Total E&P Canada Ltd.
Surface Steam Release of May 18, 2006
Joslyn Creek SAGD Thermal Operation

ERCB Staff Review and Analysis

February 11, 2010

Energy Resources Conservation Board

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ERCB Staff Review and Analysis: Total E&P Canada Ltd., Surface Steam Release of May 18, 2006, Joslyn Creek SAGD Thermal Operation

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Executive Summary

This report provides the ERCB staff (staff) review and analysis of the May 18, 2006, steam release incident at the Joslyn Creek commercial steam-assisted gravity drainage (SAGD) scheme (Joslyn Creek), operated by Total E&P Canada Ltd. (Total). Total's final report on the steam release accompanies this staff report and comprises a summary report and eight subreports.

Presented below are the highlights from the staff report.

Section 1: Incident Response and Scheme Operations Overview

- The steam release occurred near the heel of the first well pair in pad 204 (well pair 204-I1P1), and caused a surface disturbance about 125 metres (m) by 75 m, with rock projectiles travelling up to 300 m horizontally from the main crater and a plume of dust about 1 kilometre long stretching to the southwest of the release point. There was no loss of life or injury, and there were no harmful gaseous emissions.

- Steam injection pressure restrictions were imposed on Joslyn Creek prior to allowing operations to resume, and the well pair involved in the incident and three adjacent well pairs have been shut in since the release. The Board deferred approval of Total's Phase III scheme expansion application pending the submission and review of Total's final report on the steam release.

- The ERCB granted approval of scheme suspension on June 12, 2009, based largely on the poor scheme economics due to operating pressure restrictions, monitoring requirements, and shut-in well pairs. Staff expects that Total will submit an application for scheme abandonment in 2010.

- Since the steam release, the following activities have been initiated:
  - an ongoing rewrite of ERCB *Directive 051: Injection and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements* to address thermal in situ operations,
  - the development of specific application requirements to investigate caprock integrity and maximum operating bottomhole (bh) pressures, and
  - an ongoing joint study of caprock integrity by the Geology and Reserves Group and Alberta Geological Survey.

Section 2: Compliance Issues

Staff concludes that Total was in noncompliance with its scheme approval during circulation and semi-SAGD operations by

- operating at bh pressures significantly higher than the 1400 kilopascals (absolute) (kPaa) proposed in its scheme application,
- failing to implement alarms and automatic shutdown of wells exceeding the 1800 kPaa bh reservoir fracture pressure, and
- exceeding the *Directive 051* approved maximum wellhead injection pressure of 1800 kPaa.

Section 3: Geology

- Total concluded that the Clearwater shale (the approved caprock for Joslyn Creek) had a consistent thickness of 20 to 30 m in the scheme area, had no pre-existing fractures, and was a barrier to vertical flow. Furthermore, Total believed that the 5 m thick Wabiskaw A shale, located a few metres below the Clearwater caprock, was also a barrier to flow.
- Staff agrees with Total that the Clearwater shale varies in thickness from 20 to 30 m, but notes that the presence of surface casing within the Clearwater interval makes log readings subject to a greater degree of interpretation. Staff interprets the Clearwater caprock to be a non-lithified, silty mudstone, with some sandy interbeds and some vertical burrows filled with sand. The Joslyn Creek area was subject to the effects of post-depositional karsting in Clearwater and below, which may have resulted in some fracturing and faulting of the caprock and bitumen reservoir. Staff interprets the Wabiskaw A shale to be a continuous seal to gas in the steam release area, but too thin to be an effective caprock for a SAGD steam chamber.

Section 4: Steam Release Scenarios

Views of Total

The following is a step-by-step breakdown of Total's most likely steam release scenario.

1) A fast, gravity-driven local development of a steam chamber or "chimney" to the top of the SAGD pay zone, probably involving sand dilation. This occurred over a 4-month period while well pair 204-I1P1 was on steam circulation. (Total used high-density three-dimensional [3-D] seismic, analytical work, dilation theory, and a simple reservoir simulation to support this.)
2) A lateral extension of the pressurized area below the first major shale barrier in the Upper McMurray. (Total used 3-D seismic, geology, and simple geomechanical modelling to support this.)
3) One or more shear failures on the edge of this pressurized area that allowed the steam to breach within a gas zone in the Upper McMurray and/or Wabiskaw C sand or in the Wabiskaw A water sand under the Clearwater caprock. (Total used simple geomechanical modelling and historical pressures and steam rates to support this).
4) Significant water and steam storage in the localized SAGD chamber, fracture system, and Wabiskaw and Upper McMurray porous and permeable sands. (Total used historical steam rates and pressures, geology, simple geomechanical modelling, and the explosive nature of the steam release to support this.)
5) A catastrophic shear failure of the Clearwater caprock, leading to release of steam at surface on May 18, 2006. (Total used simple geomechanical modelling to support this.)

Total also reviewed the following alternative steam release scenarios:

- steam moved up nearby vertical wellbores with poor cement bonds,
- steam moved up through natural fractures within the reservoir and caprock, and
- high-pressure steam injection induced vertical fracturing of the reservoir and caprock.

Total concluded that none of these alternative scenarios was likely and provided arguments against each one.

Views of Staff

Staff reviewed Total's most likely steam release scenario and the three alternative scenarios, as summarized below:

Total's Most Likely Scenario

- Staff agrees that the mini-frac test results indicate that only horizontal fracturing of the reservoir and caprock would occur at Joslyn Creek. However, staff believes that the test results may not be representative.
- Staff believes it is unlikely that a dilation chimney would develop during the 4-month circulation period of well pair 204-I1P1 and provided arguments to support this view.
- Staff agrees that Total's high density 3-D seismic interpretation shows that the adjacent vertical wells were not within the narrow disturbed zone that extended down to injector 204-I1. However, the vertical wells were within 20 m of the injector 204-I1 and staff has concerns with the accuracy of the seismic over such short distances.
- Staff agrees with Total that the explosive nature of the steam release required storage of steam and hot water below the caprock. Therefore, the steam release did not likely occur as a single fracturing event from the wellbore to surface on May 18, 2006. This is supported by pressure and injection data that indicate an initial fracturing event on April 12, 2006.
- Staff believes that Total's geomechanical modelling was reasonable and showed that shear failure of the caprock could have occurred due to pooling of high-pressure steam and water in porous and permeable zones beneath the Clearwater shale.

Alternative Steam Release Scenarios

- Staff believes that the most likely initial pathways for steam rise were either a vertical fracture or a horizontal fracture that propagated to a nearby abandoned vertical evaluation well and then moved up through gaps in the cement plug. Arguments were provided to support this view.
- Staff agrees with Total that the vertically rising steam established communication with an Upper McMurray/Wabiskaw C gas zone or the Wabiskaw A water sand at the base of the Clearwater caprock and that steam and water pooled in one or more of these porous and permeable intervals.
- Staff believes that it is likely that the large pool of high-pressure steam and water eventually led to shear failure of the caprock.
- Staff believes that natural fractures and the presence of silty, sandy intervals in the caprock could have contributed to the steam release.

Section 5: Staff Recommendation and Conclusions

Compliance Enforcement

Given that the scheme has been suspended by Total and is expected to be abandoned, staff recommends that no further action be taken by the ERCB regarding noncompliances.

Most Likely Steam Release Scenario

For reasons provided in its review and analysis of Total's final report, staff concludes that the following is the most likely steam release scenario.

- The underlying cause of the steam release was the injection of steam at excessively high pressures.
- The conversion of well pair 204-I1P1 from steam circulation to semi-SAGD forced high-pressure steam into the bitumen reservoir. Eighteen days later, on April 12, 2006, a vertical fracture was initiated near the heel of the injector and established communication with the Wabiskaw C gas sand.
- High-pressure steam and water pooled under the Wabiskaw A shale causing it to fail under shear on April 21, 2006, and to establish communication between the injector and the Wabiskaw A water sand directly underlying the Clearwater caprock.
- Between April 21 and May 18, 2006, high-pressure steam and water pooled under the Clearwater caprock causing it to fail under shear to surface.
- Once the Clearwater was breached, a rapid drop in pressure occurred. This pressure drop caused hot water that had accumulated in the Wabiskaw A water sand and the Wabiskaw C gas sand to flash to vapour. This provided the energy for a catastrophic explosion that disturbed a large surface area and subsurface volume and threw rocks several hundred metres into the air.

Alternative Scenarios

- Staff concludes that the next most likely steam release scenario is one that involves the nearby evaluation well. On April 12, 2006, a horizontal fracture was initiated near the heel of the injector and established communication with the abandoned evaluation well AB/09-33-095-12W4. Steam then moved up through gaps or channels in the well's cement abandonment plug until it reached the Wabiskaw C gas sand. At that point, the scenario would be the same as the staff's most likely steam release scenario.
- Staff believes that natural fractures and the presence of silty, sandy intervals in the caprock could have contributed to the steam release. However, in the absence of operation at excessively high pressures, staff concludes that it is unlikely that these weaknesses would have resulted in a steam release.

1 Incident Response and Scheme Operations Overview

1.1 Steam Release

On May 18, 2006, at about 5:15 a.m., a catastrophic release of steam occurred at the Joslyn Creek thermal in situ oil sands scheme (Joslyn Creek), located about 60 kilometers north of Fort McMurray and just south of Canadian Natural Resources Limited's Horizon Oil Sands Lease, as shown in Figure 1. At that time, Joslyn Creek was operated by Deer Creek Energy Limited, a subsidiary wholly owned by Total E&P Canada Ltd. (Total). For the purpose of this report, Total will be referred to as the operator. Joslyn Creek uses steam-assisted gravity drainage (SAGD) to recover bitumen. This SAGD scheme was approved by the Energy Resources Conservation Board (ERCB) to operate below the fracture pressure of the McMurray Formation, where the bitumen resource is located. Joslyn Creek has 17 well pairs drilled from 4 surface pads. The steam release occurred above the injector (I)-producer (P) well pair 1 of pad 204 (well pair 204-I1P1; injector 03/01-33-095-12W4 and producer 05/01-33/095-12W4), as shown in Figure 2.

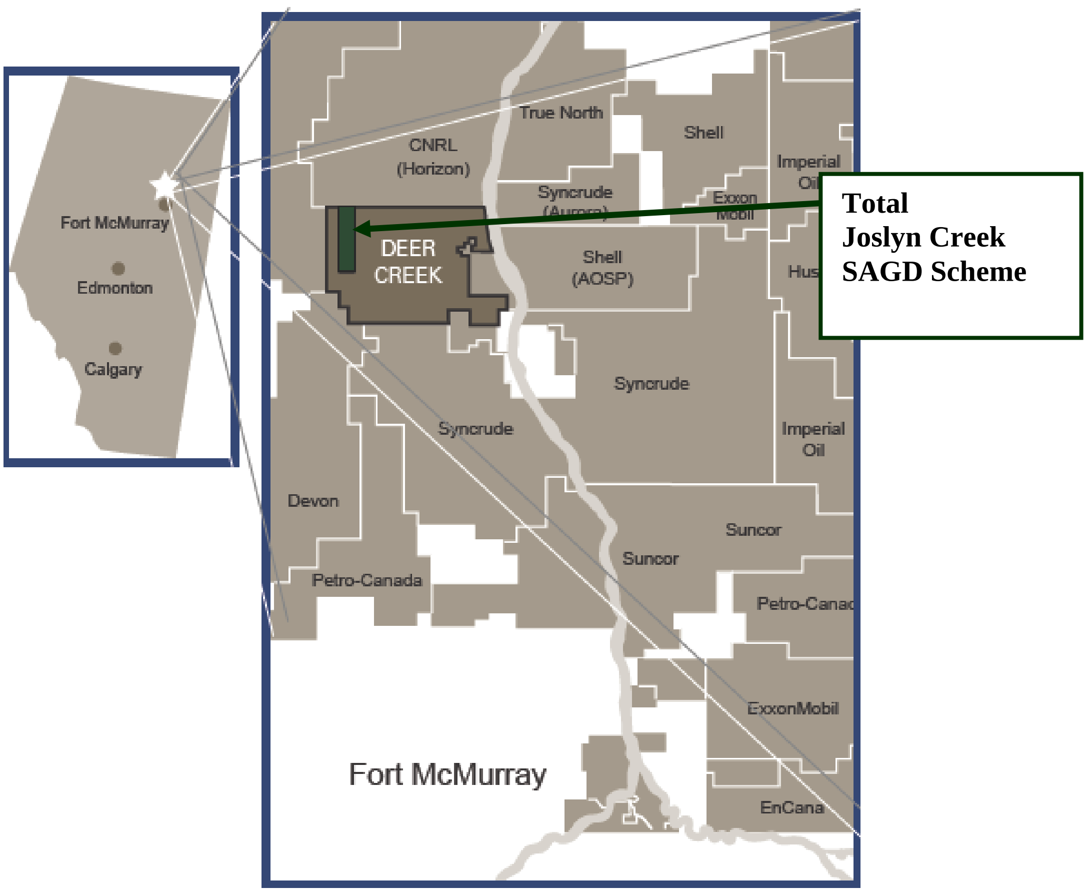

Figure 1. Joslyn Creek SAGD scheme location

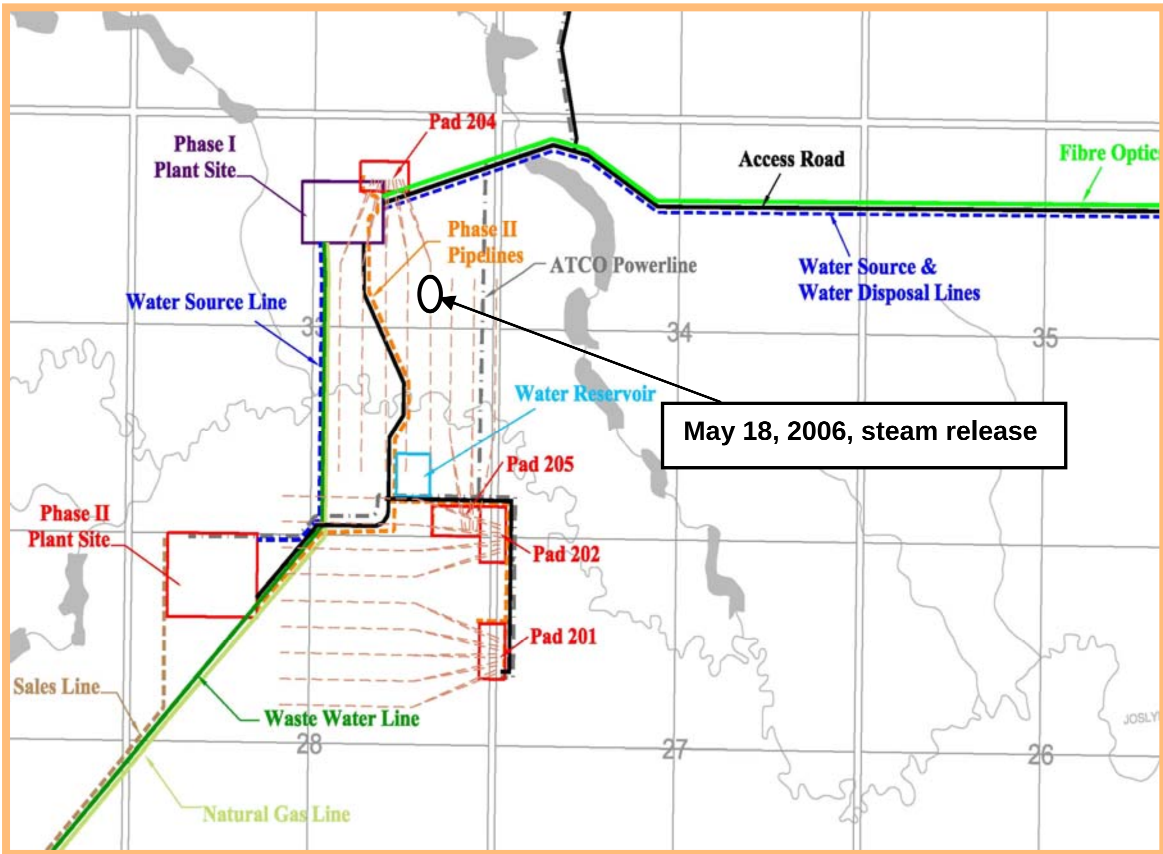

Figure 2. Site of steam release

The steam release caused a surface disturbance about 125 metres (m) by 75 m (see Figure 3). Within this disturbed area is a triangular-shaped crater. Surface uplift and subsidence zones are present in the vicinity of the main steam release zone. Tensile cracks and rotated ground are associated with a major sinkhole feature, located adjacent to the main steam release crater. This is believed to have formed in response to the ejection of a significant volume of soil and bedrock. The majority of this displaced material was deposited in the immediate area, but there was evidence of a fine dusting of material and rock across an area about 1 kilometre (km) long by 100 m wide to the southwest of the release point. Rock projectiles, some of which originated from the Clearwater shale, travelled as much as 300 m horizontally from the main crater, and probably greater than this distance vertically. The total volume of displaced material overlying the soil was estimated to be between 1400 and 1700 cubic metres (m^3). There was no loss of life or injury resulting from the steam release and no harmful gaseous emissions into the atmosphere.

Figure 3. Photos of the incident site from Total's final investigation report to the ERCB

1.2 Operations Prior to Steam Release

1.2.1 Scheme Overview

Joslyn Creek is located northwest of Fort McMurray in Townships 95 and 96, Range 12, West of the 4th Meridian. Phase I (the pilot) and Phase II of the project were authorized under ERCB Approval No. 9272. The project was approved to produce 1910 m^3/d (12 000 barrels per day) of bitumen. At the time of the release, Phase II facilities were operational and there were four well pads in operation or under development (pads 201, 202, 203, and 204).

The oil sands resource being developed is within the McMurray Formation, which consists of a sequence of uncemented quartz sands and associated shales. The McMurray Formation is underlain by the Upper Devonian carbonates of the Waterways Formation and is overlain by the Clearwater Formation, comprised primarily of shales. The Clearwater shale forms the sealing "caprock" to prevent steam migration from Joslyn Creek. Above the Clearwater shale is the unconsolidated Pleistocene sands, silts, and clays that were deposited as glaciers melted and receded from the region at the end of the last ice age. These glacial-age deposits are not expected to be a barrier to steam migration to surface if the steam were to somehow break through the Clearwater shale caprock.

SAGD recovery is accomplished using horizontal well pairs, where a steam injector is drilled 5 m above, and parallel to, a bitumen producer, and the well pair is located near the base of the bitumen pay. As steam rises above the injector, the heated bitumen becomes mobile and flows down by gravity to the underlying producer.

Joslyn Creek is the shallowest SAGD development in Alberta, with the depth of the horizontal steam injection wells less than 100 m from surface, depending on the surface topography and placement within the bitumen reservoir.

At the time of the incident, well pair 204-I1P1 had recently been converted to SAGD production, while the other four well pair injectors at pad 204 were on steam injection under semi-SAGD. The four well pairs in adjacent pad 202 were on steam circulation. Well pads 201 and 203 were still under development and were not circulating or injecting steam at the time. The single well pair from Phase I, located immediately adjacent to pad 204, was on SAGD production. Figure 4 illustrates the operational status at the time of the steam release.

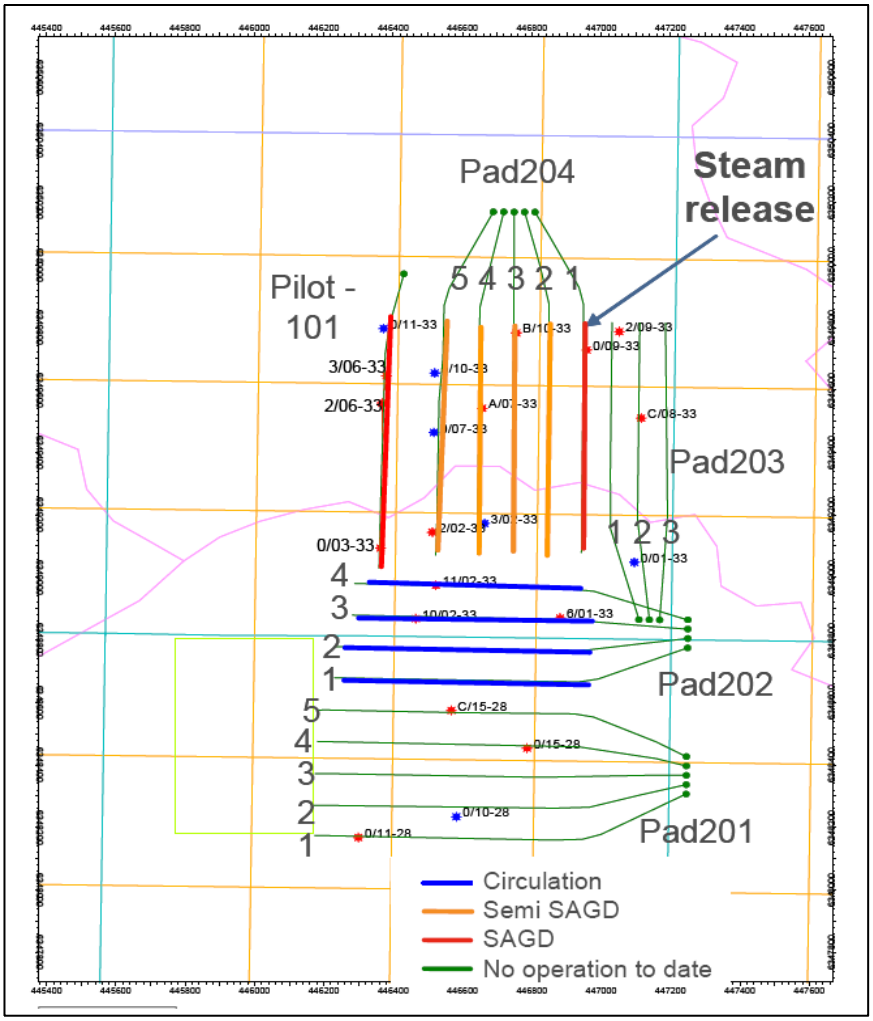

Figure 4. Operational status of well pairs at the time of steam release

1.2.2 Steaming Operations at the Incident Well Pair

Total's steaming strategy for well pair 204-I1P1 comprised three phases: circulation, semi-SAGD, and SAGD.

Circulation Phase

From December 2, 2005, to March 26, 2006 (about 4 months), the well pair was under steam circulation, with both the producer and injector circulating steam in and out of the wellbore. Total believed that circulation heated the reservoir by conduction mainly. During this period, both the producer and injector bottomhole (bh) pressures varied considerably, increasing from about 1200 kiloPascals (gauge) (kPag) to about 1750 kPag. In the last week of circulation, the producer circulation bh pressure was lowered to about 1400 kPag, while the injector remained at about 1700 kPag. Total believed that this forced fluid communication between the injector and the producer.

Semi-SAGD Phase

From March 26 to May 2, 2006, well pair 204-I1P1 operated under semi-SAGD. During this phase, the upper well injected steam into the reservoir at both the heel and toe of the well, while the lower well continued to circulate steam. Total believed that this phase allowed a much faster, but less uniform heating of the reservoir. From March 26 to April 12 (about 2½ weeks), the upper well injected steam at an average rate of about 60 m^3/d (cold water equivalent [cwe]) and at a bh pressure between 1700 and 1800 kPag. On April 12, the upper well pressure began to drop and fluctuate. At the same time, its steam injection rate increased significantly to 160 m^3/d (cwe). ERCB staff (staff) and Total agree that this was likely an indication of the first fracturing event at the well pair. After April 12, the lower well was circulating steam at about 300 kPa below the upper well's bh pressure but occasionally exceeded that of the upper well's. A similar but less severe pressure drop and steam rate increase occurred on April 21, and on April 25 and 26 there were two more pressure drops, while the steam rate remained fairly constant. During this time, Total had no way of knowing whether the injected steam was moving down and being produced by the lower well or moving out into the reservoir. That is because steam injection was only measured at the upper well, and neither well had production measurement. This made it impossible to calculate a material balance on the well pair to monitor how much steam injection remained in the reservoir.

SAGD Phase

Well pair 204-I1P1 was shut in on May 2, 2006, to convert it to SAGD operations. A pump was installed in the production well. On May 11, the well pair went back on stream, with 204-I1 on injection and 204-P1 on production. SAGD operations lasted until May 18, when the steam release occurred. No bitumen production was reported to the Petroleum Registry of Alberta for this period. During SAGD operations, the steam injection rate was increased in steps: on day 1, it was 80 m^3/d; on days 2 to 5, it was 100 m^3/d; on day 6, it was 120 m^3/d; and on days 7 and 8, it was 160 m^3/d. Over those eight days of steaming, the bh pressure increased at both wells from about 800 kPag to about 1400 kPag. The maximum injection bh pressure of 1400 kPag was lower than the injection pressures during the circulation and semi-SAGD phases, and about 400 kPa below the estimated minimum fracture pressure at the depth of injector 204-I1.

1.3 Initial Response to Steam Release

Notification of Regulatory Authorities: The ERCB Bonnyville Field Centre was notified by Total at about 8:30 a.m. on May 18, 2006. Alberta Environment (AENV) and Alberta Sustainable Resource Development were also contacted on the morning of May 18, 2006, and a follow-up letter was sent to AENV on May 25, 2006.

Public Safety/Emergency Response: Total contacted the community of Fort McKay to inform town officials of the incident on May 18, 2006. The RCMP was also notified. Total stopped vehicular traffic at Joslyn Creek.

ERCB Incident Response: Inspectors from the Bonnyville Field Centre visited Joslyn Creek on May 19, 2006. Their site inspection determined that the level of compliance was satisfactory. ERCB Resources Application staff visited the site on June 7, 2006.

1.4 Incident Investigation

Since the steam release at Joslyn Creek in May 2006, a multidisciplinary team of ERCB staff has been working with Total staff to thoroughly investigate the incident. The process has been both collaborative and iterative.

The Bonnyville Field Centre sent a letter to Total dated May 24, 2006, requesting specific technical data to support the investigation. This was followed up by geological questions sent from the ERCB Calgary office on June 12, 2006. These documents are attached as Appendix 2.

From July to September 2006, Total and the ERCB went through a process to bring wells safely on injection and production at Joslyn Creek (see Section 1.5).

From September 2006 to mid-2007, Total specialists in Calgary and France continued their detailed scientific investigation of the incident and presented an interim report to ERCB staff. Part of this investigation involved a state-of-the-art high-density three-dimension (3-D) seismic program conducted over the affected area to better understand the pathway of the steam release.

From mid-2007 to mid-2008, Total processed and analyzed the new seismic data and completed the first draft of its final investigation report on the steam release. ERCB staff conducted a review of the draft final report and provided Total with requests for additional information and analysis.

In September 2008, after further follow-up discussions and information exchanges between ERCB staff and Total, staff was satisfied that the report was complete. Subsequently, staff commenced a detailed review of Total's final investigation report, including analyzing the associated data, and worked on finalizing this staff report.

Several interim findings arising from the review of this incident have already been used to further enhance the ERCB's regulatory requirements and processes:

- New SAGD scheme or amendment applications are required to address caprock integrity and maximum injection bh pressures by providing the following:

- Structural analysis for evidence of karsting, salt dissolution, and faulting. The analysis must incorporate all available data, including the results of any 3-D seismic programs.
- Core studies of the caprock that include analysis of lithology and lithification and may require the drilling of additional cored wells into the caprock.
- A study of caprock thickness variability, with particular attention to possible erosion of caprock by overlying sands.
- A study of any porous/permeable zones that may exist between the top of the bitumen pay zone and the base of caprock that would allow pooling of high-pressure steam.
- Any geomechanical modelling of the reservoir and caprock that was conducted.

The intent is for the ERCB to use this information to set maximum injection bh pressures in all thermal in situ scheme approvals.

- A joint study of caprock integrity by the Geology and Reserves Group and the Alberta Geological Survey has been launched.
- *Directive 051: Injection Wells and Disposal Wells—Well Classifications, Completions, Logging, and Testing Requirements* is being rewritten, with participation from the In Situ Oil Sands Group, to specifically address needed changes for thermal in situ operations.

1.5 Post-Incident Operations and Monitoring

1.5.1 Operations

Total immediately shut in well pair 204-I1P1 after the steam release occurred. Adjacent well pairs 202-I4P4 and 204-I2P2 were also shut in, and adjacent well pair 203-I1P1 was not permitted to start up. These four well pairs have remained shut in since the steam release. In addition, the Board deferred approval of the Joslyn Creek Phase III expansion (submitted in early 2005), pending the submission and review of Total's final investigation report. Total withdrew its Phase III expansion application on September 30, 2008.

The operational status of the other Phase I and Phase II wells immediately following the steam release was as follows:

- The Phase I well pair (pad 101) remained on SAGD operation.
- Well pairs 204-I3P3 and 204-I5P5 were shut in, and well pair 204-I4P4 went back on circulation from semi-SAGD.
- Well pairs 202-I1P1, -I2P2, and -I3P3 remained on circulation.
- All wells in pads 201 and 202 had not commenced operations.

Total submitted a plan to the ERCB on July 21, 2006, to commence Phase II SAGD production at pad 202 (Appendix 3). The ERCB approved Total's start-up plan on August 17, 2006 (Appendix 4). Two follow-up letters were sent to Total on September 5, 2006, outlining operating and reporting conditions to the pad 202 SAGD start-up approval and requesting further information on the steam release incident (Appendix 6). The primary condition issued by the ERCB for all Joslyn Creek pads was to restrict the steam injection bh pressure to a maximum of 1200 kPag at the heel of the horizontal section of the well. This maximum operating bh pressure was based on a fracture pressure gradient of 20 kPag/m, an injector depth of 85 m, and an additional 500 kPag safety margin. Following its post-incident geomechanical review, Total justified the 1200 kPag operating bh pressure as corresponding to a depth of 60 m (Total's expected top of steam chamber/top of pay) with the same fracture gradient applied (20 kPag/m), but without the additional pressure safety margin.

Over several months following the steam release, well pairs in pads 201, 202, and 204 were brought on production (except the incident and adjacent wells). Pad 203 wells were not brought on production until May 2008.

1.5.2 Monitoring

Monitoring was carried out for two purposes: to detect any containment issues and to track the rise of the steam chambers over time. The latter was to ensure that operating bh pressure was lowered to an appropriate level as the steam chambers rose to shallower depths. Up to the suspension of the scheme in February 2009, Total interpreted that none of the steam chambers in the operating wells had reached the top of pay, and so the operating bh pressure remained at 1200 kPag.

In the Phase I and Phase II areas, the following monitoring was implemented by Total:

- Thermocouples were installed in fifteen observation wells to monitor the steam chamber rise by recording temperatures twice daily. In its October 8, 2008, performance presentation to the ERCB, Total reported that none of the observation wells had steam to the top of pay.

- Four other observation wells were equipped with permanent vibrating wire piezometers cemented outside the tubing at different depths, from the reservoir up to the Wabiskaw A water sand immediately underlying the Clearwater caprock to monitor the pressure front movement on an hourly basis.

- To monitor surface heave, sixty InSAR corner reflectors were installed to cover the horizontal drains and part of the build-up sections of the original pilot well pair and well pairs 204- I4P4 and -I5P5. In addition, 131 tiltmeters were installed to cover the build-up sections of the pilot well pair and well pairs 204-I4P4 and -I5P5.

  This overlap between the two monitoring networks allowed for comparison of the performance of the two methods. InSAR was to provide heave data to follow steam chamber development over a larger area, while tiltmeters were to detect a potential cement sheath or casing failure and steam migration along this leak path, allowing sufficient time to shut down steam injection in a well pair before the steam had any chance to pressure up a shallower layer.

- To ensure safety, the following pre-release warning signs were monitored:
  - Water steam ratio (WSR) and voidage replacement ratio (VRR)—If the WSR went below 0.7 or if the VRR went above 1 under stable operations, Total would interpret that as steam leaking away from the chamber and would investigate.
  - Injector bh pressure at the heel—Total had manual and automatic pressure monitoring to ensure that injector bh pressure at the heel wouldn't exceed 1200 kPag.

An alarm would sound at 1200 kPag, and steam injection shutdown would occur at 1250 kPag.

- Correlation between steam injection rates and injection bh pressures—Any significant deviation in the correlation between steam injection rates and injection bh pressures would be immediately investigated. Normal practice by Total was to reduce bh pressures while investigating the problem.

1.6 Scheme Suspension

On February 6, 2009, the In Situ Enforcement and Surveillance Section approved an interim turndown of operations at Joslyn Creek, pending a decision on an application for suspension of operations. The application for suspension was based on poor scheme economics due to the lower price of bitumen, the 1200 kPag limit to operating bh pressure subsequent to the steam release, the corresponding lower bitumen production rates, and the increased costs due to additional monitoring for possible containment issues. In addition, the long-term shut-in of four wells due to the steam release (the incident well and the three offsetting wells immediately to the east, west, and south) contributed to the poor economics. The ERCB granted approval of scheme suspension on June 12, 2009, with the issuance of Amendment No. 9272D. The approval requires Total to submit a report by January 31, 2010, outlining its options and plans for Joslyn Creek and specifies that Total cannot recommence operations at Joslyn Creek without prior ERCB approval. Staff does not expect operations to recommence at Joslyn Creek and anticipates that Total will be submitting an application for scheme abandonment in 2010.

2 Compliance Issues

2.1 Noncompliance with Approved Operating Pressure

Staff conducted a review of the Phase II application and approval process regarding the applied-for and approved maximum operating bh pressure. It should be noted that in situ approvals do not explicitly specify a maximum operating bh pressure for schemes. Section 4.2.2 of the Total Phase II application stated, “The maximum bottomhole injection pressure will not exceed the estimated formation fracture pressure of 1,800 kPa abs (at 90 m depth). The operating plan calls for injecting steam at approximately 1,400 kPa abs initially, and progressively reducing the steam injection pressure as the steam chamber grows vertically.” A contradiction between the maximum operating bh pressures in the first sentence and the second may be interpreted, but was not further clarified in any supplemental information requests and responses submitted. Phase II was approved on May 18, 2004, with Approval No. 9272B. As in all in situ scheme approvals, most of the operating and design features were not specifically mentioned in the approval. Instead, clause 1(1) of the approval states “…as such scheme is described in…”, and applications related to the scheme are listed. In addition, as found in all in situ approvals, clause 1(2) and (3) requires the operator to notify and obtain approval from the Board for any substantive alteration or modification to the applied-for scheme design or equipment. Staff concludes that Total was in noncompliance with its approved scheme operating bh pressure. The operating bh pressure, as applied for and approved, was an initial 1400 kiloPascals(absolute) (kPaa), with a progressive reduction over time. Had the scheme been operated within these bounds, then the steam release would not likely have occurred.

The Phase II application also stated, “Bottomhole steam pressure readings will be monitored (and alarmed) on the control room board. Automated steam shutdown controls will intervene if the operators do not reduce the bottomhole steam injection pressure.” Given that exceeding the proposed 1400 kPaa operating bh pressure would not likely have been considered a safety issue by the applicant, staff interprets that the alarm was to indicate when the 1800 kPaa maximum bh pressure was exceeded. This corresponds to a bh pressure of about 1700 kPag, and based on tabulated pressure data submitted with Total’s final report, was exceeded on numerous occasions by Total during circulation and semi-SAGD (but by less than 100 kPa). Staff concludes that Total was in noncompliance with the approved operating strategy for ensuring that steam injection could not accidentally exceed fracture pressure.

2.2 Noncompliance with Maximum Wellhead Injection Pressure

Section 2.4 of *Directive 051* designates steam injection wells as Class IV (injecting potable water or steam from potable water or recycled water). Section 2.4 also states, “Wells injecting fresh or potable water should be subject to minimal monitoring and surveillance.” Therefore, for all but Class IV wells, Section 8.1 of *Directive 051* limits the maximum wellhead injection pressure to “…the lesser of 90 per cent of the formation fracture pressure, or the pressure at which the hydraulic isolation logging was conducted.” For Class IV wells, Section 8.1 states, “Wellhead pressures will not generally be limited.”

On October 25, 2005, an application for placing pad 204 wells on injection was made in accordance with *Directive 051* (Appendix 5). In its application, Total stated that a maximum bh pressure of 1800 kPaa would not be exceeded. Although the application did not specify what maximum wellhead injection pressure was being applied for, and Section 8.1 does not require that one be imposed by the ERCB, the *Directive 051* approval issued on November 1, 2005, limited the wellhead injection pressures to a maximum of 1800 kPaa. There appears to have been some confusion between the maximum bh pressure committed to in the *Directive 051* application and the maximum wellhead pressure that was approved. However, no further correspondence is evident in ERCB files that would indicate that the operator objected to the discrepancy or to the imposition of a maximum wellhead pressure that was seemingly in contradiction of Section 8.1. Wellhead pressure data provided in Total’s final report on the steam release showed that the approved maximum was exceeded on numerous occasions, sometimes significantly. Therefore, staff concludes that Total was in noncompliance with the *Directive 051* approval prior to the steam release.

3 Geology

3.1 Views of Total

3.1.1 General Geology

Total interpreted that the targeted McMurray sand was deposited within stratigraphic sequences comprising fluvial, estuarine, and marine systems that correspond to the Lower, Middle, and Upper McMurray, respectively. The McMurray was deposited on, and filled, Devonian surface lows and is overlain by the Wabiskaw Member, Clearwater Formation, and Pleistocene.

The structure on top of the Devonian surface ranges from a high of 245 metres above mean sea level (m MSL) in the central area to a low of around 205 m MSL in the north and south. Lower elevations are a result of collapse due to salt dissolution of the underlying Prairie Evaporite Formation.

Total interpreted three separate units within the Wabiskaw Member that could be correlated over Joslyn Creek. These units, from deepest to shallowest, were the Wabiskaw C sand (Kcw1), Wabiskaw A shale (Kcw2), and Wabiskaw A sand (Kcw3). Kcw1 overlies the McMurray and consists of medium-grey mud interbedded with 10 to 30 per cent fine-grained glauconitic sand, and Total believed that it was unlikely to act as a pressure seal or as a lateral pressure drain. Kcw2 was interpreted to be an offshore, partly fissile shale, which Total believed would be a sealing unit to a steam chamber. It has an average thickness of 4.8 m that Total correlated throughout Joslyn Creek and maintains an essentially constant thickness. Finally, the topmost unit, Kcw3, consists of offshore transition, fine-grained sand interbedded with 15 to 25 per cent medium-grey wavy mud beds. This unit presents a fairly constant thickness of around 2 m. Wabiskaw sands and silts have shown permeability in the 300 to 2000 milliDarcy (mD) range. Total stated that this level of permeability may be enough for this unit to act as a lease-scale pressure drain of low to fair quality.

The total overburden thickness is approximately 40 to 60 m, with 20 to 30 m being the marine shales of the Clearwater Formation. Total stated that the Clearwater shale was a barrier to vertical flow and was slightly variable in its character. This variability could be attributed to the range in its fissility, color, density, and lithology. The remaining sediments consist of the downcutting Pleistocene deposits.

3.1.2 Reservoir Seal

Total made various observations at a regional scale to suggest that fractures occur in all stratigraphic intervals, but that such occurrences are extremely rare in the McMurray and above. Total interpreted the fractures to be more common in the Devonian and related to large-scale fault replay and salt dissolution. It believed that fractures contained within the Devonian did not radiate through the McMurray Formation and interpreted that any collapse structure, and associated fracturing, occurred pre-Cretaceous.

Total considered the presence of a gas cap at the top of the McMurray to be strong evidence supporting the quality of a steam chamber seal at Joslyn Creek. The gas cap has been mapped throughout Joslyn Creek and is trapped by the Wabiskaw Member, specifically Kcw2.

Total stated that the presence of a gas cap overlying the McMurray and specifically around the steam release area discounted the possibility of open fractures existing in the Kcw2 sealing interval. Total also contented that a sealing interval capable of trapping and containing gas over geologic time should be capable of acting as a seal provided that it is not severely heated. Figure 5 is a type log from Total’s 2008 scheme performance presentation to the ERCB showing Kcw2 (labeled as regional seal) and the Upper McMurray gas.

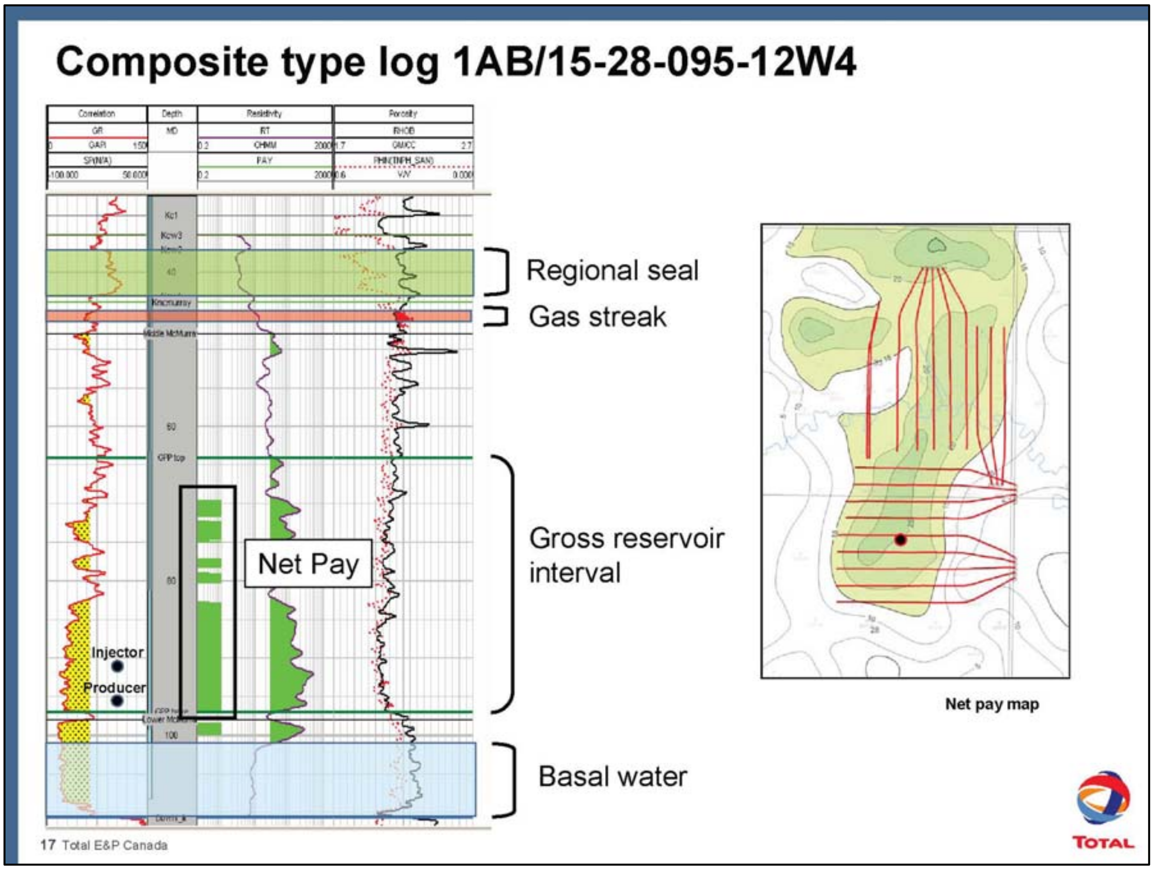

Figure 5. Total's type log illustrating the regional seal and top McMurray gas

3.2 Views of Staff

3.2.1 General Geology

The McMurray reservoir at Joslyn Creek is a shallow deposit, with the McMurray top at ≤50 m from surface. As a result, surface casing is often set over portions of the Clearwater caprock, suppressing log responses and making it more difficult to determine markers and thickness. Notwithstanding these challenges, staff believes that there is sufficient information from logs to reach conclusions on the general thickness and continuity of the Clearwater caprock in Joslyn Creek, although subject to a greater degree of interpretation.

Staff reviewed wells in the area of the incident and agrees that Total's interpretation of a Clearwater Formation that varies from 20 to 30 m in thickness and is continuous in the scheme area is reasonable. Staff interprets that the strata beneath the Clearwater shale (T21 marker) consists of, from shallowest to deepest, the Wabiskaw A sand, a 1.5 m water-saturated sandy, silty mudstone with 21 per cent maximum porosity, the 3 to 6 m Wabiskaw A shale, and the gas-saturated Wabiskaw C sand.

3.2.2 Reservoir Seal

Presence of Continuous Regional Mudstone

Staff geologists completed an independent review of Joslyn Creek on January 26, 2008 (Appendix 1). Staff also reviewed several filings by Total addressing geological issues that may have been related to the May 18, 2006 steam release.

Staff interprets the Clearwater caprock to be a non-lithified, silty mudstone, with some sandy interbeds and some vertical burrows filled with sand. Total believed that the presence of a gas cap beneath the Wabiskaw A shale discounted the possibility of open fractures and supported its assertion that the shale was an adequate seal, sufficient to isolate a steam chamber. Staff agrees with Total's interpretation that gas is trapped beneath the Wabiskaw A shale and that its presence in all wells in the general area of the steam release indicates that the Wabiskaw A shale is a continuous seal to gas in this area. However, the Wabiskaw A shale is relatively thin (3 to 6 m) and has never been recognized by the ERCB as an effective caprock that would stop the vertical rise of a high-pressure, high-temperature SAGD steam chamber.

Natural Fractures Within the Caprock Interval Due to Karsting

Karst or karst topography is a unique type of landform that develops in regions of carbonate and/or evaporate rocks due to weathering and erosion processes. It develops in these rocks because they are particularly susceptible to chemical dissolution, where underground solution processes dissolve the rocks to create and enlarge cavities and caves. The development of caves and cavities weakens support of the overlying bedrock units, which results in collapse that in turn causes subsidence, local faulting, and fracturing. The Devonian succession underlying the oil sands deposits of northeastern Alberta are largely carbonate and evaporate. The Devonian carbonate and evaporate rocks have undergone and continue to undergo the development of karst features.

Joslyn Creek is located near the northwestern limit of the regional salt dissolution trend in northeastern Alberta. In Township 95-12W4M, there is irregular topography on the sub-Cretaceous unconformity, with a broad arch of ridges separated by intervening, circular lows. This pattern is characteristic of karst topography that developed during a long period of erosion along the unconformity. Some of this large-scale karst influence continues up to the end of Wabiskaw time (or younger). Joslyn Creek is in Section 33-95-12W4M and sits upon a paleotopographic high on the sub-Cretaceous unconformity that continues as a high through to the end of Wabiskaw time. There is a smaller scale "high-and-low" irregular pattern on this ridge structure that likely represents karst subsidence that influenced deposition. This interpretation is substantiated by the seismic profiles submitted by Total in its final report, which showed a smaller-scale paleotopographic low underneath the incident area, and by the staff core review, which revealed that the core proximal to the site had evidence of karst.

Total agreed with staff that fractures exist within the Devonian at the steam release location, but Total interpreted that the collapse structure and associated fracturing occurred pre-Cretaceous and were not likely present in the McMurray or above. This conclusion appears to be based largely on Total's review of cores from the 15 wells closest to the steam release area. Total found no evidence of natural fracturing in any of the cores. Total believed that its interpretation that fracturing occurred pre-Cretaceous was further supported by its interpretation of high-density 3-D seismic, indicating the lack of disturbed Lower McMurray sediment, and by its core and log review, demonstrating that there are no younger sediments at the base of the Devonian lows.

However, the staff core review noted the presence of sand-filled fractures in the T21 (top of Wabiskaw) interval at well AA/04-31-095-12W4, which is adjacent to Joslyn Creek (about 4 km from the steam release site). While this well is farther away than the 15 cored wells reviewed by Total, the presence of fractures within the T21 interval indicates that movement creating the fracture occurred subsequent to deposition of the T21, which contradicts Total's view that fracturing in this general area occurred pre-Cretaceous.

Total concluded that no geologic feature was identified on seismic that would suggest that local pre-existing geological conditions (faults, fracture, etc.) played any significant role in the steam release process. However, staff notes that with regard to the high-density 3-D seismic taken after the steam release, evidence of fracturing within the disturbed area of the steam release would have been destroyed by the release.

Staff conclusions on the quality of Clearwater caprock are as follows:

- While the Clearwater Formation at Joslyn Creek is continuous and between 20 to 30 m thick, it is a non-lithified, silty mudstone with some sandy intervals.
- The Joslyn Creek area was subject to the effects of post-depositional karsting in Clearwater and below, which may have resulted in some fracturing and faulting of the caprock and bitumen reservoir.
- The Wabiskaw A shale, while interpreted to be a sealing shale to gas in the local area of the steam release, is too thin to be a caprock for a SAGD steam chamber.

4 Steam Release Scenarios

4.1 Views of Total

4.1.1 Most Likely Steam Release Scenario

Total concluded that the events leading to the steam release were all related to an excessively high operating bh pressure during circulation and semi-SAGD, peaking at about 1800 kPag.

The following is a step-by-step breakdown of Total's most likely steam release scenario with supporting information.

1) A fast, gravity-driven local development of a steam chamber to the top of the SAGD pay zone, probably involving sand dilation.

Based on the results of the mini-frac test conducted at well AA/8-29-95-12W4, Total interpreted that the fracture gradient at Joslyn Creek was approximately 21 kPa per metre of depth (the original Deer Creek application used a more conservative fracture gradient of 20 kPaa/m). This gradient represented the overburden weight and was obtained by integrating the bulk density log. Since the mini-frac test showed that the overburden stress was always less than the minimum horizontal stress, Total concluded that the orientation of the fracture would be horizontal. Total reasoned that although the operating bh pressure at well pair 204-I1P1 was at or near the fracture pressure of about 1800 kPag for that depth, the resulting horizontal fracture could not have moved up through the Clearwater caprock. Therefore, Total concluded that a tensile hydraulic fracturing of the caprock was not likely the mechanism for the steam release.

Based on the above and supported by the results of the high-density 3-D seismic survey of the release area, Total believed that the most likely mechanism for the movement of high-pressure steam/water through the middle McMurray bitumen pay zone was the formation and vertical propagation of a small dilated zone or chimney, about 30 m in diameter, probably soon after the start of circulation. The 3-D seismic was interpreted by Total to show two chimneys, one reaching down to injector 204-I1 (see Figures 6 and 7).

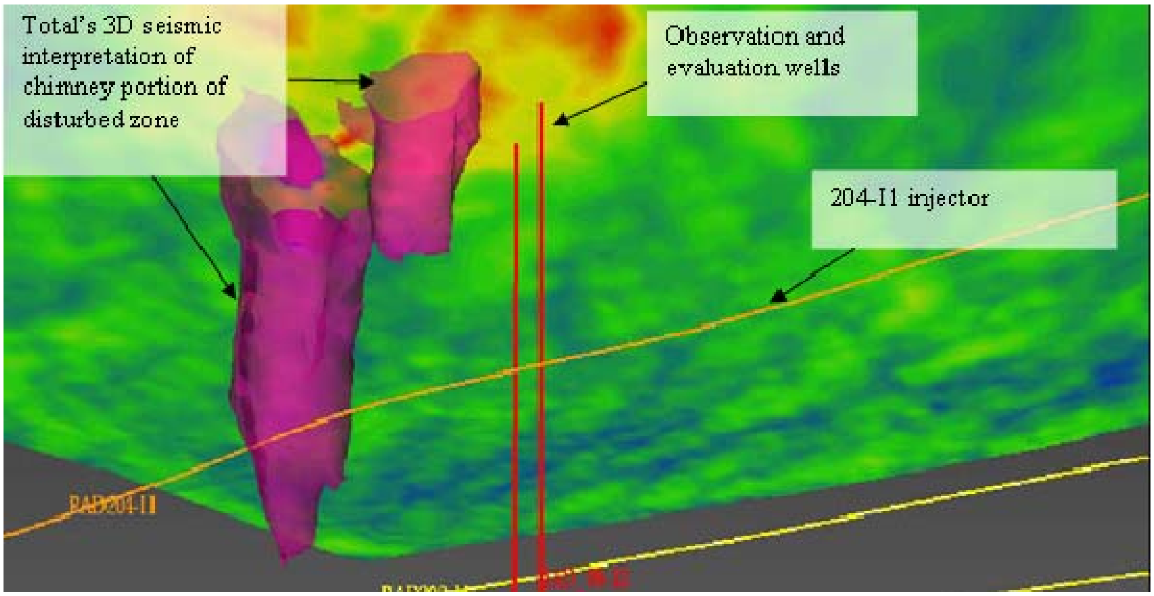

Figure 6. Total's 3-D seismic interpretation of dilation chimneys

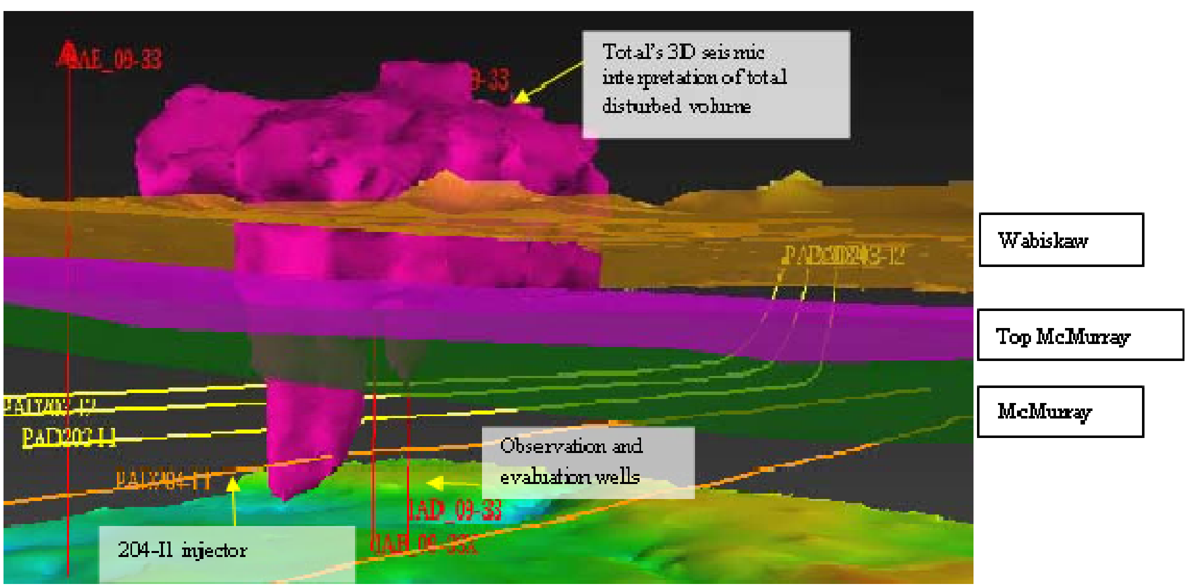

Figure 7. Total's 3-D seismic interpretation of total disturbed volume of steam release

Total believed that for a dilation chimney to develop, there would need to be a combination of a localized point of initiation, the presence of a relatively clean, unconsolidated sand, and steam pressure at or near the fracture pressure. Total represented this chimney by explicitly introducing a 50 Darcy chimney into its reservoir simulator. It did not model the chimney development with a geomechanical model.

