ALASKA STATE LEGISLATURE

Senator Charlie Huggins, Chair
Senate Special Committee on Energy
State Capitol, Room 119
Juneau, AK 99801
Phone: 465-3878
Fax: 465-3265

Representative John Harris, Chair
House Rules Subcommittee on AGIA
State Capitol, Room 208
Juneau, AK 99801
Phone: 465-4859
Fax: 465-3799

Third Special Session
Twenty-Fifth Legislature

Howard Johnson Plaza, Anchorage

Tuesday June 17, 2008

9:00-5:00 p.m.

Joint Meeting AGENDA

Presentations: Review of AGIA Findings and Determination; Natural Gas Pipeline Project as proposed by TransCanada Alaska Company, LLC and Foothills Pipelines Ltd. (TC Alaska) to the State of Alaska.

Point Thompson Unit

- Background of the Point Thompson Unit: Litigation History & Status

  Nan Thompson, Units Manager, Div. of Oil & Gas, DNR

  Steve Moothart, Petroleum Geologist, Div. of Oil & Gas, DNR

  Anil Chopra, Reservoir Engineering Advisor, PetroTel

Julie Houle DU 0x6

- Alaska Oil & Gas Conservation Commission

  Cathy Foerster, Commissioner Engineering

- ExxonMobil Alaska

  Craig Haymes, Production Manager

- Chevron North America Exploration & Production

  John P. Zager, General Manager, MidContinent/Alaska Business

  Vince LeMieux manager - " " Unit "

Testimony: By Invitation, Teleconference

presented - 6-17-2008 Tuesday 4 PM Anch AK
AGIA License Hearings SENR/HRLS

Chevron

Global Upstream and Gas

Chevron - Alaska Area
Point Thomson Testimony to the Alaska Legislature

John Zager
General Manager, Alaska

Vince LeMieux
Manager, Alaska New Ventures

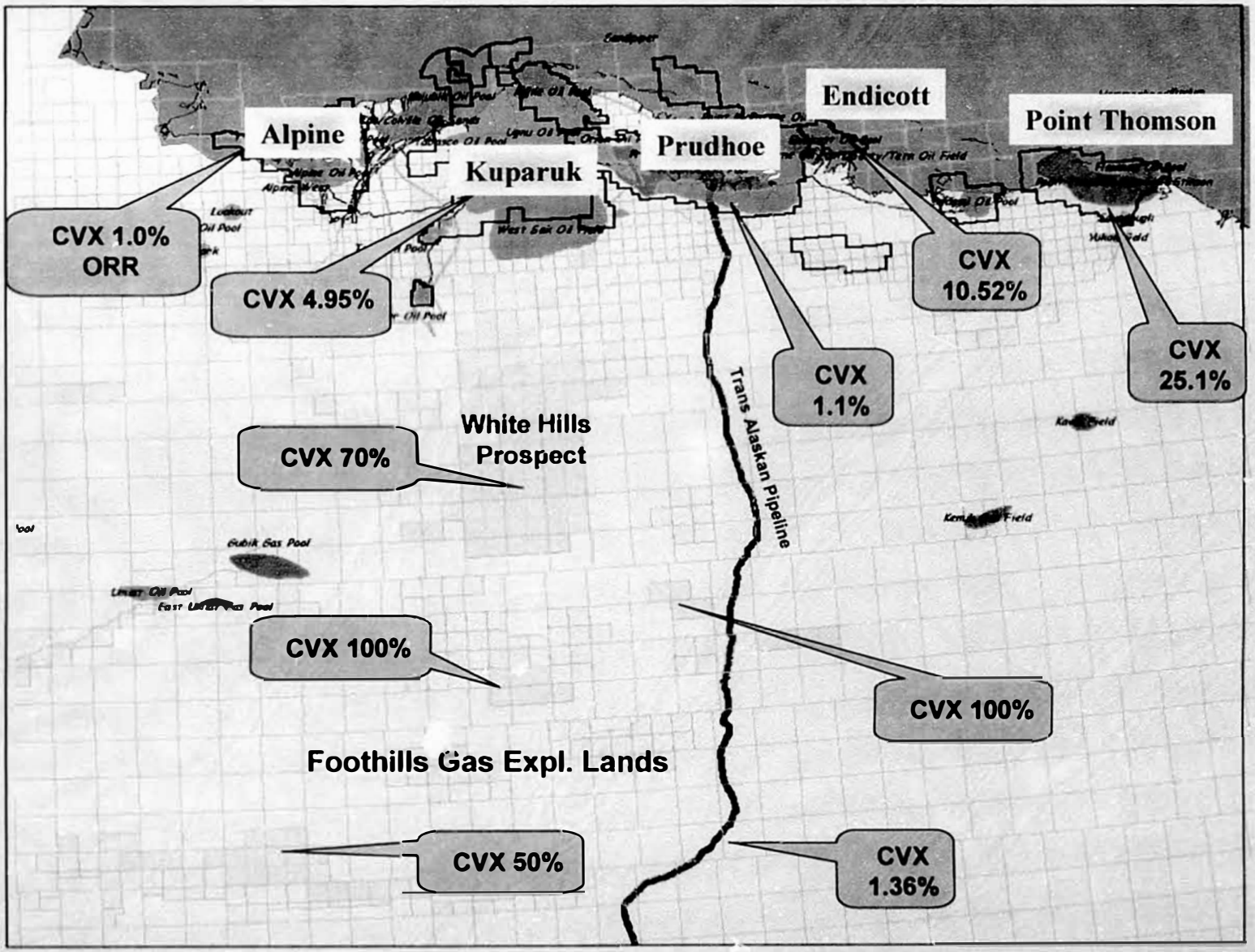
Anchorage, Alaska
June 17, 2008

Chevron has standing in the commercialization of North Slope gas

Working interests (WI) in established North Slope fields (PBU, KRU, DIU) and an overriding royalty interest in Alpine

- Active exploration, development and operation of oil and gas assets on the North Slope:
  - Completed the first season of our exploration program in our White Hills Prospect; and
  - Working on exploration of gas prospective leases in the Foothills area.
- Chevron is a 25% WI in the Point Thomson leases. Unique to Chevron, Point Thomson is its major source of North Slope gas.
- We have proposed an aggressive plan to begin production (POD), starting with gas cycling, condensate production and preparation of the field for major gas sales.
  - At a minimum the DNR decision will delay development through loss of 2008-09 drilling season.
  - It currently appears that the DNR is set on preventing development in favor of litigation by terminating the unit.

Chevron North Slope Assets



Point Thomson: Fact or Fiction?

#1: "Point Thomson is not needed for a gas pipeline."

#2: "The lessees are warehousing Point Thomson."

#3: "DNR rejected the plan of development on its merits."

#4: "The lessees are not doing any work on Point Thomson."

#5: "Point Thomson is 'wildly economic'."

Point Thomson: Fact or Fiction

#1: "Point Thomson is not needed for a gas pipeline."*

Fact:

- There are insufficient proven reserves available to back a commercially viable 4.5 BCFD gas pipeline without Point Thomson.
- Will anyone commit FT (ship-or-pay) for the 'yet to find' (YTF) resources? Without Point Thomson, this is a significantly bigger number.
- A Prudhoe Bay-only pipeline delivers less value to the State and Producers through higher tariff rates and the loss of oil resulting from blowing down Prudhoe Bay.

* This contradicts the previous administration position.

Point Thomson: Fact or Fiction

Chevron

#2: "The lessees are warehousing Point Thomson."

Fact:

- At no time has there ever been a way to get the gas to market; it is disingenuous to say it has been warehoused.
- Until the recent ramp up in prices, the condensate resource was clearly uneconomic; it remains challenged.
- The oil resource is problematic due to its depth, range in quality, and potential range of recoverable volumes. It is currently viewed as economically challenged. The proposed POD is designed to resolve these uncertainties.

Point Thomson: Fact or Fiction

Chevron

#3: "DNR rejected the plan of development on its merits."

Fact:

- The prior plan and amended plan were rejected because they did not "commit to put the unit into production." The current plan commits to put the unit into production as well as delineate all reservoirs.
- In its April 2008 decision, the DNR stated that the current plan is "a technically reasonable first step for developing these lands."
- But instead of considering the plan on its merits, the Commissioner of the DNR has:
  - Taken the unprecedented step of decertifying wells for the purpose of terminating a unit through administrative action.
  - Has ruled that the proposed PODs do not coincide with his preferred development all the while refusing to specifically lay out his preferred development.
  - Moved to expropriate the asset despite acknowledging the plan's merits by claiming a lack of "trust" of the lessees.*
  - Refused to meet with the lessees to outline his expectations.

* For over 27 years, the Commissioners of DNR and the lessees agreed the PODs set out the appropriate course of action for the development of Point Thomson as evidenced by the ongoing DNR approval of the PODs up to August of 2005.

Point Thomson: Fact or Fiction

#4: "The owners are not developing Point Thomson."

Fact:

- Over the last 30 years, the owners have spent over $800 million on the exploration and development of Point Thomson.
- Despite the State's move to expropriate the leases, the lessees have dedicated significant resources to continue technical work:
  - Reservoir simulation and flow stream modeling;
  - Planning for development;
  - Initiating engineering design for facilities;
  - Making financial commitments for drilling rig and long-lead items; and
  - Progressing permitting applications.

Point Thomson: Fact or Fiction

#5: "Point Thomson is wildly economic."

Fact:

- The complexity and unique nature of this reservoir makes it a very challenging and expensive field to develop.
- While the upstream has been described as delivering a greater than 50% rate of return (ROR), specific to PTU it appears that the Black & Veatch base case depicts the value at a modest 13% ROR
  - Aggressive assumptions on gas price and cost trends
  - Base case of an initial gas blow down (i.e., no gas cycling)

The Future of Point Thomson

The Commissioner's **new view** of PTU ("validated" by the PetroTel report): PTU needs to cycle gas for as many as 20 years before major gas sales.

Chevron Comments on PetroTel report:

- PetroTel's work is theoretical; they clearly indicate they did not consider physical, environmental, safety, and economic factors; as a result of this and other optimistic assumptions, it significantly overstates resources in place and the amount that is recoverable.
- PetroTel claims that the field has "as much as 500MMSTB" of incremental recoverable liquids if cycled for 20 years. Even assuming cycling is possible and economic, the incremental liquid volumes are likely to be less than 150MMSTB and would likely result in an acceleration of PBU blow down **resulting in less oil produced on the North Slope not more.**

The Future of Point Thomson
Chevron's View

- There is great uncertainty and therefore great risk in a gas cycling condensate project; it may or may not work.
  - Point Thomson has unique, challenging reservoir issues – it is like no other field, anywhere in the world.
  - Cutting edge technology is required for facilities and drilling.
  - Wide range of potential outcomes; most likely is failure
- Successful "oil rim" development is not certain.
  - Characteristics of the oil rim; oil quality, oil distribution across the field, oil reservoir quality, aquifer impact, etc. increase risk
  - Economics will be particularly challenged given potential recoveries and costs per well.
- One point of agreement by all: a phased approach is required (consistent, again, with the proposed POD).
  - In its April 2008 decision, the DNR stated that the plan is "a technically reasonable first step for developing these lands"

Developing Point Thomson Correctly

Chevron

The right progression for PTU will be:

- Proceed with the proposed POD to bring PTU into production:
  - With timely approval, delineation drilling to begin this winter further testing extent and quality of reservoir
  - Gas cycling project progressed to test viability
  - Prepare for Major Gas sales in parallel with development work
  - Results from production in 2015 – 2018 timeframe
- If cycling doesn't work, adjust to PTU gas blowdown and preserve gas at Prudhoe Bay, and therefore, maximize overall oil production on the North Slope

Consequence of delay in proposal to produce PTU

- Under sizing of the initial pipeline 4 – 4.5 bcf/d to 3.5 bcf/d, thereby crippling economics and slashing over all revenues
- Premature termination of cycling at PBU and loss of oil ($120 wellhead/boe for oil vs $24 wellhead/boe for gas)
- Lower value of entire gas project to State and Producers

Chevron desires to market North Slope gas

- Chevron is currently not a participant in any of the proposed gas lines
- Chevron will participate in future North Slope gas sales:
  - We will commit FT for our known gas reserves to a pipeline that we are confident provides reasonable upstream economics and terms
- Our drivers are predictable economics and risk sharing:
  - Key Variable — Controllable?
    - Point Thomson resolution — Yes
    - Future Gas prices — No
    - Construction cost — Partially
    - Cost risk allocation — Yes
    - Certainty of state taxes — Yes
  - Many of these elements are aligned with the State
    - Encouraging the development of infrastructure to realize the value of gas assets on the North Slope
    - Doing projects in the most economic way; especially true given the nature of the ACES tax approach

Summary

- PTU is critical to any major gas pipeline.
- PTU development should begin as soon as possible; the proposed POD is the right plan.
- The DNR should have approved the proposed PTU plan on its merits. Why didn't it . . . ?
- The current lessees can and will (if allowed) develop Point Thomson better and faster than anyone else.
- Chevron is being forced to litigate to protect its rights.
- Chevron wants to sell its North Slope oil and gas.

So . . . Where are we?

- Protracted litigation; No settlement discussions
- Point Thomson is out of the gas pipeline
- Everyone agrees on the substance of the proposed POD
- Chevron stands ready to perform the proposed plan
- Owners remain ready to drill in 2008-09

And . . . What can be done?

- An independent, objective review of the pipeline analysis should be undertaken
- In an open and honest government, the parties to the Point Thomson litigation would sit down and talk through their differences

hand out 6-17-08
SENR/HRLS mtng Anch AK
AGIA License Hearings

Chevron

John Zager
General Manager, Alaska
Mid-Continent/Alaska

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Fax 907 263 7897
Mobile 907 223-0128
Email jzager@chevron.com

To Distinguished Members of the Alaska State Legislature:

As you debate the pros and cons of the various gas line proposals in the days ahead, we respectfully encourage you to keep Point Thomson as part of the discussion. After all, Point Thomson is a critical component to any gas pipeline. Without Point Thomson gas, a gas line may be unnecessarily delayed, stalled or downsized – and fail to deliver Alaska's full potential to a state and nation eager for Alaska energy.

Without Point Thomson gas, Alaska will lose valuable oil revenues if gas from Prudhoe Bay is prematurely diverted into a pipeline instead of being used – as it is today – to recover millions of barrels of oil.

Chevron believes that the proposed plan of development for Point Thomson delivers everything the Department of Natural Resources needs to fulfill its constitutional duty to ensure the development of Alaska's resources "for the maximum benefit of its people." The DNR has acknowledged that the proposed development plan is a "technically reasonable first step for developing these lands."

More importantly, if allowed, this plan could begin immediately and secures vital information that will be critical to making the correct development decisions for Point Thomson; thus maximizing the value of North Slope oil and gas resources. It provides:

- Immediate development backed by firm produce-it-or-lose-it milestones
- A stage 1 commitment of $1.3 billion to:
  - Determine if gas cycling will even work
  - Delineate the thin oil rim and shallower oil reservoirs
  - Prepare for major gas sales
  - Set the stage for multi-billion dollar full-field development
- Drilling commencing this winter - jobs for hundreds of Alaskans
- Production to help keep the pipeline flowing
- Elimination of the delays and risks associated with a protracted legal battle

Chevron is committed to developing Point Thomson and believes that no one can make this happen better or faster than the current leaseholders. The need is great, the risks are high and the timing is critical. Point Thomson gas is a key element in any responsible gas pipeline formula.

Point Thomson is essential to turn Alaska's dream of a successful gas pipeline into a reality.

Sincerely,

John Zager
General Manager, Alaska
Chevron North America Exploration and Production

Handout 6-17-2008 Tues 4PM Anch AK
AGIA License Hearings

Chevron

John Zager
General Manager, Alaska
Mid-Continent/Alaska

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John Zager
General Manager, Alaska
Chevron North America Exploration and Production

bp passed out @ SENR/HRLS Mtng 6-17-08 Tuesday, Anch AK

Doug Suttles
President

BP Exploration (Alaska) Inc.
P.O. Box 196612
900 E. Benson Boulevard
Anchorage, Alaska 99519-6612

June 16, 2008

HAND DELIVERED

The Honorable John Coghill, Chair of House Rules Committee, Alaska Legislature
&
The Honorable Charles Huggins, Chair of the Senate Special Committee on Energy, Alaska Legislature

Re: Point Thomson Plan of Development, 2008

Direct 907 564 5422
Main 907 561 5111
Fax 907 564 5900
doug.suttles@bp.com

Mr. Chairman,

I would like to take this opportunity to confirm BP's position with regards to bringing Point Thomson into production.

BP is fully supportive of the proposed plan to delineate, develop and produce Point Thomson liquids (condensate and oil) and gas. BP has a significant stake in the leases holding a 32% working interest. BP demonstrated its commitment to the $1.3 billion Plan of Development by:

(i) providing a letter of commitment from our Chief Executive of Exploration and Production, Andy Inglis (attached),

(ii) agreeing to unit termination if the parties fail to meet specific milestones, and

(iii) changing the unit vote to a simple majority in order that no one party can block development decisions.

We believe that time is of the essence and that the delineation and development of Point Thomson as proposed, will provide vital information for finalizing the design of any gas pipeline project and the optimum development of Pt Thomson liquids.

We are very concerned that the study conducted by PetroTel Inc. for the Department of Natural Resources (DNR) only became public after the recent Point Thomson hearings before the DNR. The Pt Thomson owners have not been provided the opportunity to review the data on which the study is based or to respond to it on the record. The conclusions reached in the study have neither been audited nor critically examined by those who know the realities of the Point Thomson field best.

Point Thomson is very important to BP. We wish to move forward with delineation and full field development of both liquids and gas. The availability of Point Thomson gas is critical for the success of any major gas pipeline project.

BP stands ready to work with the State of Alaska to settle the current dispute over Pt Thomson. We are confident that we can find a solution that works for all parties.

Thank you for the opportunity to confirm BP's position regarding this important issue for BP, Alaska and the gas pipeline project.

Sincerely,

Sincerely,

Doug Suttles

cc: Alaska Legislature

Andrew Inglis FREng CEng FIMechE
Group Managing Director and
Chief Executive of Exploration and Production

BP p.l.c.
1 St James's Square
London
SW1Y 4PD
United Kingdom

12 March 2008

Our Ref: AGI/DS/CB

Mr Thomas E Irwin
Commissioner
Department of Natural Resources
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Anchorage
Alaska 99501-3650

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Main +44 (0)20 7496 4000
Fax +44 (0)20 7496 4628
[illegible]

Dear Commissioner

As Chief Executive of Exploration & Production, I write to assure you of BP's commitment to the Plan of Development recently proposed by the owners of the Pt. Thomson Unit. BP is fully committed to carrying out the Plan of Development and, on approval of the Plan of Development, will proceed to fully fund its share of the commitments contained therein.

Yours sincerely

A. G. Inglis

A G Inglis
Group Managing Director and
Chief Executive of Exploration and Production

bp

6-17-2008 Hand out
SENR/HRLS AGIA License Hearings

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Group Managing Director and
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BP p.l.c.
1 St James's Square
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SW1Y 4PD
United Kingdom

12 March 2008

Our Ref: AGI/DS/CB

Mr Thomas E Irwin
Commissioner
Department of Natural Resources
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Alaska 99501-3650

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Group Managing Director and
Chief Executive of Exploration and Production

Registered in England and Wales No. 102498
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London
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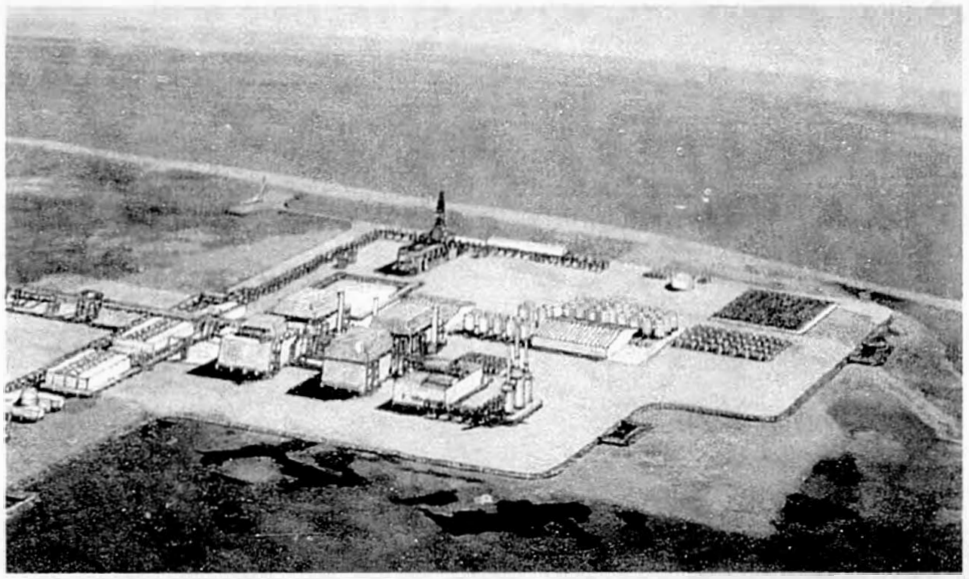
United Kingdom

presented: 6-17-2008 AGIA License Hearings
Tuesday
Anch. AK

ExxonMobil

Point Thomson Unit Development



ALASKA COMMITTEES ON AGIA / ENERGY

June 17, 2008

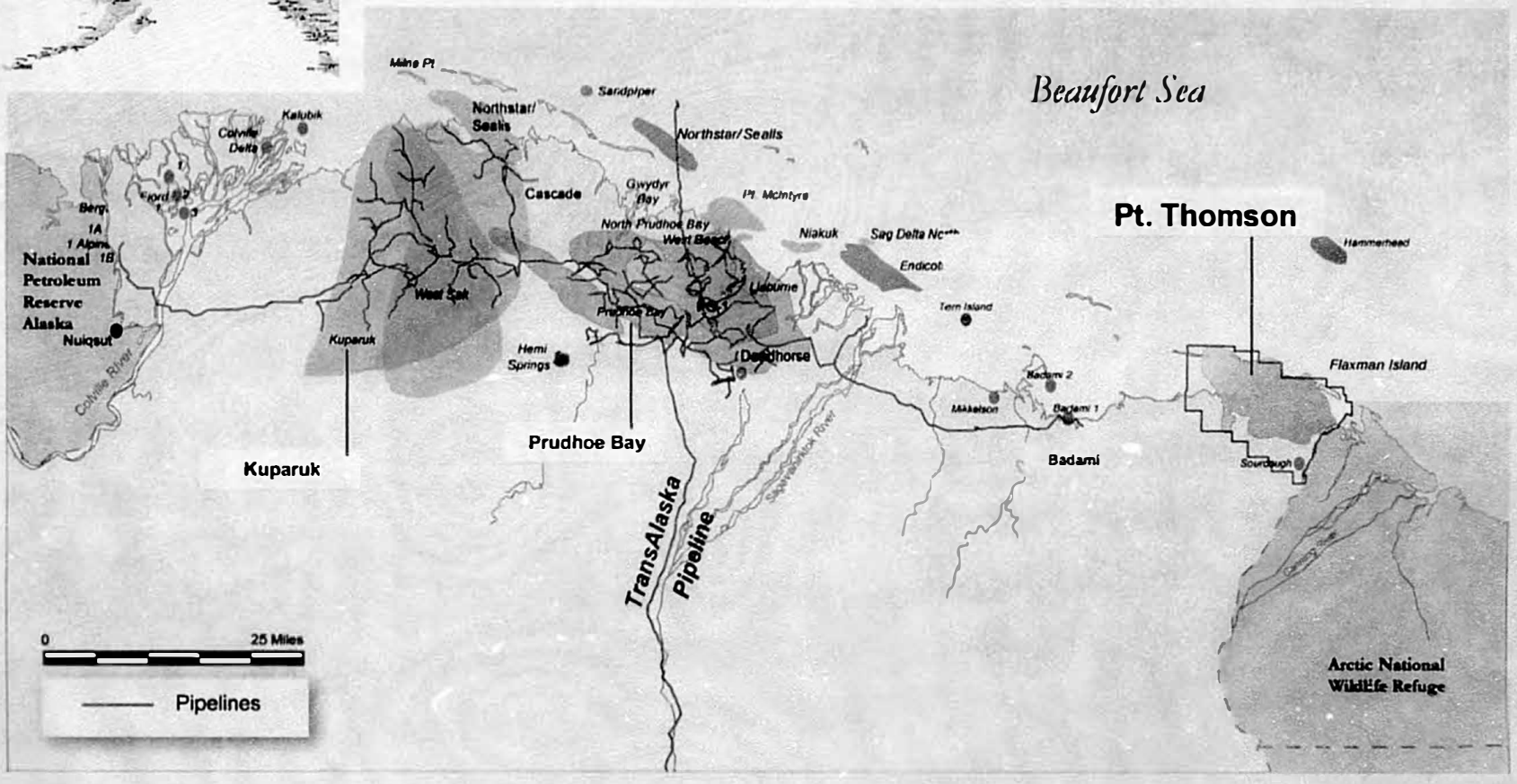
Craig A. Haymes
ExxonMobil Alaska Production Manager

$60-100 Million cost per well @ pt. Th.

Point Thomson – Isolated from Rest of North Slope

ExxonMobil

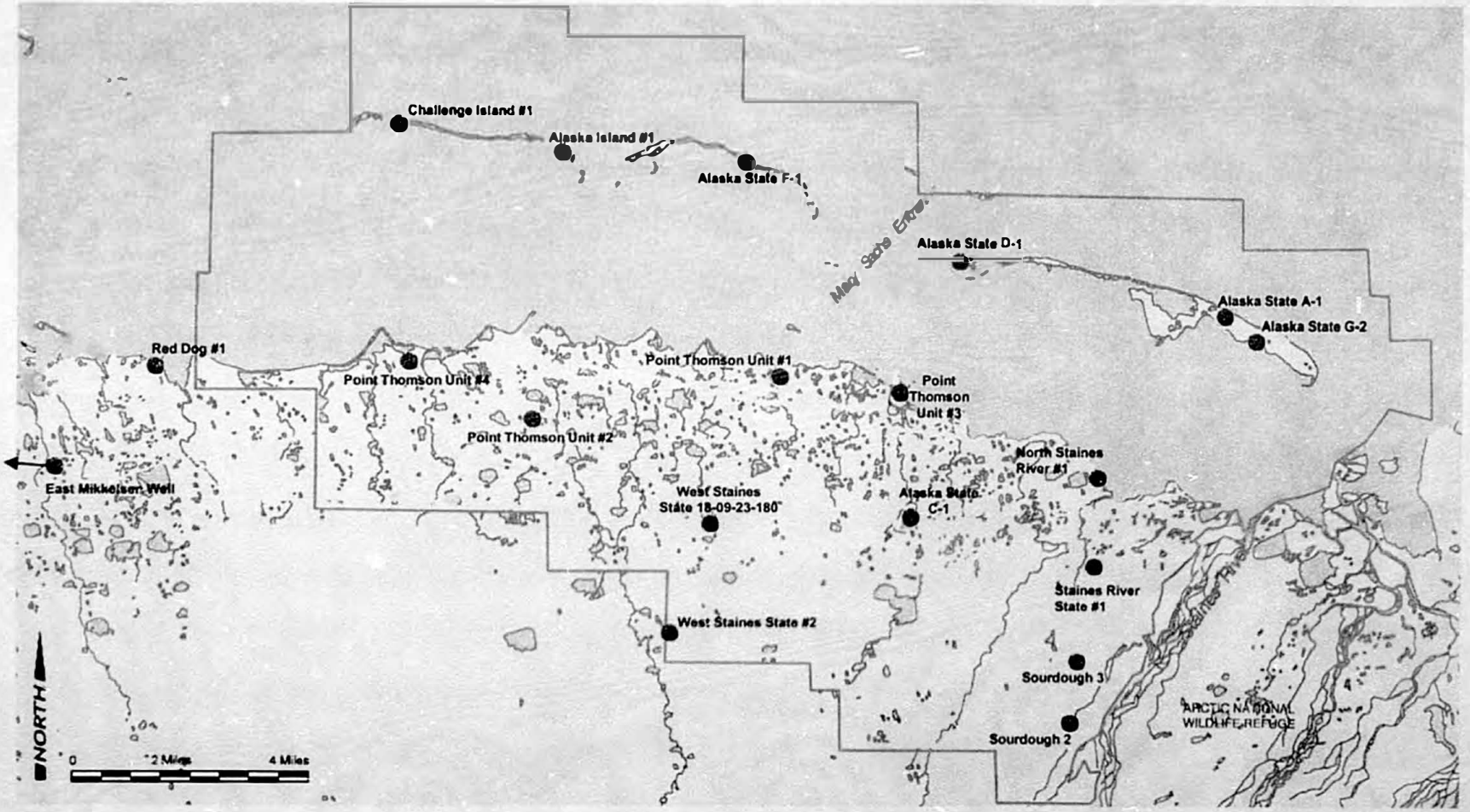
- Located in remote and environmentally sensitive area
- 60 miles east of Prudhoe Bay and TransAlaska Pipeline
- 22 miles east of Badami



Point Thomson – Obtaining Information

ExxonMobil

- 19 Exploratory Wells Drilled
- Eight 3D Seismic Acquisitions



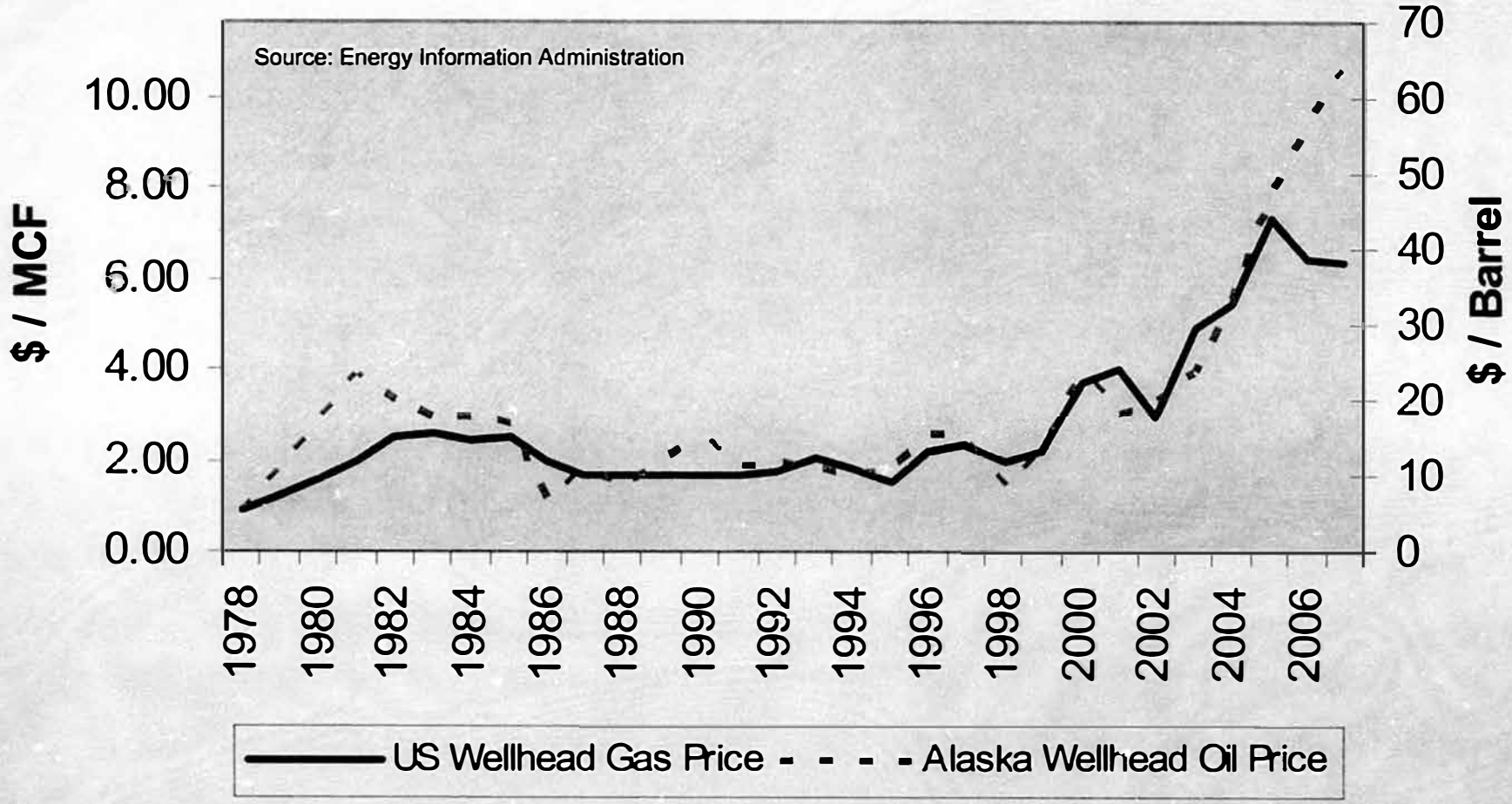
Point Thomson – POD Commitments

ExxonMobil

Point Thomson Unit
Plan of
Development
and
Operations

Historical Oil and Gas Prices

ExxonMobil



Point Thomson Plan of Development (POD)

