Memorandum
State of Alaska

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Subject: Commercialization of North Slope Gas - What Should the State Be Doing?

I. INTRODUCTION.

What should the state government do to promote the project to pipe Alaska North Slope natural gas to tidewater, liquefy it, and tanker the liquefied natural gas (LNG) to customers in Japan, Taiwan and South Korea? The Departments of Revenue, Natural Resources, Commerce and Economic Development and Law have prepared this briefing paper to address this question. The three major North Slope oil producers (Arco, BP, and Exxon), and the Yukon Pacific Corporation (YPC), were consulted in the preparation of this paper.

Alaska North Slope proven natural gas reserves are very large: in the range of 35 trillion cubic feet (tcf). They include Prudhoe Bay at 26 tcf, Point Thomson at 3 to 5 tcf, and Kuparuk, Lisburne, and Endicott, together at 2 to 6 tcf. The amount of energy in these gas reserves is equivalent to 6 billion barrels of oil - the amount of current remaining developed oil reserves on the North Slope.

Since 1970 various interested firms have continuously studied the possibility of commercializing these large North Slope gas reserves. First came the Gas Arctic Project of the early 1970's (a pipeline through the Arctic Refuge and up the McKenzie River to the mid-continent). Then followed the El Paso project of the mid-1970's (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to California). Next came the Alcan Project of the late 1970's and early 1980's (a pipeline to Fairbanks and then down the Alcan Highway to the mid-continent - some of the southern Canadian portions of this project were actually constructed). This was followed by the proposed Trans Alaska Gas System project (TAGS) in the early 1980's that has now evolved into the project proposed by YPC today (a pipeline to a Prince William Sound liquefaction plant and LNG deliveries to the Far East). During the 1980's and 1990's, while the TAGS sponsors were promoting their project to deliver Alaska LNG to the Far East, some of the Prudhoe Bay producers continued to study projects to deliver North Slope gas to the North American mid-continent. Recently, however, the major North Slope producers have clearly shifted the focus of their ANS gas commercialization efforts to the Far East.

Here's where things sit today. The producers recently released their findings on a proposed project that would market Alaska LNG in the Far East. Representatives of the major North Slope producers then visited potential customers in Far East markets. Representatives of YPC have just completed another of their many Far East marketing trips. Further, Phillips, a relatively minor

Prudhoe Bay producer with significant interests in a yet undeveloped North Slope gas and condensate field, Point Thomson, has recently proposed to commence the project by marketing gas from that field to expedite commencement of a North Slope to Far East LNG project.

At today's energy prices and projected construction costs, the economic feasibility of the proposed Alaska LNG project appears doubtful. Minimally, either increases in gas prices or decreases in projected construction costs must occur to make the project economically viable. If constructed, the potential revenues to the state over the life of the project under the current tax and royalty fiscal regime will be much smaller - by at least a factor of 10 - than the revenues the state will receive from North Slope oil developments over the life of those projects. However, as North Slope oil production continues its decline, proposals to commercialize the vast natural gas reserves on the North Slope inevitably draw increased attention. North Slope gas would make some contribution to state revenues, thereby somewhat offsetting the revenue loss of declining oil production. Further, many environmentalists contend that developing North Slope gas is much more environmentally responsible than further North Slope oil development.

We recommend the state address several issues now to enhance the chances that interested firms - including the North Slope lessees - will construct a North Slope gas project for three reasons. First, new marketing opportunities may soon open. Second, long lead times will be required to construct the project. Third, the competition from other countries to capture the gas marketing opportunities in the Far East are and will continue to be formidable.

We recommend you designate a working team from the pertinent executive departments to accomplish the following:

1. Determine if any modifications to the terms of the state's fiscal regime applicable to ANS gas production would significantly enhance the economic feasibility of the proposed project;

Build PK Thompson LC pipe (1) oil (2) gas

2. Carefully evaluate the costs and benefits of the potential modifications to the state's fiscal regime that would significantly enhance the economic feasibility of the proposed project;

3. Determine if there are any modifications to the federal tax structure pertaining to this proposed project the state could responsibly promote that would significantly enhance the economic feasibility of the proposed project;

See AG & Regulators now needed [illegible] TPC be player

4. Determine and pursue actions to facilitate federal action on permits and licenses needed for the proposed project;

5. Determine what actions the state could take with respect to its options to take its royalty share of North Slope gas production in-kind that would promote the construction of the project;

6. Determine what actions the state could take with respect to its royalty-in-kind options to maximize state benefits from the proposed project;

Why

7. Determine and pursue actions to assist in marketing ANS gas to would-be customers in the Far East;

8. Assist in interesting would-be investors, particularly those from the Far East destination market countries, to commit to the project;

9. Evaluate whether the state should or should not invest in the proposed project;

10. Work with the Point Thomson working interest owners who have apparently expressed an interest in providing large volumes of gas for the proposed project well before 2010, the date the Prudhoe Bay producers have indicated as "most likely" for the commencement of gas deliveries from the Prudhoe Bay reservoir;

11. Work with the Prudhoe Bay producers to better understand the effect that large scale gas sales will have on future oil production from the Prudhoe Bay reservoir;

12. Evaluate the environmental considerations pertinent to the differing routes and terminal locations for the proposed pipeline project;

13. Work with the producers and YPC to ascertain what other steps the state might responsibly take to facilitate this project; and

14. Determine whether there are any other feasible commercialization options, including:

mexico to LA
specific user
Steel
Power Co

- Marketing the gas in the Lower 48;
- Converting gas on the North Slope to hydrocarbons that are liquid and can be transported in the TAPS pipeline; or
- Generating electricity on the North Slope and using high efficiency transmission lines to move the electricity to market.

not feasible now
w/o super conductors

II. FACTORS INFLUENCING THE COMMERCIALIZATION OF NORTH SLOPE GAS.

Five major factors currently determine the feasibility of the large scale commercialization of North Slope gas. They are:

- The cost of developing the gas delivery system relative to expected gas prices
- The demand for the gas in the Far East markets and competition among potential supplies of LNG
- The pipeline economic disadvantage in competing for a place in the market
- How the sale of the gas would affect Prudhoe Bay liquid production
- The availability of an alternative North Slope gas supply prior to full scale Prudhoe Bay

gas availability

1. Cost Relative to Expected Gas Prices

Developing the transportation system to move North Slope gas to the Far East market will be very expensive. Here is what will be needed:

- Gas conditioning plant (approximately 10% of total cost)
- Pipeline to tidewater (approximately 40% of total cost for a Valdez route)
- LNG plant and marine terminal (approximately 25% of total cost)
- A fleet of LNG tankers (approximately 25% of total cost)

(3,4

Both the producers and YPC currently estimate that the project would cost $15 billion. There may be opportunities to reduce the cost by $3 billion through infrastructure sharing, more efficient pipeline construction methods, larger LNG liquefaction trains, and a more economic ship design. The producers claim it would cost $100 million for a detailed engineering study to assess whether significant savings are now possible. The producers differ in their assessments of the likelihood that they will soon actually undertake such a study.

