerns, but CBM development will be closely monitored. Additionally, the little exploration that has been done has yet to undercover commercial production potential. Production costs could be high because of infrastructure development and water re-injection requirements.

Start-up Date

More than 1 million acres have been leased or licensed for CBM development in the Cook Inlet Basin[134]. Approval of leasing standards has helped to alleviate community opposition to development and lifted the leasing moratorium for the Susitna Basin, therefore, CBM development is imminent.

Investment

CBM production is significantly more costly than conventional gas production because CBM requires fracturing and dewatering before gas production can begin. Further investment in water pumping and re-injection equipment will be necessary. Also, if CBM development occurs in the undeveloped region of Susitna Basin, gathering and transport pipelines will be need to transport the gas to the existing pipeline infrastructure. We estimate that investment to develop 1-2 TCF of CBM would be in the range of $1 to $5 billion, though this number is highly uncertain.

Residential Monthly Bill Impacts
CBM development could significant increase monthly utility bills because it is likely to be more expensive to develop than conventional natural gas resources in Cook Inlet.

Uncertainties
The major uncertainties related to CBM development in Cook Inlet are the size and cost to recover the potential gas resource. The few exploratory wells that have been drilled in Susitna Basin did not report commercial production levels and development costs were almost 10 times higher than CBM production in Wyoming.[135]

Environmental Considerations
CBM development has higher environmental impacts than conventional on-shore natural gas production because of the fracturing and water production required to liberate the gas from the coal. Some environmental impacts include waste water and fracturing fluid disposal, noise, air pollution from water pumps, and land use. CBM development has the potential to transform a natural area into an industrial landscape because of the high density of well pads, roads, pumps, and pipelines.

Impacts on Alaskans
CBM development has potential for significant positive impacts on the Alaskan economy including new jobs for CBM production and monitoring as well as royalty and other tax revenues. CBM development would increase Alaska's energy independence because it is a local gas resource.

Supply Alternative: IMPORT LNG

Import Liquefied Natural Gas (LNG) to existing Kenai LNG Facility.

This existing facility would be converted into a Receiving and Regasification Terminal. The terminal would be sized to receive and store LNG imported from world markets and provide up to 200 million cubic feet per day to the Cook Inlet natural gas pipeline system for delivery to homes and businesses during peak winter demand. Estimated annual energy service is 73 billion cubic feet (BCF) for an investment of $62.5 million.[136] We use a range of 40-120 BCF and $50-$100 million in our analysis.

BACKGROUND

When it was first operational in 1969, the Kenai LNG plant was the world's largest LNG project. After almost 40 years of operation and several enlargements, it is presently one of the smallest operational LNG facilities producing about 1.7 million tons of LNG annually.[137] The plant is nearing the end of its useful life and the export license that grants plant owner's ConocoPhillips and Marathon Oil Corporation permission to sell Cook Inlet natural gas to utilities in Japan will expire in 2009.[138]

The Kenai LNG plant is the largest consumer of Cook Inlet natural gas using 213 million cubic feet per day or 78 billion cubic feet per year. Most of this gas comes from the North Cook Inlet and Kenai fields at a cost of $1.50 per thousand cubic feet.[139] At present production levels, forecasts for these reserves show that they will be depleted by 2012. In addition to exporting LNG to Japan, the Kenai facility also provides natural gas to the Fairbanks area. The LNG is transported by truck from Kenai to Fairbanks where it is stored until needed by Fairbanks Natural Gas (FNG) customers. At this time, the stored liquid is converted back to natural gas and delivered by pipeline to homes and businesses

EVALUATION RESULTS

Energy Service

A recent study of future operating scenarios for the Kenai LNG plant found that a receiving and regasification terminal using existing storage and delivery infrastructure would have a capacity of about 200 million cubic feet per day[140]. This is equivalent to about 73 billion cubic feet annually. We assume a range of 50-120 Bcf depending operating parameters and imported LNG prices.

Prerequisite for Success

Access to LNG that is affordable to Cook Inlet customers will require an LNG source and delivery costs from a very competitive supplier.

Start-up Date

Estimated start-up date is 2011 assuming plant shutdown in 2009 at the expiration of the current LNG export license. This start-up date seems ambitious given limited construction season in Cook Inlet.

Investment

Estimated investment for 200 million cubic feet per day capacity with additional storage tank is $63.6 million. An additional $100 million is required for a full-containment LNG storage tank. We estimate an investment range from $70 - $200 million.

Residential Monthly Bill Impacts

Estimated operating costs for 200 million cubic feet per day facility are $12 million per year.[141] Imported LNG is assumed to cost $4.50 per thousand cubic feet. Gross sales price at that price would be $4.95 per thousand cubic feet. Presently, Enstar, the natural gas utility in Cook Inlet, has contracts that will pay much high prices than that in the near term. However, world market LNG prices have also increased significantly. Therefore, we estimate relatively large impacts on residential bills (+50-100%)

Uncertainties

The study that we used to estimate facility investment, capacity, and costs was a preliminary review of future options for the Kenai plant. There is significant uncertainty in these values. Additionally, future world market LNG prices are highly uncertain. It seems unlikely that the Kenai facility will be able to negotiate favorable contract terms for LNG delivery and prices because it would be a relatively small terminal in a remote location.

Environmental Considerations

The environmental impacts of the receiving and regasification terminal would not be much different than those of the existing Kenai LNG facility: risks of spills loading or offloading LNG and unmitigated facility impacts (noise, odor, truck traffic, allowable air and water emissions).

Impacts on Alaskans

This alternative has potential for the most adverse impacts to Alaskan citizens of all those considered in this study because it relies on an imported fuel. This could have a large negative impact on the regional economy because the money spent on imported fuel is sent outside Alaska.

Supply Alternative: OTHER ALASKA GAS

Develop potential natural gas resources in Bristol Bay, Copper River, and Nenana Basins.

BACKGROUND

Other areas in southern Alaska hold potential for significant natural gas resources including: Bristol Bay, Copper River, and Nenana Basins. Total gas reserves in these basins are highly uncertain because there has been little exploration activity.

Of the three Basins, Bristol Bay has experienced the most exploration activity. A lease sale held in October 2005 resulted in over 200,000 acres near Port Moller being sold to Shell Offshore, Inc and Hewitt Mineral Corporation. [142] Reserve estimates for Bristol Bay are in the range of 7 TCF for conventional gas though the limited exploration to date makes this value highly uncertain.[143]

The Copper River has only recently experienced exploration and drilling. Forest Oil Corporation drilled a gas exploration well near Glennallen in 2005 and did not find gas.[144] The potential gas resource in this Basin have yet to be estimated. The Copper River basin will probably continue to be explored despite disappointing results because it lies along the route of the proposed Spur Line and this infrastructure could be used to deliver gas to Cook Inlet.

Nenana Basin may have gas resources of 3 TCF, however, little exploration data is available to support this estimate.[145] The Nenana Basin is a high priority for exploration because it could provide gas to Fairbanks and other interior communities. LNG deliveries to Fairbanks will likely ceases in 2009 if the export license for the Kenai LNG plant is not renewed.

EVALUATION RESULTS

Energy Service

Any of these basins have the potential to hold more natural gas than Cook Inlet. However, there is great uncertainty about the resource estimates. We estimate that these Basins could produce between 50 and 100 BCF per year.

Prerequisite for Success

There needs to be significant investment in exploration in all of these basins to determine commercial resource potential and recovery costs.

Start-up Date

Even though licenses have been issued for Bristol Bay, it will likely be several years before any significant gas production will come on-line. Additionally, the pipeline infrastructure needed to transport the gas to Cook Inlet is not likely to be built until 2012.

Investment

Investment required to produce and transport natural gas from basins outside Cook Inlet is highly uncertain. We estimate it will be in the range of $1 to $5 billion.

Residential Monthly Bill Impacts

Additional transport costs to deliver gas from these basins to Cook Inlet as well as the large investment needed to develop these gas resources and transport infrastructure will likely result in significant increases in monthly utility bills.

Uncertainties

The primary uncertainty for this alternative is the size and accessibility of economically recoverable gas resources in the Bristol Bay, Copper River, and Nenana Basin.

Environmental Considerations

Exploration and production of natural gas in these relatively pristine areas could have significant unmitigated environmental impacts especially to wildlife. If these areas are developed, they will be transformed from natural areas into a more developed landscape and the associated risks of spills, accidents, and other industrial emissions will be possible.

Impacts on Alaskans

Developing these basins could have significant positive impacts for Alaskans because it represents an opportunity for new jobs and government revenues. This development would also improve Alaska's energy security as these are local energy resources.

