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September 1, 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

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 (Revised September 1, 2016). This revision makes two changes to the March 31, 2016 plan:

1) It changes the production forecast in section 3.2 to be consistent with the correction in our May 2, 2016 letter.
2) It makes changes to section 3.6 regarding marketing of hydrocarbons.

As you know, BPXA, the State, and other PBU working interest owners, have signed the Alaska LNG Project Confidentiality Agreement and BPXA and the State have signed a separate Bilateral Confidentiality Agreement. The latter agreement expressly prohibits sharing or discussing the marketing information that the division is currently requesting. Furthermore, BPXA possesses neither the right, nor the ability, to direct the PBU working interest owners to market gas nor to provide gas marketing information to the division. These confidentiality agreements and antitrust law prohibit BPXA from requesting, possessing, or discussing the PBU working interest owners' proprietary marketing information. In any event, that information is not related to the operation and development of the PBU as set forth in the Prudhoe Bay Unit Agreement.

Sincerely,

Scott Digert
Reservoir Development Manager, Greater Prudhoe Bay East
Alaska Reservoir Development
BP Exploration (Alaska) Inc.

cc: w/attachment: G Wong, ExxonMobil 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
(Revised September 1, 2016)

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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

- **<u>In-Line Inspection (ILI)</u>** 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 though 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 157-196 MB/D. The total NGL production for 2016 is expected to be between 36-45 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®[i] 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

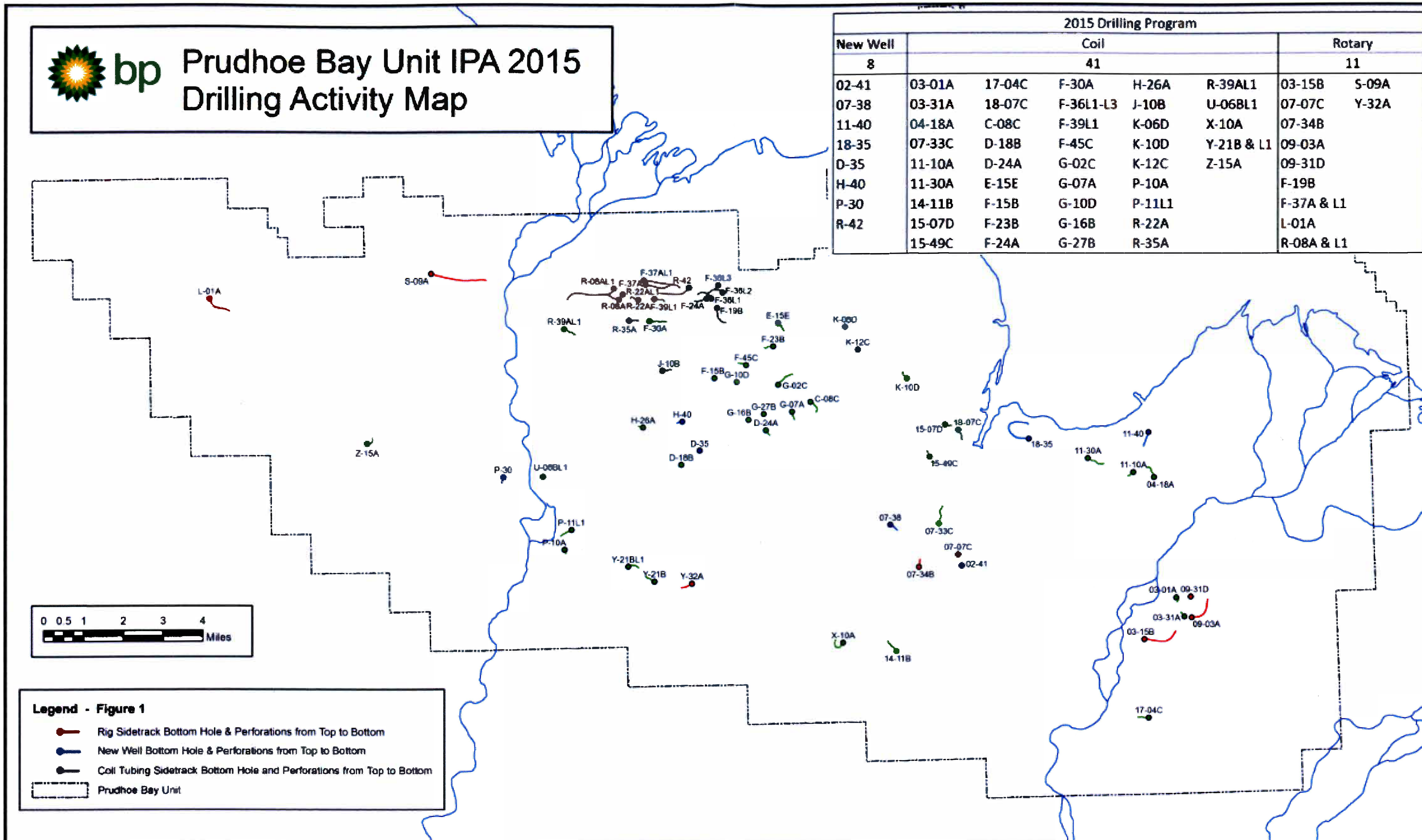
3.6 Major Gas Sales

Major gas sales (MGS) from Prudhoe Bay remain dependent upon a number of factors, including 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 them 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. The PBU operator has entered into confidentiality agreements and made certain technical information related to unit operations, facilities and gas production available to third parties in support of potential gas-related projects.

