



March 30, 2017

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**Hand Delivered**

Ms. Chantal Walsh, Director  
Division of Oil and Gas  
Department of Natural Resources  
550 West 7<sup>th</sup> Avenue, Suite 1100  
Anchorage, AK 99501-3560

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

Dear Ms. Walsh:

BP Exploration (Alaska) Inc., as the operator of the Prudhoe Bay Unit and on behalf of the working interest owners, submits the accompanying 2017 Plan of Development and Annual Progress Report for the Initial Participating Areas. This Plan of Development (“POD”) provides a review of the 2016 activities as well as descriptions of future development activities under consideration consistent with previous PODs.

Questions can be directed to Bill Bredar at 564-5348 or through email at [William.bredar@bp.com](mailto:William.bredar@bp.com).

Sincerely,

A handwritten signature in black ink that reads 'Frank Paskvan for Karina Garner'. The signature is written in a cursive style.

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

cc: w/attachment: G. Smith, ExxonMobil Production Company  
H. Jamieson, ExxonMobil Production Company  
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PRUDHOE BAY UNIT  
INITIAL PARTICIPATING AREAS  
ANNUAL PROGRESS REPORT AND  
2017 UPDATE TO PLAN OF DEVELOPMENT  
JULY 1, 2017 – JUNE 30, 2018

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FIGURE 2: 2017 IPA RIG ACTIVITY CANDIDATES

## **1.0 INTRODUCTION**

This Annual Progress Report and update to the Plan of Development for the Oil Rim Participating Area and Gas Cap Participating Area (IPA) within the Prudhoe Bay Unit (PBU) has been prepared in accordance with the Findings and Decision of the Commissioner on the Application for Change of Unit Operator, dated June 27, 2000. This Plan of Development updates and modifies the initial Plan of Development and Operation for the IPA that was incorporated into both the Prudhoe Bay Unit Operating Agreement and the Prudhoe Bay Unit Agreement as Exhibit "E". The plan period for this submission addresses the period July 1, 2017, through June 30, 2018.

The objective of the Plan of Development for the 2017 plan period is to maximize commercial production of crude oil in a cost-effective, safe, and environmentally responsible manner. The Annual Progress Report summarizes development and production activities from January 1, 2016, to December 31, 2016. The Plan of Development provides an overview of the activities that will comprise the development and production program for the IPA (Permo-Triassic) reservoir during the 2017 plan period. This update to the initial IPA Plan of Development assumes a continuation of the current business climate and reflects the current understanding of the 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 and Injection Volumes**

#### **A. Crude and Condensate**

Crude and condensate rates averaged 197.9 MB/D in 2016. 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. This increase from 2015 is due to the lack of any production impacting facility TARs, strong wellwork and drilling performance, and increased emphasis on mitigating and minimizing deferrals. A total of 72.43 MMB were delivered to the Trans-Alaska Pipeline System (TAPS) during the year ending December 31, 2016.

#### **B. Produced Gas**

IPA gas production totaled 2578 BSCF or 6883 MMSCFD for the reporting period, which continues to be governed by facility handling constraints. Field gas offtake (FGO) increased by 59 MMSCF/D, (2.3%) from the previous year. Re-injection of dry gas amounted to 2327 BSCF (6375 MMSCFD), 90.3% of the produced gas stream. Gas production that was taken in kind and removed from the PBU included about 6.7 BSCF (0.3%) of natural gas, and about 13.9 MMB of Natural Gas Liquid (NGL), which equates to about 16 BSCF (0.6%) of natural gas. Fuel usage accounted for 149 BSCF (406 MMSCFD), 5.8 % of the produced gas. Flare volumes were limited to 6.6 BSCF, (0.3%). Miscible Injectant production, which was reinjected in enhanced oil recovery operations, totaled 73 BSCF (2.83%), of which 50 BSCF (1.9%) was injected within the IPA. Minor gas sales totaled 7 BSCF (0.3%). Gas taken in kind and exported to the Northstar Unit was 0.087 BSCF (.003%).

### **C. Natural Gas Liquids**

NGL production for the IPA averaged 38 MB/D for the reporting period, with 13.9 MMBO delivered to TAPS.

