

**07/19/16
PRESENTATION
PLAN OF
DEVELOPMENT
FOR THE
PRUDHOE BAY
UNIT**

<TARGET><BILL></BILL><SUBJECT>07-19-16 PRESENTATION
PLAN OF DEVELOPMENT FOR THE PRUDHOE BAY
UNIT</SUBJECT><COMM>SRES29</COMM></TARGET>



ALASKA STATE LEGISLATURE

SENATE RESOURCES COMMITTEE

SEN. CATHY GIESSEL
Chair
State Capitol, Room 427
Juneau, AK 99801-1182
(907) 465-4843 Fax 465-3871

Sen. Mia Costello, Vice-Chair
Sen. Peter Micciche
Sen. Bert Stedman

Sen. John Coghill
Sen. Bill Stoltze
Sen. Bill Wielechowski

Memorandum:

TO: Liz Clark, Senate Secretary
FROM: Senator Cathy Giessel, Chair, Senate Resources Committee
DATE: July 11, 2016
RE: Senate Resources Committee Hearing

Senate Resources Committee Meeting Announcement

Tuesday, July 19, 2016 - 1:00 pm - 3:00 pm Anchorage LIO Auditorium

+ - Plan of Development for the Prudhoe Bay Unit

- Invited Testimony
- + Listen Only Teleconference

Alaska Oil and Gas Conservation Commission

Cathy Foerster, Chair

Gas Offtake Allowables

Prudhoe Bay:

Before: 2.7 BCF/day, but
not really

Now: 3.6 BCF/day

Pt Thomson:

Before: No offtake
allowable in place

Now: 1.1 BCF/day

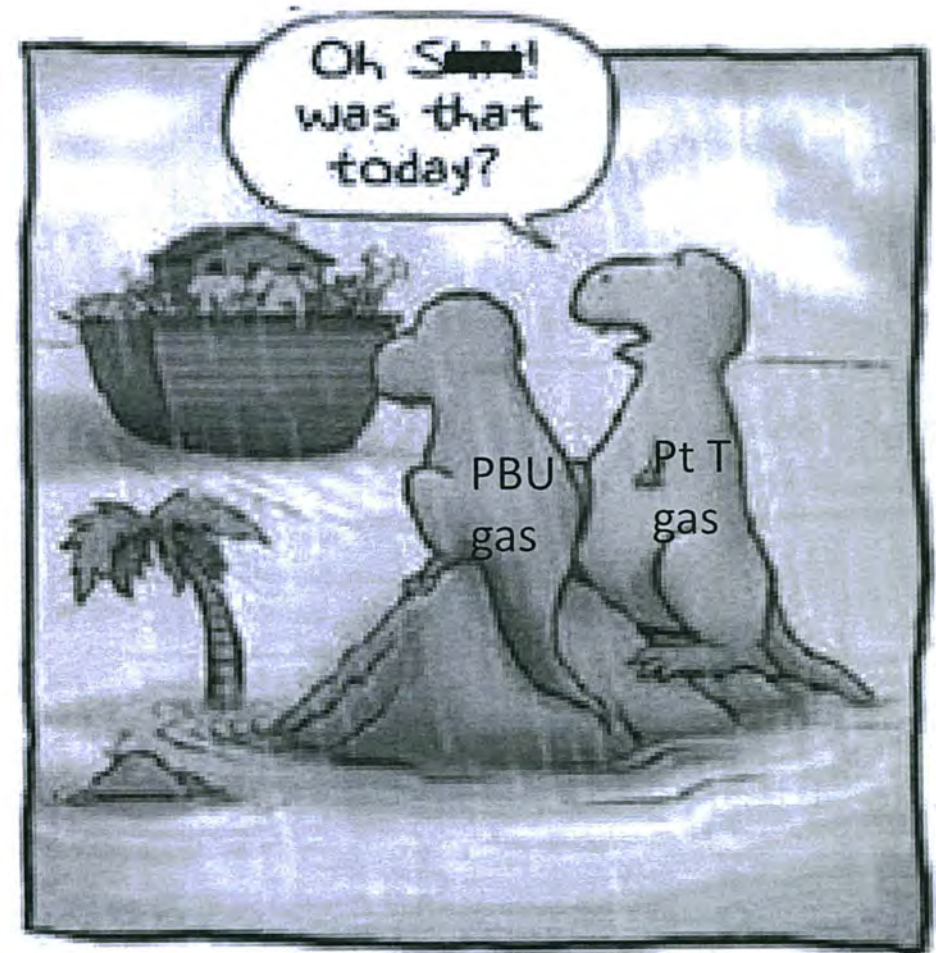
Bottom Line: Sufficient offtake to meet the currently-proposed project needs

AOGCC Responsibilities

- Protect human safety
- Protect fresh ground waters
- **Prevent waste**
- **Encourage greater ultimate recovery**
- Protect correlative rights

Encourage Greater Ultimate Recovery

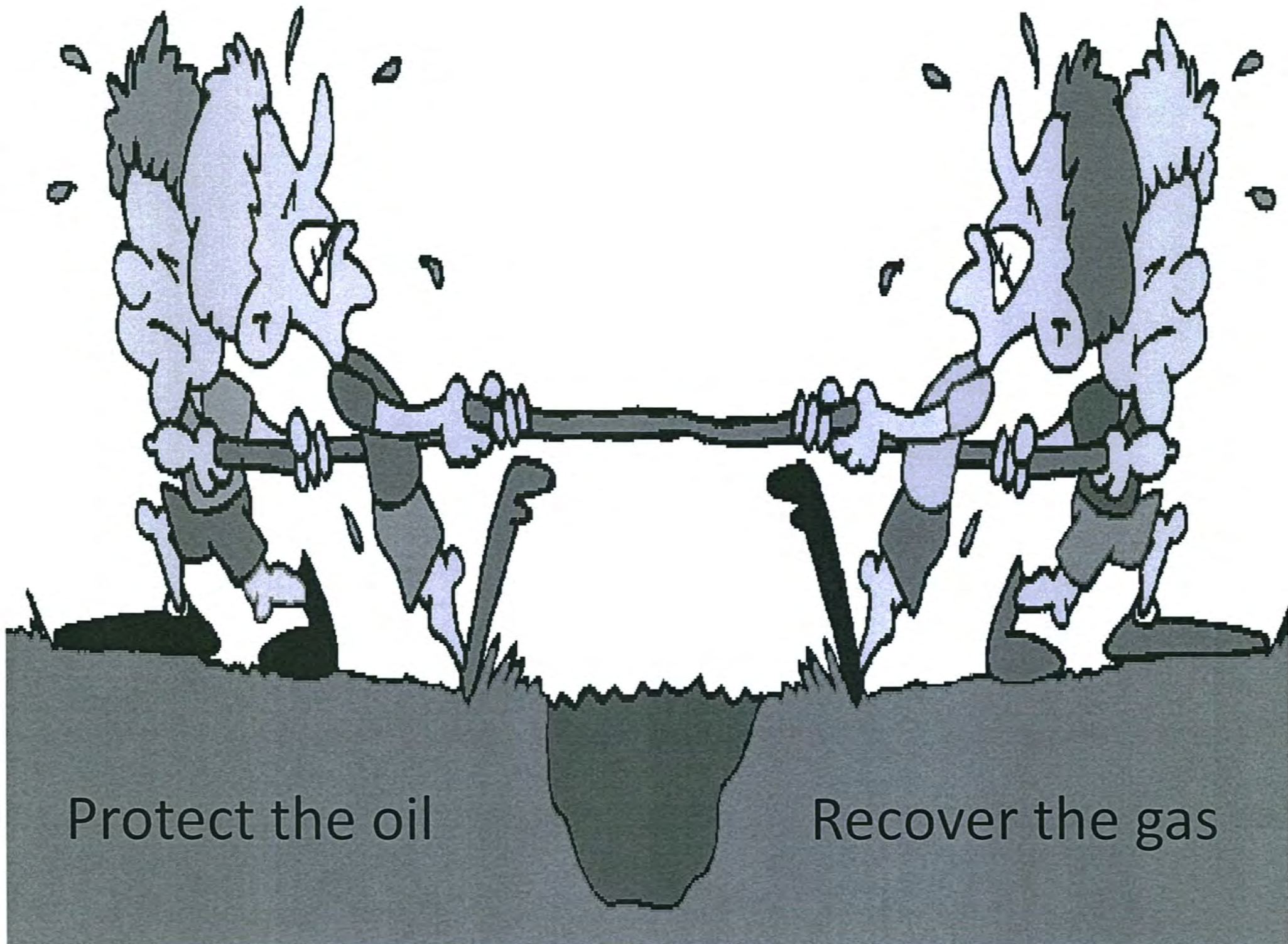
- Prudhoe Bay
 - 22 trillion cubic feet of gas
- Pt Thomson
 - 6 trillion cubic feet of gas



Prevent waste

- Prudhoe Bay
 - 2.5 billion barrels of oil
- Pt Thomson
 - 200 million barrels of condensate





Protect the oil

Recover the gas

Timing is
Everything



Summary of the Rulings

- Prudhoe Bay
 - Offtake allowable increased to 3.6 BCF/day on an annual average
 - In 5 years BP must provide report of oil recovery acceleration activities and results
 - CO₂ injection for EOR authorized, based on positive study results
 - CO₂ disposal authorization outside AOGCC jurisdiction
- Pt Thomson
 - Offtake of 1.1 BCF/day allowed
 - Prior to MGS, Exxon must demonstrate that cycling isn't feasible

Prudhoe Bay IPA

Reservoir Overview and 2016 Plan of Development
Senate Resources Committee Hearing



Corri Feige, Director
Paul Decker, Manager, Resource Evaluation Section
Division Oil and Gas
Alaska Department of Natural Resources
July 19th, 2016

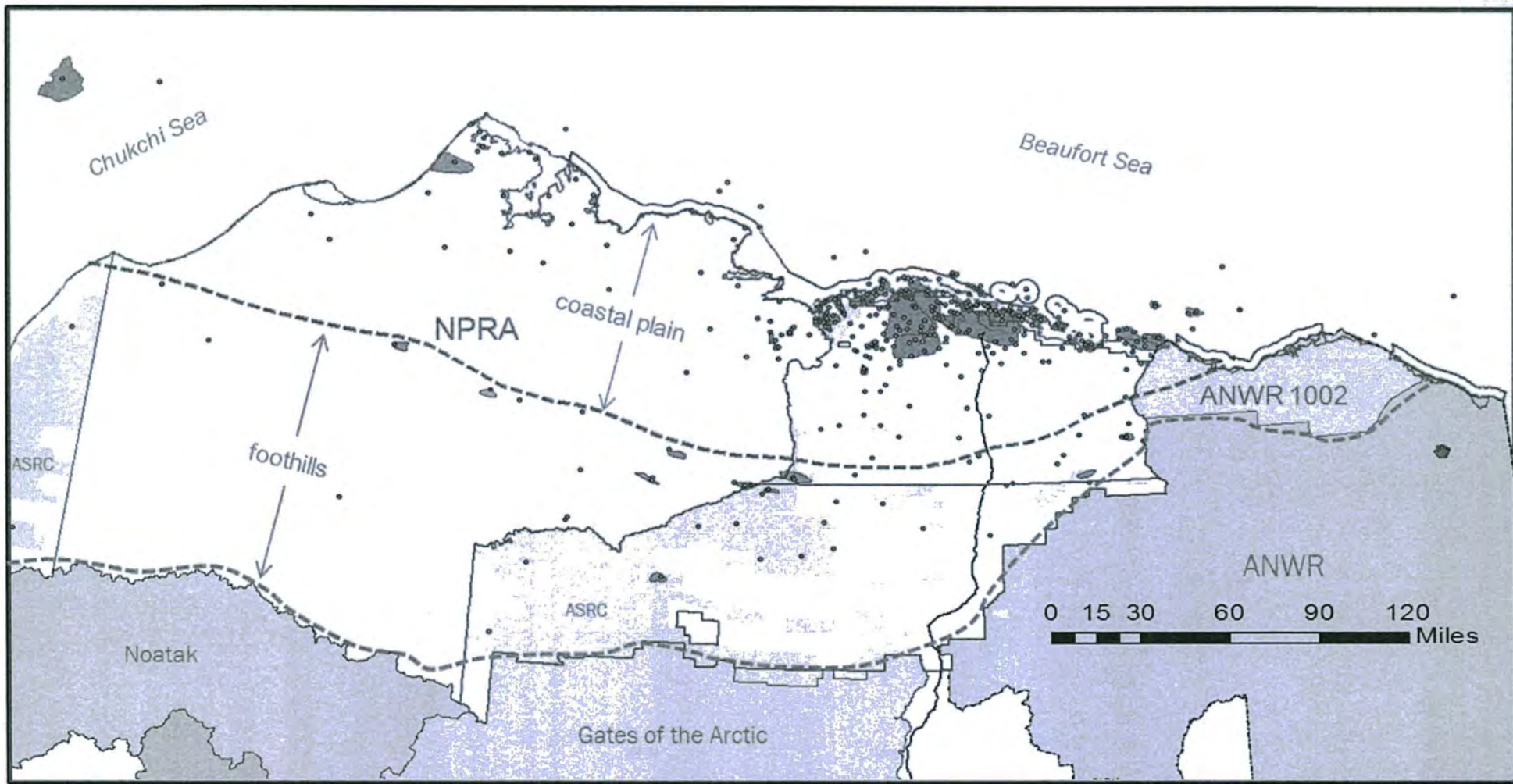


OVERVIEW

- Prudhoe Bay Unit (PBU) Overview
- PBU Initial Participating Area (IPA) Reservoir & Production
- Plan of Development (POD) Process & Requirements
 - What is a POD?
 - POD Requirements
 - POD Process
- PBU IPA 2016 POD & Where We Are Today

NORTHERN ALASKA OIL & GAS

- LOCATION MAP -



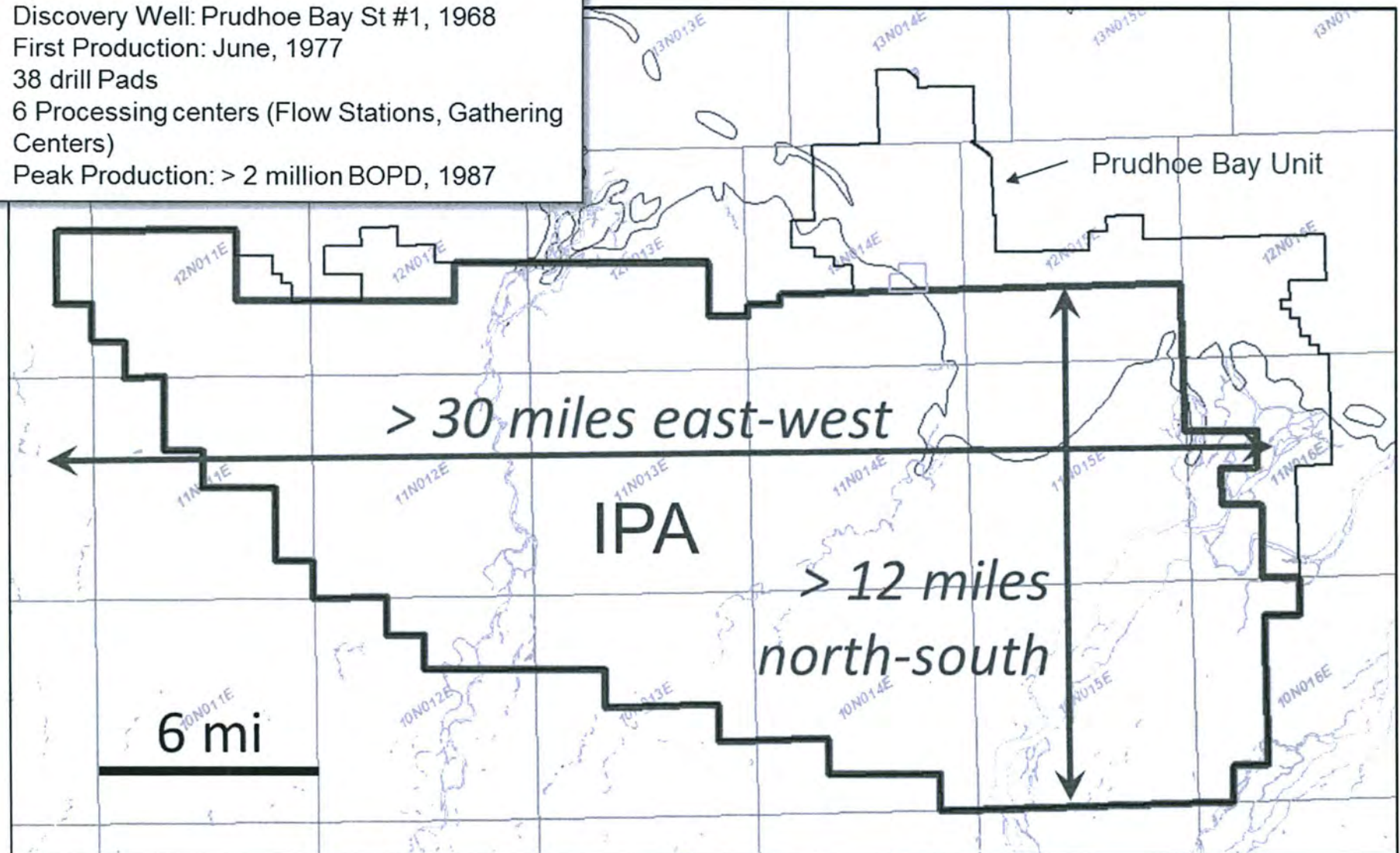
Oil accumulations in green, gas accumulations in red. Black dots are exploration wells. Red outlines are state areawide lease sale boundaries. Green areas are permanently protected federal lands.

PRUDHOE BAY UNIT

- INITIAL PARTICIPATING AREA -

Prudhoe Bay Unit IPA

- Discovery Well: Prudhoe Bay St #1, 1968
- First Production: June, 1977
- 38 drill Pads
- 6 Processing centers (Flow Stations, Gathering Centers)
- Peak Production: > 2 million BOPD, 1987

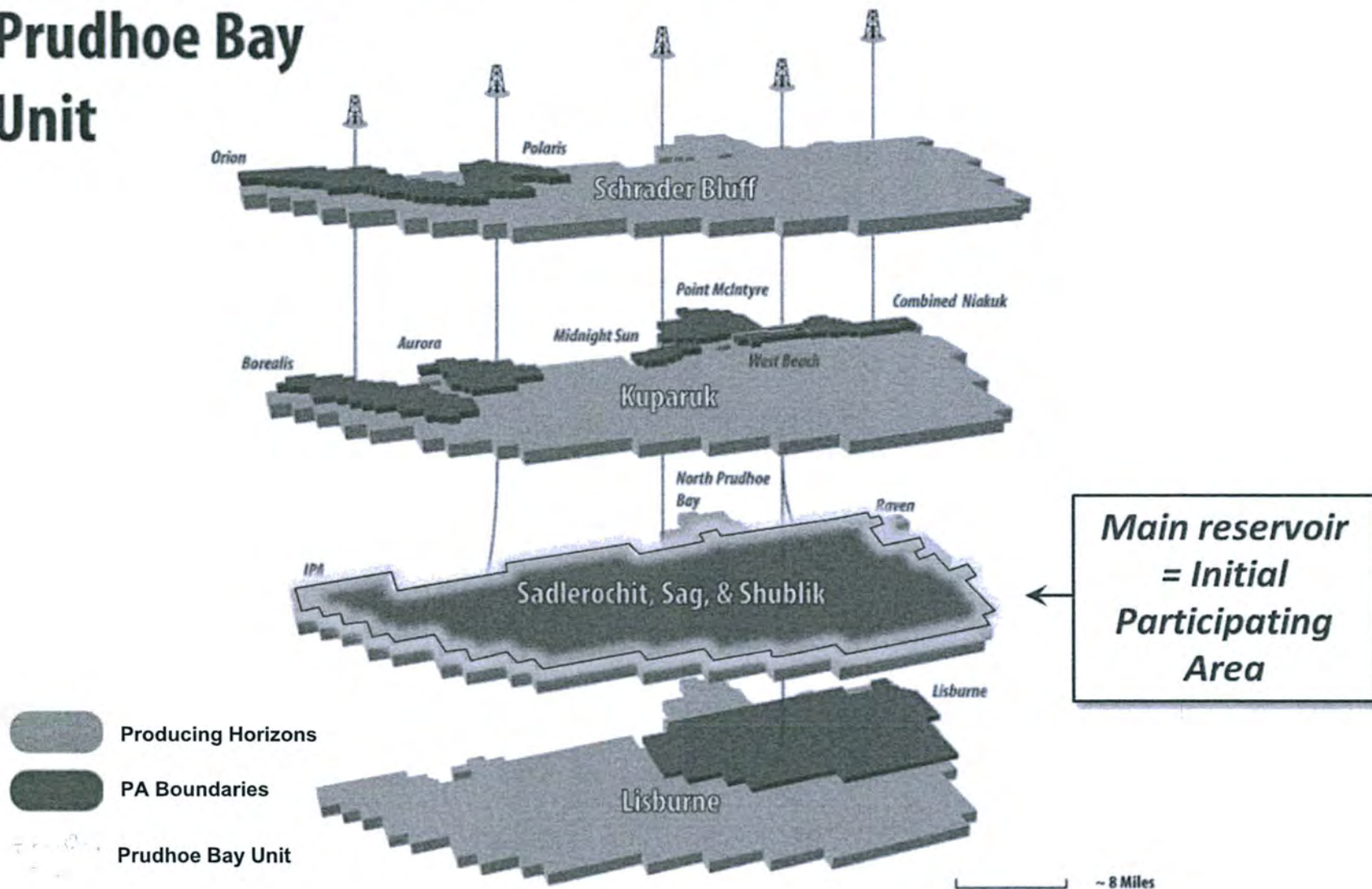


PRUDHOE BAY UNIT

- 13 PARTICIPATING AREAS -

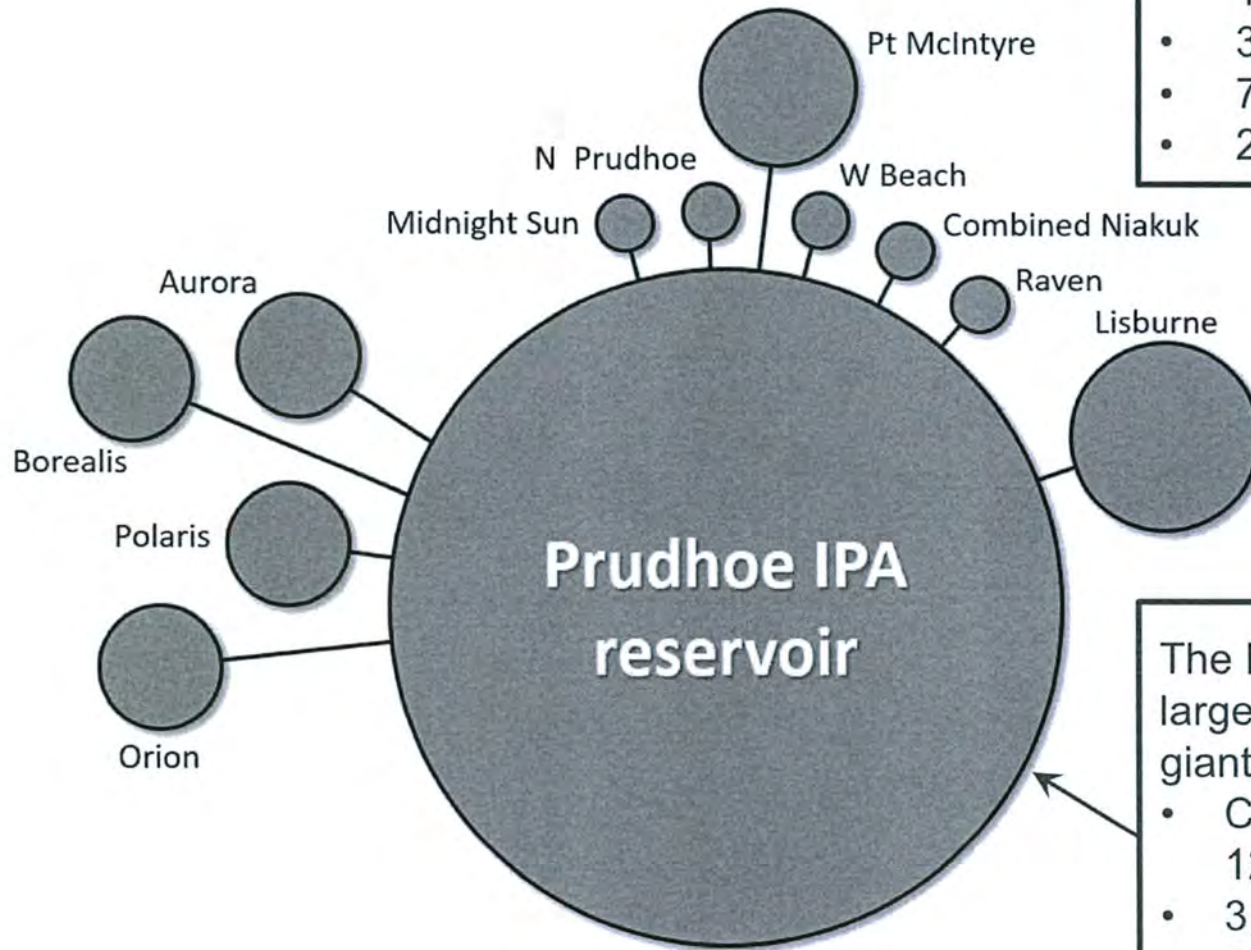
- Production from 4 different geologic formations
- Annual Plan of Development required for each PA

Prudhoe Bay Unit



PRUDHOE BAY UNIT

- PARTICIPATING AREAS -



- Unit-wide Cumulative Oil Production: 13.3 billion barrels oil + NGLs
- 3,951 total development wells
- 735 active producers
- 248 active injectors

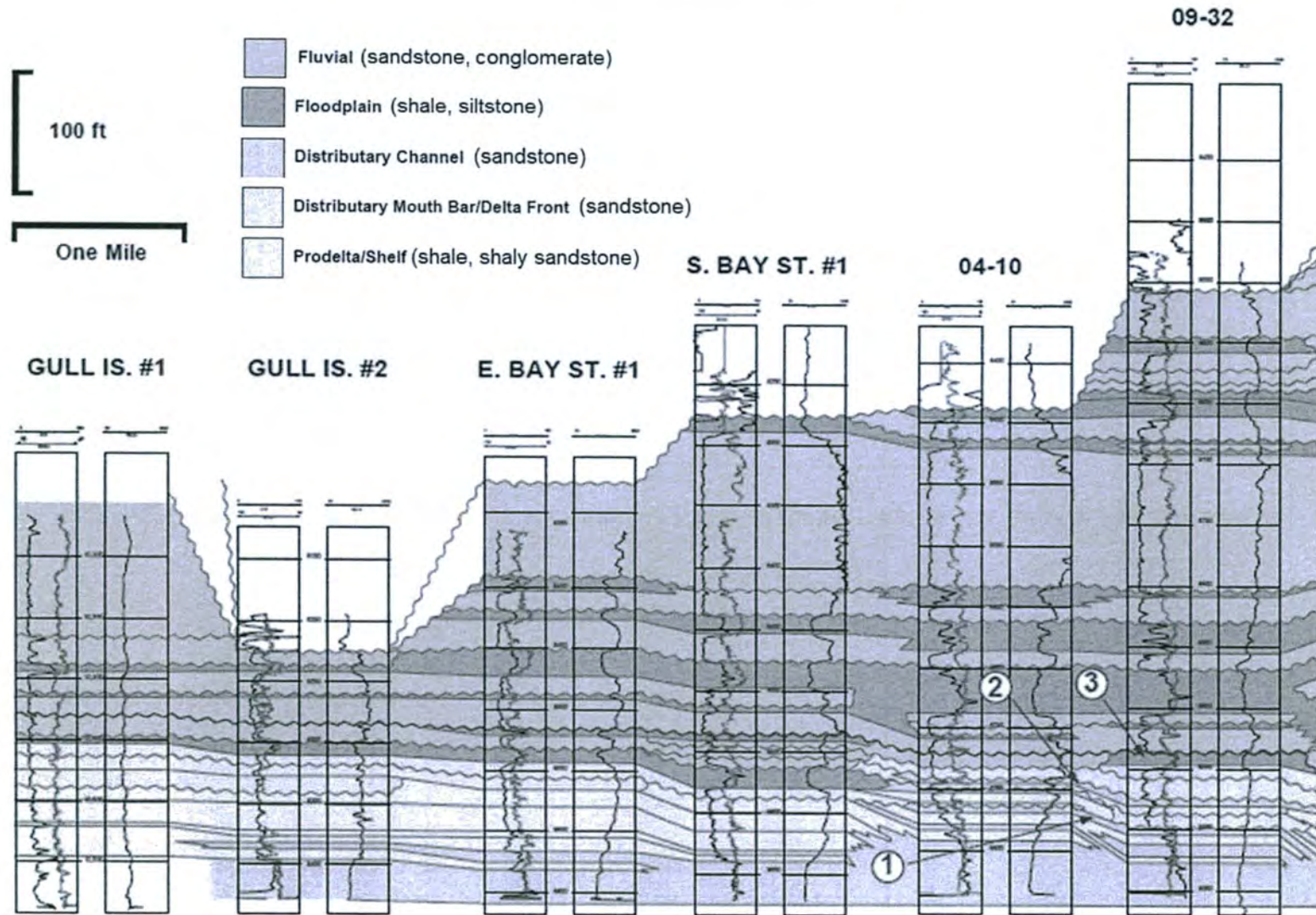
Statistics as of May, 2016 include sidetracks, laterals, plug-backs, and P&A'd; exploratory & delineation wells are excluded

The Initial Participating Area is by far the largest of these PAs and hosts the super-giant Prudhoe Oil Pool

- Cumulative Oil Production: 12.3 billion barrels oil + NGLs
- 3,293 total development wells
- 607 active producers
- 163 active injectors

PRUDHOE BAY RESERVOIR CROSS SECTION

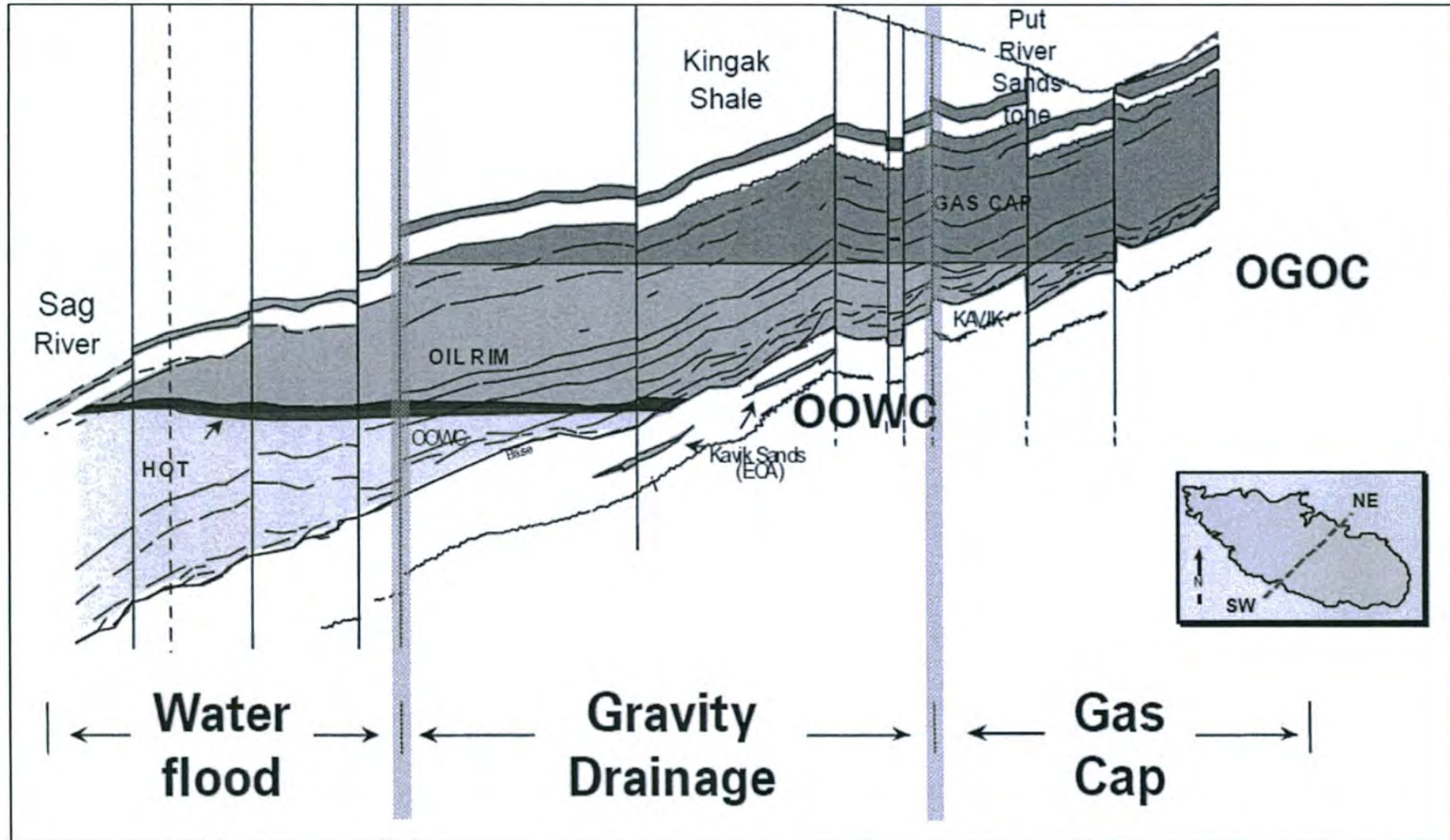
Fluid flow, oil recovery vary by zone due to variations in thickness and continuity of various rock types



PRUDHOE BAY RESERVOIR

- INITIAL CONDITIONS -

Prior to development, reservoir had simple, discrete fluid layers: gas cap, light oil column, heavy oil/tar mat, and water leg (aquifer)

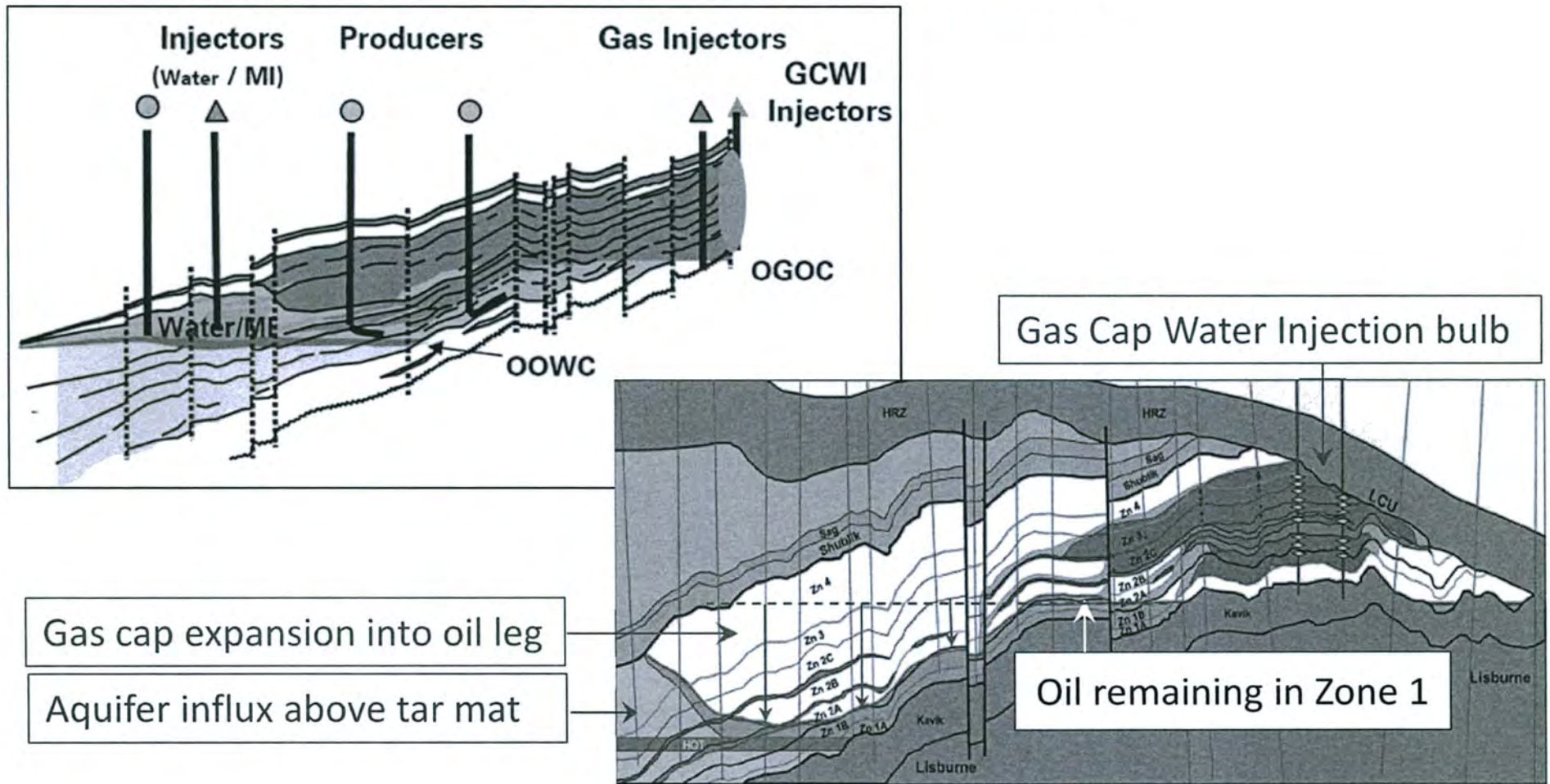


Graphic after Digert, 2016 (courtesy BP)

PRUDHOE BAY RESERVOIR

- CURRENT CONDITIONS -

After nearly 4 decades of production, oil, gas, and water are complexly intermixed throughout the reservoir due to permeability contrasts, gas cap expansion, and state-of-the-art secondary and enhanced recovery projects (waterflood, miscible injection/water-alternating-gas, lean gas reinjection, gas cap water injection, etc.)



Graphics after Digert, 2016 (courtesy BP)

MAXIMIZING OIL RECOVERY

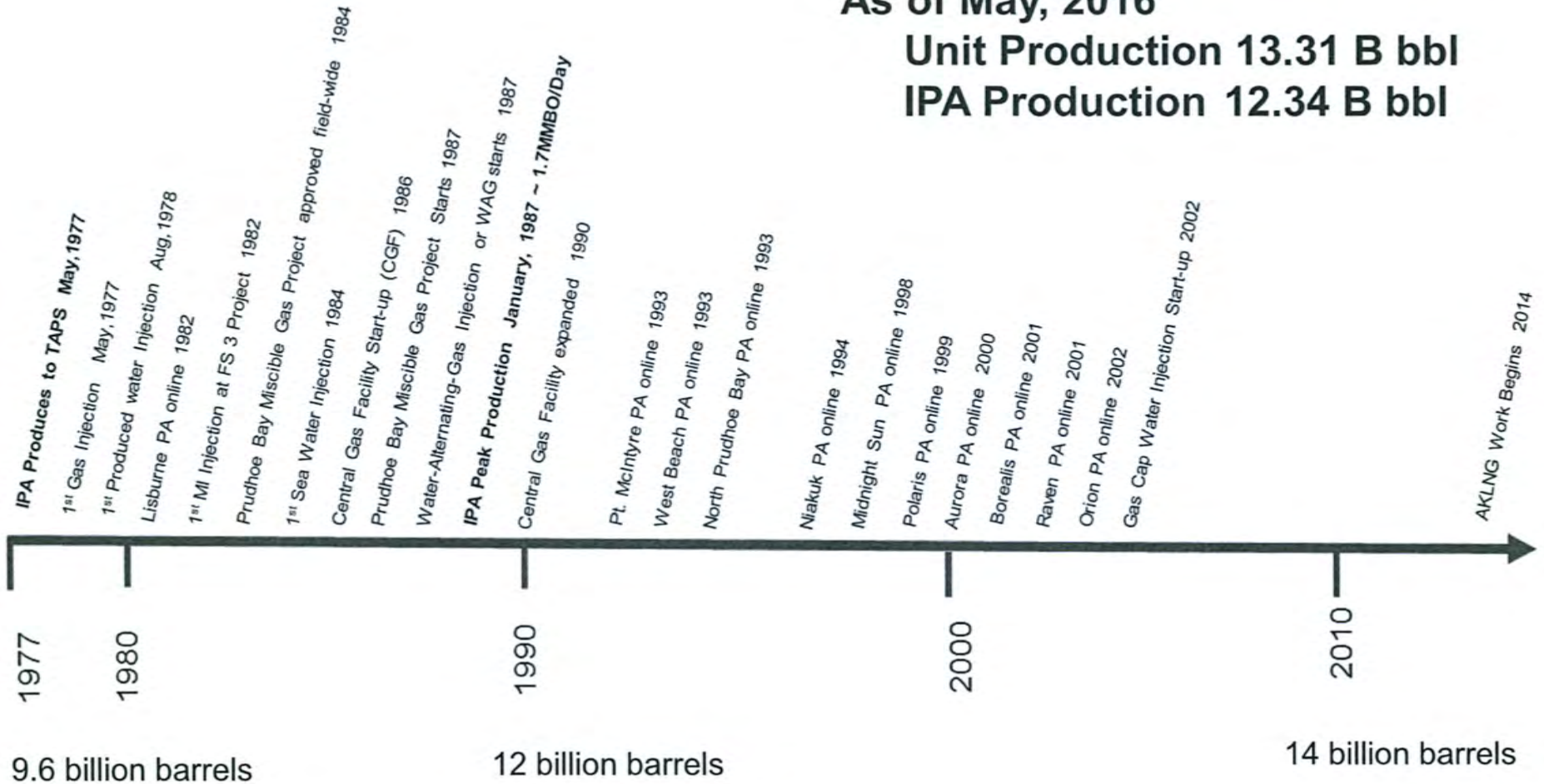
- The Prudhoe IPA was initially expected to recover 9.6 billion barrels. Cumulative production to date is more than 12.3 billion barrels oil + NGLs.
- Currently, Estimated Ultimate Recovery (EUR) is ~14 billion barrels, or 46% greater than estimated when field development began.
- The WIOs have been diligent in maximizing oil recovery at Prudhoe Bay IPA:
 - Greatly expanded use of coiled tubing sidetrack drilling and well workover jobs, with 4 successive years of increasing activity
 - Large scale restoration of reservoir energy through Gas Cap Water Injection (GCWI), waterflood, miscible gas injection, and huge expansions of gas cycling capacity
 - Recognition and exploitation of new targets created by complex oil-gas-water distributions
 - Optimization of vapor phase oil recovery through lean gas injection to scavenge otherwise immovable relict and residual oil
 - Expanded development of Sag River sandstone reservoir
 - Numerous facilities and pipeline maintenance and replacement projects to improve recovery and extend field life by decades

PRUDHOE BAY UNIT HISTORY

As of May, 2016

Unit Production 13.31 B bbl

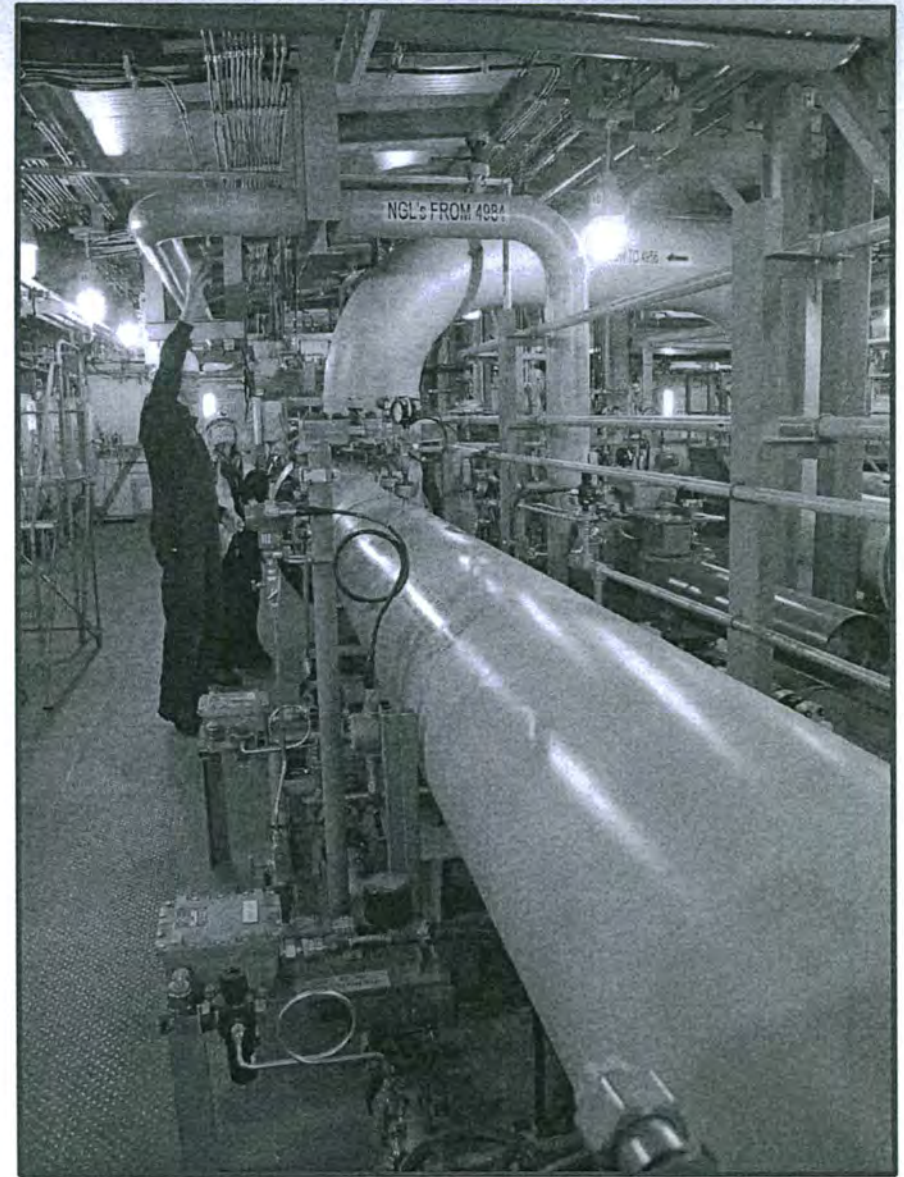
IPA Production 12.34 B bbl



Increase in Estimated Ultimate Recovery (EUR) over time

WHAT IS A PLAN OF DEVELOPMENT (POD)?

- Once a PA is formed, a POD is required under 11 AAC 83.343
- Submitted annually by the unit Operator.
- Opportunity for both parties to discuss past and planned unit activities.
- Demonstrates to the state that unit resources are diligently developed & produced.
- All operations must be conducted under an approved POD.



