



Canadian Natural Resources Ltd.
Primrose East Bitumen Emulsion
Release
January 3, 2009

ERCB Investigation Report

January 8, 2013

ENERGY RESOURCES CONSERVATION BOARD

ERCB Investigation Report: Primrose East Bitumen Emulsion Release, January 3, 2009

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Published by

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Executive Summary

On January 3, 2009, a surface release of bitumen emulsion was discovered near the 1A74 wellhead located on Pad 74 in the Primrose East development area of Canadian Natural Resources Limited's (CNRL) Primrose and Wolf Lake project (PAW). The Primrose East development area employs a high-pressure cyclic steam stimulation (HPCSS) process to recover bitumen from the Clearwater Formation. Primrose East is about 350 kilometres northeast of Edmonton, inside the Cold Lake Air Weapons Range.

Bitumen emulsion was observed south and east of the 1A74 wellhead near the southeast corner of Pad 74, and also near two thin surface fissures south and east of Pad 74. On discovering the bitumen emulsion, CNRL immediately shut in all steam injection at Primrose East and initiated emergency flowback to depressurize the formation. Approximately 11 380 tonnes of solids (including snow, organic material, soil, and bitumen) was ultimately removed from the site for landfill disposal, and 904 cubic metres of bitumen was recovered from the surface of Pad 74 and transported to CNRL's Wolf Lake plant.

On May 4, 2009, CNRL submitted its Pad 74 Interim Investigation Report. The report summarized CNRL's static investigation of the bitumen emulsion release over the January 2009 to April 2009 period. The static investigation gathered evidence about the bitumen emulsion release immediately after it was discovered and focused on wellbore integrity, aquifer contamination, and delineation of the bitumen emulsion pathway to surface.

The static investigation's findings were largely inconclusive. As a result, CNRL applied for and received ERCB approval to conduct limited diagnostic steam injection with enhanced monitoring at Primrose East to try to identify the bitumen emulsion release pathway. Diagnostic steam injection did not reactivate the release pathway. However, the ERCB is of the view that the successful steaming at more traditional PAW steam volumes without incident show that HPCSS can be safely conducted at Primrose East.

In February 2011, CNRL submitted its Pad 74 Final Investigation Report, which included the results of the 2009 static investigation, supplemental filings, and the results of the dynamic investigation that took place from August 2009 to March 2010. CNRL concluded that a general pattern of the bitumen emulsion flow path to surface could be inferred, but that a detailed flow path could not be determined with certainty.

The ERCB agrees that the bitumen emulsion pathway cannot be identified with certainty based on the available data. However, the ERCB is of the view that the Clearwater shale was likely breached by high-pressure steam injection not related to a wellbore issue, that the Grand Rapids Formation water sands did not act as a diverter, and that a pathway found through the Colorado Group likely involved a wellbore or a series of pre-existing faults.

The ERCB notes that the steam volume injected in Cycle 1 at Primrose East was significantly higher on a pore volume basis than in past HPCSS operations at PAW due to reduced well spacing. The ERCB is of the view that this likely contributed to the bitumen emulsion surface release. CNRL acknowledged that the Cycle 1 injection volumes may have contributed to the release.

The ERCB is also of the view that geological weaknesses in combination with stresses induced by high-pressure steam injection may have contributed to the release. The geological weakness may be caused by deposition, subsequent erosion, or stressing along the salt collapse edge at Primrose East.

As a result of this incident the ERCB has put limits on the steam injection volumes that CNRL is allowed to inject per cycle. In addition, with the ERCB's concurrence, CNRL has undertaken a pressure monitoring program in the Grand Rapids Formation. When pressure changes are measured, particularly in conjunction with increases in steam injectivity, steam injection is reduced or suspended, as considered necessary.

On a broader scale that encompasses all steam injection operations in Alberta's oil sands, the ERCB continues to review and assess its requirements with respect to both caprock and wellbore integrity issues.

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1 Bitumen Emulsion Release Incident and Response

On January 3, 2009, at approximately 8:00 a.m., a surface release of bitumen emulsion was discovered near the 1A74 wellhead located on Pad 74 in the Primrose East development area of Canadian Natural Resources Limited's (CNRL) Primrose and Wolf Lake project (PAW).

The Primrose East development area employs a high-pressure cyclic steam stimulation (HPCSS) process to recover bitumen from the Clearwater Formation. Primrose East consists of 80 wells on four pads, and is located at Township 67, Ranges 2 and 3, West of the 4th Meridian, approximately 350 kilometres (km) northeast of Edmonton, inside the Cold Lake Air Weapons Range, see Figure 1.

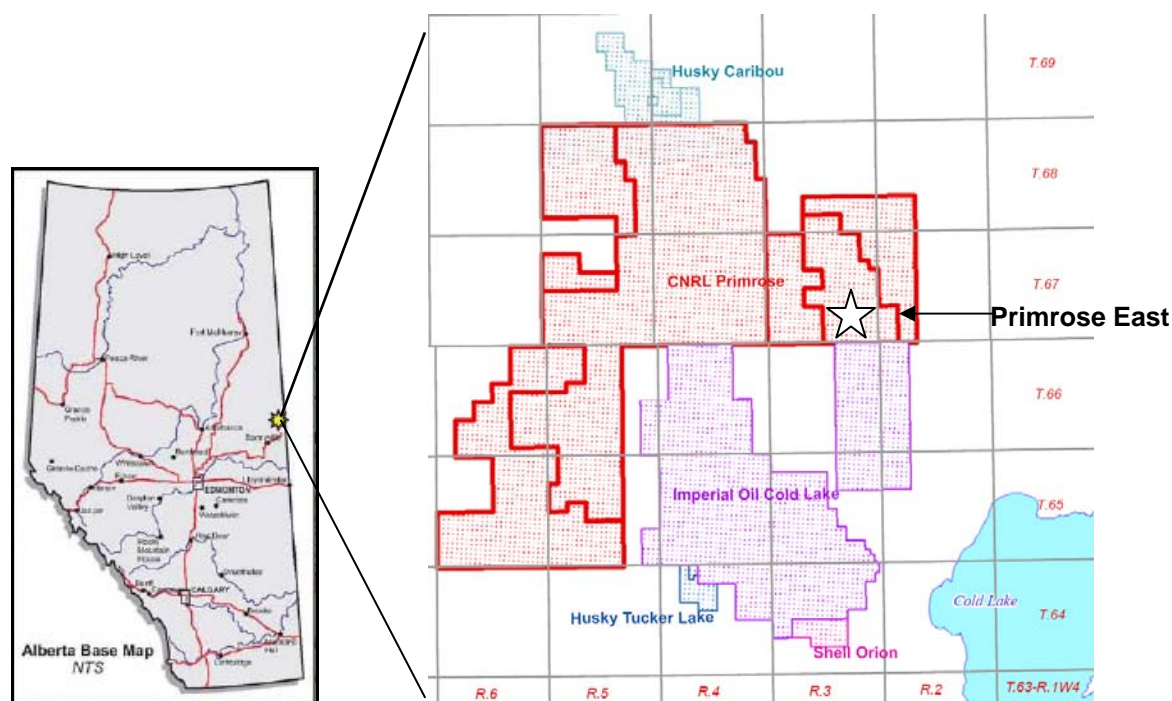


Figure 1. Primrose and Wolf Lake Project

As shown in Figure 2 and Figure 3, accumulations of bitumen emulsion were observed south and east of the 1A74 wellhead near the southeast corner of Pad 74. The bitumen emulsion had flowed south across the top of the pad and had pooled in the ditch located along the inside of the pad's south berm. Bitumen emulsion was also observed near two thin (1 to 2 millimetres) surface fissures south and east of Pad 74. The composition of the bitumen emulsion indicated that it originated in the Clearwater Formation.

