TAGD FIELD TEST UPDATE FOR AER

JANUARY 2014 TO DECEMBER 2014

Presented 2015-04-13

ATHABASCA
OIL CORPORATION

INTRODUCTION

DOVER WEST LEDUC ASSET

TAGD PROCESS

TAGD FIELD TEST

- Introduction
- Subsurface
- Surface
- Compliance

PLANS

DOVER WEST LEDUC ASSET

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THE LEDUC CARBONATE

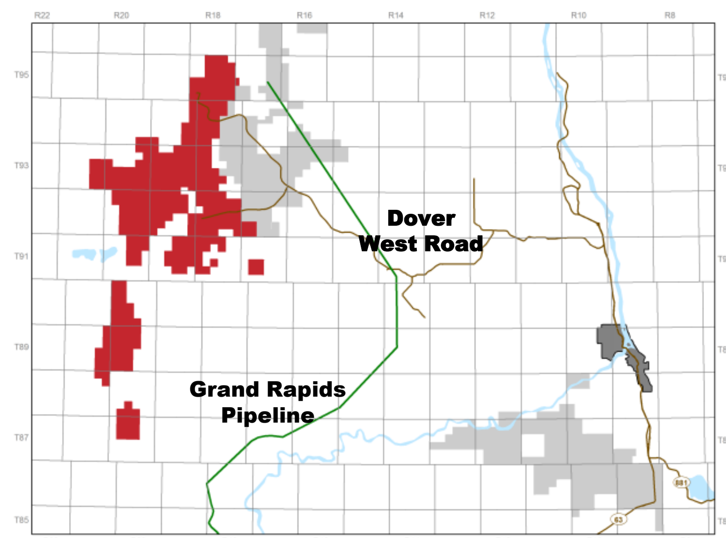
OPPORTUNITY

- Northern extent of well-known prolific Leduc light oil reservoirs, but filled with bitumen.
- 14.8 billion bbl OOIP[1] (best estimate) in the Leduc carbonate reef (up to 100 m net pay).
- 2.7 billion bbl contingent resource best estimate based on CSS.
- Asset has potential for > 350 000 bbl/d[2], based on TAGD.

	Leduc Light Oil	Dover West Leduc
Average Porosity	5%	15%
Average Permeability	1 000 mD	>3 000 mD
Recovery Factor	70%	Estimated >50%

Dover West Leduc

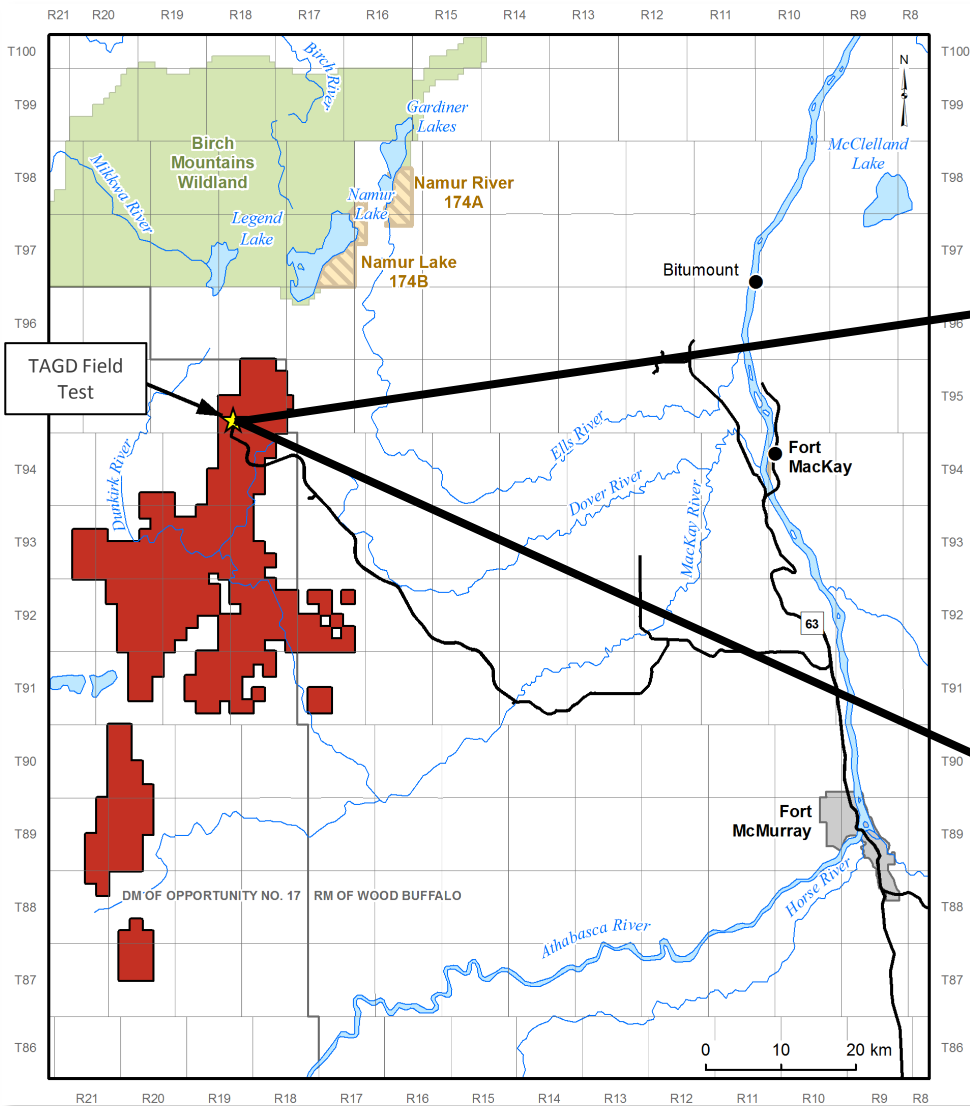
Imperial Wizard Lake
Peak rate: 13 000 bbl/d
Recovery factor: 85%



(1) Discovered (11 600 million bbl) plus Undiscovered.

(2) Based on management estimate.

AREA MAP OF DOVER WEST



TAGD PROCESS

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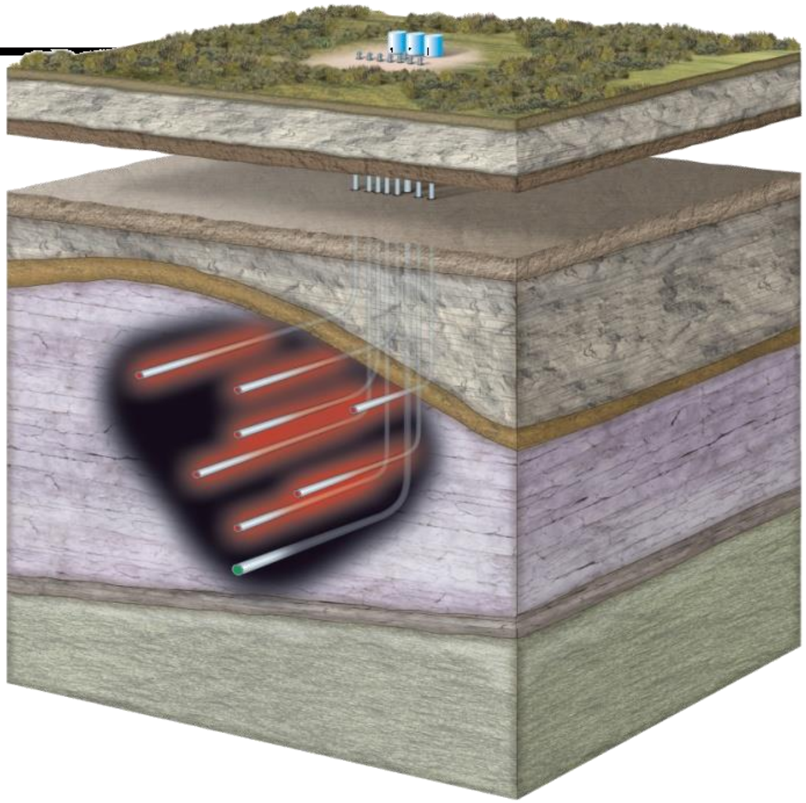
TAGD OVERVIEW



THERMAL ASSISTED GRAVITY DRAINAGE

An in situ recovery process, in which:

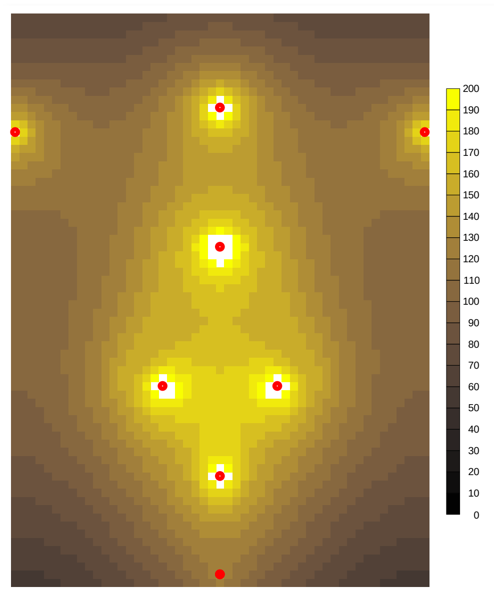
- The reservoir is heated using a pattern of horizontal heating wells.
- Sufficient temperature is reached such that bitumen will flow by gravity to production wells.

WHAT IT'S NOT:

- NOT just a near-wellbore stimulation process – goal is reservoir-wide heating.
- Does NOT involve flow of electrical current in the reservoir; instead, reservoir heating occurs via thermal conduction.
- Does NOT result in chemical alteration of the bitumen – target temperature to achieve sufficient reduction in viscosity, without cracking the bitumen.

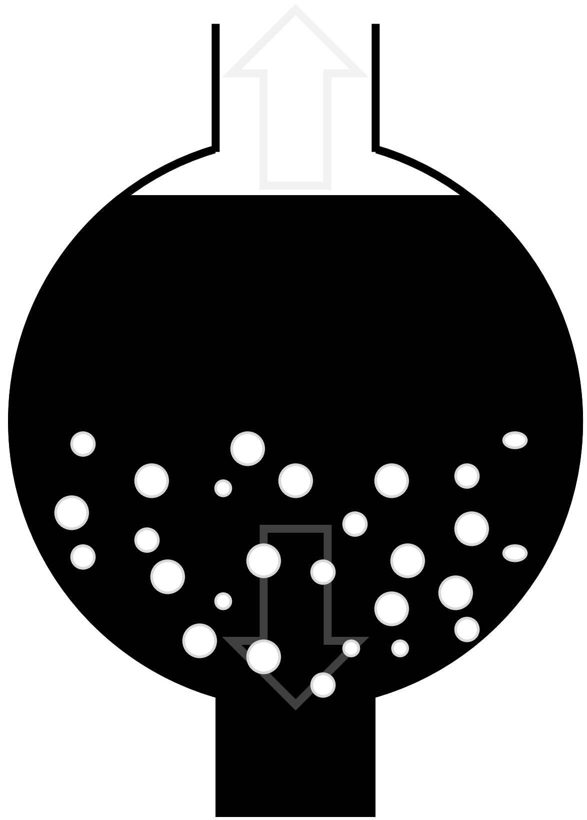
TAGD PROCESS – 3 KEY ELEMENTS

1. Conduction Heating



Heating reduces viscosity and mobilizes oil

2. Internal Drive

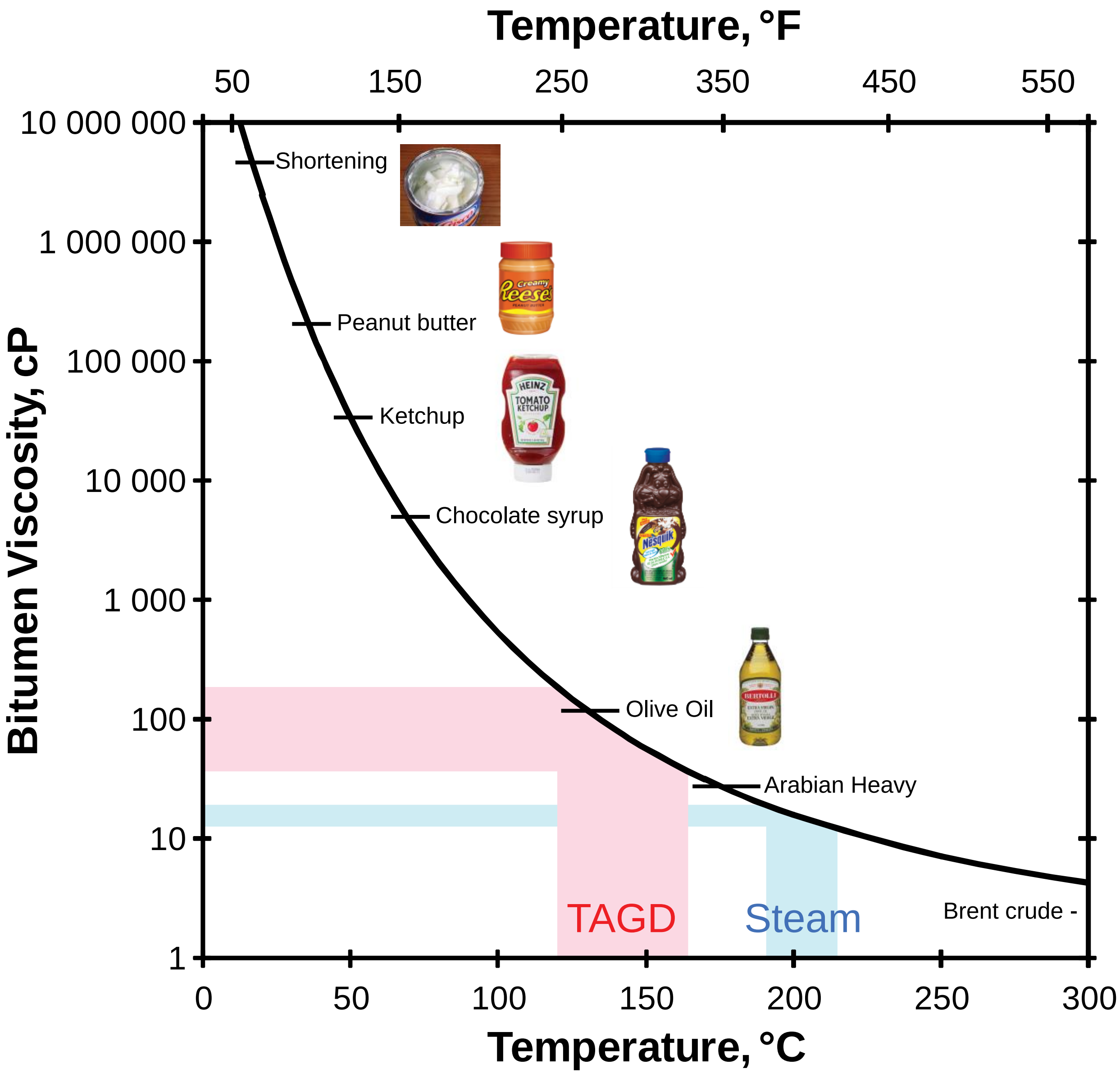


Internal drive replaces voidage

3. Gravity Drainage

Mobilized oil flows down by gravity

1: HEATING



AOC's Leduc

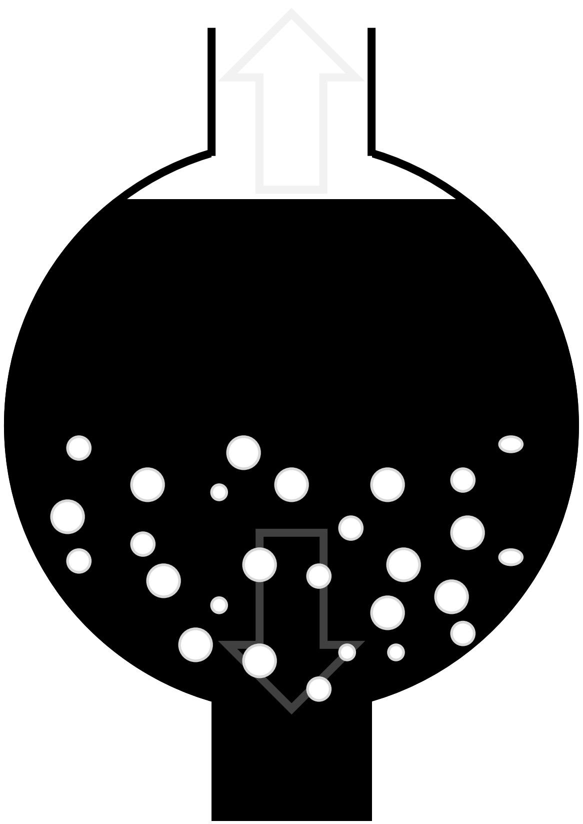
- Depth: ~280 m ASL
- Temperature: 12 °C
- Pressure: 480 kPa
- Leduc viscosity@ 12°C:

  13 x 106 cP

- Steam injection pressure dictates high temperature
- Trade-off between additional energy (and cost) vs. benefit of reduced viscosity
- Conductive heating achieves desired optimum temperature
- Target temperature achieved via selection of well spacing and heater power input

2 & 3: GRAVITY + INTERNAL DRIVE

Gas-Oil Gravity Drainage



Voidage Replacement

- Expansion of in-place fluids

+

- Solution gas evolution

+

- CO_2 generation (dolomite dissolution)

+

- Connate water vapourization

+

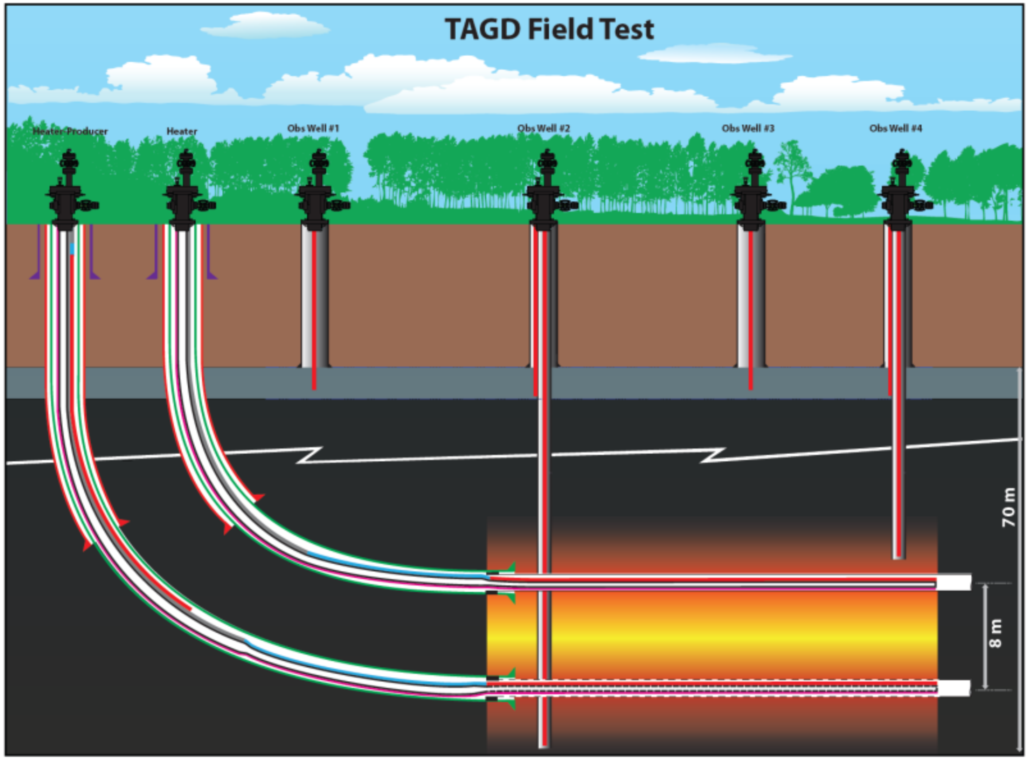
- Top gas drive from gassy bitumen zone

+

- Gas injection (optional)

TAGD FIELD TEST INTRODUCTION

TAGD FIELD TEST



OBJECTIVES

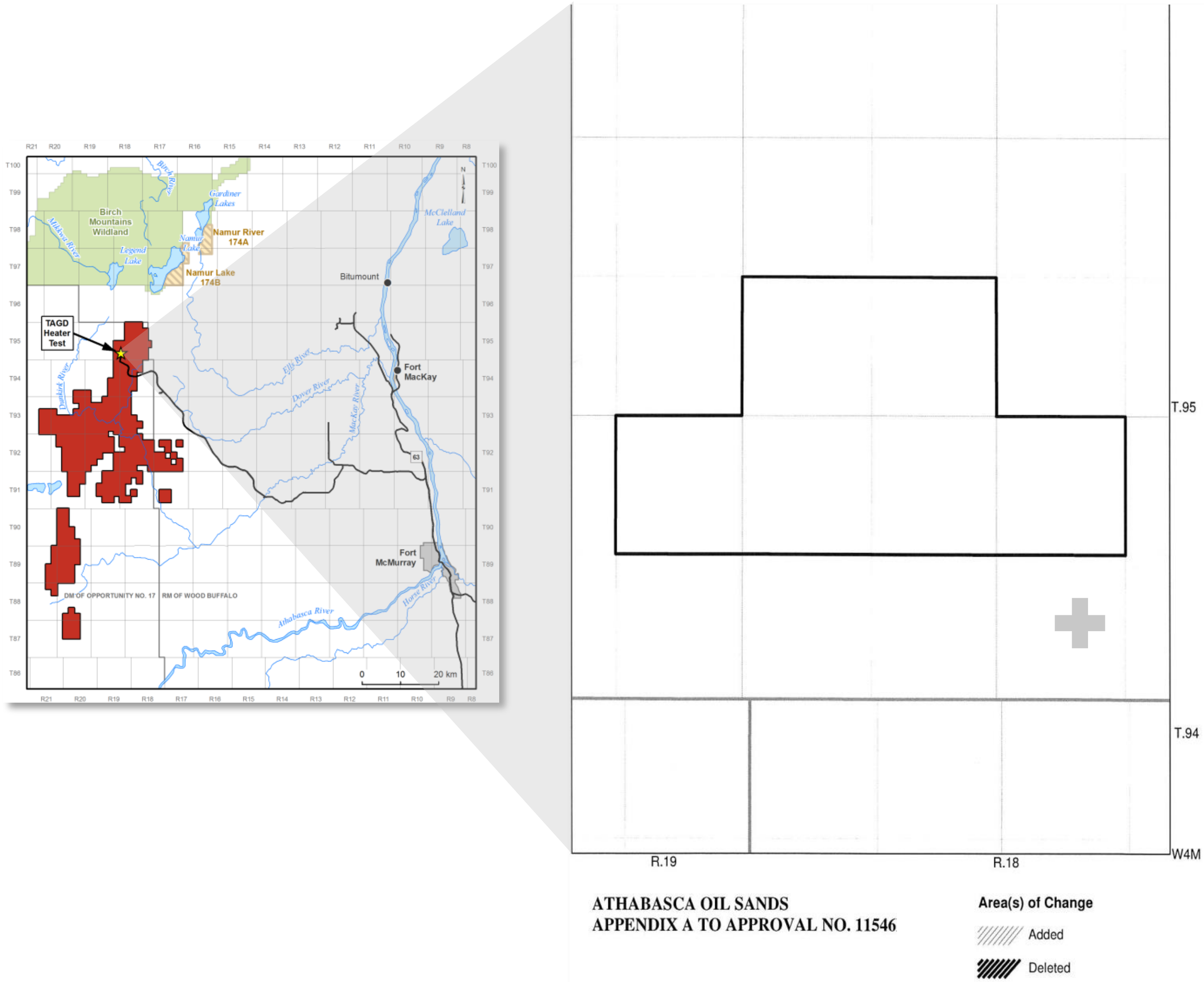
- Proof of TAGD concept.
- Drill horizontal wells in a fractured, vuggy carbonate.