Infrastructure sharing includes:

- Use of the Prudhoe Bay compression facilities, camps and power generation for the gas conditioning plant

Yukon River Bridge
telecom system
camps
work pads
Air strips

- Conversion of some of the TAPS pump stations to compressor stations, and using the oil pipeline workpads and state highways for the pipeline
- Use of the Valdez marine terminal facilities, civil work and loading berth for the LNG plant[1]

auto/ welder i.e. [illegible]

Pipeline construction advances include Arctic application of state-of-the-art ditching machines, use of high strength pipe, and pipe laying rates that are much faster than those used at the time TAPS was constructed.

Larger LNG liquefaction trains[2] (larger than currently available) can reduce per unit liquefaction costs.

In addition, the producers have been analyzing additional savings from pipeline routes to the northwestern Alaska coast at either Wainwright or Kivalina. These routes avoid mountains and are less than half the distance to Valdez. They would, however, require ice-breaking LNG tankers, which have never operated in pack ice before. By reducing the high fixed cost of the pipeline, the western route would afford the project the opportunity to commence operations in smaller stages and thus enhance the start-up economics of the proposed project. The staging advantage is discussed in more detail in Section II(3) below. The producers are still studying the

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[1] There is some question as to whether an LNG plant located very close to the oil facilities might violate exclusion zone requirements for LNG siting established by the U.S. Department of Transportation.

[2] A train is an individual liquefaction and shipping unit.

relative advantages and disadvantages of the western routes.

On an overall project basis, the minimum cost efficient size of the project appears to require a sale and delivery of 2 billion cubic feet (bcf) per day. This results in annual deliveries of 14 million metric tons of LNG - the unit of measure used in the Far East LNG markets.[3] The project requires a ten year lead time to achieve full operation; five years for construction, and five years to ramp-up to full production.

enriched more w/propane

LNG is sold in the Far East markets on a per million British Thermal Unit (mmbtu) basis. Generally, pure natural gas - methane - has an energy content of about 1,000 btu per cubic foot; that is one million btus per thousand cubic feet (mcf). However, both the North Slope producers and YPC maintain that the North Slope gas would be "spiked" with ethane, propane, and butane to increase the energy value per unit of volume and thus to enhance its value.[4] The producers estimate the gas used for the proposed project would be spiked to 1,170 btu per cubic foot for the first ten years, and 1,100 thereafter. In the economic analysis we have done for this paper, we have assumed an average energy content of 1,150 btu per cubic foot of natural gas for the duration of the project. This "spiking" enhances the value of the gas by 15%.

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[3] To put the likely size of a gas line project in context with the current North Slope oil production operations, a two billion cubic feet per day gas line would carry the energy equivalent of about 350,000 barrels per day of oil.

[4] Ethane, propane and butane are more complex hydrocarbons often classified as "NGL's" at ordinary temperature and pressure. These substances are, however, gases. They have significantly higher energy content per cubic foot than methane.

If this project is constructed, how much will it cost to ship ANS gas to the Far East? If the project (1) costs $15 billion (both the producers' and YPC's current estimate), (2) operates for 25 years with daily throughput of 2 bcf, and (3) earns a 4% after-tax real rate of return (11.4% nominal), then it will cost $5/mmbtu to ship the ANS gas from the North Slope to the Far East.[5] This cost includes a 50 cent/mcf operating cost and a 30 cent/mcf cost pertinent to the state's 20 mill oil and gas property tax.[6] LNG today is selling for about $3.50/mmbtu in the Far East, 30% lower than the $5.00/mmbtu projected cost for transporting gas from the North Slope of Alaska to that market. At this price, these economic projections yield a negative wellhead value of $1.50/mmbtu for the project Put otherwise, based on these projected costs, a threshold gas price of $5.00/mmbtu in the Far East markets is necessary to yield a zero wellhead value at the North Slope. It is obvious that if these costs are correct, then higher wellhead values would be required to induce investors to construct this project.

If the gas price remains at $3.50/mcf in the destination market, how would it be possible to raise the wellhead value? By reducing the capital costs for the project by one third either by significantly lowering the rate of return on the project or by greatly reducing construction costs or

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[5] This assumes 75% debt, 25% equity, with a nominal rate of return of 12.9% on the equity and a rate for the debt two percentage points below the return on equity. YPC has suggested that 75-25 is a likely debt/equity ratio for the project. We have assumed equity and debt rates of return that may not accurately reflect those that would be obtained for financing the project. We believe, however, that a real after-tax rate of return of about 4% for the project is the lowest return investors would accept. See Appendix A for a more detailed discussion of the economic analysis pertinent to this project.

[6] This 50 cent/mcf operating cost has been suggested as the likely operating cost by both the producers and YPC.

both.[7]

What about the LNG price in the Far East? For this proposed project to be economically feasible, that price would have to increase to at least $5.00/mmbtu if the project and capital costs cannot be significantly reduced.

LNG in Japan currently commands a 15% premium over crude oil on an energy equivalent basis.[8] This premium arises from several factors:

- Gas burns much more cleanly than fuels derived from crude oil.
- Gas powered units such as gas turbine electric generators are more efficient and require lower capital costs than their oil powered cousins.
- Recognizing the high costs of LNG projects, parties in the Far East markets have negotiated premiums for LNG with respect to crude oil at low oil prices, and corresponding discounts at high oil prices.

It follows that a $5/mmbtu LNG price is equivalent to a price of $25 per barrel (bbl) for crude oil.

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[7] Pursuant to the settlement agreement governing the TAPS tariff, the TAPS oil pipeline has been permitted to earn a 6.4% after-tax real rate of return (15% nominal). The gas pipeline should be less risky than TAPS. A strong argument can be made that a 4% after-tax real rate of return will be required for this project. See Appendix A for a more detailed discussion.

[8] Currently crude oil prices in Japan are between $17 and $18 per barrel. There are 5.8 times as many btus in a barrel of crude oil as an mcf of gas. Thu the following equation -- 5.8 X 3.5/17.5 = 1.16 -- tells you that a btu of energy derived from LNG selling for $3.50/mmbtu costs 16% more than a btu of energy derived from crude oil selling for $17.50/bbl.

In other words, given the current relationship between oil prices and gas prices, oil prices would have to be $25/bbl in order for North Slope gas to provide a 4.1% real rate of return on the proposed transportation investment and leave a zero North Slope wellhead value. Currently crude oil sells for about $17-18/bbl in Japan. If LNG did not command a premium over crude oil, the equivalent oil price in the Far East would have to be $29/bbl.

