PRIMROSE FLOW TO SURFACE
CAUSATION REPORT

Report Prepared for:

ALBERTA ENERGY REGULATOR AND ALBERTA ENVIRONMENT AND SUSTAINABLE RESOURCE DEVELOPMENT

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AER	Alberta Energy Regulator
CBL	Cement Bond Log
CSS	Cyclic Steam Stimulation
DFIT	Diagnostic Fracture Injection Testing
ESRD	Alberta Environment and Sustainable Resource Development
FEI	Formation Expansion Index
FTS	Flow to Surface
GC-MS	Gas Chromatography–Mass Spectrometry
InSAR	Interferometric Synthetic Aperture Radar
MFC	Multi Finger Caliper
OSE	Oil Sands Exploration
PAW	Primrose and Wolf Lake
PIT	Pressure Integrity Test
PRE	Primrose East
PRE A1	Primrose East Area 1
PRE A2	Primrose East Area 2
PRN	Primrose North
PRS	Primrose South
RST	Reservoir Saturation Tool
TVD	Total Vertical Depth

GEOLOGIC FORMATION ABBREVIATIONS

QUAT	Quaternary
LPRK	Lea Park
NIOBRA	Niobrara
FSPK	First White Speckled Shale
SSPK	Second White Speckled Shale
BFRC	Belle Fourche
FS	Fish Scales
WSGT	Westgate
VKNG	Viking
JLFU	Joli Fou
GDPD	Grand Rapids
CLWR	Clearwater
MCMR	McMurray

1 EXECUTIVE SUMMARY

1.1 Purpose

This report is intended to provide the Alberta Energy Regulator (AER), Alberta Environment and Sustainable Resource Development (ESRD) and the public with an explanation on what was the cause of flow to surface (FTS) at the Canadian Natural Primrose sites. Canadian Natural has been working with an independent third party technical review panel (the panel) on these conclusions. Interaction between Canadian Natural and the panel included work sessions, data reviews, feedback on concepts, and open discussion. Work with the panel has been ongoing since March 2014. This Causation Report represents a step towards the final report. Some supporting data for this report has been provided to the AER through the monthly Enforcement Order (EO-2013/05-NR) data submissions. The compilation of a final report will take a significant amount of time due to the amount of data gathered and the complexity of the matter. Therefore, in order to share the information on the cause of FTS events sooner, this Causation Report was created. The final report will include further detail and supporting data on the causes of identified FTS events.

1.2 Summary

At Canadian Natural's Primrose thermal operation, bitumen emulsion was discovered at surface at four locations in 2013. Shortly after their discovery, a study was undertaken at each FTS site resulting in 85 Quaternary ground water wells and 50 deeper delineation wells drilled, 105 cased holed wells studied and several geological, engineering and geomechanical studies. From the study, a causation review has been completed, which addresses the mechanisms important to understand the most likely pathway(s) from the Clearwater reservoir to surface at each FTS site.

1.2.1 Environmental Impacts

Laboratory testing results for dissolved hydrocarbons and chlorides encountered by the Quaternary groundwater wells are currently below Alberta Tier 1, Natural Area (ESRD, 2010a) criteria and often below laboratory detection limits. Studies of the FTS sites to date indicate the following:

- Low dissolved constituent concentrations in surface and groundwater shows a lack of produced water impact suggesting that most of the formation water and condensed steam released from the Clearwater reservoir leaked-off before reaching the Quaternary and surface.
- Significant amounts of bitumen emulsion have not been observed in the Quaternary aquifers suggesting that its high viscosity has limited accumulation in these units and the occurrence of bitumen emulsion is concentrated along the fracture pathways.
- The surface cleanup is complete at all Primrose FTS sites and meets the following regulations:
    - Alberta Environment. 2010a. Alberta Tier 1 Soil and Groundwater Remediation Guidelines

- Canadian Council of Ministers of the Environment. 2014. Sediment Quality Guidelines for the Protection of Aquatic Life
- Alberta Environment and Sustainable Resource Development. 2014. Environmental Quality Guidelines for Alberta Surface Waters

1.2.2 Causes

The causation review has identified four conditions which enable or significantly increase the probability of an FTS event. All conditions are common to all FTS sites, so all four conditions must be addressed to prevent future FTS events. The enabling conditions are:

1 Excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids Formation.

2 A vertical hydraulically induced fracture that propagates up to the top of the Grand Rapids Formation.

3 Vertical pathways to facilitate fluid transfer through highly impermeable shales that have in-situ stress states that usually favor horizontal fracturing.

- Wellbore pathways which are the most likely and efficient vertical pathway to at least the Viking Formation and as high as the Westgate Formation in the case of this study
- Natural fractures and faults in the shales
- Vertical hydraulically induced fractures

4 An uplift of the overburden above the Clearwater reservoir that changes stress in the overlying shale such that the minimum horizontal and vertical principal in-situ stresses approach each other.

Data analysis at the Primrose FTS sites has shown reasonable commonalities and mutually supportive findings. The causation and elements of the FTS pathway are illustrated in Figure 1-1.

- There were localized large Clearwater reservoir fluid releases of bitumen emulsion, formation water or condensed steam into the Grand Rapids Formation.
- The releases can induce vertical hydraulic fractures to the top of the Grand Rapids Formation eventually finding a vertical pathway to access the Colorado Group.
- Once into the Colorado Group the bitumen emulsion initiates fracturing and seeks the path of least resistance (i.e., least energy required to propagate) utilizing natural fractures, faults, bedding planes or wellbore features where present and hydraulically induced fracturing. This results in a net climb in elevation with a dominant lateral propagation to the base of the Niobrara Formation.
  - In the Primrose area, data suggests that the minimum principal in situ stress from the Niobrara Formation to very near surface is horizontal. This means the bitumen emulsion could have moved through vertical hydraulically induced fractures, or have re-opened vertical natural fractures to the surface at FTS locations in these areas.
- Steaming operations at the FTS sites caused lifting of the overburden resulting in a subsequent increase in the vertical stress above the steaming area.
  - The greater the amount of uplift, the greater the change in stress in the Colorado shales.

- Current geomechanical modelling supports that under conditions of significant uplift, the minimum horizontal and vertical principal in-situ stresses closely approach each other within the Colorado Group. It is this change in stress that plays a role in FTS events.

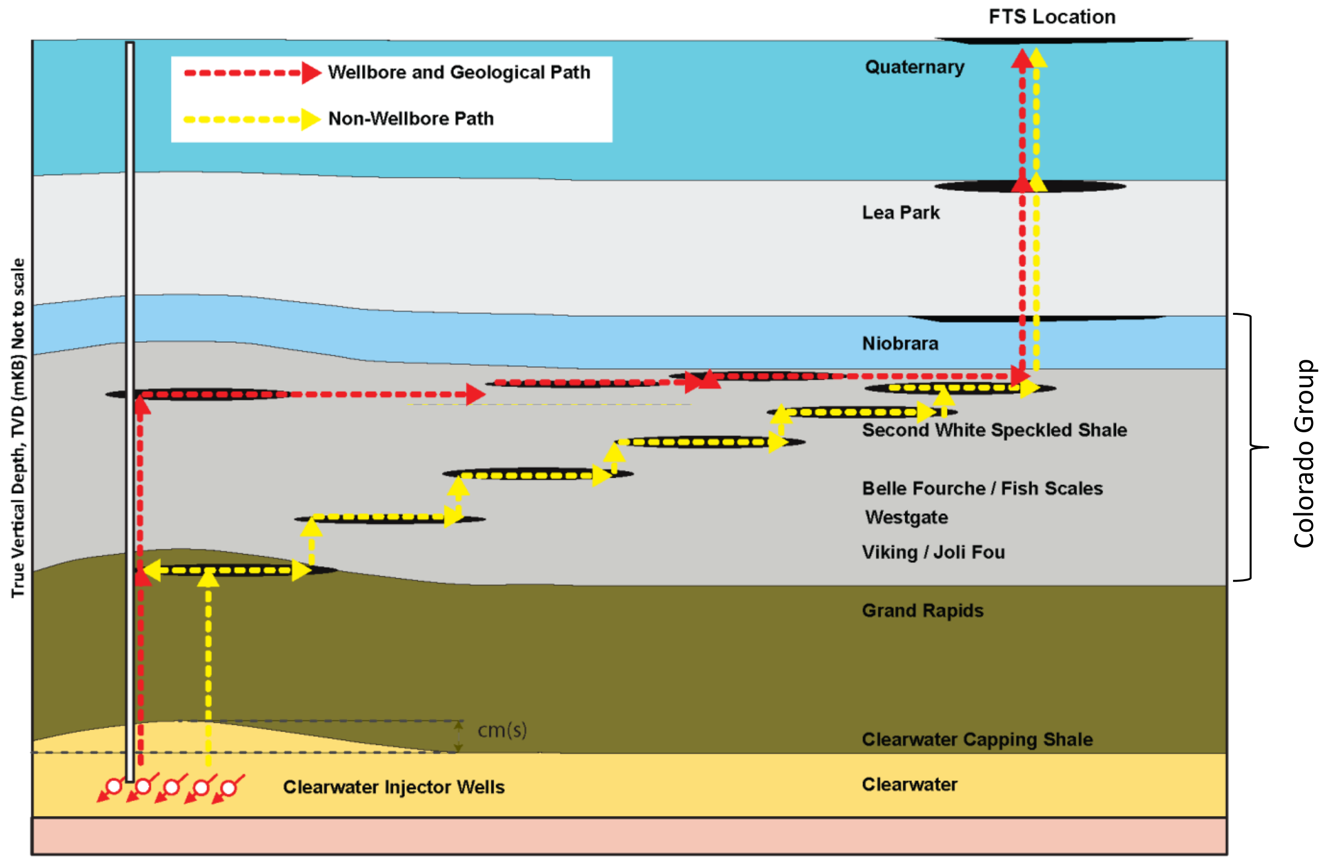


Figure 1-1 Conceptual Schematic of Possible Flow Paths

In summary, the cause of the Primrose FTS events indicates that four enabling conditions have been observed at each FTS location. To ensure a future FTS event cannot occur again, all four conditions must be addressed.

Although not within the scope of this report, the identified causes indicate that changes to steaming strategies and enhanced monitoring, as well as remediation of defective wellbores can prevent the conditions for FTS events.

2 INTRODUCTION

Primrose and Wolf Lake (PAW) has been in commercial operation since 1984. PAW currently operates under AER Approval 9140 and the subsequent amendment approvals allow for recovery of bitumen from the Clearwater reservoir, the Grand Rapids Formation (B10) and the McMurray Formation within the PAW Project Area. In the Primrose area the approved recovery strategy is single well Cyclic Steam Stimulation (CSS). The CSS process uses a single well to inject steam and subsequently produce emulsion in a cyclic nature over the life of the well. Operations here have utilized various inter-well spacing, well lengths and injection volumes over the past 30 years to optimize the recovery process and ultimate recovery of the resource at Primrose.

Bitumen emulsion was discovered at the following FTS sites within Canadian Natural's Primrose operating area (Figure 2-1):

- January 3, 2009: 14-01-067-03 W4M (Pad 74), Primrose East Area 1
- May 20, 2013: 10-01-067-03 W4M (10-1), Primrose East Area 1
- May 20, 2013: 10-02-067-03 W4M (10-2), Primrose East Area 1
- June 8, 2013: 02-22-067-03 W4M (2-22), Primrose East Area 2
- June 24, 2013: 09-21-067-04 W4M (9-21), Primrose South

The above discoveries were reported to regulatory bodies, steaming in the area was curtailed, and eventually shut in by AER order. No additional sites, other than above, have been discovered to date. Canadian Natural conducts routine aerial surveys of the operating area to confirm this.

Request for approvals for containment and clean-up activities were completed as soon as FTS was recognized and these activities were undertaken as soon as regulatory approval for access to the sites could be attained. As work progressed, approvals handled on an as needed basis were consolidated into an Environmental Protection Order (EPO-2013-33/NR) for the 9-21 site and later a comprehensive Enforcement Order (EO-2013/05-NR) which covered all sites. Canadian Natural has installed containment systems and completed surface cleanup in accordance with regulations for all sites and continues to monitor and report on each in accordance with the orders. The current rates at the FTS sites are minimal.

Canadian Natural undertook the FTS study under existing surface access wherever possible and worked within the Enforcement Order for any additional surface access.

The study has several objectives:

1 To collect additional subsurface data for use in identifying the cause(s) of FTS events and report these results to the AER and the ESRD.

2 To locate and delineate the most likely FTS flow path from its source in the Clearwater reservoir, through the Grand Rapids Formation, the Colorado Shale Group and the Quaternary strata to the FTS sites.

3 To gather information at each site to assist in characterization of geological, hydrogeological and geochemical conditions within the Quaternary section and understand possible environmental impacts.

Under EO-2013/05-NR the follow reporting is required to AER and ESRD:

- Daily open hole and cased hole rig updates (concluded)
- Weekly reports
  - Weekly plant updates (concluded)
  - Comprehensive report on the Enforcement Order
- Monthly reports
  - Surface Site Containment, Delineation, and Remediation Report
  - Groundwater Report which is about to convert to an annual report summarizing all Geology and Regional Groundwater Delineation, Monitoring and Remediation for the past year
  - Source/Flow Pathways Investigation Report (on activities and results - not interpretation or analysis)
  - Site Surface Water Management and Monitoring Report
  - Data submission from the study
- Wildlife Management Report
- Communications Report
- Annual Reclamation Report
- Annual Groundwater Report
- Reclamation Plan
- Surface Site Containment Final Report
- Source/Flow Pathways Final Report
- Site Surface Water Management Final Report
- Reclamation Final Report

Canadian Natural is in compliance with all reporting that is required as per the Enforcement Order.

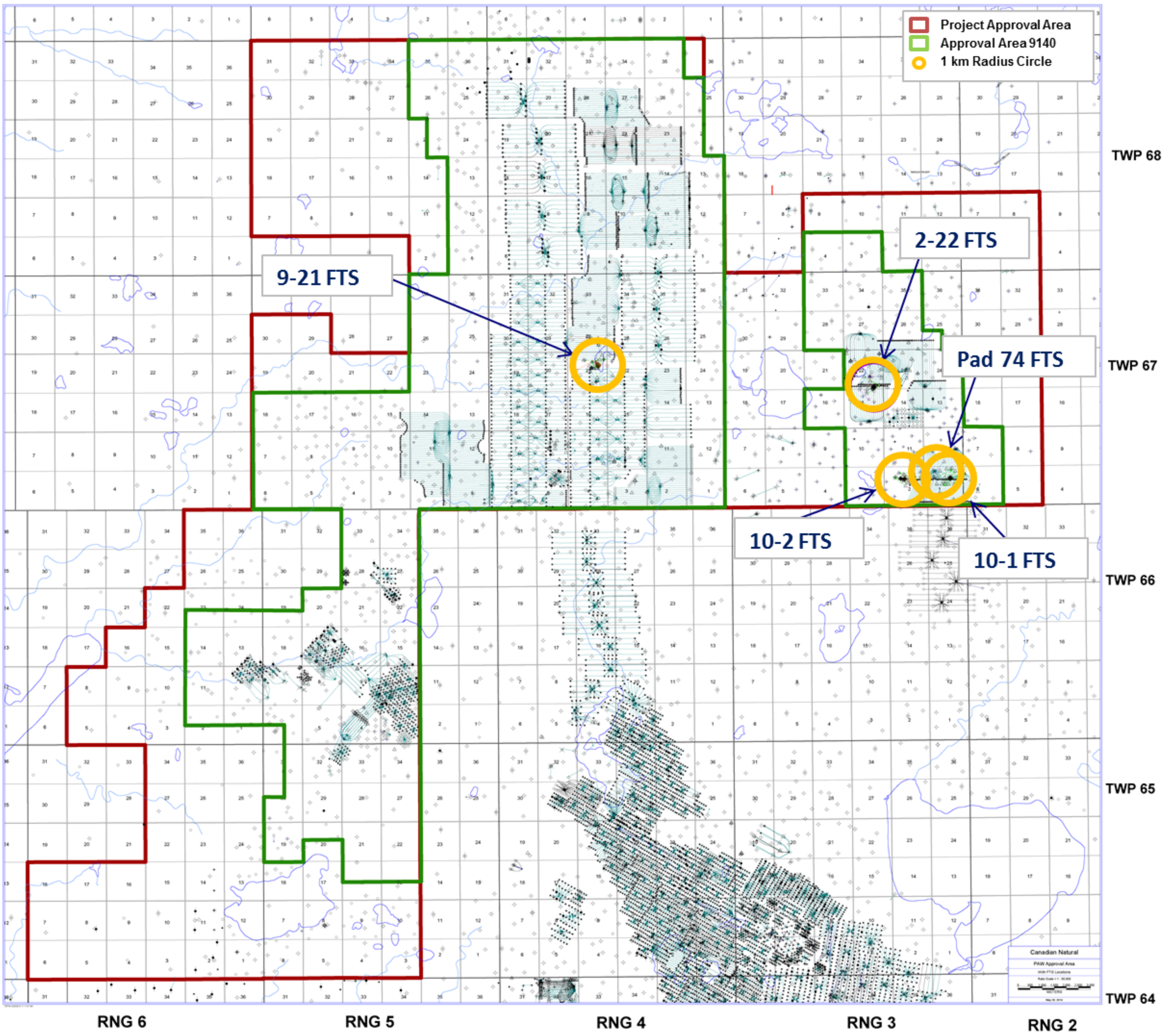


Figure 2-1 FTS Site Locations

3 ACTIVITY SUMMARY

Canadian Natural launched formal cleanup, groundwater and FTS studies after discovery of FTS events in Primrose. Activities include, but are not limited to, the highlights shown in Table 3-1.

Table 3-1 Summary of Study Activities

Summary of Study Activities
ENVIRONMENTAL
• 99 m^3 of bitumen emulsion recovered from surface at 2-22 FTS site • 559 m^3 of bitumen emulsion recovered from surface at 10-2 FTS site • 350 m^3 of bitumen emulsion recovered from surface at 10-1 FTS site • 170 m^3 of bitumen emulsion recovered from surface at 9-21 FTS site
• 82,508 tonnes of impacted solids removed (combined from all four sites)
HYDROGEOLOGY
• 66 FTS site wells drilled and completed • 19 test holes drilled • 7146 m drill length (total) • 434 m core interval (total)
DRILLING
• 50 Cretaceous delineation wells drilled, amounting to: ✦ 30,909 m drill length (total) ✦ 6,825 m core interval (total)
• Log acquisition: ✦ Resistivity ✦ Porosity ✦ Density ✦ Dipole sonic ✦ Sonic scanner ✦ Micro-imager ✦ Gamma ray
GEOLOGY
• Core analyses: ✦ X-Ray diffraction, ✦ Particle size distributions, ✦ Thin sections ✦ Dean Stark saturations • Detailed core logging
GEOPHYSICS
• 3D seismic acquisition for the 9-21 FTS area, including data acquisition over the water body (2014)
• 4D seismic analysis over PRE A1 (2004, 2009, 2010, 2013)
• Conducted induced electromagnetic survey
• Reprocessing historical 3D seismic and passive seismic data
• 3D shear wave processing and analysis
GEOMECHANICS
• 7 Diagnostic Fracture Injection Tests (Diagnostic Fracture Injection Testing (DFIT) or mini-fracs)

Summary of Study Activities
• 2 wells cored for testing – 57 samples of preserved core
• Lab testing: ✦ Index ✦ Triaxial ✦ Cyclic loading ✦ Direct shear ✦ Creep ✦ Ultrasonic ✦ Tensile strength
• Interferometric Synthetic Aperture Radar (InSAR) analysis of historical data from 2011 to 2013
• Modeling: ✦ Numerical modelling of changes in stress state in Colorado Group due to reservoir uplift ✦ Analytical stress modelling of reservoir uplift ✦ Hydraulic fracture containment of Colorado Group
WELLBORE STUDIES
• 19 re-entries (plug-tracks) into previously abandoned wells for remediation purposes • Review of historical abandonment practices and completions of all wells in Primrose • 105 cased hole studies (various logging and perforating)
ENGINEERING
• Analysis of historical data (2009 Pad 74 Final Report, Clearwater reservoir injection, production data, thermal fibre, passive seismic, Grand Rapids Formation pressure monitoring, Bonnyville / Quaternary pressure monitoring)
GEOCHEMISTRY
• 254 bitumen emulsion samples collected and analyzed by Gas-Chromatograph Mass-Spectrometry
INDUSTRY AND REGULATORY COLLABORATION / CONSULTATION
• Regular information sharing and cooperation with AER and ESRD • Formation and collaboration with an Independent Third Party Technical Review Panel consisting of industry experts • Information sharing sessions with AER and industry leaders in CSS • Enhanced information sharing on the corporate website • Consultation with First Nations groups ✦ Open house for Cold Lake First Nations ✦ Increased notifications of activities
FTS DETECTION METHODS
• Executed Methods in 2013/2014 ✦ Visual Inspection: ▪ Ground level survey along available access and seismic cut lines (completed over steamed areas in Primrose) ▪ Airborne visual sweep (completed over PAW) ○ Boreal Laser Infrared Gas Detection (aerial mounted gas detection) • Executed Methods in 2009 ✦ Visual Inspection: ▪ Airborne visual sweep (completed over Pad 74 vicinity) ✦ Aerial mounted detection technologies: ▪ Boreal Laser Infrared Gas Detection ▪ Thermal Imaging ▪ Forward-Looking Infrared Gas Detection Camera ▪ Visible Spectrum Camera

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

4 GEOLOGY OVERVIEW

The regional stratigraphy utilized in this report is outlined in Figure 4-6. Steaming operations are conducted within the oil sands of the Clearwater reservoir. This formation is overlain by the 100 – 135 m thick, inter-bedded sand and shale strata of the Grand Rapids Formation. The Grand Rapids Formation is overlain by the 160 – 190 m thick Colorado Group, which is predominantly shale (Figure 4-7).

These formations are in turn overlain by the Lea Park Formation, which can be up to 120 m thick composed of silty shale. Its thickness however, can be highly variable due to deep incisions of the overlying Quaternary formations. For the purposes of this report, the Lea Park Formation is considered to be the top of bedrock.

During the Tertiary and Quaternary periods, glacial melt waters have eroded deep valleys into the Lea Park Formation and Colorado Group bedrock units. These valleys are generally filled with intercalated glacial tills and fresh water aquifers. Although not occurring directly at the FTS sites, these deep channel incisions do occur within the Primrose area, and have been mapped using well control and depth corrected 3D seismic data.

As part of the FTS study, 85 test and monitoring wells have been drilled into the Quaternary formations at the FTS sites, and 50 wells have been drilled into the bedrock (Colorado Group and Mannville Group) formations. Canadian Natural has also acquired approximately 434 m of core from the Quaternary formations, and 6,825 m of core from the bedrock formations.

4.1 Definitions

Fracture: A crack, joint fault or other break in rocks. Deformation due to a momentary loss of cohesion or of resistance to differential stress and a release of stored elastic energy (Bates, R.L. and Jackson J.A. 1984).

Fault: A fracture or fracture zone along which there has been displacement of the sides relative to one another parallel to the fracture (Bates, R.L. and Jackson J.A. 1984).

Bedding plane: In sedimentary or stratified rocks, the division plane that separates each successive layer or bed from one above or below (Bates, R.L. and Jackson J.A. 1984).

4.2 Stratigraphy

4.2.1 Clearwater Reservoir

The Clearwater reservoirs occur in tidally-influenced distributary channels near the top of the formation. One of the FTS sites (9-21) occurs above a N-S oriented valley which consists of a muddying upwards, transgressive valley fill. Four of the FTS sites (10-2, 10-1, 2-22 and Pad 74) occur above a N to NW-oriented valley. This unit consists of several sanding upwards cycles that were deposited as a series of prograding tidal sand bars. Despite being younger, the erosive nature of the units places them in similar stratigraphic position relative to the top of the Clearwater reservoir.

These strata are charged with bitumen which may locally be overlain by gas. Bitumen viscosities vary both vertically and laterally, with a typical dead oil viscosity of 10E+04 cP through most of the Primrose field. Bitumen in PRE is generally less viscous (typically 7E+04 cP) but, substantially lower values (approximately 3E+04 cP) have been recorded in the uppermost part of the reservoir in PRE.

The reservoir sands are capped by a 2 - 4 m thick transgressive unit which passes vertically into a low density, dark shale which marks the top of the Clearwater reservoir. A 2 - 3 m thick, bioturbated mudstone with ripple-laminated sand interbeds in the base of the Grand Rapids Formation overlies the top of the Clearwater reservoir.

The combination of these shale rich zones forms an average of 5 – 6 m meter thick capping layer for the Clearwater reservoir. These shale intervals are deposited as widespread, regional transgressive events across all of the Primrose areas of operation. Well logs and core data indicate that the capping layer is very consistent in this area, and has not been observed to be thinner than 3.5 m in any area.

4.2.2 Grand Rapids Formation

In the Primrose area, the Grand Rapids Formation consists of regional shoreface sandstones separated by shales that correspond to marine flooding surfaces. Occasionally, incised valleys cut into these regional markers and replace them with thick, predominantly brackish water saturated sandstone and shale facies.

Of note in the FTS areas, there is regionally extensive brackish water saturated sand in the lower Grand Rapids B12 (Rex level) in which the B12 pressure monitoring system is located. Also a large incision at approximately the Grand Rapids B6 (Sparky level) cuts down nearly to the Clearwater Capping Shale in Primrose east. 3D seismic data, the lack of bitumen in the overlying brackish water sand, and existing well data show this incision did not erode into the Clearwater Capping Shales at the base of the Grand Rapids Formation.

4.2.3 Colorado Group

In the Primrose area, Canadian Natural is following the Colorado stratigraphy as outlined by Tu *et al.,* 2007, (Figure 4-7). The Colorado Group in the Primrose area is comprised of a 160 – 190 m thick package of shale, mudstone, siltstone, and sandstone. Formations and individual shale members that can be reliably mapped in the Primrose area are discussed below. They have been grouped together based upon Canadian Natural's interpretation of their depositional relationship.

For further clarity, in many areas of eastern Alberta and western Saskatchewan, the Colorado Group has been sub-divided in to the Upper Colorado and Lower Colorado shales, with the upper division including the Second White Speckled Shale Formation. This division is consistent with Canadian Natural's interpretation of the Colorado Group.

4.2.3.1 Joli Fou, Viking and Westgate Formations

The Joli Fou, Viking and Westgate formations represent a series of distal progradational shorefaces that show several sanding upwards cycles (although mudstone is the predominant lithology). They range in thickness from 25 – 30 m, 3 – 10 m and 42 – 55 m respectively. Differentiation between the Joli Fou and Viking formations is not always possible, while the base of the Westgate Formation is demarcated by a 50 – 75 cm lag.

The Joli Fou Formation is a thick mudstone which exhibits evidence of dewatering-induced soft sediment deformation. Natural fractures with high dip angles in the range of 30 to 90 degrees are observed on micro image logs (Figure 4-1). On Figure 4-1, Figure 4-2, Figure 4-3, Figure 4-4 and Figure 4-5, n represents the fracture count from micro image logs on the 50 Cretaceous wells drilled to date as part of this study.

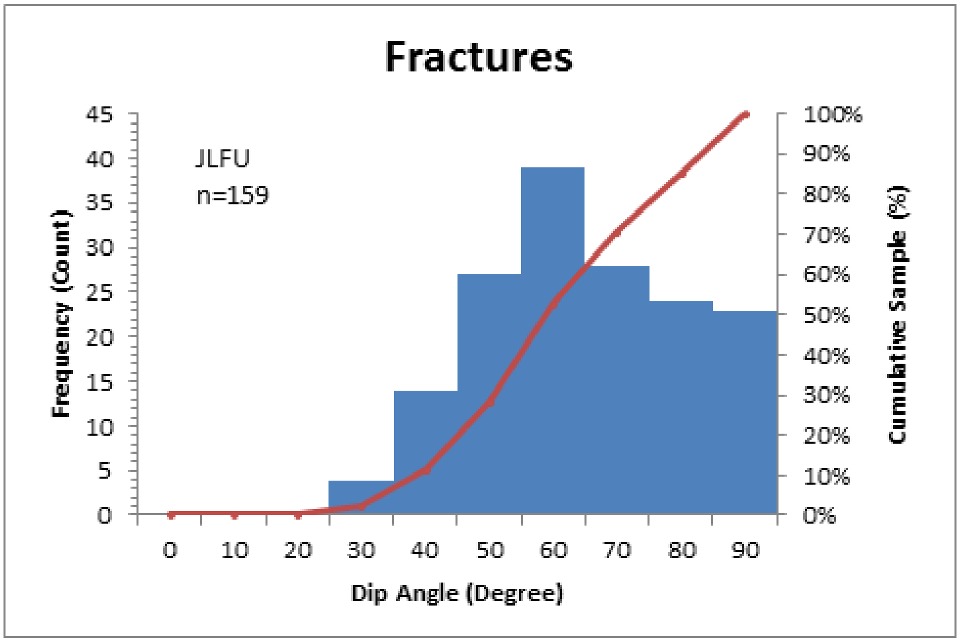


Figure 4-1 Number and Dip Angle of Fractures Observed in the Joli Fou Formation

Occasionally, faults have also been observed in core. This is consistent with horizontal 3D seismic images near the top of the Viking Formation which also generally indicates small scale normal faulting (on the order of 2 – 3 m movement) occurs within these shales. Faults are typically non-conductive.