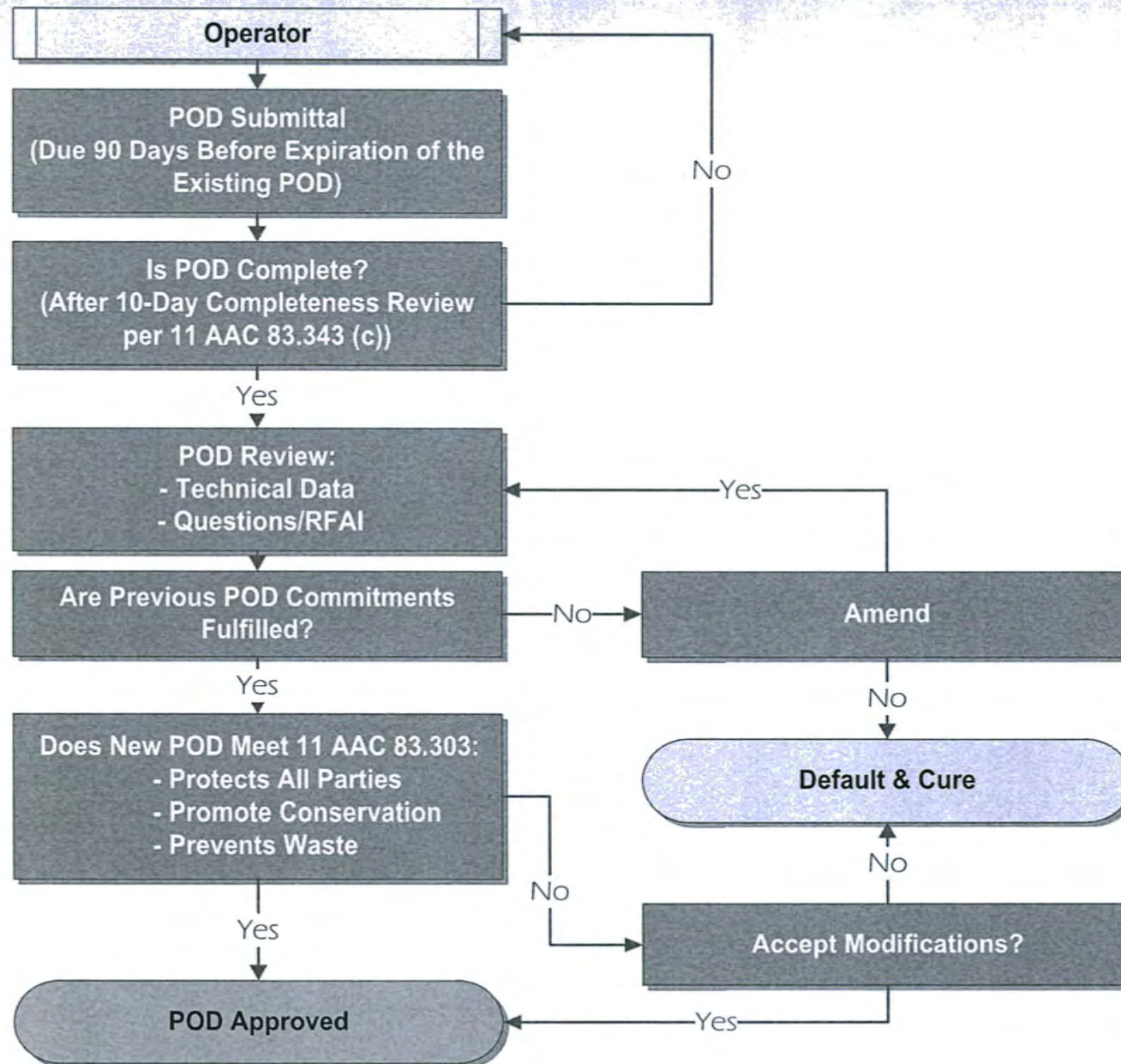
POD REQUIREMENTS

11 AAC 83.343(a)(1-4) Describes what the POD must include:

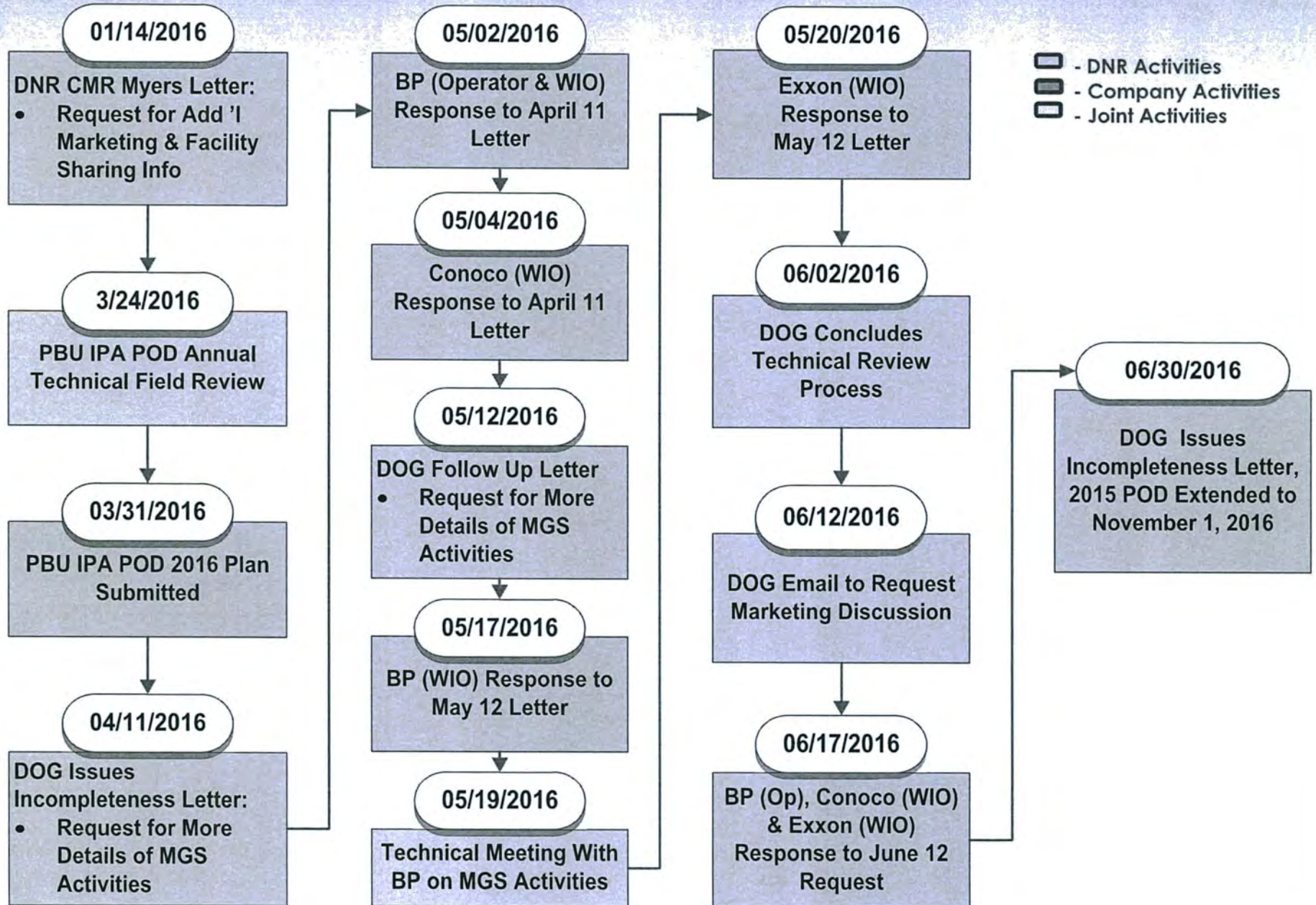
“...The plan must include a description of the proposed development activities based on data reasonably available at the time the plan is submitted for approval as well as plans for the exploration and delineation of any land in the unit not included in a PA. The plan must include, to the extent available information exists...”

1. Long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established;
2. Plans for the exploration or delineation of any land in the unit not included in a PA;
3. Details of the proposed operations for at least one year following submission of the plan; and
4. The surface location of proposed facilities necessary for unit operations (pads, roads, camps, etc.).

PLAN OF DEVELOPMENT PROCESS



PBU IPA 2016 POD TIMELINE



WHERE WE ARE TODAY

- POD submittal is “incomplete” NOT in “default”
- Currently operating under extended 2015 POD
- Anticipating responses from WIOs about “...how WIOs are marketing gas resource and moving toward MGS...” due to DOG by September 1, 2016





Senate Resources Committee

22 February 2012

William C. Barron
Director
Division of Oil and Gas





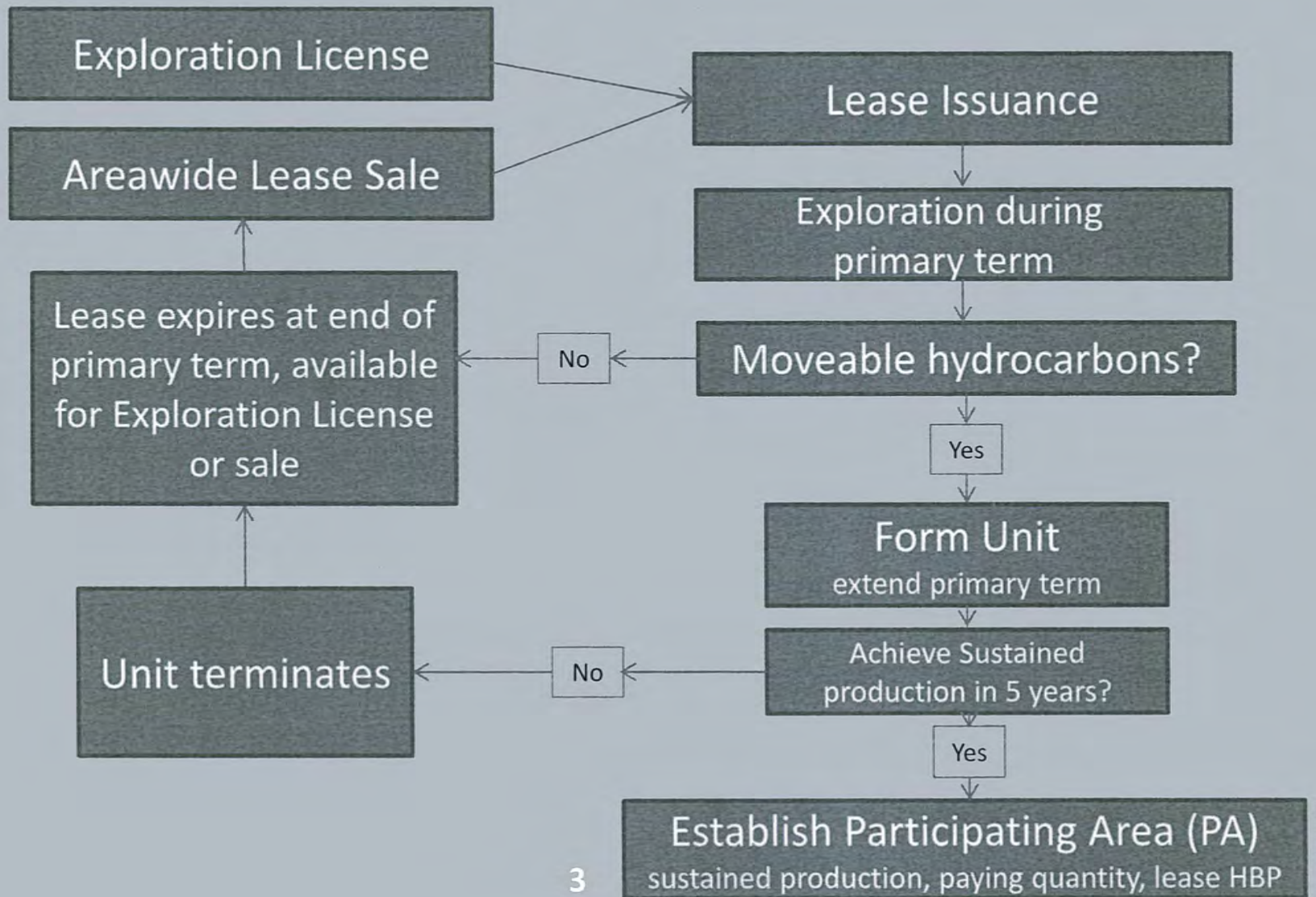
Land Management: Life of the Lease

- Areawide Lease Sale/Exploration License
 - Primary term commences
- Exploration during primary term
 - If producible hydrocarbons are demonstrated by drilling and testing of a well, candidate for unitization
- Unitization
 - Primary term of lease extended 5 years
 - Work scope
- Establish Participating Area (PA)
 - Capable of producing in paying quantities
 - Subject to a Plan of Development (POD)



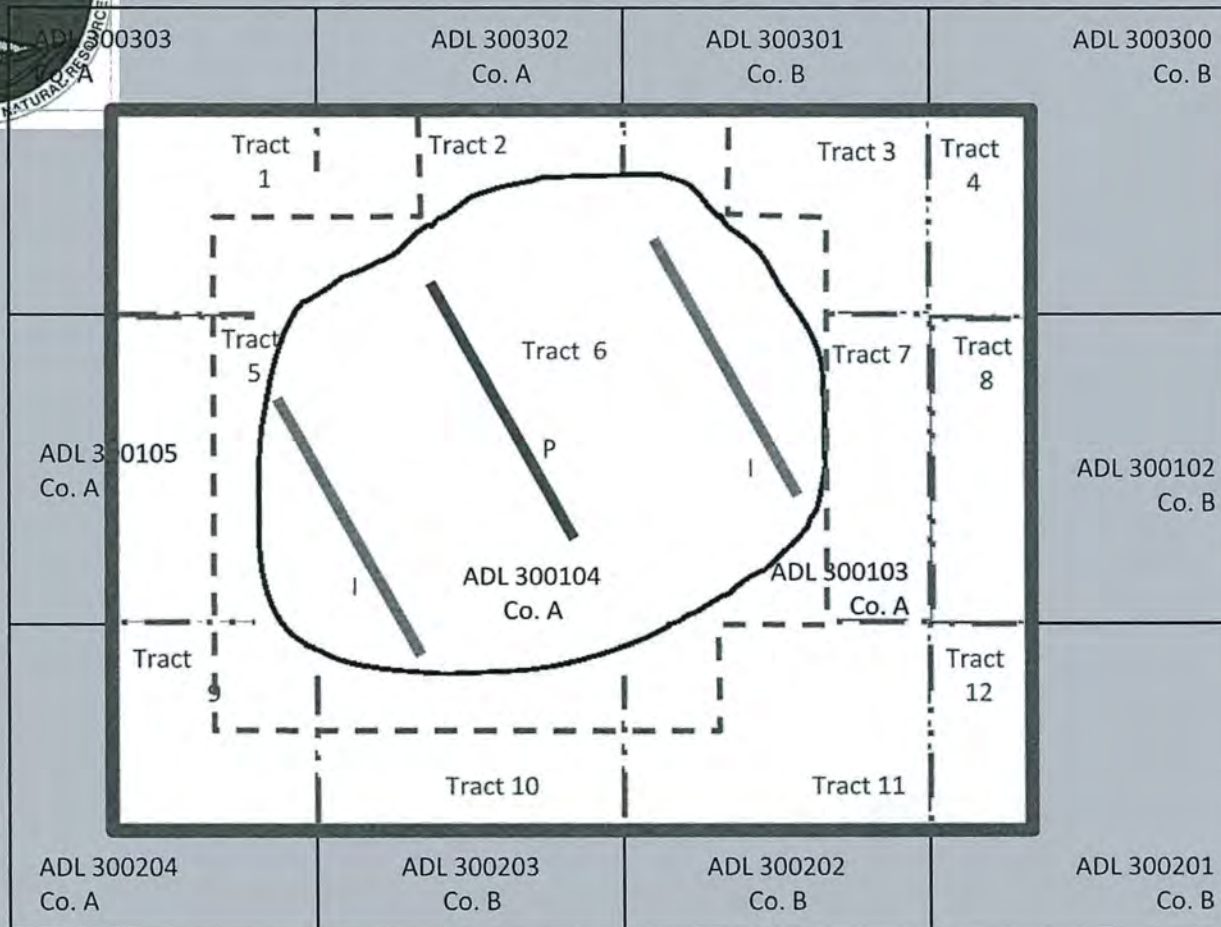


Land Management: Life of Lease





How a Unit Works



- Producer Well
- Injector Well
- Reservoir
- PA Boundary
- Unit Boundary
- Unit Tract
- Lease Boundary
- Section Boundary

Prod. Allocation

Tract	%
1	<1
2	14
3	12
4	0
5	6
6	41
7	20
8	0
9	<1
10	6
11	<1
12	0

Unitization provides for the efficient development of the reservoir while protecting each lessee's interest in their fair share of the hydrocarbons produced. It also extends the life of a lease even though a well may not be drilled on it.





Land Management: When is a PA formed?

- A PA is formed once the unitized reservoir is on “sustained production”: wells are producing into a pipeline or other means of transportation to market
- Separate PA required for each producing horizon
- Approval of a PA includes approval of allocation factors
 - Sets out proportions of costs and revenues paid and received by working interest owners
 - Approval meets 11 AAC 83.303: Protect all parties





What is a Plan of Development (POD)?

- Once a PA is formed, a POD is required under 11 AAC 83.343
 - Must be filed for approval if a PA is proposed, or reservoir sufficiently delineated to initiate development activities
 - POD is submitted annually for review and approval
 - If POD deemed insufficient for approval, DNR may propose modifications. If Operator agrees to modifications, POD approved.
 - If not accepted by Operator, and no approved POD, current POD may expire.
 - **Development activities must be conducted under an approved POD**





POD Requirements

11 AAC 83.343(a)(1-4)

- Describes what the POD must include
 - 1) long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established
 - 2) plans for the exploration or delineation of any land in the unit not included in a PA;
 - 3) details of the proposed operations for at least one year following submission of the plan; and
 - 4) the surface location of proposed facilities necessary for unit operations (pads, roads, camps, etc.).





North Slope Units and PAs February, 2012

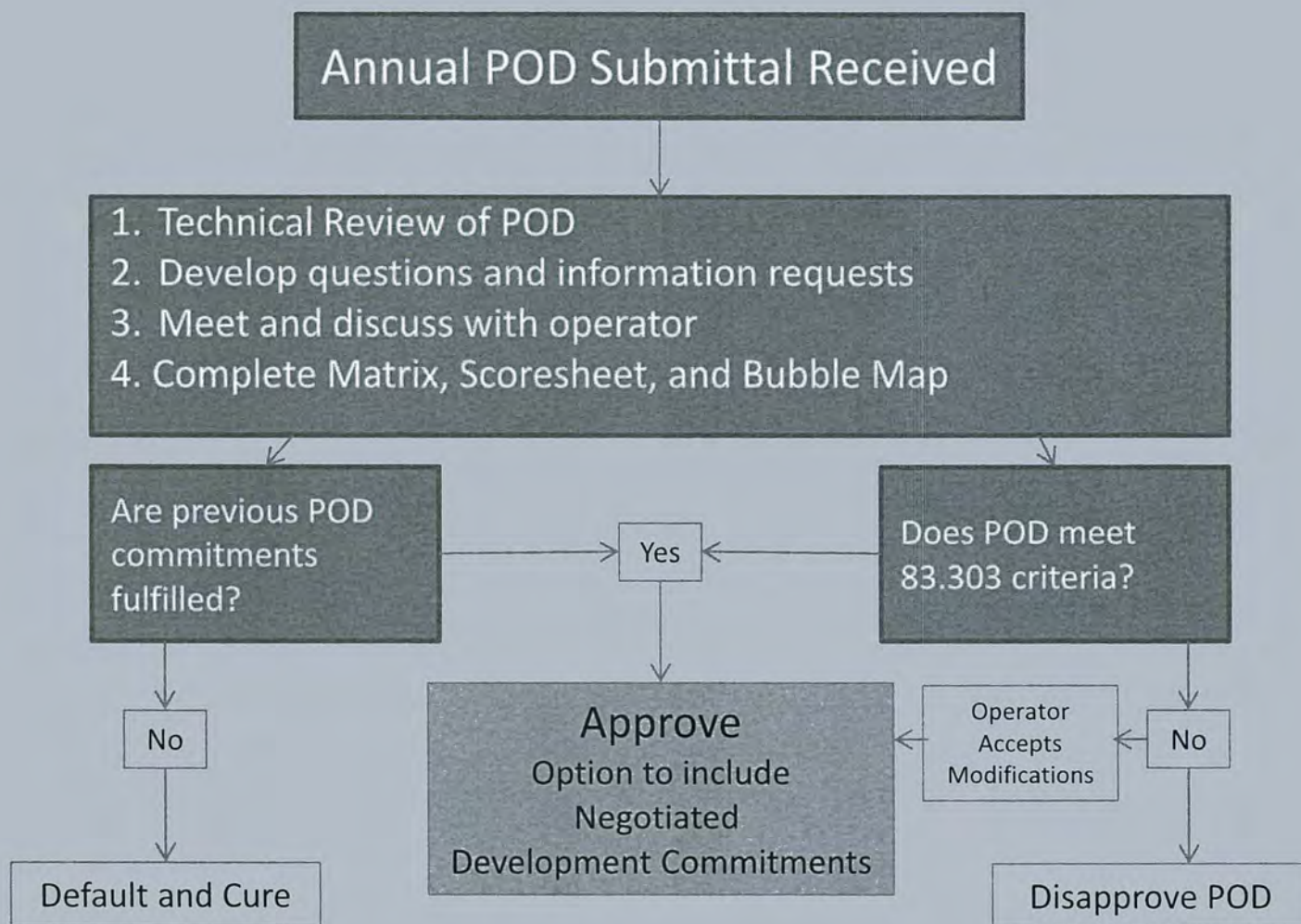
18 Existing SOA Units, 42 PAs, 2 Units Proposed

- Akjaq Unit (Proposed)
- Arctic Fortitude Unit
- Badami Unit
 - Badami Sands PA
- Bear Tooth Unit (Federal)
- Beechey Point Unit
- Colville River Unit
 - Alpine, Nanuq Nanuq, Nanuq Kuparuk, Fiord Kuparuk, Fiord Nechelik, Qannik PAs
- Dewline Unit
- Duck Island Unit
 - Eider, Endicott, Sag Delta North PAs
- Greater Moose's Tooth Unit (Federal)
- Kachemach Unit
- Kuparuk River Unit
 - Kuparuk, Meltwater, Tabasco, Tarn, West Sak, NEWS PAs
- Liberty Unit (Federal)
- Milne Point Unit
 - Kuparuk, Schrader Bluff, Sag River PAs
- Nikaitchuq Unit
 - Schrader Bluff PA
- Northstar Unit
 - Northstar PA
- Oooguruk Unit
 - Kuparuk, Nuiqsut, Torok PA's
- Placer Unit
- Prudhoe Bay Unit
 - Aurora, Borealis, Gas Cap, Lisburne, Midnight Sun, Niakuk, Combined Niakuk North Prudhoe Bay, Oil Rim, Orion, Polaris, Pt McIntyre, West Beach, West Niakuk, Raven PAs
- Putu Unit
- Qugruk Unit
- Southern Miluveach Unit
- Telemark Unit (Proposed)
- Tofkat Unit





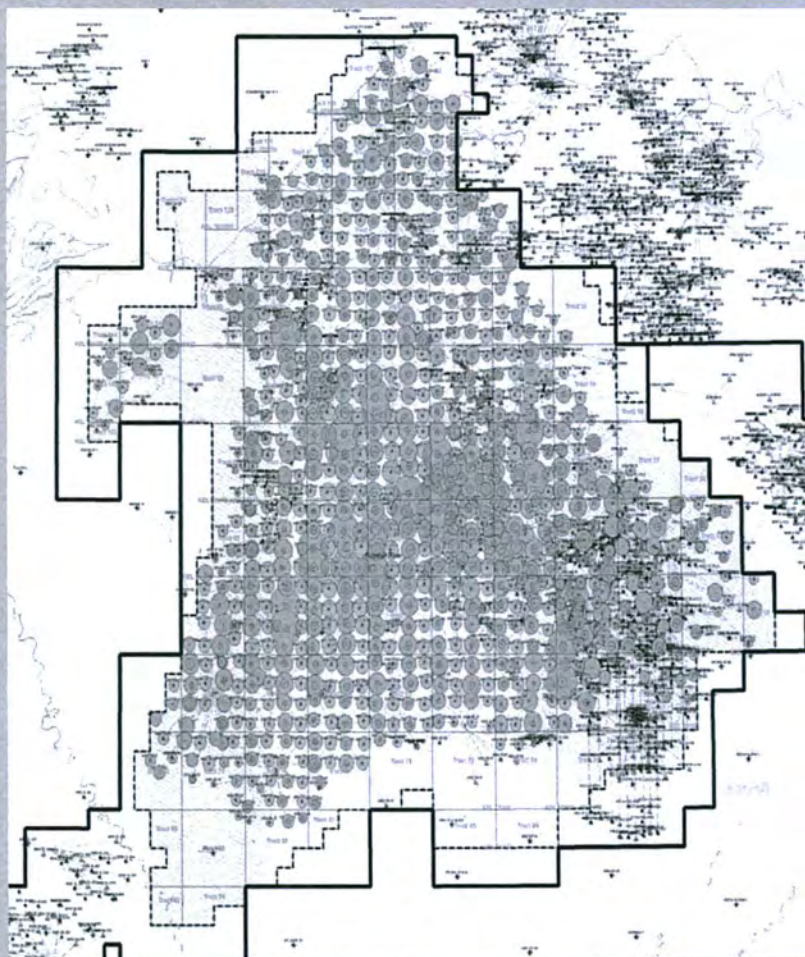
POD Process





Evaluating PODs on a complex unit - DOG Evaluation Tools

Bubble Map



Score sheet

Unit Name:	POD Decision	Decision Due By Date:					
PA Name:		Form Submitted Date:					
Include Bubble Map as attachment, (drainage radius of all wells in all PAs)							
GG & E Narrative Summary (ADGCC Pool Statistics, 2010)							
Geology:							
Cum Production Stats:							
OOIP: CONFIDENTIAL							
Cum Oil Produced to Date: (YE 2010)		MMSTB					
% Recovery to Date:							
Cum Voidage Replacement to date (YE 2010)		MRBI/MRBP					
Average Daily Production:							
		2008	2009	2010	2011	2012	2013
Oil	MSTB/D						
Water	MSTB/D						
Gas	MMSCF/D						
Average Water Cut							
%							
Average Current GOR							
SCF/STB							
Original GOR							
SCF/STB							
Average Current Reservoir Pressure							
psi							
Original Reservoir Pressure							
psi							
Bubble Point Pressure							
psi							
Average Daily Injection:							
		2008	2009	2010	2011	2012	2013
Water	MSTB/D						
Gas	MMSCF/D						
Well activity							
		2008	2009	2010	2011	2012	2013
Well Status							
# Active wells							
Producer (active as of year end)							
Injector (active as of year end)							
Shut in (through entire year)							
Drilling Activity							
New Wells							
CTD							
Workovers							
Sidetracks							
Facilities (current capacities)							
		Oil	Gas	Water			
Current POD Pertinent Issues (Bullet Points)							
Recovery Factor (Inc? Dec? Causes)							
Field Decline							
Infrastructure							
Facility issues							
Pipeline issues							
Well issues							
Data							
Core							
Logging							
Well test data							
Seismic							
Facilities							
Plan Forward							
Explore							
Seismic							
Drilling / Workover							
Maintenance and Repair							
Production							





Case Studies for PODS

- Conoco's Kuparuk Unit
 - Discovered: 1969
 - Cumulative Production: 2.45 billion barrels (AOGCC, Dec 2011)
 - PA List
 - Kuparuk River, Meltwater, Tabasco, Tarn, West Sak, and Northeast West Sak
- BP's Milne Point
 - Discovered: 1969
 - Cumulative Production: 301 million barrels (AOGCC, Dec 2011)
 - PA List
 - Kuparuk River PA, Sag River PA, Schrader Bluff PA, Ugnu
- BP's Prudhoe Bay and satellites
 - Discovered: 1967
 - Cumulative Production: 12.22 billion barrels (AOGCC, Dec 2011)
 - PA List
 - Aurora, Borealis, Combined Niakuk, Gas Cap PA, Lisburne, Midnight Sun, North Prudhoe Bay, Oil Rim PA, Orion, Pt. McIntyre, Polaris, Raven PA, West Beach



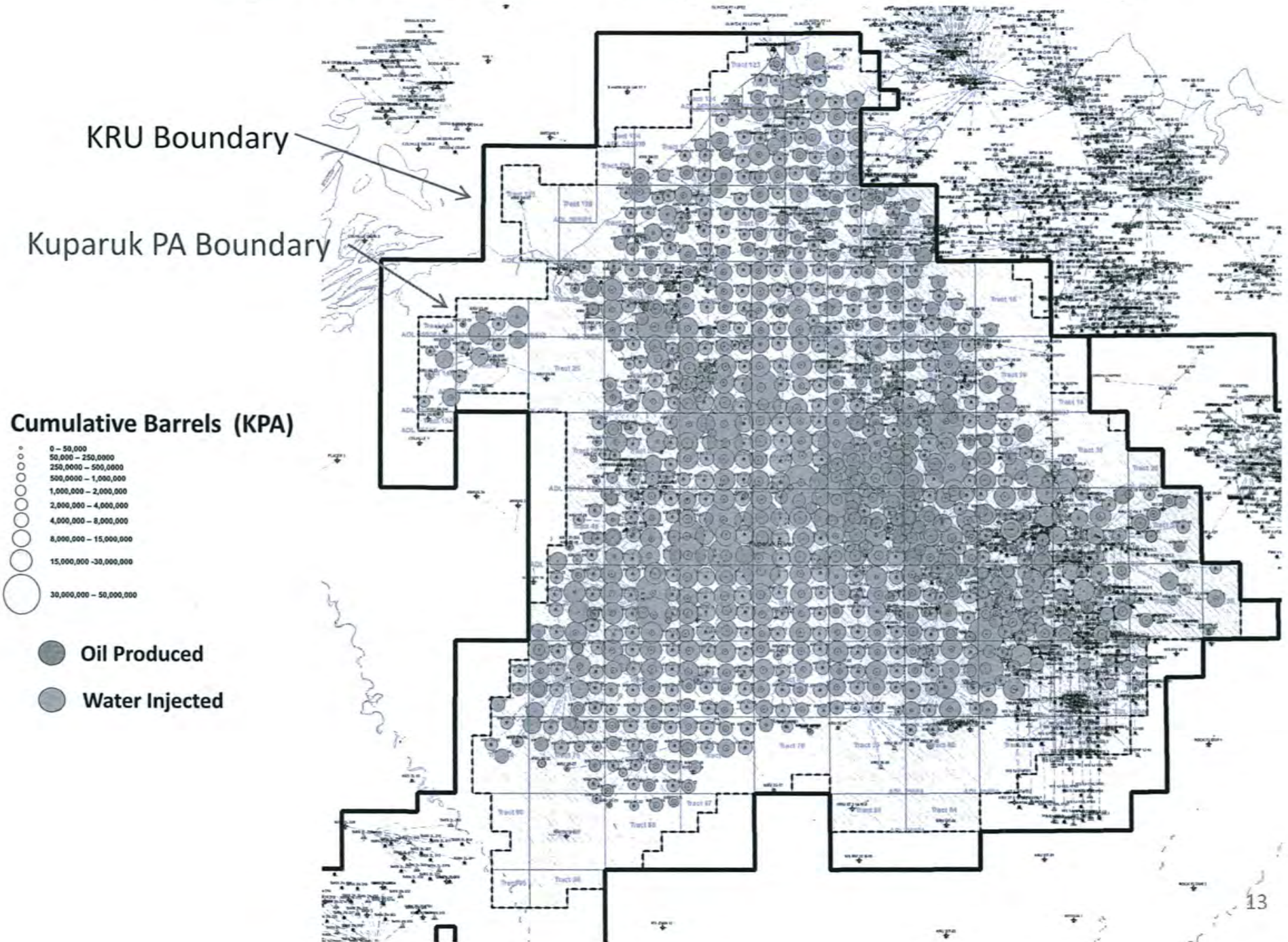


Conoco's Kuparuk River Unit POD

PA	POD Review Topics	Field Activity
Kuparuk PA	<ul style="list-style-type: none"> Development drilling in West Sak, NEWS, Kuparuk PA Infill drilling - CTD, Sidetracks Impacts to operations: surface casing corrosion, subsidence Gas management, impact to production Expansion in 2011 	<ul style="list-style-type: none"> Shark's Tooth (Kuparuk PA) Dedicated CTD unit Negotiating gas supply from PBU Development drilling and outboard injectors
Tarn PA	<ul style="list-style-type: none"> Multiple new wells planned Expansion in 2011 	<ul style="list-style-type: none"> Rotary wells and sidetracks and first CTD 2 grass roots wells
West Sak & NEWS	<ul style="list-style-type: none"> Continued studies on MBEs 	<ul style="list-style-type: none"> VRWAG Workovers

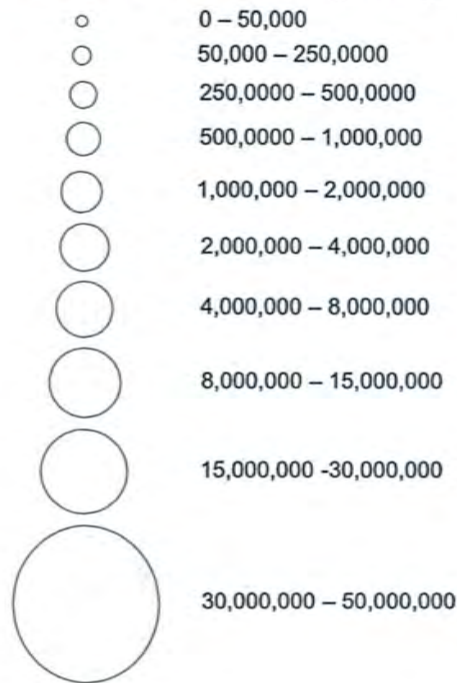


Kuparuk River Unit (KRU) Bubble Map

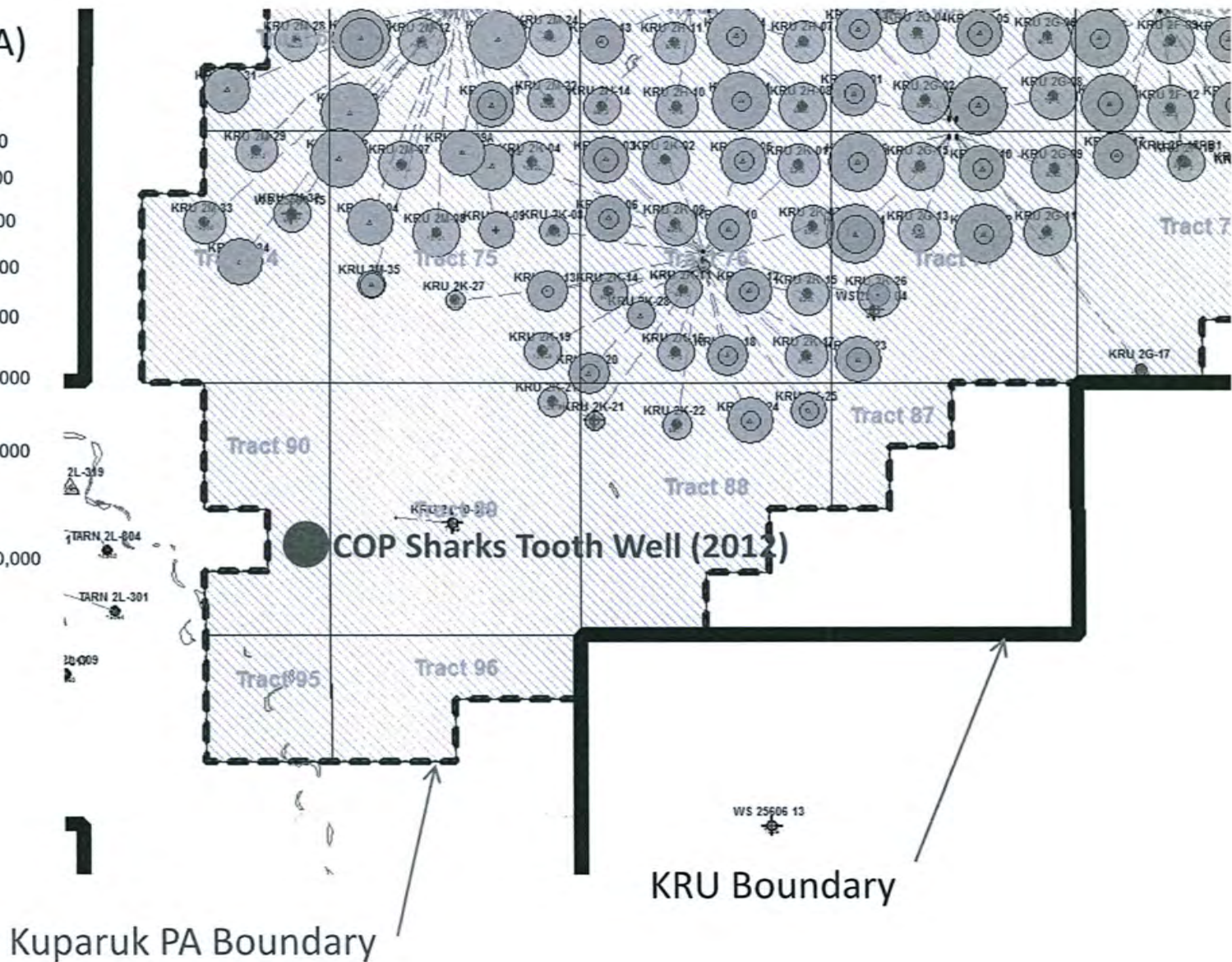


Southwest Portion Kuparuk River Unit (KRU)

Cumulative Barrels (KPA)



- Oil Produced
- Water Injected



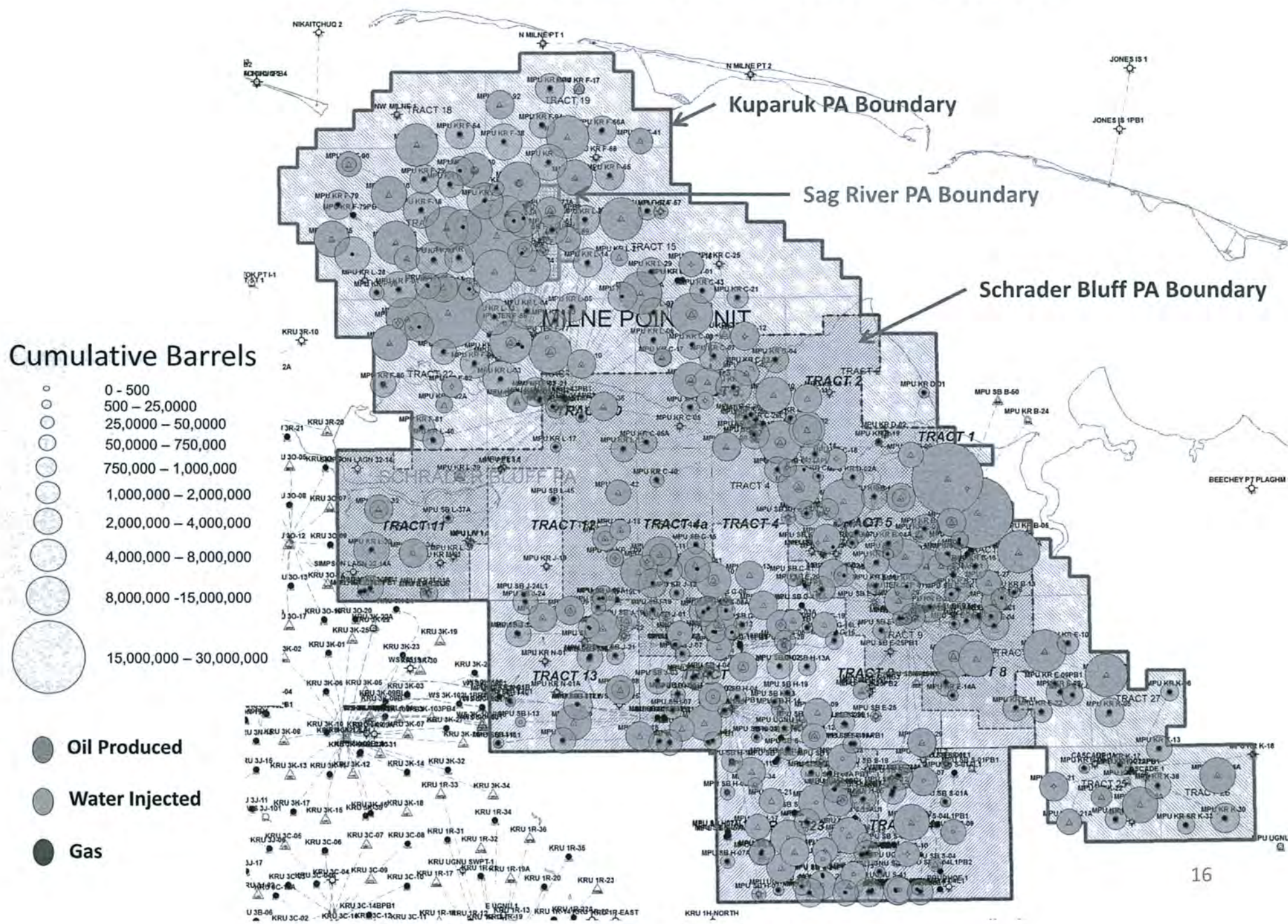


BP's Milne Point Unit

PA	POD Review Topics	Field Activity
Kuparuk PA	<ul style="list-style-type: none">▪ EOR/USWAG/LoSal▪ Drill rig availability/optimization▪ Mechanical issues/gas injection▪ Workovers	<ul style="list-style-type: none">▪ Repro Seismic 4D▪ Rotary rig secured▪ 4 wells planned
Schrader Bluff PA	<ul style="list-style-type: none">▪ ESP failures▪ MBEs	<ul style="list-style-type: none">▪ Rate of failure declining▪ Continued studies and tests to remediate MBE wells
Ugnu (Pilot Program)	<ul style="list-style-type: none">▪ 5 year pilot program▪ CHOPS	<ul style="list-style-type: none">▪ Pilot facilities on-line▪ Expect 4 Wells on production



MPU Cumulative Production and Injection (All Zones)



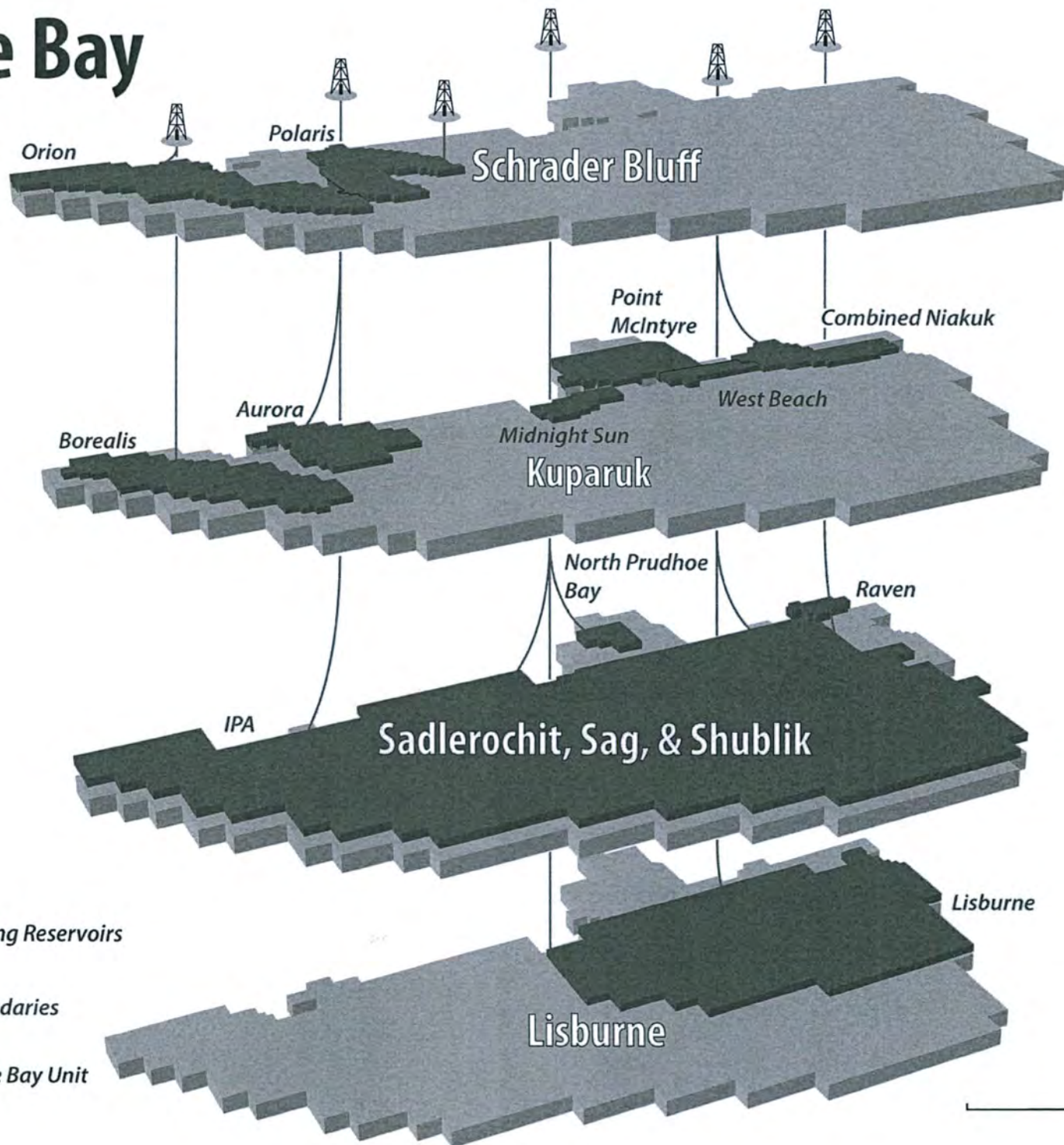


BP's Prudhoe Bay Unit

PA	POD Review Topics	Field Activity
IPA	<ul style="list-style-type: none"> Optimization of gas and water handling facilities Infrastructure maintenance, repairs and upgrades EOR/waterflood/GCWI/WAG 	<ul style="list-style-type: none"> Infill drilling and sidetracks-46 to 62 per year Wellwork-2000, including workovers, additional perforations, stimulations, well diagnostics
Borealis	<ul style="list-style-type: none"> Continued field development I-pad construction GPP 	<ul style="list-style-type: none"> 2 wells planned 2012 on Z-pad, 1 producer and 1 injector
Orion	<ul style="list-style-type: none"> Continued field development I-pad construction GPP 	<ul style="list-style-type: none"> No new development wells in 2012