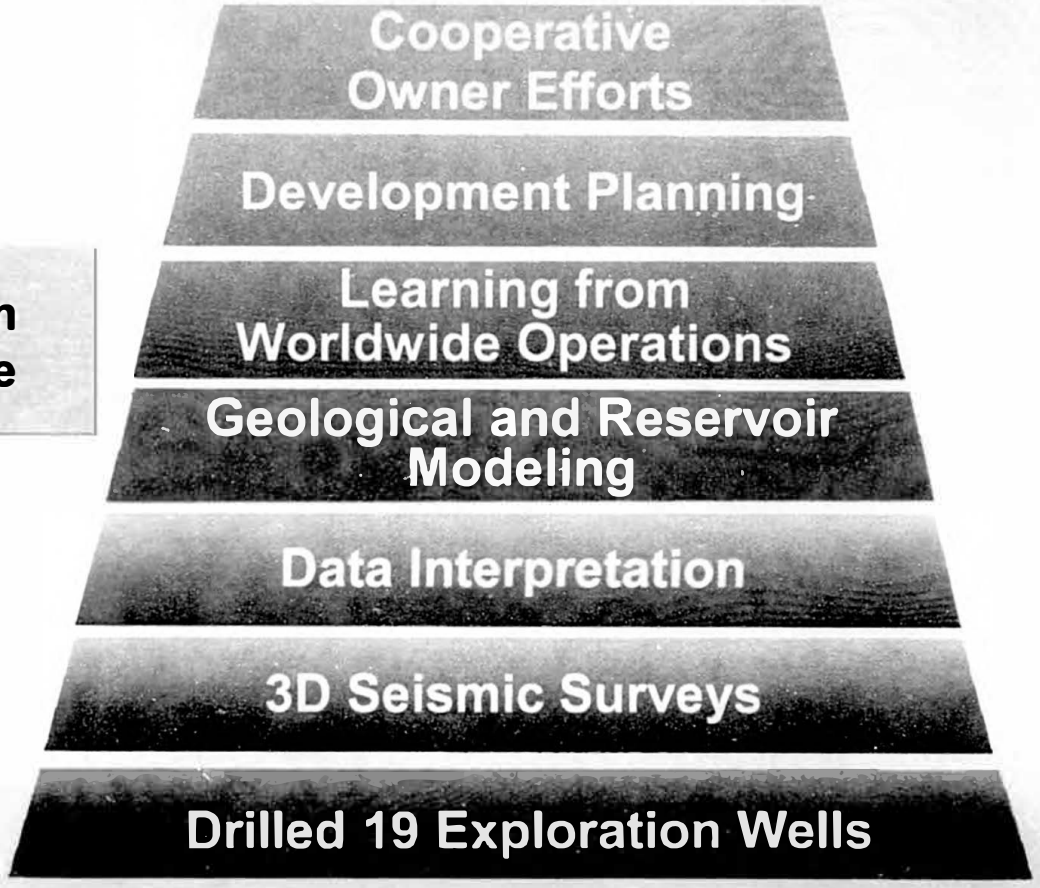
ExxonMobil

Plan of Development (POD)

$1.3 Billion Project

- **Future Expansion Capability**

> $800 Million spent to date

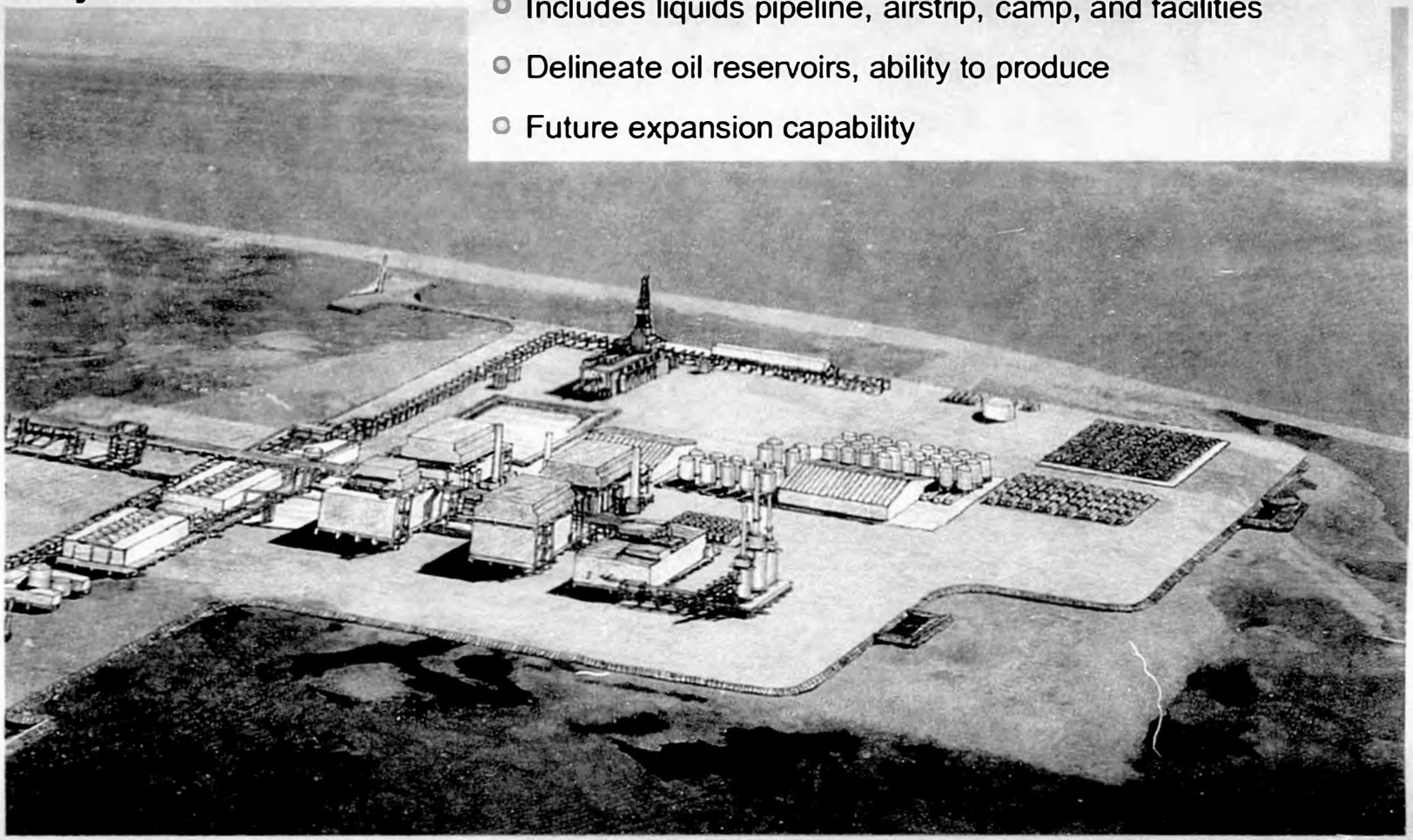


PTU POD - Plan to Produce Condensate

ExxonMobil

- Production by YE 2014: 10,000 BPD, inject remaining gas
- Includes liquids pipeline, airstrip, camp, and facilities
- Delineate oil reservoirs, ability to produce
- Future expansion capability

Project Illustration



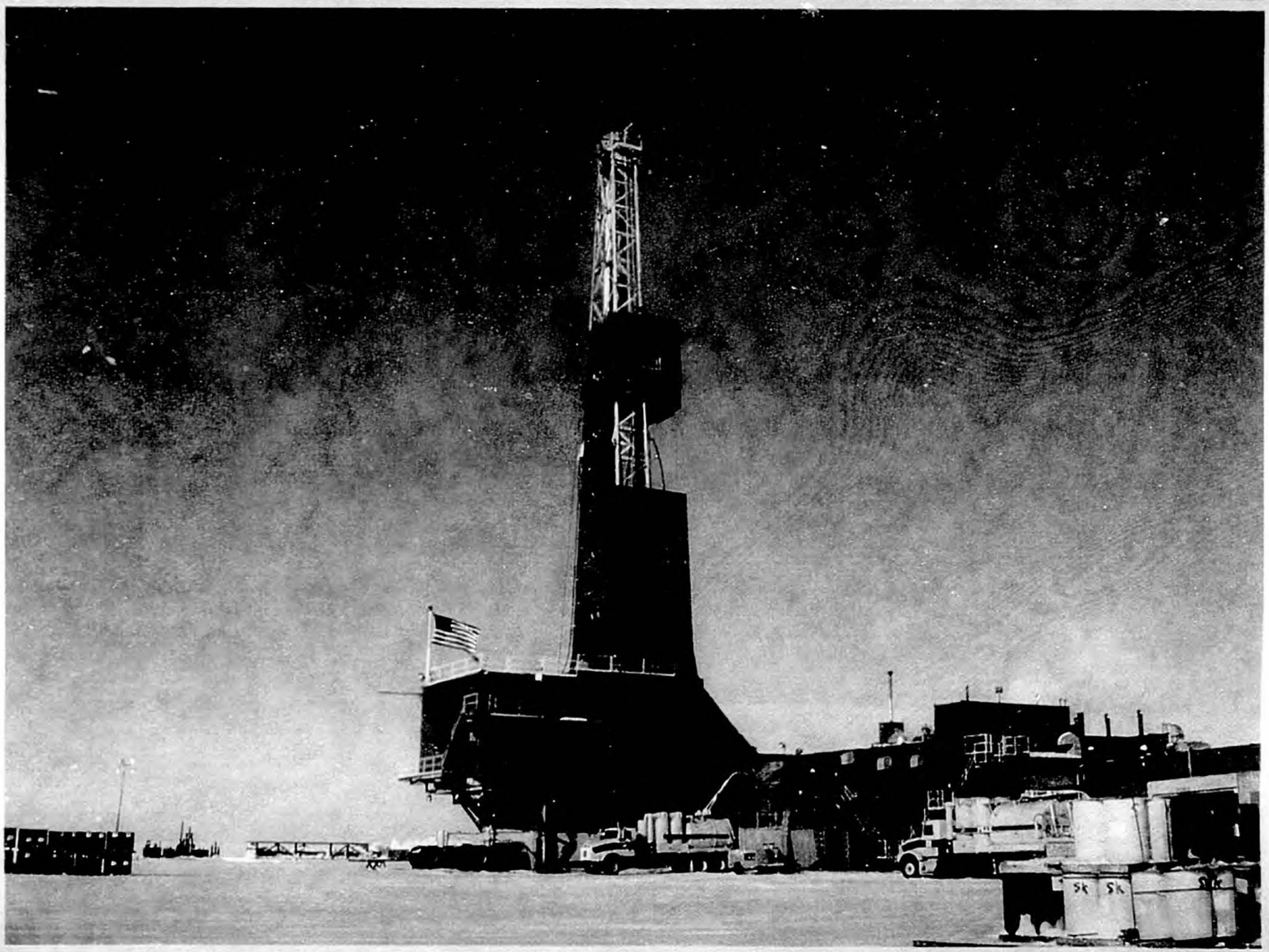
PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered

PTU - Drilling Rig with Upgrades Underway

ExxonMobil



PTU – Project Activity Underway

ExxonMobil

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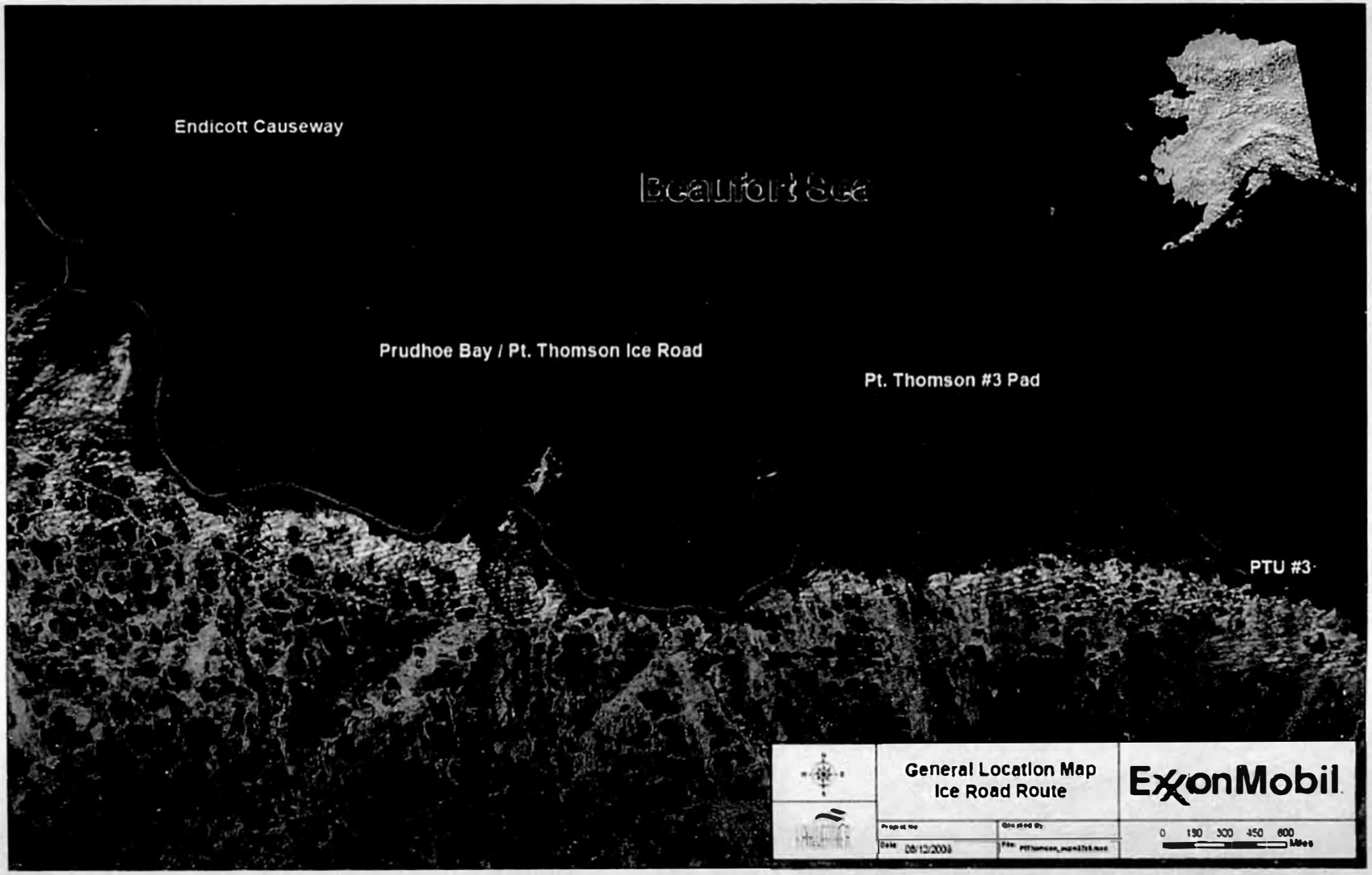
- **50 mile ice road and airstrip contracted to Alaskan company**

PTU – 50 Mile Sea Ice Road

ExxonMobil



PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- 50 mile ice road and airstrip contracted to Alaskan company
- **Drilling/Project site survey week of 6/23**
- **Permitting applications in June**
- **Barging of ice facilities and pad equipment in July/August**

PTU – Route for Summer Barge Activity

ExxonMobil

PTU – Summer Site Preparation Plan

ExxonMobil

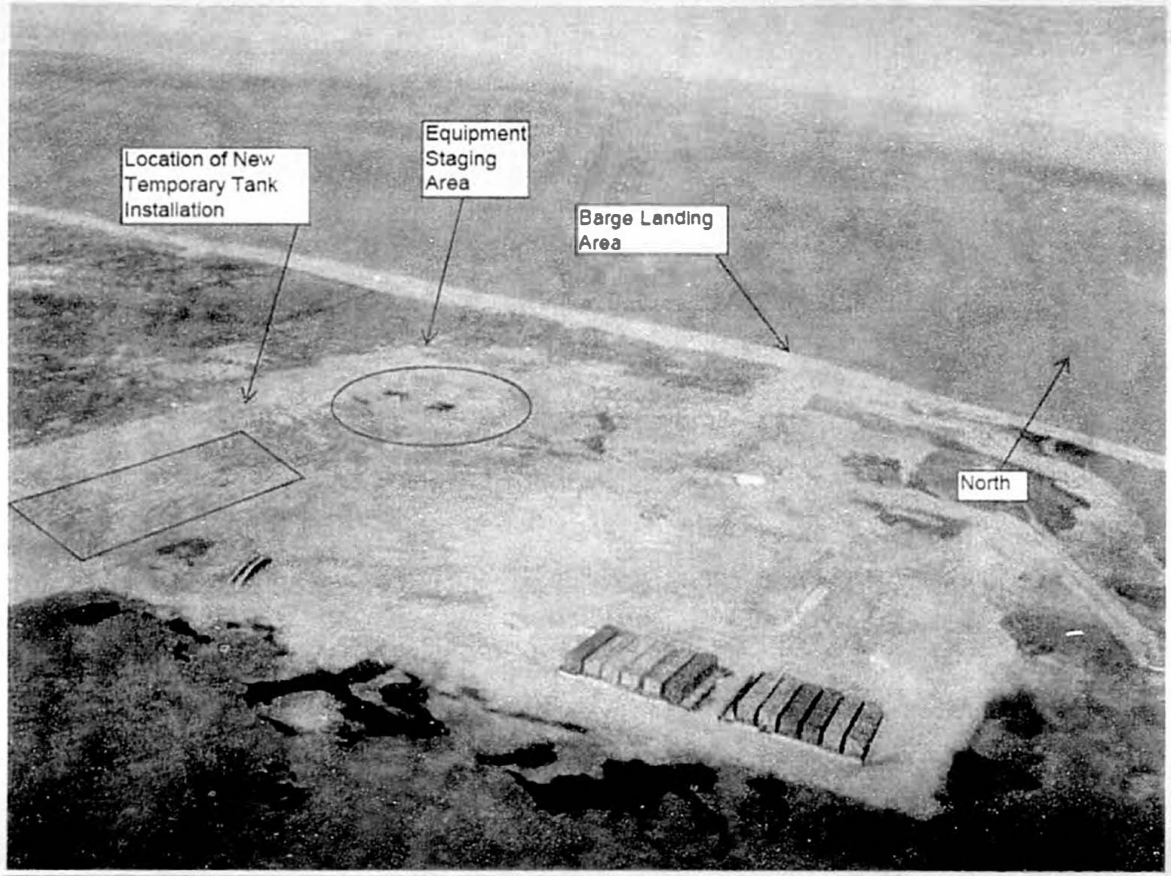


Figure 2
ExxonMobil
Point Thomson
Equipment Staging and Pad Preparation Project Schedule

ID	Task Name	Start	Finish
1	Barging of Equipment and Materials	7/15/08	8/30/08
2	Camp Setup	7/15/08	7/20/08
3	Gravel Hauling	7/21/08	7/30/08
4	Pad Preparation	8/1/08	8/15/08
5	Onsite Equipment Backhaul	8/16/08	8/17/08
6	Final Equipment Staging	8/16/08	8/30/08
7	Security Crew Standby	9/2/08	1/31/09

PTU – Project Activity Underway

ExxonMobil

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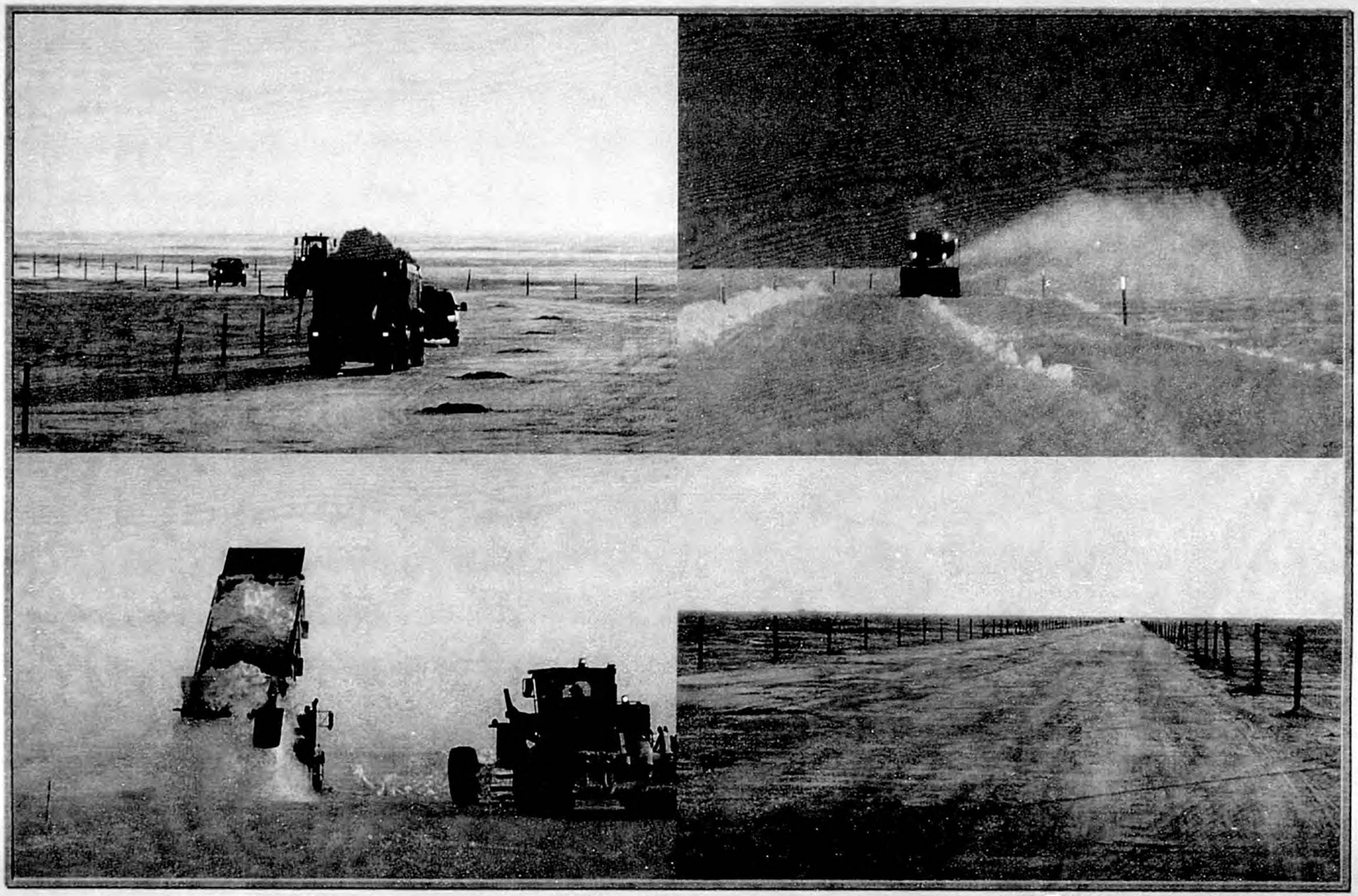
- Drilling/Project site survey week of 6/23
- Permitting applications in June
- Barging of ice facilities and pad equipment in July/August
- **Construct ice road and mobilize rig to PTU in December/January**

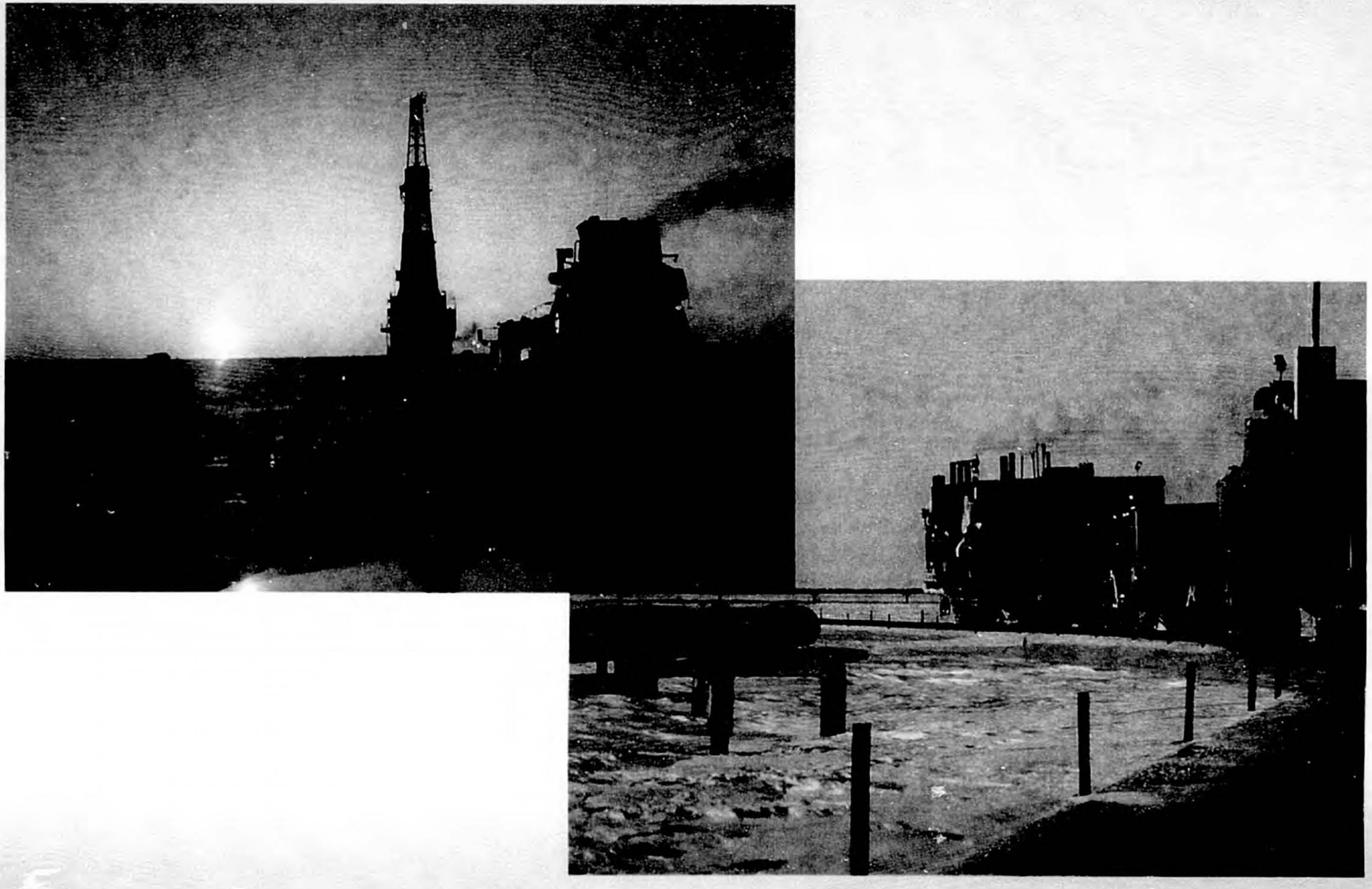
PTU – Ice Road Construction & Maintenance

ExxonMobil



PTU – Rig Move Over Ice Road

ExxonMobil

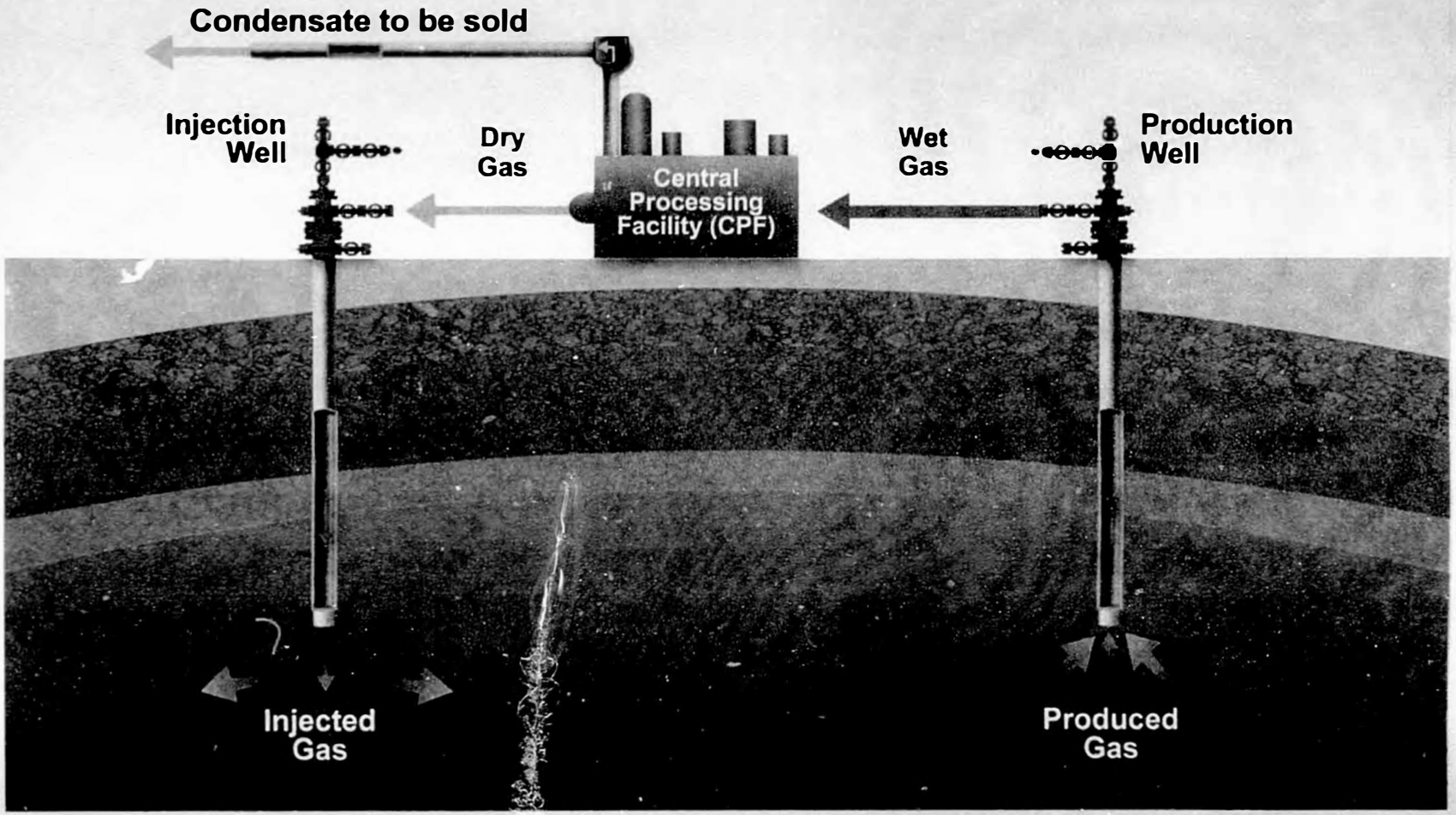


PTU – Project Activity Underway

ExxonMobil

- Nabors Rig 27E contracted
- Rig upgrades ($20M) commenced – Anchorage, North Slope
- Long lead drilling materials ordered
- 50 mile ice road and airstrip contracted to Alaskan company
- Drilling/Project site survey week of 6/23
- Permitting applications in June
- Barging of ice facilities and pad equipment in July/August
- Construct ice road and mobilize rig to PTU in December/January
- **Spud 1st well February 2009**