### **D. Miscible Gas**

The Prudhoe Bay Miscible Gas Project (PBMGP) continued operation with injection of a total of 50 BSCF of Miscible Injectant (MI) during the report period. The CGF produced approximately 200 MMSCF/D during 2016, with about 64 MMSCF/D injected into areas outside the IPA (Aurora, Borealis, Orion, Polaris, and Pt. McIntyre).

### **E. Produced Water**

Water production averaged 853 MB/D (without W-400). This water rate yields a field wide average water cut of 81%.

### **F. Injected Water**

Waterflood (WF) and Water Alternating Gas (WAG) operations continued through the reporting period with an annual average of 691 MB/D of produced water injected. During 2016, 77 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 increased from 102 MB/D to 107 MB/D. This represents a produced water injection efficiency of 84.5%. Additional FS-1 water was also disposed of at the Lisburne Production Center.

Additionally, approximately 371 MB/D annual average of seawater, from the Seawater Treatment Plant, was injected in the FS2 flood area. Seawater injected as part of the Gas Cap Water Injection project averaged 321 MB/D. In total, IPA seawater injection averaged approximately 344 MB/D for the year.

Supplemental Prince Creek water produced from W-400 in 2016 was 9.2 MB/D. The Prince Creek water augments water injection at the Eileen West End.

## **2.2 Development**

Field development activities have continued in accordance with the 2016 Plan of Development.

### **A. Enhanced Recovery – Injected Water**

Waterflood (WF) and Water Alternating Gas (WAG) operations continued through the reporting period.

The Gas Cap Water Injection (GCWI) project continued throughout the reporting period.

### **B. Enhanced Recovery – Miscible Gas**

Miscible gas injection operations continued throughout the operating period as per the Prudhoe Bay Miscible Gas Project with MI delivered to MI-capable drill sites within operational constraints. The available MI was allocated based on the MI efficiency (barrels of oil per unit of MI) to projects within the

IPA, including: (1) PBMGP patterns, (2) Miscible Injection Stimulation Treatment (MIST) patterns, (3) Eileen West End (EWE) patterns, and to the other fields in the Prudhoe Bay Unit area.

In 2016 MI injection was expanded to two new MIST wells and three new Sag wells. It was not possible to inject MI into an Upstructure Zone 4 (UZI) pattern on N-pad due to well and flowline constraints. However, the matter is being reviewed with a focus on addressing these constraints. Pilot testing of foam/MI injection is on hold due to technical and economic challenges. Low Temperature Separator (LTS) continuous methanol injection project was progressed in 2016 and was near implementation at CGF by year end in an attempt to reduce derimes, the LTS operating temperatures, and to increase MI manufacture rates.

### **C. Well Activity**

A modified rig program continued with 37 wells drilled during the reporting period. 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 2016 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 activity remained at a high level in 2016 with 336 rate adding jobs done and about 1000 total jobs performed. Wellwork activity included capacity sustainment (addition of perforations, stimulations, gas and water shut-offs), well diagnostics, surveillance, and rig workovers.

### **D. Facility and Reservoir Optimization**

Summarized below are significant activities over the past year:

#### **Sea Water Treatment Plant**

Continued work at the Seawater Treatment Plant (STP) has increased reliability and seawater supply for injection. In 2016 a maintenance turnaround (TAR) was completed at the STP that included the main seawater header replacement, critical valve replacements, and high voltage electrical switchgear preventative maintenance (PMs). Additionally all four gas fired heaters received full internal fire tube repairs.

#### **Seawater Injection Plant**

In 2016 the Seawater Injection Plant (SIP) TAR included the main seawater header replacement, critical valve replacements, and STP pig receiver replacement. A gas generator swap on the 15101 gas turbine driven seawater injection pump was also completed.

#### **Integrity Management Activities**

In-Line Inspection. In-Line Inspections (ILI, or smart pigging) were performed on one produced oil pipeline, fifteen three-phase cross-country pipelines, seven produced water injection (PWI) pipelines, one seawater injection (SWI) pipeline, and the field fuel gas trunk line totaling over 112 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 100% of ILI anomalies that were due, to date, from ILI runs that were completed in 2011 through 2015. Follow-up inspection and mitigation, as necessary, are complete on 100% of ILI anomalies that were due to date from 2016 runs. To date, all in-line inspection reports but one from the 2016 campaign have been received from the ILI vendors.

