June 19, 2017

HAND-DELIVERED

BP Exploration (Alaska) Inc.
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Ms. Chantal Walsh, Director
Division of Oil and Gas
Department of Natural Resources
550 West 7th Avenue, Suite 1100
Anchorage, AK 99501-3560

Re: Greater Point McIntyre Area Plans of Development

Dear Director Walsh:

BP Exploration Alaska (BPXA), as Operator of the Prudhoe Bay Unit, submits with this letter six updates to the Plans of Development for Lisburne, Combined Niakuk, Point McIntyre, Raven, North Prudhoe Bay and West Beach Participating Areas in the Greater Point McIntyre area of the Prudhoe Bay Unit.

The updates to the Plans of Development may contain geological, geophysical, or engineering data that is labeled 'confidential.' Data labeled 'confidential' is a confidential and valuable trade secret of BPXA and the Prudhoe Bay Unit working interest owners, and BPXA requests that the data be kept confidential as provided in the Prudhoe Bay Unit Agreement and AS 38.05.035(a)(8), 11 AAC 82.810 and other applicable law; and note that such data is protected from misuse and disclosure by the Alaska Uniform Trade Secrets Act (AS 45.50.910 et seq.).

Any questions can be directed to Bill Bredar at 564-5348 or through email to William.Bredar@bp.com.

Respectfully,

for

Katrina Garner
Fieldwide Manager
Alaska Reservoir Development Team
BP Exploration (Alaska) Inc.

cc: Mr. Jon Schultz, ConocoPhillips Alaska, Inc.
Mr. Gerry Smith, ExxonMobil Alaska, Production Inc.
Mr. Dave White, Chevron USA
Mr. Dave Roby, Alaska Oil and Gas Conservation Commission

Lisburne

PRUDHOE BAY UNIT
LISBURNE PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Lisburne Participating Area (LPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the LPA POD is to identify strategies to maximize commercial oil production from the Lisburne reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the LPA POD assumes a continuation of the current business climate and reflects the current understanding of the Lisburne reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, CONDENSATE AND NGLS

Crude, condensate and NGL rates for the Lisburne Field averaged 10.7 MB/D for the reporting period April 1, 2016 to March 31, 2017. A total of 3.9 MMB of Lisburne oil and NGL was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period.

B. PRODUCED GAS

Lisburne gas production totaled 68.7 BSCF for the reporting period with 42 BSCF re-injected into the Lisburne Gas Cap to provide pressure support. 6.3 BSCF was consumed as fuel or flare gas. For the report period, Lisburne gas production averaged 187.6 MMSCF/D yielding an average GOR of 17,558 SCF/STBO. Lisburne NGL separation averaged 1.26 MB/D with a total of 0.46 MMB delivered and shipped with crude oil production through TAPS during the reporting period.

C. PRODUCED WATER

Lisburne water production for the reporting period was 3.1 MMB, yielding an average water production rate of 8.5 MB/D and average water cut of 44%. LPC produced water not used for water injection in the Pt. McIntyre reservoir is injected into the LPC-01 and LPC-02 Cretaceous interval disposal wells. Water injection into the two Cretaceous disposal wells totaled 18 MMB (including Pt McIntyre, Niakuk and FS1 produced water) yielding an average water disposal injection rate of 52 MB/D for both wells.

2.2 DEVELOPMENT

Development activities have continued in accordance with the LPA POD. Summarized below are the significant development activities over the past year. More details regarding these activities can be found in Section 3.

A. Enhanced Recovery - Injected Water

Seawater injection into the Lisburne reservoir gas cap continues to be used to supplement the benefits of gas injection for oil recovery.

Seawater injection continued into 04-350 (peripheral Wahoo), NK-25 (Alapah) and L5-13 & L5-15 (mid-field Wahoo).

On July 14th 2008, the Lisburne Gas Cap Water Injection (GCWI) Pilot commenced injecting into the L5-29 well, as approved under CO 207A.001 and AIO 4E.029. During the reporting period the GCWI Pilot was approved for permanent injection under AOGCC Conservation Order 207B.16. The injector remained shut in throughout the reporting period awaiting repair. Repair is planned during the current POD plan year. Water breakthrough has reached wells L5-28, L5-32, L5-33 and L5-36. Breakthrough indications include rise in watercut, GOR suppression, as well as water sample analysis for seawater trace minerals.

Peripheral Lisburne Wahoo seawater injector 04-350 commenced injection in May 2012. A total of 0.815 MMB of seawater was injected during the reporting period, for an annual average rate of 2227.8 bbl/day. Seawater production has been observed in offset L3-22.

Mid-field Lisburne Wahoo seawater injectors L5-13 and L5-15 commenced injection in March 2013. A total of 1.67 MMB of seawater was injected in both wells during the reporting period, for an average rate of 2277 bbl/day per well. Seawater breakthrough to offset producer L5-16A has been detected. L5-13 developed integrity issues at the end of the reporting period and has since been secured with plans to abandon the well.

Lisburne Alapah seawater injector NK-25 commenced injection in March 2013. A total of 1.7 MMB of seawater was injected during the reporting period, for an average rate of 4651 bbl/day. Seawater breakthrough to the offset producer NK-26 has been confirmed. NK-

26 was shut in for repair during the reporting period and options are being evaluated to repair the well and restore production capability to the area.