Supply Alternative: COAL GASIFICATION

Construction of a new coal gasification facility that would supply the Agrium fertilizer plant in Nikiski with feedstock for its ammonium hydroxide and urea processes as well as generate 350 mega-watts (MW) of electric power. The coal gasification project proposed by Agrium, Inc is called Blue Sky[146]. The coal gasification facility would be located at the existing Agrium facility and use coal from the existing Usibelli coal mine in Healy or from the proposed Beluga coal mine across Cook Inlet from Nikiski.

Coal gasification produces hydrogen and carbon monoxide from the high temperature combination of coal and oxygen. The hydrogen and carbon monoxide would be further processed to become the feedstock for Agrium's anhydrous ammonia and urea production lines. Other by-products such as carbon dioxide could be used for enhanced oil and gas recovery. This process also has the potential to generate up to 350 MW of electric power. The facility would use 100 MW and the remainder could be sold into the Railbelt grid or provide power to the proposed Pebble Mine on the west side of Cook Inlet or other industrial facility.

BACKGROUND

The second largest consumer of Cook Inlet natural gas is the anhydrous ammonia and urea manufacturing facility owned by Agrium, Inc. This facility which began production in 1968 consists of two ammonia plants and two urea plants. At full operation, the facility can produce about 1.4 million tons of fertilizer and consume 54 billion cubic feet (BCF) per year of Cook Inlet gas. Gas delivery constraints and rising costs have limited production at the plant. In 2004, the plant was operating at half capacity with annual consumption of 25 BCF.[147]

The great majority of anhydrous ammonia and urea produced at the Agrium facility is exported to Asia.[148] Agrium is constrained on the price it can pay for natural gas because its product prices are set by world markets. The plant has stayed competitive because its major feedstock is Cook Inlet natural gas. Most of the gas for the plant comes from the McArthur River field at a cost of about $1.20 per thousand cubic feet.[149] Agrium's contracts for low cost gas expired in 2005 and the plant was scheduled to be shutdown in November 2005. Alaska's governor convened a Task Force to find options to keep the plant and its 180 high paying jobs operating. In July 2005, Agrium announced that it had secured a gas contract that would keep the plant operational through November 2006. While the details of the contract were not released, Agrium offered $3.00 per thousand cubic feet with potential for higher prices paid if higher fertilizer prices supported it.[150]

EVALUATION RESULTS

Energy Service

According to Agrium plant manager Bill Boycott, "We're talking about a complex that will consume roughly 4 million tons a year of coal and produce 2 million tons a year of fertilizer for sale into the Pacific Rim,"[151] The new facility would include also include a coal-fired power plant generating 100 MW of power needed for the coal gasification process and as much as 250 MW for sale to the Railbelt power grid. The equivalent gas consumption for this level of fertilizer and electricity production is estimated to be between 40 and 65 BCF.

Prerequisite for Success

In order to be successful, the Blue Sky project will need a reliable and affordable source of coal. Transport of coal to the Agrium facility from the exiting Usibelli coal mine near Healy will require either barging the coal from Seward to Nikiski or transporting the coal by rail to Wasilla, then by truck to Port Mackenzie, and then by barge down Cook Inlet to Nikiski. Transport by barge will likely be less expensive, but this route may not be open during winter months because of rough seas and ice conditions. The Beluga coal mine has not been developed and will require significant investment ($150 million) to open the mine and develop port facilities.

Start-up Date

Reported start-up date for the Blue Sky project is 2011. This date is targeted to take advantage of federal loan and grant programs for coal gasification projects.

Investment

No investment figures have been reported for the Blue Sky project. Based on estimates for integrated gasified combined cycle power projects, a range of $100 to $500 million is estimated for a project of this size.

Residential Monthly Bill Impacts

If the electric power produced by the Blue Sky project is sold into the Railbelt grid, the price would depend on the success of Agrium to secure grants and low-interest federal financing for the Blue Sky project, the cost of coal, and the efficiency of the gasification process. Since electric power is a by-product of fertilizer production, other income will be available to cover project costs and the resulting cost of electricity should be comparable to existing rates.

Uncertainties

Uncertainties related to the Blue Sky project include the efficiency of coal gasification process using Alaskan coals and availability and cost of coal transport to Nikiski. Both of these uncertainties affect the level of investment and operating costs for the proposed coal gasification facility.

The efficiency of coal gasification with low-rank coals such as those from Usibelli and Beluga coal mines has not been demonstrated on a commercial scale in the US. These coals have heating values in the range of 8000 British thermal units (Btu) per pound. The efficiency of coal gasification power plants drops significantly with coals that have heating values below 11,000 Btu per pound.[152] Lower efficiency will result in higher investment and operating costs to produce feedstock and power production required by the Agrium facility.

Environmental Considerations

Coal gasification is a relatively clean process and Agrium has potential uses for all of the by-products. Carbon dioxide could be used in enhanced gas and oil recovery. This would also reduce potential greenhouse gas emissions. Increasing the demand for coal will result in more coal mining in Alaska which has some unmitigated environmental effects such as full reclamation of mined lands, waste water, and overburden handling.

Impacts on Alaskans

Coal gasification would have many positive aspects for Alaskans because it would result in the development of local coal resources bringing new jobs and preserving existing jobs at the Agrium facility and the associated tax revenues.

Demand Alternative: COAL POWER

Construction and operation of new coal-fired electric generation facility.

Alaska has abundant coal resources. In south central Alaska, there is a coal mine near Healy operated by the Usibelli family company. A new coal mine is proposed at the Beluga coal field located on the west-side of Cook Inlet. Coal-fired power generation in Alaska has been hampered by the low quality of Alaskan coals, lack of coal transport infrastructure, and unsuccessful demonstration of clean coal technology at the Healy Clean Coal project.

This alternative is based on the construction and operation of a coal-fired generation facility on the design and scale of the Emma Creek Energy Project proposed by Usibelli. This project would be a 200 megawatt (MW) mine mouth plant using 1.5 million tons of coal per year and producing 1.6 million MW-hours per year of electricity for the Railbelt grid[153].

BACKGROUND

Coal power in Alaska has had very limited success. The Healy Clean Coal Project located near the Usibelli coal mine, was completed in 1998 at a cost of $297 million. Most of this funding came from federal grants and State bonds. This plant is a mine mouth plant, 50 MW in size. The Healy Clean Coal Project has been shutdown since testing was completed in 1999.[154]

The Healy plant recently made headlines as an on-going dispute between the owner Alaska Industrial Development and Export Authority (AIDEA) and the operator Golden Valley Electric Association (GVEA) went to State court. AIDEA is suing GVEA for damages related to non-operation of the plant. The entire dispute relates back to the demonstration testing completed from January 1988 through December 1999. GVEA claims the test results showed that the plant could not be operated safely or reliably. AIDEA claims that with relatively modest investment this plant could be operational. The recent Energy Policy Act includes an $80 million loan for refurbishment of the Healy Clean Coal Project.

The lack of transport infrastructure as well as coal characteristics make mine mouth plants the most feasible arrangement for Alaska. Presently, the only infrastructure suitable for coal transport is the Alaska Railroad and a barge loading facility in Seward which is used to export Usibelli coal to Korea. The coal at the Usibelli mine and at the Beluga coal field have a high moisture content meaning that for every four tons of coal shipped, one ton is water.[155] The Usibelli coal mine near Healy has the added challenge for mine mouth plants of being 15 miles from Denali National Park. The means that the power plant must meet the most stringent air quality standards to protect air quality in the national park, adding extra cost for air pollution control. A mine mouth plant near the proposed Beluga coal field would have similar emissions restrictions as it is located near Lake Clark National Park and Preserve.

EVALUATION RESULTS

Energy Service

The proposed Emma Creek Energy Project would use about 1.5 million tons of coal to power 200 MW of generation and produce 1.6 million MW-hours of electricity per year. A natural gas-fired facility would use between 10 and 15 billion cubic feet (BCF) of natural gas to generate the same amount of electricity.

Prerequisite for Success

Since mine mouth plants are the most feasible arrangement for coal-fired generation in south central Alaska, successful demonstration of clean coal technologies using Alaskan coals is needed. Clean coal technology is the most affordable way that mine mouth plants could meet the stringent air emission requirements for locations near national parks. The coals from the Usibelli and Beluga mines have relatively low heating values in the range of 8000 British thermal units (Btu) per pound. Clean coal technology has not been extensively operated with low heating value coals. Successful operation of the Healy Clean Coal Project would help overcome this barrier.

