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# PRIMROSE, WOLF LAKE, AND BURNT LAKE DIRECTIVE 54 ANNUAL PRESENTATION

## SUBSURFACE ISSUES RELATED TO RESOURCE EVALUATION AND RECOVERY

January 2016

PREMIUM VALUE. DEFINED GROWTH. INDEPENDENT.

# Primrose, Wolf Lake, and Burnt Lake 2014 Annual Presentation to the AER

Directive 54: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

- January 27, 2016
  - 3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery
- January 28, 2016
  - 3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

# Outline - Subsurface Issues Related to Resource Evaluation and Recovery

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# Primrose, Wolf Lake, and Burnt Lake Directive 54 Presentation - Acronyms

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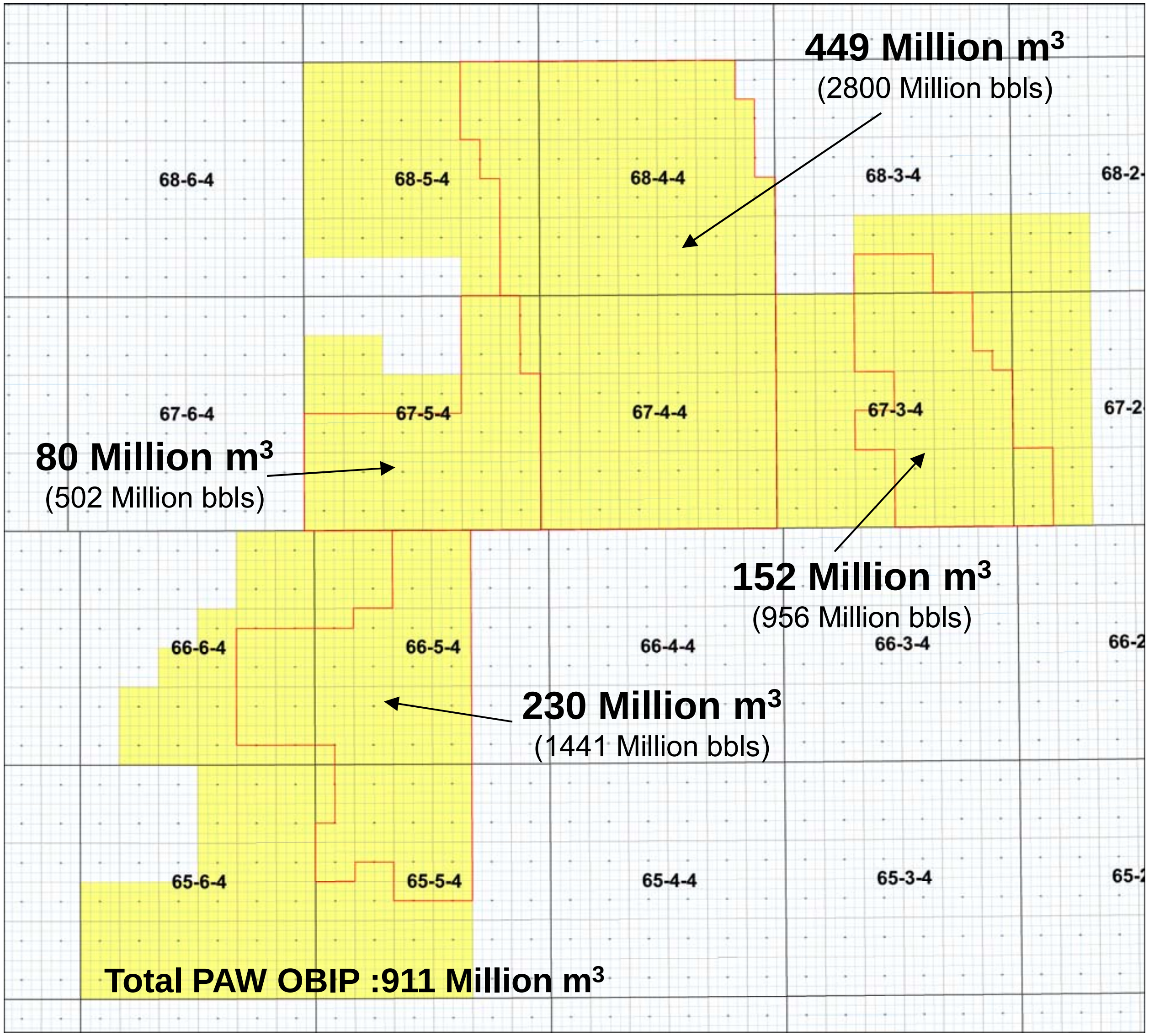
| | |
|---|---|
| AER | Alberta Energy Regulator |
| Avg. | average |
| bbls | barrels, petroleum, (42 U.S. gallons) |
| BHA | bottom hole assembly |
| Bit | bitumen |
| bitwt | bitumen weight |
| CD | cyclic drive |
| CDOR | calendar day oil rate |
| CDSR | calendar day steam rate |
| cP | centipoise |
| CSOR | cumulative steam to oil ratio |
| CSS | cyclic steam simulation |
| Cumm | cumulative |
| dev | deviated |
| DFIT | diagnostic fracture injection testing |
| DI | depletion index |
| dP | pressure differential |
| e3m3 | thousand cubic metres |
| EO | enforcement order |
| ESP | electric submersible pumps |
| ESRD | Environment and Sustainable Resource Development |
| FTS | flow to surface |
| FUP | follow up process |
| GPS | global positioning system |
| HP | horse power |
| hz | horizontal |
| Hz | hertz |
| IHS | Inclined hetreolithic stratification |
| InSAR | interferometric synthetic aperture radar |
| KB | Kelly Bushing |
| kg/m | kilograms per metre |
| kPA | kiloPascal |
| kPa/day | kiloPascal per day |
| LGR | Lower Grand Rapids |
| LIDAR | laser imaging, detection and ranging |
| LPCSS | low pressure cyclic steam stimulation |
| m | metre |
| $m^3$ | cubic metres |
| $m^3$ /d | cubic metres per day |
| $m^3$ /well | cubic metre per well |
| Max. | maximum |

# Primrose, Wolf Lake, and Burnt Lake Directive 54 Presentation - Acronyms

| | |
|---|---|
| mD | milli-Darcy |
| mm | millimetre |
| MMbbl | million barrels |
| MPa | Mega Pascal |
| mTVD | metres true vertical depth |
| MWSDD | mixed-well steam drive drainage |
| OBIP | original bitumen in place |
| Obs | observation |
| ohm·m | ohm·metre |
| PAW | Primrose and Wolf Lake |
| PCP | progressing cavity pumps |
| PRE | Primrose East |
| PRE A1 | Primrose East Area 1 |
| PRE A2 | Primrose East Area 2 |
| PRS | Primrose South |
| PRN | Primrose North |
| PV | pore volume |
| PVS | pore volume steam |
| RF | recovery factor |
| RTK | real-time kinematic |
| SAGD | steam assisted gravity drainage |
| SF | steamflood |
| So | oil saturation |
| SOR | steam oil ratio |
| SPM | strokes per minute |
| SAR | synthetic aperture radar |
| tbg. | tubing |
| TD | total depth |
| TVD | true vertical depth |
| VAF | volume over fill-up |
| WDI | water depletion index |
| WHT | wellhead temperature |
| YE | yearly |

# Primrose and Wolf Lake OBIP within Scheme Approval 9140 Development Area




**OBIP numbers include:**

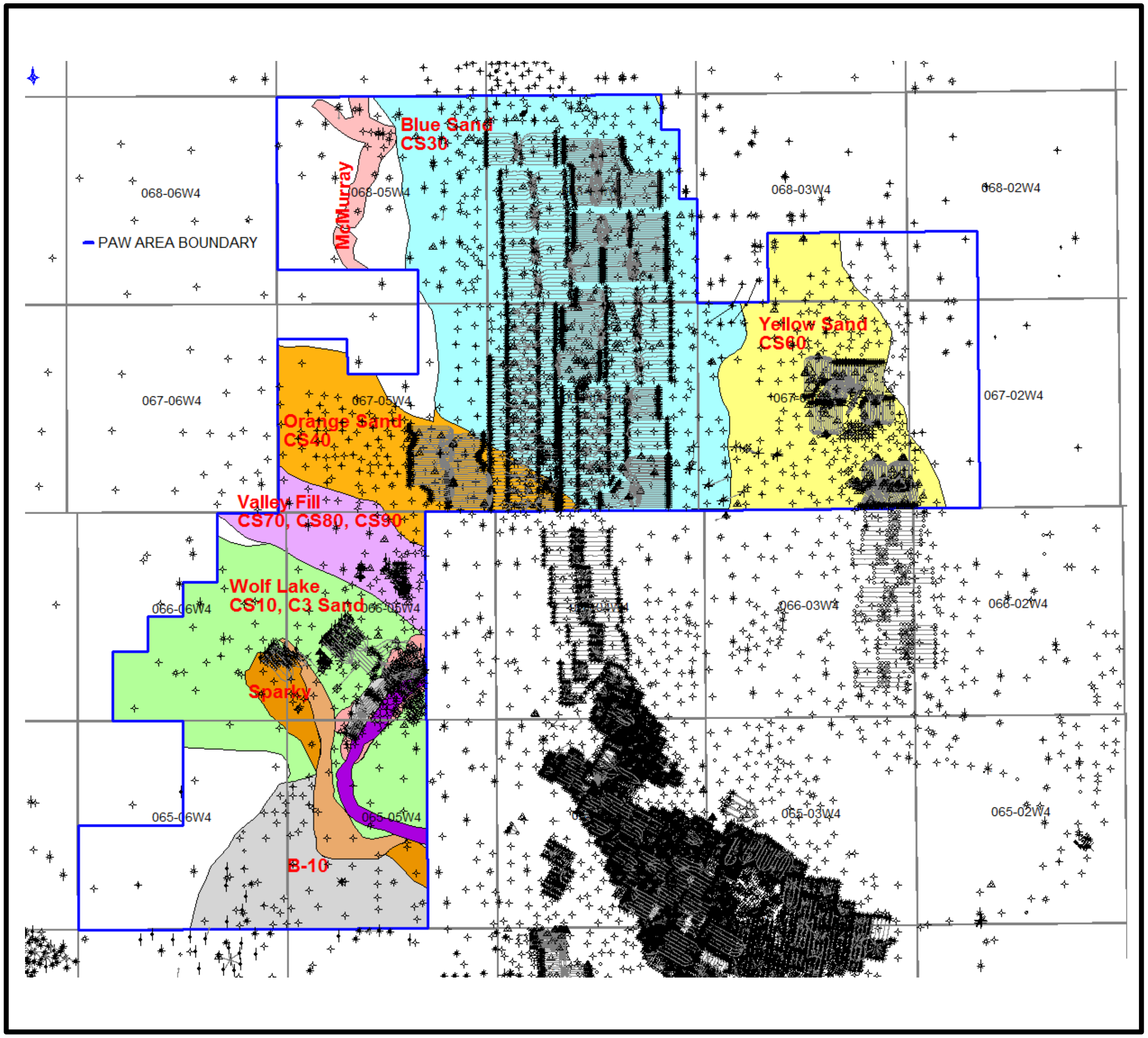
- **McMurray**
- **Clearwater**
- **Grand Rapids**

**Pay criteria for each area and formation shown in subsequent slides**

**Average Primrose and Wolf Lake (PAW) Clearwater Reservoir Characteristics**

**Oil saturation:** 60%
**Bitumen weight:** 9%
**Pay thickness:** 11m
**Porosity:** 32%
**Horizontal permeability:** 3,000mD
**Vertical permeability:** 900mD
**Viscosity:** 100,000cP (at 15ºC)

# Primrose and Wolf Lake Index Map




**Development History for PAW**

**Orange/Blue Sand (Primrose South and North)**
1981-1983 (Dome): Moore Pilot Vertical Well CSS
1992 (Amoco): CDD Pilot Phase 5 Horizontal Well Steam Drive
1993-1999 (Amoco): Phase 1-20 Horizontal Well CSS
1996 (Amoco): Phase 2-3 MWSDD Steam Drive Drainage Pilot
1998 (Amoco): BD-18 SAGD Pilot
2000 (CNRL): Phase 21 Horizontal Well CSS
2003-2004: Phase 29-31 Horizontal Well CSS
2004-2006: Phase 51-55 Horizontal Well CSS
2003: Phase 14 Surfactant in Steam CSS
2003: Phase A1-A2 Cyclic Gas
2004: Phase A1 Cyclic Rich Gas
2005: Phase B2 Solvent in Steam CSS
2005-2007: Phase 27, 17 in-fill, 28 (80m spacing) Horizontal CSS
2006: Phase BD-18 VAPEX
2008-2009: Phase 58, 59, 62, 63, 66, 67 Horizontal Well CSS
2010-2011: Phase 22-24 Horizontal Well CSS
2011-2012: Phase 25-26 Horizontal Well CSS
2011-2013: Phase 60,61,64,65,68 Horizontal Well CSS
2013: Phase 40-43 Horizontal Well CSS
2014: Phase 40-43 Horizontal Well CSS

**Yellow Sand (Primrose East)**
1986-1988 (Suncor): Phase 14A-14B Slant Pads
1996 (Suncor): Burnt Lake Pilot SAGD
2007-2008 (CNRL): Phase 74, 75, 77, 78 Horizontal Well CSS
2011-2012: Phase 90-95 Horizontal Well CSS

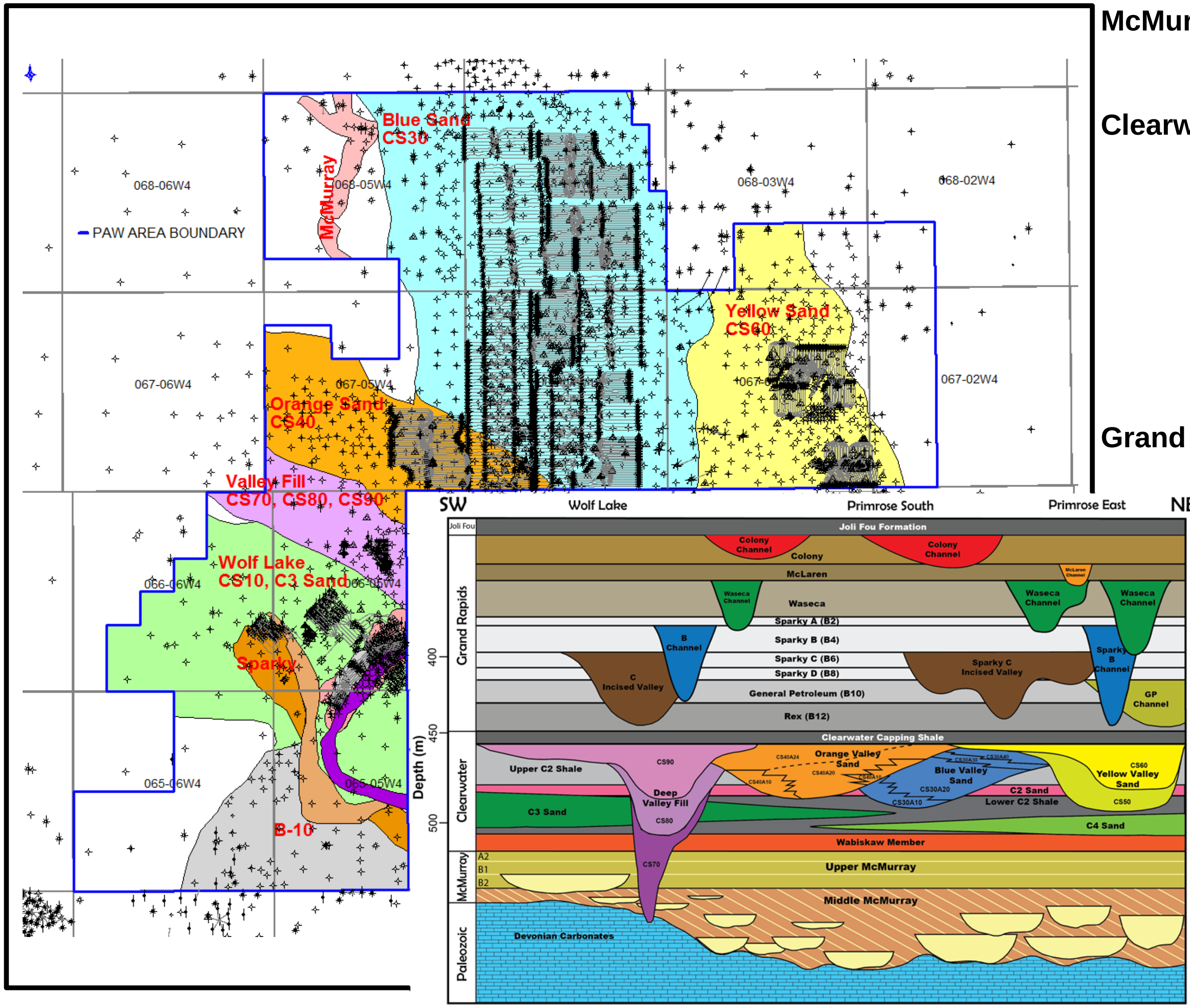
**Valley Fill (Wolf Lake)**
1988 (BP): Z8 Vertical Well CSS
1989 (Amoco): HWP1 SAGD Pilot
2005 (CNRL): Z13 Vertical Well CSS

**C3 Sand (Wolf Lake)**
1966 (BP): Phase A Vertical Well Pilot
1978-1988 (BP): Marguerite Lake Pilot
1980-1985 (BP): Wolf Lake 1 West Vertical Well CSS
1980-1985 (BP): Wolf Lake 1 East Vertical Well CSS
1987-1988 (BP): Wolf Lake 2 Vertical Well CSS
1994 (Amoco): Wolf Lake 1 East Horizontal MWSDD
1996 (Amoco): Wolf Lake 1 West Horizontal MWSDD
1999-2000 (CNRL): Phase E2 and N Horizontal CSS

**B10 Sand (Wolf Lake)**
1989 (BP): E14 Vertical Well CSS Pilot
1997 (Amoco): D2 Pair 1 SAGD
2000 (CNRL): D2 Pair 2-6 SAGD
2000-2001: SD9 SAGD
2001: S1A SAGD
2004: S1A SAGD re-drill
2010: S1B SAGD

**McMurray Sand (Wolf Lake)**
2010 (CNRL): MC1 SAGD

# Regional Stratigraphy




**McMurray:** Estuarine to shoreface deposits

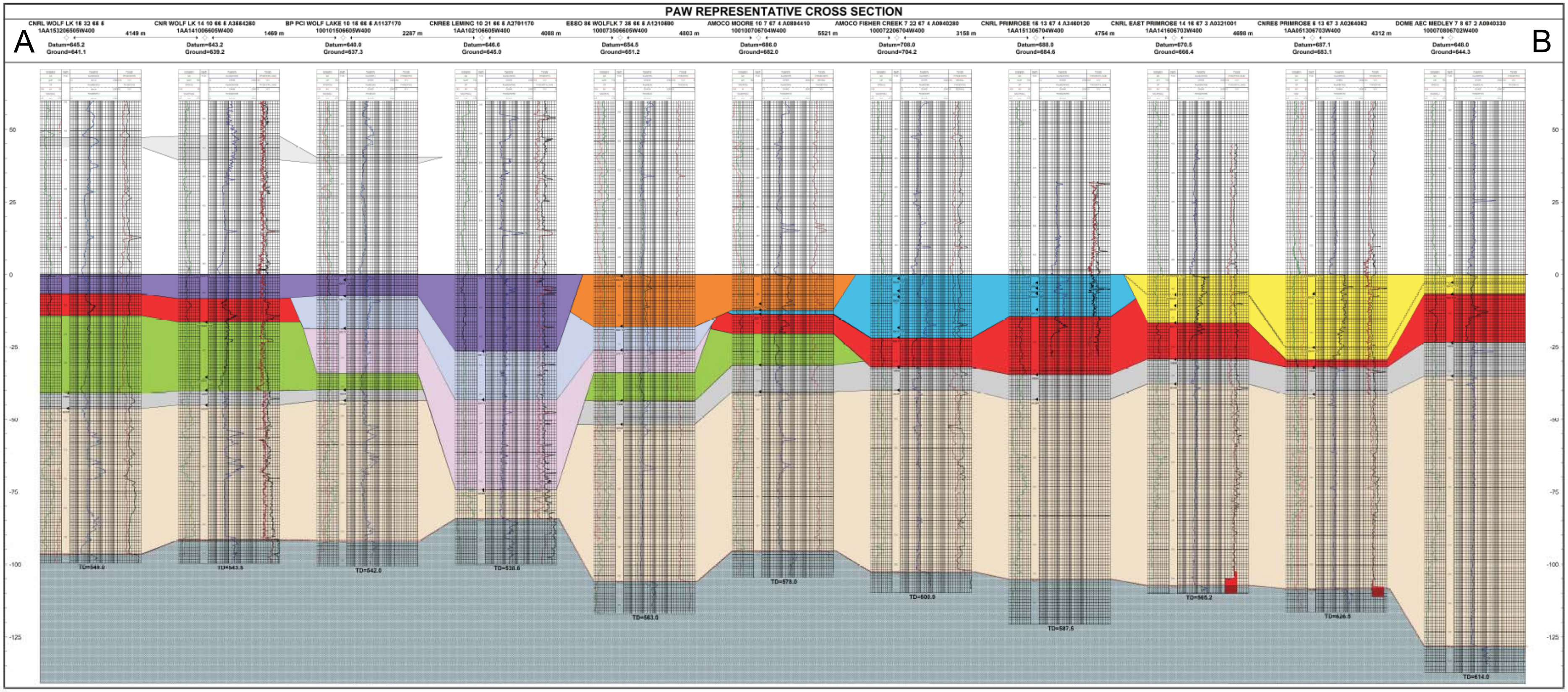
**Clearwater:** Compound incised valley system

Estuarine deposits vary from valley to valley

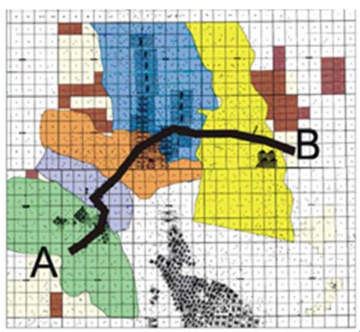
Valley specific reservoir facies assemblages

**Grand Rapids:** Shoreline deposits cut by channels

# Representative Stratigraphic Cross Section

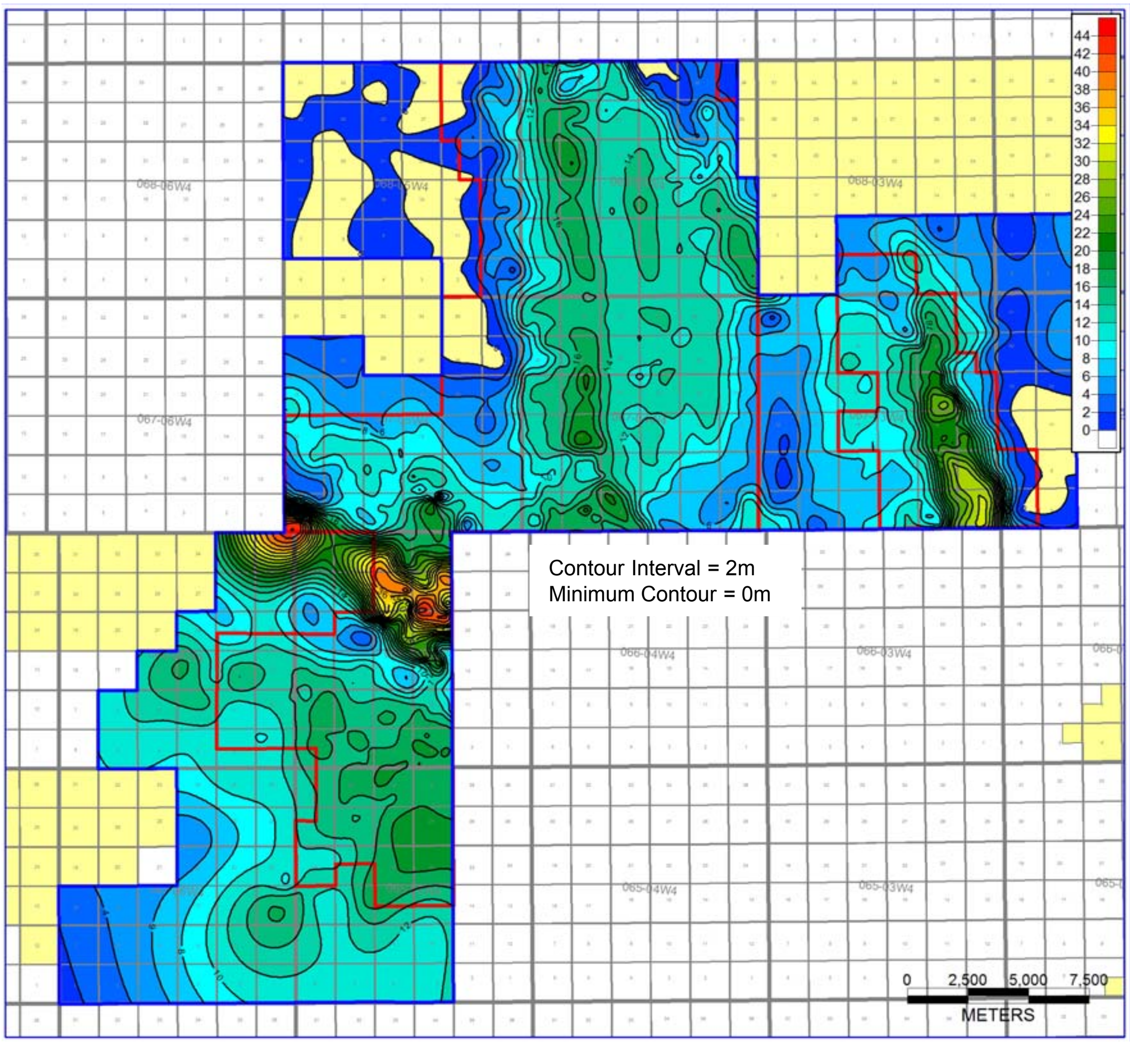






# Clearwater Net Pay Isopach

### Regional Clearwater Net Pay




**Primrose:**

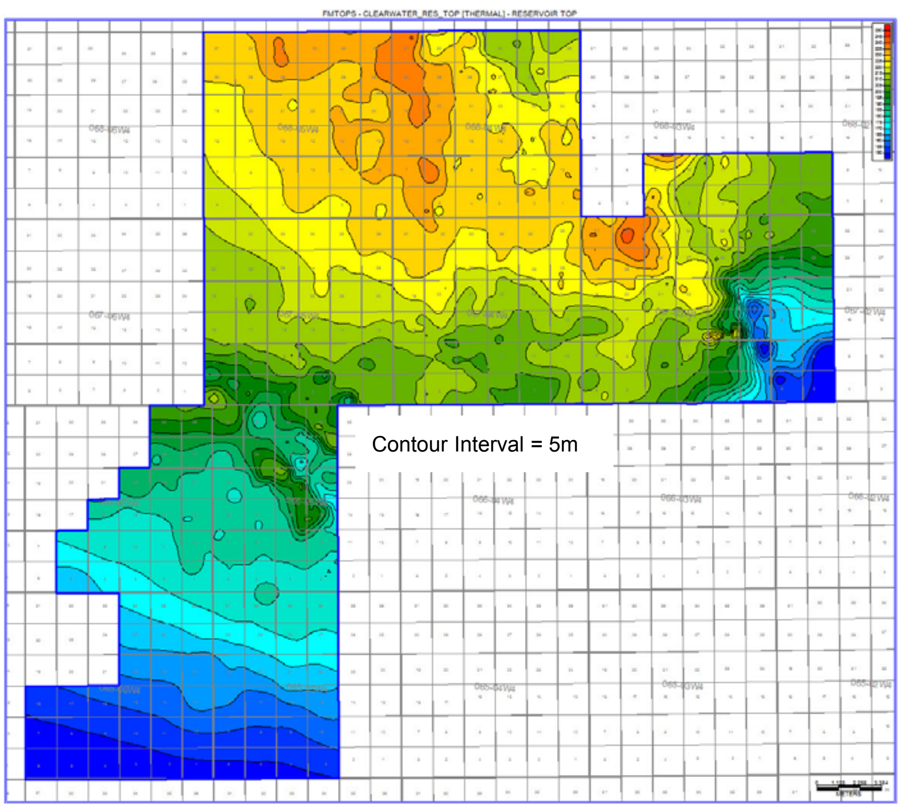
- Blue Valley
  - bitumen weight (bitwt) >6%, (FAA has no Berthierine and <10% mud)
- Orange Valley
  - bitwt >6%, (O30 <10% mud)
- Yellow Valley
  - bitwt >6%, (FA3 <10% mud, vertically continuous)

**Wolf Lake:**

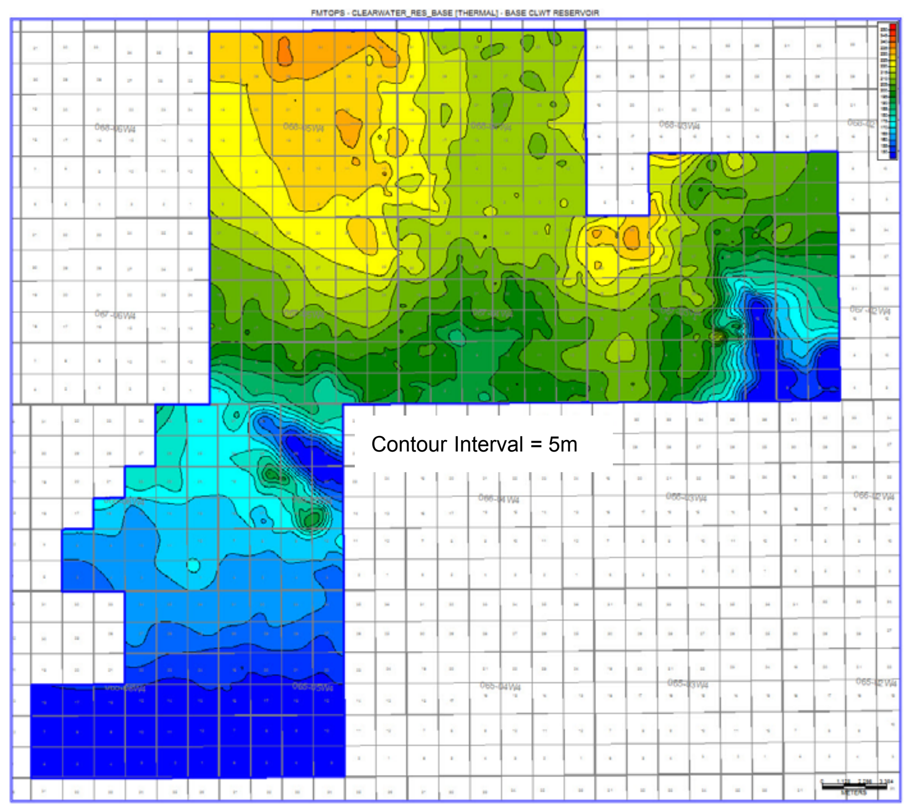
- C3 sand
  - bitwt >6%,
- Valley Fill:
  - bitwt >6%

# Clearwater Formation Structure

### Reservoir Top Structure




### Reservoir Base Structure



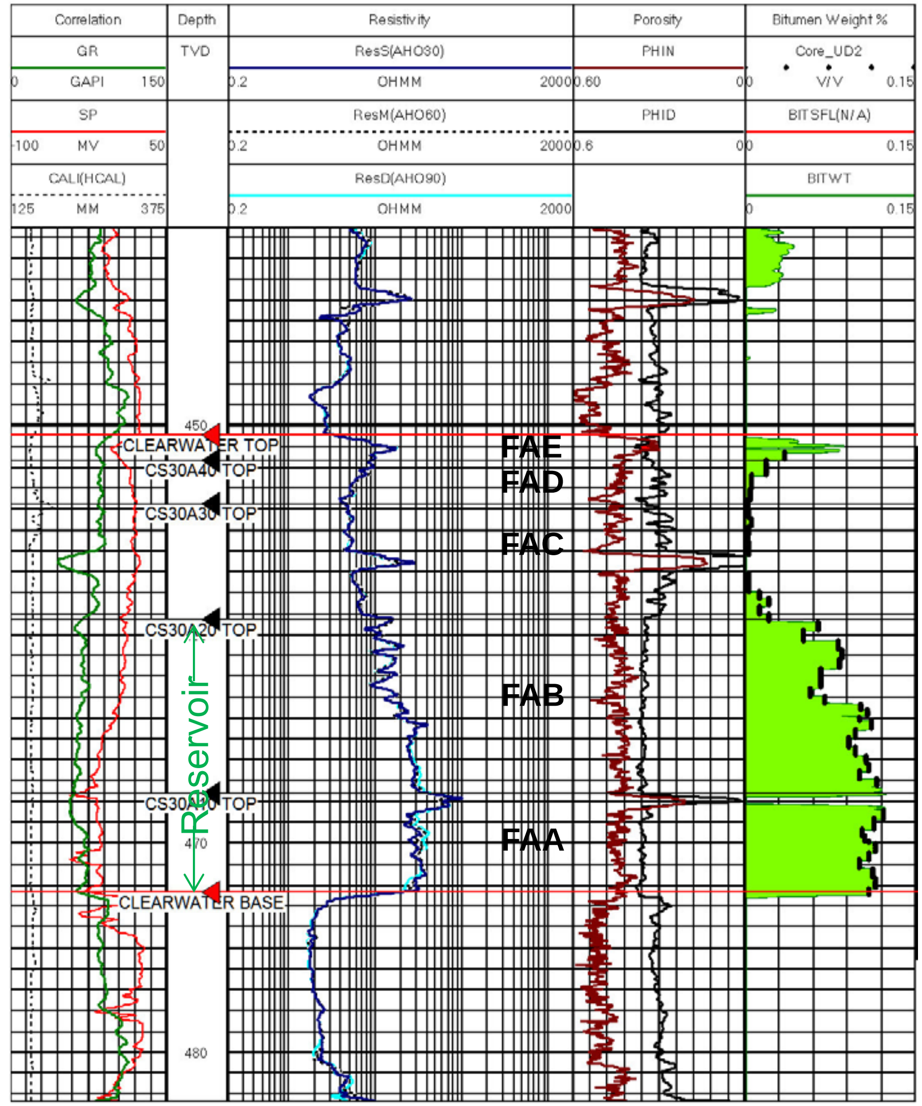

- Clearwater reservoir base is the start of continuous deposits with bitwt >6% and <10% mud beds
- Clearwater reservoir top is the termination of continuous deposits with bitwt >6% and <10% mud beds

# Blue Sand (Primrose South and North)

## Reservoir Characteristics

- Reservoir: FAB & FAA
- Avg. oil saturation: 62%
- Avg. bitumen weight: 9.3%
- Max. net pay thickness: 23 m
- Avg. porosity: 32%
- Avg. horizontal permeability: 3,000 mD
- Avg. vertical permeability: 900 mD
- Avg. viscosity: 100,000 cP (at 15°C)

**1AA060406804W400**



# Orange Sand (Primrose South)

## Reservoir Characteristics

- Reservoir: O10
- Avg. oil saturation: 65%
- Avg. bitumen weight: 9.8%
- Max. net pay thickness: 20 m
- Avg. porosity: 32%
- Avg. horizontal permeability: 3,000 mD
- Avg. vertical permeability: 900 mD
- Avg. viscosity: 100,000 cP (at 15$^{o}$C)

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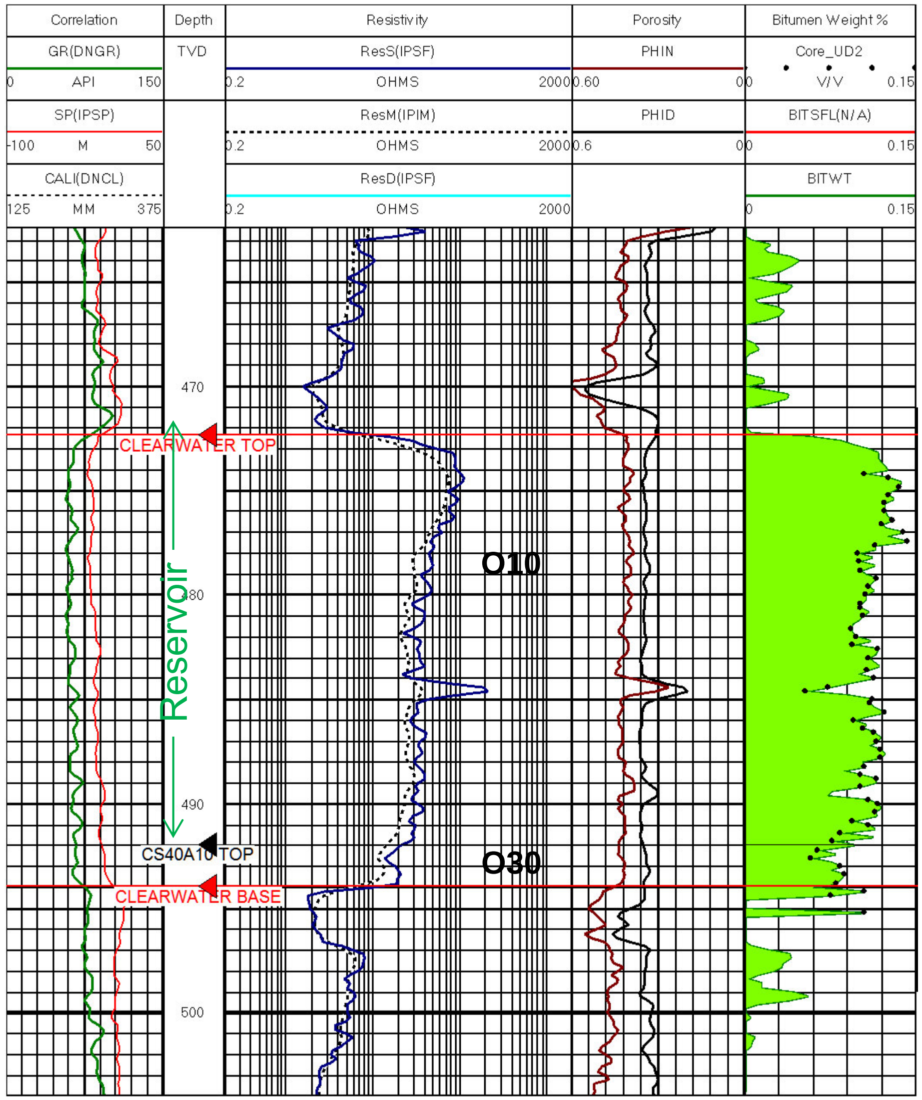

# Yellow Sand (Primrose East)

## Reservoir Characteristics

- Reservoir: FA7, FA8 & FA9
- Avg. oil saturation: 63%
- Avg. bitumen weight: 9.5%
- Max. net pay thickness: 29 m
- Avg. porosity: 32%
- Avg. horizontal permeability: 3,000 mD
- Avg. vertical permeability: 900 mD
- Avg. viscosity: 70,000 cP (at 15$^{o}$C)

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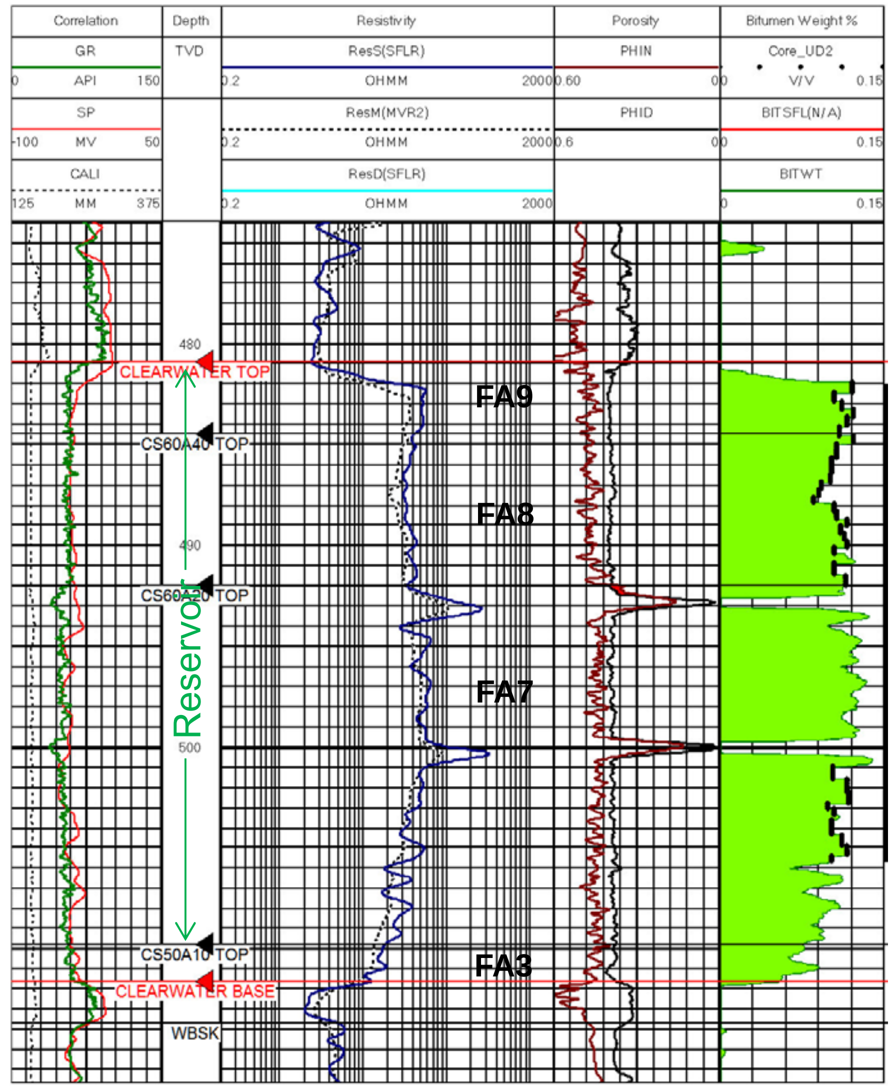

# Valley Fill (Wolf Lake)

## Reservoir Characteristics

- Reservoir: CS80
- Avg. oil saturation: 57%
- Avg. bitumen weight: 8.9%
- Max. net pay thickness: 42 m
- Avg. porosity: 33%
- Avg. horizontal permeability: 3,000 mD
- Avg. vertical permeability: 2000 mD
- Avg. viscosity: 100,000 cP (at 15$^{o}$C)

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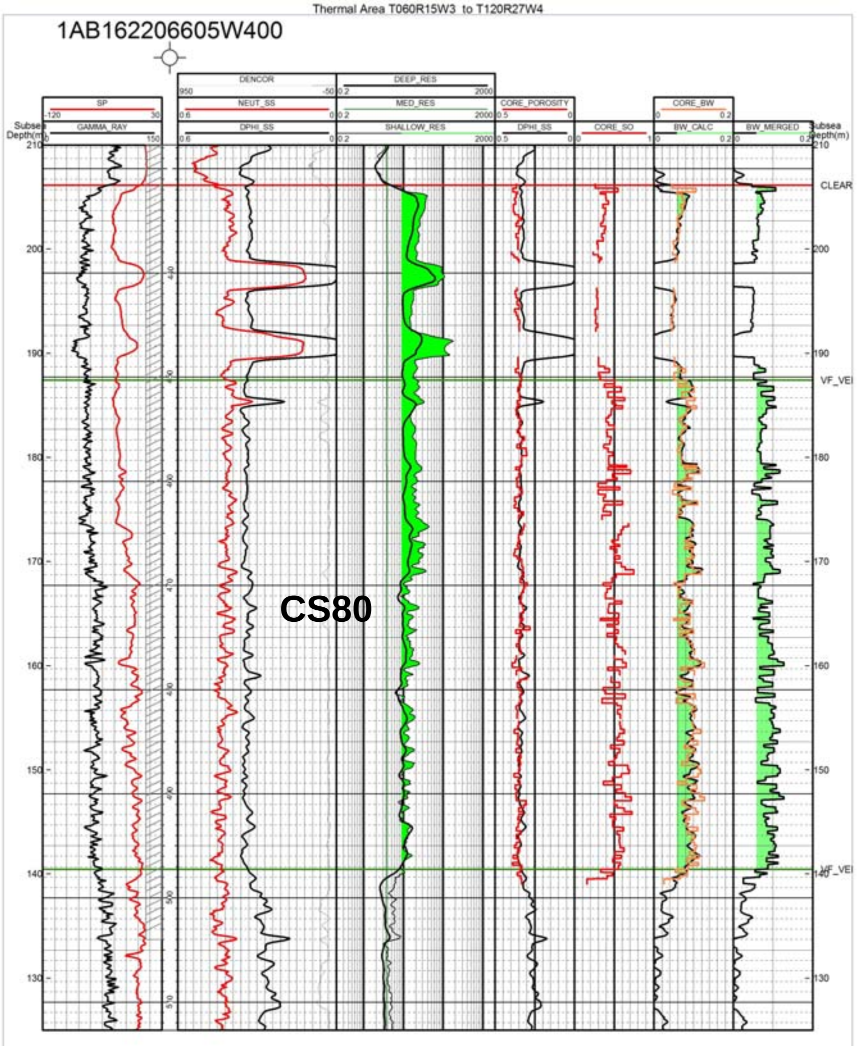

# C3 Sand (Wolf Lake)

## Reservoir Characteristics

- Reservoir: C3-20 & C3-30
- Avg. oil saturation: 50%
- Avg. bitumen weight: 7.8%
- Max. net pay thickness: 17 m
- Avg. porosity: 33%
- Avg. horizontal permeability: 2,000 mD
- Avg. vertical permeability: 200 mD
- Avg. viscosity: 100,000 cP (at 15$^{o}$C)

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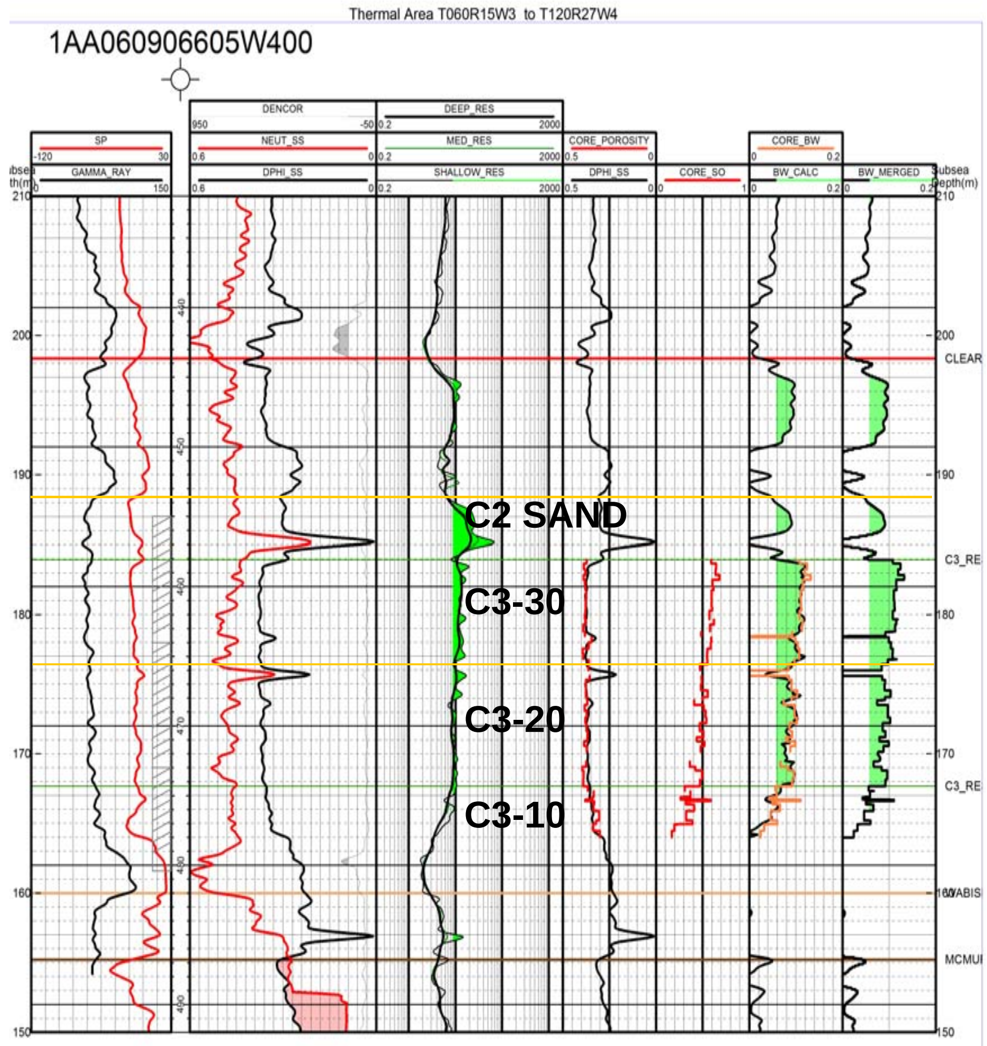

# Grand Rapids B10 Pay Isopach

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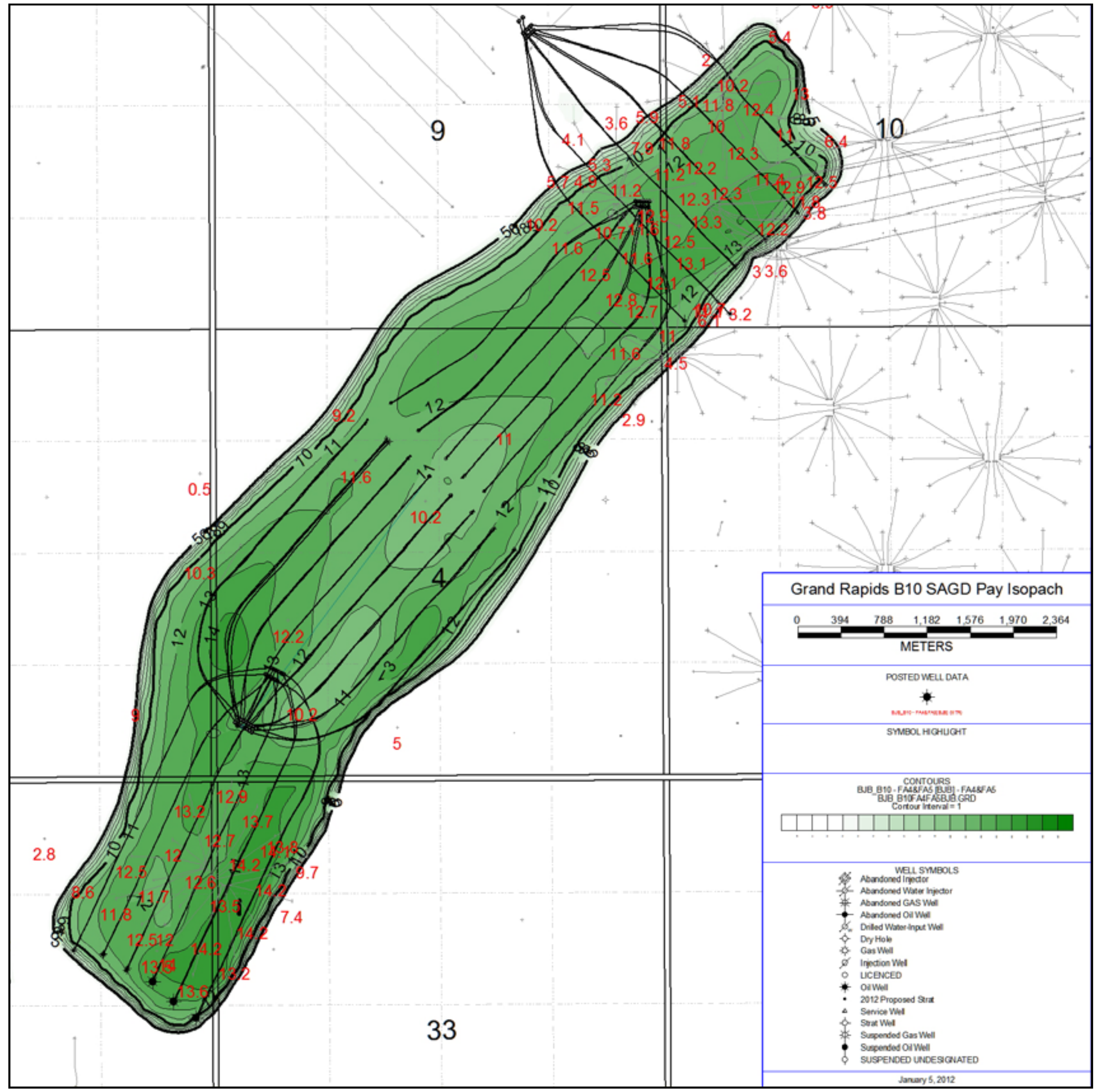
Grand Rapids B10

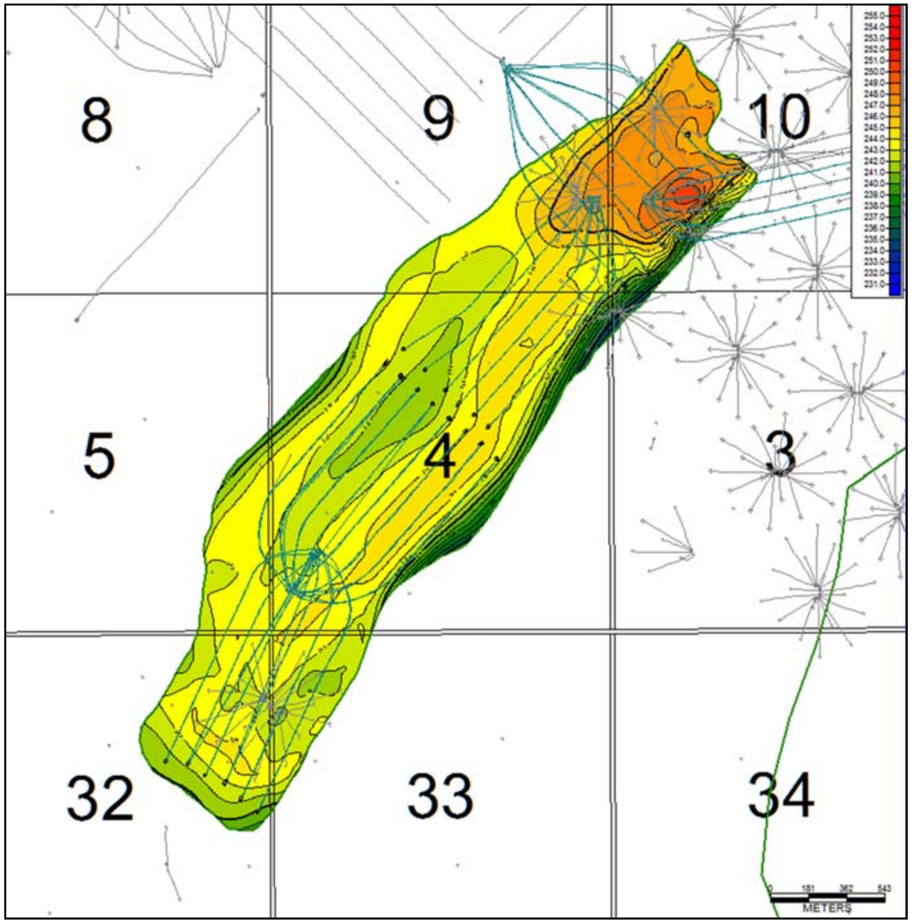
- Channel deposits in FA4 & FA5, (Net pay >10m for development)
- All 4 B10 SAGD Pads highlighted as black wells.