SCOPE

- 1 horizontal heater well.
- 1 horizontal heater-producer well.
- 4 vertical observation wells.
- Instrumentation to measure downhole pressure and temperature.

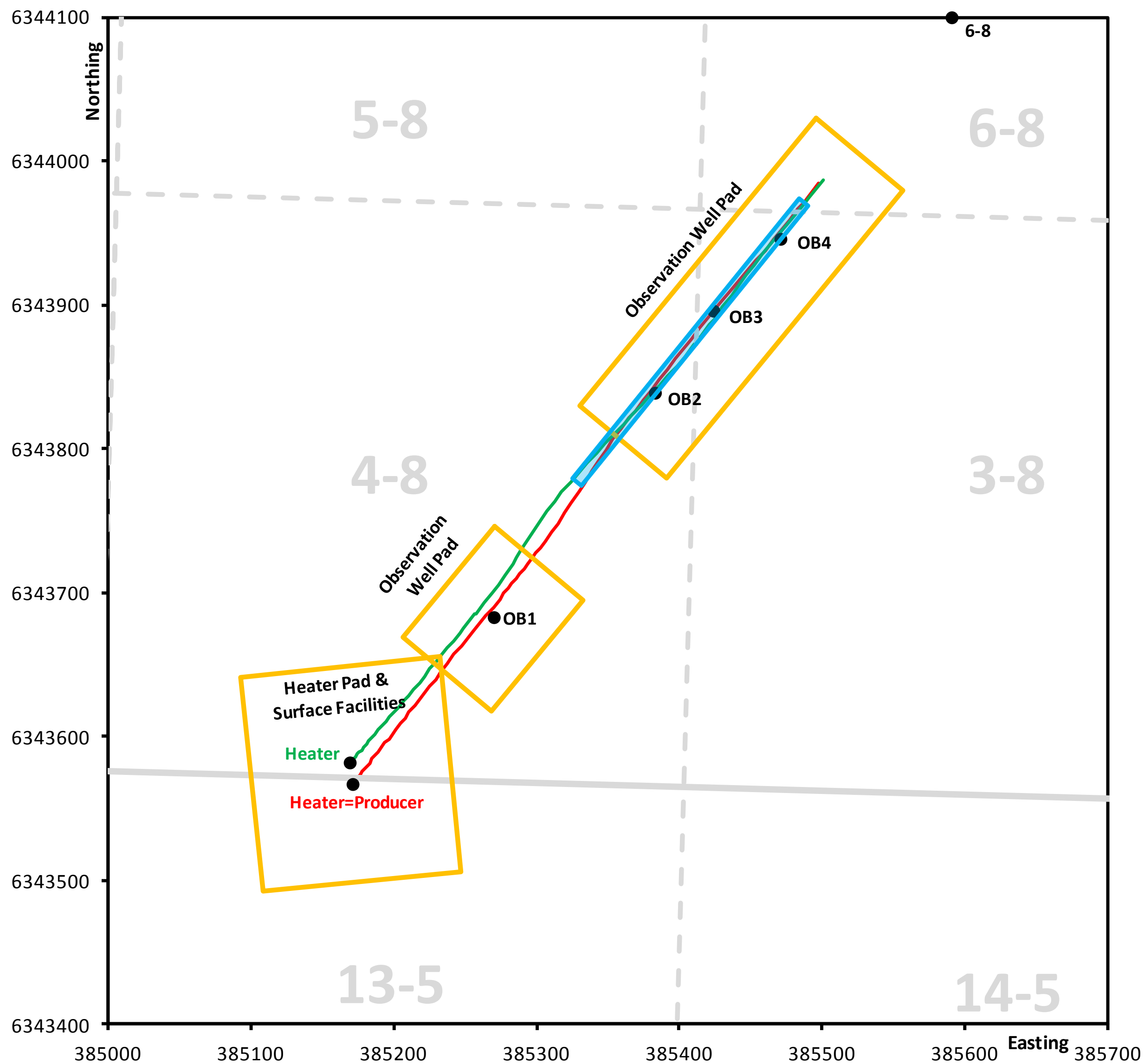
SCHEME MAP

- No change in 2014



TAGD FIELD TEST SURFACE AND SUBSURFACE LAYOUT

- No change in 2014



TIMELINE

○ June 18, 2010	Filed TAGD Field Test Application #1653013
○ December 17, 2010	Received Approval 11546 for the TAGD Field Test
○ January to March 2011	Drilled And Completed Wells
○ May 2011	Heating Initiated
○ June 6, 2011	Received Approval For Early Production
○ July 21, 2011	Received Approval 11546A Extend Project Life
○ October to November 2011	Production Cycle #1
○ February to April 2012	Production Cycle #2
○ September 5, 2012	Received Approval 11546B for the Addition of Submerged Combustion Evaporator
○ October 25, 2012	Received Approval 11546C for the Addition of Submerged Combustion Evaporator Tank

TIMELINE

○ November 27, 2012	First Evaporation
○ December 2012 to February 2013	Production Cycle #3
○ September 19, 2013	Received Approval 11546D for the TAGD Pilot Project
○ October 17, 2013	Filed Amendment for Gas Injection Test
○ October 31, 2013	Received Approval 11546E for the Gas Injection Test
○ December 10, 2013	MARP approval for the TAGD Pilot Project

2014 IN REVIEW

Gas Injection Test — **January & February**

- Injected natural gas into OB1 up to 42,000 m^3/d.

Oil Cut Test — **March**

- One test performed to observe changes in oil cut with heating and time.

Heater Wellbore Fluid Change — **May**

- Replaced natural gas with liquid heat transfer fluid.
- Reduced average wellbore temperatures by ~58°C. More uniform wellbore temperature.

Production Cycle #4 — **June onward**

- Pumping between 2 m^3/d to 24 m^3/d of fluid.
- 512 m^3 of bitumen produced in Cycle #4.

Heater Failures During Production Cycle

- Surface failures repaired easily.
- Downhole failures resulted in reduced capacity.

Multiphase Analyzer Trial — **June onward**

- Installed an additional multiphase analyzer to evaluate performance.

Gas Co-injection — **December**

- Injected gas into heater-producer well to stimulate productivity.
- Injected gas at an average rate of 600 m^3/d

TAGD FIELD TEST SUBSURFACE

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OBIP
APPROVAL AREA AND OPERATING PORTION

	Area	Thickness	Rock Volume	Porosity	Bitumen Saturation	Net-to-Gross	OBIP
	(m^2)	(m)	(m^3)	(%)	(%)	(frac)	(m^3)
TAGD Field Test Area	647 500	83	53 500 000	14.2	86	0.96	6 272 000
Approval Area No. 11546	3 940 000	75	312 615 000	14.7	89	0.94	37 000 000
Operating Portion	2 000	12	24 000	15	88	1.00	3 170

OBIP = rock volume x porosity x bitumen saturation x net-to-gross

Net Pay cutoffs are:

< 6% porosity

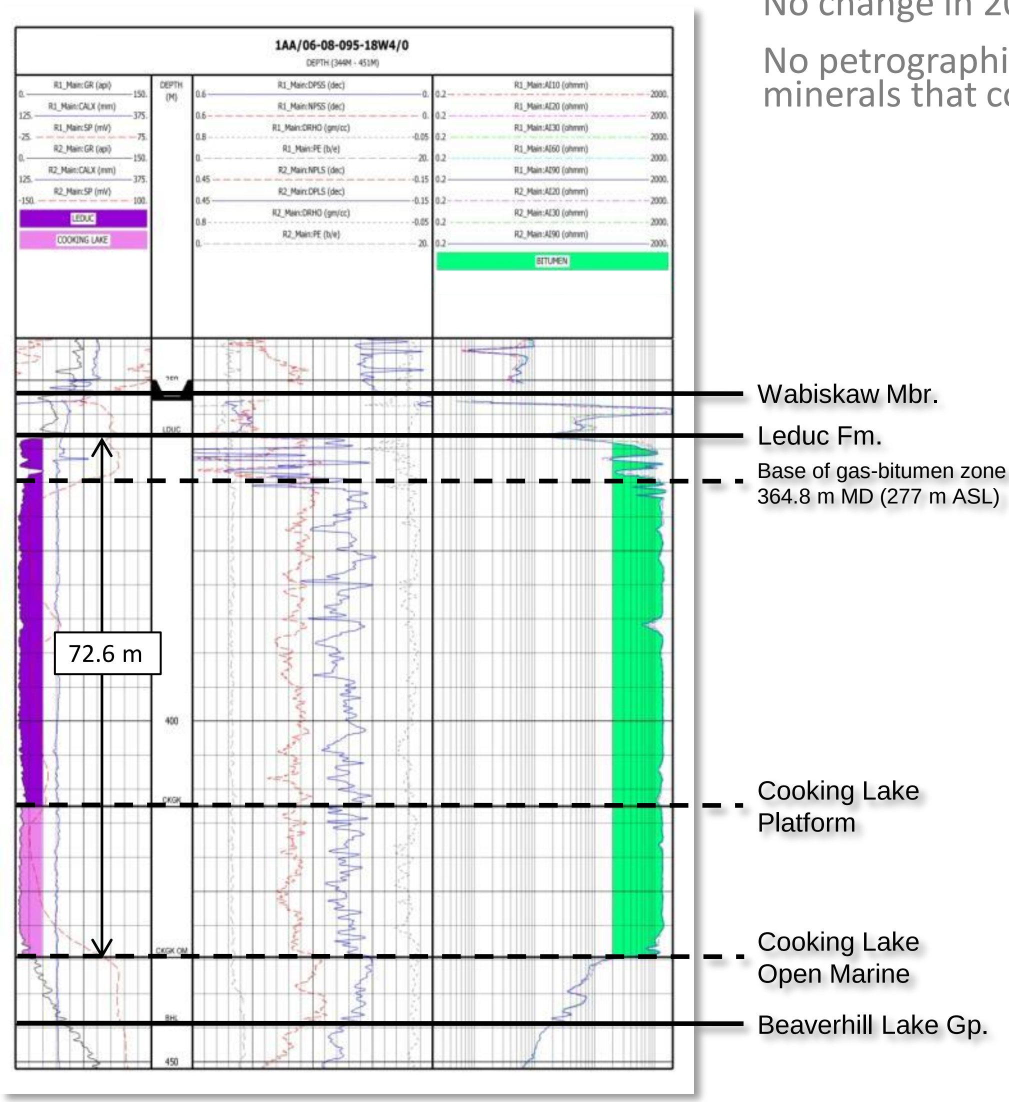
> 20% S_w

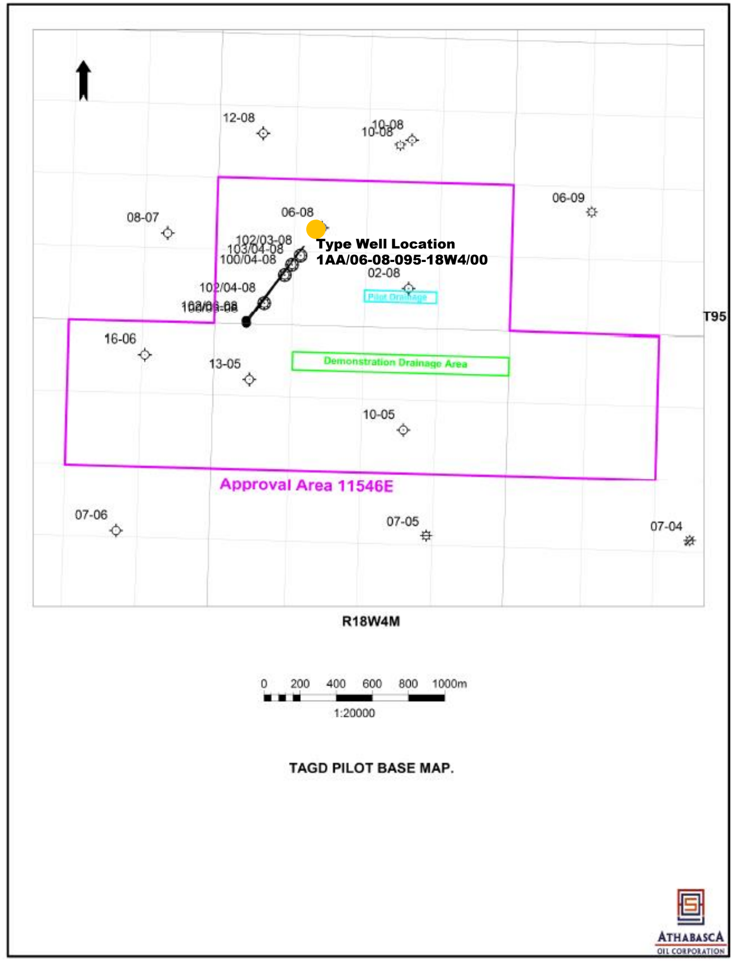
> 10% V_{shale}

TYPE WELL LOG 1AA/06-08-095-18W4/0

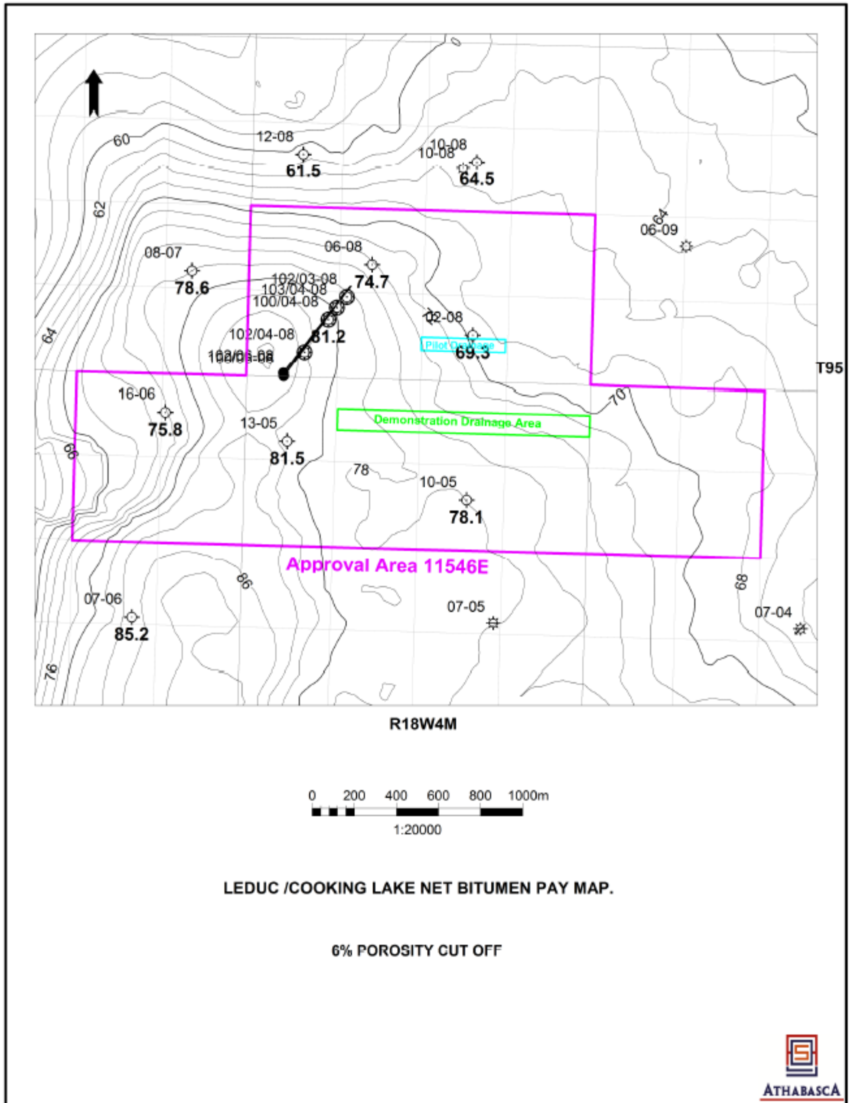
No change in 2014

No petrographic analysis were completed to identify minerals that could impact the scheme recovery.



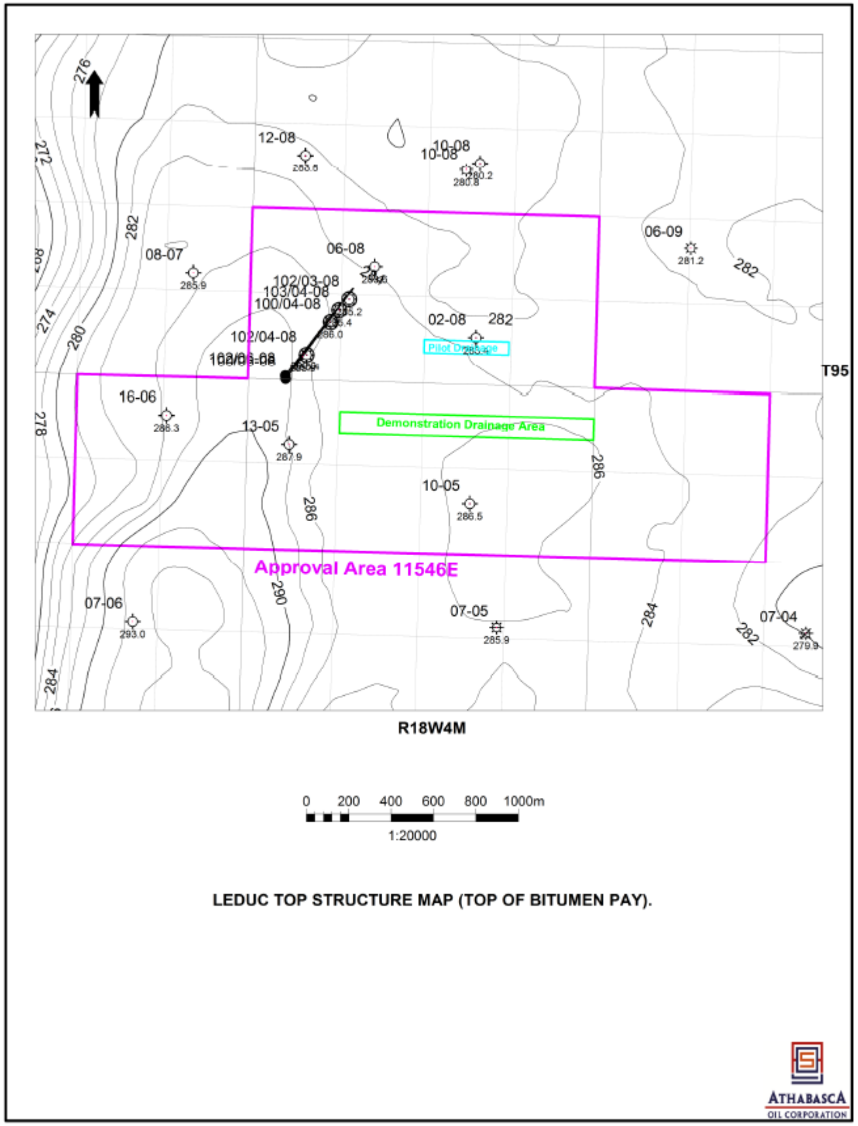


NET BITUMEN PAY MAP



- No change in 2014
- Net pay ranges from 66 to 86 m in the approval area.

