



2019 Annual Summary Report on Casing Integrity

Submitted: March 11, 2020

EXECUTIVE SUMMARY

Casing Failures

- Total number of wells containing casing failures in 2019 (all depths) was 87, versus 76 in 2018.

Near Surface

- 52 wells with failures in 2019, versus 37 in 2018. Recent increases attributed to aging wellbores.
- Failure frequency of 1.0% of wells per year in 2019.
- All failures in 2019 were Level 0 (no adverse environmental consequence)
- All 52 failures in 2019 were on low pressure wells or wells already suspended, that had no potential for liquid release.
- 47 failures were detected operationally through visual checks, and remaining 5 were detected during rig work on isolated wellbores.
- 39 failures were repaired in 2019. 26 wells repaired by surface casing patch, 1 well repaired by external composite wrap, 11 wells repaired by near surface dig-out and replacement, and 1 well repaired by slimhole. Remaining wells were suspended or abandoned.

Intermediate Depth

- 23 wells with failures in 2019, versus 36 in 2018.
 - 12 of 24 failures were on low pressure, active wells.
 - 3 of 24 failures were on high pressure, active wells.
 - 8 of 24 failures were zero pressure wells (suspended or rig on well).
- Failure frequency of 0.4% of wells per year in 2019.
- All failures in 2019 were Level 0 (no adverse environmental consequence).
- 3 high pressure failures in 2019; 1 required heavy mud kill.
 - Lowest number of high pressure casing failures over 14 year period
- No multi-well failures occurred in 2019.
- 9 casing failures detected operationally, all of which were detected by passive seismic
- 14 casing failures detected with casing integrity (CI) checks, which include 4 identified on wells already isolated.
- Of the 23 failures, 16 were repaired or are planned to be repaired (i.e: slimhole, MH Patch). The remaining 7 wells are zonally abandoned or full subsurface abandoned.

Clearwater

- 12 failures in 2019, versus 3 failures in 2018.
- No adverse environmental impacts.

Well Casing Repairs

- Casing repairs completed on 152 wells in 2019 that returned to service. Some of these wells failed prior to 2019.
 - 42 repairs on near surface failures (27 near surface patches, 1 external composite wraps, 13 near surface dig-out and replacement, and 1 slimhole)
 - 8 proactive repairs on high near surface corrosion wellbores (near surface dig outs and replacements)
 - 27 repairs on intermediate failures (20 slimholes, 7 MH patches)
 - 62 proactive slimhole repairs on wellbores with intermediate impairments.

Casing Failure Detection Initiatives

Alarm Management

- Detection: Automated software for real-time passive seismic alarms is now functional for all passive seismic wells, accelerating response time for a potential casing failure detected by the passive seismic systems. Real-time casing failure alarm notifications through email and text message directly to Cold Lake personnel.

Near Surface Casing Integrity Initiatives – External Corrosion

- Prevention: Silicate solution trial ongoing. 25 wellbores on a single pad had product pumped into the near surface external annulus outside of the production casing. Corrosion coupons were utilized as a means of corrosion progression and installed in both silicate injected well and non-silicate injected well on the same pad. At the 6 month mark, coupons were pulled and results were favorable. Expansion of trial planned for 2020.
- Prevention: Continued application of high temperature resistant metallic aluminum external casing coating year round in a synergistic manner with external ultrasonic testing. Coating also being applied during surface dig out and replacements, as well as newly completed wellbores.
- Repair: Continued trial application of external composite wrap repairs on wells with near surface failures that will operate below 4 MPa and 230°C. Refining of installation programming for increased success of installation ongoing through field, lab and shop setting tests.
- Repair: New RML-LSA surface casing patch trial ongoing. 10 failures have been successfully repaired by RML-LSA patches in 2019. Continued trial and additional candidates continue to be assessed for near surface repairs, as well as assessing the patch for intermediate depth repairs.

Intermediate Depth Casing Integrity Initiatives

- Prevention: Conducted through tubing trial of a vendor wireline logging tool, with the purpose of demonstrating whether or not the tool could detect production casing impairments. Results were compared against caliper logs on five wellbores. It was determined that the tool is capable of identifying some impairments, but was insensitive to their severity. The final trial conclusion is that the tool is not suitable for use at this time.
- Repair: Single well trial of intermediate cemented patch in low pressure steam flood area for Producer Only status. The first intermediate cemented patch was successfully installed in May 2018 and a follow up pressure test was completed in May 2019, which confirmed the patch integrity after 1 year of low pressure operation. Imperial expanded the low pressure intermediate cemented casing patch trial and obtained approval for a second cemented patch which will be implemented in 2020. AER non-routine casing repair applications will continue to be obtained for future candidate wellbores.
- Repair: Commercialization of two high pressure – high temperature steam-able casing patches;
 - Saltel casing patch has been installed in a total of six wells since 2016. Will apply technology again on next favorable candidate- none identified in 2019.
 - Schlumberger MHE patch installed in 2016. Pressure test after full cycle was successfully completed in November 2017. Will apply technology again on next favorable candidate- none identified in 2019.

1.0 INTRODUCTION

Pursuant to the requirements of AEUB Decision 99-22, condition #9 and clause 6.2 of AEUB Approval 8558, Imperial hereby submits the 2019 Annual Summary Report on Casing Integrity and remediation efforts.

This report has been submitted annually since 2000 and as such builds on information that was included in previous reports, with focus on 2019 performance.

For the purpose of this report, a casing failure is defined as a break or crack in the production casing that results in the well's inability to contain pressure. A primary failure is defined as being limited to a single well; a secondary (or multi-well) failure occurs when fluid loss from a primary failure results in immediate adjacent well failures. Casing failures have been classified by the following three depth intervals:

- Near surface (0 to ~25 mTVD).
- Intermediate, including the Quaternary, Colorado group, and Grand Rapids formations.
- Clearwater, at the interface between the Clearwater production formation and the overlying Grand Rapids formation, or lower.

Undetected high pressure near surface and intermediate well failures in the upper part of the wellbore have potential for environmental consequence due to aquifer contamination or breach to surface. Clearwater production formation failures only affect the operability of the well. The existing casing integrity program for Cold Lake was designed to address the concerns associated with the near surface and intermediate depth intervals, and was not intended to deal with failures within the production formation.

Near surface and intermediate depth casing failures with potential for adverse environmental impact are assigned an environmental consequence level. Clearwater failures do not have an adverse environmental impact, and therefore are not assigned one. Casing failures that occur within the Glacial Till or within 75 meters of the Colorado Shale group (bedrock) top and have produced fluid loss are ESRD (now AER) reportable. The response follows the Cold Lake Operations Incident Response Plan. Consequence levels are assigned jointly by environmental and engineering personnel utilizing the descriptions provided in Table 1.

Table 1: Environmental Consequence Matrix for Casing Failures

Consequence Level	Environmental Consequence Description
Level 0	<ul style="list-style-type: none"> - Failure occurred within the bedrock with fluid loss below the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m³ produced fluid, dependent on proximity of wellbores at failure depth) - Failure occurred within the Glacial Till, but only released inert fluid (e.g. N₂ gas) or minimal produced fluid not requiring remediation
Level 1	<ul style="list-style-type: none"> - Failure occurred within the bedrock with fluid loss above the typical threshold required to cause a multi-well failure (approximately 1000 – 5000 m³ produced fluid, dependent on proximity of wellbores at failure depth) - Failure released fluid into the Glacial Till and there is low potential of the fluid migrating to a freshwater aquifer (i.e. volume released from failure is low, or the aquitard layer is thick)
Level 2	<ul style="list-style-type: none"> - Failure with fluid release to surface or fresh water aquifer requiring longer term remediation efforts

Note: Bedrock is defined as solid rock that underlies unconsolidated surface material (i.e. Bedrock includes the Lea Park and/or Colorado Group and lower formations).

For the purpose of this report, failures are defined as being detected either operationally or through a casing integrity (CI) check. An operational detection is defined as a failure detected with the differential flow & pressure (DFP), nitrogen soak, passive seismic (PS) systems, or detected by visual means. A casing integrity check detection is defined as a failure detected as part of the pre-steam casing integrity process (identified through a service rig based casing integrity check, or Electro-Magnetic (EM) logging casing integrity check), or by an integrity check conducted as part of another workover. The failures detected as part of the D013 five year pressure testing requirement of a suspended well are also considered as detected through a CI check.

2.0 CASING INTEGRITY DATA

A historical summary of well casing failures by depth interval at Cold Lake is provided in Table 2. All 23 of the intermediate depth casing failures detected in 2019 were classified as primary commercial intermediate failures originally completed with L-80 or N-80 casing strings. All 52 of the near-surface and intermediate casing failures that occurred in 2019 were deemed to be Level 0 environmental consequence events. Of the 75 near-surface and intermediate failures detected in 2019, 56 were detected operationally and 19 were detected through casing integrity checks.

Table 2: Historical Failure Summary by Depth Interval

Depth Classification	Year											
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Surface	16	16	11	13	7	21	19	25	20	41	37	52
Intermediate	30	29	34	34	30	33	33	37	23	54	36	23
Clearwater	56	58	17	19	8	9	17	25	9	10	3	12
Total	102	103	62	66	45	63	69	87	52	105	76	87

2.1 Near Surface Casing Integrity Data

Since 1996, 325 commercial wells have failed in the near-surface region, including 52 near surface failures detected in 2019. Near surface casing failure frequency has increased in recent years, as the average age of wellbores has increased. Details describing the failures that occurred in 2019 are provided below in Table 3. In addition to failed wells in 2019, 8 wells were proactively repaired (near surface dig outs and replacement) due to high corrosion measurement near surface.

