ATHABASCA OIL CORPORATION

HANGINGSTONE D54 PERFORMANCE REPORT 2021

June 2022

ATHABASCA OIL CORPORATION

AGENDA

SUMMARY

- Development Overview
- Subsurface
- Surface Operations
- Regulatory and Compliance

DEVELOPMENT OVERVIEW

HANGINGSTONE PROJECT

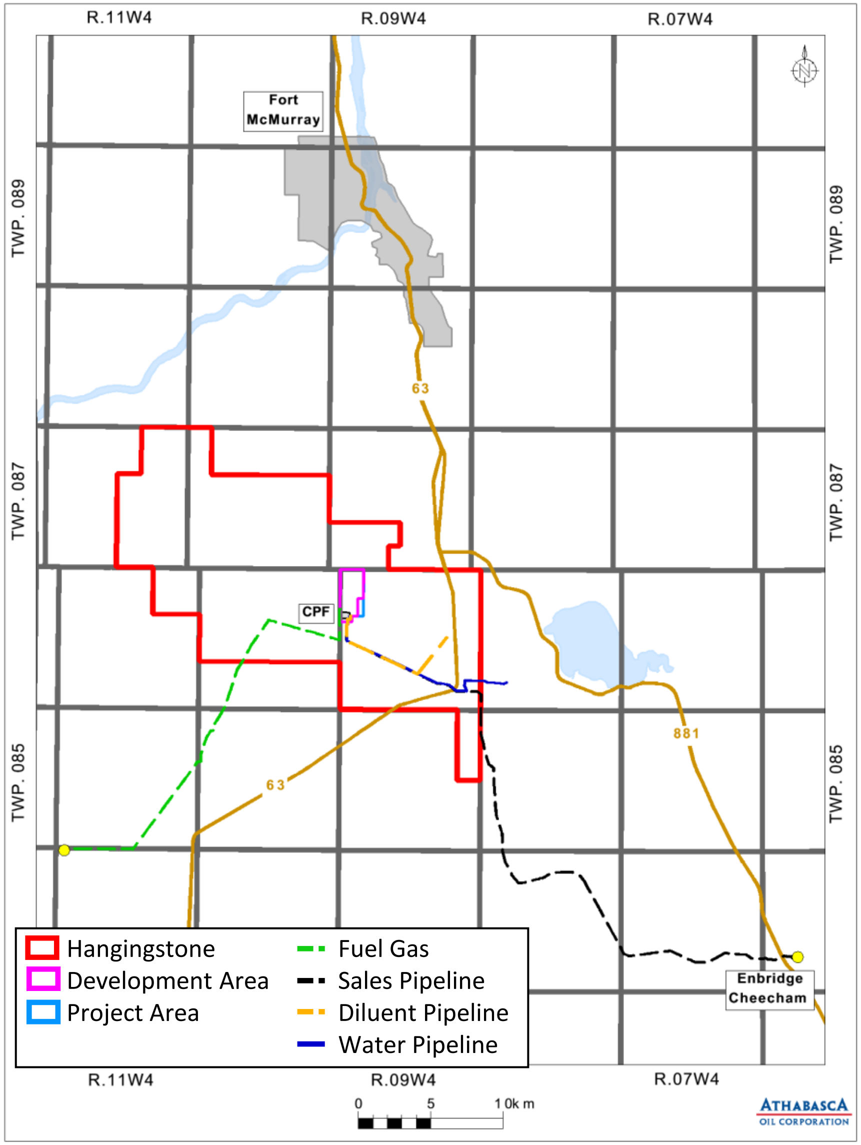
- First steam March 2015
- 25 wellpairs

PROJECT DETAILS

- Located 20 km south of Fort McMurray, AB
- 5 production pads (5 pairs per pad)
- Central Processing Facility (CPF)
- Offsite services and utilities

INFRASTRUCTURE

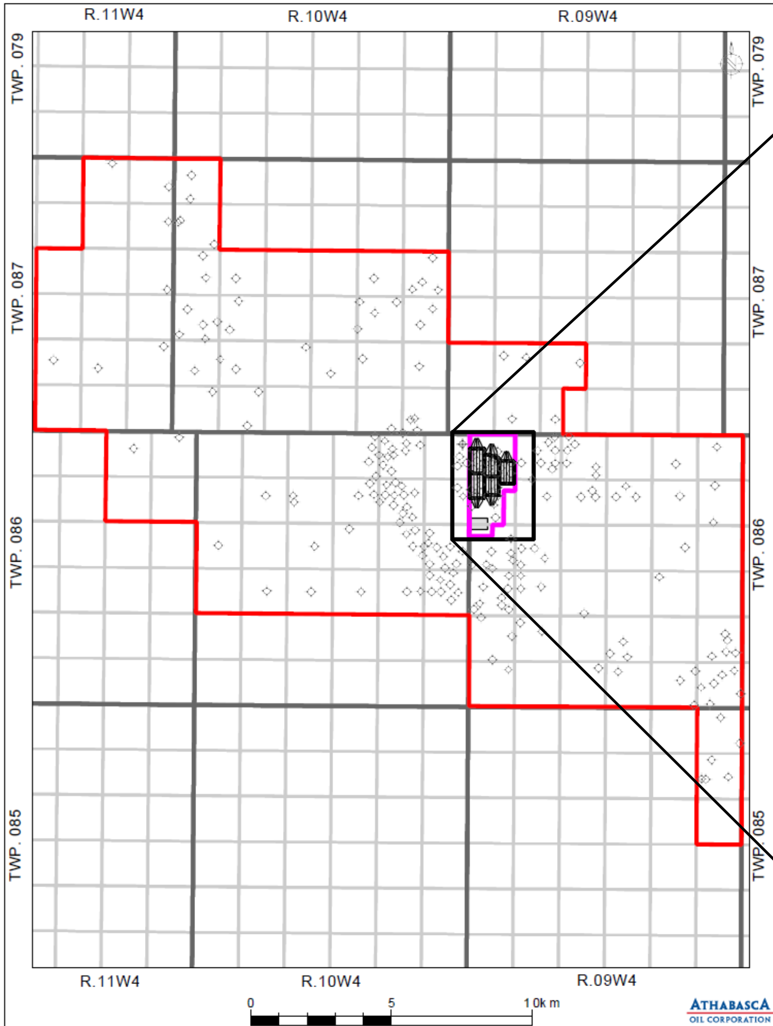
- Fuel gas from TransCanada Pipeline (TCPL)
- Dilbit export to Enbridge Cheecham Terminal
- Diluent from Inter Pipeline (IPL)