On discovering the bitumen emulsion, CNRL immediately shut in all steam injection at Primrose East and initiated emergency flowback to depressurize the formation.

CNRL notified the Energy Resources Conservation Board (ERCB), Alberta Environment and Water (AEW), and Alberta Sustainable Resource Development on January 3, 2009, and ERCB representatives were on site later that day. It was agreed that steam injection would not resume without ERCB approval.



Figure 2. Photo of Pad 74

Since discovering the release, CNRL has removed approximately 11 380 tonnes of solids (including snow, organic material, soil, and bitumen) from the site for landfill disposal, and recovered 904 cubic metres (m³) of bitumen from the surface of Pad 74 and transported it to CNRL's Wolf Lake plant.



Figure 3. Schematic of Pad 74 showing the location of the bitumen emulsion releases

2 Operations Prior to Bitumen Emulsion Release

Development in the PAW project area began in 1980. CNRL acquired the project in 2000 and later expanded and converted the wells from below fracture pressure CSS to HPCSS. In 2007, CNRL received approval to expand the project area to the east. This development, known as Primrose East, included a new steam generation facility and four new pads comprising 80 HPCSS wells at the time of the release.

HPCSS operations at Primrose East use horizontal wells to inject high-pressure steam into the bitumen reservoir. The horizontal wells are about 60 metres (m) apart in the reservoir, and the steam is injected above the reservoir fracture pressure. Steam injection rates are typically 1800 to 2200 m³ per day, with cumulative injection volumes at approximately 80 000 m³ per well.

Each HPCSS cycle consists of an injection phase and a production phase. For the injection phase, CNRL uses a pressurized steam wave strategy by which wells are steamed in a sequential pattern to limit interwell communication. Wells are first steamed to create a steam front that moves away from the injection point. Behind the steam front, the reservoir is allowed to soak before the wells are switched to production. The soaking period not only mobilizes the bitumen but also buffers the producing wells from the wells undergoing high-pressure steam injection. After an initial period of production, the wells must be put on artificial lift. Each HPCSS well goes through a number of cycles throughout its productive life.

Primrose East began Cycle 1 steam injection at Pad 77 on August 29, 2008, and on September 25, 2008, steam injection began on Pad 78. By October 1, 2008, a seven-row steam wave had been established, and Cycle 1 production began on October 17, 2008. At the time of the bitumen emulsion release, 26 wells at Primrose East had completed their first steam injection cycle. The Primrose East well operation status on January 2, 2009, is shown in Figure 4.

At the time of the incident, Primrose East had passive seismic and thermal fibre monitoring wells on each pad to detect horizontal movement of fluid in the shales of the Colorado Group. Each HPCSS well was also monitored using a differential pressure alarm to detect well failures. While these systems were determined to be working correctly at the time of the failure, none detected the loss of containment.

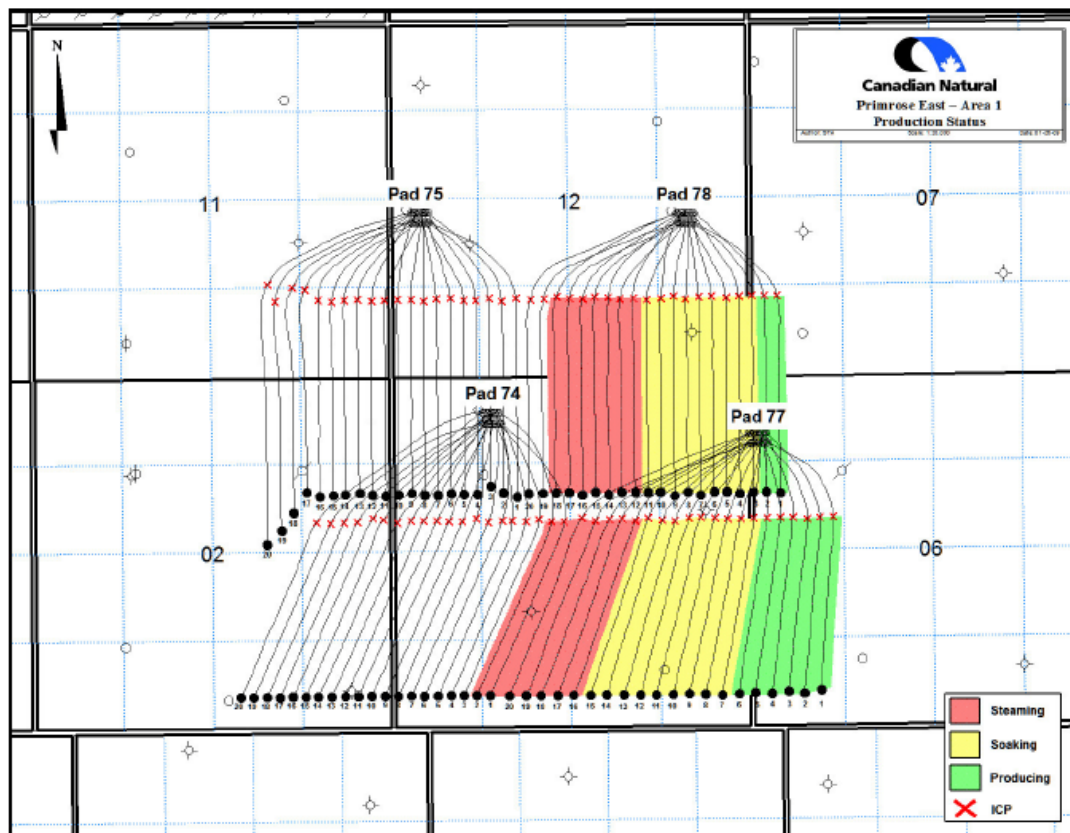


Figure 4. Primrose East well operation status on January 2, 2009

3 Investigation

On May 4, 2009, CNRL submitted its Pad 74 Interim Investigation Report. The report summarized CNRL's static investigation of the bitumen emulsion release over the January 2009 to April 2009 period. In February 2011, CNRL submitted its Pad 74 Final Investigation Report, which included the results of the 2009 static investigation, supplemental filings, and the results of a dynamic investigation that took place from August 2009 to March 2010.

3.1 Static Investigation

The static investigation gathered evidence about the bitumen emulsion release immediately after it was discovered, and focused on wellbore integrity, aquifer contamination, and delineation of the bitumen emulsion pathway to surface.

3.1.1 Wellbore Integrity

CNRL reviewed the well design and construction data and did diagnostic work on all wells that had been steamed and on all wells that may have played a role in the surface release.

The review of the well design and construction data included an assessment of dog leg severity, drilling procedures, casing and connections, cementing, and pre-steam conditioning. The review indicated that the design and construction of all wells was consistent with other wells operated by CNRL at the PAW project.

The diagnostic work included fluid suppression tests, multi-sensor caliper (MSC) logs, residual saturation tool (RST) logs, temperature logs, and cement bond logs. This work did not point conclusively to a single or multiple well failure or pathway.

3.1.2 Aquifer Contamination

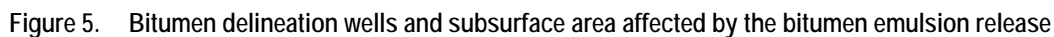
As part of the Primrose East development, two aquifer monitoring wells had been drilled on Pad 77. One monitoring well had been completed in the Bonnyville Formation Unit 1 (Bonnyville Aquifer), and the second monitoring well had been completed in the Upper Quaternary. During the static investigation, 28 additional monitoring wells were drilled to delineate the aquifers in the area and to assess any impacts on non-saline aquifers. Twenty-five of these wells were equipped with transducers capable of recording pressure and temperature. Three wells down gradient of the surface fissures were also monitored for electrical conductivity.

