2010 Annual Summary Report on Casing Integrity

Submitted: March 30, 2011

Property of Imperial Oil

EXECUTIVE SUMMARY

Casing Failures

Near Surface

- 11 failures in 2010 versus 16 failures in 2009.
- 1 detected with casing integrity checks, 10 detected operationally.
- None in 2010 were assessed above a level zero environmental consequence.
- 1 well in 2010 proactively taken out of steam service due to excessive wall loss.

Intermediate Depth

- 34 failures in 2010 (34 primary failures & 0 secondary failures) versus 30 failures in 2009. (0.73% failure frequency in 2010 vs 0.65% in 2009) The number of failures increased slightly from 2009 but remains below 2007 and 2008 levels.
- 20 detected with casing integrity checks, 14 detected operationally which includes 12 with passive seismic and 2 wells detected by the nitrogen soak/nitrogen fluid monitoring programs. 5 of the 20 wells detected by casing integrity checks were detected by regulatory pressure testing requirements on previously suspended wells.
- No multi-well failures occurred in 2010.
- No failures in 2010 were assessed above a level 0 environmental consequence.
- Decreases in percentage of failures that were high pressure
- Decreasing consequence with lower number of failed wells with fluid loss, and lower fluid loss volume to the break
- 5 wells in 2010 proactively taken out of steam service due to impairment or deformation.

Clearwater

- 15 failures in 2010.
- No adverse environmental impact identified.

Casing Failure Detection Initiatives

Alarm Management

- A new method of filtering Delta Flow and Pressure (DFP) alarms was developed in 2009. Prototype testing progressed through 2010. If successful, full implementation is planned for Q2 2011.

Targeted Selection

- Risk based process to identify which wells should receive minimum required casing integrity checks, as well as to identify wells that should be checked incremental to the minimum standard.

Near Surface Casing Integrity Initiatives

2010 Bentonite Top-up Program

- Excluding approximately 1000 below grade wells where bentonite top-ups are not able to be completed, 3808 of 3808 wells have received bentonite top-ups.
- Top-ups will be completed annually and before each steam cycle going forward.
- There are approximately 1000 late cycle wells where bentonite top-ups are not able to be completed as conductor pipes are below grade level. All 1000 wells are operated at low pressure and have a casing integrity check prior to each steam cycle. Infrared technology was tested in 2010 to detect leaks however the results were inconclusive. Filtered methane detection with helium purging testing will be conducted 2011 as a method for detecting leaks.

Casing Shroud Installation

- 3808 of 3808 wells have had casing shrouds installed. Casing shrouds will be monitored in conjunction with bentonite the top-up program.

New Well Corrosion Assessment

- Statistical analysis determined uphole casing failures are related to time and no correlation to cycle number. Operating practices are being revised to trigger Vertilog inspections based on well age.

Alternative Corrosion Measurement Technologies

- Analysis of alternative logging tools to the Baker Atlas Digital Vertilog is planned to progress in 2011.

Alternative Casing Repair Technologies

- A near surface casing patch for low pressure steam operations has been designed as an alternative to excavating below the failure depth and replacing the failed section of casing. This technology is being considered for field trial in 2011, pending ERCB approval.

Surface Corrosion Mitigation for New Well Installations

- Lab testing of a high temperature external coating which would be applied prior to cementing is currently underway with results evaluated by Q2 2011.

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Intermediate Depth Casing Integrity Initiatives

Casing Retrieval

- Casing retrieval operations complete on 4 wells. Analysis concluded evidence of embrittlement and ductile overload. Overall, program validated Imperial Oil's Root Cause Failure Analysis process and results will feed other initiatives such as the fatigue resistant connection design.

Material Testing

- Completed a series of tests comparing T95 to L80 casing
- Results indicated T95 has a slightly higher sulfide stress cracking resistance compared to L80 under monotonic conditions.
- T95 performance was similar to L80 under cyclic loading. Further testing is planned for 2011 to compare the low cycle fatigue characteristics of T95 vs. L80.

Instrumented Well / Wellbore Environment Model

- Producing wellbore environment sampling program was implemented in late 2009 to identify wells at risk of SSC due to lower temperature and higher H_2S partial pressure. To date over 900 wells have been sampled and 7 wells have been shut in and purged due to risk of SSC.
- Instrumented Well – equipped well T06-09 with downhole instrumentation to measure temperature, pressure, H_2S concentration, and take liquid samples to determine acidity. Results have lead to a H_2S concentration correction factor from surface sampling to further reduce the risk of SSC on cold producing wells.