Prudhoe Bay Unit



Producing Reservoirs

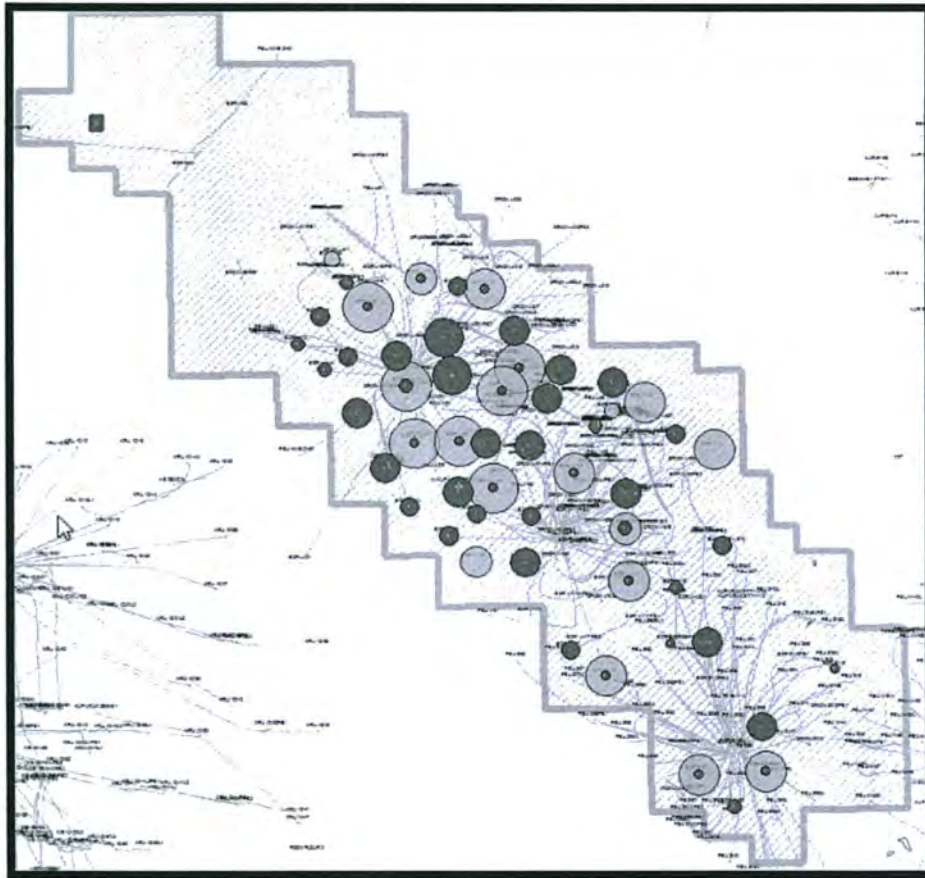


PA Boundaries

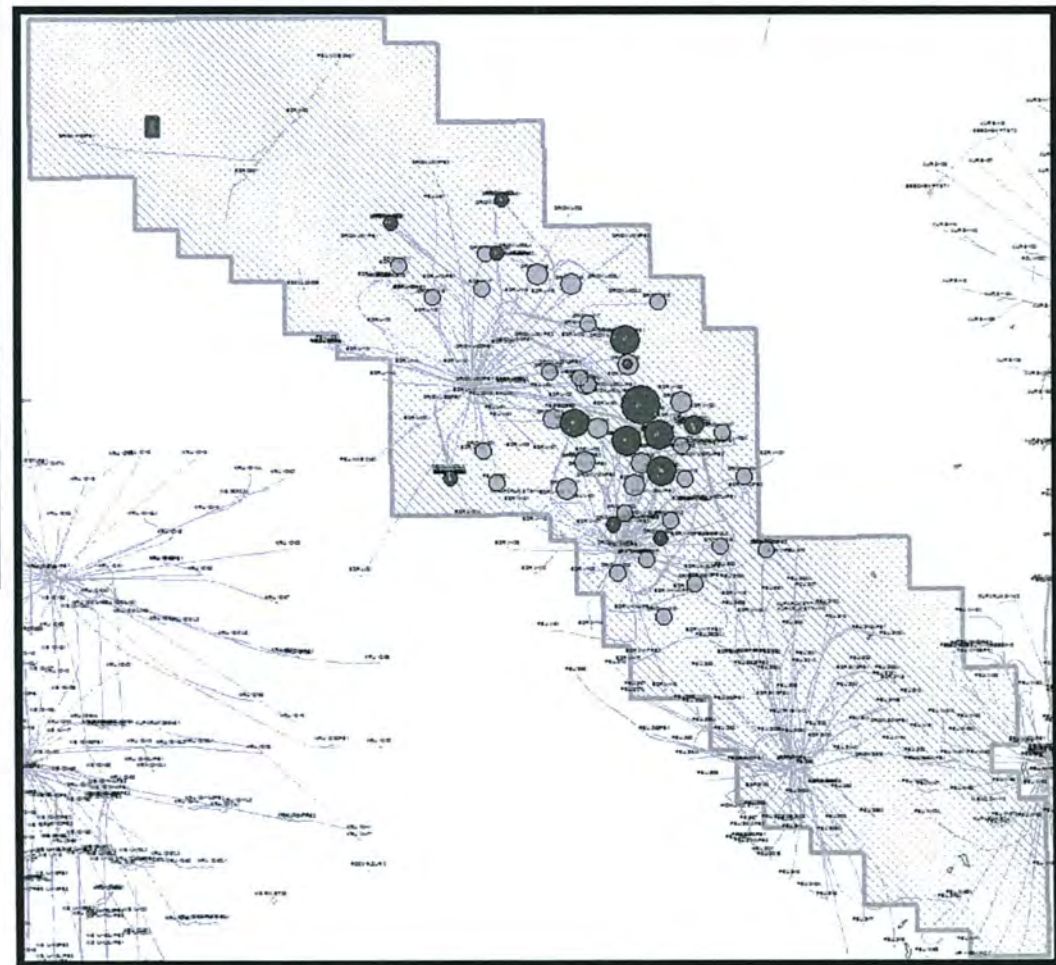


Prudhoe Bay Unit

Borealis Cumulative Production and Injection



Orion Cumulative Production and Injection



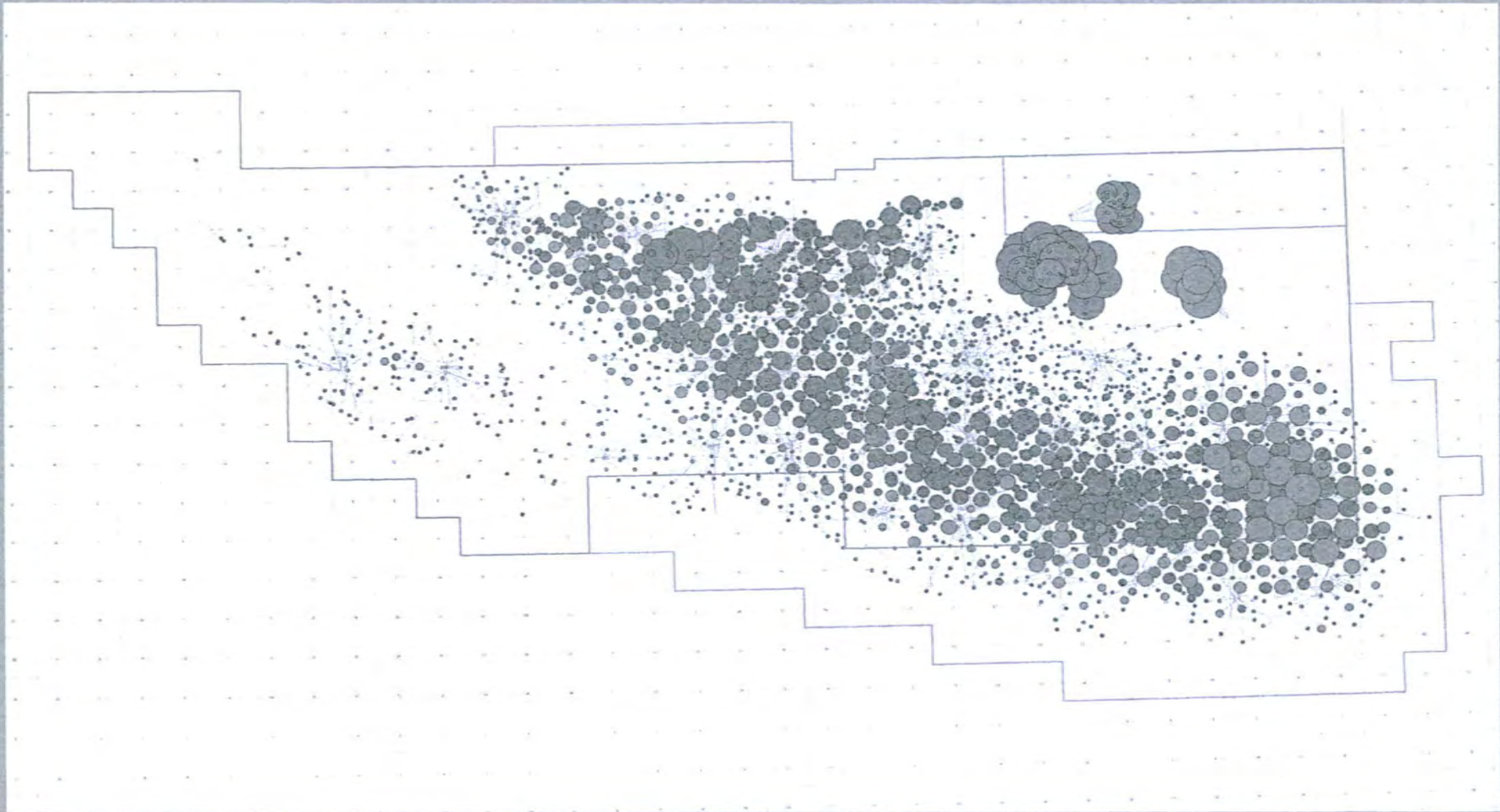
Cum Barrels

- 0 – 50,000
- 50,000 – 1,000,000
- 1,000,000 – 2,000,000
- 2,000,000 – 4,000,000
- 4,000,000 – 8,000,000
- 8,000,000 – 15,000,000

- Oil Produced
- Water Injected



PBU IPA Bubble Map



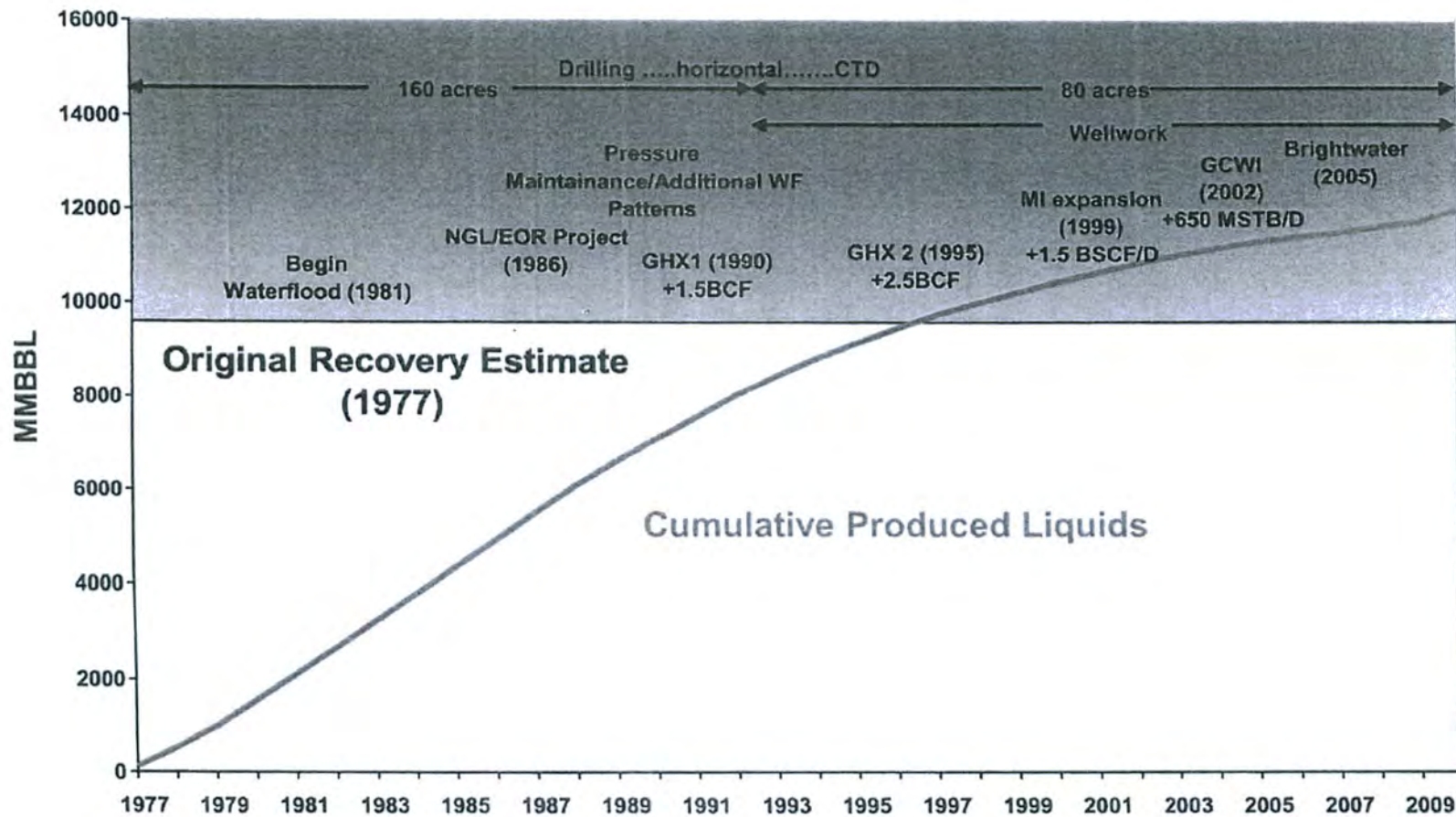


PBU - Borealis and Orion PAs 2012 Plans of Development

- PODs not approved
 - Working with unit operator to evaluate the development of another option around approval
 - Proposed modifications that would qualify the plans for approval
- What results from rejected POD
 - PAs lack approved POD
 - **11 AAC 83.343: No development activities allowed without approved POD**



Prudhoe Bay Development History





Summary

- Leases unitized when producible hydrocarbons proved by drilling and testing
 - PAs formed when unitized reservoir achieves sustained production
- PODs submitted for each unit which has PAs
 - Technical review and analysis to determine if plan meets criteria of 11 AAC 83.303
 - Complex units producing from multiple horizons
 - Development activities must be conducted under approved POD





THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Natural Resources

DIVISION OF OIL AND GAS

550 W. 7th #1100
Anchorage, AK 99501
Main: 907.269.8800
Fax: 907.269.8939

June 30, 2016

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Scott Digert, Manager of Reservoir
Management BP Exploration (Alaska) Inc. P.O.
Box 196612
Anchorage, AK 99519-6612

RE: Prudhoe Bay Unit – Initial Participating Area Plan of Development

Dear Mr. Digert:

On April 1, 2016, the Department of Natural Resources (“DNR”) timely received the proposed Prudhoe Bay Unit (“PBU”) – Initial Participating Areas (“IPA”) 2016 Plan of Development (“POD”). The POD was proposed by BP as operator for the PBU on behalf of all the working interest owners (“WIOs”). The purpose of this letter is to inform you of the status of the proposed POD in accordance with the provisions of 11 AAC 83.343.

Background

By letter dated April 11, 2016, the DNR commissioner informed BP Exploration (Alaska) Inc. (“BPXA”), as operator, that the POD submitted for the PBU IPA for 2016 was not complete with respect to its treatment of marketing discussions related to the development and production of natural gas in preparation for Major Gas Sales (“MGS”)—and suggested modifications that could make it complete. BPXA’s response to the notice and suggested modifications as operator, plus individual WIO responses from BPXA, ConocoPhillips, and Exxon, have not provided complete information or made the modifications as requested,¹ and DNR has not received a modified POD.

As the agency charged with reviewing and approving the development plans for short-term and long-term development activities, DNR has a responsibility to thoroughly evaluate plans of development and assess their potential impacts on the State. DNR has reviewed the proposed 2016 PBU IPA POD, including information received in technical review meetings, and determined that it is not complete and does not fulfill the requirements of 11 AAC 83.303 and 11

¹ DNR requests that any responsive information held by ConocoPhillips, Exxon and BPXA, as WIOs, be submitted in writing. Upon review of written submissions, DNR may schedule meetings as follow-up to the submissions, if necessary. If there is information that cannot be provided in writing, please provide a detailed written description of such information and an explanation as to why it cannot be provided in writing.

AAC 83.343(c). Because the 2016 POD submittal continues to be incomplete, DNR cannot evaluate it under the regulatory criteria.

1. THE PROPOSED POD'S DISCUSSION OF OIL COMPLIES WITH 11 AAC 83.303

The proposed POD contains sufficient information with respect to development and production of oil and the operator was so informed on April 11, 2016. Following is DNR's review of the proposed POD as it pertains to development and production of oil.

A. The 2015 annual report

The Prudhoe Bay reservoir management strategy continues to emphasize optimizing base field production within facility constraints through wellwork, reservoir pressure maintenance, flood optimization, and continued well sidetracking and new well development drilling. In 2015, BPXA again conducted a high level of drilling and wellwork in the IPA with 8 grassroots wells and 52 sidetrack wells. BPXA also performed 413 rate adding jobs and ~1,400 non-rate adding jobs. Rig workovers ("RWO") have continued to increase over the past four years with 27 RWOs in 2015. Drilling and wellwork in all categories has been increasing for the last four POD periods in the IPA. In 2015, the IPA produced an average of 196,400 barrels of oil per day (71.7 million barrels total) and approximately 6.9 billion standard cubic feet of gas per day ("bscf/d"), of which 6.24 bscf/d was reinjected as lean gas and miscible injectant ("MI") into the field for enhanced oil recovery. The remainder of the produced gas is used for fuel gas, minor gas sales, and making natural gas liquids to be delivered to TAPS.

Drilling activity was extensive in all six IPA depletion areas. Three wells were drilled in the FS-2 area, referred to as the "East of Sag" drilling campaign, and successfully tested the pattern rotation concept. Two wells drilled in 2014 and one in 2015 will test the conversion from inverted 9 spot to 5 spot patterns. In the northern portion of FS-2 area, three more wells were drilled in 2015 to target Zone 1A where the initial results show promising oil saturation levels. There were 12 wells drilled and completed in the Western Waterflood area (five Sag River wells and 7 Ivishak wells) in 2015 with four rig workovers to repair mechanical integrity. The UZI Project progressed in 2015 after continuing to demonstrate improved oil recovery in areas where the gas cap has expanded and gravity drainage process is less effective. Installation of the N-Pad UZI project was completed in 2015 and three more producers will be converted to injectors. In the Sag River Development area, 11 wells were drilled and completed, mostly in the NW Fault Block. Of the 11 wells, eight are producers which are all on production and three are MI/waterflood injectors. Sag River horizontal injector-producer pairings have not proven viable due to high well costs and lower-than-expected rates. Finally, two new coil sidetrack wells were drilled in the East West End/ NW Eileen area as voidage replacement ratios are maintained around the target level of 1.

The facility work to debottleneck western PBU fluid and gas handling was completed in 2015 with the commissioning of a jumper line at U-Pad. Two turnarounds ("TARs") were also completed at the Gathering Center 1 and Flow Station ("FS") 1 in 2015. Other projects

completed during the 2015 POD period were the N-Pad UZI and Drill Site 16 and 17 pipeline replacements. Continued facility and integrity management activities such as additional upgrades to the seawater treatment plant ("STP") and pipeline in-line inspection or smart pigging work occurred in 2015. Nearly 104 miles of pipelines were inspected. Facility and pipeline work is important for maintaining field operations and preparation for future Major Gas Sales.

B. The 2016 proposed plan of development for oil

For the 2016 POD period, BPXA anticipates reduced drilling and wellwork activity as three drilling rigs will be removed from service in the PBU due partly to market price conditions. In 2016, BPXA estimates four planned RWOs, eight rotary penetrations, and 24 coil penetrations. The higher success rate of non-rig workover repairs enables more wells to be returned to service without use of a rig, reducing the need for rig workovers. BPXA has focused on drilling and RWOs in the Gravity Drainage depletion area; however, the drilling is increasingly challenged by gas cap expansion and water encroachment. Increases in oil production in FS2 have resulted through shutting in water injector wells and re-perforating wells higher in the oil columns at Drill Site 03, 04, 09, and 11. This program has been successful in adding oil production and BPXA plans to continue an uphole add-perforation campaign in the remaining wellbore candidates. Another significant plan for 2016 is expansion of MI injection into two more MI sidetrack wells and injection into one Updip Zone 4 Injection ("UZI") pattern on N-Pad. UZI's long-term viability is dependent upon future allocation of MI and injection water which makes water handling and gas handling capacity important.

Facility upgrades continue to be major investments necessary to maintain field operations. There are no TARs scheduled for 2016. A substantial project began in 2014 with the replacement of the Stock Tank Vapor & Intermediate Pressure turbine-driven gas compressors at FS-1, FS-2, and FS-3. The compressor replacement was completed for FS-1 in 2014, the FS-3 compressor will be installed in 2016 with the FS-2 compressor installation in 2017. Evaluations are planned for the Seawater Treatment Plant to continue seawater injection efficiency for the Gas Cap Water Injection project pressure support and other water injection projects. BPXA also plans piping modifications at Skid 50 (FS-3), pipeline modification for the STP 36-inch flowline from Point McIntyre, and more than 110 miles of pipeline in-line inspections.

C. Analysis

When considering a POD, DNR must consider the criteria in 11 AAC 83.303(a) and (b). Accordingly, DNR considered the public interest, conservation of natural resources, prevention of economic and physical waste, protection of all interested parties including the State, environmental costs and benefits, geological and engineering characteristics of the reservoirs or potential hydrocarbon accumulations, prior exploration activities, plans for exploration or development, economic costs and benefits to the State, and any other relevant factors, including mitigation measures. 11 AAC 83.303(a)-(b).

The 2016 POD period predicts a reduction in oil-related drilling and RWO work for the coming year. However, the 2015 POD period reported another year of high levels of oil-related drilling

and workovers at the IPA. The activities conducted at the IPA over the last four years have seen record levels of drilling, RWOs, and rate adding jobs along with heavy investment in facility upgrades, pipeline replacements and inspection, and TARs. The IPA experienced an average daily production decline of only about 7,000 barrels of oil per day in 2015. The Prudhoe Bay field has exceeded its original recovery factor estimate by 2.7 billion barrels of oil due to investments beyond drilling wells. BPXA is progressing and developing new reservoir projects such as UZI, new MI targets, Sag River, and "pattern rotation" or pattern inversion in the east of Sag area. After such extensive drilling activities and pilot programs, a period of evaluation and assessment is acceptable. BPXA continues major facilities investments targeting debottlenecking constrained facilities and enhanced water and gas injection.

As the field has matured, the investments to maintain and replace aging infrastructure are key components to process and handle gas and fluids as efficiently as possible. The continuing investments in 2015 and proposed plans for 2016 are preventing physical and economic waste and continuing to provide economic benefits to the State. Finally, increasing pipeline integrity management and facility maintenance activities promotes the protection of all natural resources and the public interest.

BPXA provided a correction to a sentence on page 18 of the 2016 POD's Production Forecast which the Division will incorporate with the 2016 POD. The sentence containing the production forecast should read (correct figures noted in bold):

The average annual IPA crude and condensate production for 2016 is expected to be between ~~137-176~~**157-196** MB/D. The total NGL production for the 2016 is expected to be between ~~29-37~~**36-45** MB/D.

Having considered the 11 AAC 83.303 (a) and (b) criteria, DNR finds that the discussion of oil development and production and the use of natural gas to the extent needed to enhance oil production in the proposed 2016 POD complies with the provisions of 11 AAC 83.303. However, because the 2016 POD submittal continues to be incomplete regarding marketing for the development and production of natural gas, the POD cannot be fully evaluated under the regulatory criteria.

2. THE PROPOSED 2016 PBU IPA POD IS INCOMPLETE

For reasons that follow, the Director finds that the proposed 2016 PBU IPA POD is not complete.

A. Background facts about the gas resources at PBU

The Alaska Oil and Gas Conservation Commission reports that “[t]he operator, BP, estimates ... gas in place” at Prudhoe Bay to “be 46 trillion cubic feet.”² Furthermore, the size of these resources has made Prudhoe Bay gas the backbone upon which any gas pipeline that will transport gas from any unit on the North Slope will be built.

The Alaska legislature has specifically determined that the responsible development of such gas resources is in the best interests of the people of Alaska. In the enabling legislation for DNR, the legislature directly spelled out that the State has an interest in maximizing the development of both its oil and gas resources. Thus, AS 38.05.180, “Oil and gas and gas only leasing” provides as follows:

- (a) The legislature finds that
 - (1) the people of Alaska have an interest in the development of the state's oil and gas resources to
 - (A) maximize the economic and physical recovery of the resources;
 - (B) maximize competition among parties seeking to explore and develop the resources;
 - (C) maximize use of Alaska's human resources in the development of the resources

B. The duty to market the PBU gas

DNR regards it as established law that the WIOs, individually and as a unit, are obligated to diligently develop, produce, and market gas from the PBU. This obligation is inherent in the broad requirements for development of the unitized resources under Alaska law, the Prudhoe Bay Unit Agreement, and the express and implied terms of the PBU leases. Without an obligation to market, the express terms of the leases and Prudhoe Bay Unit Agreement that extend development duties to all of the oil and gas resources would be meaningless for this remote field. An implied duty to market also applies under a standard implied-covenant analysis.

The leases within the PBU include express requirements for “reasonable development;” “drill[ing] such wells as a reasonably prudent operator would drill having due regard for the interests of Lessor as well as the interest of Lessee;” “reasonable diligence in...producing;”

² Alaska Oil and Gas Conservation Commission website, AOGCC Pool Statistics, Prudhoe Bay Unit, Prudhoe Oil Pool, available online at: http://doa.alaska.gov/ogc/annual/current/18_Oil_Pools/Prudhoe%20Bay%20-%20Oil/Prudhoe%20Bay,%20Prudhoe%20Bay/1_Oil_1.htm.

“reasonable diligence in...operating;” and “to carry on all operations hereunder [the lease] in a good and workmanlike manner in accordance with approved methods and practices.” While the operator has been diligent in the development of oil at PBU, like diligence is required for the gas in order to accomplish a MGS.

Even in the absence of such express obligations, courts have universally found standard lease requirements supportive of an implied duty to market. This obligation extends to the full unit; once leases are unitized, it has long been established that implied duties extend to the larger unit area now operated as a single property. *See, e.g.,* Maurice Merrill, *Implied Covenants, Conservation and Unitization*, 2 Okla. L. Rev. 469, 477 (1949). In addition, DNR’s approval powers over unit plans of development are broader, and serve broader purposes, than merely enforcing the traditional duty of reasonable development, whether express or implied. Judge Gleason emphasized this breadth of power in her first decision in the Point Thomson litigation.

The adequacy of plans for development and production cannot artificially be divorced from plans for marketing the resources developed and produced. In the case of the PBU, DNR cannot adequately protect the interests of all parties and perform its approval responsibility without receiving both marketing and development information.

C. The need to plan for development and sale of all PBU resources

While DNR acknowledges the proposed use of gas in the current POD time period to enhance the production of oil, the State and the WIOs must prepare for the time when such use will no longer be necessary or appropriate. Major Gas Sales, in the relatively near future, are necessary to realize the benefit of the enormous gas resource within the PBU to the people of Alaska, and planning for MGS must be done now.

The State and the WIOs began the PBU relationship with the understanding that MGS were both important and an entirely proper subject for a POD. When the PBU was formed, several decades ago, the WIOs assured Alaska that MGS would occur within five years after first oil production at Prudhoe Bay. Exhibit “E” Plan of Development to the Prudhoe Bay Unit Agreement, 1977, p. E-2 (“It is planned to commence gas pipeline deliveries of 2 BCF/D as soon as pipeline and plant to condition the gas to specification can be completed. This is currently estimated to be about five (5) years after the start of oil production.”). Nevertheless, the proposed 2016 POD does not offer a meaningful plan or information that reflects what the WIOs are actually doing towards planning, preparing, or accomplishing MGS. Instead, the proposed POD contains only a simplistic truism that “Major Gas Sales (MGS) from Prudhoe Bay remains dependent upon a number of factors, including market demand and the availability of an offtake project.”³

Given the production, development, and marketing requirements within the PBU leases, the Prudhoe Bay Unit Agreement (“PBUA”), and the law, Alaska is entitled to a firm commitment to

³ 2016 Proposed PBU IPA Plan of Development at 21.

move the PBU toward MGS. Meaningful progress on the development and marketing of Prudhoe Bay gas inherently requires a commitment of the resource toward a development and marketing program. Alaska is entitled to specific, detailed information concerning what the WIOs are doing to plan and prepare for MGS, including the timeline and measurable milestones that can be evaluated during the next POD review period.

D. Plan of Development for MGS incomplete

Given the importance of PBU MGS to the State of Alaska and the necessity that the WIOs actively commit the PBU gas for MGS to occur, the plans to make this happen are of vital interest to DNR and Alaska. Notwithstanding DNR's January request for detailed information regarding plans for MGS, the entirety of the PBU POD "plan" with respect to MGS in Section 3.6 fails to meet the regulatory requirements for a plan of development. In its entirety, the proposed plan for this vitally important state resource reads as follows:

3.6 Major Gas Sales

Major gas sales (MGS) from Prudhoe Bay remains dependent upon a number of factors, including market demand and the availability of an acceptable offtake project. In the meantime, the PBU working interest owners will continue to use gas to enhance and accelerate oil recovery and for NGL production for shipment through TAPS or use in enhanced oil recovery operations.

The PBU working interest owners will continue to evaluate viable plans and incorporate [sic] into the current plan of development to further optimize gas and oil recovery, and to address facilities, equipment, wells, and operational changes to position for major gas sales.

These three sentences are not sufficient to adequately plan to develop the PBU in order to accomplish MGS.

The first sentence states two basic facts--that MGS will require demand for the gas and a pipeline to transport that gas. These truisms just raise questions. DNR has previously suggested what information could be given to answer those questions. Stated in more general terms, DNR would like to understand the following: What are the specific factors upon which MGS depend, and what are the WIOs doing to address those factors? What type of market demand is required? What is an "acceptable offtake project"? What are the WIOs doing to explore or evaluate the market demand? What are the WIOs doing to develop an "acceptable offtake project"? What are the WIOs doing to allow an "acceptable offtake project" to be developed by third parties? What are specific obstacles preventing the WIOs from committing to MGS and what are the WIOs doing to address any obstacles?

The second sentence discusses what the WIOs will do until MGS - i.e., use the gas to enhance oil recovery. While DNR appreciates the critical importance of this gas use, this tells DNR nothing

about if, when, or how, the WIOs are planning and preparing to accomplish MGS. As stated above, the State and the WIOs are looking at the time where use of the gas for enhanced oil recovery will no longer be necessary or appropriate. Planning and development required for MGS in the relatively near future is necessary now.

The third sentence is too general to be adequate or indicate meaningful planning. It states that the WIOs will “continue to evaluate viable plans,” but it does not describe what plans the WIOs are evaluating, if any, let alone any details about such plans or what the result of the WIOs’ evaluation is or has been. The general commitment to “address facilities, equipment, wells and operational changes to position for major gas sales,” likewise lacks any specific details that could be considered as specific commitments or milestones for DNR to evaluate the WIO’s actions in this regard. Again, DNR previously suggested the type of information and details that could answer some of the fundamental questions raised by this statement, but the WIOs have not provided any such information and details. If the WIOs wish to incorporate by reference the dates in the AOGCC order as specific commitments, they should state so explicitly in a modified 2016 PBU IPA POD.

The simple “plan” presented in Section 3.6 does not represent “long-range proposed development activities” for bringing the unit’s “underlying gas reservoirs . . . into production, and maintain[ing] and enhanc[ing] production once established,” as required by 11 AAC 83.343(a)(1). Even if the POD proposes some general, vague activities moving toward MGS, it does not offer specific, verifiable “details of the proposed operations for at least one year following submission of the plan,” as required by 11 AAC 83.343(a)(3).

Given the amount of natural gas at PBU and its importance to the State, the Section 3.6 “plan” for how the PBU will be developed with respect to natural gas and what the WIOs are doing to prepare for PBU MGS does not offer DNR sufficient information to evaluate its compliance with the criteria found in 11 AAC 83.303. The proposed 2016 PBU POD is therefore incomplete in this regard.

E. Additional suggestions as to information and action that will make the POD complete

DNR believes that meaningful progress on the development and production of Prudhoe Bay gas inherently requires a commitment of the resource toward a marketing program. History shows that this is not a situation where pipelines can be expected to be built absent a prior commitment. Historically, Alaska has found itself in a “Catch-22” circumstance whereby the WIOs have cited the lack of a pipeline to justify not achieving MGS while simultaneously not taking firm strides toward making gas available for a third party project. This is not consistent with the WIOs’ obligations to take reasonable steps to market the natural gas found at the PBU, and to act diligently towards achieving such sales.

The WIOs’ interest (or lack thereof) in developing MGS by investing in a pipeline project must not preclude other means of developing production and MGS at Prudhoe Bay. The WIOs are not required to guarantee that a third party ultimately builds a pipeline. However, DNR believes that

it is directly adverse to the State's interests for the WIOs to use their refusal to market gas to third parties to effectively veto otherwise viable pipeline projects.

DNR believes that the WIOs' lease obligations (both express and implied) as well as their duties under the Prudhoe Bay Unit Agreement and otherwise applicable law require reasonable diligence on the WIOs' part to market gas. This includes a duty to make gas available from Prudhoe Bay to third-party projects on commercially reasonable terms in the absence of a binding commitment to progress a WIO-sponsored MGS project.

DNR has attempted to secure information regarding what the unit operator and PBU WIOs are doing to plan and prepare for PBU MGS and how MGS will be accomplished, and it has provided suggestions to the unit operator and PBU WIOs by which they might bring the 2016 POD into compliance with the relevant regulations.⁴ While the following (and the previous suggestions) is not suggested as the only means by which the WIOs might submit a complete POD with respect to the PBU natural gas resources, DNR provides the following additional guidance as to what DNR believes is necessary in the current POD for it to be approved in order to assist the WIOs in completing this POD process and moving towards reasonable development and marketing efforts with respect to Prudhoe Bay gas.

The POD must discuss what actions will be taken in the coming POD year and show specifically how and when the WIOs will undertake reasonable and diligent efforts to develop the PBU gas for MGS, including how and when they plan to get the gas to market. This may require a showing as to how and when the WIOs have met or will meet with potential purchasers of gas and/or potential sponsors of gas transportation projects, including but not limited to the state of Alaska, to negotiate in good faith over the various aspects of a gas commitment with respect to natural gas produced at Prudhoe Bay. It is understood that a gas commitment would ultimately involve the WIOs dedicating PBU gas to a project that would transport that gas to market. DNR suggests that, for purposes of a modified POD, showing how and when the WIOs will achieve a gas commitment is necessary.

DNR expects and will enforce Alaska's rights to have the WIOs take all reasonable steps to develop and produce PBU gas, including getting it to market, whether by themselves or by making it available to third parties.

As submitted, the proposed POD is incomplete and insufficient to allow DNR to evaluate its compliance with the regulatory requirements. In order to be complete and allow DNR to evaluate its adequacy, the WIOs must submit a modified POD that provides additional, detailed information concerning marketing plans and activities that will result in and are related to the commencement of MGS. The proposed plan must adequately explain what specific, measurable, verifiable actions the WIOs will take during this POD period that demonstrate a diligent and adequate effort and commitment towards marketing for and accomplishing PBU MGS. While DNR has previously provided suggestions as to what information would be adequate to make the

⁴ See letter dated January 14, 2016, and follow-up email dated March 14, 2016; DNR letters to BPXA, as operator, dated April 11, 2016, and May 12, 2016.

POD complete, the unit operator and WIOs should submit whatever information they believe will cause the proposed POD to comply with 11 AAC 83.343 and 11 AAC83.303 as part of a modified proposed POD, and DNR will evaluate it under those criteria. If it is the unit operator's and WIOs' position that they cannot provide any of the requested information because such information does not exist, DNR requests that the unit operator state this in writing as part of a modified POD.

3. DNR'S RESPONSE TO CHALLENGES

The unit operator and two WIOs responded to DNR's April 11, 2016 request for additional information in a May 2, 2016, letter from BPXA (as unit operator), signed by Mr. Scott Digert, a May 2, 2016, letter from BPXA (as an individual WIO), signed by Mr. David Van Tuyl, and a May 4, 2016 letter from ConocoPhillips (as individual WIO), signed by Jon Schultz. The letter from ConocoPhillips did not present any discussion of the issues, but contained a request to meet to discuss DNR's requests for information, subject to a confidentiality agreement and "entirely separate from any discussions related to the Division's review of the IPA POD submitted by the PBU Operator." Because the information requested by DNR regarding development for MGS will be part of the 2016 POD, a meeting outside the POD process cannot provide the information necessary to make the POD submittal complete or adequate. As noted above, DNR requests that the unit operator and WIOs submit additional information in a revised 2016 POD. The letters from BPXA as unit operator and WIO raised several objections and challenges to DNR's requests that DNR would like to briefly respond to.

A. DNR's authority

Both the unit operator and individual WIOs have asserted that DNR's requests for plans regarding how they will get PBU gas to market constitute rulemaking because the requests allegedly require a new POD in an entirely new area. They also argue that the request exceeds DNR's authority because it is "outside the scope of the regulations," and that DNR would have to initiate a rulemaking procedure in order to secure the requested information. This is not correct.

DNR is called upon each year under its regulations to undertake a fresh analysis of an updated POD under 11 AAC 83.303 and 11 AAC 83.343(c). As the unit operator and the WIOs themselves point out, in 2015 AOGCC, at the WIOs' request, approved a significant expansion of potential gas offtake rates at PBU, thus positioning PBU for MGS in the relatively near future. Further, 11 AAC 83.343(a) specifically requires a POD to include, among other things, information concerning "long-range proposed development activities for the unit, including plans to delineate all underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established." Arguing that this regulation cannot be read to allow DNR to require information on the WIOs marketing plans ignores the broad implications of "maintaining and enhancing production," which cannot be accomplished without marketing.

In addition, DNR is not permanently bound to only one approach to secure the development of its resources. The fact that the PBU unit operator and WIOs have not been required to provide

DNR with objective verifiable milestones with respect to MGS in the past does not prevent DNR from imposing such requirements in the future. The factors DNR should consider, and the information it has a right to request when needed, can (and must) vary with time and technology, and with reference to the stage of PBU development.

DNR's existing powers allow the specific information needed to change as circumstances change. Nothing in the PBUA or the governing law suggests that the WIOs can avoid providing a plan of development for a valuable resource by claiming that DNR has not asked for such information in the past and, therefore, must engage in a new rulemaking process before it can ask now. It is the WIOs' duty under their leases, under the PBUA, and under the law to provide a complete plan of development of all resources. Given the current status of the field, it is now time to take measurable, verifiable steps towards MGS, and DNR is entitled to know what those plans and steps are and will be.

B. Antitrust arguments

The letters from BPXA also claim, in conclusory fashion, that DNR's requests raise antitrust concerns because the State may someday compete with individual WIOs in marketing ANS gas. Providing information specifically requested by a state in pursuit of its responsibilities under the PBUA and related statutory and regulatory provisions does not raise antitrust concerns. As discussed above, the information sought is required by 11 AAC 83.343. The antitrust laws are not violated when information is disclosed to the state as required by agreement or law. Moreover, the State is seeking and has consistently been seeking, a path to bring north slope gas to Alaskan, U.S., and world markets – a procompetitive, not anticompetitive result – and therefore something the antitrust laws are designed to encourage, not bar. Also, as the unit operator and the WIOs know, the AKLNG project information is not available to DNR for use in the POD approval process and therefore cannot fulfill the WIOs' responsibility to provide information necessary to that process unless the WIOs separately provide DNR with that information through the POD process.

Trade secret and confidentiality agreement arguments

Together, the unit operator and WIOs also claim multiple violations of confidentiality and trade secrets laws. These arguments do not have merit. As previously discussed, DNR has statutory and regulatory power to ask for this information. Any legitimate confidentiality concerns can be addressed by protective agreements, but the fact that some pertinent information may need to be confidential in some settings cannot prevent disclosure when the information is needed to determine whether the WIOs are complying with the intended purposes of unitization. The claim that the Alaska Uniform Trade Secrets Act (“Act”) protects the information sought by the State is also mistaken. That statute allows the owner of a trade secret to ask the court to enjoin the actual or threatened misappropriation of a trade secret. “Misappropriation” is defined as the acquisition of a trade secret by improper means, or disclosure of a trade secret without express or

implied consent.⁵ “Improper means” is further defined to include “theft, bribery, misrepresentation, breach of a duty to maintain secrecy, or espionage”⁶ Nothing in DNR’s demand for marketing information implicates any of the protections provided under this Act because acquisition of this information, even if it is a trade secret (which the division does not believe it is), is not being sought in an improper way and is not a misappropriation of the information as defined by the statute.

C. Duty to market beyond the North Slope

The WIOs also claim that they have no duty to market beyond the Alaska North Slope because there is no “non-local” market, and that in the absence of someone building a pipeline they have no duty outside the Alaska North Slope (“ANS”). This objection also is misplaced. First, the State is entitled to a commitment from the WIOs to take specific, measurable action sufficient to secure a pipeline from others if the WIOs will not act. The State is entitled to receive information showing that the WIOs are actually pursuing all reasonable efforts to develop and market the full gas resource, and not simply assertions from the WIOs that they will be ready when demand increases to some unstated level. Second, the focus on an ANS/non-ANS boundary is inappropriate. One purpose of the requests is to determine whether the WIOs are meeting their responsibility to develop the gas resource by also enabling other parties to consider building a pipeline, thus leading to optimal development and production of gas from the PBUA. It never has been likely that local ANS sale of oil or gas would sustain adequate development and production of those resources over any long-term. Third, as discussed above, a prudent operator’s responsibility is not so narrowly limited even under implied covenants. DNR is entitled to consider a wider range of factors than the reasonably prudent operator standard in determining the WIOs’ compliance with their duties to develop and market. DNR’s POD approval and oversight responsibility is not limited by implied-covenant law but instead is based upon the broader set of concerns enshrined in statute, regulation, and the PBUA. DNR needs a modified POD, with substantially more specific, detailed information to determine whether the proposed plan for development of PBU for MGS really conserves all resources, avoids waste, protects all parties in interest, and meets other unit requirements.

D. Information already produced, offer for a technical MGS workshop, and confidentiality

The unit operator argues that DNR already has access to information relevant to information it is seeking, citing information from AOGCC hearings, a FERC hearing, and non-confidential AKLNG project information. If the unit operator wants to rely on specific public information, it is required to produce the specific information on which it relied in response to DNR’s request as part of the proposed POD. At the very least, it must identify that information specifically. The unit operator cannot avoid its responsibility to provide a specific, detailed plan of development of gas by talking about other proceedings generically. DNR is entitled to specific responses in

⁵ AS 45.50.940 (2).

⁶ AS 45.50.940 (1).

order to evaluate the specific plans of the PBU unit operator and WIOs for getting PBU gas to market.

Similarly, the PBU WIOs have offered to have “technical meetings” to discuss their plans for gas. Although a “technical” meeting might be helpful to follow up on a written proposed POD regarding plans to develop and market PBU gas, it is not a substitute for submitting a modified POD to objectively manifest the unit plan for development. The unit operator and WIOs must submit responses to DNR’s requests in writing as part of a modified POD that DNR may evaluate.

Finally, some of the WIOs have indicated that they may be willing to provide certain information if it is held confidential under AS 38.05.035(a)(8). DNR has made clear that it will keep information confidential under AS 38.05.035(a)(8) if requested and applicable.

4. THE PLAN OF DEVELOPMENT OBLIGATIONS ARE CLEAR

Section 4.2 of the PBUA provides as follows with respect to the “Method of Development and Operation”:

To the end that Unitized Substances economically recoverable may be increased and waste prevented, Working Interest Owners shall with due diligence develop the Unit Area in accordance with good engineering and production practices. Such engineering and production practices shall include a plan of development and operation on a Reservoir basis (or portion thereof), designed to efficiently and economically produce Unitized Substances.

A plan of development and operation for each subsequently established Participating Area shall be submitted to the Director for approval as information upon which to base such plan is developed.

The PBUA language thus reiterates the WIOs’ broad development and operational obligations—obligations also existing under their leases “[t]o the end that Unitized Substances economically recoverable may be increased and waste prevented”—and requires “due diligence [to] develop the Unit Area in accordance with good engineering and production practices.” Furthermore, it recognizes that “[s]uch engineering and production practices shall include a plan of development and operation on a Reservoir basis (or portion thereof), designed to efficiently and economically produce Unitized Substances.” This obligation extends to the production of gas, which cannot be accomplished with respect to the PBU without marketing that gas or committing it to a project on reasonable terms. DNR is entitled to know how the unit plans to proceed to get PBU gas to market.

Section 4.2 of the PBUA set up and approved the original plan of development. The Original POD, Exhibit E to the PBU Agreement, provided as follows with respect to gas development:

It is planned to commence gas pipeline deliveries of 2 BCF/D as soon as a pipeline and plant to condition the gas to specification can be completed. This is currently estimated to be about five (5) years after the start of oil production. Studies have shown that the Prudhoe Bay (Permo-Triassic) Reservoir could be managed so that the planned deliveries would not affect ultimate oil recovery. Depending upon the reservoir performance, it might be possible to increase gas deliveries to 2.5 BCF/D.⁷

The argument that a gas plan is a substantively new obligation is contrary to the PBUA and the WIOs' prior actions.

The WIOs have suggested that long-range information does not exist and that they are not required to provide it. Clearly, if information does not exist, it cannot be provided. However, DNR expects the WIOs to specifically identify information that does not exist—e.g., “There have been no communications with third parties concerning gas commitments.” Further, the WIOs' suggestion that they are not required to produce long-range information is contrary to the explicit language of 11 AAC 83.343 and does not comport with the very purpose of a plan of development.

5. DNR WILL ALLOW ONE FINAL OPPORTUNITY TO PROVIDE A COMPLIANT PLAN OF DEVELOPMENT

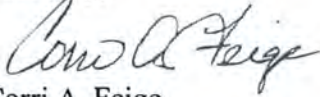
As previously indicated, the proposed 2016 POD cannot be approved at this time because it is not yet complete. Given the importance of the gas resource to the State and the need to protect all parties in interest, including the WIOs, DNR will allow yet more time for an adequate submission on this topic. The PBU WIOs shall, in accordance with 11 AAC 83.343(c), be given additional time within which to propose an adequate POD regarding MGS. In that regard, DNR reiterates that the information requested by DNR in its previous letters and herein is the information that DNR suggests would make the POD complete, but the WIOs may submit whatever specific information they believe will comply with 11 AAC 83.343 and 11 AAC 83.303 to show how and when they are marketing the gas resource and moving toward MGS, and DNR will evaluate it under those criteria. A modified proposed POD shall be due by September 1, 2016.

In the meantime, DNR hereby amends the existing 2015 PBU IPA POD to allow operations consistent with oil development and local gas sales as described in the proposed 2016 POD and discussed herein in Section 1, and will temporarily extend the 2015 POD (as amended) to allow continued operations at PBU consistent with that amended POD. The 2015 POD (as amended) will expire on November 1, 2016.

⁷ Original PBU POD, Exhibit E.

If you have questions regarding this matter, contact Kyle Smith with the Division at (907) 269-8807, or via email at kyle.smith@alaska.gov.

Sincerely,

A handwritten signature in cursive script, appearing to read "Corri A. Feige".

Corri A. Feige
Director

cc: DOL
David Van Tuyl, Regional Manager, BP Exploration Inc.
Jon Schultz, Manager – Great Prudhoe Area, ConocoPhillips Alaska, Inc.
Gilbert S. Wong, OBO Asset Manager, ExxonMobil Production Company

From: [Smith, Kyle S \(DNR\)](#)
To: [Clifton, Sean C \(DNR\)](#)
Subject: FW: IPA POD
Date: Tuesday, 28 June, 2016 15:10:46

From: Feige, Corri A (DNR)
Sent: Tuesday, June 28, 2016 2:58 PM
To: Smith, Kyle S (DNR) <kyle.smith@alaska.gov>; Beckham, Jim B (DNR) <jim.beckham@alaska.gov>; Davidson, Temple (DNR) <temple.davidson@alaska.gov>
Cc: Decker, Paul L (DNR) <paul.decker@alaska.gov>
Subject: FW: IPA POD

FYI –

Kyle – Please put copies of these in the file.

Thanks!

From: Rutherford, Marty K (DNR)
Sent: Tuesday, June 28, 2016 2:56 PM
To: Bilbao, Damian F <damian.bilbao@se1.bp.com>
Cc: Weiss, Janet L <Janet.Weiss@bp.com>; Buckendorf, Randal <Randal.Buckendorf@bp.com>; Coughlin, Patrick J <Patrick.Coughlin@bp.com>; Feige, Corri A (DNR) <corri.feige@alaska.gov>; Shine, Jim M (DNR) <jim.shine@alaska.gov>
Subject: RE: IPA POD

Damian, thank you for contacting me and advising DNR of BP's intentions (as the PBU Operator) to continue to operate the Prudhoe Bay Unit unless you receive a written order from DNR advising you to shut-in the field. Your email below accurately reflects the content of our phone conversation.

