

AK LEGISLATURE FINANCE COMMITTEES FILES 2007-2008 3215

equipped with computers and software allowing review of the simulator results.

It is important to note that the data and information provided to us falls within the standards of AS 31.05.035(d) and 20 AAC 25.537(b) governing confidentiality of information.

In simple terms, the data that has been made available to us is 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 most efficient way for us to get access to it was to agree to keep it confidential.

Our most recent study began in January 2006, and was completed in late 2006. In the course of that study, BP and its partners were cooperative and provided us all that we needed.

On February 28, 2007, we published a summary report. That report is available on the AOGCC website (www.aogcc.alaska.gov); and a copy is in your packet.

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 receive an application or otherwise have enough information to make a meaningful determination, we will convene public hearings and make as much information available as is needed and legally allowed to support any change in the assigned natural gas offtake allowable.

It is our intent to complete our evaluations, hold hearings and make our final rulings on gas offtake allowables for both Prudhoe Bay and Pt Thomson well in time for the "open season" process.

As of now, here's what we can say:

- (1) The later gas sales begin, the smaller will be the oil losses.
- (2) The lower the offtake rate, the smaller will be the oil losses.
- (3) The more the oil production is accelerated before gas sales start, the smaller will be the oil losses.
- (4) The more that is done to mitigate detrimental effects of gas sales, the smaller will be the oil losses.
- (5) 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.
- (6) Depending on the life of the North Slope infrastructure, delaying gas offtake too long, could result in decreased gas recovery.

By the time a pipeline project is ready, selling gas from Prudhoe Bay can very likely proceed 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 confident, that unless a substantial delay occurs (which could make our analysis stale and require additional analytical work), we will be adequately prepared to make a timely determination of the correct Prudhoe Bay gas offtake allowable rate when an application does come before us.

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

A year ago the AOGCC, and 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.

In summary:

- (1) There are hundreds of millions of barrels of oil and condensate at risk if Alaska doesn't manage natural gas offtake properly.
- (2) The AOGCC is charged with setting gas offtake allowables that will prevent loss of the State's valuable hydrocarbon resources.
- (3) The AOGCC intends to perform its function so that we will 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) A lot remains to be done for Pt Thomson; so delay is possible there.

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

5/4/07

The Palin-Parnell Administration presents

AGIA

The Alaska Gasline Inducement Act

Alaska Gasline Project from Lenders' Perspective
Presentation to House Finance
5/2/2007

The Lenders' Perspective



Lenders consider 5 Cs:

- **Capacity**
 - The debt repayment capability of the pipeline project.

- **Collateral**
 - The secondary source of debt repayment.

- **Character / Credit**
 - Project sponsors (the active equity investors) who are experienced in the pipeline industry and have solid credit history.

- **Commitment**
 - Financial and non-financial commitments from sponsors indicating their incentives to the success of the pipeline project.

- **Conditions**
 - Future market, regulatory, economic and environmental conditions that could impact the viability of the project.

Financing Perspective



- The critical items for a greenfield natural gas export pipeline from Alaska include:
 - Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing.
 - Equity funding, typically of 20%-30% of the project's forecast capital structure. One or more equity sponsors with the project development, management, and operations skills necessary to undertake this project. *will drive ↑ pipeline tariff*
 - Division of cost overrun risks among parties which have the financial strength, and appropriate skills and incentives to manage and bear this risk.
 - FERC, NEB, and other regulatory approvals
- Each of these critical elements is magnified due to the extraordinary size of the proposed project.
- Federal loan guarantees will be helpful in maximizing the quantity of debt and limiting the cost of pipeline debt financing, (and the delivered cost of pipeline gas to consumers), but are not a substitute for any of the key elements listed above.

Firm Transportation (FT) Commitments



- Firm long term commitments to ship natural gas, at a price, quantity, and term sufficient to service and repay the necessary debt financing are normally necessary for a successful financing.
 - Demonstrate (via open season) the need for the project from regulatory perspective
 - Provide equity investors with necessary assurance of earning an acceptable return
 - Critical to give lenders assurance of debt repayment (in absence of federal guarantee)
- Bulk of the shipper commitments will very likely come from the parties which own the gas supply.
 - Only the producers have sufficient economic interest to make firm transportation commitment
 - Given the high level of capital expenditure necessary for the project, the exact terms of the shipping commitments are of great importance to suppliers in determining the acceptability of their economics
 - Shipper commitments are normally needed 1) prior to closing on debt financing and pipeline construction, and 2) prior to equity making large "at risk" commitments – including large pre-approval development outlays

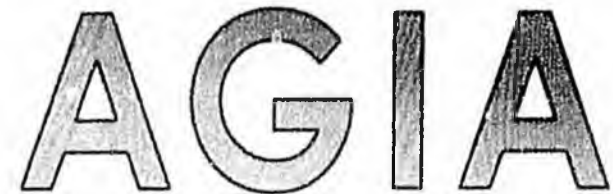
Equity Commitments



The Alaska Gasline Inducement Act

- Equity Commitments are a pre-condition to debt financing and federal guarantees
- Typical greenfield FERC regulated pipeline project is funded with 20%-30% base equity.
 - Exact level is dependent upon project economics and reserves, but some minimum needed to establish sponsor credibility as owner
- Ability to attract equity sponsors rests upon ability to:
 - attract sufficient firm and binding transportation commitments
 - share development cost risks with other interested parties
 - share cost overrun risks with shippers
 - provide a clear regulatory path to approval

Cost Overruns



The Alaska Gasline Inducement Act

- Mitigating cost overruns is a key financing concern
- Substantial increases in cost of large capital projects have occurred in recent years, across many industries globally.
 - Complex causes, including higher commodity prices and skilled labor shortages
 - Extreme cost overruns have occurred for mega-projects in the nearby Alberta oil sands
- Because of market conditions, and the project size, there is a limited ability to shift cost overrun risk to contractors and suppliers.
- The magnitude of cost overrun risk, and the modest equity returns typically associated with pipeline equity, will likely drive some need for sharing of this risk between equity investors and shippers
 - Shippers, in turn, will need more protection against potentially very large cost overruns than would be provided in a typical “cost of service” arrangement

Department of Energy Loan Guarantees



- The Alaska Natural Gas Pipeline Act of 2004 gave the U.S. Department of Energy the ability to issue up to US\$18 billion in loan guarantees in support of the Alaska natural gas pipeline project.
- Key loan guarantee provisions in Alaska Natural Gas Pipeline Act of 2004 are extremely favorable:
 - Maximum guaranteed debt would be the lesser of US\$18 billion (indexed to inflation) or 80% of total capital costs, including interest during construction
 - Owners of Canadian portion of pipeline also eligible
 - Term of 30 years
 - Unusual credit support language indicating that no *"contractual commitment or other form of credit support of the sponsors (other than equity contribution commitments and completion guarantee or ... throughput or other guarantee from prospective shippers greater than such guarantees as shall be required by the project owners)"* will be required for loan guarantee
- Favorable terms of legislation may be limited by practicalities of Department of Energy implementation:
 - DoE has been slow to implement the loan guarantee provisions of the Energy Policy Act of 2005
 - DoE solicited public feedback in May 2005 to assist in future rulemaking on pipeline loan guarantees, but has yet to issue any further guidelines or draft regulations

Conclusions



The Alaska Gasline Inducement Act

- AGIA has some helpful elements
 - Up to \$500 million of risk sharing capital during the project development phase, the most risky stage of the pipeline project
 - The Resource Inducement section encourages FT commitments
 - A requirement that an application shall describe the means for preventing or managing cost overruns for the proposed project
- A pipeline will not be built without lenders' debt financing
- The financing of the pipeline project needs to be supported by firm transportation commitments, a robust federal guarantee, or a combination of both.
- Finally, there is a lot of what ifs and unknowns with this project, but there is nothing in AGIA which would preclude project financing.

SARAH PALIN, GOVERNOR

**ALASKA OIL AND GAS
CONSERVATION COMMISSION**

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May 2, 2007

Honorable Harry T. Crawford, Jr.
State Representative
Alaska State Capitol
Juneau, Alaska 99801

Re: Total North Slope Field Fuel Uses

Dear Representative Crawford:

In a letter dated April 27, 2007 you requested total North Slope fuel uses for all uses including flaring for 1996, 1998, 2000, 2002, 2004, and 2006. Attached is a spreadsheet of total North Slope Field gas disposition for years 1974-2007.

If you need anything further, please let me know.

