STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

Office of the Commissioner
550 W. 7th Avenue, Suite 1400
Anchorage, Alaska 99501
Fax: (907) 269-8918

Appeal by Point Thomson Unit Owners	)
of the Decision of the Director,	)
Division of Oil and Gas,	)
dated October 27, 2005, entitled	)
Amended Decision Denial of the Proposed Plans	)
For Development of the Point Thomson Unit	)
	)

APPEAL OF DIRECTOR'S AMENDED DECISION

Exxon Mobil Corporation ("ExxonMobil"), as Point Thomson Unit Operator, on behalf of itself and the other Point Thomson Unit working interest owners ("PTU Owners"), appeals the decision of the Director of the Division of Oil and Gas, dated October 27, 2005, entitled Amended Decision Denial of the Proposed Plans for Development of the Point Thomson Unit ("Amended Decision"). This appeal is made pursuant to 11 AAC 02.010(e), and in accordance with the Amended Decision and extensions by the Department of Natural Resources ("DNR") in letters dated November 10, 2005, May 26, 2006, August 31, 2006, and September 8, 2006.

The Twenty-second Plan of Further Development and Operation for the Point Thomson Unit was submitted to DNR on August 31, 2005 ("POD 22"). The Director, by decision dated September 30, 2005, disapproved POD 22. On October 27, 2005, the Director issued the Amended Decision.

In the Amended Decision, the Director made certain determinations and sought to impose certain conditions that are not supported by the factual record or controlling law. The work plans set forth in POD 22 are reasonable and prudent and provide for the development and operation of the

unit area in a reasonably prudent manner. The Amended Decision improperly seeks to impose conditions and requirements that go beyond the requirements of the Point Thomson Unit Agreement and applicable lease, statutory and regulatory provisions.

The following is submitted in compliance with the requirements set forth in 11 AAC 02.030.

Decision Being Appealed - 11 AAC 02.030(a)(7). The PTU Owners appeal to the Commissioner the October 27, 2005 decision by the Director of the Division of Oil and Gas entitled Amended Decision Denial of the Proposed Plans for Development of the Point Thomson Unit. A copy of the Amended Decision is attached as Exhibit A.

Basis upon Which Decision is Challenged and Material Facts Disputed by Appellant - 11 AAC 02.030(a)(8) and (a)(9). It was error for the Director of the Division of Oil and Gas to disapprove POD 22 for the following reasons.

1. The Amended Decision is inconsistent with and fails to apply the terms and standards for approval of a plan of development set forth in the Point Thomson Unit Agreement and any applicable statutes and regulations to approval of POD 22. The work plans set forth in POD 22 provide for the timely development of the oil and gas resources within the unit area and satisfy the requirements of the Point Thomson Unit Agreement and any applicable statutes and regulations. Whether the previous work activity undertaken by the PTU Owners demonstrates prudent and diligent efforts by the PTU Owners to develop the PTU in a timely and proper manner and is consistent with and supports the activities being undertaken by the PTU Owners in support of a gas sales development is a mixed question of law and fact.

2. The Amended Decision improperly imposes obligations and commitments upon the lessees through approval of a plan of development that go beyond the requirements for a plan of development set forth in the Point Thomson Unit Agreement and any applicable regulations of the DNR. Whether the representative commitments that the Division maintains should be included in POD 22 would provide for development of the unit area in a reasonably prudent

manner, or would establish arbitrary deadlines and requirements is a mixed question of law and fact.

3. The Amended Decision is inconsistent with and fails to apply the principles and standards regarding oil and gas leasing and unitization to approval of a plan of development. The Amended Decision seeks to require the drilling of unnecessary wells and inefficient development of the unit area. The Amended Decision seeks to require specific actions by the PTU Owners even though such action would not be undertaken by a reasonably prudent operator. Whether the work plans set forth in POD 22 are consistent with how a reasonably prudent operator would undertake development at PTU in a reasonably prudent manner is a mixed question of law and fact.

4. The Amended Decision improperly denies a one year deferral of the deadlines and obligations set forth in Paragraphs 4 and 5 of Section II.D[1] of the May 24, 2002 Finding and Decision of the Director on the PTU Application for the Second Expansion and Third Contraction of the Unit Area ("Expansion Decision"). The owners of the expansion area leases requested, by letter dated August 31, 2005, that DNR defer for one year the deadlines regarding drilling set forth in the Expansion Decision.[2] In the Amended Decision, the Director denied the request.

The timing and the number of wells set forth in the Expansion Decision were based upon the gas injection project that the PTU Owners were pursuing when the application for approval of expansion of the Unit was filed in February 2001. In requesting an extension of the drilling deadlines, the owners of the expansion area leases explained, in a letter dated June 21, 2005, that conducting a development drilling program predicated on the timeline of a project that was not commercially viable would be inefficient from a capital and technical work perspective. The

[1] Paragraph 4 of the Expansion Decision, provides that development drilling must begin by July 15, 2006, or the Expansion Acreage will contract out of the unit effective that date and the Applicants will pay the State a $20 million Extension Charge. Paragraph 5 of the Expansion Decision further provides that the Applicants must complete drilling seven development wells in the PTU by June 15, 2008, or the Expansion Acreage contracts out of the unit effective that date and the Applicants will pay the State a $27.5 million Extension Charge.

[2] Paragraph 15 of the Expansion Decision provides "the Applicants may request and DNR may agree to extend any deadline provided herein. If DNR does not agree to extend a deadline, the deadline shall not be extended."

DNR is aware that a gas injection project can not proceed on the basis anticipated in 2001, and that additional time to progress a gas sales project or other development option is necessary.

The PTU Owners are continuing with work plans to progress development, but there is not a specific project for which development drilling should begin at this time. Development drilling should be based upon the timing and schedule for a specific development project and should not begin until there is a specific project that is proceeding.

The request for extension of the deadlines sets forth clear reasons for approval of the requested extensions that are consistent with the PTU Owners current work activity and the position of the State regarding PTU development through a gas sales project. Under the circumstances, DNR should allow additional time before development drilling should be initiated. The Commissioner should reverse the decision by the Director and approve the August 31, 2005 request for extension of the drilling commitments and obligations in the Expansion Decision.

Reserved Issue. In the Amended Decision, the Director improperly determined that failure to obtain approval of the unit plan of development is grounds for default under the PTU Agreement and the State oil and gas regulations and set forth a demand to and conditions for cure inconsistent with the terms and standards set forth in the leases, the Point Thomson Unit Agreement, statutory and regulatory provisions. Contrary to the assertion in the Amended Decision, failure to receive DNR approval of a plan of development does not constitute default under DNR regulations nor under the Point Thomson Unit Agreement. 11 AAC 83.374(a) provides that "failure to comply with" the terms of an approved plan of development is a default under the unit agreement, not the failure to obtain approval.[3]

[3] 11 AAC 83.374. Default. (a) Failure to comply with any of the terms of an approved unit agreement, including any plans of exploration, development, or operations which are a part of the unit agreement, is a default under the unit agreement.

. . .

(d) If a default occurs with respect to a unit in which there is a well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner will, in his discretion, seek to terminate the unit agreement by judicial proceedings.

However, even if failure to obtain approval of a plan of development were to constitute default, under the terms of the respective leases (and DNR regulations) a final determination of default is not to be made by the DNR.[4] If DNR wishes to terminate the unit agreement, the DNR must pursue judicial action to terminate the unit agreement and may not take such action through its administrative proceedings. Accordingly, the issues of whether disapproval of POD 22 and failure to have an approved POD constitutes default and whether DNR has authority to make any final determination regarding default are not matters for determination by the Commissioner in this appeal and the PTU Owners reserve those issues.

This appeal only addresses the Director's disapproval of, and the grounds for the Commissioner's approval of, POD 22. This appeal does not represent and shall not constitute a waiver of any legal rights that any PTU Owner might have to pursue other legal remedies or avenues with respect to determinations or actions purportedly made by the DNR in the Amended Decision and the PTU Owners expressly reserve all such rights and remedies.

Remedy Requested - 11 AAC 02.030(a)(10). On October 18, 2006, the PTU Owners submitted a modified Plan of Further Development and Operation for the Point Thomson Unit ("Modified POD") that encompasses the term of POD 22 and extends through September 30, 2010. The Modified POD should be approved and a decision by DNR on the Modified POD submittal would moot this appeal, allowing DNR to vacate the Amended Decision and the PTU Owners to withdraw this appeal.

On November 9, 2005, a six-month extension of the deadlines and obligations set forth in the Expansion Decision was requested. By letter dated November 10, 2005, the DNR agreed to

[4] Paragraph 34 of the DL-1 lease provides as follows:
34. DEFAULT: TERMINATION. Whenever Lessee fails to comply with any of the provisions of this lease other than the payment of rental and said Lessee fails within sixty days after written notice of such default to commence to remedy and thereafter prosecute diligently operations to remedy such default, Lessor may cancel this lease if at that time there is no well on said land capable of producing oil or gas in paying quantities. If at such time there is on said land a well capable of producing oil or gas in paying quantities, this lease may be cancelled only by judicial proceedings. In the event of any cancellation under this paragraph, Lessee shall have the right to retain under this lease any and all drilling or producing wells as to which no default exists together with a parcel of land surrounding each such well or wells and such rights of way through said land as may be reasonably necessary to enable Lessee to drill and operate such retained well or wells.

extend the deadlines and obligations by six months, but has not agreed to further extend the deadlines. On October 18, 2006, a proposal to resolve the obligations in the Expansion Decision was provided to DNR. The PTU Owners believe the resolution to the Expansion Decision obligations set forth in the October 18, 2006 letter is fair and reasonable. Favorable action by DNR on that proposal would resolve that issue for purposes of this appeal.

