Canadian Natural

APPLICATION REGISTERED

December 18, 2013

Application No. 1783161

OIL SANDS AND COAL MINING BRANCH

December 17, 2013

Alberta Energy Regulator
Suite 1000, 250 – 5 Street SW
Calgary, Alberta, T2P 0R4

Attention: **Andrew MacPherson**
Via e-mail: Andrew.MacPherson@aer.ca

Re: Steaming Restriction Canadian Natural Resources Ltd Primrose East Thermal Operations
Location: 067-03W4M
FIS Incident No.: 20131016 and 20131126
AER Scheme Approval No. 9140

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1 Introduction

Pursuant to the Alberta Energy Regulator's letter dated 14 June 2013, File No. 4010, Canadian Natural Resources Limited (Canadian Natural) is requesting the Alberta Energy Regulator (AER) to approve a change to the recovery process for Primrose East Phases 74, 75, 77, and 78 (PRE A1 in Figure 1.1a) as indicated in the original Primrose East Application No. 1442966 (2006). The proposed recovery process is a low pressure resource recovery strategy since current depletion levels of PRE A1 are sufficient to warrant a transition from single-well Cyclic Steam Stimulation (CSS) to a multi-well steamflood follow-up process (FUP). This application is consistent with an AER Directive 078 Category 2 Amendment as the proposed operating strategy modifications will result in changes to the resource recovery process with no adverse environmental impacts. Furthermore, the transition to low pressure FUP will not increase the surface footprint as additional clearing of vegetation or stripping of soil is not required. This application is not a Category 3 amendment because the proposed resource recovery process will not result in an adverse and material change to the environmental or socioeconomic impacts predicted and assessed in previous applications.

The initial phase of Canadian Natural's Primrose East development, PRE A1, is characterized by high resource quality and high thermal efficiency. The objective of the modified resource recovery strategy is to recover crude bitumen at reservoir pressure levels which prevent flow to surface or flow into a fresh water aquifer through any potential conduit within PRE A1. This will eliminate the risk of groundwater contamination from steaming operations. Canadian Natural proposes to achieve this objective by adopting a continuous injection-production operating strategy with dedicated injection and production wells, similar to the steamflood strategy being trialled at the Primrose South D1 (PRS D1) location as described in AER Application No. 1717587 (2012).

1.1. Request for Approval

Canadian Natural is requesting approval to commence steam injection into as many as 40 horizontal wells located on four heavy oil pads within Township 067 Range 03 W4M more specifically on Phases 74, 75, 77 and 78 as detailed in Figure 1.1b.

Under the proposed operating strategy, steam injection would be subject to a well specific maximum bottomhole pressure (BHP) constraint ranging from 3.9-4.4 MPa based on a minimum overburden thickness between the top of the Clearwater reservoir sand and the base of the deepest non-saline aquifer ranging from 315-390 m across PRE A1, plus a conservative quaternary pore pressure gradient of 6 kPa/m. Target injection rates would range from 800-1500 m^3/d per well during the initial fill-up phase as

BHP rises from current levels below 1.0 MPa toward the well specific limit followed by a reduction to 200-800 m^3/d per well once the BHP limit is reached and injection rates become controlled by existing levels of interwell communication initially and by artificial lift capacity eventually.

Canadian Natural's amendment request demonstrates how all identified risks relating to steamflood operations are reasonably mitigated.

A summary of Canadian Natural's oil sand and P&NG rights within the area surrounding the Primrose East Project is provided in Figures 1.1c and 1.1d.

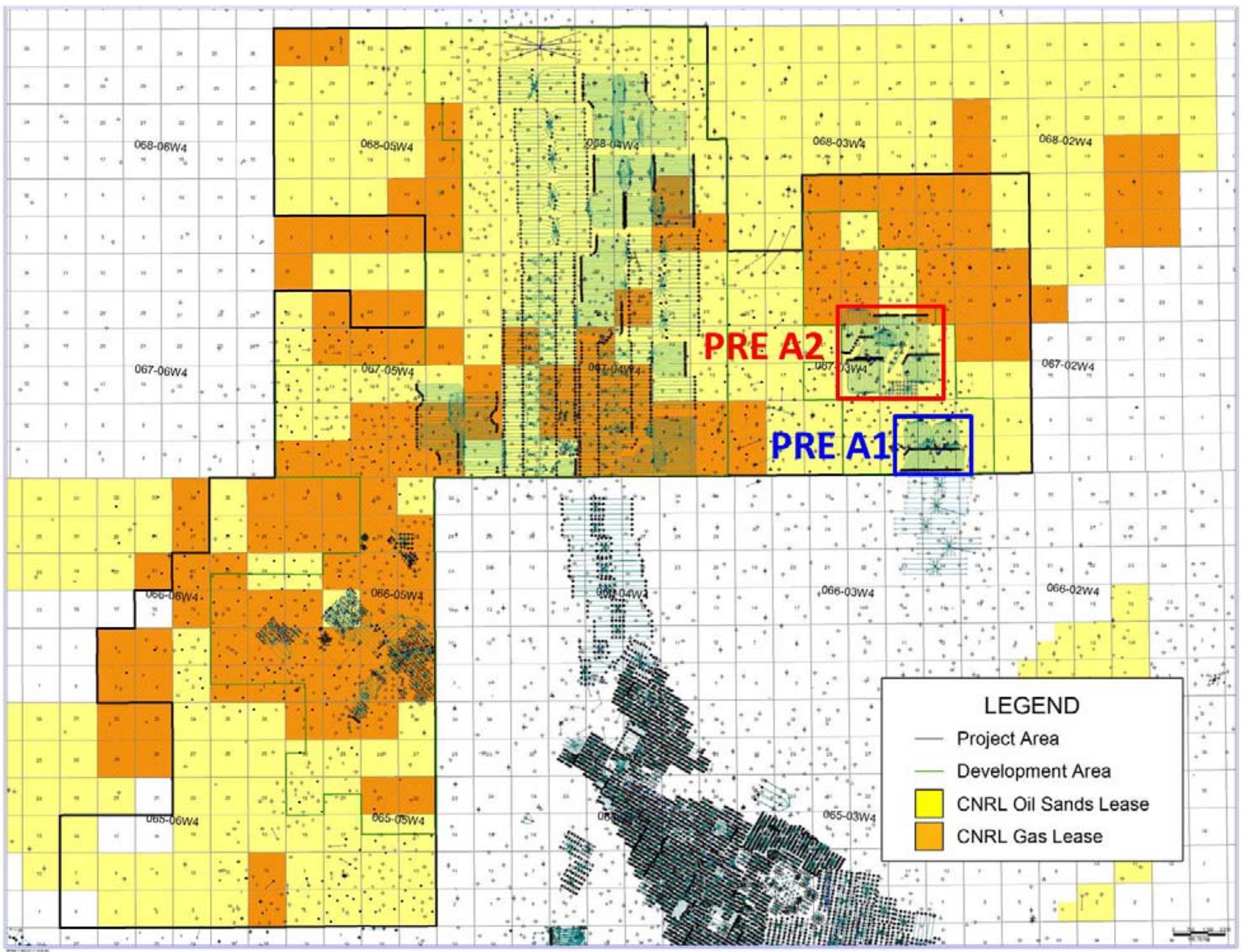


Figure 1.1a Primrose and Wolf Lake Commercial Oil Sands Project

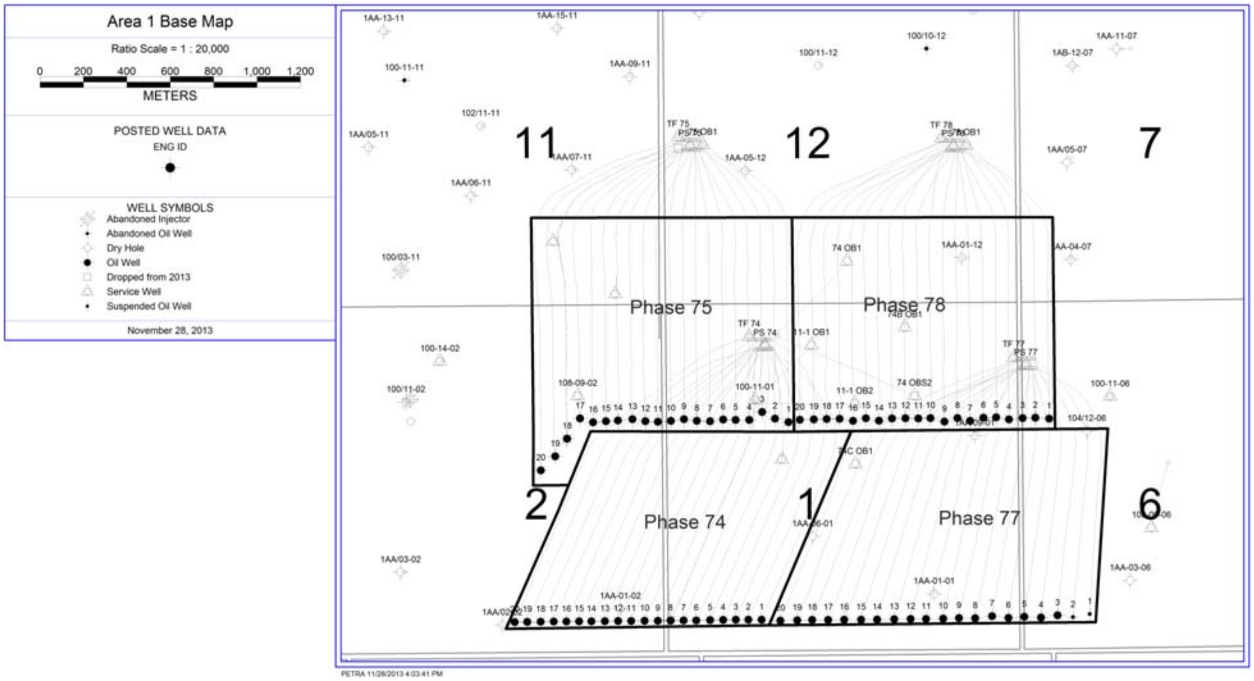


Figure 1.1b Detailed Map of PRE A1 Wells

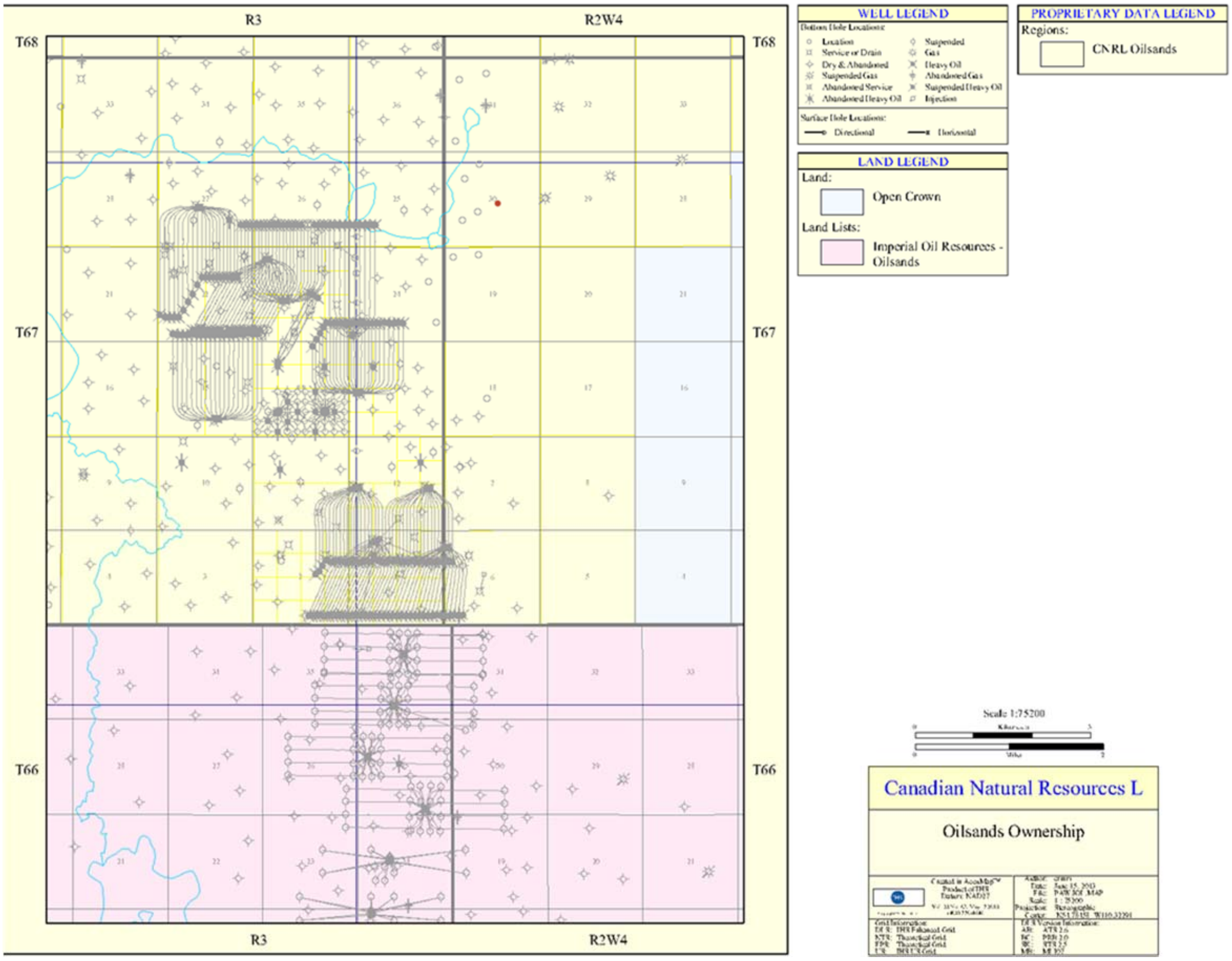


Figure 1.1c **Oil Sand Lease Holders within the Primrose East Area**

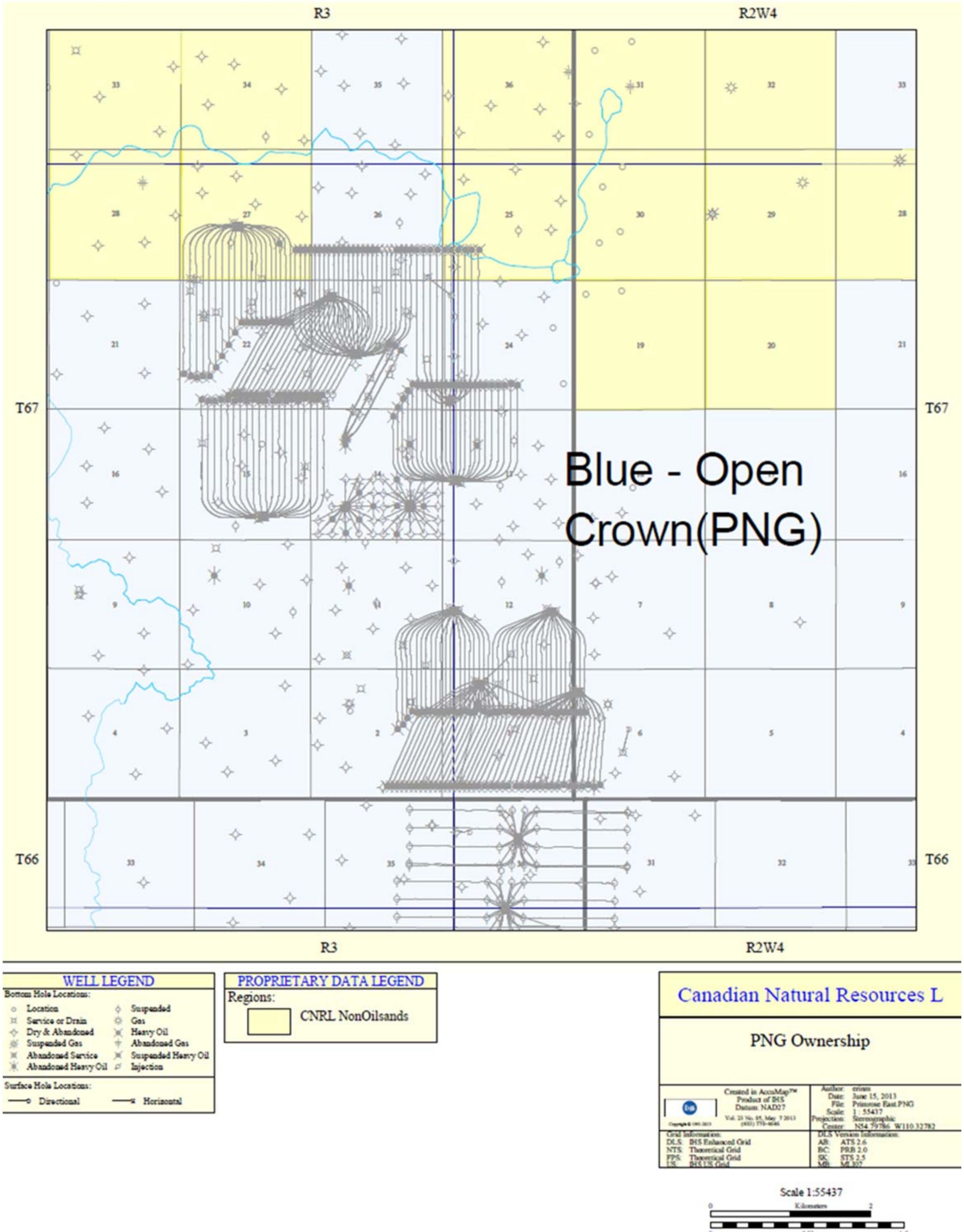


Figure 1.1d P&NG Lease Holders within the Primrose East Area

2 Geological and Reservoir Data

A geologic summary of the Primrose and Wolf Lake (PAW) region and the Primrose East area has been provided in Application 1442966 (2006) and Application 1649421 (2010) submitted for development approval of the Primrose East Expansion Project and Primrose East Phases 90-95 (PRE A2 in Figure 1.1a) respectively. The following sections summarize the information presented in that document.

2.1. Clearwater Geology

The Clearwater Formation in the PAW region consists of a number of distinct valley systems incised into regional strata and one another (Figure 2.1). Primrose East (Yellow Sand) is one such incised valley system consisting of two distinct cleaning upward fill successions, the younger of which eroded and replaced much of the older system on the eastern (thickest) part of the valley (see inset).

2.2. Clearwater Structure

The Cretaceous strata in Primrose East were deposited through a period of time when salt dissolution at depth was actively occurring. This process is likely the main control on the location and orientation of the Yellow Valley. Structure on the base of pay is considerable (>50 m) and reflects the erosional nature of the valley system superimposed on the ongoing salt dissolution (Figure 2.2a). The structure at the top of the Clearwater Formation (Figure 2.2b) illustrates the degree of post-depositional collapse as this surface is regional in nature, and would have been flat at the time of deposition.

2.3. Clearwater Pay

The net pay of the Yellow Valley consists of a combination of facies with less than 10% mud interbeds and with average bitumen saturation equal to or greater than 9% by weight (Figure 2.3). There are a number of small gas caps found in structural highs in the Clearwater while no bottom water exists at the base of the Clearwater in Primrose East.

