PROVEN | EFFECTIVE | STRATEGY

Canadian Natural

February 2014

PRIMROSE/WOLF LAKE CYCLIC STEAM STIMULATION (CSS)

2014 WELL INTEGRITY PRESENTATION

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

CNRL's Well Integrity Philosophy

1. Develop a further understanding of well failure mechanisms

2. Ensure monitoring resources are applied effectively to minimize risk to HSE and resource recovery

3. Prolong well life through improved well design and operational practices

Agenda

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1. Review 2014 Well Failure Statistics
2. Review On-Going Well Integrity Initiatives
3. Discuss Future Initiatives
4. Conclusions

Part 1 Failure Statistics - Definitions

- Near-surface failure – 0m – 25 m TVD
  - CNRL had the first near-surface failure in 2014
- Out of zone failure – failure depth is between 25 m TVD and the interface of the Grand Rapids/Clearwater formation
  - Includes failures within the Grand Rapids, Colorado and Quaternary formations
- In zone failure – occurs within the Clearwater formation
  - Includes failures within the Clearwater capping shale

Part 1 Failure Statistics – Overview

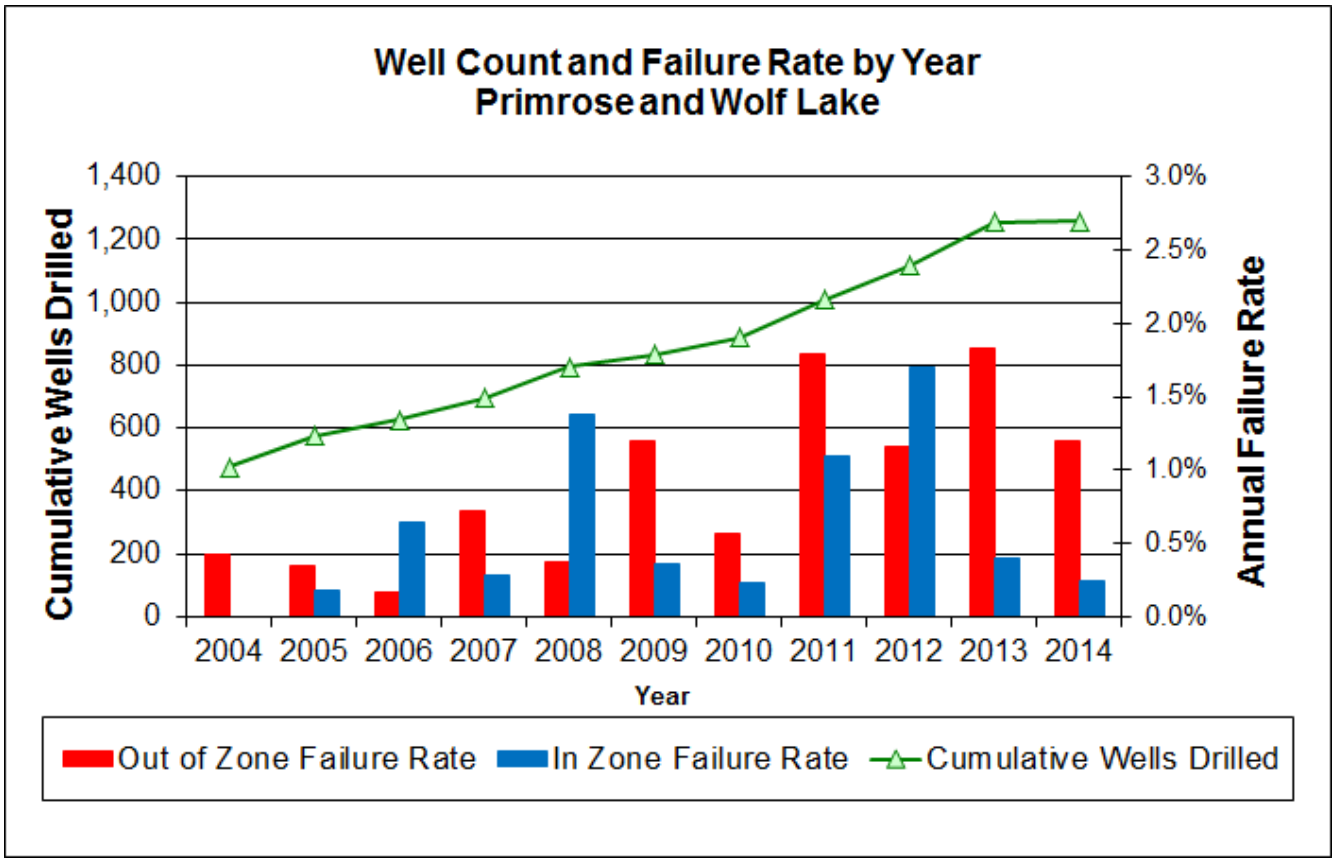
- Out of zone casing failure rate has decreased in 2014
  - Majority of failures were concentrated in 2 areas which have had a large number of previous well failures (Primrose North pads 51 to 54 and pads 58, 62, 66, and 67)
- In zone (Clearwater) casing failure rate has decreased in 2014
- No failures have occurred in the most recently drilled pad since 2012:
  - 60, 61, 64, 65, 68: 4 steam cycles
  - 25, 26: 5 steam cycles
- A reduction in out of zone failure rate for pads drilled in 2013 onward is anticipated – the data will be available as those pads reach cycle 4 in 2017

Part 1 Failure Statistics – Overview

- 2014 failure count vs:
  - Cycle
    - Most out of zone failures occur during or after cycle 4
  - Geological Formation
    - Majority of out of zone failures occurred in the Belle Fourche and Westgate formations
  - Operating Stage
    - Majority of failures occur in production phase when casing is cooled and in tension – in 2014, no out of zone failures during HP operations

- Method of detection
  - In 2012-2014, on pads where passive seismic is used, there is 100% detection rate for out of zone casing failures below the surface casing

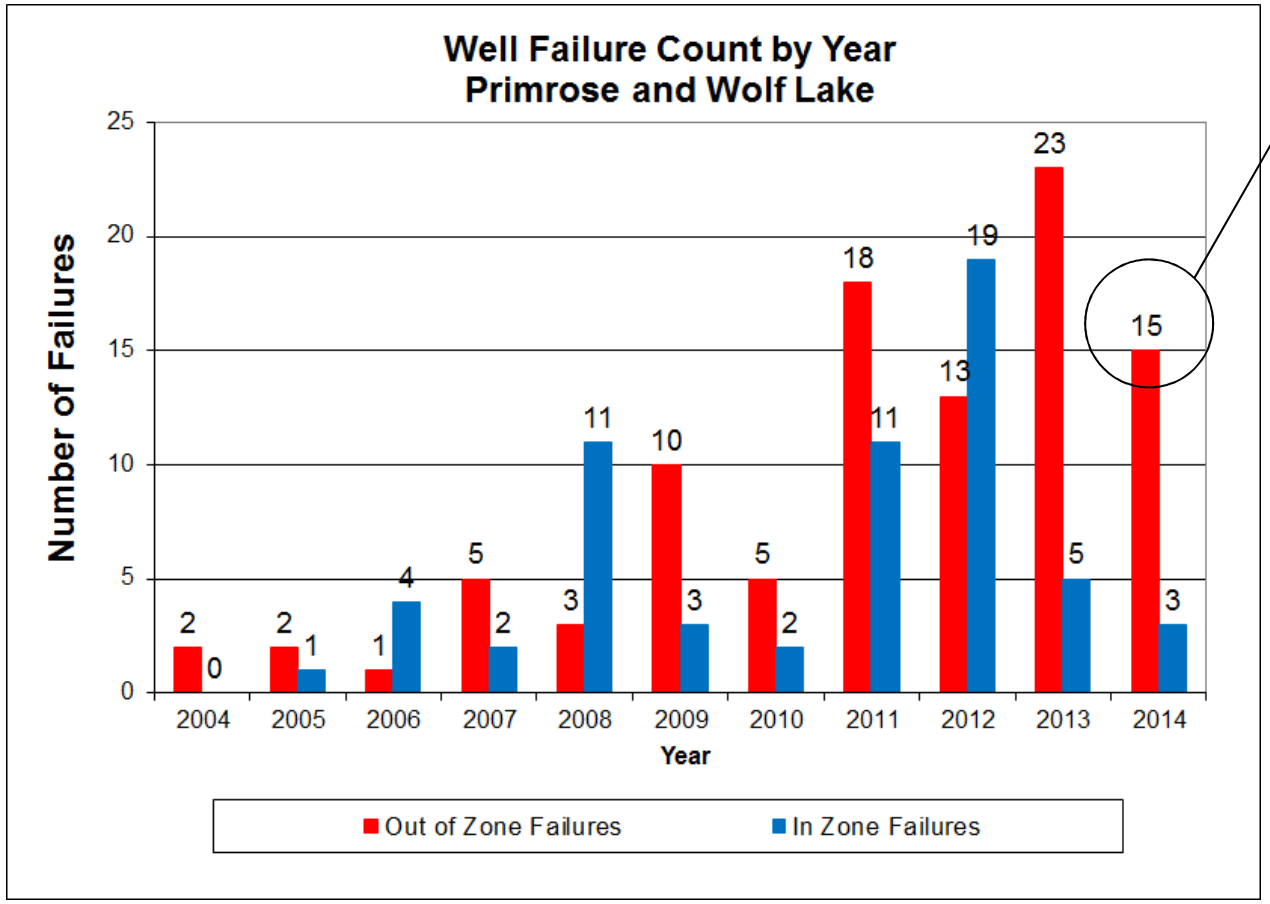
Well Failures by Year



In 2014:

- 1.2% of the wells had an out of zone failure
- 0.2% of the wells had an in zone failure

Well Failures by Year



10 of 15 out of zone well failures occurred in 2 areas

– Primrose North Pads 51 to 54 (6)

– Primrose North Pads 58, 62, 66, and 67 (4)

These two areas have had a high number of casing failures during the previous years

Well Integrity – 2014 Well Failures

- Primary Out of Zone Casing Failures – 15 wells with out of zone casing failures

Majority of the failures occurred on Primrose North Pads 51-54 and 58, 62, 66, and 67

On pads where Passive Seismic is used - all out of zone well failures below the surface casing were detected

Well	Area	Lisc #	Detection Method	Confirmation Date	Measured Depth (mKB)	Total Vertical Depth (m)	Formation
2A93	PRE	432630	PS	16-Aug-14	634.2	456.0	LOWER GR
8A74	PRE	380836	MFC	26-Nov-14	93.6	93.6	QUATERNARY
2A74	PRE	380830	PS	23-Mar-14	311.2	305.1	WESTGATE
2B52	PRN	317129	PS	15-Mar-14	246.3	245.1	BELLE FOURCHE
18A62	PRN	402539	PS	24-May-14	262.7	260.2	BELLE FOURCHE
19A67	PRN	409670	PS	28-Sep-14	259.0	257.5	BELLE FOURCHE
7A66	PRN	396922	PS	25-Feb-14	332.0	327.5	JOLI FOU
6C51*	PRN	309853	PS	21-Jan-14	176.8	176.7	LEA PARK
5C53	PRN	319083	PS	7-May-14	303.5	303.0	WESTGATE
5A51	PRN	309877	PS	9-May-14	298.5	297.5	WESTGATE
7C51*	PRN	309851	PS	12-Jun-14	303.3	298.5	WESTGATE
6A58*	PRN	396752	PS	16-Oct-14	291.8	289.6	WESTGATE
8B54	PRN	327884	PS	30-Nov-14	298.3	290.6	WESTGATE
12A42	PRS	455689	VISUAL (CURE OUT)	10-Nov-14	14.0	14.0	QUATERNARY
19-Z8	WL CSS	132136	PIT	11-Feb-14	276.5	269.6	WESTGATE

Well Integrity – 2014 Well Failures

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- Primary Out of Zone Casing Failures – 15 wells with out of zone casing failures

Well	Tubular OD (mm)	Failure In	Cycle of Failure	Well Phase During Failure	Repair Method
2A93	244.5	CONN	2	SHUT IN	SLIMHOLE
8A74	244.5	CONN	6	UNKNOWN	PATCH
2A74	244.5	CONN	3	SHUT IN	SLIMHOLE
2B52	177.8	CONN	4	PUMP - WO	PATCH
18A62	244.5	CONN	3	PUMP - WO	PATCH
19A67	244.5	CONN	3	PUMP	SLIMHOLE
7A66	244.5	CONN	6	PUMP - WO	PATCH
6C51*	244.5	CONN	4	PUMP	PATCH
5C53	244.5	CONN	4	SHUT IN	PATCH
5A51	244.5	CONN	4	PUMP - WO	PATCH
7C51*	244.5	CONN	4	PUMP - WO	PATCH
6A58*	244.5	CONN	6	PUMP - WO	PATCH + SLIMHOLE
8B54	244.5	CONN	5	SHUT IN	PATCH
12A42	244.5	PIPE BODY	1	CURE OUT	SLIMHOLE
19-Z8	177.8	CONN	10	UNKNOWN	BRIDGE PLUG

Most well failures occur during the latter stages of production when the wellbore is cool and the casing is in tension

14 of the 15 out of zone CSS well failures were at the connection

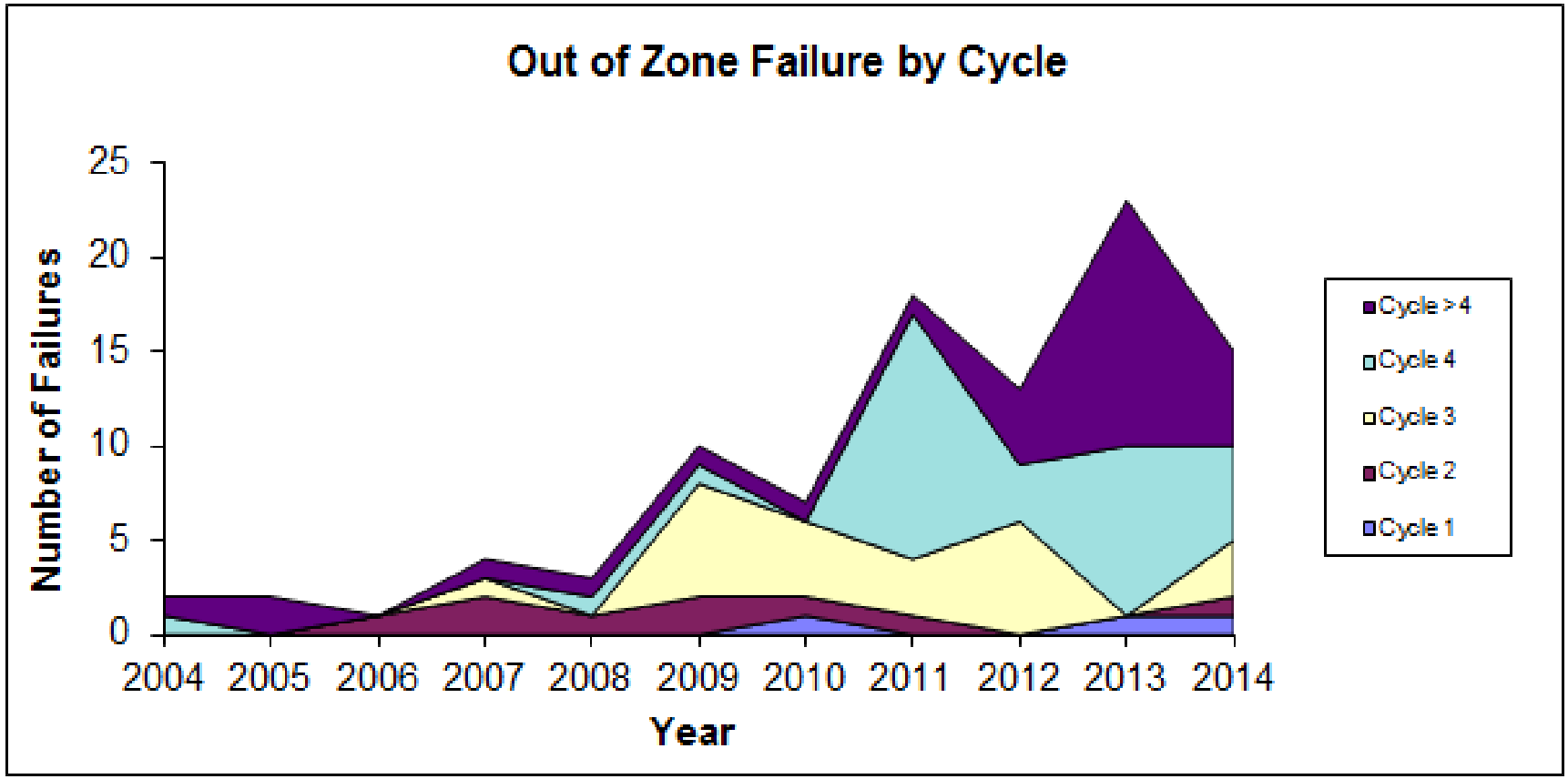
Well Integrity – 2014 Well Failures

- In Zone Well Failures – 3 wells with in zone casing failures

Well	Area	Lisc #	Detection Method	Confirmation Date	Measured Depth (mKB)	Total Vertical Depth (m)	Formation
5A95	PRE	433412	PIT	13-Jun-14	850.3	492.0	CLEARWATER SAND
15A66	PRN	396910	IMPAIR	1-Dec-14	559.0	464.1	CLEARWATER SHALE
6C30*	PRS	284606	PS	1-May-14	560.7	463.1	CLEARWATER SHALE

Well	Tubular OD (mm)	Failure In	Cycle of Failure	Well Phase During Failure	Repair Method
5A95	244.5	CONN	2	UNKNOWN	PATCH
15A66	244.5	PIPE BODY	6	UNKNOWN	ZONAL SUSP. w/CEMENT
6C30*	244.5	CONN	5	TRICKLE STEAM	PATCH, ZONAL SUSP. w/CEMENT

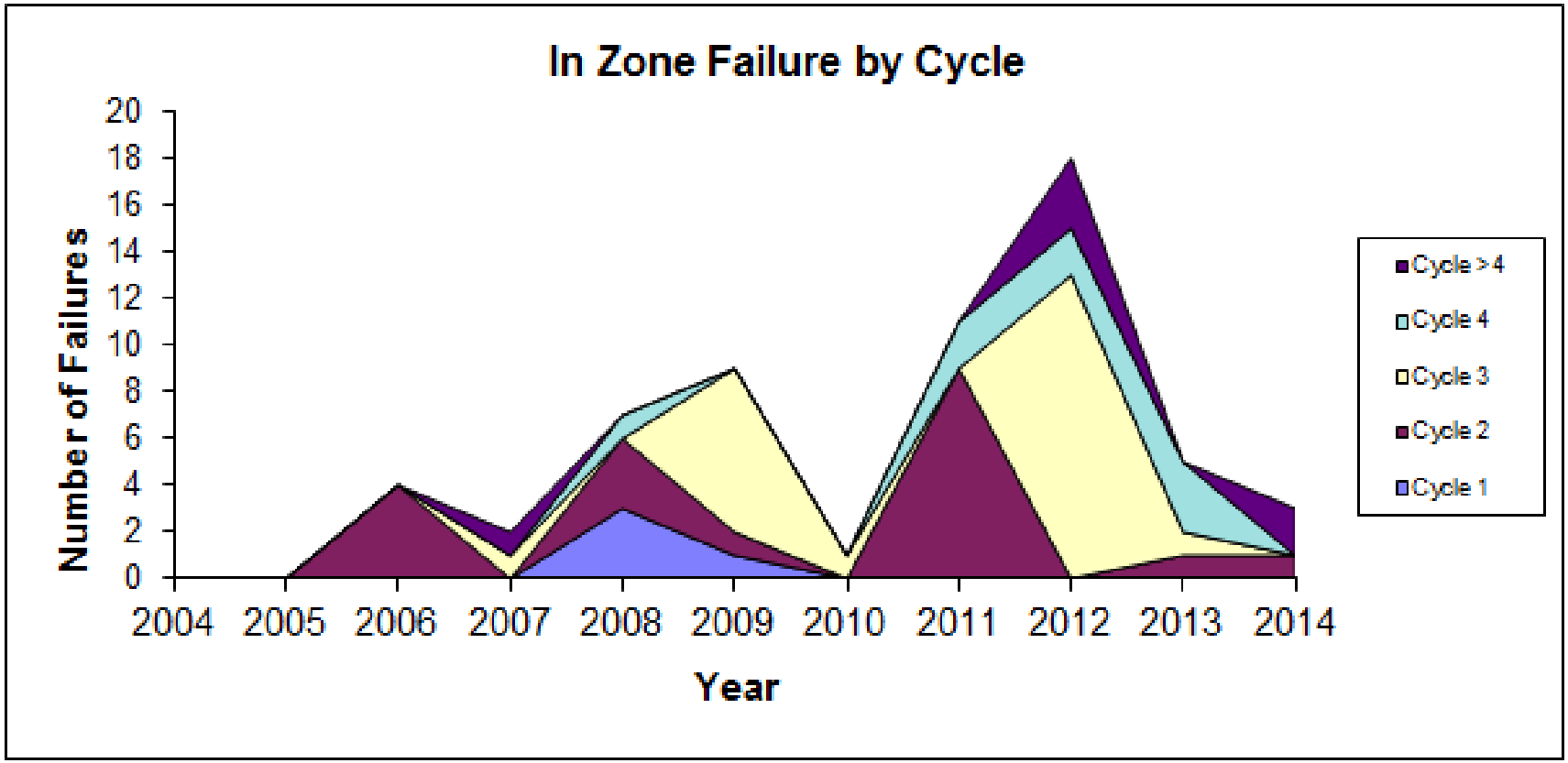
Out of Zone Failures by Cycle



In 2014, the majority of Out of Zone failures occurred in commercial cycle 4+

Failure rate decreased in 2014

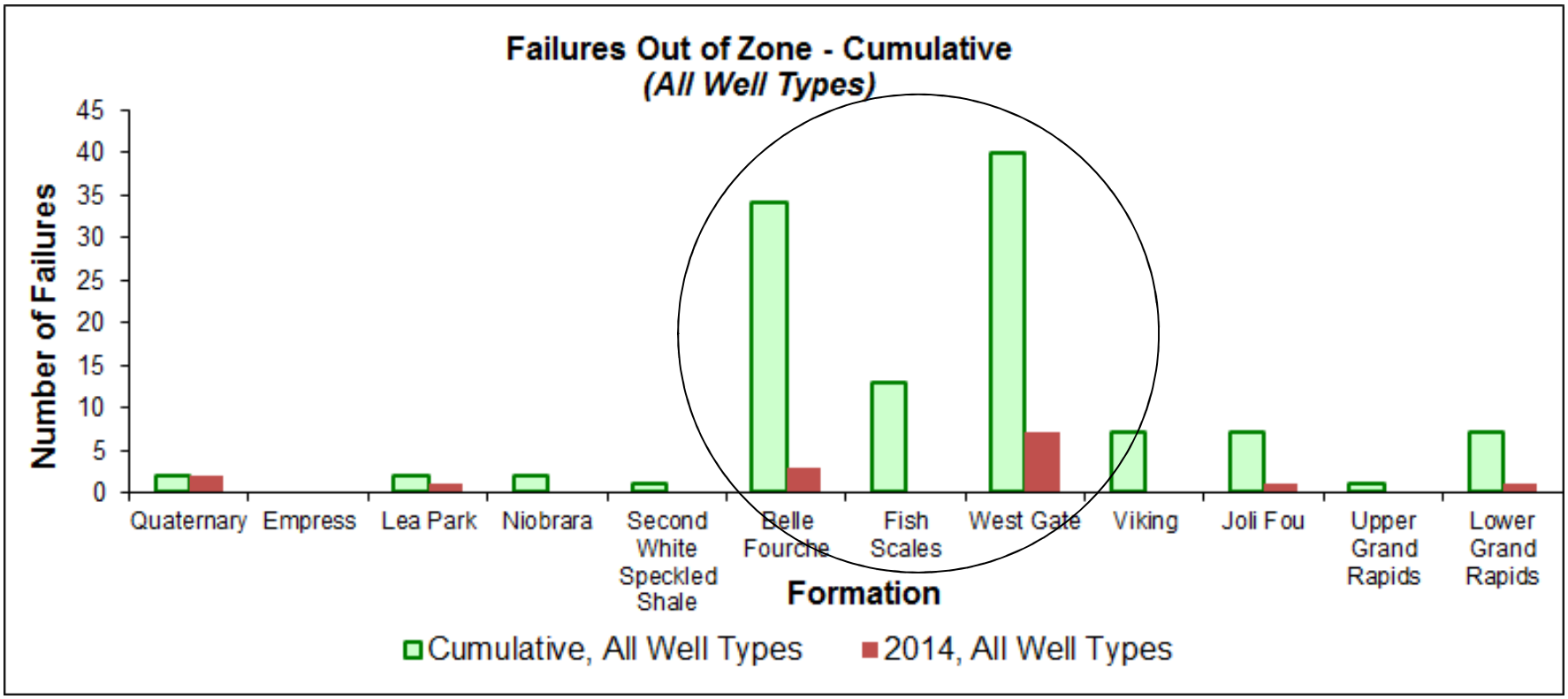
In Zone Failures by Cycle



In 2014, the majority of In Zone failures occurred in commercial cycle 4+

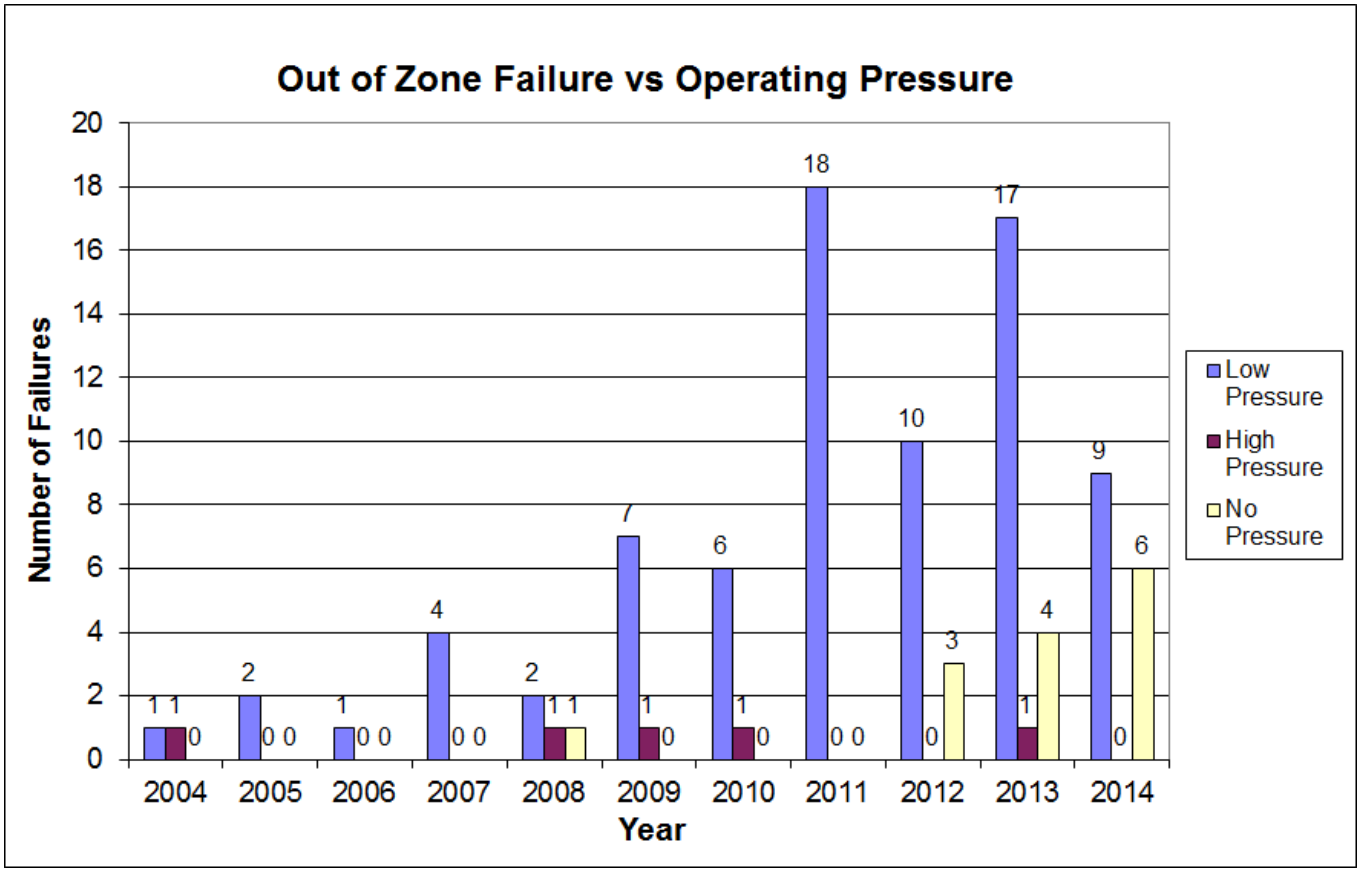
Failure rate decreased in 2014

Out of Zone Failures by Formation



Majority of the out of zone horizontal well casing failures occur in the Belle Fourche, Base of Fish Scales and Westgate geological formations

Out of Zone Failure vs Operating Pressure

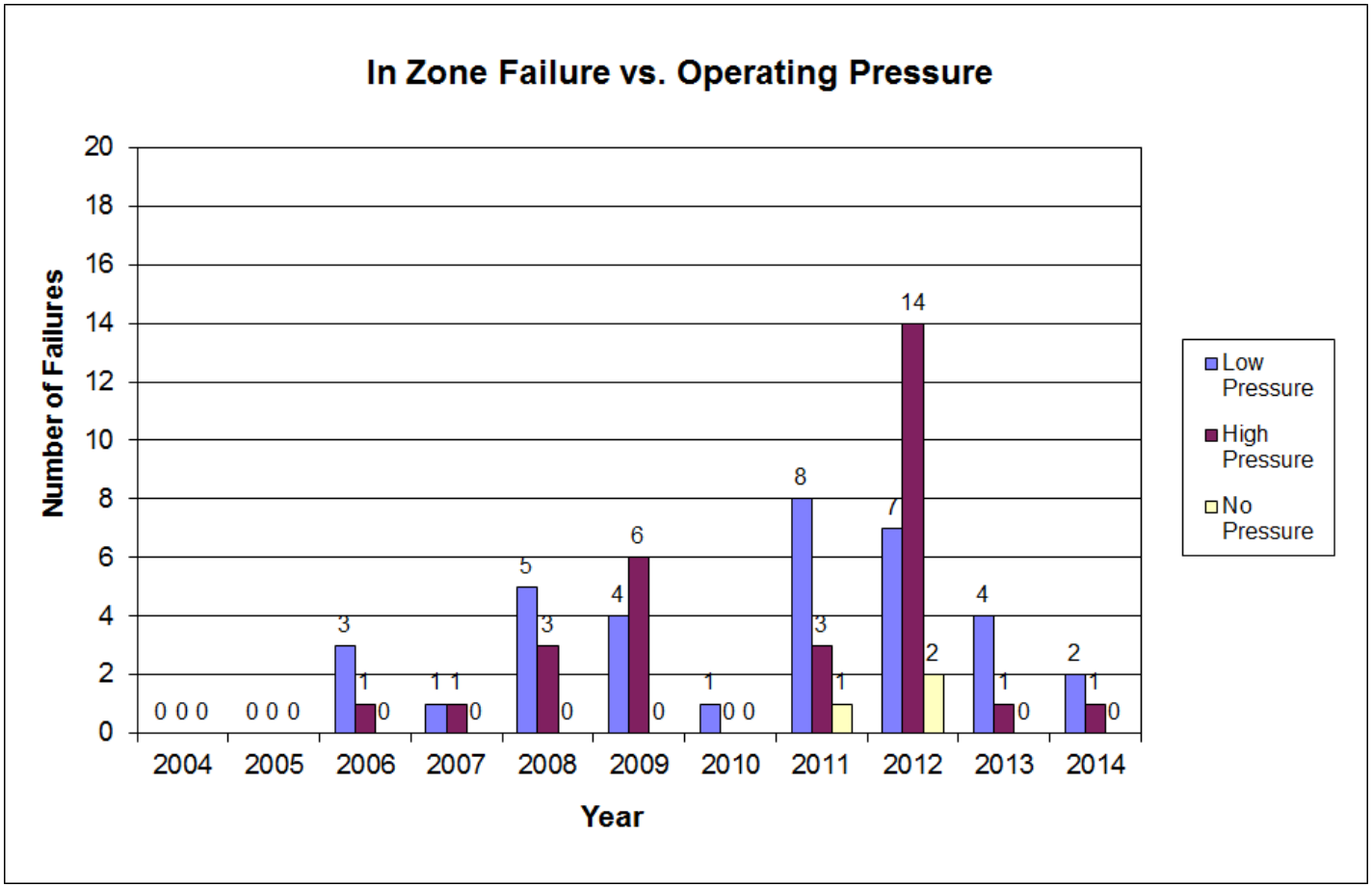


No HP failures in 2014

Majority of failures occur while under low pressure

- **High Pressure – Failed during HP steam, soak, trickle production or flow back**
- **Low Pressure – Failed during pumping or while well is shut in**
- **No Pressure – Failed during a work over**

In Zone Failure vs Operating Pressure



1 HP failure and
2 LP failures

Passive Seismic Detection Reliability

2012 to 2014 passive seismic detection rate 100%*

*On pads equipped with passive seismic, from 2012 to 2014, the detection rate for out of zone failures below the surface casing has been 100%.

From 2009 to 2014, on pads equipped with passive seismic, the detection rate of out of zone well failures is 95%

Part 2 Outline – Current Initiatives

- CSS Casing Integrity Protocol
  - Protocol revised and issued
- Understanding Failure Mechanisms
  - Computational analysis software implementation for interpreting local pipe deformations
- Thermal Well Design
  - 9 5/8 in. 40# L-80 Thermal Casing Connections Qualification
    - Physical testing and Finite Element Analyses update
- Failure Investigation
  - 12A42 production casing break at 14.7 mKB

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Casing Integrity Testing

Regular casing integrity tests start before commercial cycle 4

If well fails gauge ring test, run scraper and caliper log

Prior to Commercial Cycle	Gauge Ring/Scraper Test Proportion (% wells/pad)	Pressure Test Proportion (% of wells/pad)
1	N/A	100% (part of the completion process)
2	when production tubing is pulled	no scheduled test
3	when production tubing is pulled	no scheduled test
4	25%	25%
5	25%	25%
6	50%	50%
7	50%	50%
8	50%	50%
9+	100%	100%

Comparing Protocol with Scheme Approval

Before Commercial Cycle No.	9140 Application (2000 and 2006)* *From 1997 Imperial table - application says: "current practice, will use as guide and modify as experience is gained"	2014 Casing Integrity Protocol
4	0%	25%
5	50%	25%
6 & 7	50%	50%
8	100%	50%
9	100%	100%

Casing Integrity Protocol calls for start of testing pre-cycle 4 at 25%, goes up to 50% pre-cycle 6, and then up to 100% pre-cycle 9

Testing: Well Selection Criteria

1. Unresolved/low probability PS alarms
2. Delta flow/delta P alarms
3. Wells next to a Class 5 impairment well
4. Failed gauge ring run (if caliper log not yet run) or prior caliper log showed the impairment continuing to grow
5. > 3,000 casing revolutions during installation
6. Shut in >1 month (regardless of whether they were purged)
7. Shut in >1 week without purging the tubing-casing annulus

Casing Deformation Severity Classification

Class 4, out of zone: subject to review with Well Integrity before steam

Class 5, out of zone: POW or repair

Deformation Severity Class	Amount of Deformation at the Connection (mm)		Amount of Deformation in Pipe Body (mm)		Disposition
	177.8 mm OD casing	244.5 mm OD casing	177.8 mm OD casing	244.5 mm OD casing	
1	<3	<4	<5	<7	OK to steam.
2	3–4	4–6	5–7	7–10	OK to steam.
3	5–6	7–9	8–9	11–13	Requires pressure test before steaming
4	7–8	10–12	10–12	14–17	Requires a pressure test; subject to review with Well Integrity Engineer
5	>8	>12	>12	>17	1) Impairment is located above the top of the Clearwater Sand: convert well to POW, zonally suspend or repair well. 2) Impairment is within the Clearwater sand; subject to review with Well Integrity Engineer.

Shear Liner Installation in 8A67

- Two class 5 impairments both within the Clearwater reservoir detected in 8A67 (Jan. 2014 caliper log)

- 7 in. shear liner (uncemented) installed in Feb. 2015 in the Clearwater (from 582 to 743 mKB) – preventative measure taken to mitigate t loss of well access due to potential formation movement

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- Thermal Well Design
  - Tenaris Hydril 563 performance overview
  - TSH-Blue 9 5/8 in. 40# L-80 Thermal Casing Connections Qualification
    - Physical testing and Finite Element Analyses update
- Failure Investigation
  - 12A42 production casing break at 14.7 mKB

Interpreting Pipe Deformations

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Goals:

- Characterize deformations by analyzing the well trajectories
- Pre-steam casing integrity checks
- Understand pad and area-wide failure patterns
- Track deformations over time and correlate to failure frequencies

Well 6C30: 602 to 608 mKB, Buckle and Flex

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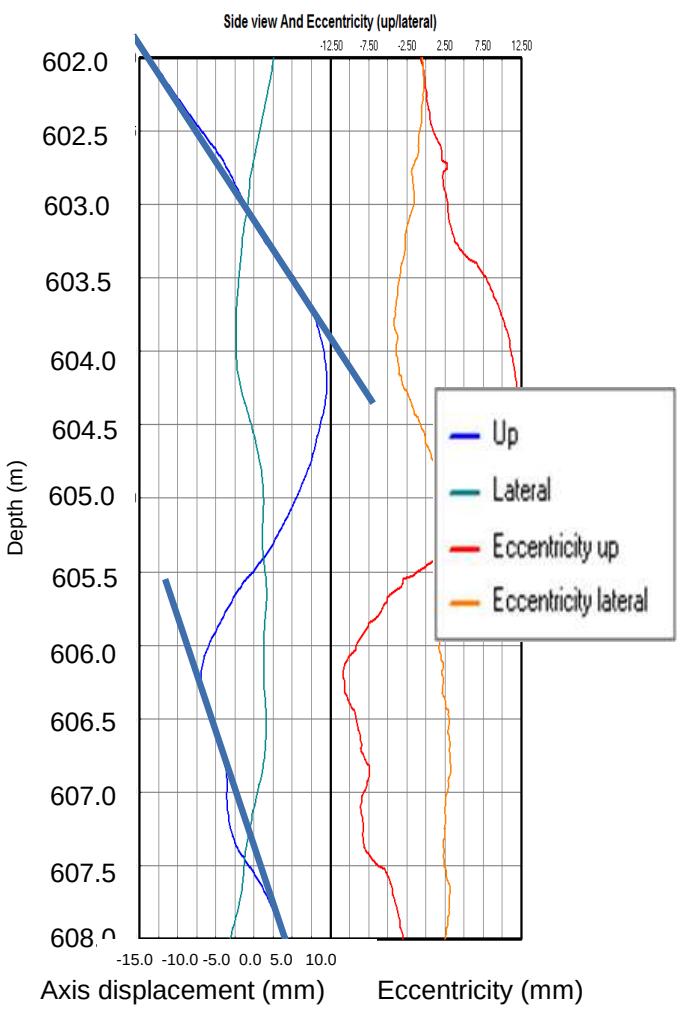
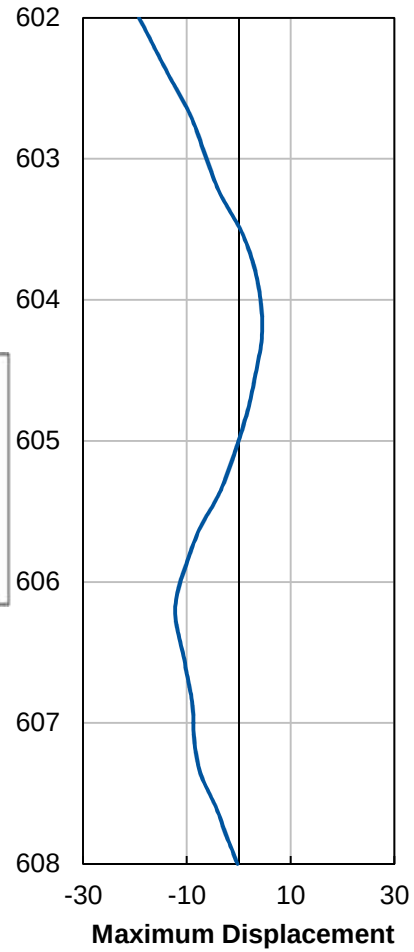
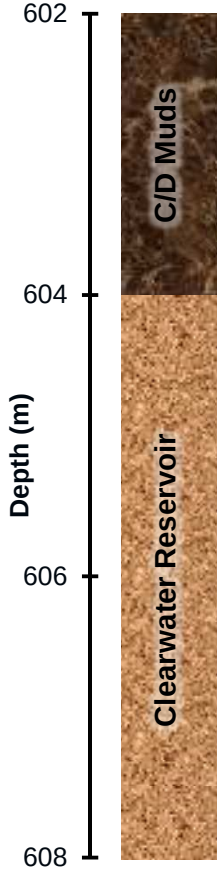
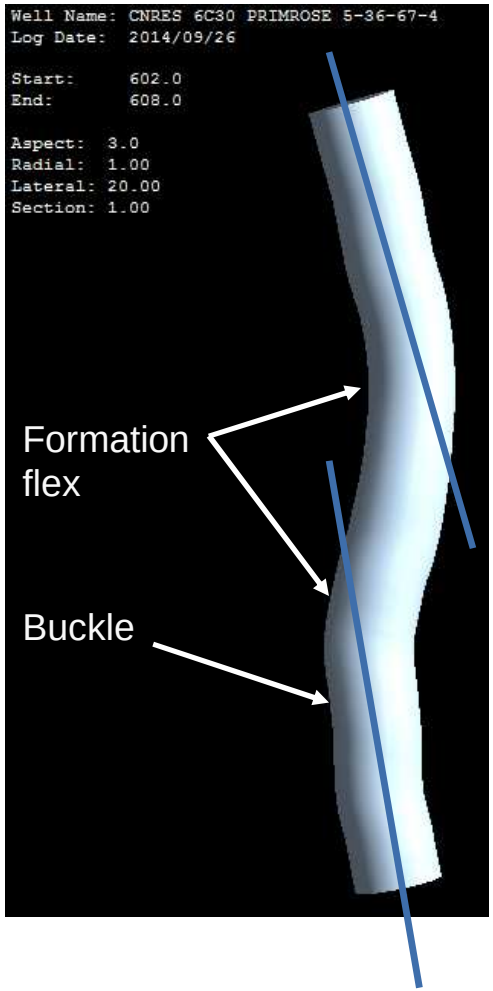
Formation flex and buckle features can be distinguished

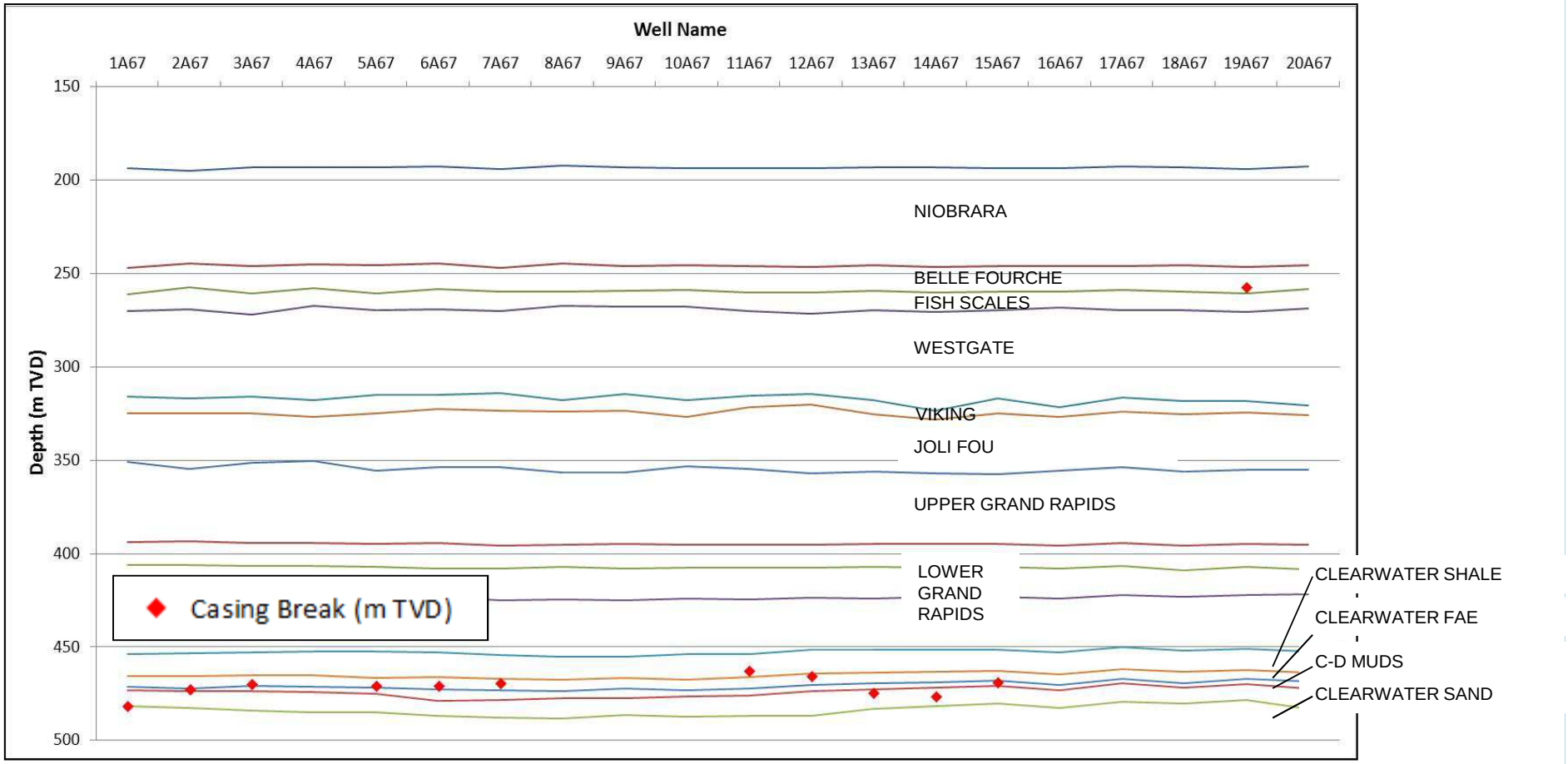








Pad 67 Stratigraphy with Breaks



Breaks concentrated in the Clearwater, one in the Belle Fourche

Computational Analysis Software Conclusions

- Casing breaks located in: Colorado and Clearwater
- Causes of failure: fatigue life, thermal cycling of the casing, and formation movement
- Area analyses: further understanding of variables impacting casing integrity performance

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Thermal Connections Qualification

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Casing connections aspects evaluated:

Sealability

Mechanical integrity: tensile/compressive efficiency

Fatigue performance - mitigates against premature crack initiation during installation

40# 9-5/8” L80 Connection Qualification

CNRL’s connection qualification is comprised of three aspects:

1. Thermal Cycling Physical Testing based on CSS operating conditions
2. Finite Element Analysis (FEA) – Thermal Cycles and Curvature Loading
3. Fatigue Testing

Thermal Cycling Physical Testing

Tested at upper bound of **337 °C** and lower bound of **room temperature**, max internal pressure **13.8 MPa**, over 10 thermal cycles

- Sample is axially constrained

Connection seepage rate limits:

- 1 mL/minute for holds at 337 ° C
- 10 mL/minute for holds at room temperature

Result: passed seepage rate criteria

Finite Element Analysis

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Purpose is to analyze:

- **Seal contact pressures**
- **Seal and thread contact stresses**
- **Plastic equivalent strain**

FEA Results

Thermal cycle loading case complete, curvature loading cases to be completed

Confirmed for the thermal cycling case:

- Seal contact intensities are maintained with thermal loading
- Seal and thread contact stresses below the UTS
- Plastic equivalent strain predictions after 1 cycle are well below 10%

Fatigue Testing

- Fatigue testing was conducted in 2013 and 2014 by the manufacturer
- The higher the DLS, the larger the difference between the number of cycles to failure and the number of cycles to fatigue crack initiation
- Current rotations criteria: aim for 2,000; flag for testing if >3,000

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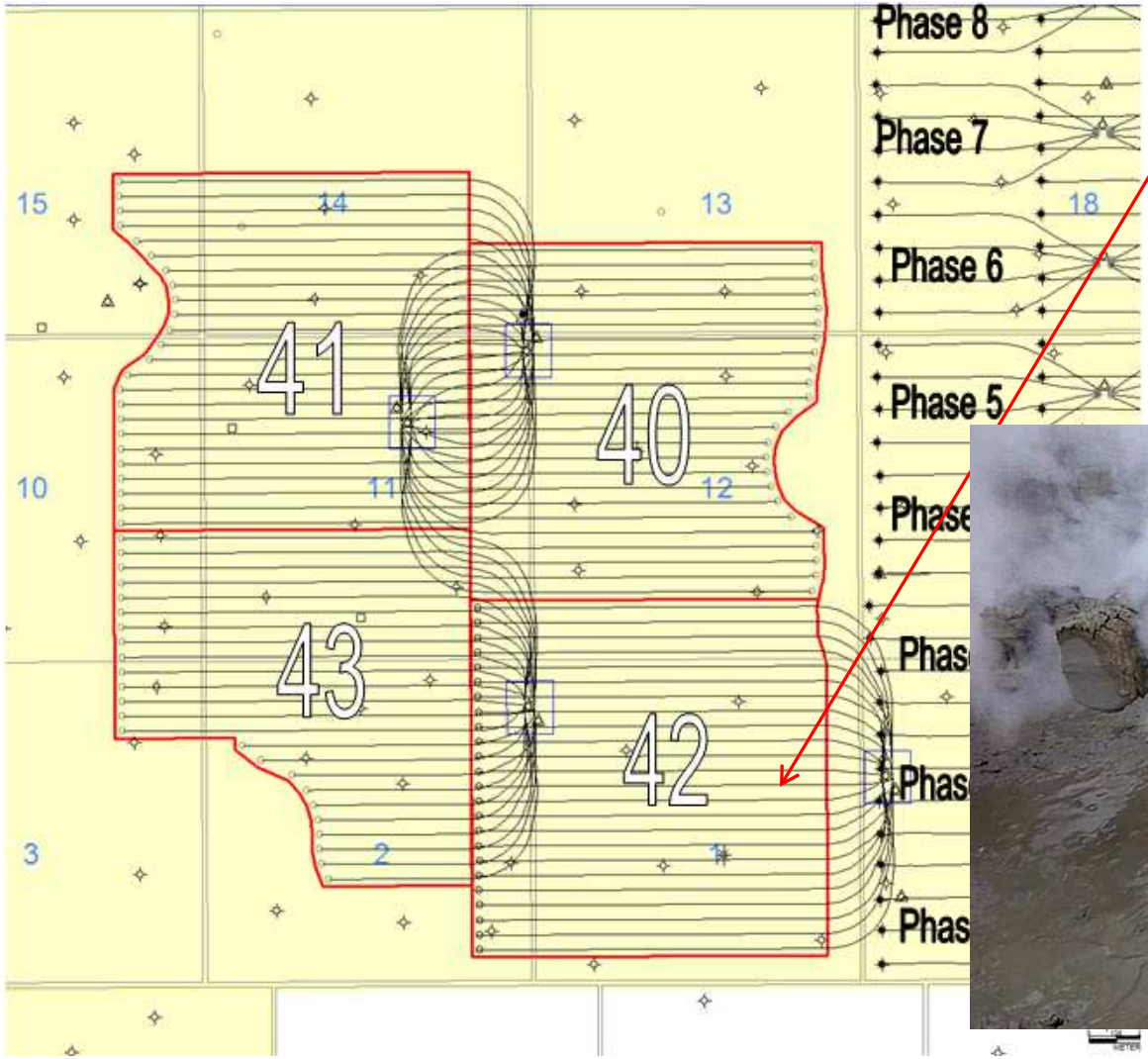
12A42 Near-surface Break

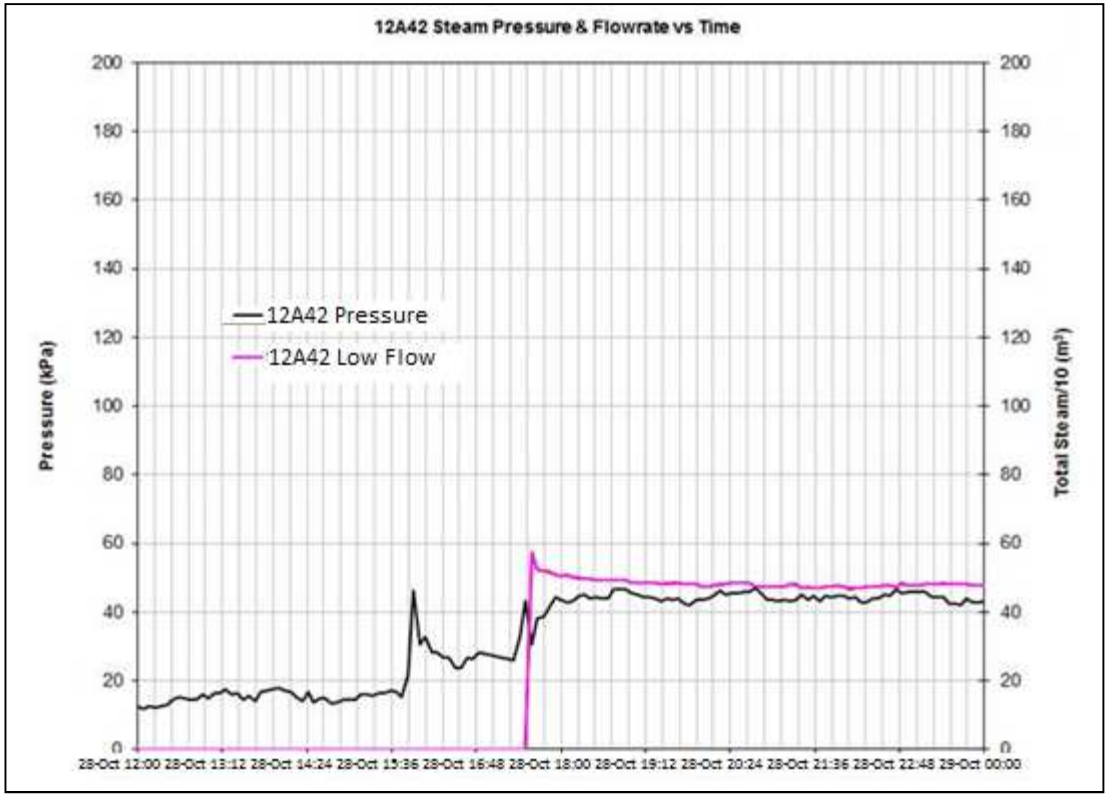


On Oct. 28, 2014, 12A42 experienced a failure of production and surface casing at ~14 mKB

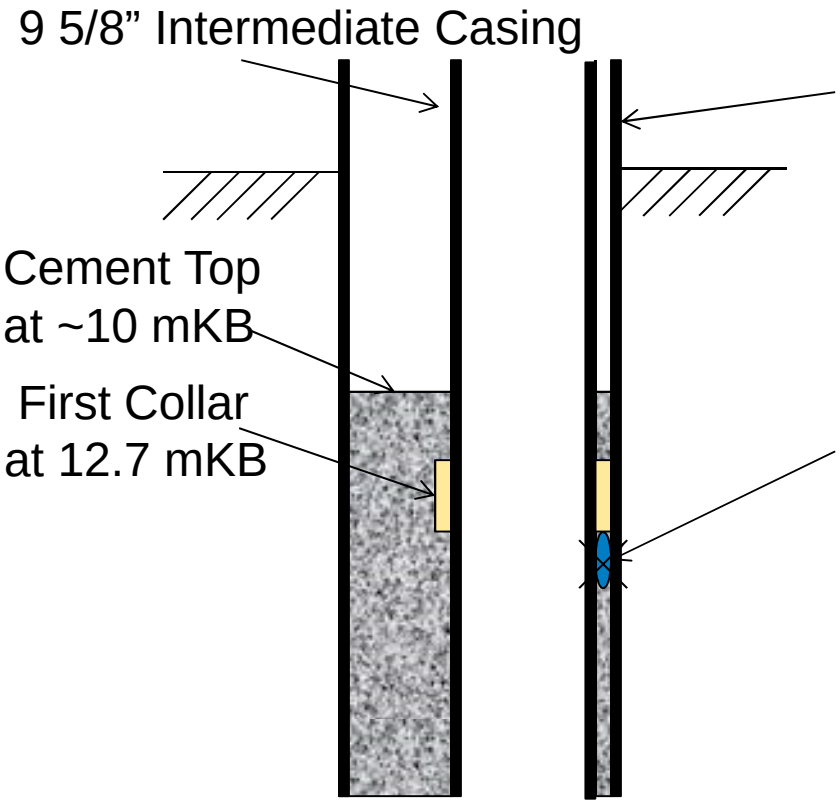
12A42 Near Surface Break

During initial cure out operations at the time steam was introduced to the well, steam started to escape through the surface casing.

- Casing pressure did not build past ~40 kPa during steam injection and remained constant until well shut-in



12A42 Near Surface Break



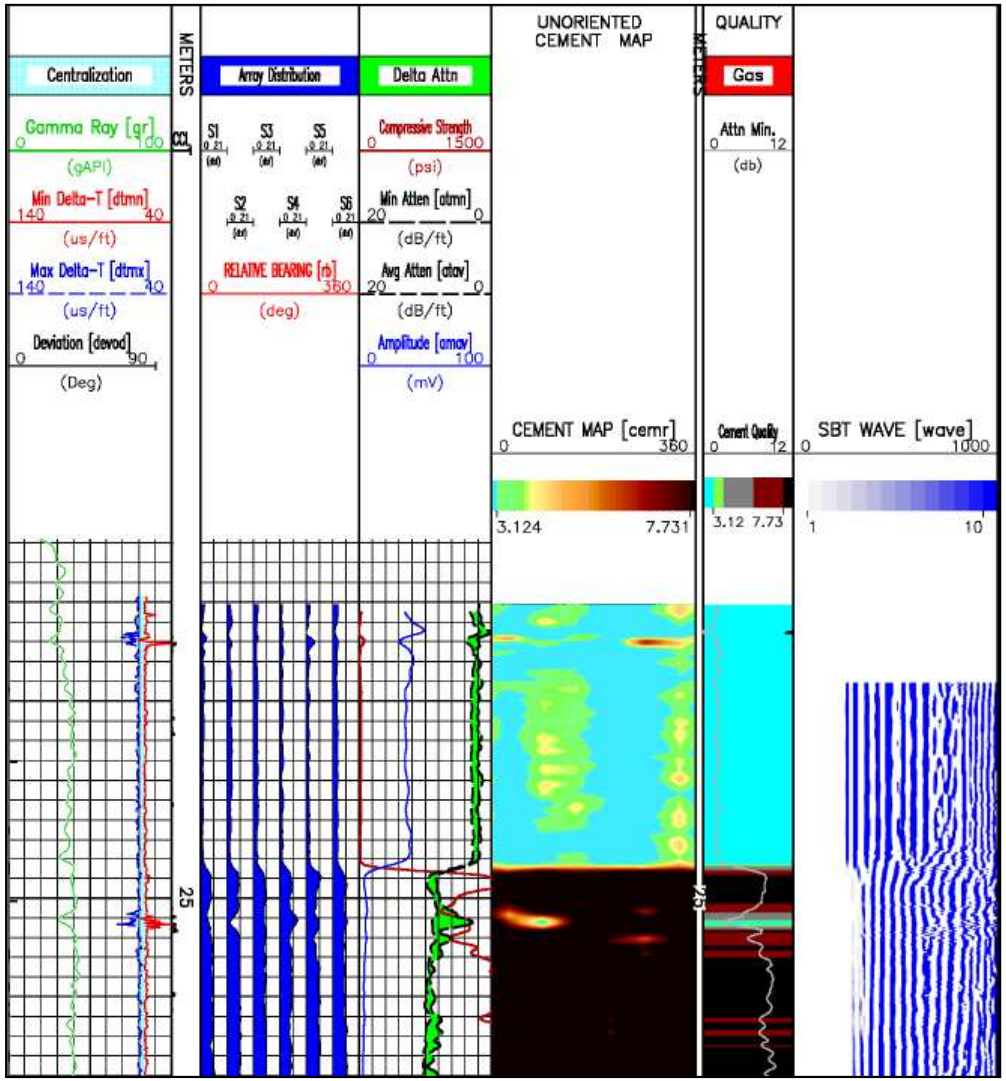
Intermediate casing collapse and Surface casing burst at 14 mKB

- Cause of failure:
  - Thermal expansion of a trapped water pocket

Reasons for trapped water pocket:

- Production casing eccentric to the surface casing
- Loss of pipe movement while pumping cement

Cement Integrity Log and Cement Returns

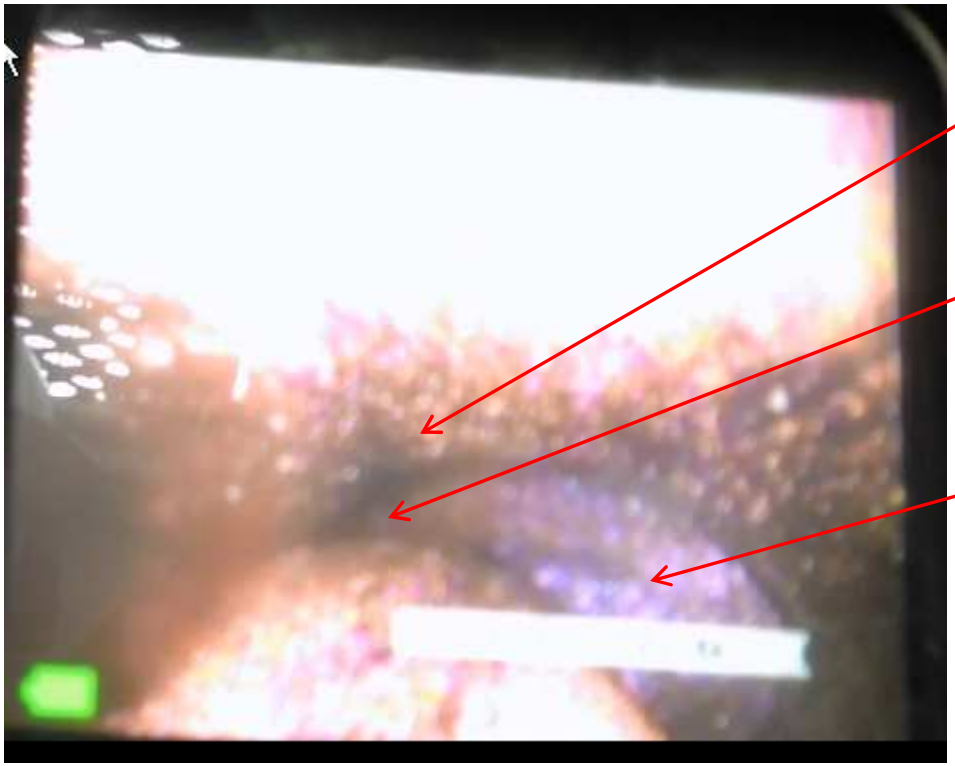


Cement integrity log not available above 23.5 mKB due to the internal liquid level

- Based on hole gauge, 11 m^3 of cement returns expected
- 10 m^3 of cement returns to surface reported (1800 kg/m^3)
- The cement returns observed during the primary cement job were classified as “good” quality cement
- No slumpback reported after placement of primary cement

12A42 Eccentric Intermediate Casing

Intermediate/surface casing annulus – cement top



13 3/8” surface casing

9 5/8” intermediate casing eccentric to the surface casing

Cement top

Changes to Well Construction Practices

12A42 was one of the first wells drilled in the 40 series

Adjustments made during the drilling of 40 series pads:

- Changed centralizer type and frequency within surface casing
- Casing is now reciprocated and rotated to improve circulation efficiency

Repair – 7” casing was installed and cemented in place and the well was steamed during cycle 2 operations

Section 3 - Future Initiatives

- CSS Casing Integrity Protocol
  - Work on protocol continues in 2015
    - Targeted selection process in the process of implementation
    - Developing risk-based area-specific casing integrity testing requirements
- Computational Analysis Software
  - Development group participation
  - Analyses for pre-steam checks and area analyses
- Well Integrity Management Software Evaluation
  - Complete technical/economic evaluation and recommend path forward

Section 4 Conclusions

- CNRL continues to obtain further understanding of well failure mechanisms
- Well design changes have had a positive impact on well integrity performance
- Questions/Comments?

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, the construction and future operations of the North West Redwater bitumen upgrader and refinery and disclosures relating to the Devon Canada Asset acquisition 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, 2013 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), 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, 2013 and a preparation date of February 3, 2014. 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. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 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 targeted to be released in late March 2013

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, 2012. 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.

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 "Financial Highlights" 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.

