TAGD Field Test Update For AER

January 2015 to December 2015

Presented 2016-04-04

ATHABASCA OIL CORPORATION

INTRODUCTION

DOVER WEST LEDUC ASSET

TAGD PROCESS

TAGD FIELD TEST

- Introduction
- Subsurface
- Surface
- Compliance

PLANS

Dover West Leduc Asset

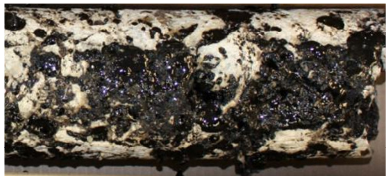
Athabasca Oil Corporation

THE LEDUC CARBONATE

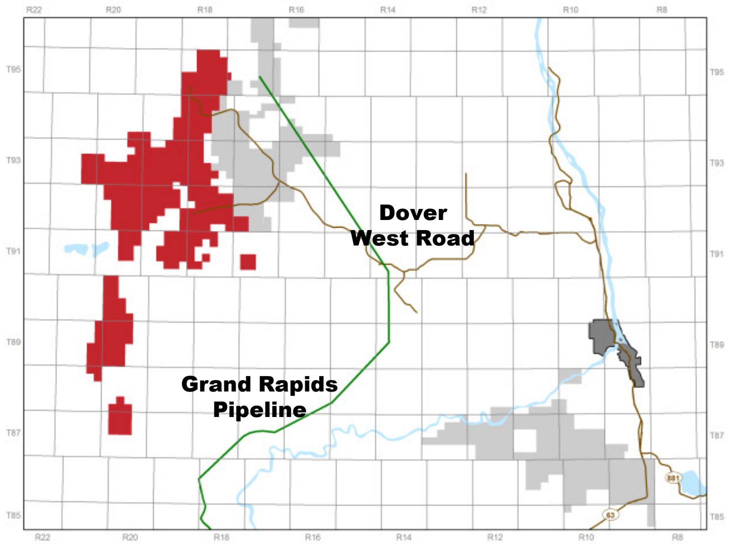
OPPORTUNITY

- 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).
- Asset has potential for > 350 000 bbl/d[2], based on TAGD.

Dover West Leduc



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

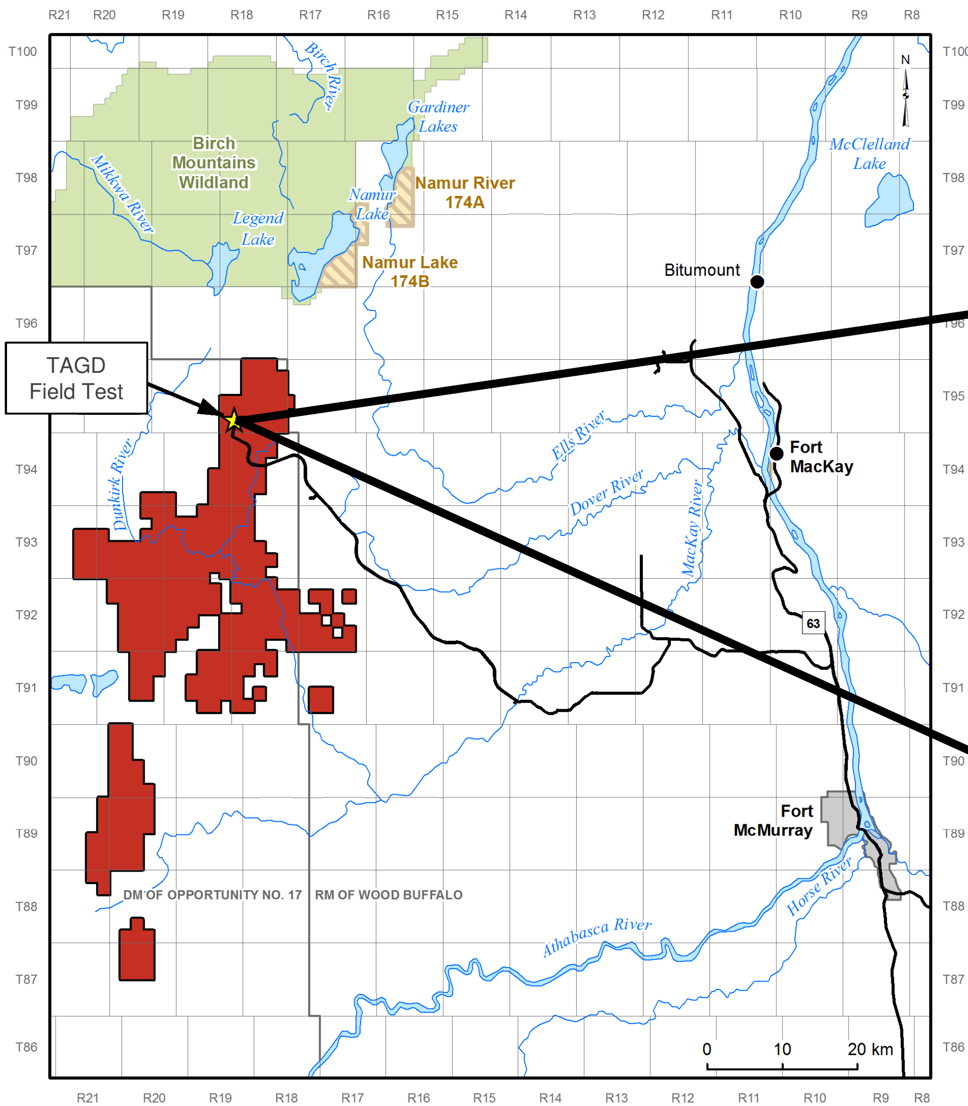


	Leduc Light Oil	Dover West Leduc
Average Porosity	5%	15%
Average Permeability	1 000 mD	>3 000 mD
Recovery Factor	70%	Estimated >50%

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

(2) Based on management estimate.

AREA MAP OF DOVER WEST



TAGD Process

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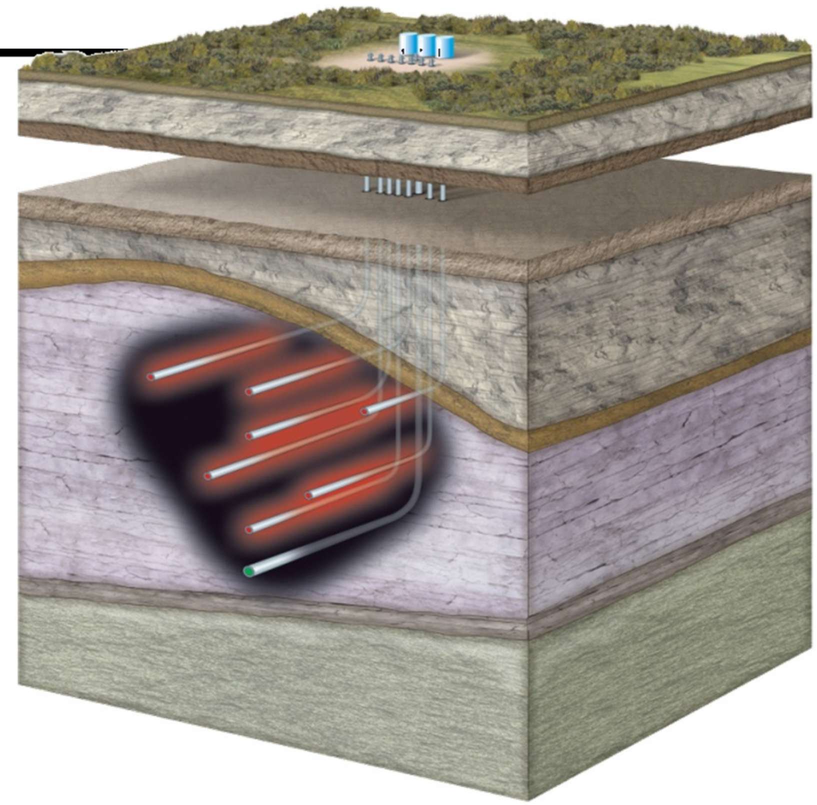
TAGD OVERVIEW



THERMAL ASSISTED GRAVITY DRAINAGE

An in situ recovery process, in which:

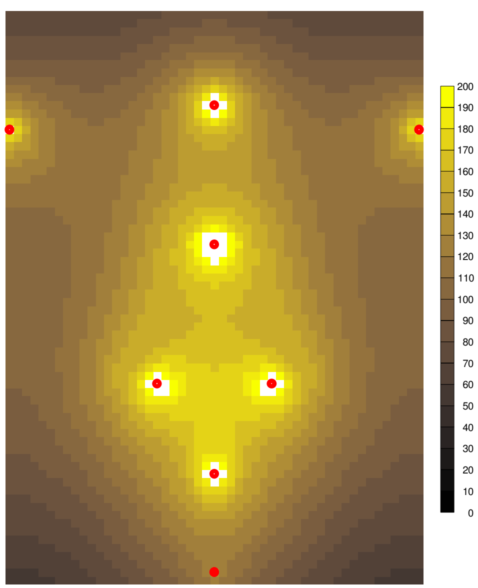
- The reservoir is heated using a pattern of horizontal heating wells.
- Sufficient temperature is reached such that bitumen will flow by gravity to production wells.

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.

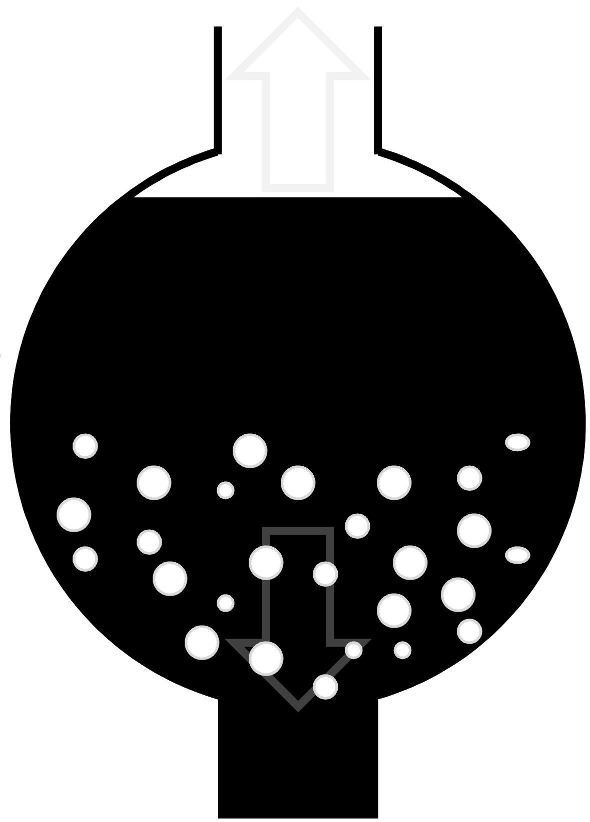
TAGD PROCESS – 3 KEY ELEMENTS

1. Conduction Heating



Heating reduces viscosity and mobilizes oil

2. Internal Drive

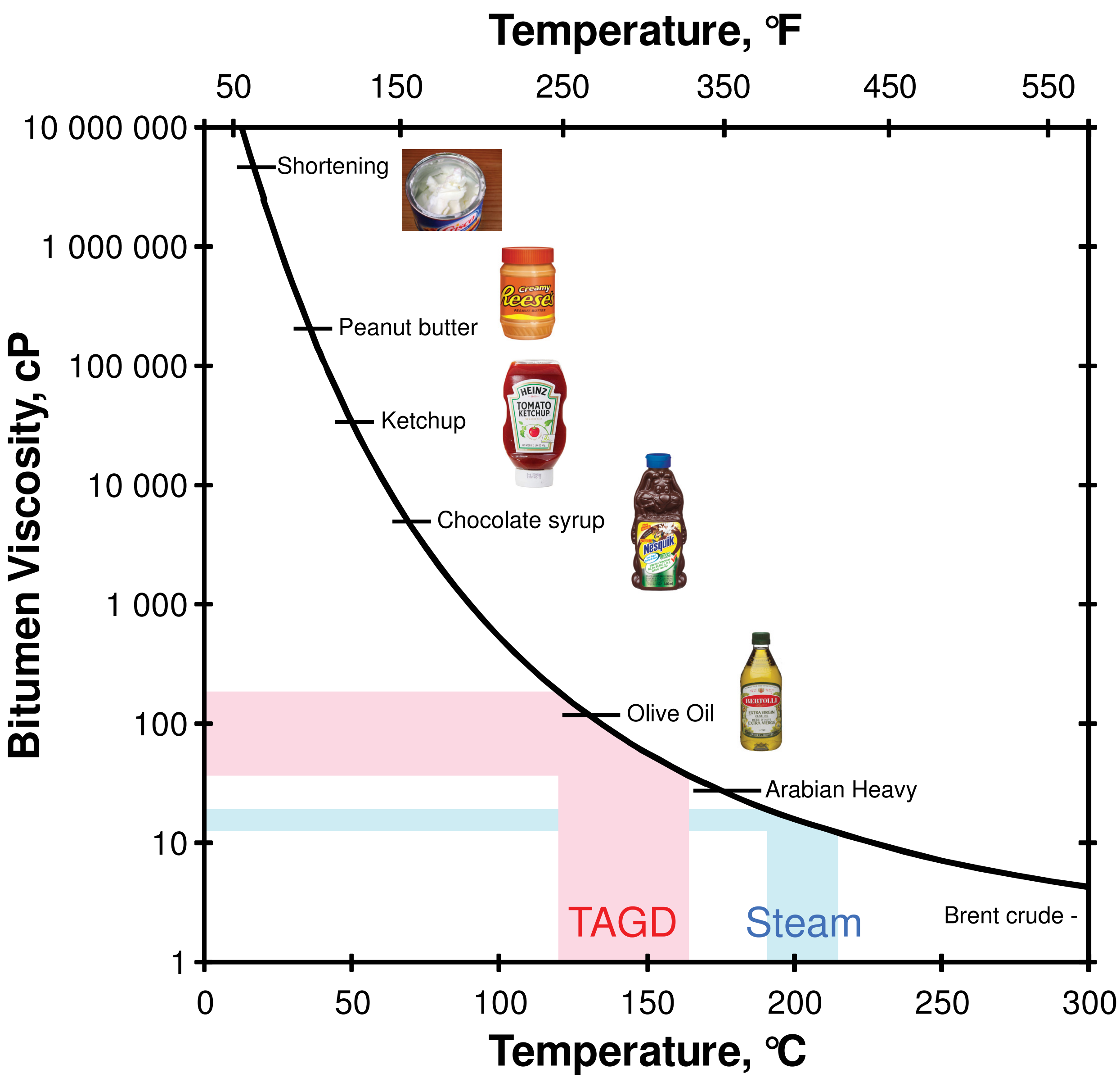


Internal drive replaces voidage

3. Gravity Drainage

Mobilized oil flows down by gravity

1: HEATING



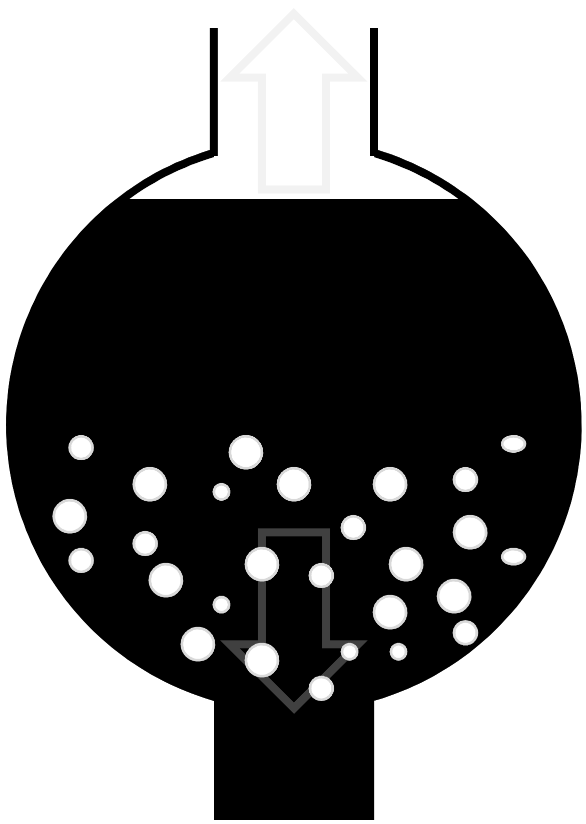
AOC Leduc

- Depth: ~280 m ASL
- Temperature: 12°C
- Pressure: 480 kPa
- Leduc viscosity@ 12°C: 13×10^6 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