Investigation of the Quaternary sediments focused on evaluating impacts on the Bonnyville Aquifer, which is recognized as the only domestic-use aquifer at Primrose East. Bitumen emulsion and anomalously high pressures were discovered at four of the Bonnyville Aquifer monitoring wells located along the interpreted trace of the surface fissures.

CNRL conducted a study that assessed the solubility of bitumen emulsion constituents as a function of temperature to predict what effects temperature would have on bitumen solubility. There remains uncertainty about how the bitumen emulsion will break down over time with heat from further steam injection and about what constituents may be released into the Bonnyville Aquifer.

- 1) Monitor the movement of contamination down gradient in the Bonnyville Aquifer.
- 2) Further understand the effect of heating from steam injection on the movement of bitumen contamination within the Bonnyville Aquifer.
- 3) Monitor any further releases of bitumen emulsion from the Clearwater Formation.

CNRL drilled six wells to delineate the subsurface areal extent of the bitumen emulsion release and to help identify the bitumen pathway to surface. Figure 5 shows the location of these six wells and an estimate of the subsurface area affected by the release.



3.2 Dynamic Investigation

Findings from the static investigation were largely inconclusive. As a result, CNRL applied for and received ERCB approval to conduct limited diagnostic steam injection with enhanced monitoring to help in the investigation. The key objectives of the diagnostic steam injection were

- to identify the location and mechanism of the Clearwater shale breach as the originating source of the Pad 74 release, and
- to identify the release pathway.

Diagnostic steam injection occurred between August 2009 and March 2010 in three phases and areas as shown in Figure 6.

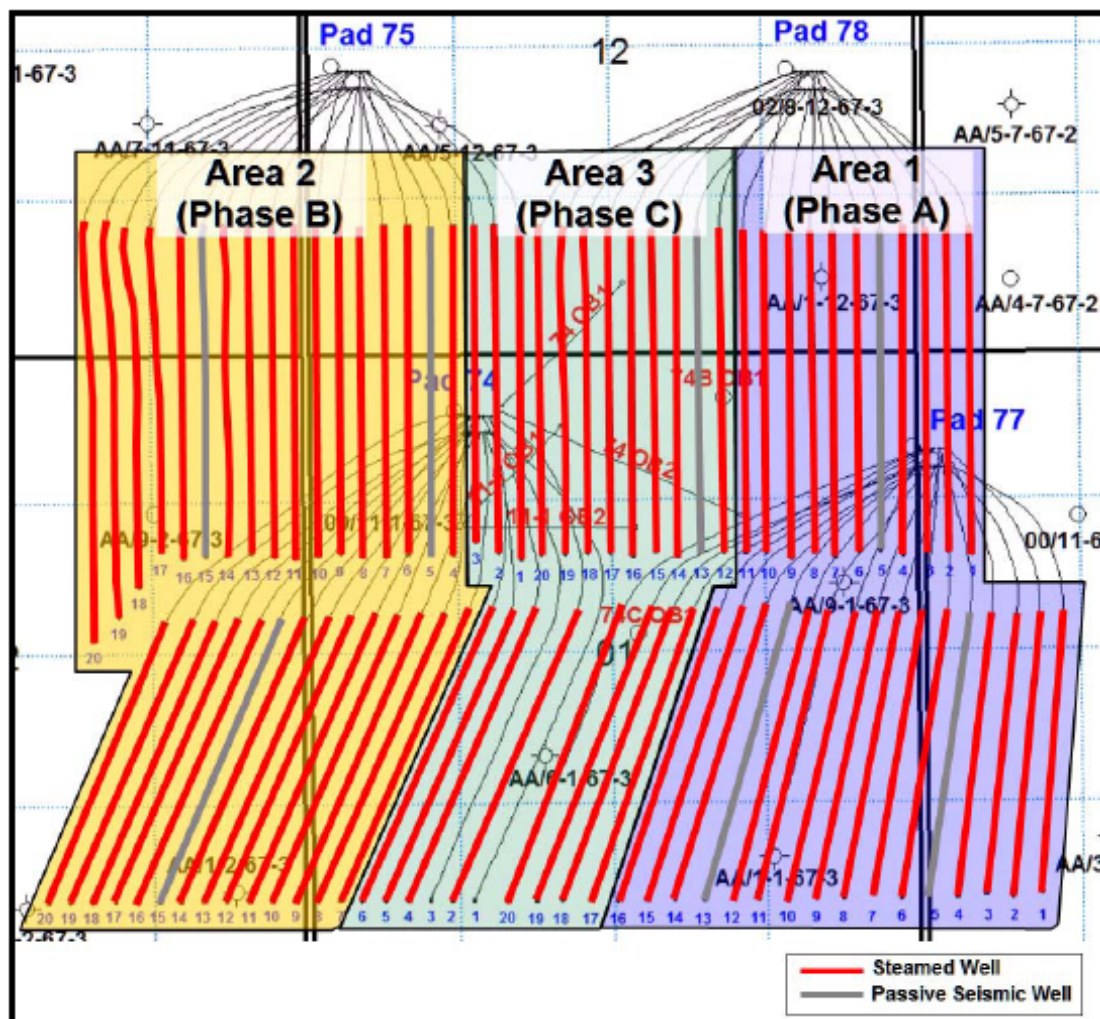


Figure 6. Primrose East diagnostic steam injection phases and areas

3.2.1 Objectives

The objective of Phase A was to resteam those wells that had been steamed prior to the bitumen emulsion release and to observe the reservoir response with enhanced monitoring equipment. To prevent a possible reoccurrence of a bitumen emulsion release, steam injection rates were reduced to about 50 per cent of the initial steaming rates.

During Phase A, the wells were steamed for about 30 days at an injection rate of 2000 m³/day/well. The steam wave started at the 1A77 well and moved westward to the 15A77 and 11A78 wells. Due to the close interwell spacing (60 m), there was significant communication between wells, and leak-off made it difficult to reach fracture pressure.

The objective of Phase B was to acquire baseline heave response data, determine whether the vertical fractures would be contained within the Clearwater Formation, and change the minimum stress regime of the reservoir. Phase B involved two cycles of steam injection on those wells that had previously only been preconditioned with about 1000 m³ of steam per well.

In the first cycle of Phase B, steam injection was limited to 10 000 m³ per well. In the second cycle, 35 000 m³ of steam per well at a rate of 2000 m³/day/well was injected. The steam wave started at the 20A75 well and moved eastward to the 3A75 and 7A74 wells.

The objective of Phase C was to use multiple stages of steam injection to confirm that the bitumen emulsion release pathway originated at or near the 1A74 well, and to confirm that most of the flow pathway involved the 1A74 well.

In Phase C, steam injection occurred in four stages, beginning at 1000 m³/d in the first stage and increasing to 2000 m³/d by the fourth stage. During the first three stages, only two wells were steamed at any one time, increasing to six wells during the fourth stage. In the first three stages the wells were operated below fracture pressure. The fourth stage was operated at fracture pressure. The combined volume of steam injected during all four stages was less than that for other PAW wells.

3.2.2 Enhanced Monitoring Program

The enhanced monitoring program consisted of a deepened thermal fibre system, deepened passive seismic system, Grand Rapids pressure monitoring, bitumen in shale monitoring, and aquifer monitoring. This was in addition to the existing standard differential pressure monitoring and passive seismic/thermal fibre systems designed to identify casing failures and fluid migration due to flow behind pipe, mainly within the Colorado shales.

