Husky Oil Operations Limited

Tucker Thermal Project

Commercial Scheme Approval No. 9835

Annual Performance Report

Alberta Energy Regulator

June 30, 2021

Advisory

This presentation contains information in compliance with:

AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

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Introduction

Section 4.1

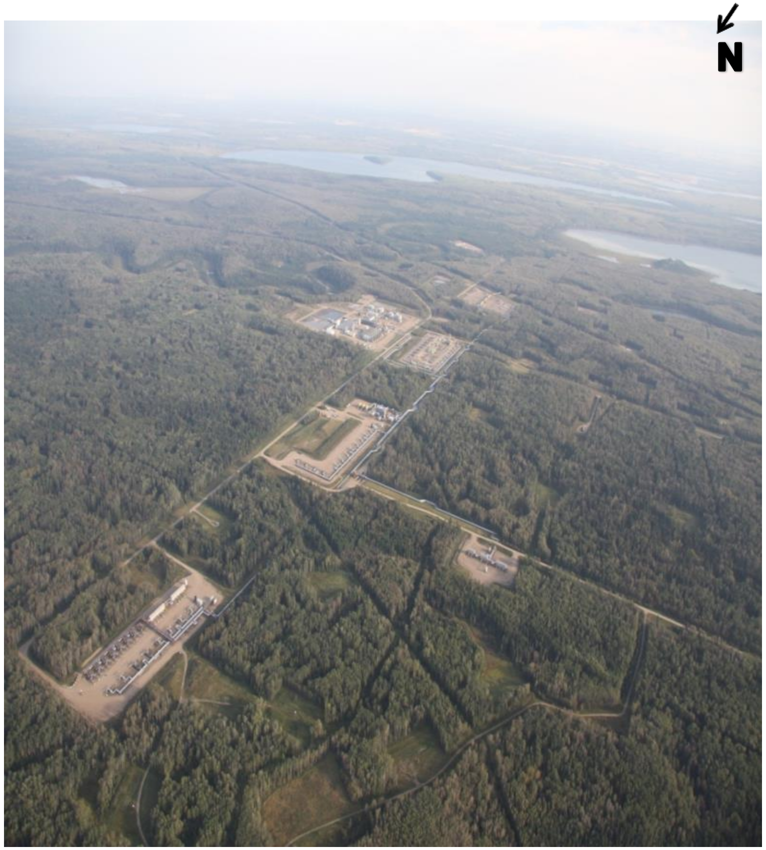
Project Overview

Section 4.1.1

- AER Commercial Scheme Approval No. 9835
- Clearwater, Grand Rapids and Colony Reservoirs
- 9-10º API Bitumen
- First Steam August 20, 2006
- First Production November 29, 2006

- Field Facilities:
  - Six well pads, infield pipelines and central pump station

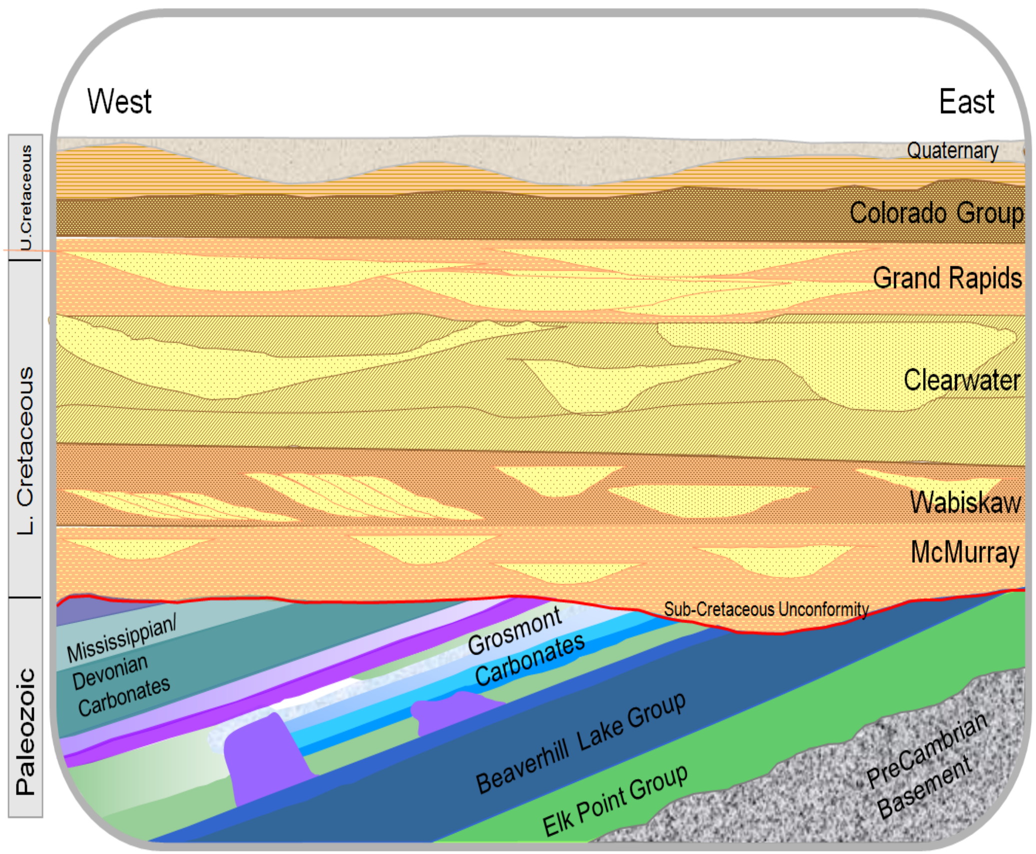
- Central Plant:
  - Emulsion treating
  - Water Treatment
  - Steam Generation
  - Utilities

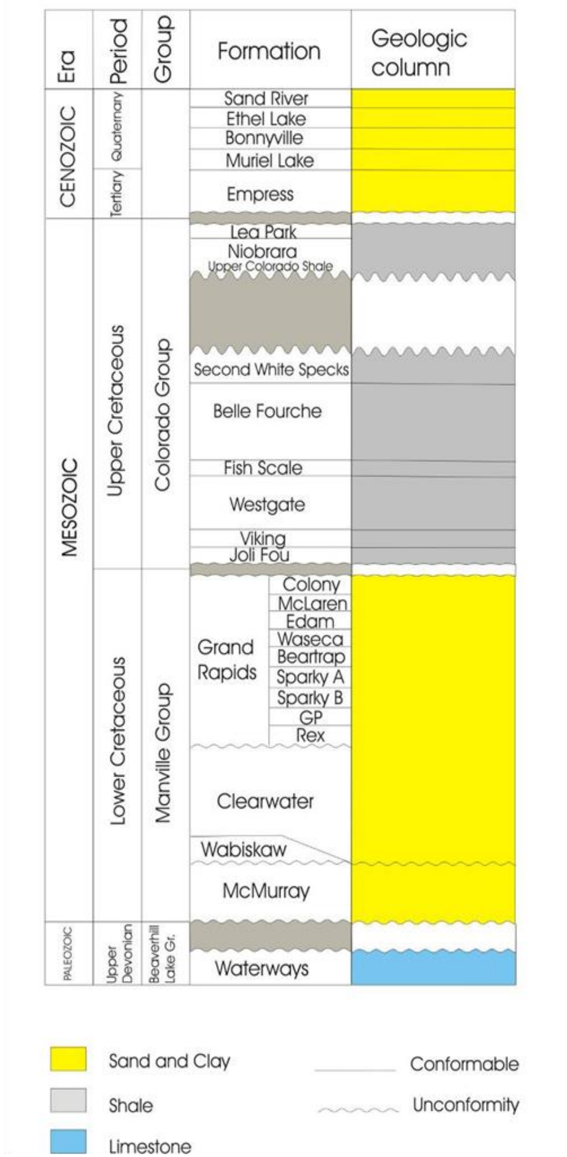


Regional Stratigraphy

Section 4.1.1

- Marginal marine deposits consisting of stacked incised valleys and shoreface deposits