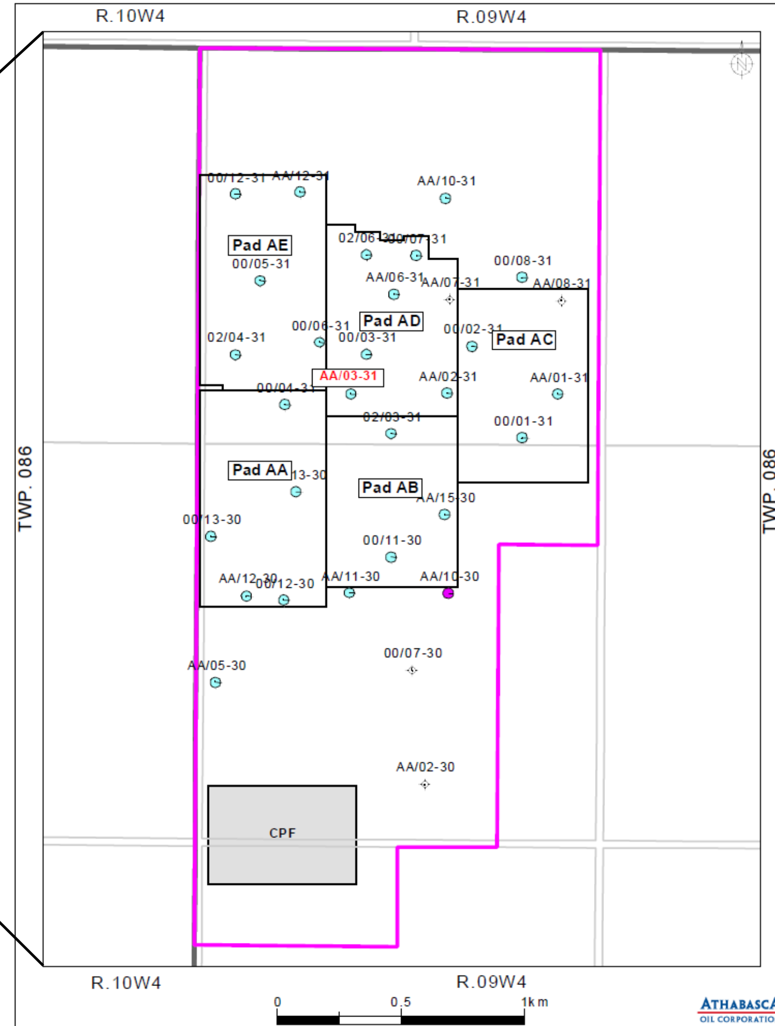


SUBSURFACE

ATHABASCA
OIL CORPORATION

SURFACE DATA OVERVIEW





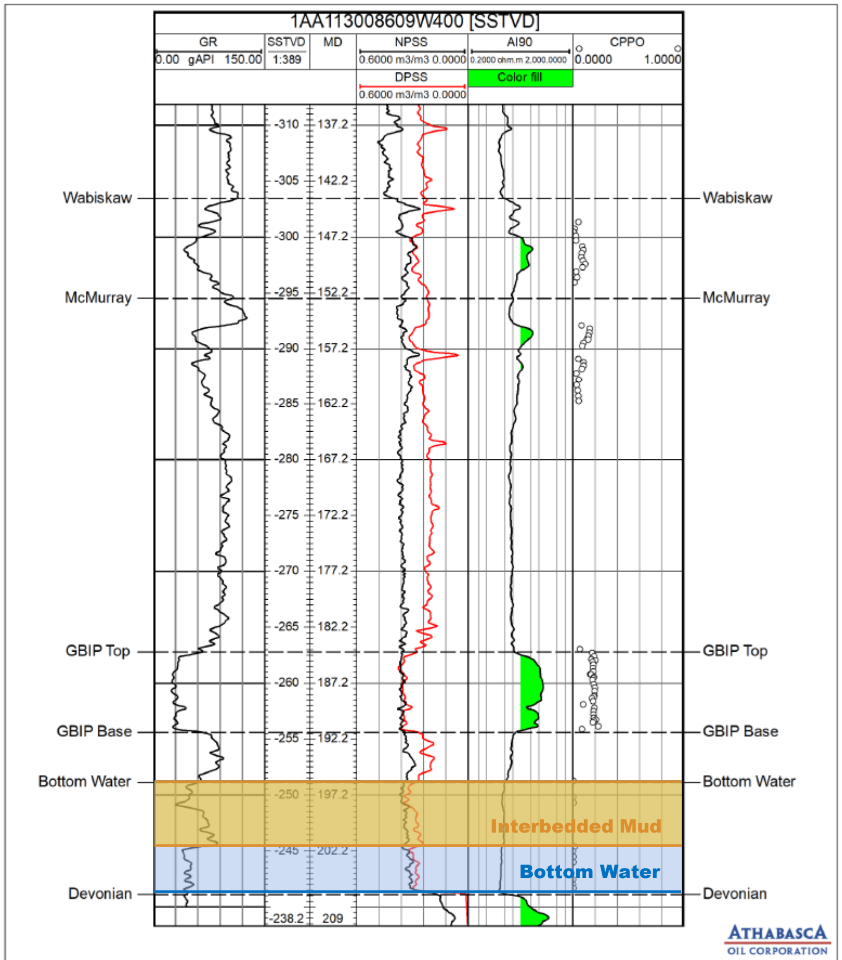
Area	Area (km²)	MCMR Cored Wells	Image Logs	Caprock Core
Development Area	5.1	26	31	1
Project Area	5.6	26	31	1

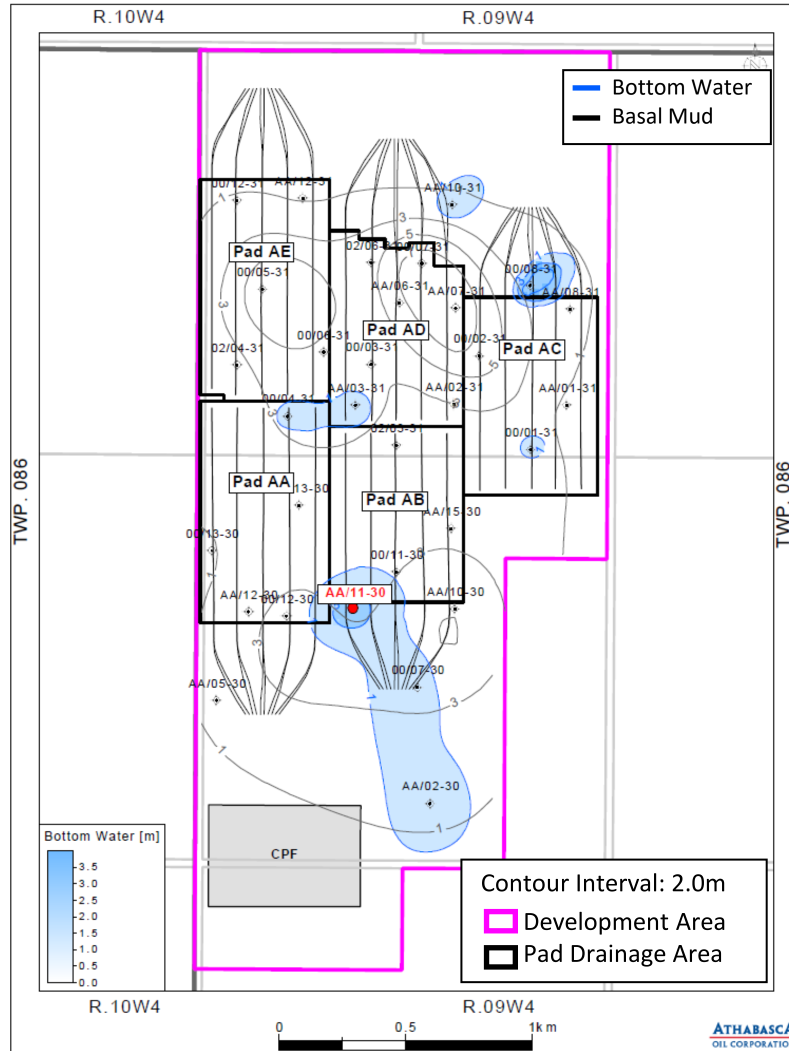
- Wells with Core
- Caprock Core Well
- Development Area
- Pad Drainage Area

