Alaska North Slope
Gas Commercialization
BRIEFING PAPER

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I. INTRODUCTION

A. THE RESOURCE

Alaska's North Slope contains 35 trillion cubic feet (tcf) of already discovered natural gas, the energy equivalent of 6 billion barrels of oil or about half of the original recoverable oil reserves in Prudhoe Bay. This is a very large amount of gas and could supply 10 percent of the total Lower 48 needs for 15 years.

Most of the gas – about 26 tcf -- is in the Prudhoe Bay reservoir, with about 3 tcf to 5 tcf at Point Thomson and the rest distributed among other North Slope reservoirs.

That total represents only the gas that has been found while exploring for oil. It's a safe assumption that significantly more gas exists on the North Slope and would be found if there were a market for the resource. Petroleum geologists estimate the North Slope's potential gas reserves at up to 100 trillion cubic feet.

The gas has been used during the past two decades of Prudhoe production to enhance oil recovery. Each day about 8 billion cubic feet (bcf) of gas are produced and re-injected back into the reservoir. That gas is not lost; just think of it as a savings account with limitations on early withdrawal.

Natural gas is almost all methane, used for residential and commercial heating and — more importantly in the context of a world hungry for clean-burning fuel — natural gas is the fuel of choice for new electrical generating plants. Natural gas also is used as the feedstock for various manufacturing processes, such as the fertilizer plant at Nikiski.

What follows is the Department of Revenue's analysis of the various proposals for commercializing Alaska North Slope gas, including a discussion of the current situation, the resource itself and legislative issues.

There are five matrices at the end of this report. The Department of Revenue prepared two matrices comparing the various proposals and listing the current positions of interested parties. The Department of Environmental Conservation prepared three charts to provide a broad-brush review of environmental issues for the major proposals.

B. GAS COMMERCIALIZATION

The commercialization of North Slope gas is elusive. If it's the carrot on a stick, then the stick is a pipeline hundreds of miles long.

A major problem is that natural gas has low energy density compared to crude oil. The same volume of natural gas in a pipeline provides about one-fifth the energy of oil. As a consequence, it's much more expensive to transport gas than it is oil. Looking at a map and measuring Alaska's distance from world energy markets tells us why the gas remains on the North Slope.

In addition to its distance from market, and the high cost of getting it to market, North Slope gas for the past 24 years has had a higher use – going back into the ground to pressurize the oil field. North Slope gas is injected back into the reservoir to maintain pressure for forcing oil out of the ground. Any gas commercialization project at Prudhoe Bay would decrease the pressure in the reservoir and reduce oil recovery, costing the state and producers lost income.

We estimate that a gas project depleting about 2 billion cubic feet per day starting up in 2007 -- with a six-year ramp-up to full capacity -- would reduce total oil production from the Prudhoe Bay oil field by about 300 million barrels over the remaining life of the field.

Reduced oil production also would increase the TAPS tariff – lower oil flows would mean higher charges for the oil that remains.

Notwithstanding the inevitable losses from decreased oil production, it would make sense to commercialize the gas if substituting gas production for oil production would result in an increased total revenue stream from the reservoir.

C. RECENT INTEREST IN NORTH SLOPE GAS

As the oil flow at Prudhoe Bay declines, the untapped gas reserves increase in value relative to the remaining oil reserves. Although there are no producing gas fields on the North Slope, much of the infrastructure needed to commercialize its gas reserves already exists (such as drilling pads and support services). In addition, as the oil reservoir has aged, gas as an instrument of enhanced oil recovery has become less important.

Technological advances also make the region's gas more attractive than when Prudhoe started producing oil 24 years ago.

The "environmental premium" reflected in Lower 48 prices for natural gas also could help attract the billions of dollars needed to develop North Slope gas reserves.

U.S. gas demand is expected to noticeably increase in the next 10 years as coal, oil and nuclear plants are retired and replaced with newer gas-powered plants. Gas prices in the Lower 48 have been climbing recently due to high weather-related and industrial demand. The weather-related demand is not just relegated to winter heating; the increased demand for electricity to power summer air conditioners is adding to the need for more generating capacity.

While over the past 15 years the long-term market price for gas in the Midwest has been no more than $2 per million BTUs, the price approached $4.50 earlier this summer. However, just as with oil prices, gas prices can fluctuate and there's no guarantee that today's high prices will become permanent. The futures market shows that buyers are well aware of this. As of July 17, natural gas prices for August 2000 delivery were $4.14, but the price was down to $3.21 for June 2002 delivery and $3.05 for July 2003 shipments.

D. REALIGNMENT AT PRUDHOE BAY

In originally establishing their respective working interests for the leases that comprise the jointly operated Prudhoe Bay field, the producers allocated production and cost percentages for their shared oil and gas production. While some producers mostly owned leases principally overlying oil reserves, other producers mostly owned leases principally over gas reserves.