2.4. Clearwater Capping Shale

The most immediate barrier to vertical fluid propagation in the Primrose East area is the Clearwater capping shale, which directly overlies the Clearwater reservoir. This is a regionally continuous, marine shale deposit that is present throughout the PAW area (Figure 2.4).

2.5. Grand Rapids

The Clearwater succession is overlain by a thick succession of Grand Rapids strata (Figure 2.5) consisting of a stacked sequence of prograding shoreface strata cut at various levels by channel incisions. Along the eastern edge of Primrose East, salt dissolution at depth has focused these channels such that little of the regional strata are preserved.

2.6. Colorado Group

The Colorado Group is a thick succession of marine shale deposits approximately 165 -180 m thick (Figure 2.6a). Structure at the top of the Colorado (Figure 2.6b) continues to show the imprint of salt dissolution at depth although the anticline is much more subdued due to the infilling of the low over time by the older Cretaceous strata.

This strata is finally overlain by the shales of the Lea Park, which form the bedrock in Primrose East.

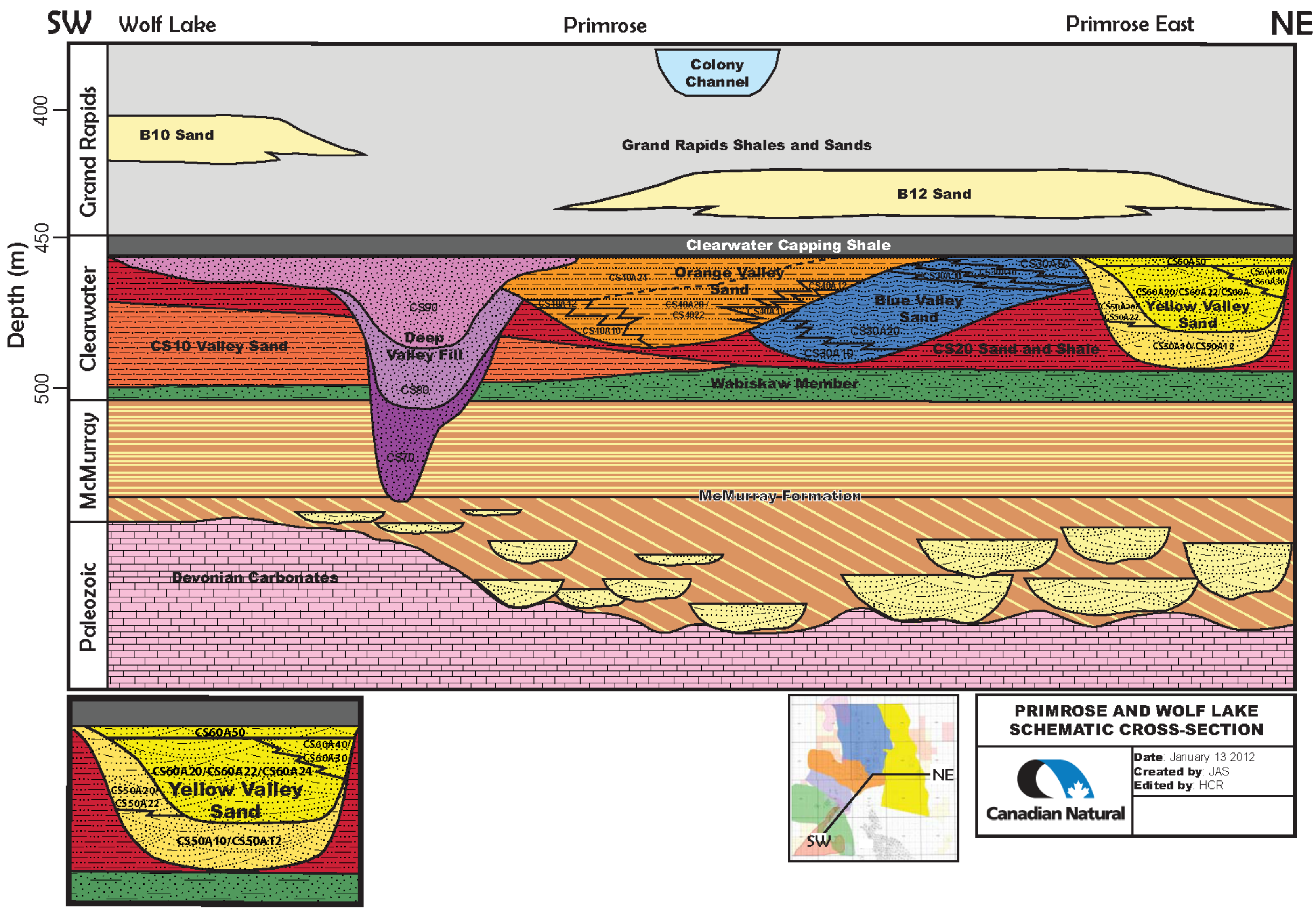


Figure 2.1 **Primrose and Wolf Lake Schematic Cross-section and Yellow Sand Detail**