Geological Study of the Colorado Shales

- Geological review of the Colorado Shales has identified two key markers within the Fish Scales formation that correlates a majority of failures to within 2m of these markers.

- A new directive initiated in 2010 to avoid placing casing connections within 2m of these specified markers. Field results being stewarded and to date 72 wells have had collars spaced out to avoid connections at the specified markers.

Well Load and Resistance Studies

- Model studies using a layered rock property incorporating metallurgical properties of the casing body and connections to predict the distribution and magnitude of plastic strain and estimate when material failure will occur has lead to the development of a new software.
- Production Injection Management Fatigue Estimation Toolkit (PIMFET) calculates shear slip and casing fatigue life and allows the user to optimize steam strategies to minimize shear stress and casing damage while maintaining bitumen recovery.
- PIMFET software completed Beta testing in 2010, with planned production release in early 2011.

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Well Environment

- Improved nitrogen purge management has lead to near 100% compliance throughout 2010.
- Improved compliance helps mitigate the occurrence of failures due to SSC.

Well Design

- L80 casing is still considered to be the optimal casing material to balance post-yield material properties and SSC resistance. Based on material testing results, T95 will continue to be evaluated.
- A new fatigue resistant connection design has been developed by the ExxonMobil Upstream Research Company. Physical testing of the design will take place in 2011.

1.0 INTRODUCTION

Pursuant to the requirements of AEUB Decision 99-22, condition #9 and clause 6.2 of AEUB Approval 8558, Imperial Oil Resources hereby submits the 2010 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 2010 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 according to the following three depth intervals:

- Near surface (0 to ~25 mTVD).
- Intermediate depth including the Quaternary, Colorado group, and Grand Rapids formations.
- Clearwater, at the interface between the Clearwater formation and the 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 potential aquifer contamination or breach to surface. Clearwater failures only affect the serviceability 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 zone.

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 Bedrock top, and have potential for fluid loss are Alberta Environment 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	- 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, dependant on proximity of wellbores at failure depth) - Failure occurred within the Glacial Till, but only released inert fluid (e.g. N_2 gas) or minimal produced fluid not requiring remediation
Level 1	- 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, dependant 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	- 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 the 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, or passive seismic (PS) systems, or detected by visual means. A casing integrity 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) The failures detected as part of the 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 casing failures by depth interval at Cold Lake is provided in Table 2. All 34 of the intermediate depth casing failures detected in 2010 were classified as primary commercial intermediate failures (no early casing design failures). None of the 45 near surface or intermediate failures in 2010 were assessed an environmental consequence above level 0. Of the 45 surface and intermediate failures detected in 2010, 24 were detected operationally and 21 were detected through casing integrity checks.

Table 2: Historical Failure Summary by Depth Interval

Depth Classification	Year						
	2004	2005	2006	2007	2008	2009	2010
Surface	0	1	1	5	5	16	11
Intermediate	21	16	26	36	39	30	34
Clearwater	57	51	70	71	81	56	15
Total	78	68	97	112	125	102	60

Casing integrity data for the three failure depth intervals is presented in the following subsections.

2.1 Near Surface Casing Integrity Data

Since 1991, 118 commercial wells have failed near surface, including 11 surface failures detected in 2010. Details describing these failures (including primary cement tops) are provided in Table 3. In addition to failed wells, a further 119 wells have either been proactively repaired or taken out of steam service due to excessive wall loss.