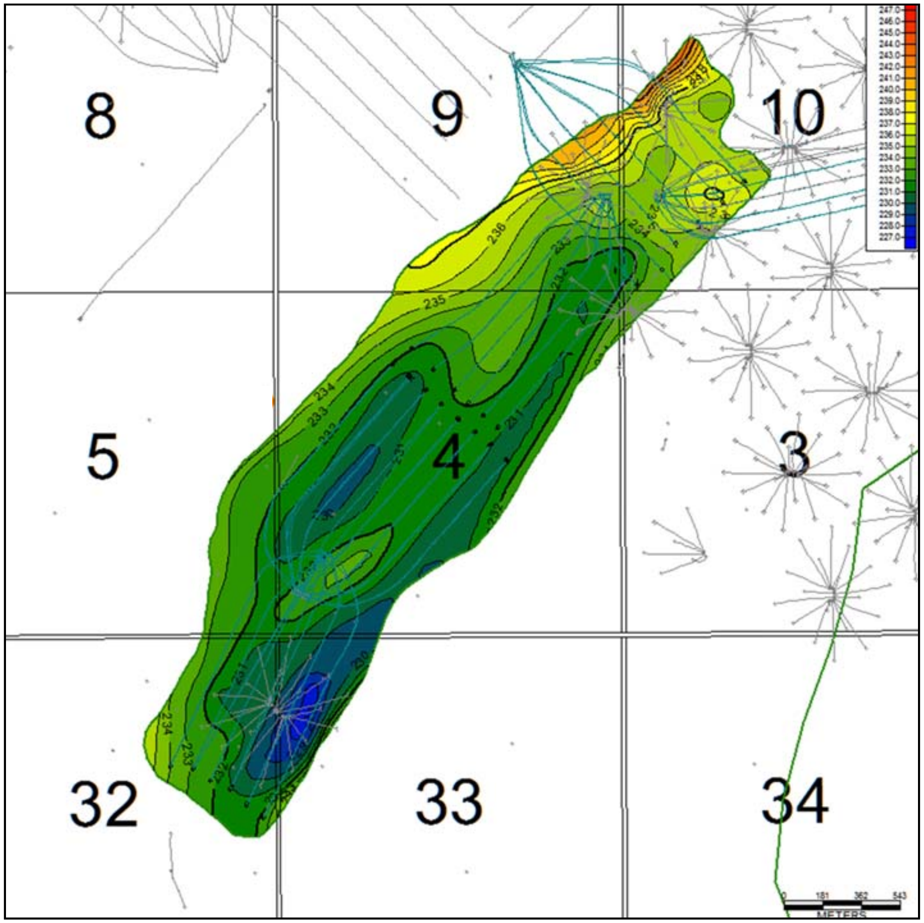

**Contour Interval = 1m, Minimum 5m shown**

# Grand Rapids B10 Structure

### Reservoir Top Structure




### Reservoir Base Structure




SAGD pay defined as clean sand in FA4 and FA5

- Average bitumen weight 11.5%

# Wolf Lake SAGD B10 Sand Reservoir Characteristics

## Reservoir Characteristics

- Reservoir: FA5 & FA4
- Average oil saturation: 75%
- Average bitumen weight: 11.5%
- Maximum net pay thickness: 16 m
- Average porosity: 33%
- Average HZ permeability: 3,200 mD
- Average Vertical Permeability: 2,500 mD
- Average Viscosity: 100,000 cP (at 15°C)
- No connected bottom water

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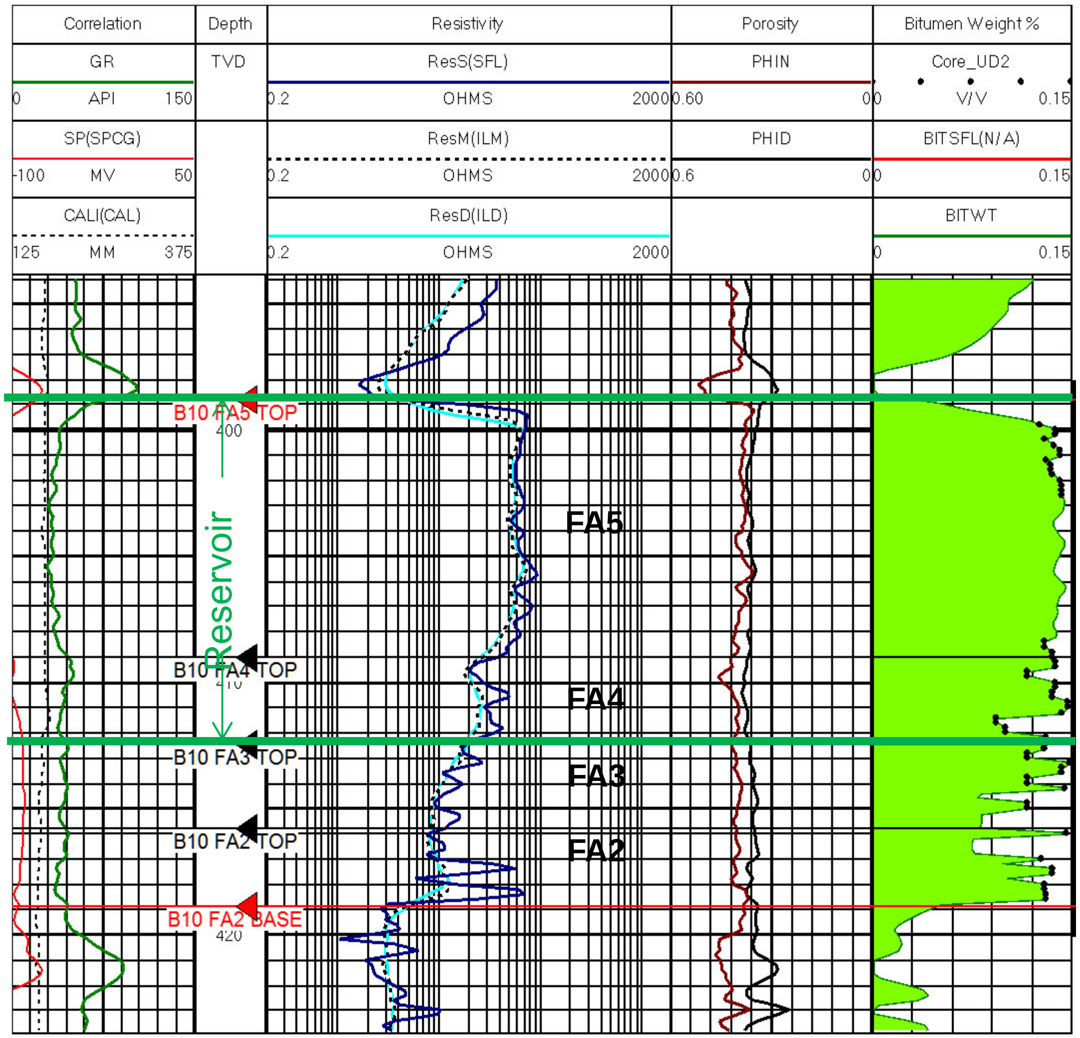
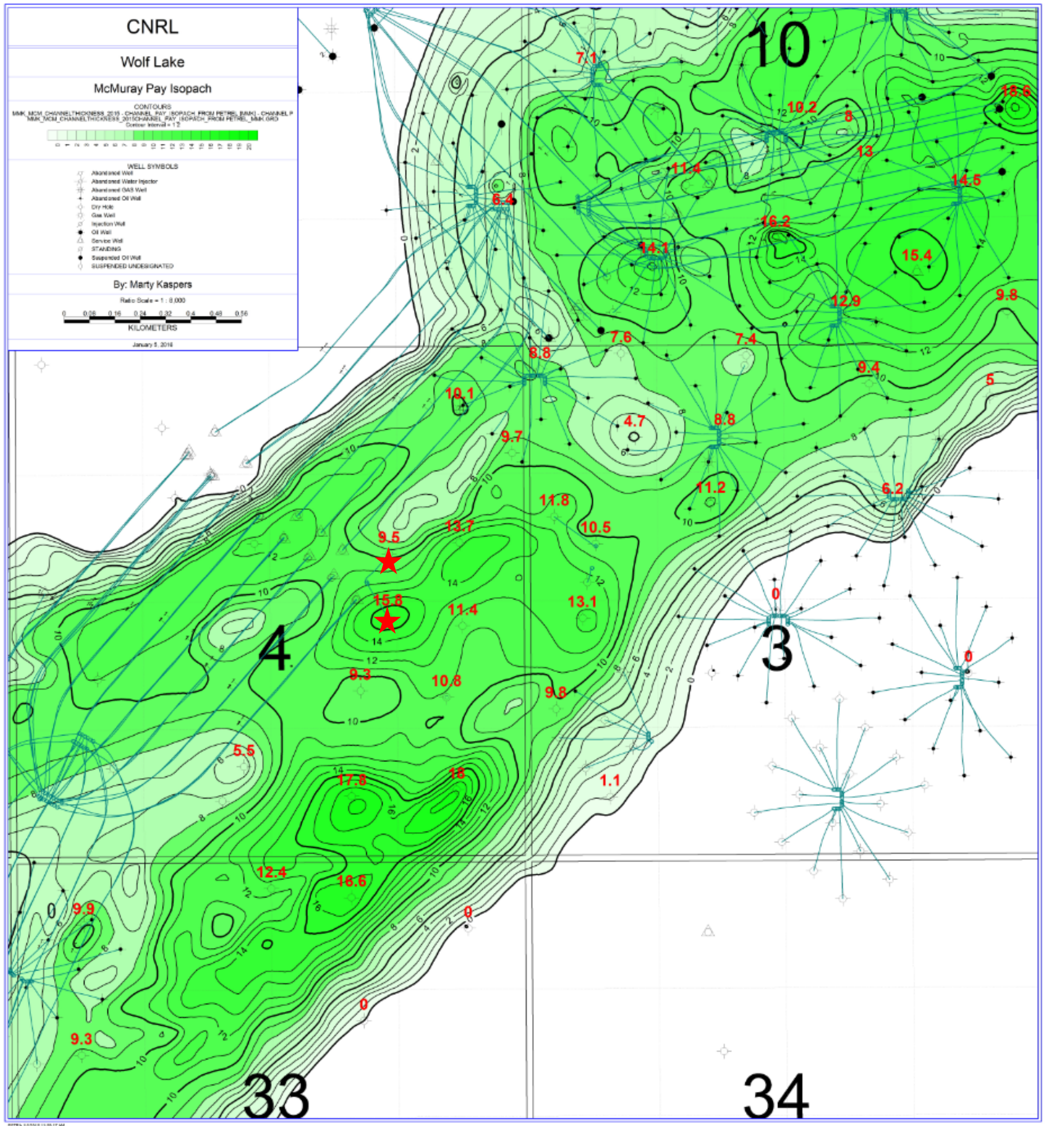


# Wolf Lake McMurray SAGD Pay Isopach

McMurray Sand

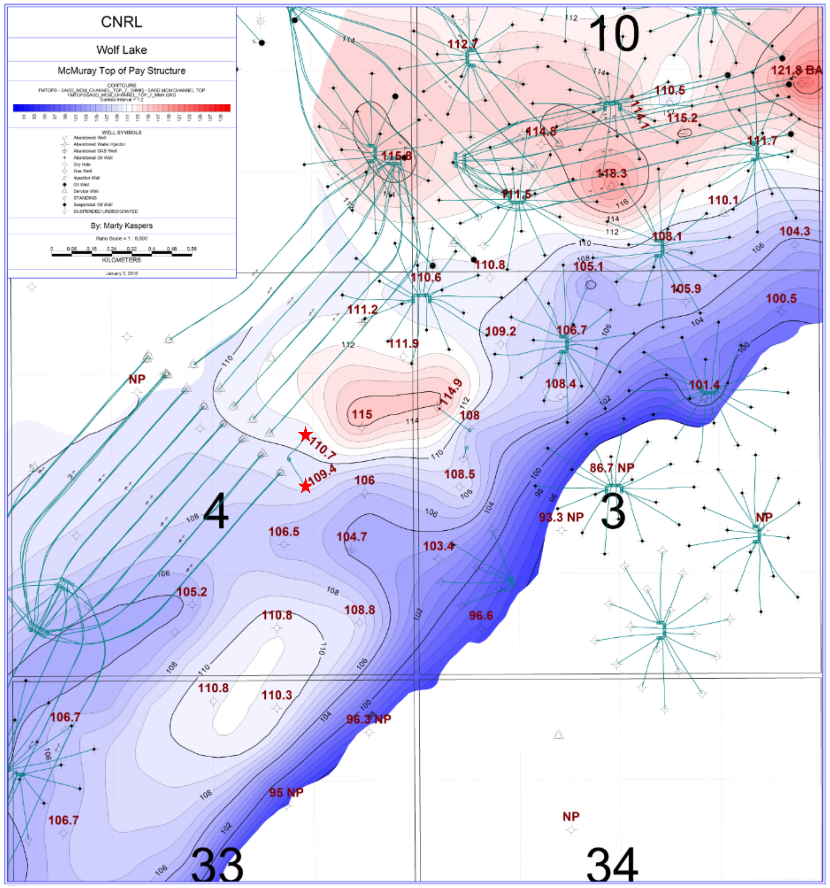
- Channel deposits with bitwt >10%
- Net pay >10m for development
- 2015 drilled strat wells ★



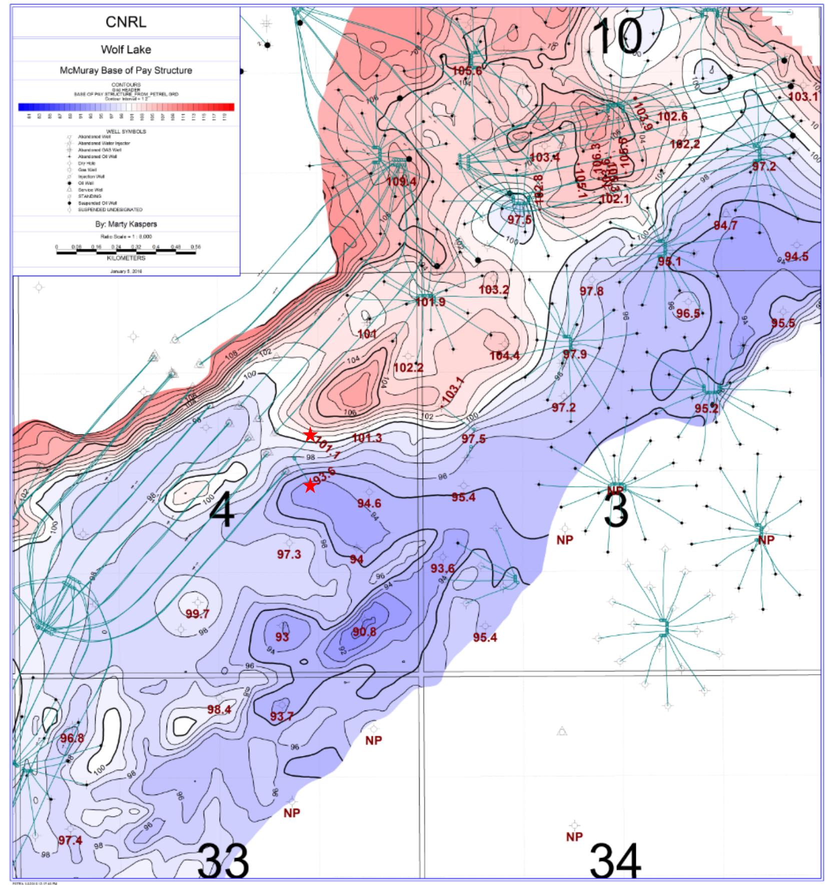

Contour Interval = 1 m

# Wolf Lake McMurray SAGD Pay Structure

## Reservoir Top Structure




## Reservoir Base Structure




- SAGD Pay defined by continuous clean sand and breccia. IHS is not included.
- Base of reservoir, above bottom water, corresponds to bitumen weight 10% (~6ohm·m).



2015 drilled strat ★ Contour Interval = 1m

# Reservoir Characteristics- Wolf Lake McMurray

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## Reservoir Characteristics

- Reservoir: FA5
- Average oil saturation: 73%
- Average bitumen weight: 11.9%
- Maximum net pay thickness: 19 m
- Average porosity: 34%
- Average HZ permeability: 6,000 mD
- Average Vertical Permeability: 5,000 mD
- Average Viscosity: 100,000 cP (at 15$^{o}$C)

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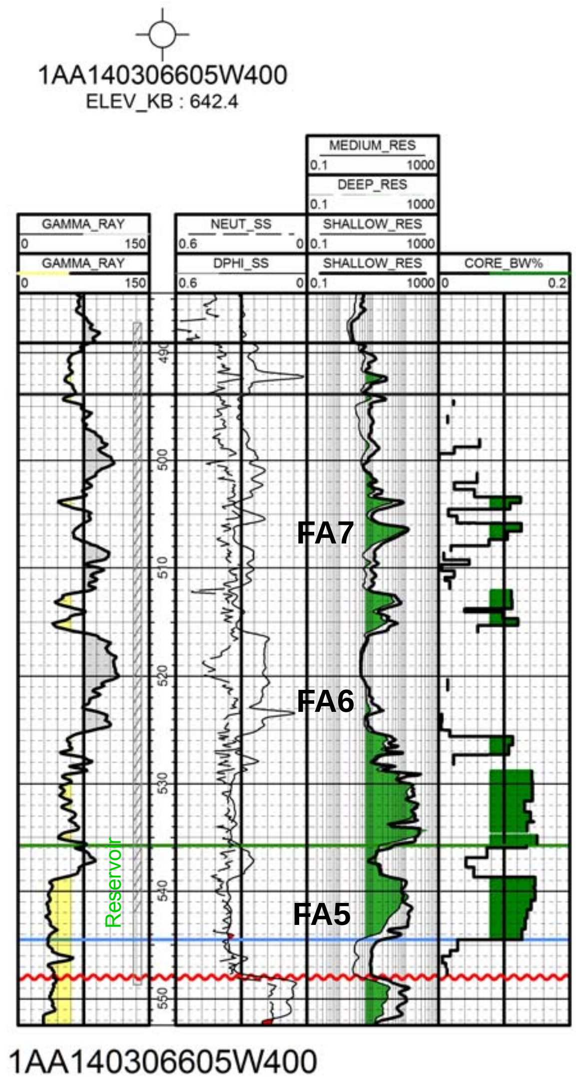
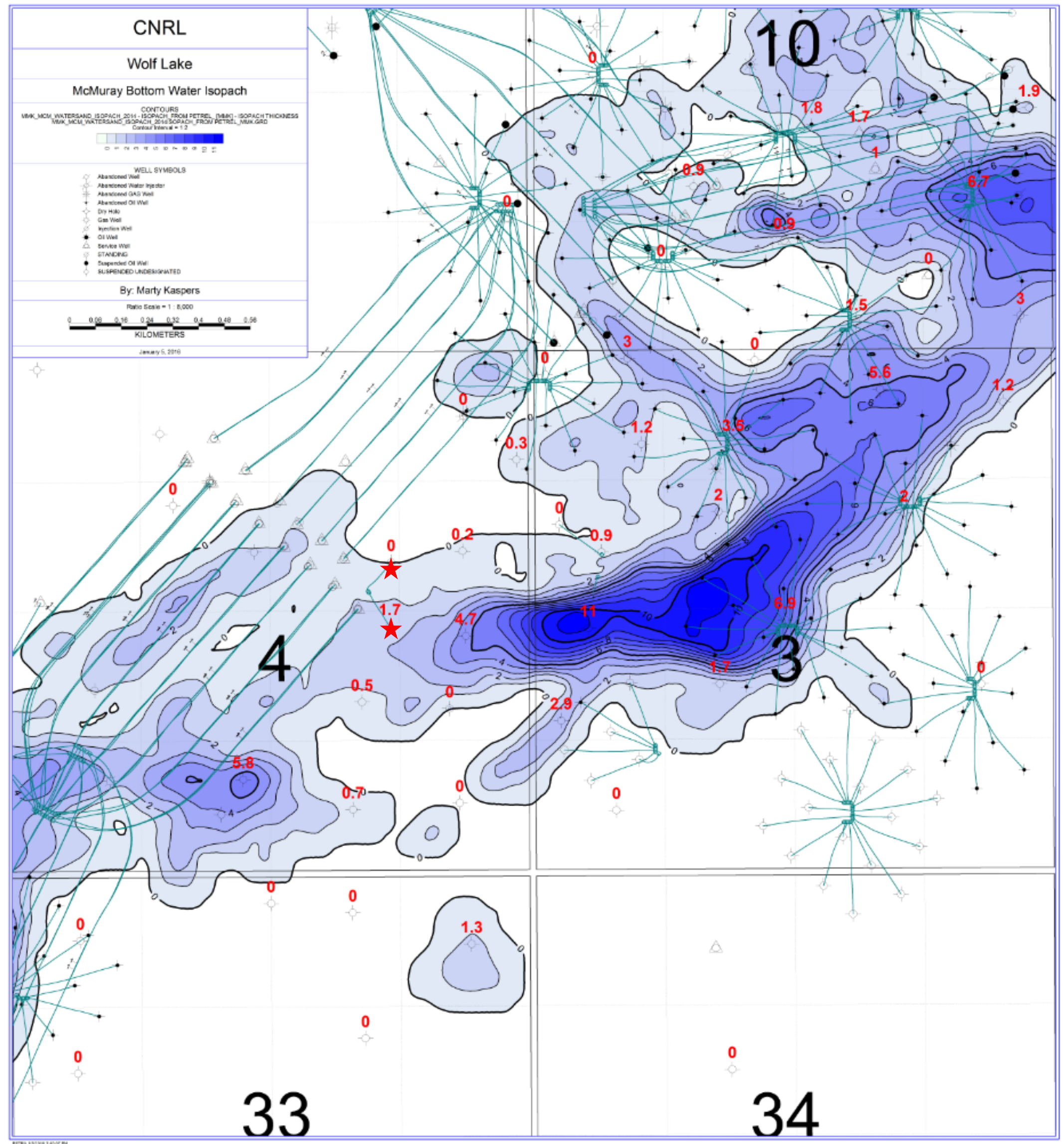


# Wolf Lake McMurray Bottom Water Isopach

- McMurray Bottom Water Isopach
- Cut-offs are less than 6 ohm·m
- Isopach represents a gross water interval

2015 drilled strat ★

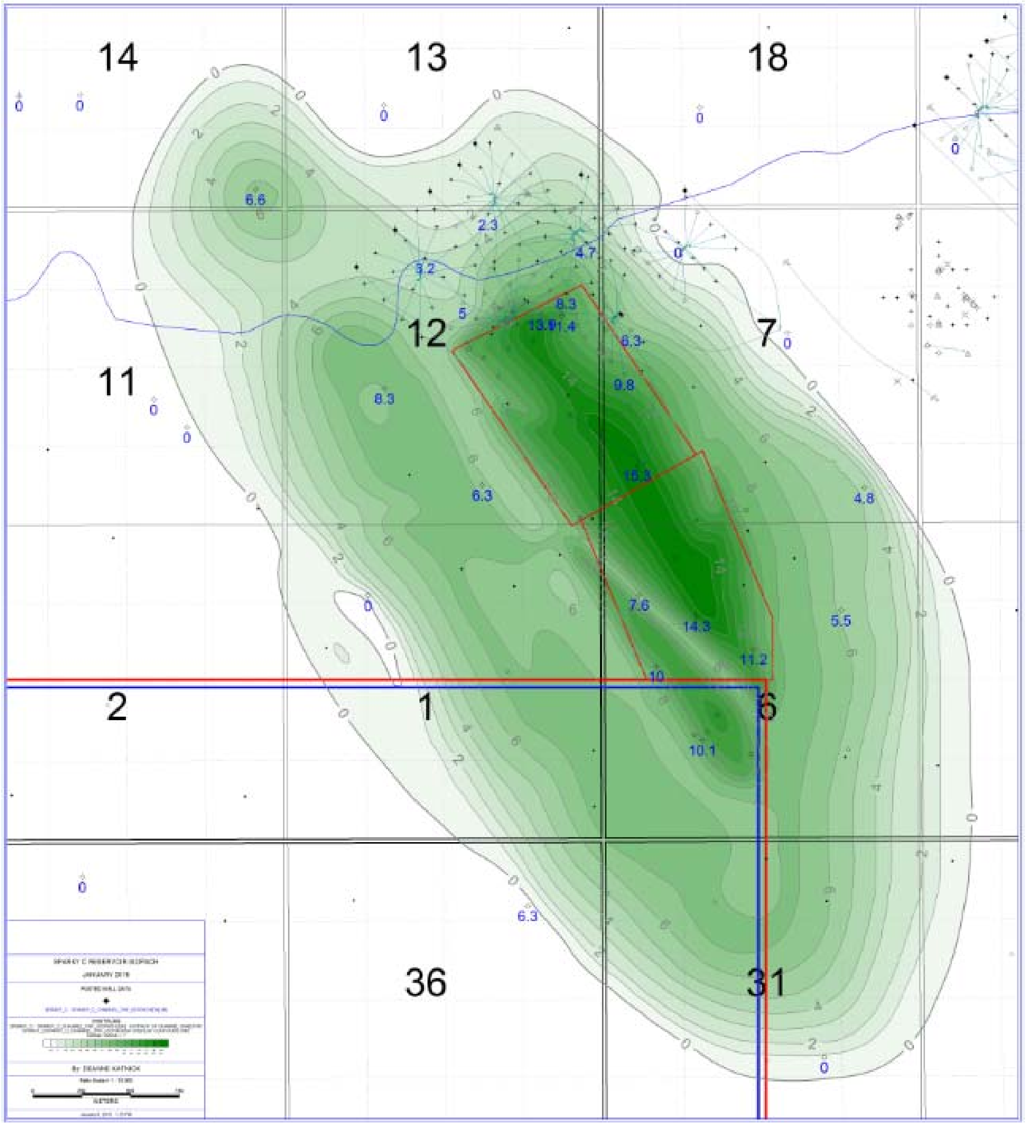
Contour Interval = 1m



# Wolf Lake Sparky "C" SAGD Pay Isopach

Sparky "C" Sand

- Channel deposits with bitwt >10%.
- Net pay >10 m for development




**Contour Interval = 1 m**

# Sparky "C" SAGD Pay Structure

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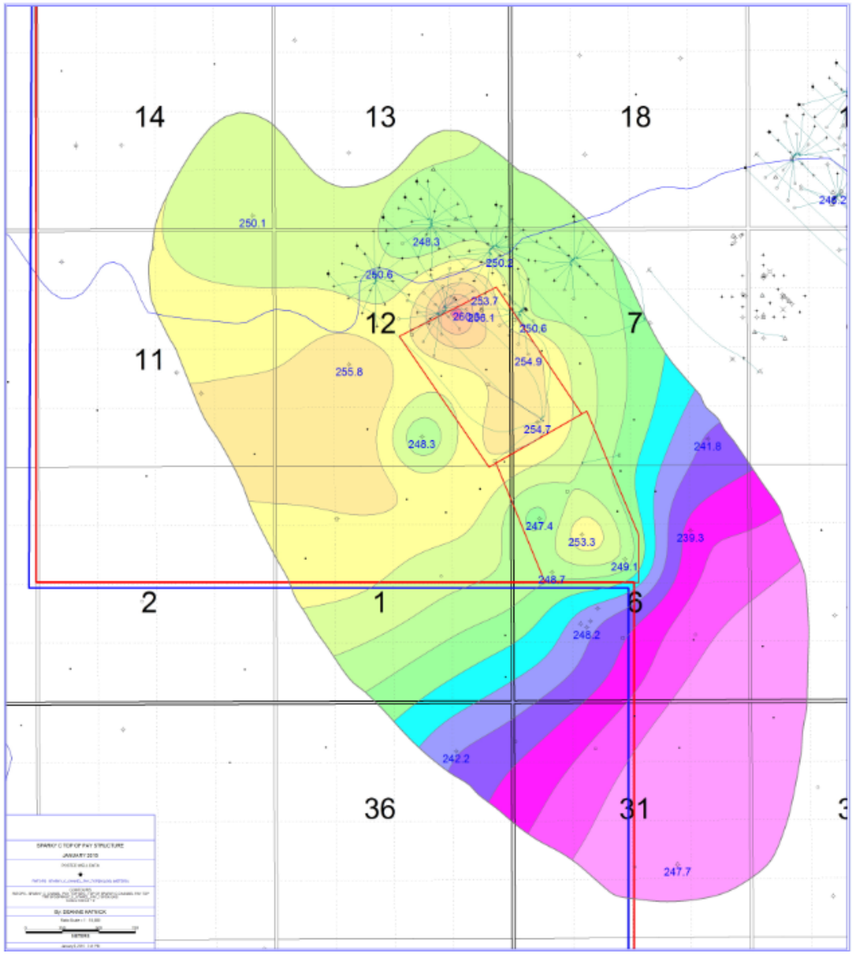
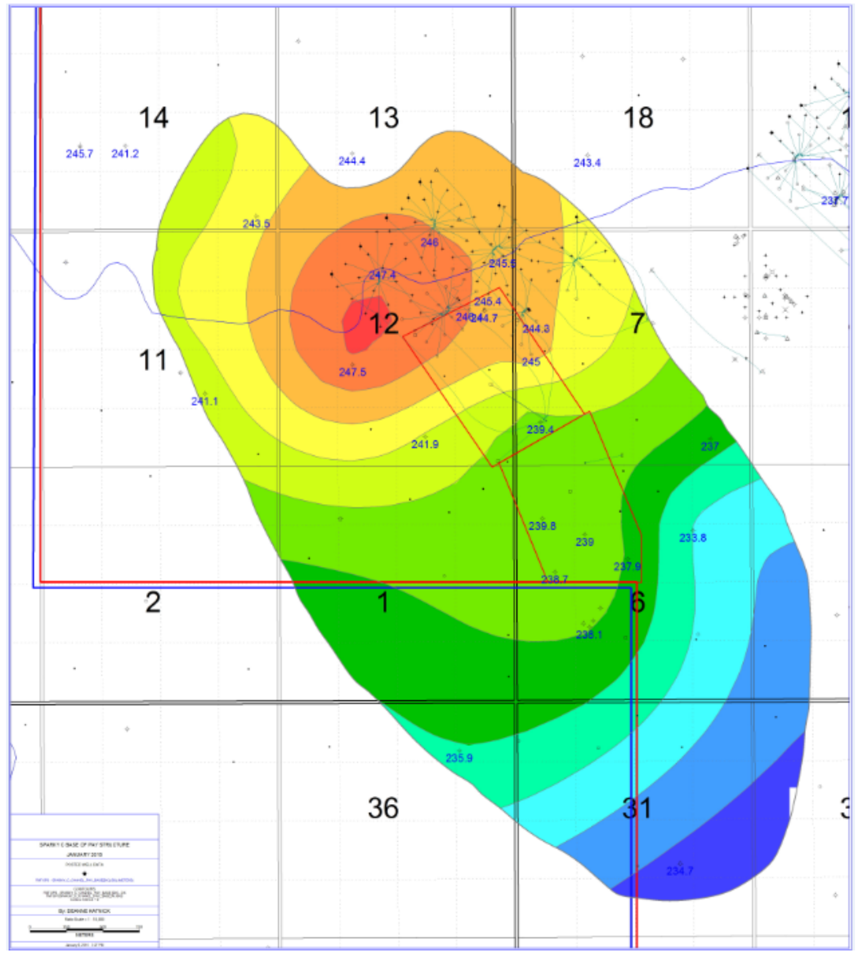
## Reservoir Top Structure




Contour interval = 2m

## Reservoir Base Structure




Contour interval = 2m

# Reservoir Characteristics- Sparky "C"

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Reservoir Characteristics

- Reservoir: Facies 1 clean sand
- Average oil saturation: 77%
- Average bitumen weight: 13.0%
- Maximum net pay thickness: 15.3 m
- Average porosity: 35%
- Average HZ permeability: 5,300 mD
- Average Vertical Permeability: 4,200 mD
- Average Viscosity: 170,000 cP (at 20$^{o}$C)
- Average Bottom Water: 0.5m

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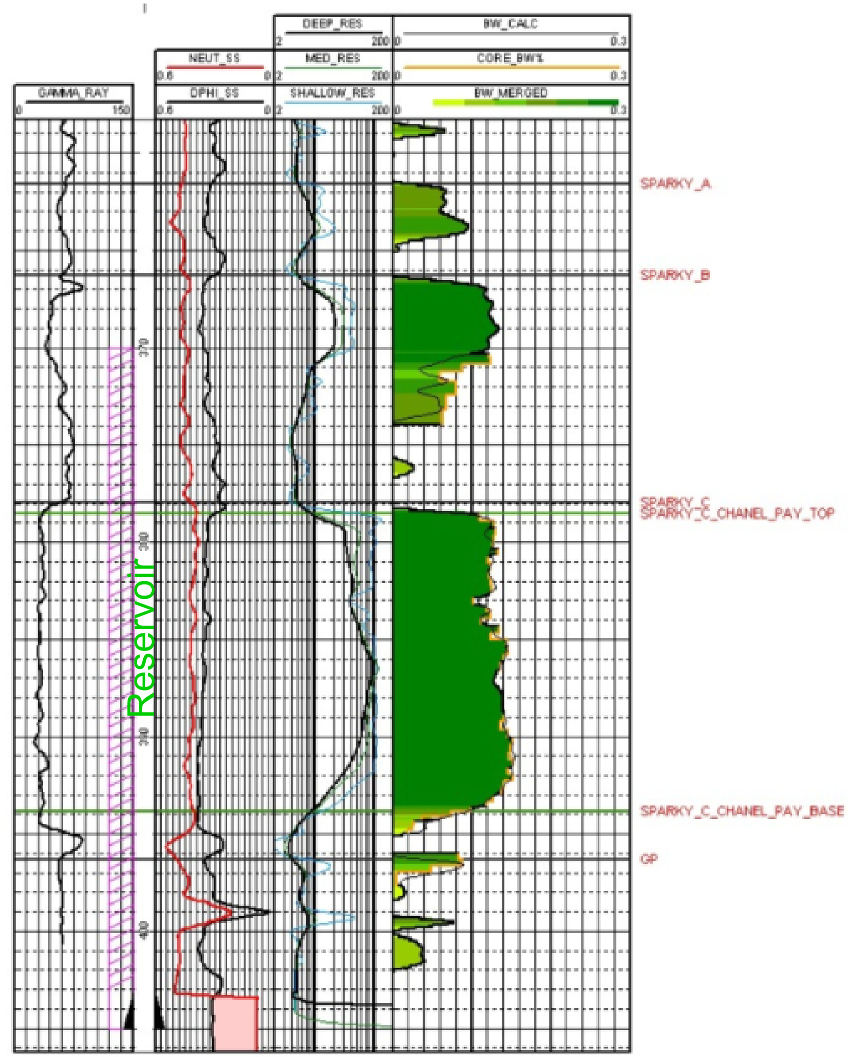


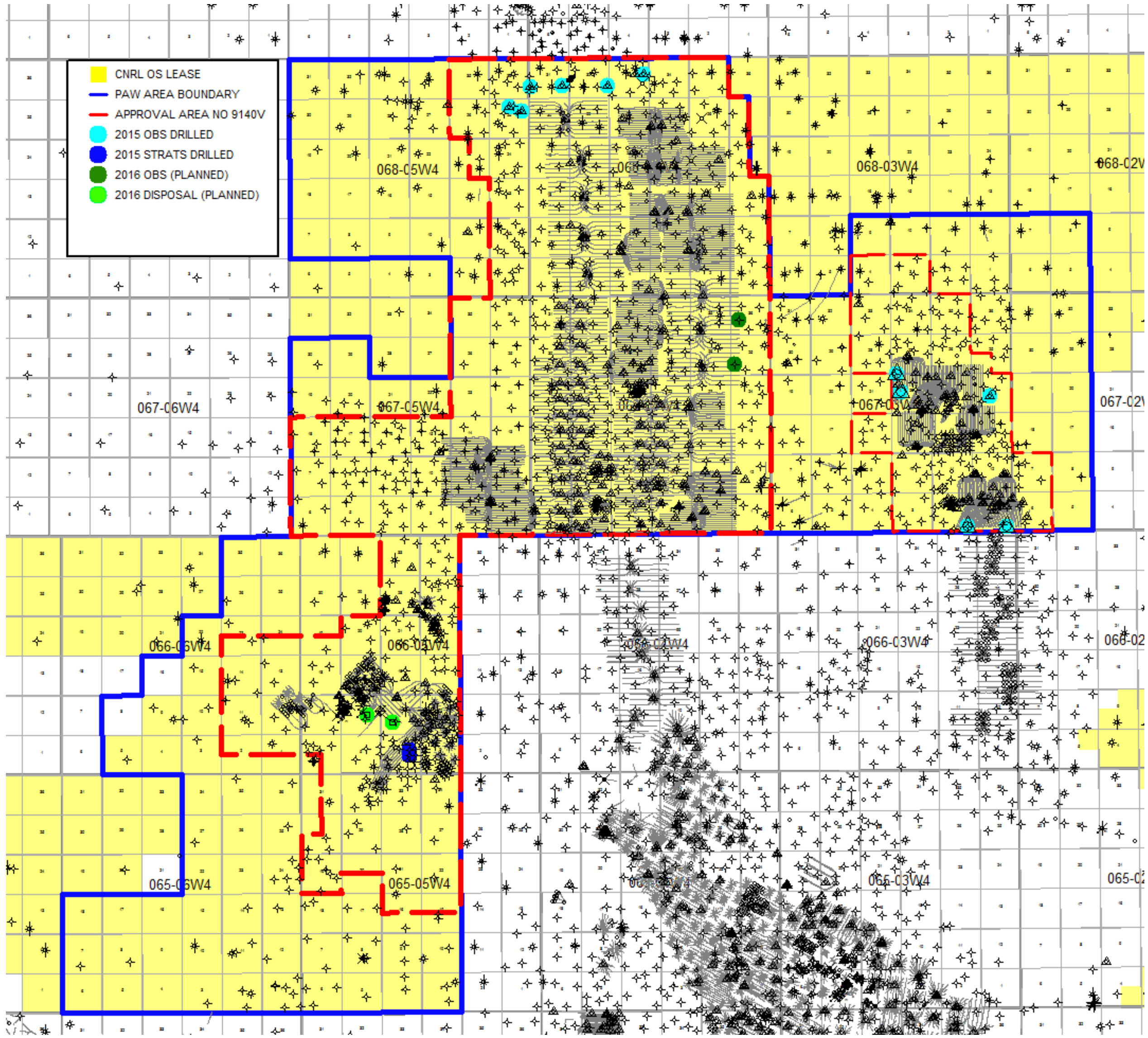
# Progress in 2015 → Plans for 2016

2015

- 2 stratigraphic wells drilled
- 11 observation wells drilled

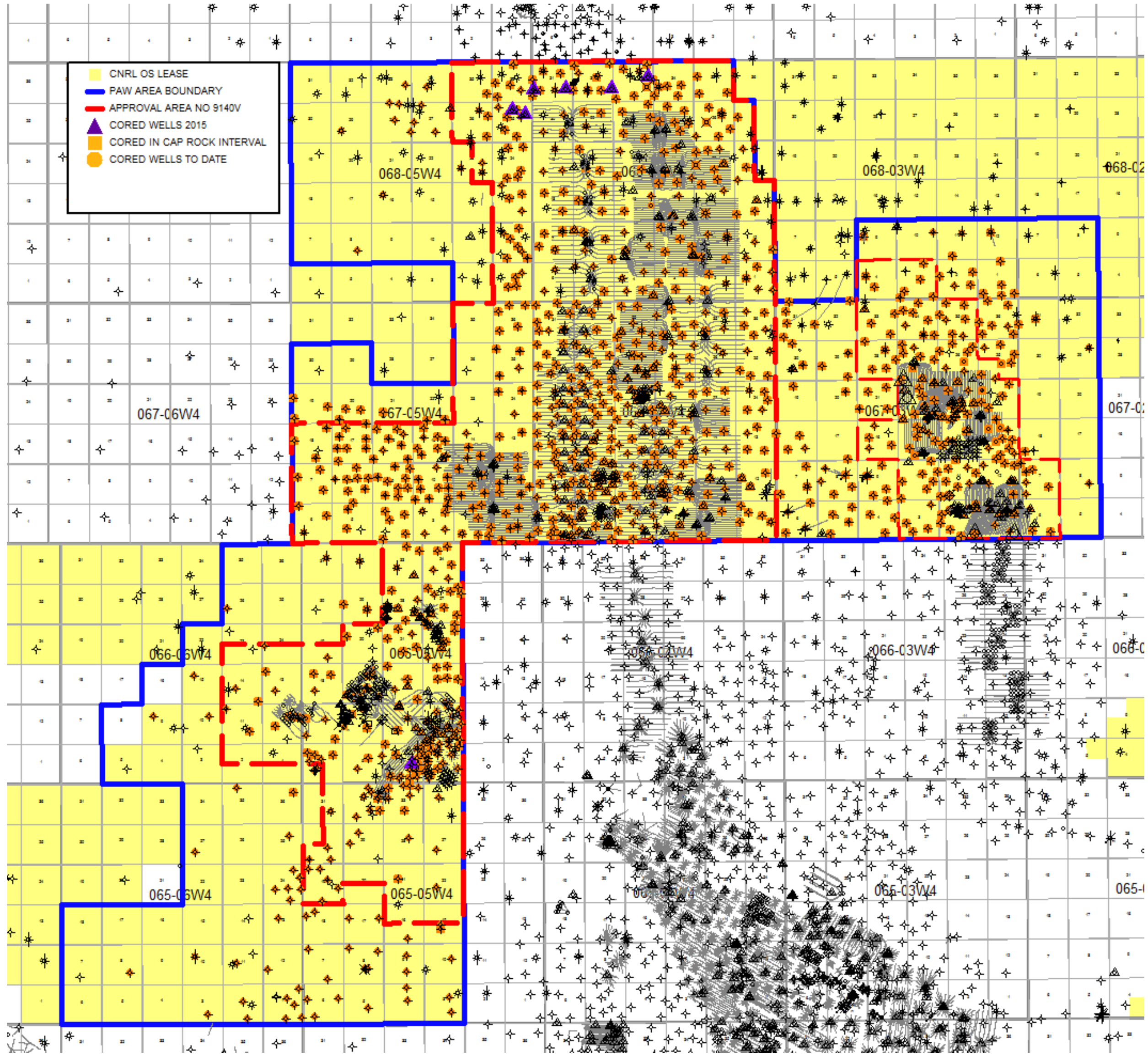
2016

- 2 observation wells planned
- 2 possible disposal wells

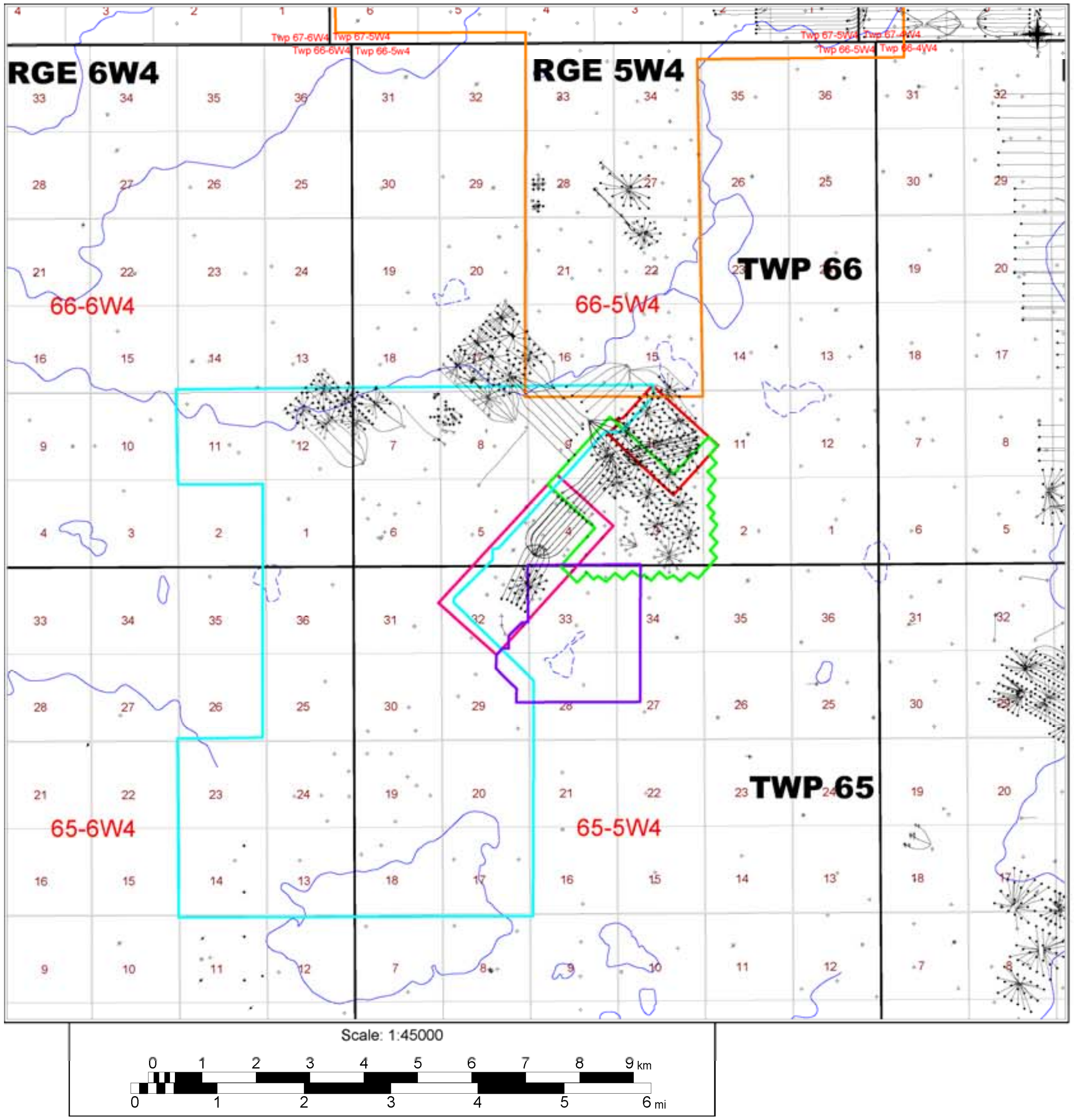


# Cored Wells Within PAW

- Total wells cored: 1,043
- 2015 wells cored: 7
- Wells with Clearwater Capping Shale recovered in core interval: 814

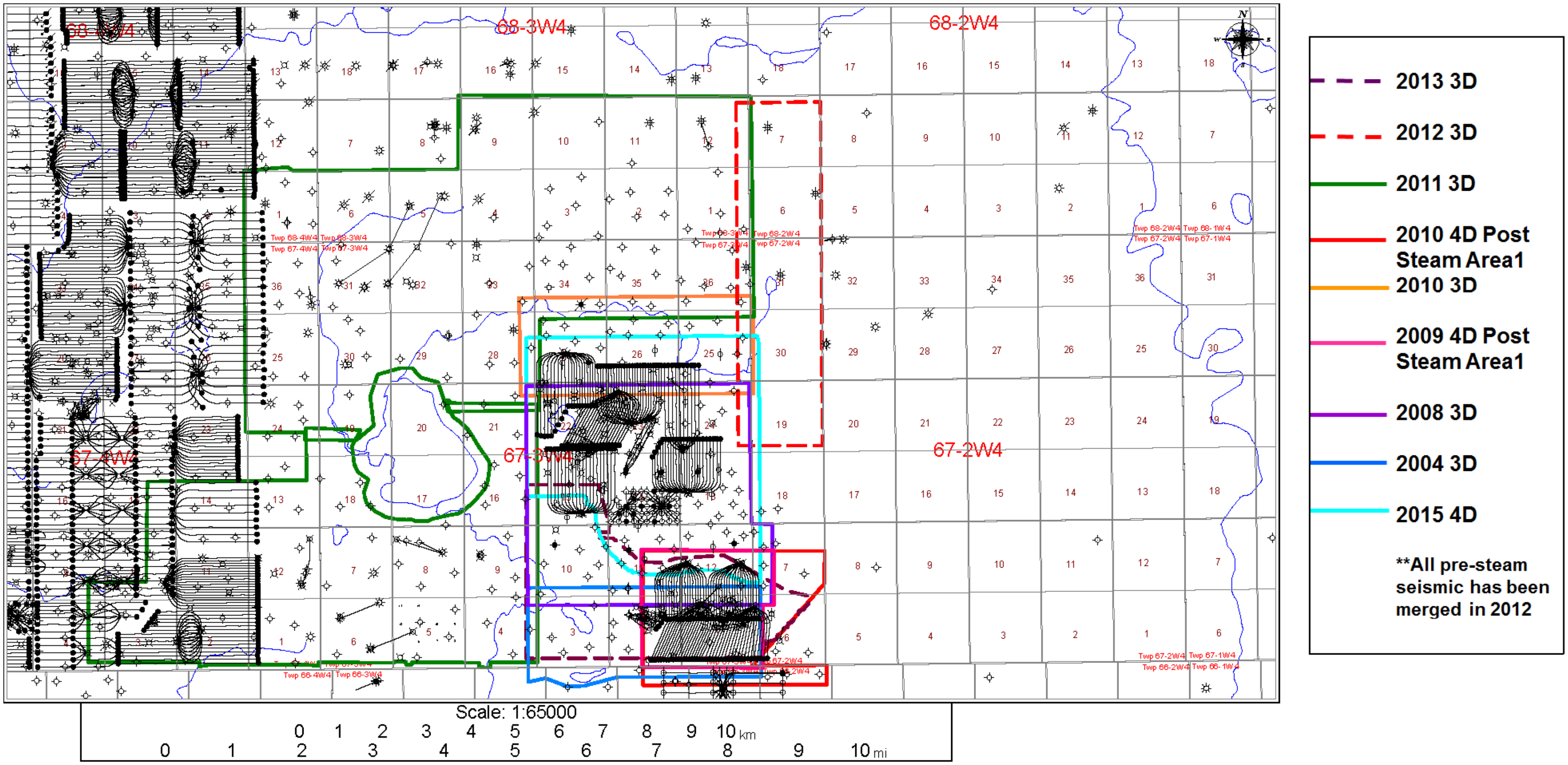


# 3-D Seismic Wolf Lake - TWP 65/66 R 5/6

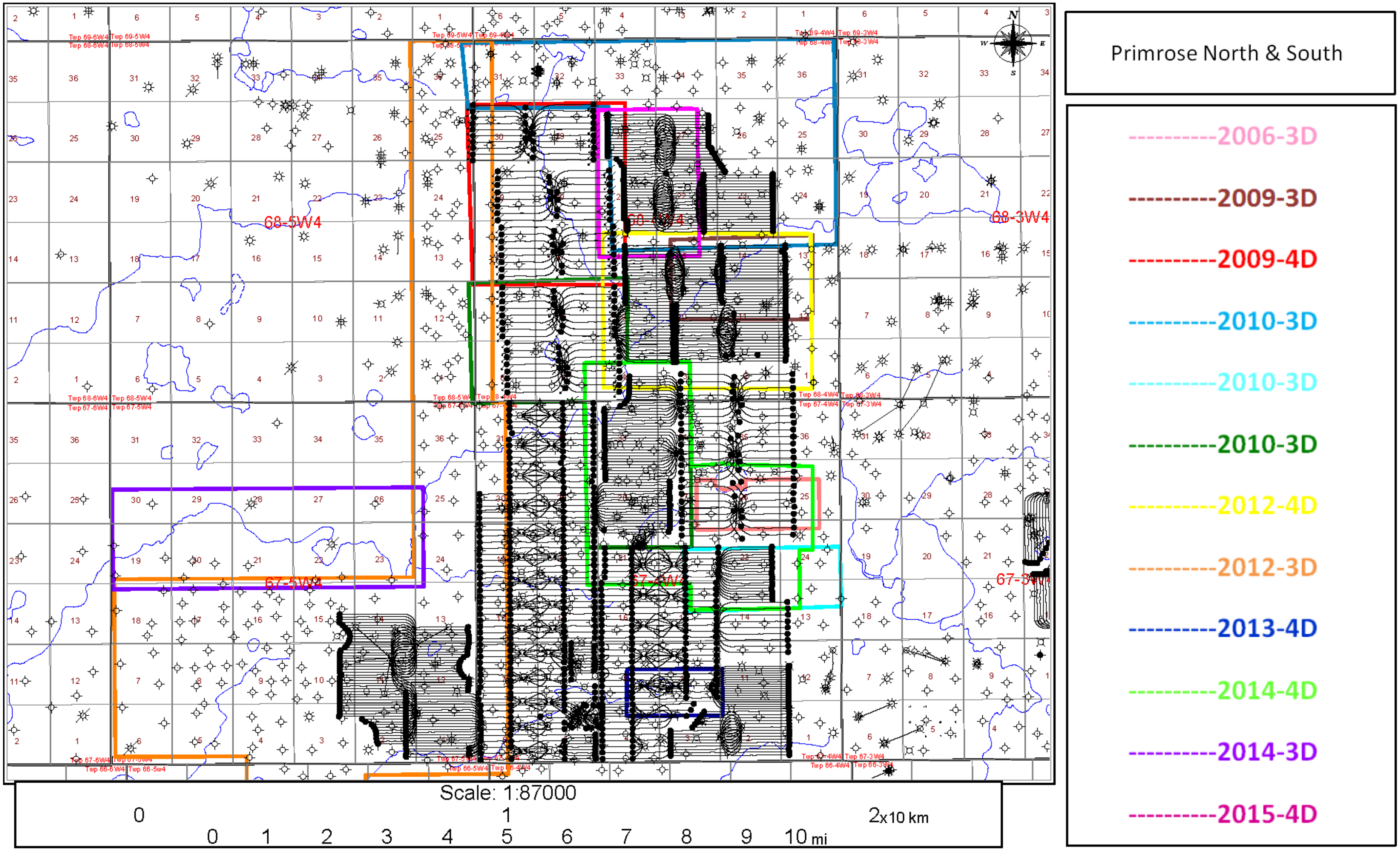



| Wolf Lake Seismic | |
|---|---|
| Red | 3D 2009 Wolf Lake I |
| Magenta | 3D 2009 Wolf Lake II |
| Green | 3D 2011Wolf Lake III |
| Cyan | 3D 2012 Wolf Lake IV |
| Orange | 3D 2012 Primrose North XIII |
| Purple | 3D 2014 Wolf Lake V |