Appendix A sets forth a more detailed discussion of the economics of the proposed ANS LNG project.

2. <u>Far East Demand for LNG and Competition Among Potential Suppliers.</u>

Current LNG consumption in the Far East is about 55 million metric tons per year (mmty).[9] LNG consumption has been increasing at 6% per year since 1980, and is expected to grow between 5% and 10% annually through 2010. However, exponential growth cannot continue in this market indefinitely. Therefore, we have used a 6% annual growth rate for LNG demand in the Far East for planning with respect to this proposed project. Six percent annual growth would result in LNG consumption in the Far East markets of about 100 mmty in 2005 and 130 mmty in 2010.

There is no unsatisfied demand in the Far East LNG markets before the year 2000. Contracts sufficient to fill all the anticipated increases in the Far East demand through the end of this decade are already in place.

[9] The proposed North Slope to Far East gas transportation project operating at 2 bcf per day would supply 14 mmty - about 25% of the current supply. The 55 million tons of LNG consumed each year in Far East markets is the daily energy use equivalent of about a million and a half barrels of oil per day - about the volume that currently flows through TAPS.

The LNG market opportunities are significantly different than the market opportunities for crude oil. There are few LNG buyers. Because of the large up-front investments required for an LNG project, and to reduce risk, long term contracts must be in place before the producers, the buyers or YPC would commence construction of the ANS gas transportation project.

The competition for selling LNG to the Far East is considerable. The following table shows, by country, existing supplies.

CURRENT SUPPLY TO FAR EAST LNG MARKET	
Location	**Gas Supply (mmty)**
Alaska (Cook Inlet)	1
Abu Dhabi	5
Brunei	7
Indonesia	27
Australia	7
Malaysia	8
Total	55

Capacity to supply an additional 8 mmty from Malaysia and 6 mmty from Qatar is currently under construction. Relatively low cost expansion of existing LNG facilities in Australia, Indonesia, and Malaysia of 5 mmty each (a total of 15 mmty) are under serious consideration.

The following table summarizes the existing supplies, supplies currently under construction, and available low cost expansion opportunities at existing LNG plants:

CURRENT AND NEAR TERM LNG SUPPLIES TO FAR EAST MARKET	
Source	**Gas Supply (mmty)**
Existing Supplies	55
New Plants Under Construction	14
Low Cost Expansion Opportunities Available	15
Total	**84**

Including the North Slope, new grass roots projects could add the amounts reflected in the following table.

LARGE NEW LNG PROJECTS PROPOSED TO SUPPLY THE FAR EAST MARKETS	
Location	**Gas Supply (mmty)**
Alaska	14
Australia	13
Indonesia (Natuna)	15
Oman	6
Papua New Guinea	6
Qatar	15
Sakhalin	10
Yemen	5
Total	**84**

The Qatar, Oman and Yemen projects appear to be in the advanced planning stages. The Indonesian project is the giant Natuna field, for which Exxon is the proposed operator. Given the large size of both the proposed Natuna and Prudhoe Bay projects, there is - at most - room for only one of these as a source of supply in the Far East LNG market in the near term. At full development it would appear that the proposed Natuna project is more expensive per mcf delivered than the proposed North Slope project. However, the Natuna project can be staged in increments; staging the North Slope project severely affects its economics, especially with a Prince William Sound terminal.

The gas reserves in most of the countries supplying the Far East LNG market are very large and are expanding. Much of this gas was found in the course of exploring for oil. These gas supplies are more than ample for current markets. If deliberate exploration for gas ensued, it is likely that these gas reserves would increase substantially. The following table shows 1993 year-end gas reserves for selected countries.

CURRENT RESERVES OF MAJOR FAR EAST MARKET LNG SUPPLIERS	
Country	**Reserves (tcf)**
Abu Dhabi	177
Australia	100
Indonesia	89
Malaysia	72
Qatar	236
Total	**674**

Alaska has about 35 tcf in discovered reserves on the North Slope.

If demand in the Far East LNG market continues to grow 6% annually, the demand in 2005 will be 100 mmty. Given apparent lower cost supplies of 84 mmty from existing, under construction, and low cost expansion sources, this leaves 16 mmty for new grass roots suppliers. At a 14 mmty minimum, an Alaskan project would have to capture 88% of the projected unfilled demand in 2005 to be able to fit into the market. Using the same assumptions, the demand in 2010 would be 130 mmty. Of this, 46 mmty would be available for grass roots projects for which construction has not yet commenced; a new Alaska project coming on line in 2010 would have to capture 30% of this projected unfilled demand.

3. The Pipeline Economic Disadvantage in Competing for a Place in the Market.

Of all the grass roots projects, Alaska is the only one which requires a major pipeline to bring the gas to tidewater. Nearly half of the total anticipated construction cost for the proposed Alaska project is attributable to the pipeline. The pipeline is a burdensome one-time, up-front cost that places the proposed Alaska project at a competitive disadvantage.

The proposed Alaska gas project only achieves the economies of scale which make it feasible at its full 14 mmty proposed capacity. While many of the competing projects also have comparable per unit costs, they attain those costs at much lower production levels. This is particularly true for the projects proposed in Qatar, Oman and Yemen. The need to cover the costs for the one-time, up-front pipeline investment is what makes the proposed Alaska project different. It may only be economic if its sponsors can begin the project at full capacity. Placing 14 mmty at once in the Far East LNG market may be difficult, given that multiple buyers will need to simultaneously commit to the project.

Increments to existing projects have a "nimbleness" advantage to big new baseload, grass roots projects. Suppose there is just enough room in the marketplace in 2005 for the proposed Alaska project - 14 mmty. If any small addition to an existing project captures *any* part of the 14 mmty demand in the marketplace, the Alaska project may not be able to make a go of it. Furthermore, proposed increments to already existing LNG projects in most cases have a per unit cost advantage over the per unit costs of new grass roots projects.

Projects without major pipelines do not necessarily require as high a proportion of their investment up front. Ships and liquefaction facilities can be added in increments. Pipeline capacity cannot easily be added in increments. Therefore, projects which require a high proportion of investments in pipelines must capture bigger increments in the developing markets to be economic. This necessarily provides any project without a substantial pipeline leg an advantage. For this reason the producers have looked - and will continue to look - carefully at the proposed western route. Even though the tanker costs, the offshore loading terminal costs and the risk of supply disruptions pertinent to the proposed western route would be higher, reducing the proposed project's pipeline cost might make it possible to achieve competitive costs at reduced production levels. The western route project might well be economic with initial volumes well below 14 mmty. Obviously if the required initial amounts are smaller, it would be much easier to fit such a project into the market.