Table 3: 2010 Surface Depth Failures Summary

No.	WELL INFORMATION				FAILURE INFORMATION						
	Well	License	UWI	Primary Cement Top mGL	Detection Date mm/dd/yy	Detection Method		Depth		Cycle	Environmental Consequence Level
								mKB	mGL		
1	J07-10	112648	107/16-16-065-04W4	5.5	01/03/10	Operational	Visual	4.3	-0.6	11	0
2	D62-09	157796	100/11-36-064-04W4	0.0	01/14/10	Operational	Visual	4.3	0.2	9	0
3	B06-14	110271	105/15-13-065-04W4	4.8	01/19/10	Operational	Visual	4.1	-1.9	13	0
4	J08-17	119083	110/13-15-064-04W4	16.3	03/02/10	Operational	Visual	4.4	1.4	12	0
5	R02-10	134601	104/04-23-065-04W4	12.6	03/28/10	Operational	Other	4.8	1.8	7	0
6	R05-05	132584	110/16-14-065-04W4	0.4	03/28/10	Operational	Other	4.4	1.0	6	0
7	J03-05	109704	105/07-22-065-04W4	15.7	05/08/10	Operational	Other	7.8	3.3	10	0
8	A04-16	103951	100/01-15-065-04W4	0.2	05/26/10	Operational	Visual	4.0	-0.2	13	0
9	R02-17	134608	111/01-22-065-04W4	20.8	07/05/10	CI Check	Visual	3.0	-1.6	8	0
10	D24-20	114843	103/12-01-065-04W4	0.0	07/05/10	Operational	Other	3.7	0.7	9	0
11	D53-20	155440	100/07-35-064-04W4	0.0	11/23/10	Operational	Visual	4.3	0.2	9	0

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 the 11 near surface failures detected in 2010.

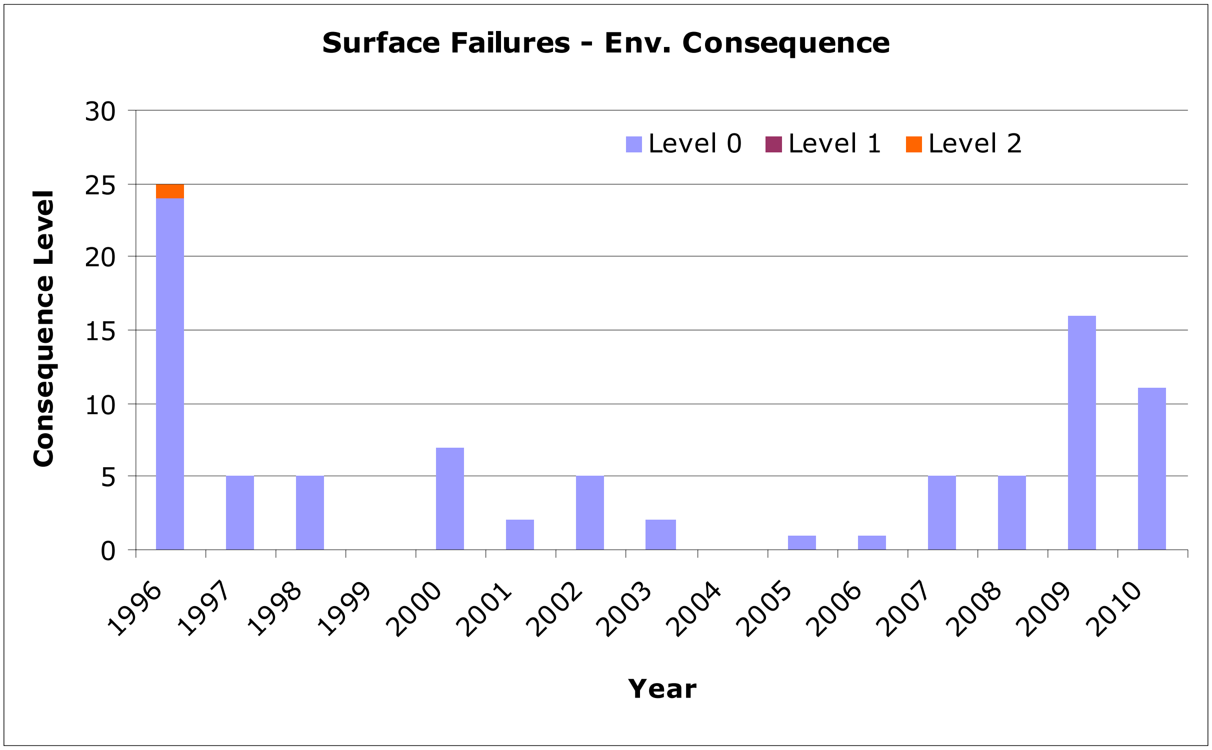

Figure 1: Cold Lake Surface Failures by Consequence Level

The number and frequency of near surface casing failures for the commercial casing design in Cold Lake are summarized in Figure 2. Failure frequency is the number of failures divided by the total number of wells operating. The peak failure rate observed in 1996 marks the inception of the Casing Integrity Operating Practices, at which time the cement and bentonite top-up program was initiated to mitigate the occurrence of surface failures. Positive results were observed and the surface failure frequency declined; however, failure frequency increased between 2006 and 2009. Many of the failures occurred on 'old' wells (steamed prior to 1996 before the implementation of the Casing Integrity Operating Practices). The bentonite top-up program and production casing inspection practices were further upgraded in 2010 and are targeted to mitigate the risk associated with a high pressure (capable of flow) casing failure where there is potential for environmental impact. Also, the installation of the casing shrouds was a major initiative undertaken in 2010 aimed to help reduce external corrosion. All 11 failures in 2010 occurred on 'old' wells.