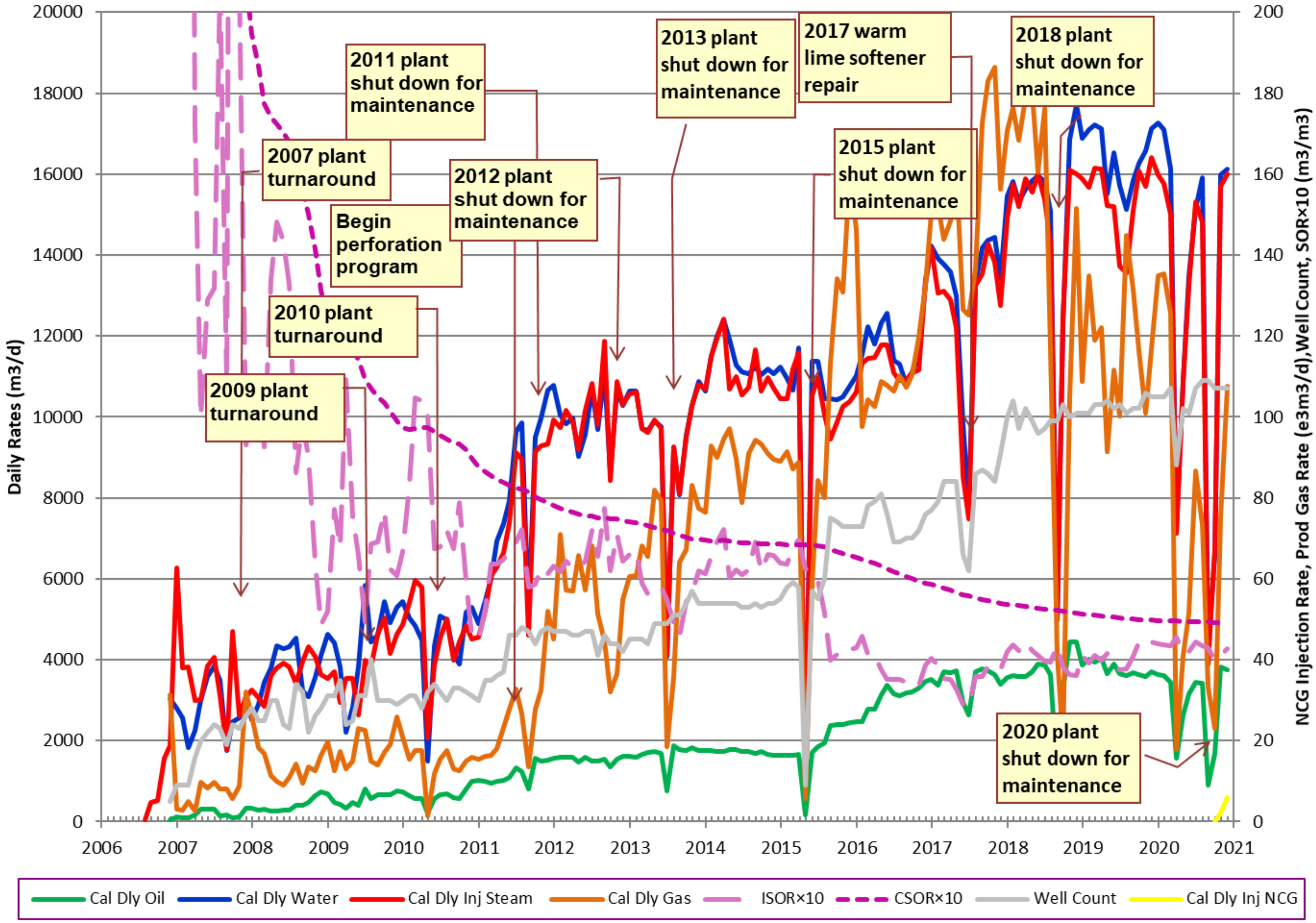


Subsurface

Section 4.2, subsections 2 to 7

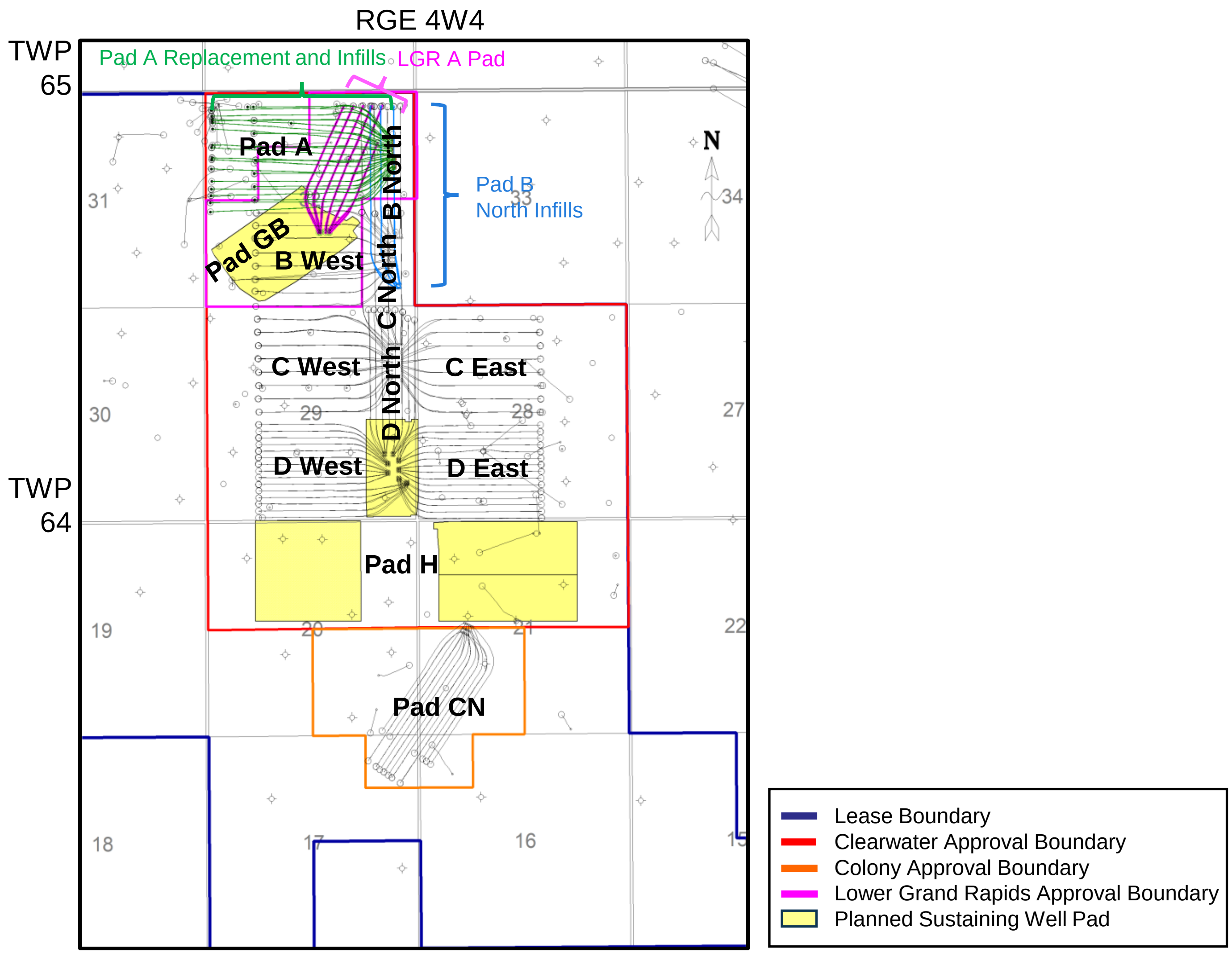
Production Plot

Section 4.2.2



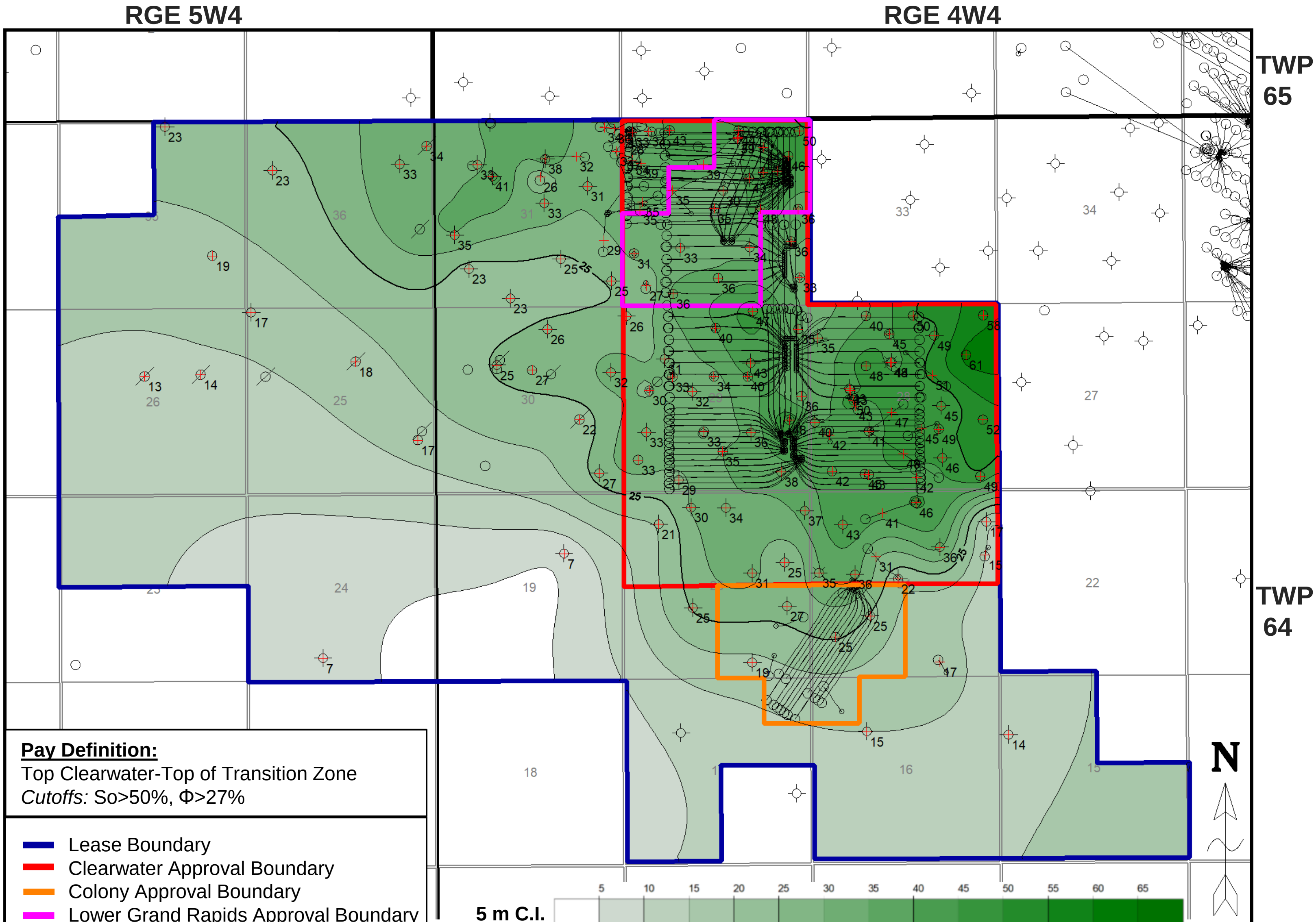
Development Map

Section 4.2.3.a



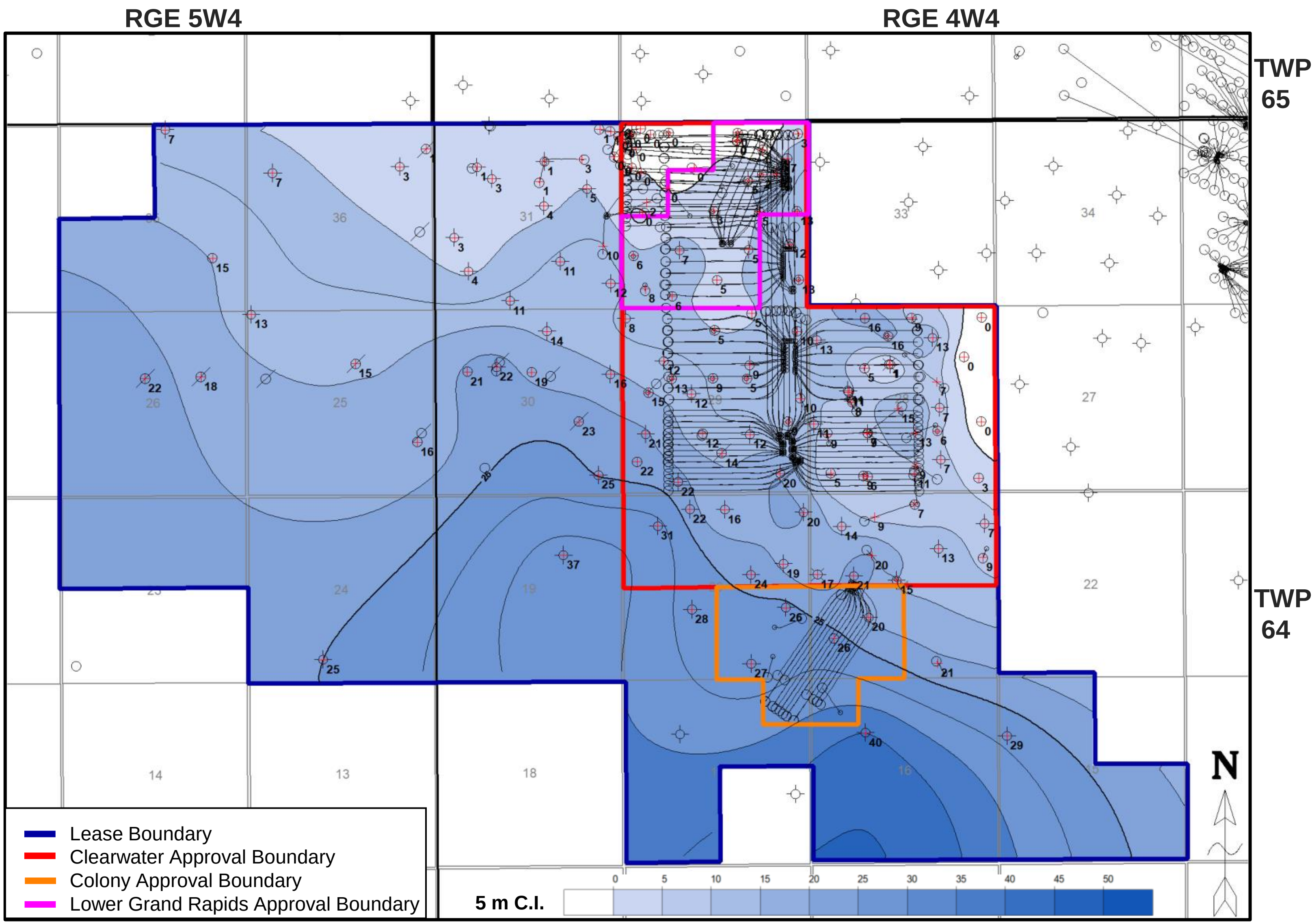
Isopach Map of SAGD Net Pay

Section 4.2.3.b - Clearwater



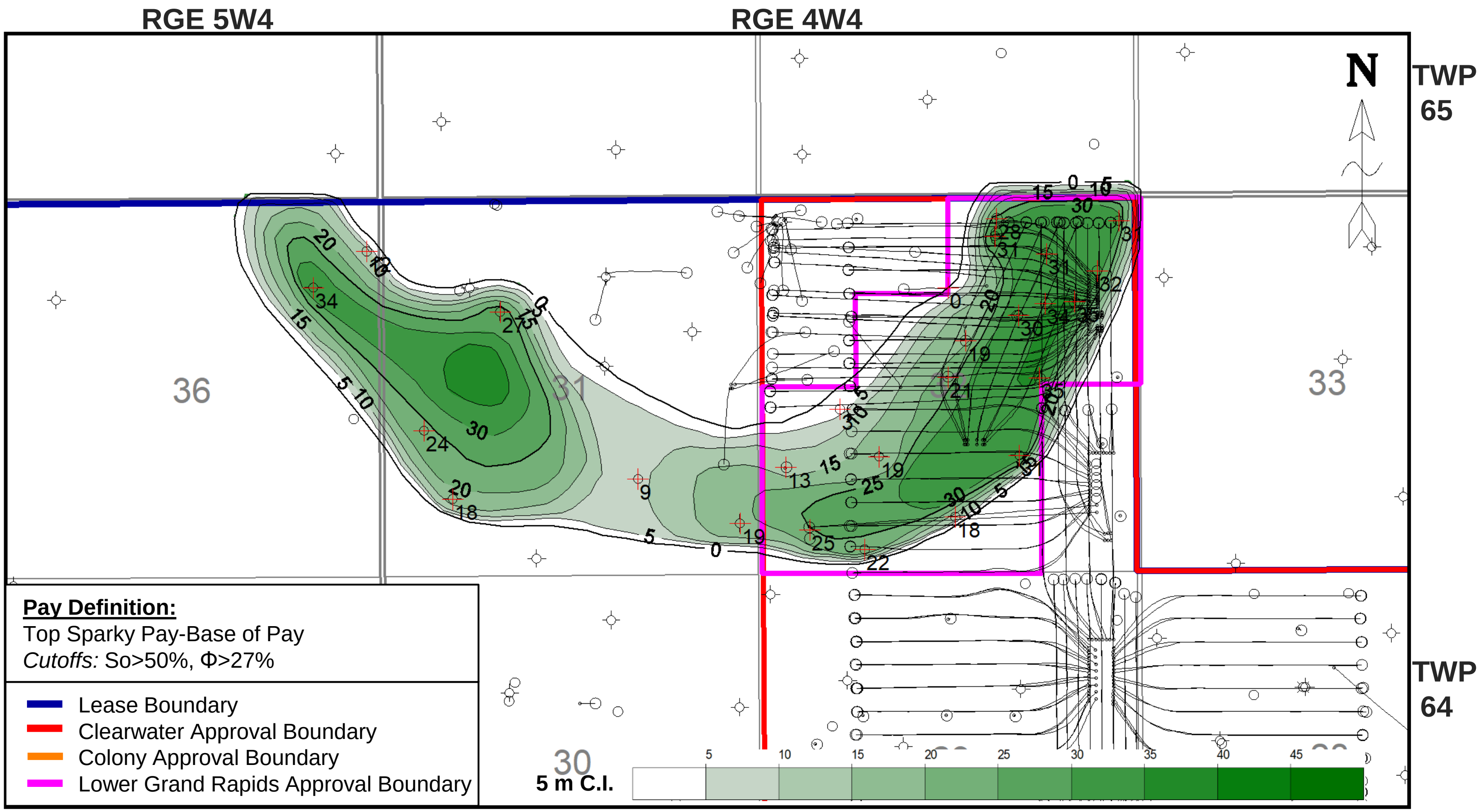
Isopach of Bottom Water

Section 4.2.3.c - Clearwater



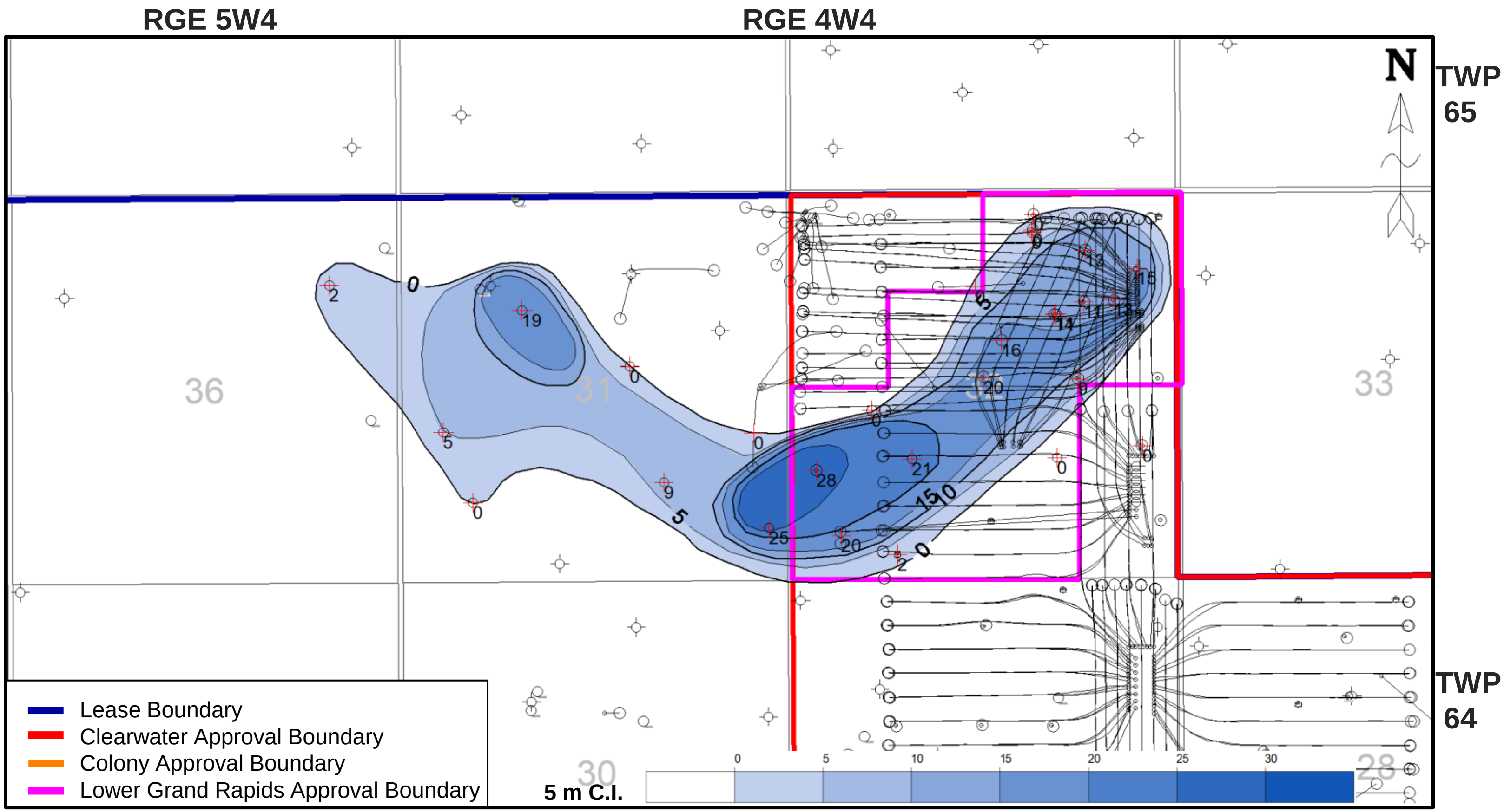