B. Well Activity and Rate Adding Surface Projects

Two wells: L1-13 and L5-12A, were drilled and completed into the Lisburne Formation during the reporting period. Seventeen additional Lisburne wells had a total of eighteen rate-adding interventions and repairs performed during the reporting period. These rate-adding interventions included perforations, acid stimulations, hydraulic fracture stimulations, gas-lift work, profile modifications, tubing patches, casing repairs and surface component repairs. The Lisburne Gas Cap Water Injection Project achieved permanent status via Conservation Order 207B on January 26, 2017.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

The Lisburne Participating Area is divided into three areas for depletion planning purposes. The East Lisburne area includes the L5 pad area and areas east of the L5 pad to the boundary of the LPA. It includes both Wahoo and Alapah production. West Lisburne includes L1 pad and the Lisburne Gas Injection (LGI) pad west to the boundary of the LPA. The West Lisburne area has Wahoo only production. The Central Lisburne area also has LPA Wahoo only production from the remaining L2, L3, and L4 pads. L2 pad has some IPA production associated with the L2 re-route project.

Oil recovery from the East and West areas of the Lisburne Wahoo reservoir continues through a combination of solution gas drive, gas cap

expansion supported by gas injection at LGI pad, gas cap water injection in L5-29 and mid-field water injection from L5-13 & L5-15. Solution gas drive is the primary recovery mechanism in the Central area supplemented by weak aquifer influx in addition to peripheral water injection from 04-350.

The current Lisburne development plan is focused in five key areas: (1) maximizing commercial oil production through optimization of field gas offtake; (2) remedial wellwork; (3) optimizing voidage replacement; (4) evaluation of reservoir pressure maintenance options; and (5) reservoir characterization.

A map of the Lisburne Field showing current fulltime production, cycle production, injection, shut-in, plugged and abandoned/temporarily abandoned wells and sidetracked wells is included as Attachment 1.

East Lisburne

The East Lisburne area includes wells drilled from both L5 pad and Heald Point to the eastern boundary of the LPA. There are three cycle producers, nine full time producers, one Alapah seawater injector (NK-25), two mid-field seawater injectors (L5-13 and L5-15) and one gas cap seawater injector (L5-29) in this area. L5-29 has been shut in since July 2015 but plans are underway to repair it. During the reporting period, the East Lisburne work effort included managing and monitoring of the Lisburne GCWI pilot through fluid sampling L5 offset producers. Reservoir surveillance activities such as static reservoir pressure measurements were completed as part of surveillance for the gas cap water injection (GCWI) pilot project. Conversion of mid-field Wahoo producer wells L5-13 and L5-15 to seawater injection was completed in March 2013 (see section 3.4 Projects).

Conversion of Alapah producer NK-25 to seawater injection was successfully completed in March 2013. Monitoring of this flood will continue via the injector NK-25 and the offset Alapah producer NK-26 (see section 3.4 Projects). Newly acquired seismic and the recent well problems in the producer NK-26 will factor into the future plans for this area.

West Lisburne

West Lisburne, including L1, K and Lisburne Gas Injection (LGI) pads and extending to the western boundary of the LPA, includes wells completed in the Wahoo. There are ten full time and three cycle producers, and three gas injectors in this area. Additional work on L1 pad included obtaining reservoir pressure measurements.

Central Lisburne

The Central Lisburne Area includes pads L2, L3, and L4. There are twelve full time and seven cycle producers in this area. Activities in this area included continued operation of peripheral water injector 04-350i between L3 and L4 pads and obtaining reservoir pressure measurements.

3.2 PRODUCTION MANAGEMENT

The LPC continues to be gas constrained. Due to the high GOR nature of Lisburne wells, oil production rates are influenced by seasonal ambient temperature cycles and corresponding compressor efficiencies that in turn drive oil offtake rates.

Certain wells in the field exhibit a GOR behavior that responds positively to a shut-in period compared to continuous production. Appropriate wells are rotated through a cycle of several days of production followed by days or weeks of shut-in. When production is resumed, the GOR is generally reduced resulting in increased oil production.

3.3 Drilling and Other Well Activity

Current plans include drilling an additional well, L3-25, during the POD plan period. This well is depicted in Attachment 1. Several Lisburne drilling locations are being considered for possible future drilling. Additional drilling is contingent on the performance and evaluation of the 2015-2017 drilling program.

3.4 Projects

The L5 GCWI pilot project commenced injection in July of 2008. The initial injection rate was 2 MB/D, and over time has been gradually increased to an injection rate of about 15 MB/D. 22.1 MMB of seawater has been injected in L5-29 since the start-up. Water injection is expected to continue during the permanent phase. The peripheral Wahoo seawater injection pilot commenced injection in May 2012. 4.3 MMB of seawater has been injected in 04-350. The mid-field Wahoo seawater injection pilot commenced in March 2013 with the conversion to injection of wells L5-13 and L5-15. A combined total of 7.3 MMB of seawater has been injected in L5-13 & L5-15. The Alapah seawater injection pilot commenced injection in March 2013 into converted producer NK-25 and injected 5.9 MMB of seawater. A full report of the multiple projects' surveillance can be found in the Lisburne Annual Reservoir Surveillance Report.

Currently, re-injection of the Lisburne produced gas is occurring for pressure support of the Wahoo. Additional support in the Wahoo reservoir through the use of water injection continues. This effort is currently focused on the L5 pad and Drill Site #4 which both have available seawater supply.

