Husky Oil Operations Limited

McMullen Thermal Conduction Process Experimental Pilot Project

Experimental Scheme No. 11541

Annual Performance Presentation

Alberta Energy Regulator

March 18, 2016

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1. Brief Background

Project Overview – AER Approvals

- December 20, 2010 - AER issued Experimental Scheme Approval 11541 for the McMullen TCP experimental scheme application (AESRD issued EPEA Approval 265571-00-00 on
January 10, 2011)

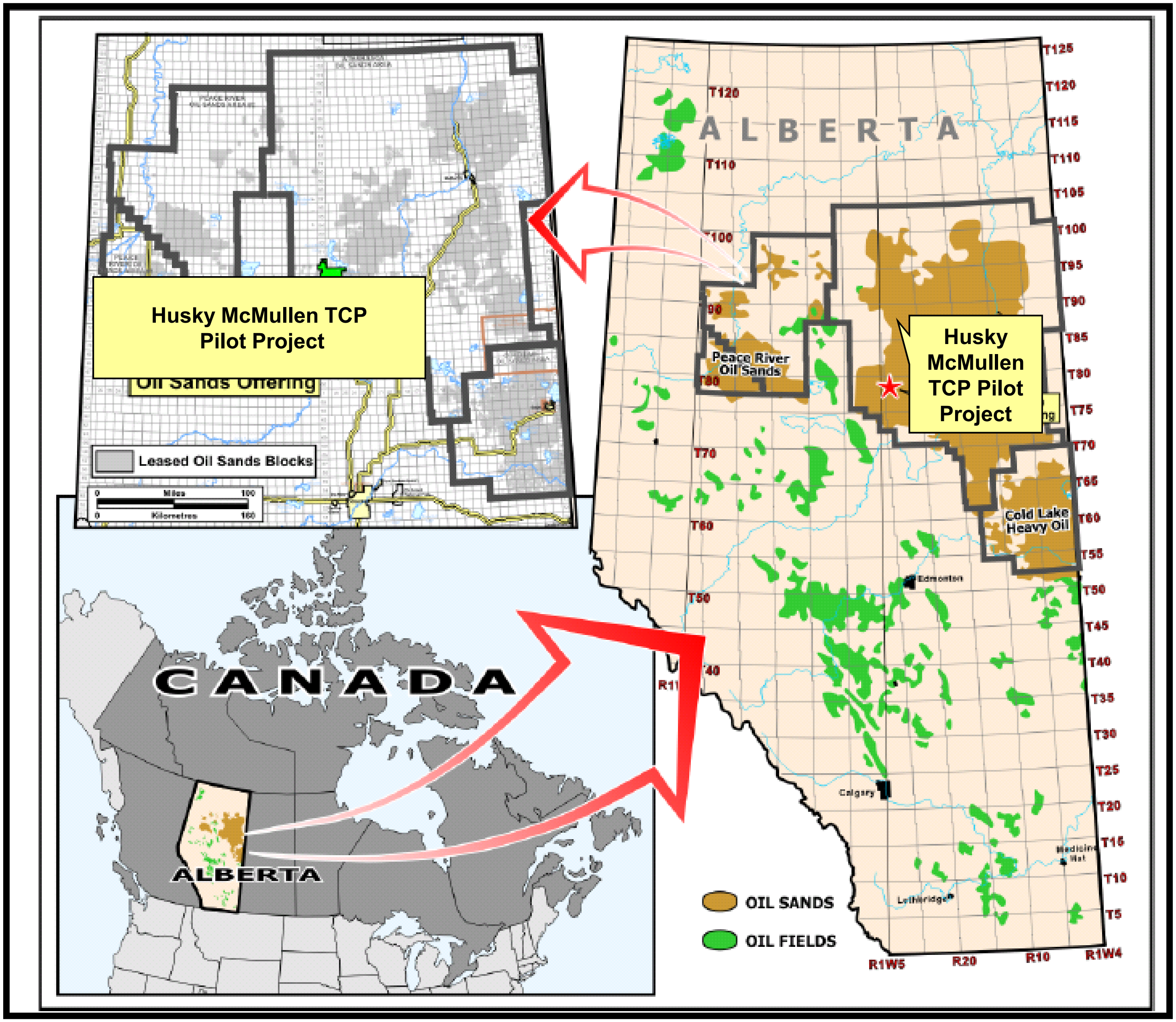
- January 19, 2012 - AER issued Experimental Scheme Approval 11541A for three additional horizontal production wells as a modification to the scheme

- August 7, 2013 – AER issued Experimental Scheme Approval 11541B for the handling of sour gas at the facility for all production wells

- October 30, 2013 – AER issued Experimental Scheme Approval 11541C to extend the experimental scheme approval and confidentiality period to July 31, 2015

- April 21, 2015 – AER issued Experimental Scheme Approval 11541D to extend the experimental scheme approval to July 31, 2018 and confidentiality period to July 31, 2016

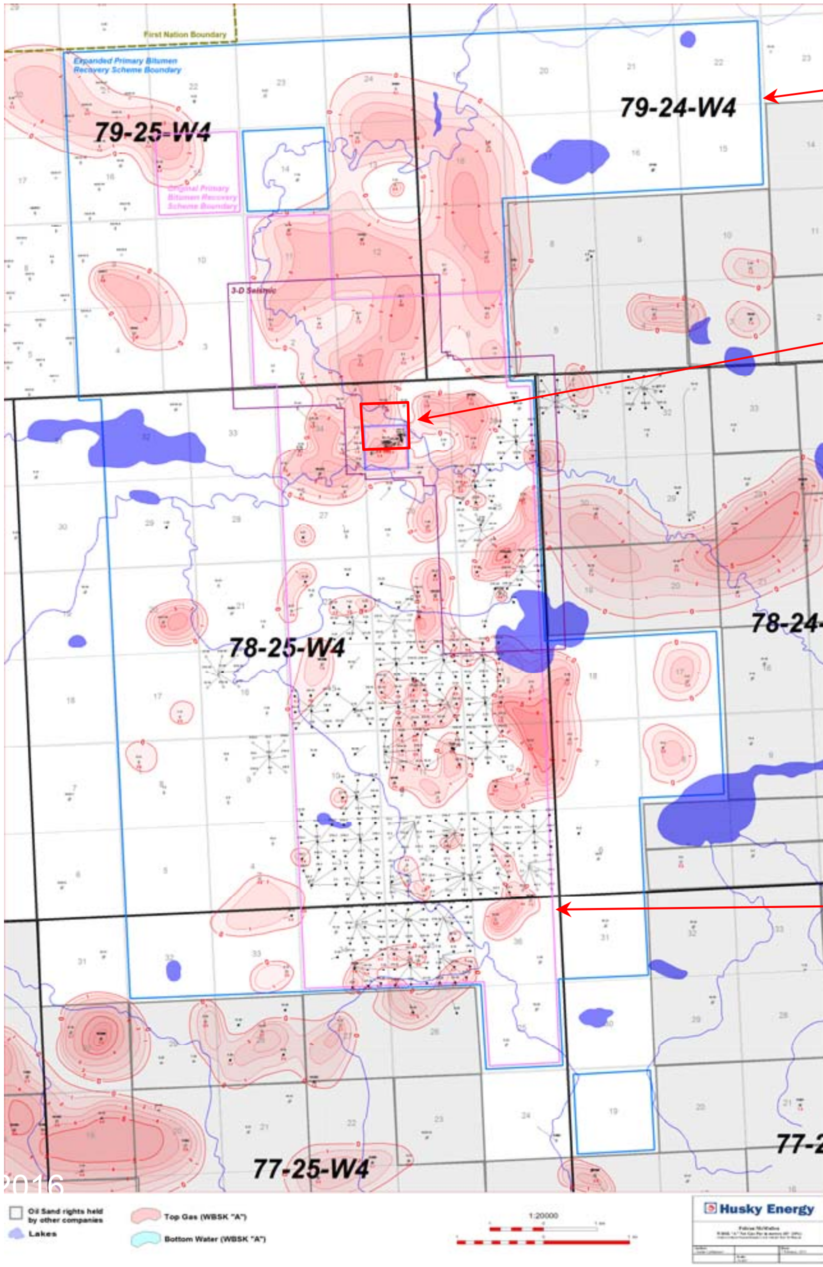
McMullen Thermal Conduction Project (TCP)



Project Location

- Project location is the SW/4 of 35-078-25W4
  - Based on core and log data from 100/03-35-078-25W4 well drilled in November 2008
  - 100/03-35-078-25W4 well has a depleted gas zone of 4 meters in thickness that overlies a bitumen zone of 6 meters in thickness
- Thin bitumen zone of 6 meters has excellent reservoir characteristics
  - Classified as a homogeneous, unconsolidated, clean sand with good porosity, excellent permeability and good oil saturation
- There is no underlying water in contact with the bitumen
- The overlying gas cap has a good seal (Clearwater Shale)

Wabiskaw “A” Project Area Gas Cap Map



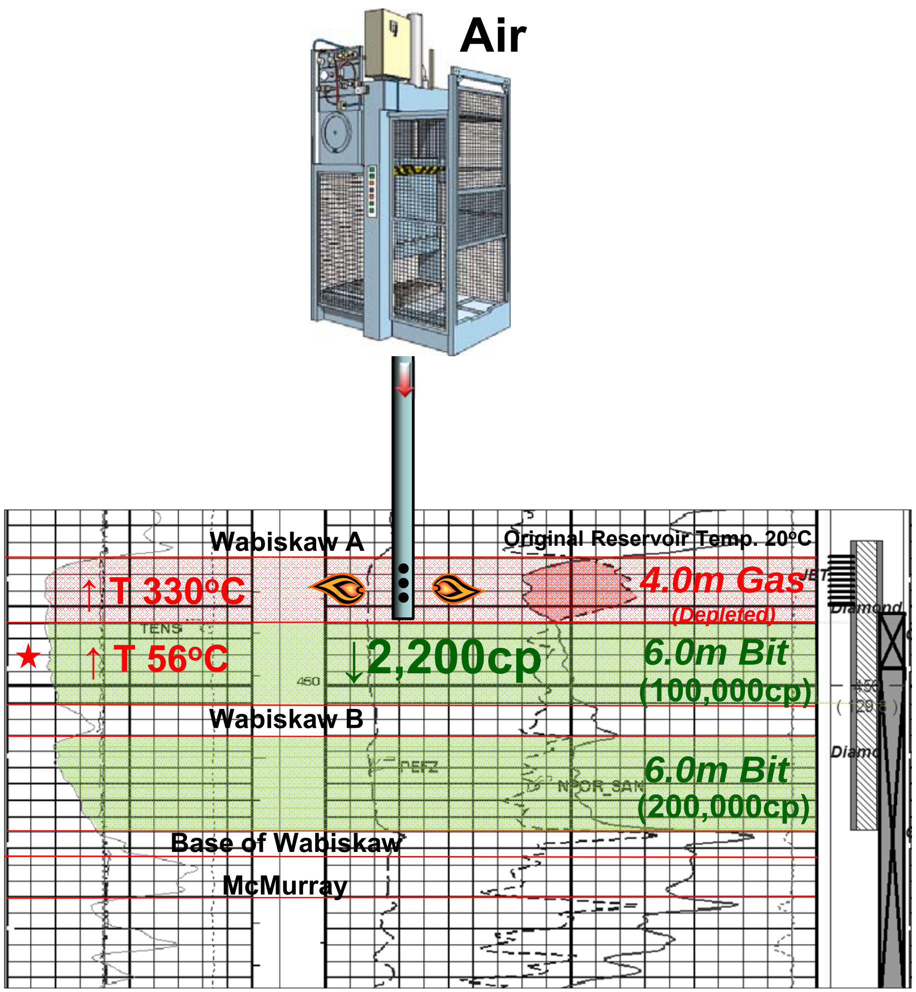
AER Approved Expanded Primary Area by an additional 41 sections for a total of 68 sections (down-spaced to 36 wells/section)

McMullen TCP Pilot Project SW 35-078-25W4 Application area

AER Initial Approved Primary Area of 27 sections - down-spaced to 36 wells/section

Husky has drilled 300 wells since 2008

Project Scope

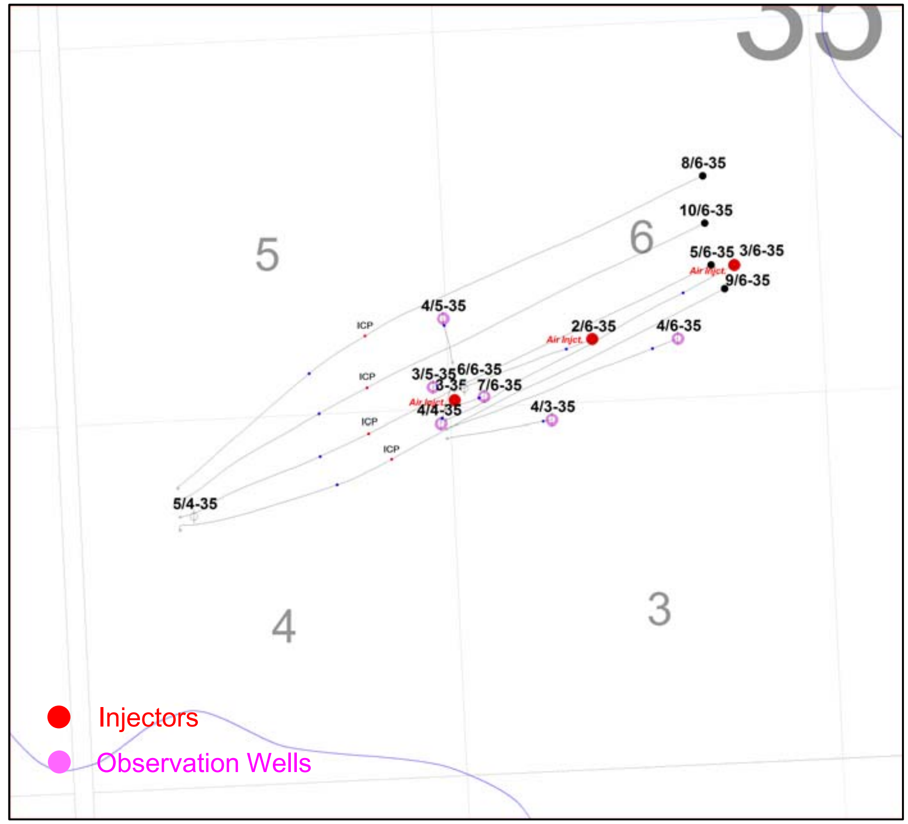


★ *Targeted Zone*

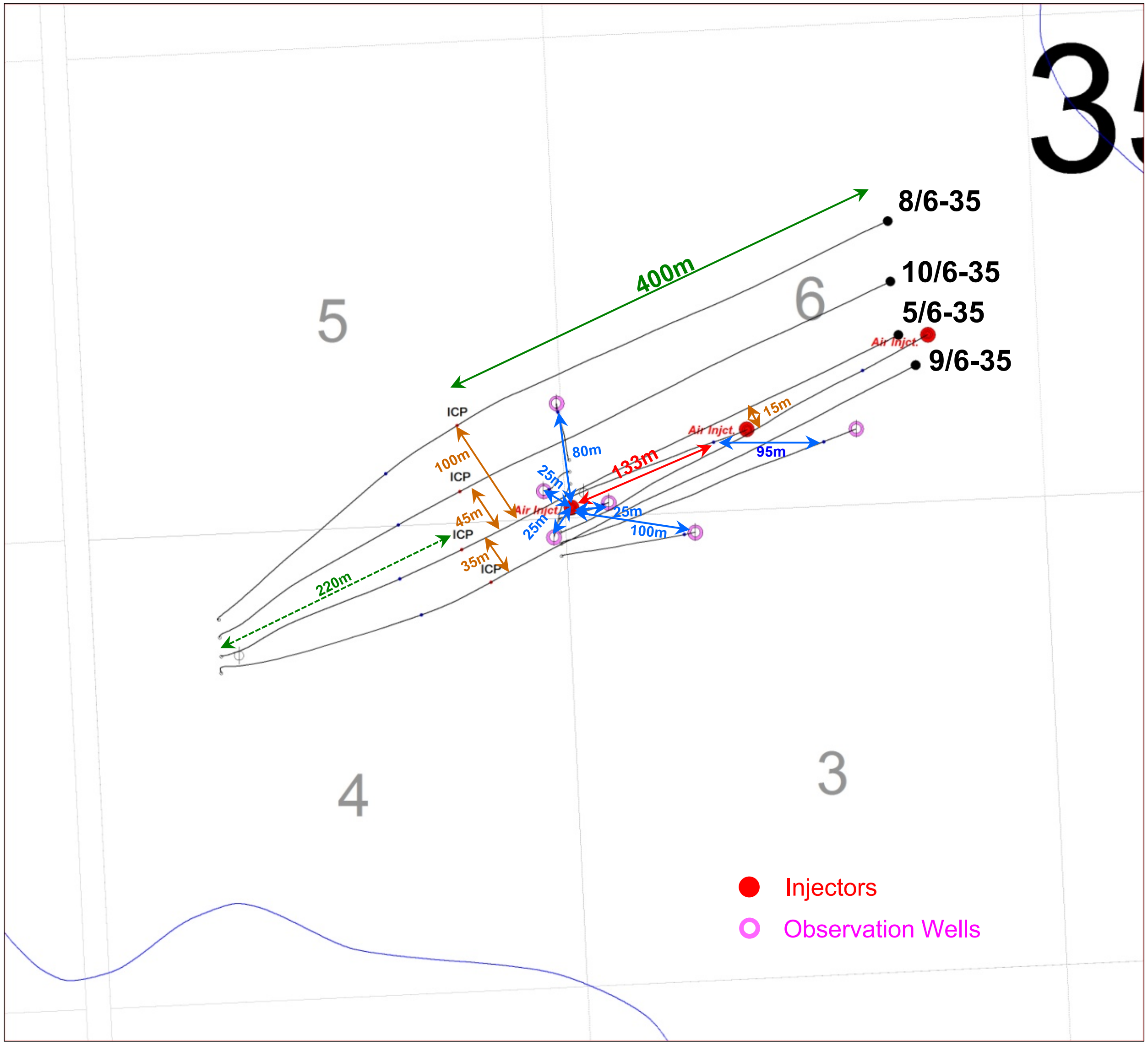
- Purpose:
  - Recover bitumen underlying depleted gas cap
- What We Do:
  - Ignite and oxidize residual oil saturation (8-15%) within depleted gas cap
- How We Do it:
  - Ignition process: Steam/Linseed Oil/Steam/Nitrogen/Air (spontaneously combusts)
  - Wait (3-6 months+) for heat to conduct to underlying bitumen
- What We See: (within the depleted gas cap)
  - Combustion zone peak temperature 330°C (burn tube test 600 degrees Celsius (°C))
- What We Need: (within bitumen zone)
  - Heated > 56°C to lower viscosity to less than 2,200cp to start producing
- What We Get:
  - Flow rate 25 m^3/day (from 400m HZ Well)
  - Recovery factor > 50%

Project Status

- 2011/2012 - 13 wells drilled and facility construction completed
- September 28, 2011 – start of temporary steam
- December 8, 2011 – start of first air injection
- January 19, 2012 - received approval to drill three additional horizontal producers
- October 2012 - 3rd train air compression added
- November 1, 2012 – first horizontal well on production
- October 2013 - three additional horizontal wells on production
- September 18, 2014 – shut-in of air injection
- October 31, 2015 – suspension of Project operations
- July 31, 2016 – expiry of confidentiality period



Inter-Well Spacing



Project Objectives

December 2015 - 49 Months after Start of Air Injection:

- Successful ignition and continuous combustion
  - Achieved
- Heating the underlying bitumen through thermal conduction to mobilize the oil
  - As predicted (~25 m^3/d; 25-30% BS&W)
- Determine combustion front velocity through the depleted gas zone
  - As predicted
- Determine optimal well spacing for future design of a commercial project
  - Requires Pilot expansion to test new spacing
- No Injected air or combustion gas breakthrough into the horizontal producers
  - Achieved

Improved Recovery Technique

- New innovative technology
  - To recover bitumen underlying a depleted gas cap
- Thermal recovery process
  - Conducts heat downward from the gas zone to the bitumen leg in order to mobilize the oil for production
- Combustion reactions
  - Will be confined to the gas zone and results in high temperature oxidation
- Significant reduction in fresh water usage
  - Over conventional steam assisted methods (Cyclic Steam Stimulation and Steam Assisted Gravity Drainage)
  - Water requirements are for initial steaming only (8311 m^3 Cold Water Equivalent (CWE) for the initial heating of the three injectors to ensure ignition when air is injected)

2. Geology / Geosciences

OBIP Reserve Estimate - Volumetric Methodology

Average Reservoir Parameters:

- Net Oil Pay = 6 m
- Porosity = 31%, So = 70%
- Oil FVF = 1.00 m^3/m^3

Entire approval area - 64 ha (SW/4 section 35-078-25W4)

- OBIP = 833 e^3m^3

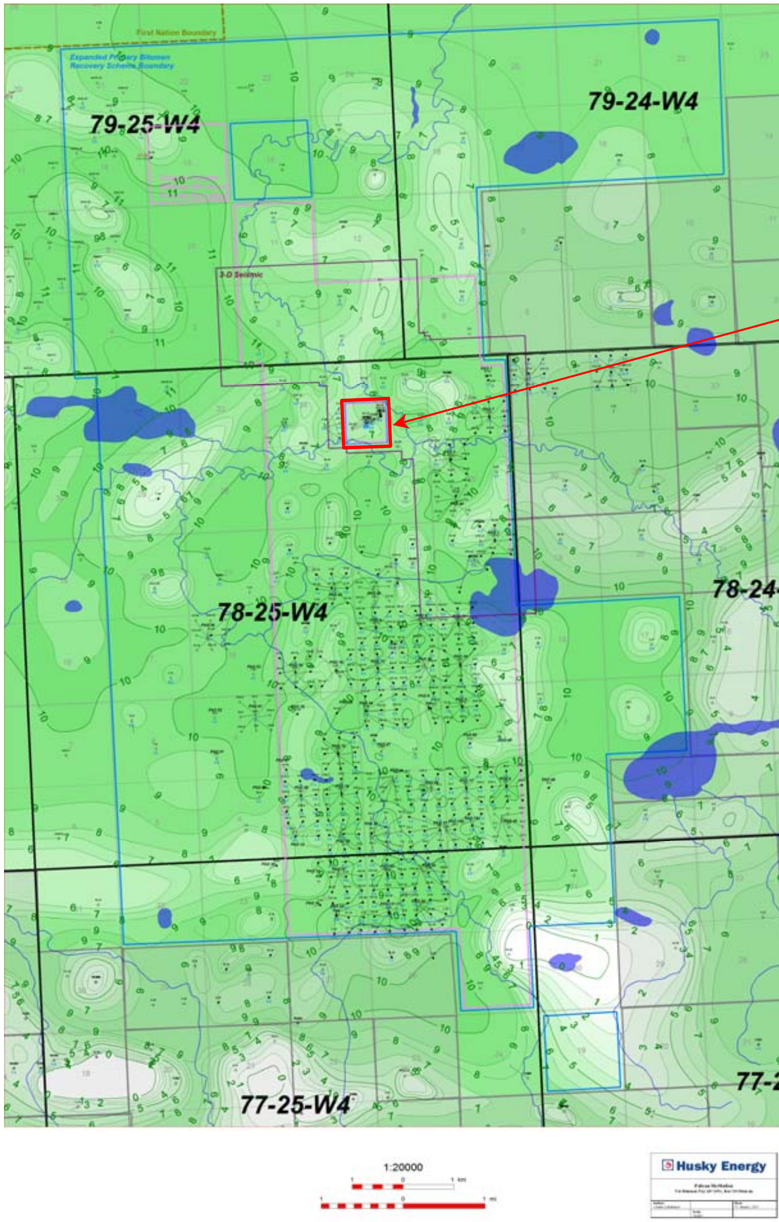
Planned operating portion of the Project - 13 ha (prior to shut-in of air injection)

- OBIP = 169 e^3m^3

Actual operating portion of the Project - 6 ha (after shut-in of air injection)

- OBIP = 78 e^3m^3
- The premature shut-in of air injection (and shut-down of combustion) resulted in a smaller portion of the Project being heated than originally estimated. The actual operating portion of the Project (6 ha) is based on an estimated drainage area size of 75 m on either side of the injectors (width) by 400 m long (length of a HZ well).

