ConocoPhillips

Erik Keskula
North Slope Development Manager

ConocoPhillips Alaska, Inc.
700 G Street
Anchorage, AK 99501
Phone 907.265.6202

June 28, 2016

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

RE: 2016 Kuparuk River Unit Plans of Development

Dear Ms. Feige,

Attached for your review are the 2016 updates to the Plans of Development for the Kuparuk, Meltwater, Tabasco, Tarn and West Sak Participating Areas (PA) within the Kuparuk River Unit. These updates are submitted pursuant to the requirements set forth in the "Decisions and Findings of the Commissioner" associated with the field participating area applications.

As always, these plans are subject to change based upon business conditions. ConocoPhillips Alaska, Inc. submits this update as Operator of the Kuparuk River Unit.

We look forward to hosting a presentation and review of the Plans on July 14th at ConocoPhillips' Anchorage offices (700 G Street).

Sincerely,

Erik Keskula
North Slope Development Manager

Attachments

CC: Mr. Kevin Pike, ADNR-DOG
Ms. Cathy Foerster, AOGCC
Mr. Randall Hoffbeck, ADOR
Mr. John Dittrich, BPXA
Mr. Dave White, Chevron
Mr. Gilbert Wong, ExxonMobil

ConocoPhillips

TRANSMITTAL
CONFIDENTIAL DATA

FROM: Marc Lemons, Mgr., RE & Planning
ConocoPhillips Alaska, Inc.
P.O. Box 100360
Anchorage AK 99510-0360

TO: Kevin Pike, Petroleum Land Manager
State of Alaska, DNR, Division of Oil and Gas
550 W. 7th Ave., Suite 1100
Anchorage, Alaska 99501-3510

RE: 2016 Kuparuk River Unit Plans of Development
DATE: 06/28/2016

Transmitted:

Greater Kuparuk Area, Alaska

1 CD each:

SA 2016 Kuparuk River Unit Plans of Development (Confidental) TO RE VAULT

SA 2016 Kuparuk River Unit Plans of Development (Non-Confidental)

cc: Robert Cookson, GKA Engineering Technician

Receipt: SEAN CLIFTON Date: 2016-06-28

TDM GIS-Technical Data Management | ConocoPhillips | Anchorage, Alaska | Ph: 907.265.6947

ConocoPhillips

UNIT PLAN OF DEVELOPMENT
KUPARUK PARTICIPATING AREA

AUGUST 1, 2016 – JULY 31, 2017

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

This document is the annual update to the Kuparuk River Unit Plan of Development, submitted to the State of Alaska Department of Natural Resources (DNR) as required by Article 5, Section 5.1 of the Kuparuk River Unit Agreement and 11 AAC 83.343. The Department of Natural Resources, through a letter dated April 11, 1986, required the submittal of the annual updates to the Kuparuk River Unit Plan of Development by July 1 of each year for approval by August 1.

The effective plan period for this submittal is August 1, 2016, through July 31, 2017. This update to the Kuparuk River Unit (KRU) Plan of Development is submitted by ConocoPhillips Alaska, Inc. (“ConocoPhillips" or "CPAI"), the unit operator, on its own behalf and on behalf of the other KRU working interest owners BP Exploration (Alaska) Inc. (BP), Chevron U.S.A. Inc. (Chevron), and ExxonMobil Alaska Production Inc. (ExxonMobil), (all, collectively hereinafter referred to as "KRU WIOs").

This update covers development plans for the Kuparuk Participating Area (KPA). Assumptions that formed the basis for this plan are consistent with the current business climate. Changes in business conditions, applications of new technologies, new insights into reservoir performance or other changes may alter the timing, scope, or feasibility of one or more components of this plan.ConocoPhillips, BP, Chevron and ExxonMobil have signed Greater Kuparuk Alignment Agreements and have proceeded with development of additional reservoirs (Meltwater, Tarn, Tabasco, and West Sak) within the Kuparuk River Unit. As required in the Special Supplemental Provisions approved for each reservoir, Plans of Development are submitted individually for each participating area.

The following information is provided in response to the DNR letter dated January 14, 2016, requesting additional information in annual updates of the Plan of development for the KRU.

2.0 FIELD STATUS

The following information describes the status of the field as of December 31, 2015, and forms the basis of the 2016 Unit Plan of Development. A map showing the development status of the field is included as Attachment 2.

- Major facilities in place are the same as in 2015.

- The Kuparuk field is developed from 45 drill sites (DS) including DS2T which is shared with the Tabasco Field, and drill sites 1B, 1C, 1D, 1E, 1J and 3K which are shared with the West Sak Field.

- The Kuparuk field had 850 active* wells in 2015:
  - 474 producers
  - 376 injectors
    - Including 124 Water-Alternating-Gas (WAG) injectors**

- Drill site status at year-end 2015:
  - Water flood only at 19 Drill Sites
  - Immiscible WAG (IWAG) at 20 Drill Sites
  - Miscible WAG (MWAG) at 4 Drill Sites
  - Production only at 2 Drill Sites***

- Cumulative oil production = 2.38 billion barrels

**Active is defined as having produced or injected fluid between January 1, 2015 and December 31, 2015.*
***WAG injectors are defined as those wells currently involved in the WAG scheduling process.*
****Water flooding is planned to begin at Drill Site 2S in 2016. There are no future plans to inject at Drill Site 1J into the Kuparuk reservoir.*

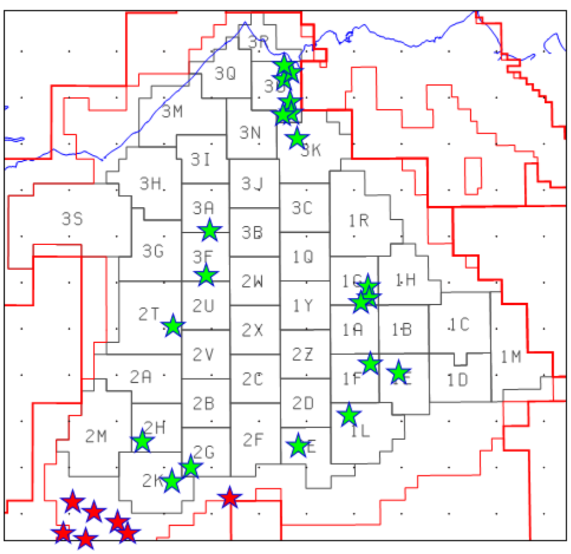
3.0 SUMMARY OF 2015 ACTIVITIES

Summarized below are significant development accomplishments at Kuparuk over the preceding year (January 1, 2015 to January 1, 2016):

- 2015 KPA oil production averaged 78.2 MBOPD gross (with another 26.4 MBOPD gross from satellites.)

- Successful implementation of a 20 well Coiled Tubing Drilling (CTD) program generated a peak incremental oil rate of approximately 3.5 MBOPD gross. Forty-eight laterals were drilled and completed in these wells.

- Completion of eight grassroots rotary wells.



New Rotary Wells (7):
- 2F-22: C-Sand Injector (pre-produce)
- 2S-02: A-Sand Injector (pre-produce)
- 2S-07: A-Sand Injector (pre-produce)
- 2S-01: A-Sand Producer
- 2S-04: A-Sand Injector (pre-produce)
- 2S-08: A-Sand Injector (pre-produce)
- 2S-10: A-Sand Injector (pre-produce)

CTD Sidetracks (20):
- 1E-14: C-Sand Producer
- 1L-04: A-Sand Producer
- 3O-13: A-Sand Producer
- 3O-12: A-Sand Injector (pre-produce)
- 3O-16B: A-Sand Injector (pre-produce)
- 2K-15: A-Sand Producer
- 2T-08A: A-Sand Producer
- 2G-14: A-Sand Injector
- 1F-19: A-Sand Producer
- 3F-18: A-Sand Producer
- 2H-14: A-Sand Injector
- 3O-08: A-Sand Producer
- 1G-11: C-Sand Producer
- 1G-12: A-Sand Producer
- 1G-05: A-Sand Injector (pre-produce)
- 3K-01: A-Sand Producer
- 2E-15: A-Sand Producer
- 3A-03B: A-Sand Producer
- 3O-01A: A-Sand Producer
- 3O-06: A-Sand Injector (pre-produce)

Figure 1: Location of 2015 CTD and rotary drilling projects

- Successful execution of a workover program that added approximately 6.5 MBOPD gross oil in 2015.

- Successful execution of non-rig wellwork activity that includes slickline, electric line, and service coiled tubing jobs that added approximately 13.2 MBOPD gross oil in 2015.

- Successfully completed the following activities during a major Turnaround at Central Processing Facility 2 (CPF): 1) Regulatory Emergency Shutdown Test, 2) Seawater Header Piping Repair, 3) Plant Glycol Renewal Project, and 4) Coalescer Vessel Inspection / Upgrade Project. The CPF2 Coalescer Project required wet oil to be routed to CPF1 which processed fluid for the entire field without business interruption.

- Completed installation of Natrual Gas Liguid (NGL) Injection Pumps at CPF2 along with a MI jumper piping. Installing this infrastructure enabled directing CPF2 Miscible Injectant (MI) to strategic WAG Enhanced Oil Recovery (EOR) patterns aligned with reservoir management strategies in a post-NGL import environment.

- The drill sites 3A, 3H, 3I and 3M WI line was temporarily shut down to complete tie-ins to an adjacent gas injection line re-purposed to ensure continuous seawater injection. Permanent repairs on the drill sites 3A, 3H, 3I and 3M WI common-line will be executed in early 2016 (currently in-progress).

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state or national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for the Kuparuk River formation. Following is the annual update to the Unit Plan of Development.

4.1 OVERVIEW

The objective of the development plan is to identify strategies to maximize value through oil production and recovery from the Kuparuk Reservoir in a cost-effective, safe, and environmentally responsible manner.

The 2016 Plan assumes a continuation of the current business climate. There are many challenges to delivering on our proposed plan. Future investment decisions include evaluation of all factors affecting economic assessment including cost, production, technical, regulatory environment, and fiscal framework.

4.2 Reservoir Management

Kuparuk Base Reservoir Management is focused on simultaneously optimizing the life cycle of the sub-surface depletion processes of primary production, water flooding, miscible gas EOR, and immiscible gas flooding. This optimization requires prioritizing and staging the depletion mechanisms in order to load the existing pipeline and facilities infrastructure in the most cost efficient manner. Facility capacity utilization is maximized and constraints are modeled and mitigated through maintenance, repairs, and upgrades when economically feasible. The depletion options for Kuparuk are:

- Delineate and optimize development of remaining areas of competitive oil accumulation such as the peripheral areas.
- Evaluate and economically optimize water flood where incremental rate and recovery justify the process. An example is the A sand redevelopment accessing poorly swept A sand areas via CTD.
- Management of excess water volumes e.g. via water shut-offs, particularly in commingled A and C sand completions.
- Management of lean gas volumes in excess of fuel gas requirement.

4.3 DRILLING PROGRAM

The development drilling strategy is to target high value locations and to apply the appropriate well construction and completion technologies in an effort to minimize development drilling costs.

Existing wells that are currently shut-in due to mechanical problems or low production rates may be sidetracked to new bottom-hole locations. As the field matures, horizontal, multi-lateral, and CTD sidetrack technologies will play an increasing role in Kuparuk in order to access incremental resources at reduced cost. Cost reductions and efficiencies will be essential to unlock the full value of Kuparuk resources.

To date, the 2005 Kuparuk West Sak (KWS) and 2011 Western Kuparuk (WK) 3D Seismic analysis has resulted in a significant number of leads for infill or sidetrack drilling. Candidate wells developed from these leads include a mix of coiled-tubing sidetracks, new wells, and rotary sidetracks, depending on the structural complexity of the area, expected oil recovery, and operational status of proximal wells.

For 2016, approximately 21 CTD sidetrack projects and 8 new rotary wells are planned.

4.4 Field Extensions – New Drill Site Development

On January 18, 2012, the Shark Tooth #1 well was spud on Tract 90, ADL 25603. The surface and productive horizon location was 1792’ FNL, 1025’ FEL, Sec. 20, T10N, R8E, UM. The primary objective was the Kuparuk interval; both Kuparuk C and A sands were encountered. Construction of the new 2S drill site to access the Shark Tooth resource was completed in 2015 and production from this drill site began in October 2015.