Start-up Date
Estimates for the time to permit, design, and construct the Emma Creek Energy Project are 7.5 years. Modifications at the Healy Clean Coal Project are expected to take from 15 to 18 months.

Investment
The Emma Creek Energy Project is estimated to require an investment of $421 million.

Residential Monthly Bill Impacts
Despite the large capital investment, coal-fired generation produce less expensive electric power than natural gas in the long run because of cheaper fuel and operations costs. An analysis by the Usibelli Coal Mine, Inc. showed that the cost of electricity from coal-fired generation is less than natural gas-fired generation at natural gas prices above $3.00 per thousand cubic feet.[156]

Uncertainties
The major uncertainty for the future of coal power in Alaska is operation of clean coal technologies with Alaskan coals

Environmental Considerations
While clean coal technology results in very low air emissions, there are other environmental considerations related to coal power including the need for large amounts of cooling water, solid waste/ash disposal, and significant greenhouse gas emissions. Additionally, there are secondary impacts related to increased coal mine development and operations.

Impacts on Alaskans
Coal power has the potential for significant positive impacts on the Alaskan economy as it is based on the development of a relatively untapped indigenous energy resource. Coal power would bring new jobs in coal mining and power plant construction and operation as well as new government revenues.

Demand Alternative: HYDRO POWER

Construction and operation of new hydro electric generation facilities

This alternative considers low and medium-sized hydro power resources (less than 10 mega-watts [MW]) as this scale is most feasible with the existing electricity load and infrastructure in Cook Inlet. Most of these projects would be classified as run-of-river and would be constructed without impoundments. Some projects may include diversion works to channel the water through the turbines, but the water would return to the river. Large-scale dams and hydropower projects such as the Susitna Hydro project (1600 MW) are unlikely to be built even with natural gas shortages because of environmental issues and financing difficulties.

BACKGROUND

Alaska has made significant investment in hydropower and now has more than 50 hydro projects generating about 14 percent of the State's electricity. Despite this development, there is potential for much more hydropower; Alaska holds the one-third of undeveloped hydro power sites in the U.S.[157]

Most of the existing hydropower projects in Alaska are less than 10 MW in size. The majority of these projects are located in Southeast serving isolated towns and villages that are not connected to outside electric grid. Hydropower in Alaska faces several challenges including matching the generator for a potential hydropower site to the electric load and infrastructure that it will serve. Sufficient electric loads must be served by the hydro project or it will not be cost-effective. For example, the Tazimina River Hydroelectric Plant located on the Alaska Peninsula has the potential to produce 6 million kilo-watt (kWh) per year. The plant is currently producing 2.6 million kWh per year on average because there is insufficient transmission infrastructure to send the electricity to other villages or industrial loads.[158]

Another challenge for hydropower in Alaska is the seasonable variability of stream flow and salmon runs that affect the availability of hydropower. During winter freeze up, hydropower is not available to meet electric demand. Hydro project design in Alaska must consider harsh environmental conditions and may have to be removable to accommodate spawning salmon or other wildlife needs.

EVALUATION RESULTS

Energy Service

For this alternative, we assume that between 10 and 50 MW of hydropower will be developed in the medium term. This generation will most likely consist of several small to medium-scale projects (<10 MW). The natural gas that would be consumed to generate 10 to 50 MW of power is on the order of 0.5 to 2.5 billion cubic feet (BCF).

Prerequisite for Success

US DOE has identified a multitude of sites suitable for hydropower in the Cook Inlet Basin.[159] However, there are likely to be only a few locations that will have the right combination of generation potential and infrastructure access to merit investment. The sites with the most potential for success would probably be on the west side of Cook Inlet, where new hydropower could be used to serve new mining (Pebble Creek) or other industrial loads. Further research and feasibility studies will be needed to identify and exploit these hydropower sites.

Start-up Date

Because hydropower requires substantial upfront capital investment, there is a long lead-time from project conception to operation. Additionally, federal licensing for hydropower project can be a lengthy process. The earliest we would expect a new hydropower project to become operational is 2015 because there are no new projects in the Cook Inlet Basin that have license approval. Expansion of existing hydropower facilities could be operational sooner.

Investment

Hydropower is very capital intensive and site specific. The level of investment depends on the location, site arrangement, and generator design. Based on data from recently completed small-scale hydro projects in Alaska such as South Fork, Humpback Creek, and Tazimina, we would expect hydropower investment to cost from $1 to $2 million per MW.

Residential Monthly Bill Impacts

Although hydropower is capital intensive, it is one of the least expensive power plants to operate because there is no fuel and relatively low maintenance costs. Assuming that the hydropower project is properly scaled so that all of the power generated can be readily sold, the capital cost will be sufficiently spread across consumers to have little impact on monthly bills.

Uncertainties

The major uncertainty with hydropower as an alternative for providing Cook Inlet with energy service is the number of locations in the Cook Inlet Basin where hydropower can be built and operated cost-effectively.

Environmental Considerations

Small-scale run-of-river hydropower projects have limited but permanent environmental impacts such water diversions affecting the riparian environment and river flow as well as the development of an industrial facility in remote or pristine locations.

Impacts on Alaskans

Hydropower has the potential for small positive impacts on the Alaskan economy and community. It uses a renewable resource to generate electricity and supports energy self-sufficiency. Hydropower also provides a small number of jobs during construction and operation (often in remote areas with limited job opportunities).

Demand Alternative: WIND POWER

Construction and operation of new wind-powered electric generation facilities.
Alaska has significant wind energy resource sites. Several small-scale wind-diesel hybrid projects have been built and are successfully operating in Alaskan villages such as Kotzebue and Wales. However, larger scale wind projects have yet to be built in Alaska.

A large-scale wind energy project has been proposed at Fire Island in Cook Inlet by a consortium of regional utilities including Chugach Electric Association. The Fire Island development would use 300 to 400 foot tall wind turbines to generate up to 100 mega-watts (MW) of electric power. The electricity would reach Anchorage via an undersea cable from Fire Island to Port Woronzof near Ted Stevens International Airport.[160]

BACKGROUND
Wind power in Alaska has been limited to small-scale systems in rural villages where electricity costs 25 cents per kilo-watt hour (kWh) or more because it is generated using diesel fuel. Small-scale (<1 MW) wind-diesel hybrid systems are cost-effective at these high electricity prices. In the Cook Inlet area, where electricity costs 8 to10 cents per kWh, wind power has not been cost-effective.

With natural gas prices rising and future fuel supplies in question, wind power is becoming an attractive alternative to natural-gas fired generation. In 2005, the Denali Commission awarded Chugach Electric Association an additional $471,000 to complete a feasibility study for the Fire Island wind project.[161] Preliminary study results found that the Fire Island wind project, could generate up to 100 MW of electric power replacing up to 14 percent of Chugach Electric's natural gas use. The cost to build the Fire Island wind project would total $175 million including $135 million for wind turbines and $40 million for electrical and other infrastructure. Chugach Electric is requesting $20 million from the State to help pay for the proposed project.

EVALUATION RESULTS
Energy Service
Based on preliminary analysis of the Fire Island Wind project, Chugach Electric estimates that it will save between 7 and 14 percent of its annual natural gas consumption. The potential savings amounts to 2.5 to 5 billion cubic feet (BCF) per year.

Prerequisite for Success
Wind power requires a location with consistent, medium speed winds. While Alaska has many good wind energy sites, most of these are in remote locations too distant from electric infrastructure or load to be feasible as an affordable power source. As a capital intensive generation technology that has not been proven on a large scale in Alaska, it can be difficult to attract investment for wind power.

Start-up Date
Estimated start-up date for the Fire Island Wind project is 2011.

Investment
The Fire Island Wind project is reported to require an investment from $93 to $175 million depending on the size of the project (50 or 100 MW) and the ultimate cost for the infrastructure to transport the electricity from Fire Island to Anchorage. Chugach Electric is working with the State and federal government to provide grants and loans to finance this project.

Residential Monthly Bill Impacts
Current cost estimates for large scale wind power are about 7 cents per kWh. Cost for the Fire Island Wind project are likely to be higher because it is the first large scale wind project in Alaska and because delivery and installation of wind generators is likely to be more expensive in Alaska. However, electricity generated by the Fire Island Wind project will probably be the same or below present electric rates of 9 to 11 cents per kWh.

Uncertainties
The major uncertainty related to wind power is the output and availability of the generator. Or, how much electricity will be produced and when? Because wind energy is an intermittent resource, utilities can not dispatch wind power as it would other generators such as natural gas or hydro. They get power when the wind blows. That is why site selection is so important. Good wind energy sites have consistent low to medium winds, rather than large intermittent gusts. Wind measurements on Fire Island have shown it to be a good wind energy site.