Total provided the following to support why a dilation chimney initiated where it did along well pair 204-I1P1:

- Particularly good reservoir quality in the vicinity of the steam release point relative to the rest of the well.

  The vertical observation well 00/09-33-095-12W4 (well 00/9-33) and the vertical strat well AB/09-33-095-12W4 (well AB/9-33) are about 10 m and 20 m, respectively, from horizontal well pair 204-I1P1. Total interpreted that they encountered the best quality reservoir in the Phase II area. A channel with very high porosity and oil saturation and no shale extended from a few metres above injector 204-I1 up to a depth of 68 m. Total stated that there were no vertical wells to assess the reservoir quality farther from the toe of the well pair, so further inferences on reservoir quality were purely based on geostatistical arguments.

- Proximity of the initiation point to the heel of the injector.

  Total stated that steam quality in the liner and heat losses to the reservoir were higher at the heel than at the toe during circulation, despite the fact that injection was only at the toe of the well. Therefore, Total concluded that it was more likely that the dilation chimney would initiate at the heel of injector 204-I1.

- Producer-injector distance

  Total provided a plot of separation distance of well pair 204-I1P1, which indicated that there was a slight, localized minimum at the location of the steam release. Total's argument appeared to be that this localized minimum may have resulted in localized communication between the wells, which would aid in drainage of the bitumen and condensed steam, and thus promote growth of the dilation chimney at that point.

2) A lateral extension of the pressurized area below the first major shale barrier in the upper McMurray.

Total believed that the chimney would have risen through the good-quality bitumen pay in the Middle McMurray as the circulation phase continued. At some point in time, the chimney would have reached the first major shale barrier/baffle in the more heterogeneous Upper McMurray and vertical movement would have stopped, with growth switching from vertical to horizontal beneath the shale. Shale barriers may stop upward pressure transmission because of their low permeability.

3) One or more shear failures on the edge of this pressurized area that allowed the steam to breach within a gas zone in the Upper McMurray/Wabiskaw C sand or in the Wabiskaw A water sand under the Clearwater caprock.

Over time, the volume and pressure of this expanding high-pressure pool of steam and water caused shear failure of the shale. Total interpreted shear failure based on the following:

- A brittle fracture orientation would be horizontal and would not be expected to move upward and breach the shale. It would, however, assist in the continued horizontal growth of a high-pressure area under the shale.

- The ongoing integrity of the shale barrier would depend on the surface area of the pressurized zone and on the difference between the pressure and the vertical stress. In this case, the operating bh pressure was well above the vertical overburden stress at the first shale barrier depth of just over 60 m. Total's geomechanical modelling indicated that if a pool of steam and water at such a pressure were to grow to a sufficient size under the shale barrier, the shale would heave upwards significantly, with the maximum shear strain and stress located along the shoulder of the heaved area. When the area and pressure were sufficient, the deformation would become so great that the shale fails under shear. The point of maximum shear stress and failure would be along the outer edge of the pressurized area, as shown in Figure 8.

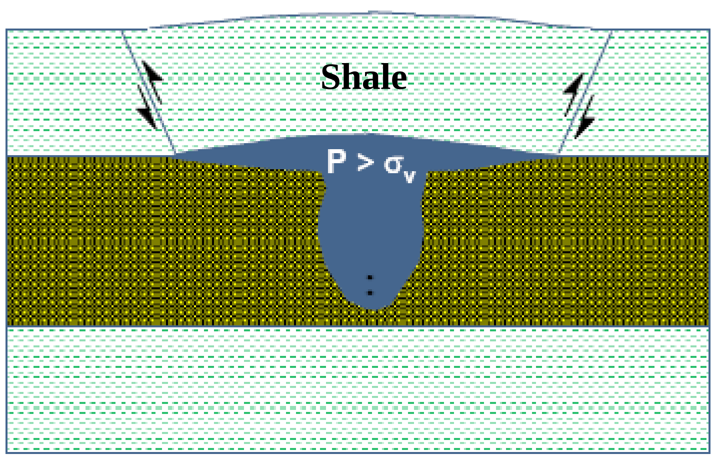

Figure 8. Simplified model of shear failure due to heave from Total's final report to the ERCB

- In addition to the modelled strains and stresses, Total proposed that high temperature effects may also have degraded the shale and aided in its failure. These thermal effects were not modelled or discussed further.

Total believed that the initial shear failure of the first major Upper McMurray shale likely established communication with the porous and permeable Wabiskaw A water sand just beneath the Clearwater caprock (Kcw3) or with a gas zone in the Upper McMurray or Wabiskaw C sand. This would have established a continuous path from injector 204-I1 through the dilation chimney in the McMurray pay zone and then through the shear failure zone to the Upper McMurray/Wabiskaw. Total concluded that this scenario provided a very good explanation for the sudden increase of injection rate accompanied by a bh pressure drop from 1800 to 1600 kPag that occurred on April 12-13. At that time, Deer Creek Energy operating staff attributed this bh pressure drop and steam rate increase to sudden communication between injector 204-I1, which was on injection, and producer 204-P1, which was on circulation.

The Total report also indicated that there may have been more than one shear failure of Upper McMurray or Wabiskaw shales before the final shear failure to surface. It used "injectivity"[1] to help identify seven of these possible events, but then discounted all but three. These three events, which Total believed occurred on April 12-13, April 25, and April 27, were supported by sudden drops in injection bh pressure while steam rate remained flat or increased. Staff therefore concludes that Total's injectivity approach is unnecessary and will not be referring to it again in this report.

4) A significant water/steam storage in the localized SAGD chamber, fracture system, and Wabiskaw and Upper McMurray porous and permeable sands.

Once the steam reached the porous and permeable Wabiskaw underlying the Clearwater shale, it was able to condense and accumulate over an extended period of time before reaching the critical pressure required for shear failure to occur. Total believed that before and during this storage period, high-pressure steam and water may also have been accumulating in any porous and permeable gas streaks in the Middle and Upper McMurray. Total believed that a significant fraction of the 1000 to 2600 m^3 (cwe) of steam estimated to be lost from injector 204-I1 probably ended up in the Wabiskaw and gas bearing McMurray by the time the Clearwater caprock and Quaternary overburden experienced shear failure. Assuming that this volume had condensed in the reservoir and had been flashed back to steam during the release to surface, Total estimated that the energy involved in the release would have been in the order of 10^{12} joules.

5) A catastrophic shear failure of the Clearwater caprock leading to release of steam at surface on May 18, 2006.

Total believed that the explosive character of the release was due to both the large volume of energy stored within the condensed steam and the sudden breaching of the caprock, causing this stored energy to be released as the water flashed back to steam. Total believed that any scenario for the Joslyn Creek steam release must therefore include not only the mechanism for the breach of the caprock, but also the opportunity for storage of sufficient condensed steam to result in an explosive release. Total did not believe that significant energy would have had time to accumulate if the steam release were due to a vertical fracture from injector 204-I1 to surface on May 18, 2006. Moreover, the injection bh pressure was not high enough to fracture the McMurray at the 204-I1 well depth on May 18, 2006, having only reached a pressure of about 1400 kPag when the incident occurred.

Once shear failure conditions were reached below the Clearwater seal, nothing stopped the fast propagation of shear failure faulting toward the surface even under the reduced bh pressure applied at the time of the release. Live steam breached the surface quickly, followed by a water/steam mix when upward-moving water flashed to steam while depressurizing, thus lifting the remaining water at high velocity. All rock volumes within and adjacent to the steam/water zone experienced fluid movement at very high velocities. Total rock failure happened along faults/fractures within the Clearwater, Wabiskaw, and McMurray due to these extreme velocities. Such complete rock failures were responsible for rock ejection at surface.

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[1] Total's formula for injectivity, as defined in its report, was "steam injection rate per 100 kPa of pressure differential between the injector and producer."

4.1.2 Alternative Steam Release Scenarios

Total acknowledged that alternative steam release scenarios were possible and provided the following analysis:

1) Wellbore Pathway

The steam release occurred within close proximity of two existing wellbores: observation well 00/9-33 and evaluation well AB/9-33.

Total did not believe that the wellbore pathway was a likely scenario because

- Total's high-density 3-D seismic interpretation indicated that both observation well 00/9-33 and evaluation well AB/9-33 were not within the chimney of disturbed zone that extended down to injector 204-I1, and
- both wells were interpreted by Total to be more than 30 m from the surface crater that resulted from the steam release.

2) Pre-existing Natural Fracture Pathway and/or Poor Caprock Integrity

Total conducted a visual inspection of the 15 cored wells closest to the steam release area and did not identify fractures in the overburden interval from top of SAGD pay to surface. Consequently, it concluded that it was unlikely that pre-existing fractures caused the steam release. Total also concluded, based on its geological interpretation, that the caprock was of sufficient quality to be a barrier to the vertical flow of steam.

3) Vertical Hydraulic Fracturing of the Reservoir and Caprock

Total believed that fracturing due to high-pressure operations could possibly be oriented in a direction other than the horizontal. This occurs in deeper formations where the minimum principle stress is horizontal. However, it could occur in shallow formations if the vertical stress and minimum horizontal stress were close to one another. If such were the case, then a vertical fracture could move up from the wellbore and provide a pathway for steam.

However, Total did not believe, based on the mini-frac test results, that it was likely that fracturing in a direction other than horizontal could occur at Joslyn Creek, and therefore the fracture could not have moved upward to breach the caprock. The mini-frac test report on well AA/08-09-095-12W4 concluded that the vertical stress and minimum horizontal stress were close, but also concluded that the expected fracture orientation would be horizontal.

Total also concluded that a vertical fracture moving up from the wellbore to breach the caprock would have initiated when bh pressures were at fracture pressure during circulation. Yet fracturing events did not occur until after conversion to semi-SAGD, and the steam release occurred after conversion to SAGD, when bh pressures were at their lowest relative to circulation and semi-SAGD.

Finally, Total believed that a vertical fracture moving from the wellbore through the caprock on May 18, 2006, would not have allowed any time for storage of energy in the reservoir. Total concluded that the catastrophic nature of the steam release required such energy storage through a buildup of steam and steam condensate beneath the caprock.

4.2 Views of Staff

4.2.1 Arguments Supporting Total's Most Likely Scenario

As summarized below, staff believes that Total's release scenario is plausible for many of the reasons provided in its detailed analyses.

1) Mini-Frac Test Results Support Horizontal Fractures Only

The mini-frac test on well AA/8-9-095-12W4 indicated that a vertical fracture of the caprock was unlikely because the minimum principal stress was due to the overburden. Based on this interpretation, shear failure of the caprock would be more likely than tensile failure by vertical fracturing.

2) Total Was Able to Model Shear Failure of Caprock

Total's geomechanical model was able to show that shear failure of the caprock to surface would occur at the pressures existing at the time of the steam release for a pool of steam and condensate under the caprock with a bh pressure of 1400 kPag and an area of 100 m diameter, which is consistent with the injection bh pressure at the time of the steam release and the area of disturbance of the Wabiskaw zone identified by 3-D seismic.

3) Total's 3-D Seismic Interpretation Does Not Support Vertical Wellbore Involvement

Staff agrees that Total's 3-D seismic interpretation would appear to show that both the 00/9-33 and AB/9-33 vertical wells were not within the narrow disturbed zone that extended down to injector 204-I1.

4) Multiple Fracturing Events and Energy Storage Do Not Support a Vertical Fracture Event from Wellbore to Surface

The steam release did not occur until after the steam injection bh pressure had been lowered by 300 to 400 kPa below the estimated fracture pressure for the injection well depth. This would imply that the steam release was not due to a sudden fracturing from the injection well to surface. Staff agrees that this is further supported by the high energy of the steam release and by the series of at least three fracturing events interpreted by drops in the bh pressure at the heel of injector 204-I1 over a period of weeks after conversion to semi-SAGD. Staff agrees that a catastrophic surface release would require storage of steam and steam condensate. Total assumed that most of the energy storage occurred after the first shear failure event on April 12, 2006. Staff identified a possible two additional shear failures on April 21 and April 25, 2006, based on bh pressure drops at the injector heel with either stable or slightly increasing steam rates.

5) 3-D Seismic Results Support Localized Dilation Zone Pathway

Total's seismic interpretation identified a narrow chimney of disturbance extending from injector 204-I1 to the main disturbed zone at the top of the McMurray. In addition, the geomechanical analysis provided by Total showed that it was theoretically possible for a dilation zone to move vertically from the well to the top of bitumen pay. This was supported by Total's reservoir modelling, which showed that a chimney with a 50 Darcy vertical permeability would allow steam to move up over the 4-month circulation period.

4.2.2 Arguments Against Total's Most Likely Scenario

Staff believes that there are a number of outstanding concerns with Total's scenario as detailed below.

1) Steam Release Occurred In Proximity To Vertical Wells

Staff considers it to be a significant coincidence that the steam release occurred in the same location as two vertical wells: observation well 00/9-33 and evaluation well AB/9-33. Figure 9 shows an aerial photograph of the the release site, with the location of the two vertical wells and well pair 204-I1P1 overlaid. It shows that the main steam release surface crater was within 20 m of the bottomhole location of evaluation well AB/9-33 and within about 30 m of observation well 00/9-33. Both wells are completely within the surface disturbed area caused by the steam release, and both are less than 20 m from the well pair 204-I1P1.

The abandoned evaluation well AB/9-33 was not cased and could not be located from surface.

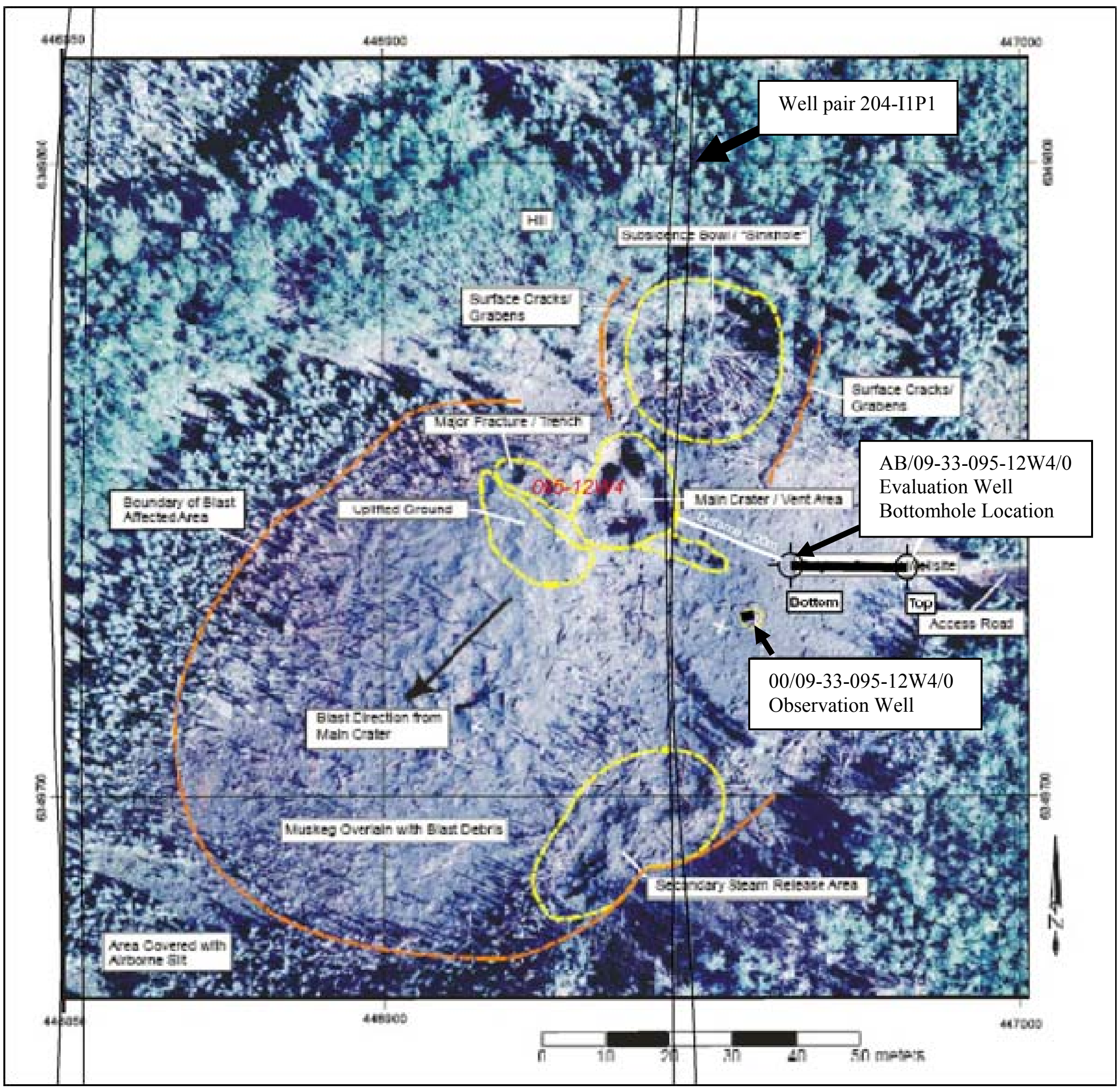

Figure 9. Vertical wells overlaid on a photograph of release site from Total's final report

2) Localized Vertical Dilation Chimney Would Be Unique

While there are several papers describing the geomechanical benefits of dilation/shearing, staff is not aware of any technical literature describing a narrow dilation chimney that could extend vertically over 20 m of pay, nor has such an unstable, localized growth of a SAGD steam chamber been reported at other SAGD operations. To the contrary, a paper by Patrick Collins entitled *Geomechanical Effects on the SAGD Process*[2] argues that dilation/shearing in shallow deposits will encourage steam chamber growth horizontally, rather than vertically. (Mr. Collins also did the analysis of the Joslyn Creek mini-frac test for Total.) Total's main support for the dilation chimney were the high-density 3-D seismic interpretation and its belief that vertical fracturing could not occur. Staff notes that a vertical fracture would likely provide the same seismic response, and staff does not accept that the mini-frac test results are necessarily representative (see Section 4.2.3[3]).

Total was unable to model the formation of the chimney directly. Perhaps this could be done by using a geomechanical model coupled with a reservoir simulator and a discretized wellbore model, but staff has doubts that such modelling would be successful.

3) Chimney Formation During Circulation Phase Requires Drainage

Staff and Total agree that in order for a SAGD chimney to develop, in addition to sand dilation, drainage of the bitumen and condensed steam from the developing chimney would have to occur. However, Total believed that the chimney developed during the 4-month circulation phase, when both the injector and producer were circulating at identical high pressures. Staff believes that during circulation flow should be away from the well pair due to the large pressure difference between the wells and the reservoir. Total could not model drainage during circulation since its model's mechanism for circulation was electric heating. In staff's view, the earliest opportunity for drainage was the last week of circulation when a bh pressure differential of about 200 kPa was imposed between the injector and producer, and then during the 18 days under semi-SAGD prior to the first fracturing event on April 12, 2006. If this is the case, the entire chimney would have to have developed and delivered sufficient steam to the first shale barrier to cause shear failure within a total time of about three weeks.

4) Limited Support for Chimney Initiation Point at Heel of Well

While Total was able to demonstrate that the two vertical wells within the steam release area (wells 00/9-33 and AB/9-33) encountered good reservoir quality, it was not able to establish that this location had better quality sand than other locations along the well pair. Evaluation well 00/08-33-095-12W4, which is closer towards the toe of well pair 204-I1P1, encounters what staff interprets to be comparable reservoir quality with thinner pay. Staff concludes that the evidence of unique reservoir quality improvement at the steam release area is not supported by the data.

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[2] Collins, Patrick M. "Geomechanical Effects on the SAGD Process." *SPE Reservoir Evaluation & Engineering* 10, no. 4 (August 2007): 367-75.

Similarly, Total did not provide modelling or analysis supporting its contention that the heat transfer to the reservoir would be greatest at the heel of the well during circulation, when steam was being injected to the toe of the well.

5) Steam Release Occurred After Conversion of Well Pair 204-I1P1 to Semi-SAGD

Total stated that during circulation the reservoir was heated mainly by conductive heat transfer. Steam was not expected to move into the reservoir (i.e., convective heat transfer), because the easiest pathway was back up the well. However, under semi-SAGD the returns on the injector 204-I1 were shut in. Steam continued to be injected at the toe through the long tubing, but the short tubing was converted to inject steam at the heel of the injector (the producer 204-P1 continued to circulate). The steam had nowhere to go but into the reservoir. Staff believes that it is likely no coincidence that the first fracturing event, identified from bh pressure and injection information, occurred 2½ weeks after well pair 204-I1P1 went on semi-SAGD (see Figure 10). The sudden introduction of steam to the heel of the injector likely also explains why the steam release occurred near the heel.

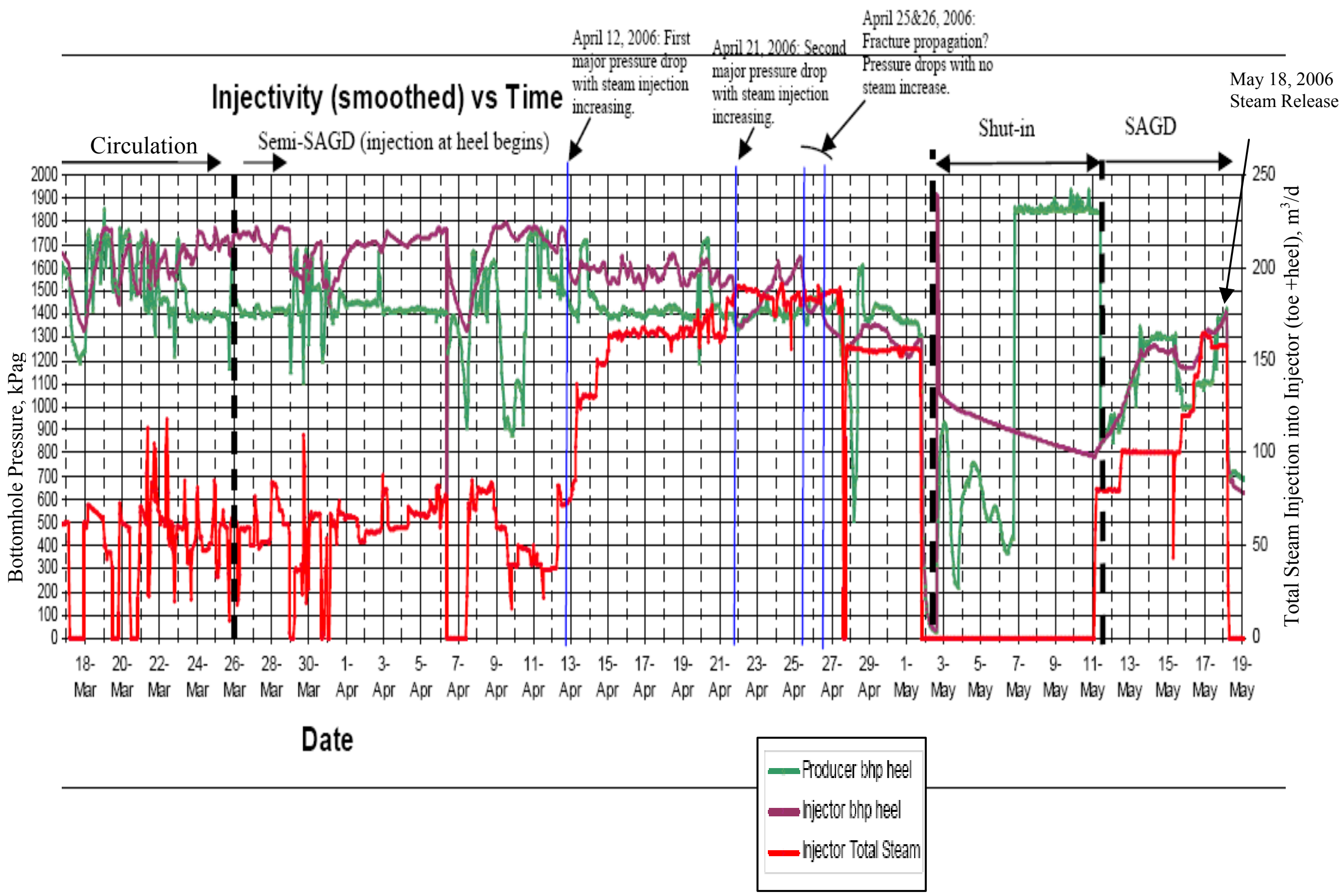

Figure 10. Well pair 204-I1P1 pressures and steam injection rates

6) Integrity of Caprock Is Questionable

Total interpreted the Clearwater shale and underlying Wabiskaw A shale as sealing units for a SAGD steam chamber. However, in its detailed core review, staff interprets the Clearwater shale to be a non-lithified mudstone with sandy mudstone intervals, which may limit its ability to contain a steam chamber, and concludes that the Wabiskaw A shale is too thin to be a caprock for a SAGD steam chamber. In addition, staff believes that there is evidence of karst influence up to the end of Wabiskaw time (or younger) that could result in natural fractures in the McMurray, Wabiskaw, and Clearwater. Staff concludes that weaknesses in the reservoir and caprock may have contributed to the steam release.

4.2.3 Staff Analysis of Alternative Pathways for Steam Release

Staff believes that there are three alternative scenarios for the steam release. These alternatives may be in combination with each other or in combination with portions of Total's most likely scenario.

1) Wellbore Pathway

Staff believes that it was a significant coincidence that the breach of caprock occurred in close proximity to two vertical wells. The following is a scenario for the steam release involving one of these wells.

- While on circulation, the pathway of least resistance for steam injected at the toe of injector 204-I1 was back up the short tubing at the heel of the well, so it is less likely that fracturing would have occurred during circulation. When well pair 204-I1P1 was converted from circulation to semi-SAGD on March 26, 2006, the short tubing was converted over to steam injection, forcing all injected steam (toe and heel) to move into the reservoir.
- Sometime after the start of semi-SAGD, a horizontal fracture initiated near the heel of the 204-I1wellbore and moved out into the reservoir until it encountered a vertical wellbore. Within the pay zone saturated with cold, immobile bitumen, the fracture may have had very little leakoff and could have grown quickly.
- High-pressure steam moved up channels or gaps left in the cement plug in abandoned evaluation well AB/9-33 or behind cemented casing in observation well 00/9-33. On April 12, 2006, communication was established up the wellbore with either an Upper McMurray/Wabiskaw C gas zone or the Wabiskaw A water sand at the base of the Clearwater caprock. This would account for the sudden drop in bh pressure and the increase in steam injection rate.
- Steam continued to flow into the upper zone, and shear failures or vertical fractures of upper shale barriers occurred until a final shear failure or fracture of the caprock on May 18, 2006.

Staff notes that this scenario does not require the existence of a dilation chimney, but could still match other aspects of Total's release scenario. The main weakness of this scenario is that Total's 3-D siesmic interpretation showed that these wells slightly offset the vertical chimney interpreted for the steam release pathway. Staff is concerned that the seismic may have been affected by the much larger disturbed area above the narrow chimney, reducing the accuracy of the response for determining the exact chimney location relative to the vertical wells.

If the seismic interpretation is not sufficiently accurate, then one of the vertical wells could have provided a pathway for the steam, most likely well AB/9-33. Total was unable to locate the AB/9-33 wellbore. Total determined that well 00/9-33 was undamaged by the steam release except for a bent casing, making it a less likely candidate.

Regarding the potential for the vertical wells to have gaps or channels in the cement, Total's *Cement Bond Insights* document lists the following problems with the two wells at the steam release site.

- AB/9-33 corehole well abandonment—a single-stage plug back and abandonment with no cement returns reported and no tagging of the cement top. Staff concludes that the well abandonment could have left sections of the hole without cement, providing the steam with a pathway. In addition, a cement bond over a clean unconsolidated oil sands zone is not necessarily a seal.
- 00/9-33 well cement job—a narrow $2^{7}/_{8}$ inch tubing served as casing for this observation well, the cement top was not tagged (but there were returns to surface), and no cement bond log was run. Staff agrees with Total that without a cement bond log, it is not possible to be sure that the cement job was good, despite having cement returns.

2) Pre-existing Natural Fracture Pathway and/or Poor Caprock Integrity

This scenario would see steam flowing upwards along naturally occuring faults or fractures caused by the subsidence due to karsting. Karsting is interpreted over much of northeastern Alberta (see Appendix 1 for more details on karsting). Once well pair 204-I1P1 was converted to semi-SAGD, a horizontal fracture was initiated as predicted by the mini-frac test results, but when it encountered a natural fracture, the steam was diverted upwards, providing communication with an upper gas zone or water zone. This would show up as the April 12, 2006 fracturing event. From then on, the scenario could be as in Total's scenario, with shear failure of internal shales and then the final shear failure of the caprock. Alternatively, the caprock may also have natural fractures, which allowed the high-pressure steam pooling under it to work its way up through the caprock until communication with the surface occurred on May 18, 2006.

Staff believes that the presence of natural fractures alone is not sufficient for this scenario to have occurred. The natural fractures would have to have been infilled over time with material that provided some improved permeability to flow. If all that existed were closed fractures, they would not likely reopen unless the minimum principle stress was horizontal and the fracture closure pressure was exceeded. Similarly, the presence in the caprock of silty mudstone, sandy interbeds, or vertical burrows filled with sand could have provided a pathway for the high-pressure steam.

3) Vertical Hydraulic Fracturing of the Reservoir and Caprock

This scenario sees steam initiating a vertical fracture at injector 204-I1 on April 12, 2006 (after conversion to semi-SAGD), which established communication with an upper McMurray/Wabiskaw C gas zone or the Wabiskaw A water sand. The vertical fracture provided a pathway for steam to pool within one or all of these zones while the fracture continued to progress more slowly through the Wabiskaw shales and/or the Clearwater caprock until the caprock was breached on May 18, 2006. The progress of the vertical fracture would likely be slowed by much greater leak-off once a permeable zone had been reached, which would explain why it did not immediately cause a steam release. As with the vertical wellbore pathway, while this scenario does not require the existence of a dilation chimney, it would still allow for energy storage within permiable zones and several fracturing events to be observed as the fracture progressed through the Upper McMurray, Wabiskaw, and Clearwater.

The vertical fracture scenario could also be combined with other scenarios, the most likely being that a vertical fracture moved rapidly from the wellbore to the Wabiskaw C gas zone, where it was halted by excessive leakoff. Steam and water then began to accumulate under the Wabiskaw A shale and eventually caused it to fail under shear on April 21, 2006, and establish communication with the Wabiskaw A water sand, directly underlying the Clearwater caprock. From this time onwards, high-pressure steam and water accumulated under the Clearwater caprock until on May 18, 2006, it failed under shear.

The key argument against the vertical fracture scenario is that the mini-frac test results indicated that only horizontal fracturing should occur. However, the mini-frac results also indicated that the vertical stress was only a little lower than the minimum horizontal stress, and the test was done on a well over 1 mile from the release site. If karsting reduced the minimum horizontal stress below the vertical stress locally, then a vertical fracture could have occurred. A vertical fracture would also be consistent with Total's 3-D seismic interpretation. The fracture path reaching down to the injector could have shown up on the siesmic as a narrow disturbed zone reaching down to the injector.

In support of this scenario, an example of a localized reduction in horizontal stress due to karsting was provided in Husky Oil Operations Limited's October 2008 submission on its proposed Caribou CSS scheme.[3] Husky provided the results of a mini-frac test on well AA/04-07-069-04W4. This well was drilled in a sinkhole area caused by karsting (see Figure 11), and the mini-frac results showed that the local fracture gradients were significantly below the vertical stress gradient of 21 kPa/m (they varied from 11.5 to 16.7 kPa/m).

Husky concluded that fractures would be vertical within the localized sinkhole area, but expected them to be horizontal elsewhere. Husky had planned to do further testing, but the application has since been withdrawn. Staff concludes that over distances of less than 1 km the fracture pressure could drop significantly and the fracture orientation could change from horizontal to vertical. Since karsting also results in the formation of natural fractures, staff believes that this scenario could occur in combination with the natural fracture pathway scenario.

[3] Application No. 1589158: Caribou Lake Thermal Demonstration Project, Amendment Application, Husky Oil Operations Limited. Registered on October 2, 2008. Withdrawn by letter dated April 8, 2009.

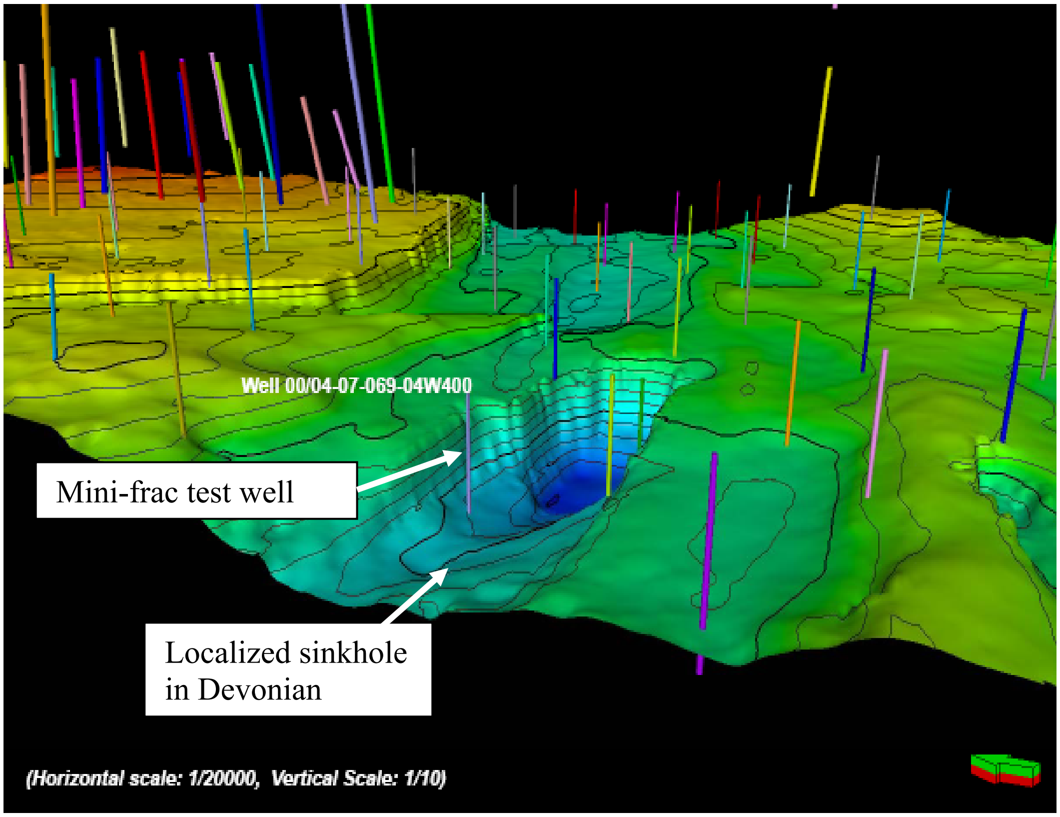

Figure 11. 3-D seismic mapping of localized sinkhole from the Husky Caribou application

5 Staff Recommendation and Conclusions

5.1 Compliance Enforcement

As discussed in Section 2, staff concludes that Total was in noncompliance with both the scheme approval and with the *Directive 051* approval by operating at such high pressures prior to the steam release. The scheme was brought into compliance when Total reduced operating bh pressure to a maximum of 1200 kPag subsequent to the steam release.

In addition, staff concludes that Total was in noncompliance with the approved operating procedure that was intended to ensure steam injection could not exceed fracture pressure. Although the fracture pressure of 1800 kPaa identified in Total's scheme application was exceeded on numerous occasions, an automated steam shutdown did not intervene when operators failed to reduce the steam injection bh pressure. This was in noncompliance with the approved procedure identified in Total's scheme application.

Given that the scheme has been suspended by Total for an indefinite period and is expected to be abandoned, staff does not recommend any further action be taken by the ERCB regarding noncompliances.

5.2 Steam Release Scenarios

Based on the review presented in Section 4.2, staff conclusions on the most likely steam release scenario and most likely alternative scenario are discussed below.

Most Likely Scenario

The underlying cause of the steam release was the injection of steam at excessively high bh pressures. Well pair 204-I1P1 was injecting at or close to the fracture pressure interpreted from mini-frac test results. As the steam moved upward, the fracture pressure was definitely exceeded at shallower depths.

Staff has reached the following conclusions regarding the most likely steam release scenario:

- The conversion of well pair 204-I1P1 from steam circulation to semi-SAGD forced high-pressure steam into the bitumen reservoir and, for the first time, steam was injected at the heel of the well. Eighteen days later, on April 12, 2006, a vertical fracture was initiated near the heel of the injector and established communication with the Wabiskaw C gas sand.

- High-pressure steam and water pooled under the Wabiskaw A shale causing it to fail under shear on April 21, 2006, and to establish communication between the injector and the Wabiskaw A water sand directly underlying the Clearwater caprock.

- Between April 21 and May 18, 2006, high-pressure steam and water pooled under the Clearwater caprock causing it to fail under shear to surface. Once the caprock was breached, a rapid drop in pressure occurred. This pressure drop caused hot water that had accumulated in the Wabiskaw A water sand and the Wabiskaw C gas sand to flash to vapour. This provided the energy for a catastrophic explosion that disturbed a large surface area and subsurface volume and threw rocks several hundred metres into the air.

Alternative Scenarios

Staff concludes that the next most likely steam release scenario is one that involves the nearby abandoned evaluation well AB/9-33, with a bottomhole location about 20 m from the main surface crater and a similar distance from the injector 204-I1.

On April 12, 2006, a horizontal fracture was initiated near the heel of the injector and established communication with the evaluation well. Steam then moved up through gaps or channels in the well's cement abandonment plug until it reached the Wabiskaw C gas sand. From this point, the scenario would be the same as the staff's most likely scenario described above, culminating in shear failure of the caprock.

Staff believes that neither of the above scenarios precludes a contribution to fracture and shear failure pathways from pre-existing weaknesses in the reservoir and caprock. However, in the absence of operation at excessively high bh pressures, staff concludes that it is unlikely that these weaknesses would have resulted in a steam release.

Staff does not believe that Total's dilation chimney pathway is a likely scenario for the initial vertical rise of the steam for the reasons provided in Section 4.2.2.

Appendix 1: Staff independent geological review of Joslyn Creek steam release, January 26, 2008

ERCB Geological Investigation of Joslyn Creek Steam Release

To: Andrew MacPherson and Tom Keelan, In Situ Enforcement and Surveillance, Resources Applications Group

January 26, 2008

Re: Geological Investigation Summary: Joslyn Creek SAGD Blowout Event
by Frances J. Hein and Brent Fairgrieve, Geology and Reserves Group, ERCB

Study Approach & Methods

Literature Review and Compilation of Geology of the Area

Available geological literature in the area was reviewed. Sources of information included government publications, previous Deer Creek/Total submissions to the ERCB, and the material filed by Total addressing potential causes of the Joslyn Creek SAGD Blowout event. Material was also reviewed from previous geological studies of the area, air photos, surface photos, auger-hole logs, maps, other surveys; and application material filed at the ERCB[1].

Core Examination, General Description, and Photography of Selected Cores; and Correlation with Wire-Line Logs

The focus of the core examination was to examine the sealing potential of the T21 interval and to determine the presence of karst features within the Paleozoic. The lithological character of the T21 interval determines the sealing potential. For example, silty shale would not be as an effective seal as pure fissile shale within the T21 sequence. The presence of karst features within the Paleozoic suggests there is potential for structural movement in the area. Any movement within the Paleozoic could have contributed to disruption of the overlying seals above the steam chamber.

Of the approximately forty-seven cores in the Joslyn Creek area, thirty-three cores were reviewed. The remaining 14 cores were not examined as they were:

- too deep to intersect the shales above the Wabiskaw,
- poorly recovered,
- in poor condition,
- mislabeled, and/or mixed up in the boxes.

The cores reviewed were correlated with the geophysical logs, described and 24 were digitally photographed. The core observations, their condition, and general findings are presented in Table 1. Figure 1 shows the seventeen cores reviewed in the immediate area of the Joslyn Creek SAGD site. Figure 2 denotes the 16 additional cores examined

[1] The References section provides all references used in this review.

adjacent to the site. All digital photographs are included on the accompanying CD, with some reproduced and annotated as figures in the present report.

Tops and markers picked on wire-line logs

The stratigraphic nomenclature for the picks on the wire-line logs for this study is shown in Figure 3 and Table 2. This stratigraphic nomenclature was published by Hein et al. (2006) and follows the traditional definition of formations and their subdivisions in the area, each separated by various transgressive (T) and erosional surfaces. All available geophysical logs for wells were interpreted in Township (Twp) 95, Range (R) 12W4 Meridian and in the bounding sections north of the Joslyn Creek site in Twp 96, R12W4 Meridian (Figure 4). The T21 and Paleozoic tops of the 630 wire-line logs reviewed are presented in Table 3 (on CD-only).

On-Site Visit September 2007

A site visit was done with Don Davis, the Total Field Superintendent, on Wednesday September 12, 2007, by Fran Hein, in conjunction with other AGS geologists who were working with her on a field crew in the area. An orientation meeting was done with John Foulkes, General Manager, Operations and Don Davis, prior to the site visit of the incident area. Don Davis accompanied EUB staff on their visit to the incident area.

Results

The main geologic factors assessed in this review were:

- thickness and character of the overburden[2] above the Wabiskaw-McMurray deposit;
- presence of upper thief zones; and
- occurrence of any pre-existing zones of weakness in the area.

Overburden above the Wabiskaw-McMurray deposit

The competence of the cap rock is essential for containment of the injected steam in the SAGD operation. If the competence of the cap rock is under question, this would severely limit the operating pressure of the SAGD process. The thickness and character of the overburden above the Wabiskaw-McMurray deposit is important because this gives information regarding the competence of the cap rock. If the overburden has pre-existing discontinuities, such as faults, or lateral changes in lithologies, there is risk of seal fracturing either through fault reactivation or top seal hydrofracture/shear failure.

The thickness of the overburden is one of the main attributes that contributes to the integrity of the cap rock. Of equal importance is the lithology. In general, if a homogeneous sediment package is buried, the overburden stress will be evenly

[2] Overburden is defined as the cumulative sediment thickness from the surface to the top of the Wabiskaw McMurray.

distributed, resulting in a laterally uniform rate of consolidation. However, due to inherent lateral facies changes, the overburden stress will be laterally variable. Lateral overburden stress variation, caused by original lateral lithology changes, may be exacerbated by localized structural features, such as faults or subsidence-induced fractures. These interactions between pre-existing discontinuities and natural lithologic variations may have considerable effects on differential compaction, which in turn would produce variable consolidation and non-homogeneous distribution of overburden stress.

The structural integrity of the existing well-bore casings and their cement in the vicinity of the cap rock is also essential for the containment of the injected steam. In addition there is a potential for leaks through man-made pathways, such as the presence of old wells which may have been abandoned without thermal cements suitable to withstand SAGD temperature effects. Due to the lack of cement-bond logs for the site area, the well-bore integrity, including possible cement – SAGD steam and fluid interactions, could not be assessed in this review.

The Joslyn Creek area is on the southeastern flank of the Birch Mountains mapped as the Dover Plain by Andriashek and Atkinson (2007, their figure 2). The geophysical logs reviewed indicate the highest recognizable bedrock markers in overburden encounter shallower (younger) stratigraphy to the west (Figure 5). The T21, T31 and T41 are transgressive surfaces, recognizable on wire-line logs that are overlain by very fine grained sediment ranging from mudstone, to sandy/silty mudstone to very fine siltstone. The thickness of the fine sediment overlying the transgressive surfaces ranges from being absent, where it is removed by later erosion, to a maximum of ~ 2 metres thick.

In the area immediately surrounding the Joslyn Creek site, the T21 marker (top Wabiskaw) is present. Just west of the site, both the T31 (top Clearwater C) and the T21 markers occur. Further west, the T41 (top Clearwater B), the T31 and T21 markers are present. The zero edges of the T41 to T21 markers are parallel to the Athabasca River valley. The preservation of the shallower stratigraphy to the west reflects the history of glacial erosion in the area (Figure 5). Joslyn Creek is located within the drainage of the Athabasca River – a main glacial melt-water valley that removed much of the overburden adjacent to the present valley during the end of the last ice age. The effect of erosion of the glacial melt-water valley diminished to the west, where there is preservation of shallower stratigraphy (marked by the presence of the T41 and T31 markers).

Detailed maps of the depth to T21 (or overburden thickness) were constructed in Twp 95, R12W4 Meridian (Figures 6 & 7). The thickness of overburden (or depth to the top of the Wabiskaw T21 marker) varies considerably across Twp 95, R12W4 Meridian, from approximately 10 m in the east; to exceeding 60 m in the west (Figure 6). Figure 7 indicates the overburden thickness ranges from approximately 29 m to 47 metres within the area of the scheme site. Much of the variation in overburden thickness results from the combined influences of relief along the sub-Cretaceous unconformity (i.e. thin deposition of all units above bedrock highs as a result of the low accommodation space) and the depositional and erosional events resulting from glaciation.

A summary of the caprock lithologies is presented on Figure 8 for the area surrounding the Joslyn Creek SAGD site. Figure 9 presents these lithologies in the immediate area of the site (Section 33). Summary of the lithologies observed is presented in Table 4.

The core indicates that the shales overlying the Wabiskaw-McMurray deposit are not true fissile shales in the immediate area of the Joslyn Creek SAGD site. They are often sandy, particularly above and below the T21 marker (at the top of the Wabiskaw). Core examination indicates the log intervals exhibiting a shale response can be a siltstone, silty shale, or sandy silty mudstone. The sand and silt occurs as interbeds, thin laminae or burrow fills. At the site, variation exists within the Wabiskaw and overlying Clearwater shale interval. The top of the Wabiskaw is sandy shale containing sand beds and sand filled burrows overlain by fissile Clearwater shale in the well AB/03-33-095-12W4 (Figures 10 to13). In contrast, the nearby well 00/16-33-095-12W4 the Wabiskaw is a sandy shale, lacking sand beds and sand burrow fills observed in the AB/03-33-095-12W4 well and is overlain by fissile Clearwater shales which contain alternating with sandy shale or sandy mudstone (Figures 14 to 17).

It is interesting to note that in the well AA/04-31-095-12W4 (located 2.5 miles west of the site) the interval above and below the T21 marker was sandy and overlying Clearwater shale horizons were vertically fractured (Figures 18 & 19, Table 4). The presence of slight infilling within the fractures observed in this core, indicate these are due to natural processes and not core handling procedures. Such fractures in overburden are not uncommon in Alberta. There are three natural processes that could account for fracturing of caprock in this area:

- loading and unloading by glacial ice sheets;
- faulting associated with evaporate dissolution and carbonate karsting; and,
- tectonic processes along basement faults in the area.

Figure 20 denotes gas occurrences within the shallow sediment or overburden within Alberta. It is postulated that fractures form a conduit permitting gas to flow from the underlying bedrock into the overburden. It is noteworthy that there is a reported occurrence two townships to the east of the site in 95-10W4. The loss of caprock integrity as a seal is also supported by the occurrence of hydrocarbons within shallow overburden in the site area (see Table 5). Further, in appendix B of the Millennium EMS Solutions groundwater report there is information regarding the auger-hole drilling reports from February 1 and 2, 2007. In five out of the seven auger holes that were drilled at this time, there was a presence of hydrocarbon or bitumen odour at the 2.1 to 9.5 metre interval (Table 5). The presence of this odor, particularly at the most distal hole from the event MW07 suggests to ERCB staff that sediment above the scheme is permitting the migration of petroleum into the shallow horizons.

<u>Upper thief zones within the overburden</u>

The presence of gas and/or water within the overburden above the confining steam chamber seal is important because their presence indicate the overburden is porous and permeable. To prevent breach of the confining seal the operating pressure of the SAGD process must be closely monitored. If the confining seal is fractured as a result of excessive steam chamber pressure, there would be an uncontrolled loss of steam into the overburden and/or quenching of a steam chamber.

As previously noted, there are a number of wells drilled in northeast Alberta where gas was encountered in shallow wells during or after drilling (Figure 20). Some of these gas occurrences are clearly in the Quaternary (glacial) succession. Its presence in the Quaternary suggests the communication with the underlying sediments being exploited has occurred. Gas has migrated through the upper seal as a result of fracturing or presence of sediment such as silty sand within the seal.

Other thief zones occur within the Quaternary glacial-channel fills and the associated sediments. Andriashek and Atkinson (2007) mapped about thirty buried channels and glacial-drift aquifers in the Fort McMurray region. In their assessment of the area, there are approximately six glacial channels cut into bedrock on the west side of the Athabasca River, with the Willow Channel mapped south of the Joslyn Creek Lease 24 (Figure 21).

An outcrop exposure of Willow Channel sediments previously mapped by Andriashek (2000) in the southwest corner of Sec. 26, Twp 94, Rge. 12W4 Meridian has a 2-3 m thick boulder bed, within a succession of cross bedded fine sand. The Willow Channel as currently mapped extends for 14 km from Twp. 94, Rge. 12W4 Meridian to the southwest corner of Twp. 95, Rge. 11W4 Meridian. The minimum width is about 1 km wide, and it is interpreted from wire-line logs to incise bedrock 25 – 30 m (Andriashek and Atkinson, 2007). There is insufficient data to determine the western or northwestern extent of this feature (Andriashek and Atkinson, 2007).

<u>Structural controls and pre-existing zones of weakness</u>

The presence of pre-existing zones of weakness is important because such zones would likely limit the operating pressure of the SAGD processes in the specific area. If such pressures were exceeded there would likely be the situation of a potential uncontrolled loss of steam and non-containment of the steam chamber.

In the study area there are two main structural controls. The first is the influence of karst processes, and the second is the underlying regional tectonics of the area. Karst development is commonly tied to regional tectonics of the area and karst processes can also lead to the development of regional systems of faults and subsidence. The two processes are related to one another, although they are discussed separately below.

<u>Structural influences due to karstification</u>

Karst or karst topography is a unique type of landform that develops in regions of carbonate and/or evaporate rocks due to the weathering and erosion processes. It develops in these rocks because they are particularly susceptible to chemical dissolution, where underground solution processes dissolve the rock to create and enlarge cavities and caves. The development of caves and cavities weakens support of the overlying bedrock units, which results in collapse that in turn causes subsidence, local faulting, disruption of surface flows with a poorly developed landscape. Karst topography is very irregular, with many closed depressions, disrupted ridges and paleohighs, and a chaotic landscape pattern. The Devonian succession underlying the oil sand deposits of northeastern Alberta are largely carbonate and evaporate. The Devonian carbonate and evaporate rocks have undergone and continue to be undergoing the development of karst features. These paleokarst and karst features are preserved as paleotopographic features in the subsurface and as modern features in the landscape of today.

The Joslyn Creek lease area occurs near the northwestern limit of the regional salt dissolution trend in northeastern Alberta (Hein and Cotterill, 2006). The lease area is also located along the southwestern margin of the Bitumont Basin – a large salt withdrawal basin and/or fault-graben structure (Figure 22, Hein and Cotterill, 2006b). In Township 95, Range 12W4 Meridian there is irregular topography on the sub-Cretaceous unconformity, with a broad arch of ridges separated by intervening, circular lows. This pattern is characteristic of karst topography that developed during a long period of erosion along the unconformity. The presence of these paleogeographic and tectonic features results in considerable variation in paleotopographic relief along the sub-Cretaceous unconformity. These features control most of the thickness variation in the Wabiskaw-McMurray succession (Figures 23 to 26).

Some of this large-scale paleotopographic control and karst influence continues up to top Wabiskaw time (or younger to the recent). This is evident on the Wabiskaw structure maps (Figures 27 & 28), in the western and southern portions of Township 95, Range 12W4 Meridian. Both maps show similar patterns between the Paleozoic and Wabiskaw structure maps (compare Figures 25 & 27). Other structural trends cross cut one another – for example there appears to be a linear low on the Wabiskaw structure map that meanders across the eastern part of the township that empties at the northeast corner into the Bitumont Basin. This is interpreted as a possible Clearwater incised valley fill that does not relate directly to underlying structure on the sub-Cretaceous unconformity (compare Figures 25 & 27). The Joslyn Creek lease area in Section 33 sits upon a paleotopographic high on the sub-Cretaceous unconformity that continues as a high through to the end of Wabiskaw time (compare Figures 26 & 28). There is a smaller scale ‘high-and-low’ irregular pattern on this ridge structure (compare Figures 26 & 28) that likely represents karst subsidence that influenced on deposition. This interpretation is substantiated by the seismic profiles submitted by Total in their final report that show a smaller scale paleotopographic low underneath the incident area.

The karst interpretation is supported by the core review (Figures 29 & 30, Table 4). The core proximal to the site had evidence of karst. Evidence included karst breccia, fractures in limestone, disruption of laminae, and the occurrence of marl, interpreted in the region as being a karst-lake deposit (AA/05-33-095-12W4, Figures 31 & 32). Examples of the core features showing karst development are: minor disruption of laminae (04/06-33-095-

12W4 Figure 34), karst brecciation and dissolution (AA/05-33, Figure 33, 05-33; AB/08-33, Figures 35 & 36; and AA/15-33, Figures 37 & 38); the occurrence of clay-filled fractures and mineralized faults in the limestone (AB/08-33, 13-33, and AA/16-33-95-12W4, Figures 39 to 41). A similar paleokarst interpretation was previously presented by Deer Creek Energy Ltd. in 2001 their application #1277348 to the Board. In this application the variability of depth to bedrock was interpreted to reflect an irregular karstic topography of paleohighs with intervening sinkholes along the sub-Cretaceous unconformity (Figures 42 & 43).