Table 3: 2019 Surface Depth Failure Summary

NO.	District	Well	Date	Years since first step	Depth (m) ¹	Pad Cycle	Detection Method ²	Env Conseq ³	Repair Method
1	Maskwa	D63-14	2019-12-20	25.8	5.0	11	Operational	0	Surface Patch RML
2	Mahihkan	H02-15	2019-12-17	34.2	5.0	8	Operational	0	Surface Patch RML
3	Mahihkan	J13-06	2019-12-13	31.9	5.0	11	Operational	0	Surface Patch RML
4	Mahihkan	H23-06	2019-12-11	23.3	5.0	13	Operational	0	Surface Patch RML
5	Mahihkan	H45-17	2019-12-02	11.8	5.0	7	Operational	0	Surface Patch RML
6	Mahihkan	J01-08	2019-12-01	34.2	5.0	11	Operational	0	Slimhole
7	Mahihkan	J01-13	2019-11-29	34.4	5.0	10	Operational	0	Surface Patch RML
8	Mahihkan	J01-10	2019-11-28	34.2	5.0	8	Operational	0	Surface Patch RML
9	Mahkeses	G01-18	2019-11-05	19.9	5.0	6	Operational	0	Surface Patch RML
10	Mahihkan	L11-16	2019-10-22	22.4	5.0	11	Operational	0	Surface Patch RML
11	Mahkeses	G03-35	2019-10-08	19.7	5.3	10	Operational	0	Surface Patch
12	Mahihkan	H01-13	2019-09-29	34.3	5.0	9	Operational	0	Not Repaired - Zonal Abandonment
13	Mahihkan	R02-11	2019-09-27	27.0	5.0	8	CI Check	0	Not Repaired - Zonal Abandonment
14	Maskwa	E07-20	2019-09-25	16.8	5.0	10	Operational	0	Not Repaired - Zonal Abandonment
15	Maskwa	E07-15	2019-09-25	16.8	5.0	10	CI Check	0	Not Repaired - Zonal Abandonment
16	Mahihkan	L07-03	2019-09-23	21.3	5.0	8	Operational	0	Surface Patch
17	Maskwa	E10-09	2019-09-18	23.0	5.0	10	Operational	0	Not Repaired - Zonal Abandonment
18	Maskwa	B02-14	2019-09-12	34.4	5.0	11	CI Check	0	Surface Patch
19	Maskwa	F07-02	2019-09-11	19.8	5.0	10	Operational	0	Surface Patch
20	Mahkeses	ONN-16	2019-09-05	22.4	5.0	8	Operational	0	Not Repaired - Zonal Abandonment
21	Mahihkan	H26-06	2019-09-03	23.8	5.0	7	Operational	0	Not Repaired - Zonal Abandonment
22	Mahkeses	0HH-04	2019-08-30	31.4	5.0	8	Operational	0	Not Repaired - Zonal Abandonment
23	Mahihkan	L06-21	2019-08-23	24.3	4.2	9	Operational	0	Surface Digout
24	Maskwa	D27-15	2019-08-16	33.6	4.7	10	Operational	0	Surface Digout
25	Maskwa	D01-16	2019-08-07	33.4	5.0	14	Operational	0	Surface Digout
26	Maskwa	D53-18	2019-08-06	26.0	4.8	10	Operational	0	Surface Patch
27	Maskwa	B05 Infill-22	2019-07-26	23.0	5.0	7	Operational	0	Not Repaired - Zonal Abandonment
28	Mahihkan	H01-05	2019-07-16	33.9	5.0	9	Operational	0	Not Repaired - Zonal Abandonment
29	Maskwa	D53-09	2019-07-16	25.9	5.0	8	Operational	0	Surface Patch
30	Mahihkan	H33-11	2019-07-05	23.9	5.0	9	Operational	0	Surface Patch
31	Maskwa	A03-10	2019-05-19	34.3	4.8	11	CI Check	0	Not Repaired - Zonal Abandonment
32	Mahkeses	Y05-19	2019-05-12	15.4	4.3	9	CI Check	0	Not Repaired - Zonal Abandonment
33	Maskwa	D53-11	2019-04-29	26.0	4.3	10	Operational	0	Surface Patch RML
34	Mahihkan	R01-04	2019-04-29	28.5	4.2	10	Operational	0	Surface Patch RML
35	Maskwa	D53-10	2019-04-25	25.9	5.0	10	Operational	0	Surface Digout
36	Maskwa	D62-15	2019-04-23	25.8	4.4	11	Operational	0	Surface Patch
37	Mahihkan	L05-09	2019-04-16	22.3	3.8	14	Operational	0	Surface Digout
38	Maskwa	D65-15	2019-04-01	22.7	3.8	14	Operational	0	Surface Digout
39	Mahihkan	H02-07	2019-03-25	34.0	3.8	14	Operational	0	Surface Digout
40	Maskwa	D64-20	2019-03-25	25.9	3.8	14	Operational	0	Surface Patch
41	Maskwa	A02-16	2019-03-22	34.6	3.8	14	Operational	0	Surface Patch
42	Maskwa	D65-05	2019-03-21	22.7	3.8	14	Operational	0	Surface Patch
43	Maskwa	F03-13	2019-03-13	20.8	3.8	14	Operational	0	Surface Patch
44	Mahihkan	H32-19	2019-03-06	24.1	3.8	14	Operational	0	Surface Digout
45	Mahkeses	G03-28	2019-02-26	19.7	3.8	14	Operational	0	Surface Digout
46	Mahihkan	H10-13	2019-02-24	17.3	3.8	14	Operational	0	Surface Digout
47	Maskwa	C02-10	2019-02-13	33.5	3.8	14	Operational	0	Surface Digout
48	Mahihkan	J06-09	2019-01-30	34.2	3.8	14	Operational	0	Surface Patch
49	Maskwa	F06-29	2019-01-28	20.3	3.8	14	Operational	0	Surface Patch
50	Mahihkan	L05-27	2019-01-28	22.3	3.8	14	Operational	0	Surface Patch
51	Maskwa	B05 Infill-47	2019-01-21	23.0	3.8	14	Operational	0	Not Repaired - Zonal Abandonment
52	Mahkeses	G03-32	2019-01-04	19.7	3.8	14	Operational	0	External Composite Wrap

Historic consequence levels associated with near surface casing failures since 1996 are displayed in Figure 1. All near surface failures, except H01-03 in 1996, were assessed at a level 0 environmental consequence, including all 2019 failures.

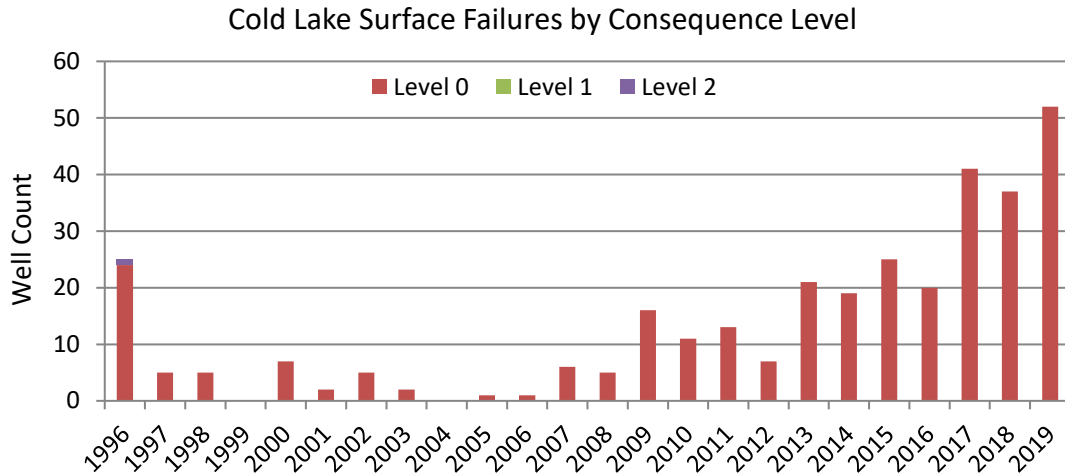


Figure 1: Cold Lake Surface Failures by Consequence Level

In 2019, all near surface corrosion failures occurred on late-life, low pressure wells with no potential for liquid release at surface. Hence, there were no potential adverse consequences associated with these failures. The average years in operation for these failed wellbores was 26 years.

The number and frequency of near surface external corrosion related casing failures for the commercial casing design in Cold Lake are summarized below in Figure 2. The 2019 near surface casing failure frequency was 1.0%. Failure frequency is the number of failures divided by the total number of wells operating. The peak failure frequency of 1.26% (red line) observed in 1996 marks the inception of Imperial’s casing integrity operating practices. At that time, the bentonite top-up program was developed to reduce corrosion and subsequent improvement was observed with reduction of corrosion at the primary cement top depths. Failure frequency has increased in the 2013-2019 period. This increase is a result of the aging well population, with many low pressure operating wells now at 25+ years-of-service. With a decrease of corrosion at the original primary cement top, the corrosion cell has moved very close to surface (within 1 meter of final grade).

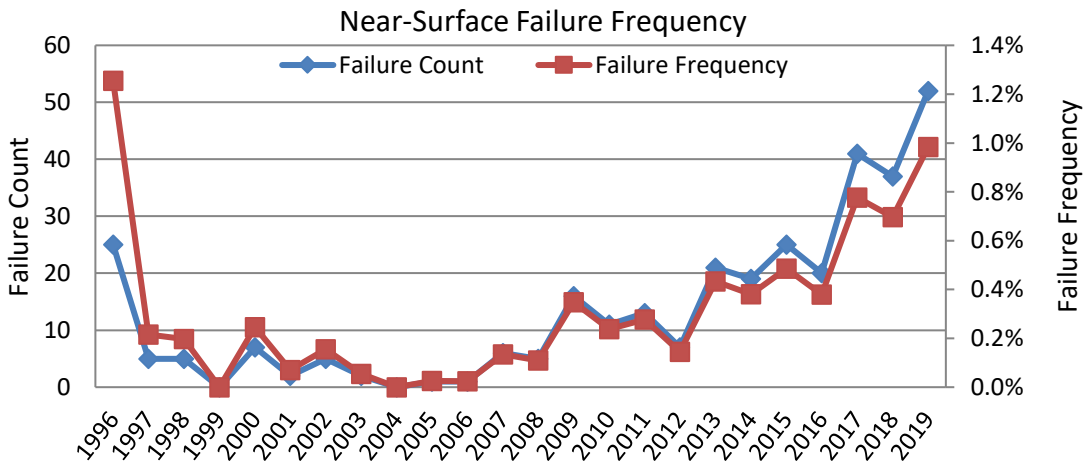


Figure 2: Commercial Near-Surface Failures and Failure Frequency

For information on near surface corrosion initiatives targeted at preventing potential high consequence failures, and new repair strategies for failures in aging areas, see Section 3.2.