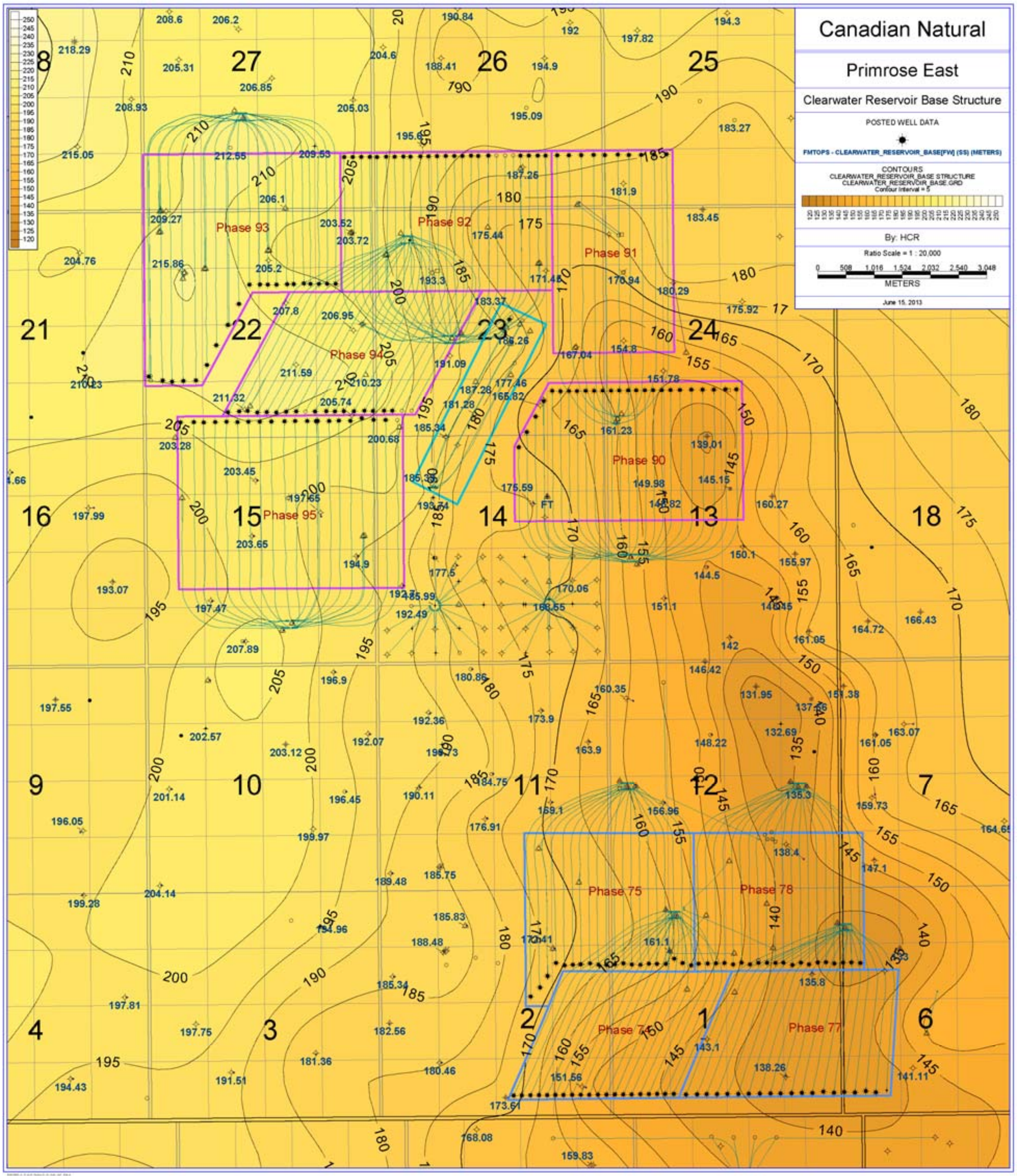


Figure 2.2a Clearwater Formation Base of Net Pay Subsea Structure

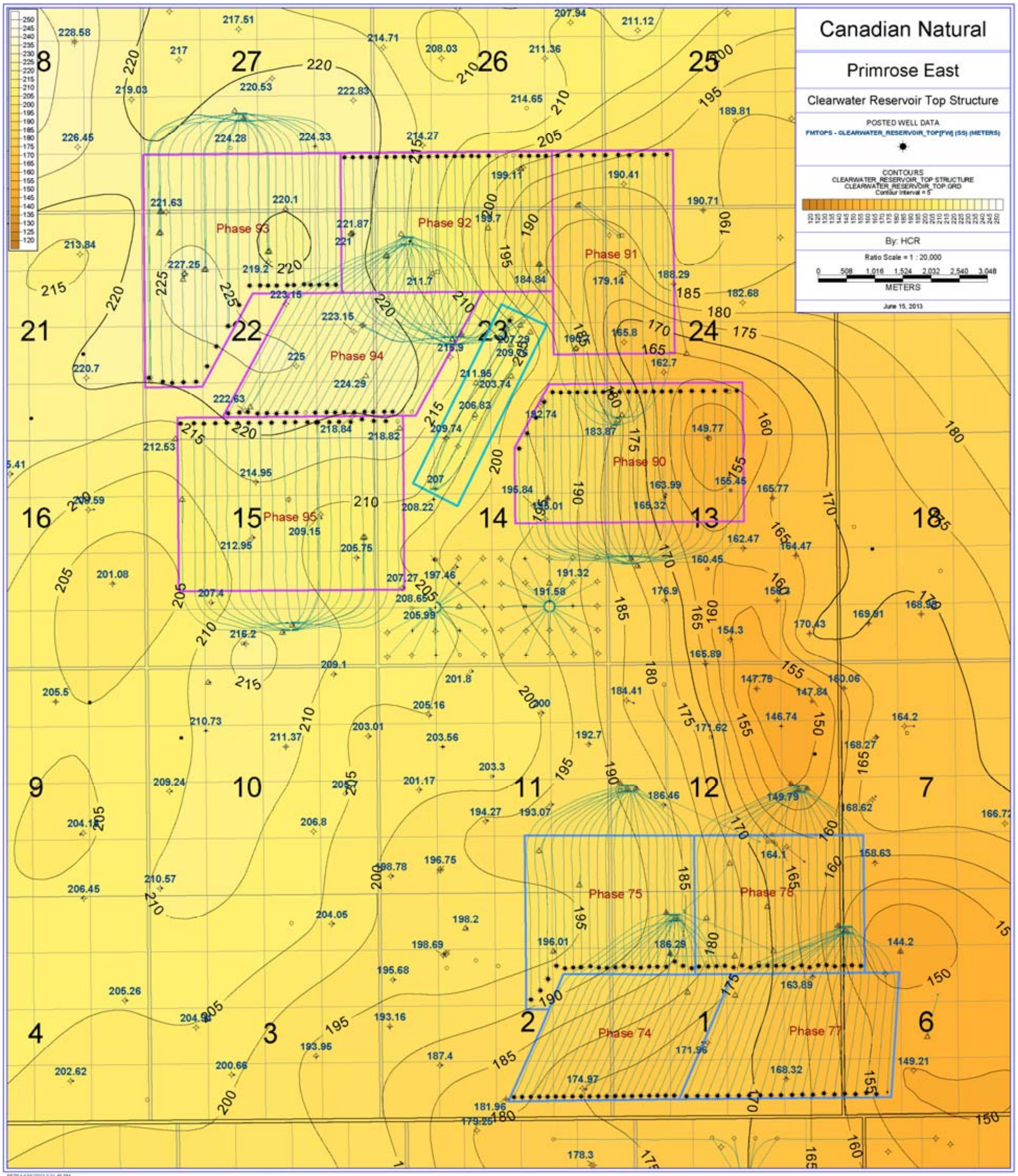


Figure 2.2b Clearwater Formation Top of Net Pay Subsea Structure

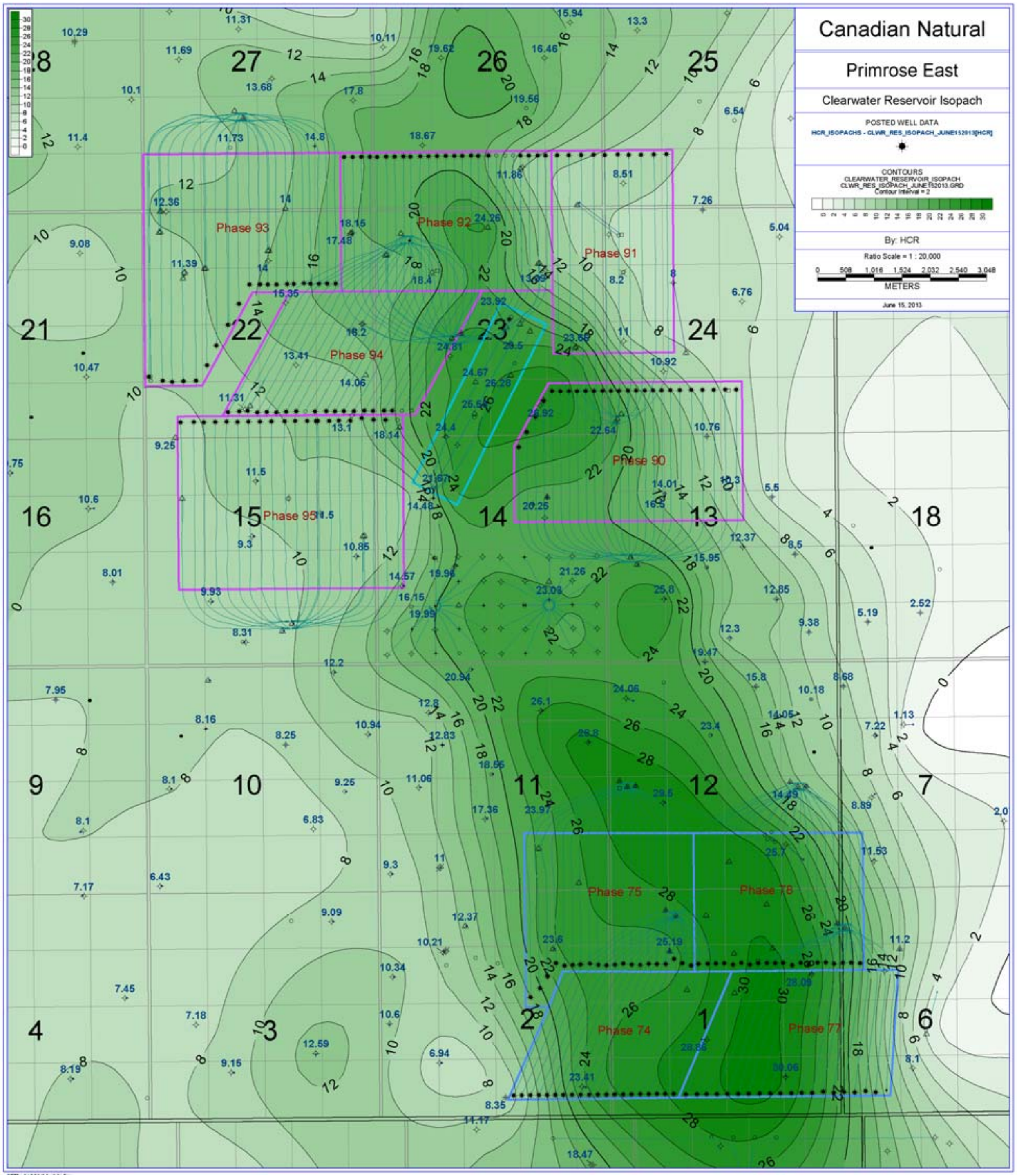


Figure 2.3 **Clearwater Formation Net Pay Isopach**

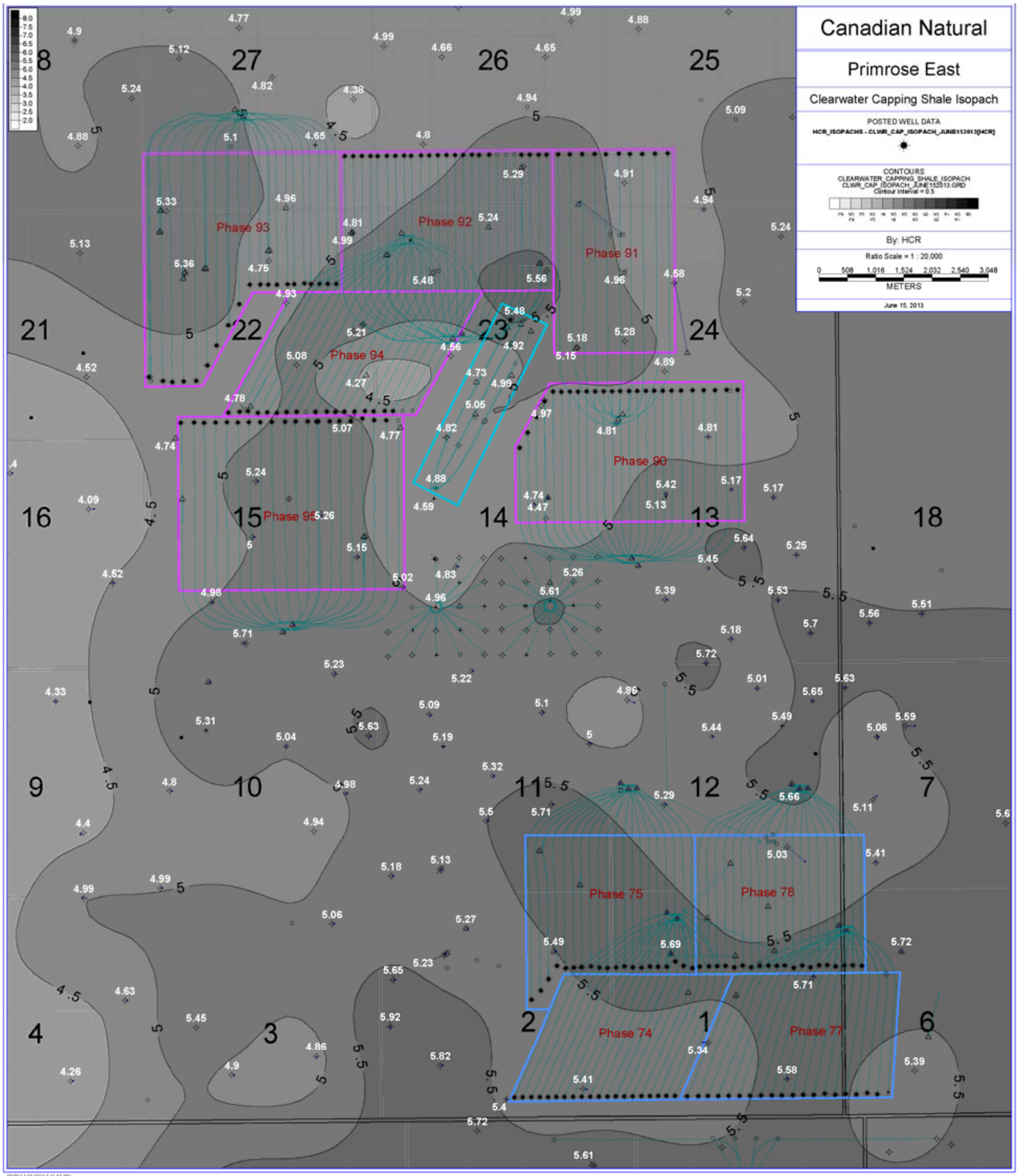


Figure 2.4 **Clearwater Capping Shale Isopach**

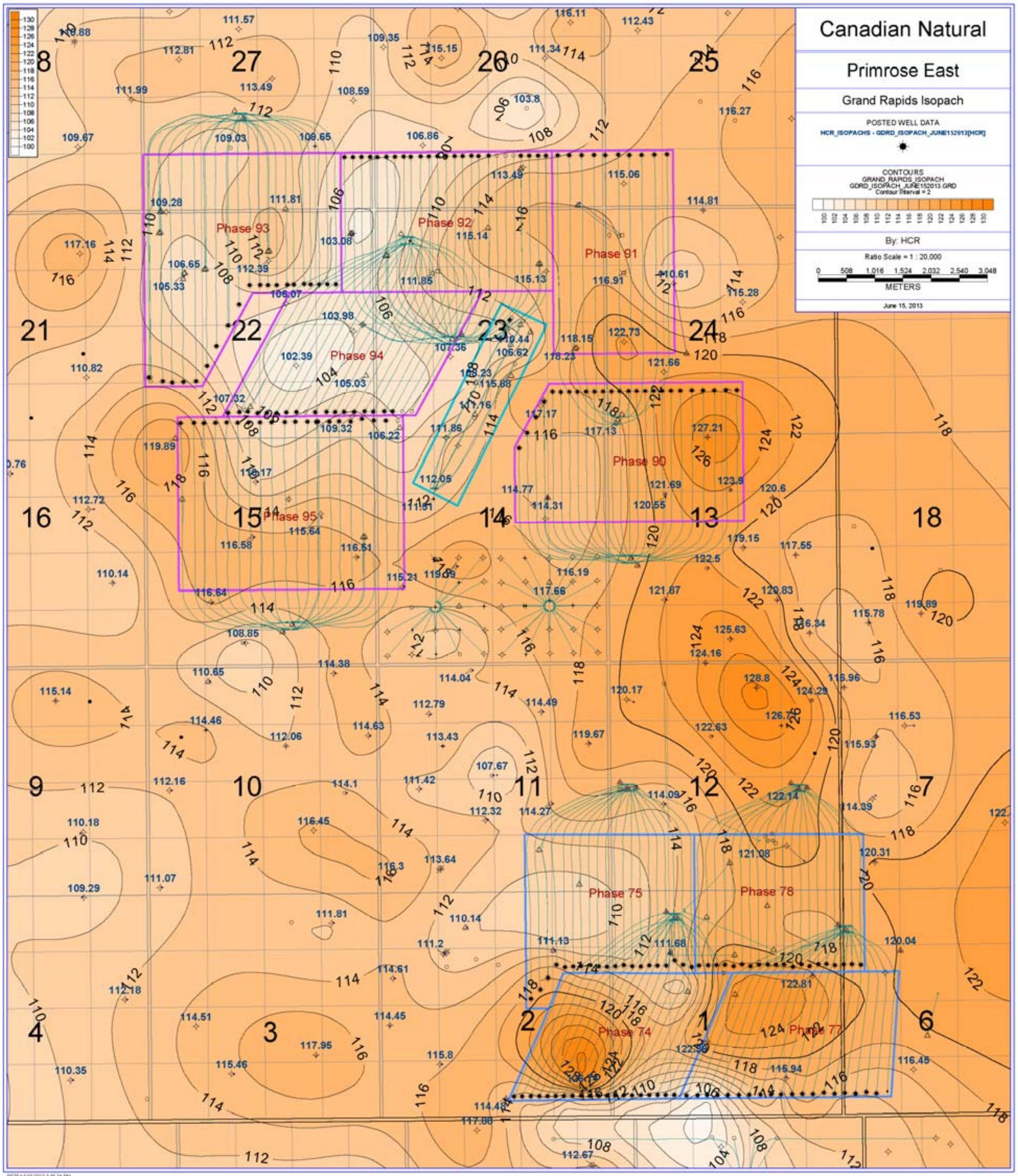


Figure 2.5 Grand Rapids Formation Isopach

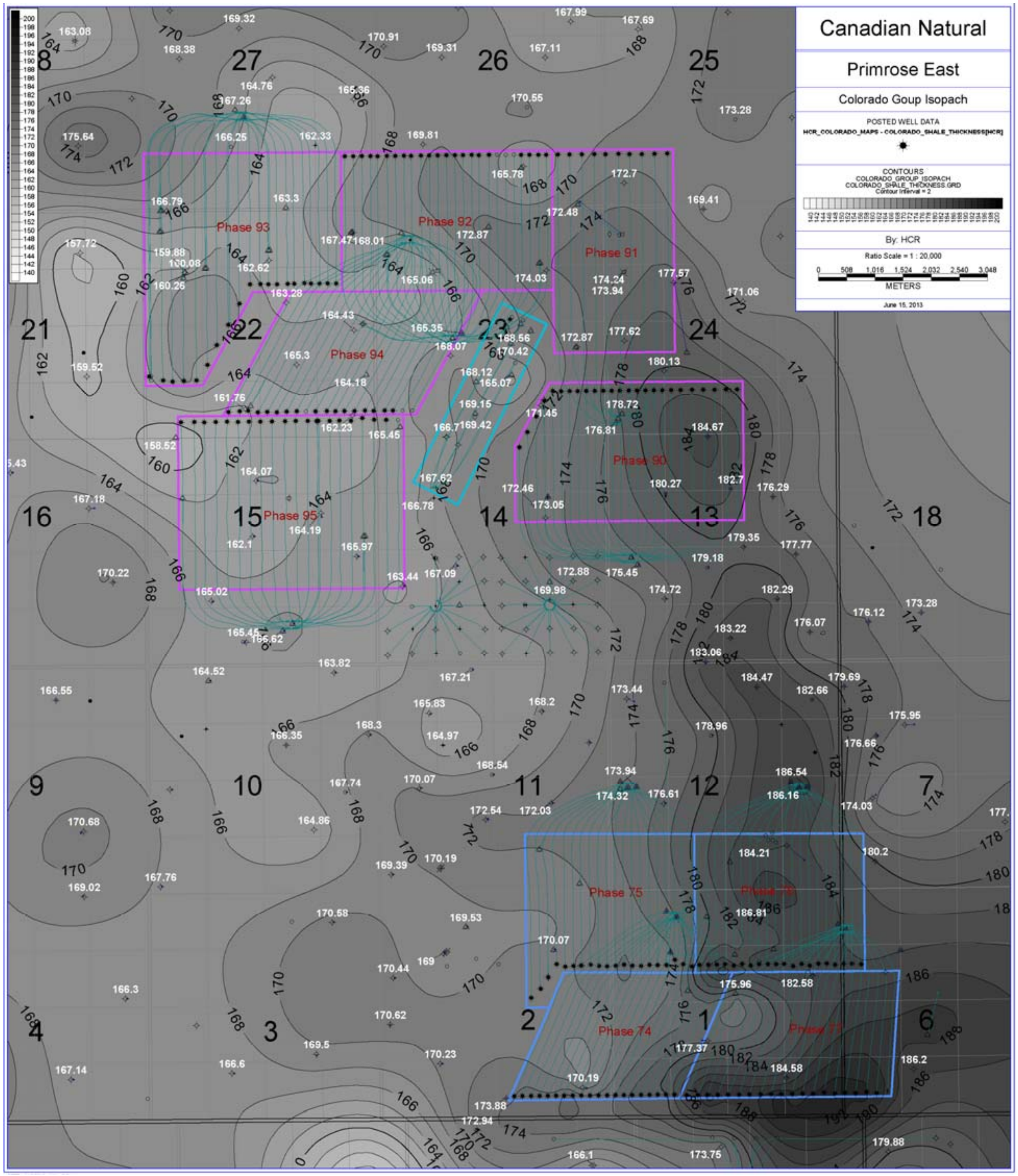


Figure 2.6a **Colorado Group Isopach**

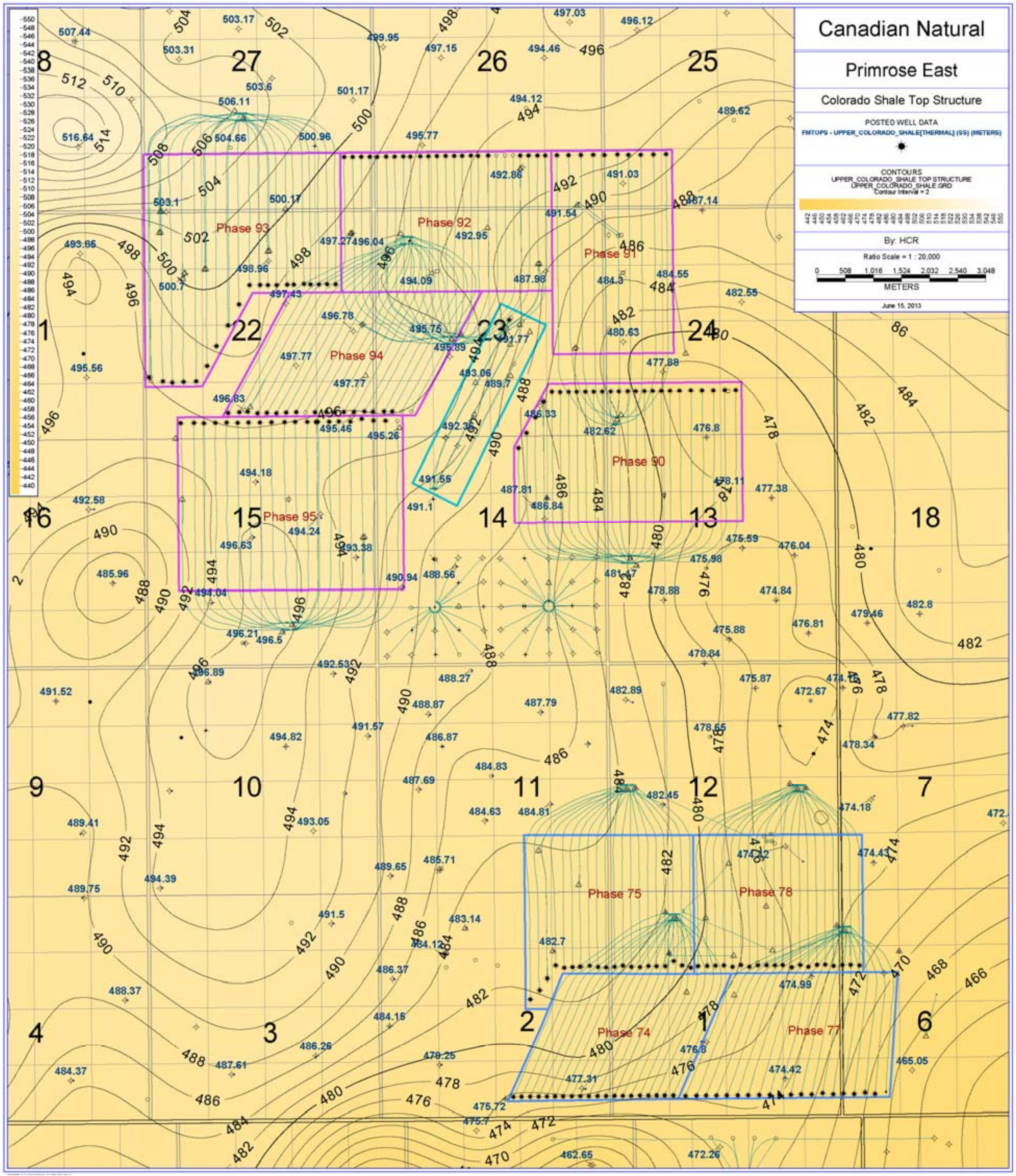


Figure 2.6b Colorado Shale Formation Top Structure (Subsea)

3 Modified Resource Recovery Strategy

As described by Canadian Natural in previous regulatory applications, the CSS process employed in PRE A1 takes advantage of various mechanisms to recover bitumen from the Clearwater Formation. The relative dominance of these mechanisms changes as a function of reservoir maturity, from formation dilation and re-compaction drive in early cycles over solution-gas drive in intermediate cycles to gravity drainage in mature cycles. Hence, an optimized resource depletion plan should include the adaptation of recovery strategies to changing reservoir conditions. There is an obvious opportunity to convert from single-well CSS to a low pressure multi-well follow-up process once the level of interwell fluid communication becomes sufficiently pronounced to limit the effectiveness of injected steam at achieving significant incremental formation dilation. Canadian Natural originally envisioned a conversion to a gravity drainage process once a recovery factor (RF) of 15-25% was achieved as detailed in AER Application No. 1442966 (2006). The average RF across PRE A1 is currently 19.7%, i.e. at the midpoint of the originally envisioned conversion range.

3.1. Originally Envisioned Follow-up Process

At the design stage of the PRE expansion, Canadian Natural intended to drill horizontal wells with reduced spacing (i.e. less than 160-188 m apart) in areas with reservoir thickness in excess of 15 m and wide spacing (i.e. 160-188 m apart) in the remainder of the region.

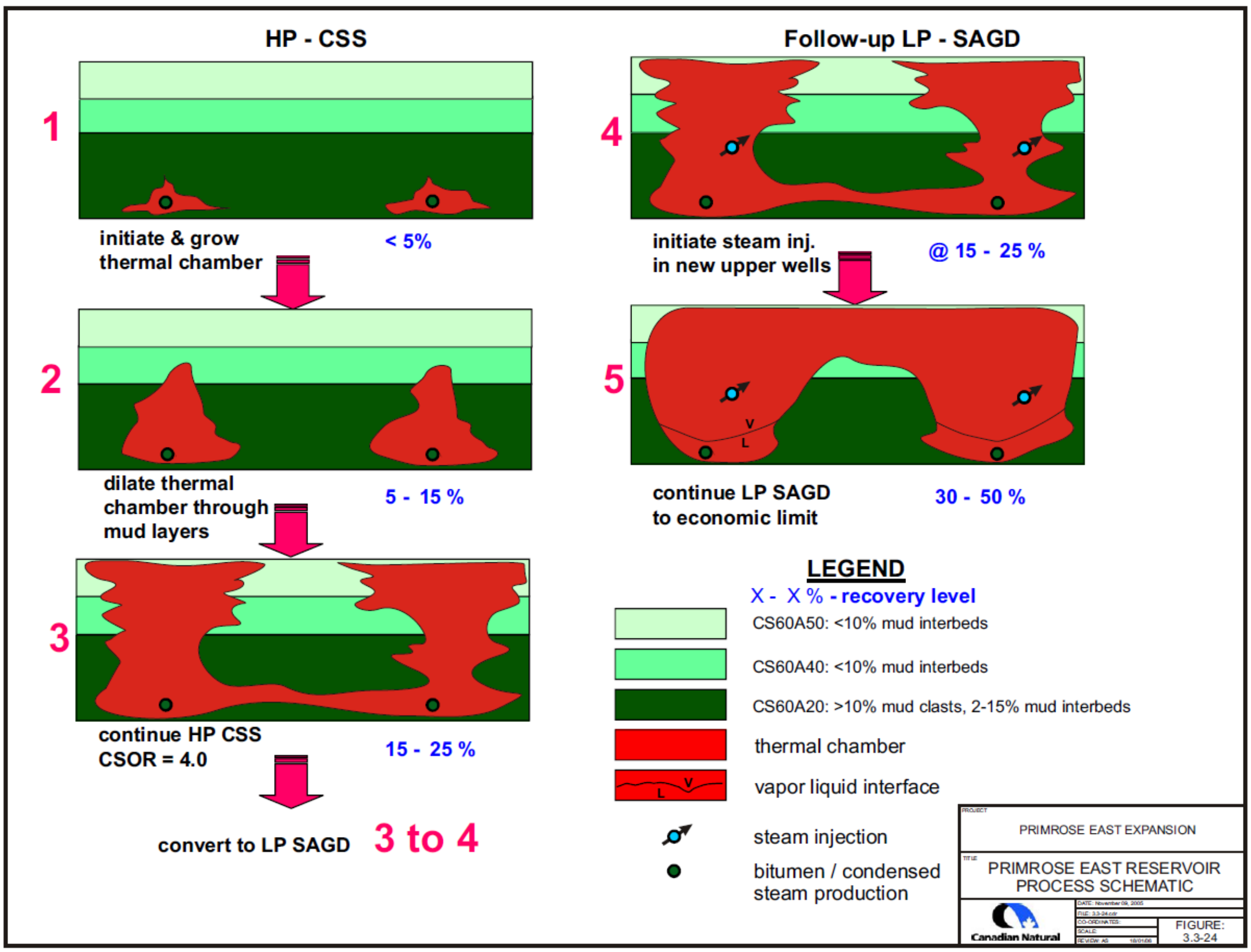


Figure 3.1 Originally Envisioned CSS to FUP in PRE per Application No. 1442966 (2006)

Following the recovery of 15-25% of the bitumen originally in place using CSS, Steam-Assisted Gravity Drainage (SAGD) or a variant of SAGD was to be implemented as a FUP to CSS in areas with reservoir thickness in excess of 15 m by drilling infill wells displaced 3 to 5 m vertically and 0 to 60 m laterally from the existing CSS wells located near the base of pay. The infill wells were to be operated as dedicated SAGD injectors and the existing CSS wells as dedicated SAGD producers until the economic limit was reached at which point a recovery factor range of 30-50% was projected.

3.2. Currently Proposed Follow-up Process

In the case of PRE A1, effective reservoir thickness (i.e. above liner elevation, H_eff) varies from 10.5 m to 27.5 m with a mean of 21.1 m. In consideration of the large reservoir thickness, 80 horizontal wells were drilled and spaced 60-68 m apart and operated under CSS. To date, an effective RF (i.e. based on perforated liner length, RF_eff) of 19.7% has been achieved and interwell communication observed during the 2012 CSS cycle has become significant.