Thermal Fibre System

A thermal fibre system had been installed at Primrose East to monitor the Colorado shales for containment loss resulting from wellbore-related issues. For the diagnostic steam injection, the thermal fibre system was expanded and deepened to cover the Grand Rapids and Clearwater Formations. The deepened thermal fibre system included 13 wells: seven observation wells above the Clearwater Formation and six converted production wells in the upper interval of the Clearwater Formation, including the 1A74 and 2A74 wells. The enhanced thermal fibre system was designed to identify reservoir containment loss and determine the role that wellbores may have played in the release.

Thermal fibre data collected from the 1A74 and 2A74 wells did not show evidence of near-wellbore or behind-casing flow in the Colorado shale and Westgate intervals, convective heat transfer at the interface between the Grand Rapids and Joli Fou Formations, or significant conductive cooling at the top of the Clearwater Formation.

The thermal fibre data also indicated that during the diagnostic steam injection, there was no loss of Clearwater reservoir containment, nor were any hydraulically induced horizontal fractures observed to intersect the original Colorado shale thermal fibre wells.

Passive Seismic System

A passive seismic system consisting of geophone arrays had been installed on all four pads at Primrose East. These geophone arrays were spaced at equal distances across the Colorado shales and were designed to identify responses that might indicate loss of Clearwater reservoir containment. The passive seismic system was expanded for diagnostic steam injection by adding deeper arrays of geophones in the Lower Grand Rapids Formation in eleven additional wells: four vertical observation wells and seven production wells.

Passive seismic monitoring across the Colorado shales was designed to detect hydraulically induced horizontal fractures. The deeper passive seismic monitoring was designed to detect seismic events associated with shear failure or fluid flow from the top of the Clearwater Formation into the Lower Grand Rapids Formation.

During diagnostic steam injection, microseismic activity associated with deformation of the Clearwater Formation was observed, but there was no indication of fracture growth. Microseismic activity observed in the Grand Rapids Formation was determined to be associated with heave.

Grand Rapids Pressure Monitoring

A network of 10 wells was installed in the Lower Grand Rapids Formation to detect any Clearwater shale breaches and to help determine the location of the breach that led to the bitumen emulsion release. During diagnostic steam injection, the pressure monitoring system detected the expected heave-related responses, but no breaches were detected.

Bitumen in Shale Monitoring

Bitumen emulsion originating from the Clearwater Formation was encountered in the Westgate Formation at the 11-1 OB2 well, which was drilled as part of the static investigation.

Pressure and temperature data collected at the 11-1 OB2 well during diagnostic steam injection did not indicate hydraulic communication between the Westgate and Clearwater Formations. The pressure response was more stable than would have been expected from poroelastic heave. CNRL stated that it was likely due to the effects of heave on trapped pockets of bitumen within the Westgate Formation from the initial release. The temperature data from the 11-1 OB2 was also generally stable. This data supported CNRL's contention that the release pathway was not reactivated during diagnostic steam injection.

Aquifer Monitoring

During diagnostic steaming, 25 aquifer monitoring wells were monitored for pressure and temperature, and three of these wells down gradient of the surface fissures were also monitored for electrical conductivity. The Bonnyville Aquifer was also sampled every two weeks to detect the release of fluids.

Pressure and temperature measurements showed poroelastic effects on the Bonnyville Aquifer. The data collected from the monitoring wells near the surface fissures were difficult to interpret due to poroelastic effects on both the fracture and the aquifer. During diagnostic steaming, no release of fluids into the Bonnyville Aquifer was detected.

4 Geology

4.1 Views of CNRL

4.1.1 Stratigraphy and Depositional Environments

CNRL used the stratigraphic nomenclature presented in Figure 7 for the Primrose East area. The following is a summary of CNRL's interpretation for the main stratigraphic units within Primrose East from oldest to youngest.

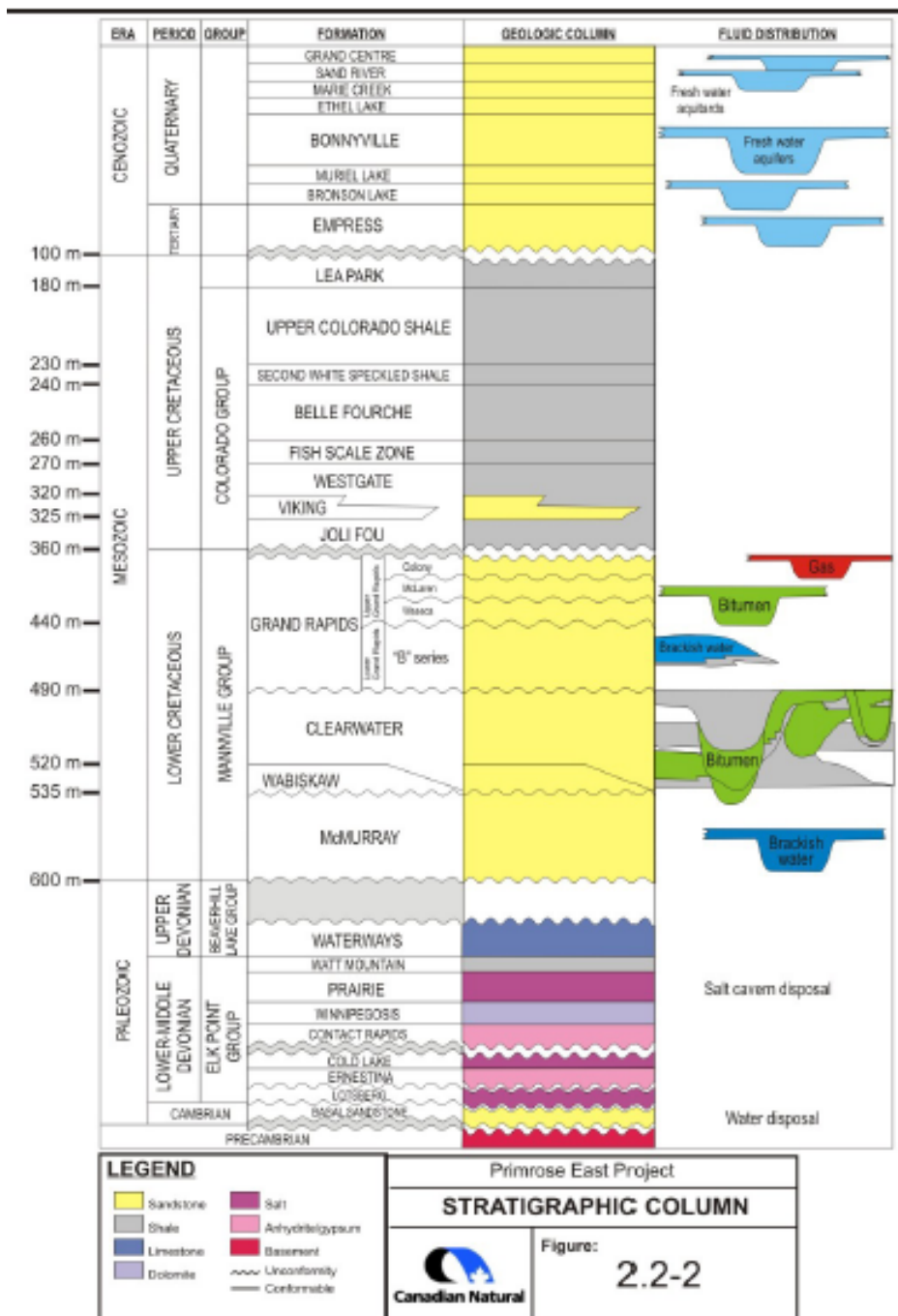


Figure 7. Primrose East stratigraphic column

- The Devonian strata lie unconformably on the Cambrian sandstones. The Devonian consists of calcareous shales and argillaceous limestones of the Beaverhill Lake Group and various carbonate and evaporite rocks of the Elk Point Group. These Devonian carbonates and evaporites have undergone differential erosion and dissolution by meteoric water, which caused subsidence before, during, and after Mannville Group deposition. This dissolution and subsidence is evident in the Paleozoic top structure map and in the structural cross-sections provided by CNRL. Forty metres of relief over the salt

dissolution edge is visible on the time structure map on the Paleozoic unconformity shown in Figure 8. The average thickness of the Devonian strata is 600 m.