If DNR does not take action that otherwise renders this appeal moot, the PTU Owners request that the Amended Decision be reversed and vacated and POD 22 approved, with any determination of default thereby resolved. A one year deferral of the deadlines and obligations in the Expansion Decision should be approved.

Address for Notices or Decisions - 11 AAC 02.030(a)(11). Any notice or decision regarding this appeal should be sent to the following:

Richard J. Owen, Alaska Production Manager
ExxonMobil Production Company
3301 C Street, Suite 400
Anchorage, Alaska 99503
Facsimile: (907) 564-3789

with a copy to:

C. Stephen Luna
Law Department
Exxon Mobil Corporation
800 Bell Street, Suite 1707J
Houston, Texas 77002
Facsimile: (713) 656-6123

Affected Agreements and Leases - 11 AAC 02.030(a)(12). This appeal concerns the Point Thomson Unit Agreement and the State of Alaska leases subject thereto.

Request for Hearing and Submittal of Additional Written Material - 11 AAC 02.030(a)(13) and (d). The PTU Owners are not requesting an oral hearing pursuant to 11 AAC 02.030(a)(13). The PTU Owners are submitting additional written material to the Commissioner and believe the additional information supports a decision by the Commissioner to approve the Modified POD submitted on October 18, 2006 without an oral hearing. Although the Commissioner need not

decide the issue, the additional written material addresses factual issues and bases for this appeal and thus also supports approval of POD 22 without an oral hearing.

DNR regulations, at 11 AAC 02.030(d), provide that an appellant may submit additional material within 20 days after the deadline for filing the appeal if the appellant includes notice of intent to file the additional written material. DNR instead has set November 3, 2006, the same date as the time for appeal, as the date by which appellant must submit for consideration by the Commissioner any information or documents in connection with this appeal. Given the hearing that has been scheduled by the Commissioner for ten days from the date for appeal, the PTU Owners are submitting for consideration by the Commissioner additional written information that supports this appeal and approval of POD 22.

Dated this 3rd day of November, 2006, at Houston, Texas.

C. Stephen Luna
Counsel for Exxon Mobil Corporation,
Operator of the Point Thomson Unit

STATE OF ALASKA
DEPARTMENT OF NATURAL RESOURCES
ADDITIONAL MATERIAL REGARDING PLAN OF DEVELOPMENT
FOR THE POINT THOMSON UNIT

INTRODUCTION

As Unit Operator for the Point Thomson Unit (Unit or PTU) and on behalf of the PTU Working Interest Owners (Owners or PTU Owners), Exxon Mobil Corporation (ExxonMobil) submitted a modified Plan of Further Development and Operation for the Point Thomson Unit (Modified Plan or Modified POD) on October 18, 2006. This Modified Plan includes significant work activity to progress development of the Point Thomson Unit. Under the Modified Plan, the PTU Owners are continuing their efforts to evaluate and pursue potentially viable options to develop the hydrocarbon resources within the Unit. The PTU Owners have been prudent and diligent in pursuing PTU development.

The Twenty-Second Plan of Further Development and Operation submitted by ExxonMobil on August 31, 2005 (POD 22) included significant work activity by the PTU Owners to progress PTU development for the period encompassed by POD 22. POD 22 was not approved by the Division of Oil and Gas (Division), by Amended Decision Denial of the Proposed Plans for Development of the Point Thomson Unit, dated October 27, 2005 (POD 22 Decision). The PTU Owners appealed the denial of POD 22 to the Commissioner, on November 3, 2006.

This submittal provides additional information regarding the work activity contained in the Modified Plan submitted by ExxonMobil on October 18, 2006. The Modified POD covers the one-year period requested in POD 22 and encompasses an additional four-year period from October 1, 2006 through September 30, 2010, that is needed to accomplish the work set forth in the Modified POD. This Modified POD should be approved by the Department of Natural Resources for the period through September 30, 2010.

The work activities in the Modified POD encompass work plans in POD 22 and thus this submittal of additional material also addresses approval of POD 22. The PTU Owners have

These amendments to the Unit Agreement reflect the recognition that production from the Unit is dependent upon the availability of pipeline transportation from the Unit Area and that the PTU Owners could not be required to take on the burden of constructing a pipeline or otherwise creating a market. Under the circumstances, the lessees could not be expected to begin producing shortly after a discovery, potentially years before a market for the production was available. While the Owners have been diligent in pursuing development of the hydrocarbon resources encountered within the Unit, the availability of means of transporting production from the Unit has been a factor that has prevented moving to commercial production.

Plan of Development Process

Section 10 of the Unit Agreement provides for preparation of plans of development for the Unit and approval by DNR:

> 10. PLAN OF FURTHER DEVELOPMENT AND OPERATION. Within six months after completion of a well capable of producing unitized substances in paying quantities, the Unit Operator shall submit for the approval of the Director an acceptable plan of development and operation for the unitized land which, when approved by the Director, shall constitute the further drilling and operating obligations of the Unit Operator under this agreement for the period specified therein. Thereafter, from time to time before the expiration of any existing plan, the Unit Operator shall submit for the approval of the Director a plan for an additional specified period for the development and operation of the unitized land. The Unit Operator expressly covenants to develop the unit area as a reasonably prudent operator in a reasonably prudent manner.

One effect of the certification of the PTU No. 1 well as capable of producing in paying quantities was to move the Unit from the exploratory stage provided for in Section 9 of the Unit Agreement into the development stage provided for in Section 10.

Initial Plan of Development

Exxon had filed a Plan of Operations for the Point Thomson Unit No. 2 well with the DMEM on September 21, 1977. By letter dated November 18, 1977, the Owners requested that the Plan of Operations for the drilling of the Point Thomson Unit No. 2 well be considered as the Plan of

Further Development and Operation for the Point Thomson Unit specified by Section 10.[10] The section in the Plan of Operations for the PTU No. 2 well entitled "Development Plans" provided as follows:

> If oil is discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez pipeline will be the probable marketing outlet from the area. Oil and casinghead gas would be processed through central oil gathering facilities with oil being pipelined to the Trans-Alaska line passing approximately 46 miles to the west.
>
> If commercial quantities of gas are discovered, development of a gas market outlet will be related to studies to market gas from the Prudhoe area.

The Plan of Development for drilling the Point Thomson Unit No. 2 well was approved by DNR on May 25, 1978,[11] for the period through January 1, 1979. The Point Thomson Unit Well No. 2, on ADL 47567, was spudded on February 4, 1978, reached a total depth of 14,117 feet and was suspended on August 12, 1978. The PTU No. 2 Well was certified by DNR as capable of producing in paying quantities on January 5, 1979.

Second through Twentieth Plans of Development

Following discovery of oil and gas within the Point Thomson Unit, the Owners have undertaken significant work to progress development of the Point Thomson Unit Area. In addition to having drilled eighteen wells within the Unit Area, the Owners have conducted seismic surveys, gathered and analyzed extensive data from wells, developed models to evaluate the reservoir and project options, initiated engineering for specific potential projects and expended countless man-hours and invested significant funds to progress development. Appendix IV sets forth the work effort that has occurred under the Plans of Development approved by DNR from the Second Plan of Development through the Twentieth Plan of Development.

[10] The Amended Decision discusses a number of the Plans of Development submitted by the Owners. The Plans of Development and approvals are on file with DNR and the Owners request that they be included as part of the record in this matter.

[11] The approval from DNR stated that the plan dated November 18, 1977, was filed on January 3, 1978.

Dated this 3rd day of November, 2006 at Houston, Texas.

C. Stephen Luna
Counsel for Exxon Mobil Corporation
Operator of the Point Thomson Unit

VERIFICATION

STATE OF TEXAS

COUNTY OF HARRIS

Before me the undersigned Notary Public, on this day personally appeared Walter D. Morgan, who, after being duly sworn, stated under oath that he is duly authorized by Exxon Mobil Corporation to make this statement, that he has read the above Additional Material Regarding Plan of Development for the Point Thomson Unit and that every statement in the Additional Material Regarding Plan of Development for the Point Thomson Unit is within his personal knowledge, or is corporate knowledge that he has confirmed, and is true and correct.

SUBSCRIBED AND SWORN TO BEFORE ME on November 3, 2006.

Notary Public in and for
The State of Texas

State of Alaska
Department of Natural Resources
555 West 7th Avenue, Ste. 1400
Anchorage, AK 99501

Re: The matter of an Appeal from the October 27, 2005 Amended Decision on Proposed Plan of Development for the Point Thomson Unit

Point Thomson Unit

November 3, 2006

Statement of the Alaska Oil and Gas Conservation Commission

The Alaska Oil and Gas Conservation Commission (Commission) is an independent quasi-judicial agency of the State of Alaska with jurisdiction over all lands subject to the State's police powers. [1]

Among its responsibilities, the Commission is charged with preventing waste and insuring greater ultimate recovery of oil and gas resources located within the State of Alaska. [2]

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[1] AS 31.05.005; AS 31.05.027

[2] The Commission was established by the Alaska Oil and Gas Conservation Act (Act), which is codified under Chapter 31.05 of the Alaska Statutes. The following sections of the Act are relevant to these proceedings:

Sec. 31.05.030(b) "The commission shall investigate to determine whether or not waste exists or is imminent, or whether or not other facts exist which justify or require action by it."

Sec. 31.05.030(c) "The commission shall adopt regulations and orders and take other appropriate action to carry out the purposes of this chapter."

Sec 31.05.030(d)(9) The commission may require "the filing and approval of a plan of development and operation for a field or pool in order to prevent waste, insure a greater ultimate recovery of oil and gas, and protect the correlative rights of persons owning interests in the tracts of land affected."