The problem created by the large minimum size of the North Slope project is further exacerbated by the number of buyers that would be required to consume the proposed project volume. Most likely the need to find buyers for this new large volume all at once will require sales to several customers in more than one country, and the sale to any one customer is likely to be dependent on sales to all other customers. This could make marketing the ANS gas a complicated endeavor.

4. The Role of Gas in Prudhoe Bay Liquid Production.

Currently the highest and best use of the gas in the Prudhoe Bay reservoir is to facilitate the production of liquids. Gas reinjected into the reservoir increases liquid recovery as a result of several different recovery mechanisms. When does it make sense to sacrifice liquid recovery for gas production? The answer is: when substituting gas production for liquid production results in a more valuable stream of total outputs from the reservoir. Today the highest value is achieved by maximizing liquid production from the North Slope because the liquid streams are so much more valuable than the likely flow of gas. As liquid production rates decline, however, a time may come when the potential gas stream will become more valuable than that of the liquids sacrificed by sending the gas to market. The volume of liquids sacrificed declines every year the project is delayed.

The liquid recovery mechanisms at Prudhoe Bay all depend directly or indirectly on reservoir pressure. Production is facilitated by higher pressure, which pushes the oil out of the rock. The pressure in the reservoir depends mainly on the amount of oil, gas and water in the reservoir. Because of its compressibility, reinjection of produced gas is the primary mechanism used to maintain pressure in the Prudhoe Bay reservoir. Injection of sea water and produced water are also major elements in the Prudhoe Bay reservoir pressure maintenance program.

A Major Gas Sale (MGS) of Prudhoe Bay gas would permanently remove the gas from the Prudhoe Bay reservoir and consequently accelerate the decline in reservoir pressure. The pressure in the Prudhoe Bay reservoir is currently declining at 30 pounds per square inch (PSI) per year. When production began in 1977, the Prudhoe Bay reservoir pressure was 4,200 PSI; today it is 3,400 PSI. The producers estimate that an MGS would triple the rate of annual decline to 90 PSI unless new steps were taken to mitigate some of the loss. There is no disagreement that in the short run (next 8-10 years) accelerated reservoir pressure decline would result in less ultimate oil production. There is some disagreement as to the timing and total volume loss associated with the proposed gas pipeline project, and on the manner in which the loss might be mitigated. However, there appears to be no guaranteed, low cost way to mitigate these losses.[10]

Thus the optimal date for an MGS depends on the expected performance of the Prudhoe Bay reservoir as well as predicted oil and gas prices. The longer the expected benefits from gas

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[10] Where maintaining high reservoir pressure is necessary to maximize liquid recovery, in some locations around the world the natural gas may be valuable enough to justify marketing it and replacing it in the reservoir with another gas - usually nitrogen cryogenically recovered from the atmosphere. The producers at Prudhoe Bay have considered this option, but the projected wellhead value of Prudhoe Bay gas has always been too low to justify it. Similarly, the Prudhoe Bay producers have considered attempting to mitigate pressure losses through expanded waterflood; they have concluded that would be destructive to gravity drainage in other parts of the reservoir and to oil well hydraulic performance. Finally, the Prudhoe Bay producers have considered injecting water into the apex of the gas cap (as opposed to the oil rim); this step, they believe, could eliminate much of the liquid recovery achieved by the vaporization of residual liquids in the gas cap that occurs with gas cycling.

pressure maintenance and gas cycling, the later the optimal date for commencing an MGS. However, very late in the life of the field, losses in liquid production as a result of an MGS become quite small relative to the value of a gas sale. In addition, the economies of scale realized by producing and selling both oil and gas from the same facilities are such that an MGS would probably extend the time during which oil production would continue to be economic. To the extent an MGS would extend field life, liquid losses would be negated. Likewise, there could be some accelerated oil recovery benefits realized due to increased gas handling capacity resulting from an MGS after 2015.[11]

The producers now believe that 2005 would be the earliest appropriate time to possibly begin deliveries pursuant to an MGS. They contend that 2010 is the "most likely" time they would commence deliveries under an MGS. The producers have selected the year 2005 as the earliest appropriate time for three reasons:

- The liquid loss after 2005 from diverting gas for commercialization may be de minimis.
- The producers believe 2005 will be a good time to enter the markets (see section on demand above).

[11] As the field matures more and more gas is produced with each barrel of oil. Currently approximately 7.5 billion cubic feet of gas are produced each day with the oil at Prudhoe Bay. Oil production capacity is constrained by the ability to process and reinject this large volume of associated gas. Depending on the North Slope equipment scheme ultimately installed, some gas handling capacity is freed up as some gas is diverted for sale. Increasing the gas handling capacity at Prudhoe Bay would certainly result in acceleration of oil recovery, but probably not in significant additional oil recovery. Gas handling capacity probably cannot increase, however, until the waterflood/EOR project ends (around 2015), because of the bottleneck caused by the limited gas dehydration capacity of the flow stations/gathering centers.

- The intra-field compensatory agreements between the oil rim and gas cap owners will mostly be completed then.[12]

Regarding the liquid losses, the producers now estimate that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of the Prudhoe Bay field. They estimate a loss of 100 million barrels of oil for a 2010 sale. The significance of those losses will depend on the relative prices of oil and gas as well as actual operation and development decisions made over the next ten years. For instance, if we assume the wellhead values of Prudhoe Bay oil currently forecast by the Department of Revenue, then the gas must be worth at least 40 cents per mcf at

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[12] The Prudhoe Bay field is unitized with two participating areas: the oil rim and the gas cap. BP owns a relatively higher percentage of the oil rim (51%), and Arco and Exxon own relatively higher percentages of the gas cap (42% each). The gas cap currently has 70% of the gas resources and the oil rim 30%. Thus BP still owns 25% of the overall gas reserves, and has no apparent motive for being disinterested in commercializing the Prudhoe Bay gas absent negative impacts on oil production. Pursuant to an order from the Alaska Oil and Gas Conservation Commission, the working interest owners are currently attempting to unitize the two properties.

In 2005 the fuel gas supply option, whereby the oil rim owners are obligated to secure a certain volume of gas from the gas cap owners to fuel field operations, lapses.

Also, major gas sale delay credits cease in 1997. These are reimbursements of payments of the oil rim owners to the gas cap owners for early investments made by the gas cap owners in anticipation of an early gas sale. The oil rim receives some of their already-paid reimbursements back if there is an MGS before 2005.

In addition, through another agreement, in 2005 the gas cap owners will beg to supply half the gas needed to make miscible injectant for enhanced oil recovery operations. Currently the oil rim owners supply all of the gas. This will release oil rim gas for sale.