4.5 Enhanced Recovery

Miscible water-alternating gas was the main EOR process for the Kuparuk field through July 2014. During that time, 23 MWAG drill sites serviced the Kuparuk reservoir which included 115 available EOR patterns. Once NGL imports from Prudhoe Bay stopped in July 2014, the field either received water only or IWAG. The field continues to manufacture miscible injectant at two of its CPF. Miscible injectant is manufactured by blending together produced lean gas and NGLs. With the conversion of the Oliktok pipeline from NGL service to gas service, only the NGLs originate from the Kuparuk field itself (known as indigenous NGLs).

In 2015, the MWAG program operated in full MI production mode for 4 MWAG drill sites. During 2015, the Greater Kuparuk Area produced an average of 6,970 BOPD of indigenous NGLs. Indigenous NGLs are blended with available lean gas and generated an average of 39 MMSCFD of MI injected into the Kuparuk Field. The total estimated incremental oil+NGL sales for 2015 from the ongoing Kuparuk MWAG project was 15.9 MBOPD.

Prior to July 2014 (during NGL imports) the priority for gas management at the Kuparuk field was to balance solvent injection between the A sand and C sand. This maximizes total EOR and returned NGL rates while avoiding excessive gas production rates, which would cause production impacts due to gas handling limitations. For the year 2015, the priority for gas management was to balance lean gas injection and MI injection to minimize gas production impacts. The total Greater Kuparuk Area (GKA) annual average gas production rate in 2015 was 255 MMSCFD, up from 221 MMSCFD during 2014. The nominal average MI minimum miscible pressure was 2,570 psi during 2015. This is based on the average MI composition from 2015.

Historically, GKA has been long on solution gas production (i.e., solution gas production has exceeded fuel gas demand) and the surplus gas was re-injected as part of a gas storage, IWAG or MWAG operation. The gas balancing & management techniques discussed above were applied to minimize the impacts of system gas constraints while maximizing EOR production.

4.6 Full Field Lean Gas Chase

As planned in late 2014 the KRU transitioned to importing fuel gas. The imported Prudhoe gas is used as fuel gas only and not introduced into the production system, either by injection or in the gas lift system. This is due to corrosion concerns relating to the relatively high CO_2 content (10-12%) of Prudhoe gas. Commencing imports before going gas short will reduce the volume of Kuparuk gas required for fuel usage, enabling the excess Kuparuk gas to be re-injected as a lean gas chase and indigenous MI without introducing any Prudhoe gas into the reservoir. Indigenous MI at drill sites 1B, 1C, 1D, and 1E will get first access to any gas available for injection and all remaining gas will be used for lean gas chase. During 2015, the average MI injection rate into these expansion drill sites was 39 MMSCFD (DS1BCDE).

Injection of lean gas into the Kuparuk reservoir after the ramp down of the EOR flood has two main benefits:

1) Recovery of a proportion of the NGLs trapped in the reservoir as part of the EOR process
2) Maintenance of liquid rates in high water cut producers by providing a formation lift benefit at the sand face as the gas cycles through the reservoir from the injectors to the producers. Kuparuk has a relatively low gas lift system pressure of around 1,400 psi due to production casing, pipeline and compressor limitations. As watercuts increase, FBHPs increase, resulting in increasingly inefficient gas lift characteristics as the gas lift “jumps” to a higher gas lift mandrel. Maintaining higher a Gas-Oil Ratio (GOR) in producers with continued gas injection is predicted to offset at least part of this impact.

4.7 Facilities

4.7.1 Gas Handling

Gas handling limits with the gas lift compressors will continue to constrain production from the Greater Kuparuk Area. Historically the summer months see greater impacts as turbine output is lower. Gas capacity debottlenecking continues to be studied as part of the facility management plan. Smaller projects with high added value will be emphasized, evaluated, and progressed in conjunction with larger projects to expand gas lift compression capacity. However, an acceptable large project has yet to be identified for implementation.

4.7.2 Water Handling

Water handling capacity has often been a constraint on oil production rate. This became more so in 2006 with the segregation of the produced water and seawater injection streams at CPF2 in order to reduce high corrosion rates in the water injection systems. This segregation often results in under-utilization of pump capacity as each Water Injection Pump (WIP) is dedicated to either produced water or seawater (SW), making them more difficult to optimize against system dynamics.

In addition to the WIP under-utilization issue, in 2010 turbine driver speeds continued to be restricted to prevent catastrophic blade failures. In 2014, upgraded blades began to be phased in during planned turbine overhauls. This will allow speed increases and subsequent water injection capacity increase. These constraints have resulted in localized areas of increased voidage within the reservoir.

To ensure integrity of the KRU water injection infrastructure, inspection of WI flow lines using ILI (in line inspection, or smart pigging) technology at a high level and has become a core inspection program with each line scheduled for recurring inspection at 3-year intervals. Baseline ILI has been completed on all WI lines and the recurring phase started in 2011. The ILI campaign has resulted in far better condition data, but has also resulted in the de-rating of several lines which subsequently required shut-in for repair or replacement. Significant effort and expenditures will continue to be required to maintain, replace, and re-purpose pipelines.

Repurposing of unneeded flow lines (typically involving conversion from gas injection to water injection service) has emerged as a common method for avoiding complete line replacement. Consolidation of like flow lines will be considered where surplus capacity exists following risk-based evaluation.

To mitigate the impacts of the water injection constraints discussed above, the Operator is evaluating several facility projects to restore and enhance water injection capacity at each CPF to ensure the reservoir management guidelines will be met and recovery optimized.

The various issues and constraints at each CPF are discussed below along with the projects being evaluated. Each CPF has stand-alone water injection systems and so are addressed individually.

4.7.3 CPF1

Clean water injection in West Sak at drill sites 1C, 1D, 1E and 1J is a high priority with studies to evaluate means to improve injection water quality. These studies will look at the feasibility and economics of various options to provide cleaner water to these drill sites.:

4.7.4 CPF2

Currently, injection at CPF2 is limited by pump capacity and, to a lesser extent, source water availability. The new drill site 2S wells and satellite fields Tarn, Meltwater and Tabasco use the same facilities as Kuparuk at CPF2 and generally produce less water than is injected. WI expansion projects include:

- Annual winter conversion of one produced water pump to seawater service (to maximize overall injection rate) continues. Also, the turbine driver speeds are increased but limited to mitigate the higher risk of blade failure. As discussed earlier, upgraded blades are being phased in during planned turbine overhauls. Water injection pump capacity expansion at CPF2 continues to be evaluated, but due to high cost and low benefits a feasible project has yet to be identified.

4.7.5 CPF3

Injection at CPF3 is limited by injection well capacity. Current plans and issues include:

- Repairs to individual injection well lines are being undertaken as needed.

- Longer term, development of West Sak in the area of drill sites 3C, 3J and 3K may require upgrades to the CPF3 water injection and production systems. Studies will be undertaken of the CPF3 issues and optimal solutions in due course. The timing of further West Sak developments at CPF3 is covered in the West Sak Unit Plan of Development.

- Seawater deliveries to the OU have totaled 21.3 MMBBLs from 2009 through 2014. The OU Operator recently estimated that the OU demand for KRU seawater would increase through 2015 from about 7 thousand barrels of water per day (MBWPD) to about 16 MBWPD by year-end.

4.7.6 Seawater Treatment Plant

A multi-disciplinary team continues to address the inspection, mitigation and near/long term repair issues to manage the corrosion in the entire SW system.

4.7.7 Corrosion Monitoring and Mitigation

Kuparuk corrosion monitoring and mitigation programs are managed in accordance with the North Slope Operations and Development Corrosion Strategy Manual. Program enhancements such as improved corrosion inhibitors, maintenance pigging methods, new monitoring and inspection technologies, internal coating and sleeving, and data management software are continually being evaluated and incorporated into the program to ensure facility longevity. As discussed earlier, baseline ILI on water injection lines has resulted in the de-rating and subsequent repair or replacement of several lines, but has significantly improved estimation of remaining life and enhanced long term planning capability. A multi-disciplinary team is now in place and uses this information to optimize pipeline replacements, repairs, repurposing and consolidations.

4.7.8 Artificial Lift

The most common artificial lift method for Kuparuk producers is gas lift. The injection pressure for the gas lift system is limited to 1,400 psi due to compressor, pipeline and production well casing limitations. With watercuts increasing to as high as 95% in some Kuparuk wells as the field matures, many wells cannot lift from the bottom due to the gas lift system pressure constraints.

To date, this has been mitigated to a large extent in the MWAG and IWAG areas by the returned MI and lean gas, which essentially provides an artificial lift benefit from the sand face. As additional water injection projects are progressed, the excess mobile gas in the reservoir will decrease, GORs will collapse and gas injection will cease. Studies are ongoing to improve the artificial lift system, as well as evaluate the lift benefits from large scale lean gas injection after the commencement of fuel gas imports from Prudhoe Bay.

4.7.9 Other Facility Projects

With increased water and heavy oil production, vessel and tank modifications and upgrades will be evaluated as most vessels will require entry within the next five to ten years. The Turnarounds are also evaluated as opportunities to conduct repairs, overhauls, and upgrades on rotating equipment such as gas compressors to prevent and reduce production deferral.

Electronic equipment used at Kuparuk is becoming obsolete at an increasing rate as manufacturers introduce new equipment and no longer wish to support older equipment. As such, process control systems among other systems will continue to be upgraded and automated as current equipment becomes obsolete and no longer maintainable. The fire and gas systems have been upgraded at the CPFs and the seawater treatment plant with upgrades currently in the process of being upgraded.

Obsolescence of the turbines driving the water injection pumps and power generation equipment may require large capital expenditures. Transmission lines, substations, and other electrical equipment in the field are approaching their end of life and will need to be replaced to maintain current levels of reliability.

Changing regulations will continue to require facility upgrades to improve safety and reduce emissions.

Much of the operations support infrastructure will be assessed for upgrade or replacement to target another 25 years of production from the KPA and the KRU satellite fields. Some of the larger infrastructure projects include upgrading the Kuparuk airstrip and upgrading and refurbishing portions of the Kuparuk camp and office space have been completed.

4.8 RECENT EXPLORATION / APPRAISAL ACTIVITY

At KRU the overlying Cretaceous Brookian Moraine interval is currently being tested to evaluate for productivity and waterflood performance. CPAI plans to evaluate a horizontal producer/injector pair to determine commerciality. Two Moraine wells were drilled in 2015. The Moraine 1 vertical well was drilled off of ice and plugged and abandoned. The purpose of this well was to acquire extensive logs with whole core for detailed reservoir and overburden characterization studies, including special core analysis. Well 3S-620 was drilled as a stimulated horizontal producer with drilling completed in 1Q 2015. This well is the producer lateral. Injector well 3S-613 was drilled in Q2 of 2016 to support producer well 3S-620. Injection in well 3S-613 is contingent upon approval of the Area Injection Order (AIO). Results from special core analyses and reservoir performance from the 3S-620 producer well and 3S-613 injector well will guide future development plans for the Moraine interval.

The 1H-Ugnu-401 well was originally drilled and completed in 1998 to test the Ugnu B sands. The well has been produced intermittently for the last 12 years with the aid of diesel diluent. In 2013, a coiled-tubing deployed, mineral insulated electric heater was installed in the well to reduce in-situ viscosity of the oil in the producing lateral. The well produced in this manner through most of 2014 until it was shut in due to problems with the Electric Submersible Pump (ESP). ConocoPhillips continues to work through ESP troubleshooting in an effort to return 1H-401 to production with an upgraded pump to determine if higher oil production rates can be sustained.

4.9 FUTURE EXPLORATION / APPRAISAL PLANS

Both appraisal and exploration opportunities exist within the KRU. An infrastructure-led exploration strategy has been developed based on new and reprocessed 3D seismic and the incorporation of technologies such as horizontal wells and multi-stage hydraulic fractures to improve recovery in lower permeability reservoirs.

5 HISTORICAL EXPLORATION / APPRAISAL RECAP

2014-2015:

CPAI drilled two wells under Tract Operations to further evaluate the Moraine formation.

- The 3S-620 is a multi-stage hydraulically fractured horizontal producer. This well will serve as the producing lateral for a horizontal producer/injector well pair. Horizontal injector well 3S-613 is planned to serve as the injector well to support well 3S-620 pending approval of the AIO. The primary objectives of the well pair are to evaluate commerciality and flood performance.
- The Moraine 1 well was drilled off of ice to acquire extensive data including whole core. This well was subsequently plugged and abandoned. Special Core analysis results are pending to aid with reservoir characterization efforts.

2013-2014:

Analyses are ongoing for the 3S-19 well tests results to appraise the Moraine interval.