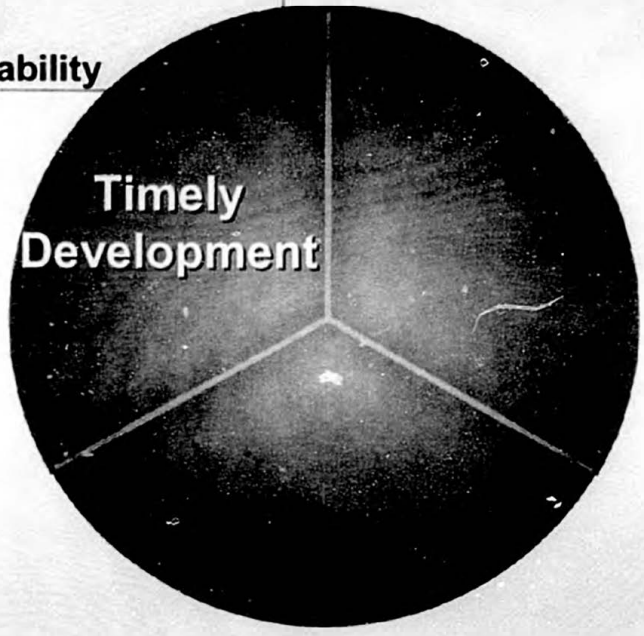
Point Thomson - Produce Condensate by Cycling Gas ExxonMobil



PTU POD - Addressing DNR's Concerns

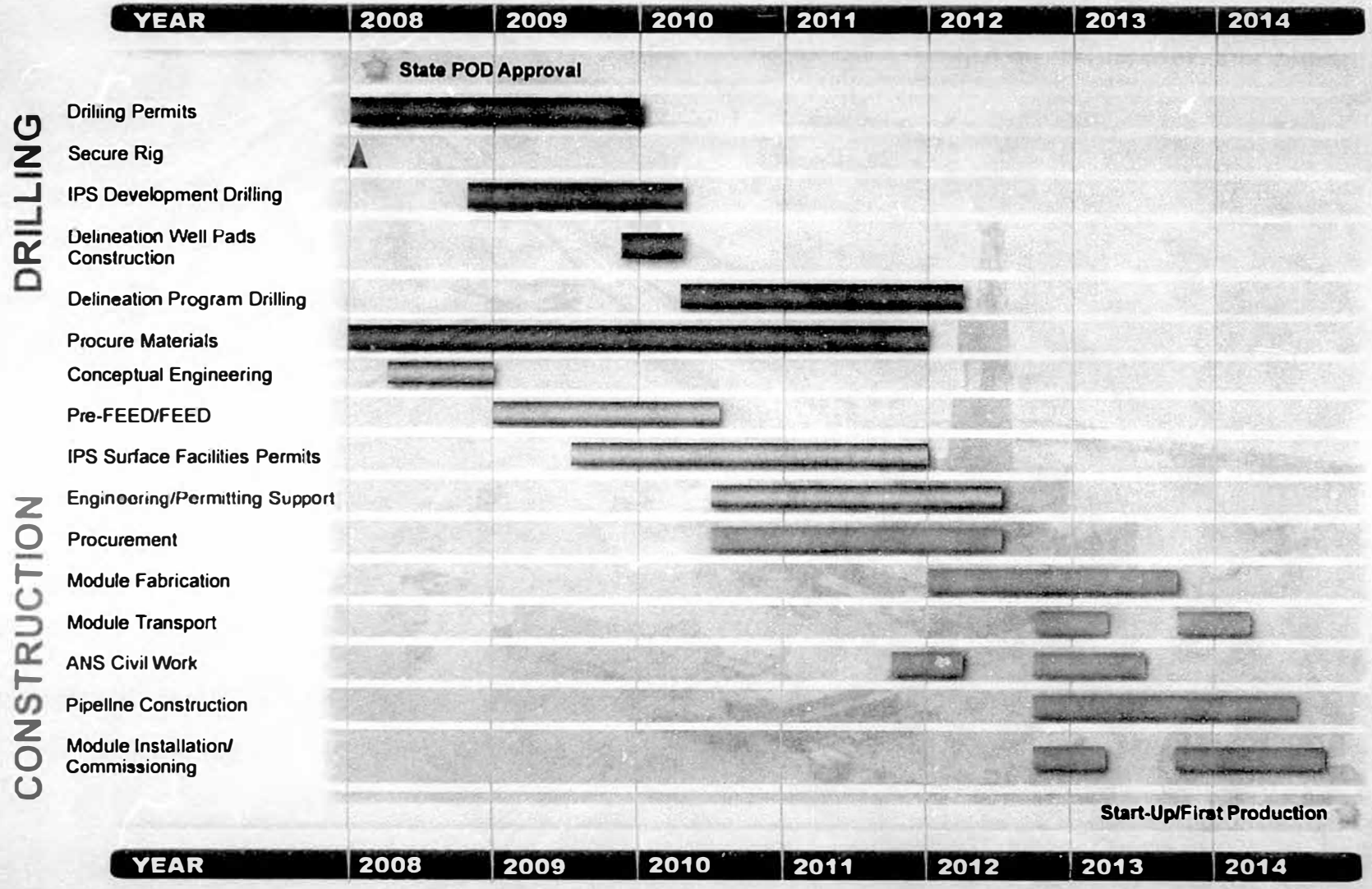
ExxonMobil

- Engineering & Drilling Starts 2008
  - > 200 jobs by next winter
- Production begins 2014
- 10,000 Barrels per Day
- Future Expansion Capability



PTU POD - Clear and Committed Timeline

ExxonMobil



PTU POD - Addressing DNR's Concerns

ExxonMobil

- Engineering & Drilling Starts 2008
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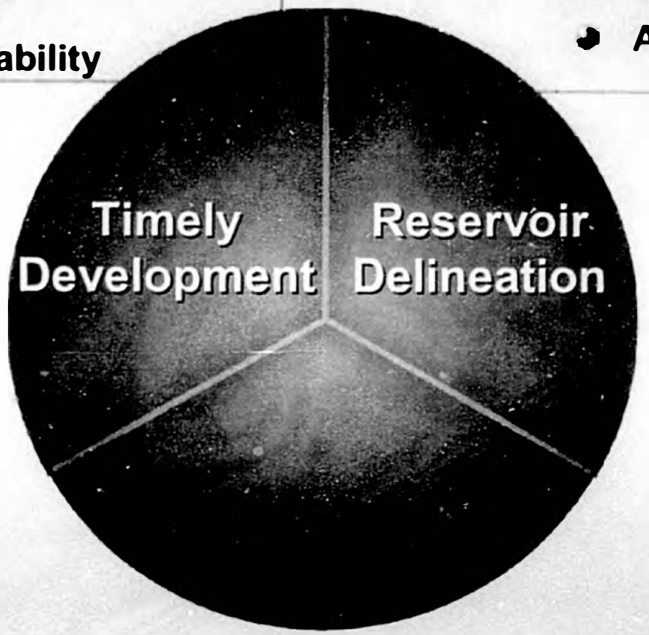
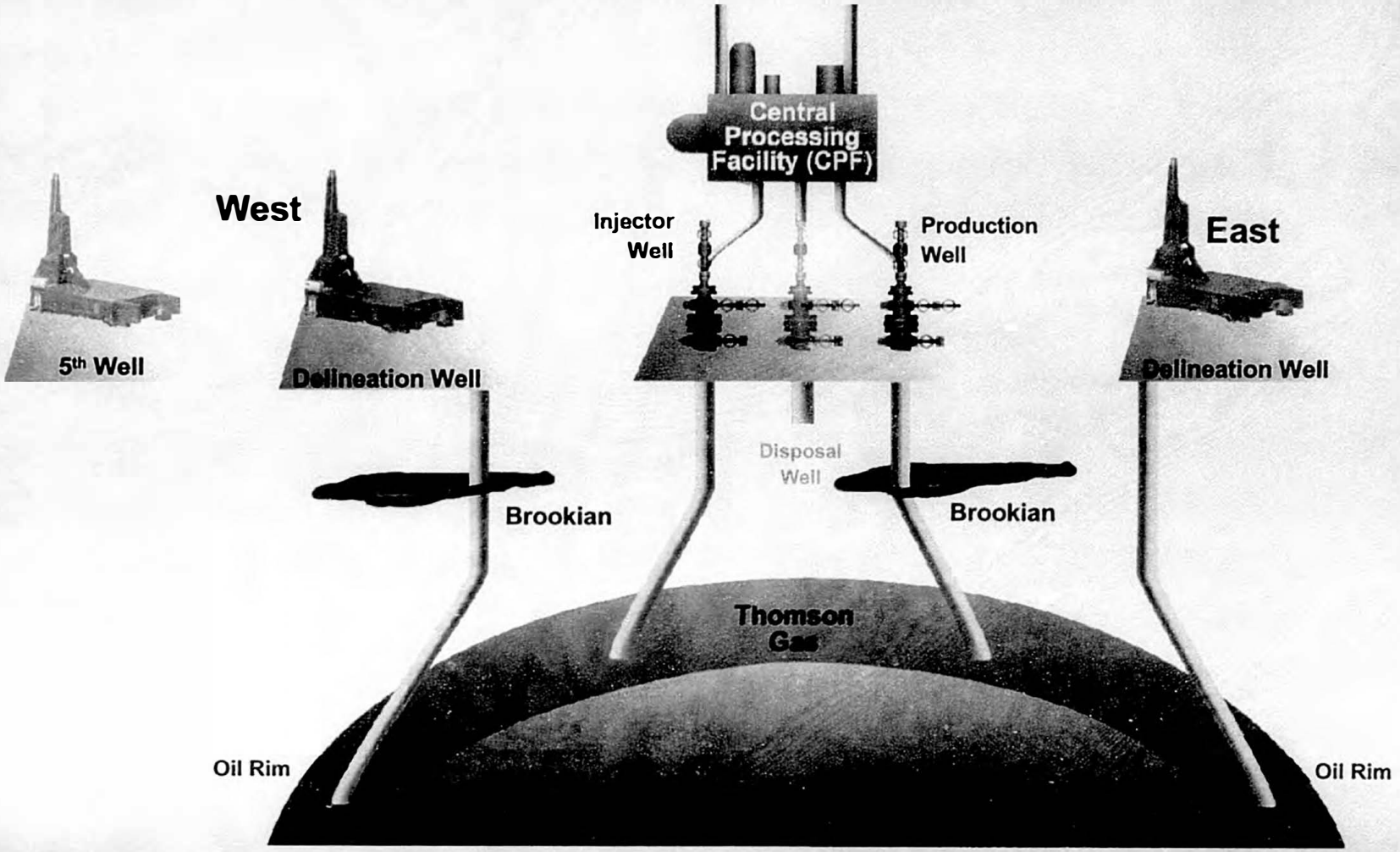
- Production begins 2014
- 10,000 Barrels per Day
- Future Expansion Capability

- Drilling Program – Gas, Oil, Condensate
  - 2 gas cycling wells
  - 3 oil / gas delineation wells
  - Additional Wells if required



PTU POD - Plan to Develop and Delineate

ExxonMobil



PTU POD - Addressing DNR's Concerns

ExxonMobil

- Engineering & Drilling Starts 2008
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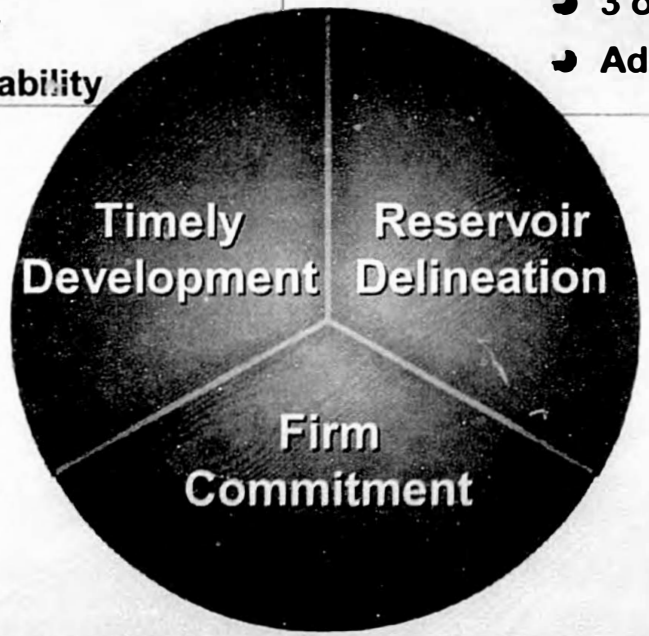
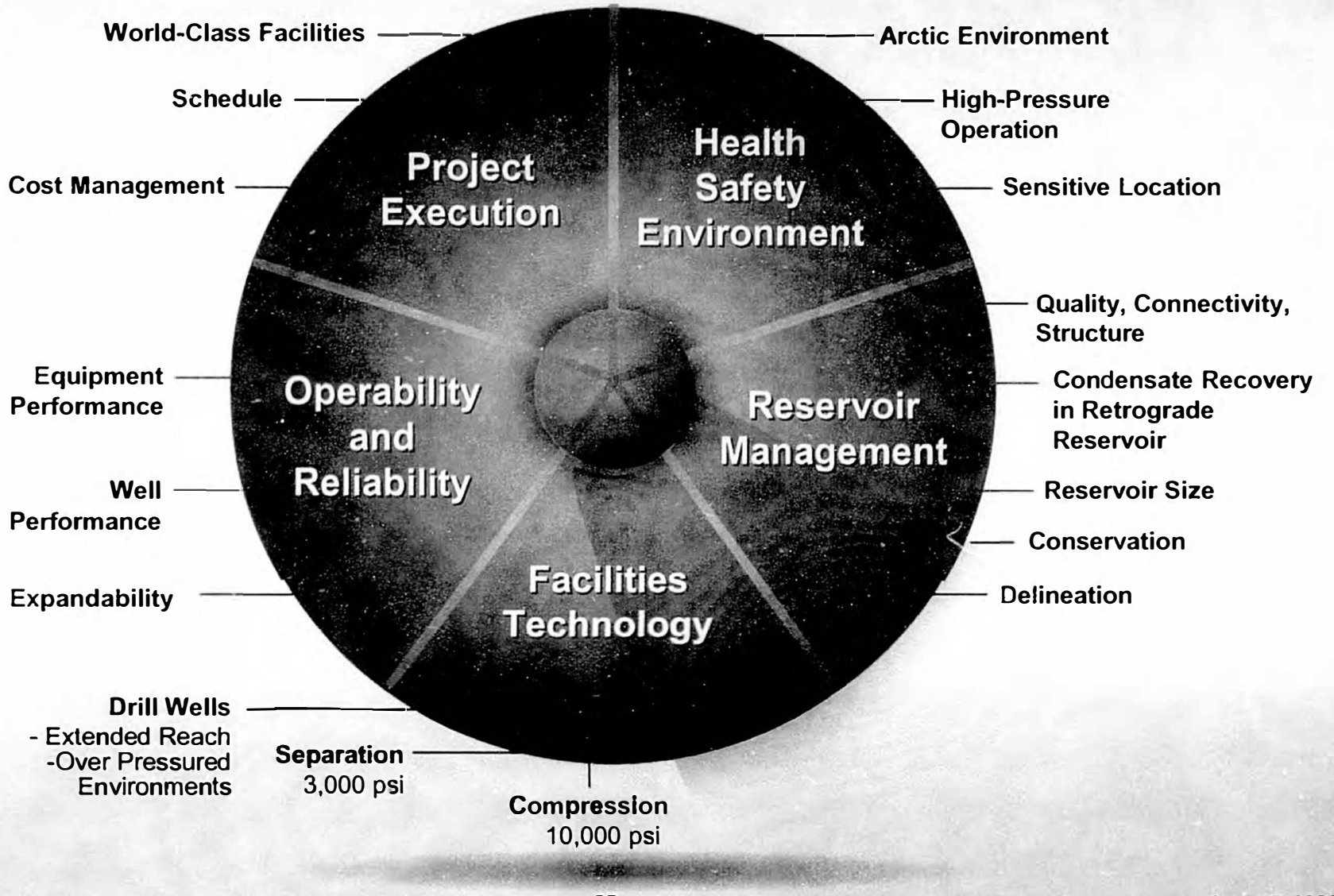


- Term of POD through to Production
- Owners support $1.3 Billion Project
- Already Secured Rig; Long Lead Materials
- Scheduled Milestones for State to Monitor Progress
- Owners Support Assured by Corporate Executives
- Agreed to Unit Termination if Milestones Not Met

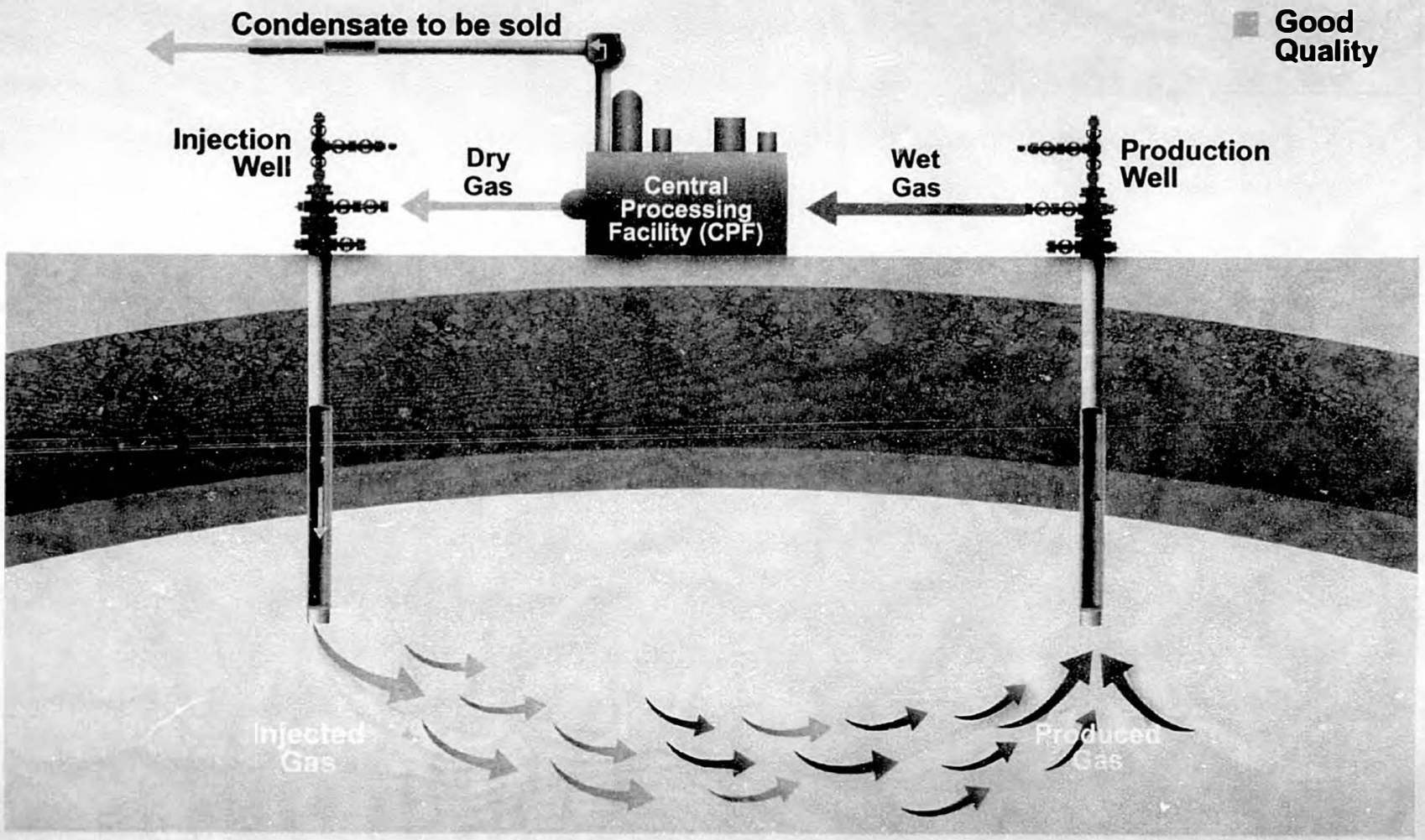
PTU POD - Prudently Manages Risk

ExxonMobil



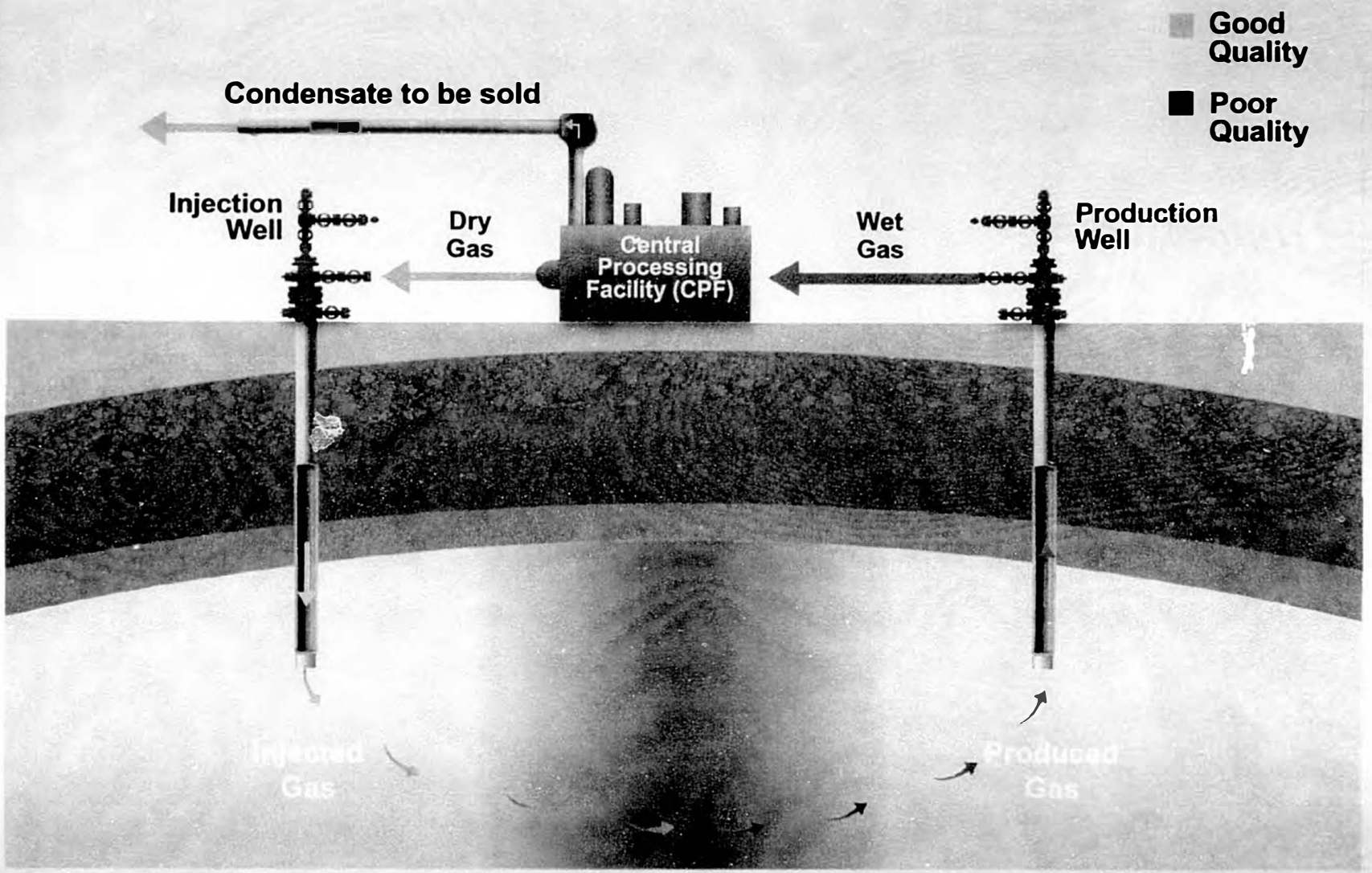
PTU - Reservoir Quality and Performance

ExxonMobil



PTU - Reservoir Quality and Performance

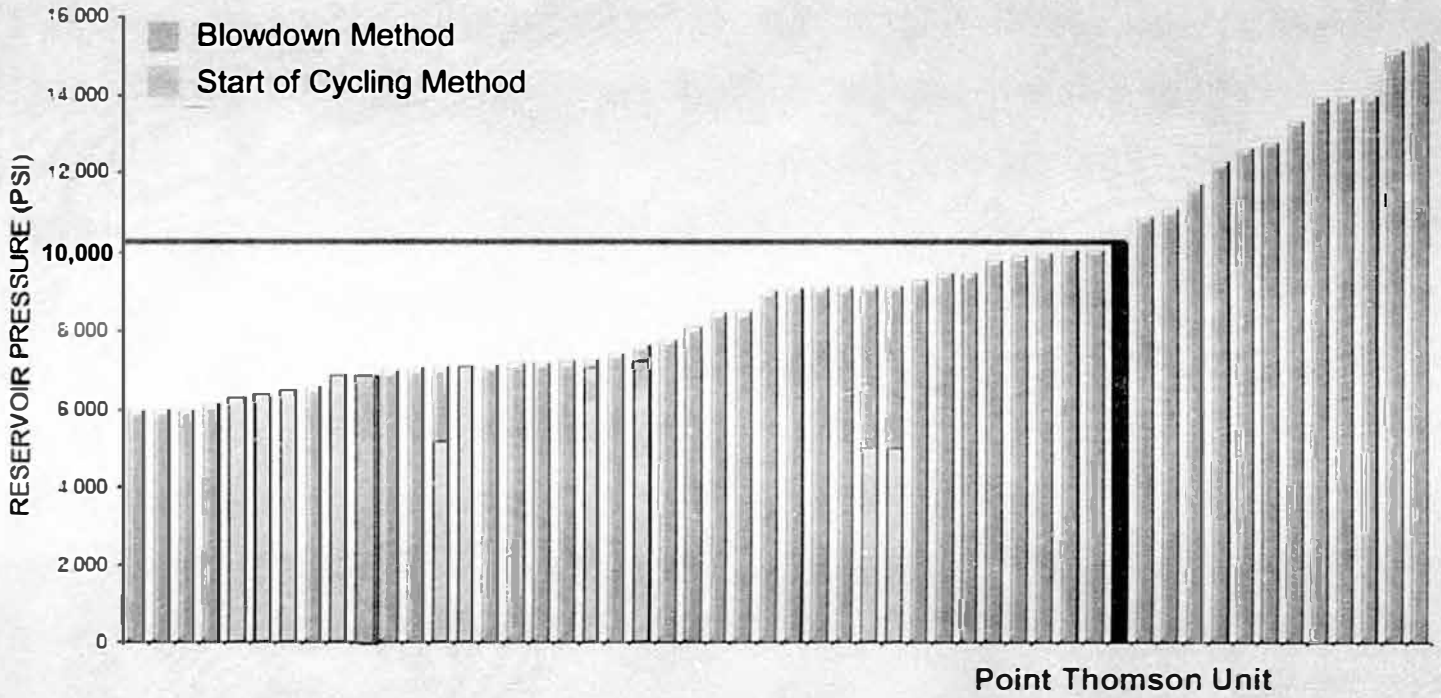
ExxonMobil



Cycling at High-Injection Pressure

ExxonMobil

World-Wide Gas – Condensate Reservoirs

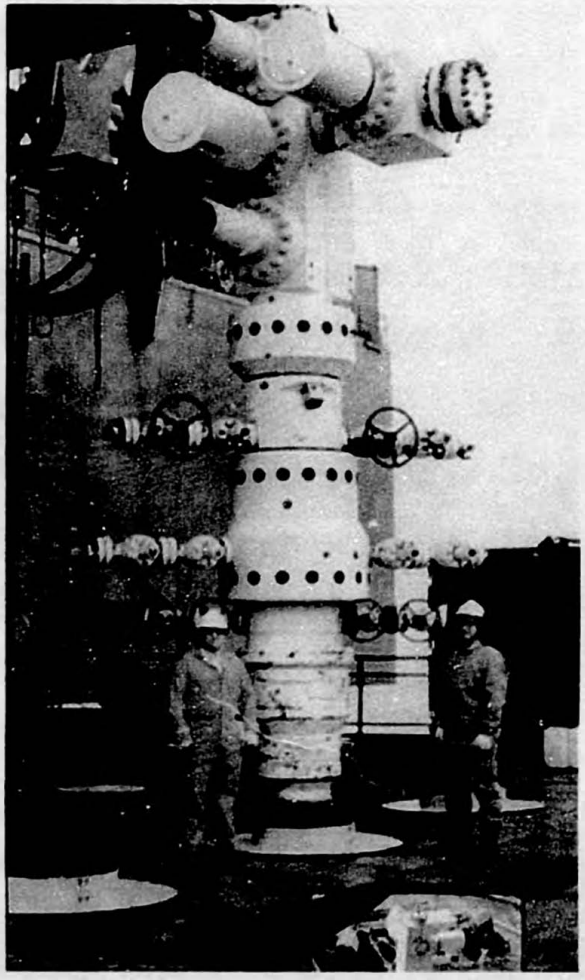


- No cycling projects similar to Point Thomson
  - >10,000 psi injection pressure
- World's highest pressure gas cycling project

Wells Required for High-Pressure Operations

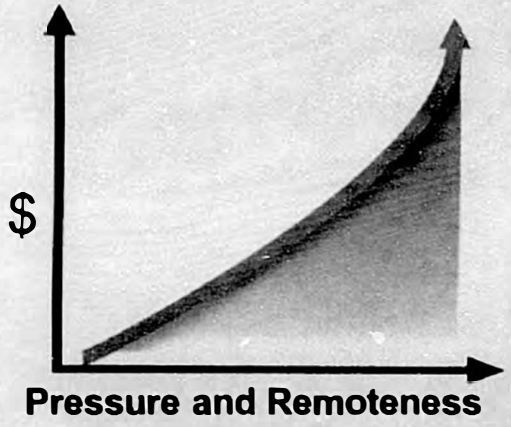
ExxonMobil

Point Thomson Well



Point Thomson Drilling

- Abnormal pressure
- Extended reach
- Heavy mud
- World class wells



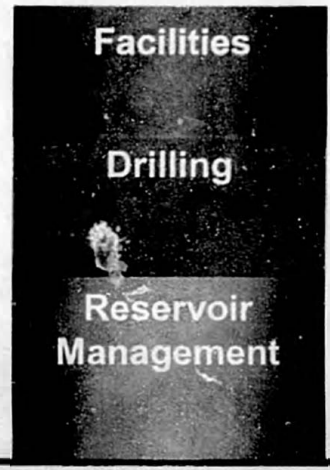
PTU POD - Phased Approach Mitigates Risk