- The main structural element affecting the deposition of the Lower Mannville sediments in the Primrose East area is the south-east plunging Athabasca Anticline, interpreted to be caused by the dissolution of salt deposits from the Middle Devonian Prairie Evaporite Formation.

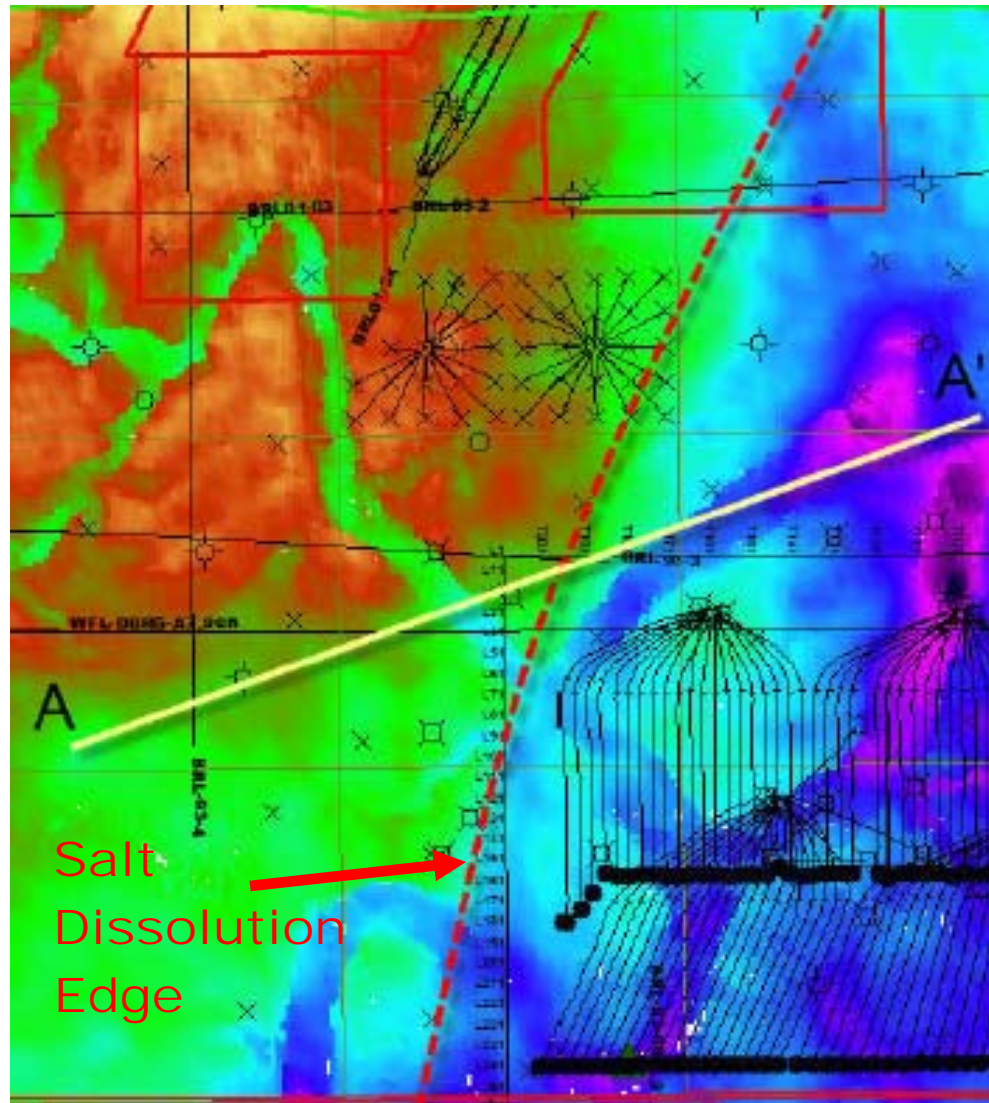


Figure 8. Time structure map of the Paleozoic unconformity

- Immediately overlying the pre-Cretaceous unconformity is the McMurray Formation. The McMurray Formation consists of sands and shales interpreted as fluvial or estuarine channel deposits overlain by regional sandstones. The average thickness of the McMurray Formation is 100 m.
- The Wabiskaw Member is the lowermost member of the Clearwater Formation and unconformably overlies the McMurray Formation. The Wabiskaw is on average 10-15 m thick and was deposited in a shallow marine environment.

- In Primrose East, the Clearwater Formation consists of two stacked sequences, forming some of the thickest and richest reservoir at PAW. The valley thins abruptly to 3 m towards the east and more gradually to the west. The thickest part of the valley coincides with a structural low and is up to 30 m thick.
- The Grand Rapids Formation can be subdivided into the Upper and Lower Grand Rapids. The Upper Grand Rapids consists of the Colony, McLaren, and Waseca. The Lower Grand Rapids consists of amalgamated sands from a number of parasequences.
- The Colorado Group and the overlying Lea Park Formation is a shale interval with a combined thickness from 140 to 300 m. CNRL believed the variable thickness of these shales is the result of post-Cretaceous erosion combined with subsidence. CNRL said that these shales are the seals for fluids (including gas) in the Clearwater and Grand Rapids Formations. Similarly, they are an effective barrier to communication between any fluids associated with production from or injection into the Clearwater or Grand Rapids and fluids of the Quaternary freshwater aquifers. The Colorado Group consists of the following units:
 - Joli Fou Formation—consists of dark gray, noncalcareous shale with siltstone interbeds and bentonites.
 - Viking Formation—consists of upward coarsening silty and fine-grained sand. CNRL observed that commonly, towards the base, interbedded shales become abundant.
 - Westgate Formation—consists of a wedge of noncalcareous mudstone and siltstone. The gray mudstone dominates the top and base intervals, whereas coarsening-upwards intervals of siltstone to sandstone are mainly concentrated in the middle part of the formation.
 - Fish Scales Formation—consists of well-laminated claystone and mudstone and is approximately 6 m thick.
 - Belle Fourche Formation—consists of noncalcareous to slightly calcareous mudstone and siltstone.
 - Second White Speckled Shale Formation—consists of calcareous claystone to siltstone and is distinctively fissile in core.
 - Upper Colorado Group shale—consists of the Verger Member (about 4 m thick), the Cold Lake Member (about 21 m thick), and the First White Specks Member. CNRL notes that all three members are predominantly shale.

4.1.2 Caprock Integrity

In characterizing the caprock integrity of the geologic column overlying the Clearwater Formation at Primrose East, CNRL recognizes three dominant characteristics that act to prevent vertical migration of fluids. CNRL believes that the strata overlying the Clearwater Formation provides multiple barriers to vertical flow in the event that the Clearwater shale, which directly overlies the Clearwater bitumen reservoir, is compromised. These three characteristics are

- high horizontal stresses within competent shales and in particular high stress contrasts,
- lack of high-angle natural fracturing, and
- presence of high-permeability sands in the Lower Grand Rapids Formation that help impede vertical fluid migration through lateral fluid leak-off.