Sincerely,



Cathy P. Foerster
Commissioner

514107

GAS DISPOSITION
NORTH SLOPE

<u>Year</u>	<u>Sold</u>	<u>Reinjected</u>	<u>Lease Operations</u>	<u>Other (Shrink)</u>	<u>Flare < 1 Hr</u>	<u>Flare > 1 Hr</u>	<u>Flare Pre-1995</u>	<u>Pilot / Purge</u>	<u>TOTAL (MCF)</u>
1974	136,267	0	1,574,493	0	0	0	1,076,405	0	1,710,760
1975	0	0	1,747,392	0	0	0	1,061,146	0	1,747,392
1976	0	0	2,601,672	0	0	0	1,253,565	0	2,601,672
1977	1,089,266	68,079,911	13,562,344	0	0	0	10,871,756	0	82,731,521
1978	0	271,854,320	18,826,145	0	0	0	2,313,159	0	290,680,465
1979	0	390,135,672	23,559,180	0	0	0	1,840,081	0	413,694,852
1980	0	546,509,480	28,967,138	0	0	0	1,800,728	0	575,476,618
1981	8,581,676	595,105,936	35,933,705	0	0	0	2,463,982	0	639,621,317
1982	14,000,336	715,615,225	48,430,730	0	0	0	3,504,533	0	778,046,291
1983	14,588,522	791,979,337	55,686,290	0	0	0	2,524,293	0	862,254,149
1984	15,088,326	815,929,228	68,917,316	0	0	0	5,893,379	0	999,934,870
1985	20,088,651	932,433,536	87,583,097	429,994	0	0	3,955,943	0	1,040,535,278
1986	20,000,566	974,346,448	89,987,287	6,737,128	0	0	5,909,843	0	1,091,071,429
1987	43,382,200	1,246,008,090	122,987,338	2,642,510	0	0	12,961,727	0	1,415,020,138
1988	48,581,554	1,454,630,573	146,017,694	610,195	0	0	5,798,801	0	1,649,840,016
1989	39,809,917	1,465,365,209	155,574,755	1,088,024	0	0	6,920,191	0	1,661,837,905
1990	37,680,944	1,546,707,029	159,170,572	1,141,078	0	0	8,698,009	0	1,744,779,623
1991	45,592,431	1,854,612,855	175,112,147	1,582,330	0	0	7,101,603	0	2,076,899,763
1992	48,663,964	2,086,288,595	184,023,821	1,940,119	0	0	10,092,493	0	2,320,916,499
1993	46,345,834	2,246,166,126	187,167,540	2,025,671	0	0	19,083,628	0	2,481,705,371
1994	44,232,750	2,536,387,742	198,462,396	1,930,184	0	0	10,585,018	0	2,781,013,072
1995	48,638,357	2,834,319,492	205,658,266	4,751,106	1,008,526	2,263,885	0	3,605,648	3,100,245,280
1996	53,544,447	2,853,814,382	213,108,235	0	1,171,569	1,113,525	0	3,512,626	3,126,264,784
1997	54,501,684	2,874,258,399	215,808,275	0	1,050,985	1,933,793	0	3,270,717	3,150,823,853
1998	51,852,342	2,899,208,855	212,765,726	1,647,273	1,210,457	1,472,868	0	3,395,919	3,171,553,440
1999	50,246,879	2,892,880,089	208,818,872	3,206,077	1,221,949	854,100	0	3,315,505	3,160,543,471
2000	50,712,595	3,063,581,153	211,912,214	1,857,203	932,830	1,651,148	0	3,418,412	3,334,065,545
2001	49,223,417	2,948,515,834	212,038,799	3,269,346	900,484	1,270,145	0	3,575,528	3,218,793,553
2002	66,411,281	3,009,055,700	224,109,025	2,447,053	672,553	1,690,210	0	3,597,633	3,307,983,455
2003	79,951,162	3,096,531,473	229,135,954	13,852,651	741,039	702,759	0	3,762,183	3,424,677,231
2004	77,333,706	3,139,951,408	225,997,941	11,885,313	565,855	1,119,781	0	3,779,555	3,460,633,559
2005	69,144,592	3,135,383,457	234,984,760	15,206,869	629,632	755,822	0	3,825,405	3,459,930,537
2006	63,428,748	2,737,906,016	208,176,807	13,294,234	826,496	1,486,366	0	3,789,735	3,028,908,402
2007	17,341,239	795,895,664	59,079,682	5,730,234	130,539	166,831	0	938,949	879,283,138

5/2/07

5-1-07

**ExxonMobil AGIA Testimony
House Finance Committee 5-2-07**

testimony

FINANCE COMMITTEE:

Co-Chairmen: Representatives Mike Chenault (R) / Kevin Meyer (R)

Vice-Chair: Representative Bill Stoltz (R)

Members: Representatives Richard Foster (D); Mike Hawker (R); Mike Kelly (R); Bill Thomas, Jr. (R); Harry Crawford (D); Les Gara (D); Reggie Joule (D); Mary Nelson (D)

INTRODUCTION

Good afternoon Chairmen Chenault and Meyer, Vice-Chair Stoltz and members of the House Finance Committee. My name is Marty Massey. I am the U.S. Joint Interest Manager for ExxonMobil, a position I have held since November 2001, and I am responsible for the commercialization of ExxonMobil's gas resources in Alaska.

ExxonMobil has been in Alaska for over 50 years and has been a key player in Alaska's oil industry development. We hold the largest working interest at Prudhoe Bay (36.4%) and our current net production in Alaska is approximately 150,000 barrels per day. We have benefited from our involvement in the State of Alaska, and we believe that Alaska has benefited from this long-term relationship as well. Commercializing Alaska's North Slope gas will allow us to continue this mutually beneficial relationship for another 50 years or more.

EXXONMOBIL READY TO PROGRESS PROJECT

The Alaska Gas Pipeline Project is important to Alaska, to our nation, and to ExxonMobil. The project has the potential to generate billions of dollars in revenues for the State of Alaska, the U.S. federal government, and Canada, and could provide a stable and secure source of clean energy for Alaska and North America for decades to

come. For ExxonMobil, the project is significant and has the potential to add over 1 billion cubic feet per day of gas sales, which would be more than a 10% increase to our current worldwide daily gas production. This project could also add over one billion oil-equivalent barrels to proved reserves, nearly enough to replace a year of our production. Given the significant impact this project could have on our business, we strongly support efforts to advance a pipeline project.

As an illustration of our commitment, ExxonMobil has spent more than \$180 million studying ways to commercialize Alaska gas. Since the 1970's we have evaluated LNG, gas to liquids and gas pipeline alternatives. Based on these studies we have determined that a Producer Gas Pipeline Project will result in the best value for the State, the Producers and the nation.

GENERAL FEEDBACK ON AGIA

I would now like to provide you with some feedback on AGIA. ExxonMobil embraces the concept of competition all over the world and is ready to participate in a competitive and market-based environment. AGIA, as it is written today, does not encourage market-based competition due to its prescriptive nature. In addition, AGIA does not adequately address the significant upstream issues and risks associated with the scale and magnitude of the Alaska Gas Pipeline Project. We have consistently advised the Legislature and the Administration that AGIA, in its current form, will not encourage competitive proposals and will not result in a commercially viable project. We strongly believe AGIA will not create an acceptable framework for this world-scale mega-project unless it allows the parties taking the risks to make a proposal that properly manages the risks.

After listening to the testimony over the past several weeks, it has become clear to me that one of the reasons the Administration's view of the project is so different from ours is due to flawed assumptions in the State's economic model. The Administration's model fails to recognize the integrated nature of this basin-opening project. The upstream pays for the midstream and you cannot split them apart when evaluating commercial viability. Any attempt to do so will deliver erroneous results. This issue is critically important, because if you put in place a process based on a flawed analysis, it will most likely fail. For this reason it is important that the State's economic model be corrected. The Administration's approach is not consistent with how project economics are evaluated, and I'll expand on this later in my testimony.

To ensure the best result, the logical way forward in our opinion is for AGIA to establish the State's broad key objectives, then allow applicants flexibility so that they can compete to meet those objectives and define the parameters that are necessary to make the project commercially viable. As an illustration of what I am proposing, AGIA could allow the applicant to demonstrate how their proposal encourages exploration and development in Alaska rather than specifying the method of project access and expansion.

If you were to amend AGIA to make it objective driven, it would allow open competition, maximize the number of applicants and allow those applicants to propose innovative solutions to meet the State's needs and open the basin. The State could then evaluate the proposals and select the one that best serves Alaska's needs and assures Alaskans realize the maximum value for their resource. That process would allow ExxonMobil,

the largest leaseholder of gas on the North Slope, to compete under the AGIA process while providing the State complete flexibility on who is chosen to move the Alaska Gas Pipeline Project forward.

To understand why it's important to use broad objectives as opposed to prescribing specific requirements, it is helpful to review project risks and issues surrounding its development that will have to be addressed by an applicant.

PROJECT RISK / PRODUCER CAPABILITIES

The tendency exists for many to underestimate the size, magnitude and risks associated with this project. The Alaska Gas Pipeline Project is a world-scale undertaking with significant risks. In fact, the project would be the largest private investment in North America – significantly larger than most “model” worldwide oil and gas “mega” projects. Let me be clear, this will be a precedent setting global mega-project. As you heard last week from Mr. Fred Rich of Sullivan and Cromwell (Head of Global Project Development and Finance), this project’s financing could be many times greater than the largest North American project financing to date (the Alliance pipeline). There is not really another project that compares.