In 2019, 47 of the near-surface casing failure events were found operationally via visual inspection. The remaining 5 were detected during rig work on isolated wellbores; 2 failures were identified during regulatory pressure testing, 1 failure was detected during a routine zonal abandonment and 2 failures were detected during casing integrity checks. The historical detection trends are shown in Figure 3 below.

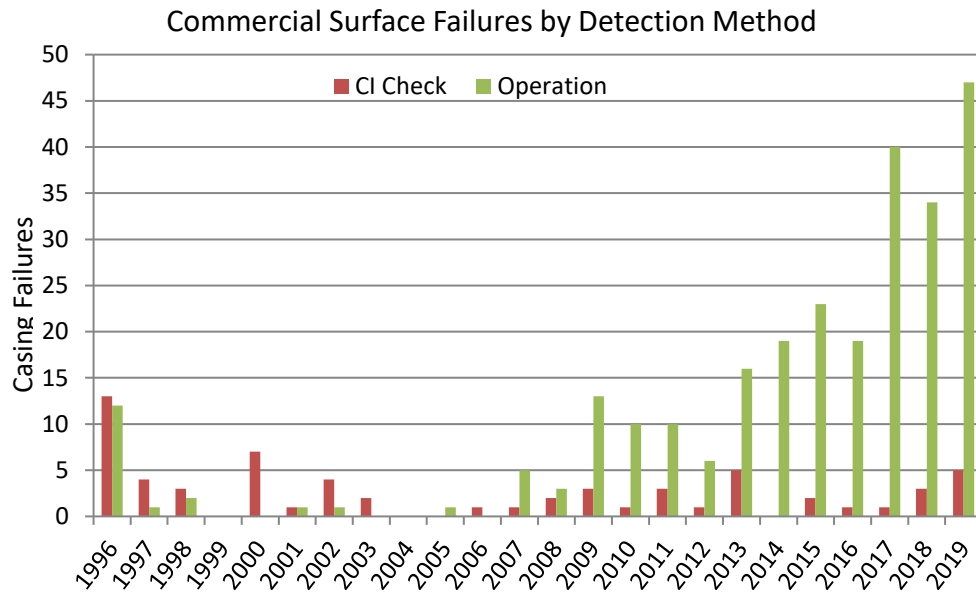


Figure 3: Commercial Surface Failures by Detection Method

Near Surface Depth Casing Failure Resolution:

Of the 52 near surface failures in 2019, 26 wells were repaired by surface casing patch, 1 well was repaired by external composite wrap, 11 wells were repaired by near surface dig-out and replacement, 1 well repaired by slimhole and the remaining 13 wells are suspended or zonally abandoned with no near term repair plan.

2.2 Intermediate Depth Casing Integrity Data

The scope of this document includes intermediate depth failures that have occurred in wells with L-80 or IK-55 casing (also referred to as 'commercial' design), and does not include early casing designs, such as SOO-95. There were no failures in wells of pre-commercial casing design in 2019.

Since the implementation of the casing integrity operating practices in 1996, a total of 672 primary intermediate casing failures have been detected in wells with commercial casing designs. Approximately 63% of these failures were identified during rig-based casing integrity checks (i.e. pre-steam & regulatory D013 5 year pressure tests), with the remaining 37% identified through operational monitoring systems (DFP, N2 soak or passive seismic). Details of the 23 wells with casing failures occurring in 2019 are included in Table 4 below.

Table 4: 2019 Intermediate Depth Failure Summary

No.	District	Well	Date	Depth(mKB)	Depth(mTVD)	Pad Cycle	Formation	Pipe Body / Connection	Connection Type	Env Conseq	Repair Method
1	Nabiye	N04-GRM	2019-12-20	268.0	268.0	7	Colorado Shales	Connection	--	0	MH Patch
2	Mahihkan	L09-19	2019-12-18	296.0	294.8	6	Colorado Shales	Connection	NSCCM	0	Slimhole Planned
3	Mahihkan	L09-20	2019-12-02	264.0	263.2	6	Colorado Shales	Connection	NSCCM	0	Slimhole
4	Maskwa	B02-18	2019-10-18	304.9	282.6	11	Colorado Shales	Connection	--	0	MH Patch
5	Mahkeses	0DD-04	2019-08-21	230.0	219.3	9	Colorado Shales	Unknown	--	0	Well Abandonment
6	Mahkeses	0DD-10	2019-08-19	319.0	296.6	9	Colorado Shales	Unknown	--	0	Well Abandonment
7	Maskwa	B02-02	2019-08-17	245.8	233.6	11	Colorado Shales	Connection	--	0	MH Patch
8	Mahkeses	V10-09	2019-08-10	294.1	293.2	7	Colorado Shales	Connection	--	0	Slimhole
9	Mahkeses	V08-10	2019-06-26	269.0	268.9	9	Colorado Shales	Connection	QB2	0	Slimhole
10	Maskwa	D09-08	2019-06-25	255.2	254.4	9	Colorado Shales	Unknown	OBTC	0	Not Repaired - Zonal Abandonment
11	Maskwa	E11-30	2019-06-11	314.0	305.7	8	Colorado Shales	Connection	--	0	Not Repaired - Zonal Abandonment
12	Maskwa	B02-13	2019-05-30	307.8	305.4	11	Colorado Shales	Connection	--	0	Slimhole
13	Mahihkan	H04-06	2019-05-24	278.0	267.2	9	Colorado Shales	Connection	--	0	Not Repaired - Zonal Abandonment
14	Nabiye	N06-09	2019-05-10	293.8	293.2	6	Colorado Shales	Connection	STC	0	Slimhole
15	Maskwa	B02-09	2019-05-09	292.0	279.8	11	Colorado Shales	Connection	--	0	MH Patch
16	Mahihkan	H59-03	2019-04-07	272.0	270.6	8	Colorado Shales	Unknown	NSCC	0	Not Repaired - Zonal Abandonment
17	Maskwa	D65-15	2019-04-06	184.0	180.9	8	Colorado Shales	Connection	OBTC	0	MH Patch
18	Nabiye	N05-09	2019-04-05	310.6	309.4	6	Colorado Shales	Connection	STC	0	Slimhole
19	Mahihkan	H32-19	2019-03-11	287.5	273.6	9	Colorado Shales	Unknown	--	0	MH Patch
20	Mahihkan	H68-22	2019-02-24	277.5	275.8	6	Colorado Shales	Connection	SWNA	0	Not Repaired - Zonal Abandonment
21	Maskwa	C02-10	2019-02-23	312.0	299.1	13	Colorado Shales	Connection	--	0	MH Patch
22	Mahihkan	H62-10	2019-02-03	240.0	240.0	7	Colorado Shales	Unknown	--	0	Slimhole Planned
23	Mahihkan	H59-H07	2019-01-13	220.0	220.0	8	Colorado Shales	Unknown	NSCC	0	Slimhole Planned

Historic environmental consequence levels associated with intermediate casing failures since 1998 are displayed in Figure 4. In 2019, there were no intermediate casing failure events that were classified higher than a Level 0 Environmental Consequence event (no events resulted in adverse environmental consequences). Three historical intermediate failures have required aquifer remediation (H15-10 in 1999, H39-H04 in 2006, and V13-31 in 2012).

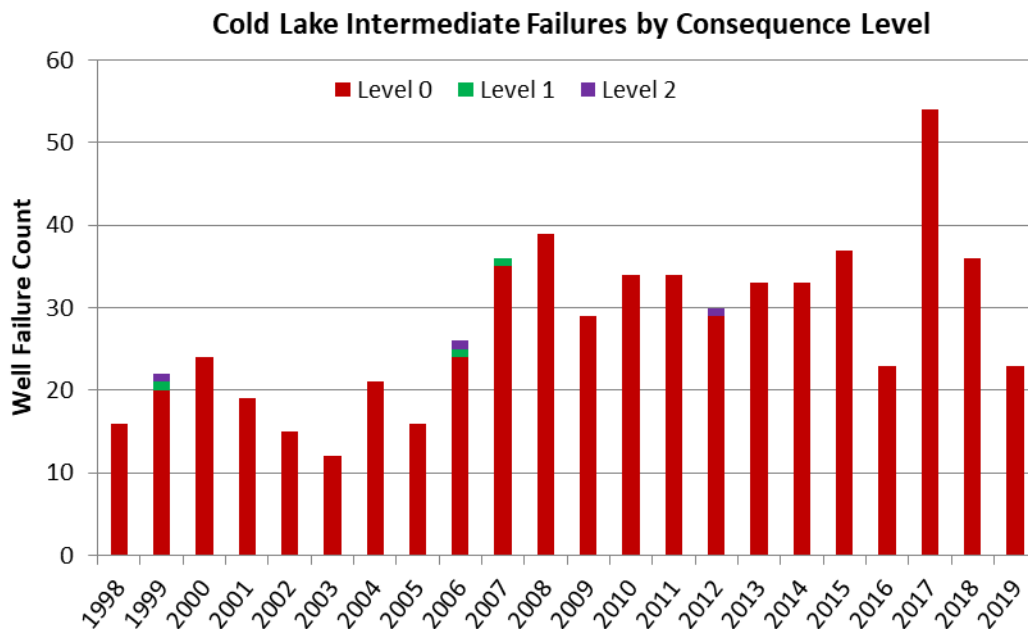


Figure 4: Cold Lake Intermediate Failures by Consequence Level

Many enhancements to Imperial’s casing integrity processes and detection systems, as discussed in section 3.0, have led to a reduction in the rate of higher potential consequence events since 2007, as shown in Figure 5. In 2019 there were 3 high pressure failures, or 13% of the total intermediate failures.

