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FERC Policy-
Rolled in Rates- In Alaska

AGIA
The Alaska Gasline Inducement Act

- 2004 ANGPA mandate to FERC:
  - "promote competition in the exploration, development and production of Alaska natural gas." (§103(e)(2)(b)).

FERC Policy- Rolled in Rates- In Alaska

AGIA
The Alas'.a Gasline Inducement Act

- FERC Concluded:

"incremental pricing of expansion could put expansion shippers at a significant rate disadvantage compared with initial shippers, and accordingly could discourage exploration, development and production of Alaska natural gas." (Order 2005 at ¶ 123)

FERC Policy- Rolled in Rates- Lower 48

AGIA
The Alaska Gasline Inducement Act

- From 1960's until 1999 FERC preferred rolled-in pricing. (Statement of Policy, 71 FERC ¶ 61,231 (1995)).

- Changed in 1999 because, "it no longer fits well with an industry that is increasingly characterized by competition between pipelines." (Statement of Policy, 88 FERC ¶ 61,227 (1999)).

FERC Policy- Rolled in Rates- Lower 48/Alaska

AGIA
The Alaska Gasline Inducement Act

- "Our existing lower-48 states policy favoring incremental rates for expansions does not apply in the case of an Alaska natural gas project. There is likely to be only one Alaska pipeline so there will be little or no opportunity for competition between pipelines." (Order 2005 at ¶ 123).

FERC Policy- Rolled in Rates- Lower 48/Alaska

AGIA
The Alaska Gasline Inducement Act

A rate increase is not necessarily a subsidy. (*see*, order 2005-A at ¶ 50).

"An alternative …definition of subsidization could be whether the expansion rate is no higher than the actual initial rate or of an initial rate without built in subsidies." (Order 2005-A at ¶ 49)

FERC Policy- Rolled in Rates- Alaska

AGIA
The Alaska Gasline Inducement Act

"Whether a rolled-in expansion rate that is higher than original rates is a 'subsidy' is a question that necessarily would have to be reviewed in the context of a future NGA section 7 filing. At that time, … [arguments] relating to whether the federal government's loan guarantees and accelerated depreciation amount to a 'subsidy' of initial shippers' rate may be raised." (Order 2005 at ¶ 124, emphasis in original).

Governmental Contribution to Rates

AGIA
The Alaska Gasline Inducement Act

Government Contributions reduce rates by more than 15%:

- Loan Guarantee up to $18 billion
- 7-year accelerated depreciation
- Federal income tax credit for GTP
- AGIA $500 million

AGIA Policy- Rolled in Rates

AGIA
The Alaska Gasline Inducement Act

- AGIA caps roll-in filing commitment roughly at level of governmental contributions to the project.

- Permits 2d or 3d generation of expansion shippers also to enjoy the benefit of governmental contributions made available to initial shippers.

FERC Process

AGIA
The Alaska Gasline Inducement Act

"A pipeline company

PROPOSES

But the FERC

DISPOSES."

(an old industry adage)

FERC Process

AGIA
The Alaska Gasline Inducement Act

- AGIA does not intrude on FERC's authority.
- AGIA requires that the licensee ***PROPOSE*** rolled-in rates
- FERC will ***DISPOSE.***

AGOCC

TESTIMONY OF JOHN K.NORMAN, CHAIR AOGCC
SENATE FINANCE COMMITTTEE
APRIL 27, 2007

This afternoon I'll discuss the AOGCC's role in North Slope gas sales and give you a status report.

Most knowledgeable Alaskans know the significance of 35 TCF of natural gas. However, very few people realize that hundreds of millions of barrels of oil and condensate could be lost if gas offtake is not correctly managed.

Oil is Alaska's bird in the hand and gas is our bird in the bush. The AOGCC is responsible for setting the gas offtake allowables from the North Slope oil fields to ensure that we do not harm our bird in the hand while aspiring to grasp our bird in the bush.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after most of the oil has been produced. Until then, the gas that is produced with the oil is used to promote increased liquid production in various ways.

For example, gas might be reinjected into the reservoir to provide the energy needed to get the liquid hydrocarbons to the surface, or the gas might be used for enhanced oil recovery operations.

Both of those are happening right now at Prudhoe Bay and other North Slope fields.

Therefore, North Slope gas sales will involve trade-offs between oil and gas recovery. It's not practical to get every drop of oil out of the ground before starting gas sales, and the AOGCC certainly does not take that position. We just want to ensure that the trade-

AOGCC
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offs that inevitably will occur result in greater ultimate recovery of both gas and oil

Prudhoe Bay has an existing gas offtake allowable. It is 2.7 BCF per day and it was set in 1977.

The AOGCC usually waits for an application from the operator to apply or modify pool rules. However, in 2005 we recognized that:

(1) North Slope gas sales discussions were heating up,

(2) the 2.7 BCF per day gas offtake allowable for Prudhoe Bay was set in 1977, about the time the field began to produce; and, although that offtake rate was based on the best available information at the time, we now have 30 years and 11 billion barrels of production and production-related data to help determine a better number

(3) most of the publicly discussed pipeline options could require more than 2.7 BCF per day offtake from Prudhoe Bay

(4) performing the necessary studies to determine an appropriate offtake could take a lot of time, and

(5) the AOGCC did NOT want to cause any project delays.

To give us the most current information, BP and the other Prudhoe Bay working interest owners agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. They voluntarily set up a data room in BP's Anchorage offices, equipped with computers and software allowing review of the simulator results.

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It is very important to note that the data and information offered meet the standards of AS 31.05.035(d) and 20 AAC 25.537(b) governing confidentiality of information.

In simple terms, the data made available to us was not something we were otherwise entitled to, it belonged solely to the Prudhoe Bay working interest owners, we needed it to perform our study, and the only way for us to get access to it would be to agree to keep it confidential.

The study began in January 2006, and ended in late 2006. BP and its partners were helpful and provided us all that we needed.

This past February, we published a summary report, approved by BP and its partners. The report is available on the AOGCC website.

As soon as we announced that we had completed our study, everyone wanted to know the magic number, but it's not that easy.

First, it's a multi-variable equation. The right offtake volume will depend on when sales start, how aggressively the oil has been produced in the meantime, and what mitigating steps are in place and planned. And second, there are legal restrictions on what results of the study we can share and how we share them.

As soon as we have enough information to make a meaningful determination, we will hold public hearings and make as much information available as is needed and legally allowed to support the assigned offtake allowable.

We intend to complete our evaluations and make our final rulings on gas offtake allowables for both Prudhoe Bay and Pt Thomson well in time for the "open season" process.

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That said, here's what we can say:

(1) The later gas sales begin, the smaller the oil losses.

(2) Depending on the life of the North Slope infrastructure, delaying too long could result in decreased gas recovery.

(3) The lower the offtake rate, the smaller the oil losses.

(4) The more the oil production is accelerated before gas sales start, the smaller the oil losses.

(5) The more that is done to mitigate the detrimental effects of gas sales, the smaller the oil losses.

(6) Oil loss is more sensitive to the acceleration of oil production and the mitigating steps than it is to start-up timing or offtake rate.

By the time we get a pipeline built, selling gas from Prudhoe Bay will likely be okay at a higher offtake rate than the current 2.7 BCF per day, provided BP and its partners continue working: (1) to accelerate oil production (for example: aggressive infield drilling and operational vigilance to minimize production interruptions) and (2) to mitigate for gas losses (gas cap water injection and using CO2 for EOR, for example).

We are comfortable that, unless a substantial delay occurs (which could make our analysis stale and require additional analytical work), we will be adequately prepared to determine the Prudhoe Bay gas offtake allowable when an application comes before us.

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Now I would like to talk about Pt Thomson, where we can't make such a confident statement.

One year ago the AOGCC, Exxon, and its partners agreed upon a similar process for studying the allowable gas offtake from Pt Thomson. The AOGCC contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. Exxon and its partners agreed to give AOGCC staff and consultants access to a data room in Exxon's Houston offices. It was agreed that the data room would include reservoir engineering, geologic and simulation information and would be equipped with computers and software allowing review of the simulator results. The study was supposed to begin before September 2006 and last up to six months. Exxon and its partners indicated that they planned to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate for Pt Thomson.

Unfortunately we were not able to follow that time line. Exxon had delays in preparing the data room and information. The process was finally slated to begin late last year, about the same time that the DNR found Exxon and its partners to be in default on their leases. We attended one meeting where Exxon presented a small portion of the information we would need, but since then the study has been on hold pending resolution of legal issues.

Without a thorough study, it will be very difficult for the AOGCC to have sufficient information to make a gas offtake ruling on Pt Thomson. So that one remains a wild card – in many ways.