Environmental Considerations
Wind power is one of the cleanest sources of energy available. Unmitigated impacts can include noise and view shed impacts although some people actually prefer to view moving windmills. There can be some impacts to wildlife (birds), however, turbine layout can help to mitigate these impacts.

Impacts on Alaskans
While wind power is a renewable resource that will help Alaska with its energy security, the generators and other equipment are manufactured in other parts of the US or overseas. This means that investment dollars in wind power will flow out of the Alaskan economy.

Demand Alternative: NUCLEAR POWER

Construction and operation of small-scale nuclear reactor similar to the project proposed for Galena.

BACKGROUND

Nuclear power has historically been built on a scale unsuitable for the relatively small and disperse electric power needs in Alaska. New reactor technology is being built on a much smaller scale (10 to 50 MW). Toshiba has offered the community of Galena a Small Innovative Reactor for free if they are willing to pay the operating costs estimated at 10 to 20 cents per kilo-watt hour (kWh).[162] Galena residents who currently pay around 30 cents per kWh have accepted the offer. Toshiba made this offer to Galena to demonstrate small-scale nuclear power and to get this technology licensed in the U.S.

The Toshiba reactor design is called 4S (Super Safe, Small and Simple). The reactor and fuel are in a sealed unit with no mechanical parts. The cooling medium is liquid sodium metal. The reactor would be buried up to 100 feet underground and capped with concrete to create an impenetrable barrier and cooling medium. In addition to electric power, the reactor could produce steam for heating as well as hydrogen and oxygen for other purposes.

EVALUATION RESULTS

Energy Service

Small-scale nuclear reactors have been proposed for Alaska in the 10 to 50 MW range. This would correspond to a natural gas-fired power generation facility that uses 0.5 to 2.5 billion cubic feet (BCF) of natural gas per year.

Prerequisite for Success

Small-scale nuclear power has not been commercially demonstrated or licensed in the U.S. Galena could be the first installation of nuclear power at this scale. At a minimum, after procuring regulatory approval, this first installation would have to successfully demonstrate cost-effective operation of small-scale nuclear technology.

Start-up Date

The Nuclear Regulatory Commission has created a new streamlined process for site and technology licensing that should require less time to complete.[163] However, as a new technology and new location the nuclear reactor project proposed for Galena is facing a full review. Estimated start-up for the Galena project is 2012.

Investment

Toshiba has reported an investment of $125 million for a 50 MW nuclear reactor. No investment estimates for a 10 MW reactor have been reported.

Residential Monthly Bill Impacts

Electricity generated by small-scale nuclear reactors is estimated to cost between 10 and 20 cents per kWh depending on debt servicing and other products (heat, hydrogen) that can be sold to offset generation costs.

Uncertainties

The small-scale self-contained nuclear reactor technology is new and has not been demonstrated on a commercial scale. Commercial operation, efficiency, and availability of this technology is uncertain. Additionally, nuclear reactor sites must also be reviewed and licensed. Alaska is one of the most geologically active places on earth making site approval difficult.

Environmental Considerations

One of the features of Toshiba's 4S technology is that there are no emissions. Spent nuclear fuel is contained in the reactor unit. Nuclear power has the advantage of not generating any direct greenhouse gas emissions. Nuclear waste is a potential environmental consideration. Risk of accident and impacts to reactor site are also potential issues.

Impacts on Alaskans

Nuclear power does not offer any great advantages to Alaskan citizens other than as an alternative power generation technology. It uses an imported fuel and generation technology. Small-scale nuclear will not generate a significant number of construction or operator jobs.

Demand Alternative: TIDAL POWER

Construction and operation of new generation facilities that capture tidal energy.

Tidal power systems operate similar to hydropower systems by capturing the energy of flowing water. In tidal power systems, the energy comes from inflow and outflow of tides rather than from harnessing the potential energy of falling water as in hydropower. Electricity is generated with a generator submerged in a location with strong tidal current. Cook Inlet has some of the strongest tidal currents in the world and is considered to be an ideal location for tidal energy. However, silting and icing conditions as well as lack of electric load and infrastructure have made investment in tidal power unattractive to date.

BACKGROUND

Tidal power operates on the same physics principles as hydropower; capturing the energy of flowing water. However, tidal power uses the difference in tide heights rather than waterfalls to create a pressure head. Several countries including Canada, Japan, Russia and China are working on large-scale tidal projects.[164] A large scale tidal project in Cook Inlet could have the potential to generate 16 times the State's annual electricity consumption.

Cordova Electric Cooperative completed a feasibility study of an impoundment tidal system in 1998. This study found that a 5 MW tidal power system would cost about $14 million. The Cooperative elected to develop Power Creek hydropower project instead.

EVALUATION RESULTS

Energy Service

Although large scale tidal power in Cook Inlet has the potential to provide the energy service needed in Cook Inlet many times over, the likelihood that a system of this scale would be financed and constructed is quite low. Additionally, environmental considerations such as icing and silting could make tidal power operation on a large scale infeasible. Therefore, we consider the tidal power alternative on the scale proposed for Cordova of 5 to 10 MW.

Prerequisite for Success

Tidal power has yet to be demonstrated on a commercial scale, especially in environmental conditions similar to Cook Inlet. The tidal power system proposed for Cordova would have been "second generation" technology.[165] Until tidal power is demonstrated on the scale and in the icing and silting conditions similar to Cook Inlet, it will probably not be feasible.

Start-up Date

Because tidal power has yet to be demonstrated or licensed on a commercial scale, the lead time for operation is expected to be 10 to 15 years (2015 to 2020).

Investment

Estimated investment for the Cordova Tidal Power project was $2.8 million per MW or $14 million for 5 MW project.

Residential Monthly Bill Impacts

Tidal power can be expensive to build and operate. Estimated costs for the Cordova Tidal Power project were in the range of 12 cents per kilo-watt hour (kWh), though this cost included significant debt coverage. Other demonstration projects have reported costs higher than 26 cents per kWh, which is more than double current electric rates.

Uncertainties
As a new technology that has yet to be demonstrated in Alaska, the construction, operation and regulation of tidal power is highly uncertain.

Environmental Considerations
Environmental impacts of barrage-type tidal power systems can include a barrier for fish and other wildlife passage (a potentially significant issue in Alaska with salmon runs) as well as commercial boat traffic.

Impacts on Alaskans
As a new and foreign-built technology, tidal power does not offer any significant positive impacts for Alaskans other than being a renewable energy technology that would support energy self-sufficiency.

Demand Alternative: NATURAL GAS CONSERVATION

Reducing natural gas consumption by increasing end-use efficiency with measures such as appliance upgrade or weatherization programs.

BACKGROUND

End-use conservation comprises a wide range of programs and activities. In Alaska, there are many incentives for improving end-use efficiency such as high energy prices in rural Alaska and extreme weather conditions throughout the State. Several State agencies administer end-use energy efficiency programs including:

- Alaska Energy Authority – administers the Rebuild American Program conducting energy audits and identifying opportunities for end-use conservation in home, schools, and other public facilities.

- Alaska Housing Finance Corporation (AHFC) - funds residential energy conservation and weatherization programs. Between 2000 and 2004, Alaska received more than $1.5 million each year for weatherization projects from U.S. Department of Energy.[166] These funds were used by AHFC to weatherize over 3,200 homes throughout the State.

- Alaska Building Energy Efficiency Standards Building codes and EnergyStar appliance standards also contribute to end-use energy efficiency by requiring new and renovated buildings to meet minimal energy requirements and to encourage consumers to purchase more efficient appliances.

End-use conservation of natural gas usually involves measures such as weatherization (adding building insulation, improving window and door seals) and improving gas furnace and water heater efficiency. There are also behavioral measures such as turning down thermostats that also reduce end-use gas consumption.

From 2004 to 2006, the gas utility company in Cook Inlet, Enstar, increased residential and commercial rates by more than one-third from about $5.00 per thousand cubic feet (mcf) to $6.75 per mcf.[167] Enstar's rates are expected to continue rising based on recent contracts between Enstar and Cook Inlet gas producers that link gas prices to prices in the Lower 48. These higher rates are a strong incentive for consumers to reduce consumption either through behavioral changes, improving furnace efficiency, or substituting with an alternate heating fuel such as wood.

EVALUATION RESULTS

Energy Service

A recent forecast of natural gas demand estimated that under a high price scenario, residential and commercial demand would increase between 5 and 10 billion cubic feet over the next 20 years.[168] We estimate that half of this growth in consumption could be eliminated through natural gas conservation programs.