The high pressure failure frequency has been decreasing over time. The trend is a result of continued casing check program optimization, improvements in risk-based targeted selection of wells checked, and enhanced usage of the PIMFET shear stress management tool which helps to define steaming strategies. Of the 3 high pressure failures, 1 was a heavy mud kill, and 2 were successfully managed by flowing up the tubing with N2 on the annulus to maintain the fluid level below the casing failure.

In 2019, there were 8 wells with intermediate failures located on already suspended/zonally abandoned wells or on 'No Pressure' (e.g. well suspended, or during pressure tests while rig on well) with no potential for liquid loss (34.7% of total). If these 'No Pressure' failures are excluded, there were a total of 15 wells with failures on 'Low Pressure' and 'High Pressure' active wells. The green bars show that this is the historic low for high pressure failures over the last 14 years.

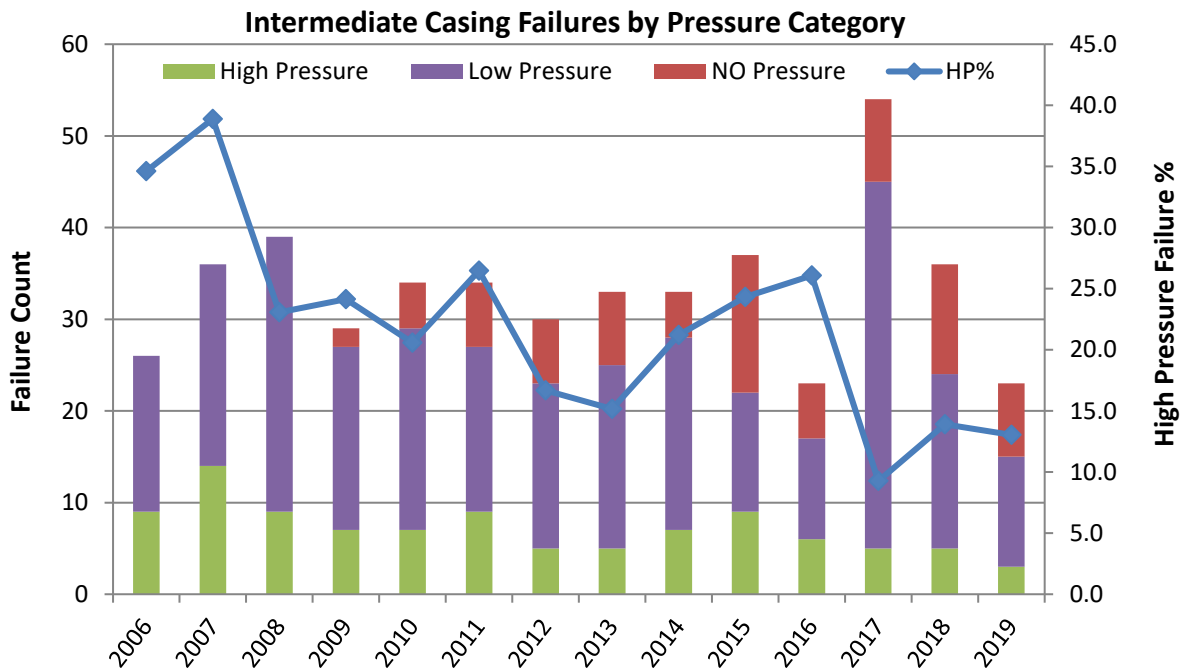


Figure 5: Intermediate Casing Failures by Pressure Category

In 2019, there were no casing failures with subsurface liquid losses that could have had an adverse impact on the integrity of adjacent wellbores, and there were no adverse environmental impacts. The total volume of subsurface liquid loss in 2019 was 2.0 m3, as shown in Figure 6.

The primary response to a high pressure intermediate casing failure is to control the fluid level below the casing break depth with nitrogen on the annulus and flow back production fluids up the tubing to avoid produced liquid losses through the casing break, with concurrent de-pressuring of the reservoir in the area of influence as needed. Imperial maintains all necessary well control materials in the field in order to perform a high pressure mud well kill if the nitrogen and flow back primary response procedure is not possible or practical, as outlined in Section 3.5.

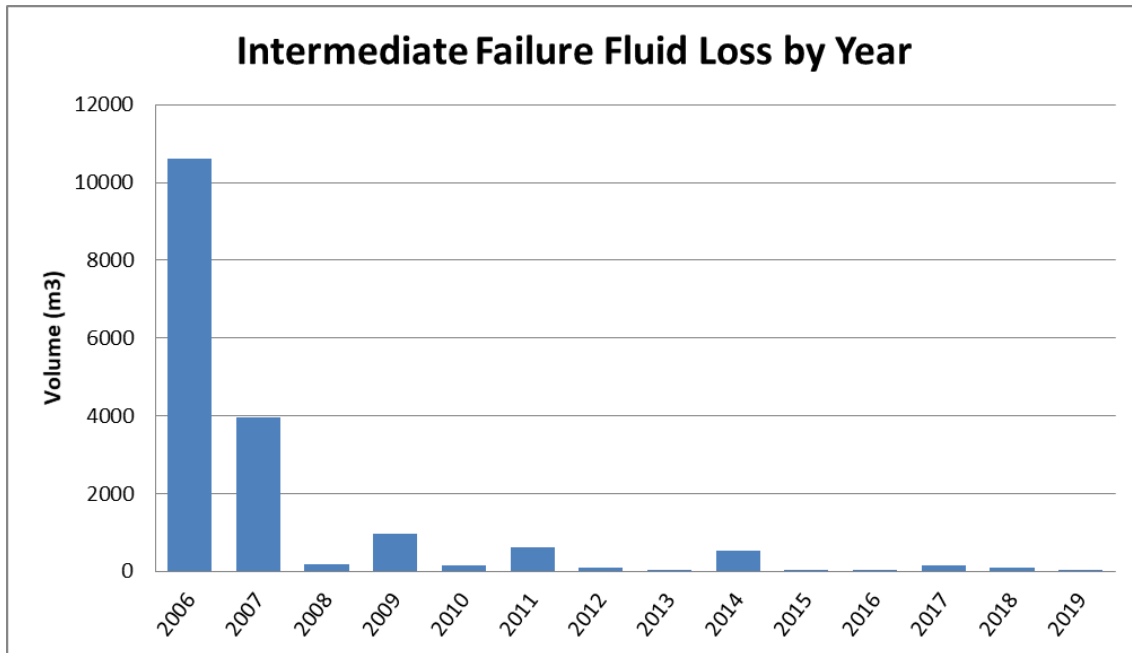


Figure 6: Intermediate Depth (Subsurface) Failure Liquid Loss by Year

The primary intermediate casing failure frequency for commercial casing design and total Cold Lake district well count are presented in Figure 7. Intermediate casing failure frequency for 2019 was 0.4%. Variations from year to year can be attributed to aging wellbores and is also driven by the steam schedule, which can increase/decrease failure rates based on the number of pre-steam checks required each year and numbers of wells steaming.

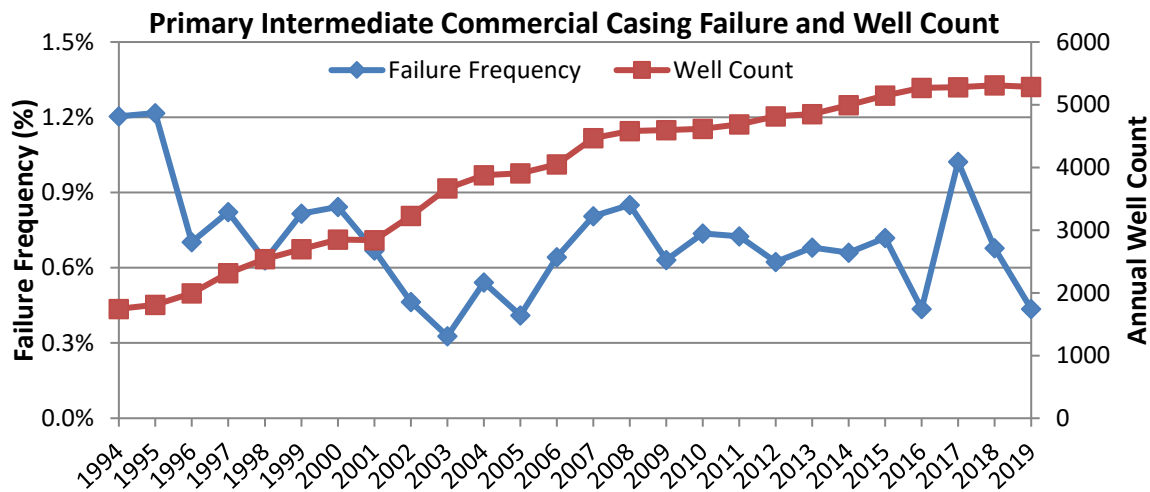


Figure 7: Intermediate Casing Failure and Well Count

In Figure 8, the number of primary intermediate casing failures for Cold Lake commercial casing design wells are stacked by early (1-4), mid (5-7), and late (8+) cycle periods. Early cycle failures continue to be lower than mid and late cycle failures.

In 2019, there was no early cycle failures.

For mid-cycle failures, 62.5% were found through Passive Seismic (5/8), 37.5% were found through Casing Integrity Checks (3/8)

For late-cycle failures, 20% were identified through Passive Seismic (3/15), 67% were found through Casing Integrity Checks (10/15), and 13% were found through regulatory pressure testing (2/15).