2012-13:

- A perforation and hydraulic fracture pilot test in existing well DS 3S-19 was performed in 2012/13 to evaluate the overlying Cretaceous Brookian Moraine interval.

2011-12:

- On January 18, 2012, the Shark Tooth #1 well was spud on Tract 90, ADL 25603. The surface and productive horizon location was 1792' FNL, 1025' FEL, Sec. 20, T10N, R8E, UM. The primary objective was the Kuparuk interval, both Kuparuk C and A sands were encountered.
- WK 3D Seismic Survey: In 2011-12 the KRU WIOs acquired and processed 220 surface sq. miles of seismic data within the KRU.

2010-11:

- None

2009-10:

- None

2008-09:

- The Tarn South well, 2N-342 was drilled in 2007 to the Tarn/Bermuda interval., The well was converted to jet pump in 2009 due to lift problems caused by the low flowing temperature of the produced fluids. This area now resides inside the Tarn Participating Area (PA).
- The 2N-310 Cairn test occurred in 2008. The Cairn interval was tested while drilling a Tarn reservoir development well (an injector). Both gas and oil was discovered in the Cairn interval, and additional appraisal will be required to determine the Cairn development potential in this area.
- 3K-103 and 3K-108, offset injectors to 3K-102, were drilled in 2008 from drillsite 3K to the West Sak interval within Sections 35 and 36, T13N, R09E, UM, within KRU Tract 004, ADL 25519 outside of the existing West Sak PA. On December 16, 2008 an application for the formation of the NEWS PA was filed with DNR. This application was approved by DNR on May 29, 2009 retroactive to March 1, 2008.

2007-08:

- The Tarn South well, 2N-342 was drilled in 2007 to the Tarn/Bermuda interval, outside of the existing Tarn PA.
- 3K-102 was successfully drilled in 2008 from drill site 3K to the West Sak interval within Sections 35 and 36, T13N, R09E, UM, within KRU Tract 4, ADL 25519 outside of the existing West Sak PA.

2006-07:

- 1J-109 well completed as a producer in the West Sak B sand within ADL 390705 within Section 6, T10N, R11E, UM.
- 1J-180 pre-produced and completed as an injector in the West Sak D and B sands within ADL 385172 within Section 5, T10N, R10E, UM.
- 1J-182 completed as a producer in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.
- 1J-184 pre-produced and completed as an injector in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.

- 1J-136 pre-produced and completed as an injector in the West Sak D and B sands within ADL 380058 within Section 4, T10N, R10E, UM.
- West Sak PA Expansion Application submitted on or before April 9, 2007.
- Continued evaluation of potential 3K Development.
- Continued evaluation of potential 1H Development.
- Reference is made to the drilling commitments for Area 4 contained in the 8th KRU expansion decision as amended. KRU WIOs met these drilling commitments by drilling two wells within Expansion Area 4 in 2006/07.

2005-06:

- The 1Q-101 well was drilled in 4Q 2005 to evaluate the West Sak Formation in ADL 25634, KRU Tract 21 to a bottom hole location within Sec. 24, T12N, R09E, UM.
- The 3J-101 well was drilled in 4Q 2005 to evaluate the West Sak Formation in ADL 25630, KRU Tract 13 to a bottom hole location within Sec. 3, T12N, R09E, UM.
- The 1H-North well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25636, KRU Tract 19 to a bottom hole location within Sec. 15, T12N, R10E, UM.
- The 1R-East well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25636, KRU Tract 19 to a bottom hole location within Sec. 3, T16N, R09E, UM.
- The 1H-South well was drilled in 2Q 2006 to evaluate the West Sak Formation in ADL 25637, KRU Tract 18 to a bottom hole location within Sec. 23, T16N, R10E, UM.
- 2005 KWS 3D Seismic Survey. In 2005-06 the KRU WIOs processed 221 surface and 190 full fold sq. miles of seismic data within the KRU.
- Antigua #1 Well. In 2Q 2006 ConocoPhillips and co-owners Pioneer Natural Resources Alaska, Inc., Union Oil Company of California and ExxonMobil Alaska Production Inc. ("Antigua Owners") drilled the

Antigua #1 Well in Section 35, T10N, R10E, UM within ADL 390484. ADL 390484 lies immediately adjacent to the KRU south of 1J Pad.

2004-05:

- 1D-30-L1 well -- Kuparuk
- 1D-32-L1 well -- Kuparuk
- 10th Expansion of the KPA to include the W2 of Section 30 and the NE4 of Section 31, T. 11 N., R. 11 E., UM.
- 1H-105 -- West Sak appraisal well
- 2005 KWS seismic survey acquired 190 full fold sq. miles of seismic data within the KRU.
- ADL 355024 farm out (portions) enabled drilling of Kigun #1 well by Kerr-McGee Oil & Gas Corporation and Armstrong Alaska, Inc.

2003-04:

- The Winstar joiner agreement enabled drilling of the Winstar Oliktok State #1.
- Placer #1 and Placer #2 wells were drilled in early 2004 after completion of a joiner agreement with the Arctic Slope Regional Corporation in 2003.
- Techniques for high-frequency (HFVS) 3D seismic data acquisition were tested for possible future application in the KRU.

2002-03:

- 2L-03 (Serac)
- 2G-17 (Cayman)
- Cirque #3

2001-02:

- Palm #1– Kuparuk
- Palm #1A (3S-26)- Kuparuk
- 2P-415
- Silvertip #1 (1J-14) – Kuparuk/West Sak
- 2K-27 – Jurassic exploratory tail
- Resolution 3D Seismic Survey – 363 mi^2
- Eastern Bounded Area 3D Seismic Survey – 55 mi^2

2000

- Meltwater North #1 - Bermuda
- Meltwater North #2 - Bermuda
- Meltwater North #2A – Bermuda
- SE Delta 3D Seismic Survey – 153 mi^2

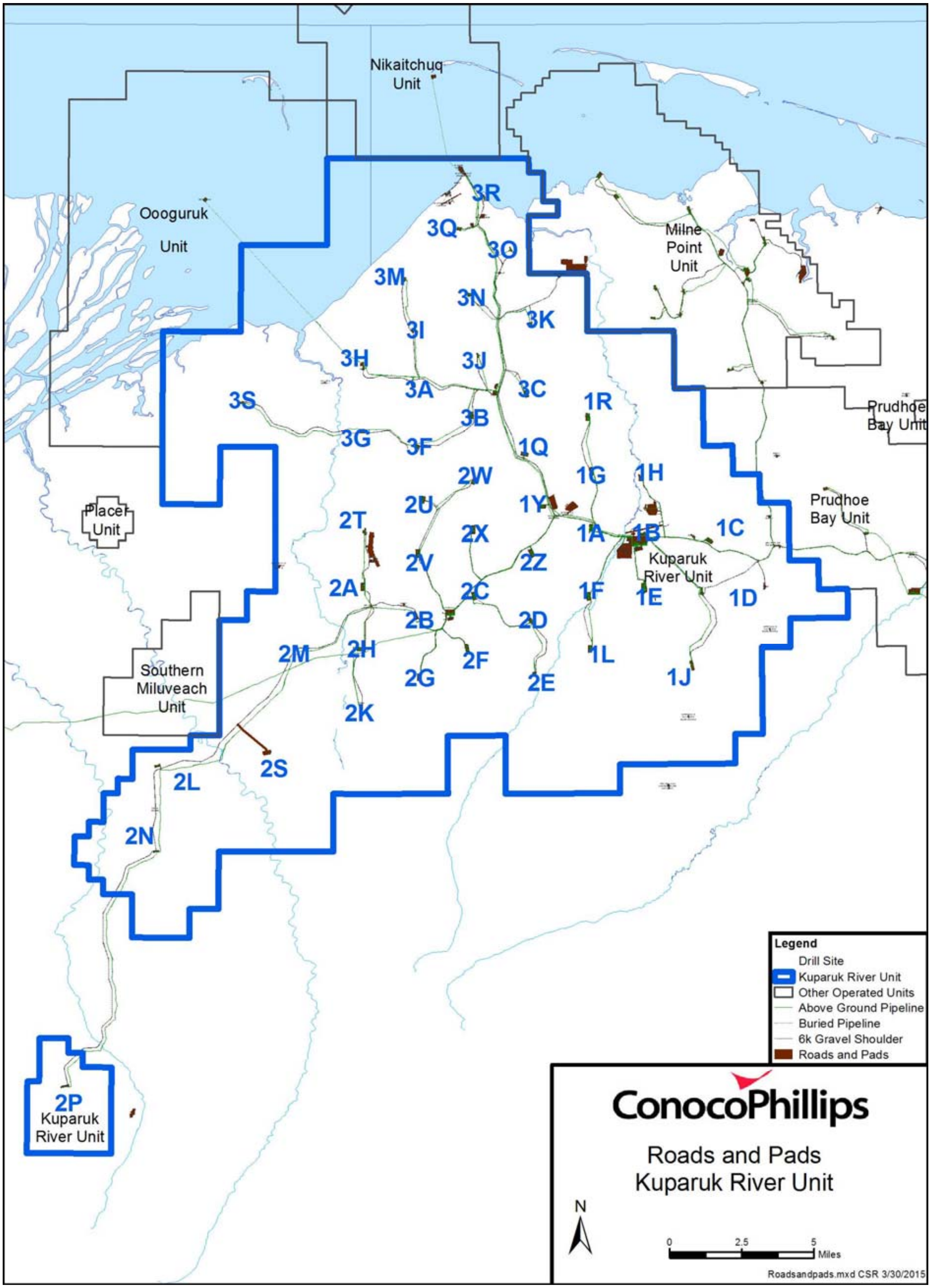
1999

- Meltwater South #1 - Bermuda

1998

- Kalubik #2 - Moraine
- Kalubik #3 – Kuparuk/Moraine/Jurassic
- 2L-329 - Arete
- 2L-305 – Iceberg
- Meltwater 3D Seismic Survey – 138 mi^2
- Kuparuk 4D Seismic Test Survey – ~5 mi^2

Attachment 2: Kuparuk River Unit Roads and Drill sites



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UNIT PLAN OF DEVELOPMENT
MELTWATER PARTICIPATING AREA

AUGUST 1, 2016 – JULY 31, 2017

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1.0 INTRODUCTION

Exploration drilling in early 2000 discovered an oil accumulation approximately nine miles south of the existing Tarn Oil Pool. The exploration program consisted of three successful penetrations (Meltwater North #1, Meltwater North #2 and Meltwater North #2A) in what is now known as the Meltwater Oil Pool. Development of the Meltwater Field began in 2001 and was completed in 2004 after 2 phases of development drilling.

Meltwater Working Interest Owners approved the Meltwater Special Supplemental Provisions in 2001 which include a requirement for an Annual Development Plan.

This document provides an overview of the projects and strategies that comprise the development program for the Meltwater Participating Area. The effective plan period for this submittal is August 1, 2016 through July 31, 2017. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the Meltwater reservoir. Changes in business conditions and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Meltwater field began production in November 2001. Injection of miscible injectant (MI) was initiated in January 2002 and the miscible water-alternating-gas (MWAG) process was implemented in May 2003. The field currently operates with continuous lean gas injection after the water injection (WI) line was taken out of service in October 2009 due to corrosion damage and miscible injection was discontinued after the importation of Prudhoe Bay natural gas liquids (NGL) were stopped in July of 2014. Nineteen development wells have been drilled to date. Lean gas is also currently used for gas lift at drill site (DS) 2P.

The status of the Meltwater field as of December 31, 2015 is summarized below:

- 19 wells drilled at DS 2P.
  - 13 producers
  - 6 gas injectors
- 16 active* wells at DS 2P.
  - 10 producers
  - 6 injectors

* Active is defined as having injection or production between January 1, 2015 and December 31, 2015

Meltwater 2015 Annual Average Production and Injection Rates

- Oil Production Rate: 1,569 BOPD
- Gas Production Rate: 11,364 MSCFD
- Water Production Rate: 128 BWPD
- MI Injection Rate: 0 MSCFD
- LG Injection Rate: 22,138 MSCFD
- Water Injection Rate: 0 BWPD

Meltwater Cumulative Production and Injection as of Dec. 31, 2015

- Cumulative Oil Production: 18,893 MSTBO
- Cumulative Gas Production: 52,519 MMSCF
- Cumulative Water Production: 36,200 MSTBW
- Cumulative MI Injection: 56,673 MMSCF
- Cumulative LG Injection: 17,063 MMSCF
- Cumulative Water Injection: 25,136 MSTBW

3.0 SUMMARY OF 2015 ACTIVITIES

Summarized below are significant accomplishments at Meltwater over the preceding year (January 1, 2015 through January 1, 2016):

- Maintenance pigging of the DS 2P produced oil line (2PPO) is scheduled for 6 to 12 month intervals. Two pigging operations were completed in 2015. The maintenance pigging program and inhibition programs appear to be adequately controlling corrosion rates.