Because of this size, many factors impact commercial viability, including cost and the potential for cost over-runs, gas price, schedule delays, construction conditions, and regulatory and State fiscal uncertainties. Our previous cost estimate of \$20 billion (which is in \$2001) will be substantially higher due, in part, to increasing steel prices, which have nearly doubled since 2001, and because we are experiencing hyperinflation on industry and construction labor costs. World-wide mega-projects are also placing

pressure on pricing and availability of global materials, and skilled manpower. In addition, as we have observed over many years, natural gas prices remain highly volatile.

The State of Alaska cannot anticipate how individual applicants will view the various risks I have discussed or how applicants may choose to address them. Establishing a set of rigid, prescribed terms in AGIA will not allow the flexibility needed by individual applicants to weigh and manage those risks in a way that maximizes value to the State and the applicant.

HOW PIPELINES ARE FINANCED

The way projects are financed gives some insight into who bears the risks for projects of this type and how these risks are managed. Last week you heard how pipelines are financed from Mr. Rich. Commercially-sound oil, gas, and pipeline projects traditionally have been able to obtain financing if they have strong sponsors with proven track records and the financial strength to both provide upfront lender required sponsor equity and to backstop key project commitments. For the Alaska Gas Pipeline Project, key project commitments take the form of completion support (either a full debt guarantee or additional equity overrun commitments) and firm, long-term gas transportation commitments. Firm transportation commitments are binding obligations made by companies to pay for the cost of reserving long term gas capacity as shippers on a pipeline. These commitments are made during an "open season", which is a period during which any and all prospective gas shippers can make binding commitments for a specific volume of transportation capacity.

As you may recall, Mr. Rich indicated that for a project of this scale and magnitude, financial institutions will require substantial, long-term, firm transportation commitments to provide funding. These commitments must be provided by creditworthy shippers because this tariff stream underpins the debt repayment. Furthermore, lenders not only look at the contractual commitments, but place equal importance on the underlying economics of the project. Any potential reduction in the Producer's netback is a concern to the lender since it increases the likelihood that the integrated project may not be economic, that the transportation charges are not paid, and that as a result the lenders are not repaid. Looking at this another way, the lenders are assessing how effectively the parties taking the risks are managing these risks. They will also want these risks reduced to a minimum to make sure they will get paid back. For this reason they would prefer stable fiscal regimes, project sponsors who have a proven track record of delivering mega projects on time and on budget, project sponsors with ownership in the upstream, and shippers who can support and will honor multi-billion dollar firm transportation agreements.

WHO BEARS PROJECT RISKS

That is why it is so important to understand who bears the project risks. Through the firm transportation commitments, the project development costs and the associated cost over-run risks are ultimately borne by the shippers. For this project, the shippers will be the Producers, and, directly or indirectly, the State or the State's shipper. These firm transportation commitments are valued in the tens of billions of dollars for our company alone, and could be over \$100 billion for all the shippers. Shippers must make long-term ship or pay transportation commitments and agree to pay transportation and treating rates that are ultimately based on the final cost of the pipeline and treating

facilities. The only information the shippers will know in advance of making these multi-billion dollar commitments will be a projection of the transportation charges based on the project sponsor's initial estimate of costs. The firm transportation commitments must be paid regardless of whether the shipper making those commitments actually transports gas through its reserved capacity and irrespective of the actual transportation charges. The shipper is also required to pay this reserved capacity commitment even if the market price for the gas is less than the cost of transportation.

For these reasons, the parties taking the risks for a project of this magnitude need to be able to manage those risks. The Producers, as shippers, cannot make firm transportation commitments during an open season unless they are confident the gas pipeline project can be built and operated cost effectively so that producing and shipping gas over the long-term is commercially viable.

INTEGRATED GAS PIPELINE PROJECT ECONOMICS

For this reason, AGIA needs to bring together the upstream and the midstream and provide for an integrated proposal. Any approach that evaluates them separately is flawed. Let me expand on this point. You heard last week that lenders evaluate the upstream very carefully when financing the midstream. The reason is simple – the upstream pays for the midstream. When I say upstream, I'm talking about the revenue generated from production and sale of the gas and liquids through the pipeline project. Without the commitment of capital to the pipeline by a producer-affiliate or the huge financial obligation required for firm transportation commitments to a third-party pipeline, there is no way the transportation system will be built. Thus, any analysis of the project which excludes midstream capital or the firm transportation commitments is not correct.

Lenders and project sponsors do not make that mistake because they recognize that major gas pipeline projects are built on the back of direct capital commitments or, long-term, firm transportation commitments.

Since firm transportation commitments are legally binding commitments that are the backbone of any financing and essential to funding a pipeline, it only makes sense to account for these commitments when evaluating project economics. Surprisingly, the Administration's analysis of the economics fails to incorporate these financial obligations associated with underpinning the pipeline. Let me expand on this point by asking you to think about the economics from a shipper perspective. The shipper can either make the investment in the midstream through one of its pipeline affiliates or make a commitment to a third party to build the pipeline. In the case of making the commitment to a third party, the shipper must pay the third party for the cost of the pipeline plus a return to the pipeline builder for the investment he ultimately made, not what he projected the costs to be when the commitment was made. So in this case the shipper is paying for the ultimate cost of the pipeline plus the profit the pipeline builder requires. When you think about it this way, the economics have to be worse for the shipper when he makes a transportation commitment versus directly investing in the pipeline.

Because the Administration's economic analysis is flawed, the resulting assertion that the producer's stand-alone upstream economics are robust and improved without ownership of the pipeline is absolutely incorrect. Again, the upstream pays for the midstream and it is no more complicated than that.

Since it appears AGIA is based on this flawed economic analysis, it is critical the legislature address this issue and AGIA be modified to recognize who is taking the risk, the shipper. For ExxonMobil any decision to invest will be based on integrated project economics. It only makes sense for the State to evaluate the proposal on an integrated basis as well because the State is in the same position as the producers receiving the bulk of its revenue from the sale of gas. Because we both receive our revenue from the sale of gas, we should be aligned on the best approach for minimizing transportation costs and maximizing netback value.

IMPORTANCE OF STATE / PRODUCER ALIGNMENT AND BENEFITS OF THE PRODUCER PROJECT

Let me now talk about the importance of alignment between the State and the Producers and the benefits of a Producer Project.

Maximizing the value to the State of Alaska and the resource holders means selecting the right design concept for this mega-project and then executing the Project to deliver the lowest possible cost and fastest possible completion. On a project of this size and magnitude, project construction and operating experience should be a significant consideration. Only a limited number of companies have demonstrated the capabilities, financial strength and arctic experience to effectively participate in and manage world-scale mega-projects.

The Producers have mega-project experience on numerous projects world-wide and have demonstrated success in meeting project objectives. A critical component of that experience is the Producers' Arctic experience in Alaska and throughout the world.

ExxonMobil's arctic experience is extensive - over 40 years – with developments in multiple types of arctic environments. Large projects with significant complexity in harsh environments are what we do and we are extremely qualified to take on this work. ExxonMobil's global project development company is unique within industry and leads the industry in project cost and schedule performance.

ExxonMobil has also demonstrated world-class leadership in safety, health and environmental performance. ExxonMobil is a leader in operating efficiency and a pacesetter in operating safety.

In addition to our project and operational excellence, ExxonMobil has the financial strength to make this mega-project a reality. ExxonMobil has consistently maintained one of the strongest financial positions of any company in the world. We are one of just a few public companies to maintain the highest credit rating from Standard and Poor's (AAA) and Moody's (Aaa), and we have done so for each of the last 88 years. Our financial strength minimizes the likelihood that external financing requirements will significantly delay the project timeline, even in times of financial market turmoil.

It is important to remember that the Alaska Gas Pipeline Project is a basin-opening project that will benefit the State and the oil and gas industry in Alaska for decades into the future. Basin-opening projects throughout the world have progressed and been successful when there is alignment between the host government and the leaseholders. The Producers and the State both want a pipeline project to commercialize the known ANS gas resources and open the basin to gas exploration.

We believe a Producer gas pipeline project will result in maximum value to the State and the Producers. The reason is the Producers and the State have maximum incentive to control costs. Low capital and operating costs, which result in lower treating and transportation costs, and access to premium market price, result in higher netback value on the gas. It's important to keep in mind that the State will receive the majority of its revenue from the value of gas sales via revenue received under its lease royalty agreements and from production taxes, which are valued based on the netback received from the gas.

Third-party owners do not share the same incentives in that they actually benefit from increased capital costs.

Based on the demand for workers that this Project will generate, Alaskans are obviously key to successful project execution. Both the State and the Producers want Alaskans to benefit from the many job opportunities that will exist.

We believe that financial strength, experience and the ability to get the job done should be critical components of any evaluation of proposals. When you consider carefully the options available, a Producer pipeline will provide maximum value to the State of Alaska.