Prerequisite for Success

The major prerequisite for success - higher gas rates - has already been initiated by Enstar.

Start-up Date

Enstar has been significantly increasing natural gas rates for the past three years. Natural gas conservation measures, especially behavioral changes, are occurring presently.

Investment
Alaska has been receiving about $1.5 million per year for weatherization programs throughout the State. In order to achieve the significant level of natural gas conservation needed to reduce consumption by 2.5 to 5 BCF over the next 10 years, we estimate that investment in gas conservation programs would need to be in the range of $2.5 to $10 million per year.

Residential Monthly Bill Impacts
Total monthly bills could decrease for natural gas consumers because of reduced gas use. However, if natural gas consumption were to drop below the level needed by Enstar to support its investment in natural gas transmission and delivery infrastructure or below the levels required in their supply contracts, residential bills could increase because Enstar would need to add charges to cover these costs.

Uncertainties
Conservation programs have significant uncertainty regarding the level of energy savings that are actually achieved. Two factors affect energy savings: 1) Participation: these programs are usually voluntary and require significant end-user participation; 2) Snap-back: the persistence of the energy savings depends on end-users continuing to maintain and use the conservation measures that were implemented to obtain the energy savings. Snap-back refers to the phenomenon of end-users reverting to previous energy use patterns because they are not maintaining or using the energy saving device or measure.

Environmental Considerations
Generally, end-use efficiency programs result in net environmental benefits because the same level of energy service is achieved with less natural gas being burned.

Impacts on Alaskans
Potential impacts on Alaskans from natural gas conservation are mixed. The money that is saved by households with lower gas bills can be used in other parts of the Alaskan economy generating new jobs and revenues. However, most of the devices or materials that would be used to increase natural gas efficiency (setback thermostats, building insulation, and efficient furnaces) are manufactured outside Alaska. This means the investment in natural gas conservation programs could have a negative impact on the State economy.

Demand Alternative: ELECTRIC CONSERVATION

Reducing end-use electric consumption by increasing appliance or lighting efficiency.

BACKGROUND

Since almost 80 percent of Cook Inlet's electricity is generated by natural gas-fired power plants, improving end-use electric efficiency could save significant amounts of natural gas. Some of the electric conservation measures implemented by the Alaska Housing Finance Corporation in 2004 included: replacing 50 refrigerators with energy-efficient models; replacing old, inefficient water heaters; and replacing incandescent light bulbs with compact fluorescents. All of these measures indirectly saved natural gas.

Until 2006, electricity prices in the Cook Inlet region were stable.[169] Price increases for natural gas have forced most electric utilities to increase their rates. While these rates increases are significant (10 to 20 percent), electricity is relatively moderately priced in the Cook Inlet region. Furthermore, availability of inexpensive natural gas has resulted in gas being the predominate energy source for space and water heating in the region. The major end-uses for electricity are refrigeration and lighting.

EVALUATION RESULTS

Energy Service

Natural gas consumption for electric power generation is expected to increase 0.5 to 5 billion cubic feet (BCF) over the next 20 years.[170] Given relatively stable electric rates and the end-uses for electricity in the Cook Inlet region, we only expect modest savings from end-use electric conservation programs in the range of 0.5 to 2.5 BCF.

Prerequisite for Success

Increased electric rates are needed to initiate electric conservation along with education and incentive programs. Many electric utilities in Washington, Oregon, and California have implemented very successful light bulb and appliance replacement programs that use rebates and other incentives to induce end-use electric conservation. These types of programs would be needed for significant savings to occur in Cook Inlet.

Start-up Date

Higher electric rates in 2006 should initiate some electric conservation. New incentive programs take about one year to design and implement. We estimate that measurable electric savings could begin in 2007.

Investment

Alaska has been receiving about $1.5 million per year for weatherization programs throughout the State. In order to achieve the significant level of electric conservation needed to reduce consumption by 2.5 to 5 BCF over the next 10 years, we estimate that investment in electric conservation programs would need to be in the range of $5 to $10 million per year.

Residential Monthly Bill Impacts

Total monthly bills could decrease for electric consumers that implement electric conservation measures. However, if electricity use were to drop below the level needed by Chugach Electric and other electric utilities to support their investment in power plants and transmission infrastructure or below the levels required in their gas supply contracts, residential bills could increase because the electric utilities would need to add charges to recoup these costs.

Uncertainties

Conservation programs have significant uncertainty regarding the level of energy savings that are actually achieved. Two factors affect energy savings: 1) Participation: these programs are usually voluntary and require significant end-user participation; 2) Snap-back: the persistence of the energy savings depends on end-users continuing to maintain and use the conservation measures that were implemented to obtain the energy savings. Snap-back refers to the phenomenon of end-users reverting to previous energy use patterns such as replacing an energy-savings compact fluorescent light bulb with an incandescent bulb.

Environmental Considerations

Generally, end-use efficiency programs result in net environmental benefits because the same level of energy service is achieved with less electricity and natural gas being burned.

Impacts on Alaskans

Potential impacts on Alaskans from electric conservation are mixed. The money that is saved by households with lower electric bills can be used in other parts of the Alaskan economy generating new jobs and revenues. However, most of the devices or materials that would be used to increase electric efficiency (compact fluorescent light bulbs and efficient refrigerators) are manufactured outside Alaska. This means the investment in electric conservation programs could have a negative impact on the State economy.

Demand Alternative: DISTRIBUTED GENERATION

Construction and operation of new distributed generation facilities. These on-site electric generators could include fuel cells, non-gas-fired cogeneration, and diesel generators.

BACKGROUND

Providing electric power in a place as remote and sparsely populated as Alaska, can be expensive and difficult. Distributed generation or generating power at the end-user's location can be a cost-effective strategy for meeting Alaska's relatively small and dispersed loads. Some analysts would classify the majority of Alaska's generation as "distributed" because a good share of electricity in some communities (Valdez, Homer) is co-generated at industrial facilities. While there are a variety of reasons for using distributed generation, the major ones are to avoid large electric power transmission costs from a central facility to remote load or to improve or expand electric service in a region distant from centralized power stations.

Alaska is a leader in operating and testing fuel cell systems. Fuel cells produce electricity through an electrochemical reaction using hydrogen rather than using fuel combustion and a generator set. Fuel cells are relatively compact and self-contained requiring little maintenance or fuel delivery so they are an ideal technology for distributed generation. University of Alaska Fairbanks has become a leader in fuel cell technology testing because of the relatively large number fuel cells operating in the State.[171] One of largest fuel cell projects was operated by Chugach Electric at the US Postal Service facility at Ted Stevens International Airport. Also, one of the first fuel cells to use propane as a hydrogen source is operating at Exit Glacier Visitor Center in Kenai Fjords National Park near Seward.

Chugach Electric Association and the US Postal Service (USPS) worked together to create a deal the provided the USPS office located at Ted Stevens International Airport with 5.5 years of electric service and free heat using fuel cells. Chugach Electric received $1 million in prepayment from USPS for the electricity as well as funding from other partners to cover the cost of 6 fuels cells (200 kilo-watts kW each) and an experimental control system that enabled grid connection. The project was 1 MW in size and used natural gas as a methane source. Total cost for the project was $5.5 million.[172] The project proved to be successful, however, it was not profitable for Chugach Electric to operate the fuel cells and they were removed in August 2004.[173]

The 5 kW fuel cell operating at Exit Glacier was installed in August 2003. Unfortunately, this first unit was damaged during shipment and had to be replaced. The new unit was installed in 2004 and has been operating successfully since then.[174]

EVALUATION RESULTS

Energy Service

Since fuel cells have been successfully demonstrated on a large (1 MW) and small (5kW) scale in Alaska, we expect distributed generation, in general, and fuel cells, in particular to be implemented in the near and medium term. Total energy service for fuel cells is estimated to be between 5 and10 MW or about 0.25 to 0.50 billion cubic feet (BCF) of equivalent energy service.

Large cogeneration projects will likely be installed in this same time frame, however, to be considered an alternative to natural gas-fueled energy service in Cook Inlet these projects must use a fuel other than natural gas. Therefore, potential cogeneration projects are included in this analysis in the energy service estimates for coal gasification and coal power.

Prerequisite for Success

Many of the hurdles related to distributed generation have already been cleared for applications in Alaska, including successful operation on a useful scale, relatively high electricity prices, and significant electric and heat loads that are located far from central power stations.

Start-up Date

We expect that further development of distributed generation will occur by 2010.

Investment

Fuel cells and other types of distributed generation are generally more expensive than central power sources. The fuel cells used by the USPS cost about $4.5 million per MW for equipment and installation.