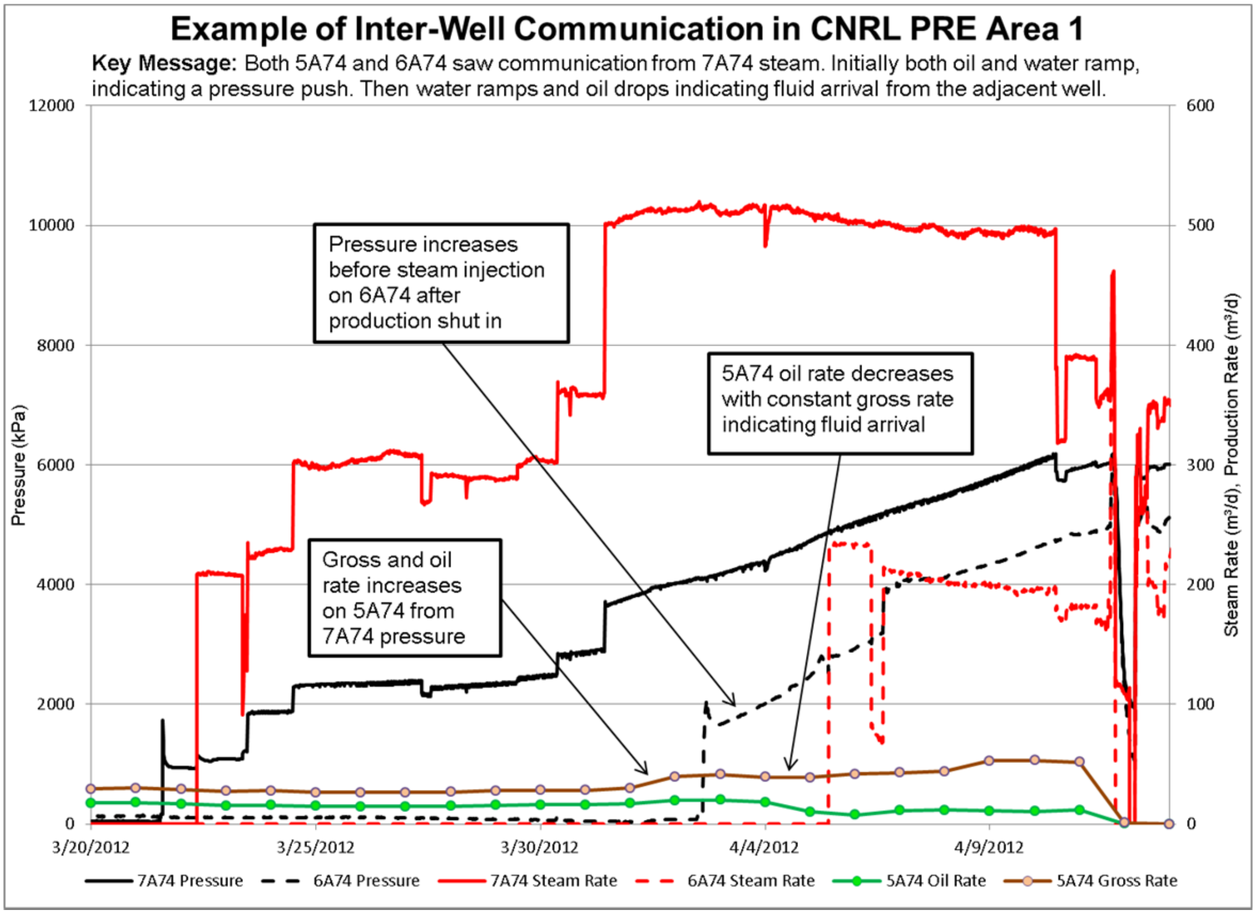
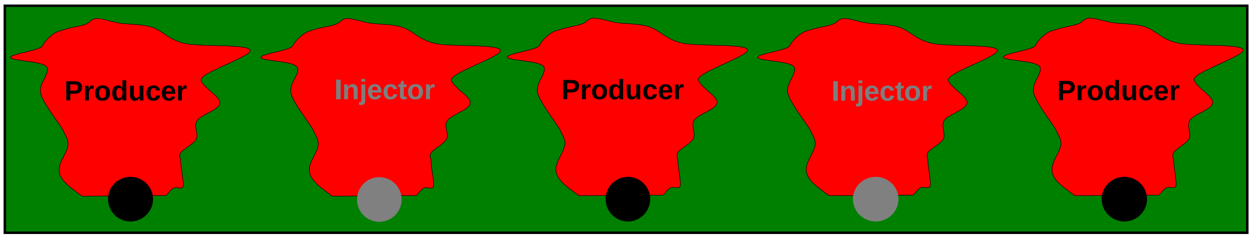


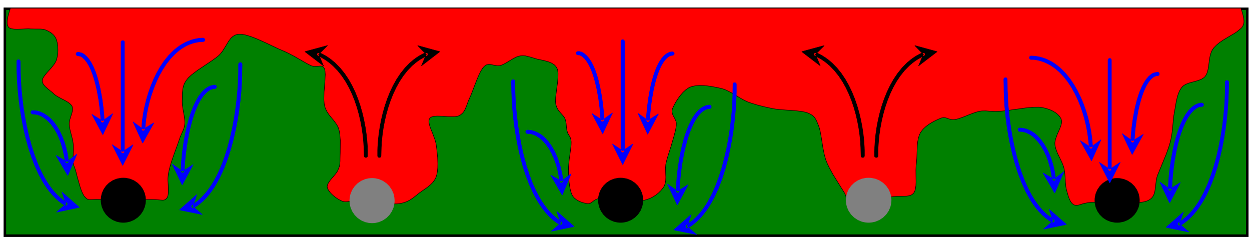
Figure 3.2a Evidence of Significant Interwell Communication during 2012 CSS Cycle

Given the well spacing and degree of interwell communication illustrated in Figure 3.2a, Canadian Natural proposes to implement a steamflood (SF) strategy as a FUP to CSS in PRE A1. Injector drilling would be both costly and technically challenging at current levels of depletion, and as such the steamflood approach is considered superior to SAGD as no additional wells are required and existing hydraulic connections between wells are deemed performance enhancing rather than limiting. As illustrated in Figure 3.2b, approximately half of the wells would be operated as dedicated continuous injectors while the remainder would be operated as dedicated continuous producers.

The proposed wellbore utilization is based on a review of wellbore impairments, current cycle production characteristics, extent of liner access and recovery factor of a well and that of its immediately adjacent neighbors as well as the degree of interwell communication observed during the last CSS cycle. As some of these factors may change over the course of the well servicing program, to be conducted prior to commencement of steam injection, Canadian Natural would like to retain the flexibility to modify the current proposal accordingly.



Remnants of interwell communication from last HPCSS cycle



Interwell communication during gravity drainage dominated stage of SF

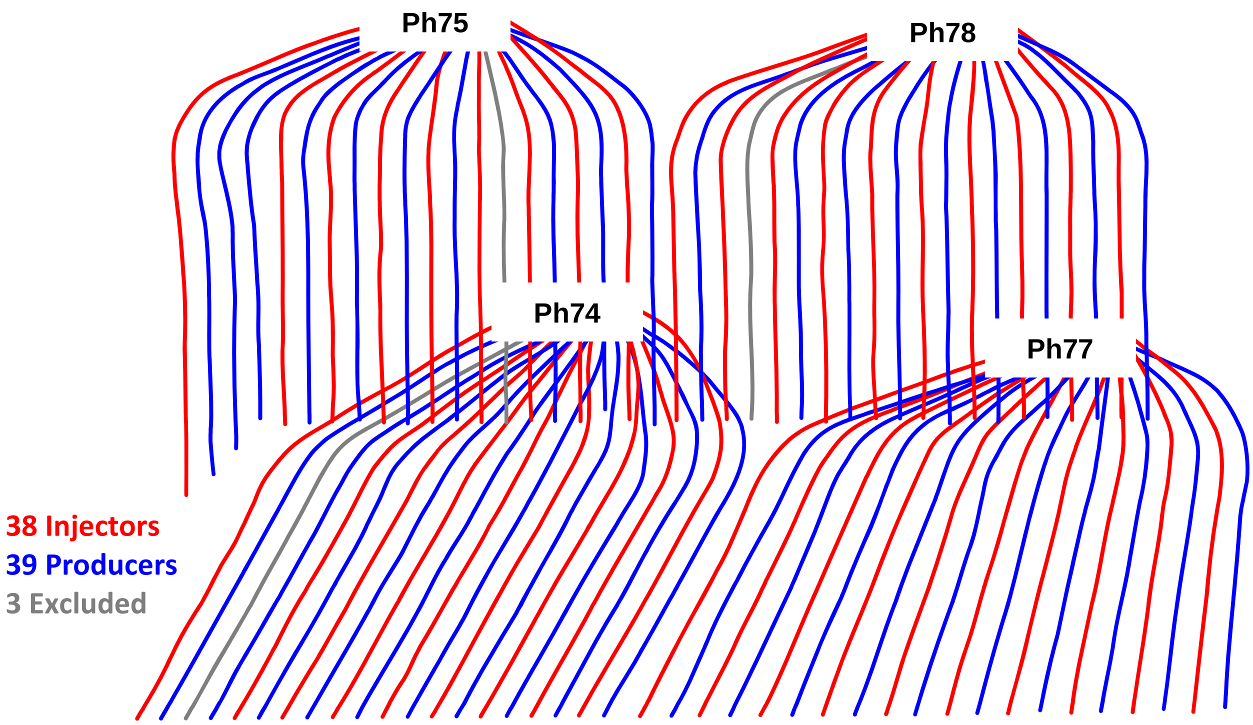


Figure 3.2b Currently Proposed FUP to CSS and Wellbore Utilization in PRE A1

3.3. Steamflood Process Characteristics

Canadian Natural's proposed steamflood operating strategy and process characteristics have been previously described in AER Application No. 1717587 (2012) in the context of the PRS D1 steamflood process field trial. As detailed in Figures 3.3a and 3.3b, the D1 field trial has been operational for close to 18 months and performance to date is directionally encouraging as a relatively large calendar day steam rate (CDSR, cumulative steam injected divided by cumulative time) has been achieved at injection pressures below 1.0 MPa while cumulative steam-oil ratio (SOR) continues to decrease and calendar day oil rate (CDOR, cumulative oil produced divided by cumulative time) continues to increase.

Parametric reservoir simulation studies suggest that SF SOR increases only modestly with CDSR over a relatively wide CDSR range as long as producers remain in a pumped-off state; relative permeability related degradation of bitumen mobility occurs otherwise. Since CDOR is the quotient of CDSR and SOR, this implies that higher CDSR results in higher CDOR which in turn results in increased economic viability.

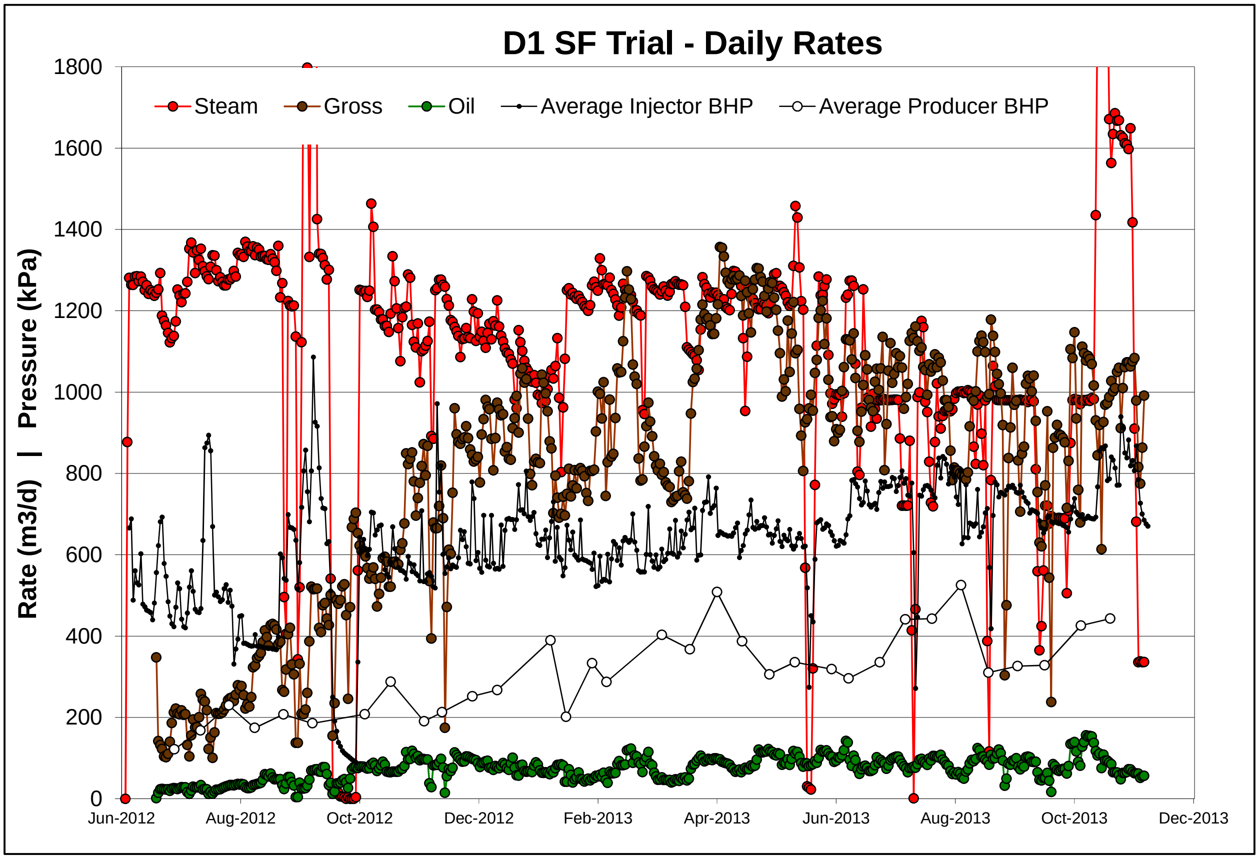


Figure 3.3a Rates and Pressures Observed at PRS D1 Steamflood Trial

D1 is still within the displacement dominated phase of the steamflood process, i.e. widespread breakthrough of live steam has not yet occurred as evidenced by the relatively constant pressure gradient of approximately 300 kPa between injectors and producers as well as distributed downhole temperature measurements. During this phase, flow rate per unit reservoir area between injectors and producers is a function of fluid mobility and available pressure differential. Since fluid mobility is dictated by the state of depletion and heating of the interwell zone, higher flow rates require a higher pressure differential, i.e. injector BHP should be increased in order to maximize economic viability. Given a sufficient pressure differential, mechanical or hydraulic constraints on artificial lift equipment limit the rate at which steam condensate and mobilized bitumen can be removed from the reservoir and, if targeting a constant operating pressure, these constraints also limit the rate at which steam can be injected into the reservoir.

Pump jacks of D1 producers were upgraded prior to the start of the field trial to accommodate a significant stroke length increase, and pump diameters are currently being upgraded for this specific reason. An important learning from the D1 trial is that average producer pump efficiency has been limited to approximately 70% as operation below the bubble point results in the liberation of large volumes of free gas, confirmed by a cumulative gas-oil ratio (GOR) of approximately 90 since the start of the trial.

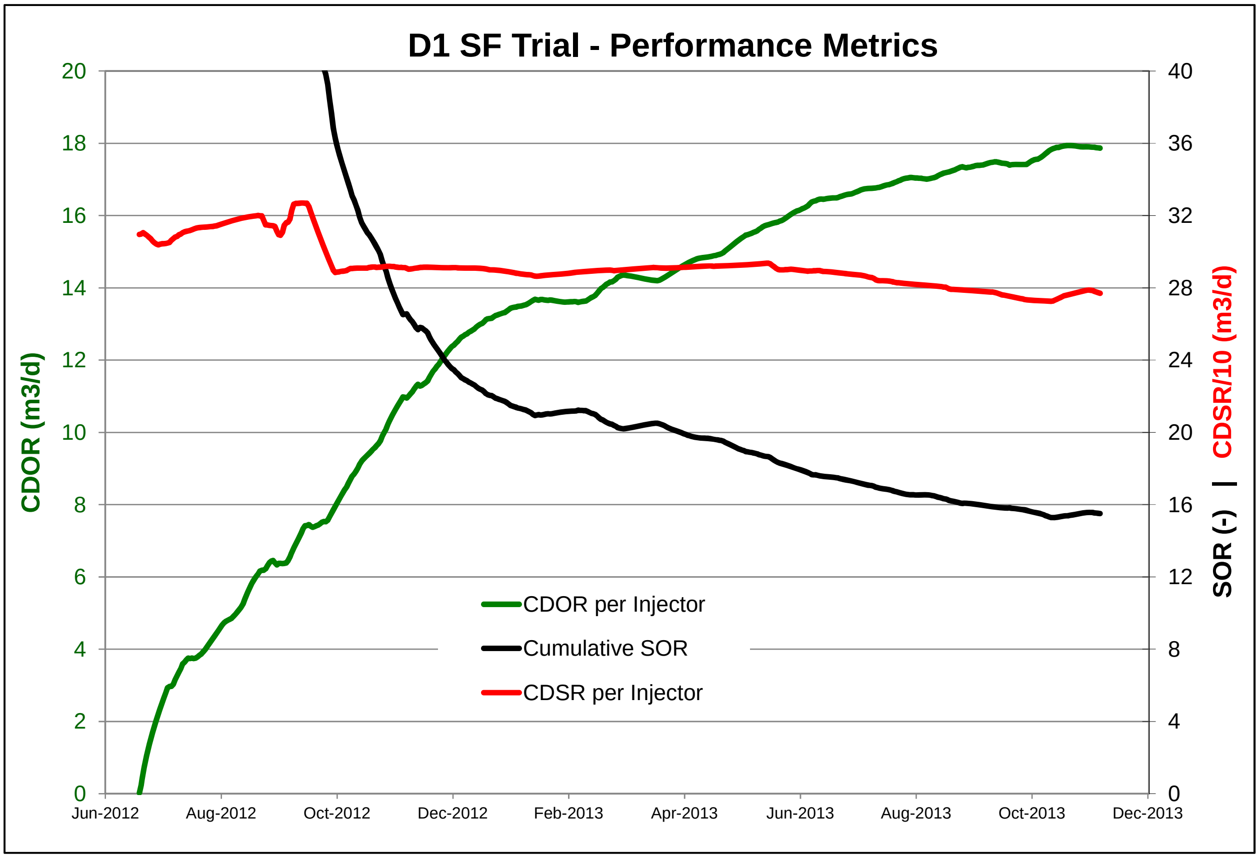


Figure 3.3b **Cumulative Process Metrics Observed at PRS D1 Steamflood Trial**

Once sufficient heat has been introduced into the reservoir region between injectors and producers to allow the formation of an overriding steam chamber, widespread breakthrough of live steam occurs and the gravity drainage dominated phase of the steamflood process begins. During this phase, the rate of condensate and bitumen withdrawal and hence steam injection becomes subject to the additional constraint of steam trap control due to further degradation of pump efficiency at the onset of vapour interference. Depending on the size of installed artificial lift equipment, the reservoir condensation potential at a given operating pressure may or may not become the primary limiting constraint during this phase of the process.