So, in summary:

(1) There are hundreds of millions of barrels of oil and condensate at risk if Alaska doesn't manage gas sales properly.

(2) The AOGCC is charged with setting gas offtake allowables that will protect Alaska's valuable hydrocarbon resources.

(3) The AOGCC intends to perform its function so that it does not delay the project, i.e., before an open season.

(4) We've done the technical work to prepare us to address Prudhoe Bay's offtake without causing that delay.

(5) There's still a lot to be done for Pt Thomson; so delay is possible there.

Thank you and we would be happy to take your questions.

BIOGRAPHICAL INFORMATION

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Admitted to Bar: Missouri (1964); Alaska (1969); U.S. District Court, District of Alaska (1969); U.S. Court of Appeals, Ninth Circuit (1972); U.S. Supreme Court (1972).

Member: Greater Anchorage Area Board of Health (1973-1975); State Division of Lands Advisory Committee (1976-1977); Federal Bureau of Land Management Advisory Council (1982-1985); President, Common Sense for Alaska, Inc. (1981-1982); Vice President, Anchorage Chamber of Commerce (1983-1985); Chairman, Commonwealth North, Hartig Research Fellowship Trust (1981 - present); Board of Directors, Resource Development Council (1988 - 2004); Trustee, Iditarod Trail Race Foundation (1976-present); U.S. Department of Commerce, Alaska District Export Council (1992 - present); American Institute of Professional Geologists (2003 - present); Outstanding Lawyers of America (2003 - present); The Best Lawyers in America (2004-present); Alaska Bar Association (Chairman, Natural Resource Law Committee (1977-79), Fee Arbitration Panel (1977-1981), Environmental/Natural Resource Law Section (1980-present), Discipline Hearing Committee (1983-1987); American Bar Association (Member, Environment, Energy and Resources Section; State Chairman, Committee on Environmental Quality, Young Lawyers Section, 1971-1973); Official Alaska Representative and Vice Chairman, Interstate Oil and Gas Compact Commission (2004-present) (Chairman Steering, Nominating and Split Estates Committees).

Positions Held: Chairman, State of Alaska Oil & Gas Conservation Commission (2004-present); Founding Partner and Shareholder, Hartig Rhodes Hoge & Lekisch, P.C. (1971-2004); Assistant Attorney General, State of Alaska, Department of Law, Natural Resources Section (1969-1971); Exploration Representative, Skelly Oil Company, Alaska/Texas (1967-1968); 1st Lt., United States Army, Germany (1964-1966).

Published Works: "Section Line Dedications for Construction of Highways," Alaska Law Journal (Feb. 1970); "Production, Conservation and Utilization of Natural Gas in Alaska," Natural Resources Lawyer (Nov. 1970); "Alaska's D-2 Lands," Alaska Mineral Development Institute Paper No. 5, Rocky Mountain Mineral Law Foundation (Aug. 1978); "Legal Considerations When Entering the Alaska Energy Market," IBC Global Conferences (Sept. 2002); Alaska Oil & Gas Law Reporter, Rocky Mountain Mineral Law Newsletter (1984 - 2004).

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MEMORANDUM STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Chair John K. Norman
Commissioner Daniel Seamount
Commissioner Cathy P. Foerster

DATE: February 28, 2007

FROM: Jane Williamson
Sr. Reservoir Engineer

SUBJECT: Prudhoe Major Gas Sales Study

Blaskovich Services, Inc. (BSI) and Commission staff recently completed a study of the impact of a future Major Gas Sale (MGS) on oil and gas recovery from the Prudhoe Oil Pool. The following is provided as a summary of major findings and conclusions from this study.

Foreward – Historical Review and Study Purpose

In 1977, the Commission set the maximum allowable Prudhoe Oil Pool annual gas offtake rate at 2.7 billion standard cubic feet per day (BSCF/D), which contemplated an annual average gas pipeline delivery sales rate of 2.0 BSCF/D. This allowable, set out in Rule 9 of Conservation Order 341D, was approved without benefit of production history. The Commission recognized that the rates may be changed as production data and additional reservoir data became available.

Over the past five years, there has been significant activity concerning a potential major gas sale. BPXA, Exxon-Mobil, and ConocoPhillips commissioned a $125 million dollar study to determine the conceptual feasibility of a gas pipeline. The tentative plan resulting from this study was for a 4.3 BSCF/D pipeline, with capacity to expand to 5.6 BSCF/D. The Prudhoe Bay Unit, Prudhoe Oil Pool is the only North Slope developed field with significant gas reserves (estimated at more than 24 trillion cubic feet (TCF)) and is of primary importance for any decision concerning the pipeline. Pt. Thomson, with over 8 TCF of gas and several hundred million barrels of gas condensate and oil, was assumed to also provide a supply of gas for the pipeline. The companies and the State of Alaska have devoted significant resources to negotiate fiscal terms to build the pipeline. Based on these efforts, the Commission became concerned that no application for modification to the Prudhoe gas offtake rule had been submitted.

As a result of a Commission inquiry and several public hearings, the Commission published a report on December 5, 2005 concluding that there was a need to comprehensively revisit the question of the appropriate gas offtake limits in light of several decades of reservoir development and information that has become available since 1977. Because delay in the Commission's decision-making could disrupt the timetable for a potential gas pipeline project, the Commission adopted a proactive approach to ensure there would be an adequate factual basis for its eventual decision on

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allowable gas offtake. The Prudhoe Working Interest Owners (WIO) and the Commission therefore agreed to principles allowing the Commission consultants and staff to access their reservoir simulation and other relevant engineering studies for the purpose of analyzing gas offtake rates and gas sales startup timing for the Prudhoe Oil Pool. Blaskovich Services, Inc. (BSI) was commissioned to provide reservoir engineering consultation in this study.

This work-study officially began in late January 2006. A brief summary follows:

Summary of 2006 Commission Audit Results

The Prudhoe WIO full field reservoir simulator was used as the primary tool in this evaluation. In addition to runs made assuming no gas sales, simulation runs were made at various gas sales rates (1.0-5.6 BSCF/D) and gas sales startup dates (2015, 2019, and 2024). Some simulation cases were run to test the impact of other factors such as changes in waterflood operation, fuel usage, CO_2 offtake, and some drilling/workover variations. We also evaluated the effect of varying assumptions for end of the field life (EOFL).

Throughout our analysis, we searched for major factors that would affect the trends in total hydrocarbon recovery as a function of gas offtake rates and timing. We were not searching for "the" optimum development strategy. We did not value one type of energy resource (e.g., liquids or gas) over another, but equated them using their relative energy content in units of barrels of oil equivalent (BOE). Based on our analysis of currently available data, we have reached the following major conclusions.

- A major gas sale at Prudhoe represents approximately an additional 4 billion BOE recovery.
- The latest WIO model needs improvements in its ability to predict future field performance. Model errors are increasing with time. Nevertheless, it is the best tool currently available. It should be suitable for comparing directional trends in energy recovery during a gas sale.
- Increased oil capture prior to gas sales can increase hydrocarbon recovery and result in recovery trends that are less sensitive to either gas offtake rates or gas sales startup dates. This was the only mitigation option evaluated that significantly improved trends in BOE recovery.
- End of field life (EOFL) is a major source of uncertainty in determining the gas sale strategies that will maximize energy recovery.
    - Comparison of model reserves predictions at the same date for EOFL tended to favor an earlier, higher rate gas sale. We found the time limit EOFL approach to be inappropriate because ending energy production rates could be vastly different between the high rate, early startup case and the low rate, delayed startup case.

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  - Model results based on equivalent EOFL rate limits consistently show that total energy recovery is substantially decreased with an earlier, higher rate gas sale. We believe that rate limits are more reasonable than time limits for comparison of gas sales model predictions. However, exclusive use of rate limits is flawed because the risks of wells and field infrastructure failures with age are ignored.

- Well, facilities and infrastructure failures can significantly increase the risk of lost hydrocarbons. The longer that gas sale is delayed, the greater the risk of well and facilities failure resulting in premature field shutdown. Furthermore, near term failures will defer production and may result in more reserves loss with early gas sales. Diligent efforts to maintain, repair, and replace aging wells and facilities will help to mitigate risks and maximize recovery under any sales scenario.

Recommendations

The Commission has not received a request for a new gas offtake rule. At this time, we cannot recommend a specific gas offtake rate and sales startup timing. The Prudhoe WIO model evaluations and studies that have been shared with us are not sufficient to justify an allowable above that specified in Rule 9, CO 341D. An early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons. However, even greater volumes may be at risk if gas sales are indefinitely delayed and Prudhoe wells and infrastructure fail before these reserves can be recovered.