Isopach Map of SAGD Net Pay

Section 4.2.3.b – Lower Grand Rapids



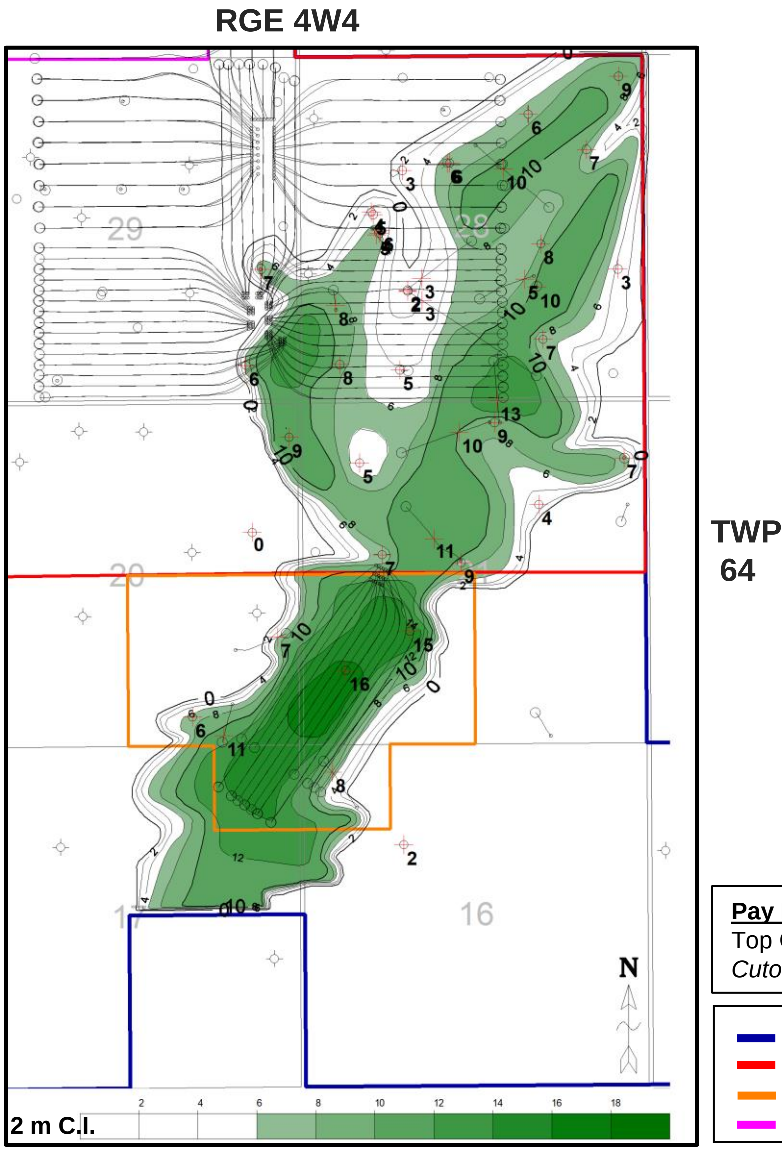
Isopach of Bottom Water

Section 4.2.3.c – Lower Grand Rapids



Isopach Map of SAGD Net Pay

Section 4.2.3.b - Colony



Pay Definition:
Top Colony Pay-Colony Channel Base
Cutoffs: So>50%, Φ>27%

- Lease Boundary
- Clearwater Approval Boundary
- Colony Approval Boundary
- Lower Grand Rapids Approval Boundary

Geomechanical Data/Analysis

Section 4.2.3.d

Capping Shale Properties						