STRUCTURE MAP OF TOP OF BITUMEN PAY

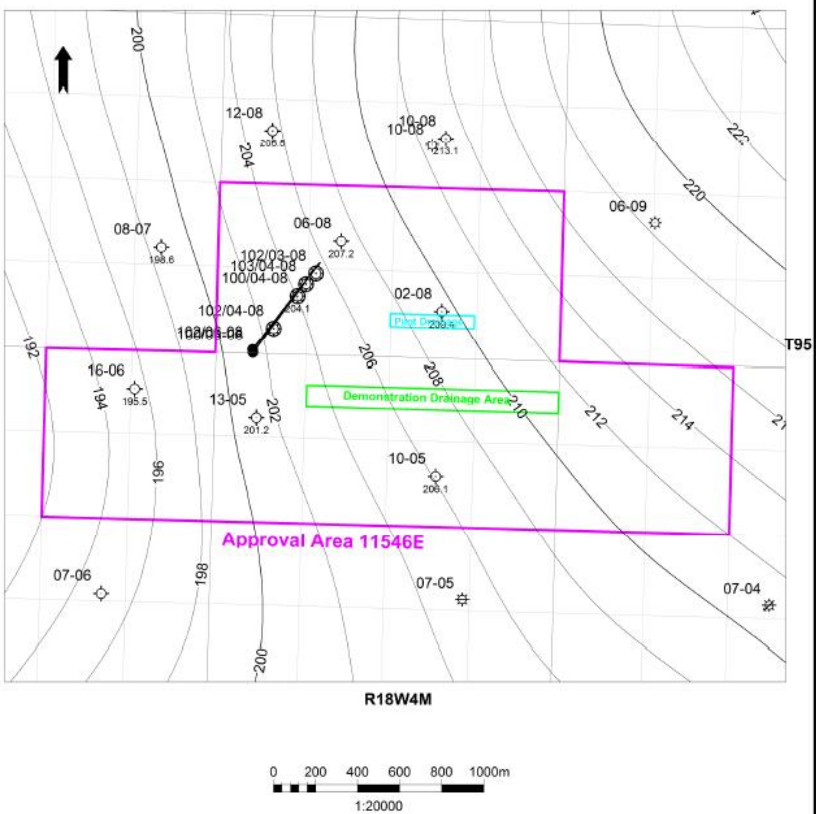


No change in 2014

The top of the bitumen pay is the eroded Leduc Formation.

The structure for the top of the Leduc ranges from 281 to 292 m ASL in the approval area.

STRUCTURE MAP OF BASE OF BITUMEN PAY



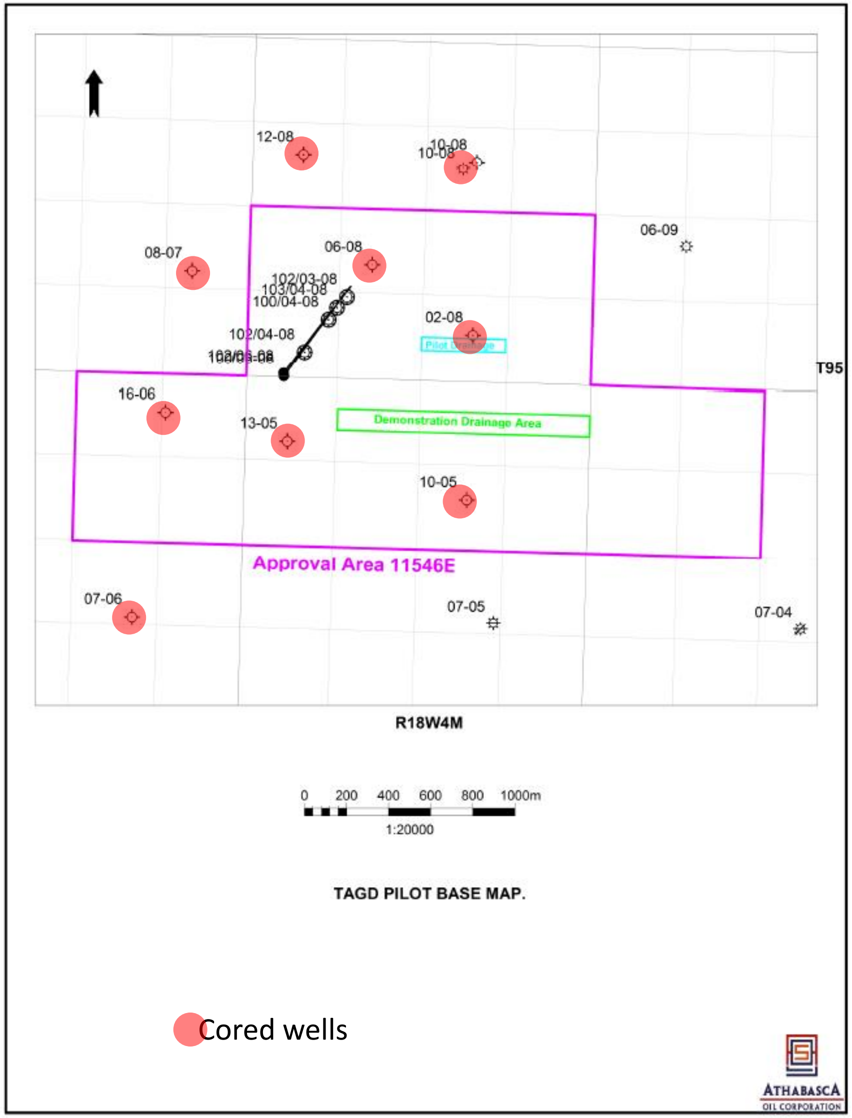
COOKING LAKE MARINE STRUCTURE MAP (BASE OF BITUMEN PAY).

No change in 2014

The base of the bitumen pay is the top of the Cooking Lake open marine unit.

The structure for the top of Cooking Lake open marine unit has a uniform southwest dip and ranges from 192 to 216 m ASL in the approval area.

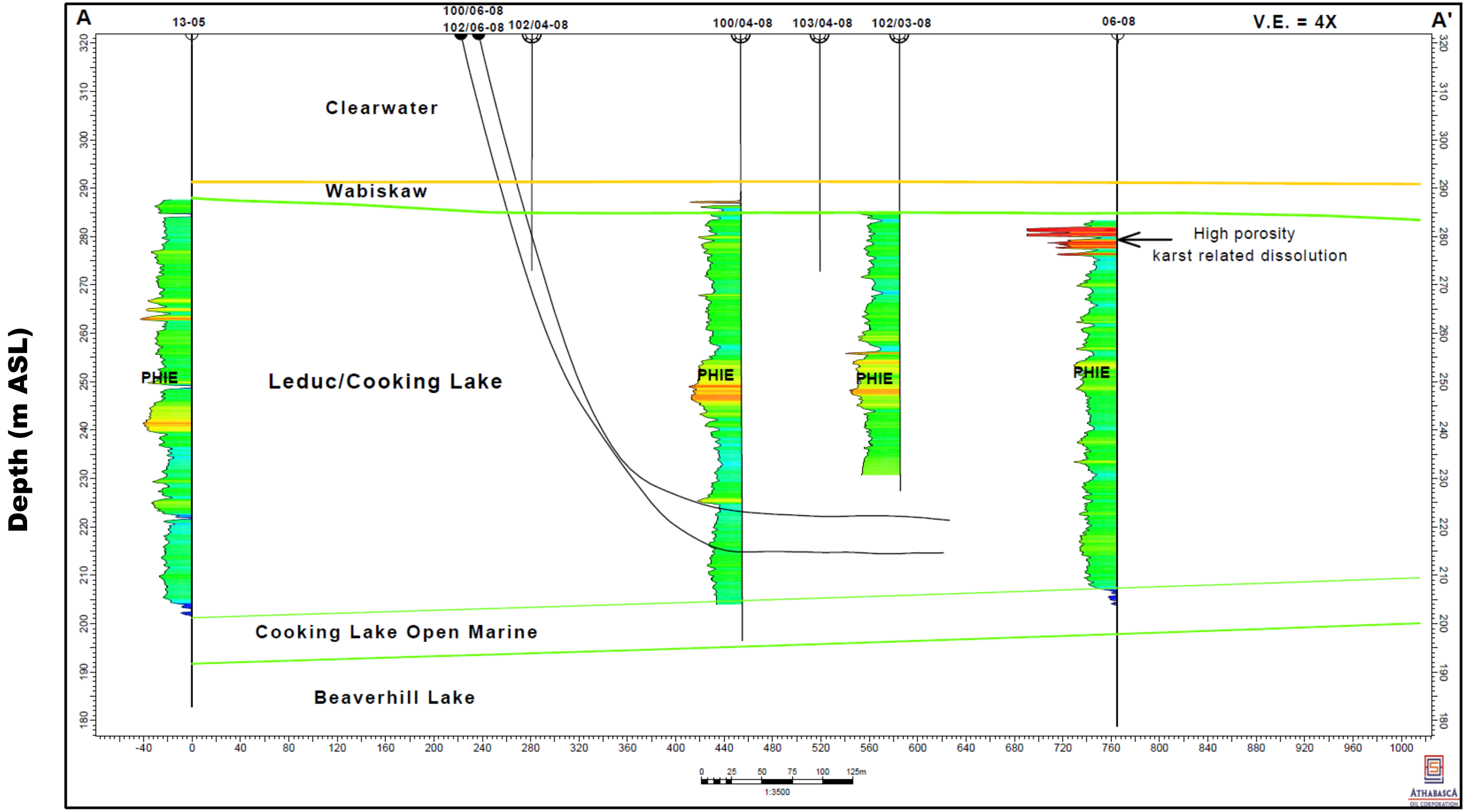
LOCATION OF CORED WELLS



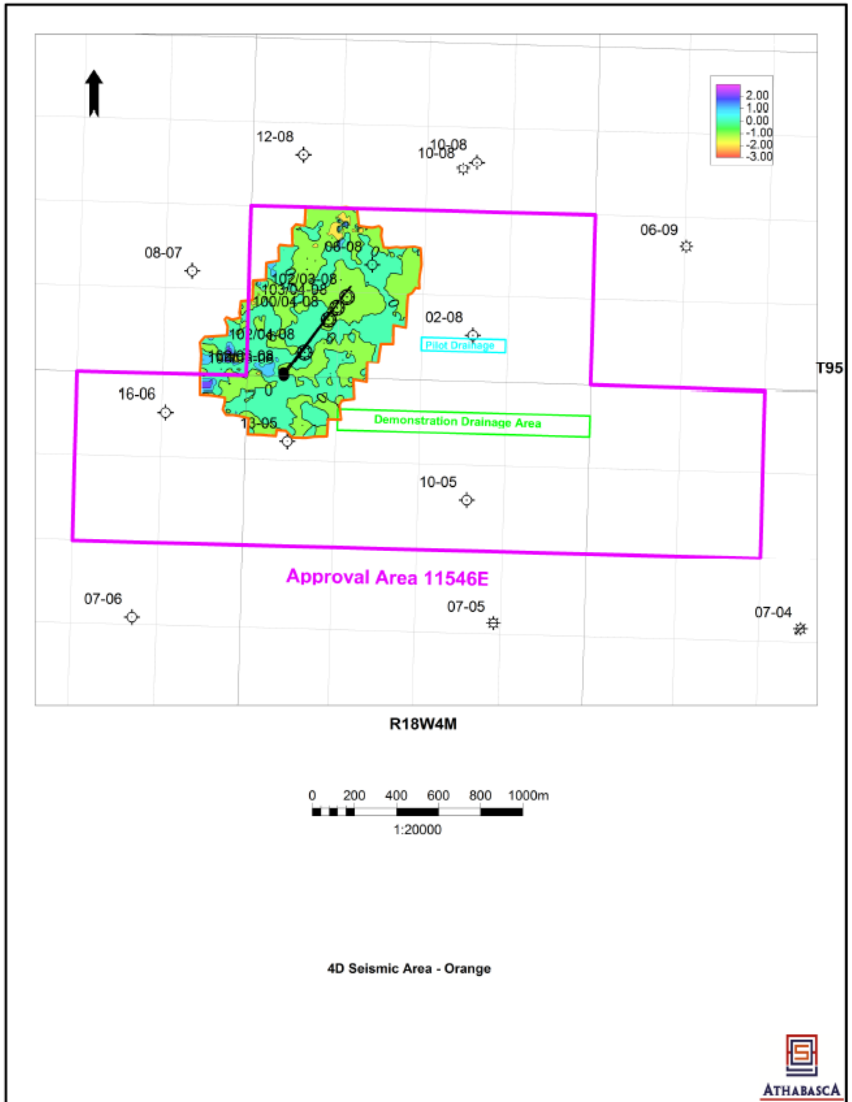
- No change in 2014
- There are five cored wells in the approval area including the type well 1AA/06-08-095-18W4/0.
- Adjacent wells around the approval area have been cored.
- Routine core analysis measured the porosity, bitumen saturation, and permeability (k_h, k_v, and k_{max}).
- Select cores have been CT scanned to understand the porosity-permeability relationship.

STRUCTURAL CROSS SECTION

- No change in 2014

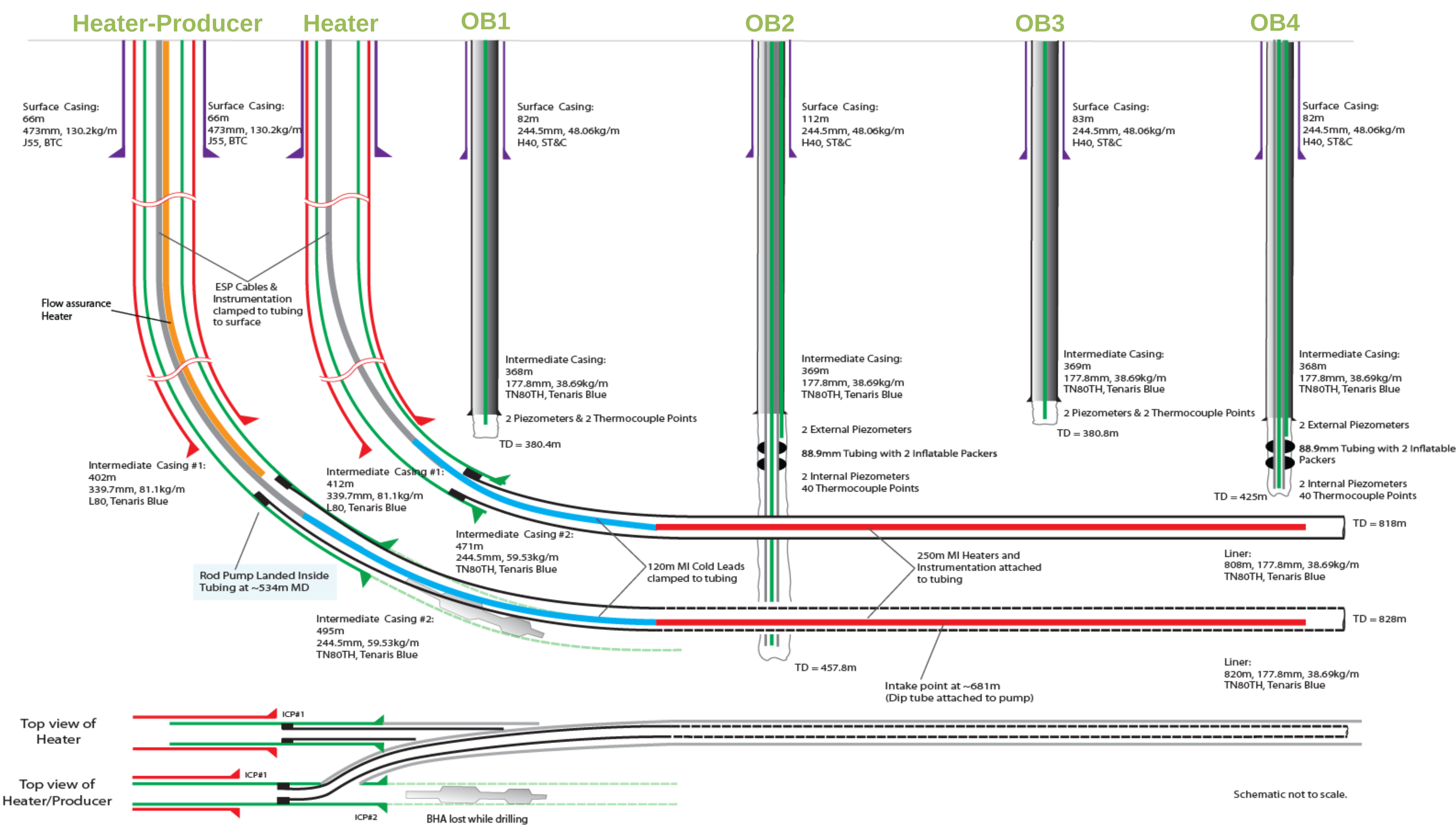


SEISMIC

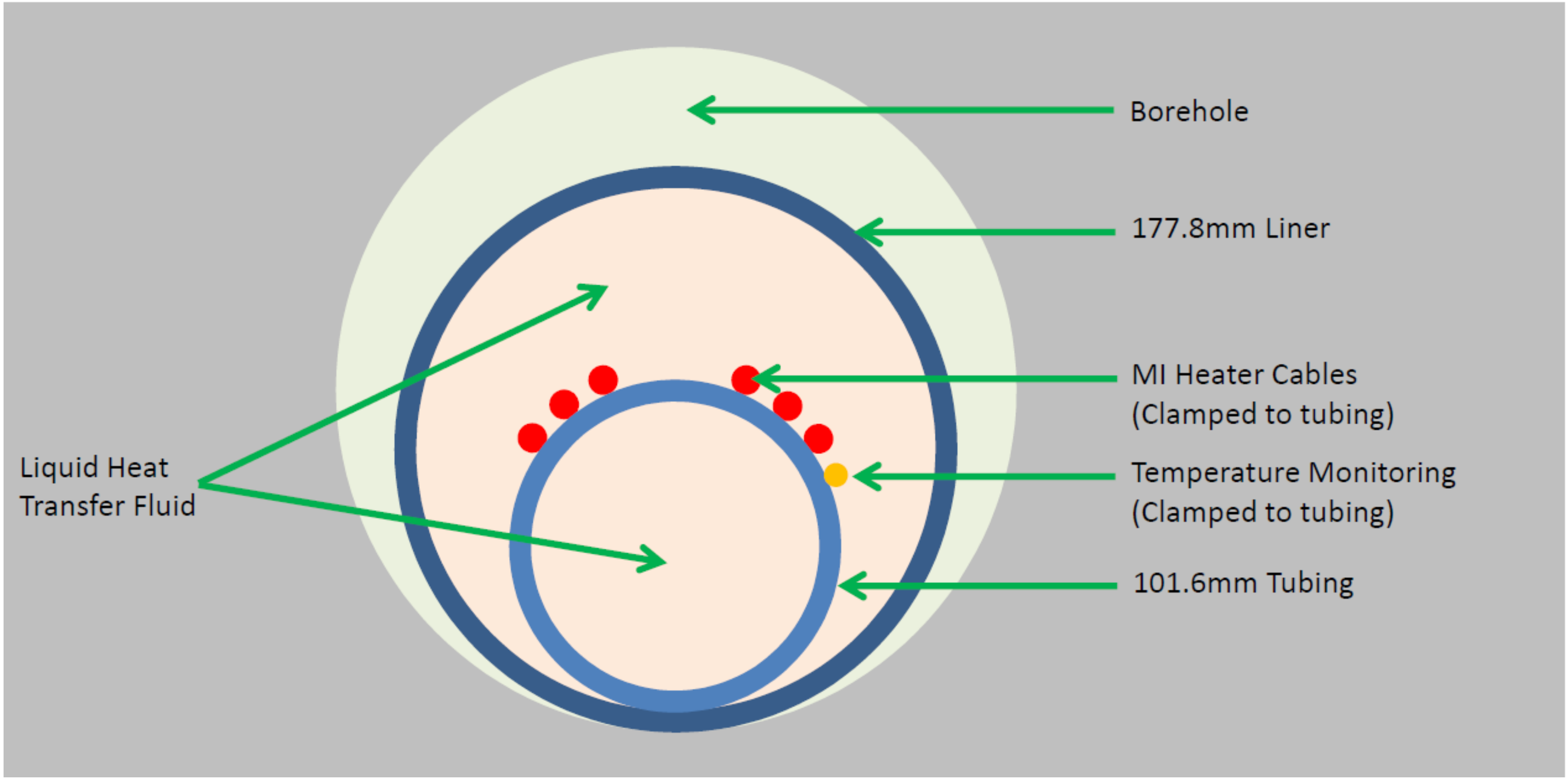


- No change in 2014
- 4D monitor survey acquired Q4 2012.
- 0.8 km^2 total area being monitored.
- Original 2010 survey being used as baseline.
- Time delay map of the Beaverhill Lake surface between the 4D monitor survey (2012) and original (2010) survey.
- Time delay results show no correlation to TAGD Field Test.