ExxonMobil

Apply Critical Learnings

- Well Data
- Dynamic Information from Cycling
- Operability Learnings for Expansions

POD

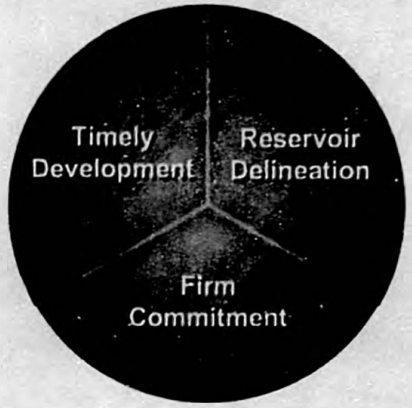


- Utilize Proven Technology
  - Compressors and Separators
- Fewer Wells
- Limit Reach to Proven Capability
- Apply Proprietary Technology
- Targets Reservoir "Heart"

Proposed Plan of Development for Point Thomson

ExxonMobil

- **Provides for Production**
  - Commence Engineering 2008
  - Commence Drilling Program Winter '08–'09
  - Provides Jobs – Over 200 People Employed Next Winter
  - 10,000 Barrels Condensate Per Day - 2014
- **Further Delineates Reservoirs**
  - Producer and Injector Wells
  - 3 oil/gas Delineation Wells
  - Additional wells if required
- **Provides Information About Reservoirs**
  - Reservoir Quality, Performance, and Size
  - Prudently Manages Risk – Reservoir & Technology
- **Conservation**
  - Cycling Enhances Resource Recovery
- **Minimizes Environmental Impacts**
  - IPS Utilizes Existing Gravel Pad
  - Offshore Drilling from Onshore Pad
  - Utilization of Ice Roads
- **Expandability**
  - Cycling, Oil Production, and Major Gas Sales



Importance of PTU Gas to Gas Pipeline

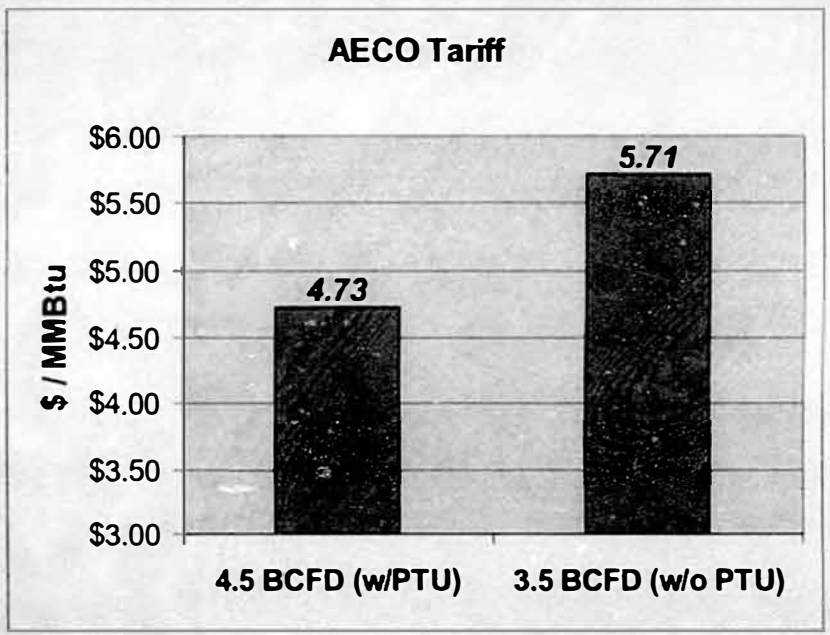
ExxonMobil

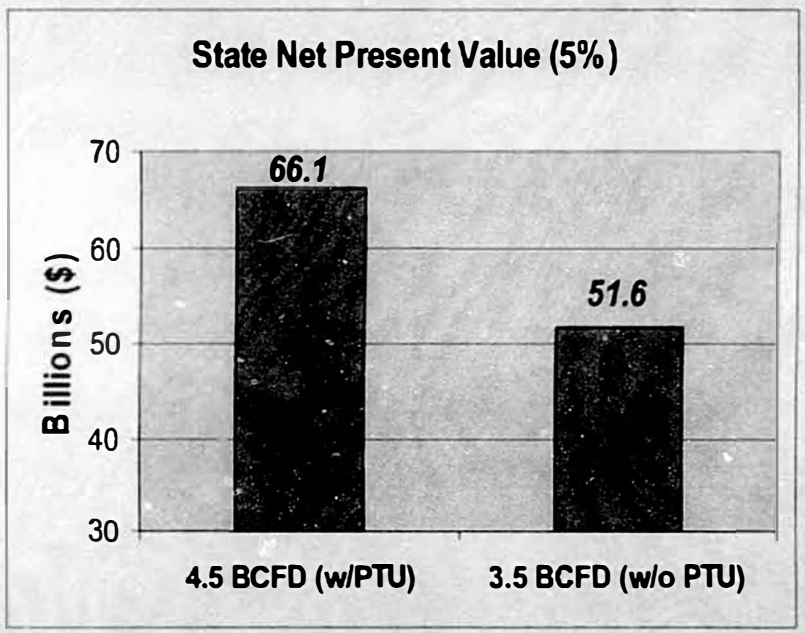
- **PTU Gas represents ~25% of the discovered North Slope gas resource**
- **Supports critical firm transportation commitments ("FT") necessary to secure project financing**
- **Provides security of supply for downstream consumers**
  - Not relying solely on Prudhoe Bay Unit gas or "yet to find" gas to meet commitments
- **Improves liquid recoveries at Prudhoe Bay**
  - Not required to produce Prudhoe Bay Unit at higher gas rates to meet FT / marketing requirements
- **Provides economies of scale for a gas pipeline project**
  - Allows optimization of initial project design
  - Reduces tariff, increases value to all stakeholders

Importance of PTU Gas to Gas Pipeline

ExxonMobil

- **Without PTU gas, pipeline tariff increases by ~$1.00 / MMBtu**
  - Less value for State *($14.5 billion dollars)* and Producers
  - Essentially requires a PBU gas discovery within the next few years
- **Significant impacts on shippers, including explorers**
  - Annual Impact: ***$1.3 billion dollars***
    - 3.5 BCF / Day * 365 Days * $1.00 / MCF
  - Impact over 25 years: ***$32 billion dollars***





Source: Black and Veatch – Alaska Gasline Determination Forum

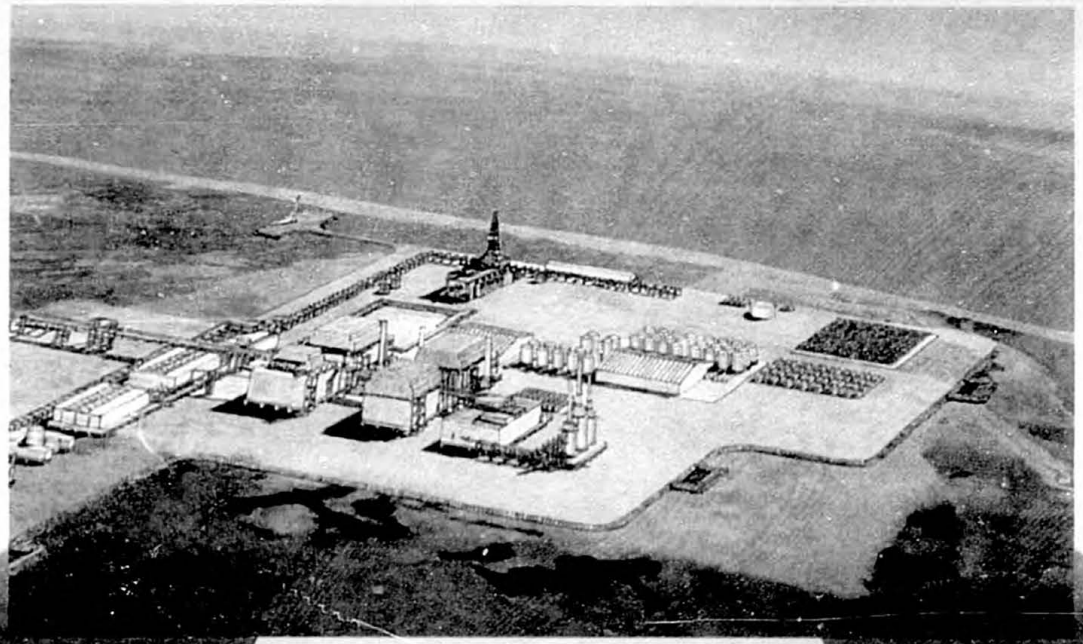
PTU – DNR Summary of PetroTel's Assessment

ExxonMobil

- **PTU lease holders have not been provided the recent PetroTel study, but based on DNR's summary of the analysis;**
  - Report appears to be based on selective and limited data
  - Report indicates significant critical work yet to be done
  - Report does not address key development planning, reservoir planning, economics, environmental considerations, costs, feasibility of drilling wells . . .
- **No sound technical conclusions can be drawn from this report; significant work remains.**
- **The DNR's summary of the PetroTel report clearly overstates the developable liquid hydrocarbons (condensate and oil)**
  - Oil recovery at PTU is unlikely to exceed 5% (PetroTel - "close to 50%")
- **Our technical work shows that over 90% of developable hydrocarbons (gas, condensate, oil) can be produced today through a gas sales development**
- **Our POD provides the opportunity to recover even more liquids prior to the start of gas pipeline operations**
- **PTU lease holders remain willing to share their technical work and expertise on these issues**

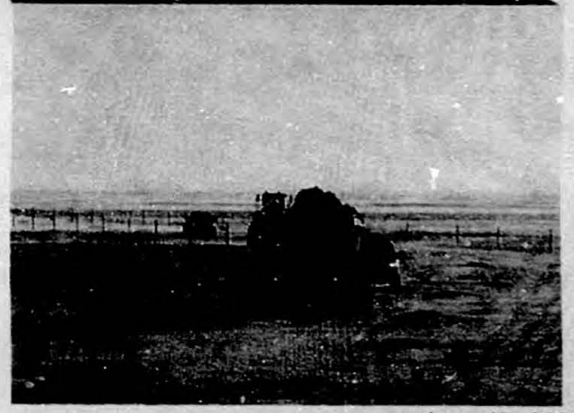
Point Thomson Project

ExxonMobil

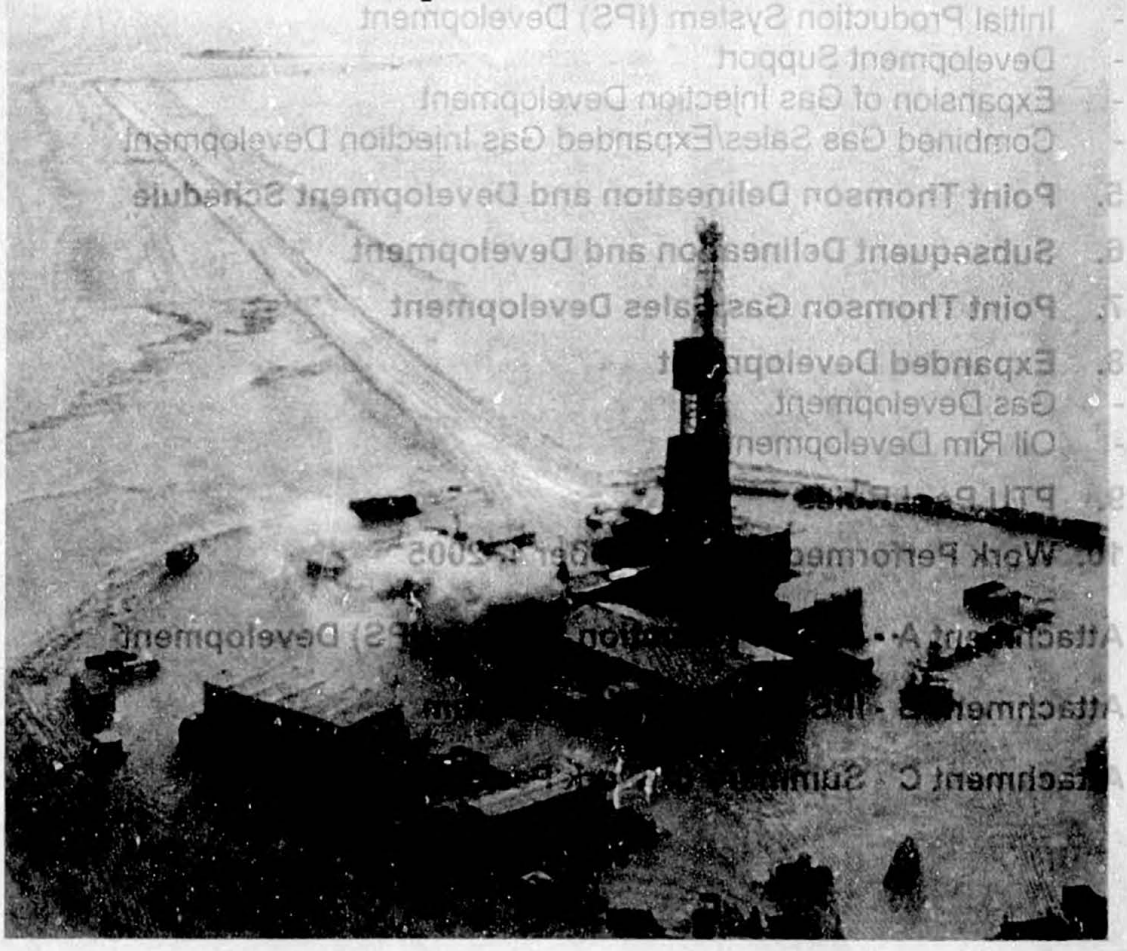


ExxonMobil

Taking on the world's toughest energy challenges.



Point Thomson Unit Plan of Development and Operations



2/19/08

POINT THOMSON UNIT

Plan of Further Development and Operation
For the period October 1, 2005 to December 31, 2014

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POINT THOMSON UNIT

Plan of Further Development and Operation
For the period October 1, 2005 to December 31, 2014

1. Introduction

This Plan of Further Development and Operation (POD) describes the timely delineation, development and operation, and proper conservation of the oil and gas resources of the Point Thomson Unit (PTU or Unit) area. The POD sets forth a plan to begin production of PTU hydrocarbons through a phased approach to fully delineate and develop both liquids and gas within the Unit area. The costs of work activities during the term of this POD are estimated at $1.3 billion.

The initial phase of production constitutes a major development project. The project involves drilling wells beginning in the 2008-09 winter season and constructing production facilities, pipelines, and support infrastructure.

PTU hydrocarbons will be produced and processed at PTU. Liquid hydrocarbons will be delivered for sale through new and existing oil pipelines and all remaining gas will be injected back into the Thomson Sand reservoir to maintain pressure for continued hydrocarbon recovery and for subsequent gas sales. Production start-up is anticipated by year-end 2014. The overall project, including the schedule, is described in detail in this POD.

This POD provides a minimum of five wells to further delineate and develop the Thomson Sand reservoir and other hydrocarbon reservoirs in the PTU. The drilling program is described in Section 3. Specific plans are included for delineation, evaluation, and testing of the oil in the Thomson oil rim and the Brookian. All wells will be designed to be capable of being used as producers or injectors if viable.

This POD includes development work for initiating gas sales from the PTU. This encompasses reservoir and facilities engineering work and application for pool rules from the Alaska Oil and Gas Conservation Commission (AOGCC), all of which are needed for individual owner participation in a gas pipeline project open season.

The work in this POD will accomplish the following key objectives for the State and PTU owners:

- Establishes production of hydrocarbons in a timely manner, prior to gas sales, providing benefits to the people of Alaska in the form of taxes, royalties, and jobs;
- Minimizes environmental impacts;
- Provides for delineation, appraisal and development of reservoirs within the Unit area;
- Allows individual PTU owners to take advantage of gas sales opportunities and participate in an open season for a gas pipeline; and
- Extends infrastructure on the Eastern North Slope thereby facilitating other potential developments in the area.

This POD also describes work performed since expiration of the most recently approved plan of development. Exxon Mobil Corporation (ExxonMobil), as Point Thomson Unit

Operator and on behalf of the PTU Working Interest Owners (Owners), requests approval of this POD for the period October 1, 2005, through December 31, 2014.

2. Point Thomson Unit Development

Resource Base

The Thomson Sand, the primary reservoir in the PTU, is a large high pressure gas-condensate reservoir. The Pre-Mississippian section directly underlies and is in pressure communication with the Thomson Sand. Because of the proximity and pressure communication between these reservoirs, development of the Thomson Sand will also deplete the Pre-Mississippian section.

The Thomson Sand contains an oil rim below the gas. The potential for production contribution from the oil rim is uncertain. The delineation program includes drilling, testing and evaluation of the potential for oil rim production. Thomson Sand reservoir wells will be designed to penetrate and evaluate the Brookian in one or more potential accumulation areas (e.g., either Flaxman, Iceberg, or Calloway). If encountered, formation evaluation (open-hole logging, sidewall cores, fluid samples and testing as appropriate) will be conducted to evaluate the potential for production contribution.

As part of owner efforts to determine an appropriate development plan for PTU, an extensive reservoir evaluation and development planning assessment was completed in 2007. This work included a Thomson Sand reservoir description and uncertainty analysis and provided comprehensive and integrated geologic and reservoir simulation models to allow for evaluation of a wide range of development options. The analysis provided an improved understanding of the factors having the greatest impact on resource size and reservoir performance and further confirmed that uncertainty exists due to variations in predictions of reservoir size, quality, and connectivity.

Development Considerations

The optimal development plan for the PTU must take into account the following development considerations:

- Anticipated resource size, quality, performance and uncertainty associated with these parameters;
- Timing and availability of a gas pipeline;
- Minimizing impacts in an environmentally sensitive location;
- Management of technology related to high pressure gas production and injection and extended reach drilling in abnormally pressured formations; and
- Prudent management of capital, especially due to high cost of development in a remote arctic location.

A discussion of these development considerations and options to address them is included in this POD to provide the necessary context for PTU development plans.

A key consideration for any development plan is the uncertainty as to how the reservoir will perform under production. Certain development plans are more robust and better able to accommodate this uncertainty. The Thomson Sand gas contains the dominant share of the hydrocarbon resource in the PTU, and selling gas is central to any development plan to

provide greater hydrocarbon recovery and generate maximum value to all parties and interests from the resource within the Unit area.

In general, gas depletion for a major gas sale development is best at coping with downside reservoir scenarios because it is less sensitive to compartmentalization or reservoir heterogeneity while accessing the largest quantity of hydrocarbons. A gas sales development is the best way to develop the PTU resources for the maximum benefit of the State and the owners. However, it requires a gas pipeline and gas market, and it is recognized that a gas pipeline is at least a decade away.

There are other development options, such as gas injection that have the advantage of a readily available market for the condensate production and are not dependent on external enablers such as a gas pipeline, but introduce other challenges.

Any PTU development project must be implemented in a high cost environment which is driven by the development location (remote, arctic, environmentally sensitive location) and the resource characteristics (deep, high pressure, low yield gas condensate reservoir with a large areal extent). Gas injection has a number of challenges including the need for well communication over long distances and the fact that the majority of the liquids recovered in a gas injection project would be recovered in a gas sales development.

Based on the uncertain timing, viability and lengthy project execution period associated with a gas pipeline, alternatives to a gas sales development were considered with the goal of bringing the PTU hydrocarbon resources into production in a timely manner, prior to gas sales, utilizing a prudent development plan. When considering a gas injection project, two competing forces must be considered:

- Large scale development provides economy of scale and lower unit development costs but is exposed to greater impacts from uncertainties surrounding the key development parameters.
- Small scale development has reduced economy of scale and higher unit development costs but is less impacted by uncertainties surrounding the major development parameters. It also provides early confirmation of important development data to be used for full development of the PTU oil and gas resources.

Taking into account these development considerations, a phased development plan was determined to be the most prudent approach for PTU. To implement this approach, an initial production system (IPS), which incorporates gas injection into the Thomson Sand, was selected. The IPS development approach was selected because it will:

- establish production and revenue prior to gas sales
- test the key areas of uncertainty, which include:
  + evaluation of the reservoir characteristics and performance to determine subsequent development option(s), which could include gas injection expansion and/or gas sales
  + technology qualification and implementation to ensure development reliability and efficiency (i.e., to ensure minimal impacts to project cost, schedule and long-term operability). Key technology challenges include:
    - high pressure gas operations (~10,000 psi)
    - high pressure gas separation

- extended reach drilling into abnormally pressured formations
- high rate gas well production (i.e., well design and production)

- allow efficient use of capital and reduce the risk of under-utilized facilities
- establish infrastructure, including export pipeline, wells, gravel mine, gravel pads, communications facilities, airstrip, camp facilities, and a disposal well which are consistent with future development phases
- minimize environmental impacts
- provide maximum flexibility to incorporate learnings and utilize the installed infrastructure to develop additional oil and gas resources within the Unit area

IPS development plans are more fully described in Section 4. Subsequent phases of field development will depend upon delineation, IPS results and the status of a gas pipeline project. Development scenarios include: 1) expansion of gas injection, 2) gas sales, or 3) a combination of expanded gas injection and gas sales. Use of IPS facilities for potential delineation, long term production and development of the Brookian after Initial Thomson Sand development, will also be determined.

3. Drilling

This POD fully delineates all of the PTU reservoir horizons. A multi-year drilling program will be commenced in the 2008-09 winter season to drill a minimum of five wells. The Point Thomson Delineation and Development Schedule in Section 5 depicts a continuous drilling program. Drilling will deliver production to IPS and evaluate Thomson Sand gas and oil rim potential, Pre-Mississippian, and Brookian oil potential. Delineation objectives of the program are provided below.

The drilling program involves wells drilled from the central, western, and eastern areas of the field. New gravel pads will be constructed to accommodate delineation wells to the western and eastern areas of the PTU and future drilling for full field development. The well program will be optimized during detailed well planning based upon results from previous wells to achieve the most efficient combination of delineation targets.

The drilling will begin from the Point Thomson No. 3 location with the central injector and producer wells for the IPS project. Operations from the PTU-3 site minimize environmental impacts by utilizing an existing gravel pad and provide greater drilling flexibility. The central gas injection well will develop an area located northwest of the PTU-3 site. The central producer will develop an area to the southeast of PTU-3. These wells will be fully evaluated using wireline logs, core, and samples and pressures from the reservoir. While the wells have been located to achieve project objectives, the overall IPS schedule, as detailed in Section 5, will allow time (without impacting production start-up) to side-track a well should it encounter reservoir conditions that are not anticipated and that could adversely impact performance.

A disposal well will also be drilled from the Point Thomson No. 3 location to support drilling, delineation and production operations.

Drilling from the western pad will target the Thomson Sand gas and oil legs and the Brookian. Where practicable, wells will penetrate the Pre-Mississippian. The area west of PTU-1 is an area of the field with uncertainty as to structure, facies and reservoir rock

quality. The program allows drilling toward the western syncline ("graben") and other western targets, including potential horizontal trajectory well bores in the oil column.

Drilling from the eastern pad will also target penetrating the Thomson Sand reservoir, including the eastern extent of the oil rim and the Brookian. Similar to the western area delineation drilling, the eastern pad drilling will evaluate structure, contacts and facies, with potential for a horizontal well into the oil rim.

Viable wells will be tied back to the IPS facilities.

The wells drilled under this POD will gather important information on stratigraphy, reservoir rock properties, structure, PVT data, fluid contacts and productivity. In particular, additional data acquired during the drilling program will be integrated with existing data to determine viability of oil production and potential integration with IPS facilities. The drilling program will provide opportunities for collection of critical dynamic reservoir information through testing or longer term production.

Delineation drilling provides definition for development optimization with the following objectives:

- Evaluate areas of Thomson Sand reservoir uncertainties (facies and structure) and confirm areas of high gas resource density
- Gain additional information on the Pre-Mississippian
- Obtain fluid properties from various locations and reservoirs
- Improve understanding of the oil characteristics and long-term productivity of the Thomson Sand oil rim
- Evaluate Brookian productivity and characteristics

The drilling program continues with a third well designed to evaluate oil production from the oil rim in addition to evaluating other PTU reservoir uncertainties. The presence of an oil rim in the Thomson Sand reservoir has been known for some time. Assessment of oil rim potential involves fluid sampling, coring, pressure monitoring and analysis followed by extended on-site well tests, where merited.

The remaining drilling objectives and locations will be determined in detailed design based on previous drilling results.

The Brookian reservoirs have substantial risks and uncertainties associated with their development as demonstrated previously on the North Slope at Badami. Results to date at PTU have been consistent with the poor reservoir quality seen at Badami. Past studies have found these developments to not be commercially viable on a stand-alone basis.

In wells planned for Thomson Sand development, LWD (logging while drilling) data will be collected in Brookian penetrations to evaluate one or more of the prospects known as Iceberg, Calloway or Flaxman. These results will be evaluated to determine the value of additional information such as sidewall cores, wireline logs and fluid samples.

Commercial development of the Thomson Sand is viewed as the best path to potential development of the Brookian by providing a shared infrastructure that would reduce appraisal and development costs. To facilitate Brookian delineation and development, the suitability of IPS surface facilities for a long term Brookian production test after initial Thomson Sand development will be determined.

4. Development Work Scope

Initial Phase Production and Gas Injection Development

This POD is a firm commitment to drill wells and begin commercial production from the Thomson Sand utilizing an IPS. Production start-up is anticipated by year-end 2014, provided POD approval is received and required permits are obtained in a timely manner. During the POD period, owners will drill delineation/development wells, complete Conceptual Engineering, Front End Engineering and Design (FEED) and execution planning, obtain permits and authorizations and construct facilities for the IPS project. The IPS development schedule reflects an estimate of the time required to secure the necessary permits through multiple agencies.

Initial Production System (IPS) Development

IPS development will achieve production of PTU hydrocarbons and assist with full development of both liquids and gas through a phased approach. The IPS development is not dependent on an off-lease road. Thomson Sand development wells, a central production facility (CPF), and infrastructure to support operations will be located at the existing PTU #3 exploratory well gravel pad. The small footprint required and utilization of an existing gravel pad will minimize new gravel requirements and environmental impacts.

Drilling for the IPS project will begin in the 2008/2009 winter season with the central injector and producer wells from the Point Thomson No. 3. The central gas injection well will develop an area located northwest of the PTU-3 site. The central producer will develop an area to the southeast of PTU-3.

Additionally, a disposal well will be drilled at the PTU-3 site to support drilling and production operations.

The IPS will be designed to produce at a gas offtake rate of 200 million cubic feet per day. This will yield condensate rates of about 10,000 barrels per day. Gas production rates at this level may be achieved from a single production well in the high pressure Thomson Sand reservoir. The processed gas will be compressed and re-injected into the Thomson Sand reservoir through a gas injection well. Liquid hydrocarbons will be separated and stabilized at the CPF, then shipped through a new pipeline from the PTU to a Badami pipeline tie-in for delivery to the TransAlaska Pipeline System (TAPS).

The CPF will consist of two trains capable of processing 100 million cubic feet per day and 5,000 barrels per day each. Each train will be equipped with reciprocating compressors capable of re-injecting gas at the required injection pressures (~10,000 psi). The liquids pipeline will be sized to handle full field development. Disposal of waste liquids will be handled using an on-site disposal well. Other infrastructure such as camps, utilities, warehouse, in-field road and airstrip will be included. No permanent off-lease roads are necessary during the term of this POD. These facilities will be designed to accommodate future development options. Attachment A shows a preliminary IPS development plot plan and description. Attachment B shows a preliminary IPS process flow diagram.

The IPS performance will provide information to address reservoir and technical uncertainties and help manage those risks. Expected production and pressure response associated with the IPS have been evaluated in recent technical studies. Data obtained

during the drilling program will be used to test model predictions. Production response from the IPS will further narrow the range of resource uncertainty. Low-side scenarios will be identified relatively quickly, likely within the first year of production. High-side scenarios will take a longer production period to establish or differentiate.

Development Support

Technical and environmental activities will be conducted, including updating and/or supplementing previous environmental baseline studies, preparing and submitting applications, and working with regulatory agencies to secure necessary drill well and facilities permits and minimize environmental impacts. To minimize environmental impact, opportunities for use of adjacent infrastructure for logistical support will be evaluated.

Expansion of Gas Injection Development

The IPS project will be designed to provide flexibility for expansion. In addition to facility and drilling considerations, the reservoir development and monitoring plan will include acquisition of information to reduce resource uncertainty for analysis of expansion options. Additional details are provided in Section 8.

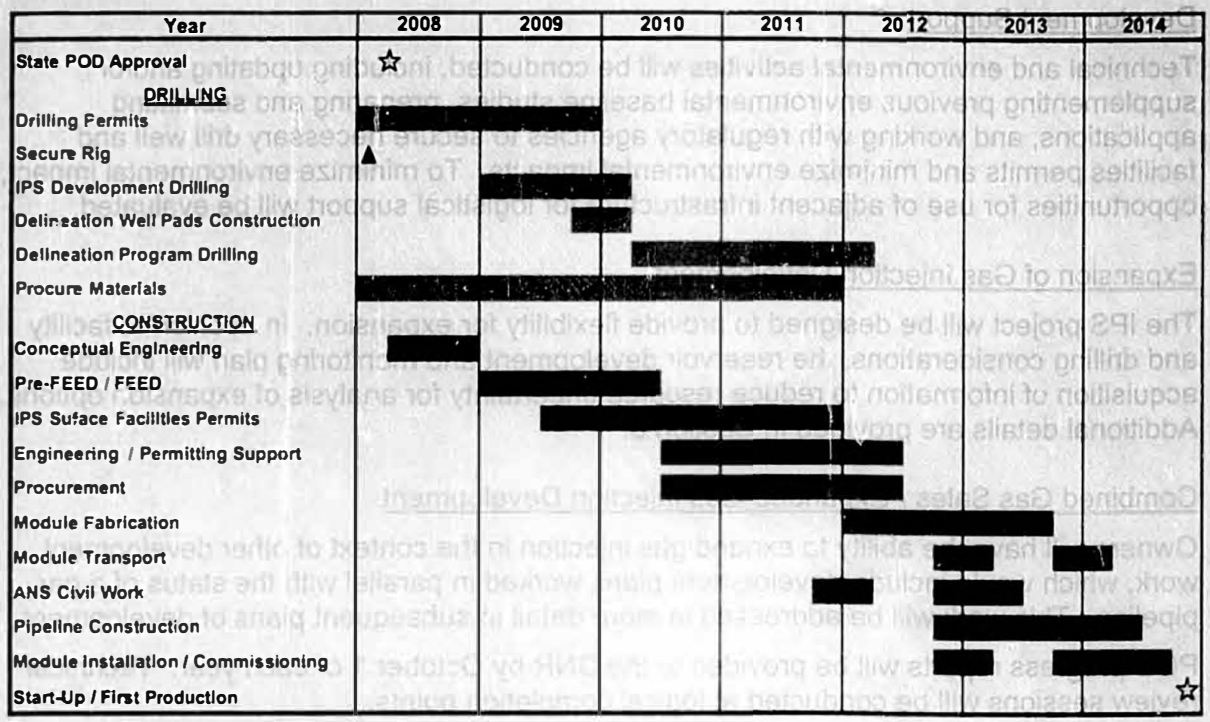
Combined Gas Sales / Expanded Gas Injection Development

Owners will have the ability to expand gas injection in the context of other development work, which would include development plans worked in parallel with the status of a gas pipeline. This work will be addressed in more detail in subsequent plans of development.