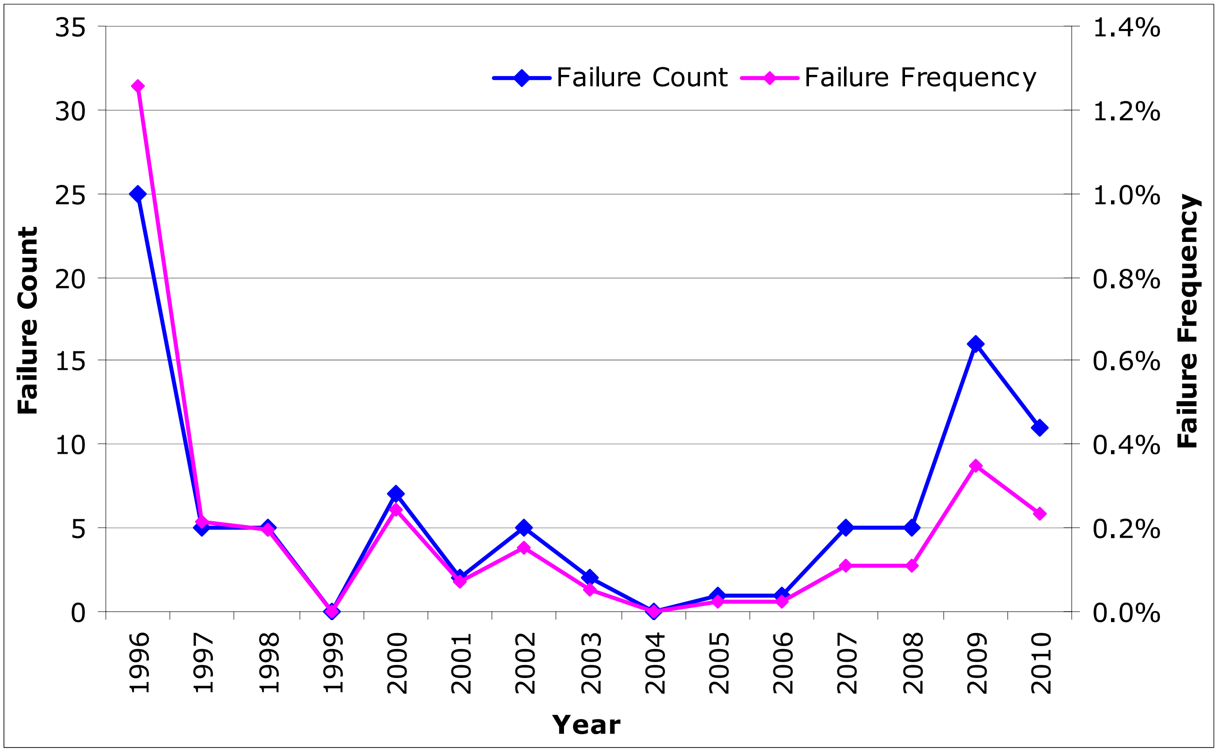

Figure 2: Commercial Surface Failures and Failure Frequency

Near surface failure detection method is displayed in Figure 3

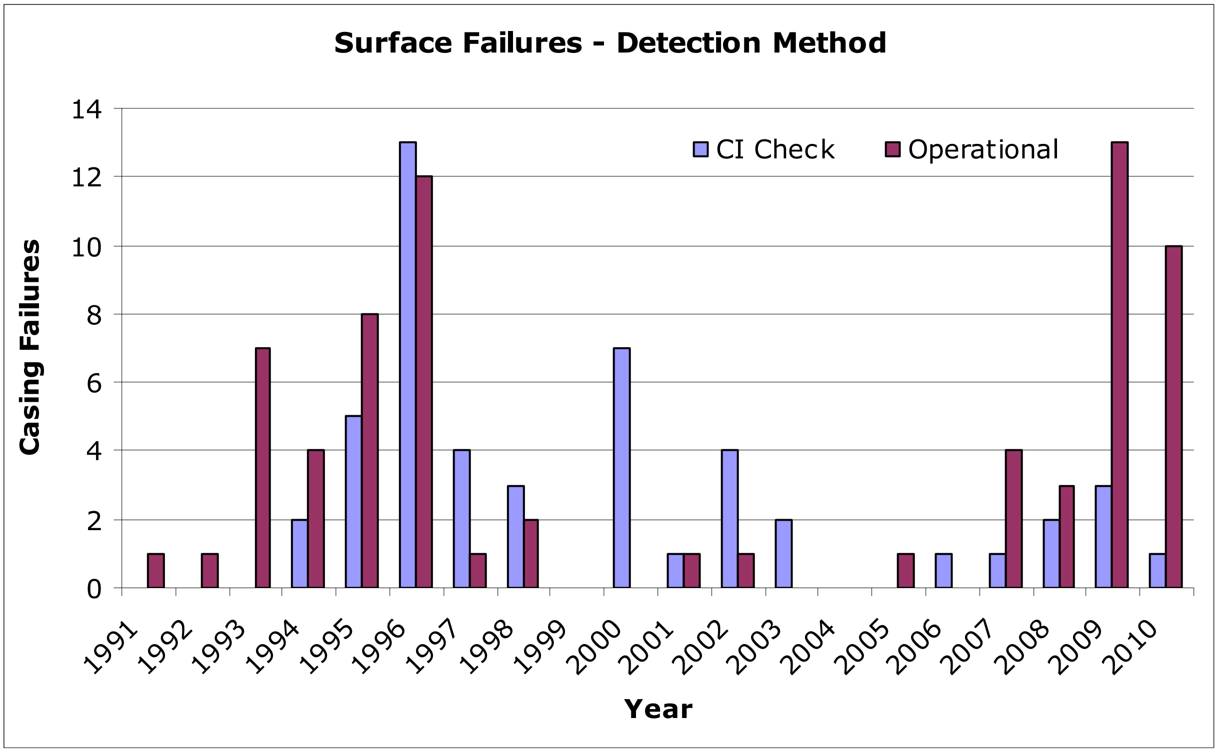

Figure 3: Commercial Surface Failures by Detection Method

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 earlier casing design in cyclic steam stimulation (CSS) operation in 2010.

Since the implementation of the Casing Integrity Operating Practices in 1996, a total of 343 primary intermediate casing failures have been detected in wells with the L-80 or IK-55 casing designs. Approximately 64% of these failures were identified during pre-steam casing integrity checks. In addition, 499 wells were taken out of steam service or repaired due to intermediate impairments or excessive deformation. There have been two intermediate failures which have required aquifer remediation (H15-10 in 1999 and H39-H04 in 2006). There have been two multi-well failure events since 1996:

- T09-01 primary intermediate casing failure in 2006 with one secondary failure on T09-07 in 2006.
- H33-06 primary intermediate casing failure in 2007 with secondary failures on H33-08 and H33-10 in 2007, as well as H33-01, H33-12, and H33-15 in 2008.

Details on the 34 primary intermediate failures, which occurred in 2010, are provided in Table 4.