We are concerned that Rule 9 does not specifically require a plan for such a major change in the Prudhoe Oil Pool depletion strategy. The ultimate impact of gas sales on hydrocarbon recovery cannot be appraised in the absence of a proposed development plan that identifies the start date, sales rate and liquid loss mitigation efforts. Although the start-up for gas sales is a minimum of 8 years away, many decisions that affect the project will be made earlier. Depletion planning should be required prior to commitments to sell gas so that the Commission is adequately informed and assured that other factors do not exist that would justify or require action by the Commission.

Regardless of the timing of their submittal, the Prudhoe WIOs need to develop near-term strategies to prepare the field for gas sales with focus on methods to increase the capture of oil prior to gas sales and to ensure facility and well downtime is minimized. On a regular basis, the Commission needs to be kept informed of the progress of the depletion planning efforts, including review of study plans, reservoir study results and other relevant information that may impact the Commission's ultimate decisions concerning gas sales offtake. The exchange of information in the past year was very successful and a similar mechanism of exchange should be considered during the depletion planning stage.

We wholeheartedly appreciate the cooperation of the Working Interest Owners over the past year, particularly that of the BP technical representatives who worked with us in this endeavor.

This report reflects the evaluation and opinions only of the authors and does not necessarily reflect those of the Prudhoe Owners or other Commission staff.

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the

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pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, the gas cap in an oil reservoir should only be "blown down" when no more commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

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Role of the Alaska Oil and Gas Conservation Commission in Approving Pool Rules for the Point Thomson Field

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas production rates should be allowed from North Slope oil fields. As part of this process, the AOGCC will evaluate ExxonMobil's proposed plan to develop the Point Thomson Field as a gas field rather than as an oil field. Generally, the most total hydrocarbon recovery from a retrograde condensate field would be achieved by conducting gas cycling operations to produce condensate (a liquid hydrocarbon that is considered "oil" under the Commission's governing law) until all of the economically recoverable liquid hydrocarbons have been produced. Only then should the gas be sold. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Point Thomson is the largest proven yet still undeveloped field in Alaska. It is also one of the most difficult to develop and manage properly because the majority of the resources are contained in what is called a retrograde condensate reservoir. Retrograde condensate reservoirs around the world tend to be deeper and have higher pressures and temperatures than conventional reservoirs. These abnormally high temperatures and pressures cause the fluids in the reservoir to have unusual properties. Thus, a retrograde condensate reservoir acts differently than a typical oil field such as Prudhoe Bay or a typical gas field such as the Kenai Gas Field. The differences in behavior are technically complex and difficult to describe, understand, and address; yet understanding and addressing these differences are essential to evaluating whether a plan of development satisfies the conservation requirements administered by the Commission.

A conventional oil reservoir is typically filled with a liquid hydrocarbon that has some solution gas in it. In such a reservoir all the fluid exists as a liquid, but as it is brought to the surface its pressure drops and some of its solution gas is released. The same thing happens underground. As the pressure decreases in the reservoir, gas in the oil comes out of solution. To understand how this works, think of a bottle of soda. Before the bottle is opened, its contents are under pressure and it appears that there is just liquid in the bottle. However when the cap is removed, the pressure in the bottle is reduced and bubbles will start to form and float to the surface of the soda.

Conversely, a conventional gas reservoir is typically filled with hydrocarbon gas. The gas may have a small amount of hydrocarbon liquid, called condensate, vaporized in it. This condensate will not drop out as a liquid in the reservoir because the temperature is too high. However it will separate from the gas when the gas is brought to the surface where the temperature is lower. This is similar to what happens when someone blows warm breath onto a cold window and watches it fog up. The water that exists as a vapor inside the warm lungs turns to condensation as it hits the cold window.

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Retrograde condensate reservoirs do not behave in the same ways that conventional oil and gas reservoirs do. Dropping the pressure in the reservoir does not cause gas to form from oil, as is the case in a conventional oil reservoir. Nor does vaporized condensate remain a vapor, as is the case in a conventional gas reservoir. Rather, for a retrograde condensate reservoir, as the pressure decreases, liquids drop out of the gas in the reservoir.

When a retrograde condensate field is produced like a conventional gas field, the gas is produced and sold at high rates. Initially a large amount of condensate is produced with the gas. However the reservoir pressure drops quickly and condensate production drops dramatically because condensate is dropping out in the reservoir instead of at the surface. To further the problem, condensate that drops out in the reservoir is much more difficult to produce than that which remains entrained as a vapor in the gas. The liquid tends to build up and clog the pore spaces in the reservoir rock. Also, since this reservoir has never been exposed to liquid before, the rock acts as a sponge and some of the condensate will be immobilized and never come out. To make things worse, once the condensate comes out of the gas, very little of it will return to a gaseous state even if the reservoir pressure is later increased. In other words this is a problem that you can't fix after you cause it; it's like unringing a bell.

In addition to lost condensate recovery, if the reservoir pressure is reduced too quickly, the gas recovery will also decrease. The condensate that clogs up the reservoir and won't come out also blocks the gas from coming out. This is similar to an air filter on a car. When the filter is new, air will flow through it freely, but as it gets older the pores in the filter begin to clog with dirt (as the pores in the reservoir would clog with condensate) and the air will not flow through as well. Eventually no air at all will flow.

So what's the answer? To maximize condensate production from a retrograde condensate reservoir, it is necessary to keep the reservoir pressure high until the condensate has been recovered. Often this is accomplished through a process known as "gas cycling." In this process hydrocarbon gas is produced, the condensate is removed and sold, and the now-lean gas is injected back into the reservoir to maintain pressure and to sweep more condensate to the surface. As this process continues, the gas produced slowly becomes leaner and the yield of condensate decreases. Eventually the gas is stripped of most of the liquids and it is safe to sell the gas. This method delays gas sales, but it results in greater ultimate recovery of both liquid and gaseous hydrocarbons.

Another method used to develop retrograde condensate fields is to inject a substitute gas such as nitrogen or carbon dioxide either to replace or to supplement the produced gas for pressure maintenance. Unfortunately, there is currently no substitute gas available to Point Thomson.

These are just a few of the more common methods used for developing retrograde condensate fields and each has advantages and disadvantages that must be considered. Primary depletion as a gas field is the least efficient and results in the lowest hydrocarbon recovery. However, it is the simplest and cheapest method for the operator since it does

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not require an investment in equipment to recycle the gas. Gas cycling yields greater hydrocarbon recovery but may be less attractive to the operator because it has a higher up-front development cost for compression and it has low up-front cash flow due to the deferral of gas sales. Injection of outside substances has the possibility of maximizing both condensate recovery and cash flow, but it is the most expensive method because in addition to compression equipment it requires the purchase of a substitute gas.

Selection of an optimal method of development must consider all of the unique aspects of the reservoir in question, as well as the practicality and applicability of the various development methods.

The operator of the Point Thomson Unit has indicated that the only development scenario that makes sense is to develop Point Thomson as if it were a normal gas field, which would likely result in significant loss of condensate. Since the AOGCC must determine whether this development option is consistent with good oilfield engineering practices and will result in greater ultimate recovery, the agency is working with an outside consultant who has extensive retrograde condensate reservoir expertise. The AOGCC and its consultant are evaluating different development options and developing a sound technical basis for conservation orders relative to the development plan that is ultimately proposed by the operator of the Point Thomson Unit.

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Role of the Alaska Oil and Gas Conservation Commission in North Slope Gas Sales

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope natural gas to market. The Alaska Oil and Gas Conservation Commission ("AOGCC") has an important responsibility in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of oil and gas. To fulfill this role, the AOGCC must determine what gas offtake rates should be allowed from North Slope fields, most notably the Prudhoe Oil Pool and the Pt. Thomson gas condensate reservoirs.

There are over 35 trillion cubic feet of gas reserves within these two fields. However, hundreds of millions of barrels of oil and condensate could be lost if gas offtake from these fields is not correctly managed.

In general, maintaining reservoir pressure enhances oil recovery, but producing gas depletes reservoir pressure. Therefore, gas reserves in most fields are usually sold only after the liquid hydrocarbon reserves have been depleted. Until then, the gas that is produced is used to promote liquid production in various ways (including being reinjected so that it can provide the energy needed to get the liquid hydrocarbons to the surface and providing a source of gas for miscible injectant used in enhanced oil recovery operations). And that is exactly what is happening right now at Prudhoe Bay and other North Slope fields.

