



Caltex Energy Inc.
Hydraulic Fracturing Incident
16-27-068-10W6M
September 22, 2011

ERCB Investigation Report

December 20, 2012

ENERGY RESOURCES CONSERVATION BOARD

ERCB Investigation Report: Caltex Energy Inc., Hydraulic Fracturing Incident, 16-27-068-10W6M,
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1 Description of Incident

On September 22, 2011, Crew Energy Inc. (Crew) was performing a hydraulic fracturing operation on the Caltex HZ ELM 11-34-068-10W6M (actual bottomhole location) well and inadvertently perforated above the base of groundwater protection at a depth of 136 metres measured depth (mMD).¹ Hydraulic fracturing operations were subsequently conducted using gelled propane as a carrier fluid, pumping 20.07 tonnes of sand and 130 cubic metres (m³) of gelled propane.

When it was realized that hydraulic fracturing had occurred through the shallow perforations, flow-back operations of the fractured interval were conducted. A two-well groundwater monitoring program was initiated and is ongoing to evaluate the impact of the incident upon groundwater. The monitoring wells are located approximately 50 metres (m) northeast of the surface location of the hydraulically fractured well located at LSD 16-27-068-10W6M. This location was recommended by Crew and accepted by Alberta Environment and Sustainable Resource Development (ESRD) based on the hydraulic gradient and expected aqueous transport direction.

Chronology of Events

September 21

- The well was filled with fluid to circulate out debris.

September 22

- The perforating gun was run in on coil and the well was perforated.
- The coiled tubing collapsed.
- Coiled tubing was re-run in and the well was blown dry with nitrogen.

September 23

- Propane fracturing conducted.
- The bridge plug was set but the casing failed a pressure test.

September 24

- A downhole packer was run in to conduct pressure isolation tests. Perforations were confirmed to be between 130 and 150 mMD

September 25

- A downhole camera was run in to determine the exact location of the perforations; they were found at 136.21 mMD
- Begin flowing well.

¹ Note that the original licensed well bottomhole location was LSD 14-34-068-10W6M. Caltex was purchased by Crew Energy Inc. prior to the event. Crew was in the process of amalgamating the two companies' operations and had responsibility for the activities at the well site.

September 26 – October 9

- Well continued to flow.

October 10 – 14

- No operations.

October 15

- Squeezed cement plug into the perforations at 136 mMD.

2 Investigation

Crew findings are largely captured in Appendix A: *Crew Energy Root Cause Analysis* and supplemented with information provided throughout the investigation.

The investigation included

- an incident report prepared by Crew immediately following the incident,
- a meeting with Crew, ESRD, and the Energy Resources Conservation Board (ERCB) on February 9, 2012, to review the incident data, the groundwater monitoring plan, and Crew's activities to manage the 16-27 hydraulic fracturing operation, and
- a follow-up meeting with Crew and the ERCB on February 23, 2012, to allow Crew to provide the ERCB with their plans to better manage the risk with future high vapour pressure (HVP) hydraulic fracturing operations.

2.1 Change of Fluid

2.1.1 Observations

Debris in the wellbore following an earlier stage of the fracturing operation at a depth of 1650 mMD caused the running of a bridge plug to not reach the planned setting depth. The debris resulted in the addition of the step to circulate the well with potassium chloride (KCl) water to remove the debris from the well. As a consequence, the well was left fluid filled rather than gas filled as called for in the completions program.

2.1.2 Crew Findings

A program deviation necessitated the well be circulated to water prior to perforating.

2.1.3 ERCB Findings

A change occurred to the coiled tubing perforating plan where the well was filled with KCl water instead of the nitrogen originally planned. This change would have caused the wellbore to have lower compressibility due to the presence of the water when stripping and snubbing the coiled tubing perforating gun into the well. Consequently, pressure build-up would have been more rapid compared to a nitrogen-filled well.

2.2 Pressure Monitoring

2.2.1 Observations

While stripping the perforating gun into the well, the pressures in the coil and in the coiled-tubing-to-production-casing annulus were to be maintained at 8000 kPa. This was to be achieved by bleeding fluid from the well to the test separator. Real-time recording of the pressures was not available because the coiled tubing unit data recorder was not functional. The coiled tubing service company operator observed a spike in annulus pressure to 10 000 kPa but did not record the corresponding depth. Therefore, the pressures inside the coiled tubing and in the annulus outside the coiled tubing when the coiled tubing jumped are uncertain. The volume of fluid bled off to the test separator was also not recorded to confirm that the annulus pressure was being managed.