3.4. Proposed Operating Conditions

Pending completion of the on-going investigation into the root causes of the FTS incidents in PRE A1, Canadian Natural proposes to limit injector BHP to hydrostatic levels relative to the elevation of the deepest non-saline aquifer plus a Quaternary pore pressure gradient. This will prevent the possibility of Clearwater fluids flowing into a freshwater aquifer. This precautionary measure will ensure that proposed steamflood operations cannot exacerbate existing or potentially cause additional FTS.

Values annotated in blue on Figure 3.4a indicate overburden thickness (OBT) values based on determination of the top of the bedrock from well logs while grey contour lines indicate OBT values based on determination of the top of the bedrock from seismic data. Figure 3.4a can be used to determine the hydrostatic head pressure from the top of the Clearwater sand to the base of the Quaternary. Based on the density of water at 60°C, an OBT range, between the top of the Clearwater reservoir sand and the top of the bedrock (base of Quaternary), of 315-390 m across PRE A1 has a hydrostatic head range of 3.0-3.8 MPa.

Figure 3.4b can be used to determine the pore pressure at the base of the Quaternary. Based on a conservative Quaternary pore pressure gradient of 6 kPa/m, PRE A1 has a base of Quaternary pore pressure range of 0.5-0.9 MPa.

An injector specific BHP limit of 3.9-4.4 MPa is proposed. For example, 20A75 BHP would be limited to a hydrostatic head of 3.0 MPa plus a Quaternary pore pressure of 0.9 MPa for a total of 3.9 MPa. Conversely, 2A78 BHP would be limited to a hydrostatic head of 3.8 MPa plus a Quaternary pore pressure of 0.6 MPa for a total of 4.4 MPa. These examples illustrate that the deep quaternary channel on the western side of PRE A1 results in a thicker quaternary and a reduced OBT from the Clearwater sand top to the base of the Quaternary. Ultimately, an interconnected steam chamber is expected to develop across PRE A1 at which time Canadian Natural would limit the steam chamber pressure to the lowest injection pressure constraint of 3.9 MPa.

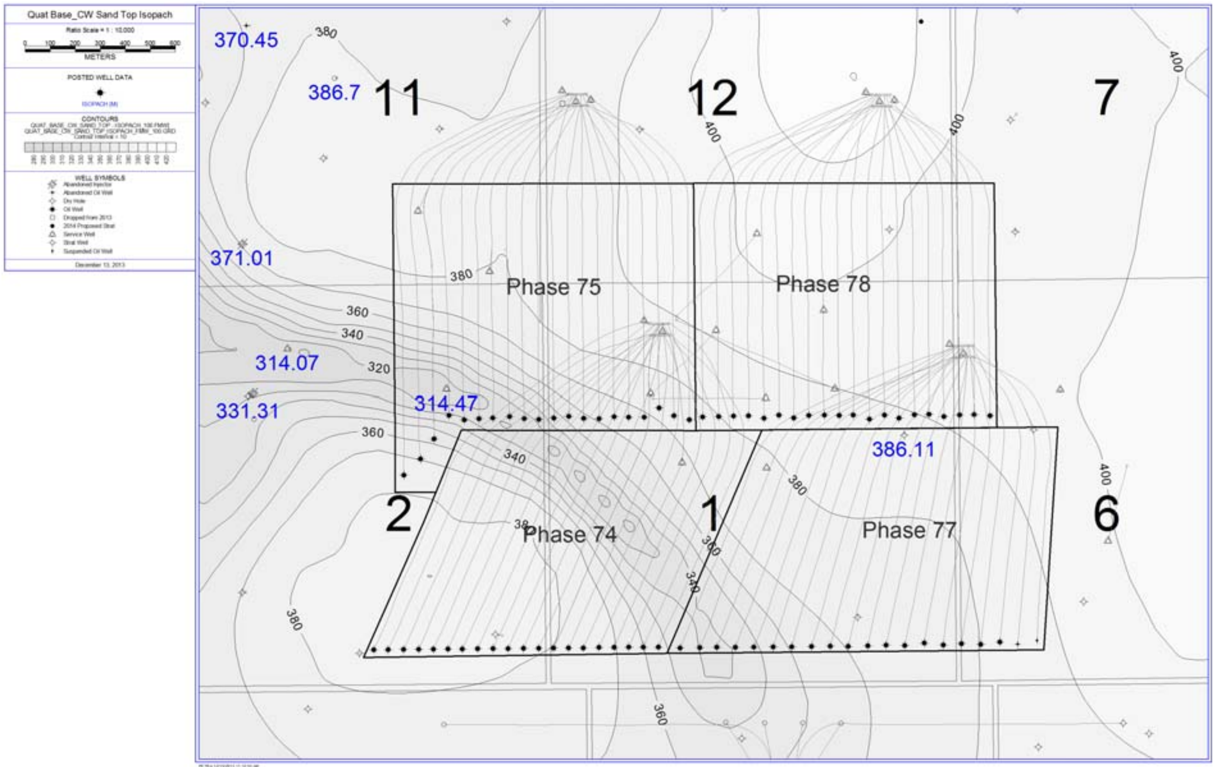


Figure 3.4a Isopach between Top of Clearwater Sand and Top of Bedrock

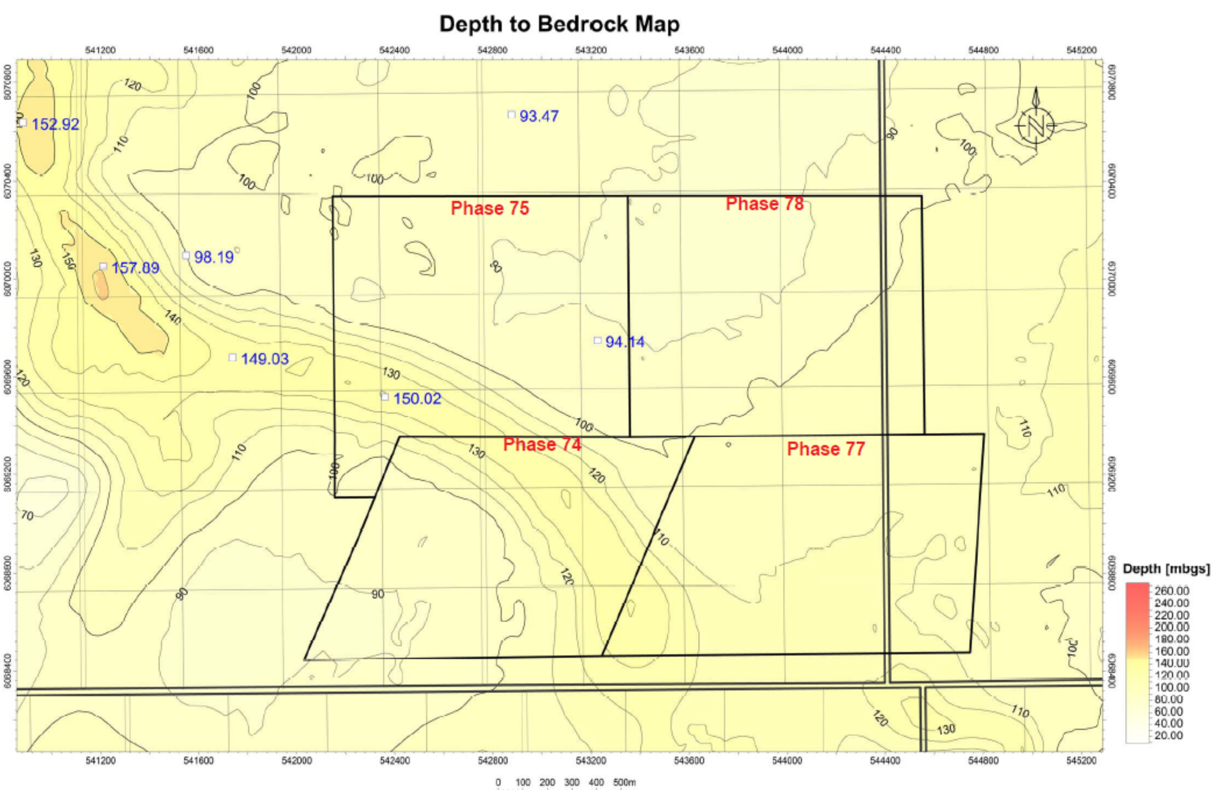


Figure 3.4b Isopach between Top of Bedrock and Surface

At the commencement of steam injection, Canadian Natural plans to inject down the tubing or casing-tubing annulus at rates of 800-1,500 m^3/d per injector until fill-up is achieved as the injector specific BHP limit is reached. Rate step down tests may be used during this period to infer reservoir pressure. As injection rates are expected to decline to 200-800 m^3/d per well following fill-up, further steam injection is to occur down the tubing exclusively. A fuel gas blanket will be maintained in the casing-tubing annulus to minimize wellbore heat losses and to provide a method of continuous reservoir pressure surveillance.

Maximization of the pressure differential between injectors and producers implies a need to maximize fluid withdrawal. Ideally, producer BHP would remain at minimum levels during the entire displacement dominated phase, but will realistically rise toward the injector pressure limit once artificial lift capacity (ALC) limits imposed by mechanical or hydraulic constraints are reached. Such constraints should be removed as much as possible in an effort to pursue a purely reservoir transmissibility driven performance potential during the displacement dominated phase. Canadian Natural intends to upgrade artificial lift equipment on producers to facilitate an increase in pump diameter from 3.25” to as high as 5.50” if warranted by process performance. Withdrawal rates may eventually decrease below mechanical ALC limits in order to satisfy steam trap control requirements during the gravity drainage dominated phase.

As in SAGD, there is a benefit to operating steamfloods above the bubble point of bitumen (~3.0 MPa at initial Clearwater reservoir temperature of 15°C) related to the reduced liberation of non-condensable solution gas and the associated increase in the rate of heat transfer between steam and bitumen at the edge of the steam chamber. The proposed operating strategy will result in operation of producers below the bubble point for a potentially prolonged period of time. This condition, however, is viewed as a necessity as operation of producers at or slightly above the bubble point while subject to a maximum injection pressure limit of 3.9-4.4 MPa would significantly limit the pressure differential available during the displacement dominated phase.

3.5. Performance Projections

The sustained ability to inject up to 300 m^3/d per well at reservoir pressures below 1.0 MPa in the D1 trial suggests that the proposed steamflood process is likely a technically viable FUP to CSS in the Clearwater Formation in general. While depletion levels in PRE A1 at the time of conversion from CSS to SF are lower than that of PRS D1, PRE A1 features thicker pay, tighter well spacing, lower oil viscosity and less time since the last steam injection cycle as summarized in Table 3.5.

Table 3.5 Comparison of PRS D1 and PRE A1 Reservoir Characteristics

Location	RF_eff (%)	H_eff (m)	Well Spacing (m)	Live Viscosity (cP)	Years b/w CSS and SF
PRS D1	35.3	17.5	80	22,900 – 106,100	7
PRE A1	19.7	21.1	62	11,100 – 55,100	2

Due to these pronounced differences in reservoir conditions, D1 trial performance metrics such as SOR and CDOR trends cannot be directly applied to PRE A1 and thus an extensive numerical simulation study was undertaken in an effort to assess the performance potential of the steamflood process in PRE A1.

As reservoir thickness has a significant impact on gravity drainage dominated recovery processes, the wide range of reservoir thickness encountered in PRE A1 (10.5 m to 27.5 m, mean of 21.1 m and standard deviation of 3.6 m per Figure 3.5a) was incorporated in this study. As detailed in Figure 3.5b, the 80 wells were grouped into three statistically meaningful bins with mean thicknesses of 16.8 m, 21.7 m and 24.7 m based on the fact that well specific reservoir thickness approximates a normal distribution.

Mean	21.1	Std Deviation	3.6
Min	10.5	Max	27.5
	Normal Distribution		PR-E A1 Actual
Domain	Probability	Cum Probability	Cum Probability
10.2	0.1%	0.1%	0.0%
12.0	0.5%	0.6%	1.3%
13.8	1.5%	2.3%	3.8%
15.7	3.6%	6.7%	10.0%
17.5	6.6%	15.9%	16.3%
19.3	9.7%	30.9%	26.3%
21.1	11.0%	50.0%	42.5%
22.9	9.7%	69.1%	63.8%
24.8	6.6%	84.1%	90.0%
26.6	3.6%	93.3%	92.5%
28.4	1.5%	97.7%	100.0%
30.2	0.5%	99.4%	100.0%
32.0	0.1%	99.9%	100.0%

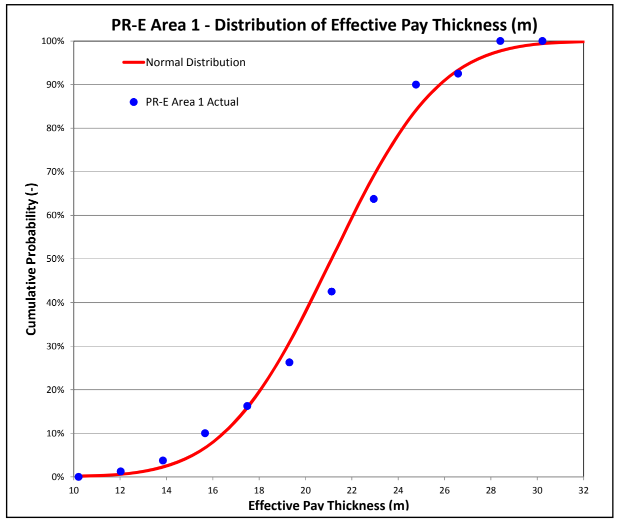


Figure 3.5a Effective Pay Thickness in PRE A1 Approximates Normal Distribution

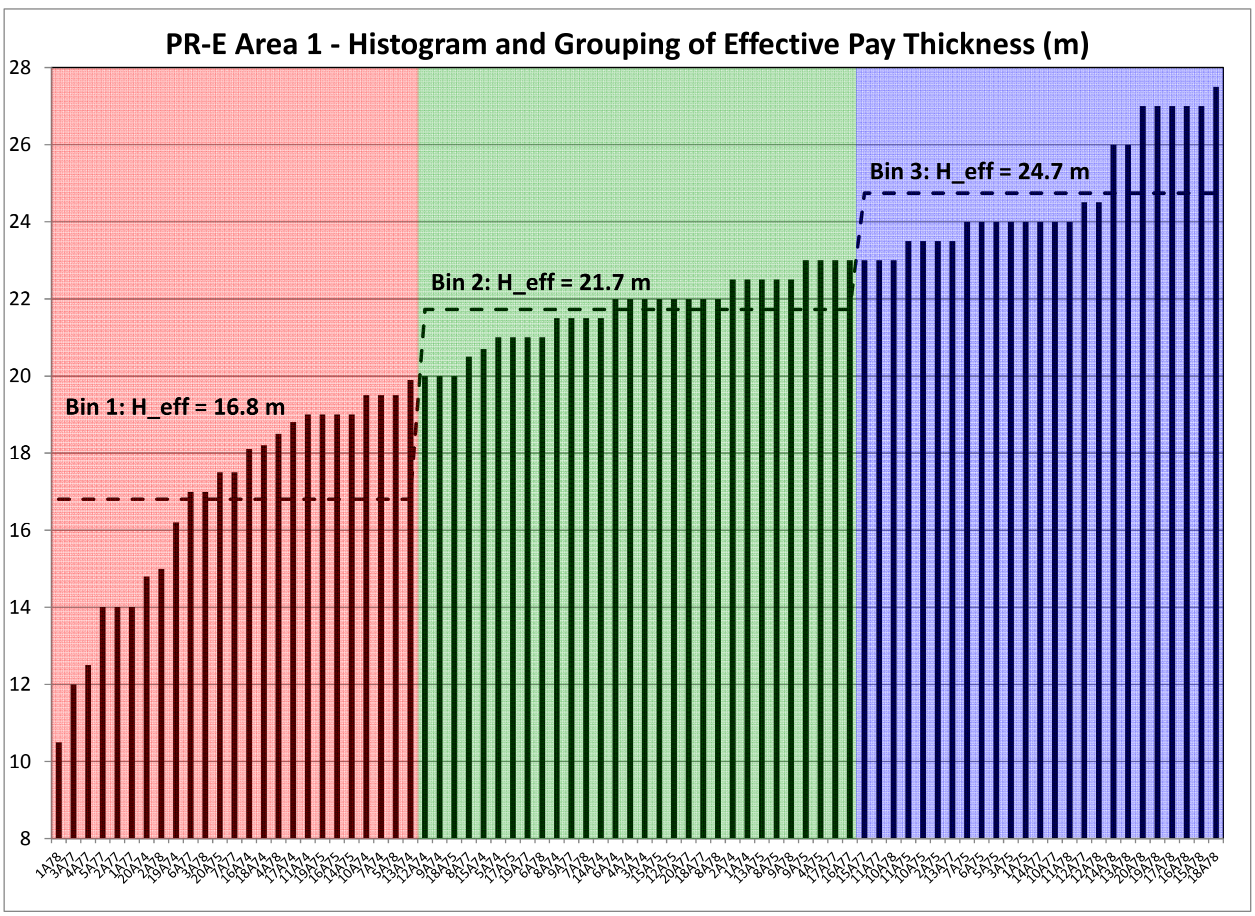


Figure 3.5b Grouping of PRE A1 Wells into Statistically Meaningful Bins

In order to generate a credible performance forecast using reservoir simulation, operational history must be replicated in a reservoir model so as to create representative conditions at the point of CSS to SF conversion – a process commonly referred to as model history matching. Since the wells within a bin tend not to form a contiguous area in the field (Figure 3.5c), operational history can vary significantly between wells. For example, wells 1A77 and 20A75 are both assigned to Bin 1 but due to the complex operational history of this area, timing of first cycle steam injection differs by more than 13 months.