Well Pad	Capping Shale Issues to date	Capping shale Fracture Pressure Exceeded	Shale Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
CN	No	No	305	20.0	6,100	Horizontal
GA	No	No	357	19.9	7,120	Horizontal
Clearwater	No	No	426	21.8	9,280	Horizontal

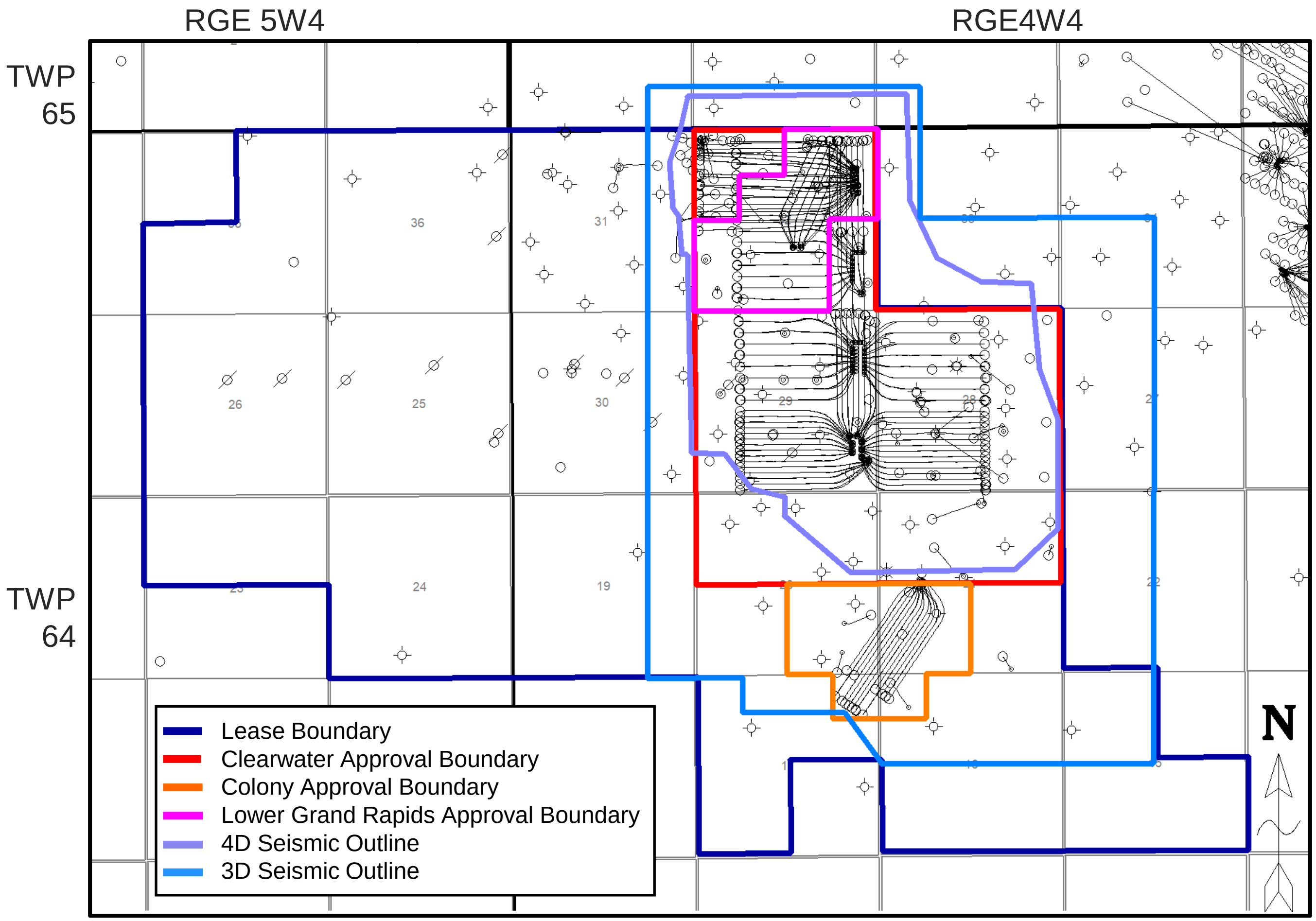
Sand Properties				
Well Pad	Sand Depth (m)	Measured Fracture Gradient (kPa/m)	Measured Fracture Pressure (kPa)	Fracture Regime
GA	375	17.0	6,360	Vertical
Clearwater	446	16.0	7,140	Vertical