Marty

From: Bilbao, Damian F [<mailto:damian.bilbao@se1.bp.com>]
Sent: Tuesday, June 28, 2016 11:49 AM
To: Rutherford, Marty K (DNR) <marty.rutherford@alaska.gov>
Cc: Weiss, Janet L <Janet.Weiss@bp.com>; Buckendorf, Randal <Randal.Buckendorf@bp.com>; Coughlin, Patrick J <Patrick.Coughlin@bp.com>
Subject: IPA POD

Dear Commissioner Rutherford:

I wanted to confirm our conversation today in which I told you that regardless of the division's forthcoming decision on the IPA POD update, BP intended to continue to:

- operate and produce the PBU as a reasonable prudent operator according to the terms of the PBUA and PBUOA and Alaska statutes and regulations; and

- supply oil and gas to all working interest owners so that they can continue to fulfil their contractual obligations to oil and gas purchasers and to properly pay taxes and royalties upon that production to the state.

Neither BP nor any other PBU working interest owners believes that it is the state's best interest to shut-in the field and you agreed that it was in the best interests of all parties, including the state, that the field not be shut-in. Therefore, BP and the other PBU working interest owners will not shut-in the field unless they receive a written order from the DNR to do so.

If I have misstated the substance of our conversation, please kindly correct me.

Sincerely,

Damian Bilbao
Director Business Development, Alaska LNG

From: [Smith, Kyle S \(DNR\)](#)
To: [Clifton, Sean C \(DNR\)](#)
Subject: FW: Resend - Corrected -- PBU IPA POD
Date: Tuesday, 28 June, 2016 13:31:14
Attachments: [image001.png](#)
Importance: High

From: Pathrose, Vinod [<mailto:vinod.pathrose@exxonmobil.com>]
Sent: Friday, June 17, 2016 2:38 PM
To: Smith, Kyle S (DNR) <kyle.smith@alaska.gov>
Subject: FW: Resend - Corrected -- PBU IPA POD
Importance: High

Kyle,

In response to Director Feige's June 12th email, ExxonMobil believes that DOG has been provided all the information needed or required to complete the POD process for 2016-2017.

Separately, we want to mention that ExxonMobil, as a PBU WIO, currently sells gas for local use on the North Slope and is always evaluating and pursuing opportunities to market its gas for in-state use and for export outside of Alaska, including as part of a Major Gas Sale.

As previously communicated, sharing plans or details regarding individual WIO marketing efforts is not appropriate or permissible for a number of reasons. Principally, the information is commercially sensitive and sharing it creates significant federal and state antitrust concerns.

As to other information referenced in recent DOG communications, ExxonMobil is continuing to progress the Alaska LNG project and remains ready to reengage with the State Gas Team on matters associated with natural gas disposition in relation to this project. We remain willing to share appropriate information with the State Gas Team under existing confidentiality agreements.

Regards,
Vinod

From: Feige, Corri A (DNR) [<mailto:corri.feige@alaska.gov>]
Sent: Sunday, June 12, 2016 6:11 PM
To: Pathrose, Vinod
Cc: Smith, Kyle S (DNR)
Subject: Resend - Corrected -- PBU IPA POD
Importance: High

Dear Vinod –

In an effort to complete the 2016 PBU IPA POD review process in as timely and consistent a manner as possible, the Division requests that you please provide a discussion of your marketing plan for the PBU, as it relates to the long term development plans for the unit and moving toward a major gas sale. You will find attached a high-level, conceptual timeline associated with the updated Pool Rule 9 issued by the AOGCC in late 2015, which the Division has developed for general reference purposes. To the extent that it is known, please include this same time period in the discussion of a marketing plan for the PBU. Please include a list of any agreements or contracts that you believe will be necessary to

market PBU gas and a discussion of what steps, if any, will need to be taken in the coming year to advance those agreements or contracts in anticipation of a major gas sale from the PBU. Finally, please discuss what Exxon, as a working interest owner, is doing in the marketplace to promote a major gas sale from_PBU.

Upon request, the Division will keep this information confidential under the provisions of AS 38.05.035(a)(8).

Please send this information to Kyle Smith (kyle.smith@alaska.gov) at the Division by close of business on June 17, 2016 so that it may be considered in a timely fashion. We very much appreciate the information you have provided to the Division already and thank you in advance for your continued assistance in helping the Division understand the long term plans related to unitized substances.

If you have any questions, please don't hesitate to contact either myself or Kyle Smith.

Kind Regards –

Corri Feige

Director - Division of Oil and Gas
Alaska Department of Natural Resources
550 W. 7th Avenue/Ste. 1100
Anchorage AK 99501-3510
Direct: 907.269.7493
Cell: 907.538.4804



CONFIDENTIALITY NOTICE: This e-mail message, including any attachments, contains information from the Department of Natural Resources (DNR), State of Alaska and is for the sole use of the intended recipient(s). It may contain confidential and/or privileged information. The unauthorized review, use or disclosure of such information may violate state or federal law. If you are an unintended recipient of this e-mail, please delete it, without first saving or forwarding it, and, so that the DNR is aware of the mistake in sending it to you, contact Corri Feige at (907) 269.7493 or corri.feige@alaska.gov.



Jon Schultz
Manager, Greater Prudhoe Area

ATO-928
P. O. Box 100360
Anchorage, AK 99510-0360
phone 907.265.1315

jon.schultz@conocophillips.com

June 17, 2016

Confidential pursuant to the Amended and Restated State of Alaska-ConocoPhillips Alaska Confidentiality Agreement dated effective November 19, 2015, AS 38.05.035(a)(8), and other applicable law

Corri A. Feige
Director, Division of Oil and Gas
Alaska Department of Natural Resources
550 W. 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3501

Kyle Smith
Petroleum Land Manager
Alaska Department of Natural Resources
550 W. 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3510

Re: PBU IPA POD

Dear Director Feige and Mr. Smith:

ConocoPhillips Alaska, Inc. (ConocoPhillips) received Director Feige's email note of June 12, 2016 regarding the Prudhoe Bay Unit (PBU) Plan of Development (POD) for the upcoming year. It is unfortunate that the Division continues to insist that ConocoPhillips disclose its marketing plans as an apparent pre-condition to the Division's approval of the PBU Operator's annual POD. Since the State, working through the Department of Natural Resources (DNR), is a potential competitor of ConocoPhillips with regard to the sale of gas, as well as a potential purchaser of ConocoPhillips' gas, from that field, the Division's demands are particularly problematic. I reiterate our prior response to you dated May 4, 2016, which supported and endorsed the PBU Operator's position stated in its letter to you dated May 2, 2016 that forcing disclosure of such information within the POD approval process is neither lawful nor proper and ConocoPhillips requests that the Division approve the POD promptly.¹

¹ In its May 4, 2016 response, ConocoPhillips also offered to meet with the Division to discuss the Division's demand for marketing information. The Division has not suggested or scheduled any meeting time.

Corri A. Feige
Kyle Smith
June 17, 2016
Page 2

Nonetheless, ConocoPhillips appreciated participating in the technical workshop with the Division on May 19, in which BP, as the Operator, provided the remaining technical detail necessary for approval of the POD. We also appreciated the Division's acknowledgment, following that workshop, that the technical requirements of the POD were now complete. Technical information about the operation of the field is all that is required under the Division's regulations and all that has ever been required in the past as a condition to an annual POD approval.

In an attempt to avoid the potential for disruption of PBU operations should the Division persist in its unprecedented, unauthorized and unlawful demands, and without waiving any objections to the Division's demands, I am providing the following information.

You have asked specifically for "a discussion of your marketing plan for the PBU, as it relates to the long term development plans for the unit and moving toward a major gas sale." You have previously described the information demanded as "specific commitments and timelines regarding how gas will be marketed in the future" (Director Feige letter to Scott Digert, BPXA, dated May 12, 2016) and "discussion of the efforts to market oil and gas from the unit" including "a delineation between local marketing and MGS" (Director Feige letter to Scott Digert, BPXA, dated April 11, 2016). As noted earlier in this letter and elsewhere,² the State has publicly described itself as in, and pursuing, a role that is or would be a competitor of ConocoPhillips for LNG or gas customers in an ANS gas commercialization project, or a competitor of other potential customers for ConocoPhillips' gas on the North Slope. The State is a competitor in oil marketing as it takes and sells royalty in kind from time to time.

ConocoPhillips complies with the anti-trust and competition laws and has policies and practices in place to assure that compliance. ConocoPhillips will not risk non-compliance to respond to an unauthorized demand. With regard to any discussion or information disclosure on these marketing topics, [REDACTED]

[REDACTED] please recognize that discussions and information regarding ConocoPhillips' marketing activities or plans are proprietary and would be improper to discuss. Because the State (specifically through DNR) is, at a minimum, a potential competitor or customer, ConocoPhillips may not discuss, among other matters, current or future pricing or bidding information, non-public information regarding current or prospective customers other than the State itself, current marketing plans or proprietary strategic plans, current market share or market position, or other non-public competitively-sensitive information. See also section 3(C) of Attachment 2.

² See, e.g., Attachment 2 and Attachment 3.

Corri A. Feige
Kyle Smith
June 17, 2016
Page 3

We can, of course, tell you that ConocoPhillips plans to continue to work with the State to make ConocoPhillips' available PBU gas available to the State, including for a State-led project, on mutually agreeable commercially reasonable terms. DNR is aware of the difficult commercial circumstances faced by gas producers and developers of gas infrastructure in both U.S. and world markets. Those circumstances affect any proposed project, whether it be the proponent's only project or one of several.

To recap efforts to date and to be continued with the State, please see the Governor's letter dated June 8, 2015 (released to the public on June 16, 2015 at a joint meeting of the House and Senate Natural Resources committees in Nikiski; copy attached as Attachment 1), acknowledging the importance of joint venture marketing to the success of a project in which the State would participate. ConocoPhillips supports the Governor's position that a joint venture marketing structure would facilitate progress and support the viability of a major North Slope gas project in which the State is a participant. We continue to await the State's pursuit of its joint venture marketing requirement stated in the June 8, 2015 letter.

Further, please see the confidentiality agreement ConocoPhillips first entered in August 2015 with DNR, which was subsequently amended on November 19, 2015 (Amended and Restated State of Alaska-ConocoPhillips Alaska Confidentiality Agreement, or "SOA-CP CA"; copy attached as Attachment 2). Among other things, the SOA-CP CA was entered into to allow ConocoPhillips to negotiate terms for making its share of gas available from PBU to the State in support of the development of the AKLNG Project or another North Slope gas project and to pursue discussions regarding ConocoPhillips' offer to "purchase, dispose of, or market the state's royalty gas taken in kind and gas delivered to the state under AS 43.55.014" so that DNR could modify leases pursuant to AS 38.05.180(hh) and (ii) in support of the AKLNG Project. The SOA-CP CA also specifically addresses the prohibition on discussing proprietary and sensitive matters including marketing plans and other topics listed in the paragraph above (see SOA-CP CA at paragraph 3(C)).

Soon after amending the SOA-CP CA, ConocoPhillips, at the State's behest, entered the Gas Availability Agreement of December 4, 2015 with DNR (along with BP; copy attached as Attachment 3). This Gas Availability Agreement reflects further commitments between ConocoPhillips and DNR related to continuing good faith negotiations for ConocoPhillips making its natural gas anticipated to be provided from PBU available to the State on mutually agreeable commercially reasonable terms in the event, if ever, ConocoPhillips indicates it does not intend to continue with the AKLNG Project.



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Governor Bill Walker
STATE OF ALASKA

June 8, 2015

Janet Weiss & Dave VanTyle
BP Exploration Alaska, Inc.
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Anchorage, AK 99508

Joe Marushack & Pat Flood
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage, AK 99510-0360

Bill McMahon & Jim Flood
ExxonMobil Development Company
Wellness 2, 5A.345
22777 Springwoods Village Parkway
Spring, Texas 77389

Dear AK LNG Sponsors:

A few weeks ago, we jointly set a goal to finalize the term sheets for all major project enabling contracts by the middle of June. It is now June 8th. Despite the efforts of all parties, it is clear we are not on schedule to achieve this goal.

There are at least two major issues and at least three smaller major issues. I have summarized the State's listing of those issues along with my comments.

I am asking that this list be considered by the VAMOU on Tuesday to determine if consensus can be reached on the completeness of the list. The goal would be to gain agreement on a final list of major issues in order for our respective negotiating teams to share a common focus and issue prioritization. The resulting list would then be presented at the Sponsor Meeting on Wednesday with the Sponsor representatives tasked to resolve these major issues – especially the two large major issues. Resolution of these major sticking points will be a catalytic event enabling substantial progress on finalizing the terms of the project contracts.

To the extent there are issues remaining after the Sponsor Meeting where the parties are substantially apart, I would like the State to engage in a shuttle diplomatic effort with producers, with a goal of gaining issue closure or at least a clear understanding of the extent of remaining disagreement. Following the best efforts of our teams to reach closure on the major issues, I

Confidential

Subject to Alaska LNG Project Confidentiality Agreement dated effective May 9, 2014

DISCLOSED BY GOV. WALKER TO PUBLIC ON JUNE 16, 2015

Attachment 1

would like to meet face to face during the week of June 15th with each Sponsor executive individually to attempt to resolve the remaining issues. I would like to resolve the major issues in these meetings so we can begin the process of drafting contracts

The AK LNG team will be briefing the Legislature on the 16th of June in Kenai, Alaska. After months of expectation, the people of Alaska and their elected representatives are anxious for concrete progress.

Large Major Issues

1. The largest issue is Joint Venture Marketing vs. Equity Marketing. The State believes it will be very difficult, if not impossible, for this project to proceed with the PBU and PTU fields with all the current participants outside a Joint Venture Marketing context.
2. Upstream issues – to the extent they are not resolved by Joint Venture Marketing. Most of the remaining upstream issues can be resolved through the use of separate Joint Ventures that would receive the gas from the PBU and PTU fields with support between the two Joint Ventures along the lines of the proposal attached as Appendix A.

Other Major Issues

3. Fiscal Stability: It will only deal with the gas dedicated to this Project from PBU and PTU. It will not include oil. The State is willing to consider a 25 year term in order to facilitate integrated project financing. The State believes a Constitutional Amendment will provide the certainty that all parties would like. Attached as Exhibit B is an example of what I envision the constitutional amendment might look like.
4. 48 inch line: Constructing a 48 inch line will alleviate the issues of open access and expansion. The Producers have stated they do not need or want a 48 inch line. The State is willing to pay for this expansion subject to legislative approval, but it would own all the benefits of the increased size. The State would also pay for installing the valves, pads etc. to accommodate four more compressor stations that will be added when demand exists from new developments or fields. The State intends to use this expansion capacity to encourage open access.
5. East vs. West Cook Inlet crossing: It is my understanding that the studies for the two routes are under way but that the tentative conclusion at this point in time is that the Western Route is the preferred alternative. The Matsu Valley constitutes the second largest population base in the State of Alaska and has some of the highest industrial potential in the State. Consequently, the State strongly prefers the Eastern Route since the studies to date do not indicate any insurmountable obstacles. Also, the Eastern Route will better enable this Project to better fulfill the statutory domestic gas mandate.

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Sincerely,



Bill Walker
Governor

Enclosure

Appendix A – Joint Venture Marketing Model
Appendix B – Sample Draft Constitutional Amendment

cc: Dona Keppers, SOA, Deputy Commissioner of Revenue
Dan Fauske, AGDC
Steve Wright, SOA, Department of Natural Resources
Audie P. Setters, SOA, Gas Team, General Manager

Confidential

Subject to Alaska LNG Project Confidentiality Agreement dated effective May 9, 2014

**AMENDED AND RESTATED STATE OF ALASKA – CONOCOPHILLIPS
CONFIDENTIALITY AGREEMENT**

This Amended and Restated State of Alaska – ConocoPhillips Confidentiality Agreement (“**SOA-CP CA**”) is entered into by and between ConocoPhillips Alaska, Inc. (“**CPAI**”), ConocoPhillips Alaska LNG Company (“**CALC**”), and the Commissioner of the Alaska Department of Natural Resources (“**DNR**”) and the Commissioner of the Alaska Department of Revenue (“**DOR**”) on behalf of the Administration of the State of Alaska. CPAI and CALC are sometimes referred to collectively as “**ConocoPhillips**”. DNR and DOR are sometimes referred to collectively as “**State Parties**”. CPAI, CALC, DNR and DOR are sometimes referred to individually as “**Party**” or collectively as “**Parties**”. This SOA-CP CA shall become effective as of November 19, 2015 (“**Effective Date**”), when it has been signed by all Parties.

RECITALS

- A. CALC and other parties currently are pursuing the “**Alaska LNG Project**”, which would treat, transport, and liquefy Alaska North Slope gas for shipment as LNG to foreign countries, and would be designed to have at least five (5) off-take points in Alaska for the opportunity for access for future In-state deliveries of natural gas.
- B. CPAI owns certain oil and gas leases on the Alaska North Slope (“**ANS**”) and is evaluating and pursuing the potential commercialization of ANS natural gas resources through the Alaska LNG Project.
- C. Under AS 38.05.020(b)(12), the Commissioner of DNR is authorized to enter into confidentiality agreements to maintain the confidentiality of information related to contract negotiations and contract implementation associated with a North Slope natural gas project, and information under those confidentiality agreements is not subject to AS 40.25 (Alaska Public Records Act), except as set forth in Section 2(B)(i) and (ii) of this SOA-CP CA. AS 38.05.020(b)(10) and (11) authorize the Commissioner of DNR, in consultation with the Commissioner of DOR, to participate in negotiation of agreements and contracts, and development of terms associated with a North Slope natural gas project, as defined in AS 38.05.965(27).
- D. Under AS 40.25.100(a), information in the possession of DOR that discloses the particulars of the business and affairs of a taxpayer or other person, including information under AS 38.05.020(b)(10) and (11), that is subject to a confidentiality agreement under AS 38.05.020(b)(12) is not a public record and shall be kept confidential.
- E. The Parties intend that this SOA-CP CA be, and be treated as, a “confidentiality agreement” for purposes of the statutes described in Recitals C and D above.
- F. Under AS 38.05.180(hh), DNR may consider modifications to a lease from which a lessee has committed gas to a North Slope natural gas project.
- G. Under AS 38.05.180(ii), before making a modification to a lease under AS 38.05.180(hh), DNR must make a written determination that the lease may be modified, based on a clear and convincing showing by the lessee that, among other matters, the lessee or an affiliate of the lessee has offered to purchase, dispose of, or market the state’s royalty gas taken in kind and gas delivered to the state under AS 43.55.014 on the same or substantially similar terms as the lessee or an affiliate of the lessee sells, disposes of, or markets the lessee’s gas (“Purpose 1”).
- H. Pursuant to AS 31.25.080(a)(24), DNR and DOR will provide input to other state entities regarding contract terms relating to an Alaska liquefied natural gas project, including contracts for services related to operation, marketing, transportation, gas treatment, marine terminal operation or liquefaction.

Confidentiality Agreement – Page 1

Execution Version

- I. Pursuant to Recital H above, the SOA and ConocoPhillips also wish to, separately from Purpose 1, conduct initial discussions of potential terms under which, in the event that ConocoPhillips were to transfer its interest in the Alaska LNG Project, ConocoPhillips could:
- (i) sell to a state entity, and a state entity could purchase, ANS natural gas for the Alaska LNG Project or an alternative project to monetize ANS natural gas that the state entity is authorized to pursue and for which the state entity is authorized to enter into confidentiality agreements, and
 - (ii) toll a daily rate and overall quantity of capacity in the Alaska LNG Project or in an alternative project to monetize ANS natural gas of mutually agreed size that a state entity is authorized to pursue and for which the state entity is authorized to enter into confidentiality agreements,
- which would commercialize ConocoPhillips' ANS natural gas resource for a mutually agreed time period ("Purpose 2"; collectively with Purpose 1, the "Purposes").
- J. In accordance with AS 38.05.180(ii)(4) and other law as applicable, including AS 45.50.910-.945 (Alaska Uniform Trade Secret Act), and as also contemplated in Section 8.3.3 of the Heads of Agreement dated January 14, 2014 and AS 31.05.080(a)(24), the Parties wish to hold discussions, participate in negotiations, and exchange information with each other concerning the Purposes or otherwise related to contract negotiations and contract implementation associated with marketing for a North Slope natural gas project ("Discussions").
- K. In such Discussions, ConocoPhillips is willing to disclose, in its sole discretion, to the State Parties, and the State Parties are willing, in their sole discretion, to disclose to ConocoPhillips, certain Confidential Information (as defined below) that is not in the public domain, and that the Parties normally would not communicate to third parties, subject to the obligations of confidentiality, restricted use and conditions of this SOA-CP CA.
- L. The Parties acknowledge that the Discussions will be of a commercially sensitive and confidential nature, and that the Parties have a mutual interest in maintaining the confidentiality of Confidential Information (as defined below) regarding or conveyed in the Discussions.
- M. In the course of Discussions, it may likely be necessary or desirable for a Party to communicate certain Confidential Information ("Disclosing Party") to another Party ("Receiving Party").

AGREEMENT

In consideration of the mutual promises and covenants set out in this SOA-CP CA, the Parties hereto agree as follows:

1. **Confidential Information.** "Confidential Information" means information related to the Purposes or conveyed in the Discussions in whatever form communicated or maintained (whether oral, written, electronic or visual) and whether prepared by the Disclosing Party (as defined in Section 2 below) or otherwise, which is furnished or disclosed by a Disclosing Party to a Receiving Party (as defined in Section 2 below) during the term of this SOA-CP CA, in connection with the Discussions and including the content of all Discussions. The Parties shall use reasonable efforts to (1) mark all Confidential Information "**Confidential – SOA-CP CA**" if written, electronic or visual, as provided in Section 2(C) below, and all oral disclosures shall be prefaced with the oral statement that the information to be disclosed is or includes Confidential Information, and (2) with respect to any written record (such as notes, summaries, and the like) made of visual or oral Confidential Information, date and mark as "**Confidential – SOA-CP CA**" as provided in section 2(C) below. The failure to mark any Confidential Information as "**Confidential – SOA-CP CA**" shall not affect the confidentiality of any Information made available under this SOA-CP CA pursuant to the terms hereof.

Confidential Information does not include information that

- A. is or becomes after the Effective Date part of the public knowledge or public literature through no fault of the Receiving Party;
- B. was lawfully in the Receiving Party's possession prior to the Effective Date under no direct or indirect obligation of secrecy or confidentiality to any Party or Its Affiliates;
- C. was acquired independently by the Receiving Party from a third party (being a person or entity who is not a Party or a Party's Affiliate as defined herein) rightfully in possession of the Confidential Information and who represents that it has the right to disseminate such information; or
- D. Is independently developed by or for the Receiving Party by persons who have not had access to Confidential Information at any time.
- E. is received by the State pursuant to applicable confidentiality statutes or other law, notwithstanding the same or similar information may have been provided to DNR or DOR as Confidential Information under the SOA-CP CA.

2. This Confidentiality Agreement itself is not Confidential Information.

3. **Nondisclosure and Restricted Use of Confidential Information.**

- A. Confidential Information shall be held in strict confidence by the Receiving Party and, except as expressly set forth in this SOA-CP CA, shall not be disclosed without prior written consent of all Disclosing Parties who own or control the Confidential Information, to the extent such Disclosing Parties have the authority to grant such consent, except to those professional consultants, Affiliates, agents, assigns, attorneys, employees (including employees of Affiliates), directors, officers and/or members ("**Representatives**") of the Receiving Party with a need to know the Confidential Information for the specific Purpose to be discussed, and will be used solely to pursue the Discussions regarding the specific Purpose. Notwithstanding any other provision of this SOA-CP CA, any Confidential Information to be disclosed by a Disclosing Party is disclosed at the sole discretion of the Disclosing Party. The Receiving Party shall advise all of its Representatives to whom Confidential Information is disclosed of the obligations undertaken in this SOA-CP CA, shall ensure that each Representative has all necessary authority to comply with the provisions of this SOA-CP CA prior to disclosure to such Representative, and shall instruct such Representatives to comply with the terms of this SOA-CP CA as if they individually were parties to this SOA-CP CA. The Receiving Party shall be responsible for any breach of this SOA-CP CA by the Receiving Party or its Representatives, and shall immediately notify the other Parties, as provided in Section 21 herein, if the Receiving Party learns of any use or disclosure of a Disclosing Party's Confidential Information in violation of this SOA-CP CA.

For the purposes of this SOA-CP CA, "**Affiliate**" means in relation to a Party, any company, corporation, partnership or other legal entity (In this definition, each such entity and each Party are sometimes referred to as a "**Company**"), which:

- i. is directly or indirectly, owned or controlled by such Party;
- ii. directly or indirectly owns or controls such Party; or

- iii. is directly or indirectly, owned or controlled by a Company that also, directly or indirectly, controls such Party.

For the purpose of this definition, a Company is directly owned or controlled by another Company that owns or controls shares or other interests carrying in the aggregate more than 50 percent the voting rights exercisable at a general, shareholders, or members meeting of the first-mentioned Company, or the right to appoint or dismiss a majority of the directors thereof, or the power to direct or cause the direction of the management or policies through the ownership of securities, by contract or otherwise. A Company is indirectly owned or controlled by a Company or Companies (the "**parent Company or Companies**") if a series of Companies can be specified, beginning with the parent Company or Companies and ending with the particular Company, so related that each Company of the series, except the parent Company or Companies, is directly controlled by one or more of the Companies in the series. DNR and DOR are Affiliates of each other but not of any other state entity for the purposes of this SOA-CP CA.

- B. The Parties recognize that there are exceptions to confidentiality and potential disclosures required under AS 38.05.020(b)(12)(A) and (B) for any agreement that may be reached for Purpose 1.

- i. For the purposes of AS 38.05.020(b)(12)(A), the Parties agree that the "terms of a proposed contract" means a final, complete, execution-ready contract, agreed by the parties thereto, submitted by the Commissioner of DNR to the legislature for the purpose of obtaining authorization for the governor to execute such contract ("**Final Contract**"). Except as set forth in this subsection (i), the Parties agree that all Discussions concerning any "terms of a proposed contract", and all contract drafts preceding any Final Contract, are not subject to AS 38.05.020(b)(12)(A) and shall remain Confidential Information. For the avoidance of doubt, any Final Contract shall be labeled by the Parties, "**Final Contract for Legislative Authorization & Public Disclosure – AS 38.05.020(b)(12)(A)**".
- ii. For the purposes of AS 38.05.020(b)(12)(B), DNR will, in good faith, confer with ConocoPhillips as to what Confidential Information DNR intends to share with the members of the legislature, their agents, and contractors under AS 38.05.020(b)(12)(B) related to the agreements or contracts negotiated under 38.05.020(b)(10) and (11) to which the State is a party and which are the subject of Discussions. Prior to the disclosure by DNR of Confidential Information under this subsection (ii) to the members of the legislature, their agents, and contractors, such third parties must first execute the Legislative Confidentiality Agreement, dated effective November 28, 2014, which requires signatories to keep Confidential Information confidential in the same manner as under confidentiality agreements entered into under AS 38.05.020(b)(12), such as this SOA-CP CA. Except as set forth in this subsection (ii), the Parties agree that all Discussions and Confidential Information are not subject to AS 38.05.020(b)(12)(B).

- C. The Parties recognize that certain Discussions for Purpose 1 may relate to joint venture marketing, pursuant to AS 38.05.180(ii)(4) ("**JV Marketing Discussions**"). In such JV Marketing Discussions, to permit appropriate due diligence, the Parties may discuss proprietary, but not competitively sensitive, historical aggregate cost and price information, and similar historical aggregate and other non-competitively sensitive information. However, the Parties *will not discuss*, among other matters, current or future pricing or bidding information; current or future non-Alaska LNG Project cost information; non-public information regarding current or prospective customers; current

marketing plans or proprietary strategic plans; current market share or market position; other non-public competitively-sensitive information related to LNG sales transactions; or, the existence or content of any AS 38.05.180(ii)(4) discussions the State Parties may or may not be having with any persons not parties to this SOA-CP CA. At all JV Marketing Discussions, in addition to other requirements of this SOA-CP CA, the Parties will (i) have respective counsel present; and (ii) ensure notes of the Discussions are taken and retained.

4. **Required Disclosure.** In the event that a Receiving Party is required by law, court order or regulatory authority to disclose any Confidential Information received pursuant to this SOA-CP CA, then the Party shall promptly notify the other Parties, as provided in Section 21 herein, of such requirement prior to disclosure, if legally permissible, so that the Disclosing Party or Disclosing Parties, as applicable, may seek an appropriate protective order and/or waive compliance with the terms of this SOA-CP CA. In the event that a protective order or other remedy is not obtained, or Disclosing Party or Disclosing Parties waives compliance with the provisions hereof, the Receiving Party making the disclosure agrees to furnish only the minimum portion of the Confidential Information that it reasonably determines, after consultation with its counsel, is necessary to comply with the law, court order, subpoena or other mandatory disclosure obligation, and to exercise reasonable efforts to obtain assurance that confidential treatment will be accorded such Confidential Information. Absent waiver by the Disclosing Party or Disclosing Parties, which shall be granted or withheld in each Disclosing Party's sole discretion, a Party shall not comply with any requested disclosure of Confidential Information not required to be made by law, court order or regulatory authority.
5. **Remedies.** Each Party acknowledges that money damages would not alone be a sufficient remedy for any breach of this SOA-CP CA and that the Parties shall be entitled to injunctive or other equitable relief to remedy or prevent any breach or threatened breach of this SOA-CP CA. Such remedy shall not be the exclusive remedy for any breach of this SOA-CP CA, but shall be in addition to all other rights and remedies available at law or in equity. Notwithstanding the foregoing, the Receiving Party's liability to another Party for breach of this SOA-CP CA shall be limited to direct damages and shall exclude any other liability, including, without limitation, special, indirect, punitive or consequential damages in contract, tort, warranty, or strict liability.
6. **No Other Agreement.** It is understood that neither this SOA-CP CA, nor the disclosure of Confidential Information under this SOA-CP CA, nor the ongoing discussions and correspondence by the Parties shall constitute a promise by or an obligation of any Party to enter into any other or further agreements or to proceed with any possible relationship or other transaction. The Parties acknowledge and agree that if mutually agreed terms are reached for Purpose 2, an additional state party or parties and additional authority will need to be added to and incorporated into this SOA-CP CA in order to finalize and execute any agreement. In no event shall the exception described in subsection 3.B(i) above be invoked for any agreement regarding Purpose 2 without the written mutual agreement of all Parties involved and any decision by ConocoPhillips to not disclose an agreement or proposed agreement regarding Purpose 2 shall not be negatively invoked or construed against ConocoPhillips.
7. **No License.** It is understood that nothing contained in this SOA-CP CA is intended or shall be construed as granting or conferring rights of any kind, by license or otherwise, in any Confidential Information disclosed to a Receiving Party.
8. **Amendment.** This SOA-CP CA may not be amended except in a writing executed by all of the Parties.
9. **Assignment; Successors and Assigns.** No Party may assign any right, remedy, obligation or liability under this SOA-CP CA without the prior written consent of the other Parties. This SOA-

CP CA shall be binding upon and shall inure to the benefit of the Parties and to the extent permitted by this section, their respective successors and permitted assigns.

10. **Representations and Warranties.**

- A. Each Disclosing Party represents and warrants at the time of disclosure that (i) it has the lawful and sufficient right to disclose the Confidential Information that it discloses to the Receiving Party pursuant to this SOA-CP CA and (ii) any such disclosure does not violate any law, and the Confidential Information may be used in accordance with the terms of this SOA-CP CA, subject to any additional restrictions that may be agreed in writing between the Disclosing Party or Disclosing Parties and the Receiving Party prior to the disclosure under this SOA-CP CA.
- B. *Each Receiving Party acknowledges that the Disclosing Party makes no representation or warranty, and expressly disclaims any representation or warranty, as to the accuracy, usefulness, correctness, applicability, quality, fitness for purpose, or completeness of the Confidential Information.* The Receiving Party uses or relies upon the Confidential Information disclosed pursuant to this SOA-CP CA at its sole discretion and risk, and neither the Disclosing Party nor any of its Representatives shall be subject to liability resulting from any use of or reliance upon the Confidential Information by the Receiving Party. Each Party hereby disclaims any and all liability that may be based, in whole or in part, on any Confidential Information, or any errors or omissions in the Confidential Information.
- C. DNR and DOR each represents and warrants that it is properly authorized and has sufficient and proper authority under the laws cited above to enter into and effectively implement the obligations of confidentiality and sole purpose use provided in this SOA-CP CA for the Purposes, and acknowledges that ConocoPhillips relies upon such representations and warranties as inducement to entering into Discussions pursuant to this SOA-CP CA.

11. **Waiver.** No provision of this SOA-CP CA may be waived except in a writing executed by the Party against which such waiver is sought to be enforced.

12. **Governing Law and Dispute Resolution.** The laws of the State of Alaska, without giving effect to its conflicts of laws principles, will govern all questions concerning the construction, validity and interpretation of this CA and the performance of the obligations imposed by this SOA-CP CA.

Any and all claims, demands, causes of action, disputes, controversies and other matters in question arising out of or relating to this SOA-CP CA, including any question regarding its breach, existence, validity, cancellation or termination, which the Parties do not resolve amicably within a period of three months from the date a dispute arises, shall be resolved exclusively by Alaska courts, and the parties consent to the jurisdiction of Alaska courts for the purpose of litigating all such claims and disputes.

13. **Term.** This SOA-CP CA shall remain in effect until the Confidential Information is disclosed into the public domain through no fault or breach of the Receiving Party.

14. **Return or Destruction.** Upon written notice from the Disclosing Party, the Receiving Party shall immediately destroy (and provide written verification of such), or return to the Disclosing Party all Confidential Information in the possession or control of the Receiving Party or the possession or control of its Representatives.

15. **Individual and Not Joint or Collective Liability.** The liability and obligations of each of the Parties under this SOA-CP CA are separate and individual, and not joint or collective. Each of

the Parties is responsible for its and its Representatives' actions or inactions under this SOA-CP CA and for compliance with the terms of this SOA-CP CA.

16. **Entire Agreement; Other Agreements.** This SOA-CP CA supersedes and replaces that certain "AS 38.05.180(ii)(4) State of Alaska-ConocoPhillips Marketing Confidentiality Agreement" dated effective August 20, 2015 by and among the Parties. With respect to the specific subject matter contained herein, this SOA-CP CA constitutes the entire and final agreement of the Parties.
17. **Counterparts.** This SOA-CP CA may be signed in counterparts and may be delivered by facsimile or PDF, each of which shall be deemed an original, and all of which together constitute one and the same instrument. This SOA-CP CA is effective as of the Effective Date when it has been executed by all Parties.
18. **Authorization and Binding Obligations.** Each Party represents to the other Parties that the execution, delivery and performance of this SOA-CP CA have been duly authorized, and this SOA-CP CA has been duly executed and delivered by the signatory so authorized, and the obligations contained herein constitute the valid and binding obligations of such Party.
19. **Severability.** Whenever possible, each provision of this SOA-CP CA shall be interpreted in such a manner as to be effective and valid under applicable law but if any non-material provision of this SOA-CP CA is held to be invalid, illegal or unenforceable under any applicable law or rule, the validity, legality and enforceability of the other provisions of this SOA-CP CA will not be affected or impaired thereby.
20. **Ethics and Conflicts of Interest.** Conflicts of interest relating to this SOA-CP CA are strictly prohibited. Except as otherwise expressly provided herein, and except as between a Party and its Affiliates, no Party to this SOA-CP CA, nor any employee or officer of such Party, shall, directly or indirectly,
 - A. pay salaries, commissions or fees to employees or officers of any other Party, or designees of such employees or officers, or
 - B. make to or receive from any employee or officer of any other, or designee of such employee or officer, any payments or rebates, or
 - C. favor employees or officers of the other Parties, or designees of such employees or officers, with gifts or entertainment of significant cost or value, or with services or goods sold at less than full market value, or
 - D. enter into business arrangements with employees or officers of the other Parties unless all such employees or officers are acting as Representatives of their respective Party.

Nothing herein shall be construed as prohibiting any Party from negotiating or entering into any transaction with a third-party, including transactions regarding potential purchases or sales of natural gas.

21. **Notices.** All notices and communications allowed or required under this SOA-CP CA shall be provided in writing to the specific Representatives of the Parties listed below (as may be changed by written notice to the other Parties) by personal delivery with a reliable written record of delivery, certified mail (return receipt requested), facsimile with an automatically generated successful transmission record received and retained, or email with a "delivered" receipt received and retained. All such notices shall be deemed effective as follows: (a) if by personal delivery, when delivered; (b) if by mail, on the date indicated on the returned receipt; (c) if by facsimile, when received by recipient's facsimile device; and (d) if by email, when received by recipient's

email server; provided that if a notice is provided by facsimile or email after the normal business hours of the recipient, the notice shall be effective on the next business day.

DNR

Attn: Commissioner Mark Myers
Address: 550 W. 7th Avenue, Suite 1400,
Anchorage, AK 99501
Fax: (907) 269-8918
Email: mark.myers@alaska.gov

DOR

Attn: Commissioner Randy Hoffbeck
Address: P.O. Box 110400
Anchorage, AK 99501 - 110400
Fax: (907) 465-2389
Email: randall.hoffbeck@alaska.gov

CPAI

Attention: Vice President - Commercial Assets Alaska (currently Leo Ehrhard)
Address: ConocoPhillips Alaska, Inc.
ATO 21-2126
P.O. Box 100360
Anchorage, AK 99510-0360
Fax: (907) 263-4438
Email: Leo.W.Ehrhard@conocophillips.com

CALC

Attention: President (currently Darren Meznarich)
Address: ConocoPhillips Alaska LNG Company
ATO 2020
P.O. Box 100360
Anchorage, AK 99510-0360
Fax: (907) 263-4438
Email: Darren.L.Meznarich@conocophillips.com

22. Interpretation

- A. References to "day," "month," "quarter" and "year" shall unless otherwise stated mean a calendar day, month, quarter and year respectively.
- B. Where the context requires, words denoting the singular only shall also include the plural, or vice versa. References to "persons" and "third parties" shall include natural persons and bodies corporate, unincorporated associations and partnerships.
- C. Unless the context otherwise requires, any reference to a statutory provision (including those contained in subordinate legislation) is a reference to such provision as amended or re-enacted or as modified by other statutory provisions from time to time and includes subsequent legislation made under the relevant statute.
- D. References to the word "include" and "including" are to be construed without limitation.
- E. The words "will" and "shall" are employed interchangeably in this SOA-CP CA with no difference of meaning.

23. **No Precedent.** Nothing in this SOA-CP CA is intended to establish, or will establish, a precedent between the Parties with respect to any other agreement.

IN WITNESS WHEREOF, the Representatives of the Parties indicated below have executed this SOA-CP CA by their respective duly authorized signatories effective as of the Effective Date.

ConocoPhillips Alaska Inc.
By: [Signature]
Name: Leo Ehrhard
Title: Vice President
Date: Nov. 19, 2015

ConocoPhillips Alaska LNG Company
By: [Signature]
Name: Darren Mezmarich
Title: PRESIDENT
Date: NOV/19, 2015

Commissioner of the Department of Natural Resources
By: [Signature]
Name: MARC BYERS
Title: Commissioner
Date: 11-15-2015

Commissioner of the Department of Revenue
By: [Signature]
Name: Randall J. Hoffbeck
Title: Commissioner
Date: 11-18-15

Dated December 4, 2015

GAS AVAILABILITY AGREEMENT

By and Among

**Department of Natural Resources of the State of Alaska
ConocoPhillips Alaska, Inc.
BP Exploration (Alaska) Inc.**

This Gas Availability Agreement (the "Agreement") is made effective on December 4, 2015, by and among:

- (1) **The Department of Natural Resources of the State of Alaska ("DNR");**
- (2) **ConocoPhillips Alaska, Inc.**, a corporation incorporated under the laws of the state of Delaware and qualified to do business in Alaska ("**ConocoPhillips**"); and
- (3) **BP Exploration (Alaska) Inc.**, a corporation incorporated under the laws of the state of Delaware ("**BP**"),

(each a "**Party**" and together the "**Parties**").

Recitals:

- (A) The Parties and their Affiliates intend to work together to progress the AKLNG Project.
- (B) The Parties and their Affiliates intend to enter into further agreements governing the development of the AKLNG Project and the relationships between the Parties.
- (C) The Parties now wish to enter into this Agreement to provide for a process whereby, if a Party's AKLNG Project Affiliate (other than the DNR AKLNG Project Affiliate) becomes a Non-continuing Party (as defined below) at any time during the term of this Agreement, the remaining Parties' AKLNG Project Affiliates may continue to progress the AKLNG Project and such Non-continuing Party will make its gas available to the State or its designee if mutually agreed commercially reasonable terms can be reached between the relevant Party and DNR.

Now, in consideration of the foregoing, it is hereby agreed as follows:

1. Definitions and Interpretation

1.1 Definitions

In this Agreement, including the recitals hereto and except to the extent that the context expressly requires otherwise, capitalized terms used herein shall have the following meaning:

"**Affiliate**" means in relation to a Party, any company, corporation, partnership or other legal entity (in this definition, each such entity and each Party are sometimes referred to as a "**Company**"), which is:

- (a) directly or indirectly, owned or controlled by such Party;
- (b) directly or indirectly owns or controls such Party; or
- (c) directly or indirectly, owned or controlled by a Company that also, directly or indirectly, controls such Party.

For the purpose of this definition, a Company is directly owned or controlled by another Company that owns or controls shares or other interests carrying in the aggregate greater than 50 percent of the voting rights exercisable at a general, shareholders, or members meeting of the first-mentioned Company, or the right to appoint or dismiss a majority of the directors thereof, or the power to direct or cause the direction of the management or policies through the ownership of securities, by contract or otherwise. A Company is indirectly owned or controlled by a Company or Companies (the “**parent Company or Companies**”) if a series of Companies can be specified, beginning with the parent Company or Companies and ending with the particular Company, so related that each Company of the series, except the parent Company or Companies, is directly controlled by one or more of the Companies in the series. The Affiliates of DNR are those State entities, including AGDC, that otherwise meet the requirements of the definition above, when acting only in the State's proprietary capacity (and not in a governmental capacity) including other independent corporations.

“**AGDC**” means Alaska Gasline Development Corporation, a public corporation and government instrumentality of the state of Alaska including its Affiliate, TransCanada Alaska Midstream LP.

“**AKLNG Project**” means the LNG project to monetize North Slope gas resources as described in the Federal Energy Regulatory Commission Docket PF14-21-000.

“**AKLNG Project Affiliate**” means as to ConocoPhillips, ConocoPhillips Alaska LNG Company and as to BP, BP Alaska LNG LLC and as to DNR, AGDC in its capacity as a participant in the AKLNG Project.

“**Non-continuing Party**” has the meaning ascribed to it in Clause 3.

“**PBU**” means the Prudhoe Bay Unit.

“**PTU**” means the Point Thomson Unit.

1.2 Interpretation

In this Agreement, except to the extent that the context requires otherwise:

- (a) references to the laws of the State of Alaska include the applicable laws of any political sub-division of the State of Alaska;
- (b) recitals are not operative terms and impose no obligations and give rise to no rights;
- (c) references to an agreement or other document (including this Agreement), or to a provision contained in any of these, shall be construed, at the particular time, as a

reference to it as it may then have been amended, varied, supplemented, modified, suspended, assigned or novated; and

(d) references to Parties include their successors and permitted assigns.

2. **Intentions**

As of the effective date of this Agreement, each Party agrees that it or its AKLNG Project Affiliate is currently targeting a FEED sanction decision for the AKLNG Project no later than July 1, 2017.

3. **Bilateral Negotiations**

During the term of this Agreement, provided that the DNR AKLNG Project Affiliate is continuing and has not indicated it is discontinuing its participation in the AKLNG Project then to address the possibility that the ConocoPhillips AKLNG Project Affiliate or the BP AKLNG Project Affiliate indicates it does not intend to continue with the AKLNG Project (either such ConocoPhillips or BP AKLNG Project Affiliate a "Non-continuing Party"):

- (a) ConocoPhillips and DNR will continue to use reasonable efforts and negotiate in good faith for the purpose of ConocoPhillips entering into a bilateral agreement with the State or its designee on mutually agreed commercially reasonable terms, with such commercial reasonableness to be determined by each Party at the sole discretion of such Party, regarding the availability of natural gas from oil and gas leases in the PBU and the PTU from which the ConocoPhillips anticipates natural gas would be provided for the AKLNG Project in the event, if ever, that the ConocoPhillips AKLNG Project Affiliate becomes a Non-continuing Party; and
- (b) BP and DNR will continue to use reasonable efforts and negotiate in good faith for the purpose of BP entering into a bilateral agreement with the State or its designee on mutually agreed commercially reasonable terms, with such commercial reasonableness to be determined by each Party at the sole discretion of such Party, regarding the availability of natural gas from oil and gas leases in the PBU and the PTU from which the BP anticipates natural gas would be provided for the AKLNG Project in the event, if ever, that the BP AKLNG Project Affiliate becomes a Non-continuing Party.

4. **Term**

This Agreement is effective upon execution by all Parties and shall continue in effect until the earliest to occur of:

- (a) the written agreement of all Parties to terminate this Agreement;

- (b) for each Party other than DNR, upon full execution of its bilateral agreement, as referred to in Clause 3;
- (c) the DNR AKLNG Project Affiliate gives a final indication it does not intend to continue with the AKLNG Project;
- (d) the date falling ninety (90) days after any Party notifies the other Parties in writing that it has become aware of the expiry or termination of the Alaska LNG Project Pre-FEED Joint Venture Agreement, if such expiry or termination occurs; or
- (e) December 1, 2017.

5. **Assignment**

The Parties may not assign or transfer all or any part of their rights, benefits or obligations under this Agreement without the written consent of all of the other Parties.

6. **Governing Law**

This Agreement shall be governed by and construed in accordance with the laws of the state of Alaska.

7. **No Liability or Damages**

- (a) Nothing in this Agreement requires any Party to reach or execute any legally binding or enforceable agreement or to refrain from engaging in any business whatsoever, nor does any Party have any liability in connection with the subject matter of this Agreement.
- (b) No Party is liable to any other Party or its Affiliates, officers, employees or agents, for any direct, indirect, special, incidental, consequential or punitive damages or otherwise liable for any loss of actual or potential profits, loss of production or business interruption arising out of or in any way connected with this Agreement, including any breach of the terms of this Agreement.

8. **Miscellaneous Provisions**

8.1 **No Agency**

- (a) This Agreement does not constitute any Party as the agent, partner or legal representative of another Party for any purposes whatsoever, and no Party shall have any express or implied right or authority to assume or to create any obligation or responsibility on behalf of or in the name of any other Party.
- (b) No Party is an agent for nor is obligated to enter into or cause the execution of agreements on behalf of any Affiliate or other entity.
- (c) The obligations of the Parties under this Agreement are several and not joint.

8.2 Other Agreements

This Agreement shall not be interpreted as:

- (a) altering or amending any upstream oil and gas agreement, including any lease or unit agreement, or
- (b) satisfying any duty or obligation thereunder.

8.3 Conduct of the Parties

Each Party warrants that it and its Affiliates have not made, offered, or authorized and will not make, offer, or authorize with respect to the matters which are the subject of this Agreement, any payment, gift, promise or other advantage, whether directly or through any other person or entity, to or for the use or benefit of any public official (i.e., any person holding a legislative, administrative or judicial office, including any person employed by or acting on behalf of a public agency, a public enterprise or a public international organization) or any political party or political party official or candidate for office, where such payment, gift, promise or advantage would violate (1) the applicable laws of the United States or the State of Alaska; (2) the laws of the country of incorporation of such Party or such Party's ultimate parent company and of the principal place of business of such ultimate parent company; or (3) the principles described in the Convention on Combating Bribery of Foreign Public Officials in International Business Transactions, signed in Paris on December 17, 1997, which entered into force on February 15, 1999, and the Convention's Commentaries. Each Party shall defend, indemnify and hold the other Parties harmless from and against any and all claims, damages, losses, penalties, costs and expenses arising from or related to, any breach by such first Party of such warranty. Such indemnity obligation shall survive termination or expiration of this Agreement. Each Party shall in good time (1) respond in reasonable detail to any notice from any other Party reasonably connected with the above-stated warranty; and (2) furnish applicable documentary support for such response upon request from such other Party.