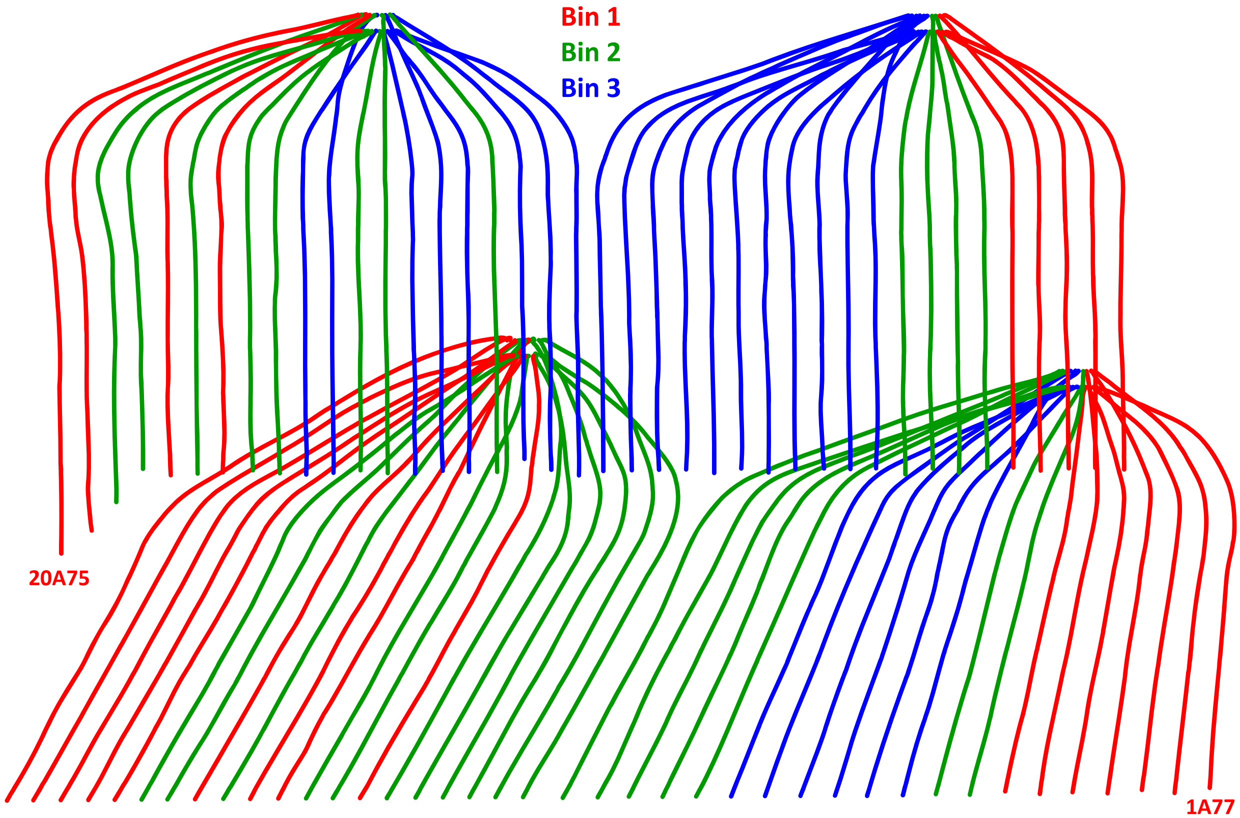


Figure 3.5c Wells within a Bin Tend not to Form a Contiguous Area

Hence, a bin specific pseudo operating history had to be established for model history matching purposes. While each bin's pseudo operating history identically reflects bin average cycle volumes, it only attempts to approximate cycle specific rate characteristics. Due to multiple steam-in and production commencement periods, the level of agreement between pseudo and actual operating history can only be assessed at the end of the 4 pseudo CSS cycles since intermittent trajectories will necessarily differ as shown in Figure 3.5d for the case of Bin 2.

Reservoir models comprising 7 wells were history matched for each of the three bins, with model quality and inferred predictive capability deemed acceptable based on the reasonable agreement between actual and modelled full field performance demonstrated in Figure 3.5e.

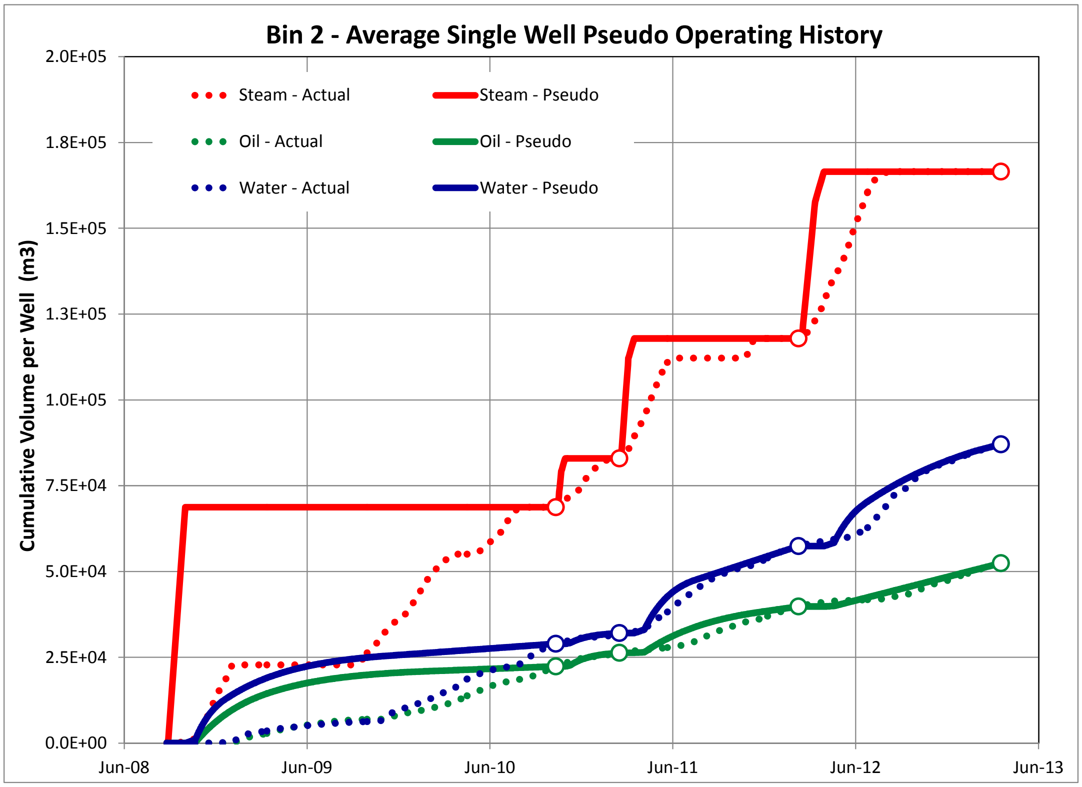


Figure 3.5d Comparison between Bin 2 Single Well Pseudo and Actual Operating History

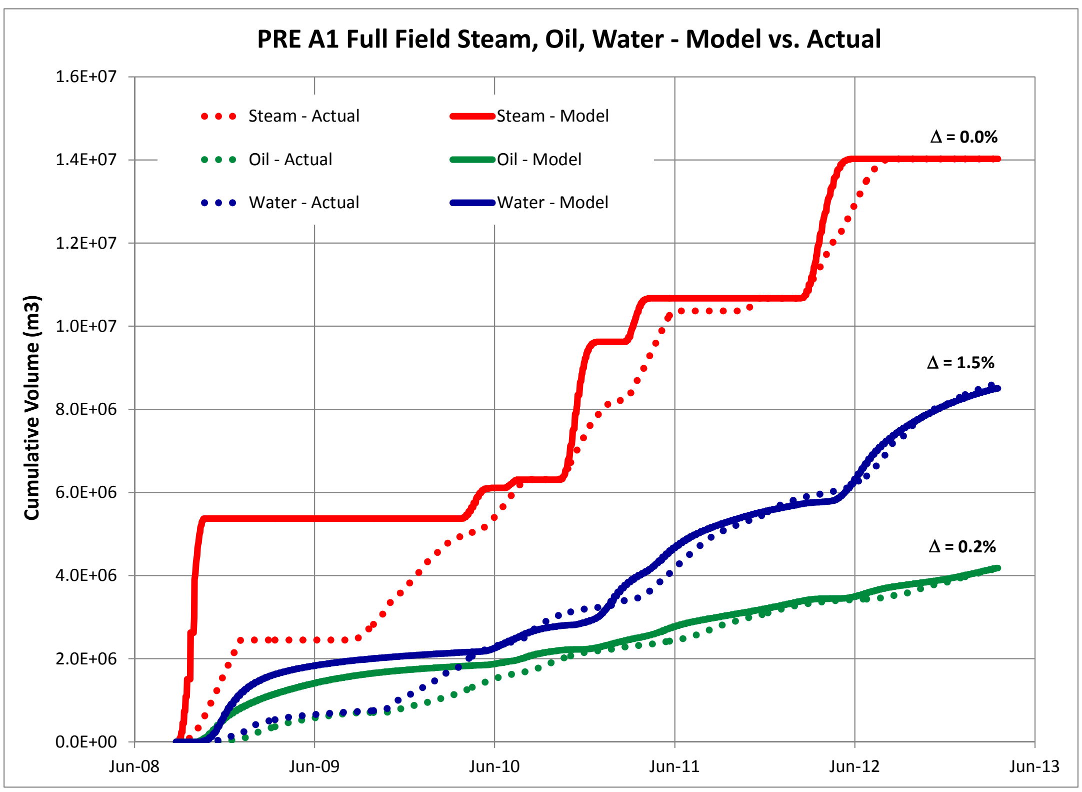


Figure 3.5e Comparison between Full Field Model and Actual Operating History

Having developed simulation models with depletion and interwell communication levels representative of current reservoir conditions, steamflood performance potential in PRE A1 was assessed in a parametric reservoir simulation study. Due to non-uniform conformance development between horizontal wells in a displacement process, the impact of heterogeneous longitudinal steam conformance existing at the end of the CSS operating history was given particular attention. In an effort to bracket the potential range of performance outcomes, two extreme scenarios were considered: a low side (LS) case based on strongly heel dominated longitudinal conformance leading to early steam breakthrough near producer pump intake locations and a high side (HS) case based on uniform longitudinal conformance leading to piston-like displacement between the two sets of wells.

Figure 3.5f illustrates the projected impact of longitudinal conformance on CDSR and instantaneous SOR (SOR_i), two key steamflood performance indicators as previously discussed. Since the current extent of interwell communication varies across PRE A1, Canadian Natural expects variations in initial reservoir inflow characteristics and hence optimization of artificial lift equipment will likely include multiple pump sizes. For this reason, CDSR is expressed in relation to maximum producer ALC rather than in absolute terms.

During the initial high rate fill-up period, steam is injected at rates in excess of maximum ALC. Once fill-up is achieved, injection rates are expected to steadily decline until fluid communication starts to occur between injectors and producers. Simulations suggest that interwell communication will develop faster in the LS case as comparable bitumen recovery to date originates from a shorter reservoir section and hence initial water mobility between wells will be higher than in the HS case. As a result, injection rates in the LS case are expected to approach ALC controlled peak rates earlier than in the HS case. The duration of these peak injection rates, however, is limited by the onset of steam production which is projected to occur much earlier in the LS case due to higher initial water mobility and higher rate of steam injection per unit length of effective liner section.

SOR_i is expected to approach a relatively stable minimum once producers enter the gravity drainage dominated phase. Initially, reservoir inflow is expected to exceed planned ALC, and hence ALC rather than the reservoir condensation potential still limits withdrawal rates. Similar to CDSR trends, simulations indicate that the minimum SOR_i will be reached earlier in the LS case. Since injected steam will sweep through an area featuring higher depletion levels at the end of CSS operations, the minimum SOR_i is expected to be larger in the LS case. Eventually, once ALC exceeds reservoir inflow, production of live steam occurs and the reservoir condensation potential rather than ALC becomes the primary process constraint. Initially, steam injection and oil production rates decline proportionately but eventually oil production rates decrease faster than steam injection rates as elevated depletion levels are reached and process efficiency declines toward the economic limit.

Hence, the early benefit of strongly heel dominated longitudinal conformance soon turns into an impediment to SF performance both from a CDSR and SOR_i perspective, resulting in reduced thermal efficiency and lower ultimate recovery expectations as compared to the ideal case of uniform longitudinal conformance. Average PRE A1 steamflood performance expressed in terms of pore volume (PV) steam injected is expected to fall within the envelope defined by the LS/HS bounding curves illustrated in Figures 3.5f and 3.5g. Corresponding steam injection and oil production profiles as a function of time will be determined by actual artificial lift performance.

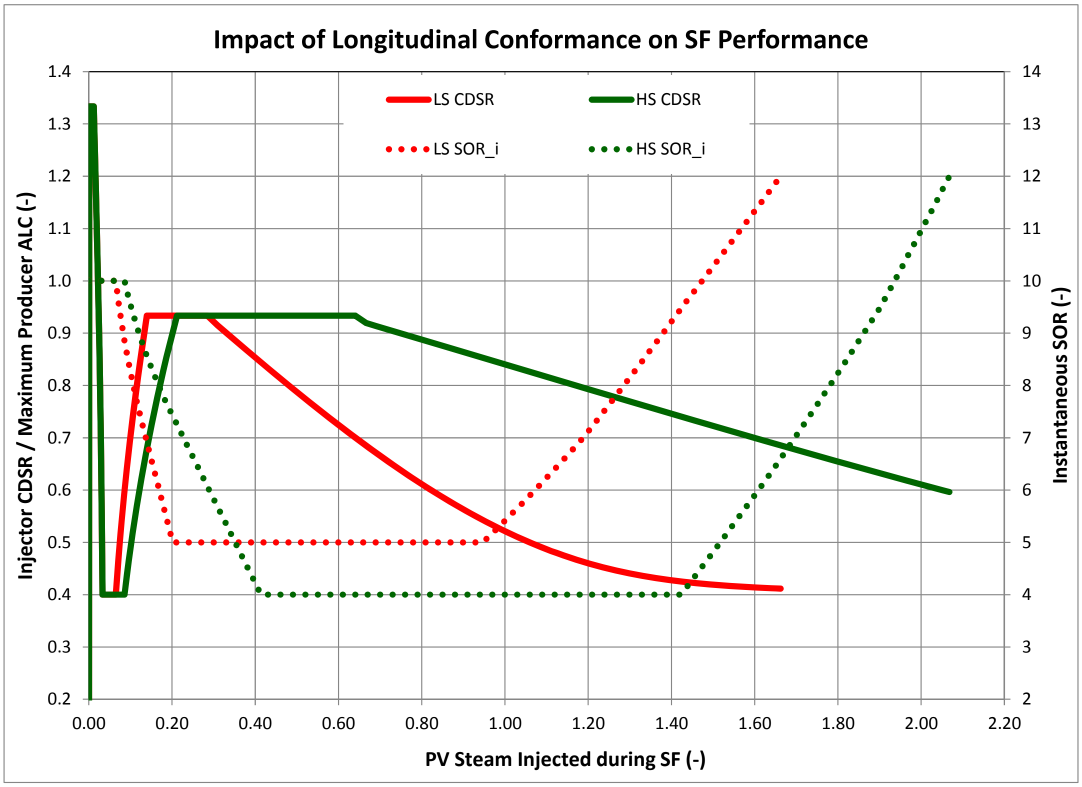


Figure 3.5f **Impact of Longitudinal Conformance on Steamflood CDSR and SOR Projections**

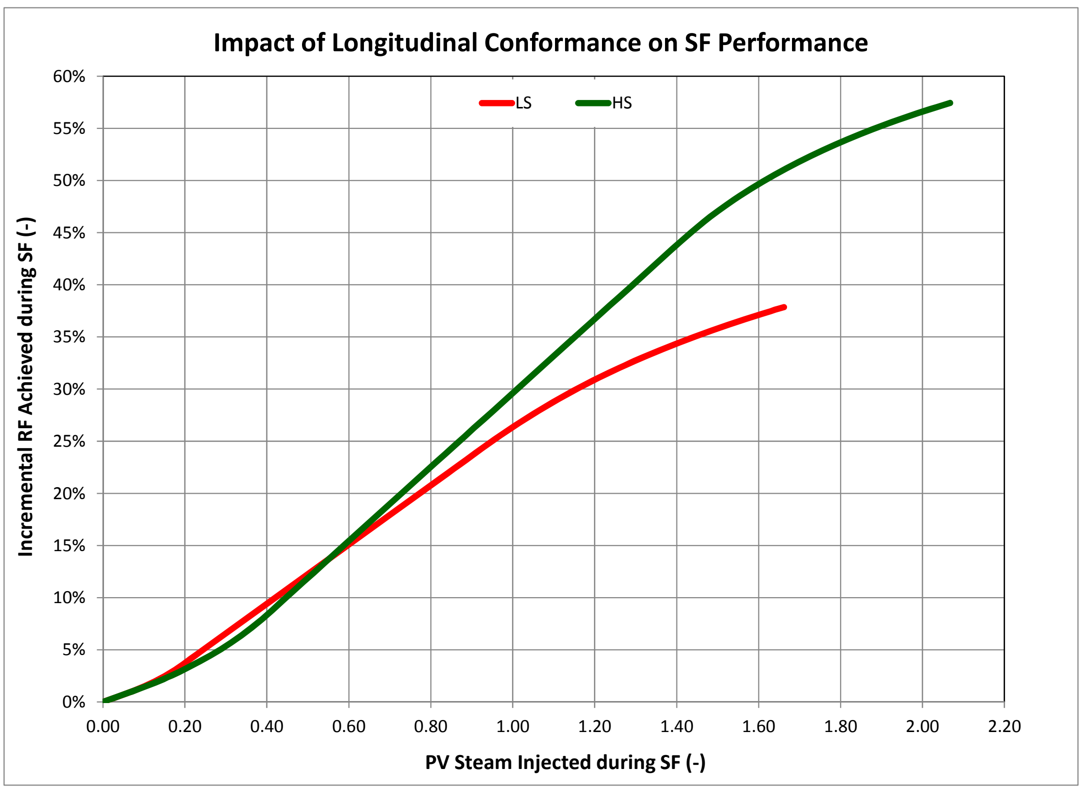


Figure 3.5g **Impact of Longitudinal Conformance on Steamflood RF Projections**

4 Risk Identification and Mitigation for Flow To Surface

Canadian Natural has completed a thorough review of all potential risks identified in the context of steamflood operations and has devised risk mitigation strategies to ensure that these risks are properly mitigated. The following section will detail Canadian Natural's proposed risk mitigation strategies.

Two conditions are required to create and/or increase fluid flow to surface:

a) An existing or induced conduit through the overburden
b) Sufficient pressure to facilitate flow

To mitigate the potential for flow to surface, the pressure condition enabling flow must be understood and eliminated. Three potential sources for increased pressures have been identified:

1) Clearwater operating pressure
2) Compression of fluid within the overburden
3) Conductive heating of fluid within the overburden

In addition, Canadian Natural has considered the impact of energizing potential flow paths along steaming wellbores and creating additional challenges for the FTS investigation. The overall assessment is that these risks are mitigated with the proposed plan.

4.1. Clearwater Operating Pressure Initiating/Enabling Fluid Flow to Surface

As with any steam injection process, the potential of fluid travelling to surface and/or a fresh water aquifer during steamflood operations has been identified as a risk. In order for fluid to flow to surface or into a fresh water aquifer, the fluid pressure must exceed its hydrostatic head. Hydrostatic head is defined as the pressure exerted by a column of fluid, and is a function of column height (overburden thickness) and fluid density. The minimum overburden thickness from the top of the Clearwater sand to the Quaternary base is 315m TVD. Using the density of water at 60^{o}C, the minimum hydrostatic head required for liquid to reach the Quaternary base is 3.0 MPa. When incorporating a conservative quaternary pore pressure gradient of 6 kPa/m, the pressure required to flow into an aquifer is greater than 3.9 MPa (see section 3.4). Thus, liquids are unable to flow through a conduit to surface or into a freshwater aquifer under the proposed steamflood target reservoir pressures. As discussed in section 3.4, a well specific maximum operating pressure is proposed accordingly.