Sec. 31.05.030(f) "The commission may classify wells as oil or gas wells for purposes material to the interpretation or enforcement of this chapter."

Sec. 31.05.095 "The waste of oil and gas in the state is prohibited."

Sec. 31.05.170(9) "'oil' includes crude petroleum oil and other hydrocarbons regardless of gravity which are produced at the wellhead in liquid form and the liquid hydrocarbons known as distillate or condensate recovered or extracted from gas, other than gas produced in association with oil and commonly known as casinghead gas."

Sec. 31.05.170(15) " 'waste' means, in addition to its ordinary meaning, 'physical waste' and includes
"(A) the inefficient, excessive, or improper use of, or unnecessary dissipation of, reservoir energy; and the locating, spacing, drilling, equipping, operating or producing any oil or gas well in a manner which results or tends to

Commission regulations define an oil well as:

> *"...a well that produces predominantly oil at a gas-oil ratio of 100,000 scf/stb or lower, unless on a pool by pool basis the Commission establishes another ratio."* [3]

The Department of Natural Resources (DNR)'s October 27, 2005 Amended Decision states that the Point Thomson Unit (PTU) *"is known to contain at least 8 trillion cubic feet of gas and 200 million barrels of gas condensate and oil"* [4] Based upon these volumes, the effective gas-oil ratio for this reservoir is 40,000 scf/stb – significantly less then the 100,000 scf/stb limit set by the regulations.

To date, the Commission has received no application for pool rules from the PTU owners. Accordingly, the Thomson Sand Reservoir (TSR) is presumed to be an oil pool and will remain so unless and until the Commission establishes Pool Rules that provide otherwise.

Until relatively recently, gas cycling for condensate production was considered to be a viable alternative for reservoir development. This has changed and the proposed Pt. Thomson Unit Plan of Further Development and Operation for the period October 1, 2005 to September 30, 2010 (POD) expresses the owners intent to *" ...progress development plans for gas sales from the PTU."* [5]

If major gas offtake from the PTU is the preferred alternative then it is essential that an application for Pool Rules be filed with the Commission at an early date.

The proposed POD states *"throughout the past year, the Owners have continued to diligently conduct work necessary to develop the PTU hydrocarbon resources as part of POD 22 submittal."* The Commission has a concern with this statement because it makes the supposition that the TSR is a gas reservoir and, as stated above, the Commission currently classifies the TSR as an oil reservoir.

Section 3.1 of the POD states *"prior work indicates the most value for the Owners and the State will be derived if the Point Thomson gas field is developed as part of a Pipeline*

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result in reducing the quantity of oil or gas to be recovered from a pool in this state under operations conducted in accordance with good oil field engineering practices;

"(C) producing oil or gas in a manner causing unnecessary water channeling or coning;

"(D) the operation of an oil well with an inefficient gas-oil ratio;"

[3] 20 AAC 25.990(45)

[4] DNR Amended Decision (revised version) dated October 27, 2005, P3; see also The Point Thomson EIS Newsletter, October 2002, as published jointly by the Environmental Protection Agency, US Army Corps of Engineers and the US Fish and Wildlife Service, where it is stated at page 2: *"This reservoir contains an estimated 8 trillion cubic feet of gas and over 400 million barrels of recoverable condensate."*

[5] ExxonMobil letter, October 18, 2006

Project." As cited above, the Commission's responsibility is to prevent the physical waste of hydrocarbon resources.[6] Maximizing value to the owners and the State at the possible expense of additional reserves is not a valid reason for committing waste. The owners have yet to demonstrate to the satisfaction of the Commission that developing the PTU as a gas field will be the only viable alternative for a prudent operator to pursue. Until they do, the Commission will continue to regard the PTU as an oil field and steps taken towards developing it as a gas field risk being viewed as steps taken towards wasting hydrocarbon resources. Point Thomson could be part of a gas line project and still cycle condensate first; if the operator makes prudent use of the time available.

Section 5.1 of the proposed POD states *"[t]he Owners will progress sharing of confidential PTU technical data with the Alaska Oil and Gas Conservation Commission (AOGCC) via a data room process. After this process is completed, a request for approval of a conservation order to authorize the desired gas offtake rate from the Thomson Sand reservoir will be submitted. This submittal, which will include the PTU depletion plan, will be timed to allow the conservation order to be issued prior to the open season for a Pipeline Project."* The Commission has several comments relative to these statements.

(i) Section 6 of the agreement between the Commission and the PTU owners titled Principles Governing Commission Access to Point Thomson Unit Reservoir Study Process ("Study Principles"), adopted by the Commission on April 26, 2006, states *"[t] he Operator shall provide written notice to the Commission when the Study begins and access to the Data Room is first available, which shall be not later than September 1, 2006."* As of this date, the PTU owners have not made the data room available to the Commission; however, a letter from ExxonMobil dated August 24, 2006, proposed modifying the schedule in the Study Principles to provide data in phases. According to the letter the first product to be provided to the Commission would be a gas field classification study. The PTU owners were to *"present the results to the Commission in the second half of September"*; this study has yet to be presented to the Commission.

(ii) In this same letter the PTU owners stated *"[w] e suggest sharing of technical work currently being conducted to prepare reservoir development plans for Point Thomson gas sales to begin in the 1st quarter of 2007. Our subsurface teams are currently developing geologic and reservoir simulation models. A key aspect of this work is an uncertainty analysis to better understand the high and low side scenarios in addition to the base case. This work should be completed in 1Q 2007."* Based on the schedule of activities outlined in the proposed POD, it is unclear whether the Owners are planning their work activities in such a way as to allow them to meet this deadline.

[6] AS 31.05.095; AS 31.05.170(15)

(iii) Based on the referenced letter and the proposed schedule contained in section 2.1 of the proposed POD, it appears the PTU owners intend to complete work on the gas sales case prior to commencing work on alternative development scenarios. If the PTU owners apply to the Commission for an allowable gas offlake rate prior to completion of the analysis of alternative development scenarios, they risk having the Commission deny their application as incomplete.

Section 6.5 of the POD states *"[a] comprehensive PTU review was held for the AOGCC and their consultants on May 11, 2006. The review included discussion of the previous gas injection development study efforts and introduced the Owners' work to assemble a worldwide database of potential Point Thomson analogue reservoirs."* The Commission did indeed participate in this meeting at which the PTU owners did present a reasonably thorough overview of the prior gas injection project including estimated costs, reserves, facility capacities, and other information. However, the PTU owners declined to provide the Commission with a copy of this presentation and said that this was the last time the Commission would see the gas injection development scenario as it had been eliminated as a development option. Section 3.2 of the proposed POD appears, however, to recognize that with changes in the State's oil tax structure and market conditions, this type of development scenario may be viable and will be reconsidered, but with the gas sales development remaining as the preferred scenario.

For the Commission to fulfill its statutory mandate, we must have all the facts presented to us before we can make a determination to reclassify what by definition is an oil reservoir as a gas reservoir. Attached as Exhibit "A," is a simplified explanation of some of the complexities that must be considered by the Commission in adopting Pool Rules for this important reservoir.

If the Commission receives the level of cooperation we expect from the PTU owners and if we receive a timely application for Pool Rules and a depletion plan for the Thomson Reservoir, then we expect to be able to discharge our responsibilities within the time line proposed by the operator. On the other hand, if we fail to receive full and timely cooperation from the owners, project delays could result.

This is a significant hydrocarbon reservoir, the largest proven accumulation of oil and gas in the State that is still undeveloped. The Commission's sole objective in providing these comments to the DNR is to ensure that we will receive, in a timely manner, the information we need to establish appropriate Pool Rules for the Thomson Sand Reservoir. Toward this end, there are several items in the proposed POD that we believe must be completed prior to submission of a Pool Rule application to the Commission. These include:

(i) Completion of the revised geological, engineering, and economic models necessary to evaluate the gas sales and alternative development scenarios as outlined in section 3 of the POD.

(ii) Completion of the evaluation of alternative development scenarios as described in section 3.2 of the POD.

(iii) Completion of drilling of the well proposed in section 4 of the POD. Selection of the drilling location for this well should be done in consultation with the DNR and the Commission to help ensure that it will answer the questions that must be answered and, that can only be answered by drilling a well or wells.

(iv) Resumption and timely completion of the process established between the Commission and the PTU owners that is described in section 5.1 of the POD.

In conclusion the Commission does not believe that the uncertainty that still exists about the potential development of the PTU can be used as justification for a decision that may promote waste of tens to hundreds of millions of barrels of oil and condensate. This is especially true in light of the fact that much of this uncertainty could have been eliminated already had the PTU owners adhered to the work commitments specified in previous POD's and agreements.

Submitted this 3rd day of November 2006.

Alaska Oil and Gas Conservation Commission
By

John K. Norman
Chairman

I certify that on November 3, 2006, a true and correct copy of this statement of the Alaska Oil and Gas Conservation Commission, was served by mail to each of the following:

Richard Todd, Esq.
Senior Assistant Atty. General
State of Alaska, Dept. of Law
1031 W. 4th Ave., Ste. 200
Anchorage, AK 99501-1994

Mr. Richard J. Owen
Alaska Production Manager
ExxonMobil Production Company
P.O. Box 196601
Anchorage, AK 99519-6601

Mr. Don Dunham
Performance Unit Leader
Greater Kuparuk Area & Pt. Thomson
ACT Business Unit
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

William M. Walker, Esq.
Walker and Levesque, LLC
731 N Street
Anchorage, AK 99501

Ceresa Tolley
Administrative Clerk III
Alaska Oil and Gas Conservation Commission

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 preferred scenario 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.