POD progress reports will be provided to the DNR by October 1 of each year. Technical review sessions will be conducted at logical completion points.

5. Point Thomson Delineation and Development Schedule

The current schedule for the delineation drilling and IPS development project is provided below (note that certain field activities may be dependent upon Alaska seasonal constraints).



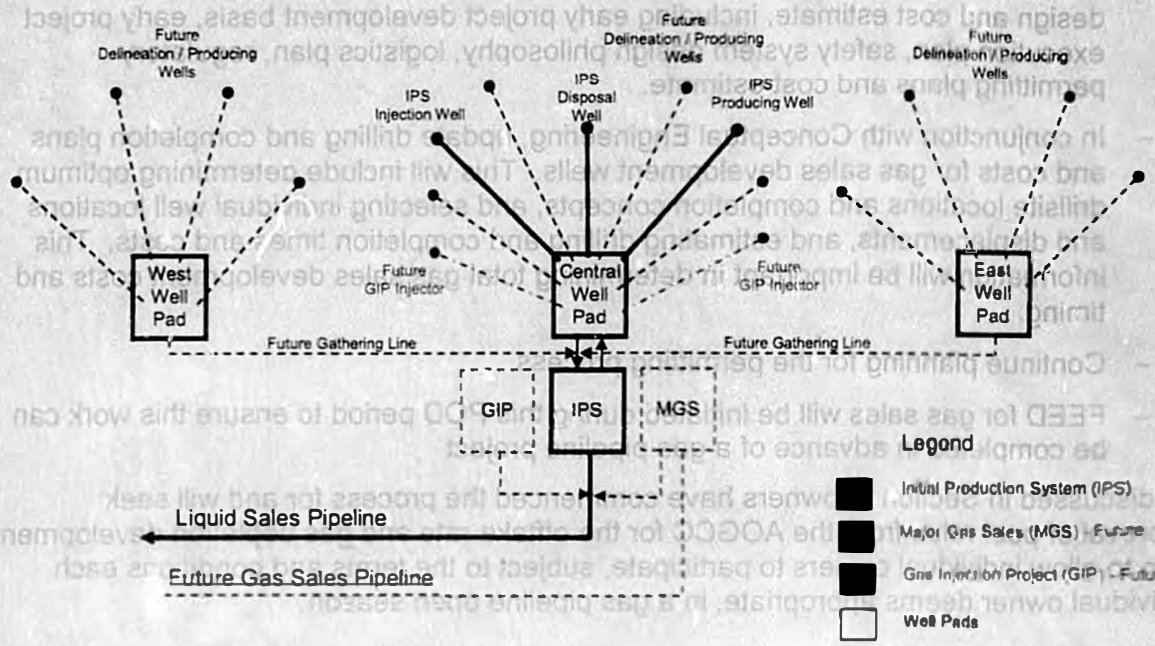
IPS project work will encompass the following activities:

- Perform Conceptual Engineering for the IPS project
- Perform FEED and execution planning to define the IPS project in sufficient detail to submit permit applications and update costs
- Initiate drilling in the 2008-09 winter season, upon receipt of permits
- Review and update environmental baseline studies, prepare permit applications, and support the permitting process to obtain the approvals
- Initiate construction, upon receipt of permits

6. Subsequent Delineation and Development

Subsequent phases of field delineation and development will be determined based upon reservoir and facilities performance with the IPS, the status of a gas pipeline project, expected hydrocarbon recovery, and commercial viability. Development scenarios include 1) expansion of gas injection, 2) gas sales or 3) a combination of expanded gas injection and gas sales. Use of IPS facilities for delineation, long term production and development of other reservoirs after initial Thomson Sand development will also be determined. Figure 4.1 is a diagram that depicts conceptual development plan scenarios for the options described above. Attachment A also provides a conceptual expansion plan for the CPF.

Figure 4.1 Conceptual Development Diagram



DEVELOPMENT PHASING:

- Initial Phase: Initial Production System or IPS (Solid Lines)
- Subsequent Phases (Dashed Lines) Could Include:
  - Gas Injection Project (GIP) Expansion
  - Major Gas Sales (MGS)
  - Combination of Both

7. Point Thomson Gas Sales Development

A significant step for a PTU gas sales development is to secure firm shipping capacity through a gas pipeline. To accomplish this, individual owners will need to make long-term commitments in an open season nomination process. This requires that the owners have confidence in the ability to produce the necessary volumes of gas from PTU and a good understanding of the cost of the facilities and wells required to implement a gas depletion development plan.

Owners will complete the work necessary to allow each individual owner to participate, subject to the terms and conditions each individual owner deems appropriate, in an open season for a gas pipeline after approval of pool rules by the AOGCC. PTU gas sales will require major facilities and pipeline additions / expansions and the drilling of additional wells. Gas sales Conceptual Engineering will be undertaken in parallel with engineering work for the IPS to ensure the IPS and potential gas sales development designs are integrated and compatible. Front End Engineering and Design (FEED) will be initiated during the POD period to ensure PTU gas sales development work can be accomplished in parallel with a gas pipeline. The following specific work tasks will be initiated and conducted during the POD period:

- Using geological modeling and reservoir simulation work completed in 2007, conduct Conceptual Engineering to develop the detail and quality of the facility design and cost estimate, including early project development basis, early project execution plan, safety system design philosophy, logistics plan, regulatory permitting plans and cost estimate.
- In conjunction with Conceptual Engineering, update drilling and completion plans and costs for gas sales development wells. This will include determining optimum drillsite locations and completion concepts, and selecting individual well locations and displacements, and estimating drilling and completion times and costs. This information will be important in determining total gas sales development costs and timing.
- Continue planning for the permitting process
- FEED for gas sales will be initiated during this POD period to ensure this work can be completed in advance of a gas pipeline project

As discussed in Section 9, owners have commenced the process for and will seek approval of pool rules from the AOGCC for the offtake rate and gas depletion development plan to allow individual owners to participate, subject to the terms and conditions each individual owner deems appropriate, in a gas pipeline open season.

8. Expanded Development

Gas Development

The IPS design will allow for expansion of gas injection development. Screening studies of expansion of gas injection development will be conducted after the IPS has commenced production and key performance information has been gathered. This work will be used to assess the potential for additional development through expansion at varying injection capacities. This work will be addressed in more detail in subsequent plans of development.

Oil Rim Development

The Thomson Sand reservoir contains an oil column (oil rim) that underlies the gas and will be further appraised. Technical work that has been conducted to date indicates there are limited reservoir targets where high quality reservoir rock intersects the oil rim. To help address technical uncertainty regarding drilling cost, sand thickness, and producibility of the oil, delineation wells will be drilled to evaluate the Thomson oil rim, as discussed in Section 3.

Data collected during the drilling of each oil rim delineation well will be evaluated to determine the value of collecting additional information such as core, wireline logs, fluid samples and productivity. Depending upon the results from static data and other information gathered in drilling the wells, the next step would be to install temporary test equipment onsite and conduct a production test to improve understanding of the viability of developing and producing the oil rim.

During Conceptual Engineering and FEED for the IPS project, facilities will be designed to accommodate production from viable Thomson Sand oil rim wells. If oil rim testing results

are encouraging, production from viable wells will be processed at the IPS facilities. The pipeline, described in Section 4, for full scale liquid development of the PTU can accommodate production from the oil rim.

9. PTU Pool Rules

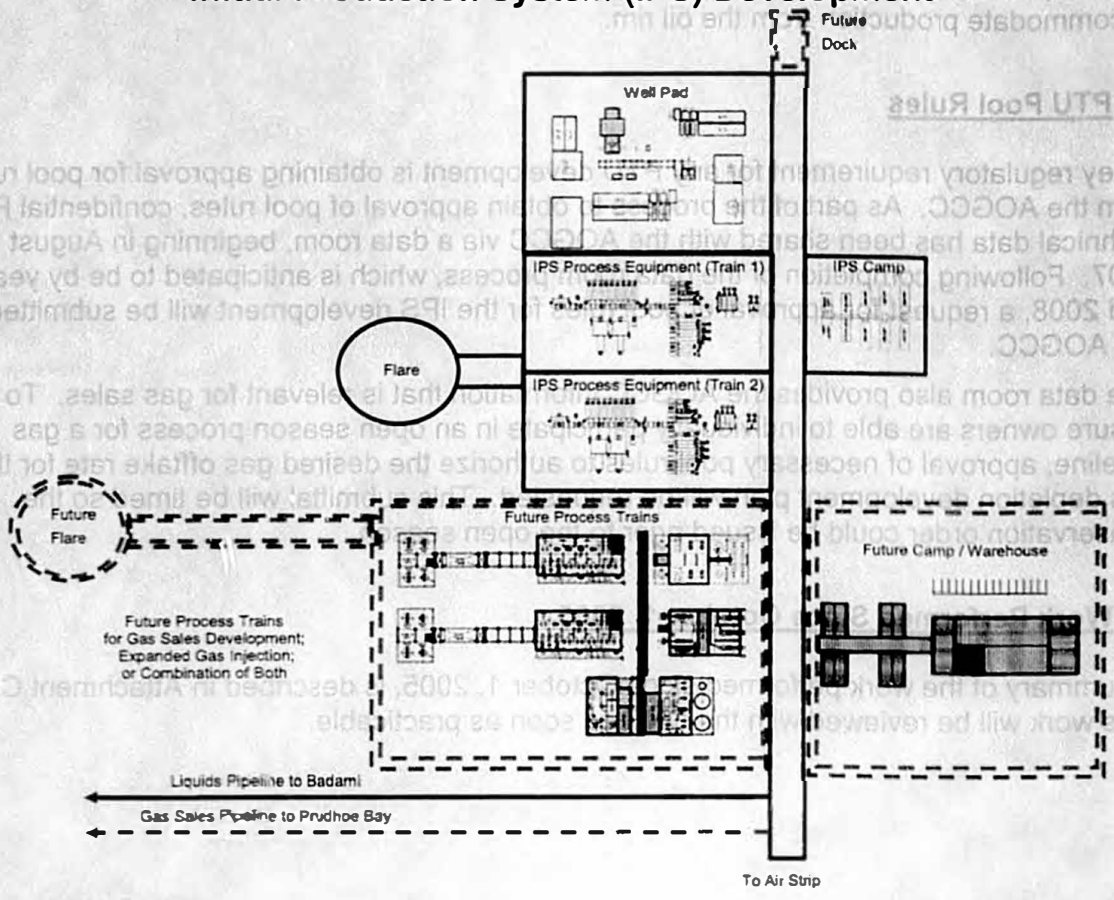
A key regulatory requirement for any PTU development is obtaining approval for pool rules from the AOGCC. As part of the process to obtain approval of pool rules, confidential PTU technical data has been shared with the AOGCC via a data room, beginning in August 2007. Following completion of the data room process, which is anticipated to be by year-end 2008, a request for approval of pool rules for the IPS development will be submitted to the AOGCC.

The data room also provides the AOGCC information that is relevant for gas sales. To ensure owners are able to individually participate in an open season process for a gas pipeline, approval of necessary pool rules to authorize the desired gas offtake rate for the gas depletion development plan will be requested. This submittal will be timed so the conservation order could be issued prior to the open season.

10. Work Performed Since October 1, 2005

A summary of the work performed since October 1, 2005, is described in Attachment C. This work will be reviewed with the DNR as soon as practicable.

Attachment A
Initial Production System (IPS) Development



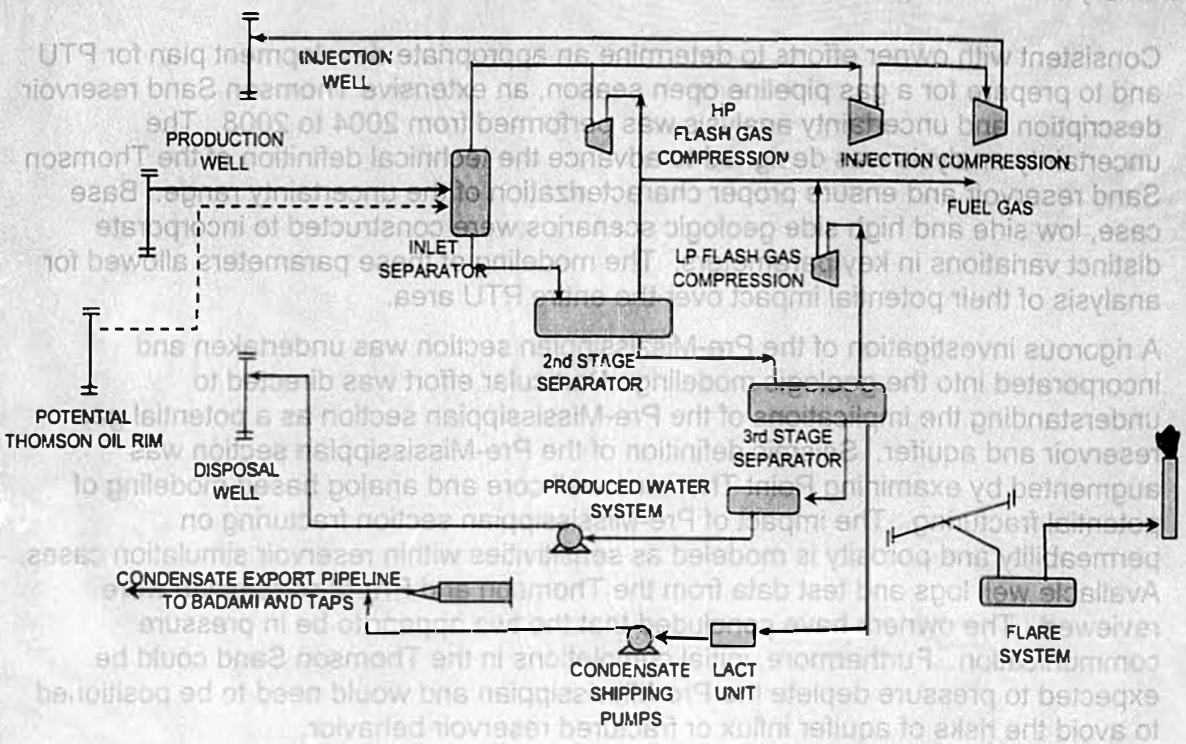
IPS Design Basis

- Single pad with 3 initial delineation/development wells (producer, injector and disposal)
- Initial Production system for separation, compression and condensate stabilization
  - 2 train x 3 stage flash separation
  - 2 train x 2 stage gas injection compression (3,000 psi to 10,500 psi)
- Power, water, sewage, diesel and methanol tanks, telecom
- Liquid hydrocarbon export: 8" to 12" pipeline to Badami pipeline tie-in point
- Construction camp, operations camp and warehousing; airstrip

Summary

- Initial Gas Rate: 200 million cubic feet per day
- Initial Condensate Liquids Rate: 10,000 barrels per day
- Initial oil rim liquids rate for processing at IPS facilities to be determined in conceptual engineering

Attachment B
IPS Process Flow Diagram



Attachment C
Summary of Work Performed To Date

A summary of the work performed since October 1, 2005, is described below.

C.1 Consistent with owner efforts to determine an appropriate development plan for PTU and to prepare for a gas pipeline open season, an extensive Thomson Sand reservoir description and uncertainty analysis was performed from 2004 to 2008. The uncertainty analysis was designed to advance the technical definition of the Thomson Sand reservoir and ensure proper characterization of the uncertainty range. Base case, low side and high side geologic scenarios were constructed to incorporate distinct variations in key parameters. The modeling of these parameters allowed for analysis of their potential impact over the entire PTU area.

A rigorous investigation of the Pre-Mississippian section was undertaken and incorporated into the geologic modeling. Particular effort was directed to understanding the implications of the Pre-Mississippian section as a potential gas reservoir and aquifer. Seismic definition of the Pre-Mississippian section was augmented by examining Point Thomson well core and analog based modeling of potential fracturing. The impact of Pre-Mississippian section fracturing on permeability and porosity is modeled as sensitivities within reservoir simulation cases. Available well logs and test data from the Thomson and Pre-Mississippian were reviewed. The owners have concluded that the two appear to be in pressure communication. Furthermore, initial completions in the Thomson Sand could be expected to pressure deplete the Pre-Mississippian and would need to be positioned to avoid the risks of aquifer influx or fractured reservoir behavior.

An iterative preliminary reservoir model construction and simulation effort was completed in support of the overall uncertainty analysis. This work was used to evaluate changes in the geologic models and identify major factors impacting dynamic performance and recovery. A rigorous analysis of these major factors was implemented and formed the basis for input to the geologic models. After the geologic models were constructed and reviewed, they were used in full field compositional reservoir simulations. These simulations form the core of a statistical analysis that studied key subsurface factors impacting a PTU development.

The factors having the greatest impact on resource size and performance were facies, porosity distribution, and structural uncertainty related to velocity-depth conversion. The facies distribution was varied to represent a reasonable range of possible depositional environments for the Thomson Sand, ranging from laterally amalgamated fan deltas to more discrete fan delta lobes with intervening lower quality siltstone facies. Correspondingly, the porosity ranges were varied to be consistent with the facies distributions. Three facies types are present in the Thomson Sand; conglomerates, sandstones and siltstones. Conglomerates exhibit high as well as low porosity due to the deleterious effects of cementation, sandstones exhibit the best porosity, and the siltstones generally exhibit the lowest porosity. The facies and porosity impacted both the resource size and recovery. The impact of structural uncertainty was analyzed and varied as a function of distance from well control by flexing the structure up and down. Structure primarily impacts the resource

size. Although these three factors had the most significant impact, other factors that could impact the resource and recovery were investigated as part of the uncertainty analysis such as reservoir thickness and water saturation, as well as Pre-Mississippian volume, connectivity, and faulting.

The results of the uncertainty analysis served as a guide in the selection of input parameters for the construction of representative low, high and base case models. Based on the geologic models completed in 2007, the in-place resource range for the Thomson Sand in the Point Thomson field was updated. The resultant simulation models formed the basis for the PTU development planning studies conducted in 2007.

C.2 Development planning studies were completed to evaluate alternate development options. This included developing screening cost estimates for facilities and drilling. The alternate development options included gas injection and gas storage options. This work resulted in the selection of the IPS described in this POD as the appropriate way to bring the PTU into commercial production.

C.3 Facilities and pipeline work was focused on preparing execution plans for Conceptual Engineering for both hydrocarbon liquids production via the IPS and gas sales. The execution plan includes a detailed scope of work listing each of the deliverables to be prepared, the degree of completion (initial, update, final) and responsible party (owner, Engineering Contractor). The plan also includes determination of organization and staffing level requirements. This will allow for a rapid initiation and ramp-up of Conceptual Engineering upon completion of the reservoir simulation work.

C.4 Significant completion related technical studies were conducted including a laboratory study to measure and analyze rock compressibility data from Point Thomson core samples, a surface subsidence study, a well operability limit (WOL) study and a completion design study. The results of these studies will be used during the Conceptual Engineering phase to study, refine and optimize the completion concept selected.

C.5 Previous permitting support documents were reviewed in preparation for permitting activities. A significant amount of work for the previous gas injection development has been identified as applicable for other development options.

C.6 The process of applying for pool rules from the AOGCC was initiated. The AOGCC and the owners agreed to a protocol for the sharing of confidential data with the agency and the protocol was adopted by the AOGCC at a public meeting on April 26, 2006.

A comprehensive PTU review was held for the AOGCC and their consultants in May 2006. The review included discussion of the previous gas injection development efforts and introduced the owners' work to assemble a proprietary worldwide database of potential Point Thomson analogue reservoirs. The results of the analogue study and worldwide database were presented to the AOGCC in December 2006. The data room process was initiated in August 2007 with the first in a series of steps to share confidential subsurface description and development plans for the

Thomson Sand reservoir. Steps 1 and 2, comprising Reservoir Data & Interpretation and Structure & Seismic Interpretation, have been completed. Step 3 on Fluid Data & Analysis is ongoing.

C.7 In preparation for commencing drilling in the 2008/2009 winter season, detailed well construction work has been performed to establish the functional and technical specifications for hardware (i.e., casing, tubing, wellhead, trees and subsurface drilling and completion equipment), drill rig requirements, fluid design (i.e. mud and cement), and well operability limits. A drill rig has been secured and purchase orders for long-lead materials placed to commence development drilling for the IPS.

TESTIMONY OF CRAIG HAYMES

ON POINT THOMSON'S 2008 PLAN OF DEVELOPMENT

TO THE ALASKA COMMITTEES ON AGIA / ENERGY

JUNE 17, 2008

INTRODUCTION

Chairmen, members of the committee, legislators:

Good afternoon. For the record, my name is Craig Haymes. I am the Alaska Production Manager for ExxonMobil, based in Anchorage. I want to thank the committee and the legislators for the opportunity for ExxonMobil, as operator, and on behalf of the 27 lease holders to update you on Point Thomson and particularly to present a brief outline of the Point Thomson Unit (PTU) Plan of Development (POD) that was submitted to the Department of Natural Resources (DNR) on February 19, 2008. You should have received a handout package which contains a PTU brochure, my prepared testimony and associated slides, along with a copy of the February 19, 2008 PTU POD.

I intend to discuss three key areas today.

- The PTU POD and the benefits we see for the State and the 27 lease holders from this plan
- The criticality of Point Thomson gas to the success of the Alaska gas pipeline project

- Significant concerns we have with the recent representation of Point Thomson resources through DNR's summary of PetroTel's report

Before I move into the details of the POD, I would like to make a few introductory comments. ExxonMobil and the other 26 lease holders were very surprised and disappointed with the DNR's decision last week to not reconsider the POD that was submitted on February 19, 2008. The POD contains a project that is already underway that will bring the PTU resources into production by year end 2014. There is no faster path to bring the PTU into production, there is no other way to ensure that the PTU gas will be available for a gas pipeline, gas which is critical to the success of a gas pipeline. Until 3 weeks ago, everyone agreed that Point Thomson was critical for a gas pipeline. We don't understand how this can change so rapidly, when Point Thomson contains 25% of the known gas resources on the North Slope. I will discuss the criticality of Point Thomson gas in more detail later in the presentation.

As I mentioned, this POD is a project that will bring PTU into production by 2014. We have Alaskan companies working on the project right now. We are ramping up to over 200 jobs by February 2009 alone. Significant spending is already happening and activities are undeway in the State today. We are moving forward with critical activities in preparation to commence a multi-year drilling program this winter. The first well will be commenced in less than 8 months! Since the decision last week, we have had quite a few phone calls from concerned contractors, Alaskans, and employees on their future. We are awarding more contracts to Alaskan companies this week and next. We have

told everyone to keep going, because we are optimistic that the DNR will want to resolve this issue in a way that will put Alaskans to work now.

We have consistently stated that we, and the other 26 lease holders, want to resolve the Point Thomson dispute rather than litigate. We believe the current POD provides a way forward. The DNR recognized in their decision on April 22, 2008, that the POD "...may present a technically reasonable first step for developing these lands from a conservation perspective." We are happy to have further discussions with the DNR on our POD. The 27 lease holders do not want to litigate, but if we have to we will. We would like to find a way to resolve this issue with the DNR. We are looking to the future.

As I mentioned the fastest path to move Point Thomson to production is through the current lease holders and through the current POD. The drilling program that commences this winter will provide us with important information about the reservoir, the initial production data we obtain will be critical to assess the resource size at Point Thomson. The drilling, reservoir and dynamic production data will be essential for future expansion, leading to a gas sales development.

With those opening remarks, I would now like to provide you with a brief overview of the PTU POD.

The PTU POD is an unconditional commitment to production by year end 2014 through a project estimated to cost $1.3 Billion. The PTU POD is supported by all of the lease holders. The PTU POD will not only establish production and further delineate the Point

Thomson resources, but will also set-up Point Thomson for future phases of development, including additional gas cycling, oil production, gas sales or some combination. With this initial phase of development, Point Thomson will be the highest pressure gas cycling project in the world, and gas cycling will be through world class drill wells. While the owners are excited with the current POD, there are significant unique challenges and risks with the Point Thomson reservoirs, which I will highlight today.

POINT THOMSON – ISOLATED FROM THE REST OF THE NORTH SLOPE

The PTU is located 60 miles east of Prudhoe Bay and the Trans-Alaska Pipeline and 22 miles east of Badami. The PTU is in a remote and environmentally sensitive area, close to ANWR. There is no road to the PTU. It is an area of approximately 80,000 acres.

The Point Thomson reservoir straddles the coastline and is over 12,000 feet deep. The pressure of this reservoir is 10,200 psi, which is over twice the pressure of Prudhoe Bay. The Point Thomson reservoir is abnormally pressured, which means that the pressure is extremely high for the depth. As such, higher cost drilling and well completion operations are required due to the stringent safety measures necessary to maintain well control. In addition, high pressure injection and fluid handling facilities are required to safely manage these high pressures. I will talk more about those challenges later.

Under this POD, the condensate, which is a liquid hydrocarbon recovered from the gas at the surface (like diesel or kerosene) would be exported through the Trans Alaska

Pipeline System (TAPS) by tying into the existing oil pipeline network as shown in red. I will talk more about the way a condensate is recovered later.

POINT THOMSON – OBTAINING INFORMATION

Nineteen exploration wells have been drilled at Point Thomson, represented by each of these red dots. Fourteen of these wells penetrated the Point Thomson reservoir. We have collected over 3600 feet of core from these wells and completed 20 well tests.

In addition to the 19 wells that have already been drilled, we have also integrated the data from eight 3D seismic surveys. Seismic interpretation at Point Thomson is complicated due to variances in perma-frost thickness. The permafrost thickness at Point Thomson is as much as 2000 feet onshore and thins offshore beneath the shallow coastal waters. This variance creates challenges in determining the complex structural picture of the deep Thomson reservoir.

POINT THOMSON – POD COMMITMENTS

There has been quite a bit of discussion about whether the lease holders at the PTU have fulfilled the commitments they made.

I would like to define a plan of development or POD. A POD contains work plans that are necessary to ultimately develop and produce a reservoir for optimum hydrocarbon recovery. The process for a POD is the same for any reservoir in Alaska. Work undertaken in a POD usually consists of activities such as studies, engineering or drilling of wells. These work activities are agreed with the DNR up front when the POD

is approved, and then the lease holders move forward with those work plans. As the lease holders move forward with the work plans, new information is obtained and changes in the planned work activities may result. These changes to work plans are reviewed with the DNR and factored into the future work plans and the next POD. The DNR approves the next POD, perhaps with conditions or changes, which are discussed and agreed, and then the lease holders continue with their work plans. This cycle continues for the life of the reservoir. Typically, PODs have a term of one to two years. This is the same process that is used at Prudhoe Bay, Kuparuk, Endicott, and most, if not all of the reservoirs in the State, including Point Thomson.

There have been 21 PODs at PTU between 1978 and 2005 and all were approved by the DNR. Historically, the work performed by the lease holders pursuant to these POD's was reviewed by the DNR and served as a basis on which subsequent POD's were approved.

On a number of occasions during this 27 year period, the lease holders sat down with the DNR and reviewed the work completed and why it was not prudent or economic to begin producing Point Thomson resources at that time. These work activities have advanced the DNR's and lease holders' current understanding of the resource potential at the PTU and the significant risks that exist. These reviews never would have occurred if the lease holders had not been devoting their significant efforts, including spending over $800 million, to find ways to begin production at Point Thomson. It was the information gathered from this past work that has allowed the lease holders to arrive at the current POD.

The recently submitted POD is unique and I want to focus on this. This POD specifies both work activities and a firm commitment to develop Point Thomson and to bring it on production. The State wants production at the PTU, as does ExxonMobil and the other 26 lease holders who are committed to production of hydrocarbons from the PTU through this POD. I will talk more about this commitment and assurances offered shortly.

PTU – EFFORTS TO DEVELOP

There has been a lot of discussion recently about timely development at PTU. As I mentioned earlier, the 27 lease holders have spent over $800 million to date in an effort to develop PTU resources. The PTU has significant risks, many of which I will talk about later.

Prior to 2002, oil averaged less than $20 per barrel and gas averaged less than $4 per million cubit feet, and the outlook for prices reflected that reality. Historically the lease holders looked at many different ways to commercialize the PTU resources, whether it was gas cycling, oil production or gas sales, but no development was found to be commercially viable. All of these results were reviewed with the DNR on a regular basis, and the work completed was taken into account for the subsequent POD.

It is only recently that commodity prices have increased significantly; however, given historical volatility of prices, there is still a risk that higher oil and gas prices will not be sustained. It is important to recognize that significant investments are required to

develop PTU resources - an estimated $1.3 billion for 10,000 barrels per day of condensate is an example. The lease holders are taking on the price commodity risk any time they make an investment over decades.

POINT THOMSON – PLAN OF DEVELOPMENT

This PTU POD is based on a foundation of objective technical work. We have used all of the data from the 19 exploration wells and the eight 3D seismic programs. We have taken that data and using state-of-the art modeling techniques, analyzed the very challenging reservoirs in the Point Thomson field.

We have looked beyond Point Thomson and assessed over 230 analogous fields worldwide to assist us in developing this POD. I will talk more about these results shortly. We have also utilized the collective expertise of four of the largest private oil and gas companies in the world.

To date the lease holders have spent over $800M at Point Thomson. This POD commits the lease holders to an estimated $1.3 Billion project, and includes an in al phase of production designed to accommodate future expansion capability.

PTU POD – PLAN TO PRODUCE CONDENSATE

Through this POD, the Point Thomson facilities will produce 10,000 barrels per day of condensate by year end 2014, by cycling 200 million cubic feet per day through production facilities. The facilities include an export liquids pipeline sized for the

expected full development (up to 70,000 barrels per day), an airstrip, camp and facilities.

The drilling and production facilities will be designed and installed to minimize the impact on the environment. We will be using ice roads and existing gravel pads as much as practicable, and no off-lease roads are planned.

The PTU POD includes a commitment to drill a minimum of five wells, not only to cycle gas and produce condensate, but also to delineate all of the PTU reservoirs. In addition to the gas cycling, oil production can be accommodated in these facilities if the oil rim is found to be productive through well testing. These oil wells will be drilled so that they can also be potential gas production wells in the future. This POD provides for the delineation of all PTU reservoirs. The production facilities are being designed and built so that they can be expanded, either for cycling, oil production, gas sales or combinations of these options. The lease holders have significant incentive to fully develop the resource. The initial estimated cost of $1.3 billion produces 10,000 barrels of condensate per day, but we need to build on that to realize the full value of the PTU resources.

PTU – PROJECT ACTIVITY UNDERWAY

The lease holders are committed to the PTU POD. Key project activities to achieve production by 2014 are underway right now. We have significant resources working on this project.

We have already contracted the Nabors Rig 27E and commenced $20 million of rig upgrades to ensure it is ready to commence drilling at the PTU this winter. Significant rig upgrades are required, including new drilling mud and electrical systems, to ensure that the rig can drill safely into the very high pressure Point Thomson reservoir. This upgrade work is happening now.

We have also ordered long lead materials for the first well. These long lead materials include casing strings and wellhead equipment which are made of high strength steel using special corrosion resistant alloys. These materials require at least nine months to manufacture and are scheduled to arrive in Alaska in November 2008.

Next week we will award a contract to an Alaskan company worth tens of millions of dollars to construct and maintain a 50 mile ice road and airstrip at the PTU. The ice road will run from Endicott along the coastline to the PTU and require over 30 to 40 workers to build and maintain. Another activity that will commence next week is a PTU site survey to ensure that we scope and plan all necessary equipment and materials for preparing the site for the drill rig.

We had initiated discussions with the DNR to progress permitting applications for the site activity and drilling operations this winter. Approval of these permits will be critical to ensure we can continue to progress the project activities as we ramp up to over 200 jobs by Feb 2009.