WELLBORE SCHEMATIC

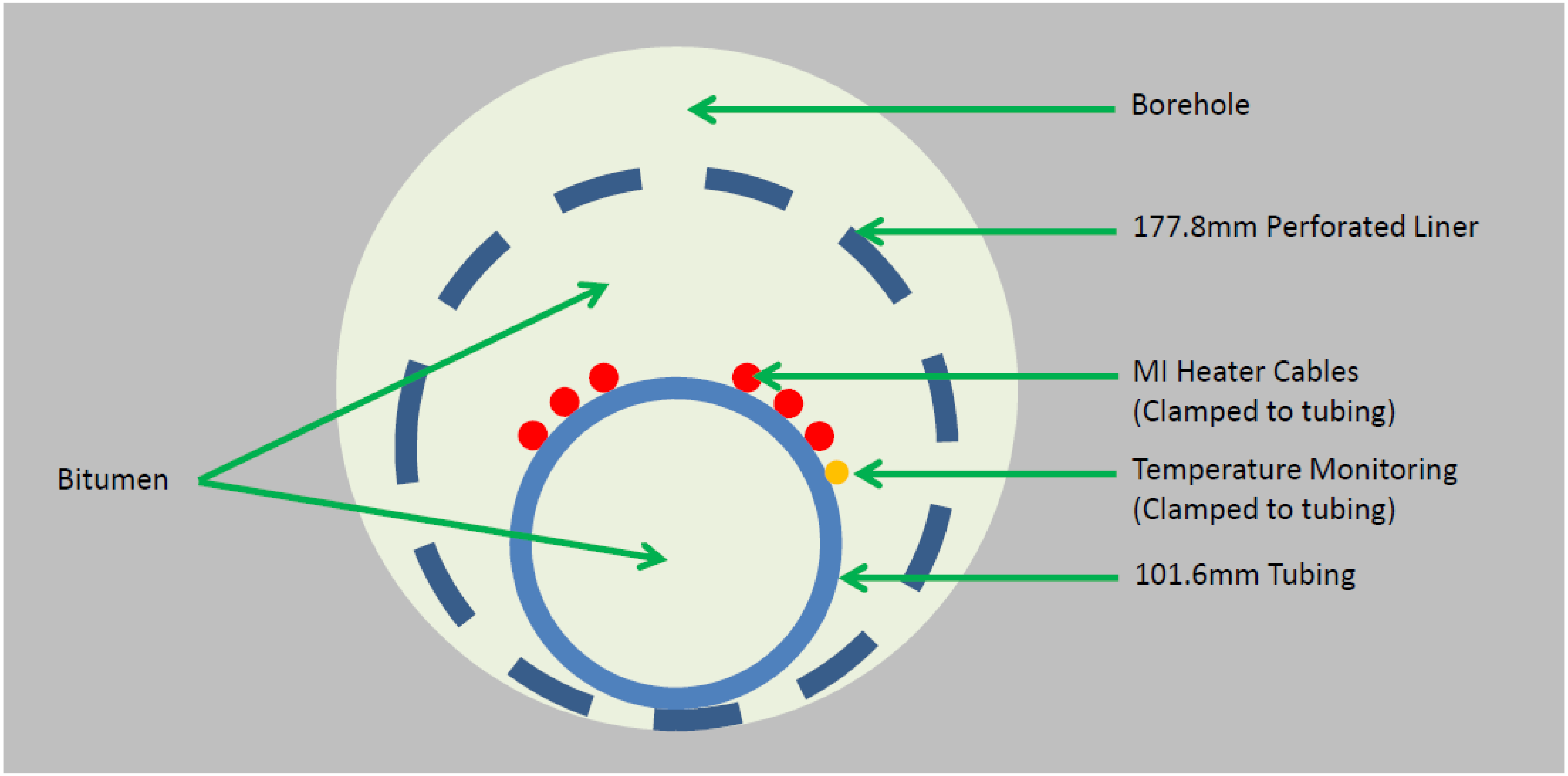


HEATER WELL COMPLETION



- Prior to heat transfer fluid addition, AOC operated the well in vacuum. Observed high wellbore temperatures which limited power output.
- Heat transfer fluids added in Heater well to improve transfer of energy to reservoir, and reduce wellbore temperatures. This change enabled increase of power from Heater well.
- Heat transfer fluids tested: natural gas (July 2013), oil based fluid (May 2014)

HEATER-PRODUCER WELL COMPLETION



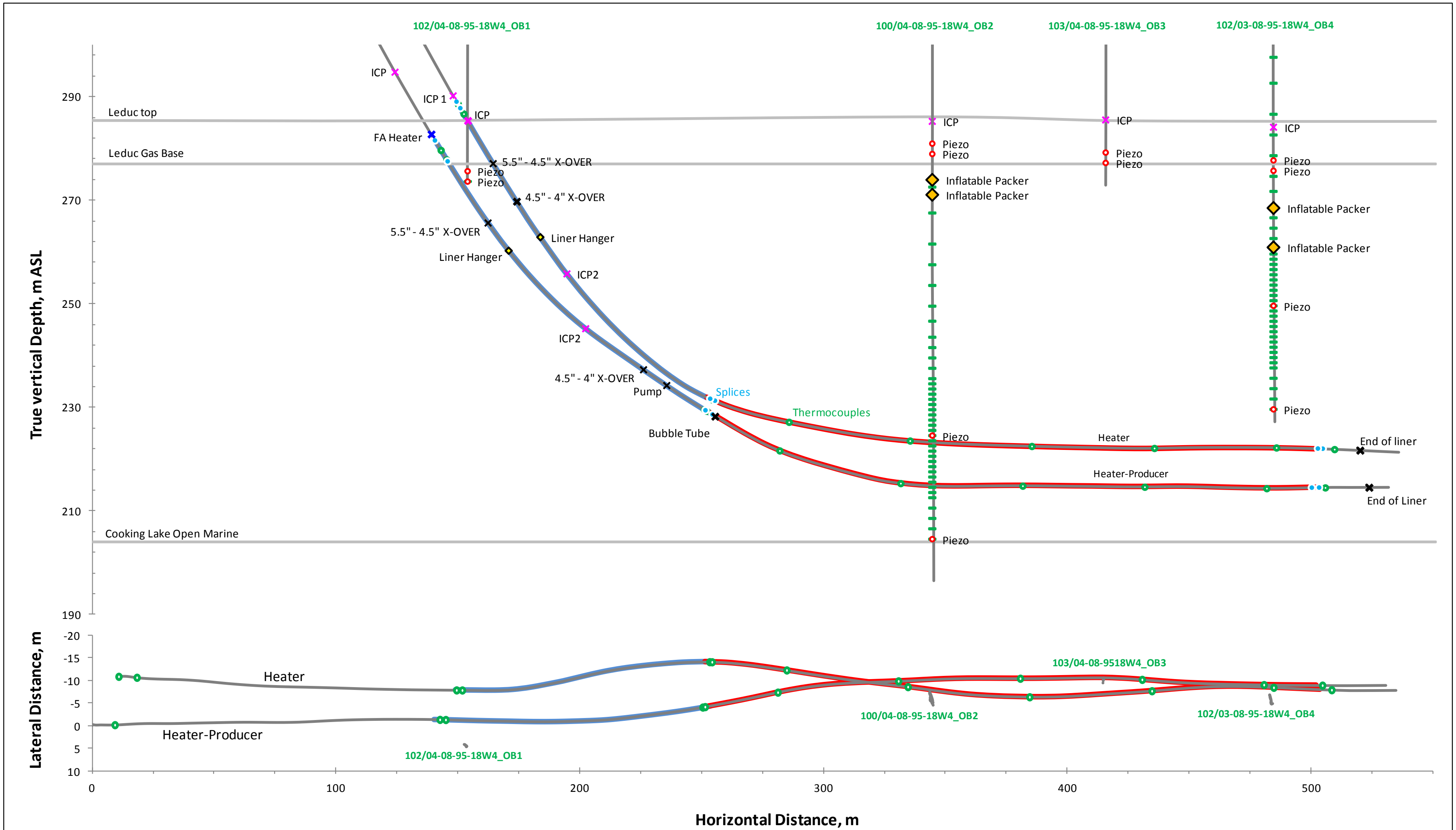
- Producer is heated to accelerate thermal communication between wells

ARTIFICIAL LIFT

STEAM-RATED BOTTOM HOLE INSERT PUMP:

- landed at 80° inclination.
- pumped with hydraulic pumping unit.
- pump was changed in September 2013 to help minimize gas locking issues.
- have pumped between 2 and 24 m^3/d with new pump.
- flow assurance heater maintains 70°C uphole.
- dip tube attached to bottom of pump to lower intake point and achieve a more uniform in-flow.
- performed well

INSTRUMENTATION IN WELLS



- Base oil introduced in observation wells to reduce temperature smearing effects due to reflux

INSTRUMENTATION OBSERVATIONS

Heater Well

- Fibre DTS data began to deviate from thermocouple data in April 2012.
- Fiber is now reading erroneously higher temperatures in majority of the heated section of the well.
- 1 failed thermocouple point.

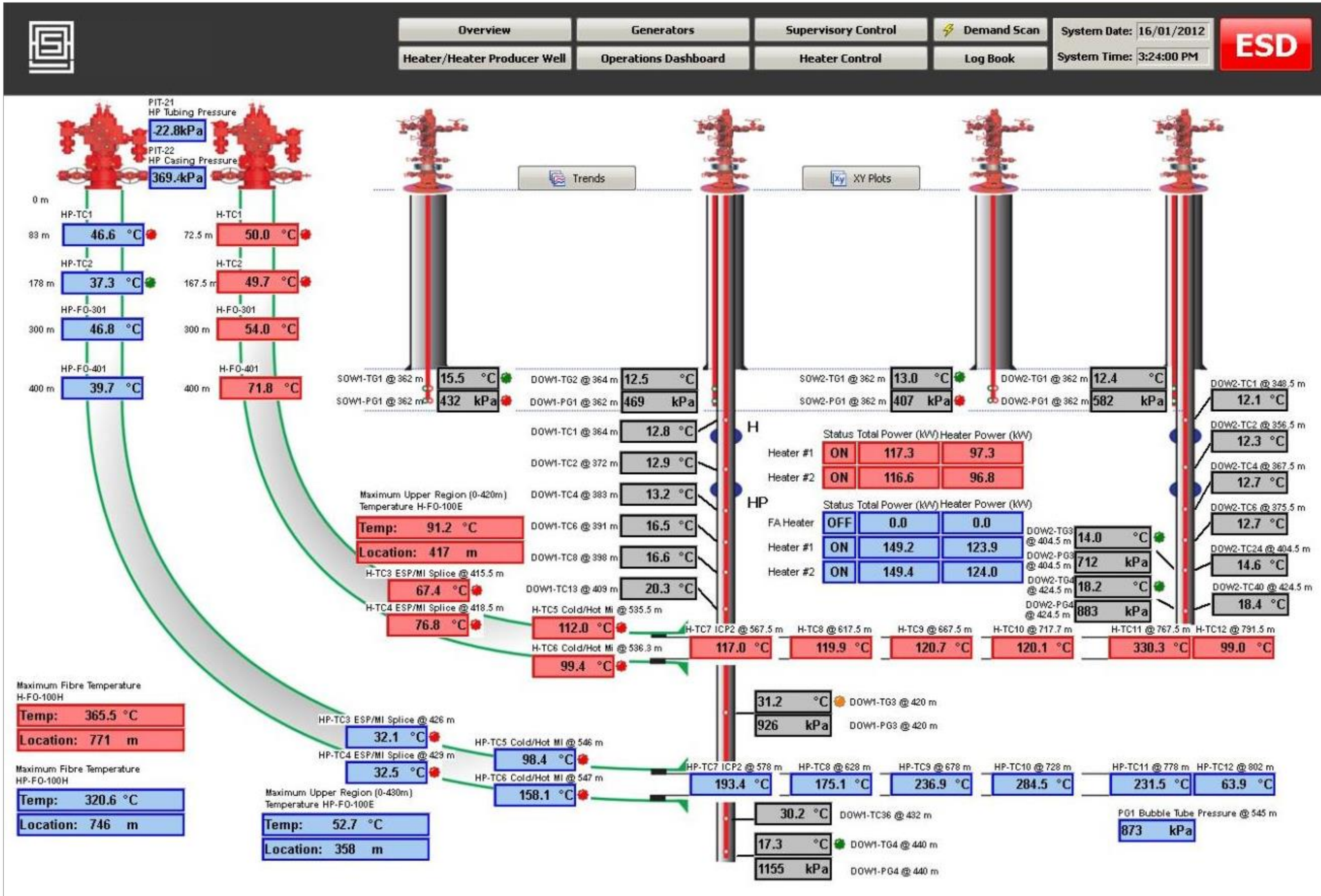
Heater-Producer Well

- Fibre DTS data agree well with thermocouple data.
- 5 failed thermocouple points.
- Bubble tube has failed. Currently bubbling natural gas down casing annulus for pressure measurement.

Observation wells

- Convection in wellbore annulus is smearing temperature readings
- OB4 well has 2 failed thermocouple points.

SCADA



- Instrumentation tied to central data acquisition system for remote real-time monitoring and control from the field and Calgary

TAGD FIELD TEST PRODUCTION SUMMARY

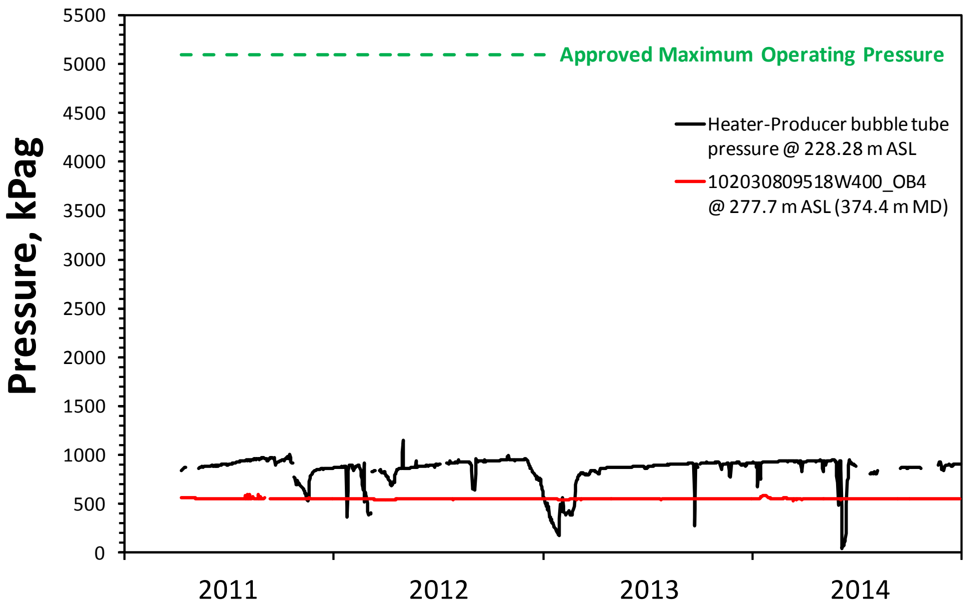
- Heating all year in Heater well and Heater-Producer well.
- Production Cycle #4 (June 2014 to year-end).
  - Pumping from 2 to 24 m^3/d fluid
- Oil Cut Test

	Total Volume	Oil Cut (Corrected for load fluid)
March	14.3 m^3	94%

GEOMECHANICS

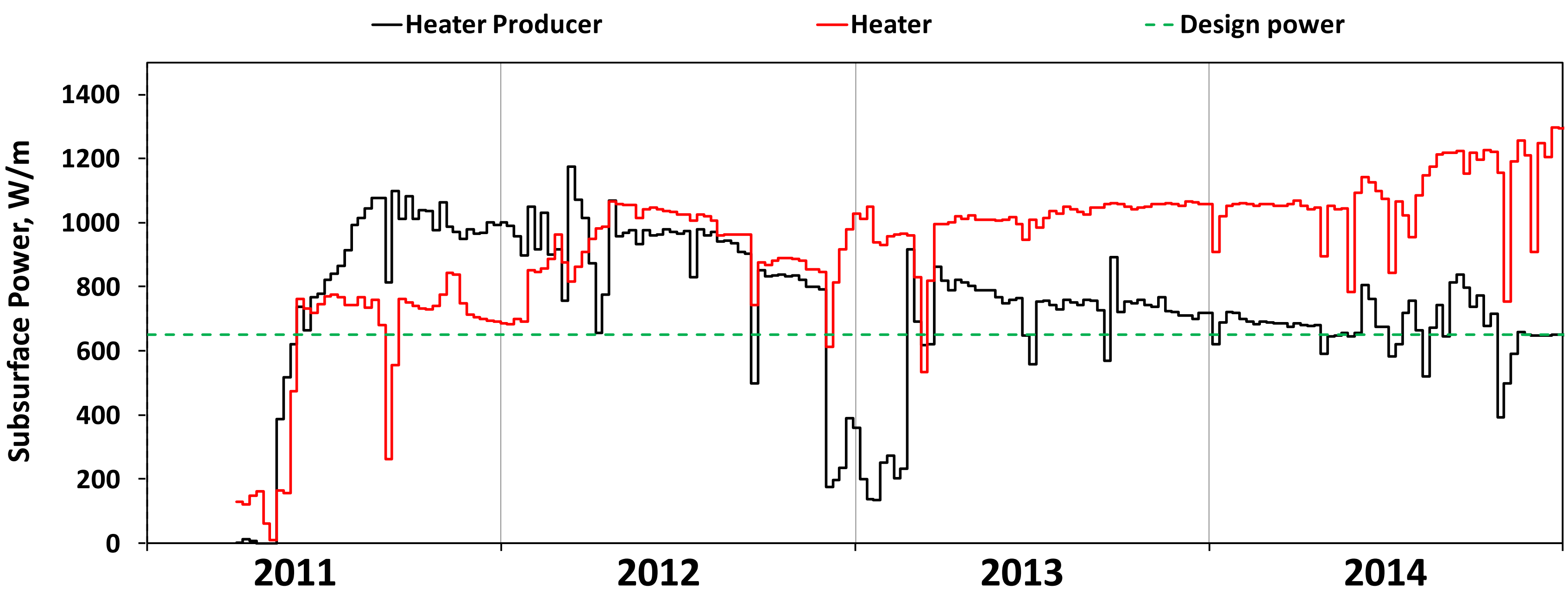
Year	Well	Formation	Depth (m)	Min Stress		Vertical Stress	
				MPa	kPa/m	MPa	kPa/m
2008	15-30-93-17W4	Clearwater	203	4.4	21.7	4.47	22.0
2008	15-30-93-17W4	Clearwater	194	4.24	21.9	4.27	22.0
Average					21.8		22.0
2010	15-26-95-17W4	Clearwater	277	5.7	20.6	5.9	21.3
2010	15-26-95-17W4	Clearwater	264	5.3	20.1	5.6	21.3
Average					20.3		21.3
2011	12-30-92-18W4	Clearwater	201	4.19	20.8	4.32	21.5
2011	12-30-92-18W4	Clearwater	181	4.02	22.2	3.89	21.5
Average					21.5		21.5
2011	10-8-95-18W4	Clearwater	340	7.2	21.2	7.15	21.0
2011	10-8-95-18W4	Clearwater	335	7.32	21.9	7.26	21.7
Average					21.5		21.4

Mini-Hydraulic Fracture Test Summary (TAGD Pilot Application)

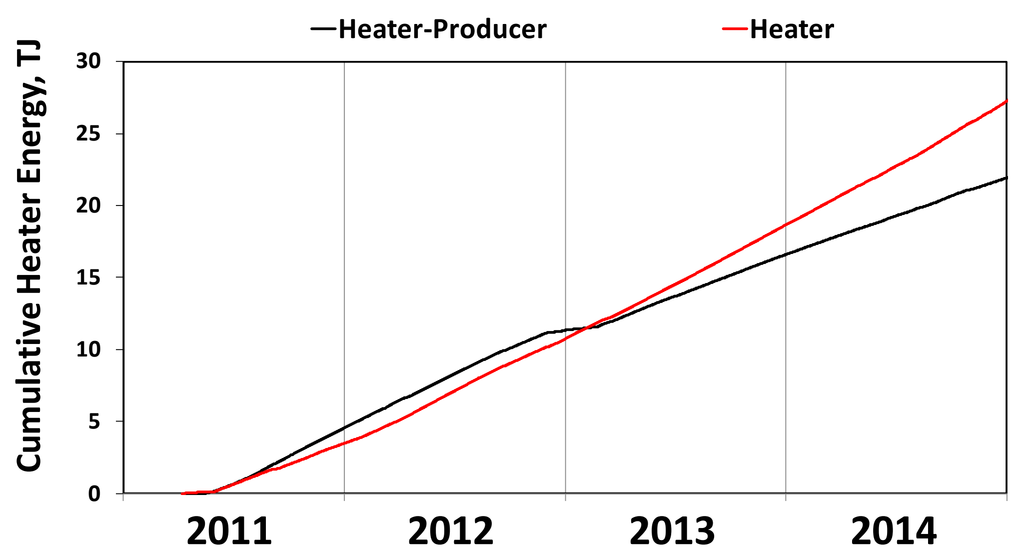


- At caprock depth of 340 m TVD, fracture pressure estimated to be 7 300 kPa (i.e. 21.5 kPa/m).
- Minor increase in pressure due to heating at producer; no change in pressure at observations wells in gas-bitumen zone.
- All observed pressures well below maximum operating pressure of 5 100 kPa as specified in the Application.
- No heave monitoring was conducted.