COMMISSIONER'S DECISION ON APPEAL FROM THE DIRECTOR'S OCTOBER 27, 2005 DECISION DENYING THE PROPOSED PLANS FOR DEVELOPMENT OF THE POINT THOMSON UNIT

November 27, 2006

Findings and Decision of the
Commissioner, Department of Natural Resources, State Of Alaska

I. SUMMARY OF DECISION.

This is the final Decision of the Alaska Department of Natural Resources on the appeal from the October 27, 2005 decision of the DNR Director of Oil and Gas rejecting the Twenty-second Plan of Development (22nd POD) for the Point Thomson Unit (PTU) submitted by the PTU Operator, ExxonMobil Corporation (ExxonMobil), on August 31, 2005 (Director's Decision). The Director's Decision also put the PTU in default for failure to submit an acceptable plan of development (POD) and gave the PTU lessees (Lessees) an opportunity to cure the unit default by submitting an acceptable plan of development.

This Commissioner's Decision (1) denies the request for modification of the 2001 Expansion Agreement, as amended, which affects only the expansion leases; (2) affirms the Director's Decision in all respects to the extent it is consistent with this Commissioner's Decision, but the Director's Decision is disapproved to the extent it can be read to mean the PTU contains certified wells; (3) adopts and incorporates into the Commissioner's Decision the findings and rationale of the Director's Decision as modified by this Decision; (4) rejects the cure or revised 22nd PTU POD submitted by the Lessees on October 18, 2006; and (5) terminates the PTU.

This Commissioner's Decision is effective November 27, 2006.

II. Facts.

This Commissioner's Decision relies on the facts discussed in the Director's Decision with the following additional facts:

A. Facts regarding appeal process.

The Director's Decision gave the PTU Lessees 20 days to appeal the decision and 90 days to cure by submitting an acceptable POD. ExxonMobil requested that the DNR

Commissioner grant extensions of time. The DNR Commissioner granted ExxonMobil's requests. Time was ultimately extended to October 20, 2006 to submit a cure and to November 3, 2006 to submit appeal papers. Hearing on the appeal was held November 20, 2006, and pre-filed testimony was filed November 3, 2006. Time was also extended to give the Alaska Gasline Port Authority (Port Authority), and Mr. Jim Whitaker, Mayor of the City of Fairbanks, an opportunity to be heard.

On October 18, 2006, ExxonMobil submitted a proposed cure in the form of a revised plan of development for the Point Thomson Unit. BP Exploration (Alaska) Inc. (BP) and Chevron submitted letters in support of the cure. On November 3, 2006, BP submitted additional materials in support of the cure.

On October 18, 2006, ExxonMobil also submitted a request to modify the 2001 Expansion Agreement under which 12 leases and about 40,000 acres were added to the PTU in return for Lessees' commitment to do certain items of work including the drilling of wells and agreement to automatic contraction of the expansion leases out of the unit if the work commitments were not met.

Approximately 5,000 pages of documents regarding the appeal and cure including pre-filed testimony were submitted to DNR on November 3, 2006 by various entities.[1] DNR received written submittals from a number of PTU Lessees including ExxonMobil, BP, and Chevron. In addition, DNR received written submittals from the Alaska Oil and Gas Conservation Commission (AOGCC), Port Authority, Mr. Whitaker, former Governor Walter Hickel, and former legislators and delegates

[1] These documents and an index are in the DNR file. They are numbered "PTU22P_00001 to "PTU22P_04991." Non-confidential documents are available in the DNR public file.

to the state constitutional convention, Mr. Jack Coghill and Mr. Vic Fischer.

BP requested that some of the materials it filed be kept confidential. Counsel for DNR sent an email to BP requesting that the confidential materials be redacted and resubmitted and stating that until further notice, the Commissioner would not consider confidential materials. BP submitted redacted testimony, and withdrew some documents, but insisted on confidentiality for a number of documents.

DNR did not receive a request for evidentiary hearing, and the November 20, 2006 hearing was limited to oral argument. Commissioner Michael Menge presided over the proceeding. Mr. Don Dunham of BP, Mr. Vince LeMieux of Chevron and Mr. Richard Owen of ExxonMobil made statements on behalf of the Lessees. AOGCC Commissioner and Chair, Mr. John Norman, made a statement on behalf of the AOGCC. The following persons made statements on behalf of the Port Authority and Mr. Whitaker: Mr. Mark Cotham, Mr. Daniel Johnson, Mr. Radoslav Shipkoff, and Mr. William Walker. In addition, former Governor Walter Hickel and Mr. Vic Fischer made statements. The hearing began at 9:00 AM and closed at 12:00 Noon on November 20, 2006 with no objections to the procedure used on the appeal and no presentations were cut short by the Commissioner.

Some of Lessees' key points on appeal are (1) that the appeal and adequacy of the proposed cure are to be decided under the Reasonably Prudent Operator (RPO) standard, i.e., the Lessees do not have to do anything that a RPO would not do including putting the unit into production; (2) DNR cannot terminate the unit unless it first successfully prosecutes an action, presumably jury trial in Superior Court, which finds Lessees have breached the RPO standard; (3) the revised 22nd POD / cure meets the RPO standard; (4) the unit cannot be terminated because the lessees have been precluded from producing by a *Force Majeure* event, being the lack of a gas

pipeline, and (5) DNR and the Lessees have agreed that the only way to develop this unit is as a gas "blow down"[2] project which cannot be done until a gas pipeline is built.[3]

The assertion that DNR and the Lessees have agreed that the PTU can only be developed as a gas blow down project is not supported by the record. DNR has repeatedly requested that the unit be adequately delineated and put into production. The unit contains more than dry gas. Oil and gas liquids are also available. Lessees' assertion was expressly rejected in the DNR file and the Director's Decision:

"The premise that the PTU can only be developed if a North Slope gas pipeline is built is inappropriate. In addition to dry gas, the unit contains 100s of millions of barrels of hydrocarbon liquids. These hydrocarbons could be produced using mostly existing oil pipelines without construction of a North Slope gas pipeline." (Director's Decision at 2)

Lessees' appeal papers also assert that they have been working closely with AOGCC to obtain approval for a gas blow down project. AOGCC's position is that it has not received the cooperation of the Lessees. In April 2006 the Lessees committed to provide AOGCC access to ExxonMobil's data room not later than September 1, 2006, but as of the date of the hearing in this matter, access has not been provided to the AOGCC.

Notwithstanding Lessees' repeated assertions that the PTU is a gas reservoir which may only be developed as a gas blow down project, they have not provided AOGCC with sufficient information to determine that the PTU is primarily a gas field, as opposed to an oil field. The data available to the AOGCC

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[2] A gas blow down development produces gas and liquids together without engaging in pressure maintenance or gas re-injection (cycling) to improve recovery of liquids.

[3] Nothing in the leases, unit agreement, regulations or statues allow the Lessees to delay production until a gas pipeline is constructed.

indicates that the PTU is an oil field. Like DNR, the AOGCC has determined that an additional exploratory well or wells are necessary. The AOGCC needs the information before it can determine whether to grant the Lessees' request to treat the PTU primarily as a gas instead of an oil development.

DNR has repeatedly requested that Lessees drill an exploratory well to, among other things, better delineate the various hydrocarbon deposits and to firm up the potential of liquids production. A pure gas blow down project will result in the loss of millions of barrels of gas condensate. Neither DNR nor AOGCC are prepared to allow a pure gas blow down project in the face of such a potential hydrocarbon loss without more data indicating it is appropriate. Lessees contend the data indicate uncertainties which prevent them from engaging in liquids production, yet they refuse to obtain more data to reduce the uncertainties.

The Port Authority position can be summarized as the state has the right to terminate the PTU, and it is in the state's vital interests that the unit be terminated.

B. Facts regarding the proposed cure.

On October 18, 2006, ExxonMobil submitted a proposed cure in the form of a revised 22nd POD. Other Lessees submitted memoranda, pre-filed testimony and other documents in support of the cure.

The Director's Decision rejected the original 22nd POD because it failed to commit to put the unit into production. The 22nd POD stated that the Lessees could not find an economic way to put the unit into production. The POD stated that the unit may never be produced until there is a gas pipeline and until state taxes and royalties are modified.

Given that the unit had been in existence since 1977 and that it was known since the early 1980s to contain oil, gas liquids

and gas reservoirs, the Director's Decision found the Lessees' continuing refusal to produce unacceptable. The Director put the unit into default because the 2005 22nd POD submitted stated the Lessees had still not found a way to produce hydrocarbons from the unit. The Director's Decision gave the Lessees 90 days to cure the default by submitting a revised POD which made a meaningful commitment to put the unit into production.

In addition to gas, the PTU contains hundreds of millions of barrels of gas condensate and oil. The Director's Decision stated that a revised POD had to commit to additional exploration and delineation of hydrocarbon accumulations above and below the Thomson Sand gas reservoir. Lessees needed to have commercial project sanction by October 2006, and a commitment to begin commercial production by October 2009.

The Director's Decision included an example of an acceptable POD:

> "To cure the default, the Unit Operator shall submit an acceptable POD within 90 days, by Thursday, December 29, 2005.
>
> a) An acceptable unit plan must contain specific commitments to timely delineate the hydrocarbon accumulations underlying the PTU and develop the unitized substances. The following commitments represent an acceptable PTU plan of development:
>
> - Development activities for the unit, including plans and deadlines to delineate the Thomson Sand Reservoir, bring the reservoir into commercial production, maximize oil, condensate, and gas recovery, and maintain and enhance production once established; and plans for the exploration or

delineation and production of other hydrocarbon accumulations and lands that lie stratigraphically above or below the Thomson Sand Reservoir;

- The PTU Owners shall sanction a commercial PTU development project by October 1, 2006, and provide the Division with evidence of corporate approval and commitment of project funding.