The resulting allocations were cumbersome. For example, BP owned just slightly more than 50% of the working interest in the Oil Rim yet had only a 13% working interest in the Gas Cap. However, not all of the gas is in the Gas Cap. There also is a substantial volume of gas dissolved in the oil in the Oil Rim. BP's working interest in the total gas was 24%, almost double its interest in the gas contained within the Gas Cap.

The uneven allocation of oil and gas production and costs provided a variety of incentives – and disincentives – for commercializing North Slope gas. It made disputes more likely than if there were common shared interests. What might be good for a major gas owner might not be as good for a company with a greater share of the oil in the same reservoir.

Proponents of North Slope gas commercialization were handed an unexpected bonus from the following chain of events: BP's purchase of Arco; BP's subsequent sale of Arco's Alaska assets to Phillips; and the subsequent lawsuit by Exxon that stimulated a realignment of the working interests at Prudhoe Bay.

The result brought order to the companies' interests in the Oil Rim and the Gas Cap. Instead of different rates for gas in the Gas Cap and the Oil Rim, BP now has the same 27% interest in both the Oil Rim and the Gas Cap. Phillips holds a 36% interest in each area, with Exxon at 37%. Simply put, what is good for one is now equally good for all.

Accordingly, the barriers to gas commercialization that may have resulted from the disparity of interests, including the need for complicated substance and cost allocation accounting mechanisms, have been removed.

E. MAJOR OPTIONS FOR GAS COMMERCIALIZTION

Commercialization options for North Slope gas fall into one of three major categories:

- Liquefied natural gas (LNG).
- Gas-to-liquids (GTL).
- Natural gas, moving through a pipeline to markets in the Midwest.

Any one of these options could cause the North Slope to become a center for gas exploration and development. One way to think about it would be that we have the opportunity to create an industry, not just a project. If, in fact, the producable gas on the North Slope totals 100 trillion cubic feet, those reserves would support the natural gas industry in Alaska for well over half a century.

Though this report provides more information on each option in separate sections, it is important to note that there are at least two possibilities for the natural gas pipeline. One is a line running offshore from Prudhoe Bay to the gas-rich Mackenzie Delta region of Canada's arctic plain. From there, a line would be constructed south to connect with the existing gasline network in northern Alberta. The other option is a gasline from Prudhoe Bay, south to Fairbanks and then turning into Canada and along the highway to Alberta. Other, less talked about options, would run a pipeline from Prudhoe either through or around the Arctic National Wildlife Refuge and then into the Mackenzie region.

The three options of LNG, GTL or a gasline should not be considered as an either or proposition, but rather it is possible that the North Slope's gas reserve could support two of the projects. And some would say that all three are possibilities are different levels of production and, perhaps, at different times. For example, a gasline from Prudhoe Bay to Fairbanks could provide a gas supply for a GTL plant in Fairbanks at the same time as it heads into Canada with a still substantial flow of natural gas for Midwest markets. Or, a gasline could run to Fairbanks and then branch in two directions – one line to Canada and a second line to Valdez or the Kenai Peninsula to supply a GTL plant and/or an LNG plant.

The synergies from the three options could make all of them more possible.

It is important to remember that none of these projects have been demonstrated to be economic at this time, and it is not certain if any of them will ever be economic.

F. STATE REVENUES

As stated in the introduction, gas is intrinsically more expensive to transport to market than oil because the value of the flow per dollar invested is less for gas than for oil. Accordingly, it is unlikely that any gas project, even if commercially feasible, would bring in state revenues approximating those of oil. No one should look at the North Slope gas reserves as the same golden egg as the region's oil reserves – the goose may be the same but one egg is Double AA jumbo and the other is medium.

That said, a gas commercialization project could go a long way toward reducing the state's long-term gap between income and the cost of essential public services.

Based on modeling of various alternatives, it is our judgment that a gas project could bring in as much as $200 million annually to the state treasury on a sustained basis. However, it also could produce much less, depending on whether the project is located all or in part in Alaska; pipeline tariffs; market prices for the gas; and ownership of the project.

II. LIQUEFIED NATURAL GAS

A. INTRODUCTION

Liquefied natural gas (LNG) is methane refrigerated to minus 260 degrees Fahrenheit to turn it into a liquid, making it suitable for shipment by tanker.

An Alaska North Slope LNG project would entail conditioning of the raw gas on the North Slope to remove carbon dioxide and the construction of a natural gas pipeline from the North Slope to tidewater, where it would be liquefied into LNG and shipped on specialized tankers to market. Valdez or the Kenai Peninsula are considered the most likely locations for the liquefaction terminal.

For many years, LNG was considered the most likely option for commercializing gas. The Lower 48 appeared to have ample lower-cost supplies, and GTLs were in their technological infancy and very expensive. LNG has always been geared toward markets with few energy resources nearby and only costly options for importing their energy supplies. The Far East was such a market. Customers were importing expensive LNG from distant sources, including Cook Inlet, and there was hope Alaska North Slope LNG could be competitive in this market.