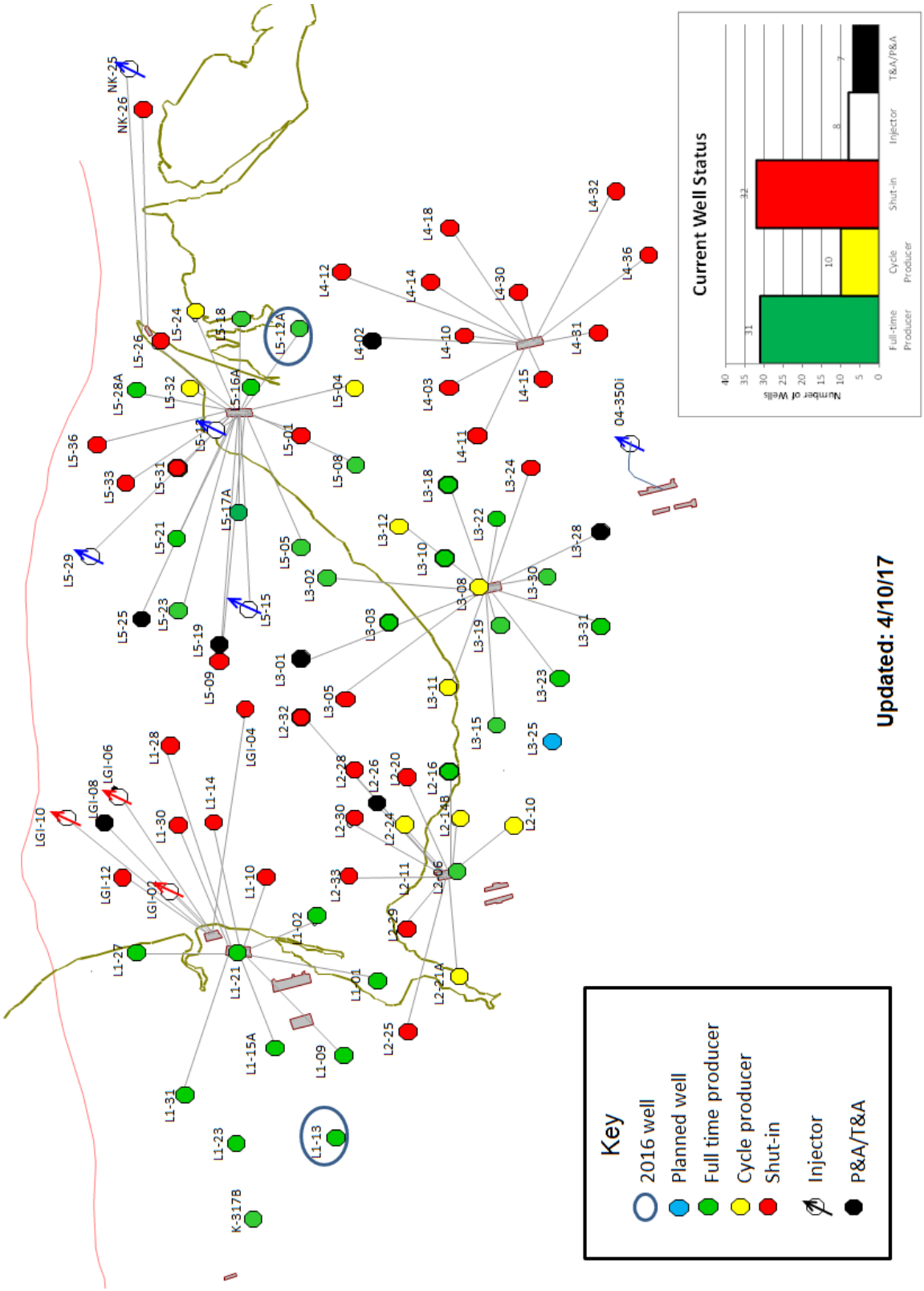
In 2014 the L4 pad export line was shut-in due to line wall loss concerns. Evaluation of future opportunity and line repair options for L4 are being considered as a potential future project.

3.5 PRODUCTION ALLOCATION

Production of oil and gas will continue to be allocated to the Lisburne Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There are test separators at Lisburne Drill Sites L1, L2, L3, L4, L5, K-pad, and Niakuk that are utilized to satisfy those conditions.

ATTACHMENT 1 LISBURNE FIELD WELL STATUS MAP

Current as of May 2017



N Prudhoe

PRUDHOE BAY UNIT
NORTH PRUDHOE BAY PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the North Prudhoe Bay Participating Area (NPBPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the NPBPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the NPBPA POD assumes a continuation of the current business climate and reflects the current understanding of the North Prudhoe Bay reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT - SUMMARY OF DEVELOPMENT ACTIVITIES AND STATUS

Production from North Prudhoe Bay occurred from a single well completed in 1993 (WB-03). Previous reports have set forth the recompletion and testing activities that have been undertaken on WB-03. The well was shut-in February 2000 due to safety concerns arising from continued proppant production from an earlier fracture stimulation of the Sag River Formation. Attempts to eliminate flowback of proppant were made. Due to safety and environmental considerations production testing was suspended. Production is

currently shut-in due to integrity concerns. To date, total crude and condensate production totals 2.1 MMB.

3.0 DEVELOPMENT PLANS

BP as Prudhoe Bay Unit Operator has reviewed the condition and history for WB-03, and concludes that the well is not currently in condition to bring on line and flow. Significant challenges also remain for development of the Ivishak and Sag River intervals due to structural complexity, reservoir compartmentalization, and fluid contact uncertainty. This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing was completed September 2016. Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation will focus on improving the structure mapping over the field and an understanding of the subsurface areas of interest (Kuparuk, Sag, Ivishak, Lisburne, and Alapah intervals).

Niakuk

PRUDHOE BAY UNIT
COMBINED NIAKUK PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Combined Niakuk Participating Area (CNPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the CNPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the CNPA POD assumes a continuation of the current business climate and reflects the current understanding of the Niakuk reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE,CONDENSATE AND NGLS

Niakuk crude, condensate and NGL rates averaged 1.3 MB/D for the reporting period April 1, 2016 to March 31, 2017. This rate, combined with production from the other GPMA fields, fully utilized available Lisburne Production Center (LPC) capacity, within

reservoir management constraints. A total of 0.478 MMB was delivered to the Trans-Alaska Pipeline System (TAPS).