Residential Monthly Bill Impacts

Electricity from distributed generation and fuel cells can cost from 5 to 15 cents per kWh depending on the fuel or hydrogen source and the operating arrangement. The fuel cell system at the USPS also provided heat and allowed the USPS to avoid investment in a new fuel tank for the existing heat system. Therefore, fuel cells and distributed generation can be much more cost-effective if considered from a total energy service perspective (heat and electricity).

Uncertainties

The availability and operating efficiency of the distributed generation system are uncertain because as these are relatively new technologies or small-scale systems they are somewhat unique. These uncertainties will diminish as more systems are installed and operated. Few fuel cell systems use a hydrogen source other than natural gas.

Environmental Considerations

Most distributed generation systems, especially fuel cells, are very clean to operate and have little outside impact because they are installed at existing commercial or industrial facilities. Some distributed generation systems such as diesel generators can have significant environmental impacts.

Impacts on Alaska

Distributed generation enables business and industrial development in remote locations creating new jobs and industries throughout the State. However, as an imported generation technology installed at an existing facility there would be few construction or operating jobs and fuel cells could have a negative effect on the Alaskan economy.

APPENDIX D
REFERENCES

[1] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South-Central Alaska Natural Gas Study. June 2004.
http://www.fe.doe.gov/programs/oilgas/publications/naturalgas_general/southcentralalaska_study.pdf
[2] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South-Central Alaska Natural Gas Study. June 2004.
http://www.fe.doe.gov/programs/oilgas/publications/naturalgas_general/southcentralalaska_study.pdf
[3] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[4] Ibid.
[5] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[6] Galena Nuclear Power Plant. Presentations at the 2005 Alaska Rural Energy Conference. Valdez, Alaska. September 20, 2005.
[7] Ken Wilber. The Integral Operating System 1.0. Sounds True Recordings. 2005. Don Beck and Chris Cowan. Spiral Dynamics. Blackwell Publishers. 1996.
[8] Hellenthal Associates February 20, 2003. Spur Line or Cook Inlet Exploration?
[9] The Wall Street Journal. Jeff Lowenfels. In a Nimby World, Alaskans Woo Project To Their Backyard Builds Support For Natural Gas Pipeline January 27, 2006; Page A1.
[10] Petroleum News. Alan Bailey. "New Contract Sparks Debate". Vol. 11. No. 2. Week of January 8, 2006. http://www.petroleumnews.com/pnarchpop/060108-02.html.
[11] Petroleum News. The Explorers. Released November 2005.
[12] Wall Street Journal. R.A. Dillion. Harris Wants Other Gas Line Proposals Aired. FBSX News-Miner. Published on January 25, 2006.
[13]American Gas Association. Natural Gas Glossary. Available at:
http://www.aga.org/Content/NavigationMenu/About_Natural_Gas/Natural_Gas_Glossary/Natural_Gas_Glossary_(A).htm#A
[14] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South-Central Alaska Natural Gas Study. June 2004.
http://www.fe.doe.gov/programs/oilgas/publications/naturalgas_general/southcentralalaska_study.pdf
[15] Ibid.
[16] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[17] U.S. Department of Interior. Minerals Management Service. Press Release "MMS Reevaluate Proposed Cook Inlet Sale". December 6, 2005.
http://www.mms.gov/alaska/latenews/newsrel/News%20Releases%202005/051108-3407.pdf
[18] Information from the following sources:
Cook Inlet Oil and Gas. Kenai Peninsula Borough Oil and Gas History.
http://www.cookinletoilandgas.org/kpb/history.htm

ConocoPhillips Fact Book. 2005. www.conocophillips.com,

Marathon. Oil Corporation. 2005_Factbook.pdf . Available at www.marathon.com.

Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.

[19] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at:
www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[20] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[21] Ibid.

[22]Jeff Barron. UPDATE: Enstar secures 60-Bcf supply agreement from Marathon to tie in natural gas for next decade. November 18, 2005. http://www.snl.com/InteractiveX/article.aspx?CDID=A-2225859-10852
[23] Ibid.
[24] Petroleum News. Dispelling the Alaska Fear Factor. Annual Publication 2005-2006. http://www .petroleumnews.com/products/FearFactor2005.pdf.
[25] Minerals Management Service. Cook Inlet Gas Gathering System Available at: http://www.mms.gov/alaska/ref/EIS%20EA/DEIS/Maps/Map_18.pdf
[26] Petroleum News. The Explorers: Oil and Gas Companies Investing in Alaska's Future. Annual Report. Released November 2005. Available at: http://www.petroleumnews.com/products/explorers2005.pdf.
[27] Marathon Oil Corporation. Fifty Years on the Last Frontier. Marathon Alaska. Presented on August 25, 2005.
http://www.cookinletoilandgas.org/PowerPoint%20Presentations/PDF%20Versions/August%2026%20Field%20Tour.pdf
[1]Power plant data from: Chugach Electric. http://www.chugachelectric.com/inside/facilities.html and ML&P: http://www.mlandp.com/new%20paint/utilityprofile2004.pdf accessed on February 2, 2006.
[2]Institute for Social and Economic Research (ISER). University of Alaska Anchorage. Alaska Power Statistics 1960-2001. November 2003. From:
http://www.iser.uaa.alaska.edu/Publications/akelectricpowerfinal.pdf.
[3]Jim Posey, General Manager Anchorage Municipal Power & Light. Electric Power Update. Presentation to the Anchorage Chamber of Commerce. March 10, 2003. Available at:
http://www.chugachelectric.com/pdfs/news/Anchorage_Chamber_03-10-03.pdf.
[4]Ibid.
[5]U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. Available at:
www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[6]Alaska Department of Natural Resources. Alaska Natural Gas In-State Demand Study. ASP 2001-1000-2650. Prepared by Econ One Research, Inc. and Acadian Consulting Group. January 23, 2002. From: http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/demand/instate_gas_v1.pdf.
[7]Ibid. Appendix C. In-State Natural Gas Demand and Supply Issues.
[35] Bill Boycott. Agrium Inc. Kenai Nitrogen Operations: Adding Value to Alaska. March 2004. Available at: http://www.cookinletoilandgas.org/Industry/Agrium/Agrium/PowerPoint%20Presentations/boycott.pdf.
[36] Agrium Inc. Image downloaded from: http://www.agrium.com/company_profile/our_operations/791.jsp on February 5, 2006.
[37] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at:
www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[38] Petroleum News. Steve Sutherlin. Agrium Fertilizer Plant gets year reprieve. July 24, 2005. Vol. 10, No. 30. Available at: http://www.petroleumnews.com/pnarchpop/050724-15.html.
[39] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. From: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[40] ConocoPhillips Fact Book. 2005. From: www.conocophillips.com,
Marathon. Oil Corporation. 2005_Factbook.pdf. Available at www.marathon.com.
Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. From: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[41] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at:
www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[42] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.

[43] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.

[44] Alaska Department of Natural Resources. Alaska Natural Gas In-State Demand Study. ASP 2001-1000-2650. Prepared by Econ One Research, Inc. and Acadian Consulting Group. January 23, 2002. From: http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/demand/instate_gas_v1.pdf.
[45]Enstar Rates. 2006. Downloaded from: http://www.Enstarnaturalgas.com/CompanyInfo/rate_info.htm on 2/2/06.
[46] Petroleum News. Alan Baily. New contract sparks debate. January 08, 2006. Vol 11. No.2 Downloaded from: http://www.petroluemnews.com/pnarchpop/060108-02.html on February 5, 2006.
[47] Enstar Natural Gas Company. Tony Izzo, President. Cook Inlet Oil and Gas in Transition. Presentation to RDC Annual Conference. November 15, 2005. From: http://www.akrdc.org/membership/events/conference/2005/presentations/izzo.pdf.
[48] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[49] Alaska Department of Natural Resources. Division of Oil and Gas. Cook Inlet Natural Gas Monthly Production Statistics. FY 2004.
[50] Bill Popp. Kenai Peninsula Borough. Cook Inlet Oil & Gas 2004 Annual Report. January 21, 2005. From: http://www.cookinletoilandgas.org/KPB/Economics/KPB%20Oil%20&%20Gas%20Industry%20Report%2001.21.05.pdf.
[51] Associated Press. Continuing cold temporarily shuts down Nikiski fertilizer plant. Downloaded from: http://www.ktva.com/local/ci_3445642 on February 8, 2006.
[52] Petroleum News. Kristen Nelson. Unocal applies to provide more gas storage; new project underway. February 27, 2005. Vol. 10, No.9. Available at: http://www.petroleumnews.com/pntruncate/611892659.shtml
[53]Alaska Department of Natural Resource. Division of Oil and Gas. DNR Approves Unocal Cook Inlet Gas Storage Lease. October 19, 2005. Available from: http://www.dnr.state.ak.us/standard/dsp_media_release.cfm?id=547&title=DNR%20Approves%20Unocal%20Cook%20Inlet%20Gas%20Storage%20Lease.
[54]Kenai Peninsula Borough. Public Notice of Gas Storage Lease Application. 1/06/2006. Available from: http://notes5.state.ak.us/pn/pubnotic.nsf/0/40894d9b2bbf54ce892570ee00649cc7?OpenDocument
[55] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. From: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[56] ConocoPhillips Fact Book. 2005. From: www.conocophillips.com,
Marathon. Oil Corporation. 2005_Factbook.pdf. Available at www.marathon.com.
Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004. From: http://www.dog.dnr.state.ak.us/oil/products/publications/annual/report.htm.
[57] Bill Popp. Kenai Peninsula Borough. Cook Inlet Oil & Gas 2004 Annual Report. January 21, 2005. From: http://www.cookinletoilandgas.org/KPB/Economics/KPB%20Oil%20&%20Gas%20Industry%20Report%2001.21.05.pdf.
[58] Bill Popp. Kenai Peninsula Borough. Current Issues and Projects Summary. August 15, 2005.
[59]Image downloaded from: http://www.marathon.com/Our_Business/Marathon_Oil_Company/Exploration_Production/United_States/Alaska/ on February 8, 2006.
[60] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[61] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[62]Fairbanks Natural Gas. http://www.fngas.com/about.html.
[63] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.