Table 4: 2010 Intermediate Depth Failures Summary

No.	WELL INFORMATION			FALURE INFORMATION										
	Well	License	Unique Well Identifier	Detection Date	Detection Method		Depth		Depth Class	Pipe Body / Connection	Connection Type	Primary / Secondary / Slimhole	Cycle	Environmental Consequence Level
				mm/dd/yy			mKB	mTVD						
1	D62-09	157796	100/11-36-064-04W4	01/14/10	Operational	PS - LP	280.1	277.6	Westgate Fm	C	OBTC	P	9	0
2	V04-17	291598	106/02-34-064-03W4	01/24/10	CI Check	CI Check	254.9	254.9	Fish Scale Fm	C	NSCC	P	6	0
3	R03-13	131567	105/13-14-065-04W4	02/06/10	CI Check	CI Check	294.0	292.0	Joli Fou Fm	Pipe	OBTC	P	9	0
4	D54-02	127200	102/13-35-064-04W4	02/07/10	CI Check	CI Check	324.4	297.5	Joli Fou Fm	C	OBTC	P	11	0
5	D54-04	127202	105/14-35-064-04W4	02/27/10	CI Check	CI Check	316.0	296.0	Joli Fou Fm	C	OBTC	P	11	0
6	Y16-19	256883	106/13-31-064-03W4	03/03/10	Operational	PS - LP	335.6	331.4	Joli Fou Fm	C	VAM	P	7	0
7	G01-15	221373	109/09-08-065-03W4	03/05/10	Operational	PS - HP	315.2	305.5	Joli Fou Fm	C	OBTC	P	9	0
8	L08-23	276378	105/06-29-065-04W4	03/18/10	Operational	N2 Soak	296.5	287.9	Joli Fou Fm	C	QB2	P	8	0
9	D55-13	127639	104/06-35-064-04W4	03/26/10	CI Check	CI Check	262.0	261.0	Westgate Fm	C	OBTC	P	11	0
10	D26-07	114962	103/01-02-065-04W4	04/24/10	CI Check	Regulatory PT	282.3	280.5	Fish Scale Fm	Pipe	OBTC	P	9	0
11	E10-03	189356	111/14-25-064-04W4	04/21/10	CI Check	Regulatory PT	126.3	125.7	Upper Colorado Shale	C	OBTC	P	7	0
12	H05-09	110184	106/15-22-065-04W4	04/24/10	CI Check	CI Check	259.1	258.3	Westgate Fm	C	OBTC	P	7	0
13	H04-01	111140	102/04-27-065-04W4	05/01/10	CI Check	Regulatory PT	304.2	278.3	Westgate Fm	C	OBTC	P	10	0
14	D33-14	225549	110/14-02-065-04W4	05/03/10	Operational	PS - LP	297.4	284.2	Fish Scale Fm	C	NSCC	P	8	0
15	D65-15	188552	107/03-36-064-04W4	05/11/10	CI Check	CI Check	281.6	268.8	Westgate Fm	C	OBTC	P	8	0
16	U02-22	273354	103/02-03-065-03W4	06/10/10	Operational	N2 Fluid Level	363.5	352.7	Joli Fou Fm	C	NSCC	P	6	0
17	F07-30	221727	106/01-17-065-03W4	06/28/10	Operational	PS - HP	294.4	285.9	Westgate Fm	C	OBTC	P	7	0
18	H58-09	323674	102/16-09-066-04W4	07/17/10	Operational	PS - HP	216.5	216.5	Fish Scale Fm	C	NSCC	P	4	0
19	F07-14	221709	104/15-08-065-03W4	08/13/10	Operational	PS - LP	281.8	270.8	Westgate Fm	C	OBTC	P	7	0
20	J13-20	125663	100/15-10-065-04W4	08/18/10	CI Check	CI Check	291.5	272.1	Westgate Fm	C	OBTC	P	10	0
21	F07-20	221715	104/08-17-065-03W4	08/26/10	Operational	PS - LP	325.3	307.7	Joli Fou Fm	C	OBTC	P	7	0
22	Y16-07	256868	107/04-06-065-03W4	08/25/10	CI Check	CI Check	258.1	257.1	Fish Scale Fm	Pipe	NSCC	P	7	0
23	H42-13	285599	105/04-34-065-04W4	09/10/10	CI Check	CI Check	223.0	223.0	Fish Scale Fm	C	NSCC	P	6	0
24	H47-20	302905	102/04-10-066-04W4	09/14/10	Operational	PS - HP	202.0	200.0	Fish Scale Fm		NSCC	P	6	0
25	H47-12	302912	105/03-10-066-04W4	09/18/10	Operational	PS - HP	210.0	210.0	Fish Scale Fm		NSCC	P	6	0
26	E01-02	291793	100/06-12-065-04W4	09/19/10	CI Check	Op work	294.8	294.2	Joli Fou Fm	C	NSCC	P	7	0
27	E08-05	189038	102/08-36-064-04W4	10/20/10	Operational	PS - LP	218.2	213.0	Belle Fourche Fm	C	OBTC	P	8	0
28	J05-04	112749	102/09-22-065-04W4	10/21/10	CI Check	Regulatory PT	236.0	234.0	Westgate Fm	C	OBTC	P	12	0
29	D25-03	115011	105/12-01-065-04W4	11/17/10	CI Check	CI Check	221.0	216.1	Fish Scale Fm	C	OBTC	P	13	0
30	D51-08	127836	104/16-35-064-04W4	11/27/10	Operational	PS - LP	222.0	221.5	Fish Scale Fm	C	OBTC	P	9	0
31	T07-20	248856	102/01-33-064-03W4	12/12/10	CI Check	CI Check	601.0	469.7	Lloydminster Member	Pipe	NSCC	P	7	0
32	D51-06	127834	102/16-35-064-04W4	12/15/10	CI Check	CI Check	225.8	219.2	Fish Scale Fm	C	OBTC	P	9	0
33	U01-15	253509	103/01-04-065-03W4	12/16/10	CI Check	CI Check	270.9	269.5	Fish Scale Fm	C	NSCC	P	7	0
34	E03-03	199234	102/15-01-065-04W4	12/20/10	CI Check	CI Check	311.5	300.3	Joli Fou Fm	C	OBTC	P	8	0