There are other incentives in the unit operating agreements for the oil rim owners to support an MGS. Upon an MGS, the gas cap owners will pick up significantly higher proportions of the operating costs of the field. Further, once an MGS occurs the oil rim owners get allocated proportionally more liquids.

the wellhead to offset the value of the barrels lost as a consequence of a gas sale commencing in 2005. To offset the loss of barrels for a gas sale commencing in 2010, the gas wellhead value must only be 15 cents/mcf. The likely level of gas prices is discussed more fully above. These "loss" estimates assume a five year ramp-up to 2 bcf of gas per day sold from Prudhoe Bay. Appendix C describes the derivation of these loss projections.

5. Point Thomson - A Potential Supply Source Prior to Prudhoe Bay Gas Availability?

Phillips Petroleum has recently suggested the use of gas from the Point Thomson field to jump start the proposed ANS gas project. The Point Thomson reservoir, a large gas and gas condensate reservoir which overlies a very thin oil rim, is located 60 miles east of Prudhoe Bay. The Department of Natural Resources estimates the reservoir contains 3 tcf of recoverable gas reserves; some producers have estimated the reservoir contains 5 tcf. The reservoir is included in the Exxon-operated Point Thomson Unit.

Phillips, one of the Point Thomson working interest owners - which has interests with co-lessees Mobil and Chevron (together these companies are often referred to as MPC with respect to their jointly leased North Slope properties) - is willing ~~to commit its gas now~~ to the YPC project. Together MPC owns the leases which cover 47% of the surface acreage included in the unit and claim to have a higher percentage of the recoverable reserves in the unit. Phillips believes it may be able to supply up to 1 bcf per day of natural gas from this reservoir for up to five years. If supplying this amount was indeed feasible, early Point Thomson production could assist in making it possible to commence a North Slope gas project before significant volumes of gas are required from the Prudhoe Bay reservoir. Early gas sales from Point Thomson could allow a gradual phase in of gas sales from Prudhoe Bay.

There are many technical questions that would have to be addressed with respect to this Point Thomson proposal. The Point Thomson reservoir is a very high pressure retrograde condensate reservoir; that means liquids drop out of the gas recovered from the reservoir when the pressure of the gas drops. Under the Phillips proposal would the gas be kept at high pressure and moved to Prudhoe Bay for liquid recovery? Can gas production at the volumes Phillips proposes occur without dropping reservoir pressure to the point where there are significant volumes of liquid lost in the reservoir? Since the Point Thomson reservoir pressure is so high (almost right at 10,000 PSI), doesn't it make sense to produce the reservoir until the pressure drops to the 4,000 - 5,000 PSI range before reinjection and cycling commence to avoid the very high reinjection costs that a 10,000 PSI reservoir would require? If the answer to that question is "Yes," doesn't that suggest that the Phillips proposal may have merit in promoting the development of the Point Thomson resource?

Deal w/ (1) Liquid or pipe

The cost of bringing Point Thomson reserves to the Prudhoe Bay area would, of course add to the cost of the pipeline portion of the project.

III. OTHER CONSIDERATIONS.

1. What's in it for the State.

On the revenue side, under the applicable fiscal regime the State will receive severance taxes, royalties and property taxes from the gas project. The property tax will be the most significant. With $11 billion of assessed property (which excludes the ships), the 20 mill Oil and Gas Property Tax will yield $220 million per year initially; the tax revenue from this tax will decline with the depreciation of the property. Half of the revenue from this tax will go to cities and boroughs. This tax will affect the economics of the project two ways. First, because it applies during the construction period, it is a large additional up-front cost imposed on the project; second, once the project is operating, the annual property tax bill will add 30 cents per mcf to the operating costs of the project on an equivalent amortized basis.[13]

If the netback from the Far East yielded a 50 cent/mcf wellhead value, taxes and royalties would total $60 million annually. Based on current cost projections, a 50 cent wellhead value would be achieved only if LNG prices were $5.50/mmbtu in the Far East (and oil prices were $27.50/bbl - see discussion in Section II(1) above). Under the current applicable state corporate income tax statute, the state would receive about $30 million per year in corporate income taxes from the project. Thus, if world energy prices increase by 60 percent, the state could expect about $190 million per year in taxes and royalties from the project during the early years of operation. That amount would, of course, decline as the value of the gas pipeline depreciated.

[13] The $5/mmbtu LNG cost discussed on page 10 in Section II(1) includes the amount of this tax.

Construction of a pipeline to transport gas from the North Slope to Valdez would create 10,000 construction jobs and 600 permanent operational jobs. A pipeline following the TAPS corridor would also make natural gas available to Fairbanks, Valdez and other smaller communities along the route.

An MGS would enhance the economics of other gas deposits on the North Slope.

In addition, as discussed above, the commercialization of gas late in the life of the Prudhoe Bay reservoir would probably enhance oil production economics as well.

2. The Role of Yukon Pacific.

YPC has been active in promoting an ANS LNG project that would use the TAPS route to Valdez. YPC is a subsidiary of CSX Corporation, a conglomerate with holdings concentrated in transportation. CSX owns one of the nation's largest railroads, and it owns Sealand. As a consequence of other business involvements, CSX has had significant experience in marine transportation and in certain aspects of the gas business.

YPC has spent large amounts of time and money obtaining several of the major permits necessary to transport and market gas. These include:

- Presidential finding for the project.
- Project-wide environmental impact statement.

- Federal right-of-way.
- State right-of-way.
- Department of Energy authorization for export of gas.
- Final environmental impact statement for a liquefaction plant at Anderson Bay near Valdez.
- FERC order granting authorization for LNG facility siting.

Although the degree to which some of these permits may be exclusive is questionable, there is considerable time, expense, and expertise invested in their procurement.

The North Slope producers clearly have the right to utilize the Prudhoe Bay gas for oil production as long as they are not wasting the gas. They also have the right to market the gas. If Prudhoe Bay gas commercialization yielded a higher net present value than utilizing the gas in the field to maximize oil production, the state might be able to take action to compel the producers to market the gas. In the absence of some sort of successful state action to compel Prudhoe Bay gas sales, YPC must depend solely on the oil rim and gas cap owners to obtain Prudhoe Bay gas.

There are disagreements among YPC and the producers. YPC has argued that based on the public statements made by the producers, there is no reason the gas should not be currently available for sale. YPC has also argued that: (1) the Prudhoe Bay producers will not sell the gas because of intra-owner conflict in the field resulting from the disparate oil/gas ownership; (2) specific companies are improperly advancing their own interests either in the field or in other places in the world with a decision not to sell even though, according to YPC, selling would maximize the overall benefits from the Prudhoe Bay Reservoir; and (3) the State should take action to force the Prudhoe Bay producers to enter into an MGS. We believe there are sound engineering and economic reasons behind the current plans for short term and mid term gas use at Prudhoe Bay.