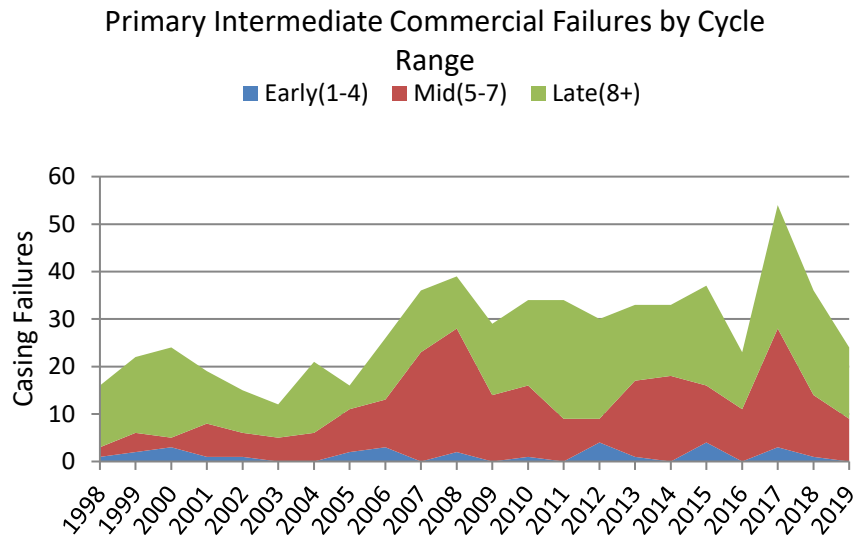


Figure 8: Intermediate Failures by Cycle Range

Figure 9 shows intermediate failure frequencies for commercial casing design wells, which are again divided into early (1-4), mid (5-7), and late (8+) cycle classifications. The failure frequency is calculated by dividing the number of failures in a cycle classification by the total number of wells in that classification. Early cycle failure frequency is typically driven by unique wells or rare events. Mid cycle failure frequency steadily increased between 2004 and 2008, due primarily to failures at Mahkeses. Similar increases have occurred from 2012-2018 as Mahihkan North pads have become mid cycle. The number of mid cycle failures has fluctuated annually, dependent on how many pads are moving through this period when casing failures generally start to be observed. The late cycle failure frequency trend has stayed fairly consistent for the past several years. The total number of wells in each of the three cycle classifications is distributed as follows:

- Early (1-4) – 276 wells
- Mid (5-7) – 1452 wells
- Late (8+) – 3557 wells
- Total – 5285 wells

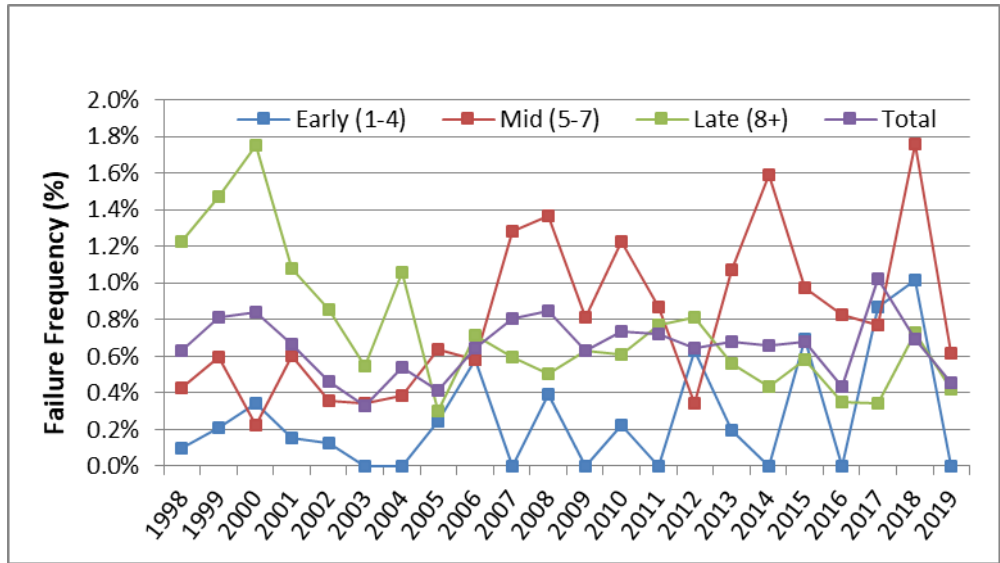


Figure 9: Intermediate Failure Frequency by Cycle Range

The intermediate failure detection method is displayed in Figure 10. Approximately 58% of intermediate casing failures are identified during rig based casing integrity checks since 1998. The percentage of operationally identified casing failures has generally increased since 2002, mainly due to increased detection capabilities and enhancements through the passive seismic and nitrogen soak monitoring programs. 8 failures were detected by operational monitoring systems in 2019.

15 failures were detected by casing integrity checks in 2019. 5 occurred on wells that were already isolated from the Clearwater reservoir (i.e. rig based D013 5-year pressure tests on suspended wells or during other wellwork activities on prior suspended/abandoned wells).

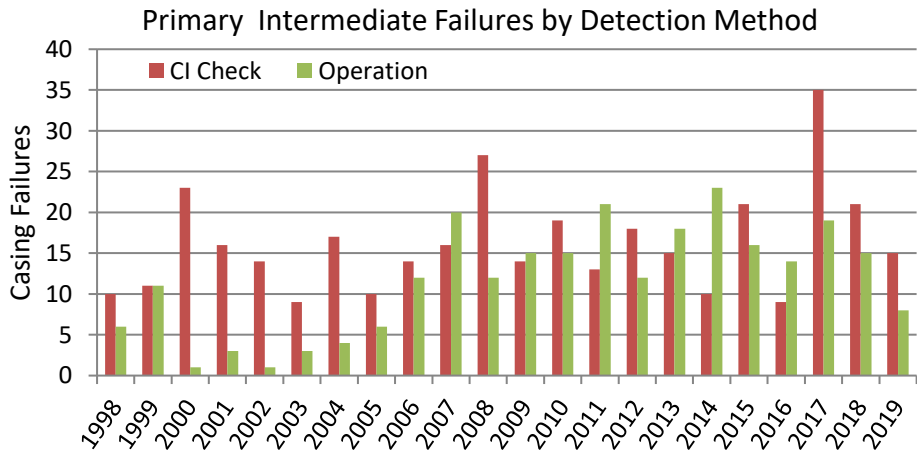


Figure 10: Primary Intermediate Failures by Detection Method

Intermediate Depth Casing Failure Resolution:

The 23 intermediate depth well failures discovered in 2019 were managed in the following way:

- 6 wells repaired with slimhole repairs

- 3 well are awaiting a slimhole repair (plug set)
- 7 wells repaired with a retrievable MH Casing Patch
- 5 wells zonally abandoned
- 2 wells full subsurface abandoned

The cemented slimhole remains the most common repair procedure to return wells to high pressure steaming operations. In total there were 83 slimhole repairs completed in 2019 (one due to near surface failure paired with CWT failure). Of these 83 wells, 62 were performed proactively on wells with casing impairments (not casing failures). Some of these repairs were on wells which failed prior to 2019.

2.3 Clearwater Casing Integrity Data

In 2019 there were 12 Clearwater casing failures detected. Well failure details are displayed in Table 5.

Table 5: 2019 Clearwater Failures Summary

No.	District	Well	Date	Depth(mKB)	Depth(mTVD)	Pad Cycle	Depth Class
1	Mahkeses	V10-31	12/28/2019	856.00	432.73	7	Clearwater
2	Nabiye	N02-09	10/24/2019	513.00	487.34	6	Clearwater
3	Maskwa	F08-H03A	10/9/2019	476.00	405.39	6	Clearwater
4	Mahkeses	ODD-08	8/13/2019	441.20	434.53	9	Clearwater
5	Nabiye	N09-04	7/8/2019	736.00	462.77	5	Clearwater
6	Mahkeses	V10-21	7/8/2019	509.90	437.60	7	Clearwater
7	Nabiye	N09-10	6/27/2019	547.00	463.14	5	Clearwater
8	Nabiye	N05-05	4/28/2019	647.20	444.58	6	Clearwater
9	Nabiye	N05-16	4/13/2019	467.00	439.71	6	Clearwater
10	Nabiye	N05-09	4/2/2019	471.70	444.41	6	Clearwater
11	Nabiye	N04-15	2/18/2019	475.30	445.59	6	Clearwater
12	Mahihkan	H65-10	1/26/2019	455.00	432.00	7	Clearwater

The number and frequency of Clearwater casing failures for the commercial casing design in Cold Lake since 1998 are presented in Figure 11. Clearwater failure performance has stayed in a similar range since 2010, which represents a step change reduction from earlier Clearwater failure rates. The reduced failure frequency is likely attributed to a larger portion of the field moving to low pressure operations, an increase in horizontal well development, and enhanced intermediate depth shear stress management having a collective effect on Clearwater top formation movement.

Commercial Clearwater Failures and Failure Frequency

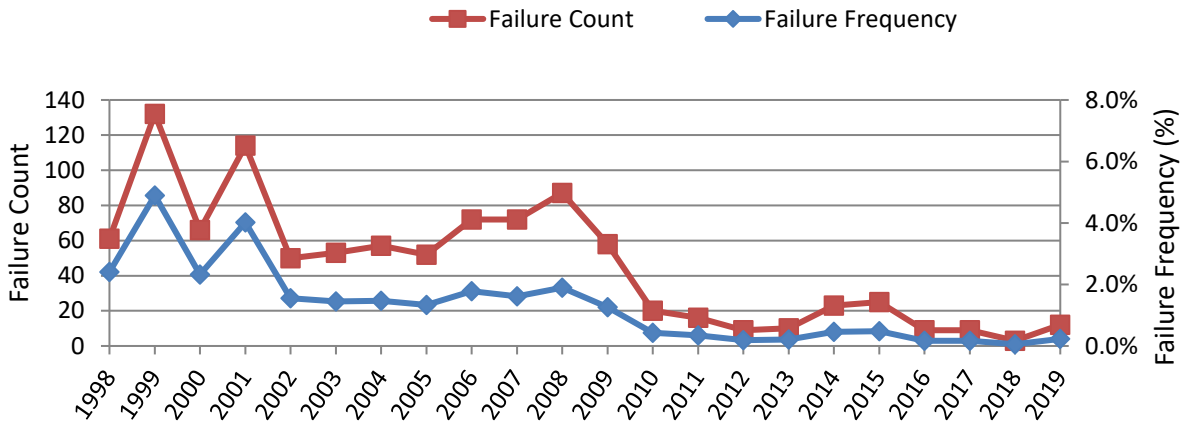


Figure 11: Clearwater Failures and Failure Frequency

2.4 Directive013 Pressure Tests

The table in Figure 12 displays the results of regulatory D013 5-Year pressure tests on suspended wells. In 2019, 91 wells required pressure tests and integrity of the suspension plug was confirmed on 90 wells. One well (E07-18) had a small pressure bleed off thru the suspension plug and required remedial work on the isolation. An additional nine wellbores on E07 pad had unsuccessful pressure tests and are undergoing additional diagnostics and remediation to ensure isolation in early 2020.