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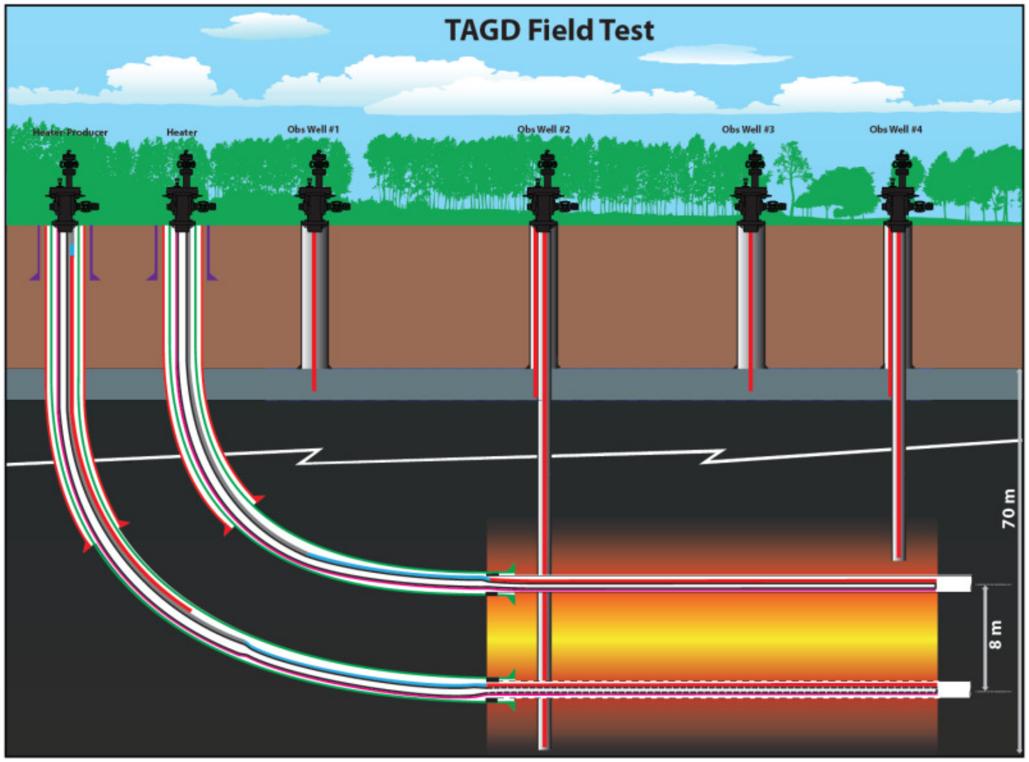
TAGD FIELD TEST



OBJECTIVES

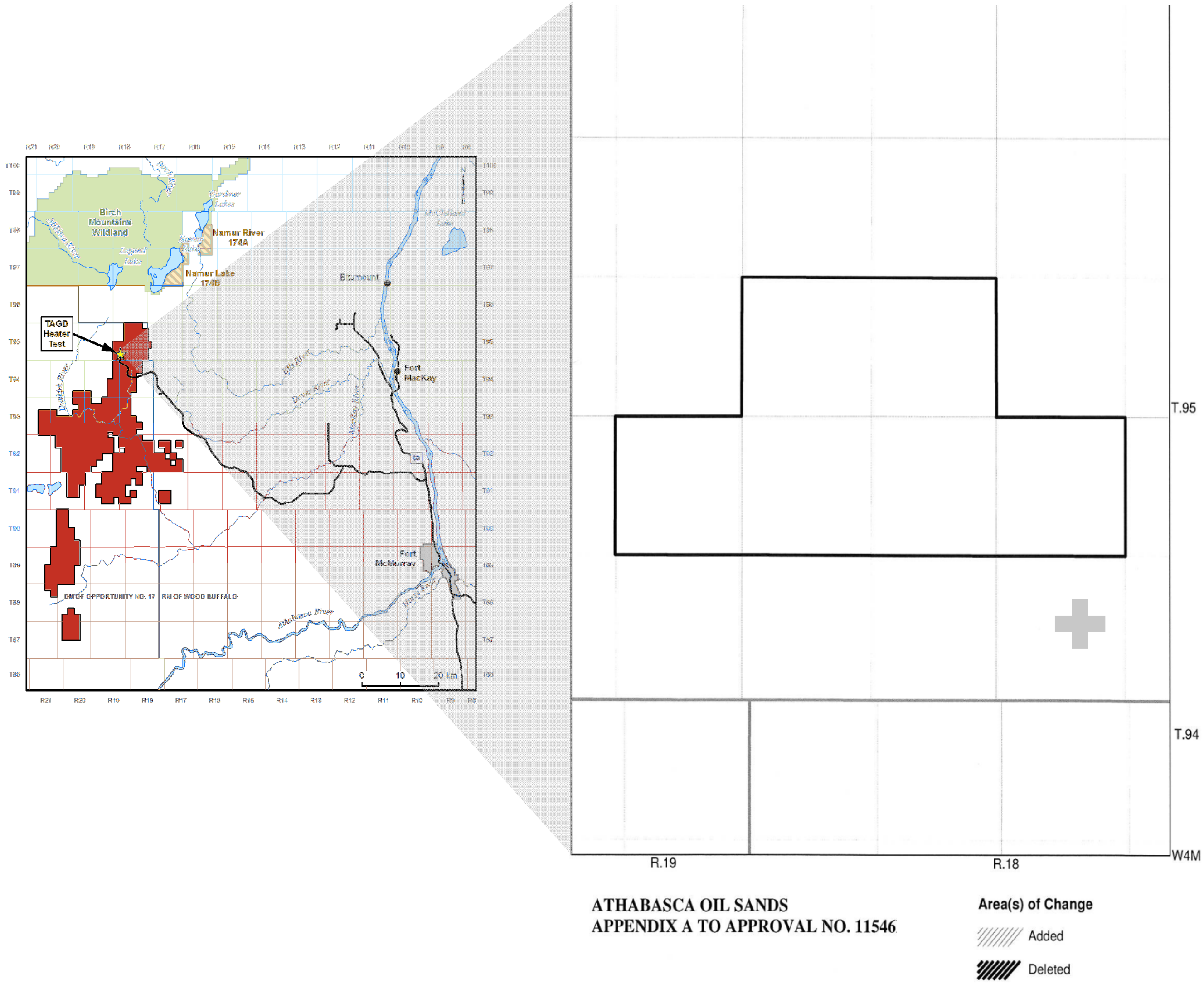
- Proof of TAGD concept.
- Drill horizontal wells in a fractured, vuggy carbonate.

SCOPE

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

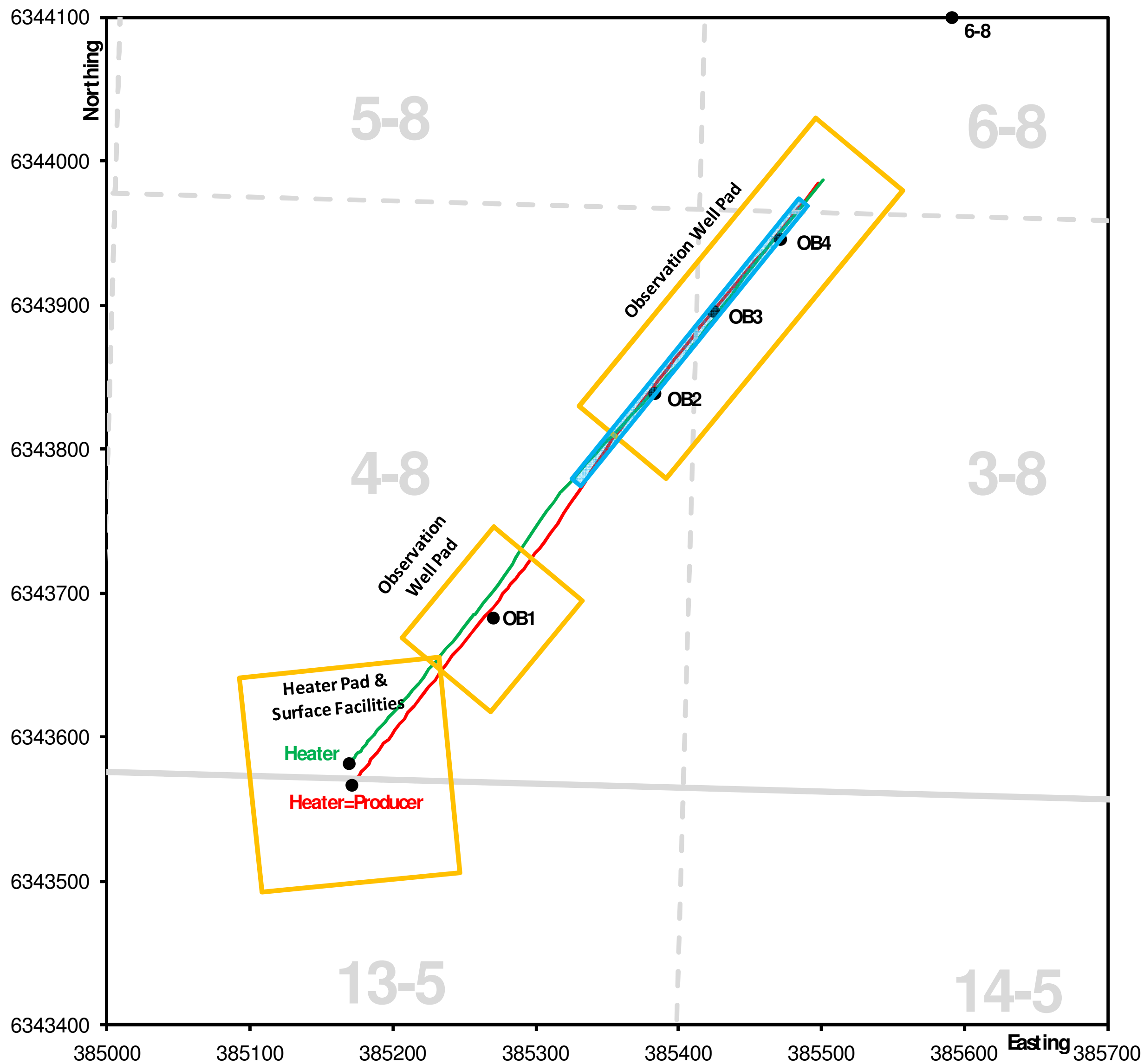
SCHEME MAP

- No change in 2015



TAGD FIELD TEST SURFACE AND SUBSURFACE LAYOUT

- No change in 2015



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
- January 2014 to February 2014 Conducted Gas Injection Test
- June 2014 Began Production Cycle #4
- December 2014 Began gas co-injection

2015 IN REVIEW

Production Cycle #4 **June 2014 to May 2015**

- Pumping between 2 m^3/d to 30 m^3/d of fluid.
- 798 m^3 of bitumen produced in Cycle #4.

Test Successfully Completed **September 2015**

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:

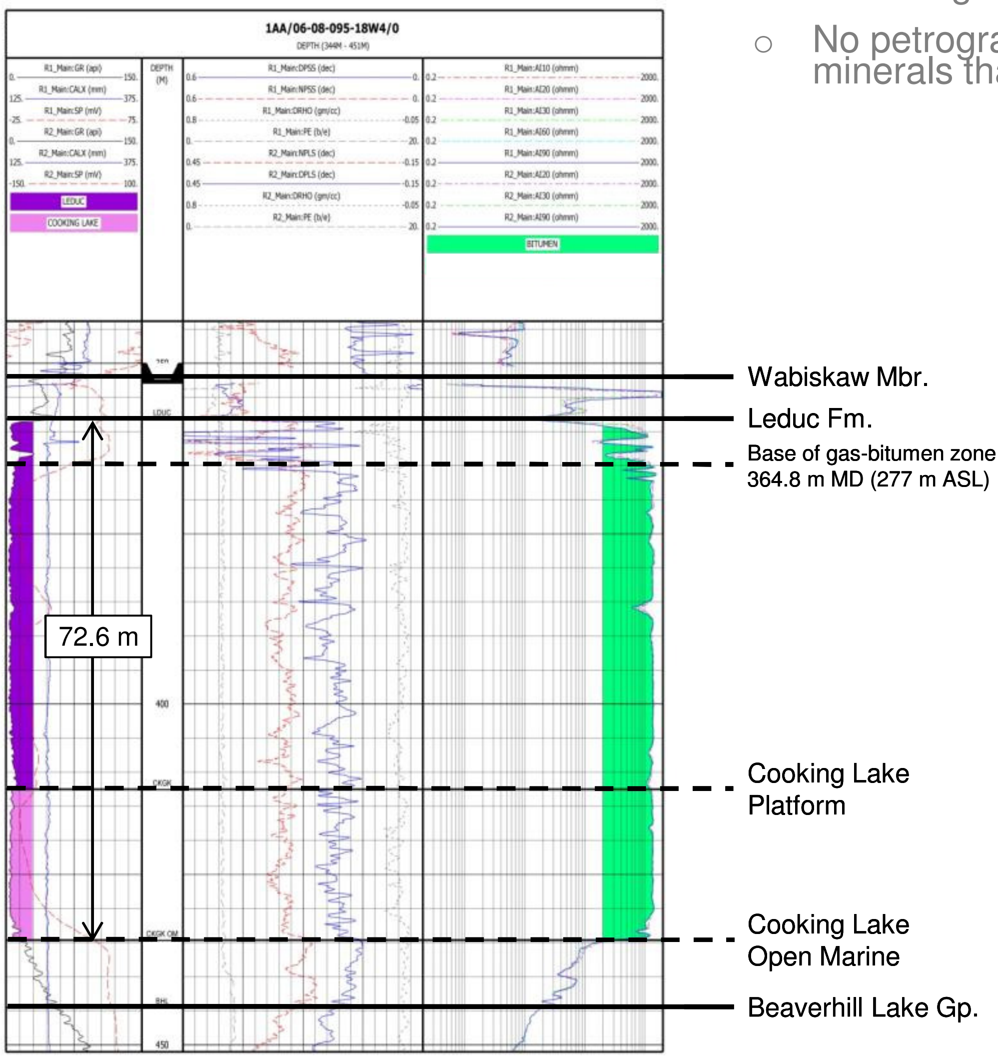
< 6% porosity

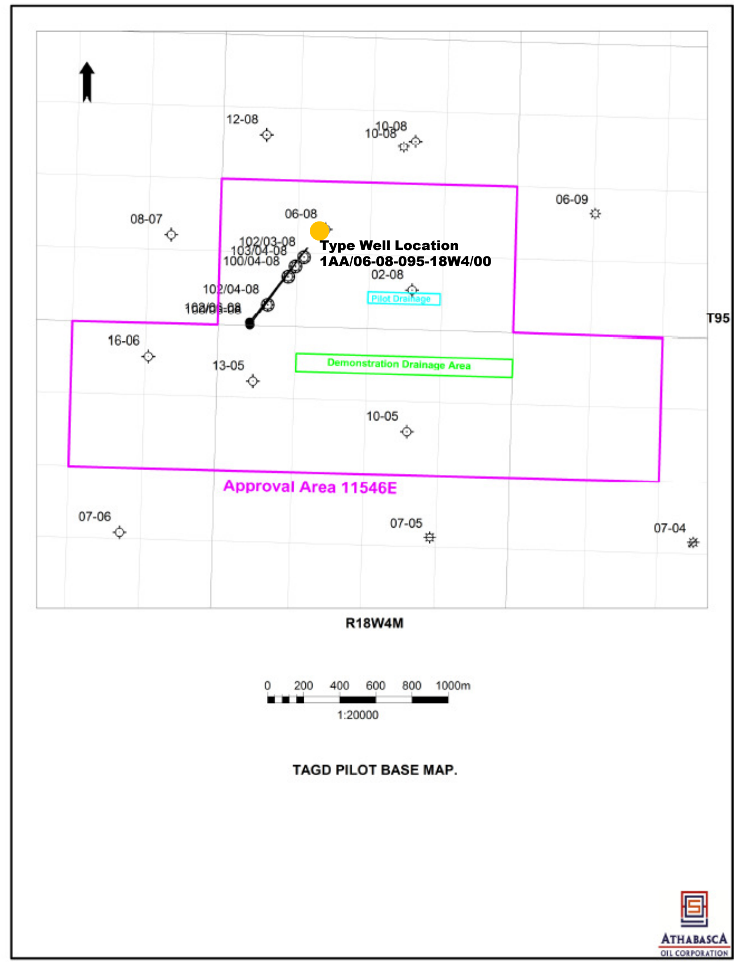
> 20% S_w

> 10% V_{shale}

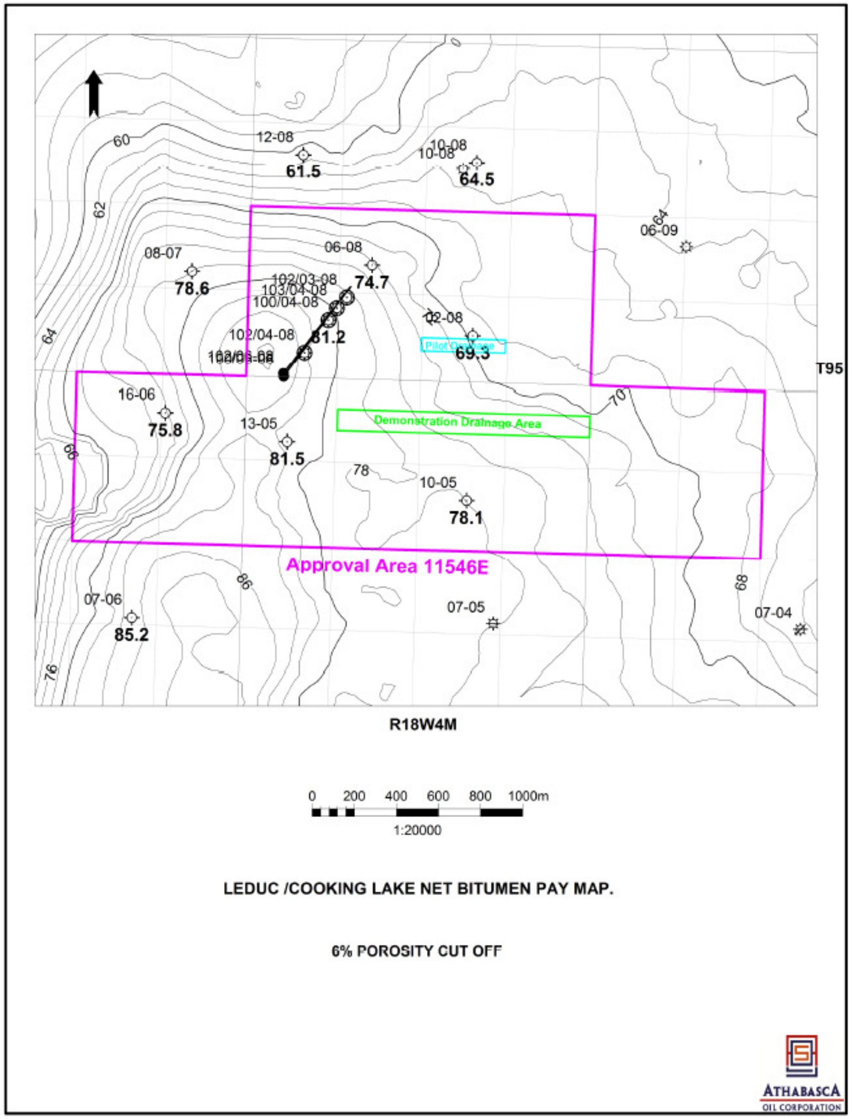
TYPE WELL LOG 1AA/06-08-095-18W4/0

- No change in 2015
- No petrographic analysis were completed to identify minerals that could impact the scheme recovery.