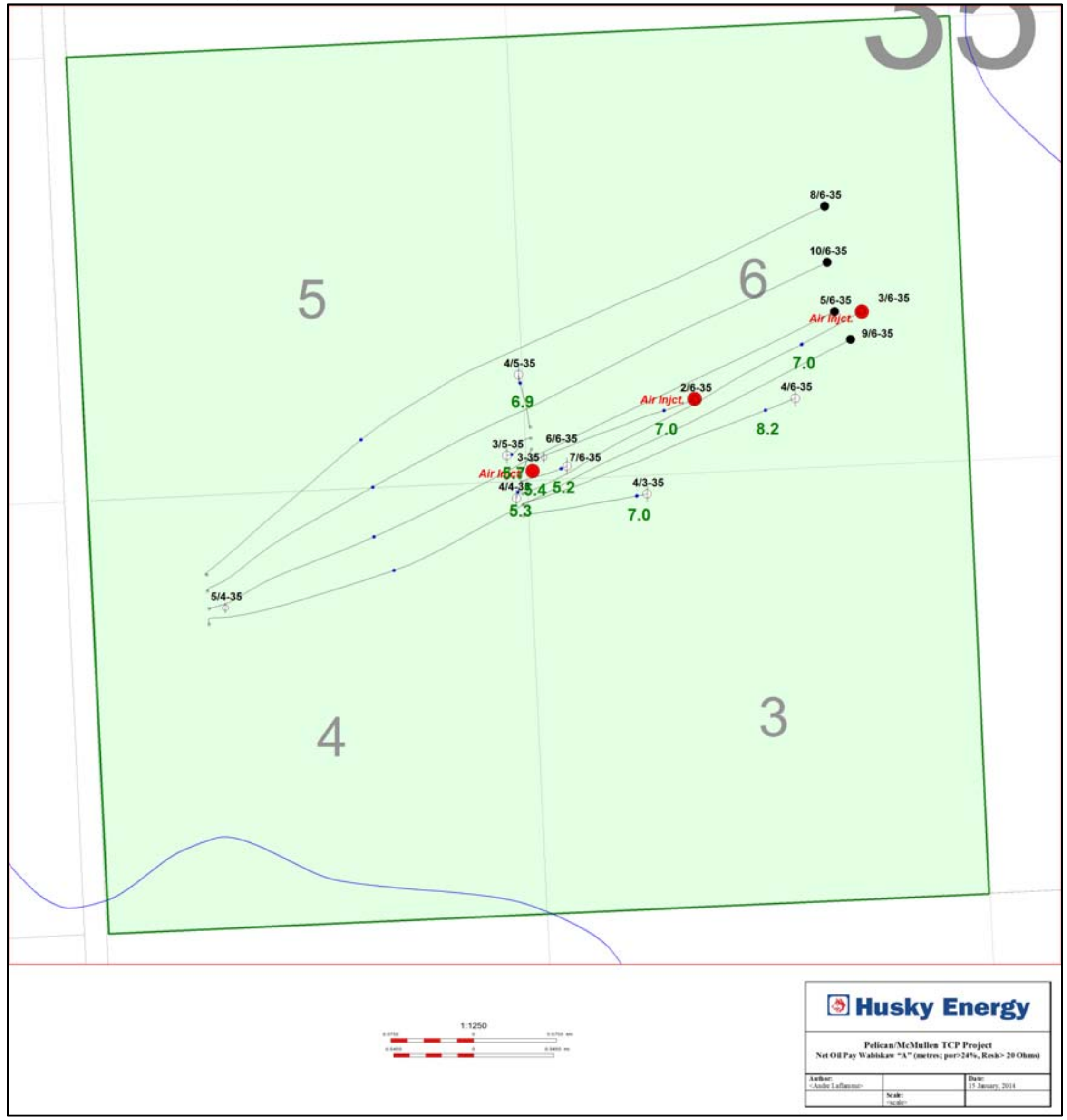
Wabiskaw "A" Net Oil Pay Map



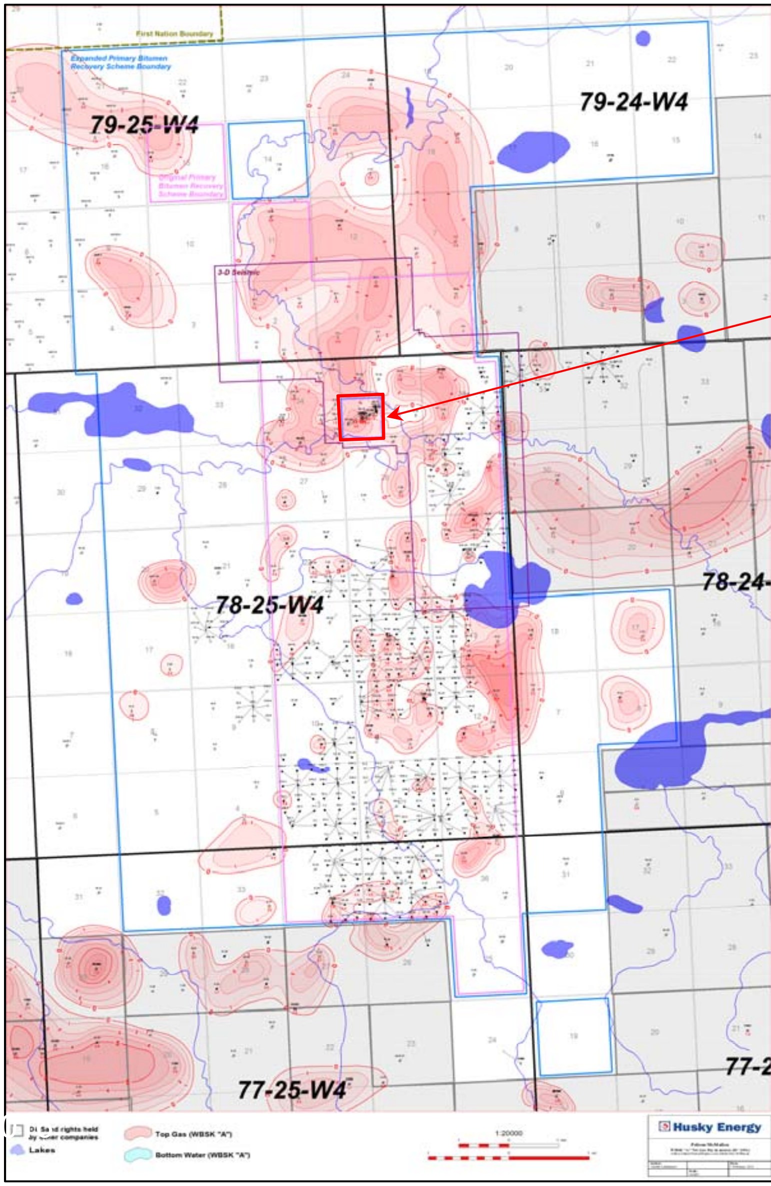
SW 35-078-25W4
Application area

Wabiskaw “A” Net Oil Pay Values

- SW 1/4 of Section 35-078-25W4



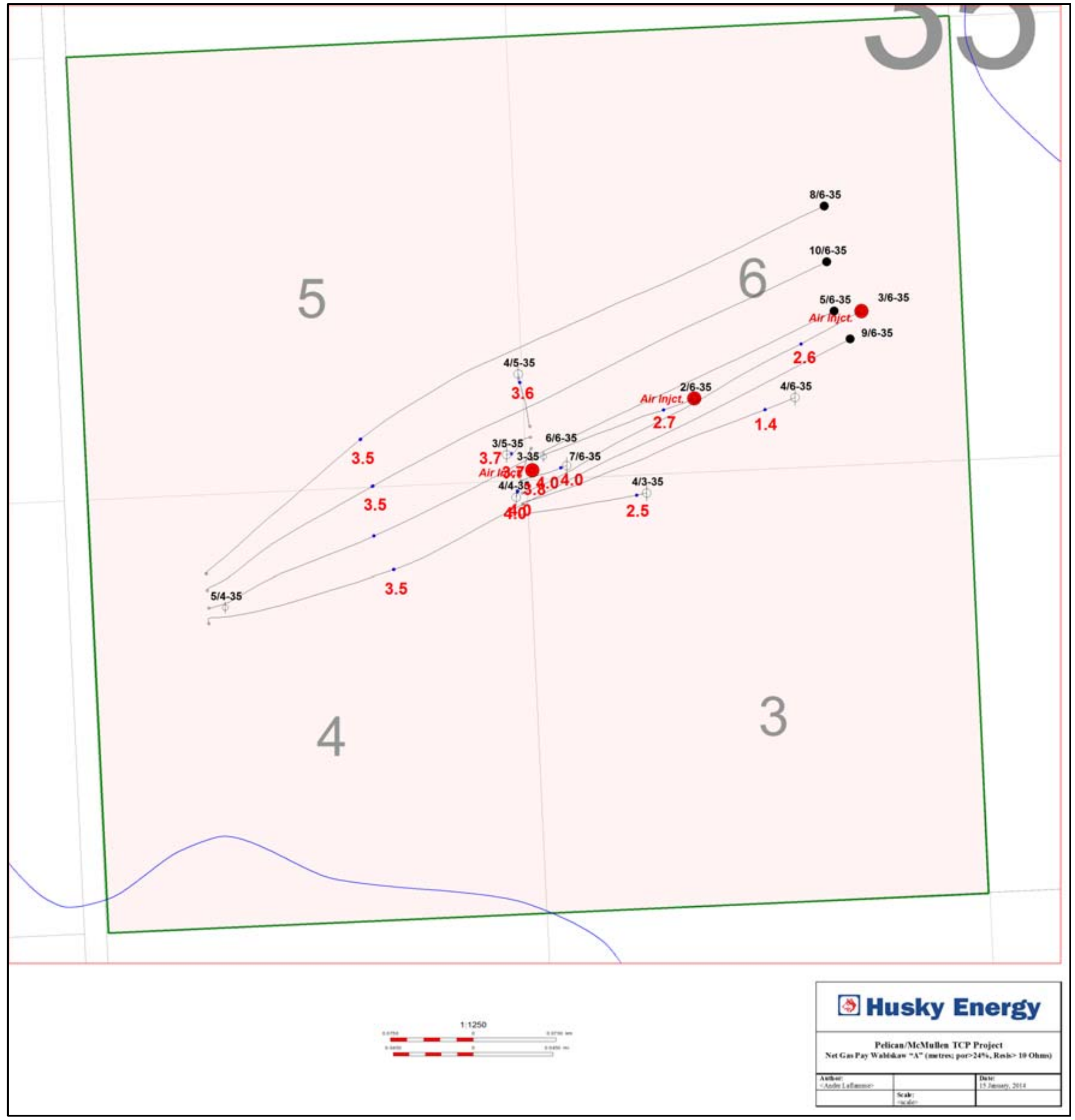
Wabiskaw "A" Net Gas Pay Map



- SW 35-078-25W4 Application area

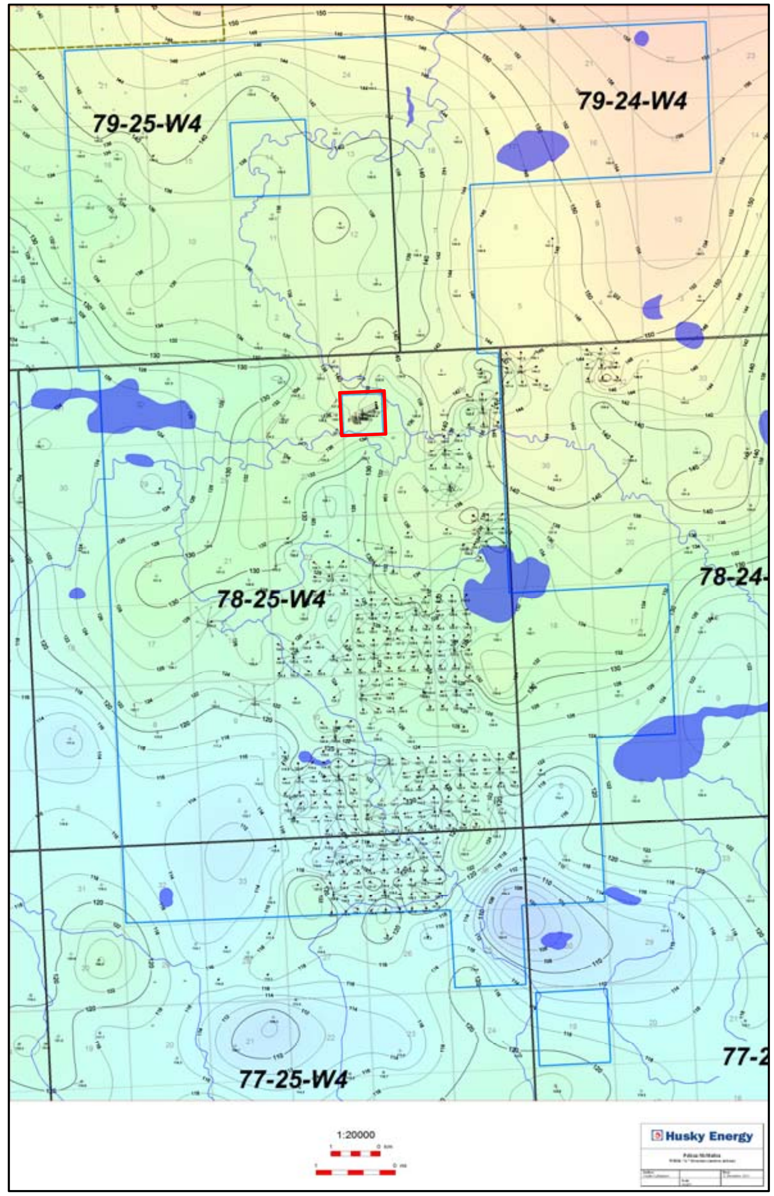
Wabiskaw "A" Net Gas Pay Values

- SW 1/4 of Section 35-078-25W4



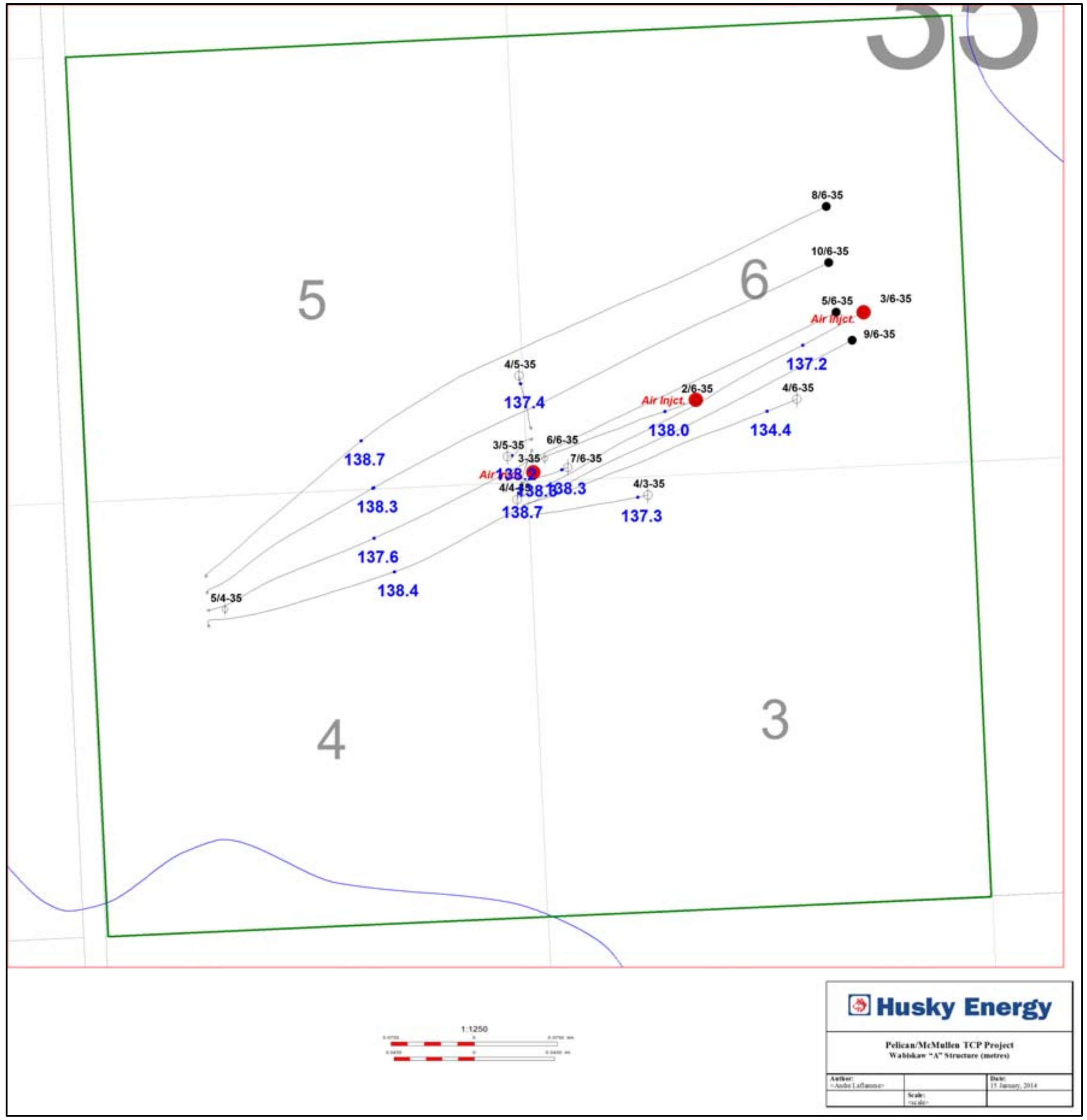
Wabiskaw "A" Structure Map (SW 03-078-25W4)

- All depths are subsea



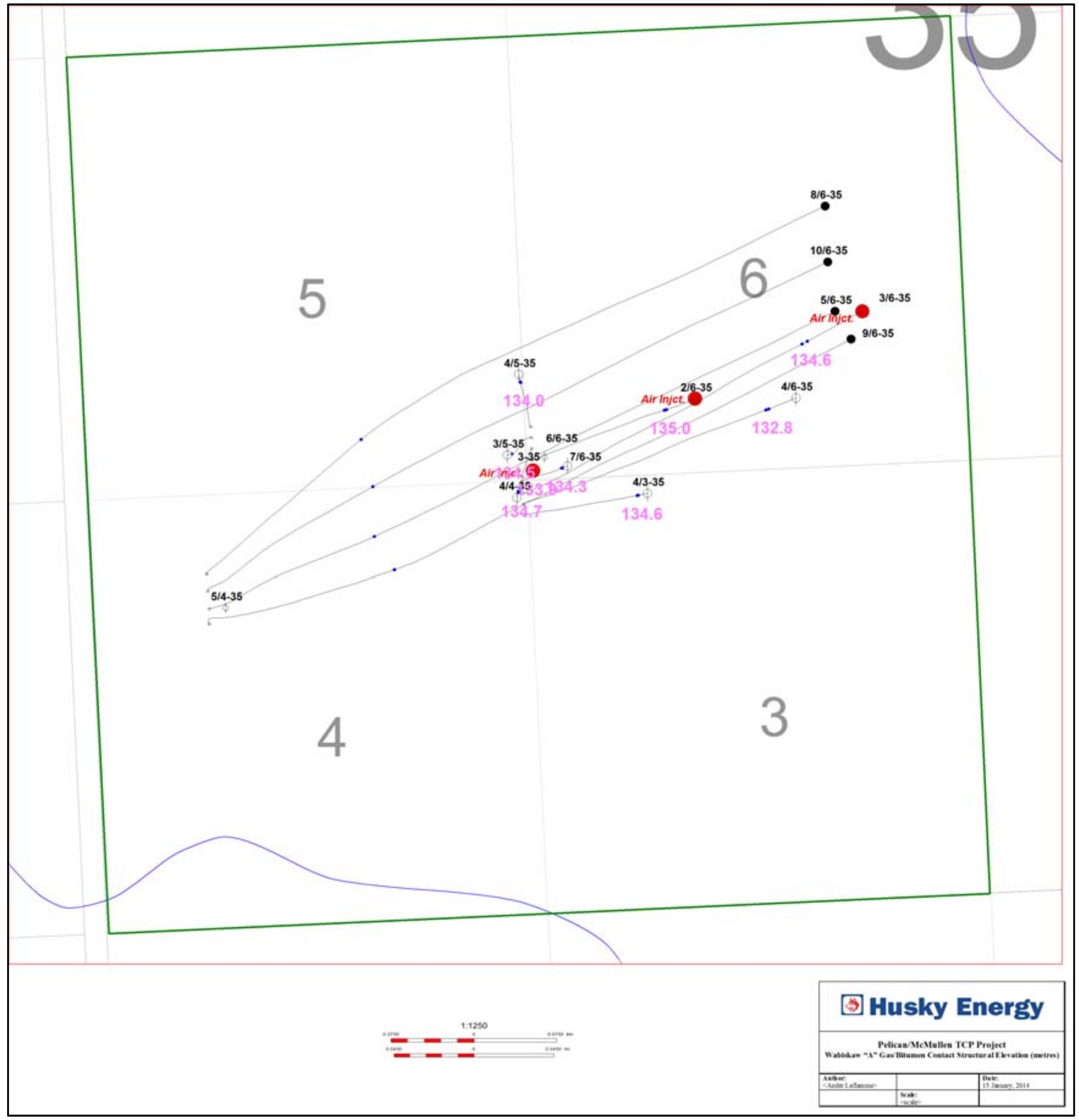
Wabiskaw "A" Structural Values

- SW 1/4 of Section 35-078-25W4
- All depths are subsea

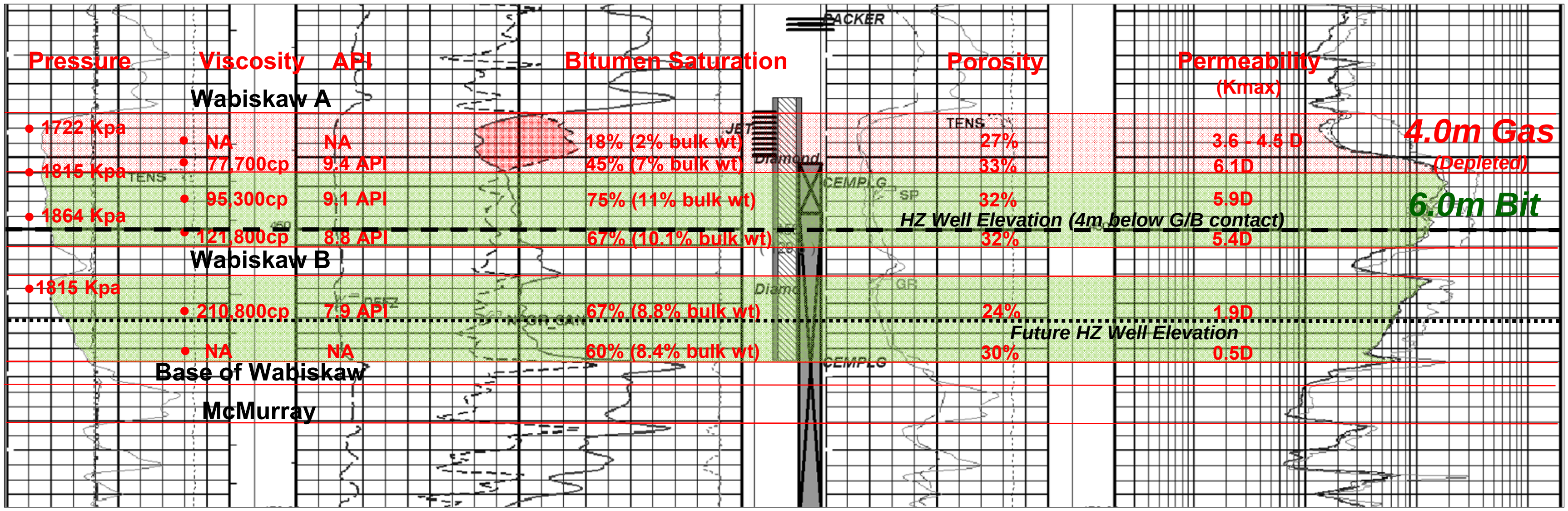


Wabiskaw "A" Gas/Bitumen Contact Structural Values

- SW 1/4 of Section 35-078-25W4
- All depths are subsea



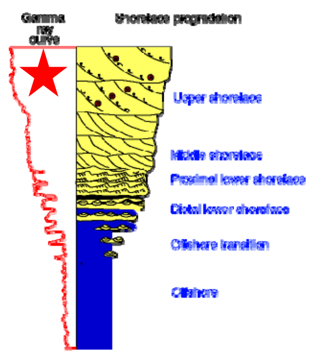
Reservoir & Fluid Characteristics (100/03-35-078-25W4)