# 3-D Seismic: Primrose East

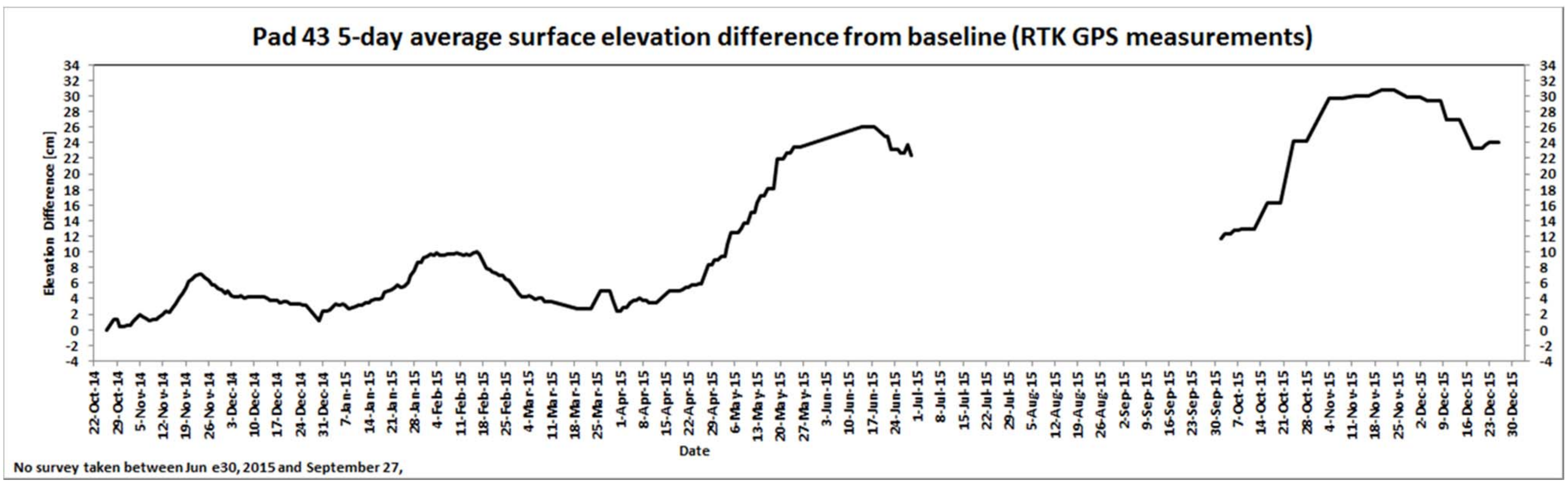


# 3D Seismic: Primrose North and South Township 67 & 68-04W4



# Surface Heave Measurement – Phases 40-43

- Continuing acquisition of SAR over Primrose South Phases 40 – 43
- Ongoing image processing using InSAR over Primrose South Phases 40 - 43
- Continuation of measuring surface elevation changes by RTK GPS surveys at Primrose South Pad 43
- Using surface movement data to validate reservoir geomechanics model of CSS process



# Reservoir Performance

- Artificial Lift Summary
- Thermal Subsurface Well Design
- Steam Quality
- SAGD Recovery Process Basics
- SAGD Typical Well Schematics
- Wolf Lake SAGD
- Burnt Lake SAGD Pilot
- CSS Recovery Process Basics
- CSS Typical Well Schematics
- Wolf Lake CSS
- Primrose CSS
- Primrose Follow-Up Processes

# Artificial Lift Summary

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| Operating Area | Rod Insert | Tubing Pump | PCP | ESP |
|---|---|---|---|---|
| Primrose South | 645 | 1 | 3 | 0 |
| Primrose North | 305 | 0 | 0 | 0 |
| Primrose East | 129 | 30 | 0 | 0 |
| Burnt Lake | 3 | 0 | 0 | 0 |
| Wolf Lake CSS | 40 | 0 | 1 | 0 |
| Wolf Lake SAGD | 5 | 22 | 0 | 1 |
| Primrose brackish | 0 | 0 | 0 | 10 |
| Wolf Lake Brackish | 0 | 0 | 5 | 1 |
| Fresh Water (10-66-5W4) | 0 | 0 | 0 | 6 |

**Rod Pump Lift Capacity Range**

| Pump Size | Pump Jack | Stroke Length | Efficiency | SPM | $m^3/d$ |
|---|---|---|---|---|---|
| 2" | 160 | 86" | 80% | 9 | 45 |
| 2.5" | 456 | 120" | 80% | 9 | 100 |
| 2.5" | 456 | 144" | 80% | 9 | 120 |
| 3.25" | 456 | 120" | 80% | 9 | 170 |
| 3.25" | 456 | 144" | 80% | 9 | 200 |
| 3.25" | 1280 | 240" | 80% | 9 | 340 |
| 3.75" | 1824 | 240" | 80% | 9 | 450 |
| 3.75" | Rotoflex | 288" | 80% | 5 | 300 |
| 4.75" | 1824 | 240" | 80% | 9 | 720 |
| 4.75" | Rotoflex | 288" | 80% | 5 | 480 |
| 5.5" | Rotoflex | 288" | 80% | 5 | 650 |

**ESP Capacity Range**

| Pump Stage Count | Recommended Pump Operating Range @ 60Hz (m3/day) | Motor Type HP |
|---|---|---|
| 40 | 205 - 800 | 168 |
| 44 | 380 - 740 | 86 |

**Operating temperature range :50 ºC to 330 ºC**
**Operating differential pressure range : 1 kPa to 6,500 kPa**
**3.25” Rod Pump is in majority of wells**

# CSS Pad Design

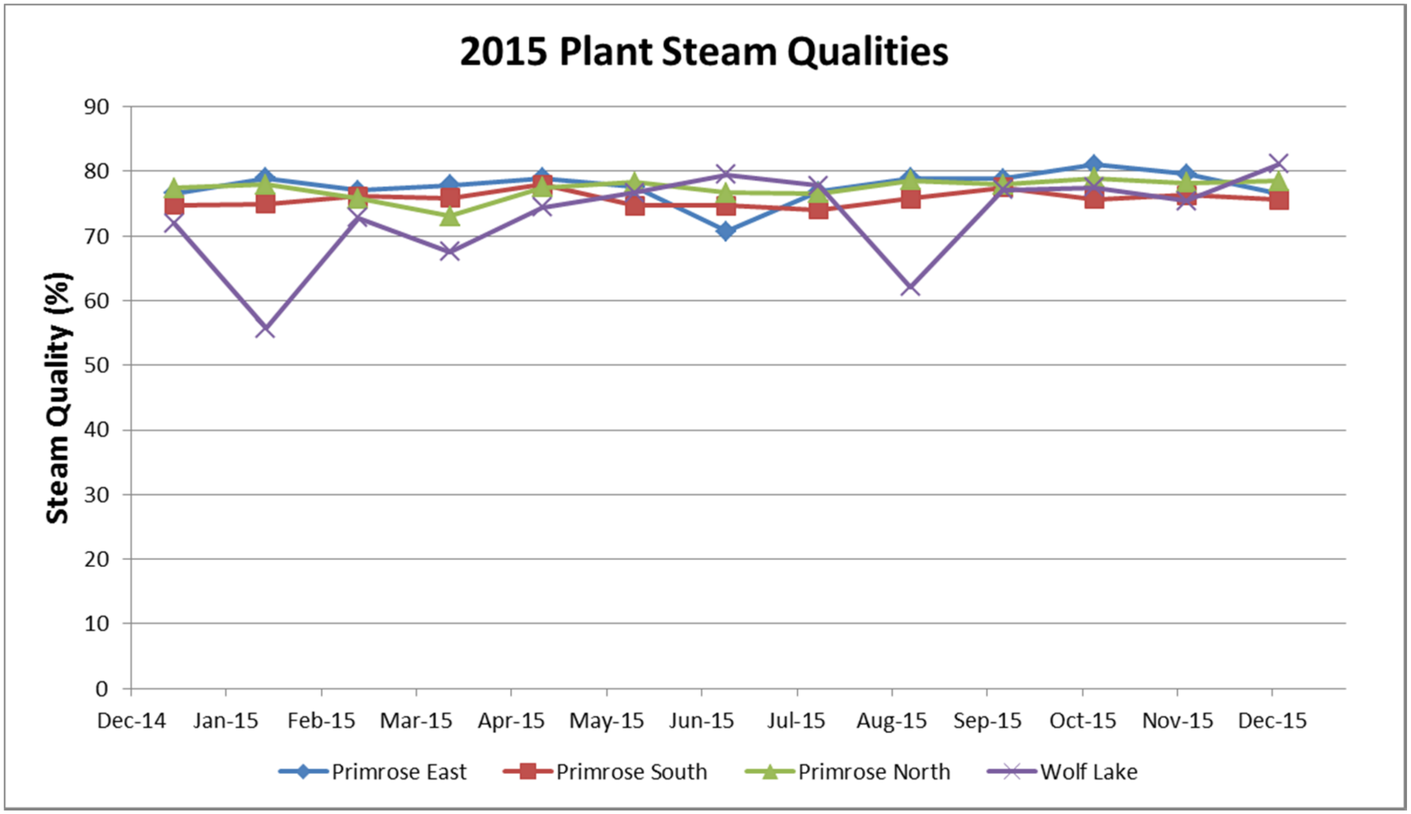
| Phase | Wells per Pad | Design Spacing (m) | Well Length (m) | Development Date |
|---|---|---|---|---|
| 1-21 | 16-20 | 160 | 600 | 1993-2000 |
| 27 | 7 | 160 | 1,400 | 2005 |
| 29-31 | 16-20 hz<br>8-10 dev | 188 | 1.200 | 2003-2004 |
| 51-54 | 16 hz<br>8 dev | 188 | 1,200 | 2004-2006 |
| 55 | 20 hz<br>10 dev | 160 | 1,200 | 2004-2006 |
| 28 | 10 | 75 | 1,000 | 2005-2007 |
| 74, 75, 77, 78 | 20 | 60 | 900 | 2007-2008 |
| 58, 59, 62, 63, 66, 67 | 20 | 80 | 1,000-1,700 | 2008-2009 |
| 22-24 | 18-20 | 80 | 1,200-1,600 | 2010-2011 |
| 90-95 | 10-25 | 60 - 80 | 800-1,600 | 2011-2012 |
| 25A/B, 26 | 15-20 | 60 & 80 | 600-1,700 | 2011-2012 |
| 60, 61, 64, 65, 68 | 20 | 80 | 1,000-1,800 | 2011-2013 |
| 40-43 | 24 | 74 | 800-1,700 | 2013-2014 |

- Design evolution over life of project with goal to optimization of resource recovery
  - Reduction in pad capital per well
  - Increase areal recovery
  - Configuration integrates future follow up processes

# SAGD Pad Design

| Phase | Wells Pairs | Design Spacing (m) | Well Length (m) | Development Date | Formation |
|---|---|---|---|---|---|
| D2 | 6 | 140 | 650 | 1997-2000 | Grand Rapids |
| SD9 | 6 | 90 | 950 | 2001 | Grand Rapids |
| S1A | 8 | 100 | 950 | 2004 | Grand Rapids |
| S1B | 6 | 100 | 900 | 2010 | Grand Rapids |
| MC1 | 6 | 70 | 900 | 2010 | McMurray |

# Steam Quality - 2015




- The steam quality at most pads is between 0.5 and 1.0 percent lower than the quality at the plant (the furthest pads may be up to 4 percent lower)
- Quality change varies depending on the operating pressure, operating flow rates, line size and distance between the plant and the pad

# SAGD Basics – Well Warm Up

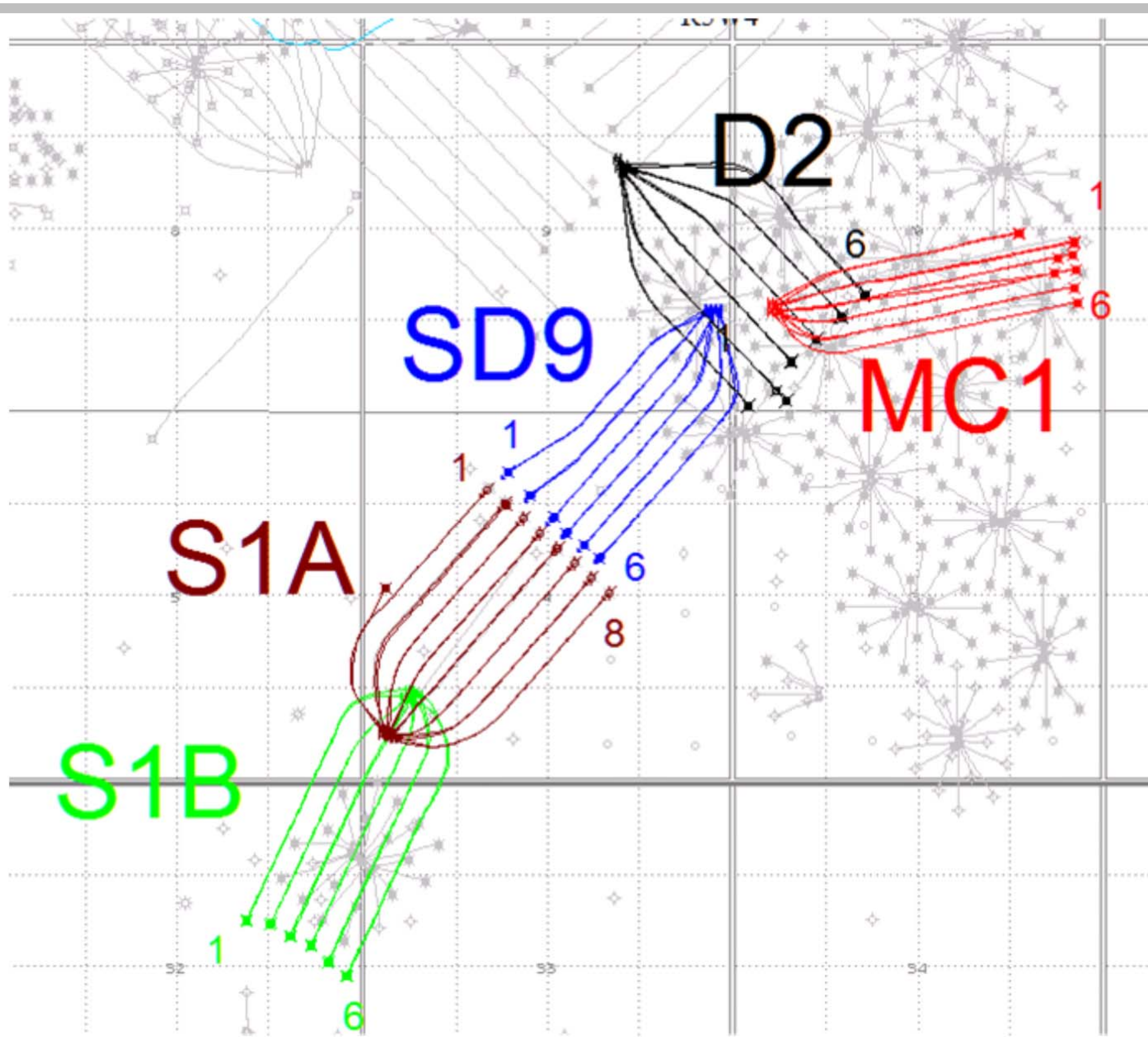
Canadian Natural

- For both wells of SAGD pair
  - Inject steam down tbg. string to toe
  - Produce water and steam via 2nd tbg. string from heel
- Continue steam circulation for 2 to 4 months
  - Duration determined by temp. and performance observations
- Measure and monitor injection and returned volumes, pressures and temperature

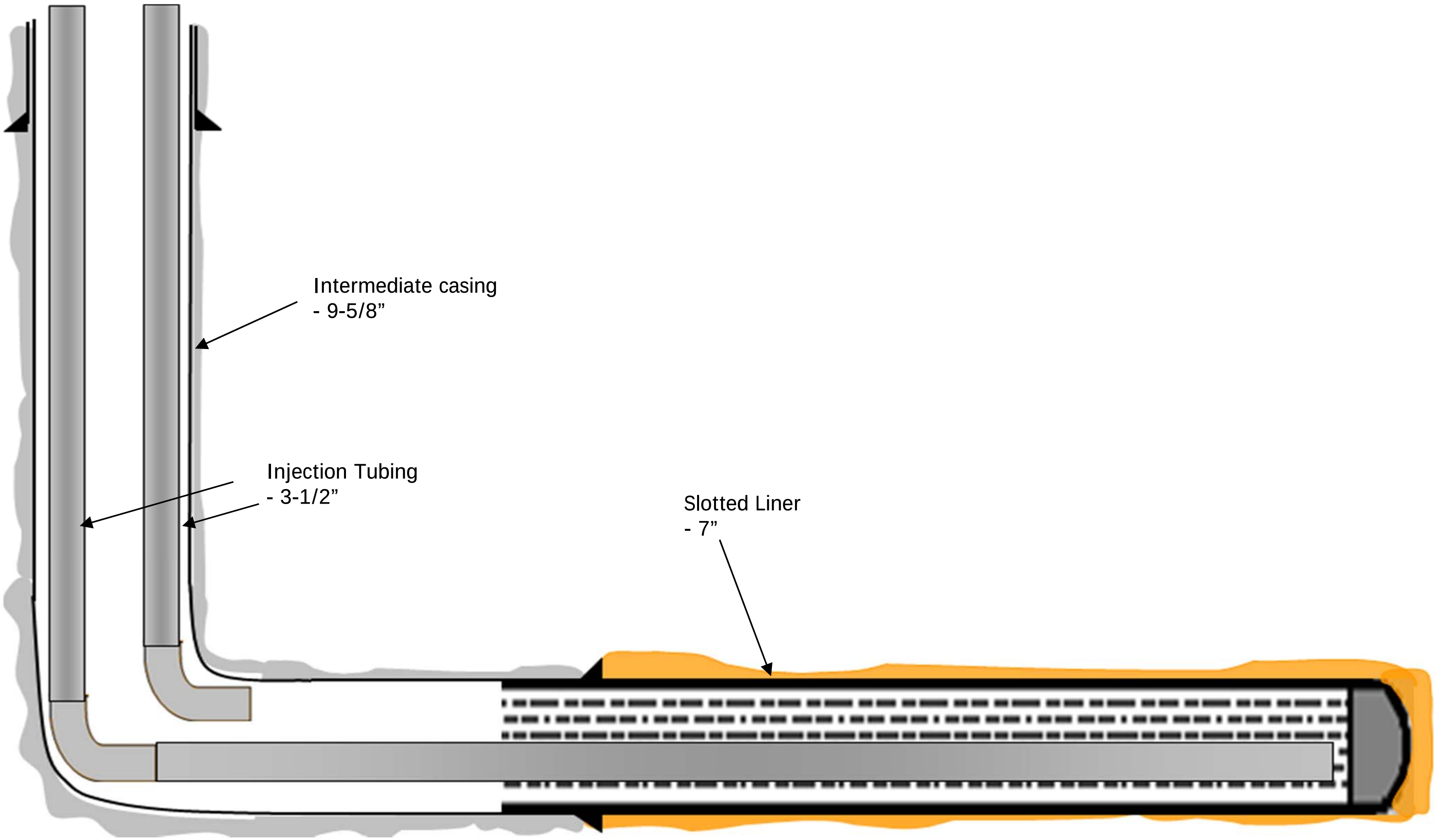
# SAGD Basics – Injection / Production

- Inject steam into upper well
  - Balance between toe and heel
  - Control based on reservoir response and temperature observations in producer
- Pump fluid from lower well with artificial lift
  - Monitor bottomhole pressure data for both injection and production wells
  - Bottomhole temperature observations influence how wells are operated
  - Typical fluid production rates vary from 150 $m^3/d$ to 600 $m^3/d$

# Wolf Lake SAGD Location Map

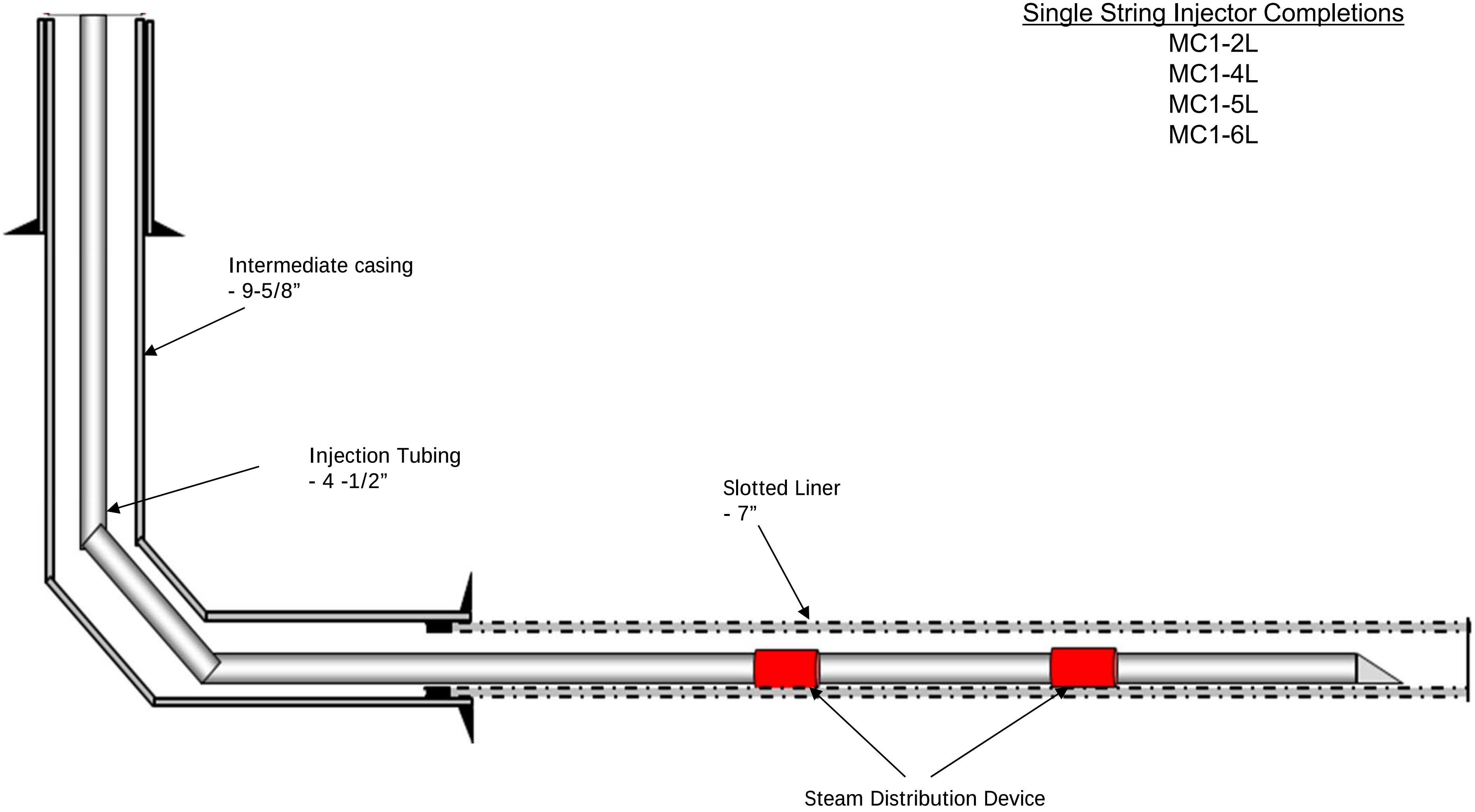


# Sample Parallel String Injector Completion

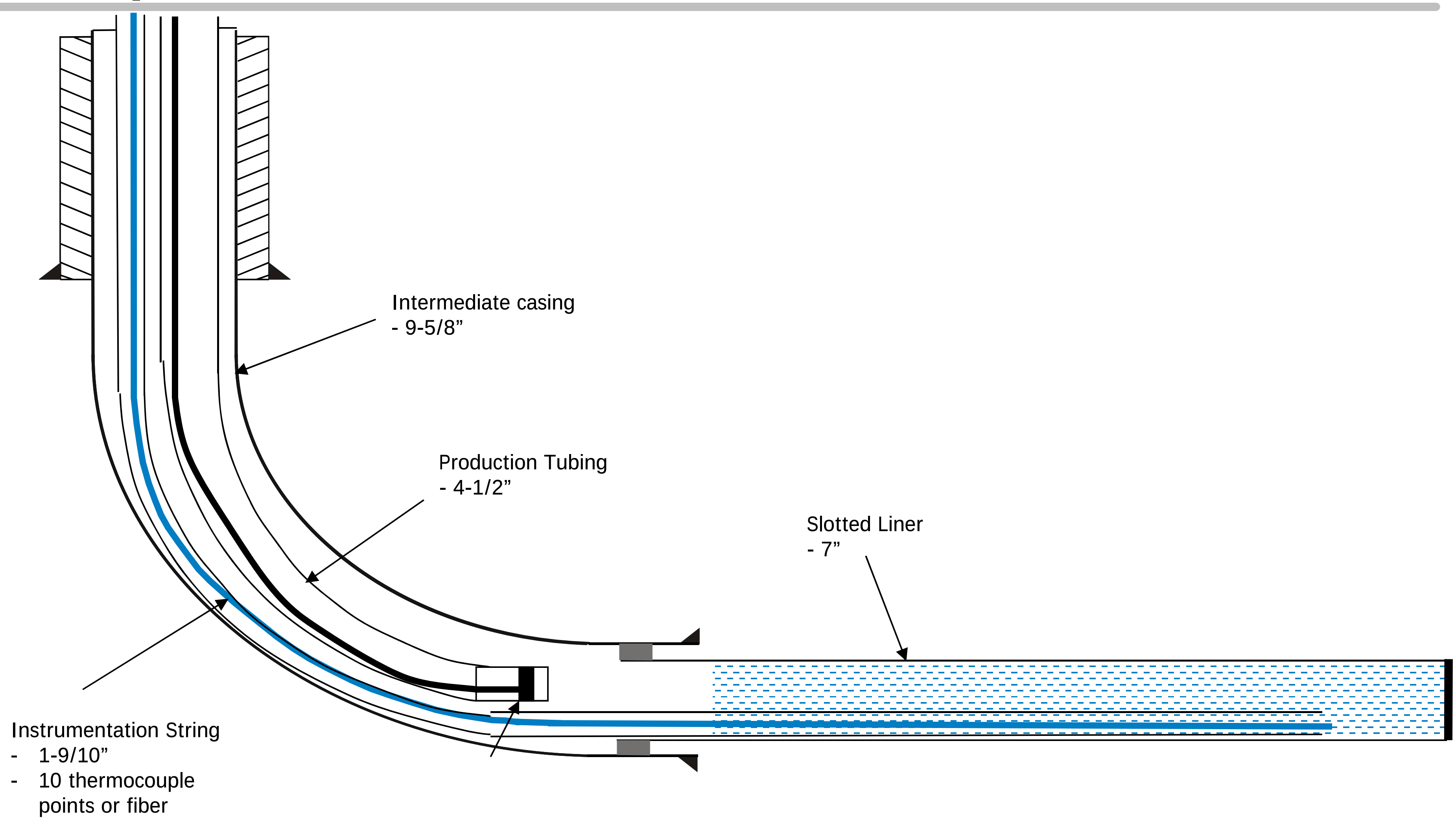


# Sample Single String Injector Completion

<u>Single String Injector Completions</u>
MC1-2L
MC1-4L
MC1-5L
MC1-6L

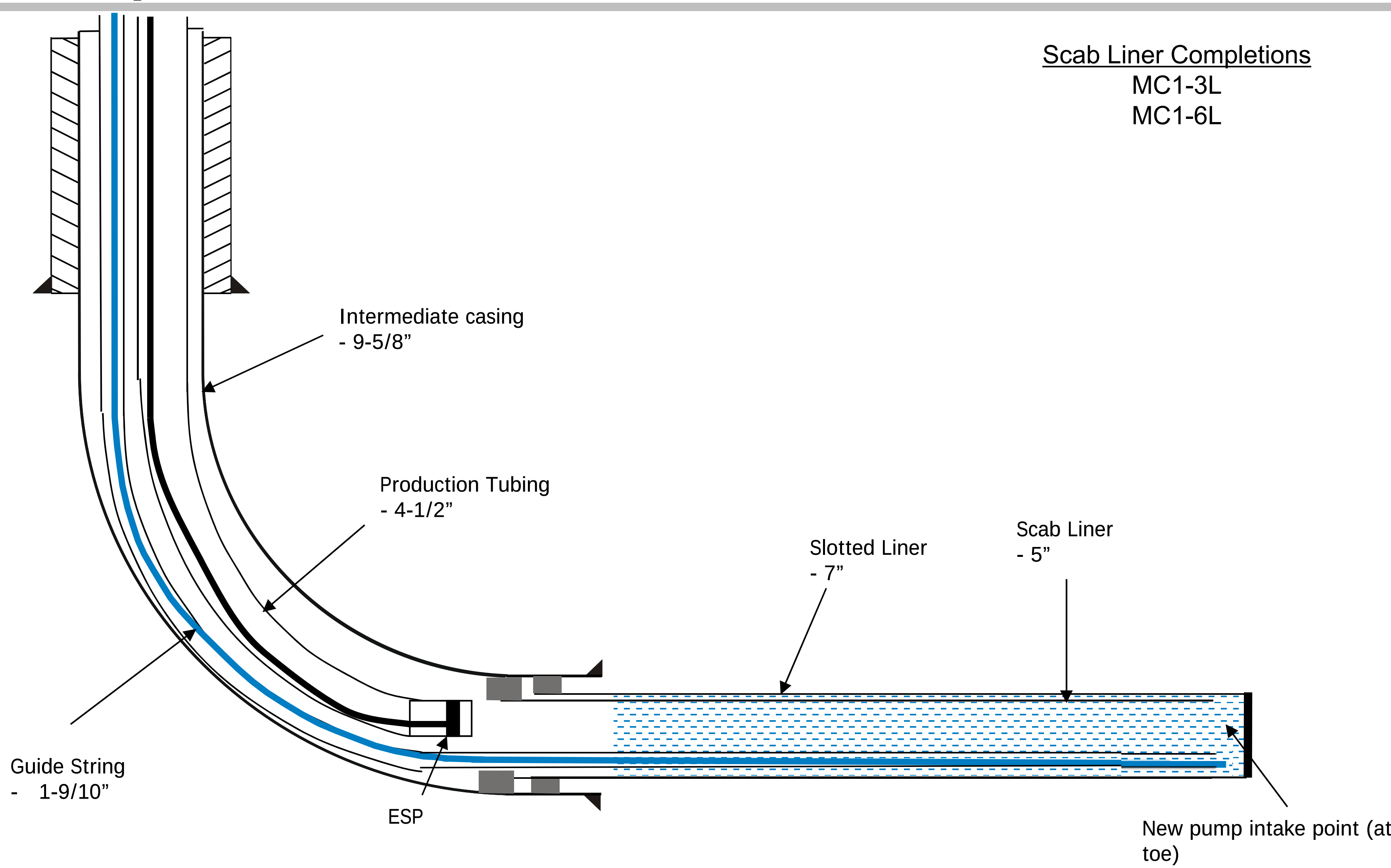


# Sample Producer with Rod Pump Completion



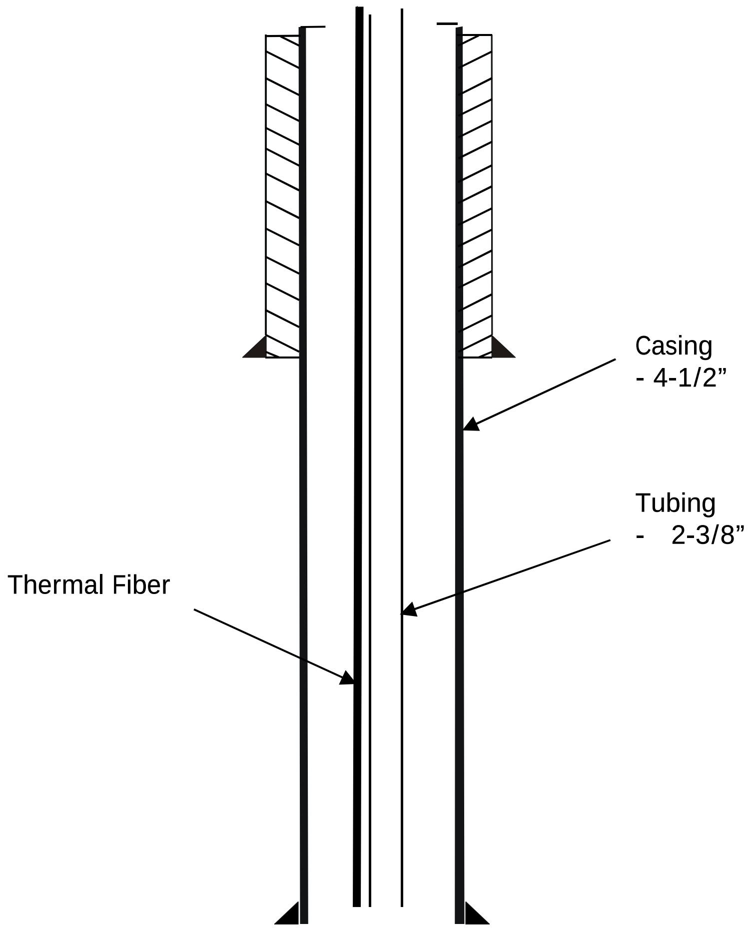
# Sample Producer with Scab Liner Completion

Scab Liner Completions
MC1-3L
MC1-6L



# Sample Observation Well Completion

Temperature Only



# Wolf Lake SAGD

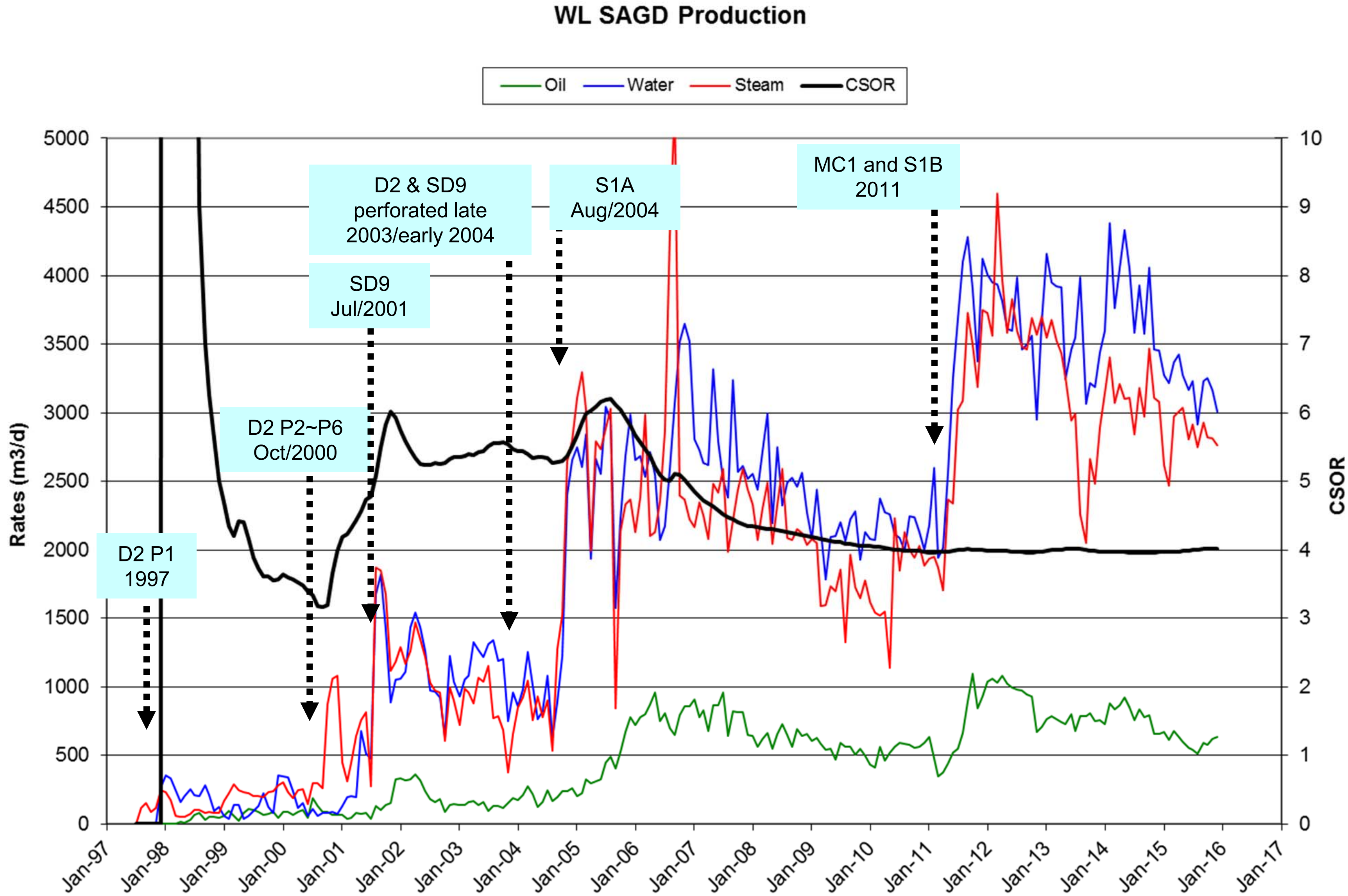
| | D2 (B10) | SD9 (B10) | S1A (B10) | S1B (B10) | B10 Total | MC1 (MCM) |
|---|---|---|---|---|---|---|
| Active Wellpairs | 0 | 6 | 7 | 6 | 19 | 5 |
| 2015 Bit Prod, e3m3 | 0 | 37 | 26 | 82 | 145 | 76 |
| 2015 Avg. SOR (*dry steam) | 0 | 5.6 | 9.2 | 3.3 | 5.0 | 4.2 |
| Cumm Bit, e3m3 | 313 | 919 | 999 | 336 | 2,568 | 487 |
| Cumm SOR (*dry steam) | 4.9 | 3.9 | 4.1 | 3.6 | 4.1 | 3.6 |
| OBIP, e3m3 | 1,877 | 1,819 | 2,682 | 1,971 | 8,349 | 1,443 |
| 2015 YE RF, % | 17 | 51 | 37 | 17 | 31 | 34 |
| Estimated Ultimate RF, % | 50 | 52-55 | 50 | 50 | 50 | 50 |

- Current production is from B10 Grand rapids & MCMR
- SD9 recovery is over 50%, considering options for blowdown
- S1A has had a positive response to stimulations
- S1B has had a positive response to stimulations
- MC1 reservoir heterogeneities are causing operational challenges
- Estimated ultimate recovery of OBIP is expected to be > 50% in SAGD operations

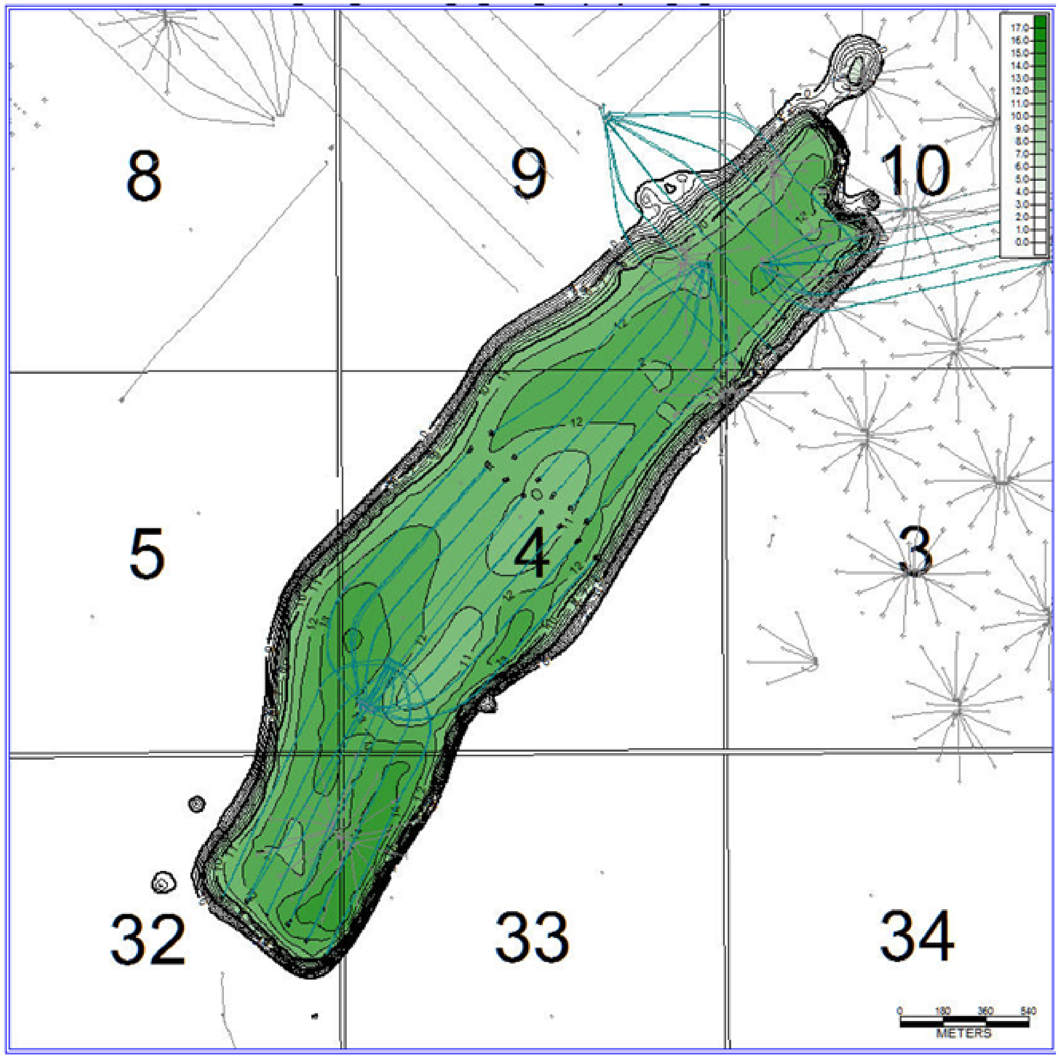
# Wolf Lake SAGD Operational Strategy

- Operate wells based on a target steam chamber pressure, target sub-cool, and gross analog rates
- Steam chamber pressure is measured by annulus gas pressure in the injector and is controlled by the steam injection rate. Current target pressure for SD9 is 2,100 kPa
  - Current target pressure for S1A is 2,500 kPa
  - Current target pressure for S1B is 2,600 kPa
  - Current target pressure for MC1 is 3,200 kPa
- Wolf Lake SAGD operational pads inject dry steam
- Sub-cool is determined based on the difference between the saturated temperature of the steam chamber pressure and the highest temperature along the producer lateral
  - Target to maintain a minimum 0-30 °C sub-cool

# Wolf Lake SAGD Performance

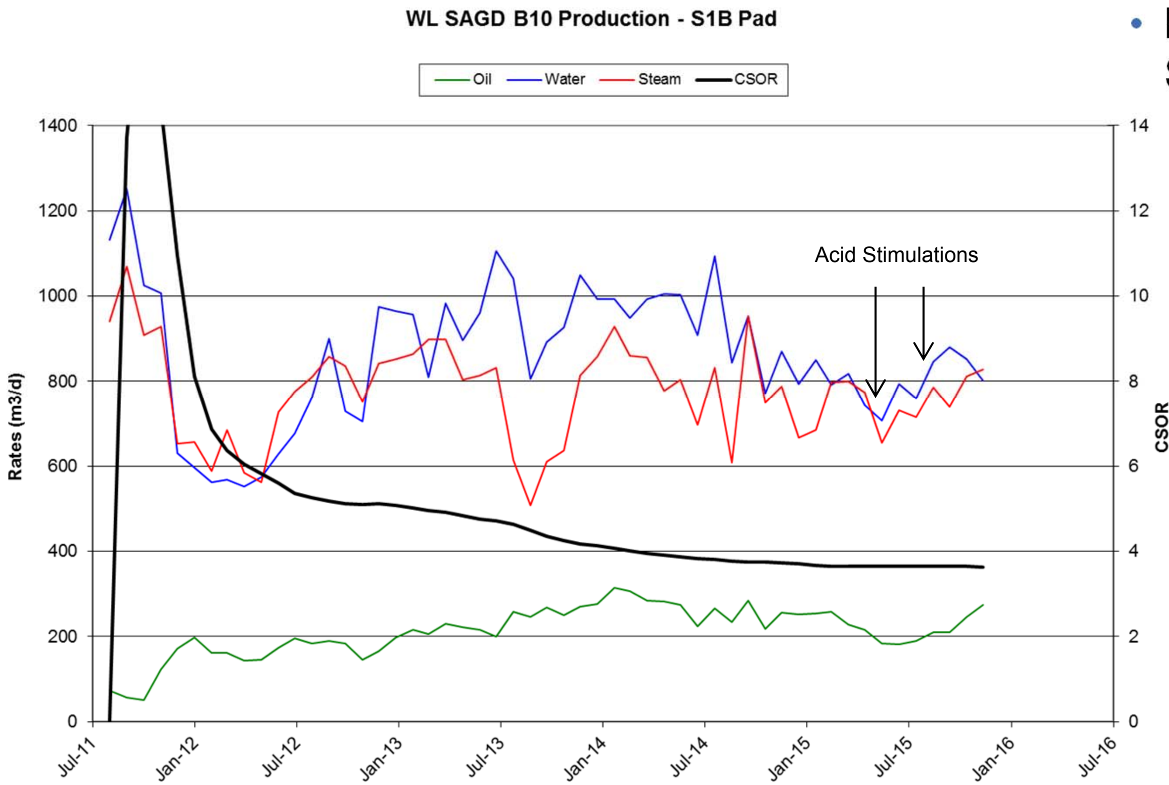


# Wolf Lake SAGD
# B10 Pad S1B – Low Recovery




- SAGD well pair: 6
- ERCB Approval: Jul 8, 2010
- Completed Drilling: Oct. 2010
- First Steam: Aug. 2011
- Hz section length: 900 m
- Inter- well-pair spacing: 100 m
- Avg. net pay: 12 m
- Avg. So: 75%
- Avg. porosity: 33%
- Current RF: 17 %

# Low Recovery – S1B Pad Production History




- Plugging has been observed on all S1B producers
  - Identified using:
    - injector/producer pressure differentials
    - wellbore shut-in temperature transients
    - lower than analogue oil production rates
  - High WSR March 2013-Jan 2014
    - Banked fluid production from a pad wide Producer plugging remediation program utilizing:
      - Perforations
      - Hydrochloric Acid
      - Hydrofluoric Acid

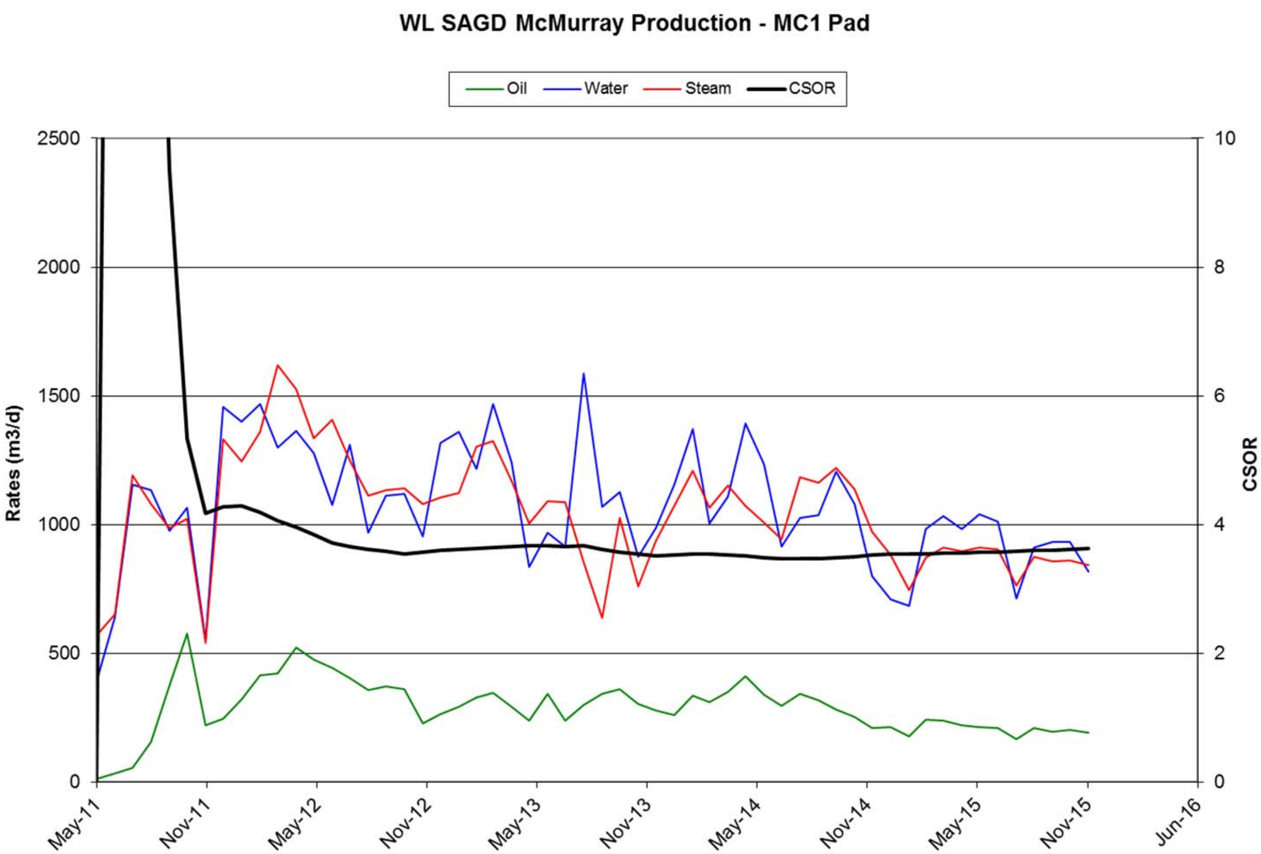
**2015 Activity**

- **Additional Hydrochloric Acid stimulations performed in June and September**

**2016 Plan**

- **Continue to optimize wells and identify plugging/assess stimulation strategies**

# Mid Recovery – MC1 Pad Production History




- SAGD well pair: 6
- AER Approval: Feb 16, 2010
- Completed Drilling: Aug. 2010
- First Steam: May 2011
- Hz section length: 900 m
- Inter- well-pair spacing: 70 m
- Avg. net pay: 12 m
- Avg. So: 73%
- Avg. porosity: 34%
- Current RF: 34 %