B. Produced Gas

Niakuk gas production totaled 0.8 BCF for the reporting period, of which none was re-injected into the Niakuk reservoir. The produced gas is processed at the LPC and injected into the Lisburne and Pt. McIntyre reservoirs. A total of 139 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 56.08 B/D with a total of 0.021 MMB delivered and shipped with crude oil production through TAPS during the reporting period.

C. Produced Water

Niakuk water production for the reporting period was 7.3 MMB, yielding an average water production rate of 20 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre reservoir.

2.2 Development

Development activities have continued in accordance with the CNPA POD. Summarized below are the significant activities at Niakuk over the past year. More details regarding these activities can be found in Section 3.

A. Enhanced Recovery - Injected Water

Waterflood operations are conducted to maintain field pressure and optimize conformance. During the reporting period three water injection wells, NK-10i, NK-13i, NK-18i were in operation. NK-15i is shut-in for future sidetrack opportunity. NK-23i is shut in because the surface line is not in service, and is awaiting repairs. NK-28i is shut back in after additional TxIA communication was found. NK-16i

remains shut in due to a thief zone connection to NK-21. The total water injected into the reservoir during the reporting period was 5.4 MMB, averaging 14.7 MB/D.

B. WELL ACTIVITY

Niakuk has an active non-rig wellwork program and scale inhibition program. During the reporting period:

- NK-42 had a successful repair for a TxIA communication and an optimized gas lift system desiign installed.
- NK-09 had a scale clean out and with a inhibition treatment performed

Two oil samples were taken from NK-43 during the reporting period (6/16 and 12/16) for geochemical analysis to confirm production allocation splits between the Sag River and Kuparuk reservoirs. The analyses showed that 83-95% of oil production in NK-43 is from the Kuparuk.

3.0 PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

The structural and stratigraphic complexity of the Niakuk reservoir precludes positioning injectors and producers in a uniform pattern (Attachment 1). Emphasis is given to a dynamic reservoir management strategy. Elements of this strategy include selective perforation and profile modification to isolate water-bearing zones in production wells and to open un-swept zones in injection wells. Production profiles are obtained, as needed, to better understand which zones are receiving pressure support and which zones are isolated. Pressure surveys are taken to monitor the performance of offtake and injection strategies. These data help determine the continuity of individual reservoir zones and the

communication characteristics between wells. Analysis of this information is used for material balance calculations.

3.2 PRODUCTION MANAGEMENT

Reservoir management and waterflood strategies are designed to optimize commercial oil production from the Niakuk reservoir. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts.

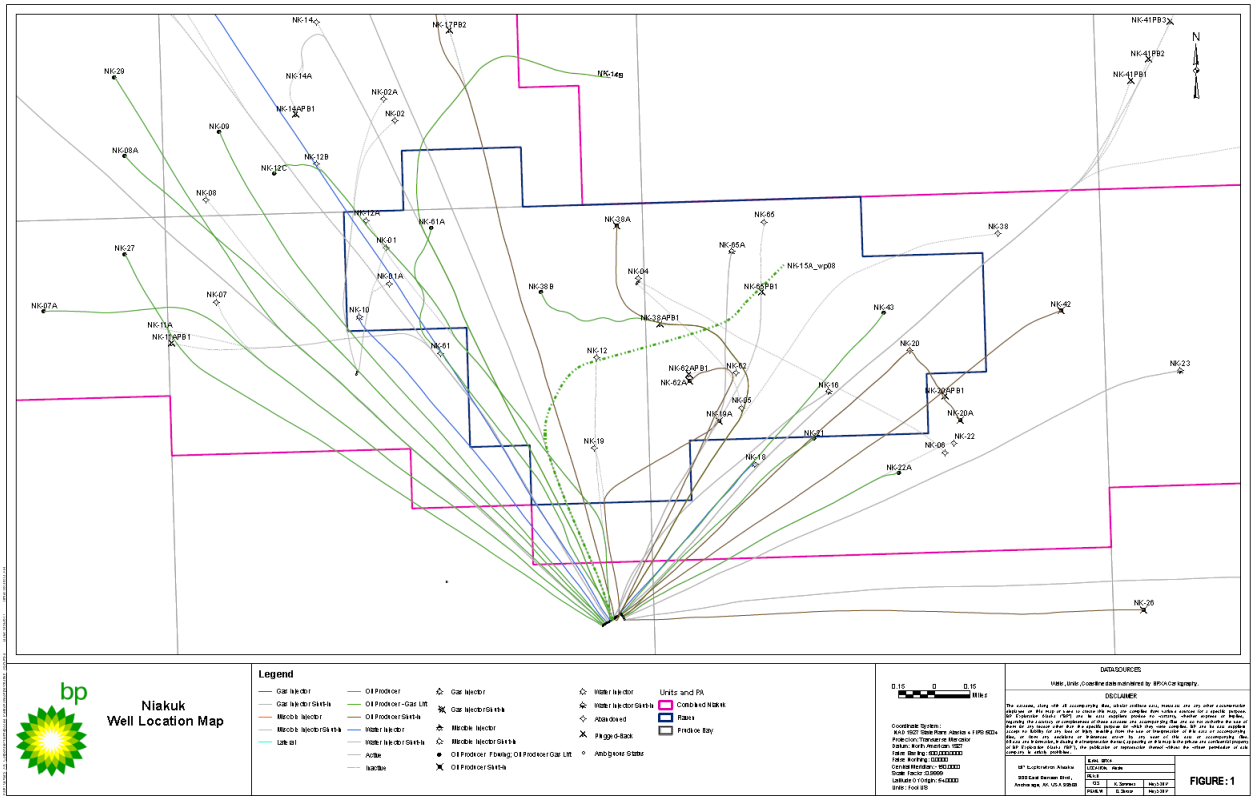
3.3 DRILLING AND OTHER WELL ACTIVITY

As part of the ongoing reservoir management strategy, Niakuk development well targets are continually being evaluated. Technical work to assess potential infill and peripheral drilling locations continued during the report period. An updated integrated subsurface description project has been underway during this year and has been utilizing the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing completed September 2016. Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation of the data has been focusing on improving the structure mapping over the field and an understanding of the subsurface areas of interest.