PROVEN | EFFECTIVE | STRATEGY

THE PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

Canadian Natural

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

PROVEN | EFFECTIVE | STRATEGY

Canadian Natural

2014 PRIMROSE, WOLF LAKE, AND BURNT LAKE ANNUAL PRESENTATION TO THE AER

SUBSURFACE ISSUES RELATED TO RESOURCE EVALUATION AND RECOVERY

January 2015

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

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

Canadian Natural

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

January 27, 2015

3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery

January 28, 2015

3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

Outline - Subsurface Issues Related to Resource Evaluation and Recovery

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

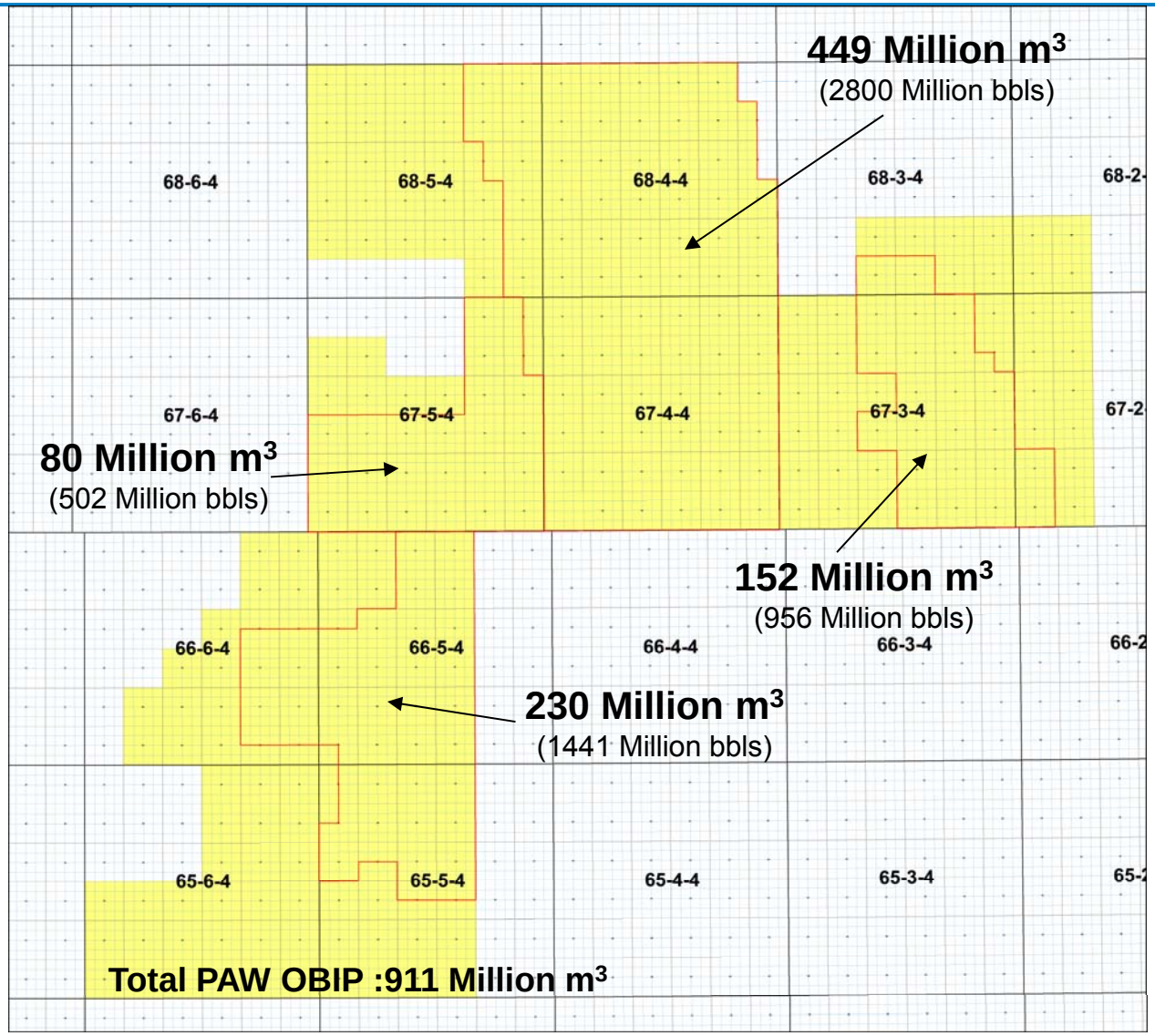
Canadian Natural

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

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

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
SAGD	steam assisted gravity drainage
SF	steamflood
So	oil saturation
SOR	steam oil ratio
SPM	strokes per minute
tbg.	tubing
TD	total depth
TVD	true vertical depth
VOF	volume over fill-up
WDI	water depletion index
YE	yearly

Primrose and Wolf Lake OBIP within Scheme Approval 9140 Development Area



OBIP numbers include:

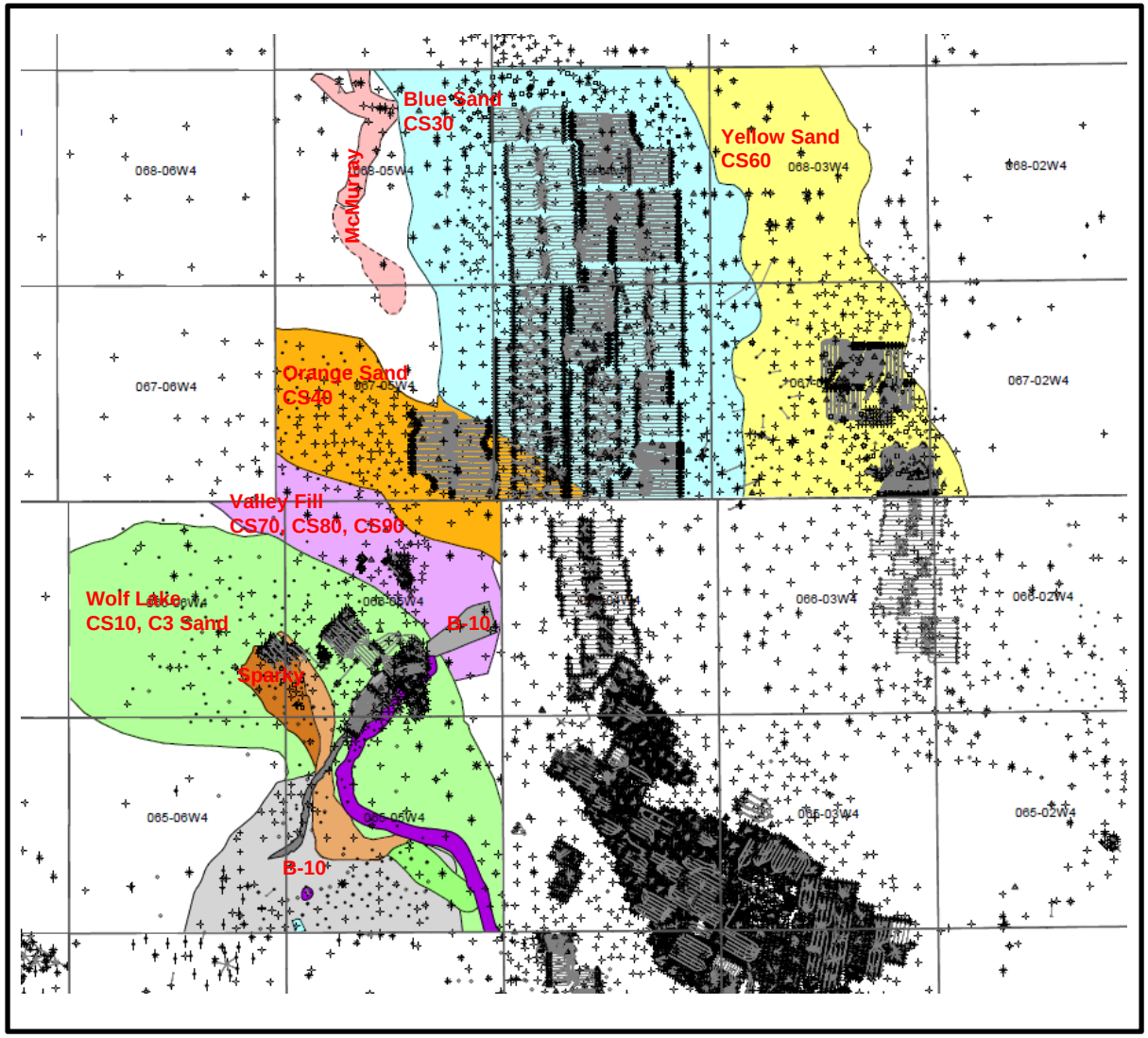
- **McMurray**
- **Clearwater**
- **Grand Rapids**

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: 11 m
Porosity: 32%
Horizontal permeability: 3,000 mD
Vertical permeability: 900 mD
Viscosity: 100,000 cP (at 15°C)

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

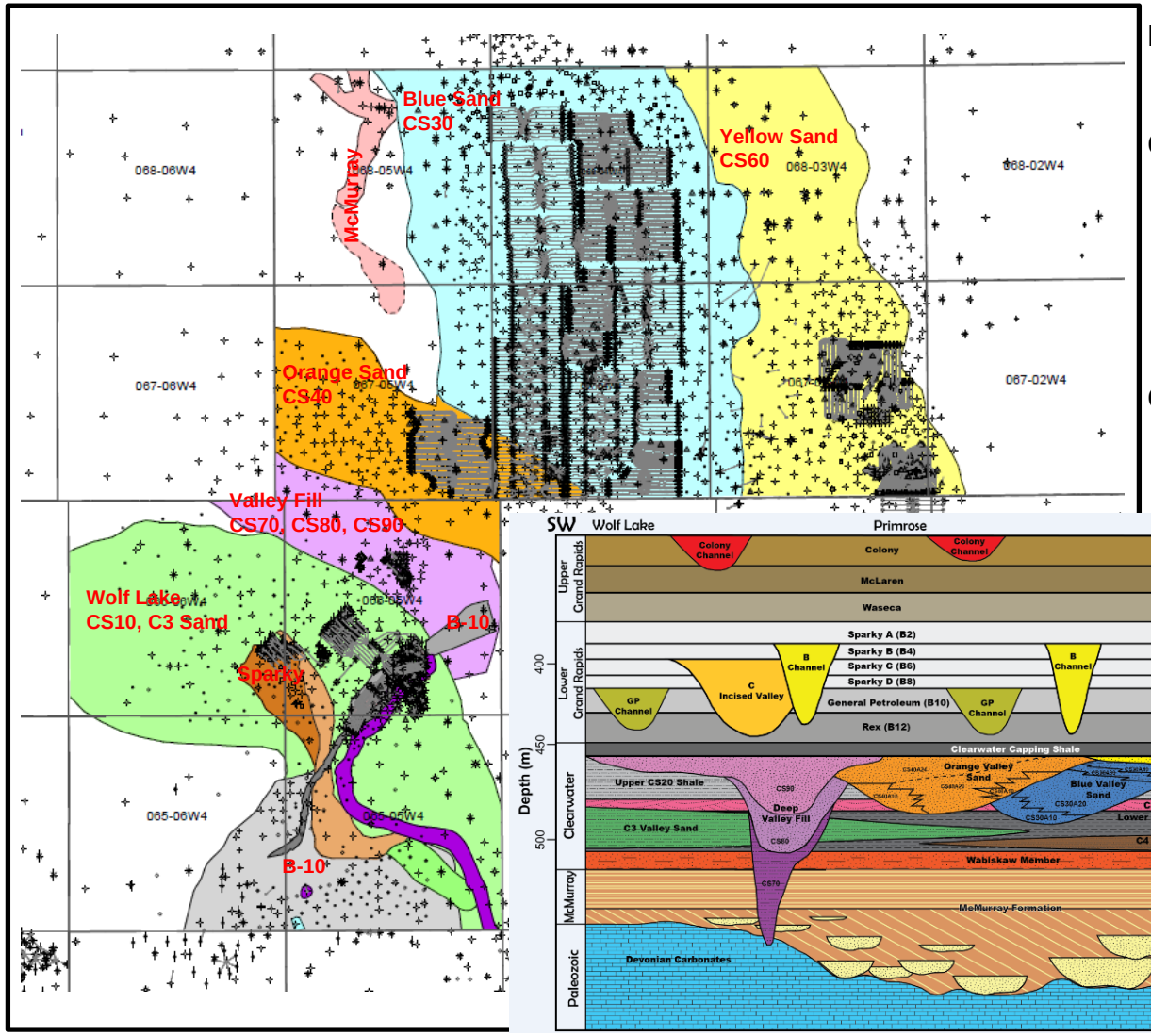
Valley Fill (Wolf Lake)
1988 (BP): Z8 Vertical Well CSS
1989 (Amoco): HWP1 SAGD Pilot
2005 (CNRL): Z13 Vertical Well CSS

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

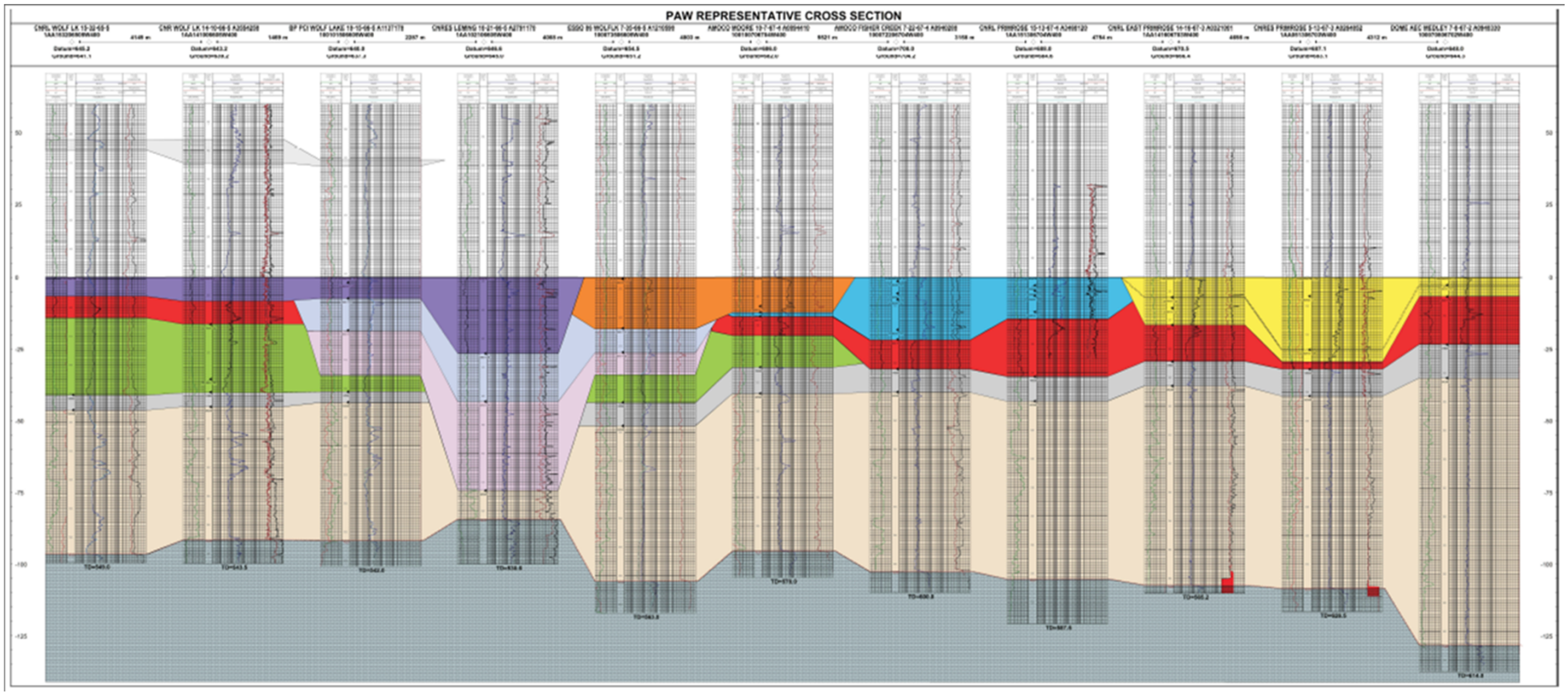


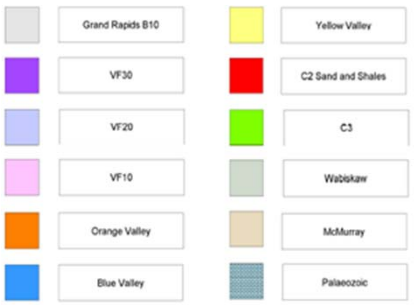
McMurray: Estuarine to shoreface deposits

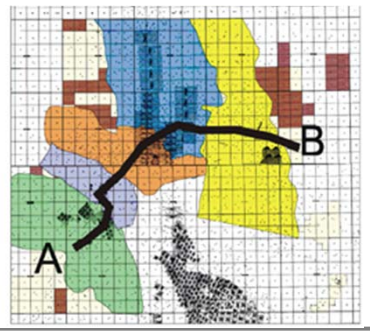
Clearwater: Compound incised valley system
Estuarine deposit vary from valley to valley
Valley specific reservoir facies assemblages

Grand Rapids: Shoreline deposits cut by channels

Representative Stratigraphic Cross Section



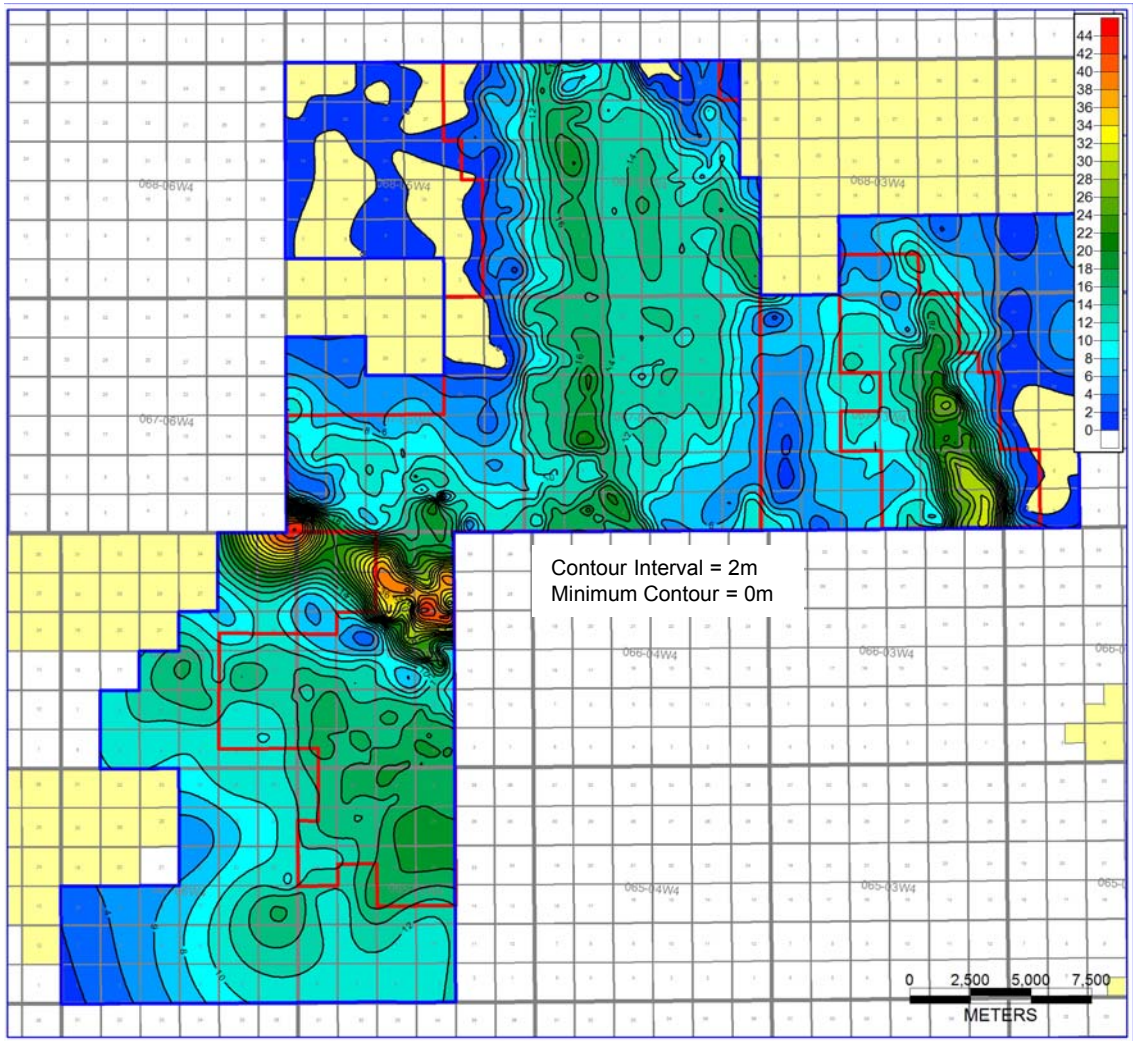




Clearwater Net Pay Isopach

Canadian Natural

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)

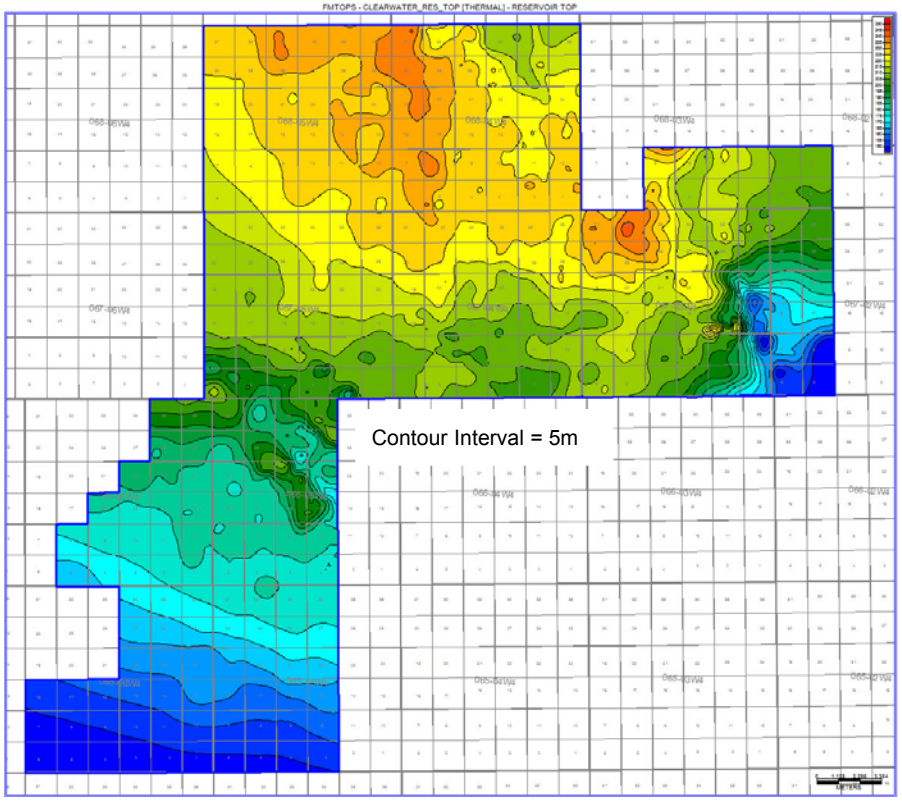
Wolf Lake:

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

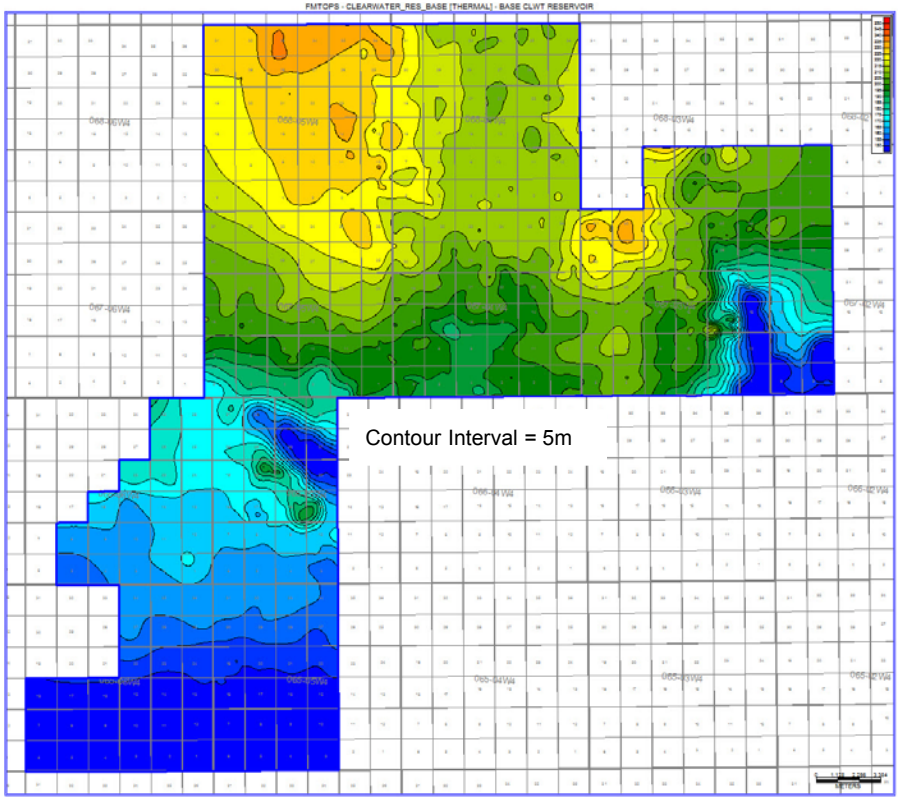
Clearwater Formation Structure

Canadian Natural

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)

Canadian Natural

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)

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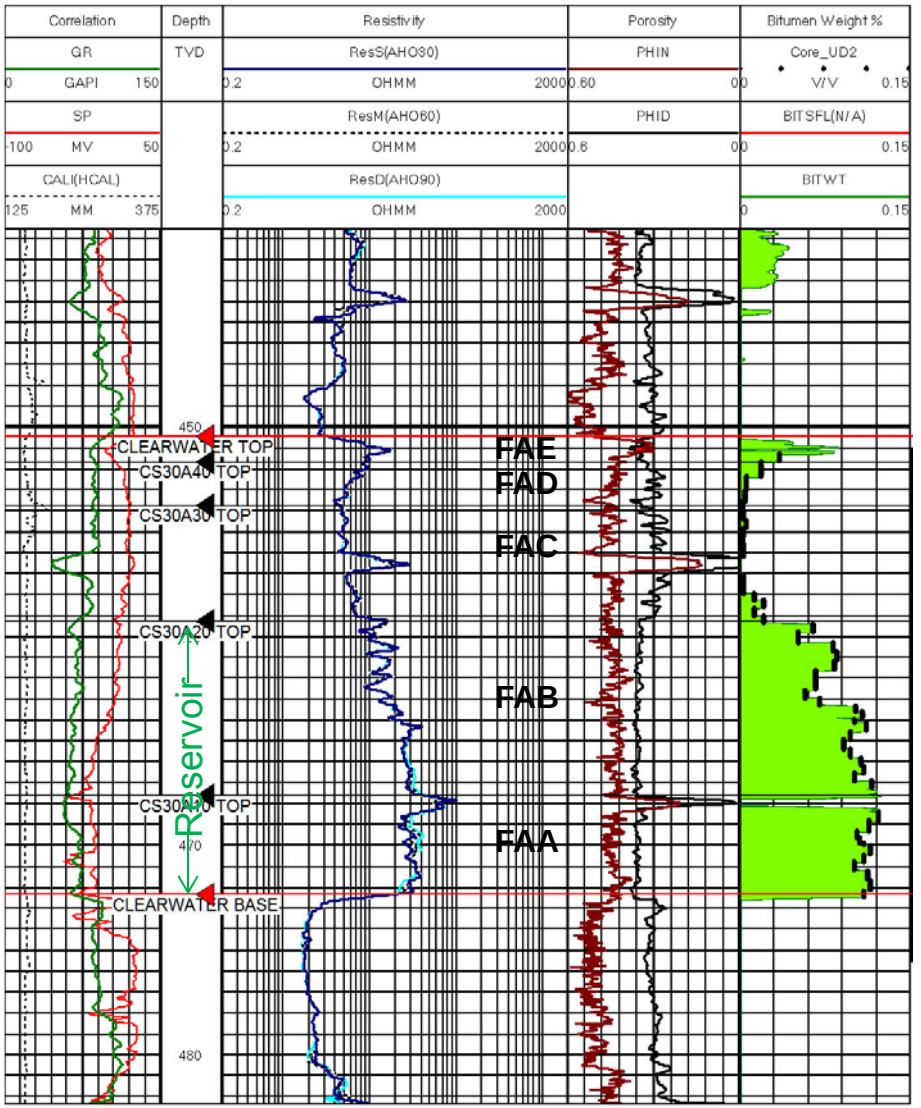

Orange Sand (Primrose South)

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°C)

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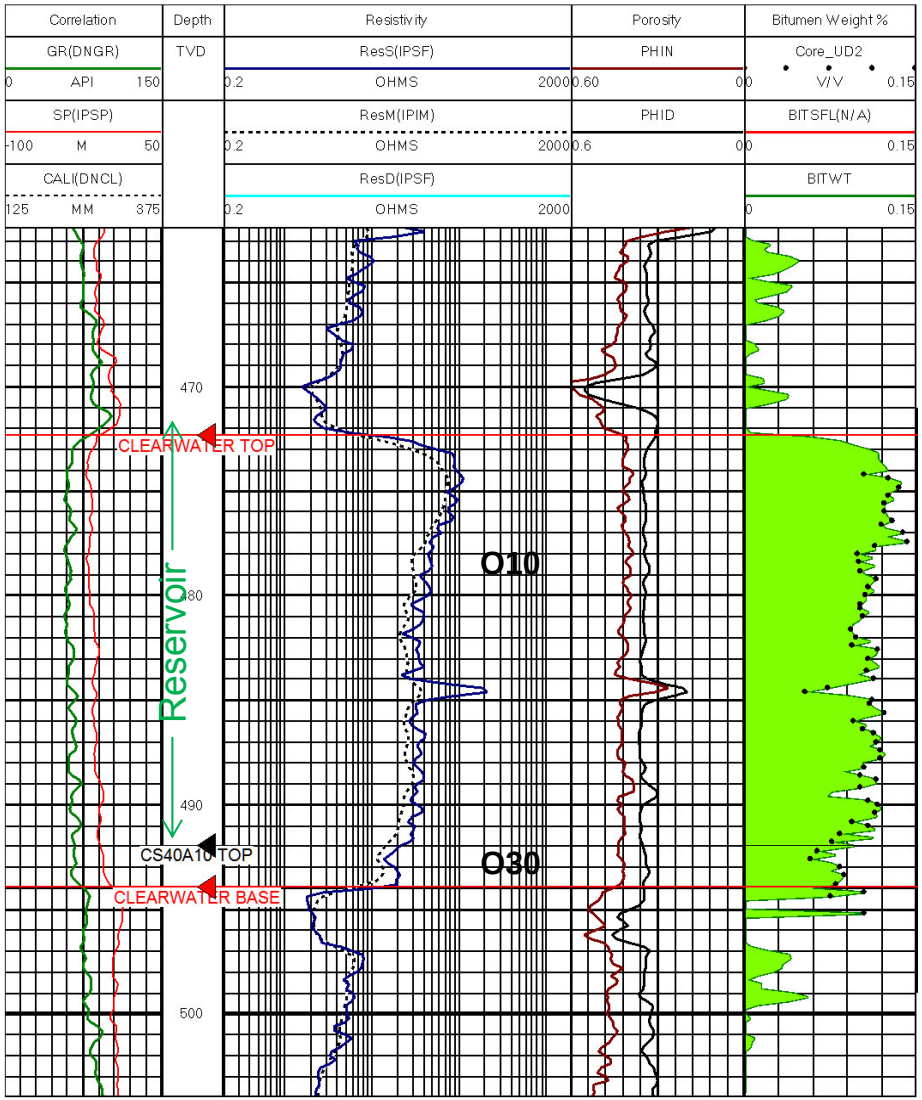

Yellow Sand (Primrose East)

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°C)

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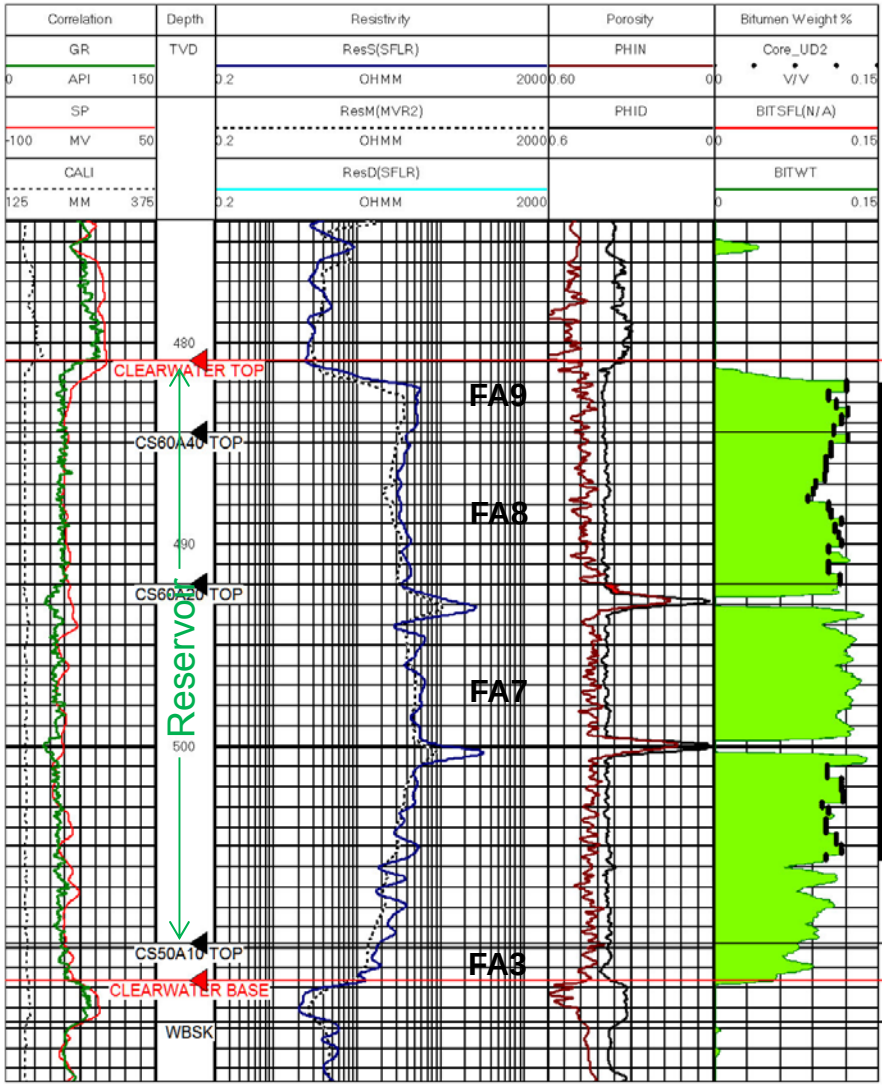

Valley Fill (Wolf Lake)

Canadian Natural

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: 200 mD
- Avg. viscosity: 100,000 cP (at 15°C)

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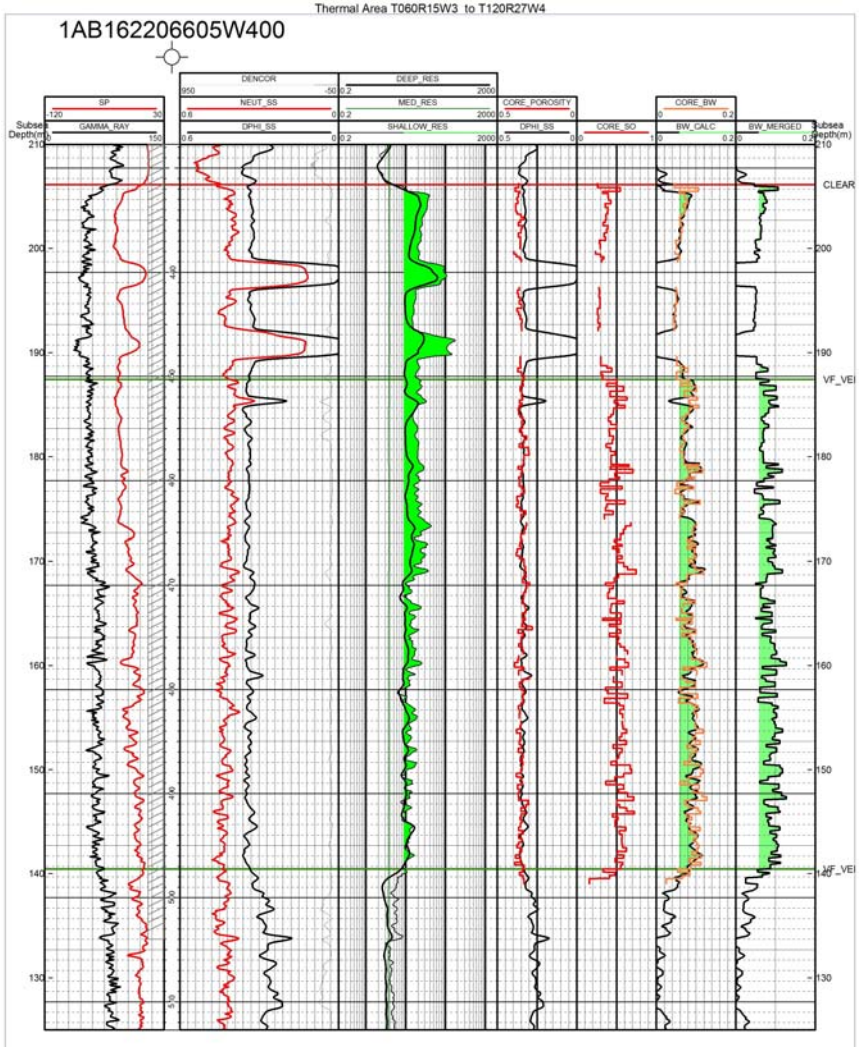
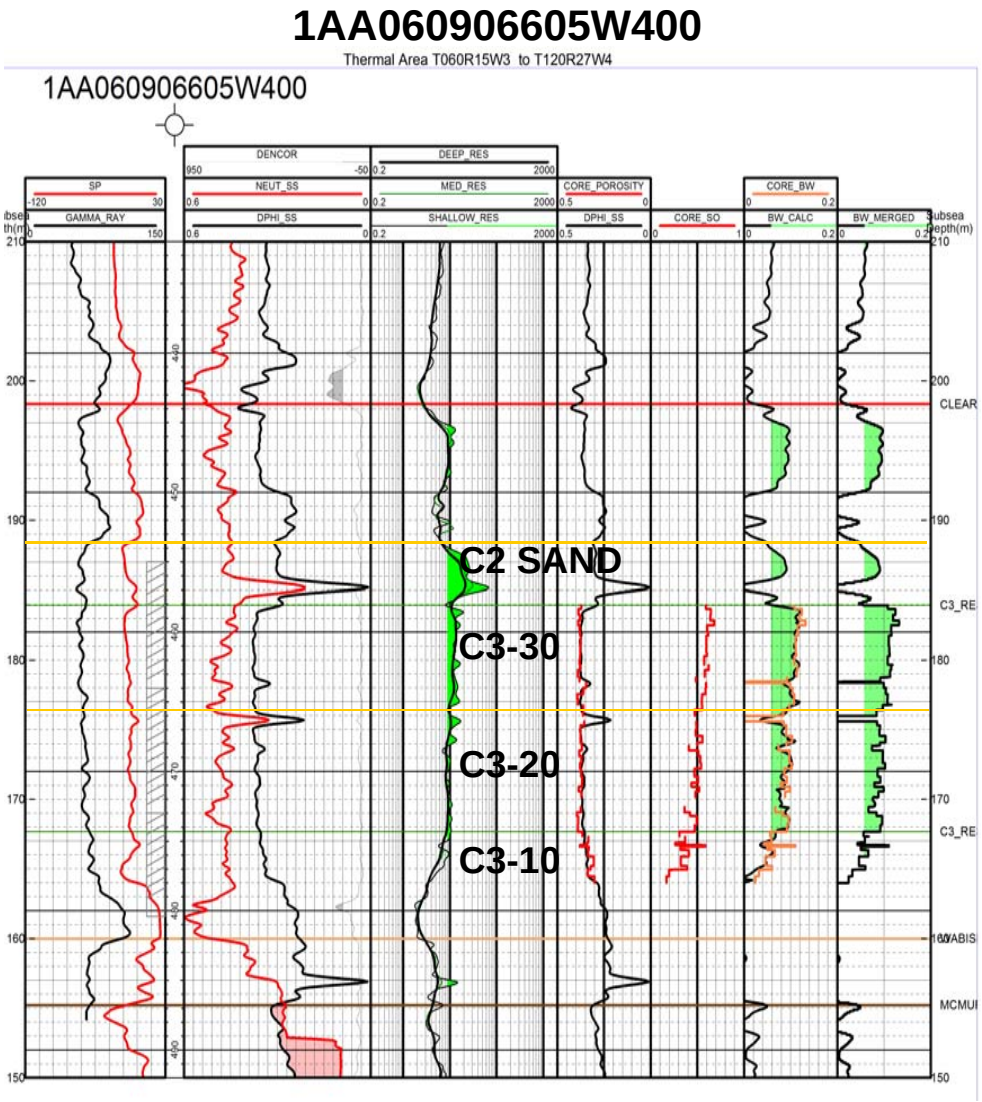


C3 Sand (Wolf Lake)

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°C)

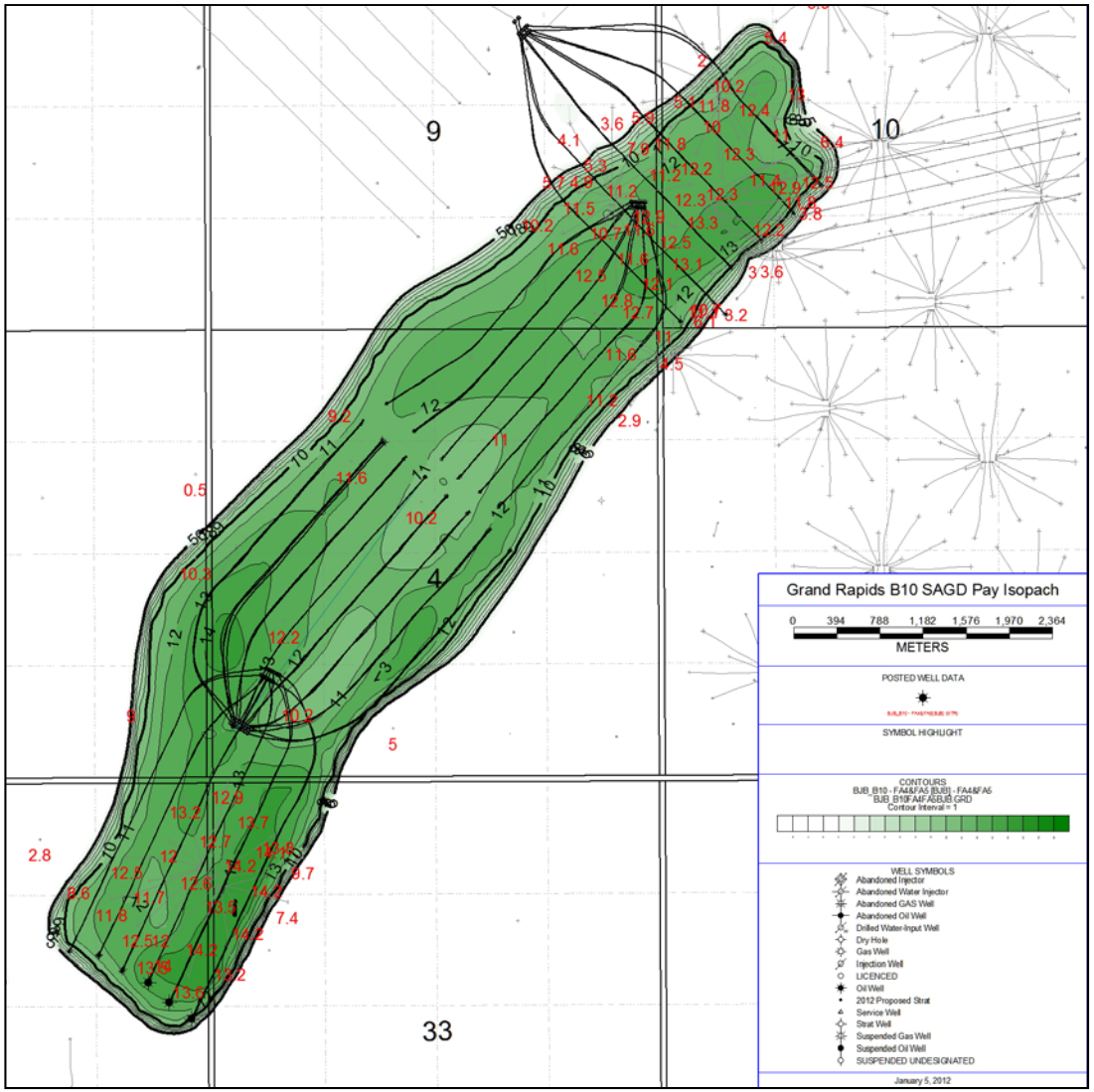


Grand Rapids B10 Pay Isopach

Canadian Natural

Grand Rapids B10

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



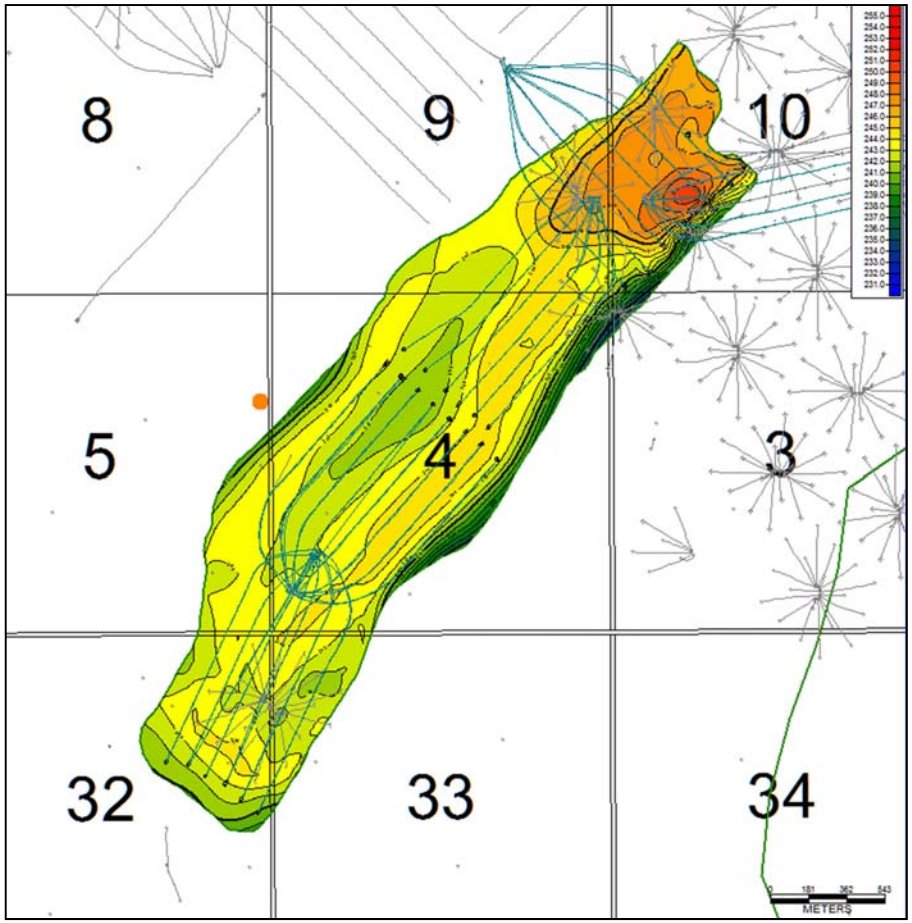
Contour Interval = 1m,

Minimum 5m shown

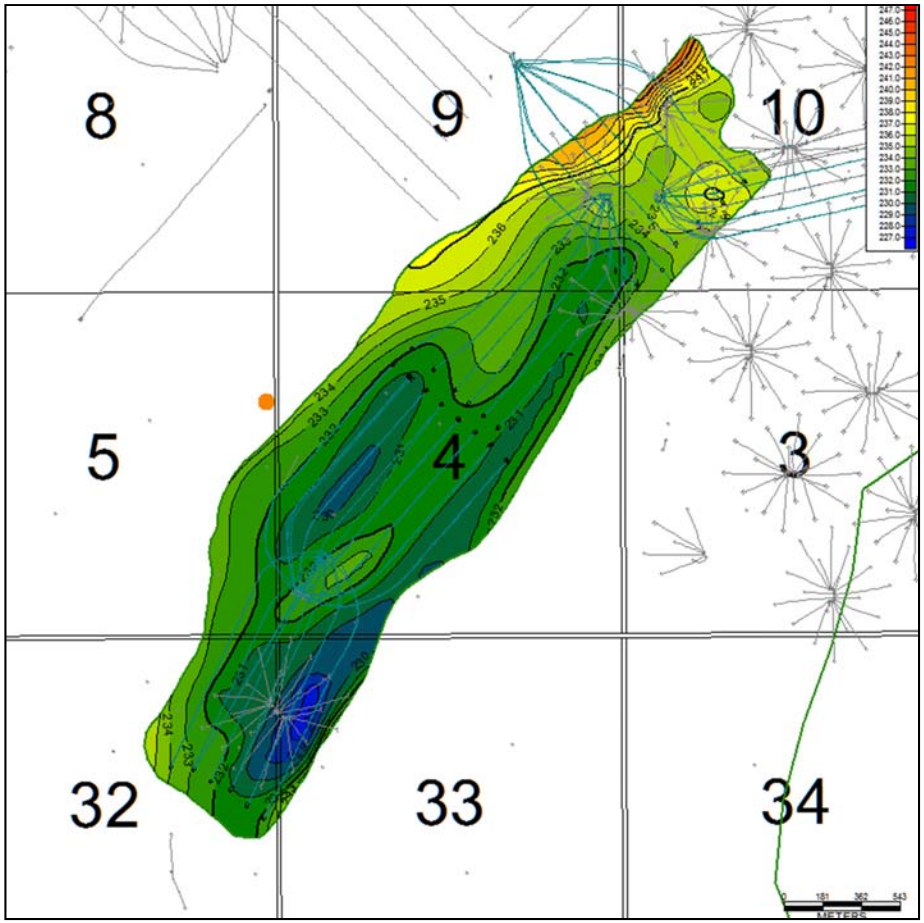
Grand Rapids B10 Structure

Canadian Natural

Reservoir Top Structure



Reservoir Base Structure



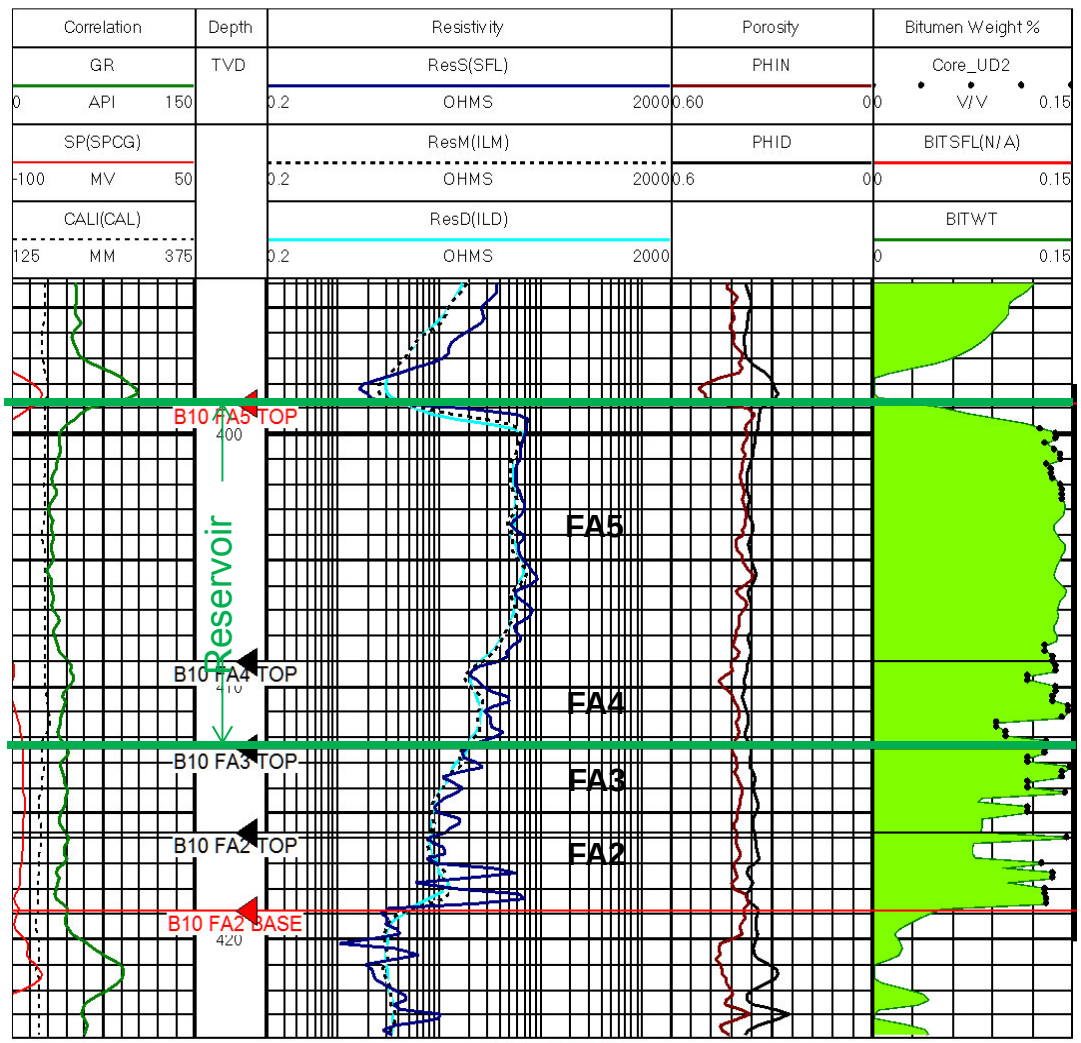
SAGD pay defined as clean sand in FA4 and FA5

- Average bitumen weight 11.5%

Wolf Lake SAGD B10 Sand Reservoir Characteristics

Reservoir Characteristics

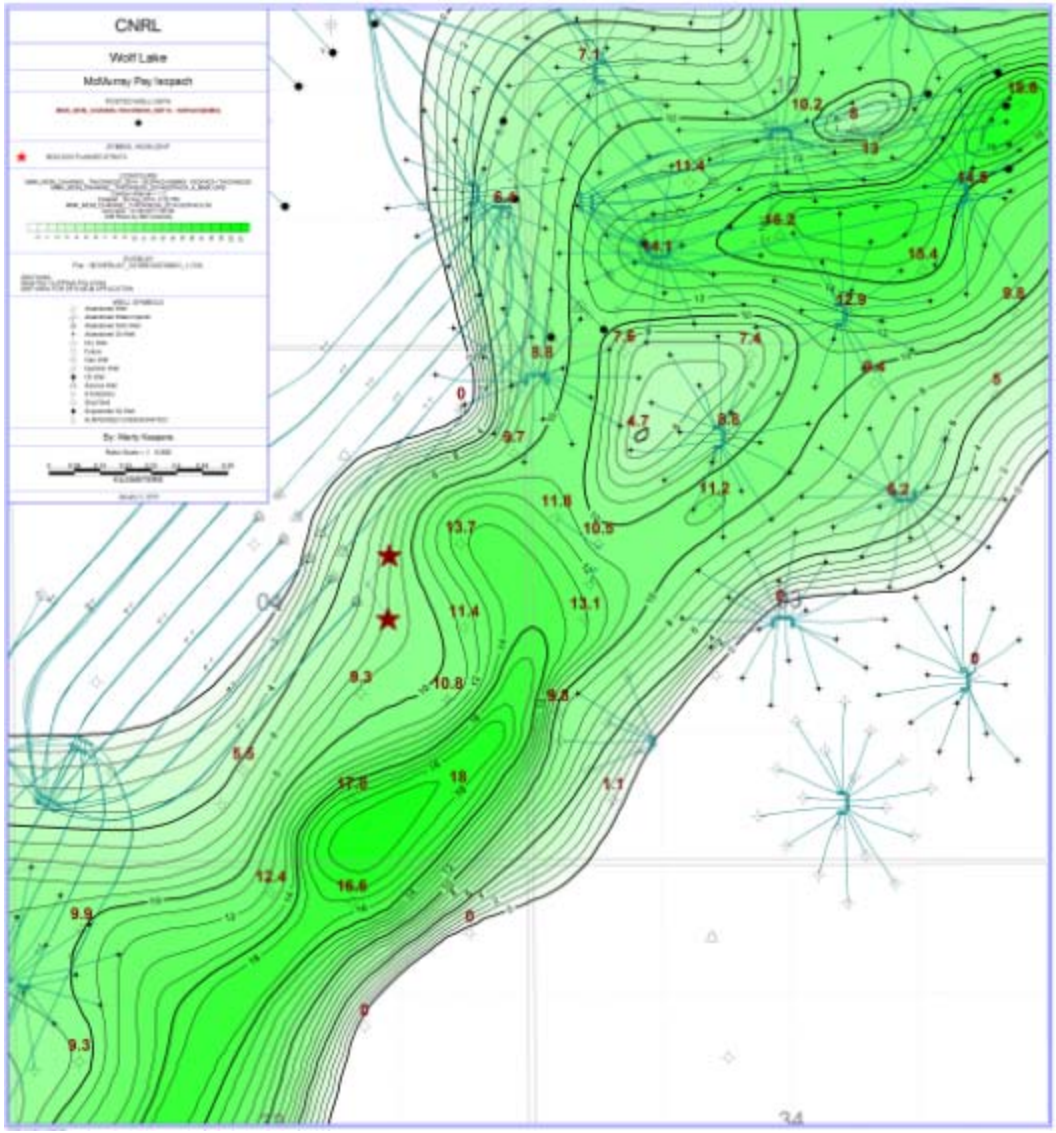
- Reservoir: FA5 & FA4
- Average oil saturation: 75%
- Average bitumen weight: 11.5%
- Maximum net pay thickness: 16 m
- Average porosity: 33%
- Average HZ permeability: 3,200 mD
- Average Vertical Permeability: 2,500 mD
- Average Viscosity: 100,000 cP (at 15°C)
- No connected bottom water



Wolf Lake McMurray SAGD Pay Isopach

McMurray Sand

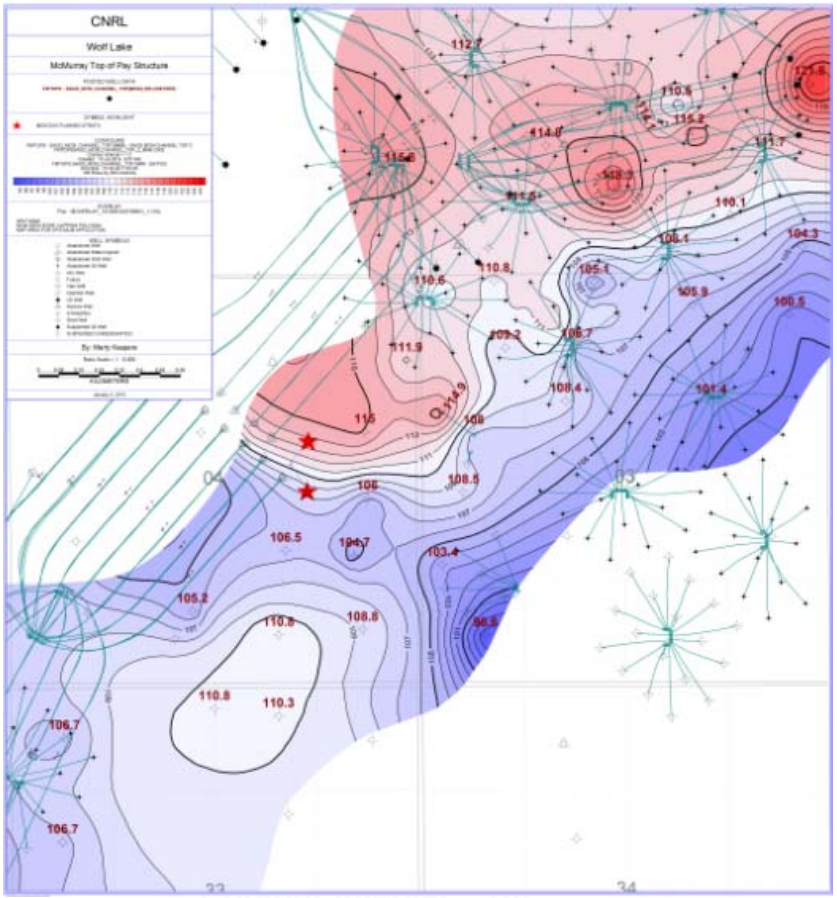
- Channel deposits with bitwt >10%
- Net pay >10 m for development
- Proposed 2015 strat wells ★



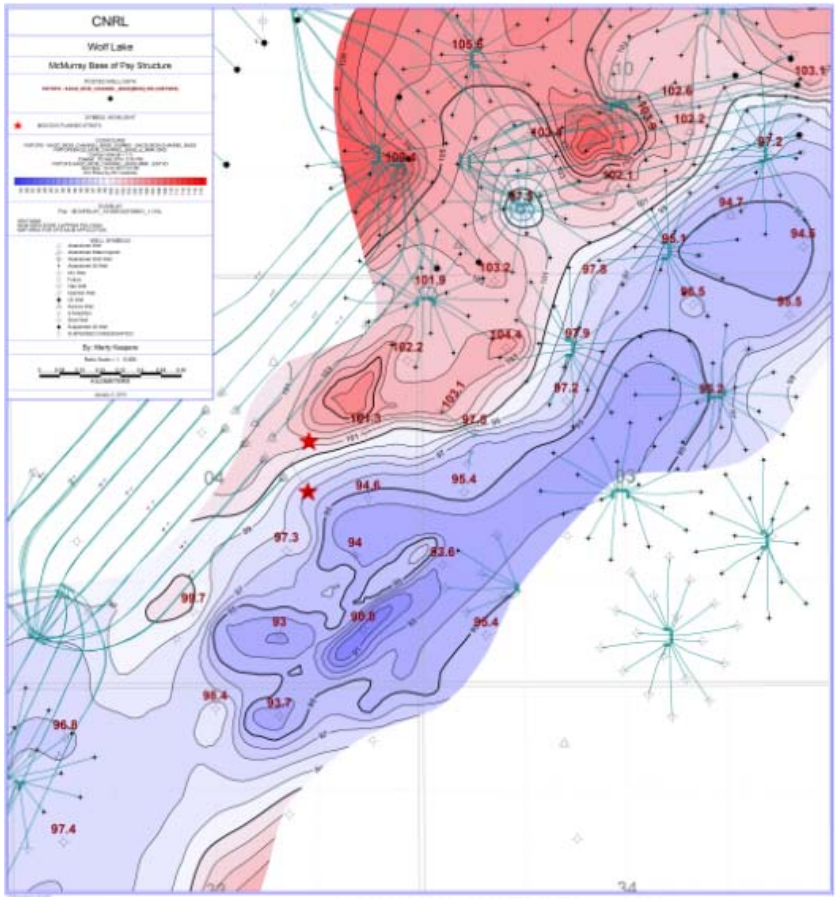
Wolf Lake McMurray SAGD Pay Structure

Canadian Natural

Reservoir Top Structure



Reservoir Base Structure



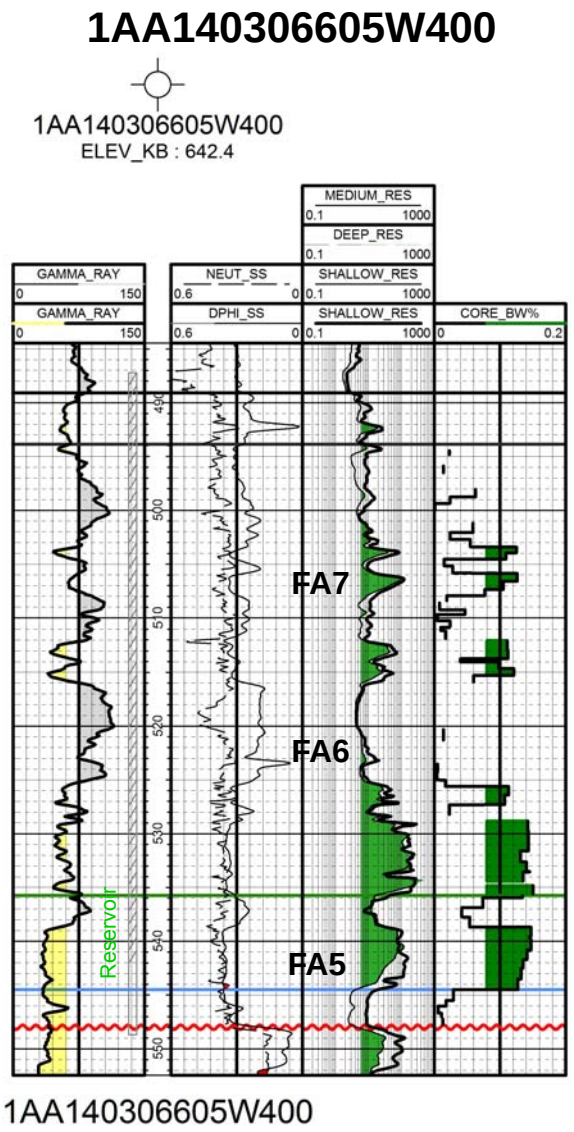
- SAGD Pay defined by continuous clean sand and breccia. IHS is not included.
- Base of reservoir, above bottom water, corresponds to bitumen weight 10% (~6ohm·m).