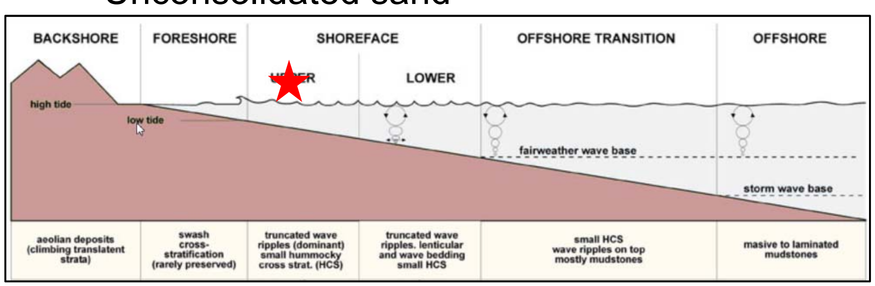


WABISKAW "A"

Marine Shoreline Deposit

- Fine-grained
- Coarsening upward
- Homogeneous & continuous
- Unconsolidated sand

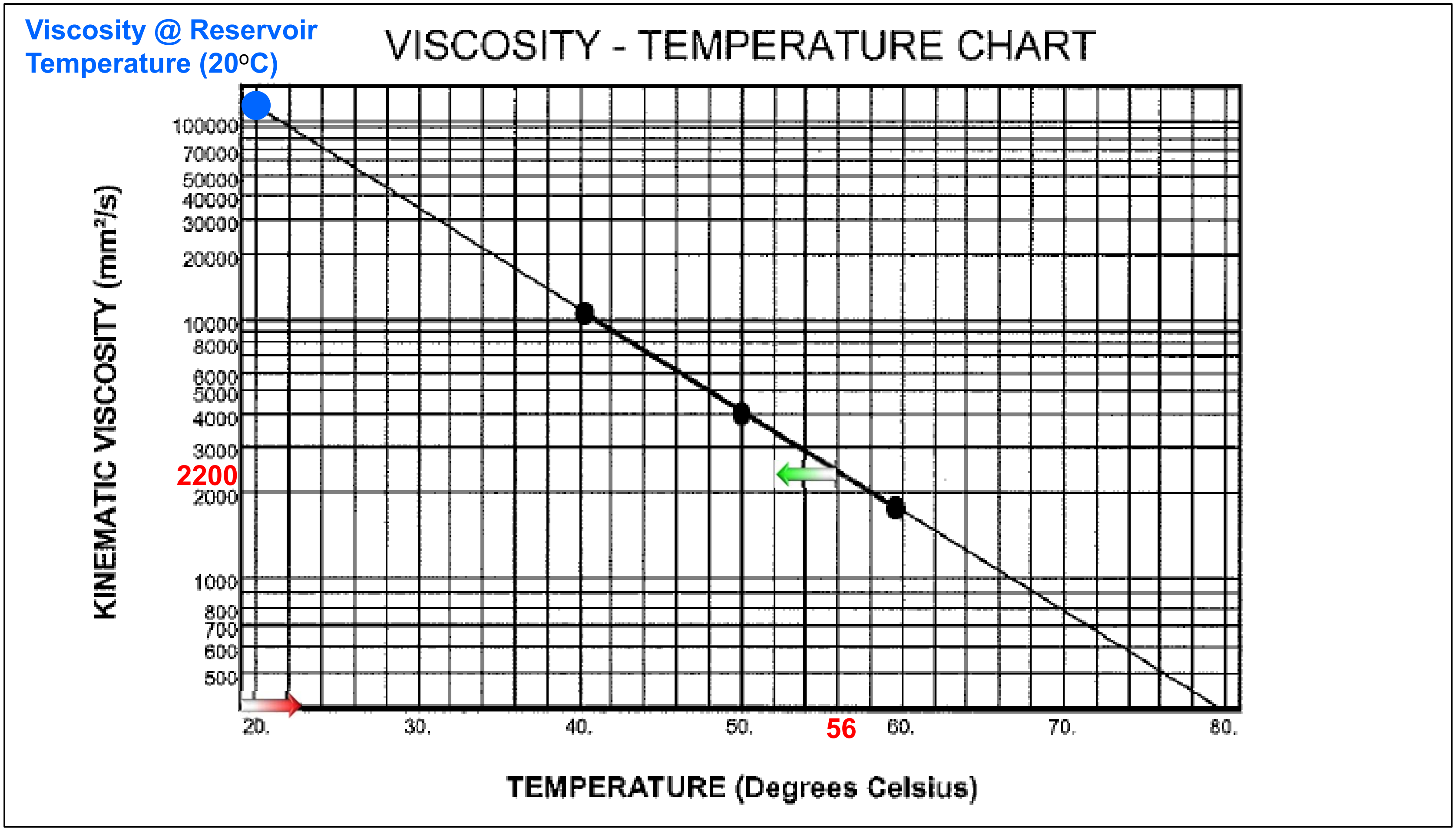




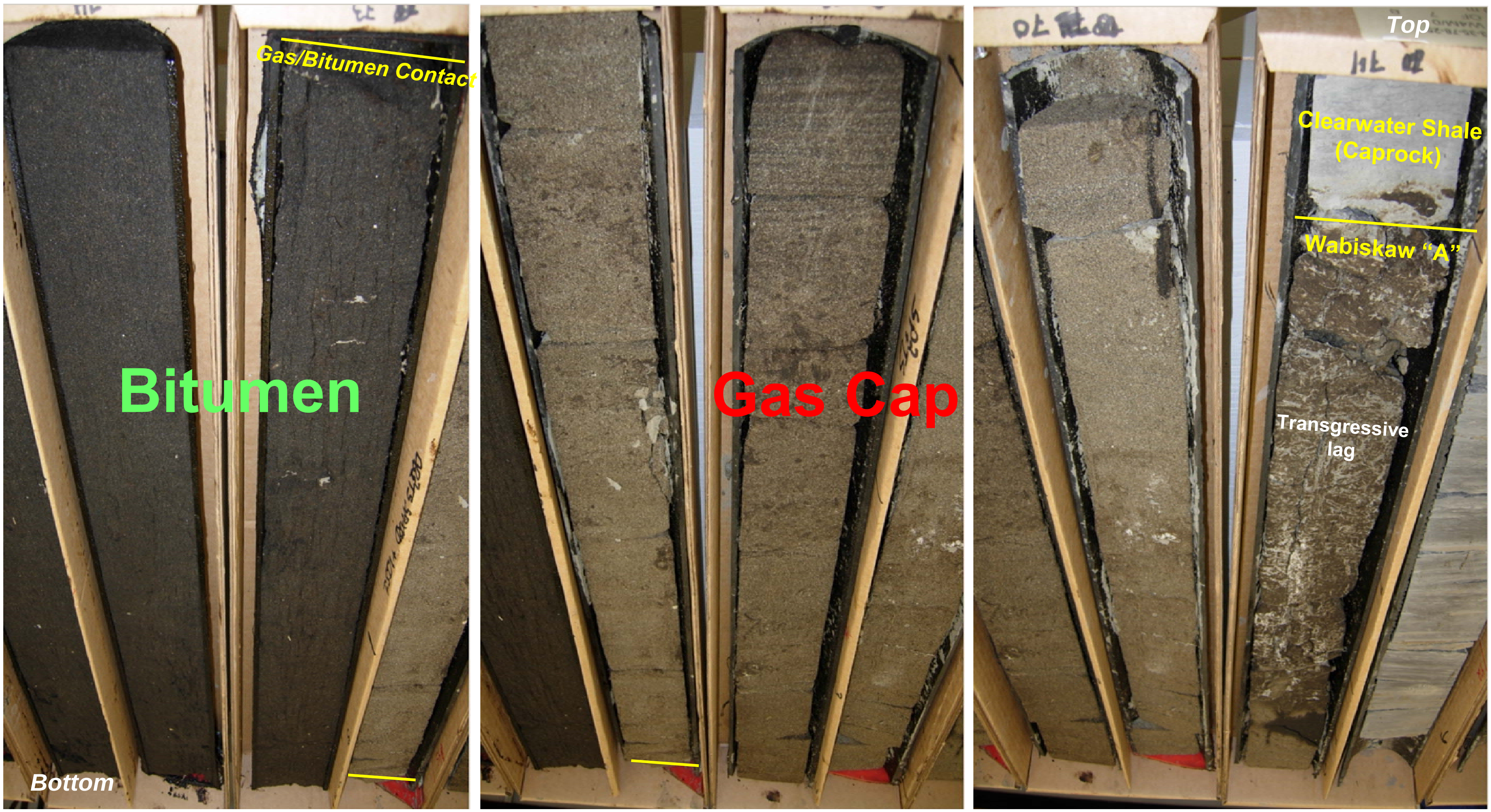
- Drilling Depth: ≈ 450m
- Porosity: ≈ 31%
- Permeability: ≈ 5 Darcies
- Net Pay: ≈ 6m
- Oil Saturation: ≈ 70%
- TAN: 1.3
- Viscosity (core): Average 122,000 cp
- Viscosity (prod): Average 190,000 cp
- API: 8.8
- Pressure (current) : ≈ 2,200 kPa (December 2015)

Well 100/03-35-078-25W4

- Oil Viscosity (4 m below the Gas Cap)



Fluid Contacts – Well 100/03-35-078-25W4



Mineral Composition in the Gas and Bitumen zones – Well 102/03-35-078-25W4

X-RAY DIFFRACTION ANALYSIS
(combined mineral analysis)

Company: Husky Energy Inc.
File No: 52135-08-2307B
Analyst: S.H

	Gas Zone	Bitumen Zone				
	Husky 102 Pelican 3-35-78-25	Husky 102 Pelican 3-35-78-25				
Sample ID	OB2	OB3	OB4	OB5	OB7	OB8
Depth Interval (m)	443.75	445.3	447.75	450.2	455.45	458.35
Mineral	Whole Rock Weight %	Whole Rock Weight %				
Quartz	93	96	94	94	93	81
K-Feldspar	0	0	1	1	1	2
Plagioclase	0	0	0	0	0	0
Anhydrite	0	0	0	0	0	0
Calcite	0	0	0	0	0	0
Dolomite	0	0	0	0	0	0
Halite	0	0	0	0	0	0
Siderite	0	0	0	0	0	0
Pyrite	0	0	Trace	Trace	Trace	1
Total Clay	7	4	5	5	6	16
Total	100	100	100	100	100	100
Clay Mineral	Relative Clay %	Relative Clay %				
Smectite	0	0	0	0	0	0
Illite / Smectite *	3	8	4	5	9	7
Illite	37	28	33	34	33	34
Kaolinite	21	41	36	32	31	40
Chlorite	39	23	27	29	27	19
Total	100	100	100	100	100	100

* Illite / Smectite Mixed-Layer Clay

The percentage of smectite layers in illite / smectite clay: 60-70%

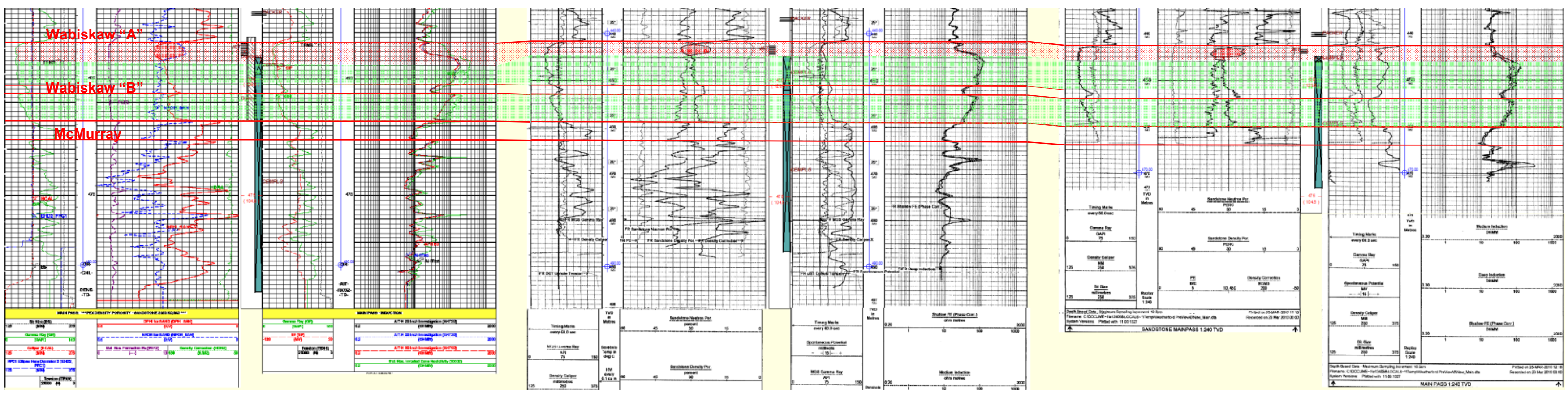
Due to inherent limitations in X-ray diffraction quantification, results must be considered semi-quantitative.

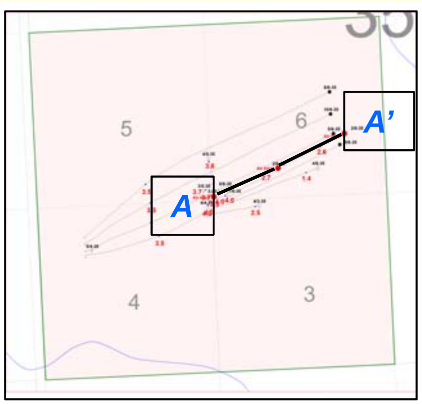
Structural Cross-Section

- Structural cross-section between the three injector wells

A *A'*

00/03-35-078-25W4	02/06-35-078-25W4	03/06-35-078-25W4
RR 2008-11-19	RR 2010-03-15	RR 2010-03-22
KB: 579.6m	KB: 579.5m	KB: 579.6m



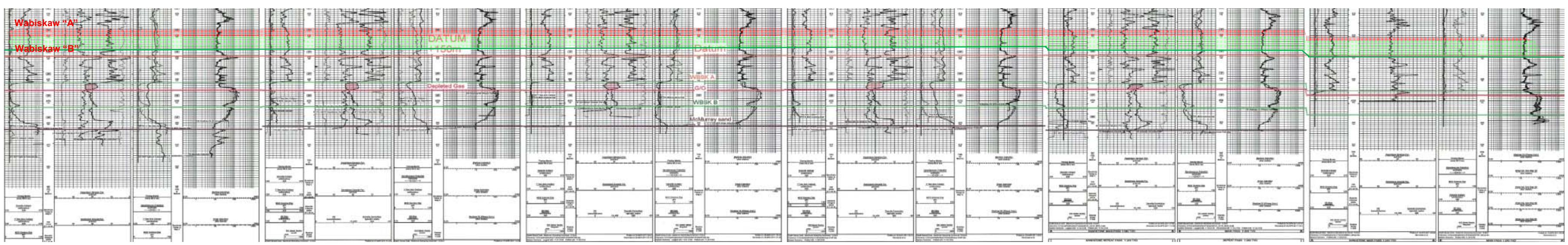


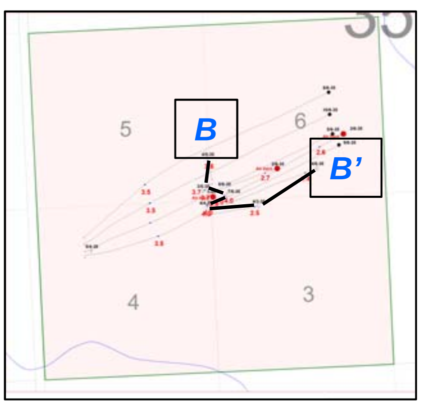
Structural Cross-Section

- Structural cross-section between the six observation wells

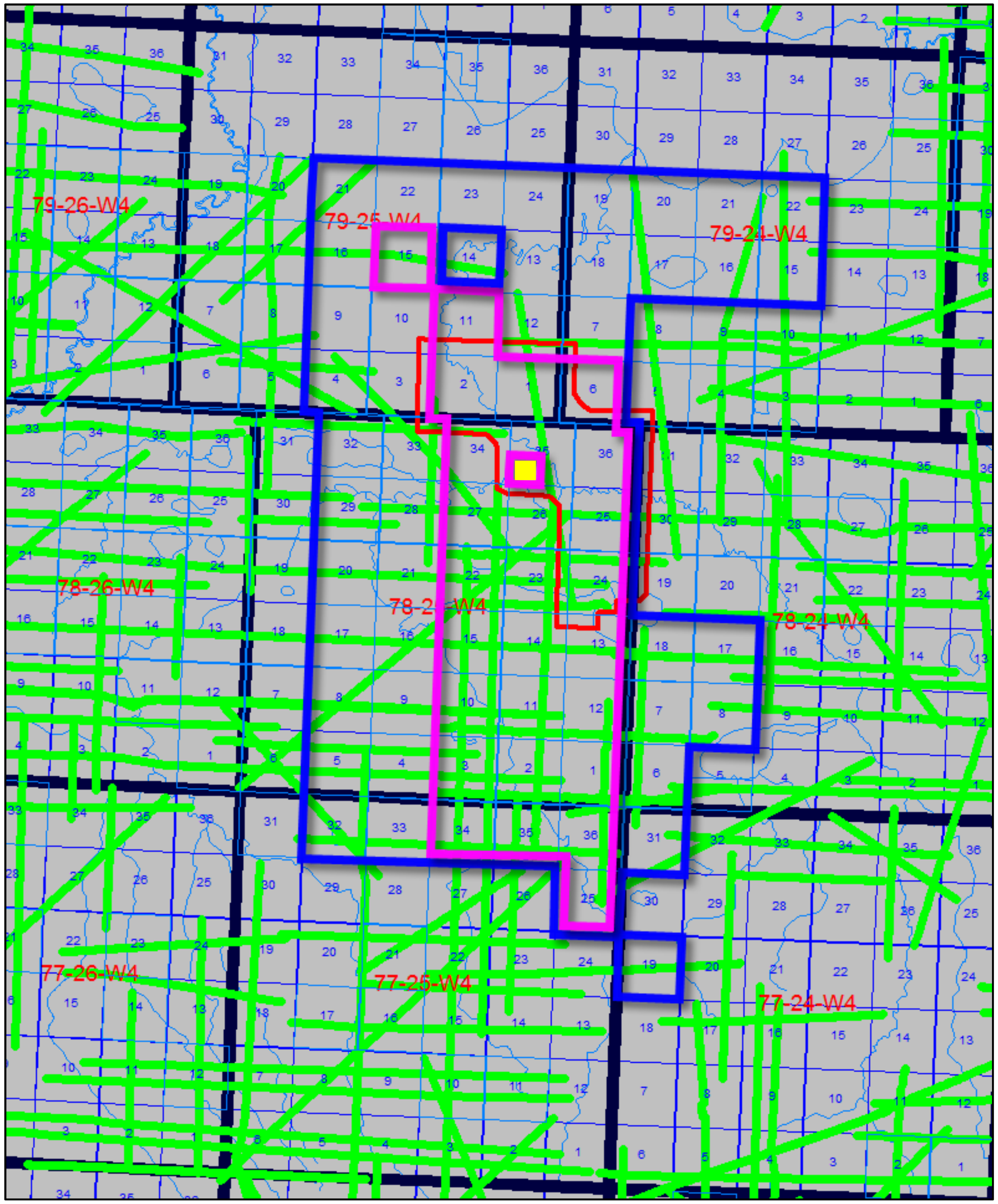
B *B'*

04/05-35-078-25W4	03/05-35-078-25W4	07/06-35-078-25W4	04/04-35-078-25W4	04/03-35-078-25W4	04/06-35-078-25W4
RR 2011-03-11	RR 2011-03-16	RR 2011-03-20	RR 2011-03-29	RR 2011-04-04	RR 2011-03-26
KB: 578.8m	KB: 579.5m	KB: 579.3m	KB: 579.7m	KB: 579.6m	KB: 579.6m





Seismic Coverage



Original Primary Recovery Scheme Boundary

Expanded Primary Recovery Scheme Boundary

TCP Recovery Scheme Boundary

Husky 3-D Seismic Coverage

Husky 2-D Seismic Coverage

Cap Rock Integrity Program

- Caprock (overlying Wabiskaw “A”)
  - Clearwater shale sequence (~95 meters thick)
- Pilot mini-frac test
  - Conducted in March 2010 on the 14-36-078-25W4 well (RR October 18, 2008)
  - Interpreted in-situ minimum stress in cap rock shale = 8,200 kPa
  - Fracture gradient = 18.51 kPa/m
- AER Scheme Maximum Operating Pressure Approval: 5,000 kPa
- Injection pressures
  - During steaming phase: 2,200 – 2,500 kPa
  - During air injection phase: 2,800 – 3,000 kPa (prior to shut-in air injection)
  - Air injection shut-in: September 18, 2014
  - Current reservoir pressure: ~ 2,200 kPa (December 2015)

Surface Monitoring Program

- Surface heave monitoring is not required
  - due to the small volume of steam that was injected (8,311 m^3 CWE) prior to the start of continuous air injection

3. Drilling and Completions

Thermal Cement Temperature Ratings

Well	Type of Well	Temperature Rating (degrees Celsius)	Type of Cement
105/06-35-078-25W4	Horizontal	1000	LDP-C-310+0.20% SMS + 0.15% CDF-4P+0.40% CFL-6+0.30%+0.40% CFL-4
108/06-35-078-25W4	Horizontal	1000	LDP-C-310+1%CFR-5+0.5% CFL-3+0.3% CitricAcid+6%Gypsum+1%TAE+0.15%CDF-4P
109/06-35-078-25W4	Horizontal	1000	LDP-C-310+1%CFR-5+0.5% CFL-3+0.3% Citric Acid+6%Gypsum+1%TAE+0.15%CDF 4P
110/06-35-078-25W4	Horizontal	1000	LDP-C-310+1%CFR-5+0.5% CFL-3+0.3% Citric Acid+6%Gypsum+1%TAE+0.15%CDF-4P
100/03-35-078-25W4	Air Injection	360	Thermal 40 Expandomix + 1.00% CaCl2 + 0.25% CFR-2 + 0.35% CFL-3
102/06-35-078-25W4	Air Injection	1000	UHTC + 3.0% CFL-6 + 0.20% SMS + 0.20% CR-2 slurry @ 1900 kg/m3
103/06-35-078-25W4	Air Injection	1000	UHTC + 3.0% CFL-6 + 0.20% SMS + 0.20% CR-2 slurry @ 1900 kg/m3
104/05-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P
103/05-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P
104/06-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P
104/04-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P
104/03-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P
107/06-35-078-25W4	Observation	1000	LDP-C-310+0.1% CR-2 + 0.3% CFL-6 + 0.2% SMS + 0.15% CDF-4P

Note:
1000 ^{o}C cement is a special cement that was ordered from Chesapeake Virginia

Thermal Cement Wellbore Integrity

- 100/03-35-078-25W4 drilled in November 2008 as an evaluation well
  - thermal cement rated for 360^oC
  - the Project location was based on core and log data from this well
  - converted to an air injection well for the Project

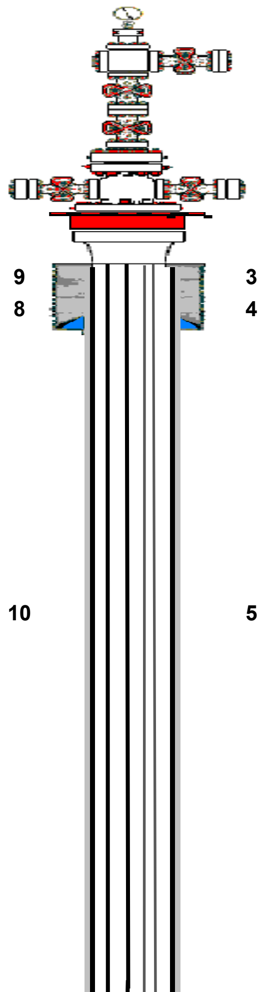
- Observed temperatures in the 100/03-35-078-25W4 air injection well
  - max temp of 220^oC during the 30 day steaming phase (October 2011)
  - temperatures constant 20 – 25^oC since start of air injection (December 2011)