The North Slope gas sales project will ultimately involve trade-offs between oil and gas recovery. The documents *Role of the Alaska Oil and Gas Conservation Commission in Establishing an Allowable Gas Offtake Rate for Prudhoe Bay* and *Role of the Alaska Oil and Gas Conservation Commission in Managing Development of the Point Thomson Field* explain these trade-offs. This document explains the process the AOGCC is using to insure greater ultimate total hydrocarbon recovery, i.e., recovery of both oil and gas, as the North Slope gas project moves forward.

Normally, the operator of an oil or gas field applies to the AOGCC for "Pool Rules." These are specific rules that stipulate how to develop the reservoir in a way that maximizes oil and gas recovery. However, the Point Thomson Owners have not yet applied to the AOGCC for Pool Rules.

Nor have the Prudhoe Owners applied for amendment of current pool rules to allow for a higher gas offtake rate. The existing Prudhoe gas offtake rate was set in 1977 at 2.7 billion standard cubic feet (BCF) of gas per day. After deducting gas used as fuel and in enhanced recovery operations, this leaves about 2 BCF of gas per day available for sales. However, the gas sales scenarios that are being discussed publicly could require increasing the Prudhoe gas offtake allowable.

Normally the AOGCC would wait for an application from the Owners before performing the reservoir studies necessary to establish or increase gas offtake rates. However, that would delay the AOGCC's decision-making such that it could disrupt the timetable for a potential gas pipeline project. (The AOGCC needs to complete its evaluations and make its rulings for both

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Prudhoe Bay and Pt Thomson so the Owners have approved gas offtake allowables that they can use in the "open season" process that is required under the Federal Energy Regulatory Commission ("FERC") regulations. The current draft version of the Alaska Stranded Gas Fiscal Contract requires the Producers to apply to the AOGCC within 6 months of the effective date of the contract for issuance of pool rules to authorize the field gas offtake rate for Point Thompson.)

Therefore, the AOGCC has chosen a proactive approach. There are two ways the Commission might take a proactive role with respect to such studies. One would be to conduct or arrange for consultants to conduct independent reservoir studies. The other would be to participate with the Owners and operators in their reservoir simulation studies, so that questions can be answered and adjustments can be made up front. Assuming adequate cooperation on the part of the Owners, the latter approach has significant advantages: lower cost to the State of Alaska, less time required to complete evaluation of the studies, more complete and accurate input data, and use of proven, probably more sophisticated reservoir evaluation tools.

In 2005 the Commission held hearings to inquire whether the gas offtake rate from Prudhoe should be updated. The AOGCC decided that, although the 1977 allowable was based on the best available data at the time, the appropriate gas offtake allowable must now be redetermined using the almost thirty years worth of reservoir description and performance information that has become available since 1977. Further, the Prudhoe Owners and the AOGCC established principles by which to perform collaborative studies. The report of the inquiry and the resultant study principles were issued by the AOGCC on December 5, 2005.

The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Prudhoe study. The Prudhoe Owners have agreed to provide the AOGCC staff and consultants access to their simulators including the underlying engineering, geologic, and geophysical information. A data room has been set up in BP's Anchorage offices, equipped with computers and software allowing review of the simulator results. The Owners have voluntarily offered to make the data room information available. The information meets the standards of AS 31.05.035(d) and 20 AAC 25.537(b) entitling it to be held confidential during this study period.

This study process began in January 2006, and is anticipated to be complete by the end of this year. Following this study period, either the Owners will submit an application to amend the Prudhoe gas offtake allowable or the AOGCC will call for a hearing. In either case, the AOGCC will hold public hearings to review the development plans associated with the proposed gas sales. The Owners will be required to submit for the record reservoir studies that best reflect a reasonable range of offtake options and their effects. The AOGCC may request (including by subpoena) any other pertinent information that has been used in the study but is not included in the Owners' submission of evidence in the hearings. Claims of confidentiality for evidence in the hearings will be determined by the AOGCC during the course of the hearings under governing law.

On April 26, 2006 the AOGCC and the Pt. Thomson Owners agreed upon a similar process for studying the allowable gas offtake from that field. The AOGCC has contracted reservoir evaluation consultants to assist its technical staff in performing the Pt Thomson study. AOGCC staff and consultants will have access to a data room in ExxonMobil's Houston offices. The data

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room will include reservoir engineering, geologic and simulation information and will be equipped with computers and software allowing review of the simulator results. The study will begin before September 2006 and will last up to six months. The Point Thomson Owners have indicated they plan to apply to the Commission in late 2006 or early 2007 for Pool Rules and a gas offtake allowable rate.

AOGCC
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SITE: Offnets	BILL #
COMMITTEE:	UPDATE #:
DATE:	

		REPRESENTING/AFFILIATION	Testify Yes/No
✓ Kathy Foerster		Oil & Gas Conservation	?'s

AK GASLINE PORT AUTHORITY

Alaska Gasline
PORT AUTHORITY

Senate Finance Committee

April 28, 2007

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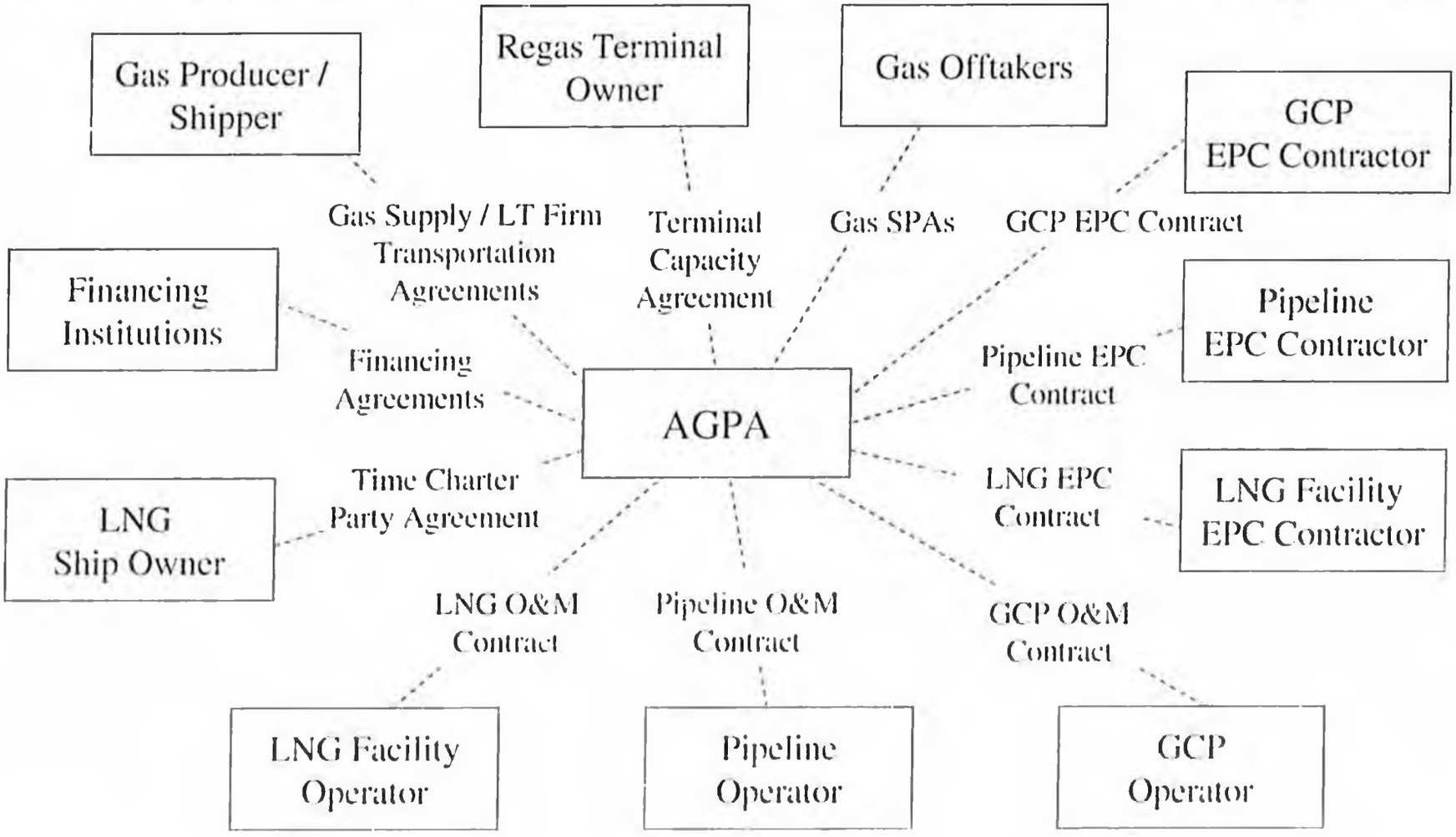
AGIA is Good for Alaska