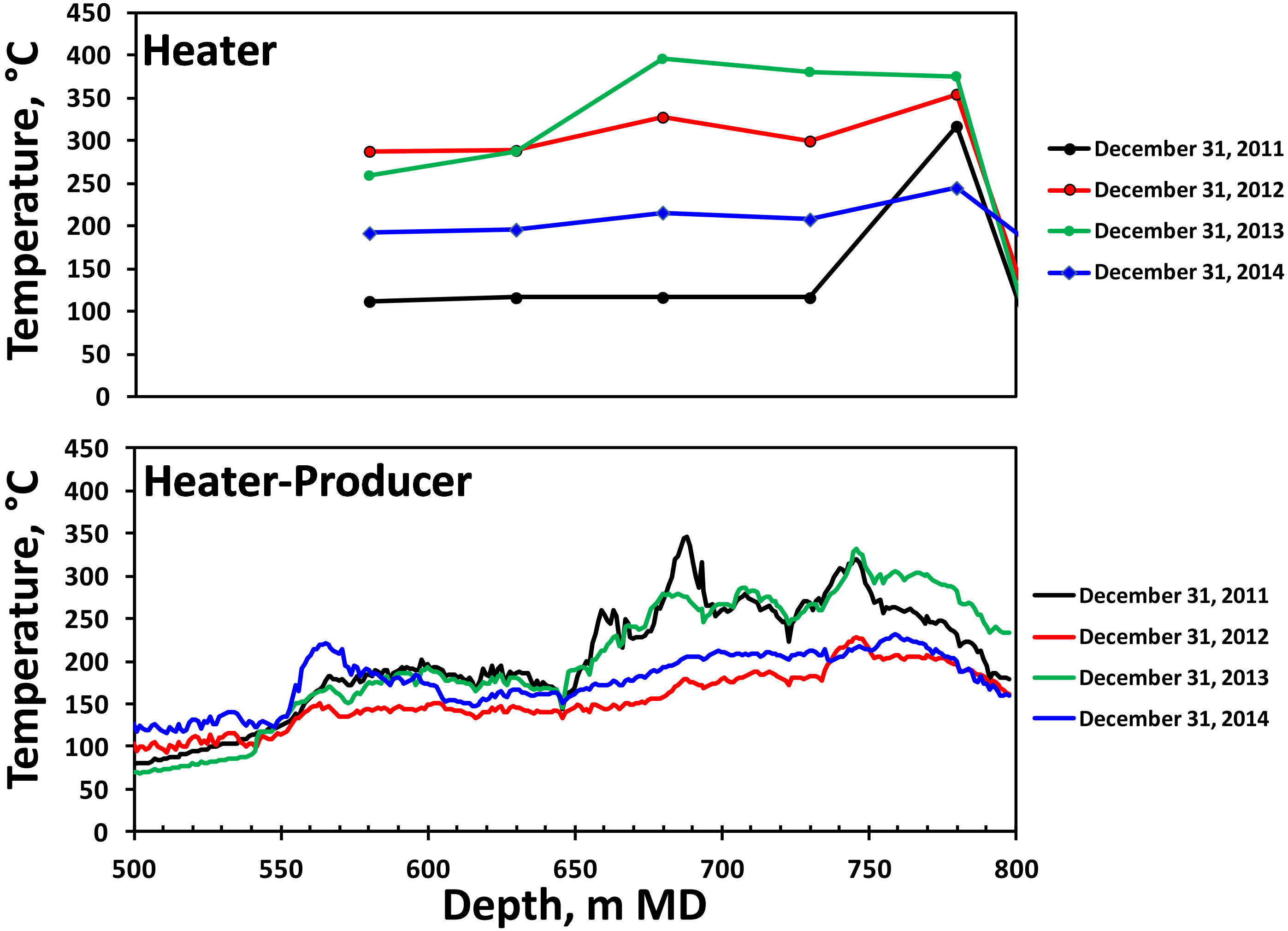
HEATING PERFORMANCE



- Heater running at full power.
- Heater producer limited by maximum temperature.
- Heater power increased in mid-2014 when adding heat transfer fluid
- Power in producer decreasing as well warms up

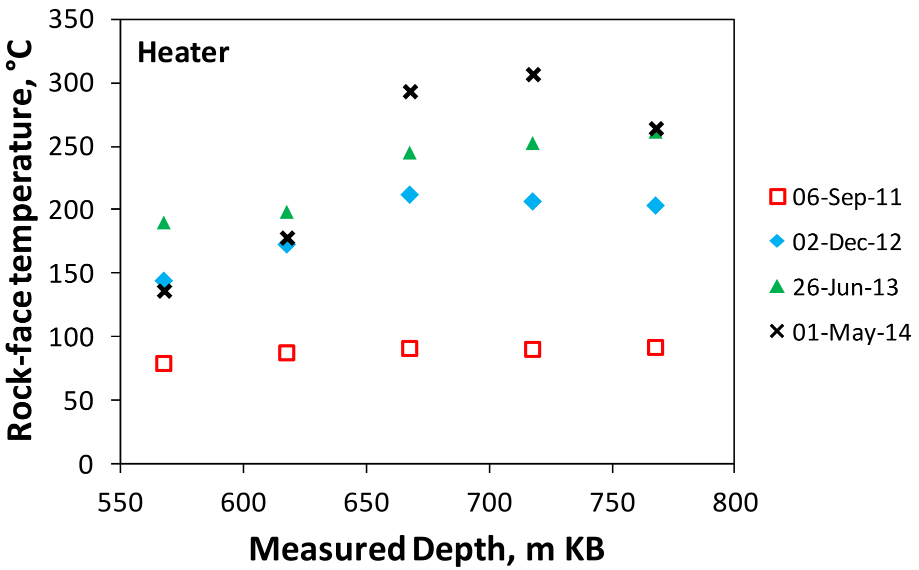


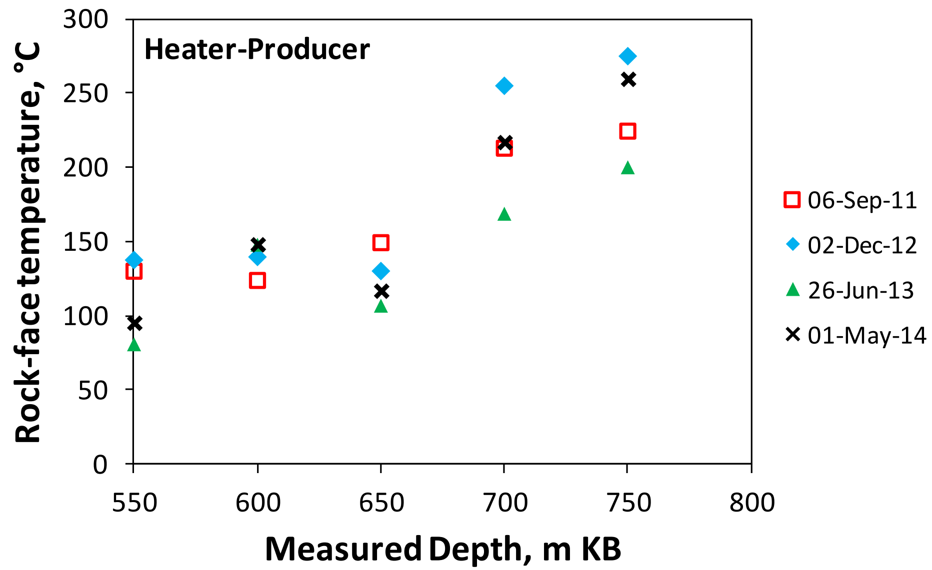
HEATING WELL TEMPERATURES



Thermocouple data used to monitor heater temperature as fiber readings have become unreliable.

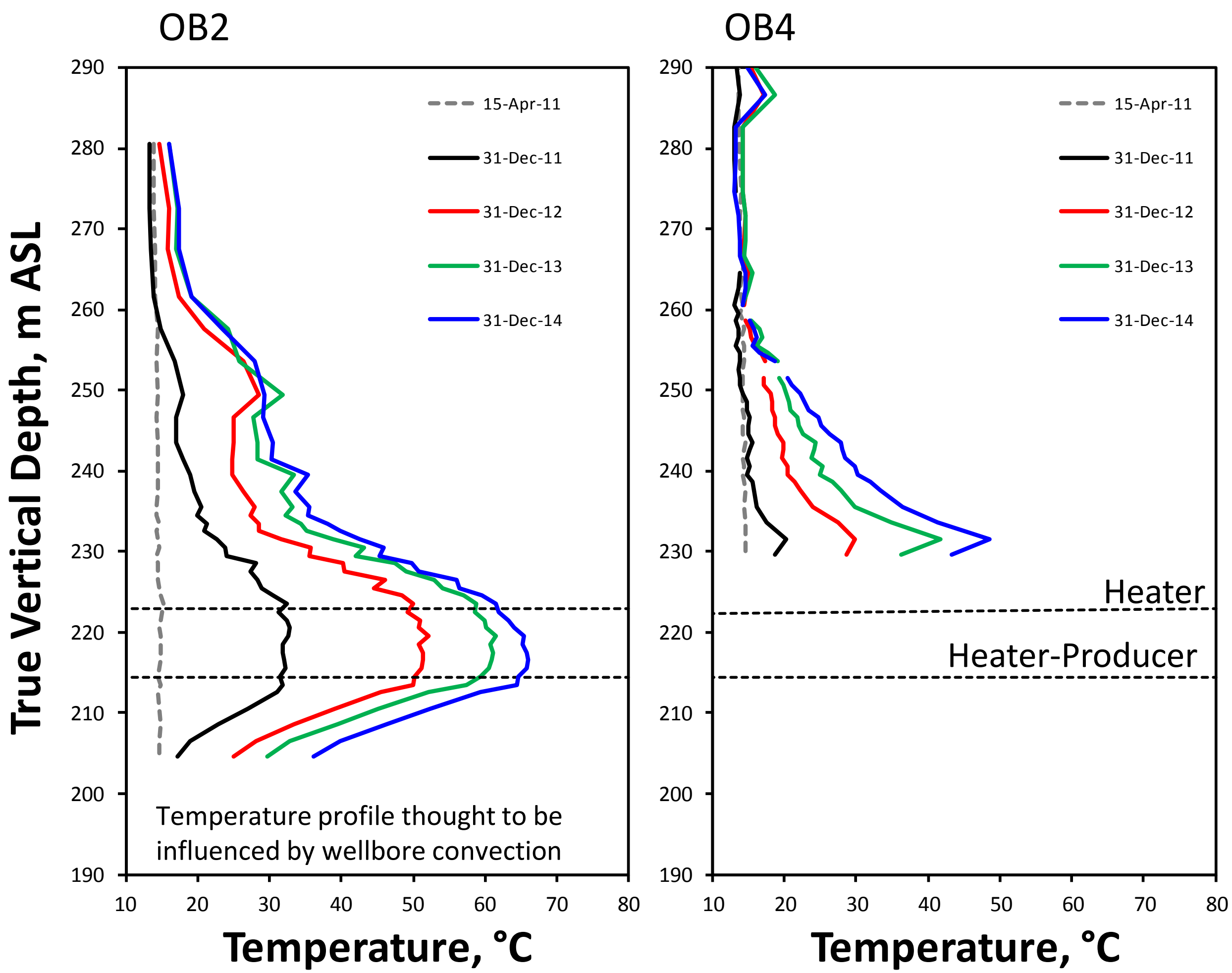
ROCK FACE TEMPERATURE





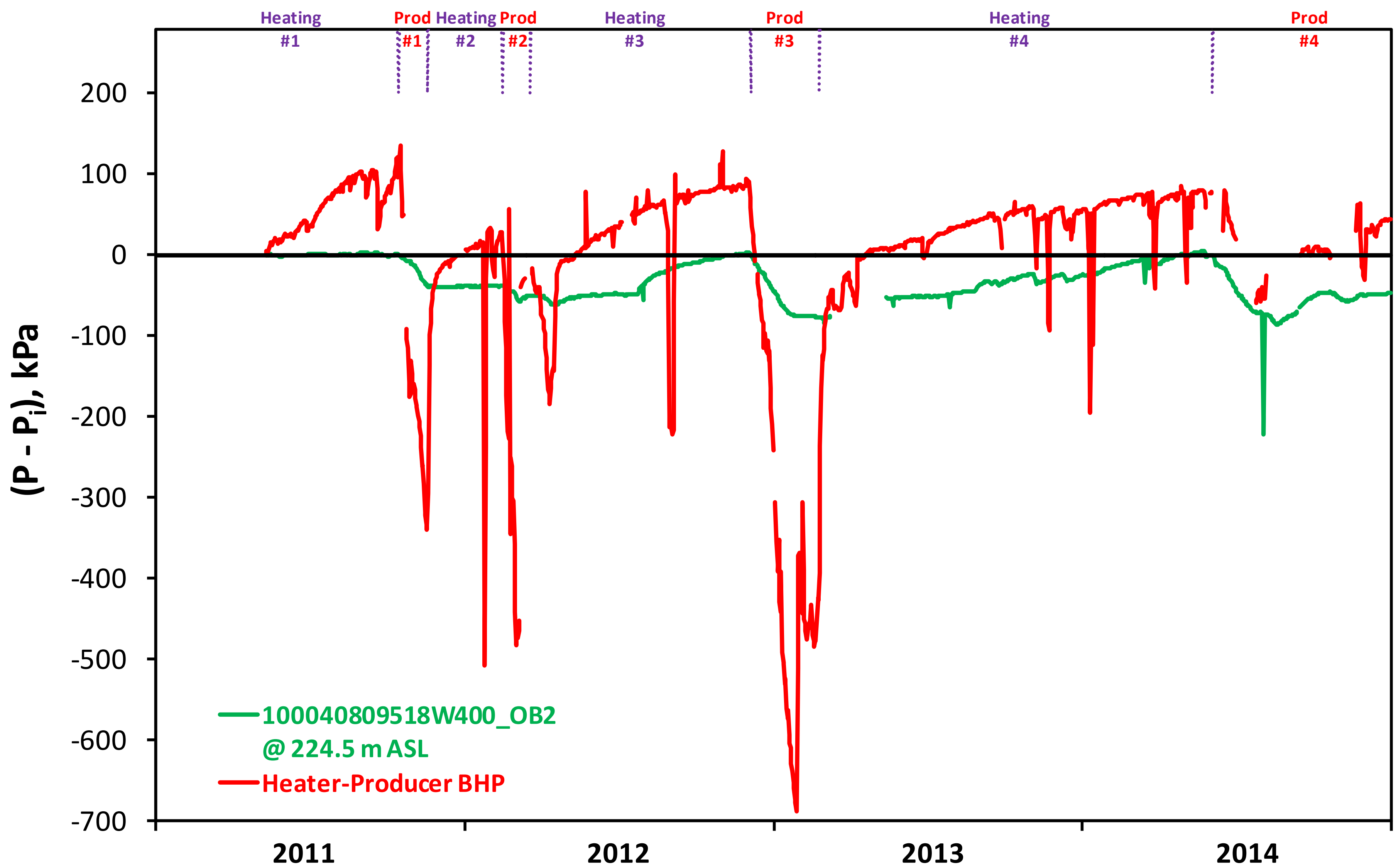
- Based on transients observed when heaters are shut off
- Non-uniform rock-face temperature along well potentially due to:
  - Porosity variations along well
  - Refluxing in build section
  - Fluid phase distribution along well

OBSERVATION WELL TEMPERATURE



- Observed peak temperatures lower than expected from simulation.
- Convective smearing of temperatures.

HEATING PHASE – PRESSURE CHANGES



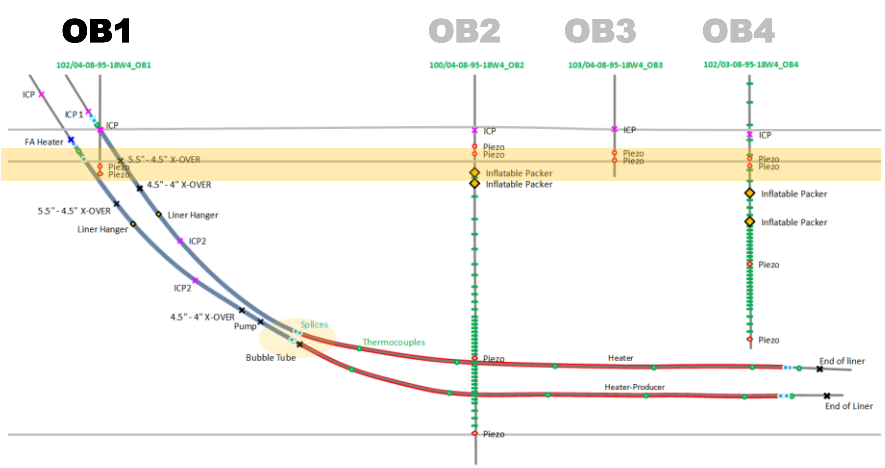
GAS INJECTION TEST (2014 Q1)

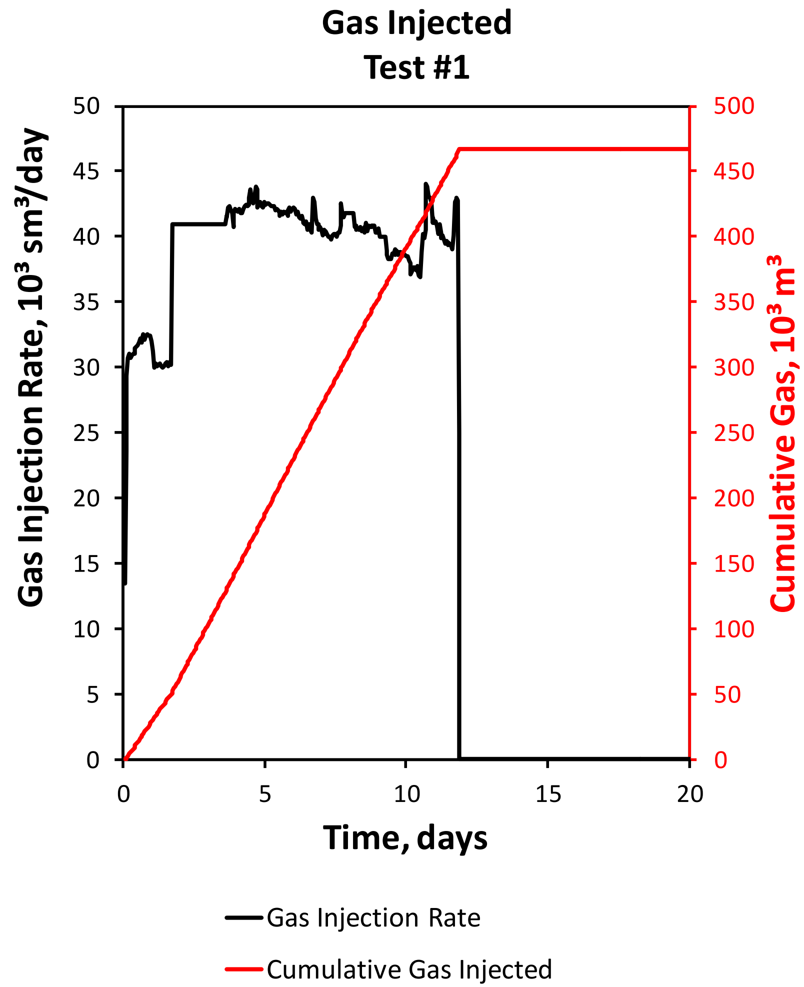
Objective:

- Investigate volume and lateral extent of the gas-bitumen transition zone
- Determine presence and degree of vertical communication
- Assess gas injectivity and effective gas permeability

Procedure:

- Inject natural gas into OB1 at ~ 42 000 m3/d.
- Shut-in injection and monitor pressure at injection well, observation wells, and TAGD producer during injection and fall-off periods
- Repeat test.
- A total volume of 643 x 10^3 m^3 was injected for two tests.



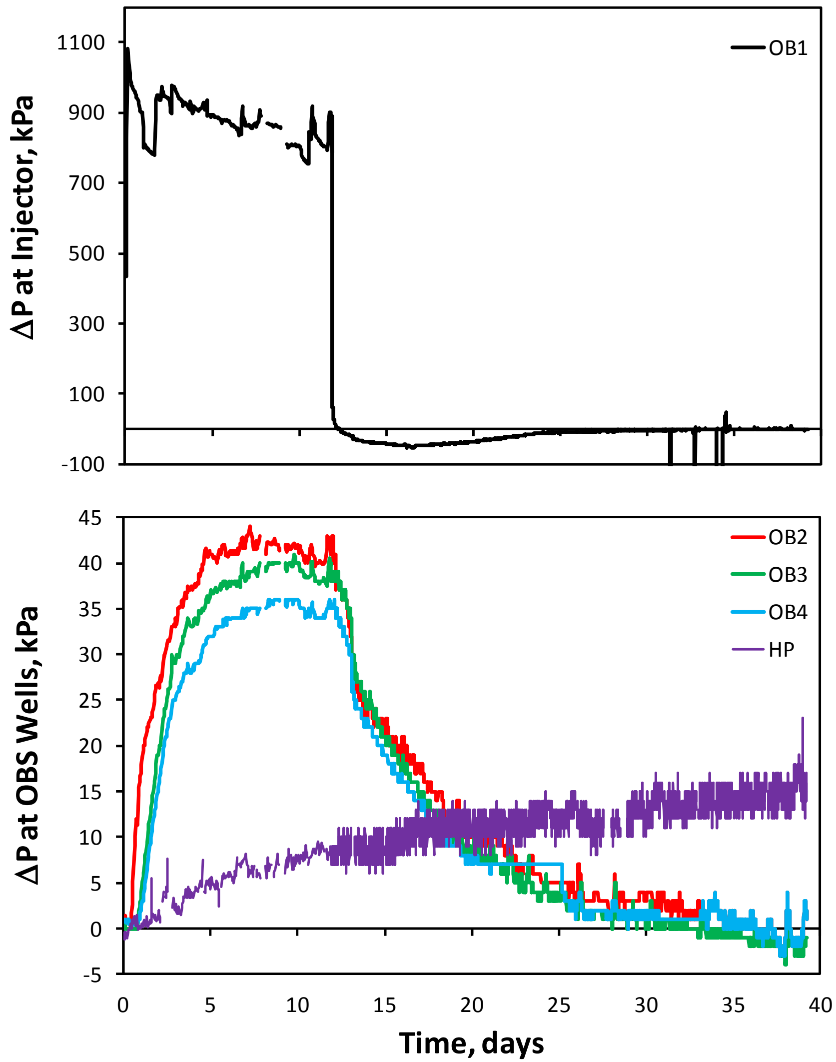


GAS INJECTION TEST (2014 Q1)