[64]http://www.eere.energy.gov/windandhydro/windpoweringamerica/images/workshops/02_wind_diesel/kotz2_s.jpg.

[65] Petroleum News. Alan Bailey. Harnessing Alaska winds. May 29, 2005. Vol. 10, No. 22. Available at: http://www.alternative-energy.ws/content/view/120/.
[66] Alaska Journal of Commerce. Clair Chandler. Grant fuels further study on wind power project. Web posted May 15, 2005. Available at: http://www.alaskajournal.com/stories/051505/hom_20050515003.shtml
[67] Bill Boycott. Agrium Inc. Kenai Nitrogen Operations: Adding Value to Alaska. March 2004. Available at: http://www.cookinletoilandgas.org/Industry/Agrium/Agrium/PowerPoint%20Presentations/boycott.pdf.
[68] Agrium Inc. Image downloaded from: http://www.agrium.com/company_profile/our_operations/791.jsp on February 5, 2006.
[69] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[70] Petroleum News. Steve Sutherlin. Agrium Fertilizer Plant gets year reprieve. July 24, 2005. Vol. 10, No. 30. Available at: http://www.petroleumnews.com/pnarchpop/050724-15.html.
[71] Black & Veatch. New/Events. From Petroleum News. Step Closer to Coal. November 21, 2005. Available at: http://www.bv.com/news/articles/nov05/step_closer.htm.
[72] http://www.netl.doe.gov/publications/press/1998/tl_healystart.html.
[73] Alaska Industrial Development and Export Authority (AIDEA). Project Fact Sheet: Healy Clean Coal Project (HCCP). Reviewed July 18, 2005. http://www.aidea.org/PDF%20files/HCCP/HCCPFactSheet.pdf.
[74] Alaska Business Monthly. "Usibelli revived: things are looking for this interior coal mine". August 2005.
[75] http://www.eere.energy.gov/femp/images/derchp_alaska.jpg.
[76] Alaska Journal of Commerce. Patricia Liles. Alaska at the forefront of fuel cell studies. Web posted July 2, 2004. Available at: http://www.alaskajournal.com/stories/070204/loc_20040702007.shtml.
[77] U.S. Department of Energy. Federal Energy Management Program. Combined Heat and Power Case Study: Fuel Cells Provide Reliable Power to U.S. Postal Service Facility in Anchorage Alaska. PNNL-SA-35098. February 2002. Available at: http://www.eren.doe.gov/femp.
[78] Chugach Electric Association. 2004 Annual Report. Available at: http://www.chugachelectric.com/pdfs/2004_annual_report.pdf.
[79] Image downloaded from: http://www.mms.gov/alaska/kids/shorts/workplat/cookinlt.jpg.
[80] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[81] Aurora Gas, LLC. Press Release. July 26, 2005. Aurora Gas, LLC Progresses in Effort to Bring More Cook Inlet Gas to Market. http://www.aurorapower.com/newspop05_07_26.htm.
[82] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[83] Petroleum News. The Explorers. Released November 2005.
[84] Ibid.
[85] Alaska Business Monthly. Mike Bradner. "Less Than a Decade: Firewood for Fuel?" September 2005.
[86] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[87] Alaska Department of Natural Resources. Enforceable Standards for Development of State Owned Coalbed Methane Resources in the Matanuska-Susitna Borough. December 2004. Available at: http://www.gasdrillingmatsu.org/dnrstandards.html
[88] Alaska Power Association. New Energy for Alaska. March 2004. Available at: www.alaskapower.org.
[89]U.S. Department of Energy. Energy Efficiency and Renewable Energy. Wind & Hydropower Technologies Program. Hydropower Setting a Course for our Energy Future. DOE/GO-102004-1981. July 2004. Available at: http://www.nrel.gov/docs/fy04osti/34916.pdf.
[90]Image downloaded from: http://www.marathon.com/Our_Business/Marathon_Oil_Company/Exploration_Production/United_States/Alaska/ on February 8, 2006.
[91] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[92] Bill Popp. Kenai Peninsula Borough. Current Issues and Projects Summary. August 15, 2005.
[93] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.

[94] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[95] "Transport of North Slope Natural Gas to Tidewater" report to ANGDA April 7, 2005, Michael Baker
[96] "Delta Junction to Glennallen Natural Gas Pipeline Engineering Feasibility and Cost Assessment" report to ANGDA Sept. 2005, URS Corp.
[97] "UA Policy Brief: The Alaska Natural Gas Pipeline - What's It All About?" Nov. 2005, Institute of Social and Economic Research • University of Alaska Anchorage.
[98] Kenneth Griffin. Alaska Department of Natural Resources. Division of Oil and Gas. Alaska's Department of Natural Resources: Staying the Course. Presentation to the Resource Development Council Annual Conference. November 16, 2005.
[99] John Barnes, Marathon Oil Corporation. Alaska Oil and Gas: On the Verge of Another Boom? Presentation at the 26th Annual Resource Development Council Conference. November 16, 2005.
[100] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[101] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[102] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[103] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[104] Aurora Gas, LLC. Press Release. July 26, 2005. Aurora Gas, LLC Progresses in Effort to Bring More Cook Inlet Gas to Market. http://www.aurorapower.com/newspop05_07_26.htm.
[105] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[106] Petroleum News. The Explorers. Released November 2005.
[107] Ibid.
[108] Alaska Business Monthly. Mike Bradner. "Less Than a Decade: Firewood for Fuel?" September 2005.
[109] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[110] http://www.undergroundinfo.com/uceditorialarchive/Jan03/janpipeline.pdf
[111] http://www.enstarnaturalgas.com/CompanyInfo/rate_info.htm.
[112] "Transport of North Slope Natural Gas to Tidewater" report to ANGDA April 7, 2005, Michael Baker
[113] "Delta Junction to Glennallen Natural Gas Pipeline Engineering Feasibility and Cost Assessment" report to ANGDA Sept. 2005, URS Corp.
[114] "Cook Inlet Oil, Gas and Mining Update" presented to Kenai Chamber of Commerce 26 Oct. 2005, Bill Popp.
[115] "UA Policy Brief: The Alaska Natural Gas Pipeline - What's It All About?" Nov. 2005, Institute of Social and Economic Research • University of Alaska Anchorage
[116] "Monetizing Northern Frontier Gas; Is the Market Window Closing?" 11 May 2005, Tristone Capital
[117] "Report to Congress on progress made in licensing and constructing the Alaska natural gas pipeline" FERC February 1, 2006
[118] "Interim Feasibility Report All-Alaska LNG Project" Sept. 2004, ANGDA
[119] "Report to Congress on progress made in licensing and constructing the Alaska natural gas pipeline" FERC February 1, 2006.
[120] "Monetizing Northern Frontier Gas; Is the Market Window Closing?" 11 May 2005, Tristone Capital
[121] "Cook Inlet Oil, Gas and Mining Update" presented to Kenai Chamber of Commerce 26 Oct. 2005, Bill Popp.
[122] "Report to Congress on progress made in licensing and constructing the Alaska natural gas pipeline. FERC February 1, 2006.
"Cook Inlet Gas Spur Line Project" report to ANGDA Sept. 2004, R.L. Odsather
[123] "Delta Junction to Glennallen Natural Gas Pipeline Engineering Feasibility and Cost Assessment" report to ANGDA Sept. 2005, URS Corp.
[124] http://www.allalaskalng.com