Due to the nature of this type of faulting, displacement dissipates downward near the base of the Joli Fou Formation, and tends to disappear upwards within the Westgate Formation. The dewatering-induced soft sediment deformation behavior below the Fish Scales Formation is pervasive throughout the region.

In the upper cycles of the Westgate Formation, the shales become more quartz-rich, sedimentary layering becomes more visible in core, and the number of fractures observed in core and on micro image logs tend to increase compared to the underlying Viking and Joli Fou formations. Over 90 percent of the natural fractures observed on micro image logs dip in the 40 to 90 degree range (Figure 4-2).

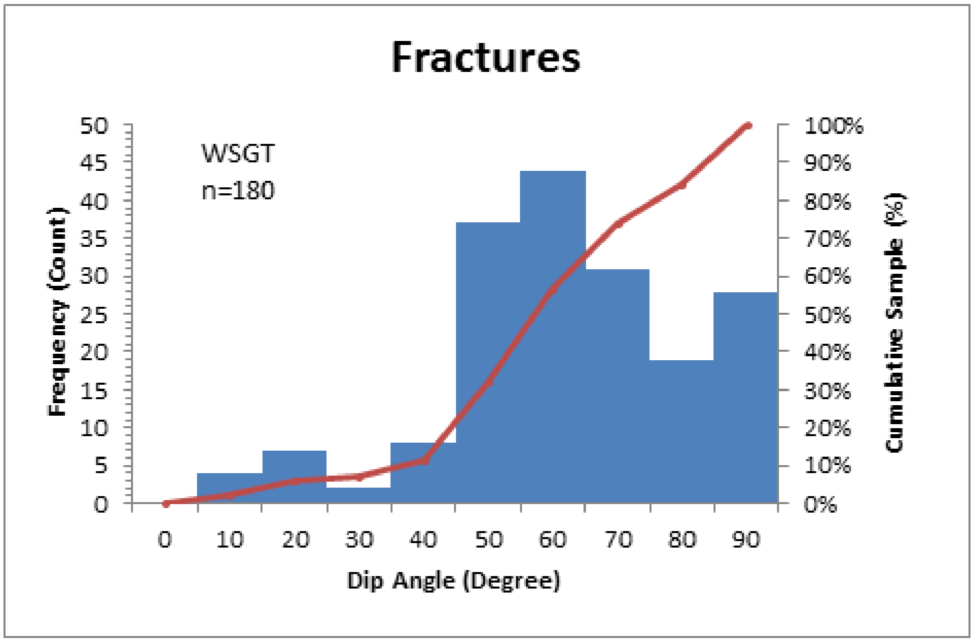


Figure 4-2 Number and Dip Angle of Fractures Observed in the Westgate Formation

4.2.3.2 Fish Scales and Belle Fourche Formations

The 3 – 12 m thick Fish Scales Formation often contains a basal bio-clastic lag. It is comprised of medium grey mudstone. The Belle Fourche Formation is 15 – 30 m thick and consists of two distinct units. The basal unit does not have an observable base and is a similar lithology to the underlying Fish Scales unit. The upper Belle Fourche Formation has an erosional lag and consists of interlaminated mudstone and low permeability sandstone. The 30 – 40 cm “X-bentonite” occurs near the base of the upper unit and cm-scale bentonites are common above it. Fractures observed in core and on micro image logs in these formations are relatively uncommon, but do occasionally occur.

Figure 4-3 indicates the number and associated dip angles of all natural fractures observed on micro image logs from the base of the Fish Scales and Belle Fourche Formations.

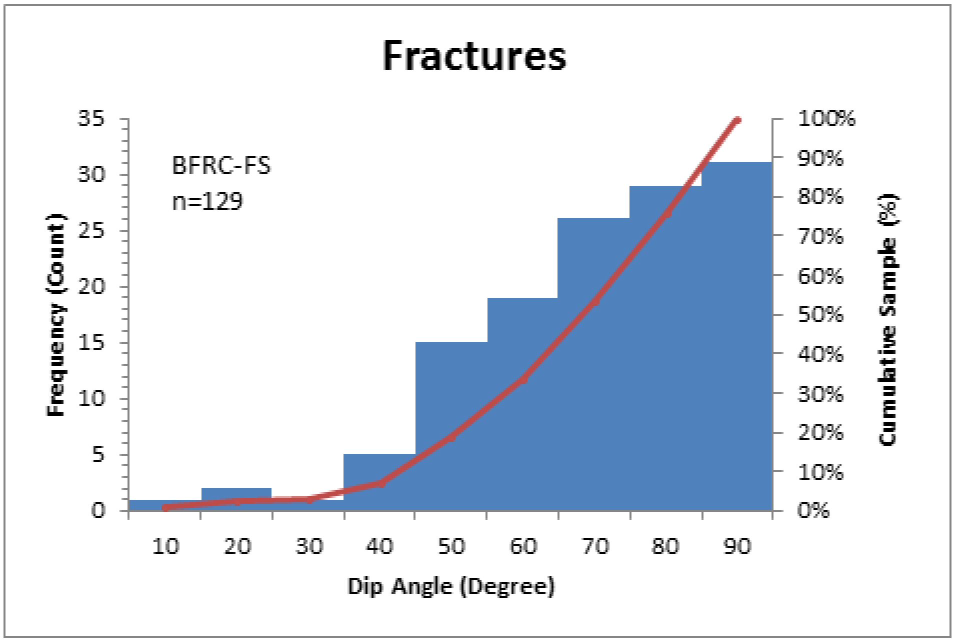


Figure 4-3 Number and Dip Angle of Fractures Observed in the Fish Scales and Belle Fourche Formations

4.2.3.3 Second White Speckled Shale and Niobrara Formations

The Second White Speckled Shale Formation is a highly organic, calcareous mudstone which is 5 – 10 m thick.

The Niobrara Formation consists of several distinct members which are the Verger, Cold Lake, First White Specks and a recently identified No White Specks Members. It broadly correlates to thick chalk deposits in the United States. In the Primrose Area, these members have received terrigenous clastic input, which reduces their relative carbonate content.

The 1 – 6 m thick Verger Member is non-calcareous mudstone, similar in character to the Second White Speckled Shale Formation. The 6 – 18 m thick Cold Lake Member is a structureless grey mudstone. The First White Specks Member is a 25 – 40 m thick dark, highly organic and calcareous mudstone. Natural fractures in these units are high angle to vertical, and tend to be more numerous in the First White Specks Member than in the shales below.

4.2.4 Lea Park Formation

The Lea Park Formation is light brown mudstone with common lenses of rippled sandstone and abundant siderite nodules. Depending on the amount of Quaternary erosion, it varies from 0 – 120 m thick. Curved, intermediate angled mud-lined (healed) fractures are common as are an apparently unrelated set of near vertical fractures.

Figure 4-4 indicates the number and associated dip angles of all natural fractures observed on micro image logs from the base of the Second White Speckled Shale Formation to the top of the Lea Park Formation.

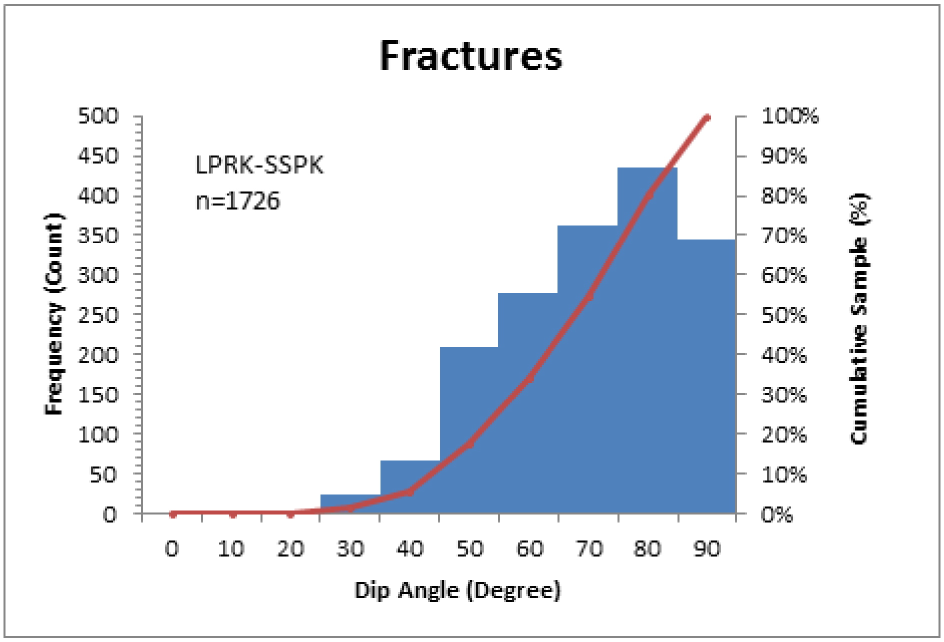


Figure 4-4 Number and Dip Angle of Fractures Observed in the Second White Specks, Niobrara and Lea Park Formations

4.2.5 Quaternary Sediments

FTS locations occur on relative bedrock highs near the confluence of the regionally mapped Sinclair and Helina Valley Systems. The Quaternary deposits consist predominantly of regionally extensive till sheets with sand aquifers hanging from the tops of the units. Two features are present in the vicinity of the FTS locations. The first is the Burnt Lake Channel, which cuts to near the base of the Lea Park Formation. The second is a small subglacial tunnel channel, which cuts midway into the Lea Park Formation. Neither has affected the Colorado Group shale. High angle to vertical fractures are present in till units (Figure 4-5).

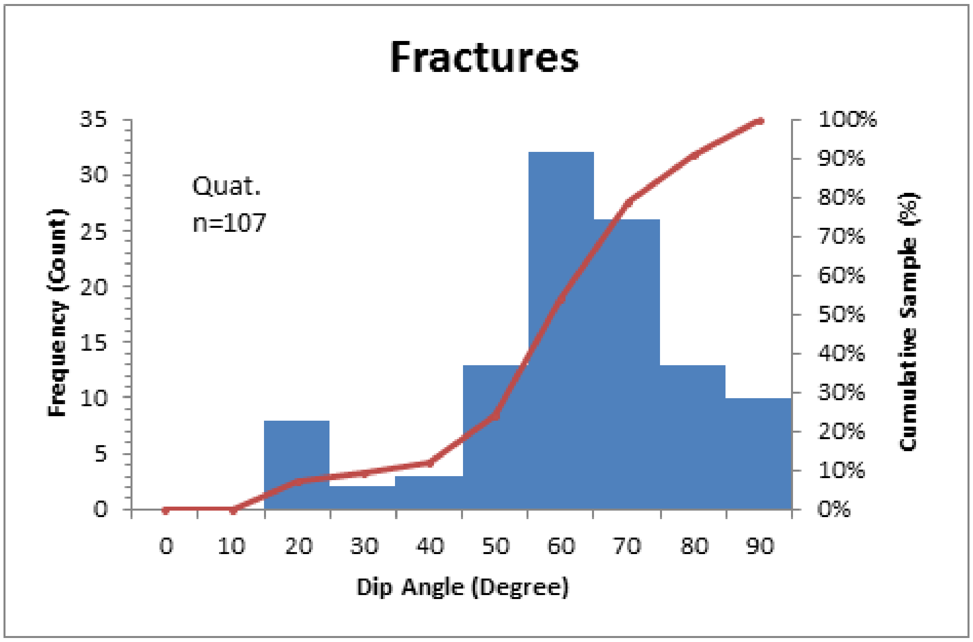


Figure 4-5 Number and Dip Angle of Fractures Observed in the Quaternary Formations

4.3 Structure

The Cretaceous and younger strata at Primrose form a southerly dipping anticline. The western limb of this feature dips to the southwest and represents the regional dip of the strata into the Western Canada Sedimentary Basin along the edge of the province. The dip reversal occurs in a roughly north south line between PRE, and PRS. This structural change was created through the dissolution of the underlying Devonian Prairie Evaporite Formation salts.

The full Prairie Evaporite Formation is approximately 175 m thick in the western Primrose area. Beginning in the area between PRE and PRS, it gradually thins eastward due to dissolution at depth. The zero edge is located 20 – 25 km further to the east. The post depositional subsidence of the overlying strata created the eastern limb of the anticline. PRE is located partway through the dissolution zone where approximately 80 m of salt has dissolved at the eastern edge of the project.

The dissolution of the Devonian salts and the subsidence of the overlying strata is clearly a diachronus process. Much of the salt dissolution post-dates the deposition of the Cretaceous strata, as evidenced by the current day structural reversal of these formations. Over thickening of these Cretaceous formations demonstrates that syn-depositonal subsidence was also a component of this process. Comparisons of the salt loss to the structural changes and over-thickening demonstrate a portion of the dissolution also pre-dates the Cretaceous strata.

The salt dissolution process is regional in scale and may modify the principal in-situ stresses.

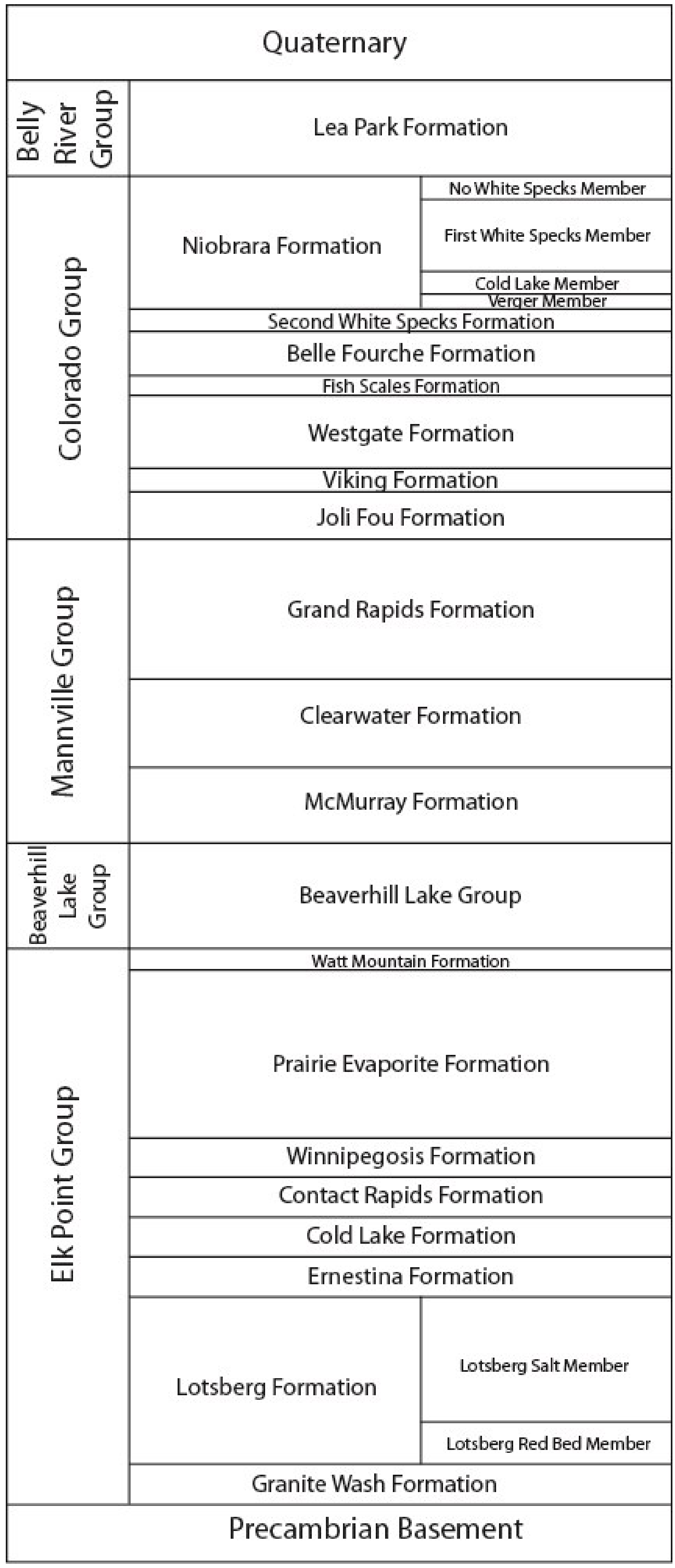


Figure 4-6 Regional Stratigraphic Column for the Primrose Area

(Internal Nomenclature)

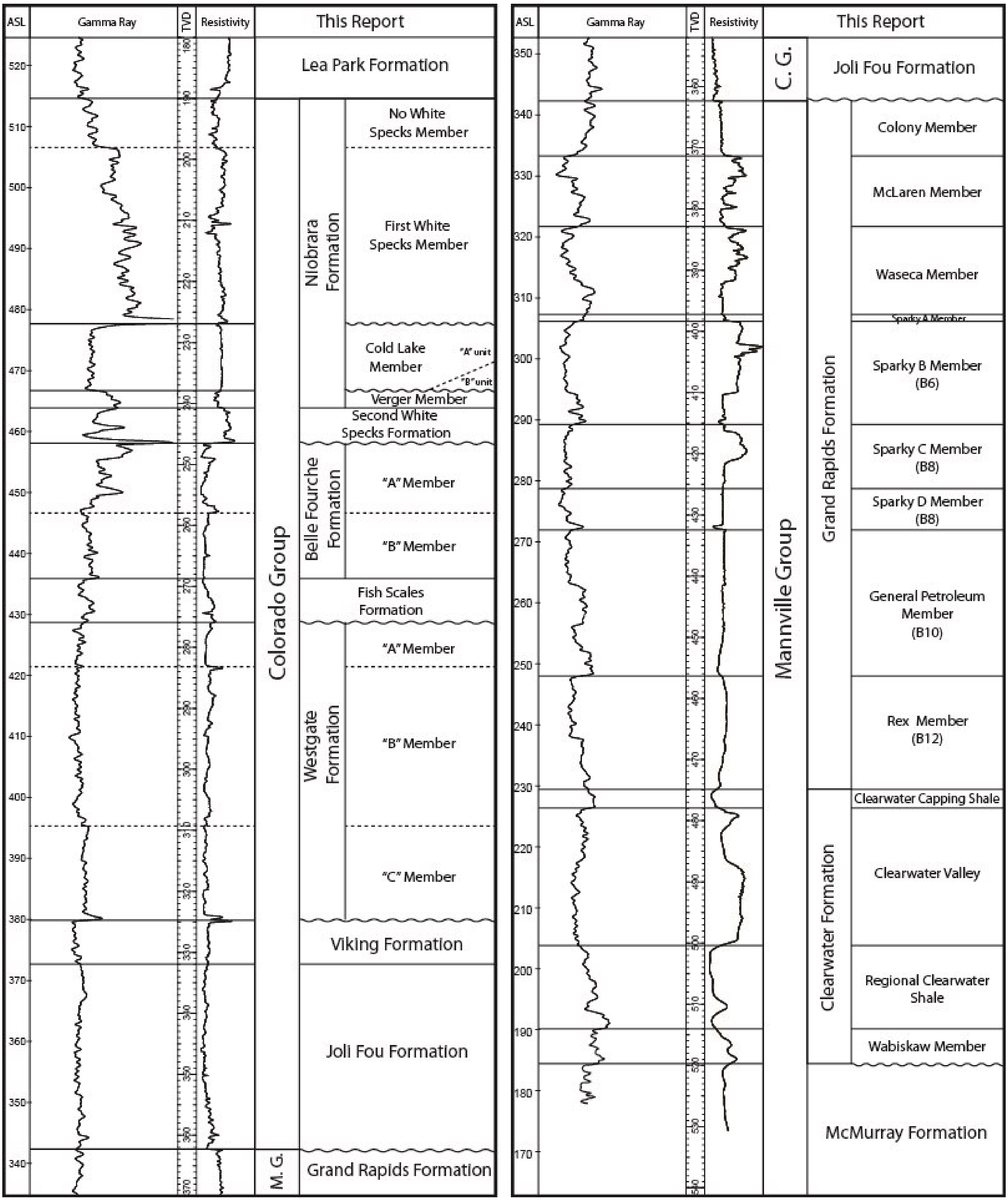


Figure 4-7 Detailed Stratigraphic Column for the Mannville and Colorado Groups in the Primrose Area (Internal Nomenclature)

5 HYDROGEOLOGY OVERVIEW

Groundwater monitoring wells were installed at the four FTS sites discovered in 2013. The wells are completed in non-saline Quaternary aquifers identified during drilling. Wells drilled at these sites has shown bitumen emulsion passed through the aquifers and on to the surface through vertical hydraulically induced fractures. Based on drilling results and core data, the lateral flow of emulsion into Quaternary aquifers is limited. The highly viscous bitumen emulsion tends to flow in fractures rather than into the permeable aquifers.

Laboratory testing results for dissolved hydrocarbons and chloride for samples taken from the wells are currently below Alberta Tier 1, Natural Area (ESRD, 2010a) criteria and often below laboratory detection limits at monitoring wells completed on the FTS pads (including wells completed across zones where bitumen emulsion was encountered during drilling). Similarly, groundwater results collected at the Pad 74 FTS site since 2009 continue to show dissolved hydrocarbon and chloride concentrations below Alberta Tier 1, Natural Area criteria at monitoring wells completed across regional aquifers down-gradient and immediately adjacent to the surface fracture.

Results from four 2013 FTS sites and data collected at Pad 74 suggest very low dissolved hydrocarbon and dissolved constituent groundwater impacts associated with an FTS event. Overall, results collected to date suggest a limited potential for regional impacts to Quaternary aquifers associated with FTS events outside of the immediate areas of the FTS sites.

Quaternary well drilling is nearing completion and Canadian Natural will continue to closely monitor the groundwater effects of the FTS sites. A separate document will be prepared for the Geology and Regional Groundwater Delineation, Monitoring and Remediation Plan as required by the Enforcement Order. Reporting on groundwater monitoring and hydrogeological activity is completed each month in accordance with the Enforcement Order.

6 GEOMECHANICS

6.1 Summary

Bitumen emulsion flow mechanisms through the Colorado Group were evaluated and the integration of historical data with the causation review has resulted in the following findings:

1. Existing wellbores with poor hydraulic isolation due to cement placement are low resistance flow paths for vertical movement.

2. In-situ principal stress states typically favor horizontal hydraulically induced fracturing within most of the Colorado Group formations (Joli Fou – Second White Speckled Shale formations).

3. Under typical or average conditions, vertical to horizontal in-situ stress differences limit the permeability of natural fractures and faults.

4. Significant vertical flow occurs within natural fractures and faults only under unusual conditions:
   a) A pressure equal to or greater than the normal stress acting upon a natural fracture, fault, or bedding plane
   b) Sufficient vertical connectivity of the natural fractures or faults
   c) The existence of more isotropic stress conditions that may be promoted by overburden uplift

5. Tensile parting (i.e. opening of natural fractures, faults and bedding planes) can only occur at high pressures at or above the minimum principal in-situ stress. This means that the stress state heavily influences the orientation of bitumen emulsion hydraulically induced fractures.

6. With CSS operations, one mechanism to modify in-situ stresses is uplift induced stress change. The greater the amount of uplift, the greater the change of in-situ stresses.

7. The uplift induced stress changes increase the vertical stress above the area of CSS injection and this results in:
   - A reduced stress contrast between the vertical principal stress and the minimum horizontal principal stress within the Joli Fou Formation and higher
   - An increased hydraulic fracture pressure within the Joli Fou Formation
   - An increased minimum principal stress contrast between the Grand Rapids and Joli Fou formations
   - Under conditions of significant uplift induced stress changes the permeability of natural fractures, faults, and bedding planes increases sufficiently to accommodate FTS bitumen emulsion flow rates, in the presence of hydraulic fracture pressure
   - Data relevant to the geomechanical aspects of the Primrose FTS sites, will be included and discussed within the Final Report

6.2 Definitions

Total stress: Force per unit area transmitted in a normal direction across a plane.

Effective stress: Total stress less the pore pressure of entrained fluids.

Pore pressure: Pressure of the fluid filling the void space between the solid particles or fracture faces.

Uplift: Upward movement of a horizontal surface as a result of CSS operation.

Heave: Upward movement of ground surface as a result of reservoir uplift.

Dilation: Increase in the volume of a granular porous media (typically dense sand) due to shearing or elevated pressure and temperature. Also an increase in pore volume of a fracture commonly due to shearing on the plane of the fracture.

Diagnostic Fracture Injection Testing (or mini-frac): A test conducted to determine an in-situ stress that involves fluid injection and fracturing of a rock. It can also be used to estimate the far-field formation pressure in low permeability rocks.

Micro-frac: A small volume hydraulic fracture test typically conducted open-hole with a straddle packer arrangement, to measure the minimum in-situ stress.

6.3 Nomenclature:

σ	Total stress
σ'	Effective stress
σ_h	Minimum horizontal principal total stress
σ_H	Maximum horizontal principal total stress
σ_v	Vertical total stress
σ_{min}	Minimum principal total stress
σ_{normal}	Total stress acting normal to a plane
τ	Shear stress
P	Pore pressure
ϕ	Friction angle
θ	Azimuth
δ	Dip
Δh	Height difference
$P_{dynamic}$	Dynamic fracture pressure
k	Permeability

6.4 Concepts

Within the area of CSS operations, one of the three principal stress directions is assumed to be vertical and the other two are oriented horizontally. Observations in the Primrose area are consistent in general with more wide scale observations in Alberta that place the orientation of the principal maximum horizontal stress as NE-SW. The principal stress in the vertical orientation can be determined from integrating bulk density logs. Determinations of maximum horizontal stress orientations have been made through the use of Passive Seismic systems and micro imaging logging throughout PAW. The principal stress magnitudes in the minimum horizontal orientation have been determined by micro-fracs or DFITs in the PAW development areas.

A hydraulically induced fracture will always open with the minimum amount of work required, which leads to a plane perpendicular to the minimum stress. Hydraulically induced fracture orientations are determined using field observations such as drilling induced tensile fractures, borehole breakouts, passive seismic observations and micro imaging along with knowledge of stress magnitudes in the overburden. While natural fractures and faults can have some influence on hydraulically induced fracture propagation, the overall orientation of a hydraulically induced fracture is usually controlled by the orientation of the minimum principal stress (Zoback, 2007).

Natural fractures and faults typically have elevated permeability values over that of the matrix itself. The permeability of these features will be enhanced with an increase in their aperture. An increase in aperture may occur when shear movement occurs along a plane of a fracture or fault, and will surely occur when there is a tensile parting of a pre-existing but closed natural fracture or fault. Shear movement will be controlled by the level of effective stresses in the rock and will be increasingly likely as pore pressures increase resulting in decreasing effective stress. When a fluid pressure is greater than the normal stress acting on the natural fracture or fault (Potluri et al, 2005) tensile parting cannot be avoided. When shear occurs along a natural fracture or fault, either an increase or a decrease in aperture is possible depending on the mechanical properties, the effective stress state, and other factors.

6.4.1 Caprock

A cyclic recovery process that operates over a wide range of reservoir pressures both above and below the initial reservoir pressure utilizes hydraulic isolation from permeable formations in the overburden and underburden. This hydraulic isolation is typically provided by a shale/mudstone formation with many orders of magnitude lower vertical permeability than that of the reservoir. In addition to hydraulic isolation, CSS operations at fracture pressure utilize competent barriers to contain hydraulic fractures. Fracture barriers exist within the overburden as formations with horizontal stress contrasts, where the barrier has a higher minimum horizontal stress relative to the rock below.

With CSS injection at pressures at or above the vertical stress, thermo-elastic, poro-elastic, and poro-plastic effects occur within the Clearwater reservoir (Kry, 1989). Initial in-situ stresses can be altered by CSS-induced reservoir uplift. The amount and type of change in stress will among other things depend on depth and lateral proximity to the source of uplift (Kry, 2000).

6.5 Geomechanical Characterization

6.5.1 Principal In-Situ Stresses

At the FTS sites, the vertical stress has a gradient range of 20.1 – 21.5 kPa/m over the Colorado Group, Grand Rapids Formation, and Clearwater reservoir. The minimum horizontal stresses have been determined by micro-frac or DFIT. Stress determinations have been conducted on twelve wells within the PAW development area, and interpretations have been conducted on different data sets by an Imperial Oil consultant, Schlumberger, and Canadian Natural as shown in Figure 6-1. Within the Colorado Group, many minimum horizontal stresses have been determined with a preponderance favoring horizontal orientations for hydraulically induced fractures. These measurements were primarily conducted in open boreholes using packers. The validity of measuring minimum horizontal stresses greater than the vertical stress from a mini-frac test is supported by test results observed by Gronseth and Kry, 1987.

It is recognized that tectonic stresses have generated significant horizontal stress anisotropy in Alberta (Bell, Price, and McLellan, 1994). The magnitude of the principal maximum horizontal stress is sometimes approximated by a calculation. Assuming a tectonic strain up to the point where calculated principal minimum horizontal stresses match DFIT measurements (Collins 2002), will yield an estimate of the principal maximum horizontal stresses for appropriate rock properties. The magnitude of the principal maximum horizontal stress will be limited by the shear strength of natural fractures and faults within a formation. Within the Colorado Group, in the Primrose development area, the principal maximum horizontal stresses are estimated to be approximately 20% higher than the principal minimum horizontal stresses based on the above.

A typical maximum principal horizontal stress orientation is N45°E, which has been assessed from passive seismic and micro imaging observations within the Primrose area.