**Fire and Gas Activities.** The FS-2 Fire & Gas Renewal project is in operation, with minor modifications made to improve performance of the installed system. The FS-1 Fire & Gas Renewal project is in construction with cutover planned in 2018. The GC-1 Fire & Gas Renewal project entered the concept development (CD) stage with CD completion anticipated in 3Q 2017.

**Safety Systems.** The FS-1 safety system renewal (SSR) project is in construction with commissioning scheduled to begin in May, 2017. Completion is scheduled for late summer of 2017. As of March 2017, the FS-3 SSR project is in the Execute stage with the project anticipated to begin construction in 2018. FS2 SSR entered the CD stage with CD completion anticipated in 3Q2017.

### **3.0 UPDATED PLAN OF DEVELOPMENT**

#### **3.1 Reservoir Management**

##### **Fieldwide Reservoir Management**

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

The 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 recovery of remaining oil as well as 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. Management of the oil vaporization process incorporates lean-gas surveillance through gas sampling of wells. Activity to improve vapor-born liquid recovery includes selective perforations in areas where sweep efficiency and condensate recovery are under-performing.

### **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 warranted 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 that 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). During the reporting period, a perforation campaign was implemented to move up higher in the hydrocarbon column in wells in DS-03, DS-04, DS-09, and DS-11 to improve condensate recovery. This program has proven to be successful in adding oil and condensate production with competitive gas oil ratios into the Flow Station 2 facility. There are plans to continue an up-hole add-perf campaign in remaining candidate wellbores.

Several additional programs have been underway to determine how to best recover bypassed 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 producing at very high water cuts, reflecting the challenge of drilling in a mature waterflood area. The 09-11 producer was converted to injection and brought on line in 2015 to support the new 5 spot pattern. While the 5 spot pattern conversion concept has not been proven to be viable on a broader scale at FS2, "pattern rotation", which targets much of the same, bypassed oil through coil and rotary sidetrack drilling, has been shown to be viable. This program was piloted in 2015 with the drilling of 3 wells (03-01A, 03-31A, and 09-03A). Each well has found bypassed oil within their respective waterflood patterns. These results led to a larger program in 2016 with the drilling of six coil tubing producer sidetracks (03-21A, 09-01A, 09-02A, 09-49A, 16-15A, and 16-17A), one coil tubing injector sidetrack (09-18Ai) and one rotary producer sidetrack (09-27A). Seven of the eight wells were completed and are producing economic quantities of oil with the total rate from the program to date at 4000 BOPD and cumulative oil production of nearly 1.7 MMSTB. The 16-15A well did not encounter as much oil as expected incurring significant drilling losses and share stability issues, and operations were suspended on the well. Four



additional coil sidetrack wells are in the process of being executed at DS 03, DS09, and DS 17 as part of the winter 2017 “East of Sag” drilling program.

In 2016, an active MIST program continued in addition to WAG injection in the base Prudhoe Bay Miscible Gas Project. Several MIST injectors were put on injection in 2016 including two recently drilled injectors (03-33C and 09-31D). The offsetting producers to those wells have seen substantial increase in oil production and decreased water cuts over the last six months. Future plans are to continue to drill MIST injectors as necessary to develop the EOR target in the FS2 area.

In addition, five producers and one injector were drilled in the FS2 area in Zone 1A as part of an ongoing development of waterflood and gas drive targets. Wells drilled in Zone 1A include the 11-40, 11-32A, 11-12A, 11-10Ai, 04-33B, and 04-18A. This well set drilled in 2016 is currently producing a little over 2000 BOPD and will continue to be a target in future wells drilled in the 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 down-structure gas cap expansion.

In 2016 four wells were drilled and completed from West Waterflood pads targeting oil in Ivishak Zone 4. All four wells were in the Northwest Fault Block (NWFB) area of the West Waterflood. All four were drilled as rotary sidetracks and put on production in 2016;; two wells were drilled from R-Pad (R-10A and R-16A), and two were drilled from M-Pad (M-08A and M-23A). These wells were infill targets in down-structure patterns along the periphery of the oil rim,, in previously undeveloped fault blocks.,

Two wells drilled from WWF pads targeting the Sag River are covered in the Sag River section of this document.