3.4 PRODUCTION ALLOCATION

The production of oil and gas will continue to be allocated to the Combined Niakuk Participating Area in accordance with the conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at Heald Point.

ATTACHMENT 1 – NIAKUK WELL LOCATION MAP



Pt. McIntyre

PRUDHOE BAY UNIT
PT. MCINTYRE PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT

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ATTACHMENT 1: Map of Pt. McIntyre Participating Area

1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Pt. McIntyre Participating Area (PMPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the PMPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the PMPA POD assumes a continuation of the current business climate and reflects the current understanding of the Pt McIntyre reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE AND CONDENSATE

Crude, condensate and NGL rates averaged 12.4 mb/d during the reporting period April 1, 2016 to March 31, 2017. Field offtake was managed to maximize production within the available pipeline and facility constraints, while maintaining close to full voidage replacement. A total of 4.5 MMB was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period. All Pt. McIntyre

production until October, 2016 went to the Lisburne Production Center (LPC). The completion of the STP-36 Project that month enabled all PM-2 production to go to GC-1.

B. PRODUCED GAS

Pt. McIntyre total gas production (including MI breakthrough in EOR patterns) totaled 51.3 BCF for the reporting period. Produced gas supplied from the LPC is injected into the Pt. McIntyre gas cap to provide pressure support and promote recovery in the up-structure area. A total of 50.9 BCF was injected into the Pt. McIntyre gas cap/gravity drainage area during the reporting period. Lean gas supplied from the LPC for Pt. McIntyre gas cap re-injection is a mixture of gas from Pt. McIntyre, Lisburne and Niakuk production.

A total of 4.1 BCF of Pt. McIntyre gas produced was consumed as fuel or flared. The fuel and flared gas was consumed for normal LPC and GPMA drillsite operations.

NGL separation averaged 0.91 MB/D with a total of 0.33 MMB delivered and shipped with crude oil production through TAPS during the reporting period. This NGL volume is the allocated Pt. McIntyre NGL production in the LPC.

C. PRODUCED WATER

Pt. McIntyre water production for the reporting period was 26.6 MMB, yielding an average water production rate of 72.7 MB/D.

2.2 DEVELOPMENT

Development activities have continued in accordance with the PMPA POD. Summarized below are the activities at Pt. McIntyre over the

past year. More detail regarding these activities can be found in Section 3.

A. ENHANCED RECOVERY - INJECTED WATER

Waterflood and WAG operations are conducted to help maintain field pressure and improve reservoir recovery efficiency. During the reporting period, 16 waterflood patterns were in operation. Produced water from the Pt. McIntyre Field is normally used for re-injection. Additional produced water is provided from the PBU IPA and is pumped to the LPC from Flow Station 1. Water injection totaled 34.5 MMB for the report period. This volume is equivalent to a daily rate of 94.5 MBWPD.

B. ENHANCED RECOVERY - MISCIBLE GAS

The Pt. McIntyre miscible gas (MI) enhanced oil recovery project continued operation with injection of a total of 11.9 BCF of MI during the report period (33.0 MMSCFD). All MI gas was supplied from the PBU CGF facility.

C. WELL ACTIVITY

Pt. McIntyre has an active non-rig wellwork program and scale inhibition program.

D. RATE ADDING SURFACE PROJECTS

The STP 36-inch pipeline had been used to send some production from PM-2 to GC1, but was taken out of service in November 2011 because of concerns about external corrosion. About 1.8 miles of the STP-36 line cannot be used due to cathodic protection issues. The remaining ~8 miles of the ~10 mile line was smart pigged in 2014 to evaluate returning the line to service. The option to use an

existing common line and then jumper into the useable portion of the STP 36" line requires that all PM-2 production go to GC1, rather than splitting PM-2 production between LPC and GC1. Benefits of this added flow into GC1 were evaluated, and restoration of the STP-36 line to service was completed October 2016, resulting in increased production at LPC.

3.0 PLAN OF DEVELOPMENT

3.1 RESERVOIR MANAGEMENT

Pt. McIntyre is undergoing a tertiary recovery process involving alternating cycles of miscible gas injection and water injection (WAG) to maximize commercial production and total recovery from the reservoir.

The reservoir management strategy is to utilize injection-to-withdrawal (I/W) ratios at a pattern level to maintain the reservoir pressure above that required for miscibility (minimum miscibility pressure) during the MWAG process and to stabilize the gravity drainage waterflood interaction area of the field. This is accomplished by setting optimum injection rates, managing pattern offtake, and cycling high Formation GOR (FGOR) production wells as needed.

Miscible gas injection (MI) started in October 2000 with injection into well P2-23. The target cumulative MI injection is currently estimated at 35% of the hydrocarbon pore volume. After the cumulative target slug size of MI has been injected into the formation, pressure support will be maintained with water injection. A total of 271 BCF of MI gas has been injected into the reservoir to date.

3.2 PRODUCTION MANAGEMENT

Reservoir management and EOR strategies are designed to optimize oil production from the Pt. McIntyre reservoir. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios.

3.3 DRILLING AND OTHER WELL ACTIVITY

Technical assessment of the subsurface is ongoing. This area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged Pre-Stack Depth Migration (PSDM) processing completed September 2016. Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation will focus on improving structure mapping over the field and understanding of the subsurface areas of interest (Kuparuk, Sag, Ivishak, Lisburne, and Alapah intervals).