In three wells (D09-08, H04-06 and H68-22) new intermediate casing failures were discovered above the top of the isolation plug. In an additional well (A03-10), a near surface casing failure was discovered.

New intermediate and surface depth failures found during the 5-Year pressure test are noted in the columns in Figure 12. These are called 'No Pressure' failures since the suspension plugs were isolating the Clearwater perforations from the upper wellbore, and therefore there are no consequences. These failures are also included in the report sections above.

Suspended Well Five Year Pressure Test Performance

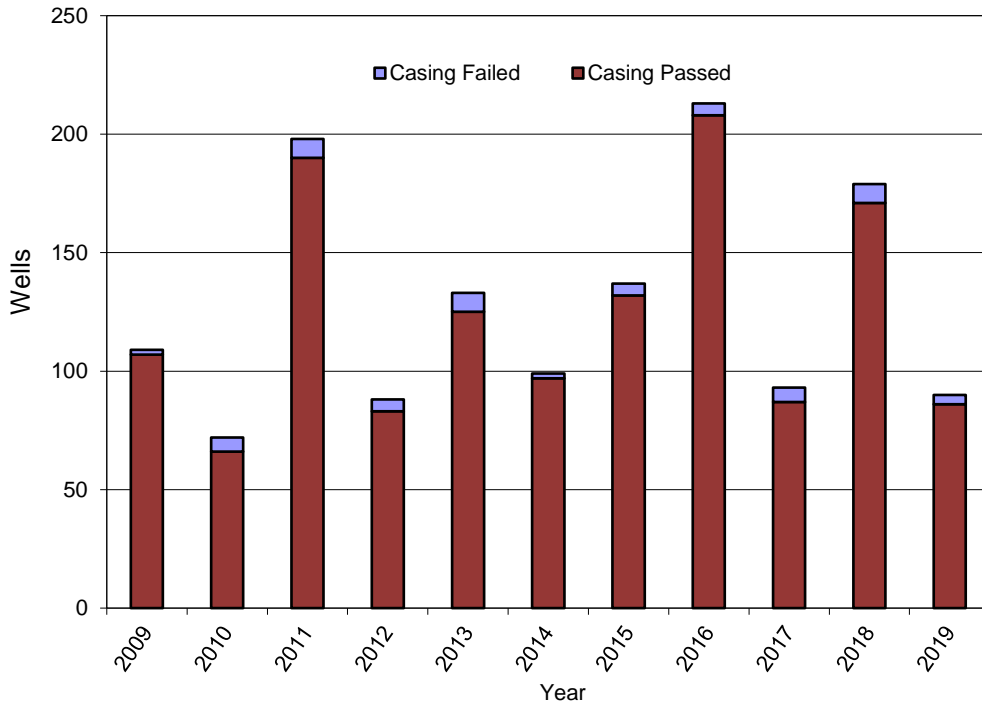


Figure 12: Suspended Well Five Year Pressure Test Performance

3.0 Cold Lake Casing Integrity Management

Casing integrity is a critical component of the Operations Integrity Management System in Cold Lake. Primary failure mechanisms that have been identified in Cold Lake wells are: for near surface depths - external corrosion, and for intermediate depths - stress corrosion cracking (SCC), sulphide stress cracking (SSC), and metal fatigue (high strain – low cycle) due to formation movement and slip. The Cold Lake Casing Integrity Operating Practices were formally introduced in 1996 providing improvements in three major areas – prevention, detection, and response to casing failures. Through a continuous improvement approach, the Casing Integrity Operating Practices have been enhanced, modified, and updated with new learnings since their implementation. These practices are reviewed and updated annually.

Improvements and initiatives in detection and prevention, and response to casing failures relevant to 2019 and the future will be discussed in the following sections.

3.1 Casing Failure Detection

The manner in which casing failures are detected at Cold Lake has evolved through time. Imperial continues to rely on several complimentary and overlapping detection systems including:

- Differential Flow and Pressure (DFP) alarms and steam trend analysis during steam injection
- Nitrogen Soak monitoring during soak and shut-in
- Pressure and fluid level monitoring during soak, trickle flow back, and shut-in
- N₂ blowdown testing on steam injection wells
- Passive seismic monitoring
- Groundwater monitoring
- Casing integrity check process
- Visual monitoring

Current initiatives will be discussed in the following subsections.

3.1.1 Alarm Management

The monitoring system used during the steam injection portion of the cycle is known as the Delta Flow and Pressure (DFP) program. Steam injection and pressure trends are analyzed on a 15 minute frequency to detect pressure drops and corresponding flow increases. Varying levels of alarms are generated for pressure drops between 25 kPa and 250 kPa. All alarms are investigated and potential casing failure events are cross-referenced to other detection systems in order to diagnose a potential casing failure. The DFP algorithm was most recently upgraded in 2013 to reduce the number of false alarms and streamline failure detections after prototype test verification.

A passive seismic performance review in 2014 recommended an increased focus on systems operating in high pressure pad areas (>6MPa). Hind-casting of failure data has shown that passive seismic is highly successful at detecting casing failure events on high pressure pads and this strategy will best utilize the system's strengths. Passive seismic systems on lower pressure pads (<6MPa) will be taken out of service, since low pressures cannot enable fluid excursion out of intermediate casing failure depths. This strategy will improve the focus on the high pressure pad systems.

Since 2017 additional upgrades to the passive seismic event screening process and assessment tools have been implemented. The software for real-time passive seismic alarms is now functional for all high pressure pads, allowing for earlier identification and immediate notification to Imperial's passive seismic team located in Calgary and field personnel in Cold Lake.

3.1.2 Casing Integrity Check Process

Since the inception of the Casing Integrity Operating Practices in 1996, casing integrity checks have been conducted proactively to detect casing failures and impairments. A basic casing integrity check consists of both a 21 MPa pressure test and a gauge ring/scrapper run to at least the top of the Clearwater formation. Although a well may pass the 21 MPa pressure test, information from the gauge ring/scrapper pass can initiate further diagnostics which are used to confirm if well integrity remains acceptable for steam injection activities. This is commonly completed with a multi-sensor caliper log run to determine the extent of a potential casing impairment or deformation. Near surface external corrosion inspections are performed on wells at a prescribed age. Either an in hole corrosion inspection log or an external ultrasonic test is completed to verify corrosion. Corrosion inspection logs are being synergized with earlier cycle casing integrity checks to optimize the logging schedule and ensure a sample set of corrosion data is collected on each pad. In 2017, corrosion assessments practices were changed such that deviated wells will be assessed one year earlier, prior to their ninth year of operation.

The required casing integrity checks performed on a pad prior to steaming is defined as part of the Casing Integrity Operating Practices, and is provided as Attachment 1. Certain circumstances (e.g. known impairments, passive seismic events, unusual fluid levels and nitrogen soak trends) can trigger additional checks incremental to this minimum standard.

In 2007 a risk-based targeted selection process was implemented to select which wells should be inspected prior to being placed on steam. This assessment is completed through review of data such as prior casing integrity check results, passive seismic casing events, nitrogen soak trends and fluid levels, DFP alarms, and suspect steam trends. There are defined standards describing when targeted selection requirements are to be completed and closed out prior to beginning steam injection. As further understanding of casing failure mechanisms is developed the targeted selection criteria are updated accordingly. Wells deemed as having higher potential for sulphide stress cracking based on H₂S sample partial pressure data were incorporated into the process in 2013.

In 2012 Imperial qualified the use of through tubing Electro-Magnetic (EM) logging as a method of performing a casing integrity check. Through tubing logging, specifically the Schlumberger EM Pipe Scanner Inspection Tool, was field trialed and qualified in Cold Lake. The through tubing logging technique is a less invasive method of evaluating the current casing string condition and does not require a service rig. Imperial has implemented the use of the Schlumberger EM Pipe Scanner as a method of casing integrity check for specific applications where determining if the casing has a failure is the objective of the integrity check.

In 2015 an analysis of casing failure data showed that failure frequency rates for larger 9-5/8" cased horizontal wells were statistically lower than that of deviated 7" well casing. Statistically valid data for 9-5/8" CSS wells were available up to and including cycle 7. The presence and rate of casing impairments mirrored the casing failure performance and shows limited impairments occur on 9-5/8" horizontal wells through the early and mid-cycles. Based on this statistical evidence, EM log inspections began to be used as the standard casing integrity check technique through the first seven operating cycles for 9-5/8" wells. In addition, traditional rig based integrity checks continue to be completed synergistically on 9-5/8" wells with tubing movement maintenance activities to check and verify well impairment performance. This change is shown in Attachment 1 (5th column).

The above mentioned casing failure statistical analysis also revealed that for 7" new/upgraded casing (majority of active 7" wells in Cold Lake), both casing impairments and failures start to occur during cycle 5; one cycle ahead of the previous commencement of CI checks (pre-cycle 6). To more proactively identify and mitigate mid-cycle integrity issues, the first round of CI checks for pads with commercial new/upgraded casing that have a passive seismic well now occurs one cycle earlier prior to cycle 5 (as of 2016). These checks consist of traditional CI checks and synergistic checks completed with other tubing movements in early cycles. The practice allows for proactive measures to be taken (i.e. slimhole, shear liner, take out of steam service) that aids in reducing the overall casing failure frequency. This change is shown in Attachment 1 (4th column).