With permit approvals, we will be in a position to undertake significant activities, including:

- During July and August, the barging of ice road construction facilities and pad equipment to the PTU, including camp set-up, gravel hauling, mobilization of earthwork equipment and pad preparation. This will require two deck barges (200' by 60'), accompanying tugs and significant other support services including aviation. Approximately 23 round trips from Prudhoe Bay will be required given the significant materials and equipment required. Over 20 people will be required for this activity, contracted with Alaskan companies.
- During December and January, the construction of the 50 mile ice road and subsequent mobilization of the drilling rig to the PTU site. Over 30 to 40 people will be required for this activity through an Alaskan company to be announced next week.
- By February 2009, we will spud the first well of a multi year drilling program, with over 200 jobs required for the drilling operation through Nabors drilling contractor.

The lease holders are excited with the PTU POD Project and look forward to working with the State to progress this initial phase to production by 2014.

POINT THOMSON – PRODUCE CONDENSATE BY CYCLING GAS

What do we mean by cycling gas to produce condensate? The cycling of gas requires two wells; a production well and an injection well. These wells will be placed four miles apart in the heart of the reservoir to provide a true test on the effectiveness of cycling gas at Point Thomson. There are some significant risks, which I will discuss later.

The gas reservoir is at a temperature of 230 degrees F and a pressure of 10,200 psi. The gas production well is expected to produce 200 million cubic feet per day. We then take that produced or "wet" gas, which is gas saturated with condensate, through a central processing facility where the pressure and temperature will be reduced through multiple separators. As the temperature and pressure drop, some of the wet gas condenses into a liquid called gas condensate. The condensate, which is somewhat like diesel or kerosene. will then be sent to market via TAPS. After condensate is extracted, the dry gas remaining (excluding fuel) is pressured to 10,200 psi and then injected back into the reservoir. Over time, more and more of the injected dry gas moves through the reservoir towards the production well and helps to produce more wet gas. That is why this recovery mechanism is called a "cycling" project, as the gas is cycled through the reservoir. By injecting the gas, reservoir energy is conserved for future production and gas sales.

PTU POD – ADDRESSING DNR'S CONCERNS ON TIMELY DEVELOPMENT

The lease holders have prepared this POD based on significant technical analysis of all available data and through prudent management of the risks and good reservoir management practices. The lease holders have leveraged the expertise of four of the largest oil and gas companies in the world, ExxonMobil, BP, Chevron and ConocoPhillips.

As the lease holders developed the POD we listened very carefully to the DNR's concerns. Earlier this year the DNR advised the lease holders that they would like to

see a POD that contained timely development, reservoir delineation and a firm commitment to complete the work plans. We believe the current POD addresses these concerns.

However, to ensure we were taking into account DNR's concerns, we requested specific feedback and guidance on what DNR wanted to see in the next POD. It has been very frustrating to the 27 lease holders that in the year leading up to last weeks rejection of the POD we received no additional guidance on what the POD should contain, despite our repeated requests to the DNR. In fact, the DNR actually advised us to disregard their prior guidance. This lack of communication has been disappointing, but we continue to believe that dialogue between the DNR and lease holders provides the best path for resolution of the POD and the PTU in a way that will maximize benefits of this resource to the people of Alaska and the lease holders.

As I mentioned, the DNR requested the lease holders address three general areas as part of the POD. The first area was around timely development.

The lease holders believe the PTU POD addresses DNR's concerns about timely development through a detailed schedule of milestones leading to production by 2014. We already have Alaskan contractors in place to commence the five-well drilling program this winter and will employ over 200 workers.

As I mentioned earlier, Point Thomson will be producing 10,000 barrels per day of condensate by 2014 through this initial development phase, with future expansion capabilities.

PTU POD – CLEAR AND COMMITTED TIMELINE

As part of the PTU POD, the lease holders submitted a detailed schedule that would allow the DNR to monitor progress and milestones on an ongoing basis. There are three main components to this schedule. Blue represents drilling activities, grey engineering and permitting activities and green procurement, construction and installation activities.

As shown on the schedule we are commencing the five-well drilling program this winter and it will continue through to 2012. We are planning to start the drilling program now to provide us with early information for the project design, but also to ensure that if there are any delays with drilling these world class wells, that the delay does not impact production by 2014.

We have allowed four years in the schedule to complete engineering and permitting activities which are critical for the success of the project. Finally, we have allowed two years to order the high pressure long lead materials required, and two winter seasons to install the facilities, leading to production by year end 2014.

In our POD we committed to this timeline of milestones and stated that we would look for ways to accelerate the schedule.

In addition to these activities, we also included in the POD a commitment to complete the AOGCC Pool Rules Data Room process, which we commenced voluntarily in August 2007. We are prepared to complete this process by the end of this year. We also committed to complete conceptual engineering and to submit a Pool Rules application to the AOGCC by mid 2009 for a gas sales development. These are essential activities that will underpin a gas sales development at PTU, critical for an Alaska gas pipeline project.

PTU POD – ADDRESSING DNR's CONCERNS OF RESERVOIR DELINEATION

As I mentioned earlier, the lease holders listened very carefully to what the DNR were looking for in this POD. I have already discussed the first area, and would now like to discuss the second area – reservoir delineation.

The lease holders believe the PTU POD meets DNR's concerns on reservoir delineation through a minimum of a five-well drilling program for this initial phase. The POD not only commits to cycling gas and producing condensate, but also commits to drill three additional delineation wells. In fact, the POD states that the lease holders will drill additional wells as necessary to achieve the objectives of cycling gas and delineation of all reservoirs.

What do the wells look like?

PTU POD – PLAN TO DEVELOP AND DELINEATE

The PTU POD has a clear production commitment and a delineation commitment that will set up PTU for future development.

In addition to the cycling project wells, there will be three additional delineation wells targeting gas and oil reservoirs, as shown in the East, West and an unspecified location (5th well). These delineation wells will target a thin heavy oil rim at the edge of the gas reservoir, and through logging and well testing, we will determine If these wells can commercially produce oil. If productive, the oil wells can be tied back to the central processing facility and the oil produced and exported along with the condensate through TAPS.

However, there is great risk with these oil rim wells. The oil is very viscous or heavy and therefore does not flow easily. The heavy oil accumulation is relatively thin and discontinuous and sandwiched between gas and water. Since the gas and water are much more mobile in the reservoir, there is a high risk that the gas and water will flow preferentially rather than the more viscous heavy oil. We certainly hope that these wells are commercially viable, as each one will cost approximately $80 to $100 million dollars. To put that in perspective, a typical Prudhoe Bay well currently costs $6 to 8 million dollars – a PTU well is 10 to 15 times more than a Prudhoe Bay well.

The delineation wells will also target the shallower Brookian oil prospects and test their potential. It should be noted that the Brookian oil prospects are not connected to the

main Thomson reservoir and appear to be very similar to the Badami accumulations that BP is developing at the Badami Unit 22 miles to the west of PTU.

If the oil delineation plan indicates that the oil rim cannot be produced in commercial quantities, we will keep the wells and could use them as future gas production wells. We can do this, as the wells will also penetrate the gas reservoir. This is important as we can also use these wells to monitor the pressure on the flank of the reservoir, as we cycle gas in the center and produce condensate. By monitoring the pressure of these wells on the flank we can determine if the production and injection wells are communicating with each other. That information will help us determine the size and dynamic characteristics of the reservoir. If we get favorable results, we will have the ability to expand gas cycling with the next phase of development.

For example, we could expand the central production facility to accommodate additional cycling using the wells that were drilled to help delineate the Thomson resource The beauty of this POD is that it provides the flexibility to accommodate different outcomes and to pursue future expansions in a timely manner.

The lease holders have significant incentive to expand the facilities and produce more liquids and gas. Spending $1.3 billion for 10,000 barrels per day of condensate has significant technical and operational challenges, but we view it as a necessary and prudent step for the lease holders to take.

PTU POD – ADDRESSING DNR's CONCERNS ON FIRM COMMITMENT

As I mentioned earlier, the lease holders listened very carefully to what the DNR were looking for in this POD. I have already discussed the first and second area, and would now like to discuss the third area – firm commitment.

During the March hearing, where the lease holders unanimously supported and presented this PTU POD to the DNR, we discussed numerous assurances to demonstrate our firm commitment to bring PTU onto production by 2014. Specifically we provided:

- A timeline that provided a clear path to production. This is a unique POD for PTU. This means that the lease holders have agreed to carry all of the development risks, all of the reservoir risks, all of the technical risks to bring Point Thomson into production.
- Confirmation that we had secured a drill rig and ordered long lead materials to ensure we can commence drilling the five-well program this winter.
- A detailed schedule, as I showed you earlier, which would allow the DNR to monitor progress on an ongoing basis.

After the hearing in March, the lease holders provided the DNR with two additional assurances. Senior management from BP, Chevron and ExxonMobil sent letters to Commissioner Irwin confirming that our respective corporations were fully aware of the PTU POD, and were fully committed to the POD.

Finally, the lease holders provided a draft proposed Superior Court order that would provide the DNR the ability, through the Superior Court, to terminate the PTU if any one of seven interim milestones, as outlined in the PTU POD schedule, were not met.

The lease holders believe they have clearly demonstrated a clear commitment to production for the PTU. Some may ask, how can we trust the lease holders to keep their commitments? As I mentioned, this POD contains unique commitments; commitments that have not been made before with clear mechanisms for the DNR to ensure performance.

PTU POD – PRUDENTLY MANAGES RISK

The PTU POD is a phased development that will prudently manage many risks. I have grouped the main risks into five key areas.

It will be important for the lease holders to effectively manage the health, safety and environmental risks of this project given the high pressure operation will be in an arctic environmentally sensitive location

It is also critically important that the reservoir risks are managed appropriately, for both the state and the lease holders. The Point Thomson reservoir is a retrograde condensate field that behaves differently compared to traditional oil and gas reservoirs. There are uncertainties in reservoir quality, connectivity and size that are particularly significant to gas injection and cannot be resolved with seismic interpretation or delineation drilling alone. Delineation of the gas and oil sections of the reservoir and

initially cycling gas in the 'heart' of the reservoir will allow us to prudently manage these risks. I will discuss the cycling risks in more detail shortly. Cycling the gas will conserve the resource and set-up Point Thomson for the next phase of development.

Managing the high pressure operations and facilities will also be important. We will require separation facilities rated for 3,000 psi and compression facilities rated in excess of 10,000 psi. The inlet separator alone will require a steel wall thickness of six inches. The wells that we will drill will be extended reach and in an over-pressured environment. Prudently managing the facilities and leveraging technology will be critical for the success of the project.

As we drill and operate the high pressure operations we will learn from facility and well performance, which will allow us to successfully manage operations in future developments.

Finally, the Point Thomson world class wells and facilities will require world class project management skills. Management of costs and schedule will be critical for this initial phase and subsequent phases of development. Over the last five years, the average facilities cost and schedule of 44 ExxonMobil operated major projects came within five percent of the cost projected at funding.

ExxonMobil and the lease holders are fully committed to bring Point Thomson into production by year end 2014, which will set up Point Thomson for subsequent expansions for gas cycling, oil production, gas sales or combinations.

PTU – RESERVOIR QUALITY AND PERFORMANCE

I would now like to discuss reservoir quality and performance associated with the cycling operation.

When we drill the production and injection wells we are hoping to find high quality reservoir. We are also hoping that when we commence cycling gas between these wells that the gas will flow freely as represented by the red arrows from the injection well on the left to the production well on the right. It is this sweeping effect that will push wet gas with condensate to the producer and allow the production of condensate to the TAPS pipeline.

However, as we all know, no reservoir is homogenous; they are in practice of variable quality and accurately quantifying the degree of quality is paramount to selecting the appropriated development concept for the reservoir.. For example, we could drill the two wells and find the quality is good in the vicinity of the well, but then when we cycle the gas find that the two wells do not communicate or communicate poorly. In such a case, this would directly translate into significantly less condensate produced than would be expected in a good quality reservoir.

The PTU POD prudently manages this risk by targeting the initial cycling wells in the heart of the field. This will allow us to learn more about the reservoir dynamics and performance and re-calibrate our geological and reservoir models with dynamic

production data. We can then move forward with the next phase of development, with a strategy that maximizes value for all stakeholders, the State and the lease holders.

CYCLING AT HIGH-INJECTION PRESSURE

The lease holders have completed an assessment of over 230 analogous gas fields around the world. These are gas fields operated by many different companies. I have shown a selection of these fields on this chart, represented by individual bars. Due to the proprietary nature of the study; we have removed field names from the graph.

Point Thomson is shown as the red bar, with a pressure of 10,200 psi. Blue bars represent gas fields that were developed by gas blowdown or gas sales. Yellow bars are fields that were initially developed by gas cycling. As you can see on this graph, the highest pressured known gas cycling project in the world is close to a wellhead gas injection pressure of 7000 psi Point Thomson will be the world's highest pressure gas cycling project when operational. This means that the technical challenges and cost implications are unprecedented.

WELLS REQUIRED FOR HIGH PRESSURE OPERATIONS

In addition to the high pressure facilities, we also have high pressure drilling operations. A typical Point Thomson gas injection wellhead is shown in the picture on the left hand side of this slide. This injection wellhead is rated at 15,000 psi and is over twice the height of a typical wellhead at Prudhoe Bay or Kuparuk.

As I mentioned earlier, the reservoir pressure is abnormal at Point Thomson, at over 10,200 psi. The reservoir straddles the coastline and as such will require extended reach wells. As a result we will require amongst the heaviest drilling mud in the world to drill these wells, and when completed will have world class wells. The mud density will be 16 pounds per gallon, which is over twice the density of water.

The combination of high pressure, extended reach drilling and heavy mud requirements results in drillwell costs at Point Thomson that are very high, ranging from 10-15 times the typical cost for a Prudhoe Bay well and requiring almost five times longer to drill.

PTU POD – PHASED APPROACH MITIGATES RISK

When you look at the collective risks at Point Thomson they are significant. The combination of reservoir management risks, drilling risks and facilities risks are unique. This PTU POD prudently manages these risks through the application of good oil and gas field practices, by utilizing proven technology and by leveraging the collective owner's worldwide experience.

The lease holders will be able to apply critical learnings from this initial development and set-up Point Thomson for future development expansions leading to a gas sales development.

PROPOSED PLAN OF DEVELOPMENT FOR POINT THOMSON

In summary, this PTU POD provides

- Clear commitment to production by 2014

- Over 200 jobs this winter
- Further delineates all reservoirs through a minimum of a five-well drilling program
- Provides dynamic information about the reservoirs, critical information to help determine the full potential of the resource
- Conserves the gas resources through cycling
- Minimizes environmental impacts through utilization of ice roads and existing gravel pads
- Provides flexibility and expandability for cycling, oil production, major gas sales, or combinations thereof
- Ensures that Point Thomson gas is available for a Gas Pipeline Project

ExxonMobil, and the 26 other lease holders of the PTU are excited and committed to bringing Point Thomson into production by 2014 through this POD. The dynamic information we learn from this early production will be critical to set Point Thomson up for future expansions.

IMPORTANCE OF POINT THOMSON GAS TO GAS PIPELINE PROJECT

I would now like to address the importance of Point Thomson gas to the success of a future gas pipeline. In considering all future development scenarios for Point Thomson, one key consideration is the timing of a gas pipeline project and the availability of Point Thomson gas on the success of that project

Point Thomson gas represents 25% of the discovered North Slope gas resources. It is estimated that Point Thomson can provide daily gas production of approximately 1 BCF

per day. This production will provide the economies of scale needed on a mega-project such as the Alaska gas pipeline. I would like to note that the actual field offtake is a matter that will be addressed with the AOGCC at the appropriate time.

Inclusion of Point Thomson gas is critical to the success of the Alaska gas pipeline project for a number of reasons:

- Provides support for the critical firm transportation commitments (or "FT") which are necessary to secure project financing and making the project a reality. The market is looking for long term commitments.
- Provides security of supply for downstream consumers by ensuring supply in the event of a temporary shutdown in the Prudhoe Bay Field or should "Yet to Find" gas not materialize or not be adequate to meet gas marketing commitments.
- Mitigates liquids production impacts at Prudhoe Bay. With the production of PTU for gas sales, more Prudhoe Bay gas can remain in the field and continue to enhance oil recovery. [We recognize the field offtake for PBU is a matter that will be addressed with the AOGCC]

Inclusion of PTU gas in a Alaska gas pipeline project provides economies of scale for the project design resulting in reduced tariffs on shippers of gas, which results in increased value to all stakeholders, including the State of Alaska, PTU lease holders, other field owners and even explorers. The importance of low tariffs was recognized last Friday by Governor Palin. She wrote in an ADN Compass piece that "Transportation fees must be kept as low as possible." Including Point Thomson gas in a Alaska gas pipeline does just that.

Using data provided to the public by the Administration and their consultants, the gas pipeline tariff would increase by ~$1.00/MMBtu if PTU gas is not available to participate. That is a 20% increase in tariffs for the 3.5 BCFD pipeline versus the 4.5 BCFD pipeline. In fact the consultant's report shows a reduction in NPV to the State of almost $15 Billion dollars without PTU gas. Importantly, this increase in costs could also discourage exploration.

If PTU gas is excluded from a 3.5 BCFD pipeline, approximately 18 TCF of additional discovered gas is required to fulfill a 25 year shipping commitment. This additional gas would have to come from exploration activity within the next few years in time for the first open season. The amount of discovered gas required would be almost equivalent to discovering another Prudhoe Bay, with minimal dependency on the gas to recover hydrocarbon liquids. This level of discovered gas would be required to offset the natural decline that occurs in gas reservoirs while meeting the 25 year commitment at 3.5 BCFD. If PTU gas was included, the additional gas required would be reduced significantly, substantially reducing the dependence on successful near term exploration activities. [Appendix J of Alaska Gasline Determination Document]

If the tariff is $1.00/MMBtu higher, the costs of gas transportation would increase by $1.3 billion dollars a year! Over 25 years, the potential term of the FT shipping commitments, shippers would have to pay increased costs of over $32 billion dollars!

It is very clear that PTU gas is critical to a gas pipeline project. For this reason, we believe the PTU POD should be approved so that we are all in the best position to determine how best to produce PTU and be ready for a gas pipeline.

PTU – PETROTEL ASSESSMENT

I would now like to discuss PetroTel's recent assessment work on Point Thomson, as summarized by the DNR in Appendix O of the Alaska gas pipeline determination documents. I would like to note that the PTU lease holders have not been provided with a copy of the recent PetroTel detailed study, but based on DNR's summary of their analysis we have a number of significant concerns.

The summary report appears to be based on a selective and limited data set and indicates that significant critical work is yet to be done in quite a number of major areas. The report provides an estimate of recoverable liquid and gas hydrocarbons, but does not address fundamental necessary technical work such as development planning, well and reservoir optimization, environmental considerations, risk assessment, costs and economics. This level of technical work is essential to gain a proper understanding of the resource recovery at Point Thomson or for any reservoir in the world.

Based on the significant lack of fundamental technical work no sound conclusions on producible hydrocarbon resources can be drawn from this report. In fact the DNR's summary of the PetroTel report clearly overstates the developable liquid hydrocarbons.

Let me be clear that ExxonMobil and the other 26 lease holders have as much incentive as the State of Alaska to maximize resource recovery at Point Thomson. We have completed extensive reservoir and development planning work leveraging years of objective technical work. We have utilizing the expertise of four of the largest private oil and gas companies in the world. Our assessment of Point Thomson is based on all of the data and information available and we have used state-of-the-art geological and reservoir modeling techniques. We have also benchmarked Point Thomson with over 230 analogous gas fields from around the world.

As an example, we have undertaken significant technical work assessing the potential of the oil rim in the Thomson reservoir. We have concluded that the oil rim is thin, discontinuous and heavy. Even DNR's summary of PetroTel's report recognizes that the PTU oil rim is heavy oil, thin and discontinuous; yet it estimates a recovery factor of "close to 50%". The report also assumes you can drill up to 3000 feet horizontal wells to develop the heavy oil. It is highly unlikely that such long reach horizontal wells can be drilled at Point Thomson due to the extended reach and high pressure.

The lease holders have done extensive modeling and benchmarking on the oil rim and cannot achieve an economic recovery factor that exceeds five percent. We believe that once we have the opportunity to share our technical work with the DNR we will jointly conclude that a low economic recovery factor is prudent for the heavy oil rim in the Thomson reservoir.

As I mentioned earlier, the lease holders have completed extensive technical work on all of the PTU reservoirs. This technical work shows that over 90% of the developable hydrocarbons (gas, condensate and oil) can be produced today through a gas sales development. However, we also recognize a gas pipeline project is still many years away. As such, ExxonMobil and the 26 other lease holders developed the current POD which provides the opportunity to recover even more liquids prior to the start of gas pipeline operations.

Through a confidentiality agreement, we are currently sharing all of our most recent technical work with the AOGCC through the Pool Rules Data Room process, which commenced in August 2007. We are doing this on our own initiative as we believe it is a critical step towards assessing the future development of Point Thomson, whether it be gas cycling, oil production, gas sales or a combination.

The PTU lease holders remain willing to share the same technical work and expertise with the DNR.

POINT THOMSON - SUMMARY

I would like to wrap up my testimony. In summary,

- ExxonMobil and the other 26 lease holders were very surprised and disappointed with the DNR's decision last week to not reconsider the POD that was submitted on February 19, 2008.

- The PTU project is already underway and will bring the PTU resources into production by year end 2014, with future expansions leading to a gas sales development.
- We have Alaskan companies working on the project right now. We are ramping up to over 200 jobs by Feb 2009 alone
- There is no faster path to bring the PTU into production, there is no other way to ensure that the PTU gas will be available for a gas pipeline.
- The drilling data and production data we will obtain through this POD will be critical to assess the resource size at Point Thomson.
- We are already progressing a Pool Rules process through a data room with the AOGCC, a critical step to assessing the optimum development plan for PTU resources.
- There is no better way to ensure the success of the gas pipeline than to continue to progress current PTU development. The PTU gas is critical to the success of a gas pipeline, with 25% of the known gas resources on the North Slope.
- We have consistently stated that we, and the other 26 lease holders, would like to resolve the Point Thomson dispute rather than litigate.
- We would like to find a way to resolve this issue with the DNR, we are looking to the future.

ExxonMobil has been in Alaska for over 50 years and we look forward to working with the Administration, the legislators, industry and the people of Alaska to develop Alaska's resources into the future.

Thank you again for the opportunity to testify today.

POINT THOMSON PROJECT

Commitment to Produce

POINT THOMSON PROJECT

ExxonMobil

Taking on the world's toughest energy challenges.™

Plan of Development

Provides for Production

- Commence Engineering 2008
- Commence Drilling Program Winter '08-'09
- Provides Jobs to Over 200 People Next Winter
- 10,000 Barrels Condensate Per Day - 2014

Further Delineates Reservoirs

- Producer and Injector Wells
- Western Delineation Well
- Eastern Delineation Well
- 5th Delineation Well (East or West)

Prudently Manages Risks

- Phased Approach
- Reservoir Quality and Performance
- Drilling, Facilities, and Technology

Minimizes Environmental Impacts

- IPS Utilizes Existing Gravel Pad
- Offshore Drilling from Onshore Pad
- Utilization of Ice Roads

Conservation

- Cycling Enhances Resource Recovery

Expandability

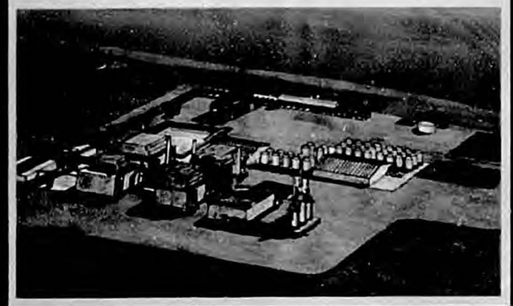
- Cycling, Oil Production, and Major Gas Sales

$800 Million Spent to Date

- 19 Wells Drilled
- Eight 3-D Seismic Surveys

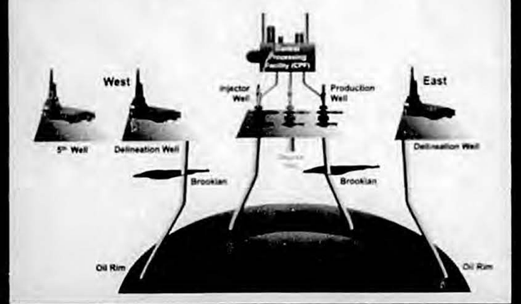
Development

Plan to Develop and Delineate



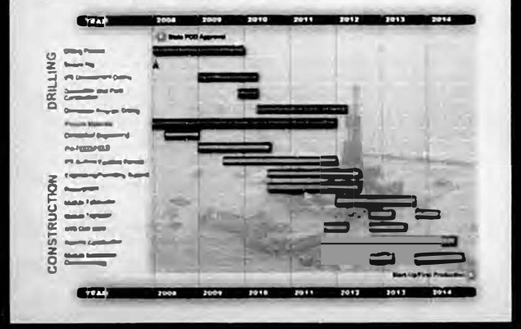
Production

Plan to Produce Condensate



Commitment

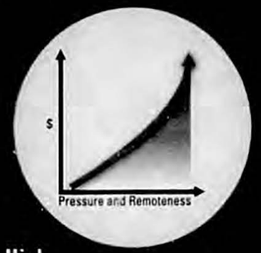
Clear and Committed Timeline



High Pressure Wells

Produce Condensate by Cycling Gas

Point Thomson Unit



Remote High Cost Environment

Challenges and Risks

World's highest pressure gas cycling project

- 10,000 psi injection pressures
- Over twice as high as Prudhoe Bay

3,000 psi separator pressure

Extended reach, abnormal pressure drilling

- World class combination of mud weight and departure

Variable reservoir rock quality

Variable Permafrost thickness

World class project in a remote environment

Solution: Phased Approach

Key Goals

- Bring PTU into Production
- Prudently Manages Risk-Reservoir and Technology
- Future Expandability
- Positions PTU for Gas Sales
- Greater Ultimate Recovery

$1.3 Billion Projected Investment by Owners

- Owners Support Assured by Senior Corporate Executives
- Already Secured Drilling Rig and Long Lead Materials
- Scheduled Milestones for State to Monitor Progress
- Agreed to Unit Termination if Milestones Not Met

SENR: presented Tuesday 6-17-2008 morning — AGIA License Hrngs Anch. AK

Background on the Point Thomson Unit and Litigation History and Status

Testimony of DNR before Special Session of Alaska Legislature

June 17, 2008

Nan Thompson, Units Manager, Division of Oil and Gas

1) Background on Point Thomson Unit-The efforts to encourage development have been ongoing for years.

   a) The essence of an oil and gas lease is timely production. The state agrees to lease its land to a developer in exchange for a share of the production; which is paid as royalties. Oil and gas leases contain a commitment that the lessee will diligently explore and develop the property. When a lessee fails to fulfill this duty, the lease is forfeited. Article 8, Section 8 of the Alaska Constitution mandates that a lessee's breach of his duty to develop results in forfeiture.

   b) An oil and gas lease is a temporary (commonly 5 to 10 years) right to explore for and develop hydrocarbon resources. The purpose of the primary term of a lease is to allow the Lessee sufficient time to explore, delineate, and produce the hydrocarbon resources. Leases expire at the end of their primary term unless the lease is producing oil or gas or the lease has become part of a unit.

   c) Units are formed when a group of lessees apply to the state to form a unit because their leases overlay a common geologic formation that holds recoverable oil or gas. There are about 48 units in Alaska, 14 on the North Slope and 34 in Cook Inlet. Unitization extends the term of lease so that the discovered resources can be produced in an efficient and coordinated manner that will maximize recovery and minimize waste.

d) ExxonMobil acquired several leases in the Point Thomson area in 1965. ExxonMobil and Chevron acquired 14 more leases in 1969 and 1970. The majority of the remaining leases were acquired in the 1980s and early 1990s.

e) The Point Thomson Unit was formed in 1977 with 18 leases comprising approximately 41,000 acres of state land. The boundaries have been expanded and contracted several times in the last 30 years. Unit boundaries can be expanded to include lands proven to overlay a producible resource. Unit boundaries are periodically contracted to exclude leases the unit operator fails to develop. The state's form unit agreement requires that all lands not included in a participating area (a process used to allocate production for royalty accounting purposes) within five years of formation of the unit contract out of the unit.

f) The Point Thomson Unit included 45 leases with approximately 106,000 acres of state land when Commissioner Menge issued his decision to terminate it in November 2006. The leasehold interests were held by ExxonMobil-52%, BP-29%, Chevron-14%, Conoco 2.8% and other minor interest holders. [1]

g) The working interest owners elect a unit operator to manage the unit's business; ExxonMobil has been the unit operator throughout this unit's history. Under the Unit Agreement, ExxonMobil was primarily responsible

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[1] The working interest owners agreed amongst themselves several years ago to cross-assign leasehold interests, but did not file the assignments with the state until the day before the leases were to expire. Under DNR's regulations, the cross-assignments are not valid until filed with DNR and approved. Because of the impending lease terminations, DNR did not process the assignments. The impact of the assignments would be to decrease EM's interest in the unit and increase Chevron's.

for exploring and developing the unitized lands. In the recent remand hearing, the working interest owners submitted amendments to the unit operating agreement to change the voting percentages with the stated purpose of preventing one of the major owners from blocking an action the other two agreed upon. Those amendments were contingent on DNR's acceptance of the 23rd POD and not agreed to by ConocoPhillips, thus their current status is not clear.

h) During the first five year of the unit's existence, ExxonMobil submitted five one-year PODs and drilled several exploration wells. The first POD promised"[i]f oil is discovered in sufficient quantities to warrant future development, the Prudhoe Bay to Valdez oil pipeline will be the probable marketing outlet for the area." Since the early 1980s, ExxonMobil has known about the existence of significant quantities of oil and gas condensate, but has not produced anything.

i) Despite significant uncertainty about the unit's resources, the unit operator drilled no more wells after 1982. New wells would yield geophysical data that would resolve the remaining uncertainties about the reservoir. Two wells were drilled by BP and Chevron in the 1990s and several other wells were drilled by other producers on lands outside of the unit boundary.

j) The unit agreement originally provided that it would expire after five years if Lessees failed to form a participating area. Participating areas are formed before production begins to allocate the production to the appropriate lease. Thus, when the parties signed the unit agreement, they expected that the unit would begin production by 1983. Because ExxonMobil was unable to commit to production by then, DNR agreed to remove the PA formation requirement to prevent the unit from terminating. The amendment extended rather than removed the obligation to produce. When DNR agreed to amend the unit agreement it expected that production would begin by the late 1980s.

k) The years since 1983 can be characterized as a struggle between the state and the unit operator, with DNR demanding development activity and ExxonMobil either insisting that it was not economic or promising to drill wells that were never drilled. The remand decision and decision on reconsideration detail the history.

l) In 1985 and 1990, DNR contracted leases from the unit because Lessees failed to drill promised wells. In 1995 DNR rejected the 12th POD because it did not include a development commitment.

m) Significant quantities of oil were discovered by ExxonMobil in 1975, and by BP and Chevron in 1994. The unit plans have never included development of this oil.

n) By the time the 13th POD was due, the Division of Oil and Gas had a new director who accepted ExxonMobil's promise to develop the unit lands with "farm-out" agreements. Then Director Boyd clearly stated the Division's objective: "Most importantly the division wants a fair and honest attempt to get this acreage explored and be appraised of efforts to develop and produce the Pt. Thomson sands accumulation itself."

o) When the negotiations over the Stranded Gas Development Act became active in 1997, ExxonMobil linked Point Thomson development with construction of a gas pipeline. ExxonMobil suggested that before the construction of a gas line, it would produce the hundreds of millions of barrels gas condensates through a gas cycling program. In 2001, Exxon also promised that the PTU's considerable oil reserves would be produced starting in 2010. From the late 1990s until 2005, DNR approved PODs with the expectation that wells would be drilled to further delineate the unit's resources and that ExxonMobil was progressing towards production with

development drilling to begin by 2006. During this period, ExxonMobil drilled no wells.