- The PTU Operator shall begin commercial production of unitized substances from the PTU by October 1, 2009.

- Details of the proposed operations to fulfill the 2006 Development Drilling Commitment, including the proposed surface location of the drill pad, bottom-hole location for the well, testing plan, and schedule of activities. The consequences of failure to fulfill the 2006 drilling commitment are specified in the Expansion Agreement." (Director's Decision at 22).

In summary, the Director's Decision informed the Lessees that the POD should: (1) commit to commercial development by October 2006 including project sanction, (2) commit to prompt delineation of all PTU hydrocarbons, (3) commit to begin commercial production by October 1, 2009, and (4) set out details of the Expansion Agreement well which is supposed to be drilled by December 2006.

The revised POD submitted on October 18, 2006 did not meet the requirements set out in the Director's Decision for an acceptable POD. The revised POD was similar to the proposed 22nd POD which was rejected in the Director's Decision in that there is no commitment to develop the unit and no firm

commitment to adequately delineate the reservoirs. Again, the Lessees claim that PTU development may not occur without a gas pipeline and royalty and tax concessions.[4] The Lessees' focus is primarily on gas, and the POD made no commitments to more fully delineate PTU hydrocarbons, especially liquids which the state estimates to be hundreds of millions of barrels. Point Thomson is one of the largest oil fields on the North Slope.

The revised POD indicates that the Lessees might drill an exploratory well into the PTU. If it is not drilled by 2010, Lessees propose to pay the state $40,000,000 instead of drilling the well. The value of the well to the state greatly exceeds $40,000,000 because a well or wells are needed to adequately appraise the PTU.

The original proposed 22nd POD rejected in the Director's Decision was for one year. The revised 22nd POD submitted as the proposed cure was for a 5 year period.

C. Facts regarding the Expansion Agreement.

In 2000 the Lessees asked DNR to approve an expansion of the PTU by 12 leases and about 40,000 acres. DNR initially disagreed because the unit had not been put into production. DNR and the Lessees entered into an agreement whereby DNR would approve unit expansion on the condition that the Lessees perform certain items of work and put the unit into production with at least 7 development wells by 2008. If the Lessees failed to perform the work in a timely manner, the expansion leases would automatically contract out of the unit and the Lessees would owe DNR certain sums of money.

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[4] Between the date of the Director's Decision and the October 18, 2006 submittal of the proposed cure, the production tax was changed from a share of production to a share of net profit and the tax change also included tax benefits for additional capital investment in hydrocarbon production infrastructure. These tax benefits transfer a significant portion of the cost of development to the State of Alaska.

To date, none of the work commitments Lessees agreed to in the Expansion Agreement have been fulfilled. The Lessees have paid the state $940,000 and two expansion leases have been relinquished back to the state as a result of the failure to meet work commitments of the expansion agreement.

The next Expansion Agreement deadline is to drill a well no later than December 2006. If Lessees fail to do so, all 29,000 acres of the remaining expansion leases automatically terminate and are relinquished back to the state without otherwise requiring the state to meet the statutory and regulatory requirements for unit or lease contraction or termination. In addition, Lessees are obligated to pay the state $20,000,000.

On October 18, 2006 ExxonMobil gave DNR a proposal to modify the Expansion Agreement. ExxonMobil proposed to drop all the well requirements – a well by December 2006 and at least 7 development wells by 2008. ExxonMobil also proposed to reduce the amount of acreage that would be relinquished as a result of the failure to meet the drilling requirements and to change the acreage that would be relinquished. ExxonMobil wanted to relinquish 20,000, not the 29,000 acres, called for by the Expansion Agreement. Less than ½ of the 20,000 acres ExxonMobil proposed to relinquish consists of expansion acreage.[5] The difference between the current Expansion Agreement obligation and the ExxonMobil proposal is that under the ExxonMobil proposal the state gets back less acreage and less valuable acreage.[6] In addition, all the drilling commitments ExxonMobil agreed to are eliminated. ExxonMobil's proposal allows it to retain the most valuable

[5] The PTU is 106,800.55 acres in size of which 29,931.44 acres are made up of expansion leases. Lessees are offering to relinquish 19,847.26 acres. Only 7,349.96 acres in the proposed relinquishment are from expansion leases.

[6] Presumably ExxonMobil proposed changing the acreage to be relinquished to allow it to retain the most valuable acreage.

portions of the Expansion Acreage without putting the unit into production.

Lessees contend that the Expansion Agreement was based on the expectation of a gas cycling project. At the time of the Expansion Agreement, the Lessees' POD focused primarily on a PTU gas cycling project, but the Expansion Agreement did not require a cycling project *per se*. The essence of the expansion agreement was that the unit expansion was approved on the condition of development and production. It did not require a particular type of production. Lessees could have complied with the Expansion Agreement by producing oil, gas, liquids, or a combination thereof.

DNR originally refused to grant the 2001 expansion because the unit had not been developed. It agreed to the expansion based on promises the unit would be developed and produced. Former DNR Director Mark Myers later offered to extend the Expansion Agreement deadlines if the Lessees drilled an exploratory well to better delineate the various hydrocarbon accumulations.

In its filings on appeal the AOGCC has also indicated an additional exploratory well or wells are needed. Lessees have consistently refused these requests for additional exploratory wells. On the one hand, Lessees insist that existing data is too uncertain to allow certain types of production, but on the other hand, Lessees refuse to drill a well or to make a firm commitment to drill a well to obtain more data.

The Expansion Agreement also provided that if Lessees determined that production was uneconomic, they could have voluntarily contracted the expansion leases out of the unit with a lesser financial obligation to the state.

D. Facts regarding certified wells.

DNR Oil and Gas Directors have certified seven exploration wells drilled into the PTU as capable of producing in paying quantities. With one exception, all of the certifications were issued in the 1970s and 1980s. All of the wells which were certified have been plugged and abandoned.

The AOGCC web site shows the dates upon which the previously certified wells were treated as plugged and abandoned: (1) Alaska State C1 well July 14, 1981; (2) PTU 2 well on August 12, 1978; (3) Alaska State A1 well on September 6, 1975; (4) Staines River State 1 well on November 5, 1986; (5) PTU 1 well on December 8, 1977; (6) Alaska State F1 well on May 30, 1982; and (7) Sourdough 2 on April 27, 1994.

On April 26, 1994, Director of Oil and Gas, Mr. Jim Eason, issued a letter certifying an exploration well, Sourdough Well # 2, as capable of producing in paying quantities. The letter states in part:

"It should be noted, however, that the well is not capable of producing in paying quantities as that phrase is defined in section 9 of the Point Thomson Unit Agreement.

Generally, certification of a well as producing in paying quantities requires the Lessee to submit annual plans of development. However, if the lease is included in an approved unit, the lessee is not required to submit a separate lease plan of development for unit activities in accordance with paragraph 10(d) of the lease. Accordingly, as long as the lease remains committed to a unit, no lease plan of development will be required."[7]

[7] DL-1 leases do not have an express provision requiring a POD upon a lease continuing beyond its primary term because of the existence of a well capable of producing in paying quantities. This is an express provision in new-form leases.

The Director knew Sourdough was not a production well. This document shows that Lessees were informed of DNR's position.

There is no existing certified PTU well capable of producing in paying quantities. A PTU production well has never been drilled. No certified PTU well exists today.

Whatever the merits of the certifications when they were originally issued, the suggestions in the Director's Decision that certified wells exist today or that the prior certifications of now non-existent exploration wells indefinitely extend the term of the leases upon which they were drilled or that the PTU should be treated as a unit with certified wells is disapproved and reversed in this Commissioner's Decision. Those suggestions are not supported by the facts. There are no certified wells in the unit capable of producing in paying quantities. All the wells which were certified have been plugged and abandoned. Inconsistent findings and statements in the Director's Decision on certified wells are hereby disapproved.

III. Discussion.

This Commissioner's Decision adopts the reasoning of the Director's Decision including, but not limited to, the analysis required by the regulations including 11 AAC 83.303. That reasoning is supplemented as follows:

A. The proposed cure.

The revised 22nd POD submitted October 18, 2006 fails for the same reasons as the originally submitted 22nd POD was rejected in the Director's Decision. Several additional points need to be made.

The proposed cure does not commit to put the unit in production. Nor does it provide a time line to achieve production. Much of the information submitted on appeal by the Lessees is focused on the risk of insufficient profit from PTU development as reason for not producing the unit.

Regarding the exploration well proposed in the revised 22nd POD. There is no firm commitment to drill the well. The offer is to pay the state $40,000,000 if the well is not drilled by 2010.

DNR has tried without success to get the Lessees to drill exploration wells to resolve among other questions the uncertainties asserted by the Lessees as a reason for not pursuing a gas cycling project. The AOGCC was also critical of ExxonMobil's approach because it assumed the only appropriate way to develop the PTU was as a pure gas blow down project before it had sufficient information to justify the conclusion that a gas cycling project was not viable. Drilling of one or more wells is required to obtain the data necessary to make that determination.

In his hearing statement, ExxonMobil's Richard Owen suggested that a well might be drilled sooner, but Lessees' written cure and proposal is that if Lessees do not drill an exploratory well by 2010, that they will pay the state $40,000,000. This is a significant sum, but a well is needed and long overdue. The $40,000,000 proposed payment is dwarfed by the benefits to the state of timely delineation and development of PTU resources. The proposed payment is no substitute for adequate delineation of the PTU hydrocarbon accumulations, now long overdue and repeatedly requested by DNR.