Uncertainty exists with the determination of principal in-situ stresses due to the following:

1 Density logging tool bias

2 Interpretation uncertainty or ambiguities

3 Other factors

Variations exist within the orientations and magnitudes of the principal in-situ stresses. Some causes of these variations are:

1 Sediment erosional and depositional history

2 Glacial loading and unloading processes

3 Vertical stress variations due to variable overburden thicknesses due to deposition or topography

4 Stress modifications proximal to faults (Shamir, 1988)

5 Structural changes (differential compaction, salt dissolution, fluid disposal induced dissolution)

6 In-situ stress modifications caused by CSS operations

Within the Colorado Group Shales, the marine depositional environment likely produces greater variations of rock properties vertically than horizontally. Numerical modeling and analytical work inputs were chosen from the acquired data with the understanding that the in-situ stresses are not known everywhere with certainty. An outlier of three standard deviations from the mean value of the minimum horizontal stress is sufficient to change the predicted hydraulically induced fracture orientation. Uncertainty clearly exists, but specific case studies can provide insights.

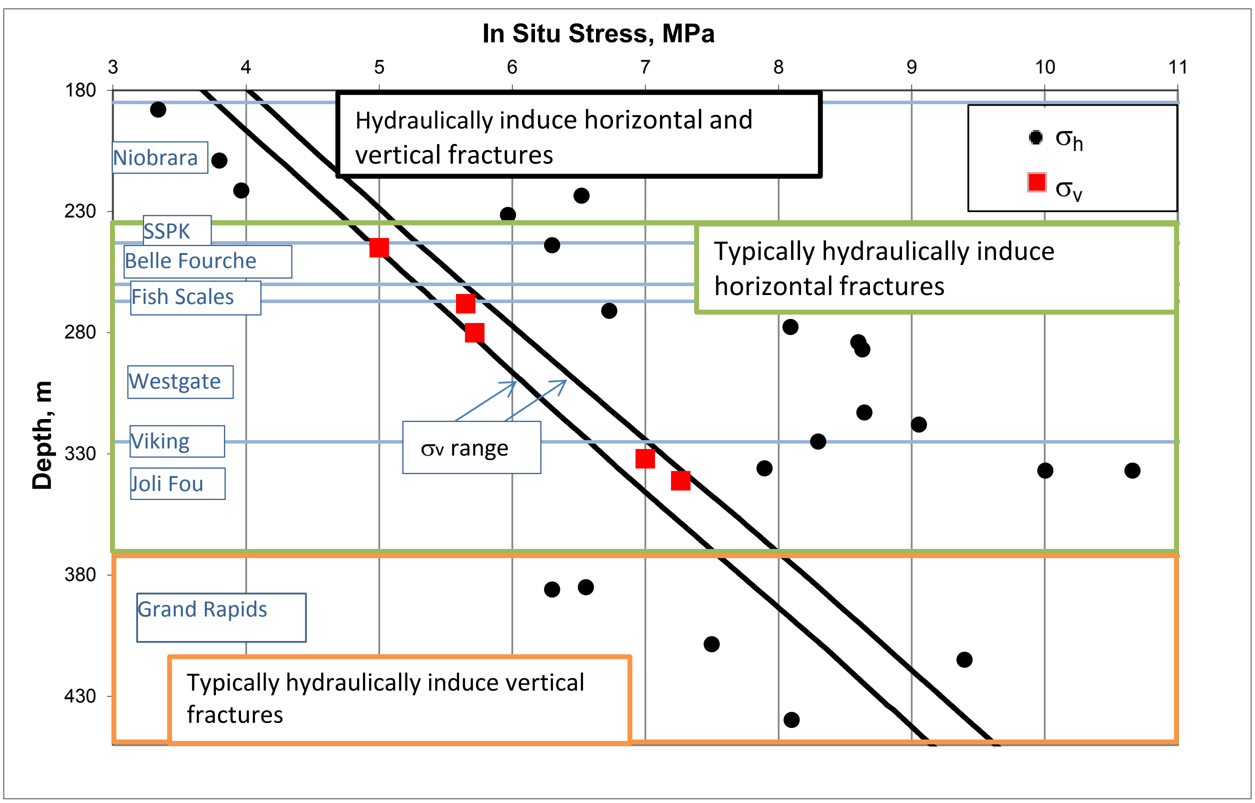


Figure 6-1 **In-Situ Stresses in Primrose and Wolf Lake**

The principal stresses within the Colorado Group can be illustrated in Figure 6-2 using typical in-situ stresses from the data acquisition.

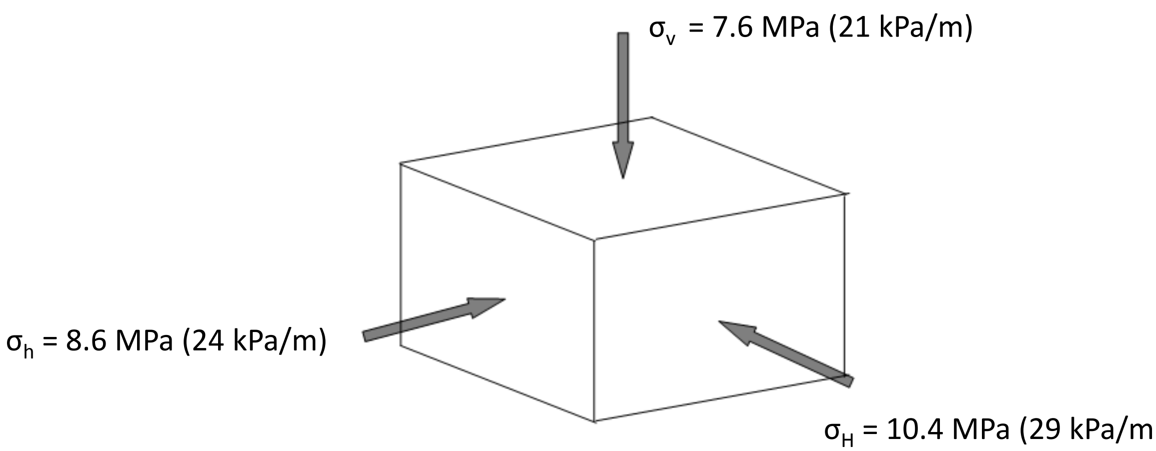


Figure 6-2 Example of Typical Principal Stresses in the Joli Fou Formation at a depth of 360 m

6.5.2 Hydraulically Induced Fractures

In the Joli Fou Formation example shown above, the minimum principal stress is vertical which implies a hydraulically induced fracture would be in the horizontal orientation. Table 6-1 outlines typical hydraulically induced fracture orientations above the Clearwater reservoir in the Primrose area.

Table 6-1 Typical hydraulic fracture orientations in the overburden over the Clearwater reservoir

Formation	Minimum Stress Orientation	Induced Hydraulic Fracture Orientation
Quaternary Sediments	Horizontal	Vertical
Niobrara – Lea Park	Vertical and/or Horizontal	Horizontal and/or Vertical
Joli Fou – Second White Speckled Shale	Vertical	Horizontal
Grand Rapids	Horizontal	Vertical
Clearwater Capping Shale	Vertical	Horizontal

6.5.2.1 Clearwater Capping Shale

The Clearwater Capping Shale usually provides isolation from the Grand Rapids Formation for commercial CSS development of the Clearwater reservoir. Intermittent releases of fluids from the Clearwater reservoir into the Grand Rapids Formation have occurred. The intermittent releases have occurred during uplift of the Clearwater Capping Shale, and the releases are due to a wellbore, injectite, shear movement of natural fractures or faults, hydraulically induced fracturing, or a combination thereof.

6.5.2.2 Grand Rapids Formation

Vertical hydraulically induced fractures can occur as observed in field data. This is consistent with measured stresses.

6.5.2.3 Joli Fou – Second White Speckled Shale Formations

Regional historical field observations indicate hydraulically induced fracture orientations to be horizontal, which is consistent with measured stresses. There are several examples of observations and tests, which are not exclusively horizontal in nature but do indicate dominantly horizontal orientations of fluid distribution. These are:

1 EE Pad Injection Test

2 Phase 21 subsurface release into the top of the Grand Rapids via 100/05-22-067-04W4 gas well

3 Casing failures resulting in fluid injection into the Colorado Group, example CNRES 5B29 PRIMROSE 4-26-67-4 subsurface release

4 CNRL 7A53 PRIMROSE 14-18-68-4 cement injection creating a horizontal hydraulically induced fracture

5 Two separate bitumen emulsion in shale anomalies spanning greater than 1 km in the region

Lab testing conducted within 2013 – 2014, initially focused on the Joli Fou Formation which is the lowest formation within the Colorado Group. The laboratory program was conducted on one inch plugs cut from core samples that were preserved to avoid moisture loss and to avoid freezing (BitCan, 2011). The geomechanical tests completed (TerraTek, 2014) suggest strong anisotropy in Joli Fou mechanical properties of peak strength, yield stress, Poisson's ratio and Young's modulus. The estimated Young's modulus from triaxial test results indicates 1.8 times greater stiffness in the horizontal direction than in the vertical direction. This would imply for equal horizontal and vertical stresses, a vertical hydraulically induced fracture requires a higher net fracture pressure than a horizontal hydraulically induced fracture for the same average fracture width. In addition, a vertical fracture would need to overcome the tensile strength perpendicular to bedding. Although this is a small sample the results indicate the anisotropy in mechanical properties supports a propensity for opening a horizontal hydraulically induced fracture over a vertical fracture, when the vertical and horizontal principal stresses are close.

6.5.2.4 Niobrara Formation

The minimum stress orientation within this formation is variable as indicated by the DFIT results which show three instances of the minimum principal stress being less than the vertical stress and two instances of the minimum horizontal stress being greater than the vertical stress. The high frequency of natural fractures may have increased the variability of stress measurement in this formation. Bitumen emulsion shows (Section 9.1) from delineation drilling have indicators supporting both minimum principal stress orientations. Different orientations likely exist, at even closely located sites within the Primrose FTS areas.

6.5.2.5 Lea Park Formation

Induced hydraulic fractures form in vertical and potentially horizontal orientations as evidenced by the delineation drilling program.

6.5.2.6 Quaternary Sediments

Induced hydraulic fractures form in a vertical orientation as evidenced by the Quaternary delineation drilling program and the Primrose Pad 74 findings.

6.5.3 Natural Fractures, Faults, and Bedding Planes

All formations within the Colorado Group contain variable frequencies of natural fractures and faults. As such, it is important to understand the likelihood of natural fractures or faults serving as conduits for bitumen emulsion flow through the Colorado Group.

6.5.3.1 Permeability Enhancement due to Shear Movement

In order to better understand the role of shear failure within natural fractures three data sources were reviewed:

1 Laboratory direct shear testing, of cored Colorado Group shale samples, to determine friction angles, provided additional data of both positive and negative vertical displacements as horizontal displacement continued under normal stresses less than 1,000 kPa. (AGI, 2001). The negative and near zero vertical displacements suggest that shear failure at low effective stresses is not enhancing the permeability of a natural fracture, while positive vertical displacements suggest shear failure is

enhancing permeability. It is speculated that varying constituent mineralogy may influence these results. The evidence for shear movement permeability enhancement is limited.

2 DFITs were conducted on four FTS delineation wells, using diesel and a diluent bitumen blend, at bitumen emulsion shows intersecting natural fractures within the Joli Fou – Belle Fourche formations. During injection at low flow rates of 2 – 5 L/min, it was observed that the rate of pressure increase did not lessen when pressures were sufficiently high such that shear failure might be expected. With probable shear failure of natural fractures, there was no definitive evidence of large permeability increases of the system. The sensitivity of this test depends at least on the magnitude of the permeability increase and the number of fractures accessed during the test. The results from the testing show fracture closure pressures consistent with the vertical stress and this testing was conducted during relatively late cycle production operations with minor Clearwater reservoir uplift and therefore represented stress conditions not modified significantly by nearby steaming operations.

3 A large field data set exists with the two separate bitumen emulsion in shale anomalies in the region. These anomalies were created by horizontal hydraulically induced fracturing as a result of inadvertent bitumen emulsion injection with near horizontal elevations mapped over 1 km in lateral extent. The fracture pressure required to create such a feature would have resulted in the Mohr Coulomb shear failure envelope being contacted and localized shear failure of numerous natural fractures and faults intersected by the bitumen fracture.

An example of a natural fracture shear failure at a pressure below the hydraulic fracture pressure is illustrated in Figure 6-3. In this example, the following assumptions are used:

Cohesion = 0

$\phi = 20°$

Depth = 300m

σ_v =6.3 MPa

σ_h =7.5 MPa

σ_H =9.0 MPa

P_p = 3.7 MPa

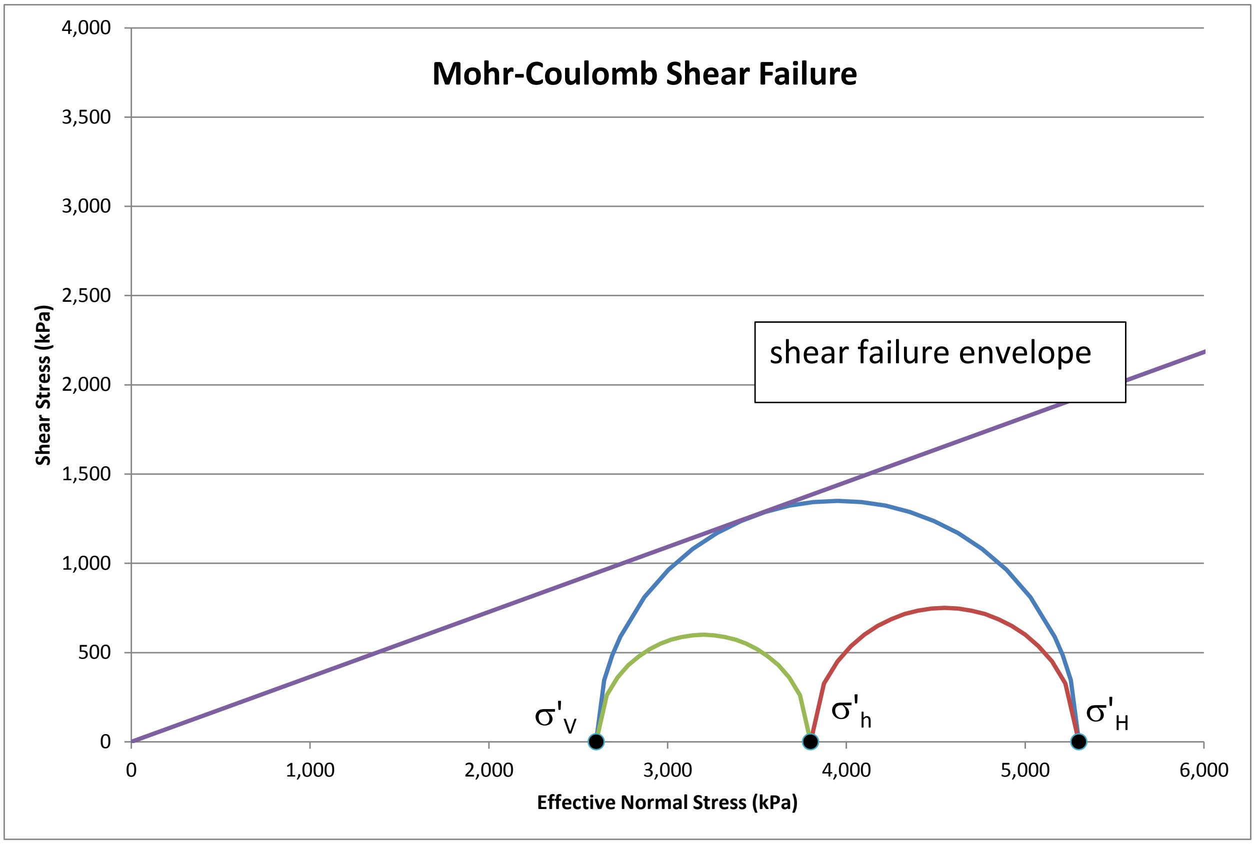


Figure 6-3 A simplified example of shear failure of a natural fracture at a fluid pressure less than the hydraulic fracture pressure

The near horizontal geometry of the bitumen emulsion in the above example indicates that shear failure of natural fractures and faults intersected did not appreciably change the direction of the bitumen emulsion movement. This is interpreted that the permeability enhancement was insufficient to divert material bitumen emulsion flow from the horizontal fracture. This also indicates that the shear strain associated with intersected faults does not appear to have resulted in significantly different hydraulic conductivity behavior between faults and natural fractures. These results indicate that the flow capacity of natural fractures and faults can be overwhelmed by the rate of injection creating a horizontal hydraulically induced fracture.

From these three data sources, shear failure permeability enhancement of natural fractures and faults is not readily apparent. While uncertainty exists, the area of shale tested with the two separate bitumen emulsion in shale anomalies is large, and it can be stated that shear failure of natural fractures and faults at low effective stresses, is less likely to be significant, than hydraulically induced tensile parting of natural fractures and faults, as an important bitumen emulsion flow mechanism through the Joli Fou to the Second White Speckled Shale formations within the PAW FTS areas.

6.5.3.2 Permeability Enhancement by Hydraulically Induced Tensile Parting

To increase the aperture and hence permeability of a natural fracture or fault, within the Joli Fou to Second White Speckled Shale formations, the fluid pressure must be increased to a level sufficient to overcome the normal stress acting upon such features. It is possible for a hybrid of shear failure and tensile failure to occur simultaneously.

This hydraulically induced tensile failure of a natural fracture or fault can be illustrated in Figure 6-4 with an example of an element of rock from the Joli Fou Formation at a depth of 360 m using typical in-situ stresses from the data acquisition. In this example, a natural fracture is illustrated with a dip angle of 10 degrees and a strike parallel to the orientation of the maximum horizontal principal stress.

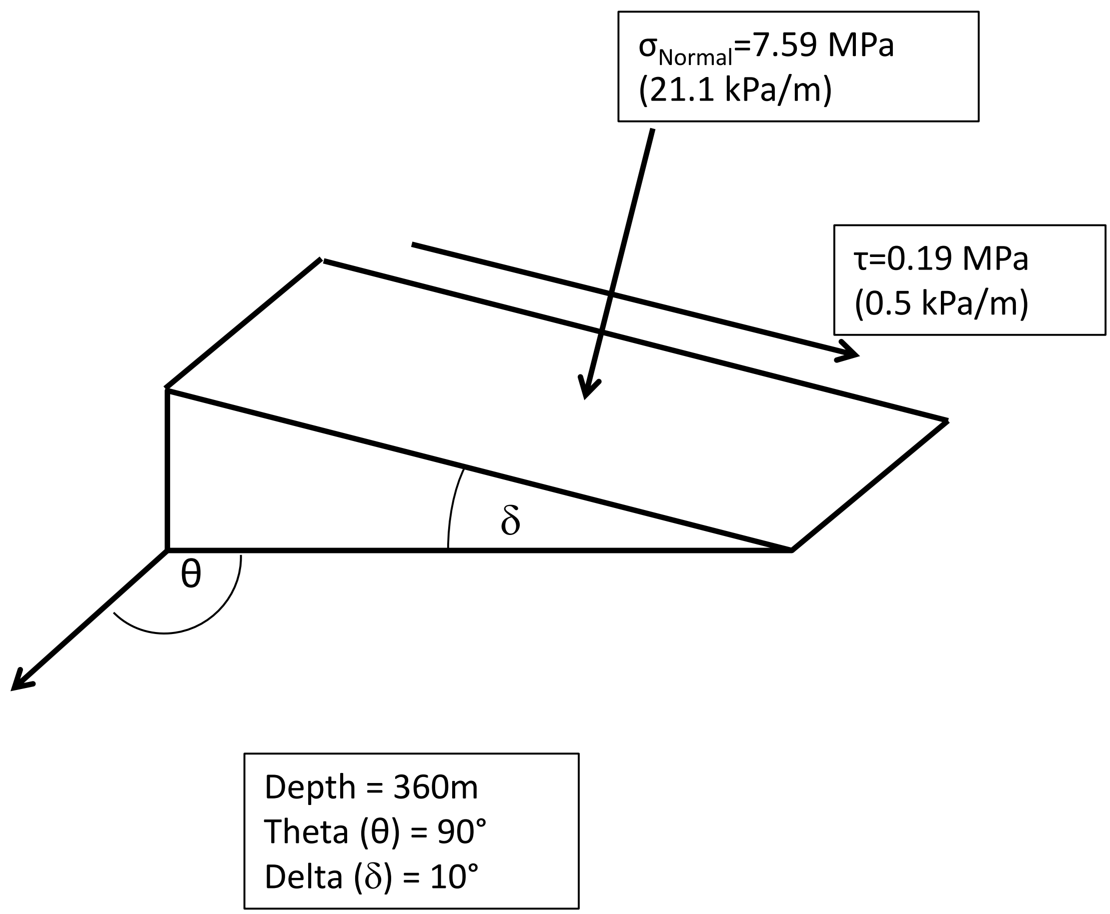


Figure 6-4 Example of stresses acting on a natural fracture with a 10 degree dip at a depth of 360 m

Brazilian tests of Joli Fou Formation samples have found tensile strengths of 160 – 200 kPa (TerraTek 2014, BitCan 2013). In the above example, the difference between the normal stress and the vertical stress is less than the tensile strength. As such, an induced horizontal hydraulic fracture may turn into this natural fracture due to tensile strength of the matrix providing greater resistance than the difference between the vertical stress and the normal stress. Using this method which is focused on normal stresses and is not focused on shear failure, a range of natural fracture or fault strike and dip values can be identified that are prone to permeability enhancement due to hydraulically induced tensile parting. For the above example, which assumes typical Joli Fou Formation initial principal stress magnitudes, the maximum dip angle of a natural fracture or fault that could be opened with hydraulic fracturing is approximately 20 degrees when the strike is aligned with the maximum horizontal principal stress.

Another bitumen emulsion flow mechanism exists, which is flow through natural fractures or faults having had minimal aperture change and relatively low permeability ($k < 10$ mD). A typical Westgate shale matrix permeability is on the order of 20 μD (AGI, 2001) and it is assumed that a typical natural fracture would have two orders of magnitude higher initial permeability than the matrix. A natural fracture or fault, with a permeability magnitude on the order of milli-Darcies or less, results in negligible flow rates of less than 1 m^3/year in the presence of horizontal hydraulic fracture pressure. In the presence of multiple fractures, flow rates would still be low relative to the FTS releases. The assumptions used for estimating the flow rate of less than 1 m^3/year are:

k = 2mD

Strike length = 5m

Linear flow length = 30 m

Pressure difference = 5.6 MPa

Viscosity = 1 cP

6.6 Stress Modification of Shales

In-situ principal stresses can be modified by a number of factors. The closer the initial principal stresses are, the more important the modifications will be. Changing the stress state from one in which the vertical stress is the minimum to one in which the horizontal stress is the minimum is a very significant change because it enables hydraulically induced tensile parting of a different subset of natural fractures and faults and means that vertical hydraulically induced fracturing would be favored.

Injection induced dilation of the Clearwater reservoir and the resulting uplift of the overburden formations has the potential to modify the in-situ stress field to the point where the vertical and minimum principal horizontal stresses converge within the Colorado Group. Canadian Natural utilized an analytical approach to estimate the amount of uplift that would be required to cause this convergence of the minimum and intermediate principal in-situ stresses. This analytical approach has a vertical displacement boundary condition at the base of the overburden.

Historically, several delineation wells drilled into bitumen emulsion shows within the Colorado Group were completed with pressure monitoring equipment and this provides field data related to the total stress change associated with Clearwater overburden uplift. In order to improve confidence in rock properties used as inputs, the pore pressure change in a numerical model can be matched to recorded pressure changes within the Colorado Group. Of the tuning parameters available, the Young's Modulus can be used to history match a set of field data. In the following example, a Young's Modulus was selected near the upper end of the undrained triaxial test findings of 0.3 - 1.1 GPa. Evaluation of the most suitable, stress-corrected values of Young's Modulus, after accounting for anisotropy, will continue since it is a first order effect on the uplift induced stress change magnitude.

At the depth of the base of the Joli-Fou (~360 m) and with the stresses assumed to be as in Figure 6-2, induced stress changes above a region of uplift were capable of making the vertical and minimum horizontal stresses converge if the Clearwater capping shale uplift was 0.6 m. Figure 6-5 illustrates the change in stress at the base of the Joli Fou Formation (360 m depth) under these conditions. One caveat is that more work needs to be done to confirm the relationship between uplift and the absolute magnitude increase in stress. The assumptions used are:

Depth = 360 m

σ_v = 7.56 MPa (21 kPa/m)

σ_h = 8.64 MPa (24 kPa/m)

E = 1.0 GPa

$\nu = 0.4$

Width of injection area = 30 0m

Depth of Clearwater reservoir top = 480 m

Strike relative to orientation of σ_h = 45°

Plane strain approach

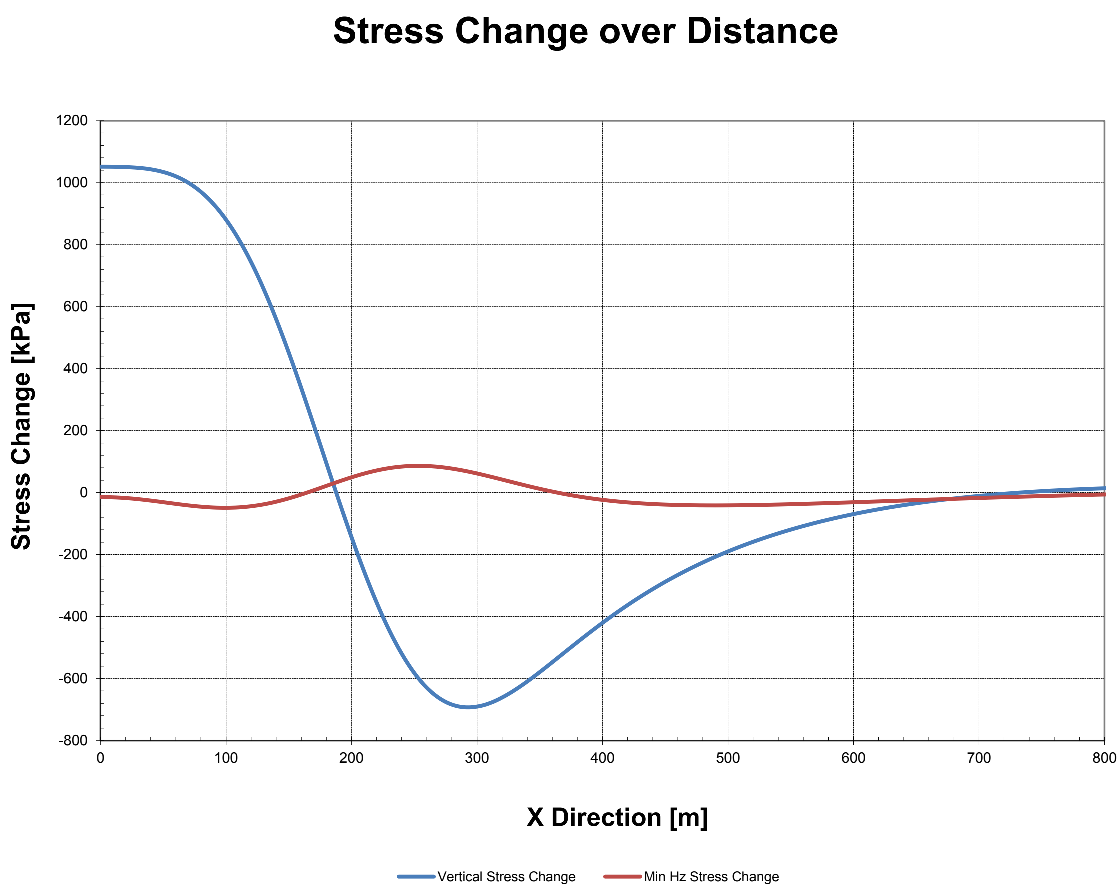


Figure 6-5 **Example of total stress changes with distance away from the center of the Clearwater uplift profile at a depth of 360 m**

Applying the results in Figure 6-5 on the stresses in Figure 6-2, the results are illustrated in Figure 6-6 where at a depth of 360 m, the initial vertical principal stress was 7.6 MPa and increased to 8.7 MPa (~24 kPa/m). The initial minimum horizontal principal stress was 8.7 MPa (~24 kPa/m) and decreased by 30 kPa. It is important to note that this convergence is dominated by the vertical stress increase and the horizontal stress change tends to be one order of magnitude lower within the Joli Fou Formation. Directly over the Clearwater reservoir uplift, the increased vertical stress at the base of the Joli Fou Formation results in a substantially increased minimum stress contrast between the Grand Rapids and Joli Fou Formations. In order to initiate hydraulically induced fracturing within the Joli Fou Formation in this example, the pressure requirement has increased by 1.1 MPa as shown in Figure 6-5.