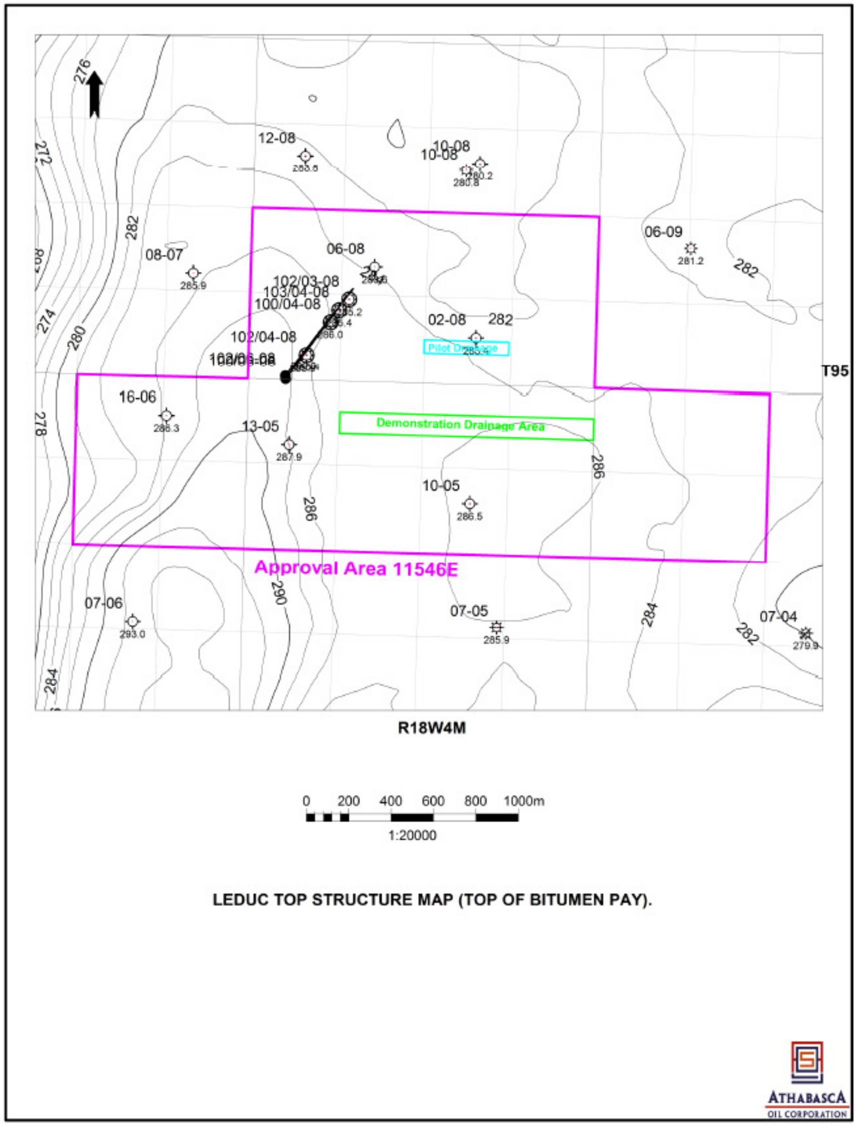


NET BITUMEN PAY MAP



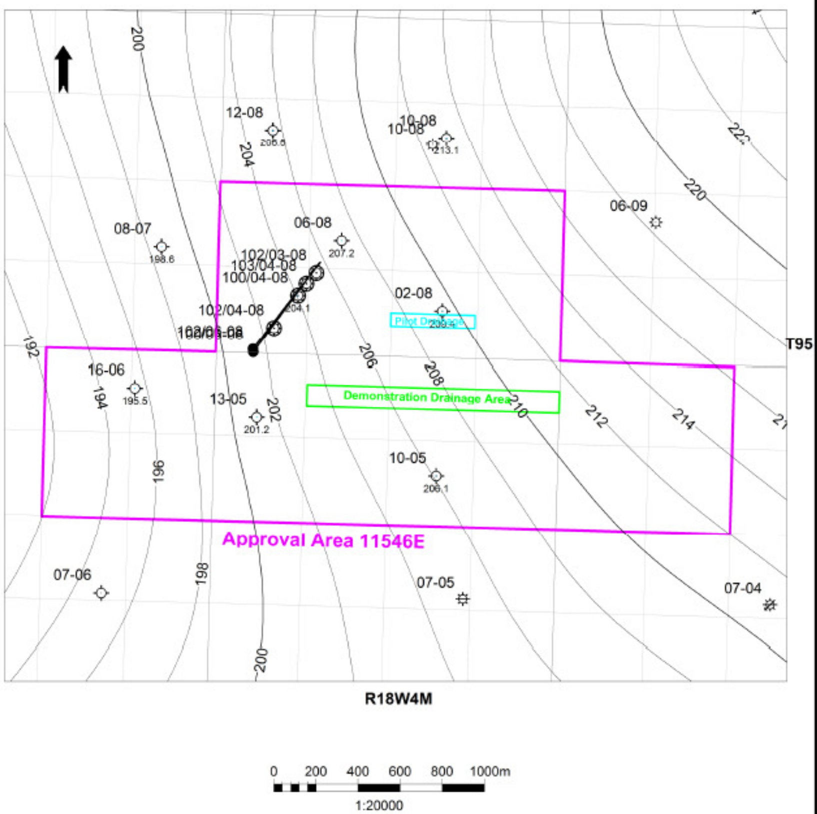
- No change in 2015
- Net pay ranges from 66 to 86 m in the approval area.

STRUCTURE MAP OF TOP OF BITUMEN PAY



- No change in 2015
- 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.

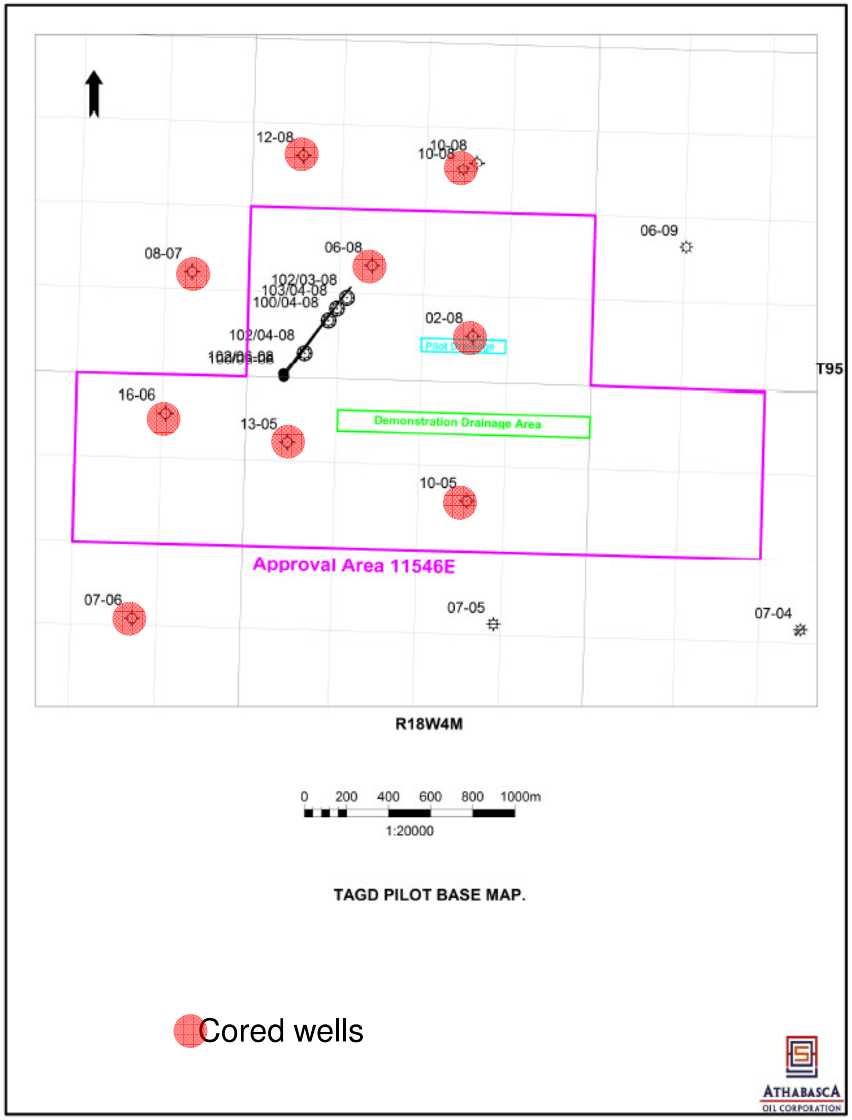
STRUCTURE MAP OF BASE OF BITUMEN PAY



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

- No change in 2015
- 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.

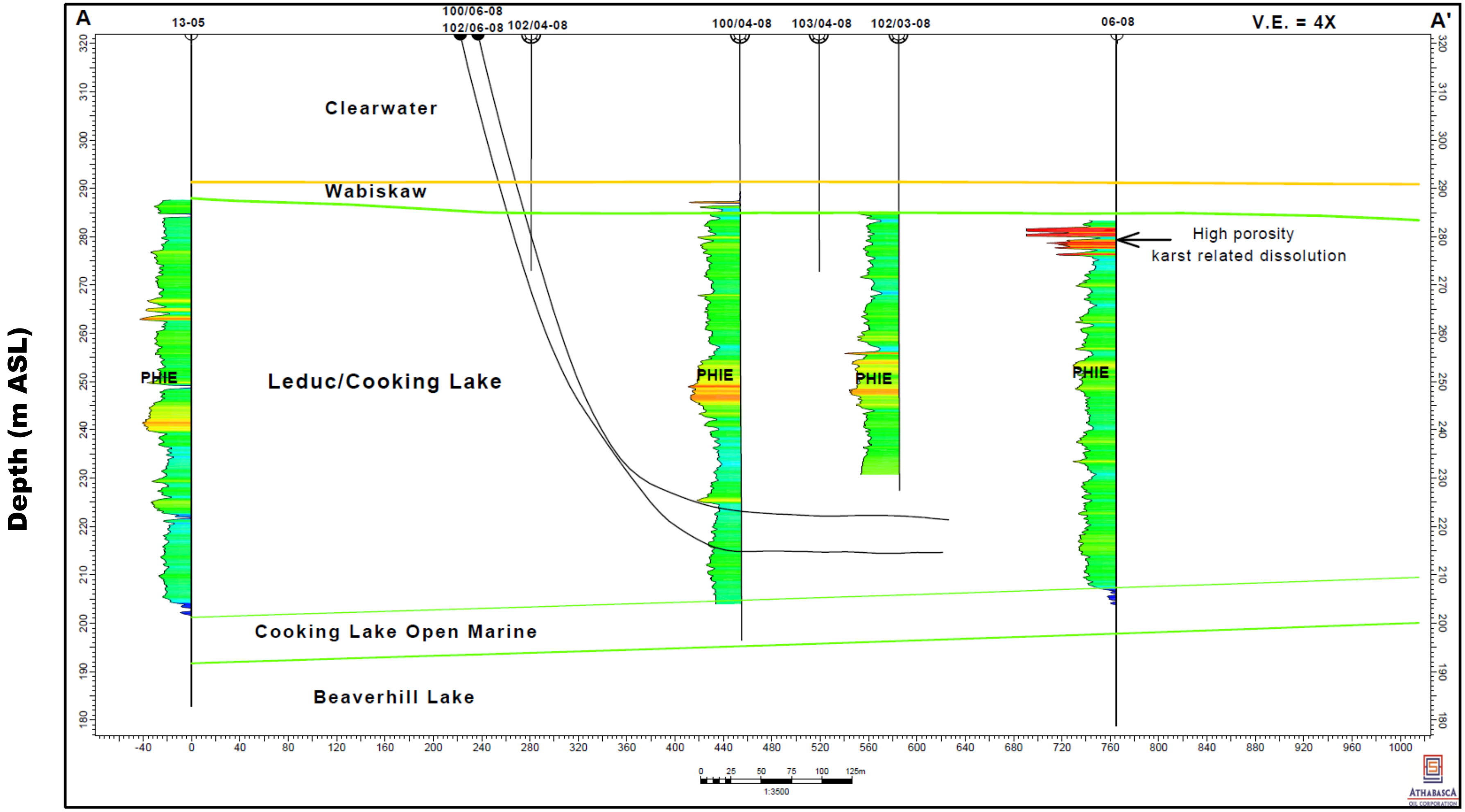
LOCATION OF CORED WELLS



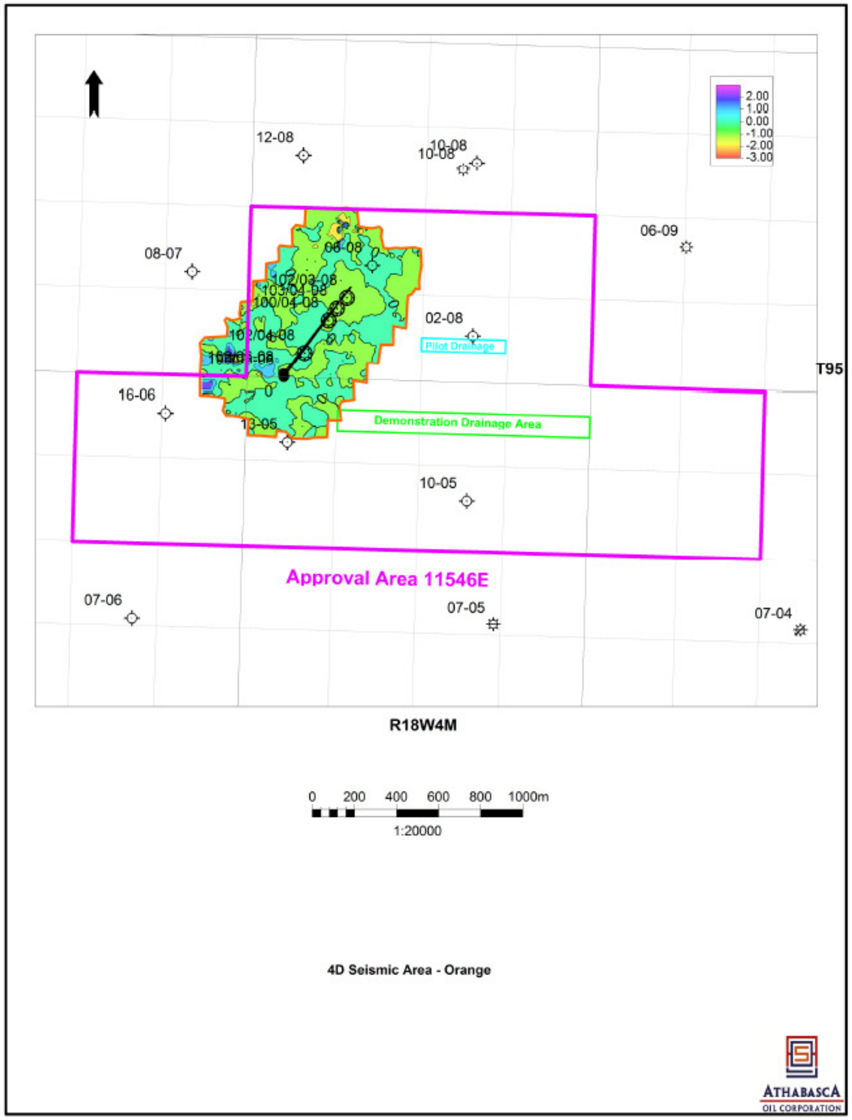
- No change in 2015
- There are five cored wells in the approval area including the type well 1AA/06-08-095-18W4/0.
- Adjacent wells around the approval area have been cored.
- Routine core analysis measured the porosity, bitumen saturation, and permeability (k_h, k_v, and k_{max}).
- Select cores have been CT scanned to understand the porosity-permeability relationship.