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 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 completed (N-01A, N-07A and N-27). N-07A, N-28 and N-29 are currently online and injecting produced water. N-01A and N-27 were determined to have channeling behind liner and have cement squeezes pending execution to achieve zonal conformance into the UZI target lenses. N-01A was planned to begin injection on MI, but the MI well flowline was damaged due to snow loading and requires a replacement. The planning of this line replacement is progressing. N-01A will be put on produced water injection after it is squeezed, then swapped to MI when the line has been replaced.

A comprehensive UZI surveillance plan has been developed to monitor the influence of the UZI injectors so that the offset producers can be perforated in the zone 4 lenses as the bypassed oil migrates past the producers. In addition to monitoring water cut and GOR changes in well tests, neutron logging will be performed at specified intervals to identify when swept oil in the zone 4 lenses has reached the producers.

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**

An area of renewed focus for development of the Sag River in 2016 was on recovering liquids from the gas cap. Sag River gas contains condensate that has not been swept out through updip lean gas reinjection and can be recovered as liquids at surface. Recovery of this resource is being done via a systematic program of adding perforations in the Sag River gas cap at existing wells completed in the Ivishak that have been identified as inefficient or under-performing. Add perforation jobs at 12 wells were executed in 2016 at pads in the GC-1, GC-3, and FS-3 areas yielding over 6000 bopd of new production at competitive GORs. One rig workover was completed in 2016 on the Sag gas cap producer C-36A. C-36A was returned to production in December, 2016 and is producing over 550 bopd at a competitive GOR.

Ongoing area and pattern performance reviews, optimization of miscible injectant usage, and structural mapping utilizing improved seismic imaging 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. An Area Performance Evaluation is underway to examine the potential of the Sag River Formation in the area of the E/K Graben on the north side of the Prudhoe Field. A Sag River horizontal rotary sidetrack, J-28A, planned for 2017 targets the Sag River oil rim where it is expected to be supported by the Sag River gas cap.

The program of adding perforations in existing, non-competitive Ivishak wells to recover condensate from the Sag River gas cap is expected to continue in 2017, with approximately 15 jobs expected. In this program, existing perforations in the Ivishak are isolated with a plug before moving uphole to perf the

Sag River. Modelling work is underway to optimize offtake of gas and associated condensate from the Sag River by facility area.

### **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 TGOR are shut in to meet the velocity constraint of the EWE LDF. The field injection is managed by an efficient application of MI for the WAG flood, and the EWE 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 2016 involved two new coil side track wells, Z-23C, W-05AL1. Additional drilling opportunities in the EWE/NWE area are being evaluated; however, these opportunities 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 reservoir management strategy. In 2016, 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 2017. The GCWI project is generally performing as expected, although the seawater injection rate is below the initial plan. 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) increased slightly to 197.9 MB/D in 2016, mainly due to the lack of production impacting facility TAR's, strong wellwork and drilling performance, and an increased emphasis on managing production deferrals. The average annual IPA crude and condensate production rate for 2017 is expected to be between 158-198 MB/D. The total NGL production for 2017 is expected to be between 30-41 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 Well Activity**

The 2017 IPA drilling activity will be reduced compared to 2016 due to the continued impact of oil prices coupled with increasing field maturity. As noted in section 2.2, 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 1.8 rig years in 2016 (0.75 rig years for rotary drilling, 1.05 rig years for coil tubing drilling) to an estimated 1.3 rig years in 2017 (~0.5 rig years for rotary drilling, ~0.8 rig years for coil tubing drilling). The resulting well counts in 2017 are estimated at 4-7 rotary drilling wells (vs. 7 rotary drilling wells in 2016) and 20-24 CTD wells (vs. 28 CTD wells in 2016). Technical work to identify and evaluate drilling locations that are economically viable in the current oil price environment is ongoing. Candidates identified to date are displayed on Figure 2.