Modern karst features are common this area of northeastern Alberta (Figure 44). The Alberta government in its mapping of the environmentally significant areas of the province includes the following major karst features at the northern limit of the Athabasca oil sands (Townships 93 to 104, Ranges 1W4 to 12W4 M): La Salinas Springs, McClelland Lake Fen and Sinkholes, Eymundson Sinkholes, Craig and Tail, Richardson Tower Lakes, among others. The influences of modern karst affect aquifers, surface drainage, local subsidence, and development of modern faults in the area.

Structural influences due to regional tectonics

Pana et al. (2001) did a GIS compilation of structural elements in northern Alberta which identified five structural lineaments within or just north of the site (Figure 45). Deer Creek Energy Ltd. (2001) presented an interpreted lineament map for the township in its assessment of primary water supply possibilities in the lease area (Figure 46). Although these lineament maps are not definitive, they do suggest the possibility of faulting in the region that is controlled by regional tectonics, and not solely related to karst processes of dissolution and subsidence.

Deer Creek Energy Ltd. in their preliminary report to Alberta Environment concerning the Steam Release Incident submitted an annotated photograph of the area that was taken prior to the steam release incident (Figure 47). This photo of the area shows many circular features. They are interpreted as possible sinkholes with flowout features near the Ells River valley, and northeast of the incident area (Figure 48). Numerous smaller circular features are present in the area of the incident, and south of Joslyn Creek heavily pitted terrain exists (Figure 48). The sinkholes with flowout features northeast of the blowout are most likely karst. The heavily pitted terrain is either karst or a type of patterned ground due to permafrost or paleo-permafrost (at the end of the last ice age) (Halsey et al., 2001; Henderson, 1959). This part of northeastern Alberta lies at the southern limit of sporadic discontinuous permafrost and isolated permafrost.

A review of the surface auger-hole information submitted by Deer Creek Energy Ltd. was not definitive in determining whether these surficial features relate to karst, permafrost, paleo-permafrost, or a combination of these processes.

Geological Conclusions

- The overburden above the confining steam chamber seal cannot be relied upon to act as a caprock if the confining steam chamber seal is breached. There will be an uncontrolled loss of steam into the overburden and/or quenching of the steam chamber. The overburden is thin (29 – 47 m) in section 33, Twp 95 R12W4 M); sandy and silty; and may be locally fractured.

- The potential for upper thief zones above the Wabiskaw-McMurray deposit is significant within the area. Their existence is substantiated by the presence of gas within the Quaternary (glacial) succession and the buried bedrock channels an associated glacial-drift aquifers.

- The presence of such glacial channel fills are significant since glacial erosion could remove potential shale or clay barriers at the top of the oil sands and removed any competent cap rocks above the oil sands in areas where there is deep erosion into the underlying bedrock. Fills of these bedrock channels are commonly sandy glacial aquifers, providing potential potable water sources in the area. Any potential steam loss or lack of containment into potable aquifers may be a similar concern as was determined for the Cold Lake CSS operations. Present mapping and ground-water mapping is not sufficient to delineate the full extent of the bedrock-channels, glacial aquifers, and areas of very shallow top gas in the area

- Structural influences in the area related to karsting and/or regional tectonics are significant in the area and may reduce the confining ability of the seal above the exploited interval. Influences regarding permafrost are likely less critical.

List of References

Joslyn Creek Area (Total/Deer Creek Energy Reports)

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Table 1. Cores examined in this study for the J Joslyn Creek Area, Twp 95 & 96, R12W4 Meridian. Highlighted ones cover the zones of interest, and were reviewed in detailed.

UWI	Notes	Location of core
AA/12-05-095-12W4	Poor core, numerous missing sections and empty boxes; also too far away	CRC - Pulled but not logged or photographed
AA/01-08-095-12W4	Core not viewed, still in aluminum sleeves, not split.	CRC - Pulled but not logged or photographed
AA/16-11-095-12W4	Poor core, drilling mud between T21 & McM	CRC - Pulled but not logged or photographed
AA/12-12-095-12W4	Abrupt Wab T21, glauconitic and shale between T21 & McM	CRC - Examined but not photographed
AA/09-14-095-12W4	High gamma in McM, radioactive shale; core too deep for T21	CRC - Examined but not photographed
AB/12-15-095-12W4	High gamma in McM, radioactive shale; core too deep for T21	CRC - Examined but not photographed
AB/09-23-095-12W4	Poor core recovery; T21 lost.	CRC - Examined but not photographed
AA/02-28-095-12W4	Good; core too deep starts in McM, but folded marl & karst breccia in lst	CRC
AA/05-28-095-12W4	Good; core too deep starts in McM, but karst breccia in lst	CRC
AA/15-28-095-12W4	Good; core too deep starts in McM, but marl, karst breccia & fractures in lst	CRC
AA/14-29-095-12W4	T21 core missing, coal response on	CRC - Examined but

Tables

	logs confirmed in McM	not photographed
AA/04-30-095-12W4	Good; confidential core @ CRC; T21 lot ss in shale, silty sandy mud above T21	CRC
AA/04-31-095-12W4	Good; confidential core @ CRC; sandy +/- T21, silty T21, fractured, Wab B, C, McM	CRC
AA/07-31-095-12W4	Good; but core too deep, starts in McM B2 mudstone; coal response confirmed	CRC
AA/01-33-095-12W4	Good; but core too deep, starts in McM channel sand w/ karst, fractures in lst	CRC
AB/03-33-095-12W4	some labeled AD/ and not AB/; but checked license ; matches AB/03-33	Shipped from Total to CRC for core viewing
AA/05-33-095-12W4	Good	CRC
04/06-33-095-12W4	labeled AC/ but checked license and location; matches 04/06-33	Shipped from Total to CRC for core viewing
AB/08-33-095-12W4	Good	McLeay Geological Consultants
AB/09-33-095-12W4	Good	McLeay Geological Consultants
02/11-33-095-12W4	Labeled AD/ but checked license and location; matches 02/11-33; core out of order and mislabeled boxes; viewed but not logged or photographed	Shipped from Total to CRC for core viewing
03/11-33-095-12W4	labeled AD/ but checked license and location; matches 03/11-33;	Shipped from Total to CRC for core viewing

	camera did not work correctly (focus out), photos not useful	
AA/13-33-095-12W4	Good; core too deep starts in McM, but fractures in lst	CRC
AB/14-33-095-12W4	Good; core too deep starts in McM, no evidence of karst in lst	CRC
AA/15-33-095-12W4	Good	McLeay Geological Consultants
00/16-33-095-12W4	labeled AD/ but checked license and location; matches 00/16-33	Shipped from Total to CRC for core viewing
AA/16-33-095-12W4	Good; core too deep starts in McM, but open and clay fractures in limestone	McLeay Geological Consultants
AB/16-33-095-12W4	Good; but core too deep, starts in McM B2 mudstone above channel sand	McLeay Geological Consultants
AC/05-36-095-12W4	Good; sandy above and below T21	CRC
AA/10-36-095-12W4	Core too deep, not viewed.	CRC - Not viewed
AA/14-01-096-12W4	Good; fissile T21, orth fractured shale between T21 & McM; sand above T21	CRC
AA/14-02-096-12W4	Good; but core too deep, starts in McM channel sand w/ coal at top of sequence	CRC
AA/04-05-096-12W4	Only 2 boxes available at CRC, not viewed.	CRC - Not viewed
AB/02-06-096-12W4	Good; confidential core @ CRC; Photographed sand above and below T21	CRC
AA/07-07-096-12W4	Good; Just catches sandy doublet	CRC

Tables

	+/- T21	
AA/02-09-096-12W4	Good; Just catches sandy doublet +/- T21; not photographed, same as AA/07-07	CRC
AA/14-09-096-12W4	Good; regional markers, sandy +/- T21; silty to sandy mud above T21	CRC
AB/11-10-096-12W4	Core too deep, not viewed.	CRC - Not viewed
AB/11-12-096-12W4	Poor core, shaly above T21, sandy below T21	CRC - Examined but not photographed
AB/13-14-096-12W4	Core missing, not viewed	CRC - Missing over T21
AA/02-15-096-12W4	Core missing over T21, not viewed	CRC - Missing over T21
AA/08-16-096-12W4	Good; Thick Clw sh, T31, T21, Thick Wab Sh, Thin Wab SS; thin ss lam & burrow. Fissile T21 alternate with sandy intervals, including orthogonal fractures in T21 & Wabiskaw shale	CRC
AA/15-16-096-12W4	Good; ss above T31, mainly shaly siltst not sh (on logs sh); sands lam & burrow; sandy above T31, silt between T31-T21 & T21-McM	CRC
AA/05-21-096-12W4	Good; complete core to casing, Clw and Viking cycles; thin Wab C ss, sh; Fissile T21, sandy shales, orthogonal fracture in core	CRC
AA/02-22-096-12W4	Good; complete core to casing, Clw sandy silty mudst cycles; thin Wab C ss, sh; Core surface casing	CRC

	to McMurray, hydrocarbon stained; upper section; T21 not sealing?	
AA/12-22-096-12W4	Core surface casing to McMurray, hydrocarbon stained upper section; T21 not sealing. Calcite fractures above T21. Core surface casing to McMurray, excellent coverage; calcite fractures above T21	CRC

Tables

Table 2. Definition of selected picks and quality codes used in the database included on the CD (modified from Hein et al., 2006).

Pick	Type of Surface	Description	Quality Codes
T41	Transgressive	Top Clearwater B	Locally Fair, Not picked regionally
T31	Transgressive	Top Clearwater C	Good
T21	Transgressive	Top Wabiskaw (usually Wabiskaw A, may be lower in Wabiskaw locally, if Wabiskaw A or B absent)	Good to Very Good
Pz or Paleozoic	Unconformity	Top of Devonian Base of McMurray Fm	Variable, Excellent to Poor (in karst areas)

Tables

Table 3. Tops and markers on wire-line logs interpreted in this study for the Joslyn Creek area, Twp 95 & 96, R12W4 Meridian.

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA142609512W400	319.6	6.2		22	29.5		32	35.1	39.8	78.8
AA033509512W400	324.3	8.9		24.7	32.6		36.3	40.2	46.1	81.1
AB063509512W400	322.3	12.3		21.1	29.3	34	36.9	39.8	45.5	93.9
AB123509512W400	322.6	7.9		24.5	33.4	35.5	36.6	37.9	40	93.3
AA043509512W400	323.6	10.9		26.9	33.9	37.3	40.4	44.1	46.5	88.4
AA052609512W400	326	10.4		25	34.8		37.6	39.8	44.1	89.6
AB053509512W400	323.9	10.3		27.3	35.8	38.6	40	40.9	45.6	84.9
AA132609512W400	328.3	7		28	35.5		37.1	41	46.1	107.9
AA122609512W400	330.9	13.4		28.7	36.3		38.7	41.5	45.3	80.5
AA133509512W400	325.1	27.2		21.3	32.6	35.4	37.1	39.9	41.5	102.6
AA012709512W400	331	14		26.6	35.4		36.9	40.2	45.4	99.1
AA162709512W400	328.6	10.6		28.2	36.5	38.7	41.2	43.2	44.9	90.6
AA013409512W400	329.5			29.3	37.9	40.8	43.2	46.5	50.5	88.1
AA092709512W400	328.3	11		33.2	41.4		45.4	46.9	51.9	110.1
AA093409512W400	327.1	2.4		26	34.3	37.1	39.3	43.3	46.5	81.4
AA162209512W400	326.8	13.2		25.2	33.8		35.3	36.3	42.9	78.2
AB162709512W400	330.1	13.3		26.7	33.7	34.9	36	37.3	38.7	98.9
AB012709512W400	328.5	18.5		19.1	29.4		31	35.6	44	89.7
AA152709512W400	328.7	19.3		25.1	33.4	37.4	41.6	46	49.9	87.1
AA022709512W400	328.2	13.4		23.8	31.5		33.5	35.9	42	87
AA023409512W400	330	17.3		25.3	33.8	36.6	37.7	42.1	46.3	86.7
AA073409512W400	329.6	19.2		25.9	33.6	37.8	39.6	42.7	47.9	87.9
AA153409512W400	330.1	13.5		32.7	40.5	43.1	46.2	47.7	52	97.9
AA103409512W400	326.8	12.3		26.6	34.9	38	40.1	42.3	44.1	88.6
AA072709512W400	330	13.9		23.3	31.4		33.2	35.9	41.6	75.6
AA102709512W400	328	17.9		19	28.4		31.3	35	38.7	102.3
AB072709512W400	330.6	14.9		30.5	38.5		40.1	43.1	47.1	94.4
AB152709512W400	325.3	6.5		23.3	32.2	33.5	36	39.7	42.1	99.8
AA062209512W400	330.6	17.9		33.4	40.9		43.1	45.7	50.6	99.4
AA032209512W400	333.5	12.2		29.4	36.8		38.5	39.9	43.2	87.5
AA032709512W400	330.7	10.7		27.6	34.7		37.1	39.9	44.1	88.5
AA112209512W400	332.5	5		29.3	36.8		38.2	39.8	42.5	81.1
AA142209512W400	327.3	8.9		25.7	33.7		35.4	37.2	44.3	78
AA033409512W400	332.2	11		28.3	36.3	39.6	44.3	47.9	51.1	87
AA112709512W400	332.5	13		30.5	38.5		41.3	43.3	46.1	99.4
AA063409512W400	329.9	15.1		28.4	36.6	39.3	41.1	44.9	47.1	88.1
AA113409512W400	331.3		13.9	30.8	39.3	42.2	43.5	46.1	47.9	83.8
AA143409512W400	331.7	10.3	16.3	32.3	40.1	43.2	45.2	50.1	52.1	99
AB113409512W400	331.1	10.7		32	40.6	41.9	43.2	45.4	49.1	87.9
AA141509512W400	333.1	13.8		25.2	32.7		34.5	35.7	39.7	84.9
AA142709512W400	331.4	32.9		32.6	42.7		45.5	50.7	53.5	108.7
AB033409512W400	330.3	16.6		28	35.9	38.8	43.7	47.3	50.2	84.1
AB112209512W400	331.9	15.2		25.5	32.9		35.9	37.7	44.1	87.1
AA132209512W400	331.7	12.1		29.1	37.3		39	40.2	44.9	86.4
AA122709512W400	331.7	13.1	19.1	37.1	45.3		47.8	50.5	56.1	108.2
AA121509512W400	330.1	12.2		24	30.9		32.5	34.5	37.3	80.5
AB121509512W400	331.9	13.4		24.1	30.9		32.6	34.3	37.6	81.2
AA042709512W400	333	13.8	21.3	39.2	47		48.4	52.4	54.5	97.1

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA131509512W400	329.7	12		23.7	31.3		32.9	34.3	36.8	80.2
AA132709512W400	330.4	32.6		30.2	38.8		42.3	47.9	50.5	89.8
AB122209512W400	330.9	10.3		26.4	33.7		36.6	38.6	44.9	85.1
AA133409512W400	335.7	18.8		36.3	44	46.3	48.2	51	53.4	106.8
AA123409512W400	333.9	13.1		33.8	41.6	44.6	47	50.6	53.8	89.7
AA052209512W400	331.7	19.9		29.2	37.1		38.4	39.8	44.6	90.4
AA053409512W400	332.6	13.5		32.7	40.8	42.8	45.6	48.7	51.7	87.3
AA122209512W400	338	9.5		27.6	34.9		36.5	37.4	40.1	84.4
AA012109512W400	336.5	11.2	16.6	33.4	40.5		42.1	43.1	47.1	87.4
AA082809512W400	334.9	9.8	16	33.8	41	42.6	46	48.8	51.8	90
AA161609512W400	331.4	13		27.6	35		36.9	38.8	42	85.2
AA081609512W400	332.1	12.9		28.8	36.8		38.4	40.5	45.7	105.1
AA012809512W400	335.9	11		32.8	39.7	41.6	44	47.2	49.9	90.4
AA162109512W400	333.5	12.4	15.9	33.5	41		43.8	45.5	49.6	95.2
AB082109512W400	336.7	18.1		29.9	37.8		39.5	40.3	44.6	93.8
AA163309512W400	333.3	13.1		32.1	40.4	43.5	45.8	49.2	52.1	104.2
AA013309512W400	333.5	9.1	15.2	32.7	39.9	41.3	43.5	47.9	50.7	87.7
AA093309512W400	336.2	9.3		34	41.5	42.9	44.8	45.7	49.9	89.7
AA162809512W400	331.4	13.5	16.2	33.4	40.5	42.1	44.6	49.4	53.8	92
AA092809512W400	336.2	12.5	15.4	36.4	44.1	46.4	48.5	53.4	57.1	
AA091609512W400	334.4	9.1	12.8	29.8	37.2		39	40.8	51.6	100.9
AB083309512W400	332.7	13		29.4	37.4	38.4	40.9	43.7	45.4	86.1
00083309512W400	331.1	9		28.7	35.9	37.3	39.4	42.3	44.1	86.3
00013309512W400	331.9	11.3		29.8	37.7	38.7	41.2	43.8	45.3	87.1
AC013309512W400	331.6	30.5		34.4	41.9	43.4	46.2	47.5	50.5	94.1
AC163309512W400	334.8	12.6	19.3	35.2	42.7	46.6	48.1	52.1	54.8	108.1
02093309512W400	336.4	26.7		34.9	42	45.1	46.2	48	51.8	107
AB091609512W400	332.1	8.7		30.1	37.7		39.5	41.6	45.1	106.2
AB082809512W400	335.9	13.2	19.6	36.2	43.8	45.7	47.5	50.5	54.9	96.9
AC082109512W400	333.1	8.3		28.1	35.5		37.1	38.8	42.9	88.9
AB092809512W400	335.4	19		38.2	45.8	48.5	49.8	55.2	58.1	102.2
AB093309512W400	338	13.8	19.4	35.9	43.2	45	47	48.8	52.5	102.6
AA092109512W400	336.3	13.8		32.6	40.1		42.1	43	46.2	89.6
00093309512W400	336.9	26.8		35.4	42.8	44.7	46.8	50.1	52	101.8
AD092809512W400	335.2	14.9	20	37	44.3	47.1	48.6	54.5	57.3	120.4
AA083309512W400	331.6	14.5		28.2	35.5	37.3	38.9	43.1	44.6	85.9
AB162809512W400	335.5	20.2		33.8	40.5	42.6	44.4	46.3	49.6	94.7
06013309512W400	335.7	27.1		34.6	41.7	43.1	46.3	48.4	52.4	94.7
AA082109512W400	333.3	20.2		31.3	38.5		40.5	42.1	46.1	98
AB163309512W400	341	14.3	23	39.1	46.6	51.3	53	56.2	59.5	110.6
AB073309512W400	339.9	50.4			45.4					96.6
00152809512W400	337.7	27		35.1	43.1	44.5	46.4	52	54.4	115.9
AA102809512W400	337	14.6	24.5	41.8	49	51.3	54.3	58.9	61.7	117.1
AA022109512W400	337.1	18.8		34.5	41.7		43.2	44.8	49.6	103.5
AA101609512W400	335.7	13	19.1	36.5	43.5		45	47.6	52.4	105.4
AA152109512W400	338.3	19		38.5	46.2		48.4	49.6	54.1	100.1
AA151609512W400	334.5	12.9	17	34.5	41.9		43.4	44.8	50.2	99.1
AB023309512W400	338	13.1		33.6	40.7	42.7	45	47.8	49.1	94.9
AA022809512W400	339	19.1		36.2	43.7	46.5	48.5	52.9	55.4	94.3
AA152809512W400	338.9	19.6		35.8	43.4	45.3	46.6	52.3	57.9	115.5
00023309512W400	340.6	19		35.1	43.2	44.6	46.6	49.4	51.6	103.2

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA102109512W400	336.8	14.3		33.5	40.9		42.5	43.8	48.2	102
AA021609512W400	336.5	14.1	19	36.3	42.7		44.5	46.6	50.7	86.4
03103309512W400	337	18.3		36.7	44.5	45.7	47.9	49.3	53.1	106.3
AB022809512W400	338.1	27.4		36.9	44.5	47.4	52	57.6	61.2	92.3
AA150909512W400	340.1	13.7	18.2	35.2	42.6		44.3	46.5	50	94.2
02103309512W400	335.7	26.9		34	41.2	43.3	44.7	47.1	50.5	99.7
02153309512W400	340.6	18.2	28.2	44.7	53.3	56.1	57.5	61.1	64.2	118.1
03023309512W400	340.4	24.5		36.6	44.2	45.6	48	49.3	52.3	98.2
AA153309512W400	340.4	34.1		41.2	48.6	52	53.7	57.1	60.4	112.6
AB072109512W400	337.6	12.9	18.7	36.2	42.5		44.8	46.3	50.4	106.1
02073309512W400	336.4	26.8		33.9	40.9	42.3	45.5	46.8	49.9	94.5
AB102109512W400	337.9	12.1	19.1	36	43.8		45.3	46.5	50.6	104.1
AA103309512W400	337	6.4	18.2	35.2	42.6	43.5	46.2	47.9	51.6	98.2
00102809512W400	339.5	21.3		41.1	48.3	51.6	55	58.5	62.1	125.5
AB152809512W400	339.5	26.8		35	42.9	45.1	46.8	52	54.6	117.4
00153309512W400	340.7	17.9	28	44.7	53	54.7	56.7	58	62.6	119.1
11023309512W400	338.2	27		34.8	41.9	43.8	45.9	47.6	50.5	97.8
02023309512W400	341	21		38.1	45.1	47.1	49.2	50.9	54	96.8
10023309512W400	337.6	26.3		34.9	42	44.3	45.9	47.7	50.9	98.2
AA062109512W400	337.4	12.9	19.4	36.4	42.6		44.9	46.6	49.7	106.2
AA141609512W400	339.3	14.1	22.2	40	48.5		49.9	52.4	56.8	94.8
02063309512W400	334.6	24		31.6	38.8	40.6	42.9	46.8	49.6	91
AA032109512W400	342.6	13.2	26.2	44.1	52.2		53.3	56	59.5	109.9
AA142109512W400	340.1	13.6	22.3	40	47.5		48.9	49.9	54.1	105
AA062809512W400	338.7	20.4	26.5	44.3	50.1	53.3	54.6		57.6	93.2
AA033309512W400	339.5	12.4		36.1	43.8	45	46.1	48.1	51.9	98.9
AA112109512W400	338.3	8.6	17	32.5	40.2		41.6	42.9	47.3	92
AA143309512W400	342	4.7	28.3	45.7	52.1	56	58	61.7	64.6	
AA112809512W400	340.5	9.7	33	51.5	59.7	62.4	64.3	72.4	77.5	119.8
03063309512W400	335.1	33.4		30	40.2	41.8	44.1	47.4	48.8	91.6
AA113309512W400	335.1	2.9	16.8	33.2	40.8	42.3	44.1	46.9	49.1	96.4
AB113309512W400	342.2	6.4	24.9	41.6	48.3	49.9	52	54.6	59.5	111.5
AA111609512W400	338	9	25.1	43.4	50.2		52.2	54.7	64.3	83.9
AB143309512W400	341.9	6.5	27.3	43.3	51.5	54.5	55.3	58.6	61.6	
AA140909512W400	336.5	19.6		35.1	42.6		43.7	46	49.3	107.9
AA142809512W400	339.6	19.6		38	45.8	47.3	50	55.3	60.7	114.8
AA032809512W400	341.1	12.3		36.9	43.3	45.8	48	49.6	51.2	94.9
AB111609512W400	340	12.4	19.6	37.1	44.3		45.5	47.4	51.8	94.5
AC142109512W400	342.2	12.1	23.4	40.6	47.3		49	50.3	54.6	103.8
AB032809512W400	345	13.8	23.5	40.2	47.3	49.2	50.2	53.2	55.2	101.5
AB062109512W400	337.6	11.8		33.9	41		42.4	44	47.4	103.9
AB112109512W400	341.2	12	20.4	37.2	43.4		46.1	47.1	51.3	109
AB142109512W400	345	19.4	23.5	39.2	45.9		47.9	49.2	54.3	105.1
AA063309512W400	337.6	20.4		37	44.6	46	50	52.7	55.6	107.3
AB032109512W400	347.7	14.9	25.1	41.9	49.3		50.8	53.4	56.4	109.8
AC113309512W400	339.9	8.2	22.4	38.3	46.3	47.5	49.9	52	57.7	113.7
AB033309512W400	336.7	19.5		39.3	46.3	48	50.7	52.1	56.3	102.8
AD112809512W400	342.6	18.2	30.5	47.2	54.7	56.9	60.2	64.7	69.1	125.1
AC143309512W400	342.3	13.8	28.2	44.8	52.3	56.2	57.6	58.8	60.5	120.8
AB053309512W400	337.6	15.8	22	38.8	46	47	48.4	50.4	54.1	110.4
AB123309512W400	342	15.2	24.7	41.6	48.8	50.4	54.6	57.2	62	116.6

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA042809512W400	343.2	21		37	44.4	47.3	49.3	50.9	54.6	100.2
AA053309512W400	338.1	19.1		37.9	45.1	47.1	49.1	52.3	59.1	110.4
AA133309512W400	341.5	20.5	27.9		51.9	53.7	57.2	60.9	64.5	114.6
AA131609512W400	342.9	32		38.3	45.1		47	49.2	53.5	96.1
AA132109512W400	346	18.6	23.3	39.6	46.4		47.8	49.5	53.3	102.2
AA052809512W400	343	18.9		39.3	46.6	47.9	49	50.2	52.5	94.9
AA132809512W400	341.5	19	27.4	46	54	55.5	58.1	62.2	69.2	106.5
AA130909512W400	339.2	8.8	22.9	38.7	45.6		47.4	50.4	52.1	114.7
AA052109512W400	343.5	12	23.8	39.9	47.1		48.7	50.5	54	98.6
AA122109512W400	338.4	12.6	18.6	35.6	42.1		43.9	45.4	49.1	101.2
AB042109512W400	341.6	11.6	24.5	41.2	48.4		50.1	52	56	110.9
AC132109512W400	343	11.2	22.2	39	46		47.6	48.9	54	101.8
AA042109512W400	344.8	19.4	24.2	40.3	47.2		49.3	51.5	55.7	101.7
AB052809512W400	341.2	13.1	25.5	42.9	50.4	52.1	53.3	55.8	57.3	99.6
AA041609512W400	341	13.3	26	43.2	50		51.8	54.9	57.9	114.1
AA123309512W400	339	23	28.2	45.5	53	54.1	59.9	63	68	118.8
AA050909512W400	340.6	24.7	27.1	43.9	50.7		52.1	54.8	56.8	104.3
AB133309512W400	328.6	16.2	29.9	46.6	54	55.5	57.9	59.9	62.2	122
AC122109512W400	338.7	6.6	21.1	38	45		46.9	48.5	55.1	120.9
AB132109512W400	342.3	12.9	20.1	36.7	43.5		45.2	46.3	48.8	97.7
AA011709512W400	344.1	9.4	32.3	49.4	56.5		58.4	61	64.1	134
AA012909512W400	338.3	12.6	19.8	36	43.6	46.5	50.2	52.9	54.8	102
AA082009512W400	340.9	13.3	25.6	42.6	50		51.2	52.7	58.2	103.5
AA091709512W400	343.5	20.1	26.8	44	50.2		52.2	54.3	57.7	117.9
AB163209512W400	344.5	16.5	31	48.3	55.6	58.1	59.9	63.6	65.5	124.1
AA012009512W400	347.8	15.7	26.4	43.3	50.7		52.5	54.6	60.5	127.4
AA082909512W400	344.8	20.2	25.9	42.8	49.4	51	52.3	54	58.2	113.2
AA081709512W400	342.7	27.1		47.5	54.3		56.1	58.6	62.4	121.1
AB012909512W400	340	16.1	21.3	38	45.2	47.6	50.3	53.1	54.9	102.3
AA092009512W400	341.7	8	23.6		45.4		46.9	48.2	53.6	121.8
AB092009512W400	343.5	16	24.6	40.3	47.3		49	50.4	56.2	101.3
AA092909512W400	345.3	11.9	30.5	47.3	54.3	56	57.3	59.5	61.9	110.3
AA013209512W400	340.5	12.3	26.3	42.7	49.8	52.2	54.3	57	62.6	108.9
AA093209512W400	341.4		27	44.5	52.7	54.5	57.2	61.3	64.6	120
AA010809512W400	342	9.6	29.3	46.5	52.4		53.9	56.8	60.8	108.2
AB093209512W400	343.7	20.2	30.5	47.2	54.4	56.1	58.9	62.2	63.5	122.6
AA163209512W400	348.1	12.3	31.9	48.9	56.5	57.9	60	63.5	65	112.7
AD163209512W400	345.2	12.5	32.2	49.2	55.6	56.9	59.4	63.4	64.8	119.2
AB012009512W400	343.2	11.4	25.2	42.2	49		50.7	52.9	56.8	111.8
AC163209512W400	347.1	15.3	33.1	50	57	58.8	61.2	64.1	65.6	115.9
AC093209512W400	340.5	17.3	29.5	47.6	54.9	58.2	63	69.7	72.6	110.1
AA162009512W400	337.9	6	22.7	39.5	46.7		48.4	52.8	55	122
AA022009512W400	342	12.1	27.3	43.8	51		52.4	54.7	57.9	106
AA072009512W400	343.2	19	26.2	43.2	49.5		51	53.2	57.7	112.3
AA152009512W400	343.6	18.8	25.2	41.2	48.5		49.8	51.5	54.9	103.8
AA072909512W400	342.5	19	26.6	43.5	51	52.5	53.9	55.2	58.5	115.1
AA152909512W400	349.9	9.7	35	52	59.4	60.4	61.7	63.7	65.5	113.1
AA023209512W400	346.2	33		49	56.3	58.1	59.8	62.1	67.5	127.9
AA070809512W400	343.5	25.9		46.6	53.4		55.2	58	61	110.2
AA071709512W400	341.7	32.2		46.3	52.7		54.5	57.3	61.2	108
AA021709512W400	340.3	30.9		48.5	55.2		56.6	59.4	63.3	157.3

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA022909512W400	342.9	20.2	28.3	45.5	51.9	55.4	59.1	65.7	67.8	124.6
AA151709512W400	344.1	43.2		46.2	53		54.2	56.5	62.4	111.8
AB072909512W400	345.6	12	30.3	47.2	53.5	55.8	57	64.5	66.5	113.2
AA102909512W400	345.7	19.8	31.5	49	56.2	57.9	59	61.3	66.6	108.5
AB072009512W400	349.7	9.8	30.9	46.5	53.9		55.2	57.4	61.3	113.8
AB152009512W400	343.3	13.3	28.1	45.7	52.8		54.7	56.3	58.5	148
AB022009512W400	349.3	17.8	34	51	56.6		58	60.5	63.2	118.3
AA102009512W400	342.8	12.7	28.5	45.5	52.3		53.7	55.5	62.1	113.5
AB102909512W400	342.9	9	29.3	45.9	52.1	54	55.1	57.2	61.8	107.4
AB113209512W400	342.7	13.4	29	46	53.1	55.1	57	60.4	65.9	112.2
AA062009512W400	347.8	12	33.8	50.5	57.5		58.8	61.3	64.5	136.2
AA031709512W400	344.3	26	31.2	48.1	54.8		56.5	59.1	63	109.9
AB142909512W400	354.9	30.9	36.4	52.2	60	61.1	62.2	64.2	66.9	120.1
AA032909512W400	342.6	9.8	30.4	46.1	53.3	54.9	56.4	61.1	67.2	135.8
AA113209512W400	345.6	10.5	31.6	46.9	54.4	56.2	58.9	63.1	78.7	113.1
AA112009512W400	342.6	5.6	25.1	41.7	48.1		49.4	51.6	63	99
AA111709512W400	343.5	8	28.8	45.7	52.4		56.1	60	62.8	106.4
AA112909512W400	343.5	6.8	27.1	42.6	49.4	51.4	52.5	55	56.6	105.6
AA033209512W400	349	14.8	36.4	52.4	59.8	61.7	64.5	66.9	69.7	118.8
AA032009512W400	346	18.7	34.3	51.3	58.8		59.8	62.2	66.2	120.8
AA142009512W400	348.1	18.8	33.3	49.8	56.9		58.1	59.9	62.6	
AA140509512W400	348.2	17	28.4	45	51.9		53.4	56.5	59.9	101.8
AA062909512W400	347.2	13.3	35.2	52.1	58.7	59.9	61.5	63.8	65.3	131.1
AA142909512W400	349	13.7	37.1	53.2	59.7	63.1	65.5	67.9	72.1	133.1
AA061709512W400	352.8	34.3		50	56.3		58	61.3	65.1	126
AA143209512W400	348.8	12.3	35.3	51.4	58.6	59.9	62.1	63.8	65	119.8
AB111709512W400	343.1		26.1	42.9	49.1		52	54.5	58.1	113.4
AB142009512W400	318.6	12.9	34	51.6	57.8	64.7	59.3	61.4		144.8
AB032909512W400	345.9	16.2	32.4	49.1	56.7	58.1	59.7	61.9	63.7	130.1
AD032009512W400	350	16.8	39.5	56.9	64.1		64.9	67.6	70.8	138.7
02142009512W400	348	33.9	39.6	51.9	59		60.2	62.3	69.3	147.7
AB062909512W400	345.6	13	34.4	50.9	58.6	60.4	61.9	67.2	70.8	140.7
AC142909512W400	347.6	16	35	51.2	59	60.3	61.6	63.6	65.7	134.3
AB033209512W400	345.8	15.1	39.9	57.9	64.1	67.9	69.8	71.6	74.2	122.1
00032909512W400	351	13.3	38.8	55.4	62.7	64.2			66.1	151.2
AB032009512W400	347.5	12.2	32.5	49.1	56		57.3	59.7	63.5	133.8
AB062009512W400	343.7	12.4	29.5	46.3	53.4		54.9	56.8	60	120.7
AA122009512W400	342.8	13	27.9	44.4	51.6		52.8	55	66.4	130.6
AA053209512W400	347.6	19	35.8	52	59	60.4	62.7	64.3	71.5	122.4
AA052009512W400	347.4	18.8	30.2	46.9	53.6		54.8	57.3	59.8	117.4
AA131709512W400	345.9	17.9	32	49	55.7		58.1	59.9	64.3	107
AA042909512W400	347.4	20.5	37	54.3	61.4	62.8	64.2	67.2	68.1	156.8
AB133209512W400	351.8	12	39.3	55.5	62.6	64	66.2	69.8	74.7	135.1
AA132009512W400	351.8	19.1	37	52.5	59.6		61.1	63.2	69.9	134.3
AA052909512W400	354.2	19	40.8	57.5	64.2	65.5	67	71.3	72.7	
AA132909512W400	346.9	19.2	31	47.7	54.8	56.3	57.7	59	63.1	132
AA051709512W400	354.7	31		51.1	57.6		59	60.8	66.9	108.4
AA050809512W400	351.7	13	31.9	48.3	55.2		56.6	60.1	66.6	116.8
AA122909512W400	346.6	20.1	33.8	50	57.2	59	62	63.1	65	135.1
AA043209512W400	349.3	13	39.1	55.7	62.3	64.1	65.3	67.6	70.9	140.4
AA120809512W400	347.3	20	34.1	51.1	58.2		59.2	62.5	65.9	119.5

Tables

UWI	**KB**	**Base Casing**	**T31**	**T21**	**A1**	**A2**	**B1**	**B2**	**Chnl**	**DEV**
AA133209512W400	355.2	13.5	41.8	58	65.3	66.6	68.3	72.3	78.6	125.2
AA121709512W400	351.3	20	36.6	54	59.7		61.6	64.5	68.4	136.3
00052909512W400	353.1	20.4	34.6	50.3	57.2	58.5	60.3	65.1	68.6	131.9
AB123209512W400	354.5	15.4	39.7	55.9	63	65.2	67.6	69.9	75.5	144.5
AB122909512W400	348.7	19.7	33	49	56.4	57.9	59.1	61.3	63.8	113.8
AB132009512W400	349	36.1		55.3	62.3		63.9	65.9	72	127.3
AB132909512W400	348.5	46.2		48.9	56.2	57.5	58.7	61.3	63.1	135.8
AB041709512W400	343.1	12.1	32.9	50.3	57.4		58.3	61.5	65.5	115.3
AA161909512W400	350.5	18.7	40.8	56.7	63.2		64.7	66.4	71.6	131.6
AA013109512W400	347.4	12.4	32.7	49.8	56	57.8	59	61.1	62.8	125.8
AA083009512W400	350.2	16.8	36.2		59.8	61.2	63	65.3	66.7	138
AA161809512W400	348.9	10	36.9	52.5	59.7		61.4	63.5	66.1	122
AA083109512W400	347.7	8.8	35.6	53	59.2	60.9	62.7	64.2	66.2	122.6
AA093109512W400	351.7	8.3	34.9	50.3	57.4	58.7	60.1	62.2	66.2	126.6
AA011809512W400	351.3	15.4	39.6	56.5	63.3		64.9	68.4	73	
AA023109512W400	353.8	12.2	39.7	56.4	63.1	64.2	66.3	68.5	70.5	144
AA153109512W400	355.6	7.4	46.9	63.9	71.3	73.2	75.5	78.2	81.3	152.7
AA073109512W400	350.2	6.4	37.5	53.6	61	62.2	63.5	65.6	68.6	131.8
AA151909512W400	352.3	17.9	41.9	58.5	65.6		66.8	69.1	73.9	128.6
AA151809512W400	349.7	13.3	38	53.4	59		60.4	63.6	66.3	128
AA103009512W400	356.1	21.3	40	55.6	62.4	63.8	65.8	67.9	69.9	123.8
AA023009512W400	353.1	18.3	47.1	64.5	71.6	72.8	73.9	75.2	79	139.4
AB071809512W400	349.2	12.4	39.6	56.8	63.1		65.9	67.7	71.9	116.8
AA153009512W400	351.5	12.5	33.8	49.9	57.2	58.3	60.2	62.7	65.3	124.9
AA071909512W400	351.2	18.4	38.2	54.4	61.3		62.2	64.6	68.1	123.9
00071809512W400	353.1	13.8	45.3	61.1	67.6		68.6	71.5	76.5	141.1
AA021809512W400	353	13.4	39.5	55.5	61.6		63.8	66.9	71.5	118.3
AA063009512W400	353.2	13.4	41.5	57	64.1	65.4	67.5	69.1	71.7	124.7
AA110609512W400	359.5	21.2	37.3	53.6	59.7		60.7	62.1	64.5	110.4
AA033109512W400	358.2	7.6	46.3	63	69.9	71	72.9	75.9	77.6	142
AA113009512W400	355.3	11.5	41.5	57.9	63.9	65.4	67	69.5	72.3	120.9
AA143009512W400	359.9	11.6	41.6	58	65.2	66.7	68.6	70.6	74.6	130.1
AA031809512W400	349.9	18.8	45.1	62.4	68.9		70.8	73.2	78.3	128.9
AA141909512W400	353.3	10.5	41.4	57.2	64.2		65.4	67.5	70.8	123.1
AA141809512W400	350.5	12.2	39.5	56.1	62.7		64	66.8	70.3	129.2
AA061809512W400	350.7	12	46.9	63	69.9		71.4	74.3	78.6	142.7
AA113109512W400	365.8	12.6	52.6	69	75.8	77.4	79.1	83.7	86.1	142.5
AA053009512W400	358.5	13.9	48.7	66.1	73.1	73.9	76.2	78	94.7	157.7
AA133009512W400	360.2	5.4	42.9	59.7	66.2	67.6	69.8	71.7	76.1	137.2
AA121809512W400	353.7	12.2	45.7	62.7	69.1		70.6	73.9	77.5	156.8
AC083609512W400	313.5	10		16.4	25.5	27.3	30.4	33.5	36.5	116.2
AE093609512W400	313	6.8		14.5	22.9	24	27	29.4	31.2	103.8
AD093609512W400	313.1	6.8		18	26.1	28.5	31.6	32.7	35.5	118.7
AD163609512W400	312.9	7		14.2	22.2	23.4	25	26.2	27.7	104.9
AA163609512W400	313.4	13.8		13	22.3	24.5	27	32.8	36.2	102.4
AA093609512W400	314.9	8.5		15.5	23.4	25.1	26.6	31.8	34.7	105
AA083609512W400	314.4	12		13.4	25.5	27.6	29.5	31	33.5	100.2
AA162509512W400	324.5	6.3		10.1	19.1		21.5	23.4	27.3	75.1
AB163609512W400	313.5	11.5		13.7	22	24.7	27.1	28.2	30.1	114.1
AC163609512W400	313.6	7.9		15.9	24.9	26.3	28.5	30.2	34.7	121.8
AB093609512W400	313.4	6.2		16.4	24.9	26.8	28.8	31.8	34.1	154.1

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AC093609512W400	313.4	5.9		15.7	24.6	26.2	29.3	32.2	33.7	125.1
AB083609512W400	313.3	7.2		14	22.8	24.7	26.8	30.1	32	108.8
00153609512W400	315.6	13.7		21	27.1	30.2	32	34	37.3	103.8
AA023609512W400	300.5	11		2.1	19.3	22.6	23.6	26.5	28.4	64.5
AA073609512W400	312.9	6.7		13.7	20.7	22.9	24.3	27.8	32.1	100
AA103609512W400	314.5	24.2		30.4	40.1	42.6	46.3	48.2	52.4	112.1
02143609512W400	315	17.6		22.3	37.4	39.3	41.1	42.5	45.5	139.4
AD143609512W400	315.8	3.8		14.9	23.3	24.7	26	27.7	31.3	
00143609512W400	316.4	39.1		42.8	49.4	52.2	55.2	58.8	61.1	135
00113609512W400	314.9	26.6		28.5	42	44.6	46	48.2	51.8	127.1
AA033609512W400	317	6.8		17.7	26.2	28.1	29.9	34.2	38.6	91.3
AA113609512W400	317	7.1		22.7	32	34.9	37.9	40.2	42.2	127.3
AA142509512W400	320.4	19.5		30.7	39.9		41.4	43.5	50.8	95.6
AB063609512W400	314.7	6.9		19.2	28.2	32.3	35.9	38	40.4	
AA143609512W400	317.3	2.6		15.1	23.9	25.5	28.5	31.2	32	147.1
AB053609512W400	317.2	6.8		16.8	25.4	29.2	31	32.5	35.3	79
AB123609512W400	317.4	8.8		22.4	31	32.6	35.3	38	40.8	102.7
AA132509512W400	318.3	5.6		18.7	27.2		29.3	31.3	35.8	77
AA133609512W400	318.2	12.5		19.5	27.7	29.7	31.4	36.5	39.2	121.8
AA163509512W400	324.3	9		21.2	28.7	33	34.9	37	39.2	85.2
AA013509512W400	322.5	8.8		18.2	27.7	29.1	31.4	32.7	35	81.9
AA093509512W400	322.2	12.4		21.6	31.2	40.8	46	49.6	51.8	104
AB103509512W400	321	7.8		21.5	30.1	32.2	34.6	37.9	40.3	112.5
AA152609512W400	323.1	13.4		21.4	29.1		32.7	34.2	36.3	78.4
AA073509512W400	322.5	13.4		21.8	30.6	33.3	35.3	39.3	43.2	81
AA153509512W400	323.7	20.7		21.6	30.9	32.6	34.4	38.4	40.2	110.5
AA113509512W400	322.8	8.6		22.3	30.1	32.7	34.2	36	39.9	100.4
AA091309512W400	317.9	6.8	6.3	12.3	18.4		20.1	21.8	25.1	85.4
AB012409512W400	318.7	5.7		4.3	17.1		19.6	21.5	26.4	70.2
AA011209512W400	321.6	7.5		19.5	26.6		27.7	30.2	32.9	65.3
AA161309512W400	316.6	6.2		5.7	14.4		16.5	20.2	29.9	72
AA082509512W400	315.1	7.6		11.3	21.2		22.1	25.2	29.5	70.1
AA082409512W400	316.2	7.5			19.3		23.6	26.3	28.2	75.9
AA081209512W400	322.5	15.5		16.4	22.7		25	26.4	28.7	69.2
AA092409512W400	317.9	6.5		11	19.7		21.6	24.6	29.3	84
AA092509512W400	316.7	4.6		9.6	19		21.6	25.2	29.1	63.8
AB012509512W400	317.4	12.7		17.5	24.9		28.4	31.2	35.9	85.5
AA012409512W400	318.8	7.9		8.9	18.2		21.3	24.9	27.7	71.3
AA021209512W400	323.9	13.5		21.4	24.6		26.1	27.7	30.2	78
AA101309512W400	314	6.1		7.3	14.3		16.1	17.8	20.4	74.7
AA072409512W400	317	5.3		14.9	19		23.2	27.7	30.1	72.3
AA102409512W400	317.9	7.9		2.9	16.5		22.4	26.4	28.5	81.4
AA102509512W400	317.5	8.4		12.5	20.5		21.8	24.6	28.7	66.3
AA152409512W400	320	8.2			18.4		19.9	21.8	26.1	69.6
AA151309512W400	317.8	7.5		6.3	14.6		16.3	22.9	28.7	71.4
AA071309512W400	314.9	3.3		12.3	20.3		21.1	23.2	27.6	79.6
AA022409512W400	318.7	8.8		12.6	17.4		19.3	21.2	24.6	80.7
AA071209512W400	324.2	20.9		24.3	30.3		31.3	33.6	37.4	77.1
AA112509512W400	319.1	2.2		14	23.3		26.9	28.9	31.2	86.4
AB032509512W400	321.7	18.6		13.8	26.2		29.6	34	36.9	75
AA112409512W400	321.6	9.3		12.6	20.7		22.1	24.4	30.3	77.4

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AB111309512W400	322.3	7.2		16.3	23.3		25.1	26.8	29.1	89
AA111309512W400	321.6	13.4		15.8	22.8		24.4	26.6	31	89.7
AA062409512W400	318.9	8.9		13.2	20.4		22	23.4	25.8	74.3
AA062509512W400	318.9	7		14	23.2		25.3	27.5	30.9	76.6
AB112409512W400	320.1	5.4		12	19.7		22.7	26	29	76.1
AA061209512W400	323.5	5.1		21.5	28.9	38	30.3	33.1		81
AA061309512W400	319.9	6		14.9	23.2		25.3	29.5	36.2	82.4
AB141309512W400	319.9	7.3		15.7	23.7		26.4	32.5	35.5	91.2
AA032409512W400	320.5	13.8		18.2	21.6		23.7	27.1	29.9	84
AB111209512W400	321.2	6.4		17.7	25.5		26.7	29.1	32.3	83
AA111209512W400	321.7	8.3		22.1	29.9		31.2	33.1	36.5	92
AA141309512W400	325.1	8.5		18.5	26.2		28.8	32.8	36.4	86.5
AA042409512W400	321.1	7.3		17.2	25.9		27.7	29	32.7	89.4
AA042509512W400	321.4	12.2		22.5	31.6		37	40.1	42.3	76.6
AA052509512W400	321	6.5		19.2	27.6		29.9	31.7	34.5	87.7
AA041209512W400	326.6	13.4		16.6	24.1		25.3	27.7	30.4	83.7
AB051209512W400	324.2	8.5		17.9	24.8		26.1	28.8	30.7	87.5
AA052409512W400	322.2	11.3		13.3	23.3		25.6	27.9	29.3	86.1
AA132409512W400	323.6	13.4		15.7	25.1		26.6	27.7	36	73.1
AA120109512W400	327.9	7.2		23	31		32	34.9	38.7	87.6
AA131209512W400	322.2	9.3		25.5	32.7		33.9	36.3	40.1	88.3
AB131309512W400	321.8	6		20.3	28.6		29.7	31.3	36.1	83.8
AA122509512W400	318.6	8.7		19.9	30.1		31.6	34	38.9	79.8
AA051209512W400	331.3	14		21.2	24.4		25.5	28.3	31.9	94.5
AB052409512W400	322.7	8.7		18.3	27		27.9	29.1	31.3	94.6
AA162609512W400	320.8	12.9		21.6	30.4		31.1	32	34.1	86.3
AA012309512W400	325.8	11.2		24.3	31.3		33	34.6	38	86.6
AA012609512W400	324.6	10.7		22.5	30.4		32.1	37.2	42	87.8
AB082609512W400	322	10.2		20.1	29		31.4	34.2	41.5	81.6
AA092309512W400	325.2	10.3		16.4	29.2		30.7	32.9	35.2	79.2
AA082609512W400	323.7	12.4		22.1	31.3		33.8	40.4	49.1	92
AB012309512W400	328.3	11.2		22.7	30.9		32.5		36.5	85.5
AB092309512W400	326.7	11.6		18.2	27.1		29.3	30.4	31.6	76.9
AA161109512W400	325.7	6.3		22.2	30.2		31.1	33.3	37	84.3
AA011109512W400	328.9	3.7		29.4	35.7		36.6	40.5	45.4	102.8
AA011409512W400	327.4	4.6		18.7	26.4		30	33.4	37.1	71.5
AA082309512W400	328.9	13		20.7	29.4		31.7	37.3	40.2	96.1
AA162309512W400	330	13.4		21.8	30.5		32.3	33.7	36.1	82.5
AB012609512W400	324.5	13.5		26.4	34.3		36	40	43.5	90.4
AA022609512W400	323.8	6.4		29.3	36.9		39.5	42.3	45.3	92.8
AB152609512W400	321	10.3		23.4	31.5		33.9	36.3	41.6	93.8
AA102309512W400	323.6	7.4		19.9	28		29.6	30.7	31.9	81.9
AB101409512W400	323.3	7.4		19.1	27		27.7	30.1	34	77.7
AB071109512W400	323.9	6.2		21.3	28.9		30.1	32.2	34.6	85.1
AA151109512W400	324.8	8.3		15.7	22.9		23.7	26.5	29.8	77.7
AA072309512W400	324.1	6.3		22.8	30.8		32.7	35	36.6	78
AA102609512W400	321.7	9.3		22.6	30.5		31.4	34.6	42	77.1
AB151409512W400	324.2	6.8		22.7	30.9		33.9	35.4	38.6	80.2
AA071109512W400	328.4	13.4		18.7	26.3		27.6	30.4	33.4	77.3
AA031409512W400	323.6	15.4		24.1	31.2		32.7	34.3	38.1	96
AB062609512W400	323.4	11.8		25.3	32.9		35.1	40.1	43.9	89.9

Tables

UWI	KB	Base Casing	T31	T21	A1	A2	B1	B2	Chnl	DEV
AA032609512W400	327.1	12		39.2	49		50.3	51.7	56.8	119.6
AA031109512W400	327.9	8.2		21.4	29.1		32.3	35.6	39.9	81.2
AA062609512W400	324.6	9.3		21.9	30.3		32.4	36.3	40.5	85.6
AA112309512W400	325.5	10.5		24.5	33.5		35.2	36.9	40	87.7
00032609512W400	327.5	10.3	21.2	40	49.3		51.7	53.5	57	111.2
AA141409512W400	326.5	12.7		23	30.6		33.4	37.4	42.6	90.5
AA111109512W400	326	7.6		20.8	27.8		29.1	31.5	34.5	88.8
AA111409512W400	326.6	13		26	33.3		36.6	40.5	42.3	96.3
AA141109512W400	326.1	15.1		17.9	24.8		28.2	30.8	31.8	81.8
AA142309512W400	326.2	14.1		29.6	36.8		39.3	41.6	44.9	88.8
AC112309512W400	325.9	11.7		28.3	35.9		38.4	40.2	42.2	81.9
AA051109512W400	325.8	20.2		19.1	26.8		29.1	31.3	33.9	90.2
AA051409512W400	335.5	20.5		21.3	30.3		31.2	33.8	38.7	88.2
AA122309512W400	326	10.7		27.6	34.9		37.3	39.5	41	84.9
AA042609512W400	324.7	17		28.1	37		38.9	40.2	44.4	95.1
AA121109512W400	326.8	22.7		20.1	27.7		28.8	31.1	34.7	77
AA131409512W400	327.4	13.5		24.9	32.1		34.9	39.1	44	81.9
AA041409512W400	327.3	16.2		21.5	28.1		29.3	32.6	34.8	97.2
AB121409512W400	328.3	13.4		24.6	32.1		33.3	36.3	43.7	89.3
AA041109512W400	331	8		17.7	25.7		27.4	29.7	32.9	88.4
AA132309512W400	328	12.9		25.1	32.6		34.3	38	41.5	87
AB091509512W400	325.3	19		23	30.3		31.6	32.9	41	81.1
AA012209512W400	328	11.5		26.7	34.3		36.6	38	40.7	83.3
AA092209512W400	328.9	11.4		29.2	37.2		38.5	41	42.9	80
AA091509512W400	311.5	33.4		39.3	44		46.3	47.4	49.1	82
AA161009512W400	328.9	21.1		23.4	30.5		32.3	34.1	37.2	84
AA011509512W400	332.8	8.8		19.6	26.8		28.3	30.7	36.5	81.1
AA091009512W400	330.1	13.5		19.7	27.9		29.6	33.2	38.6	80.5
AA081009512W400	330.7	20.7		27.1	34.3		36.2	38.8	41.6	91.4
AA082209512W400	326.9	8.8		27.4	34.1		35.1	36.8	40.2	76.9
AB021009512W400	329.4	6		22.1	29.8		30.8	32.9	36.9	77.7
AA151009512W400	330.9	8.9		21.3	29.1		30.7	33.2	36.1	88.3
AA101509512W400	326.3	12.7		18.5	26.2		27.8	29.6	35.8	80.6
AA101009512W400	328.3	15.5		21.2	28.8		30.4	32.3	34.8	86.5
AC151509512W400	327.8	8.4		20.7	27.7		29.6	31	34.7	80.3
AA071009512W400	332.5	20.8		26.2	33		34.7	37.2	40.1	82.1
AA021009512W400	332.1	20.4		26.1	32.3		33.6	36	37.3	81.2
AA151509512W400	329.5	13		20.2	26.8		28.6	30.4	34.9	77.4
AA111509512W400	328.9	6.3		21.5	28.7		30.5		32.1	76
AA061009512W400	330.2	6		20.9	28.7		30.3	32.7	34.9	80.1
AA051509512W400	331.9	16.8		23	30.3		32.2		34.3	86
AA131009512W400	331.5	12.7		29.2	36.3		38	40.9	43.8	89.6
AA041009512W400	336.5	7.9	14.4	31.7	38.3		40.3	42.6	44.7	82.7
AA011609512W400	334.4	11	18.1	35.2	41.8		43	44.1	46.4	106.2
AA090909512W400	334.7	20.1		35.1	42.3		44.1	46.5	51.2	100.5
AA070909512W400	344.1	21		37.6	45.1		46.2	49.1	51.2	93.4
AA140409512W400	340.3	20.7		39.1	45.7		46.3	50	52.5	98

Tables

Table 4. Summary evidence of karsting and character of caprock, interpreted in this study for the Joslyn Creek Area, Twp 95 & 96, R12W4 Meridian.