Alaska Gasline Port Authority

Alaska Gasline Inducement Act (AGIA) Process:

- Open, transparent and competitive
- Identifies clear evaluation criteria
- Inducements to project applicants in exchange for specific commitments
- Empowers selected applicant to build successful consortium, leading to open season

Indicative AGPA Project Structure



- Industry leaders will be involved in all components of AGPA's project

AGPA Project Description

Alaska Gasline Port Authority

Gas Conditioning Plant in Prudhoe Bay

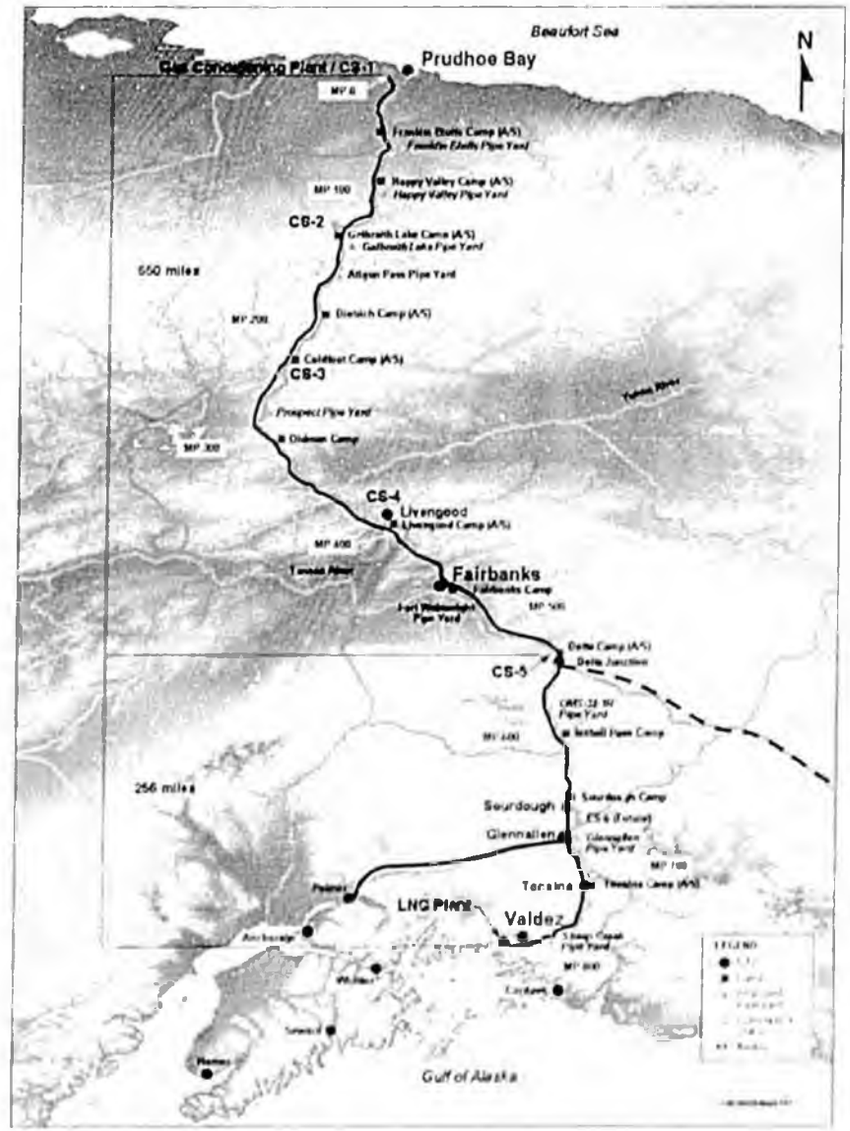
- removes impurities
- compresses and chills the gas to pipeline specifications

Pipeline from Prudhoe Bay to Valdez

- parallel to TAPS (max. capacity: 6 Bcfd)
- pre-build to Delta Junction for later tie-in for the Alaska/Canada Highway Project
- tie-in at Glennallen for a spur line to Alaska South Central natural gas grid

LNG Facility in Valdez

- integrated LNG liquefaction and LPG extraction facilities
- includes storage and vessel loading facilities



Project Status

Alaska Gasline Port Authority

1. Project Route Permitted

2. The 12 Senior Permits Acquired
   - Yukon Pacific Corporation
   - $100 million expended
   - Right-of-way
   - Project FEIS
   - LNG terminal permit

3. Bechtel Cost Estimates
   - Complete & Updated

4. Marine Transportation / Jones Act
   - MOU with the largest LNG shipping company in the world – Mitsui OSK Lines

5. Access to Multiple Markets
   - West Coast receiving terminal under construction
   - West Coast Alternatives
   - Hawaii
   - Pacific Rim

6. Anticipated Financing
   - 80% debt (Federal loan guarantee available)
   - 20% private funding

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Phased Project = Better Cost Overrun Risk Management

Alaska Gasline Port Authority

- 800 mile pipeline is 100% adjacent to TAPS, 100% in Alaska
- Infrastructure in place for entire line – roads, bridges, camp pads, etc.
- LNG project: lower overall cost overrun risk:
  - liquefaction facilities utilize proven technology and well-tested design, resulting in a relatively low level of uncertainty in cost estimate
  - low level of cost uncertainty for LNG marine transportation and regasification
  - pipeline component has the highest capital cost uncertainty – for LNG project the pipeline is only a portion of overall cost to market
- Phase approach with LNG project proceeding first: 2/3 less cost = 2/3 less risk

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LNG Project is Economic

Alaska Gasline Port Authority

- Robust economics with projected strong returns to upstream producers (with no tax concession by State)

- Favorable economics takes into consideration pre-build to Delta Junction for a future AlCan Highway

- Win-Win for Alaska with LNG:
  - Capture West Coast market now **plus** enable a later AlCan Highway project to proceed when ready
  - Earliest in-State gas availability

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Advantages of LNG from Alaska

Alaska Gasline Port Authority

- The Alaska LNG project will benefit from an efficient, low-cost liquefaction operation:
  - ambient conditions (low average temperatures) in Valdez result in significant unit cost savings in comparison with liquefaction facilities located in tropical climate
  - efficiency gains estimated in the range of 30 – 40%
- Most other LNG projects have significantly higher marine transportation costs to market due to longer shipping distances
- Many other LNG projects involve higher upstream costs due to complex, expensive field development
  - Alaska benefits from substantial existing North Slope infrastructure and developed fields (Prudhoe Bay)

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Advantage of LNG for Alaska – Phased Project

Alaska Gasline Port Authority

- Better mitigation of cost overrun risk
- Open North Slope to commercialization of gas; encourage further exploration
- Commercialize discovered gas resources, while allowing exploration for expansion to proceed
  - initial offtake for LNG project – within existing AOGCC Rule 9 limitation
- Better positioned to accommodate early in-State offtake:
  - economics of project components downstream of Alaska do not suffer diseconomies of scale due to reduced export volume – offtake at Glennallen affects only 100 miles of pipeline to Valdez
- Pre-build for expansion affects only the pipeline in Alaska
  - expansion either through addition of new LNG trains or by interconnection at Delta Junction with an AlCan Highway project
  - Availability of gas liquids in Alaska for value added processing

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AGIA Suggested Project Evaluation Criteria

Alaska Gasline Port Authority

- If applicant's offtake amounts exceed AOGCC Rule 9 limitations (2.7 bcf/d less field use), must have already filed an application with AOGCC for increased offtake limits
- Additional gas reserves needed? Budget and timeline for exploration program
- Analysis of liquids availability in Alaska for value added processing
- Current project cost estimate required with application

AGIA benefits towards advancing gas pipeline

- Rolled in rates – good for Alaska's future
- Allows for independently owned infrastructure
- Follows successful model used in other countries who also use rolled in rates and independently owned pipelines.
- $500 million skin in the game – sends very positive message about Alaska's desire to commercialize Alaska's gas
- Supports lowest tariff