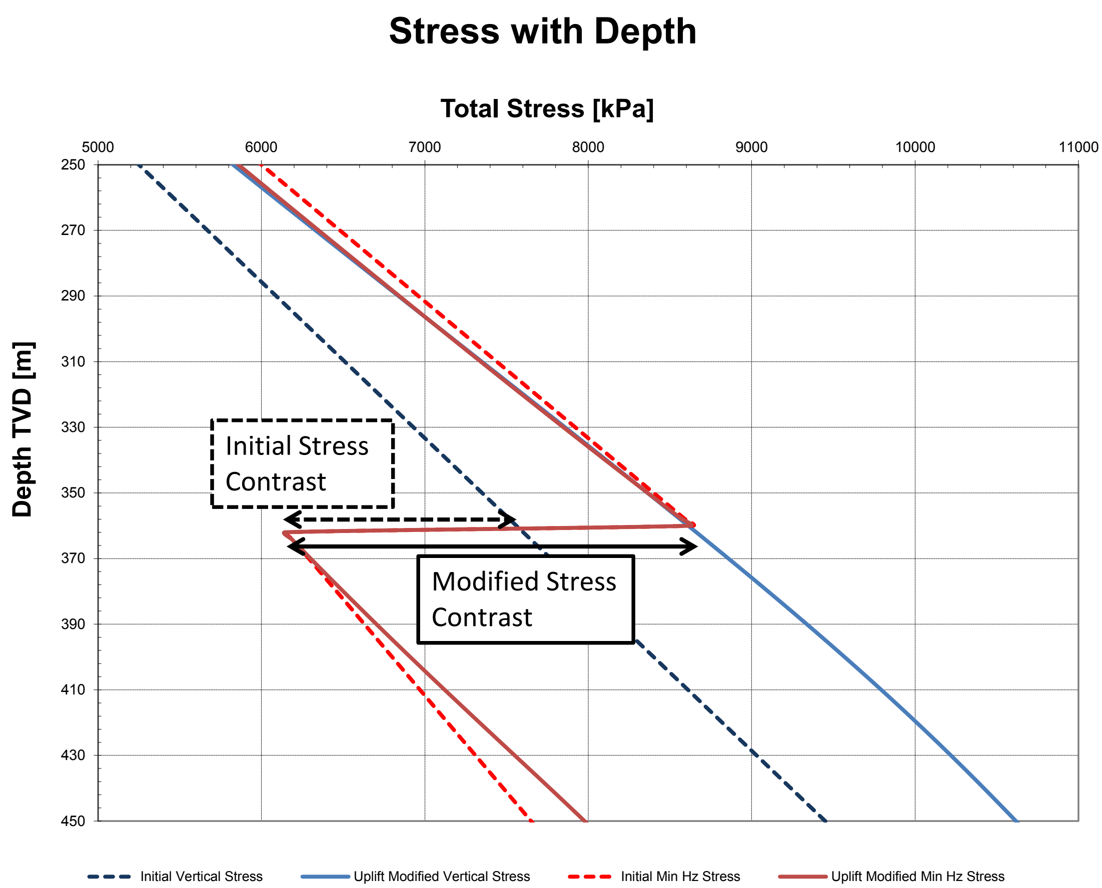


Figure 6-6 Example of calculated total stress changes with depth and effects of vertical stress approaching the minimum horizontal stress

This example of uplift induced stress changes has generated the following findings:

1 In order to increase the aperture of natural fractures or faults, with the use of hydraulic pressure greater than or equal to the normal stress, many dip angle limitations have been eliminated. Natural fractures or faults, with strikes aligned with the maximum principal horizontal stress orientation, and with similar magnitudes of the principal vertical stress and the minimum principal horizontal stress, have similar normal stress magnitudes at both high and low dip angles.

2 When a hydraulic fracture can be initiated within the Lower Colorado Group, natural fractures and faults can provide vertical connections due to modified normal stresses. This is then consistent with observed bitumen emulsion shows in cores. The uplift induced stress changes also explain why some bitumen emulsion in shale anomalies are confined to near horizontal elevations and why some bitumen emulsion in shale anomalies can make their way to surface.

3 The hydraulic fracture pressure within the Joli Fou Formation has increased above the region of uplift.

a) In the previous example, the minimum stress at a depth of 360 m was calculated to increase by 14%

4 The resistance to vertical hydraulically induced fracturing has been reduced to the anisotropy in stiffness and tensile strength of the shale.

Two limitations of the chosen analytical approach are:

1 Isotropic rock properties of Young's modulus and Poisson's ratio are required for the overburden above the Clearwater reservoir.

2 A vertical strain profile due to CSS operations is required as an input.

6.7 Geomechanical Interpretations

Three options are explored for initiating a hydraulically induced fracture within the Lower Colorado Group:

1 Where a wellbore pathway is available, it facilitates vertical fluid transport which puts higher pressures at shallower depths according to a fluid gradient rather than a stress gradient.

Wellbores are important because they can present easily quantifiable reasons for fluid migration through impermeable shales with hydraulic fracture height growth limitations. A wellbore with inadequate hydraulic isolation is an effective mechanism to initiate hydraulic fracturing within the Colorado Group as it enables an increase in pressure gradient due to the pressure reduction vertically of only the liquid hydrostatic head and frictional pressure loss. Both of these pressure changes with depth are typically less than stress gradients.

The uplift induced stress changes increase the likelihood of a wellbore being involved due to the increased fracture pressure within the Joli Fou Formation above the Clearwater reservoir uplift. One example is shown in Figure 6-7 of a wellbore with inadequate hydraulic isolation illustrating a relatively low pressure to initiate and propagate hydraulic fracturing within the Colorado Group. A fluid gradient of 10 kPa/m and no frictional effects was assumed for the example below.

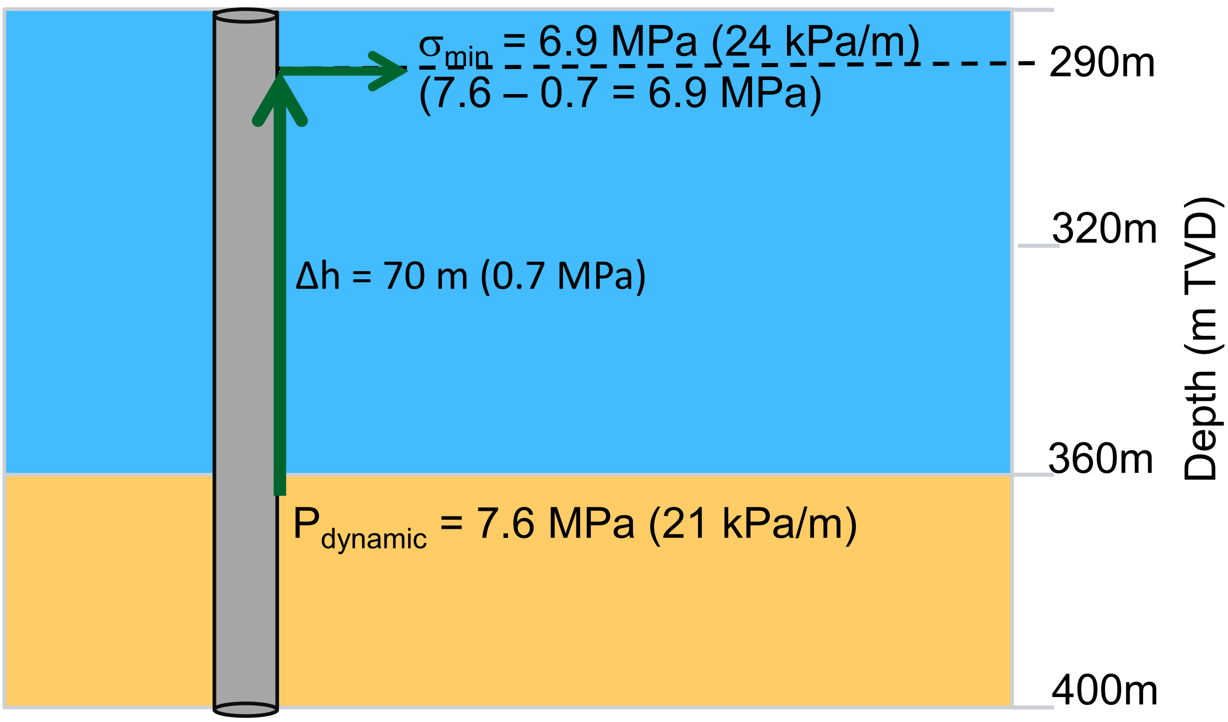


Figure 6-7 Example of pressures required for initiation of hydraulically induced fracturing in the Lower Colorado

Building upon Figure 6-6 an example pressure profile of bitumen emulsion flowing up a wellbore pathway is illustrated in Figure 6-8.

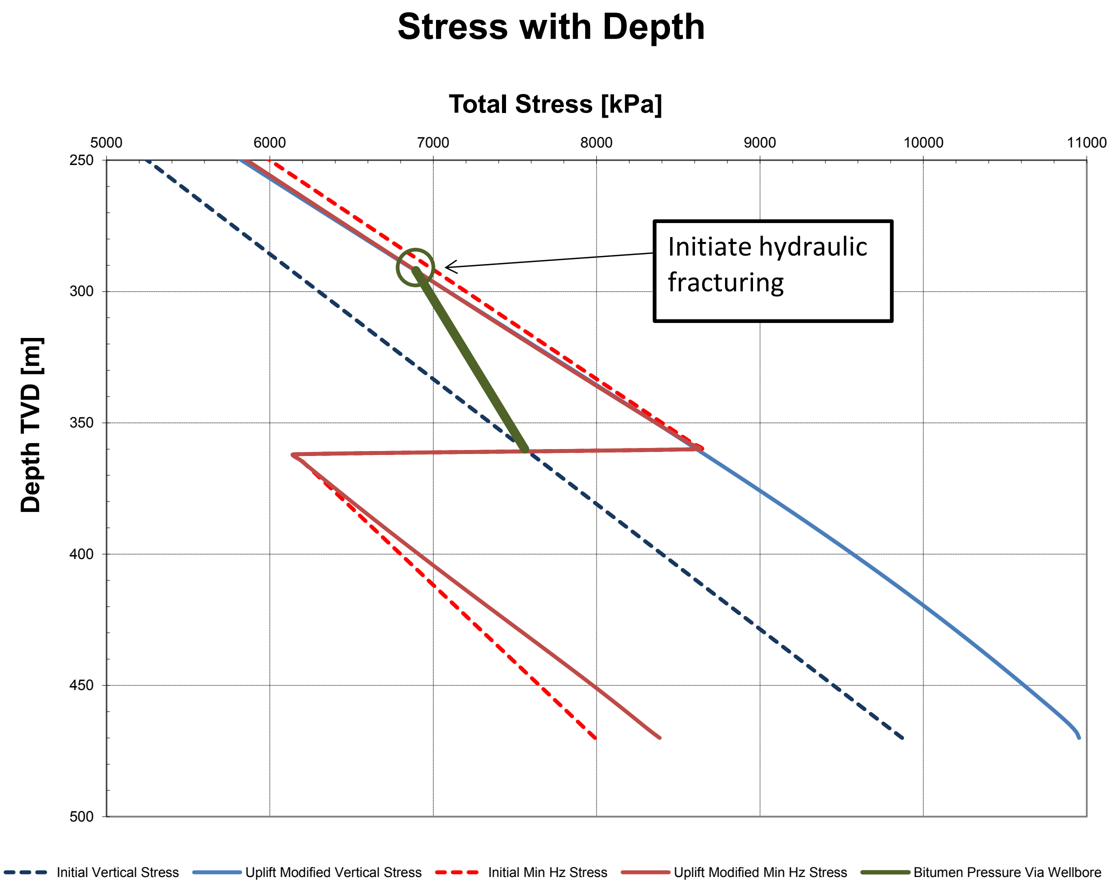


Figure 6-8 **Example of stress change with depth and pressure profile along a wellbore path intersecting the minimum stress**

2 Build sufficient dynamic fracture pressure at the top of the Grand Rapids Formation to a magnitude above the minimum horizontal principal stress at the base of the Joli Fou Formation.

Two mechanisms of increasing the dynamic fracture pressure at the top of the Grand Rapids Formation are poro- and thermo-elastic stress increases and growing frictional pressure losses with propagating a fracture at the top of the Grand Rapids Formation. Field data of CSS operation within the Grand Rapids General Petroleum Member (B10) suggest it is possible to achieve bottom hole pressures of 8,400 kPa at a depth of 410 m (20 – 21 kPa/m) when directly injecting steam. Also (Boone et al, 1991) show the poro-elastic stress increase of the order of 1-2MPa is possible within the Clearwater due to pressurization of the faces of a fracture in a permeable medium. The example from Section 6.6 would require a pressure of at least 8.6 MPa at a depth of 360 m (24 kPa/m). For the one scenario presented in Section 6.6, it would be quite challenging to achieve a dynamic fracture pressure at the top of the Grand Rapids Formation sufficient to initiate hydraulic fracturing within the base of the Joli Fou Formation.

3 Utilize a natural fracture, fault, or bedding plane, with a sufficiently large aperture and permeability enhancement due to shear dilatancy to enable significant flow rates, as a vertical conduit into the Lower Colorado Group.

The utilization of a natural fracture, fault, or bedding plane with a sufficient aperture could be realized with a sequential elevated flow rate into the feature, increasing the contact area where the effective stress has been reduced, followed by shear movement, and permeability enhancement to the point where flow rates are sufficiently large, for an FTS incident to occur. This mechanism could be enhanced by potential total stress modifications near faults. The four natural fractures tested by DFIT within the Joli Fou – Belle Fourche formations are not consistent with this described large aperture although the sample population is limited and the stress conditions under which the test were conducted are potentially not the same as during an FTS event.

Of the three options for initiating hydraulic fracturing within the Lower Colorado Group and within the assumptions of this example, the path of least resistance is to utilize a wellbore pathway. Supporting this are multiple observations indicating wellbore involvement through at least the Joli Fou Formation. Thus, there is a higher probability of a wellbore being involved with the initiation of hydraulically induced fracturing in the Lower Colorado Group at each FTS site. Other factors, such as local geology and operating strategies must also be considered.

7 WELLBORES

Where primary cementing or abandonment operations at a well or wellbore did not provide sufficient hydraulic isolation, a vertical flow path can exist independent of surrounding formation conductivity and stress states. In the case of the observed path at each FTS site a wellbore is not utilized for the entire path. Although not related to the current FTS, the possibility exists that FTS could occur during CSS operations with only a wellbore as the sole condition to allow bitumen to reach surface. Wells appear to play a role in part(s) of the pathway, namely from the Grand Rapids Formation to at least the top of the Joli Fou Formation and as high as the Westgate Formation in the case of this study.

Two common types of wells drilled in the Primrose area are Cased Operations Wells (CSS, Production, Observation, Disposal and Standing) and Oil Sands Exploration (OSE) wellbores (commonly called strat wells).

7.1 Cased Operations Wells

Conductive flow paths related to cased operations wells can occur inside or outside the casing string.

Outside Casing or External Flow Path

An external or behind-casing flow path (i.e. a channel in the cement) can result during well installation if formation or operational issues impair primary cementing, or the cementing practices applied are insufficient for the type of well. Effective hole conditioning and placement of cement are the most significant parameters in achieving sufficient hydraulic isolation across all formations. Practices that allow high pumping rates but avoid hydraulic fracturing, pump sufficient cement volume to achieve high quality returns to surface, have well-centralized casing and maintain casing movement through the entire job also are important. A cement bond log that is run several days after primary cementing is complete can help evaluate the effectiveness of the cement job, and allow inference of hydraulic isolation.

Poor placement of cement can result in a behind-casing channel which can allow fluid to flow within a formation, or from one formation to another. Flow that might be allowed through a casing annulus, utilizing a behind-casing channel with sensitivities on gap widths and viscosities, can be calculated. It can be shown that, under certain circumstances, significant flow rates can exist.

Detection of a flow path outside casing can be performed by conducting cased hole logging evaluations, or perforating through casing and testing. The effectiveness of cased hole logging detection is highly dependent on the size and fluid content of the path and whether or not flow is active. At the Primrose FTS sites, cased hole logging is viewed as not as reliable as perforations for investigation behind cased wells. Once the casing is perforated, near-wellbore fluid is drawn into the casing and a representative fluid sample is obtained and analyzed. Subsequent pressure recording of each perforated interval is also used to confirm communication between different intervals. Given the limited size of some channels, residual bitumen emulsion saturations, limited mobility of bitumen emulsion at FTS evaluation well temperatures and tendencies of being within swelling clay intervals; detecting all occurrences of flow behind pipe is difficult.

Inside Casing or Internal Flow Path

A portion of the FTS flow path can be inside casing if there is a connection between different sets of perforations or with one or more casing failures. Once the fluid gradient is considered, vertical movement of the fluid (i.e. cross-flow) can occur inside the well from the highest pressure interval to the lowest. Depending on the pressure differential and fluid viscosity, cross-flow can be at very high rates due to the large open area available.

Preventing an inside casing flow path is dependent on proper isolation of open intervals. The more common types of mechanical isolation are cement plugs and packers or bridge plugs. Casing patches and cemented-in liners are also used. Isolation is confirmed by pressure testing and confirmation of the top with a physical tag is an additional metric to confirm proper placement. If flow is suspected below the isolation point(s), drill out procedures or removal of the isolation equipment can be conducted to determine casing and cement hydraulic isolation. Sampling and analysis of fluid may be used to understand its origin.

7.2 Oil Sands Exploration Wellbores

OSE wellbores are typically drilled and abandoned during the same operation. Current regulatory standards require abandonment of these wellbores by setting cement plugs in the open hole from total depth drilled to a minimum of 15 m above the highest oil sands formation with thermal cement, as well as a surface plug. Proper placement of cement is an important factor in providing effective hydraulic isolation across all required formation intervals. Practices used to ensure isolation are, comparing the measured volume of cement placed in the well vs the theoretical volume, ensuring appropriate cement blend mixture, stopping lost circulation intervals prior to cementing, staging cement plugs across permeable formations and confirming cement top(s) with a physical tag. Low or unconfirmed cement tops and gaps in cement plugs pose a risk of allowing vertical movement of fluid through formations. The study has identified a fully cemented abandoned OSE wellbore, 1AA/09-01-067-03W4 (drilled in 2002), which is interpreted to be involved with the 10-1 and Pad 74 FTS events.

At Primrose, review of wells with unconfirmed cement plug tops or gaps in the cement plugs is performed by drilling with a cement plug tracking assembly and re-entering the open or gap section of the historical wellbore. If the drilling assembly continues to stay in the old wellbore, physically tagging and sampling the top of the cement plug is conducted. Pressures, flow rates, bitumen emulsion identification, and sampling during the delineation drilling can confirm if the existing wellbore was used as a flow path. The ability to detect a flow path can be limited due to technical complexities in tracking an uncased wellbore over longer distances.

Review of the DOME AEC 100/7-22-67-3W4 wellbore (drilled in 1984) at the 2-22 FTS location revealed a certain vintage of OSE wells which do not have cement over much of the Colorado Group interval (Figure 7-1). The DOME AEC 100/7-22-67-3W4 wellbore has been shown to be an integral part of the FTS events at the 2-22 location. A review of the region identified a number of other wells with a similar abandonment technique. In addition to the DOME AEC 100/7-22-67-3W4 the re-abandonment of the DOME AEC 100/7-22-67-4W4 well has shown that cement plug #2 was not present. Due to the deficiencies found at the DOME AEC 100/7-22-67-3W4 and DOME AEC 100/7-22-67-4W4 wellbores and the known gap over much of the Colorado Group interval, Canadian Natural has chosen to re-abandon this vintage of wells such that the entire wellbore is abandoned with pipe to ensure the quality of the cement job and allow for future re-entry if necessary. As part of the FTS study, OSE wells that have questionable abandonment practices have been evaluated using plug tracking technology. The only known wellbore abandoned with this practice and involved with FTS events is the DOME AEC 100/7-22-67-3W4.

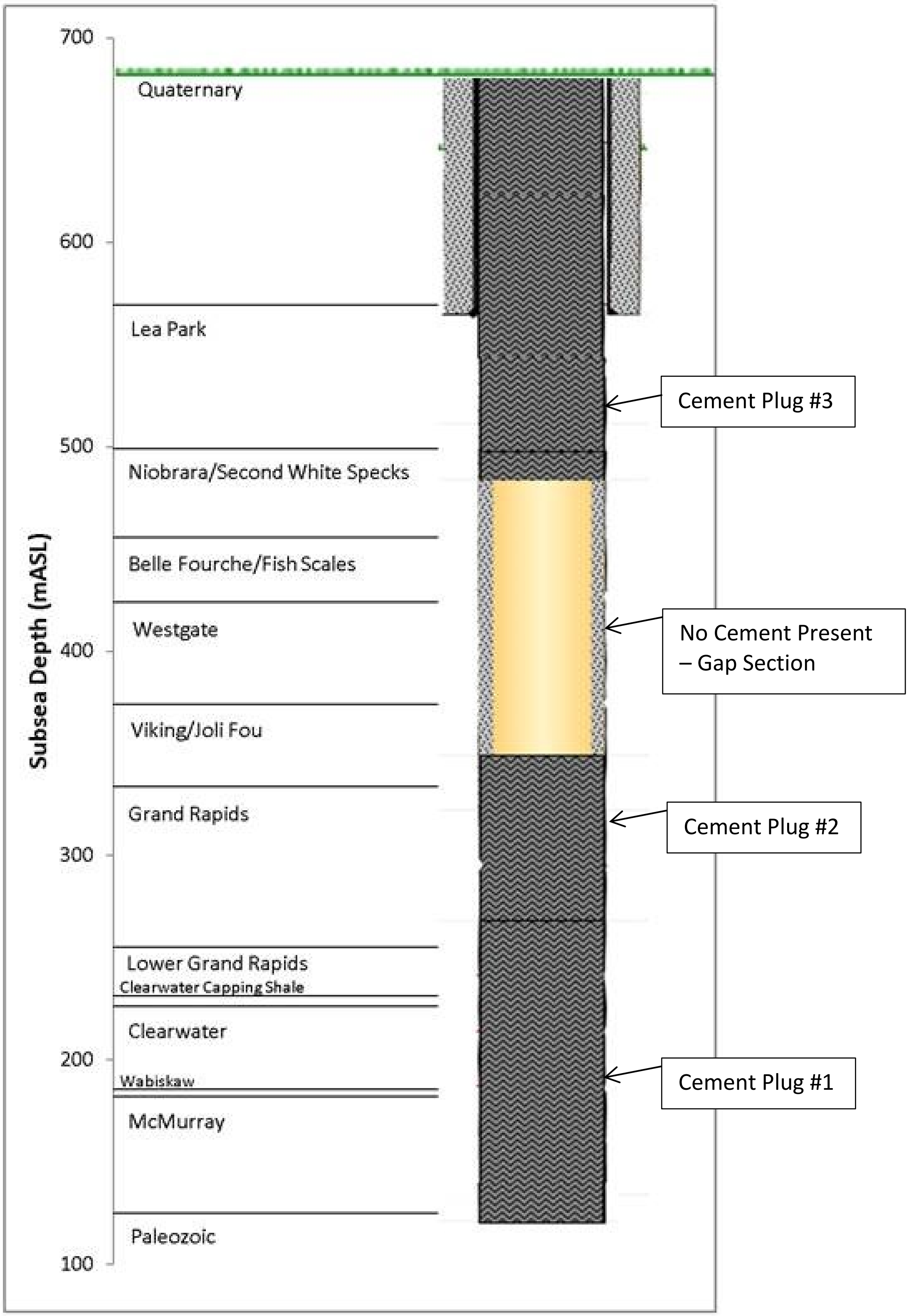


Figure 7-1 Conceptual diagram of the theoretical cement placement for DOME AEC 100/07-22-067-03W4

7.3 FTS Wellbore Study

Part of the study of the FTS events involved a comprehensive wellbore study which included logging and perforation programs. These studies were conducted to confirm casing integrity, hydraulic isolation, identify any anomalies, and identify any outside or inside casing flow paths. A summary of the cased hole studies related to the FTS sites are shown below. From these studies, bitumen emulsion behind pipe was located at:

- 10-2 FTS
  - 108/09-02-067-03W4
  - 100/14-02-067-03W4
- 9-21 FTS
  - 103/07-28-067-04W4
  - CNRES 2C21 PRIMROSE 3-22-67-4W4
  - CNRES 4C21 PRIMROSE 6-22-67-4
- 10-1 FTS
  - 100/11-01-067-03W4
- Pad 74 FTS
  - CNRL 1A74 PRIMROSE 3-1-67-3

Table 7-1 Cased Hole Logging Studies on Pre FTS Drilled Wellbores

Investigations on wells in place prior to FTS

Area	Wells Logged	PIT	RST	Temp	Noise	CBL	Perfs	MFC	Vertilog
PRS	14	10	4	14	4	5	4	4	0
PRE A1	47	45	9	24	0	4	8	2	2
PRE A2	5	3	0	5	0	0	0	0	0
Total	66	58	13	43	4	9	12	6	2

Table 7-2 Cased Hole Logging Studies on Delineation Wellbores

Post FTS Delineation Wells Investigated

Area	Wells Logged	PIT	RST	Temp	Noise	CBL	Perfs	MFC	Vertilog
PRS	19	0	0	15	0	12	8	0	0
PRE A1	19	0	1	19	0	13	8	0	0
PRE A2	1	0	0	1	0	1	1	0	0
Total	39	0	1	35	0	26	17	0	0

8 CAUSES OF FTS

The study has identified the following four conditions at each FTS site:

1 Excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids Formation.

2 A vertical hydraulically induced fracture that propagates up to the top of the Grand Rapids Formation.

3 Vertical pathways to facilitate fluid transfer through highly impermeable shales that have in-situ stress states that usually favor horizontal fracturing.
   - Wellbore path which is the most likely and efficient vertical pathway for large segments of the path to surface for some FTS events.
   - Natural fractures and faults in the shales.
   - Vertical hydraulically induced fractures.

4 An uplift of the overburden above the Clearwater reservoir that changes stress in the overlying shale such that the minimum horizontal and vertical principal in-situ stresses approach each other.

These individual conditions have been observed throughout PAW without FTS incidents occurring. It is possible that the combination of these conditions is significant.
The sections below discuss each of the conditions individually.

8.1 Excessive Release of Bitumen Emulsion from the Clearwater Reservoir into the Next Overlying Permeable Formation, the Grand Rapids Formation

Fluid leaving the Clearwater reservoir initiates FTS events. Geochemical analysis has shown a relationship between the fluid recovered at surface and the fluid in the Clearwater reservoir. This is shown in Figure 8-1, Figure 8-2, Figure 8-3 and Figure 8-4. Acronyms for Figure 8-1, Figure 8-2, Figure 8-3 and Figure 8-4 can be found in Table 8-1.