IMPORTANCE OF PREDICTABLE AND DURABLE FISCAL TERMS

I would now like to talk about fiscal predictability and its importance for a mega-project such as the Alaska Gas Pipeline Project. For ExxonMobil to progress this mega-project and mitigate its inherent risks, we will need to work together with the State on some

very important fiscal issues. Because of the nature and magnitude of the risks associated with this Project, fiscal terms that are predictable and durable are necessary. This is a common thread for any mega-project investments. In all such cases, we are willing to take geologic risks, we are willing to take cost risks, and we are willing to take commodity price risks, but we cannot take the risk of fiscal terms changing. Let me expand on this further. The first two risks, geologic and cost risk are risks for which we have developed an industry leading expertise to manage. This is what we do day after day at ExxonMobil. Market risk is inevitable in a commodity business such as oil and gas and we manage that by attempting to ensure that we deliver those products into the highest value market at the lowest cost. However, the risk of a change in fiscal terms is of a completely different nature and completely outside our control. We must have agreements that will allow us to develop this mega-project under predictable and durable terms, so that we can make an investment decision with an adequate degree of certainty. This does not mean that taxes cannot change over the life of the project. Predictability means that the State's tax and take terms are sufficiently understood that they can be defined and predictably modeled over time for purposes of evaluating the overall project economics. If fiscal terms can be changed in unpredictable ways in the future, then we are not able to make a well founded investment decision on behalf of our shareholders, nor will lenders be as confident in providing financing for a project of this size.

The Alaska Gas Pipeline Project will require massive investments, billions of dollars, to be made over a period of many years before any revenue is generated from those investments. As a result, increases in taxes on oil and gas related activities during the life of the project could significantly impact the commercial viability of the project, offset

the benefits of taking on a project of this magnitude, and could increase lender concern. Because fiscal terms could be modified under the proposed AGIA legislation, it does not provide the fiscal predictability necessary to ensure a commercially viable project.

It is important for the State to recognize that for mega-project developments, governments do grant long term fiscal stability. These contracts include fiscal stability protection that in some cases runs for the length of the contract and in other cases runs for 40 years or more.

AGIA should allow applicants to put forward their best proposal on what is required to make the project commercially viable, which will allow the State the opportunity to consider those proposals that have the best chance of actually delivering an Alaska gas pipeline.

ADDITIONAL FEEDBACK ON AGIA

I would like to now give some specific feedback on AGIA which is based on the conclusions and principles I've mentioned. I will also outline some additional thoughts on how AGIA should be modified to ensure the best chance of a successful result and allow the State to maximize value. As I previously stated, alignment between the State and the leaseholders is essential to a basin opening project of this magnitude. Therefore, establishing the right approach going forward is the most important activity for the project at this time. To be able to calculate the revenue from the upstream we must have clarity on the taxes and royalty from our oil and gas operations and the taxes and royalties must be set at a level that makes the project viable. In order to ensure a viable project from the outset, we believe this must be done at the beginning.

ExxonMobil recognizes the importance to the State, explorers and others of having access to the project so their gas can be treated and transported to markets. To ensure that a project is constructed, it must be commercially attractive to shippers at the time they make their initial firm transportation commitments. Shippers, particularly those who must invest substantially to explore for, develop and produce gas resources, will not be willing to enter into long-term financial commitments for the transportation of gas if they believe there is a substantial likelihood that their initial rates will be significantly increased in the future in order to accommodate expansions.

Under the Alaska Natural Gas Pipeline Act, Congress struck what it determined was the proper balance between encouraging investment by those willing to commit to pay for initial capacity and encouraging exploration by providing an opportunity for future access to the pipeline. Because of the unique nature of the Alaska gas pipeline project, FERC approved unprecedented policies to enable a FERC-mandated expansion to benefit explorers. The issue of how potential future shippers may access initial capacity and future expansion capacity, if needed, should be administered by the FERC for all elements of the project in the United States.

In addition, the pipeline entity should not be required to accept a FERC certificate irrespective of FERC imposed conditions.

Under AGIA, the proposed upstream inducements would require significant modification to ensure a commercially viable project is obtained. In fact, we do not believe it is practical to address these terms in legislation. Therefore, it would be better for AGIA to

not prescribe specific upstream terms and allow applicants to make proposals to address those terms.

AGIA also prescribes activities that must be completed within a specific timeframe or date certain. Setting arbitrary target dates is not consistent with good project management practices. Further, milestones are not necessary if the project is commercially viable. The Producers will progress the project at the maximum prudent pace, consistent with the industry proven "stage-gate" process for project development – there is no reason to do otherwise.

In general, AGIA lacks specifics on key fiscal terms and other requirements. To address these gaps, AGIA gives commissioners broad authority to adopt additional requirements and establish regulations. Not knowing the requirements now creates significant uncertainty.

Finally, because of the complexity and risk associated with this project, the parties must have an efficient and impartial means of handling disagreements when they arise. We believe project related agreements should provide for binding neutral arbitration as the mechanism for resolving disputes. Binding neutral arbitration is widely utilized in U.S. and international commercial agreements and is not a new concept with the State of Alaska. Arbitration is the method used to resolve disputes under the State's Royalty Settlement Agreements.

CONCLUSION

In closing, I would like to reiterate that ExxonMobil is committed to moving the Alaska Gas Pipeline Project forward. However, we cannot move the project forward if it is not commercially viable. AGIA as written does not provide for a commercially viable project. The Administration's stated goal for AGIA is to increase competition through an open and transparent process. However, in its current form, AGIA will result in less competition because it fails to adequately address the issues raised by those parties who will ultimately pay for the project. It also appears AGIA is based on flawed economic assumptions. It is critical that the legislature and administration address these problems in AGIA or we will end up with a process that sets unrealistic expectations and results in disappointment and failure. In addition, the existing prescriptive terms in AGIA will preclude ExxonMobil from being able to make an open, competitive and conforming proposal; thus, the State will be denied the opportunity to even consider terms from the party holding the largest discovered gas resource and has the capability to deliver a successful project.

ExxonMobil possesses the financial strength and project experience required to make this project a success. We are ready to work with the Administration and the Legislature to establish a process that recognizes the integrated nature of the project and mitigates the risks I've discussed to allow the project to progress. We suggest AGIA be amended to provide for a broad objective driven process that sets out what the State wants to achieve and allows each applicant to propose how best to meet those objectives and identify what is required from the State to advance the project. This process will secure more viable applications, create more competition, afford the State the opportunity to secure the most value and actually get the pipeline built. We

are ready to participate in a competitive, open and transparent process as I've described, but unless AGIA is modified we will not be able to participate.

What we are struggling to understand is why the State is insisting on such a prescriptive way forward. AGIA should allow all interested parties to submit a conforming bid so that the people of the State of Alaska have the opportunity to see and compare all of the bids put forward to build the Alaska gas pipeline.

Thank you for your attention and for the opportunity to address this important topic today. I look forward to addressing your questions.

70 minutes 5/2/07
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Contractual Commitments

The following table summarizes the Group's principal contractual obligations at December 31, 2003. Further information on borrowings and capital leases is given in Item 18 — Financial Statements — Note 29 on page F-47 and further information on operating leases is given in Item 18 — Financial Statements — Note 17 on page F-29.

Expected payments by period under contractual obligations and commercial commitments	Payments due by period						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
	(\$ million)						
Borrowings (a)	20,143	9,366	2,674	2,786	1,299	945	3,073
Finance lease obligations	4,634	127	243	248	240	248	3,528
Operating leases	8,115	1,275	1,066	895	799	728	3,352
Decommissioning liabilities	7,504	86	156	173	154	156	6,779
Environmental liabilities	2,430	465	441	402	276	186	660
Pensions (b)	26,682	633	649	652	659	666	23,423
Other post-employment benefits (c)	11,768	242	252	259	263	264	10,488
Unconditional purchase obligations (d)	67,828	45,491	7,076	3,133	1,888	1,655	8,585

- (a) Expected payments exclude interest payments on borrowings.
- (b) Represents the expected future contributions to funded pension plans and payments by unfunded pension plans.
- (c) Represents the expected future payments for postretirement benefits.
- (d) Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2004 include purchase commitments existing at December 31, 2003 entered into principally to meet the Group's short term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Item 11 — Quantitative and Qualitative Disclosures about Market Risk on page 170.

The following table summarizes the nature of the Group's unconditional purchase obligations.

Unconditional purchase obligations payments due by period	Payments due by period						2009 and thereafter
	Total	2004	2005	2006	2007	2008	
	(\$ million)						
Crude oil and oil products	22,043	19,350	344	452	422	374	601
Natural gas	19,439	13,189	2,575	1,141	489	398	1,647
Chemicals and other refinery feedstocks	10,049	2,277	1,666	753	563	545	4,245
Utilities	11,612	9,622	1,231	289	62	54	354
Transportation	2,814	738	510	365	247	204	750
Use of facilities and services	1,871	315	250	133	105	80	988
Total	67,828	45,491	7,076	3,133	1,888	1,655	8,585

for
 BP
 20(A)
 and inc. etc.