Reservoir Characteristics- Wolf Lake McMurray

Canadian Natural

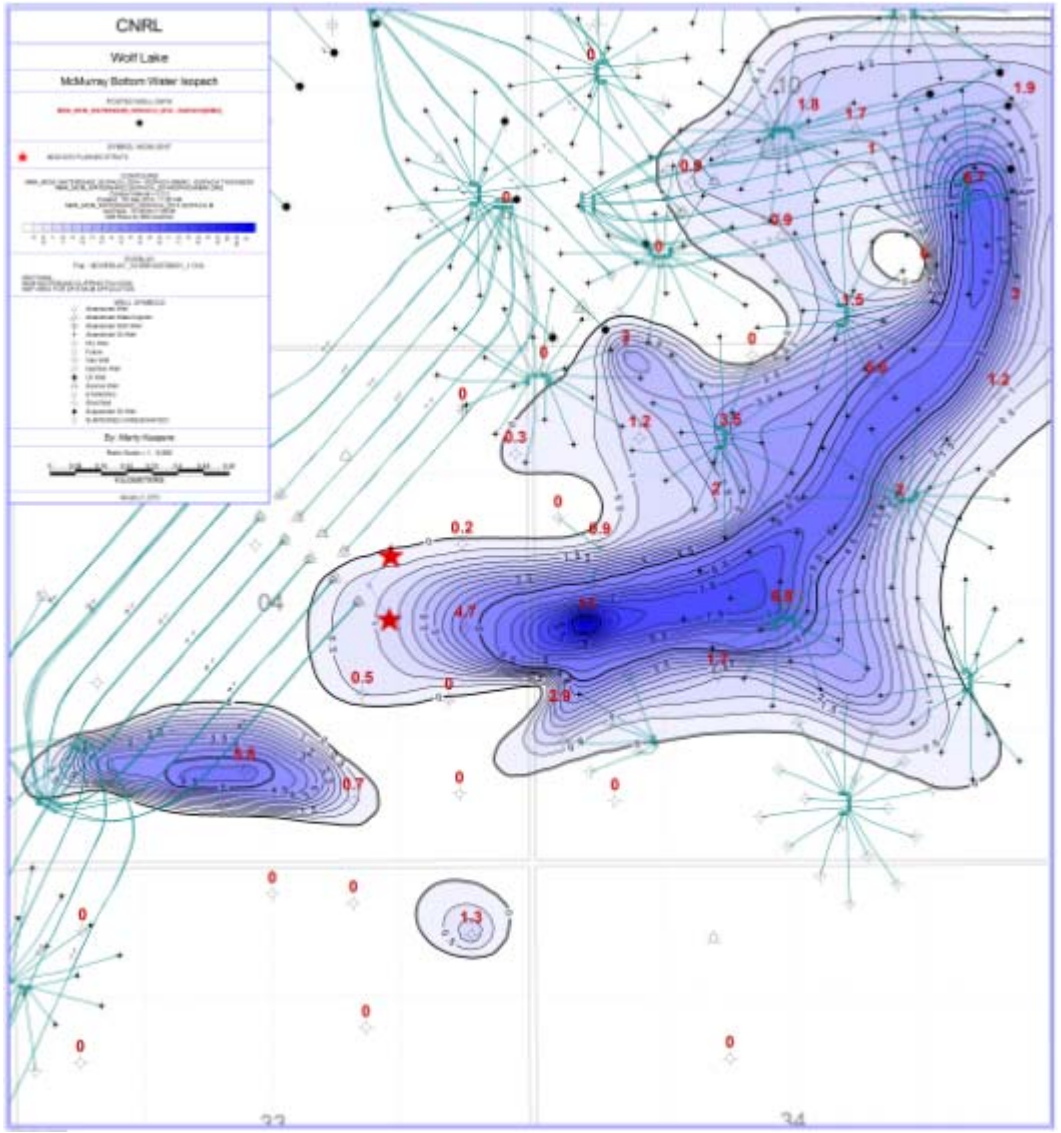
Reservoir Characteristics

- 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°C)



Wolf Lake McMurray Bottom Water Isopach

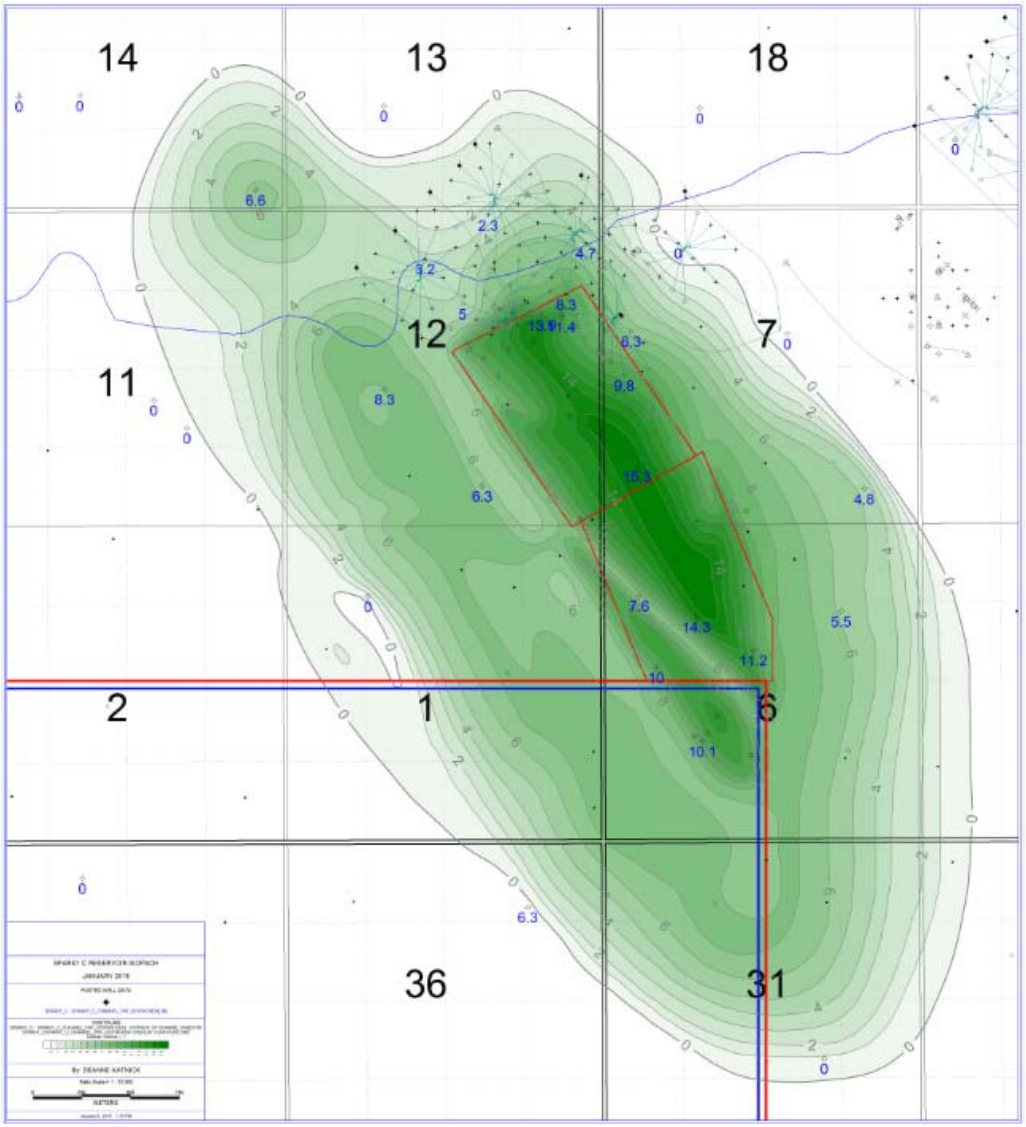
- McMurray Bottom Water Isopach
- Cut-offs are less than 6 ohm·m
- Isopach represents a gross water interval



Wolf Lake Sparky “C” SAGD Pay Isopach

Sparky “C” Sand

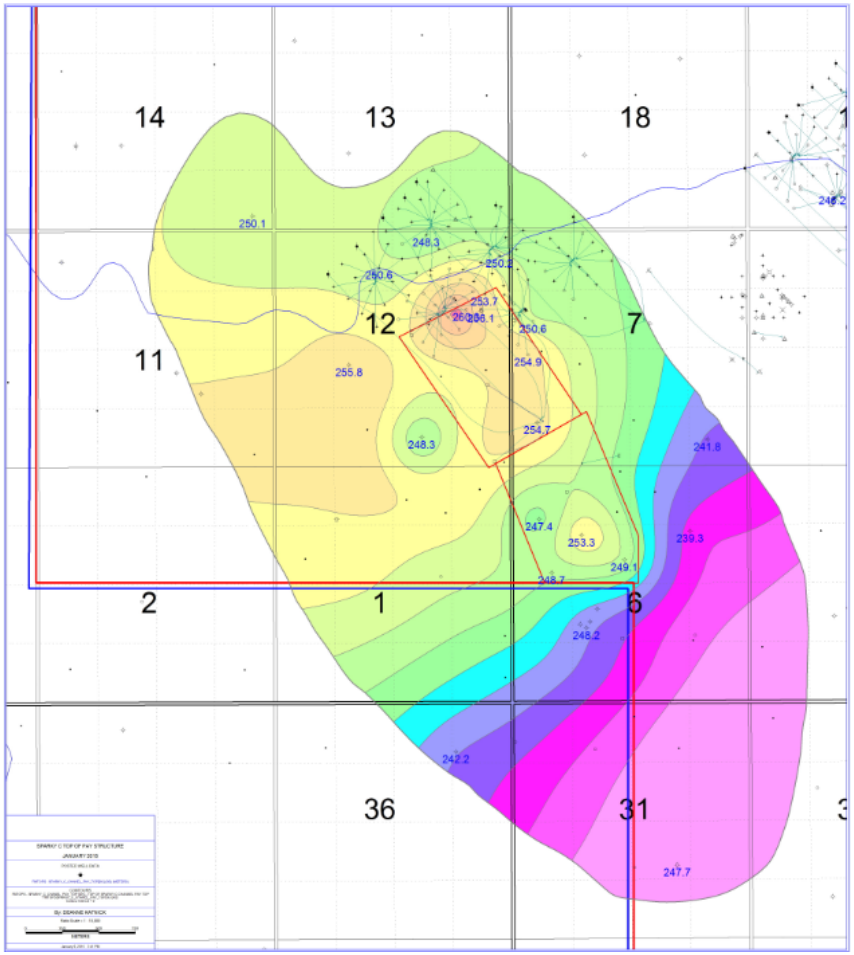
- Channel deposits with bitwt >10%.
- Net pay >10 m for development



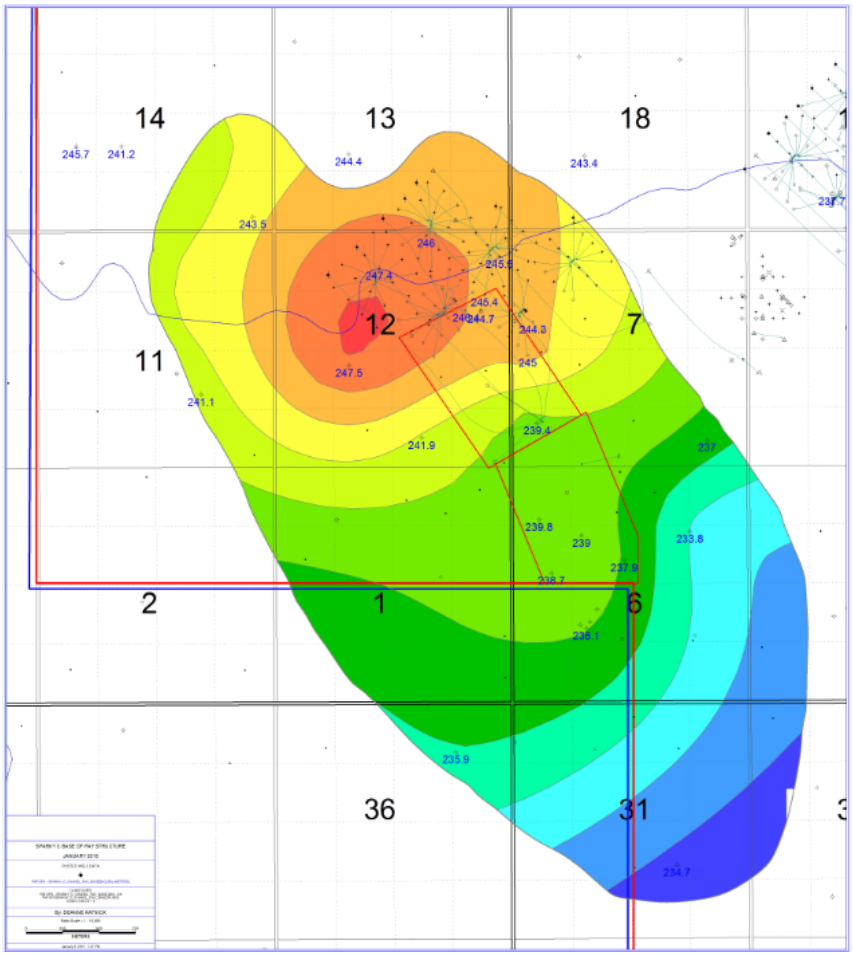
Sparky “C” SAGD Pay Structure

Canadian Natural

Reservoir Top Structure



Reservoir Base Structure



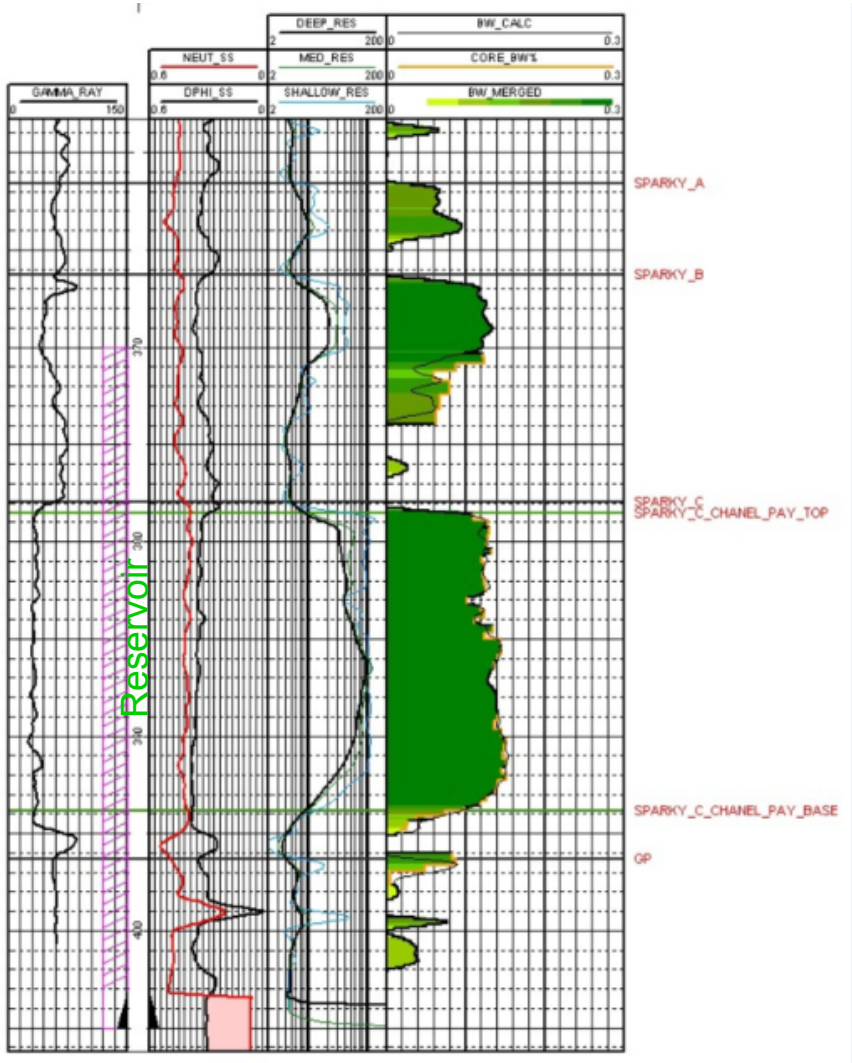
Reservoir Characteristics- Sparky “C”

Canadian Natural

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°C)
- Average Bottom Water: 0.5m

1AA040706605W400



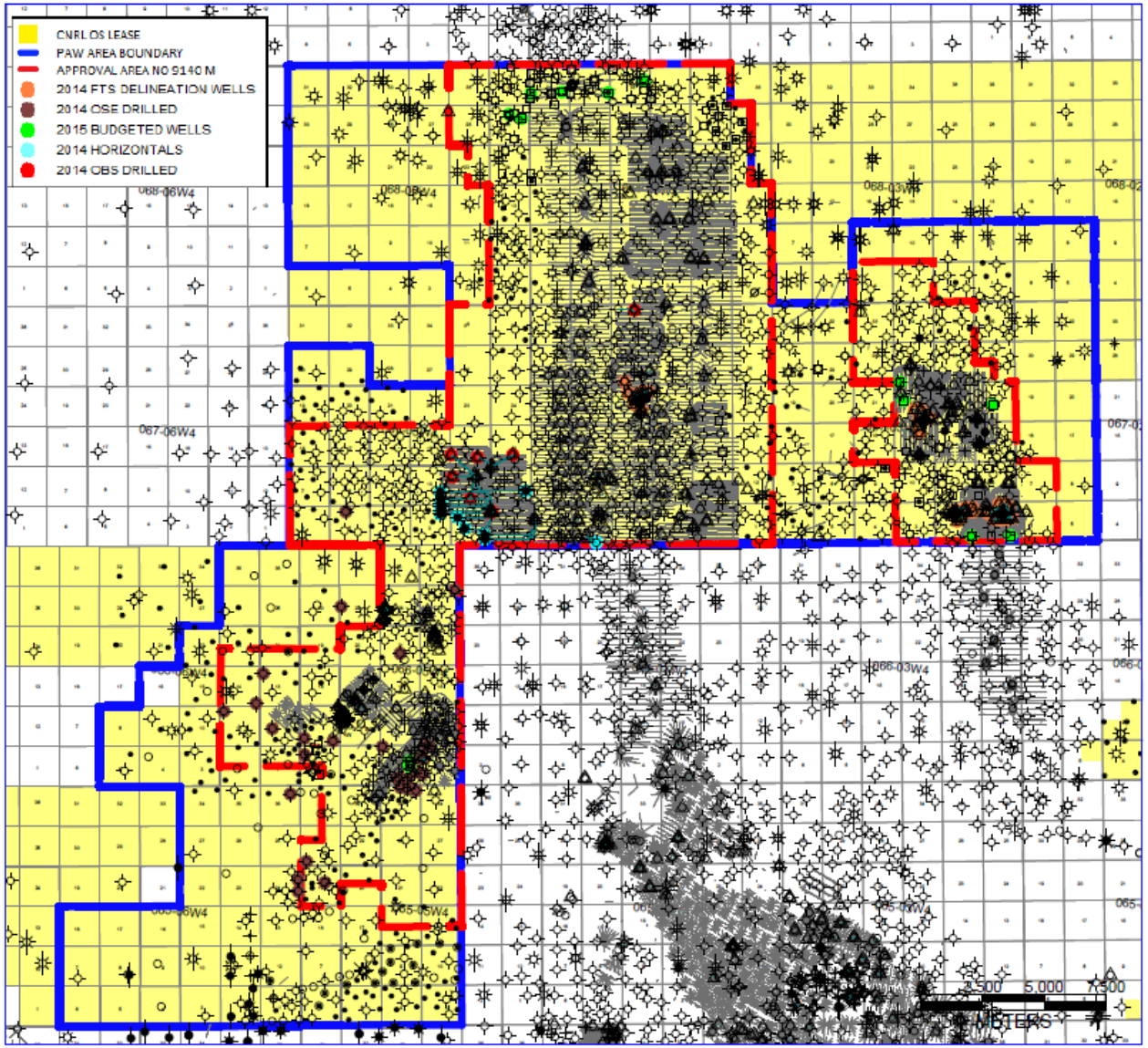
Progress in 2014 → Plans for 2015

2014

- 26 stratigraphic wells drilled
- 8 observation wells drilled
- 12 CSS production wells drilled
- 41 Delineation FTS wells
- 34 wells with core in Colorado Group (5,889 m of core in Colorado Group)

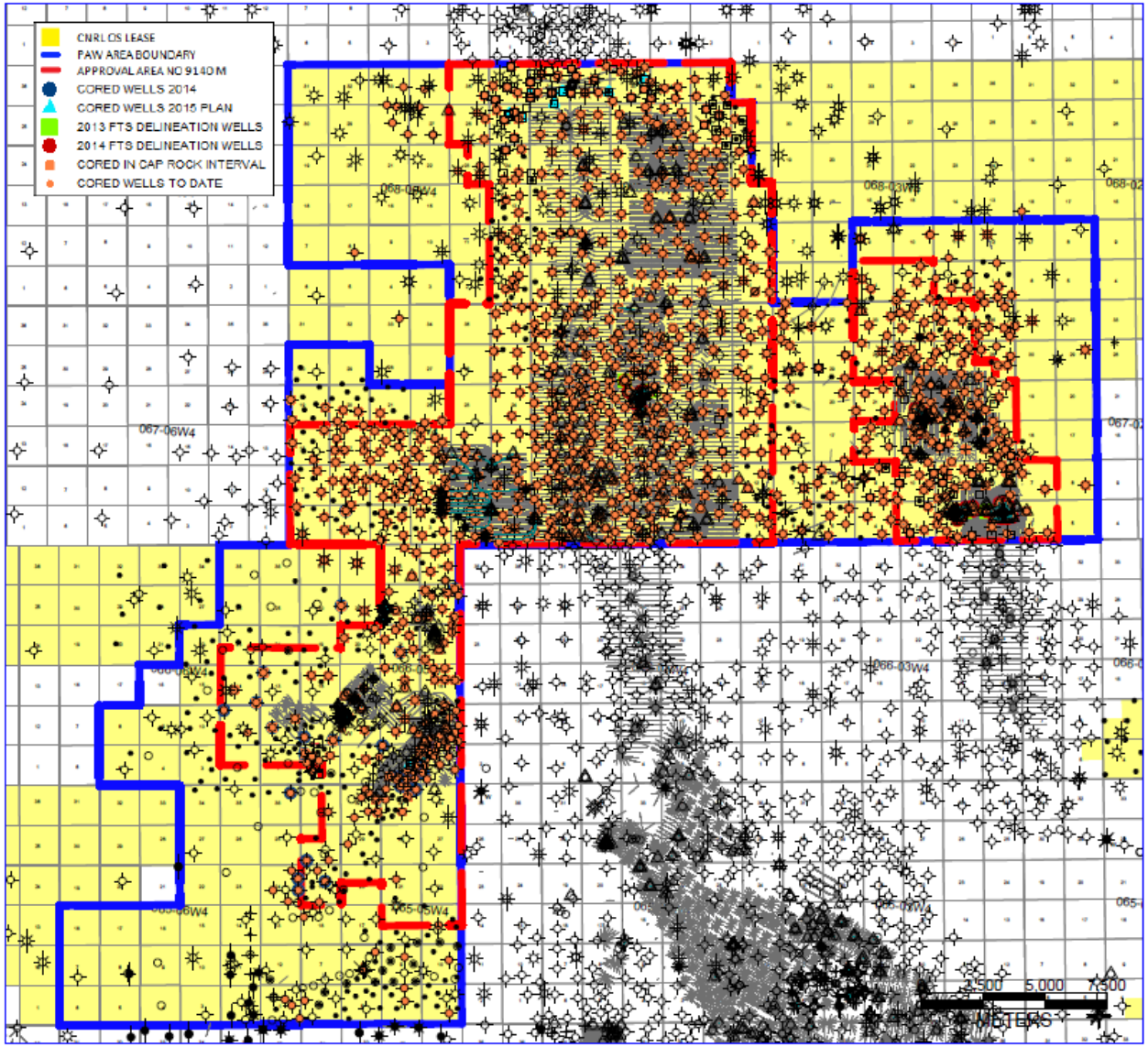
2015

- 8 stratigraphic wells planned
- 5 observation wells planned

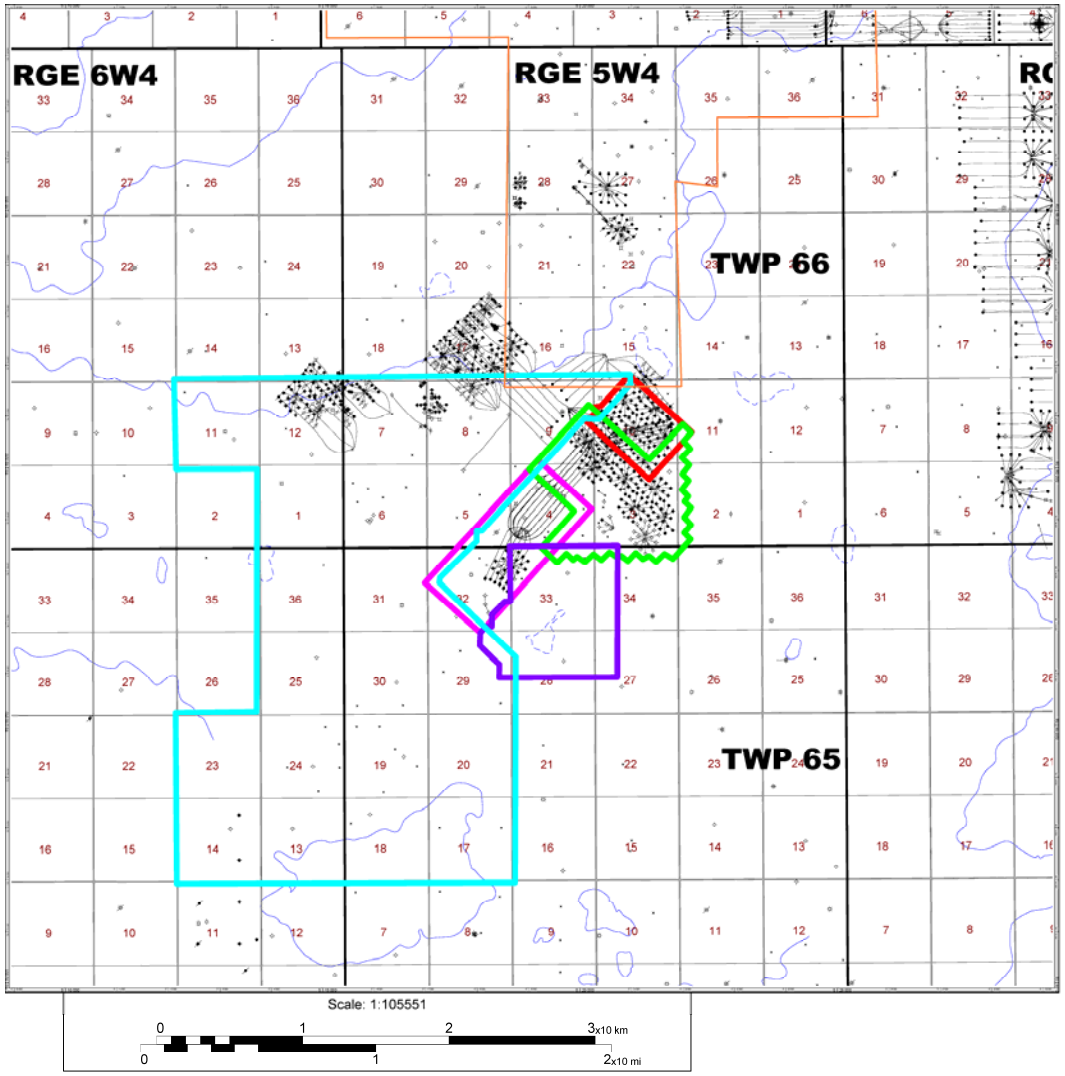


Cored Wells Within PAW

- Total wells cored: 1,036
- 2014 wells cored: 60
- Wells with Clearwater Capping Shale recovered in core interval: 808
- Total of 5,889 m of core was recovered in Colorado Group during FTS delineation drilling program.

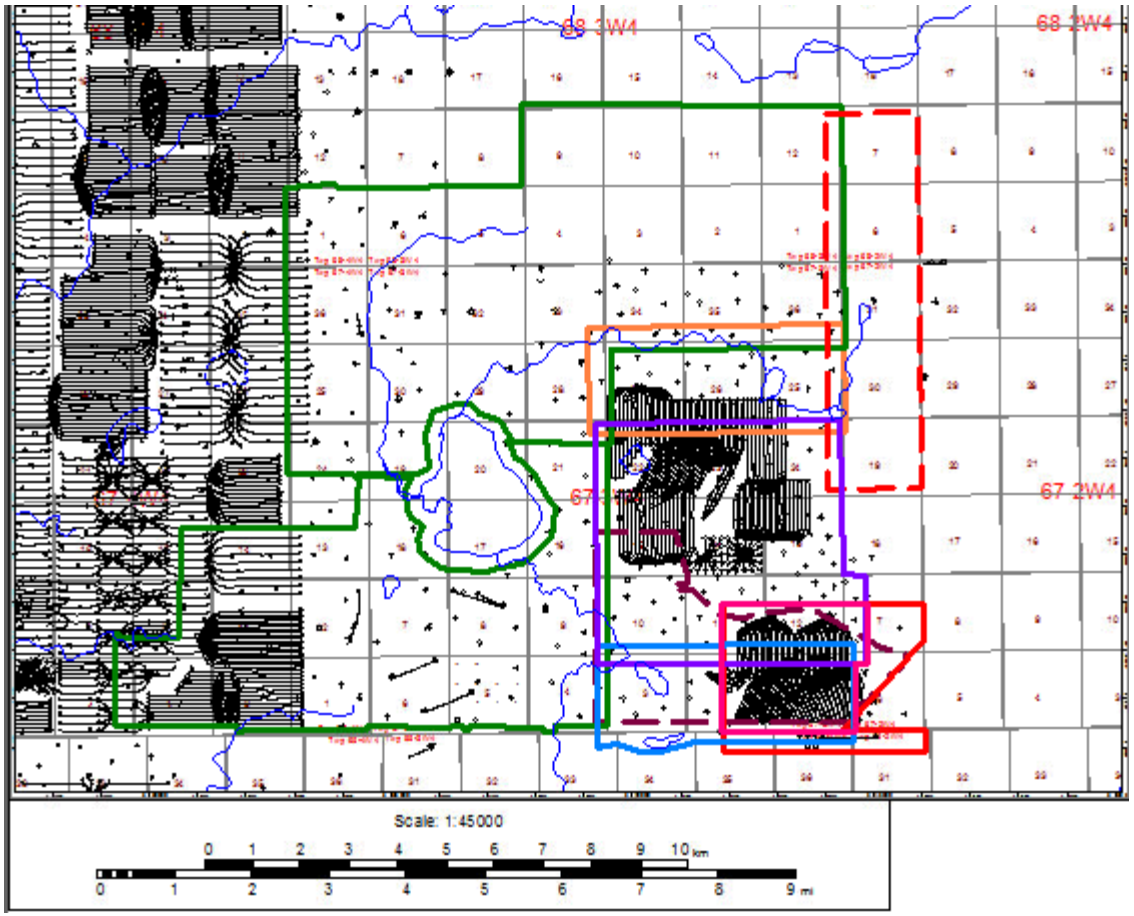


3-D Seismic Wolf Lake - TWP 65/66 R 5/6



Wolf Lake Seismic	
	3D 2009 Wolf Lake I
	3D 2009 Wolf Lake II
	3D 2011Wolf Lake III
	3D 2012 Wolf Lake IV
	3D 2012 Primrose North XIII
	3D 2014 Wolf Lake V

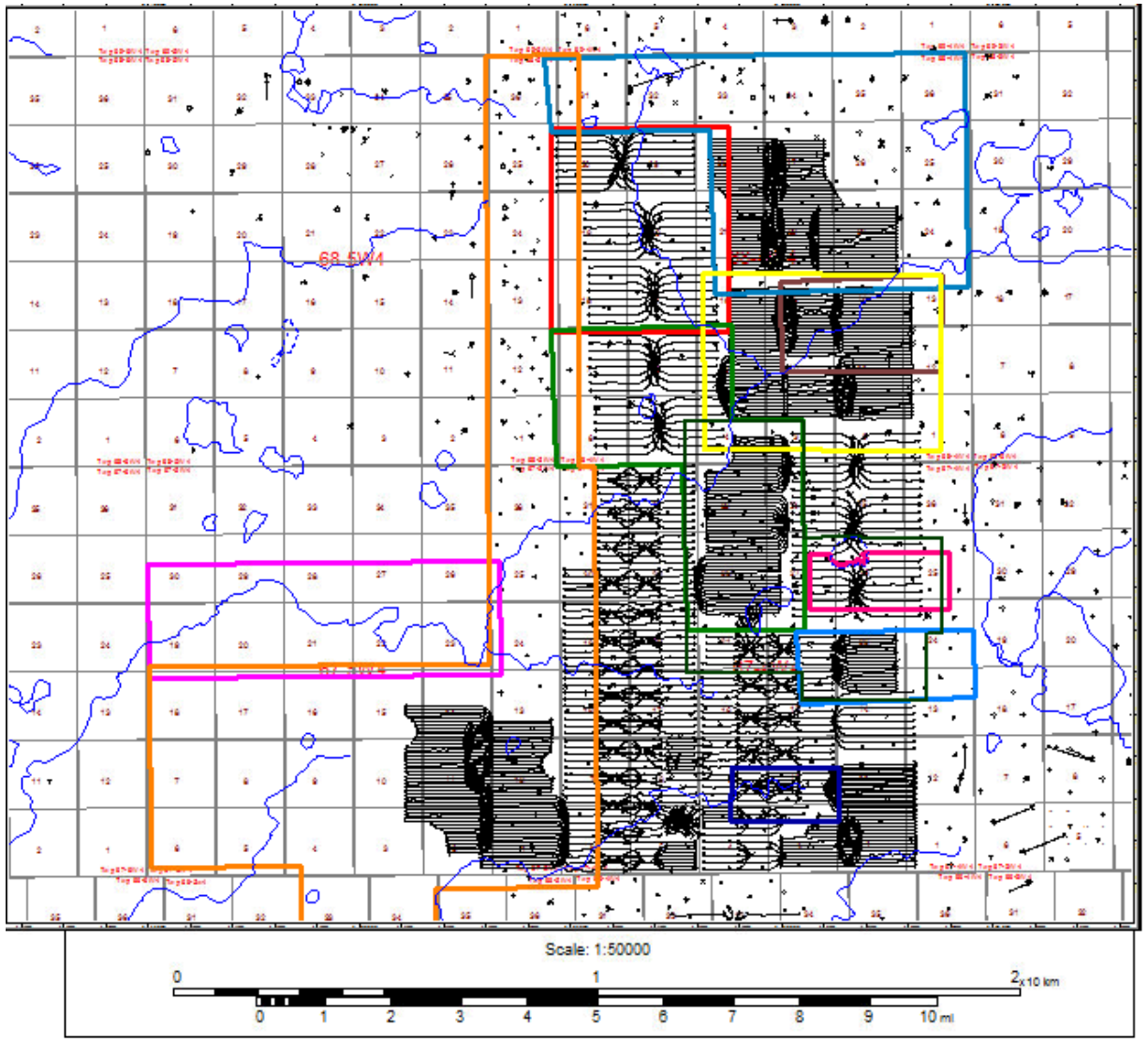
3-D Seismic: Primrose East



- 2013 3D
- 2012 3D
- 2011 3D
- 2010 4D Post Steam Area1
- 2010 3D
- 2009 4D Post Steam Area1
- 2008 3D
- 2004 3D

**All pre-steam seismic has been merged in 2012

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



- Primrose North & South

2006-3D

2009-3D

2009-4D

2010-3D

2010-3D

2010-3D

2012-4D

2012-3D

2013-4D

2014-4D

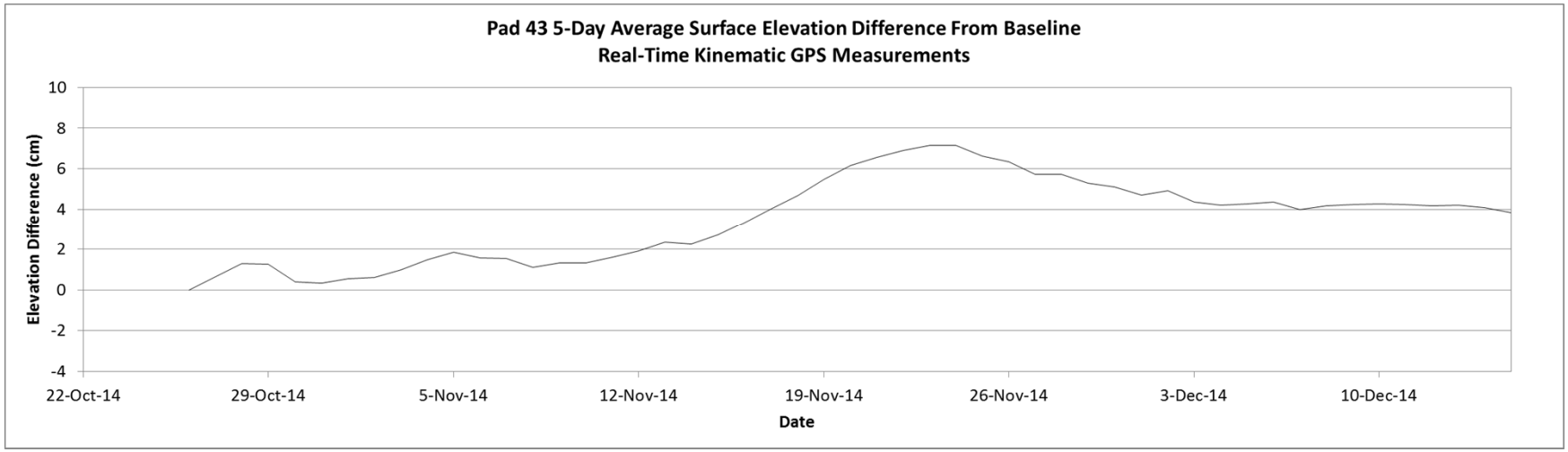
2014-3D

Surface Heave Measurement – Pad 43

Canadian Natural

2014 Activity

- High frequency Interferometric synthetic aperture radar (InSAR) acquisition from RADARSAT-2 and TerraSAR-X commenced Nov. 2nd, 2014 focused on Primrose South Phases 40-43
  - Data collection interval varies from ~1-5 days
- Surface elevation changes measured by survey commenced Oct. 22nd, 2014 at Pad 43
  - Commissioning Cycle 1 from Oct. 28th, 2014 to Nov. 24th, 2014



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

Artificial Lift Type & Distribution as at Dec. 15, 2014

Operating Area	Rod Insert	Tubing Pump	PCP	ESP
Primrose South	645	2	2	0
Primrose North	309	0	0	0
Primrose East	155	4	0	0
Burnt Lake	3	0	0	0
Wolf Lake CSS	42	0	0	0
Wolf Lake SAGD	8	20	0	3
Primrose brackish	0	0	0	10
Wolf Lake Brackish	0	0	5	2
Fresh Water (10-66-5W4)	0	0	0	6

Rod Pump Lift Capacity Range

Pump Size	Pump Jack	Stroke Length	Efficiency	SPM	m3/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"	Rotoflex	288"	80%	5	300
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

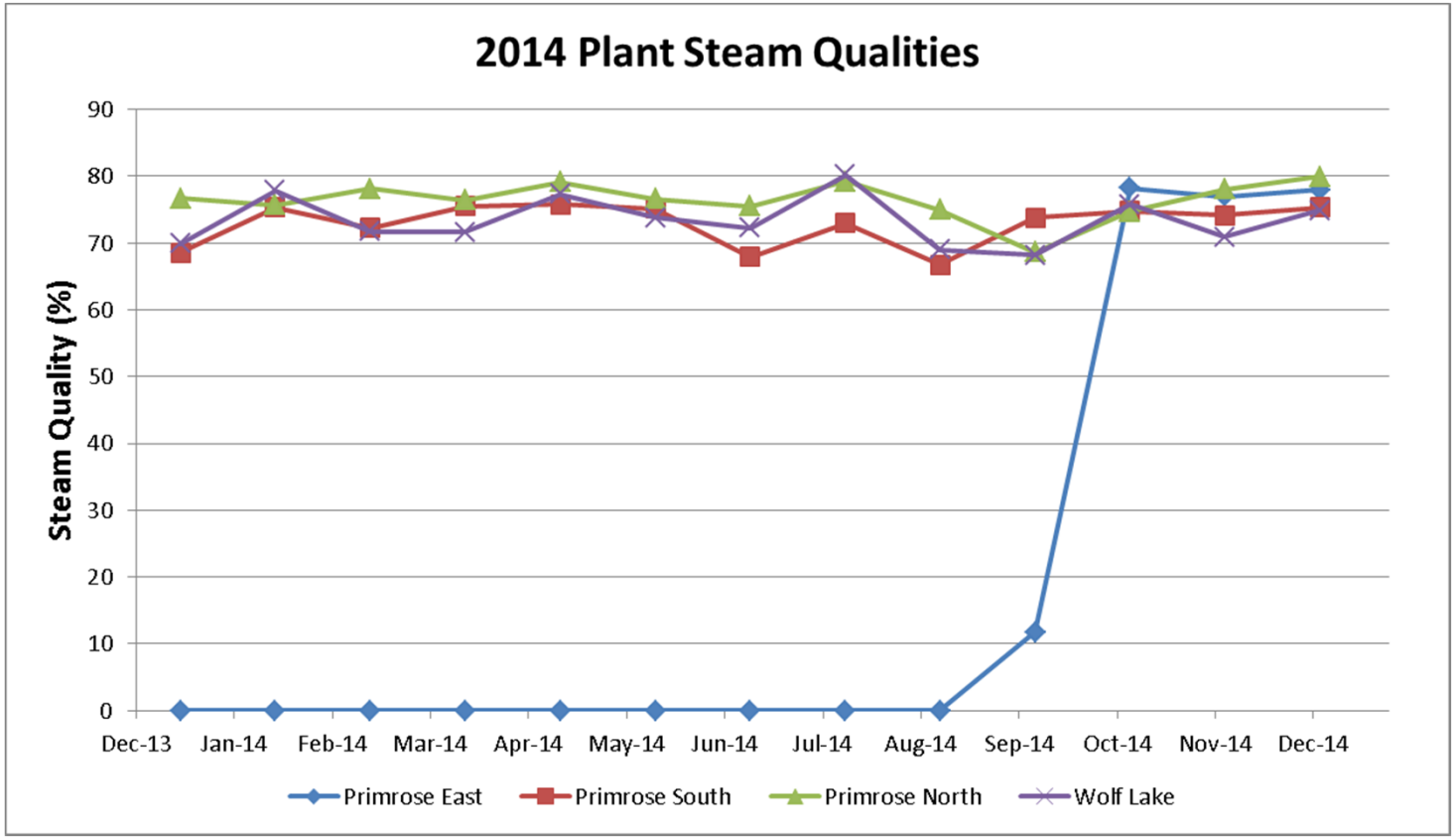
Phase	Wells per Pad	Design Spacing (m)	Well Length (m)	Development Date
1-21	16-20	160	600	1993-2000
27	7	160	1,400	2005
29-31	16-20 hz 8-10 dev	188	1.200	2003-2004
51-54	16 hz 8 dev	188	1,200	2004-2006
55	20 hz 10 dev	160	1,200	2004-2006
28	10	75	1,000	2005-2007
74, 75, 77, 78	20	60	900	2007-2008
58, 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 - 2014



- 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

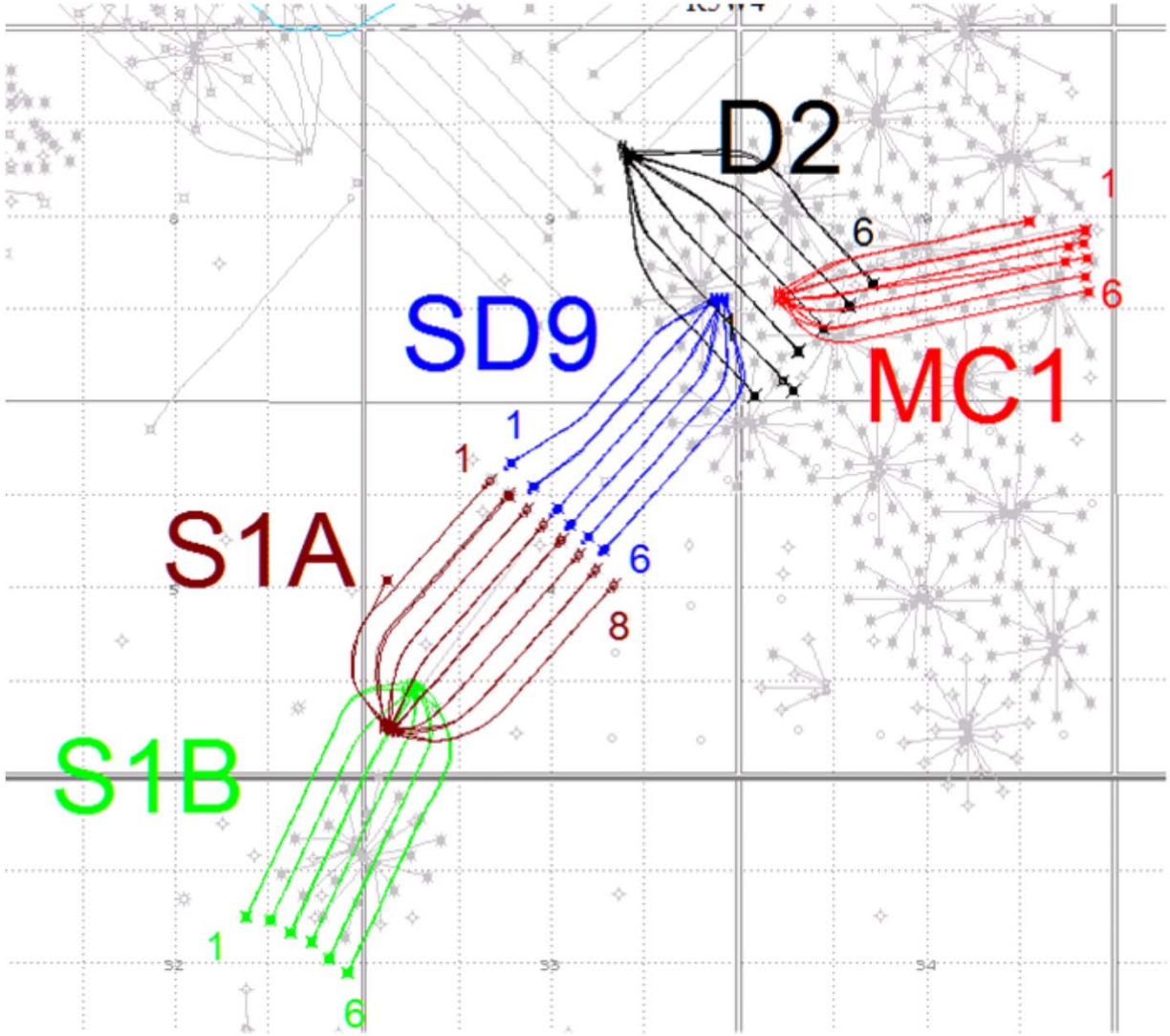
SAGD Basics – Well Warm Up

- 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
  - Typical wellhead pressures of 1 to 7 MPa
- Measure and monitor injection and returned volumes, pressures and temperature

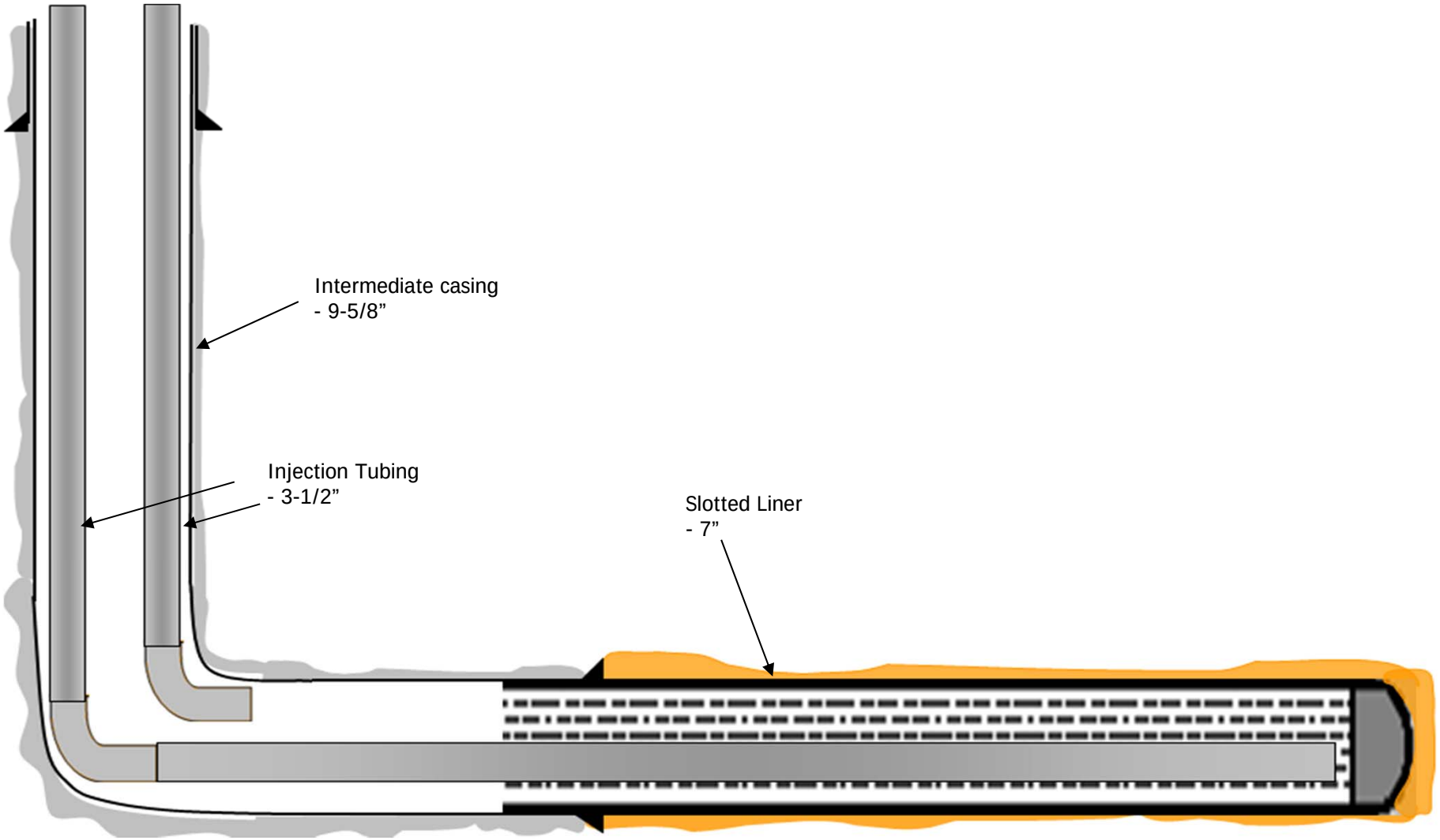
SAGD Basics – Injection / Production

- 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
  - Generally withdrawal rates exceed steam injection rates
  - Typical fluid production rates vary from 150 m^3/d to 600 m^3/d

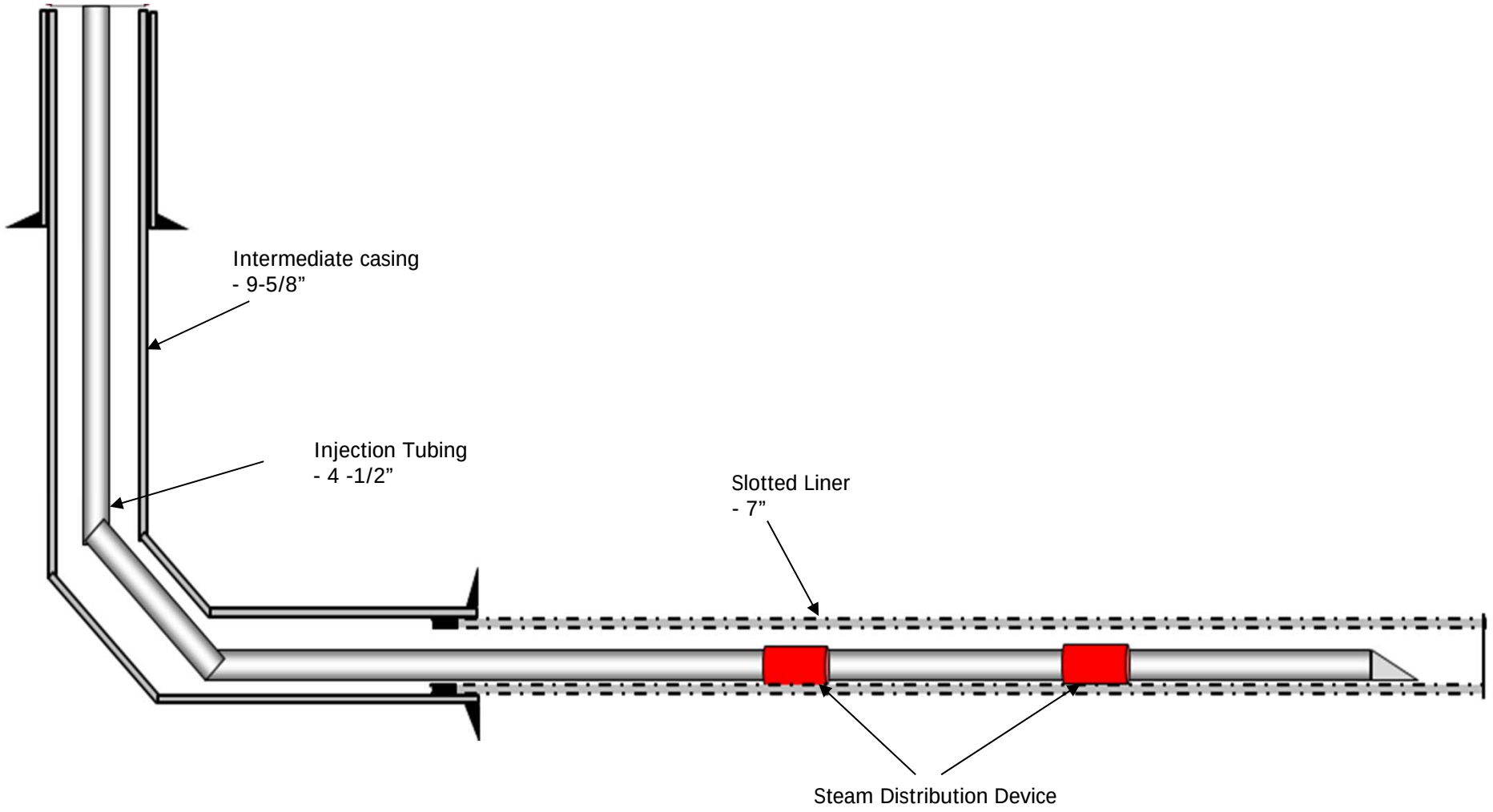
Wolf Lake SAGD Location Map



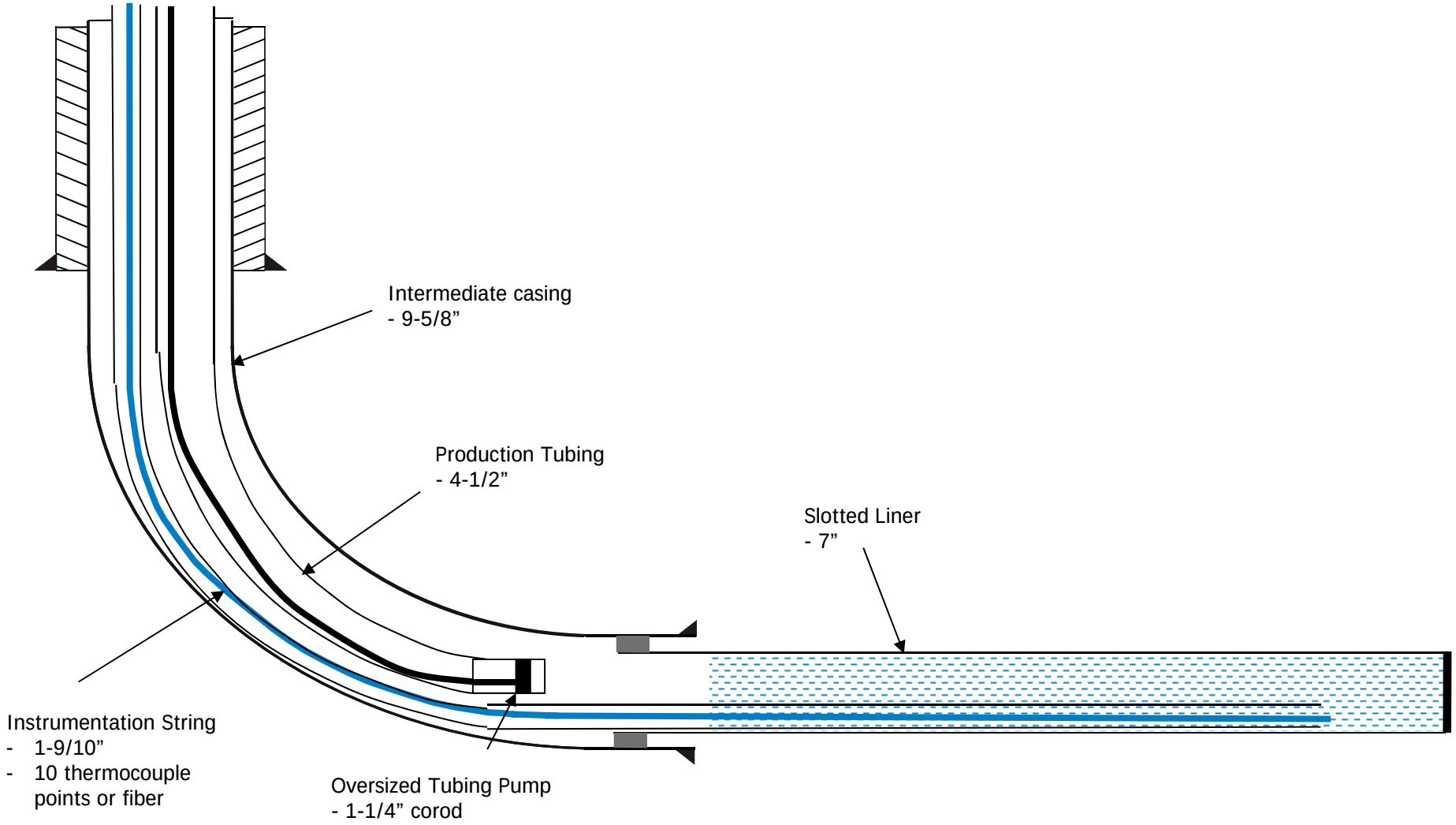
Sample Parallel String Injector Completion



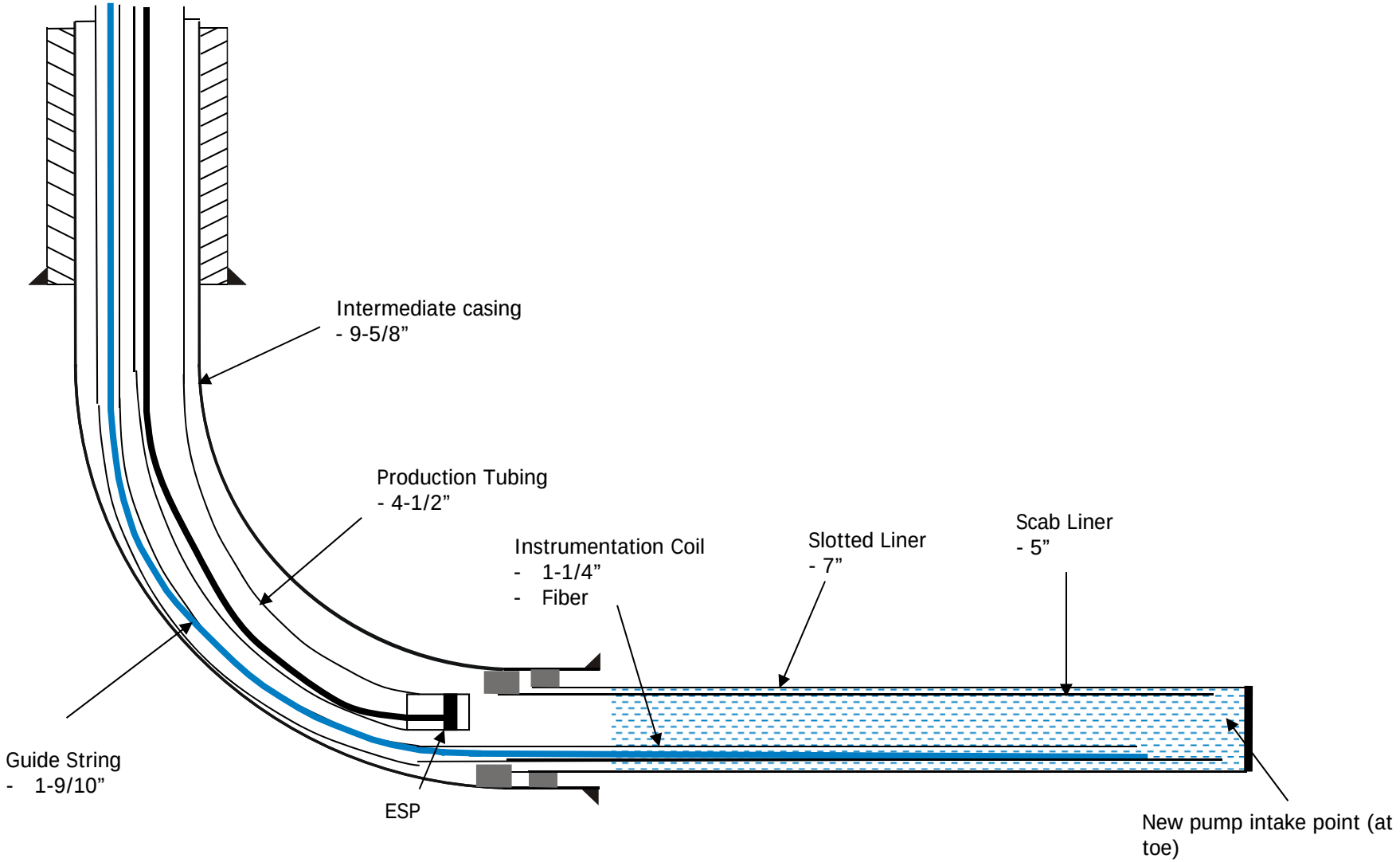
Sample Single String Injector Completion



Sample Producer with Rod Pump Completion



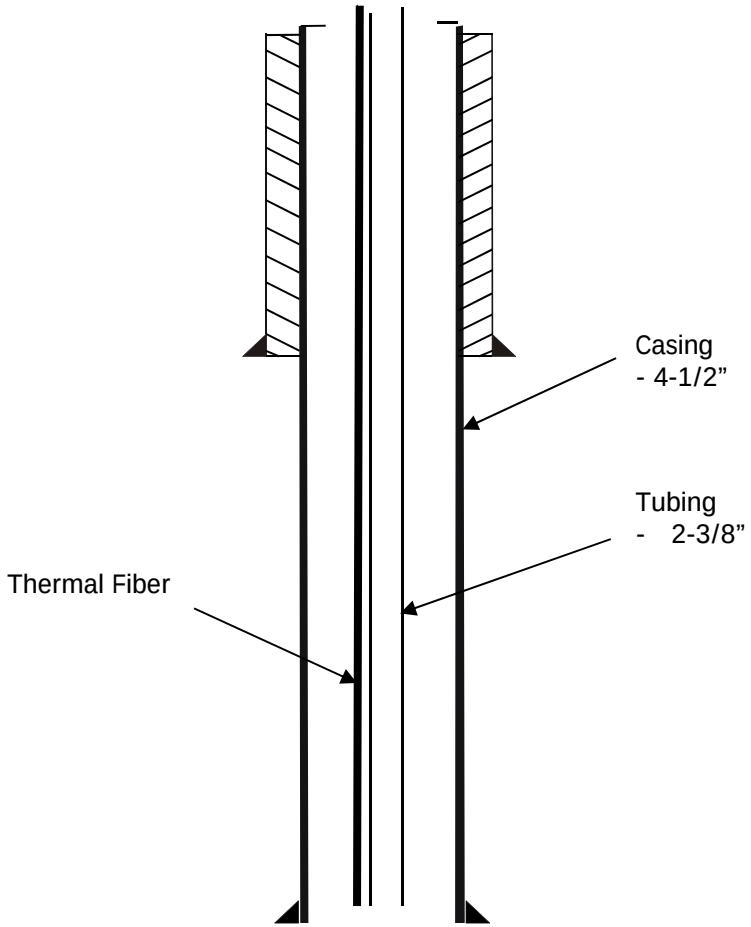
Sample Producer with Scab Liner Completion



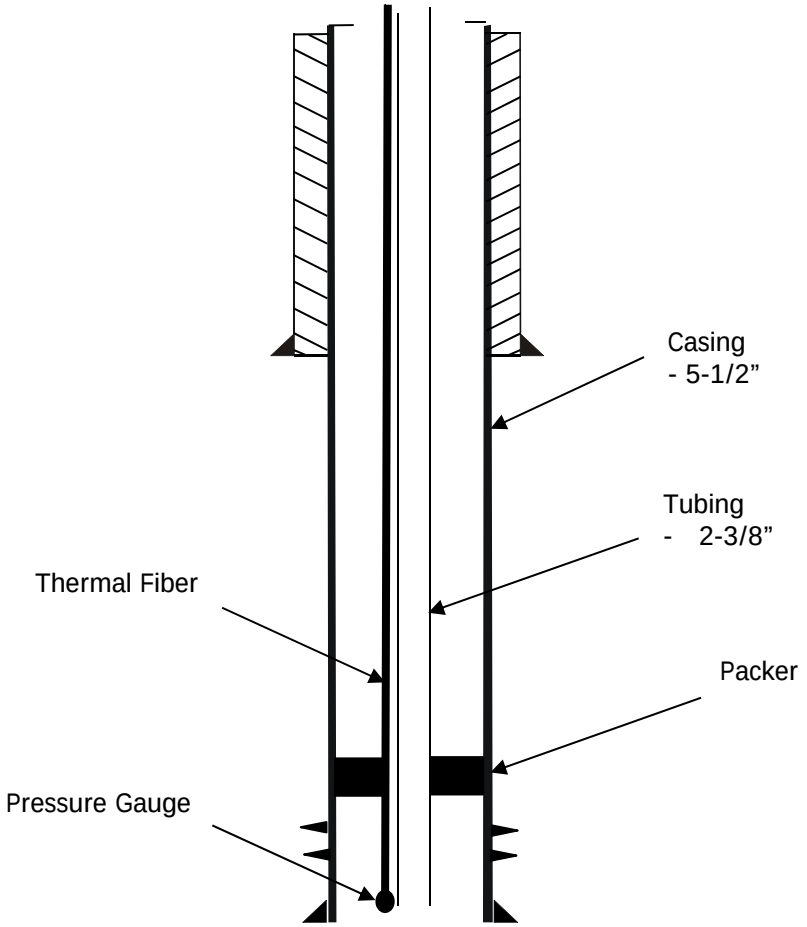
Sample Observation Well Completion

Canadian Natural

Temperature Only



Temperature and Pressure



Wolf Lake SAGD

	D2 (B10)	SD9 (B10)	S1A (B10)	S1B (B10)	B10 Total	MC1 (MCM)
Active Wellpairs	0	6	7	6	17	6
2014 Bit Prod, e3m3	0	40	50	98	179	114
2014 Avg. SOR (*dry steam)	0	5.0	6.3	3.1	4.2	3.6
Cumm Bit, e3m3	313	883	973	254	2,423	411
Cumm SOR (*dry steam)	4.9	3.9	4.0	3.8	4.0	3.6
OBIP, e3m3	1,877	1,819	2,682	1,971	8,349	1,443
2014 YE RF, %	17	49	36	13	29	29