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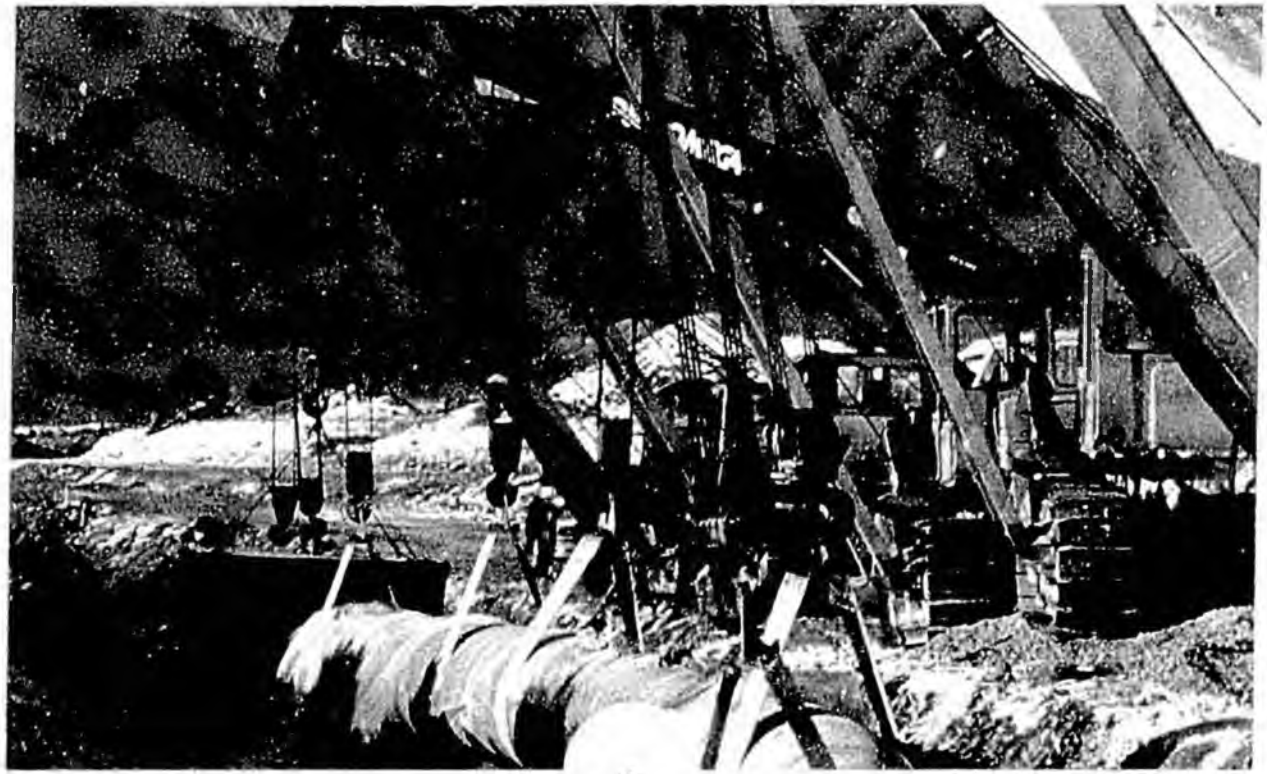
The All-Alaska Gasline. The future is on the line.



Alaska Gasline
PORT AUTHORITY

Right Sized – Right Now!

LB+A

CONSULTANTS

DAN

DICKINSON

5/3/07

Presentation to the Alaska Legislature
Senate Finance Committee
May 3, 2007

Dan E. Dickinson
CPA, CMA

- How is gas generally taxed under the PPT? What are the PPT credit implications of gasline work?

- Same as oil (almost) – on net value
- Investment downstream of the point of production not eligible for credits

How is gas taxed under the PPT

- 43.55.011
- (e) 22.5% of net value
- (f) North Slope floor triggered by oil price
- (g) & (h) Progressivity triggered by single taxpayer net value
- (i) Private royalty 1.67% for gas – 1/3 of oil
- (j) Cook Inlet Ceiling

AS 43.55.011 (e) 22.% of net value

- Total upstream costs are deducted from the revenue streams from oil and gas sales.

- Gas Revenue Exclusion (GRE) mechanism discussed in 2006 is an administratively simple way of adjusting the effective rate without changing the nominal rate or making lots of allocations.

43.55.011(f) North Slope floor triggered by oil price

- Alternative floor just applicable to North Slope Oil and Gas is triggered by oil price.
  - Consider future if Prudhoe Bay is producing 250,000 bbls oil and 3 bcf of gas.
  - If the heating value is 1,000,000 btu per mcf, that translates to the equivalent of 500,000 bbls a day – so 1/3 of the field's production will be used to set the trigger.

- Question 3. How does PPT progressivity work on gas and what is it's link to oil?

AS 43.55.011(g) & (h) Progressivity triggered by single taxpayer net value

- Progressivity is determined for each taxpayer on its total mix of oil and gas and all upstream costs
- Calculated on a monthly basis – monthly upstream costs are 1/12 of total annual costs
- Example – Next slide
  - Prices April 27 2007,
  - 1,000 btu per mcf,
  - equal mix of boe gas and oil

AS 43.55.011(g) & (h) progressivity triggered by single taxpayer net value

	Oil		Gas		Gas BOE		Taxpyr Ave
Dest Price	63.76		7.32				
Downstream Adj	(5.00)		(3.00)				
Gross Value	58.76		4.32	6.00	25.92		
Upstream Adj	(7.00)				(7.00)		
Net Value	51.76				18.92		35.34
.011(h) limit	(40.00)				(40.00)		(40.00)
Price Index	11.76				N/a		N/a
.011(g) factor	0.0025				0.0025		0.0025
Progressivity %	2.940%				N/a		N/a

Dollar/bbl progressivity Charge at various Destination values and net deductions

Per barrel Progressivity Charge

Per Barrel Costs	Monthly Average Destination Value per bbl in Dollars						
	50	55	60	65	70	75	80
5	0.56	1.25	2.06	3.00	4.06	5.25	6.56
6	0.44	1.10	1.89	2.80	3.84	5.00	6.29
7	0.32	0.96	1.72	2.61	3.62	4.76	6.02
8	0.21	0.82	1.56	2.42	3.41	4.52	5.76
9	0.10	0.69	1.40	2.24	3.20	4.29	5.50
10		0.56	1.25	2.06	3.00	4.06	5.25
11		0.44	1.10	1.89	2.80	3.84	5.00
12		0.32	0.96	1.72	2.61	3.62	4.76
13		0.21	0.82	1.56	2.42	3.41	4.52
14		0.10	0.69	1.40	2.24	3.20	4.29
15			0.56	1.25	2.06	3.00	4.06
16			0.44	1.10	1.89	2.80	3.84
17			0.32	0.96	1.72	2.61	3.62
18			0.21	0.82	1.56	2.42	3.41
19			0.10	0.69	1.40	2.24	3.20
20				0.56	1.25	2.06	3.00

AS 55.43.011(i) Private Royalty 1.67% of gross for gas

- This is one third the rate for oil which is 5% of gross.

AS 43.55.011(j) Cook Inlet Ceiling

- No direct effect on North Slope gas
- Expires in 2022
- If gas line is built from North Slope to Cook Inlet may want to consider effect of differential rates of taxation
- Ceiling potentially different for each producer:
  - Average (15 AAC 55.440) 4.947% of $3.585 per mcf.

- Are PPT gas credits applicable to the GTP in the AGIA bill?

- Under PPT – the GTP is not eligible for credits.

Only Upstream Costs Qualify as Credits

- AS 43.55.023 (a) "…may take a tax credit for a qualified capital expenditure… in the amount of 20 percent of that expenditure;"

- AS 43.55.023 (k)"…'qualified capital expenditure'…means…an expenditure that is a lease expenditure under AS 43.55.165 and is…treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code)

Only Upstream Costs Qualify as Credits

- AS 43.55.165 (a) "...a producer's lease expenditures for a calendar year are the ordinary and necessary costs upstream of the point of production of oil and gas ...and that are the direct costs of exploring for developing, or producing oil or gas...

Where is the point of Production?

- In AS 43.55.900
- (21) gas processing
- (23) gas treatment
- (27) point of production
- Are defined so that gas processing is upstream of the point of production and gas treatment is downstream of the point of production.

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (A) for oil…
- (B) for gas, other than gas described in (c) of this paragraph that is
- (i) not subjected to or recovered by mechanical separation or run through a gas processing plant, the first point where the gas is accurately metered;
- (ii) subjected to or recovered by mechanical separation but not run through a gas processing plant, the first point where the gas is accurately metered after completion of mechanical separation;

PPT Definitions: Point of Production

- AS 43.55.011(27) "point of production" means
- (B) for gas…
- (iii) run through a gas processing plant, the first point where the gas is accurately metered downstream of the plant;
- (C) for gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment, the first point where the gas processing is completed or where gas treatment begins, whichever is further upstream.