In addition to the terms for the proposed exploration well, the proposed term of the revised POD bears discussion. The five year term proposed in the revised 22nd POD does not provide for adequate protection of the public interest. The PTU has

been on annual PODs for most of its history. DNR has been unable to effect PTU production. It is not in the state's interest to agree to a five year POD.

B. The Reasonably Prudent Operator standard.

I find against Lessees' contention that the Reasonably Prudent Operator standard is determinative of the issues at hand. Their position is inconsistent with the applicable laws and agreements.

One of the state's most significant interests in oil and gas leasing is production. This interest is realized by compliance with the terms of the oil and gas leases that extend the lease term so long as there is production and by unitization which also extends the term of the lease so long as the unit is operating under a POD that meets the requirements of the applicable agreements, regulations and statutes.

The Lessees' appeal is based on the premise that they do not have to produce because they contend a Reasonably Prudent Operator would not produce. This position comes from Section 10 of the unit agreement regarding PODs which states that the Lessees' covenant to develop the unit as a Reasonably Prudent Operator. But section 10 says much more.

It requires the Lessees to submit PODs to DNR for approval. Section 10 includes specific requirements about the type and scope of work an acceptable POD must contain. The Director's Decision set out requirements for a PTU default cure which are consistent with the statutes, regulations, unit agreement and leases. The Lessees' proposed cure was not responsive. It did not include a commitment to produce any of the known PTU hydrocarbon reserves – oil, gas liquids or gas. The proposed POD did not make a firm commitment to further delineate the PTU hydrocarbon reservoirs notwithstanding DNR's repeated requests.

The Lessees' assertion that DNR has agreed that the only way to develop the PTU is a pure gas blow down project is contradicted by the decision on appeal and is otherwise not consistent with the DNR record. Lessees go on to suggest that the PTU will not be developed until a gas pipeline is constructed, and the state modifies its royalty and tax structure.

In reaching this decision, I have considered the entire DNR record including all documents submitted on this appeal. But I put no weight on the message in much of the Port Authority's materials which suggest that the state should terminate the unit and take the PTU leases back because it could potentially make a better deal when and if the leases are reissued. Although this could well be the consequence of the termination; it is possible that, if the unit is terminated and the leases return to the state, the state will have new leases and new lease terms which would enhance the state's potential return. But that is not the reasoning upon which this decision is based. This decision is not directly about leases,[8] and it is not about a state effort to get out of its contractual obligations.

Lessees' economics, adequate returns, and risk might be appropriate considerations in some situations. But they play no role here where the unit has been in existence since 1977, massive hydrocarbon deposits were discovered in the early 1980s, the unit has never been put into production, and the Lessees say it may never be put into production until a gas pipeline is constructed and the state compromises its taxes and royalties.[9] Against this backdrop, the state oil and gas

[8] To the extent the leases are considered, however, an appropriate consideration is that new lessees may have a different view which would result in a firm commitment to develop. However, even if the state were to get the PTU leases back, there is no bar to the existing Lessees reacquiring the PTU leases if and when the leases were reoffered for bid.

leasing system is not intended to require DNR to engage in a murky subjective contest about a Lessees' internal economics, development risk, or view of the difficulty of developing the unit. One of the state's primary interests is production. If production is not in the plan, the state's remedy is to terminate the unit and find another means to develop the unit.

This Commissioner's Decision is about enforcing the state's rights under the leases, unit agreement, regulations, and statutes regarding the continued existence of a non-producing unit. The critical facts underlying this decision are that the unit is made up of leases beyond their primary term and in many cases decades beyond their primary term. The unit has been in existence for nearly 30 years. Massive PTU reserves were found in the early 1980s. The unit has never been put into production. A PTU production well has never been drilled. The originally submitted 22nd POD and the revised 22nd POD submitted as a cure expressly admit that Lessees cannot find a viable way to produce the unit. Lessees also state that the unit may never be produced until a gas pipeline is constructed and the state makes royalty and tax concessions. The unitization scheme is intended to cause state leases to be developed efficiently. It is not intended to allow lessees to simply hold oil and gas leases indefinitely until such time as the probable profit from a project meets their subjective and internal expectations or the state agrees to modify its royalty or other contract rights or the state's right to collect taxes.

I specifically find that the Reasonably Prudent Operator standard does not apply to this Commissioner's Decision involving a long standing unit with leases far beyond their primary term and Lessees which unambiguously refuse to adequately explore, delineate, or produce massive known hydrocarbon reserves. The Reasonably Prudent Operator

[9] Similarly, this decision is not based on the state's Stranded Gas Contract negotiation experience.

language of section 10 of the unit agreement does not supersede the other provisions of that section, or the applicable statutes, regulations or leases. Section 10 contains significant detail on what an acceptable POD must contain and the Director's Decision asked the Lessees to comply. Instead, they ask for the protection of the RPO standard, but on these facts, it matters not what a Reasonably Prudent Operator would do, the state is entitled to terminate the PTU.

The originally submitted 22nd POD was rejected because it failed to comply with the requirements for a POD set out in section 10 of the unit agreement, the regulations and the statute. The Director's Decision asked the Lessees to comply with these requirements, but they failed to do so.

C. *Force Majeure.*

Lessees assert a novel defense. They contend that the lack of a gas pipeline constitutes a *force majeure* event relieving them of the obligation to produce. Not only does this ignore potential production of hundreds of millions of barrels of gas liquids and oil, neither one of which require a gas pipeline, it is not the type of event commonly understood to qualify as *force majeure*. Lack of existing transportation infrastructure is not something which is beyond the Lessees control. I find the *force majeure* argument has no merit.

D. Certified wells.

There is no certified well in the PTU which is capable of producing in paying quantities. Statements to the contrary in the Director's Decision are disapproved.

IV. Decision.

My decision is as follows:

A. The Director's Decision is affirmed in all respects to the extent it is consistent with this Commissioner's Decision, but it is disapproved to the extent it can be read to mean the PTU contains certified wells.

B. There are no certified wells in the PTU within the meaning of the law, the leases or the unit agreement. In addition, I hereby revoke the certifications of PTU wells as being capable of producing in paying quantities effective the date they were plugged and abandoned and no later than November 27, 2006.

C. The revised 22nd POD submitted on October 18, 2006 does not meet the requirements of the Director's Decision. I also find the POD is not an acceptable cure because it does not meet the requirements of the applicable agreements, regulations or statute. The POD does not commit to put the unit into production.

D. The request to modify the Expansion Agreement is denied. The Lessees have been on notice for some time that a well needed to be drilled by December 2006 or the remaining 29,000 acres of expansion leases would automatically contract out of the unit and revert to the state. The Lessees would also owe the state $20,000,000 for failure to drill the well. They agreed to this. The state relied on their agreement in granting the unit expansion. Lessees are now in the position where a well cannot be drilled by December 2006. Their request to modify the Expansion Agreement to eliminate the requirement that this well be drilled and to also eliminate the seven (7) development wells due by 2008 is denied. This Commissioner's Decision denies the request to modify the Expansion Agreement. By failing to meet the commitments of the agreement, including the failure to prepare to drill the well due in 2006, Lessees have breached the Expansion Agreement and

the state is entitled to have the Expansion Leases back and to receive payment.

E. The PTU is terminated.

F. The documents submitted on appeal by BP with a request for confidentiality under AS 38.05.035(a)(9) were considered but they are not part of the DNR public file on this matter.

G. This Commissioner's Decision is effective November 27, 2006.

This is the final administrative order and decision of the department for purposes of an appeal to Superior Court. An appellant affected by this final order and decision may appeal to Superior Court within 30 days in accordance with the rules of the court, and to the extent permitted by applicable law.

Nov 27, 2006

Michael Menge
Commissioner — Date
Alaska Department of Natural Resources

cc:
William Van Dyke, DNR Director of Oil and Gas
John Norman, Commissioner and Chair AOGCC
Richard Todd, Senior Assistant Attorney General

COMMISSIONER'S DECISION ON RECONSIDERATION OF THE NOVEMBER 27, 2006 POINT THOMSON UNIT TERMINATION DECISION

December 27, 2006

Findings and Decision of the Commissioner
Department of Natural Resources
State of Alaska

I. SUMMARY OF DECISION.

This is the final Decision of the Alaska Department of Natural Resources on the request of the Point Thomson Unit (PTU) lessees (Lessees) for reconsideration of the November 27, 2006 Commissioner's decision terminating the PTU (Commissioner's Decision). DNR appeal regulations do not provide for reconsideration of a Commissioner's final decision on an appeal from a decision of the DNR Director of Oil and Gas. In this case, however, I find it appropriate to issue a decision on the points raised in the request for reconsideration.

Lessees have requested the following substantive relief: (1) reversal of the finding that PTU contains no wells certified as capable of producing in paying quantities on the grounds that (a) the finding is inconsistent with a long established DNR policy to certify exploration wells and wells that have been plugged and abandoned; (b) it creates uncertainty about the status of other oil and gas units and leases; and (c) lessees of state oil and gas leases have relied on the DNR well certifications; and (2) reversal of the decision to terminate the unit on the ground that the unit contains certified wells, and therefore, the unit can only be terminated through judicial proceedings.

Lessees have also requested that DNR reopen the administrative proceedings. They claim that they did not receive fair notice that the certified well status of PTU wells was at issue.

Lessees also contend that DNR refused to allow them to review DNR files.

I find no merit in the points raised in the Request for Reconsideration.

Lessees had notice of the certified well issue. ExxonMobil argued the issue in its appeal papers as did the Port authority. The request to reopen the DNR administrative proceedings is denied.