Note: (mKB/mTVD) indicates diagnostics with rig are not complete. Depths are estimated from fluid levels during initial response.

A summary of the connection type for primary intermediate connection failures detected in 2010 is provided in Table 5. Note that both NSCC & QB2 thread designs have a metal-to-metal seal. It is difficult to draw any conclusions from the data presented due to the varying installation phases with the different connection types, and limited sample size with the QB2 design.

Table 5: 2010 Primary Intermediate Connection Failures by Connection Design

Connection Type	**Cycle Number**													
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**Total**
OBTC	0	0	0	0	0	0	5	3	4	2	3	1	1	19
NSCC	0	0	0	1	0	3	2	1	0	0	0	0	0	7
QB2	0	0	0	0	0	0	0	1	0	0	0	0	0	1
Other	0	0	0	0	0	0	1	0	0	0	0	0	0	1
Total	0	0	0	1	0	3	8	5	4	2	3	1	1	28

Note: excludes R03-13, D26-07, Y16-07, T07-20 (pipe body failures) and H42-13, H47-20 (investigation not complete)

Historic consequence levels associated with intermediate casing failures since 1996 are displayed in Figure 4. None of the 34 intermediate failures that occurred in 2010 were assessed higher than a level 0 environmental consequence.

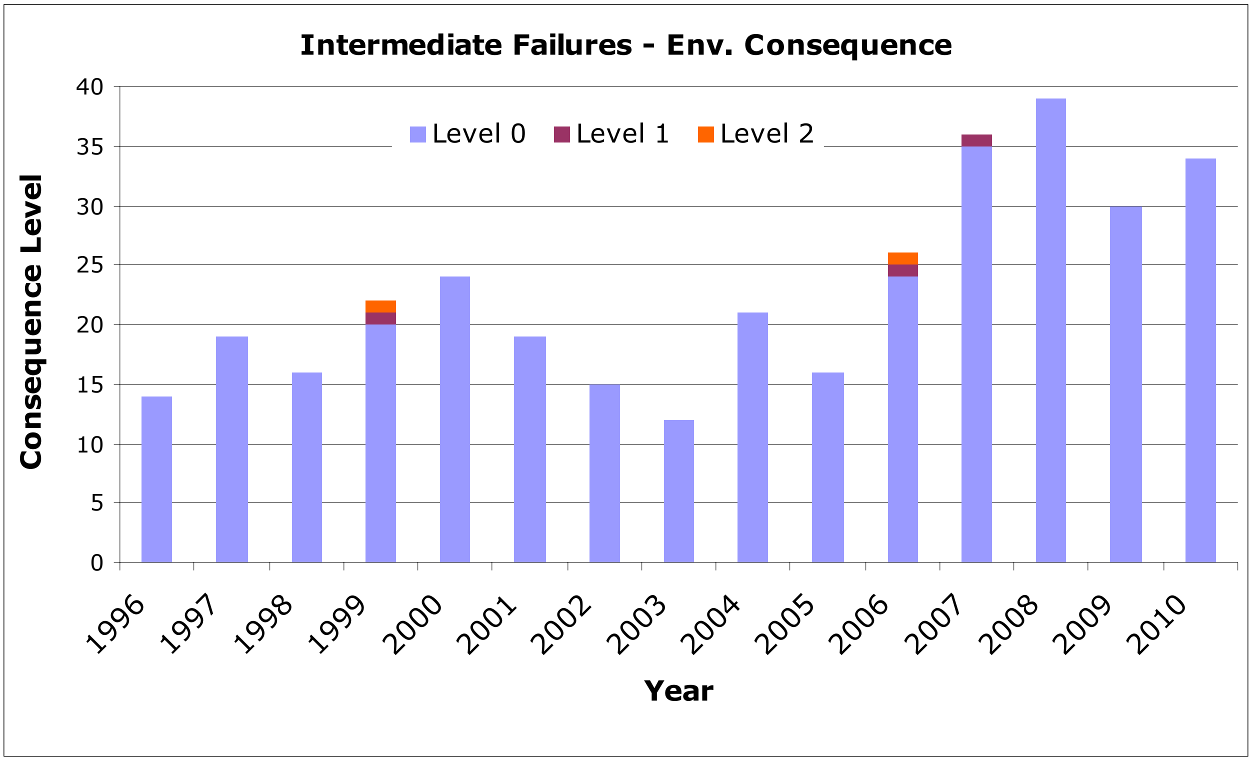

Figure 4: Cold Lake Intermediate Failures by Consequence Level