BOTTOM WATER THICKNESS MAP

BOTTOM WATER

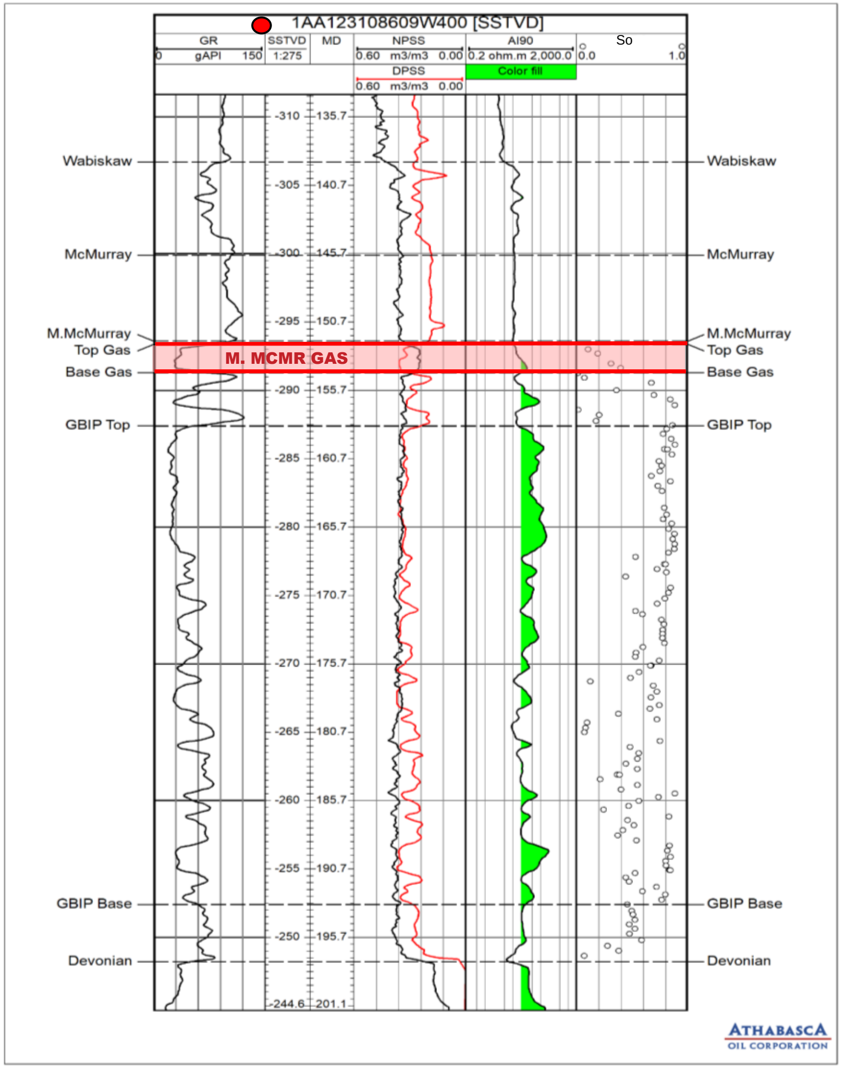
- Localized and not in direct contact with bitumen; separated by MIHS and/or basal mud
- Bottom water interval consists of interbedded mud and sand (resistivity < 10 ohm-m)