STRUCTURAL CROSS SECTION

- No change in 2015

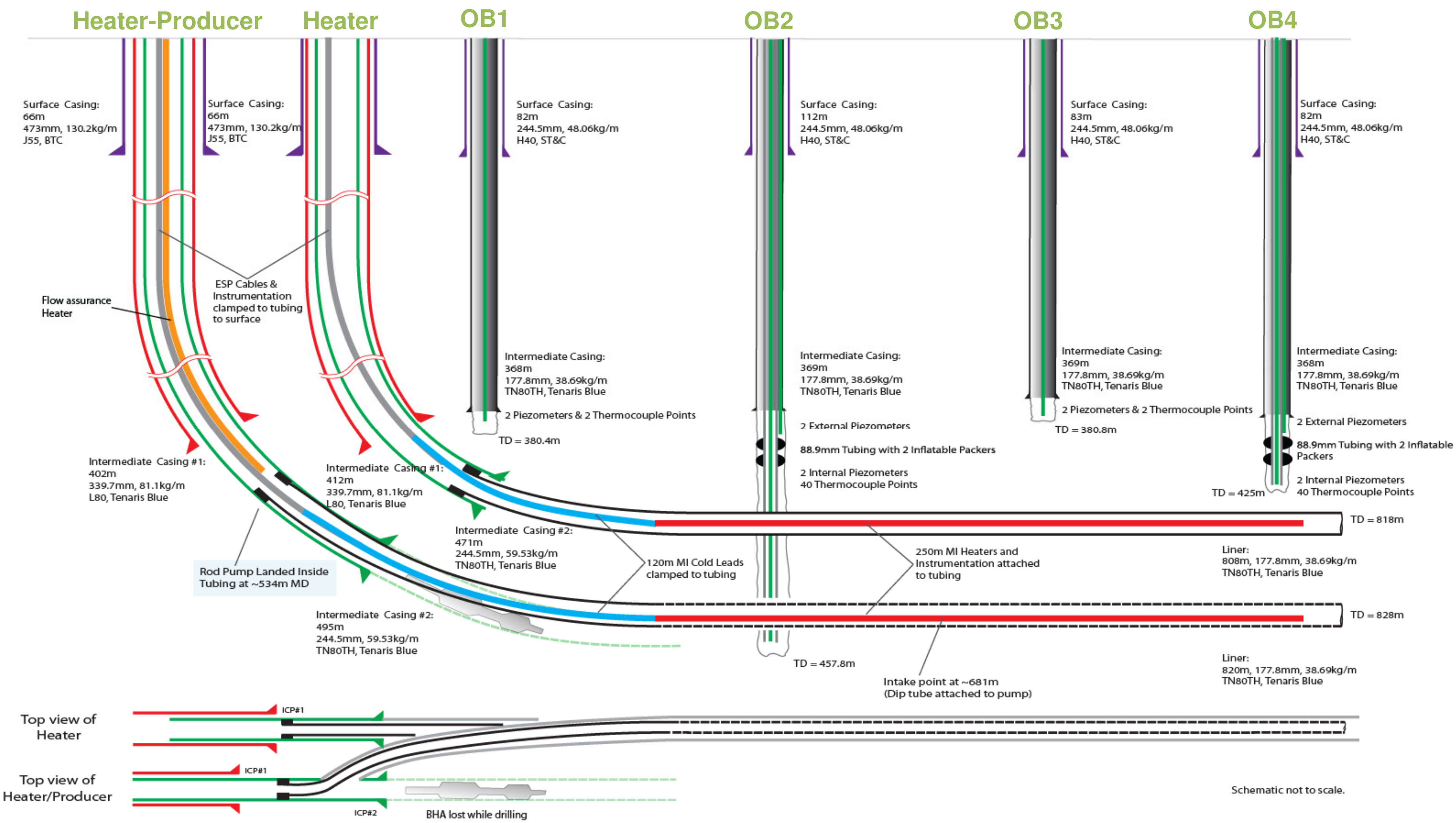


SEISMIC

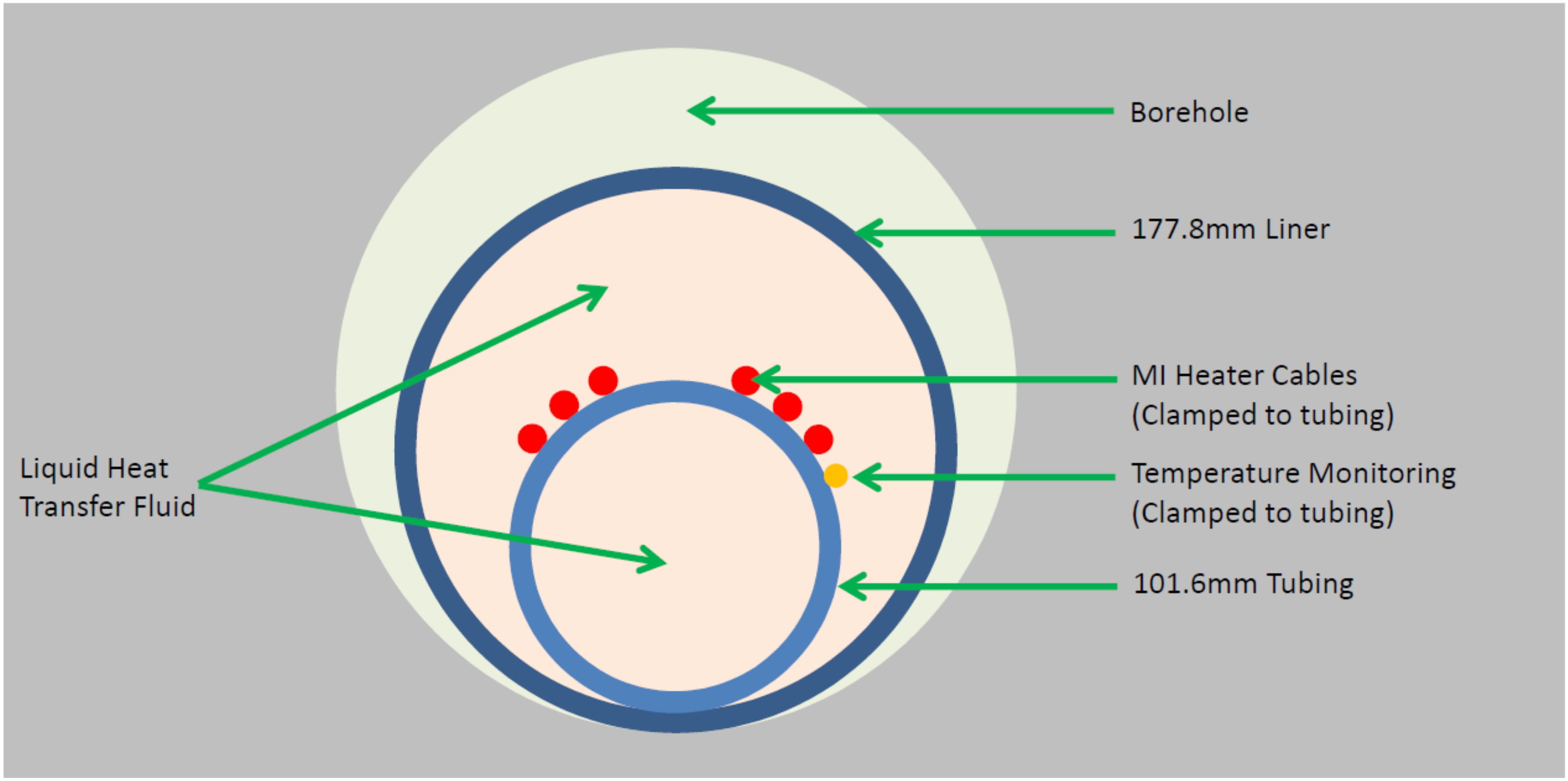


- No change in 2015
- 4D monitor survey acquired Q4 2012.
- 0.8 km^2 total area being monitored.
- Original 2010 survey being used as baseline.
- Time delay map of the Beaverhill Lake surface between the 4D monitor survey (2012) and original (2010) survey.
- Time delay results show no correlation to TAGD Field Test.

WELLBORE SCHEMATIC

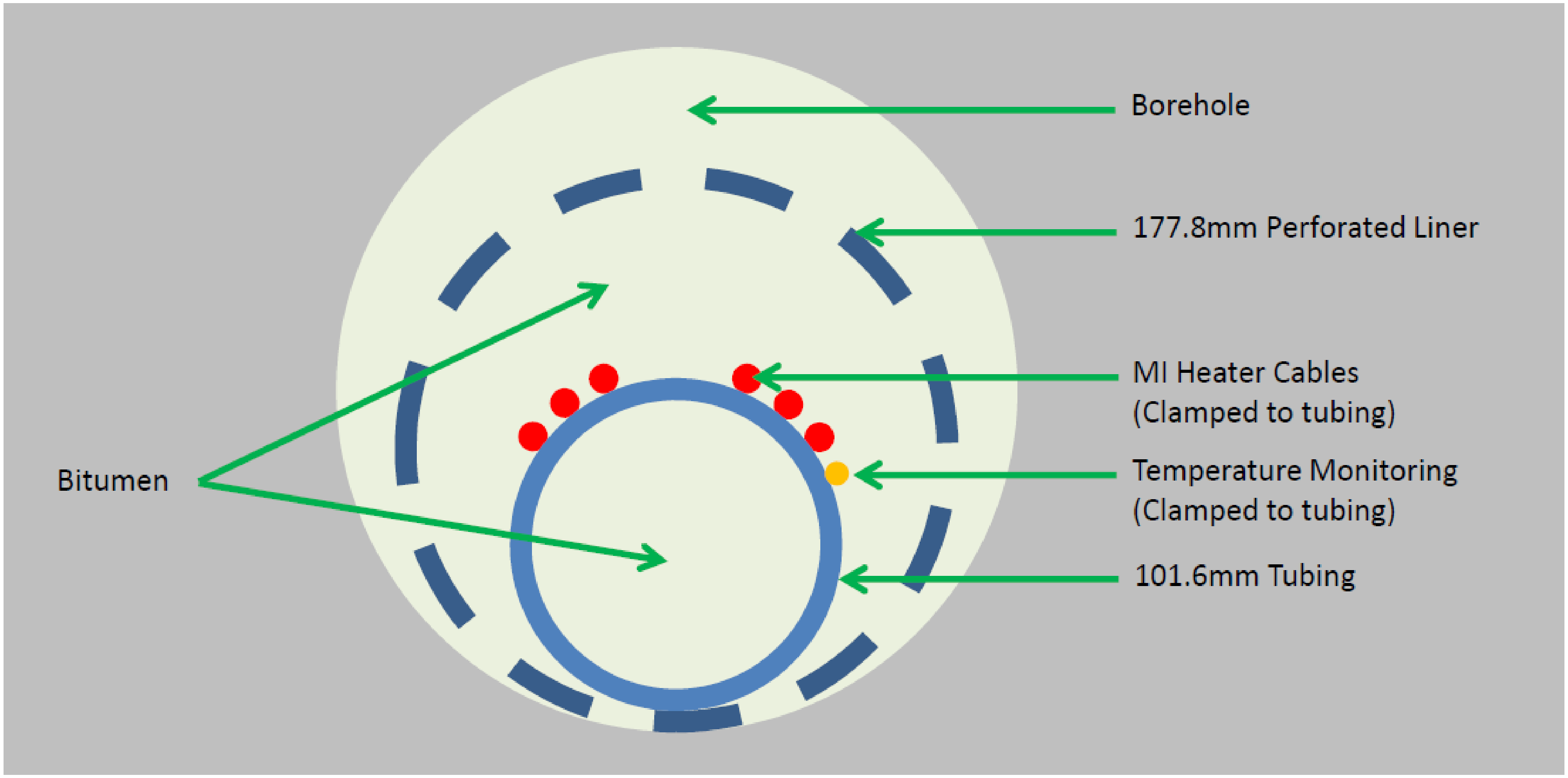


HEATER WELL COMPLETION



- No change in 2015

HEATER-PRODUCER WELL COMPLETION



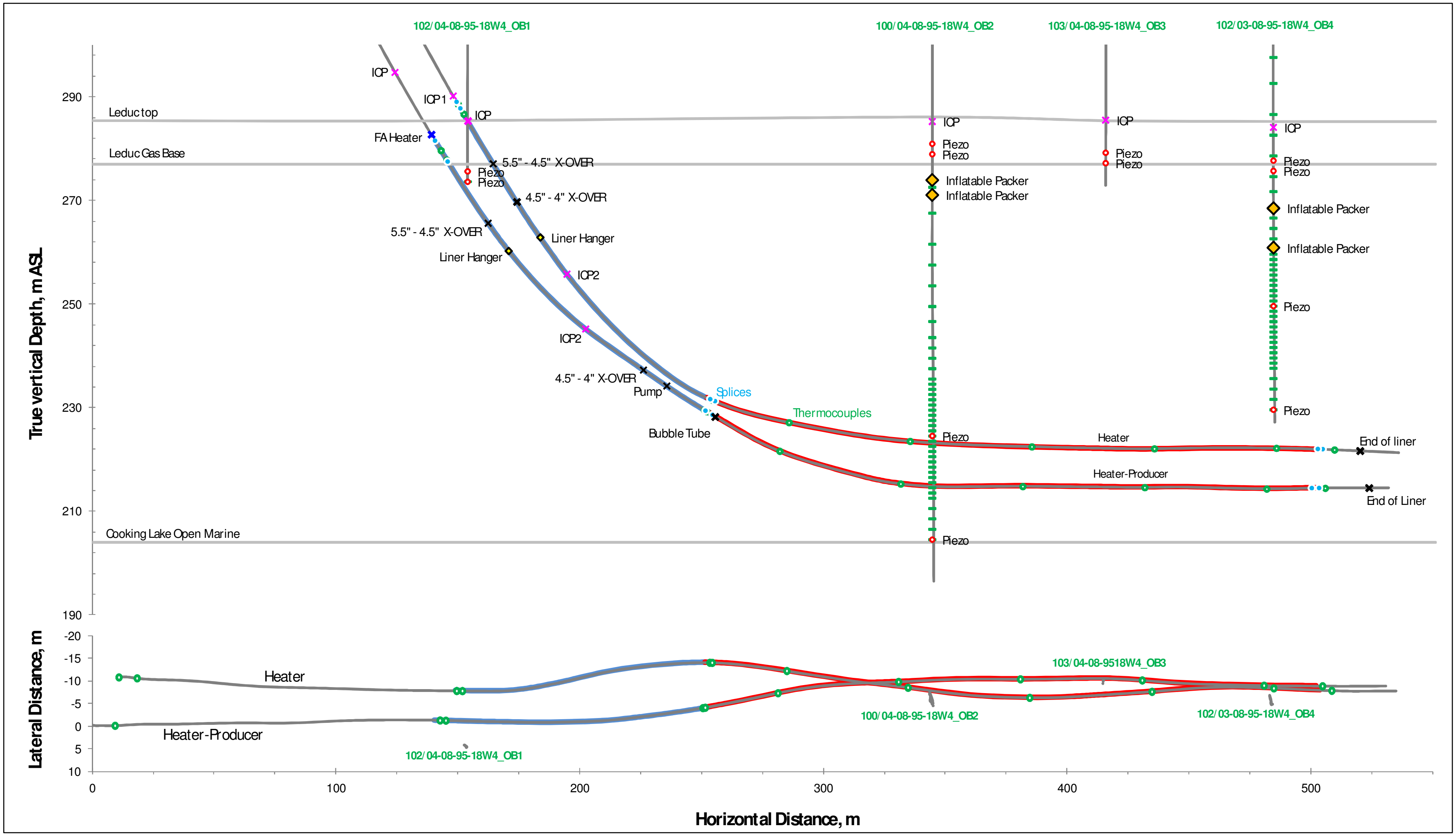
- Producer is heated to accelerate thermal communication between wells

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 30 m^3/d with new pump.
- flow assurance heater maintains 70℃ 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

INSTRUCTIONS 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.