Rig workover (RWO) activity is expected to be essentially flat when compared to 2016, with a RWO program of 2-4 wells (vs. 3 RWO's performed in 2016). The RWO activity has also been affected 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 during 2017. The LTS1 and LTS2 continuous methanol project that was progressed in 2016 will be implemented at the CGF in early 2017 to reduce derime frequency and increase NGL rates, and to allow lower LTS operating temperatures to increase MI manufacturing rates.

### **3.5 Projects**

#### **Facility and Reservoir Optimization**

**Controls Reliability & Renewal (CRR)** The objective of CRR is to modernize the PBU control systems. The goal of this activity is to reduce the backlog of aging systems, install control systems with a broader base for support, and improve lifecycle cost, while minimizing the impact on production during implementation. Plans are being developed for FS3 CCR project first. That activity will be followed by FS1 and GC2 CRRs.

**Facility Siting** The Facility Siting program was established to reduce the risk from personnel exposure of permanently occupied spaces to process safety hazards. The Facility Siting projects would address Facility Siting risk at the primary occupied areas of GPB processing facilities such as control rooms and maintenance offices by installing a standardized BRM (blast resistant module) at the corresponding facilities. In 2017 – 18, construction is anticipated to be complete for CGF Facility Siting and CCP Facility Siting. Construction start for GC2 Facility Siting is anticipated in 2018.

### **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 compressor installation at FS-3 was completed and started up in December 2016. The compressor installation at FS-2 began in January 2017 and is scheduled to be completed in 4Q 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.

### **BrightWater**

BrightWater® (a registered trademark of Nalco) 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, however there are questions around the value of this technology in the current environment.

### **Gas Quality Projects**

Upgrades and maintenance projects are underway to improve the dew point of dehydrated gas from flow stations and gathering centers. This will improve the reliability of the Central Gas Facility, which

will benefit oil production and potential major gas sales. Activity started in 2016, and will continue in 2017, including installing new dew point analyzers at all facilities. Upgrading mist eliminators and inlet devices, upgrading heat exchanger bundles, system cleaning, and replacement of contactor distributors will be performed at GC1 during the 2017 facility maintenance turnaround (TAR).

### **CGF Low Temperature Separator Entrainment Project**

Currently in the early review and planning stage is evaluation of improving the performance of CGF low temperature separators (LTS) to increase NGL production, which would also allow delivery of on-spec gas for MGS. Project scope under consideration includes replacing vessel inlet devices, demisting systems, and potentially the separator trays for each of the three LTS separators.

### **Integrity Management Activities**

Pipeline Replacement Program (PRP) Studies and Project Execution. PRP projects make flowlines in-line inspectable, and/or maintenance piggable, and/or replace pipelines. Completed PRP projects in 2016 include:

- DS04 Production Sustainment and
- GPMA STP36 Pipeline Return to Service

The DS14 Pipeline Replacement project, approved in 2016, will be completed in 2017.

### **3.6 Major Gas Sales**

**2016 MGS Activities.** During 2016, the unit operator and the WIOs undertook a number of activities that would facilitate a major gas sale (MGS) from the PBU. **Subsurface studies.** Unit operator evaluated several subsurface studies. The following list highlights activities that provide materiality for a MGS by seeking to provide the maximum amount of gas from PBU through PBU facilities:

- a) Producing additional higher BTU specification gas through the use of existing miscible injectant (MI) from the Central Gas Facility (CGF).
- b) Use of the L & V pad areas of the Prudhoe Oil Pool for by-product injection.
- c) Further refinement of subsurface injection opportunities for by-product use in the Prudhoe Oil Pool.
- d) Evaluation of the potential impact of an extended TAPS outage on the continued delivery of gas to the Gas Treatment Plant (GTP).

In addition to this IPA work, unit operator also has:

- a) evaluated production of free and solution gas from the Pt. McIntyre and Lisburne fields as part of the overall strategy on optimizing gas opportunity; and
- b) use of the Pt. McIntyre field for by-product injection after gas has been recovered.