CDP_243768

from Exxon Mobil 2003 10(K)

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company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,700 million at the end of 2002 to 6,568 million at the end of 2003. Purchases were made in both the open market and through negotiated transactions. Purchases may be increased, decreased or discontinued at any time without prior notice.

2002

Cash used in financing activities was \$11.4 billion, down \$3.7 billion, reflecting lower debt reductions. Dividend payments on common shares increased to \$0.92 per share from \$0.91 per share and totaled \$6.2 billion, a payout of 54 percent. Total consolidated short-term and long-term debt was comparable at \$10.7 billion. Shareholders' equity increased by \$1.4 billion to \$74.6 billion.

During 2002, Exxon Mobil Corporation purchased 127 million shares of its common stock for the treasury at a gross cost of \$4.8 billion. These purchases were to offset shares issued in conjunction with company benefit plans and programs and to reduce the number of shares outstanding. Shares outstanding were reduced from 6,809 million at the end of 2001 to 6,700 million at the end of 2002. Purchases were made in both the open market and through negotiated transactions.

Commitments

Set forth below is information about the corporation's commitments outstanding at December 31, 2003. It provides data for easy reference from the consolidated balance sheet and from individual notes to the consolidated financial statements.

Payments Due by Period

Commitments	Note Reference Number	Payments Due by Period				
		2004	2005-2008	2009 and Beyond	2003 Total Amount	2002 Total Amount
		<i>(millions of dollars)</i>				
Long-term debt ⁽¹⁾	15	\$ —	\$ 877	\$3,879	\$1,756	\$6,655
— Due in one year ⁽²⁾		1,903	—	—	1,903	884
Asset retirement obligations ⁽³⁾	10	125	461	2,854	3,440	3,454
Pension obligations ⁽⁴⁾	18	1,180	1,720	4,937	7,837	9,385
Operating leases ⁽⁵⁾	11	1,299	2,730	2,160	6,189	6,945
Unconditional purchase obligations ⁽⁶⁾	17	520	1,703	2,563	4,786	3,649
Take-or-pay obligations ⁽⁷⁾		833	1,874	1,340	4,047	3,475
* Firm capital commitments ⁽⁸⁾		4,251	2,173	595	7,019	8,449

This table excludes commodity purchase obligations for which an active, highly-liquid market exists and which are expected to be re-sold shortly after purchase. Inclusion of such amounts would not be meaningful in assessing liquidity and cash flow, since such purchases will be offset in the same periods by cash received from sales.

Notes:

- (1) Includes capitalized lease obligations of \$370 million. Long-term debt amounts exclude the corporation's share of equity company debt, which is included in the calculation of return on average capital employed as shown on page 27.
- (2) The amount due in one year is included in notes and loans payable of \$4,789 million (note 7).
- (3) The discounted present value of upstream asset retirement obligations, primarily asset removal costs at the completion of field life.
- (4) The amount by which accumulated benefit obligations (ABO) exceeded the fair value of fund assets for certain U.S. and non-U.S. plans at year end (note 18 on page 65). For funded pension plans, this difference was \$3.0 billion at December 31, 2003 (U.S. \$0.5 billion, non-U.S. \$2.5 billion). For unfunded plans, this was the ABO amount of \$4.9 billion (U.S. \$1.0 billion, non-U.S. \$3.9 billion). The payments by period include expected contributions to funded pension plans in 2004 and estimated benefit payments for unfunded plans in all years.

- (5) Minimum commitments for operating leases, shown on an undiscounted basis, cover drilling equipment, tankers, service stations and other properties.
- (6) Unconditional purchase obligations (UPOs) are those long-term commitments that are noncancelable and that third parties have used to secure financing for the facilities that will provide the contracted goods or services. The undiscounted obligations of \$4,786 million mainly pertain to pipeline throughput agreements and include \$1,887 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of \$1,543 million, was \$3,243 million.
- (7) Take-or-pay obligations are noncancelable, long-term commitments for goods and services other than unconditional purchase obligations. The undiscounted obligations of \$4,047 million mainly pertain to transportation, refining and natural gas purchases and include \$622 million of obligations to equity companies. The present value of the total commitments, excluding imputed interest of \$663 million, totaled \$3,384 million.
- (8) Firm commitments related to capital projects, shown on an undiscounted basis, totaled approximately \$7.0 billion at the end of 2003, compared with \$8.4 billion at the end of 2002. These commitments were predominantly associated with upstream projects outside the U.S., of which the largest single commitment outstanding at the end of 2003 was \$1.6 billion associated with the development of crude oil and natural gas resources in Malaysia. The corporation expects to fund the majority of these commitments through internal cash flow.

Guarantees


	Equity Company Obligations	Other Third Party Obligations	Total
		<i>(millions of dollars)</i>	
Guarantees of excise taxes/customs duties under reciprocal arrangements	\$ —	\$ 983	\$ 983
Other guarantees	1,872	424	2,296
Total	<u>\$ 1,872</u>	<u>\$ 1,407</u>	<u>\$3,279</u>

The corporation and certain of its consolidated subsidiaries were contingently liable at December 31, 2003 for \$3,279 million, primarily relating to guarantees for notes, loans and performance under contracts (note 17). This included \$983 million representing guarantees of non-U.S. excise taxes and customs duties of other companies, entered into as a normal business practice, under reciprocal arrangements. Also included in this amount were guarantees by consolidated affiliates of \$1,872 million, representing ExxonMobil's share of obligations of

Presentation to the Alaska
Legislature
House Finance Committee
May 2, 2007

Dan E. Dickinson
CPA, CMA

for minutes
file
5/2/07
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5/3/07

- 
- 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) & (n) 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 ngl/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 gas

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)

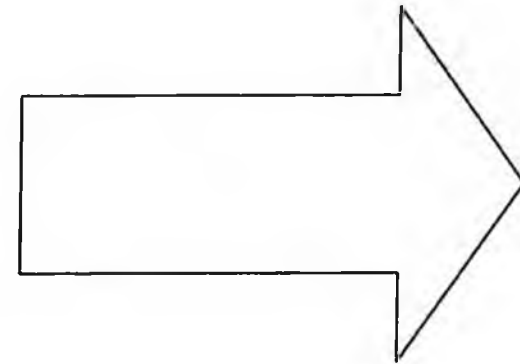
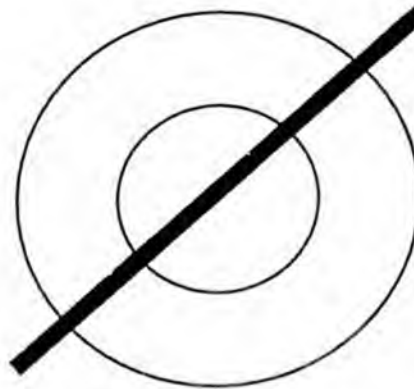
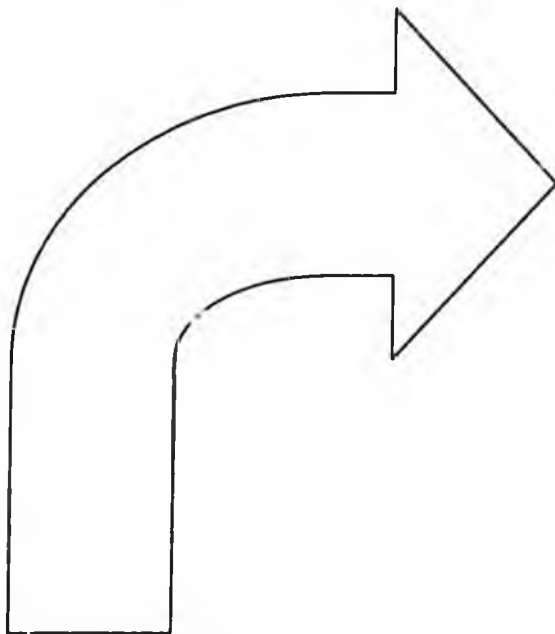
PPT Point of Production for Gas