2) Unit Litigation-DNR has been successful so far and the litigation will probably continue to the Alaska Supreme Court.

   a) The basis for the litigation was the 2001 2nd Expansion agreement and the 18th though 22nd PODs that were designed to implement the commitments made in that agreement.

   b) In 2001 ExxonMobil asked DNR to expand the unit and filed the 18th POD. They repeated their commitment to develop the land by saying "The Owners have endeavored in the attached response to unambiguously demonstrate our commitment to the development of the Point Thomson Unit. We are committing to an aggressive work program and the expenditure of substantial funds that will put us in a position to initiate project execution activities as early as possible." That "unambigous' commitment was to expedite permitting and engineering studies, drill an exploration well by 2003, a production well by 2006 and seven more production wells by 2007. DNR agreed to expand the unit based on these commitments, but none of the proposed development activity occurred. ExxonMobil eventually paid a penalty of $20 Million, plus interest, for failure to perform the promised work.

   c) Since the 21st POD expired in September of 2005, this unit has not been operated under an approved plan of development. The first proposed 22nd POD was submitted and rejected because it did not contain adequate work commitments. Intense negotiations ensued, but the revised POD submitted months later was also rejected. The unit was put in default. The working interest owners asked for reconsideration and appealed to the Commissioner. At the end of the Murkowski administration, Commissioner Menge terminated the unit because ExxonMobil submitted a POD that did

not comply with Director Myers' criteria for what an acceptable POD must contain. Acting Commissioner Rutherford affirmed Commissioner Menge's decision when the lessees asked for reconsideration after the new Governor was sworn in.

d) The litigation began with lawsuits filed in Superior Court that were eventually consolidated before Judge Gleason. ExxonMobil also separately filed an action for damages and injunctive relief that was dismissed by Judge Michalski. ExxonMobil appealed the dismissal, but never filed their brief with the Alaska Supreme Court.

e) Judge Gleason ruled in December 2007 that DNR properly rejected the 22nd POD and that it had the legal authority to terminate the unit, but remanded the case to the agency because she found that DNR had not given the parties enough notice that the unit might terminate and the opportunity to argue about other alternative remedies.

f) DNR had a hearing earlier this year on the 23rd POD, the remedy proposed by ExxonMobil. Commissioner Irwin found that the proposal did not meet the statutory criteria for approval and did not protect the state or public interests. Commissioner Irwin also found that the Lessees' failed to explain why termination was not an appropriate remedy given the unit's history. When asked to reconsider, he came to the same conclusion. The remand record will soon be sent back to Judge Gleason.

g) Judge Gleason has not set a hearing or told the parties whether she would like briefs and/or oral arguments on DNR's decision. It is likely that her final decision will be appealed to the Alaska Supreme Court.

3) Lease Actions-The timing and process for reclaiming the 45 leases varies according to the historical level of activity on those lands.

a) Almost all of the leases are beyond their primary terms, and thus held because they were a part of the unit. After the initial unit termination decision, DNR began the process of terminating the leases in February 2007 and the leaseholders appealed. Further action on the lease appeals was delayed until the status of the unit was resolved. Thus, agency action on the status of all 45 leases is pending.

b) 18 of the leases have no wells and are beyond their primary terms and therefore expire when they are no longer part of a unit.

c) On the leases with wells that were once "certified" there is a factual dispute about whether the wells are still capable of production that is likely to be litigated.

presented 6-17-2008 Tuesday morning
Anch. AK
Howard Johnson Plaza

AGIA License Hearings

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

PetroTel
Leaders in Oil and Gas Technology

Resource Assessment and Field Development Study of the Thomson Sand, in the Point Thomson Area, North Slope Alaska

Commissioned by

State of Alaska, Department of Natural Resources, Division of Oil and Gas

PetroTel Inc.

5240 Tennyson Pkwy, #207
Plano, TX 75025
Investigators:

Anil Chopra - Distinguished Reservoir Engineering Advisor
Fred Stalkup - Distinguished Reservoir Engineering Advisor
Qichong Li – Senior Reservoir Engineer
Ravi Sharma – Project Director
Thomas Phillips – Distinguished Geological Advisor
Thomas O'Brien – Distinguished Geological Advisor

Alaska Division of Oil and Gas

Jack Hartz – Reservoir Engineer
Julie Houle – Petroleum Geologist
Steve Moothart – Petroleum Geologist

Commissioned: spring 2007

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

PetroTel Leaders in Oil and Gas Technology

Point Thomson Reservoir Study
Purpose / Scope

- PetroTel Inc. conducted an independent evaluation of the Point Thomson reservoir to determine the resources contained in the reservoir and analyze possible recovery methods

- Two main objectives:
  - Construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon resource
  - Dynamic reservoir simulation to test potential development and off-take scenarios
    - Determine the impact on ultimate recovery of both gas, associated condensate and oil

- Focused on the Thomson sand and does not include resources tested from the underlying Pre-Mississippian strata or overlying Brookian accumulations

presented
Steve Moothart

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

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Point Thomson Reservoir Study
Geology / In-Place Volumetrics

- Eleven 3D geologic models were constructed
- In addition to gas and condensate, Thomson sand also contains a thin and potentially discontinuous oil-rim that tested over 18º API gravity oil
- No definitive, production test exists in the oil-rim of the Thomson reservoir
- Range of volume in the oil-rim varied in the models due to uncertainty of the depth of fluid contacts
- Original in-place hydrocarbon volumes from geologic models:
  - Gas = 8.5 to 10.4 trillion standard cubic feet (TSCF)
  - Associated condensate = 490 – 600 million stock tank barrels (MMSTB)
  - Potential oil (oil-rim) = 580 – 950 MMSTB

liquid hydrocarbons entrained in gas

42 gal @ surface conditions

presented by Steve Moothart

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

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Leaders in Oil and Gas Technology

Simulation Model Porosity

presented: Dr Chopra

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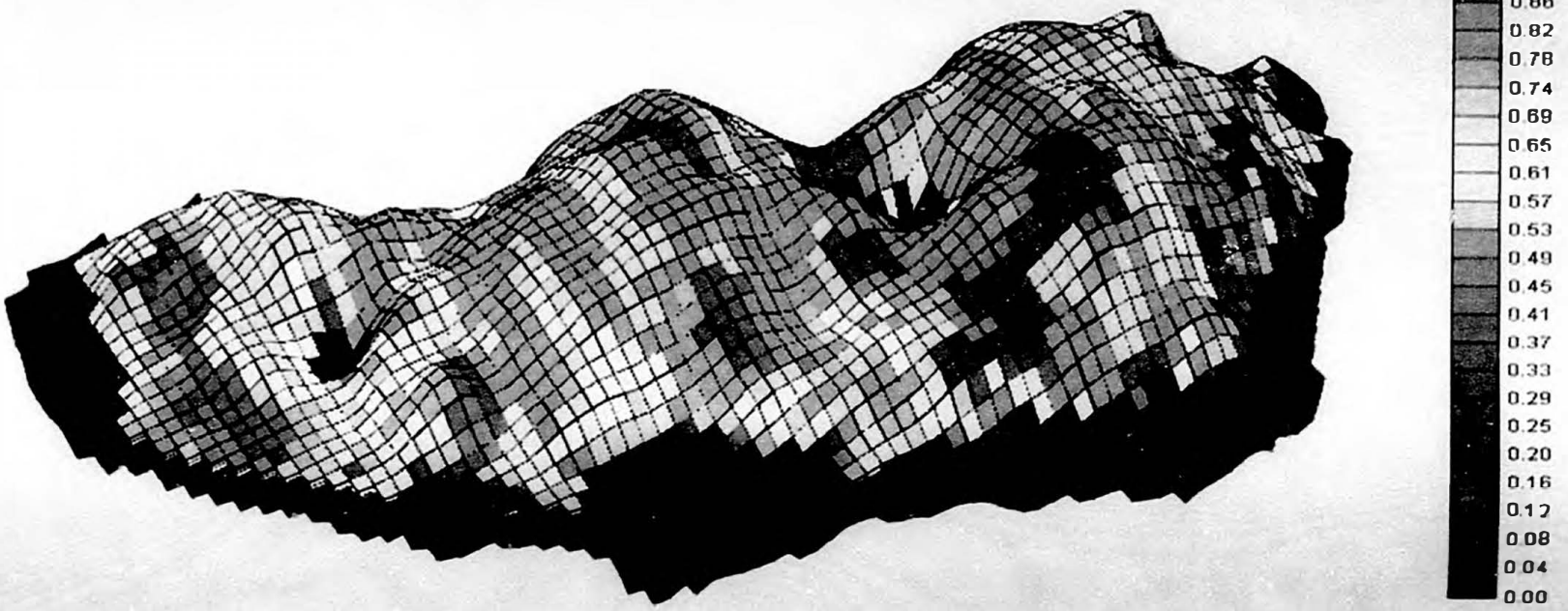
Simulation Model - Sg

(Gas Saturation)
gas in the gas cap



presented: Dr Chopra

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very high pressure

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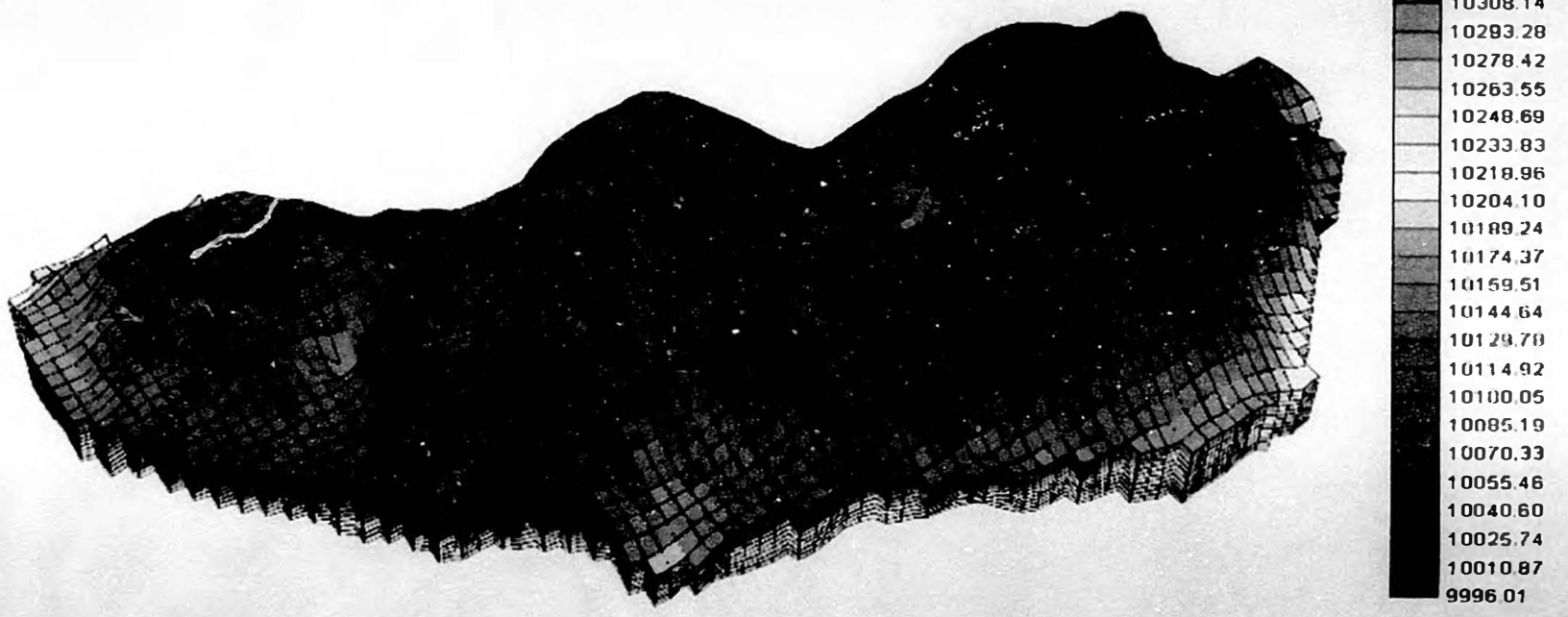
Simulation Model - Pressure

@ 12,500' depth



presented by: Dr Chopra

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Point Thomson Reservoir Study
Reservoir Modeling- Over 70 simulations

- Cases were run to model different recovery methods including primary depletion, gas cycling, and oil rim production
- Scenarios were designed to test and evaluate key sensitivities to recovery method
  - Well configurations
  - Operating constraints
  - Number of development wells
- Evaluated impact of variables on ultimate recovery with development method
- No physical constraints such as location of surface drill sites and facilities or drilling departures were modeled

presented by: Dr Chopra

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

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Point Thomson Reservoir Study
Reservoir Simulation - Primary Depletion

1st Scenario

- Primary depletion (gas blowdown) fastest - but recovers the least total hydrocarbons
  - Up to 70% of gas recovered (6-7 TSCF) with 22 wells in 12-15 years
  - Condensate recovery is approximately 26% of the in place volume (127-156 MMSTB)
  - The majority of the condensate is left in the reservoir by condensation below dew point

loss of 74% of condensate

- Pressure maintenance required to increase condensate recovery
- Reduction of reservoir pressure during primary depletion significantly reduces potential recovery from the oil-rim
- Gas blowdown and sale of the gas can be done at any time after cycling and recovery of the condensate and oil

presented by: Dr Chopra

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Point Thomson Reservoir Study
Reservoir Simulation - Gas Cycling

- Maintain reservoir pressure until all economically recoverable condensate and oil are produced
- Gas cycling applied in the gas cap in conjunction with development and gas injection in the oil-rim
- Gas cycling for 20 years increases the oil recoveries:
  - Condensate - 76% (370-450 MMSTB)
  - Oil Rim - 43% (250-400 MMSTB)
- Gas cycling for 10 years results in oil recoveries of:
  - Condensate - 62% (300-370 MMSTB)
  - Oil Rim - 39% (225-370 MMSTB)
- Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% (4.8-5.9 TSCF) of original gas in place

presented by: Dr Chopra

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

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Point Thomson Reservoir Study
Reservoir Simulation - Oil Rim Development

- Oil-rim not adequately delineated or tested
  - Additional wells are needed
- Oil Rim Production:
  - Would likely require of horizontal wells
  - Requires pressure maintenance to sustain maximum oil producibility
    - Gas cycling, direct lean gas injection, miscible gas injection (CO_2), water injection or aquifer encroachment
  - Gas injection helps reduce the viscosity, improve swelling, and mobilize oil
  - Use of offsite gas, such as dry gas or waste CO_2 from Prudhoe, may maximize recovery
- In primary depletion, potential oil-rim recoveries varied from 3-16% (30-150 MMSTB) of original oil in place depending on number of wells drilled
    - Gas cycling for 20 years could potentially recover close to 45% (250-400 MMSTB) of the in-place volume of the oil-rim
- Uncertainty in the original oil-rim volume and potential ultimate recovery
- Delineation of the oil-rim during gas cycling will determine the scale of development

presented: Dr Chopra

Alaska Department of NATURAL RESOURCES
Division of Oil and Gas

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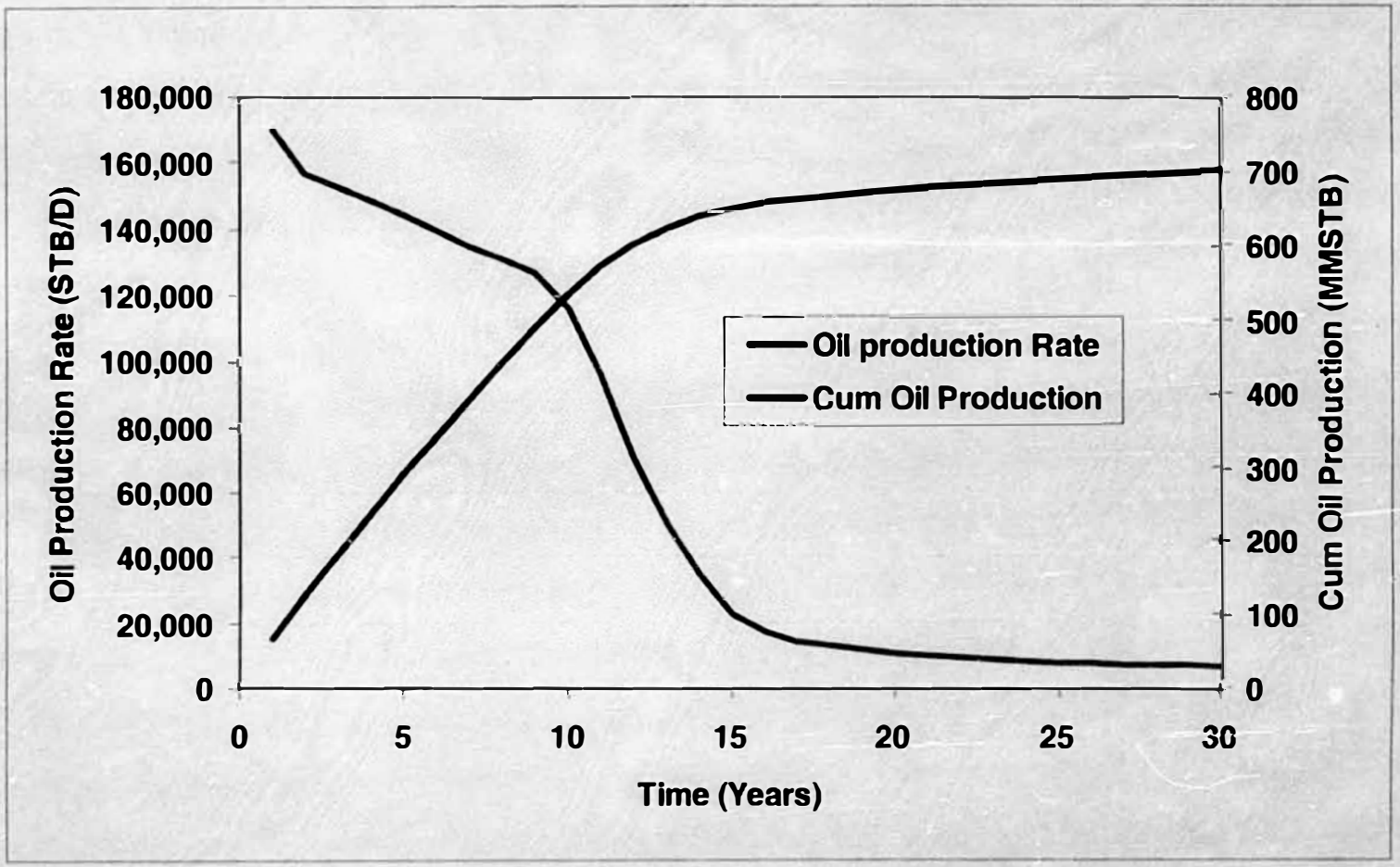
Oil Production Rate and Cumulative Oil Production

BHP=3000 psi



shows both condensate & oil

presented: Dr Chopra

Alaska Department of NATURAL RESOURCES Division of Oil and Gas

PetroTel Leaders in Oil and Gas Technology

Point Thomson Reservoir Study
Conclusions

- Primary depletion may recover 6-7 TSCF of gas and 210-305 MMSTB of condensate and oil
  - Results in the lowest hydrocarbon recovery of a retrograde condensate reservoir
  - Gas blowdown can be done after gas cycling and recovery of the condensate and oil
- Gas cycling for 15-20 years and subsequent blowdown may recover about 6 TSCF of gas and 620-850 MMSTB of condensate and oil
  - Gas cycling may delay gas sales, but can potentially increase recovery of condensate and oil by over 500 MMSTB
- Additional wells needed to delineate and test the Thomson oil-rim
  - Delineation of the oil-rim during gas cycling will determine scale of development
  - Pressure maintenance required to sustain maximum producibility and recovery of oil and condensate

presented: Dr. Chopra
Julie Houle
Nan Thompson

presented Tuesday 6-17-2008 morning

Summary of Findings for Resource Assessment and Field Development Study of the Thomson Sand, in the Point Thomson Area, North Slope Alaska

May 17, 2008

Commissioned by

State of Alaska, Department of Natural Resources, Division of Oil and Gas

For the purpose of evaluating the hydrocarbon resource of the Thomson sand and potential depletion scenarios to maximize oil and gas recovery.

Study completed by

PetroTel Inc.
5240 Tennyson Pkwy, #207
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Investigators
Anil Chopra - Distinguished Reservoir Engineering Advisor
Fred Stalkup - Distinguished Reservoir Engineering Advisor
Qichong Li – Senior Reservoir Engineer
Ravi Sharma – Project Director
Thomas Phillips – Distinguished Geological Advisor
Thomas O'Brien – Distinguished Geological Advisor

Summary of findings prepared by

Division of Oil and Gas, Resource Evaluation Staff
Jack Hartz
Julie Houle
Steve Moothart

Introduction

In 2007, the Resource Evaluation section of the Alaska Department of Natural Resources (DNR) Division of Oil and Gas (DO&G) initiated an independent technical assessment of the Thomson sand reservoir. The Division o f Oil & Gas contracted with PetroTel, Inc. to perform geologic and engineering evaluation of the Pt Thomson sands reservoir. PetroTel is recognized worldwide as industry leaders in enhanced oil recovery, reservoir characterization and simulation, coalbed methane, production, and exploration technologies. PetroTel provides professional consulting and advisory services utilizing a staff of 80 professionals with combined 1100 years of industry experience along with integrated project management support to domestic and international petroleum companies. Activities span the entire spectrum of technical, project, and commercial functions along with all facets of the hydrocarbon exploitation cycle.

With state-of-the-art software and sophisticated geostatistical and object modeling techniques, PetroTel reservoir engineers and geologists have successfully tackled a broad spectrum of difficult reservoir engineering problems by the intelligent application of reservoir simulation. Through the integration of reservoir geology, rock/fluid interactions, the dynamic pressure-volume-temperature relationships of oil gas and water (PVT properties), and process mechanisms, PetroTel engineers deliver reliable predictions of reservoir performance. Company expertise includes determination of in place hydrocarbons and reserves as well as providing a plan of development for discoveries that includes integrated economics.

PetroTel also has significant expertise in the development of gas condensate reservoirs with thin oil rims. They specialize in solutions and diagnostic tools that can advance the development of potential or undeveloped reserves. PetroTel has extensive experience that deals with pressure maintenance and improving recovery from gas condensate reservoirs.

The Pt Thomson sand accumulation is recognized as a high pressure retrograde condensate reservoir, which also contains a relatively thin oil column. The Petroleum Engineering Handbook[1] states "Development and operation of these (gas condensate) reservoirs for maximum recovery require engineering and operating methods significantly different from crude-oil or dry-gas reservoirs. The single most striking factor about gas-condensate systems (fluids) is that they exist either wholly or preponderantly as vapor phase in the reservoir at the time of discovery. This key fact nearly always governs the development and operating programs for recovery of hydrocarbons from such reservoirs; the properties of the fluids in place determine the best program in each case. A thorough understanding of fluid properties together with a good understanding of the special economics involved is therefore required for optimum engineering of gas condensate reservoirs. Other important aspects include geologic conditions, rock properties, well deliverability, well costs and spacing, well-pattern geometry, and plant costs."

The Resource Evaluation Group, DO&G undertook the evaluation of the Pt Thomson reservoir to better understand the resources contained in the reservoir and get an independent analysis of the development issues associated with gas condensate. The study had two main objectives: 1) to construct three-dimensional (3D) geologic models to evaluate the proven and potential hydrocarbon

[1] Bradley, H.B., 1987, Petroleum Engineers Handbook, 1987 Society of Petroleum Engineers, Chapter 39 Gas Condensate Reservoirs.

resource and 2) to import the geologic model into a dynamic reservoir simulator to test potential development and off-take scenarios to determine the impact on ultimate recovery of both gas and hydrocarbon liquids in the form of condensate and oil from an oil-rim in the reservoir. It should be noted that this study focuses on only the resource contained in the Thomson sand and does not Include the resource tested from the underlying Pre-Mississippian strata or the overlying Brookian accumulations

Results of PetroTel's work are summarized below.

1) The geologic and engineering analysis confirmed that gas cycling recovers more hydrocarbon than simple primary depletion based on known oil properties, gas properties, and reservoir characteristics.
2) Technical issues remain to be resolved; however, economic evaluation still needs to be done to validate conceptual conclusions and refine potential development scenarios.
3) Rigorous technical evaluation will be required as delineation of the reservoirs proceeds and additional physical information is acquired; more thorough and longer well tests are done; and as high quality reservoir oil, gas and condensate samples are acquired and analyzed.
4) Maximum recovery with gas cycling may require the import of gas in the form of waste CO2, captured inert gases, methane or natural gas from reservoirs outside of the Pt Thomson reservoir to replace voidage caused by fuel usage and shrinkage. Technical literature also suggests water can be injected into gas condensate reservoirs to maintain pressure, however, that process has not been addressed with this study.[1]
5) **Gas cycling delays gas sales, but results in greater ultimate recovery of both liquid and gas hydrocarbons. In contrast, primary depletion as a gas reservoir results in the lowest hydrocarbon recovery of a retrograde condensate reservoir. Gas blowdown[2] for sale can be done at any time after gas cycling and recovery of the hydrocarbon liquids.**
6) From the eleven static geologic models created, the volume of original gas in place (OGIP) ranged from 8.5-10.4 trillion standard cubic feet (TSCF). The volume of associated condensate ranged from 490-600 million stock tank barrels (MMSTB)[3] of condensate in place.
7) The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest possible gas and highest known water could vary from 60 feet to 145 feet in true vertical thickness, representing a wide range of potential oil column thickness in the oil-rim. The various geologic models produced a range of volumes of original oil in place (OOIP) in the oil-rim from 580-950 MMSTB.
8) Recoverable hydrocarbon resources for the Thomson sand were determined from dynamic reservoir simulation and are primarily a function of the development method employed. Over 70 scenarios were run to model a variety of development methods and well configurations within the reservoir simulator.

---

[2] Blow-down (also Blowdown) "A term applied to the commencement of production of gas for sale after the completion o a Cycling or Recycling operation. The term refers to the reduction of pressure in the formation as a result of the production of gas. ... ". Martin, Patrick H. and Kramer, Bruce M., 2000, Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 101.

[3] Million stock barrels - MMSTB, Million standard cubic feet – MMSCF or MMSCFG/D – Roman numeral designation for million. Stock tank barrel is equivalent of 42 US Gallons liquid at 60°F and 14.65 pounds per square inch absolute, psia (1 atmosphere) Standard cubic foot is measured at 14.65 psia and 60°F

9) Development of the Thomson reservoir by primary depletion (blowdown) has the potential to recover 210-305 MMSTB of liquid hydrocarbons in addition to 6-7 TSCF of gas.
10) Gas cycling for 20 years prior to gas sales has the potential to result in the ultimate recovery of 620-850 MMSTB of liquid hydrocarbons and still recover 4.8-5.9 TSCF of gas.
11) Gas cycling, has the potential to significantly increase recoverable oil and condensate as much as 500 MMSTB of condensate and oil beyond recovery from primary depletion blowdown. This incremental recovery of oil is larger than the expected ultimate recovery from the Alpine Oil Field.

The length of time required for gas cycling prior to gas sales will be determined by the resource available in the oil rim and how fast the gas volume can be cycled. The major determining factor in this decision is the number of wells that can be economically drilled and operated. More injection and production wells could accelerate cycling and recovery of the condensate liquids and oil. There are an optimal number of wells that will economically recover the maximum amount of oil and gas within a reasonable drilling budget; however, the scope of this study did not include optimization of development but rather was designed to estimate resource volumes and quantify the range of recoverable resource using conceptual development scenarios. Hydrocarbon liquids could be produced and sold using mostly existing oil pipelines prior to the construction of a North Slope gas pipeline. Once production of liquid hydrocarbons is established from the Thomson reservoir, the production facilities could be utilized to produce oil from the Brookian Flaxman and Sourdough accumulations.

Petroleum Potential and Exploration History of the Point Thomson Area

Well log and production or drill stem test data indicate that much of the Point Thomson area is underlain by the Cretaceous (Neocomian) Thomson sand that contains abundant natural gas and hydrocarbon liquids in the form of gas condensate, ranging from 35° to 45° API gravity[4],[5]. In addition to gas and condensate, the Thomson sand also contains a thin and potentially discontinuous oil-rim at the bottom of the reservoir interval that has tested oil as high as 18° API gravity. The Point Thomson area contains the potential of hundreds of millions of barrels of oil in the shallower Tertiary Brookian reservoirs. Another potential productive reservoir is composed of carbonates and bedded metasedimentary strata in the "Pre-Mississippian" basement below the Thomson sand reservoir. The DO&G reported in their 2007 annual report that the Pt Thomson Area contained estimated undeveloped recoverable resources of 295 million stock tank barrels (MMSTB) of liquid hydrocarbons and 8 trillion standard cubic feet (TSCF) of gas.

Hydrocarbons were first discovered in the Point Thomson area in 1975 in the Alaska State A-1 well. This well tested a zone of the lower Tertiary Flaxman sand of the Canning Formation from 12,565 to 12,635 feet MD(measured depth) that flowed 23° API gravity oil at a rate of 2,507 BOPD (barrels of oil per day),

[4] API Gravity – "Specific gravity measured in degrees on the American Petroleum Institute scale. The specific gravity of oil is normally specified ... in terms of API degrees. On the API scale, oil with the least specific gravity has the highest API gravity. ... the higher the API gravity the greater the value of the oil." ". Martin, Patrick H. and Kramer, Bruce M., 2000. Manual of Oil and Gas Terms, Eleventh Edition, Lexis Publishing, page 52.

[5] Condensate API gravity typically ranges from 40-60 degrees and are light color compared to oil. Black oils typically have API gravity that ranges from 25-35 degrees. Lake, Larry W., 2007. Petroleum Engineering Handbook, Volume V, Society of Petroleum Engineers, Chapter 10,

2.2 MMSCFG/D,GOR 864 SCF/STB (gas/oil ratio, standard cubic feet per stock tank barrel) (USGS, 1987).

In 1977, a second discovery well, the Point Thomson Unit No. 1 well was drilled and conducted two flow tests in the Lower Cretaceous (Neocomian) Thomson sand. From a zone between the depths of 12,963 to 13,050 feet MD, the well flowed 18° API gravity oil at a rate of 2,283 BOPD, 13.3 MMSCFG/D, GOR 5,830. Between the depths of 12,834 to 12,874 feet MD, the well tested at a rate of 3.86 MMSCFG/D, 170 BPD condensate, 45° API gravity (USGS, 1987).

Over the next seven years, six additional wells were drilled to delineate the two Pt Thomson discoveries. As a result of the additional delineation drilling, two other hydrocarbon reservoirs were encountered. In 1978, the Point Thomson Unit No. 2 well tested the "Staines River sand," a local sand in the Tertiary Canning formation at a depth of 11,580 to 11,678 feet MD that produced 21° API gravity oil at a rate of 248 BOPD, 124 MSCFG/D, GOR 500, after acid treatment (USGS, 1987).

In 1982, the Alaska State F-1 well tested the Thomson sand at a depth of 13,940 to 14,316 feet MD at a rate of 4.2 MMSCFG/D and 284 BOPD condensate of 35.3° API gravity. The well also tested the under lying "Pre-Mississippian" metasedimentary basement from 13,940 to 14,316 feet MD that flowed at a rate of 2.9 MMSCFG/D with 152 BPOD condensate of 34.8° API gravity. This test identified a third potentially productive zone in the Point Thomson area (USDOE, 1993).