2.2.2 Crew Findings

Inadequate control of pressure in the coiled-tubing-to-production-casing annulus while running the perforating gun in the water-filled wellbore may have contributed to the collapse of the coiled tubing. However, pressures sufficient to collapse the coiled tubing were not confirmed during operations monitoring.

2.2.3 ERCB Findings

The coiled tubing perforating gun was snubbed, or stripped, into the well using the original gas-filled-well procedures, even though the well was filled with KCl water. The procedures were not modified to accommodate the fluid in the well.

Of specific importance was the procedure to maintain 8000 kilopascals (kPa) of pressure on the coiled-tubing-to-production-casing annulus. Pressure gauges at the wellhead were apparently being used to monitor the wellhead pressures while stripping in the perforating gun. The coiled tubing unit computer monitoring and recording was not operational and could not track and record the pressures on the coiled tubing and within the coiled-tubing-to-production-casing annulus.

2.3 Perforating Gun Fires Off-Depth

2.3.1 Observations

At approximately 137 m, the depth where the perforations were found, the coiled tubing jumped on the reel while stripping in. This was interpreted to be a coil wrap problem on the coiled tubing reel. The possibility that the perforating gun had fired at this depth was not recognized at the time.

2.3.2 Crew Findings

The jump of the coiled tubing at 137 mMD was interpreted by Crew personnel as being a loose wrap on the coiled tubing reel.

2.3.3 ERCB Findings

The coil jump at 137 mMD is the first evidence of off-depth perforations. The possibility that the perforating gun had fired at this depth while running in was not considered at this point.

Consequently, the cause for the premature firing of the perforating gun was also not observed at this point.

2.4 Perforating Gun Attempted Firing

2.4.1 Observations

The perforating gun was run to the planned depth of 1486 mMD and pressured up to perforate the well. The firing head was shear-pin-pressure activated and set to fire at 27 330 kPa. The observed pressure was 17 000 kPa, more than 10 000 kPa below the design pressure. This difference was not acknowledged as being a significant deviation, nor was it recognized as an indicator that the well might not have been perforated at the planned depth.

2.4.2 Crew Findings

The service company providing the perforating service interpreted the 17 000 kPa as the perforating guns having fired at depth. During the Crew investigation, the service company stated this pressure was normal. Testing of an identical firing head by the manufacturer demonstrated the head should have fired within 5% of the design pressure (26 000 to 28 700 kPa).

2.4.3 ERCB Findings

The 17 000 kPa observed pressure was not acknowledged during the operation by the service company or by Crew supervision as being significantly below the set pressure. This should have been recognized as the second indication of the premature firing of the perforating gun.

2.5 Collapsed Tubing

2.5.1 Observations

While stripping the coiled tubing and perforating gun from the well, the coiled tubing was found to be collapsed from approximately 75 m to 27 m above the bottomhole assembly (BHA). The collapse was not recognized as affecting the perforation depth. The cause for the collapsed coiled tubing was not explained by the field personnel, nor was the mechanism for failure confirmed after the event. Consequently, the relationship of the coiled tubing collapse to the off-depth perforations has not been adequately explained. Appendix B: Collapsed Coiled Tubing contains pictures of the failed coiled tubing extracted from the failure analysis report done by NOV Quality Tubing.

2.5.2 Crew Findings

The coiled tubing collapse was recognized when the coil could not be stripped through the injector head. NOV Quality Tubing determined that the coiled tubing would have required an external pressure of 2230 psi (15 400 kPa) to collapse the coil. Crew concluded the collapse was due either to overpressure of the annulus or a material fault with the coil. The collapse was likely the cause of the premature firing of the perforating gun

2.5.3 ERCB Findings

NOV Quality Tubing concluded the most likely cause of the coil damage was collapse due to external pressure. Mechanical testing of the damaged section of coil did not identify off-specification materials. Consequently, an annulus pressure almost double the planned pressure of 8000 kPa was likely applied to the coil tubing to cause it to collapse. As indicated in Section 2.2.1, the highest pressure observed and reported was 10 000 kPa. Consequently, confirmation of the collapse pressure is not available.