Note:
CN – Colony
GA – Lower Grand Rapids A

Seismic Acquisition

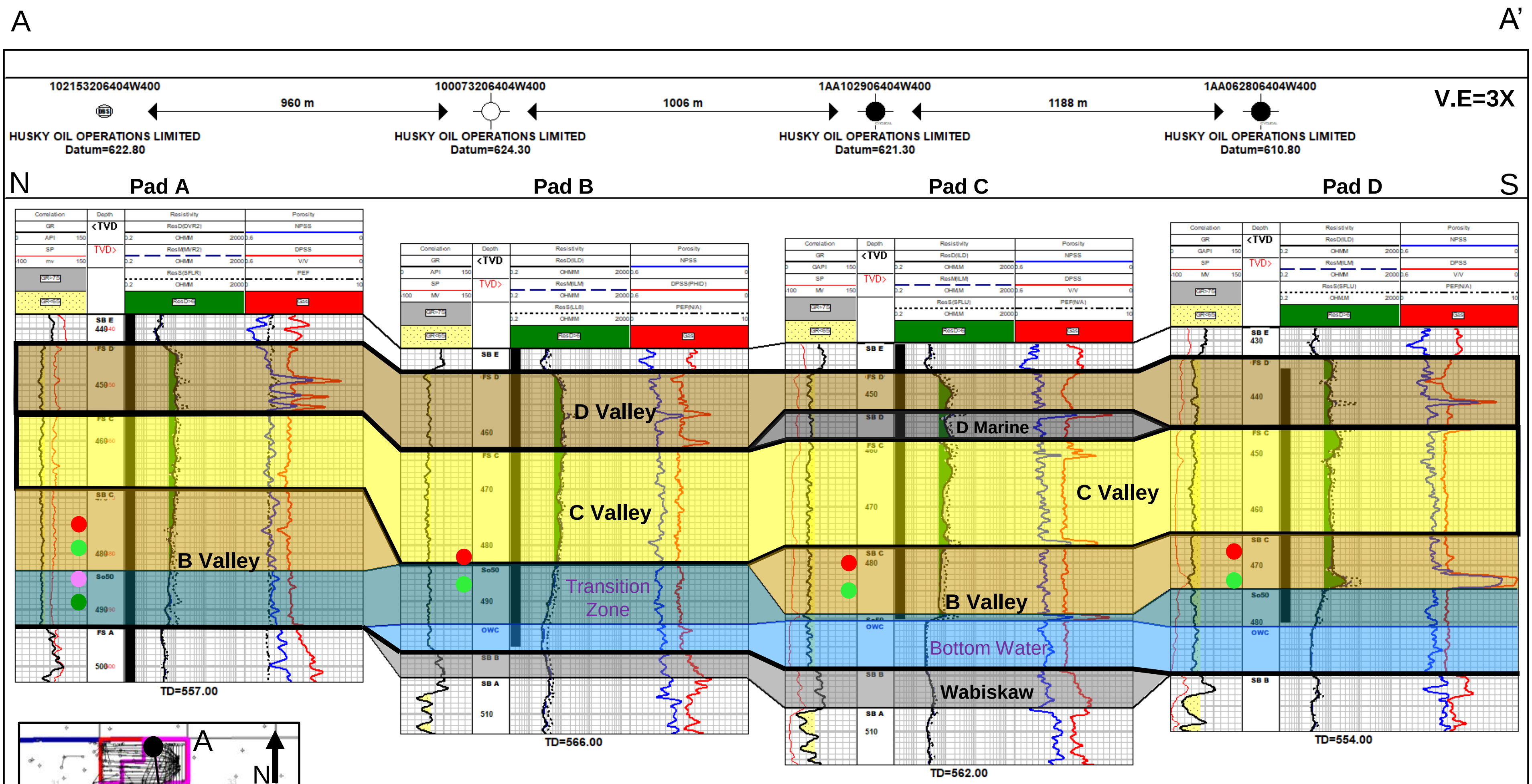
Section 4.2.3.e - Seismic

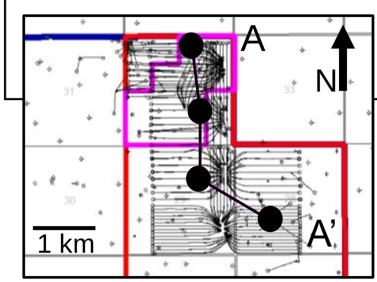
- No new seismic acquired during the reporting period



Representative Structural Cross-Section

Section 4.2.4 - Clearwater



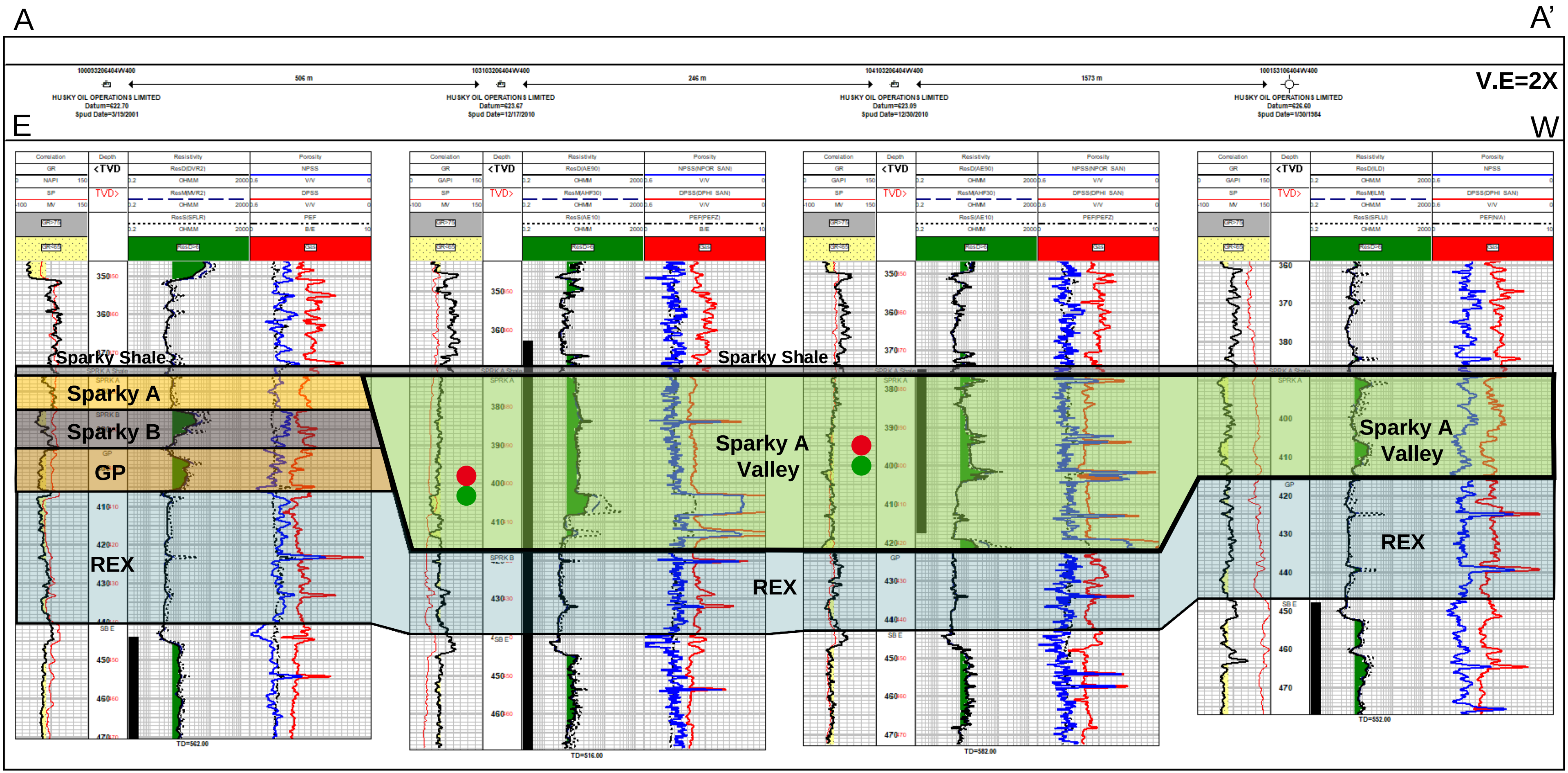


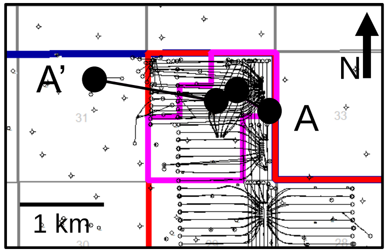
- Colony Development Area
- Clearwater Development Area
- Tucker Lease Boundary

- SAGD Injector
- SAGD Producer
- Original SAGD Injector
- Original SAGD Producer

Representative Structural Cross-Section

Section 4.2.4 – Lower Grand Rapids, Sparky

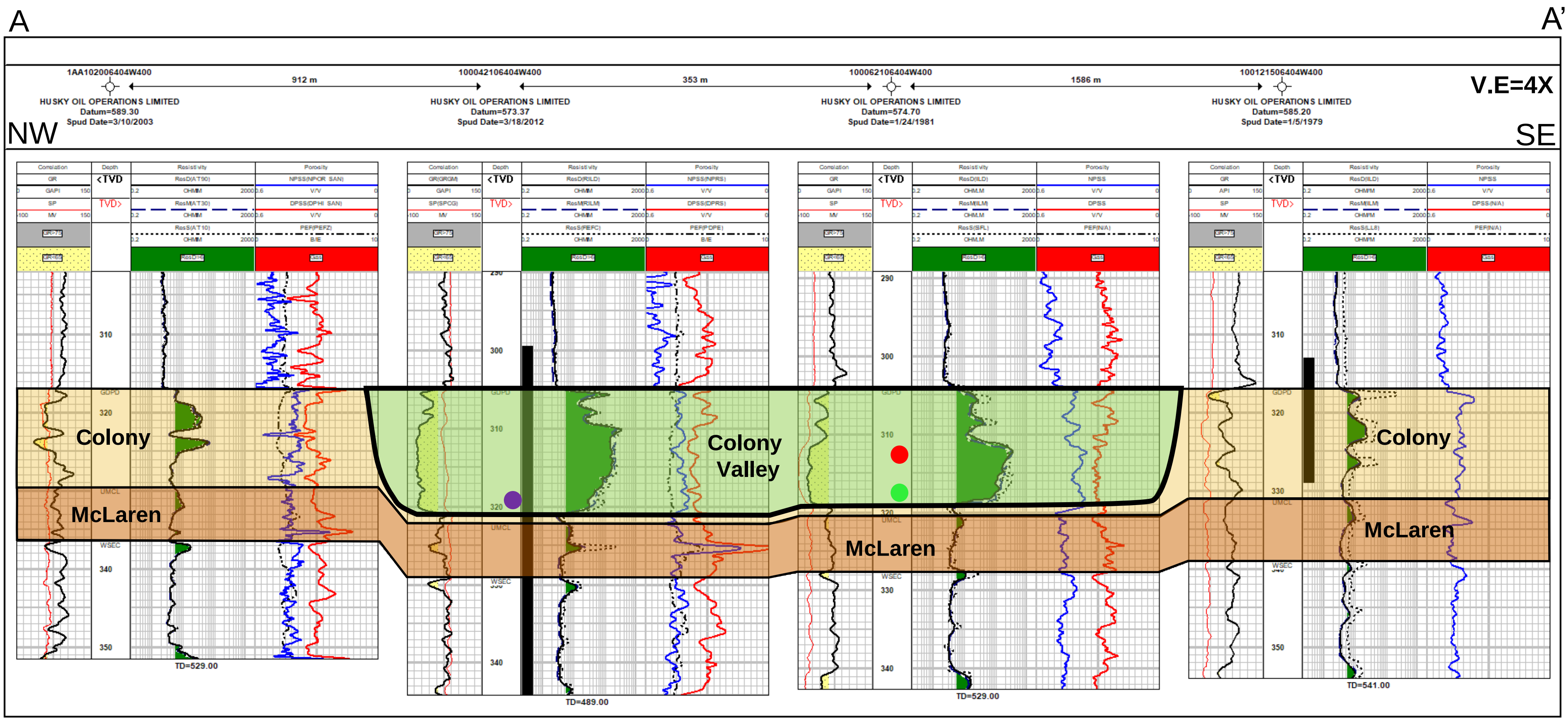


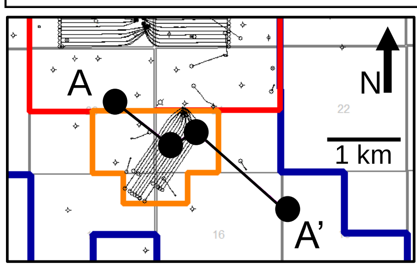


- SAGD Injector
- SAGD Producer
- Colony Development Area
- Clearwater Development Area
- Tucker Lease Boundary