8.4 Successors and Assigns

Subject to the limitations on transfer contained in Clause 5, this Agreement shall inure to the benefit of and be binding upon the successors and assigns of the Parties.

8.5 Waiver

No waiver by a Party of any one or more breaches of this Agreement by any other Party shall operate or be construed as a waiver of any future default or defaults by the same Party. No Party shall be deemed to have waived, released, or modified any of its rights under this Agreement unless such Party has expressly stated, in writing, that it does waive, release or modify such rights.

8.6 No Third Party Beneficiaries

This Agreement is made for the sole benefit of the Parties, and their respective successors and assigns as permitted under this Agreement. The Parties do not intend and this Agreement shall not be construed to create, by implication or otherwise, any rights in any other person or entity not a Party to this Agreement, and no person or entity shall have any rights or remedies under or by reason of this Agreement or any right to the exercise of any right or power hereunder or arising from any default hereunder.

8.7 Assistance of Counsel

Each provision of this Agreement shall be construed as though all Parties participated equally in the drafting of the provision. The Parties acknowledge and agree that any rule of construction that a document is to be construed against the drafting party shall not be applicable to this Agreement.

8.8 Severance of Invalid Provisions

If and for so long as any provision of this Agreement shall be deemed to be judged invalid for any reason whatsoever, such invalidity shall not affect the validity or operation of any other provision of this Agreement except only so far as shall be necessary to give effect to the construction of such invalidity, and any such invalid provision shall be deemed severed from this Agreement without affecting the validity of the balance of this Agreement.

8.9 Modifications

This Agreement may not be modified except by written consent of the Parties.

8.10 No Precedent

Nothing in this Agreement is intended to establish a precedent between the Parties with respect to any subsequent agreements.

8.11 **Counterparts**

This Agreement may be executed in any number of counterparts and this has the same effect as if the signatures on the counterparts were on a single copy of the Agreement.

IN WITNESS WHEREOF this Agreement has been duly executed on behalf of each of the Parties on the dates shown below, effective as of the day and year first written above.

State of Alaska Department of Natural Resources

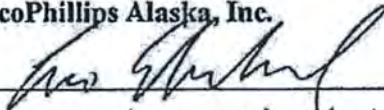
By: 

Printed Name: MARK MYERS

Title: Commissioner, Department of Natural Resources

Date: December 4, 2015

ConocoPhillips Alaska, Inc.

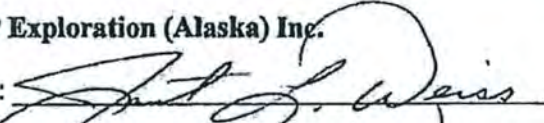
By: 

Printed Name: Leo W Ehrhard

Title: Vice President

Date: December 4, 2015

BP Exploration (Alaska) Inc.

By: 

Printed Name: JANET L. WEISS

Title: PRESIDENT

Date: DECEMBER 4, 2015

STATE CAPITOL
P.O. Box 110001
Juneau, AK 99811-0001
907-465-3500
fax: 907-465-3532



550 West Seventh Avenue, Suite 1700
Anchorage, AK 99501
907-269-7450
fax 907-269-7461
www.Gov.Alaska.Gov
Governor@Alaska.Gov

Governor Bill Walker
STATE OF ALASKA

January 18, 2016

Ms. Janet L. Weiss
President
BP Exploration (Alaska) Inc.
900 East Benson Boulevard
PO Box 196612
Anchorage, Alaska 99519-6612

Mr. Jim Flood
Vice President, Arctic Projects
ExxonMobil Development Company
Wellness 2, 5A.345
22777 Springwoods Village Parkway
Spring, Texas 77389

Mr. Joe Marushack
President
ConocoPhillips, Alaska, Inc.
700 G Street, NTC (99501)
PO Box 100360
Anchorage, Alaska 99510-0360

Re: AKLNG Project – North Slope Development

Dear Janet, Joe and Jim:

As we have discussed previously, my highest priority is to commercialize Alaska's abundant North Slope natural gas resources. Given Alaska's \$3.5 billion annual deficit, we have no option other than to monetize this valuable asset as quickly as possible. Prior to the start of the upcoming 2016 regular legislative session, I want to reiterate my expectations for the milestones that BP, ConocoPhillips, and ExxonMobil ("Producers") must reach in the near future concerning development of the AKLNG Project. It is my understanding that you and your teams are aware of and working towards these milestones.

As you know, approximately two years ago, in January 2014, the State and the Producers entered into a Heads of Agreement ("HOA"), which laid out an agreed road map for the AKLNG Project. That agreement expired as of December 31, 2015. Among other things, the HOA contemplated that a legislative session would be held in 2015 to ratify any commercial agreements negotiated by the parties to advance the AKLNG Project. In other words, the HOA anticipated that the commercial contracts would be ready for submittal to the Legislature for the last legislative session. The HOA also specifically contemplates that such project-enabling agreements will be agreed by the parties before the Commissioner of the Department of Natural Resources ("DNR") can make a determination whether to elect to take the State's royalty in kind ("RIK") for gas produced into the AKLNG Project. Unfortunately, those project-enabling agreements have not yet been agreed, largely as a result of the Producers' failure to reach alignment with each other, and with the State, on gas balancing terms and other key issues.

Ms. Janet Weiss
Mr. Joe Marushack
Mr. Jim Flood
AKLNG Project – North Slope Development
January 18, 2016
Page 2

I recognize and appreciate the fact that on December 4, 2015, BP, ConocoPhillips and the State entered into a Gas Availability Agreement (“GAA”), which I believe ensures that gas will be available for the Project if BP and/or ConocoPhillips withdraws from the Project. As you know, on the basis of commitments from BP and ConocoPhillips that led to the GAA, and commitments made by ExxonMobil in my conversation with Jim on October 23, 2015, and correspondence from ExxonMobil on this issue, I decided to continue to pursue real and substantive progress on the commercial terms for the AKLNG Project and to postpone proposing the alternative approach of a gas reserves tax bill, at least for so long as such negotiations are progressing and deadlines are met. I am satisfied with the present gas commitments from each of your companies and do not see a need to take up valuable time to further refine those existing commitments.

I have been extremely patient in allowing the negotiations to proceed in the hope that the parties will reach alignment on the agreements necessary to move the AKLNG Project forward and thereby commercialize Alaska’s gas. I gave the parties the entire year of 2015 to reach alignment. Given that the parties have failed to meet the 2015 deadline contemplated by the HOA, I am increasingly concerned about the lack of progress in negotiating the necessary commercial agreements to enable the AKLNG Project to proceed. I am determined to take significant steps to commercialize Alaska’s gas in 2016, preferably by advancing the AKLNG Project but, if the parties fail to reach alignment, then through other approaches.

Accordingly, I want to make clear my expectation that, prior to the end of the 2016 regular session, the AKLNG parties, including the Producers and the State (along with the Alaska Gasline Development Corporation), must reach agreement on the following project enabling agreements and issues:

1. Gas Supply and Balancing Agreement, including any associated Dedication Agreement and Supply Forecasting Agreement;
2. Byproduct Handling Terms;
3. Field Cost Allowance;
4. Point Thomson Lease Modifications/Conversions;
5. Joint Venture Marketing Agreement(s) and/or acceptable Producer Offers as required by Senate Bill 138 to purchase, dispose of, or market the State’s royalty gas “on the same or substantially similar terms” as the Producers sell, dispose of, or market their own gas through the AKLNG Project;
6. Members Agreement and other associated governance agreements, including terms for expansions, long-term release of unneeded capacity, and use/development of common infrastructure for new LNG/GIP trains;
7. System Use Agreement; and
8. Domestic gas sales, including a commitment by each Producer to offer to sell a pro rata amount of gas through the AKLNG Project for domestic needs on commercially reasonable terms.

Ms. Janet Weiss
Mr. Joe Marushack
Mr. Jim Flood
AKLNG Project – North Slope Development
January 18, 2016
Page 3

If the parties do not reach alignment on these important contracts and issues, then I will have no other choice but to consider other options for commercializing Alaska's gas. In addition, absent such alignment on all of these agreements and issues, my Administration will be unable to support any Fiscal Contract that the Producers may seek, or a Constitutional Amendment supporting such Fiscal Contract.

I look forward to working with you to reach the alignment needed to move the AKLNG Project forward and thereby commercialize Alaska's gas resources.

Sincerely yours,

A handwritten signature in black ink that reads "Bill Walker". The signature is written in a cursive, flowing style.

Bill Walker
Governor



Scott A. Digert

Manager of Reservoir Management
Phone 907-564-4480
Email: scott.digert@bp.com

BP Exploration (Alaska) Inc.
900 E. Benson Boulevard
Anchorage, AK 99508

P.O. Box 196612
Anchorage, AK 99519-6612

RECEIVED

JUN 21 2016

DIVISION OF
OIL AND GAS

June 17, 2016

Corri Feige, Director
State of Alaska
Division of Oil and Gas
Department of Natural Resources
550 West 7th Ave., Suite 1100
Anchorage, AK 99501-3563

RE: *2016 Prudhoe Bay Unit IPA Plan of Development
Response to Division's E-Mail dated June 12, 2016*

Dear Director Feige:

BP Exploration (Alaska) Inc. (BPXA) in its capacity as operator of the Prudhoe Bay Unit (PBU) is responding to your June 12, 2016 email to Dave Van Tuyl at BPXA regarding the PBU IPA POD Update that we submitted on March 31, 2016. Dave is not involved in any aspect of the preparation of the PBU POD Update and is instead focused on BP's participation in the AK LNG Project. Instead, the POD role falls to me and I will respond.

First, thank you very much for continuing to work with BPXA in our efforts to seek approval of the IPA POD Update. Most importantly, thank you for participating directly along with seven other Division of Oil and Gas staff in the May 19, 2016 technical workshop. I enjoyed the discussion and was happy we could answer all of your questions. At the conclusion of that meeting you told us all that you believed BPXA had addressed all of the technical questions and one of the DOG technical staff called that afternoon to confirm to me that the division now had all of the technical information it needed to find the POD Update complete and that you would be contacting individual companies on their offer to have conversations on the topic of marketing. I thanked the DOG technical staff at that time and I thank you again now. We too believe the technical workshop was a great success.

BPXA remains disappointed that the Division is still being required to hold its approval of the IPA POD Update hostage unless BPXA and the other PBU working interest owners "provide a discussion of your marketing plan for the PBU, as it relates to the long term development plans for the unit and moving toward a major gas sale" as stated in your email from this past Sunday. As I said in my May 2, 2016 letter to you and as Dave Van Tuyl discussed in more detail in a separate letter, BPXA and the PBU working interest owners continue to believe the Division is demanding extraordinary additional information that is contrary to law, the terms of the PBUA, as well as the Division's regulations and the Division's own interpretation of its regulations over many decades. Importantly, the Division is seeking information from BPXA that we are each prohibited from sharing with each other under the terms of the Gas Availability Agreement between BPXA and DNR.

As the Operator, BPXA would be prohibited by state and federal antitrust law from developing a joint marketing plan for PBU resources. Consistent with the contractual requirements of the PBUA and the POD regulations, the IPA POD Update contains plans for the development and operation of the IPA for the one-year POD period as well as a discussion of projects under evaluation by the IPA WIOs. We discussed in detail and answered to its satisfaction each and every question the Division had on the PBU IPA planning efforts in front of a major gas sale. BPXA also shared detailed technical information as part of the 2015 AOGCC Rule 9 offtake hearing and with the Division during the recent technical workshop that we were told fully addressed all of the Division's technical questions required to find the POD Update complete.

As I said in my previous letter, it is widely known that the State of Alaska is engaged in negotiations with the Alaska LNG Project participants regarding new commercial terms for the Alaska LNG Project. In fact, the Commissioner is quoted this week in the Dispatch News as saying talks between the State and each company are underway regarding the project structure, various commercial terms, and each north slope producer potentially selling its gas to the state. As we discussed in the Rule 9 hearing and with the Division at the technical workshop, none of the current discussions underway have any impact whatsoever on how BPXA would update the POD at any point in the near future. PBU gas has been extensively developed to maximize oil recovery. By expanded gas cycling and continued use of the gas for enhanced oil recovery, we have produced to date three billion barrels of oil more than originally expected. These points are addressed in quite a lot of detail in the AOGCC Rule 9 approval order and the accompanying application. Our 2016 IPA POD Update continues to appropriately focus on using gas to enhance oil recovery. Importantly, as we discussed during the technical workshop, BPXA is proceeding with the work the AOGCC required in the 2019 and 2020 timeframe as part of its Rule 9 approval. We fully expect to involve the Division in that conversation but we are years away from that effort. You and your technical team at the Division seemed to agree with this during our conversation on May 19th.

Your original letter and the recent email simply ask for information that does not exist and more importantly is not relevant to the POD Update we submitted. We respectfully request that the Division confirm that our March 31, 2016 submission of the IPA POD is complete and approve the IPA POD.

Sincerely,



Scott Digert
Manager of Reservoir Management
Alaska Reservoir Development

cc: H. Jamieson, Exxon Mobil Alaska, Production Inc.
E. Reinbold, CPAI
P. Ayer, Chevron U.S.A. Inc.
D. Roby, AOGCC
S. Gould, BPXA

From: Pathrose, Vinod
To: Smith, Kyle S (DNR)
Subject: AKLNG Public Materials
Date: Thursday, 26 May, 2016 11:17:25

Kyle,

Nice meeting you today.

The information discussed in this morning's meeting regarding IPA POD should be kept confidential under AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law.

Below are a few links to some AKLNG background material you may find useful.

AKLNG Presentations – <http://ak-lng.com/newsroom/presentations/>

Jan 2016 House Resources Hearing – http://www.legis.state.ak.us/basis/get_documents.asp?chamber=HRES&session=29&bill=&date1=20160127&time2=1300

Jan 2016 Senate Resources Documents – http://www.legis.state.ak.us/basis/get_documents.asp?chamber=SRES&session=29&bill=&date1=20160127&time2=1530

Regards,
Vinod

Vinod K. Pathrose
Commercial Supervisor

ExxonMobil Alaska Production Inc.

3301 C Street, Suite 400
Anchorage, AK 99503
832 624 7272 Tel
907 312 4002 Mobile

Vinod,

I'm following up on questions that arose after Corri Feige, Pascal, and I had the opportunity to go over our notes from our meeting last week. When we discussed the antitrust considerations in the global market, it was made clear Exxon was not only concerned with Alaska and US antitrust laws but regulatory and legal issues globally. We were hoping to gain a better understanding of the legal and regulatory concerns regarding public discussions of natural gas volume, pricing, timing, and customers in the global market. Below, I've listed questions that came to mind after our meeting. Any help with these would be appreciated.

- Could you provide more information on what limitations companies marketing gas around the world are facing?
- Are there standard operating procedures Exxon could provide detailing how a company engages in marketing of natural gas resources while avoiding the numerous antitrust laws throughout the world?
- Are there examples of international markets of particular concern?

Our discussions with Cory Quarles and you brought more clarity to the subjects of state policy barriers, in-state gas sales, and current available gas marketing options. It was also very helpful to collectively begin to explore what companies are encountering in the global market and how antitrust laws impact their efforts. We are not asking for specifics on aspects of commercially sensitive marketing information, rather additional information on the marketing process and procedures.

Hope you had a nice holiday weekend. Feel free to give me a call if this is easier to discuss over the phone.

Thanks,

Kyle

ExxonMobil Production Company

P. O. Box 196601
Anchorage, Alaska 99519-6601
907-561-5331 Telephone
906-564-3677 Facsimile

Gilbert S. Wong
OBO Asset Manager

ExxonMobil
Production

May 20, 2016

Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 W. 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3560

RECEIVED

MAY 20 2016

DIVISION OF
OIL AND GAS

Dear Director Feige:

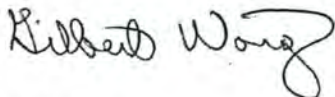
ExxonMobil has received a copy of your letter dated May 12, 2016, to the Prudhoe Bay Unit Operator BP Exploration (Alaska) Inc. (BPXA). In that letter, you mention that ExxonMobil has not provided a response to your earlier letter dated April 11, 2016, also to BPXA.

ExxonMobil provided input to BPXA regarding the IPA Plan of Development submitted to the Division and related correspondence, including the Operator letter dated May 2, 2016. Consistent with the Prudhoe Bay Unit Agreement and DNR regulations, communications regarding Prudhoe Bay Unit (PBU) plans of development are the responsibility of the Unit Operator. The Plan of Development submitted by BPXA fully addresses and satisfies the requirements for a plan of development in the PBU and DNR regulations. Accordingly, ExxonMobil did not see the necessity of sending any separate correspondence.

Given the nature of the specific inquiry in your May 12 letter ("marketing efforts for gas sales"), ExxonMobil considers BPXA's original response sufficient. Marketing efforts for gas sales, whether for local or non-local markets, are a matter for the individual working interest owners. Sharing details regarding any individual owner efforts is not appropriate or permissible for a number of reasons as outlined in the Operator's May 2 letter. Principally, the information is commercially sensitive and sharing it creates significant federal and state antitrust concerns.

ExxonMobil believes that the technical workshop led by BPXA for DNR technical staff addressed certain DNR requests and DNR has the relevant information necessary to finalize approval of the Plan of Development.

Sincerely,



GSW:vkp

David Van Tuyl
Regional Manager



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

VIA HAND DELIVERY

May 17, 2016

RECEIVED

MAY 17 2016

DIVISION OF
OIL AND GAS

Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

Re: Response to Division's Request for Gas Marketing Information

Dear Director Feige:

Based on your May 12 letter and our recent communications we remain uncertain about the specific nature and purpose of the gas marketing information the Division is seeking from BPXA. We are committed to working constructively and collaboratively with the Division on resource development and so, to avoid any miscommunication or confusion, we suggest that representatives from BPXA and the Division meet at your earliest convenience to discuss your information request. Due to the topic to be discussed, the meeting would be subject to compliance with anti-trust laws and confidentiality requirements and separate from the Division's review of IPA POD submitted separately by BPXA as unit operator.

We hope that this proposed interaction will advance the understanding of BPXA and the Division regarding marketing information. Please feel free to contact me at (907) 564-4691.

Sincerely,

A handwritten signature in black ink that reads 'David Van Tuyl'.

Dave Van Tuyl
BP Exploration (Alaska) Inc.



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Natural Resources

Division of Oil & Gas
Anchorage Office

550 W. 7th Avenue Suite 1100
Anchorage, Alaska 99501-3560
Main: 907.269.8800
Fax: 907.269.8939

May 12, 2016

Scott Digert, Manager of Reservoir Management
BP Exploration (Alaska) Inc.
Post Office Box 196612
Anchorage, Alaska 99519-6612

RE: Prudhoe Bay Unit – Initial Participating Area Plan of Development

Dear Mr. Digert:

The Division has reviewed your letter dated May 2, 2016. In that letter, BP Exploration (Alaska) Inc. (BPXA) as unit operator for the Prudhoe Bay Unit (PBU) expressed concerns regarding the Division's request for information related to gas development. The Division respectfully disagrees with BPXA's analysis. The information requested by the Commissioner of the Department of Natural Resources in his January 14, 2016 letter and subsequently by the Division in its April 11, 2016 letter to BPXA as Unit Operator is essential to the Division in understanding the "long-range proposed development activities for the unit" and must be included in the POD to the extent it exists. *See* 11 AAC 83.343.

In the May 2, 2016 letter, BPXA directed the Division to filings submitted to the Alaska Oil and Gas Conservation Commission (AOGCC) by BPXA in September 2015 in support of BPXA's application to amend Conservation Order 341E to increase the allowable gas offtake in Rule 9. The Division has reviewed those filings and will incorporate them by reference into the 2016 PBU IPA POD. The Division appreciates that the Unit Operator has provided, to the extent they currently exist, proposed plans for progressing in-fill drilling and proposed changes in existing operations during the 2016 POD period required to facilitate a MGS. The Division's technical staff will be requesting an update to the CO2 technical evaluation that was submitted as a part of the 2010 POD.

The Division also requests that the Unit Operator provide a response to the Division's request for the proposed terms by which gas balancing (if such agreement may be required), byproduct handling, and field cost allowance will be treated when a Major Gas Sale occurs. As requested in the Division's April 11, 2016 letter, if such terms have not yet been agreed upon for the PBU, the Unit Operator should explain any progress made to develop such terms and identify remaining issues that may prevent agreement on such terms and any plans to advance or finalize such terms during the 2016 POD period.

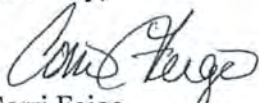
Finally, the Division has not yet received responses to questions asked regarding marketing efforts for gas sales. We continue to believe that the Unit Operator is obligated to provide this information; nevertheless, the Division in its April 11, 2016 letter authorized the Unit Operator to request that each PBU working interest owner (WIO) provide marketing information directly to the Division no later than May 1, 2016. The Division also informed the Unit Operator that

these individual responses would be considered part of the POD but would be kept confidential as appropriate, if requested. In its May 2, 2016 letter, the Unit Operator confirmed that it had made such request to each WIO. The Division received a letter from ConocoPhillips Alaska, Inc. (CPAI) on May 2, 2016 and a letter from BPXA on May 5, 2016. While appreciated, these letters do not respond to the Division's requests in sufficient detail. In order to adequately evaluate how the POD meets the requirements of 11AAC 83.343 and other law, the Division needs specific information regarding past and on-going efforts to market gas in both the local and non-local markets. To the extent it is contemplated at this time, the Division also needs specific commitments and timelines regarding how gas will be marketed in the future. The Division acknowledges the various objections raised by BPXA and CPAI regarding the Division's requests and, again, respectfully disagrees. As stated above, the requested marketing information is essential to understanding the "long-range proposed development activities for the unit," and the POD cannot be considered complete until such information is received. See 11 AAC 83.343. No response has yet been received from ExxonMobil.

The Division is actively evaluating the technical information provided by the Unit Operator as part of the proposed 2016 PBU IPA POD. We ask that the Unit Operator and the WIOs provide the information requested above as soon as possible so that evaluation of the entire POD may be completed. If we can help facilitate the exchange of any of the requested information, please let us know.

If you have questions regarding this decision, please do not hesitate to contact Kyle Smith at (907) 269-8807, or via email at kyle.smith@alaska.gov.

Sincerely,


Corri Feige
Director

cc: David Van Tuyl, BPXA
Jon Schultz, CPAI
Temple Davidson, DNR
Kyle Smith, DNR
DOL



Jon S. Schultz
Manager, Great Prudhoe Area
P.O. Box 100360
Anchorage, AK 99510-0360
Phone 907.265.1315

May 4, 2016

Corri A. Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 110
Anchorage, AK 99501-3560

Re: Division's Letter of April 11, 2016

Dear Director Feige

We refer to your April 11, 2016 letter ("Division's Letter") seeking additional information for Division of Oil and Gas ("Division") review of the 2016 Prudhoe Bay Unit Initial Participating Area Plan of Development ("IPA POD") submitted by the Prudhoe Bay Unit operator ("PBU Operator") on March 31, 2016. The Division's Letter was copied to a representative of ConocoPhillips Alaska, Inc. ("ConocoPhillips") as a working interest owner in PBU. ConocoPhillips has reviewed the PBU Operator's response to the Division's Letter, which the PBU Operator provided to the Division on May 2, 2016, and ConocoPhillips supports the content and conclusions of the PBU Operator's response.

The Division's Letter also requests that each working interest owner provide responses to the Division regarding the Division's questions concerning each working interest owner's gas marketing efforts and plans. To avoid potential confusion and miscommunication between ConocoPhillips and the Division, which could conceivably impact other confidential discussions between ConocoPhillips and the DNR and give rise to other issues, we would recommend that representatives of ConocoPhillips and the Division meet to discuss these requests. These discussions would be bilateral, subject, where applicable, to a confidentiality agreement already in place between ConocoPhillips and the DNR, in compliance with all applicable limitations on sharing marketing information and antitrust compliance requirements, and entirely separate from any discussions related to the Division's review of the IPA POD submitted by the PBU Operator. At this point, our goal is to understand the context, intent and purpose of the Division's requests.

Sincerely,

Jon S. Schultz
Manager, Greater Prudhoe Area
ConocoPhillips Alaska, Inc.

RECEIVED

MAY 04 2016

DIVISION OF
OIL AND GAS



David Van Tuyl

Regional Manager

VIA HAND DELIVERY

May 2, 2016

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

RECEIVED

Re: Prudhoe Bay Unit IPA Plan of Development
Response to Division's Letter of April 11, 2016

MAY 05 2016

DIVISION OF
OIL AND GAS

Dear Director Feige:

We are responding to your April 11 letter (Division's Letter) seeking additional information about the 2016 Plan of Development (IPA POD). In a separate letter, BPXA, as operator, responded on behalf of all the PBU working interest owners (WIOs), to the non-marketing requirements in the Division's Letter. The following is BPXA's individual response to your demand for marketing information.

In our letter as operator, BPXA emphasized that PBU gas has been extensively used to maximize oil recovery. By expanded gas cycling and continued use of the gas for enhanced oil recovery, we have produced to date over three billion barrels of oil more than originally expected. Our 2016 POD continues to focus on using gas to enhance oil recovery.

Furthermore, in our capacity as a WIO in the PBU, we are taking appropriate actions to support a major gas sale. As an equity owner, we are participating in the Alaska LNG Project (Project) with the State and have taken, and continue to take, the necessary steps to allow the marketing of Alaska North Slope (ANS) gas at the appropriate time. BPXA believes that its previous submission of the IPA POD satisfies the PBUA's and Alaska regulations' requirements. The division's demand for marketing information is unprecedented, beyond the agency's authority, and otherwise unlawful for many reasons, including each of the following:

- 1) **The division's requirement that a WIO must provide marketing information constitutes impermissible rulemaking.** The division requires that each PBU WIO provide gas marketing information as part of the 2016 annual IPA POD review and similar information for each succeeding year's POD. We understand this new "POD requirement" also was included in January letters to operators of other State units on the North Slope and in Cook Inlet. But, marketing information has never been required from any other Alaska-regulated unit as part of the POD process. Such

information has never been required from any federal-regulated unit as part of the federal POD process (upon which the Alaska process is based). The requirement is beyond the division's authority because it is outside the scope of the regulations and constitutes impermissible rulemaking. Before attempting to issue this new "regulation" and assuming there is statutory authority for it, the division must comply with the Alaska Administrative Procedures Act's requirements of public notice and an opportunity to be heard as well as other applicable legal restrictions.

- 2) **Antitrust law precludes the division's requirement that a WIO must provide marketing information.** Sharing commercially sensitive marketing information among competitors or potential competitors raises significant antitrust concerns under both federal and state law. The DNR, on behalf of the SoA, competes with the WIOs in the marketing of in-state oil and, if there is a Project, the DNR may be competing with the WIOs in the marketing of in-state gas and the marketing of LNG. The SoA has already set up a statutory process to allow the DNR to take gas in-kind from WIOs and use that gas to compete with the WIOs. And as noted in our response in objection 6, that team has agreed that this information would be kept confidential from the regulatory part of the DNR, including the division. The SoA cannot avoid these antitrust issues by obtaining the same information through an improper use of the POD process.
- 3) **The division cannot require a WIO to provide marketing information because that information constitutes a trade secret under Alaska law.** The Alaska Uniform Trade Secrets Act (AUTSA) gives statutory protection to trade secrets. Oil and gas marketing information fits within the AUTSA's definition of a trade secret as information that
 - (a) derives independent economic value from not being generally known to other persons who can obtain economic value from its disclosure or use, and
 - (b) has been maintained secret.

In agreeing to the confidentiality agreements discussed in our objection 6, the SoA recognized that this type of information was commercially sensitive and not subject to public disclosure.

The SoA, and specifically the DNR, is a competitor of the WIOs in oil marketing and that it may be their competitor in gas and LNG marketing. Requiring a WIO to provide its marketing information to the DNR through the division violates the WIO's trade secret rights, would constitute an unlawful taking of property without compensation, and, as discussed in our objection 2, is precluded by federal and Alaska antitrust laws.

- 4) **The division cannot require marketing information because there is no duty to market gas beyond the local ANS market.** A lessee has no duty to market gas if no market for the gas exists at the well. No non-local market for gas exists on the ANS. So the WIOs have no duty to market gas other than in the local ANS market. And the law is clear that they have no duty to build any pipeline, much less an 800-

mile pipeline, to get the gas to a market. If some other party were willing to bear the risk and the multi-billion dollar cost to build an 800-mile pipeline, then the WIOs might have a duty to market outside the ANS. Today, attempts to build such a massive pipeline remain as speculative as when the Alaska federal district court found the attempt to do so by the Alaska Gasline Port Authority "speculative" and ruled that the alleged non-local market for ANS gas was not "an existing and relevant economic market." See *Alaska Gasline Port Authority v. ExxonMobil Corp.*, No. 4:05-cv-0026-RRB, Order Granting Defendants' Motion to Dismiss (D. Alaska June 19, 2006), at pp. 7-8 and note 21. Until the market exists, no such duty can possibly exist.

- 5) **The division's requirement that BPXA must provide marketing information violates DNR's obligations under the Gas Availability Agreement.** DNR contractually agreed in Section 3 of the Gas Availability Agreement to "negotiate in good faith for the purpose of BP entering into a bilateral agreement with the State or its designee on mutually agreed commercially reasonable terms ... regarding the availability of natural gas ... in the PBU ... in the event, if ever, that the BP ... Project Affiliate becomes a Non-continuing Party." DNR's current effort, through the division, to obtain confidential and proprietary marketing information from BPXA and other PBU WIOs as part of the 2016 annual IPA POD process is an attempt to gain information no other commercial actor would otherwise be able to obtain in a good faith commercial negotiation to buy and sell gas. Maintaining this effort is not only an abuse of the division's regulatory function but violates DNR's express contractual obligation to "negotiate in good faith" with BPXA, violates the obligation of good faith and fair dealing implied in all Alaska contracts, and constitutes an unlawful attempt to impair BPXA's contractual rights in violation of the U.S. and Alaska Constitutions.
- 6) **The division cannot require a WIO to provide marketing information because to do so would violate the Project Confidentiality Agreement (ACA) and BP-State confidentiality agreements.** BPXA has entered into two different confidentiality agreements that limit, but also protect, its ability to share marketing information. The first is the ACA. Its purpose was to allow the parties to share confidential commercial information relating to the Project. The ACA has seven parties including, for the SoA, representatives of the DNR and the DOR. Under the ACA, BPXA is contractually bound to keep information regarding those negotiations confidential. And the SoA, including the DNR, was also so bound.

Under the ACA, the parties have shared appropriate collective marketing information. If BPXA were to share that marketing information with the division, it would breach the ACA because it is required to keep negotiating information shared within those negotiations confidential. The negotiators of the ACA explicitly recognized that confidential commercial information should not be shared with division staff acting in their regulatory capacity. We understand that DNR and DOR have established appropriate firewalls in their organizations to maintain this type of information as confidential from DNR and DOR regulatory staff. Sharing this information further would cause substantial and irreparable harm to BPXA and other WIOs who signed the ACA.

The second agreement is the BPXA-State Confidentiality Agreement. Its stated purpose was to allow BPXA and its affiliates to share with specific SoA representatives "commercial discussions" and specifically "marketing for a North Slope natural gas project ... including ... terms of the sale of gas" under certain circumstances. Again, the SoA representatives able to see the confidential information were restricted to those acting in a proprietary capacity. The information provided by BPXA in those negotiations is among the most sensitive commercial information BPXA possesses. The governor has already made public information regarding the current status of those discussions and their outcome – a Gas Availability Agreement with BPXA. See <http://gov.alaska.gov/newsroom/2015/12/governor-walker-makes-public-signed-gas-availability-agreements/>. Any further disclosure would cause substantial harm to BPXA, and the SoA has already recognized the commercially sensitive and confidential nature of this information.

- 7) **Assuming that BPXA could, and was voluntarily willing to, provide marketing information to the division, the division must agree to hold the information confidential under AS 38.05.035(a)(8).** The division's statement in its April request letter suggests that it *may hold* the marketing information "as appropriate." But the letter also recognizes that that the division "will not share or discuss commercially sensitive responses to the demand for marketing information from individual WIOs with other WIOs and will hold information confidential as requested and as appropriate." As discussed earlier, other parts of the SoA have recognized the importance of keeping this information confidential and have signed confidentiality agreements requiring the appropriate SoA representatives to keep the information strictly confidential.

BPXA may be willing to share some information with the division assuming that certain conditions can be met to ensure the disclosure would be lawful. But it would only be willing to do so with the understanding that the division would keep the information confidential under AS 38.05.035(a)(8). The information is among the most commercially sensitive information that BPXA possesses. If the division failed to keep the information confidential, BP would suffer serious adverse consequences because the information:

- contains trade secrets and commercially sensitive information,
- represents work in progress, and
- relies on assumptions that might not be fully described in the summary documents.

So before BPXA would ever consider providing marketing information, the division would have to agree in advance to hold the marketing information confidential and not to use it for any anti-competitive purpose.

May 2, 2016

Page 5

BPXA respectfully requests that the division withdraw its demands for marketing information and find the March 31, 2016 submission of the IPA POD complete.

Sincerely,



Dave Van Tuyl

cc: S. Gould, BPXA



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
Anchorage, Alaska 99519-6612
(907) 561-5111

VIA HAND DELIVERY

May 2, 2016

RECEIVED

MAY 02 2016

DIVISION OF
OIL AND GAS

Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

Re: 2016 Prudhoe Bay Unit IPA Plan of Development
Response to Division's Letter of April 11, 2016

Dear Director Feige:

We are responding to your April 11 letter ("Division's Letter") seeking additional information for Division of Oil and Gas ("Division") review of the 2016 Plan of Development ("IPA POD"), and expanding the scope of a new "POD requirement" first asserted in the January 14, 2016 letter to operators of State units ("January Letter"). We submitted the IPA POD on March 31, 2016, as Prudhoe Bay Unit operator ("PBU Operator") and on behalf of the working interest owners ("WIOs").

PBU Operator's submission of the IPA POD satisfies all requirements of the Prudhoe Bay Unit Agreement ("PBUA") and POD regulations. Yet the Division's Letter seeks extraordinary additional information concerning "the timing and type of activities that will be conducted to prepare for MGS [Major Gas Sales]." These new requirements asserted by the Division are contrary to the terms of the PBUA as well as the Division's regulations and the Division's own interpretation of its regulations over many decades.

A. The IPA POD Complies with the PBUA and Alaska POD Regulations

The requirements for a plan of development ("POD") are contained in Section 4.2 of the PBUA and 11 AAC 83.343(a). PBUA Section 4.2 states that a POD is to comprise "engineering and production practices . . . on a Reservoir basis (or portion thereof), designed to efficiently and economically produce Unitized Substances."

11 AAC 83.343(a) states that a POD submission contain, among other information, development activities for the unit, including plans to delineate underlying oil or gas reservoirs, bring the reservoirs into production, and maintain and enhance production once established, "**to the extent**

that available information exists” [Emphasis added]. 11 AAC 83.303 includes considerations that the Division will weigh in approving a POD, but does not expand the scope of the information required to be provided in a POD.

Consistent with the contractual requirements of the PBUA and the POD regulations, the IPA POD contains plans for the development and operation of the IPA for the one-year POD period as well as a discussion of projects under evaluation by the IPA WIOs. The discussion of long-term projects was based on information available to PBU Operator about those projects. Additionally, in conjunction with the submission, the PBU Operator met with Division staff and during that meeting overviewed IPA field activities and development during the previous year and planned IPA activities and development for the coming year.

This is similar to past practice, including most recently in 2015, when the PBU Operator held an annual field review with Division staff on March 24, 2015, which covered (among other matters) the technical information and plans in the 2015 IPA POD. The Division notified PBU Operator on April 10, 2015 that the 2015 IPA POD was complete, and that POD was approved by the Division on May 13, 2015. The Division has followed a similar practice for all previous POD submissions.

B. The Division Has Access to Information Relevant to the Information the Division Seeks from PBU Operator

The Division’s Letter seeks information relating to in-fill drilling plans and strategies required to initiate gas offtake for MGS, plans, strategies and timing related to CO₂ management during MGS, and technical strategies, timing and activities required to achieve a gas balancing agreement.

The Division already possesses much information related to those matters. Division staff attended the September 2015 Alaska Oil & Gas Conservation Commission (“AOGCC”) hearing on BPXA’s application for amendment of Prudhoe Oil Pool Rule 9, including the confidential portion of the hearing.

Filings and testimony during the public part of the hearing addressed potential PBU development activities, including potential drilling and workover activity that would support MGS with January 2025 startup date. That testimony also addressed projected PBU development activities that are currently assumed to occur during MGS, including normal annual turnaround maintenance events, perforations to add gas production, and conversion of the apex gas injectors to gas producers late in project life.

The AOGCC testimony described the initial Alaska LNG Project plan to return CO₂ byproduct to the PBU, as well as the initial plan for the WIOs to handle injection. Testimony also addressed the potential location for CO₂ byproduct injection, which is currently projected to occur through existing injection wells, wells converted to injection, or newly drilled and permitted injection wells. But, this CO₂ injection would not start at the time of MGS, and construction of CO₂ facilities would not start until 2-3 years before MGS start up, well beyond the time frame of the 2016 POD.

The Division also has access to public information in FERC Docket No. PF14-21-000, Alaska LNG Draft Resource Report No. 1 Section 1.3.3.2, describing potential PBU modifications and new facilities that might be necessary for the Alaska LNG Project.

Regarding the Division's interest in commercial matters, including gas balancing, related to MGS, it is public knowledge that the State of Alaska is engaged in negotiations with the Alaska LNG Project participants regarding numerous commercial agreements. DNR leadership have provided non-confidential briefings on these commercial negotiations, including to the Legislature, which is available to the Division.

More generally, the Division currently has information regarding activities related to eventual commencement of a MGS, including agreements the Governor of Alaska has determined are essential to MGS. See <http://gov.alaska.gov/newsroom/2015/12/governor-walker-makes-public-signed-gas-availability-agreements/>.

C. The PBU Operator Does Not Possess Long-Range Information the Division Wants

The Division's Letter seeks MGS-related information regarding infill drilling plans and timing required to initiate gas offtake, plans and timing related to CO₂ management, strategies, timing and activities related to gas balancing, and changes in IPA operations. PBU Operator's discussion of long-range IPA plans and activities in the IPA POD reflects information available to PBU Operator regarding those activities.

PBU gas has been extensively developed to increase oil recovery. By expanded gas cycling and continued use of the gas for enhanced oil recovery and extraction of NGLs, we have produced to date three billion barrels of oil more than originally estimated. The 2016 IPA POD continues to appropriately focus on using gas to enhance oil recovery.

Nevertheless, as the Division knows, the State of Alaska together with affiliates of the three largest PBU WIOs are collectively pursuing the Alaska LNG Project (currently in pre-FEED) with a potential startup targeted in the 2025 timeframe. PBU Operator and the WIOs are cooperating with the Alaska LNG Project participants to provide needed technical information regarding PBU operations and facilities (such as PBU gas composition, anticipated gas delivery pressures, potential gas delivery points, and so forth). Beyond that, the PBU WIOs continue to evaluate viable plans to optimize gas and oil recovery and to address facilities, equipment, wells and operational changes to position for major gas sales. Those activities are still in the evaluation stage, recognizing that the Alaska LNG Project would not be ready to receive gas from the PBU IPA for at least eight or nine years. The information that the Division's Letter seeks does not exist at this stage, and to require it violates 11 AAC 83.343(a).

D. Technical Workshop on Potential Plans and Activities for MGS

As set out in this response, and as indicated in our IPA POD submission, the PBU WIOs are evaluating plans and activity that would be necessary to support MGS. Those plans are still being developed and are not required in connection with the submission of the IPA POD. Consistent with past practice, if it would be helpful to the Division, following approval of the 2016 IPA POD, PBU Operator would be available to conduct one or more informal and

confidential technical meetings with Division staff during the next IPA POD period to discuss the Division's interest in understanding IPA plans and activities supportive of MGS.

E. The Division's Newly Asserted Requirements Are Inconsistent with the PBUA, 11 AAC 83.343, and 40 years of Well Established Division Precedent for Approval of PODs

A requirement for submission of long-range MGS related information set forth in the Division's Letter, including strategies, timing and activities related to marketing and commercial arrangements, is outside the scope of the POD terms of the PBUA and the POD regulations at 11 AAC 83.343. (See Section A.) These newly asserted requirements are also inconsistent with well-established precedent and DNR's course of conduct in approving past PODs. Over the 40 years that the Division has received and approved PODs (and reviewed annual updates to PODs), it has never required submission of such long-range hypothetical plans that extend well beyond the one-year term of the POD or information regarding marketing or commercial arrangements.

The IPA POD content is consistent with past IPA PODs submitted to and approved by the Division, including in 2015. The Division has never required the type of information now being sought. Nor has it ever attempted to interpret applicable statutes and regulations to require submission of such information as part of the POD process. The IPA POD submission, together with the information provided by PBU Operator at the overview, and the information provided at our meeting with Division staff, demonstrate that the WIOs' plans to develop the IPA fully comply with both the terms of PBUA Section 4.2 and the POD regulations, including the Division's long standing interpretation of POD information requirements.

F. The Division's Requirement For Long-Range Plans and Activities Relating to Preparations for MGS Constitutes Impermissible Rulemaking

The Division's asserted requirement of long-range information related to preparation for MGS in this year's IPA POD and all future PODs is contrary to the PBUA and the Division's regulations. The Division's Letter expands the scope of a new "POD requirement moving forward, commencing in 2016", first asserted in the January Letter, to provide information regarding "how all hydrocarbons available for offtake are being utilized on the unit, are being sold within the state, or are being prepared and/or marketed for potential future sale."

PBU Operator understands this new "POD requirement" also was included in January Letters to operators of State units on the North Slope and in Cook Inlet. The requirement is outside the scope of current regulations and constitutes impermissible rulemaking. Before issuing a new "regulation," the Division must comply with the Alaska Administrative Procedures Act's requirements of public notice, supporting material, an opportunity to be heard thus allowing all WIOs in all state units to comment on the new regulation, and prospective effect. As applied to the IPA, such a "regulation" may not contravene the PBUA. Even if properly promulgated as a regulation, the new "POD requirement" asserted in the January Letter, and expanded in the Division's Letter, would contravene the PBUA.

Nevertheless, PBU Operator voluntarily provided to the Division, in our March 31, 2016, letter information related to PBU operations, including third party access and use of PBU facilities

such as the PBU road system. That information was provided voluntarily because the Division lacks authority to require submission of that data in connection with a POD.

G. PBU Operator Does Not Have WIO Marketing Information

The Division's Letter states that the PBU Operator "indicated that the WIOs prefer that the marketing of gas from the unit be performed by the WIOs individually." This statement by the Division is a mischaracterization of PBU Operator's statement in our March 31, 2016, letter to the Division. What we stated in the letter was that "marketing of unit production is subject to U.S. antitrust laws and is performed by the WIOs individually." We further stated that PBU Operator does not possess unit marketing information because we do not market on behalf of the unit.

Instead, the Division's Letter now indicates that PBU Operator "direct each WIO to provide its own separate response" to the requested marketing information, and states that the Division would incorporate the separate responses into the IPA POD but not disclose those POD portions to any other WIO, including PBU Operator. However, PBU Operator neither possesses the right, nor the ability, to direct the PBU WIOs to market gas, and certainly cannot "direct" them to provide gas marketing information to the Division. Moreover, the fact PBU Operator does not, and cannot, possess each individual WIO's marketing information demonstrates the inappropriateness of the Division's newly asserted "requirement" to include such information in the IPA POD. Finally, an operator cannot be expected to plan and execute field development pursuant to a POD, when portions of the POD must be kept secret from that operator. Nevertheless, we have sent the Division's Letter to the other WIOs.

We have not attempted to be exhaustive in this response, rather highlighting a number of our objections to the January Letter and the Division's Letter. In light of these considerations, we respectfully request that the Division find our March 31, 2016, submission of the IPA POD complete and approve the IPA POD.

Sincerely,



Scott Digert
Manager of Reservoir Management
Alaska Reservoir Development
BP Exploration (Alaska) Inc.

cc: w/attachments: H. Jamieson, ExxonMobil Alaska Production Inc.
E. Reinbold, CPAI
P. Ayer, Chevron U.S.A. Inc.
D. Roby, AOGCC
S. Gould, BPXA



BP Exploration (Alaska) Inc.
900 East Benson Boulevard
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(907) 561-5111

May 2, 2016

Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

Re: Prudhoe Bay Unit IPA Plan of Development
Correction to Page 18 - 2016 Production Forecast

Dear Director Feige:

We have discovered an error in the 2016 production forecast numbers at the top of page 18 of the IPA POD submitted to the division on March 31, 2016. The sentence containing the production forecasts should have read (corrections noted in backline text):

The average annual IPA crude and condensate production rate for 2016 is expected to be between ~~137-176~~ 157-196 MB/D. The total NGL production for 2016 is expected to be between ~~29-37~~ 36-45 MB/D.

We respectfully request that the division make this correction in the POD. With this correction the information in the POD is consistent with the information shown in the slides used at our Annual Field Review on March 24th.

Please direct any questions to Derek Nottingham at 564-4012 or through email at Derek.Nottingham@bp.com.

Sincerely,

Scott Digert
Manager of Reservoir Management
Alaska Reservoir Development
BP Exploration (Alaska) Inc.

cc: w/attachment: H. Jamieson, ExxonMobil Alaska Production Inc.
E. Reinbold, CPAI
P. Ayer, Chevron U.S.A. Inc.
D. Roby, AOGCC
S. Gould, BPXA

RECEIVED

MAY 02 2016
DIVISION OF
OIL AND GAS



THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Natural Resources

Division of Oil & Gas

550 W. 7th Avenue, Suite 1100
Anchorage, Alaska 99501-3560
Main: 907.269.8800
Fax: 907.269.8939

April 11, 2016

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Scott Digert, Manager of Reservoir Management
BP Exploration (Alaska) Inc.
P.O. Box 196612
Anchorage, AK 99519-6612

RE: Prudhoe Bay Unit – Initial Participating Area Plan of Development

Dear Mr. Digert:

By letter dated January 14, 2016, the State of Alaska Department of Natural Resources (DNR) Commissioner requested additional information to be submitted and included as part of the Prudhoe Bay Unit (PBU) Initial Participating Areas (IPA) proposed 2016 Plan of Development (2016 POD). On March 24, 2016 the DNR, Division of Oil and Gas (Division) met with BPXA for a technical review of the 2016 POD, and on March 31, 2016, the Division timely received the Prudhoe Bay Unit (PBU) Initial Participating Areas (IPA) proposed 2016 Plan of Development (POD). The POD was submitted by BP Exploration (Alaska) Inc. (BPXA) as operator for the PBU on behalf of all the working interest owners (WIO).

