

04/08/14
Presentation:
Alaska Oil
and Gas
Conservation
Commission
Overview and
Issues

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Oil and Gas Conservation Commission Overview and
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Good afternoon. My name is Cathy Foerster and I am the chair and engineering commissioner of the Alaska Oil and Gas Conservation, or AOGCC.

Thank you for the opportunity to share with you the mission of and pressing issues before the AOGCC.

The AOGCC is an independent quasi-judicial body located in downtown Anchorage.

Although located within the executive branch, by statute the AOGCC is independent. This means that we do not report to any department within the executive branch but certainly we're held to the same administrative requirements of any other state department. Why? So that, when the DNR comes before us, they are held in no higher standing than any other applicant.

By statute, we have three commissioners. One must be a petroleum geologist. Currently that is Dan Seamount. One must be a petroleum engineer. That is me, and I am currently the Chair. And one is a public member who must have training and experience relevant to the oil and gas industry. That position is currently vacant.

On staff we have positions for 2 geologists, 6 engineers, 7 field inspectors, and several IT, data management, and administrative support staff. I said "have positions for" because we currently have 1 engineer and we are currently trying to add 1 additional field inspector position.

If you want to know our issues, here's a big one. We draw our staff from the same talent pool as industry and it's very difficult for us to compete with them on compensation. The last two engineers that left our agency went to industry, where each got a signing bonus, about a 20 percent raise, and an all-expense-paid move to Texas, which took them closer to family. We can't compete with that; so we have pretty much a constant struggle to keep positions filled.

AOGCC Mission

- Prevent hydrocarbon waste
- Protect correlative rights
- Promote greater ultimate recovery
- Protect underground fresh water
- Protect human safety

The AOGCC mission is to prevent hydrocarbon waste, to protect correlative rights, to promote greater ultimate recovery, to protect underground fresh water, and to protect human safety.

The AOGCC exercises the police powers of the State of Alaska and has jurisdiction throughout the State of Alaska including offshore state waters for conventional oil and gas, coalbed methane, shale gas, shale oil, and geothermal resource exploration and development.

Also, if a well is being drilled for other purposes but we have reason to suspect that it will encounter unanticipated hydrocarbons or other hazardous substances, our statutes give us the authority to assert jurisdiction. In fact we did that in 2012 for a CIRI underground coal gasification project.

Our authority covers resource management and conservation, drilling and well work operations, well integrity and well safety systems, custody transfer metering, and eventually well abandonment.

Typical AOGCC Approvals

- Drilling
- Sundry Wellwork
- Underground Injection
- Conservation Orders
- Other

All wells drilled in the State of Alaska for oil, gas, or geothermal resource exploration and development must receive a drilling permit from our agency.

Also, remedial or recompletion wellwork on an existing well requires a permit from us for.

The AOGCC has primacy for administering the EPA's Class II underground injection control program in Alaska, and we do our own independent review, approval, and monitoring of injection into Class I wells.

We have statewide rules covering all of our requirements, but whenever an operator wants pool-specific rules, they submit a request to us and those rules are addressed in conservation orders.

And there is a wide variety of other approvals we address, such as granting exceptions and variances from existing rules.

We stay very busy. In the new millennium we have approved over 2900 drilling permits, over 5900 sundry well work permits, over 1200 injection orders, conservation orders and other decisions and orders.

Major Issues before the AOGCC

- Increased Cook Inlet activity
- Increased North Slope activity
- Hydraulic fracturing regulation
- Suspended, orphaned, and BLM legacy well clean-up
- North Slope gas sales

We try to stay a quiet little agency, but there are several important issues before us. This is a list of the major issues currently before us. I will discuss each in some detail.

Cook Inlet Activity

- Offshore exploration
- Hilcorp and CIE
- Increased inspections, incidents and investigations
- Disputes among operators and land owners

Offshore drilling in the post-Macondo world is clearly one of the hottest topics before us. Thanks in no small way to the good work of the Legislature, new operators are coming to the Inlet. Furie (previously called Escopeta) and Buccaneer have brought jack-up rigs to the Inlet and have been exploring for the past few seasons.

On the downside, both of these companies have required much more than normal regulatory oversight. But on the upside, both are making meaningful discoveries.