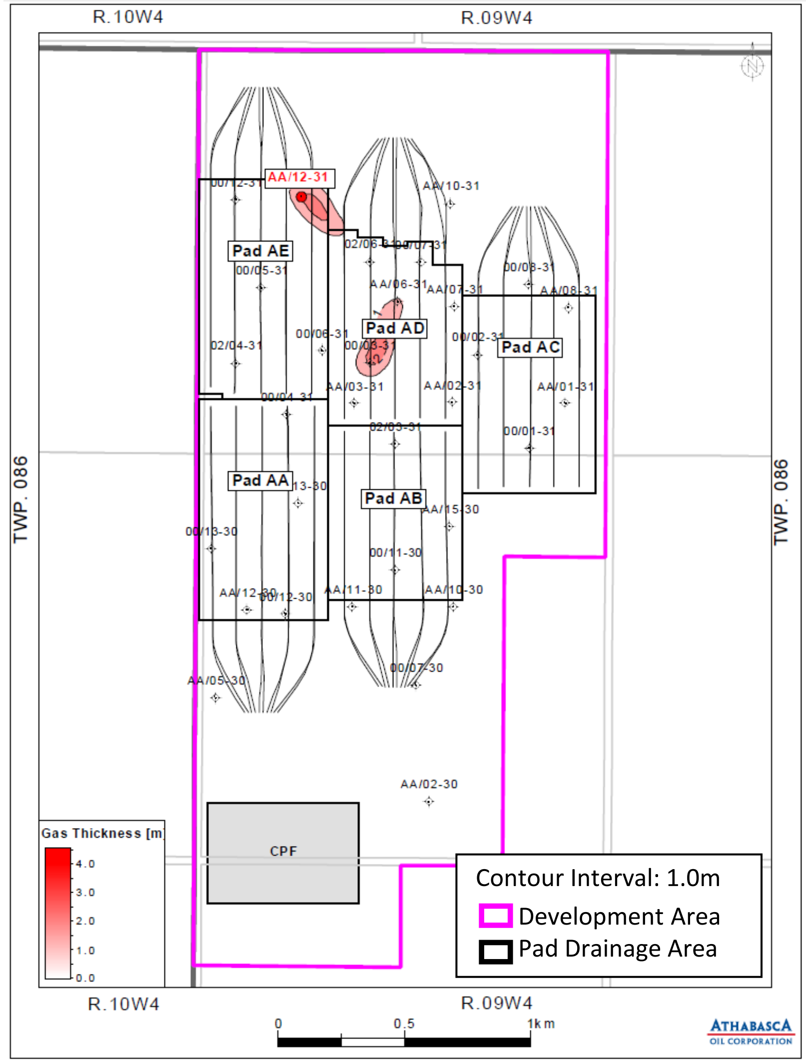




MIDDLE MCMURRAY FM GAS THICKNESS MAP

MINIMAL GAS THICKNESS AND LIMITED DISTRIBUTION WITHIN DEVELOPMENT AREA





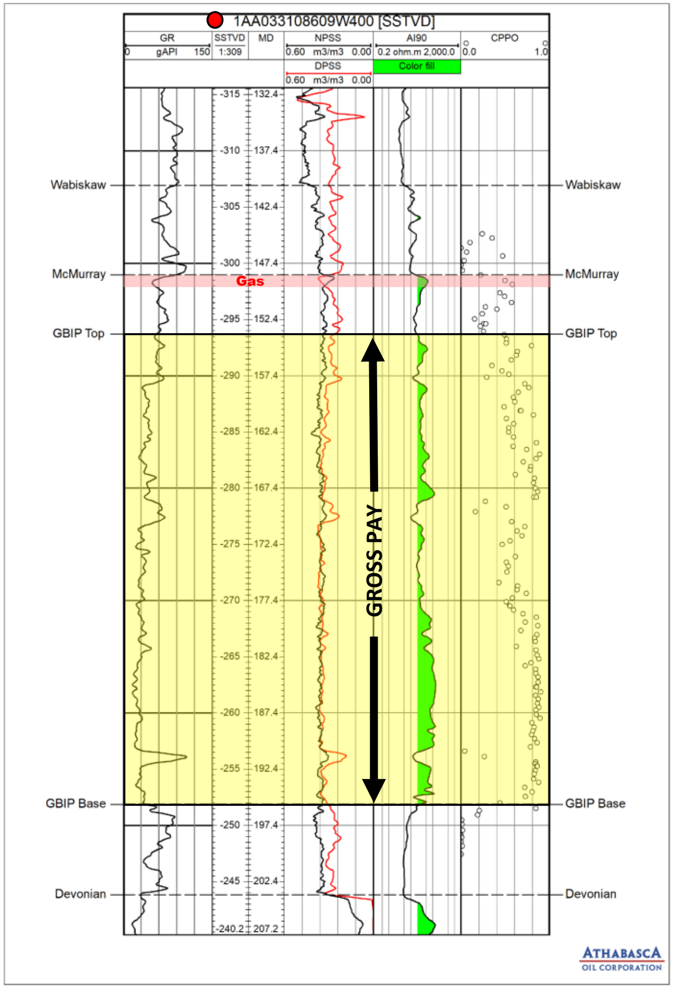
BITUMEN PAY CLASSIFICATION

RESERVOIR CRITERIA

- Facies classification based on percentage mud
  - *F1: Breccia = variable*
  - *F2: Sand = 0-10%*
  - *F3: Sandy IHS = 10-30%*
  - *F4: Muddy IHS = 30-70%*
  - *F5:Mud = >70%*
- Gross Bitumen in Place (GBIP) Reservoir criteria: F1-4, <1m F5

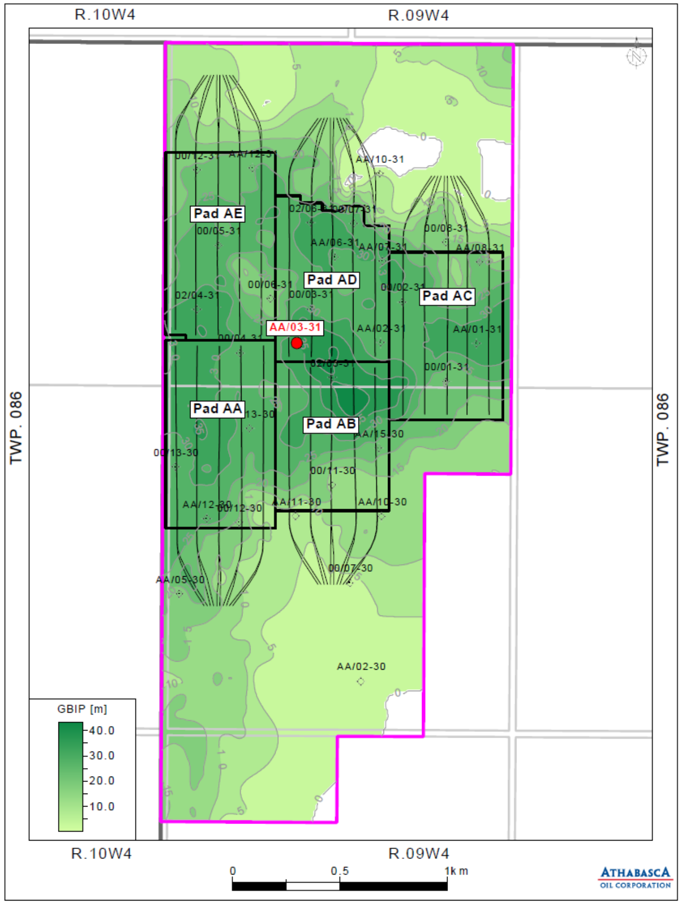
NET PAY CRITERIA

- Gross Bitumen in Place (GBIP) Petrophysical criteria:
  - *Porosity (PHIT) >= 27%*
  - *Saturation (SwT) <= 50%*



Final GBIP volumes include mid-lean zone. Mid-lean zones volumes calculated using PHIT 27% and no saturation cut off

NET PAY ISOPACH



Contour Interval: 5.0m
Development Area
Pad Drainage Area

SEISMIC DATA OVERVIEW

2021

- No new data acquired in reporting period

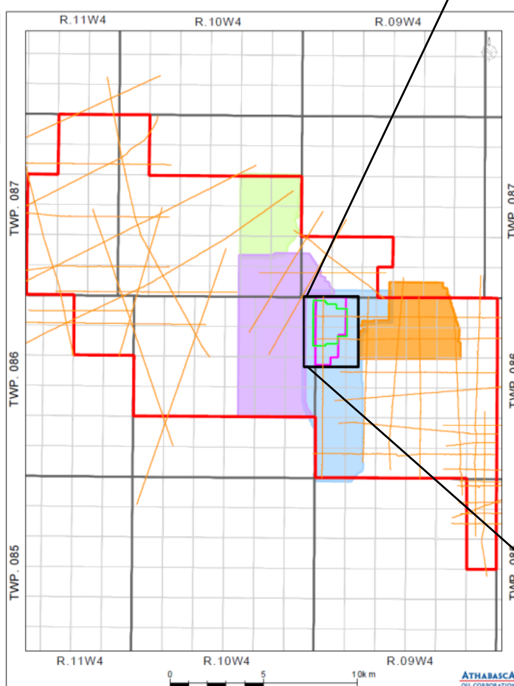
HISTORICAL

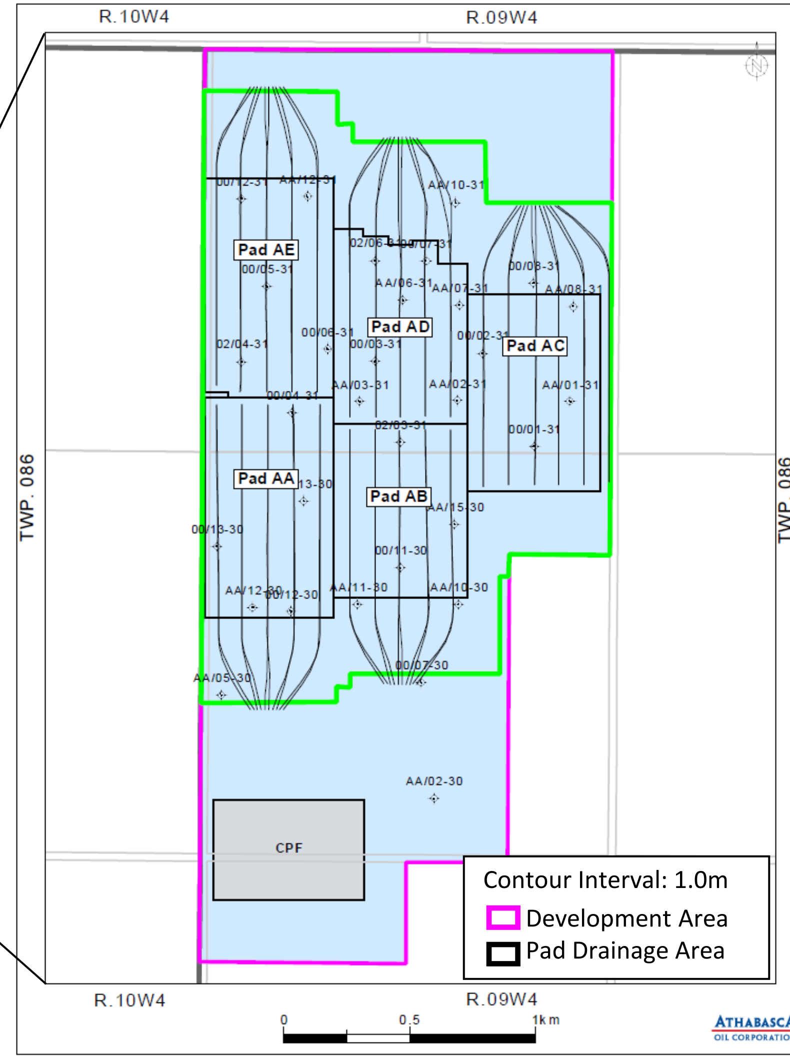
- 3D acquired in 2011 and 2012, merged in 2012
- Total proprietary 2D ~ 450 km
- Total 3D area ~98 km^2 (merged), covers development area
- Total 4D area ~3.72 km^2
  - *Baseline acquired Q1 2014*
  - *First Monitor acquired Q1 2016 / Second Monitor acquired Q1 2017*