UWI	Evidence of Karsting	Character of Caprock*
AA/12-05-095-12W4	Not evaluated	Poor core, missing sections, not evaluated.
AA/02-28-095-12W4	Folded (slumped) marl & karst breccia in lst	Core too deep starts in McM, not evaluated
AA/05-28-095-12W4	Karst breccia in lst	Core too deep starts in McM, not evaluated
AA/15-28-095-12W4	Marl, karst breccia & fractures in lst	Core too deep starts in McM, not evaluated
AA/04-30-095-12W4	None	Sand response on logs at base of Clearwater (above T21) , but is really a silty shale
AA/04-31-095-12W4	None	Confidential core @ CRC; sandy +/- T21, vertically fractured, Wab B, Wab C, McM
AA/07-31-095-12W4	None	Core too deep, starts in McM B2 mudstone above channel sand; coal, org sh
AA/01-33-095-12W4	Karst breccia and fractures in Christina Lst	Core too deep to see caprock; photographed underlying Devonian
AB/03-33-095-12W4	Slight, thin brecciation along beds	Glauconitic sands interbedded with fissile shale in Clw; glauc ss & silty mud in Wab
AA/05-33-095-12W4	Marl & karst breccia in lst	Core too deep, starts in McM channel sand, not evaluated
04/06-33-095-12W4	Minor, disruption of laminations	Thick Clw shale; thin Wab C sand on sand contact with McM A1 (no shale in between)
AB/08-33-095-12W4	Lost core, karst breccia, offset in Christina lst	Wab A, C, Possible D (or else McM B2 mudstone, not typical Wab D log), McM
AB/09-33-095-12W4	None	OBS, Clw fissile shale, underlain by sandy shale burrows & beds; Wab C, ? WabD, McM
02/11-33-095-12W4	None	Core out of order and mislabeled boxes, not evaluated
03/11-33-095-12W4	None	Sand response on logs at base of Clearwater (above T21) , but is really a silty shale
AA/13-33-095-12W4	Fractures in lst, open and clay-filled	Core too deep starts in McM, not evaluated
AB/14-33-095-12W4	None	Core too deep starts in McM, not evaluated
AA/15-33-095-12W4	Slight karst in burrowed biomicrite; bitumen st	Core too deep to see upper Clw sh, starts in sandy Wab sh, Wab C, D, McM, not evaluated

Tables

00/16-33-095-12W4	None, just bitumen staining along bedding	Fissile Clw sh alternate with sandy Clw sh; sandy Wab sh, Wab B, C, McM
AA/16-33-095-12W4	Fractures in lst, open and clay-filled	Base of McM with Dev is discordant; core too deep to see Clw cap rock (in McM) , not evaluated
AB/16-33-095-12W4	None	Core too deep, starts in McM, not evaluated
AC/05-36-095-12W4	None	Fissile Clw sh alternate with sandy Clw sh; sandy Wab sh, Wab A?, B, C, McM
AA/14-01-096-12W4	None	Fissile Clw sh alternate with sandy Clw sh; sandy Wab sh, Wab A?, B, C, McM
AA/14-02-096-12W4	None	Thin and sandy on logs; but core too deep, possible Wab D = coal at top McM channel, not evaluated
AB/02-06-096-12W4	None	Confidential core @ CRC; sandy +/- T21, Wab B, Wab C, McM
AA/07-07-096-12W4	None	Thin and sandy +/- T21; possible Wab D = coal at top McM channel sequence
AA/02-09-096-12W4	None	Just catches sandy doublet +/- T21; not photographed, same as AA/07-07
AA/14-09-096-12W4	None	Regional markers, sandy +/- T21
AA/08-16-096-12W4	None	Thick Clw sh, T31, T21, Thick Wab sh, Thin Wab ss; thin ss lam & burrows in sh
AA/15-16-096-12W4	None	Good; ss above T31, T31-T21: mainly shaly siltst not sh (on logs sh); sands lam & burrow
AA/05-21-096-12W4	None	Clw and Viking cycles; mainly sandy silty mudst; thin Wab C ss & sh, on McM
AA/02-22-096-12W4	None	Clw and Viking cycles; mainly sandy silty mudst; thin Wab C ss & sh, on McM
AA/12-22-096-12W4	None	Clw sandy silty mudst cycles; thin Wab C sandy mudst on McM mud ss

Abbreviations: Clw (Clearwater), CRC (ERCB Core Research Center), Dev (Devonian), McM (McMurray), lst (limestone), mudst (mudstone, usually sandy and/or silty), mud ss (muddy sand), sandy +/- T21 (sandy above and below the T21 marker), sh (shale), siltst (silt/siltstone), ss (sand), st (stain), T21 (marker top of Wabiskaw), Wab (Wabiskaw), OBS (Observation Well).

Tables

Table 5 . Summary of wells and boreholes where during drilling hydrocarbon or bitumen odour was noted by Total in various submissions to the ERCB.

UWI	Depth (m)	Facies	Material Description	Source of Information
1AC/01-33-095-12W4/00	6.1 to 7.2	Pgtc (2050)	Silty clay, trace fine sand, mild bitumen odour	Sub. # 28927 App.# 1389383
1AC/15-33-095-12W4/00	7.6 to 10	Pgtc (2050)	Silty clay, sandy, gritty matrix, mild bitumen odour	Sub. # 28927 App.# 1389383
1AD/11-28-095-12W4/00	10 to 11.55	Pgtc (2050)	Silty clay, sandy, mild bitumen odour	Sub. # 28927 App.# 1389383
Borehole MW1 Location 108 Drilled Feb. 1, 2007	7 to 9.5	Clay	Clay, dark grey, fine sand, small stones, hydrocarbon odour	Millenium EMS Solutions Total Final Report on Steam Release Incident
Borehole MW2 Location 109 Drilled Feb. 1, 2007	5.2 to 6.1	Sandy Clay	Sandy clay, dark grey, occasional stones, hydrocarbon odour ~ 5.2 to 6.1 m	Millenium EMS Solutions Total Final Report on Steam Release Incident
Borehole MW2 Location 109 Drilled Feb. 1, 2007	6.1 to 6.7	Clay	Clay, grey, pink mottling, faint hydrocarbon odour	Millenium EMS Solutions Total Final Report on

				Steam Release Incident
Borehole MW4 Location 103 Drilled Feb. 2, 2007	2.1 to 6.1	Clay	Clay, grey, with some fine sand, small stones, hydrocarbon odour	Millenium EMS Solutions Total Final Report on Steam Release Incident
Borehole MW5 Location 103 Drilled Feb. 2, 2007	6.1	Clay	Clay, silty, some sand, pebbles, sand lenses (< 1 cm), grey mottling, strong bitumen odour @ 6.1 m	Millenium EMS Solutions Total Final Report on Steam Release Incident
Borehole MW7 Location 103 Drilled Feb. 2, 2007	7.6 to 10.4	Silty Clay	Silty clay, trace sand, small pebbles, small sand lens (< 10 cm), grey mottles, strong bitumen odour @ 7.6 to 10.4 m	Millenium EMS Solutions Total Final Report on Steam Release Incident

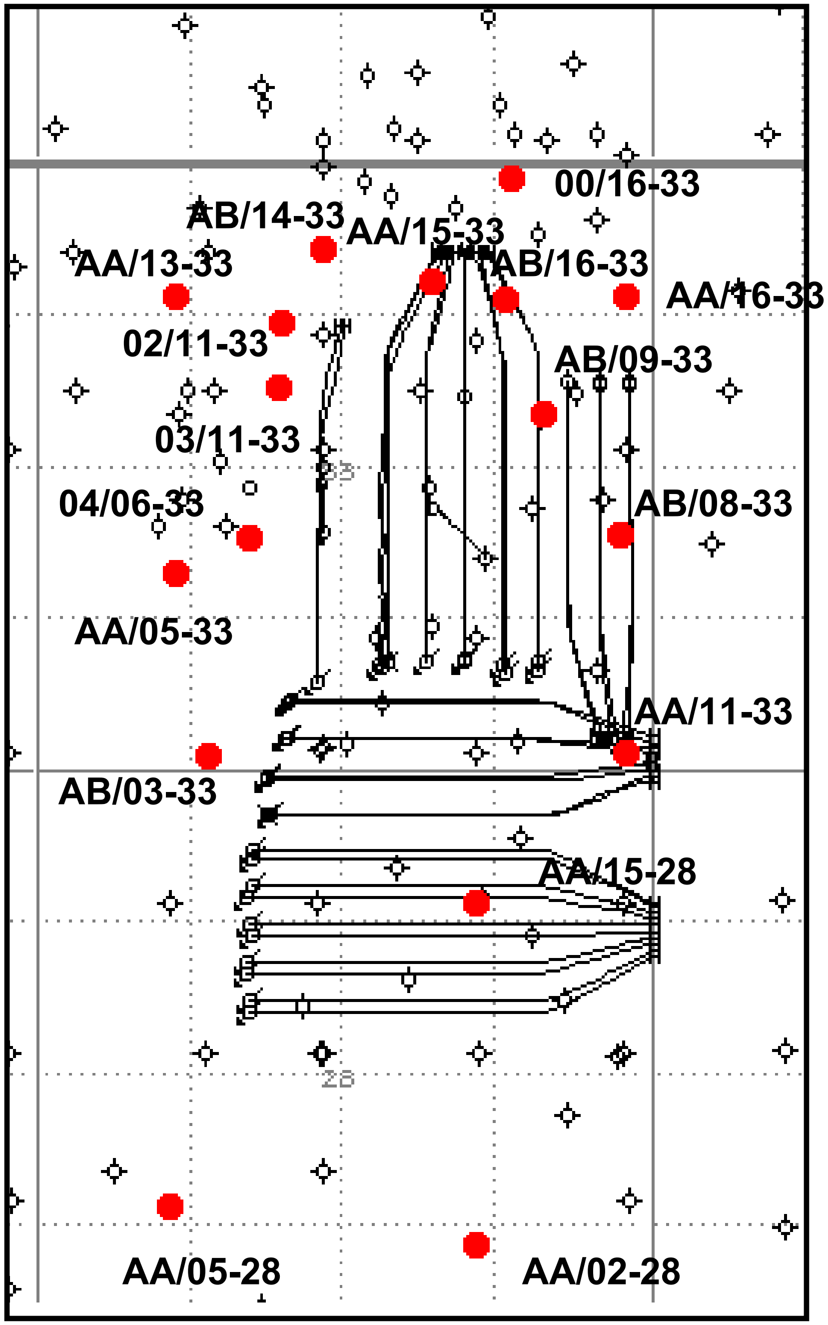


Figure 1. Cores Examined (17): Proximal to Joslyn Ck Site.

Well locations annotated.

(see Table 1)

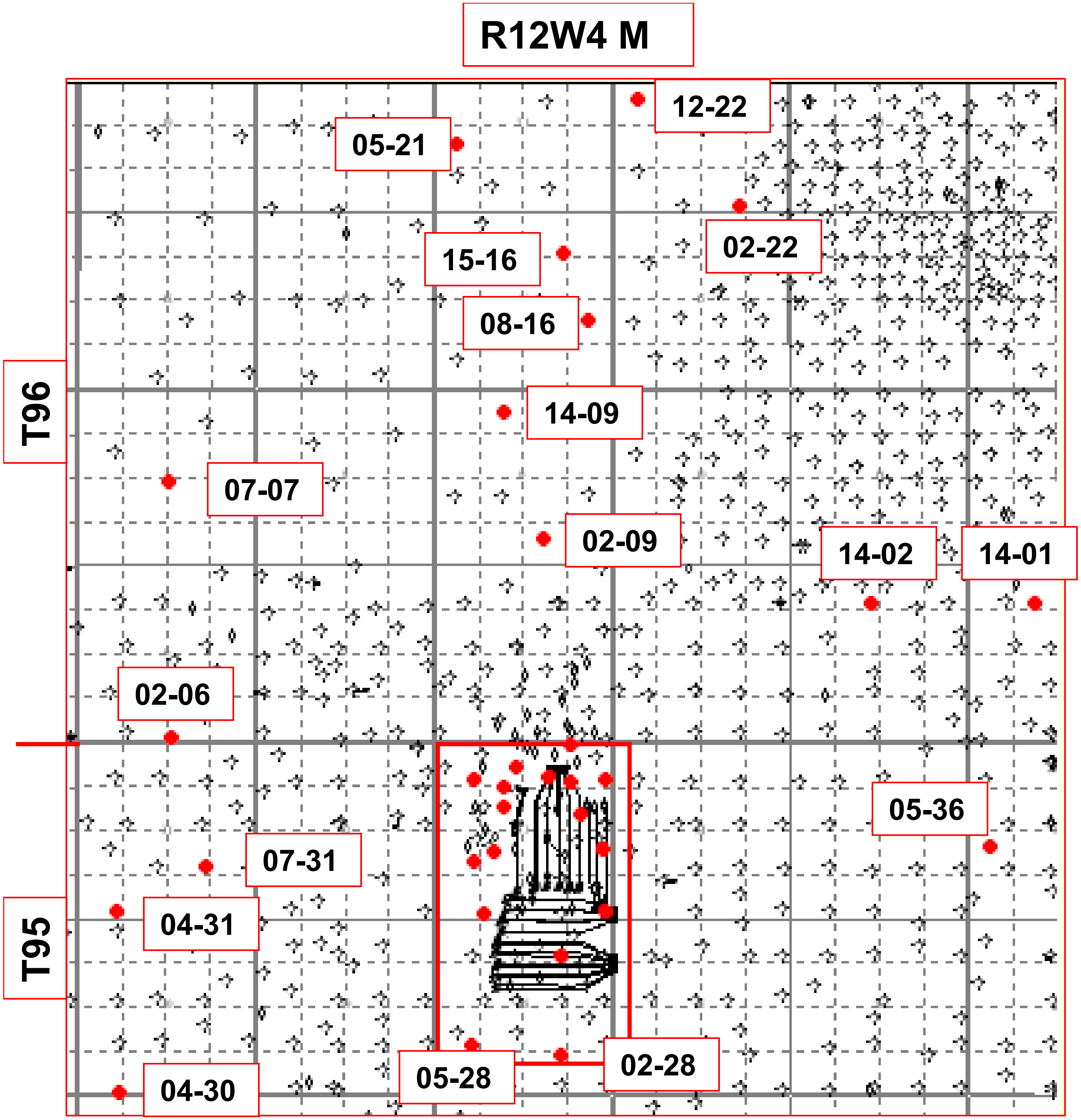


Figure 2.
Cores Examined
Joslyn Ck Area
Outside SAGD Site

(see Table 1)

GENERAL STRATIGRAPHY

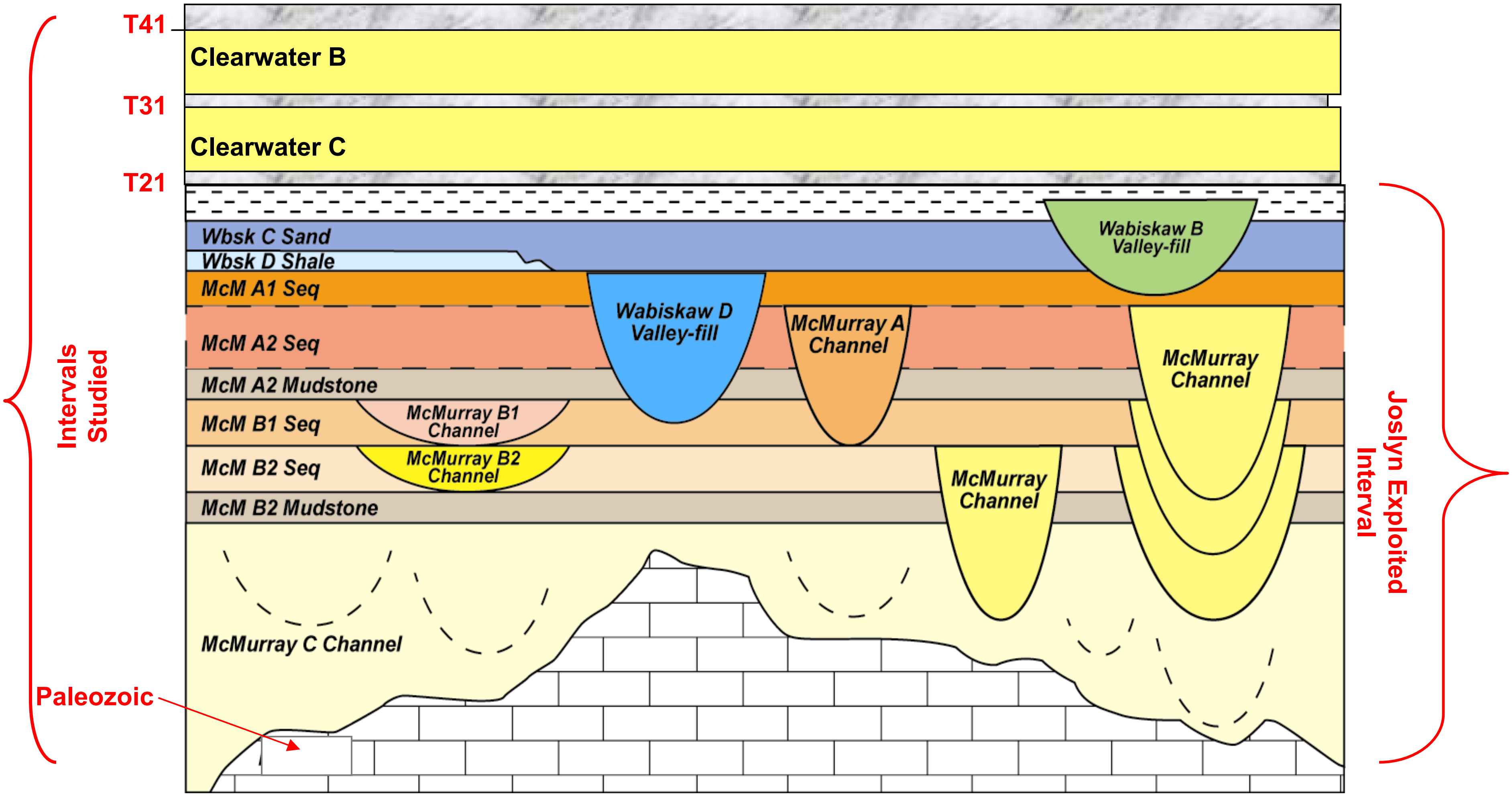


Figure 3. Stratigraphic model for the Athabasca Wabiskaw-McMurray deposit showing picks, with the Wabiskaw Marker (T21) as datum at top, and schematic showing geometric relationships between different stratal units (from Hein and Cotterill, 2006; modified from EUB, 2003; Hein et al., 2001; Wynne et al., 1994)

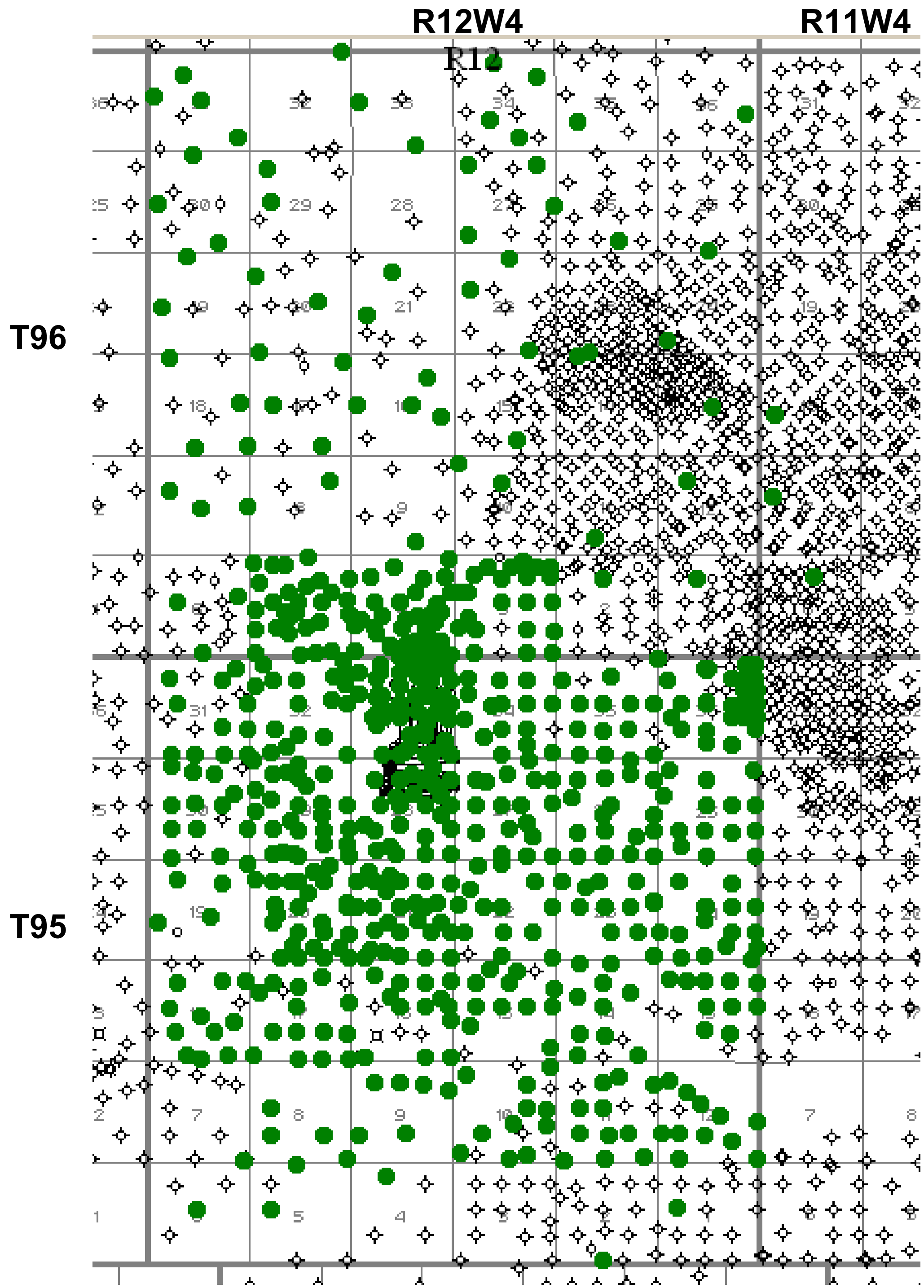


Figure 4. Wire-Line Logs Interpreted (453): Joslyn Ck and Surrounding Area, T95 & 96, R12W4 Meridian.

(see Table 3 on CD only)

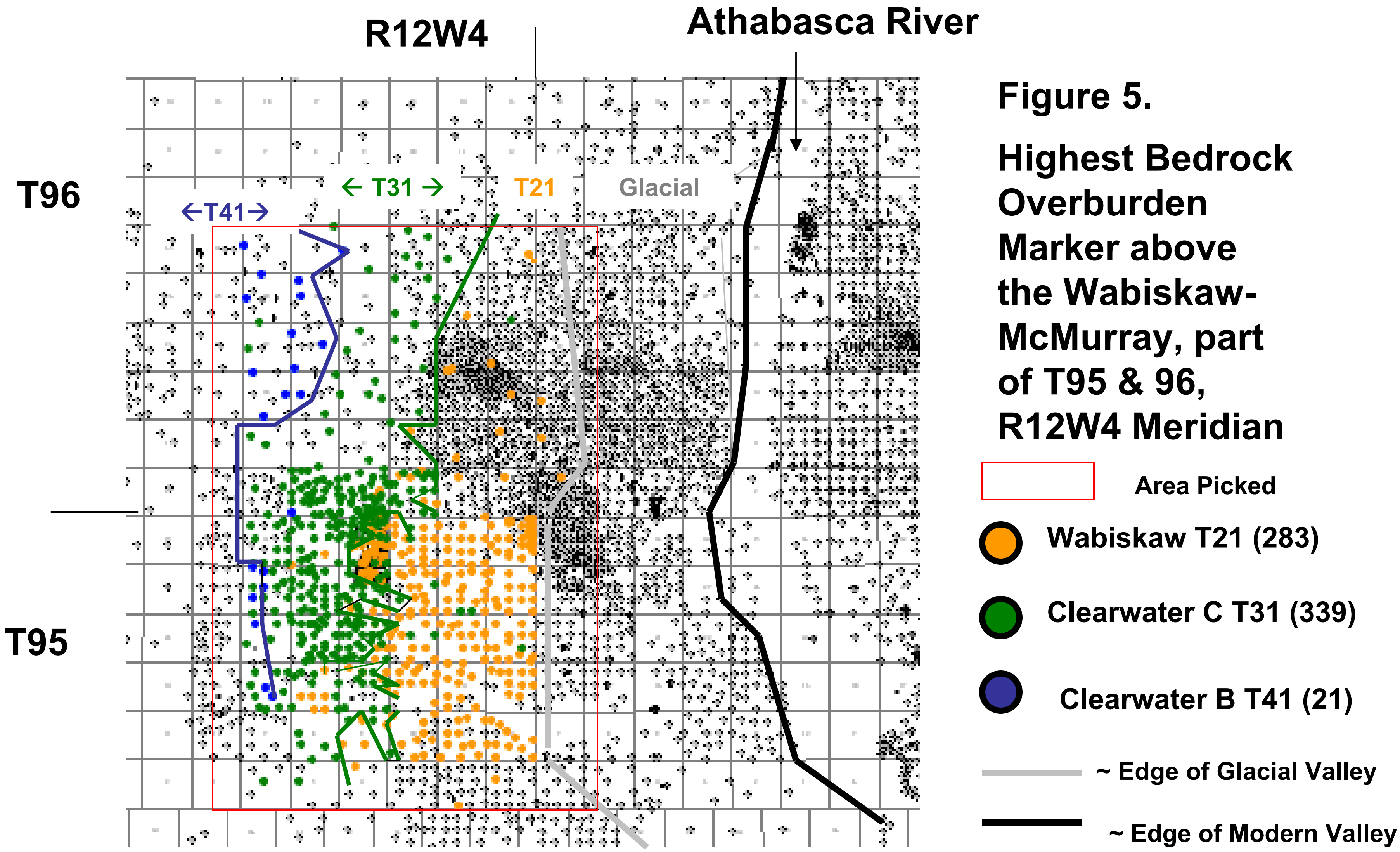


Figure 5.

Highest Bedrock Overburden Marker above the Wabiskaw-McMurray, part of T95 & 96, R12W4 Meridian

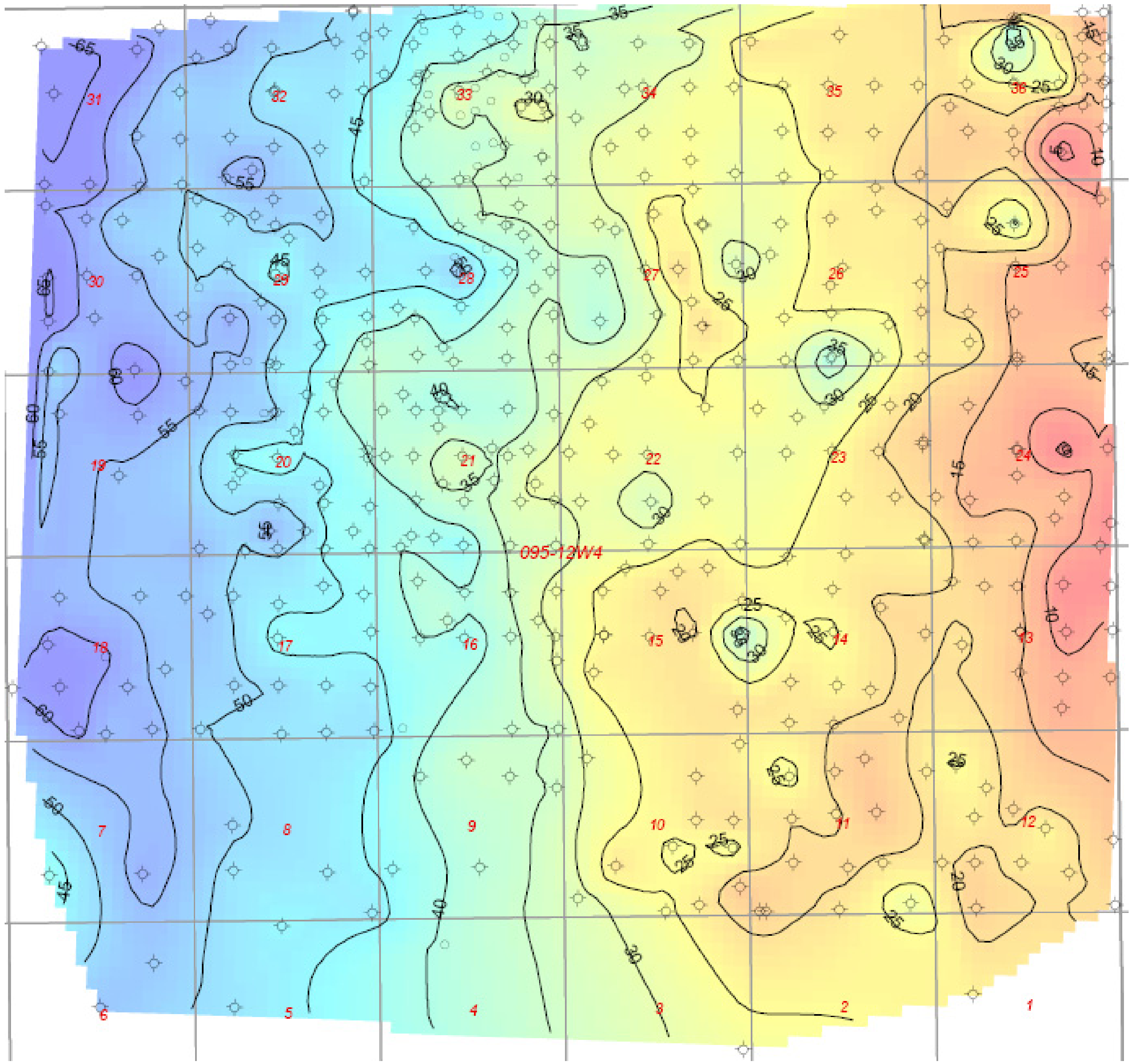


Figure. 6 Depth to Top of Wabiskaw Map, Township 95, Range 12W4 Meridian: Scale 1:50 000, Contour Interval 5 m.

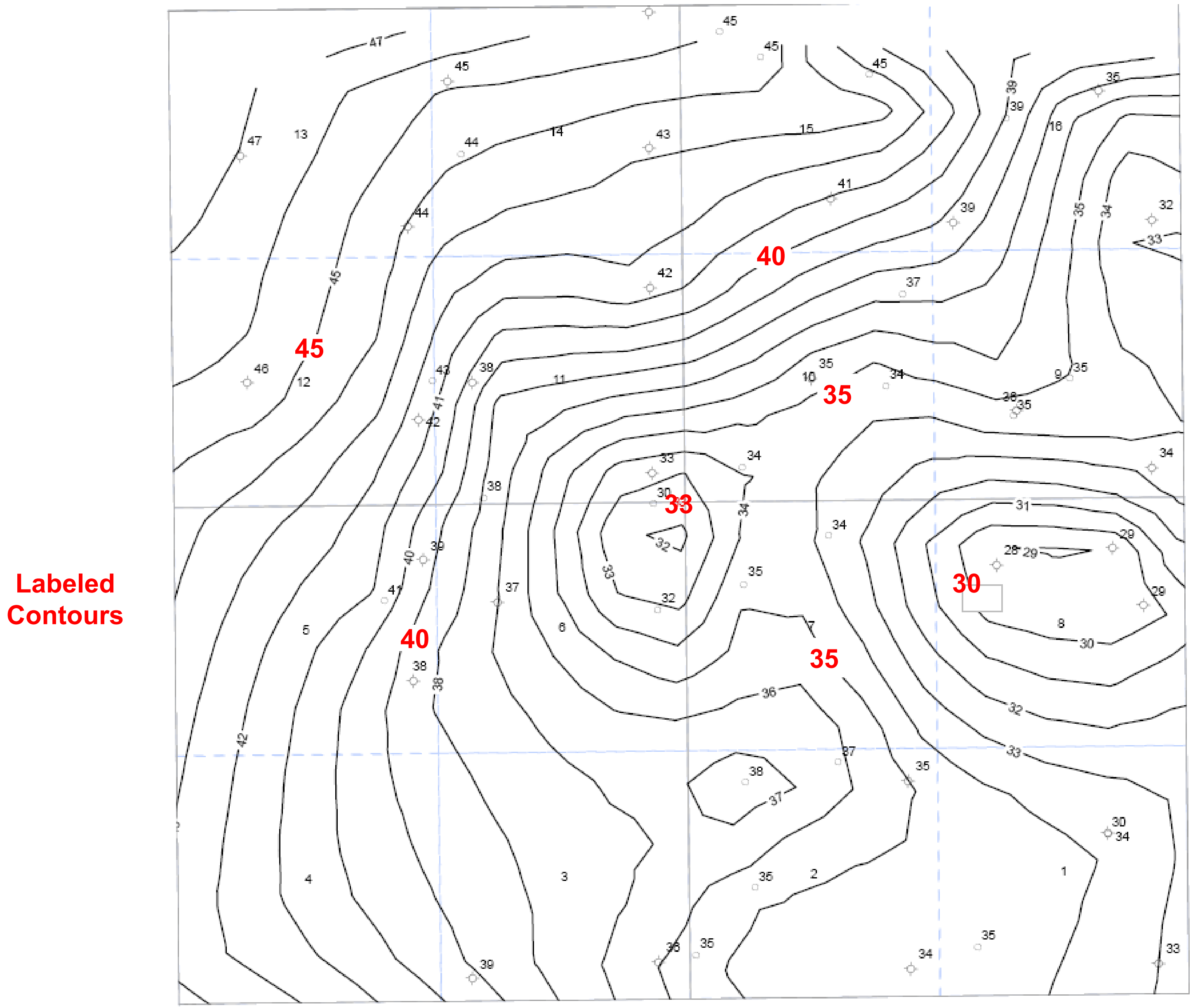
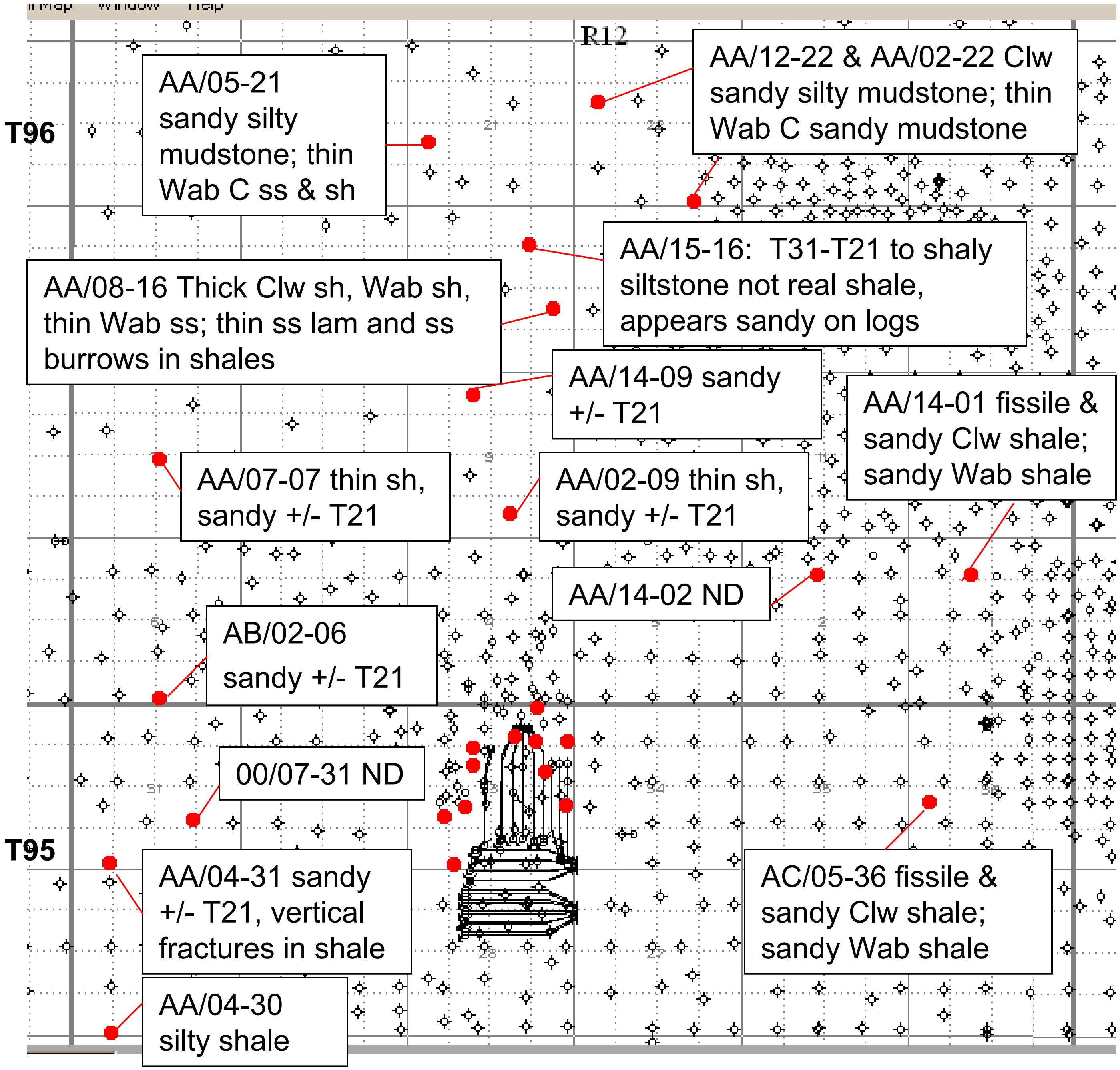


Figure. 7 Depth to Top of Wabiskaw Map, Section 33, Township 95, Range 12W4 Meridian: Scale 1: 7 500, Contour interval 1 m.



ND; not determined, core too deep to see caprock

Figure 8. Summary of Core Review Re Caprock:

Joslyn Ck Area Surrounding SAGD Pilot

(see Table 4)

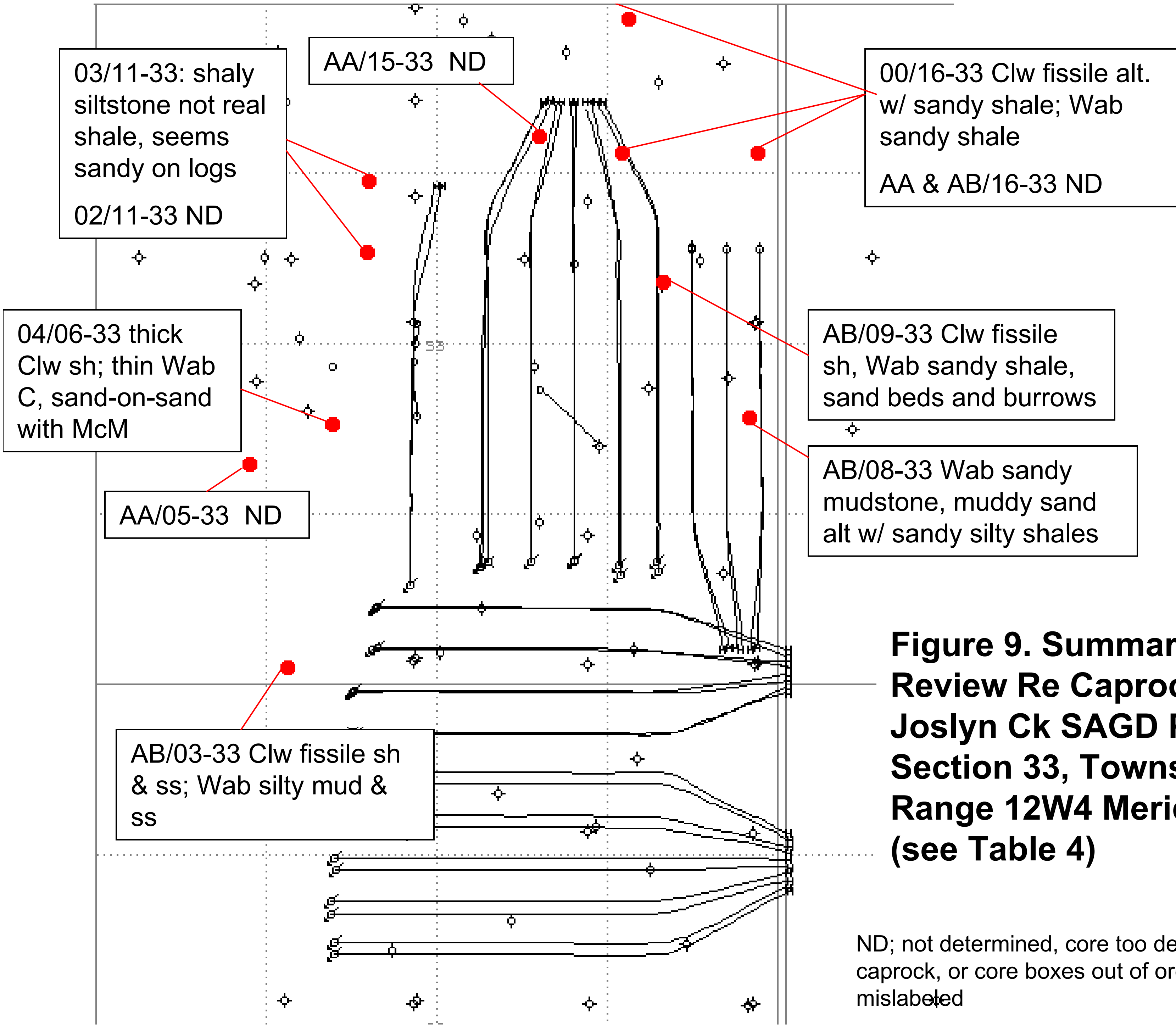


Figure 9. Summary of Core Review Re Caprock: Joslyn Ck SAGD Pilot Area Section 33, Township 95 Range 12W4 Meridian (see Table 4)

ND; not determined, core too deep to see caprock, or core boxes out of order and/or mislabeled

AB/03-33-095-12W4

Core Photos

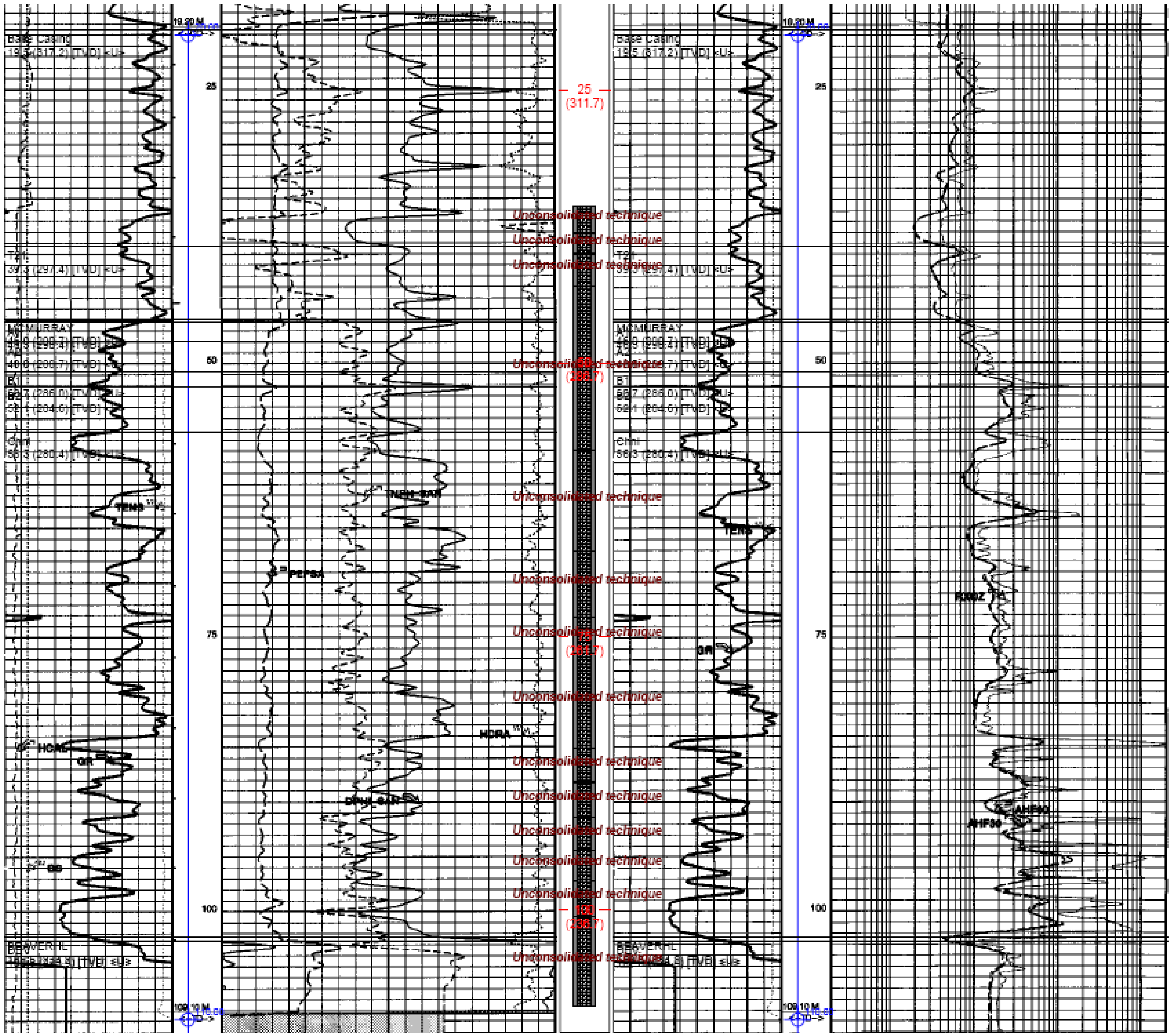
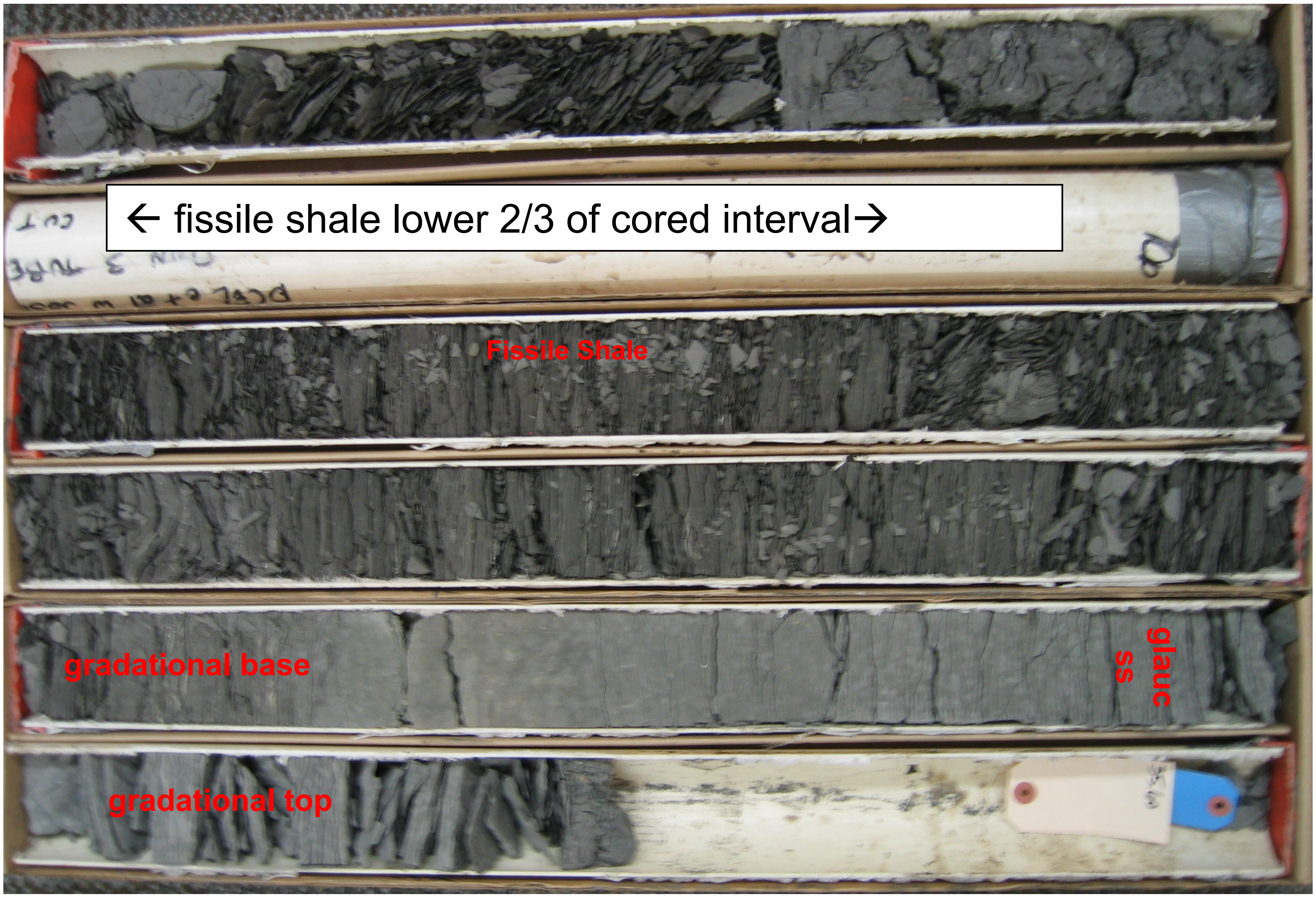


Figure 10

AB/03-33-095-12W4, Topmost Photo

Base

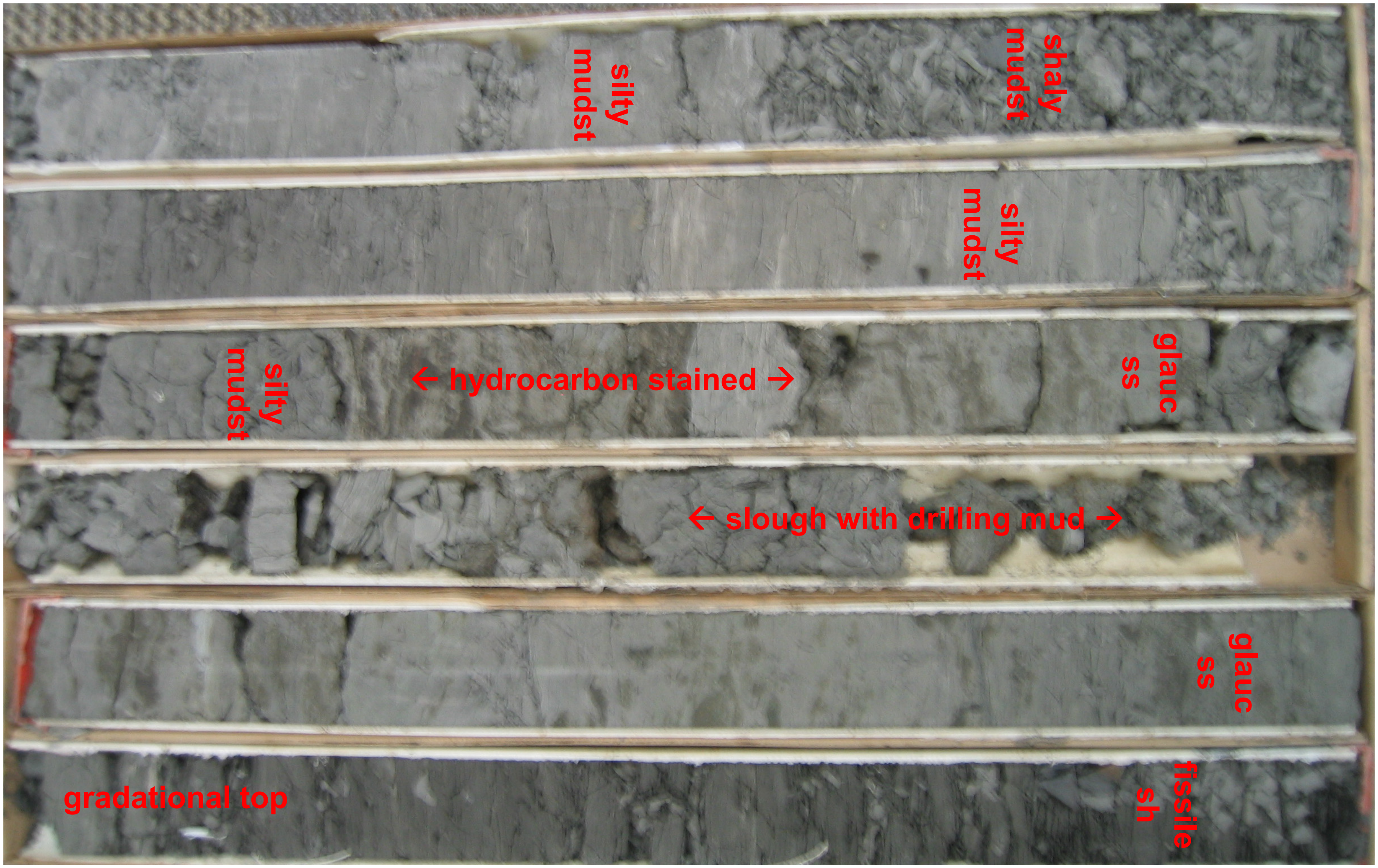


Top

Figure 11

AB/03-33-095-12W4, Middle Photo

Base



Top

Figure 12

AB/03-33-095-12W4, Lowermost Photo

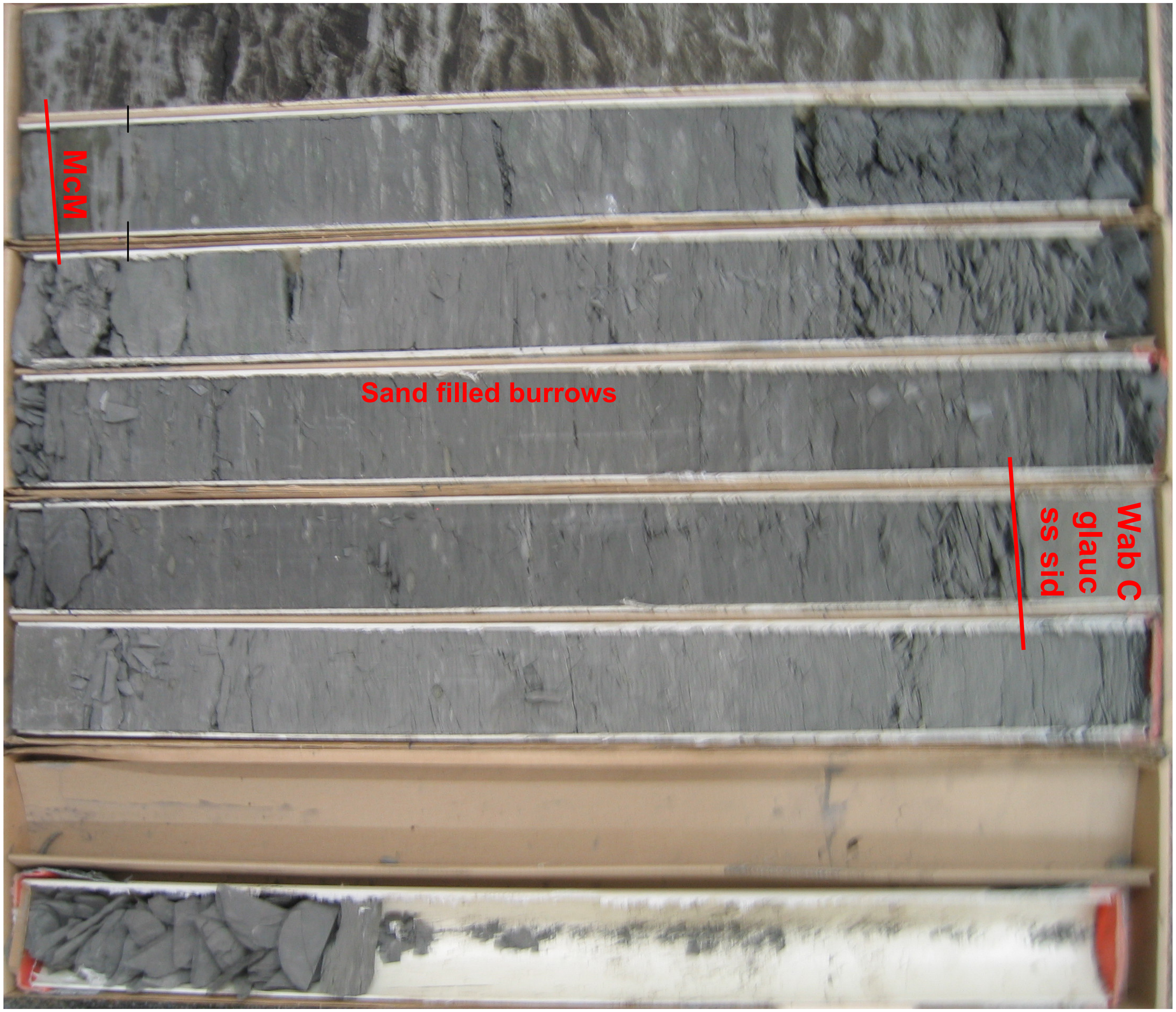


Figure 13

00/16-33-095-12W4
No wire-line logs available for this well.
Core photos 40.6 m to 51.95 m
core depth.