B. ECONOMICS

As mentioned above, an LNG project would entail gas conditioning, a gas pipeline, liquefaction facilities and tankers. This would be very expensive. Until recently, it was thought that it would take the marketing of a large volume of gas, about 2 billion cubic feet per day (bcf/d), to bring the large per-unit fixed costs, especially the pipeline, down to a point where the required per-unit gas price would be competitive. The estimated cost of a project delivering 2 bcf/d is about $12 billion. Recent engineering advances may have dropped the minimum sales volume number in half, to about 1 bcf/d, but that is still a very large amount in the available marketplace.

Alaska LNG would compete in the Asian gas market, mainly Japan, South Korea and Taiwan. The competition from other areas for the same market is intense. Whereas Alaska has 35 tcf in reserves, other countries selling into the same market, including Indonesia, Malaysia, Australia, Abu Dhabi and Qatar, have 50 times this amount. There are additional other countries around the Pacific Rim, with sizable gas reserves that are also interested in selling LNG to this market.

Currently, the available Asian market is fairly limited. Demand growth is expected to be about 5% per year over the next 10 years. China, which may be at the embryonic stage of LNG consumption, is studying the possibility of less costly pipeline gas from former Soviet republics. China's shortage of capital for LNG is also a problem. India faces a similar situation, but may become an LNG importer from either the Middle East or Bangladesh.

All LNG projects are very capital intensive. This necessitates long-term purchase contracts with buyers. Existing projects will always have an advantage in supplying incremental demand because the associated marginal costs will be so much lower than new projects. Recently, there has been a drastic increase in spot sales in Asian LNG markets from existing projects with excess supply. Alaska is the only jurisdiction that requires a long and very costly pipeline, and this additional cost necessitates the marketing of large volumes to bring down the per-unit costs. Consequently, for an Alaska project to compete at the necessary volumes, it would have to capture a large share of the incremental market

Alaska does have some advantages in marketing LNG. The political climate of the United States is considered very stable. The gas reserves are known and produced. And, with advances in trenching and welding technology, the pipeline cost disadvantage has been somewhat reduced.

But after all these different factors are considered, the possibilities for a profitable, stand-alone Alaska North Slope LNG project look bleak today.

C. RELATIVE ADVANTAGES OF AN LNG PROJECT

1. An LNG project would make natural gas available to communities along the pipeline route. The pipeline would go near Fairbanks. If the line went to Valdez, gas would be available to Valdez. A spur line from Glennallen or Fairbanks to Anchorage would be possible. If the pipeline went to Cook Inlet, the gas would be available to the communities in Southcentral Alaska. This could be important over the next several years as some people believe Cook Inlet may run out of gas in the 2010-2020 time period.

2. Another advantage of an LNG project is the very large increase in economic activity the construction of a pipeline would create for a 2- to 3-year time period. Of course, this would also create social stresses and the state could look forward to another bust when the construction boom ends.

D. THE PLAYERS

1. The LNG Sponsor Group

In 1998, a consortium of companies formed an LNG sponsor group to study the feasibility of developing a viable LNG project to commercialize North Slope gas.

The group consists of Phillips (44%), Foothills Pipeline (25%), Marubeni (19%) and BP (12%). Yukon Pacific was originally in the group but has since left. BP has recently joined. Phillips' share increased from 14% with its acquisition of Arco's Alaska assets, including a 30% interest in the sponsor group.

The group has $20 million budgeted for the first phase of conceptual engineering, which is scheduled for completion this summer. A decision whether to continue work after Phase 1 will be made soon. It is expected that at that time the group will limit its efforts to studying synergies with other projects and risk reduction.

The sponsor group's efforts have been concentrated on defining the smallest project that could gain a foothold into the market, yet retain expansion potential. The relatively high cost of the pipeline requires marketing large volumes of gas to bring down the per-unit cost of gas moving through the pipeline. Gas volume large enough to achieve the needed low per-unit cost may be too large for the market to absorb in a relatively short period of time.

The group has made some progress in figuring out how to reduce the initial project size, with the ability to expand at lower per-unit costs as market conditions warrant. Preliminary indications are that the volume could be reduced by half with a 40 percent reduction in cost through a new entry design. Although this redesign may reduce the rate of return (an estimated 0.5%), the reduction in initial volume markedly enhances the ability of the project to market the gas. This significantly reduces the market risk as well as capital cost and finance risk of the project.

The group envisions a project structure in which the sponsors would invest in the facilities, buy gas from the North Slope producers and sell the LNG, either at the marine terminal, or in Asia, or both. The group is looking at both Valdez and Cook Inlet as possible pipeline terminus sites.

The sponsor group proposed and pursued HB 290, the legislation dealing with LNG economic regulations of the proposed project (see below).

2. Port Authority

The City of Valdez, the Fairbanks North Star Borough and the North Slope Borough together have formed a port authority under AS 29.35, the Port Authority Act, to: (1) buy natural gas from producers on the North Slope; (2) build the necessary infrastructure, including conditioning plant, pipeline to Valdez, and liquefaction facilities; and (3) market liquefied natural gas at Valdez for the Far East market. Under the terms of the authorizing statute, the purpose of a port authority is to "provide for the development of a port or ports for transportation-related commerce within the territory of the authority."