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

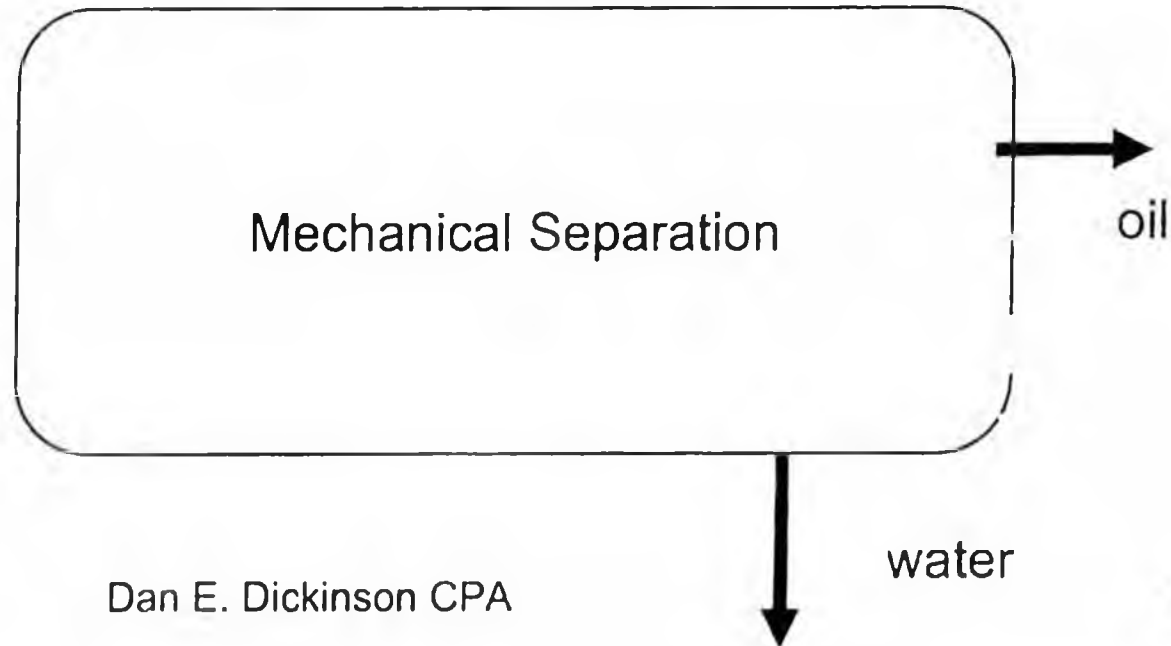
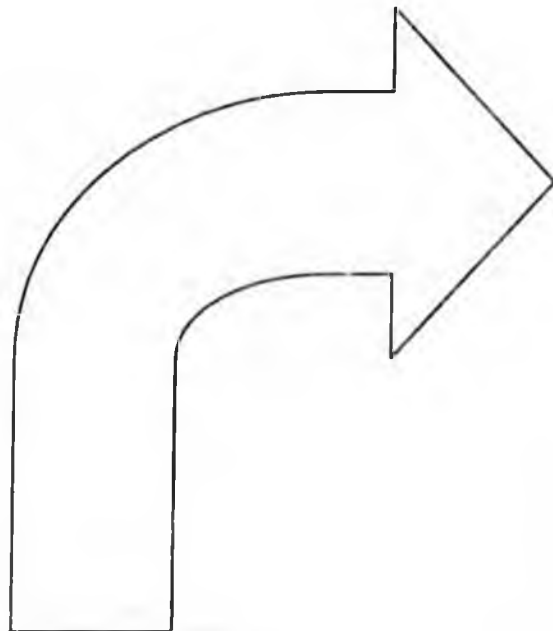
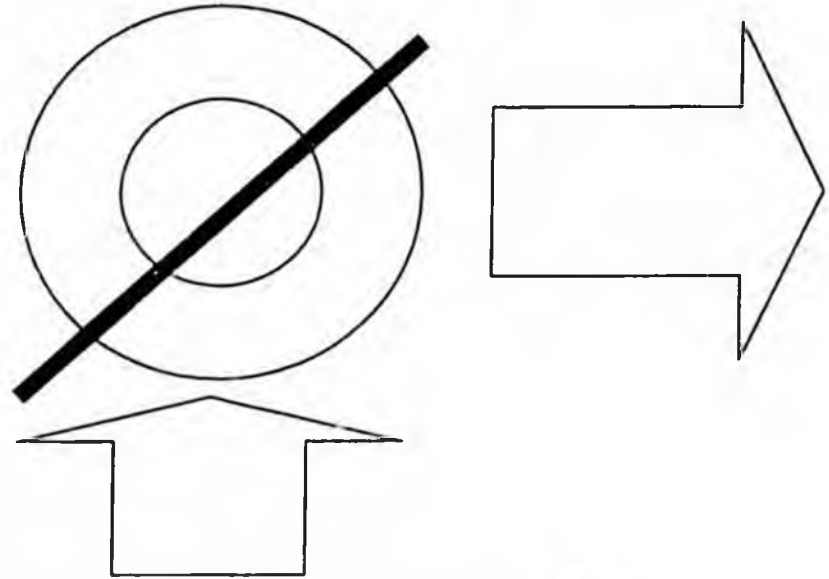
Point of Production: first point accurately metered



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



May 2 2007

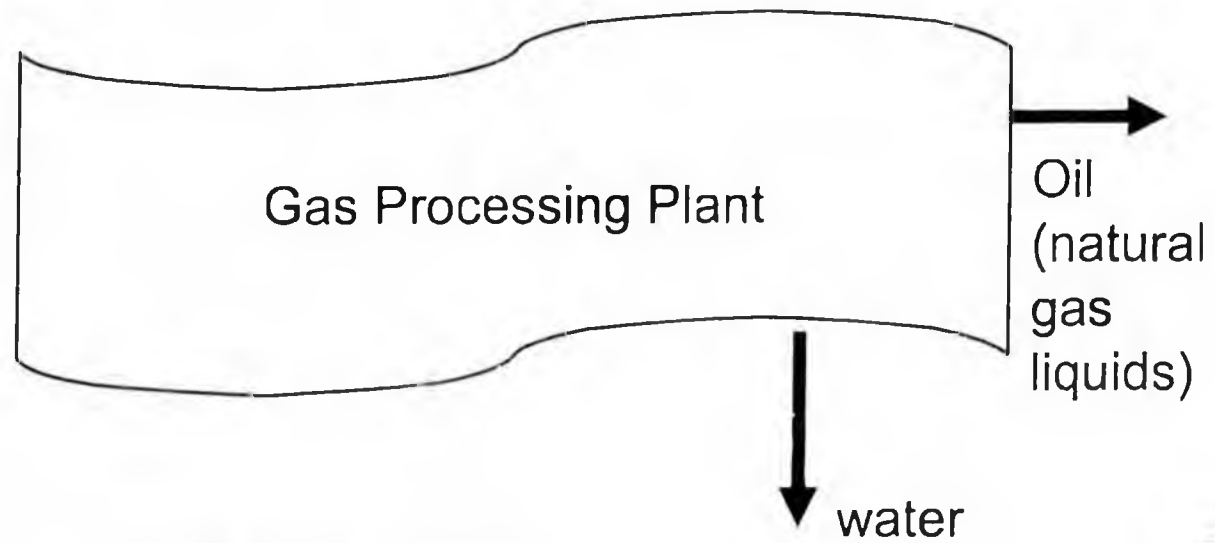
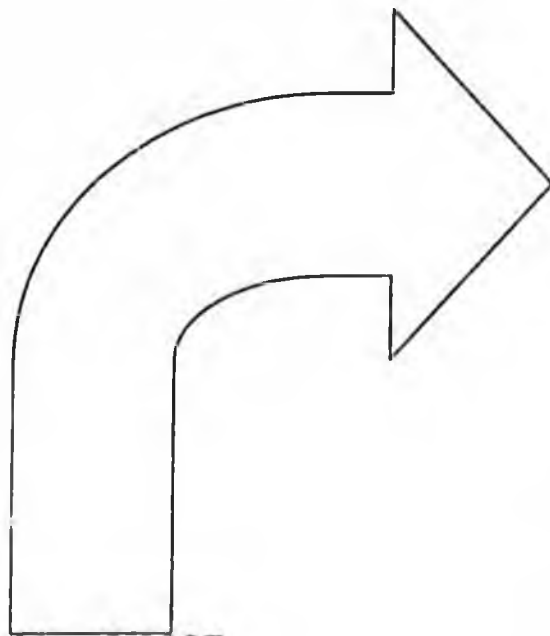
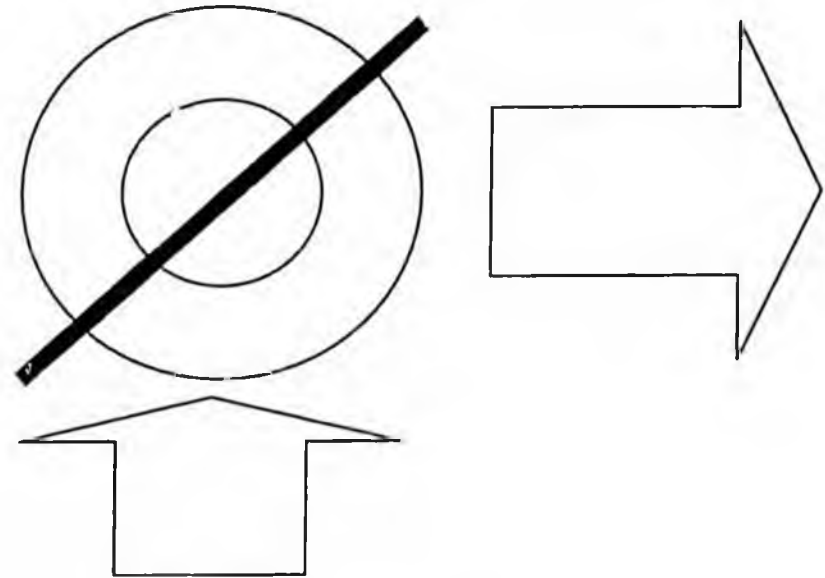
Dan E. Dickinson CPA