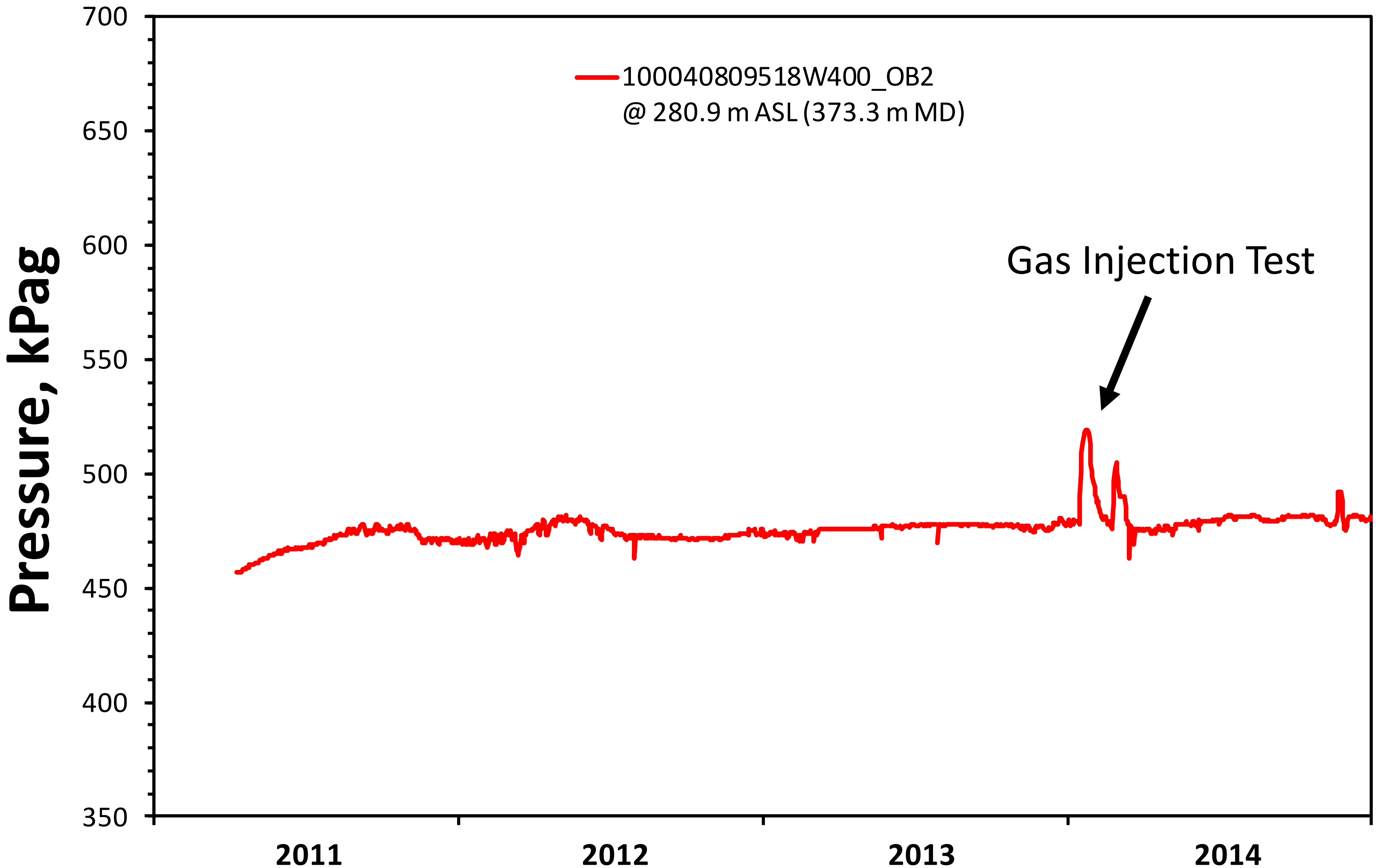
Analysis:

- Increase in post-injection pressure not observed; → large connected gas accumulation
- No measureable pressure response at TAGD producer → no or limited vertical communication between gas zone and base of Leduc
- Gas injection rate at 4500 kPa bottom-hole injection pressure estimated to be ~ 600×10^3 m^3 /d
- Permeability ~ 800 mD (effective gas)
- During both tests, OB1 pressure dropped below initial pressure after shutin
    - Static liquid in well pushed out into formation during injection. Wellbore is filled with compressed gas.
    - When shut in, gas in the wellbore decompresses, and reservoir fluids flow back into well, resulting in wellbore pressure equilibrating with reservoir

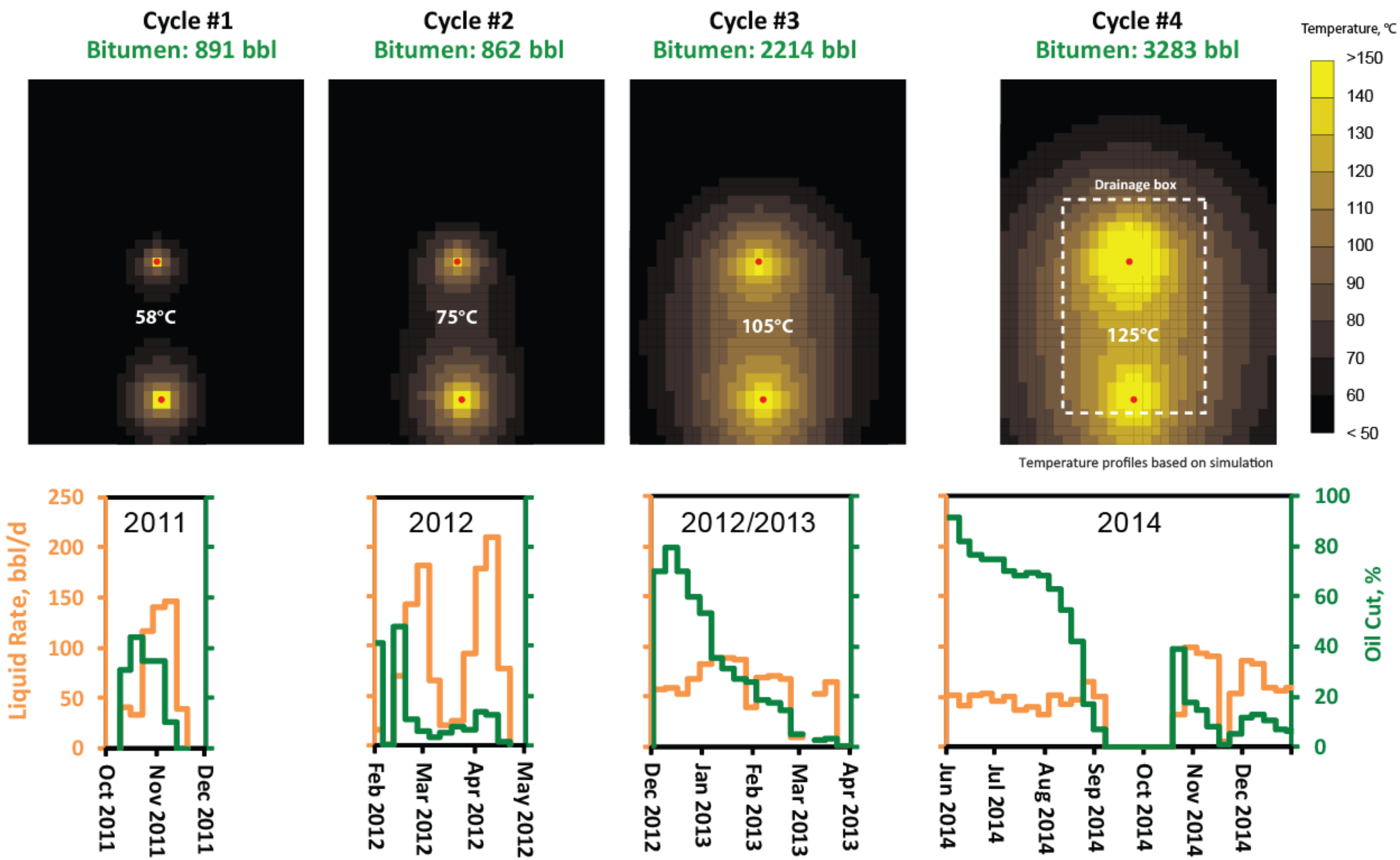
Pressure Responses



PRESSURE IN GAS-BITUMEN TRANSITION ZONE

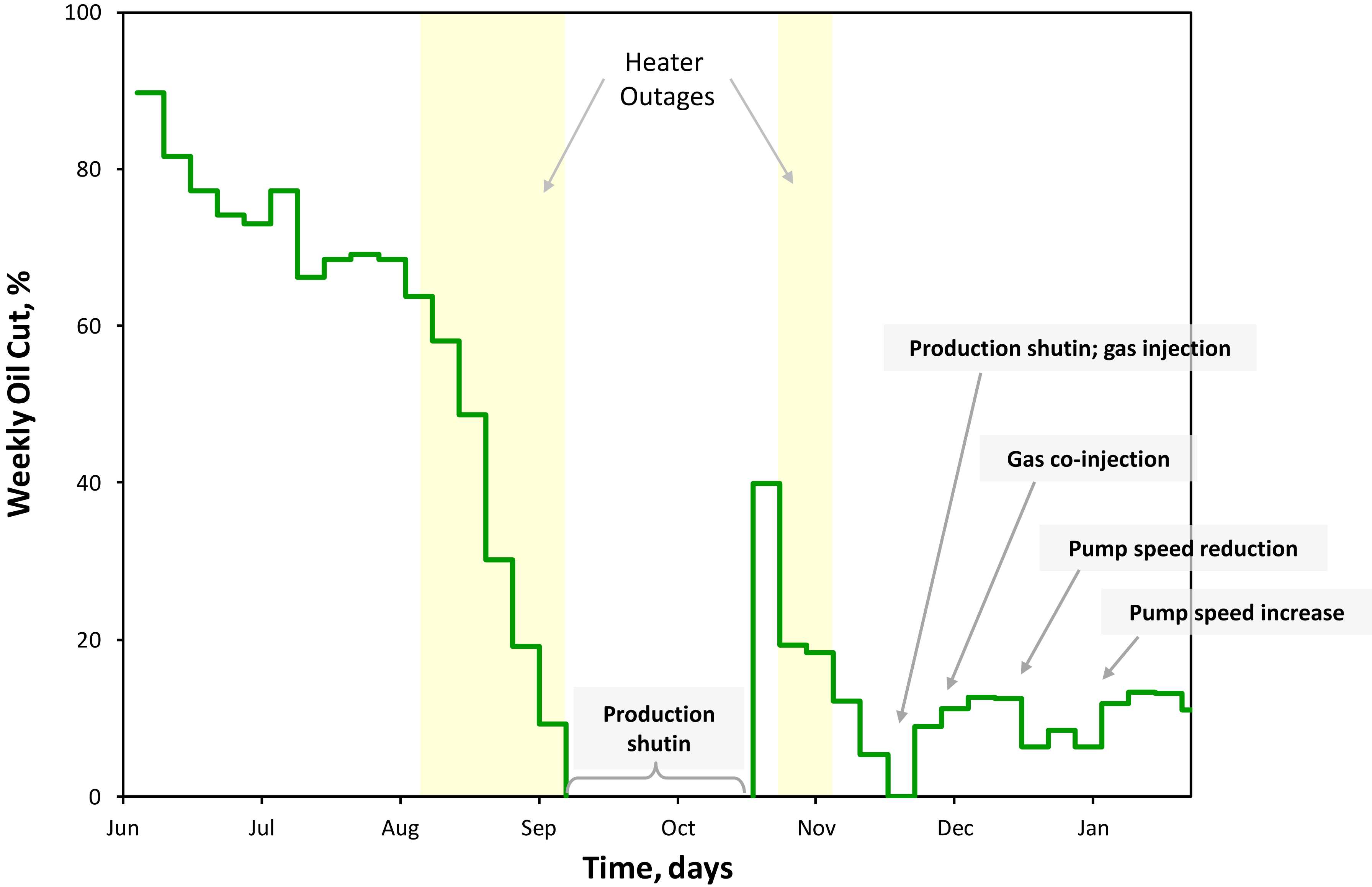


PRODUCTION HISTORY

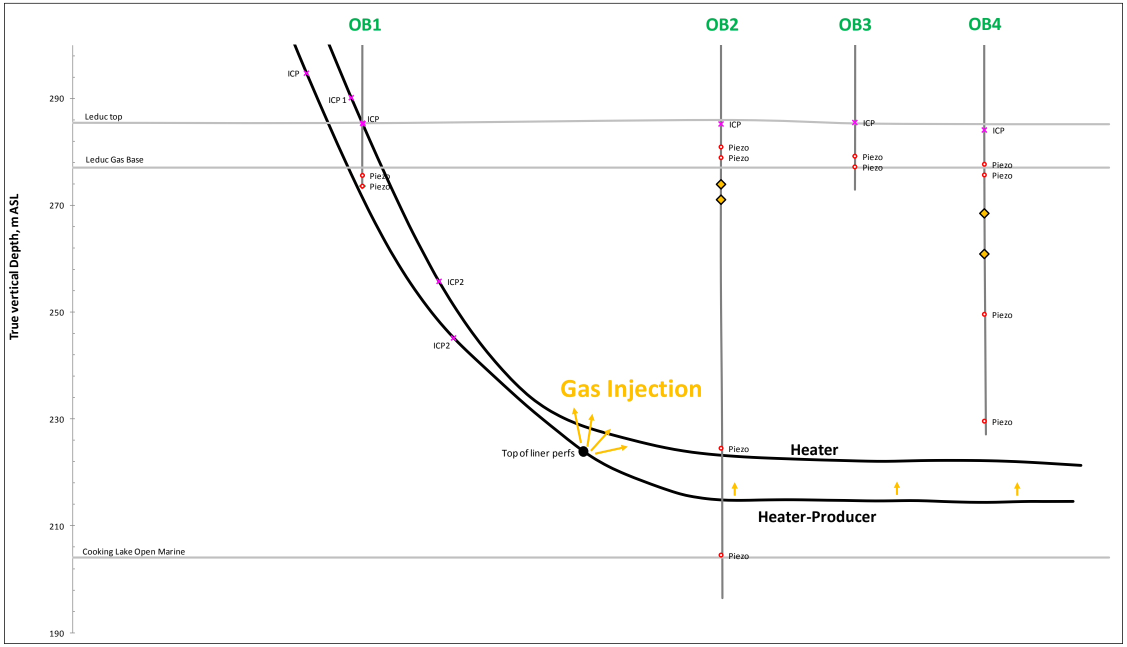


- Liquid rate controlled by pump
- High oil cut at start of each cycle
- Mobile water likely from disposal in 7-4
- Criteria for start up of each cycle varies in each cycle based on observations during heating, and predictions from history match
- Maximize oil recovery and initial oil cut

CYCLE #4 - MAJOR EVENTS



GAS CO-INJECTION



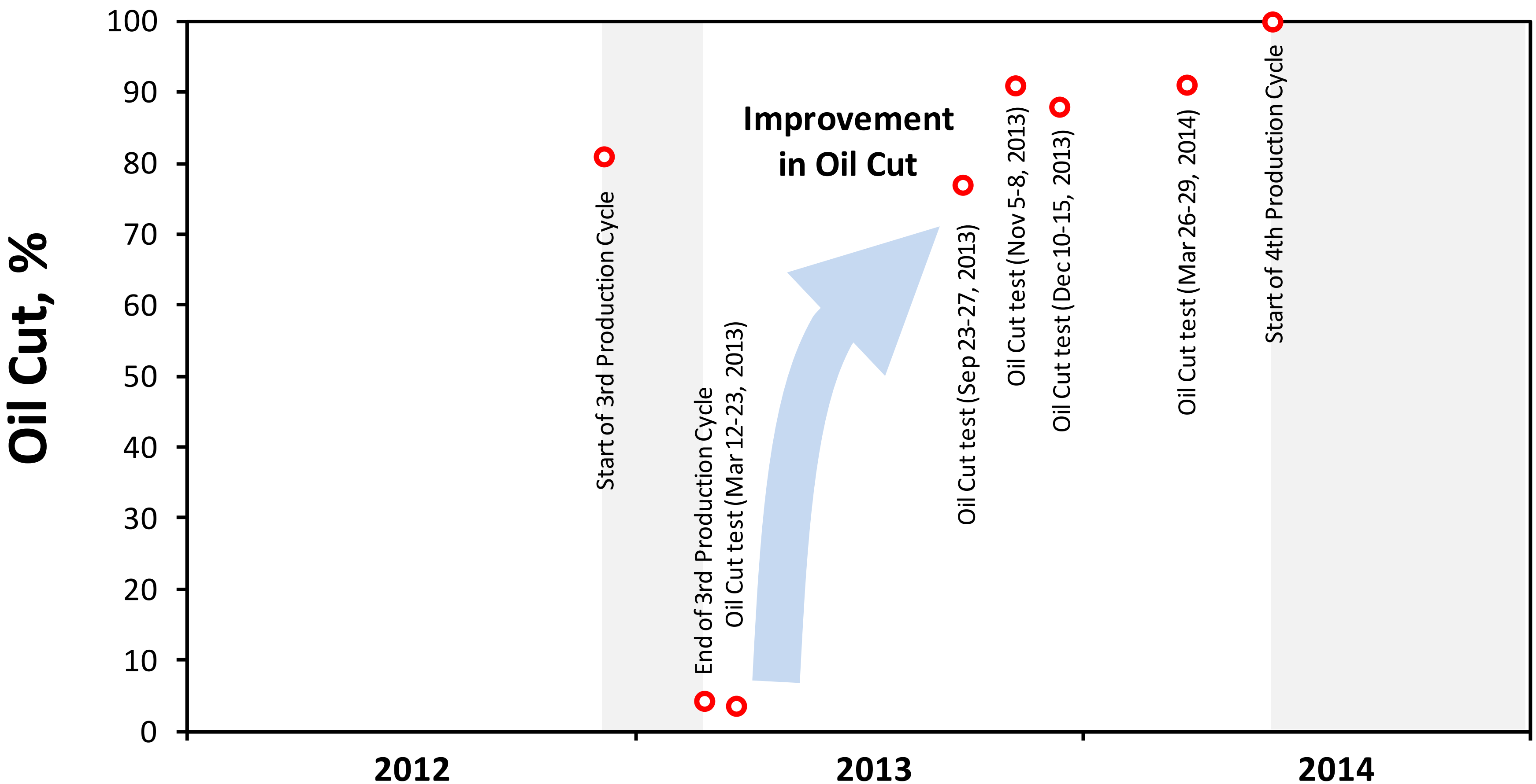
Objective:

- Understand the impact of gas co-injection on the TAGD process, particularly its role in providing additional voidage replacement for the gravity drainage process
- Gas injection during shut-in is expected to accelerate fluid redistribution by gravity drainage, and reduce the period of shut-in required between cycles

Scope:

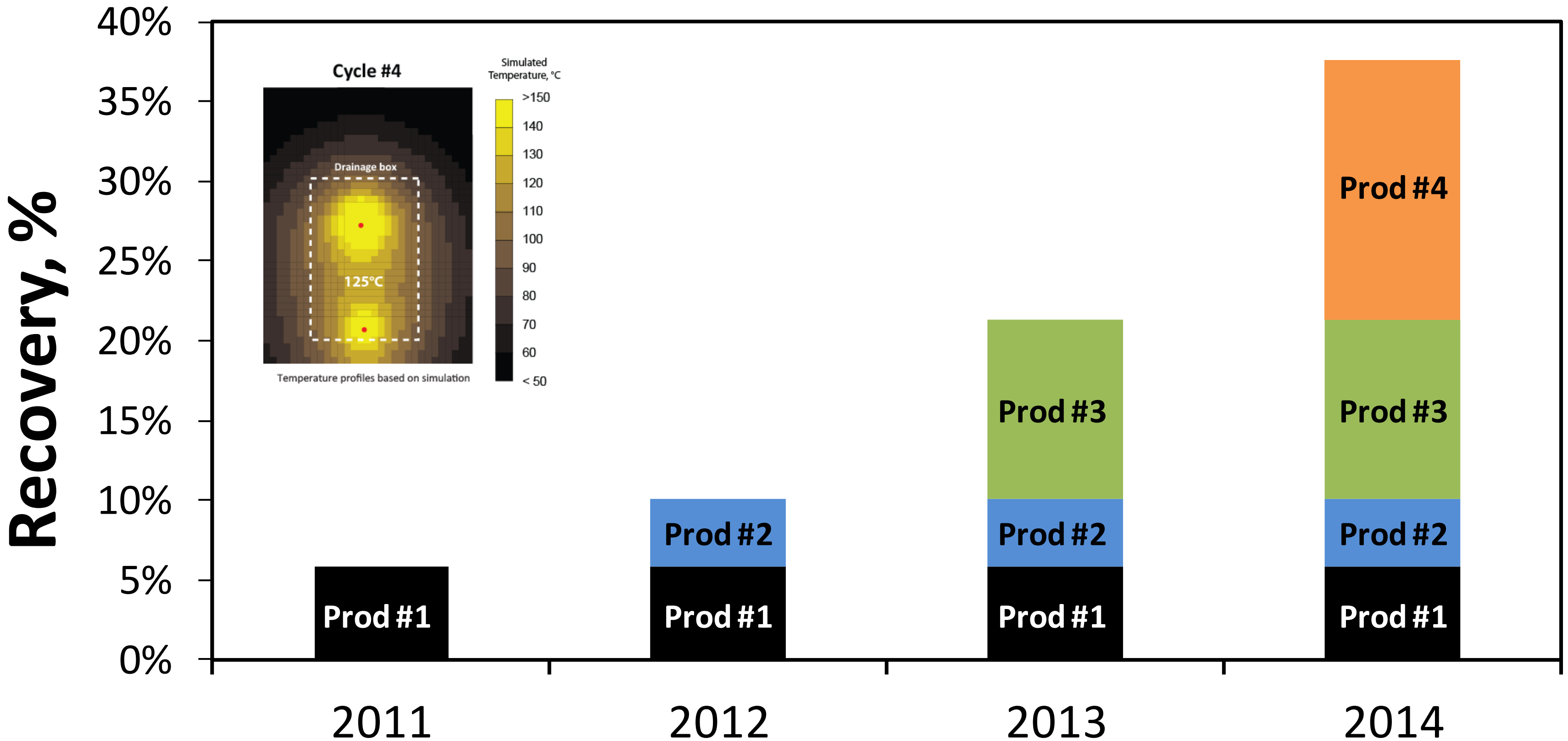
- Inject up to 1000 m^3/d of natural gas into the casing of producer well during subsequent cycles
- Injection may be conducted during both shut-in and production conditions.
- The maximum injection pressure will be 1800 kPa.
- Impact of reduced relative permeability to oil due to gas injection offset by benefit from additional voidage replacement. High vertical absolute permeability would allow for gravity drainage

OIL CUT TESTS



- Oil cut tests were conducted to establish trend of oil cut while heating.
- Evidence for redistribution of fluids by gravity as reservoir warms.