The attraction of the port authority approach is two-fold. First, the port authority structure would avoid all federal taxation on income. Under federal law, income earned by a state's political subdivisions is tax-exempt. The port authority requested a letter ruling from the IRS to establish that the port authority would be a tax-exempt political subdivision. The IRS responded with a letter ruling confirming the exemption.

The benefits of the income tax exemption would be sizable. The Department of Revenue estimates that on a 14 million metric tons per year project costing $12 billion, the tax exemption would be the equivalent of a $2 billion reduction in capital costs.

However, one important downside to the tax exemption is that it may preclude any private-equity participation in the project. As a consequence, the project would require 100 percent debt financing. Given that the Port Authority would have no other collateral to offer, any financing that may be available might come at a high cost.

Second, the interest on some of the port authority's project debt would be tax-exempt, making the debt more attractive to investors. Bond counsel to the port authority has suggested that debt would be tax-exempt only to the extent that it is used to pay for facilities directly used for public benefit. Consequently, this exemption would only apply to the infrastructure that provides gas to the communities and some small portion of the proposed port facility. Together, these are not expected to be much more than 10 percent of total project investment. Moreover, depending on how investors view the risk of the project, the tax-exempt interest rate might not necessarily be low cost.

Several aspects of the planned distribution of economic benefits from the proposed project are worth noting. First, the port authority intends to collect (from itself) a payment in lieu of property tax (PILT) equal to 20 mills of the assessed value of the project within each of the port authority municipalities and pay that amount to the municipalities. Unlike the property tax on other oil and gas facilities, the assessed value would not depreciate over time. This payment is in addition to payments the port authority says it will be distribute to itself, to other communities and to the state when it completes the project. In its advertised distribution plan, the port authority says it will pay out its "revenue" (net of operating costs, depreciation, debt, purchase price of the gas and the PILT) 60 percent to the state, 30 percent to other communities based on population, and the remaining 10 percent back to the port authority communities. We believe it is unlikely the project will have "revenue" in addition to the PILT to distribute.

3. The Yukon Pacific Corporation

The Yukon Pacific Corporation (YPC) is a business unit of the CSX Corporation, founded in 1982. YPC has obtained several permits that would be required to construct a natural gas pipeline to Valdez and a liquefaction terminal. These permits include:

- Presidential approval for export
- Project-wide environmental impact statement
- State and federal right-of-ways
- Department of Energy export authorization
- Anderson Bay final environmental impact statement

It is unclear the extent of involvement YPC would have in an LNG project. At a minimum, it would try to maximize the value of its permits. The extent to which other can duplicate its permits is unknown.

4. Cook Inlet Terminus Group

The Cook Inlet Terminus Group consists of citizens mainly from the Kenai-Soldotna area who are trying to focus on Cook Inlet, rather than Valdez, as the terminus of the natural gas pipeline.

III. GAS–TO-LIQUIDS TECHNOLOGY

A. INTRODUCTION

Gas-to-Liquids (GTLs) refers to the process of converting natural gas (methane) to high-value liquid petroleum products, mainly diesel fuel and naphtha.

A potential GTL project on the North Slope would convert natural gas to GTL products, batch them between crude oil shipments, and move them through the Trans-Alaska Pipeline (TAPS) to Valdez. At Valdez, GTLs could readily be separated from the crude oil and shipped to other markets.

B. THE PROCESS

Although there are various competing GTL technologies, they all have use similar processes. There are three basic steps: syngas manufacture, syngas conversion and product upgrading.

1. Syngas Manufacture

Oxygen, methane and steam are combined at high temperatures to produce synthesis gas (syngas), a mixture of carbon monoxide and hydrogen. To make syngas, some of the technologies require pure oxygen and some start with air. The former processes incur a high capital cost to isolate the oxygen. The latter process necessitates the costly use of larger reactor vessels to accommodate the atmospheric nitrogen. One area of GTL research is an effort to develop a ceramic membrane that would separate oxygen from air.

2. Conversion of Syngas to Paraffins

The second step involves a chemical reaction between the carbon monoxide and hydrogen (syngas) in the presence of a catalyst such as cobalt or iron, under certain temperatures and pressures, that converts the syngas to liquid hydrocarbons and water. This process was discovered in Germany in 1923 and used by the Germans to convert coal to liquid fuel during World War II. This process produces a long chain paraffinic (waxy) hydrocarbon.

3. Upgrading of Paraffins

The last step is to upgrade the product to high-quality GTL products, usually with the introduction of hydrogen and heat (hydrocracking). An important area of GTL research is the development of catalysts that will produce products that need less upgrading.

4. Product Values

GTL products are very clean. They are virtually free of sulfur, nitrogen, nickel, vanadium, asphaltenes, aromatics and salt. GTL diesel has high cetane rating, which facilitates fuel ignition and cold-weather performance. GTL products produce less nitrous oxide emissions and lower carbon dioxide emissions. Because of these properties, we estimate GTL diesel would carry a 40% premium over ANS.