PPT Definitions: Gas Processing

- AS 43.55.011 (21) "gas processing"
- (A) means processing a gaseous mixture of hydrocarbons
- (i) by means of absorption, adsorption, externally applied refrigeration, artificial compression followed by adiabatic expansion using the Joule-Thomson effect, or another physical process that is not mechanical separation; and
- (ii) for the purpose of extracting and recovering liquid hydrocarbons [producing ngls/oil];
- (B) does not include gas treatment

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) “gas treatment”
- (A) means conditioning gas and removing from gas nonhydrocarbon substances for the purpose of rendering the gas acceptable for tender and acceptance into a gas pipeline system.
- (B) includes incidentally removing liquid hydrocarbons from the g[illegible]s

PPT Definitions: Gas Treatment

- AS 43.55.011 (23) "gas treatment" (cont.)
- (C) does not include
  - (i) dehydration required to facilitate the movement of gas from the well to the point where gas processing takes place;
  - (ii) the scrubbing of liquids from gas to facilitate gas processing.

Under Current law:

- Gas Processing
- Starts with gaseous mixture of hydrocarbons, and produces natural gas liquids and gas by removing the hydrocarbon liquids.
- Gas treatment
- Starts with produced gas and removes nonhydrocarbons (including incidental hydrocarbons) to prepare the gas for tender to the pipeline. Nothing is produced.

AGIA Definitions: Gas Processing

- AS 43.55.900 (7) “gas processing” means the treatment of gas downstream of the point of production to extract natural gas liquids. CSHB 177(RES)
- AS 43.55.900 (7) “gas processing” means post-production treatment of gas to extract natural gas liquids. CSSB 104(JUD)

AGIA Definitions: Gas Processing

- Suggested Definition

- AS 43.55.900 (7) “gas processing” has the same meaning as “gas processing” in AS 43.55.900 (21)

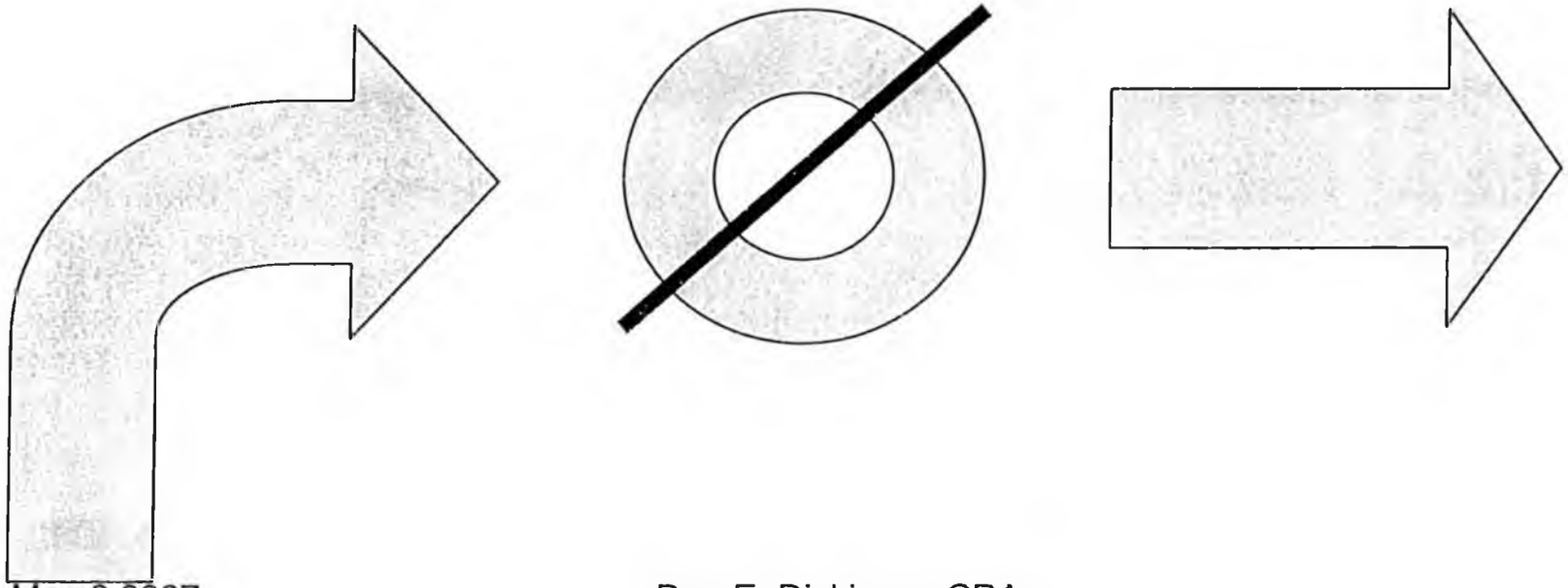
PPT Point of Production for Gas

Is the gas run through an integrated gas processing plant and gas treatment facility that does not accurately meter the gas after the gas processing and before the gas treatment?	no	Is the gas subjected to or recovered by mechanical separation or run through a gas processing plant?	yes	Is the gas subjected to or recovered by mechanical separation but not run through a gas processing plant?	no	Is the gas run through a gas processing plant?
yes		no		yes		yes
Point of Production = the first point where gas processing is completed or where the gas treatment begins, whichever is further upstream		Point of Production = the first point where gas is accurately metered		Point of Production = the first point where gas is accurately metered after completion of mechanical separation		Point of Production = the first point where gas is accurately metered downstream of the plant

Gas Point of Production

Gas not run through a gas processing point or subject to mechanical separation

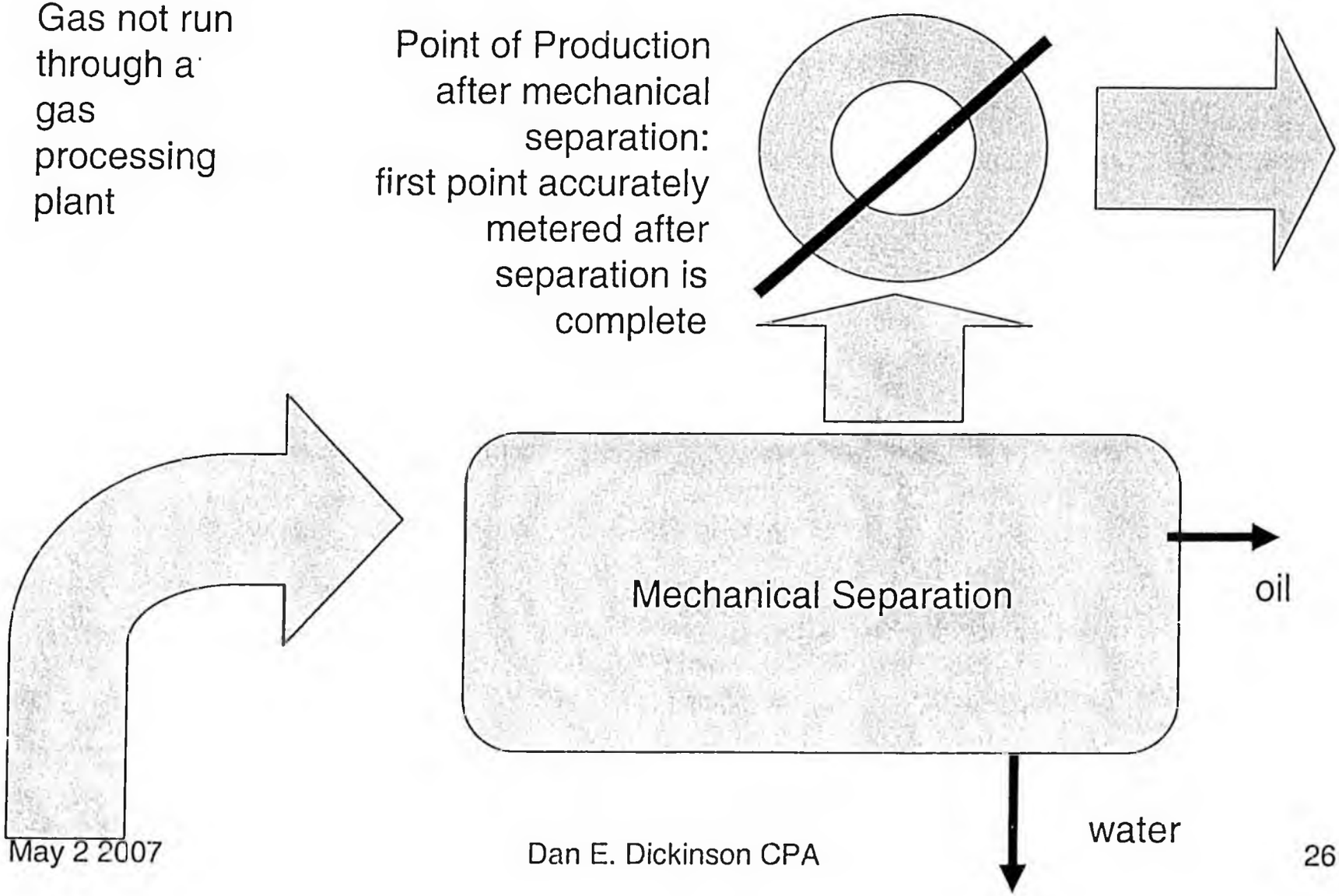
Point of Production: first point accurately metered