**Surface studies.** Unit operator performed the following integrated surface studies directly related to facilitating a MGS:

- a) By-product Metering and Depressurization: Unit operator worked with the AK LNG project (AKLNG) to confirm feasibility of flowing by-product from PBU to the GTP flares depressurization and in the event of an operational upset.
- b) CGF Tie-in Philosophy and TAR strategy: Unit operator designed a sales gas tie-in from the existing CGF to the GTP tie in. The project would provide greater operational flexibility (improving PBU reliability), reduce the requirement for a TAR during construction, and reduce overall cost from the initial design. (The tie-in strategy went from two tie-ins downstream of the three LTS units at CGF to an improved tie-in strategy of three tie-ins downstream of the LTS units).
- c) AKLNG Interfaces – Sales Gas and By-product delivery pressures: Unit operator confirmed that the could sales gas could be delivered to the GTP tie-in point at 720psig. The AKLNG requested that unit operator evaluate decreasing the existing CGF sales gas system design pressure from 790psig to 720psig.

### **Responding to requests for information**

In the 2000s, unit operator, with the WIOs' approval, has responded to thousands of questions and requests for information from parties interested in large ANS gas development projects, including the Alaska Pipeline Project, the Denali Project, AGDC's ASAP (Alaska Stand Alone Pipeline) project, and the ExxonMobil-led AKLNG project as well as information requests from FERC. In addition, unit operator has responded to many requests for information from parties interested in local gas development projects, including Norgasco, Polar LNG, Spectrum LNG, and Golden Valley Electric.

The unit operator disclosed PBU information to the AKLNG project, responding to over 145 requests for PBU information. During 2016, this included:

- Review and analysis of AKLNG's GTP air permitting modeling
- Review and analysis of AKLNG's facility documents addressing the interface between the GTP and PBU facilities, including the connection between the AKLNG GTP and the PBU Central Gas Facility
- Confirmation that sales gas could be sent to the GTP tie-in point at 720psig versus the existing CGF sales gas system design pressure of 790psig.
- Confirmation of the feasibility of flowing by-product from PBU to the GTP flares depressurization and in the event of an operational upset.
- Design of a sales gas tie-in from the CGF to the GTP that provides greater operational flexibility (improving PBU reliability), reduces the requirement for a TAR during construction, and reducing overall cost from the initial design.
- Review and analysis of AKLNG's draft FERC Resource Reports by unit operator subject matter experts
- Response to requests for detailed documentation of the CGF
- Review and analysis of AKLNG's GTP infrastructure needs, and potential impacts to PBU

### **Dual benefit projects**

Unit operator also conducted several other activities during the plan period related to existing operations that would benefit a MGS. They are discussed in Section 3.5.

### **MGS Activities during 2017**

As appropriate, activities will be undertaken during 2017-18 plan period to prepare for a MGS. As in the past, unit operator expects to respond to requests for information from AGDC related to AKLNG. The unit operator has previously worked with the AGDC-led ASAP project and responded to requests for information relating to the PBU and that project. Unit operator has provided a draft confidentiality agreement to AGDC to allow disclosure of information to the AGDC-led Alaska LNG project. Additionally, unit operator would anticipate requests for information related to applications for regulatory approvals, including a FERC application, associated with the project.

The AGDC-led AKLNG project is considering various development options, including a phased development. AGDC has not issued a timeline for major project milestones for the project. When that occurs, the unit owners anticipate undertaking appropriate activities to position for an MGS consistent with AKLNG's progress.

### **Activities to optimize the use of gas before a MGS**

As part of ongoing operations, the unit operator will continue to maximize the opportunity for producing oil by the injection of lean gas and MI into Prudhoe Bay reservoirs. The use of gas to support production and improve ultimate recovery is a viable recovery mechanism. The use of gas injection contributes approximately 40% of PBU oil production through two main mechanisms: vaporization, and enhanced oil recovery with MI. The use of gas is a valuable opportunity in the near-term and current activities will continue to pursue production through the use of processed gas.