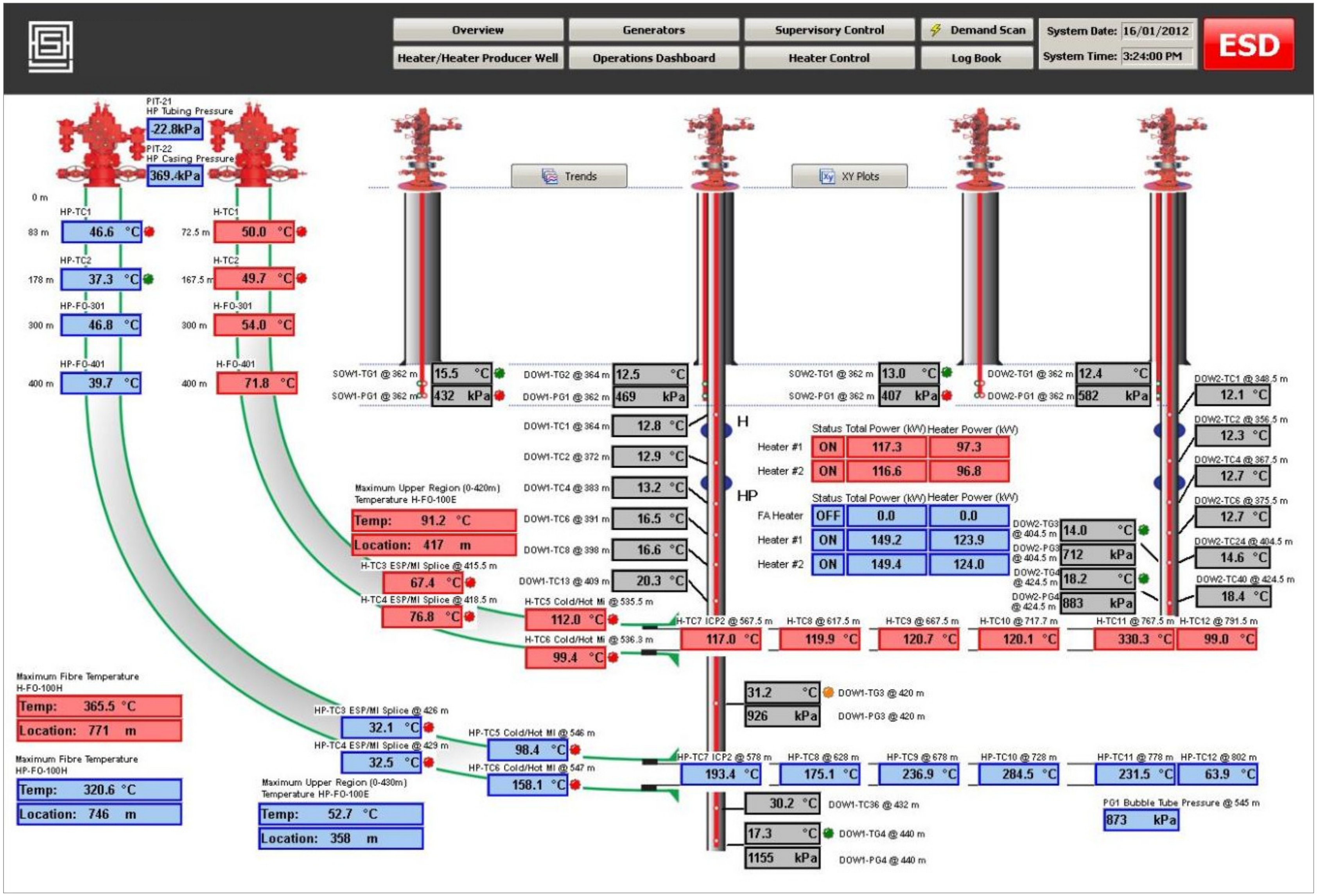
Heater-Producer Well

- 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

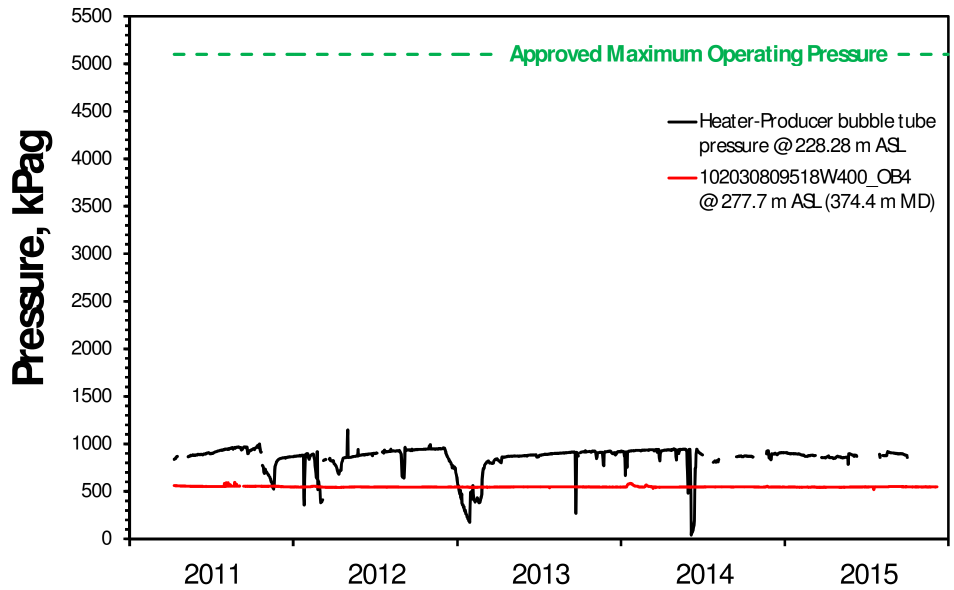
- Heating from January to September in Heater well and Heater-Producer well.

- Production Cycle #4 (June 2014 to May 2015).
  - Pumping from 2 to 30 m^3/d fluid

GEOMECHANICS

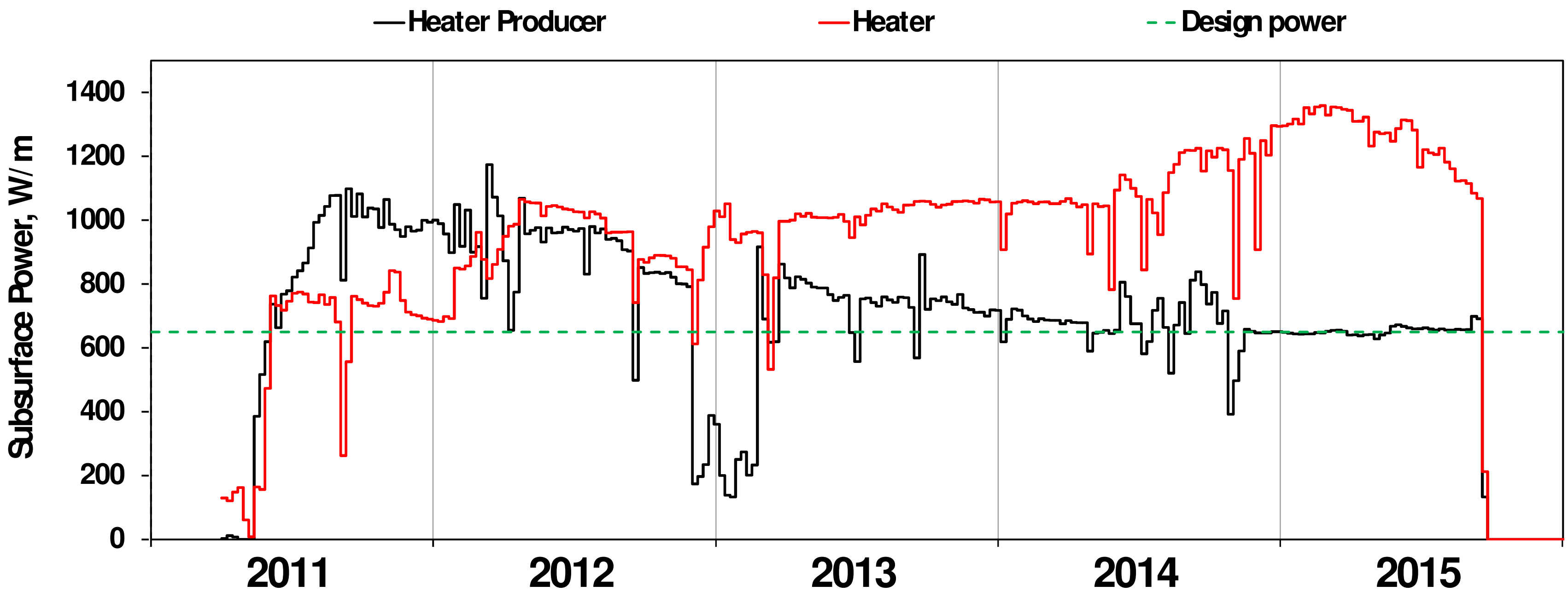
Year	Well	Formation	Depth (m)	Min Stress		Vertical Stress	
				MPa	kPa/m	MPa	kPa/m
2008	15-30-93-17W4	Clearwater	203	4.4	21.7	4.47	22.0
2008	15-30-93-17W4	Clearwater	194	4.24	21.9	4.27	22.0
Average					**21.8**		**22.0**
2010	15-26-95-17W4	Clearwater	277	5.7	20.6	5.9	21.3
2010	15-26-95-17W4	Clearwater	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)

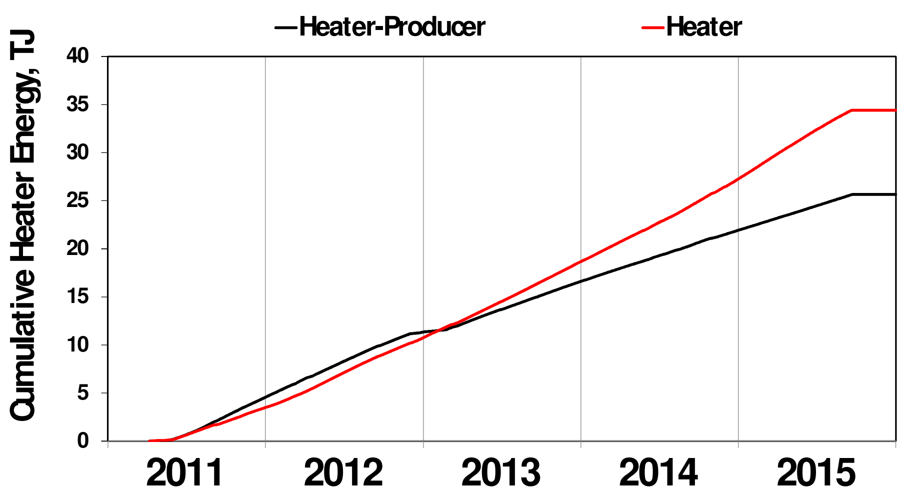


- At caprock depth of 340 m TVD, fracture pressure estimated to be 7 300 kPa (i.e. 21.5 kPa/m).
- Minor increase in pressure due to heating at producer; no change in pressure at observations wells in gas-bitumen zone.
- All observed pressures well below maximum operating pressure of 5 100 kPa as specified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

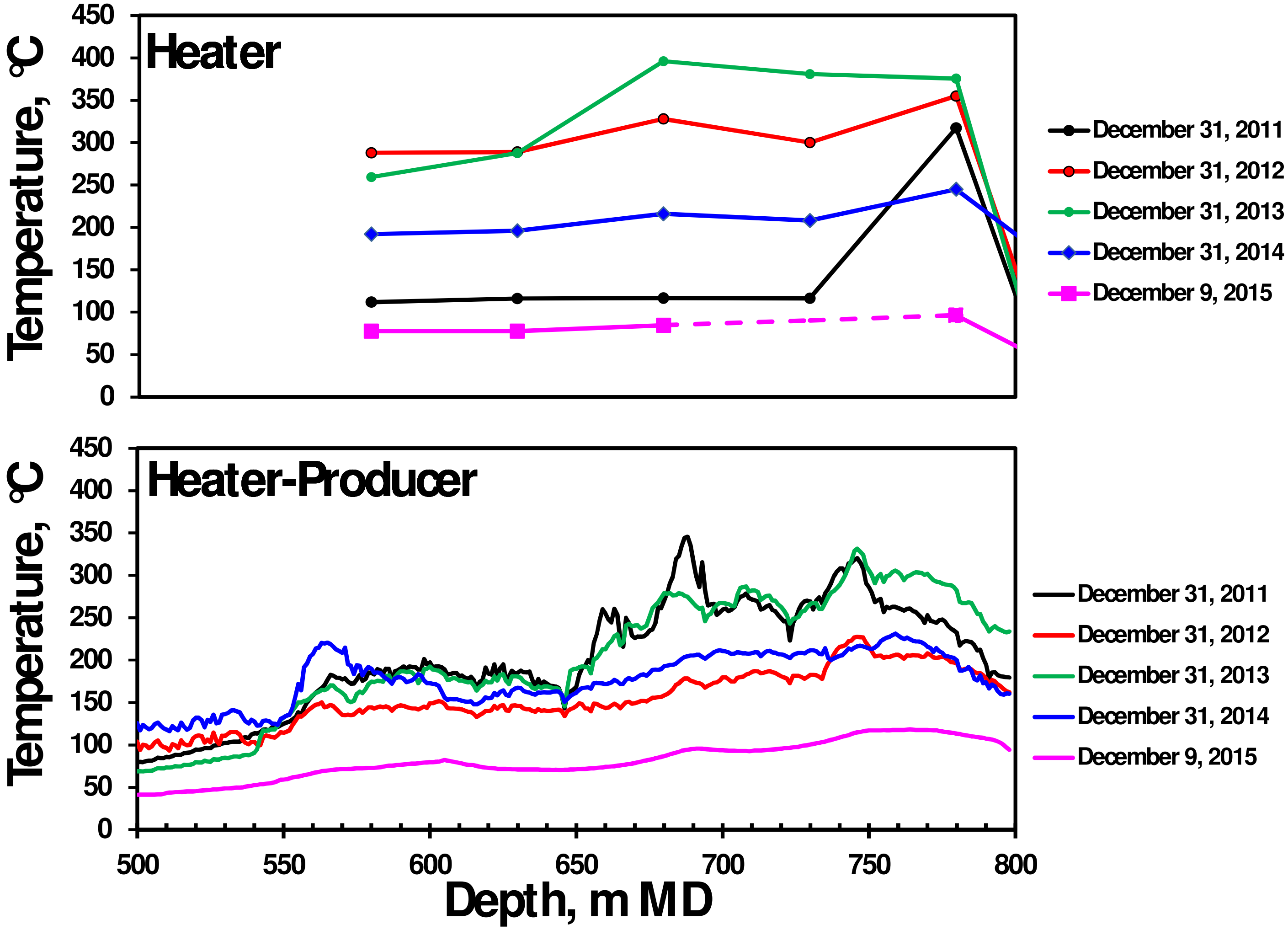
HEATING PERFORMANCE



- Heater running at full power.
- Heater producer limited by maximum temperature.