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Gas Point of Production

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

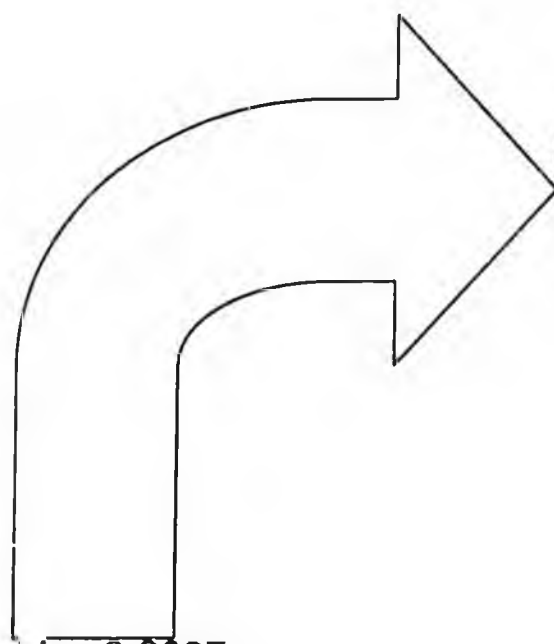
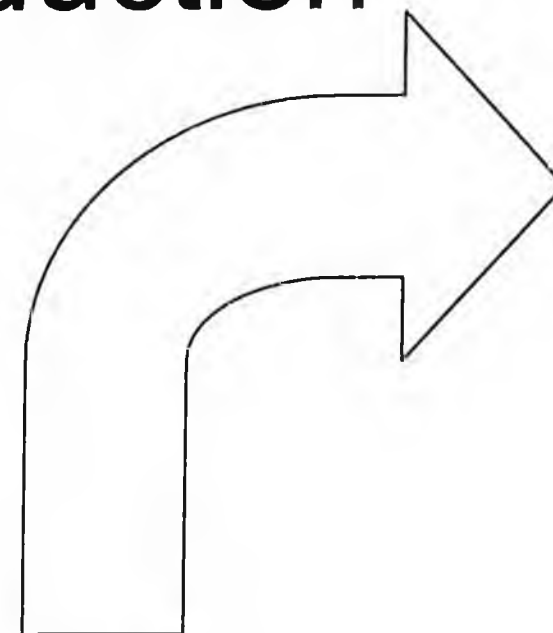
Point of Production after gas processing: first point accurately metered downstream of plant



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

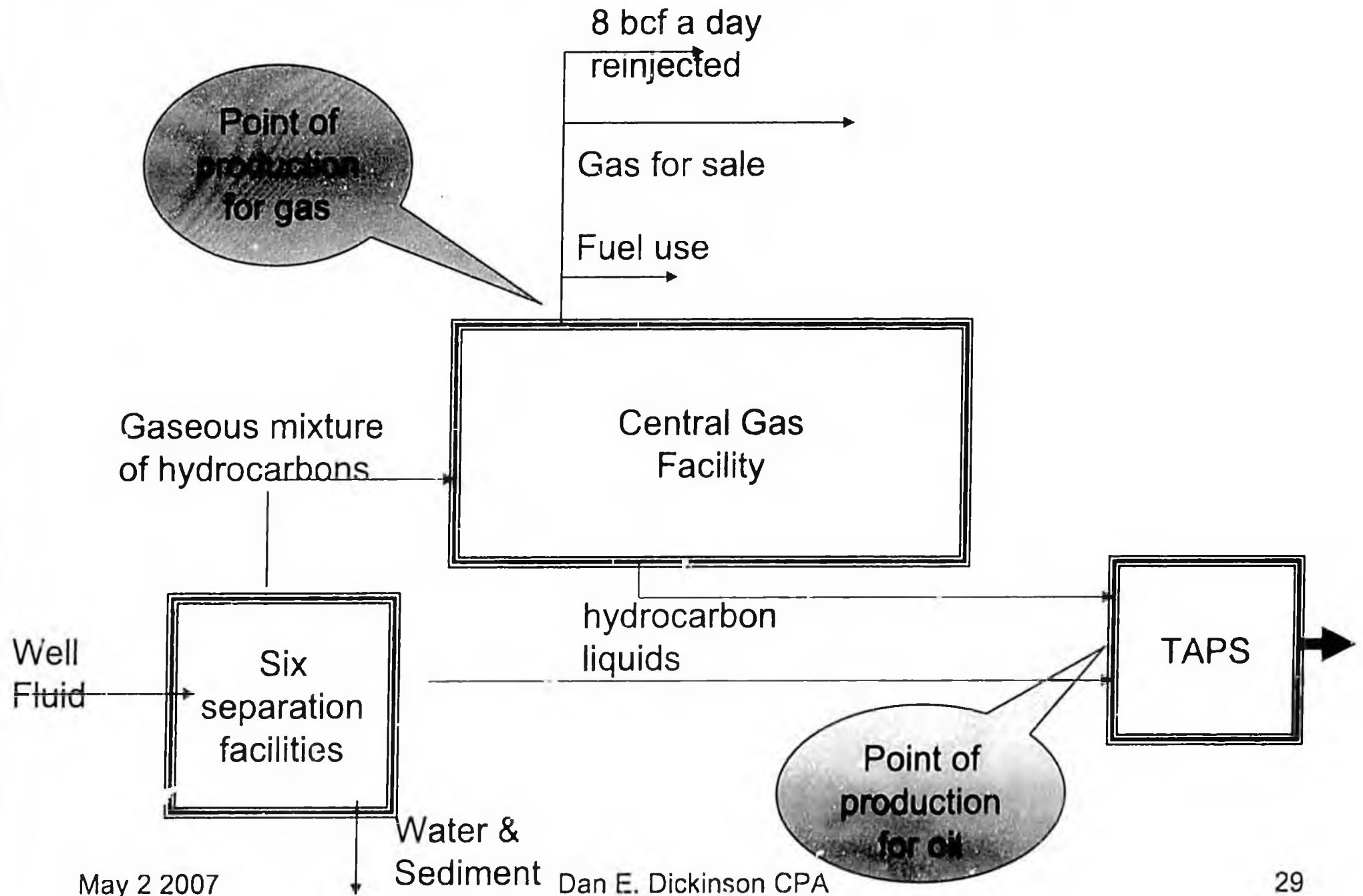


Integrated Gas Processing and Treatment Plant

Oil
(natural gas liquids)

Non hydrocarbons

Prudhoe Bay: Point of Production under the PPT



North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant, which sends natural gas liquids which are produced at the TAPS inlet:
- AS 43.55.009 (27) “point of production” means (A) for oil ... the device through which the oil enters into the facilities of a carrier pipeline...in a condition of pipeline quality...”
- AS 43.55.009 (10) “oil” means (A) crude petroleum oil: and (b) all liquid hydrocarbons that are recovered...by gas processing in a gas processing plant.