3D/4D PARAMETERS

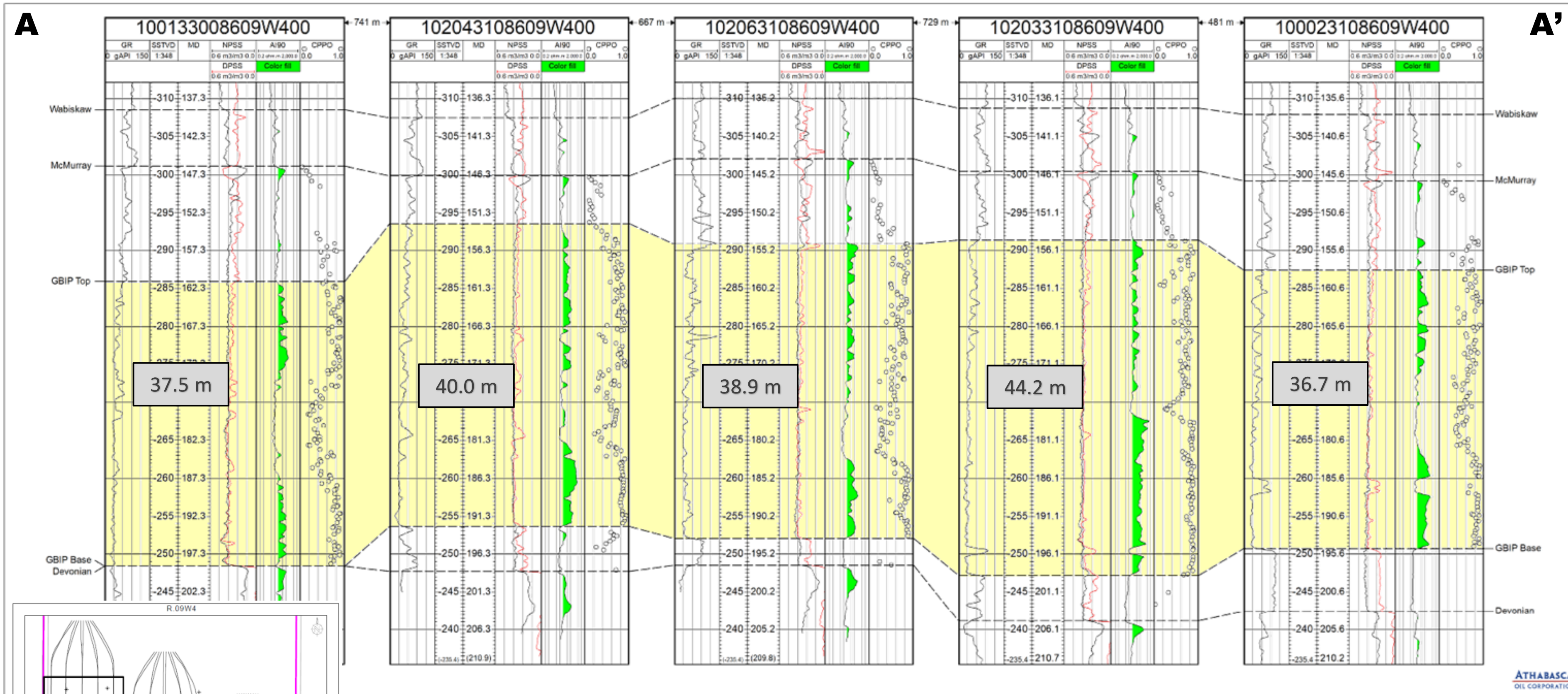
- Source line/source spacing: 60m/20m
- Receiver line/receiver spacing: 40-60m/20m

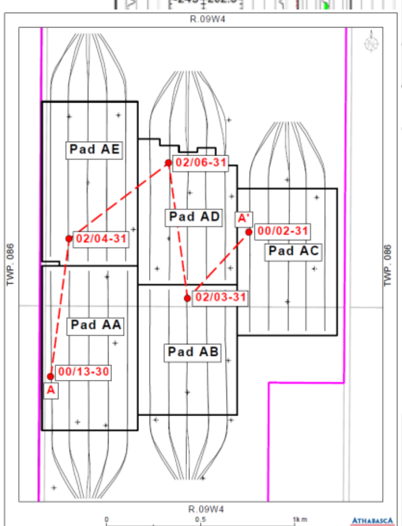
AOC Lease Area
Development Area
2011 Hangingstone River 3D
2011 Hangingstone River North 3D
2012 Halfway Creek 3D
2012 Highway 3D Seismic
2015/16/17 4D Seismic
Proprietary 2D Seismic





STRUCTURAL CROSS SECTION NW-SE ACROSS HS1 AREA





- Development Area
- Pad Drainage Area
- Cross Section A – A'

