Failure Investigation Report

Well Failure at Todd Energy Canada Ltd.

January 2019

BC Oil & Gas COMMISSION

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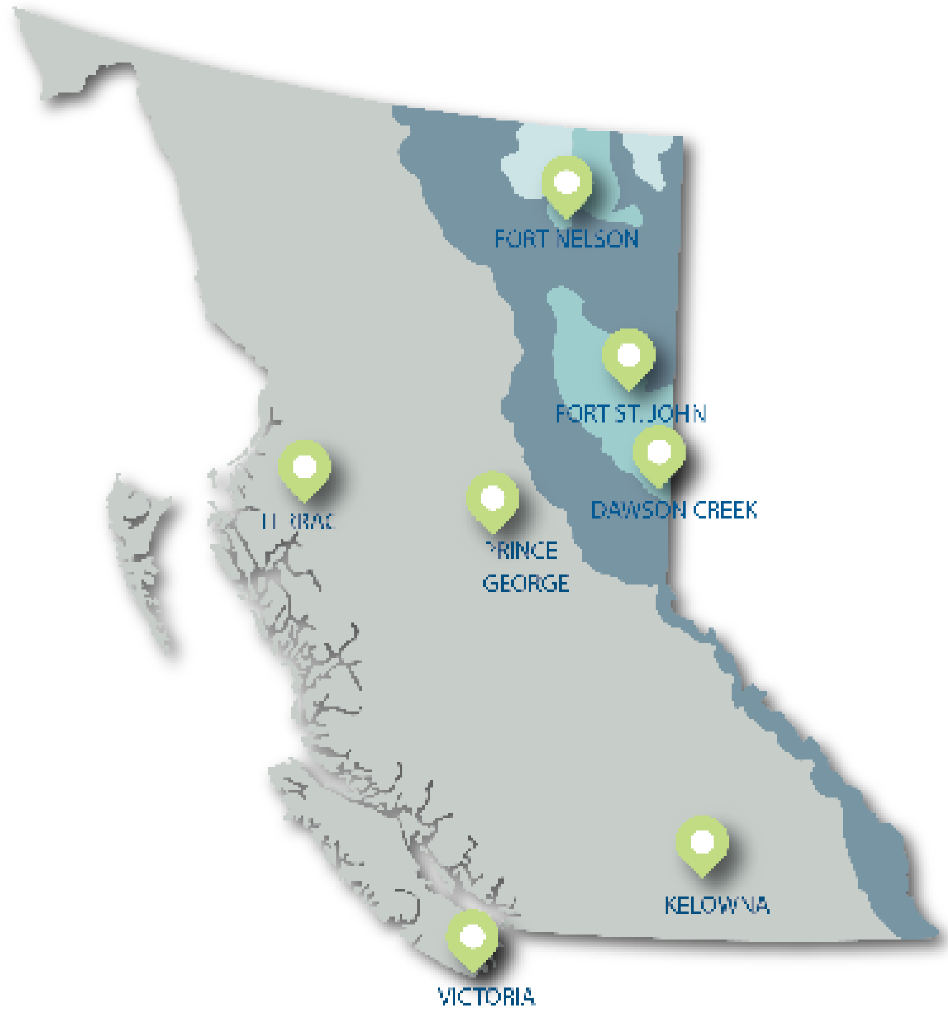
Role of the

BC Oil and Gas Commission

The BC Oil and Gas Commission protects public safety and safeguards the environment through the sound regulation of oil, gas and geothermal activities in B.C. From exploration through to final reclamation, the Commission works closely with communities and land owners, and confirms industry compliance with provincial legislation. It also ensures there are close working relationships; consults with, and considers the interests of Indigenous peoples.

With more than 20 years' dedicated service, the Commission is committed to safe and responsible energy resource management for British Columbia.



1. Investigation Procedures

All companies engaged in oil and gas activities in British Columbia are required to report incidents when the safety of persons or the quality of the environment has been placed at risk. The Commission receives and reviews these reports and provides regulatory oversight of the follow-up responses and mitigation by the company.