# Prudhoe Bay Unit IPA 2016 Rig Activity Map

2016 Rig Program								
New Well	Capital Drilling					Expense		
	Coil					RWO	P&A	
2	28					7	3	1
R-44	02-14B	09-02A	15-45D	H-27B	09-27A	02-20	G-16A	
N-31	03-21A	09-18A	16-17A	K-07F	14-28B	09-07A		
	04-33B	09-49A	B-27C	M-08A	A-29A	C-36A		
	06-04B	11-12A	C-21A	M-23A	H-25A			
	07-15B	11-32A	C-31C	U-06BL1	K-19B			
	07-19B	14-24A	D-20A	W-05AL1	R-10A			
	09-01A	15-33C	E-20C	Z-23C	R-16A			

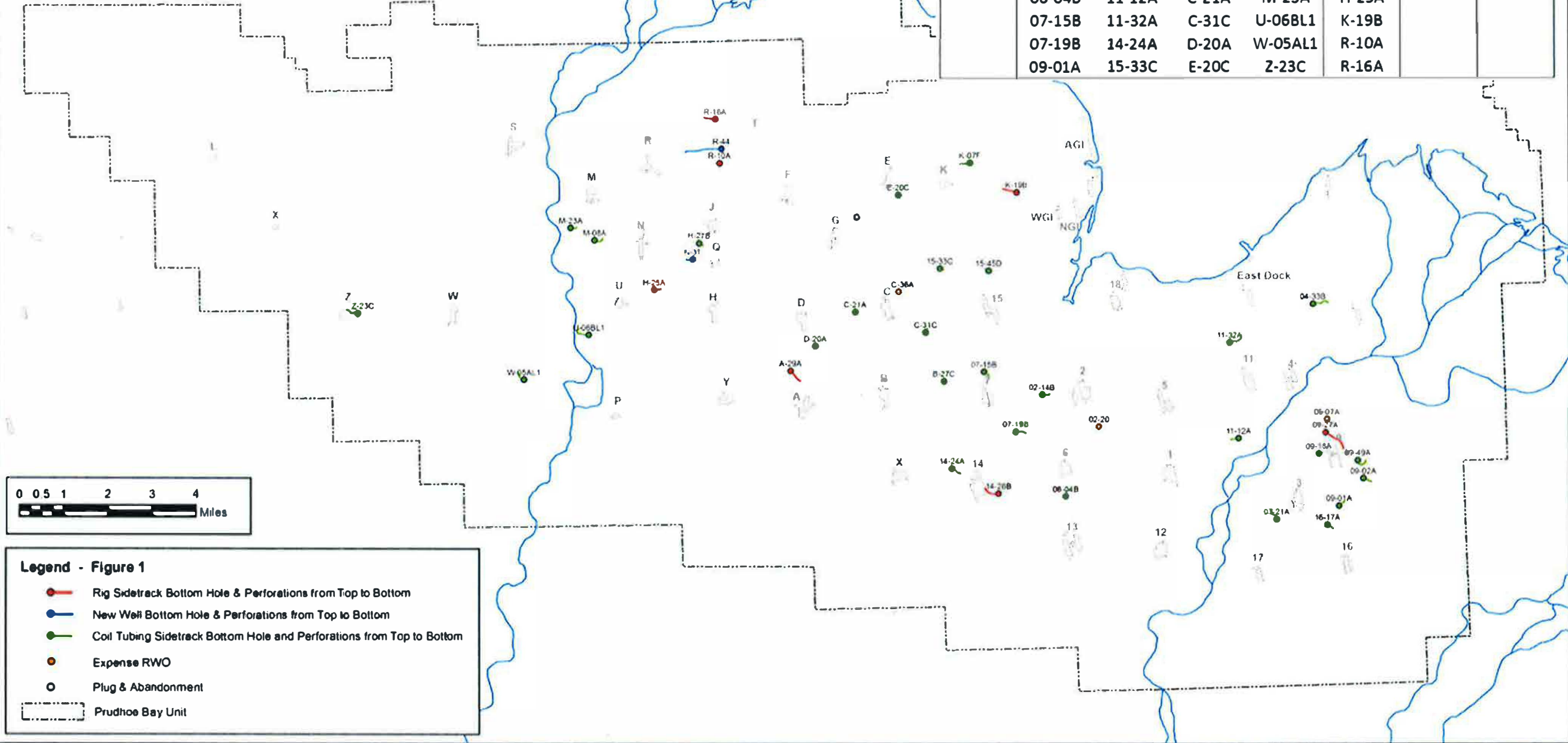


Figure 1



# Prudhoe Bay Unit IPA 2017 Rig Candidates Map

2017 Rig Activity Program				
New Well	Coil		Rotary	RWO
1	8		1	0
V-08	03-22A	C-11A	J-28A	
	03-24B	F-05B		
	09-29A	F-22A		
	17-11A	F-35A		