- Peak combustion temperatures were recorded in two observation wells
  - 103/05-35-078-25W4 and 104/04-35-078-25W4 wells
  - highest combustion temperatures observed in the gas zone ~330^oC

- There has been no indication of wellbore integrity issues within the Project

Producing HZ Well 105/06-35-078-25W4

Well:	Husky HZ 105 Pelican 6-35-78-25	**KB (m):**	584.09	**Rig:**	Precision Drilling #102	**TD (mKB MD):**	992.00
Unique ID:	105/06-35-078-25W4/00	**GL (m):**	579.62	**Spud Date:**	06/24/2011 @ 04:00 Hrs	**TVD (mKB MD):**	454.40
Surface Location:	05/04-35-078-25W4	**CF (m):**	579.62	**Rig Release Date:**	07/05/2011 @ 23:59 Hrs	**PBTD (mKB MD):**	981.59
License #	0430310	**KB-CF (m):**	4.47	**Profile:**	Horizontal	**PB (mKB MD):**	



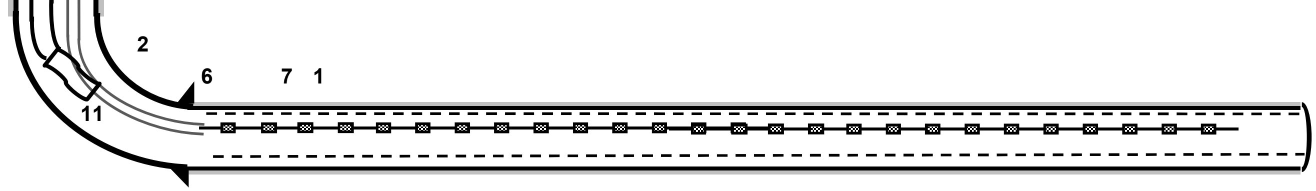
Casing Details:

Surface Hole:	444.5 mm Hole Drilled From 0.00 – 206.00 mKB
Surface Casing:	16 Jts – 339.7 mm, 81.01 kg/m, J-55, ST&C. Landed @ 205.70 mKB
Surface Casing Cement:	32.50 T – Proteus Core + 2.00% Cacl2
Returns	12.00 m3
Intermediate Hole:	270 mm Hole Drilled From 206.00 – 585.00 mKB
Intermediate Casing:	46 Jts – 219.1 mm, 47.621 kg/m, K-55, ST&C. Landed @ 584.90 mKB
Intermediate Casing Cement:	40.00 T – LDP-C-310 + 0.20% SMS + 0.15% CDF-4P + 0.40% CFL-6 + 0.30% CFL-3 + 0.40% CFL-4
Returns:	0.80 m3
Liner Hole:	200 mm Hole Drilled From 585.00 – 992.00 mKB MD
Liner Casing:	35 Jts – Slotted Liner, 139.7 mm, 25.29 kg/m, L-80, GEOCONN. Landed @ 982.00 mKB MD, Liner hanger top @ 557.60 mKB MD

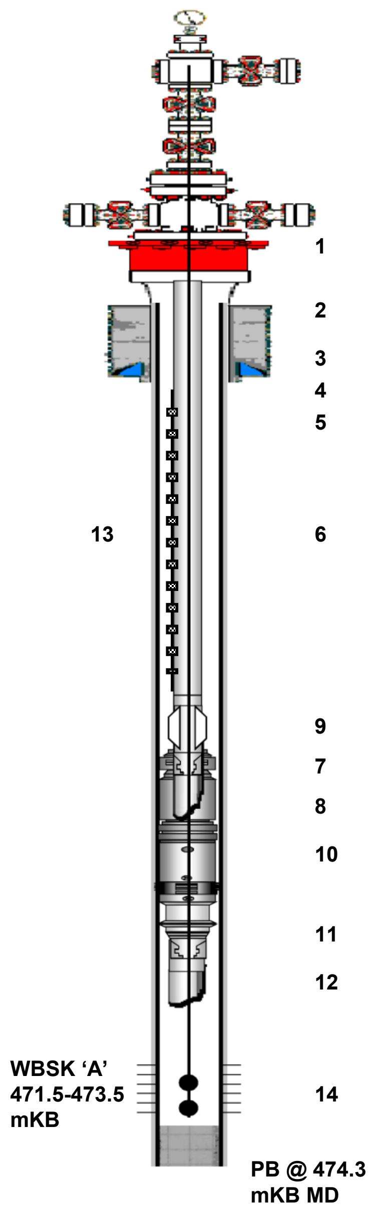
Tubing String Details:

Size: (mm) OD: 88.9 **Kg/m:** 13.84 **Grade:** J-55 **Landing Depth: (mKB MD):** 550.0

No.		**No.**	
1.	Instrumentation String #1 - Thermocouples Landed @ 970.0, 945.0, 920.0, 895.0, 870.0, 845.0, 820.0, 795.0, 770.0, 745.0, 720.0, 695.0, 670.0, 645.0, 620.0, 595.0 mKB MD	**7.**	38.1mm Coil Tubing Cointaining Both Instrumentation Strings - Landed @ 961.00 mKB MD
2.	Instrumentation String #2 - Thermocouples Landed @ 969.0, 770.0, 569.0 mKB MD + Pressure Sensors Landed @ 969.0, 770.0, 569.0 mKB MD	**8.**	R&M Energy - Hi-Temperature Tubing Rotator
3.	1 - Tubing Hanger	**9.**	1 - 114.3 mmx 88.9mm Cross-Over
4.	1 - 60.3mm x 52.4mm Cross-Over	**10.**	56 - 88.9mm. L-80 Tubing With Bevelled Couplings. Landed @ 501.3 mKB MD
5.	57 - 52.4mm Tubing Jt.	**11.**	PCP - pump intake landed at 501.30 mKB MD
6.	1 - 52.4mm Mule Shoe Jt.		



Injection Well 102/06-35-078-25W4



Well:	Husky 102 Pelican 6-35-78-25	**KB (m):**	579.46	**Rig:**	Precision Drilling #164	**TD (mKB MD):**	529.00
Unique ID:	102/06-35-078-25W4/00	**GL (m):**	575.32	**Spud Date:**	3/15/2010 3:30:00 PM	**TVD (mKB MD):**	492.12
Surface Location:	04/06-35-078-25W4	**CF (m):**	575.41	**Rig Release Date:**	3/15/2010 11:59:00 PM	**PBTD (mKB MD):**	522.20
License #	0418707	**KB-CF (m):**	4.05	**Profile:**	Directional	**PB (mKB MD):**	474.30 (Cement Top)

Casing Details:

Surface Hole:	349 mm Hole Drilled From 0.00 – 199.00 mKB MD
Surface Casing:	15 Jts – 244.5 mm, 48.068 kg/m, H-40, ST&C. Landed @ 199.00 mKB MD
Surface Casing Cement:	22.00 T – Proteus CO + 2.00% CaCl2 + 1.00% CFR-2
Returns	4.00 m3
Production Hole:	222 mm Hole Drilled From 199.00 – 529.00 mKB MD
Production Casing:	44 Jts + 1 Marker Jt - 177.8 mm, 34.228 kg/m, L-80, QB2. Landed @ 529.00 mKB MD
Production Casing Cement:	Scavenger - 1.00 T - UHTC; Lead - 15.40 T – UHTC + 0.30% CFL-6 + 0.20% CR-2 + 0.20% SMS
Returns:	2.00 m3

Tubing String Details:

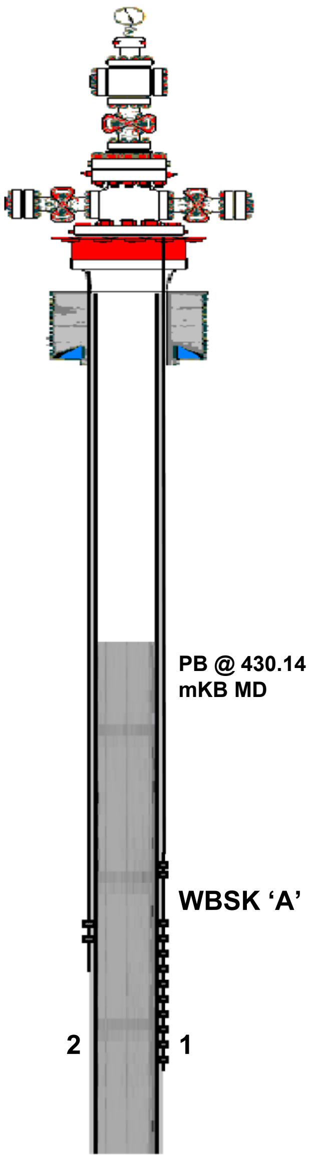
Size: (mm) OD: 88.9 **Kg/m:** 13.84 **Grade:** J-55 **Landing Depth: (mKB MD):**

No.		**No.**	
1	1 - 179.4 mm × 88.9 mm Tubing Hanger	8	1 - 88.9 mm Box Up x 101.6 mm Mule Shoe Down
2	1 - 88.9 mm Tubing Jt.	9	1 - 88.9 mm x 101.6 mm x 4.50 m Thermal PermaPack Locating Assembly
3	1 - 88.9 mm x 3.10 m Pup Jt.	10	1 - 177.8 mm Thermal PermaPack Permanent Seal Bore Packer c/w 101.6 mm x 4.50 m Integral Seal Bore
4	1 - 88.9 mm x 1.80 m Pup Jt.	11	1 - 114.3 mm x 69.9 mm SXN Nipple (67 mm No-Go Nipple)
5	1 - 88.9 mm x 1.20 m Pup Jt.	12	1 - 114.3 mm Wireline Re-Entry Guide
6	47 - 88.9 mm Tubing Jt.	13	Thermocouples @ 472.50, 472.50, 443.00, 415.00, 387.00, 358.00, 330.00, 302.00, 275.00, 247.00 mKB MD
7	1 - 88.9 mm x 69.9 mm SX Nipple	14	Thermocouples @ 473.50, 472.25 mKB MD

Isolation Equipment:

Date Set	Make:	Model:	Depth Set (mKB MD):	Pressure Tested:
July 14, 2011	Logan	177.8 mm Thermal PermaPack Permanent Seal Bore Packer	465.00	7 MPa @10 mins
April 17, 2011	Sanjel	1.20 m3 LDP-C-310 (UHTC) + 0.30% CFL-6 + 0.20% SMS + 0.10% CR-2	522.20-482.60	
July 13, 2011	Sanjel	1.30 T - LDP-C-310 (UHTC) + 0.30% CFL-6 + 0.20% SMS + 0.10% CR-2	482.60-474.30	

Observation Well 104/03-35-078-25W4



Well:	Husky 104 Pelican 3-35-78-25	**KB (m):**	579.60	**Rig:**	Precision Drilling #163	**TD (mKB MD):**	487.00
Unique ID:	104/03-35-078-25W4/00	**GL (m):**	575.40	**Spud Date:**	03/30/2011 @ 12:45 Hrs	**TVD (mKB MD):**	464.83
Surface Location:	04/04-35-078-25W4	**CF (m):**	575.65	**Rig Release Date:**	04/04/2011 @ 20:00 Hrs	**PBTD (mKB MD):**	
License #	0419607	**KB-CF (m):**	3.95	**Profile:**	Directional	**PB (mKB MD):**	430.14 (Cement Top)

Casing Details:

Surface Hole:	349 mm Hole Drilled From 0.00 – 171.00 mKB MD
Surface Casing:	13 Jts – 244.5 mm, 48.068 kg/m, H-40, ST&C. Landed @ 171.00 mKB MD
Surface Casing Cement:	20.00 T – Proteus Core + 2.00% CaCl2 + 1.00% CFR-2 + 0.15% CDF-4P
Returns	5.00 m3
Production Hole:	222 mm Hole Drilled From 171.00 – 487.00 mKB MD
Production Casing:	35 Jts + 3 Marker Jt - 114.3 mm, 14.14 kg/m, J-55, ST&C . Landed @ 484.20 mKB MD
Production Casing Cement:	29.40 T – LDP-C-310 + 0.10% CR-2 + 0.20% SMS + 0.30% CFL-6 + 0.15% CDF-4P
Returns:	5.00 m3
Liner Hole:	N/A
Liner Casing:	N/A

Tubing String Details:

No.	
1	Instrumentation String #1 (Outside Of Casing): Thermocouples @ 476.27, 475.14, 474.01, 472.01, 471.75, 470.62, 469.49, 468.36, 467.22, 464.96, 452.52, 451.38 mKB MD
2	Instrumentation String #2 (Outside Of Casing): Thermocouples @ 470.62, 464.53 mKB MD & Pressure Sensors @ 470.62, 465.53 mKB MD

4. Artificial Lift

Artificial Lift

- Horizontal production well 105/06-35-078-25W4
  - Currently equipped with high temperature metal to metal 80MET1000 PCP
  - Initially equipped with a high temperature 12-ML-17 PCP (rated for a max of 175 ^{o}C)
  - Horizontal well 105/06-35 on prod November 2012

- Horizontal production well 109/06-35-078-25W4
  - Currently equipped with high temperature metal to metal 80MET1000 PCP
  - Initially equipped with a high temperature 12-ML-44 PCP
  - Changed to a 16-ML-44 PCP (rated for a max of 175 ^{o}C)
  - On production September 2013

- Horizontal production well 110/06-35-078-25W4
  - Currently equipped with high temperature metal to metal 80MET1000 PCP
  - Initially equipped with a high temperature 16-ML-44 PCP (rated for a max of 175 ^{o}C)
  - On production October 2013

- Horizontal production well 108/06-35-078-25W4
  - Equipped with high temperature 12-ML-17 PCP
  - Well started back up October 2014
  - On production October 2013 (shut-in December 2, 2013)

5. Instrumentation in Wells

Metering and Monitoring

- Air injection will be measured on an individual well basis; four horizontal wells are equipped with production and sales tanks

- Four Horizontal Oil Production Wells
    - Thermocouples every 25m along the horizontal section
    - Pressure sensors at the heel, middle and toe of the horizontal section
    - Wells equipped with gas chromatographs to monitor produced gas composition
    - Periodic oil & gas samples for analysis
    - Issues with malfunctioning thermocouples & pressure sensors

- Three Air Injection Wells
    - Thermocouples placed at the mid-point of perforations (gas zone)
    - Two wells equipped with temperature sensors to indicate potential flow behind pipe

- Six Observation Wells
    - 12 thermocouples installed per well (2 above the gas zone, 3 gas zone & 7 bitumen zone)
    - One well equipped with pressure sensors

- Offsetting Gas Wells
    - Four area gas wells equipped gas chromatographs for monitoring of produced gas composition
    - Periodic static gradients to monitor reservoir pressure

6. 4D Seismic

4D Seismic

- Lateral distribution of heat
  - Too small to be resolved on 3D or 4D seismic surveys

- 4D seismic data
  - No plans to acquire

7. Scheme Performance

Scheme Performance

- First steam injection on September 28, 2011 (temporary – 8,311 m^3 CWE)
- First air injection on December 8, 2011
- Shut-in air injection on September 18, 2014
- Suspension of Project operations on October 31, 2015

- The purpose of the initial steam injection was to raise the formation temperature in each of the three injection wells to 180 – 200 ^{0}C to allow for ignition when switching over to air injection.

Criteria for Hoizontal Producers Start-up:

- Nine of the 16 thermocouples located along the horizontal section of the wellbore would be heated to a temperature of at least 56 ^{0}C, which would result in a bitumen viscosity of 2,200 cp or less and a flow rate of 25 m^3/d or higher.

Injection & Production History

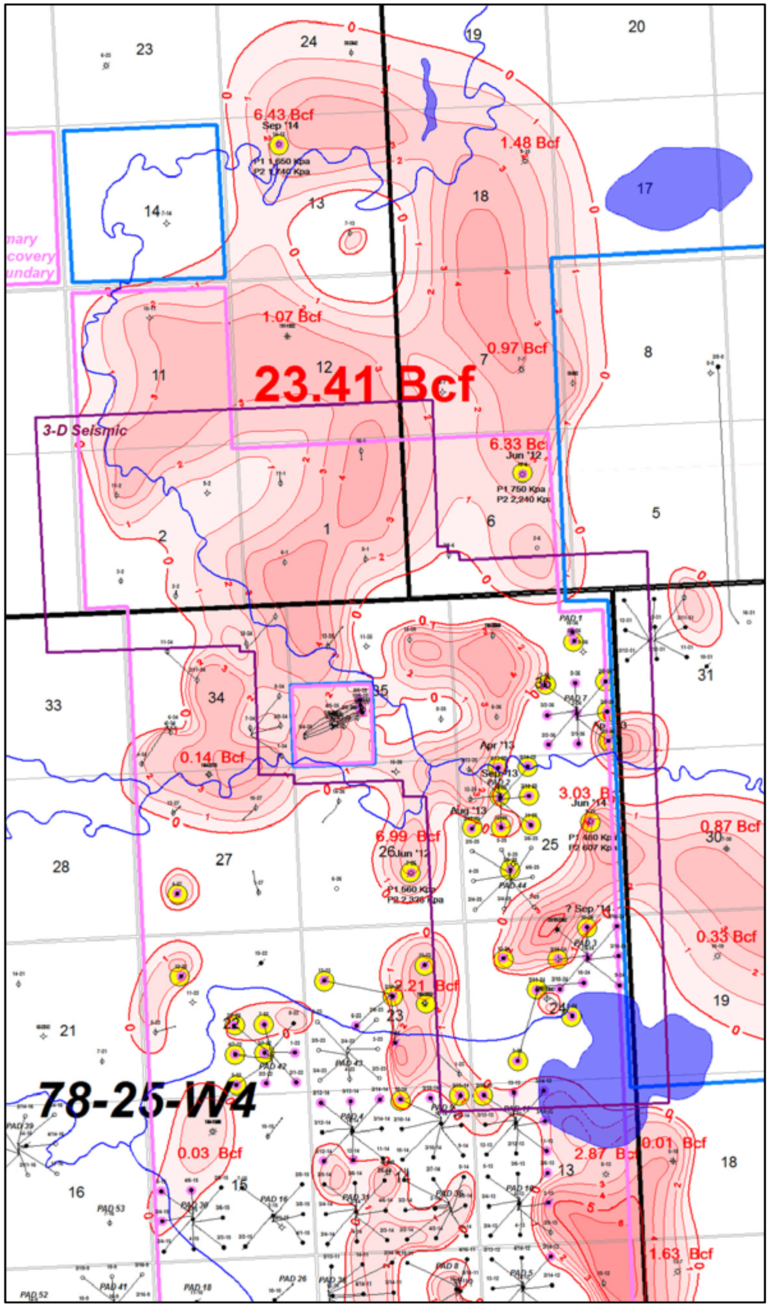
- Start-up of air injection on December 8, 2011
  - Increases in injection rate:
    - 15 e^3m^3/day on December 12, 2011
    - 20 e^3m^3/day on December 28, 2011
    - 25 e^3m^3/day on January 30, 2012
    - 40 e^3m^3/day on February 17, 2012
    - 45 e^3m^3/day on March 16, 2012
    - 55 e^3m^3/day on April 24, 2012
    - 65 e^3m^3/day on July 16, 2012 (two trains)
    - 90 e^3m^3/day on October 17, 2012 (third train)
    - shut-in air injection on September 18, 2014 (after 2 years & 10 months of injection)

- Shut-in of air injection was due to increasing concentrations of nitrogen observed in several of Husky's surrounding primary wells in the area and the potential risk to more production

- Horizontal Well 105/06-35-078-25W4 on initial production for four days in August 2012
  - Shut-in due to the detection of H_2S, production re-start was on November 1, 2012

- Horizontal wells 109/06-35-078-25W4, 110/06-35-078-25W4 & 108/06-35-078-25W4 were placed on production in September and October 2013
  - Well 108/06-35-078-25W4 was shut-in on December 2, 2013 to allow bitumen zone to be further heated; was placed back on production October 8, 2014