Certain incidents may prompt a more detailed investigation by the Commission. As a general rule, the Commission may launch an Engineering/Technical Investigation into an incident when the incident:

- Results in significant impacts to the public or other stakeholders.
- May stem from a systemic issue within the company's management systems.
- May identify deficiencies in current practices and procedures within industry.
- May identify opportunities for improvement of processes and procedures within the Commission or within industry.
- Results or may have resulted in serious injury or death.
- Attracts significant public attention.

The Commission's goals in conducting an Engineering/Technical Investigation are to identify the incident cause and contributing factors. The results of these investigations are summarized in a publicly accessible report available from the Commission website. By sharing the results and findings of these investigations, the Commission reduces the likelihood of similar events occurring. Enforcement investigations are a separate process that may rely in part on the results of a Technical Investigation. This is a report on an incident that took place in December, 2017.

2. Incident Summary

On October 2017, Todd Energy Canada Ltd. (TECL) began operations to complete wells on the a-94-J/94-A-13 multi-well pad site for production. The wellsite is located in the Birch field, approximately 30 kilometres northeast of Wonowon (see Figure 1), which is about 90 km northwest of Fort St. John. At the time of the incident, the site contained five wells.

The initial well on the site (the '0' well) was drilled by Paramount Resources Ltd. (Paramount) in 2014. In March, 2015, the well permit was transferred from Paramount to TECL. TECL drilled four additional wells, the 'A', 'B', 'C' and 'D' wells in 2017.

On Dec. 3, 2017, multiple operations were ongoing at the site. The '0' well was being flowed through testers to reduce the formation pressure while a service rig and coiled tubing unit were working to install a casing patch in the heel of the 'A' well. In addition, personnel were working to prepare production facility equipment for the wells. A total of 36 personnel were working on site.

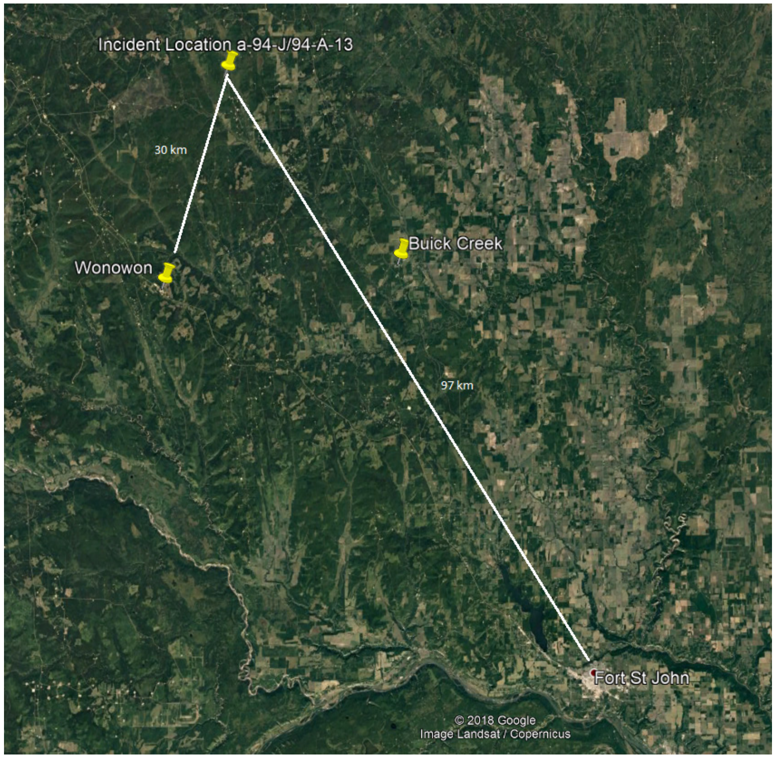


Figure 1: Location of the Site TECL Birch a-94-J/94-A-13 Multi-well Pad.

On Dec. 3, 2017 at approximately 10:51 a.m. MST, workers heard a loud bang followed by a gas release in the vicinity of the ‘0’ and ‘A’ wells. All personnel evacuated from the site. The gas cloud ignited 83 seconds after the initial gas release occurred.

TECL activated their emergency response plan and reported the incident to Emergency Management BC (EMBC) at 11:22 a.m. EMBC notified the BC Oil and Gas Commission (Commission) of the incident at 11:26 a.m. The Commission immediately activated their Emergency Operations Centre (EOC).