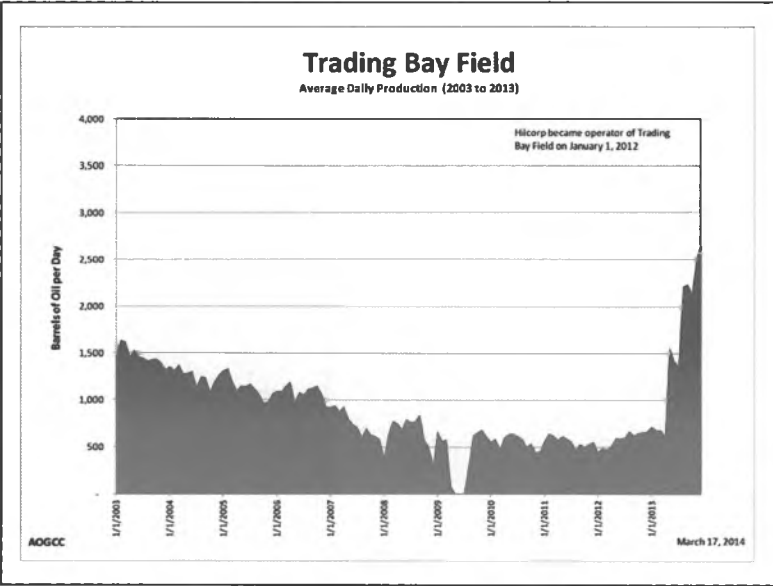
Hilcorp purchased Unocal and Marathon's interests and is very aggressively investing in restoring production in these fields.

And Cook Inlet Energy is also actively drilling exploratory and development wells in the Inlet

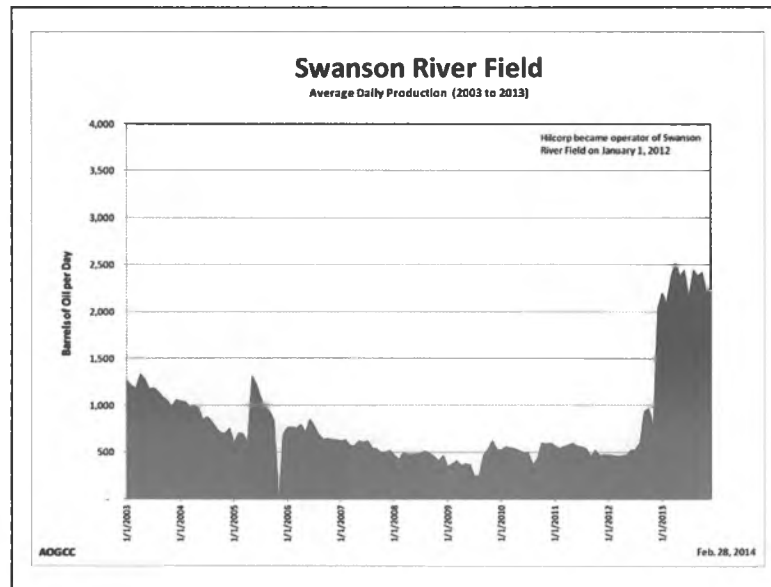
This increased activity level in the Inlet has kept us very busy. We are reviewing an unusually high number of custody transfer metering applications. Our field inspectors are conducting more inspections and safety system tests. The new operators are having difficulty complying with our regulations; so inspections and incident investigations are also up. And we are currently involved in adjudicating some very heated disputes among operators and land owners.

As Senator Micciche hears from his constituents, our modest inspection staff is being stretched thin. The result is that we have to choose between waiving witness on critical safety systems testing or causing delays for the operators. We are working hard to strike an appropriate balance but the long-term solution clearly involves identifying, recruiting, hiring, and retaining more qualified field inspectors.

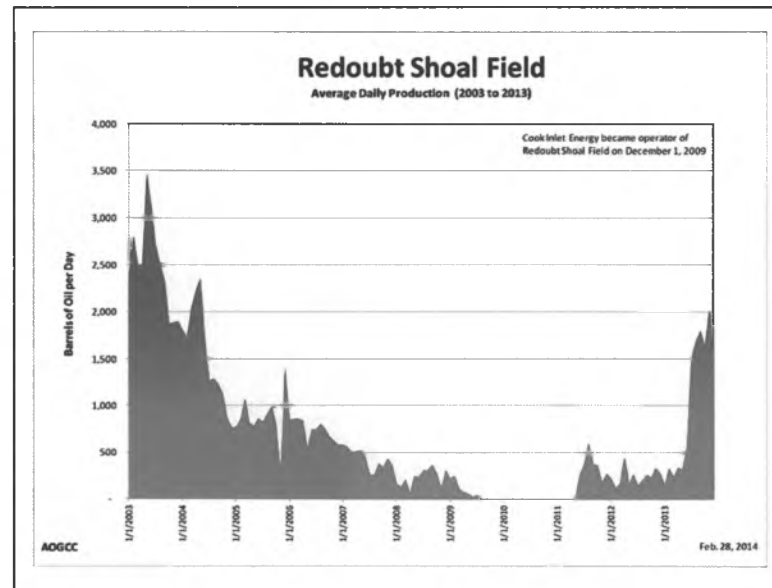
In the big picture, the increased activity is all very positive, as the increased production on the next three slides shows.



The uptick in production is due to Hilcorp’s aggressive wellwork and drilling program.



Again, the uptick in production is due to Hilcorp's aggressive wellwork and drilling program.



And this increase is due to the work of Cook Inlet Energy.

North Slope Activity

- Winter exploration drilling
- Increased work in old fields
- Viscous oil
- CD-5
- Pt Thomson
- Great Bear

Also in no small part due to the work of the Legislature, North Slope activity is also up.