- Current production is from B10 Grand rapids & MCMR
- D2 has many operational challenges, all options are being considered
- SD9 recovery is approaching 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

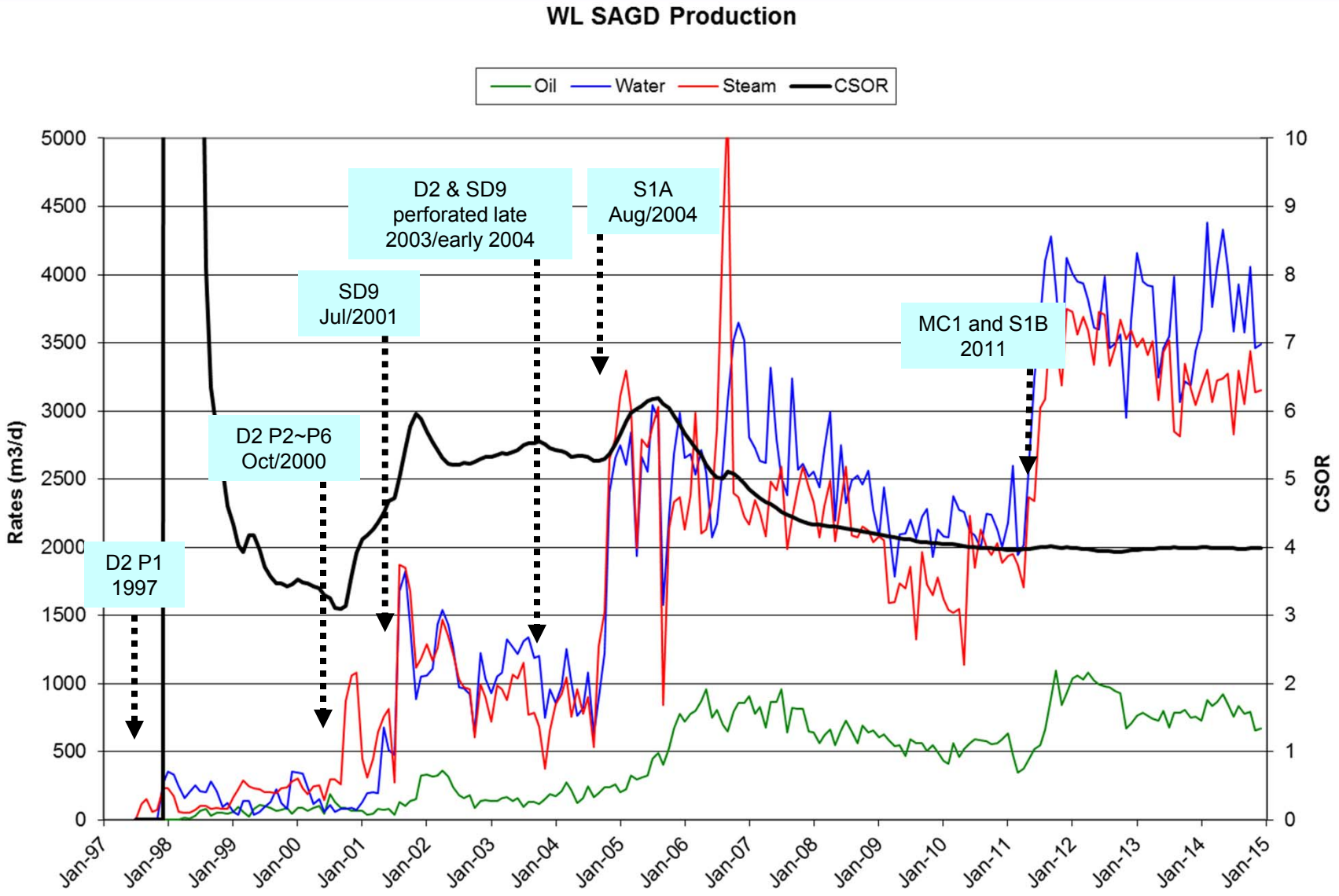
Wolf Lake SAGD Operational Strategy

- Operate wells based on a target steam chamber pressure and target sub-cool

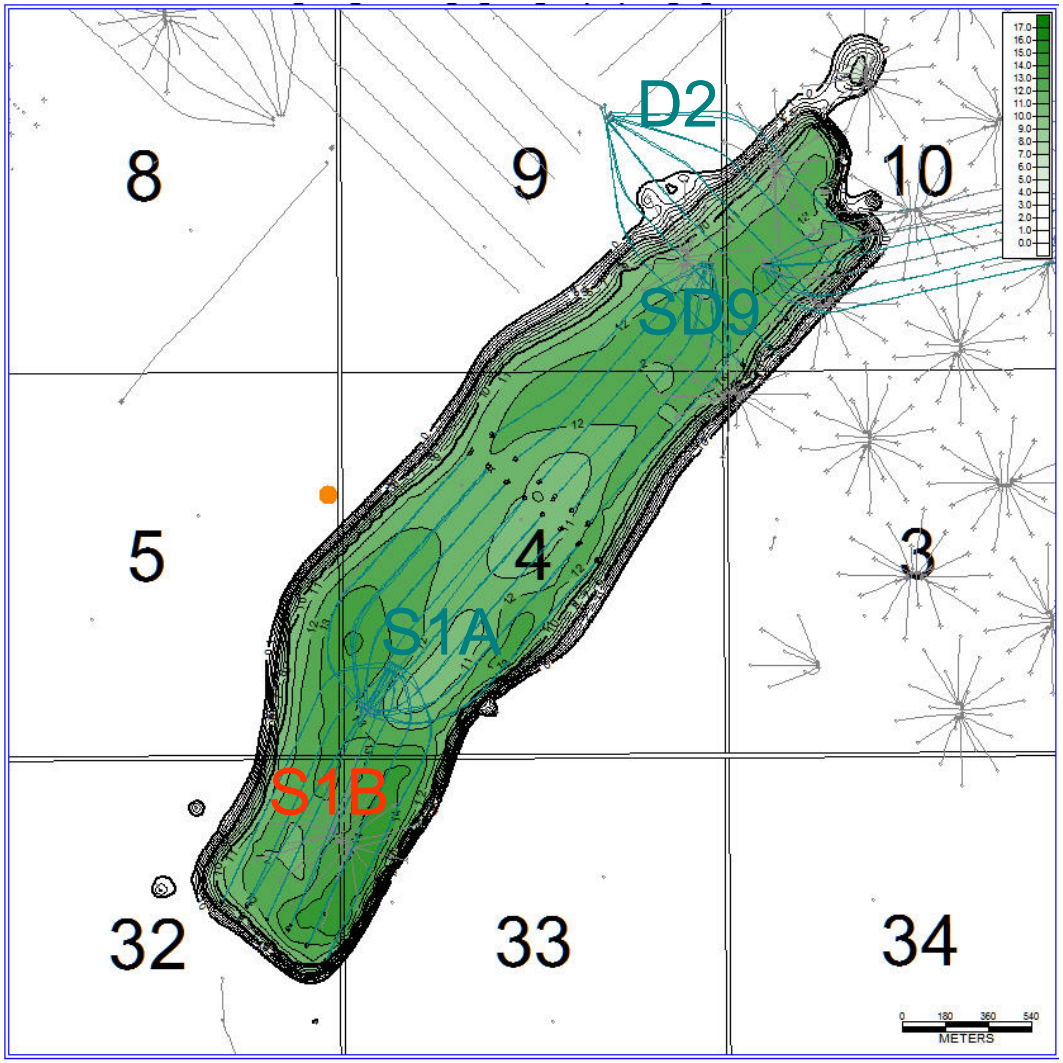
- Steam chamber pressure is measured by annulus gas pressure in the injector and is controlled by the steam injection rate
  - Current target pressure for SD9 is 2,100 kPa
  - Current target pressure for S1A is 2,500 kPa
  - Current target pressure for S1B is 2,600 kPa
  - Current target pressure for MC1 is 3,200 kPa

- 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

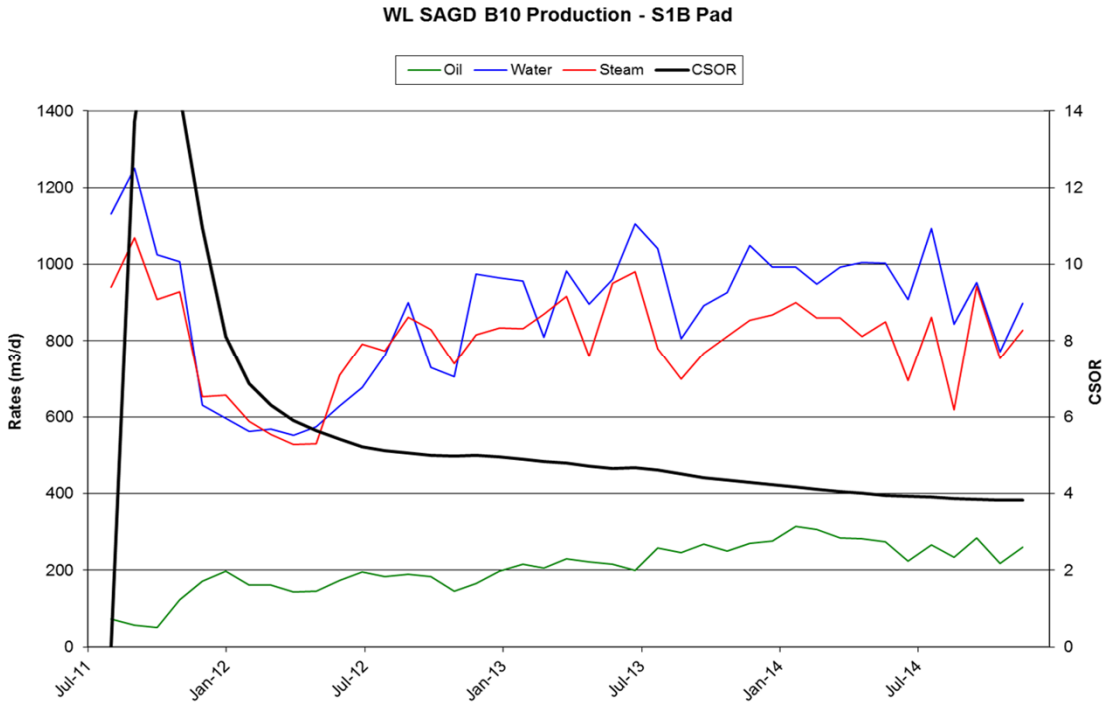


Wolf Lake SAGD
B10 Pad S1B – Low Recovery



- 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: 13 %

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

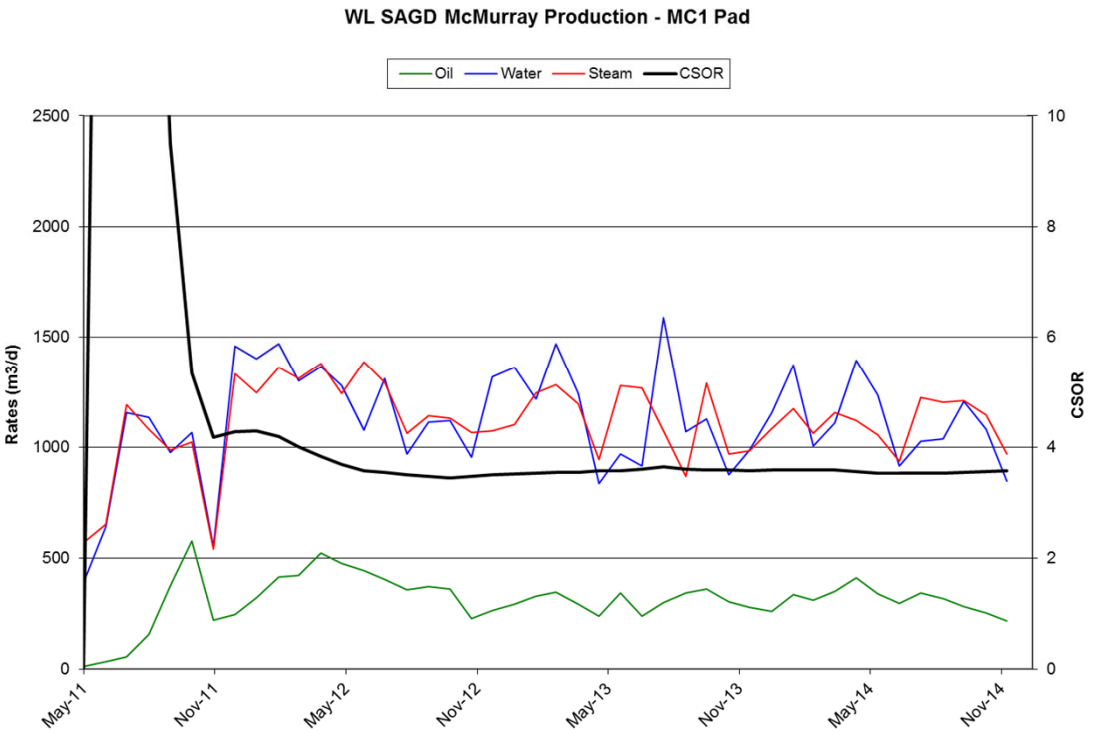
2014 Activity

- **All of the wells have now been stimulated with acid or perforations with positive results**
- **Plugging mechanism has not been determined, all stimulations have had some level of success**

2015 Plan

- **Continue to produce wells as significant pumping time is needed to develop chamber**
- **Assess future stimulations and recompletion opportunities to increase chamber development and recovery factor**

Mid Recovery – MC1 Pad Production History



- SAGD well pair: 6
- ERCB 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: 29 %

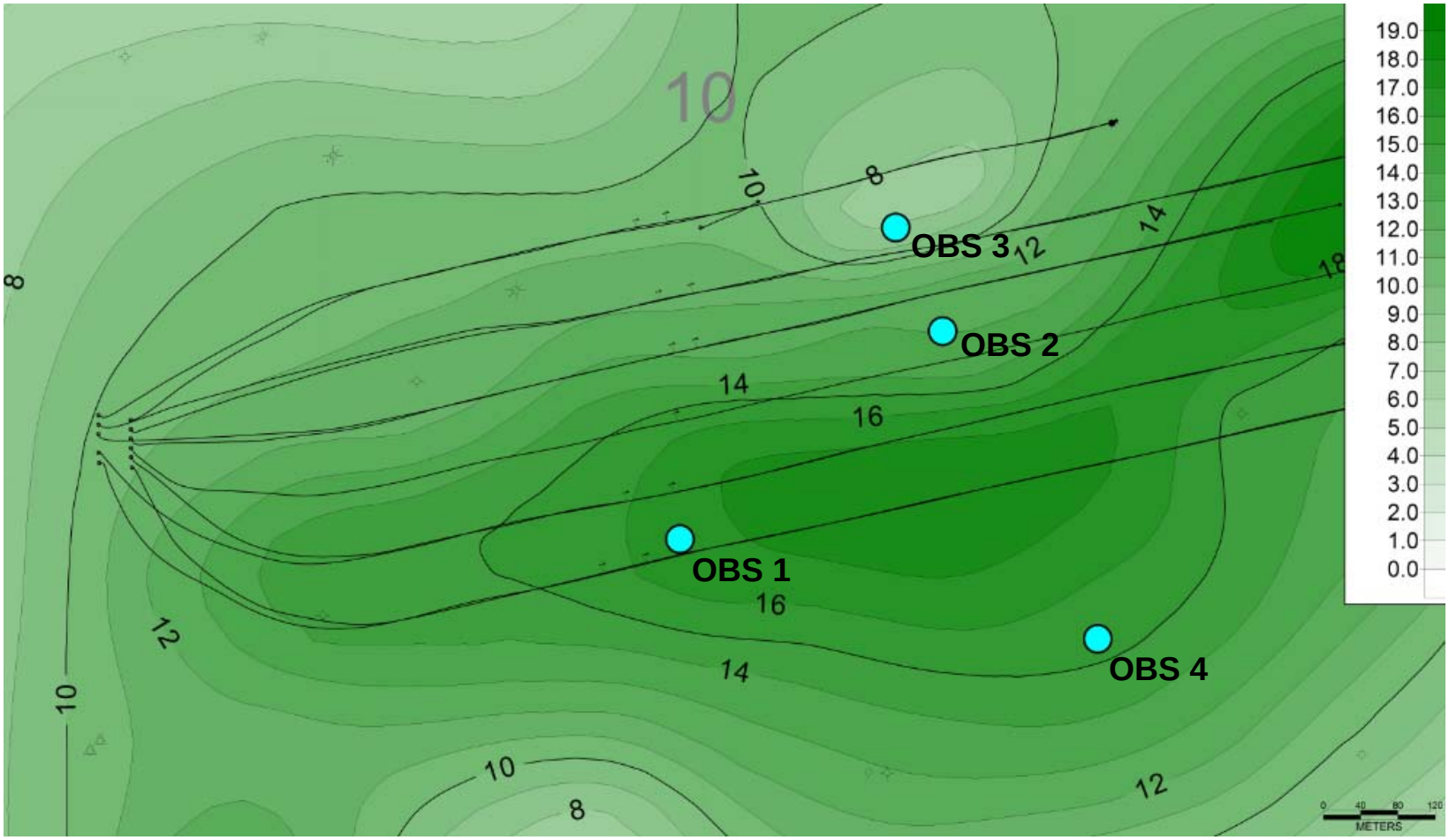
2014 Activity

- **MC1-1 Re-drill Learnings**
- **Injector Recompletions**
- **Understanding Interaction with bottom water as Recovery Factor increases.**

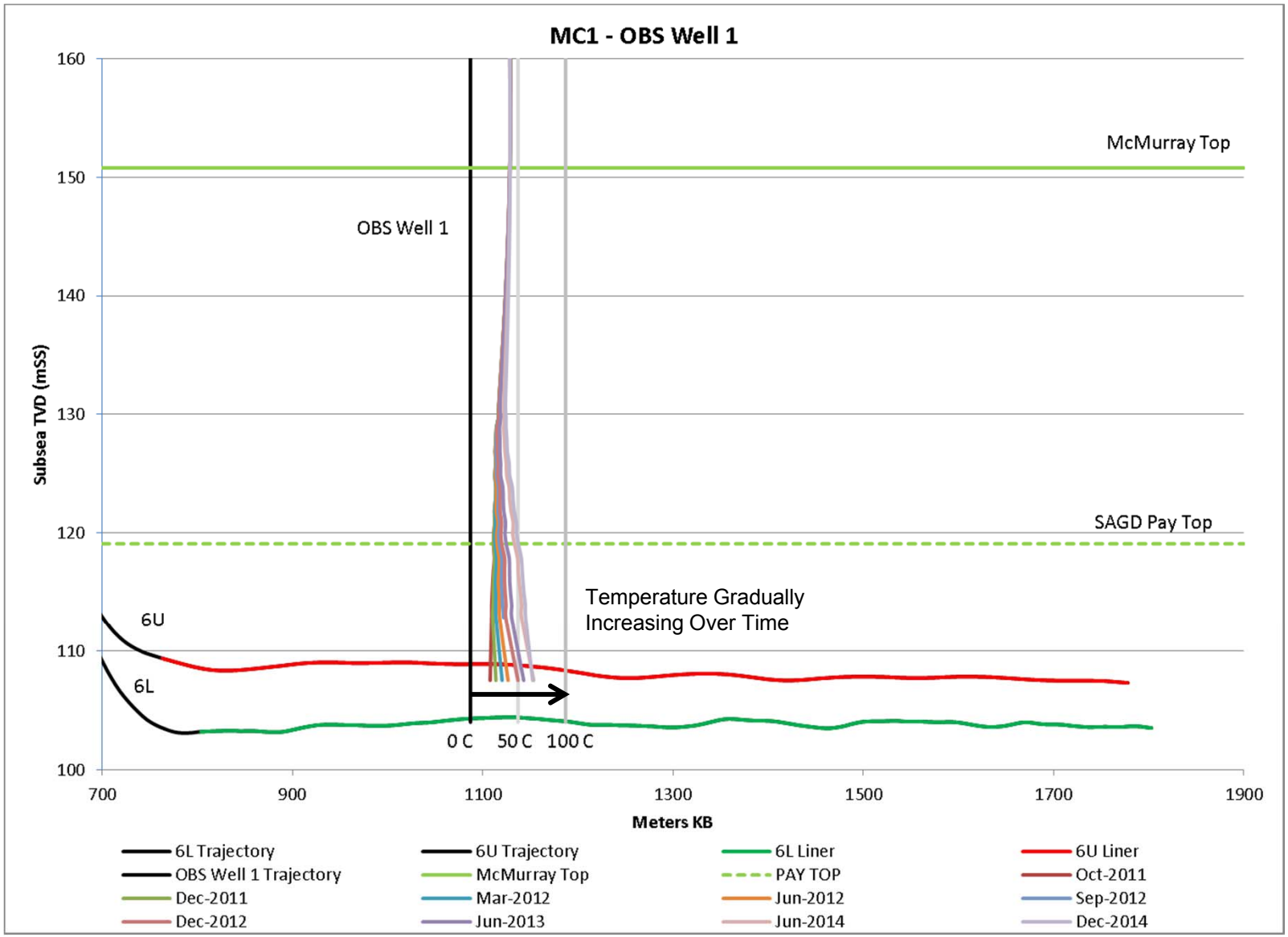
2015 Plan

- **Continue to optimize completion design**
- **Reservoir Simulation underway for blowdown / co-injection options**

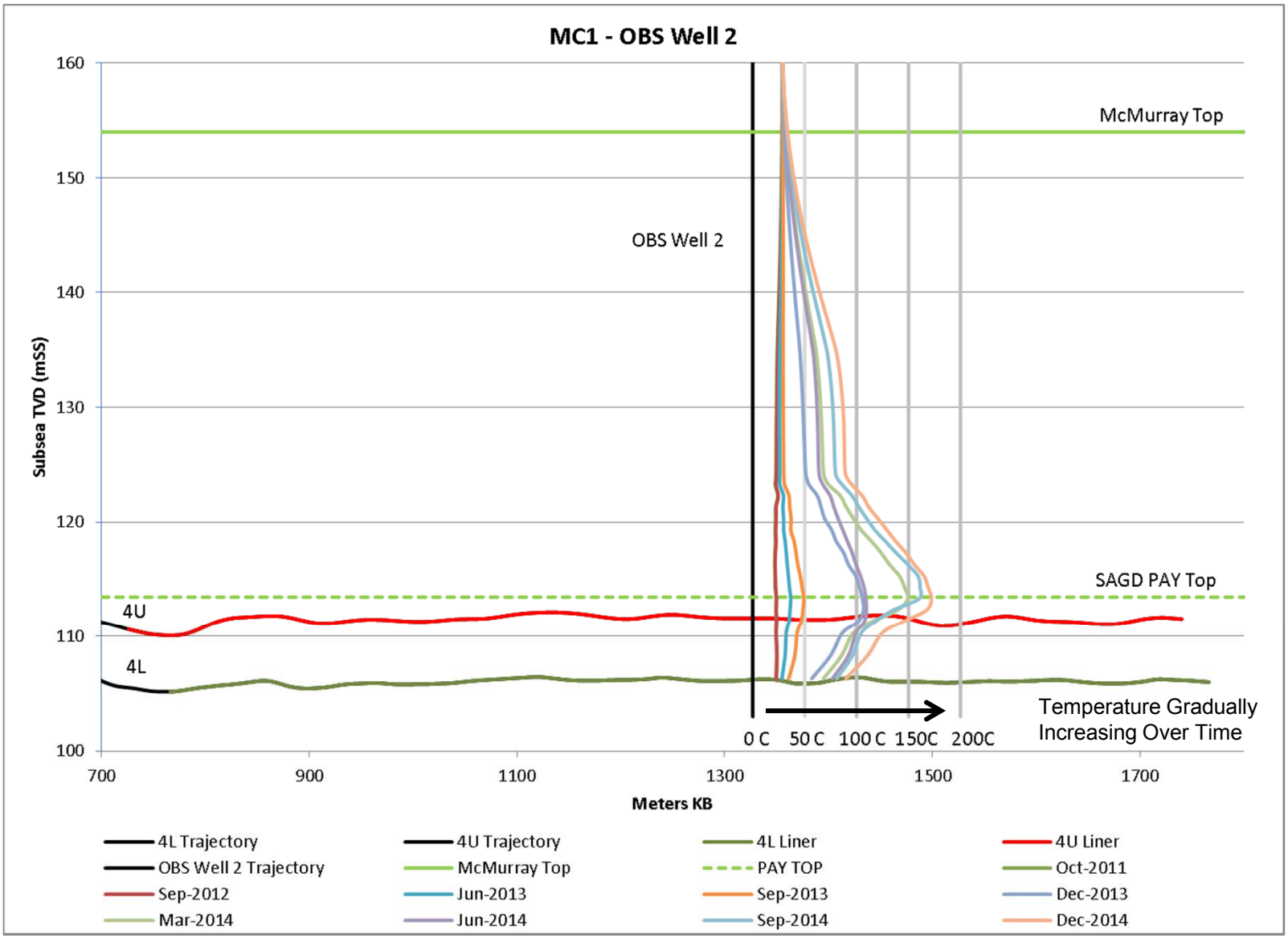
Wolf Lake McMurray SAGD
MC1 Observation Wells – TWP 066-05W4



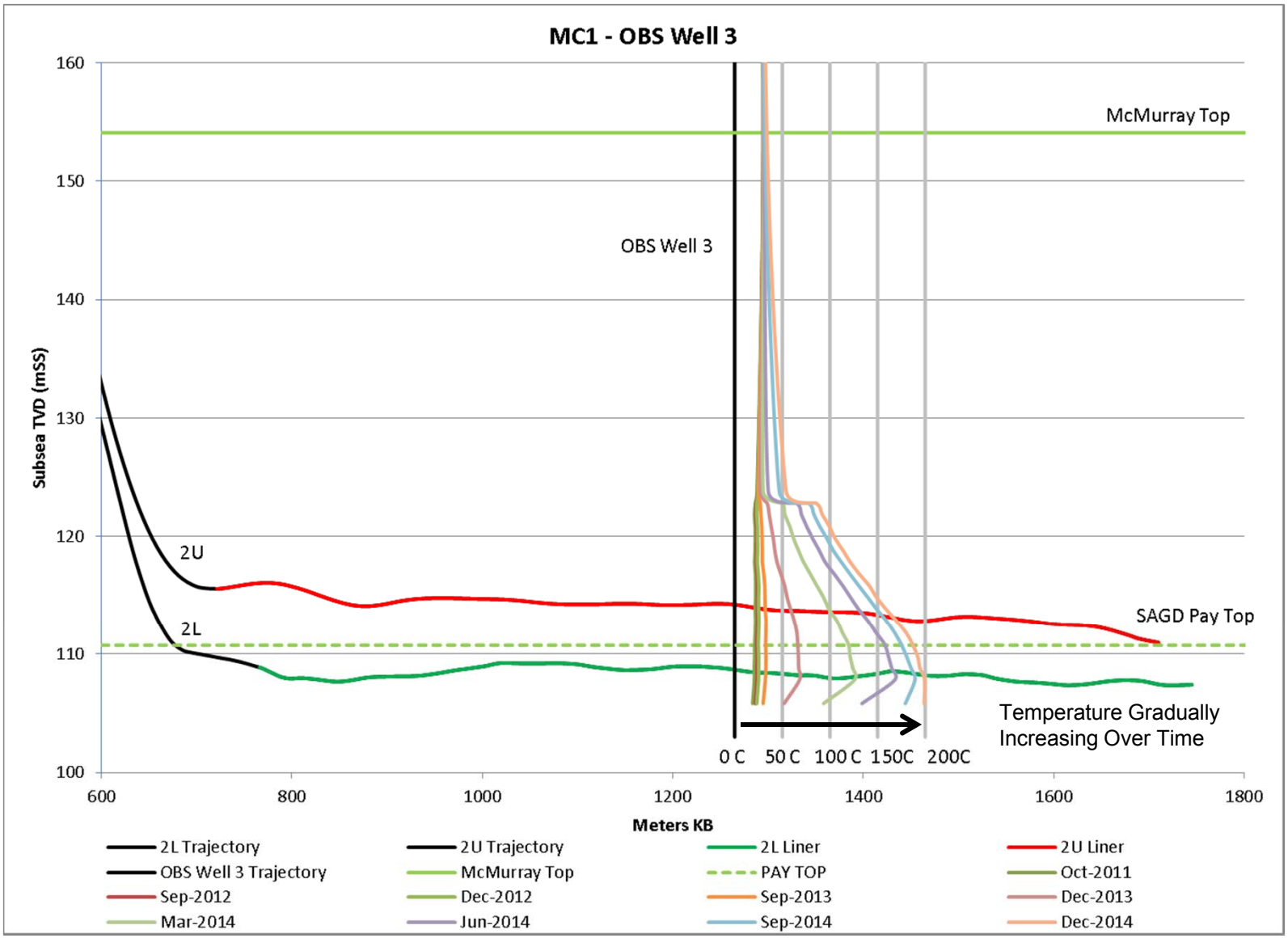
MC1 Observation Well 1



MC1 Observation Well 2



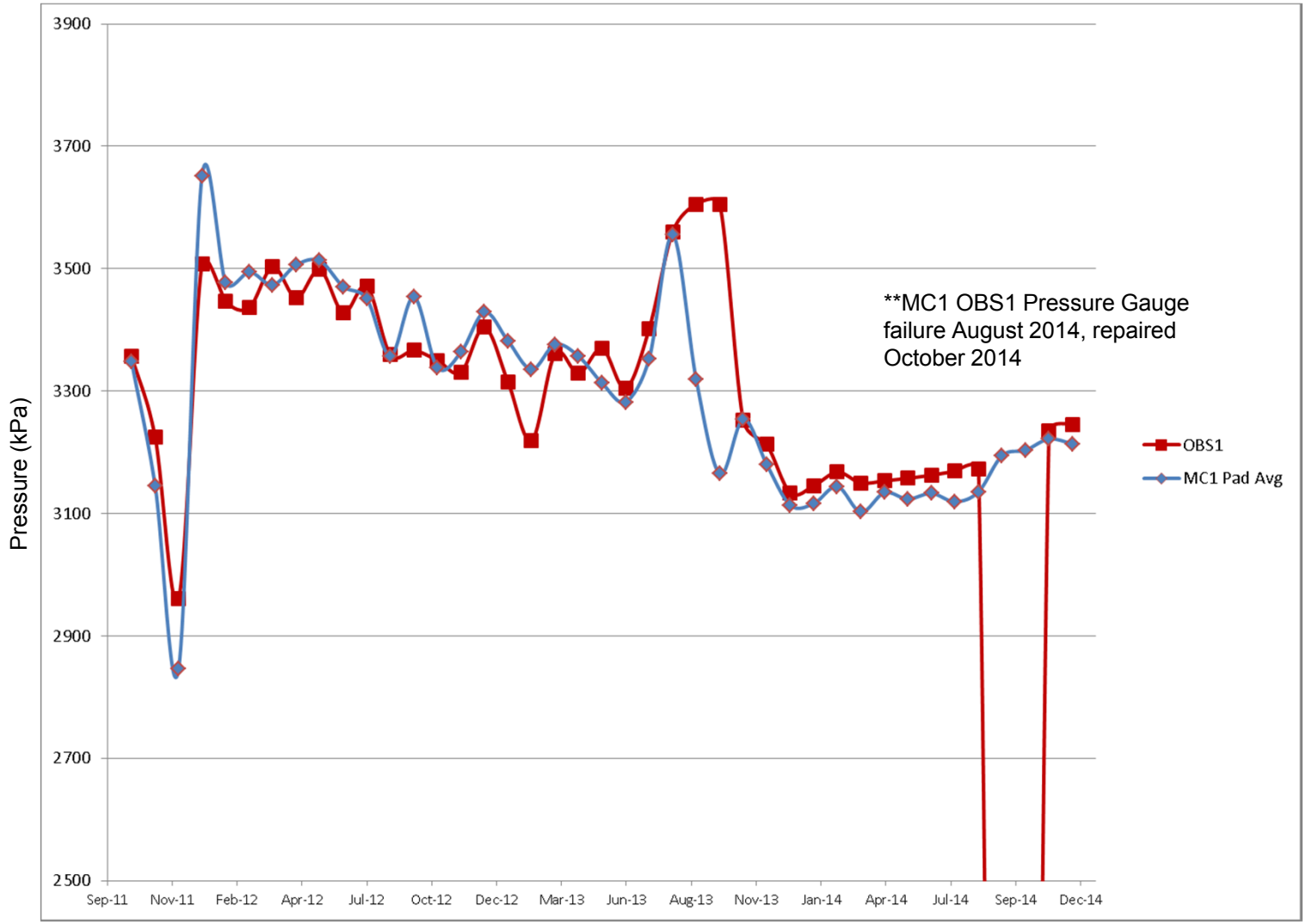
MC1 Observation Well 3



Injector Drilled Above Pay Cutoff – Due to Paleozoic High

MC1 Chamber Pressure

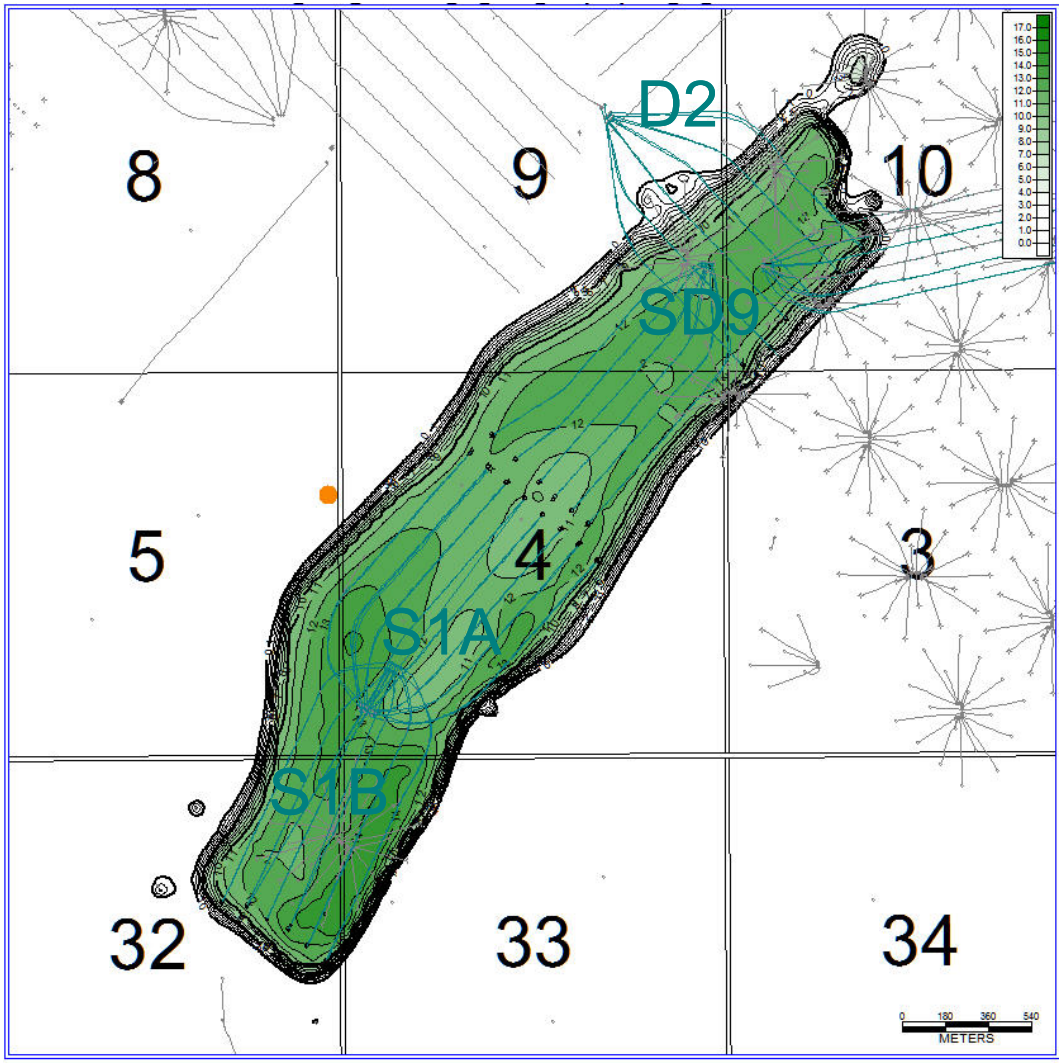
- Chamber pressure is balanced with bottom water



MC1 Pair 1 Re-drill

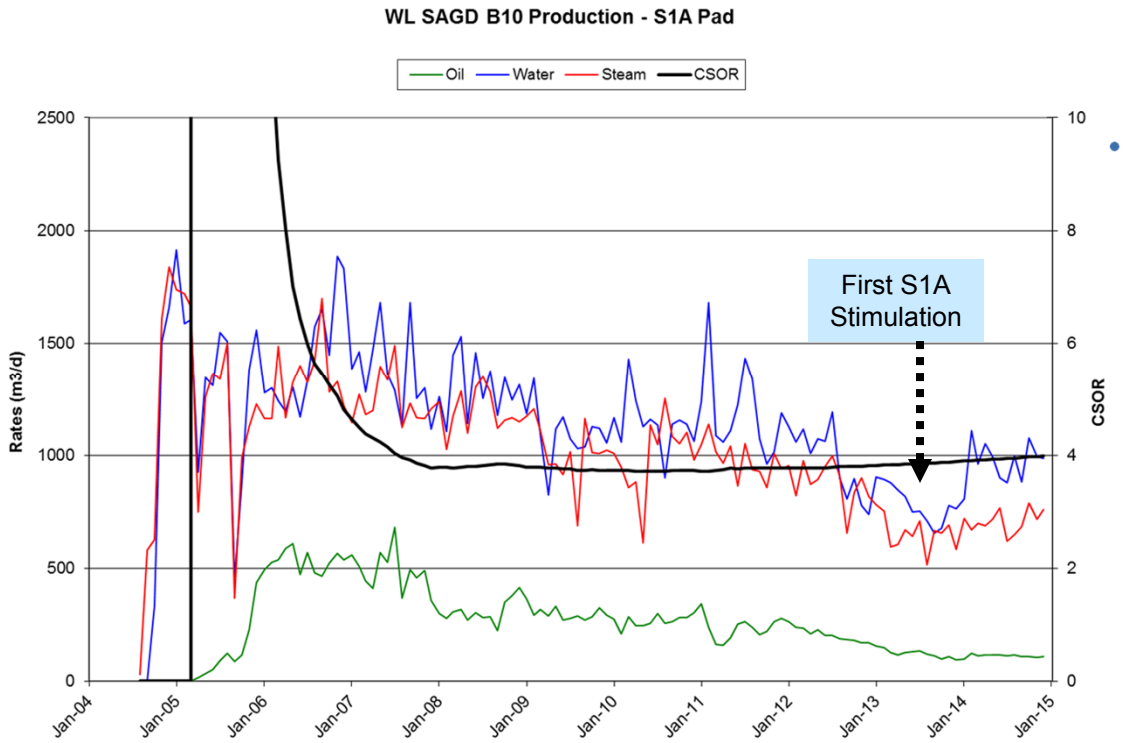
- Started re-drill in October 2013
- Producer
  - Circulation issues while drilling
  - Drilled to planned TD, liner became stuck during installation and could not free, re-drilled through the stuck liner and completed with 5” liner to TD
- Injector
  - A risk assessment was done following the producer issues and decided to extend existing lateral instead of drilling a new lateral
  - BHA became stuck at the end of liner, could not free, left in hole
- Current Operations
  - Producer/Injector
    - Steam injection into wells to maintain pressure support for pad due to bottom water interactions

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: 36 %

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

2014 Activity

- **Stimulations performed to improve longitudinal conformance. Stimulations helped to offset declining rates and help improve recovery factor.**
- **Plugging mechanism has not been determined, all stimulations have had some level of success**

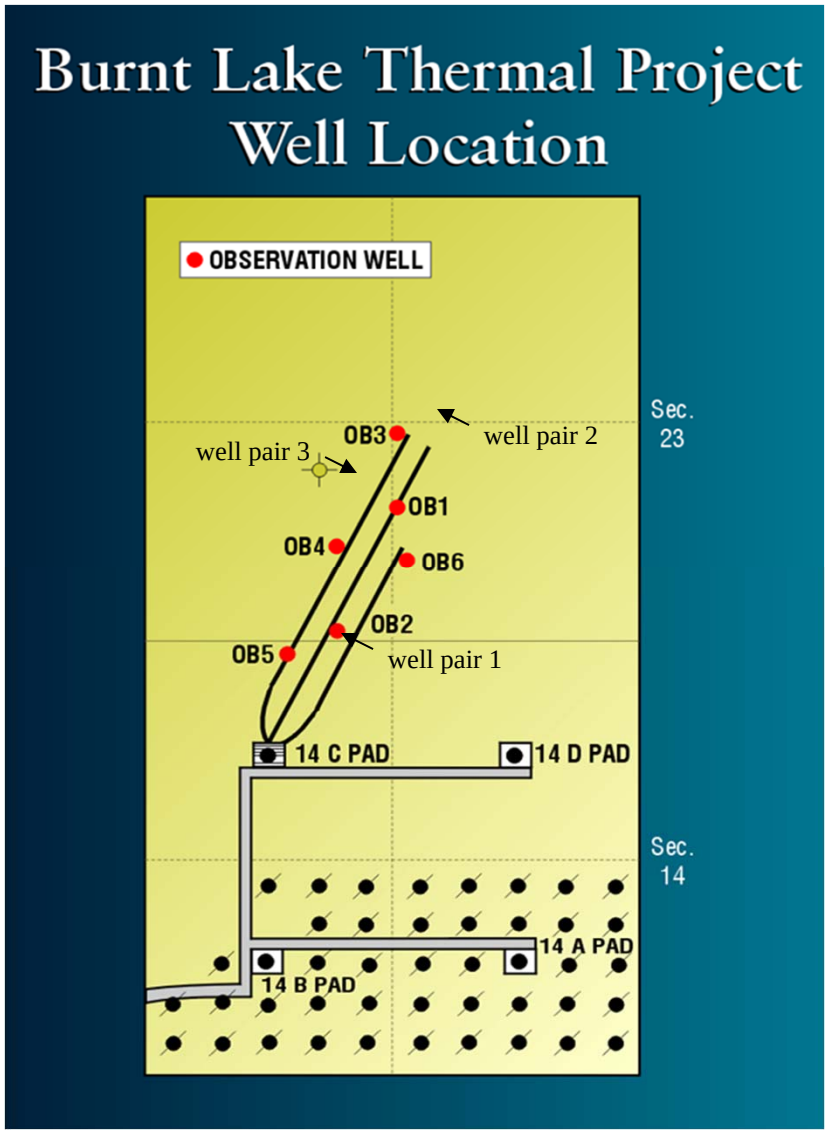
2015 Plan

- **S1A Infill and Step-out Application submitted and approved in 2014.**
- **Blowdown strategy is being considered for future operations.**

Wolf Lake SAGD - 2015 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
  - S1A Infill and Step-out Application approved

Burnt Lake SAGD Performance Summary



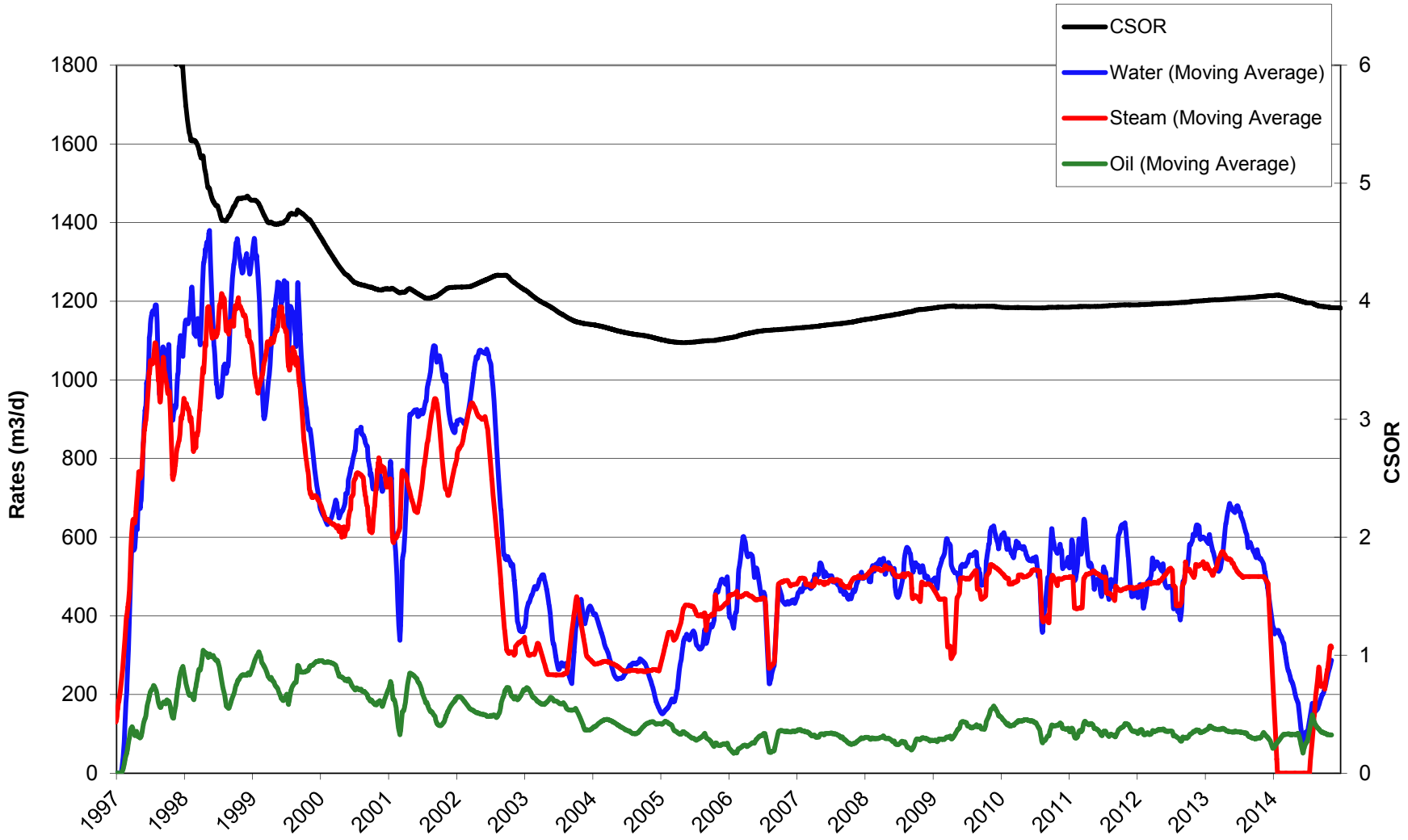
2014 Performance

Burnt Lake SAGD Pilot Production	
Active Well Pairs	3
2014 Bitumen Production (e3m3)	34
2014 Average SOR	1.3
Cumulative Bitumen Production (e3m3)	910
Cumulative SOR	3.9
OBIP (e3m3)	1,493
Recovery Factor (%)	61

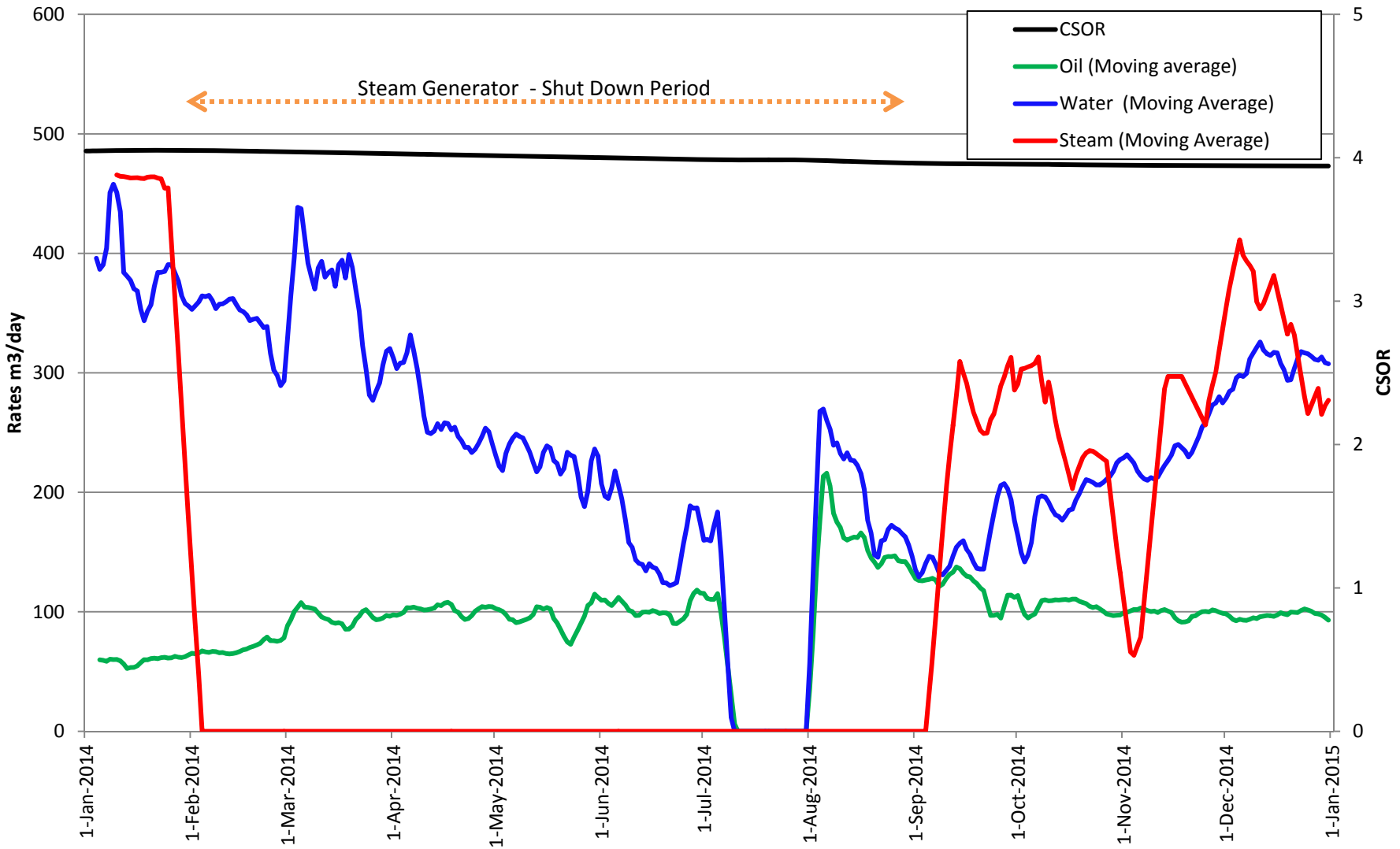
2014 Highlights:

- Steam generator was down 26/01/14 to 04/09/14. Generator failure in late January.
- Steam generation commenced September 4.

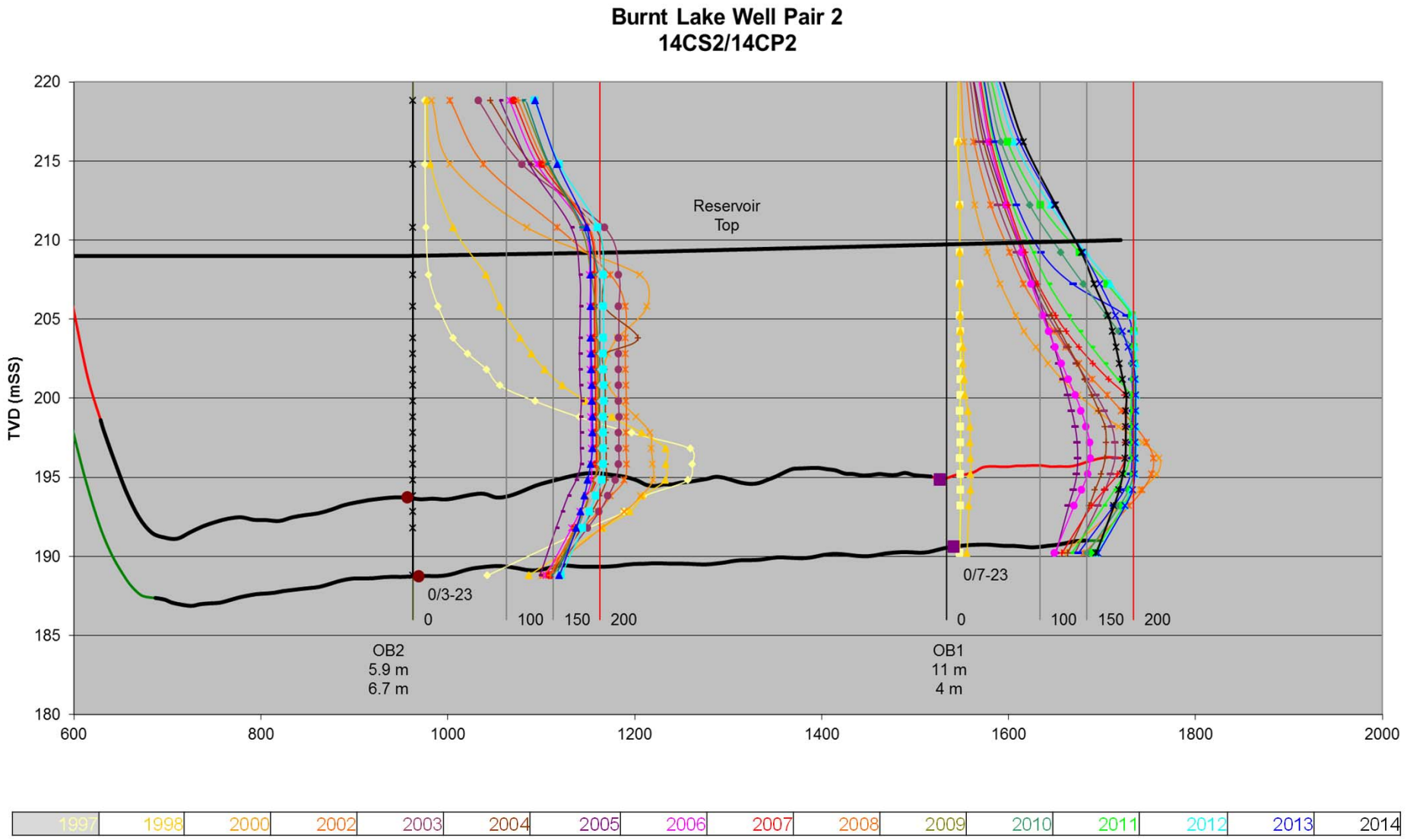
Burnt Lake SAGD Production Summary



Burnt Lake SAGD Production- 2014



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



Cyclic Steam Stimulation Overview

- CSS Basics
  - Steaming
  - 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
  - 2015 Steam Schedule
  - FTS Events
  - Future Development

CSS Basics - Steaming

- 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 (2-5 wells ahead)
  - Soak wells 3+ rows behind steam injection to reduce leak off on post fill-up wells

CSS Basics – Steaming Cycle Performance

Canadian Natural

- 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 VOF 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)
- Ultimate recovery is believed to be improved by increased cycle volumes due to improved thermal efficiencies and reservoir conformance

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

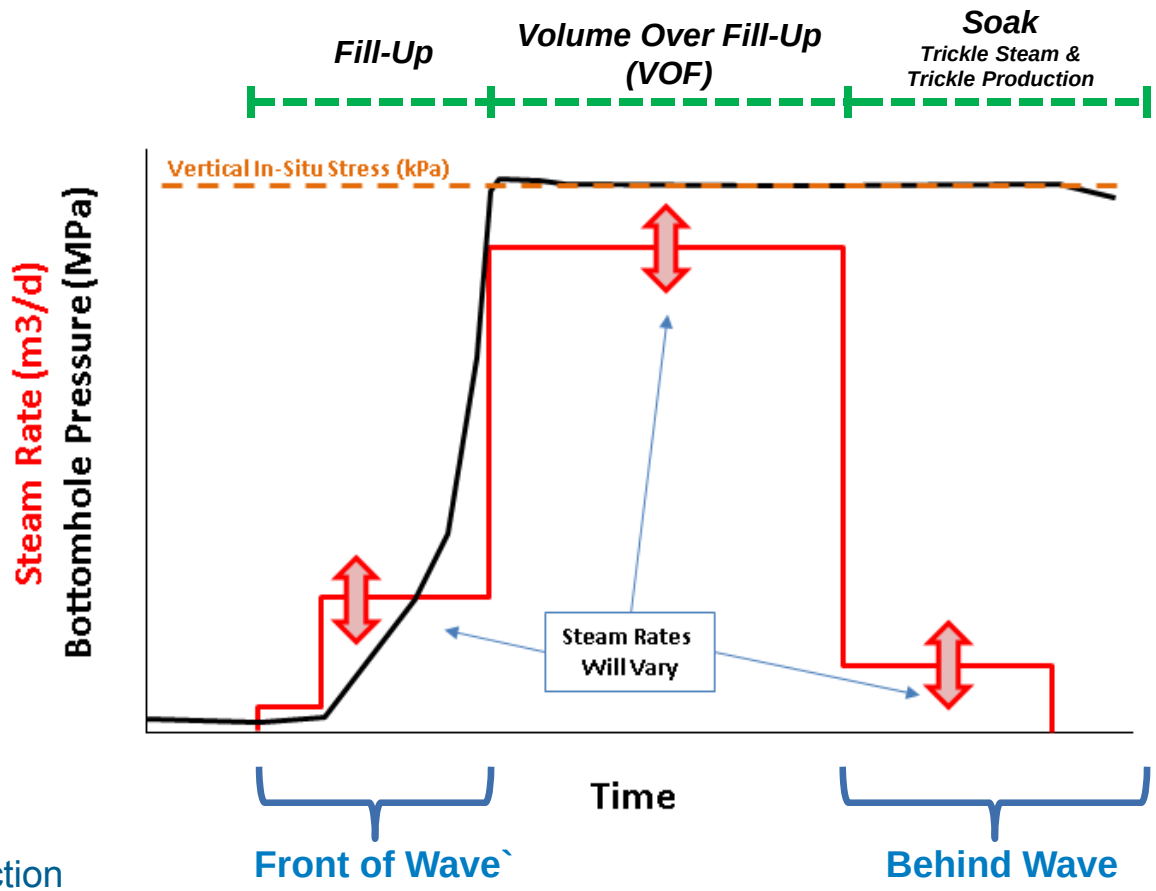
- Current steam strategy includes low volume commissioning cycles followed by commercial cycles
  - Commissioning cycle 1: ~10,000 m^3/well
  - Commissioning cycle 2: ~17,000 m^3/well
  - Commercial cycle 1+: Limited by overburden uplift
    - Formation Expansion Index (FEI) is used to calculate overburden uplift for each steaming cycle. FEI is equal to steam volume divided by area (well length x spacing) and currently limited to 0.26 or 26cm. Steam volumes are adjusted based on well area to stay at or below this limit.