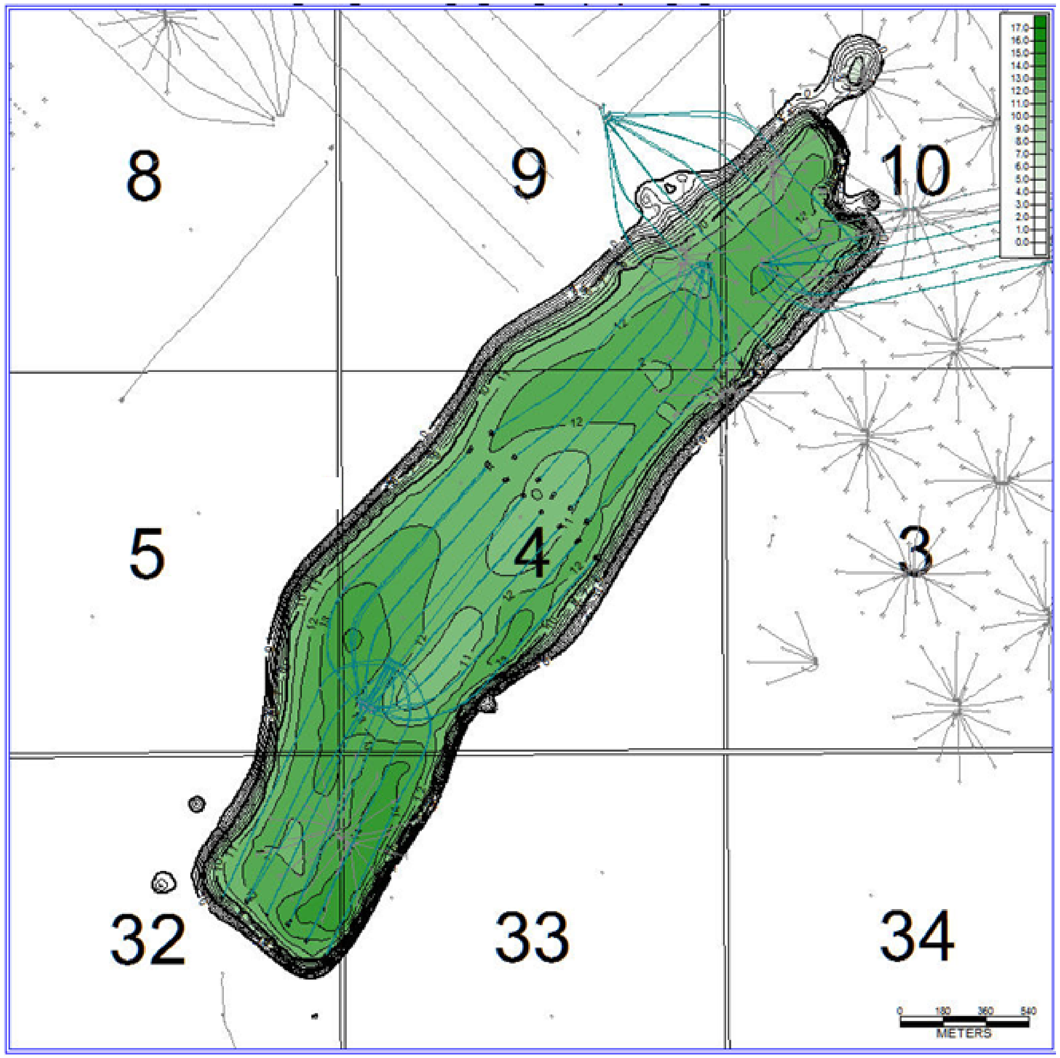
**<u>2015 Activity</u>**

- **NCG Co-Injection application submitted November 2015**

**<u>2016 Plan</u>**

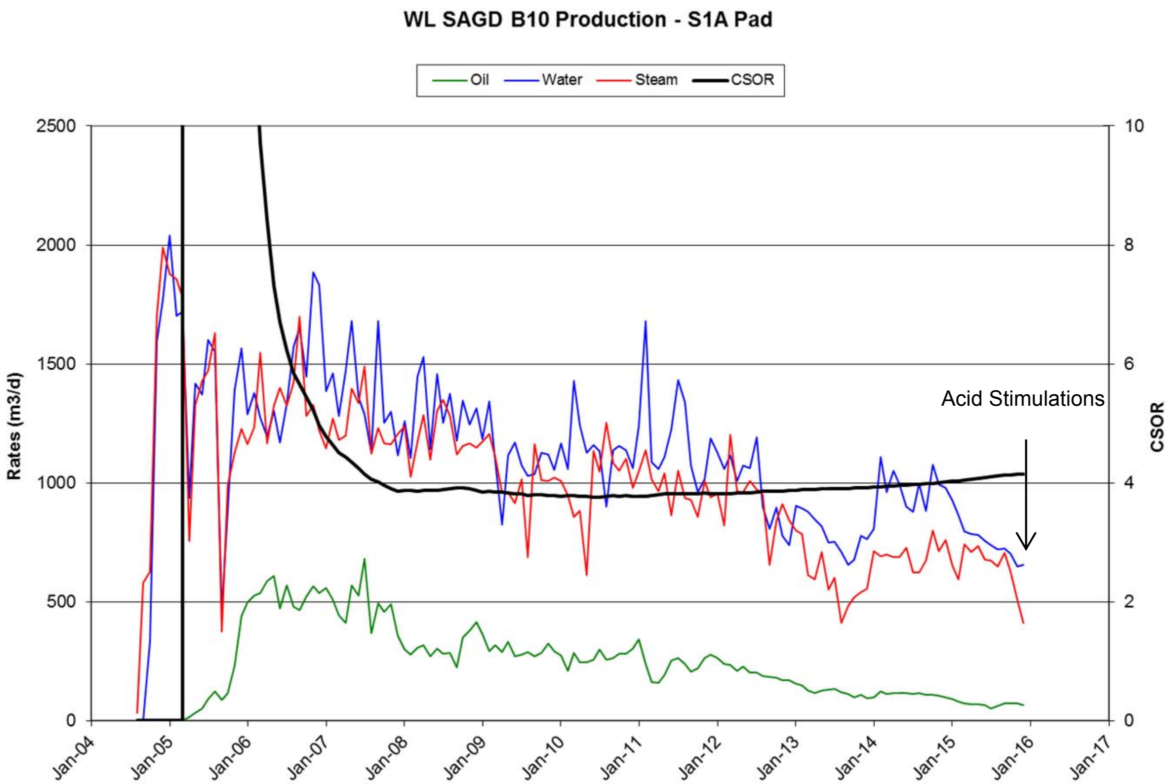
- **Co-Injection installation will continue to be evaluated**

# Wolf Lake SAGD
# B10 Pad S1A – High Recovery




- SAGD well pair: 8
- Completed Drilling: Feb 2004
- First Steam: Aug 2004
- Hz section length: 950 m
- Inter- well-pair spacing: 100 m
- Avg. net pay: 12 m
- Avg. So: 76%
- Avg. porosity: 33%
- Current RF: 37 %

# High Recovery – S1A Pad Production History




- Plugging has been observed on S1A producers
  - Identified using:
    - flowing wellbore temperature profiles
    - wellbore shut-in temperature transients
    - declining production rates
  - Jan 2014 – High WSR
    - Banked fluid production from a 3 well stimulation program utilizing Hydrochloric Acid

**2015 Activity**

- **Hydrofluoric Acid Stimulations performed across the pad in November to decrease plugging.**

**2016 Plan**

- **S1A infill application approved**
- **Blowdown strategy is being evaluated for future operations.**

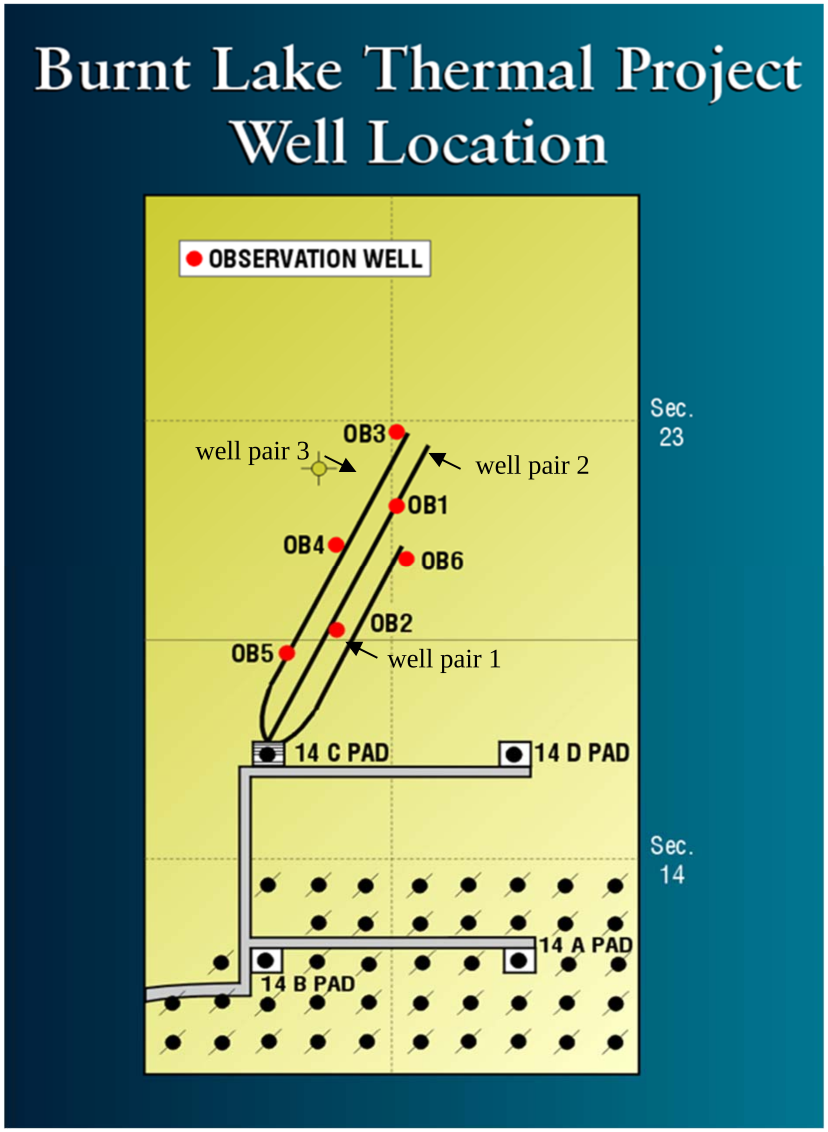
# Wolf Lake SAGD - 2016 Plan

- Continue operation, optimization and evaluation of SAGD performance in McMurray and Grand Rapids reservoirs.

- Investigate blowdown strategies for late life pads

- Investigate redrill/infill possibilities from existing pad locations

# Burnt Lake SAGD 2015 Performance Summary



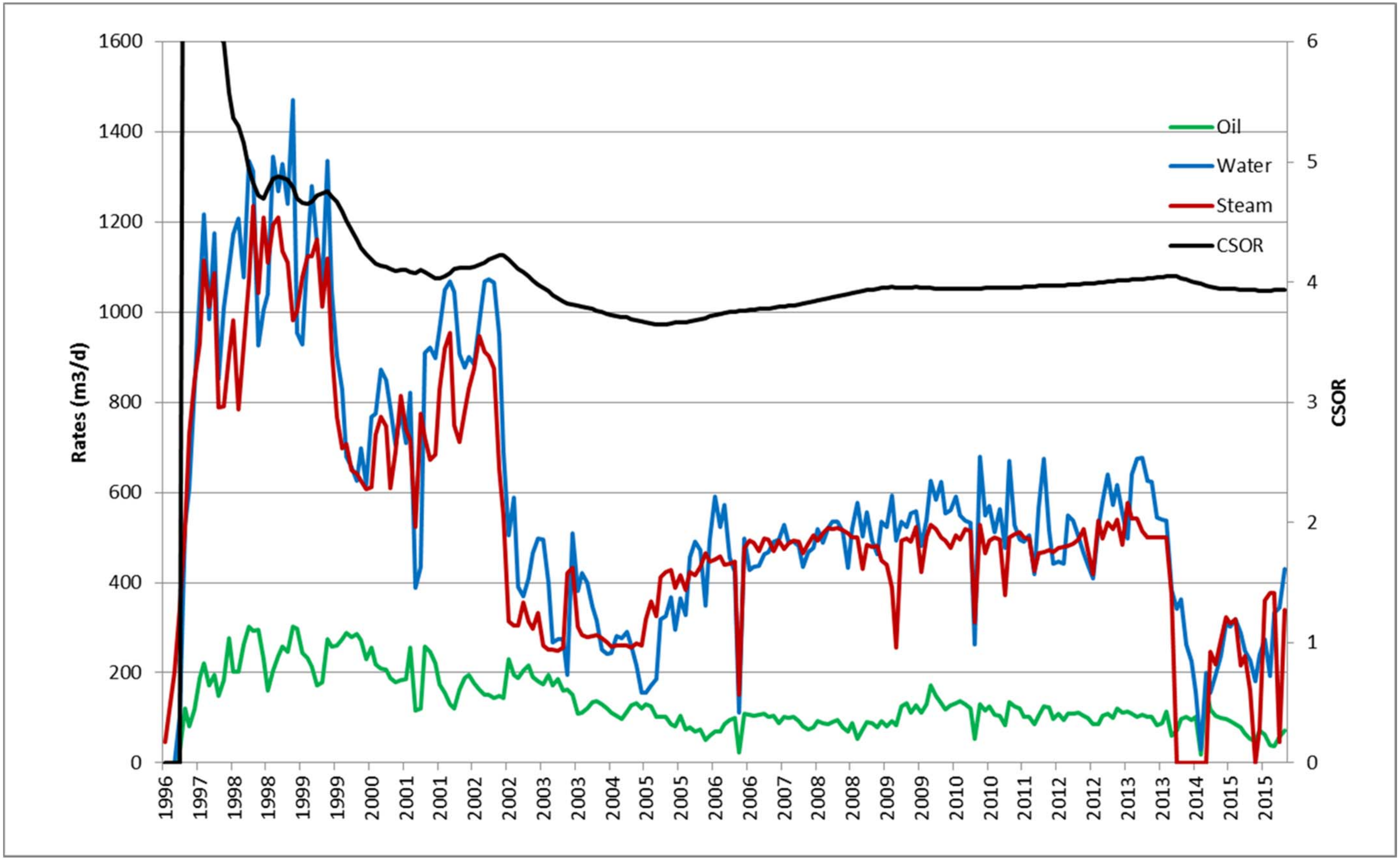

| Burnt Lake SAGD Pilot Production | |
|---|---|
| Active Well Pairs | 3 |
| 2014 Bitumen Production (e3m3) | 23 |
| 2014 Average SOR | 3.68 |
| Cumulative Bitumen Production (e3m3) | 933 |
| Cumulative SOR | 3.9 |
| OBIP (e3m3) | 1,493 |
| Recovery Factor (%) | 63 |

- Hz injector length: CP1: 940m, CP2,CP3: 1200m
- Inter- well-pair spacing: 85 m
- Avg. net pay: 22 m
- Avg. So: 75%
- Avg. porosity: 33%
- Estimated Ultimate Recovery : 70%
- 80% quality steam
  - Wet steam results in downgrade to SOR vs dry steam

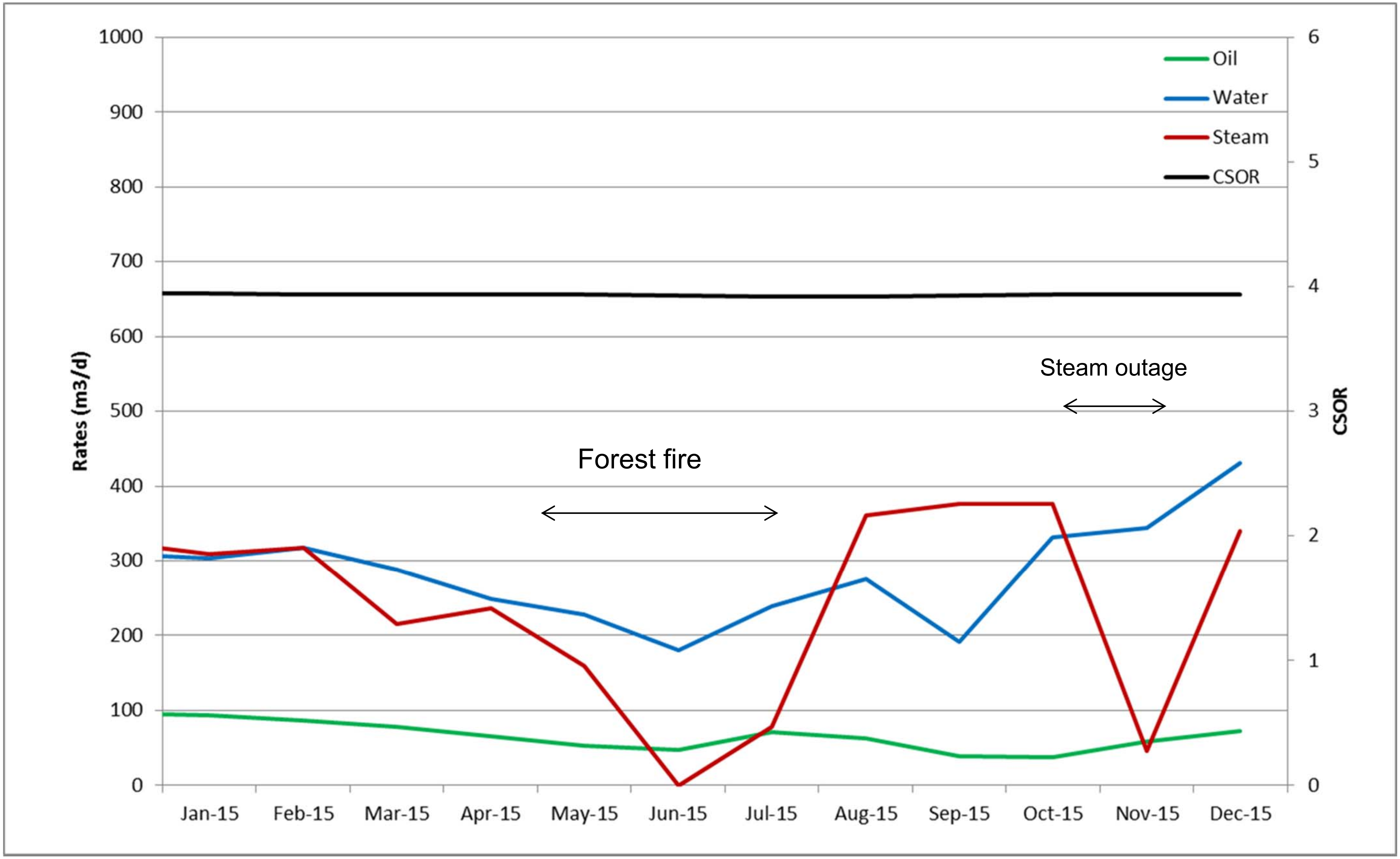
2015 Highlights

- Forest fire from May to June resulted in production and steam outage
- Water quality issues resulted in steam outage for month of November

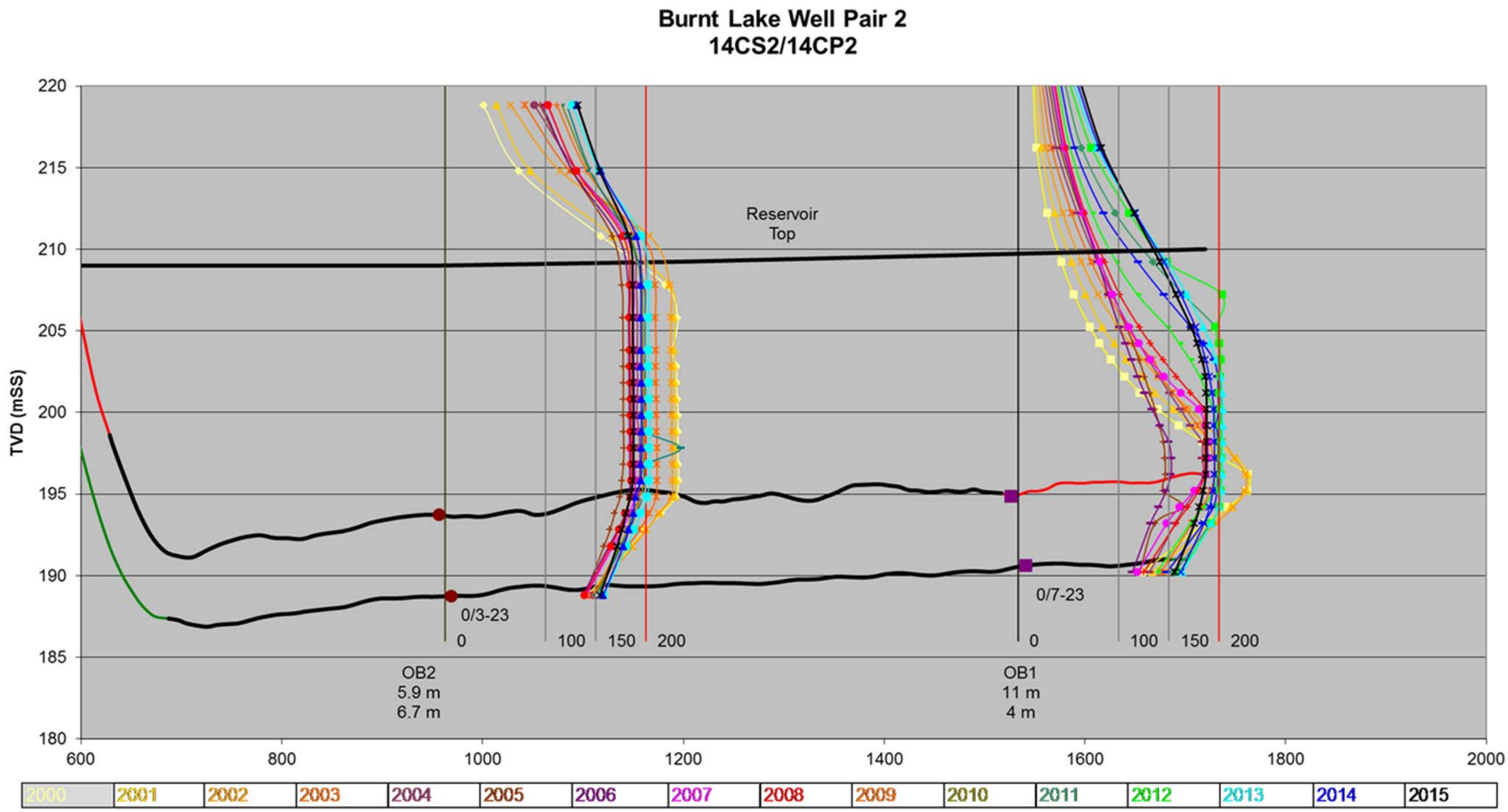
# Burnt Lake SAGD Production Summary



# Burnt Lake SAGD Production- 2015



# Burnt Lake Observation Well Temperature Profiles (CS2/CP2: Horizontal length 1000 m)



# Cyclic Steam Stimulation Overview

- CSS Basics
  - Steaming
  - Modified Steaming Strategy
  - Reservoir Pressure Management
  - Depletion
  - Geomechanics
  - Well Design
  - Observation Wells/Monitoring
  - OBIP
  - Recovery
- Wolf Lake Update
  - Valley Fill
  - C3 Sands
- Oil, Water, Steam
- Primrose Update
  - Current and Potential Recoveries
  - Performance Variation
  - Development Learning's
  - 2016 Steam Schedule
  - FTS Update
  - Future Development

# CSS Basics - Steaming

Canadian Natural

- Steam Generation - Quality of ~75%, ~15 MPa.
- Inject steam to dilate reservoir
  - Dilate reservoir with steam injection at the vertical in-situ stress (gradient is ~21 kPa/m at 500 m TVD, at ~10.5 MPa)
- Wave steam strategy through majority of wells
  - Alternate steam strategies implemented where interwell communication & Clearwater dilation profile require
- Rate and volumes are dependent on well geometry and cycle number
  - Steam strategy includes small volume commissioning cycles
  - Steam volumes selected to limit overburden uplift
  - Early cycles have limited steam volume growth
- Reservoir pressure management
  - Fill up in front of wave to increase reservoir pressure ahead of post fill-up wells (4-7 wells ahead)
  - Soak wells 3+ rows behind steam injection to reduce leak off on post fill-up wells

# CSS Basics – Steaming Cycle Performance

- Early cycle steam volumes have little to no impact on the cycle thermal efficiency
  - Performance is dependent on near well bore reservoir quality
  - Evaluating performance of multiple cycles with no VAF steam volume growth

- Mid to late life reduced cycle steam volume
  - Increases number of cycles a well receives during its life
    - Increasing casing integrity risk
    - Reduces thermal efficiency (reheating water within reservoir)
    - Increases risk of inter-well communication with multiple pressure cycles through a given area (reducing thermal efficiency)

# CSS Basics - Steaming
# Steam Injection Strategy

- Canadian Natural believes in continuous improvement to steam strategies to maximize recovery and reduce risk, and continues to examine cycle performance
- Current steam strategy includes low volume commissioning cycles followed by commercial cycles
  - Commissioning cycle 1: ~10,000 $m^3$/well
  - Commissioning cycle 2: ~17,000 $m^3$/well
    - initial steam injection is to increase the minimum horizontal in-situ stress by increasing poro-elastic and thermal elastic stresses which promotes horizontal fractures within the Clearwater sand
  - Commercial cycle 1+: Limited by overburden uplift
    - The Formation Expansion Index (FEI) is a metric used to represent Clearwater capping shale uplift for each steaming cycle
    - FEI is equal to steam volume above fill-up (VAF) divided by area (well length x spacing)
    - Currently limited to 25cm
- Improved non-conforming well criteria and remediation protocol
- Increased observations system sensitivity to limit fluid interactions with the LGR
- Steam volumes on edges of developments are tapered in Commissioning and Commercial cycles

# Why Is the FEI Metric Used to Limit Steam Volumes?

Canadian Natural

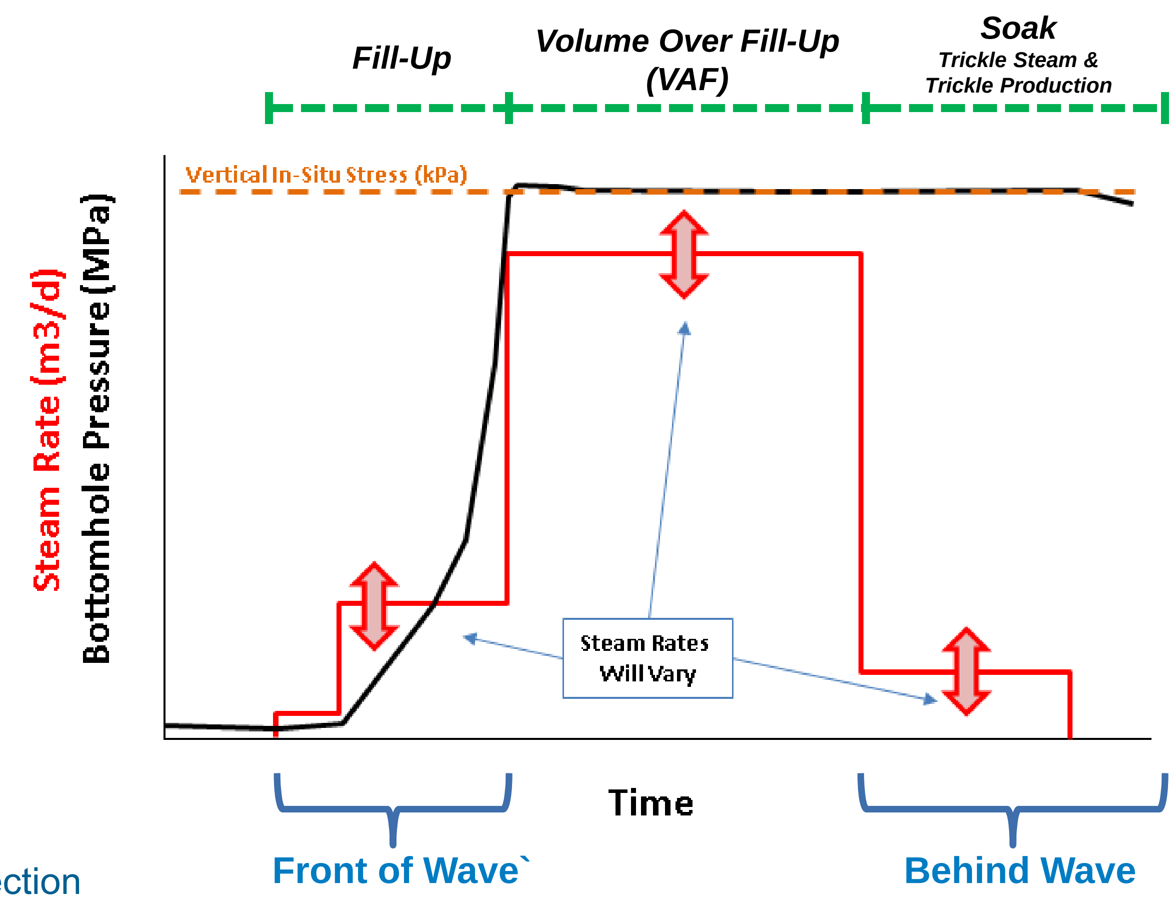
- FTS enabling condition #4 pertains to uplift induced stress changes within the Colorado Group shales

- For linear elastic behavior, the greater the Clearwater capping shale uplift, the greater the in-situ stress changes within the overburden

- An effective metric to limit this in-situ stress change is the FEI metric which is a proxy for the vertical displacement of the Clearwater capping shale
  - A steam volume divided by reservoir pore volume does not address the magnitude of stress changes within the overburden

# CSS Basics - Steaming Reservoir Pressure Management

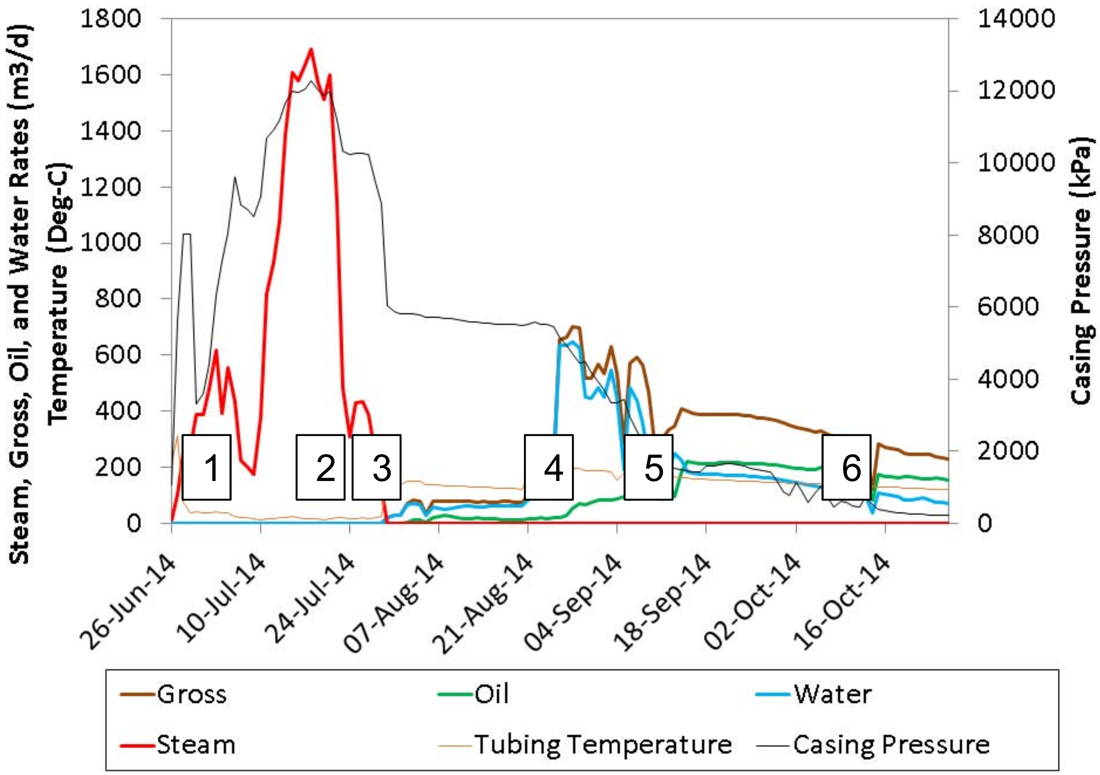
- Inter-well communication has been shown to reduce thermal efficiency. Risk managed by controlling pressure gradients around steam wave.
- Front of Wave
  - Design for a fill-up steam bank ahead of wave which establishes a controllable pressure gradient ahead of the wave




- Behind Wave
  - Soaking wells
    - Use stress to confine steam injection
    - Number of rows increased with degree of inter-well communication
  - Flow back wells
    - Design a flow back rate that balances production while keeping reasonable pressure differentials (dPs) between wells

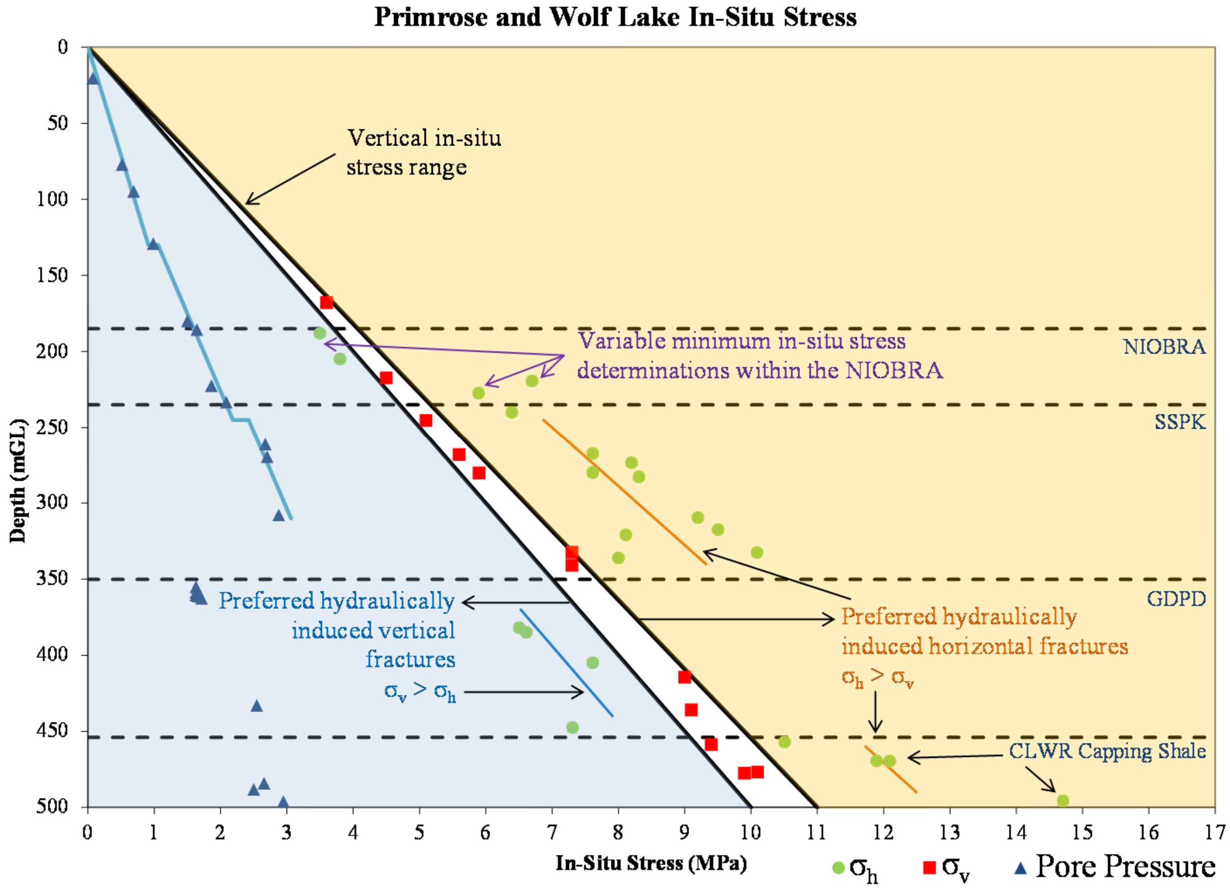
# CSS Basics - Depletion
# Fluid Recovery Basics

- Gross fluid profiles are analyzed as a function of Depletion Index, DI
  - DI is the ratio of total fluid produced to total steam injected
- Large variance in production rate through out CSS cycle
- 5 components to the gross fluid vs. DI profile. Component expectation varies by cycle, reservoir and steam strategy.
  1. **Fill-up:** Sub-dilation volumes required to fill-up increase as depletion increases
  2. **Volume Over Fill-up:** Commercial cycle design limits overburden uplift
  3. **Soak / Pressure Management:**
     **A) Trickle Steam**
     **B) Trickle Production**
     Design influenced by interwell communication / reservoir pressure management strategy
  4. **Flowback:** Targeted rates designed to control pressure differentials between drainage boxes
  5. **Pump-limited Pumping:** Artificial lift capacity constrained
  6. **Declining Production:** Gas break out from solution, vapour recovery required



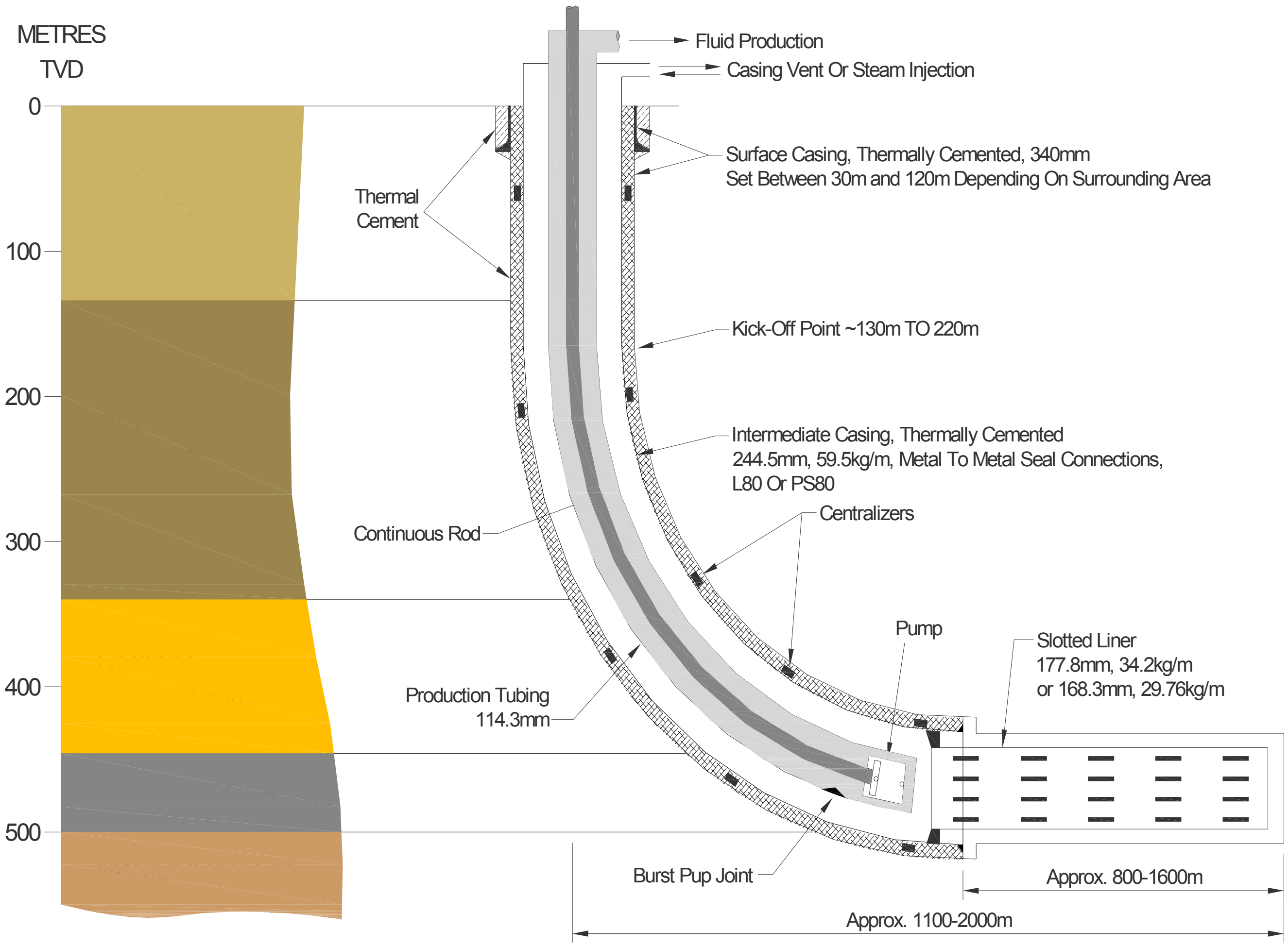
# Geomechanics: Overburden In-Situ Stresses

- The majority of the Colorado Group shales have a minimum in-situ stress oriented vertically
- Hydraulically induced fractures will propagate horizontally within most of the Colorado Group shales
- The Colorado Group shales is considered the regional seal in the Cold Lake region protecting the Quaternary aquifers
- Poro- and thermo-elastic stress increases within the Clearwater sand promote horizontal hydraulically induced fractures

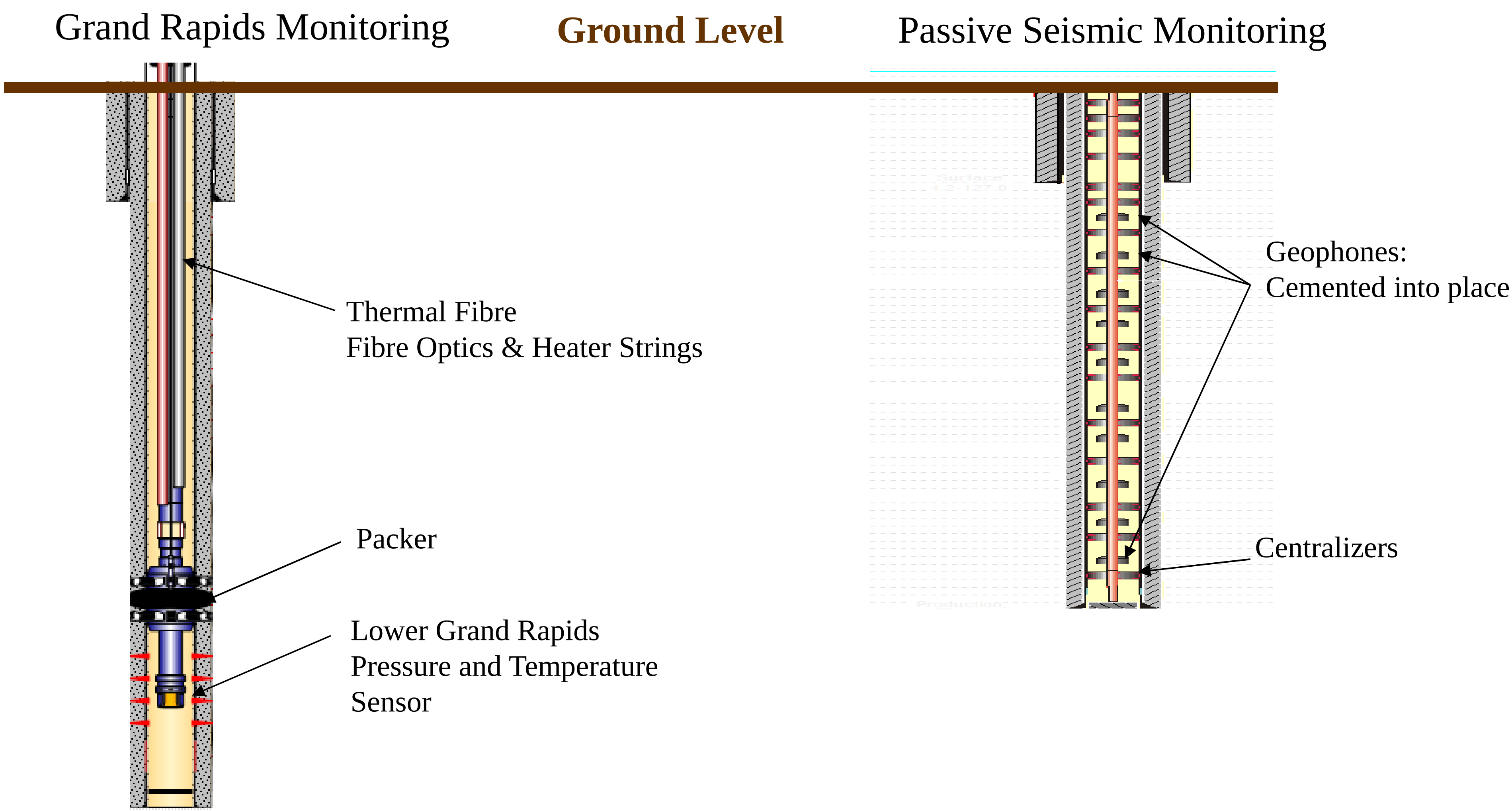


# CSS Basics – Well Design

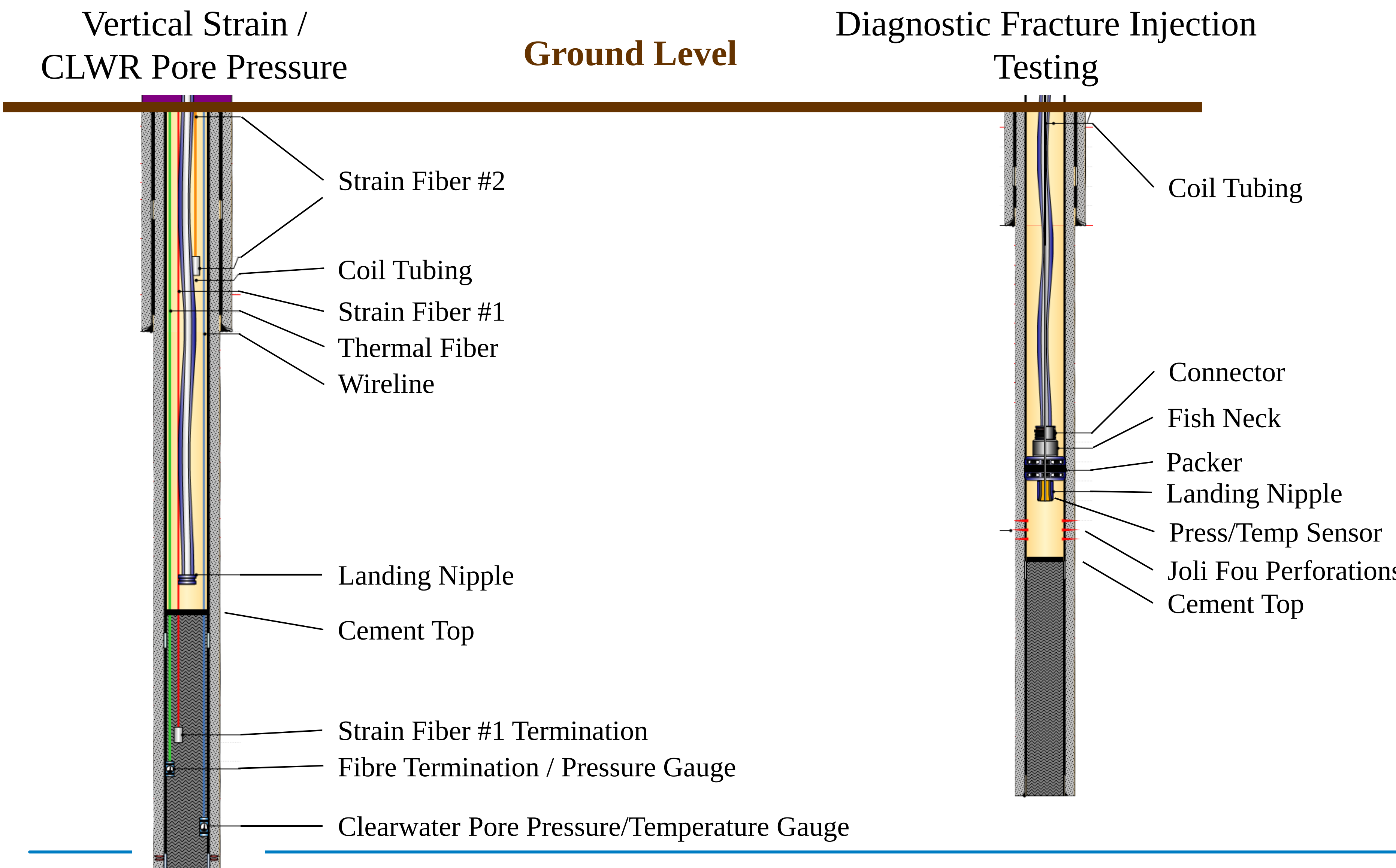
## Typical Horizontal CSS Well



# CSS Basics – Observation Wells



# CSS Basics – Geomechanics Wells



# Formation Integrity Monitoring, Passive Seismic and Geomechanics

- Passive seismic monitoring has been used since 2000. Passive Seismic surveillance is an effective tool for detecting casing failures
  - Statistics since 2012 show Passive Seismic reliability is 98% detection rate for:
    - Out of zone casing failures.
    - Casing failures outside of the surface casing.
    - Pads with functioning PS equipment.