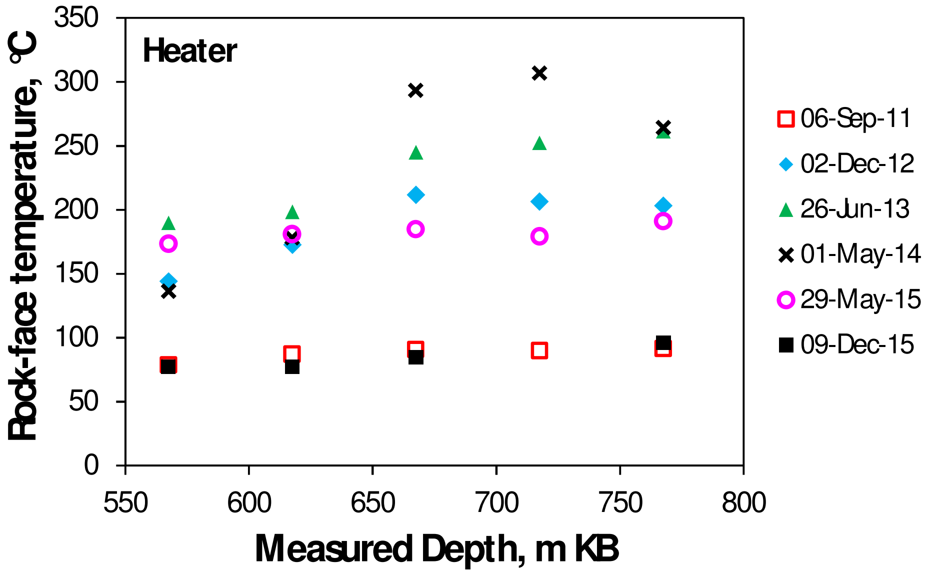


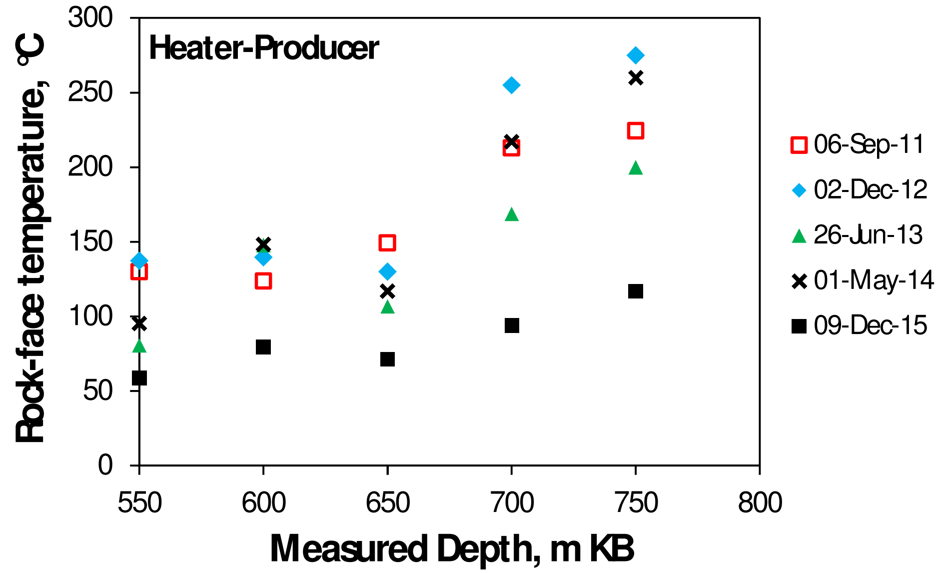
HEATING WELL TEMPERATURES



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

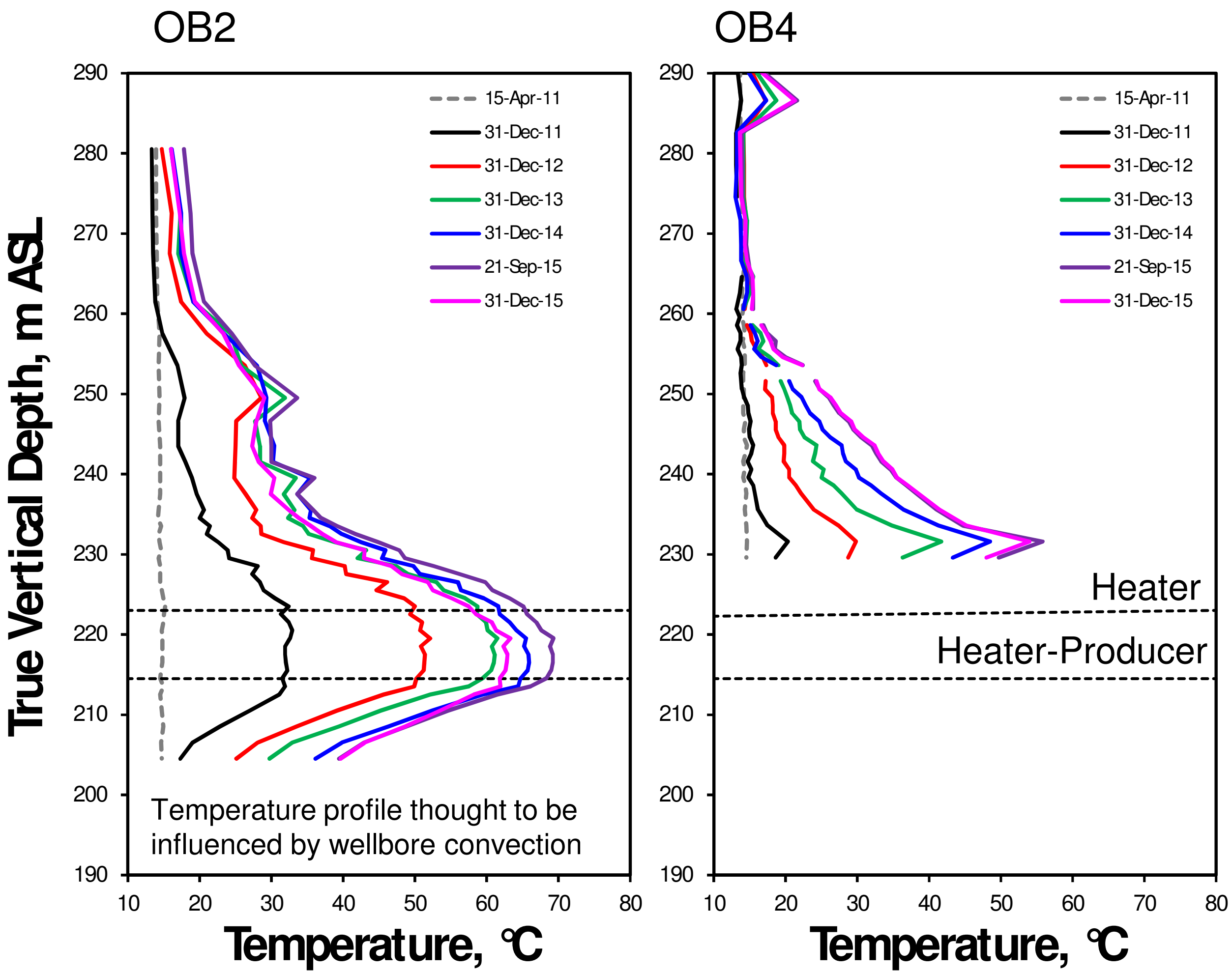
ROCK FACE TEMPERATURE





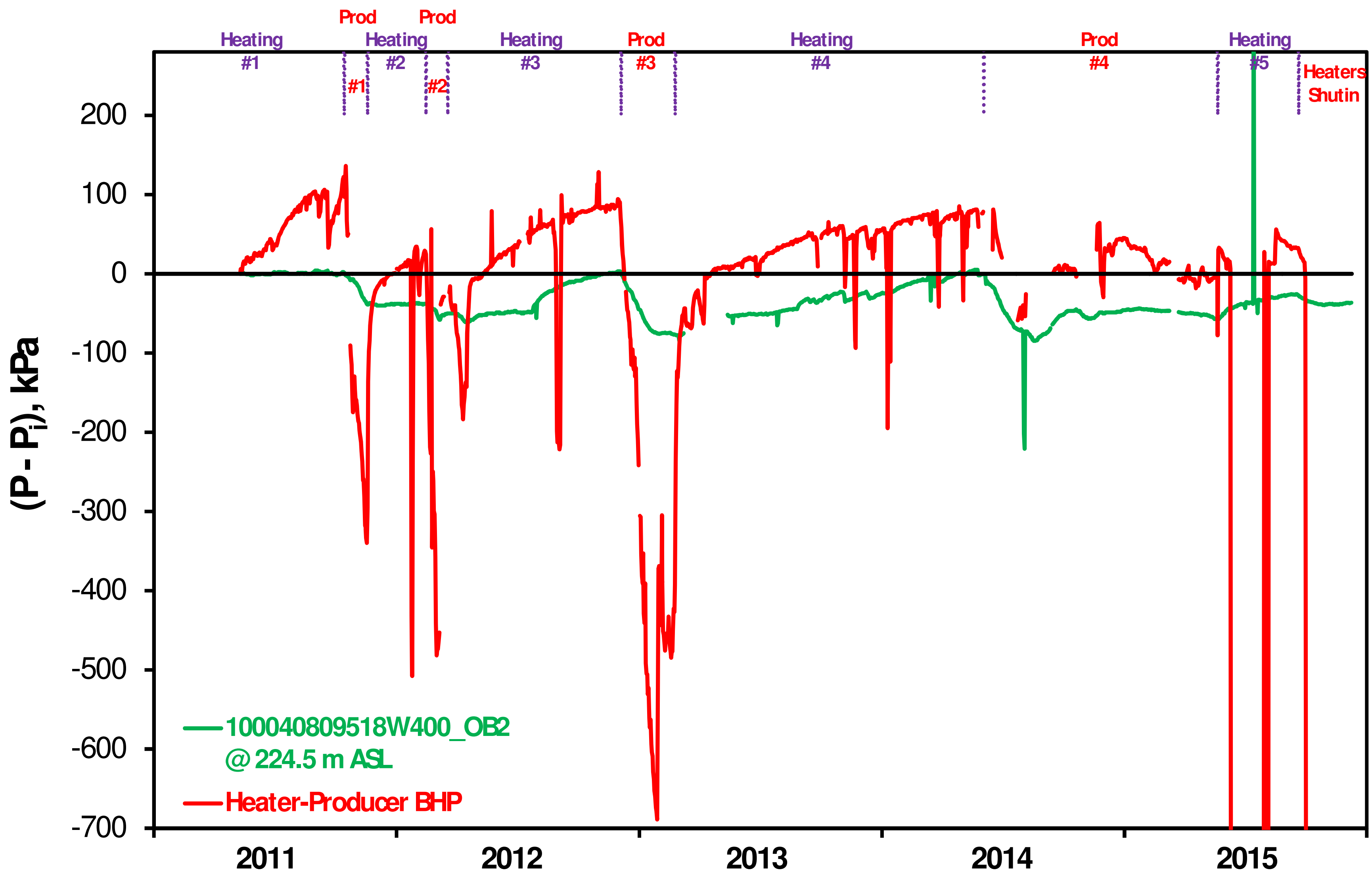
- Based on transients observed when heaters are shut off
- Non-uniform rock-face temperature along well potentially due to:
  - Porosity variations along well
  - Refluxing in build section
  - Fluid phase distribution along well

OBSERVATION WELL TEMPERATURE

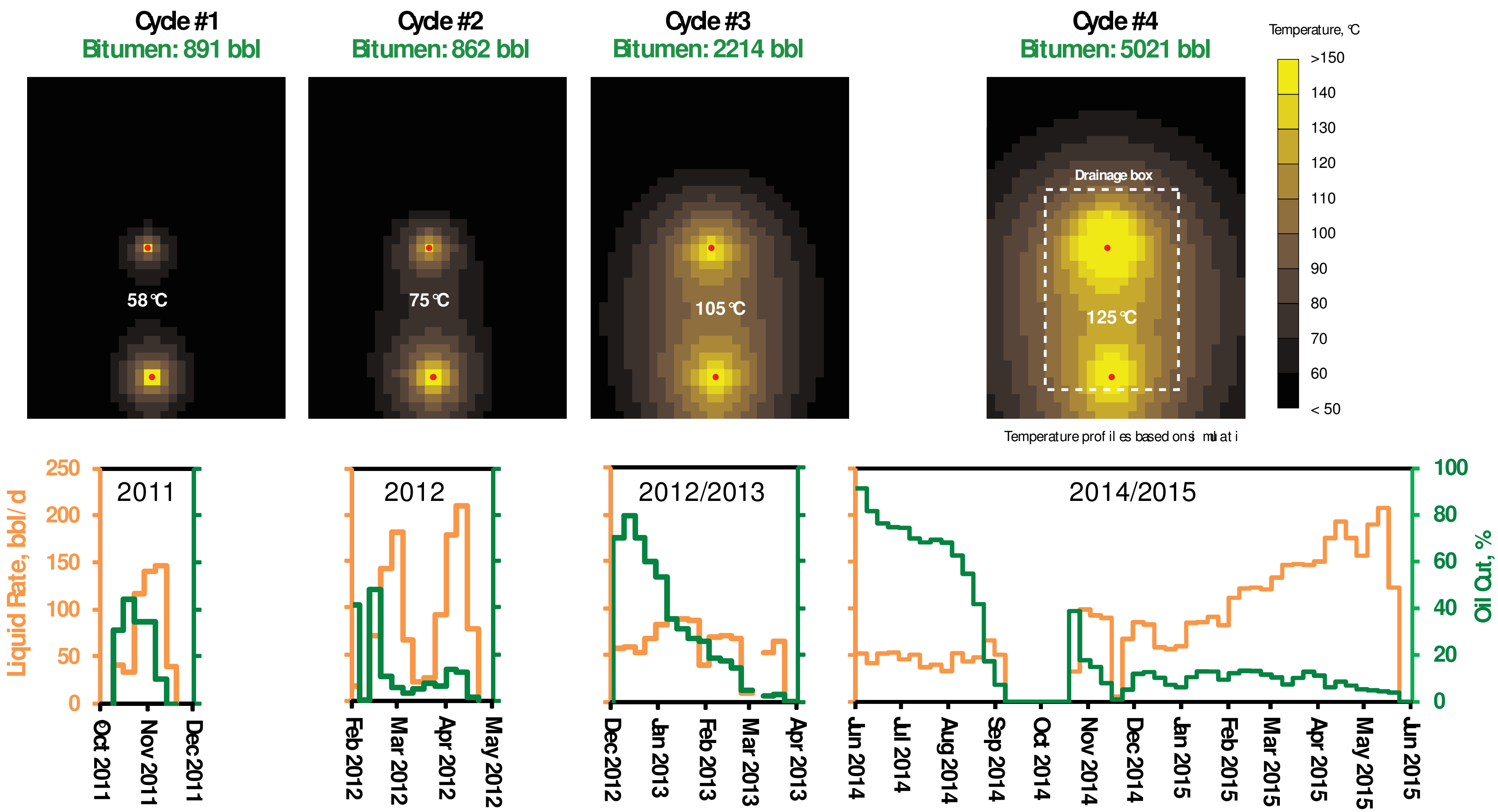


- Observed peak temperatures lower than expected from simulation.
- Convective smearing of temperatures.

HEATING PHASE – PRESSURE CHANGES



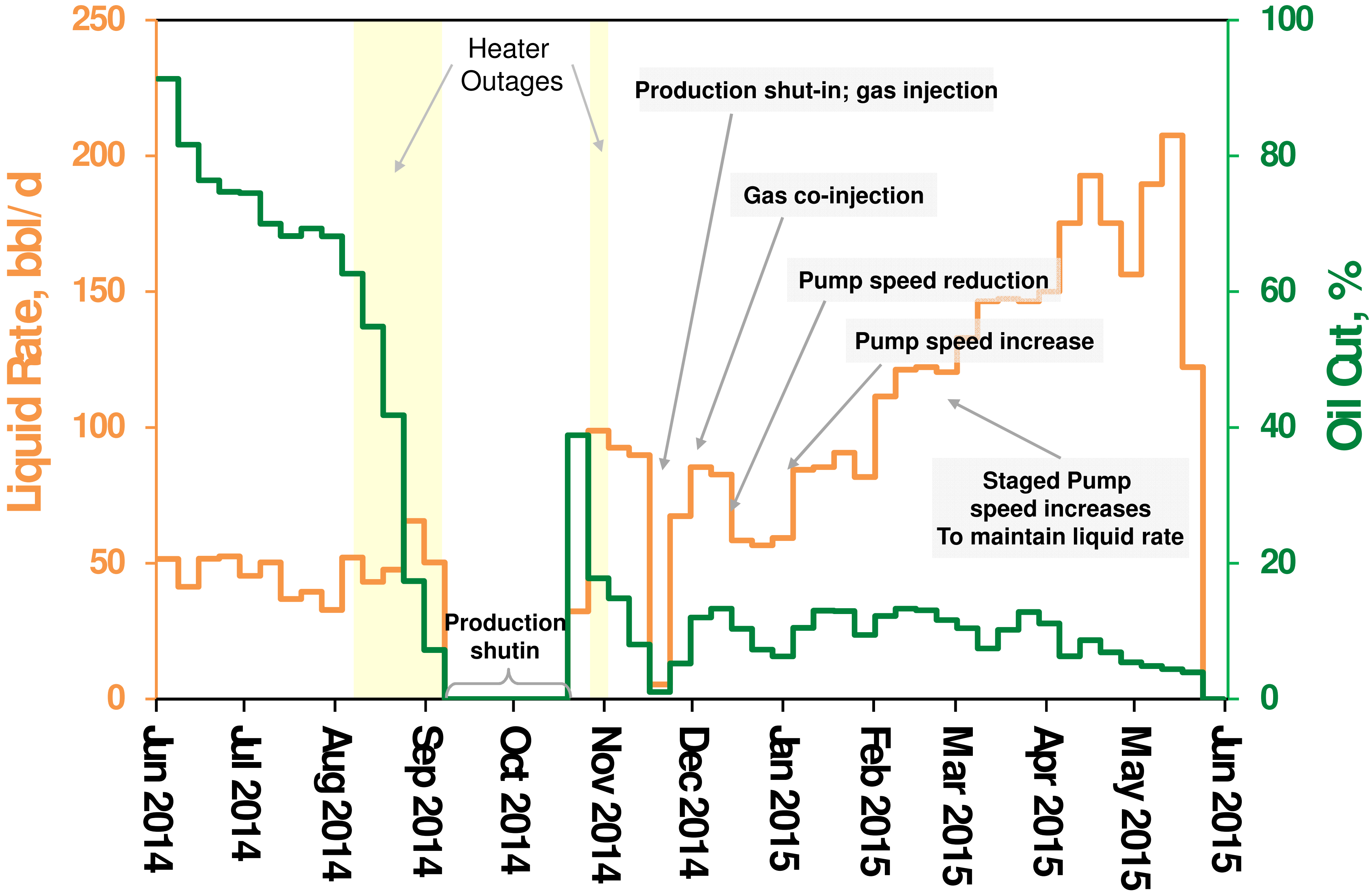
PRODUCTION HISTORY



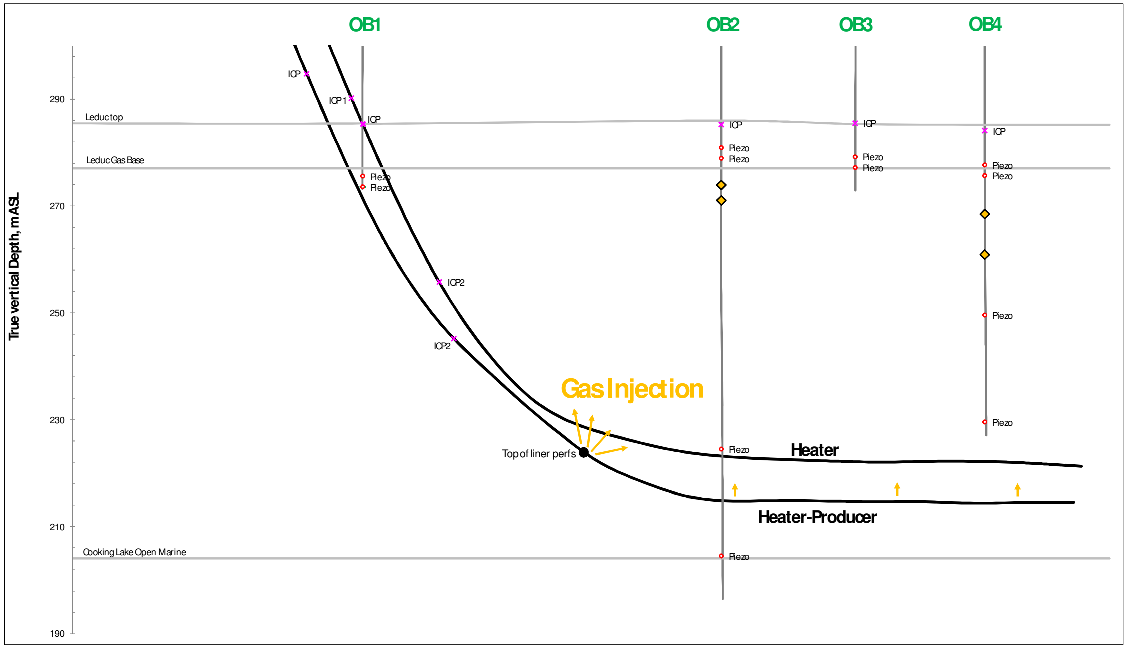
- Liquid rate controlled by pump
- High oil cut at start of each cycle
- Mobile water likely from disposal in 7-4