- Steam volumes on edges of developments are tapered in Commercial cycle 1+

- Goal of 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

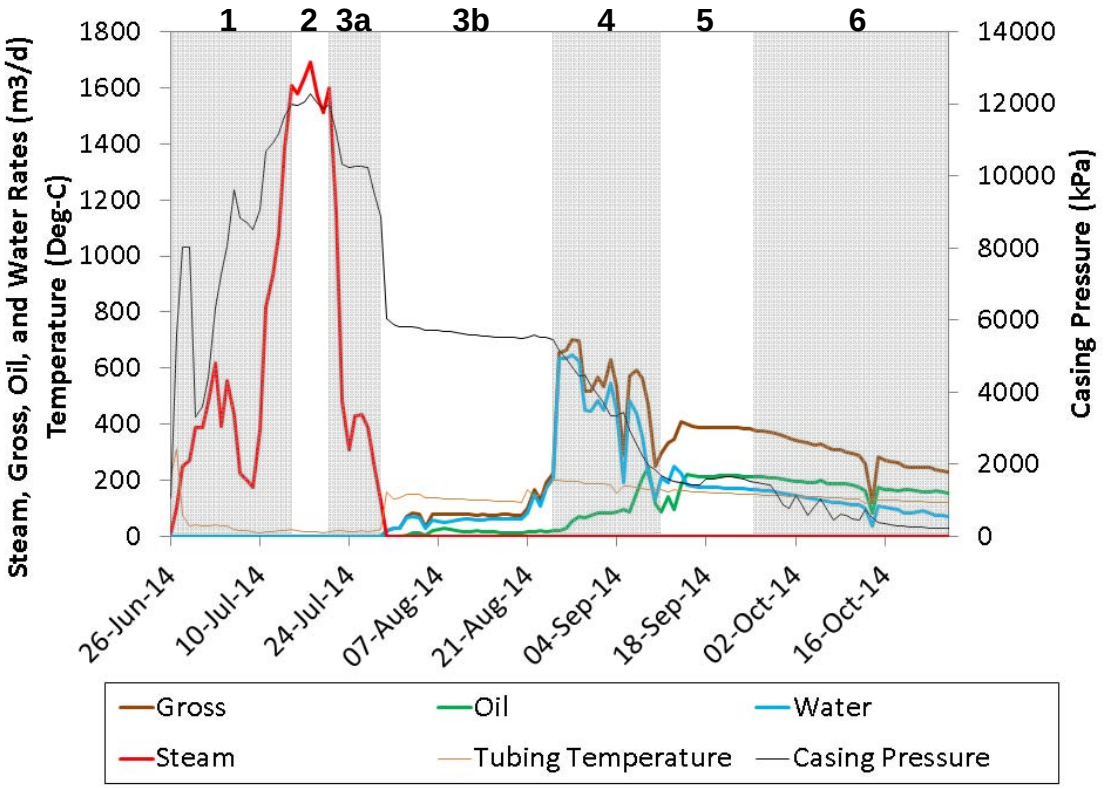
CSS Basics - Steaming
Reservoir Pressure Management

- 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



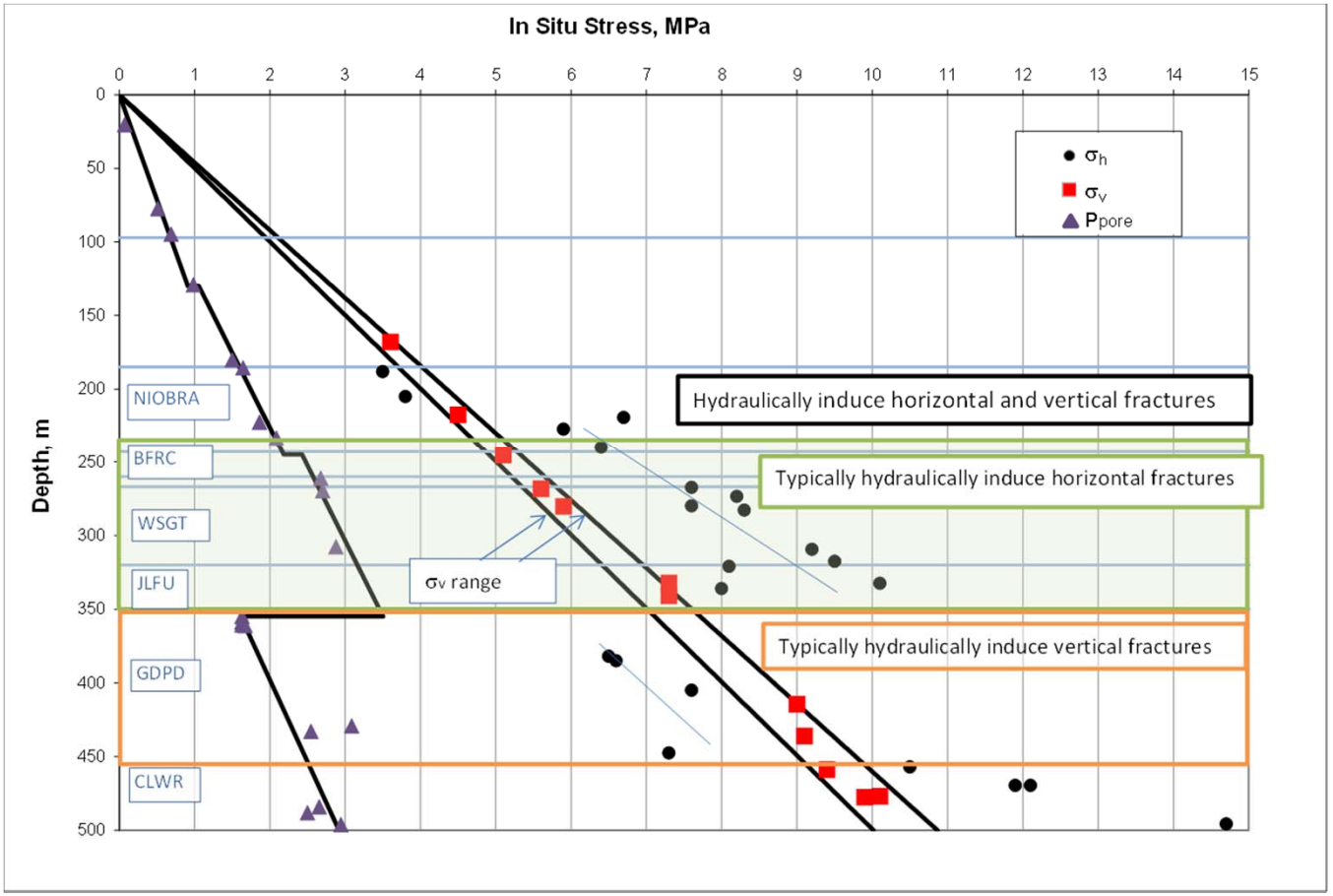
CSS Basics - Depletion Fluid Recovery Basics

- 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



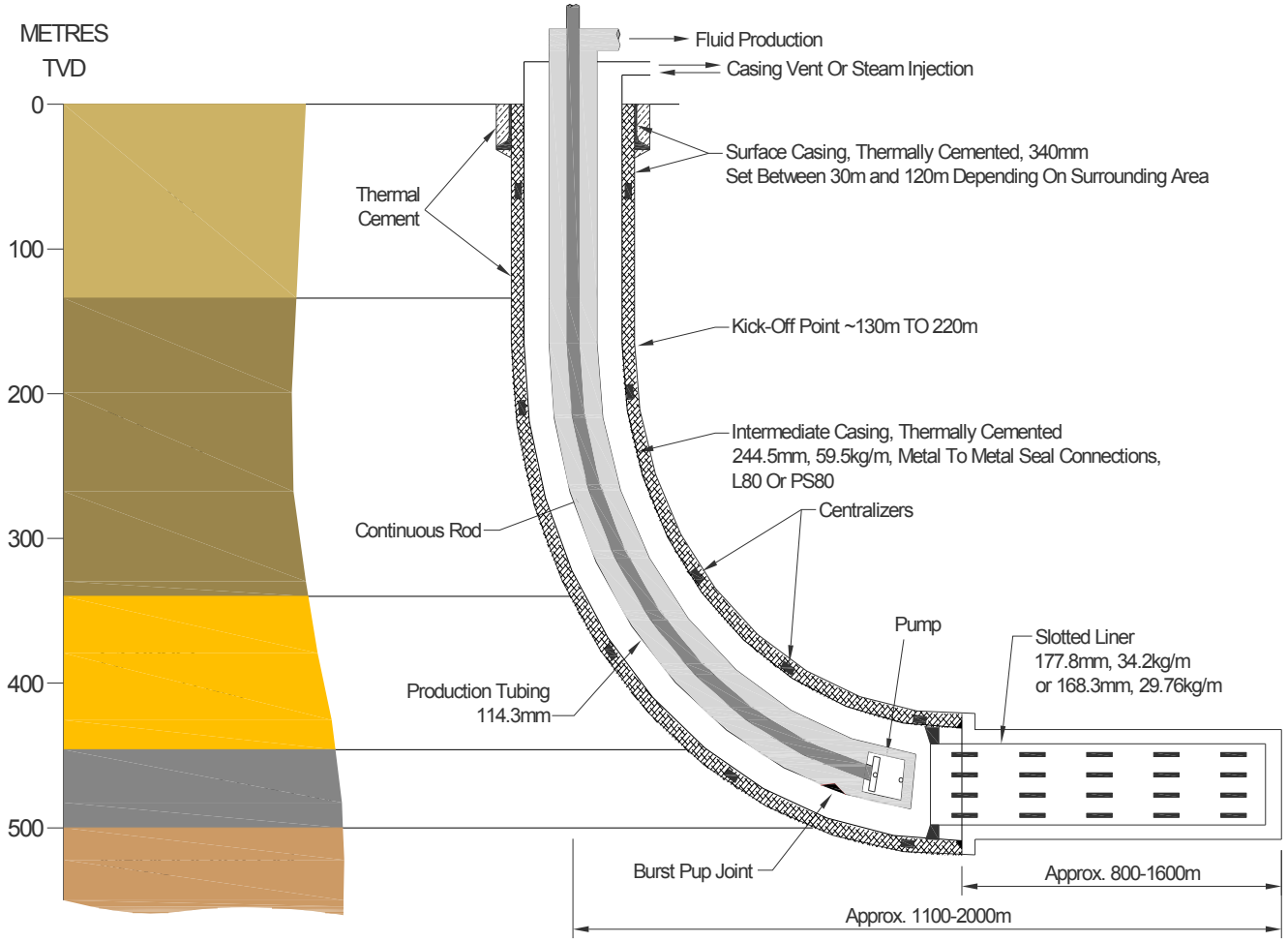
Geomechanics: Overburden In-Situ Stresses

- Colorado Group shales have a minimum in-situ stress oriented vertically
- Colorado Group hydraulically induced fractures will propagate horizontally
- Colorado Group 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

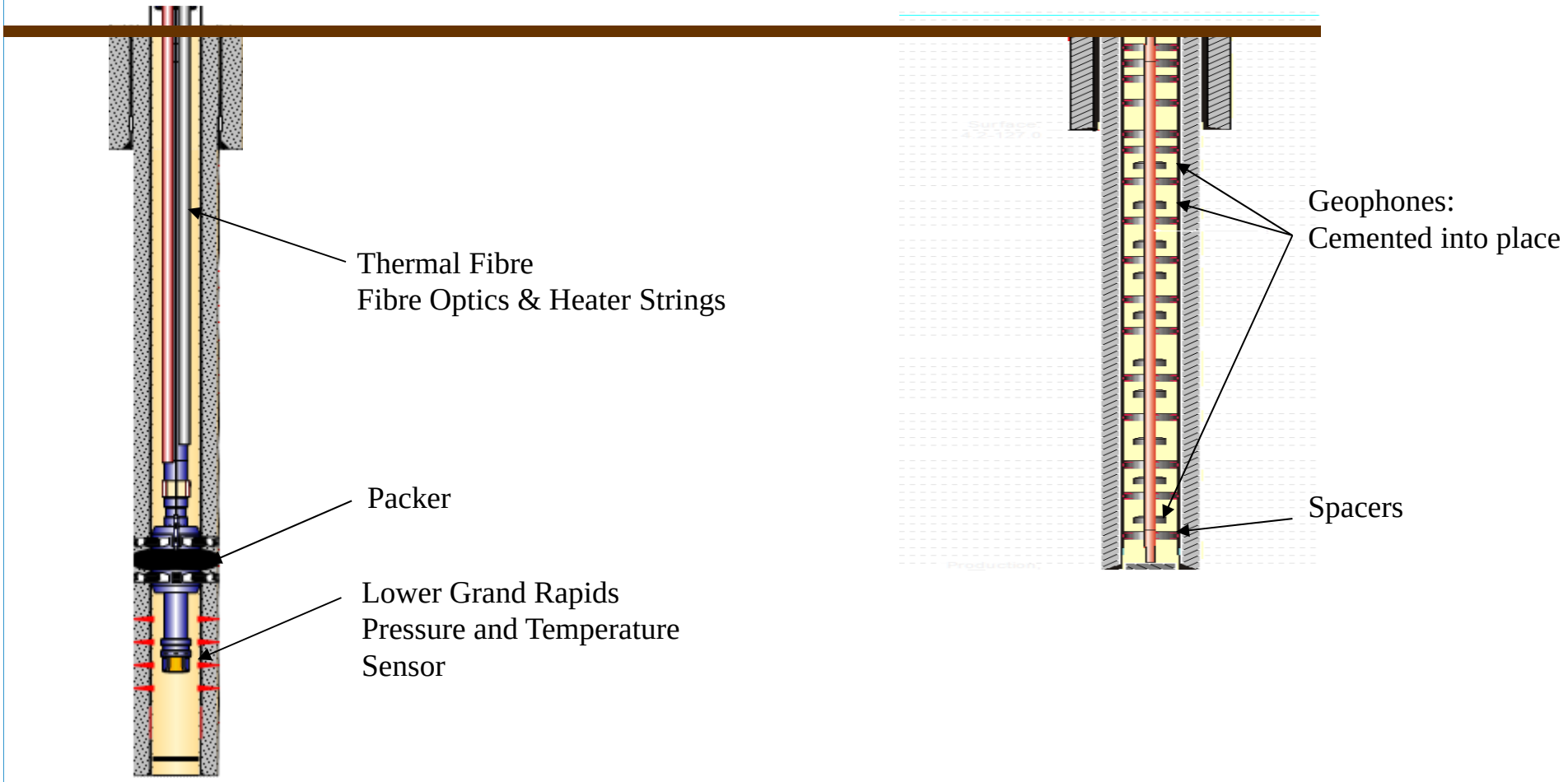


CSS Basics – Observation Wells

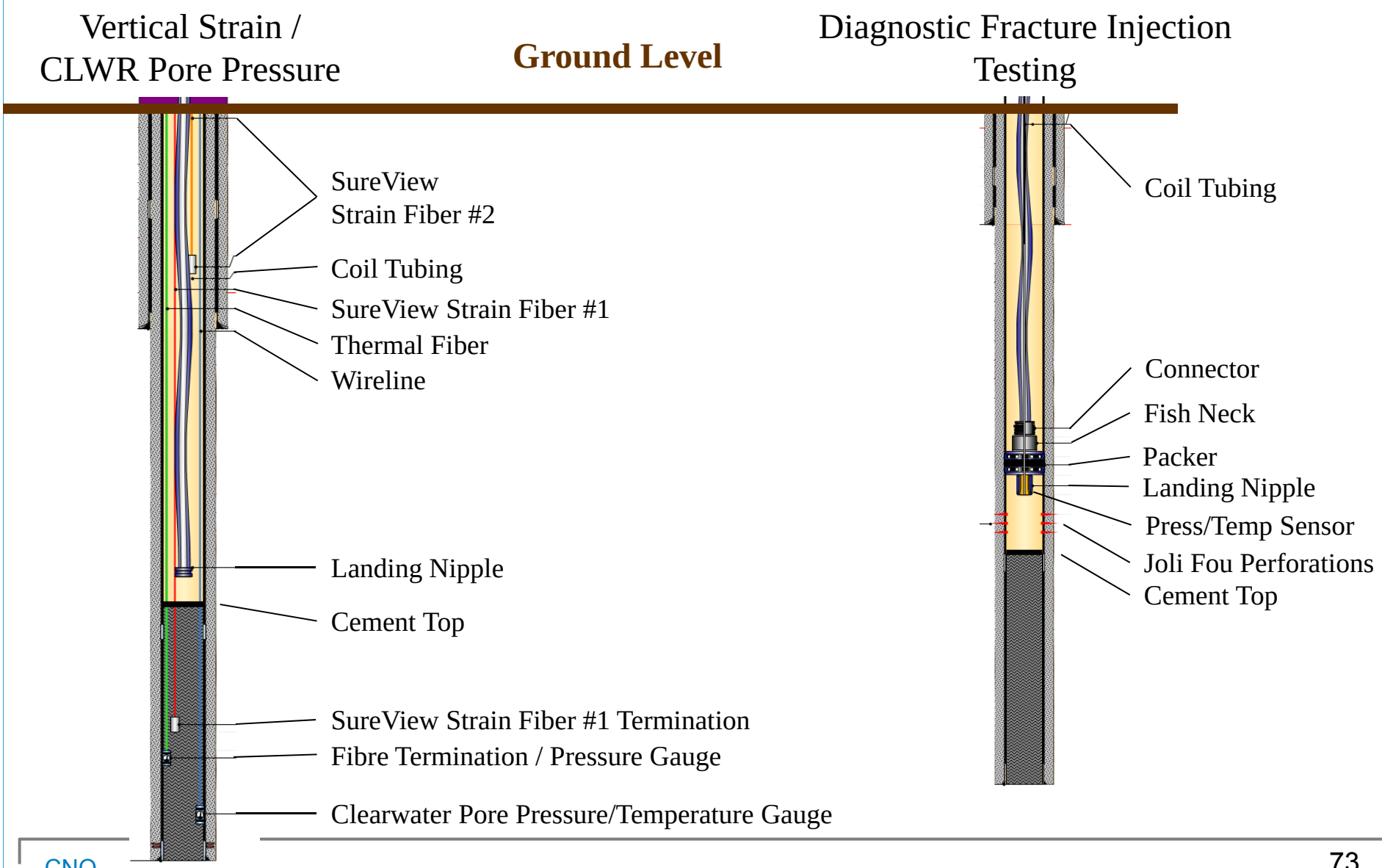
Grand Rapids Monitoring

Ground Level

Passive Seismic Monitoring



CSS Basics – Geomechanics Wells



Formation Integrity Monitoring
Thermal Fibre, Passive Seismic and Geomechanics

Canadian Natural

- 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 100% detection rate for:
    - Out of zone casing failures.
    - Casing failures outside of the surface casing.
    - Pads with functioning PS equipment.
- Thermal fibre gives us the ability to monitor for fluid migration attributed to inferior cement jobs
  - Focuses on detection of horizontal fractures intersecting observation well
- Thermal fibre is the preferred method for fluid monitoring within the Colorado Shales
  - Monitoring to date has shown no issues during steaming or production
- Geomechanics Observation Wells on Pad 43
  - Go forward plan is to continue data acquisition in 2015
    - DFITs during maximum Clearwater overburden uplift and end of CSS production cycles
  - Integrate data and improve understanding between steam injection volumes and uplift induced stress changes

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
  - Best to integrate independent data sources
    - Passive seismic, thermal fiber, injectivity plots, production data
  - All steaming pads are equipped with LGR pressure monitoring
  - Canadian Natural shall notify the AER if a LGR pressure increase is greater than 200 kPa/day

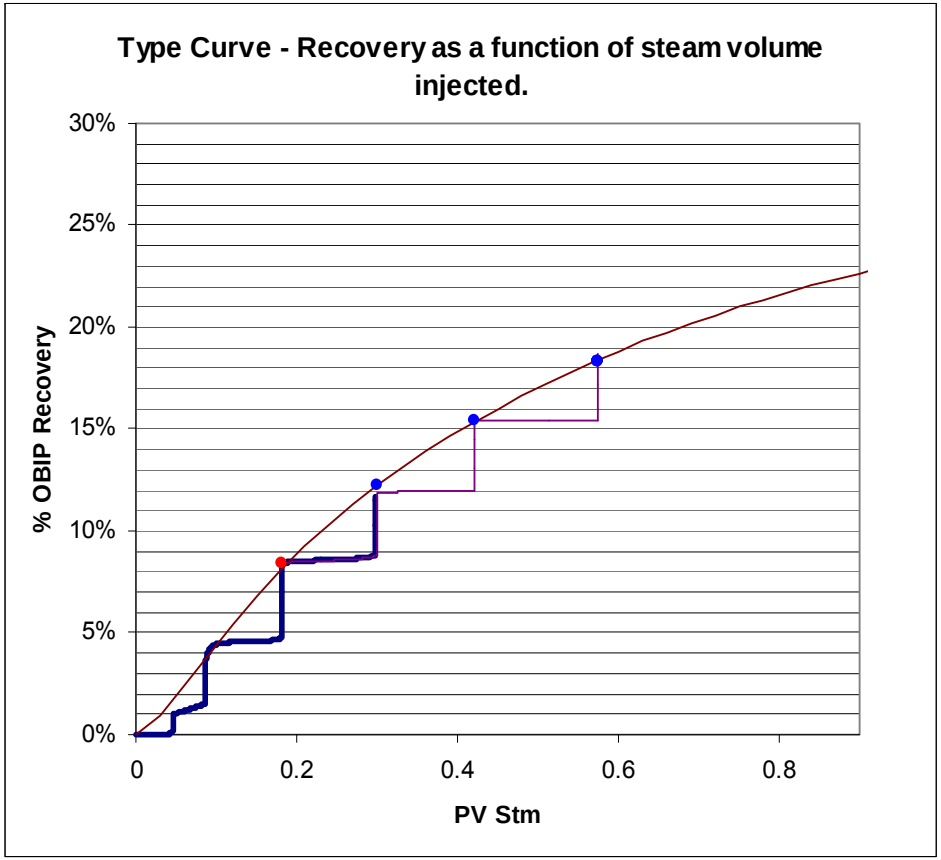
CSS Basics - OBIP Assumptions

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

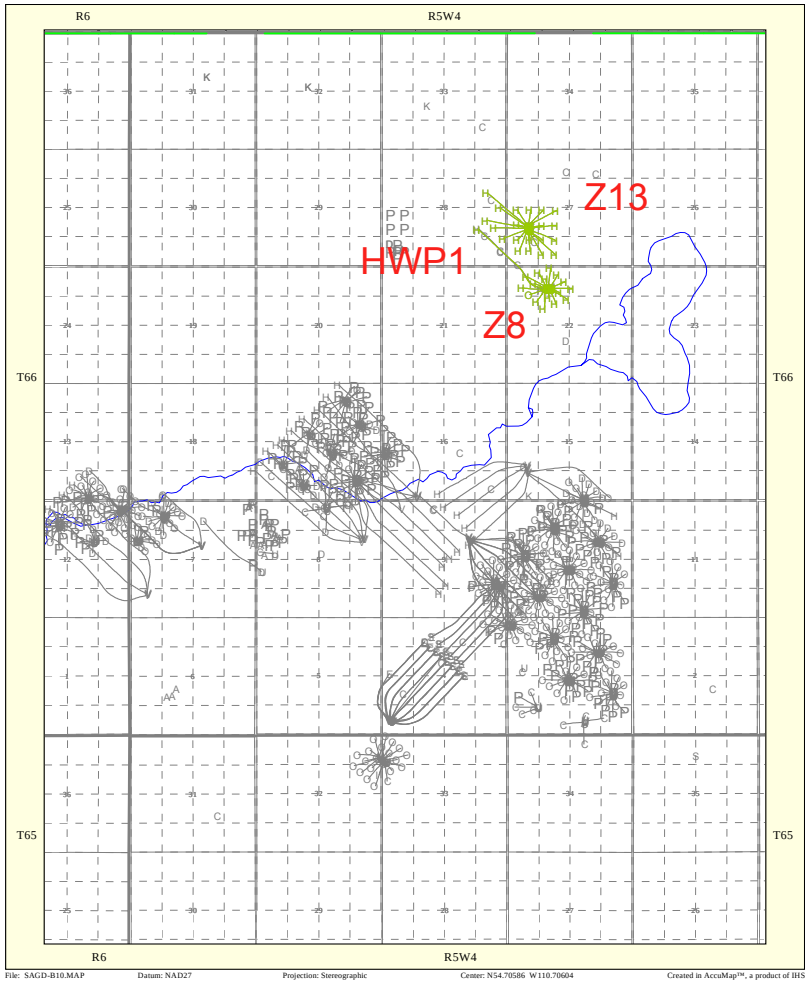
- Area is 1 well spacing wide by length of well plus ½ spacing on each end
- Net pay is as previously defined in the Geology section
- Oil saturation is determined from Bitumen Weight percentage assuming a sand/shale density of 2650 kg/m^3, water/oil density of 1000 kg/m^3, and 32% porosity

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

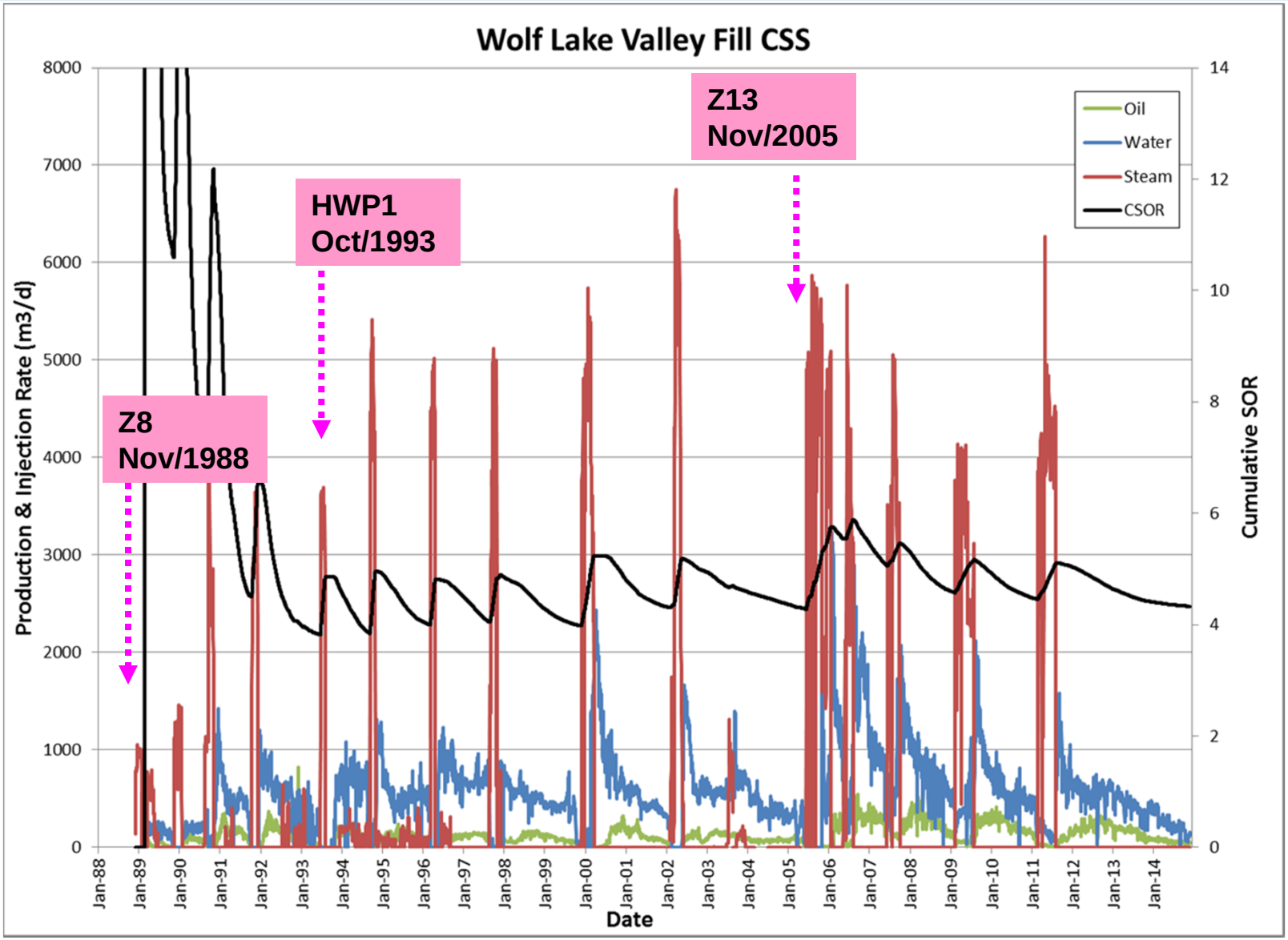


2014 Performance Summary

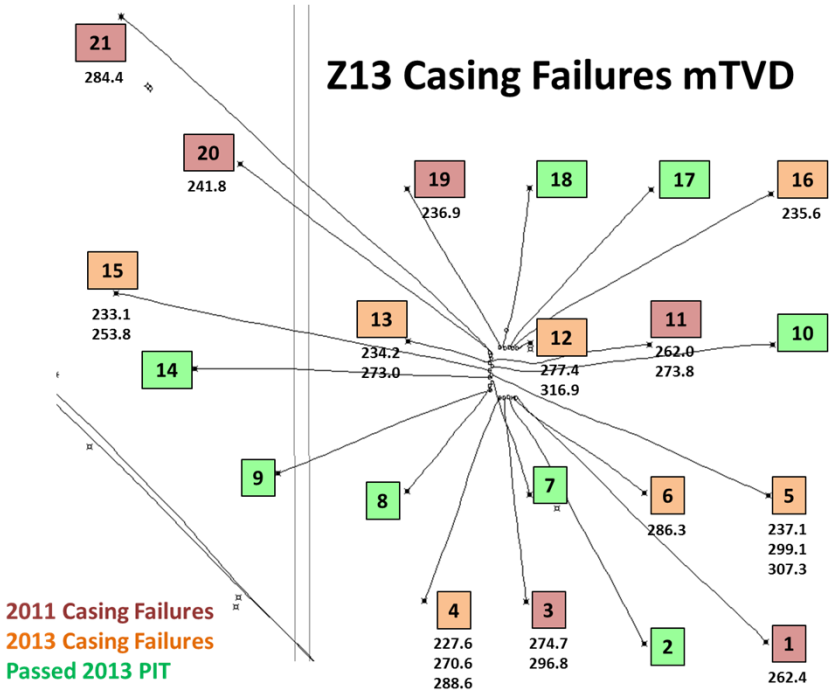
Wolf Lake Valley Fill CSS Performance Summary

Phase	Z8 & HWP	Z13	VF Total
CSS Well Count	20	21	41
2014 Steam Injection (m3)	0	0	0
2014 Bitumen Production (e3m3)	6	17	23
Cumulative Bitumen Production (e3m3)	650	428	1,078
Cumulative SOR	4.4	4.5	4.4

Wolf Lake Valley Fill CSS, All Pads

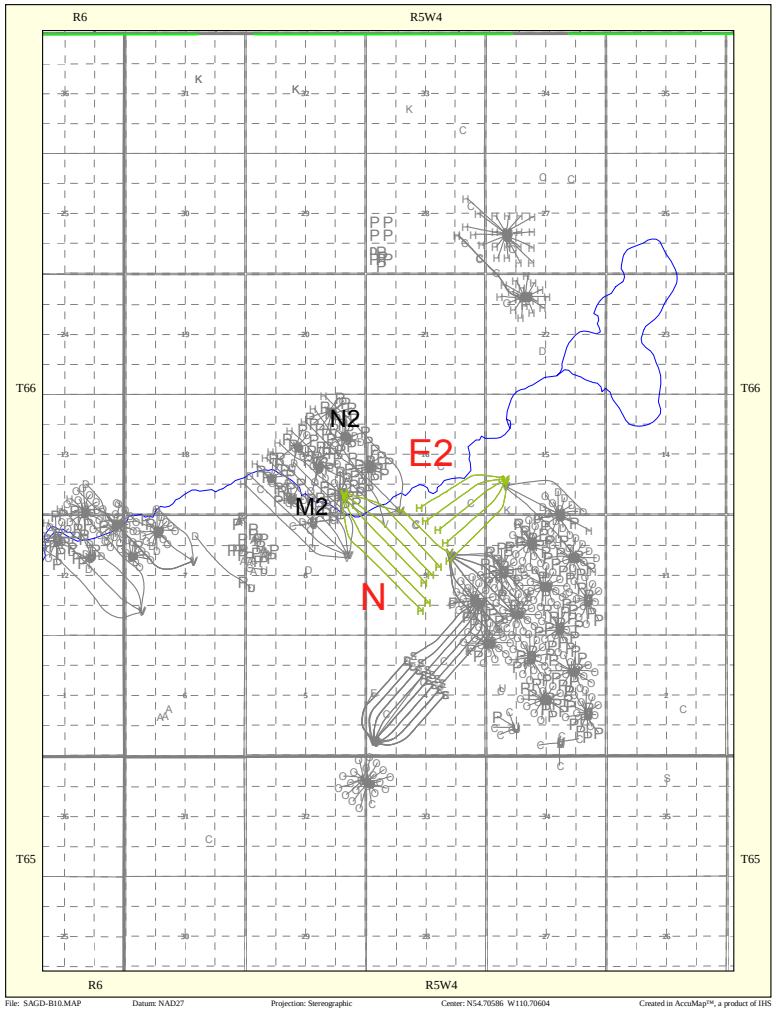


Wolf Lake Valley Fill CSS
Z13 Casing Failure Update



- 13/21 wells have failed in previous cycles
- These low cycle fatigue failures have been attributed to connection type and tensile loading
- Strategies have been developed and initiated to limit any further type of similar events
- In October 2014 elevated dissolved constituents were found in the Empress 1 formation aquifer, and reported to the AER
- These elevated levels are related to the casing failures noted
- An investigation/remediation of the elevated constituents and casing failures is currently underway

Wolf Lake C3 Sand CSS

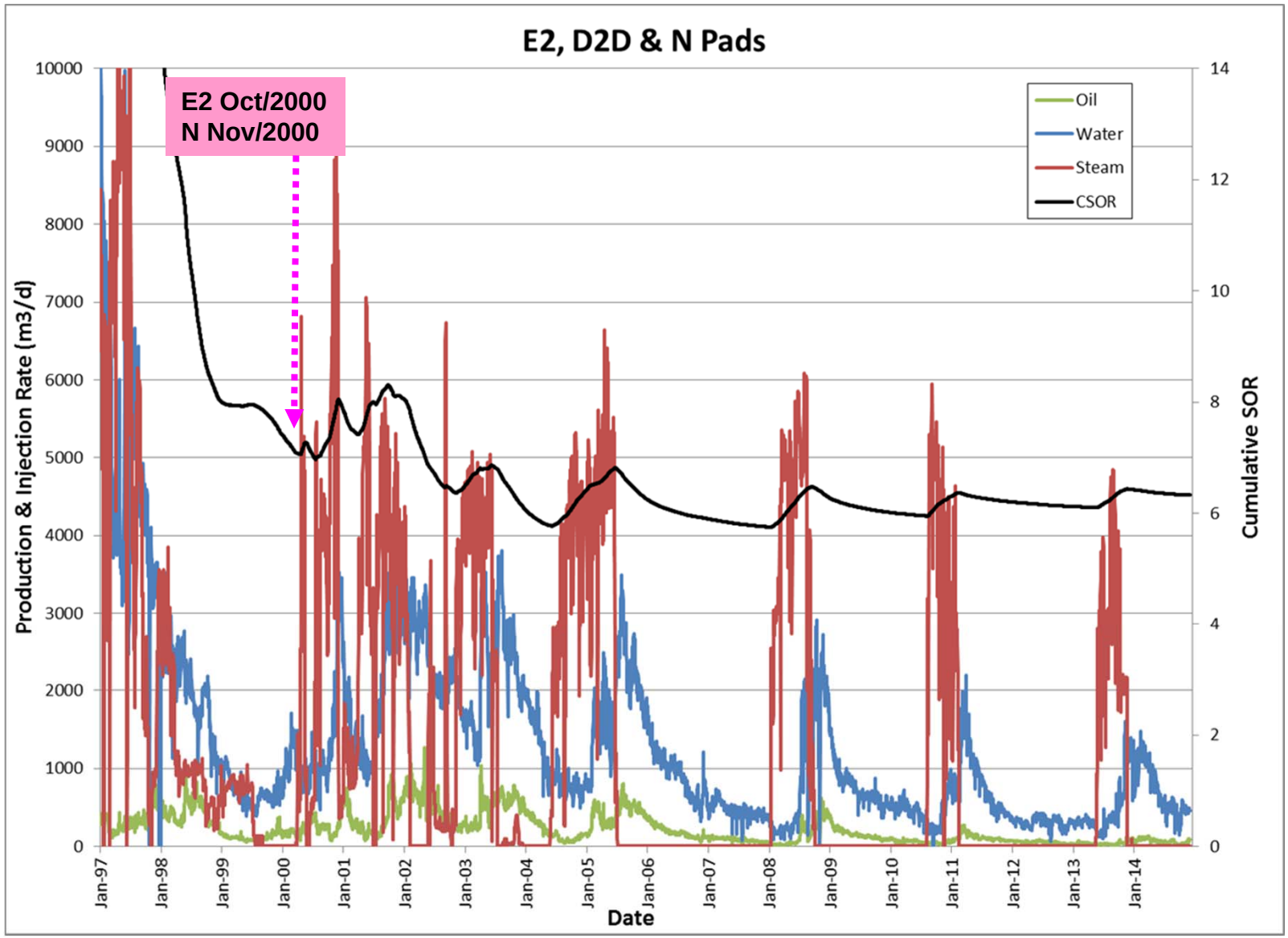


2014 Performance Summary

Wolf Lake Valley Fill CSS Performance Summary

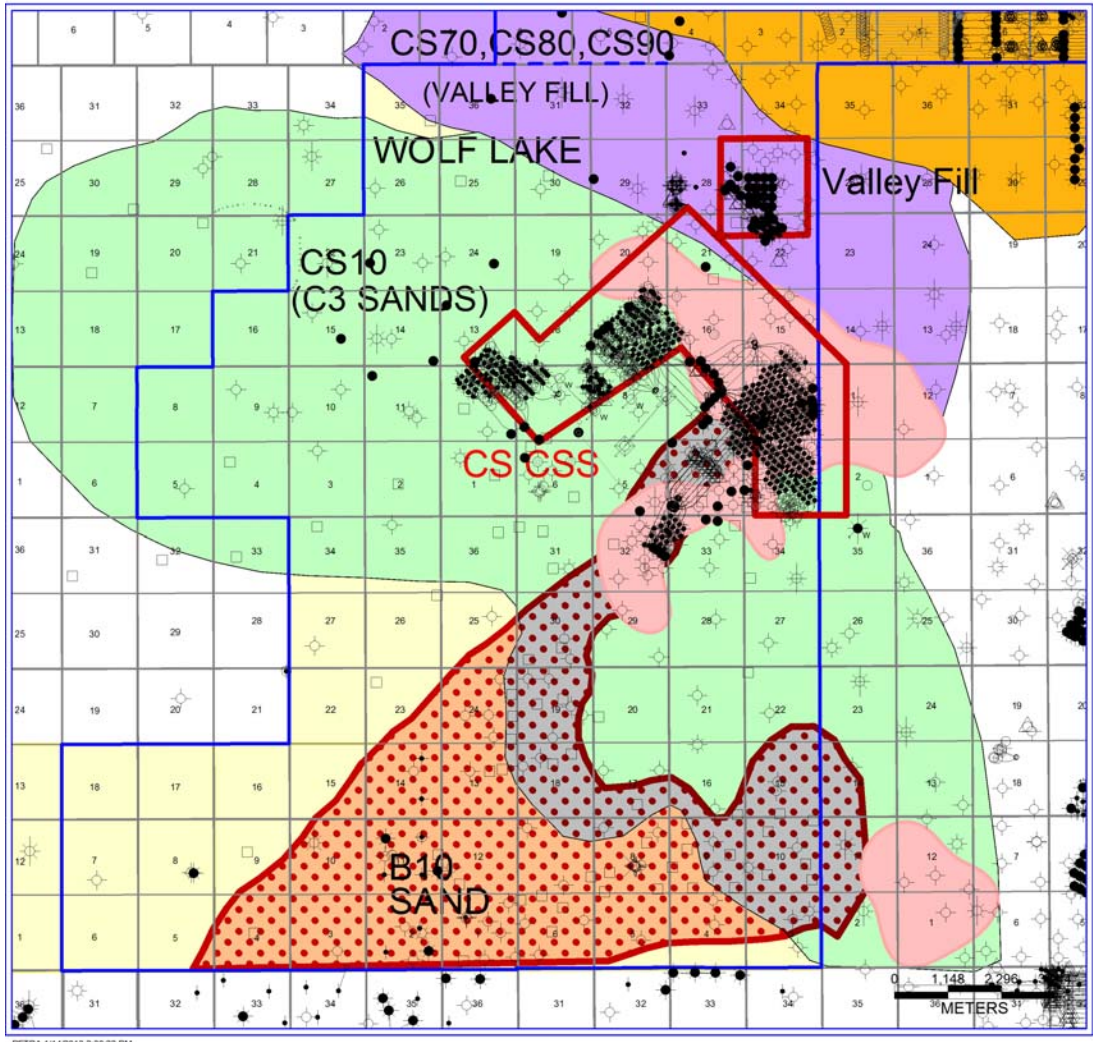
Phase	E2 & D2D	N	C3 Total
CSS Well Count	6	5	11
2014 Steam Injection (m^3)	0	0	0
2014 Bitumen Production ($e3m^3$)	18	5	23
Cumulative Bitumen Production ($e3m^3$)	553	401	954
Cumulative SOR	5.9	7.4	6.5

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

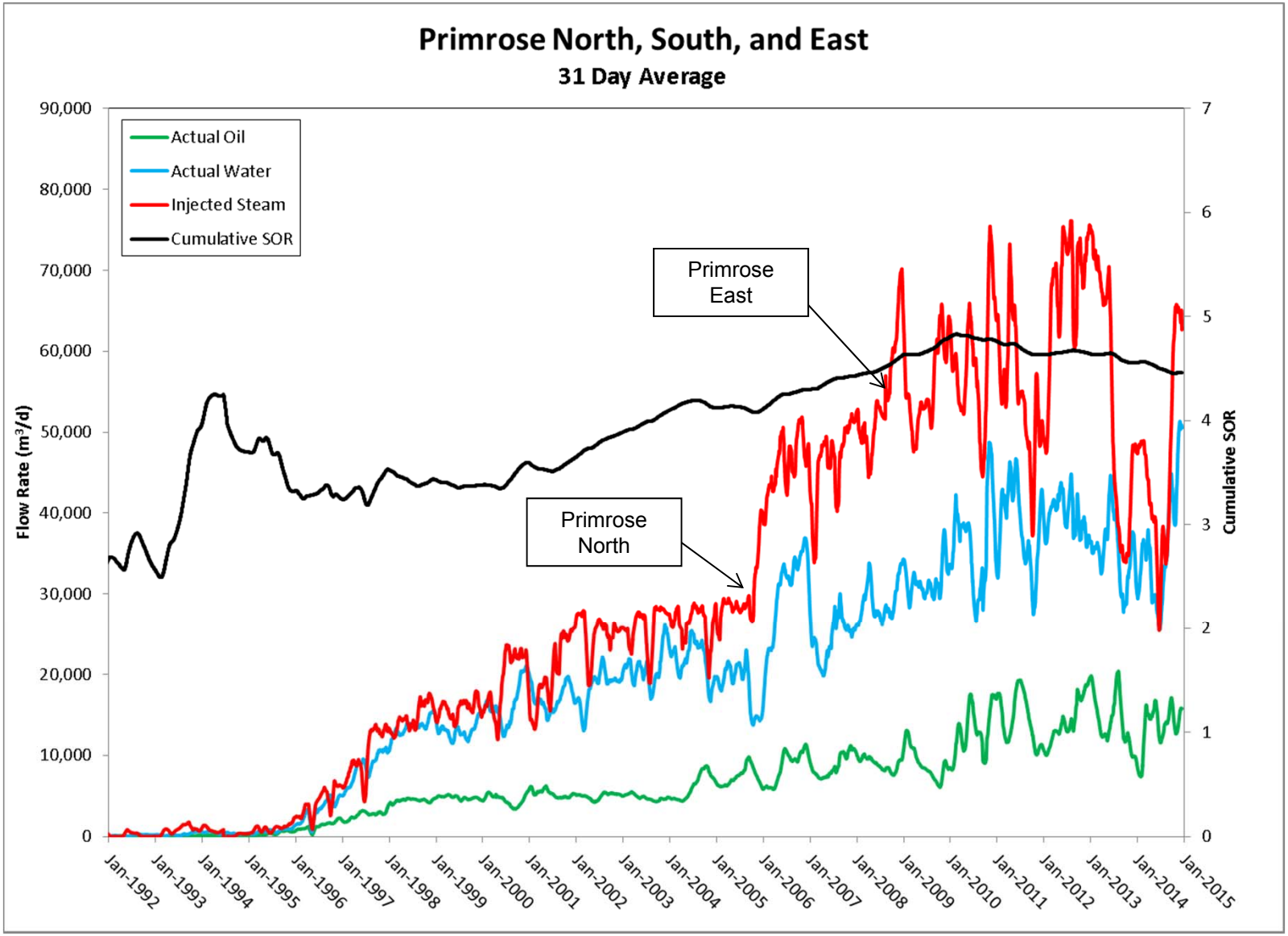


Wolf Lake 2014 / Potential Recoveries

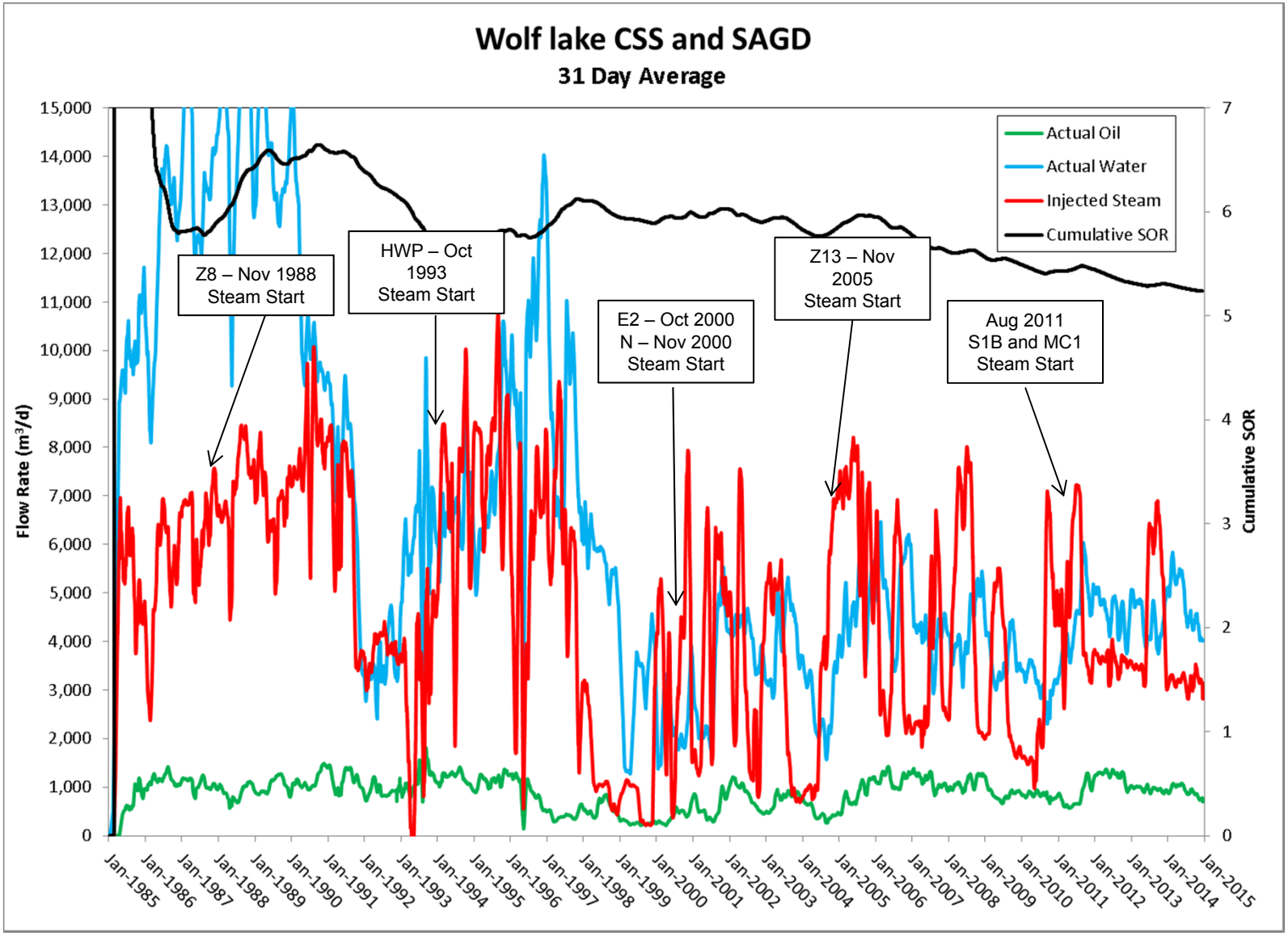
Wolf Lake Area	OBIP (e3m3)	2014 cum oil (e3m3)	RF (%)	Estimated Recoverable (%)
Valley Fill	6,943	1,077	16	21-26%
C3 Sand	4,890	954	20	26-28%



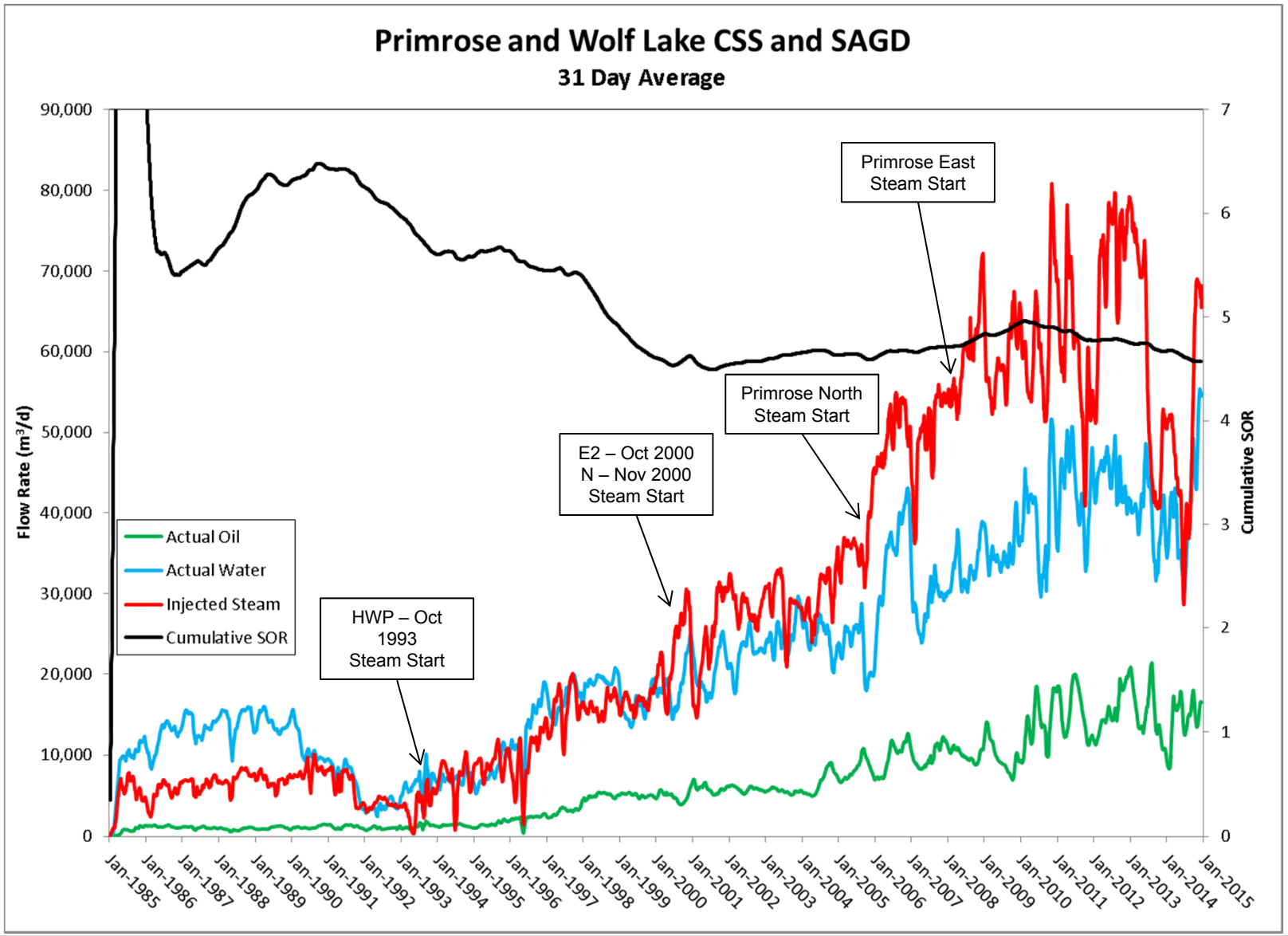
Primrose Oil, Water, Steam, and SOR



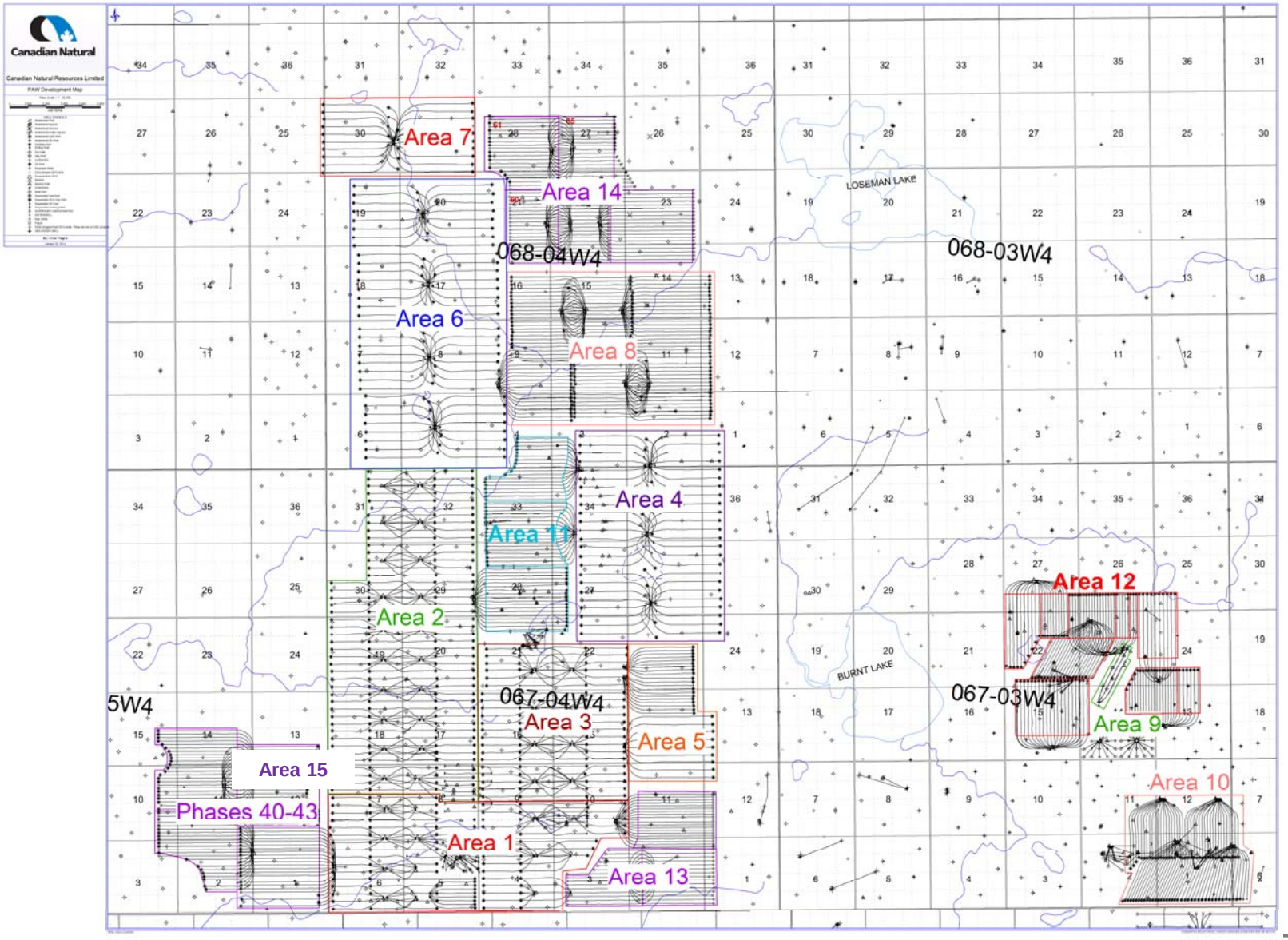
Wolf Lake Oil, Water, Steam, and SOR



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



Primrose Current Recoveries - 2014



Primrose Current / Potential Recoveries

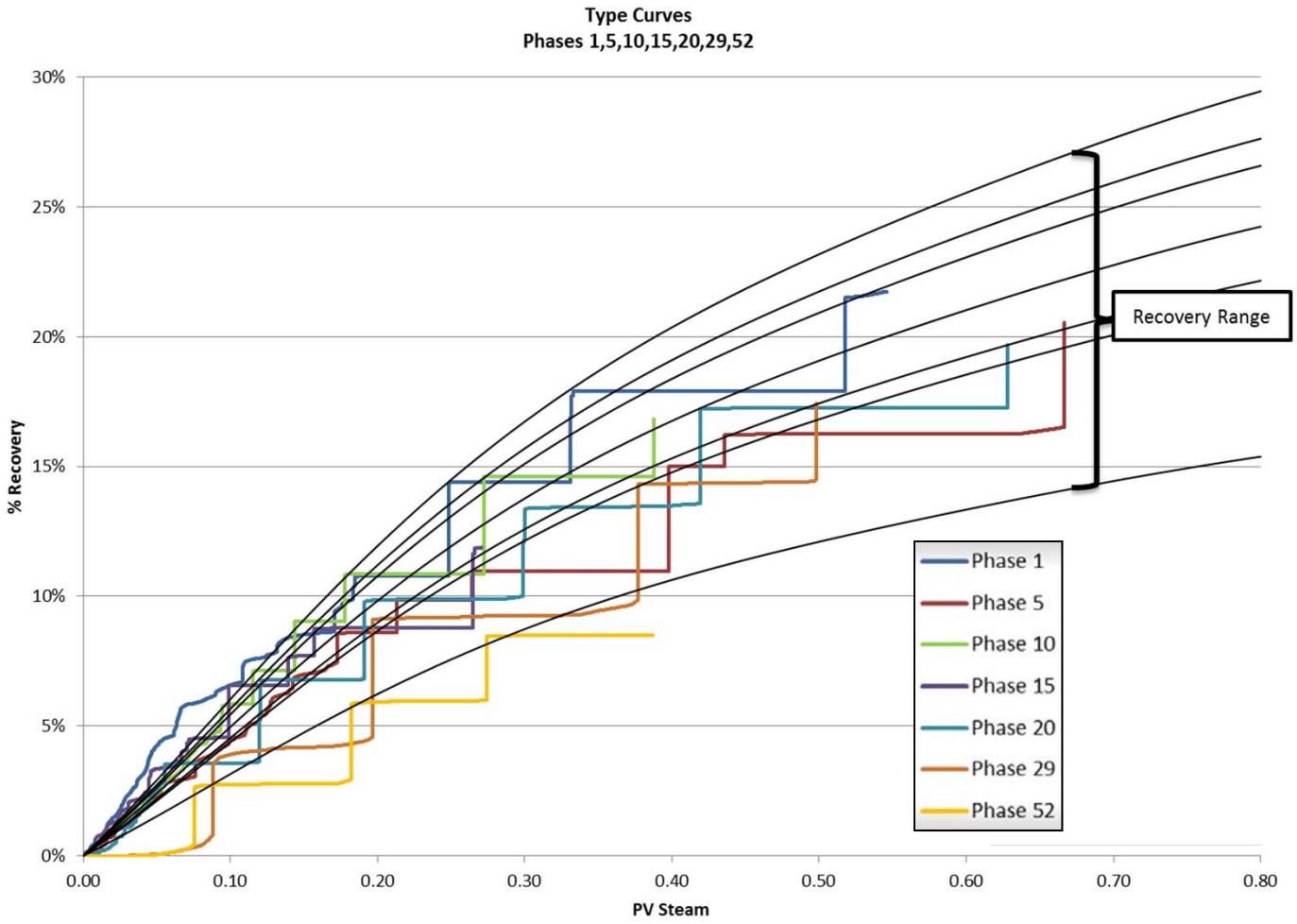
Canadian Natural

	OBIP (e3m3)	Area (m2)	Pay Thickness (m)	Porosity (dec)	Cum Oil (e3m3)	Current Recovery	Potential Recovery Range
Area 1:							
1	5,780	2,048,000	14.1	32	1,308	23%	30-36 %
2	3,934	1,536,000	12.6	32	607	15%	24-30%
3	3,901	1,792,000	10.5	32	761	19%	26-32%
P-M WSDD	2,495	768,000	17.5	32	571	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	500	12%	26-32%
16	3,377	1,280,000	13.1	32	413	12%	22-28%
16C	766	444,347	8.7	32	56	7%	15-21%
17	5,259	2,560,000	10.3	32	945	18%	21-27%
Subtotal	**33,185**				**5,732**	**17%**	
Area 2:							
5	3,221	1,536,000	9.9	32	599	19%	21-27%
CDD	998	896,000	6.0	0.32	185	19%	20-22%
D5	1,231	668,077	9.5	32	71	6%	16-22%
6	5,625	2,048,000	13.6	32	766	14%	20-26%
7	5,679	2,048,000	13.9	32	950	17%	23-29%
8	5,691	2,048,000	14.0	32	895	16%	21-27%
9	5,229	2,048,000	12.9	32	891	17%	23-29%
10	5,616	2,048,000	13.9	32	954	17%	28-34%
11	6,735	2,560,000	13.5	32	1,019	15%	26-32%
12	5,058	1,920,000	13.5	32	722	14%	22-28%
13	5,270	1,920,000	14.0	32	735	14%	20-26%
14	5,112	1,920,000	13.6	32	740	14%	21-27%
Subtotal	**55,465**				**8,527**	**15%**	
Area 3:							
18	5,772	2,560,000	11.2	32	1,126	20%	24-30%
19	5,592	2,560,000	10.9	32	1,237	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	1,146	16%	21-27%
Subtotal	**24,142**				**4,647**	**19%**	
Area 4:							
29	10,394	4,175,104	10.4	0.32	1,847	18%	20-26%
30	10,380	4,175,104	10.4	0.32	1,951	19%	21-27%
31	11,334	4,175,104	11.3	0.32	2,061	18%	21-27%
Subtotal	**32,108**				**5,859**	**18%**	
Area 5:							
27	4,628	2,726,635	8.3	32.00	862	19%	20-26%
28	2,028	900,000	11.0	32.00	710	35%	47-53%
28B	2,083	900,000	11.3	32.00	512	25%	42-48%
Subtotal	**8,738**				**2,084**	**24%**	
Area 6:							
51	14,533	4,817,342	15.1	0.32	1,512	10%	13-19%
52	14,247	4,817,342	14.6	0.32	1,381	10%	13-19%
53	14,800	4,817,342	15.8	0.32	1,217	8%	13-19%
54	15,585	4,817,342	15.7	0.32	1,791	11%	13-19%
Subtotal	**59,165**				**5,901**	**10%**	
Area 7:							
55	16,679	5,537,441	15.5	0.32	1,679	10%	13-19%
Subtotal	**16,679**				**1,679**	**10%**	

	OBIP (e3m3)	Area (m2)	Pay Thickness (m)	Porosity (dec)	Cum Oil (e3m3)	Current Recovery	Potential Recovery Range
Area 8:							
58	5,441	2,064,800	14.0	0.32	1,191	22%	45-50%
59	6,959	2,208,000	14.2	0.32	1,307	19%	45-50%
62	6,342	2,230,006	13.2	0.32	1,159	18%	45-50%
63	5,555	2,114,640	12.5	0.32	1,227	22%	45-50%
66	6,708	2,582,960	12.0	0.32	1,241	19%	45-50%
67	7,180	2,643,200	13.3	0.32	1,111	15%	45-50%
Subtotal	**38,185**				**7,236**	**19%**	
Area 9:							
Burnt Lake	1,493	259,362	24.3	0.32	907	61%	60%+
Subtotal	**1,493**				**907**	**61%**	
Area 10:							
74	6,023	1,077,635	24.7	0.32	992	16%	40-50%
75	7,169	1,234,300	25.2	0.32	1,349	19%	40-50%
77	6,625	1,195,136	25.6	0.32	1,360	21%	40-50%
78	6,743	1,177,059	25.9	0.32	1,050	16%	40-50%
Subtotal	**26,560**				**4,751**	**18%**	
Area 11:							
22	6,736	2,531,371	13.2	0.32	864	13%	45-50%
23	6,009	2,288,372	13.3	0.32	827	14%	45-50%
24	5,204	1,926,224	13.4	0.32	756	15%	45-50%
Subtotal	**17,949**				**2,448**	**14%**	
Area 12:							
90	5,498	1,541,935	19.5	0.32	656	12%	40-50%
91	2,583	1,234,697	9.9	0.32	202	8%	40-50%
92	5,854	1,486,007	18.1	0.32	505	9%	40-50%
93	4,748	1,770,501	12.9	0.32	483	10%	40-50%
94	4,141	1,200,299	16.1	0.32	156	4%	40-50%
95	4,598	1,969,607	11.4	0.32	457	10%	40-50%
Subtotal	**27,422**				**2,459**	**9%**	
Area 13:							
25A	2,718	1,727,106	7.0	32	269	10%	40-50%
25B	2,565	2,034,990	5.5	32	299	12%	40-50%
26	3,077	2,083,550	7.0	32	451	15%	40-50%
Subtotal	**8,360**				**1,018**	**12%**	
Area 14:							
60	5,052	1,720,000	14.2	0.32	423	8%	45-50%
61	6,923	2,362,000	13.7	0.32	516	7%	45-50%
64	5,262	1,856,000	12.9	0.32	492	9%	45-50%
65	5,055	2,107,081	11.3	0.32	533	11%	45-50%
68	7,220	2,894,006	10.5	0.32	571	8%	45-50%
Subtotal	**29,512**				**2,535**	**9%**	
Area 15:							
40	4,106	3,008,352	6.8	0.32	92	2%	40-50%
41	5,272	3,014,070	8.1	0.32	95	2%	40-50%
42	6,761	3,130,144	10.2	0.32	84	1%	40-50%
43	5,423	2,492,978	11.0	0.32	65	1%	40-50%
Subtotal	**21,561**				**336**	**2%**	
PR Total	**400,524**				**56,119**	**14%**	

Primrose Performance Variation

- Predictable performance up to 15% recovery factor with 160 – 188 m spacing



Tight Spacing Well Performance

Type Curves for T68,Pad 28 and Primrose East (PRE) Phase 1

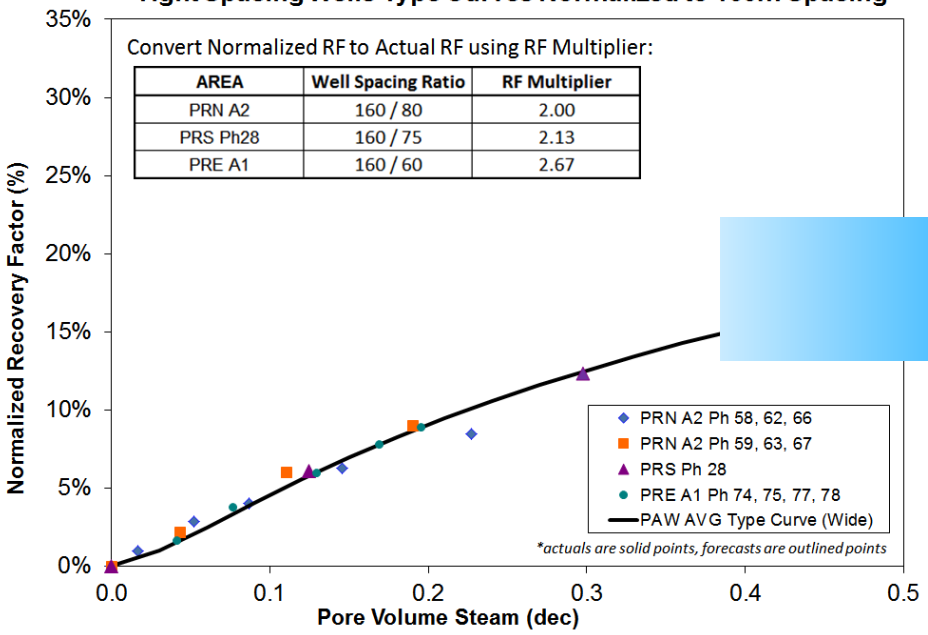
- CSS wells recovering similar amount of bitumen regardless of well spacing
- Tight well spacing actual recovery factors on track to double wide well spacing

TYPE CURVE RECOVERY

Tight Spacing Wells Type Curves Normalized to 160m Spacing

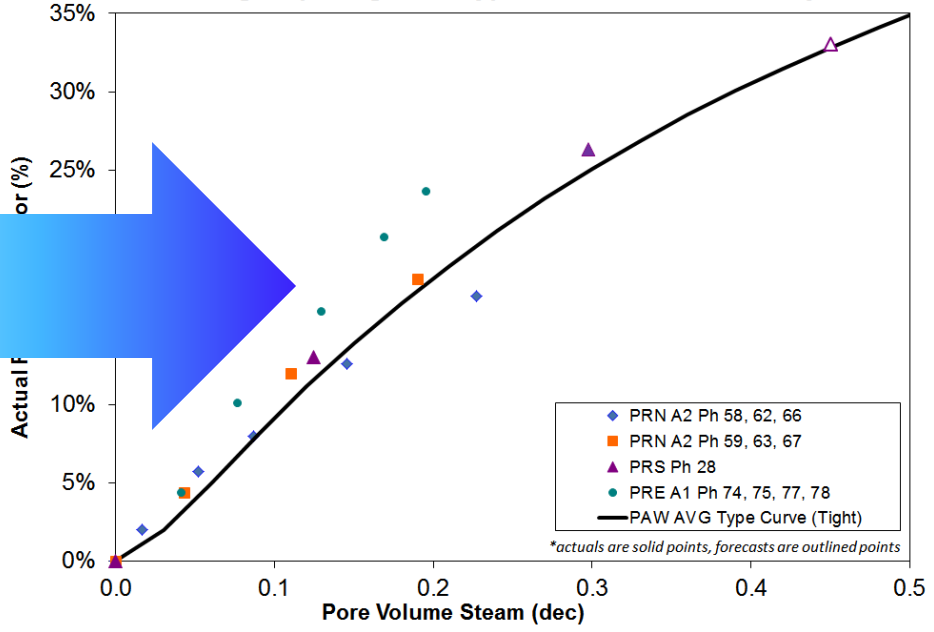
Convert Normalized RF to Actual RF using RF Multiplier:

AREA	Well Spacing Ratio	RF Multiplier
PRN A2	160 / 80	2.00
PRS Ph28	160 / 75	2.13
PRE A1	160 / 60	2.67



ACTUAL RECOVERY

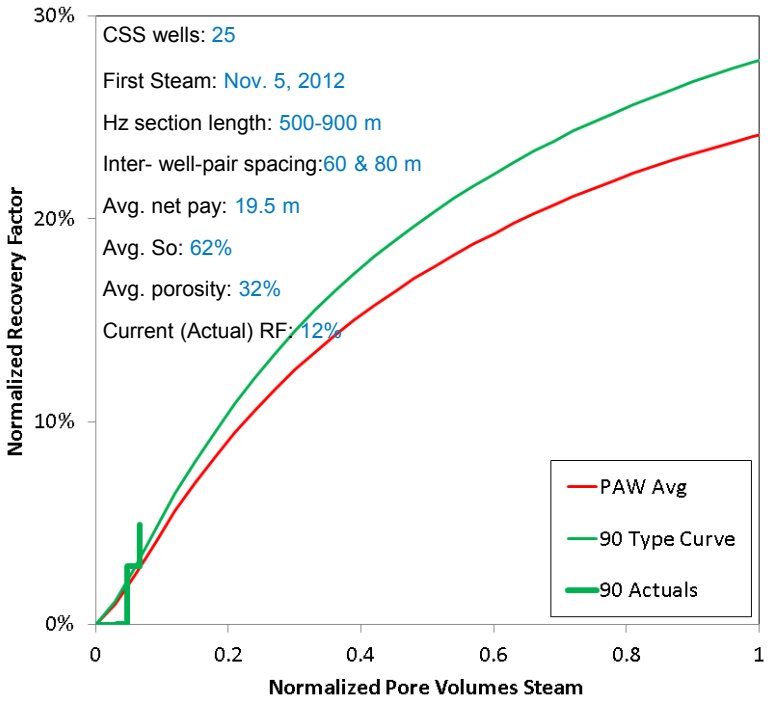
Tight Spacing Wells Type Curves Actual Recovery