- Geomechanics Observation Wells on Pad 43
  - Improve understanding between steam injection volumes and uplift induced stress changes
  - Integration and evaluation of acquired data is ongoing
    - Surface heave
    - Vertical strain
    - Repeated DFIT within the Joli Fou Formation
    - Pore pressure measurement in the B12 and Quaternary
    - Steam injection volumes and pressures

# Formation Integrity Monitoring
# Lower Grand Rapids Pressure

- Lower Grand Rapids (LGR) pressure monitoring has proven to be an effective observation system regarding formation integrity surveillance during CSS
  - All steaming pads are equipped with LGR pressure monitoring
  - Canadian Natural shall notify the AER if a LGR pressure increase is greater than the approved threshold (typically 200 kPa/day for application that lift the overburden)
  - Integration of independent data sources
    - LGR Monitoring, Passive seismic, injectivity plots, production data

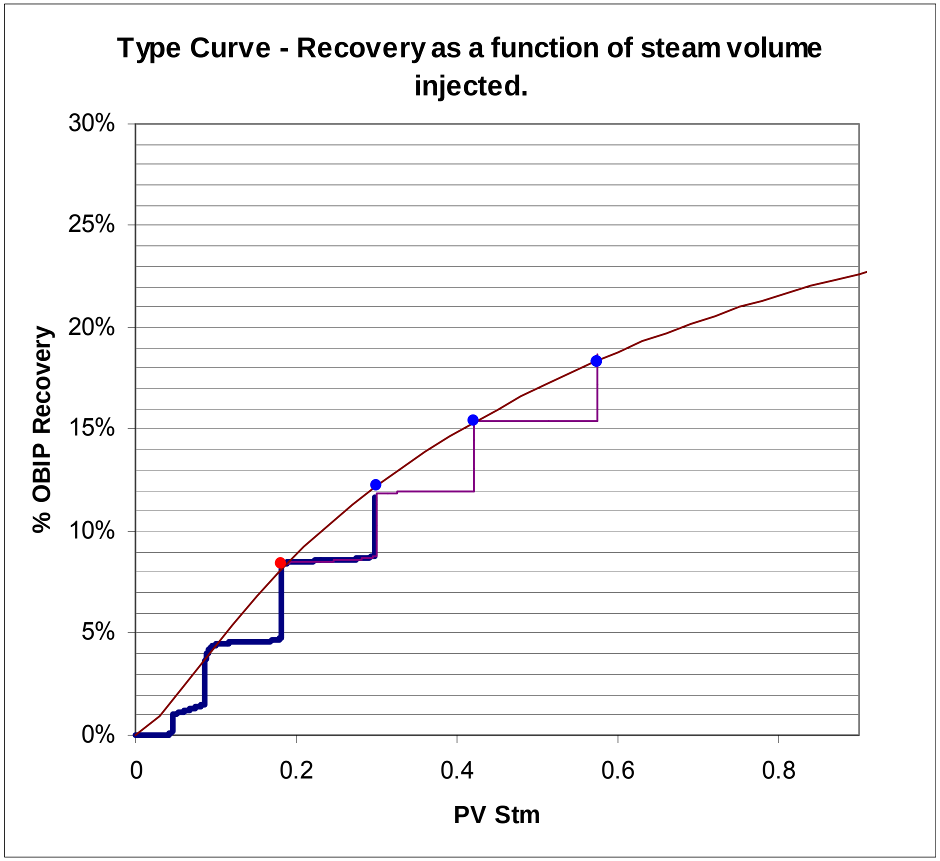
# CSS Basics - OBIP Assumptions

$$OBIP = Area \times Net\ Pay \times Porosity \times Oil\ Saturation$$

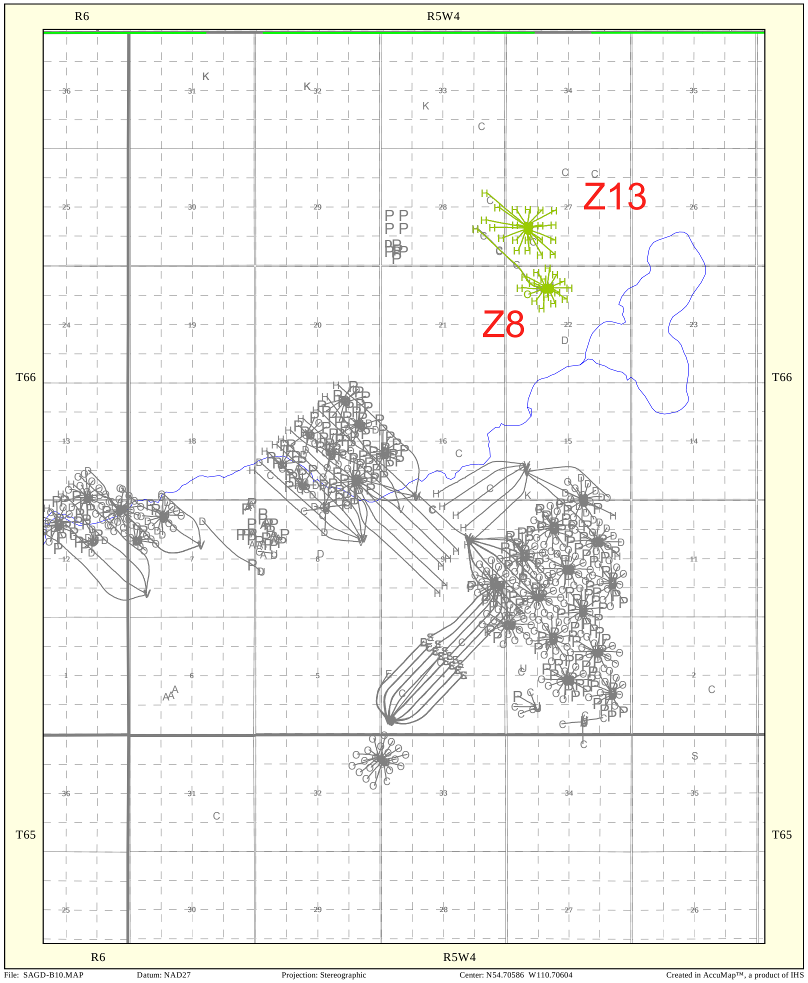
- Area is 1 well spacing wide by length of well plus ½ spacing on each end
- Net pay is as previously defined in the Geology section
- Oil saturation is determined from Bitumen Weight percentage assuming a sand/shale density of 2,650 kg/m$^3$, water/oil density of 1,000 kg/m$^3$, and 32% porosity

# CSS Basics - Recovery

- CSS life is dictated by the economic limits (SOR)
- Typical economic SOR limit 6-10
  - Oil/Gas price ratio dependent
- Forecasting is based on a type curve
- Recovery is a function of amount of steam injected
- Goal of steam scheduling is to maximize rates and recovery
- Type curve uncertainty exists for greater than 15% recovery at 160m spacing



# Wolf Lake Valley Fill CSS

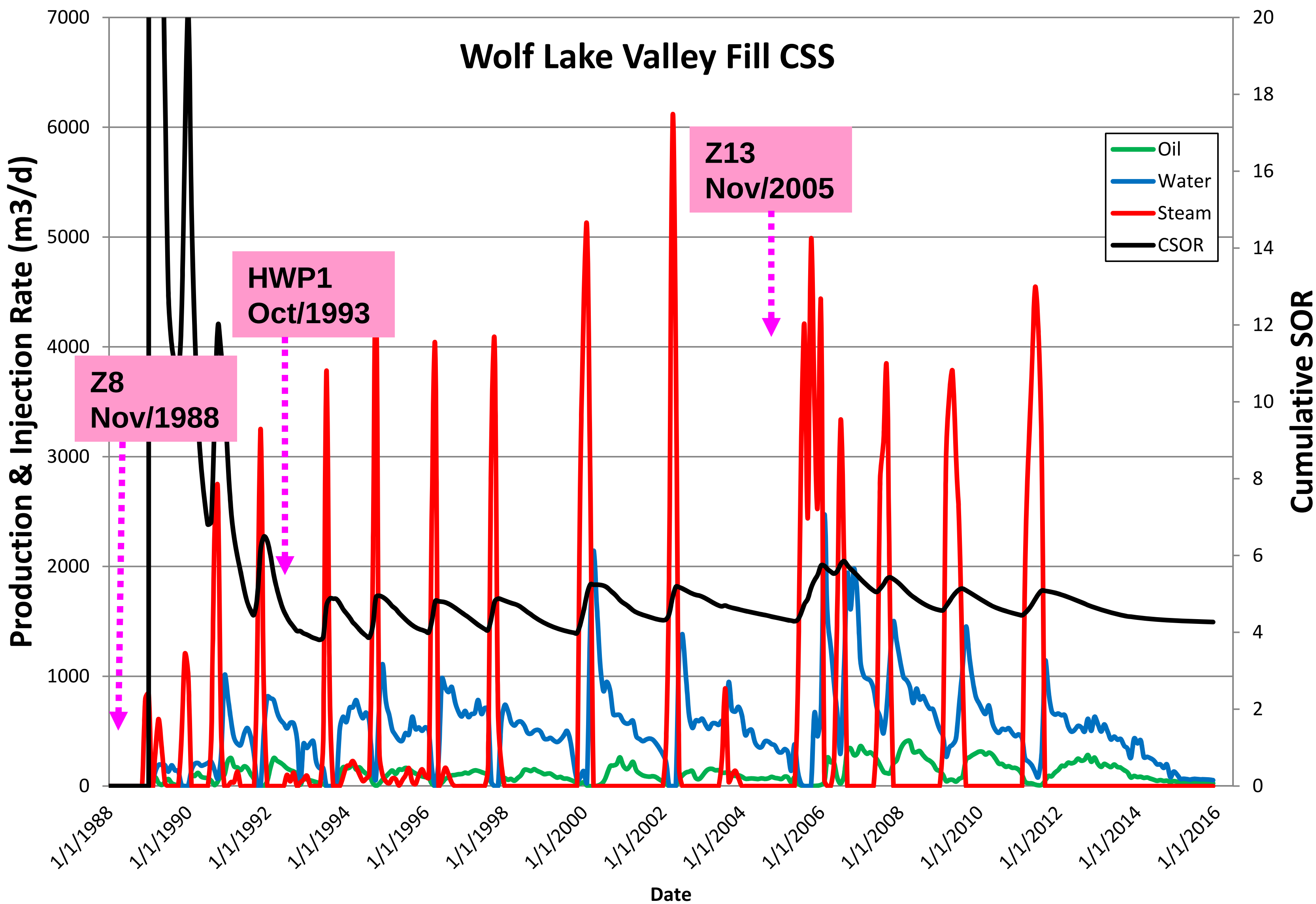



## 2015 Performance Summary

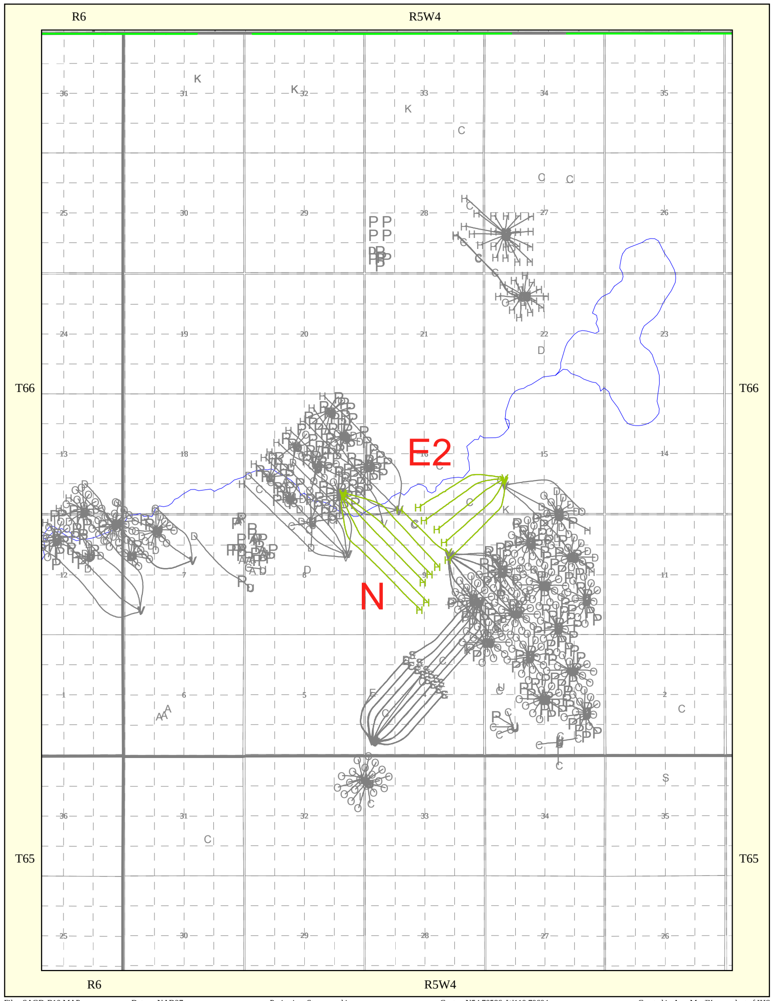
**Wolf Lake Valley Fill CSS Performance Summary**

| Phase | Z8 & HWP | Z13 | VF Total |
|---|---|---|---|
| CSS Well Count | 20 | 21 | 41 |
| 2015 Steam Injection (m3) | 0 | 0 | 0 |
| 2015 Bitumen Production (e3m3) | 0 | 11 | 11 |
| Cumulative Bitumen Production (e3m3) | 693 | 439 | 1,142 |
| Cumulative SOR | 4.2 | 4.4 | 4.3 |

# Wolf Lake Valley Fill CSS, All Pads



# Wolf Lake C3 Sand CSS

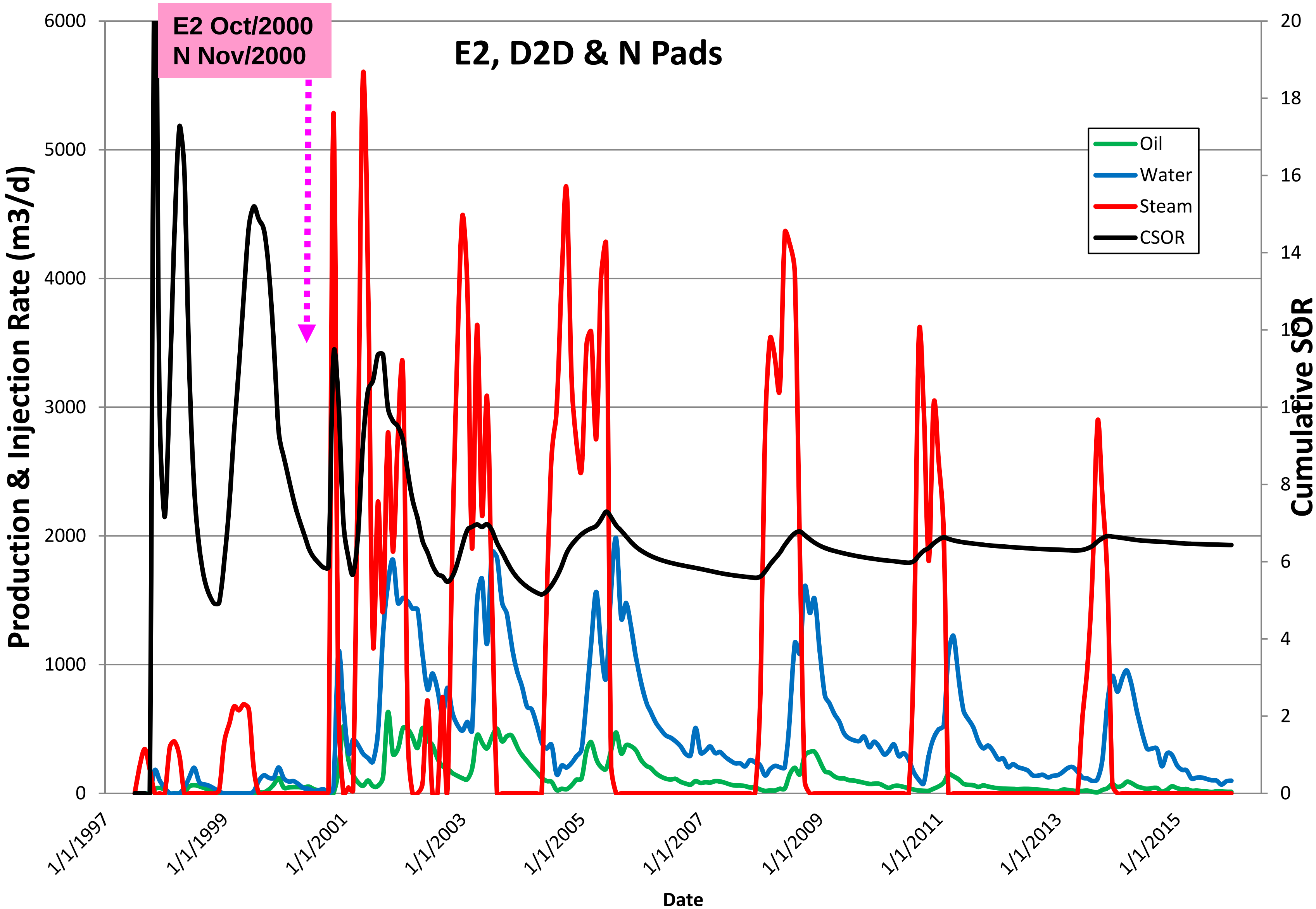



## 2015 Performance Summary

**Wolf Lake Valley Fill CSS Performance Summary**

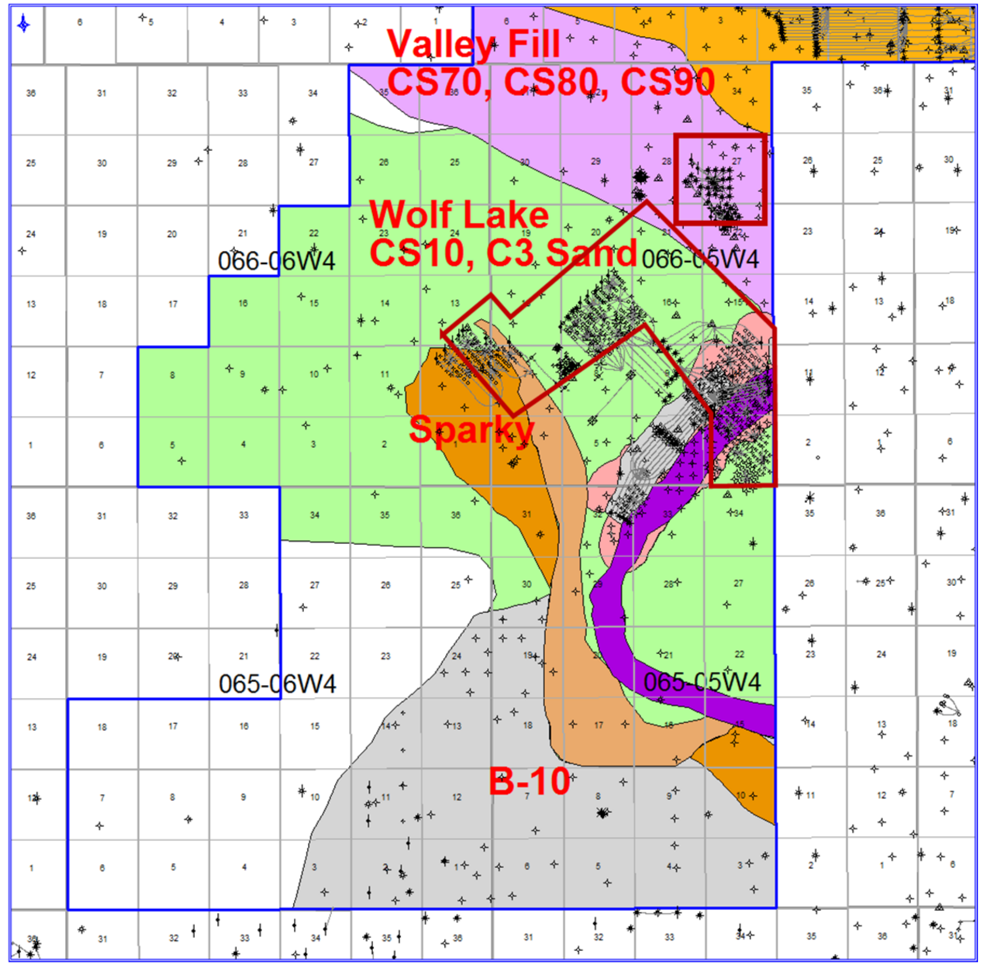
| Phase | E2 & D2D | N | C3 Total |
|---|---|---|---|
| CSS Well Count | 6 | 5 | 11 |
| 2015 Steam Injection ($m^3$) | 0 | 0 | 0 |
| 2015 Bitumen Production ($e3m^3$) | 7 | 4 | 11 |
| Cumulative Bitumen Production ($e3m^3$) | 560 | 405 | 965 |
| Cumulative SOR | 5.8 | 7.4 | 6.5 |

# Wolf Lake C3 Sand CSS – Phases E2, D2D & N

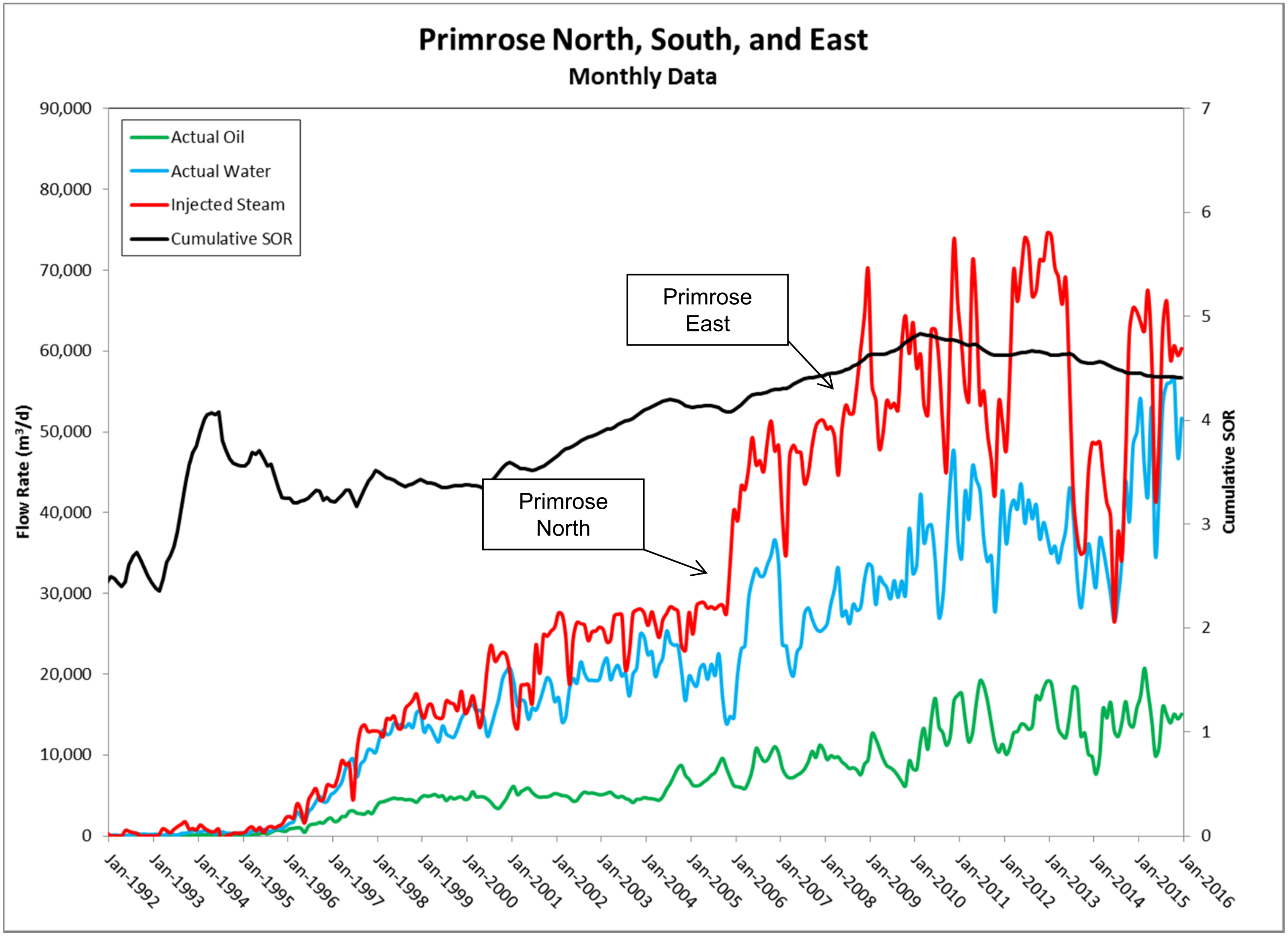


# Wolf Lake 2015 / Potential Recoveries

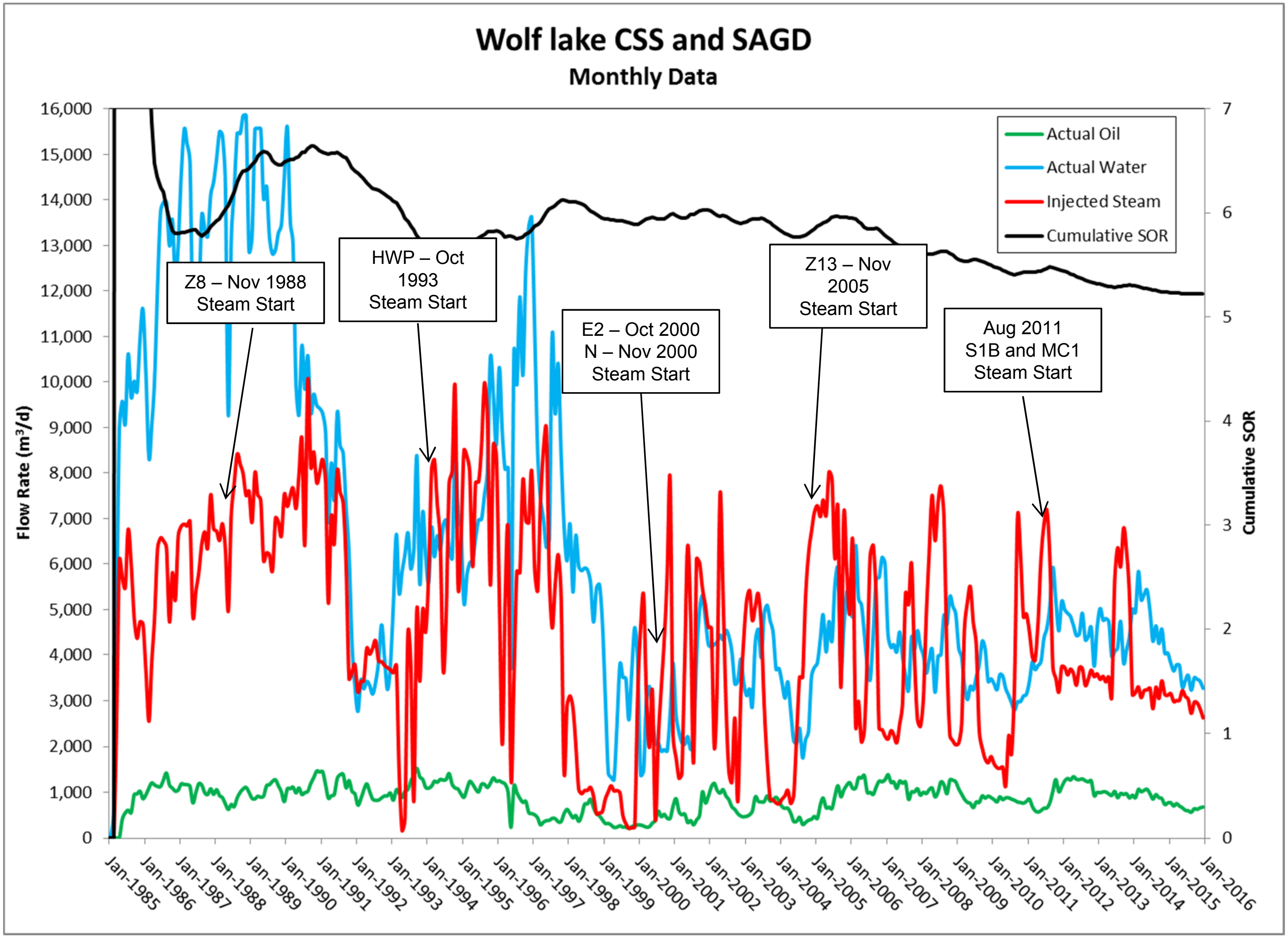
| Wolf Lake Area | OBIP (e3m3) | 2014 cum oil (e3m3) | RF (%) | Estimated Recoverable (%) |
|---|---|---|---|---|
| Valley Fill | 6,943 | 1,142 | 16 | 21-26% |
| C3 Sand | 4,890 | 965 | 20 | 26-28% |



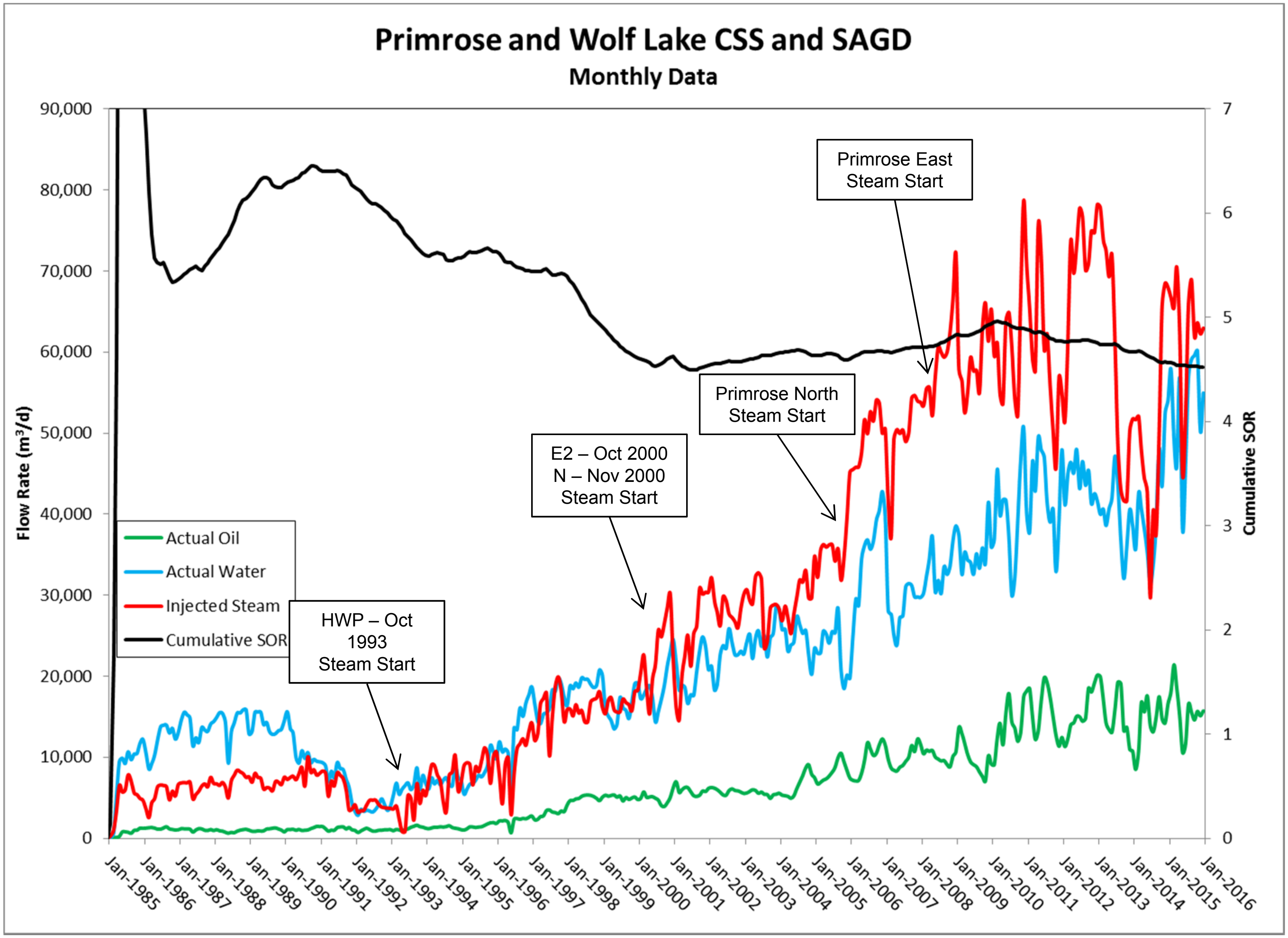
# Primrose Oil, Water, Steam, and SOR



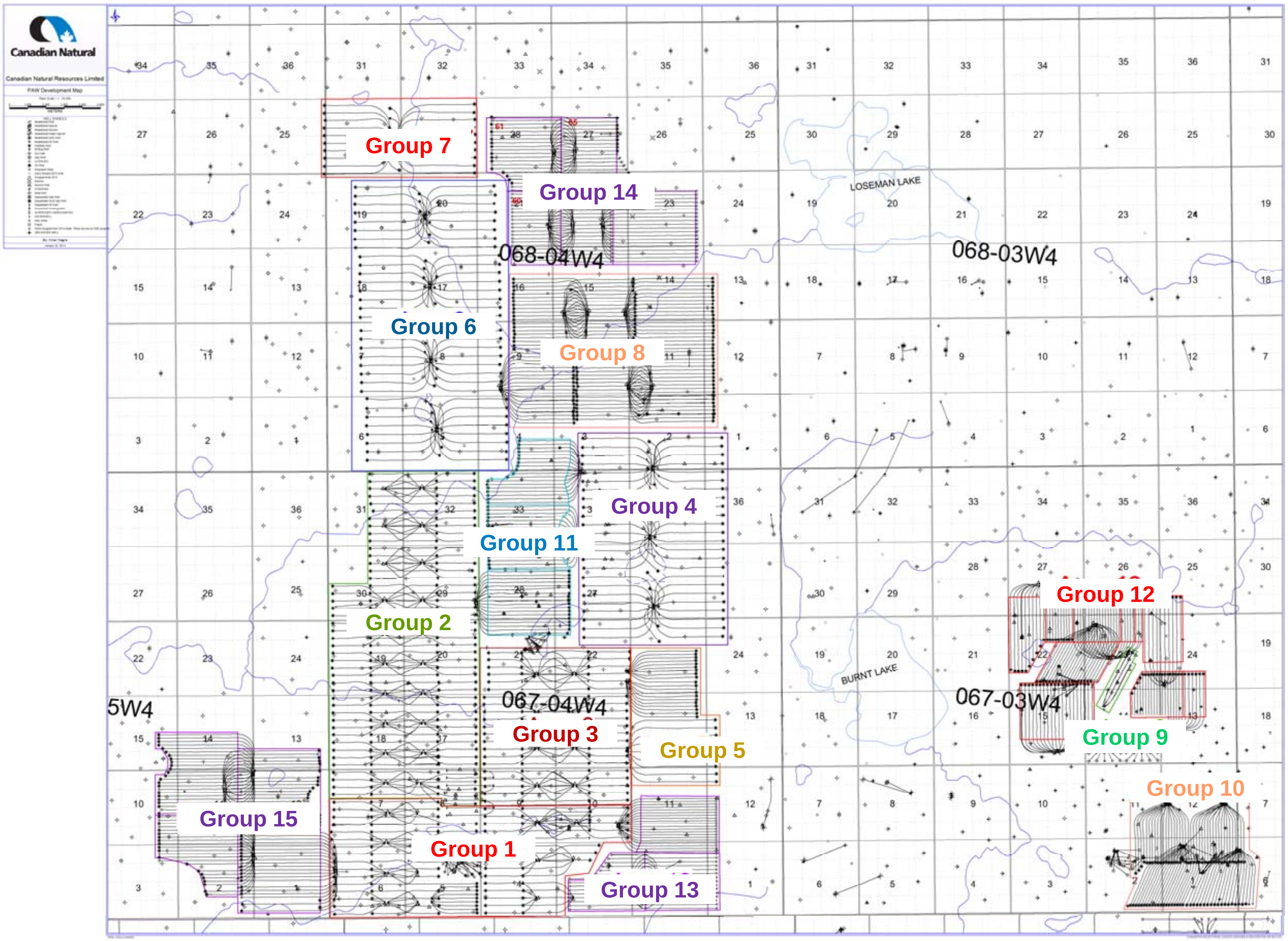
# Wolf Lake Oil, Water, Steam, and SOR



# Primrose & Wolf Lake
# Oil, Water, Steam, and SOR



# Primrose Current Recoveries - 2015



# Primrose Current / Potential Recoveries

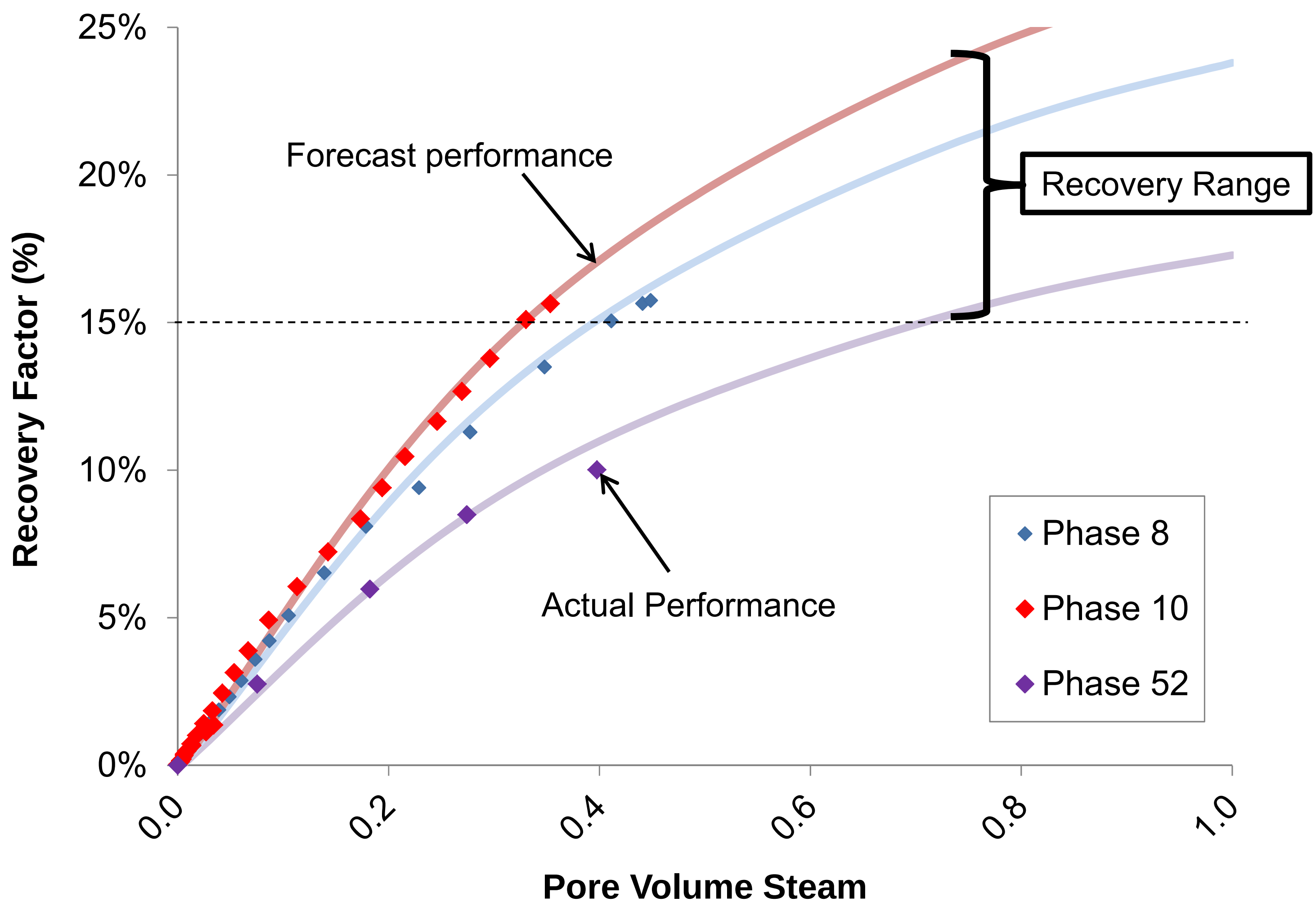
Canadian Natural

| | OBIP (e3m3) | Area (m2) | Pay Thickness (m) | Porosity (dec) | Cum Oil (e3m3) | Current Recovery | Potential Recovery Range |
|---|---|---|---|---|---|---|---|
| **Group 1:** | | | | | | | |
| 1 | 5,780 | 2,048,000 | 14.1 | 32 | 1,341 | 23% | 30-36 % |
| 2 | 3,934 | 1,536,000 | 12.6 | 32 | 620 | 16% | 24-30% |
| 3 | 3,901 | 1,792,000 | 10.5 | 32 | 762 | 20% | 26-32% |
| P-M WSDD | 2,495 | 768,000 | 17.5 | 32 | 572 | 23% | 26-32% |
| 4 | 3,533 | 1,664,000 | 10.1 | 32 | 572 | 16% | 20-26% |
| 15 | 4,139 | 1,280,000 | 15.4 | 32 | 502 | 12% | 26-32% |
| 16 | 3,377 | 1,280,000 | 13.1 | 32 | 414 | 12% | 22-28% |
| 16C | 766 | 444,347 | 8.7 | 32 | 57 | 7% | 15-21% |
| 17 | 5,259 | 2,560,000 | 10.3 | 32 | 945 | 18% | 21-27% |
| **Subtotal** | **33,185** | | | | **5,785** | **17%** | |
| **Group 2:** | | | | | | | |
| 5 | 3,221 | 1,536,000 | 9.9 | 32 | 600 | 19% | 21-27% |
| CDD | 998 | 896,000 | 6.0 | 0.32 | 185 | 19% | 20-22% |
| D5 | 1,231 | 668,077 | 9.5 | 32 | 70 | 6% | 16-22% |
| 6 | 5,625 | 2,048,000 | 13.6 | 32 | 773 | 14% | 20-26% |
| 7 | 5,679 | 2,048,000 | 13.9 | 32 | 951 | 17% | 23-29% |
| 8 | 5,691 | 2,048,000 | 14.0 | 32 | 897 | 16% | 21-27% |
| 9 | 5,229 | 2,048,000 | 12.9 | 32 | 895 | 17% | 23-29% |
| 10 | 5,616 | 2,048,000 | 13.9 | 32 | 958 | 17% | 28-34% |
| 11 | 6,735 | 2,560,000 | 13.5 | 32 | 1,023 | 15% | 26-32% |
| 12 | 5,058 | 1,920,000 | 13.5 | 32 | 728 | 14% | 22-28% |
| 13 | 5,270 | 1,920,000 | 14.0 | 32 | 746 | 14% | 20-26% |
| 14 | 5,112 | 1,920,000 | 13.6 | 32 | 748 | 15% | 21-27% |
| **Subtotal** | **55,465** | | | | **8,574** | **15%** | |
| **Group 3:** | | | | | | | |
| 18 | 5,772 | 2,560,000 | 11.2 | 32 | 1,127 | 20% | 24-30% |
| 19 | 5,592 | 2,560,000 | 10.9 | 32 | 1,236 | 22% | 29-35% |
| 20 | 5,723 | 2,560,000 | 11.1 | 32 | 1,137 | 20% | 23-29% |
| 21 | 7,055 | 3,072,000 | 11.2 | 32 | 1,145 | 16% | 21-27% |
| **Subtotal** | **24,142** | | | | **4,645** | **19%** | |
| **Group 4:** | | | | | | | |
| 29 | 10,394 | 4,175,104 | 10.4 | 0.32 | 1,865 | 18% | 20-26% |
| 30 | 10,380 | 4,175,104 | 10.4 | 0.32 | 2,013 | 19% | 21-27% |
| 31 | 11,334 | 4,175,104 | 11.3 | 0.32 | 2,126 | 19% | 21-27% |
| **Subtotal** | **32,108** | | | | **6,004** | **19%** | |
| **Group 5:** | | | | | | | |
| 27 | 4,628 | 2,726,635 | 8.3 | 32.00 | 876 | 19% | 20-26% |
| 28 | 2,028 | 900,000 | 11.0 | 32.00 | 722 | 36% | 47-53% |
| 28B | 2,083 | 900,000 | 11.3 | 32.00 | 517 | 25% | 42-48% |
| **Subtotal** | **8,738** | | | | **2,115** | **24%** | |
| **Group 6:** | | | | | | | |
| 51 | 14,533 | 4,817,342 | 15.1 | 0.32 | 1,558 | 11% | 13-19% |
| 52 | 14,247 | 4,817,342 | 14.6 | 0.32 | 1,426 | 10% | 13-19% |
| 53 | 14,800 | 4,817,342 | 15.8 | 0.32 | 1,234 | 8% | 13-19% |
| 54 | 15,585 | 4,817,342 | 15.7 | 0.32 | 1,826 | 12% | 13-19% |
| **Subtotal** | **59,165** | | | | **6,044** | **10%** | |
| **Group 7:** | | | | | | | |
| 55 | 16,927 | 5,537,441 | 15.9 | 0.32 | 1,772 | 10% | 13-19% |
| **Subtotal** | **16,927** | | | | **1,772** | **10%** | |

| | OBIP (e3m3) | Area (m2) | Pay Thickness (m) | Porosity (dec) | Cum Oil (e3m3) | Current Recovery | Potential Recovery Range |
|---|---|---|---|---|---|---|---|
| **Group 8:** | | | | | | | |
| 58 | 5,441 | 2,064,800 | 14.0 | 0.32 | 1,231 | 23% | 45-50% |
| 59 | 6,959 | 2,208,000 | 14.2 | 0.32 | 1,405 | 20% | 45-50% |
| 62 | 6,342 | 2,230,006 | 13.2 | 0.32 | 1,186 | 19% | 45-50% |
| 63 | 5,555 | 2,114,640 | 12.5 | 0.32 | 1,302 | 23% | 45-50% |
| 66 | 6,708 | 2,582,960 | 12.0 | 0.32 | 1,269 | 19% | 45-50% |
| 67 | 7,180 | 2,643,200 | 13.3 | 0.32 | 1,202 | 17% | 45-50% |
| **Subtotal** | **38,185** | | | | **7,595** | **20%** | |
| **Group 9:** | | | | | | | |
| Burnt Lake | 1,493 | 259,362 | 24.3 | 0.32 | 928 | 62% | 60%+ |
| **Subtotal** | **1,493** | | | | **928** | **62%** | |
| **Group 10:** | | | | | | | |
| 74 | 6,023 | 1,077,635 | 24.7 | 0.32 | 1,096 | 18% | 60%+ |
| 75 | 7,169 | 1,234,300 | 25.2 | 0.32 | 1,519 | 21% | 60%+ |
| 77 | 6,625 | 1,195,136 | 25.6 | 0.32 | 1,512 | 23% | 60%+ |
| 78 | 6,743 | 1,177,059 | 25.9 | 0.32 | 1,190 | 18% | 60%+ |
| **Subtotal** | **26,560** | | | | **5,317** | **20%** | |
| **Group 11:** | | | | | | | |
| 22 | 6,736 | 2,531,371 | 13.2 | 0.32 | 907 | 13% | 45-50% |
| 23 | 6,009 | 2,288,372 | 13.3 | 0.32 | 851 | 14% | 45-50% |
| 24 | 5,204 | 1,926,224 | 13.4 | 0.32 | 797 | 15% | 45-50% |
| **Subtotal** | **17,949** | | | | **2,555** | **14%** | |
| **Group 12:** | | | | | | | |
| 90 | 5,498 | 1,541,935 | 19.5 | 0.32 | 792 | 14% | 60%+ |
| 91 | 2,583 | 1,234,697 | 9.9 | 0.32 | 272 | 11% | 60%+ |
| 92 | 5,854 | 1,486,007 | 18.1 | 0.32 | 499 | 9% | 40-50% |
| 93 | 4,748 | 1,770,501 | 12.9 | 0.32 | 492 | 10% | 40-50% |
| 94 | 4,141 | 1,200,299 | 16.1 | 0.32 | 160 | 4% | 40-50% |
| 95 | 4,598 | 1,969,607 | 11.4 | 0.32 | 467 | 10% | 40-50% |
| **Subtotal** | **27,422** | | | | **2,682** | **10%** | |
| **Group 13:** | | | | | | | |
| 25A | 2,718 | 1,727,106 | 7.0 | 32 | 333 | 12% | 40-50% |
| 25B | 2,565 | 2,034,990 | 5.5 | 32 | 406 | 16% | 40-50% |
| 26 | 3,077 | 2,083,550 | 7.0 | 32 | 592 | 19% | 40-50% |
| **Subtotal** | **8,360** | | | | **1,331** | **16%** | |
| **Group 14:** | | | | | | | |
| 60 | 5,052 | 1,720,000 | 14.2 | 0.32 | 760 | 15% | 45-50% |
| 61 | 6,923 | 2,362,000 | 13.7 | 0.32 | 970 | 14% | 45-50% |
| 64 | 5,262 | 1,856,000 | 12.9 | 0.32 | 865 | 16% | 45-50% |
| 65 | 5,055 | 2,107,081 | 11.3 | 0.32 | 883 | 17% | 45-50% |
| 68 | 7,220 | 2,894,006 | 10.5 | 0.32 | 1,009 | 14% | 45-50% |
| **Subtotal** | **29,512** | | | | **4,487** | **15%** | |
| **Group 15:** | | | | | | | |
| 40 | 4,106 | 3,008,352 | 6.8 | 0.32 | 429 | 10% | 40-50% |
| 41 | 5,272 | 3,014,070 | 8.1 | 0.32 | 491 | 9% | 40-50% |
| 42 | 6,761 | 3,130,144 | 10.2 | 0.32 | 441 | 7% | 40-50% |
| 43 | 5,423 | 2,492,978 | 11.0 | 0.32 | 397 | 7% | 40-50% |
| **Subtotal** | **21,561** | | | | **1,758** | **8%** | |
| **PR Total** | **400,772** | | | | **61,592** | **15%** | |

# CSS Performance Forecasting
## Greater Variability as Recovery Increases

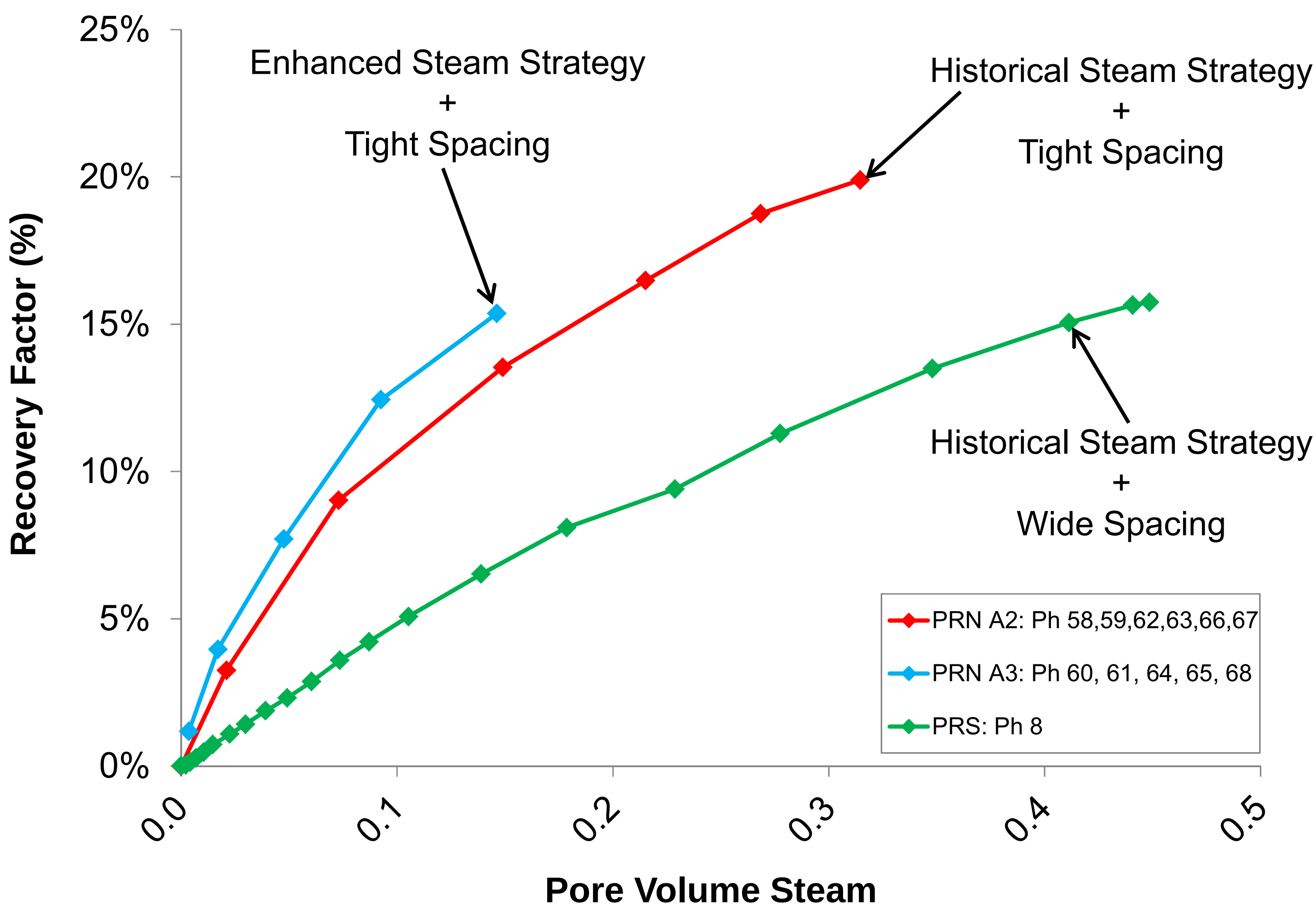
- Predictable performance up to 15% recovery factor using normalization for spacing



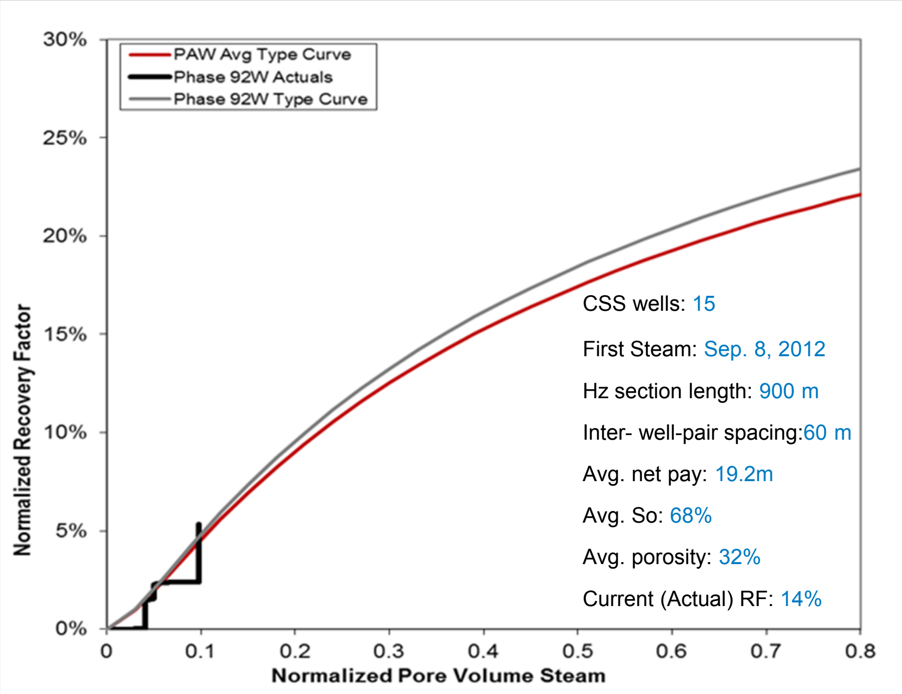
# CSS Performance Evolution

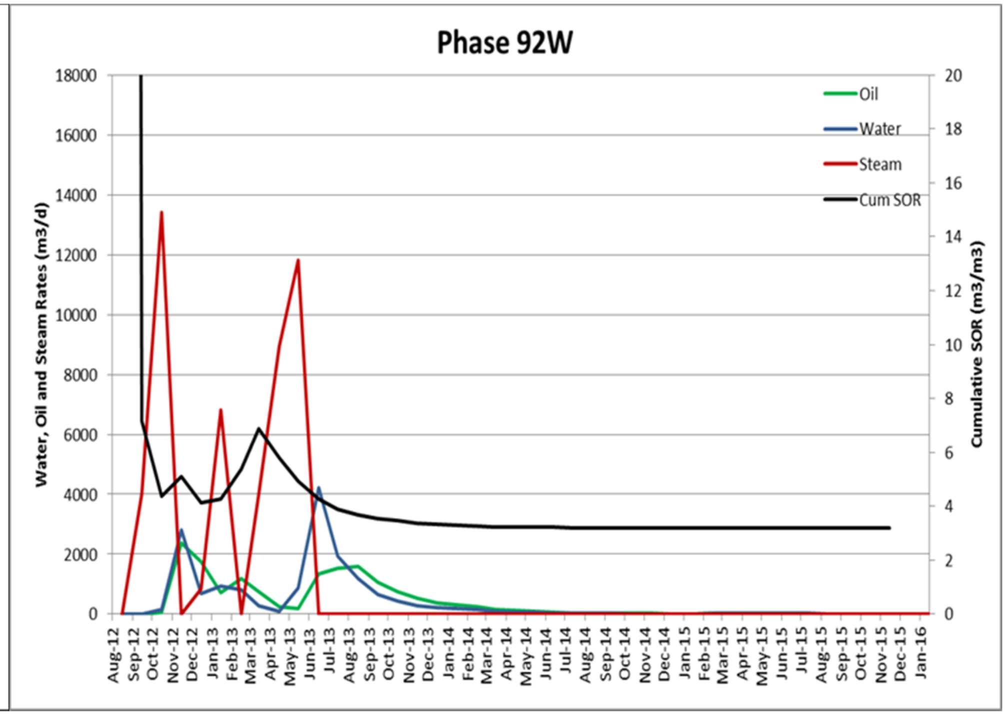
## Strategy and Spacing Optimization

- Improved thermal efficiency of steam with tighter well spacing and newest steam strategy