By 1:03 p.m. the Commission’s and TECL’s EOCs were active, road blocks were confirmed in place, mobile air monitoring, fire and well control specialists were dispatched and travelling to the site. By 4:49 p.m., air monitoring and fire specialists arrived on site, roadblocks and site security were being maintained and well control specialists arrived by midnight.

On December 4, the fire from the ‘0’ well caused the service rig on the ‘A’ well and a crane on site to topple. The service rig derrick landed on the ‘0’ well. The impact of the derrick bent the wellhead of the ‘0’ well. Figure 3 on the following page shows the layout of the wells and the impact of the fire on the ‘A’ well. The damage to the ‘0’ wellhead eliminated any ability to shut the well in, complicating and extending the operations required to bring the well under control.

At this point, the ‘0’ well was estimated to be flowing 170 000 m^3 per day of natural gas, 63 m^3 per day of liquid hydrocarbon and 66 m^3 per day of water.

Due to the potential for hydrogen sulphide (H_2S) in the gas released from the wells, both TECL and the Commission maintained air quality monitoring units in the area during the incident. Monitoring was located at the incident location, the site of the nearest resident, the incident command post and the Todd Energy a-44-I compressor station. On December 15 at 2:30 a.m., air quality monitors detected elevated readings of 12 ppb H_2S and 13 ppb SO_2 at the location of the nearest resident, approximately 8.4 km to the northeast of the incident location. Readings returned to normal by 3:45 a.m. Offsite H_2S exceeded the B.C. air quality objective of 5 ppb, but did not pose a health risk. SO_2 was below the one hour national air quality standard of 172 ppb.

Water was released from the wells on site and combined with snow melt and water used for cooling/fire suppression. Attempts were made to capture this water on site and off site through the use of ditches and catch basins. Environmental personnel were on site and continuously monitored the water collection and containment system. Following the incident, environmental personnel conducted a full soil and groundwater investigation and remediated impacted soils (see section 4.4).

Figure 2: Photo of the incident location prior to collapse of the service rig.

From December 4 to 12, operations focused on preparing the site for well control operations. Work included expanding the site to allow for equipment staging, constructing additional access points, and removing equipment from the site to allow access for well control equipment.

Heat shields and cooling water were used to protect equipment and the ‘B’, ‘C’ and ‘D’ wells from the fire. To ensure safety, most operations were limited to daylight hours only.

On December 13, operations began to remove the damaged wellhead from the ‘0’ well. Two cuts were made and the damaged wellhead was removed by December 15. Once the damaged wellhead was removed, the flow from the ‘0’ well was in the vertical direction instead of horizontally towards the ‘A’ well. At this point it was confirmed that the seals on the ‘A’ well were leaking and the ‘A’ well was confirmed to be flowing and on fire.

Compared to the ‘0’ well, the estimated flow from the ‘A’ well was low. The estimated flow from the ‘A’ well was 6,000 m^3 per day of natural gas, 2 m^3 per day of liquid hydrocarbon and 1 m^3 per day of water. The flow potential of the ‘A’ well was low as only one stage of the horizontal section had been fractured and the flow path from the ‘A’ well was through fire-damaged wellhead seals.

On December 17 and 18, a capping blowout prevention stack was assembled, pressure tested and installed on the ‘0’ well. Once the capping stack was installed, the well flow was diverted through a well test separator to flare and the blowout preventers were closed. At this point, the ‘0’ well was under control.

From December 19 to 21, the damaged wellhead was removed from the ‘A’ well. Temporary plugs were installed in the casing and a new wellhead was installed, bringing the ‘A’ well under control.

On December 22, temporary plugs were installed in the ‘0’ well, the capping Blow-out Preventer (BOP) was removed and a wellhead was installed. Both wells were secure and the incident was concluded.