Lessees do not on reconsideration challenge the grounds for unit termination stated in the Commissioner's Decision: unwillingness to commit to put the unit into production and failure to submit an appropriate Plan of Development (POD). Instead, the focus of reconsideration is the collateral finding that the PTU does not contain wells certified as capable of producing in paying quantities.

Lessees assert that if the PTU has certified wells, the Commissioner's Decision was inappropriate because the unit can only be terminated through judicial proceedings. Lessees' argument is based on a regulation. But Lessees ignore other regulations which provide for the DNR Commissioner to make unit default and related findings regardless of whether the unit contains certified wells.

Lessees also contend that DNR is estopped from revoking the certification of PTU wells as capable of producing in paying quantities. Lessees say they have relied on a long standing DNR policy of certifying wells after they have been plugged and abandoned and of certifying wells which were not production facilities to hold state oil and gas leases beyond their primary term. Lessees contend that the certified well finding is bad policy because it will generate uncertainty in the oil and gas industry. The finding suggests that many state oil and gas leases outside of the PTU will no longer be held by certified wells that were plugged and abandoned.

The Commissioner's Decision regarded the Point Thomson Unit. It did not directly regard leases, and it did not address any other unit. Certification of a well that does not exist as capable of producing in paying quantities is poor policy. DNR does not need to certify a non-existent well in order to extend

the term of a lease. There are other much more appropriate ways to extend the term of a lease. The other leases and units that Lessees are concerned about will be administered based on the facts applicable to them, and not the facts applicable to the PTU. Therefore, Lessees' argument that DNR is estopped from issuing the Commissioner's Decision is not accepted.

Lessees' contention that DNR violated the Covenant of Good Faith and Fair Dealing by terminating the unit when DNR had participated in negotiations for a gas pipeline contract is without merit. The contract was never approved. The Director's October 27, 2005 decision put Lessees on notice that they were not entitled to keep the PTU out of production until a gas line was built.

DNR did not deny Lessees access to its files. DNR asked Lessees to submit their document request in writing.

I affirm the Commissioner's Decision in all respects.

II. DNR File Records Request.

Lessees assert that DNR has denied them access to DNR files. On the afternoon of Thursday, September 14, 2006 an ExxonMobil representative contacted DNR and requested to review 105 files on Friday morning. On Friday, September 15, 2006 DNR sent ExxonMobil a letter by facsimile and mail asking ExxonMobil to put its document request in writing. Lessees have not responded to DNR's letter. Lessees' assertion is not supported by the facts.

III. The Requests for Reconsideration Do Not Challenge the Basis of the November 27, 2006 Unit Termination Decision.

The certified well finding is not the basis of the November 27, 2006 unit termination decision. The unit termination decision

is based primarily on two independent grounds neither one of which regards certified wells.

One ground for unit termination is that DNR is entitled to terminate a unit which has been known to contain massive hydrocarbon reserves for more than 30 years, but which has never been put into production, when the lessees of the state oil and gas leases making up the unit unequivocally state that they still cannot find a way to put the unit into production. DNR is entitled to terminate the unit because the purpose of forming a unit is to effect production. Units are not formed for the purpose of simply holding properties until such time as the Lessees think production will be profitable enough to commence. On these facts, when the Lessees say they cannot put the unit into production, DNR can terminate the unit as a matter of law.

The second primary ground for unit termination is the failure to submit an acceptable Plan of Development. The Director's October 27, 2005 Decision put the Lessees on notice that the 22nd POD was unacceptable, and that it failed to meet the requirements of the unit agreement and the regulations. Lessees had nearly a year to cure by submitting an acceptable Plan of Development that committed to put the unit into production. Instead they submitted a revised 22nd POD which suffered from the same defects as the original 22nd POD. As discussed in the Director's Decision, these PODs did not meet the requirements for an acceptable POD set out in the unit agreement or the regulations.

There are other facts relevant to the unit termination decision such as the Lessees' statements that the PTU will never be produced until there is a gas pipeline notwithstanding the fact that the PTU is among the largest oil reserves on the North Slope, and it also contains hundreds of millions of barrels of gas condensate. Neither the oil nor the gas condensate require a gas pipeline to produce. Lessees' statements that more tax and royalty concessions will be needed before

production can occur and refusal to drill exploratory wells to further delineate the unit, also provide grounds for unit termination, but the primary basis of the decision is the unequivocal statement that the Lessees cannot find a way to put the unit into production and their refusal to submit an acceptable POD.

Therefore, the issue of whether the PTU contains certified wells is separate from whether the unit should be terminated. The Requests for Reconsideration do not challenge the basis for the unit termination decision.

IV. Lessees Incorrectly Conclude that if The PTU Contains Certified Wells, DNR Could Not Issue a Unit Termination Decision.

Lessees contend that if the PTU contains certified wells then DNR does not have the power to issue a decision terminating the unit. This argument is based on a unit regulation 11 AAC 83.374(d) which provides:

"If a default occurs with respect to a unit in which there is a well capable of producing oil or gas in paying quantities and the default is not cured by the date indicated in the demand, the commissioner, will in his discretion, seek to terminate the unit agreement by judicial proceedings."

According to ExxonMobil, this regulation means that if a unit contains a certified well, DNR is without the power to issue a unit termination decision. This position is not supported by the regulations.

Unit regulation 11 AAC 83.374 sets out DNR remedies in the event of unit default. Subsections (a) and (b) apply to all units, subsection (c) applies to units without certified wells and subsection (d) applies to units with certified wells. Subsection (a) provides that failure to comply with the terms of the unit agreement is default, and subsection (b) provides that

DNR will give notice of the default and at least 90 days to cure. Subsection (c) provides that where the unit does not contain a well capable of producing in paying quantities, the DNR Commissioner may terminate the unit effective upon mailing the notice of termination. Subsection (d) provides that where the unit does contain a well capable of producing in paying quantities, the Commissioner will seek to terminate the unit agreement by judicial proceedings.

Regardless of whether the unit contains certified wells, the regulations anticipate that DNR will issue appropriate notices and that DNR will give an appropriate opportunity to cure. In his November 27, 2006 Decision, Commissioner Menge affirmed the notice of default and conditions for cure set out in the October 27, 2006 decision, the unacceptability of the cure offered by Lessees on October 18, 2006, and the consequences thereof: unit termination.

Regardless of whether the unit contains certified wells, it was incumbent on the DNR Commissioner to decide these issues. Even if the PTU contains certified wells, the November 27, 2006 Decision is an appropriate DNR action which facilitates court review.

V. Lessees' Request that DNR Continue the Fiction of Certifying Non-Existent Wells as Capable of Producing in Paying Quantities.

Lessees assert that the certified well finding will have a chilling effect on oil and gas development in Alaska because many leases and units are held by certified wells, and the Commissioner's Decision puts them in jeopardy. Lessees contend that the November 27, 2006 Decision contradicts longstanding DNR policy to certify wells that have been plugged and abandoned.

With regard to long standing DNR policy, it is true that DNR Directors of Oil and Gas have certified wells after they have

been plugged and abandoned and that they have also certified wells that were not production wells. But this is the first time the question has been addressed by a DNR Commissioner.

Commissioner Menge disapproved the Director's Decision to the extent that it could be read to mean the PTU contains certified wells. He also found that the PTU contained no certified wells because all the wells that had been certified were exploration wells, and they had all been plugged and abandoned. That finding conforms the status of the wells to the facts.

Regarding the assertion that the November 27, 2006 Decision jeopardizes other units and leases, the Commissioner's Decision is not that broad. It was about the continued existence of the PTU. It did not address any other unit, and it did not directly address any leases, PTU or otherwise.

Lessees contend that they have been relying on the well certification as a method of, in effect, extending lease terms all over Alaska. Now they say that all these leases will terminate because of the Commissioner's Decision. But certification of a well does not extend the lease term, and there are other methods DNR could use to extend the term of a lease or unit. It is not necessary to certify a non-existent well to hold a lease or unit. Other units and all leases will be addressed in their own proceedings, on their own facts, and in the normal course of business. The November 27, 2006 Commissioner's Decision does not directly affect those units or leases, and it does not mean that they will necessarily terminate even if they have an abandoned well that was certified.

VI. Lessees Do Not Directly Challenge the Basis for the Certified Well Finding.

PTU Lessees do not directly challenge any of the certified well findings of the Commissioner's Decision, any one of which support the finding that there are no PTU certified wells. For

instance, PTU Lessees do not contest the following findings: (1) the wells which were certified were not in fact production wells; and (2) the wells which were certified have all been plugged and abandoned.

The Lessees argue that the Commissioner's Decision reverses longstanding DNR Director's Decisions certifying plugged and abandoned wells. This fact is not contested by DNR. But the DNR Commissioner has the ultimate authority to set DNR policy, this is the first time the issue has reached the level of the DNR Commissioner, and the Commissioner has the responsibility to correct poor policy. Certification of a non-existent well is poor policy not just because the well cannot be ordered into production but because it sends the wrong message to state oil and gas lessees. According to the papers filed by Lessees on reconsideration, they interpret the certification of a well as an indefinite extension of the lease upon which it was drilled. This is not an appropriate policy. The agreements, regulations and statutes provide for lease extension where a lessee makes appropriate commitment to explore, produce or otherwise develop oil and gas leases.

VII. Exxon Was on Notice of the Certified Well Issue and Addressed it in its filings of November 3, 2006.

Lessees contend that the issue of certified wells was raised for the first time in the November 27, 2006 Commissioner's Decision. They assert that they did not have fair notice of the issue, and they request that the administrative proceedings be reopened so that they can address this issue. The record indicates that Lessees were on notice of the certified well issue.