2.6 High Vapour Pressure Fracturing

2.6.1 Observations

HVP fracturing using propane was conducted; nobody was yet aware that the perforations were at 136 mMD. The peak hydraulic fracturing surface pressure (42.9 megapascals [MPa]) was mid-range to the other intervals fractured in this well. The overall pressure response was recognized by the GasFrac supervisor as being unusual, as it declined during the operations and the well had a low shut-in pressure when the treatment was finished. (GasFrac Energy Services is the service company that provided the fracturing pumping services and the gelled propane fracturing fluid.)

2.6.2 Crew Findings

None.

2.6.3 ERCB Findings

The GasFrac supervisor's recognition of the low shut-in pressure and the declining stimulation pressure did not apparently trigger a question at the time as to whether or not there was a problem with this particular fracturing stage or that there may have been any out-of-zone communication.

2.7 Pressure Test of Casing

2.7.1 Observations

Isolation of the planned perforation interval at 1486 mMD was accomplished by setting a bridge plug at 1387 mMD. A pressure test of the casing above the bridge plug revealed that the casing did not have pressure integrity. This was the first acknowledgement of a problem in the well. Subsequent isolation pressure testing operations and a downhole camera run located the perforations at 136 mMD.

2.7.2 Crew Findings

Crew identified the loss of casing integrity through the bridge plug pressure integrity test.

2.7.3 ERCB Findings

A pressure test of the casing above the bridge plug (performed after the stimulation had occurred) revealed the off-depth perforation.

2.8 Misplaced Propane

2.8.1 Observations

Having confirmed the well had been fractured at the perforations at 136 mMD, the well was flowed back to recover as much of the propane and fracturing fluids as possible. Approximately 42 m³ of propane was not recovered.

Groundwater monitoring wells were installed to investigate the movement of the fracture fluids in the subsurface.

Two monitoring wells were installed: one completed at the depth of the perforations (137 mMD) and the other in the overlying sandstone seam considered to be a potential domestic use aquifer (DUA) at the depth of 81 metres below ground level (mbgl). The monitoring wells were installed as a nested pair approximately 50 m north of the surface location of the Crew well.

Combustible gas, assumed to be propane, was detected at surface on the deeper well using a combustible gas detection meter (LEL). However, the gelled propane chemicals were not identified in the fluid samples collected from this well. Pump test results from the deep monitoring well showed that the hydraulic properties of the fractured zone were too low to meet ESRD's definition of a DUA. Appendix C: Well Cross-Section Schematic depicts the horizontal well in relation to the off-depth perforations and the deep monitoring well

2.8.2 ERCB Findings

Hydraulic connection between the fractured zone at 137 mMD and the overlying sandstone aquifer at 81 mbgl was not observed during the pumping test. As a result, ESRD deemed that the incident posed an insignificant risk to drinking water resources.

2.9 Conclusions

- 1) If more adequate pressure monitoring equipment and procedures were in place for the fluid-filled well at the time of the incident, the premature firing of the perforating gun and the collapse of the coiled tubing may have been avoided or detected.
- 2) If the jump in the coiled tubing had been recognized as being the result of the perforating gun firing, the fracturing operation might have been prevented.
- 3) Faulty perforating equipment does not appear to have been the cause of the shallow perforations. However, if the low pressure experienced during the attempted perforating had been identified as being off specification, the fracturing operation might have been prevented.
- 4) The collapsed coiled tubing did not trigger an investigation of the cause or possible repercussions. If the collapse was investigated at the time of the operation, the fracturing operation might have been avoided.
- 5) While the abnormal fracturing pressure was recognized during the fracturing operation, this observation did not lead to an early shutdown or a question of why it was abnormal.

- 6) Based on the groundwater monitoring-well data to date, there is insignificant risk to drinking water in the area.
- 7) Collectively, Crew and the onsite service company's personnel did not adequately manage the risks associated with the coiled tubing perforating and propane hydraulic fracturing operations. There were multiple opportunities to recognize that a problem existed, which could have prevented or at least minimized the impact of the hydraulic fracturing operation above the base of groundwater protection.

3 Enforcement

The ERCB has issued a Notice of High Risk Noncompliance to Crew based on *Directive 027: Shallow Fracturing Operations – Restricted Operations*, failure to use only non-toxic fracture fluids above the base of groundwater protection.

Accordingly, Crew has now been issued a High Risk Enforcement Action, as set out in *Directive 019: Compliance Assurance*.

Crew is required to do the following to achieve compliance:

- Develop, implement, and electronically submit an action plan to grandeprairie.fieldcentre@ercb.ca by January 30, 2013. The action plan must detail what Crew will do to prevent similar noncompliance events in this compliance category in the future.