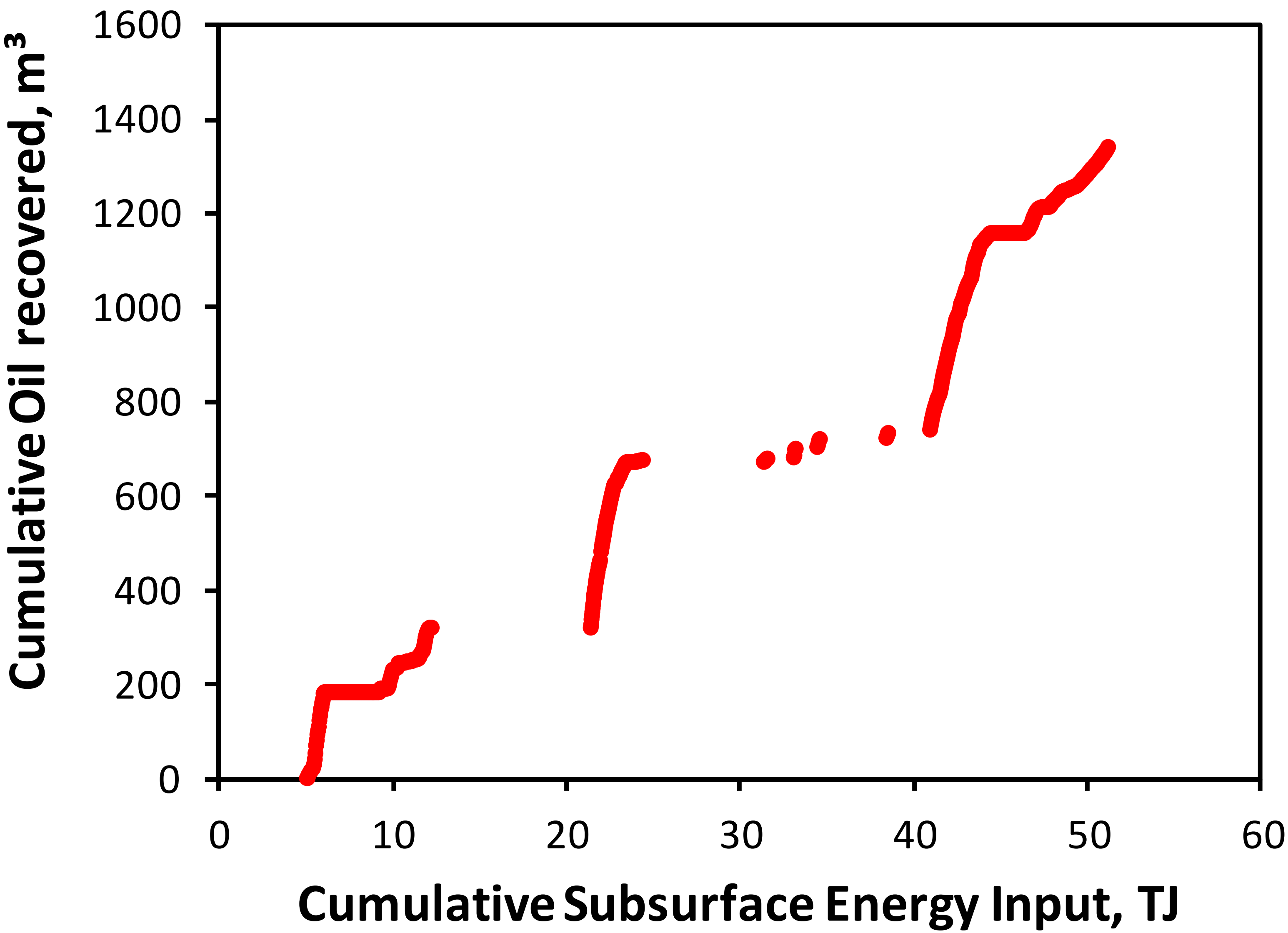
RECOVERY FACTORS TO DATE



OBIP	RF (Year end)	RF (end of test)
3 170 m^3	38%	45 to 50%

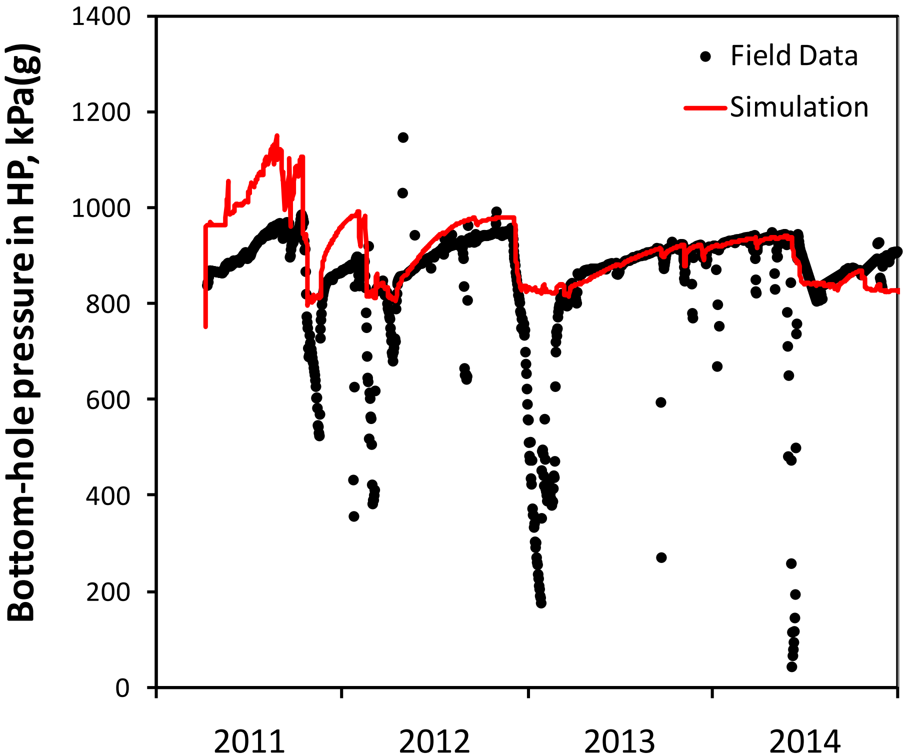
- Recovery factors (RF) have assumed a drainage box of 12 m H x 8 m W x 250 m L.
- RF only an estimate as system is unbounded

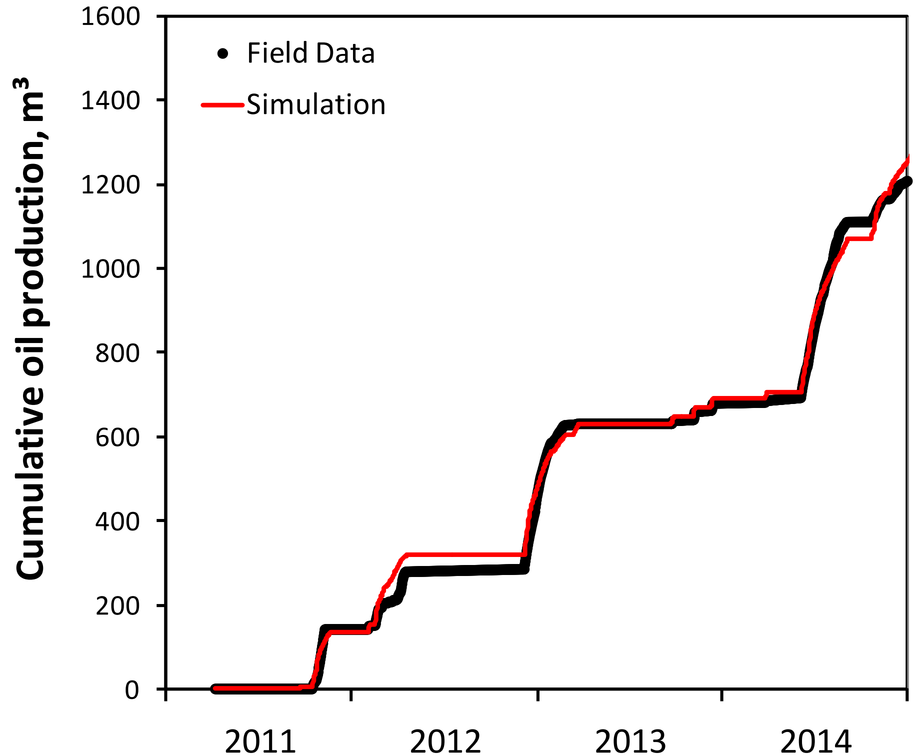
ENERGY VS CUMULATIVE OIL



HISTORY MATCH

- History matched model
  - 2D
  - Dual-permeability
  - Layer-cake model
  - Discrete wellbore model





KEY LEARNINGS

Cycle 1

Objectives:

•Investigate early production potential

Observations:

- Produced more oil than expected; watered out at the end of cycle

Learnings & Implications:

- Oil mobilized at lower temperatures than expected
- Need to operate cyclically to minimize water production

Cycle 2

Objectives:

•Determine heating time required to re-establish oil production

Observations:

- Fiber DTS showed oil production from toe and water from the heel

Learnings & Implications:

- 3 months heating is too short to establish gravity drainage between wells
- Pump intake changed to achieve uniform inflow in HZ

Cycle 3

Objectives:

•Demonstrate gravity drainage from upper well

Observations:

- High initial oil cut with gradual decline

Learnings & Implications:

- Inter-well gravity drainage demonstrated

Cycle 4

Objectives:

•Validate forecasts

•Test ways to increase heater power

Observations:

- Heat Transfer Fluid reduced temp in Heater well

Learnings & Implications:

- Higher heater power

Cycle 5 Objectives

- Increase inter-well temp to commercial target
- Test gas co-injection injection to enhance drainage

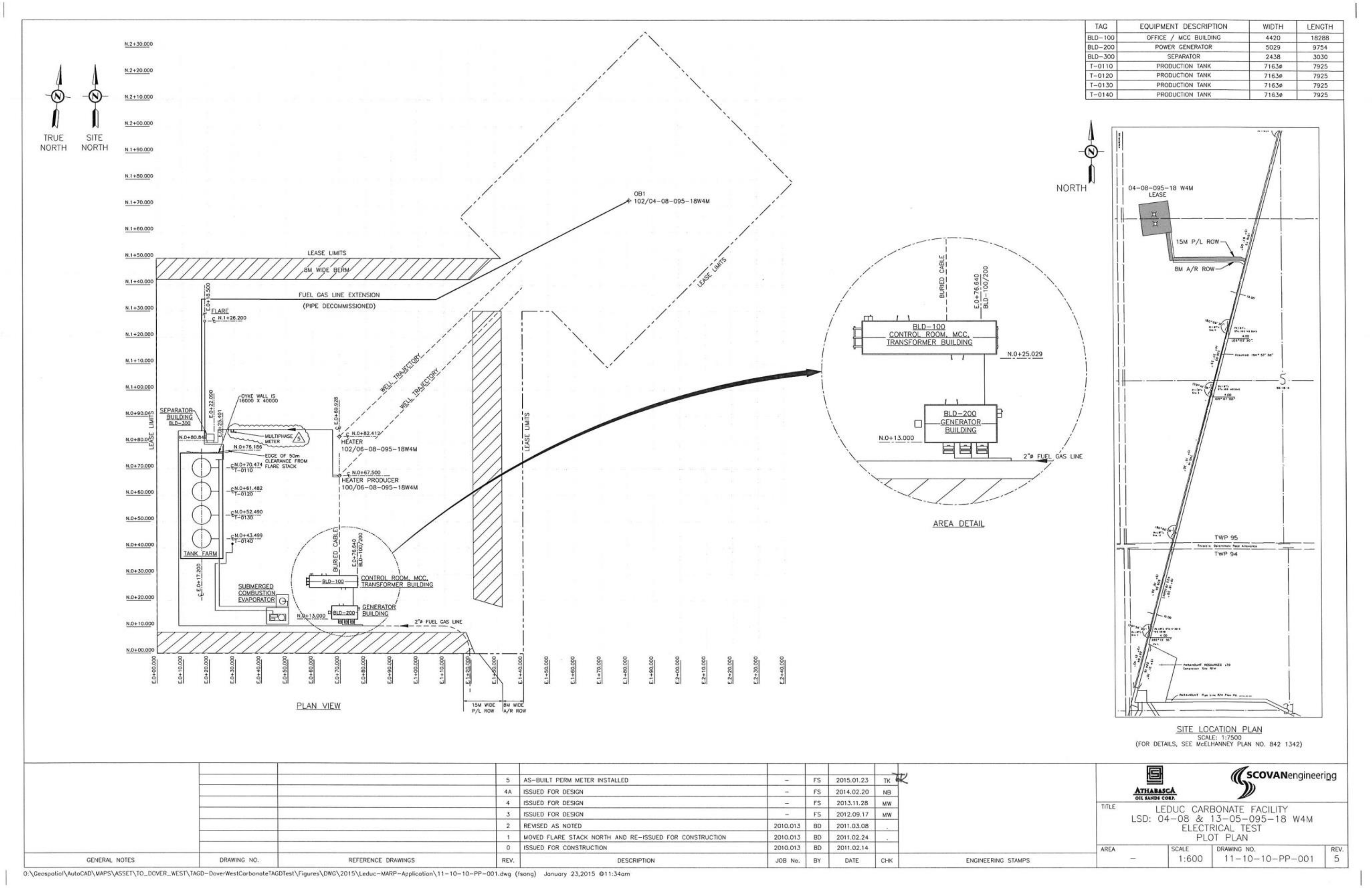
2014 KEY OBSERVATIONS

- After heating for 14 months, observed 100% oil cut at beginning of Cycle #4. Stable production with gradual decline in oil cut until several heater outages occurred.
- Heater outages were caused by ESP cable failures and surface equipment failures.
- Heat transfer fluid significantly reduced temperatures in heater well and allowed higher power output.
- No pump locking issues observed related to gas/steam production with new design.
- High inter-well connectivity observed via fluid movement (liquid & gas).
- Observed significant reflux in Heater well annulus.
- Gas co-injection into producer significantly improved the oil cut.

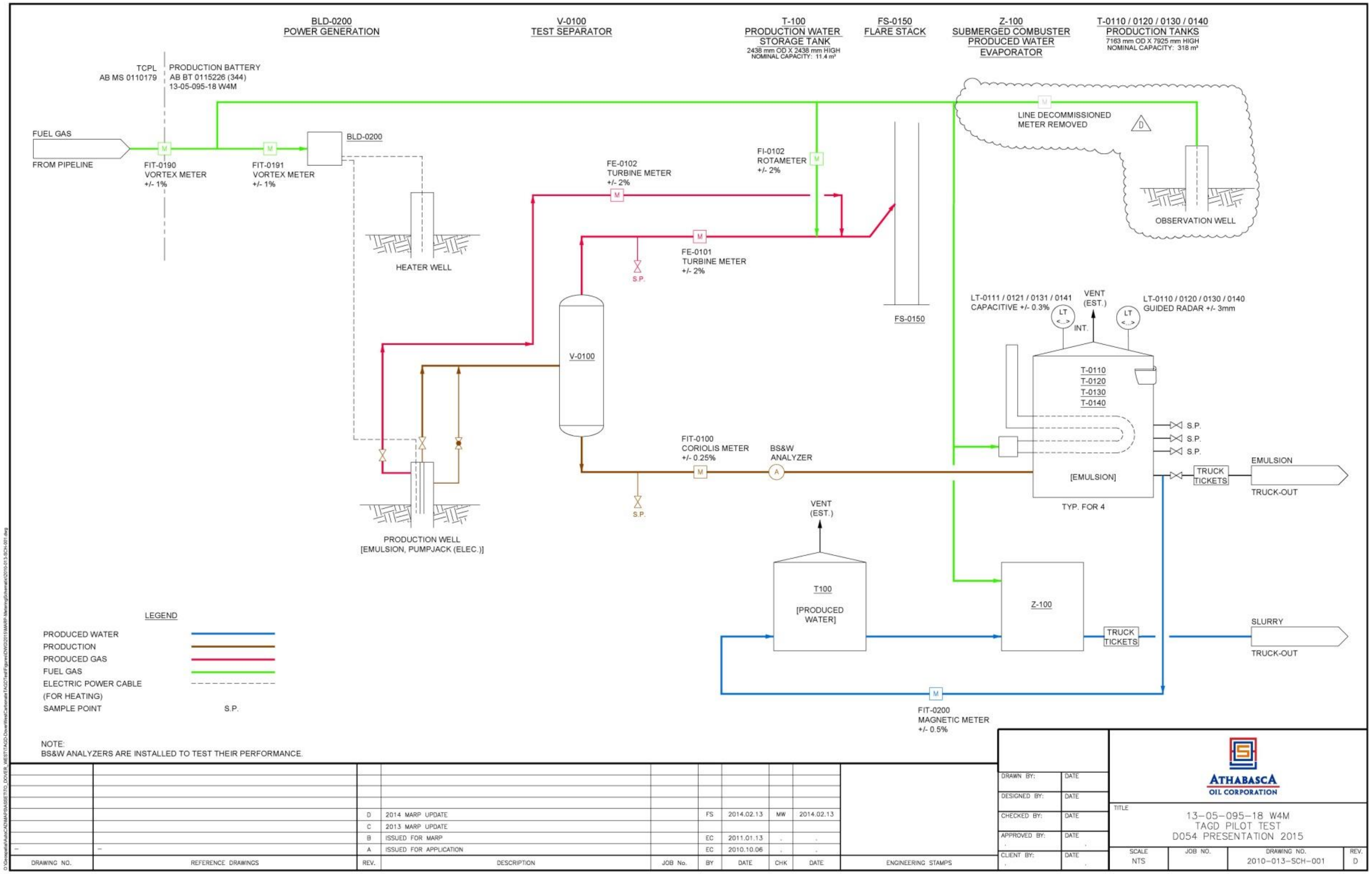
TAGD FIELD TEST SURFACE

Athabasca
Oil Corporation

FIELD TEST PLOT PLAN



GAS INJECTION TEST FLOW DIAGRAM



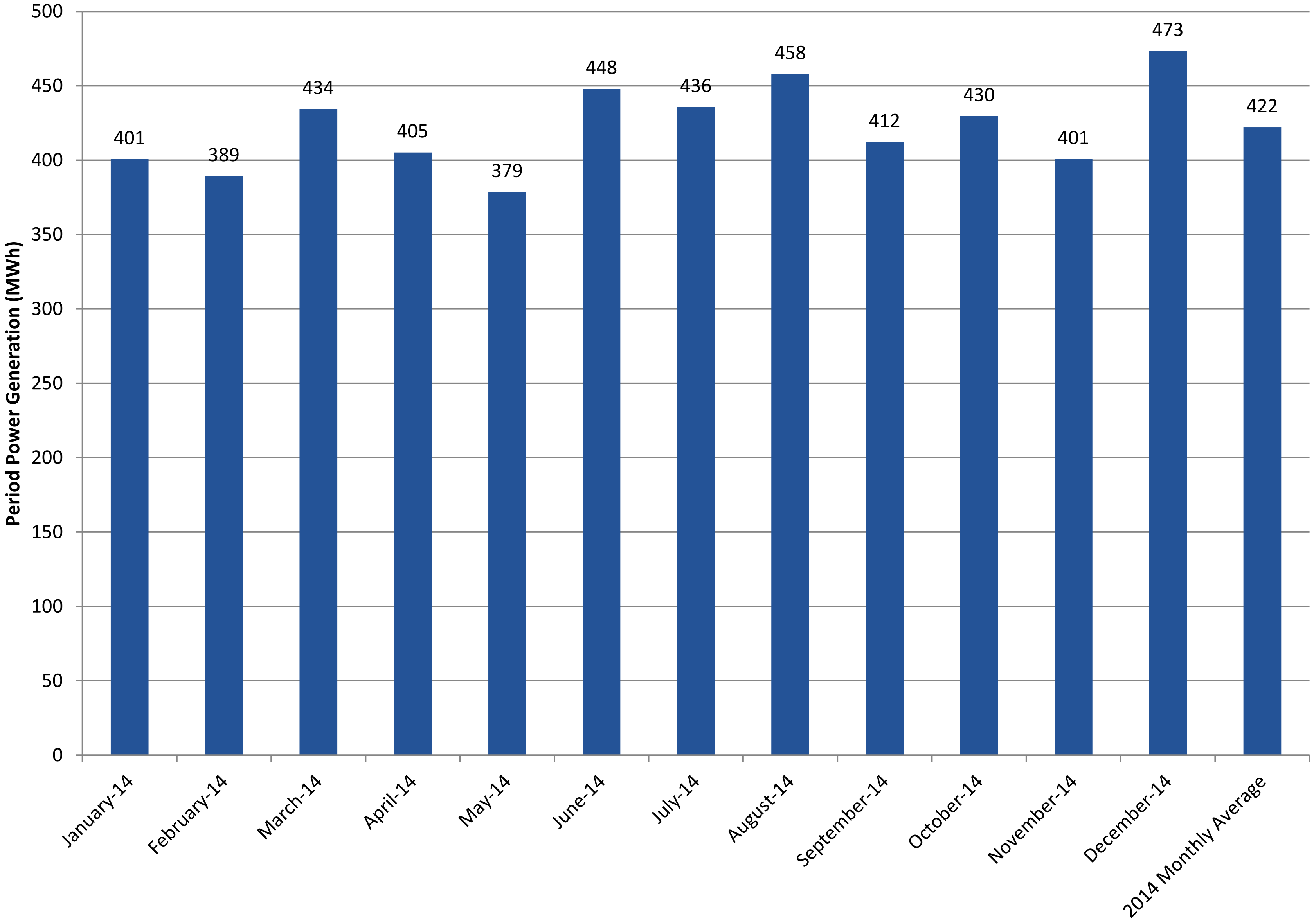
- Gas Injection Test piping and instrumentation added for the test.
- Subsequently the meter has been removed and the pipe is decommissioned.