# Early Recovery – Phase 92W
# Type Curve & Production History



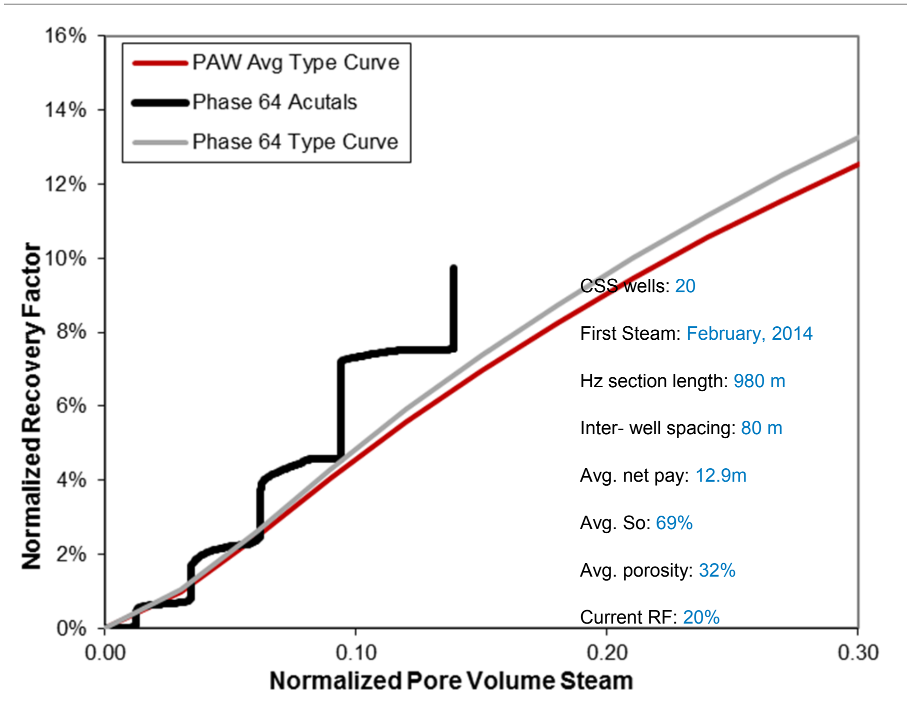

<u>**2015 Activity**</u>

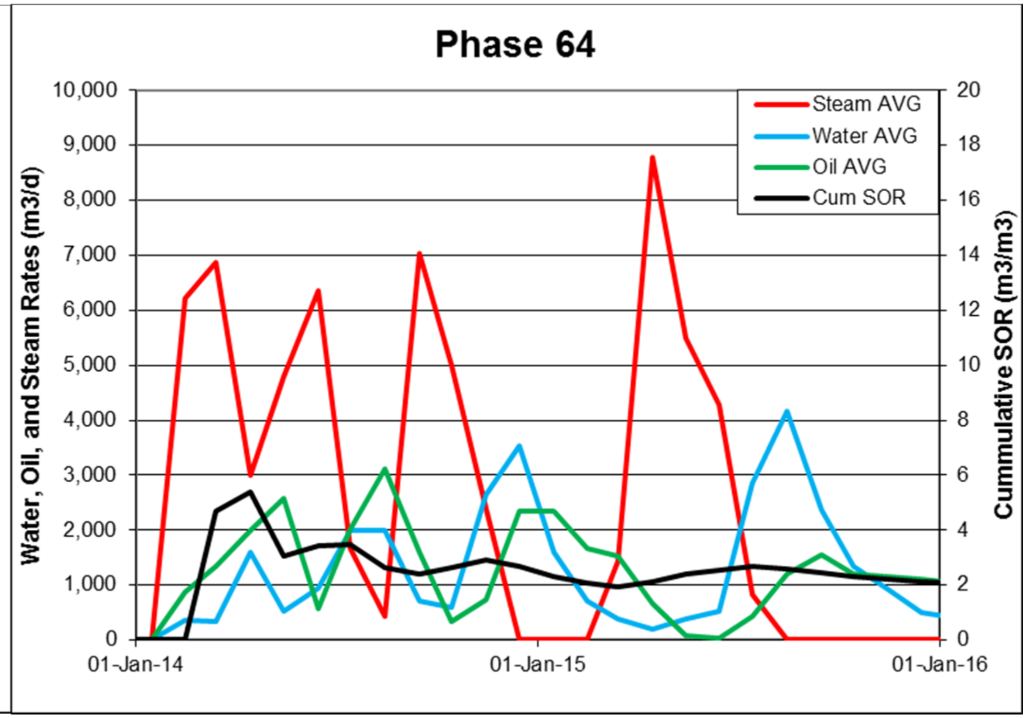
- **Pumped until end of CSS cycle. Currently shut in, too cold to produce.**
- **Application for sub-dilation pressure steam cycle submitted in March 2015.**

<u>**2016 Plan**</u>

- **Sub-dilation pressure steam cycle pending AER approval**
- **Early recovery requires further CSS cycles before any steamflood process can take place.**

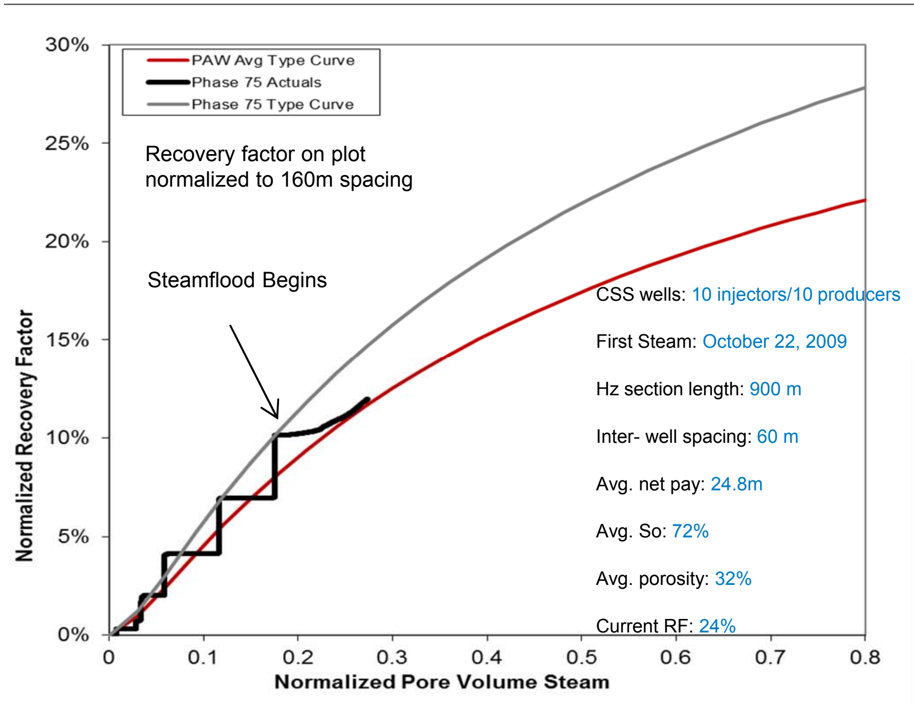
# Mid Recovery – Phase 64
# Type Curve & Production History

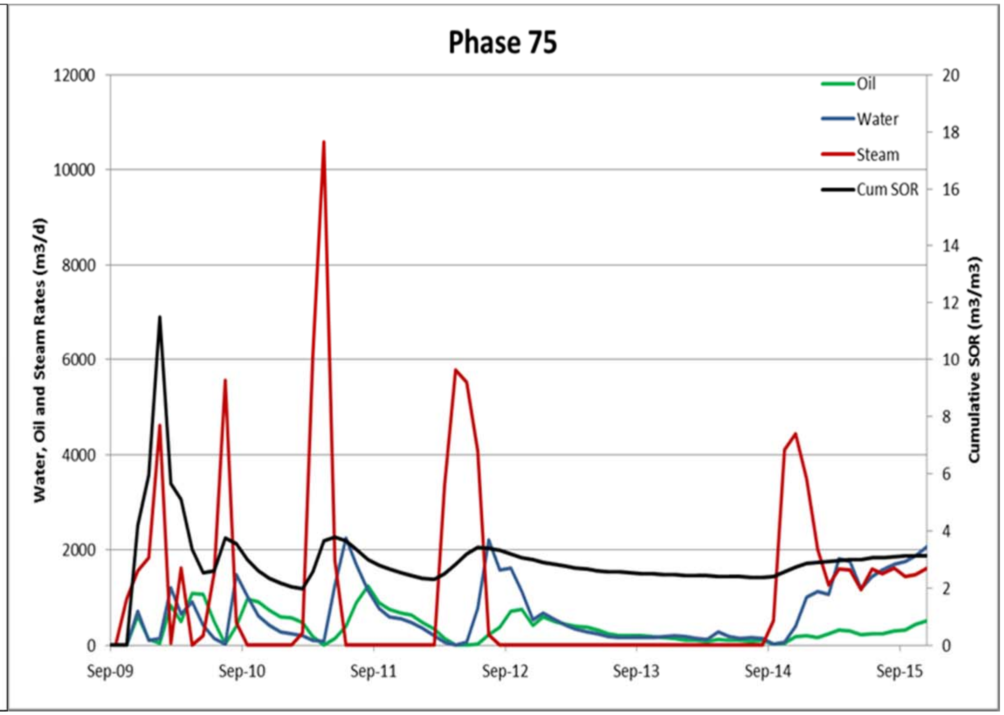



- 2015 Activity
  - Steamed Q1 – Q3 and currently pumping remainder of CSS cycle
  - Steamed in a wave fashion with pressure maintenance rows
  - Forest fire interrupted cycle in Q2 2015
- 2016 Plan
  - Will Receive steam in Q1 2016

# High Recovery – Phase 75
# Type Curve & Production History




**<u>2015 Activity</u>**

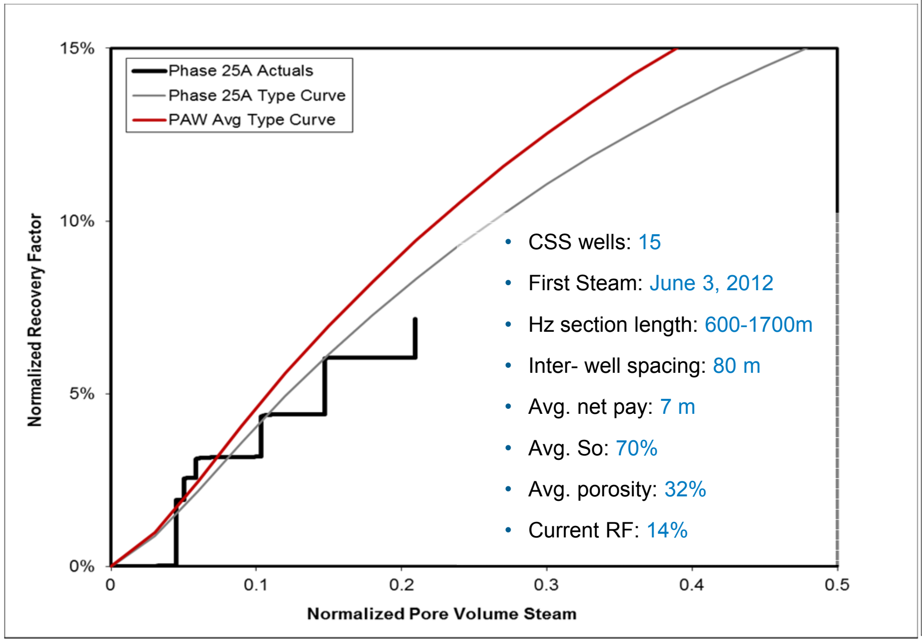
- **Steam chambers continued to develop and gross production optimized**
- **Increased pump sizes to shorten steam drive period**

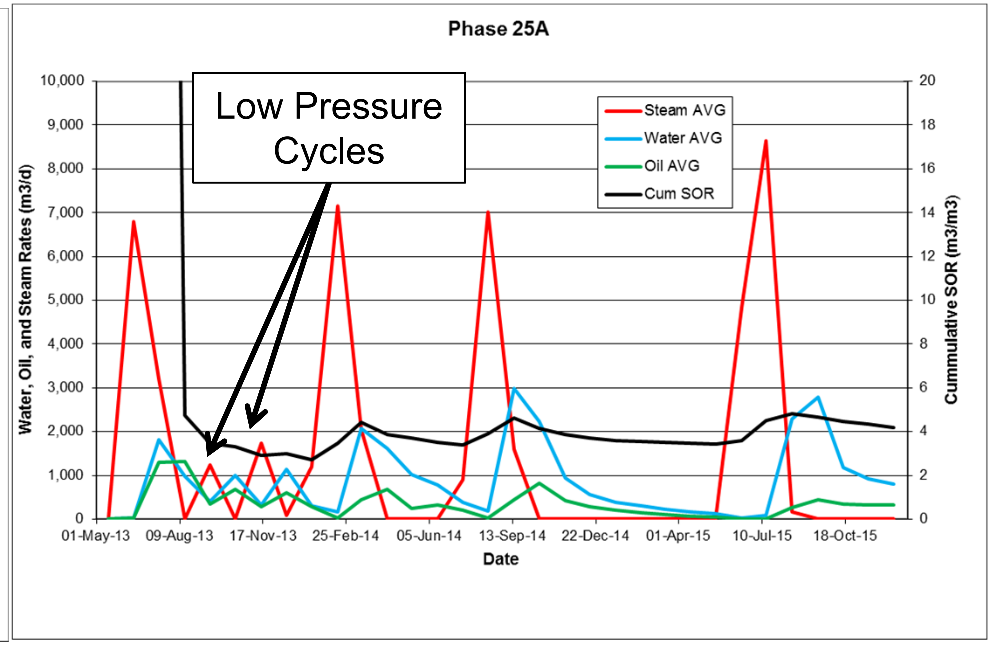
**<u>2016 Plan</u>**

- **Continue to remove production limitations**
- **Evaluate interwell longitudinal conformance and interventions**

# Phase 25-26
# Development Learning – Thin Pay Trial

Canadian Natural




Parameters in figure normalized to 160 meter spacing

<u>2015 Activity</u>

- Steamed Q2 - Performance is meeting type curve expectations in thin pay
- No evidence of thermal efficiency loss to under/overburden

<u>2016 Plan</u>

- Plan to steam Q3

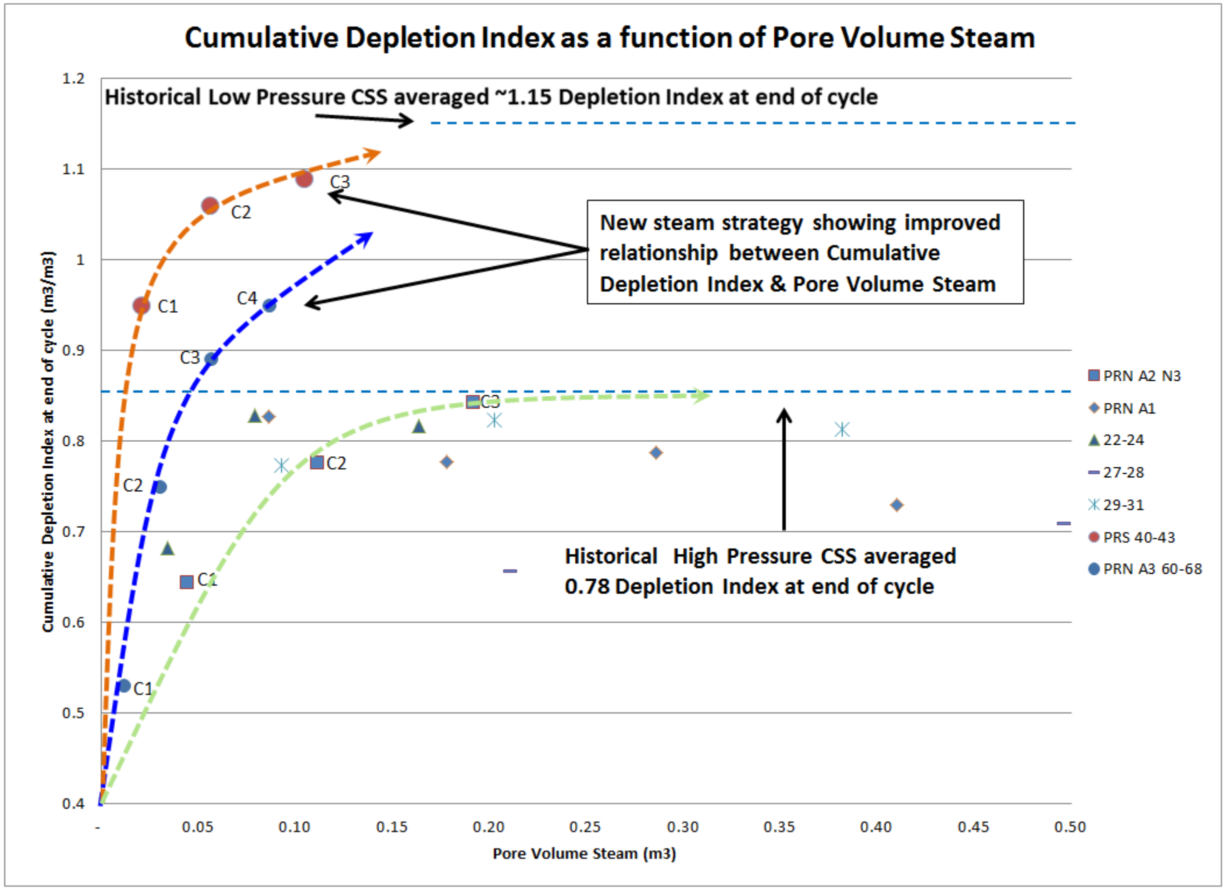
# 2015 Learnings - Enhanced Steaming Strategy

- Primrose North Area 3 (Phases 60,61,64,65 & 68) was the first area to utilize the enhanced steaming strategy from commissioning cycles onward
  - First area to receive new commissioning cycles
  - Above analogue performance from all phases
  - Fluid recovery exceeded analogs

- Primrose South Phases 40-43 is the second area to utilize the enhanced steaming strategy
  - Executed using the 60-68 learnings
  - Fluid recovery shows continued improvement indicating less fluid interaction with the Grand Rapids and lower fluid retention in the reservoir.
  - Steam schedule required flexibility as wave progressed and LGR interactions were identified

- Enhanced steaming strategy now being applied to all future steaming operations

# Enhanced Steaming Strategy
# Cumulative Fluid Recovery

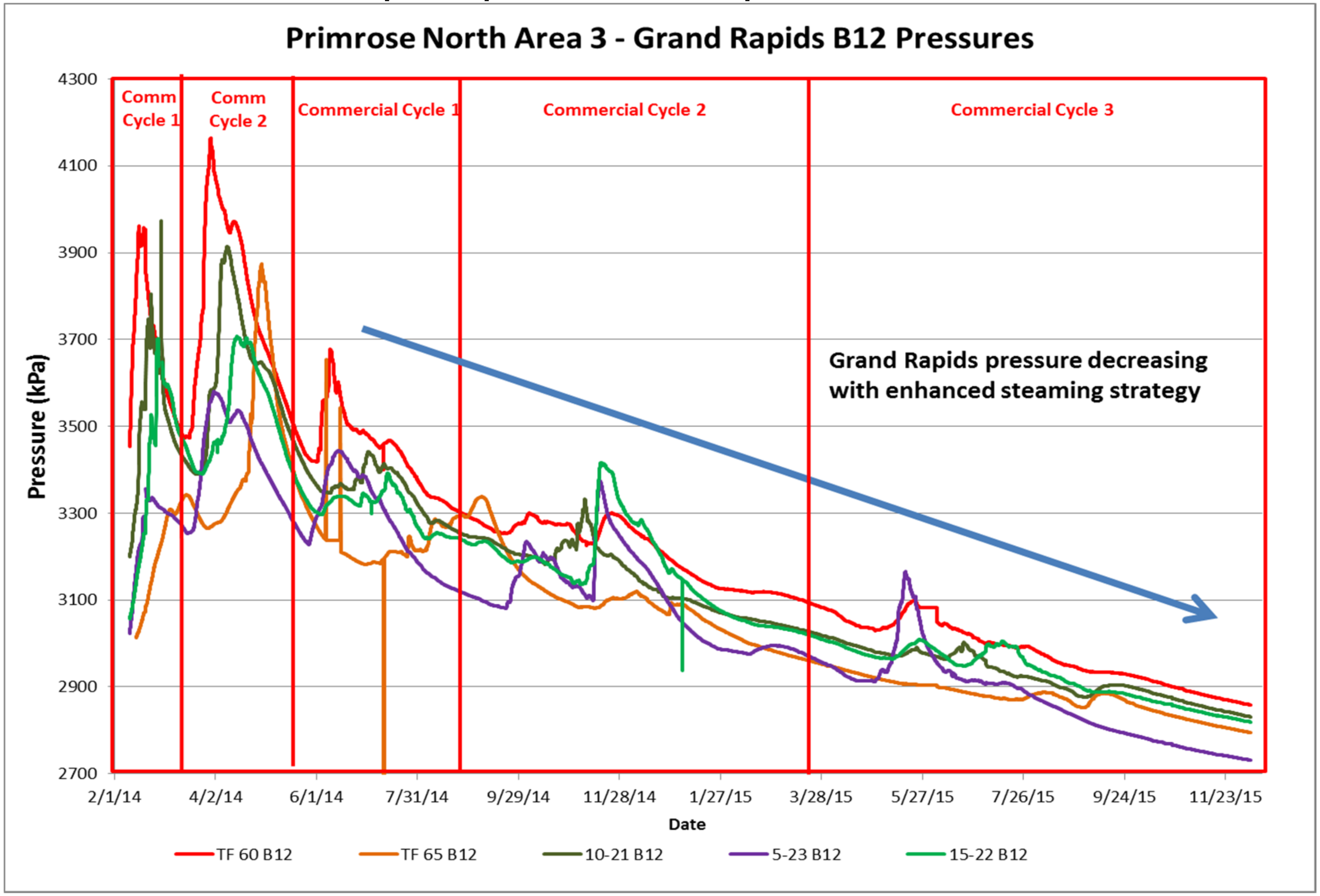



- Enhanced steam strategy (Orange and Blue) are showing continuous improvement in fluid recovery when compared to areas with large cycle to cycle steam volume growth (green)
- Relationship showing continuous improvement, cycle to cycle, using the enhanced steaming strategy
- Fluid recovery expected to continue to trend towards Low Pressure CSS analog (~1.15)

# Enhanced Steaming Strategy

## Primrose North Area 3 - Grand Rapids Impact

- Enhanced steam strategy is showing cycle to cycle improvements in the magnitude of Grand Rapids pressure response



# Enhanced Steaming Strategy
## Conclusions

- Enhanced Steaming Strategy showing improvements with fluid recovery and thermal efficiency
- Due to successful implementation of enhanced steaming strategy in Primrose North 60-68 and Primrose South 40-43 it has been adopted in all steaming areas
- Strategy continues to develop the understanding of fluid retention within the reservoir and the reduction of fluid interaction with the Grand Rapids

# Skin Damage Intervention

- Primrose and Wolf Lake wells are seeing production fall below forecasts due to Calcium Carbonate (CaCO3) scale forming near wellbore.
- Scale in PAW Clearwater:
  - Calcium used to create CaCO3 is found in Calcites and Dolomites through out the Clearwater.
  - CO2 is dissolved into solution to create carbonic acid.
  - Catalysts for this scale are: high Ph, high temp and pressure drop

$$Ca(HCO_3)_2(aq) \rightarrow CO_2(g) + H_2O(l) + CaCO_3(s)$$

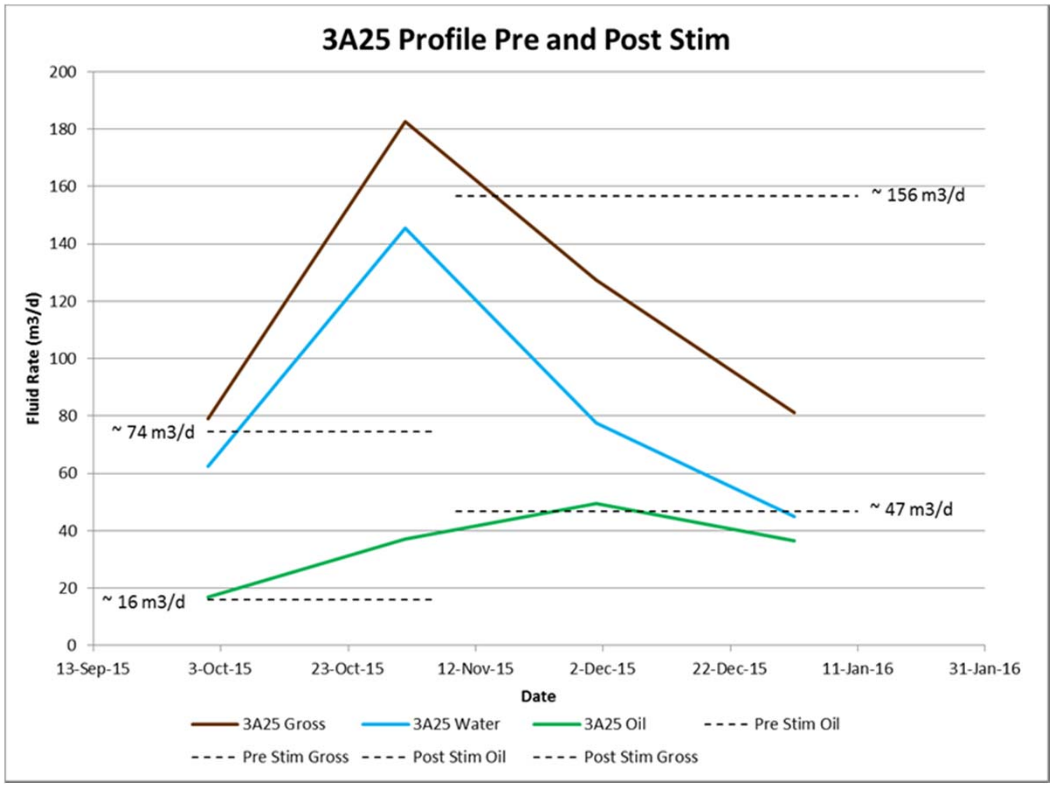
- The formation of scale confirmed by:
  - Performance below Gross vs DI expectations.
  - Pumping suppressions that indicate differential pressure across the liner.
  - Build up tests which indicate pressure differential across the liner.
  - Successful performance of acid jobs performed to date

# Skin Damage Treatment

- In 2015, 72 wells were treated for skin damage with acid stimulation via coil tubing or bullhead
- Stimulation returns must be brought on gradually to minimize plant issues such as water hardness which makes treating difficult
- Testing and studies are underway to prevent/ inhibit scale formation, minimize Wolf Lake Plant upsets, make jobs more cost effective and safer.
- The majority of all active steaming areas will receive acid stimulations to treat for scale

# Skin Damage Removal and Results

- With the scale being predominantly calcium carbonate, 15% hydrochloric acid is used with positive results
- Results are usually seen for several months after the treatment
- Overall profiles change and show oil accelerated into present time



# Primrose South
# An Example of Uneconomic Gas Conservation

Canadian Natural

- Pad AC18 was shut in August 2015 due to uneconomic gas conservation as a result of a failure with the vapor recovery unit.
- At current commodity pricing, the cost to repair the vapor recovery unit (VRU) is uneconomic.

| | |
|---|---|
| **Daily Gas Rate (m3/day)** | **2,000** |
| **Daily Oil Rate (m3/day)** | **4.75** |
| **Cost to Repair Gas Conservation Unit** | **$100,000** |

# 2016 Steam Schedules

Canadian Natural

## Primrose South

| Month | Steam Start Date | Steam Volume/Well (m3) |
|---|---|---|
| **Jan-16** | Phase 22-24 | 50,000 / 75,000 |
| **Feb-16** | ↓ | |
| **Mar-16** | Phase 15-16 | 44,000 / 24,000 |
| **Apr-16** | Phase 40-43 | 32,000 |
| **May-16** | ↓ | |
| **Jun-16** | ↓ | |
| **Jul-16** | ↓ | |
| **Aug-16** | Phase 25-26 | 32,000 |
| **Sep-16** | ↓ | |
| **Oct-16** | ↓ | |
| **Nov-16** | Phase 22-24 | 50,000 / 75,000 |
| **Dec-16** | ↓ | |

## Primrose North

| Month | Steam Start Date | Steam Volume/Well (m3) |
|---|---|---|
| Jan-16 | Phase 58, 62, 66 | 60,000 |
| Feb-16 | ↓ | |
| Mar-16 | Phase 60-68 | 42,000 |
| Apr-16 | ↓ | |
| May-16 | ↓ | |
| Jun-16 | ↓ | |
| Jul-16 | ↓ | |
| Aug-16 | Phase 59, 63, 67 | 80,000 |
| Sep-16 | ↓ | |
| Oct-16 | ↓ | |
| Nov-16 | ↓ | |
| Dec-16 | ↓ | |

## Primrose East

| Month | Steam Start Date | | | Steam Volume / Well (m3) |
|---|---|---|---|---|
| Jan-16 | Phase 74-78 | Phase 90-91 | | Steamflood (~400 CDSR), Cyclic Drive (30,000m3/well) |
| Feb-16 | ↓ | ↓ | | |
| Mar-16 | ↓ | ↓ | Phase 92-93 | 92-93 LPCSS (13,000m3/well) |
| Apr-16 | ↓ | | ↓ | |
| May-16 | ↓ | | | |
| Jun-16 | ↓ | | | |
| Jul-16 | ↓ | | Phase 92-93 | 92-93 LPCSS (15,000m3/well) |
| Aug-16 | ↓ | Phase 90-91 | ↓ | 90-91 Steamflood (~300 CDSR) |
| Sep-16 | ↓ | ↓ | | |
| Oct-16 | ↓ | ↓ | | |
| Nov-16 | ↓ | ↓ | Phase 92 | 92 Steamflood (~300 CDSR) |
| Dec-16 | ↓ | ↓ | ↓ | |

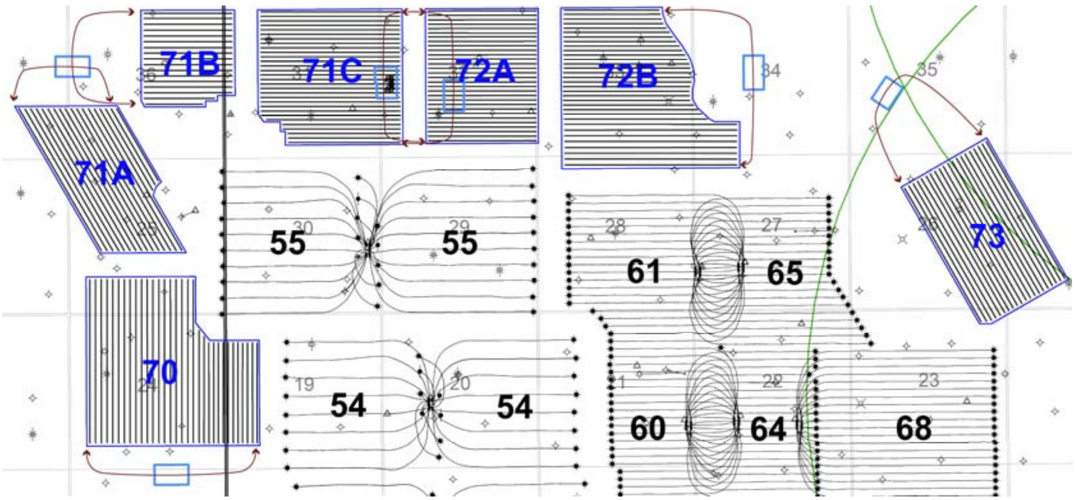
# FTS Update

- Continued monitoring on all sites
- Follow-up aerial and ground surveillance confirms there are no other FTS sites in Primrose
  - Annual surveillance program has been implemented
  - Latest aerial survey completed over October 25, 2015
  - No other FTS sites exist
- Final Report submitted March 31, 2015
  - SIRs submitted September 18, 2015
  - AER review of FTS report underway

# Primrose North Development

## Primrose North Area 4 (70-73)

- 7 CSS Phases on 6 pads with 20-33 wells/pad
  - 180 wells total
  - ~50-60 m well spacing
- 600 – 1,800 m laterals
- Steam wave injection volumes
  - Commissioning cycle 1 → ~10,000 m3/well
  - Commissioning cycle 2 → ~17,000 m3/well
  - Commercial cycle 1+ → limited by overburden uplift
- Project update and SIRs submitted September, 2015
  - Pending AER Approval



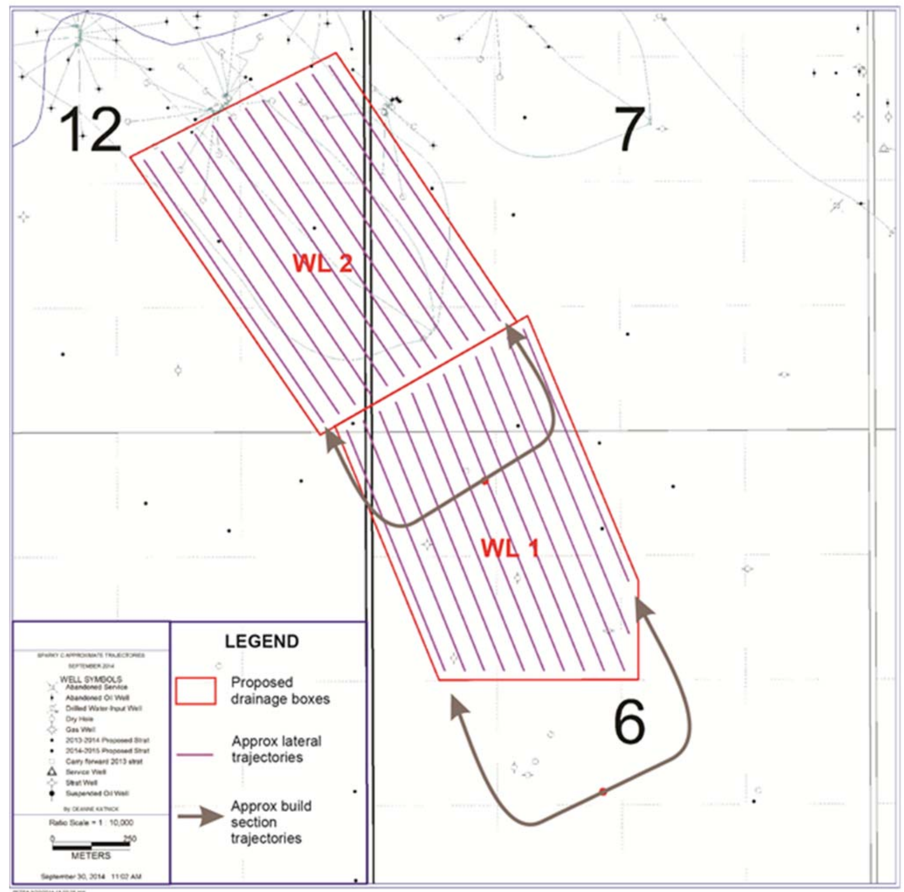
# Primrose South Development

- Primrose South Development – Proposed Application Date Q1/Q2 2016
  - Plan to apply for new phases with ~150 horizontal CSS wells in the Clearwater Formation; wells in Primrose South (67-5W4) would be steamed from PRS Plant

# Wolf Lake Grand Rapids Development

## Wolf Lake Sparky C (Pads WL1-2)

- 2 SAGD Phases with 12 well pairs/pad
  - 24 well pairs total
  - 60 m well spacing
- 800 – 1,150 m laterals
- Project update and SIRs to be submitted Q1 2016

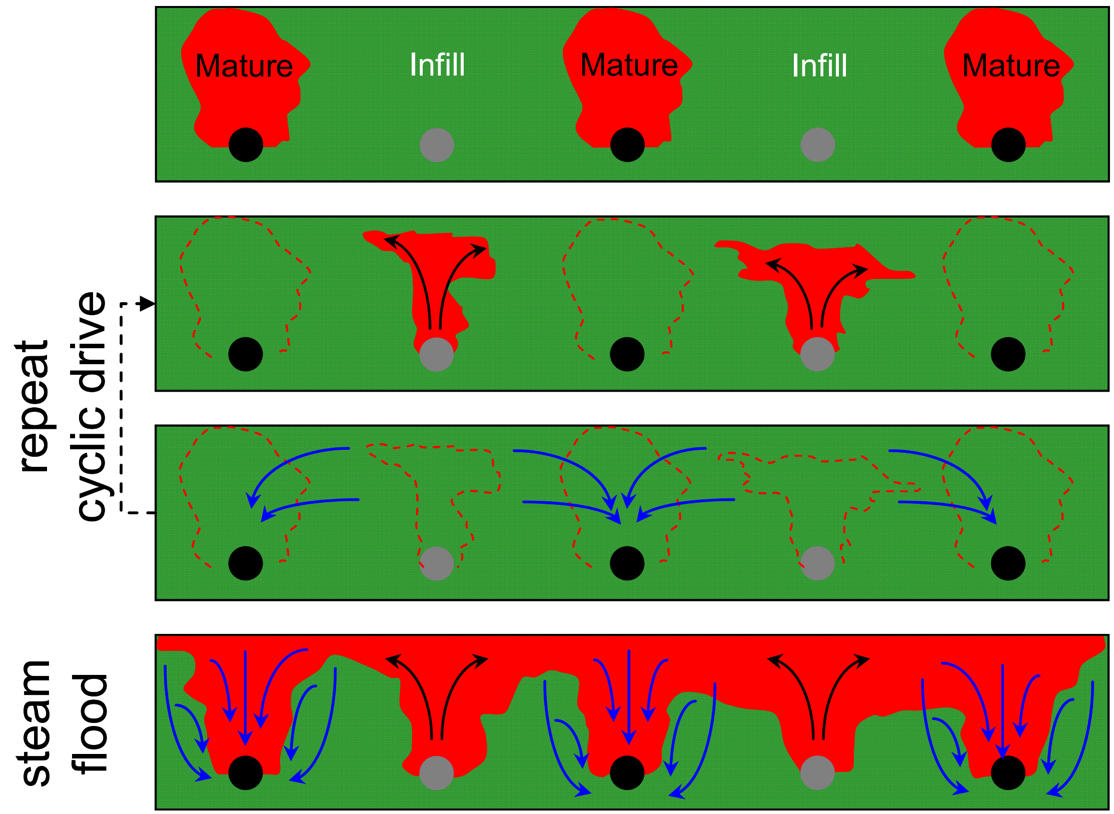


# CSS Summary

- Thin Pay
  - CSS continues to be a viable recovery method
    - Reservoir performance meeting expectations
  - Still in early life recovery, more cycles are planned
- PAW strategy change implemented to mitigate risk
  - Improved wellbore investigation and remediation
  - Enhanced steaming strategy
    - Good results for early cycle success to date, more data required
  - Increased Grand Rapids monitoring and more sensitive alarm criteria
- Skin damage
  - Evidence of skin damage throughout PAW
    - Early data suggests Calcium Carbonate
    - Successful remediation through %15 HCL stimulation

# FUP – Follow Up Process to CSS

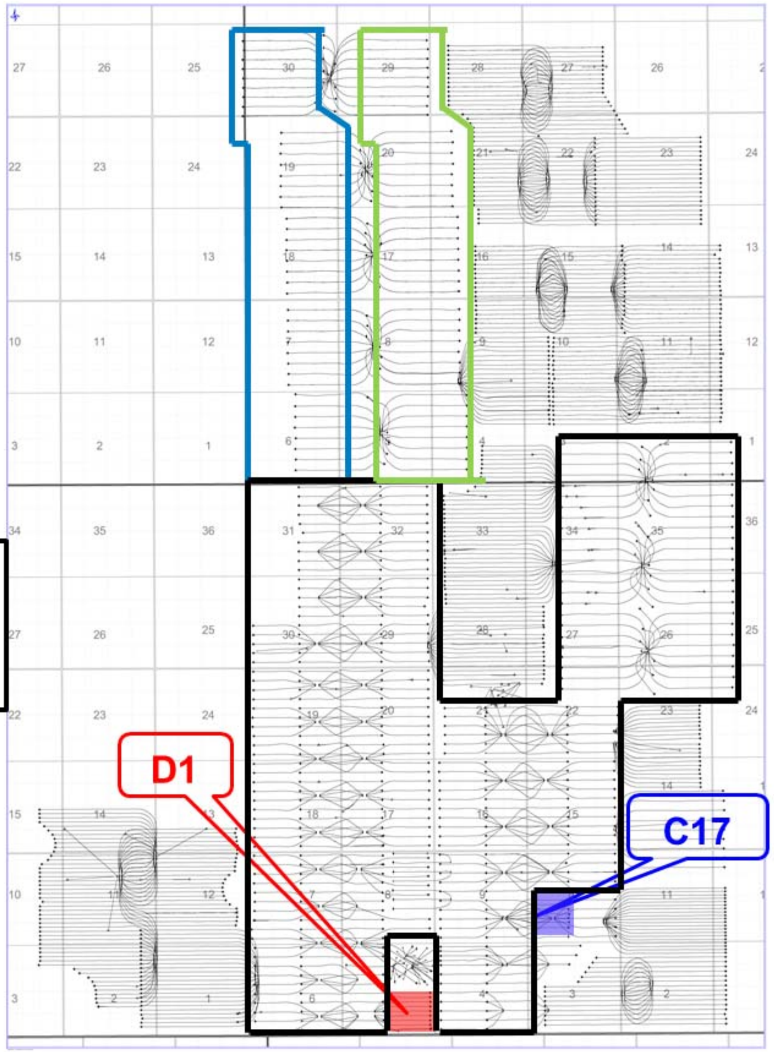
- Proposed FUP strategy is based on infill wells operated as dedicated injectors and mature wells operated as dedicated producers
- Repeated Cyclic Drive (CD) cycles at or below fracture pressure required to establish adequate inter-well communication and areal conformance; followed by Steamflood (SF)



# FUP - Infill Opportunities

PR-N
Ph 51-55

PR-S
Ph 1-21
Ph 29-31

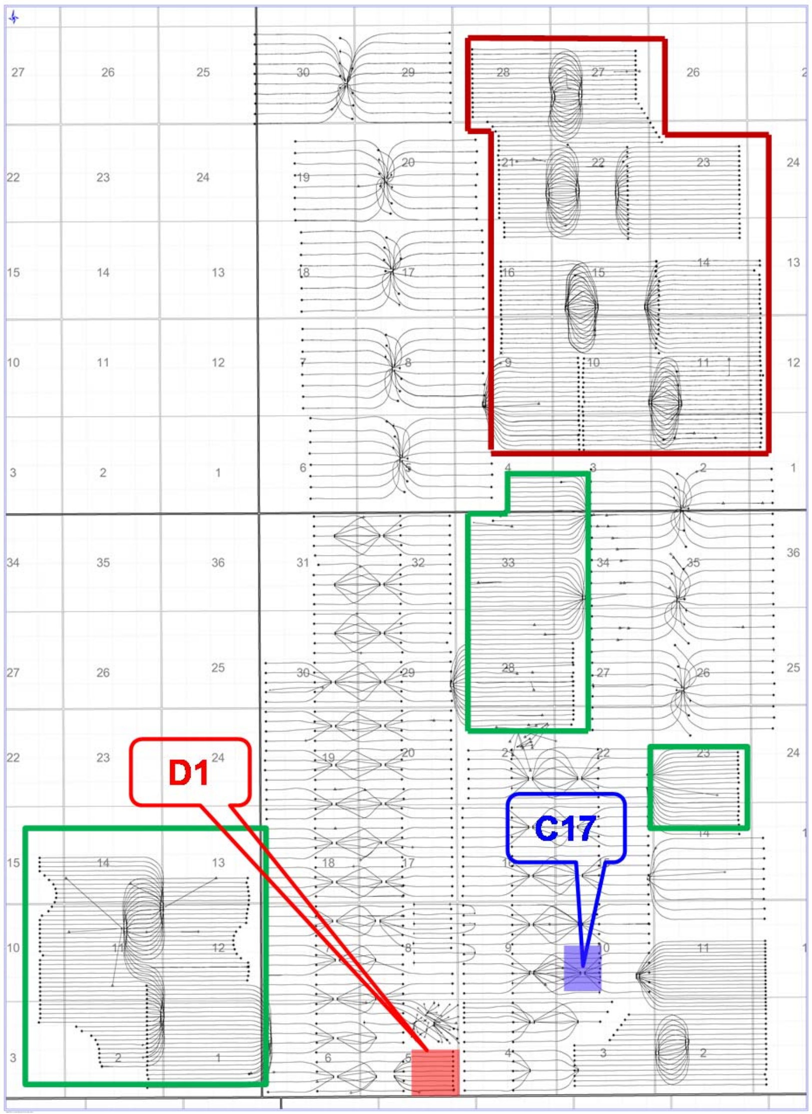



- For 160-188m spacing, FUP requires extensive infill drilling to reduce well spacing down to 80-94 m
- Field trials
  - C17: since 2007
- Targeting commercial application in Primrose South/North by 2021-2024
- PR-S Phases 1-21 OBIP ~675 MMbbl
  - Current average CSS RF ~17%
- Significant incremental recovery potential based on preliminary CD/SF performance forecasts
  - Predicting incremental recovery factors over 10%
  - Ultimate Ph1-21 CD/SF RF >35%

# FUP – Steamflood Conversion Opportunities

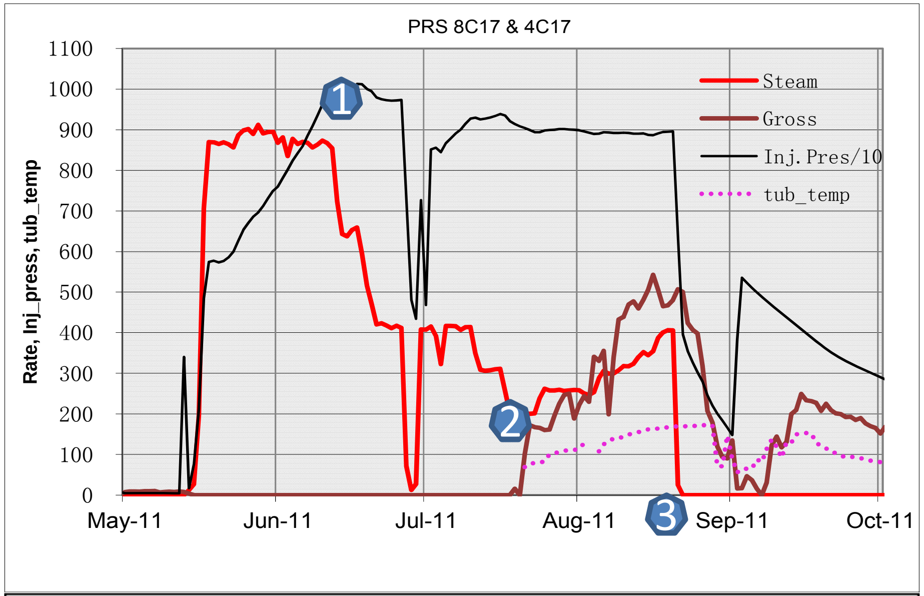
PR-N
Ph 58-68

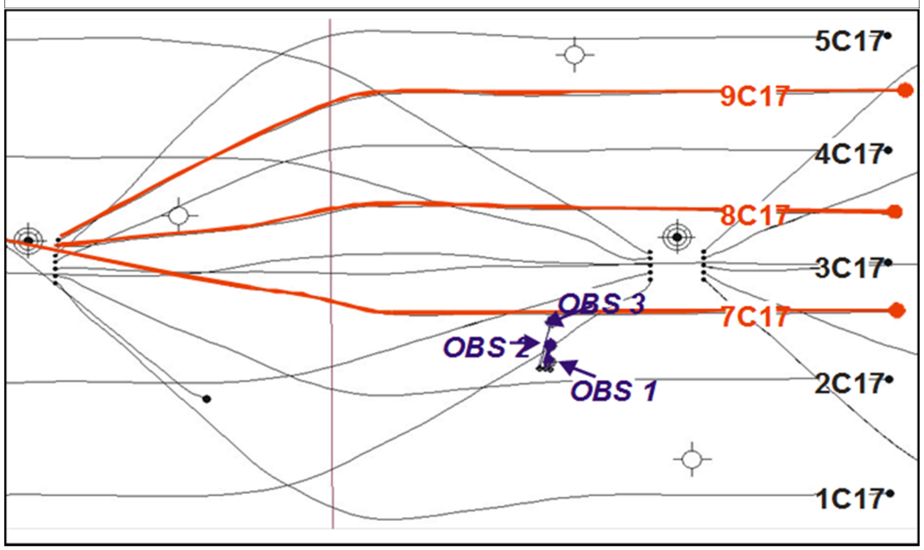
PR-S
Ph 22-24
Ph 28
Ph 40-43




- Developments with nominal 60-80m interwell spacing are expected to be able to convert directly from CSS to SF
- Field trials
  - D1: since 2012
  - PRE Area 1: since 2014
- PRE A2 currently being evaluated for steamflood conversion
- Targeting commercial application in Primrose South/North by 2021-2024

# C17 FUP Learning




- Opportunity to accelerate infill conversion to SF
- Simultaneous flowbacks and injection at pressures below the minimum in-situ stress

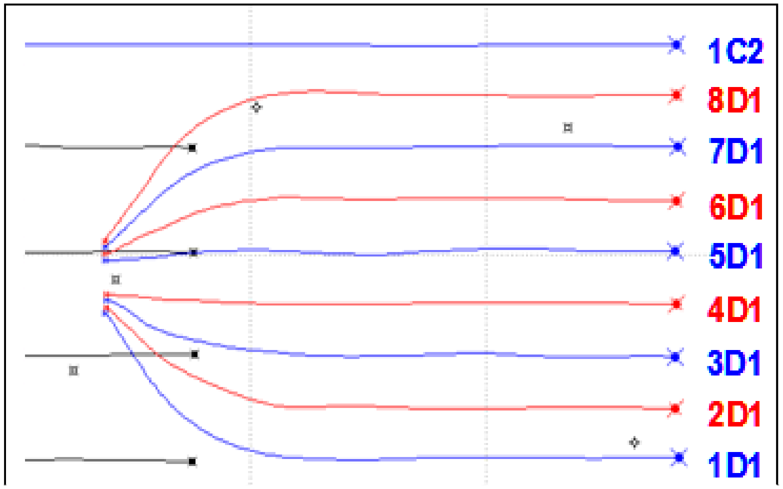
1) Fill up to a reservoir pressure of 9-10 MPa;
2) Start flowbacks
3) End steam injection

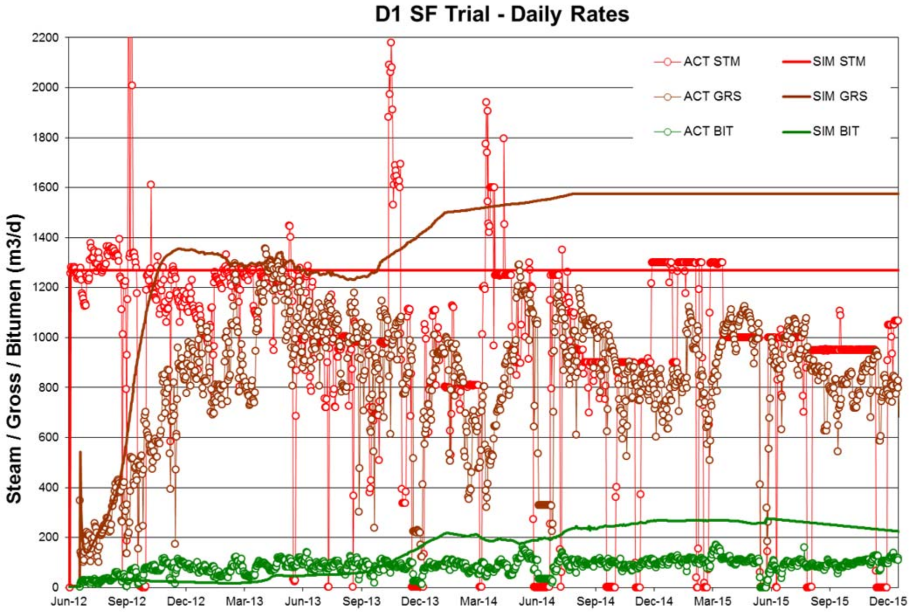
- Gross fluid increased to 500m3/d
- Steam increased to 400m3/d
- Flowing temperature increased to 180°C

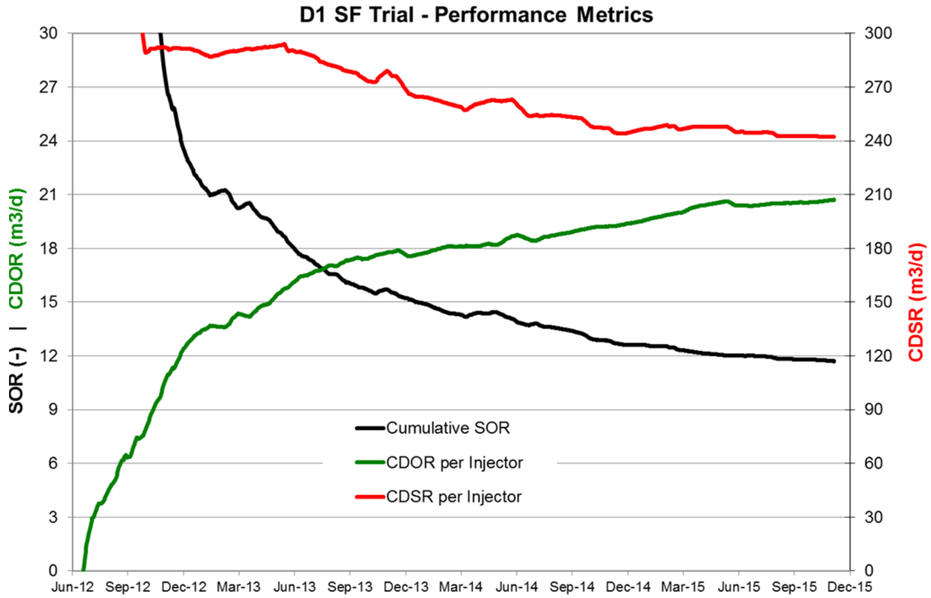
# FUP – Status of Steamflood Trial at D1

Canadian Natural

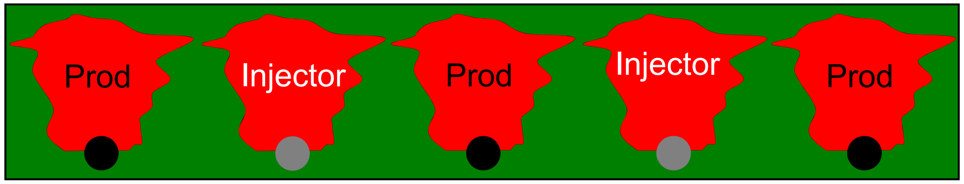
- Ongoing dedicated injection into 2/4/6/8D1 and dedicated production from 1/3/5/7D1+1C2 since June 2012
  - 7D1 experiencing sand production issues
  - 2015 performance still below simulation based expectations yet continuing to improve
  - Evaluating performance potential of increasing injector BHP from the current 0.9 MPa



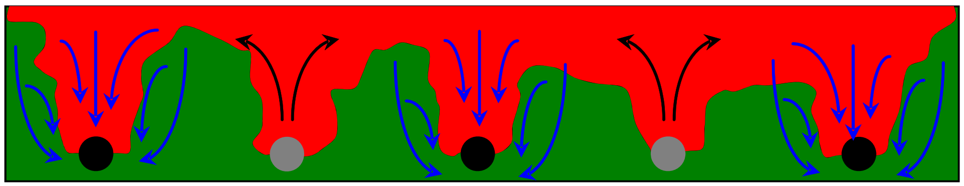



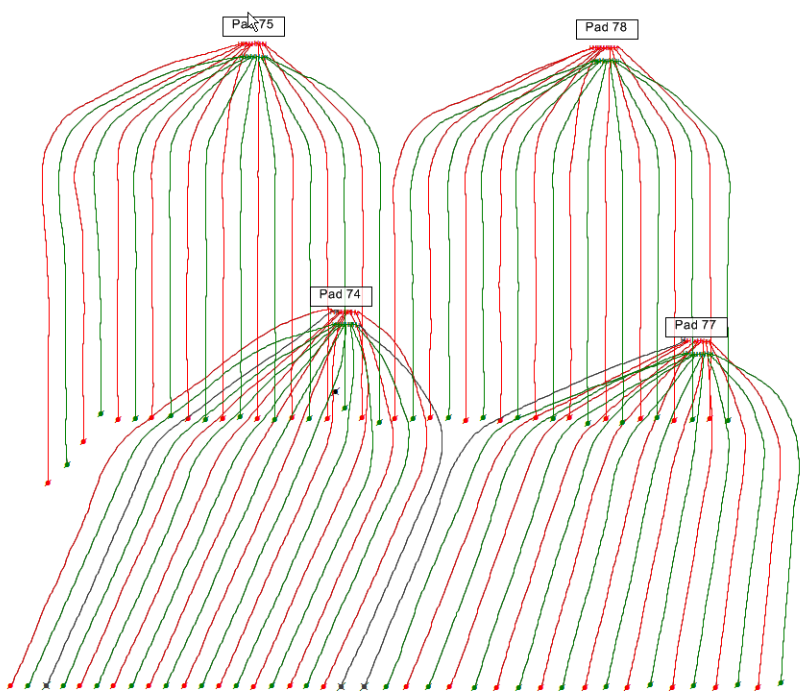



# Primrose East Area 1 Steamflood



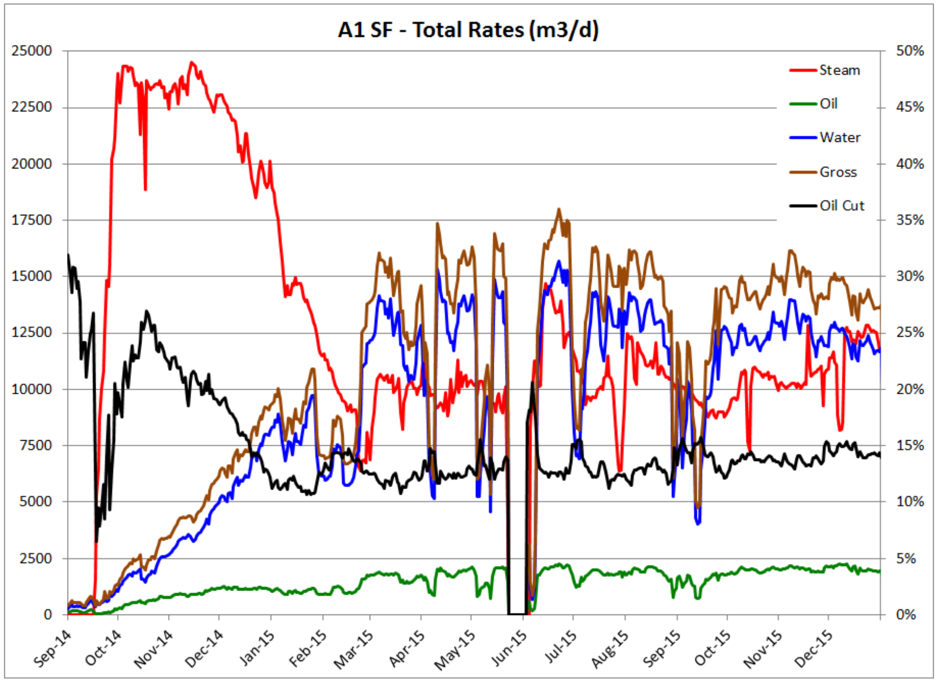

Remnants of interwell communication from last CSS cycle

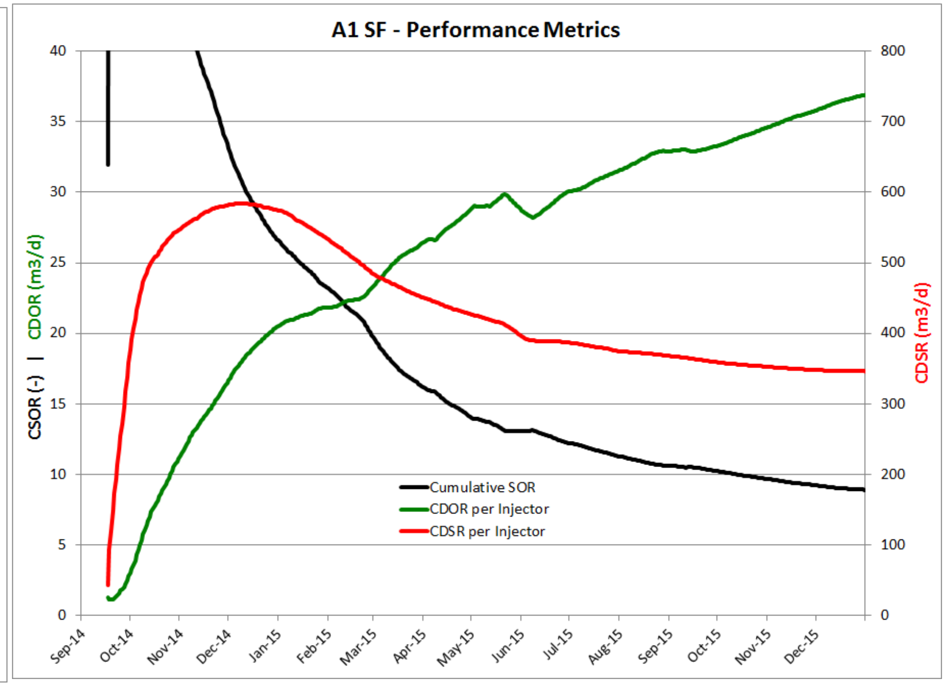





- Wells: 38 Injectors/39 Producers
- First Steam: Sept 17, 2014
- Hz section length: 900 m
- Inter- well-pair spacing: 60 m
- Avg. net pay: 23.8 m
- Avg. So: 71%
- Avg. porosity: 32%
- Current RF: 20.3%

# Primrose East Area 1 Steamflood




2015 Activity

- Currently 38 injectors / 39 producers, plan to add one more producer in 2016
- Increased pump size to shorten steam drive period
- Acid stimulations to remove skin restrictions
- Performed sand cleanouts to improve effective liner access

2016 Plan

- Continue to remove production limitations
- Evaluating interwell longitudinal conformance and interventions

# FUPS Summary

- D1 steamflood pilot continues to operate with a decreasing SOR and increasing CDOR
  - Currently evaluating options to improve performance
- PRE Area 1 steamflood has exceeded performance expectations to date
  - Acid stimulation program currently underway to address scaling issues on producing wells, leading to increases in CDSR and CDOR
  - Improving longitudinal conformance remains a fundamental challenge to be addressed in 2016
- PRE Phases 90-91 being evaluated for steamflood conversion opportunity

# Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this presentation constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansion, Septimus, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the proposed Energy East pipeline from Hardisty to Eastern Canada, and the construction and future operations of the North West Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

# Reporting Disclosures

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.  In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This document , herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2014 the Company retained Independent Qualified Reserves Evaluators (“IQREs”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2014 and a preparation date of February 2, 2015.  Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves.  GLJ evaluated the Horizon SCO reserves.  The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) requirements.  Reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report.