IV. WHAT SPECIFIC ACTIONS HAVE THE VARIOUS PARTIES URGED THE STATE TO CONSIDER?

Following are some of the ideas interested parties, including YPC and the producers, have urged the state to study:

1. Taking action to force the Prudhoe Bay producers to sell their Prudhoe Bay gas;
2. Using the state's royalty-in-kind share of Prudhoe Bay gas to promote the proposed project;
3. Marketing the state's royalty-in-kind share of Prudhoe Bay gas along with the producers to promote the project;
4. Agreeing to commit the state's royalty-in-kind share of Prudhoe Bay gas to the project at a fixed (and possibly discounted) price;
5. Altering the 20 mill Oil and Gas Property Tax so it does not impose another large front-end cost on the project; and
6. Altering the state's basic fiscal arrangements so that the state takes an equity interest in the entire project up stream from the LNG tankers, and, in exchange, agrees to forego royalties, severance tax and the 20 mill Oil and Gas Property Tax.

These questions should all be addressed in conjunction with the implementation of the 14 recommendations set forth on pages 4, 5 and 6 of this briefing paper.

APPENDIX A

Alaska North Slope Gas Transportation System Feasibility

The Relationship Between Required Rate of Return and Far East Market LNG Prices

At today's energy prices and projected construction costs, the proposed North Slope gas project is economically feasible if and only if the project's would-be investors are willing to accept a fairly low rate of return for the project. Consequently, it is unlikely these firms will be willing to provide the necessary financing to construct the project unless they are convinced of one or more of the following:

1. The project is, in fact, a very low risk project;
2. The price of LNG in the Far East is likely to increase significantly in the next few years thereby providing a much higher return for the proposed project than would be available at current prices; or
3. The project construction costs will be significantly lower than the current estimate of $15 billion.

An investor's willingness to invest depends on the balance of anticipated risk and reward from the investment. Citizens are willing to invest in passbook savings accounts with their relatively low returns (approximately 4.5% today) in part because the U.S. government insures that depositors will get their money back virtually any time they want it. On the other hand, high-risk investments command higher returns to compensate investors for the risk. For example some computer venture start-ups are currently yielding returns near 25% to their investors. For large projects, a firm's willingness to invest will depend on the perceived risk and reward of the project compared to other opportunities for investing available funds. A firm will invest in projects with the highest anticipated return balanced against the anticipated risk. Projects compete for financing based on their perceived risk and rates of return.

For example, to assure a 7% nominal rate of return (1.5% after-tax real), the proposed North Slope LNG project would need a \$3.65/mmbtu price floor in the Far East and a zero wellhead netback (the current Far East LNG price is \$3.50/mmbtu). But, one can get this same return by making a riskless investment in the government bond market.

We do not know precisely the risk would-be investors will perceive in the proposed North Slope gas transportation project. Will the project face a significant marketing risk? It is highly likely that if the project is constructed there will be little risk that the project will not have guaranteed customers. The contracts for LNG sales in the Far East would almost certainly be in place prior to construction commencement. How about the risk of very low energy prices? Far East LNG contracts are almost universally pegged to the price of oil and other energy supplies, but if oil prices fall below a certain level, the gas prices may be subject to renegotiation. To insure a 2% after-tax real rate of return, this project needs a \$3.90/mmbtu price floor in the Far East. What happens if the project costs \$18 billion rather than \$15 billion? Then the very low return realized at today's energy prices would become negative.

Will the perceived risk of this proposed project require a return equal to or greater than: (1) a thirty year treasury bond; (2) a AA corporate bond; (3) a BBB corporate bond; (4) the return equity investors currently receive for investing their funds in developed, stable utility companies; or (5) the return earned by investors in the Trans Alaska Pipeline System (TAPS) as a consequence of the tariff settlement agreement?

The charts that follow use "after-tax real" rates of return. It may be helpful to explain briefly the relationship between "after-tax real" and "nominal" rates of return. After-tax real rates of return are the returns realized after making an allowance for inflation and income taxes.

The after-tax real rate of return is the difference derived by subtracting the inflation rate from the product of the nominal rate of return multiplied by the difference obtained by subtracting the tax rate from one. It may be easier to understand this equation by expressing it algebraically as follows:

After-Tax Real Rate of Return = [Nominal Rate of Return * (1 - Tax Rate)] - Inflation Rate

To work through an example, take the applicable 30 year U.S. Government Bond rate, which currently provides a return of 6%. Further, assume an effective combined corporate income tax rate of 38.0% (35% federal and 4% composite state)[1] and an inflation rate of 3%.

[1] Since the state tax is deductible for federal taxes the combined rate is 38%.

After-Tax Real Rate of Return = [Nominal Rate of Return * (1 - Tax Rate)] - Inflation Rate

$$= [0.06 * (1-0.38)] - 0.03$$

$$= 0.0072, \text{ or } 0.72\%$$

The following table compares the nominal returns in today's marketplace with the corresponding after-tax real returns. Again the basic assumptions are: a 38% effective combined corporate income tax rate and a 3% inflation rate.

NOMINAL AND REAL RATES OF RETURN		
	Nominal Rate of Return	**Real After Tax Rate of Return**
30 Year Treasury	6.0%	0.72%
AA Corporate Bond	6.8%	1.22%
BBB Corporate Bond	7.4%	1.59%
Rate of Return Received by Equity Investors in Developed, Stable Utility Projects	10.5%	3.51%
Rate of Return Selected for Illustrative Purposes for the Proposed ANS Gas Transportation Project	11.4%	4.07%
Rate of Return Permitted TAPS Owners under TAPS Tariff Settlement	15.0%	6.40%

On the basis of this information, is a 4% after-tax real rate of return required to attract investors to the proposed ANS gas transportation project? Is it too high? Is it too low? The following analysis uses that rate of return for illustrative purposes. There are many good arguments that this 4% after-tax real rate of return is in the neighborhood of the return investors would require to invest in the proposed North Slope LNG project. One could certainly make the case that the proposed Alaska to Far East LNG project would be less risky than TAPS. There is virtually no risk that the gas cannot be produced from the reservoir. There would be a set contract in place guaranteeing a price. Construction of the TAPS project proved that such a large Arctic project can be done. The builders of the proposed LNG project can profit from the TAPS construction experience.

Figure 1 below shows the price LNG must receive in the Far East to yield various after-tax real rates of return on the proposed project.