3.4 MISCIBLE GAS ENHANCED OIL RECOVERY

Miscible gas injection will continue to be an integral part of the Pt. McIntyre reservoir management plan during 2017. Three injectors at PM-1 and ten injectors at PM-2 have been equipped for MI injection and it is anticipated that the remaining waterflood patterns will receive MI over the life of the project. Eleven patterns have now received at least one cycle of MI, and MI response has been detected in multiple wells and patterns.

3.5 PROJECTS

Well optimization and additional rate adding projects in association with the STP 36 Project are being evaluated.

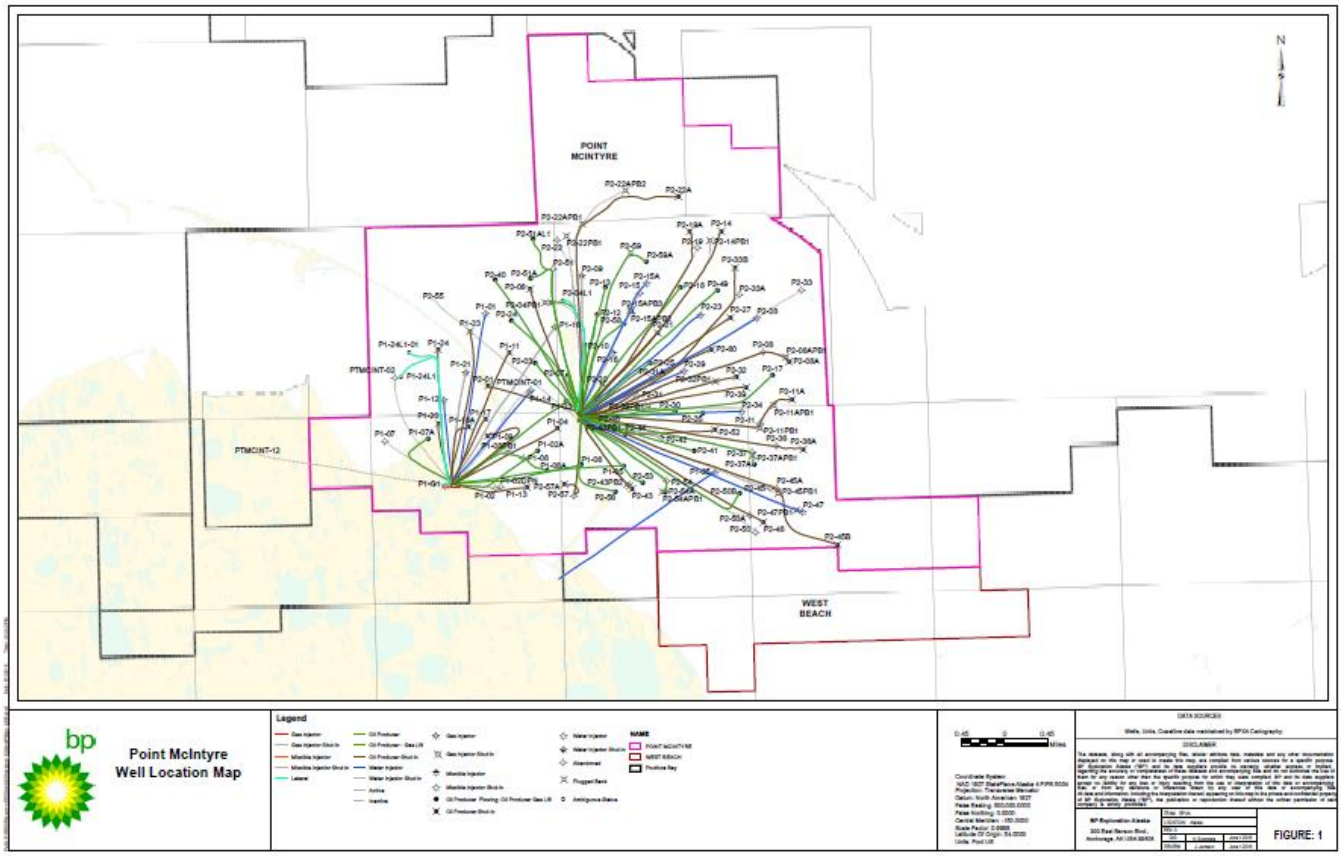
A project that expanded the volume of Miscible Injectant to PM-2 was executed and a similar expansion for PM-1 pad is being considered.

3.6 PRODUCTION ALLOCATION

The production of oil and gas will continue to be allocated to the Pt. McIntyre Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at Drill Site PM-1 and two test separators at Drill Site PM-2.

Revisions to the existing allocation procedures covering three phase PM-2 production processed through GC-1 were previously reviewed with the Alaska Department of Natural Resources and the Alaska Oil and Gas Conservation Commission.

Attachment 1: Point McIntyre Participating Area



PRUDHOE BAY UNIT
RAVEN PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 UPDATE OF PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the Raven Participating Area (RPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the RPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the RPA POD assumes a continuation of the current business climate and reflects the current understanding of the Raven reservoirs. Changes in the business climate, new insights into the reservoirs, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT

2.1 PRODUCTION

A. PRODUCED CRUDE, CONDENSATE AND NGLS

Production from Raven, combined with production from the other GPMA fields, fully utilized available Lisburne Production Center (LPC) capacity, within reservoir management constraints. Raven

crude, condensate and NGL rates averaged 0.94 MB/D for the reporting period April 1, 2016 to March 31, 2017. A total of 0.34 MMB from the Raven PA was delivered to the Trans-Alaska Pipeline System (TAPS) during the reporting period.