Representative Structural Cross-Section

Section 4.2.4 – Upper Grand Rapids, Colony





- SAGD Injector
- SAGD Producer
- Infill Producer
- Colony Development Area
- Clearwater Development Area
- Tucker Lease Boundary

Average Reservoir Characteristics and OBIP

Section 4.2.5

CLEARWATER	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	80.5	44	0.31	0.57	50,000-1,000,000	3,200	16	440	1,800	3,000
Operating	40.9	46	0.32	0.57	50,000-1,000,000	3,200	16	440	1,800	3,000

LOWER GRAND RAPIDS	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	5.7	26	0.28	0.54	100,000-300,000	2,600	14	370	1,300	1,800
Operating (Pad GA)	2.1	38	0.29	0.54	100,000-300,000	2,600	14	370	1,300	1,800

COLONY	OBIP ($X10^6$ m^3)	Thickness (m)	PhiE (Φ)	So	Viscosity (cP @ 20°C)	Original Pressure (kPa)	Original Temperature (°C)	Depth (m)	Vertical Permeability (mD)	Horizontal Permeability (mD)
Approval Area	2.8	10	0.30	0.79	25,000	2,500	12	305	2,400	4,000

Notes:
So – Oil saturation
OBIP – Original Bitumen in Place
Calculation: OBIP interval: Top of Formation → oil water contact
OBIP = Area x Thickness x Φ x S_o

Reservoir Parameters and Recovery Factors

Section 4.2.6

Well PAD		Thickness (m)	Area (10^3 m^2)	Pad Volume[1] (10^6 m^3)	Average Permeability (mD)	So	PhiE	DBIP (10^6 m^3)	Recovery to Date 12/31/2020 (10^3 m^3)	Recovery Factor to 12/31/2020 (%)	Estimated Ultimate Recovery (10^6 m^3)	Ultimate Recovery Factor (%)	OBIP (10^6 m^3)
Pad A	A Infills and Replacement (16 well pairs)	30	880	30.6	3,000	0.56	0.32	5.5	1897	34.5	2.7	50	6.7
	A original (8 well pairs)	7	640										
Pad B	B West (8 well pairs)	37	640	39.8	3,000	0.57	0.32	7.3	1338	18.3	3.6	50	7.9
	B North (4 well pairs)	8	320										
	B North Infills (3 well pairs)	40	345										
Pad C	C West (8 well pairs)	36	640	53.8	3,000	0.60	0.32	10.3	2511	24.4	5.2	50	13.1
	C North Original [2] (4 well pairs)	10	320										
	C East (8 well pairs)	43	640										
Pad D	D East (15 well pairs)	43	660	28.1	3,000	0.61	0.32	5.5	1876	34.1	2.7	50	6.2
	D North (8 well pairs)	36	330	11.8	3,000	0.61	0.33	2.4	366	15.3	1.2	50	2.8
	D west (15 well pairs)	31	578	17.9	3,000	0.63	0.32	3.6	343	9.5	1.8	50	4.2
Clearwater Total (97 well pairs)								34.6	8330	24.1	17.3	50	40.9
Pad GA (6 well pairs)		30	355	10.6	1,800	0.62	0.30	2.0	593	29.7	1.0	50	2.1
Pad CN (6 well pairs + 7 infill)		13	502	6.5	4,000	0.82	0.29	1.6	795	49.7	1.0	65	1.6
Tucker Total (109 well pairs + 7 infill)								38.2	9718	25.4	19.3	51	44.6

Note:

Developable Bitumen In Place (DBIP) – Volume x So x Phi-E (Thickness defined from top of pay to 8% bitumen weight or producer level where wells are below 8% bitumen weight)

Original Bitumen In Place (OBIP) - Top of Formation → oil water contact

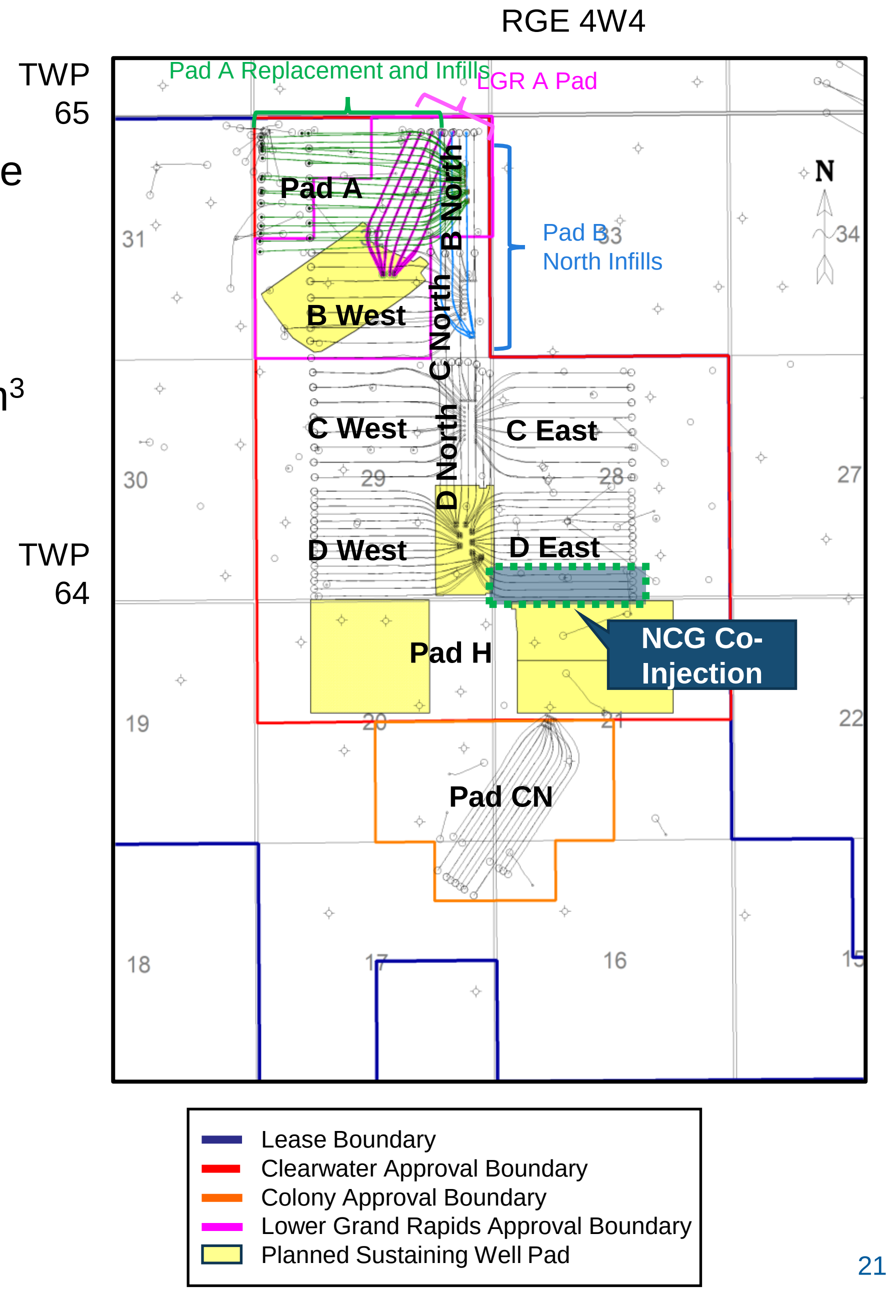
[1] Due to rounding of values, the calculated values may not equal the individual values presented in the table

[2] Pad C North future development not included in DBIP. The DBIP is equal to 1.1X10^6 m^3

Co-injection Information

Section 4.2.7

- November 2020 – started NCG Co-injection in the Clearwater Formation
- Methane was injected to wells D32S, D34S and D36S
- Cumulative NCG injection is 271×10^3 standard m^3 as per the reporting period
- The average NCG injection concentration is approximately 0.7%
- To date, limited data has been collected to evaluate the impact of NCG co-injection