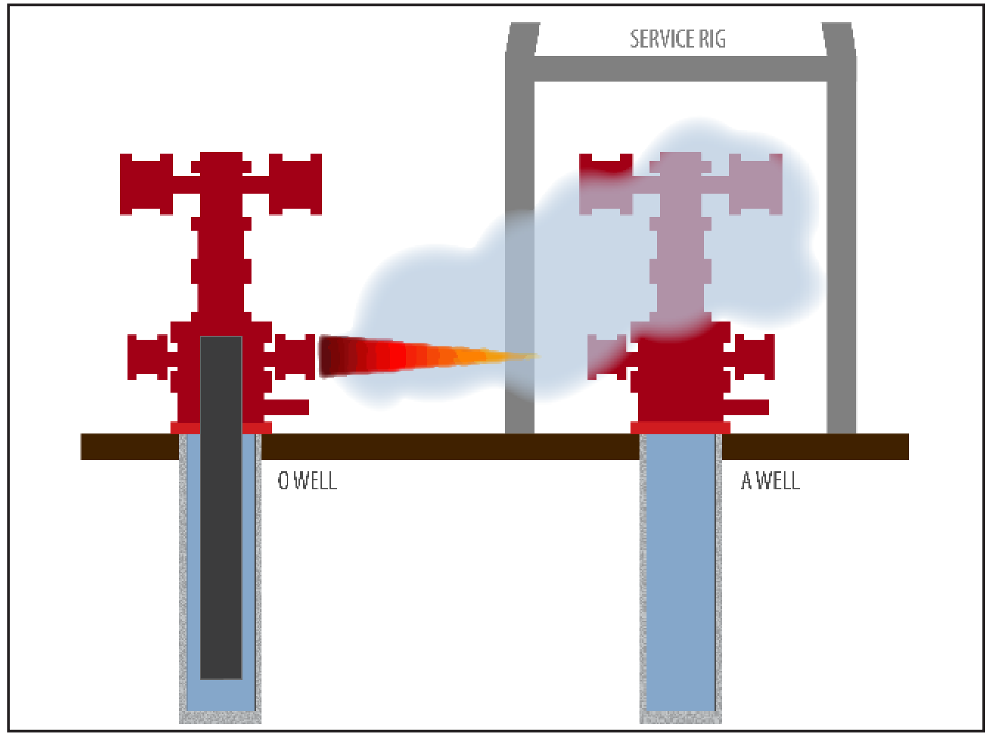


Figure 3: Illustration of the failure event.

3. Relevant Information

3.1 Incident Chronology

The following observations and statements have been made following a review of the incident logs and the response to the information requests made by the Commission. The timing of the events and the emergency response to the incident are provided in Table 1.

Table 1: Incident Time Log (in Mountain Standard Time)

Time	Detail
July 2014	• Commission issues well permits for the '0' well and the 'A' well to Paramount Resources Ltd.
Sept/Oct 2014	• '0' well is drilled and completed (hydraulically fractured).
March 2015	• Permits for the '0' and 'A' wells are transferred to Todd Energy Canada Ltd. (TECL).
Feb. 2016	• TECL conducts a suspended well check and takes pictures of the '0' wellhead.
June 2017	• Commission issues permits for the 'B', 'C' and 'D' wells.
June 2017	• Pictures of '0' wellhead taken during routine site inspection by TECL.
Nov. 23, 2017	• Pressure monitoring equipment installed on '0' well north casing valve to monitor casing pressure during fracturing of the 'A' well.
Nov. 30, 2017	• Rig up service rig to run casing patch on 'A' well.
Dec. 1, 2017	• Rig up well test equipment to flow '0' well to reduce formation pressure during service rig operations on the 'A' well. • '0' well is flowing water.
Dec. 2, 2017	• Pressure gauge on '0' well casing valve removed to address freezing/hydrate issues.
Dec. 3, 2017:	
5 a.m.	• Well testers note first burnable gas while flowing the '0' well.
10:51 a.m.	• Incident occurs - sudden gas release on '0' well. Site evacuated and emergency response activated. • Ignition occurs within 83 seconds. • Well is flowing out of control and flame is impinging on the 'A' well.
11:22 a.m.	• TECL reports incident to Emergency Management BC (EMBC).
11:26 a.m.	• Commission receives report of incident from EMBC and begins activation of Emergency Operations Centre (EOC).
1:03 p.m.	• TECL confirms that their EOC is open, roadblocks are in place, air monitoring, well control and fire safety specialists are en route. • Thirty-six people have been evacuated from the site and all are accounted for.
3:46 p.m.	• TECL confirms they have contacted area permit holders, closest residents and the Blueberry River First Nations.
4:49 p.m.	• Fire trucks and air monitoring are on site. • Site security is to be maintained overnight with well control operations resuming in the morning.