CNRL defines a competent shale as having a relative lack of natural fracturing and in particular a lack of high-angle natural fracturing. CNRL cited its previous work to characterize the strata overlying the Clearwater Formation in terms of stresses, geomechanical properties, and natural fracture tendency. Within the geologic column at Primrose East, CNRL submits that there are several barriers that form a highly redundant containment system. CNRL believes the principle barriers to vertical fracture propagation are the

- Clearwater shale,
- Lower Grand Rapids sands and shales,
- Joli Fou shale,
- Westgate shale,
- Belle Fourche shale, and
- Second White Speckled shale.

CNRL interprets that the Clearwater shale is the most immediate barrier to vertical fracture propagation at Primrose East. CNRL describes the Clearwater shale as comprising two units with a combined average thickness of 4-6 m. The lowermost shale unit is 2-3 m thick and is overlain by an additional 2-3 m of silty shale. The base of the silty shale is a thin storm deposit of fine, hummocky, cross-stratified sand. At Primrose East, this fine sand is not bitumen stained, which CNRL believes proves the sealing capacity of the underlying shale. Illite and smectite dominates the clay component of the shale and silty shale units. Formation micro-imaging (FMI) logs from four wells at Primrose East identified very few natural fractures in the Clearwater shale. Furthermore, 3D seismic data showed no evidence of larger-scale faulting or fracturing extending through the Clearwater shale.

CNRL submits that the Clearwater shale acts as a competent barrier to HPCSS operations due to its plasticity, lack of natural fractures, high stress contrast, and significant ductility contrast with the Clearwater sand. However, CNRL does not rule out the possibility of the presence of local geologic weaknesses within the Clearwater shale.

CNRL interprets the shales and permeable water sands of the Lower Grand Rapids Formation to be the second barrier to vertical fracture propagation at Primrose East. CNRL believes that fluid exiting the Clearwater Formation would leak off into these permeable water sands, thereby stopping a vertically propagating fracture. Regionally extensive shales between the permeable water sands, which have not been eroded, act as further barriers and baffles to fracture propagation or fluid migration. FMI logs from four wells at Primrose East support there being few fractures, and the examination of core from the 5-22-67-4W4 well found no fractures.

CNRL considers the Joli Fou shale, which is the lowermost shale of the Colorado Group, to be the third barrier above the Clearwater bitumen reservoir. CNRL described the Joli Fou Formation as a highly stressed and ductile shale. The FMI logs from four wells at Primrose East and one well at 8-21-67-4W4 (PAW) identified evidence of natural fracturing in one well. The Joli Fou shale is the primary seal for the numerous large gas pools found at the top of the Grand Rapids Formation at Primrose East, and CNRL believes this further demonstrates its integrity.

CNRL describes the Westgate shale as a 45-50 m thick wedge of highly stressed, ductile, non-calcareous mudstone and siltstone. Based on FMI logs and core interpretation, CNRL submits that the Westgate contains little evidence of natural fractures. CNRL considers the

Westgate as an extremely robust fourth barrier that does not permit vertical fracture propagation.

The fifth barrier is the Belle Fourche shale, which consists of more than 20 m of highly stressed, ductile shale showing, in FMI logs, minimal evidence of natural fractures.

CNRL notes the Second White Speckled shale is the sixth barrier. It is 8-9 m thick and slightly less ductile. Based on CNRL's interpretation of five FMI logs, this shale exhibits no evidence of natural fractures.

Microfracture stress testing at Primrose East shows that horizontal fracturing is favoured in all formations (Westgate, Joli Fou, Grand Rapids, and Clearwater) tested.

4.1.3 Seismic

CNRL used 3D and 4D seismic to delineate structures of different formations, identify formation tops, generate isopach maps, identify gas and steam pockets, and monitor changes within the Clearwater Bitumen reservoir that are due to steam injection. Seismic was also used in an attempt to detect faults. CNRL stated that in both pre- and post-steam injection seismic shoots, no faults were identified that could provide a direct conduit to allow for fluid migration from the Clearwater Bitumen reservoir to surface.

4.1.4 Hydrogeology

AEW defines a domestic use aquifer as a geological unit that is above the base of aquifer protection and has a bulk hydraulic conductivity of 1×10^{-6} metres per second (m/s) or greater and sufficient thickness to support a sustained yield of 0.76 litres per minute or greater. CNRL identified the Bonnyville Aquifer as the only domestic use aquifer at Primrose East.

Quaternary sediments at Primrose East are approximately 100 m thick and composed of unconsolidated clay and clay till with interbedded silt, sand, and gravel deposits. The base of aquifer protection at Primrose East is defined as the base of the Quaternary sediments plus a 15 m buffer. Nonsaline aquifers at Primrose East are present only within the Quaternary; deeper units contain saline aquifers. Aquifer flow at Primrose East and locally at Pad 74 is towards the southeast.

The Bonnyville Aquifer occurs at depths of 75-100 m and contains multiple sand and gravel lenses. In the area of Pad 74, the Bonnyville Aquifer is further subdivided into the Upper Bonnyville Aquifer and the Lower Bonnyville Aquifer as there are two continuous sand and gravel lenses separated by clay and clay till. The separation between the Upper Bonnyville Aquifer and the Lower Bonnyville Aquifer is more apparent to the southeast and less apparent to the northeast.

4.2 Views of the ERCB

4.2.1 Stratigraphy and Depositional Environments

The ERCB agrees with CNRL's geological interpretation of the stratigraphic framework identified at Primrose East, and of its depositional environments, approximate thickness, depth of occurrence, lithologies, and facies associations. The ERCB also agrees with CNRL's interpretation of structural controls at Primrose East. Of particular note is the formation of the Athabasca Anticline through the dissolution of Devonian evaporates and the development of

karsting along the sub-Cretaceous unconformity. The ERCB believes that these structural features provide a setting where fracturing and faulting of the Cretaceous strata is highly likely.

4.2.2 Caprock Integrity

The ERCB agrees with CNRL that the barriers to vertical fracture propagation at Primrose East are the Clearwater shale, Joli Fou shale, Westgate shale, Belle Fourche shale, and Second White Speckled shale. However, the ERCB does not agree with CNRL's characterization of the Lower Grand Rapids water-bearing sands as a barrier to vertical fracture propagation. While it may divert the upward flow of fluids and act as a pressure sink if encountered by a vertical fracture, it is not a barrier. The ERCB does agree that the Lower Grand Rapids shales, where not eroded, will act as local baffles.

The ERCB agrees with CNRL's interpretation that the Clearwater shale consists of two units, a regional marine shale and a silty shale, which are laterally continuous. However, the ERCB believes that the variable relative thickness, the interlaminated and intercalated character of the shales and silts, the mineralogical composition, and especially the clay/silt ratio may not result in a competent seal for HPCSS in localized areas. The ERCB further believes that the proximity of Primrose East to the underlying salt scarp may create local geologic weaknesses within the Clearwater shale, which could result in breaching of these shales during HPCSS operation.

The ERCB believes that the Colorado Group, especially its lower units, the Joli Fou and Westgate Formations, is the most reliable barrier to vertical fracture propagation at Primrose East. Based on log interpretation, these two lower units have the highest clay content and exhibit no or low natural fracture frequency. The ERCB agrees with CNRL's interpretation of the presence of natural fractures; however, the ERCB believes that where fractures or faults were not identified, the reason could be that these features were below the detection limits of the tools used. The lack of fractures on FMI logs does not rule out the possibility that these fractures exist elsewhere.

4.2.3 Seismic

The ERCB agrees with CNRL that 3D seismic can effectively delineate and map the Paleozoic unconformity, the Viking Formation, and the Colorado Formation, but due to low impedance, it cannot identify and directly map the top of the Clearwater and Grand Rapids Formations. Furthermore, conventional 3D seismic resolution cannot detect fractures in general, or faulting with throws smaller than about 3 m. The ERCB concludes that the inability of seismic to detect faults with a throw below about 3 m does not rule out the possibility that those faults exist.