A column of steam vapor is unable to develop during steamflood operations due to conduction effects from any potential conduit to the surrounding overburden. Figure 4.1a shows steam injection flow rates and pressures from a Burnt Lake injector, a SAGD well in the Primrose East area that has operated for 17 years. The surface tubing pressure dropping to 0 kPag is a result of steam vapour condensation, which increases the average fluid density within the wellbore. The data collected from the Burnt Lake pilot indicates that heat transfer from a conduit is sufficient to condense the steam vapour to liquid in the absence of flow. Under the proposed steamflood conditions, the maximum operating pressure is insufficient to enable flow to surface.

A column of non-condensable gas is unable to develop due to gas diffusion within the Grand Rapids non-oil bearing permeable layers. Pumping tests within the lower Grand Rapids indicate pressure diffusivities of 0.4-1.2 m^2/s which translate to material capacity to dissipate fluids.

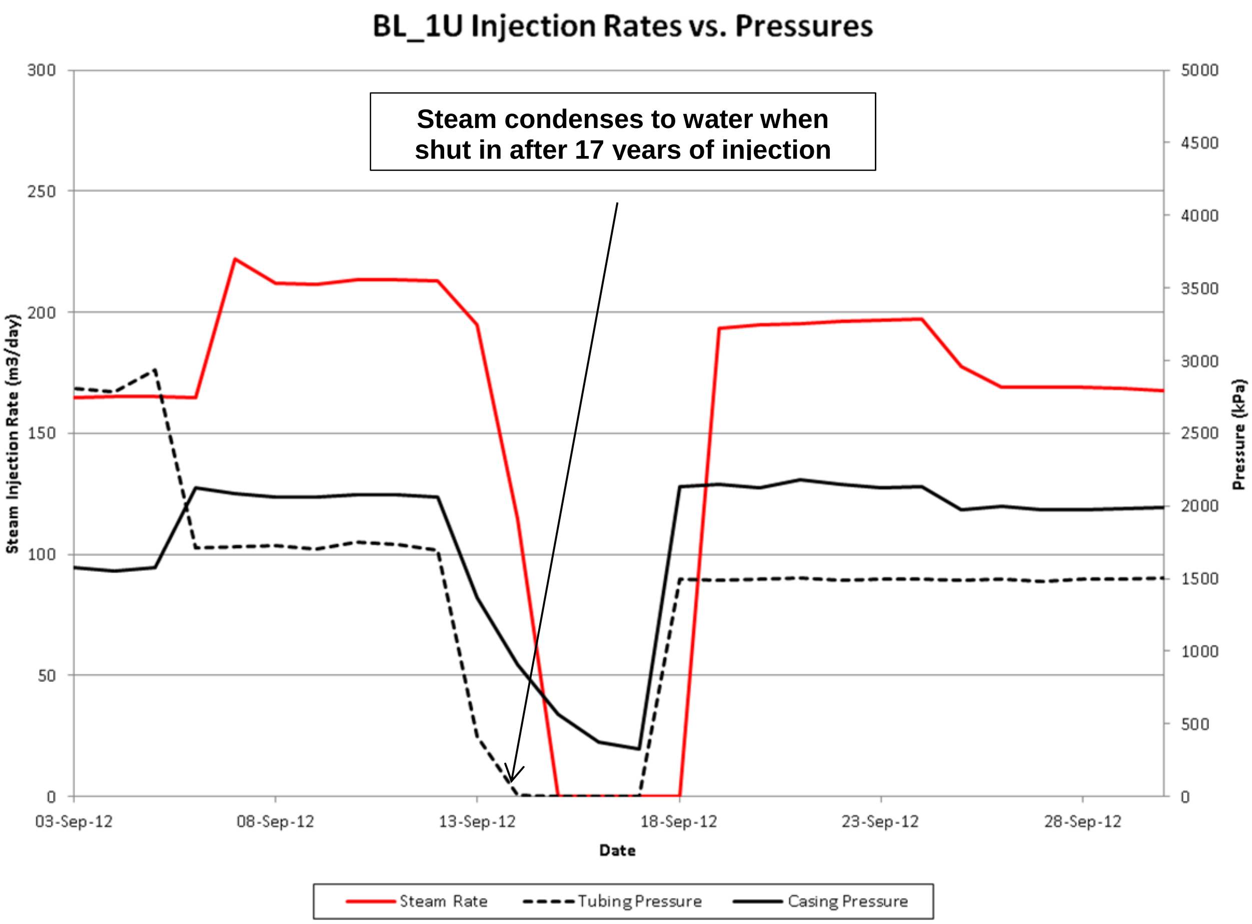


Figure 4.1a **Burnt Lake Steam Injection Rate and Pressure Illustrating Steam Condensation within a Wellbore in the Absence of Flow (Shut-In)**

4.2. Clearwater Operating Pressure Initiating/Enabling Fluid Flow to the Formation Immediately Above the Reservoir

The planned range of operating reservoir pressure limits will result in the Clearwater being approximately balanced with the regional Lower Grand Rapids pressure. The elimination of a significant pressure difference would reduce any potential flow toward that caused by fluid density differences, in the presence of any potential conduit between the two formations. The regional Lower Grand Rapids pressure range is 3.0-3.5 MPa, indicating that the proposed steamflood operating parameters are in a nearly balanced pressure state with the regional Lower Grand Rapids.

4.3. Compression of Fluids within Overburden Initiating/Enabling Fluid Flow to Surface

The anticipated extent of compression of fluids within the overburden is insufficient to initiate or enable additional fluid flow to surface or into a freshwater aquifer. Compression is induced by the amount of vertical displacement or heave occurring during steam injection. In CSS, the majority of heave is due to poro-plastic dilation of the sand, contributing up to or exceeding 50cm of heave within one year. During steamflood operation, heave is entirely due to thermal expansion, which is estimated to be an order of magnitude smaller than overall CSS induced heave levels. PRE A1 Clearwater dilation (thermal expansion) during steamflood operation is estimated to be ~5cm. The calculation for linear expansion is shown below.

$$\Delta L = \alpha L_O \Delta T$$

Parameters for this calculation are chosen from known variables. These variables are as follows:

$$\alpha_{sandstone} = 1 \cdot 10^{-5}\ \frac{1}{°C}$$
$$L_O = 10.5 - 27.5m\ (steam\ contacted\ reservoir\ height\ )\ \ (Average\ Net\ Pay\ \ of\ 21.1m)$$
$$\Delta T = 147°C\ (average\ reservoir\ temperature\ increase\ for\ saturated\ steam\ @\ 3.8MPaa\ from\ a\ current\ estimated\ Clearwater\ average\ temperature\ of\ 100°C)$$

The effect of lateral constraints results in additional vertical dilation of ~50% based on a Poisson's ratio range of 0.2-0.3.

Using these parameters the equation equals the following:

$$\Delta L = 2.3cm - 6.1cm, \qquad Mean = 4.7cm$$

Evidence of minimal heave with steam injection pressures below 9 MPa in Primrose, is shown in figure 4.3a. Heave is caused by a volumetric increase within the Clearwater (accommodation space creation). This figure illustrates a decreasing injection rate at a target surface pressure of 8.9 MPa. The falling injection rate is interpreted to be a result of a lack of accommodation space creation (e.g. minimal dilation below 9 MPa).

Additionally, Figure 4.3b shows flat Lower Grand Rapid pressures as long as Clearwater reservoir pressures remain below 9 MPa. This is interpreted to be a result of a lack of accommodation space creation.

Figure 4.3c shows that steam injection into Phase C, primarily at sub-dilation pressures, did not change the trend of the measured pressure of bitumen in the First White Speckled Shales. This constant pressure trend is interpreted to be a result of a lack of accommodation space creation (i.e. minimal dilation results in minimal compression of fluids within the overburden).

Thus, the anticipated extent of compression of bitumen within the overburden is expected to be negligible during steamflood operation.

Interestingly, the bitumen flow rate measurement from Pad 74 FTS has not increased or shown a correlation to CSS operations with material heave (Figure 4.3d). This suggests that the risk of compressing fluids within the overburden causing an increase in FTS rate is low with the proposed plan.

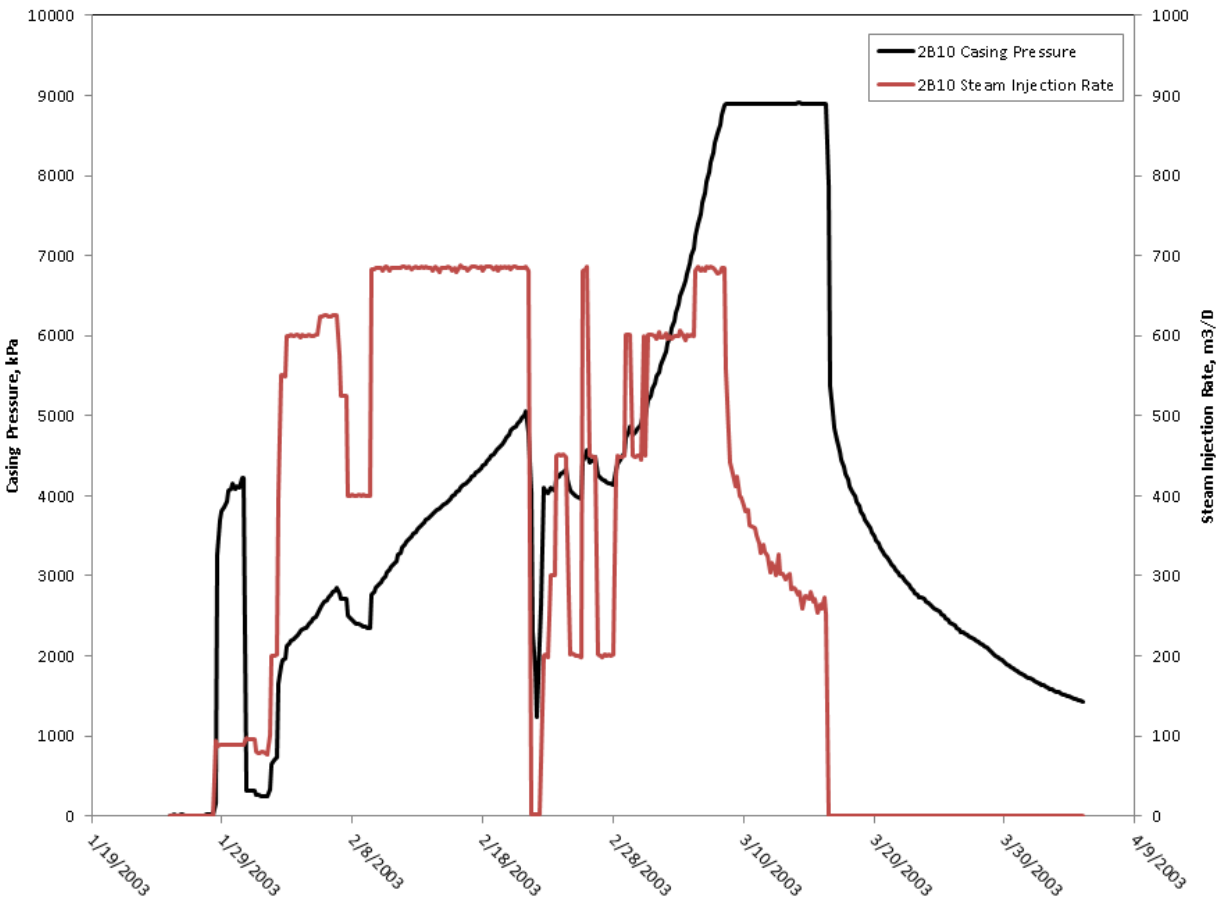


Figure 4.3a **Primrose CSS Well Illustrating Minimal Sand Shear Failure at Injection Pressures Below 9 MPa as Injection Rate Reduces due to Negligible Accommodation Space Creation**

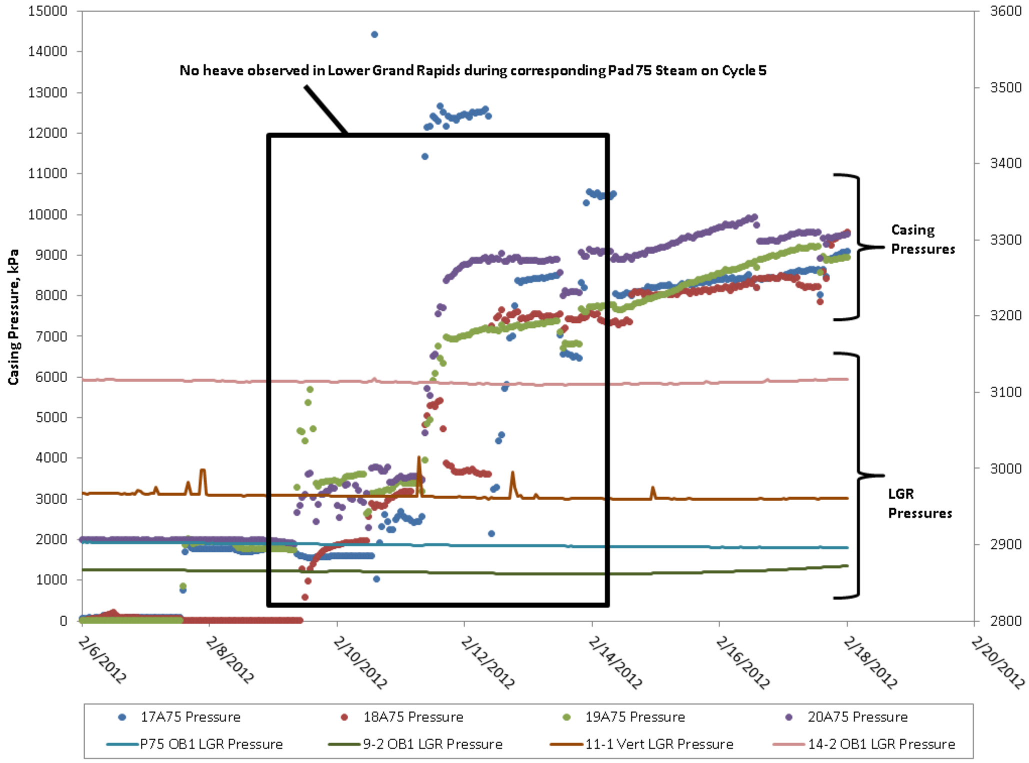


Figure 4.3b **Pad 75 Steaming Pressures During Last Cycle Prior to Full Fill-Up Showing Immeasurable Effects in the Lower Grand Rapids due to Dilation when below 9 MPa**

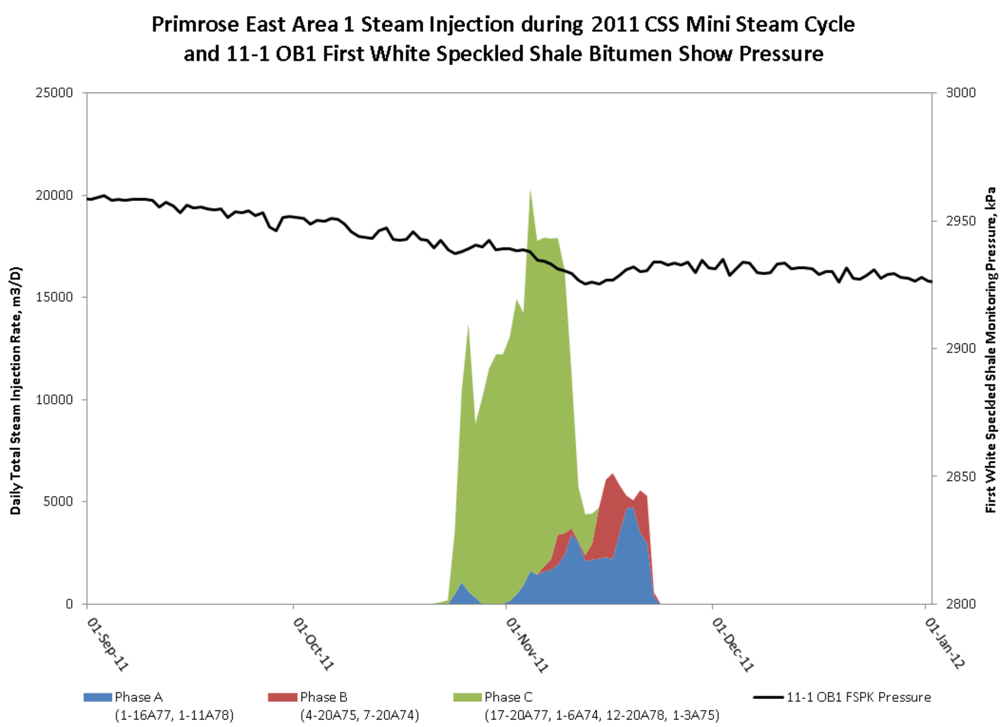


Figure 4.3c **Q4 2011 CSS Mini Steam Cycle Measured No Heave Response in the Bitumen Show within the First White Speckled Shales**

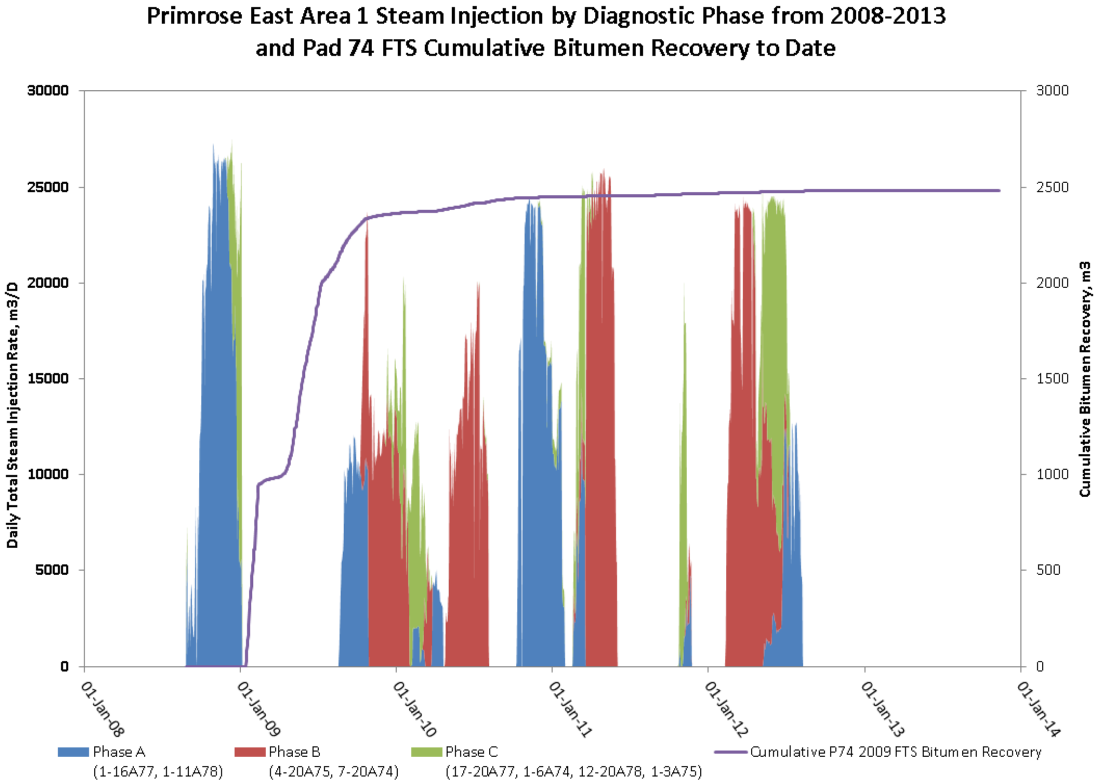


Figure 4.3d **Primrose East Area 1 Steaming History Compared to the Pad 74 2009 Bitumen Recovered at Surface where CSS Operation with Material Heave did not Increase the Pad 74 FTS Flow Rate**

4.4. Conductive Heating of Fluids within Overburden Initiating/Enabling Flow to Surface

Conductive heat transfer within the overburden is insufficient to initiate or enable additional fluid flow to surface or into a freshwater aquifer. Conductive heating of the overburden is split into two parts: conductive heating from wellbores and conductive heating through the Clearwater caprock.