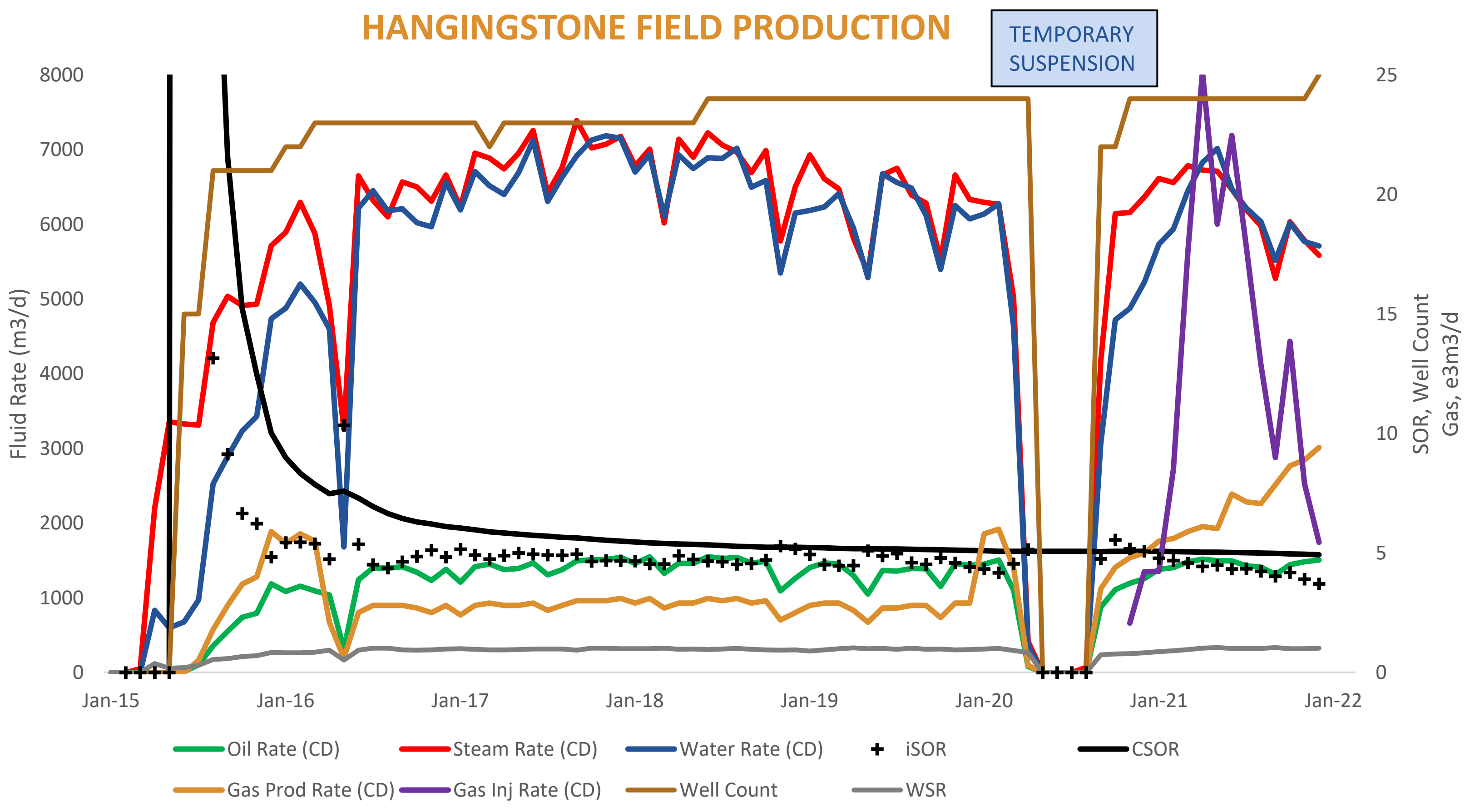
Gross GBIP thickness

*no bottom water or associated gas within wells in the cross section

PRODUCTION HISTORY

REPORTING YEAR HIGHLIGHTS

- 5 producing pads (25 producing SAGD well pairs)
- Final standing wellpair brought on production in December 2021
- Expanded NCG co-injection across all pads
- NCG rates increased early 2021 to assist with field pressure recovery following the temporary suspension
- Once the field reached pressure target, NCG rates were optimized



PAD RESERVOIR PROPERTIES AND RECOVERY FACTOR

RESERVOIR PROPERTIES

- Typical Producer Depth: 191 TVD (258 masl)
- Initial Reservoir Pressure @ 190 m TVD: 600 kPaa
- Initial Reservoir Temperature: 8°C
- Bitumen Viscosity @ initial reservoir temperature: >1 mln cP
- GBIP= Net GBIP plus Lean Zone (without saturation constraint)

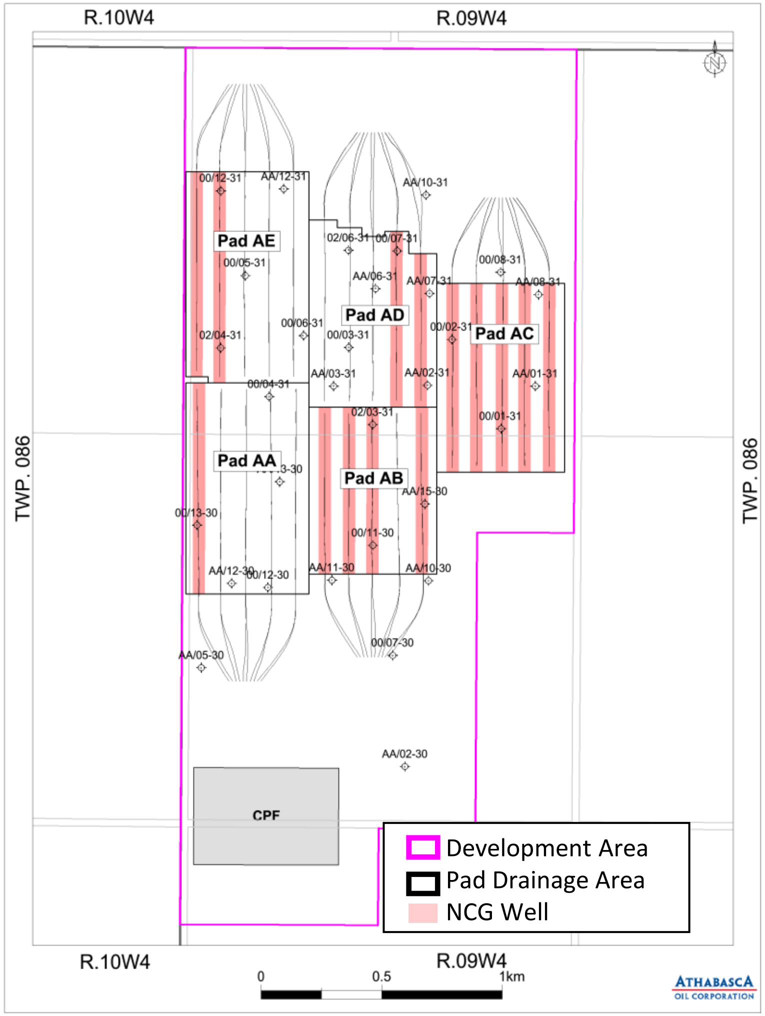
Pad	Well Pairs	Lateral Length (m)	Area (10^3 m^2)	Oil Saturation (frac)	Porosity (frac)	Perm Kh (D)	Perm Kv (D)	Net Pay (m)	GBIP Net (10^3 m^3)	Cumulative Production (10^3 m^3)	Recovery Factor (%)	EUR = Producible Bitumen in place (10^6 m^3)	EUR RF (%)
AA	5	850	459	0.72	0.35	4.6	2.9	27.5	3,543	537	15%	1.8-2.5	50-70%
AB	5	640	347	0.75	0.36	5.0	3.6	26.5	2,747	907	33%	1.4-1.9	50-70%
AC	5	750	399	0.74	0.34	4.8	3.5	25.9	2,785	356	13%	1.4-1.9	50-70%
AD	5	670	381	0.73	0.34	4.5	3.2	29.4	2,978	524	18%	1.5-2.1	50-70%
AE	5	830	448	0.73	0.34	5.3	3.7	25.3	3,102	543	18%	1.6-2.2	50-70%
TOTAL	**25**		**2,034**						**15,155**	**2,867**	**19%**		**50-70%**