Dec. 4, 2017	• Well control specialist arrives on site.
Dec. 4, 2017	• Work focuses on clearing equipment off of the site to prepare for well control operations. • Service rig on 'A' well topples. Derrick lands on wellhead of '0' well and bends wellhead. • Crane on site topples.
Dec. 5 - 9 2017	• Operations to remove damaged equipment and debris from site and prepare for well control operations.
Dec. 8, 2017	• Commission approves lease extension to allow additional area for well control operations.
Dec. 10, 2017	• Specialized well control equipment arrives on site. • Continue to prepare staging area for well control equipment.
Dec. 12, 2017	• Service rig cut and removed from the wellsite.
Dec. 13, 2017	• Fire truck continues to pump water to cool the wells. • Heat shielding in place to protect B, C, D wells from radiant heat.
Dec. 13, 2017	• Make initial cut to remove wellhead from the "0" well.
Dec. 15, 2017	• Make second cut, remove damaged wellhead from the '0' well. • All flow from '0' well is now going vertical. • Confirmation 'A' well is leaking from damaged wellhead seals and is on fire.
Dec. 16, 2017	• Operations on hold while '0' well capping procedure is finalized.
Dec. 17, 2017	• Damaged wellhead shipped to Skystone International LP Calgary for analysis. • Complete pressure test of well capping blowout preventers.
Dec. 18, 2017	• Capping BOPs installed on '0' well. • Well flow diverted to well test separator and flare. • '0' well is now under control, fire on 'A' well continues.
Dec. 19, 2017	• Cut and remove damaged wellhead from the 'A' well. It appears that flow has ceased on the 'A' well.
Dec. 20, 2017	• Pump well kill fluid and install two temporary plugs in the 'A' well. Well is now secure.
Dec. 21, 2017	• New wellhead installed on 'A' well.
Dec. 22, 2017	• Pump kill fluid in the '0' well, install temporary plugs in the '0' well and complete installation of new wellhead. • Both wells are fully secured. Incident concluded and stood down.

3.2 Information Requests

On Dec. 13, 2017, a formal request for information (information request, or IR) was issued to TECL to provide information regarding operations conducted on the ‘0’ and ‘A’ wells from the time the wells were drilled up to the time of the incident. In addition, a post incident report outlining the incident cause, contributing factors and measures taken to manage and respond to the incident was required in accordance with the Emergency Management Regulation.

3.3 Failure Analysis

The gas release was initiated from the north side wing valve of the ‘0’ well. A two inch threaded bull plug and pressure gauge were installed for the purposes of monitoring the casing pressure.

Collection of physical evidence was compromised due to the fire, duration of the incident and scope of operations required to regain well control. Physical evidence recovered from the site included the wellhead from the ‘0’ well, a two inch bull plug that was found at the base of the wellhead (Figure 4) and the backplate of the pressure gauge that was installed on the well. The backplate of the pressure gauge was recovered shortly after the incident by TECL and was subsequently misplaced during the emergency response effort.

Personnel from TECL, WorkSafeBC and the Commission conducted extensive searches of the incident location and materials recovered from the pad site, but were unable to identify any additional items that may have been installed on the ‘0’ well at the time of the incident.

The wellhead and bull plug were transported to Skystone International LP in Calgary for analysis. Figure 5 shows a schematic of the wellhead as discussed below.

Figure 4: Bull plug recovered from base of the ‘0’ well showing damage on first two threads.

The materials analysis completed by Skystone International LP showed that:

- The wellhead contained all of the parts specified by the wellhead supplier, StreamFlo Industries Ltd., except for the North Bull Plug.
- Except for the thread damage to the North Companion Flange (NCF), there was no
- pre-existing mechanical damage of the wellhead that could have contributed to the North Bull Plug separation.
- Mechanical damage to the first three thread rounds of the NCF and the first two thread rounds of the bull plug showed they were likely engaged at the time of failure and the failure was consistent with internal pressure.
- The first three thread rounds of the NCF were plastically deformed by connection with a bull plug prior to the failure event. This deformation would have prevented engaging with another bull plug. No plastic deformation associated with shear damage was observed past the first three thread rounds. The plastic deformation was consistent with shearing the thread due to internal pressure.
- The first two rounds of the external thread on the bull plug were plastically deformed by axial shear. No plastic deformation associated with shear damage was observed beyond the first two thread rounds.
- The bull plug did not contain any mechanical marks on its external surface consistent with the application of axial force capable of shearing its threads. This was consistent with the internal pressure force being applied.
- The bull plug contained tool marks consistent with its assembly, but did not contain any tool marks consistent with its disassembly.
- Based on plastic deformation, the bull plug was engaged by two turns at the time of failure.
- The deformation damage of the bull plug was a mirror image of the deformation damage of the NCF.
- Virtual fit-up showed that without plastic deformation, the NCF and bull plug could be engaged by 4.5 turns.
- There was a high probability that the NCF and bull plug were engaged and plastic deformation was introduced to them at the same time.

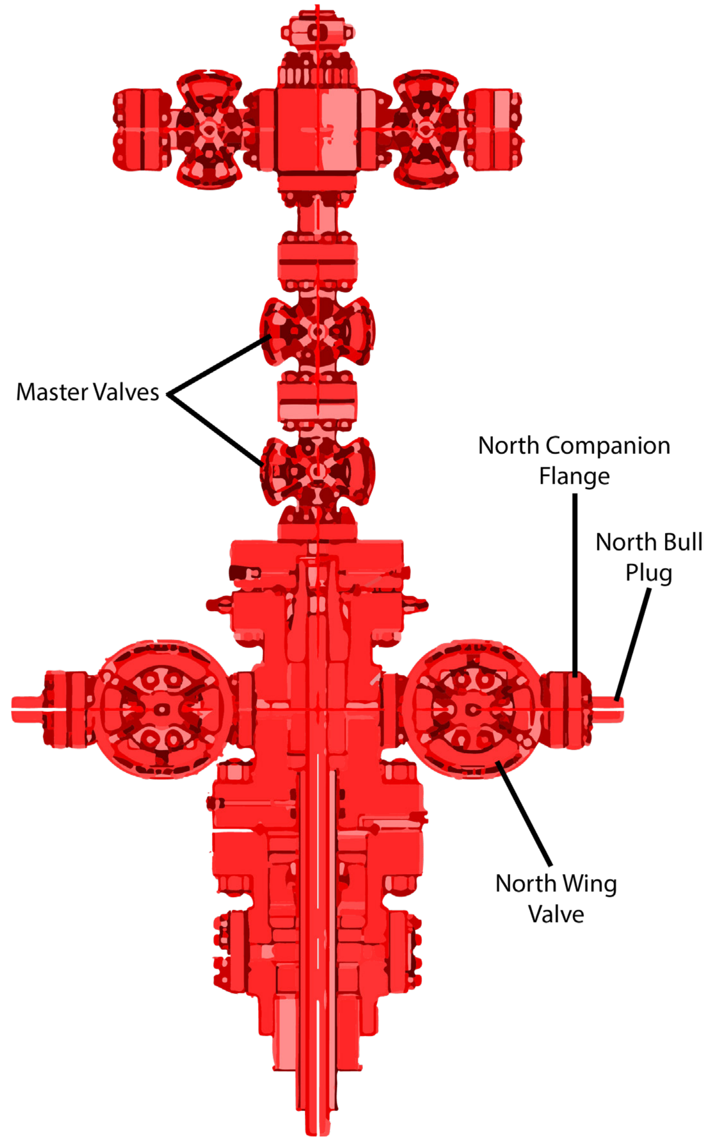


Figure 5: Diagram showing the cross section of failure location.

4. Analysis

4.1 Failure Cause and Contributing Factors

The following observations and statements are based on a review of the evidence:

- The '0' well was drilled and completed as a horizontal Montney well by Paramount Resources Ltd. in 2014.
- The well permit was transferred to Todd Energy Canada Ltd. in March 2015.
- A picture of the wellhead of the '0' well, taken during a suspended well inspection in February 2016 shows that a red painted bull plug was installed in the north casing flange of the wellhead.
- The well was being flowed through testers at the time of the incident.
- The pressure at the north casing flange at the time of the incident was 18.6 MPa.
- On Nov. 19, 2017, a contractor checked that the bull plug was tight using a pipe wrench. The contractor recalled that the bull plug was painted red.
- Prior to the incident, personnel who were interviewed recalled that the bull plug was red.
- One person recalled that the bull plug looked rusty with no paint. This observation was from the night before the incident.
- The bull plug found at the base of the '0' well after the incident was not painted and was not rusty.