Figure 14

00/16-33-095-12W4: Core Depth 40.6 - 43.45 m

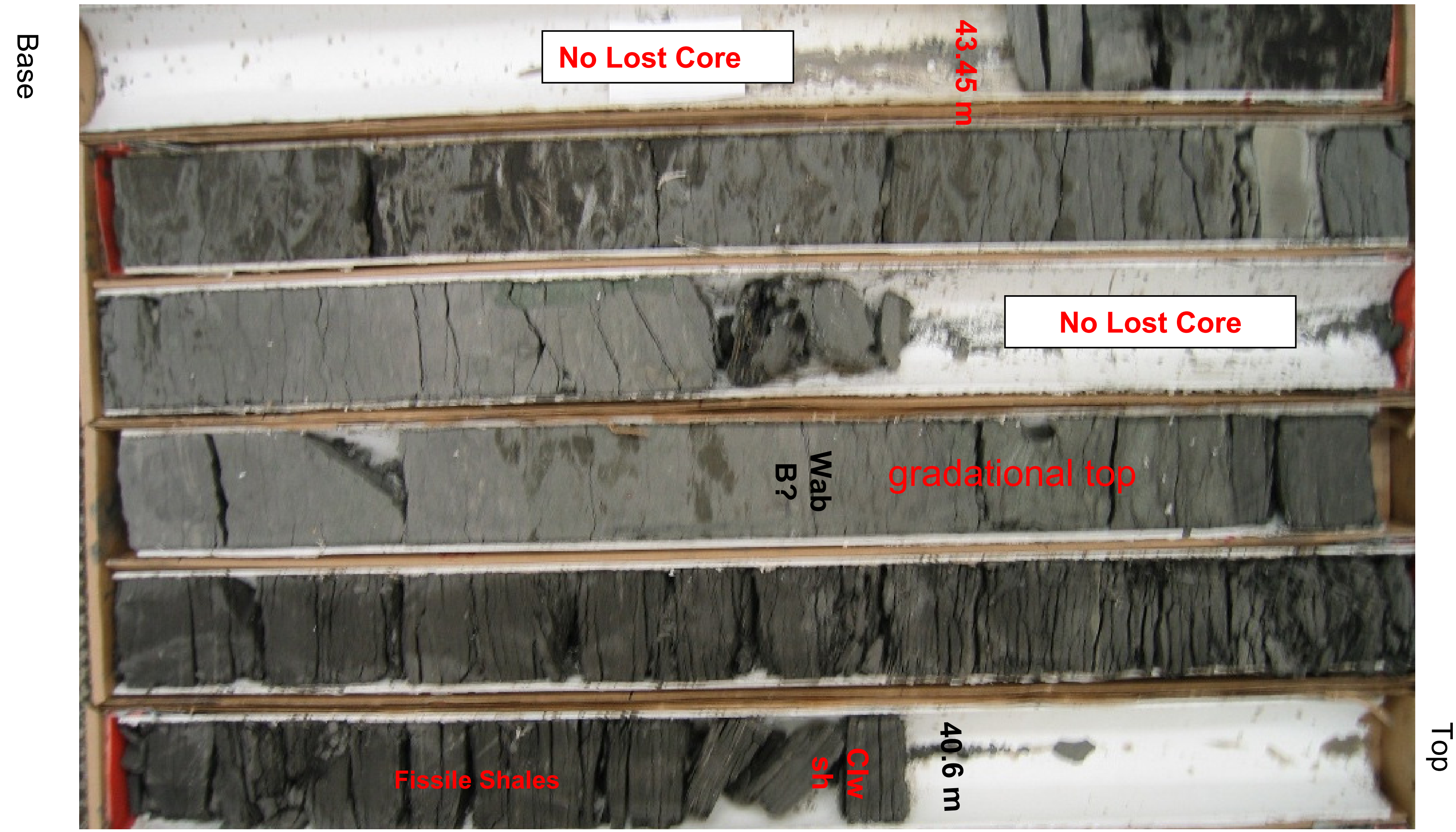


Figure 15

00/16-33-095-12W4: Core Depth 43.45 – 46.95 m

Base

Top

Figure 16

00/16-33-095-12W4: Core Depth 46.95 – 51.95 m

Figure 17

AA/04-31-95-12W4

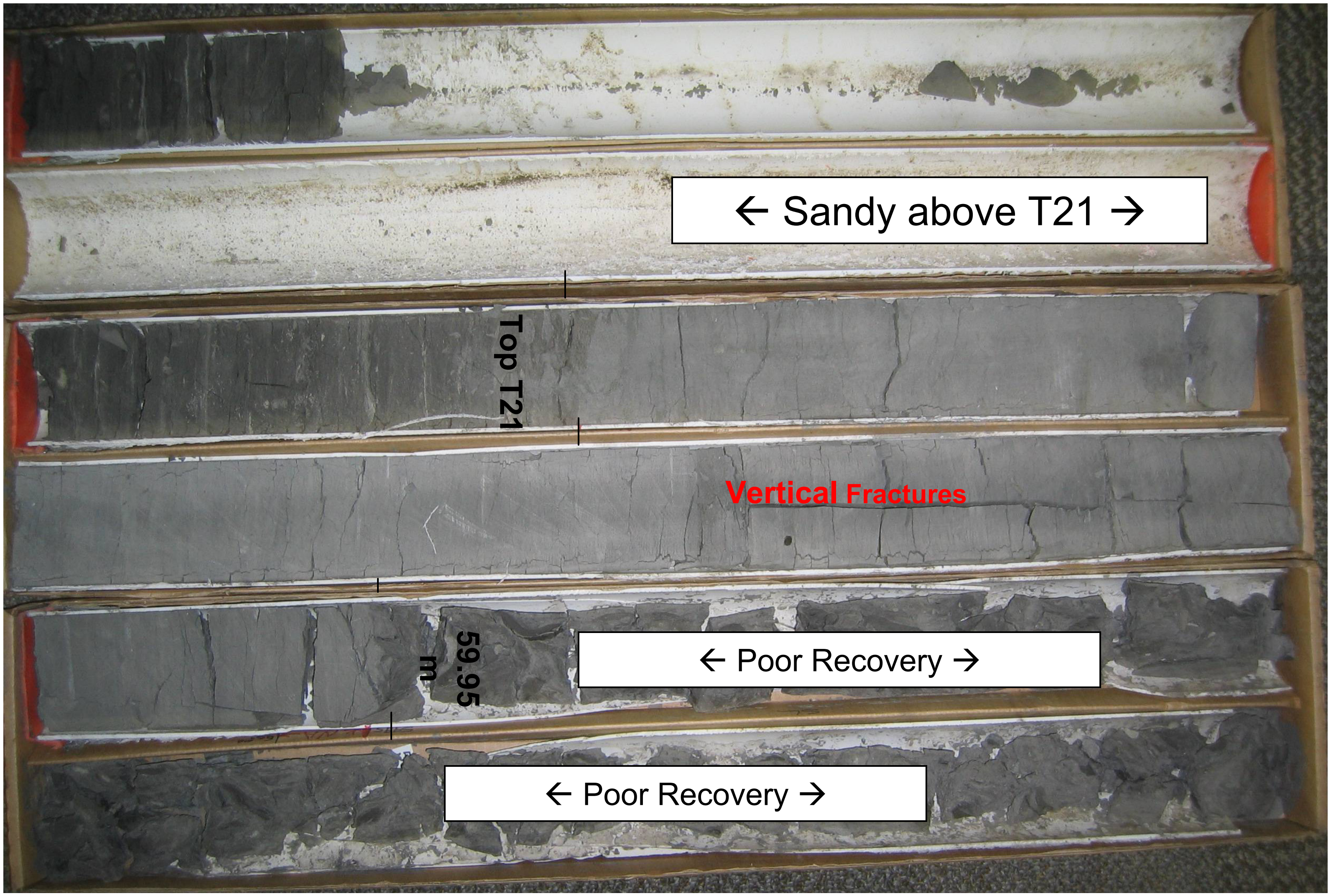
No wire-line logs available for this well.

Core photos of the interval above and below the T21 marker (+/- T21).

Figure 18

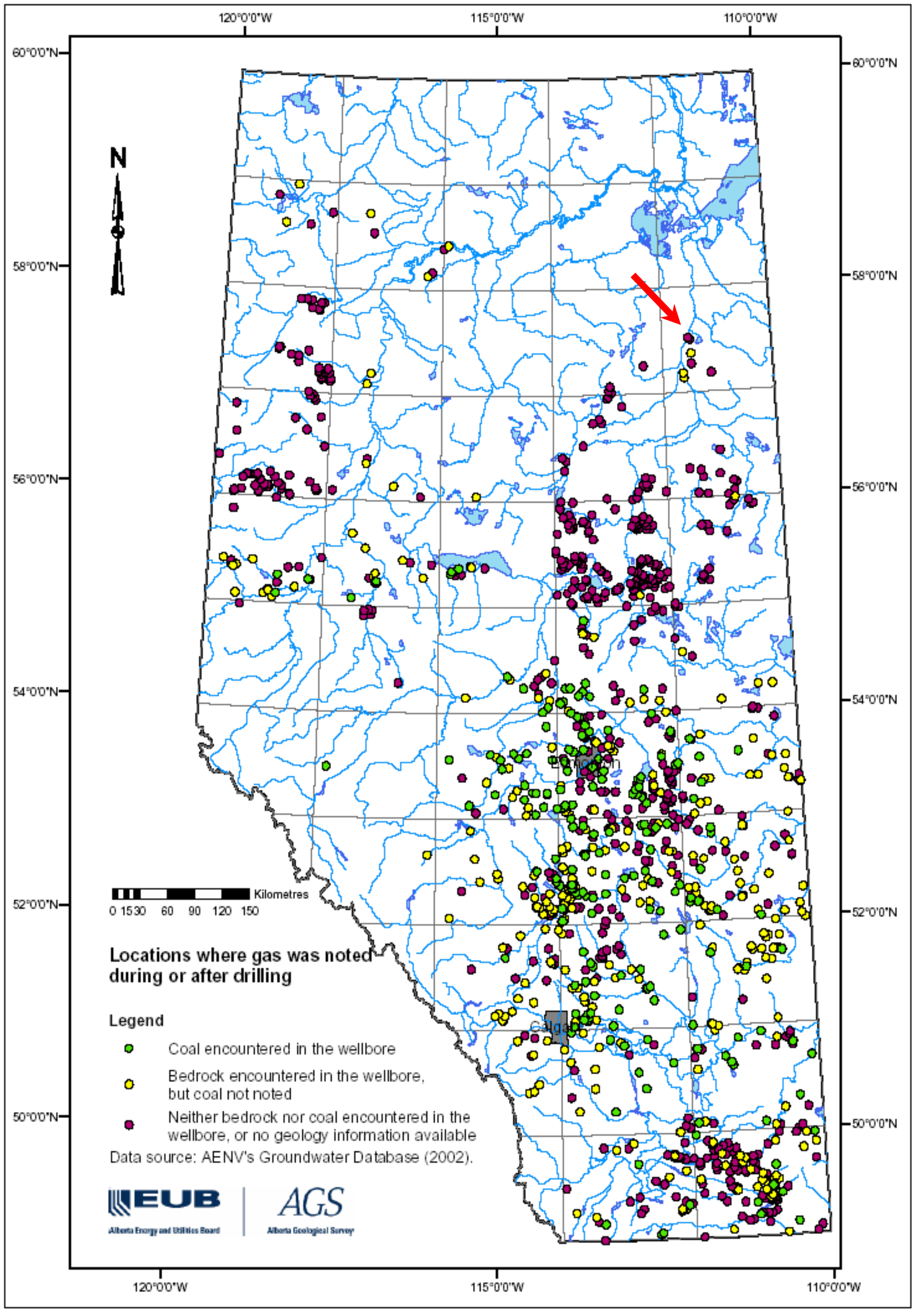
AA/04-31-095-12W4: Core Depth from ~ 1.5 m above to ~ 0.5 m below the T21 marker

Base



Top

Figure 19



Updated from: Lemay, T.G. (2003): Chemical and Physical Hydrogeology of Coal, Mixed Coal-Sandstone and Sandstone Aquifers from Coal-Bearing Formations in the Alberta Plains Region, Alberta; Alberta Energy and Utilities Board, Alberta Geological Survey, Earth Sciences Report 2003-04.

Figure 20. Locations were gas was encountered during or after drilling. The arrow shows a well in Twp 95, R10W4 M that is closest to the Joslyn Creek Incident area (modified from Lemay, 2003)

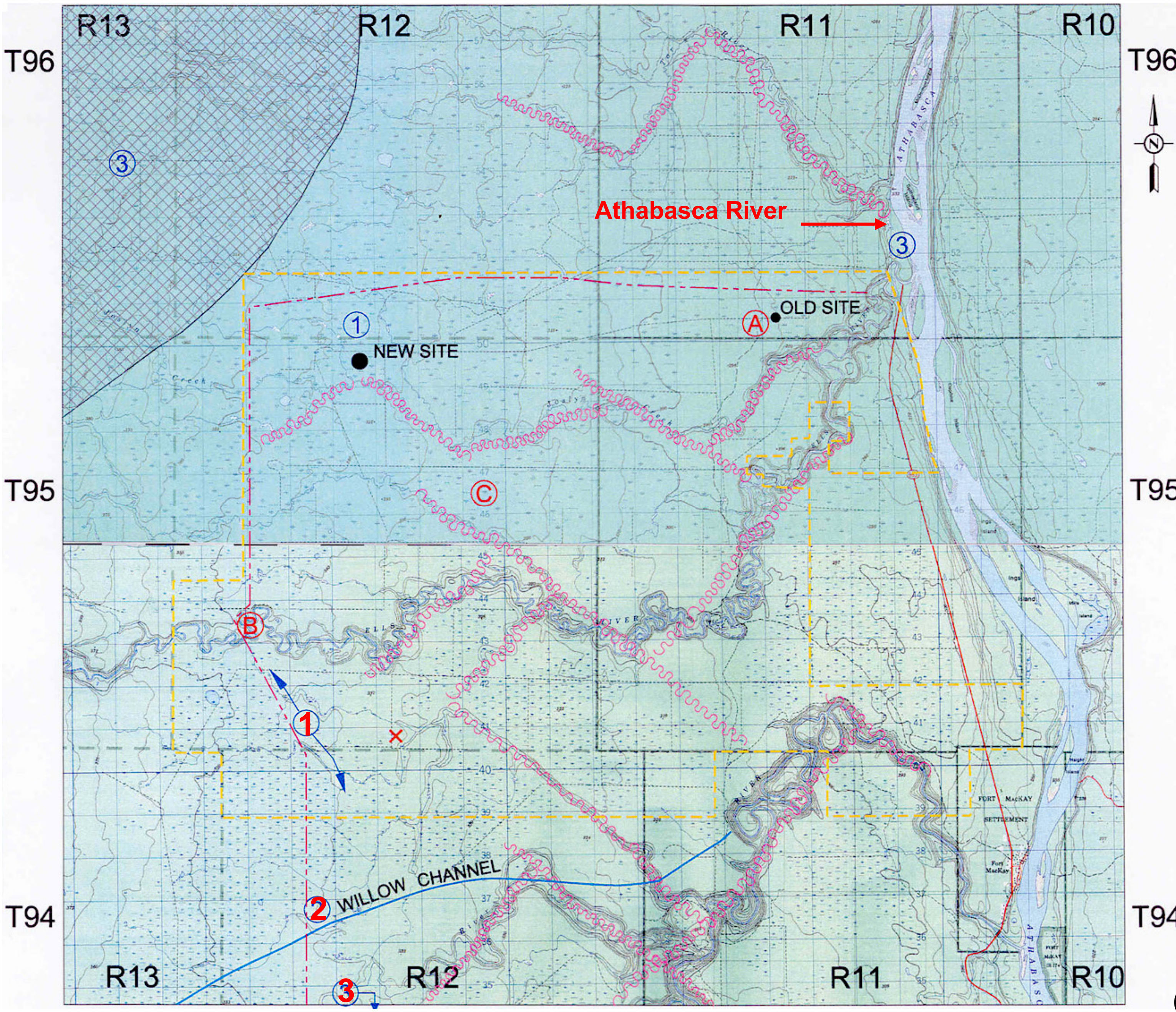


Figure 21.

Primary Water Supply Possibilities

App# 1277348

1 **Buried channel on lease**

2 **Willow Channel**

3 **Birch Channel off map**

(from Deer Creek Energy Ltd., 2001)

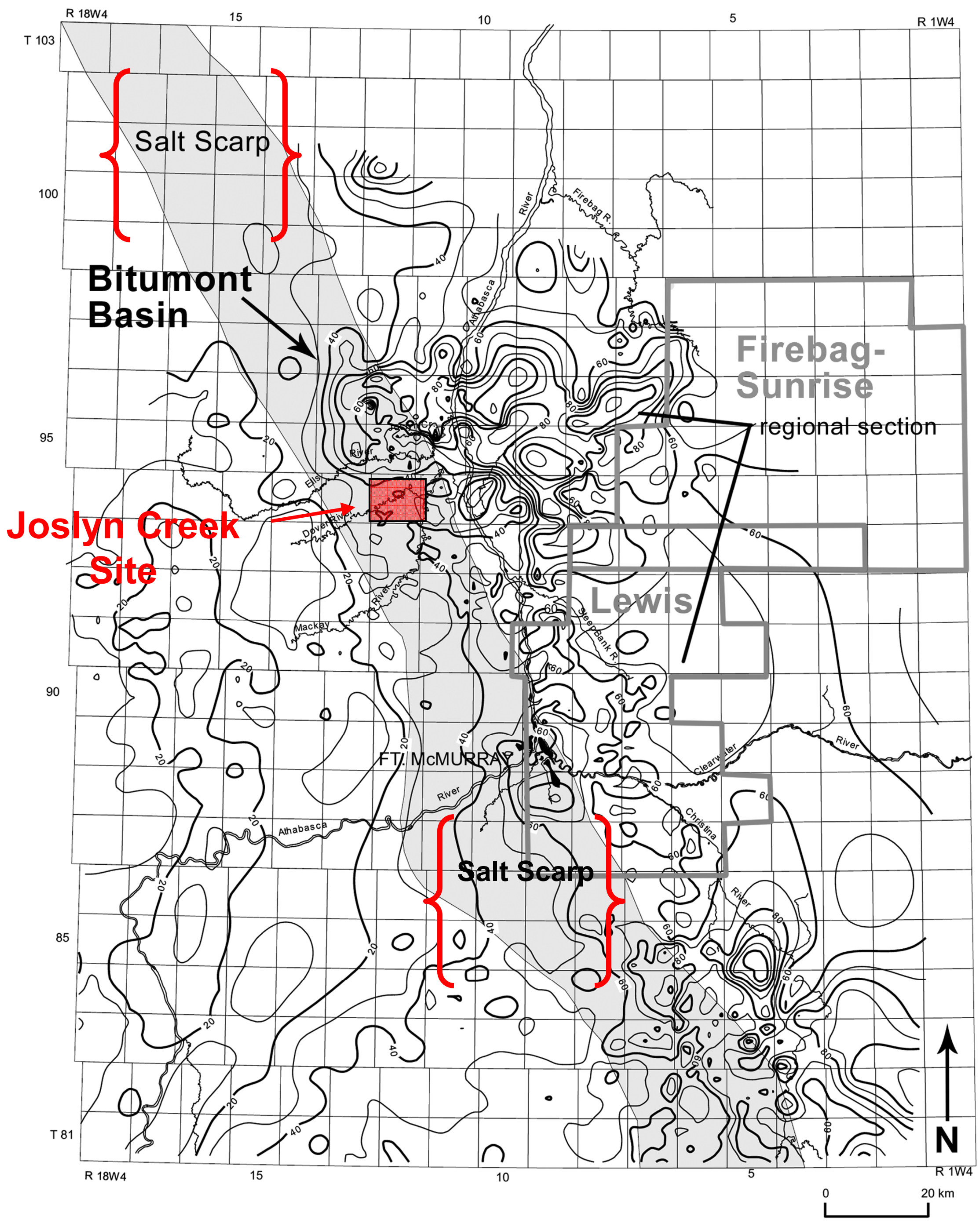


Figure 22

Joslyn Creek Area, Twp 95 R12W4 Meridian) within Salt Dissolution Trend and at the SW margin of Bitumont Basin – A large salt withdrawal basin and/or graben structure

(from Hein and Cotterill, 2006b)

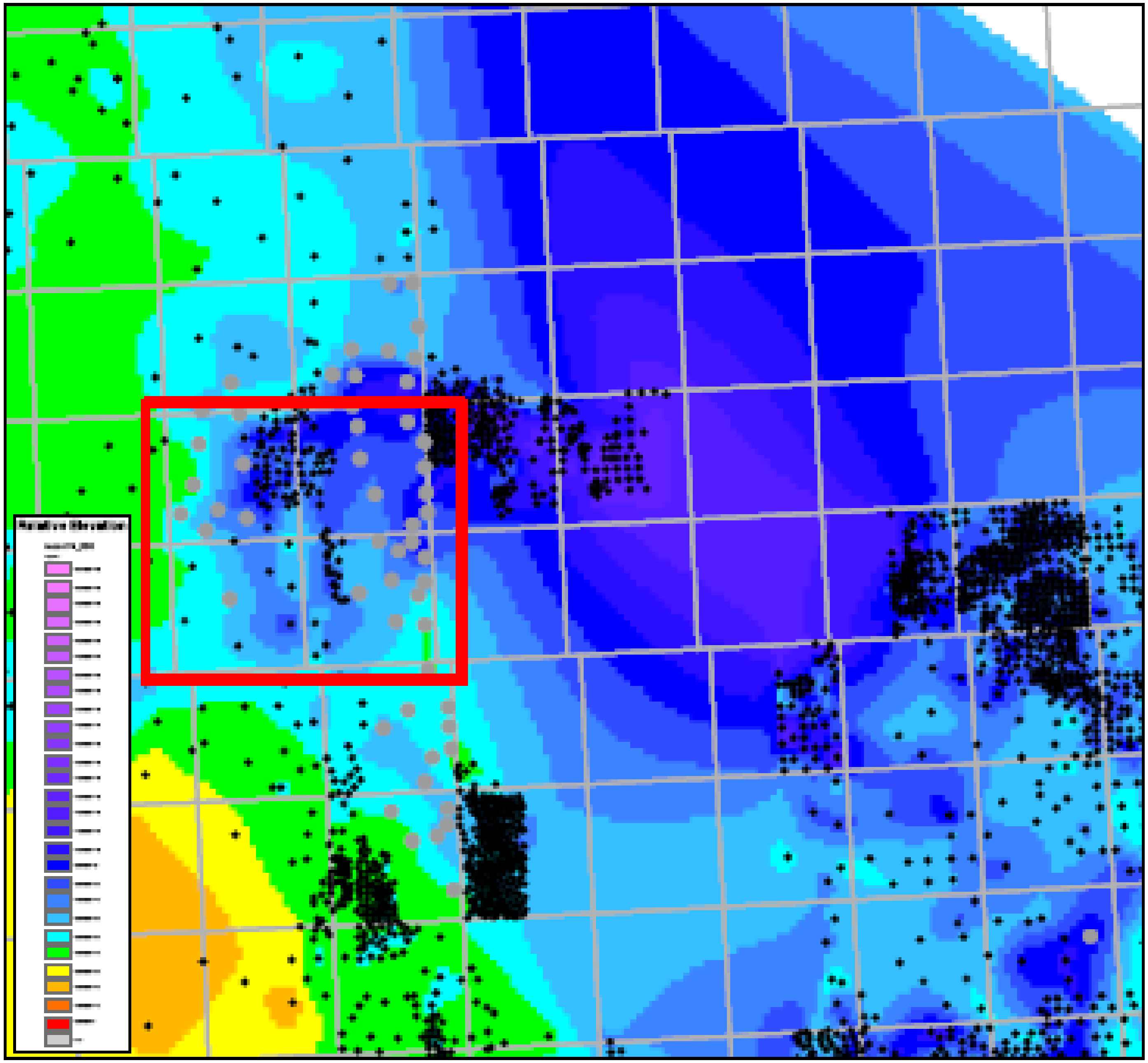


Figure 23. Isopach T21 to Pz with detailed four-township area (NW: T96 R13W4; SE T95, R12W4) outlined in red; enlarged in Fig. 16 (from Hein and Marsh, in prep).

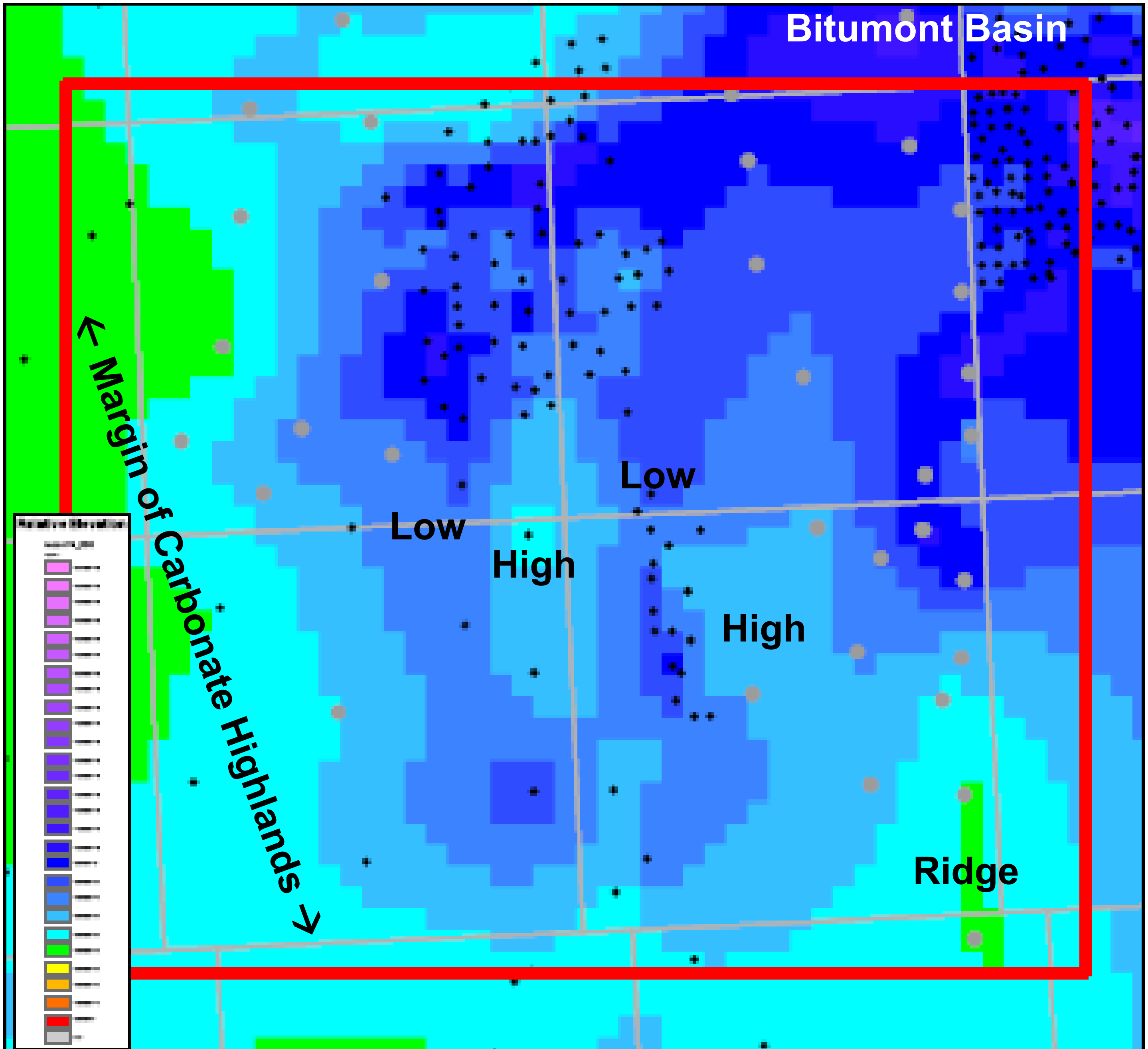


Figure 24. Enlarged isopach T21 to Pz for detailed four-township area (NW: T96 R13W4; SE T95, R12W4), annotated with paleogeography.

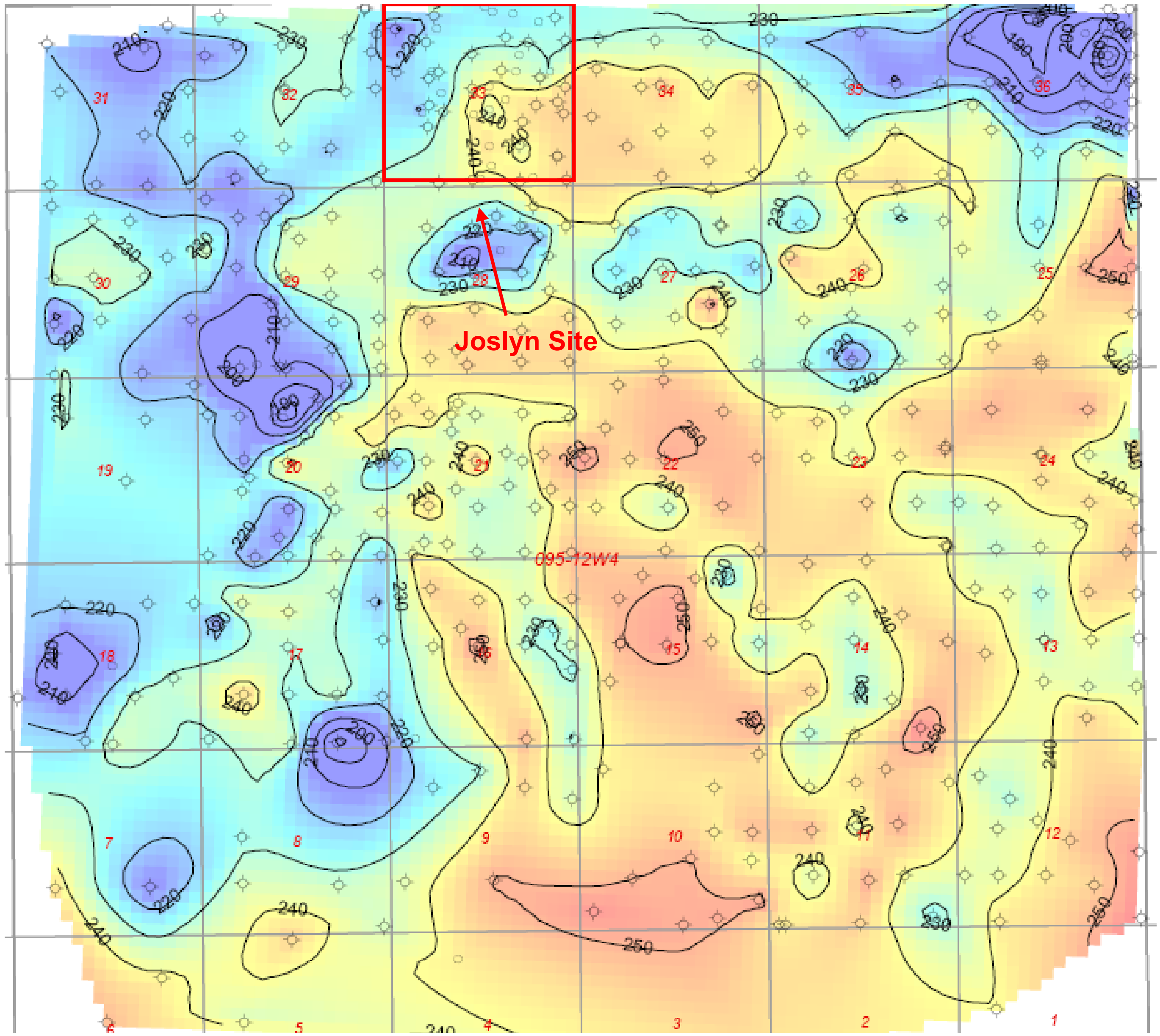


Figure 25. Paleozoic Structure Map, Township 95, Range 12W4 Meridian: Scale 1:50 000, Contour Interval 10 m. Orange and Yellow are paleotopographic highs; blue and purple are paleotopographic lows.

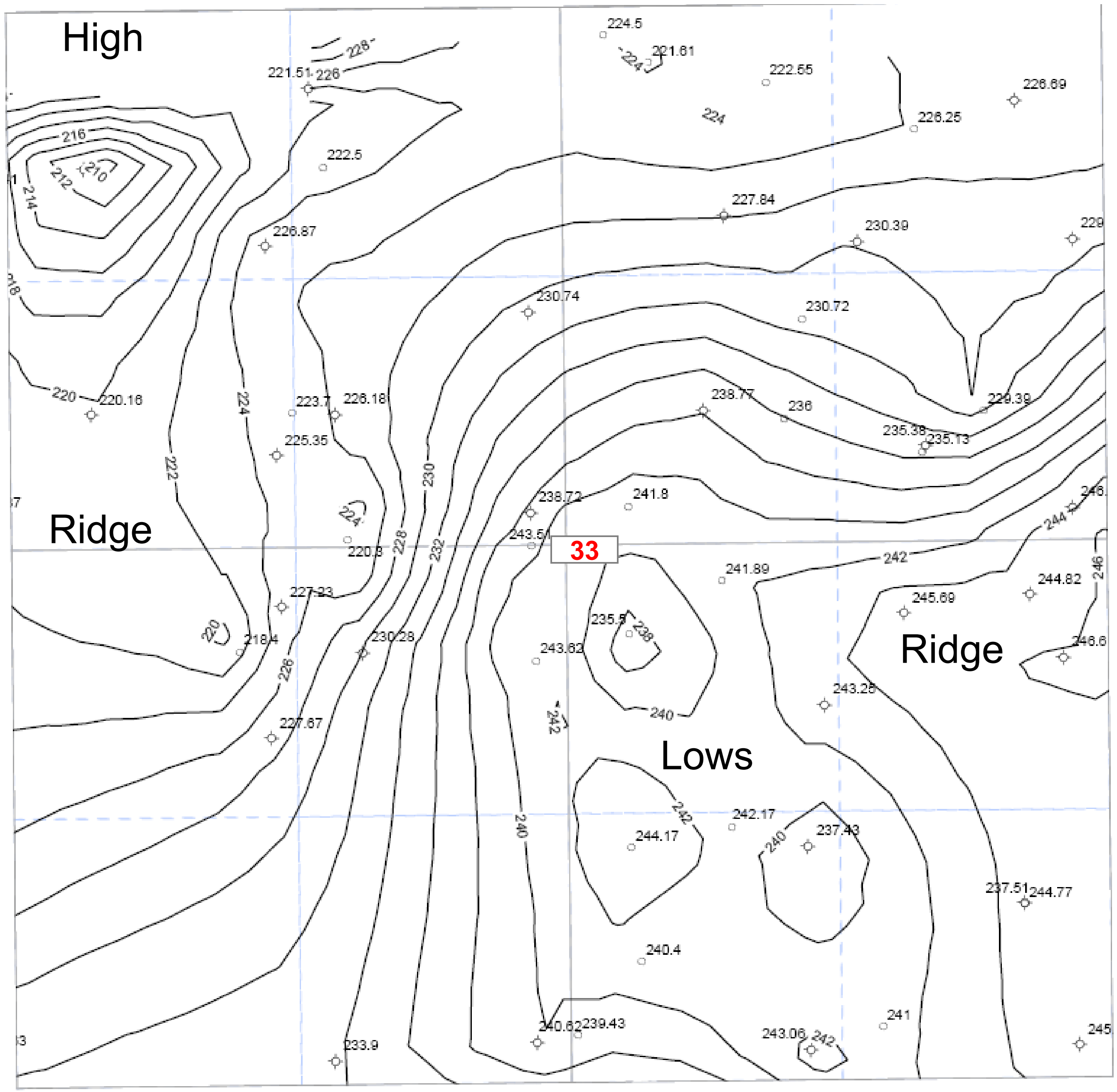


Figure 26. Paleozoic Structure Map, Section 33, Township 95, Range 12W4 Meridian: Scale 1:7 500, Contour Interval 2 m.

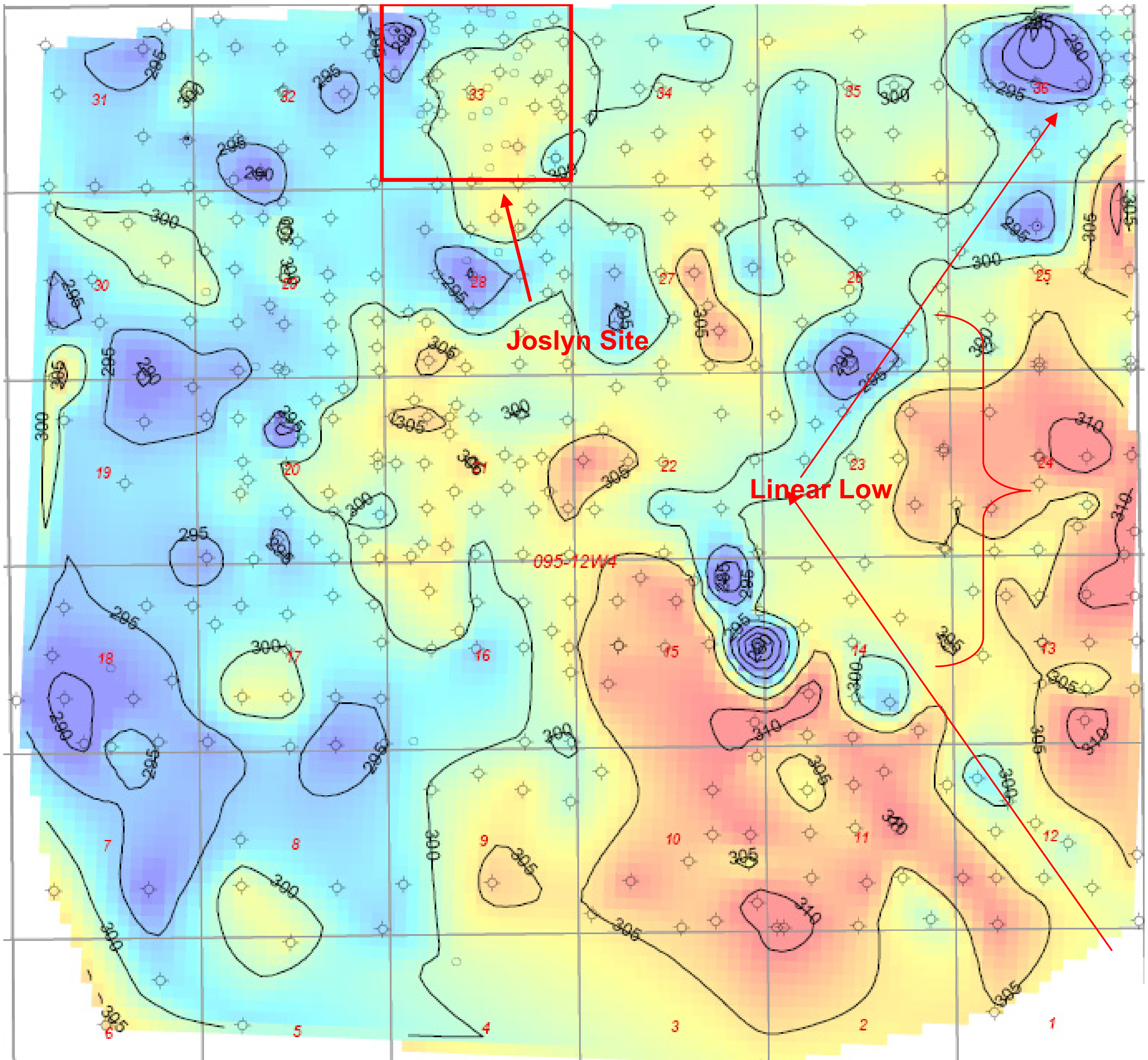


Figure 27. Wabiskaw Structure Map, Township 95, Range 12W4 Meridian: Scale 1:50 000, Contour Interval 5 m.

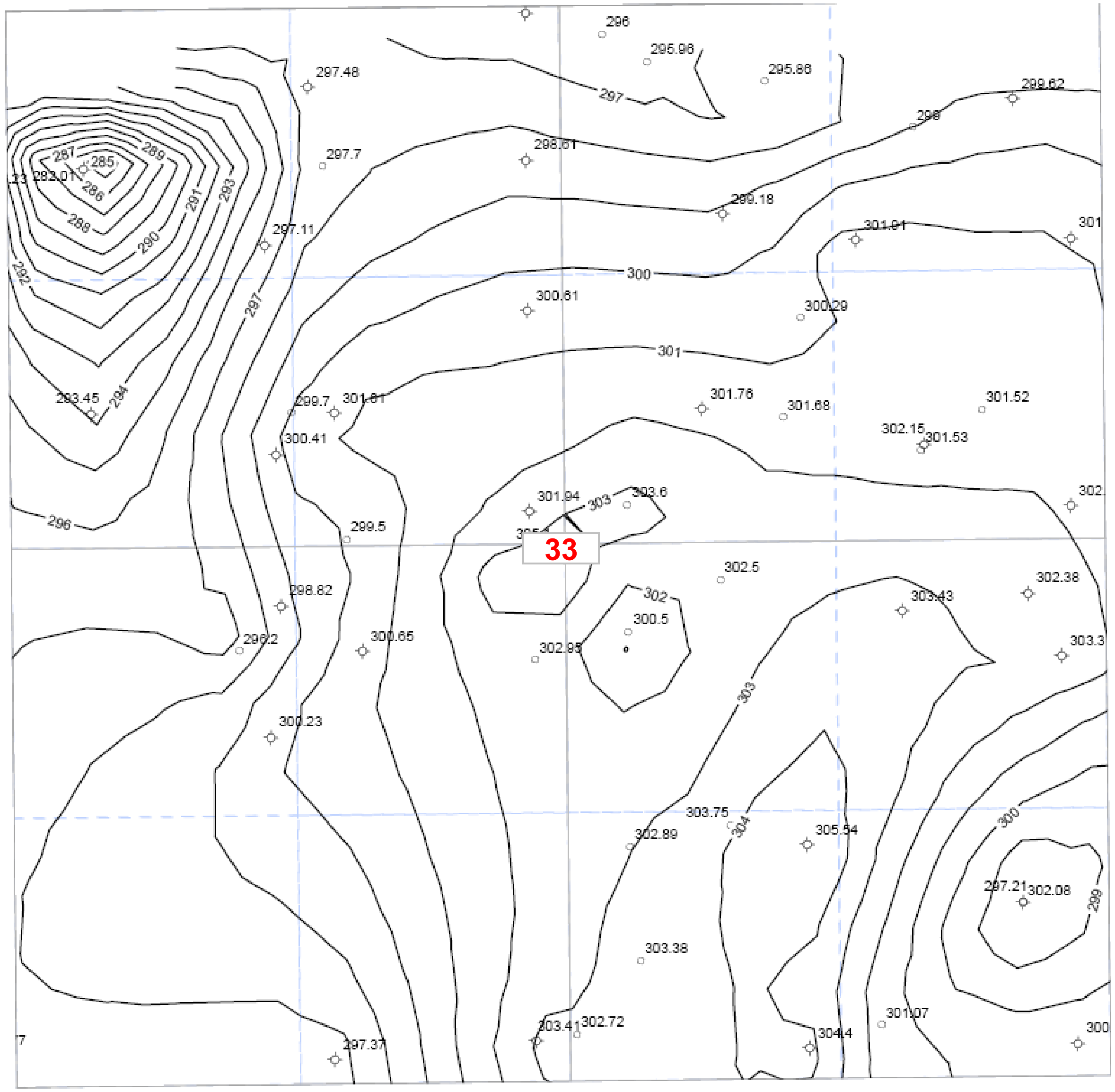


Figure 28. Wabiskaw Structure Map, Section 33, Township 95, Range 12W4 Meridian: Scale 1:7 500, Contour Interval 1 m.