In 2015, guidelines were developed for more proactive use of shear liners. A shear liner is a joint (or multiple joints) of non-cemented casing which is suspended in a wellbore from a hanger across a section of known casing damage. The frictional fit provides mechanical reinforcement to inhibit further damage to the production casing from strain concentration. In prior years, shear liners have been installed on occasion. An assessment of results from those installations has shown success in preventing further shifting of the pipe downhole.

In 2019, an assessment on infill wellbores (both 8 5/8" and 9 5/8") casing integrity was completed to determine the optimal wellbore age to start service rig casing integrity inspections on these wellbores in low pressure steamflood areas. The data showed that year 8 in operation was when these wellbore were begin to require intervention. Imperial has updated its practice to reflect this assessment with casing integrity inspections now being triggered on these well types after 8 years in service instead of 10 years.

The total well count in Cold Lake has increased over time and the frequency of casing integrity checks increases over time with a given pad's cycle number. However, the continuously changing mix of early, mid, and late cycle wells and the variety of depletion methods (e.g. high pressure CSS, low pressure CSS, steamflood) will cause fluctuations in the total number of casing integrity checks each year. Figure 13 shows the number of casing integrity checks performed each year since 2005. The numbers from 2013 forward include Schlumberger wireline EM scan log checks. The percentage of casing integrity checks that initially found near surface or intermediate depth failures is also plotted in Figure 13. The peak number of integrity checks from 2007 to 2009 were primarily due to numerous Mahkeses wells reaching their first round of casing integrity checks and the 2007 increase in casing integrity check frequency. Since those peak years the total number of casing integrity checks have generally been decreasing due to a higher number of early cycle wells being steamed, an increasing percentage of multi-bottom hole location horizontal wells per pad, an increase of injector-only infill wells, and an increase in low pressure steam flood operations. In 2019 there were a total of 327 CI checks completed (282 rig based and 45 EM Scan checks), with 12 intermediate depth failures identified during these casing integrity checks (not including regulatory pressure testing). The percentage of CI checks which identify a casing failure has generally increased over time, since the targeted selection practice identifies wells with a higher probability of a failure. The increase is also attributed to aging wellbores.

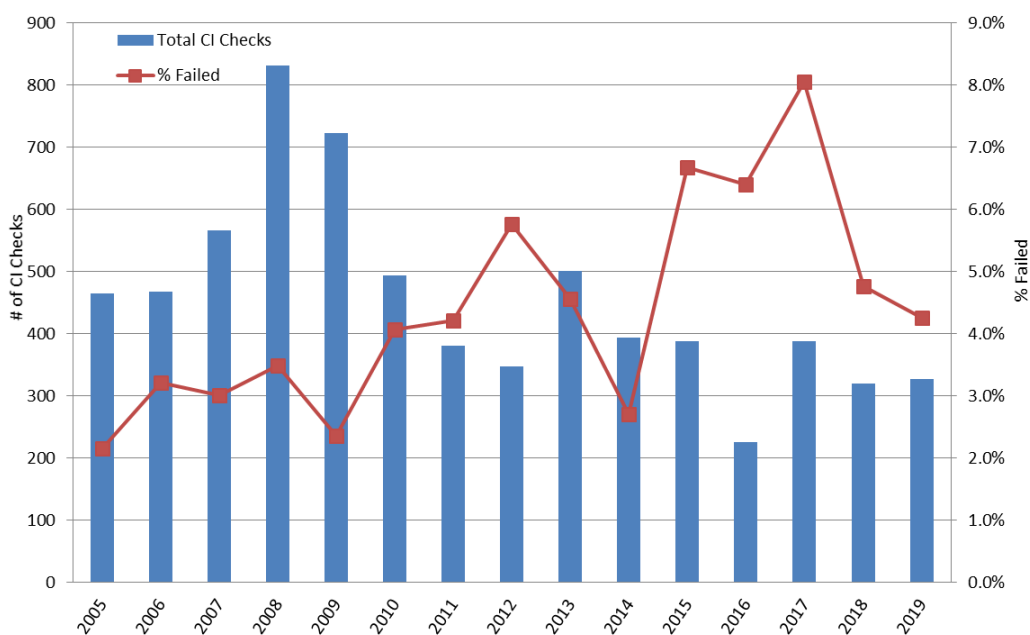


Figure 13: Casing Integrity Check History

3.2 Near Surface Casing Integrity Management

The mechanism for near surface casing failures is external corrosion. Water can collect outside the production casing through precipitation and surface water run-off from above, or condensed steam from overburden heating below, or minor wellhead packing leaks. Oxygen is also present near surface and in the heated environment with various other elements, accelerated corrosion can result.

Corrosion inspection logs or external ultrasonic testing, and casing pressure tests are completed as part of the Casing Integrity Operating Practices. Wells identified as having potential corrosion concerns are either pressure tested to ensure suitability for service, repaired, or taken out of steam service. In 2011, corrosion inspections were changed to be triggered by well age, on a years-in-service basis, instead of number of completed cycles. In 2017, the year-in-service was decreased from 10 years to 9 years for deviated wellbores, based on analysis of corrosion assessment results. This will more proactively identify wells with higher external corrosion and lead to earlier intervention activities.

Imperial's bentonite top-up program and production casing inspection practices have been utilized since 1996 to manage near surface depth corrosion and confirm well integrity prior to steam. The practices have been targeted to mitigate the risk associated with casing failures where there is the potential for environmental impact (higher pressure wells). Since the implementation of the Casing Integrity Operating Practices in 1996 there have been no surface depth casing failures of consequence beyond Level 0.

Improved primary cementing practices for new wells enhance the ability to achieve and maintain cement tops at or near surface. All wells that do not have cement to surface level are topped up with bentonite after the first steam cycle and the protective shrouds installed above the annulus. The bentonite top-ups and shrouds are maintained throughout the operating life of the wellbore.

The bentonite program's management process was further upgraded in 2013 from an annual well inspection to regular real-time inspection during operator rounds, allowing for more timely top-up and shroud maintenance.

Since 2010, casing shrouds have been installed on all wellbores to help prevent water from entering the production casing annulus. In 2016, the shroud material was upgraded from a galvanized to a stainless steel to extend life of the shroud. Additional changes were implemented in 2017 that improve how the shroud is attached to the wellbore to make for ease of installation and removal.

In 2014, Imperial initiated a field trial in the application of a high-temperature, high-performance metallic aluminum external coating material to near-surface production casing on operating wells. The product selected has a temperature rating of 400°C, which makes it suitable for CSS injection conditions. From 2014-2019 the coating product has been applied to 182 candidate wells with moderate near-surface corrosion. In 2016, coatings began to be synergistically applied on wells that were dug out for external ultrasonic testing, and were remaining in service. Prior to December 2017, wells were only being synergistically coated if temperatures were steadily above 10°C to ensure proper curing of the coating. Changes have now been made to this process to allow wells to be synergistically coated year round by hoarding and heating of the exposed casing. In 2019, Imperial started coating newly completed wellbores and wellbores which had the top joint of casing replaced due to corrosion concerns (near surface dig out repair).

In 2018, Imperial initiated a single pad trial (V10 Pad) of Silicate Solution. The top 30-60 cm of bentonite was removed from the production casing annulus and replaced with a liquid silicate product. Observations were made to determine how the product behaved after application, and how it coated the casing. Corrosion coupons were inserted in treated and untreated wells to help demonstrate effectiveness of the product. At the 6 month mark some of the corrosion coupons were pulled and compared. Initial results were limited but favorable, indicating some visible corrosion on untreated coupons and no visible

corrosion on the one treated coupon that was recovered. Imperial plans to do additional coupon inspections in 2020, and expand the pilot to additional pads.

3.2.1 *Alternative Corrosion Measurement Technologies*

From 2016-2019, surface corrosion on 241 wells was inspected using external ultrasonic testing (UT) inspection. Imperial has adopted this technology for thermal wellbores, leveraging long term industry experience with UT on surface equipment such as tanks, vessels and piping. The external UT inspection is completed by digging around the well, removing the conductor and cement around the production casing, buffing the casing, completing the external UT inspection and finally re-installing the conductor and backfilling. The benefits of the external UT inspection are cost savings for not using a service rig as well as more accurate external corrosion measurements.

3.2.2 *Alternative Casing Repair Technologies*

Imperial's original repair practice for wells with near surface failures is a surface dig out repair. This operation involves suspending the well, excavating to below the failure depth, replacing the failed section of production casing with new casing, and reactivating the well. The surface dig out is a proven repair method to return wells to high pressure CSS service, but cannot be economically justified for all wells. In 2011, Imperial tested a new near surface casing patch technology. The system utilizes a MH patch set below the failure, L80 patch pipe, and a threaded wellhead connection. The near surface patch is suitable for either lower pressure steaming (<4 MPa) or producer only well candidates (up to 10MPa) that do not require a surface dig out repair for full high pressure steam service. In 2019, 17 of these patches were installed to repair near surface failures.

In 2017, Imperial obtained approval to trial a new near surface failure repair technology; the external composite wrap. This repair involves exposing the failure by excavating the well near surface, removing the outer casing string(s) and cement, and preparing the casing via sand blasting. Once the casing has the proper NACE finish, the external composite wrap is applied over a 0.5-1.0 meter interval with multiple layers of fiberglass and carbon fiber. The external composite wrap is suitable for producer only, low pressure operation (< 4 MPa), and has a 230°C temperature limitation. 12 wells successfully had the repair installed to date and have been placed back in operation. These repairs have follow up helium testing completed once back in service after 1 month of operation and 6 months of operation. To date, 11 of the 12 successful repairs have been in service for 6+ months and have received successful 1 month and 6 month helium testing. One well had a successful 1 month helium test completed, but is not yet due for its 6 month helium verification test. Three additional composite wrap repairs were completed on near surface failures and lost integrity during the installation testing process, prior to being placed back into operation. A detailed root cause failure analysis was completed on all three failures. Further refining of the installation process is currently being progressed prior to applying for additional installations of this repair option.