On July 17, 2015, BPXA and ExxonMobil Alaska Production Inc. (ExxonMobil) as WIOs in the PBU applied to the Alaska Oil and Gas Conservation Commission (AOGCC) to amend Conservation Order (CO) 341E to increase the allowable gas offtake in Rule 9 from an average of 2.7 billion standard cubic feet per day (BSCF/D) to 4.1 BSCF/D. Subsequently, ConocoPhillips Alaska, Inc. (CPAI) and Chevron U.S.A, Inc., also as PBU WIOs, supported BPXA's application to the AOGCC to increase the allowable gas offtake limit, but requested the limit to be set at 3.6 BSCF/D. The AOGCC's decision amending CO 341E determined an average offtake rate of 3.6 BSCF/D provides adequate capacity to meet gas sale requirements and identified carbon dioxide as a potentially valuable source resource for enhanced recovery projects on the North Slope. The decision also concluded that "monitoring of development operations within the Prudhoe Oil Pool prior to commencement of major gas sales is vital to ensure that liquids recovery is maximized." As the agency charged with reviewing and approving the development plans for short-term and long-term development activities, the Division has a responsibility to thoroughly evaluate development plans and assess potential impacts to ultimate recovery and state revenues.

The Division has reviewed the proposed 2016 IPA POD and requests additional information to determine whether the plan is consistent with the provisions of 11 AAC 83.303 and 11 AAC 83.343(c).

The Division appreciates the information that the Unit Operator provided, particularly as relates to oil development and facility access and sharing as requested in the January 14, 2016 letter. However, the Division requests more detailed information on activities that will result in and are related to the eventual commencement of a Major Gas Sale (MGS) from PBU during the upcoming 2016 POD period, and long term, as referenced in 11 AAC 83.343(a)(1) and (3), in order to more fully understand BPXA's plans regarding the development of natural gas. Although the Division understands that PBU IPA currently produces oil, the Division does not fully understand the timing and type of activities that will be conducted to prepare for an MGS. Until the additional information requested below is received and reviewed, the Division cannot deem the 2016 PBU IPA POD complete. Please submit the additional information to the Division no later than May 1, 2016, so that the plan can be fully reviewed by the Division consistent with 11 AAC 83.303 and 11 AAC 83.343(c).

Section 3.6 of the 2016 POD provides:

3.6 Major Gas Sales

Major gas sales (MGS) from Prudhoe Bay remains dependent upon a number of factors, including market demand and the availability of an acceptable offtake project. In the meantime, the PBU working interest owners will continue to use gas to enhance and accelerate oil recovery and for NGL production for shipment through TAPS or use in enhanced oil recovery operations.

The PBU working interest owners will continue to evaluate viable plans and incorporate [sic] into the current plan of development to further optimize gas and oil recovery, and to address facilities, equipment, wells, and operational changes to position for major gas sales.

This section is not sufficient to allow the Division to understand how the WIOs plan to achieve an MGS or to develop the PBU IPA in order to accomplish an MGS. The Division seeks to fully understand the statements in Section 3.6. Additionally, the Division needs to understand the timing and sequence of activities, especially which activities will occur during the 2016 POD and which will occur as part of a long range proposed development plan. As such, the Division requests BPXA submit additional information on the following:

- 1) In-fill drilling plans and timing that would be required to initiate gas offtake for an MGS.
 - a) Explain how current in-fill and ST (side track) drilling helps prepare for an MGS;

- b) How many wells do the co-owners envision being needed to supply gas for an MGS?
 - c) When will these wells be drilled?
 - d) Where will these wells be located?
 - e) Will the amount of well work needed to keep the current well stock 'healthy' be continued once an MGS starts?
 - f) What additional well work will be required on existing wells to prepare for an MGS if any?
 - g) Do you anticipate shutting in production wells when a gas sale starts, if so, in what area of the field?
- 2) Plans, strategies, and timing related to CO2 management.
- a) Since CO2 is a component of the gas in the IPA what is the plan for CO2, use it or dispose of it?
 - b) Will CO2 be shipped offsite?
 - c) Will CO2 be kept in the IPA? If so, how will it be stored? Where will it be stored?
 - d) Will CO2 be used for enhanced oil recovery? If so how and when?
 - e) When do the co-owners foresee having to handle CO2?
- 3) Technical strategies, timing, and activities required to achieve a gas balancing agreement.
- a) What activities are currently planned for discussion of a gas balancing agreement? If no plans, when might these activities and discussions be commenced?
 - b) What are the technical hurdles?
 - c) What is the ideal timeframe for reaching a gas balancing agreement?
- 4) The extent to which an MGS will require changes in existing operations, such as gas processing or treatment.

The Division also requests scheduling of a technical review on these subjects prior to May 15, 2016.

In its letter dated January 14, 2016 and by follow-up email on March 14, 2016, the Division requested that specific information be included in the 2016 IPA POD. With respect to an MGS, the Department generally requested “[a] discussion of the efforts to market oil and gas from the unit” and then asked for specifics with respect to: the marketing efforts being undertaken (Request (a)(1)); a delineation between local marketing and MGS (Request (a) 2)); the extent to which an MGS will require changes in existing operations such as gas processing or treatment (Request (a)(3)); and a detailed discussion of any changes believed to be necessary to permit the marketing of gas, including different commodity prices, etc., (Request (a) 5)).

In its response, BPXA indicated that the WIOs prefer the marketing of gas from the unit be performed by the working interest owners individually. Rather than submitting a plan for joint marketing of gas from the Unit, the Unit Operator may direct each WIO to provide its own separate responses to those issues. The Division requests that responses be provided directly to

the Division no later than May 1, 2016. Those responses will be considered part of the PBU IPA POD, but the Division will not share or discuss commercially sensitive responses from individual WIOs with other WIOs and will hold information confidential as requested and as appropriate.

The Commissioner may suggest modifications to proposed plans of development. *See* 11 AAC 83.343(c). The Division provides the following suggestions as to what it believes a complete POD with respect to MGS from the PBU IPA should address:

- 1) whatever the source, be it the WIO individually or the Unit Operator, a detailed discussion of the efforts to market gas from the Unit during the preceding year, and a detailed plan for marketing efforts the WIO or Unit Operator will undertake under the proposed POD.

These discussions should include the identity of the parties with whom the current commercial agreement(s) are being negotiated, or with whom each WIO intends to have substantive discussions regarding the marketing of unit hydrocarbons including unit gas, and the commercial terms under which each WIO is offering to make resources available for long-term sale, including: the estimated volumes to be delivered, the pricing terms, the location at which title to the gas and associated risks of loss will change, and the condition of the gas at the time of delivery;

- 2) the proposed terms by which the following will be treated when there is an MGS:
 - a) gas balancing;
 - b) byproduct handling;
 - c) field cost allowance;

If the WIOs have not agreed upon such terms for the unit, the Unit Operator should discuss any progress made to develop such terms, identify remaining issues that prevent agreement on such terms, and plans to finalize such terms during the 2016 POD period;

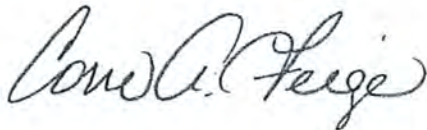
- 3) A detailed discussion of any change in circumstances each WIO believes is necessary to permit the marketing of gas. If the change(s) in circumstances involve a different commodity price, then WIOs shall detail the scenarios (including sufficient details as to important variables) under which WIOs anticipate that gas can technically and economically be produced and marketed; and
- 4) A detailed discussion of the extent to which an MGS will require changes in existing operations and/or additional operations such as gas processing or treatment. In BPXA's March 31, 2016 letter, BPXA indicates that the Unit Operator and the WIOs are currently reviewing plans and activities necessary to support MGS from the unit, but provides no details about such plans or activities.

As indicated, the proposed PBU IPA POD needs to address specific items with respect to MGS that it currently does not address. Absent this further detail, the Division cannot evaluate whether the POD meets the regulatory criteria.

The Division is available to meet to discuss these matters and the most efficient process for BPXA to submit the additional information requested.

If you have questions regarding this decision, please do not hesitate to contact Kyle Smith at (907) 269-8807, or via email at kyle.smith@alaska.gov.

Sincerely,

A handwritten signature in black ink, appearing to read "Corri A. Feige". The signature is written in a cursive style with a large initial "C".

Corri A. Feige
Director

cc: DOL
Temple Davidson, DNR
Kyle Smith, DNR

bp

March 31, 2016

Hand Delivered

Marty Rutherford, Acting Commissioner
Department of Natural Resources
550 W 7th Ave., Suite 1400
Anchorage, AK 99501

BP Exploration (Alaska) Inc.
900 East Benson Boulevard
P.O. Box 196612
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DEPARTMENT OF
NATURAL RESOURCES

MAR 31 2016

COMMISSIONER'S OFFICE
ANCHORAGE

Reference: Prudhoe Bay Unit Plans of Development
DNR Request for Additional Information


Dear Acting Commissioner Rutherford,

In response to letter of January 14, 2016, BP Exploration (Alaska) Inc., as the Operator of the Prudhoe Bay Unit, provides Attachments 1 and 2, in response to the request for additional information in connection with the annual Unit Plans of Development for the IPA.

The information in the Attachments is commercially sensitive and confidential Prudhoe Bay Unit information, and we request that the Alaska Department of Natural Resources keep this data confidential as provided in the Prudhoe Bay Unit Agreement and AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law.

Any questions can be directed to the undersigned or to Caroline Bajsarowicz at 564-4314, bajsarcj@bp.com

Sincerely,


Scott Digert
Reservoir Management Manager
Alaska Reservoir Development, BPXA
564-4480

Cc: H. Jamieson, ExxonMobil Alaska, Production Inc.
E. Reinbold, CPAI
J. Schultz, CPAI
P. Ayer, Chevron USA
C. Wyatt, BPXA
C. Bajsarowicz, BPXA
D. Richmond, BPXA



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March 31, 2016

Hand Delivered

Ms. Corri Feige, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

RECEIVED

MAR 31 2015

**DIVISION OF
OIL AND GAS**

Re: PLAN OF DEVELOPMENT AND
ANNUAL PROGRESS REPORT
INITIAL PARTICIPATING AREAS, PBU

Dear Ms. Feige:

BP Exploration (Alaska) Inc., as the operator of the Prudhoe Bay Unit and on behalf of the working interest owners, submits the accompanying 2016 Plan of Development and Annual Progress Report for the Initial Participating Areas. This Plan of Development ("POD") provides a review of the 2015 activities as well as descriptions of future development activities under consideration consistent with previous PODs.

Questions can be directed to Derek Nottingham at 564-4012 or through email at Derek.Nottingham@bp.com.

Sincerely,

Scott Digert
Manager of Reservoir Management
Alaska Reservoir Development
BP Exploration (Alaska) Inc.

cc: w/attachment: H. Jamieson, Exxon Mobil Alaska, Production Inc.
E. Reinbold, CPAI
P. Ayer, Chevron U.S.A. Inc.
D. Roby, AOGCC
S. Gould, BPXA

**PRUDHOE BAY UNIT
INITIAL PARTICIPATING AREAS
ANNUAL PROGRESS REPORT AND
PLAN OF DEVELOPMENT**

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- FIGURE 1: 2015 IPA DEVELOPMENT DRILLING PROGRAM
- FIGURE 2: 2016 IPA DEVELOPMENT DRILLING CANDIDATES

1.0 INTRODUCTION

This Annual Progress Report and Plan of Development has been prepared as provided in the Findings and Decision of the Commissioner on the Application for Change of Unit Operator, dated June 27, 2000. This Plan updates and modifies the initial Plan of Development and Operation for the Oil Rim Participating Area and Gas Cap Participating Area (Initial Participating Areas or IPA) within the Prudhoe Bay Unit (PBU), incorporated into both the Prudhoe Bay Unit Operating Agreement and the Prudhoe Bay Unit Agreement as Exhibit "E".

This Plan of Development summarizes production activities from January 1, 2015, to December 31, 2015, and outlines plans for development of the Prudhoe Bay (Permo-Triassic) Reservoir in the Initial Participating Areas for 2016. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the reservoir. Changes in business conditions and/or new insights into the reservoir could alter the timing and/or scope of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 CRUDE AND CONDENSATE

Crude and condensate rates averaged 196.4 MB/D in 2015. This rate, combined with production from the PBU Satellite fields (which are addressed in separate annual reports and plans of development), fully utilized available PBU processing capacity within reservoir management

constraints. A total of 71.7 MMB were delivered to the Trans-Alaska Pipeline System (TAPS) during the year ending December 31, 2015.

2.2 PRODUCED GAS

IPA gas production totaled 2519 BSCF or 6902 MMSCFD for the reporting period, which continues to be governed by facility handling constraints. Field gas offtake (FGO) decreased by 29 MMSCF/D or 0.41% from the previous year. Re-injection of dry gas amounted to 2276 BSCF or 6237 MMSCFD, 90.4% of the produced gas stream. Gas production that was taken in kind and removed from the PBU included about 7.2 BSCF (0.3%) of natural gas, and about 13.9 MMB of Natural Gas Liquid (NGL), which equates to about 18 BSCF (0.7%) of natural gas. Fuel usage accounted for 138 BSCF (379 MMSCFD) or 5.5% of the produced gas. Flare volumes were limited to 10 BSCF (0.4%). Miscible Injectant production, which was reinjected in enhanced oil recovery operations, totaled 66 BSCF (2.6%), of which 38 BSCF (1.5%) was injected within the IPA. Minor gas sales totaled 7 BSCF (0.3%). Gas taken in kind and exported to the Northstar Unit was .075 BSCF (3%).

2.3 NATURAL GAS LIQUIDS

NGL production for the IPA averaged 38 MB/D for the reporting period, with 13.9 MBO delivered to TAPS and none exported to the Kuparuk River Unit (KRU). NGL exports to KRU ceased July, 2014.

2.4 MISCIBLE GAS

The Prudhoe Bay Miscible Gas Project (PBMGP) continued operation with injection of a total of 38 BSCF of Miscible Injectant (MI) during the report period. The CGF produced approximately 180 MMSCF/D during 2015, with about 76 MMSCF/D injected into areas outside the IPA (Aurora, Borealis, Orion, Polaris, and Pt. McIntyre).

2.5 PRODUCED WATER

Water production averaged 833 MB/D (w/o W-400) for the year ending December 31, 2015. This water rate yields a field wide average water cut of 81%.

2.6 INJECTED WATER

Waterflood (WF) and Water Alternating Gas (WAG) operations continued through the reporting period with an annual average of 710 MB/D of produced water injected. During 2015, 83 MB/D of produced water were exported for injection into satellite fields. This was offset by produced water imports of 53 MB/D. Produced water disposal volumes decreased from 106 MB/D to 102 MB/D. This represents a produced water injection efficiency of 85.6%. Additional FS-1 water was also disposed of at the Lisburne Production Center.

Additionally, approximately 162 MB/D annual average of seawater, from the Seawater Treatment Plant, was injected in the FS1 and FS2 flood areas. Seawater injected as part of the Gas Cap Water Injection project averaged 547 MB/D. In total, IPA seawater injection averaged over 709 MB/D for the year.

Supplemental Prince Creek water produced from W-400 in 2015 was 9.8 MB/D. The Prince Creek water augments water injection at the Eileen West End.

2.7 FIELD DEVELOPMENT

Development Drilling

Field development activities have continued in accordance with the 2015 Plan of Development. An active rig program continued with 60 wells drilled during the reporting period from January 1, 2015, to December 31,

2015. New penetrations were drilled primarily by sidetracking underperforming wells using both conventional rotary and coil tubing drilling rigs. A bottomhole location map of all wells drilled in 2015 is included as Figure 1. Displayed on the map are top to bottom perforated intervals for each new wellbore. As Prudhoe Bay has matured, drilling targets continue to become smaller and more complex with increasing drilling and reservoir risk.

Wellwork

In addition to an active development drilling program, wellwork activity remained at a high level in 2015 with 413 rate adding jobs done and about 1800 total jobs performed. Wellwork activity included capacity sustainment (addition of perforations, stimulations, gas and water shut-offs), well diagnostics, surveillance, and rig workovers.

Facility and Reservoir Optimization

Summarized below are significant activities over the past year:

- **Seawater System Upgrades** Continued work at the Seawater Treatment Plant (STP) has increased reliability and seawater supply for injection.

Sea Water Treatment Plant

In 2015 diamond back trim was installed on one of the filter feed backwash flow control valves. This has proven to be very effective in times of high total suspended solids (TSS). Another valve with diamond back trim has been ordered and is scheduled to be installed in 2016. Also in 2015 a new duplex filter feed pump and a new vacuum pump to maintain low dissolved oxygen concentrations were installed. Upgrades to heater fire eyes in all service heaters are scheduled to be complete by the end of 2016. Also the design package for an upgrade to the flow meter on heater #5 has been

completed. This will allow operations to run the heater in auto vs. manual mode. This work is anticipated to be completed in 4Q 2016. Seawater oxygen control at STP was good for January 2016, with 99.4% conformance below the 20 ppb oxygen specification. Oxygen removal from seawater is vital for corrosion control. Oxygen control has improved dramatically through the years.

Seawater Injection Plant

In 2015 an impeller pump bundle on turbine 15101 was replaced. The 18" knife gate valve on the PWI line and the 42" F86 main inlet valve were rebuilt. The gas generator on injection pump 15102 was replaced. Gas control valves were upgraded giving operations better control.

Integrity Management Activities

- **In-Line Inspection (ILI)** In-Line Inspections (ILI, or smart pigging) were performed on one produced oil pipeline, thirteen three-phase cross-country pipelines, eight produced water injection (PWI) pipelines, two seawater injection (SWI) pipelines, two artificial gas lift trunk lines and the field fuel gas trunk line totaling over 103 miles in length. The scope of work for follow-up has employed the use of data integration to target key areas for additional inspection and/or repair. Field results are being continuously monitored thereby allowing for continuous refinement and improvement of the in-line inspection program. Follow-up inspection and mitigation, as necessary, are complete on 99.7% of ILI anomalies that were due, to date, from ILI runs that were completed in 2011 through 2014. Follow-up inspection and mitigation, as necessary, are complete on 87% of ILI anomalies that were due to date from 2015 runs. To date, all In-line inspection reports from the 2015 campaign have been received from the ILI vendors.

- **Fire and Gas Activities** The Phase 2 of Inlet Duct Detector (IDD) work across the Prudhoe Bay Unit is complete. The GC2 H & N Well Fire & Gas Renewal projects were completed in 4Q 2015. The IDD projects provide gas detection in the air intake of modules which contain electrical equipment. The FS-2 Fire & Gas Renewal project completed field construction activities 1Q 2015. Commissioning of the new platform began 2Q 2015. Technical issues have delayed cutover; turnover of the new platform is scheduled to complete in early 3Q 2016. FS-1 Fire & Gas Renewal is at the end of detailed-stage engineering. The Nitrogen Piloted Release System (NPRS) scope construction and commissioning is complete. Uninterruptible Power Supply (UPS) scope construction and commissioning will complete at the end of February 2016. FS1 Facility scope planning has started, construction is scheduled to start mid-summer 2016. GC-1 Fire & Gas Renewal is reentering concept development (CD) with CD completion anticipated in 4Q 2016.
- **Safety Systems** GC-2 Safety System Renewal (SSR) was commissioned and turned over to the operations group in November, 2014. As-built and other closeout related activities were complete by year end 2015. FS1 SSR is performing detailed engineering and expecting the final Issued For Construction (IFC) to be issued in April, 2016. Construction is scheduled to begin in October, 2016 and commissioning to begin in May, 2017 with completion scheduled in late summer of 2017. Lessons learned from previous SSR projects have been captured in an updated SSR projects' group workflow. As of March, 2016, the FS-3 SSR project is in the Optimize stage and expects to be in Define by year end.

3.0 PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Fieldwide Reservoir Management

The Prudhoe Bay reservoir management strategy aims to maximize recovery through 1) optimization of base field production within facility constraints; 2) wellwork to enhance production and ultimate recovery; 3) pressure maintenance; 4) flood optimization; and 5) continued development drilling.

The working Prudhoe Bay Field simulation model continues to be refined, updated, and used for development planning as well as field optimization. Progress is continuing in the development of the next generation of the Prudhoe Bay full field simulation tools.

Gravity Drainage Area

Management of the Gravity Drainage (GD) area will largely be achieved through operation, maintenance, and repair of existing wells, and well sidetracks to enhance the efficiency of the oil vaporization by lean gas injection. Management of base liquid hydrocarbon resources and ongoing development of the GD area incorporates newly acquired surveillance and updated play type analyses. Ongoing development in the Gravity Drainage area continues to target opportunity driven site-selective sidetracks as well as development of the up structure area (north of DS 15 and DS 18). The sidetrack program is designed to improve production and ultimate recovery. Sidetrack targets are based upon the results of ongoing area performance evaluations and smaller scale geologic and reservoir studies coupled with existing well performance. The majority of GD development drilling will target Zone 1 with horizontal sidetracks. Zone 2 will also be targeted in areas where sufficient light oil column can

be identified. Ongoing drilling and wellwork in the GD area is increasingly challenged by continued gas cap expansion resulting in thinner oil columns, and water encroachment from gas cap water injection.

East Waterflood/EOR Area

East Waterflood/EOR Area reservoir management is focused on optimizing water and MI injection for flood management, identifying potential new penetrations, rig workovers, and pattern reconfigurations to improve water and MI flood efficiency. The reservoir management objectives for the East Waterflood/EOR Area generally include optimizing recovery by minimizing gas influx, optimizing flood conformance and replacing reservoir voidage within the flood area.

Evaluation has been ongoing to determine if a new reservoir management strategy in the DS11 and DS4 areas is required as a result of improved oil recovery due to the double displacement process (gas displacement after water displacement). In 2014, a review of DS11 water injection performance showed that in the period from late 2008 through the majority of 2011, while injection was shut-in at DS11 due to a flowline issue, a significant oil production increase was noted as a result of allowing gas movement into the area. The additional oil production is thought to be comprised of mainly vapor borne liquids production due to increased gas rates as well as additional in-situ oil recovery as a result of improved microscopic displacement efficiency (lower residual oil saturation). As a result of this review, three injectors at DS11 were shut-in (11-26 SI 1Q 2013; 11-07 and 11-10 SI 2Q 2014) and an increase in oil production was again observed starting in 3Q 2014. One more injector was shut-in in 2015 (11-02 2Q 2015). Additionally, a more aggressive perforation campaign to move up higher in the hydrocarbon column in wells in DS-03,

DS-04, DS-09, and DS-11 was enabled by the excess gas capacity at Flow Station 2. This program has proven to be successful in adding oil production with competitive gas oil ratios into the Flow Station 2 facility; therefore, there are plans to continue an uphole add-perf campaign in remaining candidate wellbores.

Several additional programs have been underway to determine how to best recover the remaining oil in the Flow Station 2 area. Two wells (09-47A coil tubing sidetrack and 09-50A rotary sidetrack) were drilled at DS-09 as part of a 5 spot pattern test. Those wells were brought on line in 2014 and are currently producing at very high water cuts, reflecting the challenge of drilling in a mature waterflood area. The 09-11 producer has been converted to injection and brought on line in 2015 to support the new 5 spot pattern. This 5 spot test will help determine the viability of an "at scale" conversion of the current pattern flood from inverted 9 spot patterns to 5 spot patterns in the Flow Station 2 area. Another program that has shown the most promise was started in 2015 and is dubbed "pattern rotation." This program is designed to increase recovery by drilling coil tubing sidetracks and rotary sidetracks to infill the space between corner producers and side producers in the inverted 9 spot patterns. In 2015, three wells were drilled and completed to test this concept (03-31A coil tubing sidetrack, 03-01A coil tubing sidetrack, and 09-03A rotary sidetrack) as part of a 2015 "East of Sag" drilling campaign. All three wells found bypassed oil and have been on production for nearly one year. These pattern rotation wells carry a high degree of risk associated with uncertainty in remaining fluid distribution in an active waterflood. As of February 2016, cumulative oil production from the three wells is nearly 600 MSTB and combined rate is 1700 BOPD. As a result of this success, seven additional "pattern rotation" wells are in the process of being executed at DS 09 and DS 16 as part of the winter 2016

"East of Sag" drilling program. This program is comprised of 5 coil sidetrack producers, 1 rotary sidetrack producer, and 1 coil sidetrack injector.

In 2015, an active Miscible Injection Stimulation Treatment (MIST) program continued in addition to WAG injection in the base Prudhoe Bay Miscible Gas Project (PBMGP). One additional MIST injector was drilled in 2015 (09-31D rotary sidetrack). This well, along with the 03-33C (drilled in 2014) has yet to be put on MI injection due to a variety of operational issues. Future plans are to continue to drill MIST injectors as necessary to fully develop the EOR target in the FS2 area.

In addition, the 11-39 well was drilled in 4Q 2014 targeting Zone 1A in the northern portion of Flow Station 2. This well has produced over 400 MSTB in the last year and continues to produce at 1000 BOPD with a gas oil ratio of 31,000 scf/stb. As a result of this success and a study of the Zone 1A potential in the DS11 area, two coil sidetrack producers (11-32A and 04-18A), one coil sidetrack injector (11-10A), and one new well (11-40) were drilled in the second half of 2015. Oil saturations look promising and currently the wells are awaiting tie-in work to be completed. Additional study is ongoing to understand the remaining potential in the DS04 area.

West Waterflood (WWF)/EOR Area

West Waterflood/EOR Area reservoir management objectives are to optimize production offtake and enhance recovery by replacing voidage and maintaining reservoir pressure to minimize downdip gas cap expansion.

There were seven Ivishak, and five Sag River wells drilled and completed from West Waterflood pads during 2015 for oil production targeting attic traps, fault shadows, and areas of poor conformance. These wells were infill targets in downdip patterns or in the GDWFI (Gravity Drainage Waterflood Interaction) area, with three including an additional lateral each to improve pattern offtake. These targets have not fully met expectations because water movements have proven difficult to track in downdip patterns. There were four West Waterflood rig workovers completed in 2015 to repair mechanical integrity.

As in prior years, pattern/conformance reviews will continue to focus on opportunities to improve recovery and injection conformance through routine wellwork and injection management. Repositioning of some injection wells is being considered to alter pattern streamlines.

Development drilling in the periphery and GDWFI areas will continue. Ongoing wellwork activity and system optimization practices, supported by surveillance logging, diagnostic integrity testing, and injection management should mitigate production decline.

Updip Zone 4

Pattern conversions associated with the Updip Zone 4 Injection (UZI) Project will continue. The UZI Project targets remaining oil where the gas cap has expanded into Zone 4, where shale barriers and baffles make the gravity drainage process less efficient. The area of UZI potential is generally identified as immediately up-structure of the existing WF/EOR area. The UZI Project achieves improved recovery of isolated oil lenses through pattern injection of water and/or MI.

N Pad UZI project began in 2014 with the drilling of two injectors (N-28 and N-29). Construction of N Pad injection headers, providing both water and MI and tie-ins for all N Pad injectors was completed in 2015. In conjunction with the N Pad UZI Project, three producer to injector conversions were initiated in 2015 with the last conversion scheduled to conclude 1Q 2016.

Continued development of UZI type patterns will be based on evaluation of performance from previous investments. Phased UZI development in the up-structure region may encompass a mix of injector conversions, sidetracks and new wells. In some UZI patterns, rig workovers may be necessary to bring key offset wells on production.

Sag River Development

Eleven Sag River wells were drilled and completed in 2015 in the IPA. The majority of the wells were concentrated in the NW Fault Block Area, with five wells drilled at F-Pad (F-39L1, F-36L1L2L3, F-19B, F-37A, -AL1, F-30A), four at R-Pad (R-22A, -AL1, R-08A, -08AL1, R-42, R-35A), and one at S-Pad (S-09A). Additionally, one well was completed in the East Waterflood area on DS-03 (03-15B). Ten of the eleven wells were drilled as sidetracks (five with rotary drilling and five with coiled tubing drilling), with R-42 being a rotary drilled grassroots well. Four wells were drilled as multi-laterals (F-36L1L2L3, F-37A, -AL1, R-22A, -AL1, R-08A, -08AL1). Eight of the wells are producers, and three (R-22A, -AL1, R-42, S-09A) are miscible injectant (MI)/waterflood injectors. All eight producer wells have been put on production and S-09A has been put on injection. Injectors R-22A, -AL1 and R-42 are not yet operational.

2015 R-Pad producers R-08A, -08AL1, and R-35A, and injectors R-22A, -AL1, and R-42 were drilled as part of Sag MI/WF patterns. 2015 F-Pad

producers F-39L1, F-37A, -AL1, and F-36L1L2L3 were positioned to take advantage of MI/WF sweep from R-Pad Sag injectors. S-09 is a long, horizontal injector that was drilled as dedicated support to the long, horizontal Sag producer, S-13A, which was drilled in 2014. F-19B and F-30A are expected to be supported by Sag gas cap drive. 03-15B, near the far southeastern extent of the Sag River accumulation was also expected to be supported by Sag gas cap drive.

Mixed results have been seen from the three long, dedicated Sag injector-producer pairs drilled during 2012-2014. Encouraging results continue to be seen in the DS-13 horizontal Sag River injector-producer pair, 13-15Ai and 13-12A, which was completed in 2013. These wells were online throughout 2015 and evidence of pressure support has been observed. This pressure support gives credence to the idea that flooding the Sag River in peripheral areas of Prudhoe Bay is possible.

The horizontal injector Y-10B was completed in January, 2014 and is paired with the Y-13A Sag River producer. Y-13A was completed in 2013 and was fracture stimulated. Y-13A commenced production in February, 2014 and Y-10Bi began miscible injection in April, 2014. Performance of this downdip, dedicated horizontal injector-producer pair has been at lower rates than anticipated.

A long Sag River horizontal producer well, S-13A, was completed at S-Pad in November, 2014. Its companion injector, S-09Ai, was completed in January, 2015. This dedicated horizontal injector-producer pair was drilled to test the viability of flooding highly-faulted areas of the Sag River. These wells each have reservoir horizontal sections of approximately 7500' (gross), and utilize cementless completions with blank pipe and swell packers for isolation of conductive faults and

fractures. Difficulty was encountered in running the cementless completions in both wells; the completions had to be pulled out and re-run with fewer packers than had initially been planned. S-13A began production in June, 2015, and S-09A began injecting MI in April, 2015. At this time, the pilot program testing dedicated, long, horizontal injector-producer pairs has not proven to be viable, as drilling costs have been high and rates have not met expectations.

Ongoing area and pattern performance reviews, optimization of miscible injectant usage, structural mapping utilizing improved seismic imaging, and utilization of improved completion designs have been key tools to identify and economically progress additional MI/Waterflood pattern infill and Sag gas cap supported drilling targets in the Sag River reservoir.

Eileen West End / Northwest Eileen

The primary objective for the Eileen West End/Northwest Eileen (EWE/NWE) areas is to optimize production under the surface constraints of gas lift supply and the total gas oil ratio (TGOR) of the EWE large diameter flow line (LDF). This objective is accomplished through actively managing producers and injectors, protecting the base set of wells through well work, and adding new wells through drilling.

The EWE/NWE producers are actively managed based on the marginal TGOR of the EWE LDF. Producers that are above the EWE LDF marginal on a TGOR basis are shut in to meet the velocity constraint of the EWE LDF. The field injection is managed by an efficient application of miscible injection (MI) for the water alternating gas (WAG) flood, and the EWE gas cap water injection (GCWI) program. Efforts toward effective management of the GCWI and pattern WAG flood will include maintaining pattern conformance and selecting strategic areas to inject MI. A voidage

replacement ratio (VRR) of 1 is targeted for patterns with injection support, to maintain reservoir pressure and sweep oil to producers. The chemical tracer program that began in 2010 was concluded in 2015. This tracer study helped identify conformance between injectors and producers throughout EWE, and monitor the effects of gas cap water injectors within the patterns.

Drilling at EWE/NWE during 2015 involved two new coil side track wells, L-01A and Z-15A. Additional drilling opportunities in the EWE/NWE area are being evaluated, however, are challenged in the current economic environment with the complex geology, and water and gas influx..

Gas Cap Water Injection (GCWI)

The GCWI project will continue as part of the current reservoir management strategy. In 2015, static pressure surveys were acquired field-wide, confirming a continuing trend of increasing reservoir pressure. Water movement continues to be monitored by neutron logging in offset wells. A similar static pressure and neutron log surveillance plan is anticipated in 2016. The GCWI project is generally performing as expected, although the seawater injection rate is below the initial plan. Seawater System Upgrades are being considered to address this as described in Section 3.5. The main objective of mitigating further reservoir pressure decline is being achieved.

3.2 PRODUCTION FORECAST

Reservoir management strategies are designed to optimize oil rate and recovery. Crude and condensate annual average rates (excluding NGL sales) decreased slightly to 196.4 MB/D in 2015, mitigated by an active drilling, RWO, and wellwork program. The average annual IPA crude and

condensate production rate for 2016 is expected to be between 137-176 MB/D. The total NGL production for 2016 is expected to be between 29-37 MB/D. The level of fuel and flare volumes are expected to remain relatively unchanged in the future with the first significant decrease anticipated to occur with the cessation of seawater injection and miscible injection operations.

3.3 DEVELOPMENT DRILLING AND WELLWORK

The 2016 IPA drilling activity will be significantly reduced compared to 2015 due to the sharp reduction in oil prices over the course of 2015 and into 2016. As noted in section 2.7, as Prudhoe Bay has matured, drilling targets continue to become smaller and more complex with increasing drilling and reservoir risk. Drilling time will be reduced from 3.8 rig years in 2015 (1.9 rig years for rotary drilling, 1.9 rig years for coil tubing drilling) to an estimated 1.6 rig years in 2016 (~0.7 rig years for rotary drilling, ~0.9 rig years for coil tubing drilling). The resulting well counts in 2016 are estimated at 8 rotary drilling wells (vs. 19 rotary drilling wells in 2015) and 24 CTD wells (vs. 41 CTD wells in 2015). Technical work to identify and evaluate drilling locations that are economically attractive in the current oil price environment is ongoing. Candidates identified to date are displayed on Figure 2.

Rig workover (RWO) activity is also expected to be significantly reduced when compared to 2015, with a RWO program of 4 wells (vs. 27 RWO's performed in 2015). The RWO activity has also been effected by the current oil price environment as well as a higher success rate of non-rig workover (NRWO) repairs, enabling more wells to be returned to service without a rig repair. RWO and NRWO activity will generally continue to be focused on returning to service injectors and producers that are shut-in because of wellbore integrity issues, and that cannot be repaired by non-rig methods.

3.4 MISCIBLE GAS ENHANCED OIL RECOVERY

Miscible gas injection operations will continue as planned in the IPA during 2016 with MI delivered to MI-capable drill sites within operational constraints. The available MI will be allocated based on the MI efficiency (barrels of oil per unit of MI) to projects within the IPA, including: 1) PBMGP patterns, 2) MIST patterns, 3) EWE patterns, and to the other fields in the Prudhoe Bay Unit area.

During 2016, there are plans to expand MI injection into two new MIST wells which have not yet received MI. Injection into one UZI pattern on N-Pad is also planned in 2016. Pilot test of foam/MI injection is on hold due to technical and economic challenges.

3.5 PROJECTS

Facility and Reservoir Optimization

- **Seawater System Upgrades** The long-term plan for the STP continues to be evaluated as part of the IPA strategy to maximize field recovery. Seawater is used at the GCWI project for pressure support. Seawater is also injected into parts of the down-dip IPA, supporting production through waterflood and EOR operations. Plant efficiency and reliability are recognized as important levers in delivering seawater to the field, and operations continue to focus on proactive optimization, defect elimination, and maintenance enhancements in the STP system.
- **STV-IP Compressor Replacement FS-1, FS-2, and FS-3** The Stock Tank Vapor & Intermediate Pressure turbine-driven gas compressors at all three Flow Stations (FS) are scheduled to be replaced with more reliable and efficient electric motor driven compressors

designed for current and projected gas rates and molecular weights. The project was fully sanctioned in 2012, and the compressor replacement at FS-1 was completed during 2014. The construction contract was re-bid during 2015. The compressor installation at FS-3 is scheduled for 2016 and is scheduled to be started up in 4Q 2016. The compressor installation at FS-2 is scheduled to occur in 2017.

- **Eileen West End / Northwest Eileen** Facility projects will continue to be evaluated for the EWE/NWE area. Investments continue in the GC-2 facility to maintain system integrity and operability.
- **Bright Water**[®] Bright Water[®] is a sweep modification treatment that uses temperature-triggered expanding polymer particles added to the injected water to divert injection away from higher permeability thief zones toward less flooded layers. A total of 93 IPA injector treatments (7 of which have been retreatments in previously treated injectors) have been performed to date. Analysis of the treatments performed to date continues to show incremental oil production associated with reduced water cut in offset producers. Two jobs were performed in 1Q 2015 as carryover work from 2014. No jobs are scheduled for 2016, but further evaluation is ongoing.

Integrity Management Activities

- **Pipeline Replacement Program (PRP) Studies and Project Execution**

ⁱ Bright Water[®] is a registered trademark of Nalco

PRP projects make flowlines in-line inspectable, and/or maintenance piggable, and/or replace pipelines.

Completed projects in 2015 include the following:

- NGI Pipeline Restoration-DS16/17 Pipeline Replacement

Ongoing projects for 2016 and beyond include the following:

- DS04 Production Sustainment – On track for completion end of year 2016
- DS14 Pipeline Replacement – Planned for 2017 completion
- LS04/05 Make Piggable – Planning for 2017
- J-74 Production Sustainment– Planning for 2018

3.6 Major Gas Sales

Major gas sales (MGS) from Prudhoe Bay remains dependent upon a number of factors, including market demand and the availability of an acceptable offtake project. In the meantime, the PBU working interest owners will continue to use gas to enhance and accelerate oil recovery and for NGL production for shipment through TAPS or use in enhanced oil recovery operations.

The PBU working interest owners will continue to evaluate viable plans and incorporate into the current plan of development to further optimize gas and oil recovery, and to address facilities, equipment, wells, and operational changes to position for major gas sales.



Prudhoe Bay Unit IPA 2015 Drilling Activity Map

2015 Drilling Program							
New Well	Coil					Rotary	
8	41					11	
02-41	03-01A	17-04C	F-30A	H-26A	R-39AL1	03-15B	S-09A
07-38	03-31A	18-07C	F-36L1-L3	J-10B	U-06BL1	07-07C	Y-32A
11-40	04-18A	C-08C	F-39L1	K-06D	X-10A	07-34B	
18-35	07-33C	D-18B	F-45C	K-10D	Y-21B & L1	09-03A	
D-35	11-10A	D-24A	G-02C	K-12C	Z-15A	09-31D	
H-40	11-30A	E-15E	G-07A	P-10A		F-19B	
P-30	14-11B	F-15B	G-10D	P-11L1		F-37A & L1	
R-42	15-07D	F-23B	G-16B	R-22A		L-01A	
	15-49C	F-24A	G-27B	R-35A		R-08A & L1	

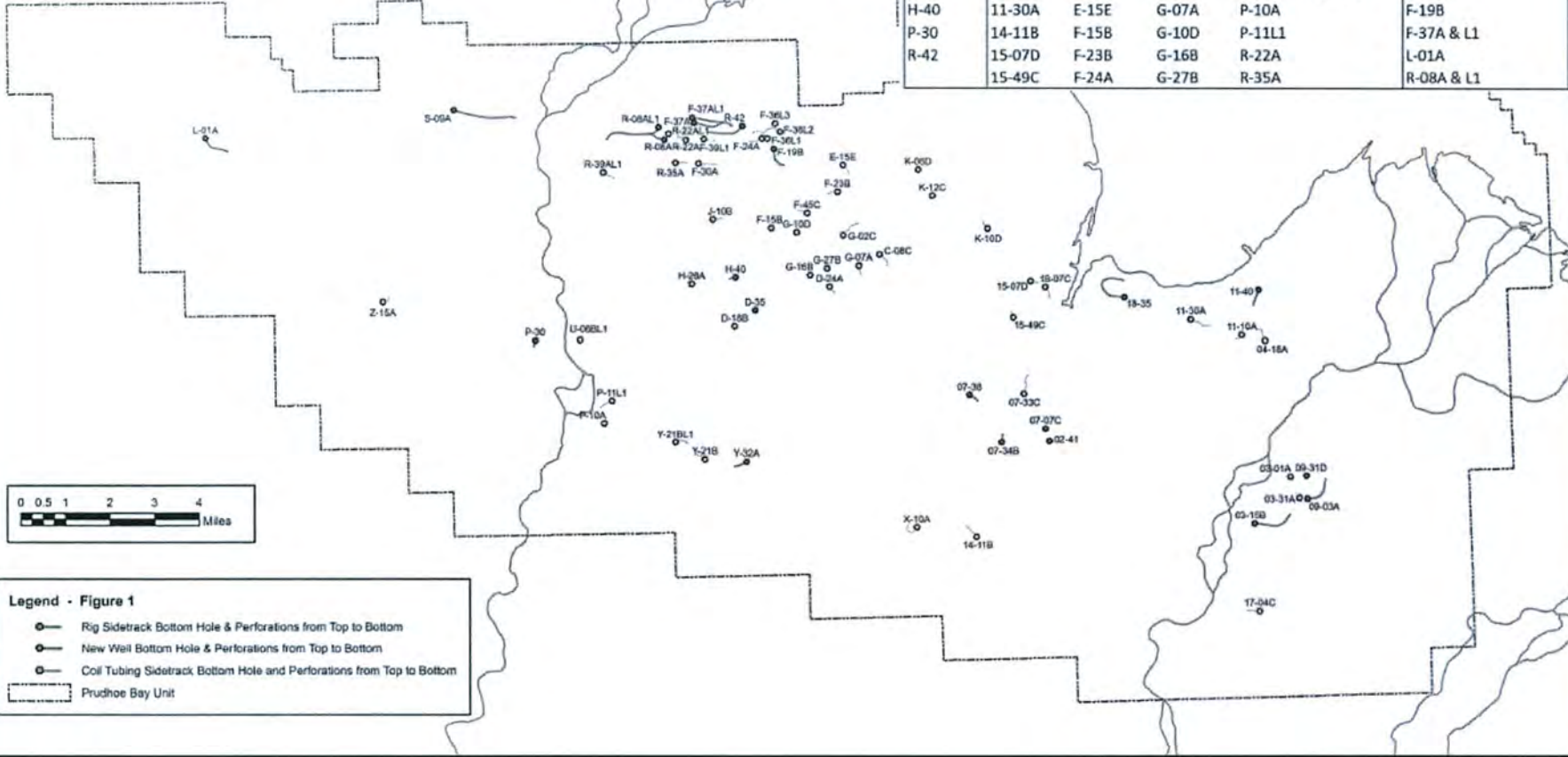


Figure 1



Prudhoe Bay Unit IPA 2016 Drilling Candidates Map

2016 Drilling & RWO Program			
New	Coil	Rotary	RWO
2	16	5	0
N-31	03-21A	16-15A	09-27A
R-44	04-33B	16-17A	A-29A
	09-01A	B-27C	K-19B
	09-02A	C-21A	R-10A
	09-18A	E-20C	R-16A
	09-49A	M-08A	
	11-32A	M-23A	
	15-45D	S-112A11	

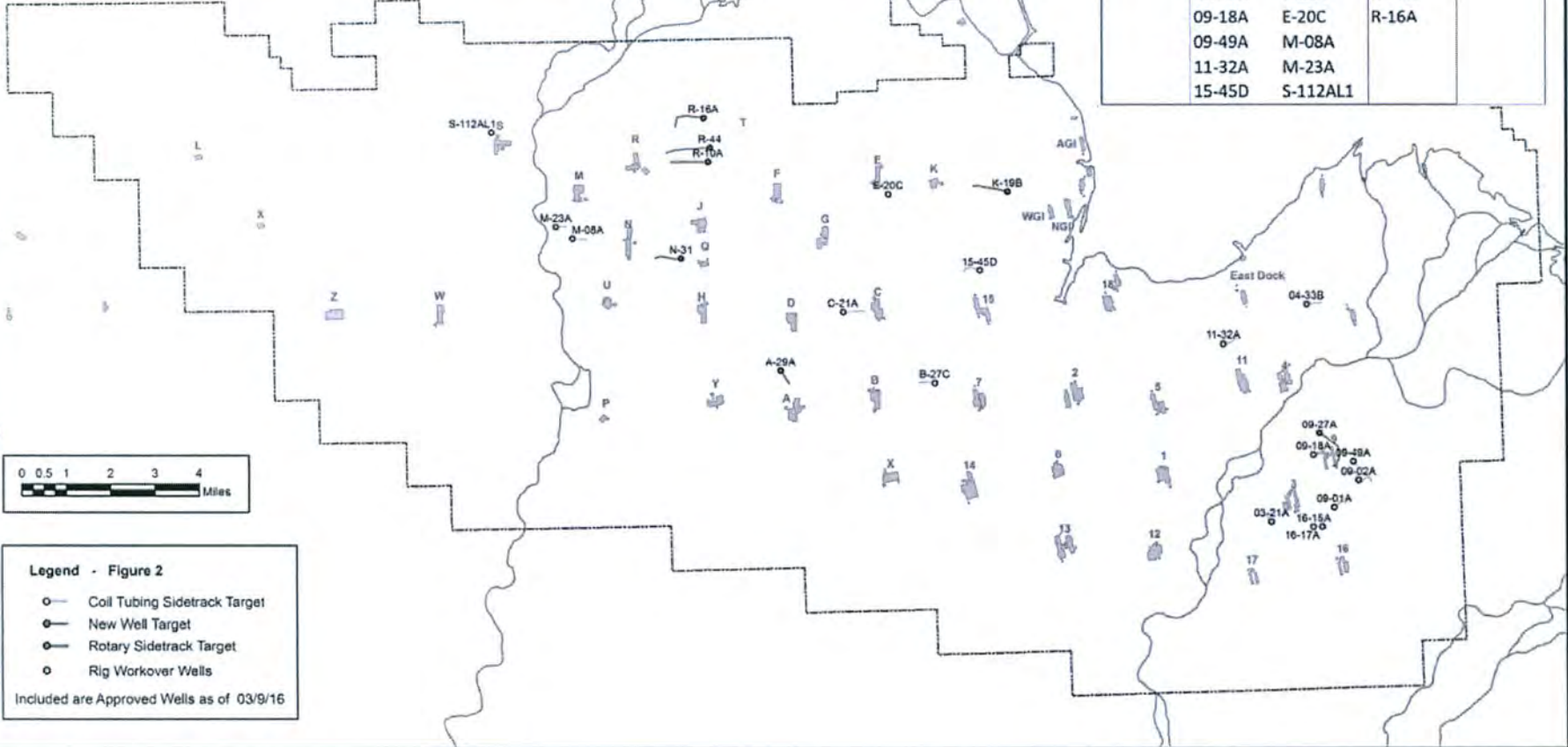


Figure 2



Prudhoe Bay Unit

Annual Field Overview of Prudhoe Bay - Initial Participating Area (IPA) Reservoir Development and Operations March 24, 2016

- **BPXA requests that the geological, geophysical, and engineering portions of this presentation (including interpretations of those data) marked as "confidential" be kept confidential under AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law.**
- **Development plans are consistent with the current business climate and understanding of the reservoirs. Changes in business conditions, new insights into the reservoir characteristics, or other information and events outside our control could alter the timing, scope or feasibility of one or more of the plan components, and could also affect forecasts of future production.**

Agenda



- Introductions (sign-in sheet)
- Safety Moment

IPA Field Overview

- 2015 Operations Summary
- 2015 / 2016 Field Activities and Development
- 5 Year Forecasts

- **BPXA requests that the geological, geophysical, and engineering portions of this presentation (including interpretations of those data) marked as "confidential" be kept confidential under AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law.**
- **Development plans are consistent with the current business climate and understanding of the reservoirs. Changes in business conditions, new insights into the reservoir characteristics, or other information and events outside our control could alter the timing, scope or feasibility of one or more of the plan components, and could also affect forecasts of future production.**



Fire Safety: Using an Extinguisher

2/05/16 Fire in Eagle River claims 1 victim



First decide if it is safe to fight the fire

Do not Fight the fire if:

You don't have adequate or appropriate equipment. If you don't have the correct type or large enough extinguisher, it is best not to try fighting the fire.

You might inhale toxic smoke. When synthetic materials such as the nylon in carpeting or foam padding in a sofa burn, they can produce hydrogen cyanide, acrolein, and ammonia in addition to carbon monoxide. These gases can be fatal in very small amounts.