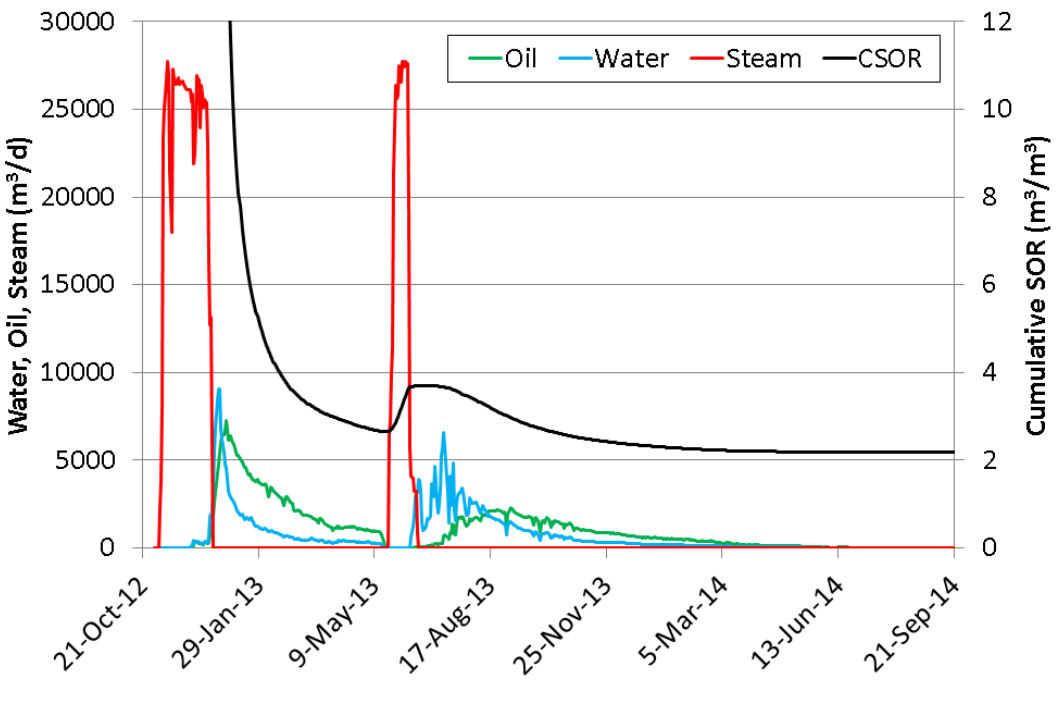


Normalized values calculated by using recoveries from 60-80m spacing but increasing the drainage area to have 160m spacing

Actual Recovery Factor (%) = 160m / Well Spacing x Normalized Recovery Factor (%)

Early Recovery- Primrose East Area 2 Pad 90





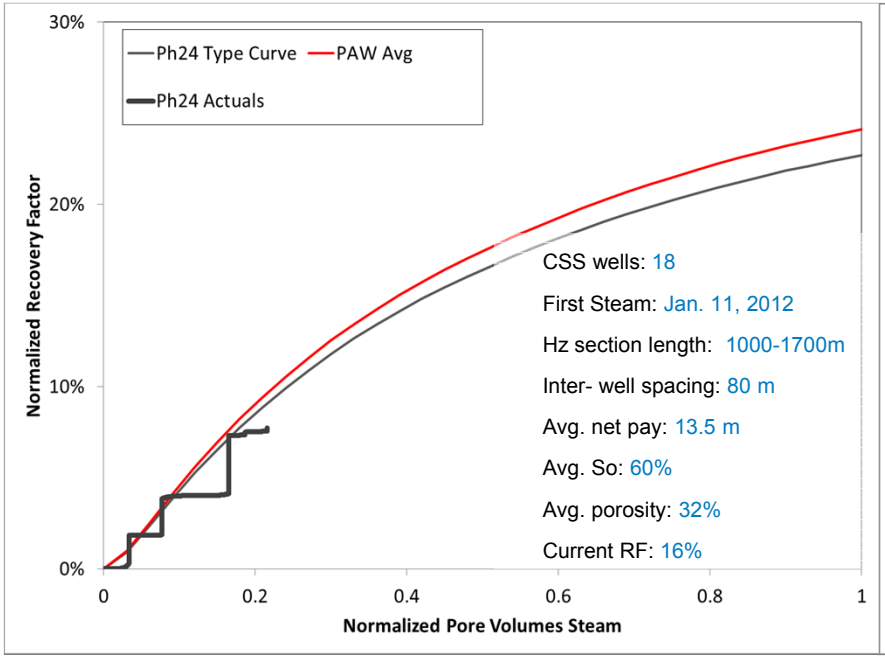
2014 Activity

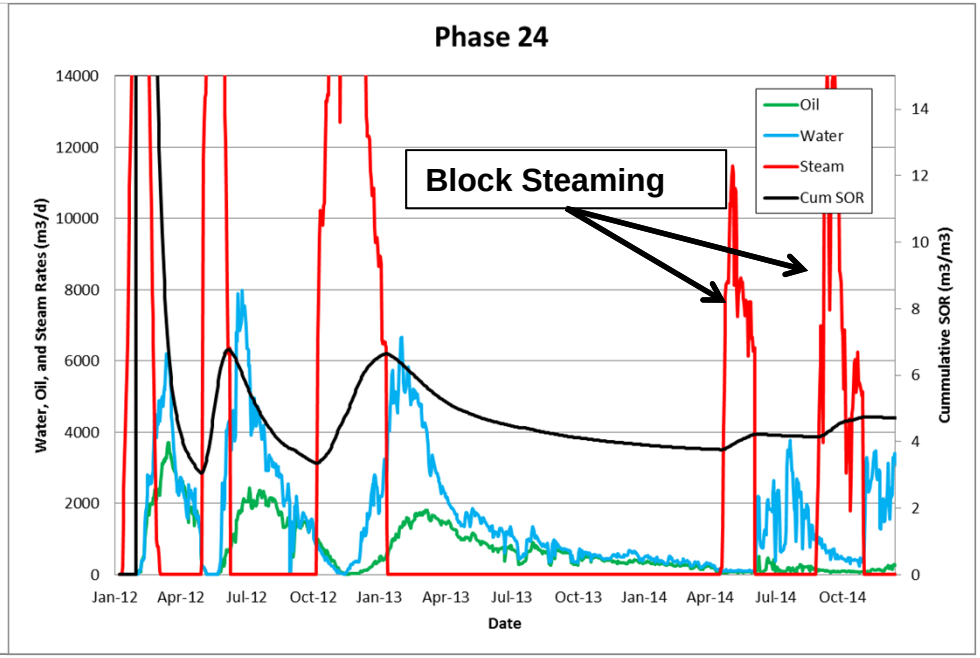
- **Pumped until end of CSS cycle. Currently shut in, too cold to produce.**
- **Previous cycle small steam volume (VOF:~1-5k m³/well) demonstrated ability to continue depletion of Yellow Sand**

2015 Plan

- **Sub-dilation pressure steam cycle pending AER approval**
  - **Early recovery requires further CSS cycles**

Mid Recovery – Phase 24
Type Curve & Production History





Parameters in figure normalized to 160 meter spacing

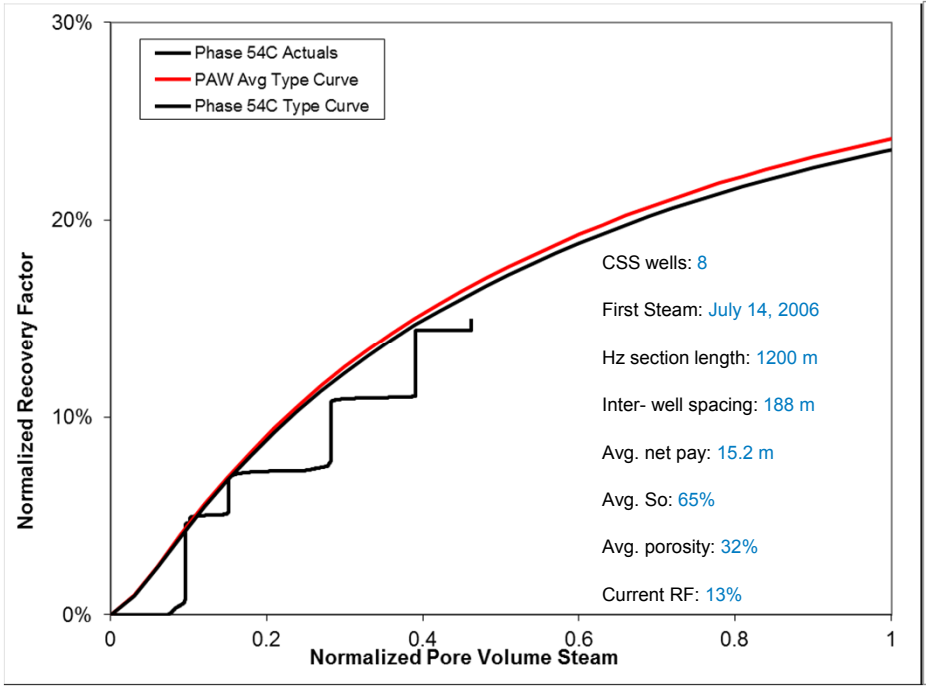
2014 Activity

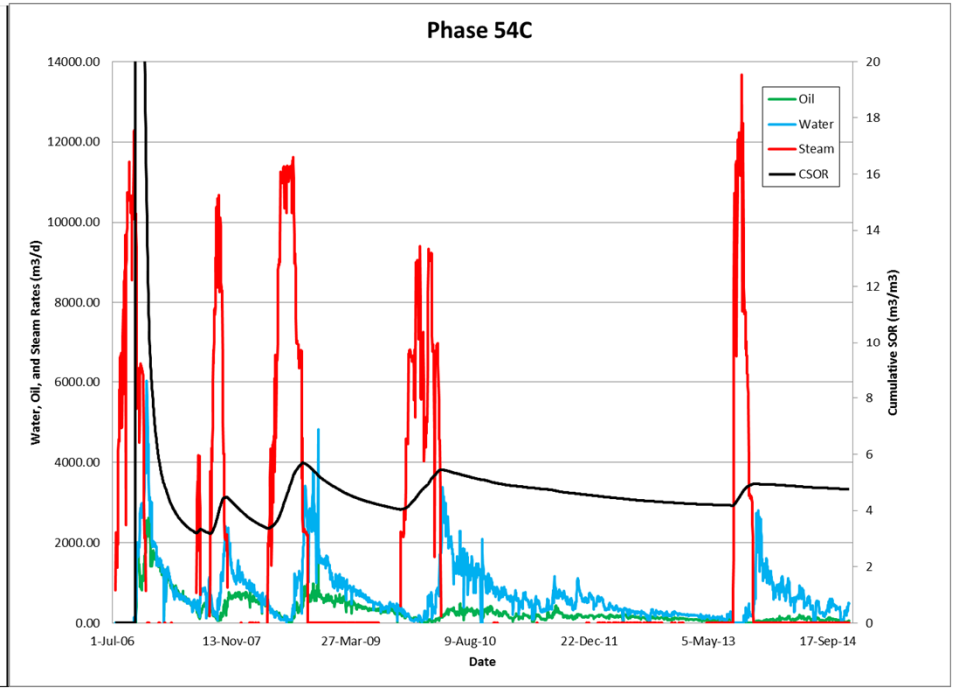
- **Steamed Q2-Q3 and needs sufficient pumping time to reach type curve**
- **Steamed in two block waves with pressure maintenance rows**
- **Oil cut and gross fluid production less than expected**

2015 Plan

- **No steam planned**

High Recovery - Phase 54C
Type Curve & Production History





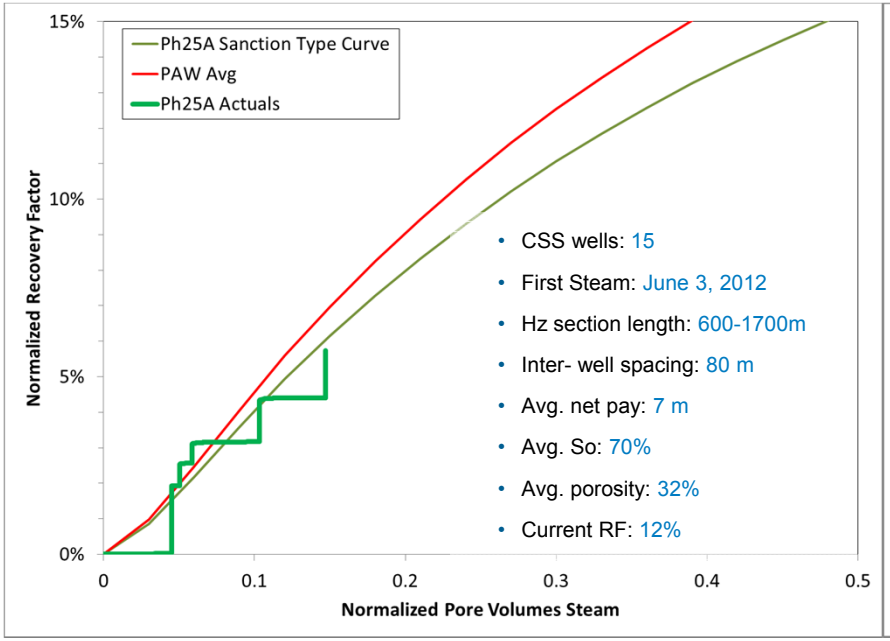
2014 Activity

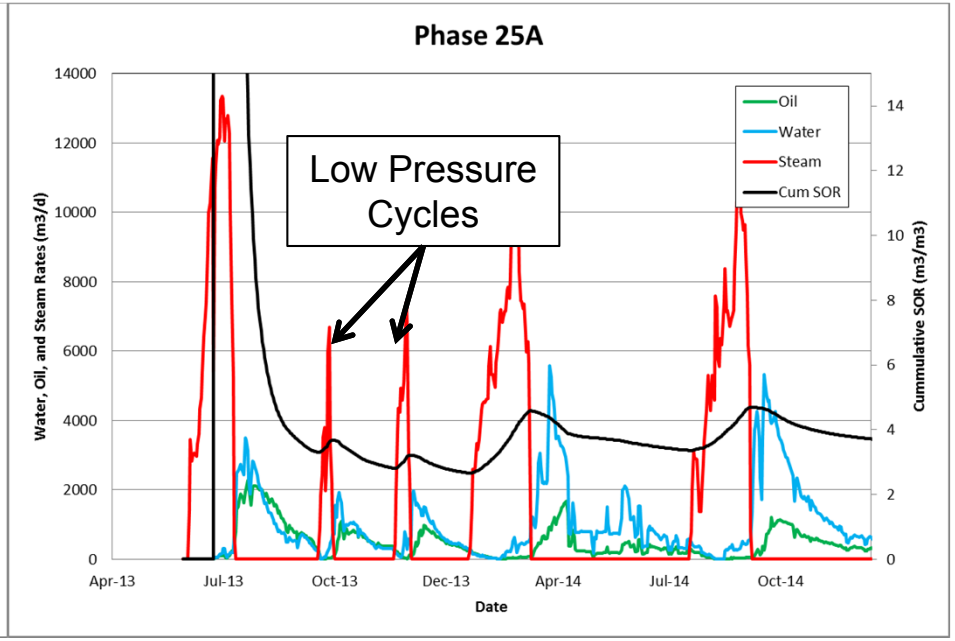
- **Production of CSS cycle started after steaming finished in Q4 2013**

2015 Plan

- **Continue to produce CSS cycle as significant pumping time is needed to reach type curve**
- **Assess future infill opportunity to increase recovery factor and economic lifetime**

Phase 25-26
Development Learning – Thin Pay Pilot





Parameters in figure normalized to 160 meter spacing

2014 Activity

- **Steamed Q1 and Q3 -Performance is meeting type curve expectations in thin pay**
- **No evidence of thermal efficiency loss to under/overburden**
- **Oil cut and gross fluid production is better than expected**

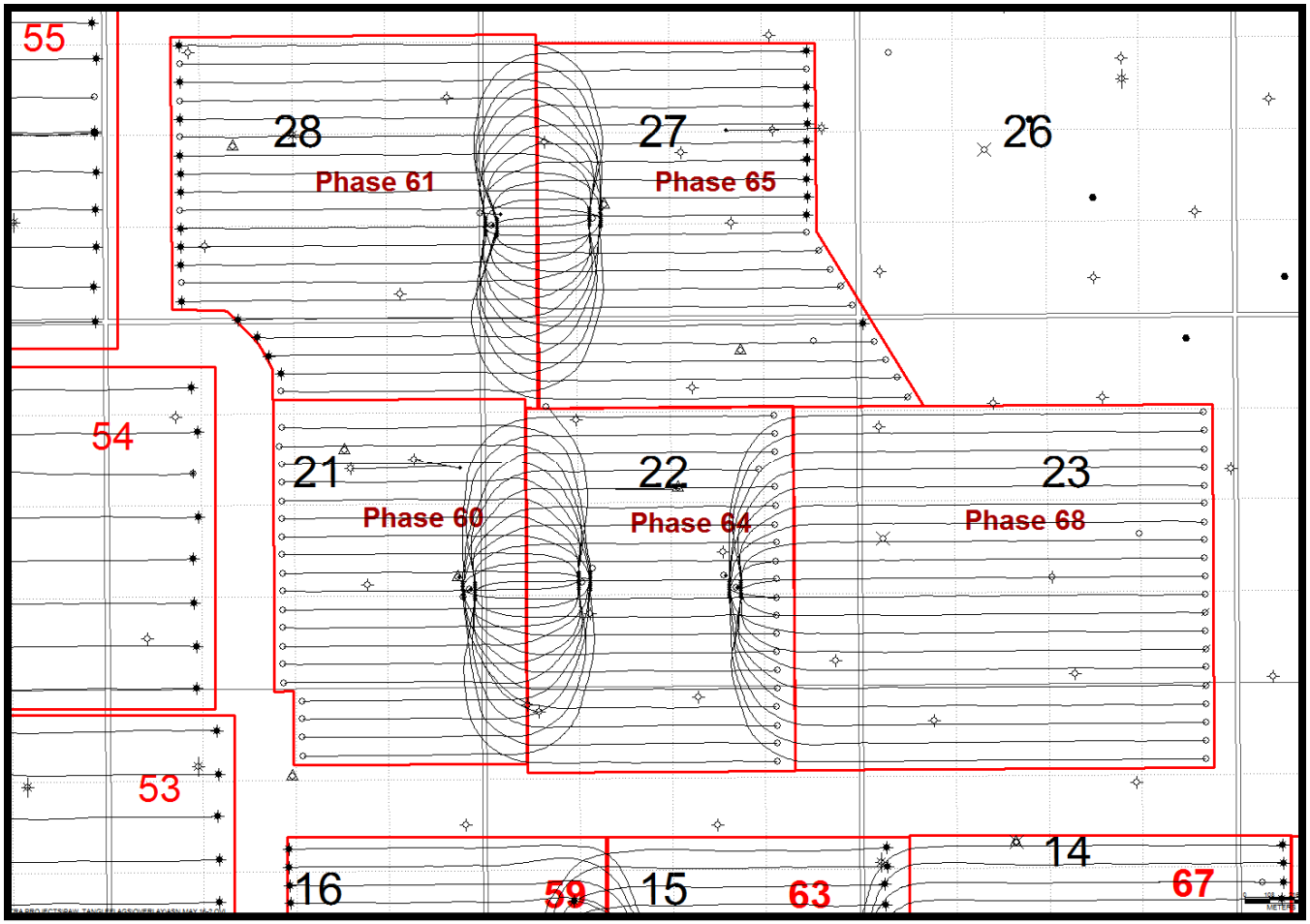
2015 Plan

- **Plan to steam Q3**

2014 Learnings - Enhanced Steaming Strategy

- Primrose North Area 3 (Phases 60,61,64,65 & 68) is the first area to utilize the enhanced steaming strategy
  - First area to receive new commissioning cycles
  - Steam strategy needed to be very flexible as the steam wave progressed
  - Exceptional performance from all phases
- Enhanced steaming strategy included steam volume reduction and enhanced surveillance systems
  - Fluid recovery from all areas exceeding previous analogs
  - Oil cuts showing strong performance to accompany gross fluid recovery
  - Less fluid interaction with the Grand Rapids using enhanced steaming strategy
  - Reservoir fluid retention lower than analogs, leading to more produced fluids
- Primrose South Orange Sands (Phases 40-43) is the second area to utilize the enhanced steaming strategy
  - Still in commissioning cycle phase
  - Steaming on-going

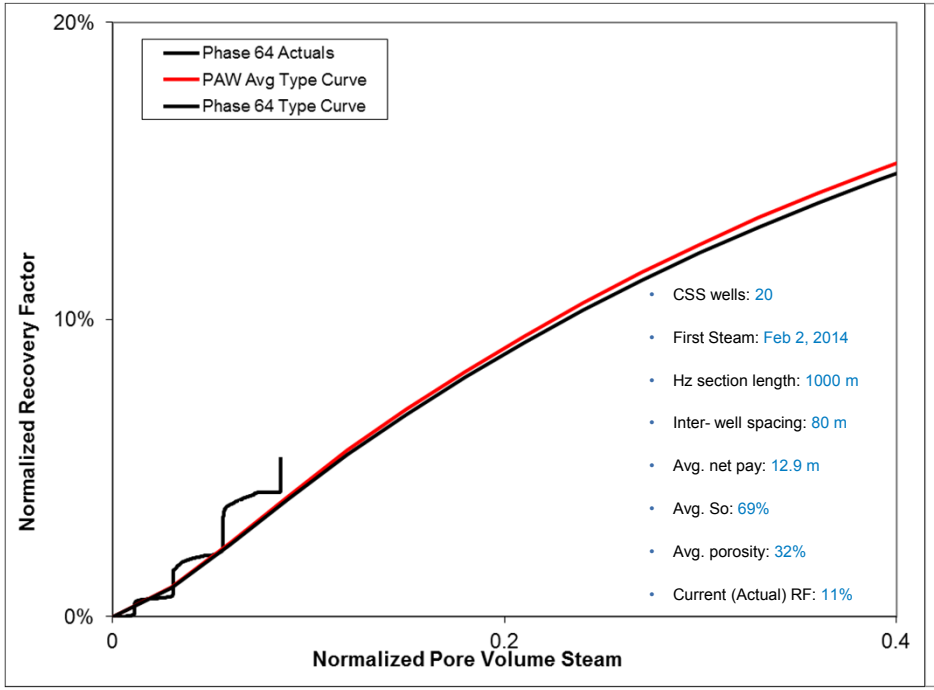
Enhanced Steaming Strategy
Primrose North Area 3 – Wellbore Design

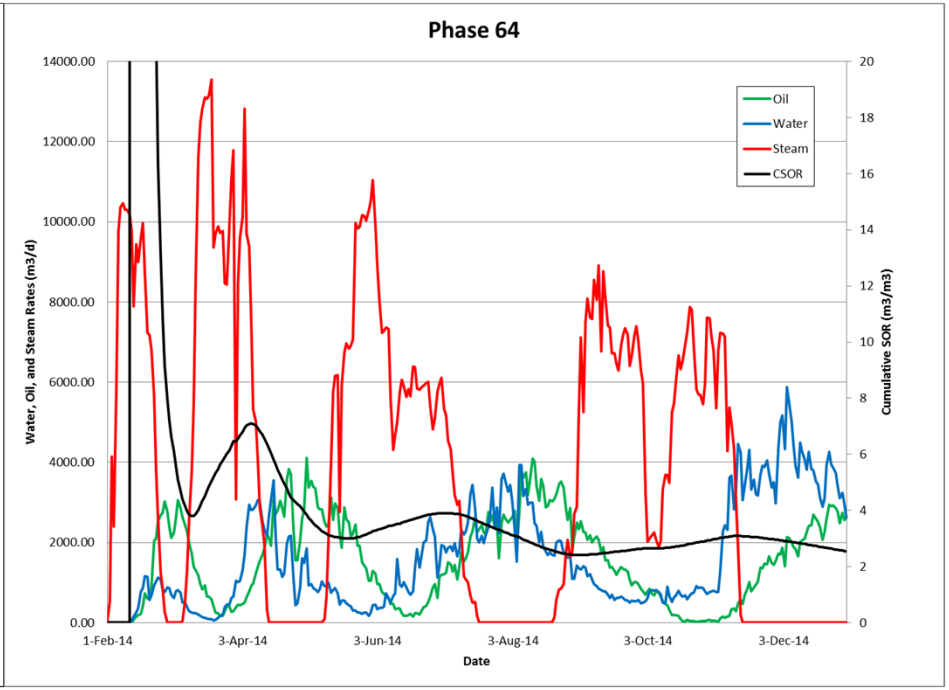


- **Phase 60**
  - 893 - 975m laterals
  - 80m spacing
- **Phase 64**
  - 1000m laterals
  - 80m spacing
- **Phase 68**
  - 1700m laterals
  - 80m spacing
- **Phase 61**
  - 1031 - 1462m laterals
  - 80m spacing
- **Phase 65**
  - 1090-1520m laterals
  - 80m spacing

- First Steam in February 2014
- Primrose North Area 3 - 100 wells at 80 m spacing

Enhanced Steaming Strategy
Phase 64 Type Curve & Production History





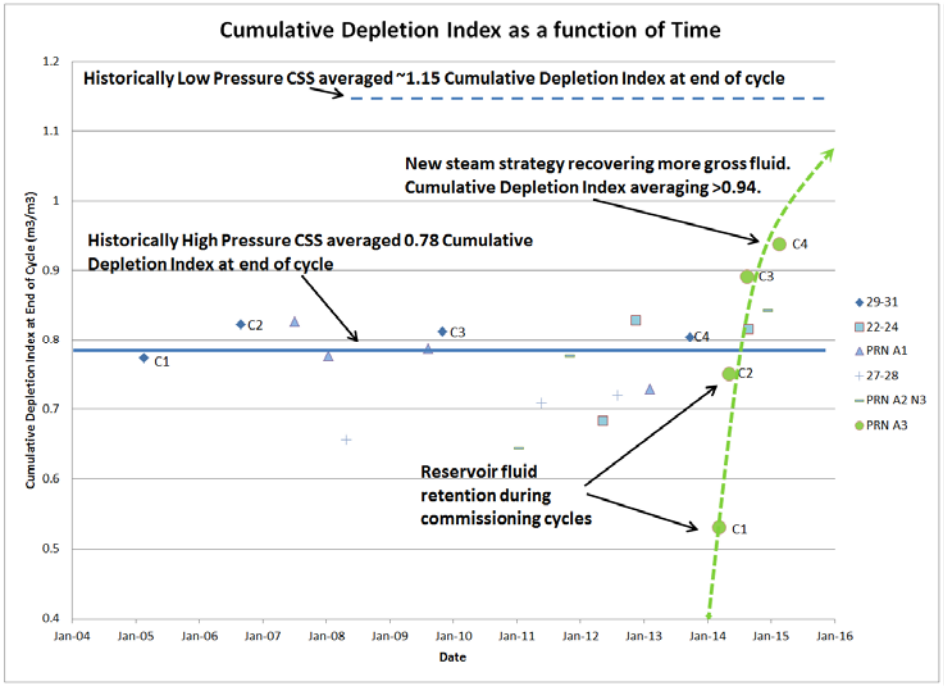
2014 Activity

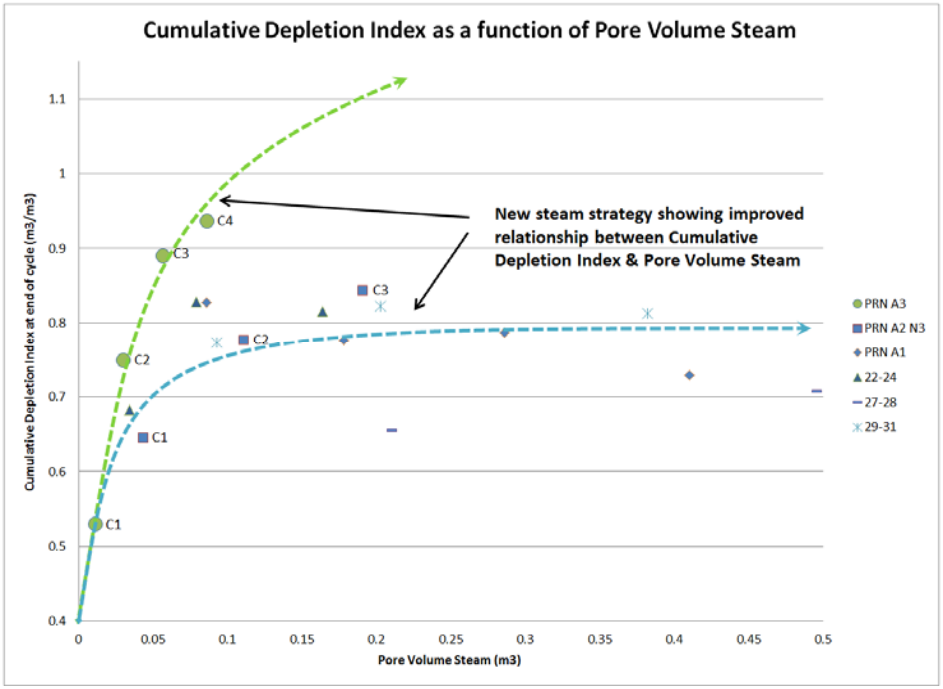
- **Completed 2 commissioning cycles and 1 commercial cycle**
- **Commercial Cycle 2 is currently producing**
- **Better than expected reservoir performance achieved**
- **Oil cut and gross fluid production is better than expected**

2015 Plan

- **Plan to begin 2 more cycles, more cycles required to confirm performance**
- **On track to continue to exceed type curve**

Enhanced Steaming Strategy
Cumulative Fluid Recovery



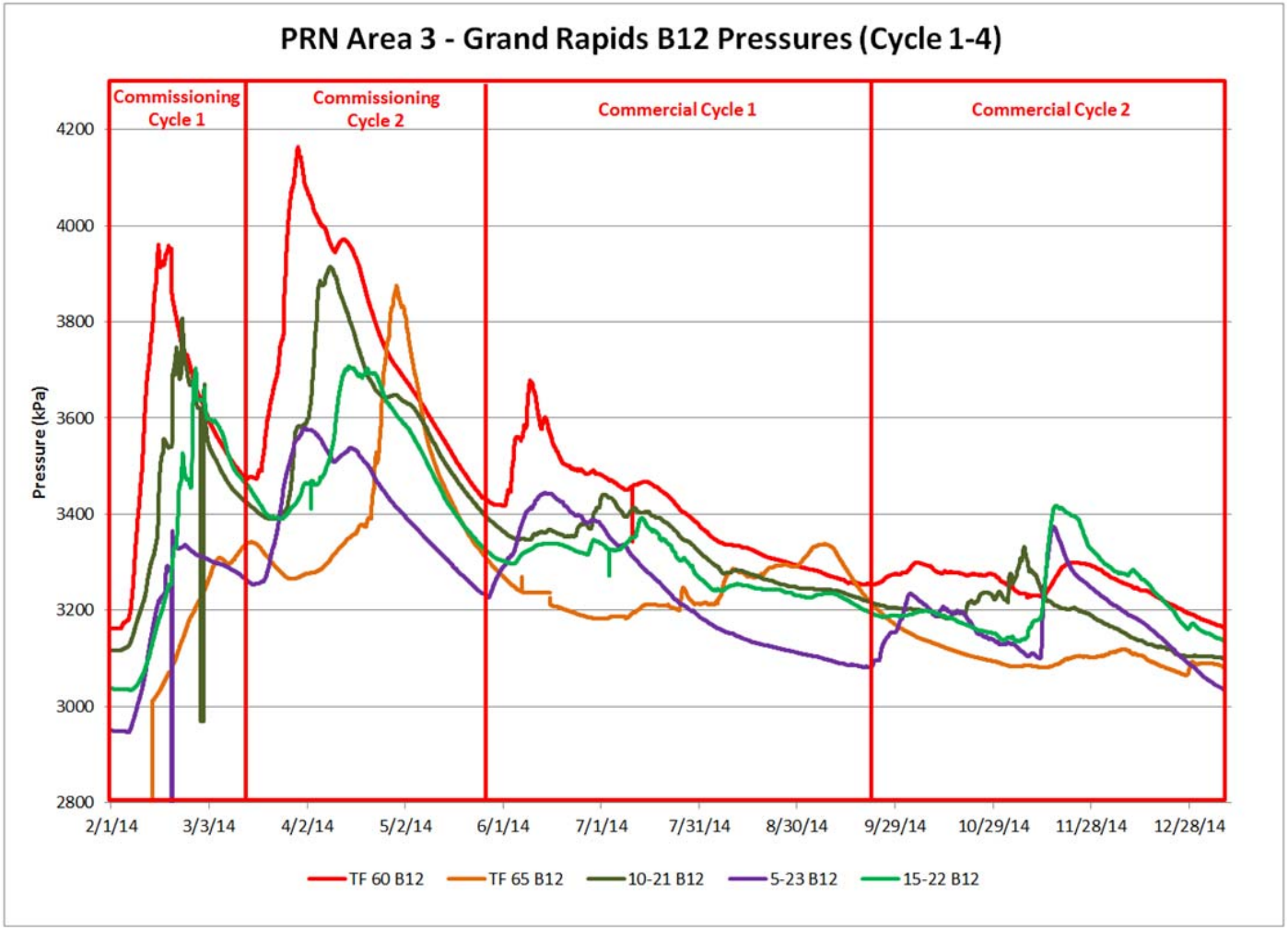


- Cumulative Depletion Index, CDI, is the ratio of total fluid recovered to total steam injected
- Enhanced steam strategy (green) is showing continuous improvement in fluid recovery when compared to areas with large cycle to cycle steam volume growth (blue)
- The strategy of using commissioning cycles has a positive impact on cumulative depletion index
- 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)
- Gradual pore volume growth has shown far less reservoir retention and Grand Rapids interaction

Enhanced Steaming Strategy

Primrose North Area 3 - Grand Rapids Impact

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



Enhanced Steaming Strategy

Conclusions

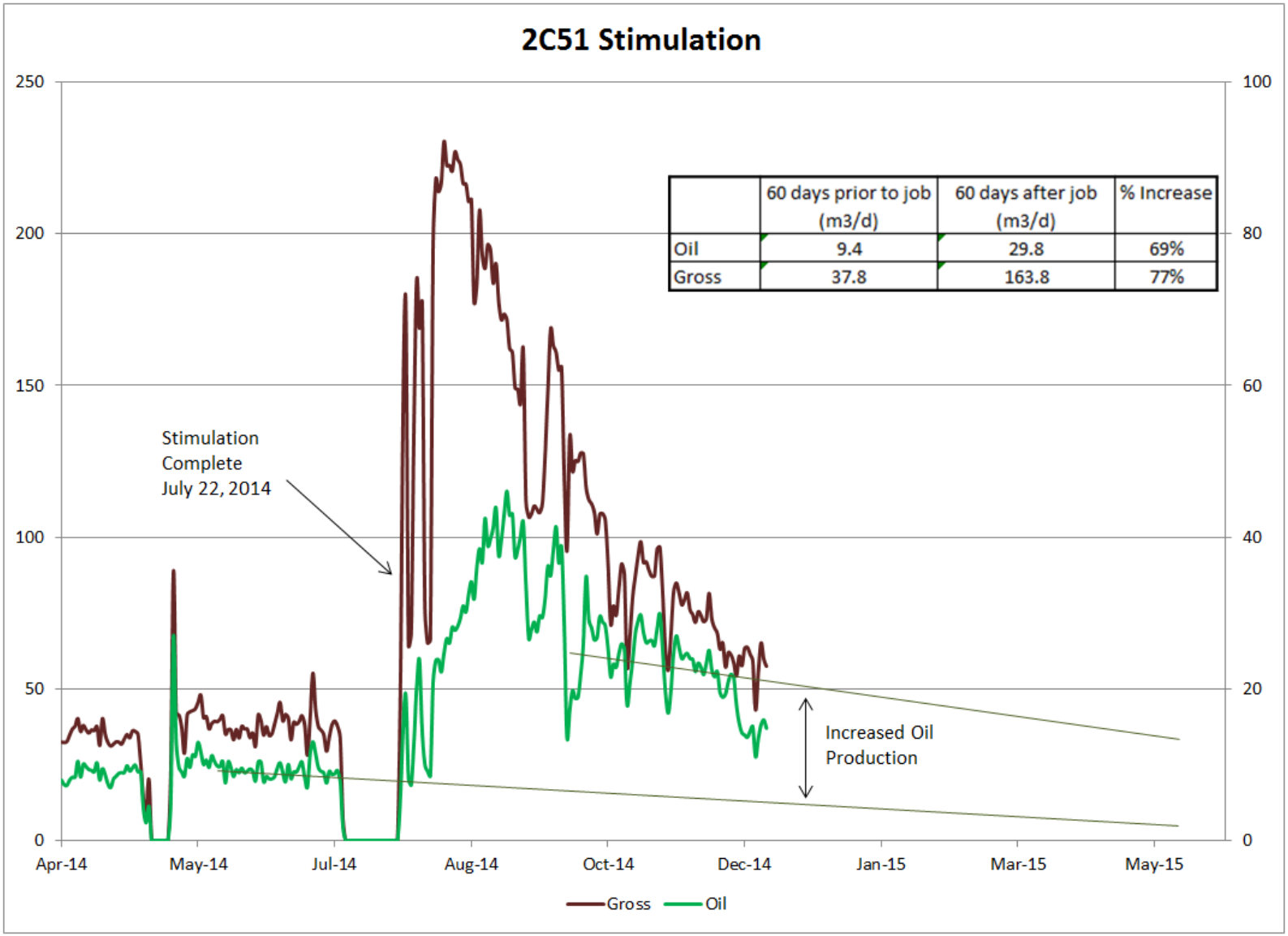
- Enhanced Steaming Strategy showing improvements with fluid recovery
- Continuing to use the new steaming strategy in Primrose South Orange Sands (40-43)
- Strategy continues to develop the understanding of fluid retention within the reservoir and the reduction of fluid interaction with the Grand Rapids.

Primrose North Stimulations

- Due to wellbore liner plugging cause by scale, stimulations are required to maximize production
- Production restrictions due to liner plugging are observed as early as Cycle 3
- Perforations or Acid Stimulations are performed to access the entire reservoir along the liner

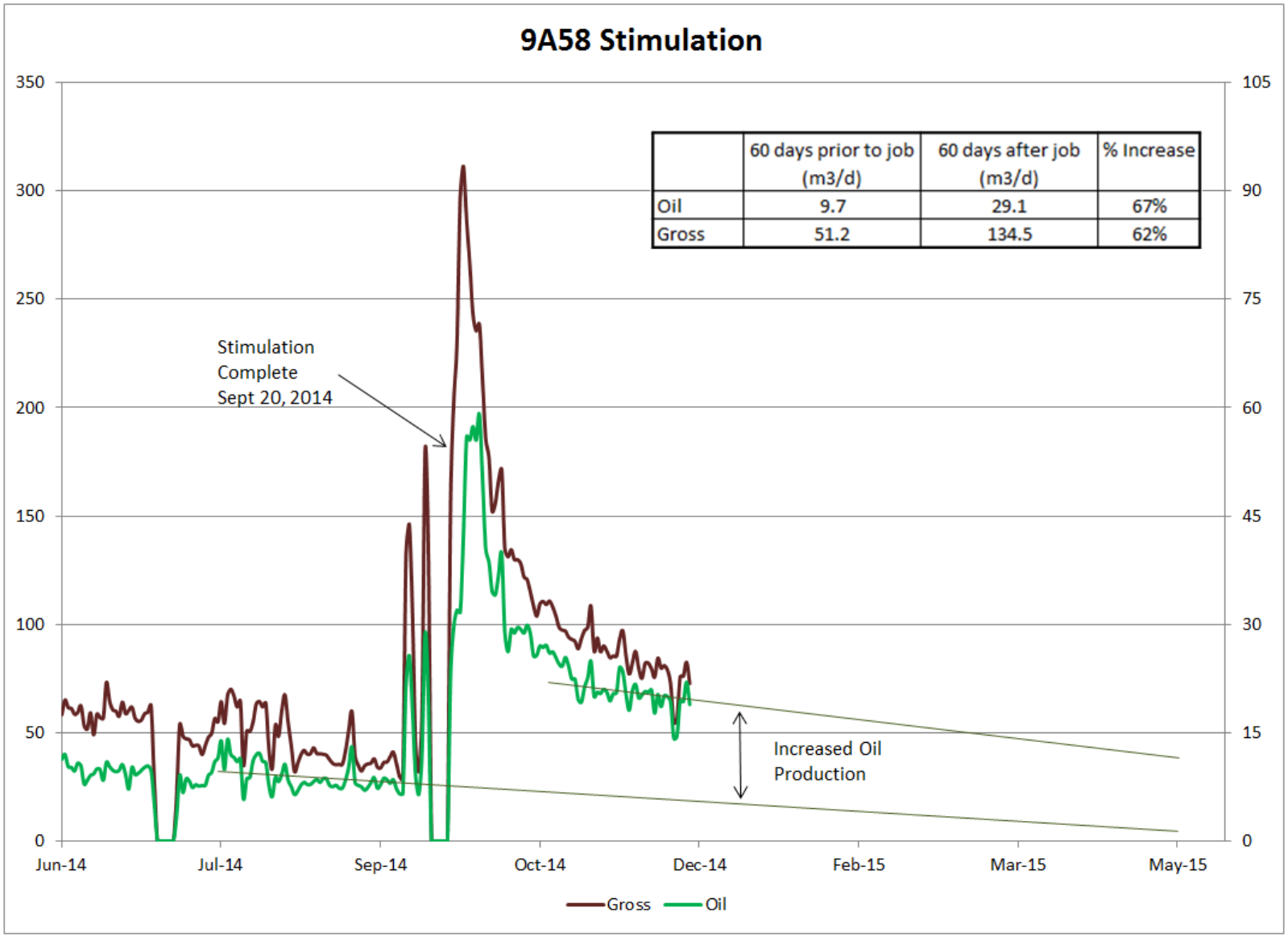
- Stimulations completed during 2014
  - Primrose North Area 1 – 15 Liner Perforations
  - Primrose North Area 2 – 10 Liner Perforations
  - Primrose North Area 3 – 2 Liner Acid Jobs

Primrose North Area 1 – 2C51 Stimulation Increased Oil Production



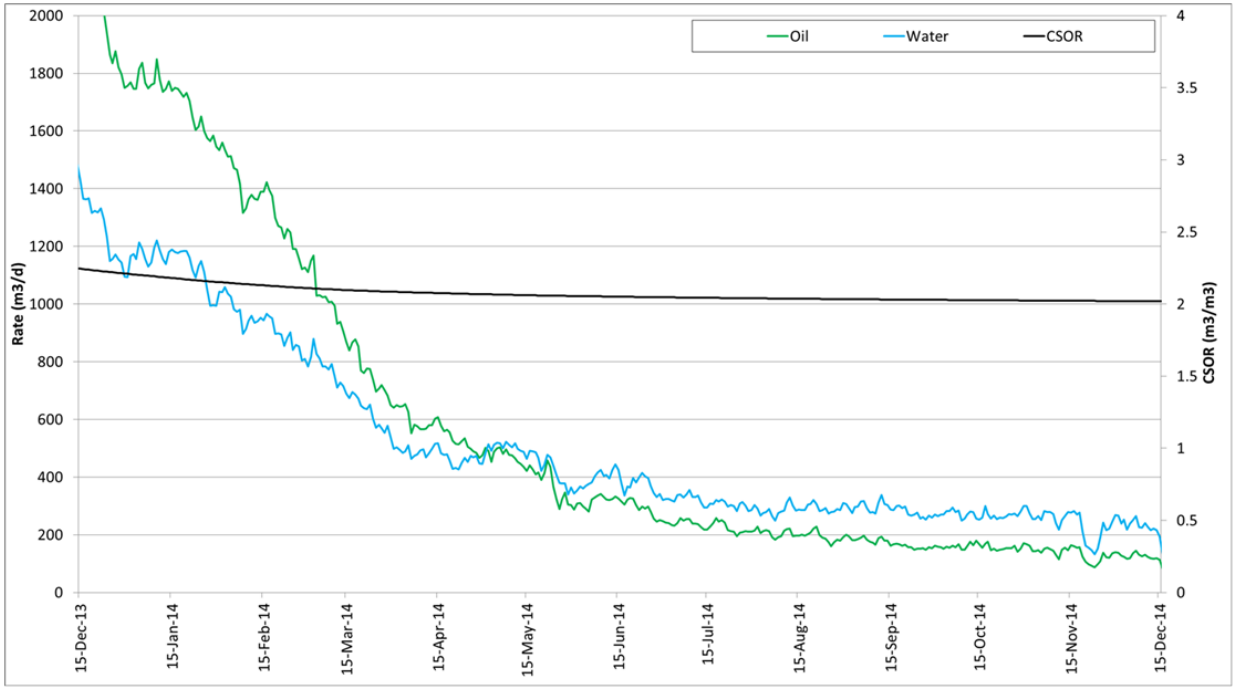
	60 days prior to job (m3/d)	60 days after job (m3/d)	% Increase
Oil	9.4	29.8	69%
Gross	37.8	163.8	77%

Primrose North Area 2 - 9A58 Stimulation Increased Oil Production



	60 days prior to job (m3/d)	60 days after job (m3/d)	% Increase
Oil	9.7	29.1	67%
Gross	51.2	134.5	62%

Primrose East Area 2 - Update



- **2014 Activity**
  - **No steam was injected into PRE A2 in 2014**
  - **All wells have been pumping for extended periods**
    - **Some wells have been shut in due to excessively cold production temperatures making it operationally difficult to pump**
    - **16 wells of 120 were pumping as of Dec. 15th, 2014**
- **2015 Activity**
  - **Planning sub-dilation CSS cycles in 2015**
    - **Pending AER approval**

2015 Steam Schedules

Primrose North

Month	Steam Start Date	Steam Volume/Well (m3)
Jan-15	Phase 59, 63, 67	65,000
Feb-15	↓	
Mar-15	Phase 60-68	33,000
Apr-15	↓	
May-15	↓	
Jun-15	↓	
Jul-15	Phase 58, 62, 66	82,000
Aug-15	↓	
Sep-15	↓	
Oct-15	↓	
Nov-15	↓	
Dec-15	Phase 60-68	39,000

Primrose South

Month	Steam Start Date	Steam Volume/Well (m3)
Jan-15	Phase 40-43	17,000
Feb-15	Phase 40-43	25,000
Mar-15	↓	
Apr-15	↓	
May-15	↓	
Jun-15	Phase 26-25	30,000
Jul-15	↓	
Aug-15	Phase 40-43	30,000
Sep-15	↓	
Oct-15	↓	
Nov-15	↓	

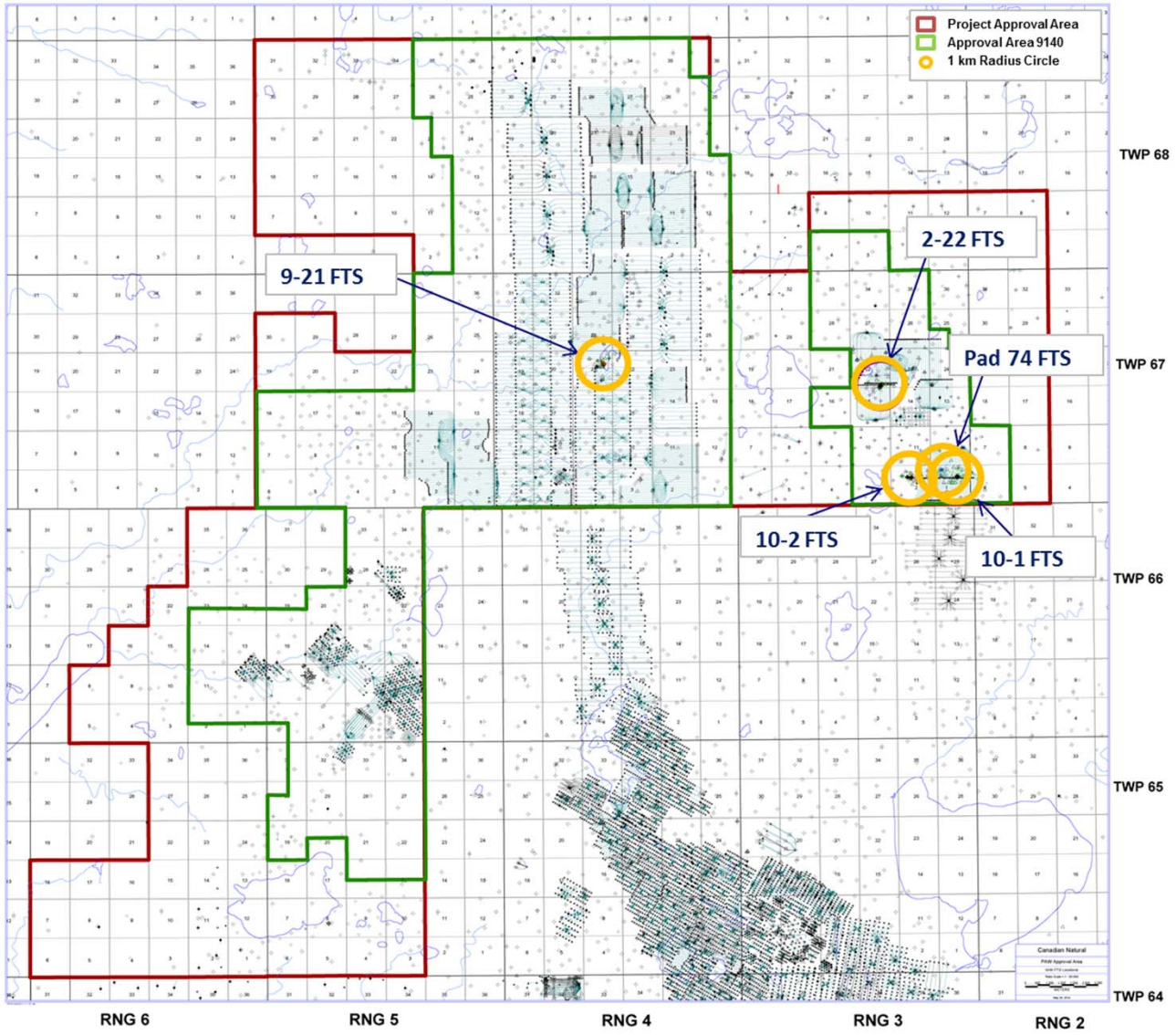
Primrose East

Month	Steam Start Date	Steam Volume/well (m3)
Jan-15	Phase 74-78	Steamflood (~400 CDSR)
Feb-15	Phase 90, 91, 92E	17,000 & 7,000
Mar-15	Phase 92W, 93	13,000 & 16,000
Apr-15	↓	
May-15	↓	
Jun-15	Phase 90, 91, 92E	20,000 & 8,100
Jul-15	Phase 92W, 93	15,000 & 19,000
Aug-15	↓	
Sep-15	↓	
Oct-15	↓	
Nov-15	↓	
Dec-15	↓	

Primrose Flow to Surface Events

- In May and June 2013, three bitumen releases, (flow to surface [FTS] sites), were identified within Primrose East:
  - 10-01-067-03 W4M (10-1)
  - 10-02-067-03 W4M (10-2)
  - 02-22-067-03 W4M (2-22)
- In June 2013, a bitumen FTS was identified at Primrose South:
  - 09-21-067-04 W4M (9-21)
- Cleanup and containment is complete at all sites
  - All sites continued to be monitored
- 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 November 1 and 2, 2014
  - No other FTS sites exist

Location of FTS Sites



Primrose Flow to Surface Events

- Canadian Natural has and continues to comply with Enforcement Order (EO) No. EO-2013/05-NR:
  - Weekly, monthly and annual reports are submitted in accordance with the EO
- The Causation Report was submitted to the AER/ESRD in June 2014
- Targeting Q1 2015 for submission of the Final FTS Report

Investigation Activity Summary: Environmental / Hydrogeology

Canadian Natural

ENVIRONMENTAL

- 103 m³ of bitumen emulsion recovered from surface at 2-22 FTS site
- 563 m³ of bitumen emulsion recovered from surface at 10-2 FTS site
- 356 m³ of bitumen emulsion recovered from surface at 10-1 FTS site
- 50 m³ of bitumen emulsion recovered from surface at 9-21 FTS site
- 111,574 tonnes of impacted solids removed (combined from all four sites)

HYDROGEOLOGY

- 73 FTS site investigation wells drilled and completed
- 20 test holes drilled
- 7,738 m drill length (total)
- 434 m core interval (total)

Investigation Activity Summary: Drilling

Canadian Natural

DRILLING
• 50 Cretaceous delineation wells drilled, amounting to:
▪ 30,909 m drill length (total)
▪ 6,825 m core interval (total)
• Log Acquisition:
▪ Resistivity
▪ Porosity
▪ Density
▪ Dipole sonic
▪ Sonic scanner
▪ Micro-imager
▪ Gamma ray

Investigation Activity Summary: Geology / Geophysics

Canadian Natural

GEOLOGY

- Core analyses:
  - X-Ray Diffraction
  - Particle Size Distributions
  - Thin Sections
  - Dean Stark Saturations
- Detailed Core Logging

GEOPHYSICS

- 3D seismic acquisition for the 9-21 FTS area, including data acquisition over the waterbody (2014)
- 4D seismic analysis over PRE A1 (2004, 2009, 2010, 2013)
- Conducted induced electromagnetic survey to investigate sub surface
- Reprocessing historical 3D seismic and passive seismic data
- 3D shear wave processing and analysis

Investigation Activity Summary: Geomechanics

Canadian Natural

GEOMECHANICS
• 7 Diagnostic Fracture Injection Tests (Diagnostic Fracture Injection Testing (DFIT) or mini-fracs)
• 2 wells cored for testing – 57 samples of preserved core
• Lab Testing:
▪ Index
▪ Triaxial
▪ Cyclic Loading
▪ Direct Shear
▪ Creep
▪ Ultrasonic
▪ Tensile Strength
• Interferometric Synthetic Aperture Radar (InSAR) analysis of historical data from 2011 to 2013
• Modeling
▪ Numerical modelling of changes in stress state in Colorado Group due to reservoir uplift
▪ Analytical stress modelling of reservoir uplift
▪ Hydraulic fracture containment of Colorado Group

Investigation Activity Summary:
Wellbore Investigations / Engineering / Geochemistry

Canadian Natural

WELLBORE INVESTIGATIONS

- 19 re-entries (plug-tracks) into previously abandoned wells for investigation and remediation
- Review of historical abandonment practices and completions of all wells in Primrose
- 105 cased hole investigations (various logging and perforating)

ENGINEERING

- Analysis of historical data (2009 Pad 74 investigation, Clearwater reservoir injection, production data, thermal fibre, passive seismic, Grand Rapids Formation pressure monitoring, Bonnyville / Quaternary pressure monitoring)

GEOCHEMISTRY

- 254 bitumen emulsion samples collected and analyzed by Gas-Chromatograph Mass-Spectrometry

Investigation Activity Summary:
Industry and Regulatory Collaboration / Consultation

Canadian Natural

Industry and Regulatory Collaboration / Consultation
• Regular information sharing and cooperation with AER and ESRD
• Formation and collaboration with an Independent Third Party Technical Review Panel consisting of industry experts
• Information sharing sessions with AER and industry leaders in CSS
• Enhanced information sharing on the corporate website
• Consultation with First Nations groups:
▪ Open house for Cold Lake First Nations
▪ Increased notifications of activities

Investigation Activity Summary: FTS Detection Methods

Canadian Natural

FTS DETECTION METHODS

- Executed Methods in 2013/2014:
  - Visual Inspection:
    - ❖ Ground level survey along available access and seismic cut lines (completed over steamed areas in Primrose)
    - ❖ Airborne visual sweep (completed over PAW)
      - ➢ Boreal Laser Infrared Gas Detection (aerial mounted gas detection)
- Executed Methods in 2009:
  - Visual Inspection:
    - ❖ Airborne visual sweep (completed over Pad 74 vicinity)
  - Aerial mounted detection technologies:
    - ❖ Boreal Laser Infrared Gas Detection
    - ❖ Thermal Imaging
    - ❖ Forward-Looking Infrared Gas Detection Camera
    - ❖ Visible Spectrum Camera

Investigation Activity Summary: FTS Detection Methods (Continued)

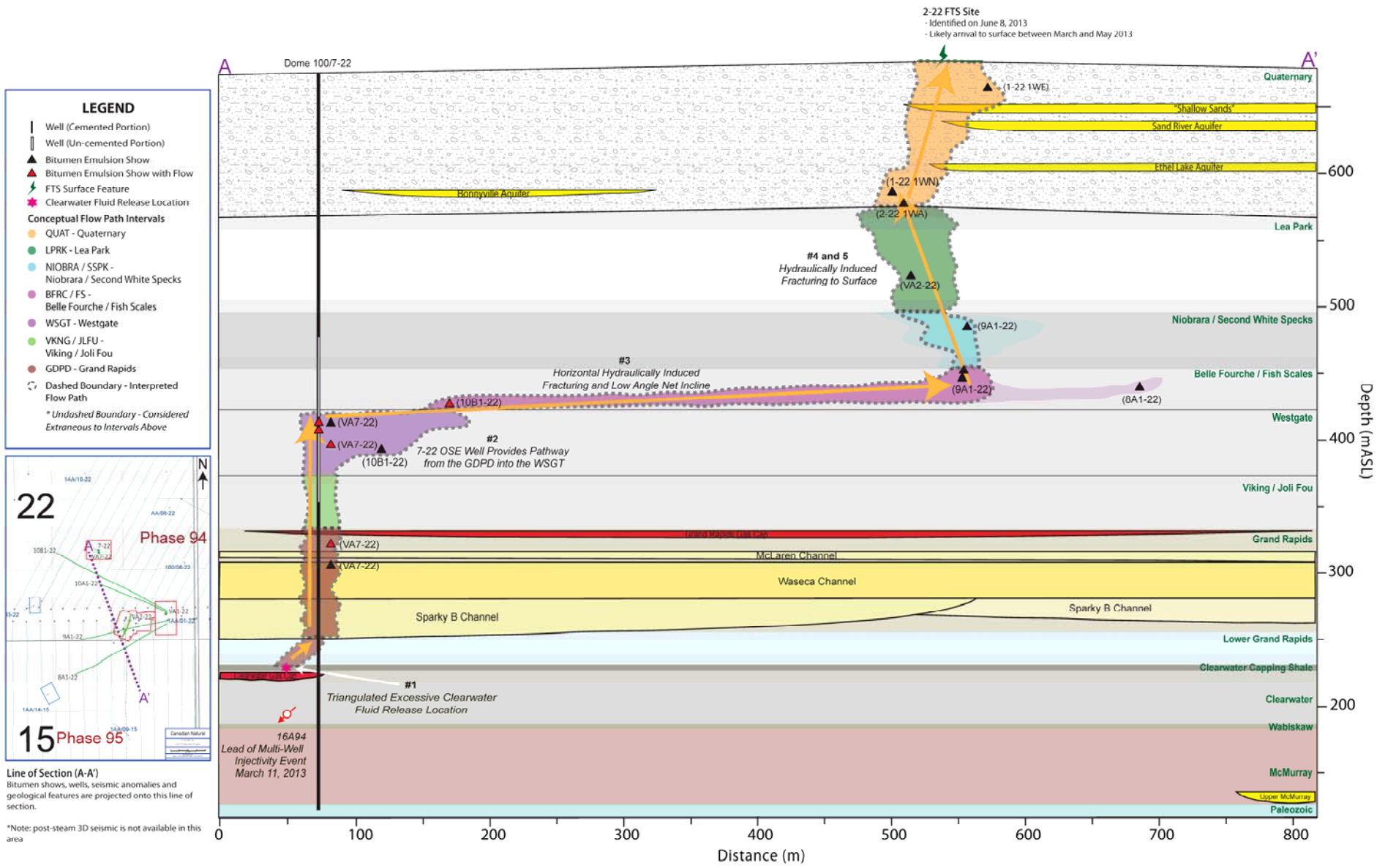
Canadian Natural

FTS DETECTION METHODS

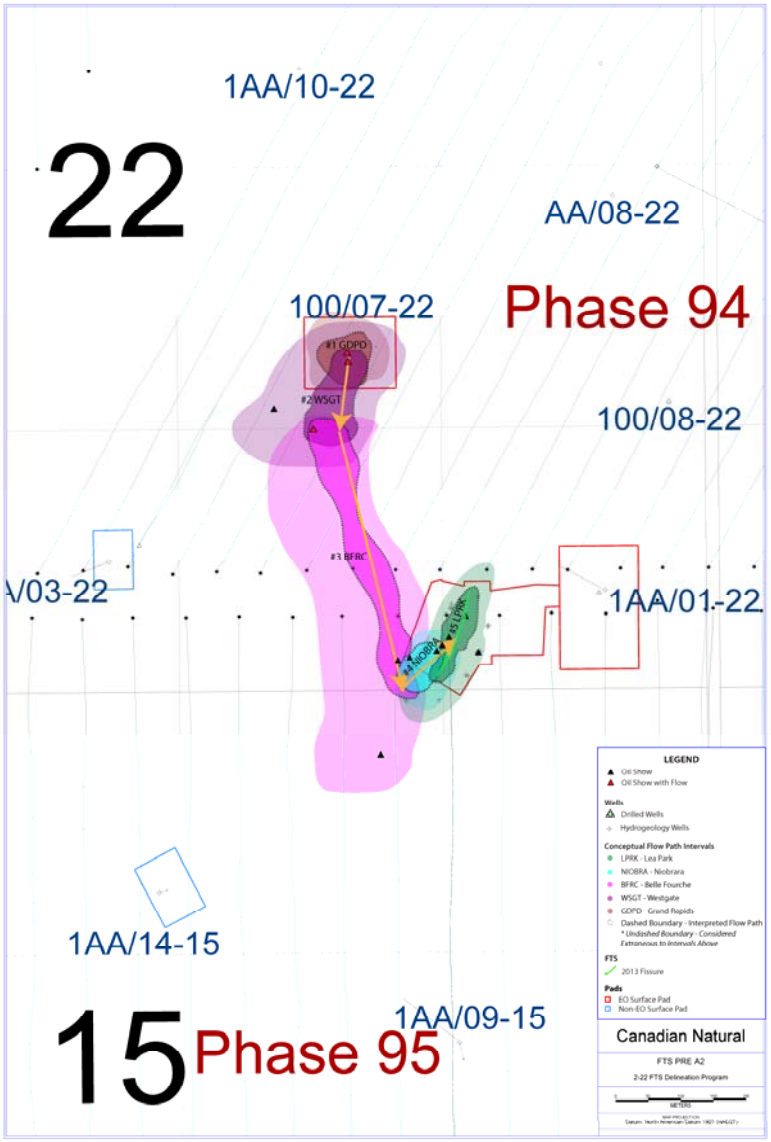
- Methods evaluated but not implemented due to unsatisfactory technology or inability to operate in the PAW area:
  - ❖ Canine Assisted Detection (Olfactory)
  - ❖ Laser Fluorosensors
  - ❖ Nuclear Magnetic Resonance
  - ❖ Gas Filter Correlation Radiometry
  - ❖ Liquid Electromagnetic Detection
  - ❖ Differential Absorption LIDAR
  - ❖ Microwave Detection
  - ❖ Ultraviolet Camera
  - ❖ Satellite Imagery and Interferometry
  - ❖ Unmanned Aerial Vehicle Imaging
  - ❖ Electromagnetic Survey
  - ❖ Gravity Gradiometry
  - ❖ Ground Penetrating Radar

Example Visual Interpretation of Flow Path: 2-22 Cross-View

Canadian Natural



Example Visual Interpretation of Flow Path: 2-22 Plan-View



Enabling Conditions of FTS Observed at each FTS Site

Canadian Natural

1. Excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids Formation.
2. A vertical hydraulically induced fracture that propagates up to the top of the Grand Rapids Formation.
3. Vertical pathways to facilitate fluid transfer through generally impermeable shales that have in-situ stress states that usually favor horizontal fracturing.
   - Wellbore pathways which are the most likely and efficient vertical pathway to at least the Viking Formation and as high as the Westgate Formation in the case of this study.
   - Natural fractures and faults in the shales.
   - Vertical hydraulically induced fractures.
4. An uplift of the overburden above the Clearwater reservoir that changes stress in the overlying shale such that the minimum horizontal and vertical principal in-situ stresses approach each other.