Figure 1
The Relationship Between Far East LNG Prices & Return on the Proposed North Slope Gas Transportation Project

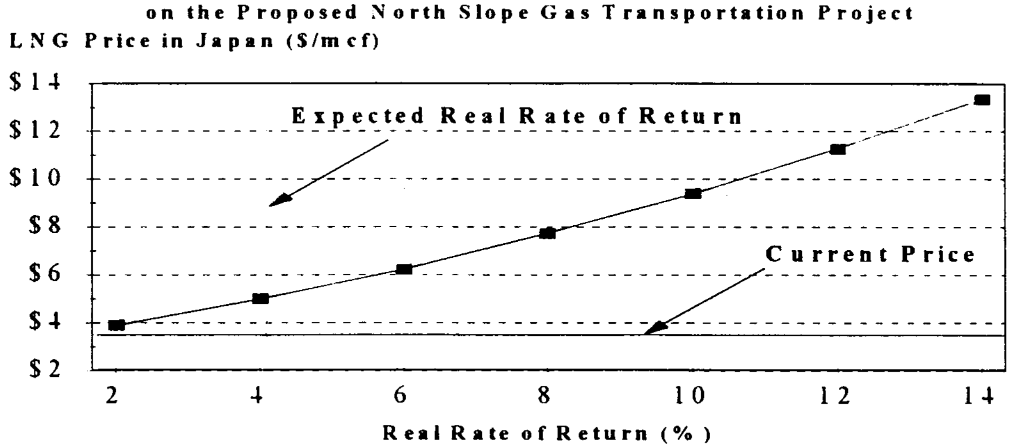

Figure 1[2] shows that to obtain a 2% after-tax real rate of return on the proposed $15 billion transportation project with a twenty-five year project life, the price of LNG in the Far East would have to be $3.90/mmbtu; at this price the project would yield a zero wellhead value. The current price in Japan is $3.50/mmbtu. This equates to an after-tax real rate of return on the project with a zero wellhead value slightly under 2%. Using the same assumptions, Figure 1 shows that a 4% after-tax real rate of return with a zero wellhead value requires a $5.00/mmbtu sales price in the Far East.

In addition to using equity to finance part of the project, the investors will probably make arrangements to issue debt to finance a portion as well. For many reasons, the interest rates on the debt issued to construct the proposed LNG project will probably be lower than the return required to attract equity capital.

For the analysis in this briefing paper, we have assumed the project would be financed by 75% debt and 25% equity. The debt/equity ratio could vary widely. We have assumed a nominal rate of return on the equity portion of the investment of 12.9%; for the debt we have assumed a nominal rate of return 2% below the equity rate. These assumed rates of return may not accurately reflect those that would be obtained for financing the project. We believe, however, that a combined real after-tax rate of return of about 4% for the project is the lowest return investors would accept.

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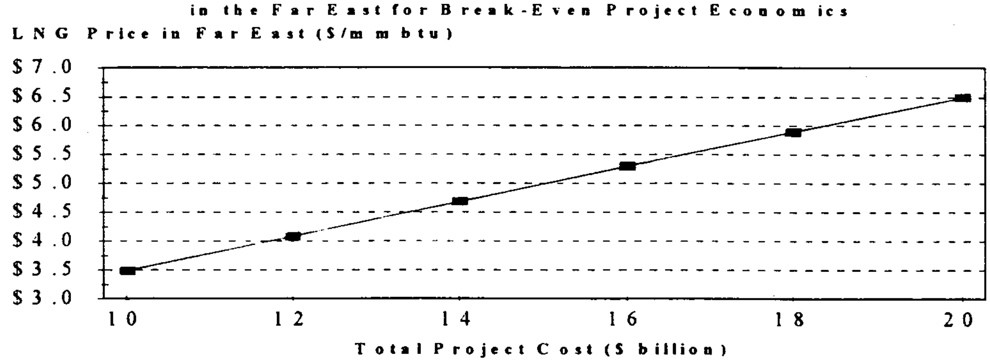
[2] These figures include a $0.50/mcf operating cost and a $0.30/mcf 20 mill oil and gas property tax payment.

At a 4% real after-tax rate of return on the project, a price of $5.00/mmbtu in the Far East would be required to yield a zero wellhead value. If the project were 100% debt financed, the required Far East price would be $4.50/mmbtu. If the project were 100% equity financed, the required Far East price would be $6.40/mmbtu.

Figure 2 depicts the break-even gas price required in the Far East at different project construction costs. For this comparison the assumed financing arrangements are: (1) 75% debt and 25% equity; (2) the equity portion requires a 5% real after-tax rate of return; (3) the debt portion of the project is financed at a rate 2% less than the nominal equity return; and (4) the inflation rate over the life of the project is 3%. At the current project cost estimate of $15 billion, the required destination price in the Far East is $5.00/mmbtu. Figure 2 shows that it would take a one-third reduction in project construction costs, to $10 billion, for the current price in the Far East, $3.50/mmbtu, to yield a zero wellhead value on the North Slope.

Figure 2
The Relationship between Total Project Cost and LNG Price in the Far East for Break-Even Project Economics



APPENDIX B

Technical Description of Gas Line Rate of Return Model

The gasline rate of return (ROR) model computes a levelized per mcf amount that computes break-even transportation costs for the entire system, including the tankers, at a specified rate of return. The model uses a cost of service methodology. The levelized cost is the total discounted cost divided by the total discounted volume. There are six cost components: depreciation, operating costs, property tax, income tax, interest, minimum cents per mcf severance tax[1], and after tax margin (profit or the return on base equity investment).

The after-tax margin is the product of the nominal rate of return and the undepreciated equity capital. The income tax allowance is the product of the tax gross-up factor and the after tax margin. The tax gross-up factor is that number which when multiplied by the after tax margin yields the state and federal corporate income tax amounts given the cost of service for the given year.[2]

In this model we assumed no inflation for the system components and 3% for the economy as a whole. We have also assumed 75% debt and 25% equity, with the cost of debt at two percentage

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[1] The minimum cents per mcf severance tax is 6.4 cents. We have assumed an economic limit factor of 0.8.

[2] Given a state corporate income tax rate of 9.4% and a federal corporate income tax rate of 35%, the tax gross-up factor is:

$$(.094 + (.35 \text{ X } (1 - .094))) / (1 - (.094 + (.35 \text{ X } (1 - .094)))) = 0.6981$$

points below the nominal rate of return.

Other key assumptions include:

- $15 billion in capital costs
- $11 billion in non-ship capital subject to the property tax
- 2 million mcf per day for 25 years
- 5 year ramp-up
- $0.50/mcf operating costs
- 1.1 mmbtu to mcf ratio

The model is shown on the following table.