- Cumulative production as of December 31, 2021
- Well Spacing: 100 m, Spacing between pads: 130 m
- Volumetrics include 25 m at heel and toe of the well pair
- Full Project Area= 5.6 $10^6 m^2$, GBIP net-hydrocarbon pore volume 22 $10^6 m^3$ (based on PHIT >= 27% and SwT <= 50%)
- Full Development Area= 5.1 $10^6 m^2$, GBIP net-hydrocarbon pore volume 21 $10^6 m^3$ (based on PHIT >= 27% and SwT <= 50%)
- OBIP is gross oil volume between base and top of pay inclusive of Lean Zone without saturation constraint
- EUR = Estimated Ultimate Recovery of Bitumen = Producible Bitumen in Place within the GBIP interval
- RF = The ratio of recoverable bitumen reserves to the estimated bitumen in place in the reservoir

NON-CONDENSABLE GAS CO-INJECTION

SUMMARY

- NCG co-injection has been expanded across all pads to help with pressure management and SOR reduction
- NCG rates increased in early 2021 to assist with pressure recovery in the field following 2020 temporary suspension (see rates on slide 11)
- Once the field reached pressure target, NCG rates were optimized (slide 11)
- No adverse impacts observed
- Continuing vertical temperature growth at observation wells



SURFACE OPERATIONS

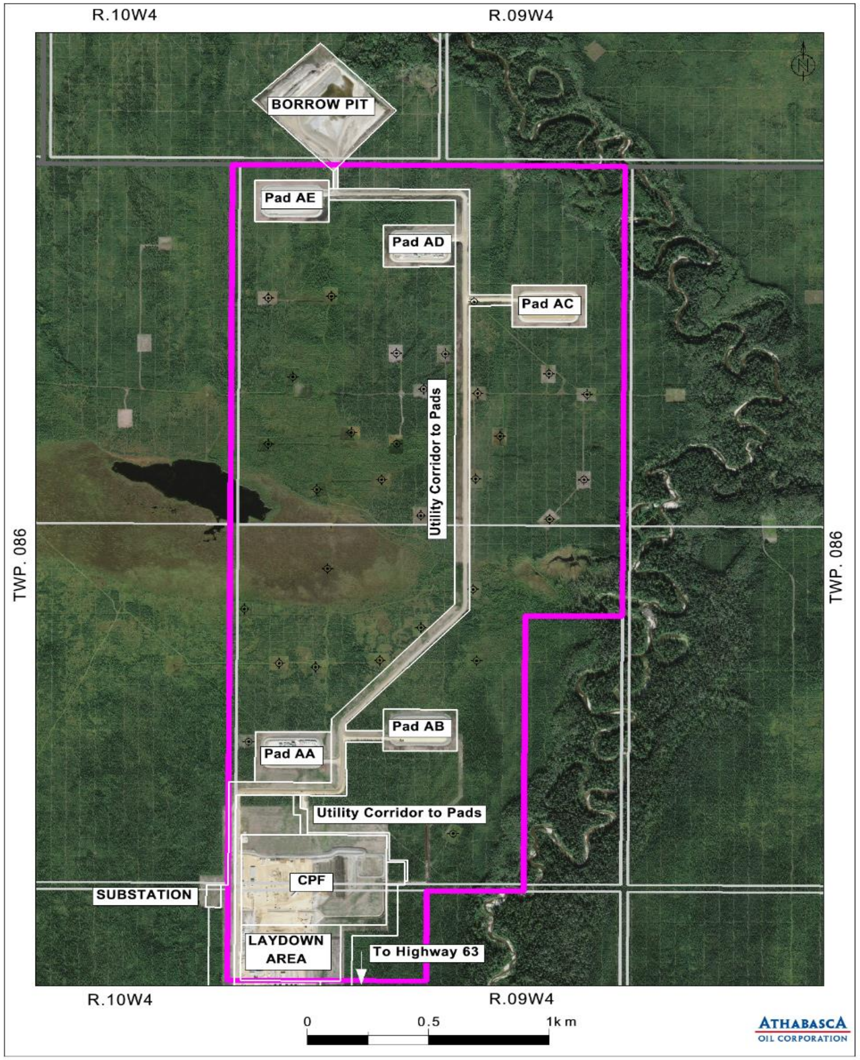
SURFACE DEVELOPMENT OVERVIEW

2021 ACTIVITY

- AA03 wellpair circulation and production
- AA05 producer well converted from PCP to ESP
- Piping and metering modifications completed to the Dilbit system to accommodate additional volumes

SUSPENSION AND ABANDONMENT

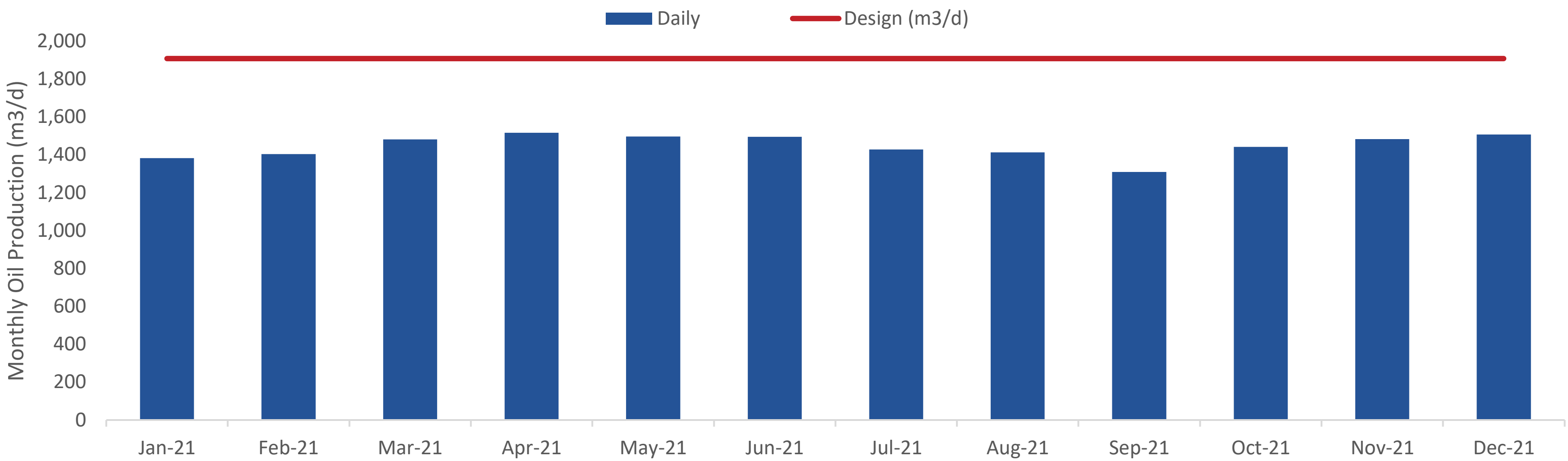
- No wells abandoned or suspended to date