Metric to Limit Steam Volumes

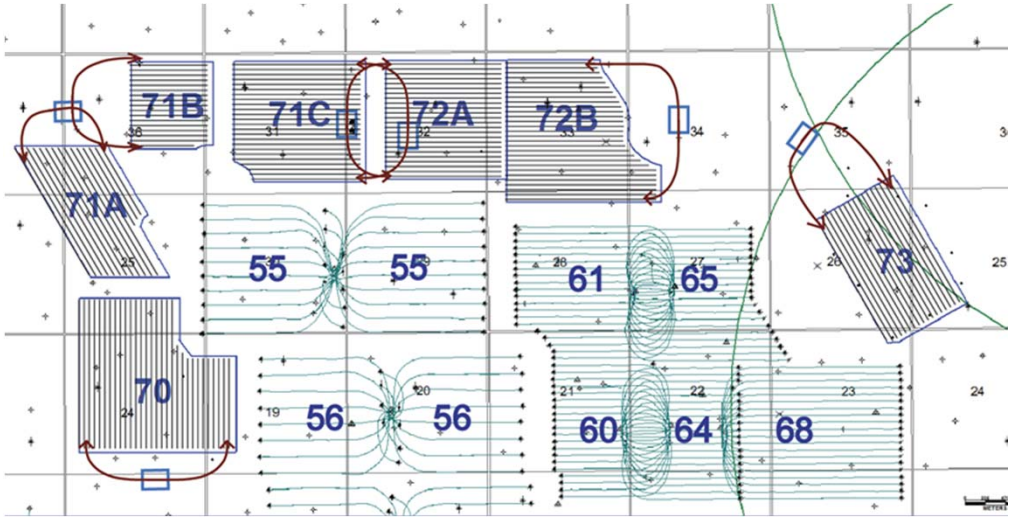
- FTS enabling condition #4 pertains to uplift induced stress changes within the Colorado Group shales
- For linear elastic behavior, the greater the Clearwater capping shale uplift, the greater the in-situ stress changes
- An effective metric to limit this in-situ stress change is the vertical displacement of the Clearwater capping shale
  - This can be represented by the steam injection volume divided by the area
  - A steam volume divided by reservoir pore volume does not address the magnitude of stress changes within the overburden

Primrose North Development

Canadian Natural

Primrose North Area 4 (70-73)

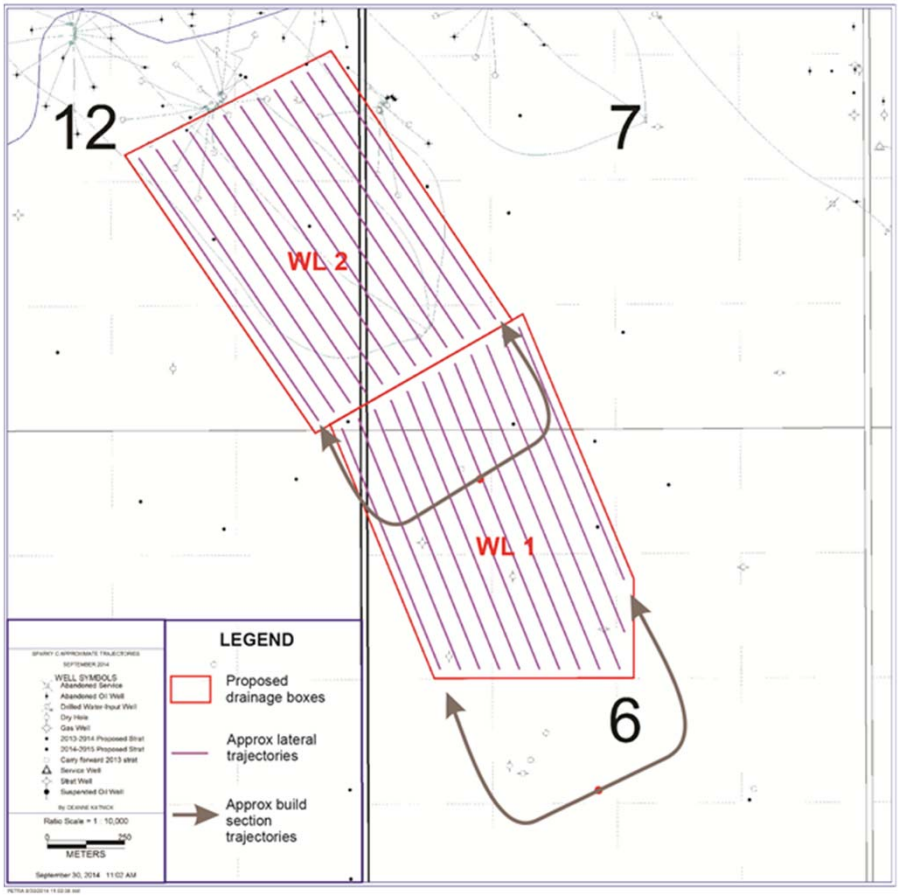
- 7 CSS Phases on 6 pads with 17-32 wells/pad
  - 156 wells total
  - ~60 m well spacing
- 900 – 1,700 m laterals
- Steam wave injection volumes
  - Commissioning cycle 1 → ~10,000 m3/well
  - Commissioning cycle 2 → ~17,000 m3/well
  - Commercial cycle 1+ → limited by overburden uplift
- Pending AER Approval



Wolf Lake Development

Wolf Lake Sparky C (1-2)

- 2 SAGD Phases with 12 well pairs/pad
  - 24 well pairs total
  - 60 m well spacing
- 800 – 1,150 m laterals
- Pending AER Approval



Future Development Plans

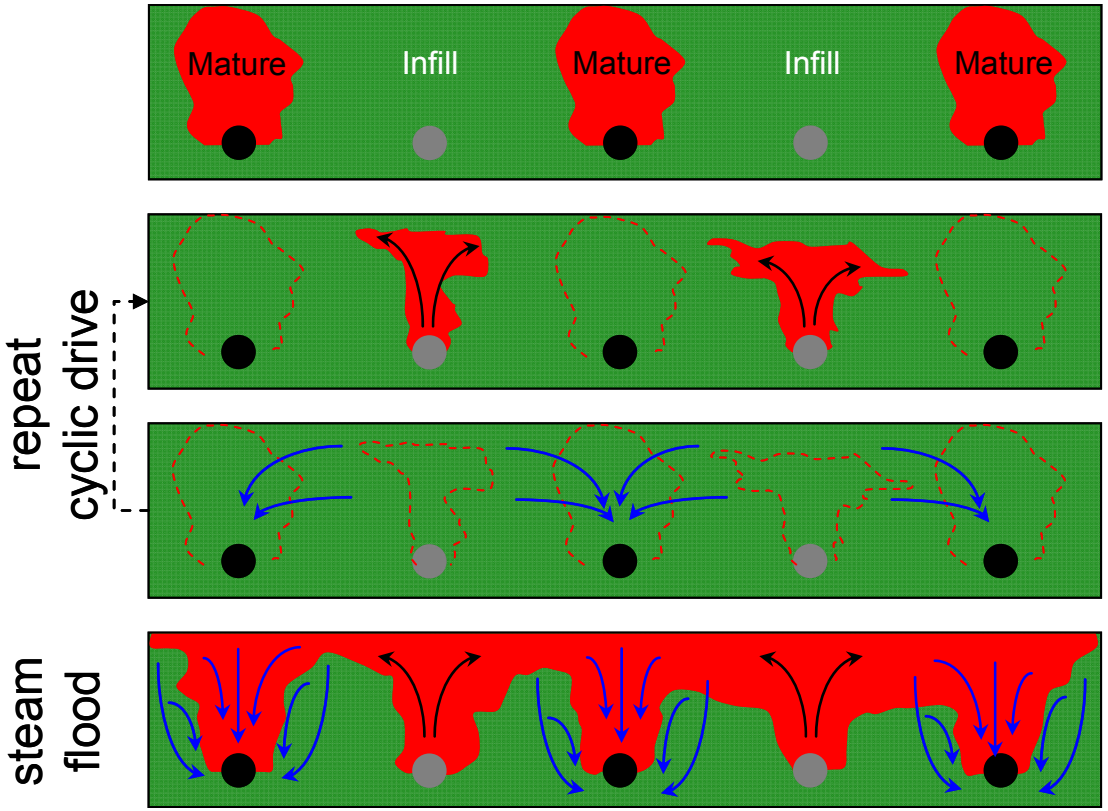
- Primrose South Development – Proposed Application Date Q1 2015
  - Plan to apply for new phases with ~150 horizontal CSS wells in the Clearwater Formation; wells in Primrose South (67-5W4) would be steamed from PRS Plant
- Primrose South Infill Development
  - Next step in advancing follow up processes to CSS
  - Infill wells in Phases 1-3 B column
  - Proposed Application date Q2/Q3 2015
- Wolf Lake Development
  - SAGD phases in 66-5W4 - Proposed Application Date Q2 2015,
  - One steam generator to be added to Wolf Lake CPF – Proposed Application Date Q3 2015

CSS Summary

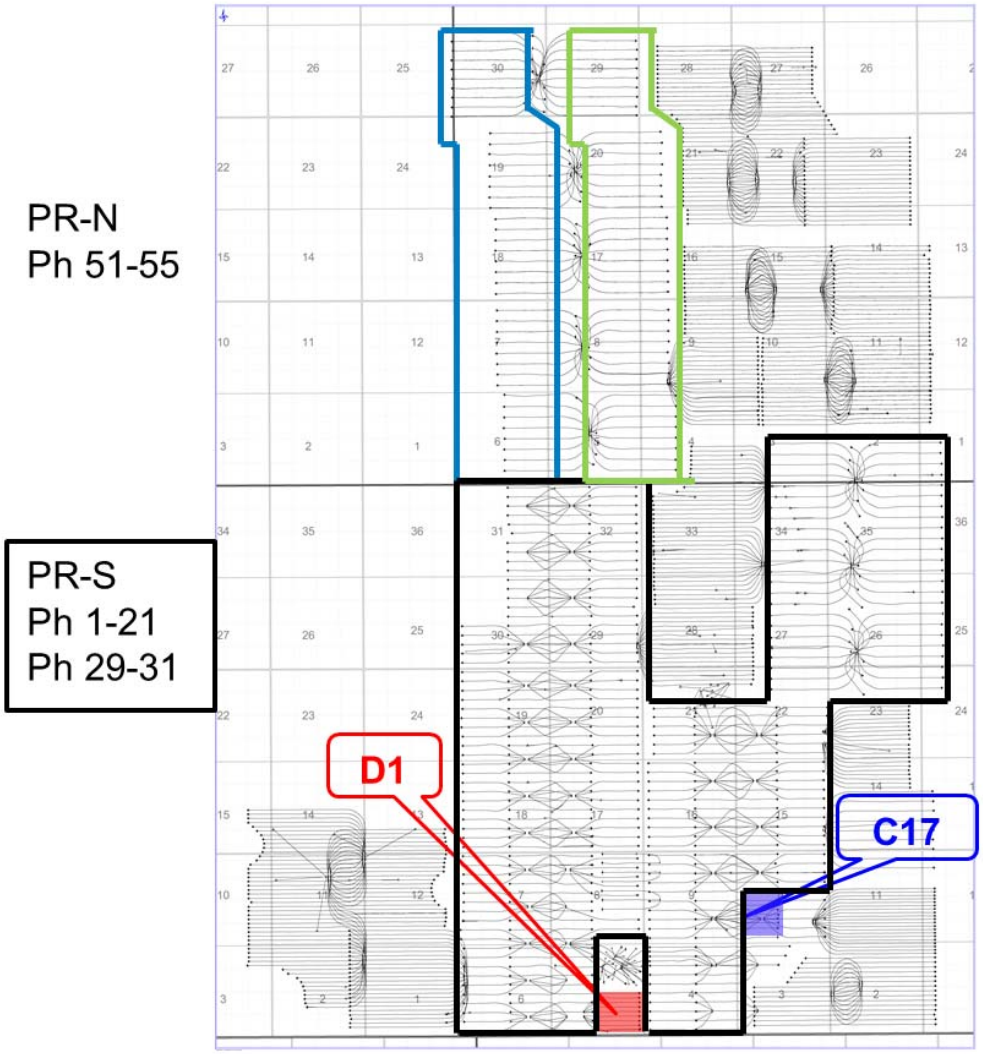
- FTS Learnings / Report
  - Causation identified and learnings adopted in enhanced steaming strategy
- PAW strategy change implemented to mitigate risk
  - Improved wellbore investigation and remediation
  - Enhanced steaming strategy
    - Good results for early cycle success to date, more data required
  - Increased Grand Rapids monitoring
  - Tighter alarm criteria
- Thin Pay:
  - CSS continues to be a viable recovery method
    - Reservoir performance meeting expectations
  - Still in early life recovery, more cycles are planned

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

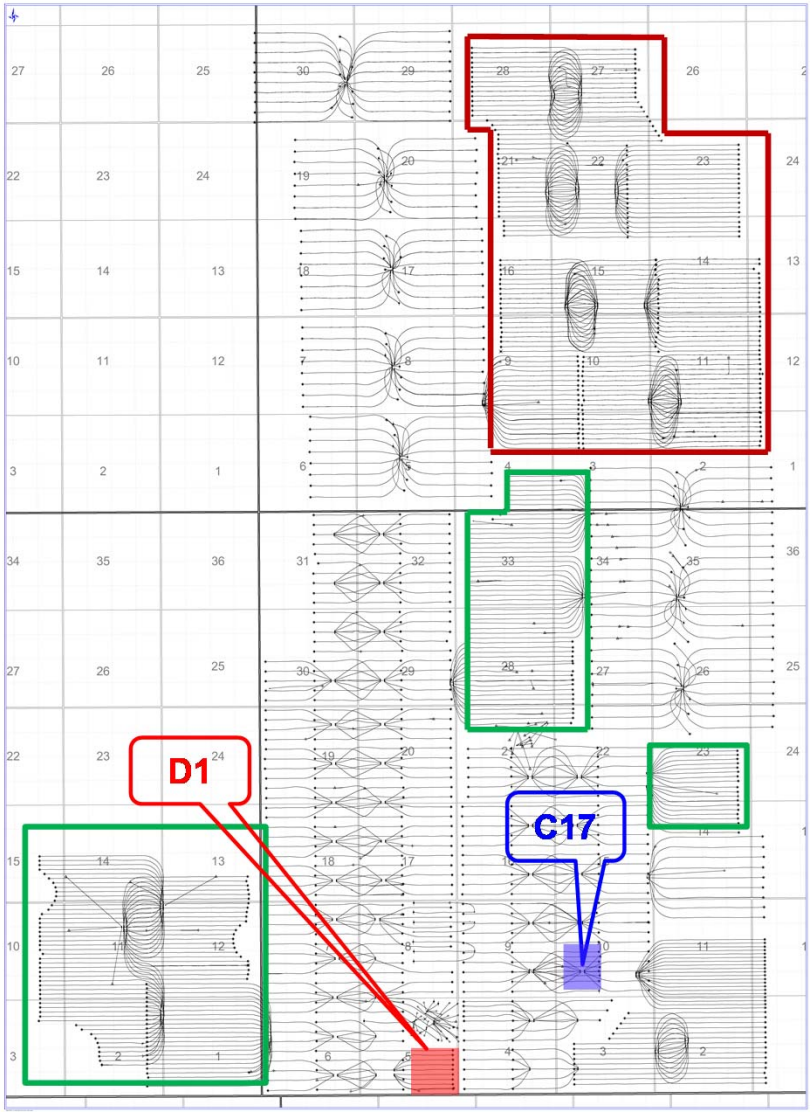


- FUP requires extensive infill drilling to reduce well spacing from current 160-188 m down to 80-95 m
- Current field trials
  - C17: cyclic drive (CD) since 2011
  - D1: steamflood (SF) since 2012
- Targeting commercial application in Primrose South/North by 2021-2024
- PR-S Phases 1-21 OBIP ~675 MMbbl
  - 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

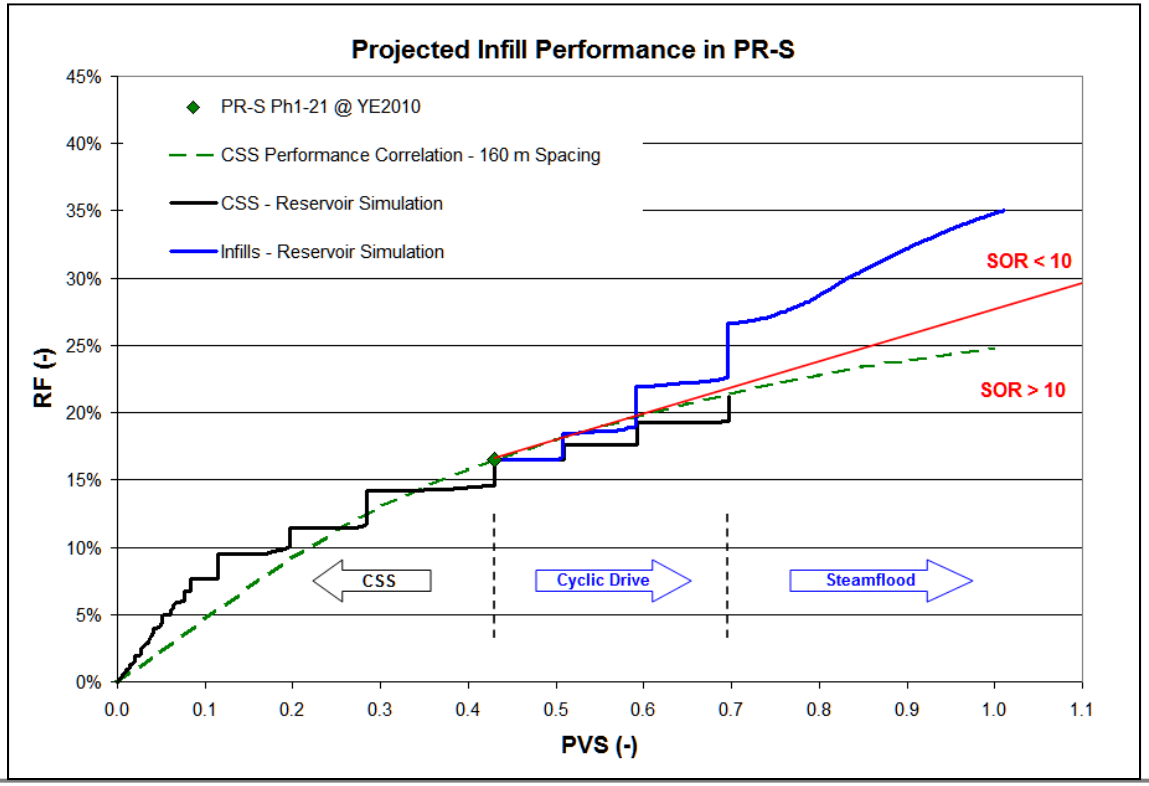
PR-S
Ph 22-24
Ph 28
Ph 40-43



- Developments with nominal 60-80m interwell spacing are expected to be able to convert directly from CSS to SF
  - Similar to the Phases 74-78 steamflood conversion
- Targeting commercial application in Primrose South/North by 2021-2024

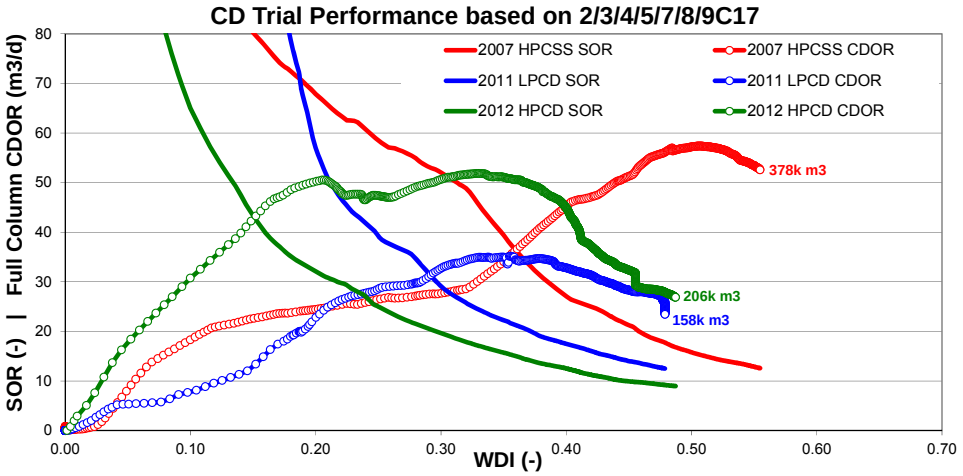
FUP – Impact of Continued CSS in PR-S

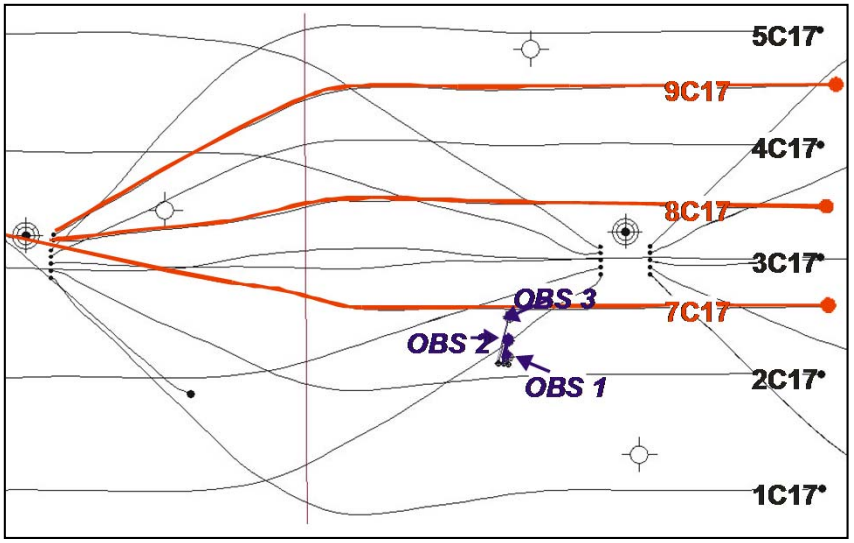
- Need to pressure up mature wells prior to first infill cycle to achieve horizontal hydraulically induced fractures, key requirement for longitudinal inter-well conformance
  - Another CSS cycle would increase steam volumes required to change stress state
  - Recommend no further CSS cycles due to negative impact on infill economics

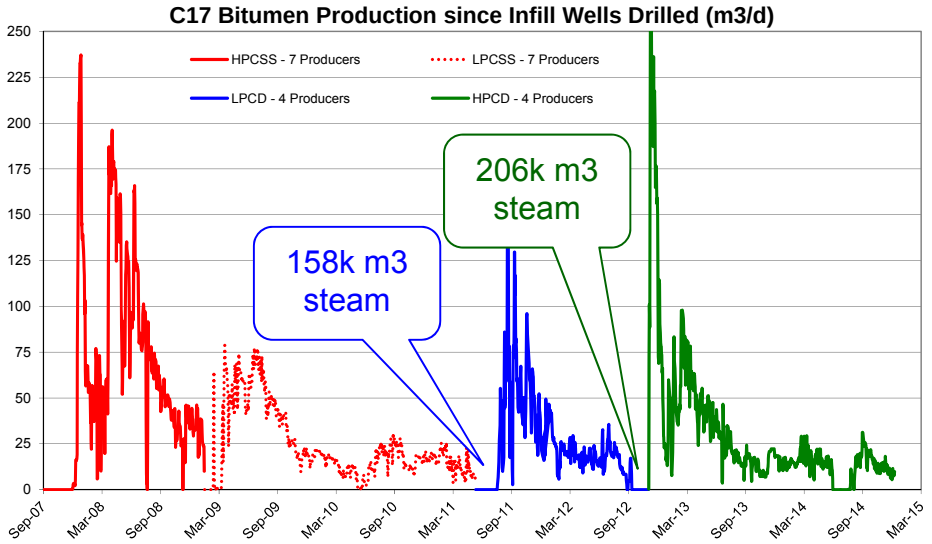


FUP – Status of Cyclic Drive Trial at C17

- 2012 CD cycle operated at dilation pressure while 2011 CD cycle operated below dilation pressure
  - Performance directionally encouraging, improved SOR/CDOR vs. WDI trends
  - Progressive reduction in achievable WDI at comparable CDSR, likely due to off-pattern fluid migration in Clearwater

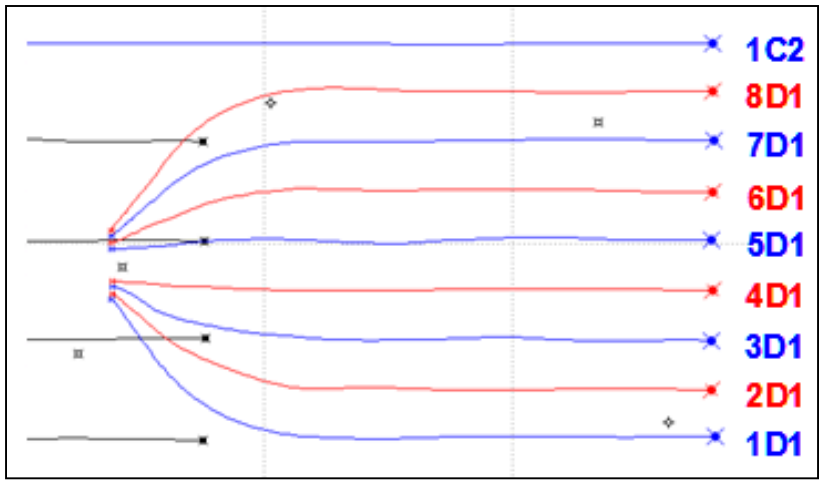


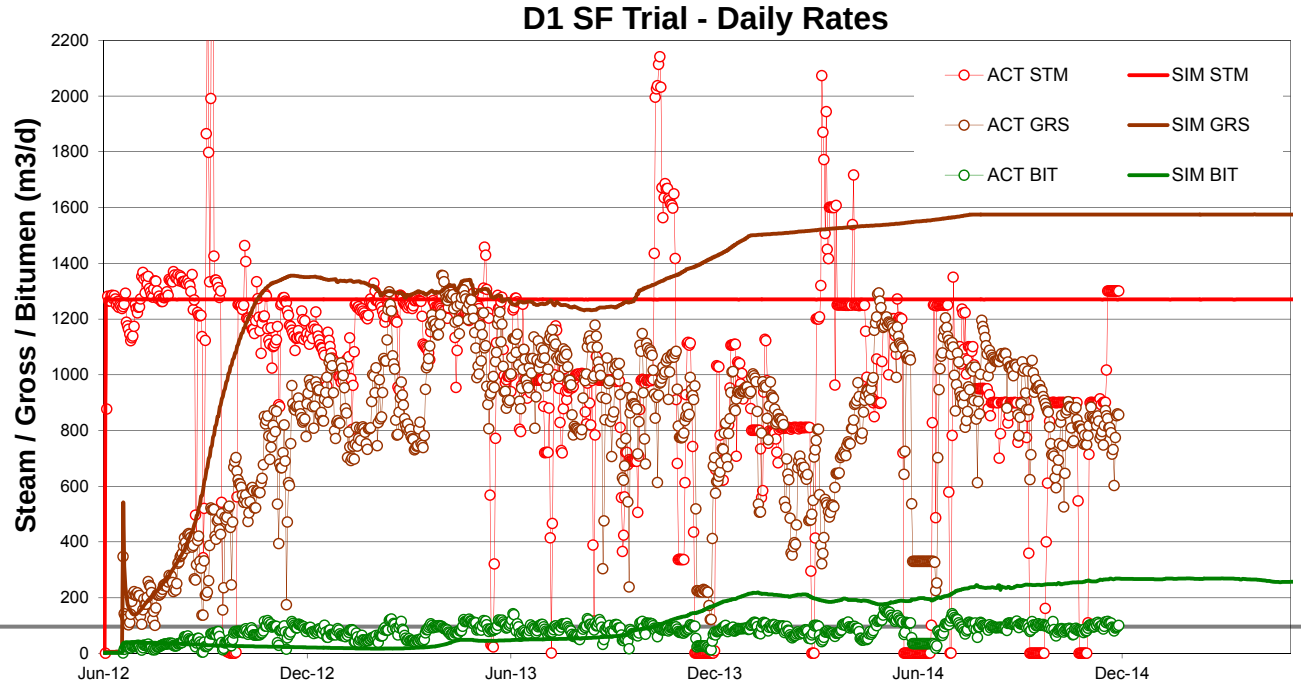




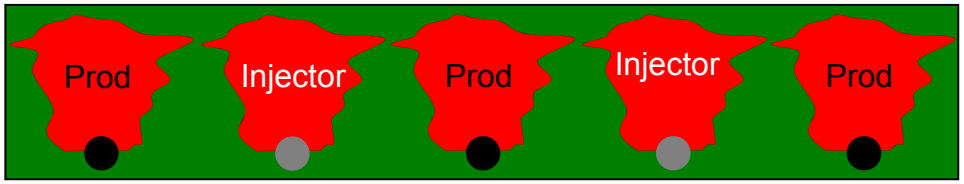
FUP – Status of Steamflood Trial at D1

- Dedicated injection into 2/4/6/8D1 and dedicated production from 1/3/5/7D1+1C2 since June 2012
  - 2014 performance significantly below simulation based expectations
  - Production (gross and oil) ~50% lower than initially expected due to impact of low steam quality and poor longitudinal conformance
  - Reservoir pressure steady ~0.5 MPa

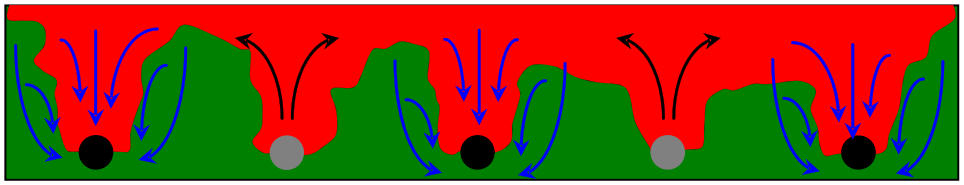


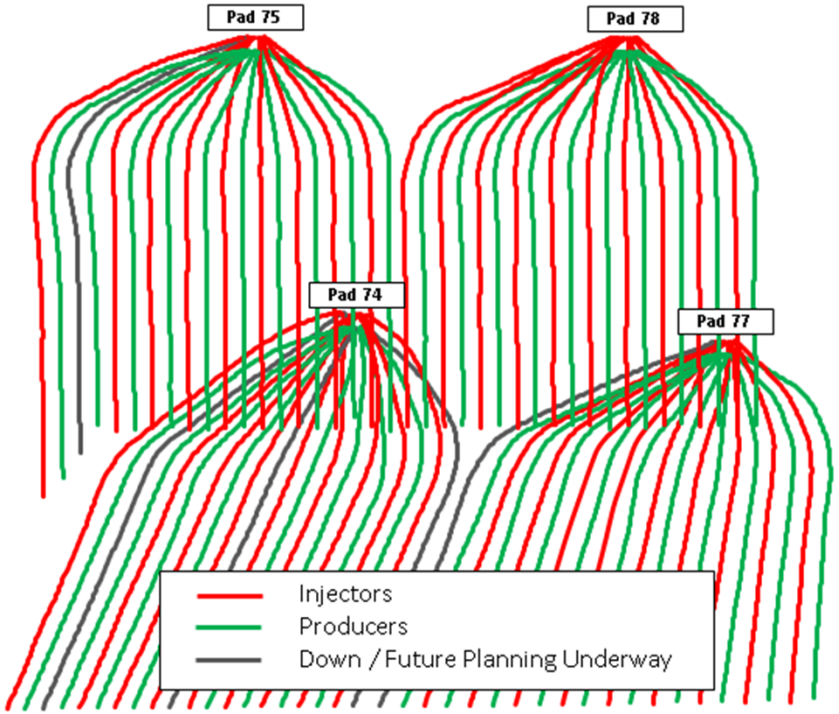


Primrose East Area 1 Steamflood



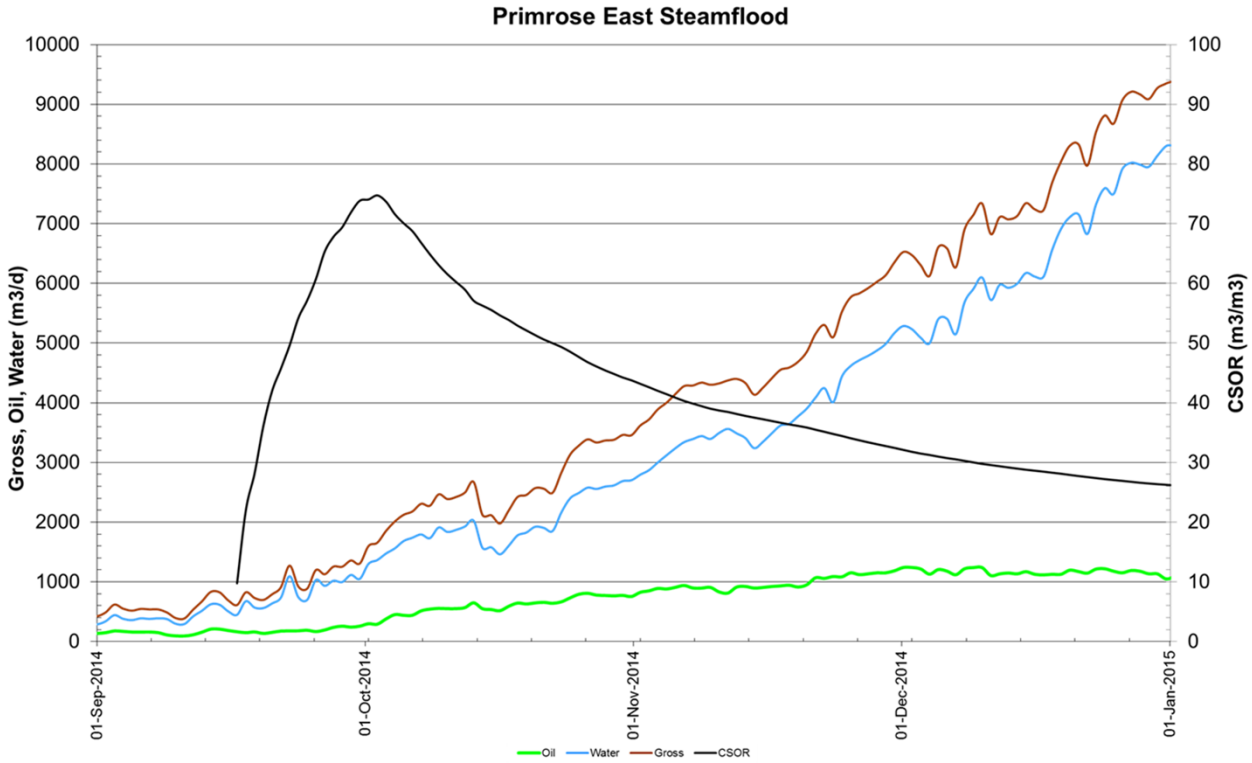
Remnants of interwell communication from last CSS cycle





- Wells: 37 Injectors/39 Producers
- AER Approval: Sept 15, 2014
- 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: 18%

Primrose East Area 1 Steamflood



- Target reservoir pressure
  - Operate above bubble point
  - Increase heat transfer to oilsand
  - Minimize gas interference in rod pumps
  - Balance thermal efficiency with steam & oil rates
  - Mitigate risk underneath FTS study area

2014 Activity

- Implementation of steamflood throughout all of Primrose East Area 1
- Currently 37 injectors / 39 producers, plan to increase to 38 injectors in 2015
- Steamflood operations commenced September 17, 2014, utilized full plant capacity
- Steam chamber grew laterally but did not reach producers

2015 Plan

- Work on developing a steam chamber and optimizing gross production
- Evaluating interwell longitudinal conformance

FUPS Summary

- Longitudinal interwell conformance is a significant technical hurdle with horizontal wells

- Planning to expand FUP trials with infill drilling in the B column of Phases 1-3
  - Objective is to demonstrate improved longitudinal interwell conformance
  - Potential to increase the calendar day steam rate of the transition to steamflood

- 2015 will continue with steamflood operation in D1 and Primrose East Area 1

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, the construction and future operations of the North West Redwater bitumen upgrader and refinery and disclosures relating to the Devon Canada Asset acquisition 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, 2013 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), 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, 2013 and a preparation date of February 3, 2014. 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. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 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 targeted to be released in late March 2013

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, 2012. 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.

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 "Financial Highlights" 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.

PROVEN | EFFECTIVE | STRATEGY

THE PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

Canadian Natural

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

PROVEN | EFFECTIVE | STRATEGY

Canadian Natural

2014 PRIMROSE, WOLF LAKE, AND BURNT LAKE DIRECTIVE 54 ANNUAL PRESENTATION

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

January 2015

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

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

Canadian Natural

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

- January 27, 2015

  3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery

- January 28, 2015

  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

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

AEMERA	Alberta Environmental Monitoring Evaluation and Regulatory Agency
AER	Alberta Energy Regulator
AGP	above-ground pipeline
AQHI	Alberta Quality Health Index
BFW	boiler feedwater
BMS	Burner Management System
BRWA	Beaver River Watershed Alliance
BS&W	basic sediment and water
CEMS	continuous emissions monitoring system
Cl	chlorine
CPF	central processing facility
CWE	cold water equivalent
DDS	digital data submission
DI	depletion index
EPEA	Alberta Environmental Protection and Enhancement Act
ESRD	Environment and Sustainable Resource Development
FTS	flow to surface
GOR	gas oil ratio
GTG	gas turbine
ha	hectare
HEP	habitat enhancement program
HRSG	heat recovery steam generator
JOSM	joint oil sands monitoring
kPa	kiloPascal
LICA	Lakeland Industrial and Community Association
LOC	license of occupation
LP	low pressure
m^3	cubic metre
m^3/d	cubic metres per day
MARP	Measurement, Accounting & Reporting Plan
mg/l	milligrams per litre
MPa	Mega Pascal
NOx	oxides of nitrogen
Obs	observation
ORF	oil removal filters
OTSG	once through steam generator
PAW	Primrose and Wolf Lake
profac	proration factor
PSV	pressure safety valve
PW	produced water
RATA	relative accuracy test audit
SAGD	steam assisted gravity drainage
SO2	sulphur dioxide
t/d	tonnes per day
tCO2e	tonnes of carbon dioxide equivalents
TDS	total dissolved solids
UWI	unique well identifier
VFD	variable frequency drive
VRU	vapour recovery unit
ZOI	zones of influence

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 non-saline water reduction
  - Wolf Lake Unit 2 desand replacement
    - Started demolition construction for the Wolf Lake Unit 2/8 desand tank replacement project.
  - Wolf Lake building expansion
    - Expansion to the admin building

Facilities

- Summary of modifications:
  - Wolf Lake slop oil treatment system
    - Commissioning and troubleshooting system continued.

- Disposal well #2 challenges
  - Disposal well #2 injection rates have been steadily decreasing over the last few years.
  - The follow remediation work has been completed with no success:
    - Disposal formation re-perforated
    - Well perforated at a second point within the disposal formation
    - Numerous acid jobs have been carried out in the past few years
  - Canadian Natural performed a pressure fall off test, and believes the well injection rates cannot be increased.

Facilities

- Summary of modifications (continued)
  - Wolf Lake Unit 2 skim tank
    - Increased tank DP to minimize upset venting.
    - Installed tank solids handling system
  - Primrose North Plant
    - Significant upgrades and repairs to the BFW tank.
  - Primrose South Plant
    - Numerous small projects executed during a planned outage
      - PSV tie-ins to flare system
      - Boundary valve upgrades
      - Separator vibration repairs and upgrades
    - Spare LP BFW pump installation
    - HRSG Duct burner improvements
  - Burnt Lake
    - Updated BMS installed to H-730

Specific Project Update

- Wolf Lake non-saline water reduction
  - Project to reduce non-saline water consumption to 3,000 m^3/d
  - Plant upgrades were completed and fully commissioned in 2014.
  - Some foaming experienced in the slurry tanks
  - Minor optimization work continues to further improve non-saline water consumption
  - Field expansion delayed due to regulatory approvals, all approvals in place now and project progressing.

Specific Project Update (continued)

- Primrose East Area
  - Steam generator conversion
    - Steam generators converted back to steamers from a BFW feed preheater.
  - Pad modifications
    - Area 1 pad piping modifications completed for steamflood operation.
    - Additional steam letdown stations
    - Additional well monitoring with fuel gas
  - Artificial lift upgrade for A1 completed for steamflood operation.
    - Upsized 31 pumpjacks
    - New pumpjacks, motors, VFDs
  - Plant studies performed for potential modifications, moving forward with some proposed modifications in 2015.

Wolf Lake CPF Performance

- Bitumen and water treatment
  - Overall water quality and oil treating targets were met:
    - Set saline water make-up record (Oct 2014)
    - Disposal rates were high due to reduced steaming
    - Production temperatures from Primrose East were challenging to handle with the reservoir cooling down
  - Successfully completed the following turnarounds:
    - Unit 8 – De-oiling only
    - Unit 9 – Water Treatment

Primrose East Steam Plant Performance

- Primrose East Plant
  - Sulphur treatment
    - Ran the sulphur treatment unit till Feb 2014
  - Conversion of OTSG to BFW heater
    - As the emulsion temperatures from Primrose East field started to decline, two (2) OTSG's were converted to BFW heaters in November 2013
    - LP BFW was heated in the OTSG's and injected upstream of the production separator
    - Upon approval for steamflood in Primrose East, the BFW heaters were converted back to OTSG's in September 2014
  - Primrose East plant resumed operation upon approval for steamflood in September 2014
  - Emulsion temperature is slowly rising as the reservoir heats up due to steamflood operation

Facility Performance

- Full Primrose South steam plant turnaround executed in June 9 – 27, 2014

- Primrose North steam plant was down Oct 1 – 7, 2014 for work on three of the OTSG to steam header isolation valves

Facility Performance

- Power generation/consumption on a monthly basis
- Net consumption high in June 2014 due to HRSG/GTG turnaround
- Net consumption high in December 2014 due to GTG work

Primrose and Wolf Lake - 2014 Power Generation and Consumption

Month	Power Generation MWh	Power Consumption MWh	Net MWh
January	64,798	61,584	3,214
February	59,898	56,250	3,648
March	63,721	58,088	5,633
April	59,212	53,293	5,918
May	59,746	51,190	8,555
June	16,246	40,057	-23,811
July	49,366	44,255	5,111
August	52,384	38,805	13,579
September	56,594	44,731	11,863
October	59,762	56,313	3,449
November	63,030	57,929	5,101
December	16,618	66,509	-49,891

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**	**e3m3**
January	96,881	19,954	1.0	5097	79.7%
February	89,646	17,330	1.7	4481	79.5%
March	88,681	19,790	0.2	4611	81.1%
April	82,329	17,898	0.7	4333	80.5%
May	81,945	18,091	1.8	3788	82.7%
June	50,219	15,040	1.0	3449	81.3%
July	75,302	15,731	1.3	2508	86.2%
August	66,715	18,362	1.5	2051	90.0%
September	88,246	20,766	1.3	1042	95.2%
October	127,501	22,033	0.6	3259	87.1%
November	127,028	18,180	0.1	83	99.5%
December	129,769	18,710	0.3	58	99.7%

*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

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 ~ 87% of total Primrose and Wolf Lake solution gas in 2014
- 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

- PAW Greenhouse Gas Emissions

Month	2014 (tCO2e)
January	237,366
February	161,822
March	212,232
April	204,816
May	205,033
June	135,983
July	185,879
August	175,349
September	222,561
October	304,474
November	302,096
December	303,285*
Year Total	**2,650,896**

* 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

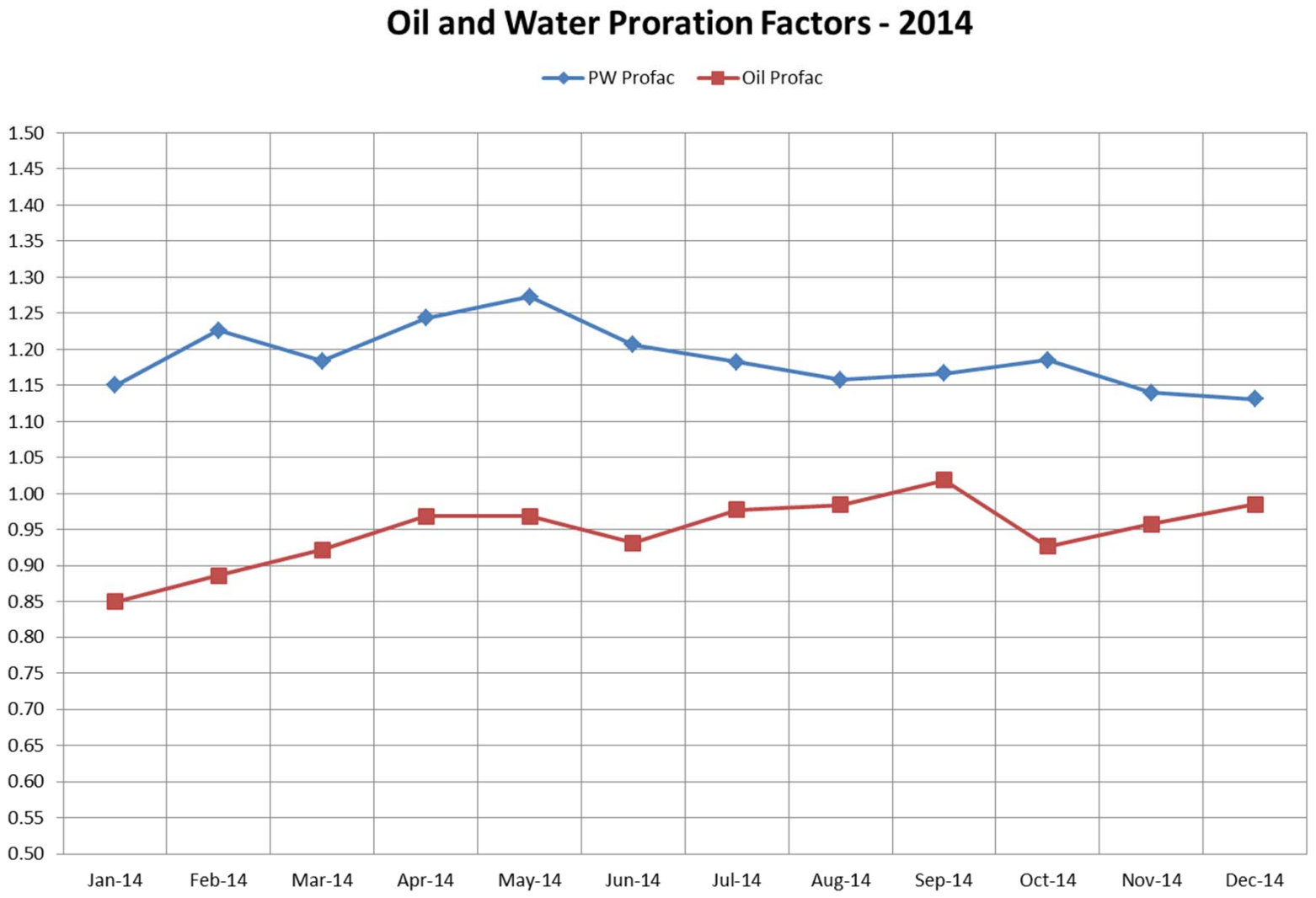
Measurement and Reporting (con't)

- 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

- Meeting held with AER on January 8, 2015 to update on the water profac troubleshooting efforts

- Factors contributing to high water profac:
  - Primrose North/South field metering issues
  - Primrose North Plant Emulsion/BFW Exchangers leak
  - Primrose South Plant Emulsion/BFW Exchangers leak
  - WL CPF PW/BFW spiral exchanger 8E-109B

- Profac improvement projects completed in 2014:
  - Addition of instrumentation to Primrose South Plant emulsion booster pump recycle line
  - Wolf Lake CPF Unit 2 ORF meter (2-FT-132) programming correction
  - Verification of Coriolis meters on all PAW field pads using a prover skid
  - Continuous verification of field AGAR meters on well pads

Measurement and Reporting

- Path forward for further water profac improvement:
  - Repair Wolf Lake CPF Unit 8 PW/BFW spiral (8-E-109B) exchanger by Q2 2015
  - Repair Primrose North Plant Emulsion/BFW shell & tube exchangers (4-E-8003 A and C) by Q1 2015
  - Repair Primrose South Plant Emulsion/BFW shell & tube exchangers (1-E-8003 B and C) by Q1 2015
  - Rewrite gas correction codes on all pads with Coriolis meters present by Q2 2015
  - Continuous improvement on testing operation due to changes in steam strategies

Measurement and Reporting

- New Measurement Technology
  - Installed multi-phase flow metering technology
    - Field tests started in 2012 and were continued in 2014 using multiphase flowmeter technologies
    - Objective is to identify a multi-phase flow meter which provides adequate performance and accuracy to replace the traditional test separator system for multiple wells

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)	1F1/10-05-67-04W4 (EL)	102/10-08-66-5W4M	1F1/11-06-67-3W4M
1F2/12-10-066-05W4M (ML)	1F1/14-05-67-04W4 (EL)	102/05-16-66-5W4M	1F1/16-12-67-4W4M
1F1/06-10-066-05W4M (ML)	1F2/15-05-67-04W4 (EL)	104/05-16-66-5W4M	1F1/11-05-67-3W4M
1F2/06-10-066-05W4M (ML/E3)	04-14-67-03W4 (BV)	109/01-17-66-5W4M	1F2/13-08-67-3W4M
1F1/13-10-066-05W4M (ML)	NW 08-068-04W4 (EL)	107/02-17-66-5W4M	1F1/14-08-67-3W4M
1F2/13-10-066-05W4M (E3)	NW 08-068-04W4 (EL)	106/08-17-66-5W4M	1F1/12-09-67-3W4M
		107/08-17-66-5W4M	1F2/12-09-67-3W4M
			1F1/10-08-67-3W4M
			1F1/02-12-67-3W4M
			1F1/07-06-67-3W4M
			1F1/16-06-67-3W4M

*Primrose non-saline water wells are utility use only

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 feed water 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)

Water Production, Injection, and Uses

- Water Quality Assessment
  - Quaternary Water Source Wells (6) - Empress Unit 3 & Muriel Lake Formations
    - Average TDS = 523 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

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

Primrose and Wolf Lake - 2014 Monthly Water and Steam Volumes

Month	Surface Water m^3/day	Non-Saline Groundwater m^3/d	Saline Water m^3/d	Produced Water m^3/d	Steam Injection m^3/d	PW Recycled %	PW Recycled Bulletin 2006-11 %
January	545	6,843	12,560	35,702	50,892	94.3	186.0
February	191	6,885	10,710	42,611	53,854	97.7	146.5
March	198	5,998	9,466	40,643	48,024	92.8	155.1
April	674	5,289	10,785	38,125	44,989	95.1	160.6
May	404	4,915	11,633	35,292	44,171	98.8	177.7
June	535	2,922	4,779	31,479	30,391	86.8	171.6
July	482	3,028	10,567	33,698	40,826	96.6	129.4
August	523	2,971	6,769	38,905	38,390	88.4	92.4
September	598	3,458	10,742	48,095	51,429	92.6	102.6
October	820	5,211	26,949	43,442	67,455	99.1	145.7
November	1,413	3,590	21,172	52,319	69,412	98.8	126.7
December	857	3,036	18,067	53,923	68,826	99.3	120.7

* Surface water is effluent diversion from Cold Lake fish hatchery and surface water runoff
* Non-saline ground water from Wolf Lake water source wells
* Saline water is from McMurray and Grand Rapids aquifers
* Blowdown recycle from Wolf Lake Steam Separator is 100%

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

Water Production, Injection, and Uses

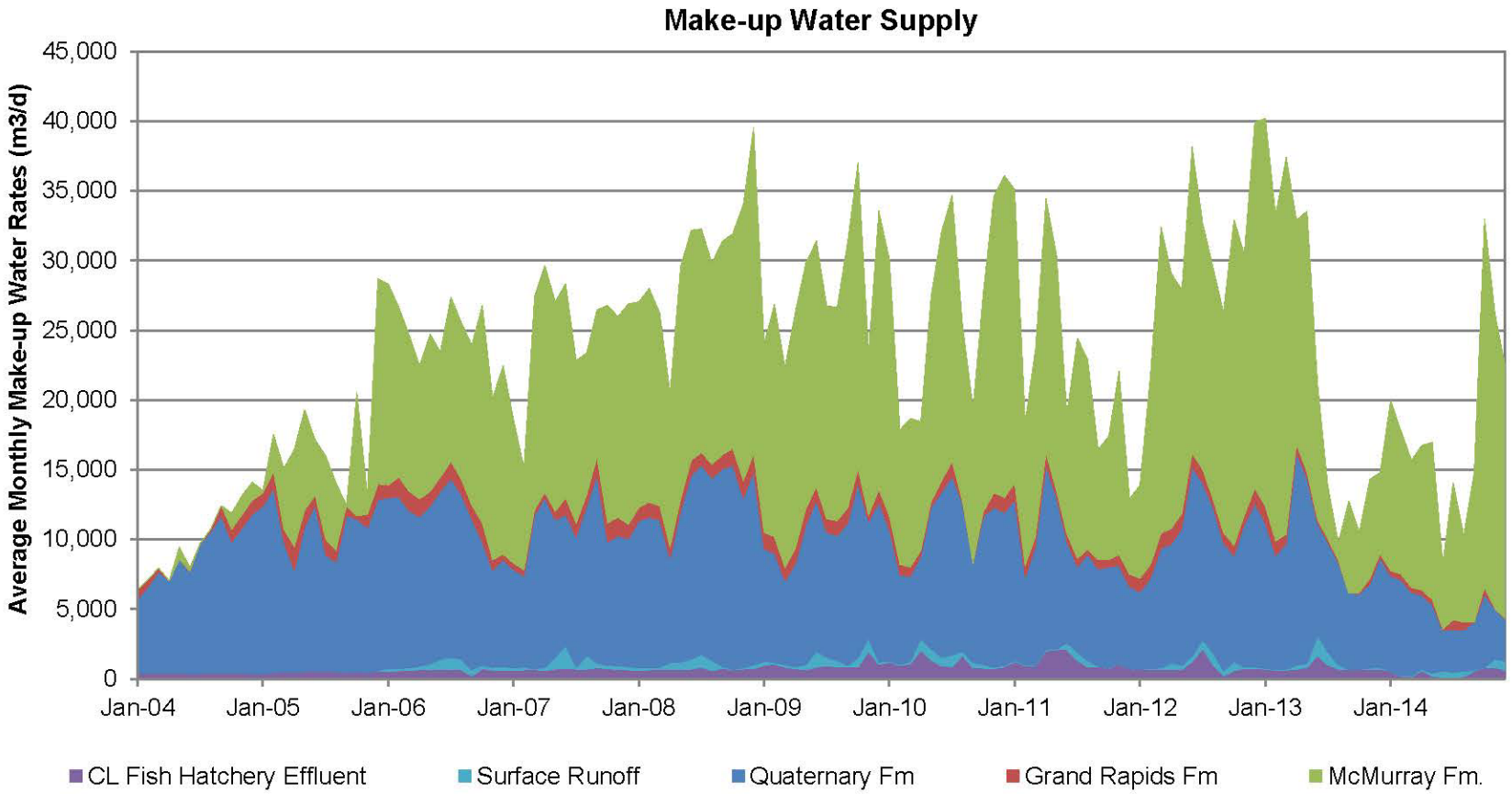
McMurray Saline Water – Avg. 12,551 m^3/d

Grand Rapids Saline Water – Avg. 327 m^3/d

Quaternary Non-saline Water – Avg. 4,500 m^3/d

Cold Lake Fish Hatchery Effluent – Avg. 380 m^3/d

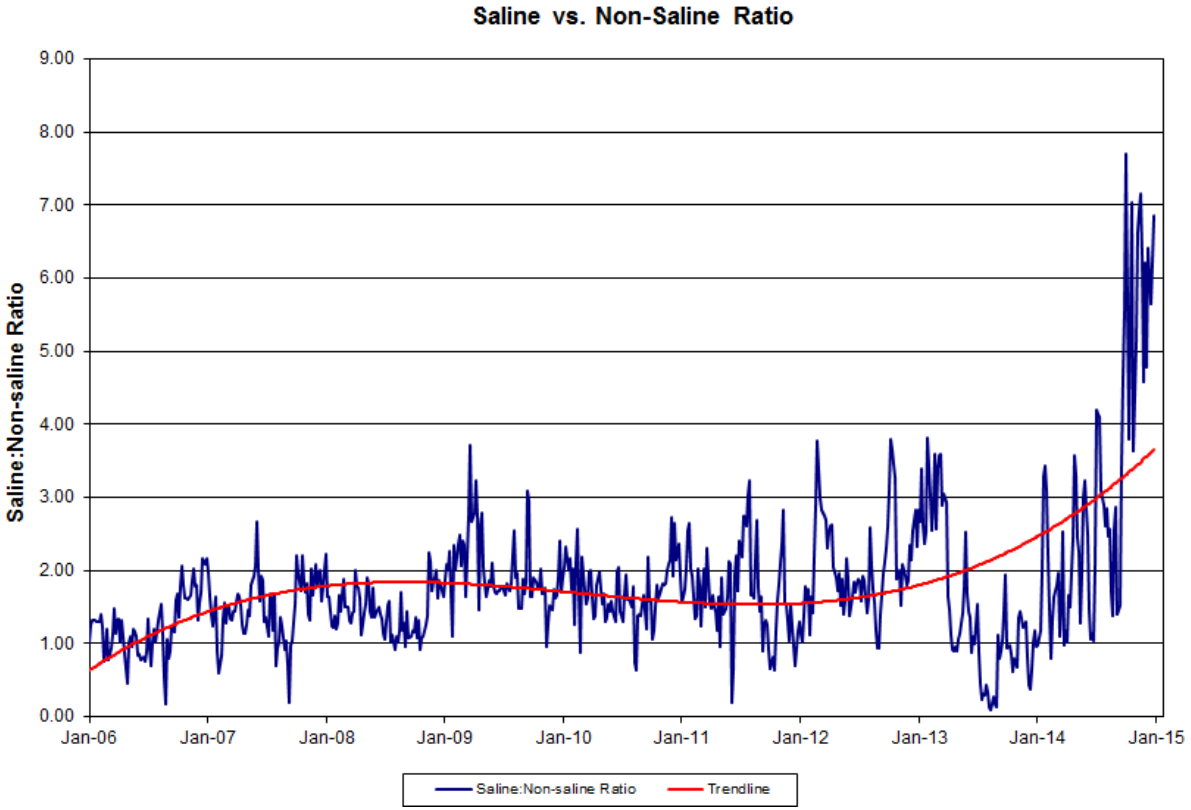
Plant Runoff Water – Avg. 257 m^3/d



- No runoff data before 2006

Water Production, Injection, and Uses

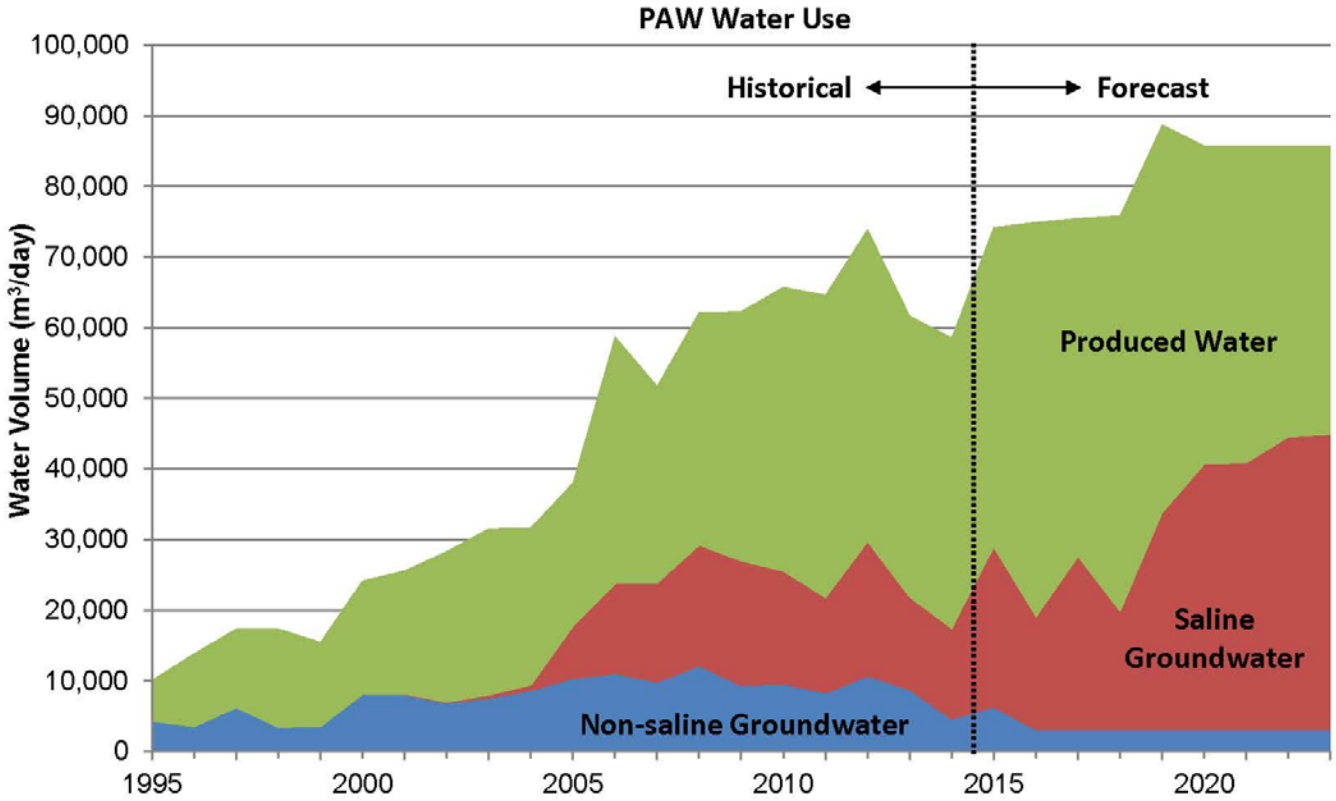
- Improved Saline to Non-Saline Groundwater Ratio
  - Saline to non-saline ratio increased from 1.5 (2013) to >3.5 in 2014
  - Non-saline decreased by almost half in 2014 (4,500 vs 8,716 m^3/d in 2013)
  - Saline usage similar in 2014 (12,878 vs.13,092 m^3/d in 2013)



- Excludes Cold Lake Fish Hatchery Effluent Volumes

Water Production, Injection, and Uses

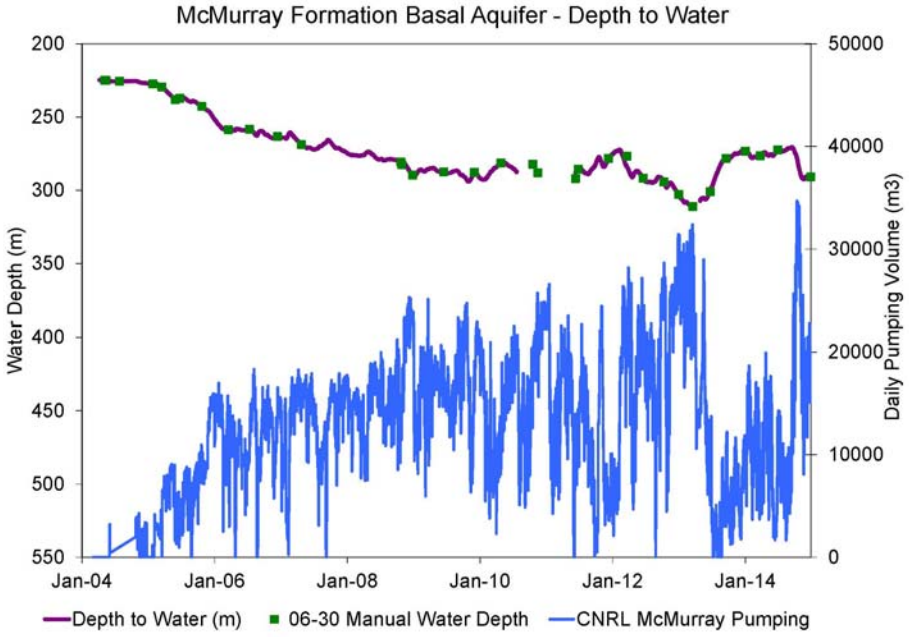
- Yearly make-up requirements up to 30,000 m^3/d over the next five years
- Planned reduction of non-saline groundwater use – down to 3,000 m^3/d
- Wolf Lake Water Act license amended to allow for additional non-saline water above 3,000 m^3/d in 2015
- The PAW water use forecast shows changes in the make-up water demand based on development assumptions used in the forecast. The increased saline make-up water requirement shown for 2019 is related to a new CSS development.

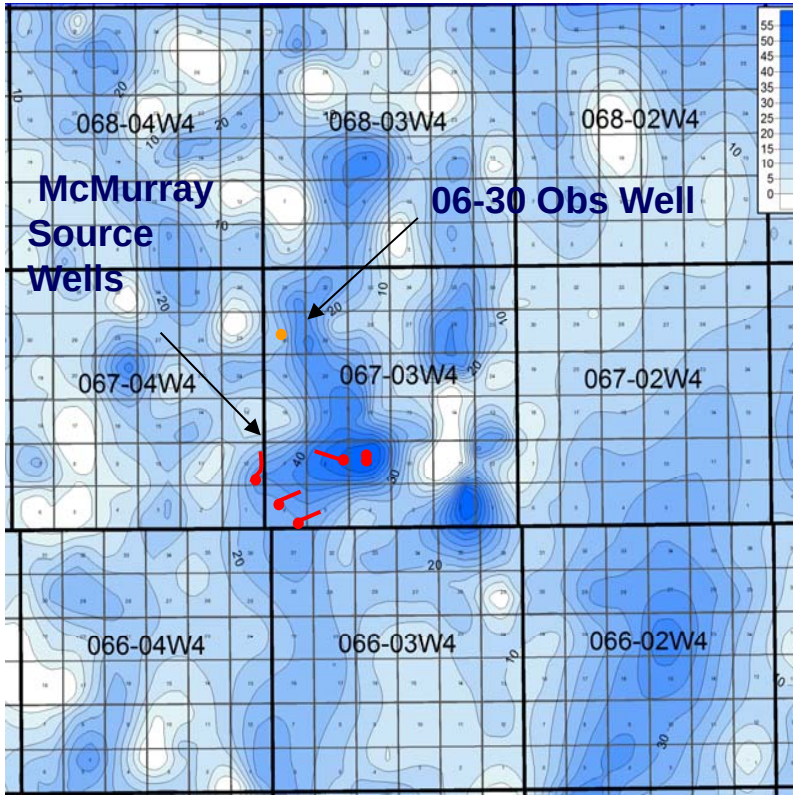


- Excludes Runoff Water and Cold Lake Fish Hatchery Effluent Volumes

McMurray Brackish Water Supply – Existing

- Producing wells
  - 4 horizontal and 6 vertical wells
- 2014 production
  - average – 12,551 m^3/d
  - maximum – 35,544 m^3/d
- Drawdown of 66 m in 6-30 obs well

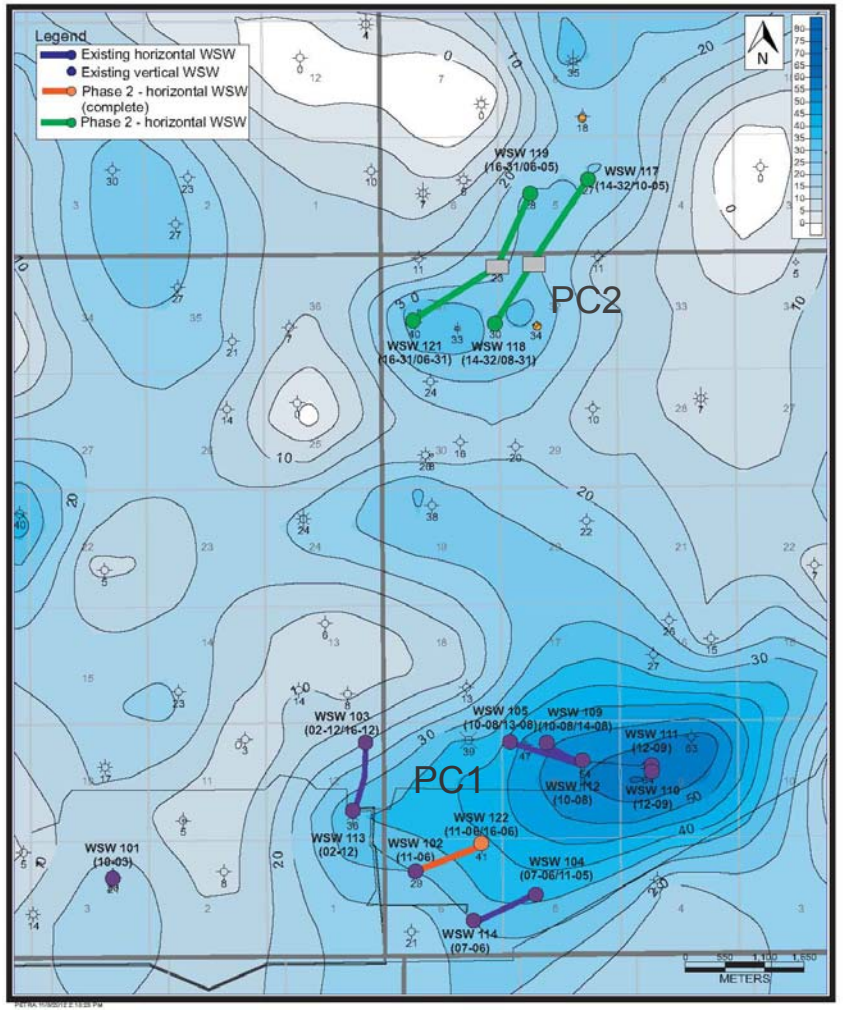




McMurray Formation Basal Aquifer Isopach Map

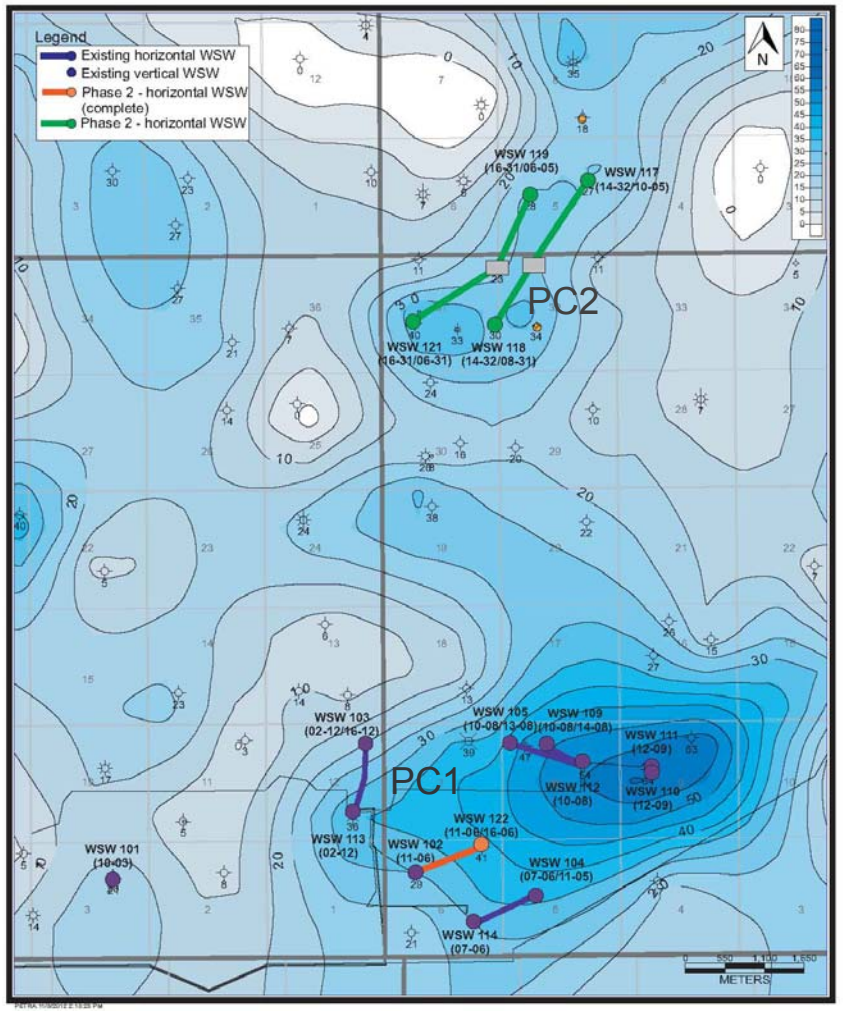
McMurray Brackish Water Supply – Phase 2 Expansion

- Phase 2 Expansion
  - Additional development in existing pumping centre (PC1)
    - add one horizontal water well (WSW122)
  - Develop new pumping centre in NW67-3 and SW68-3 (PC2)
    - add four horizontal water wells
    - following basal aquifer fairway north of existing pumping centre (PC1)
    - constrained by geology, thermal development, target circle and mineral and surface rights



McMurray Brackish Water Supply – Phase 2 Expansion

- Project Schedule
  - Pumping Centre 1
    - WSW122 was drilled and completed in 2014
  - Pumping Centre 2
    - PC 2 was delayed by objections raised during the surface land disposition and well licence regulatory process
    - Construction of PC2 started the end of 2014. Clearing for pipeline and road are underway
    - PC 2 is scheduled to be operational by Q1 2016 in order to meet commitment to decrease non-saline water use to 3,000 m^3/d
  - Required additional make-up water from alternate sources for 2015. Wolf Lake Water Act licence amended.