Failure to comply with the above requirements may result in Crew receiving a High Risk Enforcement Action (Failure to Comply), in accordance with *Directive 019*. Escalated enforcement action may include

- partial or full suspension of operations,
- self-audit or inspections,
- increased audits or inspections, or
- suspension or cancellation of permit, licence, or approval.

4 ERCB-Directed Actions

4.1 Groundwater Monitoring Wells

Crew is required to monitor the groundwater in the monitoring wells positioned northeast of the 16-27 energy well. The water is to be analyzed and provided to ESRD and the ERCB for review. ESRD currently manages the site as a contaminated site.

4.1.1 Observations

One monitoring well was completed in the hydraulically fractured sandstone (deep monitoring well) and a second monitoring well in an overlying sandstone (shallow monitoring well). The initial estimate of the hydraulic conductivity of the fractured sandstone was lower than that of a domestic use aquifer (DUA). This preliminary conclusion was confirmed by the repeat test on September 20, 2012, when the sustainable yield was calculated to be 0.6 litres per minute (L/min), which is lower than the value set by the *Alberta Tier 2 Soil and Groundwater Remediation Guidelines* for a DUA. The shallower sandstone

layer is considered to be a DUA. Both pumping tests, conducted in February 2012 and on September 20, 2012, indicated that there was no connection between the two sandstone layers.

4.1.2 Monitoring Program

The long-term instrumentation, monitoring, and sampling program for the site is pending based on the results of the pumping tests and ESRD's approval.

Combustible gas was detected through lower explosive limit (LEL) measurement at the surface during the pumping and water sampling tests in the deeper monitoring well. Crew was required to report the detection of combustible gas to the ERCB.

In addition to the routine components, the deeper monitoring well is likely to continue to be tested for isopropanolamine, being the selected indicating chemical for the presence of the fracturing fluids.

The sampling event in February 2012 detected the presence of isopropanolamine in a sample collected from the deeper well; however, isopropanolamine was not detected in either monitoring well in the samples collected on September 20, 2012. The total Kjeldahl nitrogen (TKN) and ammonia concentrations both showed a significant decrease to one-fifth of the previous concentrations, possibly indicating the attenuation of the amines as well.

The groundwater composition on September 20, 2012, continued to be impacted by the fracturing fluids. The concentrations of chloride has decreased from the February 2012 sample, but remains elevated. Benzene, toluene, ethylbenzene, and xylene (BTEX) concentrations remained unchanged between the February and September 2012 sampling events. The petroleum hydrocarbon (PHC) fractions F2 through F4 concentrations overall decreased (with the PHC fraction F1 showing an anomalous increase).

An increase in iron concentrations and a decrease in nitrate concentrations between February and September 2012 is potentially due to the biodegradation of the hydrocarbons as conditions become more anaerobic.

A significant increase is noted in the concentrations of dissolved organic carbon (DOC) and phosphorous, potentially related to biological activity.

Further sampling is needed to establish statistically significant trends in the indicator parameters' concentrations.

No compounds indicating the presence of the fracturing fluids were detected in the shallow monitoring well in either the February or September 2012 sampling events.

4.2 Proximal Drilling Risk

Because over 40 m³ of propane has not been recovered and apparently exists around the 16-27 well, there is a potential drilling risk to any new energy well drilled near the surface location of the fractured well. Crew is instructed to monitor the ERCB application website

(currently https://www3.eub.gov.ab.ca/eub/dds/iar_query/FindApplications.aspx) for well applications within a 200 m radius of the 16-27 surface location.

Should an application be identified, Crew is instructed to advise the licensee that the ERCB Well Operations Group should be advised of the application. Should Crew be the applicant, Crew is also instructed to advise ERCB Well Operations of the well application.

Should Crew elect to sell or transfer any properties within the 200 m radius of the 16-27 surface location, a condition of the transfer will be to advise the purchaser of the above notification requirements.

This condition will remain in place until the propane hazard is demonstrated to be low risk.

4.3 Hydraulic Fracturing Program Follow-Up

Crew is required to prepare and submit an action plan to manage similar high-risk operations. ERCB staff will follow up with an audit of the action plan to assess the readiness of Crew to adequately manage high-risk operations.

5 ERCB Follow-up

Through enforcement action, the ERCB will be reviewing Crew Energy's action plans to prevent future HVP fracturing incidents. Additional avenues to share the incident experience and prevent further occurrences will be investigated.