Your instincts tell you not to. If you are uncomfortable with the situation for any reason, just let the fire department do their job.

- **Pull** Pull the Pin
- **Aim** Aim at the base of the fire
- **Squeeze** Squeeze the handle
- **Sweep** Sweep from side to side until the fire is completely out



The final rule is to always position yourself with an exit or means of escape at your back before you attempt to use an extinguisher to put out a fire.

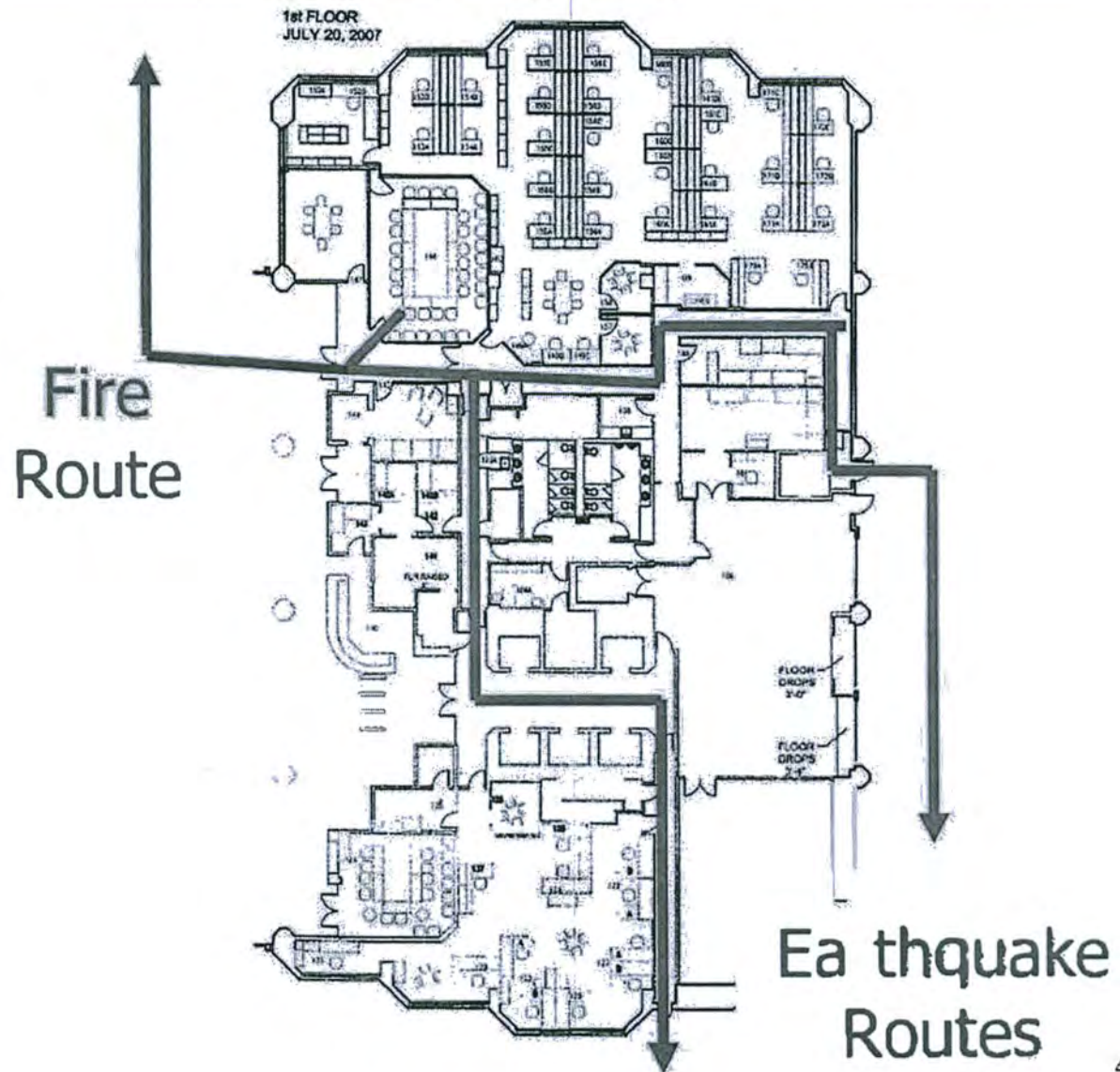
Emergency Evacuation Route



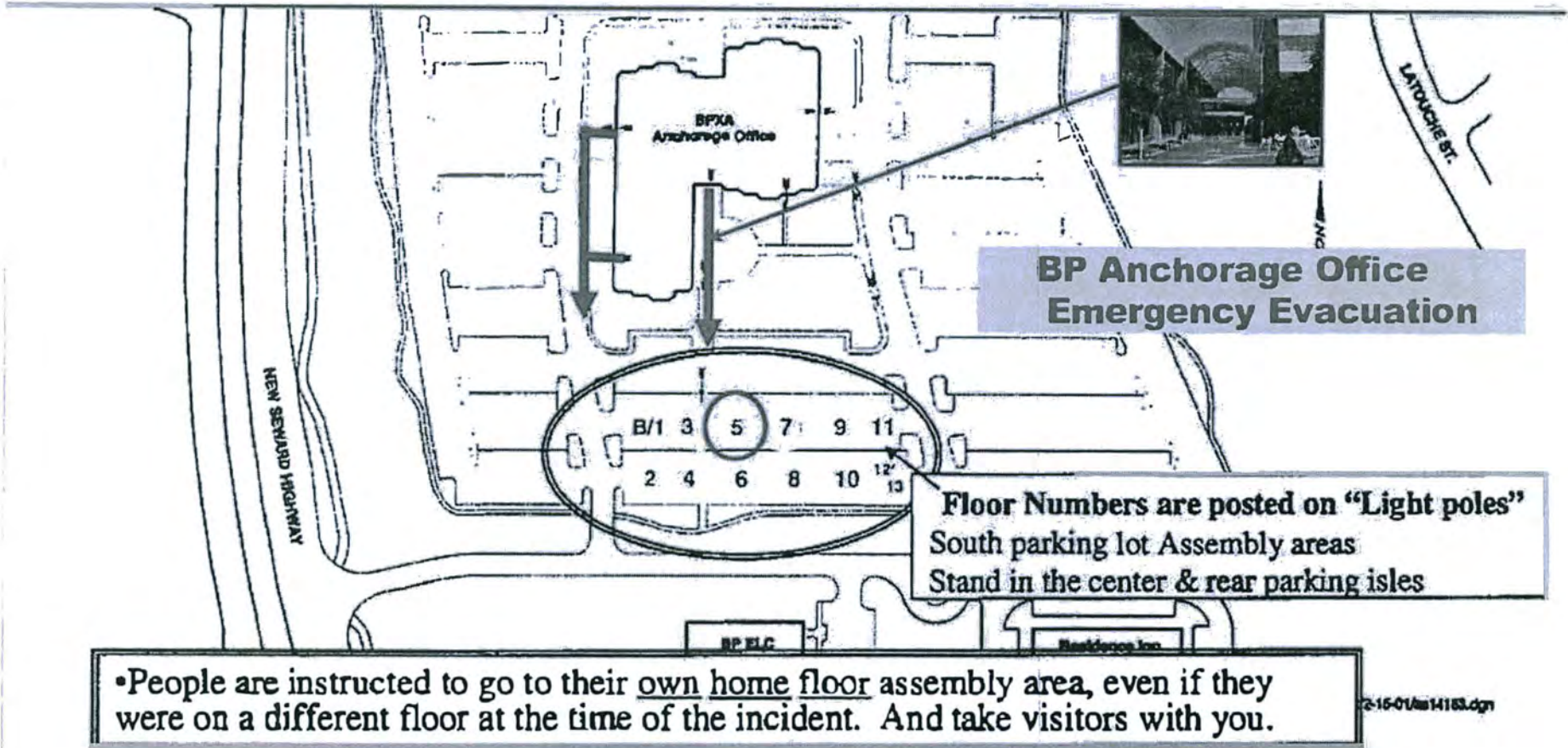
In case of Earthquake duck, cover and hold

Evacuate out rear service entrance

Proceed to south parking lot



Emergency Evacuation Route



•People are instructed to go to their own home floor assembly area, even if they were on a different floor at the time of the incident. And take visitors with you.

2015 Operations

(January 1, 2015 – December 31, 2015)



- Produced Fluids
 - Oil & Condensate
 - Average Rate: 196.4 MB/D
 - Annual Delivery to TAPS: 71.7 MMB
 - Cumulative Delivery to TAPS: 11.7 BB
 - Natural Gas Liquids
 - Average Rate: 38 MB/D
 - Annual Delivery to TAPS: 13.9 MMB
 - Cumulative Delivery to TAPS: 487 MMB
 - Cumulative Delivery to Oliktok: 152 MMB
- Total Cumulative 12.3 BB

2015 Gas Operations

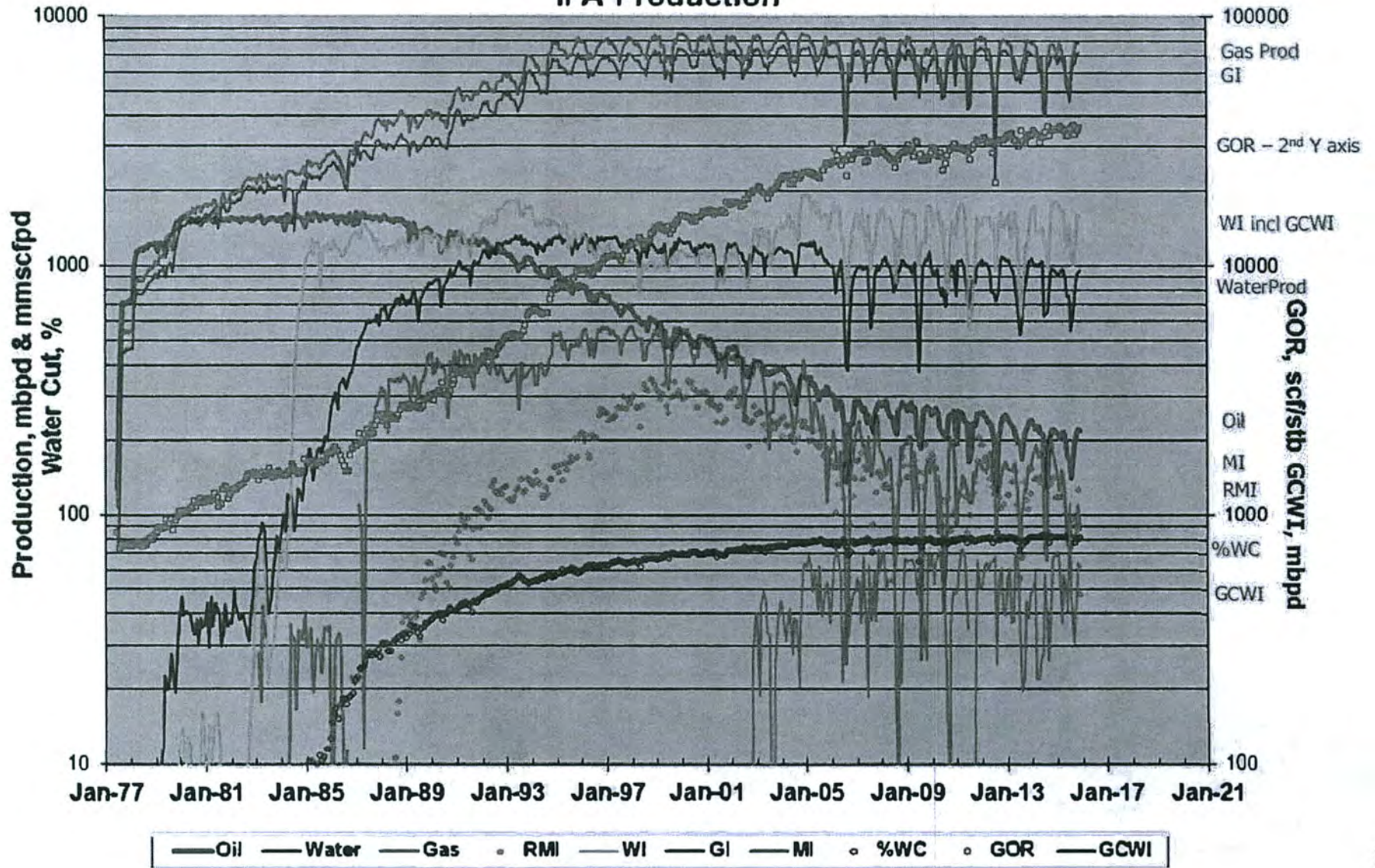


- Gas Production
 - Annual Production: 2,519 BCF
 - Percent Reinjected: 93%
 - Main Area Gas Cap: 2276 BCF, 6.2 BCF/D
 - Miscible Injectant (IPA): 38 BCF, 104 MMCF/D
 - Miscible Injectant (Satellites & PTM): 28 BCF
 - Other Uses
 - Fuel & Flare: 148 BCF
 - NGL: 18 BCF
 - Taken to Northstar: .075 BCF
 - Minor Sales: 7 BCF
 - Net Satellites Import: 7 BCF

Historical Production – IPA



IPA Production

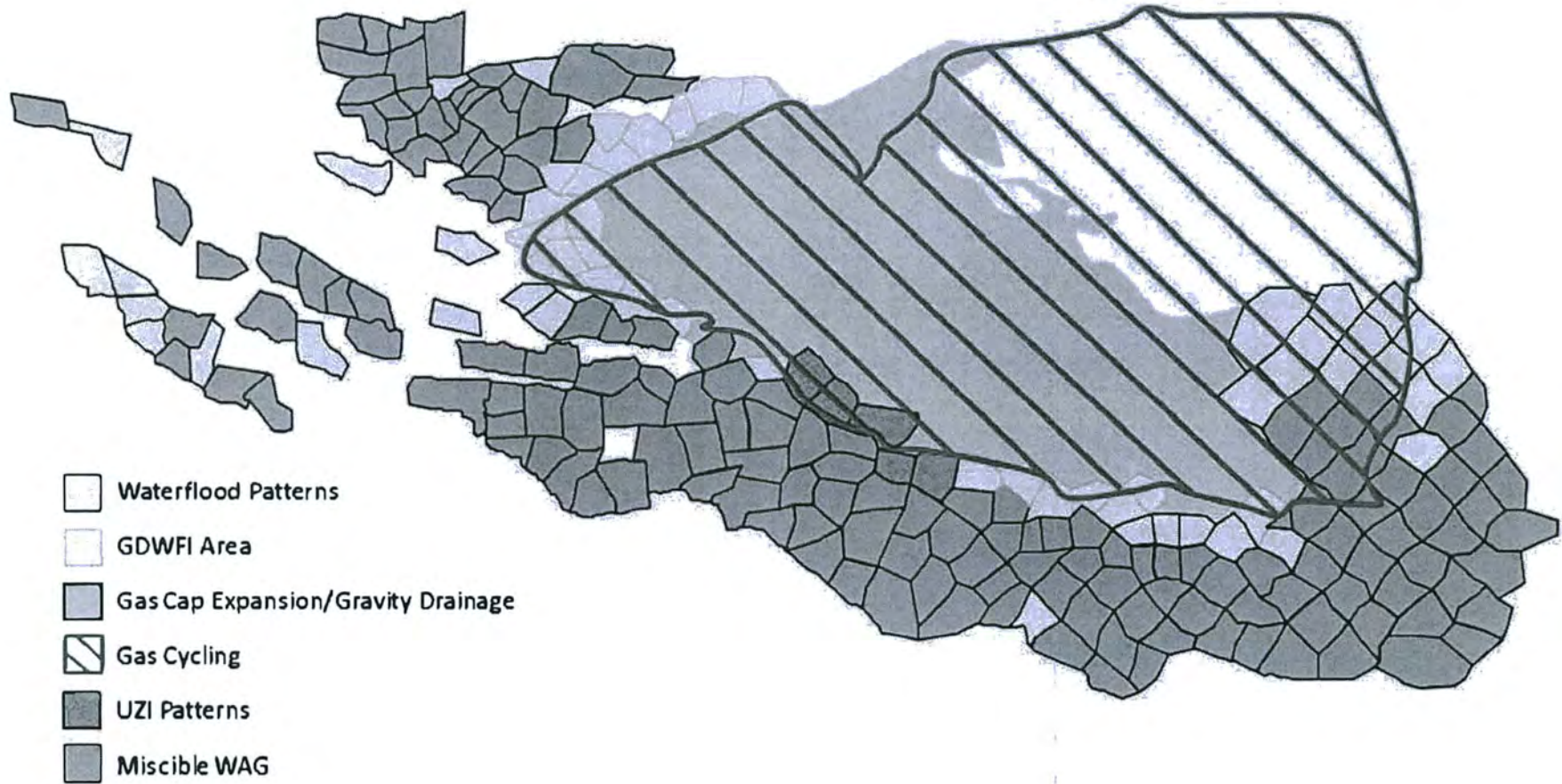


2015 Operations

MI Project Area



- Average Injection Rate: 104 MMCF/D
- WAG and Non-Conventional MI Injectors: 28



2015 Miscible Injectant Distribution

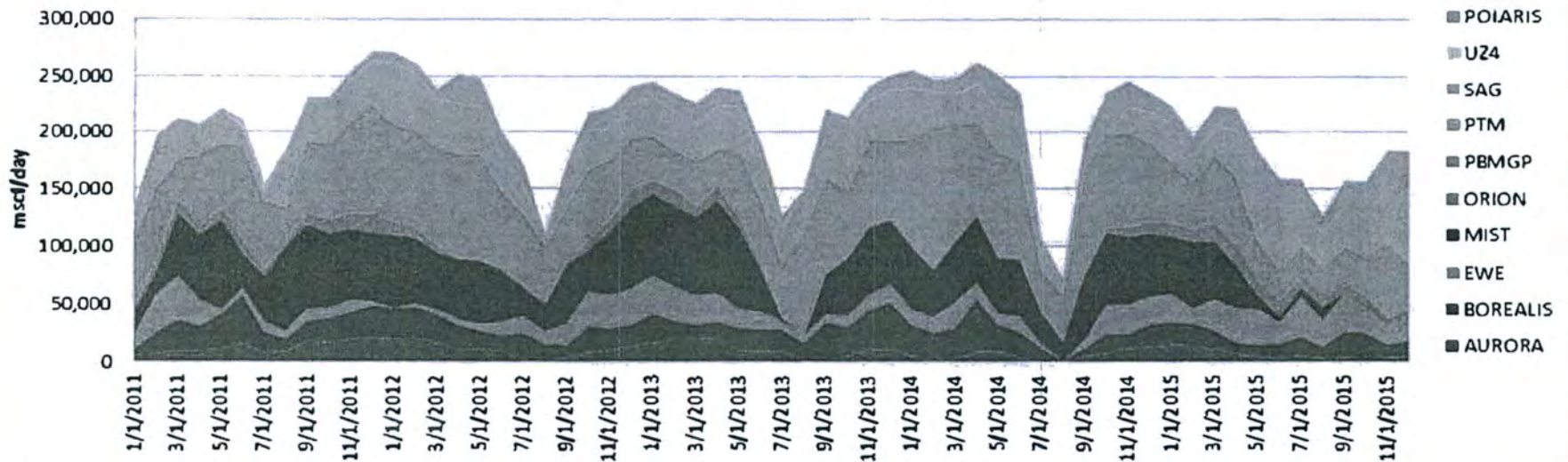


- 104 MMSCF/D (58% of CGF total) MI was utilized in IPA
- 76 MMSCF/D was injected in other PBU PA's
- Returned MI rate was 95 MMSCF/D from IPA WAG patterns.
- Patterns are ranked according to their MI utilization indicated by MI/EOR (MSCF/STB)
- MI allocated to best injection patterns to optimize oil recovery

Optimizing Injection of MI



GPB MI Distribution



2016 MI allocation:

	1Q16 MI demand	1Q16 MI Target	Comment
Aurora	10	10	meet demand
Borealis	38	25	reduce
EWE	30	30	meet demand
MIST	45	45	meet demand
PBMGP	85	50	reduce
PtMac	30	30	meet demand
SAG	30	30	meet demand
Schrader	22	22	meet demand
UZ4	30	20	reduce
Total GPB	320	262	

MI Optimization

- Patterns are ranked based on MI Efficiency
- Allocating MI to Highest Efficiency Areas
 - MIST
 - Recent Sidetracks
 - PB Satellites & EWE
 - Immature PBMGP patterns
- Considering MI Maturity measured by RMI/MI ratio

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2015 Water Production and Injection



- Water Production
 - Annual Production: 308 MMB (includes W-400)
 - Average Rate: 843 MB/D
 - Average Water Cut: 81%
 - Produced Water Injection Capacity: 1675 MB/D
 - Net Export of 30 MB/D to Satellites and 102 MB/D of disposal
- Waterflood/EOR/GCWI
 - Active in 5 Areas (FS-2, NWFB, EPWZ, WPWZ, EWE)
 - IPA Produced Water: 843 MB/D
 - Produced Water Injection Rate: 710 MB/D
 - Waterflood Seawater Injection: 162 MB/D
 - Gas Cap Seawater Injection: 547 MB/D
 - Total Water Injection Rate: 1,419 MB/D
 - Active Water Injectors: 186

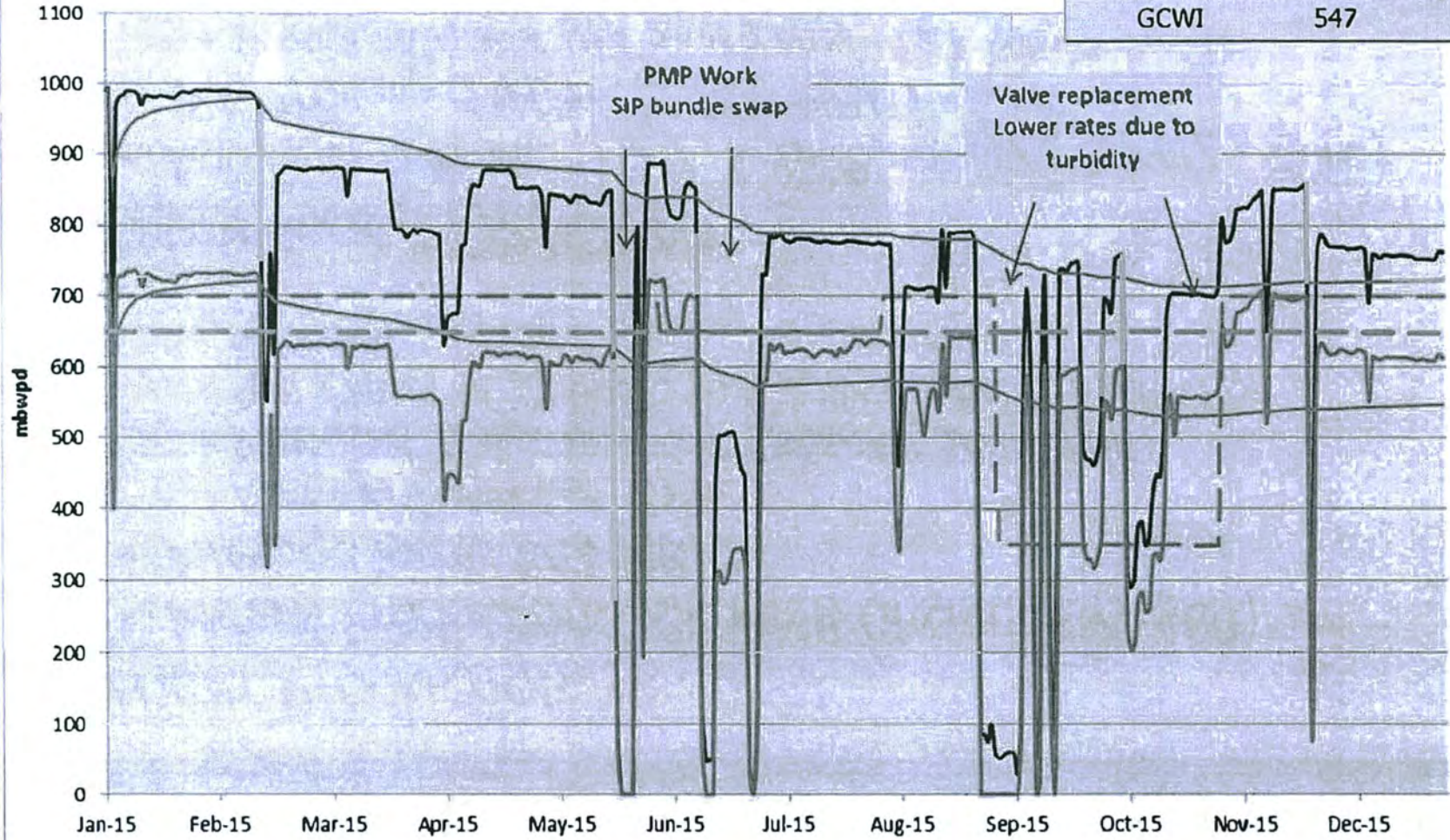
2015 Operations

STP/GCWI Performance



STP and GCWI Daily Rates

2015	Actual	Target
STP	722	633
GCWI	547	

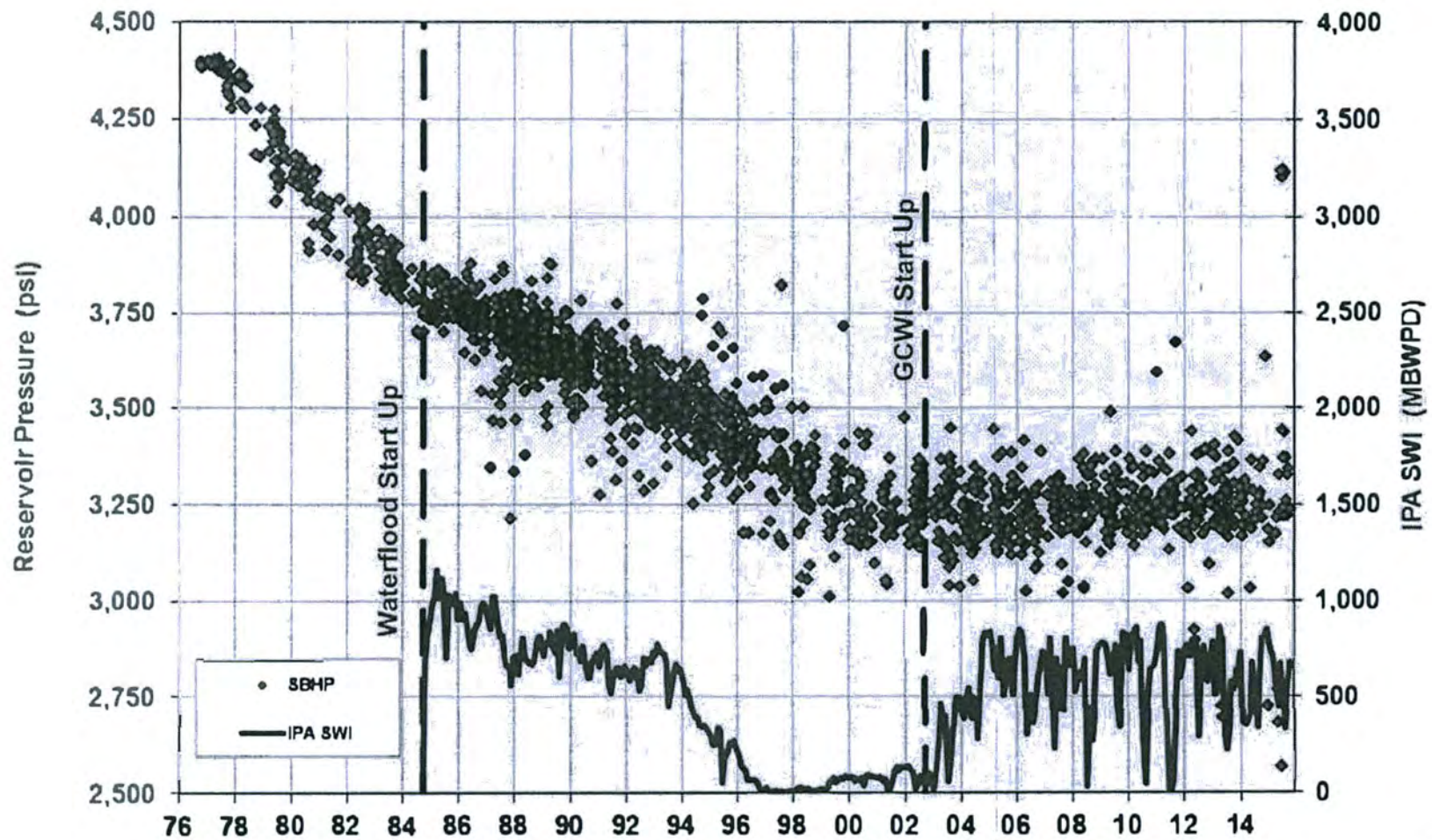


- STP KPI
 - STP
 - GCWI
 - STP AA
 - GCWI AA
 - GCWI KPI

GD Reservoir Pressure Since GCWI



GD Reservoir Pressure History



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- Field Depletion Areas Overview
- Drilling and Wellwork
- Seismic
- Facilities
- Forecasts



Field Depletion Areas

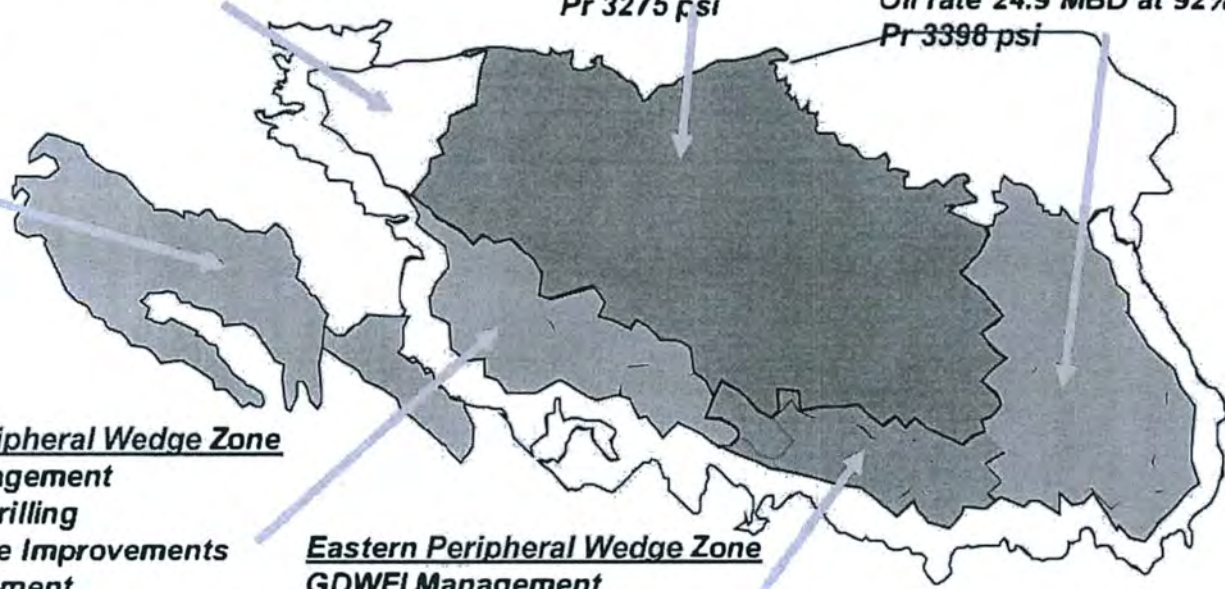
PBMGP Average Pressure = 3350 psi

Northwest Fault Block
GDWFI Management
EOR / Sag Development
Peripheral Drilling
Conformance Improvements
Oil rate 8.8 MBD at 84% wc
Pr 3335 psi

Gravity Drainage
Sidetracks
Development of
Upstructure Area
Oil rate 110.9 MBD at
53% wc
Pr 3275 psi

Flow Station Two
Conformance improvements
MIST Development
Pattern rotation
5 spot pattern test
Aggressive upstructure perf strategy
Oil rate 24.9 MBD at 92% wc
Pr 3398 psi

Eileen West
End/Northwest Eileen
Water and MI Flood
Additional Drilling
Injector conversions
Oil rate 14.4 MBD at
75% watercut (wc)
Pr 3645 psi



Western Peripheral Wedge Zone
GDWFI Management
Peripheral Drilling
Conformance Improvements
Sag Development
Oil rate 21 MBD at 86% wc
Pr 3313 psi

Eastern Peripheral Wedge Zone
GDWFI Management
Sag Development / Waterflood
Conformance Improvements
Oil rate 16.4 MBD at 89% wc
Pr 3330 psi

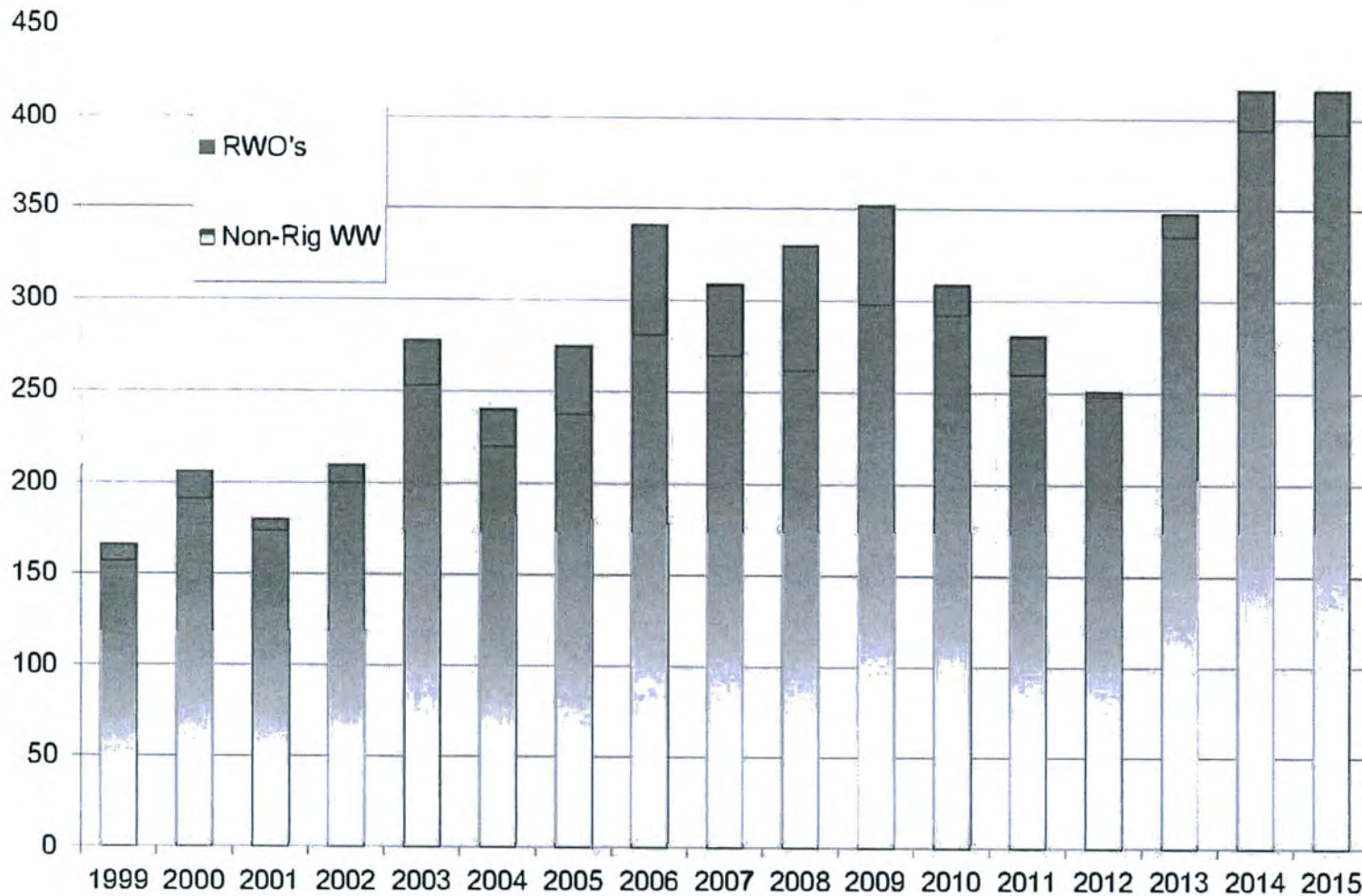
2015 Drilling and Wellwork



- Drilling
 - New Wells from Surface: 8
 - Sidetracked Locations: 52
 - 3 Capital RWOs

- Wellwork
 - Rate-Adding Jobs Completed: 416
 - 24 ERWO's
 - 12 Acid
 - 71 Add Perf/Reperf
 - 24 APF + GSO
 - 36 GSO
 - 12 WSO
 - 12 Tubing Patches
 - 225 Other Type jobs
 - Non-Rate Adding: ~ 1400

Historical Rate-Adding Wellwork Job Count



Prudhoe Bay IPA Bright Water® EOR



Year	Number of treatments
2004/5	3
2007	2
2008	5
2009	8
2010	7
2011	8
2012	15
2013	24

2014 Treatments

Proposed Injector	Injection Zones
P-06B	Z4
13-16	Z4
03-37	Sag, Z4
03-17*	Z4, Z2
03-18A*	Z2
09-16*	Z4
12-23	Z4
A-11	Sag, Z4
17-06	Sag, Z4
03-10	Z4, Z2
Y-07A	Z4
04-13	Z2
13-21	Z4
12-27A	Z4
A-31A	Z4
Y-11C	Z4
09-25**	Z2
04-10	Z2, Z1



- *93 treatments over last 10 years
- 18 treatments in 2014
- 2015: 2 jobs performed in 1Q as a carryover from 2014; evaluation of this program is on going
- 2016: Program deferred to 2017

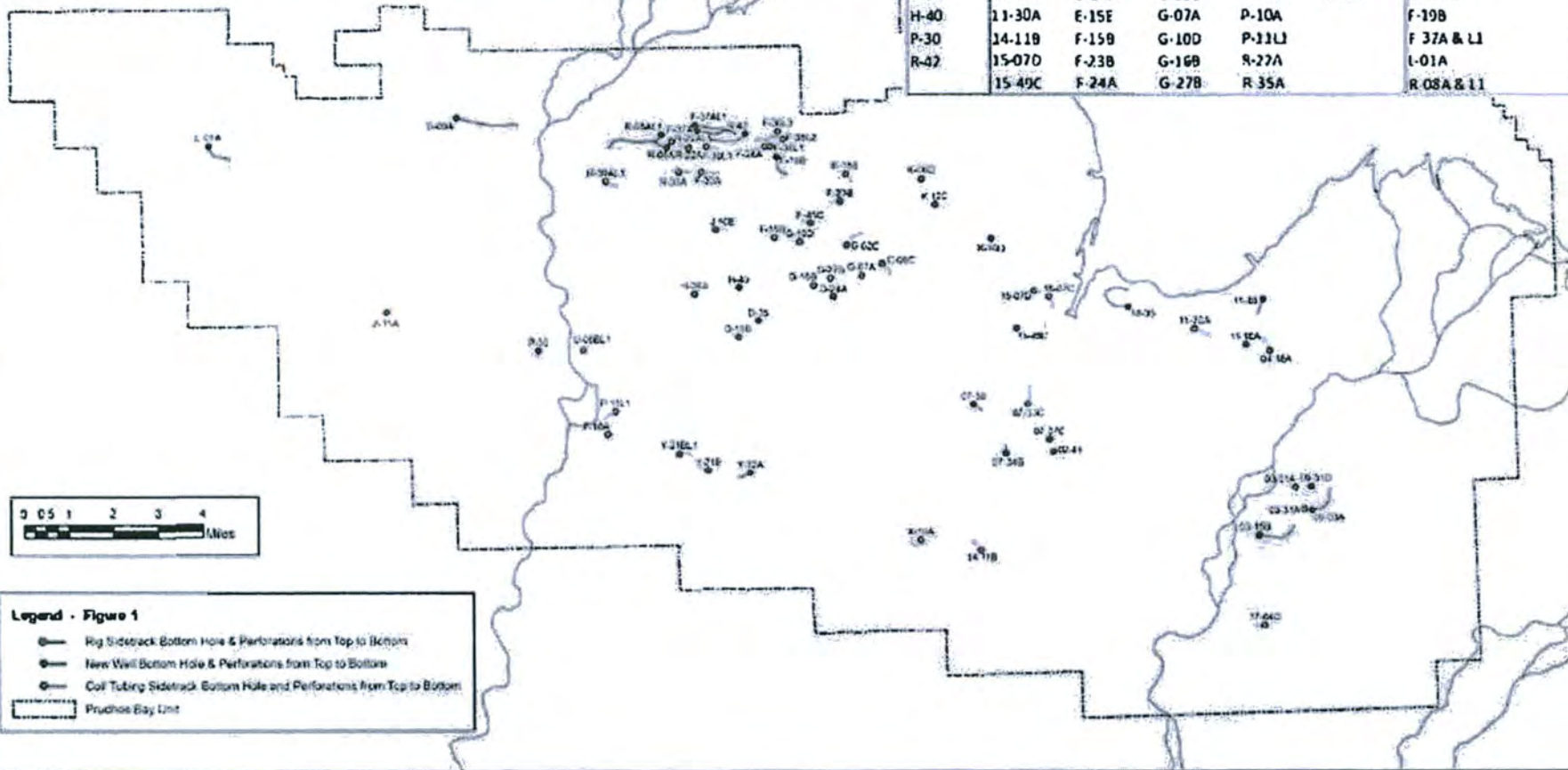
- *Bright Water* technology is a waterflood sweep modification treatment which blocks the preferential flow pathways in the pore structure, thus improving sweep efficiency.
- *Bright Water* is activated by the change in temperature behind the flood front and hence acts deep in the reservoir (the speed of activation can also be controlled by chemical grade).
- 2004/5 *Bright Water* IPA trial response is documented in SPE Paper # 129967

2015 IPA Drilling Summary



Prudhoe Bay Unit IPA 2015 Drilling Activity Map

2015 Drilling Program							
New Well	Coil						Rotary
	41						
02-41	03-01A	17-04C	F-30A	H-26A	R-39AL1	03-15B	S-09A
07-38	0-31A	18-07C	F-36L1-L3	J-10B	U-06B11	07-07C	Y-32A
11-40	04-18A	C-08C	F-39L1	K-06D	X-10A	07-34B	
18-35	07-33C	D-18B	F-45C	K-30D	Y-21B & L1	09-03A	
D-35	11-10A	D-24A	G-02C	K-12C	Z-15A	09-31D	
H-40	11-30A	E-15E	G-07A	P-10A		F-19B	
P-30	14-11B	F-15B	G-10D	P-21L1		F-37A & L1	
R-42	15-07D	F-23B	G-16B	R-27A		L-01A	
	15-49C	F-24A	G-27B	R-35A		R-08A & L1	



2015 RWO Activity



Prudhoe Bay Unit IPA 2015
RWO Activity Map

2015 RWO				
Capital RWD	Expense RWD			
3	24			
11-30	01-13	12-4A	J-03	5-34
D-24	01-16	14-08A	N-17	5-40A
Z-15	01-22B	14-26	N-19	X-17
	02-21B	14-32	P-13	
	03-12	A-06	R-06A	
	11-27A	F-16A	R-9A	
	11-29	GC-1D	S-16	



Legend - Figure 3

- All other values
- Capital RWD
- Expense RWD
- ▭ Prudhoe Bay Unit

2016 IPA Drilling and RWO Projection



	2015	2016
Rotary:		
Rig Years	1.8	0.5 - 0.7
Penetrations	19	6 - 8
Coil:		
Rig Years	1.9	0.7 - 0.9
Penetrations	41	20 - 24
Rig Work Overs:		
Rig Years	1.2	0.1 - 0.2
Wells	27	2 - 4

Planned activity levels and RWO projections are subject to change

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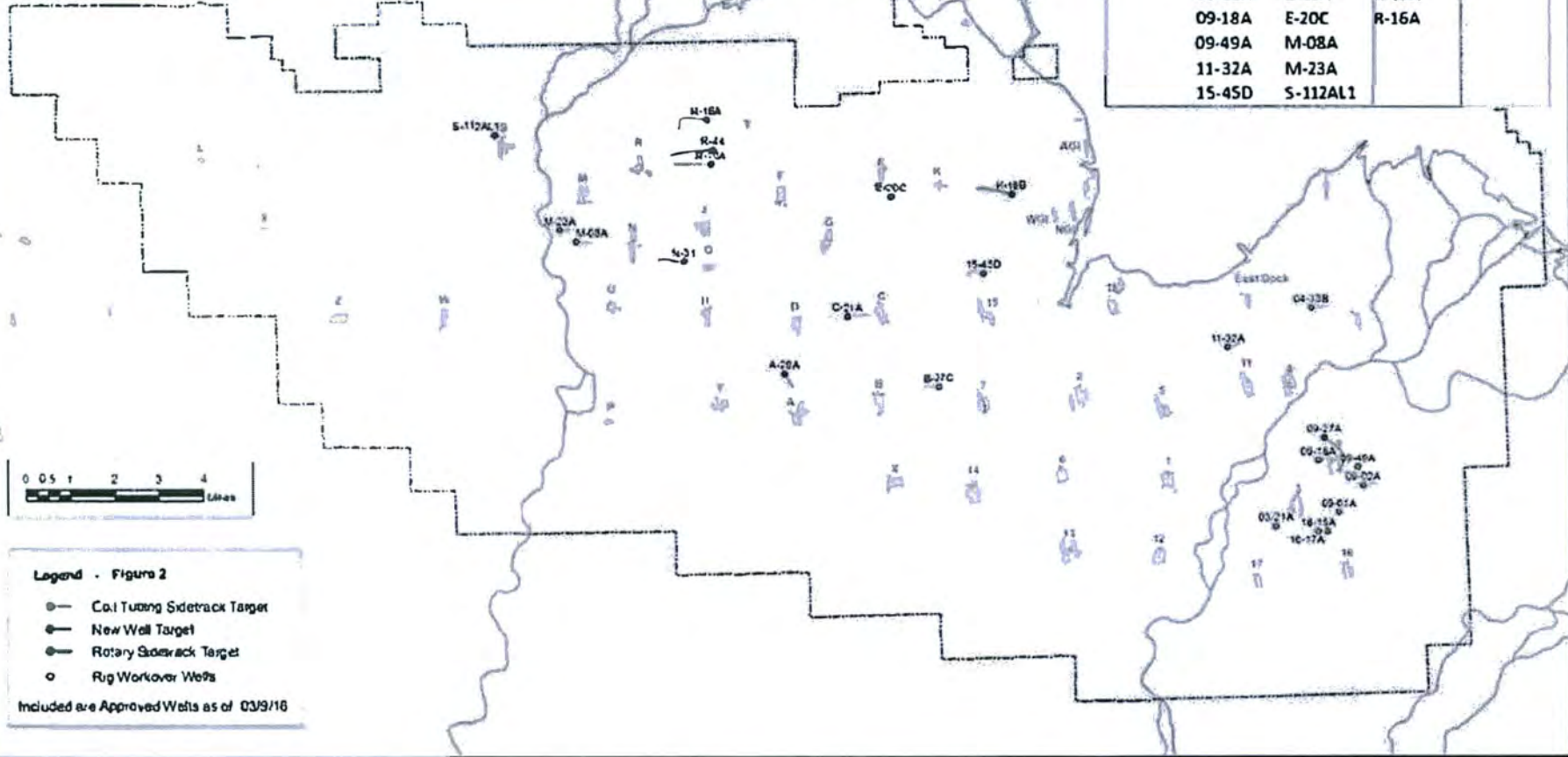
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2016 IPA Drilling and RWO YTD Approved