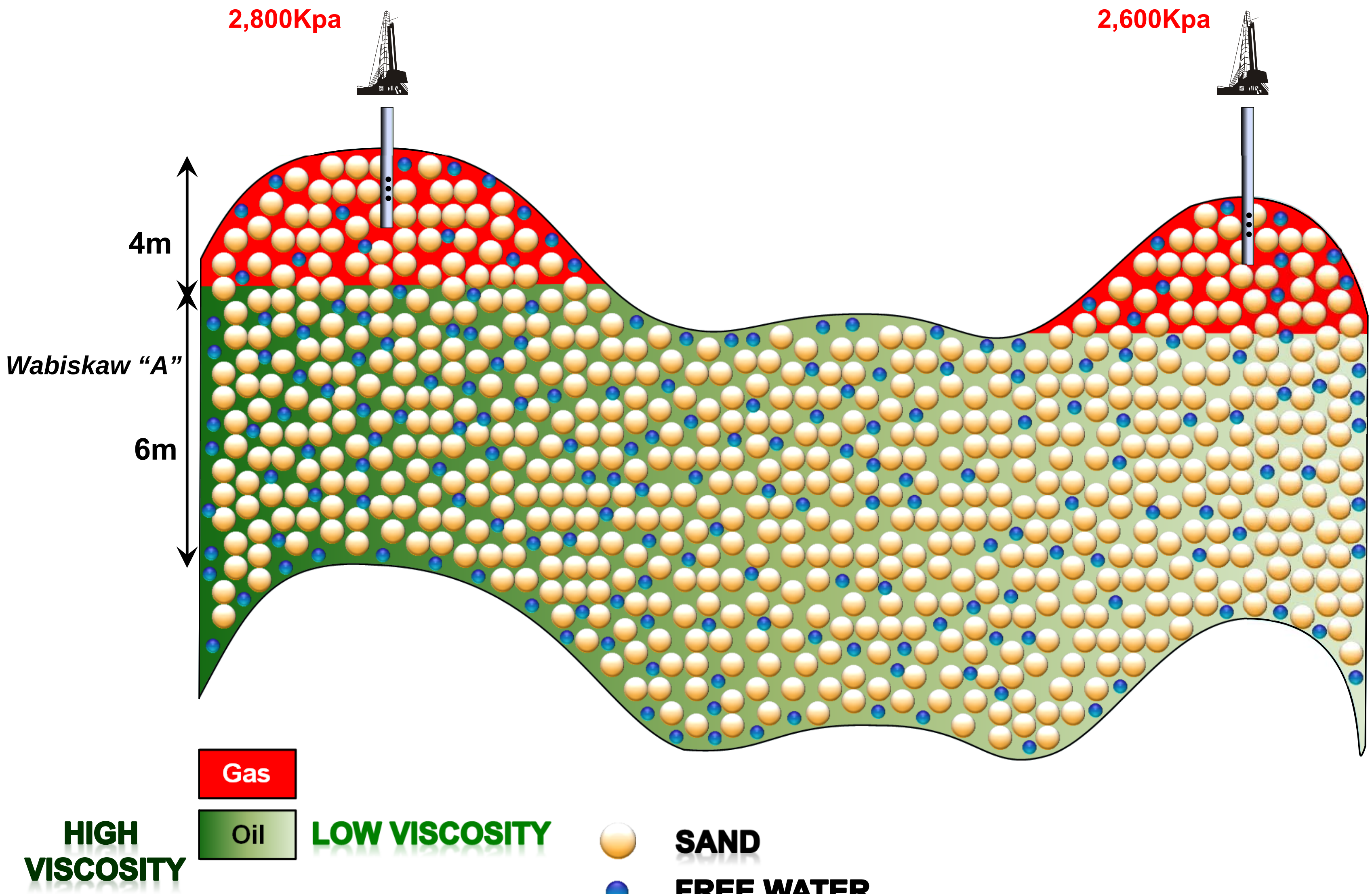
Nitrogen Monitoring



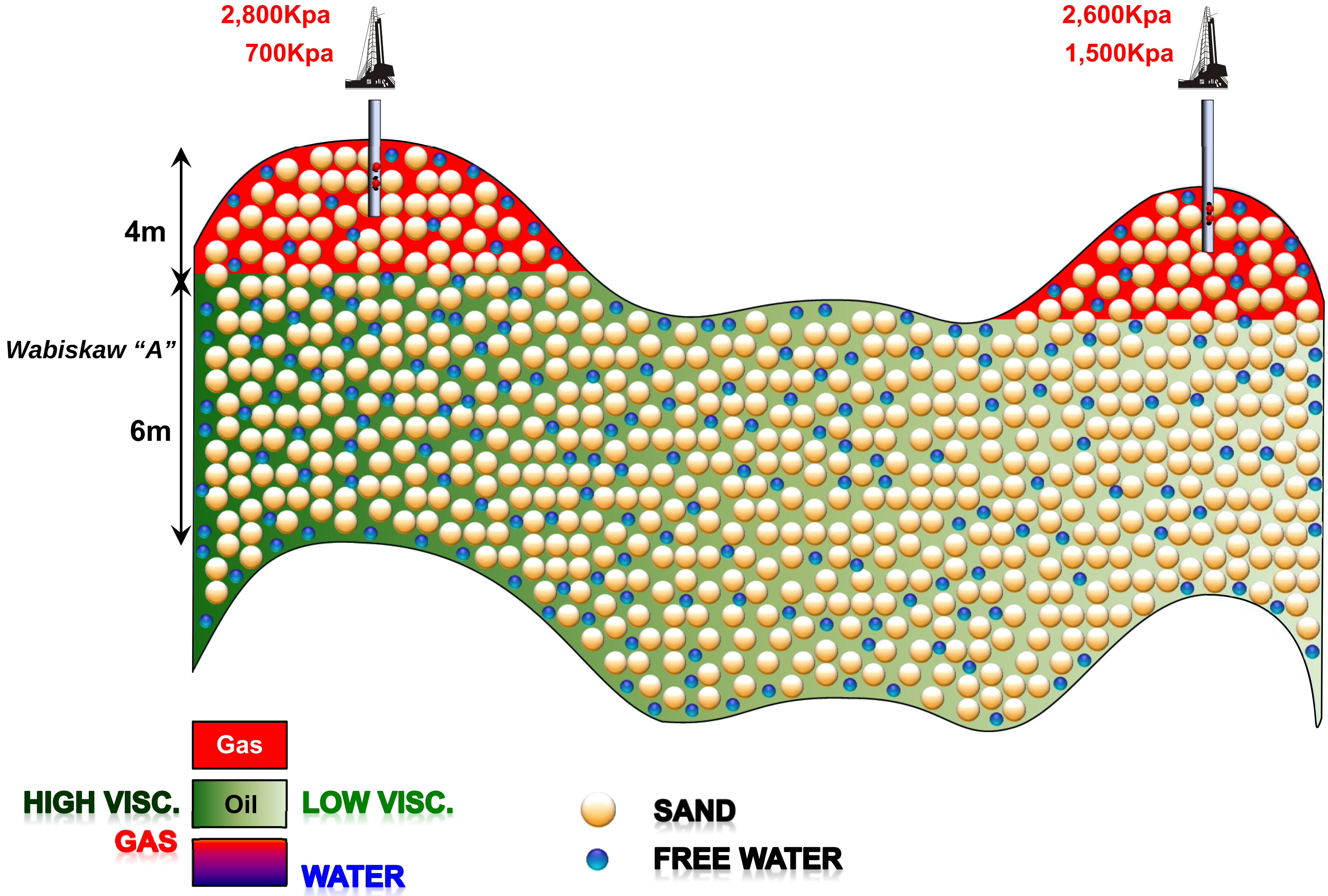
Wells monitored for Nitrogen

Wells with Nitrogen detected

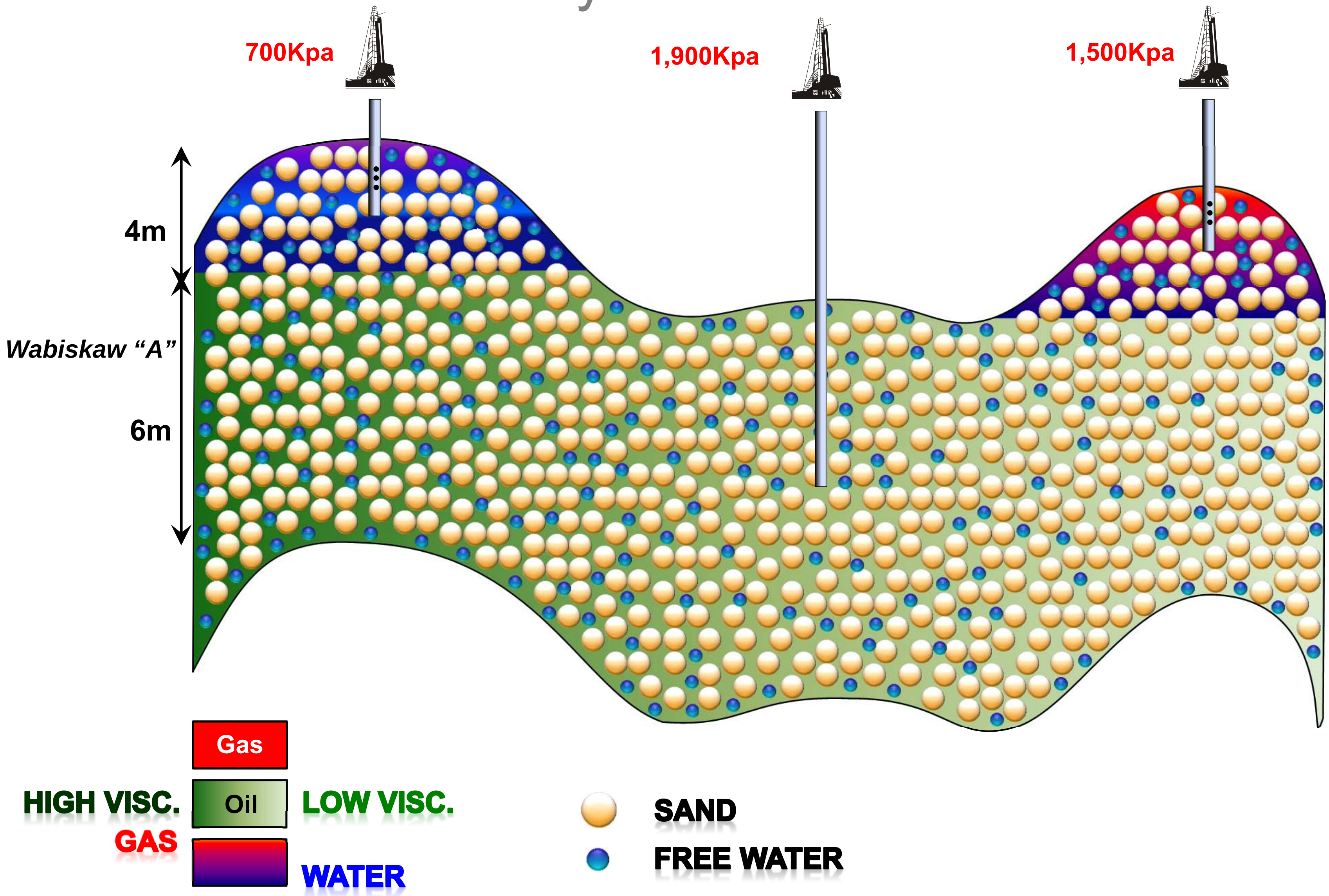
Nitrogen Breakthrough Mechanism – Gas Discovery



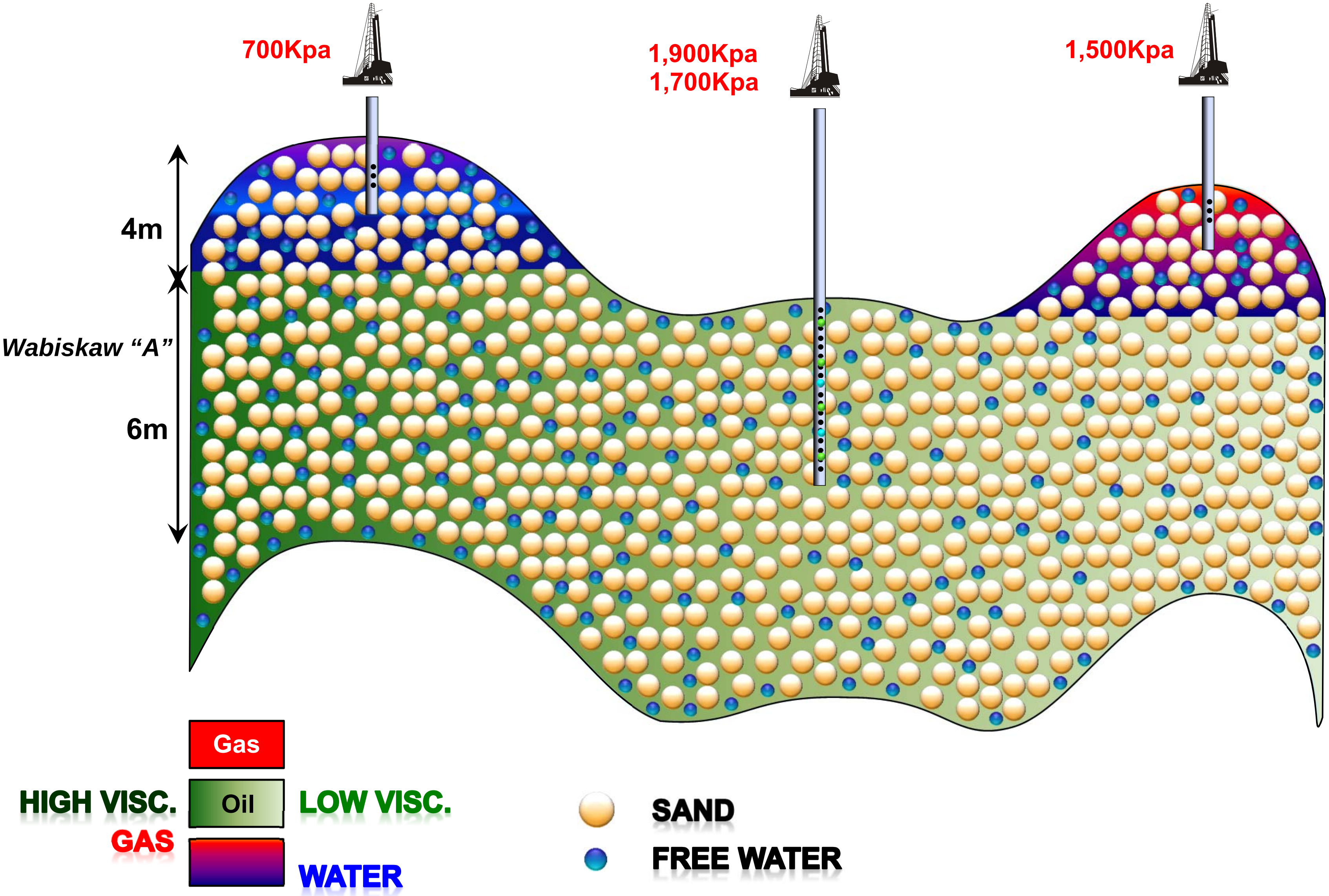
Nitrogen Breakthrough Mechanism – Gas Depletion



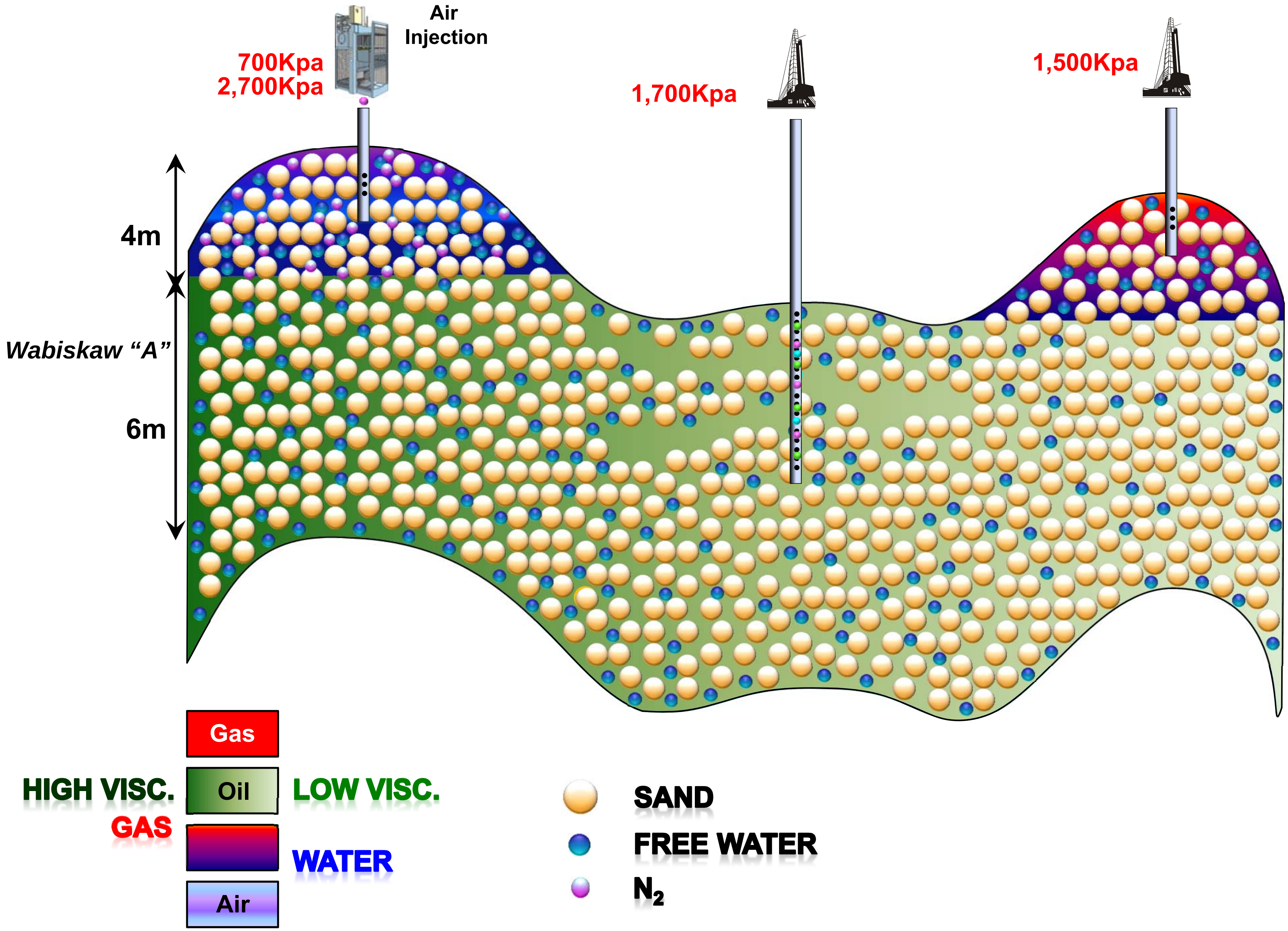
Nitrogen Breakthrough Mechanism – Bitumen Discovery



Nitrogen Breakthrough Mechanism – Bitumen Production

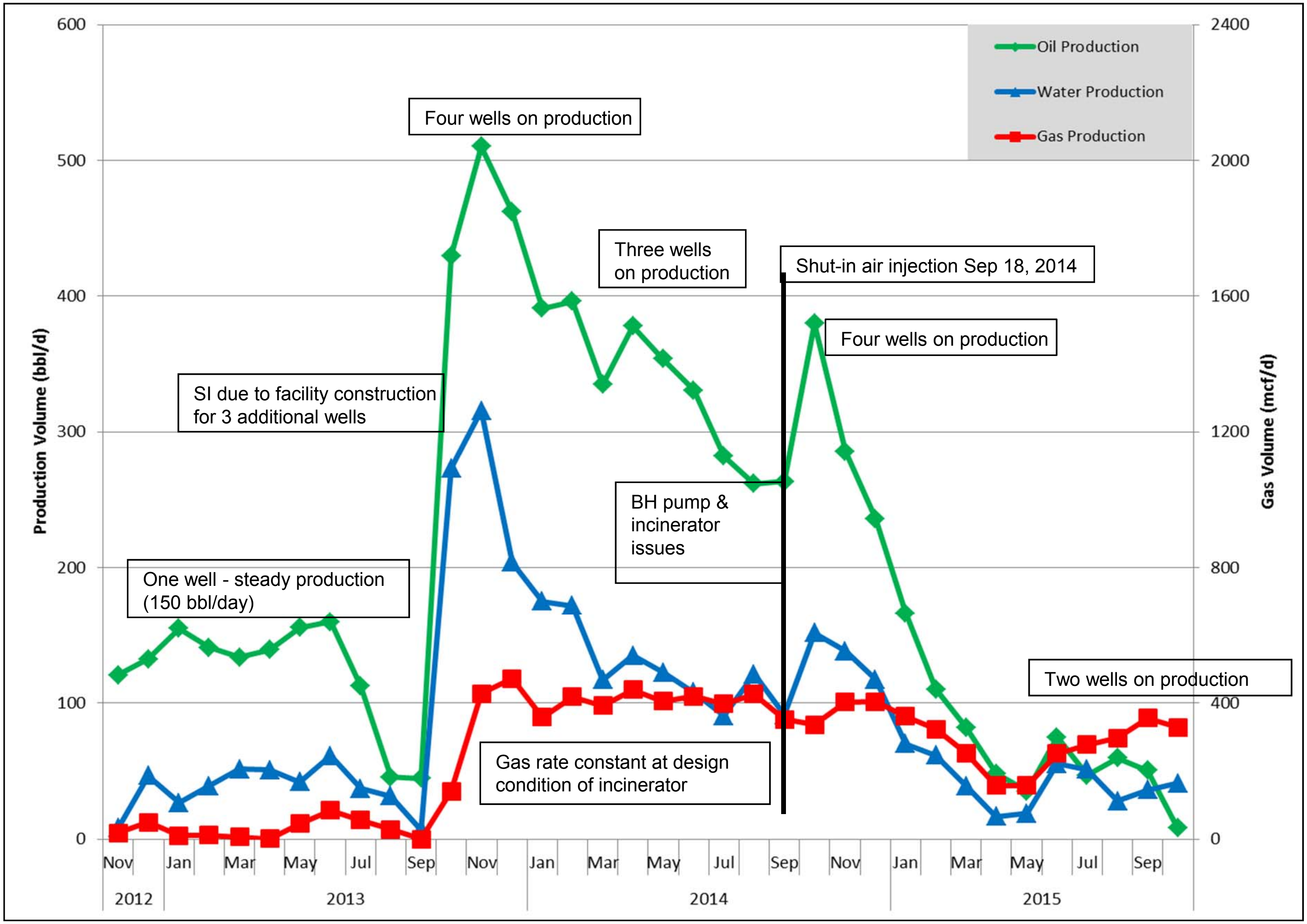


Nitrogen Breakthrough Mechanism - Air Injection

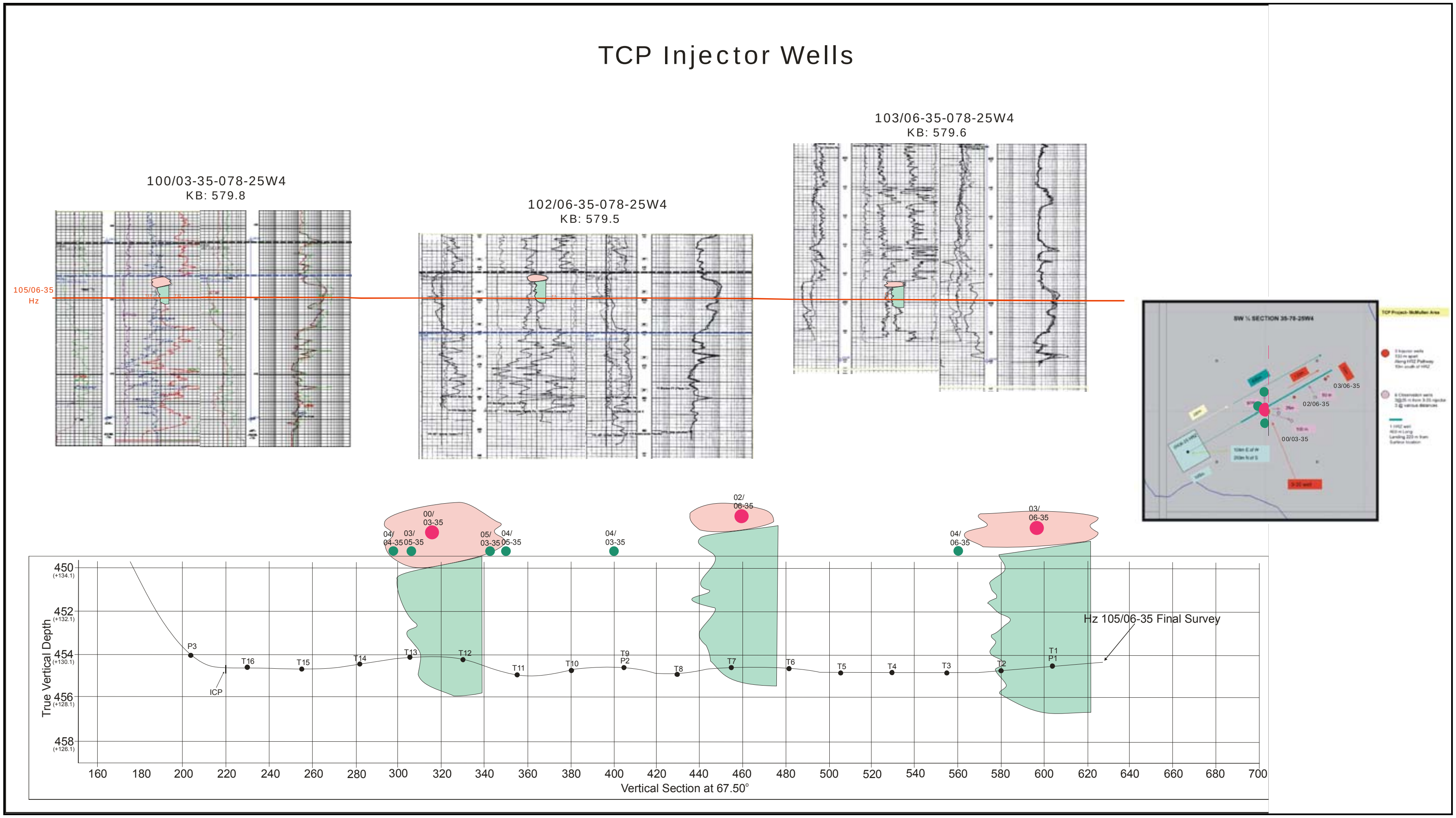


Production History

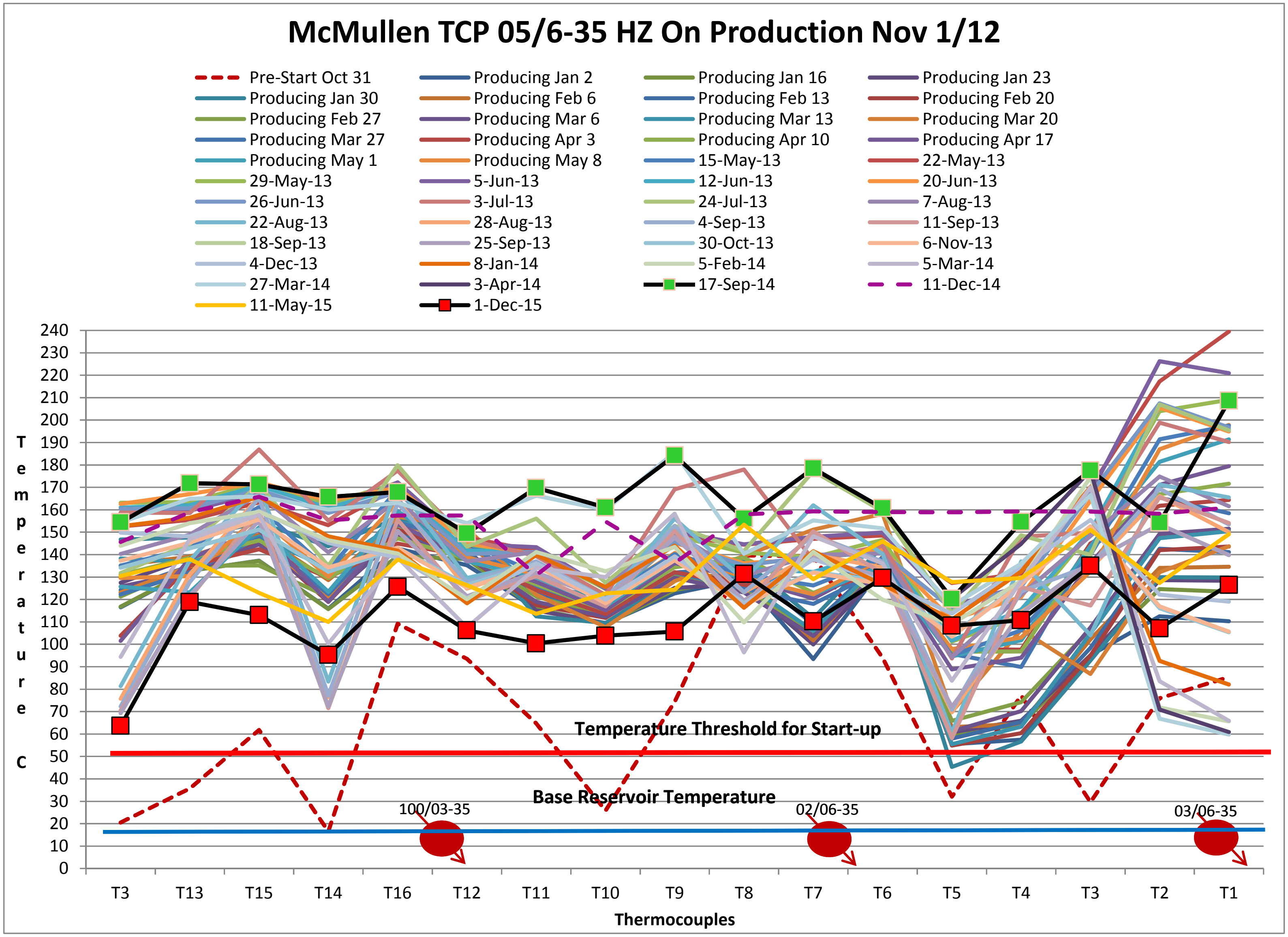
- Cumulative Oil 228.3 mstb (36.3 e^3m^3) at suspension of operations October 31, 2015