B. PRODUCED GAS

Raven gas production totaled 0.85 BCF from April 1, 2016 to March 31, 2017. Produced gas from Raven is processed at the LPC and injected into the Lisburne and Pt. McIntyre Fields. A total of 74 MMCF of produced gas was consumed as fuel or flared. NGL separation averaged 29.9 B/D with a total of 10.9 MB delivered and shipped with crude oil production through TAPS.

C. PRODUCED WATER

Raven water production for the reporting period was 1.1 MMB, yielding an average water production rate of 3.1 MB/D. Produced water is processed at the LPC and injected into the Pt. McIntyre Field.

2.2 DEVELOPMENT

Development activities have continued in accordance with the RPA POD. Summarized below are the activities at Raven over the reporting period. More details regarding these activities can be found in Section 3.

A. Enhanced Recovery - Injected Water

NK-38A was sidetracked in August, 2016 to the current NK-38B position, where it was observed early on that the new well location had significant aquifer support. NK-65A was kept off injection to understand the NK-38B natural decline to help improve the future performance and reservoir management for the Raven Pool. Recently, NK-65A was put back on injection. The total water injected into the field during the reporting period is 0.11 MMB, averaging nearly 0.3 MB/D.

B. Well Activity

NK-38-A was sidetracked to the current NK-38B into an unswept portion of the Raven Ivishak reservoir. NK-65A was placed back on injection. NK-14B was spudded in March 2017 and is an extension well delineating the outer boundaries of the Raven Oil Pool.

3.0 UPDATE OF PLAN OF DEVELOPMENT

3.1 Reservoir Management

Production from the Raven Ivishak reservoir continues to be managed and monitored for maximizing recovery and oil production. Future drilling locations are being evaluated and are expected to be moved forward for increased production and recovery in the Raven reservoirs.

Commingled production from NK-43 from the Sag (Raven PA) has gone from 5% to 16% and with an increase in water production. Based on this data, the team has been evaluating wellwork or sidetrack options.

3.2 Production Management

Reservoir management and waterflood strategies are designed to optimize oil rate and recovery from the Raven reservoirs. Long-term oil production is expected to continue to naturally decline from current rates due to increasing water cuts and gas-oil ratios.

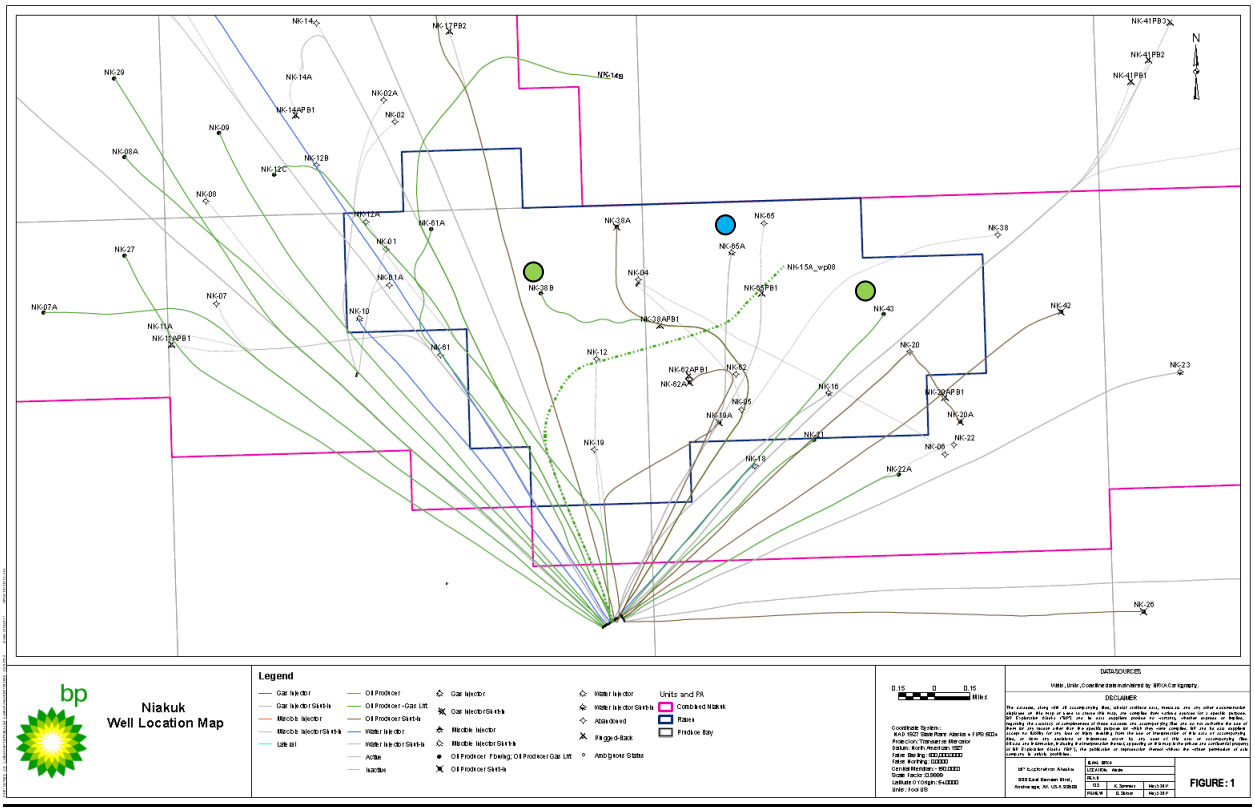
3.3 Drilling and other well activity

Technical evaluations of drilling options in Raven are currently using the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015. Interpretation of the processed data has been focused on improving the structure map over the field areas and understanding of subsurface areas of interest. Plans are for an optimized location for injection in the South Fault Block to be accessed by drilling of NK-15A. At such time, the NK-65A would be converted to a Sag River producer to recover remaining resource in that area.