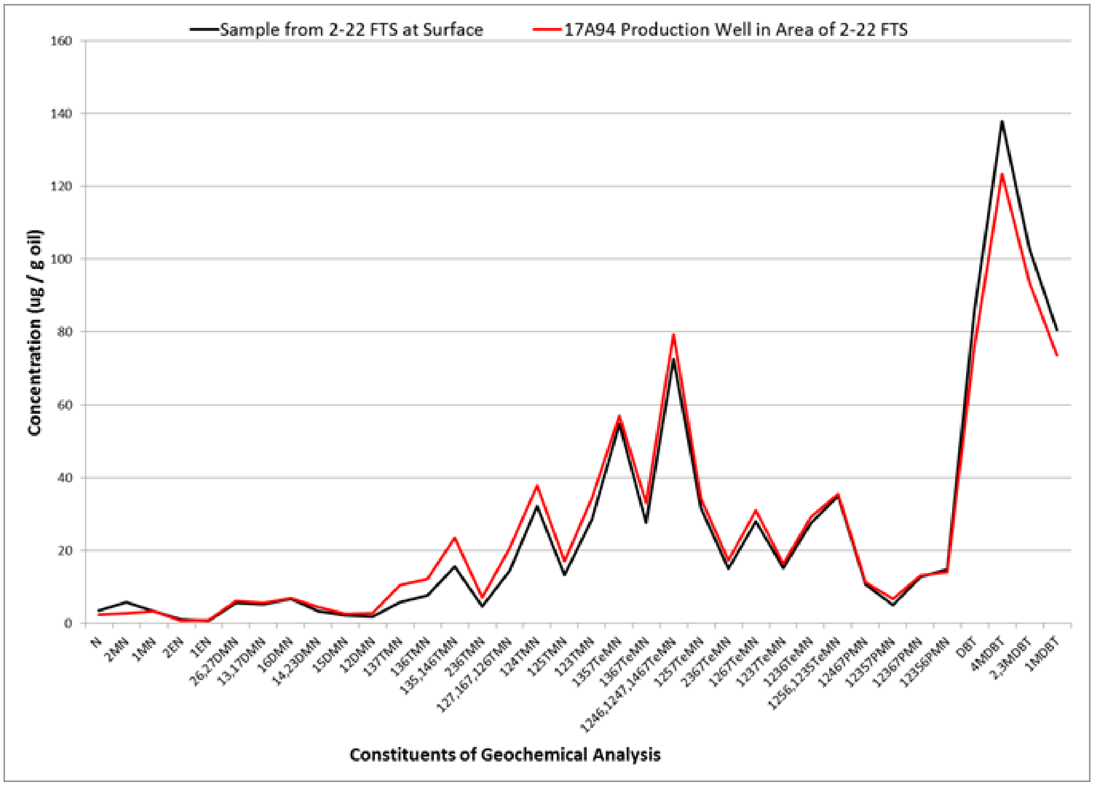


Figure 8-1 2-22 Geochemical Analysis Comparison Plot

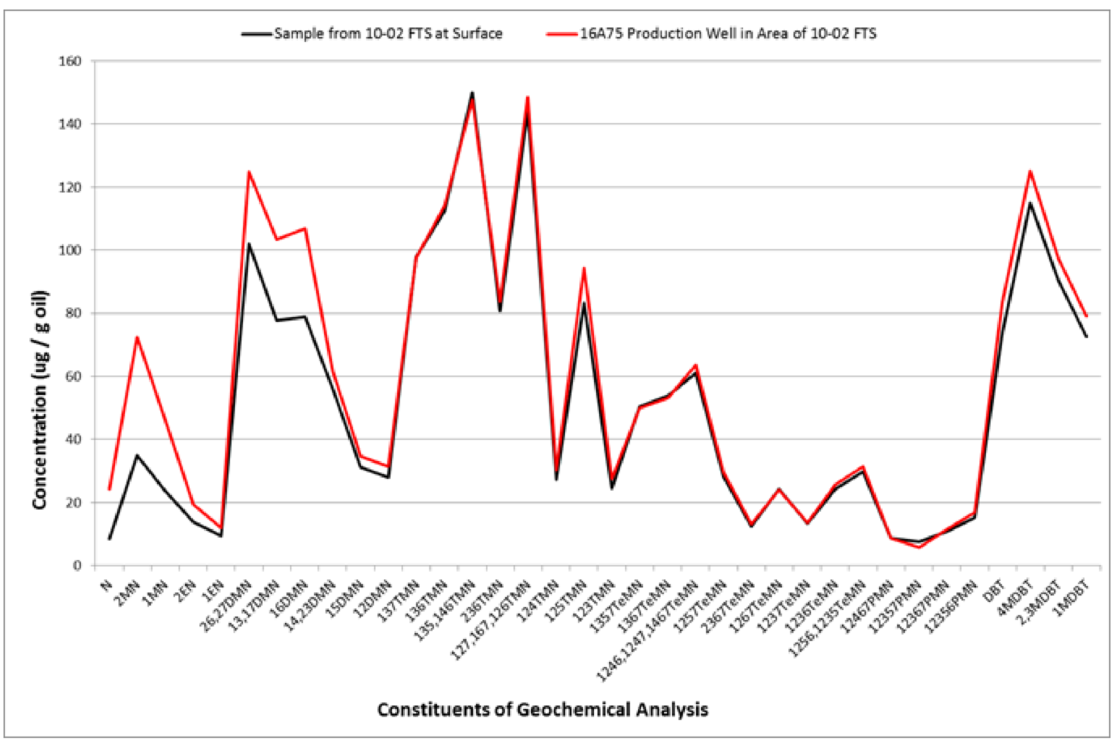


Figure 8-2 10-2 Geochemical Analysis Comparison Plot

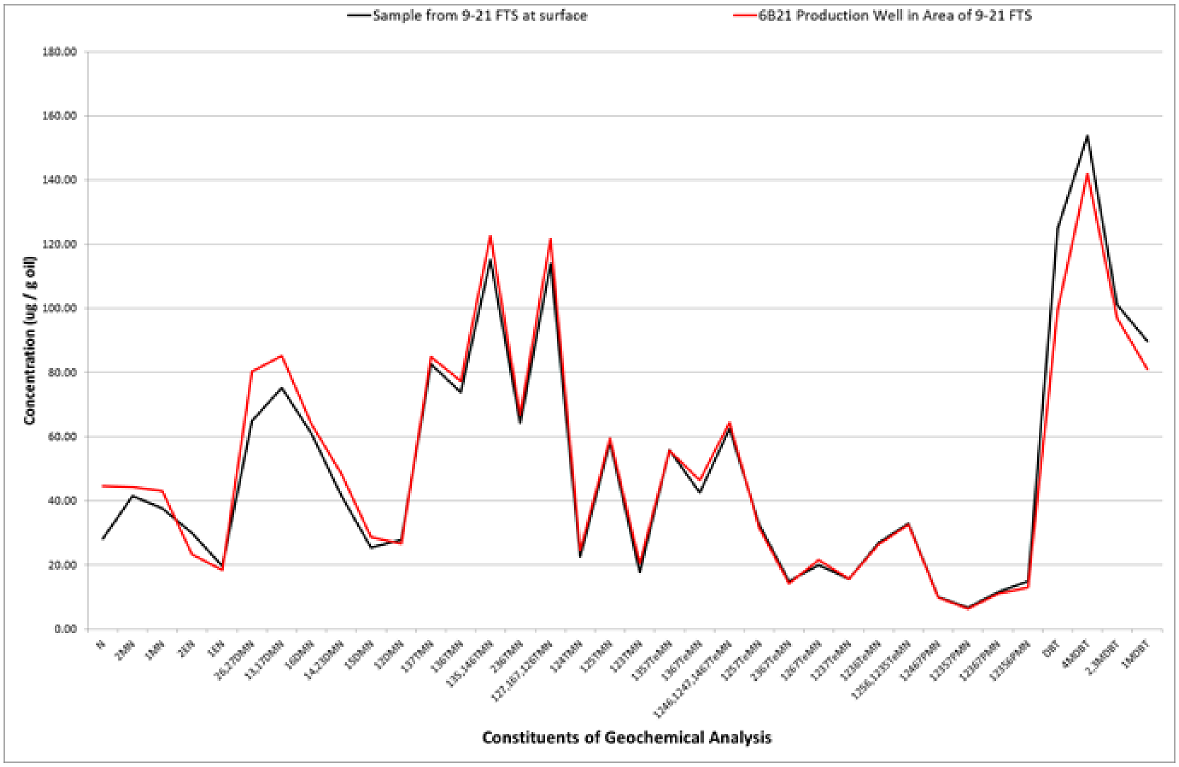


Figure 8-3 9-21 Geochemical Analysis Comparison Plot

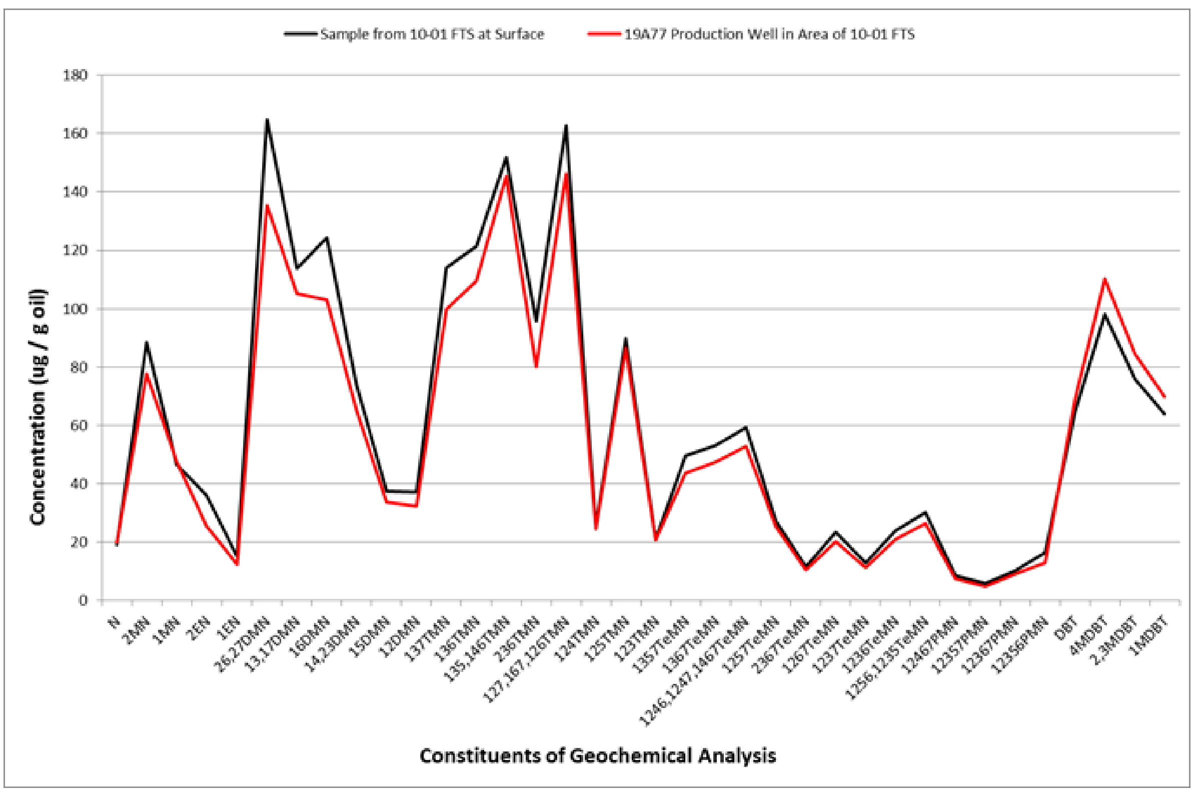


Figure 8-4 10-1 Geochemical Analysis Comparison Plot

Table 8-1 Gas Chromatography–Mass Spectrometry Acronyms

GAS CHROMATOGRAPHY–MASS SPECTROMETRY ACRONYMS	
N	Naphthalene
2MN	2-methylnaphthalene
1MN	1-methylnaphthalene
2EN	2-ethylnaphthalene
1EN	1-ethylnaphthalene
26,27DMN	2,6- + 2,7-dimethylnaphthalene
13,17DMN	1,3- + 1,7-dimethylnaphthalene
16DMN	1,6-dimethylnaphthalene
14,23DMN	1,4- + 2,3-dimethylnaphthalene
15DMN	1,5-dimethylnaphthalene
12DMN	1,2-dimethylnaphthalene
137TMN	1,3,7-trimethylnaphthalene
136TMN	1,3,6-trimethylnaphthalene
135,146TMN	1,3,5- + 1,4,6-trimethylnaphthalene
236TMN	2,3,6-trimethylnaphthalene
127,167,126TMN	1,2,7- +1,6,7- + 1,2,6-trimethylnaphthalene
124TMN	1,2,4-trimethylnaphthalene
125TMN	1,2,5-trimethylnaphthalene
123TMN	1,2,3-trimethylnaphthalene
1357TeMN	1,3,5,7-tetramethylnaphthalene
1367TeMN	1,3,6,7-tetramethylnaphthalene
1246,1247,1467TeMN	1,2,4,6- + 1,2,4,7- + 1,4,6,7-tetramethylnaphthalene
1257TeMN	1,2,5,7-tetramethylnaphthalene
2367TeMN	2,3,6,7-tetramethylnaphthalene
1267TeMN	1,2,6,7-tetramethylnaphthalene
1237TeMN	1,2,3,7-tetramethylnaphthalene
1236TeMN	1,2,3,6-tetramethylnaphthalene
1256,1235TeMN	1,2,5,6- + 1,2,3,5-tetramethylnaphthalene
12467PMN	1,2,4,6,7-pentamethylnaphthalene
12357PMN	1,2,3,5,7-pentamethylnaphthalene
12367PMN	1,2,3,6,7-pentamethylnaphthalene
12356PMN	1,2,3,5,6-pentamethylnaphthalene
DBT	Dibenzothiophene
4MDBT	4-methyldibenzothiophene
2,3MDBT	2- + 3-methyldibenzothiophene
1MDBT	1-methyldibenzothiophene

Intermittent releases from the Clearwater reservoir to the Grand Rapids Formation can occur with or without wellbores. It is believed that the releases are related to dilation of the Clearwater reservoir. The intermittent releases have occurred during uplift of the Clearwater Capping Shale, and the releases are due to a wellbore, injectite, shear movement of natural fractures or faults, hydraulically induced fracturing, or a combination thereof.

Uncertainty exists with estimating the release volumes into the Grand Rapids Formation that are associated with the FTS sites. Volumes released from the Clearwater reservoir are estimated using methods which take into account multiple data sets.

- Injection data at the time of event and subsequent production data
- Grand Rapids Formation pressure and temperature monitoring
- Analysis of depletion index
- Clearwater reservoir injection rates associated with releases to the Grand Rapids Formation

Independent techniques are used to bracket the volume calculation.

- Triangulation using pressure transient analysis
  - The use of multiple pressure monitoring points to define the location of a release, the associated injection flow rate and the associated injection duration
  - The porous media flow characterization in the Grand Rapids B12 is determined by conducting pumping tests
- Depletion Index Analog Comparison
  - Compare data from suspect location to typical CSS performance
- Steam injectivity difference method
  - Using pressure and rate data from steam injection can be used to estimate the associated injection flow rate and the associated injection duration

Multiple analysis techniques are employed to improve confidence in the volume released as there are limitations on data available and quality of data in each instance. These techniques have been carried out at each of the FTS sites and volumes calculated using these methodologies have been deemed as excessive. Details and methodology will be included in the final report.

8.2 Vertical Hydraulically Induced Fracture that Propagates up to the top of the Grand Rapids Formation

Intermittent fluid releases into the lower Grand Rapids Formation will initially be characterized by porous media diffusion into the Grand Rapids B12 water saturated sand. With sufficient flow rate, duration, and potential decreases in water permeability due to bitumen emulsion saturation increases, the pressure within the Grand Rapids B12 will increase to a point where a hydraulically induced fracture will initiate. Fracture growth is expected when the injection flow rate exceeds leak off. Excessive release volumes into the Grand Rapids Formation result in vertical hydraulically induced fractures propagating up to the top of the Grand Rapids Formation.

In the context of the FTS events, without fracture pressures being achieved within the Grand Rapids Formation, the bitumen emulsion path would not reach the top of the Grand Rapids Formation. Study of the path from Clearwater reservoir to surface has yielded evidence that vertical hydraulically induced fracturing plays a key role in the Grand Rapids Formation pathway. Data that supports this are:

- DFIT and micro-frac testing has shown results consistent with vertical hydraulically induced fracture orientations
- 3D post steam seismic anomalies are consistent with vertical hydraulically induced fractures
- A cored sample from the Grand Rapids Formation shows bitumen emulsion in a vertical hydraulically induced fracture
- Passive seismic observation of micro seismic events showing propagation to the top of the Grand Rapids Formation

8.3 Vertical Pathways to Facilitate Fluid Transfer through Highly Impermeable Shales that have In-Situ Stress States that Favor Horizontal Fracturing

The FTS study at each area has indications that bitumen emulsion moves vertically up through the Joli Fou Formation and in some cases the Viking Formation and the lower Westgate Formation. It is believed that a wellbore path is most likely responsible for the vertical movement across at least the Joli Fou Formation and as high as the Westgate Formation due to evidence at the FTS sites.

Uplift induced stress changes result in the Joli Fou Formation having an increased minimum stress contrast relative to the Grand Rapids Formation over the uplift area. A wellbore path is the most efficient vertical pathway to bypass the Joli Fou / Grand Rapids Formation interface and initiate hydraulically induced fracturing within the Lower Colorado Group. Without a wellbore pathway or a large aperture natural fracture or fault, a higher pressure is required to initiate hydraulic induced fracturing in the Joli Fou Formation.

The wellbore pathway is difficult to conclusively prove and some FTS sites have more evidence than others.

- Strong evidence of a wellbore path at 2-22 and 10-2 sites.
    - The DOME AEC 100/7-22-67-3W4 OSE wellbore shows high deliverability (200 L/min when drilling) of bitumen emulsion.
        - In contrast to wellbore flow rates at the DOME AEC 100/7-22-67-3W4 OSE wellbore, natural fractures have shown very low to negligible flow rates (maximum of 1 L/min)
    - The DOME AEC 100/7-22-67-3W4 OSE wellbore was abandoned with historical practices and identified while steaming as a release location from the Clearwater reservoir to the Grand Rapids Formation.
    - Perforations on the 108/9-2-67-3W4 OSE wellbore from the Grand Rapids to the Viking formations revealed bitumen emulsion behind the pipe.
        - Passive seismic indications along the well
        - Temperature log indications of wellbore involvement
        - Twin well confirmation of perforation findings

    - This area has been identified as a release location from the Clearwater to the Grand Rapids Formation on several cycles.
    - Suspect channeling behind pipe observed via bond log in the lower Colorado Group
- Evidence of an implied wellbore path at 9-21, 10-1, and Pad 74 sites
  - The CNRES 2C21 PRIMROSE 3-22-67-4W4 well has bitumen identified from a casing failure in the Westgate Formation
  - The 1AA/09-01-067-03W4 OSE wellbore has a twin wellbore (~10 m offset) with a bitumen emulsion show identified within the Joli Fou Formation
- Other industry studies have shown that bitumen emulsion in shale has likely resulted from wellbore paths.

8.4 An Uplift of the Overburden above the Clearwater Reservoir that Changes Stress in the Overlying Shale such that the Minimum Horizontal and Vertical Principal In-Situ Stresses Approach Each Other

Introduction of steam in the reservoir at pressure greater than or equal to the vertical minimum stress results in an uplift of the overburden and associated stress changes in the overburden. This concept has been illustrated in Section 6.6. The uplift to the Clearwater Capping Shale can potentially cause the vertical stress to approach the minimum horizontal principal stress. Natural fractures, faults and bedding planes can have permeability increases in the presence of fracture pressure. This is of significance for FTS events to develop.

Uplift of the Clearwater Capping Shale can be represented through a simple 1D calculation using volume injected at fracture pressure divided by the estimated area associated with a well. The volume divided by the area results in a vertical height increase which is defined as the Formation Expansion Index (FEI). Some assumptions for the calculation include the area that steam contacts, steam injected above fracture pressure is contained within the area defined, uniform uplift of the Clearwater Capping Shale, and the cold water equivalent steam volume is a reasonable representation of all factors causing uplift. The assumptions required reduce this term to an approximate representation of uplift for the purposes of comparison.

FEI of the Clearwater Capping Shale at the estimated time and the location of the FTS events are shown in Table 8-2 and Table 8-3. The CSS wells included in Table 8-2 are illustrated in Figure 8-5, Figure 8-6, Figure 8-7, Figure 8-9 and Figure 8-8:

Table 8-2 FEI of Clearwater Reservoir

	Well Dimensions			Volume After Fill-Up (m³)					Formation Expansion Index (m)				
	Well	Spacing (m)	Area (m²)	C1	C2	C3	C4	C5	C1	C2	C3	C4	C5
2-22 FTS	16A94	60	57620	6.7E+03					0.1				
	17A94	60	57336	1.9E+04					0.3				
	18A94	60	56959	2.1E+04					0.4				
	19A94	60	57025	3.4E+04					0.6				
	20A94	60	57186	4.5E+04					0.8				
9-21 FTS	1A22	80	140876	3.8E+04	4.3E+04	1.0E+05			0.3	0.3	0.7		
	2A22	80	142580	3.6E+04	4.5E+04	1.0E+05			0.3	0.3	0.7		
	3A22	80	143492	4.4E+04	4.0E+04	1.0E+05			0.3	0.3	0.7		
	4A22	80	143561	4.5E+04	4.3E+04	1.0E+05			0.3	0.3	0.7		
	5A22	80	143564	4.3E+04	4.2E+04	1.0E+05			0.3	0.3	0.7		
	6A22	80	143247	3.6E+04	4.7E+04	1.0E+05			0.3	0.3	0.7		
10-2 FTS	10A75	60	57340	1.1E+04	3.2E+04	4.6E+04	5.9E+04	3.2E+04	0.2	0.6	0.8	1.0	0.6
	11A75	60	57227	1.1E+04	3.1E+04	4.7E+04	2.9E+04	2.6E+04	0.2	0.5	0.8	0.5	0.5
	12A75	60	56967	9.7E+03	3.0E+04	4.4E+04	2.8E+04	5.5E+04	0.2	0.5	0.8	0.5	1.0
	13A75	60	56740	1.1E+04	3.4E+04	3.3E+04	6.4E+03	4.2E+04	0.2	0.6	0.6	0.1	0.7
	14A75	60	56886	1.1E+04	3.3E+04	3.2E+04	3.6E+04	5.6E+04	0.2	0.6	0.6	0.6	1.0
	15A75	60	56772				3.4E+04	3.6E+04	0.0	0.0	0.0	0.6	0.6
	16A75	60	57521	1.1E+04	3.6E+04	4.1E+04	1.2E+03	3.6E+04	0.2	0.6	0.7	0.0	0.6
	17A75	60	59233	1.1E+04	3.3E+04	4.0E+04	2.2E+04	4.2E+04	0.2	0.6	0.7	0.4	0.7
	18A75	60	64920	1.1E+04	3.2E+04	4.4E+04	3.0E+04	1.4E+04	0.2	0.5	0.7	0.5	0.2
	19A75	60	66478	1.1E+04	3.4E+04	4.0E+04	1.7E+04	4.1E+04	0.2	0.5	0.6	0.3	0.6
	20A75	60	75030	1.0E+04	3.1E+04	3.9E+04	2.0E+04	4.0E+04	0.1	0.4	0.5	0.3	0.5
10-1 FTS and Pad 74	1A77	60	51468	7.0E+04	1.9E+04	5.5E+04			1.4	0.4	1.1		
	2A77	60	52097	6.5E+04	1.7E+04				1.2	0.3			
	3A77	60	50978	6.9E+04	1.9E+04	5.3E+04			1.3	0.4	1.0		
	4A77	60	51664	7.0E+04	1.2E+04	3.8E+04			1.4	0.2	0.7		
	5A77	60	52267	7.2E+04	0.0E+00	5.7E+04	1.0E+04		1.4	0.0	1.1	0.2	
	6A77	60	50957	6.8E+04	1.4E+04	5.3E+04	1.6E+04		1.3	0.3	1.0	0.3	
	7A77	60	52350	7.1E+04	1.4E+04	5.5E+04	1.6E+04		1.4	0.3	1.1	0.3	
	8A77	60	52802	7.2E+04	5.8E+03	5.8E+04	2.4E+03		1.4	0.1	1.1	0.0	
	9A77	60	52877	7.2E+04	1.1E+04				1.4	0.2			
	10A77	60	53321	6.9E+04	1.4E+04	4.9E+04			1.3	0.3	0.9		

Table 8-3 FEI Summary for CSS wells associated with FTS sites

	2-22	9-21	10-2	10-1	Pad 74
Wave Direction	West-East	Block	East-West	East-West	East-West
Cycle	1	3	5	3	1
Lead Event Well(s)	16A94	none	12-14A75	10A77	10A77
Associated Uplift Wells	20A94-17A94	1A22-6A22	20-16A75 and 11-10A75	1A77-10A77	1A77-10A77
Average FEI for Associated Uplift Wells (m)	0.5	0.7	0.6	1.0	1.3