- Gathered static bottomhole pressures (SBHP) on producing wells 2P-417, 2P-429, 2P-431, 2P-441, and 2P-443.

- Routine paraffin scrapes and hot diesel flushes were conducted throughout 2015 on many Meltwater wells to maintain production.

- In late 2004, the cumulative injection-withdrawal ratio (I/W) went over 1.0 and increased steadily through 2009. Changing voidage strategy has enabled better management of the cumulative I/W. For 2015, the cumulative year-end I/W ratio was 1.2, the same for end of year 2014.

- Sand face injection pressure set at 3,400 psi to maintain injection into the Bermuda formation only.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state or national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing Kuparuk River Unit infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Meltwater and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development.

4.1 RESERVOIR MANAGEMENT

Until October 2009, Meltwater was undergoing a tertiary recovery process involving MWAG designed to maximize recovery from the reservoir. The WI line was taken out of service in October 2009 due to corrosion concerns. In 2014 the importation of Prudhoe Bay NGLs into the Kuparuk River Unit was discontinued, thus converting the Meltwater field from a MI flood to a lean gas flood. The Meltwater field is now utilizing a continuous lean gas injection recovery process. Comparing the estimated performance of Meltwater on depletion and gas injection, it is more efficient to inject gas at Meltwater than other fields in the Greater Kuparuk Area. In addition, gas injection appears to give more support to production wells because of its higher mobility. Therefore, Meltwater will utilize continuous gas injection to maintain voidage and maximize recovery for the foreseeable future.

Some production wells are exhibiting performance suggestive of primary depletion while several offset injection wells have seen significant pressurizing and consequent injection falloff. Currently, the average pressure difference between producers and injectors is approximately 1,284 psi. The SBHPs on the injection wells average approximately 3,010 psi, while the average producer pressure is 1,726 psi. Patterns are defined by injection linear features that are identified using 4-D seismic and individual turbidite deposits of reservoir quality sand. The highly discontinuous nature of the sands and stratigraphic barriers limit the ability to manage individual producer/injector pattern I/W ratios. Gas-Oil Ratios (GOR) of the producing wells will be monitored to assess the impact of the continuous lean gas injection process.

4.2 MELTWATER RESERVOIR CONTAINMENT AND WELL INTEGRITY

Meltwater has experienced anomalies in the overburden and reservoir since its initial development. These problems began as encountering unexpected shallow pressure while drilling Phase 1 development wells and continued in the form of rapid breakthrough of injection fluids at certain production wells. As a result of an internal study in 2012, ConocoPhillips identified migration of injection fluids out of the Bermuda interval. The specific mechanism(s) is not conclusively known.

This discovery prompted ConocoPhillips to adopt a new reservoir management strategy in 2012 for Meltwater. A sand face injection pressure limit of 3,400 psi was imposed. This pressure limit will maintain the bottomhole pressure at a pressure less than the formation integrity test and leak-off test data from development wells with casing set at the top of the Bermuda formation. This will further ensure that fluids injected into the Meltwater reservoir will remain in the Meltwater reservoir.

The flowback of well 2P-432 was discontinued in May 2011 to allow for the restart of gas injection in well 2P-429. In addition, a long-term pressure interaction survey between wells 2P-434 and 2P-429 was initiated to understand the impact of gas injection on the hydraulic connection between these wells. This study revealed that the pressure signal from injection into 2P-429 was transmitted to 2P-434 in less than 48 hours over a distance of ~8,000 ft. The nature of the response indicates a highly conductive, likely small volume, linear feature exists between these two wells. The behavior was confirmed with multiple injection rate changes and one full stop in 2P-429. Production history that includes rapid breakthrough of injected fluids along this same azimuth also lends support to this theory. This pressure interaction survey between wells 2P-434 and 2P-429 was repeated during the summer of 2014. The results of the survey were consistent with the 2011 survey.

Production from 2P-432 was temporarily restarted in December 2012 to provide heat and velocity to the 2PPO pipeline. In 2013, and in the foreseeable future, well 2P-432 will be brought online during the winter months on an as-needed basis to provide additional fluid rate to the 2PPO line to mitigate the potential for freezing conditions within the line to be encountered.

In 2014 the results from an investigation into the cause of a surface casing leak in well 2P-406 were finalized. It was determined that the surface casing leak was attributable to a thread leak located in the top pup joint in the surface casing and not corrosion. An additional five wells were inspected to determine the extent of the corrosion damage to the surface casings at Meltwater. This was done by cutting a window in the conductor within the cellar and obtaining the remaining thickness of the surface casing using ultrasonic tools. The results of this investigation were as follows:

- Meltwater wells are effectively protected by an annular dielectric sealant that was installed in all Meltwater conductor annuli in 2006
- The corrosion rate on the surface casing is very low

Future inspections will be conducted to continue to monitor the corrosion rate on these wells.

4.3 Drill Site 2P Pipeline Status/Outlook

The DS 2P water injection line (2PWI) remains out of service after extensive pitting damage was discovered throughout the line in 2009 by in line inspection (ILI) tools. Detailed analysis of ILI and physical inspection data confirms that this line is suitable for produced oil (PO) service. The current DS 2P produced oil line has a low average velocity and is monitored closely via several physical inspection locations. The 2PWI line will serve as a backup in the event the current PO line is taken out of service.

The gas injection (GI) pipeline has a suitable pressure rating for WI service. If artificially lifting the wells becomes difficult with gas lift or producing GORs become unmanageable, the GI line could be converted to WI service. This project could utilize WI pigging facilities installed at DS 2N in 2011 to minimize long-term corrosion associated with WI service.

4.4 Development Drilling

Further development opportunities are being analyzed in the light of the new seismic data, recent surveillance findings, absence of injection water supply, and business climate. Opportunities could include coiled drilling sidetracks or producer to injector conversions.

4.5 Artificial Lift

Meltwater completions include downhole “jewelry” that allow the application of multiple artificial lift options, such as hydraulic jet pumps, hydraulic piston pumps, lift gas, or plunger lift systems. Artificial lift selection is a well-by-well decision based on individual well properties and facility optimization.

Currently all producing wells utilize lift gas for artificial lift due to the loss of WI service to Meltwater. The lift gas volumes alone are insufficient to maintain lift gas temperatures high enough to keep hydrates from forming in the well lift gas systems therefore at least one injector must always be in gas injection service at Meltwater (~7 MMSCFD of gas injection).

As Meltwater wells mature and production rates decrease, utilizing jet pumps for artificial lift may be considered. Jet pumps would mitigate the paraffin deposition rate. However, this would require conversion of the GI line to WI use. There is no separate gas lift line to DS 2P, with gas lift being stepped down from the GI line. With the de-rating of the WI line, only water or gas can be sent for injection or for lift purposes.

The availability of a lean lift gas source has lowered the opportunity cost associated with gas lift. However, utilizing lean gas for artificial lift has lowered the wellhead temperatures of low rate wells 5-20^{o}F resulting in an increase in paraffin deposition. To mitigate this effect, the orifice valve in the gas lift design has been resized in a number of low rate wells to take the pressure drop deep in the wellbore, rather than at the surface choke. This effort has increased the temperature of the lift gas in the upper part of the inner annulus, thus mitigating the temperature suppression effect of converting to lean gas injection.

Jet pumps would allow the warm injection water (~120°F) used for power fluid to keep the temperature in the tubing string above the cloud point and thus prevents wellbore paraffin deposition. However, jet pump lift is not desirable for high rate wells because high power fluid injection rates cause tubing hydraulic restrictions.

4.6 SHALLOW GAS MONITORING

Wells 2P-406, 2P-417, 2P-431, 2P-432, 2P-434, 2P-438, 2P-441, 2P-447, 2P-448A and 2P-451 had a history of elevated outer annulus (OA) pressures. In 2012, a reduction in the Meltwater I/W ratio was implemented, extended bleeds on all Meltwater wells were completed, and a sand face injection pressure limit was imposed. The timing of these actions correlate with a measurable reduction in pressure at the surface casing shoe in all wells, with the exception of 2P-431. Investigations are ongoing to confirm and understand this correlation. In November of 2013, permission was granted by the Alaska Oil and Gas Conservation Commission to initiate an extended bleed of the outer annulus of 2P-431 in an effort to deplete the source charging the outer annulus. Construction for the facilities required to perform this extended bleed began in December of 2014.

The surface pressures are monitored daily via SetCIM (wells have pressure transducers that transmit real-time OA pressures). Fluid levels are surveyed approximately once per quarter via echometer measurements. Calculations are then made to determine the approximate pressures in the outer annulus at the C-80 interval for all wells at Meltwater.

4.7 EXPLORATION/DELINEATION

No further exploration/delineation is planned in the Cairn or Bermuda sand intervals at this time.

ConocoPhillips

UNIT PLAN OF DEVELOPMENT
TABASCO PARTICIPATING AREA

AUGUST 1, 2016 – JULY 31, 2017

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1.0 INTRODUCTION

The Tabasco accumulation was discovered in 1985 during development drilling of Kuparuk wells at drill site (DS) 2T. In 1995, the 2T-201 test well was drilled and yielded 400 BOPD of 16.5° API gravity oil. In 1997, the Greater Kuparuk Area (GKA) Alignment Agreement was completed, which aligned interests among the Tabasco owners and set the facility sharing terms and conditions for GKA reservoirs located outside the Kuparuk Participating Area. Development of the Tabasco reservoir started in March of 1998 with the drilling of the 2T-202 well.

Tabasco is a high net to gross canyon fill reservoir composed of conglomerate and pebbly/porous/cemented sands located at depths between 2,900-3,400' SSTVD. The oil within the reservoir is 16.5° API gravity with a viscosity of 251 cP at its bubblepoint pressure of approximately 1,512 psi and reservoir temperature of 71° F. The initial reservoir pressure was slightly below bubble point pressure since there was initially a small gas cap of less than 100 MMSCF.

Tabasco Phase 1 Development originally planned for up to 19 conventionally deviated wells drilled from drill site 2T on approximately forty (40) acre well spacing using waterflood as the recovery mechanism. Only nine wells were drilled (7 producers, 2 injectors) due to observed water slumping caused by gravity segregation shown in temperature logs in various offset Kuparuk wells that penetrate the Tabasco formation.

In 2003, the 2T-218 horizontal production well was drilled at the top of the structure. Performance was sufficient to justify two more horizontal production wells at the top of structure, the 2T-203 and 2T-208, which were drilled in late 2005 and early 2006, respectively. The 2T-217A was converted to injection in late 2007. Currently, the 2T Tabasco development consists of six deviated producers, three horizontal producers, and three water injectors. Presently, three of the deviated producers are shut in at Tabasco; two due to high water cut and one due to a stuck plug from a packer leak repair job. In 2013, one additional deviated producer was plugged and abandoned (P&A'd) due to low productivity. One of the three water injectors was shut in after less than 1 year of injection due to completion issues.

Work will continue in 2016 to determine if a more optimum drive mechanism and additional development wells could be implemented to produce incremental oil.

This document provides an overview of the projects and strategies that comprise the development program for the Tabasco satellite field within the boundaries of the Kuparuk River Unit. The effective plan period for this submittal is August 1, 2016, through July 31, 2017. Assumptions that formed the basis for this development plan are consistent with the current business climate. Changes in business conditions, current state and national regulations, application of improved technology, and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Tabasco field began production during May 1998. Water injection was initiated in June 1998. Twelve development wells have been drilled to date. Listed below is additional information describing the Tabasco field (as of December 31, 2015).