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

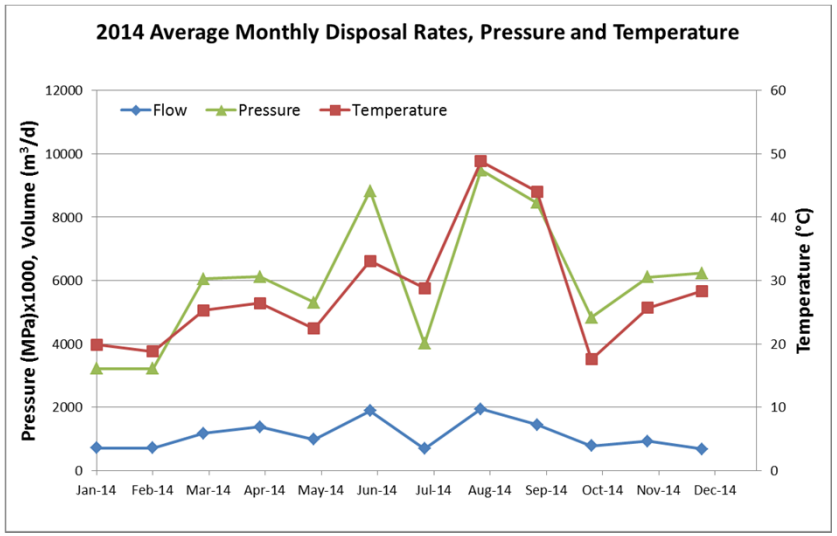
Canadian Natural

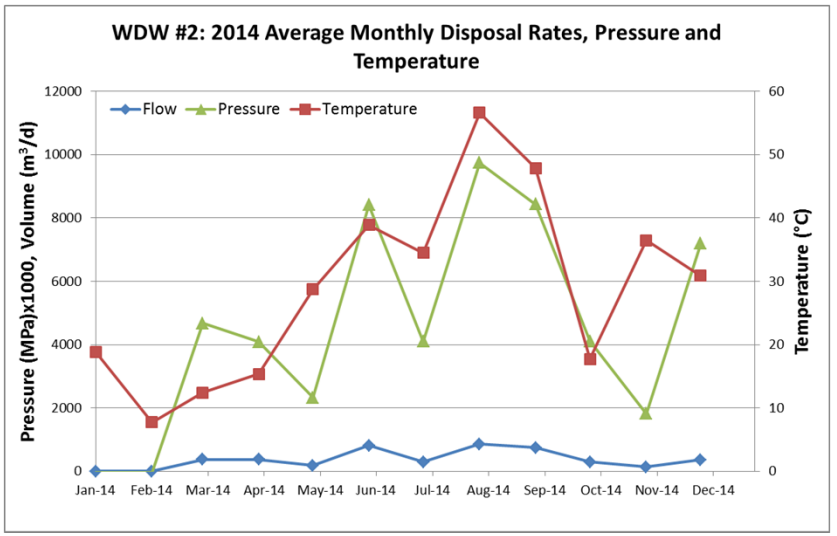
- Primrose & Wolf Lake Project Disposal Water Well UWI Listing
  - Wells shown in bold are active, (Wolf Lake - WDW#1 and WDW#9 are zonally abandoned)

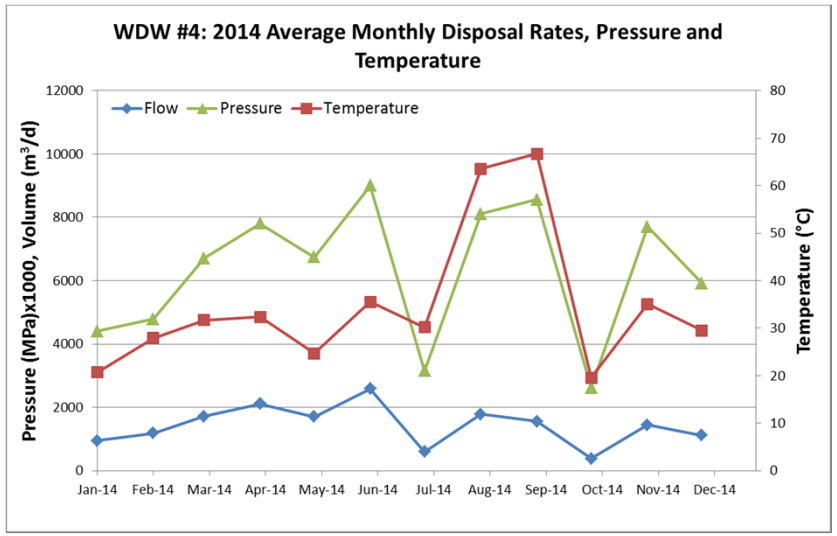
Wolf Lake		Primrose South		Primrose East	
Well	Formation	Well	Formation	Well	Formation
WDW#1 - 100090806605W400	*Precambrian*	**103100506704W400**	**McMurray**	*100031106703W400*	*McMurray*
WDW#2 - 100100806605W400	**Precambrian**			**1F1110206703W400**	**McMurray**
WDW#4 - 100050806605W400	**Precambrian**				
WDW#5 - 100150706605W400	**Precambrian**				
WDW#9 - 100140506605W400	*Precambrian*				

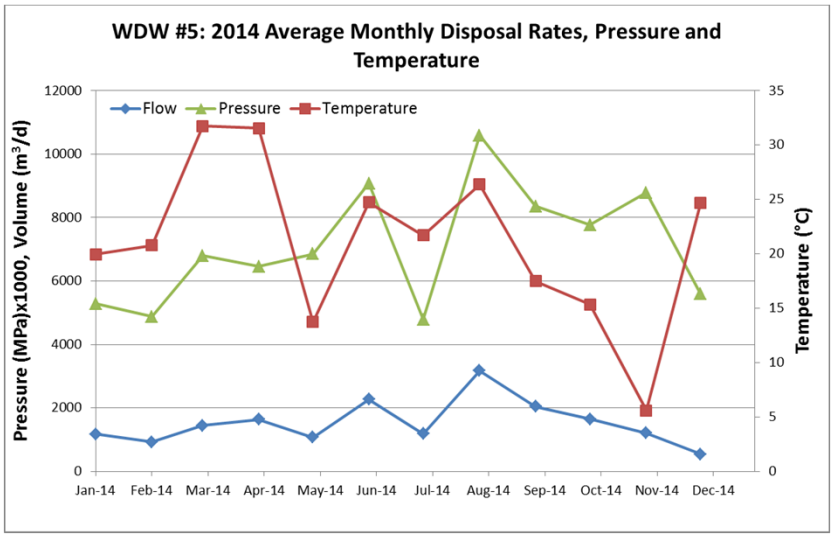
- Wolf Lake (WDW #2, 4, & 5)
  - Disposal scheme was amended on June 2010 to allow injection into WDW #4 (Approval 8672A). Maximum wellhead injection pressures decreased from 17,500 kPa to 13,770 kPa; with the ability to inject at 17,500 kPa for a maximum time period of 24 hrs.
    - Injection pressures did not exceeded 13,770 kPa in 2014.
- Primrose South
  - Injected 0 m^3 fluid in 2014.
- Primrose East
  - 3-11 zonally abandoned in the McMurray formation.
  - 11-2 continued discussions regarding potential abandonment options with AER.

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



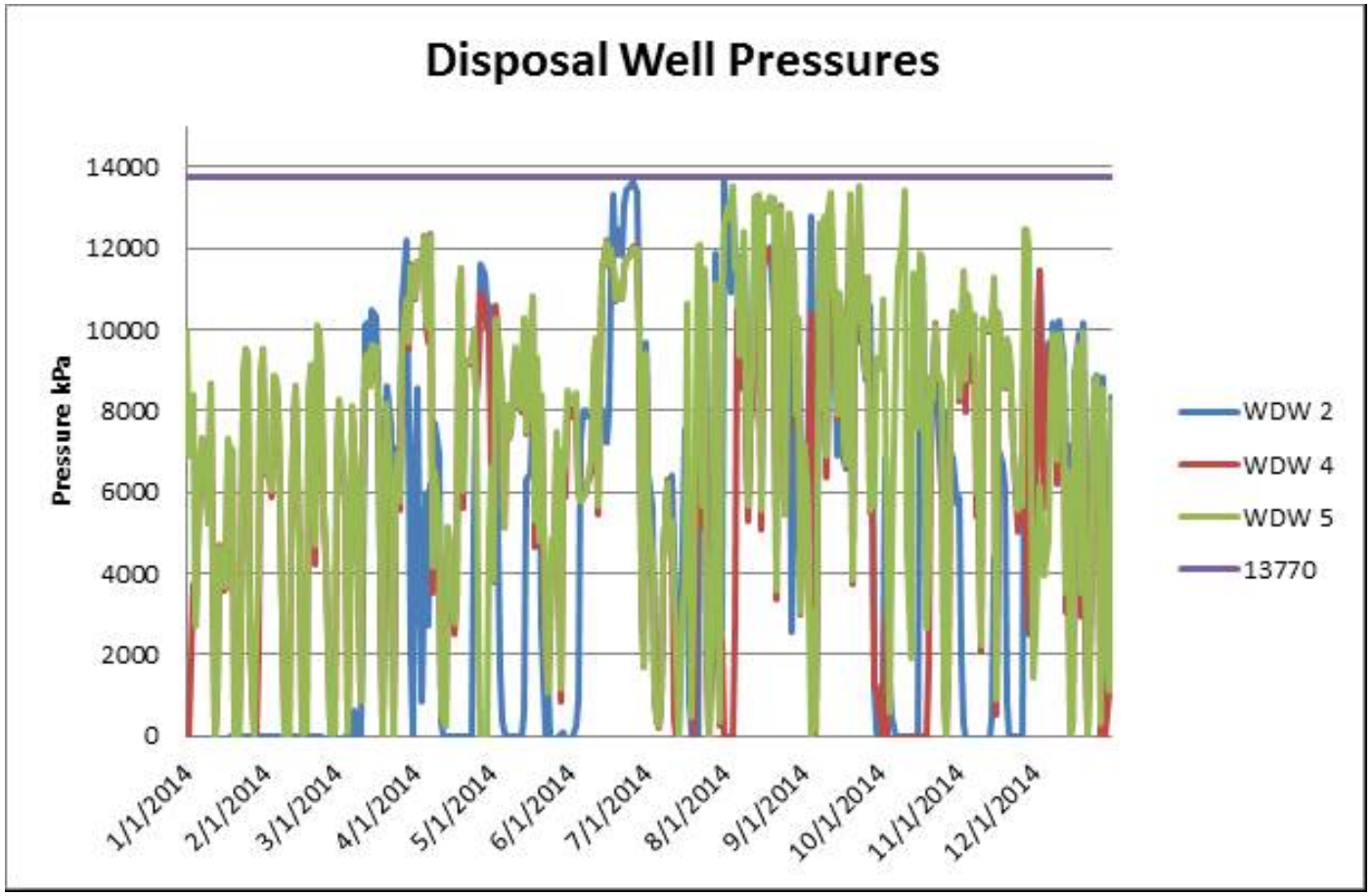






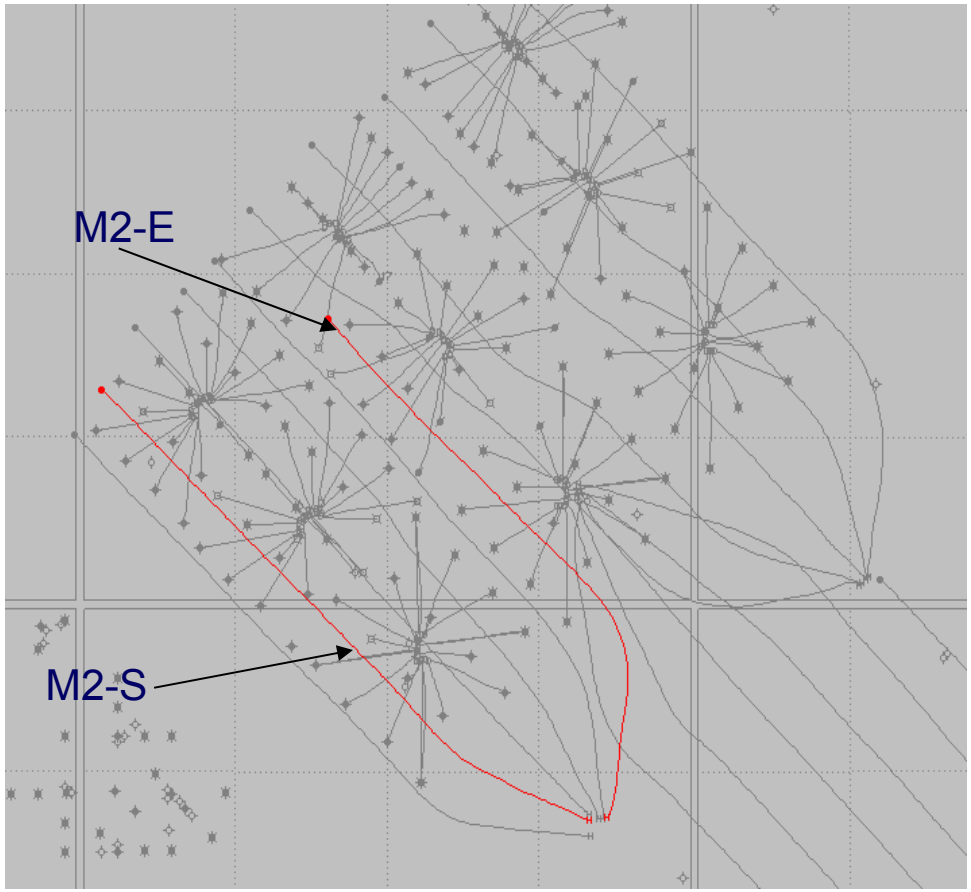
Wolf Lake Disposal Well Pressures

- Wolf Lake disposal well pressures (WDW #2, 4, & 5) did not exceed 13,770 kPa in 2014



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

- Water is stored in the C3 Formation
  - Converted two wells to injectors in June 2003
- Injected 588,503 m^3 total
  - 321,722 m^3 to M2-S
    - 16,260 m^3 in 2014
  - 266,781 m^3 to M2-E
    - 16,875 m^3 in 2014
- M2-E and M2-S are currently configured for summer operations



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

Canadian Natural

- Wolf Lake Water Storage Volumes

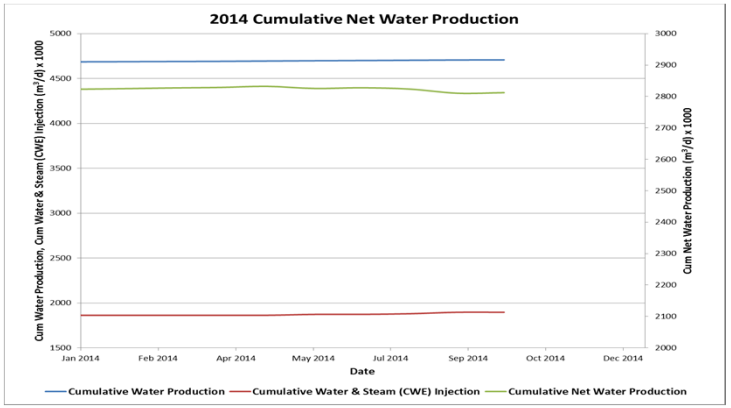
		M2_E				M2_S			
Year	Month	Gross (m^3/d)	Oil (m^3/d)	Water (m^3/d)	Water Inj (m^3/d)	Gross (m^3/d)	Oil (m^3/d)	Water (m^3/d)	Water Inj (m^3/d)
2003		21	2	20	243	40	1	39	292
2004		0		0	21	28	0.2	28	49
2005					0.3				4
2006									
2007					146				174
2008									
2009									
2010					16				0.03
2011					5.39				0.14
2012					5.19				0.09
2013					3005.91				3741.37
2014	Jan								
	Feb								
	Mar				0.5				0.3
	Apr								
	May								
	Jun				331.5				
	Jul								7.3
	Aug				223.1				
	Sep								534.1
	Oct								
	Nov				24.7				0.3

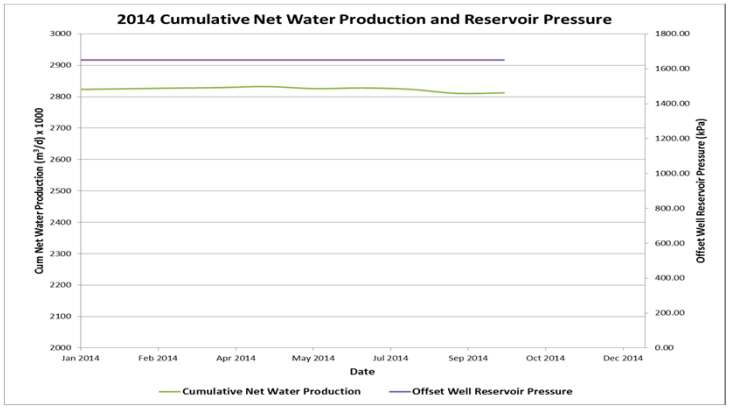
Water & Waste Disposal Wells, Landfill Waste
Wolf Lake Water Storage Compliance

- Formation Integrity and Pressure Monitoring
  - Offset well reservoir pressures never exceeded the 2.5 MPa allowable during injection periods
  - M2-E injection packer successfully passed packer isolation test on August 2, 2014
  - M2-S injection packer successfully passed packer isolation test on July 21, 2014
  - No wellbore integrity issues encountered

- Wolf Lake Water Storage – Reservoir
  - M2 & N2 Cumulative DI = 1.20
    - Cumulative Gross Production = 12,650,798 m^3
    - Cumulative Oil Production = 1,548,636 m^3
    - Cumulative Steam Injected = 9,915,737 m^3 CWE
    - Cumulative Water Injected = 588,503 m^3
  - M2 & N2 Remaining Voidage = 2,146,556 m^3

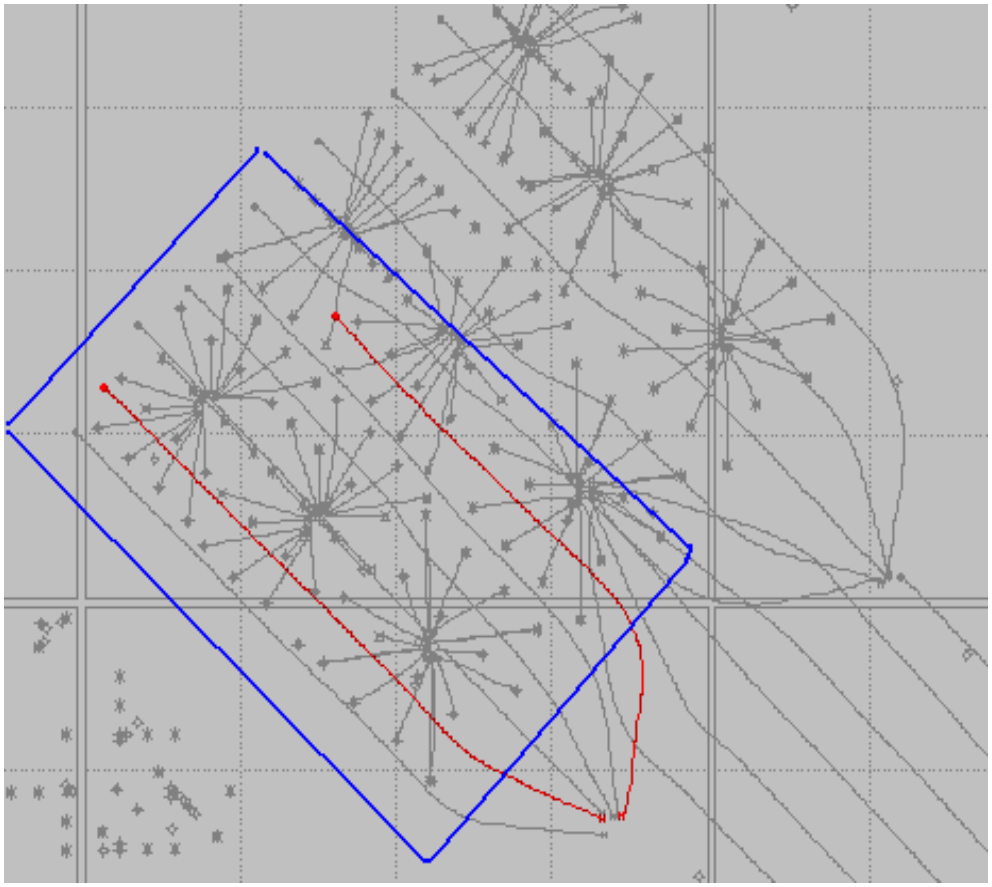
$$DI = \frac{\text{Total Fluid Produced (Bitumen + Water)}}{\text{Total Fluid Injected (CWE)}}$$





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

- From the outlined area (M2 wells and N2-F)
  - Total Injected Water = 588,503 m^3 since Jan '03
  - Total Produced Water = 655,173 m^3 since Jan '03
  - Difference = 66,670 m^3
- Expect to utilize M2 storage in 2015
- 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 2015
- M2-E and M2-S are classified as disposal wells on S-4 forms

Water & Waste Disposal Wells, Landfill Waste
2014 Annual Waste Disposal Summary

Canadian Natural

- Waste to Tervita Landfill
  - 52,983 tonnes – Contaminated soil
  - 73,017 tonnes – Lime waste
  - 2,360 tonnes – Cement
  - 1,348 tonnes – Drilling Waste
  - 22 tonnes – Misc Industrial Waste

- Waste to Terivata Cavern
  - 7,379 m^3 – Sludge hydrocarbons and sand
  - 497 m^3 – Cement
  - 4,420 m^3 – Drilling Waste
  - 48 m^3 – Hydrovac Material
  - 74 m^3 – Contaminated soil
  - 2,574 m^3 – Well workover fluids

Water & Waste Disposal Wells, Landfill Waste 2014 Annual Waste Disposal Summary (con't)

Canadian Natural

- Waste to RBW
  - 1,219 m^3 – Solid waste – contaminated soils, plastics, filters, asbestos, batteries, glycol, fluorescent tubes, caustics, acid, activated carbon
- Waste to NewAlta
  - 2,423 m^3 – Sludge hydrocarbons and co-emulsion
  - 39 m^3 – Cement
  - 20 m^3 – Drilling waste
  - 3 m^3 – Pigging waste
  - 16 m^3 – Sand
  - 4 m^3 – Contaminated soil
  - 32 m^3 – Waste waters
- Waste to Grizzly Disposal Solutions
  - 6.3 m^3 – Filters
  - 2.6 m^3 – Luboil

Water & Waste Disposal Wells, Landfill Waste
2014 Annual Waste Disposal Summary (con't)

Canadian Natural

- Waste to Tervita Transfer Station
  - 424 tonnes – Sludge hydrocarbons
  - 22 tonnes – Misc waste

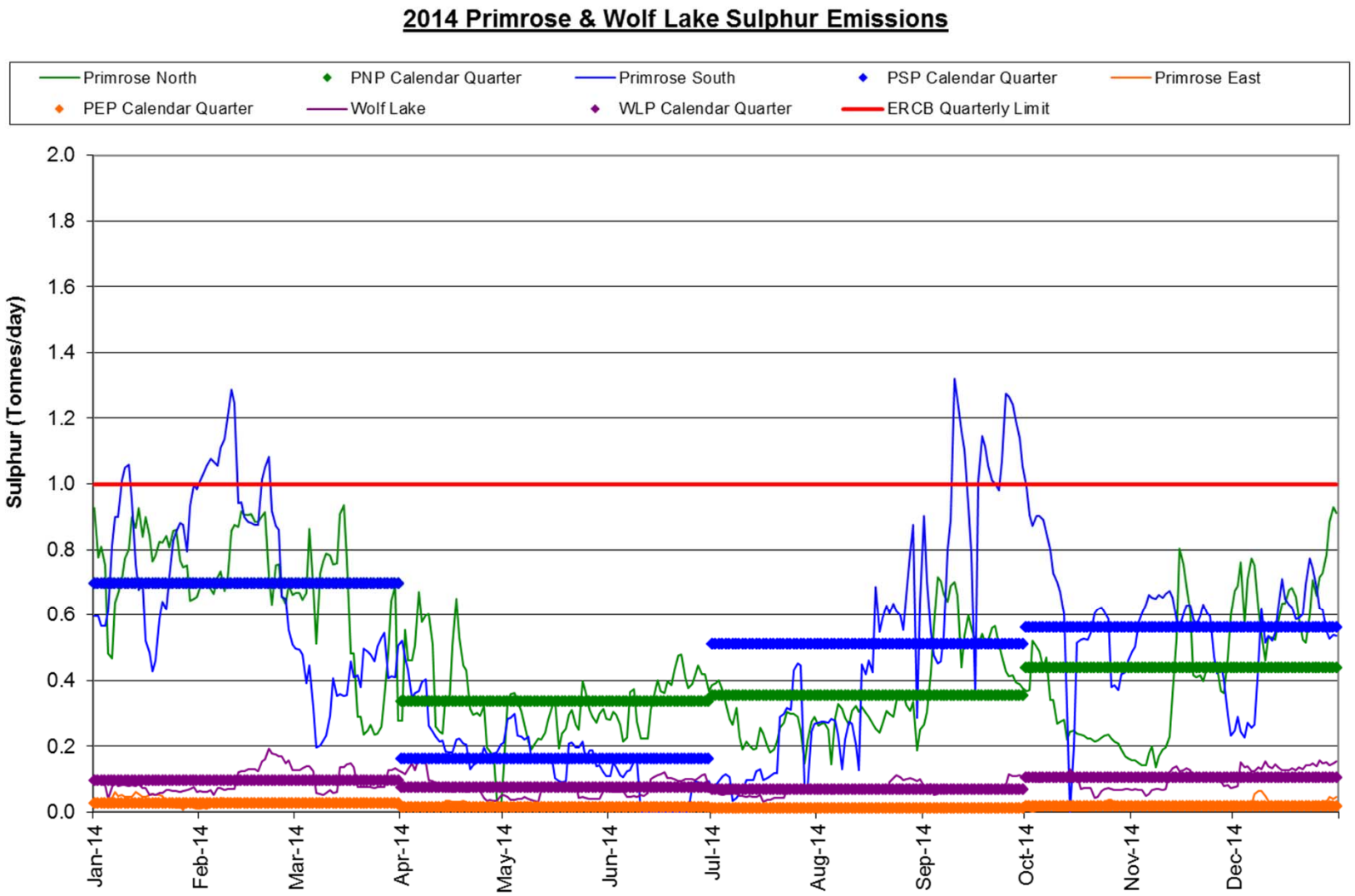
- Waste to Tervita Waste Processing (TRD)
  - 497 m^3 – Cement
  - 74 m^3 – Waste waters
  - 4,420 m^3 – Drilling Waste
  - 48 m^3 – Hydrovac Material
  - 256 m^3 – Sand
  - 7,125 m^3 – Sludge hydrocarbons
  - 74 m^3 – Contaminated soils
  - 2,574 m^3 – Well workover fluids

- Waste to Waste Management Canada
  - 2.6 m^3 – Filters
  - 0.5 m^3 – Luboil

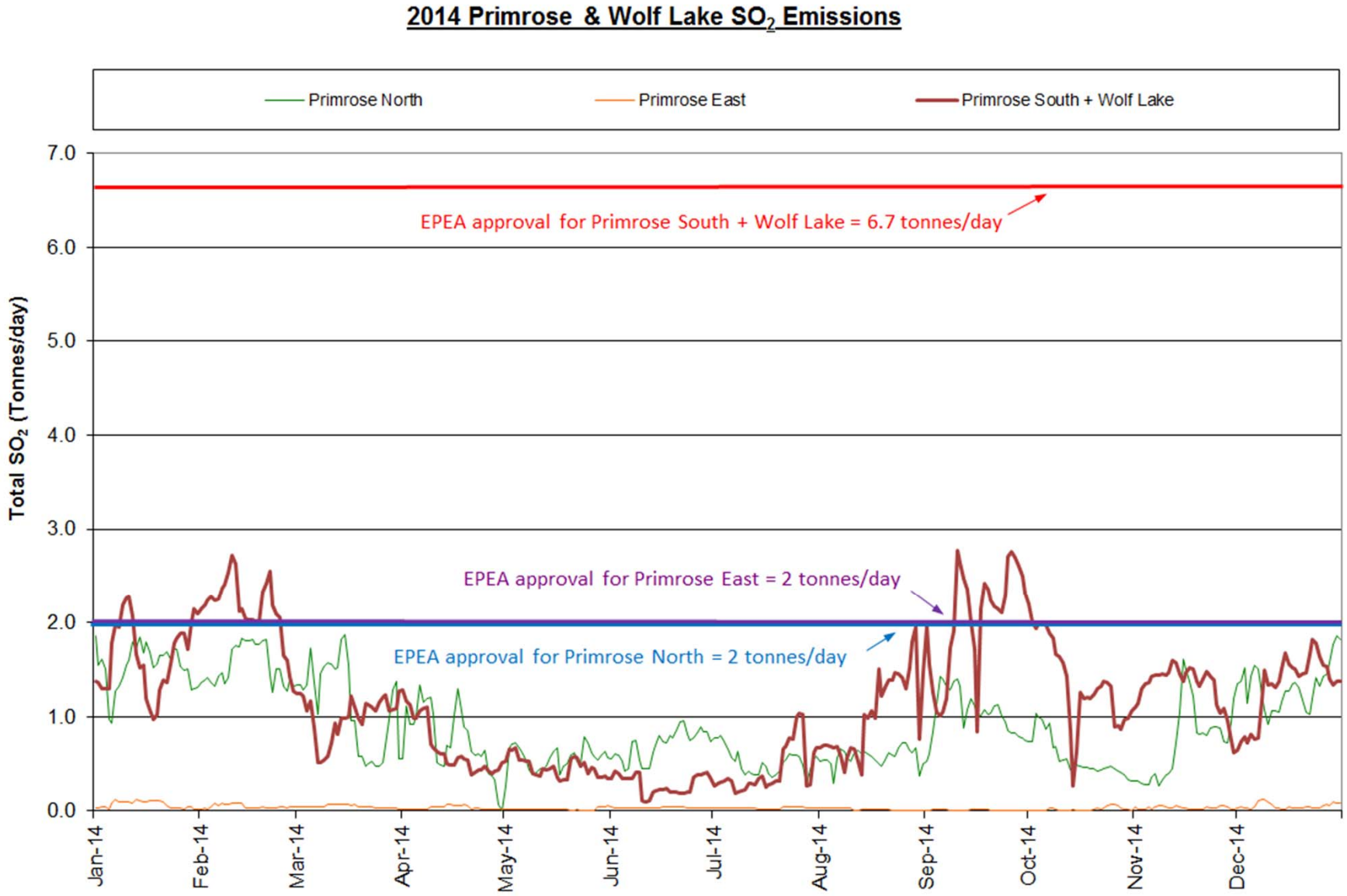
Sulphur Production

- 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 2014 to maintain sulphur levels below the 1 t/d quarterly average
  - Canadian Natural does not plan to install sulphur recovery at this time
- To maintain SO_2 levels below 2 t/d, production from the Primrose North area wells/pads were held back in Q1 and late Q4 2014.
  - 90 m^3/d of bitumen was held back for approximately 30 days due to Primrose North SO_2 limitations

Sulphur Production



SO_2 Emissions



Environmental Summary
Compliance & Amendments

- Primrose and Wolf Lake EPEA Renewal Application was submitted to AER in November 2014

- Compliance Issues
  - EPEA Approval: Air Related
    - There were no SO_2 exceedances in 2014.
    - There were no NOx exceedances in 2014.
    - The months of March and April had less than 90% uptime on the CEMS following a RATA which failed on Bias. Until a second RATA was performed which passed Bias the data from the CEMS was considered to be invalid. (ref no. 283229)
    - Late reporting of the Monthly Air Report Summary for April and May 2014, were not submitted to AER at the end of the month following the month the data was collected All Facilities (ref no. 286913).

Environmental Summary
Compliance & Amendments (con't)

- Compliance Issues
  - Water Related:
    - Failure to comply with start up date of Temporary Diversion License # 00351096. Burnt Lake Plant – Retention Pond. LSD 14-14-67-03-W4M (ref no. 284451).
    - 12 groundwater level measurement were not recorded between May 5 to August 7, 2014 (Licence #00238519)
      - Replacement instrumentation was installed immediately upon discovering

Environmental Summary
Compliance & Amendments (con't)

- Compliance Issues
  - Flow To Surface (FTS) related releases (all reported to AER Bonnyville Office as per Environmental Protection Order and Enforcement Order)
    - April 27, 2014. Off lease spill of gasoline (0.010 m3) into a waterbody. LSD 09-21-067-04-W4M (ref no. 283271).
    - May 16, 2014. Off lease release of surface water (172 m3) into muskeg. LSD 15-01-67-03-W4M (ref no. 284080).
    - May 30, 2014. Off lease release of surface water (32 m3) into muskeg. LSD 15-01-67-03-W4M, 10-01-67-03-W4M & 09-01-67-03-W4M (ref no. 284642).
    - July 18, 2014. Off lease release of surface water (3 m3) into muskeg. LSD 07-22-67-03-W4M (ref no. 520980).
    - July 27, 2014. Off lease release of surface water (40 m3) into muskeg. LSD (ref no. 287382).
  - No surface water was impacted by the above releases. Any erosion caused by the release was immediately repaired.

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 cameras along AGP
    - Thirty remote cameras are deployed along the above-ground pipeline (AGP) and stratified among AGP height categories (<1.0 m to >2.5 m)
      - Cameras record wildlife behaviour near the AGP and can confirm wildlife movement under the AGP
    - An additional 30 remote cameras are deployed along game trails or cutlines near remote cameras located on the AGP
      - These cameras record wildlife occurrence and behaviour as animals approach the pipeline
  - Winter tracking along AGP
    - Two rounds of winter tracking were conducted along the AGP to gather information on wildlife behaviour by noting movement patterns and wildlife behavioural responses (e.g., crossed, deflected, walked parallel) near the AGP.
    - Surveys were completed in February and March 2014, and each covered 22 km of pipeline.

Environmental Summary
Monitoring Programs

- General Wildlife Monitoring
  - Project area winter tracking
    - The survey objective is to document the project's influence on wildlife abundance and occurrence.
    - In total, 55 transects were surveyed in February-March 2014 and 57 transects were surveyed in December 2014.
    - Each transect is 500 m in length and all are stratified along various zones of influence (ZOI), depending on distance from disturbance, based on the following categories: 0-100 m, 101-250 m, 251-500 m, 501-1000 m and > 1000 m from core development.
  - Caribou cameras
    - 41 remote cameras were deployed for an eight week period in spring 2014
    - This represents the last survey period of a 2 year study where cameras have been placed along the Primrose lease boundaries to document caribou movement in and out of the lease.
    - Cameras deployed in 2014 were placed along the eastern and northern boundary of the Project Area in high value caribou habitat.
    - The majority of caribou detections occurred along the northern project boundary in Primrose North.

Environmental Summary
Monitoring Programs

- General Wildlife Monitoring Continued
  - Breeding songbird point counts
    - The survey objective is to document the project's influence on bird species richness and abundance.
    - A total of 60 point counts were surveyed in June 2015.
    - Point counts were placed either within 200 m of core disturbances (i.e., experimental plots) or >500 m from core disturbances (i.e., reference plots).
  - Reporting
    - Data analysis and reporting will occur in January and February 2015.
    - The report produced will consist of a compilation and synthesis of the last 10 years of wildlife monitoring data.

Environmental Summary
Monitoring Programs

Canadian Natural

- Wildlife Habitat Enhancement Program
  - Nest box program
    - 16 bird nest boxes and 2 bat boxes are on site.
    - Two nest boxes showed evidence of bird breeding, including a visual observation of a boreal owl nesting in spring 2014.
    - One additional nest box showed evidence of bird use but no breeding evidence was noted. Two nest boxes had been used by small mammals (squirrel or marten).
    - No bat activity was recorded at the two bat boxes.

Environmental Summary
Monitoring Programs

- Wildlife Habitat Enhancement Program
  - Revegetation program
    - 14 linear feature sites were treated along approximately 4.8 km
      - 13 sites where both site preparation (i.e., mounding) and seedling planting were applied
      - one site where mounding only was applied to control access.
    - 2014 marks the completion of the 2011 HEP plan implementation
      - Since program implementation in 2011, 11.8 km of the 16.2 km of linear features identified as 'available' in the approved habitat enhancement plan (Golder 2011) have been treated.
      - Non-linear features treatments total 0.6 ha of the initial 3.5 ha identified as available in the 2011 plan.
      - Areas identified as 'available' for treatment that have not been treated are no longer available for treatment as they are either under LOCs not belonging to Canadian Natural, have been identified as active areas, or have been incorporated into the current Project footprint.
      - Eight sites were visited to monitor seedling survival (planted seedling survival after three growing seasons was 91%, and survival after one growing season was 100%).
    - Next step: remote cameras will be deployed on treated sites and on comparable reference sites with no treatments to compare human and predator use.

Environmental Summary
Monitoring Programs

- Hydrology, Wetlands and Water Quality Monitoring Program 2014
  - Wetland Monitoring Component
    - Preliminary observations indicate that there were only minor differences in overall species richness among monitoring and reference sites compared to previous years.
    - Complete report comparing results since start of program (2007) will be prepared in 2015.
  - Hydrology Monitoring Component
    - All lakes appeared to exhibit hydrological regimes similar to those of past years.
    - Lake levels were typically dominated by spring runoff events and various precipitation.
    - Complete report comparing results since start of program (2007) will be prepared in 2015
  - Water Quality Component
    - Based on results from Burnt Lake and Sinclair Lake there were no large deviations observed in the analytical results when compared with those from previous years.

Environmental Summary
Reclamation Programs

Canadian Natural

- Reclamation activities in 2014:
  - Re-vegetation Program consisted of reforesting 7.2 ha
  - Approximately 22,310 tree and shrub seedlings were planted.
    - Planting on borrows accounted for 6.2 ha
      - total of 20,910 tree and shrub seedlings
    - In-fill planting on borrows and clearings accounted for 1.0 ha
      - 1,440 tree and shrub seedlings.
  - 2,480 Seedlings were planted on 2.36 ha for the Habitat Enhancement Program.

- Proposed activities in 2015:
  - Reforestation of 28.52 ha of borrow pits in Primrose North.
  - Infill Planting on 1.8 ha in Primrose East

Environmental Summary
Regional Initiatives

- 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.
  - 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)
  - 2014 was the first year LICA's activities were planned and funded through the newly created arms-length Alberta Environmental Monitoring Evaluation and Reporting Agency (AEMERA)
  - AEMERA-ESRD audited the LICA stations and air monitoring program in April 2014
    - No major failures were found and opportunities for improvement were identified

Environmental Summary
Regional Initiatives

- Beaver River Watershed Alliance (BRWA):
  - The Beaver River Watershed Alliance (BRWA) serves as the Watershed Planning and Advisory Council (as set out by Alberta Environment and Sustainable Resource Development) for the Beaver River watershed.
  - The BRWA has completed their State of the Watershed Report which provides a snapshot of regional watershed health and has begun developing the Watershed Management Plan as part of Alberta's Water for Life Strategy.
  - The BRWA has recently become engaged in discussion with JOSM representatives.
  - Their Education and Outreach Coordinator, continues to build relationships and implement training programs in the community.

Environmental Summary
Arsenic Mobility Investigation

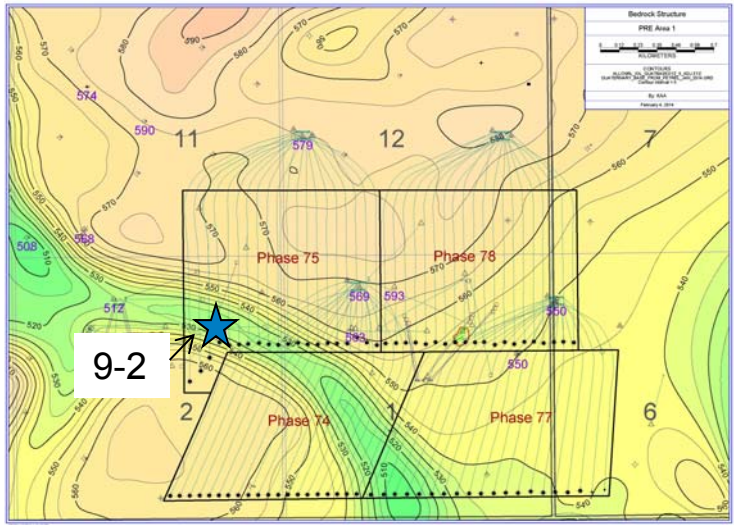
Canadian Natural

- 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-four 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.
- Research Program Highlights from 2014
  - 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 (no steam since 2005).
  - Additional Sand River aquifer monitoring well installed and included in research program.

Environmental Summary
Groundwater Monitoring and Management

- EPEA Groundwater Monitoring Programs
  - Completed as per terms and conditions outlined in EPEA Amending Approval 11115-03-04, Section 4.6 and Table 4.7-A
    - shallow groundwater monitoring at plant facilities
    - deep groundwater monitoring of source, on-pad and regional monitoring wells
  - Additional deep wells added to regional monitoring network including into the Muriel Lake aquifer at 9-2-67-3W4

- 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

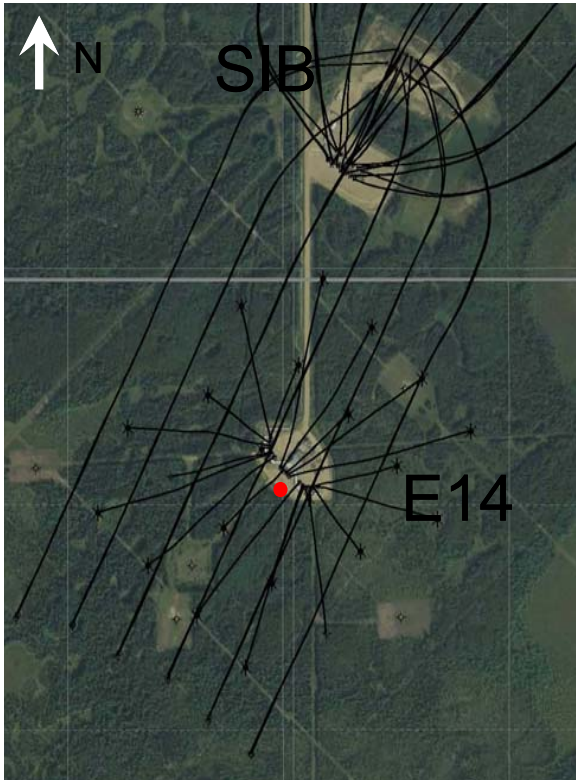
- Primrose Flow to Surface (FTS) sites (2-22, 10-2, 10-1 and 9-21)
  - Groundwater investigation drilling activities commenced in February 2014.
    - 99 boreholes drilled with 76 monitoring wells installed.
  - A groundwater monitoring program was initiated including monthly monitoring, sampling and reporting.
- Pad 74 Risk Management Plan
  - On-going application of the Pad 74 Risk Management Plan including monitoring, sampling and monthly reporting.
  - Monitoring and sampling results are reported annually to AER via EPEA Approval since March 2012.
- Groundwater monitoring results indicate very limited subsurface impacts associated with FTS.

Environmental Summary
Groundwater Monitoring and Management

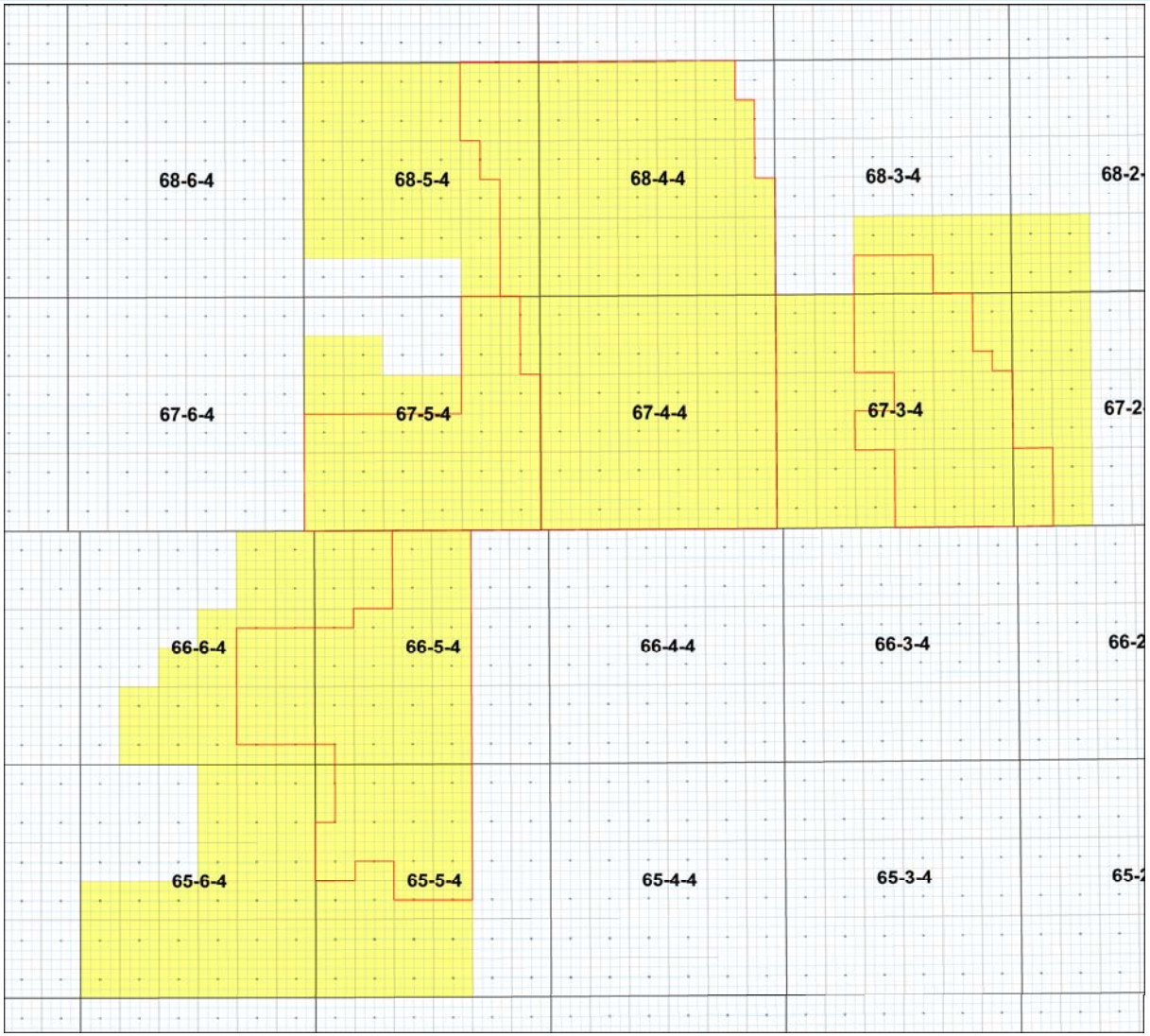
- Pad Z13 – Wolf Lake
  - Elevated levels of hydrocarbons were detected in a deep underground aquifer from a new monitoring well. This data was reported to the AER on October 29, 2014.
  - Canadian Natural will continue to work closely with the AER to monitor and assess the elevated levels from this incident. A plan will be developed to ensure that we minimize any further environmental impact of this situation.

Environmental Summary
Groundwater Monitoring at E14 Pad

- A groundwater monitoring well was installed at E14 Pad (16-32-065-05W4M) as per the amendment to the Commercial Scheme Approval 9140I for SIB Pad
  - Installed to monitor changes in the basal quaternary aquifer associated with SIB operation
  - Completed into basal Muriel Lake aquifer (121 to 127 m below ground surface)
  - No anomalous water levels or chemistry data (comparable to regional monitoring of Muriel Lake Formation)
  - In-situ groundwater temperatures remain stable



Approval 9140U – Oil Sands Primrose Wolf Lake

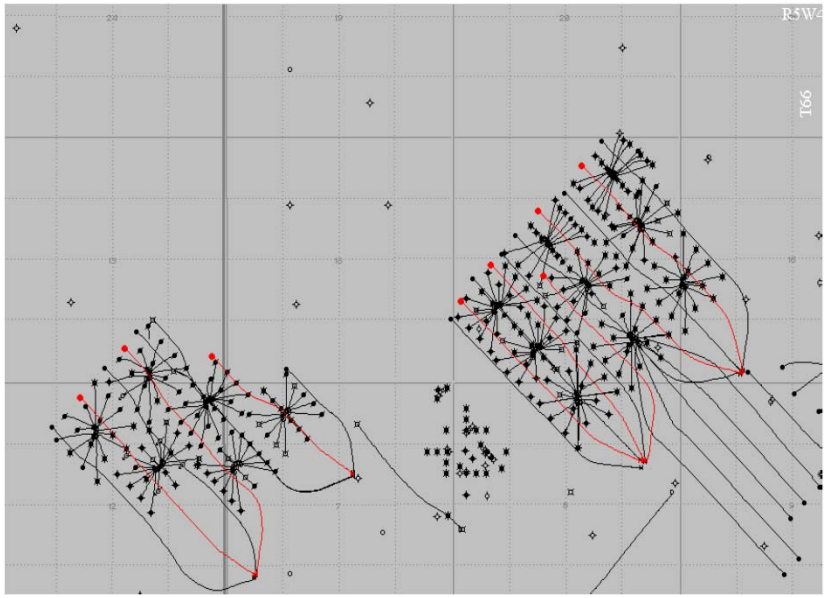


Approval 9140U – 2014 Amendments

- Amendment S - Approved January 2014
  - Approval for S1B SAGD Phase operating pressure amendment
- Amendment T - Approved September 2014
  - Approval for operation of Primrose East Area 1 Steamflood
- Amendment U - Approved October 2014
  - Approval for S1A SAGD Phase infill and step out well pairs

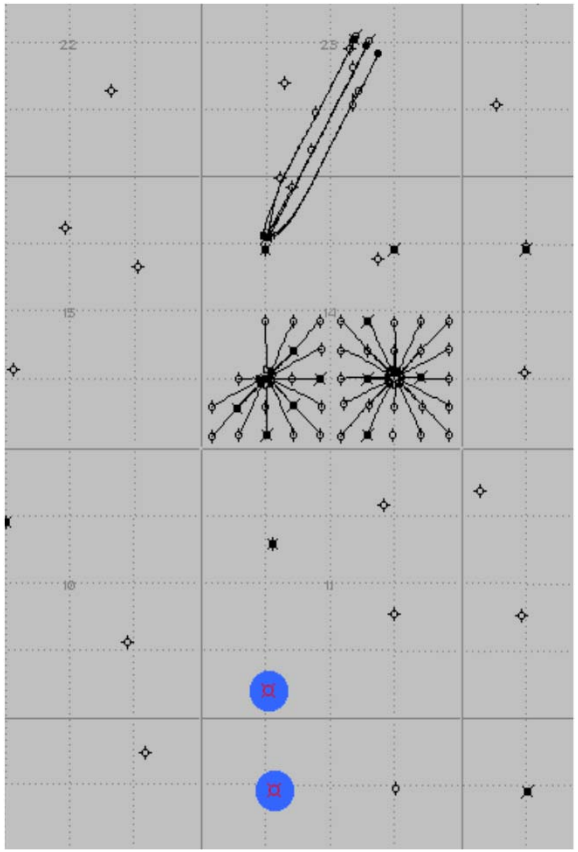
Approval 9108 – Wolf Lake Water Storage Approved July 2002

- Annual Report
  - (a) Summary of monthly injected and produced volumes/well
  - (b) Well/Formation Integrity
  - (c) Reservoir Water Storage remaining
  - (d) Water Balance, Bitumen Volumes and Incremental Recovery
  - (e) Overall performance and 2015 plans
  - (f) Discussion of produced water utilization & fresh water reductions



Approval 8186A – Burnt Lake Water Disposal Approved February 1999

- 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



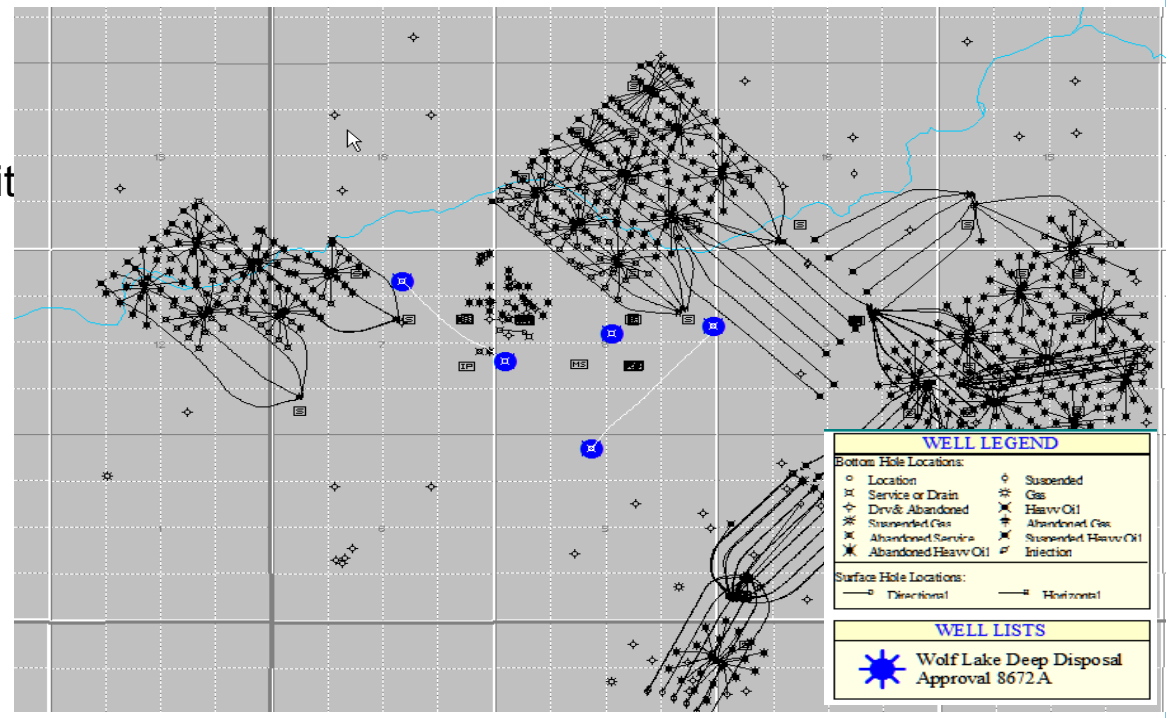
Approval 8186A – 11-02-067-03 W4 Disposal Well

- 11-02-067-03W4 Well History:
  - 1995 - Drilled as a McMurray water source well (open hole)
  - 1997 - converted to a water disposal well
  - 1999 - approval to inject at parting pressure
    - Total water injected= 1,636,000 m3 of water was injected. (~360,000 m3 water prior to high pressure approvals) injected (~1,276,000 m3 water after parting pressure approval).
  - 2007 - lack of annular isolation noted during routine test.
  - 2007 to 2010 - numerous remedial work done on the well.
  - 2012 – Suspended well.
    - Set WR plug @ 466.4 m. Pressure tested plug to 7.5 Mpa and held. Place 4 m of sand on plug and circulated wellbore over to inhibited water with a diesel cap.

- Canadian Natural plans to work in conjunction with the AER to move this well from a suspended to abandoned state

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
    - Disposal system modifications in progress to prevent this from occurring
  - Annual Report
    - 2014 Report will be prepared following annual cavern sounding

- Salt Cavern 1 – 118/12-8-66-5W4
  - Cavern volume (as of April 2014 sounding) 195,636 m^3
  - Wash water 315 m^3
    - Cavern wash water is sent to disposal wells
  - Oily waste (bitumen) 78 m^3
  - Solid waste 0 m^3
  - Next Cavern sounding expected in April 2015

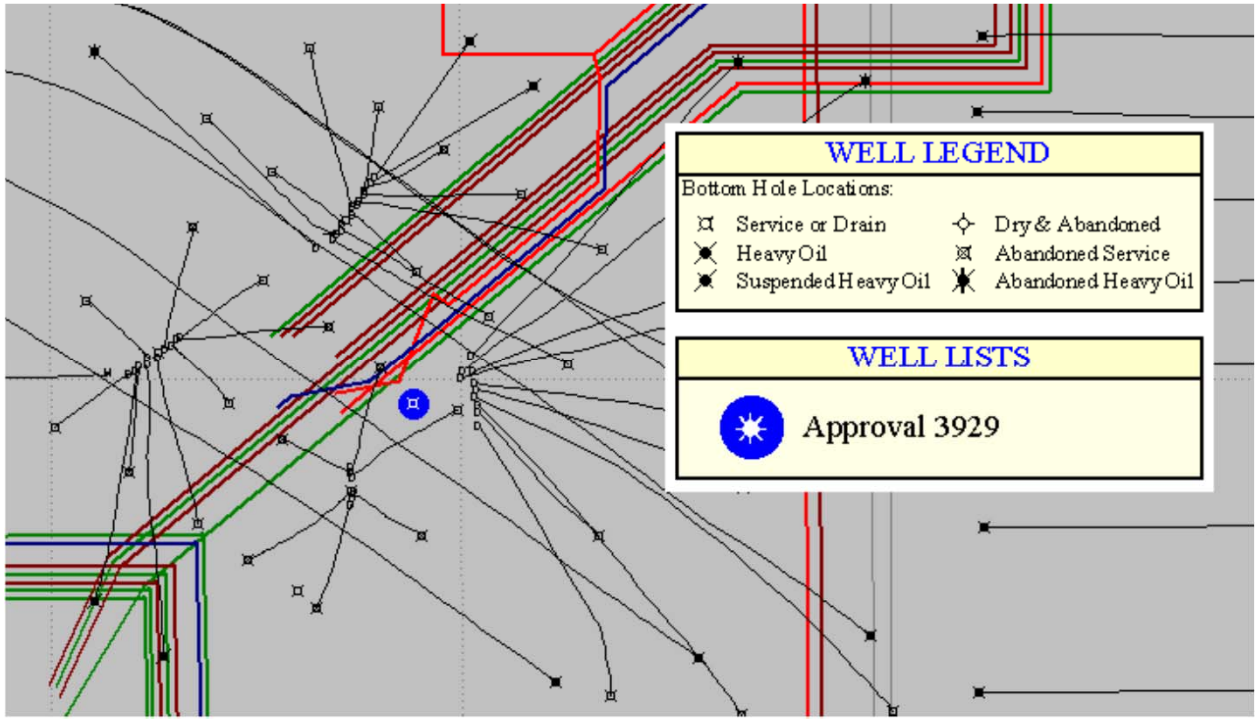
*Note: all salt cavern volumes are from sounding to sounding.

Approval 8673 – Cavern Disposal
Approved October 2000

- Salt Cavern 2 - 119/12-8-66-5W4 – Washing Only
  - Cavern volume (as of April 2014 sounding) 55,905 m^3
  - Wash water 17,922 m^3
    - Cavern wash water is sent to disposal wells
  - Next Cavern sounding expected in April 2015

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
  - 29 reportable spills were reported in 2014 including; 3 emulsion, 7 boiler feedwater, 1 gasoline, 1 granular salt, 1 hydraulic oil, 1 sales oil, 1 brackish water, 6 produced water, 7 non-saline water and 1 hydrochloric acid.
- Digital Data Submissions (DDS)
  - Notifications/Submissions were entered into the DDS as per Directives in 2014.

Compliance Disclosures

- Self Disclosures
  - S1B SAGD phase thermal compatibility commitments
    - Low risk gas wells were not zonally abandoned prior to steaming operations. These wells will be zonally abandoned by March 31, 2015
  - Clearing outside of approval area 2-22 FTS site
    - Surveying error lead to clearing outside approved area for installation of groundwater monitoring wells
  - Construction of unlicensed facilities associated with Phases 40-43
    - Facilities proceeded to construction without D56 facility licences. Construction activities were shut down until all licences were acquired
  - Commissioning cycle steaming Phase 41
    - +10% volume per well limit was exceeded on five wells
  - Water Imbalance > 5% for three consecutive months (March/April/May 2014)
    - Further review indicated that the Unit 2 ORF vortex meter was calibrated for a 8” line instead of a 6” line, thereby increasing the water volumes. Once the volumes are back corrected, the three months will be in compliance
  - Water Imbalance > 5% for three consecutive months (Oct/Nov/Dec 2014)
    - The high water imbalance for the months of November and December is partially attributed to Wolf Lake Plant pond runoff water metering malfunction. Once the volumes are back corrected, the two months will likely be in compliance

Compliance Disclosures

- Non-compliance
  - WSW 122
    - AER assessment determined Canadian Natural failed to meet the requirements of Directive 009: Casing Cementing Minimum Requirements.
    - In response to the high-risk non compliance, two new procedures were established (AER Reporting Matrix and Thermal Cement Returns Procedure)
      - Procedures were provided to AER on October 14, 2014.
      - With the new procedure, and the successful remediation of WSW122, the non-compliance has been closed.

Future Plans

- PAW Plant Control System & Electrical Upgrades
  - U9 and U1 DCS upgrades planned for 2015
  - PSP steam gen control upgrades
  - Burnt Lake HMI upgrade
- Wolf Lake Produced Water Debottlenecking
  - Upgrades planned to U8, U10, the U8 glycol system, and M2 storage system to increase the Wolf Lake water handling capability
- Wolf Lake U2/U8 Desand System
  - Tank replacement project
- Wolf Lake U10 Interface Upgrades
  - Installation of Nuclear Multiport density arrays in U10 vessels
- Wolf Lake Electrical Substation Expansion
  - Expansion of the electrical substation to support development

Future Plans

- Saline Water Expansion
  - Execution of the new road/pipeline/well development
- Primrose East Heat Integration
  - Install new exchanger for additional cooling associated with steamflood
- 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, the construction and future operations of the North West Redwater bitumen upgrader and refinery and disclosures relating to the Devon Canada Asset acquisition 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, 2013 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"), 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, 2013 and a preparation date of February 3, 2014. 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. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 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 targeted to be released in late March 2013

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, 2012. 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.

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 "Financial Highlights" 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.

PROVEN | EFFECTIVE | STRATEGY

THE PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.

Canadian Natural

PREMIUM VALUE, DEFINED GROWTH, INDEPENDENT.