State lands east of Prudhoe Bay saw renewed exploration activity during the 1990s after the discovery of the Badami oil field within turbidite sandstones of the Tertiary Canning Formation. First estimated to contain 100-150 MMSTB of recoverable oil, production began at Badami in August 1998. Since that time, production has been sporadic with the field periodically shut in due to connectivity issues within the reservoir. To date, over 5 MMSTB of cumulative oil production from Badami has been reported to the Alaska Oil and Gas Conservation Commission (AOGCC).

In 1994, BP Exploration Alaska (BPXA) and Chevron drilled the Sourdough #2 well targeting Brookian sands of the Canning formation in the southern portion of the former Point Thomson Unit; the Sourdough #3 well was drilled as a follow-up in 1996. Although the data from these wells are still held confidential, BP announced the discovery of hydrocarbons within turbidite sandstones of the Tertiary Canning Formation that could potentially contain 100 million barrels of recoverable oil in a 1997 press release. The Sourdough project would require up to 35 miles of pipeline to link up with the Badami field (Peninsula Clarion, 1997).

Additional discoveries have been announced in the offshore federal waters of the eastern Beaufort Sea within the Mississippian Kekiktuk Formation (Liberty) and Tertiary sandstones of the Sagavanirktok Formation (Hammerhead and Kuvlum). Once developed, production from Liberty is expected to peak at 40,000 BOPD, with a recovery target of 100 MMSTB (Petroleum News, 2007). While data from the U.S. Minerals Management Service (MMS) indicates that while neither Hammerhead nor Kuvlum have been fully delineated, the agency estimates 100-200 MMSTB of recoverable oil at Hammerhead, and 160-300 MMSTB at Kuvlum (MMS, 2006).

The timing of development of these and other Brookian oil accumulations in the area will likely follow the commercialization of the gas and liquids reserves within the Point Thomson sand.

Geologic Setting of the Thomson Sand

The Thomson sand is an informal name that describes a sequence that is stratigraphically correlated with the Kemik Sandstone of Early Cretaceous (Neocomian) age (Figure 1). Both intervals commonly consist of preserved isolated accumulations of locally derived sediment overlying the regional Lower Cretaceous unconformity (LCU), whose composition is controlled by the local provenance eroded by the unconformity.

The Thomson sands contain significant detrital dolomite and quartz sand that are interpreted as Neocomian age fan-delta complexes that were sourced from a northern provenance composed of northerly-dipping pre-Mississippian metasedimentary units. The Thomson interval includes a broad range of rock types ranging from conglomeratic dolomite breccia to fine-grained sandstone and siltstone. In general, the coarser conglomerate facies of the Thomson sand are present to the north, proximal to the interpreted source area, while the finer-grained distal facies are more prevalent to the south. A block diagram (Figure 2) depicts a highly interpretive, schematic representation of the depositional setting of the Thomson sand during an advanced stage of transgression of the Neocomian Barrow Arch rift margin uplift and development of the Lower Cretaceous Unconformity (LCU).

Other sand occurrences are irregularly distributed along the LCU surface to the south of the Point Thomson area, depending on local thickening into accommodation space attributed to paleotopography created by the differential erosion of Ellesmerian and pre-Mississippian units below the LCU. North of the rift shoulder uplift, syn-rift sands may have been deposited as sediment gravity flows down fault relay ramps to accumulate in relatively deep water. Similar sands form major reservoirs in the Point McIntyre and Niakuk fields north of Prudhoe Bay, but the concept has not yet been tested with a drill bit north of the Point Thomson area.

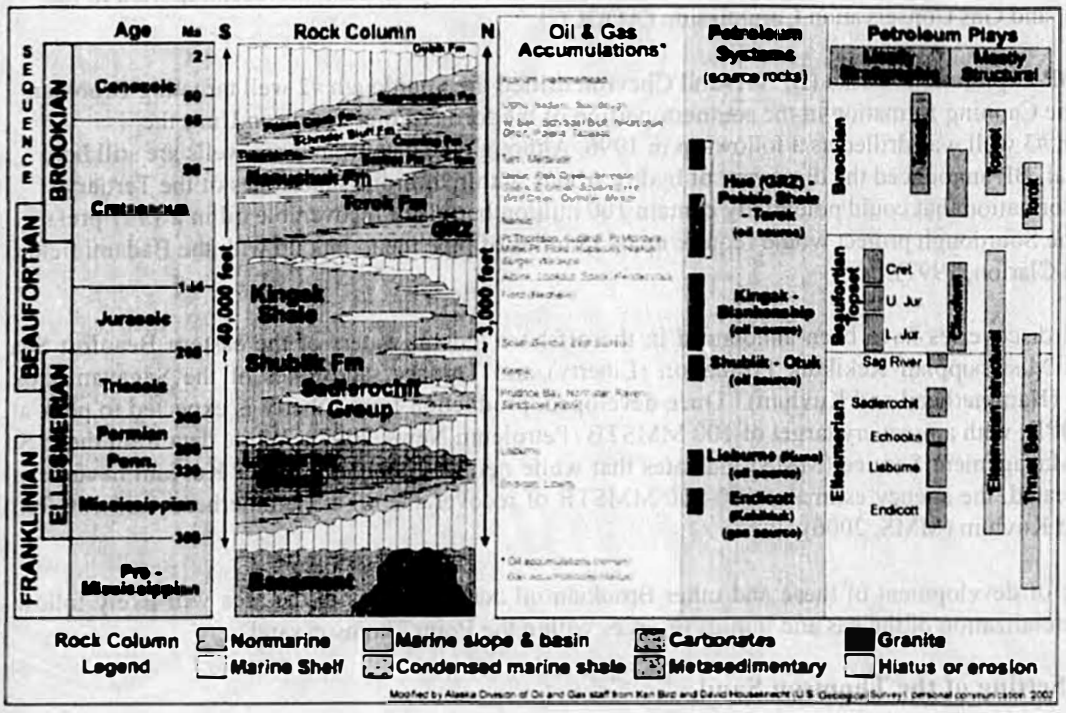


Figure 1. Alaska North Slope Stratigraphic Column

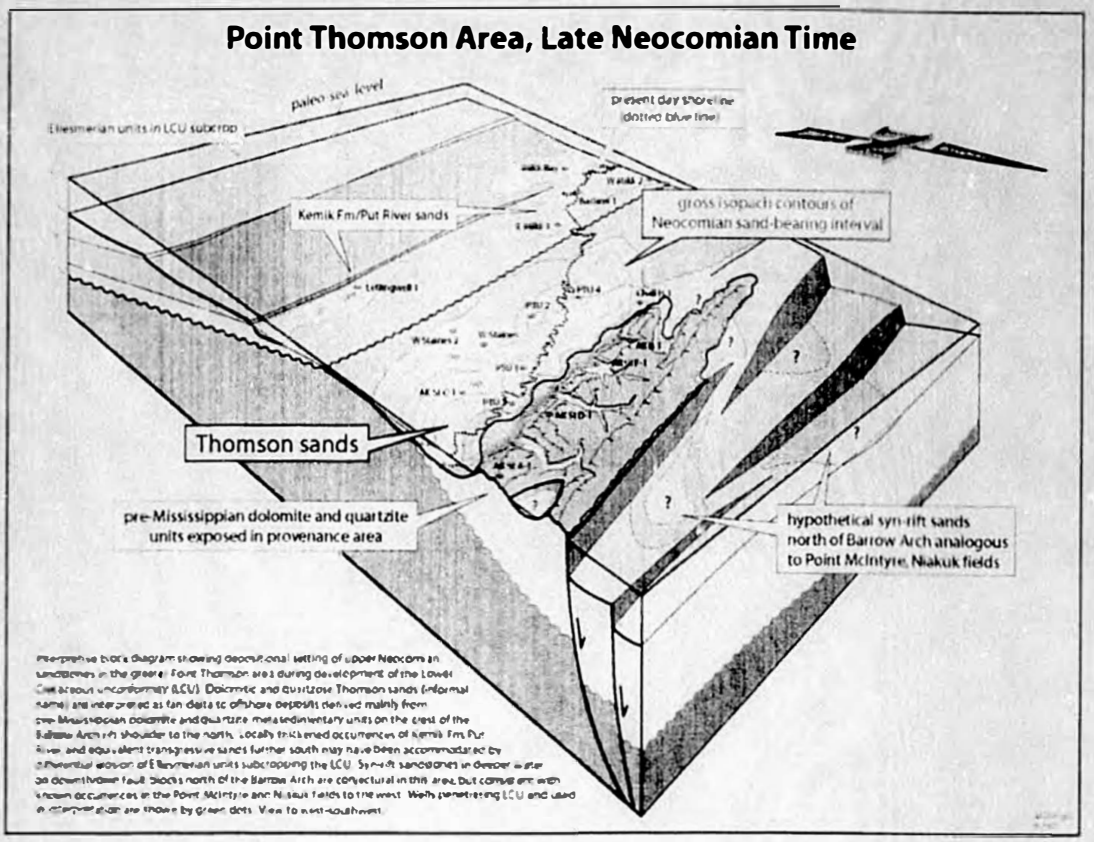
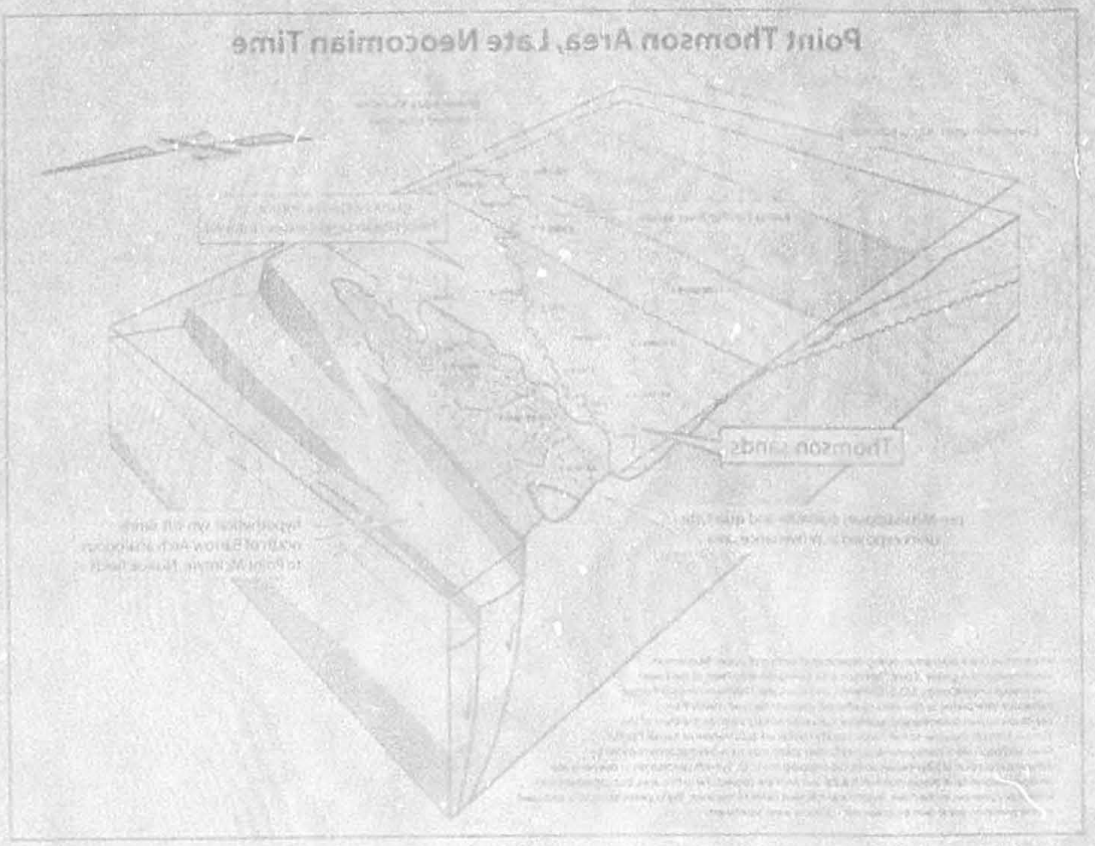


Figure 2. Block diagram of Point Thomson area in Late Neocomian time

First discovered in 1977, the oil, gas, and gas condensate contained within the Thomson sand is the largest proven, yet still undeveloped, field in Alaska. Between 1975 and 1996, a total of 17 wells have been drilled within the boundaries of the former Point Thomson unit. 1982 was the last time that a well was drilled into the Point Thomson reservoir. Although attempts were made to test most of the wells, tests were of short duration and were hampered by the high mud weights that were required to contain high reservoir pressure. Some of the tests were further complicated because they straddled both the gas and oil legs of the reservoir. No definitive, isolated test exists in the oil-rim of the Thomson reservoir. Additional wells are still needed to specifically delineate and test the productivity of Thomson oil-rim. Delineation wells in the oil-rim should include vertical pilot holes with horizontal laterals for production tests and include rigorous sampling for oil quality and PVT studies.

A number of the Point Thomson wells were drilled on the flanks of the accumulation and delineate the aerial extent of the core area of the Thomson reservoir. Along the western margin of the area though, no well has been drilled to demonstrate the western limit or trap of the reservoir or define the structural or stratigraphic continuity of the core reservoir from southeast to northwest. Additional wells are still required to adequately delineate the western limits of the hydrocarbon accumulation.


Point Thomson Area, Late Neocomian Time

Thomson Sand Retrograde Condensate

The majority of the proven hydrocarbon resource in the Thomson sand is contained in the form of gas with entrained liquids known as a retrograde condensate. The Alaska Oil and Gas Conservation Commission (AOGCC) has released a paper entitled "Role of the Alaska Oil and Gas Commission in approving Pool Rules for the Point Thomson Field"[6] which gives an informative overview of the differences between a retrograde condensate reservoir and conventional gas and oil reservoirs. Retrograde condensate reservoirs tend to be deeper and have higher pressures and temperatures than conventional reservoirs. Due to the abnormally high pressures and temperatures, the fluid in a retrograde condensate reservoir does not behave like those in conventional oil and gas reservoirs. Pressure reduction in a conventional oil reservoir, causes the gas to expand and evolve out of solution from the oil. As gas evolves the oil becomes thicker (more viscous) and flows more slowly.

Technical literature (Society of Petroleum Engineers) has abundant examples of how condensate reservoirs perform under primary depletion and gas cycling. As pressure drops in a retrograde condensate reservoir, vaporized hydrocarbon liquids will condense when the reservoir pressure decreases below a certain point (dew point). If this happens in the reservoir, the condensate will remain trapped in place and clog the pore space, causing reduction of relative permeability; reducing well productivity and ultimate recovery. During primary depletion, the reservoir pressure will steadily decrease below dew point and hundreds of millions of barrels of condensate will become trapped in the reservoir and never be produced. Once the condensate comes out of the gas in the reservoir, very little of it will return to a gaseous state even if the reservoir pressure is later increased. Ideally, reservoir pressure should be maintained above dew point to keep vaporized liquid entrained to condense in surface facilities, thereby maximizing recovery. Results of the Pt Thomson sand reservoir modeling confirm the losses of condensate recovery during blow down. The blow down cases at best recovered about one-half the condensate that cycling cases recovered. The difference is directly attributable to trapped condensate.

Prudent development practices require keeping the reservoir pressure high (near or above dew point) until all of the economically recoverable liquid hydrocarbons have been produced in order to maximize the recovery of both oil and gas in a retrograde condensate field. "Gas cycling" is considered the best method of producing a retrograde condensate reservoir. This process involves producing hydrocarbon gas; removing the condensate for commercial sales; and then re-injecting the "lean gas" back into the reservoir to maintain pressure and sweep more condensate to the production wells. Once most of the condensate has been recovered, all the wells can be converted to gas production wells and the gas sold to market.

In addition to the dry gas and entrained condensate, the Thomson sand contains hundreds of millions of barrels of oil in the oil-rim. The gas cycling process can be applied simultaneously to the Thomson oil-rim after delineation and development. These hydrocarbon liquids could be produced and sold using mostly existing oil pipelines before a North Slope gas pipeline is operational. Once production of condensate and oil begins from the Thomson reservoir, it is anticipated that this would facilitate the delineation, development and production of some of the outlying Brookian oil discoveries in the Thomson area.

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6 URL: http://www.state.ak.us/local/akpages/ADMIN/ogc/Gas PtThompson_Pool_Rules.pdf, Retrieved April, 2008.

Studies of gas cycling in both the gas cap and oil rim were conducted using static geologic models and dynamic reservoir simulations to estimate recoveries under different development schemes. Results of those studies are documented later in the Reservoir Simulation section of this report.

DNR Evaluation of the Thomson Sand

Geologic Model Results

A total of eleven 3D geologic models were constructed of the Thomson sand. The distribution of facies and reservoir properties were varied in the different cases to account for the uncertainty between the well control points. A range of depths for the fluid contacts was also used to capture the uncertainty in identifying those contacts in the well logs or from available test data. The volume of original gas in place (OGIP) from the eleven static geologic models ranged from 8.5 – 10.4 trillion standard cubic feet (TSCF).

The volume of associated condensate ranged from 490 – 600 million stock tank barrels (MMSTB) condensate in place. Publically available well test data from the Thomson sand indicate condensate yields of 44-75 barrels condensate/MMSCF gas produced. The average yield was 64 STB/MMSCF.

The potential for a significant volume of oil in place below the gas cap in the oil-rim was also identified. The range of original oil in place in the oil-rim varied greatly depending on the depth used for the oil-water contact. Publicly available data indicate that the interval between lowest known gas and highest known water could range from 60 feet to 145 feet in true vertical thickness. This is the range of thickness available to be occupied by oil in the oil-rim. The range of volumes of original oil in place (OOIP) in the oil-rim varied in the models from 580 – 950 MMSTB.

All the volumes reported out of the geologic model are original hydrocarbons in place for the Thomson sand reservoir and do not include the hydrocarbons tested from the bedded carbonates of the Pre-Mississippian basement or those hydrocarbons tested from the overlying Brookian intervals. Reservoir properties within the Pre-Mississippian strata are not as well constrained by the available data as in the Thomson sand.

Because the Thomson sand directly overlies bedded carbonate strata of the Pre-Mississippian, it is likely in communication with the Pre-Mississippian. Recoverable volumes for the Thomson sand were determined from the dynamic reservoir simulation and were demonstrated to be a function of the development method employed. Neither the Pre-Mississippian nor Brookian reservoirs were included in the reservoir simulation. Both should be considered as considerable upside since they have been successfully tested in multiple wells. Further delineation drilling is required to fully access the resources in-place and production impacts of these reservoirs on future development.

Reservoir Simulation Results

Upon initialization of the reservoir simulation model, over 70 scenarios were run to model a variety of development methods and well configurations. The development methods included primary depletion (gas blowdown), gas cycling followed by gas blowdown, and development of the oil-rim. Numerous cases were run for each type of development to test different well configurations such as horizontal wells, well constraints such as rate limits and operating pressures, and the number of development wells. In this

way, we were able to judge the relative impact the different variables had on the ultimate recovery of the resource within each type of development. All model cases were run out to thirty years of production. It should be noted that no physical constraints to the development wells such as location of surface drill sites and facilities or drilling departure from surface location have been applied during the modeling. At this stage of the analysis scenarios were designed and run to discover and evaluate the key sensitivities to recovery, rather than to derive optimal production economics.

Primary Depletion (Gas Blowdown)

Gas blowdown can be done at any time after cycling and recovery of the hydrocarbon liquids. In the following cases, gas blow down is done first without pressure maintenance or gas injection. Six primary depletion cases were run in the reservoir model. Three cases contained a fixed number of wells at startup and three cases included additional wells that were added later. Gas producers were constrained to a maximum rate of 150 MMSCF/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Cases were run with 8, 16 and 22 wells. Initial gas production rates for these three cases varied from 0.4 – 1.2 BSCF/D[7]. Additional cases included: 12 initial producers with 4 new producers drilled after 4 years, 16 initial producers with 3 additional wells drilled after 8 years, and 16 producers with 6 additional wells drilled after 4 years. Initial gas production rates for these three cases ranged from 0.8 to 1.2 BSCF/D. Three more primary depletion cases were run in both gas cap and oil rim. Cases were run with 22, 13 and 13 gas producers in the gas cap and 4, 30 and 20 oil producers in the oil rim. Oil producers were constrained to a maximum rate of 7000 STB/D and a minimum bottom-hole pressure (BHP) of 3000 psi. Initial gas production rates for these three cases ranged from 1.0 to 1.2 BSCF/D

With a BHP limit of 3000 psi, gas recovery can approach 60% for the 16- producer and 22-producer cases. The recovery can reach 70% at lower BHP of 2000 psi. The 8-producer case can recover 45% of the gas in 30 years. The number of wells and timing of drilling could be optimized to meet gas demand or gas sales contracts. Twenty-two wells could drain the gas in the reservoir in 12-15 years.

Condensate recovery during primary depletion of the gas cap is only about 25% of the in place volume after 30 years. The majority of the condensate is lost in the reservoir because the reservoir pressure drops below dew point. Pressure maintenance and gas recycling is needed to recover more condensate. Primary depletion is also detrimental to any future recovery from the oil-rim due to loss of energy within the oil by the reduction of reservoir pressure. Oil rim recovery ranged from 3-16% in the cases of primary depletion in both gas cap and oil rim if primary depletion is the only recovery method.

Gas Cycling Followed by Gas Blowdown

The model cases run demonstrate that full scale gas cycling should be initiated early in order to achieve maximum recovery of the condensate and any other potential hydrocarbon liquids in the gas cap. Cycling also maintains reservoir pressure for development of the oil-rim. In a gas cycling project, the ultimate recovery of condensate and timing of subsequent gas blowdown is a function of the rate at which the in place volume of gas can be produced and recycled. This can be optimized by the number of development wells in place.

[7] BSCF/D – Billion standard cubic feet per day.

Four base cases of cycling the produced gas for 30 years with a different numbers of wells were run to test the impact of well count on the potential ultimate recovery of condensate. Additional cases with gas blowdown commencing after 10 and 20 years of cycling were run to test how much condensate could be produced prior to blowdown for gas sales.

The four base cases consisted of: a minimum development case of 4 producers and 2 injectors; a case with 8 producers and 4 injectors; a 16-producer with 5-injector case; and a case with 22-producers and 8 injectors which resulted in the highest hydrocarbon recovery of the four cases. Producers were constrained to a maximum rate of 150 MMSCF/D and a minimum BHP of 3000 psi. The injectors were limited to a maximum rate of 300 MMSCF/D and a maximum injection pressure of 15000 psi. In all cases 90% of the produced gas was cycled back into the reservoir.

Condensate recovery after 30 years for the four cases ranged from only 24% of the in place volume for the 4-producer case, to 86% recovery for the 22-producer case. At the end of cycling the injectors can be converted to gas producers. Gas blowdown with the 30 wells producing subsequent to gas cycling can recover up to 70% of the remaining recycled gas within 12 years.

Additional cases were then run with gas cycling for both 10 years and 20 years before blowdown. For the 22-producer and 8-injector development, after 10 years of cycling 62% of the condensate is recovered and then 57% of the original gas in place (OGIP) is recovered during the ensuing blowdown. Cycling for 20 years recovers 76% of the condensate and then 56% of the gas (OGIP).

Oil-rim Development

One of the key results of the study was that it became obvious that oil rim development had to be done during a gas cycling phase. Because there is uncertainty about the quality of the oil and reservoir rock in the oil-rim, to preserve reservoir energy and sustain maximum oil producibility oil rim reservoir pressure must be maintained. The oil-rim is a relatively thin zone of the reservoir that lies between the gas cap and underlying aquifer. For this reason the use of dedicated horizontal wells will be required to avoid coning of the adjacent gas or water. Injection of the recycled gas into the oil-rim will help reduce the viscosity, improve swelling, mobilize and displace the oil.

Model cases were run that included production wells in the oil-rim as part of both a primary depletion and gas cycling developments. Individual cases in both development strategies varied the number of oil-rim producers from 4 to 20 and ultimately 30 oil wells. Sensitivities were also run on gas- oil ratio (GOR) cutoffs for the producers, minimum BHP, and the use of offsite gas for supplemental gas injection.

In a primary depletion scenario, adding four wells into the oil-rim recovered 3% of the original oil in place. Increasing the number of oil-rim wells to twenty or thirty upped the recovery to almost 16% of OOIP. In a gas cycling scenario, the addition of four wells in the oil-rim achieved 11% recovery after 30 years of cycling, going to gas blowdown after 10 or 20 years of cycling recovered 7% and 9 % of the oil-rim OOIP respectively.

Increasing the number of oil-rim wells during gas cycling development in the model increased the recovery of oil significantly. In a case with 13 gas producers, 18 gas injectors and 20 oil-rim producers, recovery of oil from the oil-rim approaches 50% of the in-place volume after 30 years of cycling. This is 3-15 times better recovery than during primary blowdown. By varying the length of time of cycling

before gas blowdown from 5 to 10 and then 20 years in the same development scenario the recoveries from the oil-rim drop to 31%, 39% and 43% respectively.

Modeling of development scenarios for the oil-rim demonstrates that to achieve maximum recovery of the oil resources located below the gas cap in the oil-rim reservoir pressure maintenance by gas cycling is crucial. The difference in recovery from the oil-rim between primary depletion and a cycling project that maintains reservoir pressure can be as much as **35% more** of the total in-place volume.

Use of Offsite Gas

Production from the oil rim increases the voidage within the reservoir. The results from model cases involving large scale development of the oil-rim (30 horizontal producers) indicated that due to the increased off-take, reinjection of 90% of the produced gas will not be sufficient to maintain reservoir pressure. A decrease in reservoir pressure below dew point results in lower condensate recoveries and the reduction also decreases oil-rim recovery.

Gas from outside sources (offsite) could be imported and injected into the Thomson reservoir to help maintain reservoir pressure. Offsite gas can be in the form of carbon dioxide (CO2), inert gas such as nitrogen, methane or natural gas.

The use of CO2 for pressure maintenance may have multiple benefits depending on the source and availability.

- CO2 is commonly removed as a byproduct from produced gas in a gas treatment plant prior to sale.
- If enough CO2 is available for pressure maintenance, it could allow sale of some Point Thomson gas before gas blowdown.
- CO2 should be fully miscible with the Thomson oil and thus reduce the viscosity and further increase recovery.

CO2 is considered a "green house gas" and re-injection into a reservoir is a method of sequestering carbon and as such government tax incentives may be available in the form of carbon credits to offset and/or mitigate CO2 re-injection costs.
Although the importation of offsite gas would require the construction of a gas line to Point Thomson, once gas cycling is completed, the line would be available for gas sales.

The large scale oil-rim development cases that needed supplemental pressure support indicated a volume of 200-500 MMSCF/D would be required in addition to the Thomson gas during the cycling process. A comparison of cases with and without offsite gas showed an increase in condensate recoveries from 33% to 60% of the original condensate in place. This is a potential increase of 130-160 MMSTB.

Conclusions from Geologic and Reservoir Modeling

1. In addition to gas, the area contains hundreds of millions of barrels of hydrocarbon liquids. These hydrocarbon liquids exist in the form of condensate liquids; a thin and potentially discontinuous oil leg at the bottom of the Thomson sand reservoir; and oil in the overlying Brookian sediments. Exploration wells drilled prior to 1982 have tested oil from each of these reservoirs. Adequate infrastructure to transport these liquids to market exists within thirty miles of this reservoir.

Therefore, the potential development of the Point Thomson area should not be limited to production of the dry gas.

2. Evaluation of the potential hydrocarbons in place in the Thomson sand reservoir by DNR and PetroTel's 3D geologic models results indicate the following volumetrics:
    - Original gas in place of 8.5-10.4 TSCF.
    - retrograde condensate - 490-600 MMSTB in place
    - Oil rim - 580 to 950 MMSTB original oil-in-places.

3. Reservoir simulation of the Thomson sand reservoir evaluated various development scenarios for the reservoir. These scenarios included primary depletion of the reservoir (gas blowdown), production and re-injection of the gas after recovering the condensate (gas cycling), and the addition of dedicated horizontal production wells into the oil-rim in both gas blowdown and cycling cases. Over 70 individual cases where run in the reservoir simulator varying the number of development wells and operating constraints in an attempt to determine the optimum recovery for each development scenario.

4. The producible liquids contained in the Thomson reservoir could technically be developed before a gas pipeline is built.

5. In order to maximize the recovery of the hydrocarbon liquids in the reservoir it is necessary to keep the reservoir pressure high until all of the economically recoverable liquid hydrocarbons are produced. This is most often accomplished through gas cycling. In the reservoir simulator cases run, gas cycling was applied in the gas cap for 30 years in conjunction with development and gas cycling of the oil-rim.

    - Gas cycling recovered 86% or 420-516 MMSTB of condensate.
    - Recovery from the oil-rim was close to 50%, 290-475 MMSTB.

6. Shorter duration Gas Cycling:
    - Cycling gas for 10 years prior to blowdown results in recoveries of:
        - Condensate - 62% or 300-370 MMSTB
        - Oil Rim - 39% or 225-370 MMSTB of the oil-rim

    - Cycling the gas for 20 years increases the recoveries:
        - Condensate - 76% or 370-450 MMSTB
        - Oil Rim - 43% or 250-400 MMSTB.

    - Subsequent blowdown of the gas cap after 10 and 20 years cycling recovers 57% and 56% or 4.8-5.9 TSCF of gas reserves.

7. Primary depletion is the fastest method to produce the gas from the reservoir but recovers the least hydrocarbons. Simulation results showed: 70% of gas recovered or 6-7 TSCF with 22 wells in 12-15 years.
    - Condensate recovery is approximately 26% of the in place volume, or 127-156 MMSTB
    - Oil-rim recovery during primary depletion is only 3-16% 30-150 MMSTB of oil.
    - The majority of the condensate is left in the reservoir by condensation below dew point.
    - Pressure maintenance and gas recycling is needed to maximize condensate recovery.

- Primary depletion reduces recovery from the oil-rim due to loss of energy by the depletion of reservoir pressure.
- Gas blowdown and sale of the gas can be done at any time after cycling and recovery of the hydrocarbon liquids.

8. A gas blowdown scenario could recover over 500 million barrels less than a gas cycling scenario. This difference is larger than the expected ultimate recovery from the Alpine Oil Field.

9. There is uncertainty in the original oil-rim volume in place and the ultimate recovery of that oil, even though it has flowed during testing of the PTU-1 exploration well.
   - Even if the oil rim was discounted entirely, the difference in condensate recovery between primary depletion (blowdown) and gas cycling for 20 years is potentially over 300 million barrels.
   - This represents three times the targeted recovery from the proposed off shore development of the Liberty Field.
   - During the period of gas cycling, further delineation of the oil-rim will determine the scale of development needed to maximize recovery from that portion of the resource.

In summary, gas cycling delays gas sales, but it is through this process that the maximum recovery of the condensate in the gas cap and any other liquid hydrocarbons can be achieved. Cycling also maintains reservoir pressure for development of the oil-rim and is a viable recovery mechanism. The length of time required for gas cycling prior to gas sales will be a combination of the resource available from the oil rim and the rate at which the in place volume of gas can be produced and recycled. A large factor in this will be the number of development wells that can be economically drilled and operated. More wells equals faster cycling and faster recovery of the condensate liquids. These liquids could be produced and sold before the construction of a North Slope gas pipeline. Production of liquid hydrocarbons from the Thomson reservoir could facilitate oil production from the other discovered reservoirs such as the Brookian Flaxman and Sourdough accumulations.

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Former Point Thomson Unit

Lease with Decertified Well

Lease Under Primary Term

Lease Beyond Primary Terms with Well

Lease Beyond Primary Term Without Well

AOGCC Suspended Well – plugged and abandoned

Decertified Well – one well certified

P&A'd Well; Never Certified

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