GTL naphtha is almost purely paraffinic with low concentrations of naphthenes and aromatics. While, unlike most naphtha, this would preclude its use for gasoline feedstock, it makes an excellent feedstock for steam cracking operations to produce petrochemicals, especially ethylene. As ethylene feedstocks are in surplus on the West Coast, the most lucrative petrochemical market in the Pacific Rim for petrochemicals is China. Based on the historic relationship of ANS to naphtha prices in China, we estimate GTL naphtha would carry a 20% premium over ANS.

C. ECONOMICS

The GTL process is very expensive. However, where GTL technologies were formerly only feasible at oil prices approaching $30 per barrel, recent advances in the applicable technologies have reduced the threshold to the point where the process may play a major part in commercializing North Slope reserves.

There are only a handful of commercial GTL plants around the world. They are either not economic, economic because of sizable government subsidies, or economic because of exceptional proximity to niche markets for some of their products.

We estimate that a 100,000 barrel per day GTL plant, converting about 0.8 bcf/d, would have capital costs of $3.5 billion.

D. RELATIVE ADVANTAGES OF GTL TECHNOLOGY

As stated in the introduction, the low energy density of natural gas necessitates relatively large capital expenditures for moving the gas by pipeline. All of the gas pipeline alternatives require marketing a large amount of gas to attain the economies of scale needed to make these projects economical. To recover the high cost these pipeline proposals all require long-term contracts for very sizable volumes in specialized markets subject to intense competition. Successfully marketing a large enough volume to support the pipeline alternatives poses a very large challenge for these proposed projects.

GTL technology solves the low energy density problem by converting the gas to substances with high energy density. Although the capital costs are by no means trivial, the economies of scale are more workable. The per unit cost to produce 20,000 barrels a day of GTL products may not be much different than that to produce 100,000 barrels per day. Thus *if* a project is economic, it can be economic at relatively lower volumes.

Moreover, since GTL products primarily enter the transportation fuels market, they require no long-term commitments from the purchaser and can be readily sold when produced. Whereas the specialized LNG market subjects participants to the idiosyncrasies of individual participants, there is a large open market for GTL products. They can be readily sold when produced. No single firm in the marketplace can control the price, and the problem of marketing large volumes of gas is absent if TAPS is available to move the GTL products.

Another potential major advantage of a North Slope GTL project involves TAPS. The TAPS tariff is directly related to throughput. More barrels means a lower tariff, not just for Prudhoe Bay oil, but for all North Slope oil. The addition of GTL products to the pipeline could bring about a significantly lower tariff than would otherwise be the case in the coming decades. Such a reduction would facilitate both the expansion of oil development on the North Slope and increase the state's revenue base for oil royalties and production taxes. All of these together may also extend the life of TAPS and the North Slope oilfields.

Our analysis indicates a large scale GTL operation could reduce the TAPS tariff by $1 per barrel in the early years, growing to $3 per barrel in the latter years.

E. RELATIVE DISADVANTAGE OF GTLS

GTLs would not provide natural gas for community use. Moreover, it is possible that because of the specialized nature of the technology much of the infrastructure would be constructed outside Alaska and constructed in modules. This would limit direct benefits to the general economy.

F. THE PLAYERS

1. Exxon

Exxon has spent in excess of $400 million in GTL research and development and is a leader in developing GTL-related technology. The company has operated a pilot GTL plant for many years in Baton Rouge, Louisiana. Exxon has developed a proprietary process called AGC-21, or Advanced Gas Conversion for the 21st Century. It uses advanced reactor technology for the efficient, large-scale production of carbon monoxide and hydrogen from natural gas. The company also has developed new catalysts for the syngas-to-GTL conversion process, and has can tailor the products to specific market conditions. Exxon has developed large process units producing about 200 barrels per day to demonstrate this technology. It has extensively patented the process.

2. BP

BP has been developing a compact steam reformer technology, which uses water, rather than oxygen, to react with natural gas to generate syngas. They recently announced they will construct an $86 million, 300 barrel per day, pilot plant in Nikiski, which will begin operation in 2002. BP is also part of a consortium including Praxair, Phillips and Sasol, looking at ceramic membrane technology for making syngas. BP is a technical adviser to a federally funded University of Alaska Fairbanks project (see below) to study ways of moving the liquids through TAPS.

Arco had built a 70-barrel per day pilot plant at its Cherry Point refinery in Washington. The plant used Syntroleum's air-based syngas generation technology. It is our understanding that the study results, being an asset of Atlantic-Richfield and not Arco Alaska, were acquired by BP in the Arco acquisition, and that Syntroleum will conduct research at the plant. Arco was also part of a consortium headed by Air Products and Chemicals to develop a ceramic membrane technology, and was participating in federal ceramic membrane research.