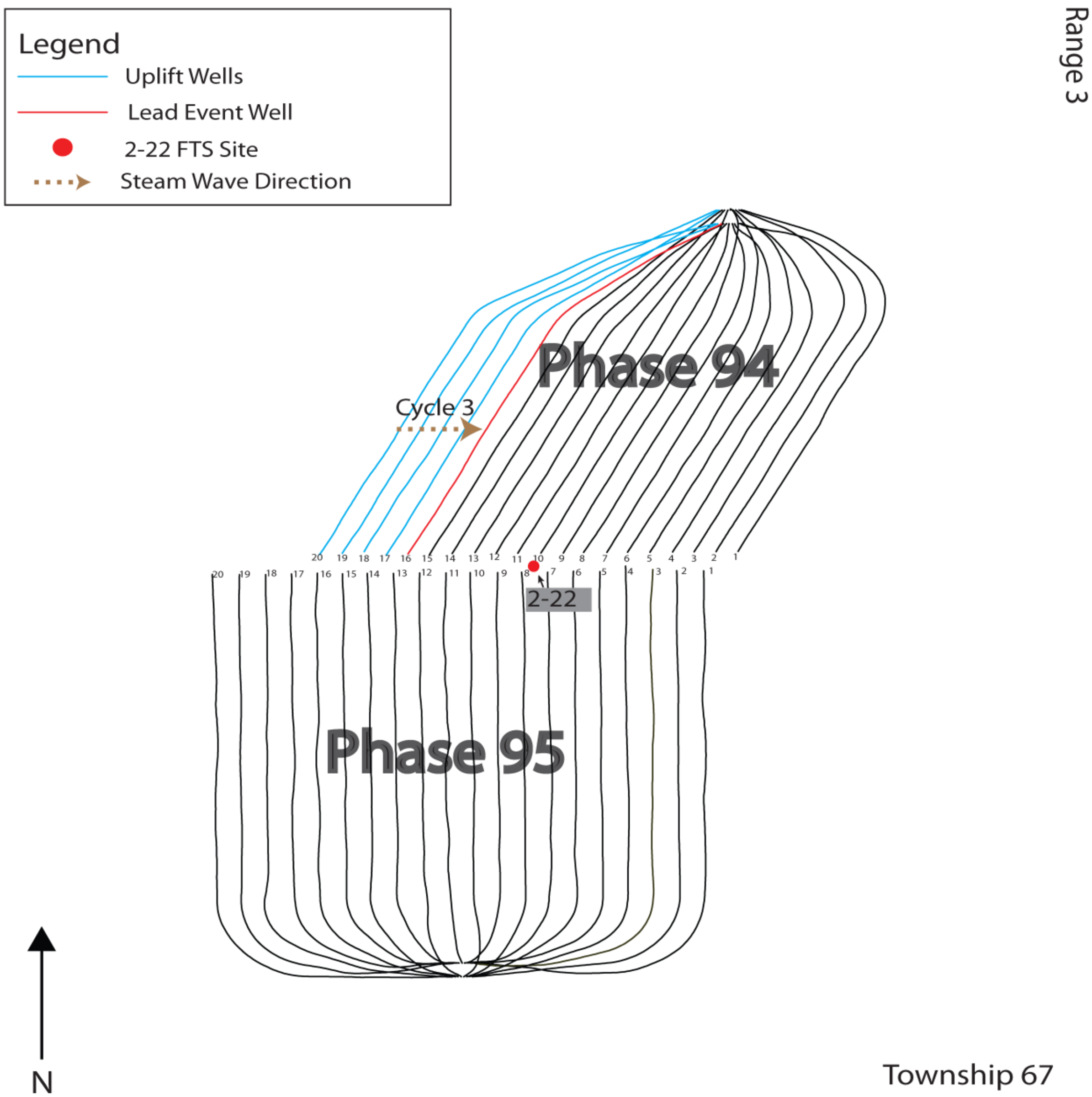


Figure 8-5 **Map of Uplift Wells as described in Table 8-3 for 2-22 FTS Site**

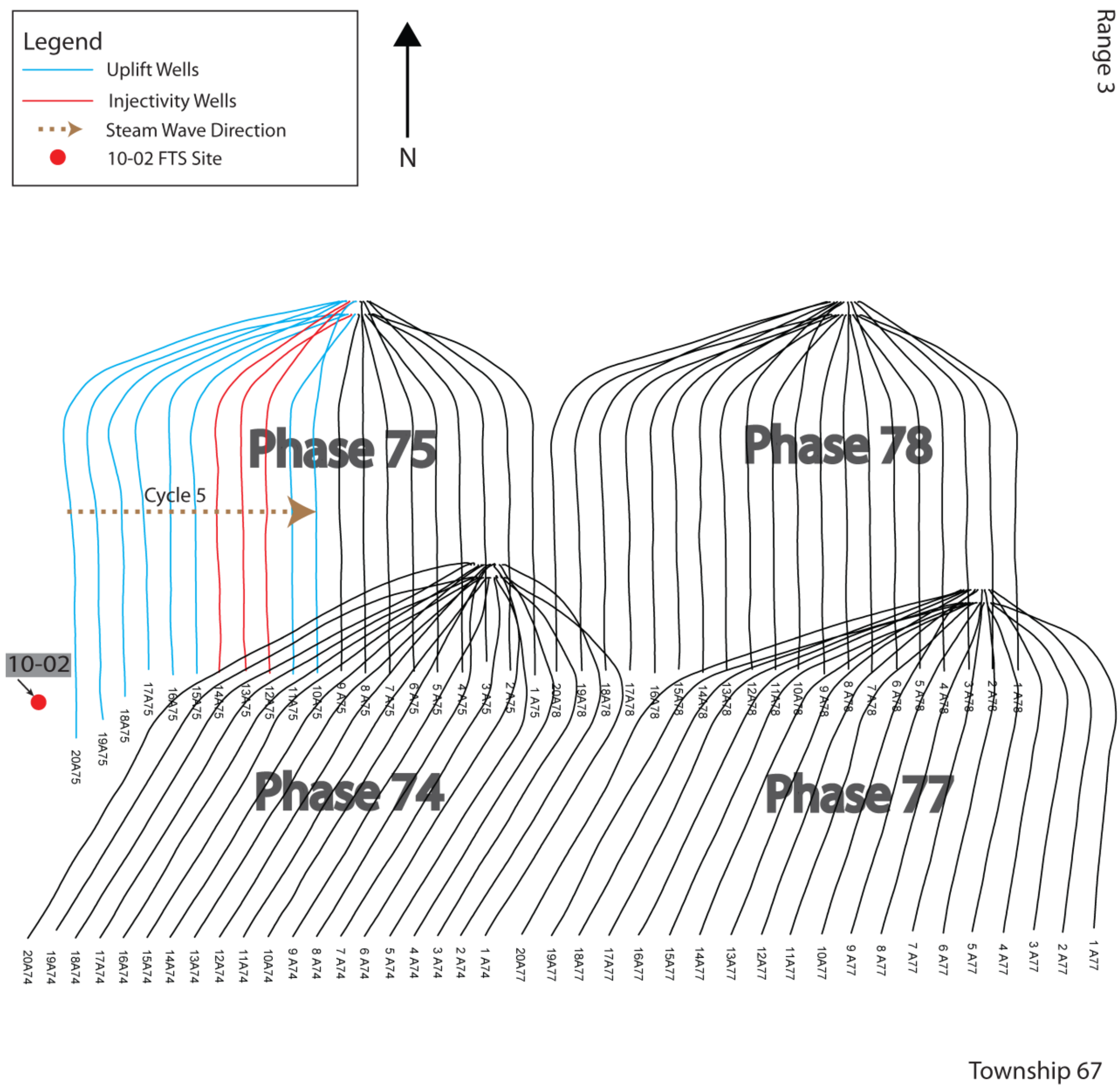


Figure 8-6 **Map of Uplift Wells as described in Table 8-3 for 10-2 FTS Site**

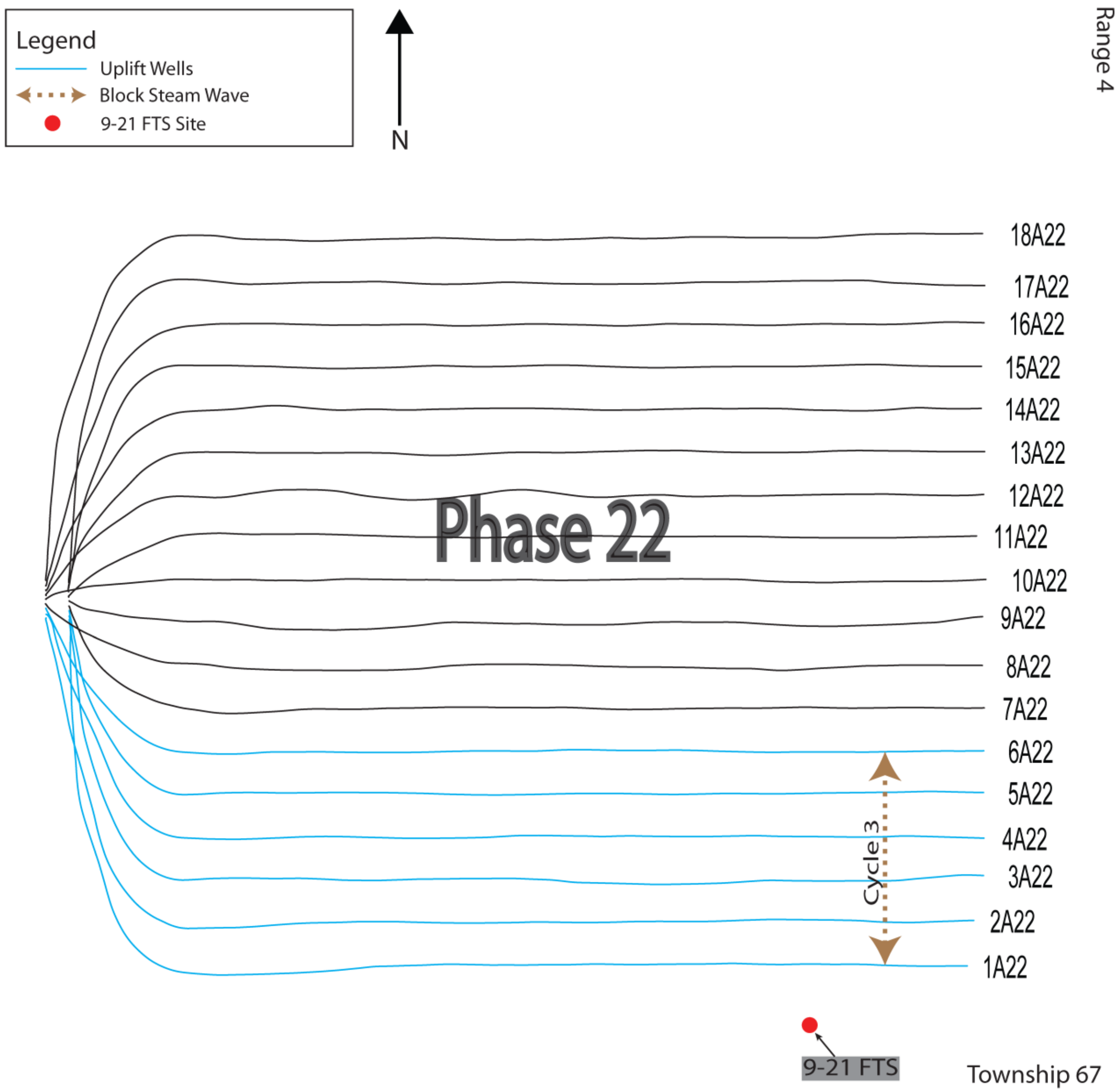


Figure 8-7 Map of Uplift Wells as described in Table 8-3 for 9-21 FTS Site

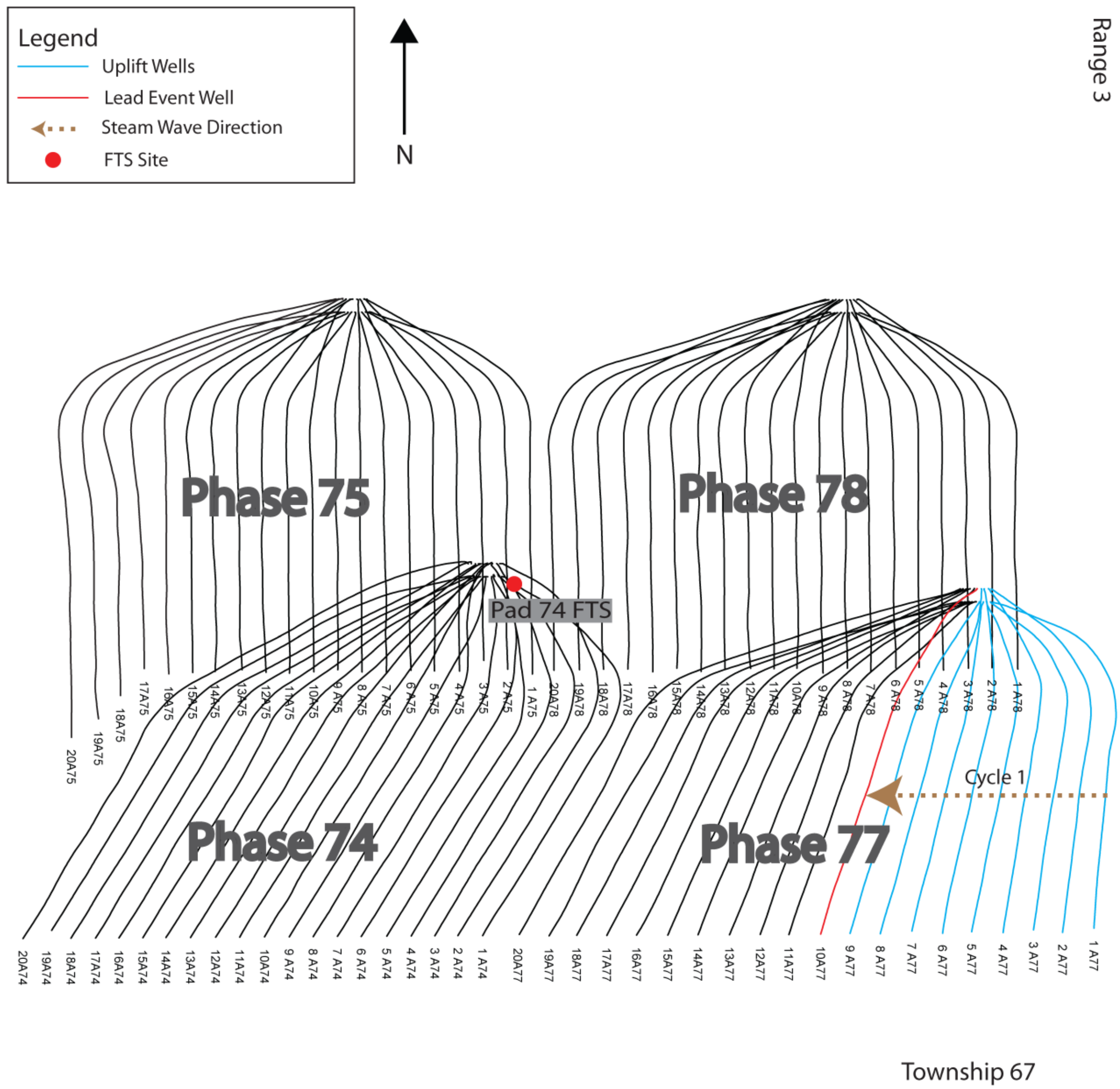


Figure 8-8 Map of Uplift Wells as described in Table 8-3 for Pad 74 FTS Site

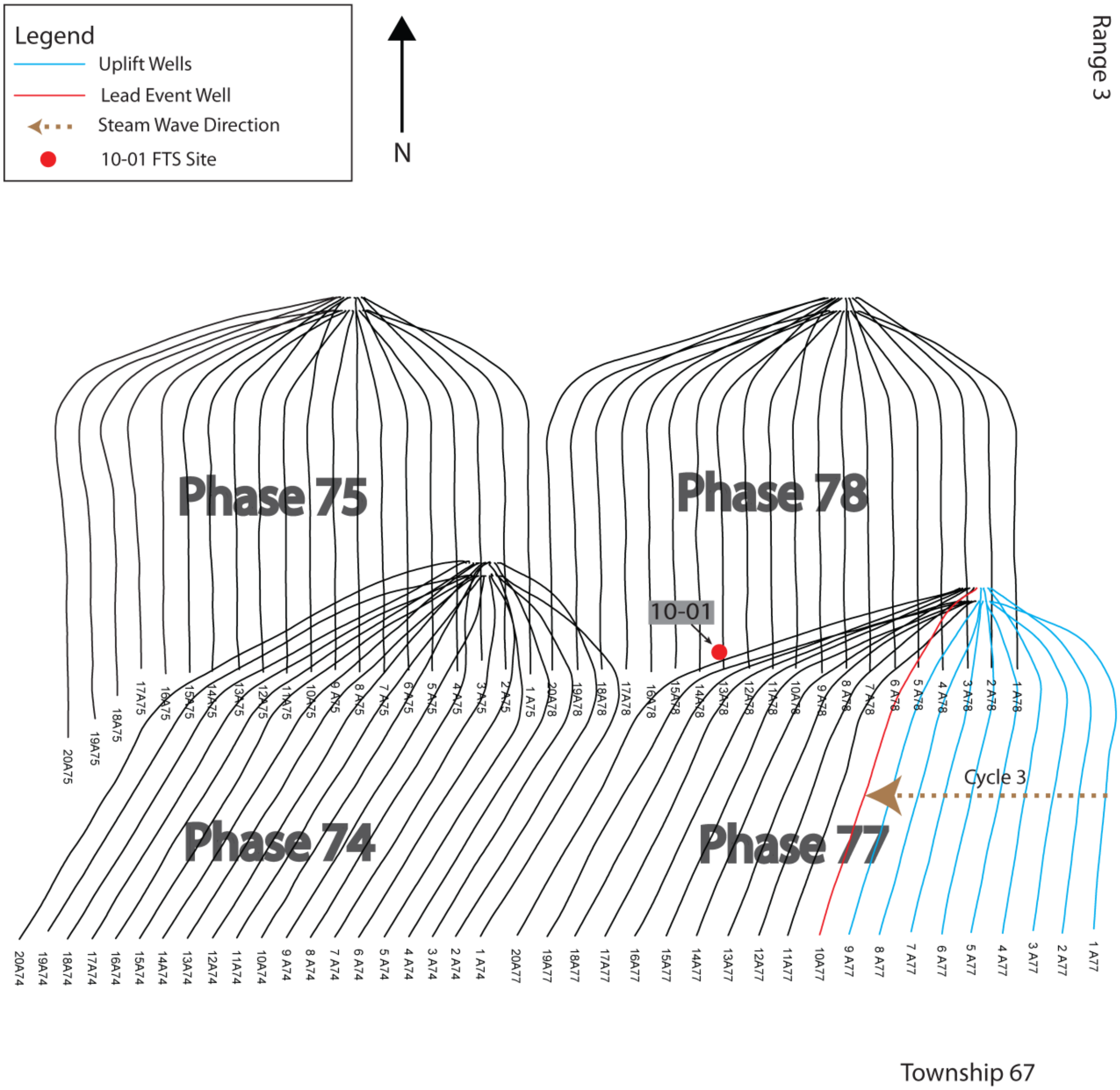


Figure 8-9 Map of Uplift Wells as described in Table 8-3 for 10-1 FTS Site

8.5 Other Indications Related to the Cause

Some indicators potentially related to FTS events have been identified. The indicators are of use in determining some operational parameters for CSS operation. They give insight as to where modified procedures may be required for an area. The factors need to be evaluated on a case by case basis and are listed below:

- Production data anomalies (i.e. watering out)
- Steam injection anomalies (simultaneous pressure decreases and steam injection rate increases)
- Abnormally elevated pressure or temperature of bitumen emulsion in the Colorado Shale

9 FLOW PATH TO SURFACE

Based on the data available the following sections describe the flow path and observed conditions to propagate fluid from the Clearwater reservoir to surface.

As shown in Figure 9-1, the three potential paths to surface are:

1 A path entirely using an open wellbore (grey)

2 A path entirely through geologic strata (yellow)

3 A path that uses a portion of open wellbore and through geological strata (red)

The portion of the path from the Clearwater reservoir to Grand Rapids Formation and from the Niobrara Formation to the surface has been shown to be either an open wellbore path or via the formation.

Portions of the general flow path segments can involve wellbores, natural fractures, faults and bedding planes, or induced fractures. The flow path characteristics are defined by their geology or the geomechanics associated with those features:

1 Wellbore

Wellbores are an artifact of drilling, whether for the purpose of exploration or production. Wells are generally abandoned or completed by placing cement, with pipe (cased hole) or without pipe (open hole). Where present, wellbore paths provide possible vertical flow conduits via:

- Flow through poor placement of cement
- Open sections between cement plugs
- Flow behind casing
- Flow inside casing via irregularities (i.e. breaks)

2 Geology

Possible geological conduits are naturally occurring features such as:

- Hydraulically conductive faults
- Hydraulically conductive natural fractures
- Hydraulically conductive bedding planes
- Permeable sediments
- Channels
- Glacial bedrock thrusts

3 Geochanics

Possible geomechanical enhanced conduits are induced features such as:

- Hydraulically induced fractures
- Hydraulically induced opening of natural fractures
- Hydraulically induced opening of faults
- Hydraulically induced opening of bedding plane

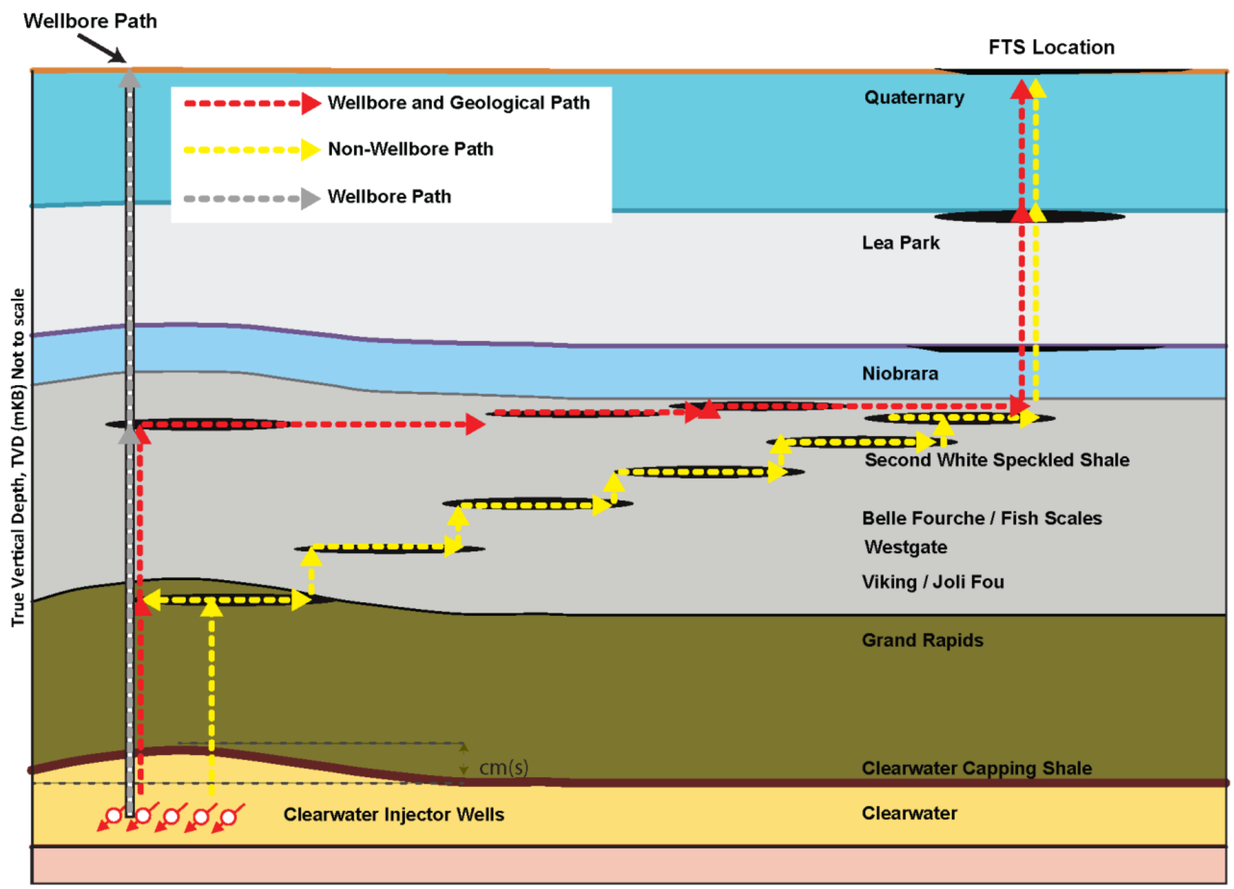


Figure 9-1 Conceptual Flow Path for FTS

While the study of FTS events has gone to great lengths and effort to gather a complete data set, exploring the subsurface with wellbores is complex. The limitations on the data set include:

- Limits to sampling subsurface area and volume
- Frequency of studied phenomena
- Current condition of the studied phenomena
- Orientation of the studied phenomena
- Orientation of wellbores with respect to the studied phenomena
- Ability to detect all studied phenomena

The FTS pathways all have significant lateral movement, and it is interpreted to occur in horizontal hydraulically induced fractures or natural fractures dipping at low angles. However the core data shows a higher number of high dip angle fractures and faults, and very few low dip angle fractures and faults. This is one of the more challenging aspects of the data set. Possible reasons for the apparent inconsistency include:

- Frequently unable to collect or identify horizontal features in core
- Use of high angle natural fractures for lateral movement

9.1 Flow Path Overview

The following is a summary of the flow paths that have been observed during the FTS study.

Delineation drilling was used to define the flow path at each FTS site. A fit for purpose drilling program was designed to detect bitumen emulsion in the subsurface. The detection was accomplished by various means:

- Physical returns of bitumen emulsion in the drilling mud system
- Core containing bitumen emulsion
- Micro imaging detection of a resistive feature associated with bitumen smearing up hole
- Perforations of a cased well to recover bitumen emulsion behind pipe

Detection by one of the above methods is defined as a show. In order to increase the certainty of shows, independent data, such as geochemical analysis and tests for flow, are applied. The result is defined as a high confidence show in that bitumen emulsion in the subsurface is clearly present at a specific point. High confidence shows are used to create graphical images that represent bitumen emulsion findings in the subsurface and are shown in Section 10. The shows that cannot be confirmed are not plotted and are categorized as false positives. Some reasons for false positives are as follows:

- Once bitumen emulsion is detected in a wellbore, subsequent shows have a higher threshold of detection due to:
    - Flow from the above show
    - Contamination of the mud system or drilling equipment
    - In some cases, if an increase in drilling mud density was required, the lower show must be at higher pressure to be detected
- Contamination from the drilling rig itself
    - Pipe lubrication
    - Hydraulic fluid
    - Contaminated drill equipment from a previous well
    - Equipment was routinely steam cleaned throughout the study, but small amounts of bitumen were observed on occasion

Detection limits of the drilling rig have been tested through a field trial and have been determined to be at least 1 cm^3 of bitumen emulsion.

Over portions of Primrose North and Primrose South, the first barriers to vertical hydraulically induced fracturing are Clearwater reservoir internal shale beds. These shale bed layers are not present in Primrose East. The next barrier to hydraulically induced fracturing is the Clearwater Capping Shale, which is regionally present over all Primrose developments.

There is evidence of intermittent Clearwater reservoir releases involving wellbore and non-wellbore facilitated paths from the Clearwater reservoir to the Grand Rapids Formation. The intermittent releases have occurred during uplift of the Clearwater Capping Shale, and the releases are due to a wellbore, injectite, shear movement of natural fractures or faults, hydraulically induced fracturing, or a combination thereof.

Loss of Clearwater Capping Shale containment during steaming can be detected by identifying injectivity events from steam injection flow rates and wellhead pressures. Releases out of the Clearwater reservoir can also be detected by pressure and temperature monitoring in the lower Grand Rapids Formation.

The next barrier to vertical fracturing is leak-off within the permeable water saturated sands within the Grand Rapids Formation. If the release flow rate can be accommodated by leak off within the lower Grand Rapids Formation, vertical movement of reservoir fluids will not continue and the released fluids will diffuse into the water saturated sands. If the release flow rate cannot be accommodated by leak off within the lower Grand Rapids Formation, a vertical hydraulically induced fracture will form and the surface area available for leak off will increase as the fracture propagates upward. With a sufficiently high flow rate and a sufficiently long duration, a vertical hydraulically induced fracture will reach the base of the Joli Fou Formation. As the vertical hydraulically induced fracture continues to propagate, the dynamic fracture pressure will increase due to building frictional losses and local poro- and thermo-elastic stress increases.

Analysis of post-steam seismic anomalies within the Grand Rapids Formation, illustrates that flows of sufficient volume and duration, to reach the top of the Grand Rapids Formation are relatively uncommon. The Grand Rapids Formation post-steam seismic anomalies are shown in Figure 9-2 and Figure 9-3.

These seismic anomalies are characterized by highly localized often circular amplitude changes and push down effects observed in post steam seismic volumes. Modelling and drilling data suggests the seismic features are observed because of the presence of liberated solution gas from the bitumen, but pressure and temperature effects may also play a role. Mapping of these anomalies shows that most do not extend to the top of the Grand Rapids Formation.

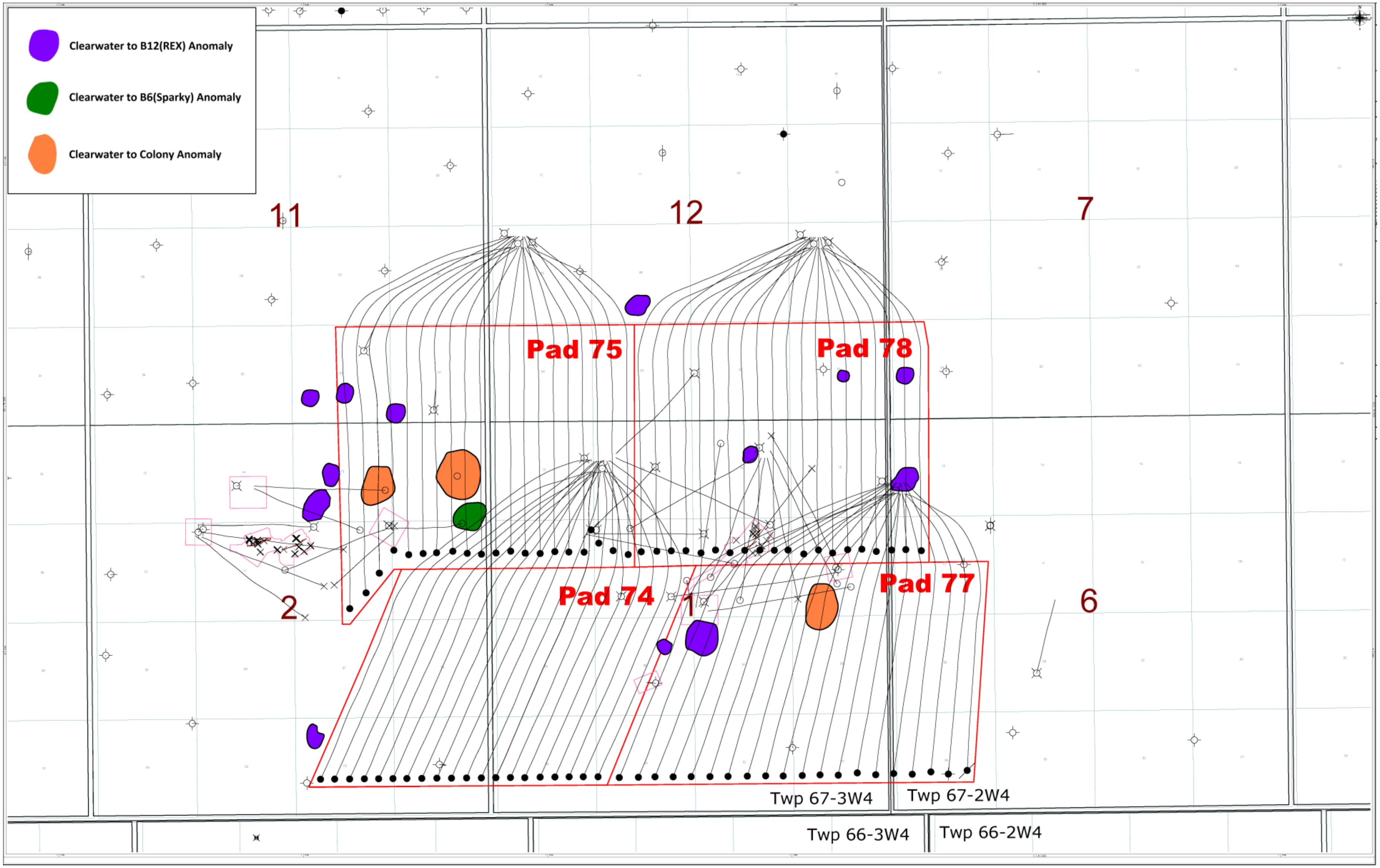


Figure 9-2 Simplified Grand Rapids Formation Post Steam Seismic Anomaly Location Map for PRE Area 1

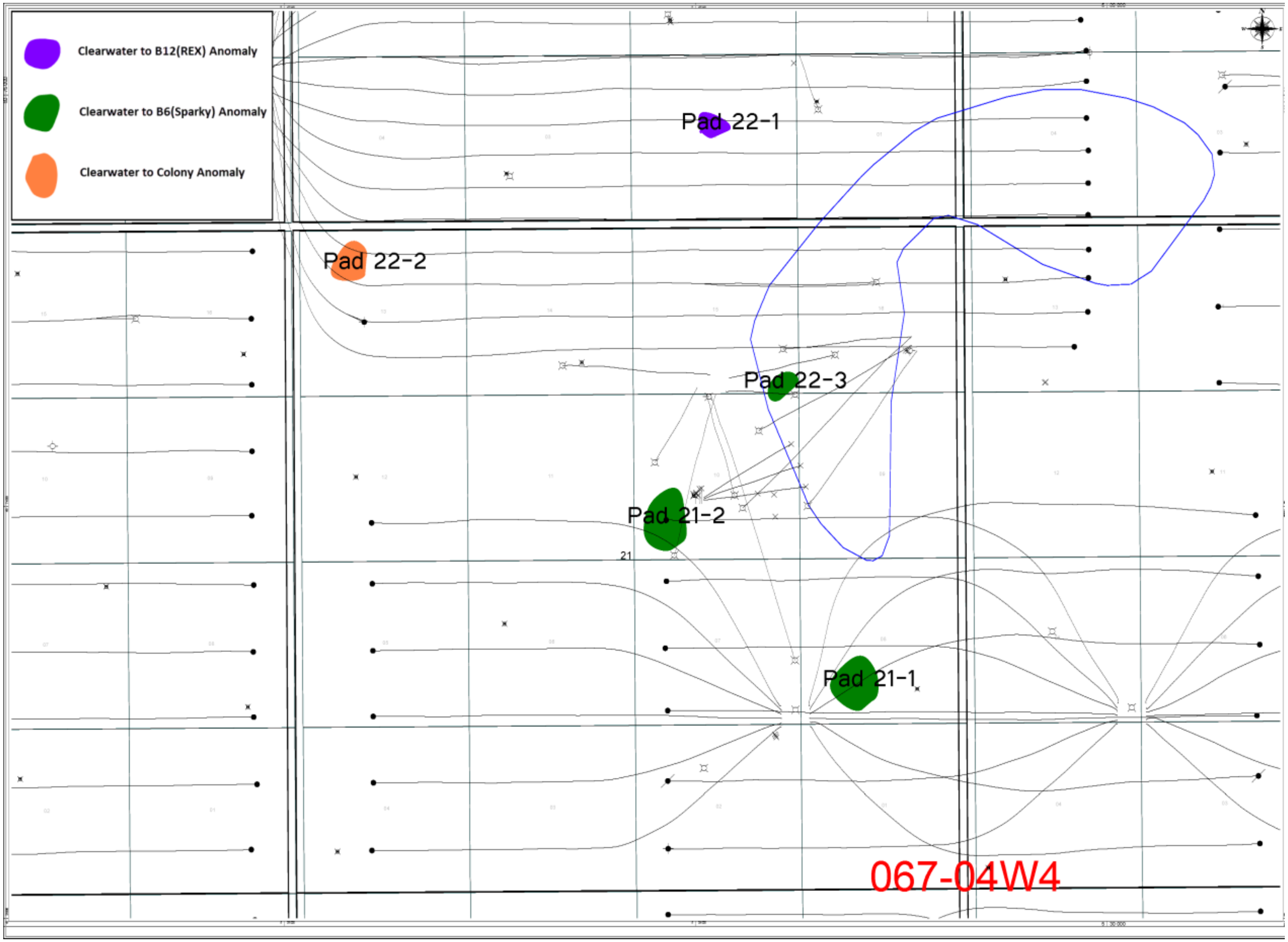


Figure 9-3 Simplified Grand Rapids Formation Post Steam Seismic Anomaly Location Map for 9-21 FTS

Fluid entry into the Colorado Group is likely via a vertical pathway. Evidence of vertical movement has been observed in studies of wellbores that are suspected to be involved. The wellbore path, due to observations from the study, is the most likely pathway to bypass the large stress contrast at the base of the Colorado Shale. However, two alternative geomechanical pathways are possibilities as described in Section 6.7.