FACILITY PERFORMANCE

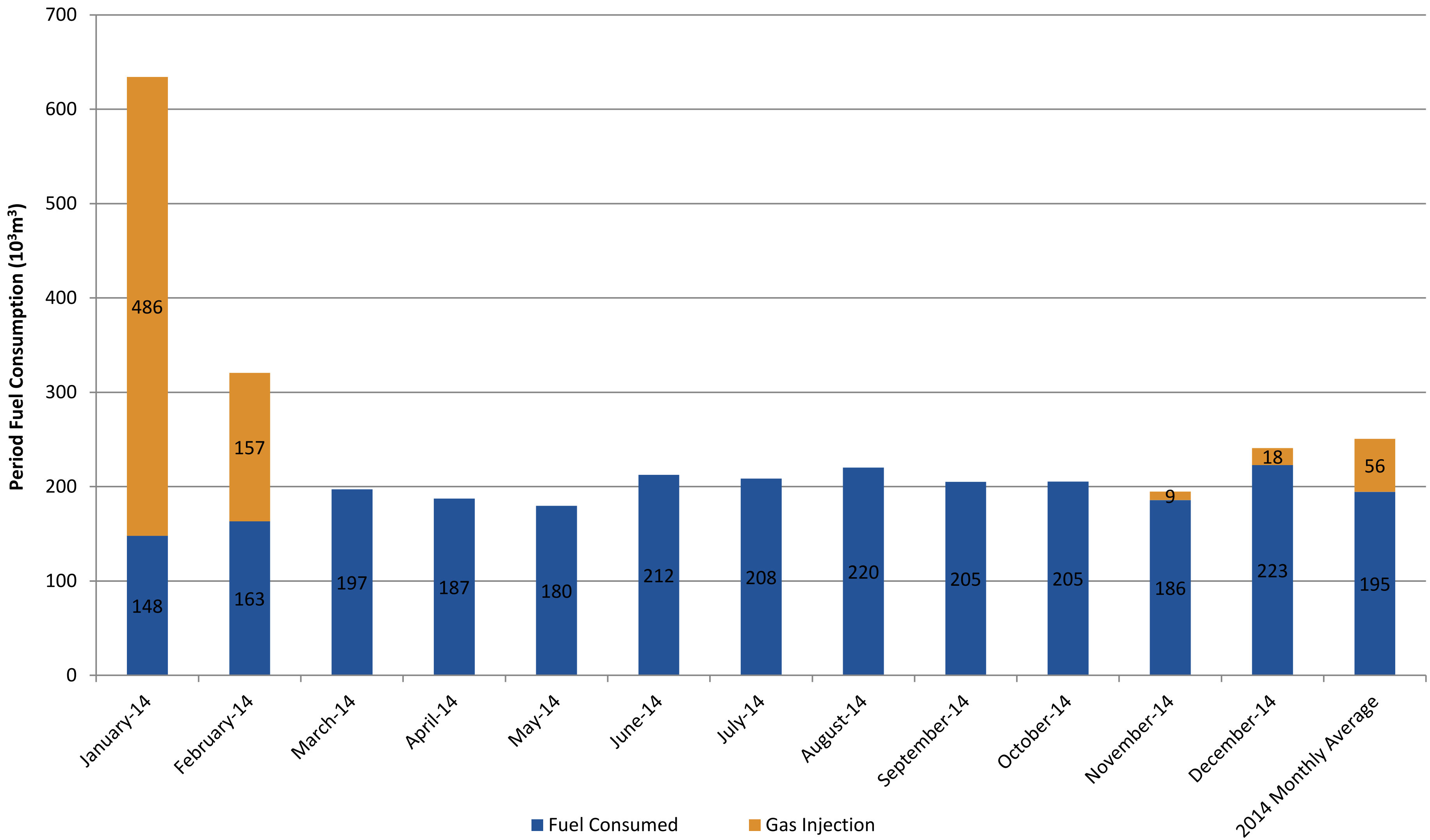
Generally stable and predictable battery performance

- Well pumping for ~162 days in 2014.
- Tubing production routed to separator.
- Solution gas is separated and sent to flare.
- Bitumen / water mix sent to production tanks.
- Emulsion trucked off site to sales.
- Submerged Combustion Evaporator operated to evaporate some of the produced water.
- Electrical power is generated on site.
- No steam generation.

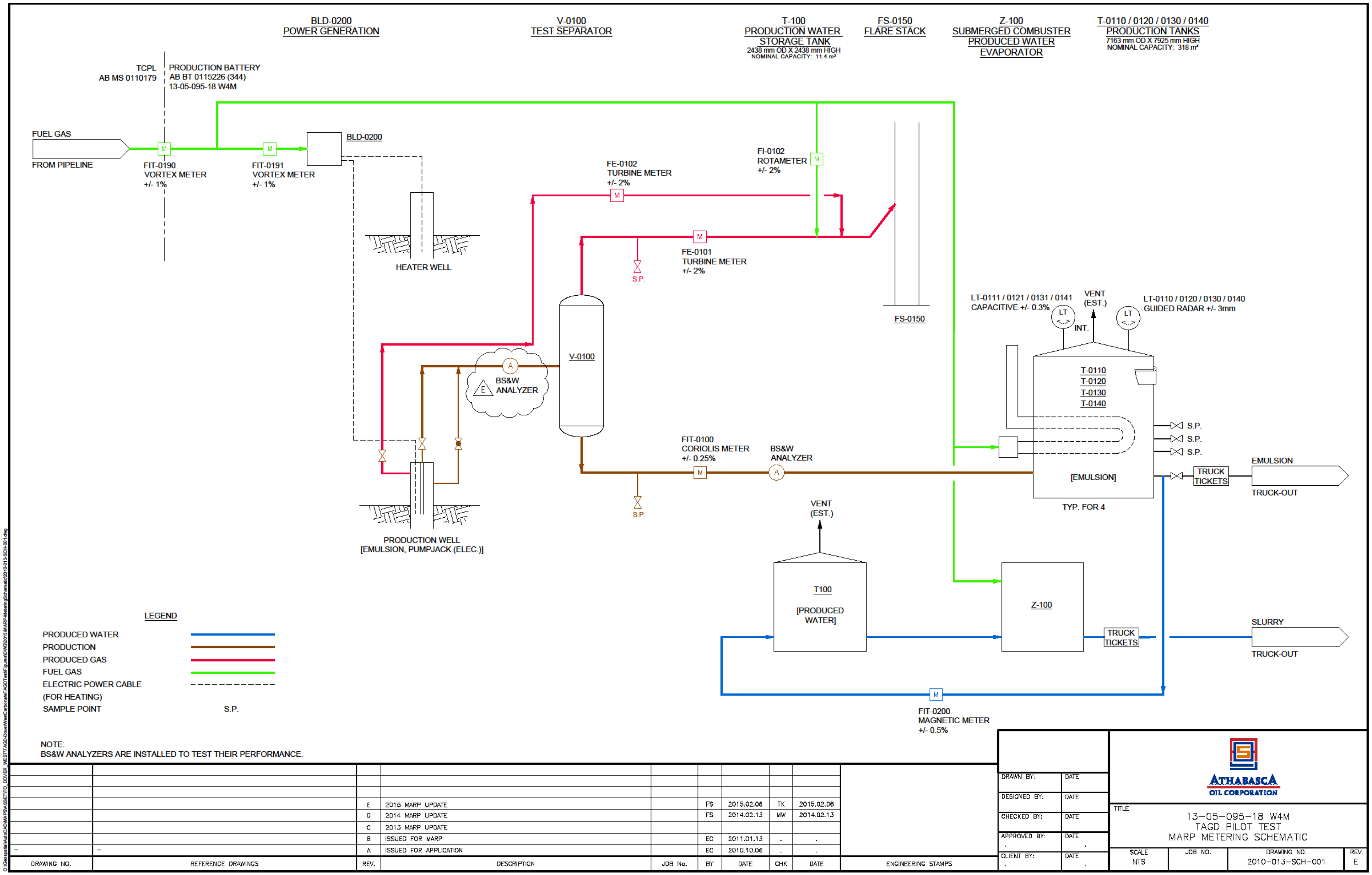
POWER CONSUMPTION



NATURAL GAS CONSUMPTION



APPROVED FIELD TEST METERING SCHEMATIC



PRODUCTION MEASUREMENT METHODOLOGY

No Changes to methodology

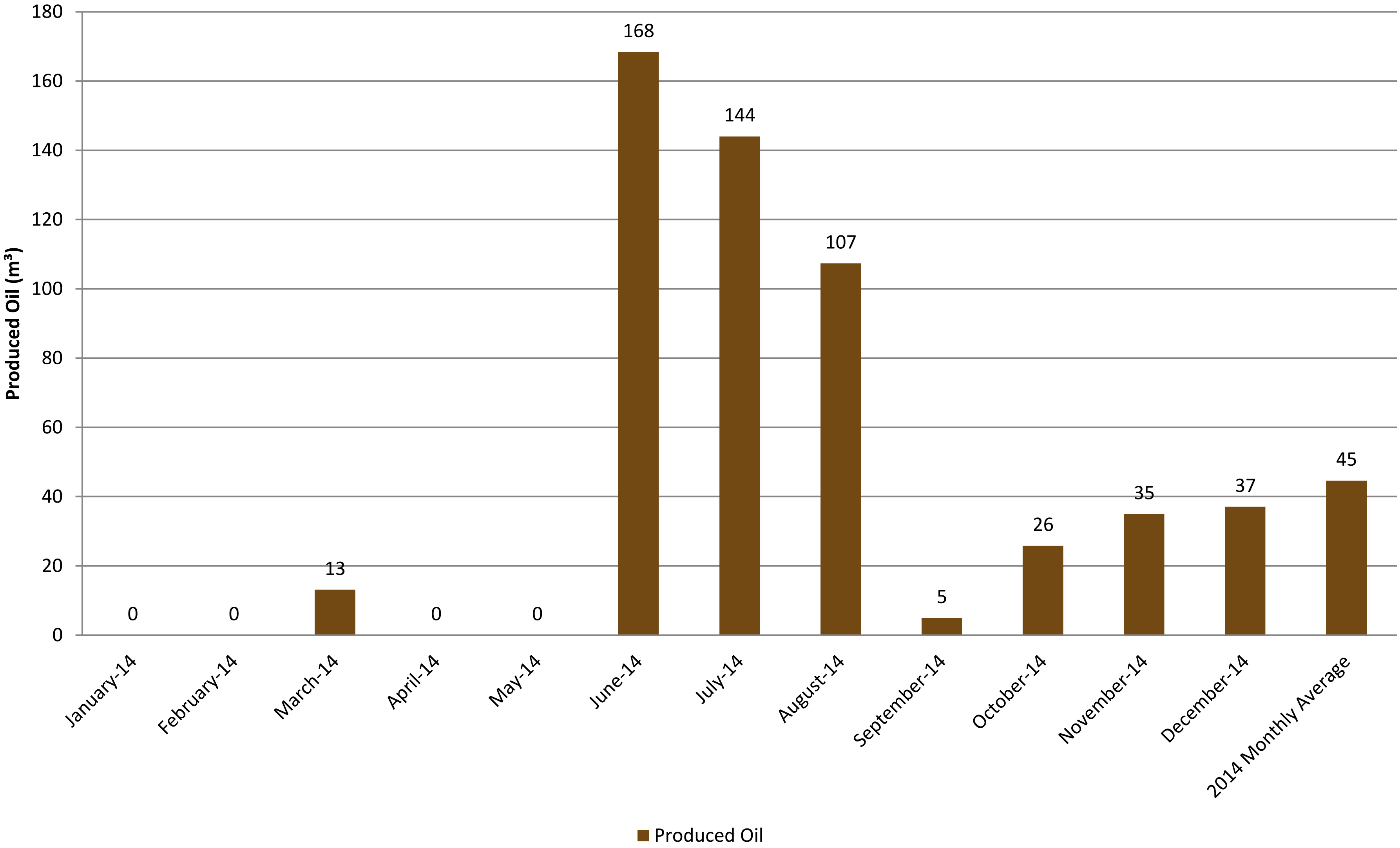
Bitumen and Water Production:

- Daily tank gauging and manual water cut measurements.
- Total fluid production meter FIT-0100 used as reference meter.
- Additional verification will be through trucking and third party processing.
- Evaluating new technologies: 2 Phase and 3 Phase BS&W analyzer.

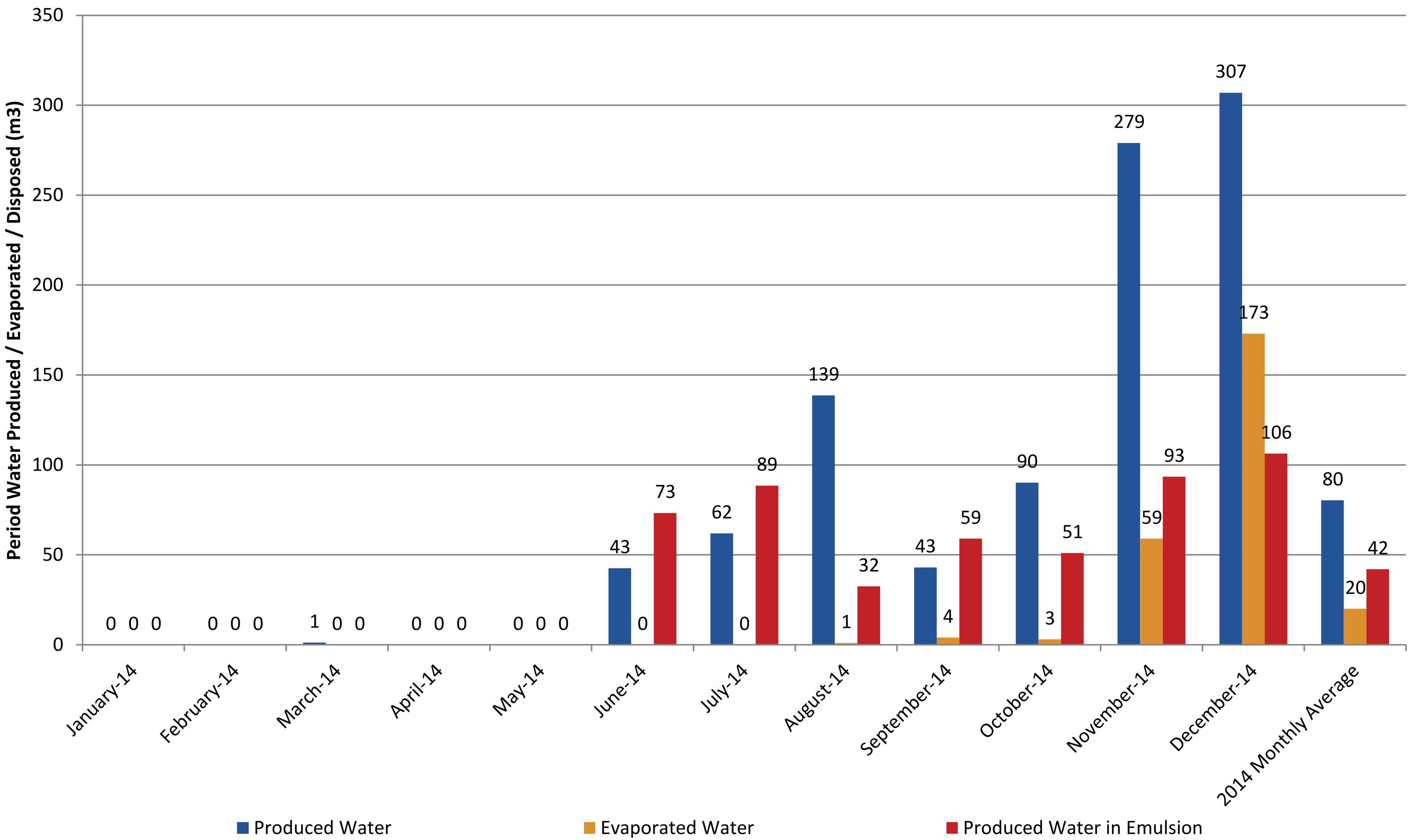
Gas Production:

- Solution gas measured from the produced gas meter at the separator.
- Casing gas measured from the produced gas meter on casing line.

PRODUCED OIL

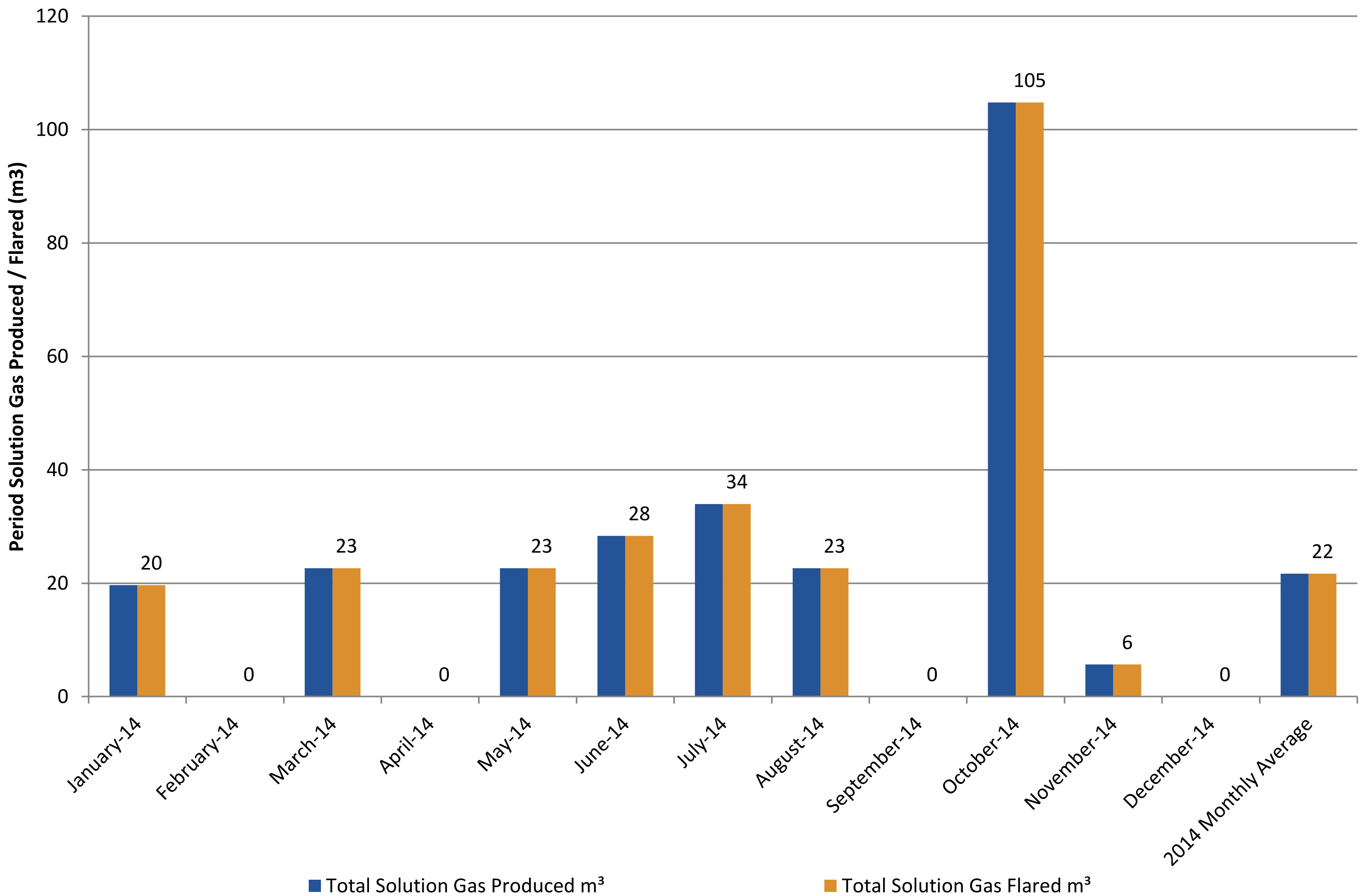


PRODUCED WATER MANAGEMENT



- Produced water was disposed through evaporation to atmosphere or was trucked with the emulsion.

PRODUCED GAS



GREENHOUSE GAS EMISSIONS

GHG emissions based on CAPP's "Calculating Greenhouse Gas Emissions" (April, 2003).

Detailed emissions calculation method used

Source	Total GHG Emissions, t CO_2e/y
Combustion	5,289
Flaring	1
Venting	0
Total	5,290

SULPHUR RECOVERY

- No Change
- The produced gas samples indicated no detectable H_2S.
- Sulphur recovery is not required for this test.

TAGD FIELD TEST COMPLIANCE

ATHABASCA
OIL CORPORATION

COMPLIANCE

AOC confirms compliance to:

Experimental Scheme Approval No. 11546E

EPEA Approval 298764-00-00

AOC has not started reclamation as the project is still active.

REGIONAL INITIATIVES

AOC is a funding member of the following:

- Oil Sands Community Alliance.
- Joint Oil Sands Monitoring Program (AEMERA).
- Wood Buffalo Environmental Association.
- Alberta Biodiversity Monitoring Institute.

PLANS

ATHABASCA OIL CORPORATION

FUTURE PLANS

AOC intends to continue operating the facility with the following objectives:

- Finish Production Cycle #4
- Possibly begin Cycle #5
- Operate heaters at highest power ever
- Understand impact of gas injection
- Understand water mobility in the Leduc Formation

AOC has received approval to construct a TAGD Pilot:

- Approval 11546D received from AER on September 19, 2013
- Approval for the MARP received from AER on December 10, 2013
- EPEA Approval 298764-00-00 received from AESRD on December 17, 2013

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