3. Alaska Natural Gas to Liquids Company

Alaska Natural Gas to Liquids Company (ANGTL) is a newly formed company that wants to place a GTL plant on the North Slope using a slurry phase distillate process developed by a South African company, Sasol. Sasol developed its initial GTL technology process in two large-scale GTL plants that use coal as a feedstock. These plants were constructed to provide South Africa with liquid hydrocarbon fuels in the face of the international anti-apartheid boycott of South Africa. These plants would not be economic at the world energy price experienced over the past 15 years. However, Sasol has developed other technology with new catalysts and has formed a partnership with Chevron to market that technology in Nigeria. ANGTL is lobbying the federal government to obtain a multibillion-dollar tax preference for GTL fuels similar to the tax preference currently available for ethanol manufacture.

IV. PIPELINE TO LOWER 48

A. INTRODUCTION

Recently there has been extensive renewed interest in transporting North Slope gas through Canada to the upper Midwest.

This idea was originally contemplated early in the life of North Slope development. From 1969 through the early 1980s, several projects competed for the franchise to carry North Slope gas to the Lower 48 market. The proponents of a project called Gas Arctic proposed a pipeline through the Arctic Wildlife Refuge to the Mackenzie Delta and then to Chicago. El Paso Natural Gas proposed a gas line to an LNG plant in Valdez, and the delivery of the LNG to a terminal in California. Finally, a consortium of companies called Alcan Gas proposed a pipeline down the oil pipeline right-of-way to Fairbanks and then down the Alcan Highway to mid-north America. The Alcan project won, and it became the proposed Alaska Natural Gas Transportation System (ANGTS). However, the project dissipated due to high pipeline costs and an ample supply of Canadian and Lower 48 gas.

Recently, however, certain events may have modified the picture:

- Improvements in pipeline construction technology.
- The extension of the gas pipeline grid to northwest Alberta.
- Increase in U.S. demand.
- Increase in Canadian exports to the U.S.- BP's merger with Amoco, which has sizable Mackenzie Delta reserves.
- Accelerating decline rates of U.S. and Canadian gas production

Two potential competing routes appear to be emerging: the Alcan route, and a route north out of Prudhoe Bay into the Beaufort Sea and east to the Mackenzie Delta (the so-called Over-the-Top Route) that would pick up gas reserves and deliver a larger volume of gas into the existing gas pipeline grid. The North Slope producers are looking at both routes and at least one other alternative. Owners of Mackenzie Valley reserves obviously prefer the Over-the-Top Route.

Advantages of the Alcan route are that it would provide gas to Fairbanks, as well as a boost to the economy from the construction activity.

The government of the Yukon Territory appears to favor this route for those very same reasons.

B. LOWER 48 GAS MARKETS

The feasibility of piping natural gas through Canada to the upper Midwest depends on many things. First is the question of the North American gas supply and gas demand. Is there room in the market to accommodate the large volume and high price needed to make an Alaska gas project economic? While U.S natural gas consumption has been increasing about 2 percent per year over the past five years, production has been growing at only 1 percent. Increasing exports from Canada have made up the difference. However, Department of Energy statistics reflect that U.S. proven reserves have actually increased slightly over the past five years. At the higher prices we should expect even more Lower 48 discoveries adding to the proven reserves base. Is there room in the market for a large volume of Alaska gas at a price of $2.50 per mcf or higher?

The U.S. consumes about 60 billion cubic feet per day. About 13 percent of this (8 bcf/d) is imported from Canada. These imports have been growing about 4% annually recently.

U.S. proven reserves are about 165 tcf. Moreover, the decline rate of new wells has been increasing over recent years; i.e., the fields in which the newer wells have been drilled have a shorter life.

Alaska North Slope gas could compete in this market if it can get to market cheaper than alternate supplies from either the U.S. or Canada. However, if Lower 48 discoveries keep up with production, it would seem unlikely that Alaska gas would be able to compete with that supply. There is a vast grid in the Lower 48 and southern Canada that can move newly discovered gas nationwide at rates that would appear to preclude Alaska gas. If, as some believe, the developing deep-water fields of the Gulf of Mexico deliver those new gas reserves, then Alaska gas would have difficulty getting into the market. If, as others believe, the deep-water Gulf of Mexico does not contain these volumes, the market may require the Alaska gas.

Other potential gas resources that could come to market at prices and volumes that might preclude Alaska gas include the reserves in Western Canada (British Columbia's 8 tcf, Alberta's 45 tcf, and the Northwest Territories' 10 tcf), and the tight-sand reserves of the mid-continental U.S.

U.S. gas demand is expected to noticeably increase in the next 10 years as old oil and nuclear plants are retired and replaced with newer combined cycle plants. The latter have lower capital costs and appear to operate most efficiently with natural gas.

Gas prices in the Lower 48 have been very high recently due to high weather-related and industrial demand, coupled with low imports. While over the past 15 years the long-term market price for gas in the upper Midwest market has been no more than $2 per million BTUs (mmbtu), levels approaching $4.50 were seen earlier this summer.

Historically gas prices have correlated highly with oil prices, and during periods of very high oil prices, gas prices have briefly exceeded the $2 level.