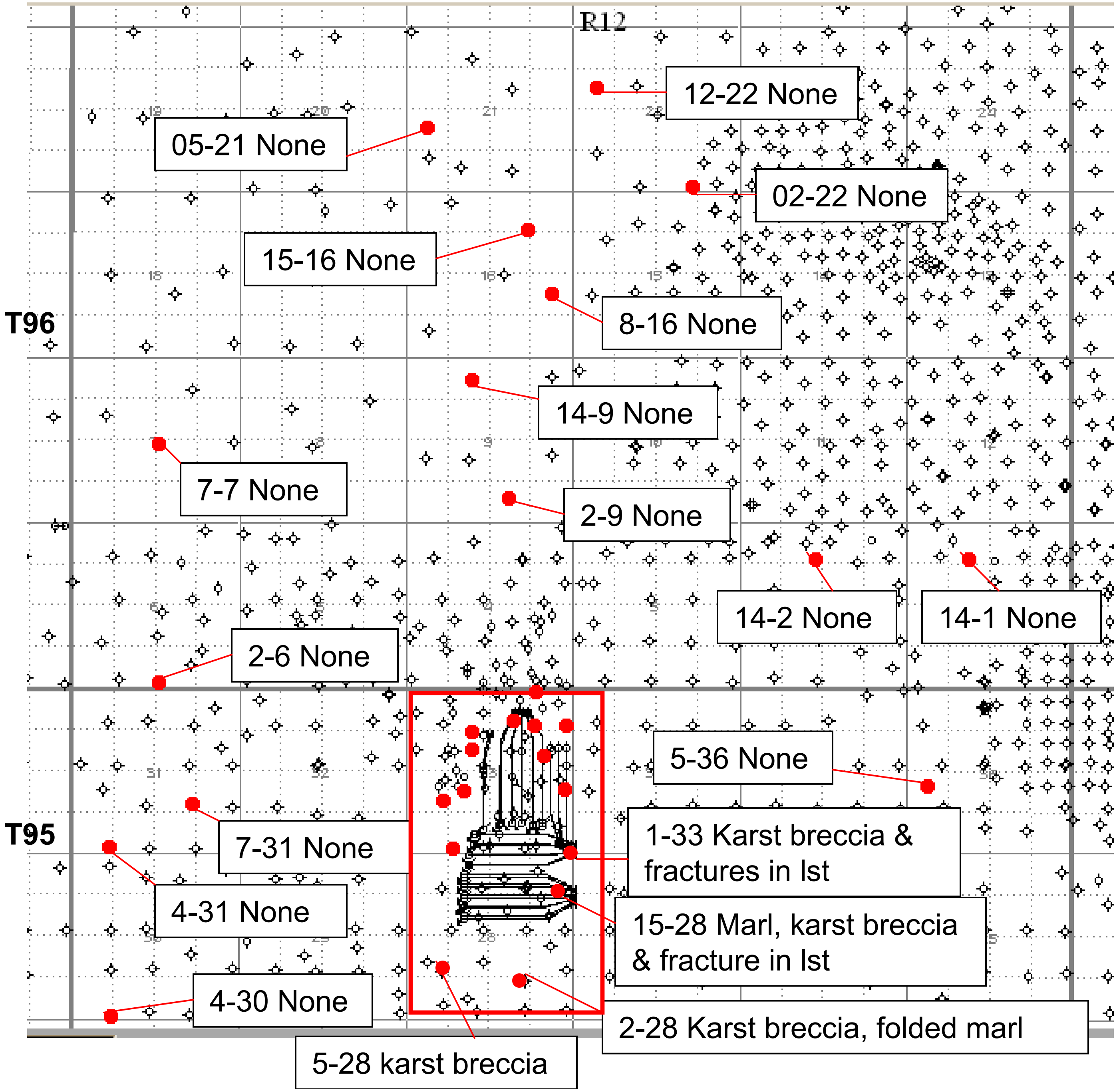


Figure 29. Summary of Core Review Re Karst Development: Area Surrounding Joslyn Ck SAGD Pilot

(see Table 4)

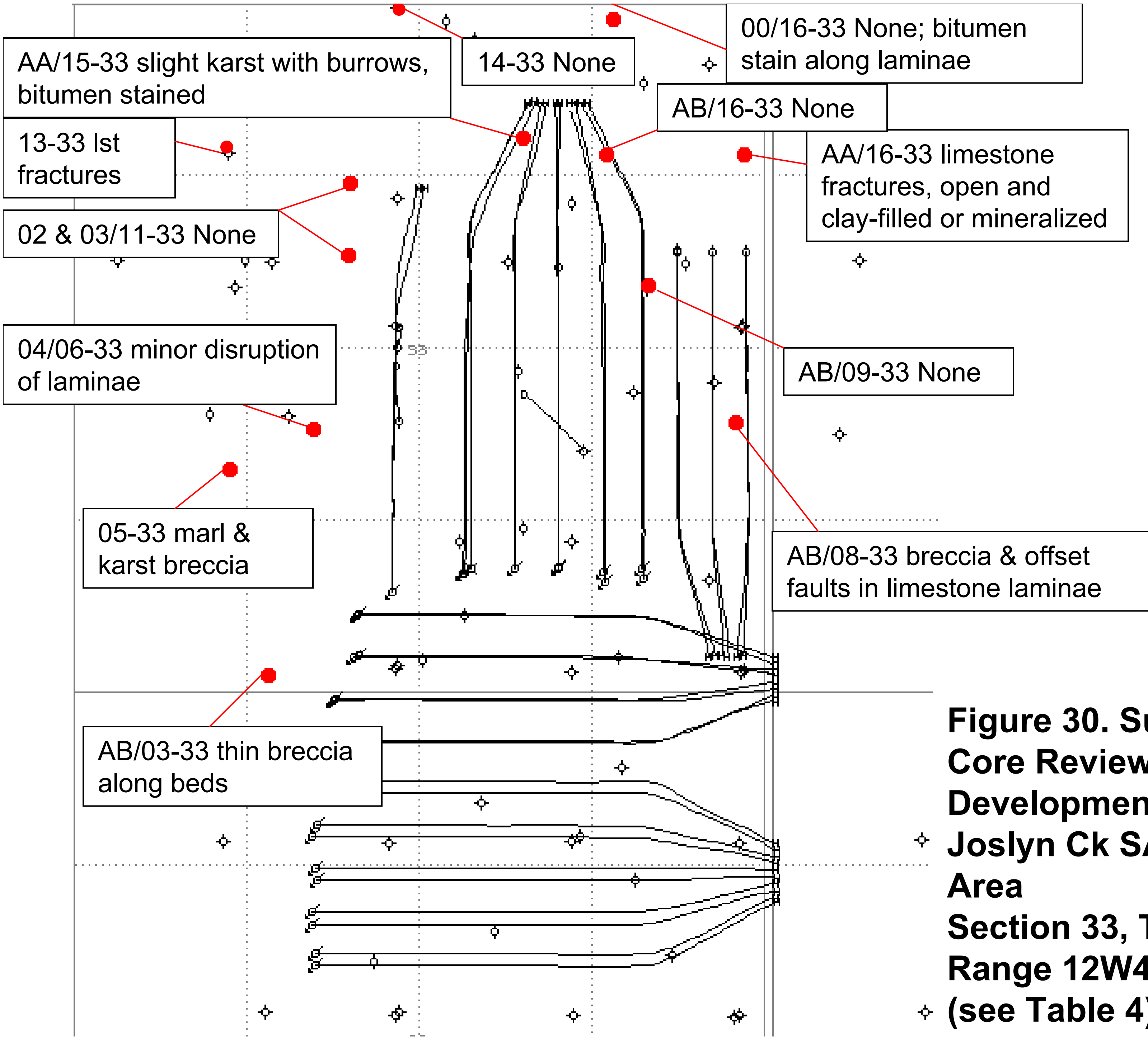
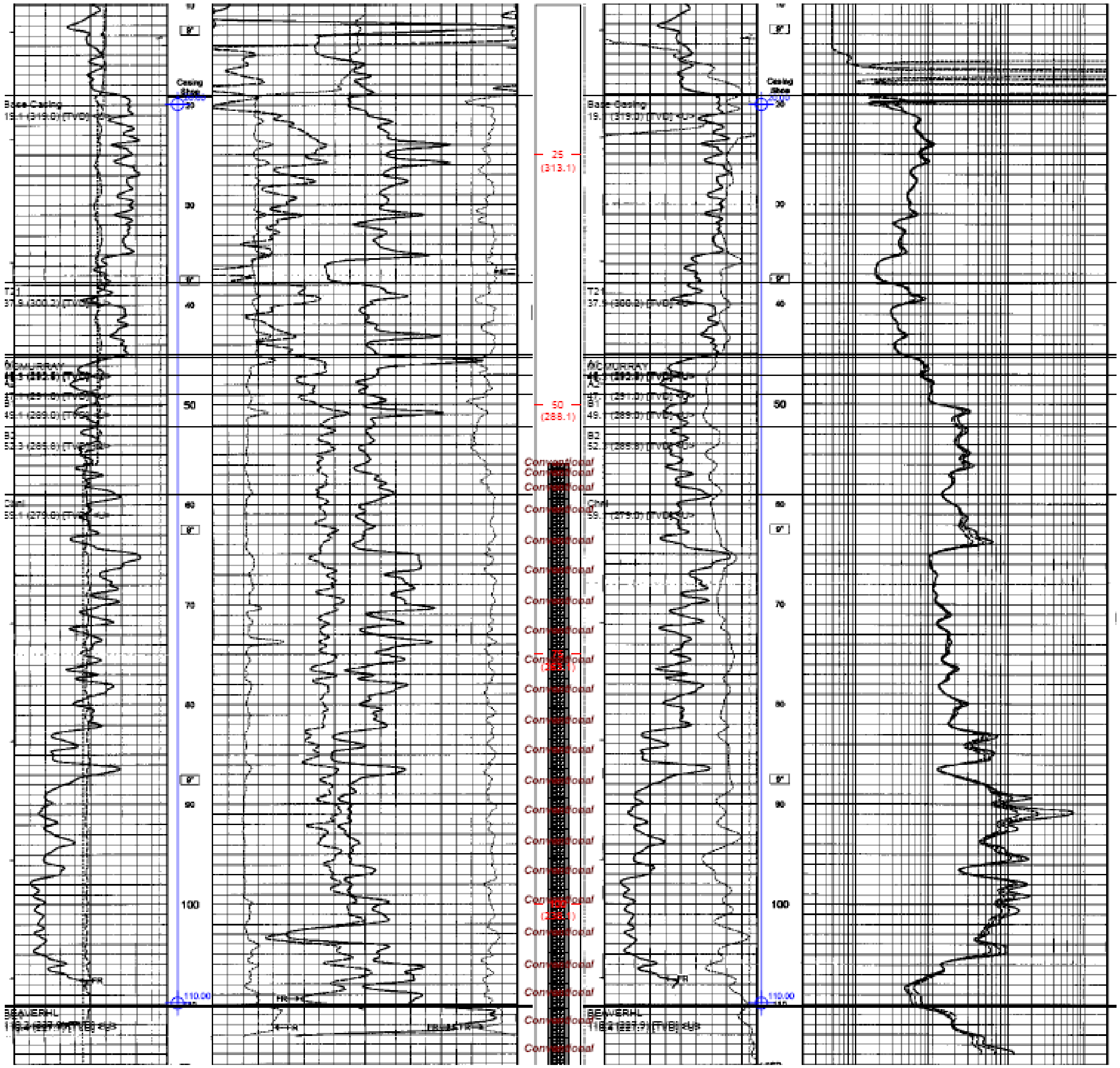


Figure 30. Summary of Core Review Re Karst Development: Joslyn Ck SAGD Pilot Area Section 33, Township 95 Range 12W4 Meridian (see Table 4)

AA/05-33-095-12W4



Core Photos

Figure 31

AA/05-33-095-12W4: Core Depth 105.05 m – 109.05 m

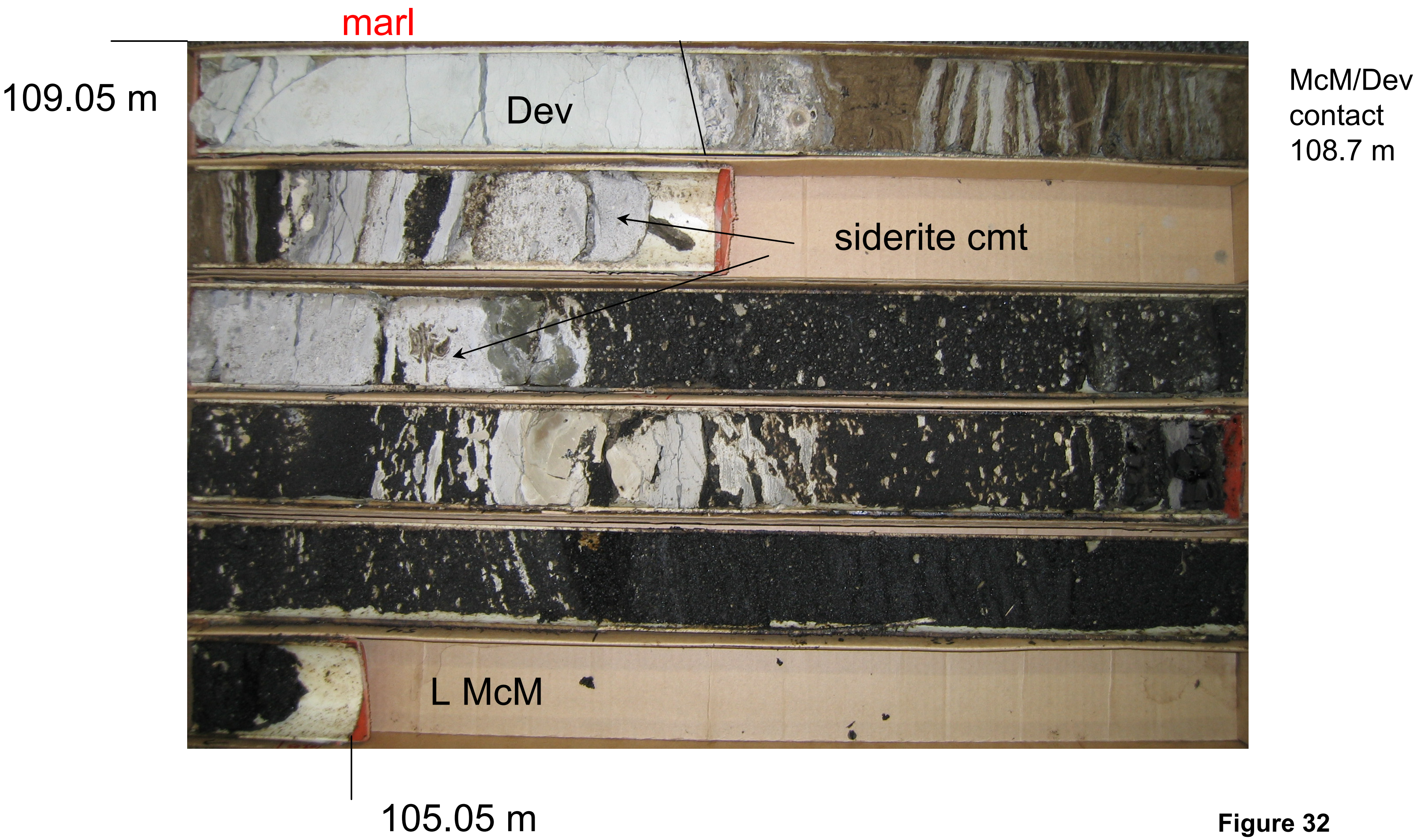
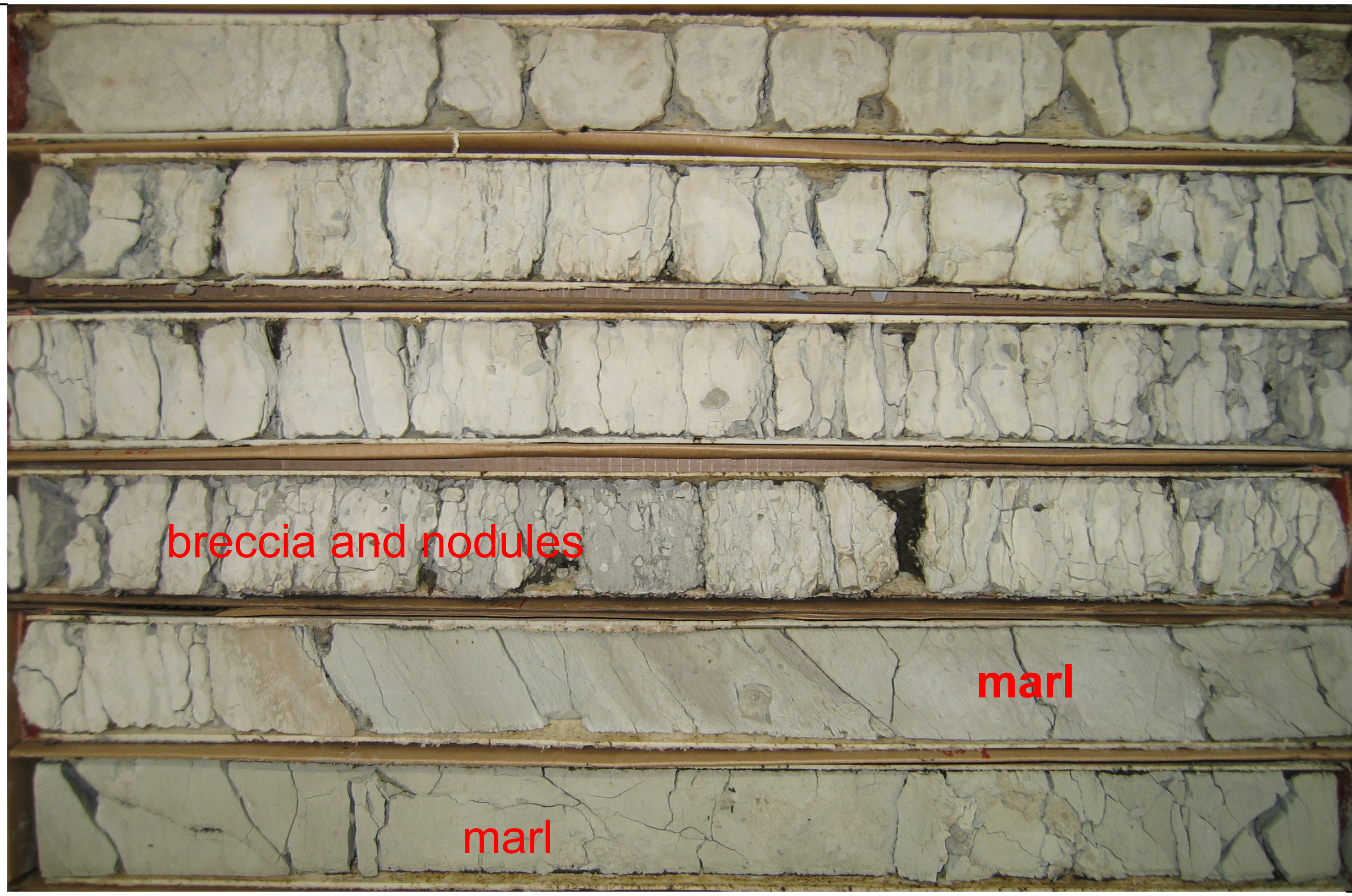


Figure 32

AA/05-33-095-12W4: Core Depth 109.05 m – 113.55 m

113.55 m



109.05 m

Figure 33

04/06-33-095-12W4: Core Photo from top Devonian down ~ 3.75 m

Figure 34

AB/08-33-095-12W4

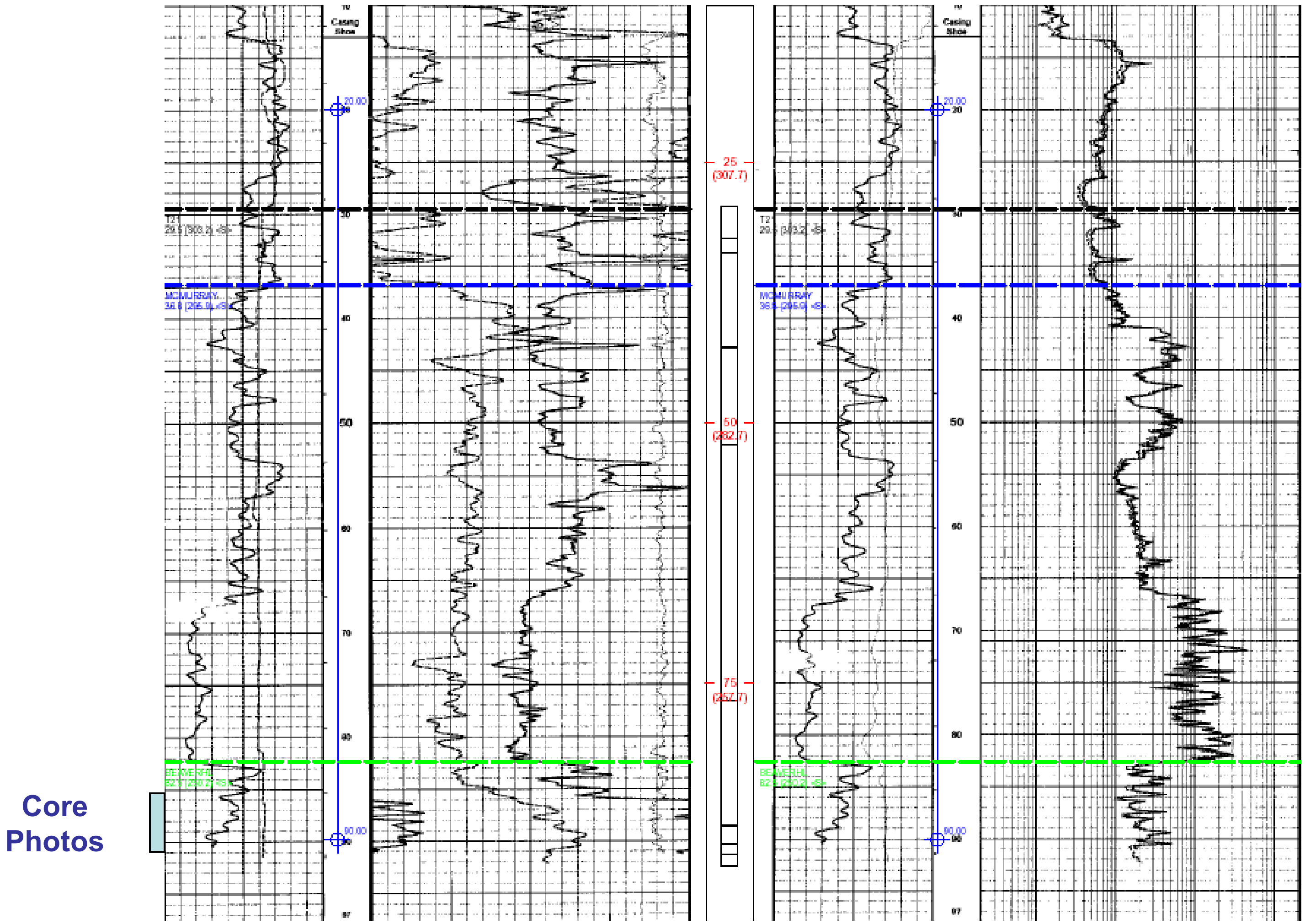


Figure 35

AB/08-33-095-12W4: Core Depth 85.7 m - 89.45 m

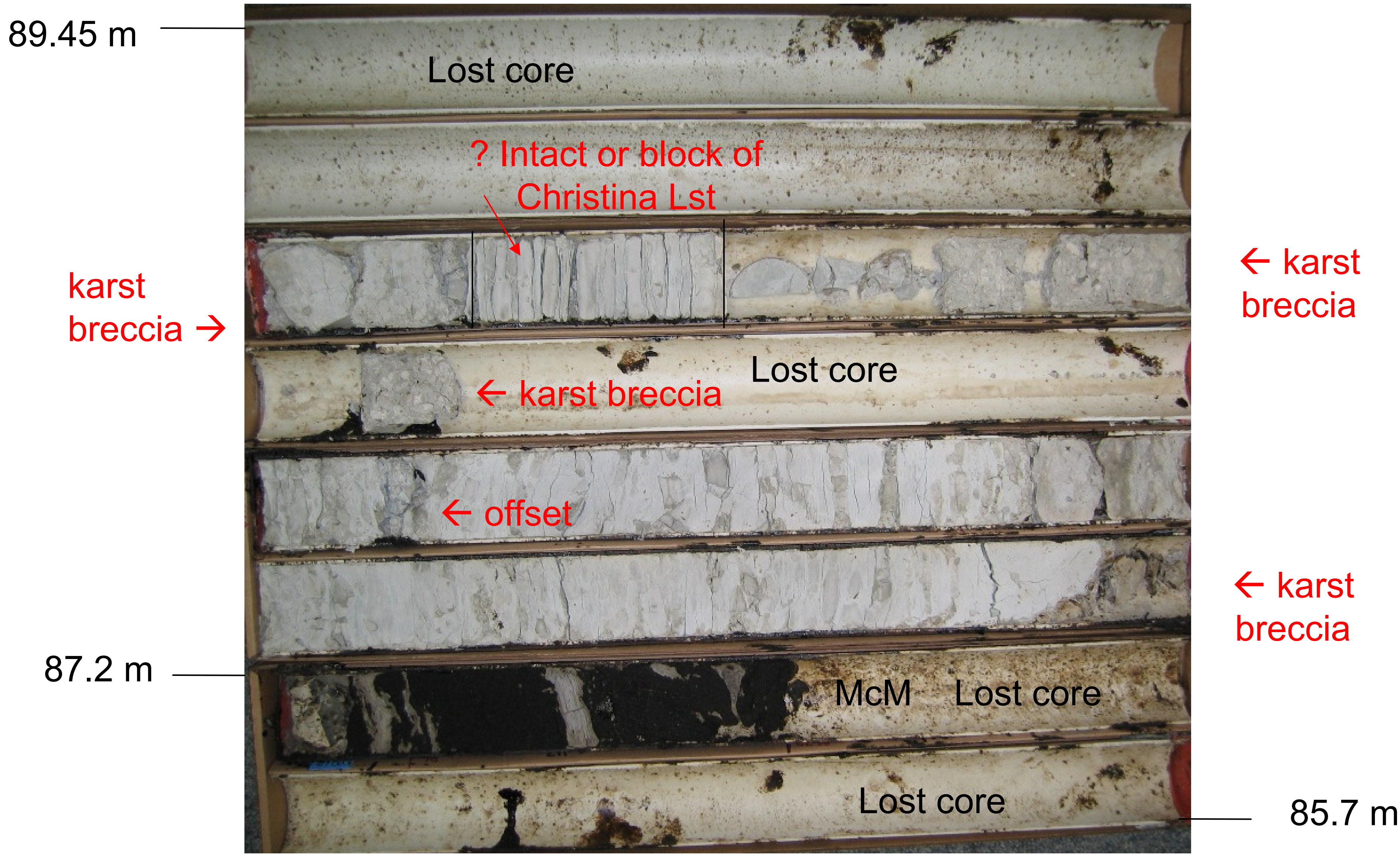


Figure 36

AA/15-33-095-12W4

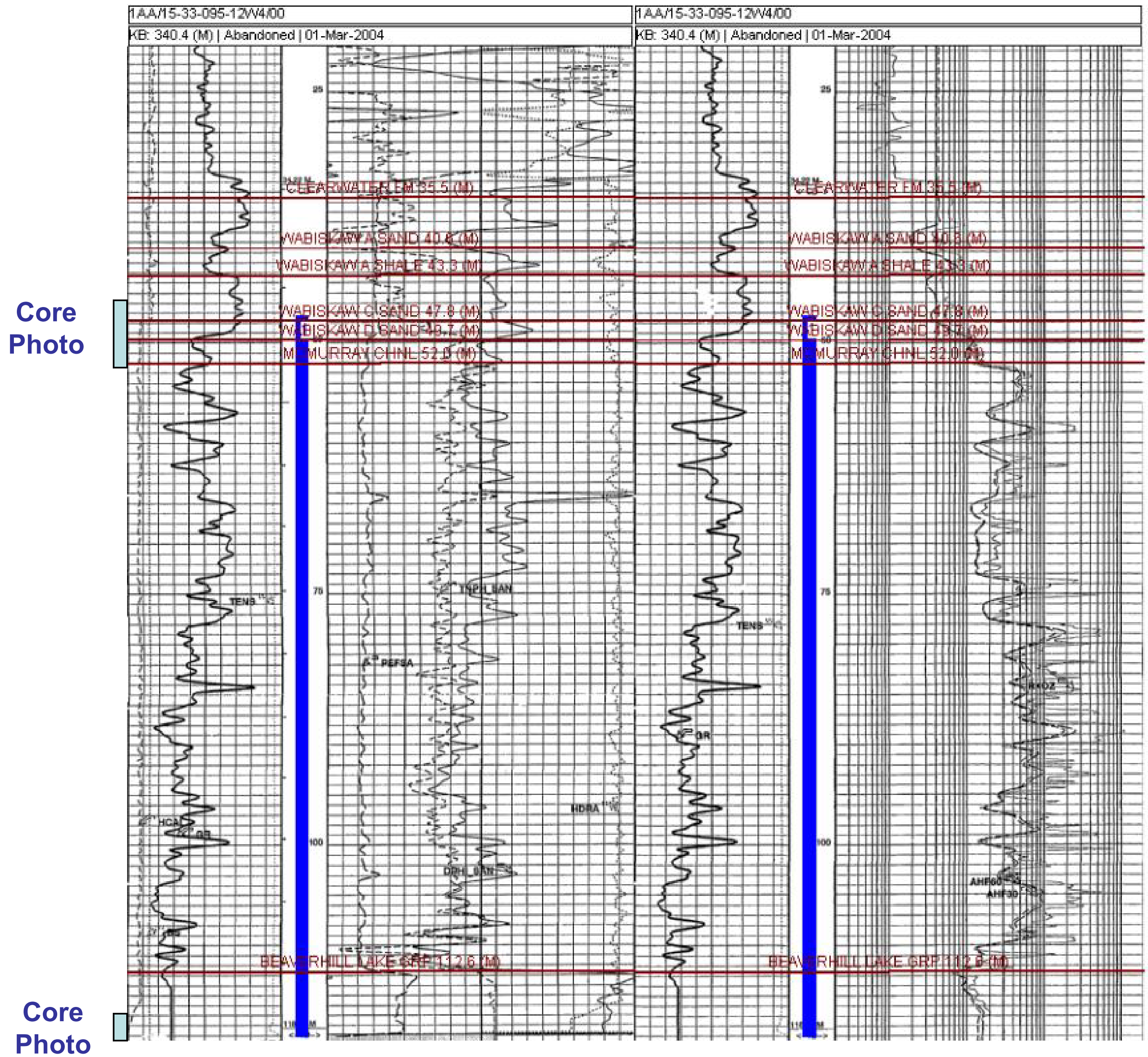


Figure 37

AA/15-33-095-12W4: Core Depth 116 m – 119.1 m

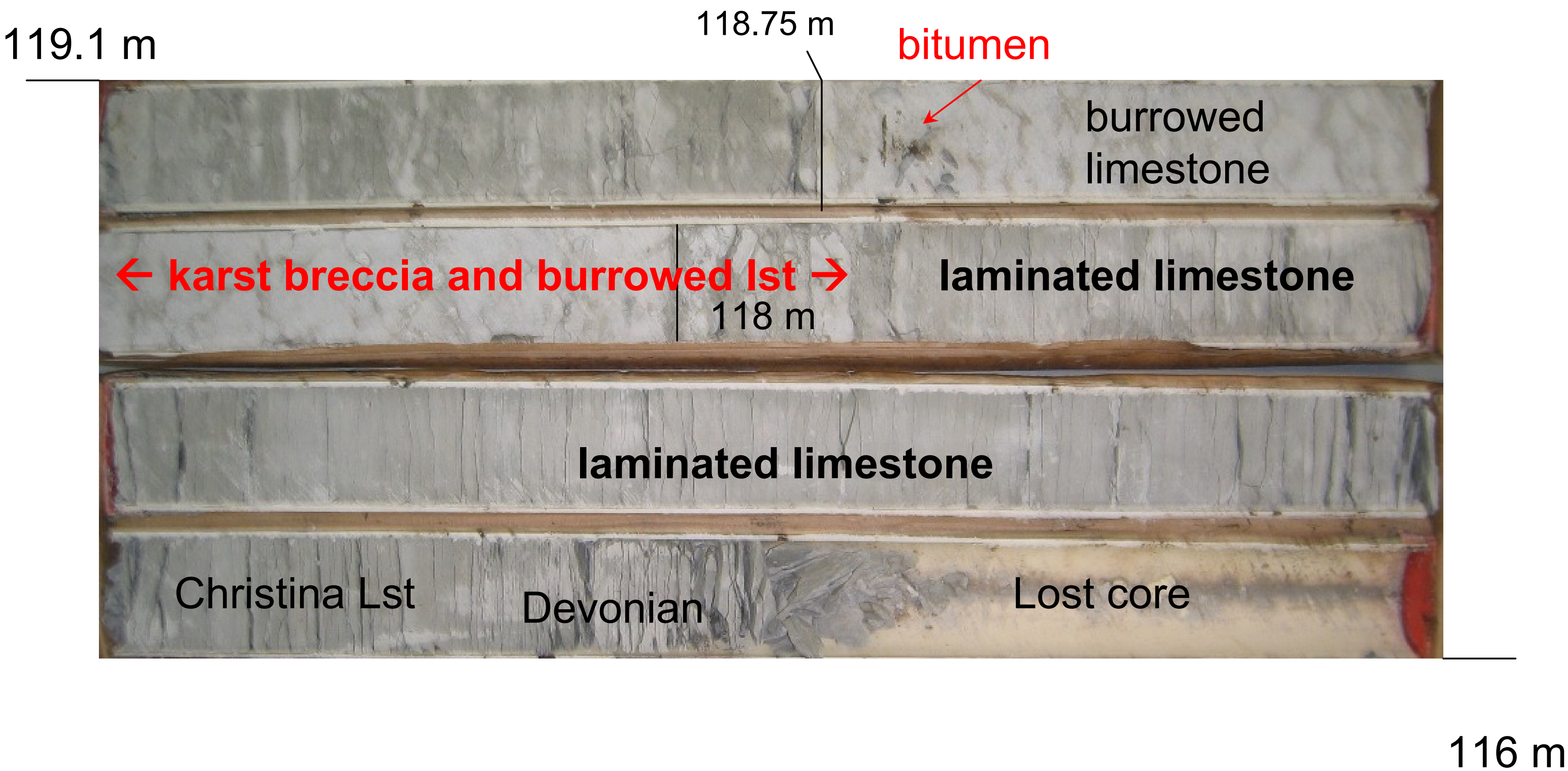
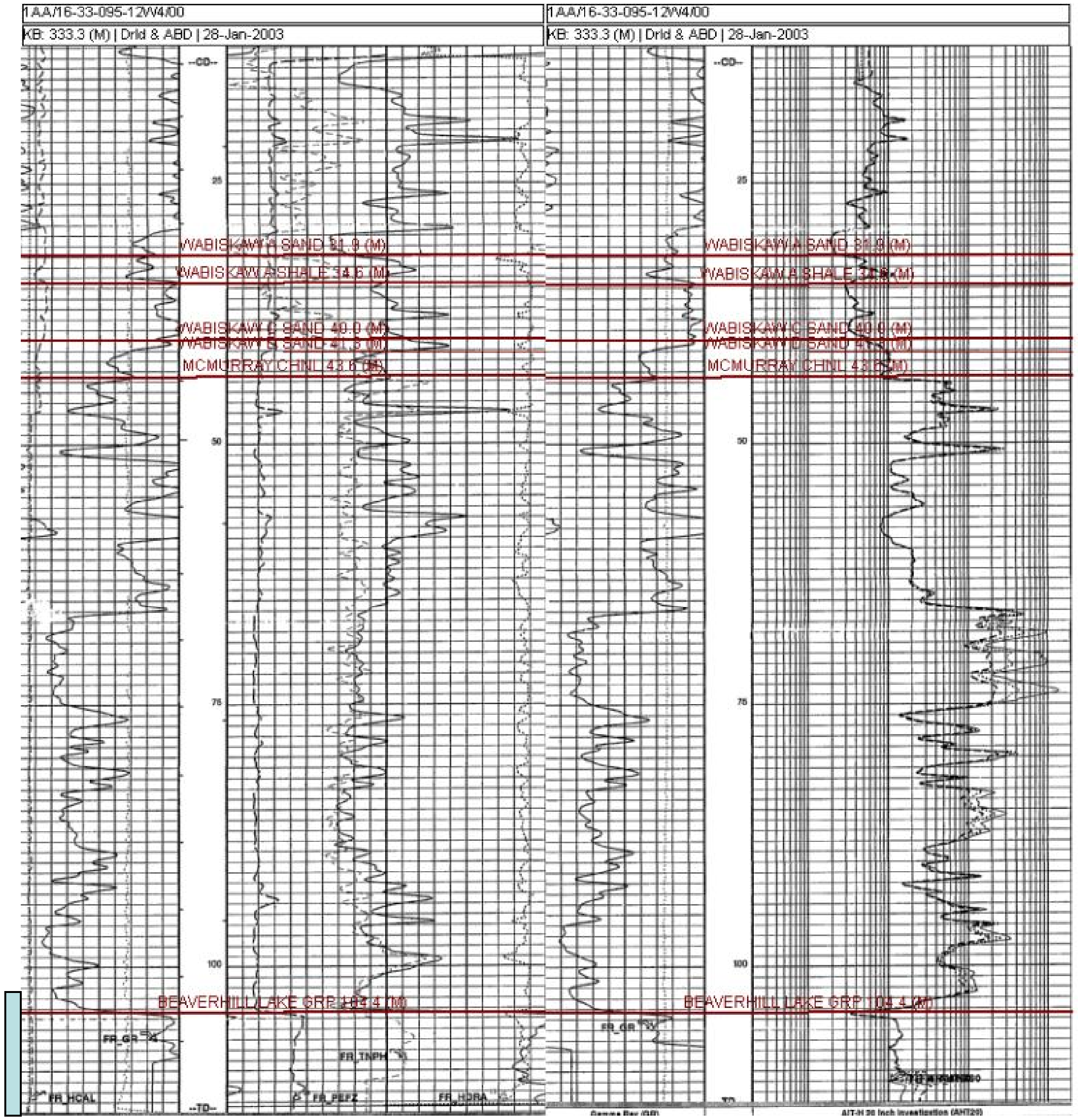


Figure 38

AA/16-33-095-12W4

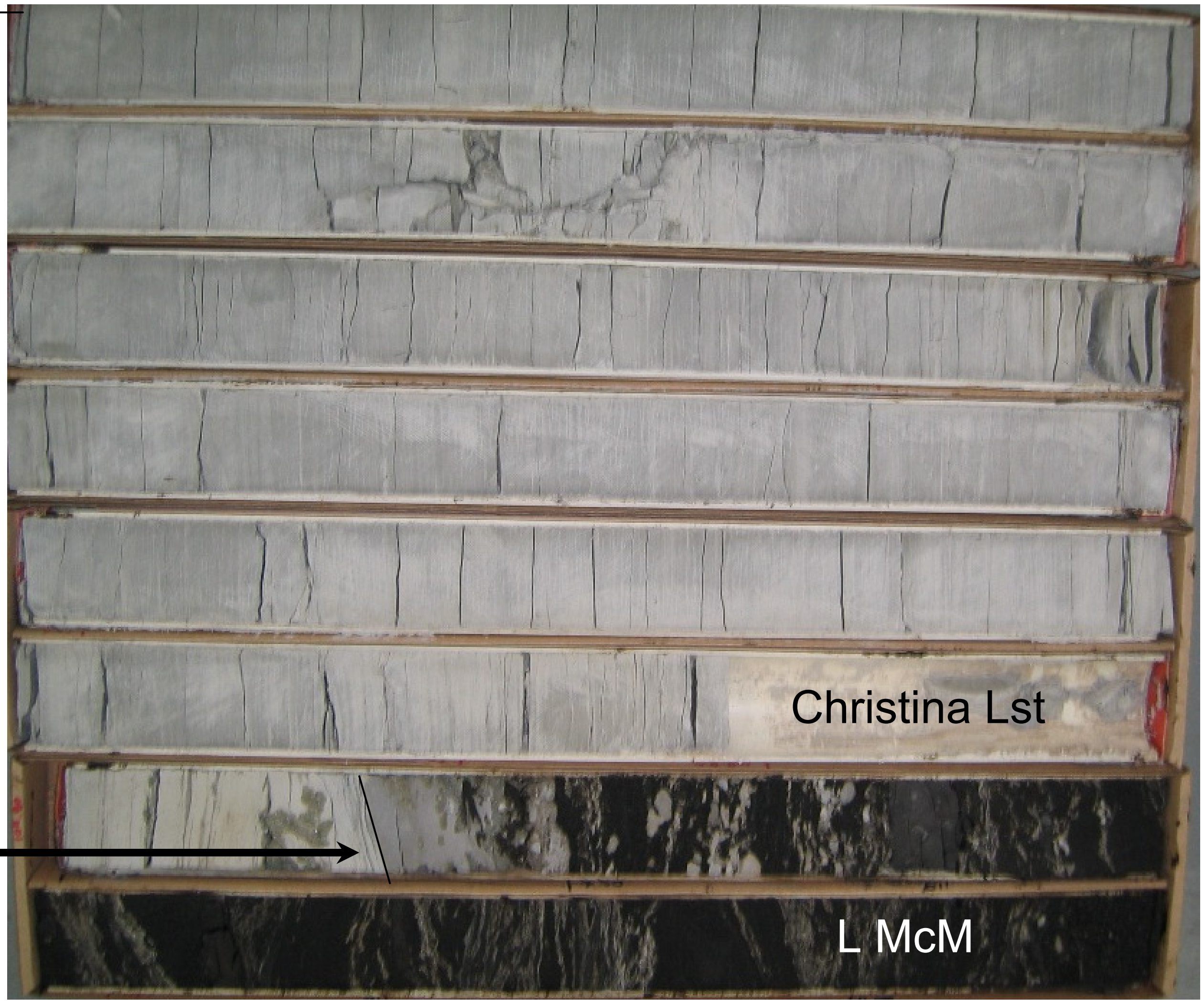


Core Photos

Figure 39

AA/16-33-095-12W4: Core Depth 103.3 m – 108.83 m

108.83 m



McM/Dev contact 104.45 m

103.3 m

Figure 40

AA/16-33-095-12W4: Core Depth 109.05 m – 113.3 m

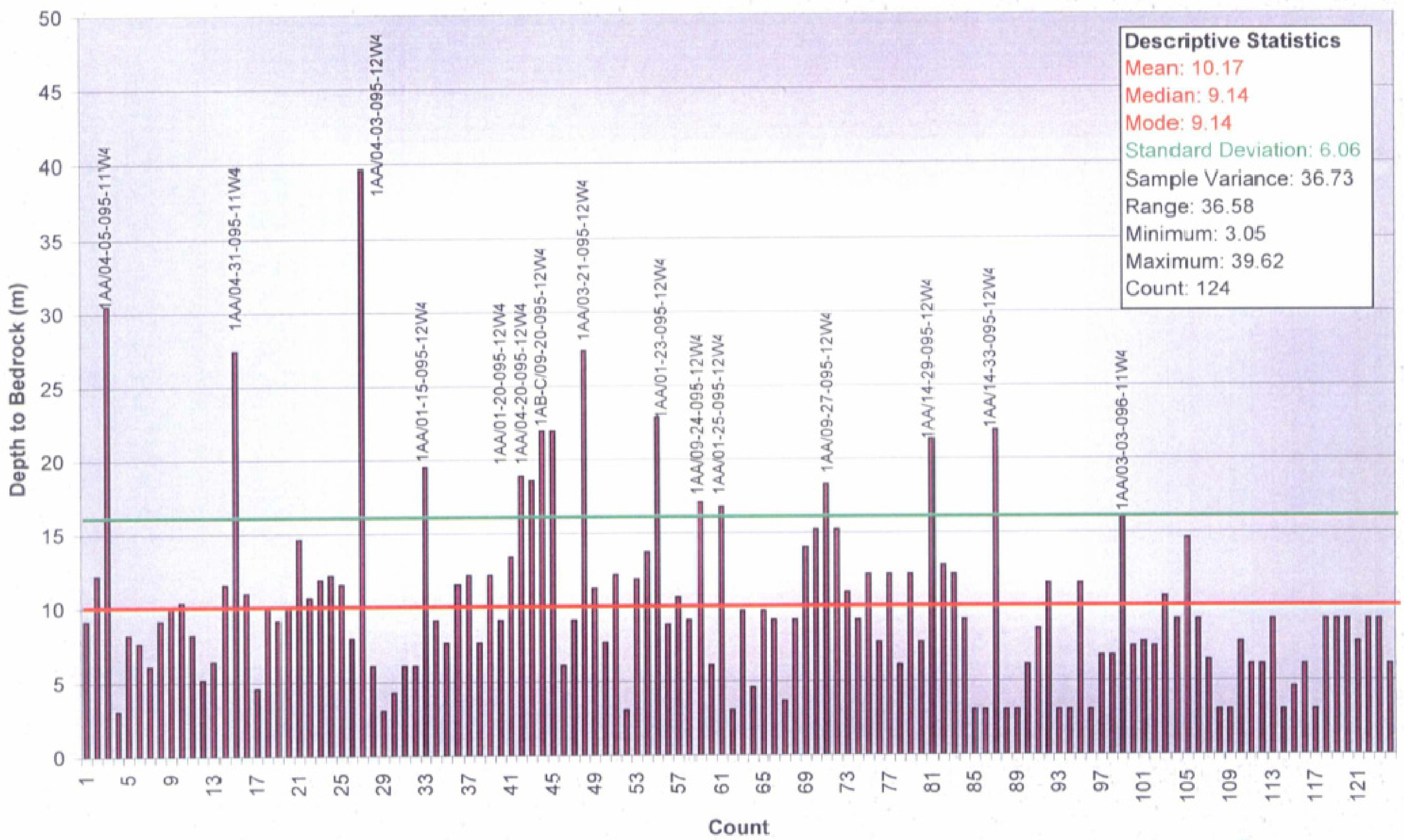
113.3 m

110.55 m

Figure 41

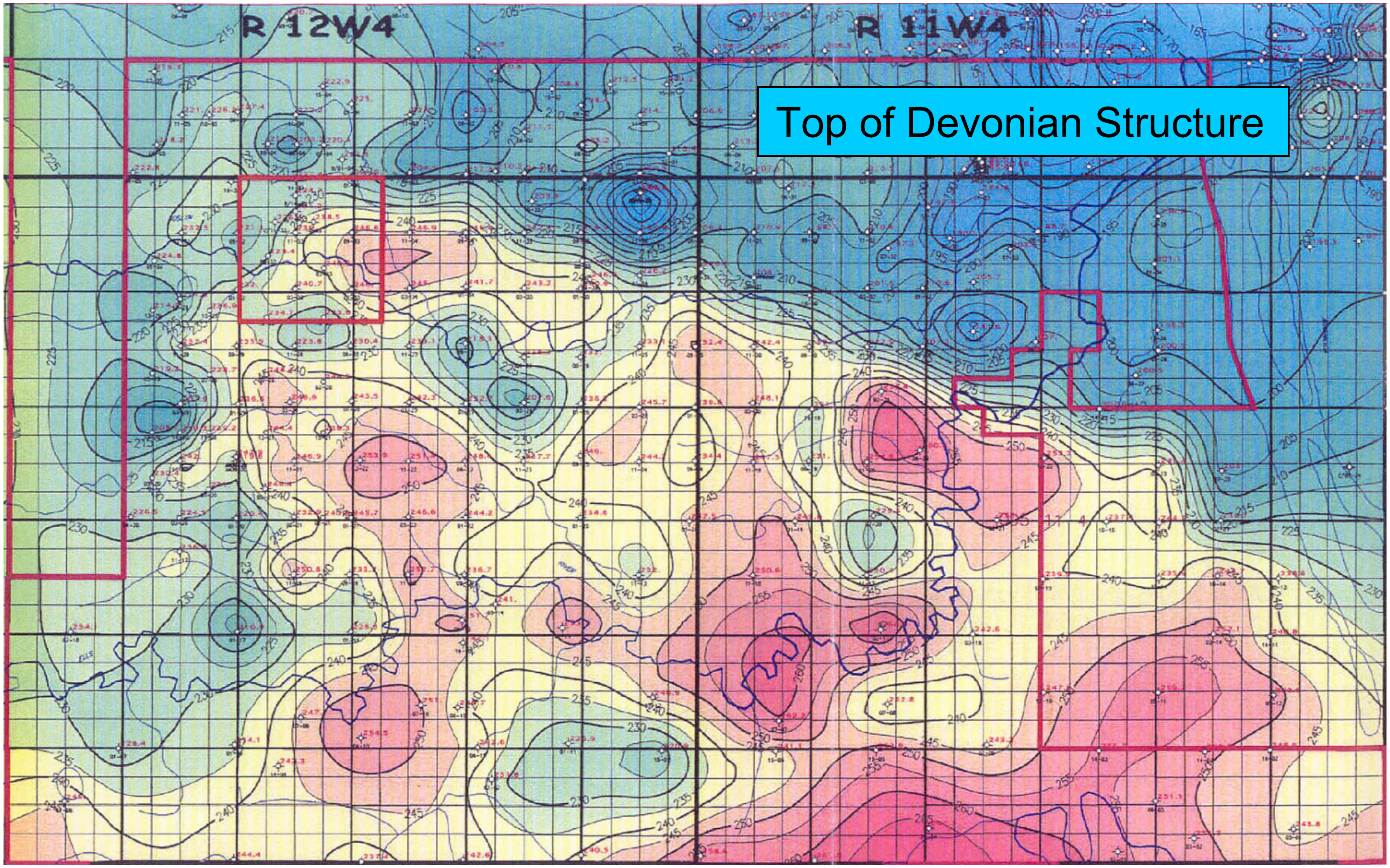
109.05 m

Figure 42. Variability of depth to bedrock in the EUB database, from Township 95 to 96, Ranges 11 to 12W4 M.



(from Deer Creek Energy Ltd., 2001)

Figure 43. Paleozoic structure map for the Joslyn Creek Lease 24 area



Paleohighs

265

245

Sinkholes

225

215

≥ m_asl

(from Deer Creek Energy Ltd., 2001)

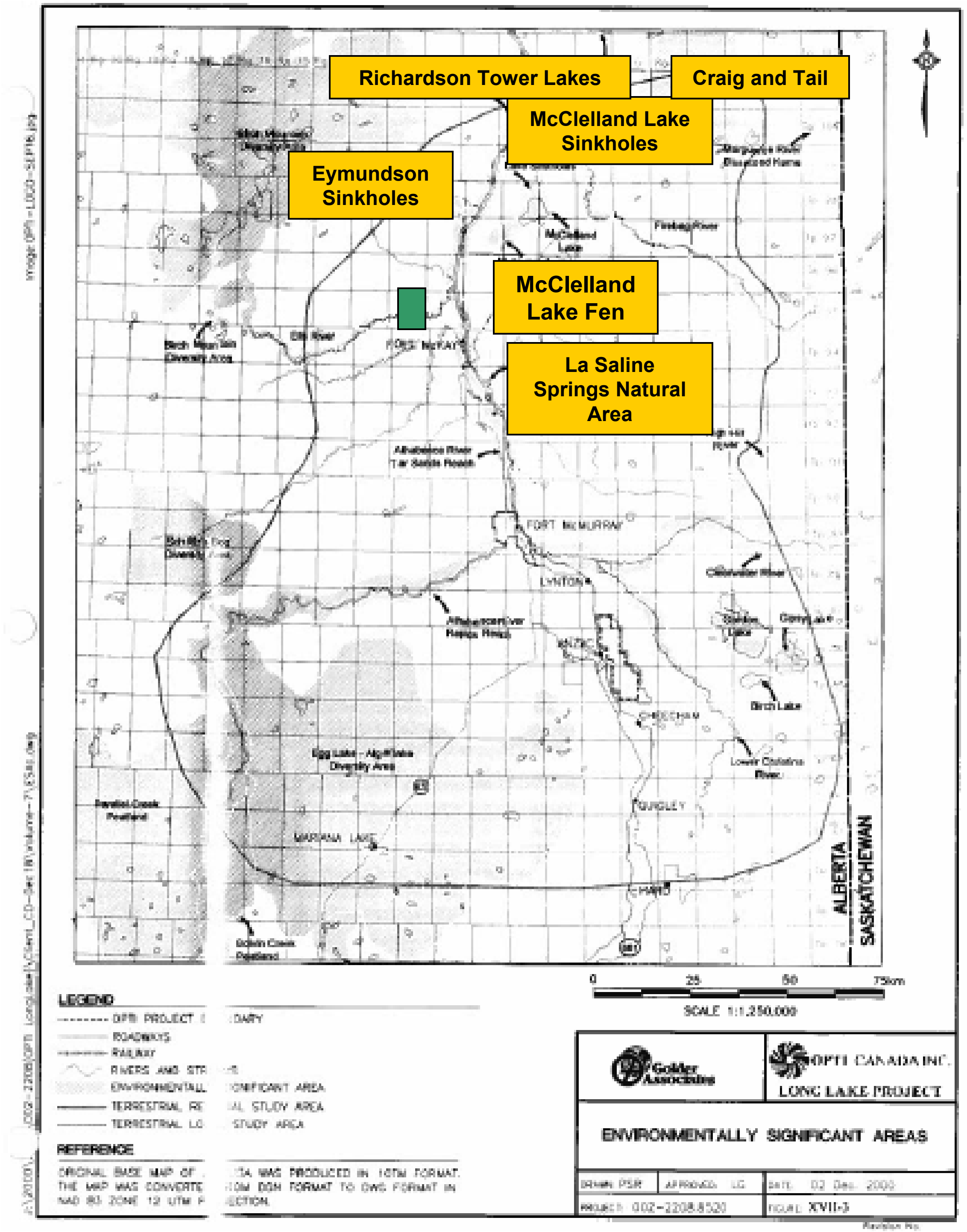


Figure 44. Location of Environmentally Significant Areas in the Fort McMurray Area, with yellow highlights indicating modern karst-related features and green the immediate area surrounding the Joslyn Creek SAGD pilot (modified from Golder and Associates, 2000).

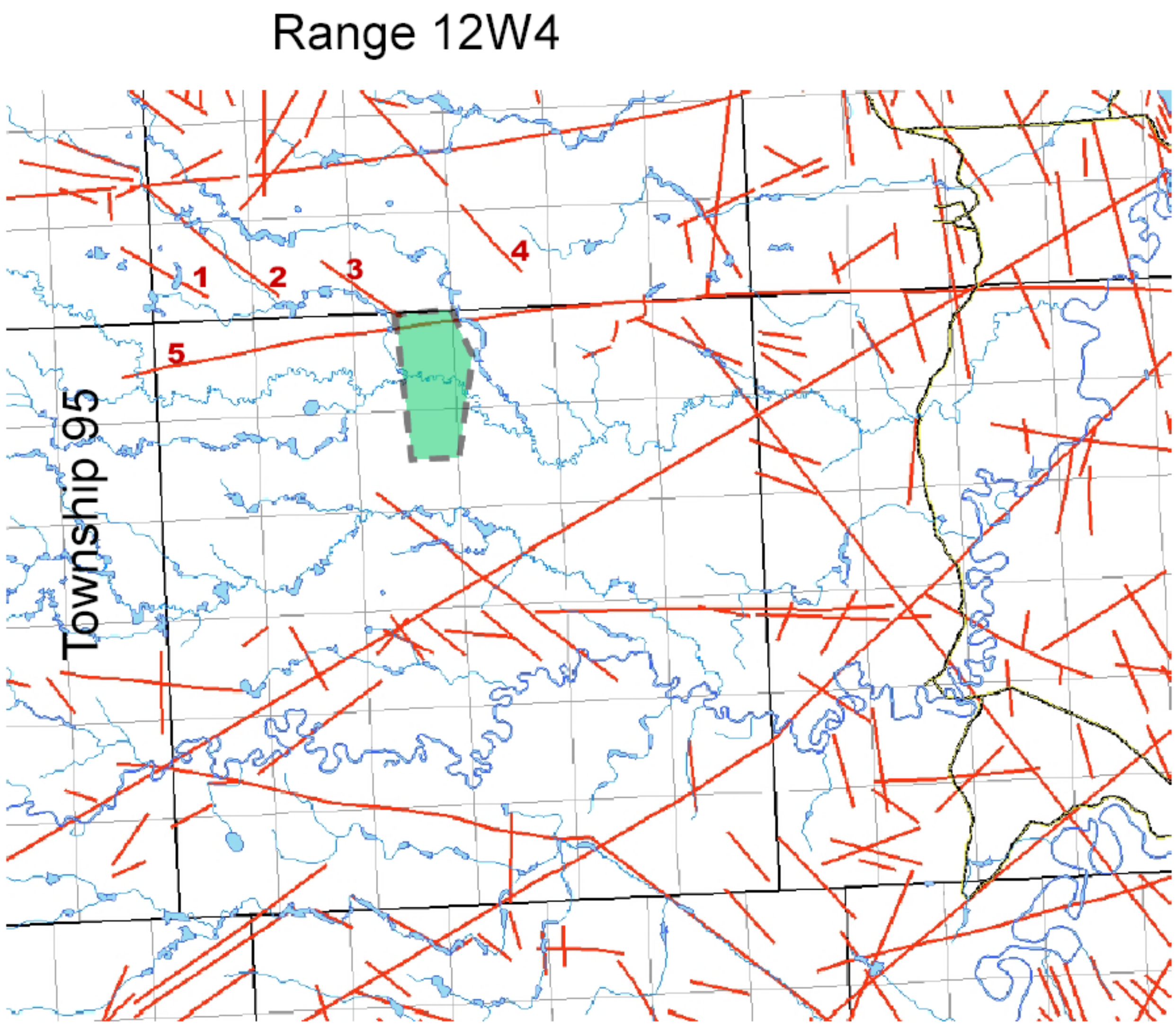


Figure 45. Location of five structural lineaments in the Joslyn Creek SAGD Pilot Area (shown in green) (modified from Pana et al., 2001).