3.4 Production Allocation

The production of oil and gas will continue to be allocated to the Raven Participating Area in accordance with conditions approved by the Alaska Department of Natural Resources, Alaska Department of Revenue, and Alaska Oil and Gas Conservation Commission. There is a test separator at the Niakuk drill site.

ATTACHMENT 1: RAVEN WELL LOCATION MAP



Raven PA Boundary

Combined Niakuk PA Boundary

West Beach

PRUDHOE BAY UNIT
WEST BEACH PARTICIPATING AREA
ANNUAL PROGRESS REPORT AND
2017 Update of PLAN OF DEVELOPMENT

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1.0 INTRODUCTION

This document contains the Annual Progress Report and update to the Plan of Development (POD) for the West Beach Participating Area (WBPA) of the Prudhoe Bay Unit (PBU). BP Exploration (Alaska) Inc. (BPXA), the PBU unit operator, makes this submission on its own behalf and on behalf of the other PBU working interest owners ConocoPhillips Alaska, Inc., ExxonMobil Alaska Production Inc. and Chevron U.S.A. Inc. The plan period for this submission is October 1, 2017, through September 30, 2018.

The objective of the WBPA POD is to identify strategies to maximize commercial production and total recovery from the reservoir in a cost-effective, safe and environmentally responsible manner. The 2017 update to the WBPA POD assumes a continuation of the current business climate and reflects the current understanding of the West Beach reservoir. Changes in the business climate, new insights into the reservoir, or other new information could alter the timing, scope, or feasibility of one or more of the plan components.

2.0 ANNUAL PROGRESS REPORT - SUMMARY OF ACTIVITIES AND STATUS

West Beach startup occurred in April 1993. The field has been delineated by eleven penetrations consisting of seven wells and four sidetracks. The field has produced a total of 3.37 MMB of crude oil, with approximately 92% coming from the original WB-04 well. Oil production was suspended in 2Q 2001 due to increasing GOR and declining reservoir pressure.

Water injection commenced at WB-06 in December 2000 and continued through September 2003, when the injector was shut-in due to an annular communication leak (IA by OA). Two attempts to cement squeeze the well

failed, and the injector remains shut-in. Cumulative injection into WB-06 is 6.8 MMBW.

WB-04 producer showed a breakthrough in water in less than 4 months from injection start-up, and was shut-in in 2Q of 2001. The well was brought back on in 3Q 2002 with high water cut and was produced intermittently through 2005 with continuing increasing water production. WB_06i continued to inject until September 2003, which resulted in increasing reservoir pressure. Pressure surveys in WB-04, WB-05B, and WB-06 from 2003 through 2009 show that reservoir pressure has stabilized at approximately 3550 psi.

WB-04 had 165 feet of perforations added in June 2008 and was brought online during June and November 2008 in an attempt to demonstrate productive capability. Two production tests were obtained before the well was shut in and freeze protected due to the risk of forming hydrates in the tubing and flowline. The oil rate ranged between 140 to 280 BOPD with high watercut and cold wellhead temperature. Cumulative production for WB-04 at that time was 3.1 MMBO.

In October of 2008, an attempt was made to pull the IBP in WB-05B which had been set at 15,765' on 8/03/05. Coil was unable to pull the IBP and an attempt was made to push it to bottom. This effort resulted in not being able to get the plug deeper than 15,710'. 40 ft. of perforations were added on 10/30/08. The well was tested with gas lift, and the oil rate ranged between 260 and 360 BOPD with high watercut and cold wellhead temperature. WB-05B was shut in and freeze protected due to the risk of forming hydrates in the tubing and flowline.

During the summer of 2009, both WB-04 and WB-05B were extensively production tested for two months. WB-04 produced at an oil rate of 70-110

bbls/day. Water cut was 92% and the well head temperature was 62 degrees F. The well produced 5,588 bbls oil and 52,723 bbls of water during the 66 days it was on line. WB-05B tested at 177-256 bopd. Water cut was 61%. Well head temperature was 57 degrees F. This well produced 4,409 bbls of oil and 6,647 bbls of water during the 23 days it was on line. A SBHP survey was run in WB-05B. The pressure at a datum depth of 8800 ft subsea was 3517 psi. Although methanol was slip streamed into WB-05B IA there were still problems with hydrates in this well. The K valve was pulled, and operations continued with a 24 hour man watch. Both of these wells were flowed simultaneously to the LPC #1 pad. These wells were manifolded though a line heater during the testing, so warm fluids were sent downstream of the pad. Modeling of the 12" production line indicated at these low rates and cool well head temperatures this line might become inoperative due to hydrates.

During the winter of 2010, the 6" test line between West Beach Pad and LPC # 1 pad had an external inspection. There was no evidence found of structural problems.

3.0 DEVELOPMENT PLANS

Production through the West Beach production lines will not be restarted until an internal pipeline integrity inspection is made. Equipment was ordered for an ILI (In Line Inspection) "smart" pig run to assess pipeline integrity. Current plans are to pig these lines ahead of any new development from the West Beach drillsite, pending further technical assessment. These assessments could be improved by the 2014/2015 North Prudhoe Seismic survey. The West Beach area was covered by the 2014/2015 North Prudhoe Seismic survey. The survey was completed in April 2015 and final merged PSDM processing was completed September

2016. Interpretation of the data is currently being prioritized across the Prudhoe Bay Unit. Interpretation will focus on improving the structure mapping over the field and an understanding of the subsurface areas of interest (Kuparuk, Sag, Ivishak, Lisburne, and Alapah intervals). West Beach production line pigging and any new development plans are subject to prioritization with other projects across the Prudhoe Bay Unit.