- 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



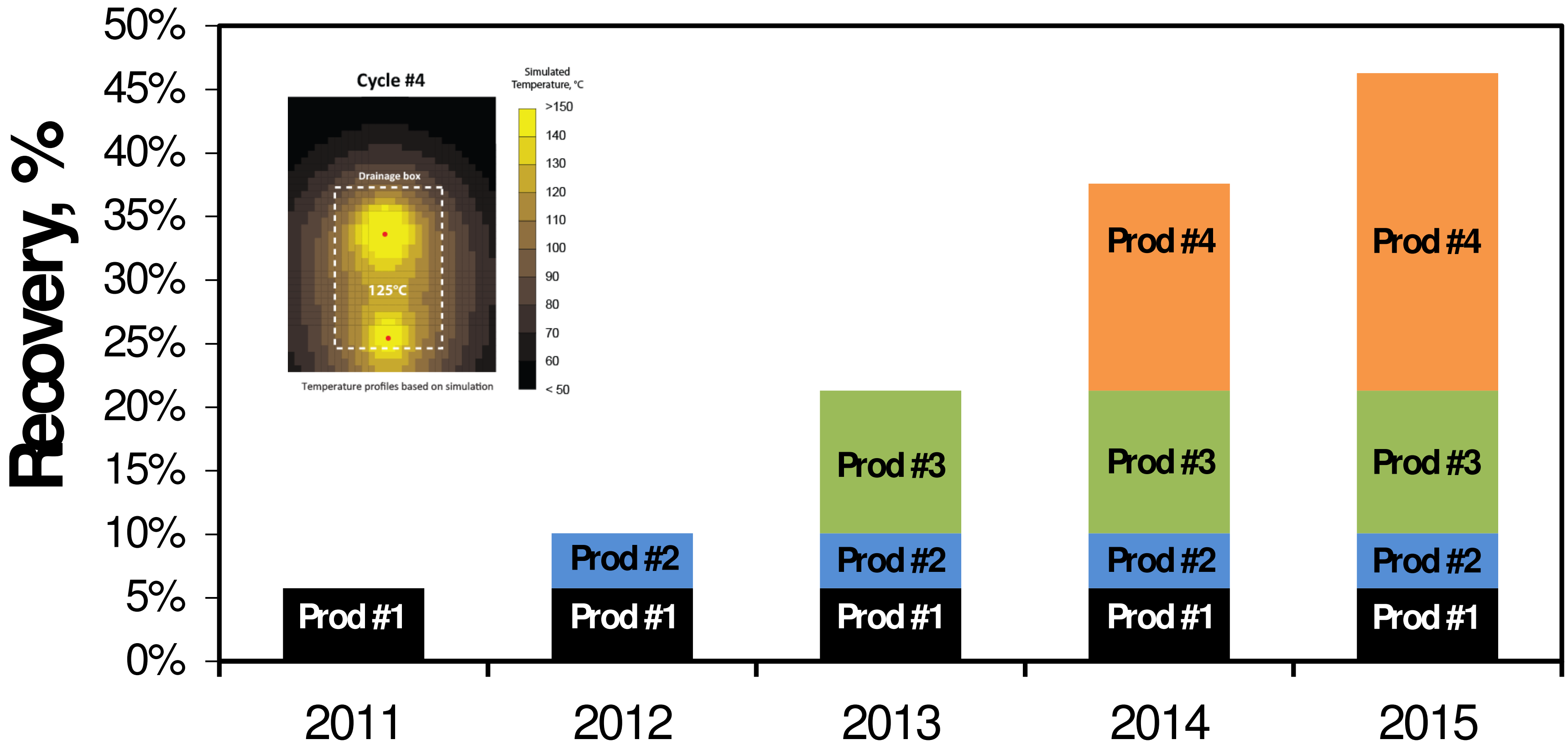
Objective:

- 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

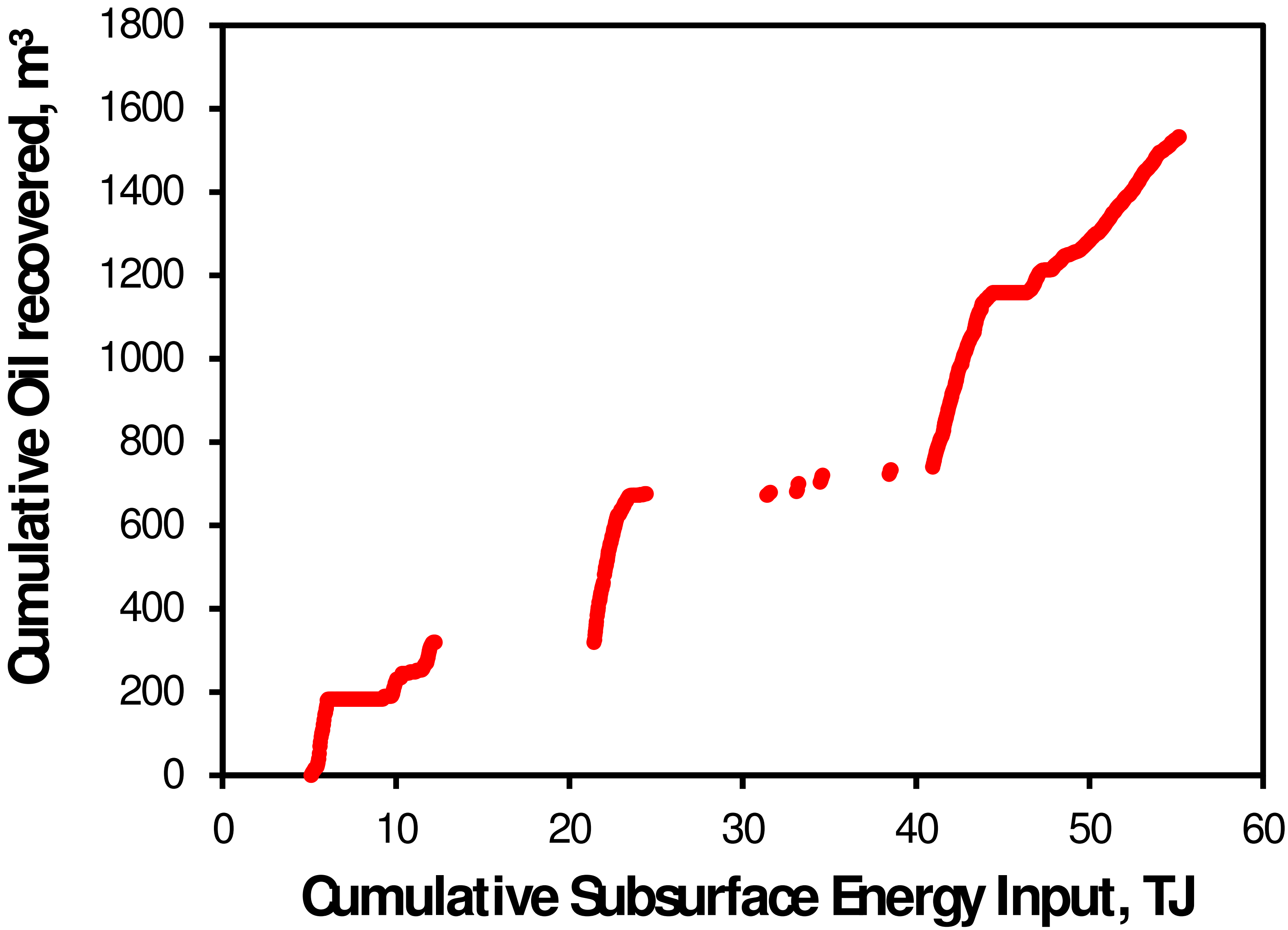
RECOVERY FACTORS TO DATE



OBIP	RF (Year end)
3 170 m^3	46%

- 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



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 to enhance drainage

2015 KEY OBSERVATIONS

- Cycle #4 was by far the best cycle. Oil production continued at gradually declining rates for 12 months
- Interwell temperatures were close to the TAGD target temperature of 150℃

TAGD Field Test Surface

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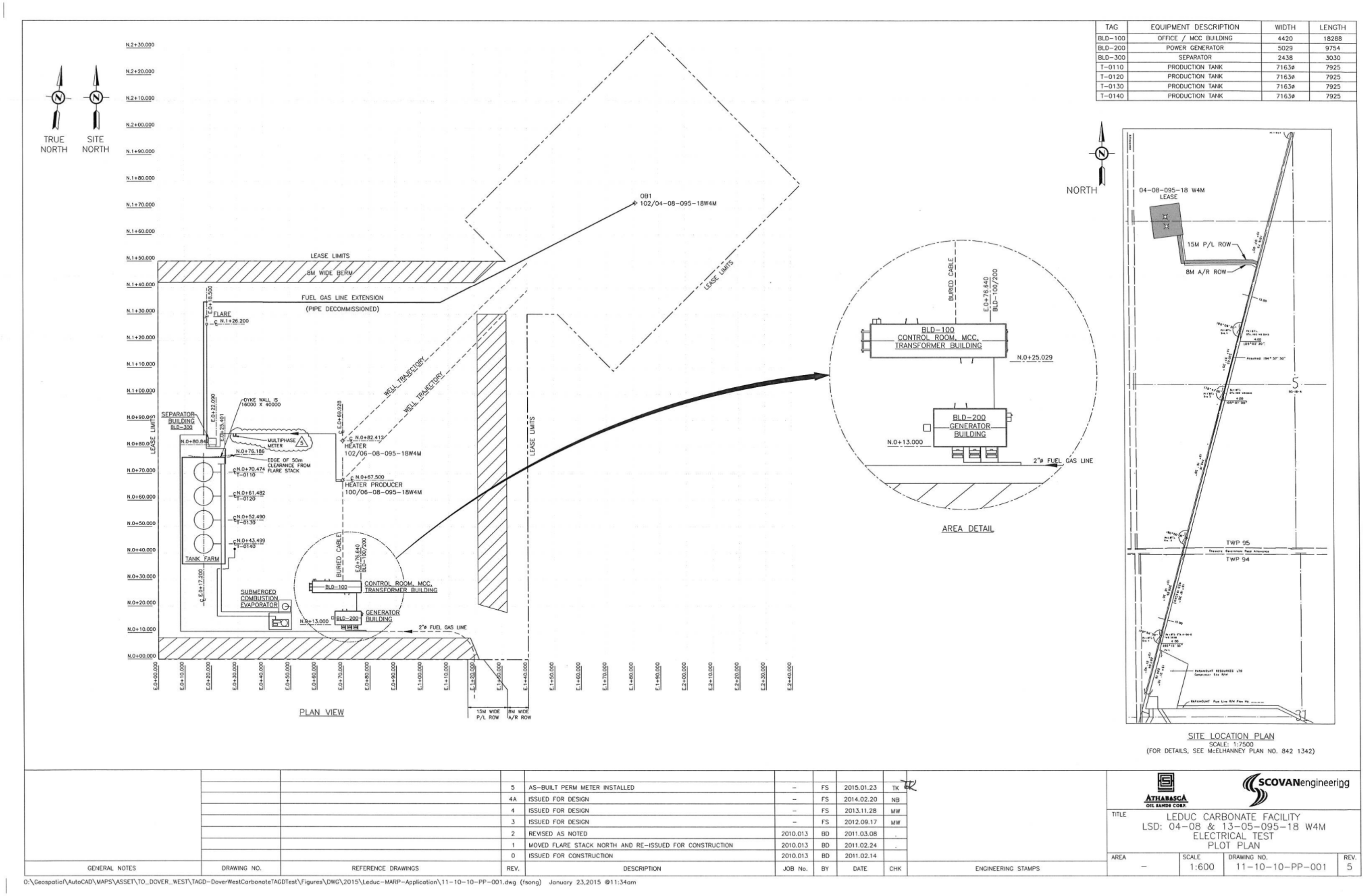
FIELD TEST PLOT PLAN



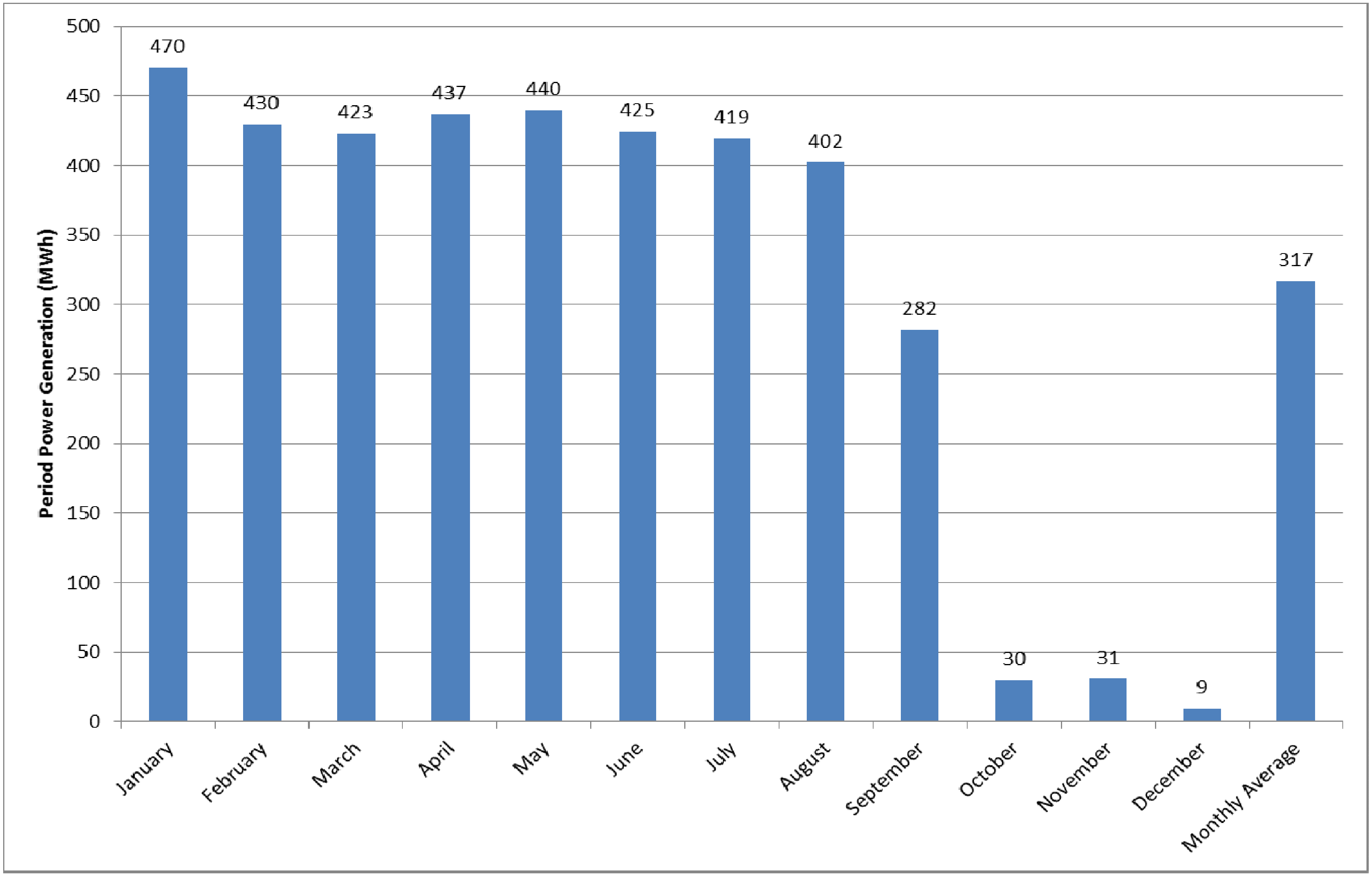
- No change in 2015

FACILITY PERFORMANCE

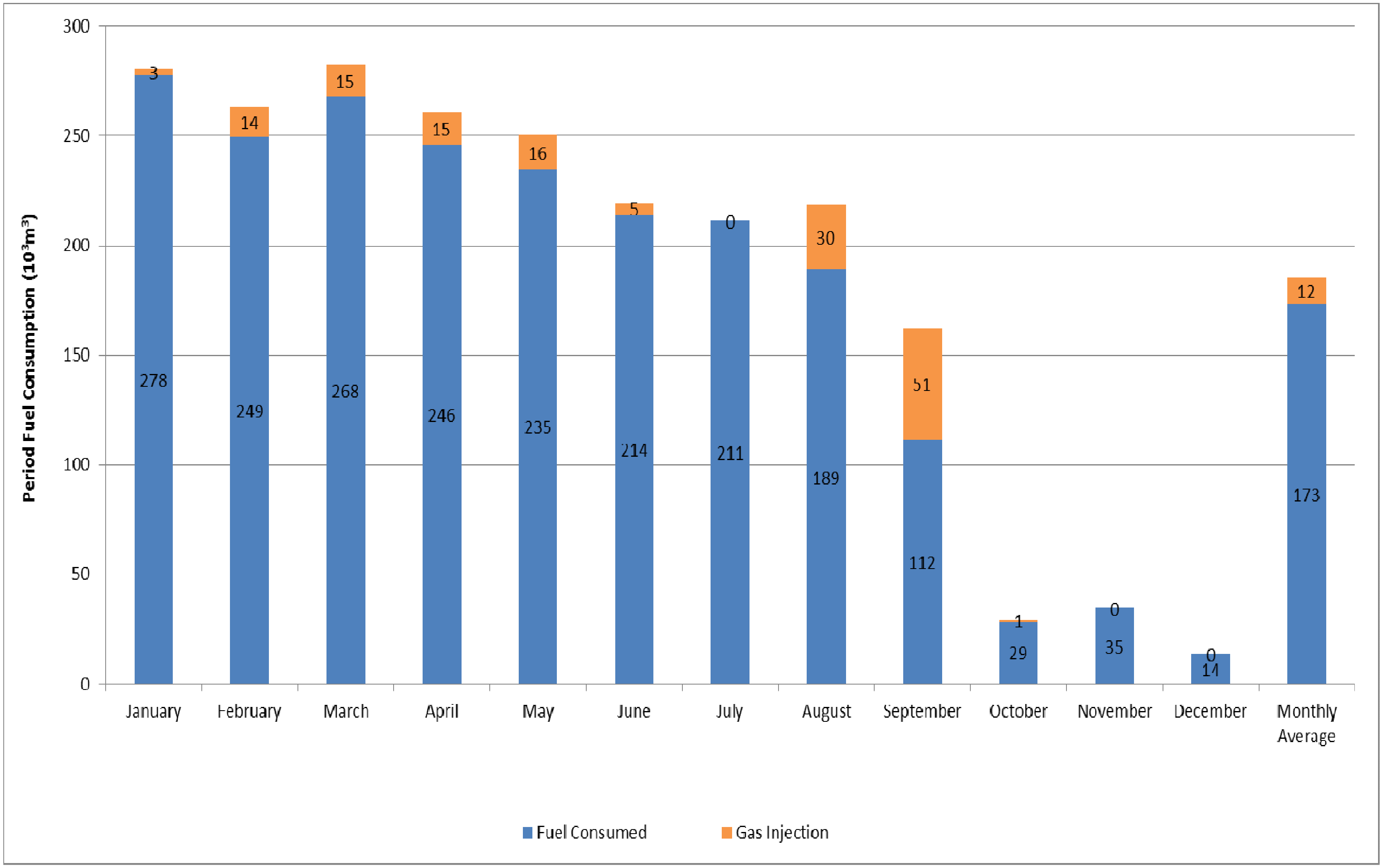
Generally stable and predictable battery performance

- Well pumping for ~139 days in 2015.
- 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.