[125] "Cook Inlet Oil, Gas and Mining Update" presented to Kenai Chamber of Commerce 26 Oct. 2005, Bill Popp.
[126] "Report to Congress on progress made in licensing and constructing the Alaska natural gas pipeline" FERC February 1, 2006.
[127] Interim Feasibility Report All-Alaska LNG Project" September. 2004, ANGDA.
[128] Interim Feasibility Report All-Alaska LNG Project" Sept. 2004, ANGDA.
[129] Interim Feasibility Report All-Alaska LNG Project" Sept. 2004, ANGDA.
[130] "Transport of North Slope Natural Gas to Tidewater" report to ANGDA April 7, 2005, Michael Baker.
[131] "Transport of North Slope Natural Gas to Tidewater" report to ANGDA April 7, 2005, Michael Baker.
[132] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[133] Alaska Department of Natural Resources. Enforceable Standards for Development of State Owned Coalbed Methane Resources in the Matanuska-Susitna Borough. December 2004. Available at: http://www.gasdrillingmatsu.org/dnrstandards.html
[134] Alaska Department of Natural Resources. Division of Oil and Gas. Alaska Oil & Gas Report. December 2004.
[135] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004.
[136] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[137] Bill Popp. Kenai Peninsula Borough. Current Issues and Projects Summary. August 15, 2005.
[138] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[139] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[140] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[141] Alaska Natural Gas Development Authority. ANGDA. Commercial Future of the Kenai LNG Plant. Prepared by Shaw Stone and Webster Consultants. DRAFT. October 2005.
[142] Alaska Division of Oil and Gas. Alaska Peninsula Areawide 2005. Lease Sale results. Available from: http://www.dog.dnr.state.ak.us/oil/products/publications/akpeninsula/as_2005_summary.pdf.
[143] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[144] Petroleum News. The Explorers. 2005. Available at: http://www.petroleumnews.com/products.shtml.
[145] Anchorage Daily News. Nenana natural gas may cut Interior heating costs. Published August 25, 2005. Accessed at: http://www.adn.com/money/industries/oi/v-printer/story/6857202p-6752985c.thml.
[146] Black & Veatch. New/Events. From Petroleum News. Step Closer to Coal. November 21, 2005. Available at: http://www.bv.com/news/articles/nov05/step_closer.htm.
[147] Bill Boycott. Agrium Inc. Kenai Nitrogen Operations: Adding Value to Alaska. March 2004. Available at: http://www.cookinletoilandgas.org/Industry/Agrium/Agrium/PowerPoint%20Presentations/boycott.pdf.
[148] Agrium Inc. Image downloaded from: http://www.agrium.com/company_profile/our_operations/791.jsp on February 5, 2006.
[149] U.S. Department of Energy. National Energy Technology Laboratory. Arctic Energy Office. South Central Alaska Natural Gas Study. Final Report. June, 2004. Available at: www.fe.doe.gov/programs/oilgas/publications/ naturalgas_general/southcentralalaska_study.pdf.
[150] Petroleum News. Steve Sutherlin. Agrium Fertilizer Plant gets year reprieve. July 24, 2005. Vol. 10, No. 30. Available at: http://www.petroleumnews.com/pnarchpop/050724-15.html.
[151] Black & Veatch. New/Events. From Petroleum News. Step Closer to Coal. November 21, 2005. Available at: http://www.bv.com/news/articles/nov05/step_closer.htm.
[152] Electric Power Research Institute (EPRI). Stu Dalton. Cost Comparison IGCC and Advanced Coal. Presentation at the Roundtable on Deploying Advanced Clean Coal Plants. July 29, 2004. Available at: http://www.climatevision.gov/pdfs/coal_roundtable/dalton.pdf

[153] Usibelli Coal Mine, Inc. Coal as a Utility Resource. Presentation to the Alaska Energy Policy Task Force. March , 2004. Available at: http://www.aidea.org/aea/EnergyPolicyTaskForce/UCM3-9-04.pdf.
[154] Alaska Industrial Development and Export Authority (AIDEA). Project Fact Sheet: Healy Clean Coal Project (HCCP). Reviewed July 18, 2005. http://www.aidea.org/PDF%20files/HCCP/HCCPFactSheet.pdf.
[155] Alaska Business Monthly. "Usibelli revived: things are looking for this interior coal mine". August 2005.
[156] http://www.aidea.org/aea/EnergyPolicyTaskForce/UCM3-9-04.pdf.
[157] Alaska Power Association. New Energy for Alaska. March 2004. Available at: www.alaskapower.org.

[158]U.S. Department of Energy. Energy Efficiency and Renewable Energy. Wind & Hydropower Technologies Program. Hydropower Setting a Course for our Energy Future. DOE/GO-102004-1981. July 2004. Available at: http://www.nrel.gov/docs/fy04osti/34916.pdf.
[159] Ibid.
[160] Petroleum News. Alan Bailey. Harnessing Alaska winds. May 29, 2005. Vol. 10, No. 22. Available at: http://www.alternative-energy.ws/content/view/120/.
[161] Alaska Journal of Commerce. Clair Chandler. Grant fuels further study on wind power project. Web posted May 15, 2005. Available at: http://www.alaskajournal.com/stories/051505/hom_20050515003.shtml
[162] Petroleum News. Alan Bailey. Economics of nuclear power for rural Alaska. November 6, 2005.
[163] Douglas Rosinski. Reactor Licensing Process Overview. Presentation at the Alaska Rural Energy Conference. September 20, 2005. Available at: http://www.uaf.edu/aetdl/PDF%20File/2005%20Conference%20Presentiations/RAEC%2005-III-C-03%20%20050909%20AREC%202005%20cd%20final.pdf.
[164] U.S. Department of Energy. Energy Efficiency and Renewable Energy. Wind & Hydropower Technologies Program. Hydropower Setting a Course for our Energy Future. DOE/GO-102004-1981. July 2004. Available at: http://www.nrel.gov/docs/fy04osti/34916.pdf.
[165] Tidal Electric of Alaska, Inc. Feasibility Study for Cordova Electric Cooperative on Cordova Tidal Power Project. 2001. Available at http://www.aidea.org/aea/publicationsaeeep.html. http://www.aidea.org/aea/publicationsaeeep.html.
[166] U.S. Department of Energy. Weatherization Program. Data available at: http://www.eere.energy.gov/weatherization/cfm/index.cfm/state_abbr=ak.
[167] Enstar Natural Gas Company. Enstar's Rates Information. Available at: http://www.enstarnaturalgas.com/CompanyInfo/rate_info.htm.
[168] Alaska Department of Natural Resources. Alaska Natural Gas In-State Demand Study. ASP 2001-1000-2650. Prepared by Econ One Research and Acadian Consulting Group. January 23, 2002. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/otherreports.htm.
[169]Homer Electric Association. Press Release. Electric Rates to Increase in 2006. January 11,2006. Downloaded from: http://www.homerelectric.com/Press%20Releases/Electric%20Rates%20to%20Increase%20in%202006.htm. On January 30, 2006.
[170] Alaska Department of Natural Resources. Alaska Natural Gas In-State Demand Study. ASP 2001-1000-2650. Prepared by Econ One Research and Acadian Consulting Group. January 23, 2002. Available at: http://www.dog.dnr.state.ak.us/oil/products/publications/otherreports/otherreports.htm.
[171] Alaska Journal of Commerce. Patricia Liles. Alaska at the forefront of fuel cell studies. Web posted July 2, 2004. Available at: http://www.alaskajournal.com/stories/070204/loc_20040702007.shtml.
[172] U.S. Department of Energy. Federal Energy Management Program. Combined Heat and Power Case Study: Fuel Cells Provide Reliable Power to U.S. Postal Service Facility in Anchorage Alaska. PNNL-SA-35098. February 2002. Available at: http://www.eren.doe.gov/femp.
[173] Chugach Electric Association. 2004 Annual Report. Available at: http://www.chugachelectric.com/pdfs/2004_annual_report.pdf.
[174] Alaska Journal of Commerce. Patricia Liles. Alaska at the forefront of fuel cell studies. Web posted July 2, 2004. Available at: http://www.alaskajournal.com/stories/070204/loc_20040702007.shtml.