Appendix A: Crew Energy Root Cause Analysis

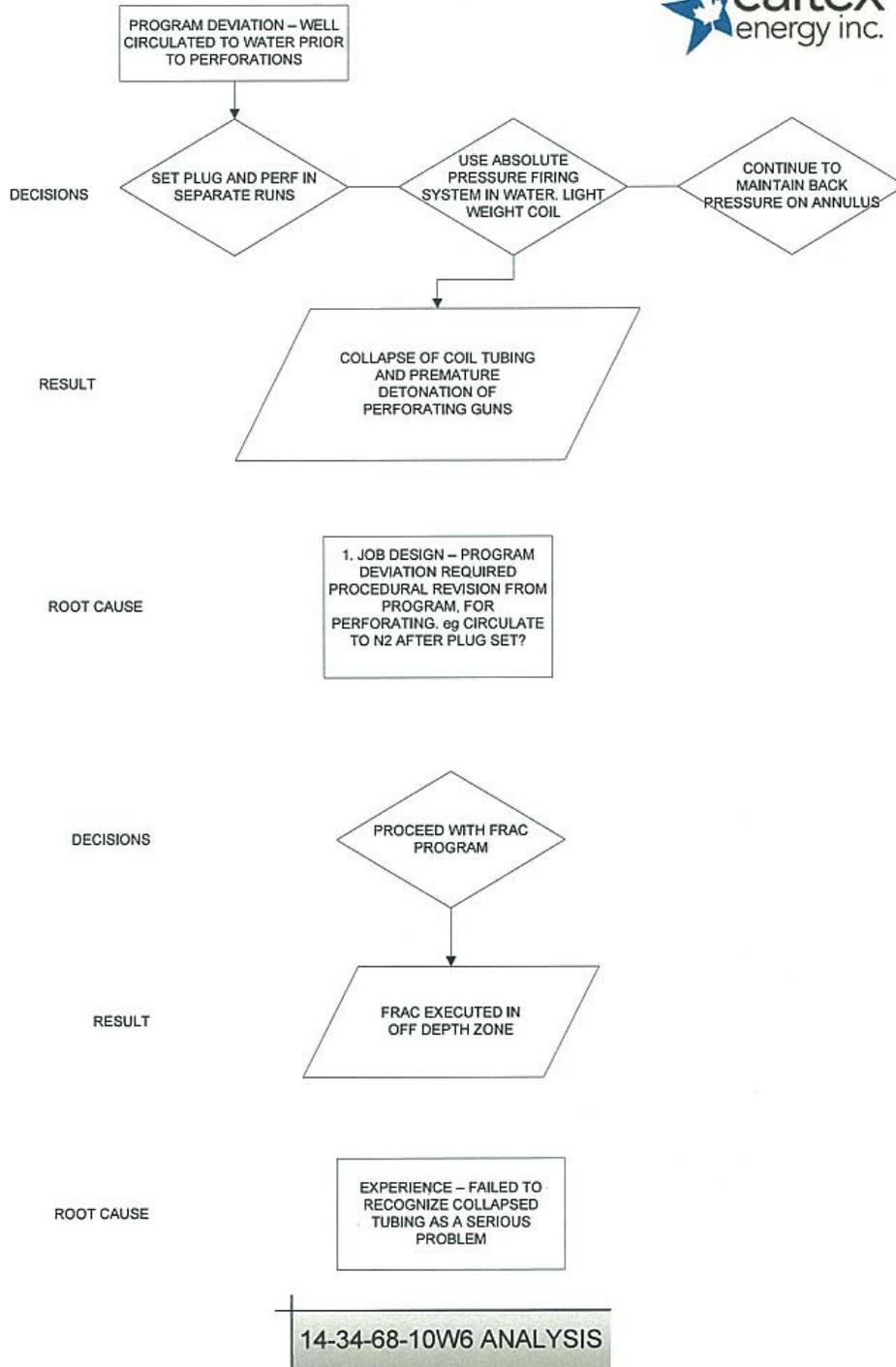




Figure 1: As recieved - Overall view of the sample (deformation is on the right).



Figure 2: As recieved – Orthogonal view of the deformed end of the supplied sample (right side of Figure 1). The deformation is most likely the result of collapse. Scale minor dimension is in mm.

Appendix C: Well Cross-Section Schematic

Caltex HZ ELM 14-34-068-10 W6M
Well Cross-Section Schematic