The study has shown that a wellbore is unlikely to be exclusively involved in the vertical travel from as low as the Viking Formation to the base of the Niobrara Formation. The flow path from the Viking Formation to the base of the Niobrara Formation involves a combination of horizontal hydraulically induced fractures connected by natural fractures, faults and/or bedding planes. These have had hydraulically induced permeability increases likely facilitated by uplift induced stress changes. Stress states, Clearwater reservoir uplift magnitudes and fracture and pore pressures govern which bedding planes, natural fractures or faults increase in aperture.

The Niobrara Formation and Lea Park Formation strata are not reliable fracture barriers (supported by DFIT stress tests) and are capable of horizontal movement of fluid. These formations have a high density of natural fractures that may act as a pathway vertically and horizontally. Field observations show that horizontal movement is more common than vertical movement in both of these formations.

Vertical hydraulically induced fractures have been observed in Quaternary sediments above the Lea Park Formation to surface. At each FTS location, the surface fracture is reasonably aligned with the maximum horizontal principal stress orientation. Field observations support that vertical hydraulically induced fractures are the final portion of the path to surface.

9.2 Other Pathways

There are other possibilities for pathways, and these are viewed as lower probability than the pathway description in Section 9.1 when considering the study findings to date. In addition to the pathway that has been described in Section 9.1 the following other flow paths have been considered:

- Wellbore conduit through the entire Colorado Group
- Network of natural fractures, faults and bedding planes through the entire Colorado Group
    - Fracture networks with sufficient conductivity that permeability enhancements are not required
- Material flow within high angle natural fractures or high angle faults in the absence of significant uplift induced stress changes
- Vertical hydraulically induced fracturing and horizontal hydraulically induced fracturing
- Horizontal hydraulically induced fracture at a low angle climb within the shale
- Permeable channel through Colorado Group
- Injectites through Colorado Group
- Combinations and permutations of the above

Considerations have been made for these alternate paths when evaluating the cause of FTS events.

10 FLOW PATH SITE SPECIFIC DETAILS

The flow path findings with respect to the probable release mechanisms from the Clearwater reservoir and subsequent flow pathways to surface reflect a comprehensive assessment of data. The data collected includes findings from delineation drilling, geomechanical work and review of operational data. Presented below are the most likely pathways for each FTS area based on the study of FTS events.

10.1 FTS Site 2-22

The study into the cause of bitumen emulsion being released from the Clearwater reservoir and flowing to surface at 2-22 in PRE A2 has generated the following pathway description (Figure 10-1 and Figure 10-2):

- An injectivity event was noted at the CNRL 16A94 PRIMROSE 2-22-67-3 and subsequent wells which are in close proximity to the DOME AEC 100/07-22-067-03W4 OSE wellbore
- Grand Rapids Formation monitoring systems detected the release from the Clearwater reservoir during cycle 1 and triangulated its location in the vicinity of DOME AEC 100/07-22-067-03W4 OSE wellbore. The bitumen emulsion then propagates to the top of the Grand Rapids Formation in a vertical hydraulically induced fracture.
- The bitumen emulsion flow path from the Grand Rapids top to the top of the Westgate Formation is most likely in the un-cemented open hole and/or along the annulus of the cemented portion of the DOME AEC 100/07-22-067-03W4 OSE wellbore. Plug tracking operations on the wellbore observed bitumen emulsion flow rates up to 200 L/min. The flow rates were sustained which indicates a high permeability connection to pressurized bitumen emulsion. Sustained flow rates of this magnitude have not been observed in natural fractures or faults.
- Evidence of a blockage in the open portion of the well has been identified during plug tracking operations, which explains why fluid movement up the DOME AEC 100/07-22-067-03W4 OSE wellbore was limited to below the Fish Scales Formation.
- Bitumen emulsion is not observed above the Westgate Formation in this wellbore. The flow path likely exits the wellbore in the Westgate Formation.
- The flow path from the Upper Westgate Formation to the base of the Niobrara Formation involves a combination of horizontal hydraulically induced fractures connected by natural fractures, faults and/or bedding planes which have had permeability increases likely facilitated by uplift induced stress changes.
- The combination of natural fractures, faults and bedding planes with horizontal hydraulically induced fractures causes a gradual inclined pathway from the Westgate Formation at the DOME AEC 100/7-22-67-3W4 OSE wellbore towards the Niobrara Formation underneath the 2-22 FTS event.
- Once the flow path reaches the Niobrara Formation it encounters a network of abundant natural fractures which can cause an accumulation of bitumen emulsion in the natural fractures or faults. The net result is lateral and vertical movement through the Niobrara Formation and Lea Park Formation.
- The bitumen emulsion flow path from bedrock and through the Quaternary deposits is due to localized vertical hydraulically induced fractures within the glacial till.

The failed DOME AEC 100/7-22-67-3W4 OSE wellbore acted as a flow path for fluid migration from the Clearwater reservoir to the top of the Westgate Formation. The mechanism for fluid flow through the remainder of the Colorado Group to surface has been determined using drilling, geological, geomechanical, and geochemical data collected throughout the study of FTS events.

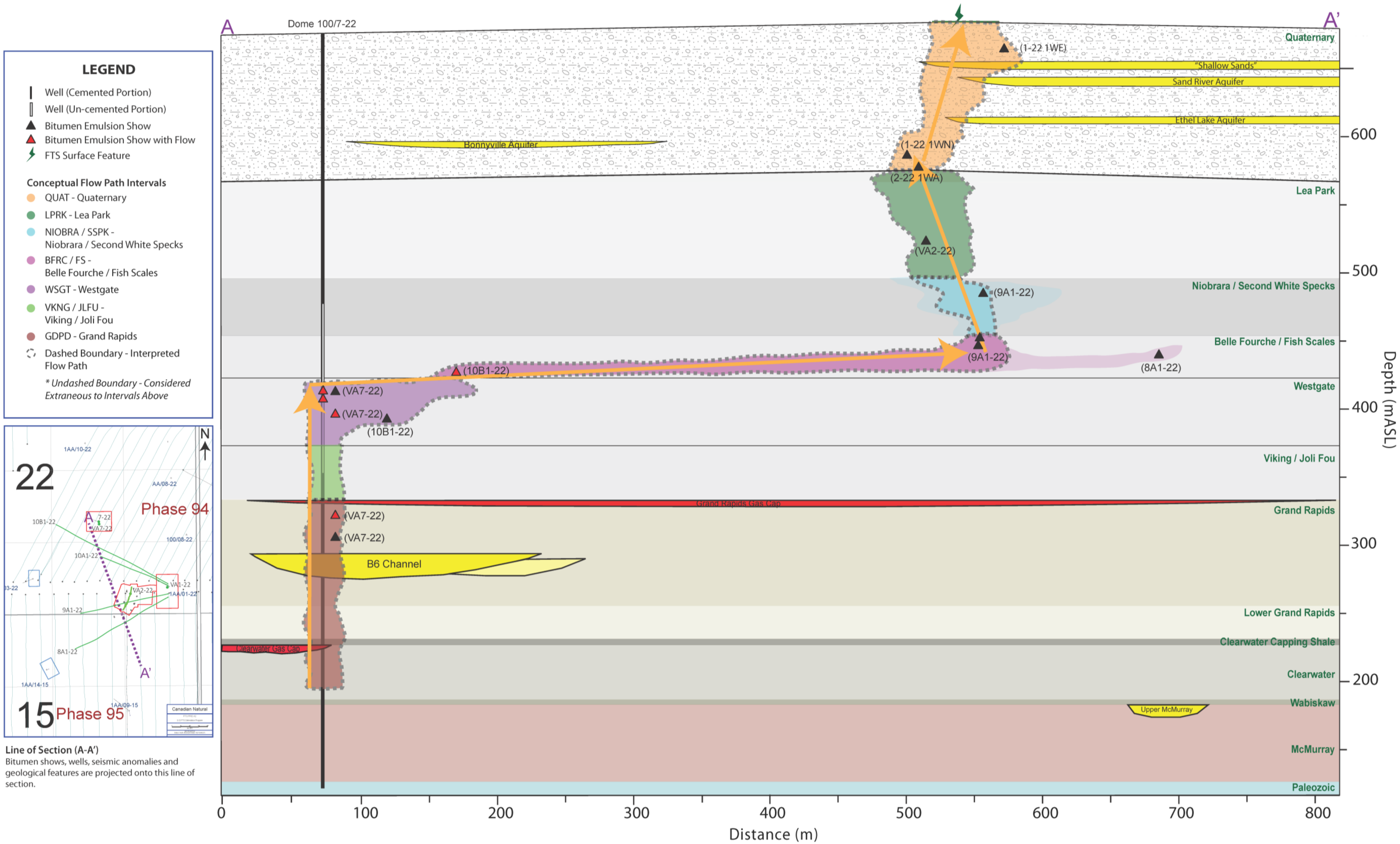


Figure 10-1 2-22 FTS – Features, Data and Conceptual Flow Path Projected on N-S Plane

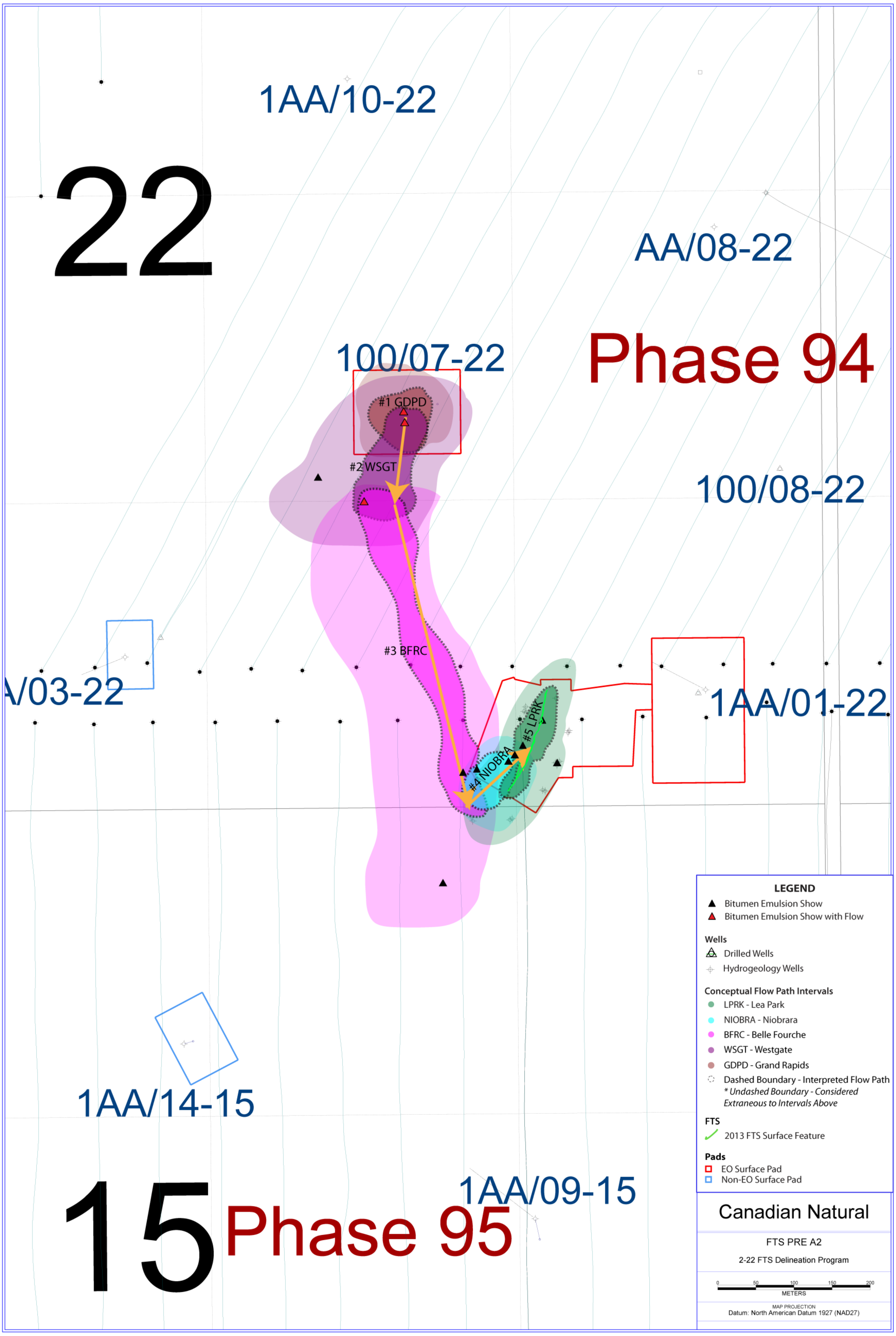


Figure 10-2 2-22 FTS – Conceptual Plan View of Bitumen Emulsion Shows

10.2 FTS Site 10-2

The study into the cause of bitumen emulsion being released from the Clearwater reservoir and flowing to surface at 10-2 in PRE A1 has generated the following pathway description (Figure 10-3 and Figure 10-4):

- The release of bitumen emulsion from the Clearwater reservoir is caused by an injection event in the CNRL 12A75 PRIMROSE 9-2-67-3 to CNRL 14A75 PRIMROSE 9-2-67-3 drainage area.
- Grand Rapids Formation pressure and temperature monitoring systems detected the release from the Clearwater reservoir during cycle 5 and triangulated its location in in the vicinity of CNRL 12A75 PRIMROSE 9-2-67-3 to CNRL 14A75 PRIMROSE 9-2-67-3 drainage area. A seismic anomaly has been subsequently observed at the 102/16-2-67-3W4 location above the CNRL 12A75 PRIMROSE 9-2-67-3 to CNRL 14A75 PRIMROSE 9-2-67-3 wellbores.
- 4D seismic shows potential connection within the Grand Rapids Formation from the release point to the 108/9-2-67-3W4 OSE wellbore. Temperature survey data and analytical calculations of flow and convective heat transfer at both locations supports the connection shown in seismic.
- The bitumen emulsion flow path is facilitated by the 108/9-2-67-3W4 OSE wellbore due to poor cement across the Grand Rapids Formation, Joli Fou and Viking Formation. Fluid samples recovered from perforations, elevated temperature, poor cement bond log and passive seismic events along the wellbore support flow behind pipe.
  - Other paths that enter the Joli Fou but terminate within it are not considered to be part of the flow path and are described further in Section 6.5.3.2.
- Bitumen emulsion is not observed above the Viking Formation in this wellbore.
- The flow path from the Viking Formation to the base of the Niobrara Formation involves a combination of horizontal hydraulically induced fractures connected by natural fractures, faults and bedding planes which have had permeability increases likely facilitated by uplift induced stress changes.
- The combination of natural fractures, faults and bedding planes with horizontal hydraulically induced fractures can cause a gradual climb from the Viking Formation at the 108/9-2-67-3W4 OSE wellbore towards the FTS site at 10-2.
- Once the flow path reaches the Niobrara Formation it encounters a network of abundant natural fractures which can cause an accumulation of bitumen emulsion in the natural fractures or faults. The net result is lateral and vertical movement through the Niobrara Formation and Lea Park Formation.
- The bitumen emulsion flow path from bedrock and through the Quaternary deposits is due to localized vertical hydraulically induced fractures within the glacial till.

The poor cement bond quality in the 108/9-2-67-3W4 OSE wellbore facilitated fluid migration from the Grand Rapids Formation to the Viking Formation. The mechanism for fluid flow through the remainder of the Colorado Group to surface has been determined using drilling, geological, geomechanical, and geochemical data collected throughout the study of FTS events.

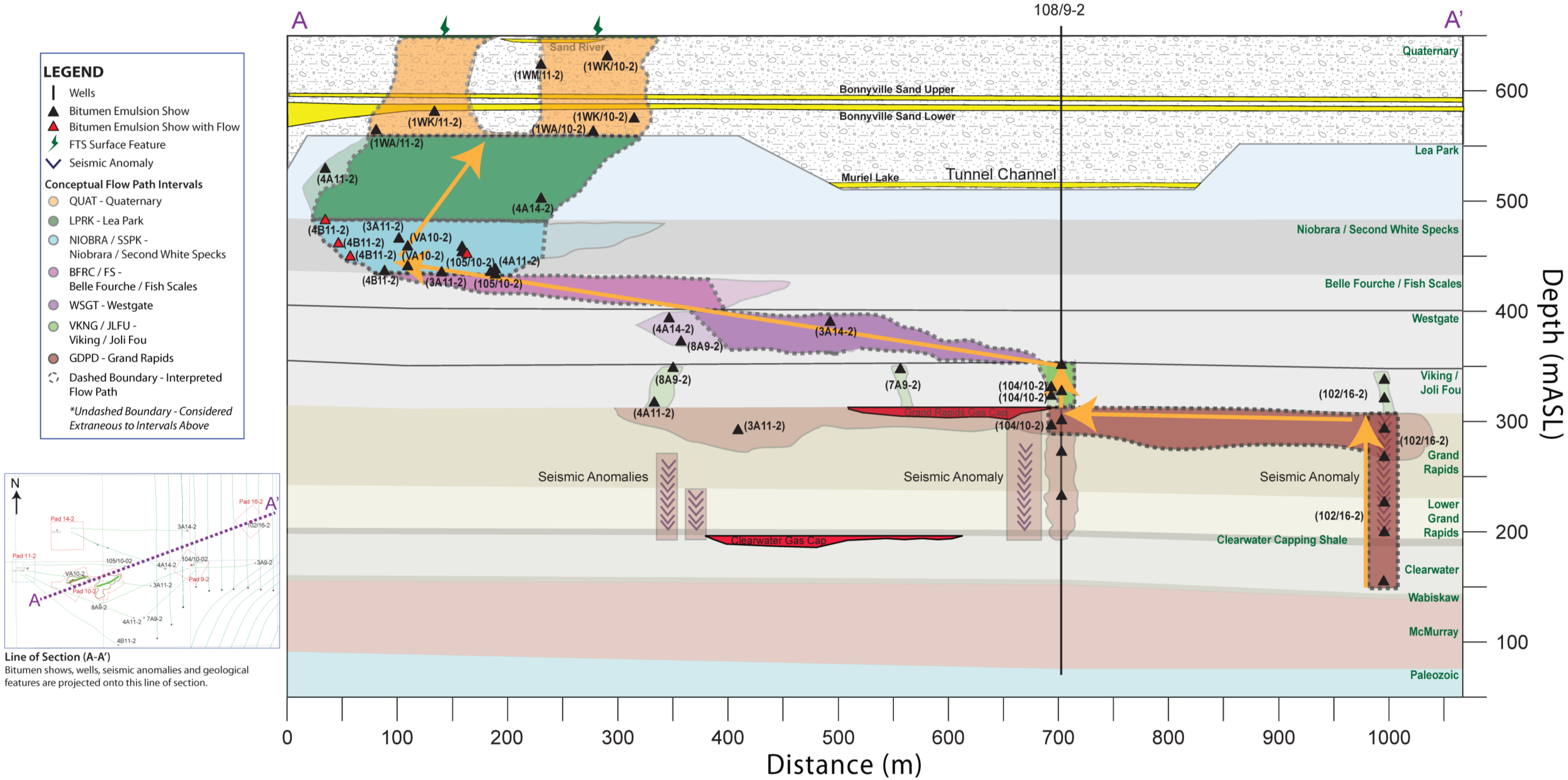


Figure 10-3 10-2 FTS – Features, Data and Conceptual Flow Path Projected on SW-NE Plane

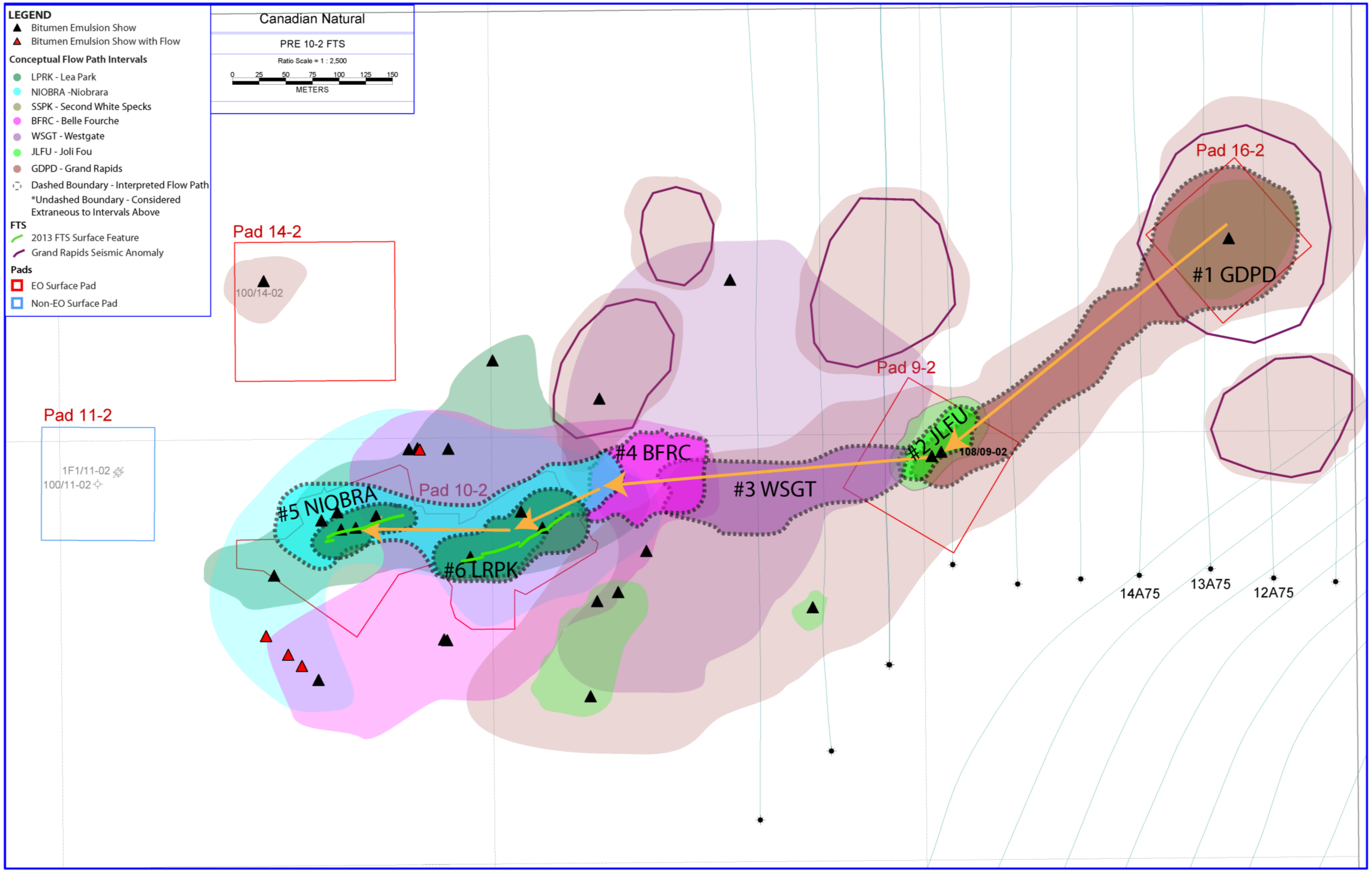


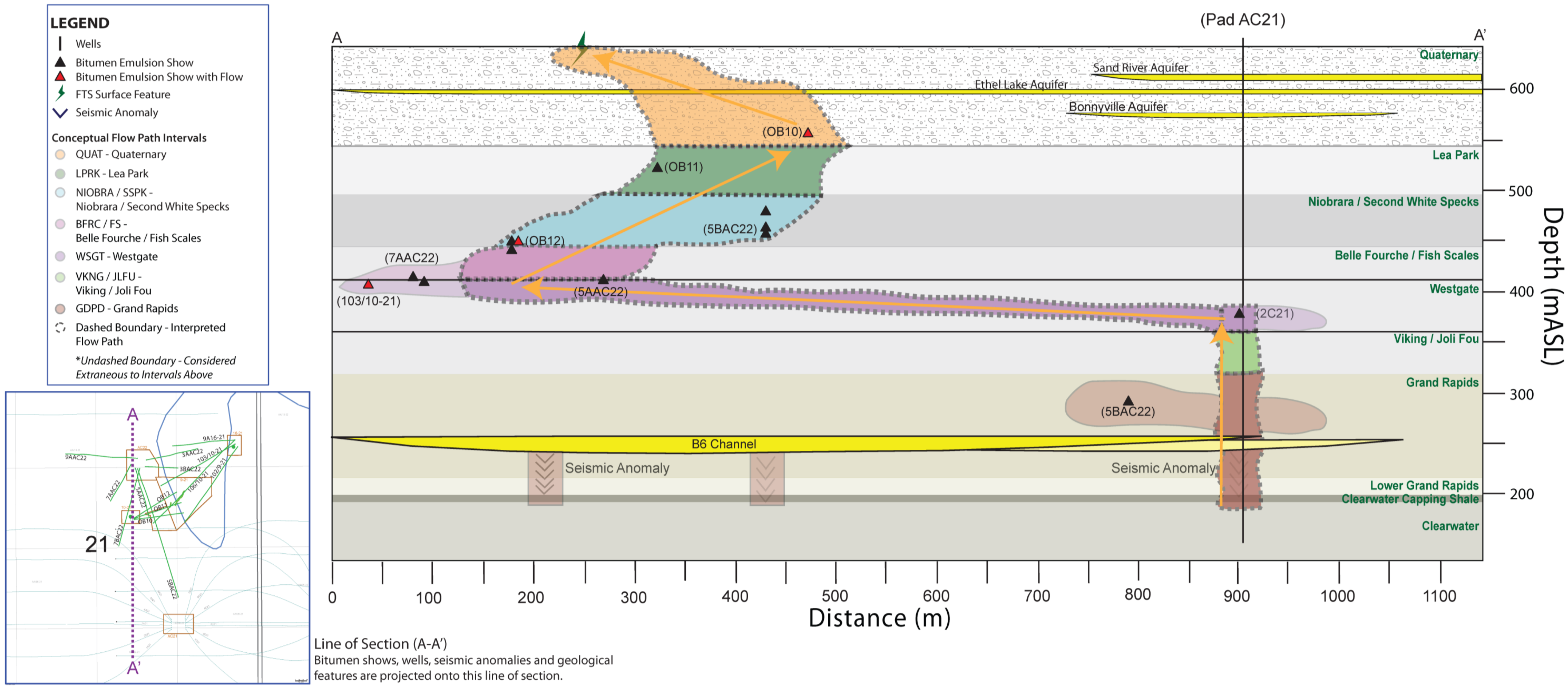
Figure 10-4 **10-2 FTS – Conceptual Plan View of Bitumen Emulsion Shows**

10.3 FTS Site 9-21

The study into the cause of bitumen emulsion being released from the Clearwater reservoir and flowing to surface at 9-21 in PRS has generated the following pathway description (Figure 10-5 and Figure 10-6). The study of this site is ongoing with alternative pathways being considered:

- The release of bitumen emulsion from the Clearwater reservoir occurred in the vicinity of the Pad AC21 during early CSS cycles (2000 – 2009).
- Clearwater reservoir depressurizing events identified in the previous steam cycles were fully attributed to inter-well and inter-pad communication. Lower Grand Rapids Formation pressure monitoring was not in place, however it is now suspected that these depressurizing events were excessive releases of bitumen emulsion into the Grand Rapids Formation.
- 3D seismic acquired in 2014 that encompasses the Phase 21 drainage area shows an anomaly in the Grand Rapids Formation that is the result of this fluid influx from the Clearwater reservoir. This seismic anomaly extends to at least the mid-section of the Grand Rapids Formation in proximity to the Pad AC21. The bitumen emulsion then propagates to the top of the Grand Rapids Formation in a vertical hydraulically induced fracture.
- It is suspected the bitumen emulsion release encountered a wellbore within the Pad AC21 and utilized it to access the Westgate Formation from the top of the Grand Rapids Formation. Discovery of bitumen emulsion influx through an existing casing failure in the Westgate Formation at suspended wellbore CNRES 2C21 PRIMROSE 3-22-67-4W4 demonstrates the presence of bitumen emulsion storage within the Westgate Formation.
- A horizontal hydraulically induced fracture within the Westgate Formation is suspected to have occurred and propagated towards the 9-21 FTS location following natural upward dip of the Westgate Formation and flowing towards a locally reduced vertical stress due to topography variations.
- The bitumen emulsion flow path from the Westgate Formation to the base of the Niobrara Formation was triggered by induced stress changes caused by uplift at Phase 22 during cycle 3.
- Once the flow path reaches the Niobrara Formation it encounters a network of abundant natural fractures which can cause an accumulation of bitumen emulsion in the natural fractures or faults. The net result is lateral and vertical movement through the Niobrara and Lea Park formations.
- The bitumen emulsion flow path from bedrock and through the Quaternary deposits is due to localized vertical hydraulically induced fractures within the glacial till.