Gasline ROR Model

Operating cost	0.5
Capital Cost	15000
% non-ship	0.733333333
Years	25
Real Equity ROR	5
Nominal Equity RO	12.903
Nominal Debt ROR	10.903
Tax Gross-up factor	0.6981
Percent Equity	0.25
Percent Debt	0.75
BTU Adj	1.15
Return on Capital dur constr	1101

Year	Gas Volume (bcf/d)	Gas Volume (bcf/y)	Operating Cost	Depreciation	Undepreciated Amount-for Property Tax	Property Tax	Depreciation (for return)	Undepreciated Amount - for return	Return on Base (after tax margin)	Income Tax Allowance	Interest	Severance Tax	Cost of Service	Discount Factor	Discount Cost	Discount Volume
0	0.4	146	73	600	15000	220	194	4851	626	437	1432	7	3395	0.941	3195	137
1	0.8	292	146	600	14400	211	194	4657	601	419	1432	13	3423	0.834	2853	243
2	1.2	438	219	600	13800	202	194	4463	576	402	1432	20	3451	0.738	2548	323
3	1.6	584	292	600	13200	194	194	4269	551	385	1432	26	3480	0.654	2275	382
4	2	730	365	600	12600	185	194	4075	526	367	1432	33	3508	0.579	2032	423
5	2	730	365	600	12000	176	194	3881	501	350	1432	33	3456	0.513	1773	374
6	2	730	365	600	11400	167	194	3687	476	332	1432	33	3405	0.454	1547	332
7	2	730	365	600	10800	158	194	3493	451	315	1432	33	3354	0.402	1350	294
8	2	730	365	600	10200	150	194	3299	426	297	1432	33	3303	0.356	1177	260
9	2	730	365	600	9600	141	194	3105	401	280	1432	33	3251	0.316	1026	230
10	2	730	365	600	9000	132	194	2911	376	262	1432	33	3200	0.280	895	204
11	2	730	365	600	8400	123	194	2716	351	245	1432	33	3149	0.248	780	181
12	2	730	365	600	7800	114	194	2522	325	227	1432	33	3097	0.219	679	160
13	2	730	365	600	7200	106	194	2328	300	210	1432	33	3046	0.194	592	142
14	2	730	365	600	6600	97	194	2134	275	192	1432	33	2995	0.172	515	126
15	2	730	365	600	6000	88	194	1940	250	175	1432	33	2943	0.152	449	111
16	2	730	365	600	5400	79	194	1746	225	157	1432	33	2892	0.135	390	99
17	2	730	365	600	4800	70	194	1552	200	140	1432	33	2841	0.120	340	87
18	2	730	365	600	4200	62	194	1358	175	122	1432	33	2789	0.106	295	77
19	2	730	365	600	3600	53	194	1164	150	105	1432	33	2738	0.094	257	68
20	2	730	365	600	3000	44	194	970	125	87	1432	33	2687	0.083	223	61
21	2	730	365	600	2400	35	194	776	100	70	1432	33	2635	0.074	194	54
22	2	730	365	600	1800	26	194	582	75	52	1432	33	2584	0.065	168	48
23	2	730	365	600	1200	18	194	388	50	35	1432	33	2533	0.058	146	42
24	2	730	365	600	600	9	194	194	25	17	1432	33	2481	0.051	127	37
														Total	25828	4496

levelized mcf amt	5.71
btu adj	1.15
break-even price ($/mmbtu)	4.99

APPENDIX C

Technical Explanation for Estimating the Value of Lost Oil

Currently the highest and best use of gas at Prudhoe Bay is to facilitate oil production. The producers have estimated that an MGS in 2005 would result in a loss of 400 million barrels of oil over the remaining life of Prudhoe Bay, and a 2010 sale would result in a 100 million barrel loss.

The significance of those losses depend on the relative values of oil and gas. Because of the time value of money these values are dependent on the time profile of the losses. The projected time profile of these losses is shown below.

The loss in oil reserves is a function of cumulative gas removed from the reservoir over time. A uniform series time rating function relates the loss of an mcf of gas to both an immediate loss of oil and a loss of oil through time.

We estimated time series of reserves losses for both 2005 and 2010 sales. These losses were multiplied by the respective predicted oil price for the subject year and discounted at 10%. The total discounted losses were divided by the total discounted volume of gas. This represents the wellhead price of gas that would make the producers indifferent to the reserve losses.

For a 2005 sale the gas price is $0.40/mcf, and for 2010 the price is $0.15/mcf. The derivation of these amounts is shown on the following tables.

Value of Lost Oil - 2005 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price ($/bbl)	Oil (bbls)	Disc Oil Loss
2005	146	0.953	139	16.61	1	16
2006	292	0.867	253	17.03	2	30
2007	438	0.788	345	17.43	3	41
2008	584	0.716	418	17.91	4	51
2009	730	0.651	475	18.75	6	73
2010	730	0.592	432	19.34	7	80
2011	730	0.538	393	19.81	8	85
2012	730	0.489	357	20.59	9	91
2013	730	0.445	325	21.15	10	94
2014	730	0.404	295	21.83	12	106
2015	730	0.368	268	22.42	13	107
2016	730	0.334	244	23.03	14	108
2017	730	0.304	222	23.65	15	108
2018	730	0.276	202	24.29	17	114
2019	730	0.251	183	24.94	18	113
2020	730	0.228	167	25.62	19	111
2021	730	0.208	151	26.31	20	109
2022	730	0.189	138	27.02	21	107
2023	730	0.171	125	27.75	23	109
2024	730	0.156	114	28.50	24	107
2025	730	0.142	103	29.27	25	104
2026	730	0.129	94	30.06	26	101
2027	730	0.117	86	30.88	28	101
2028	730	0.106	78	31.71	29	98
2029	730	0.097	71	32.57	30	95
			5679		384	2258
					value	0.40

Value of Lost Oil - 2010 Sale

Year	Gas (bcf/y)	Disc Factor	Disc Gas	Oil Price ($/bbl)	Oil (bbls)	Disc Oil Loss
2010	146	0.953	139	19.34	0	0
2011	292	0.867	253	19.81	1	17
2012	438	0.788	345	20.59	1	16
2013	584	0.716	418	21.15	2	30
2014	730	0.651	475	21.83	2	28
2015	730	0.592	432	22.42	3	40
2016	730	0.538	393	23.03	4	50
2017	730	0.489	357	23.65	4	46
2018	730	0.445	325	24.29	5	54
2019	730	0.404	295	24.94	5	50
2020	730	0.368	268	25.62	6	57
2021	730	0.334	244	26.31	6	53
2022	730	0.304	222	27.02	7	57
2023	730	0.276	202	27.75	7	54
2024	730	0.251	183	28.50	8	57
2025	730	0.228	167	29.27	8	53
2026	730	0.208	151	30.06	9	56
2027	730	0.189	138	30.88	9	52
2028	730	0.171	125	31.71	10	54
2029	730	0.156	114	32.57	11	56
2030	730	0.142	103	0.00	0	0
2031	730	0.129	94	0.00	0	0
2032	730	0.117	86	0.00	0	0
2033	730	0.106	78	0.00	0	0
2034	730	0.097	71	0.00	0	0
			5679		108	882
					value	0.16