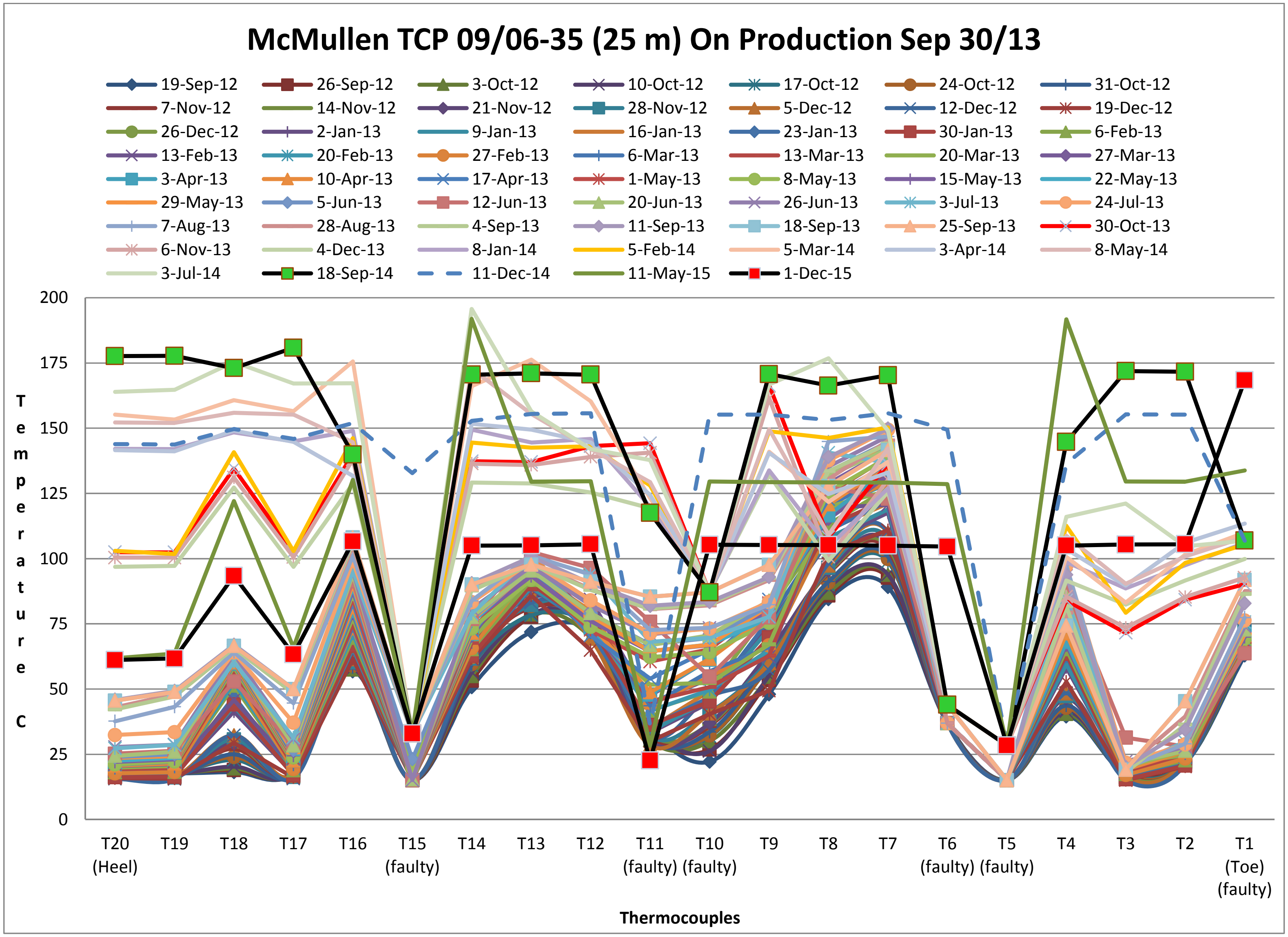
Horizontal Well 105/06-35-78-25W4 Thermocouple Placement



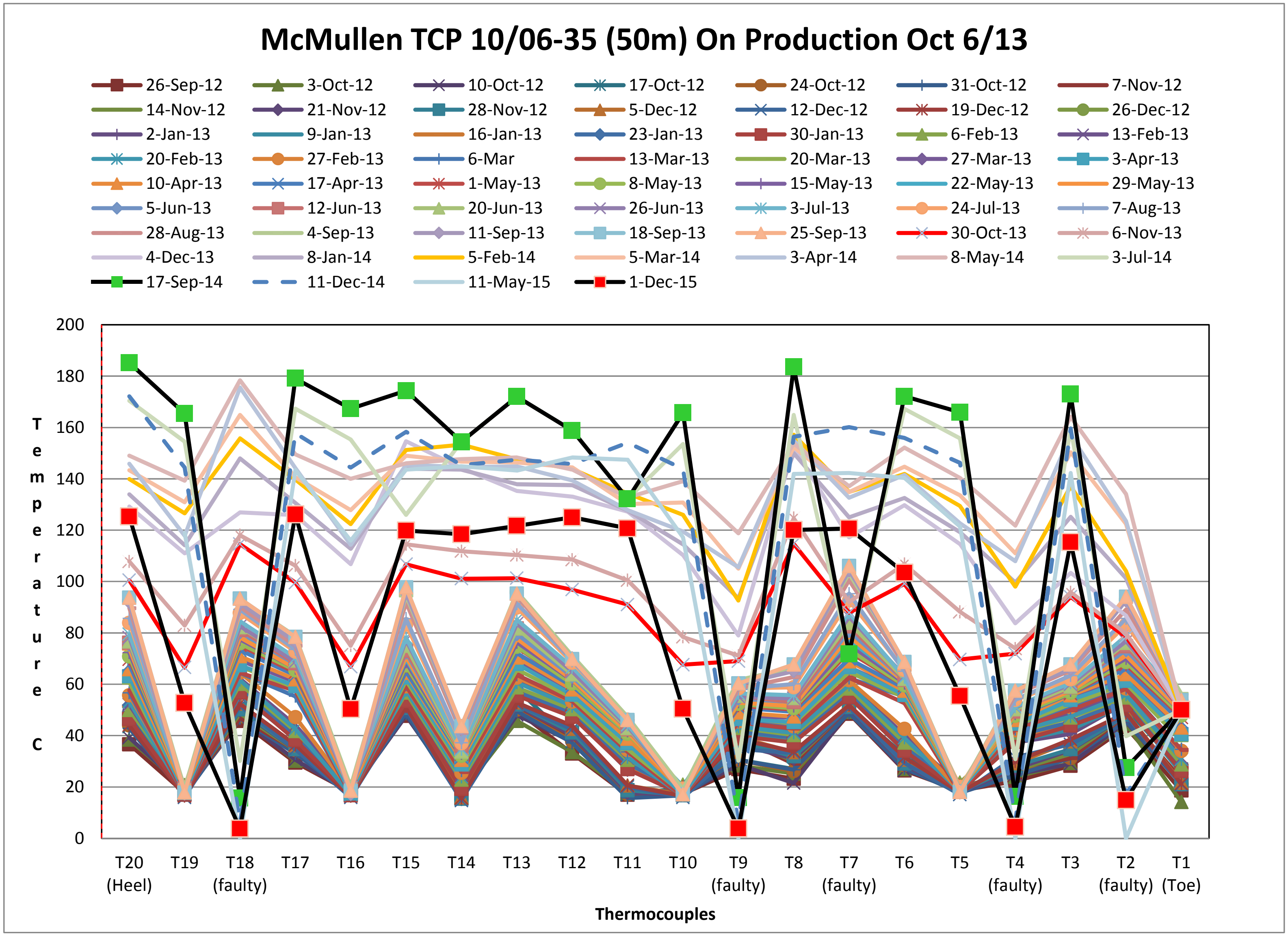
Horizontal Wellbore Temperature History



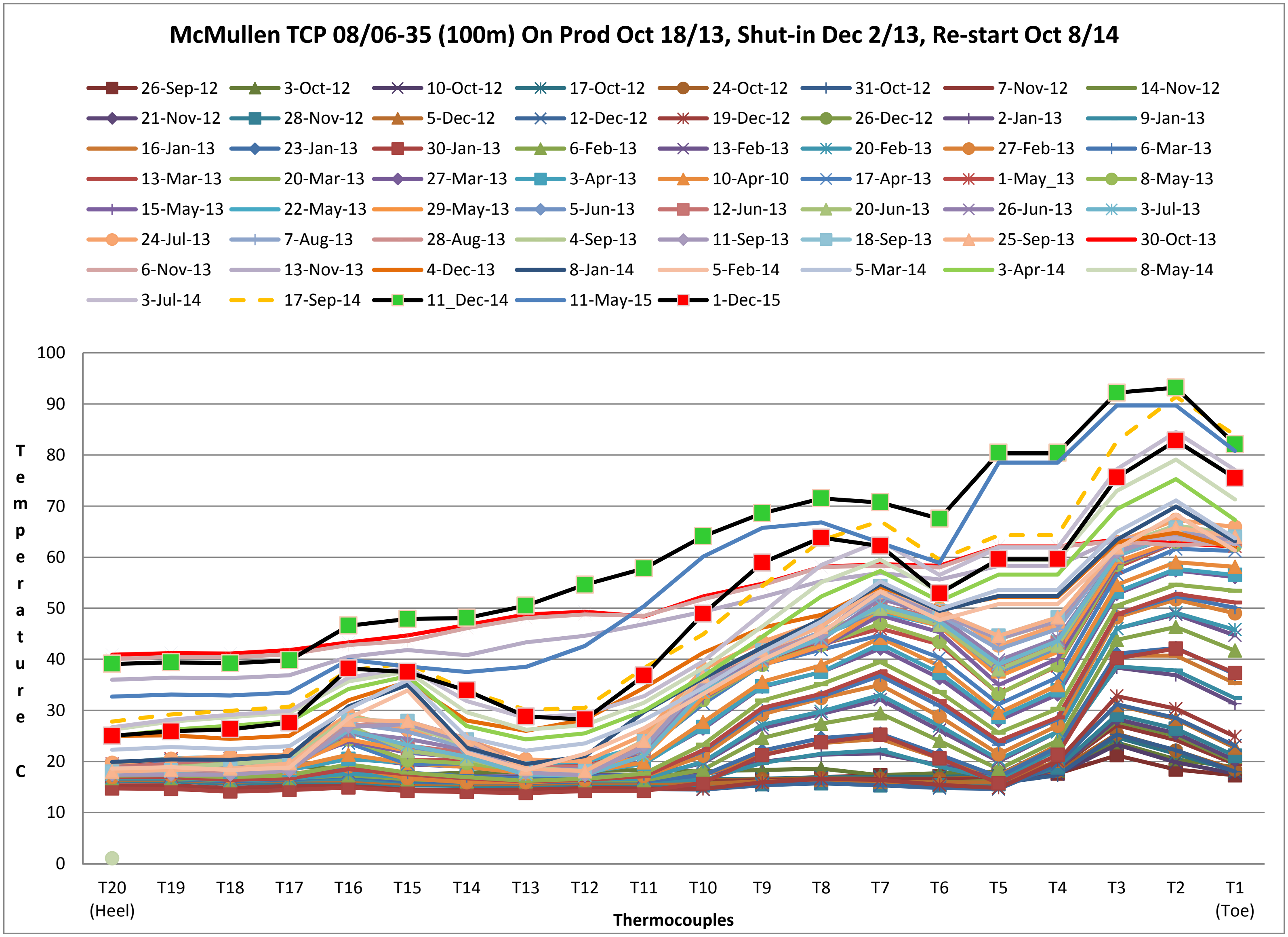
Horizontal Wellbore Temperature History



Horizontal Wellbore Temperature History

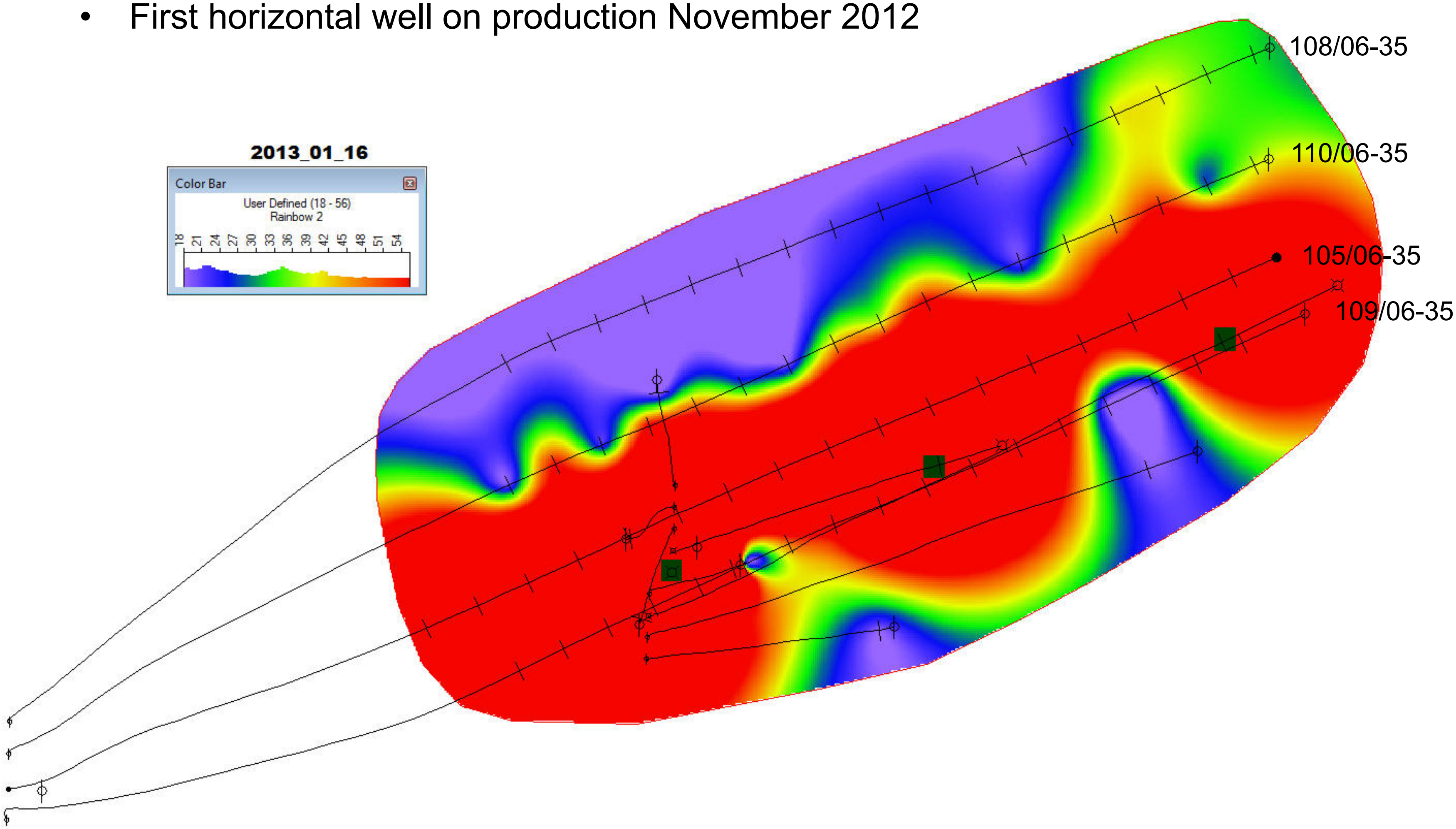


Horizontal Wellbore Temperature History



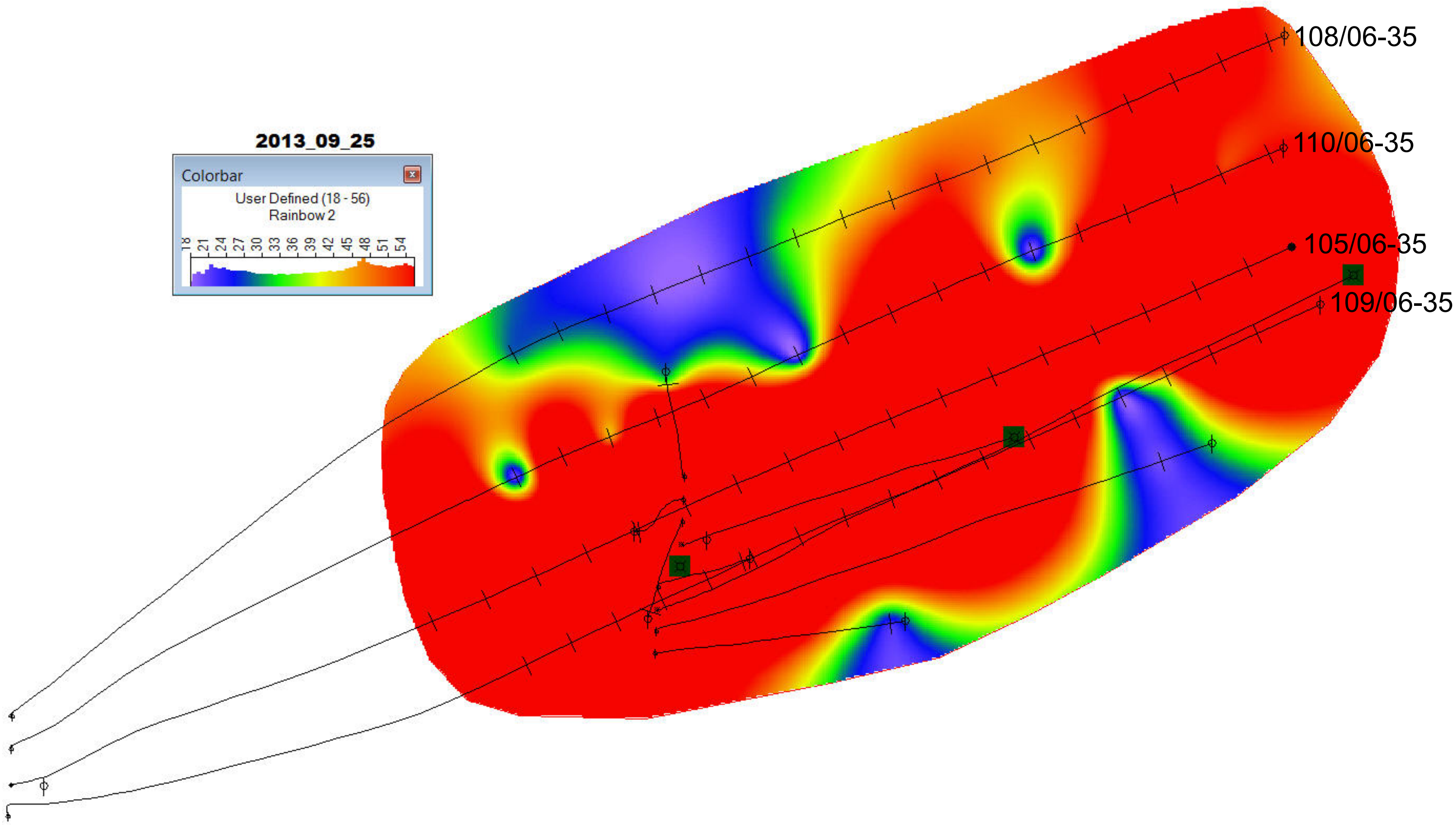
Heat Response – January 16, 2013

- 13 months after start of air injection
- First horizontal well on production November 2012



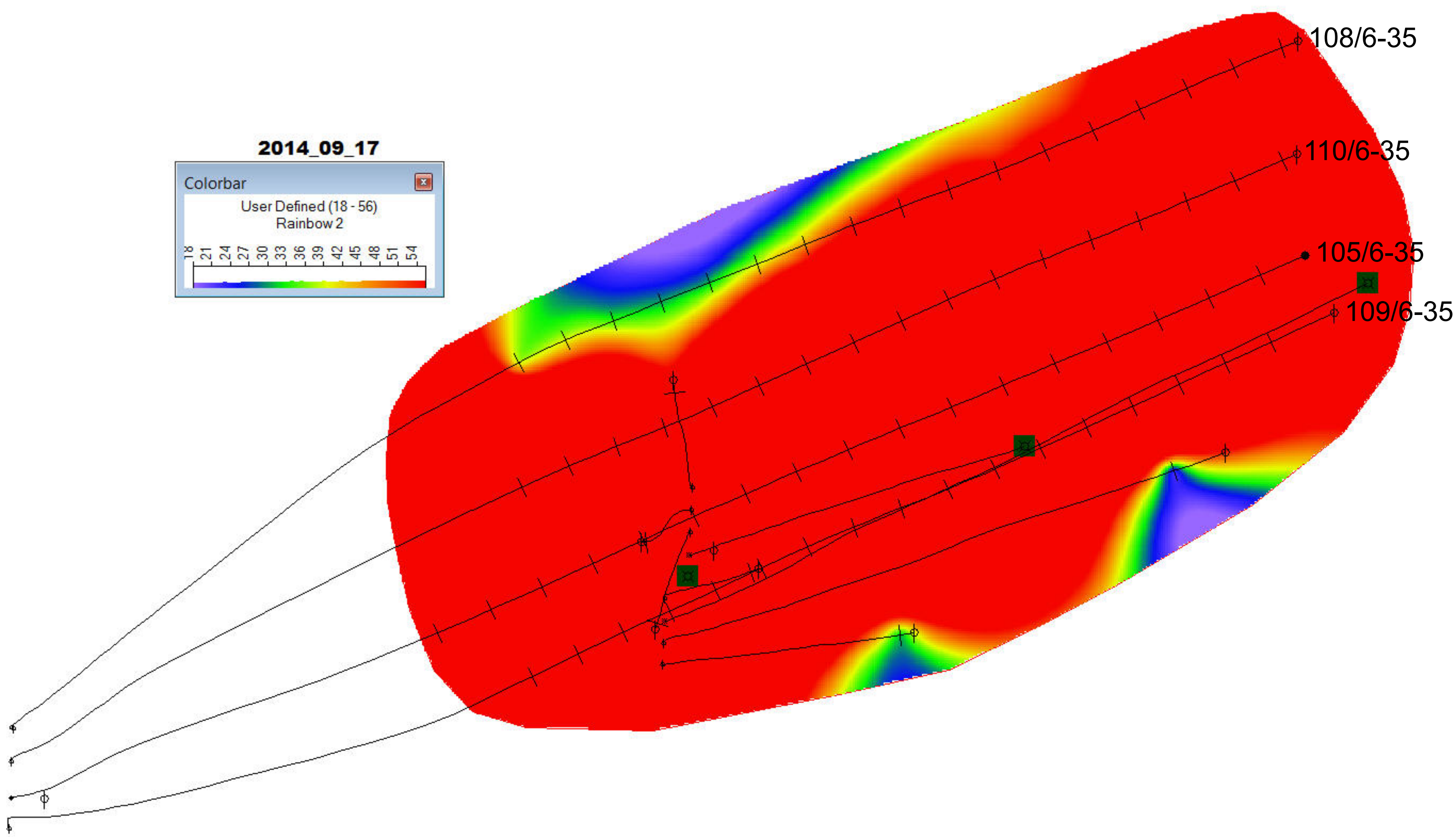
Heat Response – September 25, 2013

- 21 months after start of air injection
- Prior to placing remaining 3 horizontal wells on production