BP Exploration (Alaska) Inc., as PBU operator, is not involved in marketing of hydrocarbons produced from the unit. Such action is outside the authorized scope of operations conducted by the PBU Operator and is prohibited under the Prudhoe Bay Unit Agreement executed by the State of Alaska and the PBU working interest owners. Each PBU owner takes and markets hydrocarbons allocated to that owner and, due to competition and anti-trust considerations, the unit operator cannot and does not solicit, accept, or receive proprietary marketing information from any PBU owner.

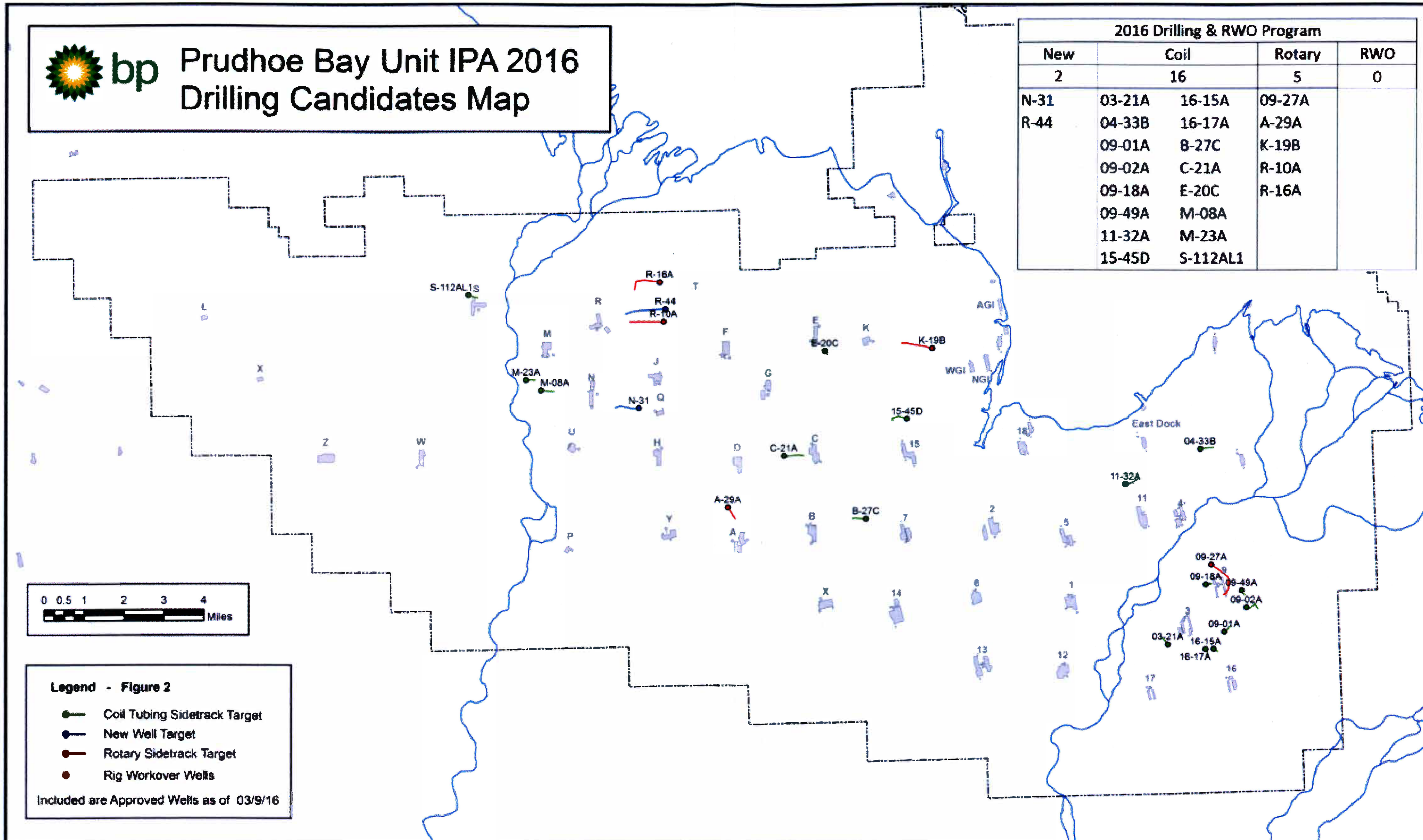
Prudhoe Bay Unit IPA 2015 Drilling Activity Map



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



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-112AL1		

Figure 2