Resources Other Than Reserves

The contingent resources other than reserves (“resources”) estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101.  No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2014.  The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies.  There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.
gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards (“IFRS”) and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the “Net Earnings and Cash Flow from Operations” section of the Company’s MD&A. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of the Company’s MD&A.

Volumes shown are Company share before royalties unless otherwise stated.

THE PREMIUM VALUE.

DEFINED GROWTH.

INDEPENDENT.

Canadian Natural

PROVEN | EFFECTIVE | STRATEGY

Canadian Natural

# PRIMROSE, WOLF LAKE, AND BURNT LAKE DIRECTIVE 54 ANNUAL PRESENTATION

## SURFACE OPERATIONS, COMPLIANCE AND ISSUES NOT RELATED TO RESOURCE EVALUATION AND RECOVERY

January 2016

PREMIUM VALUE. DEFINED GROWTH. INDEPENDENT.

# Primrose, Wolf Lake, and Burnt Lake 2015 Annual Presentation to the AER

Directive 54: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

- January 27, 2016
  - 3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery
- January 28, 2016
  - 3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

# Outline - Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

# Outline - Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

Canadian Natural

# Primrose, Wolf Lake, and Burnt Lake Annual Directive 54 Presentation

| | |
|---|---|
| AEMERA | Alberta Environmental Monitoring Evaluation and Regulatory Agency |
| AER | Alberta Energy Regulator |
| ALMS | Alberta Lake Management Society |
| AGP | above-ground pipeline |
| AQHI | Alberta Quality Health Index |
| BFW | boiler feedwater |
| BRWA | Beaver River Watershed Alliance |
| BV | Bonneyville |
| BS&W | basic sediment and water |
| CAPP | Canadian Association of Petroleum Producers |
| CEMS | continuous emissions monitoring system |
| Cl | chlorine |
| CL | Cold Lake |
| CPF | central processing facility |
| CWE | cold water equivalent |
| DCS | Digital Control System |
| DDS | digital data submission |
| E3 | Empress 3 |
| EL | Ethal Lake |
| EPEA | Alberta Environmental Protection and Enhancement Act |
| Fm | Formation |
| FTS | flow to surface |
| GOR | gas oil ratio |
| ha | hectare |
| HEP | habitat enhancement program |
| HMI | human machine interface |
| kPa | kiloPascal |
| LICA | Lakeland Industrial and Community Association |
| LPCSS | low pressure cyclic steam stimulation |
| $m^3$ | cubic metre |
| $m^3/d$ | cubic metres per day |
| MARP | Measurement, Accounting & Reporting Plan |
| mg/l | milligrams per litre |
| ML | Muriel Lake |
| MPa | Mega Pascal |
| Mwh | Megawatt hour |
| NOx | oxides of nitrogen |
| Obs | observation |
| PEP | Primrose East Plant |
| PNP | Primrose North Plant |
| PSP | Primrose South Plant |
| PAW | Primrose and Wolf Lake |
| profac | proration factor |
| PW | produced water |
| QAP | Quality Assurance Program |
| $SO_2$ | sulphur dioxide |
| SR | Sand River |
| t/d | tonnes per day |
| tCO2e | tonnes of carbon dioxide equivalents |
| TDS | total dissolved solids |
| UWI | unique well identifier |
| VRU | vapour recovery unit |
| WDW | Water Disposal Well |
| WLP | Wolf Lake Plant |

# Facilities

- Detailed site survey plans - refer to included drawings:
  - Wolf Lake Plant plot plan
  - Primrose Plant plot plans (South, North, East)
  - Typical pad plot plan (Primrose East)
- Simplified plant schematic - refer to included drawings:
  - Wolf Lake / Primrose simplified plant facilities schematic
- Summary of modifications:
  - Wolf Lake Produced Water Debottleneck
  - Wolf Lake Unit 2 Desand Tank Replacement
    - Completed Project
  - Wolf Lake M2 Storage Pump
    - Additional pump for water storage

# Facilities

- Summary of modifications:
  - Disposal Pump Reliability Upgrade
    - New control valves
  - Wolf Lake U1 Building Improvements
  - Wolf Lake DCS Upgrades
    - U9 Completed
    - U1 Ongoing, to be completed by mid-2017
  - Burnt Lake HMI Upgrades
- Disposal pipeline challenges
  - Disposal pipeline to WDW 4/5 was de-rated
  - WDW 9 re-activated
    - New aboveground line constructed to WDW 9

# Specific Project Update

- Wolf Lake Produced Water Debottleneck
  - Phase 1 completed Q3 2015
  - Phase 2 in progress to be completed by June 2016
  - Phase 3 engineering ongoing
  - Future phases are being evaluated

# Wolf Lake CPF Performance

- Bitumen and water treatment
  - Overall water quality and oil treating targets were met:
    - Set produced water treating records
  - Successfully completed the following turnarounds:
    - Unit 10 - Oil treatment train turnaround
    - Unit 1 – Disposal tank outage
  - Treating challenges existed due to large number of wellbore acid stimulations
  - Experienced high disposal rates due to high produced water rates

# Facility Performance

- Power generation/consumption on a monthly basis

**Primrose and Wolf Lake - 2015 Power Generation and Consumption**

| Month | Power Generation MWh | Power Consumption MWh | Net MWh |
|---|---|---|---|
| January | 60,176 | 69,504 | -9,328 |
| February | 50,266 | 61,659 | -11,393 |
| March | 63,463 | 72,388 | -8,925 |
| April | 59,442 | 62,399 | -2,956 |
| May | 36,089 | 47,337 | -11,248 |
| June | 46,525 | 48,960 | -2,435 |
| July | 55,809 | 60,719 | -4,910 |
| August | 56,342 | 62,672 | -6,330 |
| September | 56,930 | 56,921 | 9 |
| October | 59,860 | 61,195 | -1,335 |
| November | 60,232 | 63,437 | -3,205 |
| December | 62,995 | 70,670 | -7,675 |

Sources:
Energy Components - Cogen Accounting Report 6, PSEP - Primrose Power Plant
Power consumption was taken from BPIMS CV4338 (Total CNRL Electrical Load) / EC CV4330

- Power is bought and or sold to the grid as the field electrical demand changes, generation level is constant
- Canadian Natural reports all power produced or consumed, and conducts an annual net settlement of power generated or consumed with the Alberta Utilities Commission (AUC)

# Facility Performance

- Gas Usage on a monthly basis

| | Total Purchased Gas | Total Solution Gas Conserved | Total Vented Gas | Total Solution Gas Flared | Solution Gas Conserved |
|---|---|---|---|---|---|
| Month | e3m3 | e3m3 | e3m3 | e3m3 | % |
| January | 118,522 | 20,396 | 1.0 | 115 | 99.4% |
| February | 107,063 | 19,478 | 0.5 | 68 | 99.7% |
| March | 129,409 | 22,164 | 1.4 | 136 | 99.4% |
| April | 104,506 | 18,374 | 1.8 | 39 | 99.8% |
| May | 76,205 | 14,773 | 1.1 | 150 | 99.0% |
| June | 89,878 | 13,630 | 6.1 | 238 | 98.3% |
| July | 109,491 | 21,300 | 2.7 | 178 | 99.2% |
| August | 115,008 | 21,080 | 1.2 | 127 | 99.4% |
| September | 104,596 | 19,218 | 1.8 | 108 | 99.4% |
| October | 111,598 | 19,570 | 1.5 | 85 | 99.6% |
| November | 111,198 | 19,420 | 0.3 | 74 | 99.6% |
| December | 111,398 | 11,040 | 1.8 | 43 | 99.6% |

*Total purchased gas does not include gas from site gas wells
*Solution gas flared volumes are corrected to remove purchased gas to flare
*Total gas vented includes brackish water associated vent gas
*Total Purchased Gas and Total Vented Gas for the month of December to be confirmed following Petrinex submission.

# Facility Performance

- Flaring & Solution Gas Conservation Compliance
  - All Primrose and Wolf Lake facilities are equipped for gas conservation except one pilot well, 15BM – granted exemption in 2004
  - New pads (since 2004) are built with VRUs or are linked to a neighboring pad's VRU

- Solution Gas Flare Volumes
  - Conserved 99.4% of total Primrose and Wolf Lake solution gas in 2015

- Facility Venting Compliance
  - No routine venting in the field
  - No routine venting at Primrose North, South or East plants
  - Vapour recovery on all major sources of solution gas at Wolf Lake

# Facilities – Greenhouse Gas Emissions

Canadian Natural

- PAW Greenhouse Gas Emissions

| Month | 2015 (tCO2e) |
|---|---|
| January | 284,610 |
| February | 259,580 |
| March | 311,020 |
| April | 253,360 |
| May | 189,130 |
| June | 213,890 |
| July | 268,760 |
| August | 279,650 |
| September | 254,610 |
| October | 269,040 |
| November | 268,420 |
| December | 268,730* |
| Year Total | 3,120,800 |

* Average of 2 previous months

# Measurement and Reporting

- Measurement, Accounting & Reporting Plan (MARP) for Wolf Lake / Primrose Thermal Bitumen Scheme Approved May 1st, 2007. Annual updates in March.

- Methods for estimating well production and injection volumes reported to Petrinex
  - Produced emulsion from the scheme is commingled at the battery. Bitumen and water production from the battery is prorated to each well using monthly proration test data and proration factors.
    - Total Battery Oil (Water) / Total Test Oil (Water) at Wells = Oil (Water) Proration Factor
    - Oil (Water) Proration Factor * Each Well Test Oil (Water) Volume = Oil (Water) Allocated to Each Well

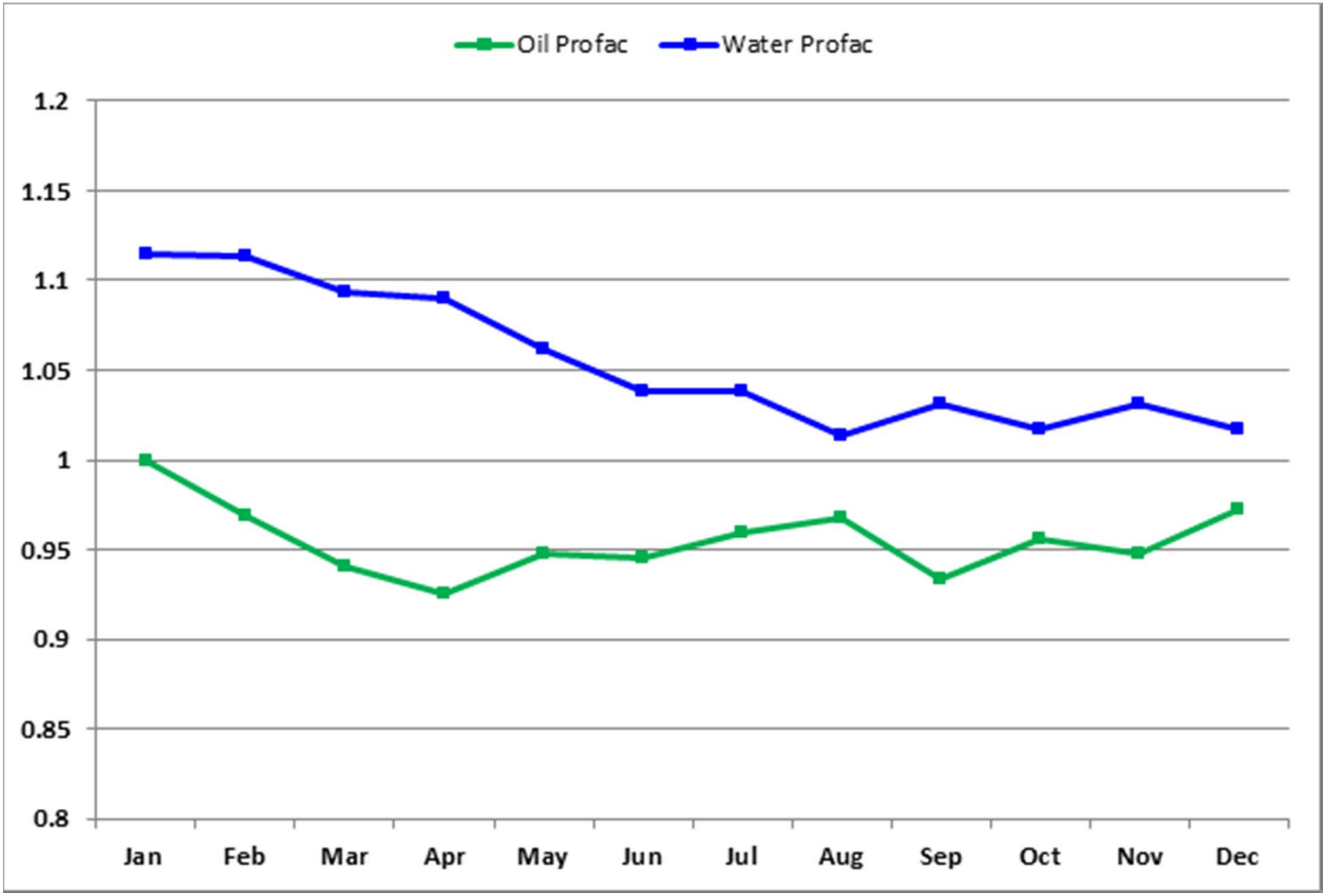
# Measurement and Reporting (con't)

- Gas allocated to each well is determined by GOR (gas oil ratio) for the battery
  - Total Solution Gas Produced / Total Battery Oil = Gas Oil Ratio
  - Gas Oil Ratio * Oil Allocated to Each Well = Gas Allocated to Each Well
- Injected volumes of steam and water are not estimated, they are continuously measured at wellhead
- Some pads have capability to take steam from Primrose South or Primrose North. Combined proration factor for both plants used for steam transfer volume estimation.

# Measurement and Reporting (con't)

- Test Durations
  - Canadian Natural field operations has identified the test durations, gross fluid rates and BS&W results required to obtain valid proration test data for each well
  - Most wells have 4 hour proration test durations; however some wells may be tested from 1 to 6 hours depending on their unique operating conditions and cycle maturity
  - Each well is tested each month and may be tested several times throughout the month

# Measurement and Reporting – Proration Factors



# Measurement and Reporting

- Profacs have significantly improved in 2015
  - Within ranges for all 2015
- Profac improvement projects completed in 2015:
  - Repaired 6 emulsion/boiler feedwater exchangers in Primrose steam plants
  - Meter programming improvements

# Water Production, Injection, and Uses

- Primrose & Wolf Lake Project Water Source Well UWI Listing

| Non-saline Water Source Wells | | Saline Water Source Wells | |
|---|---|---|---|
| Wolf Lake | Primrose* | Grand Rapids | McMurray |
| 1F1/12-10-066-05W4M (E3) | 1F1/10-05-067-04W4M (EL) | 102/10-08-066-05W4M | 1F1/11-06-067-03W4M |
| 1F2/12-10-066-05W4M (ML) | 1F1/14-05-067-04W4M (EL) | 102/05-16-066-05W4M | 1F1/16-12-067-04W4M |
| 1F1/ 06-10-066-05W4M (ML) | 1F2/15-05-067-04W4M (EL) | 104/05-16-066-05W4M | 1F1/11-05-067-03W4M |
| 1F2/06-10-066-05W4M (ML/E3) | 04-14-067-03W4M (BV) | 109/01-17-066-05W4M | 1F2/13-18-067-03W4M |
| 1F1/13-10-066-05W4M (ML) | NW 08-068-04W4M (EL) | 107/02-17-066-05W4M | 1F1/14-08-067-03W4M |
| 1F2/13-10-066-05W4M (E3) | NW 08-068-04W4M (EL) | 106/08-17-066-05W4M | 1F1/12-09-067-03W4M |
| 02-07-066-05 W4 (SR)** | 14-04-067-04 W4M (EL) | 107/08-17-066-05W4M | 1F2/12-09-067-03W4M |
| 06-08-066-5W4 (SR)** | 11-05-067-04 W4 (EL) | | 1F1/10-08-067-03W4M |
| | 10-05-067-04 W4 (EL) | | 1F1/02-12-067-03W4M |
| | 10-05-067-04 W4 (EL) | | 1F1/07-06-067-03W4M |
| | | | 1F1/16-06-067-03W4M |

* Primrose non-saline water wells are utility use only
** Wolf Lake utility wells

# Water Production, Injection, and Uses

- Water Uses:  Saline and non-saline
  - Saline water uses
    - Primary source of boiler feed water make-up supply
    - De-sand quench, filter backwash – ends up as boiler feedwater
  - Non-saline water uses
    - Utility water, utility steam, seal flush and gland water, slurry make-up, dilution water, filter backwash, quench water,
    - Water softener regenerations – recycled as boiler feedwater, or used as cavern wash
    - Boiler feedwater make-up as required from Wolf Lake water wells
    - Primrose water wells are utility use only
- Water Act Licences
  - Non-saline (Quaternary) groundwater monitored and reported as per Water Act licence requirements (one licence per plant)
  - 6 historical low-flow utility and domestic wells were licensed

# Water Production, Injection, and Uses

- Water Quality Assessment
  - Quaternary Water Source Wells (6) - Empress Unit 3 & Muriel Lake Formations
    - Average TDS = 569 mg/L
  - Grand Rapids Fm. Water Source Wells (7)
    - Average TDS = 9,721 mg/L
  - McMurray Fm. Water Source Wells (10)
    - Average TDS = 7,276 mg/L
  - Produced Water Quality
    - Typical parameters: TDS = 6,670 mg/L, Cl = 3,390 mg/L, pH 7.45, hardness = 163 mg/L

# Water Production, Injection, and Uses

Canadian Natural

- Non-saline, saline, produced and steam injection volumes

Primrose and Wolf Lake - 2015 Monthly Water and Steam Volumes

| Month | Surface Water [1] | Non-Saline Groundwater [2] | Saline Water [3] | Produced Water | Steam Injection | PW Recycled | PW Recycled Bulletin 2006-11 |
|---|---|---|---|---|---|---|---|
| | $m^3$/day | $m^3$/d | $m^3$/d | $m^3$/d | $m^3$/d | % | % |
| January | 690 | 2,934 | 11,626 | 57,889 | 65,778 | 97.1 | 186.0 |
| February | 732 | 3,216 | 18,753 | 49,278 | 64,539 | 98.9 | 146.5 |
| March | 679 | 3,756 | 26,421 | 45,828 | 71,525 | 98.8 | 155.1 |
| April | 1,197 | 2,200 | 9,630 | 56,745 | 64,344 | 92.4 | 160.6 |
| May | 865 | 2,191 | 10,936 | 38,041 | 45,750 | 72.2 | 177.7 |
| June | 766 | 2,135 | 12,597 | 46,082 | 53,180 | 86.2 | 171.6 |
| July | 715 | 2,384 | 9,347 | 57,362 | 65,973 | 96.2 | 129.4 |
| August | 922 | 2,520 | 12,527 | 59,107 | 68,975 | 94.1 | 92.4 |
| September | 918 | 2,494 | 6,367 | 59,588 | 62,344 | 93.6 | 102.6 |
| October | 855 | 2,455 | 5,448 | 60,161 | 63,056 | 94.8 | 145.7 |
| November | 987 | 2,494 | 11,572 | 50,206 | 62,747 | 99.7 | 126.7 |
| December | 713 | 2,893 | 15,305 | *54,606* | *70,532* | 99.8 | 120.7 |

Notes:
1. Surface water is effluent diversion from Cold Lake fish hatchery and surface water runoff
2. Non-saline ground water from Wolf Lake water source wells
3. Saline water is from McMurray and Grand Rapids aquifers
4. Blowdown recycle from Wolf Lake Steam Separator is 100%
5. December PW and Steam Injection rates to be confirmed

$$\text{PW Recycled} = \frac{(\text{Total PW - PW to Disposal})}{\text{Total PW}}$$

# Water Production, Injection, and Uses

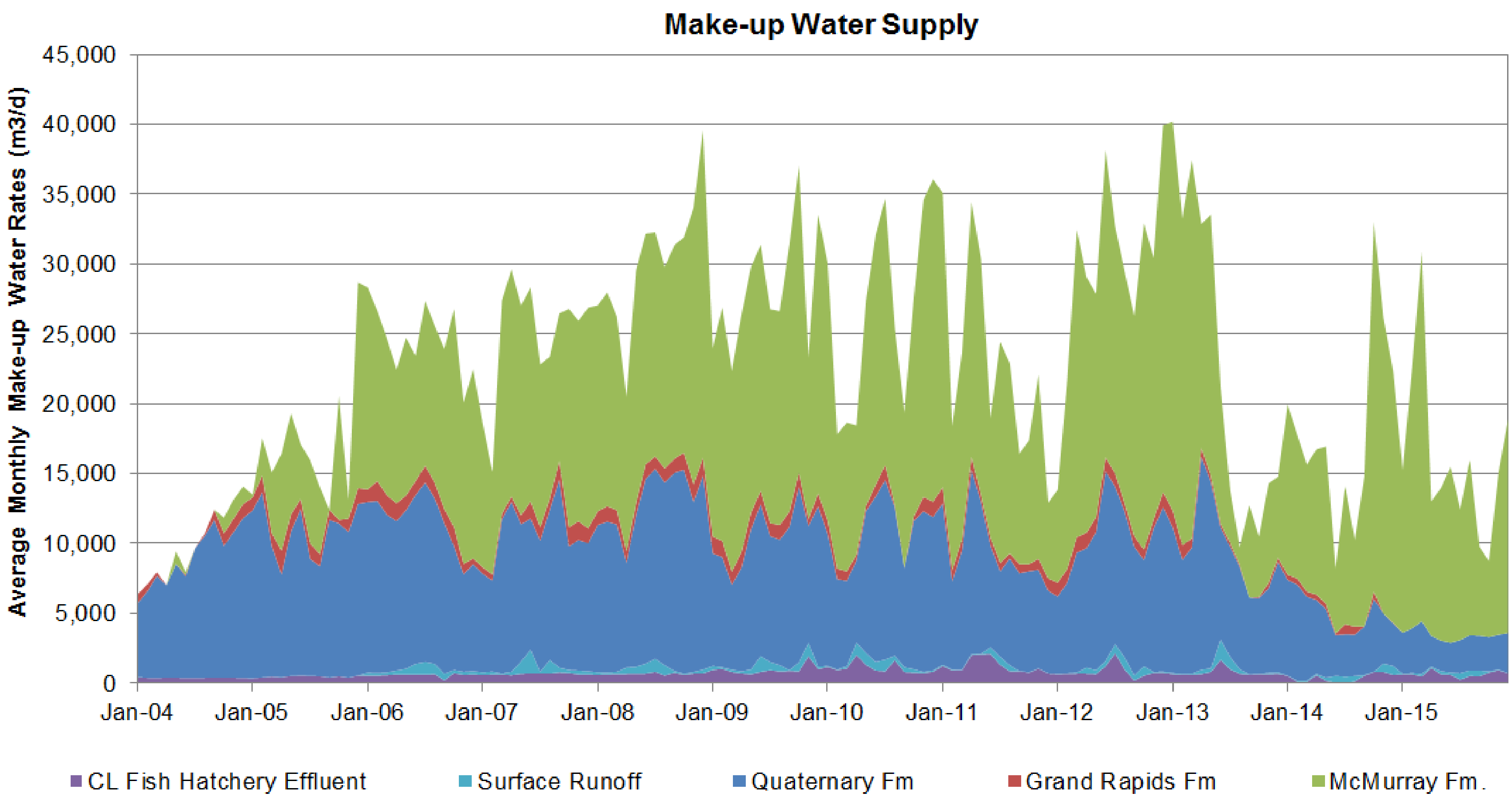
McMurray Saline Water – Avg. 12,520 m$^3$/d

Grand Rapids Saline Water – Avg. 0 m$^3$/d

Quaternary Non-saline Water – Avg. 2,640 m$^3$/d

Cold Lake Fish Hatchery Effluent – Avg. 653 m$^3$/d

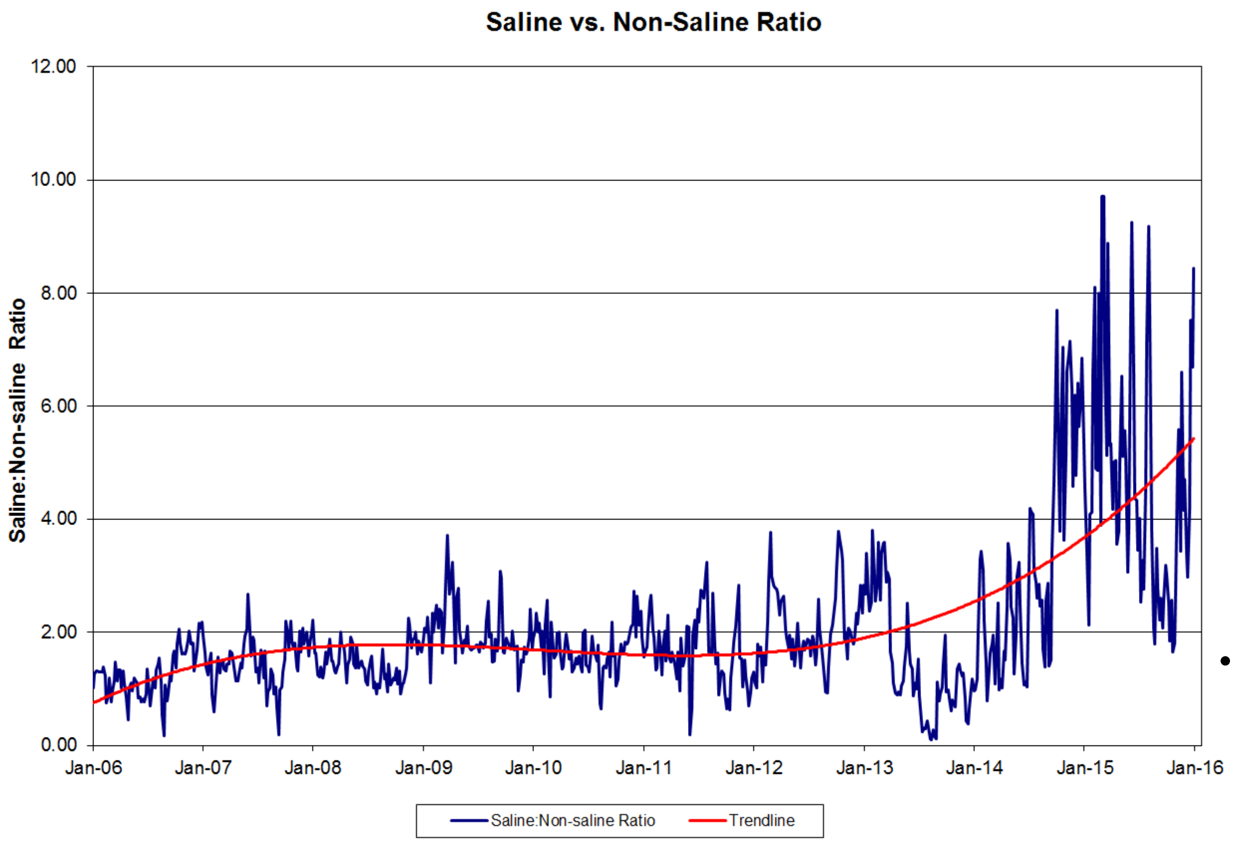
Plant Runoff Water – Avg. 183 m$^3$/d




- No runoff data before 2006

# Water Production, Injection, and Uses

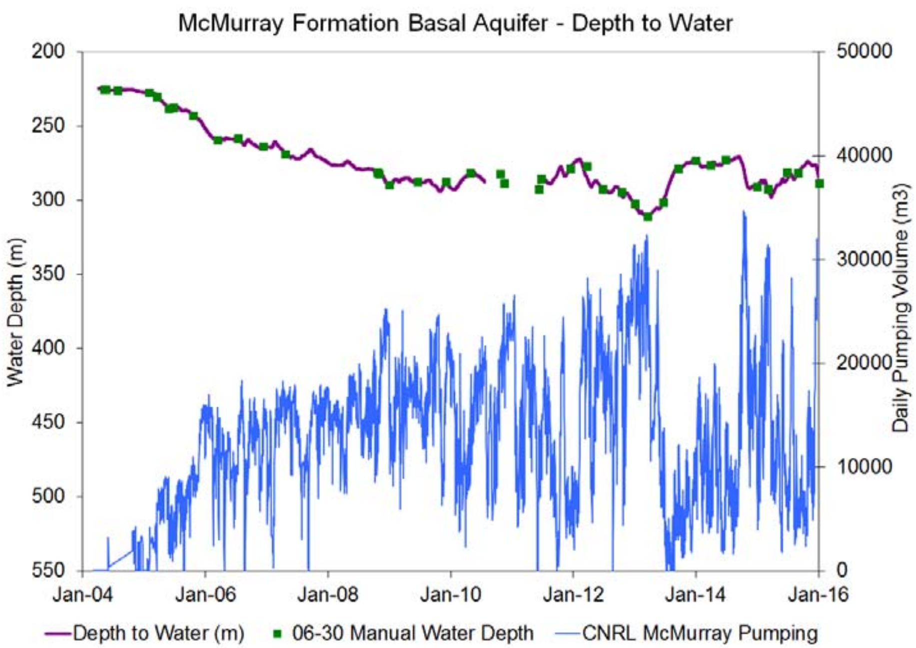
- Improved Saline to Non-Saline Groundwater Ratio
  - Saline to non-saline ratio increased from 1.5 (2014) to >4.5 in 2015
  - Non-saline decreased by almost 2000 $m^3$ in 2015 (2,640 vs 4,500 $m^3$/d in 2014)
  - Saline usage similar to 2014 (12,520 vs. 12,878 $m^3$/d in 2014)

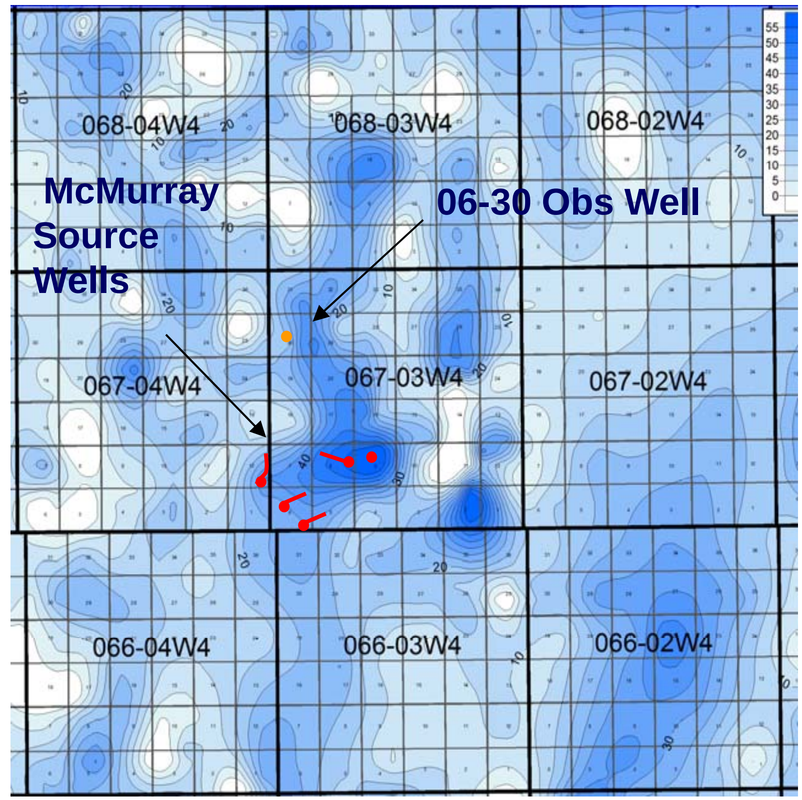



- Excludes Cold Lake Fish Hatchery Effluent Volumes

# McMurray Saline Water Supply – Existing

- Producing wells
  - 4 horizontal and 6 vertical wells
- 2015 production
  - average – 12,520 $m^3/d$
  - maximum – 32,042 $m^3/d$
- Drawdown of 63 m in 6-30 obs well




McMurray Formation Basal Aquifer Isopach Map

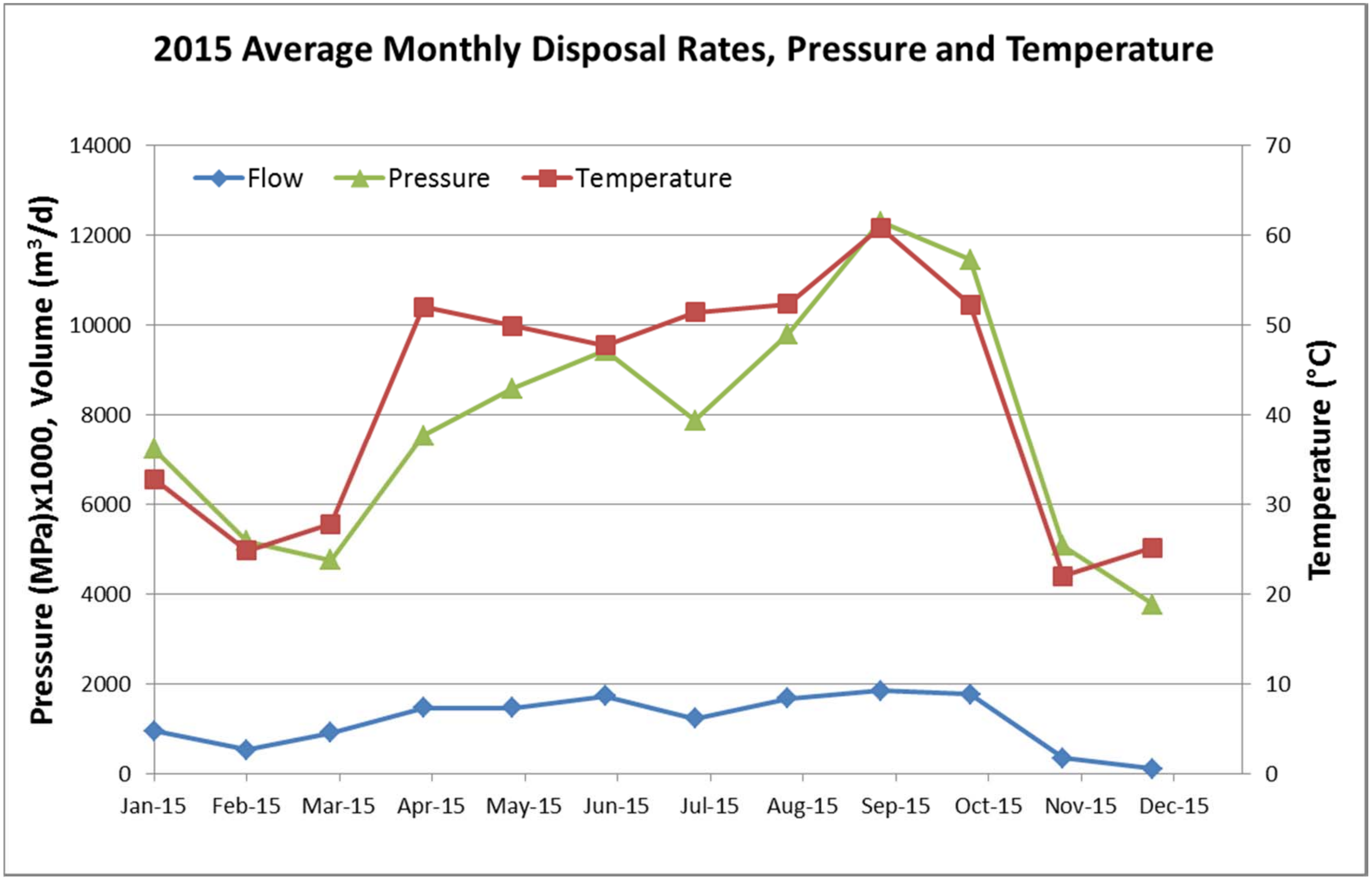
# Water & Waste Disposal Wells, Landfill Waste UWI List & Disposal Compliance

- Primrose & Wolf Lake Project Disposal Water Well UWI Listing
  - Wells shown in bold are active, (Wolf Lake - WDW#1 is being considered for reactivation)

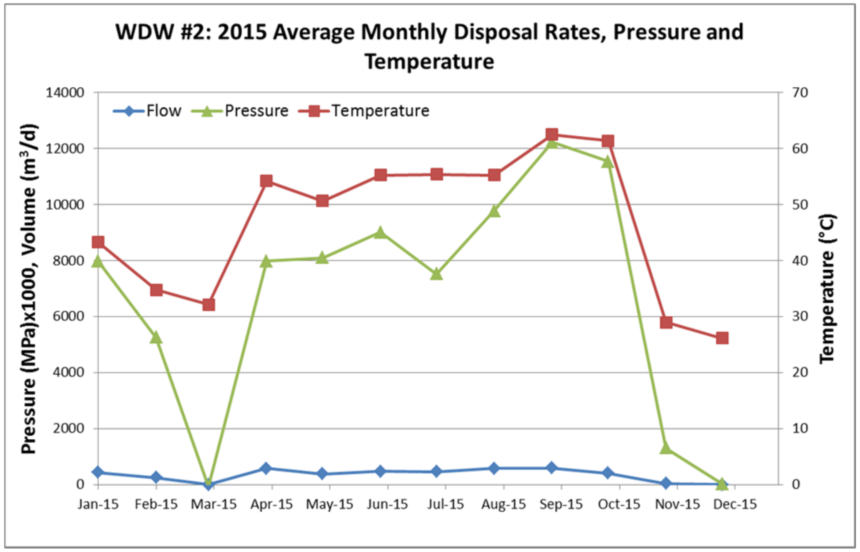
| Wolf Lake | | Primrose South | | Primrose East | |
|---|---|---|---|---|---|
| Well | Formation | Well | Formation | Well | Formation |
| *WDW#1 - 100/09-08-066-05W4/00* | *Mid Cambrian* | **103/10-05-067-04W4/00** | **McMurray** | *100/03-11-067-03W4/00* | *McMurray* |
| **WDW#2 - 100/10-08-066-05W4/00** | **Mid Cambrian** | | | **1F1/11-02-067-03W4/00** | **McMurray** |
| **WDW#4 - 100/05-08-066-05W4/00** | **Mid Cambrian** | | | | |
| **WDW#5 - 100/15-07-066-05W4/00** | **Mid Cambrian** | | | | |
| **WDW#9 - 100/14-05-066-05W4/00** | **Mid Cambrian** | | | | |

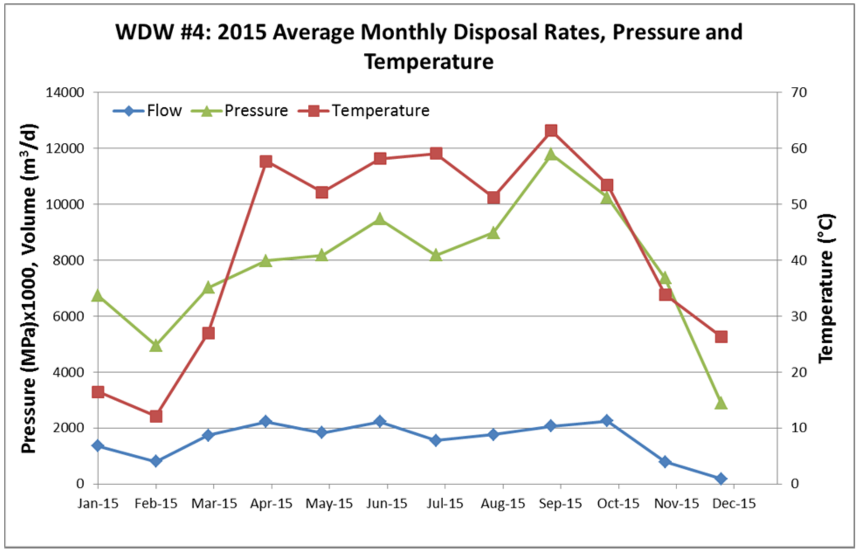
- Wolf Lake (WDW #2, 4, 5 & 9)
  - WDW#9 was re-activated.
- Primrose South
  - Injected 0 $m^3$ fluid in 2015.
- Primrose East
  - 11-2 continued discussions regarding potential abandonment options with AER.