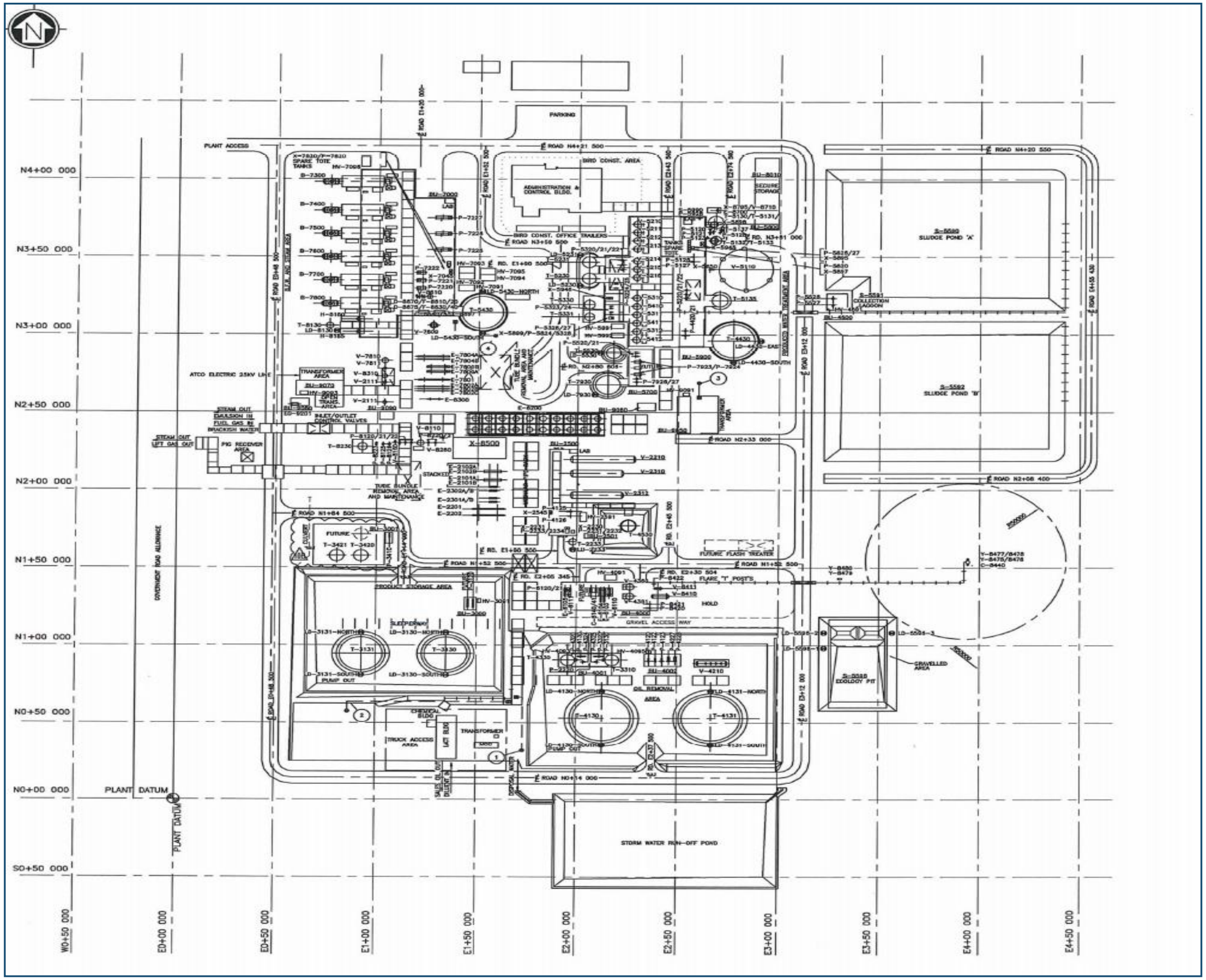


Surface

Section 4.3

Central Processing Facility - Plot Plan

Section 4.3.8.a



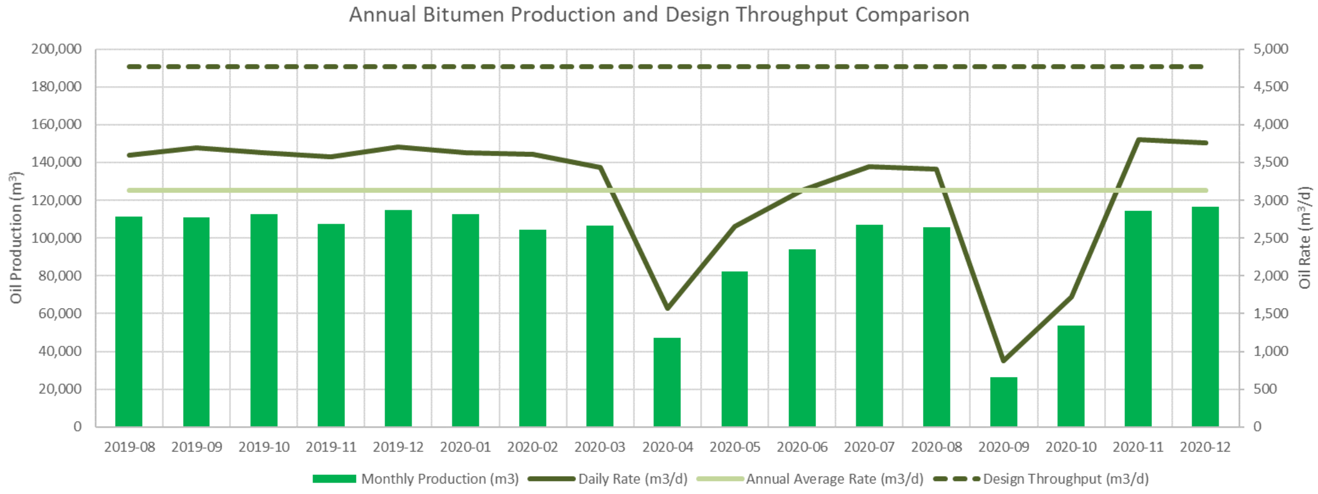
Facility Modifications

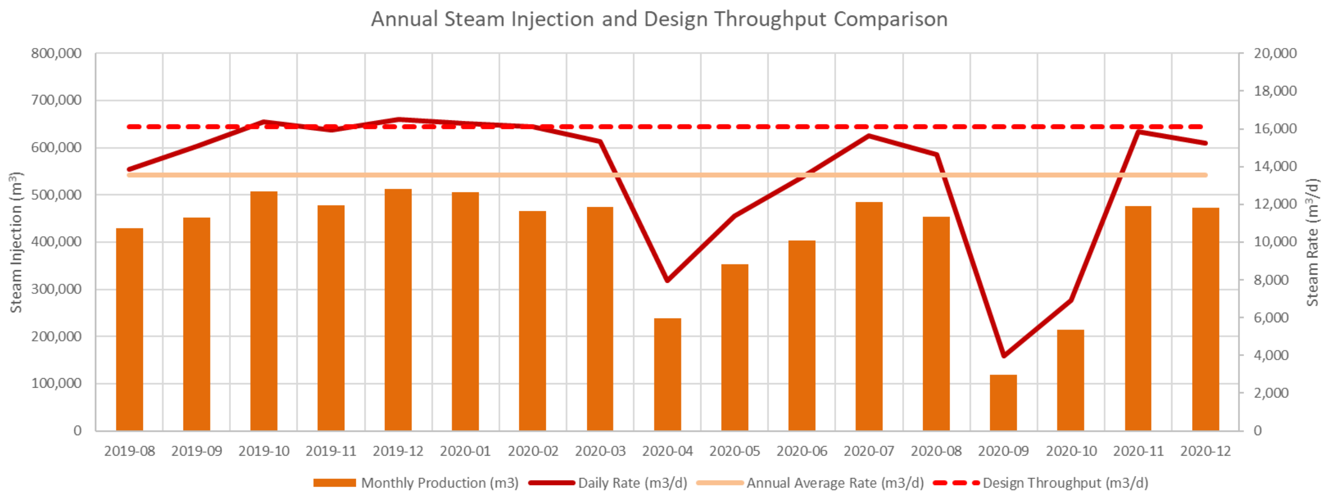
Section 4.3.8.b

- No facility modifications conducted during the reporting period

Annual and Design Throughput Comparison

Section 4.3.8.c





Note:
April 2020 to June 2020 - Production curtailment due to low oil price
September/October 2020 - Plant turnround

History and Upcoming Activity

Section 4.4

Suspension and Abandonment Activity

Section 4.4.9

- No well abandonments or suspensions occurred during the reporting period

Regulatory Applications and Approvals

Section 4.4.10.a

Act	Application Number	Description	Approval Date
OSCA	1928179	NCG Co-Injection Application	2020-08-11
OSCA/EPEA	1982771/011-147753	Clearwater Development (Pad H)	2020-10-28*
OSCA	1931738	NCG Injection Amend Application (Pad A Category 1)	2021-01-11

*Approval included revised EPEA Schedule VI Groundwater

Operational Changes

Sections 4.4.10

Material Operational Changes (b)

- September/October 2020 - Turnaround occurred
- No other material changes to facility capacity

Lessons Leaned (c)

- No significant lessons learned or changes to the operating strategy during the reporting period

Update on Pilots (d)

- Q3 2020 - Deployed two (2) Hydraulic Gas Pumps (HGPs) as a pilot to reduce gas consumption and emission. No significant reduction observed on gas consumption and emission due to various operation and facility limitations
- Q4 2020 - Commenced Non-Condensable Gas (NCG) co-injection in three wells; evaluation in progress

Compliance History

Section 4.4.11

Reportable Incidents

- AER Contravention report – Edge Reference #0357969:
  - August 24, 2019 – 3 m^3 reportable release from IGF
  - Release cleaned up; confirmatory samples taken and clean up approved by AER

Self-Disclosures

- No self-declarations recorded during the reporting period

Compliance

- All conditions of AER License F-32143 as well as all scheme approvals for the Project were met during the reporting period
- All conditions of the EPEA approval 147753-01 as amended were met during the reporting period