- 12 wells drilled at DS 2T
  - 6 deviated producers (1 P&A'd)
  - 3 horizontal producers
  - 3 injectors

- Well Status as of end of 2015
  - 5 producers on line
  - 2 producers offline due to high water cut
  - 1 producer offline due to a stuck plug from a packer leak repair job
  - 1 producer P&A'd due to low productivity
  - 2 injectors on line
  - 1 injector shut in due to completion issues

Tabasco 2015 Annual Average Production and Injection Rates

- Oil Production Rate: 1,619 BOPD
- Gas Production Rate: 265 MSCFD
- Water Production Rate: 13,110 BWPD
- Water Injection Rate: 12,907 BWPD

Tabasco Cumulative Production and Injection Volumes (YE 2015)

- Cumulative Oil Production: 19,126 MSTBO
- Cumulative Gas Production: 3,187 MMSCF
- Cumulative Water Production: 91,617 MSTB
- Cumulative Water Injection: 102,206 MSTB

3.0 SUMMARY OF 2015 ACTIVITIES

Summarized below are notable activities at Tabasco over the preceding year (January 1, 2015 through January 1, 2016):

- Tabasco produced 591 MBO, 97 MMSCF of gas and 4.8 MMBW during 2015. Water injection was 4.7 MMBW.

- The cumulative year-end 2015 injection-withdrawal ratio (I/W) is estimated at 0.91 based on current formation volume factors.

- The pool average water-oil ratio (WOR) was 8.1 at the end of 2015, compared to 10.1 at the end of 2014, which is a result of improved reservoir management.

- A tracer study started in November 2014 continued through 2015 and is ongoing in 2016. Results of the tracer study will be used to help update the full field model and drive future Enhanced Oil Recovery (EOR) options.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing Kuparuk River Unit infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Tabasco and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development which is subject to change based on new information and market conditions.

4.1 RESERVOIR MANAGEMENT

Currently, the major recovery mechanism at Tabasco is waterflood. The cumulative I/W ratio is estimated at 0.91 at the end of year 2015. As a result, the reservoir pressure has recently been maintained near 1,350 psi, compared to initial reservoir pressure of 1,500 psi. Tabascos I/W ratios will be monitored continuously to maintain an instantaneous value of approximately 1. Adjustments to injection and/or production rates will be made to achieve this goal in order to provide pressure support close to initial reservoir pressure, obtain better pattern displacement and keep gas in solution.

In the last few years, reservoir management optimization by shutting in the central canyon producers to increase the pressure support on the peripheral wells has shown positive results on total oil production and stabilization of water production. Tabasco WOR has been reduced from 10.1 in 2014 to 8.1 in 2015. Study of waterflood optimization strategies in order to maintain or improve the current field performance is our target in the next year, as well as long term.

In-depth geological study shows that when the deeper portion of the Tabasco reservoir is compared to the shallow portion of the reservoir, there are opportunities to improve sweep efficiency in the shallow portion. An evaluation of converting the long term shut-in central canyon producers, 2T-209 and 2T-220 to injection service is also planned once the tracer study is complete.

4.2 TRACER STUDY

In November 2014, chemical tracers were injected into the two online injectors, 2T-201 and 2T-217A. All active Tabasco producers are being monitored for tracer breakthrough. The concentration and duration of the chemical tracer breakthroughs have been evaluated to estimate heterogeneities within the Tabasco reservoir. The results are used to refine the Tabasco full field model. To date, tracer breakthroughs have been detected from all the producers except 2T-215 and 2T-218. The monitoring of tracers will be continued until the tracer breakthroughs are confirmed in these two wells or approach economic limitations.

4.3 EASTERN AND SOUTHERN PERIPHERY EVALUATION

Geological evaluation of future development opportunities in the Eastern and Southern periphery has been completed. The conclusion is that the Tabasco reservoir is sporadic and discontinuous in this area. No development will be pursued at this time.

4.4 FLOOD EVALUATION

Further mechanistic modeling (3D Simulation) work is planned for 2016 to determine the best EOR mechanism for the reservoir. EOR application will depend on the updated geomodel and the results from the tracer work.

4.5 EXPLORATION/DELINEATION

No further exploration/delineation is planned during this plan period.

UNIT PLAN OF DEVELOPMENT
TARN PARTICIPATING AREA

AUGUST 1, 2016 TO JULY 31, 2017

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

Exploration drilling in early 1997 confirmed a commercial oil accumulation to the southwest of the existing Kuparuk River Unit (KRU). Development of this accumulation, now known as the Tarn Oil Pool, commenced in 1997 and continued into 2001.

This document provides an overview of the projects and strategies that comprise the development program for the Tarn Participating Area. The effective plan period for this submittal is August 1, 2016 through July 31, 2017. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the Tarn reservoir performance. Changes in business conditions, current state and national regulations, application of improved technology, and/or new insights into the reservoir may alter the feasibility of these plans.

2.0 FIELD STATUS

The Tarn field was brought on-line in July 1998; a continuous miscible injectant (MI) flood began in November 1998. A new 12” water injection line was put in service in July 2001, and a continuous Miscible Water-Alternating-Gas (MWAG) flood began at the same time. The 12” water injection line allowed Tarn to utilize hydraulic jet pumps for artificial lift as an alternative to gas lift.

Following the cessation of imported natural gas liquids from the Prudhoe Bay Field Central Gas Facility at the end of July 2014, immiscible water-alternating gas utilizing Lean Gas (LG) has been applied to the Tarn reservoir. Seventy-seven development wells have been drilled at Tarn as of December 31, 2015.

Following is additional information describing the Tarn status as of December 31, 2015:

- 77 development wells drilled at two drill sites (DS) 2L and 2N.
  - 55 producers
  - 22 MWAG injectors
- 63 active* wells
  - 39 producers
  - 24 injectors

*Active is defined as having injection or production between January 1, 2015 and December 31, 2015

Tarn 2015 Annual Average Production and Injection Rates

- Oil production rate: 9.3 MBOPD
- Gas production rate: 20.7 MMSCFD
- Water production rate: 16.5 MBWPD
- MI injection rate: 0.0 MMSCFD
- LG injection rate: 18.8 MMSCFD

- Water injection rate: 23.8 MBWPD

Tarn Cumulative Production and Injection Volumes

- Cumulative oil production: 115.7 MMSTBO
- Cumulative gas production: 184.8 BSCF
- Cumulative water production: 81.5 MMSTB
- Cumulative MI injection: 188.1 BSCF
- Cumulative LG injection: 25.8 BSCF
- Cumulative water injection: 202.8 MMSTB

3.0 SUMMARY OF 2015 ACTIVITIES

Drilling:

Five development wells were drilled at Tarn in 2015. The wells are as follows in chronological order.

- Well 2N-336, a horizontal grass roots multi-stage fracture stimulated producer, was put on production April 2015. This well targeted an undeveloped area south of the main 2N accumulation. The well has recovered 65 MBO as of year-end 2015. The December 2015 average production rate was 330 BOPD.

- Well 2L-308, a horizontal grass roots multi-stage fracture stimulated producer, was put on production May 2015. The well targeted the north eastern region of the 2L periphery. The well has recovered 160 MBO as of year-end 2015. The December 2015 average production rate was 160 BOPD.

- Well 2L-328, a horizontal grass roots multi-stage fracture stimulated producer, was put on production June 2015. The well targeted the middle of a fairway just south of 2L-321 in the heart of the 2L accumulation. The well has recovered 188 MBO as of year-end 2015. The December 2015 average production rate was 190 BOPD.

- Well 2L-316, a horizontal grass roots multi-stage fracture stimulated producer, was put on production August 2015. This well targeted the middle of a fairway between 2L-311 to the north and 2L-320 to the south in the 2L accumulation. The well has recovered 64 MBO as of year-end 2015. The December 2015 average production rate was 370 BOPD.

- Well 2N-312, a slanted grass roots injector, was put on injection September 2015. This well is planned to provide support and sweep resources in the southwestern area of the 2L accumulation and the fringe area between the 2N and 2L accumulations. The well has injected 223 MBW as of year-end 2015. The December 2015 average injection rate was 1,400 BWPD.

Workover:

The 2L-307 producer rig work over was executed in December 2015 to replace the tubing and remove the whipstock. This was done to restore communication to the original perforations and therefore production.

2N-320 rig work over to replace tubing due to well integrity issues was unsuccessful due to tubing break off during pull operation. Well was plugged and abandoned December 2015.

Well conversion:

There were no wells that were converted to injection in 2015.

Facility:

To fix corrosion problems, parts of 2N-347's well line were replaced in 2015. Replacement was successful and well was put back on line July 2015. No well line upgrade program or other facility work except for new wells tie-in occurred in Tarn in 2015.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the Tarn and the Kuparuk River formations.

4.1 DEVELOPMENT DRILLING

Following the successes of the 2014-15 drilling program, new development opportunities are being evaluated with the new data available as a result of the program. While there are currently no plans to drill additional wells in Tarn before July 31, 2017, the geophysical, geological and reservoir engineering team is working to develop a new log model, net pay map, and incorporate these findings into the flow simulation to evaluate and identify additional drilling prospects.

4.2 Reservoir Management

The original Tarn development plan specified continuous injection of MI into the Tarn reservoir for pressure maintenance and enhanced recovery. The use of MWAG injection was not initially recommended due to the lower permeability nature of the reservoir seen in the exploration wells and signs of water damage in laboratory tests of the exploration well core.

The discovery of higher quality reservoir during development drilling from the 2N and 2L pads reopened the potential of using an MWAG recovery process. MWAG, as compared to continuous MI injection, is expected to yield higher recoveries than the original straight gas injection approach due to improved mobility control. Short term field tests completed in the summer of 1999, and repeated in 2000, showed no loss of injectivity or other indications of formation damage as a result of water injection. Based upon these results, full field MWAG operations were recommended, approved by co-owners, and implemented in the field.

Field performance data showed good response in the production wells from the MWAG injection program. MWAG slug sizes and WAG ratios were optimized through use of a full field simulation model of the Tarn accumulation.

Through July 2014, the Tarn MWAG process used Kuparuk spec MI injected above the minimum miscibility pressure. Following the cessation of imported natural gas liquids from the Prudhoe Bay Field Central Gas Facility at the end of July 2014, immiscible water-alternating gas utilizing lean gas has been applied to the Tarn reservoir since and is expected to continue for the foreseeable future. Active field surveillance combined with alternating water and gas injection will be used to maximize production by keeping field producing gas-oil ratio (GOR) sustainable. The strategy going forward will be to minimize GOR while optimizing return of natural gas liquids.

The reservoir management strategy of maintaining I/W ratios, on a pattern level, at or above 1.0, to achieve targeted pressures, will continue to be followed. This will be accomplished through setting optimum injection well rates and cycling high formation GOR and water-oil ratio production wells as needed.

A Full Field reservoir model (FFM) was built in 2011 including the 2L and 2N areas as well as the most recent log and core data from all recent wells. The FFM has been history-matched and is being used for forecasting or screening future production and new opportunities at Tarn. A higher resolution Tarn area 3D seismic volume, acquired January through March 2008, and a conditioned “4D” difference volume have been interpreted and incorporated into the updated reservoir model. The recent 2014-15 development wells will help to calibrate and refine the FFM.

4.3 Artificial Lift

Tarn was originally designed to utilize the MI from the injection header as a means of gas lifting the production wells which were not able to flow under existing reservoir energy. However, Tarn oil is prone to paraffin deposition when production fluids fall below the cloud point temperature of 92° F. Production fluids cool as they flow from the reservoir and paraffin begins to deposit in the tubing across the permafrost interval. Gas lifting the wells with MI further cools the produced fluid due to Joule-Thomson related cooling effects. Utilizing jet pump power fluid (produced water) with a high heat capacity increases the temperature of the produced fluids and virtually eliminates paraffin deposition in the down-hole tubulars. Jet pumps as an alternative means of artificial lift at Tarn were proven to increase production rates during the 1999 and 2000 water injection field tests.

Thirteen of the artificially lifted wells at Tarn were converted to hydraulic jet pumps in October 2001. As water breakthrough occurs, it is expected that the flowing temperatures will increase, reducing the potential for paraffin deposition. At that time, the wells could be switched back to a gas lift mechanism.

Production increases of approximately 10% were realized through use of hydraulic jet pumps. Paraffin deposition has been minimal in these wells and slickline scrapes and hot oil treatments have been virtually eliminated from the jet pumped wells.

Untreated saline produced water injected down the inner annuli as pump power fluid in 2006 accelerated tubing and casing corrosion which led to well integrity issues. As a result, eight wells were secured and shut-in for workover or sidetrack.

For this reason, recent Tarn wells were planned with gas lift for artificial lift, and current jet pump wells are being considered for conversion to gas lift as well design allows. As of December 31, 2015, there are only four remaining wells at Tarn on jet pump: 2L-311, 2L-321, 2N-342, and 2N-304. After careful consideration, future plans also exist to convert 2L-330 to jet pump due to severe paraffin issue.