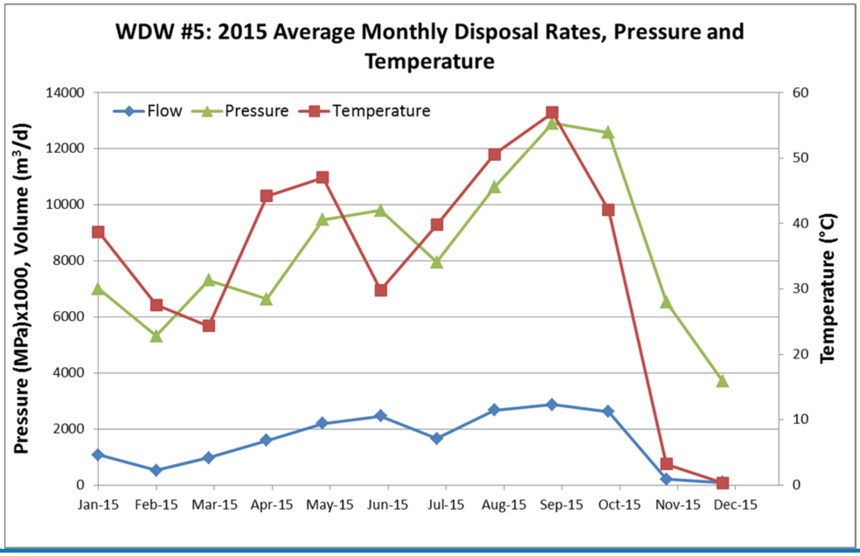
# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Disposal Volumes

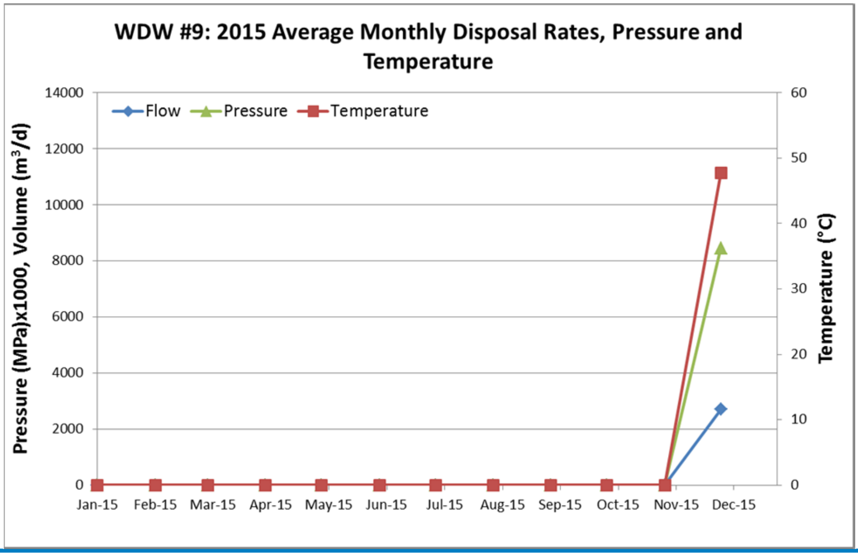


# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Disposal Volumes



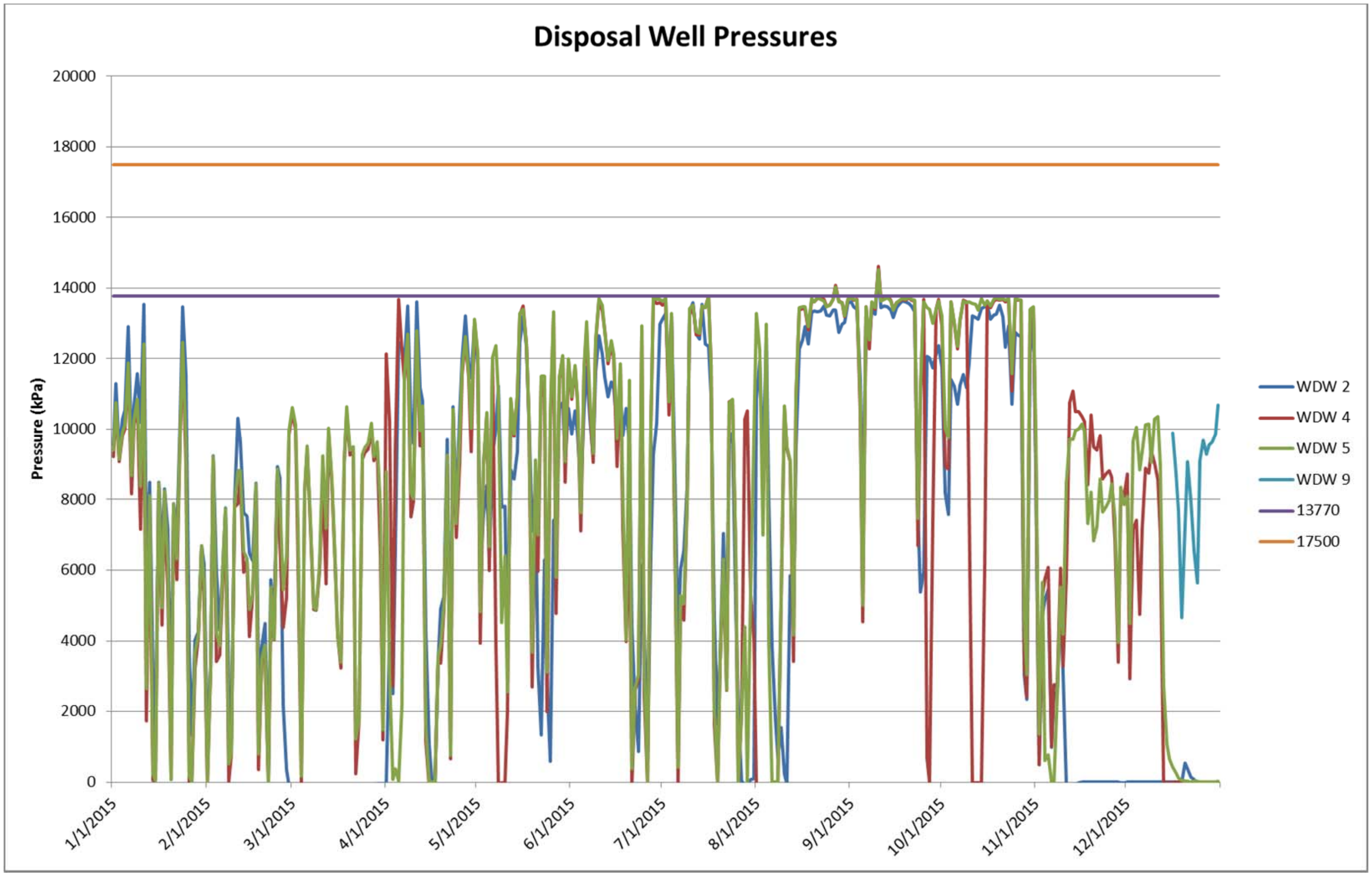



# Wolf Lake Disposal Well Pressures

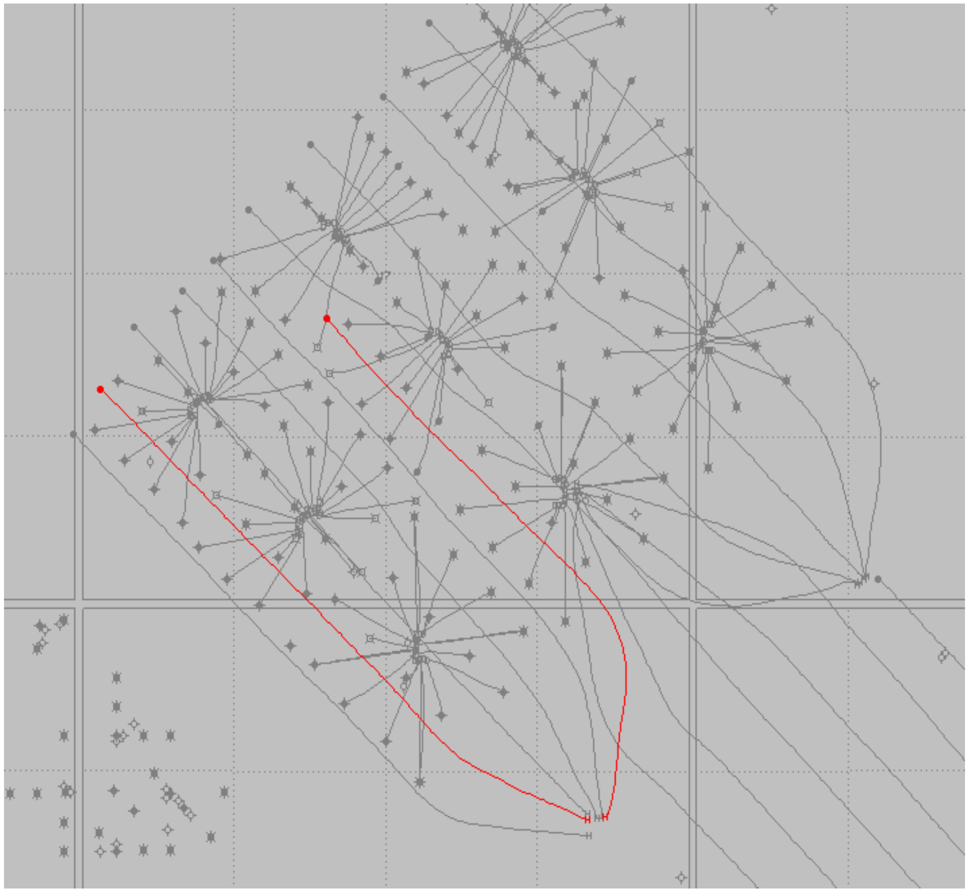
- Wolf Lake disposal well pressures (WDW #2, 4, 5 & 9)
  - Pressures did not exceed 17,500 kPa in 2015
  - Pressures exceeded 13,770 kPa during a step rate testing in September for a duration < 24 hr



# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Water Storage

Canadian Natural

- Water is stored in the C3 Formation
  - Converted two wells to injectors in June 2003
- Injected 697,111 m$^3$ total
  - 323,591 m$^3$ to M2-S
    - 56,069 m$^3$ in 2015
  - 373,5201 m$^3$ to M2-E
    - 51,788 m$^3$ in 2015
- M2-E and M2-S are currently configured for summer operations



# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Water Storage Volumes

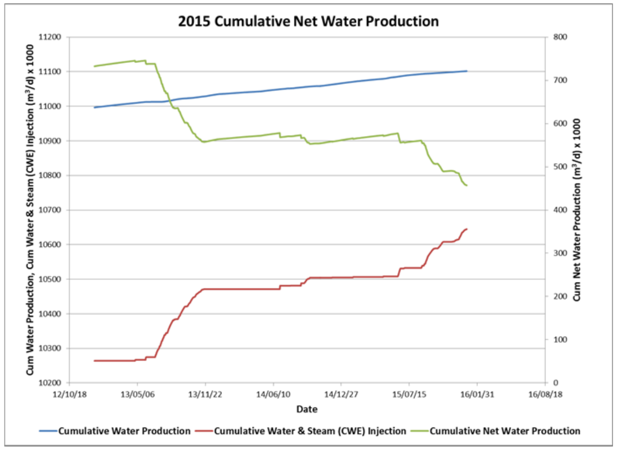
- Wolf Lake Water Storage Volumes

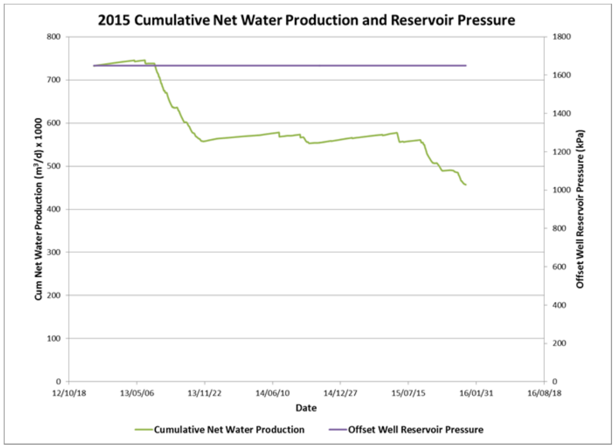
| | | M2_E | | | | M2_S | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Month | Gross ($m^3/d$) | Oil ($m^3/d$) | Water ($m^3/d$) | Water Inj ($m^3/d$) | Gross ($m^3/d$) | Oil ($m^3/d$) | Water ($m^3/d$) | Water Inj ($m^3/d$) |
| 2003 | | 21 | 2 | 20 | 243 | 40 | 1 | 39 | 292 |
| 2004 | | 0 | | 0 | 21 | 28 | 0.2 | 28 | 49 |
| 2005 | | | | | 0.3 | | | | 4 |
| 2006 | | | | | | | | | |
| 2007 | | | | | 146 | | | | 174 |
| 2008 | | | | | | | | | |
| 2009 | | | | | | | | | |
| 2010 | | | | | 16 | | | | 0.03 |
| 2011 | | | | | 5.39 | | | | 0.14 |
| 2012 | | | | | 5.19 | | | | 0.09 |
| 2013 | | | | | 3005.91 | | | | 3741.37 |
| 2014 | | | | | 16270 | | | | 17616.9 |
| 2015 | Jan | | | | 0.0 | | | | 1396.0 |
| | Feb | | | | 0.0 | | | | 0.0 |
| | Mar | | | | 0.0 | | | | 0.0 |
| | Apr | | | | 428.0 | | | | 1275.0 |
| | May | | | | 0.0 | | | | 0.0 |
| | Jun | | | | 12566.9 | | | | 10963.2 |
| | Jul | | | | 0.0 | | | | 822.1 |
| | Aug | | | | 7253.9 | | | | 5183.1 |
| | Sep | | | | 18090.1 | | | | 26164.1 |
| | Oct | | | | 10336.1 | | | | 8529.1 |
| | Nov | | | | | | | | |

# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Water Storage Compliance

- Formation Integrity and Pressure Monitoring
  - AER Approval No. 9108A was amended to use a Lower Grand Rapids Formation observation well to monitor for migration of fluids out of the zone in lieu of logging the wells used as water injectors
    - Pressures did not exceed the allowable 9 MPa on the Grand Rapids Formation observation well during water injection
  - M2-E passed packer isolation test on July 7, 2015
  - M2-S passed packer isolation test on July 6, 2015
  - No wellbore integrity issues encountered
- Wolf Lake Water Storage – Reservoir
  - M2 & N2 Cumulative DI = 1.11
    - Cumulative Gross Production = 11,865,885 $m^3$
    - Cumulative Oil Production = 1,489,431 $m^3$
    - Cumulative Steam Injected = 9,971,916 $m^3$ CWE
    - Cumulative Water Injected = 694,898 $m^3$
  - M2 & N2 Remaining Voidage = 1,199,071 $m^3$

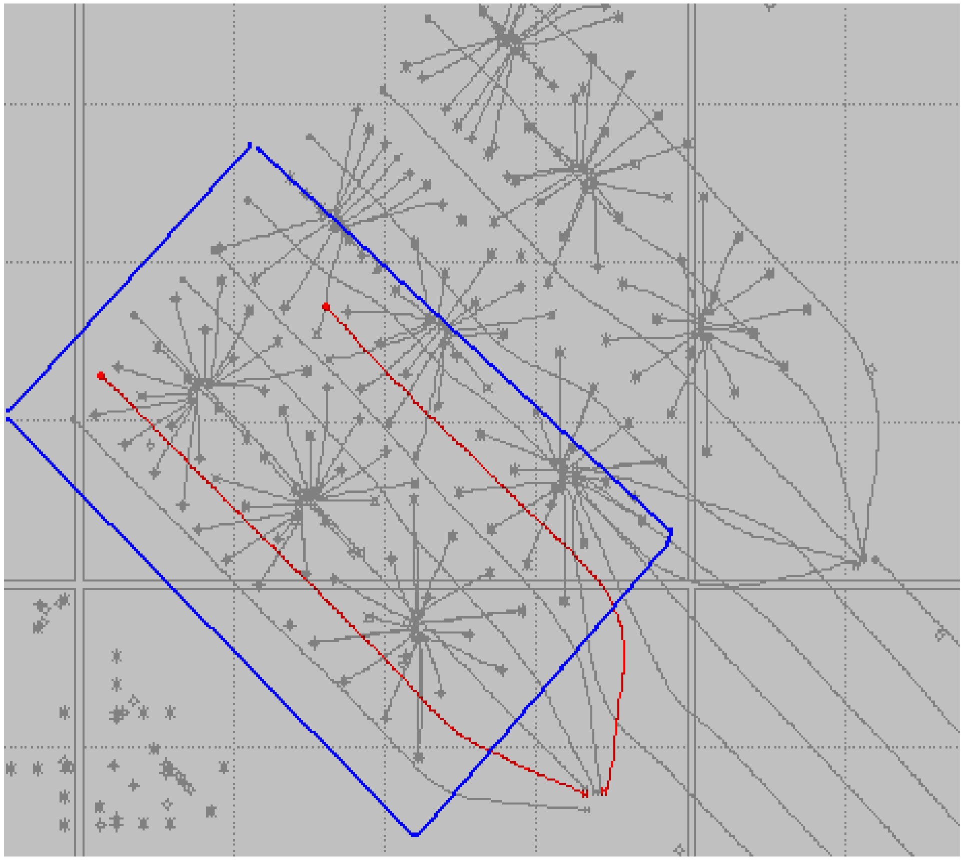
$$DI = \frac{\text{Total Fluid Produced (Bitumen + Water)}}{\text{Total Fluid Injected (CWE)}}$$



# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Water Storage Balance

- From the outlined area (M2 wells and N2-F)
  - Total Injected Water = 697,111 $m^3$ since Jan '03
  - Total Produced Water = 683,781 $m^3$ since Jan '03
  - Difference = 66,670 m3
- Expect to utilize M2 storage in 2016
- Stored water is produced through horizontal wells surrounding the M2-E and M2-S injector wells and sent to Wolf Lake water treatment plant for recycle



# Water & Waste Disposal Wells, Landfill Waste Wolf Lake Water Storage Summary

Canadian Natural

- Injectors appear to communicate readily with offset wells
- No problems anticipated when pumping out injected water
- Intend to maintain two wells for injection
- Expect to utilize water storage as required in 2016
- M2-E and M2-S are classified as disposal wells on S-4 forms

# Water & Waste Disposal Wells, Landfill Waste 2015 Annual Waste Disposal Summary

- Waste to Tervita Landfill
  - 350 tonnes – Contaminated soil
  - 57,592 tonnes – Lime waste
- Waste to Terivata Cavern
  - 3,588 $m^3$ – Sludge Hydrocarbons and Sand
  - 138 $m^3$ – Hydrovac Material
  - 46 $m^3$ – Contaminated Soil
  - 66 $m^3$ – Well Workover Fluids
  - 224 $m^3$ – Crude Oil/Condensate Emulsions (residuals after treatment)
  - 24 $m^3$ – Lime Waste
  - 311 $m^3$ – Self Heating Filters
  - 24 $m^3$ – Waste Water
  - 33 $m^3$ – Non Oilfield Waste

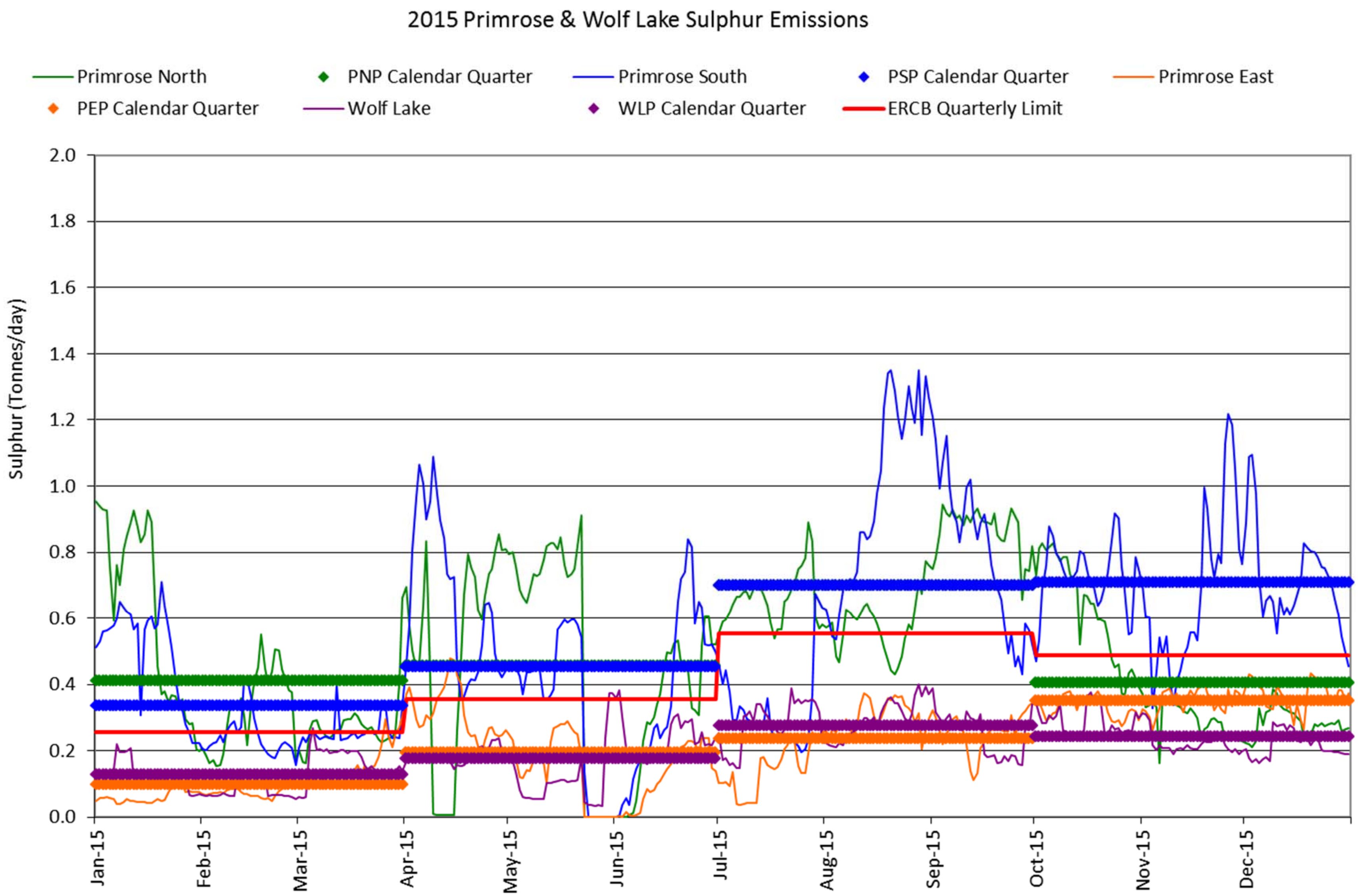
# Water & Waste Disposal Wells, Landfill Waste 2015 Annual Waste Disposal Summary (con't)

- Waste to RBW
  - 798 $m^3$ – Solid waste – contaminated soils, plastics, filters, asbestos, batteries, glycol, fluorescent tubes, caustics, acid, activated carbon
- Waste to NewAlta
  - 2,153 $m^3$ – Sludge hydrocarbons and co-emulsion

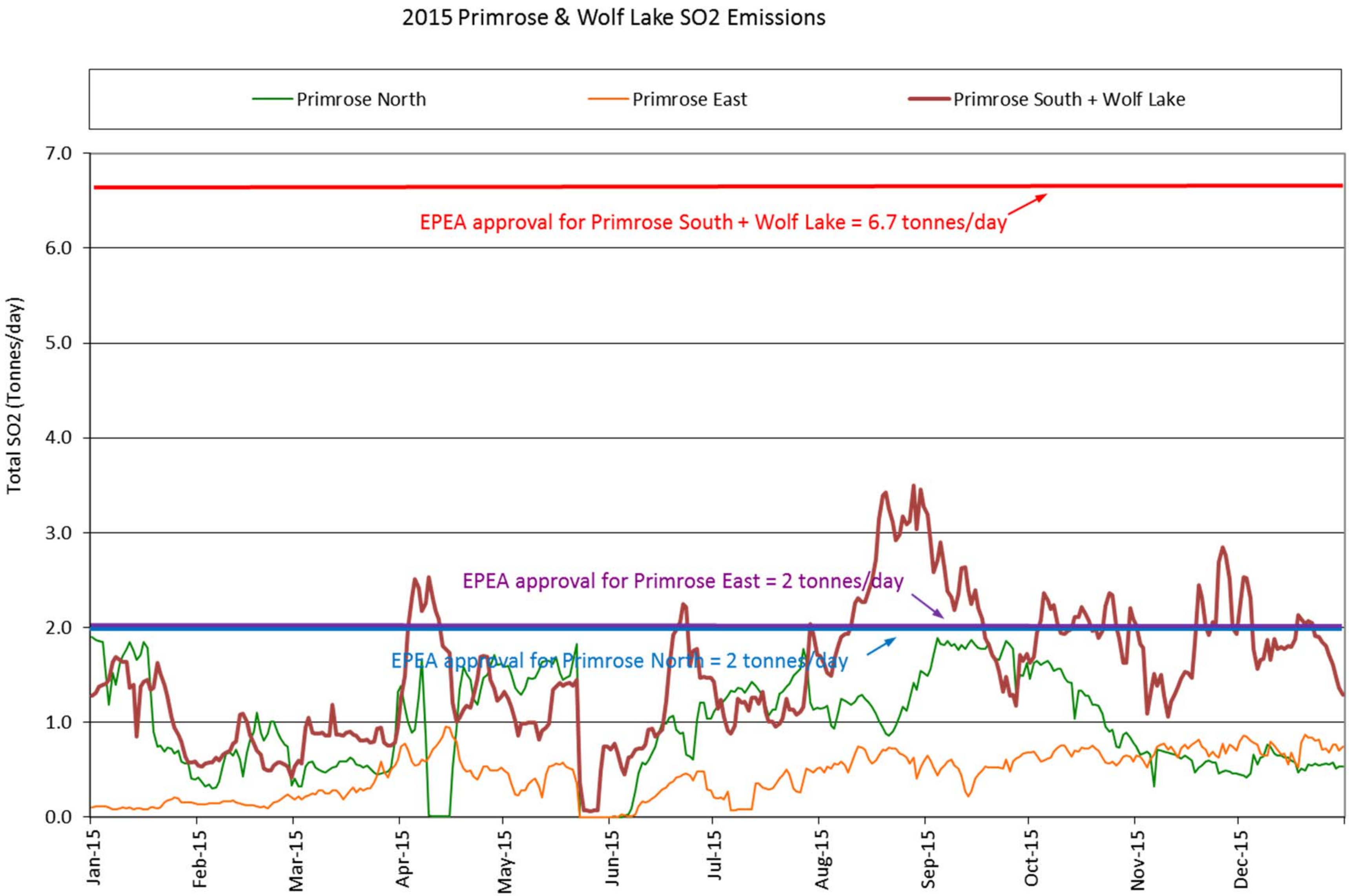
# Sulphur Production

- EPEA approval limits for $SO_2$:
  - PSP + WLP = 6.7 t/d
  - PNP = 2.0 t/d
  - PEP = 2.0 t/d
- CEMS values are used for reporting at all steam plants
  - PNP from September 1, 2010 onward
  - PEP, PSP, and WLP from April 1, 2011 onward
- Quarterly averages for all steam plants < 1.0 t/d sulphur
- Contingency for compliance with ID 2001-3 is currently to restrict/delay production to maintain sulphur level below 1 t/d quarterly average
  - Production was not restricted or delayed in 2015 to maintain sulphur levels below the 1 t/d quarterly average
  - Canadian Natural does not plan to install sulphur recovery at this time
  - Primrose South sulphur levels increased between August and September 2015 due to flowback from Phases 25 and 26
- To maintain $SO_2$ levels below 2 t/d, production from the Primrose North area wells/pads were held back for a short duration during Q1 & Q3 2015

# Sulphur Production



# $SO_2$ Emissions



# Environmental Summary
# EPEA Approval and Amendments

- Primrose and Wolf Lake EPEA Approval renewal received on September 30, 2015 (EPEA Approval 11115-04-00)
  - EPEA Approval Renewal Application submitted November 2014
  - Two rounds of SIRs were responded to in June 2015 and August 2015

- Working with the AER through the CAPP Oil Sands Transformation Group to amend EPEA Approval surface runoff testing requirements to align with Directive 55

# Environmental Summary
# Compliance

- Compliance Issues
  - EPEA Approval: Air Related
    - There were no $SO_2$ exceedances in 2015.
    - There were no NOx exceedances in 2015.
    - An Audit was completed on the CEMS QAP on January 27, 2015. There were zero noncompliance incidents related to the CEMS

# Environmental Summary
# Compliance

- Compliance Issues
  - Water Related:
    - AER Reference # 302141, Diversion License 00238513
      - Location: Wolf Lake Monitoring Well H7-04 (14-34-065-05 W4M)
      - Three weekly groundwater levels not recorded during January 10-24, 2015 due to mechanical issues with the downhole data loggers. The loggers were replaced at that time, with no subsequent problems. The cause of the failure was found to be a malfunctioned pressure transducer.
    - AER Reference # 302141, Diversion License 00238513
      - Location: Wolf Lake Monitoring Well H7-02 (14-34-065-05 W4M)
      - One weekly groundwater level measurement was not recorded on February 14, 2015. Replacement instrumentation was installed immediately upon discovering
    - AER Reference # 307304, Diversion License 00238513
      - Location: Wolf Lake Monitoring Well WOBW 01 (11-10-066-05 W4M) & WOBW 10B (15-32-065-04 W4M)
      - A total of ten weekly readings missed from two wells, due to mechanical issues with the downhole pressure transducers. The equipment was replaced and the malfunctioning loggers were sent to the manufacturer to recover the missing data/ The data was not recoverable and the missing data represents 0.6% of the readings reported during 2015.

# Environmental Summary
# Monitoring Programs

- Environmental Monitoring Programs currently underway include:
  - Wildlife Monitoring Program
  - Wildlife Mitigation Plan
  - Wildlife Habitat Enhancement Program
  - Wetlands and Hydrology Monitoring Program

# Environmental Summary
# Monitoring Programs

- Objectives of Wildlife Monitoring Program
  - To determine if the PAW project has an influence on the abundance and distribution of wildlife species;
  - The effectiveness of crossing structures; and
  - Distribution and movement of caribou.

# Environmental Summary
# Monitoring Programs

- Wildlife Mitigation Monitoring
  - Remote Camera Monitoring
    - 30 remote cameras were deployed along the above-ground pipeline (AGP) at over-pipe crossing structures.
    - Some data were lost due to the forest fire that burned and or melted 11 cameras in early June 2015.
    - The data gathered are part of mitigation monitoring commitments to document wildlife use of crossing structures and compare use of different types of over-pipe crossing structures.
  - Habitat Enhancement Program
    - Remote cameras (24) were deployed to document the effectiveness of access control measures (e.g., mounding and tree felling) implemented on linear features as part of restoration treatments.
    - Cameras were deployed to document human, predator, and prey use.
    - An additional six cameras were added in summer 2015 for a total of 30 cameras. The monitored sites include treated lines (n=15) and non-treated reference lines (n=15). Cameras remained deployed throughout the year though some data were lost due to wildfire damage to six cameras.

# Environmental Summary
# Monitoring Programs

- Wildlife Mitigation Monitoring
  - Winter tracking along AGP
    - Two rounds of winter track count surveys were conducted along the AGP
      - The first round was conducted in January 2015 and included 21 transect, each approximately 1 km in length.
      - The second round was completed in February 2015 and included 22 transects, each approximately 1 km in length.
    - Data collected documents wildlife movement around and across the pipeline. As appropriate, AGP height or crossing structure height was documented for successful movement across the AGP.
  - General Surveys
    - One full round of winter track count survey was completed in January 2015, including 57 transects each measuring 500 m in length.
    - A partial second round of surveys was completed in late February 2015 and included 18 transects each measuring 500 m.
      - The second round was not fully completed due to poor snow conditions and findings/recommendations in the 10 Year Wildlife Report prepared in March 2015.
    - The 2015 wildlife report will include a comprehensive analysis of winter track count data from baseline to 2015 to incorporate linear feature density as a potential explanatory variable to describe variation in track density.

# Environmental Summary
# Monitoring Programs

- Wildlife Habitat Enhancement Program
  - Nest box program
    - 14 bird nest boxes and 2 bat boxes are on site.
  - Breeding songbird surveys
    - Annual breeding songbird surveys were suspended in summer 2015 based on findings/recommendations in the 10 Year Wildlife Report prepared in March 2015.
    - The 2015 wildlife report will include a comprehensive analysis of breeding songbird data from baseline to 2014 to incorporate linear feature density as a potential explanatory variable to describe variation in bird abundance and species richness.
  - Seedling monitoring
    - Seedlings planted on linear features between 2011 and 2014 were monitored in September 2015 using a circular plot method to document the survival, growth, and vigour of introduced tree seedlings, as well as the presence and growth of naturally occurring vegetation.
    - Twenty one plots were visited, including 7 plots that were affected by the fire and 14 that were not burned by the fire. Total seedling density increase by 5% between the first and fifth growing season due to germination of natural seedling. Average survival of planted seedling was 84% after 5 growing seasons.

# Environmental Summary
# Monitoring Programs

Canadian Natural

- Wildlife Crossing Opportunity Assessment
  - An assessment of the full AGP network was completed to document all existing wildlife crossing opportunities.
    - The AGP network includes 141,428 m and was subdivided into 144 individual segments for comparison with the 2014 Provincial AGP Wildlife Crossing Directive. 435 crossing opportunities were documented, including 93 over-pipe crossing structures, 230 under-pipe opportunities ≥20 m in length, and 112 under-pipe opportunities <20 m in length.
    - All segments of AGP were constructed prior to the release of the provincial directive.
- Wildlife Sightings
  - Staff and contractors continued to submit wildlife sightings while working on the project site. 112 wildlife sightings were recorded in 2015.

# Environmental Summary
# Monitoring Programs

- Comprehensive Wildlife Mitigation and Monitoring Report
  - Submitted in March 2015
  - The report summarizes all wildlife mitigation and monitoring activities conducted by Canadian Natural for the PAW Project between 2000 and 2014.
  - The time period included baseline studies conducted for Canadian Natural's Primrose and Wolf Lake Project (2000 to 2002), baseline studies conducted for the Primrose East Expansion Project (2004 to 2006), and monitoring activities across the full PAW Project site (2006 to 2014).
  - The report provides an assessment of Project influence on wildlife abundance and distribution. More specifically it assessed the influence of one particular source of potential effects: all core disturbances associated with the Project.
    - Core disturbances included all permanent features such as all-season roads, AGP, well pads, processing plants, and camps.
  - Data were examined in the context of zones of influence to determine if distance from core disturbances influenced the presence and abundance of target species

# Environmental Summary
# Monitoring Programs

- Hydrology, Wetlands and Water Quality Monitoring Program 2014
  - Wetland Monitoring Component
    - Preliminary observations of the PAW wetland monitoring program's 2015 re-measurement data indicates that there were only minor differences in overall species richness among monitoring and reference sites compared to previous years.
    - A complete report comparing results for all PAW wetland monitoring data (i.e., 2007 through 2015) will be compiled. It will provide further details on statistical analysis, species richness and abundance, and presence of rare plants, as well as hydrological information, including water chemistry.

# Environmental Summary
# Monitoring Programs

- Hydrology, Wetlands and Water Quality Monitoring Program 2014
  - Hydrology Monitoring Component
    - During the 2015 monitoring program all lakes appeared to exhibit hydrological regimes similar to those of past years.
    - A complete analysis and comparison of results for all PAW hydrology monitoring events (i.e., 2007 through 2015) will be compiled for the annual report. This report will provide further details on lake levels and will draw on information from nearby water bodies and meteorological stations.
  - Water Quality Component
    - Based on the to-date results for the surface water quality samples from Burnt Lake and Sinclair Lake there were no significant deviations observed in the analytical results when compared with those from previous years.

# Environmental Summary
# Monitoring Programs

- Reclamation activities in 2015:
  - Re-vegetation Program consisted of reforesting 9.36 ha
  - Approximately 95,230  tree and shrub seedlings were planted.
    - Planting on borrows accounted for 38.42 ha
      - total of 76,150 tree and shrub seedlings
    - In-fill planting on borrows and clearings accounted for 1.80 ha
      - 9,270 tree and shrub seedlings.
    - Flow to surface sites planting accounted for 2.70 ha
      - Total of 9,810 trees and shrub seedlings

Proposed activities in 2016:

- Reforestation of 51.5 ha of borrow pits in Primrose North.
- Remedial planting on 35.3 ha in Primrose South and North for Borrows affected by forest fires in 2015.
- 5.7 ha reforestation of FTS sites

# Environmental Summary
# Monitoring Programs

- LICA Airshed Zone
  - The LICA Airshed Zone is responsible for operating a regional air monitoring network for part of the Lakeland and adjacent area inclusive of passive and continuous monitoring networks.
  - During 2015 LICA's activities were planned and funded through the Alberta Environmental Monitoring Evaluation and Reporting Agency (AEMERA)
  - In addition to posting the air monitoring network results to the LICA website, the LICA Airshed Zone also posts real time air monitoring results for the regional Alberta Quality health Index (AQHI)

# Environmental Summary
# Monitoring Programs

- Beaver River Watershed Alliance (BRWA):
  - The Beaver River Watershed Alliance (BRWA) serves as the Watershed Planning and Advisory Council for the Beaver River watershed.
  - The BRWA continues to work on the Watershed Management Plan as part of Alberta's Water for Life Strategy. Canadian Natural is part of the Technical Advisory Team
  - The BRWA completed an Indices of Aquatic Ecosystem Vulnerability project. The goal project was to develop standardized indices (models) that can be used over time to monitor, report, and run scenarios on the state of aquatic ecosystem health in the watershed. Models were developed for: occurrence of/habitat suitability for sensitive lake water birds, lake water quality, stream water quality and fish community suitability. The final report is available on the BRWA website.
  - LICA/BRWA continued to support Lakewatch program conducted by Alberta Lakewatch Society (ALMS). 10 lakes were monitored in the LICA region. Results can be found on the ALMS website.
  - Their Education and Outreach Coordinator, continues to build relationships and implement environmental education programs in the community.

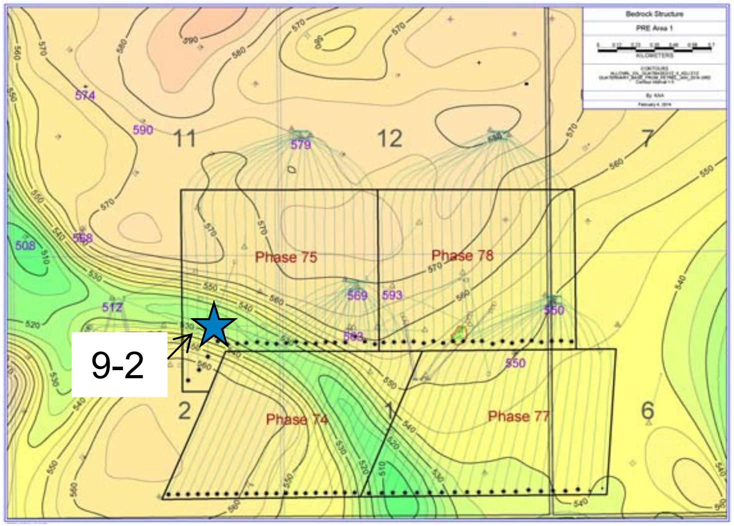
# Environmental Summary
# Arsenic Mobility Investigation

- Arsenic Mobility Research Program Description
  - Long-term research program at Z8 Pad ongoing since 2001.
  - Evaluating the liberation of arsenic associated with elevated groundwater temperatures from steaming a thermal pad.
  - Thirty-five groundwater monitoring wells installed primarily in shallow and deep Quaternary aquifers (Empress, Bonnyville and Sand River).
  - Monitoring temperature, chemistry and water level data in all wells to complete temporal assessments associated with steaming with a focus on the Empress and Sand River.
- Research Program Highlights from 2015
  - Empress aquifer results consistent with historical findings
    - thermal and arsenic plumes are migrating downgradient of the pad.
    - arsenic concentrations continue to decrease near thermal pad.
  - Additional Sand River aquifer monitoring well installed to further research on the aquifer. On-going groundwater data collection to understand flow system and geochemistry.

# Environmental Summary
# Groundwater Monitoring and Management

- EPEA Groundwater Monitoring Programs
  - Completed as per terms and conditions outlined in EPEA Amending Approval 11115-04-00, Schedule VI
    - shallow groundwater monitoring at plant facilities
    - deep groundwater monitoring of source, on-pad and regional monitoring wells

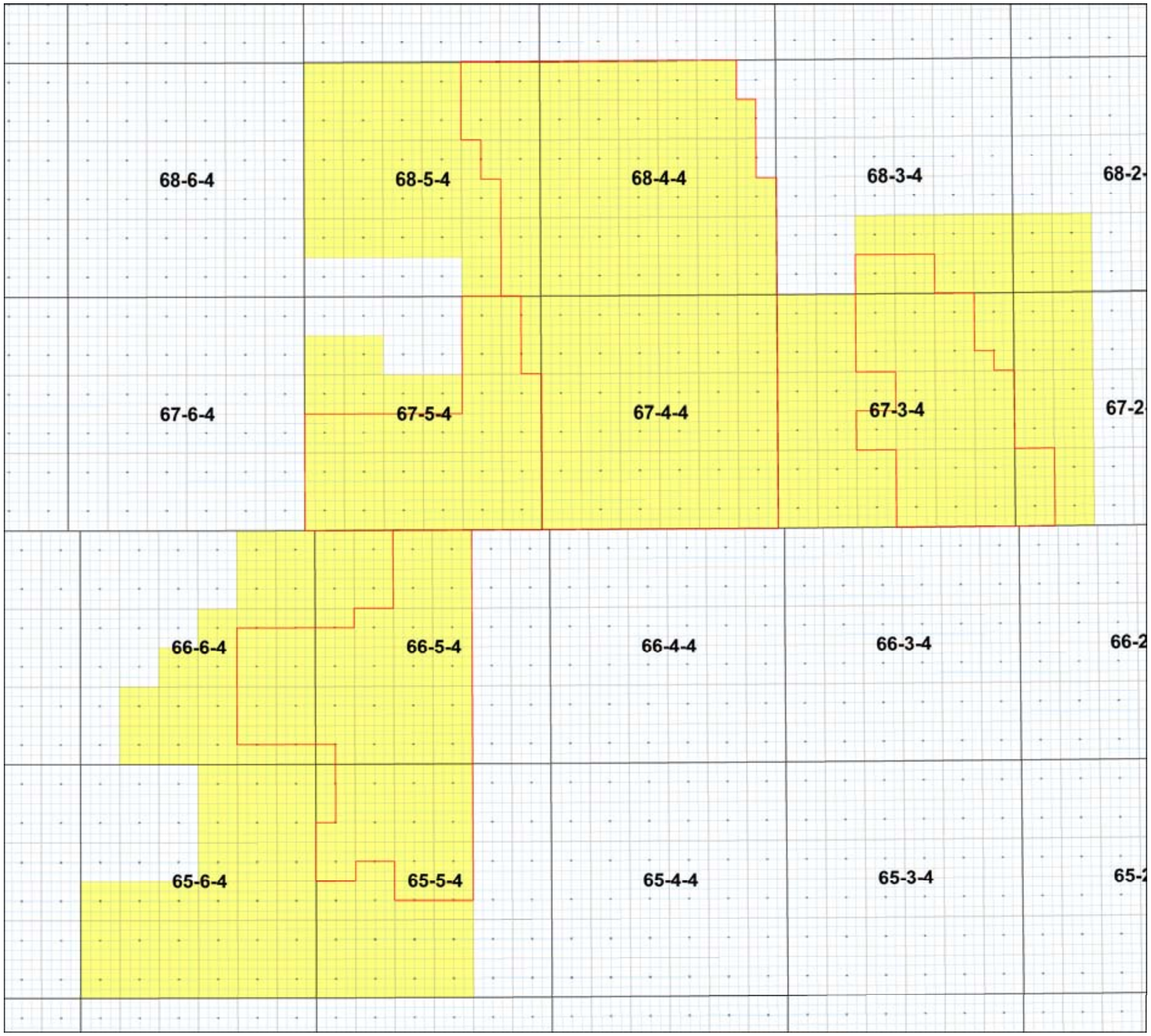
- 9-2 Groundwater Monitoring
  - Well monitored and sampled as per EPEA regional program
  - Additional samples collected to establish baseline chemistry
  - No anomalous chemistry or pressure data



# Environmental Summary
# Groundwater Monitoring and Management

- Primrose Flow to Surface (FTS) sites (2-22, 10-2, 10-1 and 9-21)
  - Groundwater investigation drilling activities were completed between February 2014 and February 2015.
    - 106 testholes drilled with 80 monitoring wells installed (4 wells abandoned).
  - A groundwater monitoring program was initiated in March 2014 under the EO including monthly monitoring, sampling, and annual reporting.
  - Risk Management Plans providing a long-term framework to identify and address potential risks submitted to the AER in November 2015.
- Pad 74 Risk Management Plan
  - On-going application of the Pad 74 Risk Management Plan including monitoring, sampling and reporting.
  - Monitoring and sampling results are reported annually to AER/ESRD via EPEA Approval since March 2012.
- Groundwater monitoring results indicate very limited subsurface impacts associated with FTS.

# Approval 9140W – Oil Sands Primrose Wolf Lake



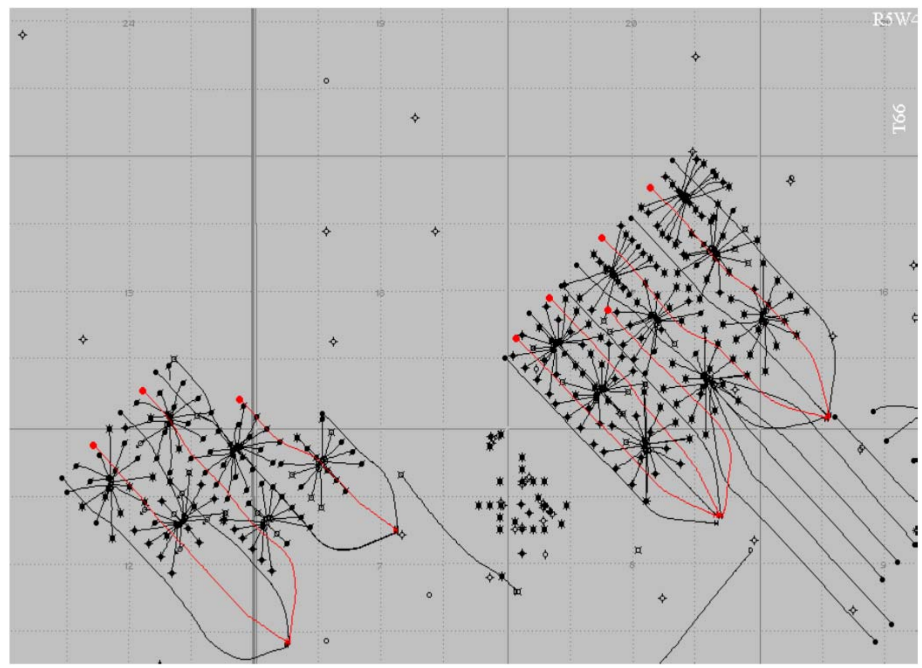
# Approval 9140W – 2015 Amendments

- Amendment U - Approved February 2015
  - Approval for Primrose East Phases 90&91 LPCSS
- Amendment W - Approved November 26, 2015
  - Approval for Directive 81 Disposal Factor Increase

# Approval 9108A – Wolf Lake Water Storage Amended October 2015

- Approval 9108A was amended in October 2015 at the request of the AER
  - The Operator must install daily pressure monitoring in the Lower Grand Rapids Formation at the 07/02-17-066-05W4M/2 well by December 31, 2015,
  - In the event that fluid migration is detected at this well, the Operator must immediately notify the AER In Situ Authorizations Group and submit a plan to assess and mitigate the potential impact of disposal operations within 60 days of detection.

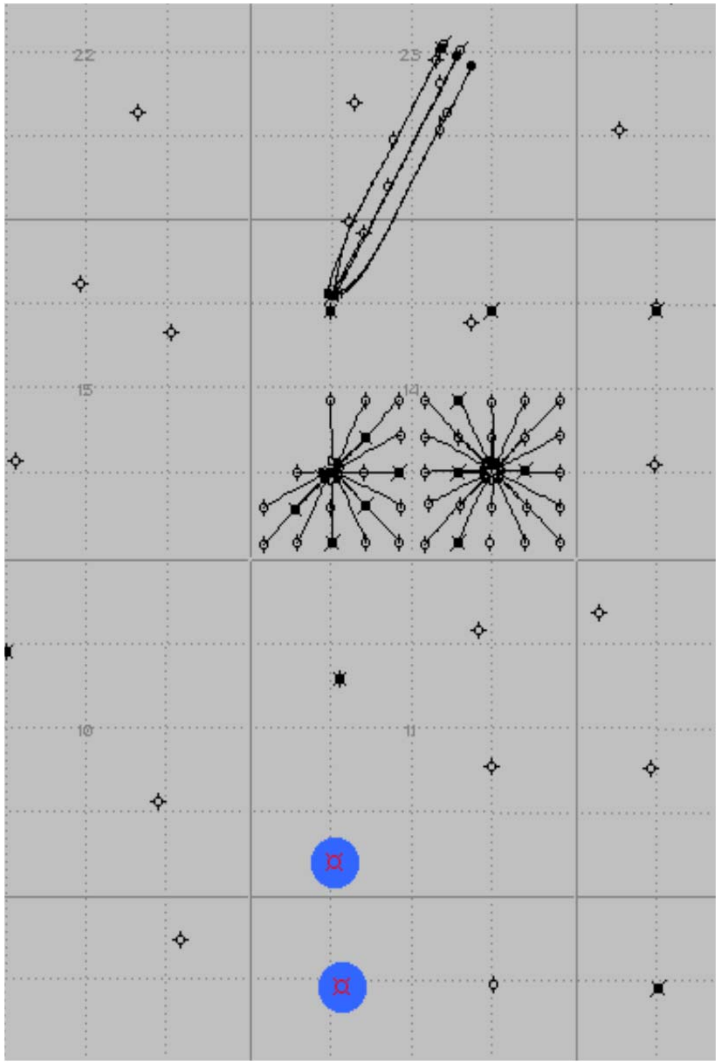
- Directive 054
  - (a) Summary of monthly injected and produced volumes/well
  - (b) Well/Formation Integrity and pressure monitoring
  - (c) Remaining Reservoir Water Storage
  - (d) Water Balance, Bitumen Volumes and Incremental Recovery
  - (e) Overall performance and 2016 plans
  - (f) Discussion of produced water utilization & fresh water reductions



# Approval 8186A – Burnt Lake Water Disposal Approved February 1999

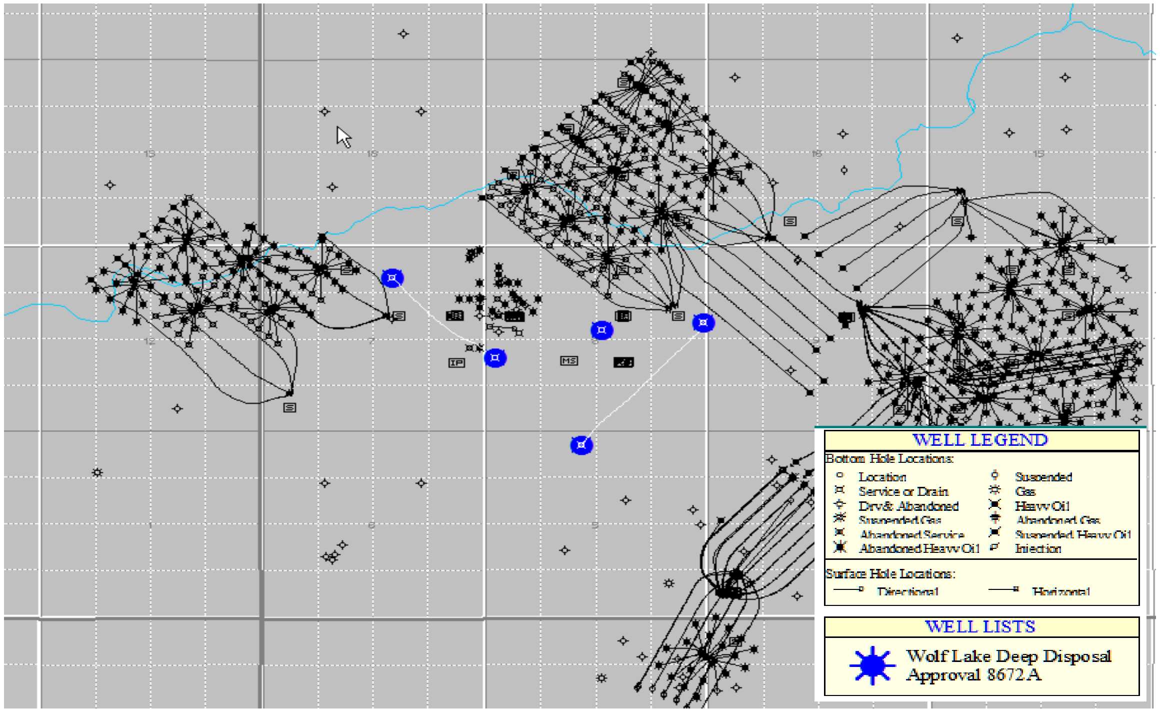
Canadian Natural

- Approval Compliance Requirements
  - Directive 51 Compliance
  - Maximum Injection Pressures (kPa)
    - F1/11-02-067-03W4/0 = 7800
    - 00/03-11-067-03W4/0 = 5500
- Injection packer isolation test failed on 11-2 in 2008
  - Well currently shut-in
  - Work in progress
- No disposal as water is now recovered and re-used



# Approval 8672A – Wolf Lake Deep Disposal Approved June 2010

- Approval Compliance Requirements  Directive 51 Compliance
- Operational injection pressure limit 13,770 kPa
- Maximum injection pressure 17,500 kPa for a 24 hour period
- Disposal wells are:
  - WDW#1 - 00/09-08-066-05W4/0
  - WDW#2 - 00/10-08-066-05W4/0
  - WDW#4 - 00/05-08-066-05W4/0
  - WDW#5 - 00/15-07-066-05W4/0
  - WDW#9 - 00/14-05-066-05W4/0



# Approval 8673 – Cavern Disposal Approved October 2000

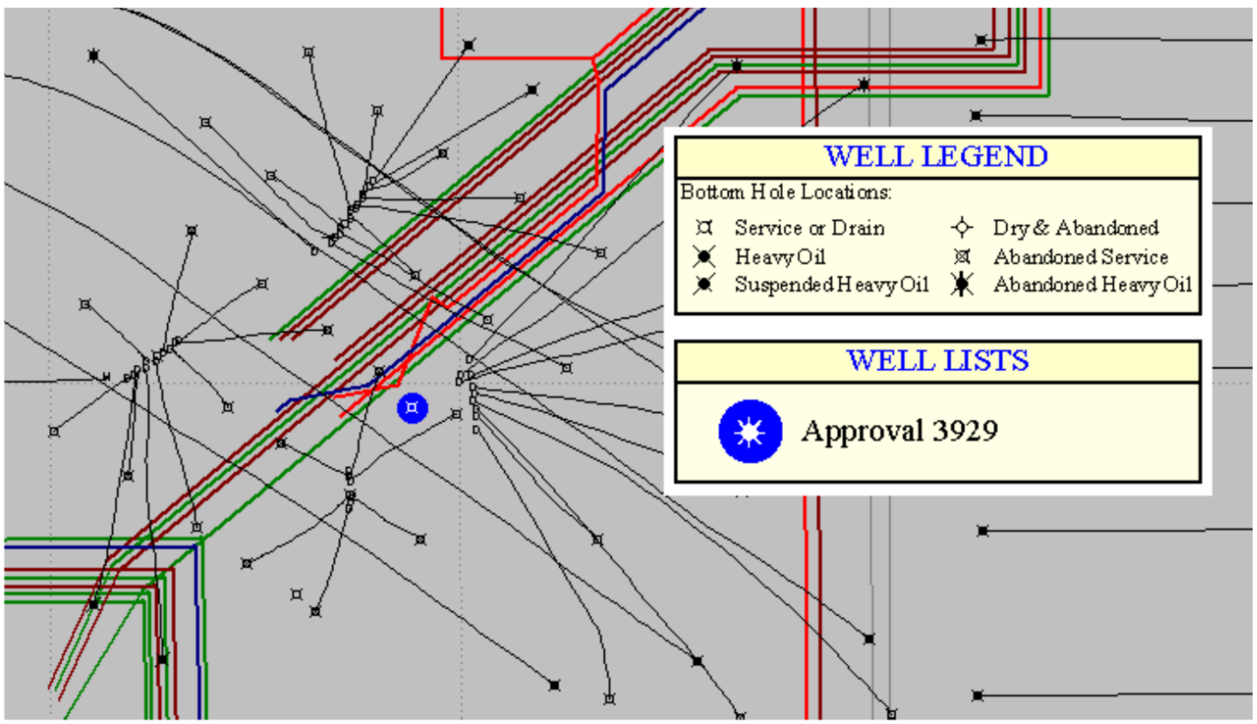
- Approval Compliance Requirements
  - Monitoring Maximum Injection Pressures
    - Did not exceed maximum allowable injection pressure
  - Annual Report
    - 2015 Report will be prepared following annual cavern sounding
- Salt Cavern 1 – 118/12-8-66-5W4
  - Cavern volume (as of April 2015 sounding) 195,392 $m^3$
  - Wash water 2,030 $m^3$
    - Cavern wash water is sent to disposal wells
  - Oily waste (bitumen) 1,401 $m^3$
  - Solid waste 666 $m^3$
  - Next Cavern sounding expected in April 2016

# Approval 8673 – Cavern Disposal Approved October 2000

- Salt Cavern 2 - 119/12-8-66-5W4 – Washing Only
  - Cavern volume (as of April 2015 sounding) 55,556 $m^3$
  - Wash water 5,784 $m^3$
    - Cavern wash water is sent to disposal wells
  - Next Cavern sounding expected in April 2016

# Approval 3929A – Primrose Class 1b Disposal Amended September 2011

- Approval Compliance Requirements
  - Originally approved 1983
  - Transferred to Canadian Natural from Dome Petroleum – September 2011
  - Directive 51 Compliance
  - Maximum Wellhead Injection Pressures (kPa)
    - 03/10-05-067-04W4/0 = 6,000



# Additional Disposal Approvals

- Approval No. 4128D – Class II Disposal
  - Transferred to Canadian Natural from Dome Petroleum – September 2011
  - Directive 51 Compliance
  - 02/10-05-067-04W4/0 = 16,000 kPA

# Compliance Disclosures

- Reportable spills
  - 13 reportable spills were reported during 2015 including; 5 emulsion, 3 salt water, 1 bitumen, 1 boiler feedwater, 1 brackish water, 1 produced water and 1 steam condensate.
- Digital Data Submissions (DDS)
  - Notifications/Submissions were entered into the DDS as per Directives in 2015.

# Compliance Disclosures

- Self Disclosures
  - Incorrect groundwater pressure measurements at 16-32a from June 6 to November 7, 2014 due to water level exceeding the gauge's range after decreased pumping in the area (self-disclosed in February 2015).
    - New pressure gauge installed on November 7, 2014, and data recovery frequency has been increased from quarterly to monthly to ensure accurate data collection continues.

# Compliance Disclosures

- Non-compliance
  - None

# Future Plans

- PAW Plant Control System & Electrical Upgrades
  - Completion of the U1 DCS upgrades
- Wolf Lake Produced Water Debottlenecking
  - Phases 2 & 3 Upgrades planned for 2016 and continuing into 2017
- Wolf Lake Electrical Substation Expansion
  - Expansion of the electrical substation to support development
- Wolf Lake Trench Upgrades
- Primrose East A2 Steamflood Conversion
  - Pad modifications on 3 to 4 pads
- Primrose East Heat Integration
  - Install new exchanger for additional cooling associated with steamflood
- Z8 Pad Steamflood Conversion
- MC1 Natural Gas Co-injection

# Future Plans

- Various small sustaining capital projects
  - To replace aging infrastructure and equipment
  - To reduce operating costs
  - To improve environmental performance

# Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this presentation constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansion, Septimus, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia, the proposed Energy East pipeline from Hardisty to Eastern Canada, and the construction and future operations of the North West Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses. The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

# Reporting Disclosures

Special Note Regarding Currency, Production and Reserves

In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This document , herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2014 the Company retained Independent Qualified Reserves Evaluators ("IQREs"), Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved and proved plus probable reserves with an effective date of December 31, 2014 and a preparation date of February 2, 2015. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. Reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 "Extractive Activities - Oil and Gas" in the Company's Form 40-F filed with the SEC in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

Resources Other Than Reserves

The contingent resources other than reserves ("resources") estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101. No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2014. The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.
gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures

This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Net Earnings and Cash Flow from Operations" section of the Company's MD&A. The derivation of cash production costs is included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of the Company's MD&A.

Volumes shown are Company share before royalties unless otherwise stated.

THE PREMIUM VALUE.

DEFINED GROWTH.

INDEPENDENT.

Canadian Natural