Certified Wells were addressed in the ExxonMobil appeal papers. ExxonMobil contended that DNR was without the power to decide to terminate the unit because the unit contained certified wells. ExxonMobil contended that a unit termination decision could only be made by a court because the unit contained certified wells. ExxonMobil also relied on a

statement in the Director's October 27, 2005 decision that the PTU contained certified wells.

The Port Authority also addressed the certified well issue in its appeal papers. The Port contended that the PTU contained no certified wells. Lessees received a copy of the Port Authority Appeal papers.

PTU Lessees made no request for the provision of appeal procedures that was denied. PTU Lessees chose not to address the certified well issue at the hearing held November 20, 2006.

It would be inappropriate to reopen the proceedings on an issue of which PTU Lessees had notice but chose not to address. Also, PTU Lessees have addressed the certified well issue in their 2,000 plus pages of filings on reconsideration.

These filings show that the Lessees' focus is that the certified well finding reverses longstanding DNR Oil and Gas Director's Decisions that certify non-existent or non-production wells. This is not disputed.

Lessees go on to assert the reversal is bad policy and that it will work against development of Alaska oil and gas resources. Lessees say they relied on the Director's certified well decisions to their detriment because the decision subjects them to loss of oil and gas leases and other units which they considered to be held by certified wells. The focus of this proceeding and the Commissioner's Decision is the PTU, not any other unit or any lease. There are appropriate ways to hold a lease or unit. Certification of a non-existent well is not one of them. Lessees can raise any argument they deem appropriate in connection with the other units and any leases they are concerned about in the normal course of business. Those leases and units are not a basis to reopen the record here.

Commissioner Menge decided that a well that has been plugged and abandoned does not qualify to be treated as a well certified as capable of producing in paying quantities. I agree. The longstanding policy upon which the Lessees say they relied was the poor policy. The new policy is in conformance with existing statutes, regulations and agreements. Certified wells will still play a role in appropriate circumstances. Finally, Lessees will have the opportunity to address the issue should they choose to appeal to the Superior Court.

VIII. Estoppel.

Lessees contend that DNR is estopped from revoking the certifications of seven PTU wells because the Lessees have relied on the DNR policy of certifying non-existent wells all over Alaska to Lessees' detriment. Again, the issue before the Commissioner in the November 27, 2006 Decision was the continued existence of the PTU, and not another unit or any leases.[1] Therefore, it is inappropriate to treat the Commissioner's Decision as having the broad impact Lessees ascribe to it.

As previously stated, DNR has other mechanisms for extending the terms of units and leases. Certification of a non-existent well is not the proper way to extend a lease.

Regarding detrimental reliance, all who hold leases with wells certified by DNR have had the benefit of that certification. In some cases this had allowed leases to be held for decades with no production and no meaningful plan of development.

The import of the November 27, 2006 Decision is not that Lessees are going to lose units and leases all over the state, it is that leases and units should not be considered to be held by non-existent certified wells. Leases will need to be held by

[1] The exception to this is the decision on the Expansion Agreement which regards the PTU expansion leases. That matter is not on reconsideration.

an appropriate commitment to explore, develop, produce or some other basis consistent with the state's interest, and they will not be held based on a fictional certification of a non-existent well.

Lessees' theory appears to be that once certified, a well holds a lease forever. This is not consistent with the statutes, regulations, applicable agreements, or meaning of certified well. Estoppel does not apply in this case to require a change to the November 27, 2006 Commissioner's Decision.

IX. Covenant of Good Faith and Fair Dealing.

Lessees contend that DNR breached the Covenant of Good Faith and Fair Dealing because Lessees negotiated a contract with the state for construction of a gas pipeline, and the 22nd PTU POD merely proposed developing the PTU in accordance with the contract. This argument fails because the gas line contract was never approved. It also fails because Lessees were on notice during the gas contract negotiations that DNR considered the PTU to be in default for failure to commit to production and failure to submit an acceptable plan of development. Lessees were given a year to cure by submitting an acceptable plan. The Director's decision unequivocally rejected Lessees' position that the PTU could not be produced until there was a gas line. Lessees' contentions regarding the Covenant of Good Faith and Fair Dealing are not supported by the facts – there was no contract and Lessees were noticed that they could not condition development on a gas line.

X. Decision.

The Commissioner's Decision is affirmed in all respects.

The Lessees' request to reopen the DNR administrative proceedings is denied.

This is the final administrative order and decision of the department for purposes of an appeal to Superior Court. An appellant affected by this final order and decision may appeal to Superior Court within 30 days in accordance with the rules of the court, and to the extent permitted by applicable law.

12-27-2006

Marty Rutherford
Acting Commissioner
Alaska Department of Natural Resources

Date

cc: Michael Menge,
Kevin Banks, DNR Director of Oil and Gas
John Norman, Commissioner and Chair AOGCC
Kurtis Gibson, Deputy DNR Director of Oil and Gas
Richard Todd, Senior Assistant Attorney General

IN THE SUPERIOR COURT FOR THE STATE OF ALASKA

THIRD JUDICIAL DISTRICT AT ANCHORAGE

ExxonMobil Corporation, Operator of the Point Thomson Unit; BP Exploration (Alaska) Inc.; Chevron U.S.A., Inc.; ConocoPhillips Alaska, Inc., Appellants, vs. State of Alaska, Department of Natural Resources, Appellee.	Case No. 3AN-06-13751 CI (Consolidated Appeals) Case No. 3AN-06-13760 CI Case No. 3AN-06-13773 CI Case No. 3AN-06-13799 CI Case No. 3AN-07-04634 CI Case No. 3AN-07-04620 CI Case No. 3AN-07-04621 CI

BRIEF OF APPELLANT CONOCOPHILLIPS ALASKA, INC.

APPEAL FROM THE DEPARTMENT OF NATURAL RESOURCES

FINAL DECISION OF THE COMMISSIONER
DATED NOVEMBER 27, 2006
&
COMMISSIONER'S DECISION ON RECONSIDERATION
DATED DECEMBER 27, 2006

Spencer C. Sneed, ABA# 7811140
Allen F. Clendaniel, ABA#0411084
DORSEY & WHITNEY LLP
1031 WEST 4TH AVENUE, SUITE 600
ANCHORAGE, ALASKA 99501
(907) 276-4557

ATTORNEY FOR CONOCOPHILLIPS ALASKA, INC.

I certify that on June 22, 2007 a copy of this brief was mailed to:
S. Ellis, J. Ballew, C. Haynes, L. Ashley, J. Harris, J. Katchen, D. Serdahely, K. Callahan, D. Crosby, S. Orlansky, and W. Rozell
and hand delivered to: *R. Todd, M. Ashburn*
By: _____

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Exc. 000532

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owned by the state.[131] But the parties in this case negotiated a unit agreement that granted the Commissioner only limited powers to modify the rate of prospecting, development and production. Section 21(a) of the PTU Agreement provides that DNR is:

> [v]ested with authority to alter or modify . . . the quantity and rate of production under this agreement . . . such authority being hereby limited to alternation or modification in the public interest . . . . [and] is also hereby vested with authority to alter or modify . . . the rate of prospecting and development and the quantity and rate of production under this agreement when such alteration or modification is in the interest of attaining the conservation objectives . . . ."[132]

Production has not yet commenced, and so the rate of production cannot be altered. And nowhere does the Commissioner attempt to justify his demands for exploration and development on the basis that they are "in the interest of attaining conservation objectives." Section 21(a) is no source for the exploration and production demands made by DNR in this case.

In 1985, Section 21(b) was amended to restrict the powers granted in Section 21 by providing that those powers:

> [s]hall not be exercised in a manner that would (i) require any increase in the rate of prospecting, development or production in excess of that required under good and diligent oil and gas engineering and production practices; or . . . (iii) prevent this

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[131] Former AS 38.05.180(n) ("A plan . . . which includes land owned by the state, may contain a provision vesting the commissioner . . . with authority to modify from time to time the rate of prospecting and development and the quantity and rate of production under the plan."). This section has been renumbered and is now AS 38.05.180(q). A subsequently repealed regulation granted the Commissioner the same authority. Former 11 AAC 83.315, Register 51 (see Attachment 1), repealed 1981, Register 78 (see Attachment 3).

[132] R. 001268.

agreement from serving its purpose of adequately protecting all parties in interest . . . ."[133]

These are prudent operator limitations on the Commissioner's Section 21 powers. Even if Section 20(a) had granted the Commissioner the contractual right to alter the rate of exploration and development, Section 20(b) would circumscribe that right by these prudent operator limitations.[134]

When DNR negotiated the PTU Agreement in 1977, it had statutory authority to negotiate for control over the contractually required rates of exploration and development in the public interest, but the parties agreed to the contrary. Section 21 precludes the Commissioner from rejecting the prudent operator standard. His failure to apply the prudent operator standard was dispositive error.

CONCLUSION

For the reasons stated, the Commissioner's decision should be vacated and the matter remanded to DNR with instructions that if it wishes to seek termination of the Point Thomson Unit, it may do so only by initiating judicial proceedings.

DORSEY & WHITNEY LLP
Attorneys for ConocoPhillips Alaska, Inc.

By: _____
Spencer C. Sneed, ABA #7811140
Allen F. Clendaniel, ABA#0411084

Dated: June 22, 2007

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[133] R. 000794.

[134] Reconsideration of the limitations imposed by Section 21 drove the Director to amend his decision, albeit not to the extent required to conform to the PTU Agreement. See Revision Version of Amended Decision, at pp. 2-3, 11, 14-15, 25. R. 0012281-306.