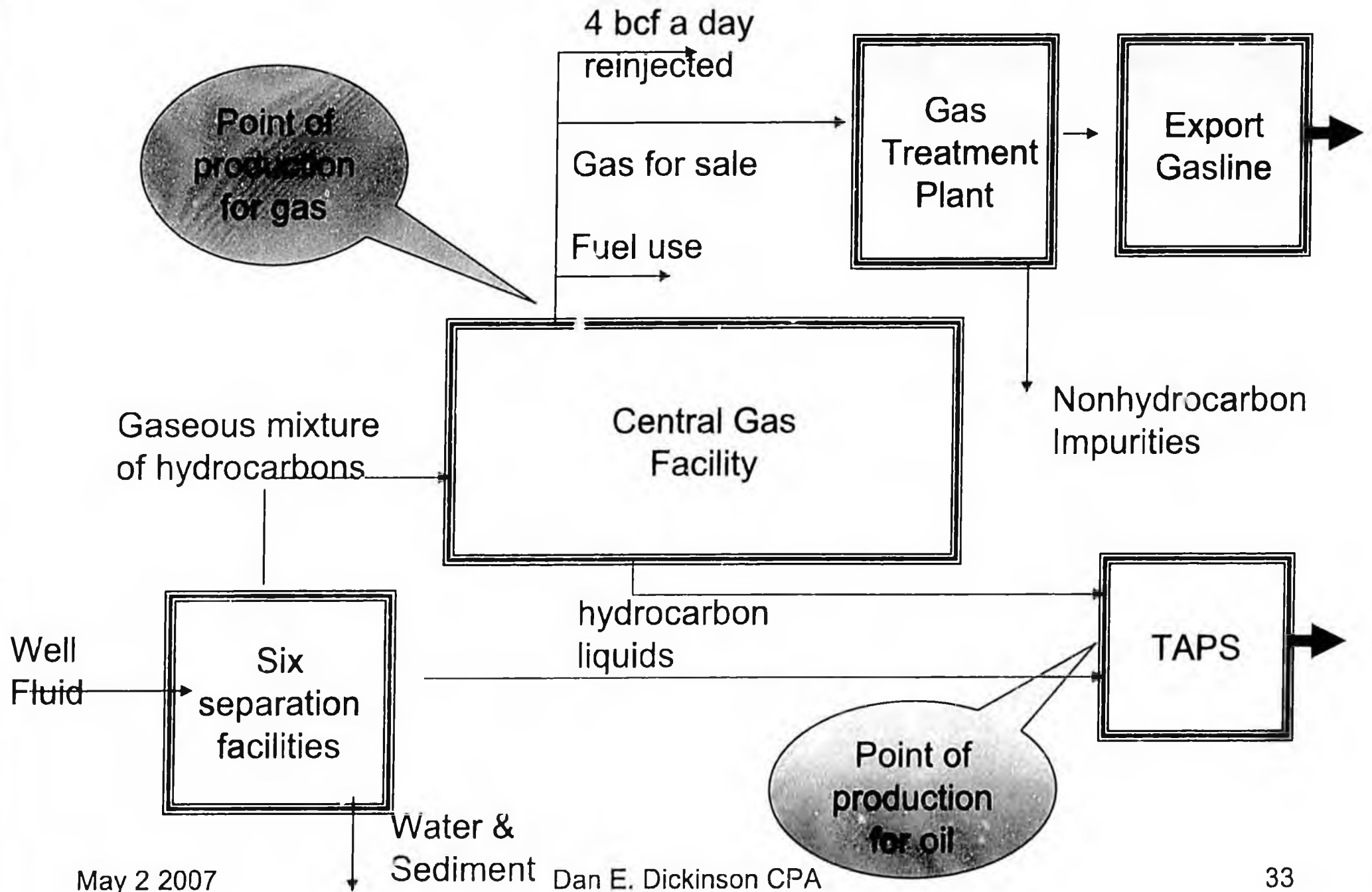
North Slope Central Gas Facility

- On the Alaska North Slope the Central Gas Facility is a gas processing plant,
- AS 43.55.020 (e) “... gas used in the operation of a lease or property in the state in drilling for or producing oil or gas or for repressuring...is not considered...as ... gas produced from a lease or property.”

Answer to the Question:

- If CGF remains a separate plant and sends gas to a Gas Treatment Plant (GTP), gas would be produced as it is metered out of plant. The GTP would be downstream of the point of production for the gas and thus associated operating and capital costs would not qualify as lease expenditures under AS 43.55.165 (a) nor would capital costs qualify for credit treatment under AS 43.55023 (a).

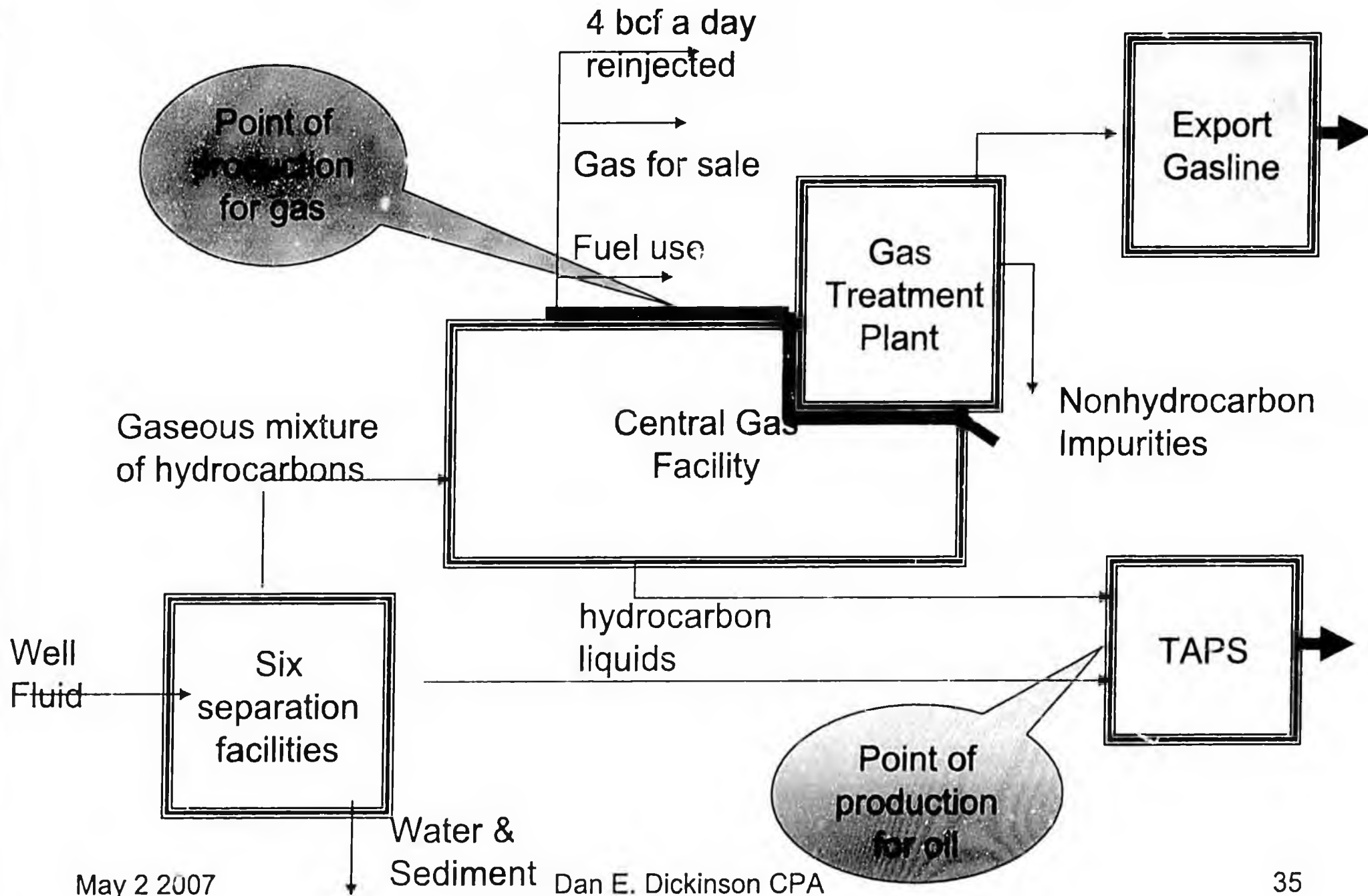
Prudhoe Bay: Point of Production under the PPT with a GTP




Answer to the Question:

- If CGF becomes integrated into a Gas Treatment Plant (GTP) (produced gas is not metered), then the gas would be produced within that integrated facility, at the furthest point upstream of the beginning of gas treatment or the end of gas processing. If the plants are integrated, the risk is that some gas processing will move downstream of the point of production, not that gas treatment will move upstream of the point of production.

Prudhoe Bay: Point of Production under the PPT w/integrated GTP



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- We are trying to determine how attractive an investment this pipeline is. Antony Scott, Commercial Analyst, DNR, Oil and Gas, in his April 11, 2007 presentation shows that using the IRR metric this project can have very high rates of return, particularly with a third party line. However we believe he does not include the cost of shippers' firm transportation commitments in his numbers when comparing an independent pipeline with a producer owned pipeline. How might this affect his results?

Firm Transportation

- Shipper makes a Firm Transportation commitment (FT) to pay the capital portion of the tariff whether it uses the pipeline or not.
- It is that financial commitment that underwrites the pipeline:
 - Required by FERC before approving a project
 - Required by lenders before lending money to a project.

Producers' returns as both shippers + pipeline owners



	NPV	IRR	P/I	NPV per BOE
\$3.50	3.0	12.6%	1.3	\$0.37
\$4.00	5.0	14.0%	1.4	\$0.60
\$4.50	6.9	15.4%	1.6	\$0.83
\$5.00	8.7	16.7%	1.7	\$1.06
\$5.50	10.6	17.9%	1.9	\$1.28
\$6.00	12.4	19.0%	2.0	\$1.50
\$6.50	14.2	20.1%	2.2	\$1.72
\$7.00	16.0	21.1%	2.3	\$1.93
\$7.50	17.7	22.1%	2.5	\$2.14
\$8.00	19.3	23.0%	2.6	\$2.33
\$8.50	20.8	23.9%	2.7	\$2.51

Producer Upstream Returns

Base case cost = \$20.5B



	NPV	IRR	P/I	NPV per BOE
\$3.50	4.1	29.8%	3.2	\$0.49
\$4.00	6.1	39.7%	4.3	\$0.74
\$4.50	8.1	48.7%	5.3	\$0.98
\$5.00	10.1	56.3%	6.4	\$1.22
\$5.50	12.1	62.9%	7.5	\$1.46
\$6.00	14.0	68.9%	8.5	\$1.70
\$6.50	16.0	74.2%	9.5	\$1.93
\$7.00	17.8	79.2%	10.5	\$2.15
\$7.50	19.6	83.9%	11.5	\$2.37
\$8.00	21.3	90.4%	12.4	\$2.57
\$8.50	22.9	95.6%	13.2	\$2.76