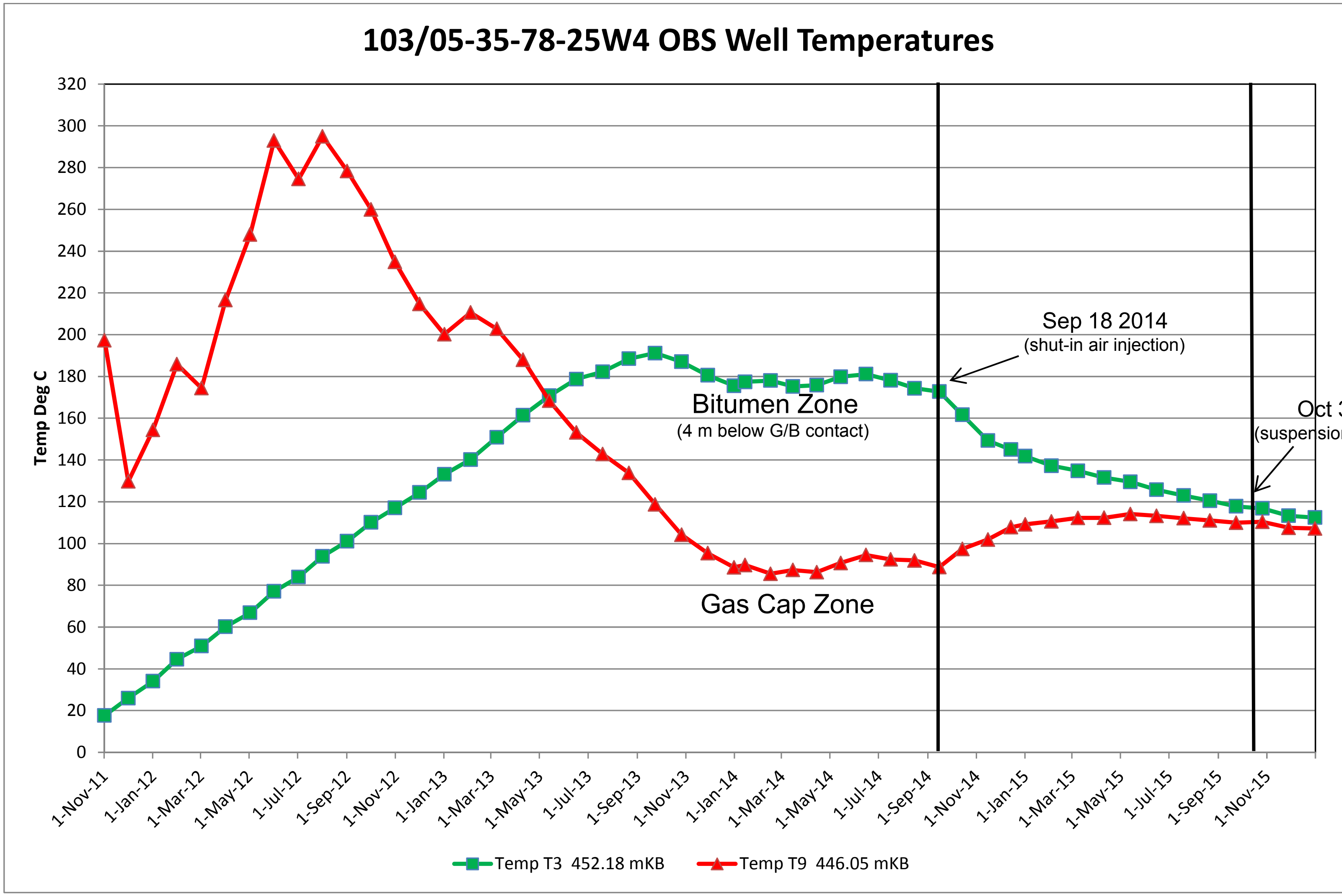
Heat Response – September 17, 2014

- 34 months after start of air injection
- Prior to shut-in of air injection on September 18, 2014



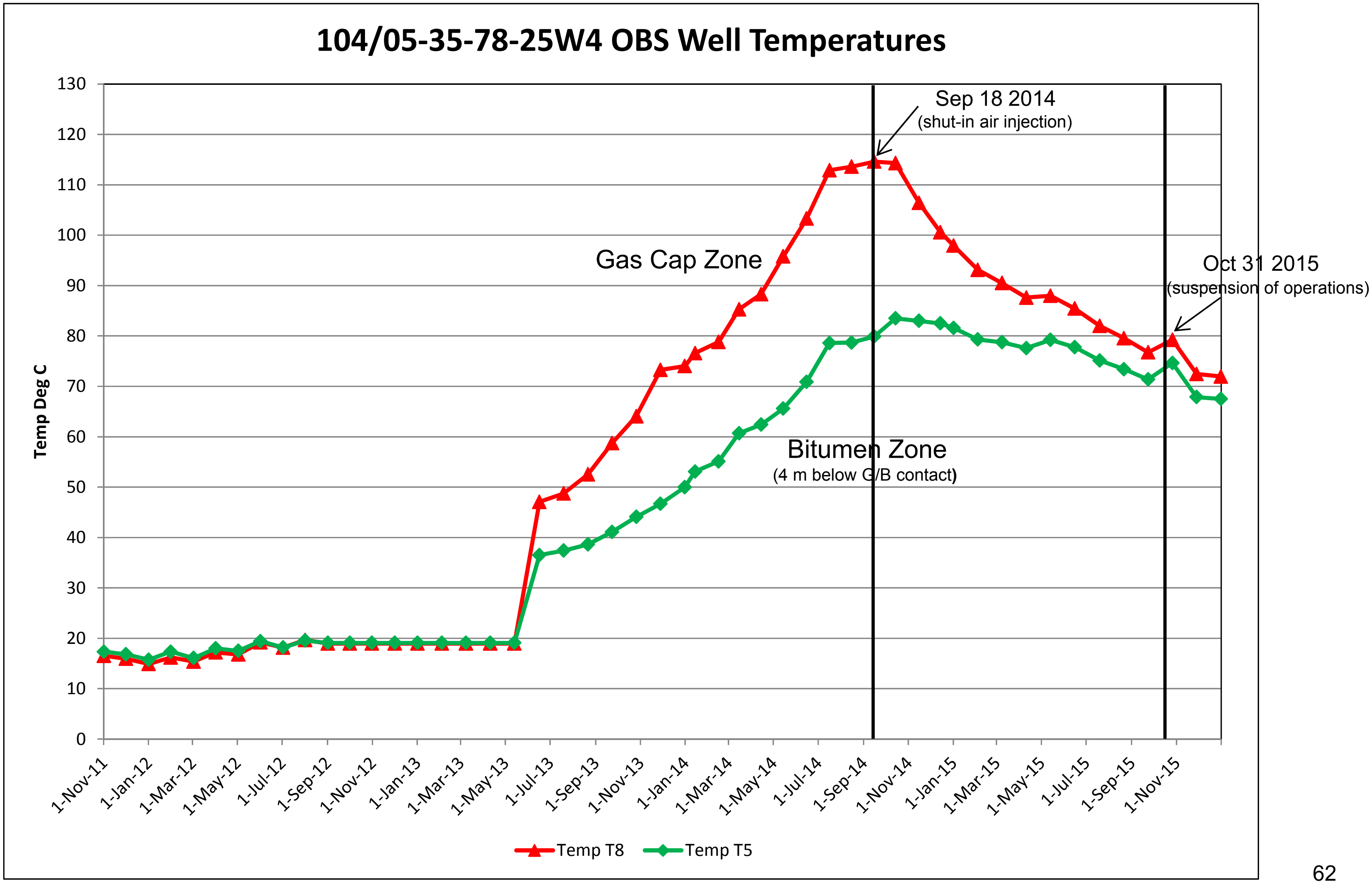
OBS Well 103/05-35-078-25W4 - Temperatures

- 25 m from well 100/03-35-078-25W4 (air injector)

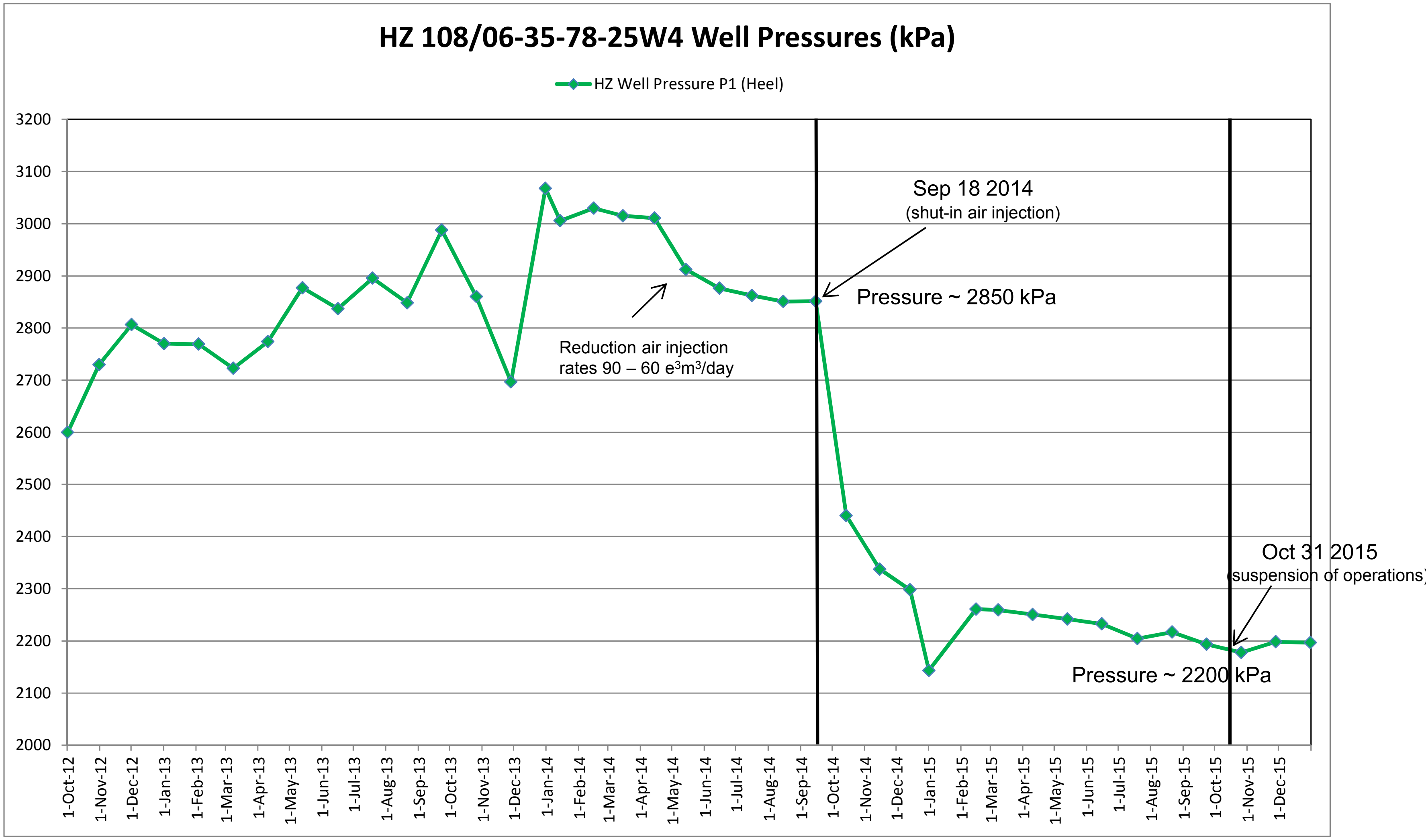


OBS Well 104/05-35-078-25W4 -Temperatures

- 87 m north of well 100/03-35-078-25W4 (air injector), ahead of the combustion front



Horizontal Well 108/06-35-078-25W4M Pressure History



Calculated Combustion Radius vs Time

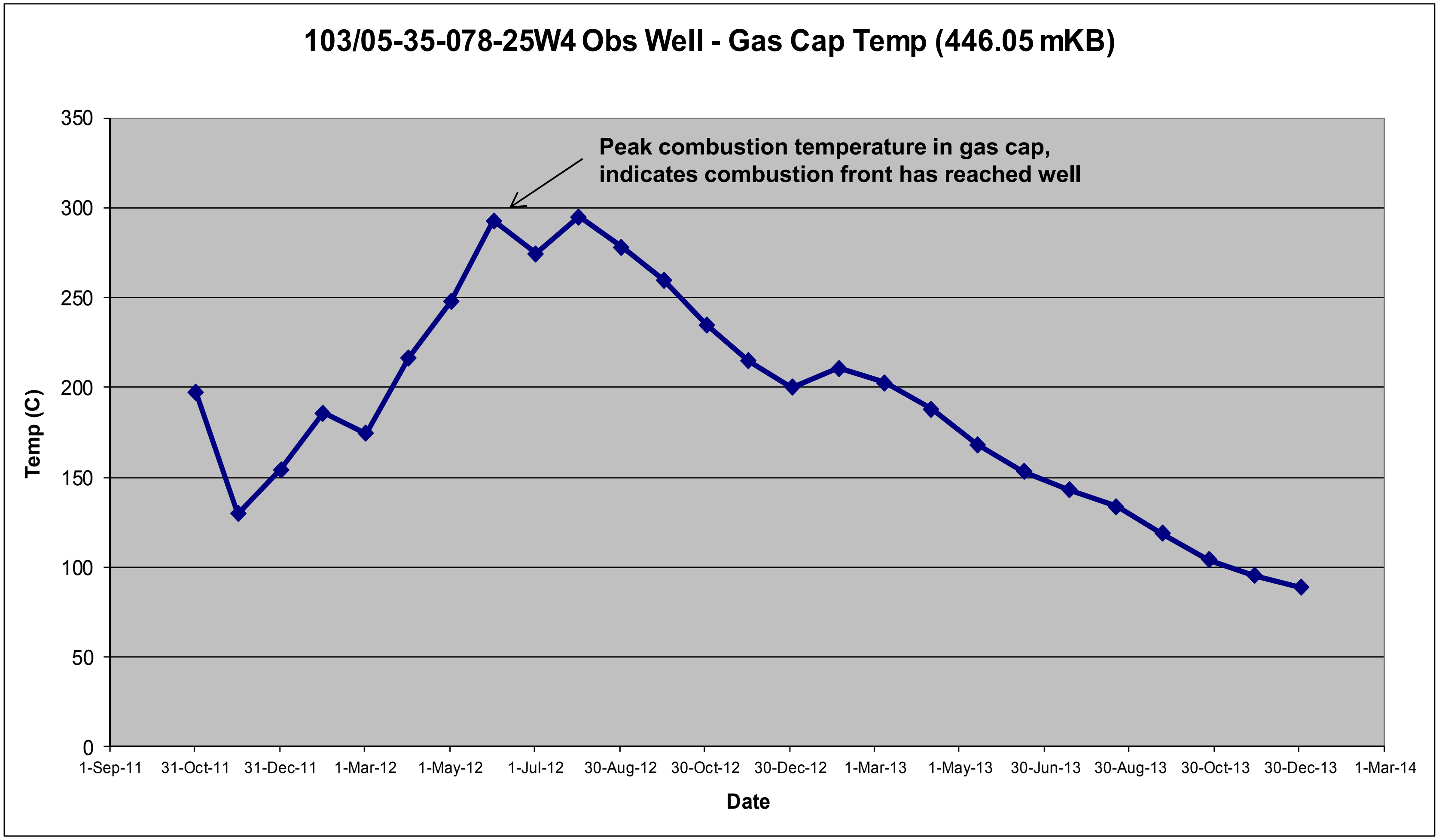
- 4m thick gas cap

Year	Calculated Gas In Place (m^3)	Injection Air (m^3/d)	Cum Injection E^3m^3	Front velocity (m/d)	Front velocity (ft/d)	Calculated Radius (m)	Comments
2012	29,851	52,900	20,896	0.134	0.440	53	actual
2013	76,727	89,900	53,709	0.080	0.263	82	actual
2014	103,759	72,500	72,632	0.048	0.160	96	actual
2015	145,474	80,000	101,832	0.048	0.159	114	estimated
2016	187,188	80,000	131,032	0.041	0.137*	129	estimated

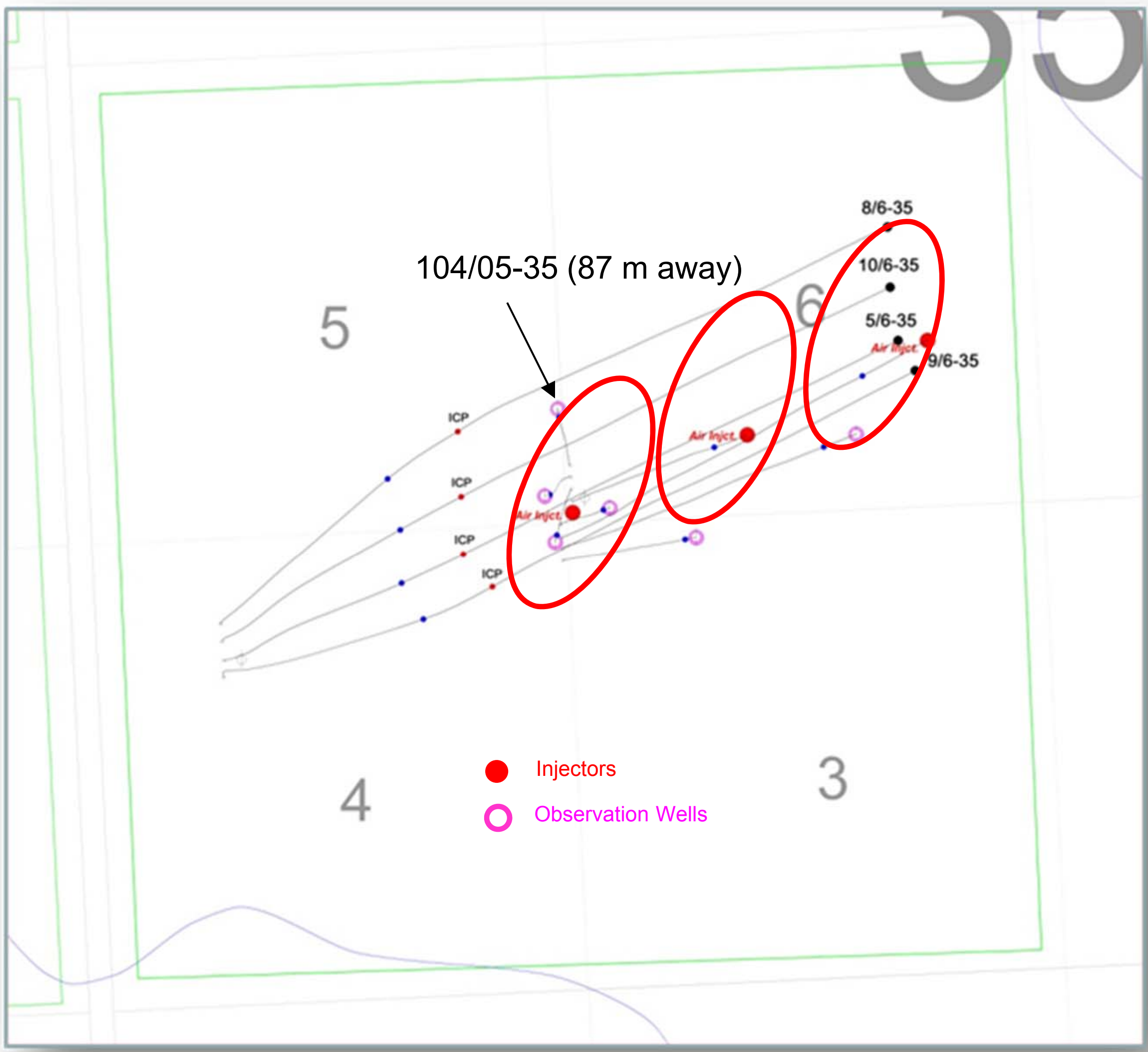
**Technical literature recommends a minimum burning velocity of 0.125 ft/d in order to have satisfactory combustion (Nelson and McNeil, "How to engineer an in-situ combustion project", Oil and Gas Journal June 5, 1961)*

OBS Well 103/05-35-078-25W4
Gas Cap Temperatures

- 25 m from well 100/03-35-078-25W4 (air injector)
- Front Velocity 25 m in 180 days – 0.138 m/d



Estimated Combustion Front Position



Ultimate Recovery - Volumetric Method

- Average Reservoir Parameters:
  - Net Oil Pay = 6 m, Oil FVF = 1.00 m^3/m^3
  - Porosity = 31%, So = 70%
  - Recovery Factor = 50%
- Entire approval area - 64 ha (SW/4 section 35-078-25W4)
  - OBIP = 833 e^3m^3
  - ROIP = 416.5 e^3m^3
- Planned operating portion of the project - 13 ha (prior to shut-in of air injection)
  - OBIP = 169 e^3m^3
  - ROIP = 84.5 e^3m^3
- Actual operating portion of the project - 6 ha (after shut-in of air injection)
  - OBIP = 78 e^3m^3
  - Cum oil produced = 36.3 e^3m^3 (suspension of operations October 31, 2015)
  - Recovery Factor to date = 46.5%

Thermal Enhanced Oil Recover - Recovery Factors

- McMullen TCP Pilot estimated > 50%
  - CMG™ numerical simulation was completed in 2015
  - Simulation has confirmed > 50% (RF at suspension of operations is 46.5%)
- Other In-Situ Fields:
  - Suplacu de Barcau Field, Romania - 56%, in operation since 1965
  - Balol/Santhal Fields India - 39/45%, in operation since 1990
  - Bellevue, Louisiana - 60%, in operation since 1970
- Steam Assisted Gravity Drainage (SAGD):
  - 45 to 65%
- Cyclic Steam Stimulation (CSS):
  - 25 to 45%

Temperature, Pressure and Quality of Steam

- No steam injection in 2012, 2013 and 2014

Performance to December 2015

- Reservoir pressure
  - Original 1,750 kPa increased to 3,000 kPa due to air injection; current ~ 2,200 kPa (December 2015)
- H_2S concentration
  - Between 400 – 2,200 ppm (average ~ 1,000 ppm)
- Oil production rate
  - Peak rate 90 m^3/day (560 bopd November 2013 – 4 wells)
  - Current 0 m^3/day (suspension of operations October 31, 2015)
- Cumulative oil production
  - 36.3 e^3m^3 (228.3 mbbl), recovery factor 46.5% at suspension of operations
- Total air injected (three (3) injectors)
  - 218 e^6m^3 (7.7 Bcf as of shut-in on September 18, 2014)

Summary of Key Learnings

- December 2015 - 49 months after start of air injection
- Safe and continuous operation of the air injection facilities
- Successful heating of the underlying bitumen through thermal conduction
  - Oil rates as predicted (25 m^3/d, 25-30% BS&W)
  - Recovered 36.3 e^3m^3 (228.3 mbbl) at suspension of operations October 31, 2015
- Successful ignition and continuous combustion
  - Based on produced gas analysis and observed temperatures
- Combustion front radius
  - Travelled a distance of ~96 m after 34 months (at time of shut-in of air injection); the front radius was estimated to travel 130 m after five years
- Effect of Nitrogen on offsetting primary production
  - Future design process requires a waste gas management program for the handling of produced gases