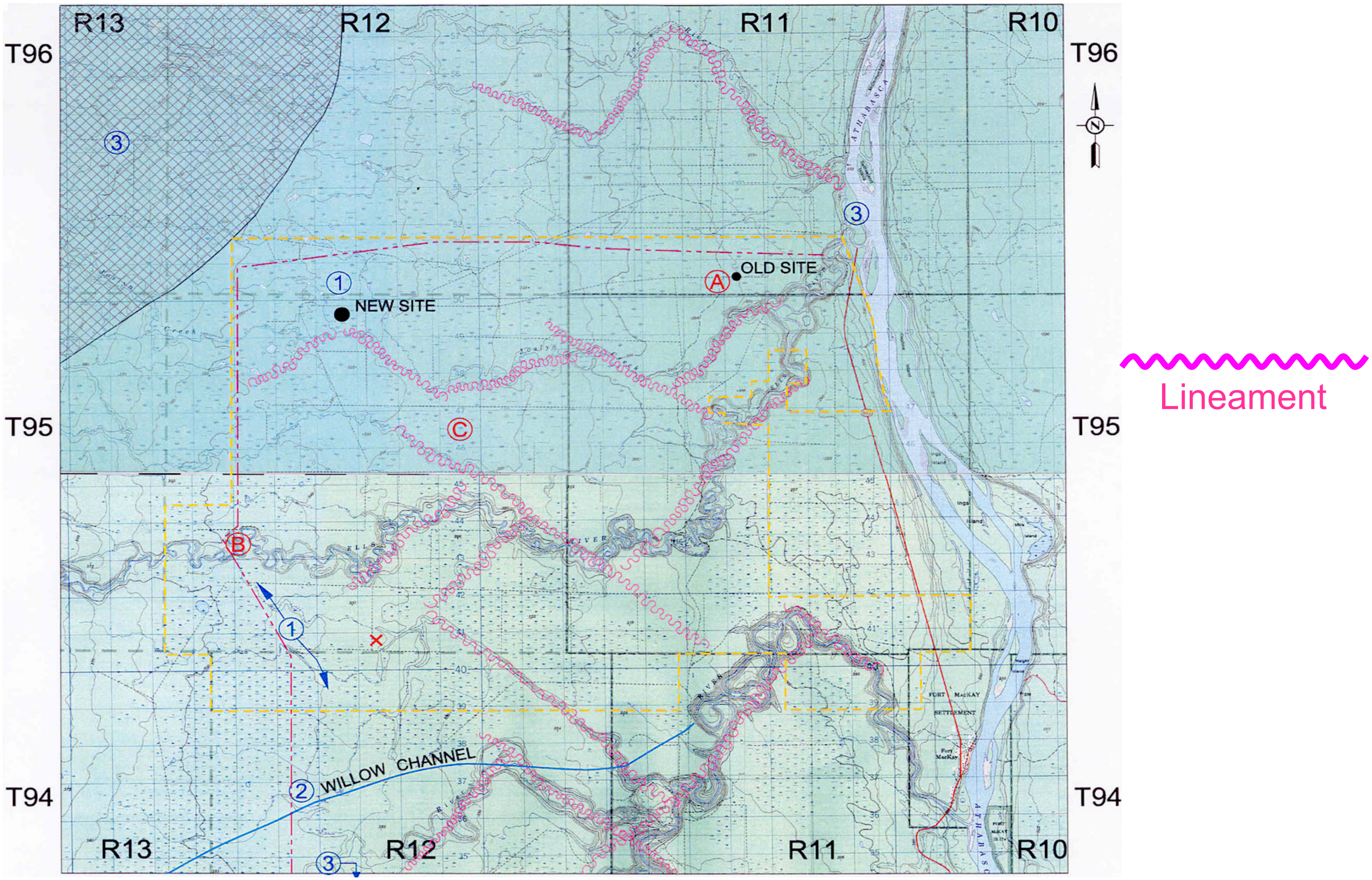


Figure 46. Location of structural lineaments in the Joslyn Creek SAGD Pilot Area (from Deer Creek Energy Ltd., 2001).

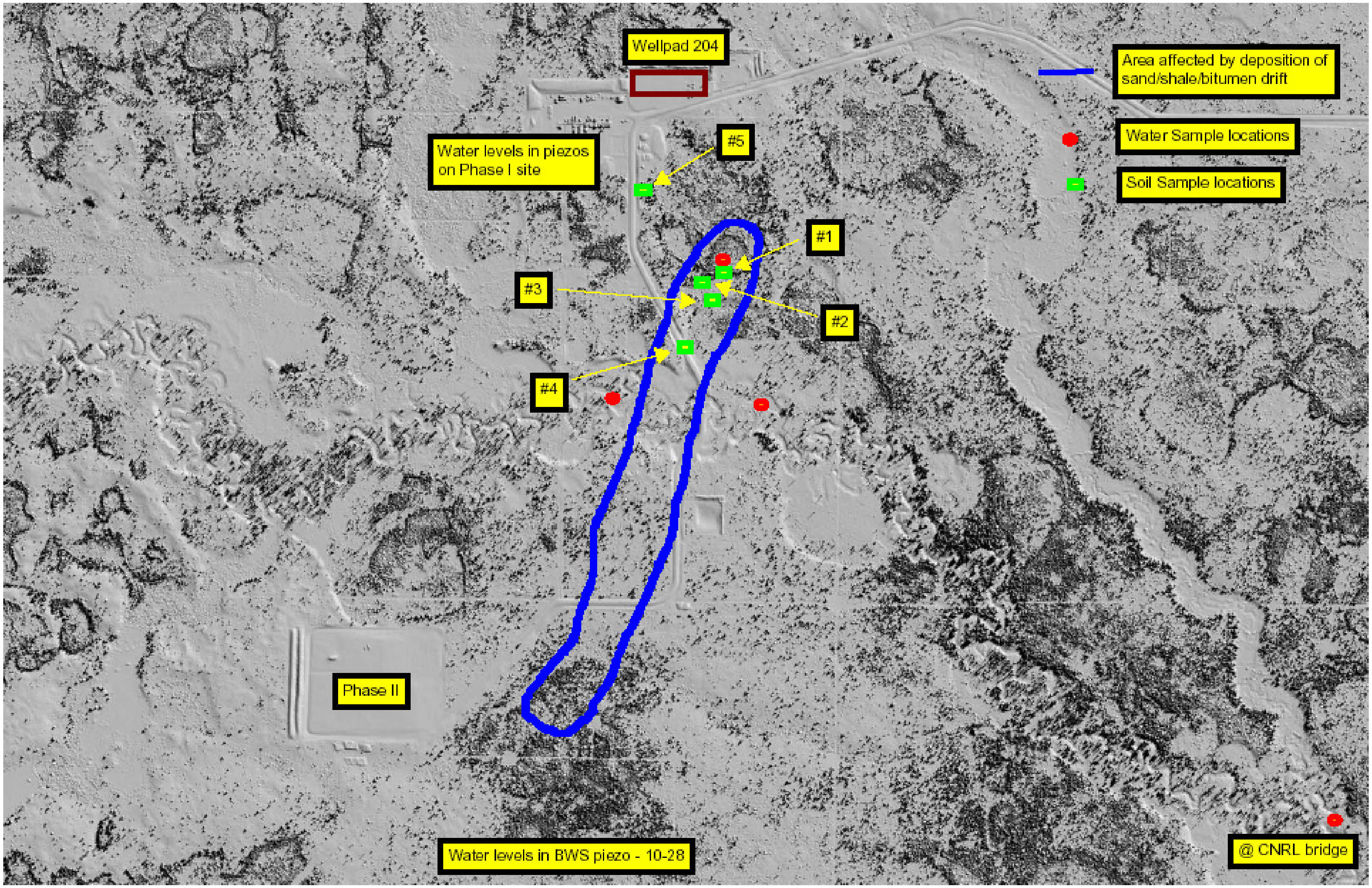


Figure 47. Air photograph showing locations of soil, water and groundwater monitoring related to the Steam Release Incident (from Deer Ck Energy Ltd. preliminary report to Alberta Environment AENV Reference # 171389)

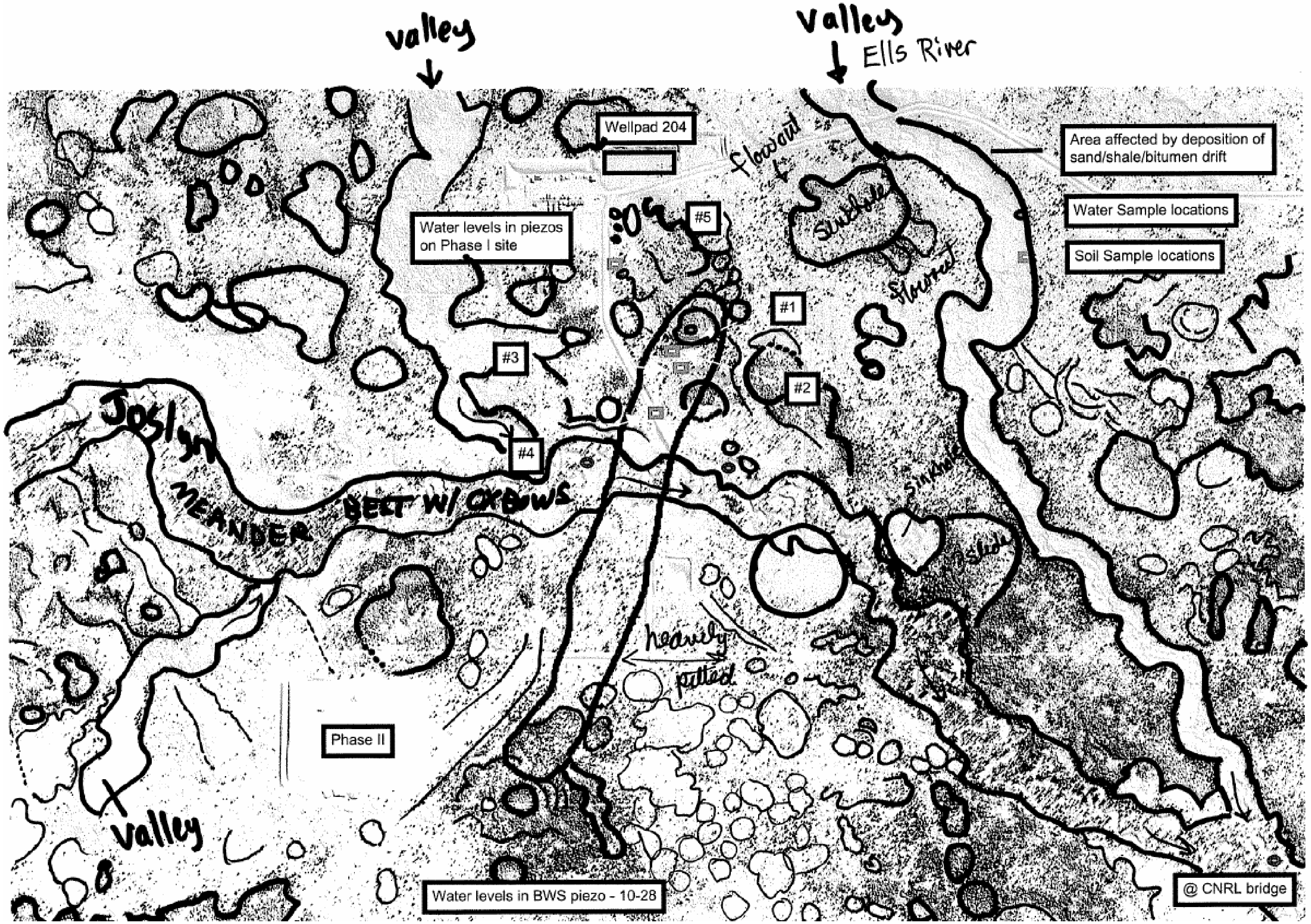


Figure 48. Air photo Interpretation Joslyn Creek Steam Release Incident area. Most of the circular features are interpreted as karst sinkholes, with mires above them. Heavily pitted area is possibly a glacial feature, and oxbow and valley belts associated with meandering rivers labeled.

Appendix 2: Staff information requests to Deer Creek Energy Ltd. (Total), May-June 2006

EUB Alberta Energy and Utilities Board
Bonnyville Field Centre P.O. Box 5169, 4901 – 50 Ave Bonnyville, Alberta T9N 2G4 Tel 780 826-5352 Fax 780 826-2366

File #4010

May 24, 2006

Mr. Don Verdonck
General Manager, Operations
Deer Creek Energy Ltd.
Bow Valley Square 2
2600, 2005 5 Avenue SW
Calgary AB T2P 2V7

Via fax: (403)264-3700

CASED HOLE UNDERGROUND BLOWOUT
WELL NAME: DCEL ET AL 204 I1 DAPHNE 1-33-95-12W4M
LSD: 103/01-33-095-12W4M
LICENCE #329502

On May 18, 2006, this office was notified of a cased hole underground blowout at the above location.

Please submit a written summary in accordance with *section 8.190(4) of the Oil and Gas Conservation Regulations*, on the sequence of events prior to, during and after the uncontrolled flow at the above location.

Please also include the following technical data that will assist in the investigation.

1. Please submit the total volume of steam that has been injected into the above well and the injection area. These volumes would begin with the first day of injection of the project.
2. Describe all injection monitoring system(s)/alarms installed in this system that monitor pressure, temperature(s) and formation integrity.
3. Please submit a well diagram for the above well outlining all the drilling and completion data. This would include hole size(s), surface casing, cement blend(s), production casing type and grade, hydrogeology, geology, tubulars, etc.

...2

4. Please submit the torque turn information on the intermediate and liner casing for the above well.
5. Outline if the above well or it's production partner well commonly known as P1 had any recent well services operation(s) conducted.
6. This steam blowout to surface created a larger crater at surface. The Alberta Energy and Utilities Board (EUB) is not able to clearly define the root cause of this event at this time. Please submit all relevant information related to overburden. This information must describe depth and makeup of the overburden. It must also outline fracture gradients, hydrostatic pressure and isolation barriers such as shale. Any downhole logs indicating shale or thermal chambers would be appreciated as supplemental information.
7. The on-site EUB inspection revealed a well(s) inside the crater area. Please submit all the drilling, completion and if applicable, abandonment operations for this well.
8. Please comment on your company's plan to conduct logging operations (eg: temperature) in an attempt to gain more downhole information. This would also assist in defining any anomalies in the string(s) of tubulars in the well.
9. Please outline your company's plans to address any potential environmental effects from this event.
10. Please include all shear stress calculations for this thermal area.
11. Please also provide all upheaval and subsidence monitoring system(s) information.

As discussed verbally with yourself, the steam injection/reservoir pressure for this project will not exceed 1,500 KPa until such time as the cause of this event is defined and the definition and action plan to address the issue(s) is deemed acceptable by the EUB.

Please schedule a meeting with the EUB Bonnyville Field Centre Office at your earliest convenience to review the above information and to discuss a go forward production operational plan.

The attached blow/blowout data sheet must be filled out where highlighted and returned with your information package.

Please have the above summary and all related information submitted to this office by June 30, 2006.

…3

Should you have any comments, questions or concerns regarding the above contact Mr. Gerry Petroskey or me at (780) 826-5352.

DHennessey

Don Hennessey
Team Leader

DH/kmi
Enclosure
pc: Dan Sarnecki, EUB Calgary
Paul Bothwell, Operations, EUB Calgary
Paul Saulnier, EUB St. Albert
Kris Geekie, EUB Calgary
Kevin Kostrub, EUB Calgary

Total E&P Canada Ltd.
Incident of May 19, 2006
Meeting Follow-Up, May 26, 2006

Pre-incident geologic conditions that were present to explain what happened

1. Pre-Incident Geologic Description of the Incident and Surrounding Area.
   a) Provide your geologic description of the area immediately surrounding the incident. Include in this description lithology, bitumen, water and/or gas saturation, facies analysis, or other geologic descriptions, and a detailed cross section between the horizontal injector well, the adjacent observation and core wells, and the 02/09-33-95-12W4 well.
   b) Submit all core photos, photoelectric logs, log descriptions, and data in the AB/09-33-95-12W4 and AB/08-33-95-12W4 wells.
   c) Submit detailed contour maps of the sub-cretaceous unconformity and the top of the Wabiskaw member beneath Section 33 and the west half of Section 34; indicate, for each map, which areas are defined on the basis of seismic or other geophysical surveys.

2. Nature of Quaternary Overburden and Possible Occurrence of Quaternary Channels
   a) Confirm and submit the evidence that indicates an absence or presence of Quaternary channels nearby to the incident; include the location and description of the content of any auger holes drilled, to inspect the Quaternary, in the vicinity of the incident.
   b) Submit a surficial geology map of the area surrounding the incident showing the thickness and distribution of overburden.

3. Nature of Fracture and Lineament Patterns in the Area.
   a) Submit any maps that show surficial or sub-surface lineaments, fractures or faults in the area prior to the event. Include all zones of weakness which may have had a potential for failure.
   b) Discuss the extent to which any precipitation or ground moisture content conditions might have contributed to any failure.

4. Nature of Muskeg, Surface Runoff, and Possible Karst Features in the Area.
   a) Submit full-scale air photos of the area taken prior to the event and include the trajectory and surface location of all SAGD, observation and core hole wells.
   b) Provide electronic maps showing up to date layouts of wells and facilities and location of incident.

   On air photos of the area, Board staff noted the occurrence of pre-existing circular, generally non-treed areas, surface features at and surrounding the incident location.

   c) Discuss the nature of such pre-existing circular features in the muskeg that lack trees, and include any shallow geophysical or other survey information (i.e. GPR) that may help determine whether these features may be related to paleokarst or modern karst sinkholes.
   d) Discuss whether the circular feature at the incident location represents a sinkhole and whether any potential fracturing of the pay and/or seal zones related to sinkhole subsidence contributed to the incident?

Post-incident geological conditions that now exist surrounding the incident area

5. Summarize your assessment of the post-incident geology and what effect the incident has had on the geology of the immediate area. To what extent has the geologic integrity of the seals in the incident area been compromised?

Provide:

a) All logs which are being rerun in any well surrounding the incident area after the incident.
b) Any surficial geology maps and air photos of the area after the event.
c) All surficial surveys of the area that give the sizes, location, and description of debris that was ejected with the incident.
d) A map that shows the thickness and distribution of the ejecta, particularly the larger-sized material. Were there any McMurray blocks of material in the ejecta? Are only Clearwater Shale blocks in the ejecta? Where did the bitumen or other low-grade hydrocarbon in the ejecta come from, and how does Total think it was transported uphole?

6. <u>Nature of Upper Thief Zone and Potential for Communication Pathway to Surface</u>
Board staff noted the possibility of an upper water zone that could be a potential thief zone, occurring above the McMurray at the Wabiskaw – Clearwater contact. This sandy zone consists of two parts, an upper part which overlies the T21 marker, and a lower part which underlies the T21 marker. Examination of resistivity logs suggests that this is not hydrocarbon-bearing.
    a) Comment on the possibility of the presence of a continuous water sand overlying the McMurray, at the upper Wabiskaw – basal Clearwater contact. Submit any evidence that supports your view regarding the potential upper water zone, including any water analysis of the formation water that may have been done.
    b) Discuss the possibility of steam (both during circulation, and during steam chamber phases) of reaching the potential upper water thief zone at wells surrounding 204 I1P1, and the potential for this zone to be a thief zone and to be a connecting pathway leading to surface.

7. For Producer 1 and Injector 1 on Pad 204 provide:
    a) Bottom hole pressure data in tabular form (Excel) for 204 P1 and I1 as presented on plots last week
    b) Provide injection and production volumes in daily format since injection start-up in February and in more detail if available for 24 hour period prior to blowout
    c) Explanation on plots of pressure data including:
        - high pressures on P1 during ESP install
        - pressure trends on both P1 and I1 after incident
        - switch from low pressure injection to high pressure mid April
        - period of 2100 kPA injection in the I1 SS in late April

8. Provide an appropriate photo record that shows all aspects of the incident (including on and off site evidence, aerial shots)

9. Provide a brief description of the plans DCEL will be considering, if any, to utilize reservoir and geo-statistical modeling tools to assist in the understanding of both what caused the incident, and for the resumption of steaming.

Appendix 3: Deer Creek Energy Ltd. (Total) request to restart Phase II operations, July 2006

DEER CREEK
Energy Limited

Dome Tower
1900, 333 – 7th Avenue SW
Calgary, AB T2P 2Z1
Main: (403) 571-7599
Fax: (403) 264-3700

EUB RESOURCES APPLICATIONS
DATE REGISTERED
JUL 17 2006
SUBMISSION # 28213
RE: APPLN # 1393583

TRANSMITTAL

Date: July 21, 2006

RECEIVED
JUL 21 2006
EUB RESOURCES APPLICATIONS

To: Alberta Energy and Utilities Board
640 – 5th Avenue S.W.
Calgary, AB T2P 3G4

Attention: Kris Geekie

From: Jennifer Harding - Senior Admin, Thermal

Re: Steam Release Technical Investigation – Application to Re-Start

---

Enclosed please find five (5) hard copies of the above noted submission that was missed in the binders sent on July 19.

If you have any questions or concerns, please feel free to contact me at (403)538-4583.

Please sign and fax back to Jennifer Harding at (403) 264-3700.

Signature

July 21/06
Date

P D

DEER CREEK ENERGY LIMITED

EUB RESOURCES APPLICATIONS
DATE REGISTERED
JUL 17 2006
SUBMISSION # 28213
RE: APPLN # 1389383

RECEIVED
JUL 21 2006
EUB RESOURCES APPLICATIONS

July 21, 2006

Alberta Energy and Utilities Board
Applications Branch
Resources Applications
In Situ Section
640 – 5th Avenue SW
Calgary, AB
T2P 3G4

Attention: Kris Geekie

Dear Mr. Geekie:

Re: Application to Re-Start Joslyn SAGD Project

Deer Creek Energy Ltd hereby makes formal application to re-start the Joslyn SAGD project. As per our conversations, we have provided information to the EUB with respect to operations at the time of the steam release, as well as the results of our investigations to date. Our analysis continues, and we will forward additional information to the EUB as we receive it.

The main focus of the operation going forward is to reduce the maximum pressure in all operating modes, and to monitor all conditions for any anomalies. There has been continuing discussion of sinkholes and the possible impact on the incident, and we have concluded that there is no visible surface evidence of any sinkholes in the vicinity of Pad 202, where we plan to begin operations.

We attach a summary of the incident and findings to date, as well as a detailed program describing the checks to be made before re-starting, and the strict operating criteria to be applied on all operations going forward.

We respectfully request the EUB review our request to re-start, and provide feedback at your earliest convenience. We are completing all of the field work in preparation, and believe we will have completed all of the required pre-start work during the week of August 1.

If you have any questions, please do not hesitate to call me at 538-6368, or on my cell at 835-7932.

Yours truly,
DEER CREEK ENERGY LIMITED

Don Verdonck
General Manager, Operations
bcc: Don Hennessey

SUMMARY of FINDINGS-JOSLYN STEAM RELEASE

The main finding of the investigation is that the incident was, in all likelihood, caused by injecting into 204-I at a pressure that was too close to or in excess of the local fracture gradient that lead to the creation and propagation of a fracture, creating an accumulation of steam/water in a permeable layer of the Wabiskaw formation, that, after sometime, resulted in a fracture of the cap rock, the Clearwater Shale, and the subsequent explosive steam release.

There was a clear anomaly on the injection behaviour on well 204-I , about one month before the incident, when the injection rates increased from 70 m3/d to 180 m3/d and the pressure dropped from 1700/1800 kPa to 1600 kPa (see Fig 1). In the opinion of the investigation team, the fracture was created at this time – none of the other wells show a similar behavior (see Fig 2 to 3).

The subsequent events within the formations after the creation of this initial fracture to the actual steam release are, however, less clear. There are 3 possible mechanisms that have been identified, namely:-

a) Vertical fracture up to the cap rock from the injector well
b) Horizontal or sub horizontal fracture to either the observation well at a distance of 8.3m from the well pair or the core hole some 16m distant from the well pair and subsequent propagation to the cap rock by a bad cementation of the well..
c) Propagation of the fracture by a locally occurring fracture system or weakness, perhaps associated with a "sink hole"

In the case of a vertical fracture, the normal behavior of any pressure induced fracture is to propagate horizontally. However, at this shallow depth with a lower overburden, there is larger likelihood of inducing a pure vertical fracture.

For the wells, though the fracture would still have to propagate some distance to reach either well, a poor cementation in either of these wells could have assisted the vertical propagation of steam but there is no evidence to prove this or not. The fact that the observation well is undamaged and a gauge ring has been run to bottom of the well indicates that this well was probably not involved, though a Cement Bond log still needs to be run, when it is safe to do this (crater not yet stable). As far as the core hole is concerned, this well has not as yet been located – there are no tubulars left in this well.

As far as any natural weak zone is concerned, there is superficial topographic evidence of a "sink" feature created by the dissolution in geological time of evaporates below the Devonian formation, causing the McMurray to locally subside and fracture. See Fig 4 and 5. Against this theory, there is no evidence of subsidence in the cores from the observation hole. The planned high resolution 3D shallow seismic, if proven feasible, may assist in substantiating this theory, though this will only be available, at best , by end of this year.

The investigation team have identified a number of contributing factors that might have contributed to the event as follows:-

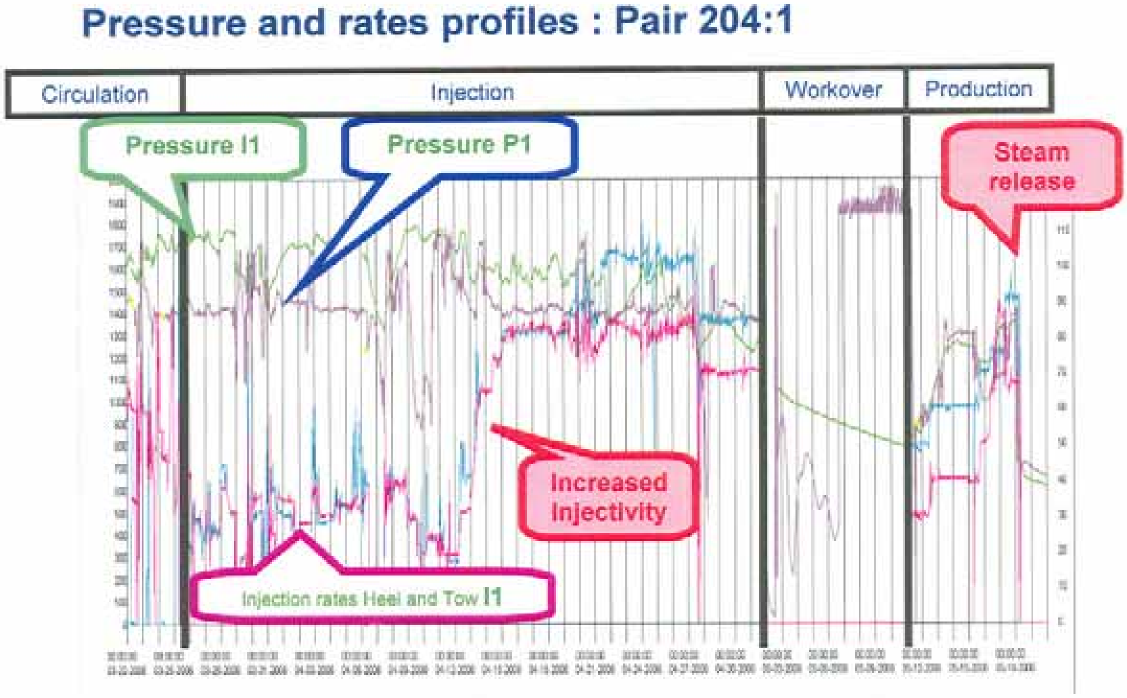
1. Observation well was not equipped by error (incorrect well identification) – if this well had been equipped, high temperatures, at horizons above the well pair, might have warned of steam/heat rising up towards the surface.
2. Reservoir of 204-1 is good quality – if there were some shale lenses, they might have deflected the fracture horizontally.
3. There were doubts on temperature measurements given by the fibre optic cable in 204-P1 and it was later replaced. With hindsight, these measurements, abnormally cold, were probably correct.
4. Pressures in injection phase of 1,700 kPa (max. 1,800 kPa) were (with hindsight) too close to fracture gradient (20-25 kPa/m), and higher than used in Joslyn Phase 1 (1,400kPa)
5. Mass balance of returned steam/water during both circulation and injection phases are inaccurate, as no individual measurements are made of (multiphase) returns in production well
6. No account was taken in pressures used in circulation and injection phases of burial depth variations. 86m burial depth of injector where steam release occurred versus 91m TVD referenced to well pad 204. At these shallow depths, these variations are significant.

CONCLUSIONS and RECOMMENDATIONS

The Taskforce conclude that it is acceptable to restart the well on injection phase and proceed progressively to put the well pads on production, as long as the mitigation measures outlined below are actioned. It is NOT recommended to begin operations on well pad 204 or the well pairs adjacent to well pair 204-1, until it is demonstrated that the subsurface damage, associated with the steam release, is localised. It is presumed that production from well pair 204-1 is no longer feasible due to the fracture in the cap rock. For the wells adjacent to 204-1, it is recommended to install additional observation wells to detect an anomalous heating up the well and consider the use of pressure measurements in the Wabiskaw formation to detect any pressuring due to steam charging this formation from below.
The mitigation measures recommended to be put in place are:-

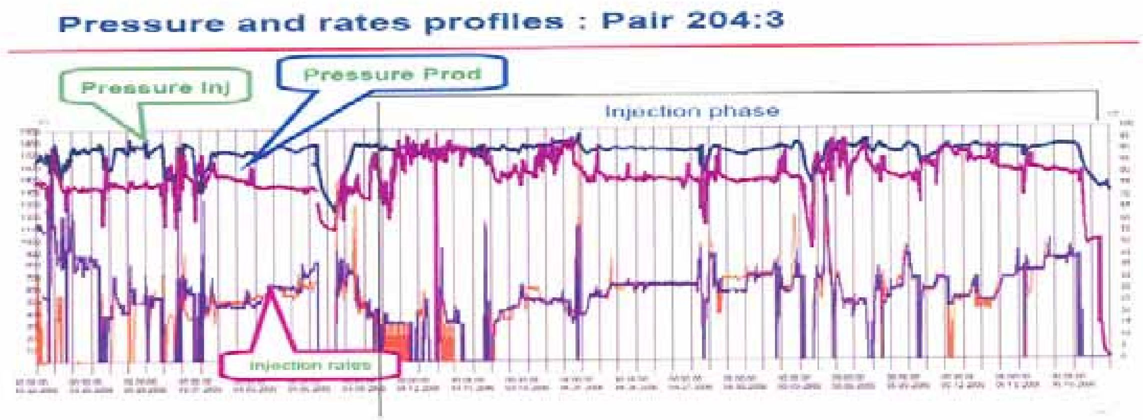
1. Primarily a problem with pressure: mini-frac test in caprock gave fracture gradient of 21-25 kPa/m. Recommend to reduce pressure to 1,200 kPa in Injection phase, leaving >25% safety margin (500kPa) to fracture at well depth of 1,700kPa, and to ALARP for circulation phase (currently 1400kPa)
2. Equip all relevant observation wells and check accuracy of all measurements (pressure and temperature) on all wells PRIOR to circulation start
3. Rigorously confirm topography of each individual well pair. Take this into account in max injection pressure limit
4. Install heave monitoring above each well path
5. Try to improve measurement/estimation on returns during injection phase
6. Very importantly, during injection phase, STOP if any anomaly is detected

FIGURE 1



Pressure and rates profiles : Pair 204:1
Circulation
Injection
Workover
Production
Pressure I1
Pressure P1
Steam release
Increased Injectivity
Injection rates Heel and Tow I1

Figure 2


Pressure and rates profiles : Pair 204:3
Pressure Inj
Pressure Prod
Injection phase
Injection rates

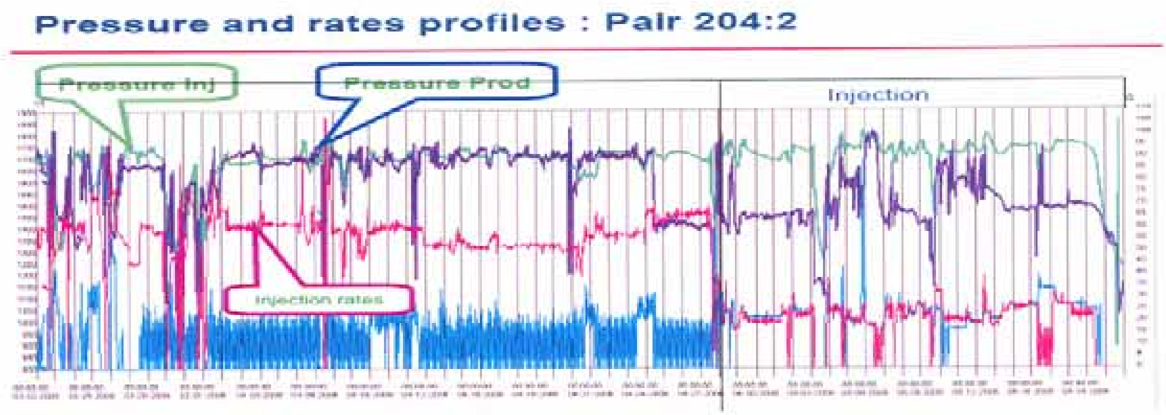

Pressure and rates profiles : Pair 204:2
Pressure Inj
Pressure Prod
Injection
Injection rates

FIGURE 4
TOPOGRAPHY Along Well Pair 204-1

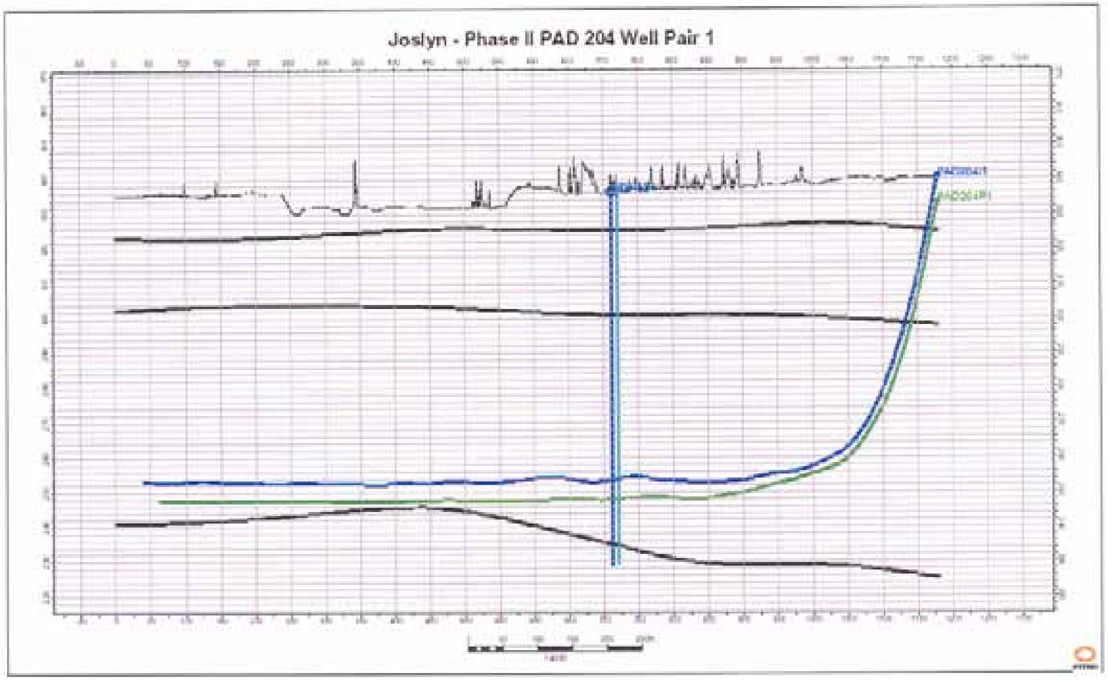
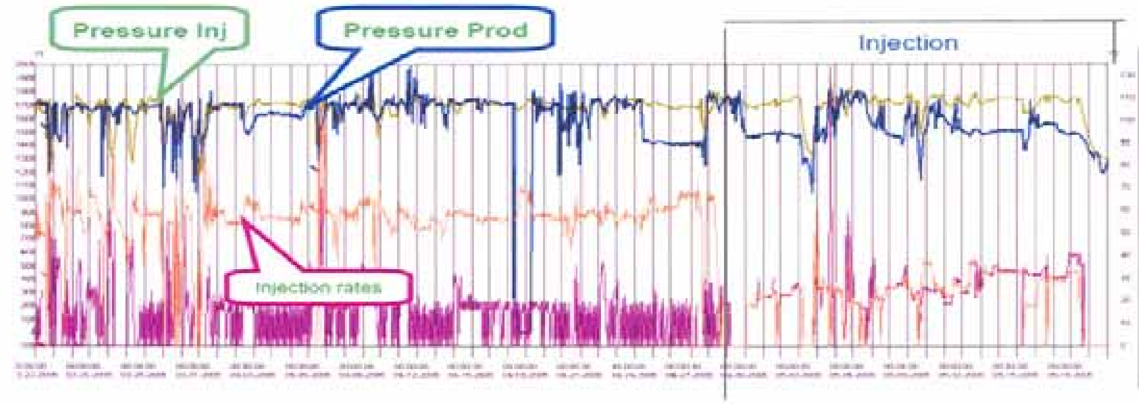


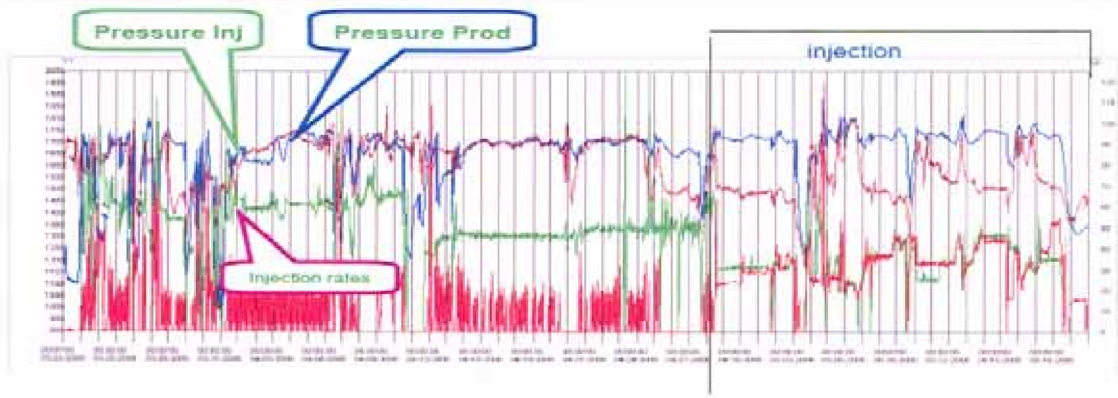
FIGURE 5 Aerial Photo before incident – note circular feature

FIGURE 3

Pressure and rates profiles : Pair 204:4



Pressure and rates profiles : Pair 204:5



ORIGINAL for SIGNATURE

DEER CREEK
Energy Limited

PHASE II SAGD

PRODUCTION START-UP PROGRAM

Injection Phase, Pad 202

3 Well Pairs

DATE: July 20, 2006

LIST OF KEY PERSONNEL

Senior Production Engineer	Paul Krawchuk Email:paul.krawchuk@total.com	O: (403) 538-6367 C: (403) 861-9486 H: (403) 244-9099
Reservoir Engineer	Mohamed Beshry Email: mohamed.beshry@total.com	O: (403) 538-5627 C: (403) 889-9174 H: (403) 242-1174
VP Thermal	Matt Cartwright Email:matt.cartwright@total.com	O: (403) 538-4579 C: (403) 606-7840 H: (403) 802-3181
General Manager, Operations	Don Verdonck	O: (403) 538-6368 C: (403) 835-7932 H: (403) 271-7932
Plant Supervisor	Tom Davis	O: (403) 538-6392 C: (780) 307-1205
	Paul Bourget	O: (403) 538-6392 C: (780) 715-6358
Facilities Engineering	Rob McNeill Mike Wilson (BDR)	C: (403) 816-6689
Facilities Construction	Don Bouschard Doug Bury	(403) 538-
Construction Field Foreman	Larry Guard	C: (403) 638-7930 H: (403) 638-4439
Main Switchboard:	Deer Creek Energy Limited	O: (403) 264-3777 F: (403) 264-3700

APPROVALS

ORIGINATOR:	P Krawchuk	DATE:	2005-05-06?
REVIEWED BY:	H. Campbell HSE Manager	DATE:	
REVIEWED BY	Site RSES (T.Davis/P.Bourget)	DATE	
REVIEWED BY:	D Verdonck	DATE:	
REVIIEWED for Taskforce	J.Foulkes	DATE	
APPROVED BY:	M Cartwright	DATE:	

DISTRIBUTION

TEPC -
J-L Guiziou President
M Cartwright VP Thermal
G. Chalier Drilling Engineer
P. Krawchuk Senior Production Engineer
T.Davis/P/Bourget Plant Supervisor (RSES)
P. Valero Field Engineer
Field Personnel (5 copies)
H. Campbell HSE Manager
D. Verdonk GM (Operations)
M. Beshry Reservoir Engineer
J. Kanderka Production Engineer
B. Harll Field Engineer
D. Loxam Manager Infrastructure

TEP FRANCE

J. Seguin EP/AMS/US C
T. Thomas EP/GSR/VDG/GEOG
R. Leruste EP/TDO/EXP/IE
M. Daubenfeld EP/AM/S
C. Baranthol EP/TDO/FP/OPS
L. Heuzé EP/HSE

TASKFORCE MEMBERS

J.Foulkes
H. Dendani
M. Brangetto
J-P Lelarge
A. Onaisi

LIST OF SERVICES

Equipment / Service	*Supplier*	*Contact*	*Phone*

None.

PROJECT STATUS

The seventeen horizontal well pairs for Steam Assisted Gravity Drainage (SAGD) oil production from the McMurray Formation for the Joslyn Phase II Project have been drilled and completed. Early steam circulation (using Phase I surface facilities) of well pairs 204-1 and 204-3 began in December 2005. The remaining three Pad 204 well pairs started steam circulation in February 2006. The four Pad 202 well pairs started steam circulation in March 2006. The Injection Phase of all five Pad 204 well pairs was completed in April/May 2006. However, on May 18th, 2006, there was a steam release to surface, resulting in the creation of a crater of some 20m diameter by 5 m depth and an affected area of 125m by 75m, with rocks and debris being ejected up to some 300 meters from the incident This steam release was along the path of well pair 204-1, which at the time was starting production by ESP. The subsequent incident investigation has identified an anomaly during the injection phase on pair 204-1, one month before the steam release. The injection rate into the injector increased from $70m^3/d$ to $180m^3/d$, with an associated drop in injection pressure from 1,700 kPa to 1,600 kPa. The investigation team have concluded that the probable cause of the steam release was the high injection pressure that caused a fracture to be created, which in turn allowed steam to rise up to the Wabiskaw formation where steam accumulated, causing a subsequent failure of the Clearwater shale, the steam release and the creation of the crater. The presence of an observation well and a core hole in the vicinity of the crater may or may not have contributed to the incident.

In consequence, subsequent operations must be conducted at a lower injection pressure so as to avoid a re-occurrence. The recommendation is to use a maximum steam injection or circulation pressure of 1200kPa, as measured at the heel of the well. This pressure gives about 500kPa safety margin compared to the expected fracture pressure, the equivalent of about 25% safety margin.

Once Pad 202 has been put on injection and the wells stabilized, and the HAZOP completed for Pad 201, circulation will commence in all wells on pad 201. Approximately 3 months of circulation are required before converting the wells to injection/production. At lower pressures, additional circulation time may be required to adequately heat the formation.

This program has been written so as to start Pad 202 steam injection and production on three well pairs, at a maximum steam injection pressure (measured at injector heel) of 1,200 kPa.The program is to be executed after receiving the permission from TOTAL S.A. headquarters, the owners of Deer Creek, and from the Alberta Regulator, the Energy and Utilities Board.

OBJECTIVES OF PRODUCTION START-UP PROGRAM

- Since the well pairs on pad 202 have been on circulation for approximately 3 months, the injection phase is ready to begin. Perform the injection phase of the production start up on injection wells 202-I1, I2 and I3, at a maximum injection pressure on the injection well of 1,200 kPa. Production wells will remain on circulation at a maximum circulation pressure of 900 kPa until evidence of the flow of bitumen from injector to producer
- Monitor and record all well parameters, including pressures, temperatures, circulation and injection rates, so as to document well behaviour and apply any lessons learnt to subsequent operations
- Complete all operations without Lost Time Injuries, using pre-job meetings, safe operating practices, safety meetings, and good communication
- Implement current best practices within the SAGD industry, adapted to these lower pressures due to the shallow depth, and identify improvements that can be applied to future SAGD projects on and off the Joslyn lease
- Ensure risk to personnel and to surface facilities (plant and infrastructure) are as low as reasonable practical
- Avoid, as far as possible, channelling of steam in the reservoir
- Strict control of personnel movements and any works to and from Pad 2O2 and the surrounding area of Pad 203 and 204, including the roads and pipelines in the vicinity.

RESPONSIBILITIES

The Senior Production Engineer is responsible for:

- Lead pre-job safety and operations meeting with field operations staff prior to starting injection phase
- Oversee all aspects of well pair operations
- Implement any changes to steam injection rates, BHPs or surface return pressures within defined operating parameters. Changes in instruction to field staff are to be transmitted in writing to ensure no misunderstanding of direction.
- Providing direction to the field Maintenance staff to ensure all instrumentation has been checked and calibrated.
- To ensure, if operating conditions deviate from defined parameters, that immediate action is taken to ensures safety of the wells, prior to initiating discussion with reservoir engineers, field engineers, operating staff and operations manager so as to determine next steps.
- In case of absence, will be replaced by Jon Kanderka, Production Engineer

The Drilling Engineer based in Calgary is responsible for:-

- Review of Pad 202 well pairs and observation wells to identify any anomalies in drilling or cementing that could effect steaming operations
- Review of all core holes in the vicinity of Pad 202 (as defined below) to identify any anomalies in drilling or cementing that could effect steaming operations.

The Manager infrastructure in Calgary is responsible for:-

- Organising the necessary forest clearance for the topographical survey above the 3 well pairs and the subsequent surveying required of the topography above these wells.

The Field Engineers located in Calgary are responsible for:

- Reviewing fibre optic data for any anomalies, on a daily basis
- Monitoring observation well thermocouple data to identify any abnormal increases in temperature, on a daily basis
- Plotting injection rates and pressures with BHPs on a continuous (greater than daily) basis to ensure the mass and pressure balances are acceptable (i.e. no excess steam loss into the formation)
- Reviewing downhole pressure trends and recommend any changes to steam injection rates
- Monitoring and plotting of well fluid returns to ensure there are no excessive losses and, in case of suspected losses, propose diagnostic procedure (test separator etc;) to senior production engineer.
- Ensuring good communications with the Field Superintendent and Field Engineers at Joslyn

The Field Superintendent is responsible for:

- Ensuring, as RSES, the overall HSE performance
- Ensuring all operating conditions are being closely adhered to by operations staff
- Ensuring that the Production Foreman is fully involved in all well operations decisions and discussions.

The Field Engineers at Joslyn are responsible for:

- Close monitoring of BHPs on injection and production wells
- Close monitoring of injection rates and surface injection pressures

- Close monitoring of BHP and injection trends to ensure mass and pressure balances are acceptable
- Estimation of fluid returns on a per well basis (where feasible)
- Reporting any operational anomalies to Field Superintendent and Senior Production Engineer
- Ensuring accurate and detailed comments pertaining to individual wellpair operation is entered into production database (QVM) on a daily basis
- Ensuring good communications with the Field Superintendent and Field Engineers in Calgary

The Reservoir Engineer is responsible for:

- Reviewing SENSA and observation well data in conjunction with production engineering team on a daily basis, with particular reference to the energy and material balance of each well pair
- Recommending changes to well operating parameters on a reservoir performance basis
- Assessing the requirement for interference testing between well pairs
- Recommending from a reservoir perspective, when the production well is ready to produce by ESP.
- In case of absence, will be replaced by an engineer from GSR/VDG

The Panel & Field Operators are responsible for:

- Monitoring BHPs on injection and production wells, recording on log sheet twice per shift
- Monitoring injection rates and surface injection pressures, recording on log sheet twice per shift
- Making adjustments as necessary to injection and production wells under direction of Senior Production Engineer
- Monitoring Bornemann (multiphase pump P-500) inlet temperature and make adjustment to E-401 fan speed and louver position. Fine tuning temperature with E-400 glycol cooler
- Monitor all aspects of Bornemann operations as per Bornemann Operator Manual
- Reporting any operational anomalies to Field Superintendent and Senior Production Engineer

CURRENT PAD AND PLANT STATUS

Phase 1 pilot well is producing to the plant via Pad 204 at approximately 45m^3/d of bitumen with approximately 200m3/d total fluid.
Well pair 204-4 is on circulation at 1,400 kPa.
Well pairs 204-1, 2, 3, 5 and 202-4 are shut in. There is currently no activity on Pads 201 and 203.
Well pairs 202-1, 2, 3 are on circulation at 1,400 kPa, with valves lined up as in Fig. 1, attached. The configuration for well pairs 202-1, 2, 3 injection phase is shown on Fig. 2, attached.

TOPOGRAPHY ALONG WELL PAIRS

The topography along well pairs 202-1, 2 and 3 are given in Attachment 1.
On all 3 well pairs, the Pad is the lowest point at 330 amsl with the injector horizontal depth of 248amsl, leaving a minimum vertical distance of 82 meters. At 21kPa/m estimated fracture gradient, this gives a minimum fracture pressure estimated as 1722kPa.
There is no plant infrastructure above the well paths, though the tails of the wells are not far from the plant site. However, the access road crosses and then runs parallel with the well path of 202-3.(see Attachment 2) Hence the importance to take special care with this well, using the observation wells (see below).

OBSERVATION WELLS & FIBRE OPTICS

Well pair 202-3 has 2 observation wells, 10/02-33 at the heel at a distance of 9.8m and 6/01-33 on the toe at a distance of 4.7m.
Well Pairs 202-1 and 202-2 do not have any observation wells.

Well Pair 202-3 is equipped with a fibre optic cable for temperature measurements in both the injector and the producer.
Well Pairs 202-1 and 2 have a fibre optic cable for temperature measurements in the producer wells only.

CORE HOLES

Core holes near to the wells are:

202-P1/I1: B/16-28 (51.5m)
202-P2/I2: None
202-P3/I3: C/01-33 (15.0m), B/02-33 (31.5m), A/03-33 (21.5m), C/03-33 (23.5m), A/01-33 (5.0m), B/01-33 (2.0m)
** Note that A/01-33, B/01-33 and C/01-33 are located in the build section, with A/01-33 and B/01-33 located close to the surface location.

SIMULTANEOUS OPERATIONS

There is no other well or construction activity expected in the vicinity of PAD 202 during these operations. Any works of any nature in the area, including the roads and the pipelines, must be strictly controlled and minimised using the existing permit to work system.

PRE –JOB CHECKS

- The topography above each well pair must be surveyed as a base line prior to the start up of any injection with a station every 100m from the toe of the well. These stations are to be resurveyed once a week during the operations to detect any heave.
  Note:- Number of stations and period of survey maybe modified following experience.
- The recommendations of the HAZOP carried out with BDR on the use of the Bornerman (P500) pump in this phase must either be implemented or a formal derogation given by the General Manager (Operations) for any recommendation that is not in place for the beginning of this program.
- As we are operating at lower pressures in circulating production wells, the well pressure is not sufficient to be received by the plant. As a consequence, the Bornemann multi-phase pump (P-500) will be used and a pre-job operational meeting must be performed (using previously performed HAZOP) to review operational procedures. The Bornemann Operator Manual must be reviewed with all operations staff and strictly adhered to during operations
- Engineering and field operations to ensure all observation wells are correctly equipped and fibre optic is installed in the production wells .
- Review of the well files of all well pairs on the pad, observation wells and core holes in the vicinity for any anomalies to be completed and results distributed to all staff concerned.
- Check all pressure and temperature instrumentation and calibrate as necessary
- Perform an on-site pre-job meeting before start-up of injection on any pair, ensuring all personnel involved are fully aware of their roles. Pre-job meeting to be chaired by the RSES, with production engineering in attendance to define operating parameters. Ensure that both shifts are equally briefed. This will require a new pre-job meeting at the beginning of the next shift.
- Ensure all steam lines are clearly marked on Pad 202 and appropriate warning signs are posted. Put sign at entry to pad, warning that steam injection is in process at high pressure and access is limited to only authorized personnel
- Emulsion flow path should be verified and all spec blinds and valves should be lined out in the proper fashion
- Bornemann pump checklist should be performed as per Bornemann Operator Manual
- Alarm setpoints need to be entered into the PLC as follows:
  - Blanket gas on injection well high pressure alarm: 1,200 kPa
  - Bubble gas on production well high pressure alarm: 1,000 kPa
- Emergency Steam Shut Down on pad 202 setpoint to be entered on PLC as 1500kPa on bubble gas gauge on both production and injection well. Note:- new function as recommended by HAZOP
- Both alarms and Emergency Shut Down should be tested prior to start up of operations.

- Pad tank volumes should be reduced in case of the need for a tank test (as described below).

DETAILED PROGRAM

The following sequence should be performed on each well pair, starting with 202-1, then 202-2 and finally 202-3. A new pair should only be started once the injection and circulation rates in the previous well pair are stabilised.

- Open valve and begin injecting steam down both long and short strings of the injector well at a minimum rate initially of 2 to 5 m3/d. BHP (measured on the blanket gas) should be monitored closely to ensure the pressure does not exceed 1,200 kPa at the heel of the injection well
- Begin circulation at 1,200 kPa heel pressure in the production well. Surface steam injection pressure should be targeted at 1,500 kPa initially to initiate flow to surface in the wells, with returns lined out through the group header system, through the E-401 overhead condenser and to the multi-phase Bornemann pump. The Bornemann pump has a high inlet temperature alarm set at 100 degrees C. As a result, the condenser will have to be run at a lower temperature set point than it is currently being operated at. The E-400 glycol exchanger can be used as a trim cooler to maintain a pump inlet temperature of 90-95 degrees C.
- The target downhole pressure for the production wells is 900 kPa, so the Bornemann inlet pressure setpoint should target 500-600 kPa to reduce the backpressure and allow the wells to flow to surface. If the production wells are unable to flow at this backpressure, the Bornemann inlet pressure setpoint should be lowered in small increments (25 kPa) until the wells start to flow. Direction on changes in operation of the pump and well operating conditions will be provided by the Production Engineers.
- Once the production wells are flowing to surface, the production well chokes should be opened in small increments to allow the BHPs to reduce from 1,200 kPa to 900 kPa, while ensuring that the wells continue to flow
- Surface emulsion temperatures should be monitored closely at this point to ensure that the wells continue to flow. A reduction in surface temperature will indicate loss of flow.
- As the producer BHPs are being reduced, the producer surface injection pressures should be reduced accordingly. There is typically ~300 kPa differential required between surface injection pressure and BHP in production wells for flow to surface to occur (this may vary from well to well). As such, surface injection pressures should be lowered as BHPs decrease, taking care to ensure there is no loss of flow
- Once production well BHPs have been reduced to 900 kPa, the surface emulsion chokes may need to be pinched in to maintain BHPs of 900 kPa. This should be done in small increments to ensure the wells continue to flow.
- Once the production wells are maintaining a constant flow to surface, the injection rate on the injection wells should be increased to a target of 15 m^3/d heel and 15 m^3/d toe if possible without the injection well BHPs exceeding 1,200 kPa.