4.2.4 Hydrogeology

The ERCB agrees with CNRL's identification of the Bonnyville Aquifer as the only domestic use aquifer at Primrose East. The ERCB agrees that nonsaline aquifers at Primrose East are present only within the Quaternary and that aquifer flow at Primrose East and locally at Pad 74 is toward the southeast.

5 Bitumen Emulsion Release Scenarios

5.1 Views of CNRL

CNRL concluded that a general pattern of the bitumen emulsion flow path to surface could be inferred, but that a detailed flow path could not be determined with certainty. Figure 9 shows CNRL's three probable release pathway scenarios, of which CNRL claimed that scenarios A and B were the most likely.

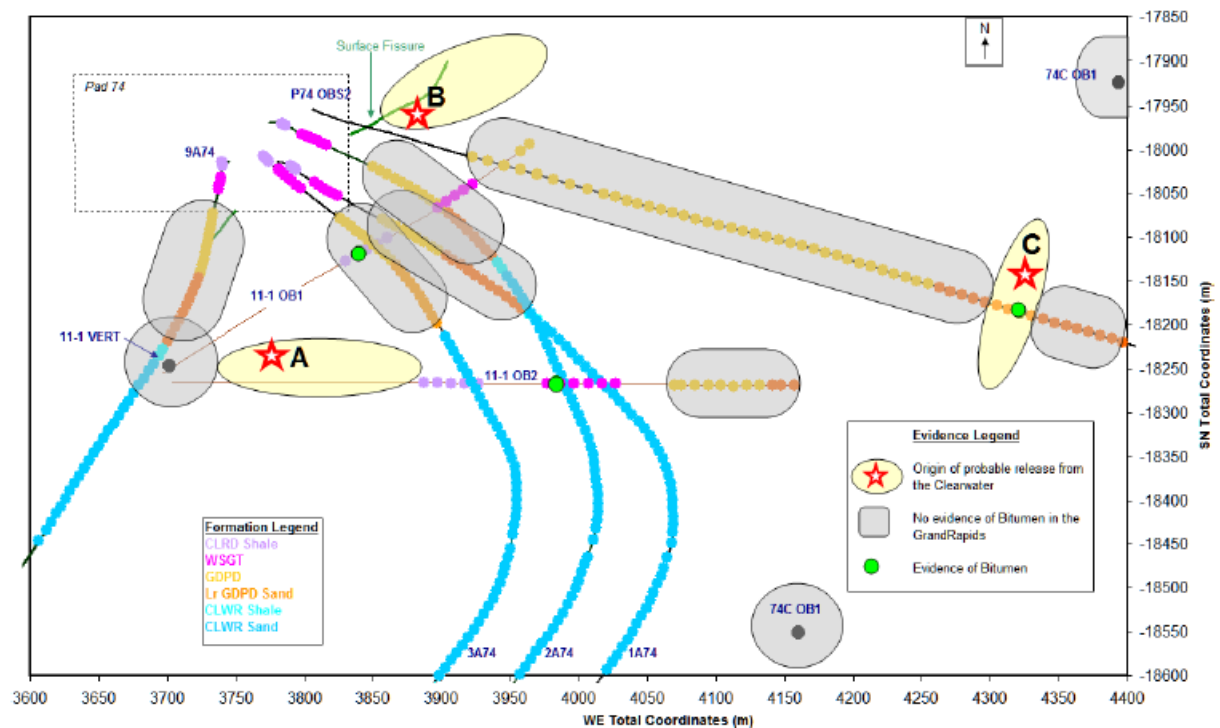


Figure 9. Probable Bitumen Emulsion release pathways

The following three pathway scenarios are described, beginning at the Clearwater Bitumen reservoir to the surface.

Scenario A

- 1) Flow in Clearwater reservoir and breach through Clearwater shale about 300 m south of Pad 74. (Refer to Figure 9).
- 2) Steam-induced north-south-oriented vertical fracture to the top of the Grand Rapids formation.
- 3) Induced horizontal fracture at the base of the Joli Fou shale and intersection with the 2A74 wellbore.
- 4) Flow along the 2A74 wellbore within Colorado Group to an elevation of 315 true vertical depth (TVD—depth at which the temperature log on 1A74 shows constant temperature).
- 5) Induced horizontal fracture at 315 TVD and intersection with the 1A74 wellbore.
- 6) Flow along the 1A74 wellbore to the top of the Colorado Group (to Lea Park).

- 7) Vertical flow along an induced fracture to the top of Lea Park Formation.
- 8) Continued flow along an induced vertical fracture through Quaternary drift and its Bonnyville Aquifer to surface.

CNRL submitted that Scenario A carried a level of improbability since the stress state measurements in the Clearwater shale favoured horizontal fractures, the geomechanical modelling predicted that failure of the Clearwater shale should not occur with the heave loads introduced during pre-release steam injection, and it was difficult to reconcile the absence of bitumen in the Westgate Formation at the 11-1 OB1 well with the bitumen show at the 11-1 OB2 well.

Scenario B

- 1) Flow in Clearwater reservoir and breach through Clearwater shale immediately east of Pad 74 (refer to Figure 9).
- 2) Induced vertical fracture in the Grand Rapids to top of formation.
- 3) Steps 3-8 are the same as in Scenario A.

CNRL submitted that Scenario B carried a similar level of improbability as Scenario A for the same reasons stated above.

Scenario C

- 1) Flow in Clearwater reservoir and breach through Clearwater shale directly below the bitumen show in the 74 OBS2 wellbore (refer to Figure 9).
- 2) Induced vertical fracture in Grand Rapids to top of formation.
- 3) Flow along a pre-existing fault or a series of interconnected minor pre-existing faults to the position of bitumen show in the Westgate Formation within the 11-1 OB2 wellbore.
- 4) Continued flow along a pre-existing fault or a series of interconnected minor pre-existing faults to the position of the bitumen show in the Colorado shale interval within the 11-1 OB1 wellbore.
- 5) Flow along an induced horizontal fracture at the top of the Colorado shale interval to intersect the 1A74 wellbore.
- 6) Flow along the 1A74 wellbore at the base of the Lea Park Formation.
- 7) Steps 7 and 8 are the same as Scenarios A and B.

CNRL submitted that Scenario C carried a relatively high level of improbability because of the conflicting evidence collected and the uncertainty that connected faults existed across the entire Colorado Group.

Breach of the Clearwater Shale

In all three scenarios, the breach of the Clearwater shale was assumed to have occurred at a single location. In Scenario A, this location was assumed to be about 300 m south of Pad 74 based on the recorded temperature above the geothermal gradient in the nearby 11-1 observation well, which indicated the occurrence of convective flow at the top of the Clearwater bitumen reservoir. In Scenario B, this location was assumed to be about 100 m east of Pad 74 based on the slight temperature anomalies observed within the Grand Rapids

Formation at the 1A74 and 2A74 wells. In Scenario C, this location was assumed to be about 550 m lateral from the location of the surface release (Pad 78 drainage area). This assumption was supported by a bitumen show at the 74 OBS2 well and a temperature anomaly at the 13A78 well. Bitumen from the adjacent 12A78 well had a composition similar to the bitumen that was released to the surface, further supporting Scenario C.

Highly localized deformation or crimps were found along the well casing in the Grand Rapids Formation at the 20A77, 19A77, 18A77, and 17A77 wells. CNRL believed that these may have been the result of a heave event associated with an influx of fluid from the Clearwater Formation and were not evidence of multiple breaches of the Clearwater shale.