8. Future Plans

Future Plans – 2016

- Monitoring activities to discontinue
  - AER granted verbal approval to Husky on December 17, 2015 to discontinue monitoring of reservoir temperature and pressure by year-end 2015; as a result down-hole monitoring of pressure and temperature and power generation at the injection & production pad sites ceased as of January 6, 2016
- AER Directive 017 annual MARP report
  - 2015 report was completed and finalized on February 2, 2016 and will be kept on file pending AER request for information
- Continue Environmental monitoring
  - 2015 groundwater, air, soil & industrial wastewater & runoff reports to be submitted March 31, 2016
  - Complete final groundwater monitoring program in spring 2016 – final report submitted in fall 2016
- Decommissioning & Reclamation Plan to be submitted to AER April 30, 2016

3.1.2. Surface Issues - Table of Contents

1. Facilities – slide 75
2. Facilities Performance – slide 79
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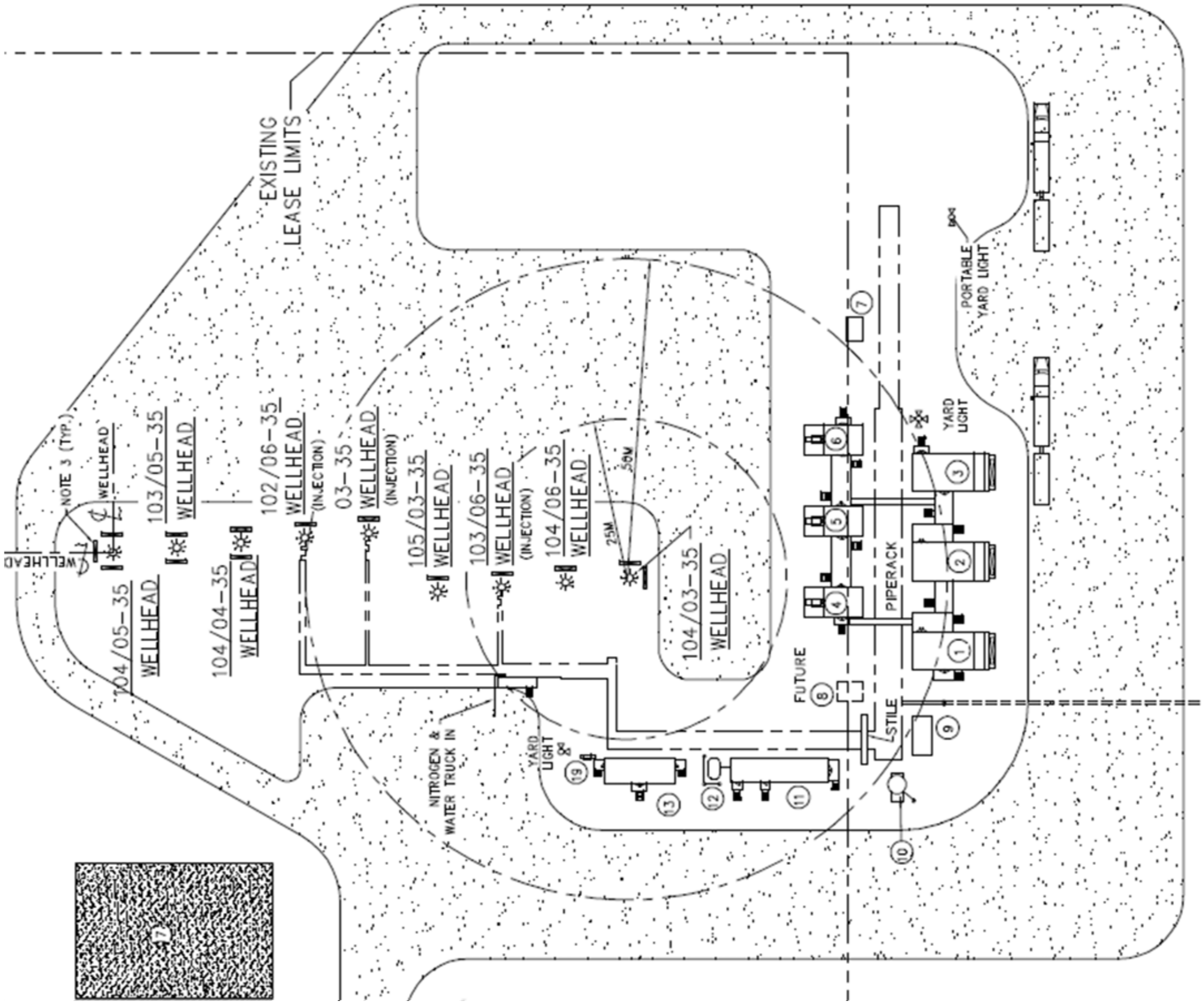
5. Sulphur Production – slide 90
6. Environmental Issues – slide 93
7. Compliance Statement – slide 95
8. Non-Compliance Events – slide 97
9. Future Plans – slide 99

1. Facilities

Project Site

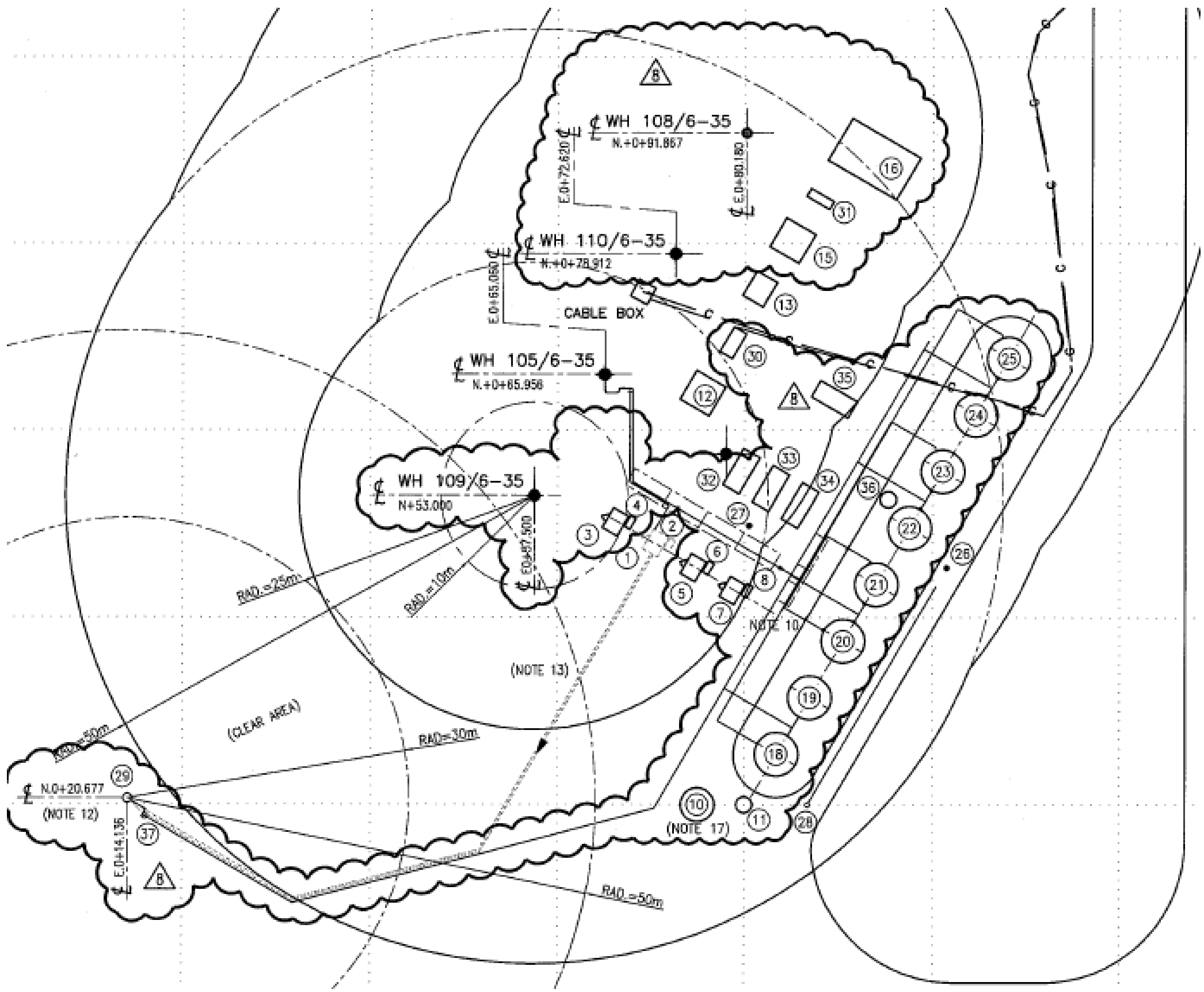
- As of October 11, 2013

Plot Plan



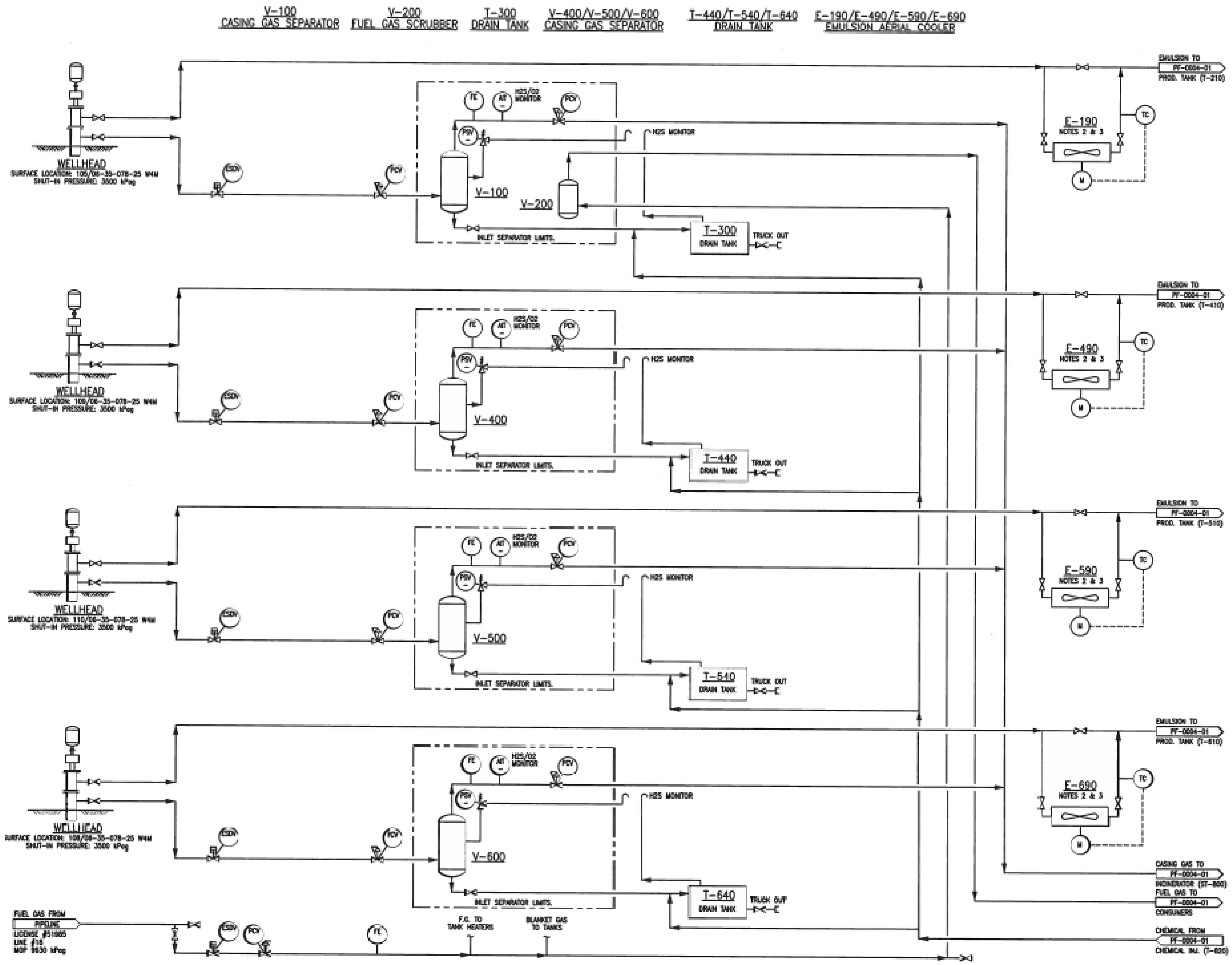
EXISTING LEASE LIMITS
NOTE 3 (TYP.)
WELLHEAD
104/05-35 WELLHEAD
103/05-35 WELLHEAD
104/04-35 WELLHEAD
102/06-35 WELLHEAD (INJECTION)
03-35 WELLHEAD (INJECTION)
105/03-35 WELLHEAD
103/06-35 WELLHEAD (INJECTION)
104/06-35 WELLHEAD
104/03-35 WELLHEAD
25M
50M
NITROGEN & WATER TRUCK IN
YARD LIGHT
FUTURE
STILE
PIPERACK
PORTABLE YARD LIGHT

Production Facilities Plot Plan

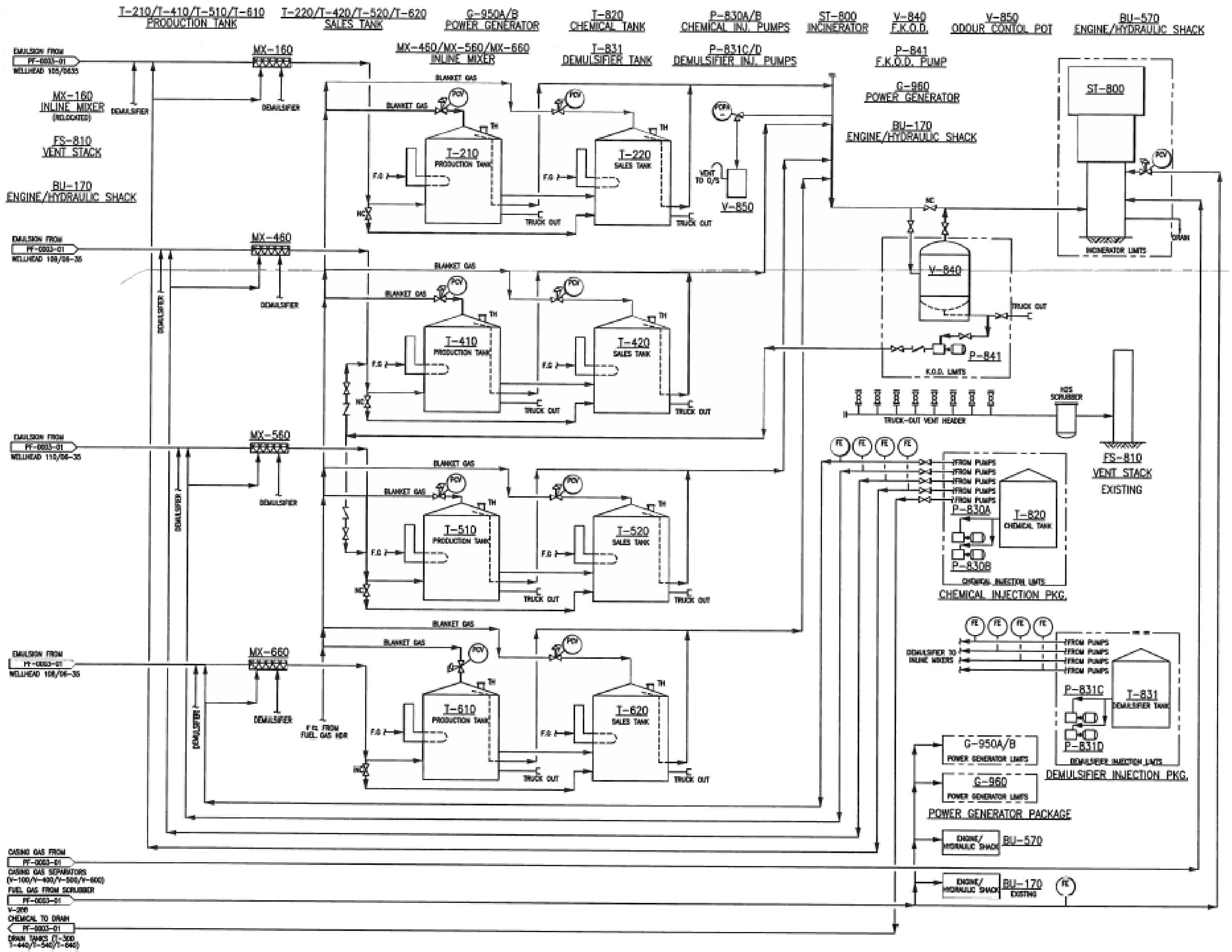


2. Facilities Performance

Production Process Flow (1/2)



Production Process Flow (2/2)



Facility Performance

- Bitumen treatment
  - Bitumen sales started in November 2012
  - H_2S scavenger injected to neutralize emulsion to meet sales specifications
  - Majority of the bitumen was trucked to Husky Blackfoot terminal for 2015

- Water treatment
  - Water trucking started in November 2012
  - Primary disposal at Husky's 16-11-078-25W4 (No. 9056B) disposal facility after being treated with H_2S scavenger (on site tanks)

- Steam generation
  - There was no steam generation in 2015

Facility Performance

- Power consumed in 2015 - generated onsite by a 151 kW unit at the injection pad and a 151 kW unit at the production pad
- Fuel gas usage in 2015:

Month (2015)	**Monthly Volume (e^3m^3)**		
	04-35-078-25W4 Production Pad	**03-35-078-25W4 Injection Pad**	**Total**
January	107.8	1.46	109.2
February	94.7	0.0	94.7
March	99.2	0.0	99.2
April	89.5	0.59	90.1
May	84.9	0.0	84.9
June	73.6	0.0	73.6
July	83.6	0.16	83.8
August	86.6	0.0	86.6
September	87.2	9.96	97.1
October	82.8	37.54	120.3
November	0.2	15.25	15.5
December	0.0	16.73	16.7
Grand Total	890.1	81.69	971.8

Facility Performance

- Latest facility design for the additional production wells
  - Incorporates the incineration of all tank vapors and casing gas produced

- Green house gas emissions:

2015 Green House Gas Emissions				AER License	Exceed AER License
CO_2 (tonnes/year)	CH_4 (tonnes/year)	N_2O (tonnes/year)	CO_2E (tonnes/year)	CO_2 (tonnes/year)	CO_2 (Yes/No)
2,607.92	28.05	.04	3,319.86	51,319.00	No

2015 NOx and CO Emissions		AER License	Exceed AER License
NO_X (tonnes/year)	CO (tonnes/year)	NO_X (tonnes/year)	NO_X (Yes/No)
44.33	23.13	182.82	No

3. Measurement and Reporting

Estimating Well Production

- 2015 Well production

Month (2015)	105/06-35-078-25W4 Oil (m³)	Water (m³)	Gas (e³m³)	109/06-35-078-25W4 Oil (m³)	Water (m³)	Gas (e³m³)	110/06-35-078-25W4 Oil (m³)	Water (m³)	Gas (e³m³)	108/06-35-078-25W4 Oil (m³)	Water (m³)	Gas (e³m³)
January	77.47	40.31	45.72	248.19	112.51	102.28	401.82	96.85	143.43	91.73	94.79	24.04
February	40.63	17.77	30.8	120.86	107.29	86.23	272.4	83.56	117.5	56.63	64.77	20.02
March	32.8	14.78	78.85	27.79	31.06	21.28	298.82	85.29	108.4	45.78	61.8	11.71
April	0	0	1.32	0	0.6	0.06	160.53	45.67	127.75	68.34	32.91	3.79
May	3.75	-3.34	1.77	3.2	-10.2	0.01	130.49	58.92	133.01	35.77	47.09	3.24
June	0	0	6.93	182.99	93.33	77.48	179.56	93.36	124.79	-5.72	77.84	3.52
July	2.2	5.28	6.67	181.45	116.25	106.67	70.43	34.75	129.12	-23.75	94.65	0
August	16.86	29.2	28.25	84.92	67.27	89.4	182.05	53.03	141.52	9	-12	0.24
September	0	0	0.02	87.36	109.88	149.83	153.32	62.49	144.3	0	0	6.24
October	-43.36	33.85	0	23.91	160.01	146.99	169.06	30.71	140.41	-2.28	0.12	0
November	-1.4	8.44	0	-73.42	73.06	0	-73.25	58.25	0	0.5	9.5	0
December	0	0	0	0	0	0	0	0	0	0	0	0
Total	128.95	146.29	200.33	887.25	861.06	780.23	1945.23	702.88	1310.23	276	471.47	72.8

Note:
Negative production values are a result of tank cleaning and balancing tank inventory

- Each well treated as a single well battery:
  - liquids: sales = production
  - gas: individual orifice meter used to measure gas production
- Proration factors – N/A
- Optimization of test durations – N/A
- New measurement technology - No

Measurement and Reporting

- Injection volumes
  - No steam was injected in 2015
  - Air injection was shut-in September 18, 2014
    - No air was injected in 2015

- Air Injection Volumes at well 100/03-35-078-25W4 Injection Pad – Per Well

Month (2015)	Volume (e^3m^3)	Daily Rate/Well (e^3m^3/d)
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September	0	0
October	0	0
November	0	0
December	0	0

4. Water Production and Injection

Water Production and Injection

- Produced water volumes:

Well	2015 Total Water (m^3)
105/06-35-078-25W4	146.3
109/06-35-078-25W4	861.1
110/06-35-078-25W4	702.9
108/06-35-078-25W4	471.5

- No produced water recycle volumes or percent

- Disposal wells:
  - 16-11-078-25W4 and 10-23-078-25W4
  - Approval No. 9056B

5. Sulphur Production

Sulphur Production

- There is no sulphur recovery
  - all produced gas is incinerated at well 04-35-078-25W4

Summary of 2015 Quarterly SO_2 Emissions				
Month	**Monthly Sulphur (tonnes)**	**Monthly SO_2 (tonnes)**	**Quarter**	**Quarterly SO_2 (tonnes)**
January	0.059	0.118	1	0.288
February	0.049	0.098		
March	0.036	0.072		
April	0.036	0.072	2	0.094
May	0.000	0.000		
June	0.011	0.022		
July	0.014	0.028	3	0.092
August	0.012	0.024		
September	0.020	0.040		
October	0.020	0.040	4	0.040
November	0.000	0.000		
December	0.000	0.000		

- Sulphur balance
  - SO_2 emissions based on 100% conversion of H_2S to SO_2

- Sulphur emissions
  - below 1 tonne/day; no sulphur recovery methods required

Sulphur Production

- Facility
  - Approved for 0.41 tonnes of SO_2 per day

	Jan 2015	Feb 2015	Mar 2015	Apr 2015	May 2015	Jun 2015	Jul 2015	Aug 2015	Sep 2015	Oct 2015	Nov* 2015	Dec* 2015
Daily Peak SO_2 (t/d)	0.004	0.004	0.002	0.002	0.000	0.002	0.002	0.002	0.002	0.002	0.000	0.000
AER Approved SO_2 (t/d)	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41	0.41
Exceeds Approval limit (Yes/No)	No	No	No	No	No	No	No	No	No	No	No	No

**Note: No produced gas for the month of November and December, facility shut-in.*

  - EPEA Approval - no requirement to monitor ambient air quality

6. Environmental Issues

Environmental Issues - Reporting

- Annual Monitoring and Reporting due March 31, 2016
  - Annual air emission and summary and evaluation report (final annual air summary report)
  - Annual Industrial wastewater and runoff report
  - Groundwater monitoring program
    - Shallow groundwater – no indication of adverse impacts
    - Quaternary channel thermal – maximum temperature increase ~3.5^{0}C (from baseline)
      - Temperatures show a declining trend post air injection suspension
    - Dissolved arsenic concentrations consistent with baseline values
    - Complete final groundwater monitoring program in spring 2016 – submit report in the fall
    - Propose to abandon groundwater monitoring wells following the confirmation of no impacts during final site reclamation

- Other Monitoring and Reporting
  - Soil monitoring (2014 and 2018)
  - Soil management report submitted November 2015
  - Soil management program hand auger assessment proposed for 2016
    - Delineate salinity in the top 15 cm of soil near the tank farm load outs in southeast corner of well 04-35-078-25W4 production site

- Participation in Alberta Biodiversity Monitoring Institute (ABMI)

7. Compliance Statement

Compliance

- To the best of Husky's knowledge, the Project is currently compliant with all regulatory approval conditions and associated requirements

8. Non-Compliance Events

Non-Compliance

- No non-compliance events for the reporting period

8. Future Plans

Future Plans

- Future Pilot expansion application activities
  - No expansion activities/commercial development are planned as the Project is currently not economic