The southern peripheral well 2N-342 was converted from gas lift to jet pump in 2009 since the well experienced frequent freezing issues associated with low flow rates. Wells 2L-321 and 2N-304 are using jet pumps for artificial lift due to mandrel size limitation as a result of smaller inner annulus after rig workover. Well 2L-311 has seen no integrity issues so far to warrant artificial lift conversion to gas lift.

4.4 PRODUCER TO INJECTOR CONVERSION

At this time eight wells have been converted to MWAG injection service: 2L-301, 2L-305, 2L-319, 2N-309, 2N-326, 2N-335, 2L-310, and 2N-308.

Other future conversions will be considered as part of the Tarn redevelopment strategy to mitigate pattern inefficiencies such as early water or gas breakthrough. Moving toward a line drive pattern with injectors aligned in a north-northwest to south-southeast direction will improve sweep efficiency and help to optimize recovery from the Tarn field. With this line drive, the risk of future short circuits between injectors and producers can be minimized and sweep optimized.

4.5 EXPLORATION / DELINEATION

The 2014/2015 Tarn drilling campaign has continued to delineate the Bermuda net pay in the field.

The Purple interval is the oldest of the Bermuda turbidite lobes. It is located to the south and east of DS2N. The production data thus far is encouraging. Further development has been evaluated and is awaiting development candidates to expand resource base in Purple.

Further work on the younger Cairn interval is ongoing as it is being evaluated for future resource addition.

ConocoPhillips

UNIT PLAN OF DEVELOPMENT
WEST SAK AND NEWS PARTICIPATING AREAS

AUGUST 1, 2016 – JULY 31, 2017

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LIST OF ATTACHMENTS

1.0 INTRODUCTION

As required by the December 18, 1997 Decision and Findings of the State of Alaska Department of Natural Resources Commissioner concerning the West Sak Participating Area in the Kuparuk River Unit, and 11 AAC 83.343, ConocoPhillips Alaska, Inc. hereby submits the Annual Update to the West Sak Development Plan.

On May 29, 2009, the Alaska Department of Natural Resources Commissioner approved the formation of the North East West Sak (NEWS) Participating Area (PA) within the boundaries of the Kuparuk River Unit, retroactive to March 1, 2008. This report also covers the Annual Update to the NEWS Development Plan.

This plan provides an overview of the projects and strategies that comprise the development program for the West Sak and NEWS PAs within the Kuparuk River Unit (KRU). The effective plan period for this submittal is August 1, 2016 through July 31, 2017. Assumptions that form the basis for this development plan are consistent with the current business climate and the current understanding of the West Sak reservoir performance. Changes in business conditions and/or new insights into reservoir performance may alter the timing, scope, or feasibility of these plans

2.0 FIELD STATUS

The following information describes the status of development in the West Sak Oil Pool as of December 31, 2015. Maps showing the development status of the West Sak PA and NEWS PA are included as Attachments 1 and 2, respectively.

During 2015, there were 109 active wells at drill sites (DS) 1B, 1C, 1D, 1E, 1J and 3K. An active well is defined as having produced or injected fluid between January 1, 2015 and December 31, 2015.

- 56 producers
- 49 water injectors
- 4 water-alternating-gas (WAG) injectors
- 9 wells were shut in (4 producers/5 water injectors)

2015 Average Rates

- Oil production rate: 13,865 BOPD
- Water production rate: 8,125 BWPD
- Gas production rate: 13,989 MCFPD
- Water injection rate: 18,825 BWPD
- Gas injection rate: 2,158 MCFPD

Cumulative Production

- Cumulative oil production: 78,568 MSTBO
- Cumulative water production: 25,616 MSTBW
- Cumulative gas production: 43,622 MMSCF
- Cumulative water injection: 106,859 MBW
- Cumulative gas injection: 7,559 MMSCF

3.0 SUMMARY OF 2015 FIELD ACTIVITIES

Summarized below are significant accomplishments at West Sak over the preceding year. :

- A request to expand the existing West Sak PA was submitted and approved in December 2015. Attachment 1 illustrates the updated extents of the expanded West Sak PA. The approved PA boundary captures wells drilled at DS1C and DS1D in 2015 and accommodates future wells planned to be drilled at DS1H in 2017.

- Eight new wells were drilled and completed in 2015 including single-lateral injector 1D-142, quad-lateral producer 1D-143, single-lateral producer 1D-145, single-lateral producer 1D-146, single-lateral injector 1C-152, single-lateral producer 1C-153, single-lateral injector 1C-154, and single-lateral producer 1C-155.

- Viscosity Reducing Water-Alternating-Gas (VRWAG) operations were challenged in 2015 due to unexpected issues arising from lean gas injection. Operational best practices were developed from the lessons learned and VRWAG operations are planned to restart in 2016. Workovers are planned for producers 1J-107 and 1J-182 in 2016 to facilitate VRWAG injection in offset injectors. Monitoring of pattern performance to re-establish a waterflood baseline will occur prior to commencing VRWAG injection.

- Waterflooding the reservoir with produced water for pressure maintenance and improved sweep continues to be the main enhanced recovery mechanism in the West Sak Oil Pool. Waterflood continues to provide recovery benefits; however, three new matrix bypass events (MBE) occurred in 2015 between wells 1C-190 and 1C-184, 1E-117 and 1J-168, as well as 1E-119 and 1E-166.

- There were six MBE remediation attempts in 2015 to treat new and pre-existing MBEs. Three of these treatment attempts re-treated previous, failed remediation attempts. Additional treatments are under evaluation for 2016 building on the prior years' successes of restoring injection support to the treated patterns.

- Field trials of through-tubing conveyed electric submersible pump (ESP) motor and pump systems (Rigless ESP) continue. The reliability of early Rigless ESP systems was challenged by electrical and mechanical issues. Successful installations incorporating key design changes were completed in 1D-145 and 1C-153 in 2015. Additionally, a successful, proactive motor pull, pump replacement, and restart in well 1D-129 occurred in 2015. Surveillance and reliability monitoring of these field trials will continue in 2016. Assuming continued success with Rigless ESP field trials, additional systems may be considered for future wells where access below the motor is required.

- The West Sak team will be evaluating the benefits of improved injectivity with cleaner injection water at West Sak in 2016. Surveillance activities at DS1E and DS3K suggest benefits from cleaner injection water in the West Sak reservoir.

- Ultra-fine Open Hole Stand-Alone Screen (OHSAS) completions were installed in four producing wells in 2014 and 2015 (1C-151, 1C-153, 1C-155, and 1D-145). Surveillance activities including periodic sand shakeouts suggest little to no sand production with low productivity impairment relative to slotted-liner completions.

Monitoring activities will continue in 2016 and beyond to establish long-term performance. Additional consideration is being given to this technology in future new developments at West Sak, should the ultra-fine OHSAS completion type prove to be a value adding investment enabling a higher inter-well gradient and reduction in MBE frequency.

4.0 PLAN OF DEVELOPMENT

ConocoPhillips is committed to a safe and environmentally sound operation. All designs are aimed at meeting or exceeding the standards specified by applicable state and national codes, the recommended practices of the relevant advisory organizations, and/or the time-proven practices of prudent operators. Plans are to make maximum use of the existing KRU infrastructure, thus minimizing environmental impacts while maximizing the economic ultimate recovery for both the West Sak and the Kuparuk River formations. Following is the annual update to the Unit Plan of Development.

4.1 HISTORICAL SUMMARY

Consistent with the original 1997 Plan of Development, Phase 1 development of the West Sak reservoir was initiated at Kuparuk DS1C and DS1D. As proposed, Phase 1 was to consist of 50 wells (31 producers and 19 injectors). A producer-bounded five-spot pattern configuration on forty (40) acre well spacing was envisioned with water flood as the drive mechanism.

Phase 1 drilling at DS1D was divided into two drilling periods, the first of which commenced in 1997 (Phase 1A). The second drilling period (Phase 1B) commenced in 1998. Phase 1A consisted of nine producers and five injectors. Phase 1B consisted of ten producers and six injectors for a total of 19 producers and 11 injectors. First production was achieved in December 1997 with production ramping up into 1999. Phase 1 producers are completed in the West Sak D, B and A sands with a mix of multiple stage fracturing/gravel packing operations or fracturing for sand control using an epoxy resin. Electric submersible pumps and electrical submersible progressing cavity pumps were originally employed as the artificial lift mechanism.

Phase 1 drilling at DS1C (originally referred to as Phase 1C) was to commence in early 1999, but a decision was made to defer additional drilling pending further evaluation of reservoir and well performance.

Engineering assessments of Phase 1B indicated that drilling costs were near the optimum and that only minor savings could be expected through further optimization of the current completions (fracturing). Additionally, it was believed that the 30 wells drilled to date provided an adequate number of penetrations to assess costs and performance associated with the conventional cased and fractured completions being pursued. Conceptual studies initiated in 1999 indicated that horizontal multi-lateral wells held significant promise in reducing overall development costs while significantly increasing reservoir performance and recovery. Thus, in an effort to develop a "step change" reduction in West Sak development costs and improve low price environment margins, a detailed engineering evaluation of horizontal multi-lateral well designs was initiated.

Beginning in 2000, three multi-lateral producers were drilled with six support injectors at DS1D. These wells were completed in the B and D intervals only. A completion design having an A sand "tag" originating in the lower lateral was determined to be overly expensive and uneconomic at that time.

This multi-lateral design (Figure 1) greatly influenced the 2001-02 development drilling at West Sak and replaced the previously planned Phase 1C development using conventional wells. Similarly, the Horizontal Undulating Injection well designs (Figure 2), as well as the D sand horizontal injection wells were incorporated into the development plans for Phase 1C.

West Sak development continued in 2003 with an eight well development program. This program included two multilateral producers, two D sand only producers, two horizontal undulating injectors, one D sand only injector and an undulating A sand producer. The lateral lengths averaged approximately 6,000 feet. The producers used jet pumps for artificial lift and had slotted liner completions.

In 2004, West Sak development moved to DS1E. Nine wells were drilled, including the first tri-lateral wells, which had laterals in the D, B and A2 sands. In total, 13 wells were drilled at DS1E. Two principal changes that were included in the 1E development were the use of oil based mud to reduce drilling damage as well as extended reach drilling to increase the area that could be developed from a single pad.