Once a well pair is stablised , the following is to be actioned:-

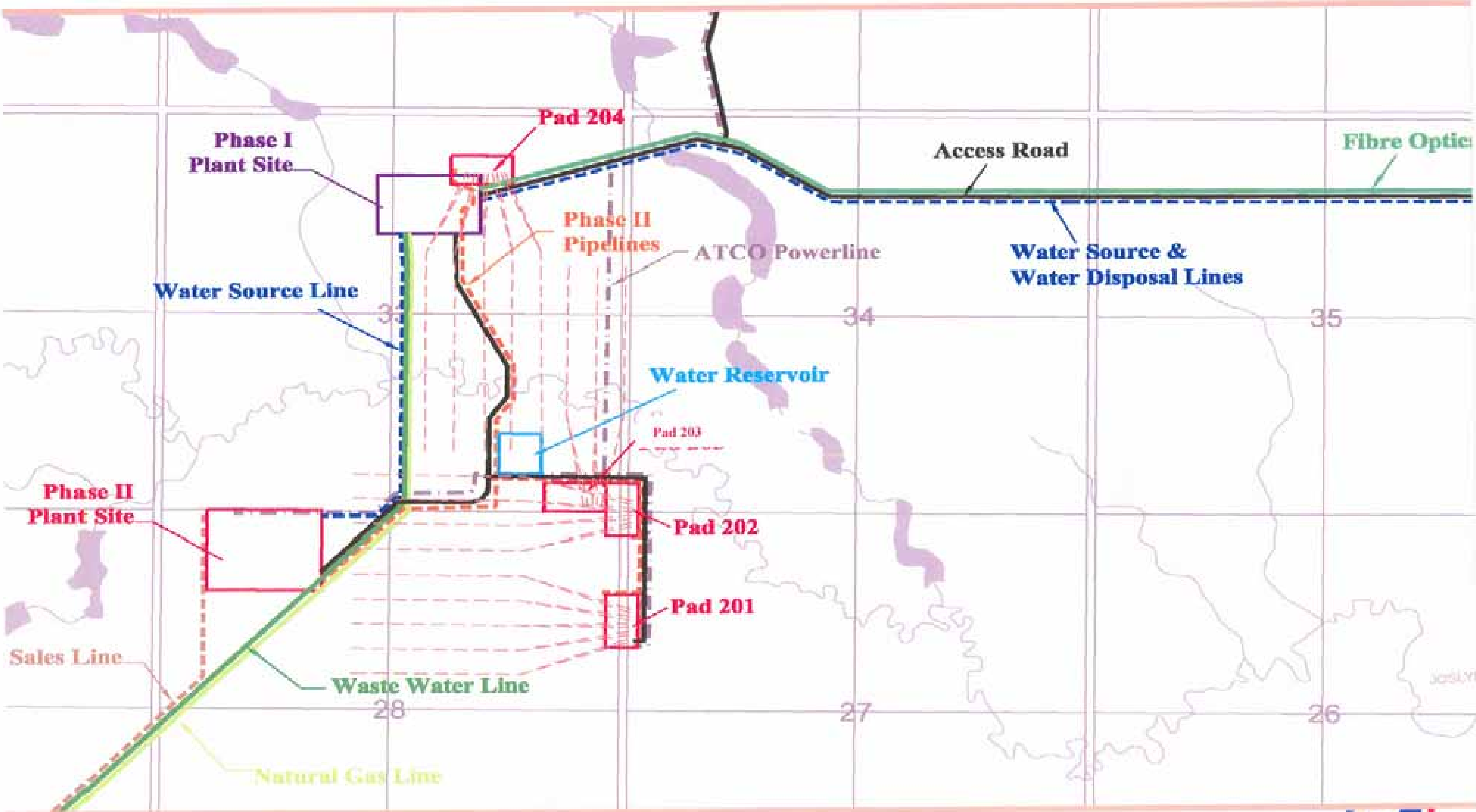
- As communication increases between the injection and production wells, the steam will be increased in slight increments of 1 to 2 m3/day, while maintaining a maximum BHP of 1,200 kPa as per the Senior Production Engineer's instructions. Once the injection rates have reached 40 m^3/d heel and 40 m^3/d toe, the production well will be ready for ESP installation and conversion to production. Note that surface injection pressure as registered on both the long string and short string of the injector should not exceed 1500 kPa.
- Record the production and injection well surface injection pressures, the steam injection rates to the long and short strings and the estimated well returns every 12 hours on the log sheet. If more than 20% increase in injection rate occurs during a 12 hour span, or the injection well BHP drops suddenly at constant or lower injection pressures, there is a danger of inducing a fracture. The well injection should be shut in and the Senior Production Engineer should be contacted for any further instructions.
- Follow up of the mass balance of steam/liquid into and out of the reservoir is very important during this phase – excessive steam/liquid loss to the reservoir could indicate the existence of a fracture. The returns from the production wells should thus be checked every 3 days by passing the flow through

the test separator, until a stable measurement of flow is achieved. There is some doubt as to the accuracy / repeatability of the test separator measurements due to the limitations of the meters with respect to multiphase flow conditions.

- If test separator measurements prove to be unreliable the wells will continue to be monitored closely to identify any anomalous pressure / flow trends. If a well is showing any anomalous trends, all other wells on the pad will be shut in and the production well in question will be lined out through the overhead condenser, cooled to 80 degrees C and flowed to the tank where a 6 hour "tank test" will be performed to determine liquid flow rate. The starting and finishing volumes of the tank should be recorded along with the duration of the tank test. After the tank test has been completed the other wells on the pad should be brought back online.
- The estimated mass balances for the previous days should then be reassessed, any trends identified and reported to the Senior Production Engineer.

NOTE: There is the possibility that due to the extended period of circulation on the Pad 202 wells (4 months) there may already be good fluid and pressure communication between injection and production wells and as such the initial potential rates of steam injection in the injection well may be higher than previously encountered. If the injection well appears to have very good initial communication due to the well taking a high volume of steam, the well should be flowed to the test separator or tank (as per above instructions) to determine the volume of fluid being produced.

Attachement 2 – Joslyn Infrastructure



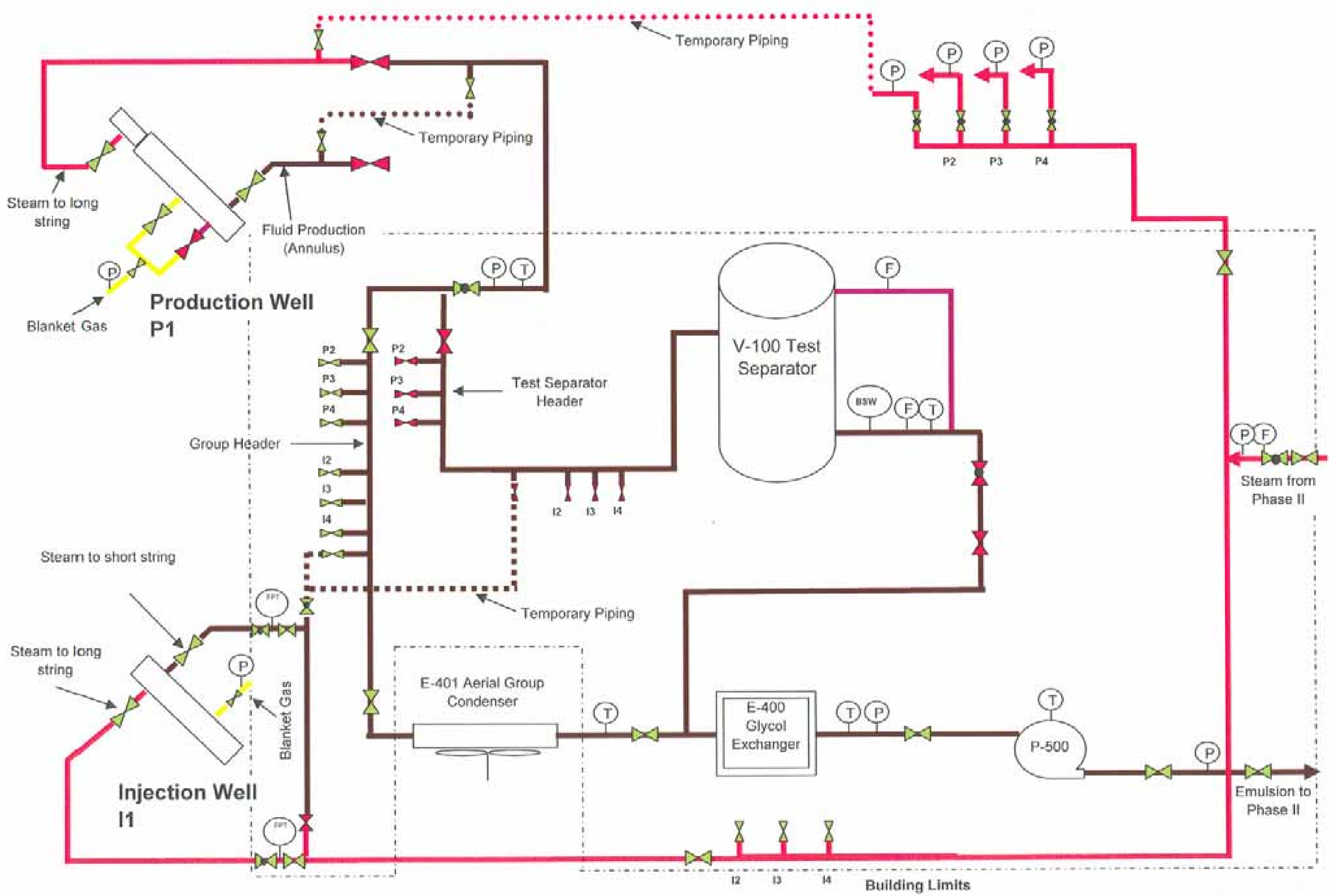


Fig. 1-Wellpad 202 Circulation Phase

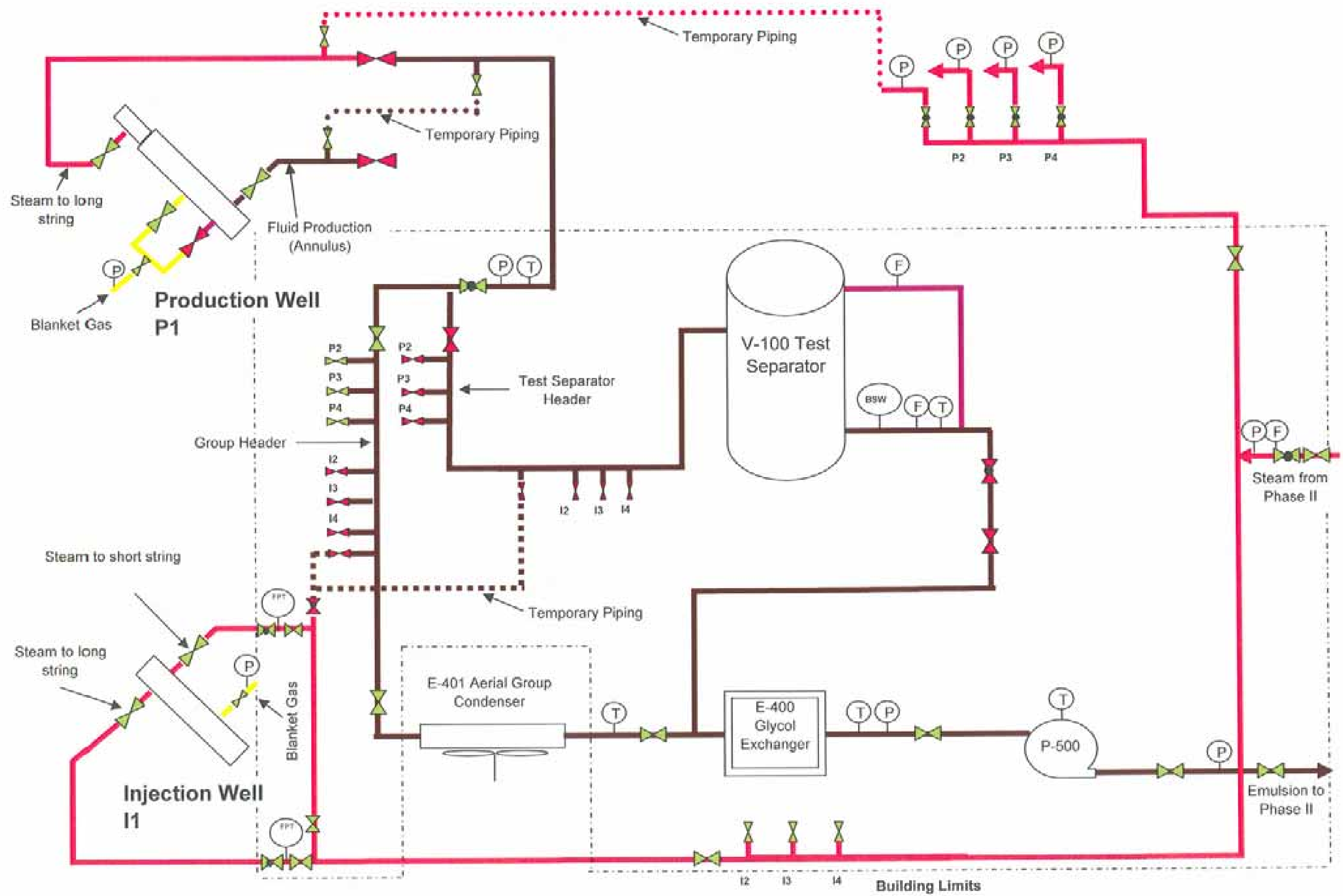
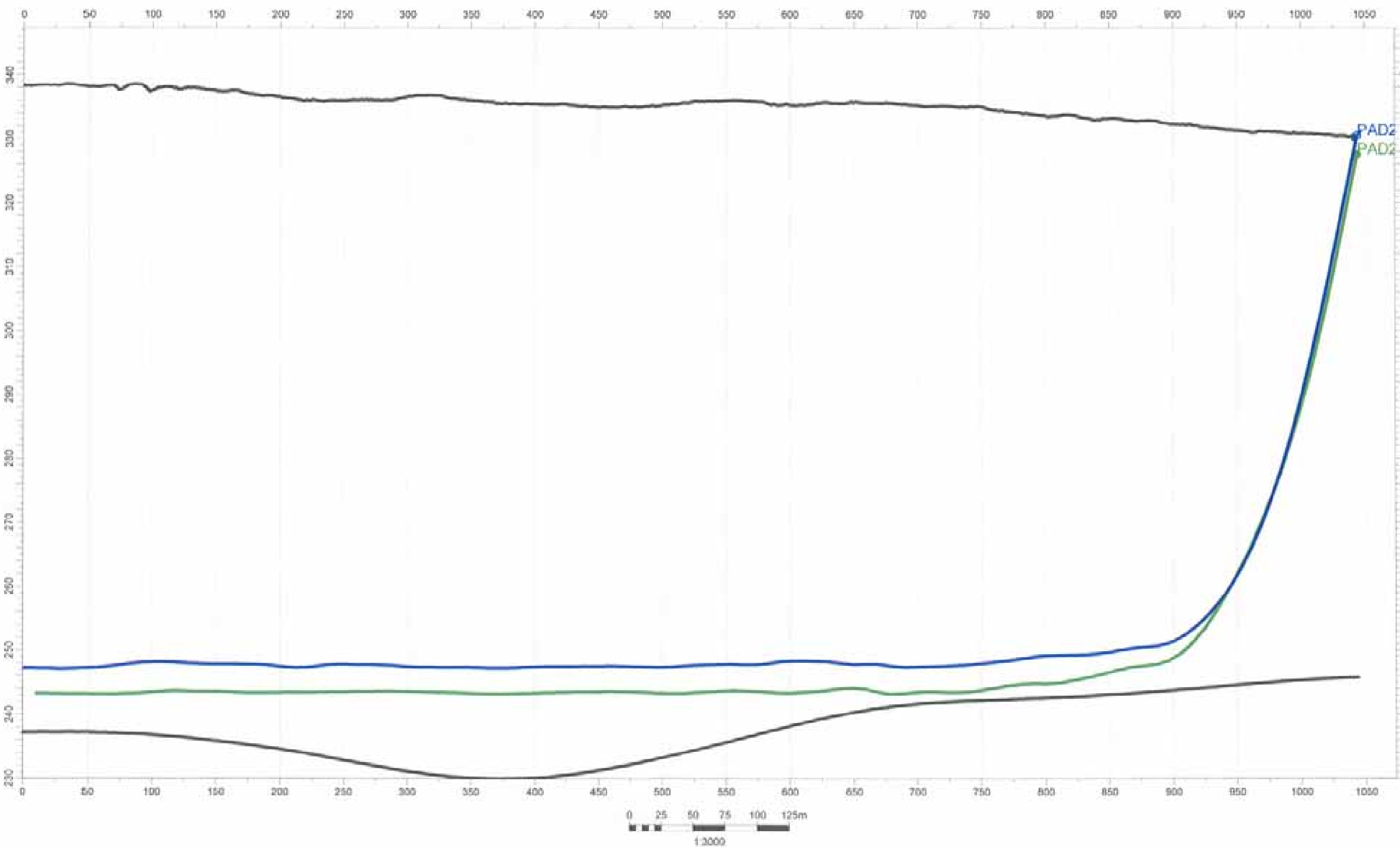
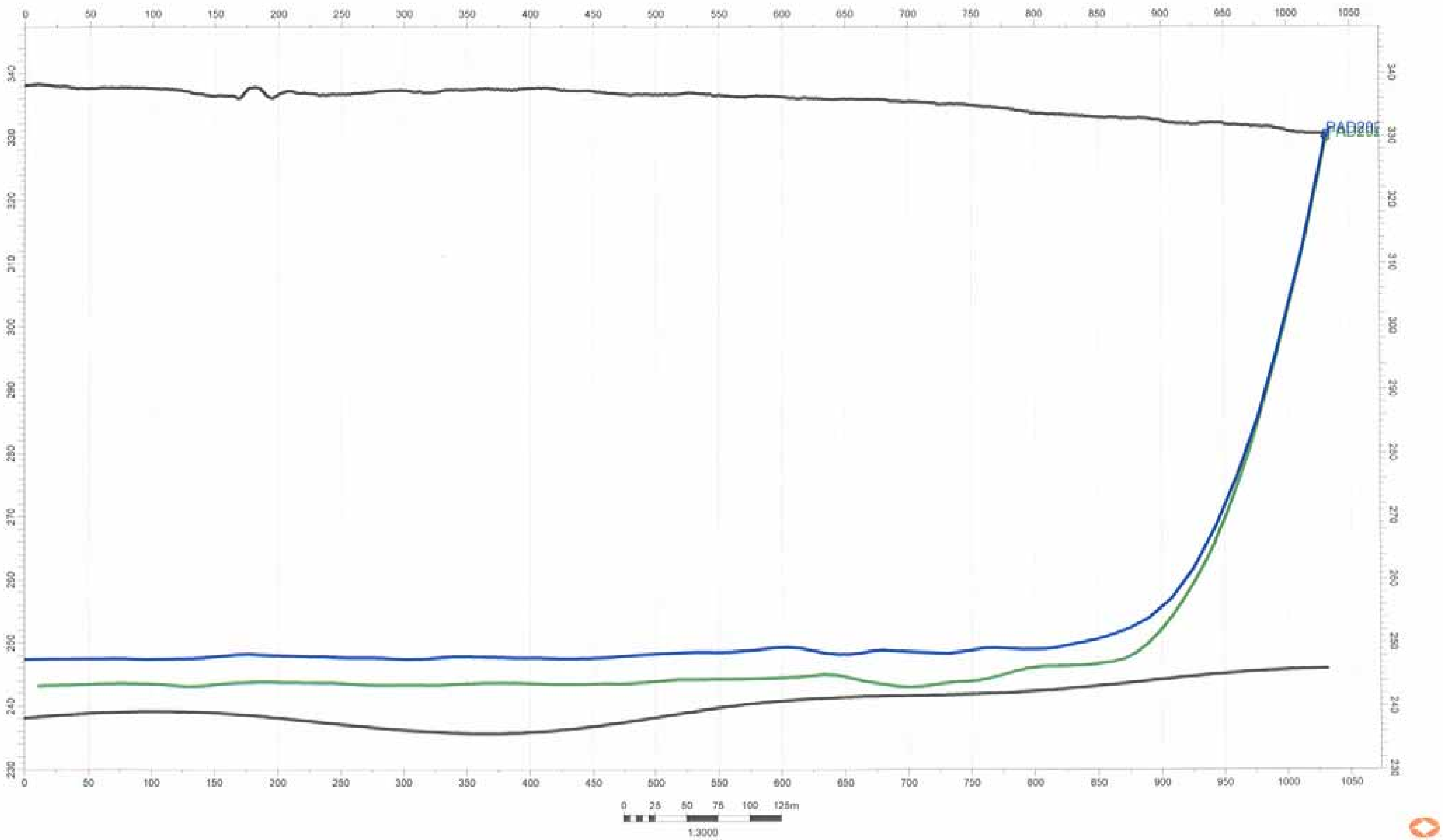


Fig. 1-Wellpad 202 Injection Phase

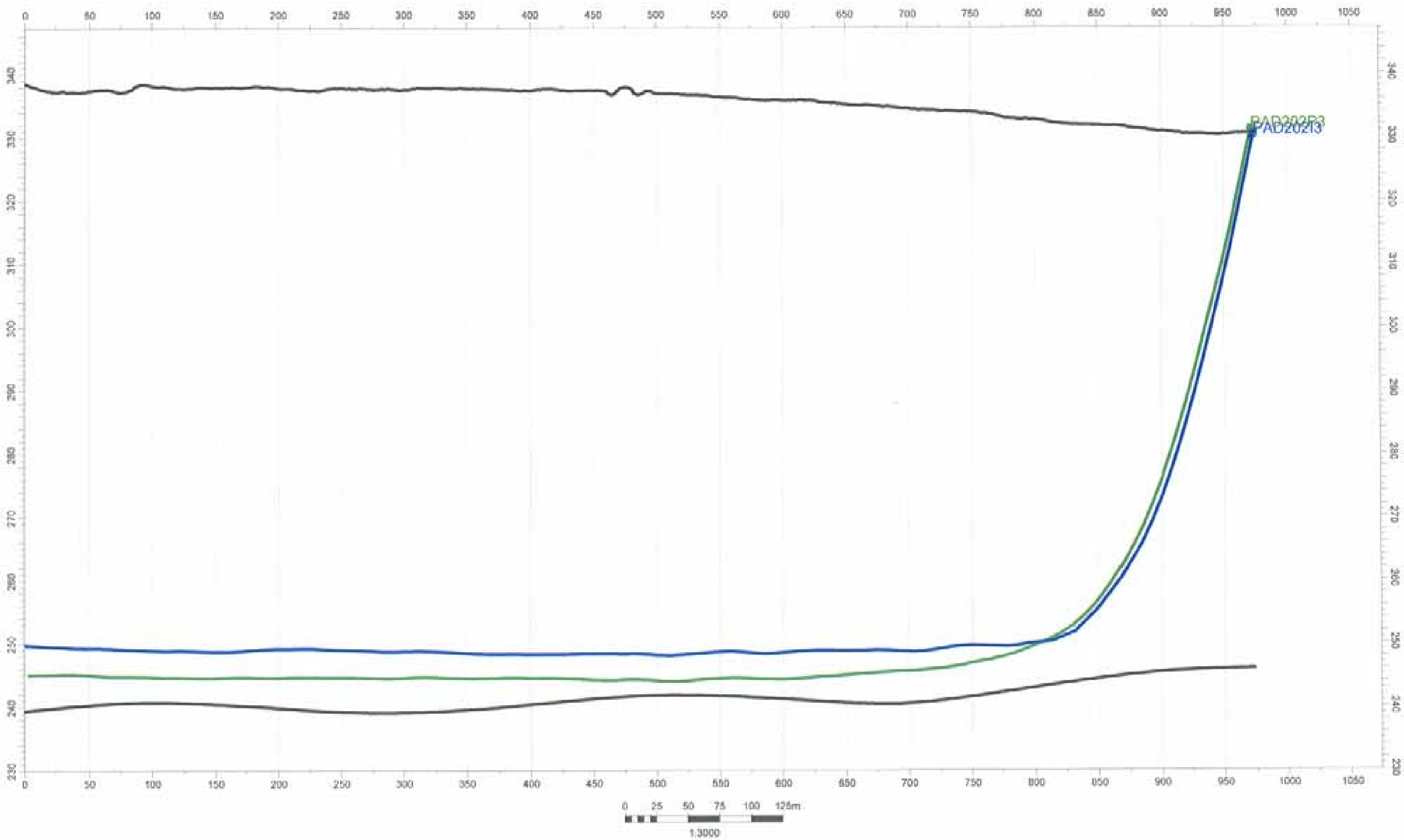
Joslyn - Phase II PAD 202 Well Pair 1



Joslyn - Phase II PAD 202 Well Pair 2



Joslyn - Phase II PAD 202 Well Pair 3



Appendix 4: ERCB letter approving Phase II restart, subject to conditions, August 2006

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

August 17, 2006

Don Verdonck
General Manager, Operations
Deer Creek Energy Limited
1900, 333-7th Avenue
Calgary AB T2P 2Z1

Dear Mr. Verdonck:

DEER CREEK ENERGY LIMITED
JOSLYN SAGD PROJECT
ATHABASCA OIL SANDS AREA
SUBMISSION NO. 28213
PHASE II SAGD: PRODUCTION START-UP PROGRAM
INJECTION PHASE, PAD 202, 3 WELL PAIRS

The Alberta Energy and Utilities Board (EUB/Board) has reviewed your submission of July 20, 2006, and follow-up correspondence of August 4, 2006, in which Deer Creek Energy Limited (DCEL) provided its detailed plans to commence the injection phase at Pad 202, well pairs 1, 2 and 3.

The Board understands that DCEL will be injecting at a pressure no higher than 1200 kPa at the injectors as per the learnings from the ongoing investigation of the steam release incident of May 18, 2006, and will continue to circulate at the corresponding producer wells. Based largely on the commitments made by DCEL in its submission, the Board is satisfied that the implementation of the injection phase at Pad 202 can commence safely.

Key operational changes noted by the Board in DCEL's submission include:

- The injection phase of the production start up on wells 202-I1, I2 and I3 must be conducted at a lower injection pressure so as to avoid a re-occurrence of steam release. Well pairs will operate at a maximum steam injection or circulation pressure of 1200 kPa, as measured at the heel of the well. This pressure gives about a 500 kPa safety margin compared to the expected fracture pressure (estimated by Total to be 20-25 kPa/m based on a geotechnical study produced by a third party), the equivalent of about a 25% safety margin. Production wells will remain on circulation at a maximum circulation pressure of 900 kPa until evidence of the flow of bitumen from injector to producer.
- Monitor and record all well parameters, including pressures, temperatures, circulation and injection rates, so as to document well behavior and apply any lessons learnt to subsequent operations.
- STOP if any anomaly is detected.

- Using pre-job meetings, safe operating practices, safety meetings, and good communication in order to complete all operations without lost time injuries.
- Implement current best practices within the SAGD industry, adapted to these lower pressures due to the shallow depth, and identify improvements that can be applied to future SAGD projects on and off the Joslyn lease.

The Board notes that the steam release investigation is ongoing and there may be some additional findings that could impact the currently approved operations. Therefore, the Board at any time may amend or terminate the approved operations if deemed necessary. Further, **until advised otherwise, DCEL must notify the Board prior to any operational changes at the Joslyn Project pads**.

The Board will be requiring additional reporting regarding the operating conditions committed to in DCEL's submission. The specifics of the reporting requirements will be forwarded shortly.

Should you have any questions or concerns please contact the undersigned at (403) 297-4173.

Yours truly,

for K. Geekie
Section Leader
Resources Applications

CC: Don Hennessey, Bonnyville Field Office, EUB (by email)
Matt Cartwright, VP Thermal, Total (by email)

Appendix 5: *Directive 051* application and approval letters, October-November, 2005

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

November 1, 2005

Paul Krawchuk, Senior Production Engineer
Deer Creek Energy Limited
2600, 205 - 5 Avenue SW
Calgary, AB T2P 2V7

Dear Sir:

G-51 SUBMISSION – DAPHNE BASAL MCMURRAY
CLASS IV INJECTION WELLS (SEE ATTACHED LIST)
APPLICATION # 1426064

The EUB has reviewed your October 25, 2005 submission requesting G-51 approval for the subject Class IV steam injection wells. These wells meet the requirements of G-51, and the EUB offers the following comments with respect to this approval:

- The cement bond logs indicate adequate bond above the injection zone. The AENV recommended base of groundwater protection is covered with cemented casing in each well.
- The casing inspection log requirement was waived as these wells were drilled in 2005.
- Based on the information provided in this application, the MWIP for each well will be 1800 kPaa.
- Injection operations may not commence if these wells do not have written G-65 approval.

Please direct any questions or concerns to the undersigned at 297-3265.

Yours truly,

Dave Baker

Dave Baker, C.E.T.
Technical Specialist
Well Operations, Compliance and Operations Branch

/db

pc. Kris Geekie, EUB- Resources Applications
Microfilm

October 25th, 2005

Alberta Energy Utilities Board
640 – 5th Avenue S.W.
Calgary, Alberta
T2P 5G4

Attention: Mr. Kris Geekie
Resource Applications

RE: Water Disposal Applications – Steam Injection Wells
DCEL ET AL 204 – I1 DAPHNE
DCEL ET AL 204 – I2 DAPHNE
DCEL ET AL 204 – I3 DAPHNE
DCEL ET AL 204 – I4 DAPHNE
DCEL ET AL 204 – I5 DAPHNE

Deer Creek Energy Ltd. hereby makes application under Section 25c of the Oil and Gas Conservation Act, and Section 15.070 of the Regulations, for Approval to inject steam into the Lower McMurray formation in the above wells.

In support of this application, we submit the following information:

1. The well will be used to inject steam as contemplated in the Joslyn Project Phase II Application. This project is located in the NW portion of township 95-12W4. These wells will be class IV Injection wells.
2. The maximum daily volume requested for each well is 400 cubic meters per day of dry steam.
3. The bottom hole conditions will be monitored with down-hole instrumentation and a maximum bottom hole pressure of 1800 kPaa will not be exceeded.
4. The wells were drilled as slant holes into the McMurray and completed horizontally in the oil zone with a slotted liner. The wells were specifically designed to handle the contemplated steam tasks and will be completed as shown in the attached diagrams.
5. The injection zone is the Lower McMurray Formation.
6. The base of groundwater protection obtained in from Alberta Environment is 100 m. below GL.
7. The geology of the zones is described in the enclosed Geological Description.
8. Deer Creek Energy Ltd. Is the lessee of all sections contiguous to the section containing the steam.

Attached hereto and forming part of this application are:

1. (5) Well Summaries for Injection or Disposal, from EUB Guide 51.
2. (5) Steam injection well Wellbore Completion Schematics.
3. Maps showing the locations of the wells in the area are included in the geological portion of this application (See item 6).
4. A copy of the Daily Drilling Reports for the injection wells (5 total).
5. A copy of the FAX received from AEP showing the Base of Groundwater protection.
6. A Geological Description of the proposed injection zone together with a Cross Section showing the logs offsetting the proposed injection wells.
7. A copy of the Cement Bond Logs (5 total).

Should you have additional questions regarding this application, please do not hesitate to contact me by phone at (403) 538-6367 or by email at paul.krawchuk@total.com

Sincerely,

Paul Krawchuk, P. Eng.
Senior Production Engineer
Deer Creek Energy Ltd.

Appendix 6: ERCB letters imposing additional start-up conditions and information requests, September 2006

EUB Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

September 5,2006 (by email)

Don Verdonck
General Manager, Operations
Deer Creek Energy Limited
1900, 333-7 Avenue
Calgary, AB
T2P 221

Dear Mr. Verdonck:

DEER CREEK ENERGY LIMITED
JOSLYN SAGD PROJECT
ATHABASCA OIL SANDS AREA
SUBMISSION NO. 28213
PHASE II SAGD: PRODUCTION START-UP PROGRAM
INJECTION PHASE, PAD 202, 3 WELL PAIRS

In follow up to the Alberta Energy and Utilities Board's (EUB/Board) letter of Aug 17th, 2006 approving Deer Creek Energy Limited's (DCEL) plans to commence its injection phase at Pad 202, wells 1, 2 and 3 the following conditions and reporting requirements have been added:

- Until advised otherwise, DCEL must notify the Board prior to any operational changes at the Joslyn Project pads.
- Well pairs will operate at a maximum steam injection or circulation pressure of 1200 kPa, as measured at the heel of the well as per the revised D-51 approval.
- The monitored and recorded data for all well parameters, including pressures, temperatures, circulation and injection rates, will be provided to the Board on a regular basis with DCEL's summary of any lessons learned and corresponding application to subsequent operations
- Provide a monthly summary of anomalies encountered and the corresponding DCEL action(s)
- Provide the results and analyses from the 3-D resistivity and 3-D seismic surveys upon completion
- Submit a formal report outlining current best practices used by companies operating at lower pressures due to the shallow depth, and identify improvements that can be applied to future SAGD projects
- Provide an overall heave monitoring program at the Joslyn SAGD site for the known and planned locations of monitoring equipment for each well pair path or potentially impacted surface structure(~)

The Operator shall provide presentations at a minimum of every 3 months to the Board that would include a summary of the production operations, any further results of the steam release technical investigations, the analysis of those investigations, and future investigation plans for the following 3 month period until further notice.

Should you have any questions or concerns please contact the undersigned at (403) 297-4173.

Yours truly,

K. Geekie
Section Leader
Resources Applications

CC: Don Hennessey, Bonnyville Field Office, EUB (by email)
Matt Cartwright, VP Termal, Total (by email)

Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

September 5,2006 (by email)

Don Verdonck
General Manager, Operations
Deer Creek Energy Limited
1900, 333-7th Avenue
Calgary, AB
T2P 221

Dear Mr. Verdonck:

DEER CREEK ENERGY LIMITED
JOSLYN SAGD PROJECT
ATHABASCA OIL SANDS AREA
STEAM RELEASE INCIDENT INVESTIGATION

The Alberta Energy and Utilities Board has completed an initial review of Deer Creek Energy Limited's steam release incident report at the Joslyn SAGD site. At this time the Board has additional questions based on the report(s) provided. To continue the investigation, the Board requires responses to the enclosed information request.

If you have any questions please contact the undersigned at 297-4173.

Yours truly,

Kris Geekie
Section Leader
Resources Applications Group

Cc: Don Hennessey, Bonnyville Field Office, EUB (by email)
Matt Cartwright, VP Termal, Total (by email)

a

A) Resources

1) DCEL/Total have submitted a number of pressure profiles from Pad 204 during the course of the steam release investigation. The location of the pressure recorders have not been defined in the submissions. Clarify whether the pressure recordings occurred at the well head, or sub-surface (toe/heel). Please label all future submissions accordingly.
2) What is the pressure differential between the wellhead pressures and the sub-surface 'heel' during injection operations, i.e at 1800kPa and 1200 kPa?
3) Comment on the geomechanical theory regarding conventional rock material with overburden pressures, as applied to the subject friable, poorly consolidated low pressure reservoir material.
4) Provide an update on information gathered from the observation well' (0019-33) at the incident site.

B) Bonnyville Office / Operations

1) Provide the 'Tower sheets' for the observation well and corehole well[2] (AB/9-33) adjacent to the steam release incident. Provide an analysis of the drilling and cementing operations as they may have impacted on the steam release incident. The EUB acknowledges receiving the Daily Drilling Report for the observation well.

2) Provide 'drilling rig leak-off data for the 204-1 wellpair and wells 00/9-33 and AB/9-33, if available.

3) Provide copies of the resistivity and spontaneous potential logs for the 204-1 well pair and well 0019-33 and well AB/9-33.

4) Provide an update of the environmental recovery plans, efforts to date, and timelines to complete the following areas (but not limited to):
   - Surface reclamation efforts.
   - Status of the soil and water sampling project.
   - Reforestation.
   - Groundwater impacts
     a. Local and regional aquifers

5) Provide the workover information for the I1-204 wellpair, specifically the pressure testing of the bridge plug, and provide the steps used to ensure that EUB Directive 33 was followed.

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[1] 00/09-33-095-12W4/0
[2] AB/09-33-095-12W4/0

C) Geology **and** Reserves

The following questions deal with the geological information submitted to the EUB on July 19,2006 in the DCEL/Total report entitled ***"Response to EUB Inquiries, Deer Creek Steam Release Investigation, 2006".***

1) **EUB** Data Request #2, Geologic Conditions:
Item 1. Pre-Incident Geologic Description of the Incident and Surrounding Area.

- Two geological maps were provided, one entitled "sub-Cretaceous unconformity structure", and the other "Devonian structure". What is the difference between these two maps? Is the same data contoured? If the maps are supposed to represent structure on the sub-cretaceous unconformity surface which is the top of the Devonian, then why are they different? The earlier map shows more circular contour features, whereas the latter one shows much of this irregularity removed. In the July 19 DCEL/Total submission, they state that no seismic was used in this mapping. DCEL/Total should explain the rationale and basis for the changes between the two maps, and their interpretation as it pertains to Karst topography.

2) **EUB** Data Request #2, Geologic Conditions:
Item 2. Nature of Quaternary overburden and possible occurrence of Quaternary channels.

- DCEL/Total submitted Quaternary overburden evidence including auger hole description sheets from Terracon. However, the sheets did not include the necessary survey location and surface elevation data for a number of auger holes. Please provide the survey data for the following holes:

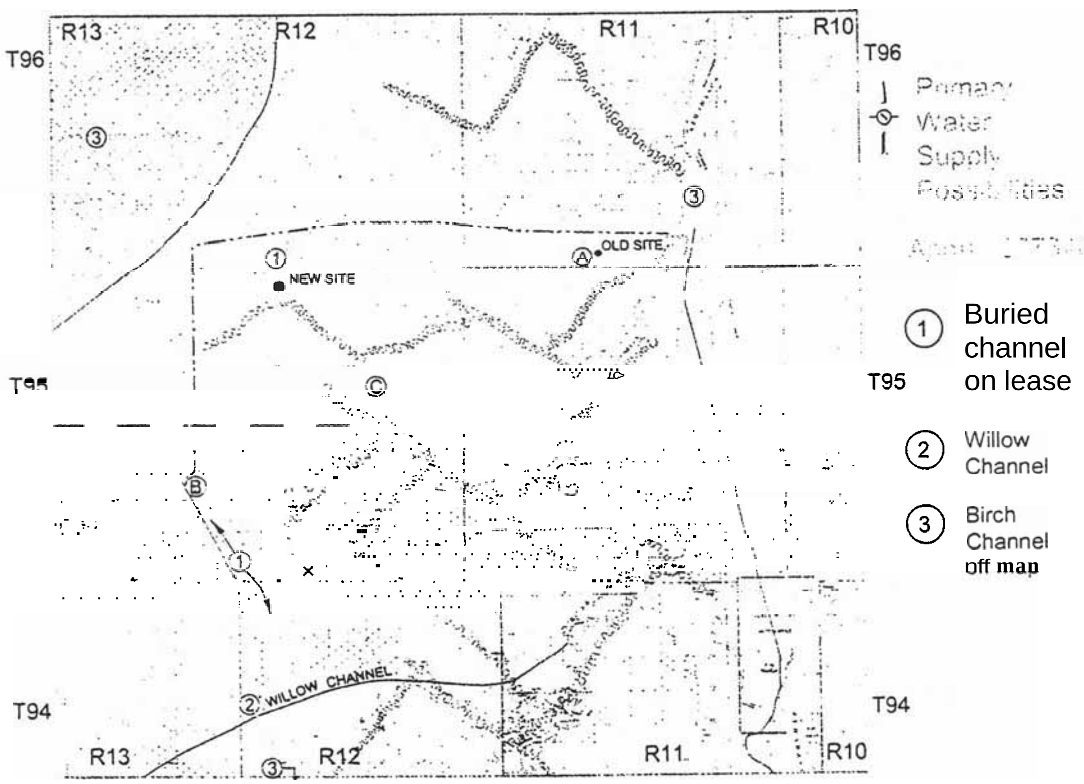
  1AB/06-28-095-12W4 Coordinates E (m) and Coordinates N (m)
  1AB/11-28-095-12W4 Coordinates E (m), Coordinates N (m) and Ground Elevation (m)
  1AC/01-33-095-12W4 Coordinates E (m) and Coordinates N (m)
  1AA/02-33-095-12W4 Coordinates E (m), Coordinates N (m) and Ground Elevation (m)
  1AB/08-33-095-12W4 Coordinates E (m) and Coordinates N (m)
  1AB/12-33-095-12W4 Coordinates E (m) and Coordinates N (m)
  1AA/13-33-095-12W4 Coordinates E (m), Coordinates N (m) and Ground Elevation (m)
  1AC/14-33-095-12W4 Coordinates E (m) and Coordinates N (m)

- It is unclear from their submitted data whether AA/02-33-095-12W4 is the same well as 0/02-33-095-12W4. The AA/02-33-095-12W4 could not be located on the maps provided, but the 0102-33-095-12W4 was located on the structure map of the unconformity surface. Please clarify.
- Any downhole logs and interpretation indicating shale or thermal chambers would be appreciated as supplemental information.
- Please provide a Quaternary overburden and auger hole location map.

In the July 19,2006, submission, DCEL/Total states:

"*Based on auger holes drilled within LSD 33, there is evidence of fluvial (creek) deposits adjacent to Joslyn Creek. These units are Holocene age and disappear with distance from the creek as shown on Cross Section A and in the previously submitted auger logs."*

The map below is from the DCEL Joslyn SAGD Phase I Application (EUB No. 1277348), under the section on *Primary Water Supply Possibilities.* Shown in the blue circle numbers are sites indicated by DCEL that are buried channel primary water supply possibilities on lease.



- What new information is available from DCEL/Total that shows that these originally mapped interpretations of buried channels now do not exist?

3) EUB Data Request #2, Geologic Conditions:
<u>Item 3. Nature of Fracture and Lineament Patterns in the Area.</u>

a) In the July 19,2006 submission, DCEL/Total stated:

"*Visual observation of air photos and Lidar survey, both in the Steam Release area and the whole Deer Creek lease, yields a moderate amount of lineaments in the area.*

Most of these appear as ancient creek and river beds. These lineaments are predominantly north-northwest trending, as confirmed by Babcock and Sheldon (1976).

A map of the structure of the Devonian Formation was compared to the air-photos to look for any surface expression of the sub-surface features. There is some evidence of sinkholes in the Devonian that appear in air-photos on the Joslyn Lease shown by changes in both elevation and vegetation. However, any possible faults or joints in the Devonian do not appear in the air-photos on the Deer Creek lease and there is no evidence of these features in the incident area. With the information available to us at this time, there is no indication of any zones of weakness that may have had potential for failure."

- The map from the DCEL Joslyn SAGD Phase 1 Application (shown above), shows in red squiggly lines the lineaments in the immediate area both on and just off lease. Submit the new information, including any Lidar and air photo interpretations, which show that these originally mapped lineaments do not correlate with underlying faults.
- Are there any updates of the geological lineament maps available, and if so please submit and provide an analysis of the potential impact of the lineaments on the steam release incident.

b) In the submission of July 19,2006, regarding the extent to which any precipitation or ground moisture content conditions may have contributed to any failure, DCEL/TOTAL stated:

"Neither, precipitation nar ground moisture content conditions have contributed to any failure."

- There is no supporting documentation/evidence for this statement. What is the basis of this opinion? Is there any meteorological evidence to show any abnormal or unusual precipitation statistics prior to the incident?

4) EUB Data Request #2, Geologic Conditions:
<u>Item 4. Nature of Muskeg. Surface Runoff. and Possible Karst Features in the Area.</u>

- In the submitted auger-hole data from the following locations, AA/1-33-095-12W4 and AA/1-33-95-11W4, glacial units sit directly upon McMurray formation, i.e. there is no Clearwater Formation. Please explain this absence, in light'of possible faulting and possible Karsting in the area.

- In the submitted auger-hole data from the following locations, AB/2-28-095-12W4, the AB/08-28-095-12W4, AB/08-33-095-12W4, AC/08-33-095-12W4, there is an indication of Disturbed Clearwater formation. Please describe the nature of this disturbance, and explain the disturbance, in light of possible faulting and karstification in the area.

- In the submitted auger-hole data from the following locations, the AB/2-28-95-12W4* and AA/04-28-095-12W4, there are occurrences of Rafted Clearwater formation. Is this glacial-rafting– as in drop stones? Or is this glacial-tectonic rafting, as in a rafted thrust blocks of Clearwater at the base of the glacial unit? Please comment on the possibility of glacio-tectonic faulting in the area.

- In the submitted auger-hole data from the following locations, the AB/9-28-95-12W4, AC/1-33-95-12W4, AC/08-33-095-12W4, AC/10-33-095-12W4, AB/15-33-095-12W4, AC/15-33-095-12W4, and AC/16-33-095-12W4, there are indications of 'mild bitumen odour' or moderate gas odor in the glacial till, fluvial alluvium and peat deposits. Please comment on the possibility of faults (glacio-tectonic or otherwise) as being conduits between underlying hydrocarbon bitumen- and gas-bearing bedrock and overlying Quaternary units, with bitumen and gas moving up into younger units dong faults in the area.

- In the submitted auger-hole data from the following locations there are frozen units (with depth of freezing from logs, or if not indicated then the bottom depths of units with freezing, indicated in parentheses): AB/02-28-095-12W4 (2.11 m), AA/4-28-095-12W4 (1.52 m), AB/08-33-095-12W4 (0.61 m), AC/08-33-095-12W4 (4.27 m), AC/15-33-095-12W4 (1.52 m), AC/16-33-095-12W4 (0.46 m). Comment on the possibility of discontinuous permafrost or seasonal (one or two seasons) ice forming vertical conduits as a possible connection between bedrock and surface.

5) EUB Data Request #2, Geologic Conditions:
<u>Item 5. Summarize the Assessment of the Post-Incident Geolonv.</u>

- Please provide all surficial surveys of the area that give the sizes, location and description of debris that was ejected with the incident. This was requested but not provided.

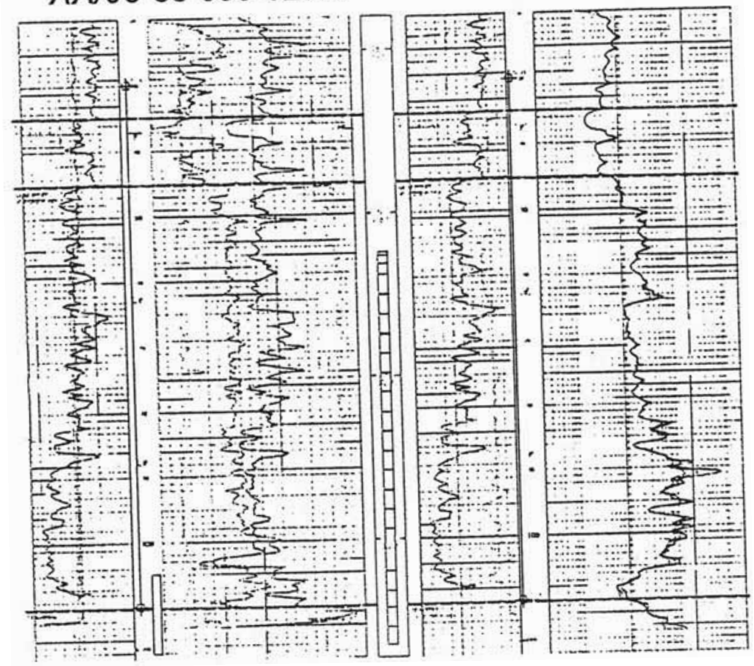
- Please provide a map that shows the thickness and distribution of the ejecta, particularly the larger-sized material. Were there any McMurray formation blocks of material in the ejecta? Are only Clearwater Shale blocks in the ejecta? Was there bitumen or other low-grade hydrocarbon in the ejecta, and if so where did it come from, and how does DCEL/Total postulate it was transported uphole?

6) Re: EUB Data Request #2, Geologic Conditions:
<u>Item 6. Nature of Upper Thief Zone and Potential for Communication Pathway to Surface</u>.

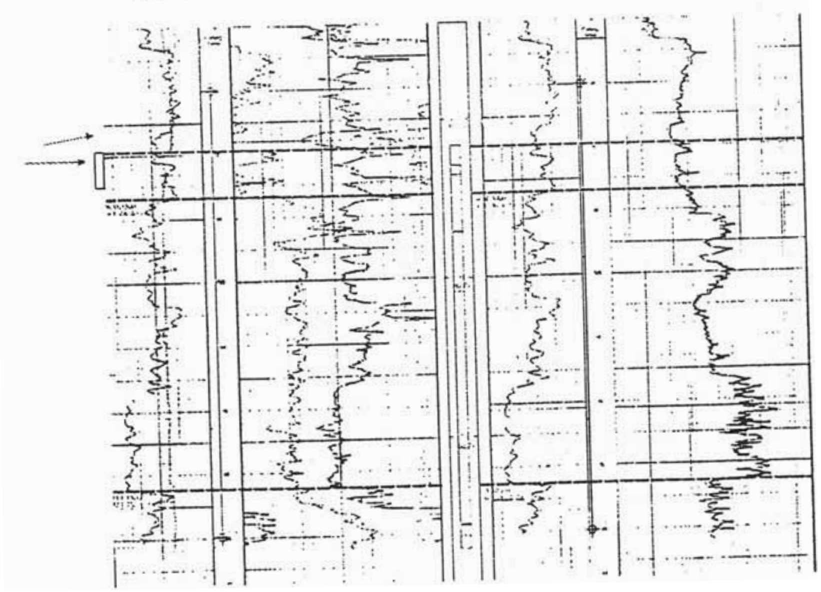
- In the submitted auger-hole data from the following locations: AB/02-28-095-12W4, there is indication of a hard, water trap of siltstone within the Clearwater Formation; and for the AA/4-28-095-12W4 of a water trap siltstone between a Rafted Clearwater and the Clearwater Formation. Comment on the possibility of this siltstone being another upper thief zone at or near the top of the Clearwater, and the potential for a communication pathway to surface.

- In each of the following logs, there are marked in pink (magenta) one or two sands that occur just above and below the T21 marker, which is at the contact between the base of the Clearwater Formation and at the top of the Wabiskaw Member. Where there are two sands, separated by the T21 marker shale, the upper sand would be at the base of the Clearwater, and the lower sand would be the Wabiskaw **A** sand. Comment on the possibility of these sands'being another potential upper thief zone at or near the top of the Clearwater, and the potential for a communication pathway to surface.

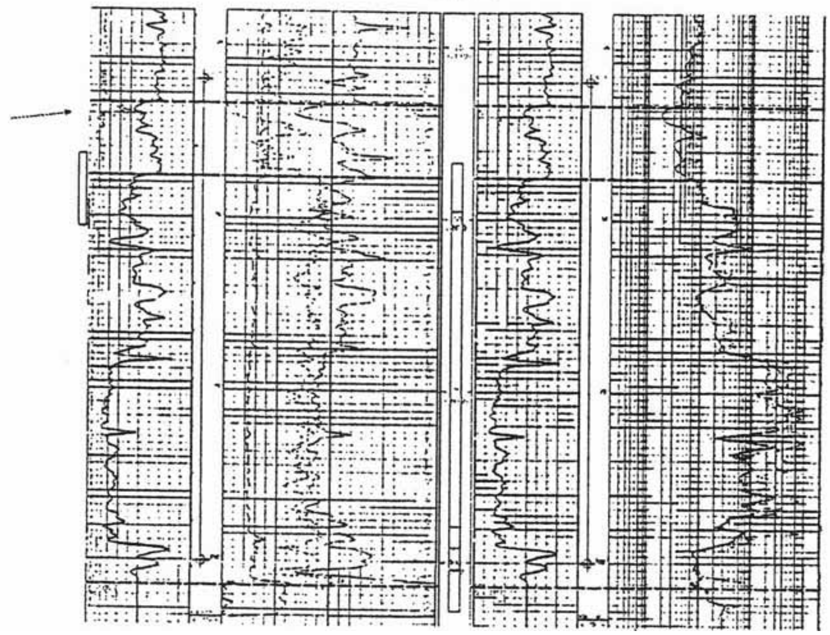
AA/05-33-095-12W4



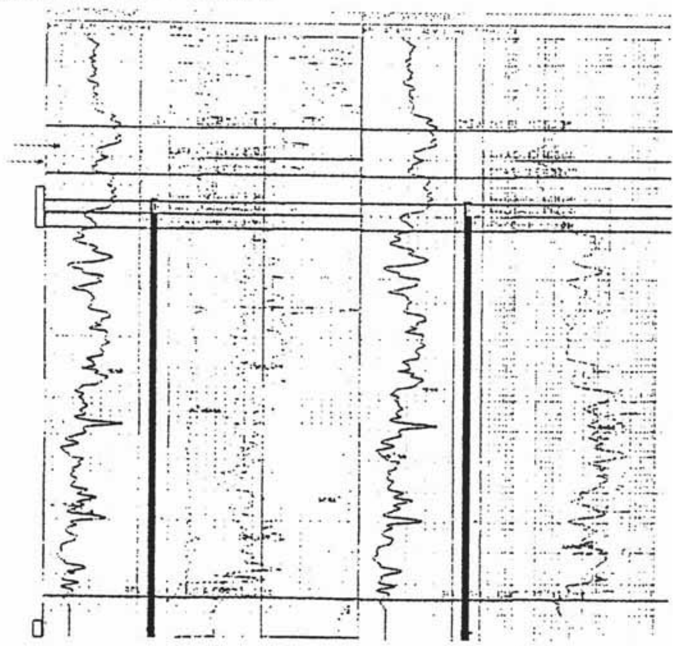
AB/08-33-095-12W4



AB/09-33-095-12W4



AA/15-33-095-12W4



AA/16-33-095-12W4,