Conduction of heat from wellbores to the overburden will remain confined to the immediate vicinity of build sections. Figure 4.4a illustrates that radial heat transfer effects due to conduction from the build section of wellbores are negligible beyond a 50 m radius after 12 years. Therefore, the majority of the overburden in PRE A1 is unaffected. The FTS locations at 10-1-67-3 and 10-2-67-3 are 650 m and 1350 m away from the nearest build sections respectively (Pad 74).

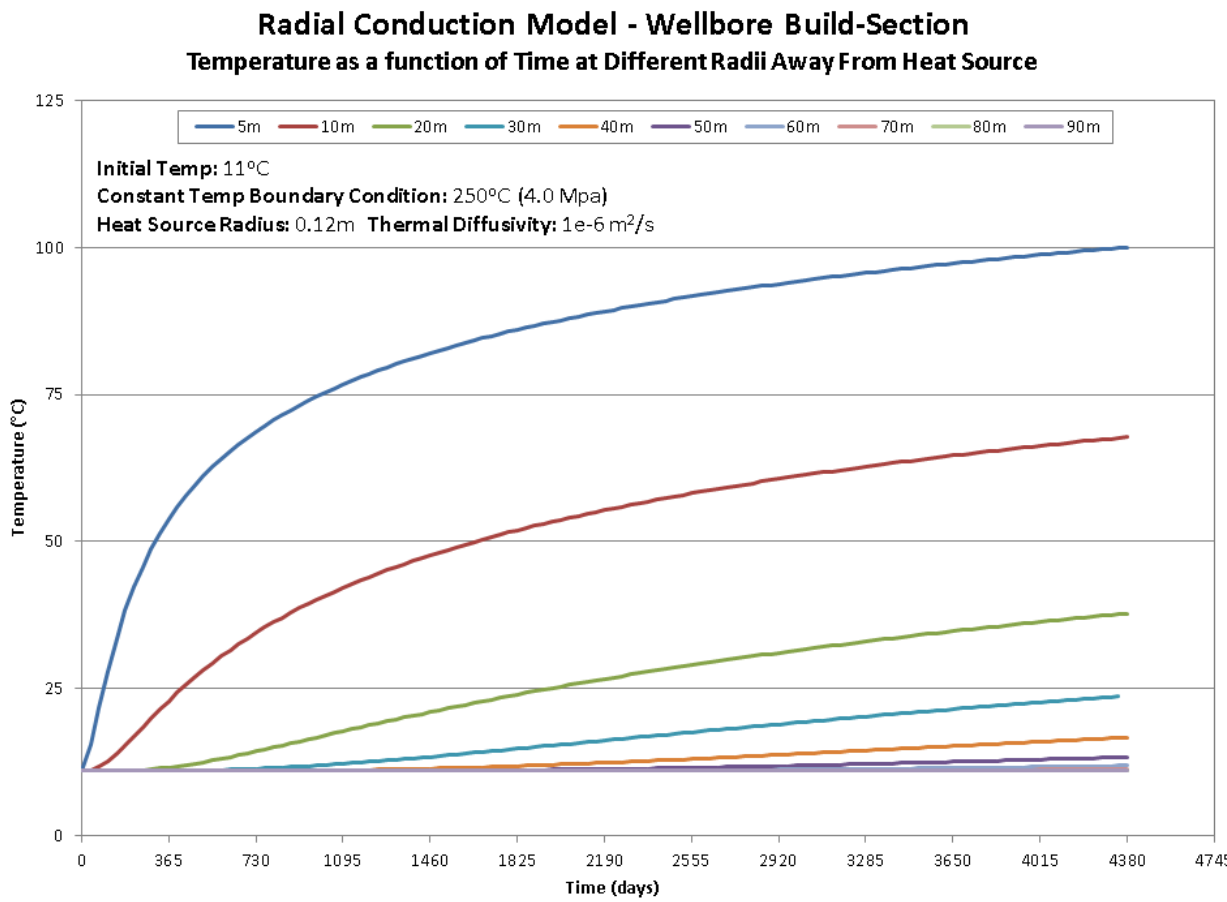


Figure 4.4a **Radial Conduction Temperature Model Simulating Conducted Heat into the Overburden from the Build Section of a Wellbore for a Continuous Steam Process at 4.0 MPa over 12 Years**

Conduction of thermal energy vertically to the overburden from the reservoir will occur over PRE A1. It is estimated that temperature increases due to conductive heat transfer will be confined to the Lower Grand Rapids. This zone is laterally continuous, highly permeable, and water saturated. Thermal expansion of the Lower Grand Rapids fluids results in minimal pore pressure increase due to the high formation permeability and low water viscosity. Additionally, field observations at the Lower Grand Rapids bitumen show at 74 OBS2 demonstrate the extent of pressure diffusion within the water sand over time (Figure 4.4b).

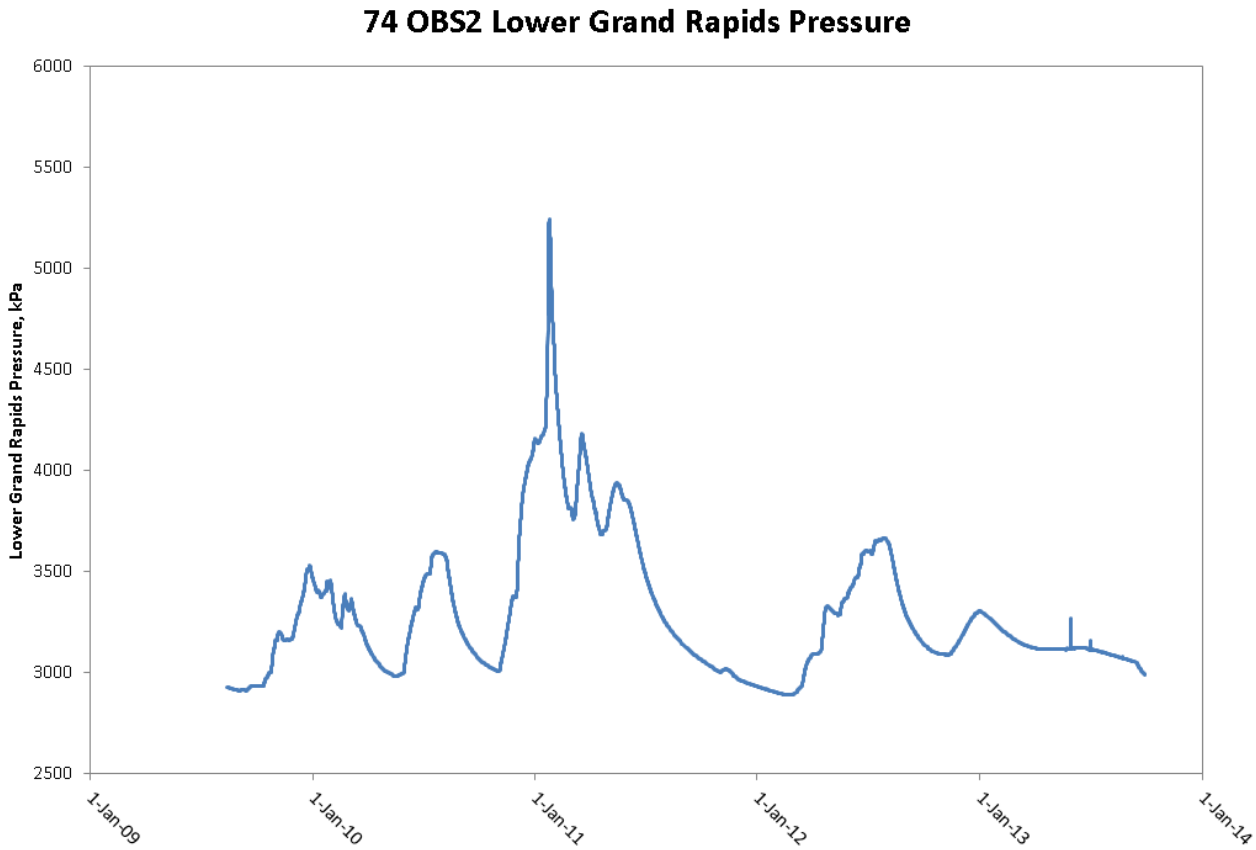


Figure 4.4b **74 OBS2 Lower Grand Rapids Bitumen Show Monitoring Well Response Demonstrating Pressure Diffusion within the Water Sand Over Time**

4.5. Energizing of Potential FTS Pathways along Steaming Wellbores

All steaming wellbores have been previously pressure tested with CSS cycles in the past, in that flow behind pipe would have occurred at historical CSS pressures. Any wellbores with potential pathways have been identified and remediated (1A74 identified and remediated in 2009-2010). Also, Canadian Natural's distributed temperature monitoring systems during diagnostic steam (ran in 1, 2, 3, 9A74 and 19, 20A77) have not indicated flow paths along operational wellbores. Thus, the risk of energizing a FTS pathway along a steaming wellbore is low.

4.6. Interrupting or Compromising the FTS Investigation

Canadian Natural has considered the risk that a steamflood operation poses to the speed and effectiveness of the FTS investigation. Canadian Natural's focus is identifying the specific flow path through the Colorado Group shales. As described earlier, the steamflood operation will have minimal effects on the Colorado Group. In addition, the PRE A1 Clearwater sub-hydrostatic head reservoir pressures show that the existing FTS is not currently connected to the Clearwater.

Regarding delineation well drilling, it is standard practice for thermal operators to drill into active steaming operations with sub-hydrostatic head pressures. Therefore, there will be no impact to Canadian Natural's delineation well schedule. All logging and remediation of producer/injector wells involved with the FTS investigation will be completed prior to the commencing of steamflood operations.

5 Enhanced Formation Integrity Surveillance Plan

The proposed PRE A1 formation integrity surveillance plan includes the trends of Clearwater injection pressure and rate, Clearwater material balance, Lower Grand Rapids pressure and temperature, Quaternary pressure and temperature as well as Thermal Fibre and Passive Seismic monitoring systems.

5.1. Clearwater Injection Pressure, Injection Rate, and Production Rate Monitoring

Canadian Natural will continuously monitor Clearwater injection pressures (tubing and casing wellhead pressures) and steam rates for increased injectivity. This data is analysed to assess casing integrity and fluid containment within the Clearwater. A daily review of injection characteristics will be conducted for all steam injection wells to monitor operating pressures, identify anomalies, and interpret anomalies. Alarms will be implemented into the distributed control system (DCS) for all injector specific maximum operating pressures. In the event of an alarm, Canadian Natural will ensure compliance is maintained by reducing steam injection rates.

Canadian Natural will perform monthly material balance checks on the water injected versus water produced for the area. Analysis on the well pair, pad and area levels will be completed on a monthly frequency with consideration of reservoir pressure trends. After achieving approximately balanced injection and production, any deviations greater than 10% from unity with a constant reservoir pressure will be identified as anomalous. The initial transition period, ending with balanced injection and production, is expected to be approximately 6 months on average but may be significantly longer in areas featuring lower than average depletion levels.

5.2. Lower Grand Rapids Pressure Monitoring

Canadian Natural will monitor Lower Grand Rapids pressure and temperature trends to further understand the interaction between the Clearwater and the formation immediately above the net pay. Currently, Canadian Natural uses a 200 kPa/d alarm criteria for Lower Grand Rapids events during CSS. Since the operating pressure is lower than CSS and an order of magnitude less heave is expected, the proposed alarm criteria for steamflood is 20 kPa/d. Additionally, an absolute pressure alarm of 3.8 MPa in the Lower Grand Rapids would be set for the entire area, which provides for a small amount of additional pressure increase over the current values to account for minor heave induced pore pressure increase.

5.3. Passive Seismic Monitoring

Canadian Natural will use Passive Seismic monitoring at all pads as this has been the primary system for identifying casing failures in the PAW area. No alarm criteria are required to be changed for this system.

5.4. Thermal Fibre Monitoring

Canadian Natural will continue to use Thermal Fibre monitoring at all pads with the intent of identifying lateral fluid movement within zones above the Clearwater reservoir. No alarm criteria are required to be changed for this system. Figure 5.4a shows the planned Lower Grand Rapids pressure monitoring, passive seismic and thermal fibre monitoring systems to be utilized during steamflood operation.

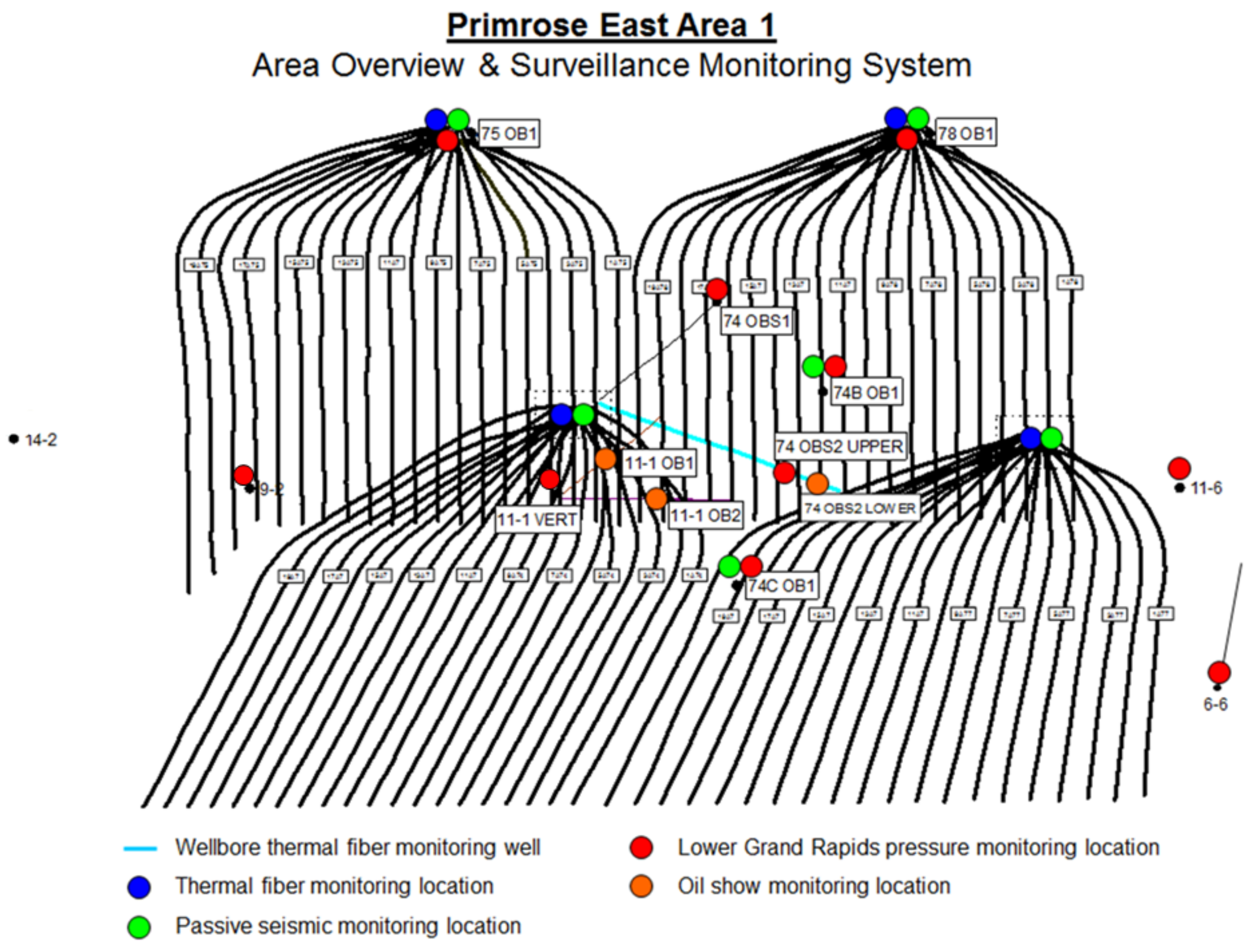


Figure 5.4a Primrose East Area 1 Surveillance Network

5.5. Quaternary Monitoring

Canadian Natural will monitor Quaternary pressure and temperature trends on all pads to identify if any casing integrity issues exist at the Quaternary level. Additionally, the Quaternary system will be used to monitor for any dilation effects.

5.6. Alarm Response

When alarms trigger, investigative steps will be taken to assess the cause of the trigger. In the event of anomalous observations typically associated with casing or formation integrity issues, steam injection rates will be reduced. Service rig investigations will be conducted where appropriate for anomalous observations typically associated with casing integrity issues. In the instance of potential fluid migration from the Clearwater into the Lower Grand Rapids, reservoir pressure management action will be taken based on hydraulic interference testing.

6 Further Considerations for Recommencing Steam Injection

Steam operations are not the only process considered for the Primrose East field. The following non-thermal recovery methods have been considered:

- Waterflood and/or polymer flood will not be successful due to high viscosities of the Clearwater bitumen in this region;
- CHOPS has been demonstrated (by Suncor pilot in area) to be uneconomic with low recovery factor;
- Viscosity reducing floods (miscible or solvent) unsuccessful as a primary depletion technique;
- In-situ combustion is technologically unproven in this type of reservoir within the Western Canada Sedimentary Basin; and
- Clearwater resource is too deep for mining operations to be viable.

Canadian Natural maintains thermal recovery is the best process for Primrose East.

7 Stakeholder Notification

Canadian Natural informed Cold Lake First Nation (CLFN) of the intent to file this Application on December 13, 2013. Although as indicated in Section 1, this application is consistent with an AER Directive 078 Category 2, and therefore notification/consultation is not technically required; Canadian Natural notified CLFN acknowledging that CLFN has concerns with our operations in this area due to the recent flow to surface events.

8 Conclusion

In closing, the request to commence steam injection into select PRE A1 wells contains several benefits in exchange for minimum risk. The proposed recovery scheme addresses the risks associated with FTS, and provides an opportunity for Canadian Natural and the AER to enhance their understanding of options for a follow up process to CSS.

If you have any questions or concerns please contact me at 403-540-4801 or email at **Dan.Lowe@cnrl.com**.

Regards,

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