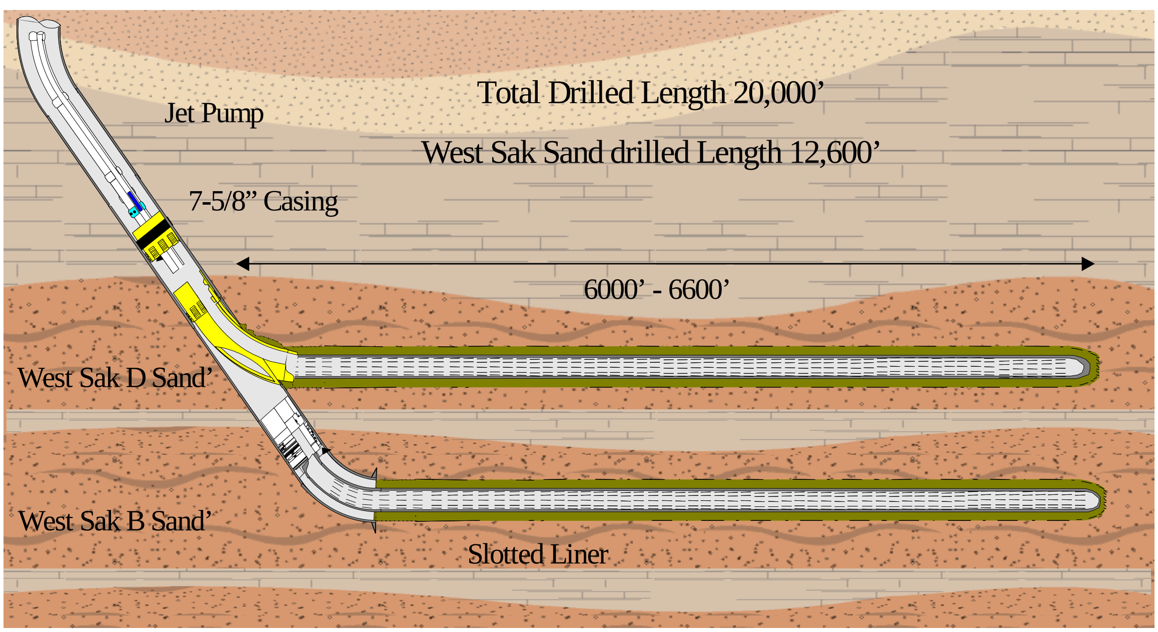

Figure 1: Schematic of a Multi-Lateral Well in the West Sak B and D Sands

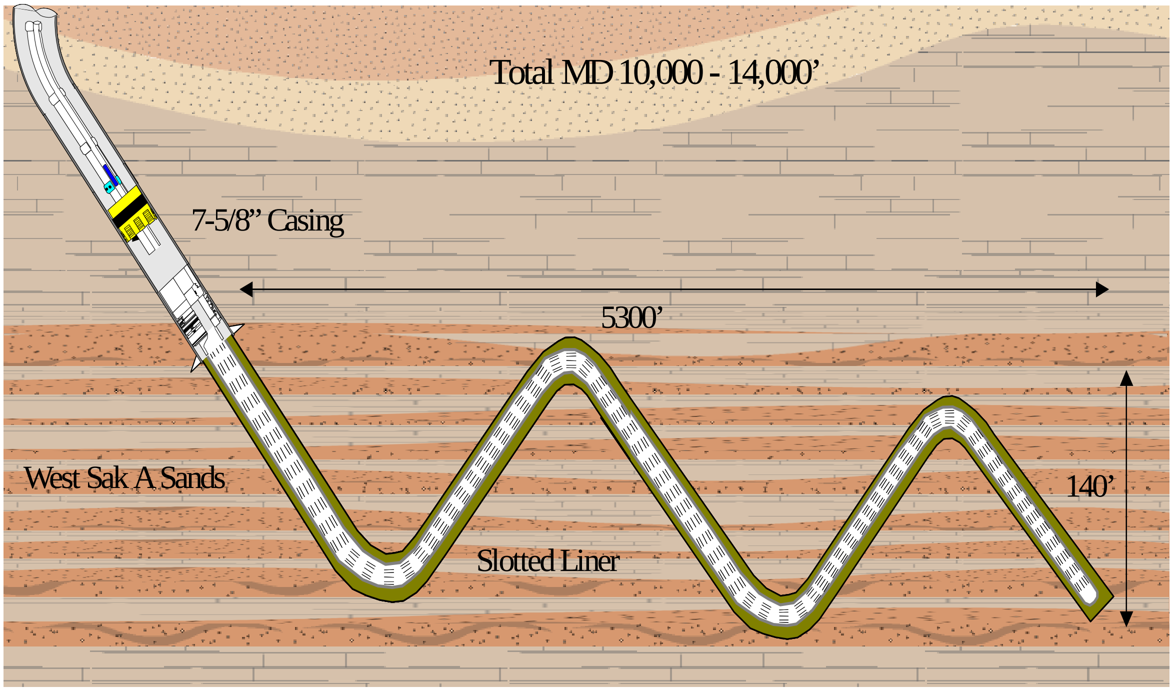

Figure 2: Schematic of a West Sak Undulating well

In 2005, DS1E development was completed and drilling commenced on DS1J. In total, 31 horizontal multi-lateral wells were drilled (17 producers and 14 injectors) and the development was completed in 2007. This represents a reduction in the number of wells premised during project sanction, which was dictated by higher than anticipated oil-water contacts on the eastern flank of the accumulation defined during the drilling phase of project execution. The well design was similar to that used at DS1E with a few differences. After the first four wells, the strategy of undulating between the upper and lower lobes of the A2 sand was changed such that the A2 laterals for the remaining wells focused only on the upper A2 sand (Figure 3). The utility of the horizontal undulating well design is being re-evaluated due to experienced drilling and performance inefficiencies (loss of net pay exposure while drilling through intervening shales) and operability challenges (impact of MBE’s and waterflood conformance). Therefore, as stated above, early in the 1J drilling program it was decided to abandon this design and target individual reservoir sands with dedicated laterals.

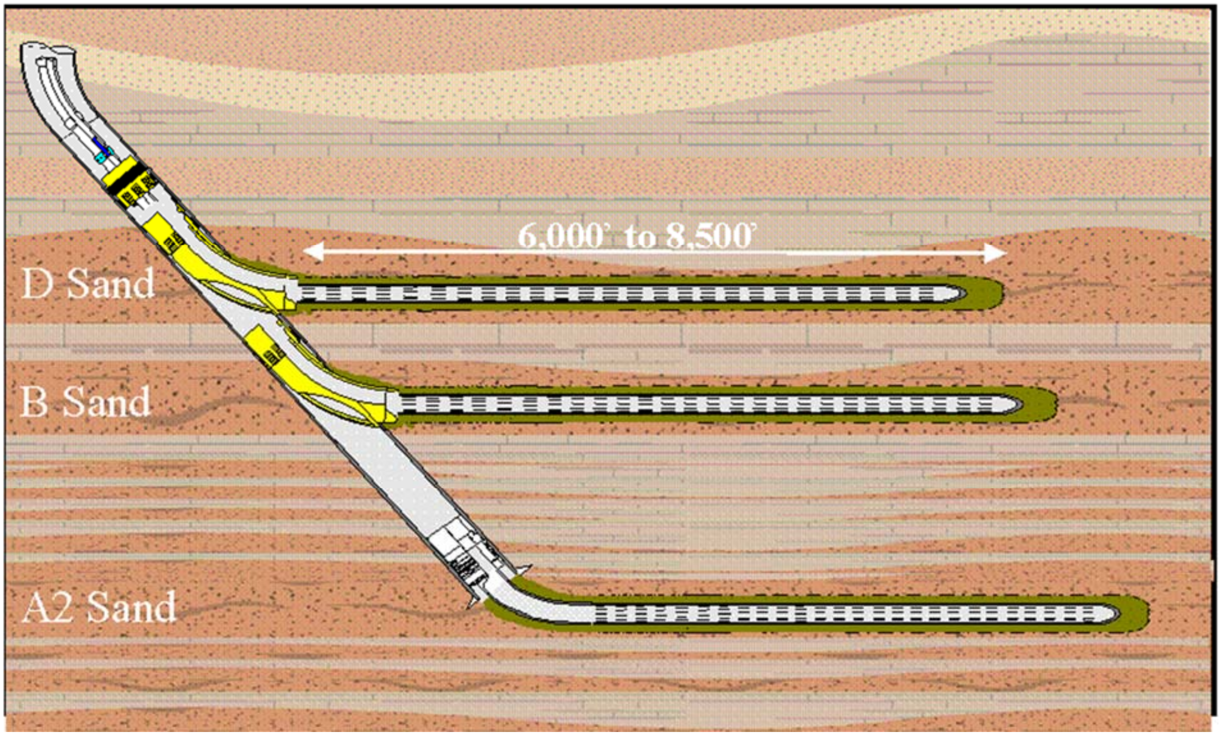

Figure 3: Current Tri-lateral Well Design

Included in the DS1J program was early drilling of two wells to develop tracts due to contract out of the West Sak PA. These areas are being developed with multi-lateral injectors and producers in a direct line-drive pattern configuration. The wells target and D, B and A2 sands and have lateral lengths between 6,000 and 8,000 feet.

Additional delineation drilling was done in the NEWS area starting in 2004 with well 1H-05A (see Attachment 2). Additional wells were drilled from DS3J and 1Q to determine oil quality and oil water contacts. West Sak 3J-101 and 1Q-101 were drilled to the West Sak and suspended at surface casing for future developments in these areas. In early 2006, three exploration wells were drilled from an ice pad to evaluate the 1R east, 1H north and 1H south areas. As a result of this drilling activity the resources in the NEWS area have been high graded and future developments will initially concentrate on the areas with the best oil quality.

In 2008, the first phase of the NEWS development was drilled at DS3K. The 2008 program consisted of drilling one horizontal multilateral producer and two horizontal multilateral water injectors. The injector wells utilized new technology to allow hydraulic isolation of the B and D sands; as well as improving injection conformance along the laterals. The injectors utilize the first TAML (Technology Advancement of Multilaterals) level 5 junctions installed in the West Sak, and should allow more control over future matrix bypass events as well as improve sweep efficiency (Figure 4).

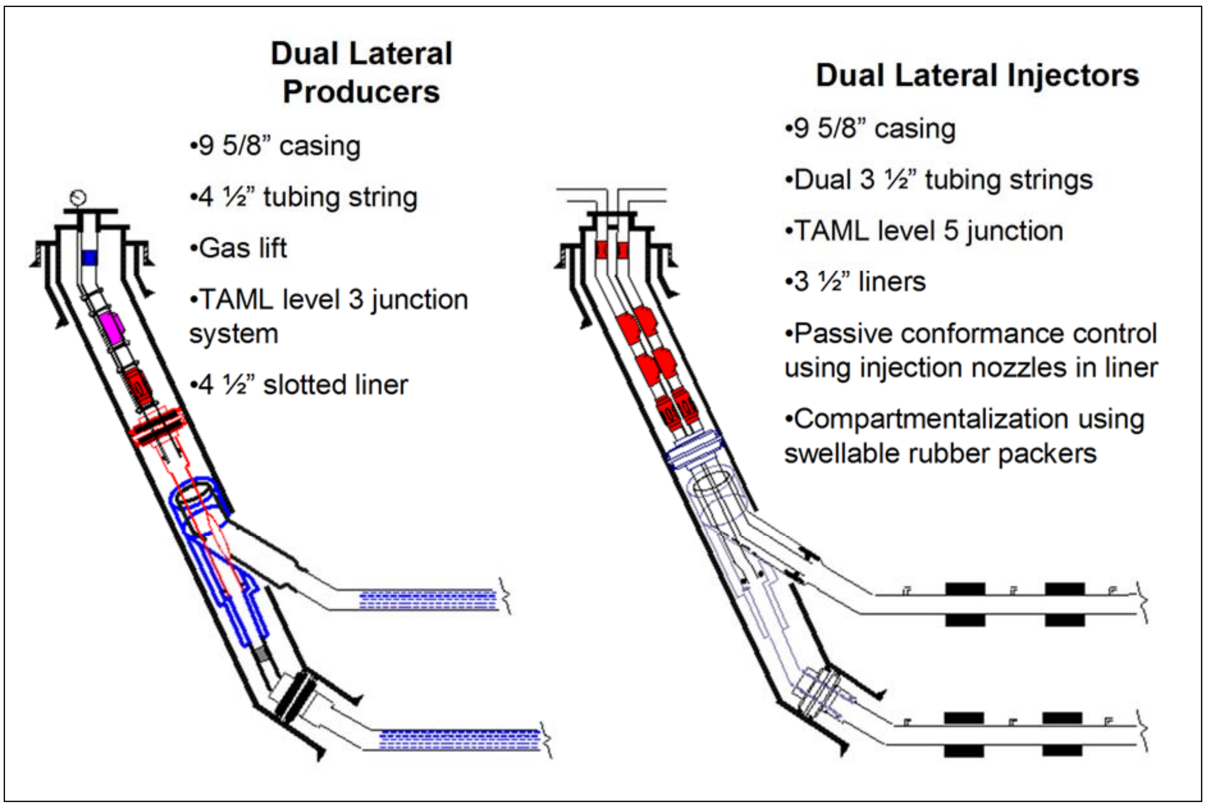

Figure 4: NEWS 3K Well Design

In December 2012, drilling commenced on 3K-105, a second horizontal multilateral producer at DS3K, with a drilling and completion design similar to the 3K-102, the existing multilateral producer.

Six new single-lateral wells (three producers and three injectors) were drilled on the north-end of DS1C over the three-year period of 2013-2015. The focus of this development was to trial a sand-control completion design utilizing ultra-fine standalone screens (OHSAS) in the producer wells, 1C-151, 1C-153, and 1C-155 as illustrated in Figure 5 below. The first injector well, 1C-150, employed ICDs similar to the DS3K wells. However, injectivity suffered over time due to low-quality injection water. The two remaining injectors, wells 1C-152 and 1C-154, were completed with slotted liner to avoid the same injectivity challenges.