Future Plans

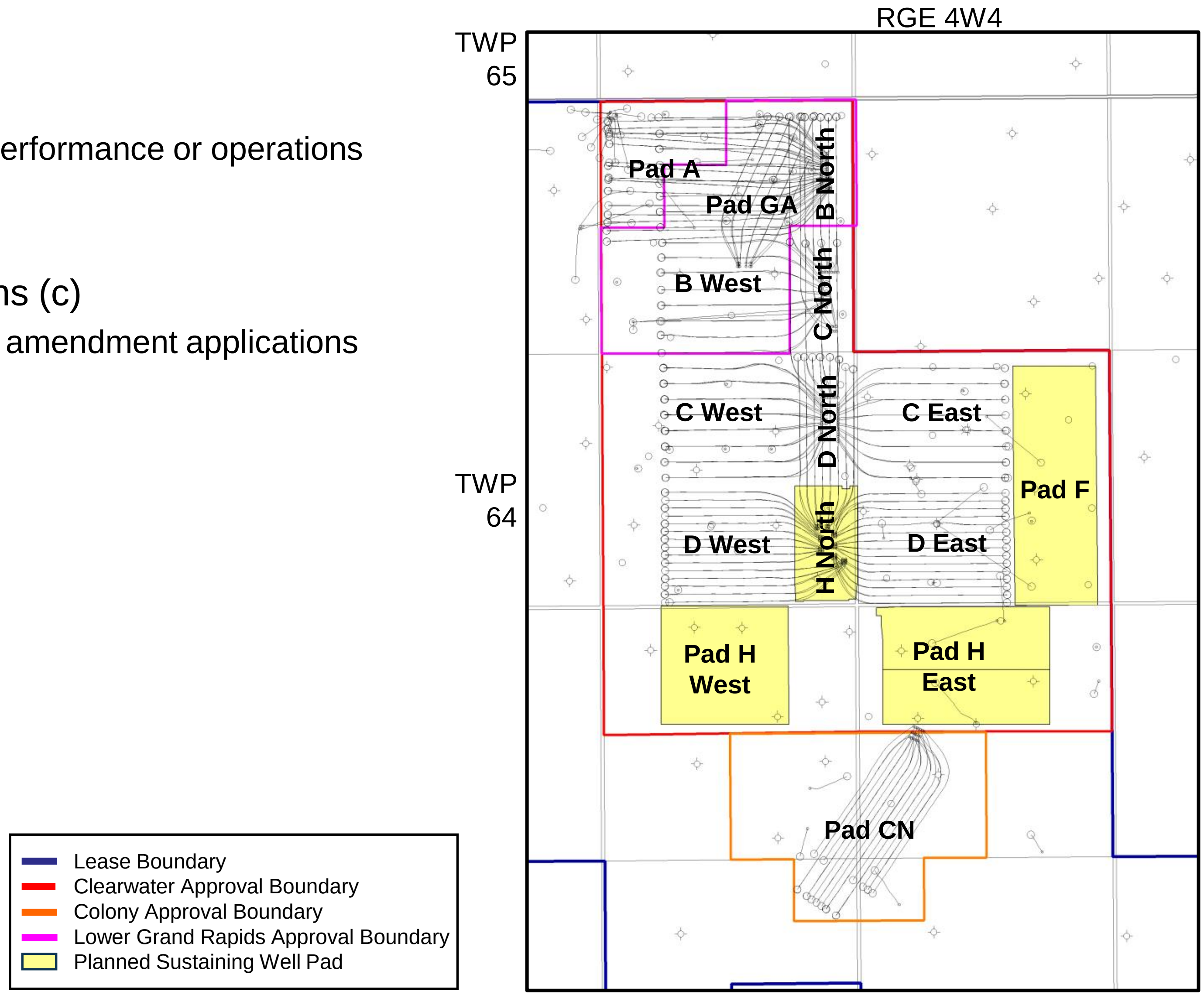
Section 4.4.12

Planned Activity (a)

- No material changes to performance or operations are expected

Expected AER Applications (c)

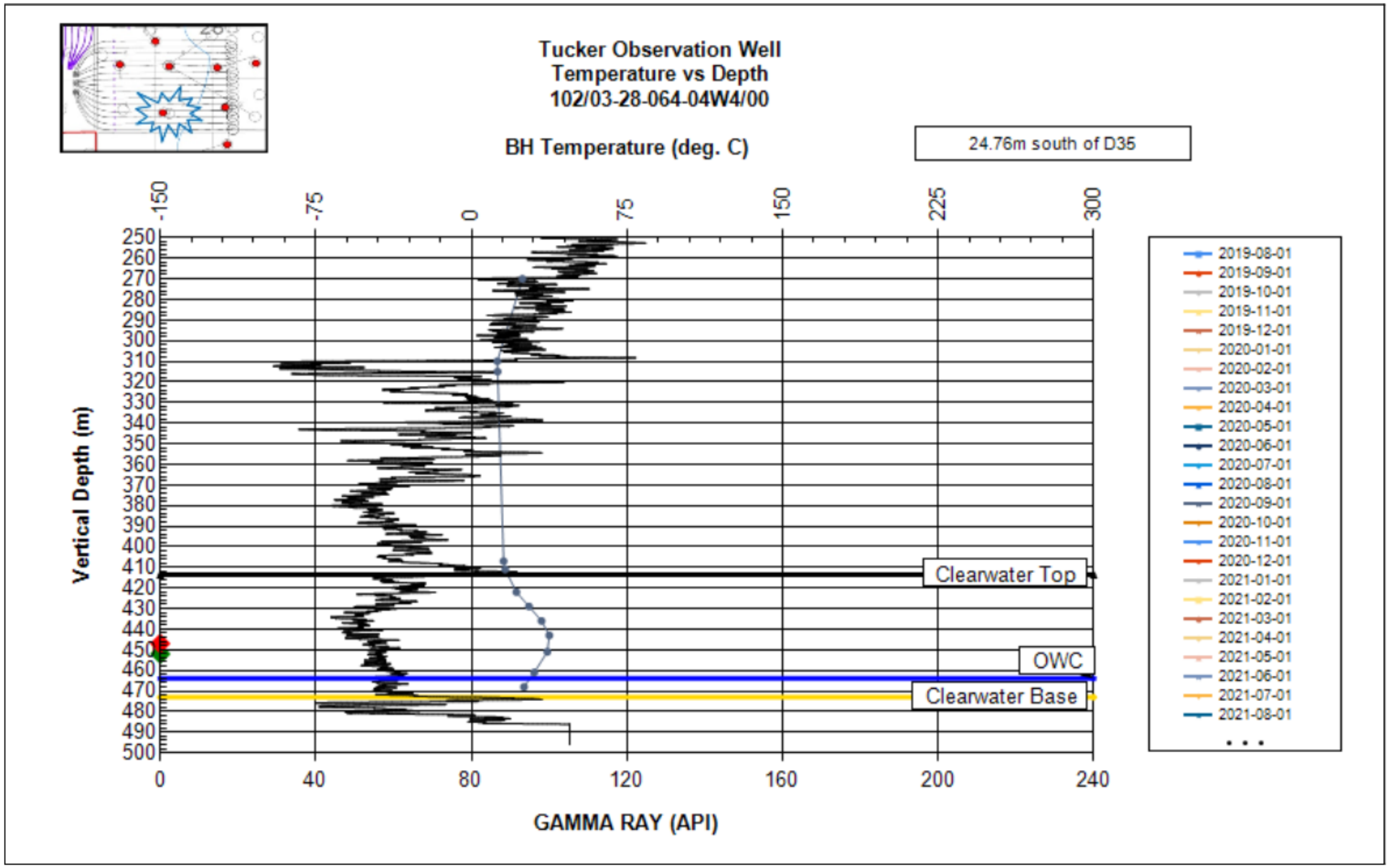
- Clearwater Development amendment applications (Pads H and F)



Monitoring Update for Approval 9835 Clause 14b

Well 102/03-28-064-04W4

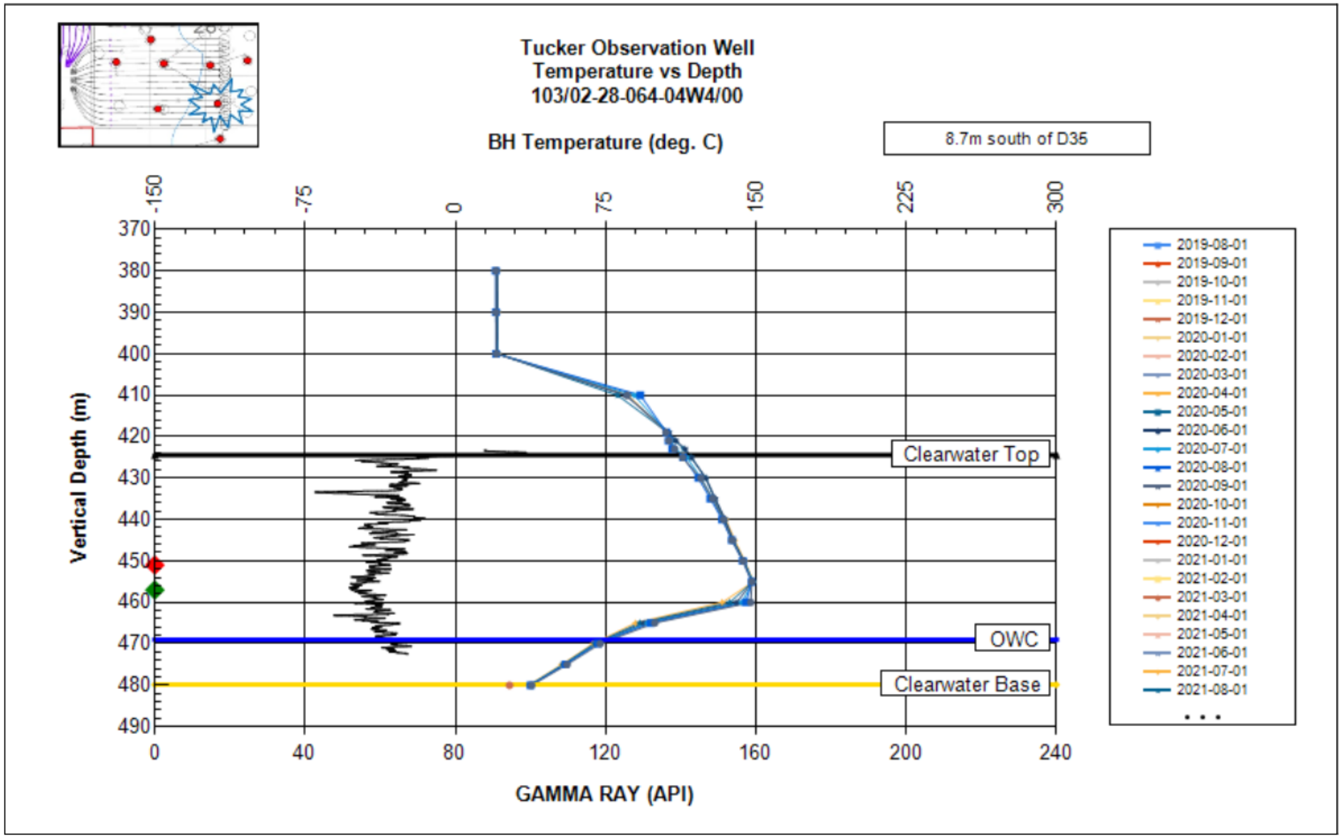
- Thermocouple string malfunction; repaired
- Minimal temperature increase over the past seven (7) years; low risk to neighboring non-thermal compatible well



Monitoring Update for Approval 9835 Clause 14b

Well 103/02-28-064-04W4

- Thermocouple string malfunction; repaired
- Temperature observed within drainage pattern is reasonable
- Well 102/07-28-064-04W4 showing no temperature change



Monitoring update for Approval 9835 Clause 14b

Well 102/07-28-064-04W4

- No temperature changes observed during the reporting period