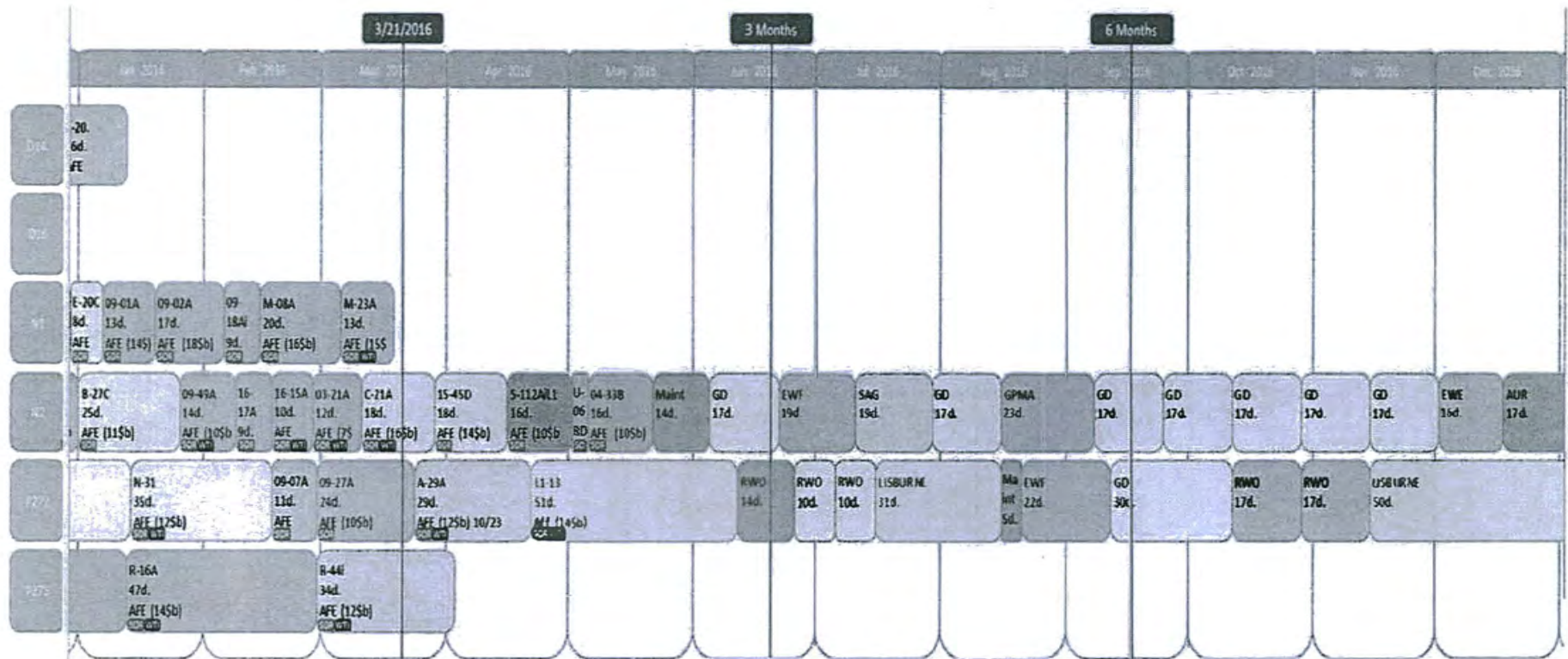
bp Prudhoe Bay Unit IPA 2016 Drilling Candidates Map

2016 Drilling & RWO Program			
New	Coil	Rotary	RWO
2	16	5	0
N-31	03-21A	16-15A	09-27A
R-44	04-33B	16-17A	A-29A
	09-01A	B-27C	K-19B
	09-02A	C-21A	R-10A
	09-18A	E-20C	R-16A
	09-49A	M-08A	
	11-32A	M-23A	
	15-45D	S-112A11	



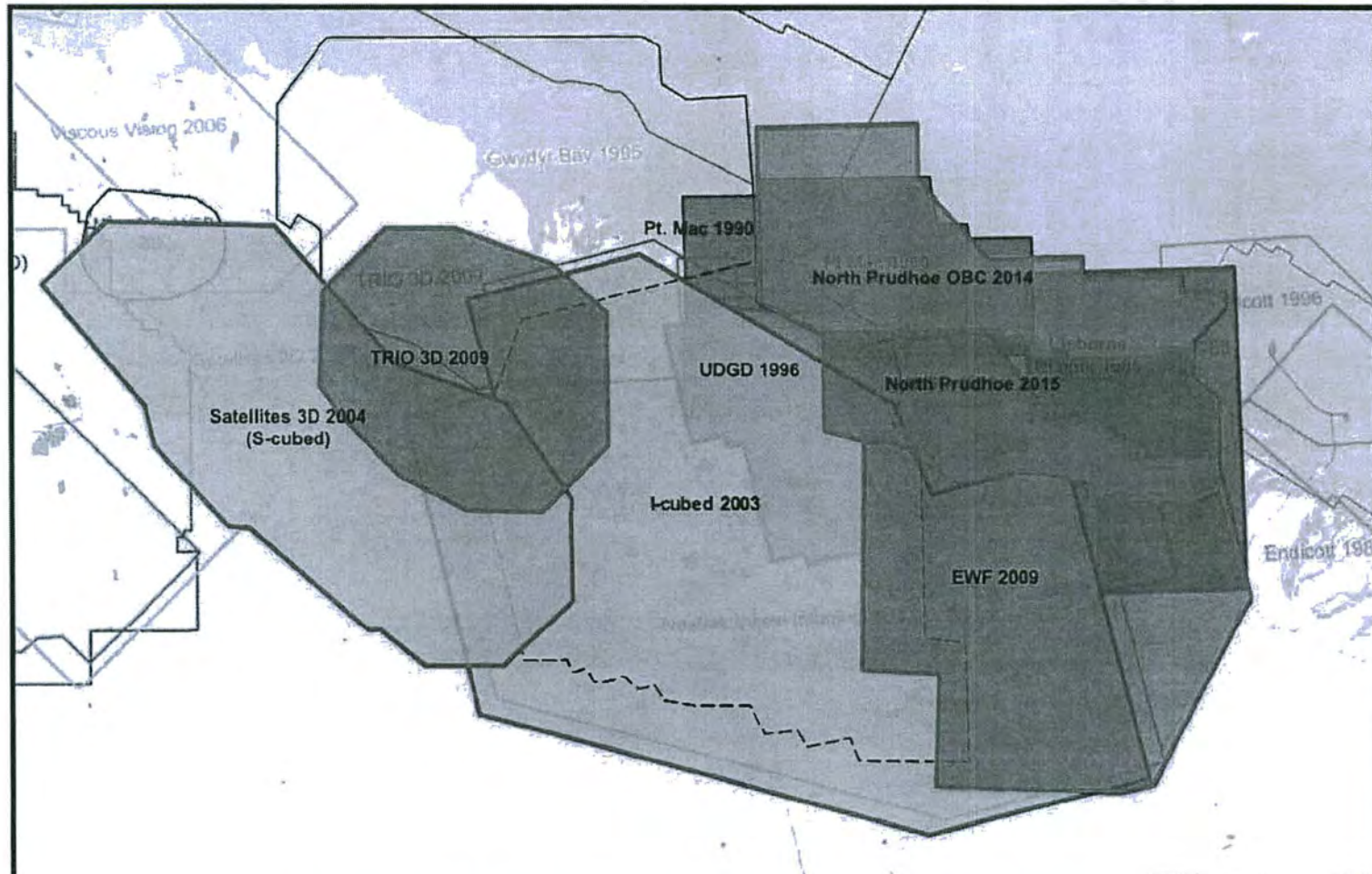
These wells are preliminary and subject to change or substitution or deferral

Draft 2016 GPB Drilling Schedule



Preliminary Plans Subject to Change

Prudhoe Bay Seismic Surveys



3D seismic surveys currently in use with date of acquisition.

Prudhoe Bay Seismic - Activities



2014 – 15 Seismic Acquisition and Processing

- S-Cubed 3D seismic PSDM processing completed.
- North Prudhoe 3D onshore acquisition completed.
- North Prudhoe 3D merged offshore & onshore PSDM preliminary processing
- Used to reduce risk and refine drilling targets (eg. evaluation of fault placement for several K Pad wells)

2015 – 16 Seismic Acquisition and Processing (ongoing & planned)

- North Prudhoe 3D merged offshore & onshore PSDM processing in progress.
- Planning for potential 3D seismic acquisition over remainder of GPB area
 - Use same parameters as North Prudhoe onshore seismic acquisition
 - Merge with North Prudhoe 3D to create single dataset over all of GPB

Independent Simultaneous Source Acquisition (ISS[®])



Conventional Land Acquisition

- Groups of 3-5 seismic vibrators
- One group of vibrators recorded at one time into the seismic receivers

Independent Simultaneous Source Acquisition (ISS[®])

- The seismic vibrators all operating independently and simultaneously
- Continuous recording
- Interfering signals removed in processing
- Benefits:
 - Faster acquisition
 - Denser spatial sampling
 - High fold, full azimuth coverage
 - Improved resolution of final images
 - Improved S/N of final images



ISS[®] is a registered trademark of BP plc

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Prudhoe Bay Seismic – NPB 3D



The ISS method used for the North Prudhoe 3D enabled and delivered:

- Safe and efficient operations in the arctic environment
- Dense sub-surface sampling due to increased source points
- Access to floating lake, river and sea ice by reducing the gross weight of fleets of vibrators to a single vibrator
- Recovery of broader bandwidth data, resulting in more geologically representative subsurface images
- A step-change in imaging, even under lakes and streams

Intermediate products from the time processing are already positively affecting the planning and drilling operations of our wells

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2015 Facility Projects/Activities



2015 TAR/Outages Completed

TARs

- GC1
- FS1

Outages

- COTU
- GC2

2015 Facility Activities Completed

- GC2 U Pad Jumper Return to Permanent Service
- FS3 Skid 50 UPS Replacement
- GC1 K7000/K7001 Lube Oil Demisters
- CCP Air Monitoring Replacement
- CGF FFGU Pipeline I/I Pigging
- CCP-FS1 Piperack Stabilize (work on hold)
- FS2 DS11-S/PWI Launcher Barrel Repl (project on hold- will revisit in 2019 in line with next set of pigging runs)

2015 Facility Projects Completed

- NGI System Restoration
- N Pad UZI
- GC2 Gas Capacity Constraint
- DS16/17 Pipeline Replacement

Facility Projects Cancelled

- CGF MI Compressor Operability Upgrades

2016 Facility TARs/Outages



Planned 2016 TARs/Outages

STP / SIP

- Integrity Projects – Piping Replacements
- Pig Receiver Upgrade

Outage

- GC2 D-Bank Slugcatcher Repairs

Preliminary Plans Subject to Change

Active/Planned 2016 Facility Activities¹



¹ Excludes WTI projects

Core Projects

- STP36 Pipeline Modifications / Controls Upgrade
- GC3 K7000/K7001 Lube Oil Demisters
- FS3 Skid 50 NGL Piping Modifications

Multiple Year Programs

- GPB Thermal Siphon Installation
- GPB Well Shelter Integrity
- GPB VSM/Saddle Assessment and Repair Program

Integrity Projects

Fire & Gas

- FS1 Fire & Gas
- FS2 Fire & Gas
- GC2 M Pad Fire & Gas
- GC2 S Pad Fire & Gas
- GC2 R Pad Fire & Gas
- GC2 J Pad Fire & Gas
- GC1 G Pad Fire & Gas
- FS1 DS1 Fire & Gas

Preliminary Plans Subject to Change

Active/Planned 2016 Facility Activities¹



¹ Excludes WTI projects

Automation

- EOA Fisher AC² Controllers Replacement
- STP-SIP EMC (PMC) Replacement
- WOA Facility Modicon PLC Replacement
- CCP Tandem 1876/1878 Mark VIe Controls Replacement

Facility Siting

- CCP
- CGF

STV-IP

- FS3

Fin Fan Floors

- CCP

Safety System Renewal

- FS1

Wet Gas Piping (2017+)

Rate Adding

- GC3 Produced Water Recycle Valve Replacement

Removal

- GC2 PHA Deadleg Removal- almost complete
- GC1 Pigging Loop Deadleg Removal- almost complete
- GC3 Pigging Loop Deadleg Removal- almost complete

Preliminary Plans Subject to Change 50

Active/Planned 2016 Facility Activities¹



Pipeline Projects

- DS04 Pipeline Replacement – In progress 2016, planned completion 4Q16
- CCP to FS1 Piperack stabilization with thermal siphons - 2016
- 24" FFGL Insulation system repair – Ongoing 2016 - 2018
- Well Pad stabilization (gravel fill) – Ongoing 2016-2017
- LS04/05 Make Piggable– Planned for 2017 looking at new option with reduced costs.
- DS14 Pipeline Replacement- Planned for 2017
- J-74 Pipeline Replacement– Planned for 2018
- 18D Make Inspectable Project - 2016-2017
- 2C Make Inspectable Project – 2016 - 2017

Preliminary Plans Subject to Change



2015 & 2016 In-Line Inspection (ILI) Activity

2015 Completed ILI Activity

Service	Pipeline Count	Miles
3-Phase	13	30.6
Fuel Gas	1	10.2
GLT	2	10.7
P-Oil	1	6.2
PWI	8	37.9
Seawater	2	8.3
Grand Total	27	103.9

2016 Planned ILI Activity

Service	Pipeline Count	Miles
3-Phase	14	45.0
Nat Gas	1	6.2
Processed Oil	1	4.8
Produced Water	8	34.6
Seawater	2	20.0
Grand Total	26	110.6

2016 Opportunity Activity

Driver & Service	Pipeline Count	Miles
Opportunity - New Pipeline Baseline	2	9.8
Opportunity - Return 12-SWI to service	1	3.8
Opportunity Project - Dpad Debottleneck	4	3.4
Grand Total	7	17

Preliminary Plans Subject to Change

5 Year Forecast Ranges



Year	Crude & Condensate		NGLs		Gas Prod MMSCF/ D		Water Prod	
	MB/D		MB/D		D		MB/D	
	High	Low	High	Low	High	Low	High	Low
2015	196	196	45	45	7,183	7,183	849	849
2016	196	157	45	36	7,700	6,300	1,050	750
2017	188	151	43	35	7,700	6,300	1,050	750
2018	181	145	41	33	7,700	6,300	1,050	750
2019	173	139	40	32	7,700	6,300	1,050	750
2020	166	133	38	31	7,700	6,300	1,050	750

Year	Water Inj		MI Injection		Avg Resv Pressure	
	MB/D		MMSCF/D		PSI	
	High	Low	High	Low	High	Low
2015	1,419	1,419	104	104	3,350	3,350
2016	1,600	1,000	165	80	3,370	3,340
2017	1,600	1,000	155	70	3,390	3,330
2018	1,600	1,000	145	60	3,410	3,320
2019	1,600	1,000	135	50	3,430	3,310
2020	1,600	1,000	125	40	3,450	3,300

- BPXA requests that the geological, geophysical, and engineering portions of this presentation (including interpretations of those data) marked as "confidential" be kept confidential under AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law.
- Development plans are consistent with the current business climate and understanding of the reservoirs. Changes in business conditions, new insights into the reservoir characteristics, or other information and events outside our control could alter the timing, scope or feasibility of one or more of the plan components, and could also affect forecasts of future production.

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End





THE STATE
of **ALASKA**
GOVERNOR BILL WALKER

Department of Natural Resources

COMMISSIONER'S OFFICE

550 W 7th Avenue, Suite 1400
Anchorage, AK 99501-3560
Main: 907.269.8431
Fax: 907.269.8918

January 14, 2016

Scott Digert, Manager of Reservoir Management
BP Exploration (Alaska), Inc
P.O. Box 196612
Anchorage, AK 99519-6612

RE: Unit Plan of Development Review Process Update — Request for Additional Information

Dear Mr. Digert:

The Department of Natural Resources ("DNR") is working proactively to ensure maximum development and monetization of Alaska's energy resources. In order to achieve this goal, it is important that DNR understand how all hydrocarbons available for offtake are being utilized on the unit, are being sold within the state, or are being prepared and/or marketed for potential future sale. The annual Unit Plan of Development ("POD") review is the appropriate vehicle through which to provide this information to the State, and as such, the inclusion of this discussion will become a part of the POD requirement moving forward, commencing in 2016.

The Alaska Land Act finds that the people of Alaska have an interest in maximizing production from state oil and gas leases and in maximizing competition in oil and gas development. AS 38.05.180(a). The DNR commissioner has the authority to prescribe a plan under which state oil and gas leases will operate. AS 38.05.180(p). A POD must set forth plans for developing state oil and gas leases. 11 AAC 83.343. The Department requests that you include the following information in the annual update to your plan of development for the Prudhoe Bay (IPA) Unit due on April 1, 2016.

- A) **Marketing.** A discussion of the efforts to market oil and gas from the unit, which should include the following information:
- 1) To the extent the information is not already provided to DNR in royalty reporting or otherwise, the identity of the parties with whom the unit operator has current commercial agreement(s), or with whom the operator intends to have substantive discussions regarding the marketing of unit hydrocarbons including unit gas and heavy/viscous oil resources. The commercial terms under which the unit operator is offering to make resources available for long-term sale, including: the estimated volumes to be delivered, the pricing terms, the location at which title to the gas and associated risks of loss will change, and the condition of the gas at the time of delivery;
 - 2) A clear delineation between marketing efforts for local North Slope gas sales, and off-Slope gas sales that do and do not meet the definition of a Major Gas Sale under Prudhoe Bay Operating Agreement Section 26.002;

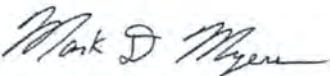
- 3) The extent to which Major Gas or other sales will require changes in existing operations and/or additional operations such as gas processing or treatment;
 - 4) A discussion of any heavy/viscous oil resources currently under production or those that may be technically and economically recoverable.
 - 5) A detailed discussion of any change in circumstances the unit operator believes is necessary to permit the marketing of oil or gas. If the change(s) in circumstances involve a different commodity price, then the unit operator shall detail the scenarios (including sufficient details as to important variables) under which it anticipates that gas or heavy/viscous oil can be technically and economically produced and marketed.
- B) **Facility Access and Sharing.** For purposes of this section, “facility” means roads, drilling rigs, flow lines, flow stations, gathering centers, pump stations, storage tanks, related appurtenances, and other facilities that gather, clean, dehydrate, condition or store crude oil, natural gas, or associated hydrocarbons and are located on a lease or property leased from the state.
- 1) For both oil and gas, each request for facility sharing and access to facilities received and the facility owner’s response to each request.
 - 2) With respect to any request for facility sharing not yet agreed to by the facility owner(s), please provide a detailed summary of the status of on-going discussions and efforts to reach agreement for facility sharing and access including technical, commercial, land status, and regulatory issues.

Where relevant to the development of oil and gas from unitized acreage, the DNR would also expect the unit operator to bring forth discussion of other efforts to progress development, such as farmout discussions and any issues that impede the further development of the unit resources, such as agreements necessary to affect development that have not yet been successfully executed.

Upon request, the information provided will be held confidential as provided in AS 38.05.035(a)(8), to the extent such information meets the requirement of that statute.

Thank you for your assistance. We look forward to an informative discussion at the next Prudhoe Bay (IPA) Unit POD review.

Sincerely,



Mark Myers
Commissioner

ALASKA STATE LEGISLATURE BUDGET & AUDIT

JOINT COMMITTEE MEETING

HOUSE FINANCE 519

JOINT RESOURCES PRESENTATIONS

BY SPENCER HOSIE and MARK COTHAN

APRIL 20, 2005

TRANSCRIPTION SUPPORT SERVICES

4782 Mills Drive
Anchorage, Alaska 99508
907/333-6256
907/337-0243 (fax)
e-mail: lsfoley@acsalaska.net

1 you, Mr. Chairman.

2 CHAIRMAN: Okay. Further questions? Seeing none, thank
3 you, Mr. Hosie. We will move on to our next presenter.

4 MR. HOSIE: Thank you, Mr. Chairman, members of the
5 Committee.

6 CHAIRMAN: We have next a group with Cothan, Harwell and
7 Evans, counsel to the Alaska Gas Port Authority.

8 UNIDENTIFIED MALE SPEAKER: Mr. Chairman, members of the
9 Committee, thank you very much for the invitation to offer a
10 second opinion on gas development issues. Because Alaska
11 doesn't have a myriad of royalty owners that other states do,
12 a lot of this comes from out of state issues and we were in
13 for the firm of Cothan, Harwell and Evans, a firm with over 70
14 years in combined experience resolving commercial oil and gas
15 issues. With me are Mark Cothan and Mark Harwell. Their firm
16 continues to focus on issues such as failure to develop and
17 other producer royalty claims. Mark Cothan will be making the
18 presentation.

19 MR. COTHAN: Thank you very much. I think today we are
20 somewhat witnessing history insofar as I believe you're going
21 to see two lawyers representing two different parties almost
22 entirely agree on what the law is and that's a rarity. The
23 law as Mr. Hosie put it -- put forth, I think, is really not
24 controversial. I think that if you would look at the
25 treatises, look at the case law, etcetera, you will not find

1 that there is truly a difference as amongst the various
2 producing jurisdictions. In fact, there is a consensus as far
3 as the law here that is very, very uncommon both in oil and
4 gas law and the law generally. We've been asked by the Port
5 Authority to review with you the legal duties and obligations
6 that the producers have with respect to the Alaska North Slope
7 gas. Obviously, my testimony is based on case law and my 23
8 years experience as a lawyer in this field and is not intended
9 to reflect any particular statement of position by the Port
10 Authority itself.

11 In finding my testimony and trying to be as informative
12 as possible, I -- I've looked at some of the discourse that
13 was associated with the general debates that are going on.
14 It's between the producers and it's between just whether or
15 not a pipeline will, in fact, be built and one of the things
16 that struck me as strangely missing was any discussion about
17 what are the producer's obligations in these circumstances.
18 There's been a lot of talk, of course, about the importance of
19 the federal loan guarantee and how that might play a role in
20 getting the pipeline built. Likewise, the producers have been
21 quite forthcoming in terms of insisting that there be royalty
22 concessions and tax concessions and who knows what other
23 concessions they may or may not be asking for but, to my
24 knowledge so far until Mr. Hosie spoke on this subject, there
25 has not been any true significant review with respect to the

1 duties that a producer has. To try and clear up the air and
2 to try and analyze for you the legal duties that we see here,
3 I plan to address five what I would regard as misconceptions
4 that exist in this area.

5 Five misconceptions that we have, first, is that the oil
6 companies own the Alaska North Slope gas; second, that the oil
7 companies have complete legal control over if and when that
8 gas is produced and marketed; third, the oil companies can
9 choose how much profit they want and delay developing or
10 marketing the North Slope gas until their profit goals through
11 state concessions or otherwise are met; fourth, the oil
12 companies, by owning the leases, have the legal right to
13 dictate the location, ownership and structure of the pipeline;
14 and then, finally, fifth, that the state is somehow in a weak
15 position to negotiate with these oil companies.

16 Let me go through each of those what I consider to be
17 misconceptions and explain to you what I believe the law is
18 and how it is established. Starting with misconception number
19 one, I believe that the reality is that the producer's leases,
20 just as Mr. Hosie indicated, give them the right to develop
21 and market the gas however they have corresponding
22 responsibilities and if, in fact, those corresponding
23 responsibilities are not met, it is my position that under the
24 clear terms of the lease, those leases can be absolutely
25 canceled such that the State of Alaska becomes the owner of

1 that gas if the oil companies refuse to adhere to their
2 divvies.

3 There was a question by former Chairman Ogan last fall
4 that I kind of liked. It's -- the question was how does one
5 get past the reality that the guys with the gas make the rules
6 and while I sympathize with what he was getting at, the point
7 is these oil companies do not own this gas. As a matter of
8 property law, as a matter of any type of underlying oil and
9 gas law, they are not the owners of this gas. As Mr. Hosie so
10 eloquently put it, what is conveyed by an oil and gas lease
11 is, first, an exclusive right to explore and produce. That is
12 how these oil companies have, for instance, produced almost 14
13 billion barrels of oil from Prudhoe Bay. On the other hand,
14 what the oil companies give back is, in the first instance, a
15 bonus which is determined by competitive bid; also a royalty
16 which, of course, is, in this instance, roughly 12-1/2 percent
17 but, finally and importantly, they give back a commitment to
18 develop, produce and market that gas.

19 I think when we talk about the ownership rights and
20 responsibilities, I think it may be helpful to try and draw an
21 analogy that, hopefully, we can all take advantage of. Let's
22 contrast for a moment the difference between just a single
23 individual owning a hamburger stand and a McDonald's franchise
24 and then we'll talk about how the oil companies' rights relate
25 to that circumstance. If we look at the single owners,

1 obviously, he owns -- he or she owns one hundred percent of
2 the hamburger stand. They also can run that hamburger stand
3 however they want to and if they run it well or if they run it
4 poorly, it remains theirs under any circumstance unless
5 somehow the law takes it away.

6 Let's contrast that now with the McDonald's franchise.
7 While a McDonald's franchise owner has a lot of the incidents
8 of ownership, in fact, he is subject -- he or she is subject
9 to a franchise agreement and that franchise agreement makes
10 various conditions which must be met in order to retain the
11 franchise. You have to have certain hours, you have to meet
12 certain quality standards. All those sorts of things are
13 normally in franchise agreements. Finally and importantly, if
14 that McDonald's franchise fails to meet its obligations under
15 the franchise agreement, it is subject to losing that
16 franchise. Now, let's contrast that just for a moment with
17 the oil and gas lease situation that we have here.

18 Again, if we were just talking about an owner of the
19 minerals, we'd have the same basic incidents. They would hold
20 one hundred percent of the title, they could run the lease
21 however they wanted to and no matter what, they would remain
22 the owner of that property. The producers have no such
23 rights. The producers have a specific contractual duty which
24 is spelled out in their leases. They must diligently develop
25 and produce the gas. They don't have the right that a normal

1 owner would to develop or not. They have to develop as a
2 matter of law. Likewise, they must, as a matter of law -- as
3 Mr. Hosie was discussing, they must diligently market that
4 gas. Finally and importantly, the lease itself specifically
5 provides that if they do not meet the terms of the lease, the
6 lease is subject to being canceled. So when we talk about the
7 ANS gas being owned by the oil and gas companies, I believe
8 that, frankly, that is a fundamental misconception.

9 Understanding that they do not own this gas, the question
10 becomes what do their rights entitle them to do in terms of
11 the control? Can they control if and when the gas is self
12 produced? Is it simply a one-way street? We believe, again,
13 the law is unquestionably that it is a two-way street, that
14 just as we've discussed already, there were rights but there
15 are also responsibilities that come with those rights. Oil
16 companies are subject to very specific duties to develop. The
17 duty to develop this acreage is expressly set out in the lease
18 and we'll talk about that language in a minute. Secondly, the
19 duty to market gas with reasonable prudence and diligence is,
20 as Mr. Hosie pointed out, something that every oil and gas
21 jurisdiction agrees exists in elite.

22 Taking a look at -- this happens to be the modern form
23 lease but I have compared it and gone back to the DL form that
24 Mr. Hosie is talking -- was talking about. Looking at the
25 language of the lease -- this is the contract, basically,

1 between the producers and the state -- it indicates the lessee
2 shall exercise reasonable diligence in drilling, producing and
3 operating wells on the leased area. It goes on, the lessee
4 must drill those wells as a reasonable and prudent operator
5 would drill, having due regard for the interests of the state
6 as well as the interest of the lessee. Now, again, if we go
7 back to the DL form, it has, essentially, comparable language
8 of the -- it's amazing, the language has not changed
9 significantly over any period of time.

10 The second duty which we've already talked about, again,
11 is reasonable diligence being required in marketing. As in
12 the case of the covenants produced, the lessee is also under
13 an implied obligation to market with due diligence the
14 products that are produced. Obviously, without that benefit
15 -- without that happening, the lessor receives no benefit.

16 I think it is important when we talk about diligence --
17 because we are talking about it as being something that is
18 going to be required of the oil companies -- that we draw some
19 distinctions. As far as the pipeline itself is concerned
20 right now, we've, of course, seen inaction. We've seen
21 inaction on the level that there's been no pipeline built and,
22 indeed, there has been -- at least to date -- no acceptance of
23 any offer to purchase that gas either. If we go within -- if
24 we talk about what is required, I think it is really the blue
25 circle and that is diligence. In other words, it is not

1 absolutely incumbent upon the oil and gas companies to succeed
2 if, in fact, success is not reasonably possible but it is
3 incumbent upon them to be diligent. In other words, they
4 cannot wait 35, 40 years in order to develop these assets.
5 They have an obligation to be out diligently trying to market
6 these -- this gas and, in fact, if we look next, there's an
7 indication here that reasonable diligence in marketing
8 requires, under the law set out in our paper, a very diligent
9 effort to seek out pipelines and to market. Just to draw a
10 distinction here as to what is due and what is not, the debate
11 here need not be over whether or not the oil companies must
12 build a pipeline. Let me tell you, the case law could not be
13 clearer that the oil companies do not have a duty to build a
14 pipeline. Under no circumstances could a court, in my
15 opinion, require them to build a pipeline. What they must
16 instead do -- and, again, the law could hardly be clearer --
17 is they must seek out in an aggressive way available markets.
18 They must respond affirmatively if an offer such as the Port
19 Authority's offer is reasonable and they cannot simply say no,
20 we don't like that, we don't like anything. Again, I
21 completely agree with Mr. Hosie's statement in that regard.

22 If, in fact, there is an existing pipeline, there's Texas
23 case authority of the Texas Supreme Court, the *Cole Petroleum*
24 case, which is cited in the written testimony. That was a
25 case where for a two or three-year period, a producer refused

1 to sell into an existing pipeline. That refusal, in turn, led
2 the Texas Supreme Court, under the lease which is very, very
3 similar to the lease we have here, to say that in and of
4 itself was grounds for cancellation of the lease and, in fact,
5 the Texas Supreme Court did that.

6 Now let's deal with misconception number three, the oil
7 companies can choose how much profit that they want and delay
8 developing or marketing the ANS gas until their profit goals
9 through state concessions or otherwise are met. This gets
10 into a lot of the issues that Mr. Hosie was talking about
11 although I draw one distinction here. As I've indicated, the
12 terms of the leases and the common law itself require that the
13 oil companies develop and market the North Slope gas when they
14 have a reasonable expectation of profit and it is my belief
15 that that reasonable expectation of profit is unquestionably
16 existent today and here is where I would draw a brief
17 distinction between what Mr. Hosie was talking about and what
18 I believe is the germane issue. We do not need in the
19 context, for instance, of the Port Authority's offer or,
20 frankly, any other offer to look very far to determine whether
21 or not the oil companies have a reasonable expectation of
22 profit. The basic equation that we would be talking about in
23 that context is simply very, very small changes have to happen
24 at the North Slope in order to instead of re-injecting the
25 gas, process it and then send it down the line and

1 particularly when you have a party such as the Port Authority
2 that has offered to specifically build the treatment facility,
3 to assume one hundred percent of the risk along with the
4 federal government loan guarantee but, nonetheless, the oil
5 company bears none of the risk of financing the pipeline. In
6 that context, I do not believe that you can at all make --
7 with a straight face -- an argument that there is not a
8 reasonable expectation of profit. Under the Port Authority's
9 figures, for example, the oil companies under, frankly, fairly
10 modest projections would stand to net a billion dollars a year
11 of -- even if the projections turned out to be far less than,
12 frankly, everyone suggests that they might be. They would
13 still, nonetheless, be making an extraordinary profit, almost
14 an infinite profit given that they don't have to expend
15 anything in the circumstances that we're talking about.

16 I think it is really helpful -- and I thought Mr. Hosie
17 got a great start on this issue -- to talk about what is going
18 on with the producers and to contrast that with the legal
19 obligations that we agree exist here. There are basically two
20 different types of categories that were the subject of
21 testimony before this Committee last fall in terms of how
22 producers look at these projects and I think both of them bear
23 significant scrutiny in light of where the development of the
24 pipeline is today. The first category is whether or not a
25 project is viewed as discretionary or non-discretionary. The

1 second has to do with do you characterize is as non-economic,
2 as economic or competitive?

3 Let's take it here as an illustration a typical oil
4 company budget and, again, this was the subject of testimony
5 by the former president of ARCO as well as the producers
6 themselves last fall were telling you this is basically oil
7 companies may look at things for budgeting purposes. They
8 first have a category of non-discretionary items. Again,
9 those were described last fall as being such items as
10 mandatory health, safety and environmental investments,
11 projects where they'll lose a concession. For instance, if a
12 cutter tells them you have until X date and by X date, you're
13 either in or you're out, that's viewed as nondiscretionary,
14 assuming they want to go forward with the project. The
15 balance of the projects that may make up an oil company budget
16 fall into the category of what is discretionary. Here we have
17 for Exxon or ConocoPhillips or BP an extraordinary list of
18 different potential projects, one of which is doing something
19 with the Alaska gas pipeline and/or simply doing something
20 with the reserves themselves.

21 Why is it that we believe today you can no longer
22 characterize the Alaska North Slope gas as a discretionary
23 decision? The reason is, to begin with, this is not a case
24 where we have any question about reserves. We have
25 extraordinary reserves -- indeed, many, many millions of cubic

1 feet of gas are actually being produced on a daily basis.
2 Instead, they are simply being reinjected. Secondly, as
3 mentioned, there is virtually no production expense that the
4 oil companies would be asked to assume if they were to accept
5 an offer such as the Port Authority's offer.

6 Finally, we have -- are blessed these days with a very
7 strong market. Gas prices appear not only today but for every
8 kind of projection, the supply and demand curves appear
9 favorable to make the State of Alaska a substantial royalty if
10 this gas can be sold. Those things combine to make more than
11 a reasonable expectation of profit.

12 We now get to the issue that I think Mr. Hosie spoke well
13 about and that is how do these oil companies rank potential
14 projects? We, again -- and in the fall testimony, fall of
15 last year, there was testimony that there was, basically, a
16 distinction that was drawn between what are noncommercial
17 projects, what are commercial projects but not competitive and
18 then what are competitive projects. Again, just to illustrate
19 the same point, we have -- out here on the fringe, we have
20 things that don't make sense. You're just going to lose money
21 doing them. No one here argues that an oil company has an
22 obligation to go out to make the state (indiscernible -
23 coughs) to lose money. We then have a category which is
24 commercial. Those are things which would return the cost, the
25 capital cost plus something and you can start out here on the

1 fringe and talk about things that would just barely break even
2 but make a little bit and then you can get further in and I
3 agree a thousand percent with what Mr. Hosie said and that is
4 as you get further in towards the commercial realm, you
5 undoubtedly will find that there are oil and gas developments
6 -- specifically, the North Slope -- where it is commercial
7 under any circumstance and a reasonable profit can be made.
8 Now, it is not the state's obligation to go out -- and,
9 indeed, we cite legal authority for this proposition -- the
10 state does not have to go out and compete with these other
11 projects. Instead, the question is are these commercial such
12 that a reasonably prudent operator would go forward with them
13 and, again -- well, I think unquestionably, that situation
14 exists today.

15 Moving to misconception number four, the oil companies by
16 virtue of owning the ANS leases have the legal right to
17 dictate the location and ownership of the pipeline. We do not
18 believe that simply because they have some rights with respect
19 to the North Slope gas, they basically can dictate who owns
20 the pipeline, where it is to go. In fact, they have, as we've
21 already spoken, a duty to prudently develop and market this
22 gas independent of any other profit making opportunities that
23 they may have. If they want to make money in Qatar, that is
24 fine but, nonetheless, they have signed an agreement and under
25 that agreement, as interpreted by every state in the union

1 that has addressed the issue, they have a duty under these
2 circumstances to market this gas. That is a duty that cannot
3 be sacrificed for other profits the producers may decide.
4 Under no circumstances could that occur.

5 I guess another place that I would draw somewhat of a
6 distinction with what Mr. Hosie was talking about is, in our
7 view, the antitrust implications of simply refusing to sell
8 gas. We believe and, indeed, there was testimony in February
9 -- a FERC expert that this Committee hired -- himself raised
10 the issue of whether or not there were antitrust concerns with
11 a simple refusal to sell any gas under any circumstances. We
12 believe that, in fact, that could -- if the oil companies
13 chose to simply refuse to sell the gas, that could be
14 construed -- it's what is known as monopoly leveraging. Now,
15 monopoly leveraging, according to the textbooks, is the
16 leveraging, a monopolist use of power in one market to gain an
17 advantage in a related market or power held in one time period
18 to gain advantage in a later period. Often the leveraging
19 occurs in a vertical context as when an upstream producer with
20 monopoly power uses that power to gain advantage in a
21 downstream market.

22 Now, the issue here is if the oil companies were to use
23 their monopoly, their 90 to 95 percent leasehold interest in
24 the North Slope -- if they are going to use that to basically
25 exclude competition along the pipelines where no other

1 pipelines can compete because of that ownership, we believe
2 that that could be construed as monopoly leveraging which
3 leads us to misconception number five, the last one.

4 We believe that it is fundamentally a misconception that
5 the state is in a relatively weak negotiating position with
6 these oil companies. The reality, we believe, is precisely
7 the opposite for three fundamental reasons. Number one, we
8 believe if the oil companies insist on not marketing these ga
9 -- the gas, their leases can be canceled and Mr. Hosie is
10 absolutely right that a traditional remedy is conditional
11 cancellation. I believe based on the language that is here in
12 the leases, that an unconditional cancellation would be
13 perfectly within the state's right and the state could if it
14 so chose unconditionally cancel that. It might require a
15 judicial proceeding but that is a power that the lease
16 specifically affords the state.

17 Secondly, if the oil companies insist on not marketing
18 Alaska stranded gas, the damages for this could be enormous.
19 Thirdly, again, we believe that anti-competitive refusal to
20 deal would be actionable under the antitrust laws and that
21 these laws provide mandatory treble damages and injunctive
22 relief.

23 Talking about lease cancellation, again, here we have one
24 of the modern forms but the DL-1 form has fairly comparable
25 language. The lease itself provides default and termination

1 and cancellation. The failure of the lessee -- that would be
2 the oil companies -- to abide by all express and implied
3 provisions of this lease is a default whenever the lessee
4 fails to comply with any of the provisions of this lease and
5 fails within 60 days after written notice of that default to
6 begin and diligently prosecute operations to remedy that
7 default, this lease may be terminated by an appropriate
8 judicial proceeding. Indeed, just to give you a little bit
9 more flavorful language, what we have not put up here is if
10 there is no well on the property, the Commissioner is given
11 the power without even going to a judicial proceeding to
12 cancel the lease.

13 There's no doubt in accordance with the case law, the
14 cases that address this issue before that, in fact, the state
15 could cancel the lease. One of the authorities, Professor
16 Summers, one of the leading treatises on law and gas says if
17 the lease contains an expressed provision for forfeiture of
18 the lease for breach of all covenants thereof -- that's
19 exactly what we just read -- which either by express terms or
20 by construction of the court includes implied covenants and
21 has the effect of making them conditions, there would seem to
22 be no doubt that the lessor is entitled to declare a
23 forfeiture for breach of the implied covenant to market and
24 recover in an action to quiet title or cancel the lease. That
25 is precisely the circumstance we believe exists if the oil

1 companies refuse to reasonably market this gas. We've been
2 through the lease provision before. It meets that. It's
3 also, as I mentioned earlier, the *Cole Petroleum* case where
4 the Texas Supreme Court addressed virtually identical
5 circumstances, stands for the same proposition.

6 Strength number two that we believe that the state brings
7 to bear in these negotiations or in developing the gas is the
8 damages claims. In other words, if the oil and gas companies
9 refuse to develop this gas, we believe that the state will
10 incur extraordinary damages for which it would have a remedy
11 in court. Perio -- again, it's one of the leading
12 authorities, Professor Coontz's treatise on the law of oil and
13 gas where he states damages are recoverable for breach of the
14 implied duty to market the product. It has been held that
15 damages may be recovered concurrently with the cancellation of
16 the lease. The measure of damages for breach of the implied
17 duty to market the product is the royalty which the lessor
18 would have received if the product had been marketed. Now,
19 particularly -- I think this damages issue really does
20 emphasize, to my way of thinking, the importance of something
21 being done sooner rather than later. In other words, if a
22 proposal such as the Port Authority can begin the flow of gas,
23 could begin that gas being sold, royalty being generated, it
24 would not have the damages, the damages would not accrue. On
25 the other hand, if the oil companies for whatever reason -- if

1 they attempt to put together a proposal and are stymied for
2 several years by antitrust considerations, if they attempt to
3 put a proposal together and they run into a five -- between
4 competing five primes and Canada, say, if all of those things
5 combine together, the state will have been banished simply
6 because the oil companies wanted to do it a different and, in
7 fact, not equal and not, we believe, the prudent way and will
8 have damaged the state by virtue of having delayed that
9 production. Now, when we talk about delayed production,
10 obviously, time is money but to me, it is more than simply
11 putting off for a little bit the receipt of royalty. I like
12 to think of royalty in this context, as every dollar of
13 royalty or every day for which royalty is not paid, that
14 royalty effectively goes to the very end of the line. In
15 other words, if you missed a year of royalty and then a
16 pipeline starts up, you don't make up that first year of the
17 royalty. Instead, you only make up that royalty at the very,
18 very end and, in fact, if the northern parts of Alaska are
19 even fractionally as productive as has been projected, you may
20 literally never make up that royalty. So I think the simple
21 proposition here is that the damages that would be sustained
22 by the state from the non-development and non-marketing of
23 North Slope gas would be enormous and, in fact, they relate
24 directly even in the event there is simply delay, it is not
25 enough to five years from now come back and say okay, now we

1 are willing to do what we should have done five years ago.

2 Finally, we can briefly talk about the antitrust claims
3 for concerted refusal to deal. We cite the authorities in the
4 paper with respect to the Sherman Act claims and the monopoly
5 claims, monopoly leveraging, etcetera. While we are not here
6 today at all to say that an antitrust violation has occurred,
7 it is our belief that should there be a concerted refusal to
8 deal with respect to this gas, that that would be violative of
9 the antitrust laws. The problem -- and just to put in
10 perspective how such a situation could occur and why it might
11 constitute a restraint of trade -- can kind of be seen in the
12 chicken and egg situation that the state's been in now for 30
13 plus years. Obviously, gas is not like oil. It can't be
14 trucked away or picked up by rail. It cannot be marketed
15 without a pipeline. However, a pipeline cannot be built
16 without the assurance of gas and so you have to figure out
17 where do you start on that equation. We believe that it would
18 be a concerted refusal to deal actionable under the antitrust
19 laws if there is a failure to build a pipeline and, in turn, a
20 refusal to sell the gas to others who are, in fact, willing to
21 build such a pipeline. The antitrust remedies, very briefly,
22 include treble damages -- in other words, three times the
23 amount of damages -- and there are special provisions for
24 injunctive relief. This might be somewhat responsive to
25 earlier questions about the time frame. It would be possible

1 under an antitrust context to go in and see expedited relief
2 from a court to order the sale of gas under reasonable market
3 terms.

4 In conclusion, the bottom line as far as the duties and
5 misconceptions that we've talked about, is, first, we believe
6 the oil companies should make available the North Slope gas to
7 the Port Authority and other competing pipeline projects on
8 the same terms and conditions that are the industry norm.
9 Second, that would allow the decision with respect to the
10 pipeline to be based on which pipeline is best for Alaska and
11 not on any perceived stranglehold that the oil companies do
12 not, we contend, possess. Third -- and this is a last resort
13 -- this is not -- I agree completely with Mr. Hosie that
14 litigation is not the first option but if, in fact, there is a
15 complete refusal to deal, we believe then fair competition
16 would have to be required by legal means.

17 In conclusion, we believe as a consequence of the Port
18 Authority's offer and, indeed, the market portions that are at
19 work here, we no longer have a situation where Alaska's gas is
20 stranded. Indeed, a market and an offer exists today for that
21 gas and we believe that this body, working together with the
22 executive, can, in fact, using the legal remedies that are
23 talked about effectively get that gas marketed. Thank you.

24 CHAIRMAN: Thank you. Do we have questions from members?
25 None? Mr. Hosie, I was wondering if you could come up. I

1 just had a follow-up question. I'm not sure, perhaps both
2 will want to answer. With regards to the concept -- if we
3 have a standing oil gas pipeline and that's certainly -- the
4 Port Authority's made a proposal -- Trans-Canada's been in
5 negotiation -- and the producers say well, we have trouble
6 deciding whether we should sell at the wellhead because you've
7 got a standing oil gas pipeline proposal but we're not sure
8 what our tax is going for or going to be just, you know, for
9 the production. What right do they have to say we don't want
10 to sell, we can't make a decision to sell until we get
11 certainty on the way that the gas is going to be taxed in the
12 field.

13 MR. HOSIE: If I may answer that first, they have no
14 right to say that unless they can come to you and persuade you
15 that absent that concession and that prospective certainty
16 what would otherwise be an economic project is suddenly
17 uneconomic. In short, it would have to be the pivotal point
18 and -- because it really does -- I disagree with Mark on three
19 things and one of them is that.....

20 MR. COTHAN: No history.

21 UNIDENTIFIED MALE SPEAKER: There you go.

22 MR. HOSIE: Mr. -- a history of mutual respect. One of
23 them is that because the dollars are so enormous -- \$20
24 billion -- if the project is marginally economic, I can't
25 imagine a court saying you must go forward and risk \$20

1 billion because things happen. Remember what happened to oil
2 prices in 1986? Nobody thought that was going to happen but
3 remember what happened. They remember. I mean, there's
4 always risk and when you're talking about a sum this large,
5 you better have a lot of room for comfort within that economic
6 circle and so if fiscal certainty, if tax -- a guaranteed tax
7 regime reaching forth in the future becomes the pivotal point
8 economically, then they can certainly ask for it and then it's
9 in the state's discretion to agree or not agree.

10 One comment on monopoly leveraging. Monopoly leveraging
11 is not actionable in the Ninth Circuit. It is in some
12 circuits. It's not actionable under the *Alaska Airlines* case
13 in the Ninth Circuit. I truly think that it is not, *per se*,
14 improper for the oil companies to say we don't want to sell to
15 a pipeline because we have our own plans going forward and
16 that was the second area of disagreement.

17 MR. COTHAN: Just to briefly respond, I don't think I
18 disagree with what Spencer just said. If it was simply
19 marginal, it would not -- we are -- that's not where we are
20 today. We are in a situation where the oil companies are
21 literally faced with a proposition where they have absolutely
22 zero risk with respect to the pipeline. That is risk that is
23 willingly going to be assumed by a third party. Those risks
24 can no longer serve as a reason for inaction. The only risk
25 that would be associated would be the commodity risk which, in

1 fact, oil and gas companies have every day of the year and, in
2 fact, if we look at the situation we're talking about, their
3 expenditures would be so minimal and, indeed, according to
4 every reasonable projection of prices, their return would be
5 so extraordinary -- I mean, we're talking about profit levels
6 here not in the hundreds but probably in the thousands of
7 percentage if you compare those two as to what they would make
8 simply by saying yes to an offer to sell to a pipeline such as
9 the Port Authority and so in that regard, I don't disagree
10 that if it was just tiny, just, oh, gosh, real close, I don't
11 disagree that a court might recognize the ability of the oil
12 industry to there make the decision but that's not remotely
13 the circumstances that the Port Authority's offer has placed
14 firmly before the oil companies.

15 CHAIRMAN: Other questions? Is it possible to get a
16 printed copy, please, of your PowerPoint presentation?

17 MR. COTHAN: We would be happy to do that.

18 CHAIRMAN: If there are no further questions, thank you
19 very much for your presentation today. Thank you, members,
20 for sitting through. I know we all have busy schedules but we
21 felt this was a very important topic to be discussed at this
22 time. Representative Samuels?

23 REPRESENTATIVE SAMUELS: Thank you for that. House
24 members, I got a note from the Speaker's office. We'll go
25 back in at 5:30.

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CHAIRMAN: The meeting is adjourned.
(Off record)