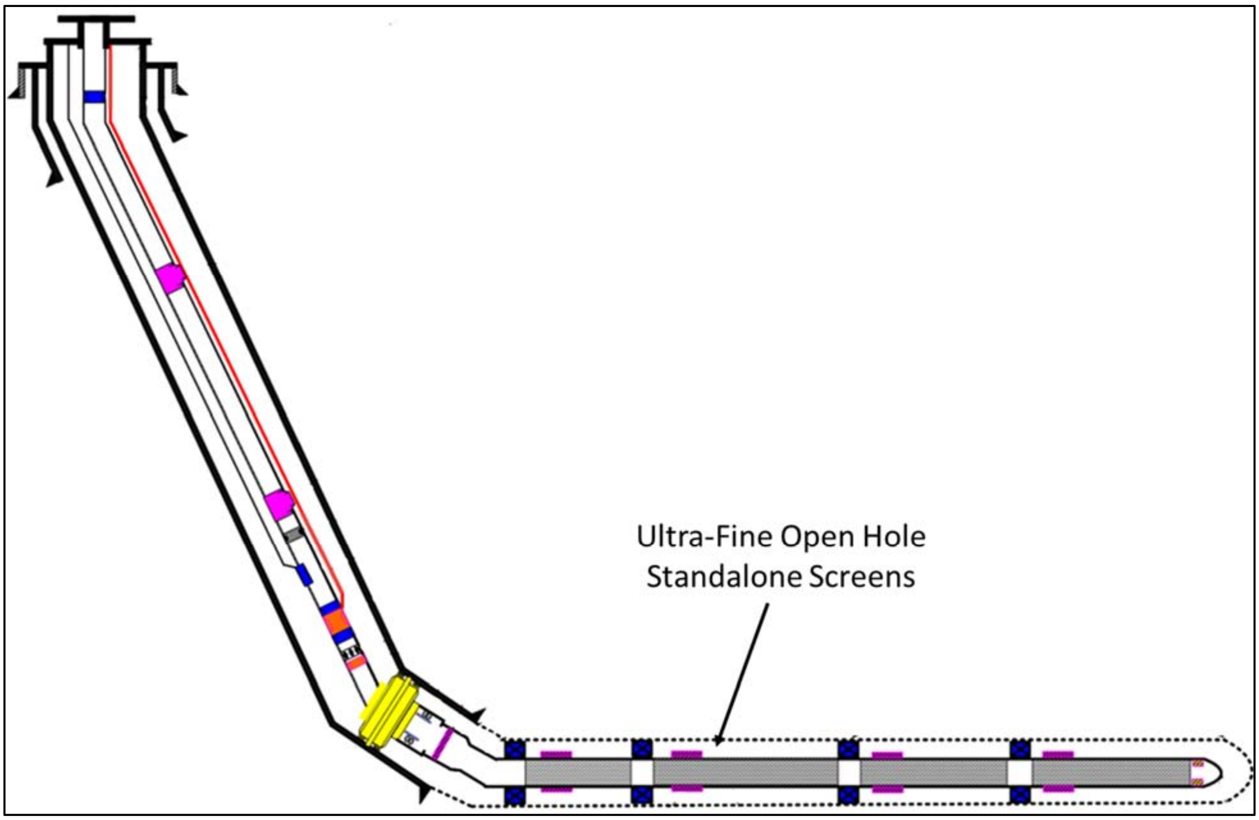

Figure 5: Ultra-fine Open Hole Standalone Completion Design

Four additional wells were drilled from DS1D in 2015 to capture stranded resource. An injector-producer pair (injector 1D-142 and producer 1D-146) was drilled on the eastern flank of the Core Area in the D sand. These wells are single-lateral and completed similar to the DS3K wells, i.e. slotted liner producer with ICDs in the injector. Two producer wells were drilled in the heart of the existing 1D-area to replace a failed previously failed well, producer 1D-140. Well 1D-143 is a quad-lateral, slotted-liner producer completed in the D, A4, A3, and A2 sands. 1D-145 is a single-lateral, OHSAS well completed in the B sand. 1D-145 trialed the OHSAS completion design in the MBE-prone B sand.

4.2 Well Completions and Artificial Lift

West Sak well completions have evolved from the initial vertical wells to a mix of horizontal wells with sand control and horizontal wells with slotted liner. As noted above, the completion design continues to evolve along with technology and operational experience.

The West Sak artificial lift strategy was initially Tubing Conveyed Electric Submersible Pumps (TTC-ESP). In 2003, several wells used jet pumps for artificial lift. After 2004, the developments at DS1E and DS1J used TTC-ESP with backup gas lift. Four wells at DS1J have been converted to jet pump service.

During the early operation of these wells, plugging due to excessive sand deposition was observed in several wells requiring them to be worked over to pull the ESP motor and convert the well to gas lift service. The change allows access to the completion via the tubing so the well can be cleaned out with coiled tubing. Gas lift is the planned artificial lift method for the NEWS development at DS1H.

4.3 FUTURE DRILLING

During 2016, West Sak operations will focus on existing developments while studying and planning the future development opportunities described below.

4.3.1 DS1D Development

Additional redevelopment wells from DS1D are being considered. The value and work scope of this effort will be developed in 2016. Results of the 2015/16 program at DS1D and DS1C will inform decisions on additional redevelopment wells at DS1D.

4.3.2 DS1C Development

Results and performance analysis of the 2015/16 DS1C drilling will inform decisions on three additional, lower-value, DS1C well targets.

4.3.3 DS1H Development

The 1H NEWS drilling program (4 horizontal multi-lateral producers and 15 vertical injectors) from the existing DS1H pad was planned for execution in 2016, but deferred based on market conditions. Much of the surface work to expand the existing DS1H gravel pad and facilities to accommodate the 19 new wells was completed in 2015 and early 2016. Remaining facility spend will be completed taking into account limits to the KRU annual capital budget. The WIOs are still determining the timing to begin DS1H drilling activities.

4.3.4 Eastern NEWS Development

The Eastern NEWS Area, see Attachment 3, represents a potential major multi-well development project requiring a new DS. The progression of technology and learnings from existing West Sak developments including recent drilling activity will provide key insights for future decisions to progress this project.

4.3.5 DS3K and DS3N NEWS Development

Additional drilling opportunities from DS3K and DS3N will be under evaluation in 2016. Most likely, these targets will be developed in multiple phases.

4.3.6 DS3R NEWS Development

Development of the West Sak reservoir from DS3R is under evaluation. The drilling of West Sak wells from DS3R may require an expansion of the existing DS facilities and, depending upon well count, potential expansion of the gravel pad. Planning for two pilot wells, drilled from existing infrastructure (injector/producer pair), began in 2013 and continues in 2016.

In the summer/fall of 2014 a new 47 square mile speculative 3D seismic survey was acquired and licensed in the Northern portion of the Kuparuk River Unit. This survey used ocean bottom node technology in the shallow offshore area. Summer ice-free acquisition and ocean bottom nodes helps mitigate the historical imaging problems associated with winter off of ice seismic. The Oliktok data is being processed through depth migration in 2015 and 2016 with expected delivery mid-year 2016. The objective of this seismic survey is to improve imaging to understand the potential in this area and improve well planning for the long horizontal wells. This new 3D coverage is critical to further development drilling in the DS3R area and is expected to improve development well positioning.

4.3.7 West Sak 4D Seismic

The 4D seismic response observed in the West Sak reservoirs continues to enhance understanding of the dynamic changes in these reservoirs. To date, one dedicated 4D seismic shoot, Kuparuk West Sak-Western Kuparuk (KWS-WK), has occurred over a 60 square mile pilot overlap area. This pilot area includes most of West Sak core area. The time period between these two seismic surveys is from 2005(KWS) to 2011(WK). The 4D processing applied to these two surveys demonstrated reservoir changes and fault compartmentalization in and around the existing developments.

The West Sak reservoirs appear to be conducive to 4D technology. Efforts are underway to understand the appropriate areas and time for its application.

Key plan milestones and plans for 4D seismic integration into West Sak development include:

1. Four-Dimensional (4D) time-lapse 3D seismic acquired over West Sak reservoirs in 1989-91, 2005, and 2011: KRU 89-91 3D, KWS 2005 3D, and WK 2011 3D.
2. Schlumberger Geosolutions (Denver) co-processed KWS 2005 and WK 2011 in 2012 (60 mi^2 dedicated 4D acquisition and processing across core area).
3. CGG Calgary co-processed KRU 89-91 3D with KWS 2005 in 2014 (approximately 200 mi^2 overlap of KRU with KWS – includes core area).
4. Close the Loop technology applied to West Sak reservoirs and finalized 2015; time-lapse 3D seismic constraints on West Sak reservoir dynamics at 2005 and again at 2011.
5. Work in progress to break out West Sak (D and B sands) pressure and saturation changes from 2005 to 2011 in core area: utilize time-

lapse 3D seismic inversion in cooperation with data analytics (random forest classification).

6. Advancing the integration of the KRU-KWS 4D seismic for understanding reservoir dynamics from field startup to 2011.

4.4 FACILITIES

Drill sites 1B, 1C, 1D, 1E, 1J and 3K currently have West Sak/NEWS production. Any new developments at existing drill sites in the West Sak/NEWS area will likely require facilities upgrades such as the addition of heaters, electrical upgrades, and pipelines. These additional facility requirements add to the economic challenge of further West Sak/NEWS development in the current business environment.

Corrosion integrity concerns affected water injection at DS3K and DS1E in 2015. Major repairs on the injection facilities at each DS are planned for 2016.

4.5 ENHANCED RECOVERY PILOT EVALUATION

During 2003, ConocoPhillips Alaska, Inc. received approval to commence a West Sak small scale enhanced oil recovery (SSEOR) Pilot Project using Kuparuk MI in a WAG pilot. The SSEOR Pilot Project consisted of three phases in two permitted areas:

Phase I : WAG wellbore completion integrity test;
Phase II : WAG injectivity test; and
Phase III : WAG breakthrough test.

Phase I of the Pilot Project was initiated in September 2003 with injection of Kuparuk MI into well 1C-135. Injection was continued for approximately two months. Well 1C-135 was returned to long-term production in April

2004. Production from the well indicated that slotted liner wells are suitable for gas production.

Phase II of the Pilot Project was initiated in March 2004 with injection into deviated conventional injectors 1C-119 and 1C-121. Well 1C-119 received one month of gas injection and the well was returned to water injection. Water injectivity after gas injection was initially lower, but recovered over about two weeks to the pre-gas injection levels. The 1C-121 injector received five months of gas injection, was shut-in for several weeks and then returned to water injection. This well also recovered to the pre-gas injection levels. Due to surface casing leaks found in both wells 1C-119 and 1C-121, no additional WAG cycles have been completed. Repairs have been made and the wells have been returned to water service only (2006 for 1C-121 and 2007 for 1C-119).

Phase III of the Pilot Project was also initiated in 2004 with gas injection into well 1C-121. Well 1C-121 was on continuous gas injection for five months and resulted in an increase in the gas-oil ratio (GOR) of offset producer 1C-102. Once well 1C-121 was switched to water injection, the GOR in well 1C-102 dropped back to its pre-gas injection level. No additional gas breakthrough was noted in well 1C-102, as subsequent WAG cycles in wells 1C-119 and 1C-121 were suspended due to failed surface casing, which was detected in both injectors during 2005. In 2005, the first WAG cycle in horizontal undulating injector well 1C-174 was completed. This first cycle was just over a month in duration and pre-gas injection water rates were established within a few days of returning to water injection. No gas breakthrough for this first cycle was observed in offset producers 1C-178 and 1C-170. The second WAG cycle in 2006 lasted just over a month but no definitive GOR response was observed in offset producers 1C-178 and 1C-170. The West Sak SSEOR Pilot Project is completed.

A VRWAG pilot project was approved by the Alaska Oil and Gas Conservation Commission (AOGCC) in 2009, and first gas injection began in November 2009. The pilot injection wells include 1E-102, 1E-117, 1J-122 and 1J-170. Well 1E-102 experienced a matrix bypass event and is now excluded from the pilot. The pilot was authorized for 36 months after the commencement of gas injection. In 2012, an extension was granted to continue the VRWAG pilot into 2013. Another extension was granted in 2013 to allow for continued pilot operations to the end of the year. Surveillance shows some enhancement of production in offset producers, and an analysis of the data with a final report detailing pilot conclusions was submitted to the AOGCC in 2013. The West Sak team requested an amendment to Area Injection Order 2B to allow for VRWAG in the West Sak Oil Pool. The request was granted on June 19, 2014 when the AOGCC issued Area Injection Order 2C. Wells 1E-117, 1E-119, 1J-122, 1J-164, and 1J-170 injected gas during 2014. Additional wells will be converted to gas injection when the appropriate well integrity criteria are met.

Lean gas injection, i.e. no solvent was blended with the blend gas, was briefly attempted in late-2014 to early-2015 following the loss of natural gas liquid (NGL) imports and downtime from indigenous NGL production equipment. Unexpected challenges arising from lean gas injection included faster breakthrough times and additional sand production. These challenges resulted in significant well downtime. Operational best practices were developed from these lessons-learned and communicated to operations personnel for implementation.