**Legend - Figure 1**

- Rig Sidetrack Target
- New Well Target
- Coil Tubing Sidetrack Target
- Expense RWO
- Prudhoe Bay Unit

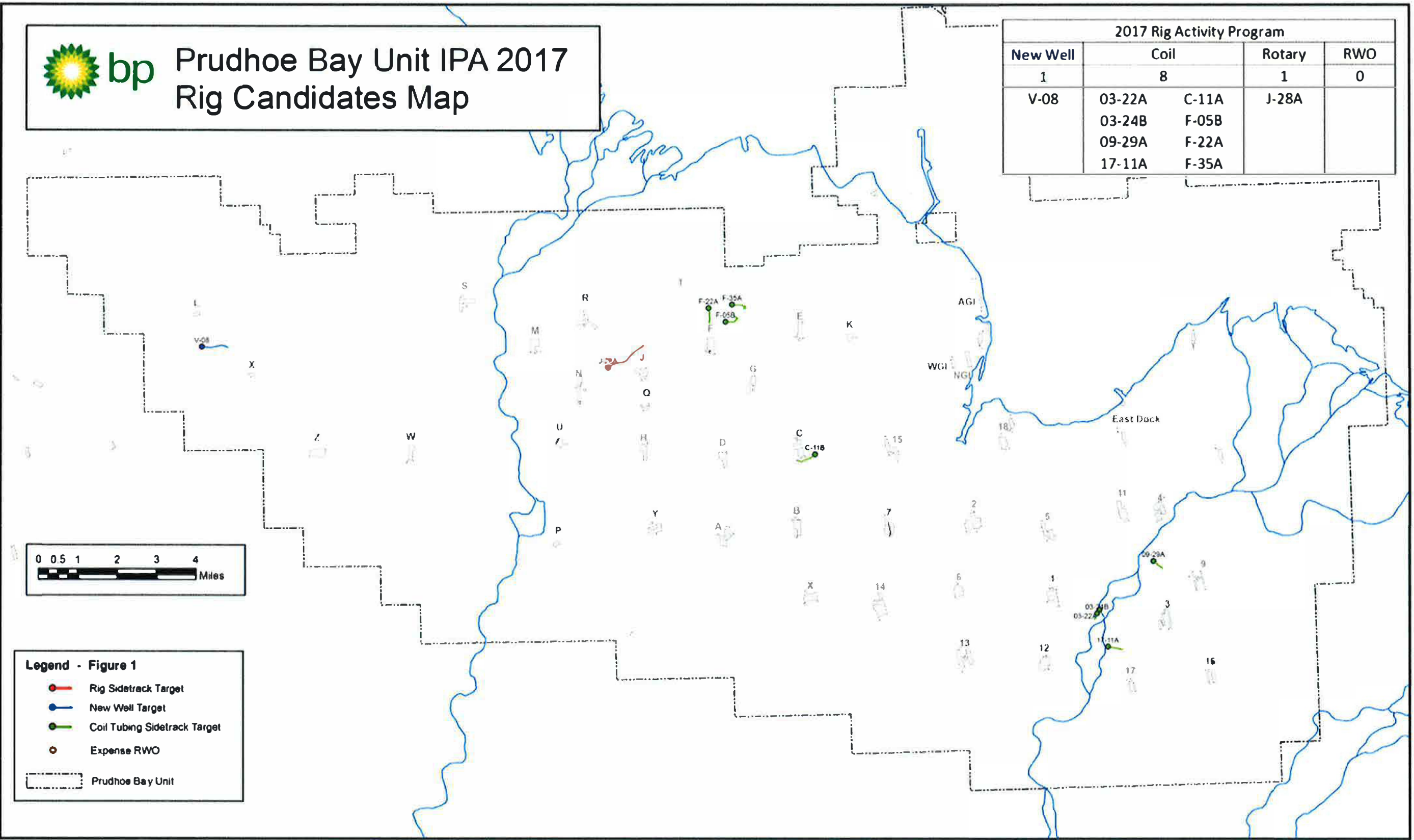


Figure 2