It is suspected that inadequate placement of primary cement of a well within the vicinity of Pad AC21 facilitated fluid migration from the Clearwater reservoir to the Westgate Formation several years ago. Steam injection and operation of Pad 22 during the most recent cycle in 2013 imposed uplift induced stresses on the Colorado Group and facilitated further fluid migration from the Westgate Formation. The mechanism for fluid flow through the remainder of the Colorado Group to surface has been determined using drilling, geological, geomechanical, and geochemical data collected throughout the study of FTS events.



Line of Section (A-A')
Bitumen shows, wells, seismic anomalies and geological features are projected onto this line of section.

Figure 10-5 9-21 FTS – Features, Data and Conceptual Flow Path Projected on N-S Plane

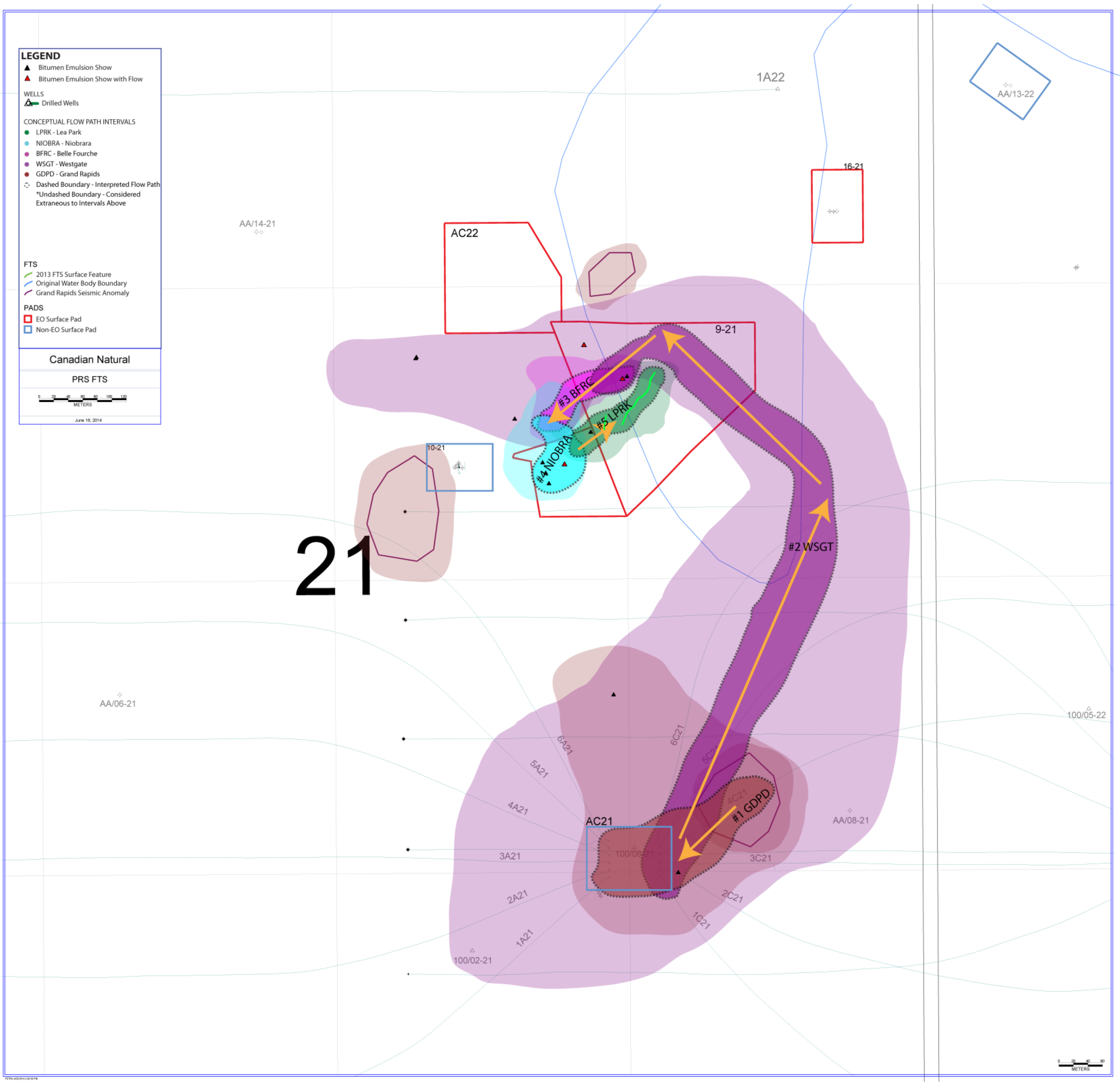


Figure 10-6 9-21 FTS – Conceptual Plan View of Bitumen Emulsion Shows

10.4 FTS Site Pad 74

The study into the cause of bitumen emulsion being released from the Clearwater reservoir and flowing to surface at 10-1 in PRE A1 and reconsideration of the findings during the 2009 FTS study has generated the following pathway description (Figure 10-7 and Figure 10-8). The study of this site is ongoing with alternative pathways being considered:

- The release of bitumen emulsion from the Clearwater reservoir occurred during cycle 1 in 2009 through the CNRL 10A77 PRIMROSE 1-1-67-3 drainage area.
- Current observations do not support a flow path involving wells CNRL 1A74 PRIMROSE 3-1-67-3 and CNRL 2A74 PRIMROSE 4-1-67-3 as described in the 2009 report on Pad 74 FTS. The 2009 report did explore an option that very closely resembles the current understanding of the FTS event at this site, but did not identify the 1AA/09-01-067-03W4 OSE wellbore, which is a recent discovery.
- 4D seismic acquired shows an anomaly reaching the top of the Grand Rapids Formation in the vicinity of the 1AA/09-01-067-03W4 OSE wellbore.
- Based on proximity to the suspected Clearwater reservoir to Grand Rapids Formation source and the presence of bitumen emulsion during delineation drilling; the 1AA/09-01-067-03W4 OSE wellbore has been identified as a likely flow path from the top of the Grand Rapids Formation to the Joli Fou Formation.
- Bitumen emulsion is not observed above the Joli Fou Formation in proximity to this wellbore. Above this point the flow path exits the wellbore.
- The flow path from the Viking Formation to the base of the Niobrara Formation involves a combination of horizontal hydraulically induced fractures connected by natural fractures, faults and bedding planes which have had permeability increases likely facilitated by uplift induced stress changes.
- The combination of natural fractures and faults with horizontal hydraulically induced fractures can cause a gradual climb from the Joli Fou Formation at the 1AA/09-01-067-03W4 OSE wellbore towards the FTS site at Pad 74.
- Once the flow path reaches the Niobrara Formation it encounters a network of abundant natural fractures which can cause an accumulation of bitumen emulsion in the natural fractures or faults. The net result is lateral and vertical movement through the Niobrara Formation and Lea Park Formation.
- The bitumen emulsion flow path from bedrock and through the Quaternary deposits is due to localized vertical hydraulically induced fractures within the glacial till.

The 1AA/09-01-067-03W4 OSE wellbore most likely acted as a pathway for fluid migration to the top of the Joli Fou Formation. The mechanism for fluid flow through the remainder of the Colorado Group to surface has been determined using drilling, geological, geomechanical, and geochemical data collected throughout the study of FTS events.

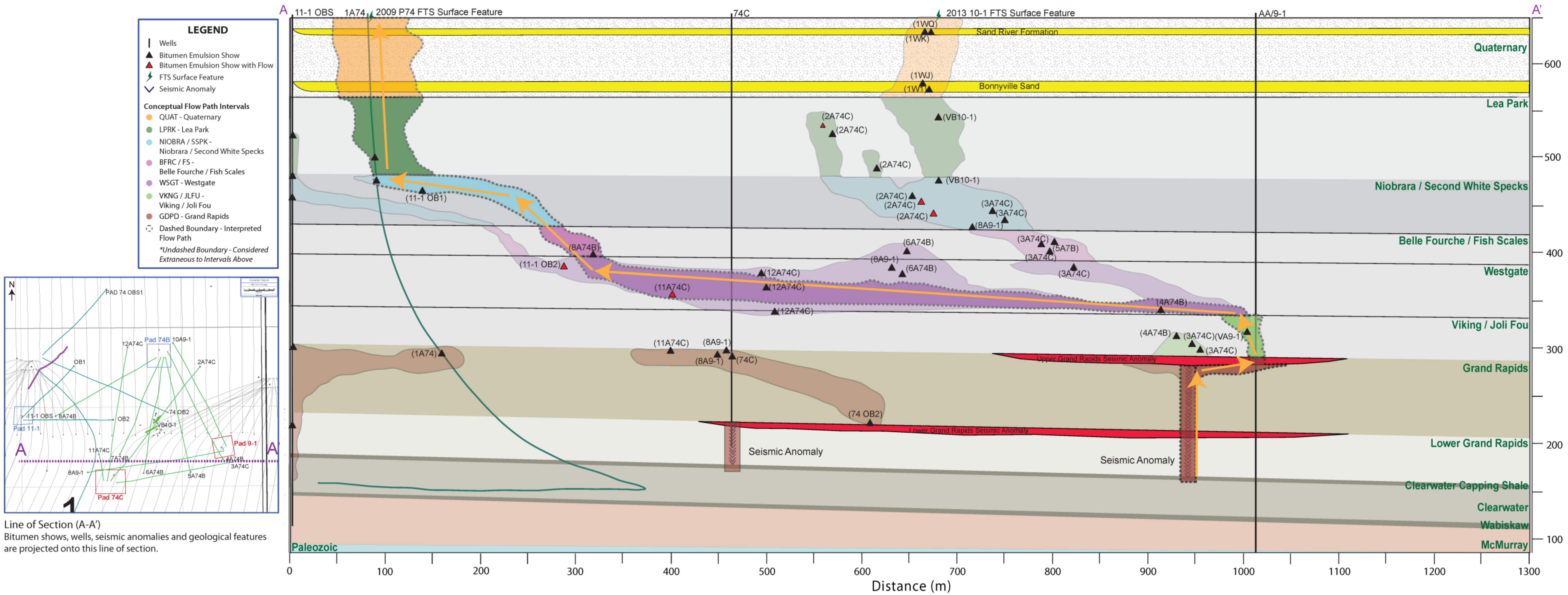


Figure 10-7 Pad 74 FTS – Features, Data and Conceptual Flow Path Projected on W-E Plane

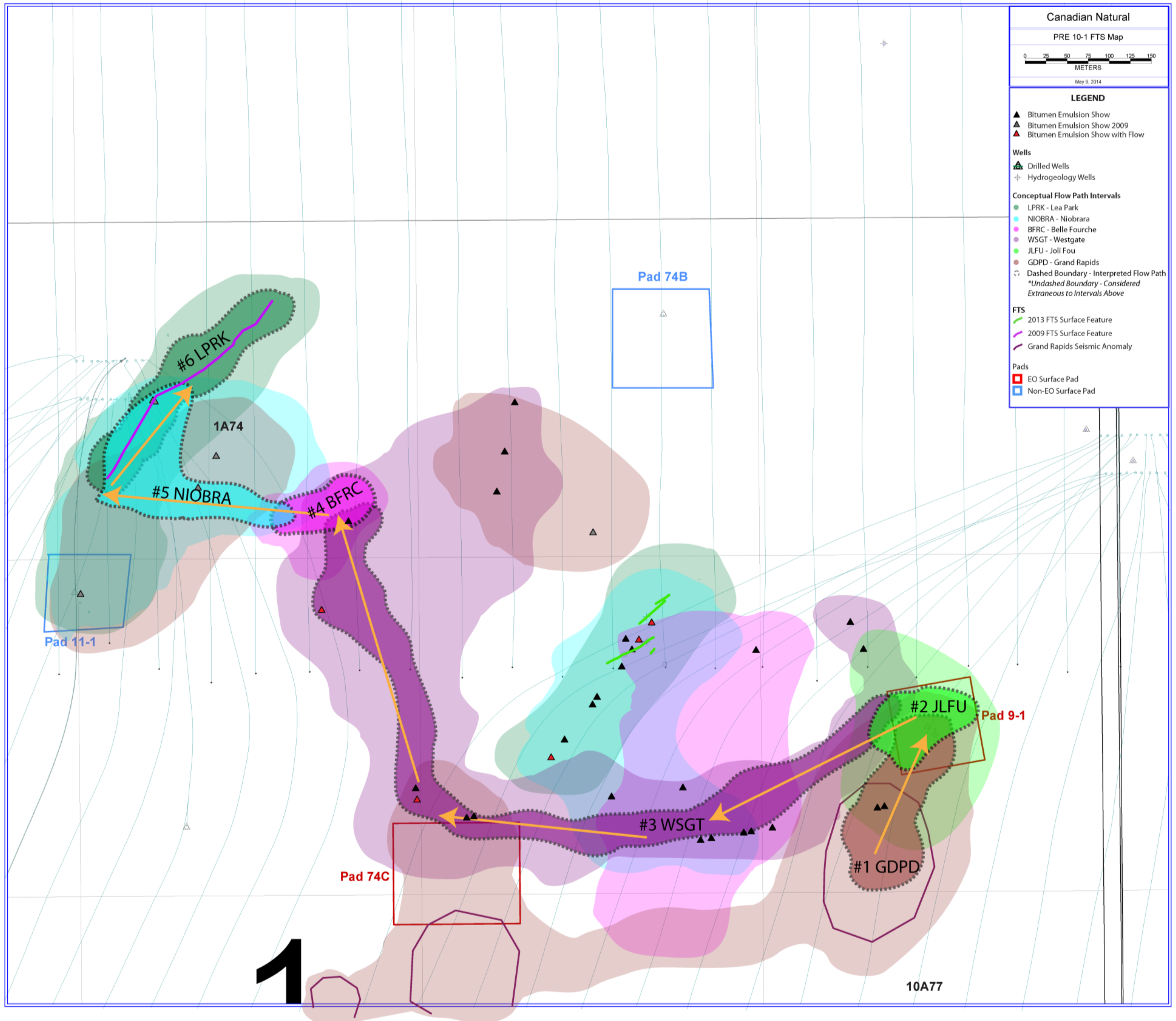


Figure 10-8 Pad 74 FTS – Conceptual Plan View of Bitumen Emulsion Shows

10.5 FTS Site 10-1

The study into the cause of bitumen emulsion being released from the Clearwater reservoir and flowing to surface at 10-1 in PRE A1 has generated the following pathway description (Figure 10-9 and Figure 10-10):

- The release of bitumen emulsion from the Clearwater reservoir originated through the CNRL 10A77 PRIMROSE 1-1-67-3 drainage area.
  - This is the same release point as the Pad 74 FTS event.
  - This could be a separate release or a continuation of the Pad 74 FTS event.
- 4D seismic acquired shows an anomaly reaching the top of the Grand Rapids Formation in the vicinity of the 1AA/09-01-067-03W4 OSE wellbore.
- Based on proximity to the suspected Clearwater reservoir to Grand Rapids Formation source and the presence of bitumen emulsion during delineation drilling; the 1AA/09-01-067-03W4 OSE wellbore has been identified as a likely flow path from the top of the Grand Rapids Formation to the Joli Fou Formation.
- Bitumen emulsion is not observed above the Joli Fou Formation in proximity to this wellbore. Above this point the flow path exits the wellbore.
- The flow path from the Viking Formation to the base of the Niobrara Formation involves a combination of horizontal hydraulically induced fractures connected by natural fractures, faults and bedding planes which have had permeability increases likely facilitated by uplift induced stress changes.
- The combination of natural fractures and faults with horizontal hydraulically induced fractures can cause a gradual climb from the Joli Fou Formation at the 1AA/09-01-067-03W4 OSE wellbore towards the FTS site at 10-1.
- Once the flow path reaches the Niobrara Formation it encounters a network of abundant natural fractures which can cause an accumulation of bitumen emulsion in the natural fractures or faults. The net result is lateral and vertical movement through the Niobrara Formation and Lea Park Formation.
- The bitumen emulsion flow path from bedrock and through the Quaternary deposits is due to localized vertical hydraulically induced fractures within the glacial till.

The 1AA/09-01-067-03W4 OSE wellbore most likely acted as a pathway for fluid migration to the top of the Joli Fou Formation. The mechanism for fluid flow through the remainder of the Colorado Group to surface has been determined using drilling, geological, geomechanical, and geochemical data collected throughout the study of FTS events.

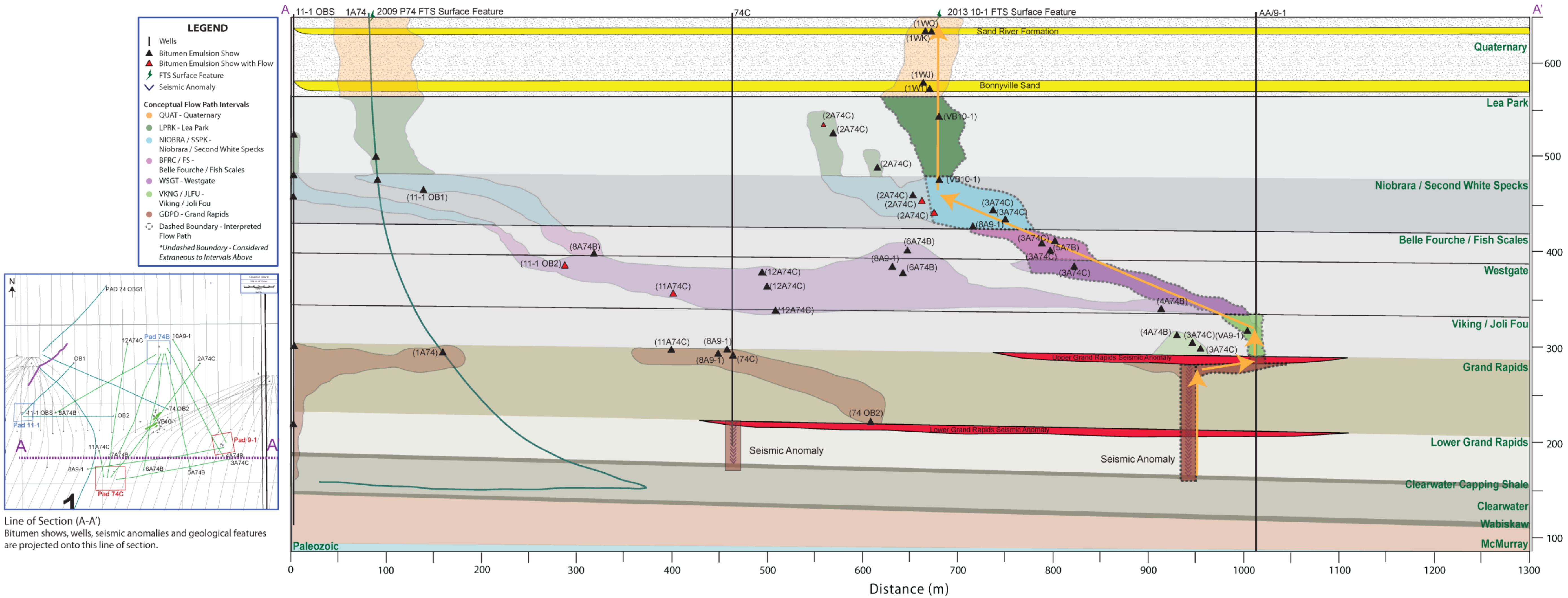


Figure 10-9 **10-1 FTS – Features, Data and Conceptual Flow Path Projected on W-E Plane**

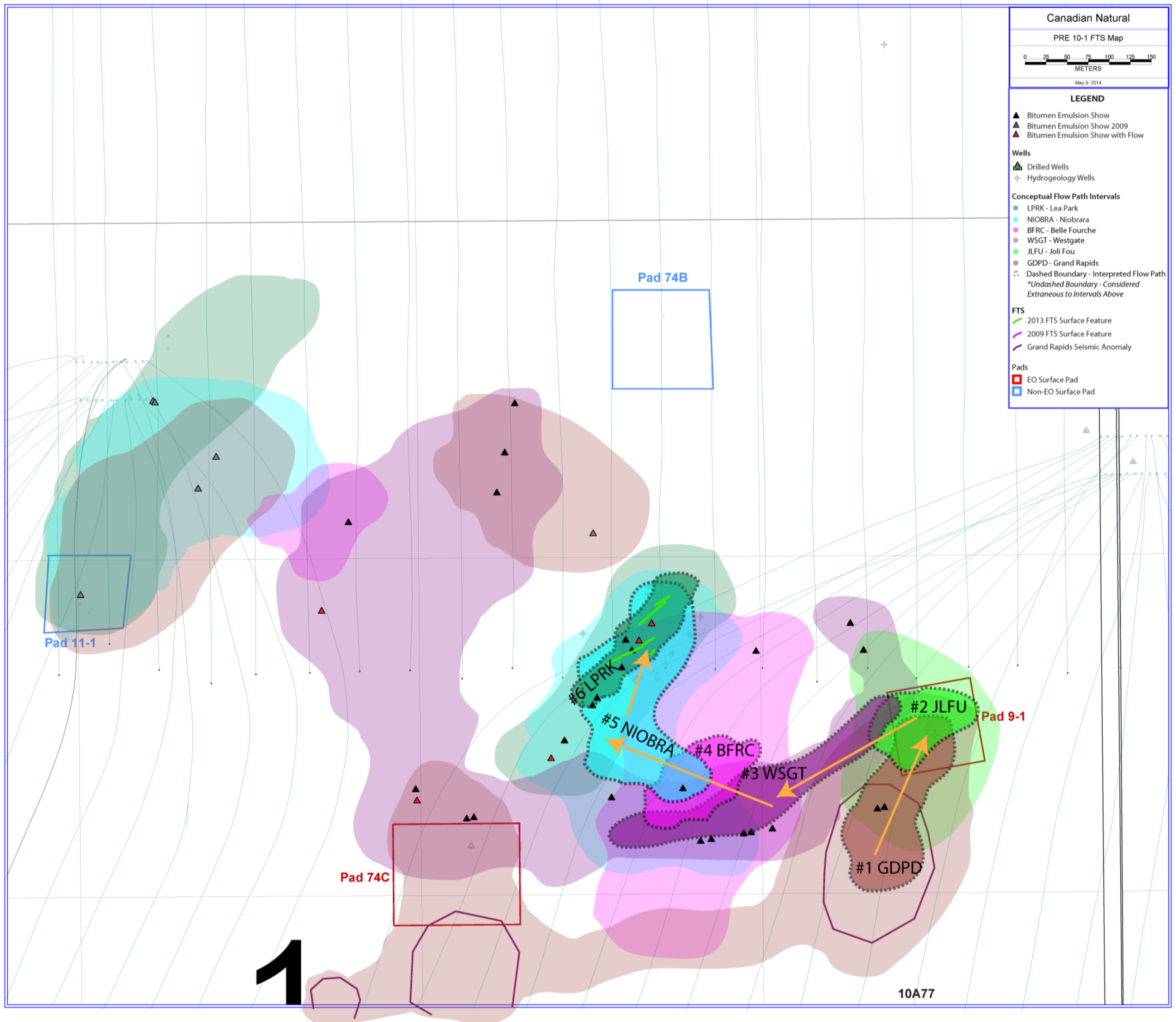


Figure 10-10 10-1 FTS – Conceptual Plan View of Bitumen Emulsion Shows

10.6 Learnings since the 2009 FTS Event

Since the 2009 FTS event and implementation of the 2013 FTS study, overall improvements in the understanding of flow to surface events include:

- Improved understanding of the geomechanics in the shale:
  - The ability to access natural fractures or faults
  - Uplift induced stress changes
    - Increased access to natural fractures or faults
    - Vertical stress approaching the minimum horizontal stress causing different fracture orientations
- The Grand Rapids Formation pressure and temperature surveillance system and understanding through seismic acquisition has improved since the static and dynamic studies in 2009-2010.
- Pressure transient analysis has improved the ability to locate Clearwater reservoir out-of-zone releases.
- Grand Rapids Formation seismic anomalies have been integrated with triangulation to further understand changes above the Clearwater reservoir associated with out of zone releases.
- Seismic acquisition with reduced bin spacing has been useful in identifying geological features previously not identified by large bin spacing, including polygonal and other faults in the Colorado Group.
- Wellbore logging and perforation techniques have progressed to better understand if a flow pathway behind pipe is present.
- Plug tracking and twin delineation wells have been implemented since the 2009 FTS event.
- The delineation well program has increased the sensitivity of data collection and amount of data collection techniques.
- More delineation wells have been drilled in 2013 (13) versus 2009 (6) in the 10-1 area.
- Coring intervals while drilling have proved useful for identifying bitumen show locations.
- DFIT testing of bitumen emulsion shows in shale formation to understand bitumen emulsion conductivity in natural fractures.
- InSAR data has demonstrated a direct correlation between injection volumes and surface heave.

11 FUTURE REPORTING

With this Causation Report on FTS events completed there are facets of the FTS events that are still being assembled and processed. Various tasks are currently being conducted and plans are underway. These are shown below:

- Event history and chronological summaries
- Environmental assessment and management plan
- Geological setting
  - Significance of salt dissolution of the Prairie Evaporite on as a modifier for FTS events
  - Assessment of geological variability at FTS sites
- 3D seismic acquisition
- Further processing, interpretation and analysis of seismic data
- Well design and construction
- Monitoring system
  - Refinement of methodology for estimating and locating Grand Rapids releases
  - Evaluate alternative monitoring strategies
    - Micro Seismic
    - InSAR Monitoring
    - Extensometers
- Cased hole wellbore studies
  - Review of Casing Failures and Caliper Survey for formation movement
- Geomechanical modeling and laboratory findings
  - Discrete fracture network modeling
  - Coupled Reservoir-Geomechanical Simulations
- Delineation well results
- Confirmation of integrated findings for each FTS site and pathway
- Risk mitigation plans
- Comprehensive data compilation

12 CONCLUSIONS

This Causation Report has been compiled to provide definition of the causes of FTS events for the AER, ESRD and the public. The final report will include further detail and complete data sets. Work on FTS events is ongoing with the independent third party technical review panel, in the form of data sharing, feedback and working meetings.

Significant actions have been undertaken to address the FTS locations in a timely manner. The study of FTS events has resulted in the drilling of 85 Quaternary wells and 50 deeper delineation wells. Studies on geology, geomechanics and engineering have also been undertaken to further understand FTS events.

12.1 Environmental Impacts

Results have shown the dissolved hydrocarbons and chlorides impact in the Quaternary above the base of ground water protection is below Alberta Tier 1, Natural Area (ESRD, 2010a) criteria. There is no risk of fresh water contamination below the bedrock due to its saline nature.

- Low dissolved constituent concentrations in surface and groundwater shows a lack of produced water impact suggesting that most of the formation water and condensed steam released from the Clearwater reservoir leaked-off before reaching the Quaternary and surface.
- Significant amounts of bitumen emulsion have not been observed in the Quaternary aquifers suggesting that its high viscosity has limited accumulation in these units and the occurrence of bitumen emulsion is concentrated along the fracture pathways.
- The surface cleanup is complete at all Primrose FTS sites and meets the following regulations:
    - Alberta Environment. 2010a. Alberta Tier 1 Soil and Groundwater Remediation Guidelines
    - Canadian Council of Ministers of the Environment. 2014. Sediment Quality Guidelines for the Protection of Aquatic Life
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12.2 Causes

The study of FTS events has identified the following four conditions at each FTS site:

1 Excessive release of bitumen emulsion from the Clearwater reservoir into the next overlying permeable formation, the Grand Rapids Formation.

2 A vertical hydraulically induced fracture that propagates up to the top of the Grand Rapids Formation.

3 Vertical pathways to facilitate fluid transfer through highly impermeable shales that have in-situ stress states that usually favor horizontal fracturing.

- Wellbore pathways which are the most likely and efficient vertical pathway to at least the Viking Formation and as high as the Westgate Formation in the case of this study.
- Natural fractures and faults in the shales.
- Vertical hydraulically induced fractures.

4 An uplift of the overburden above the Clearwater reservoir that changes stress in the overlying shale such that the minimum horizontal and vertical principal in-situ stresses approach each other.

These individual conditions have been observed throughout PAW without FTS incidents occurring. It is possible that the combination of these conditions is significant. Data analysis at the Primrose FTS sites has shown similarities and supportive observations. The following describes the causation and FTS pathway.

- There were localized large Clearwater reservoir fluid releases of bitumen emulsion, formation water or condensed steam into the Grand Rapids Formation.
- The releases can induce vertical hydraulic fractures to the top of the Grand Rapids Formation eventually finding a vertical pathway to access the Colorado Group.
- Once into the Colorado Group the bitumen emulsion initiates fracturing and seeks the path of least resistance (i.e., least energy required to propagate) utilizing natural fractures, faults, bedding planes or wellbore features where present and hydraulically induced fracturing. This results in a net climb in elevation with a dominant lateral propagation to the base of the Niobrara Formation.
  - In the Primrose area, data suggests that the minimum principal in situ stress from the Niobrara Formation to very near surface is horizontal. This means the bitumen emulsion could move through vertical hydraulically induced fractures, or re-opened vertical natural fractures to the surface at FTS locations in these areas.
- Steaming operations at the FTS sites caused lifting of the overburden resulting in a subsequent increase in the vertical stress above the steaming area.
  - The greater the amount of uplift, the greater the change in stress in the Colorado shales.
  - Current geomechanical modelling supports that under conditions of significant uplift, the minimum horizontal and vertical principal in-situ stresses closely approach each other within the Colorado Group. It is this change in stress that plays a role in FTS events.

In conclusion, the above conditions of FTS events have been observed at each site. Each condition must be addressed to prevent future FTS events.

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