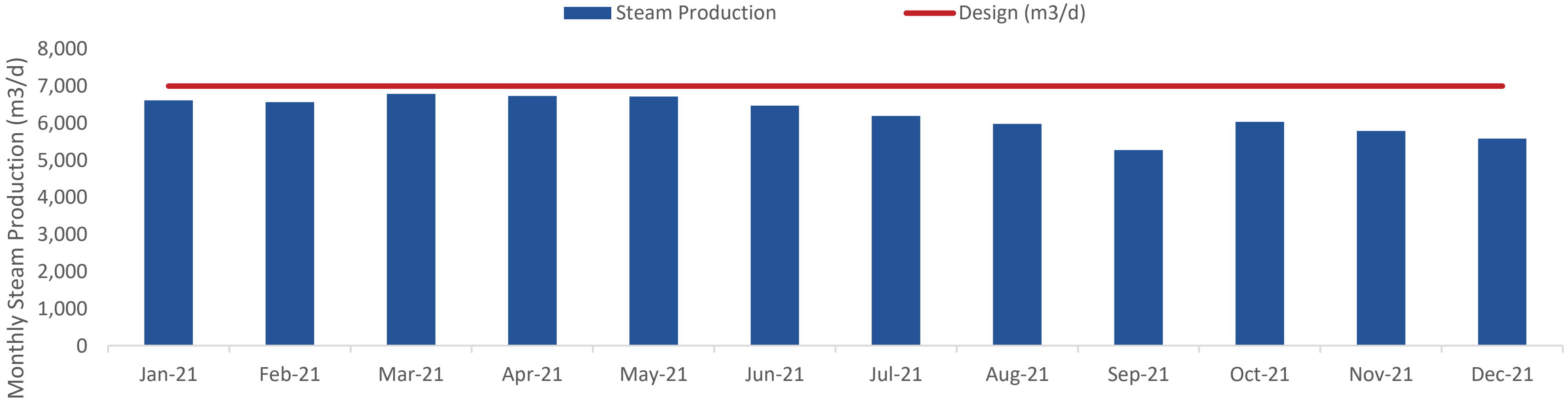
Development Area

HANGINGSTONE OIL AND STEAM RATES

OIL



STEAM



REGULATORY & COMPLIANCE

ATHABASCA OIL CORPORATION

REGULATORY

APPROVALS, AMENDMENTS, AND RENEWALS

Application No. or Approval No.	Approval Date	Description
Water Act License No. 316166 Renewal	March 5, 2021	Tier II Water Act License Renewal Source Water for Steam Generation (additional 5 year term)
EPEA Approval No. 289664-00-02 Amendment	August 25, 2021	Modifications to Groundwater Monitoring Program
Application No. 1933974 D023 Category 2	October 26, 2021	Higher Pressure Operations During Conversion of Well AA03 to SAGD
EPEA Approval No. 289664 Renewal	November 9, 2021 (submission)	EPEA Approval Renewal Application (additional 10 year term)

Notes: EPEA – Environmental Protection and Enhancement Act Approval

COMPLIANCE

NON-COMPLIANCE SUMMARY

Non-Compliance and Voluntary Self Disclosures (VSD)		
Reference	**Event**	**Corrective Action**
EDGE 0378035	Maximum operating pressure exceeded for short duration (12 minutes) while unloading fluid from new producer well (April)	Flowrates reduced on new wells to ensure surface equipment has capacity to accommodate fluid volumes.
EDGE 0381931	Maximum operating pressure exceeded for short duration (5 minutes) while unloading fluid from producer well (July)	The well alarm setting was lowered to allow additional time to implement mitigations for pressure swings.
EDGE 0386540	During cold weather surface equipment malfunctioned and inaccurately measured an exceedance of the downhole maximum operating pressure (December)	Incident will be discussed at safety meetings as a concern to be managed during cold weather events.

SPILLS

- No reportable spills in 2021

INSPECTIONS AND AUDITS

INSPECTIONS

Inspections			
Event	**License**	**Inspection ID**	**Result**
AER Facility Inspection January 14, 2021	F45426	506667	Satisfactory
AER Facility Inspection March 31, 2021	F45426	509488	Satisfactory
AER Facility Inspection July 22, 2021	F45426	513087	Low risk
AER Facility Inspection July 22, 2021	F45426	513114	Low risk
AER Facility Inspection November 9, 2021	F45426	515906	Satisfactory

AUDITS

- No audits in 2021

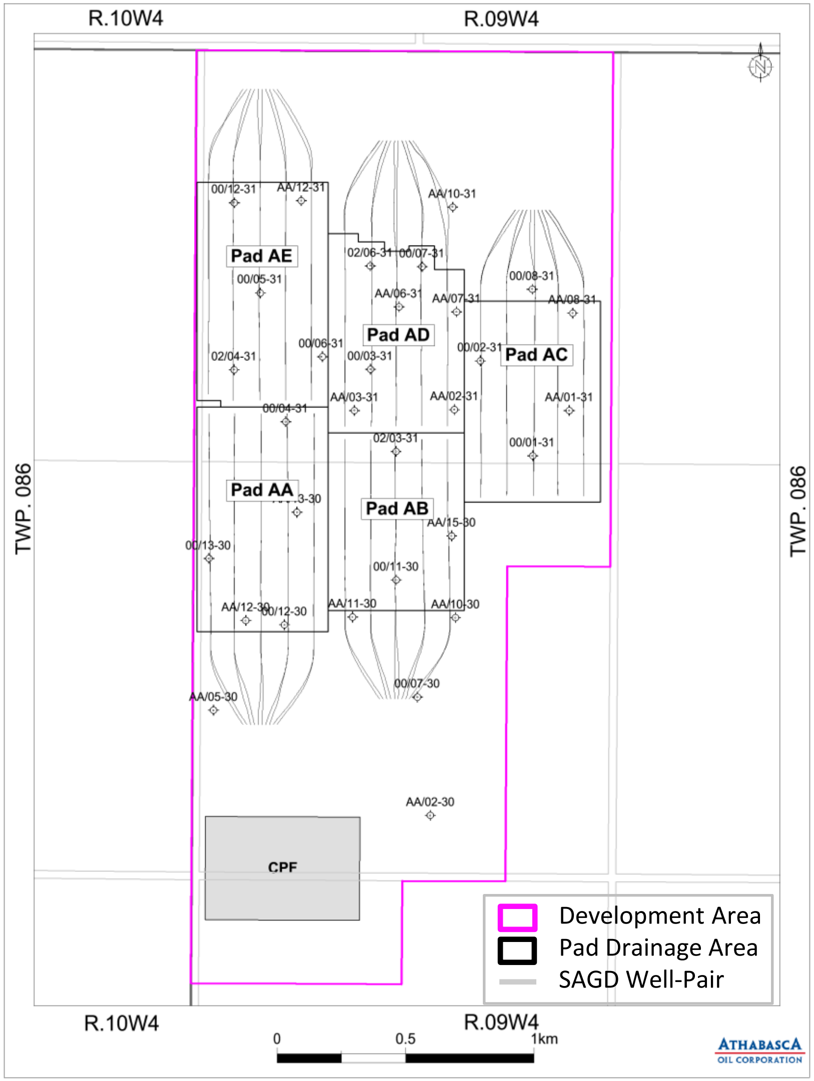
FUTURE PLANS

2022 ACTIVITY

- Continue NCG injection field-wide for pressure management and energy intensity reduction
- EPEA Approval No. 289664 renewal application approval
- Oil Sands Conservation Act Commercial Scheme amendment application for sustaining pads

FUTURE OPERATIONS

- Evaluate opportunities for producer well Flow Control Devices (FCDs)
- Develop sustaining well pads in accordance with production declines



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