Gas Point of Production

Gas not run through a gas processing plant

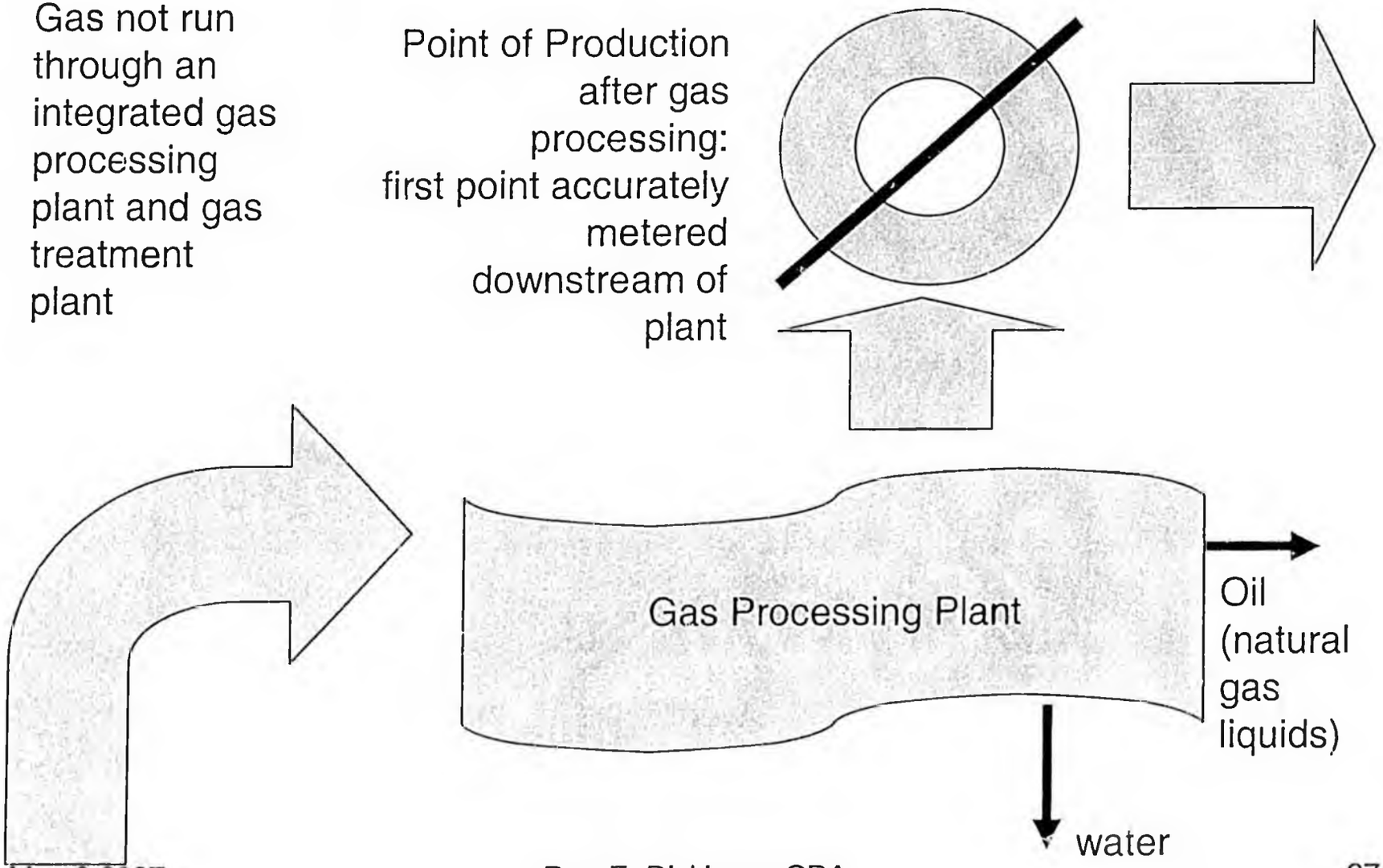
Point of Production after mechanical separation: first point accurately metered after separation is complete



Gas Point of Production

Gas not run through an integrated gas processing plant and gas treatment plant

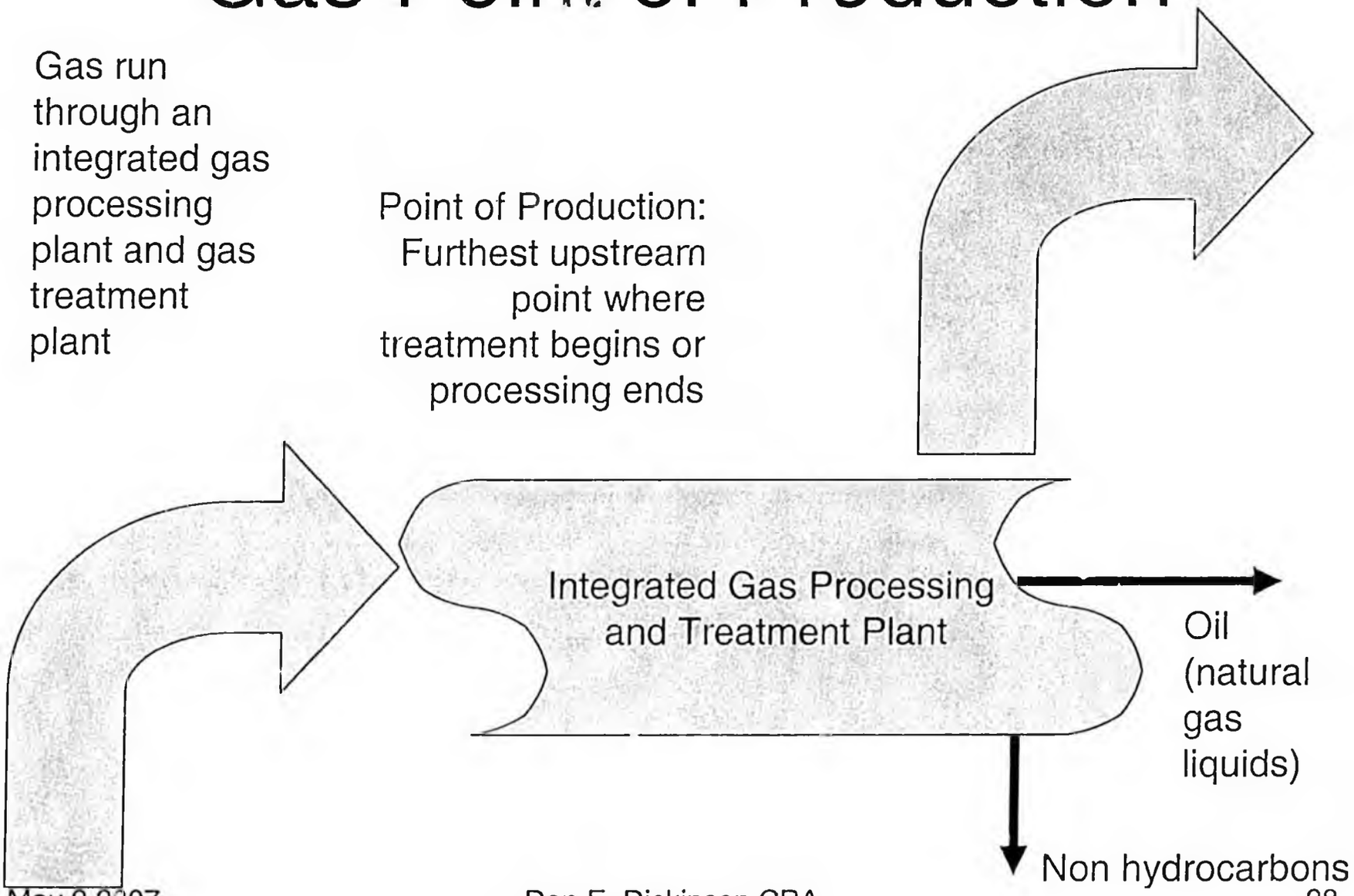
Point of Production after gas processing: first point accurately metered downstream of plant



Gas Point of Production

Gas run through an integrated gas processing plant and gas treatment plant

Point of Production: Furthest upstream point where treatment begins or processing ends



Prudhoe Bay: Point of Production under the PPT