We're into the winter exploration season. Conoco is drilling one exploratory well and Repsol is drilling 5 this season. As with new operators in the Inlet, Repsol is putting a regulatory strain on our field inspectors as well as our engineers and geologists in the office.

Activity in the legacy fields is also up. For example, over the past year Prudhoe Bay has experienced a 35 % increase in well work activity and Kuparuk has experienced an 18 % increase. Drilling activity is also up in both fields but I was not able to extract those numbers in time for this presentation. Perhaps the best news is that Prudhoe Bay and Kuparuk annual decline appear to be slowing. The last time I looked at the rolling 12-month decline numbers, Prudhoe was at 2% and Kuparuk was at 4%, compared to their usual decline of 6%.

Both Conoco and BP continue to work at unlocking the enormous potential of viscous oil on the Slope.

And Conoco is working toward development of CD-5, an expansion of its Colville development.

We're expecting renewed well work activity, possibly next year, from Exxon as it moves toward start-up of its Pt Thomson gas cycling pilot.

And we're hopeful that, as Great Bear completes its evaluation of the exploratory data it gathered, they will be back with positive results and a plan to bring Alaska into the shale business.

Hydraulic Fracturing

- Increased public interest
- Fracturing not new to Alaska
- Regulations in place, recently updated

Hydraulic fracturing has recently become a topic of interest. We've been hydraulically fracturing wells in Alaska for over 40 years. About one quarter of Alaska's wells have been hydraulically fractured. And the AOGCC has been regulating these operations since they began. The AOGCC just completed a multi-year effort to modify its regulations, first to keep up with technology advances, second to address fracturing fluids disclosure and water quality monitoring, and third to gather all of our regulatory requirements into a section titled hydraulic fracturing to make it easier for the public to see THAT we are and HOW we are regulating hydraulic fracturing. Hydraulic fracturing is a commonly used and well understood oilfield production enhancement practice, but one that carries a lot of mystique around it. Let me just offer to do my best to answer any questions that you or your constituents might have about it.



Suspended, Orphan, and BLM Well Clean-up

States like Texas and Oklahoma have thousands of orphaned wells; Alaska has only a handful. But we don't want to let down our guard and let this become a problem for our state; so we have a constant effort to hold operators accountable for properly plugging and abandoning wells that have no further utility. The only operator we have a major problem with is the Federal Government – I think you're all familiar with the BLM legacy travesty wells.

The bad news is that they're still a problem, and one that generally doesn't get better with time.

The good news is that, thanks to you guys and Senator Murkowski, Congress has given the BLM \$50million to apply to their clean-up. The even better news is that they are working closely and cooperatively with AOGCC and ADEC to ensure that the clean-up meets state standards, which are significantly higher than their own.

North Slope Gas Sales

- Prevent hydrocarbon waste
- Ensure greater ultimate recovery of total hydrocarbons

And, of course, the AOGCC has a small but important role in the seemingly-never-ending question of North Slope Gas Sales.

Remembering that early slide outlining our mission, the AOGCC is charged by statute to prevent hydrocarbon losses and ensure greater ultimate recovery of total hydrocarbons.

Those two charges have enormous implications for North Slope gas sales. In the world of petroleum engineering it is a simple truism that taking gas from an oil field puts ultimate oil recovery at risk. Prudhoe Bay is an oil field with about 2 billion barrels left to produce and Pt Thomson is also an oil field by technical definition and by the legal definition of the state of Alaska.

So the AOGCC is responsible for determining when and how much gas can be taken from those oil fields so that waste does not occur and greater ultimate recovery is achieved.

North Slope Gas Sales

- Prevent hydrocarbon waste
- Ensure greater ultimate recovery of total hydrocarbons

AOGCC developed white papers describing our role in gas offtake determination, the concerns we have with Prudhoe Bay, and the concerns we have with Pt Thomson. They're kind of long (and probably a bit boring) so I won't go through them here but all three are included for your use, perhaps as a sedative.

In addition to the field-specific issues discussed in those papers, there are a few other issues to mention. First, it is possible that the best use of the Pt Thomson gas will be to inject it into the Prudhoe Bay gas cap to get an added half billion barrels (approximate guess) out of the Prudhoe Bay reservoir. Second, as Conoco and BP work to find ways to unlock the huge potential viscous oil resource, it is highly likely that gas will be part of the solution. Third, if we build it, they will come. I.e., the USGS estimates roughly 150TCF of undiscovered gas on the North Slope. If there is the reality of a market for that gas, then the exploration work needed to realize those discoveries will likely result.

The last thought I want to leave you with is that the monkey is on the operator's back to demonstrate to the AOGCC that selling the gas from Prudhoe Bay and Pt Thomson is the best answer for preventing waste and ensuring greater ultimate recovery. So, we are looking to BP, Conoco, and Exxon to do that. And I doubt they'd spend the big bucks to build a line if they didn't think they could.

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.

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

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.

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

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.

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

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

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.