There is reason to believe that the future relationship between oil and gas prices may become more tenuous. Historically, a significant proportion of gas discovered was wet gas associated with oil production, and the two were marketed together. With increasing gas demand, discreet gas exploration and development activity will account for an ever increasing proportion of gas discoveries.

Notwithstanding rising demand, many analysts expect that long-term prices may still not rise very much above the $2.50 level. Many experienced and knowledgeable participants believe there are large amounts of reserves that can be profitably brought on for this price. Other equally experienced and knowledgeable participants disagree. Because of exploration in new areas and advanced exploration technology, most of the long-term price forecasts still project future price at about the current level in real terms. Are there investors willing to make the huge investments in an Alaska gas project that would be dependent on higher gas prices?

These proposed projects to move gas to the Lower 48 face a situation very similar to the proposed LNG project. If a sufficiently large amount of Alaska gas coupled with Northwest Territory gas were to be marketed together, the resulting economics of scale could reduce the cost of moving the gas to market a reasonable level. However, such a large amount of new gas entering the Lower 48 might be sufficient to drive the market price down to the point where the proposed project would once again become infeasible.

In conclusion, it is the availability of alternative gas supply in the Lower 48 and Canada that will determine the feasibility of marketing Alaska gas in the Lower 48.

C. ALCAN ROUTE

Congress passed the Alaska Natural Gas Transportation Act in 1976, authorizing the Alaska Natural Gas Transportation System (ANGTS). As North Slope oil production was about to commence, there was an interest in expediting North Slope natural gas commercialization. Because the applicable federal law required the certification of only one project to move Alaska gas to market, the federal government selected what it thought was the best of several competing projects as the best one. This was the Alcan pipeline option.

The legislation provided for expedited and limited judicial review and protection for the permits that would be awarded, along with the structure for granting and protecting the permits. The legislation also included regulatory approvals and environmental reviews.

The Canadian Parliament passed similar legislation, the Northern Pipeline Act. The governments entered into bilateral agreements to coordinate their respective decisions. Both governments issued certificates of public convenience and necessity, and rights-of-way over these respective federal lands.

The ANGTS route runs parallel to TAPS to Fairbanks, and then follows the Alaska Highway east into Alberta. ANGTS also provides for inclusion of Mackenzie Valley gas through a Dempster Highway lateral pipeline. The Dempster Lateral has not been environmentally permitted. Foothills Pipe Lines Ltd. currently owns the permits for the ANGTS project.

D. OVER-THE-TOP BEAUFORT ROUTE

The Arctic Resources Company (ARC) has announced plans to try to develop a major natural gas pipeline connecting gas reserves from Alaska and the Canadian Mackenzie Delta to the existing line leading to the Lower 48. Again, the producers are examining this option, as well as the Alcan route.

ARC's option includes a pipeline buried four miles offshore in the Beaufort Sea, carrying 2 bcf/d from Prudhoe Bay 400 miles east to the Mackenzie Delta where it would pick up more gas. The pipeline would then go 1,000 miles south with an additional 1.5 bcf/d of Mackenzie Delta gas production to connect with the existing North America gas grid in northwest Alberta. ARC estimates total project cost of $5 billion to $6 billion.

ARC would finance the project 100 percent through bonds, under a structure developed by the Municipal Energy Resource Corporation (MERC), a related company in Houston that works exclusively with government groups involved with capital-intensive energy projects. Their plan would place ownership of the pipeline in the hands of local municipal/First Nation governing bodies (special purpose financing vehicles) in Alaska and Canada, which would receive a fee embedded in the tariff. Financing would be secured by long-term tariff agreement contracts with major producers and pipeline companies. According to ARC, the project would be exempt from both U.S. and Canadian income tax on the same basis as the proposed Gasline Port Authority project.

According to ARC's figures, the Alcan route would be 200 to 400 miles longer for Alaska gas, and the estimated cost would be between $1 billion and $2 billion higher. If this were true, the Beaufort route, with more gas at a lower cost, would have a distinct economic advantage over the Alcan route.

(It is also possible that political forces would force construction of a Dempster lateral as a condition for the Alcan route. This would make for expensive Mackenzie gas.)

The Beaufort route would create a much smaller construction effort in Alaska, and of course provide no gas to Fairbanks. However, ARC has suggested that some of the revenue from its project could be used to finance a means for Fairbanks to secure a gas supply. Among their suggestions for a potential Fairbanks supply is the extraction and distribution of propane from the Trans-Alaska Pipeline flow.

The Over-the-Top Beaufort route naturally creates several serious environmental concerns.

E. OTHER ROUTES

Overland routes other than the Alcan path are also being examined. These include routes from Prudhoe Bay east to the Mackenzie Delta through the Arctic National Wildlife Refuge (ANWR), and routes that would skirt the southern boundary of ANWR through the Yukon Flats and then return north to the Mackenzie Delta.

While the through-ANWR route would certainly encounter environmental opposition, the around-ANWR route would add several hundred miles of pipeline to the cost.

F. ECONOMICS

The tariff to bring gas from the terminus of the line in northwest Alberta to Chicago is estimated at between 70 cents and $1 per mcf. Therefore, to break even at a $2.50 price, a project would need to be able to deliver gas to Alberta at between $1.50 and $1.80 per mcf.