In 2019, Imperial obtained approval to trial a new surface patch repair technology; the Revelation Management Ltd LSA surface casing patch. The casing patch has been designed to deliver similar long term integrity as the historic near surface MH patch, with additional enhancements for installation. The two main enhancements are as follows:

- 1) Lower seal is set hydraulically vs mechanically (casing jacks not required).
- 2) Design of the patch prevents premature setting of the lower seal when it needs to pass through tight tolerances. This is a risk with MH patches that prevents installation over intermediate depth, and Clearwater depth casing failures in some wells.

Similarly to the historic surface patch, the RML-LSA surface patch is suitable for low pressure steaming (<4 MPa) or producer only well candidates (up to 10MPa) that do not require a surface dig out repair for

full high pressure steam service. In 2019, 10 RML-LSA patches were successfully installed to repair near surface failures and further application of this patch is planned in 2020. The patch will also be evaluated for use at intermediate depths.

3.3 Intermediate Depth Casing Integrity Management

The majority of intermediate depth casing failures are caused by a combination of SSC and high strain, low-cycle fatigue. Beginning in 2006 Imperial implemented a number of wellbore design and operational changes to improve performance, including:

- Connection spacing offset away from known weak layers (slip planes)
- Enhanced shear stress management tools
- Adjusted steam volumes and strategy
- Targeted selection criteria for casing integrity checks
- Improved nitrogen purge management
- Producing well annulus gas testing environmental control

The nitrogen purge management and producing well environment control are both aimed at reducing the risk of SSC. Nitrogen purging is used to reduce the presence of H₂S in the casing - tubing annulus during shut-in periods. Nitrogen purge compliance for 2019 was 99.7% with a total of 9,674 purges during the year. Wells not achieving the purge within the 48 hour requirement are identified for follow-up testing through the casing integrity check targeted selection process.

Producing well annulus gas testing is aimed at reducing risk of SSC while operating at production temperatures below 60°C and a corrected H₂S partial pressure above 3kPaa. These wells are shut-in and purged with nitrogen until either the next steam cycle begins or a warm-up is performed.

On high wellbore pressure (>4 MPa), current N₂ purge practices were found to be effective in maintaining the wellbore environment with a high concentration of N₂, where SSC should not be of concern. At low wellbore pressure (<4 MPa) the study found that the N₂ concentration goal was not being achieved consistently with the existing practices. To improve N₂ performance, volumes have been increased by 50% on low pressure N₂ purges to help eliminate the atmosphere where SSC may begin to occur. This procedural change was implemented in 2013.

In 2016, Imperial discontinued N₂ purging at low pressure pads. Low pressure pads are defined as those with reservoir pressure below hydrostatics pressure (< 4 MPa), and where future operations will not increase pressure above that level. Discontinuing N₂ purging on low pressure pads has no effect on detection of intermediate casing failures as the reservoir pressure is too low to cause the fluid level to rise. As well, low pressure wells don't have enough pressure to cause fluid loss or result in adverse effects.

3.3.1 Well Operability – Repair Technology

Identifying a repair technology that can maintain integrity throughout high pressure CSS operations, with fluctuations in operating temperature and wellbore fluids through a steam injection and production cycle has long been a materials design challenge. The current repair method, proven successful over many years, is to maintain high pressure steam injection by cementing a slimhole pipe inside the existing production casing. However, this repair method leads to a wellbore size reduction which can limit future operations.

Imperial has progressed the following technologies to provide additional well repair options:

- Imperial has worked with suppliers to develop different casing patch technologies and strategies. A development program began in 2012 with Saltel Industries to design and test a product that could withstand high temperature, high pressure CSS operating conditions. The Saltel patch field trial was successfully completed in 2017. Six wells have been repaired using this technology; five

wells with intermediate casing failures and one well which was had a set of perforations above the production zone. Imperial has received AER endorsement to repair casing failures with this technology and return to HPCSS status after AER well specific approval is received. No additional opportunities for this repair technique occurred in 2019, but the Saltel patch will be considered for returning wells to HPCSS service in the future.

- The Schlumberger 'MHE' patch is another high temperature – high pressure casing patch technology which was trialed in 2016 on H63-H12 over a set of perforations above the production zone. Two 'warm up' volumes of steam were injected into the wellbore. After each warm-up, a rig moved onto the well and completed post steam warm up diagnostics which confirmed patch integrity. The well completed a full steam cycle and N2 Soak integrity was confirmed with fluid shots. A service rig completed a casing integrity inspection on the well in November 2017, which confirmed patch integrity. No additional opportunities for this repair technique occurred in 2019, but the MHE patch will be considered for returning wells to HPCSS service in the future.

3.3.2 Well Operability – Casing Fatigue Research & Material Testing

URC studies on casing fatigue or material testing were completed in 2016. Below is a summary of the previous 2016 well operability studies that were progressed to completion;

- The Production Injection Management Fatigue Estimate Toolkit (PIMFET) software that was developed in 2011, was last optimized in 2016 to enabled better pad pressure alignment and balance/symmetry through small steam rate adjustments which subsequently reduces the amount of fatigue induced on the casing. This has resulted in improving steam strategies and adapting operating practices for various well and pad scenarios.
- In 2016 an analysis was completed to determine if 7" 32lb/ft casing would improve overall well integrity performance and whether heavier wall pipe should replace the existing 7" 23lb/ft pipe. The assessment determined that thicker pipes would result in a longer well life at lower slip magnitudes for both the pipe body and at the connection; however, the difference is negligible at higher slip magnitudes. The benefit over the entire well life was not enough to pursue this design change for new drill wells.

3.4 Clearwater Casing Integrity Management

Formation movement is the primary mechanism for Clearwater casing failures. As a result of the CSS process, shear stresses develop which results in slip along structurally weak planes existing at the Clearwater - Grand Rapids interface. As this shear is localized, there is no impact on intermediate casing integrity. There is no evidence that Clearwater failures cause, or are related to other intermediate depth or near surface casing failures. Although there is no adverse environmental impact, operability of the well can be restricted. The casing integrity program for Cold Lake was designed primarily to address the concerns associated with the near surface and intermediate depth intervals, and was not intended to deal with the Clearwater failures.

When Clearwater casing failures are detected the well is steamed below fracture pressure, unless the failure is repaired or the location of the failure is such that steam will not encroach on the Clearwater/Grand Rapids interface. Occasionally, Clearwater failures or impairments are mitigated through the installation of shear liners or cemented patches for structural support. Balanced steaming strategies to manage intermediate depth shear stress can also minimize formation movement at the Clearwater top in order to reduce casing damage.

3.5 Casing Integrity Response

Currently, Imperial maintains the following equipment and materials on-site for well control purposes: pre-mix and returns tanks, storage silo's, approximately 300 tonnes of barite, 400 tonnes of hematite, 140m³ of 1370kg/m³ CaCl₂ fluid, 140m³ of 1500kg/m³ CaCl₂ fluid and all necessary kill fluid additives in order to respond to high pressure casing failures in a timely manner.

ATTACHMENT 1: CASING INTEGRITY CHECK FREQUENCY

Casing Checks by Cycle and Design for High Pressure CSS Wells

Prior to Steam Cycle #	Commercial Old	Commercial New/Upgraded w/o PS	7" Commercial New/Upgraded w/ PS	8 5/8" & 9 5/8" Commercial New/Upgraded w/ PS	Environmental Old	Environmental New/Upgraded
1	0	0	0	0	0	0
2	0	0	0	0	0	0
3	0	0	0	0	0	0
4	0	0	0	0	0	0
5	33 ¹	33 ¹	33	0	100 ¹	50 ¹
6	33 ¹	33 ¹	33 ¹	33 ¹ (EM Scan)	100 ²	50 ¹
7	33 ¹	33 ¹	33 ¹	33 ¹ (EM Scan)	100 ²	100 ²
8	100 ²	100 ²	50 ¹	33 ¹ (EM Scan)	100 ²	100 ²
9	100 ²	100 ²	50 ²	50 ² (Rig CIC)	100 ²	100 ²
10	100 ²	100 ²	50 ²	50 ² (Rig CIC)	100 ²	100 ²
11	100 ²	100 ²	100 ²	100 ² (Rig CIC)	100 ²	100 ²
12	100 ²	100 ²	100 ²	100 ² (Rig CIC)	100 ²	100 ²
12+	100 ²	100 ²	100 ²	100 ² (Rig CIC)	100 ²	100 ²

Commercial:	L/MN-80 or IK-55 casing design with OBTC, NKEL or QB2 connections
Non-Commercial:	All casing designs prior to Commercial.
'Old' Wells:	Wells beginning steam prior to OP#9 inception, improved steam quality and lower volume steam injection (Jan 96).
'New' Wells:	Wells beginning steam after OP#9 inception, improved steam quality and lower volume steam injection (Jan 96).
Environmental:	Pads or wells within 500m of the historical high water level of a designated water body.
Upgraded Commercial:	New casing design coming out in 1998 with NSCC-M phosphate coated 'metal-to-metal' connections (VAM SWNA, Tenaris Blue, NSCCM, NSCC, and QB2).

Horizontal 9-5/8" high pressure CSS wells utilize the EM Scanner log for the above prescribed casing checks up to and including cycle 7, and also receive synergistic rig based checks with routine tubing maintenance wellwork jobs.

Near Surface Corrosion:

1. Wells require a corrosion log at or before this cycle only if a CI check is scheduled. Only one corrosion log is expected per well during this period. All deviated wells on a pad must have a corrosion log within the first 9 years from initial steam date. For horizontal wells with 9 5/8" or 8 5/8" production casing (which use EM log up to and including cycle 8), a near surface corrosion log is required no later than 10 years after first steam in date.
2. Future corrosion log requirements should be assessed on the actual results (well specific corrosion rate) from the existing corrosion logs or external UT results for that well.