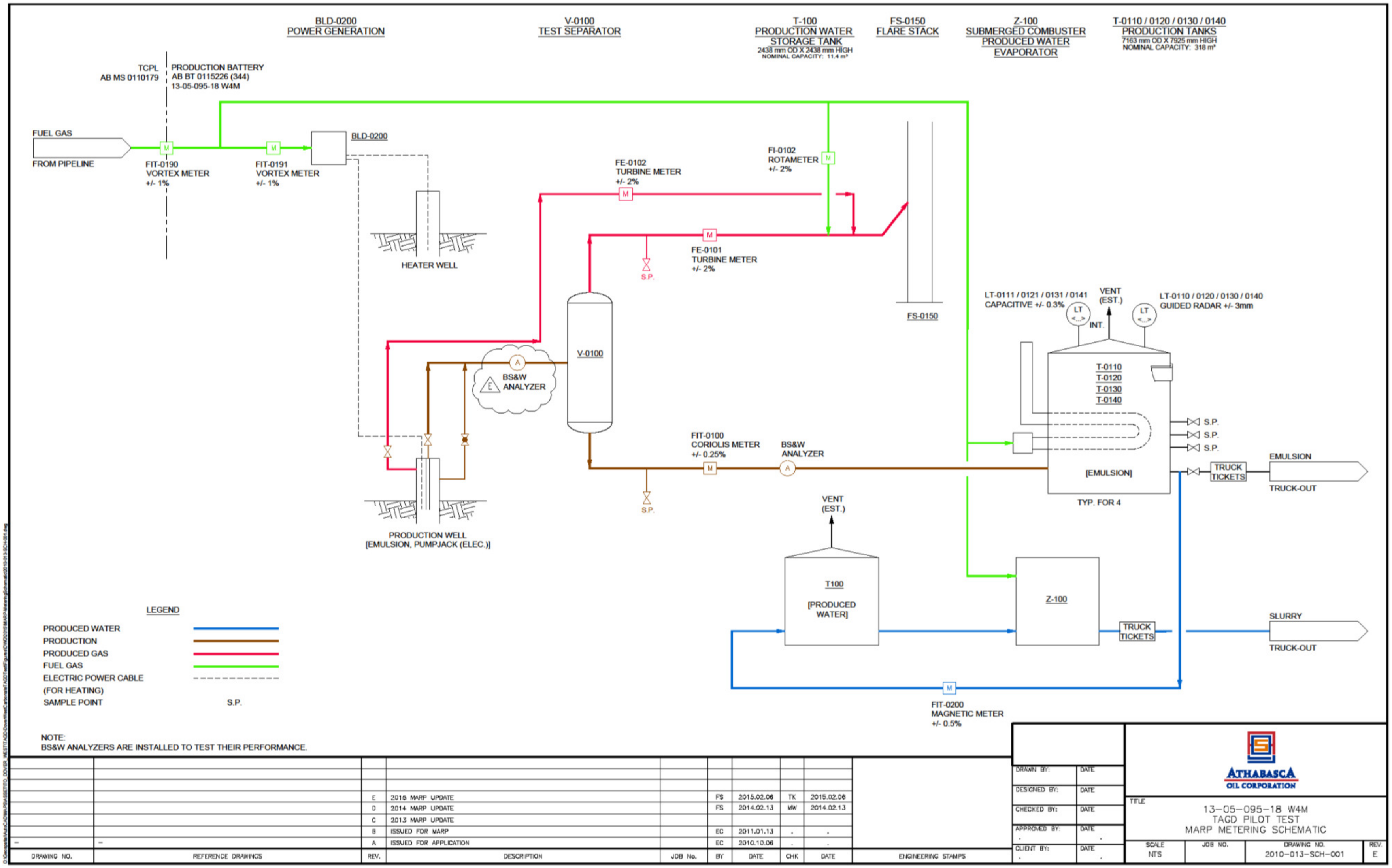
2015 POWER CONSUMPTION



2015 NATURAL GAS CONSUMPTION



APPROVED FIELD TEST METERING SCHEMATIC



- No change in 2015

PRODUCTION MEASUREMENT METHODOLOGY

No Changes to methodology

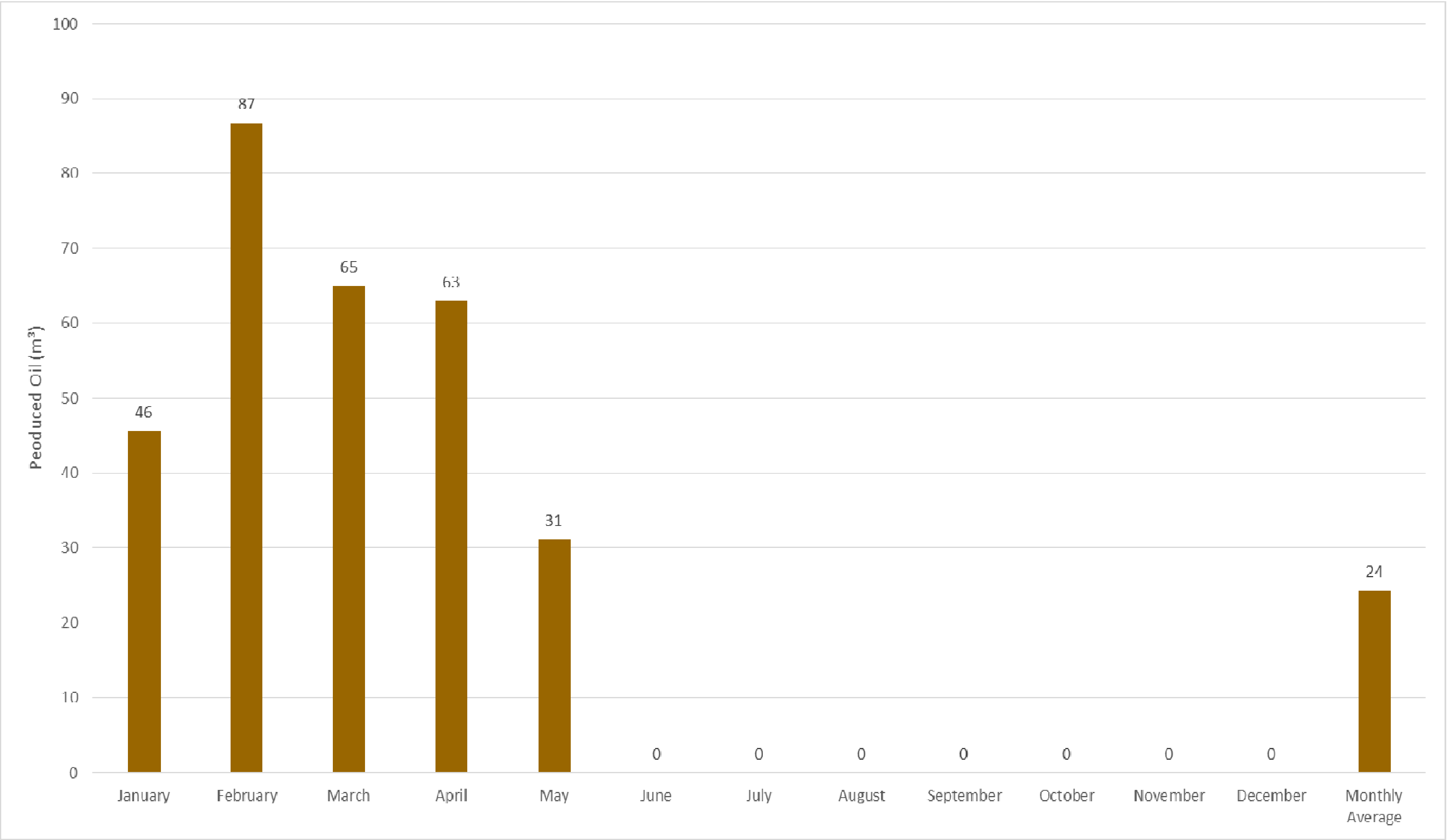
Bitumen and Water Production:

- 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.

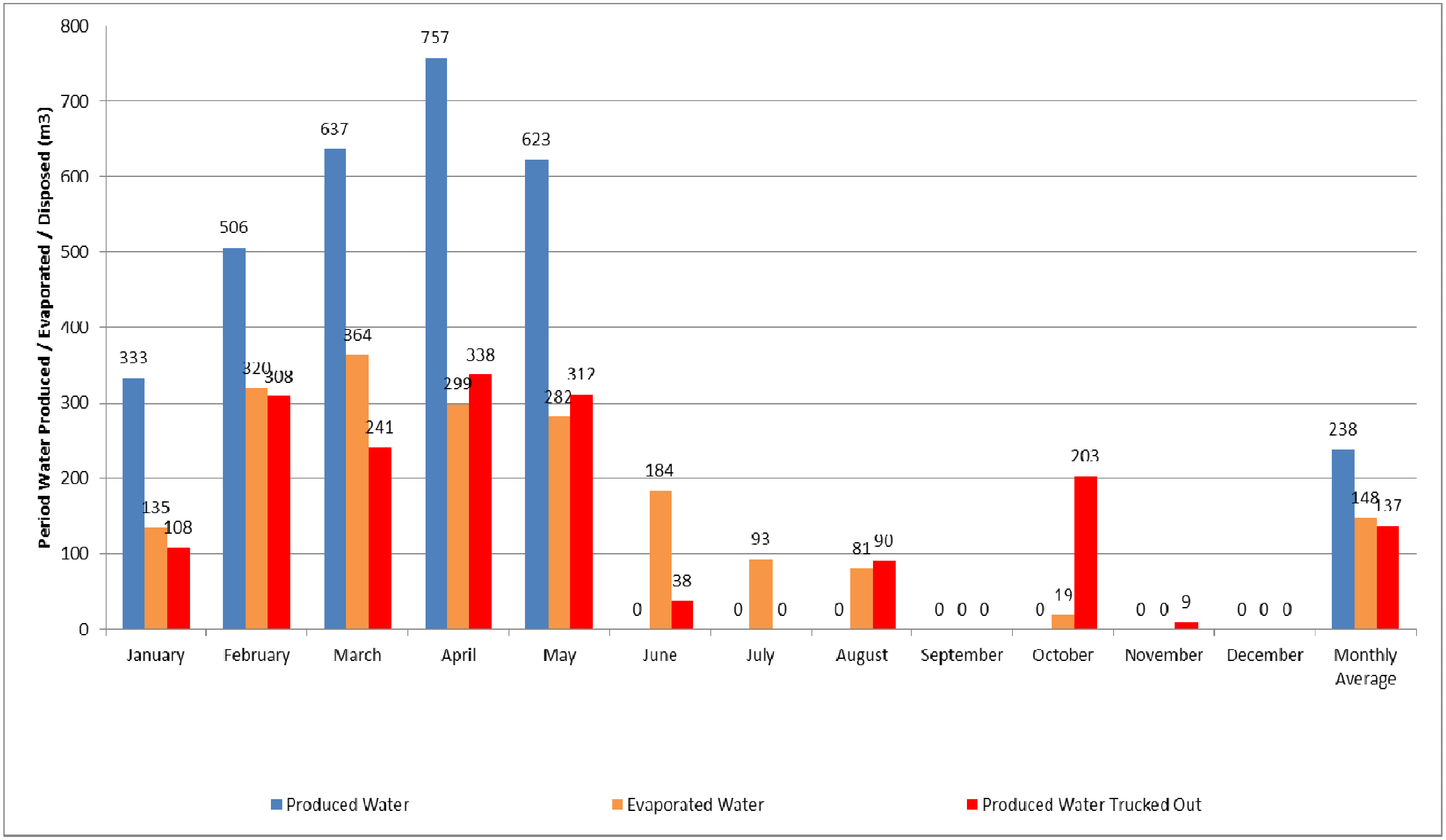
Gas Production:

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

2015 PRODUCED OIL

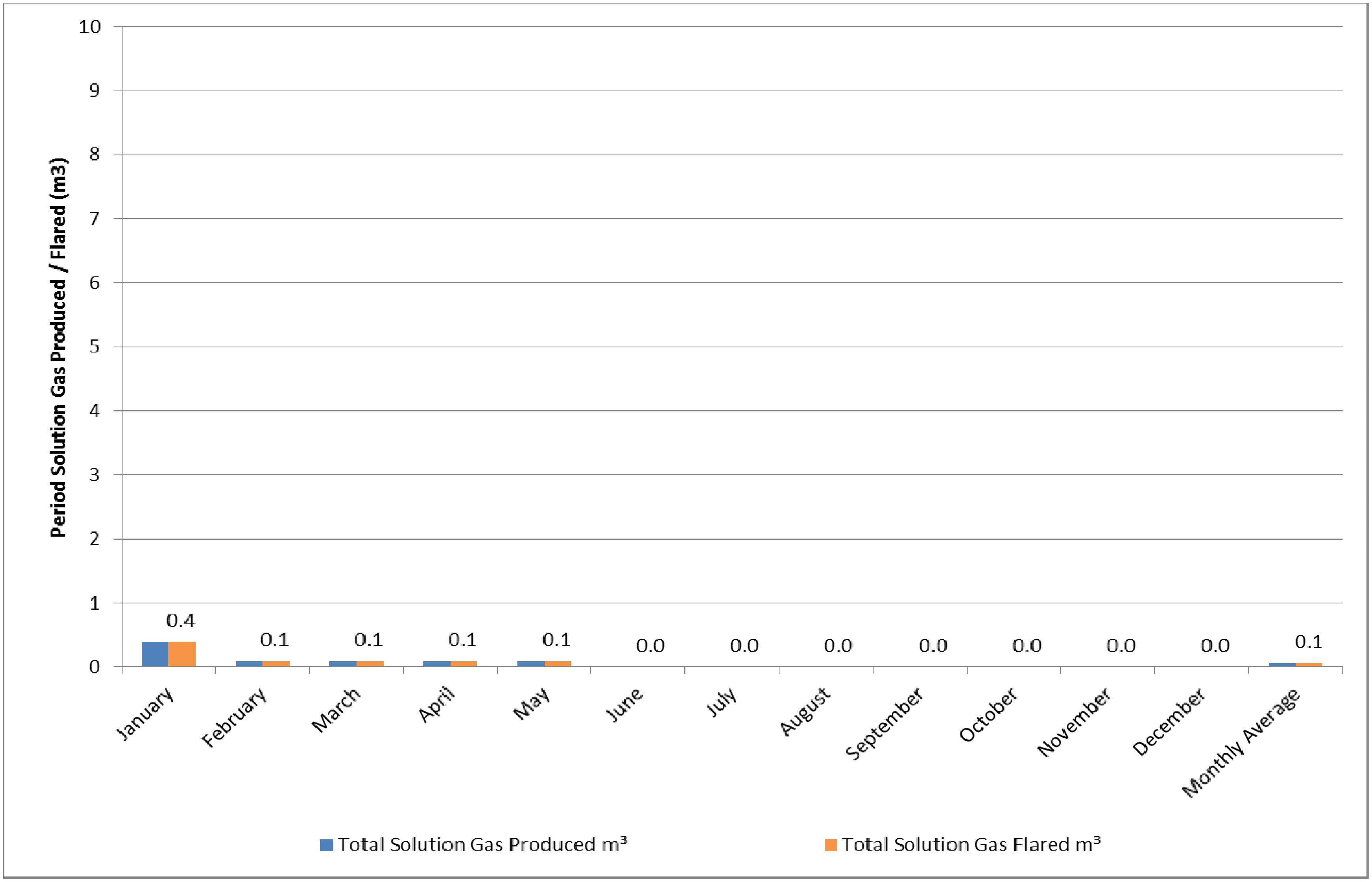


2015 PRODUCED WATER MANAGEMENT



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

2015 PRODUCED GAS



2015 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	4 590
Flaring	0
Venting	0
Total	4 590

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

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COMPLIANCE

May 8th, 2015 - AOC submitted application to inject 1 000 m^3/d of natural gas into producer well 100/06-08-095-18 W4M

August 14th, 2015 - Experimental Scheme Approval No.11546F was received for Gas Co-Injection

September 21st,2015 - AOC successfully concluded the TAGD field test

September 28th, 2015 - AOC submitted notification to the AER regarding field test conclusion

COMPLIANCE

AOC confirms compliance to:

Experimental Scheme Approval No. 11546F

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
- Wood Buffalo Environmental Association
- Alberta Biodiversity Monitoring Institute

Plans

ATHABASCA
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PLANS

The TAGD Field Test has met or exceeded all objectives

AOC terminated the TAGD Field Test in September 2015

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
- AOC may re-use some of the Field Test facilities for the TAGD Pilot

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