Analysis of the threads of the North Casing Flange and the bull plug found at the base of the well showed that:

- The damage to the casing flange and bull plug threads were a mirror image, indicating that they had been engaged.The damage to the threads of the casing flange would have prevented engaging another bull plug past the damaged area.
- The casing flange and the bull plug had been engaged by two threads.
- The threads of the casing flange and bull plug could have been engaged by 4.5 turns.
- The bull plug was not fully engaged in the casing flange.
- The failure of the threads on both the bull plug and the casing flange was consistent with failure due to internal pressure.
- Based on the available evidence, the bull plug found at the well was likely installed in the north casing flange at the time of the failure.
- Had the north casing flange and the bull plug been fully engaged, the pressure of 18.6 MPa would have been insufficient to cause a shear failure of the threads.

The investigation was not able to identify who installed the bull plug in the north casing flange or when it was installed. Based on interviews, the bull plug may have been installed within 24 hours of when the incident occurred, but this could not be verified.

Based on the preceding observations and statements, the Commission has determined the probable cause of the incident was human error when installing the bull plug on the north casing flange of the wellhead. Had the threads of the bull plug been fully engaged in the north casing flange, it is unlikely that well control would have been lost.

Figure 6: Photos of the '0' well taken by TECL February 2016.

4.2 Emergency Management

The following observations and statements are based on a review of the incident logs and responses to the information request:

- The Emergency Planning Zone (EPZ) for the well site was 2.06 km.
- The nearest resident was located approximately 8.4 km to the northeast of the incident location.
- The well failure was first identified at 10:51 a.m. MST on Dec. 3, 2017.
- The incident was reported to EMBC (Emergency management BC), at 11:22 a.m. The incident was classified as a level 3 emergency.
- By 1:03 p.m. roadblocks were in place. Air monitoring, well control and fire safety specialists had been dispatched and the TECL Emergency Operations Centre was fully operational.
- By 3:46 p.m., TECL confirmed they had contacted the Blueberry River First Nation, the nearest residents (in the area but outside the EPZ) and permit holders with operations in the area.
- By 4:49 p.m., air monitoring, fire safety specialists and Commission personnel were on site.
- By midnight, well control specialists were on site.

The Commission is satisfied TECL's response to the incident was timely and appropriate.