Given our limited data, we estimate that under any market price the Beaufort route would have a wellhead value between 50 and 85 cents greater than the Alcan route. That greater value would mean the following:

- An extra $70 million to $120 million annually in royalties and taxes to the state.
- An additional 2.2% to 3.7% in the rate of return to investors on the project.
- The financial equivalent of a $1.3 billion to $2.2 billion reduction in capital costs.

V. SYNERGIES BETWEEN PROJECTS

It is possible that some options would actually create opportunities for other options to come about. For instance:

- The Alcan route gets gas within 400 miles of tidewater. This would reduce the incremental cost of an eventual LNG project at Valdez or Cook Inlet. It also could create a GTL industry in Fairbanks for taking gas out of the Alcan line, converting it to GTL and then shipping it through TAPS to Valdez.

- An LNG project could create a GTL industry in either Fairbanks or Valdez. It also would bring the gas through Fairbanks, providing a new starting point for the Alcan route.

VI. LEGISLATION

A. STRANDED GAS DEVELOPMENT ACT

As we have shown, the economics of gas are much different than for oil. However, the state's fiscal system that applies to gas was established for oil and only passively adopted for gas. Therefore, it really isn't appropriate for gas, which is highly capital intensive and inherently less profitable.

One obvious example of a possible mis-adaptation of the fiscal system is the oil and gas property tax. The tax is front-end loaded and regressive, and is incurred as soon as construction begins, which may be years before revenues are realized. This reduces substantially the attractiveness of an investment on a present-value basis. Similarly, being based on value, the more expensive the project the higher the tax. This exacerbates the risk associated with possible cost overruns.

In addition, a tax system that is subject to change creates uncertainty and increases the risk to already risky projects that would cost billions of dollars.

HB 393, the Stranded Gas Development Act passed in 1998, allows potential LNG project sponsors to petition for changes to tailor the state's fiscal system to the economics of a specific project. Statutory terms could be replaced by contractual ones to facilitate certainty. The law currently only applies to potential LNG projects. However, the letter of intent that accompanied the 1998 act stated:

> It is the intent of the legislature that Alaska continue to work on any method of commercializing its stranded gas resource to maximize the value of these resources for the benefit of the people of the state. This could include liquefied natural gas (LNG) and gas-to-liquids conversion (GTL).
>
> While the state has studied gas development by means of an LNG project, no such state study has been performed on a GTL project. For this reason, it would be premature for the legislation to apply to GTL. If, after an economic analysis, GTL is shown to be a viable option for gas commercialization, the legislature should consider amending the Stranded Gas Development Act (HB 393) to allow applications for an appropriate fiscal regime for such a project.

Extending the application of the Stranded Gas Development Act to all gas commercialization proposals would increase the chance the state would enjoy the benefits from developing this resource.

Exxon requested legislation in 2000 to extend provisions of the act to potential GTL projects. The company, however, backed away from the bill during the controversy over BP/Arco merger issues.

B. HB290

HB 290, which passed in the 2000 legislature, addressed regulatory issues of an LNG project, including rights of access to the pipeline and the gas.

HB 290 addressed capacity allocation issues by modifying the laws applicable to gas utilities and oil and gas transmission pipelines. The bill placed the intrastate portion of the pipeline into common carrier status, while placing the tariff provisions under the Public Utility Act. Any community that needs gas within the first three years of pipeline operation may apply to the Regulatory Commission of Alaska for capacity. The cost of any expanded capacity after start-up is born by the recipient of the gas.

Relative Benefits Comparison Matrix

(+3 strongly positive to –3 strongly negative)

	LNG via Kenai	LNG via Valdez	Lower 48 via Alcan	Lower 48 via Mackenzie	GTL
Extend and Improve NS Oil Business	+2	+2	+2	+2	+3
Alaska Construction Jobs and Business	+3	+3	+2	+1	+2
Gas Supply for Fairbanks and Southcentral	+3	+2	+1	0	0
State Revenue	?	?	?	?	?
Environmental Costs	See DEC Matrix	See DEC Matrix	See DEC Matrix	See DEC Matrix	See DEC Matrix
Social Costs	-3	-3	-2	-1	-1

Apparent Current Positions of Interested Parties

(+3 strongly support to –3 strongly oppose)

	LNG via Kenai	LNG via Valdez	Lower 48 via Alcan	Lower 48 via Mackenzie	GTL
BP	+1	0	+1	+2	+2
Exxon	0	0	0	0	+2
Phillips Alaska	+1	0	+2	+1	+1
Chevron Sasol	0	0	0	0	+2
Yukon Pacific	-3	+3	+1	-3	-3
Williams	0	+2	0	0	0
Foothills Pipeline	+1	0	+2	-3	0
ARC/MERC	-3	-3	-3	+3	0
Mayors Port Authority	-3	+3	+1	-3	-3
Cook Inlet Terminus Group	+3	-3	0	0	0