CNRL submitted that if multiple breaches of the Clearwater shale had occurred, it was unlikely that they collectively contributed to the surface release. Multiple breaches would act to diffuse the pressure and release rate, such that these events would not support a fracture to surface. Multiple small-scale fractures within the Grand Rapids Formation would suggest smaller fracture widths, smaller fracture conductivity, and therefore greater pressure drops along the pathway. Phase B diagnostic steam injection showed no evidence of breaches through the Clearwater shale.

Release Pathway Through the Colorado Group

In Scenarios A and B, CNRL argued that the Westgate Formation in the Colorado Group was an extremely robust barrier what would not permit vertical induced fracture propagation. All data collected (FMI, pressure, micro-frac) was consistent with the position that induced fractures in the Colorado Group would be horizontal and that wellbore involvement was necessary to create a path for vertical flow. Scenario C assumed the pre-existence of a single fault or a pre-existing network of minor faults. CNRL believed that the existence of these faults was unlikely, based on measured data.

5.2 Views of the ERCB

The ERCB and CNRL agree on many aspects of the bitumen release pathway scenarios. However, the ERCB disagrees with some parts of each of CNRL's proposed release scenarios.

Scenario A

The ERCB believes that this is a possible explanation of the release pathway.

The ERCB notes that a fracture intersecting a wellbore, as described in steps 3 and 5, could be detectable in MSC logs if the fracture caused deformation in the wellbore casing. MSC logs on the 1A74 and 2A74 wells did not indicate any wellbore impairment or deformation. However, the ERCB also notes that a wellbore casing without deformation does not conclusively confirm that no fracture intersected the wellbore.

Scenario B

As with scenario A, the ERCB believes that this is a possible explanation of the release pathway with the same reservations about the lack of detected wellbore deformation and the reliability of RST logs to detect flow behind pipe in an HPCSS well.

Scenario C

The ERCB agrees that this is a possible but less likely explanation of the release pathway. In particular, the 550 m lateral offset assumed by CNRL from the breach of the Clearwater shale to the location of the surface release is too great to correspond to the 12°C emulsion temperature recorded at the surface. The ERCB expects that a much larger volume of bitumen emulsion would be required (more than 2000 m³) from such a distance to reach this temperature at surface.

Breach of the Clearwater Shale

The ERCB believes that single or multiple breaches of the Clearwater shale are equally likely. Given the dissolution of the underlying salt formation, weaknesses or even faulting is possible.

The ERCB believes that the highly localized deformation or crimps along the well casing in the Grand Rapids Formation at the 20A77, 19A77, 18A77, and 17A77 wells may be related to the breach of the Clearwater shale by shear failure.

Release Pathway Through Colorado Group

The ERCB agrees with CNRL's assessment that the probable release pathways through the Colorado Group are limited to a wellbore pathway or a pre-existing network of faults.

6 Role of Steam Injection Volumes and Reduced Well Spacing

6.1 Views of CNRL

CNRL acknowledged that the Cycle 1 injection volumes used at Primrose East may have contributed to the surface release. CNRL stated that a localized weakness in the Clearwater shale may increase the potential for a breach by high-pressure steam when the injection volume is larger. CNRL also stated that an irregular steam pattern was likely due to higher than expected interwell communication, which was a result of the reduced spacing and increased steam injection volumes. Steam progressed quickly westward across Primrose East ahead of the steam wave to unsteamed wells, inducing larger shear stresses into the Clearwater shale and possibly causing it to fail.

6.2 Views of ERCB

Cycle 1 injection volumes of about 80 000 m³ per well were used at Primrose East prior to the bitumen emulsion release. As shown in Figure 10, this was significantly greater on a reservoir pore volume basis than the volumes used elsewhere at PAW. The ERCB believes that the reduction of interwell spacing from 180 m used elsewhere at PAW down to 60 m at Primrose East, combined with the high individual well cycle injection volumes, likely contributed to the release. During the Area 2/Phase B diagnostic steaming, more traditional volumes were used without incident, which further supports this conclusion.

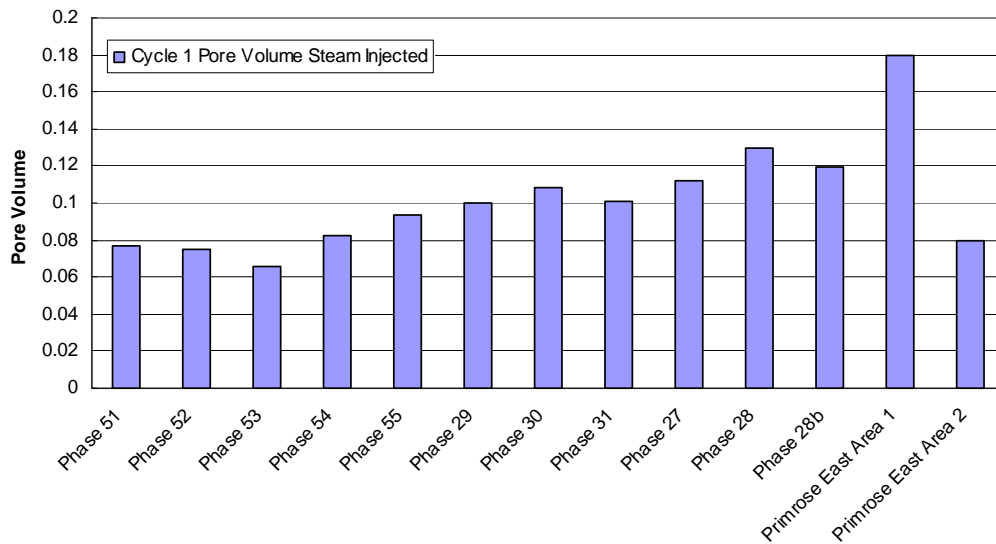


Figure 10. Cycle 1 pore volume steam injection at PAW shown chronologically

7 Summary of ERCB Views

A static investigation was conducted immediately after the bitumen emulsion release was detected. The static investigation examined well design and construction data, aquifer contamination, and possible bitumen emulsion pathways to surface. No clear evidence was found to show that a wellbore was responsible for the entire release pathway.

Diagnostic steam injection at Primrose East did not reactivate the release pathway. However, the successful steaming of Area 2 at more traditional PAW steam volumes without incident show that HPCSS can be safely conducted at Primrose East.

A contributing factor in the release may have been geological weaknesses in combination with stresses induced by high-pressure steam injection. The geological weakness may have been caused by deposition, subsequent erosion, or stressing along the salt collapse edge.

CNRL proposed three release scenarios to explain the data collected from delineation drilling after the incident. While none of these scenarios entirely matches the data, it is likely that the Clearwater shale was breached by high-pressure steam injection not related to a wellbore issue, the Grand Rapids Formation water sands did not act as a diverter, and a pathway through the Colorado Group was found that likely involved a wellbore or a series of pre-existing faults.

Steam volume injected in Cycle 1 at Primrose East Area 1 was significantly higher on a pore volume basis than past HPCSS operations at PAW due to reduced well spacing. This likely contributed to the bitumen emulsion surface release.

8 ERCB Regulatory Response

As a result of this incident the ERCB has put limits on the steam injection volumes that CNRL is allowed to inject per cycle. In addition, with the ERCB's concurrence, CNRL has undertaken a pressure monitoring program in the Grand Rapids Formation. When pressure changes are measured, particularly in conjunction with increases in steam injectivity, steam injection is reduced or suspended, as considered necessary.

On a broader scale that encompasses all steam injection operations in Alberta's oil sands, the ERCB continues to review and assess its requirements with respect to both caprock and wellbore integrity issues.