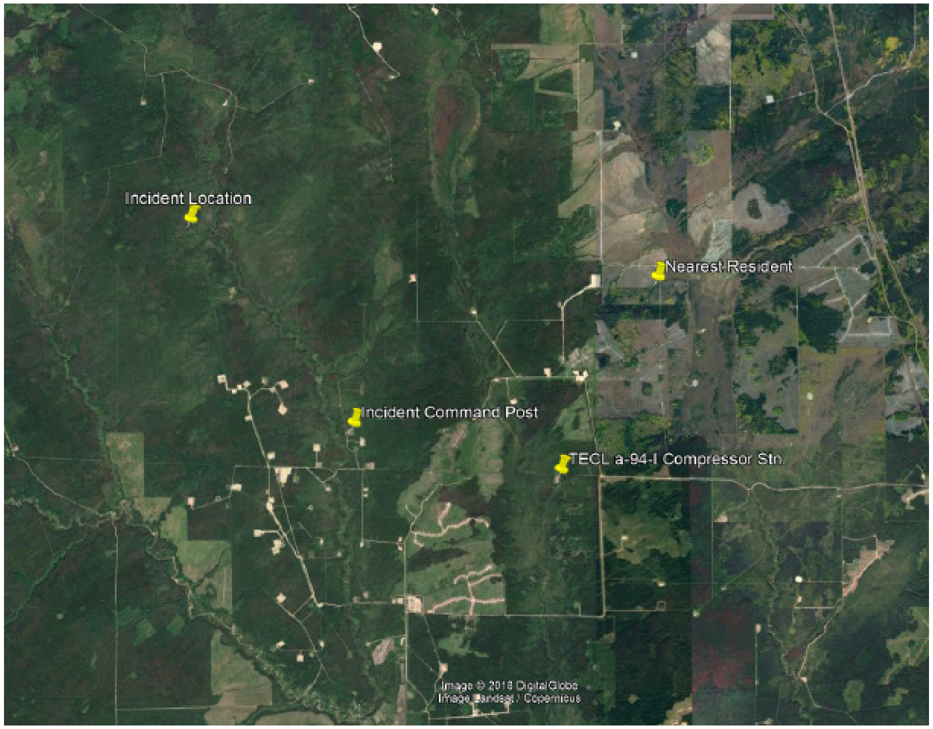


Figure 7: Air Monitoring Locations

4.3 Air Quality Monitoring

Throughout the incident response, air was monitored on site through the use of personal gas monitors. In addition, TECL and the Commission deployed mobile air monitoring units to monitor air quality in the vicinity of the site (Figure 8).

Monitoring was located at the incident location, the site of the nearest resident, the incident command post and the Todd Energy a-44-I compressor station (Figure 7 - previous page). On Dec. 15 at 2:30 a.m., air quality monitors detected elevated readings of 12 ppb H_2S and 13 ppb SO_2 at the location of the nearest resident, approximately 8.4 km to the northeast of the incident location. Readings returned to normal by 3:45 a.m. Offsite H_2S exceeded the B.C. air quality objective of 5 ppb, but did not pose a health risk. SO_2 was below the one hour national air quality standard of 172 ppb.

The WorkSafe BC short term exposure limit (15 minute time-weighted average) for H_2S is 10 000 ppb (10 ppm). The B.C. Ministry of Environment (MOE) air quality objective for H_2S is 5 ppb (0.005 ppm) based on a one hour average. The MOE objective is based on the odour threshold for H_2S.

The national air quality standard for SO_2 is 172 ppb (0.172 ppm) based on a one hour average.

Figure 8: Photo of the Commission Roaming Air Monitor Unit.

4.4 Soil and Water

During the incident, an estimated 1,184 m^3 of liquid hydrocarbon and 60 m^3 of salt water was released from the wells. In addition, fresh water was released from fire suppression activities and snow melt. The majority of the liquid hydrocarbon burned and a majority of the water was collected and recycled on site or evaporated due to the heat of the fire. An unknown quantity of the water migrated offsite to the southeast of the site.

The nearest water bodies are an S4 stream, immediately to the south of the site, which flows approximately 278 m before joining an S2 stream to the east of the site. There are no registered water wells within 500 m of the site.

TECL retained Highmark Environmental Services Ltd. (HESL) to monitor and manage fluids during the incident and to investigate and remediate contamination after the incident. Following the incident, a Stage 2 Preliminary Site Investigation was completed to delineate soil contamination. During the Stage 2 PSI, it was confirmed that contaminants had migrated offsite and impacted the S4 stream to the south of the site.

In February 2018, 5,010 tonnes of impacted soils were excavated from areas that had been impacted by the spill. Confirmatory samples were taken and all samples met the applicable Contaminated Sites Regulation standards for soil.

Following remediation, stream restoration activities were completed on the impacted portion of the S4 stream. These included backfilling, installation stream substrate and erosion control materials, installation of silt fencing to minimize sedimentation, installation of boulders and large woody debris and reseeding of the area with a forestry seed blend.

Six monitoring wells have been installed to monitor for any impacts to groundwater.

The Commission is satisfied TECL's response to the incident was timely and appropriate.

5. Directions

1. Todd Energy Canada Ltd. shall develop a procedure to ensure that wellhead components are assembled by competent personnel and that connections are inspected and documented prior to being pressurized.

TECL has developed and implemented a wellhead checklist. The checklist includes:

- Wellhead equipment specifications.
- Wellhead assembly procedures.
- Pressure test requirements.
- Supervision requirements.
- Documentation and sign-off requirements.

2. Todd Energy Canada Ltd. shall conduct ongoing monitoring of the groundwater monitoring wells sufficient to demonstrate that remediation is complete. A monitoring report shall be submitted to the Commission.

TECL has retained Highmark Environmental Services Ltd. and this work is ongoing.

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