Many enhancements in Imperial's casing integrity processes, as discussed in section 3.3, have lead to a reduction in the percentage of high pressure casing failures as shown in Figure 16. These enhancements, in addition to the improvements in other detection systems has demonstrated success in reducing higher pressure failures that have more potential for loss of liquids through the casing break and resulting consequences. In 2010, there were 4 new failures identified during pressure tests on suspended wells that had no potential for loss of liquids.

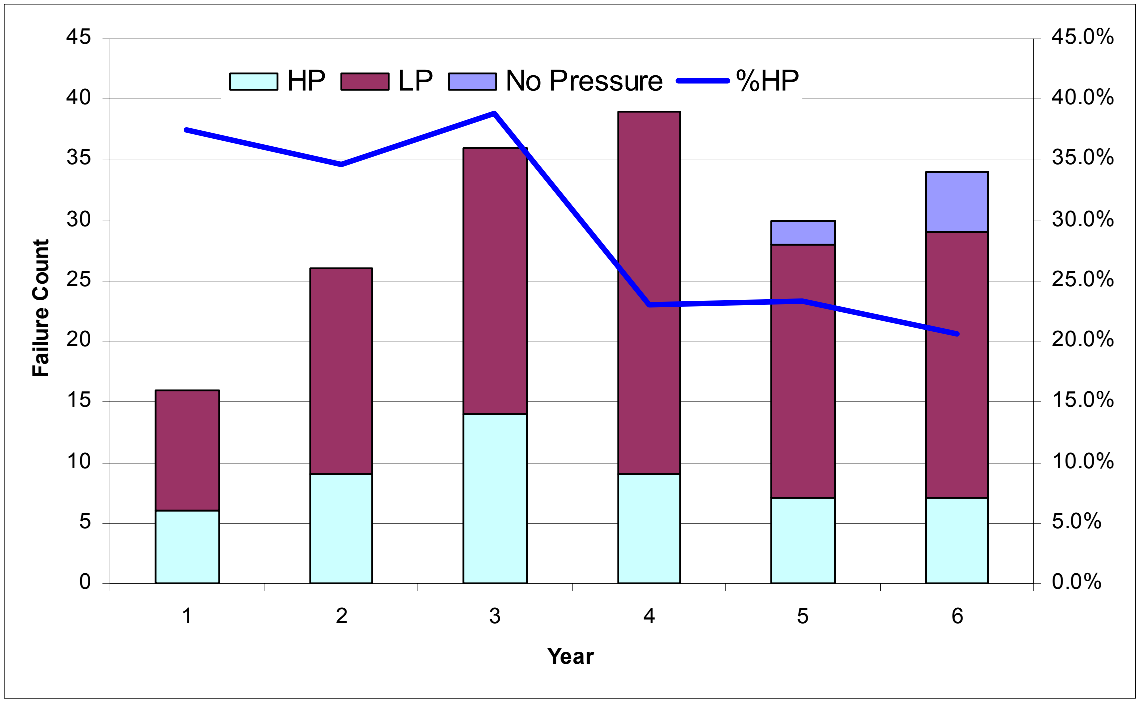

Figure 5: Intermediate Casing Failures by Pressure Category

The primary response to a high pressure intermediate casing failure is to control the fluid level below the casing break depth with nitrogen to avoid liquid losses out through the break, followed by immediate depressuring of the area. Imperial also maintains all necessary kill fluid additives in order to perform a high pressure fluid or mud well kill if the primary response is not possible.

In 2010, both the number of wells that experienced liquid loss to the break (blue line) and the volume of liquids lost out of the break (blue bar) was reduced as shown in Figure 6. Only one barite mud kill was required in 2010 (H47-12).

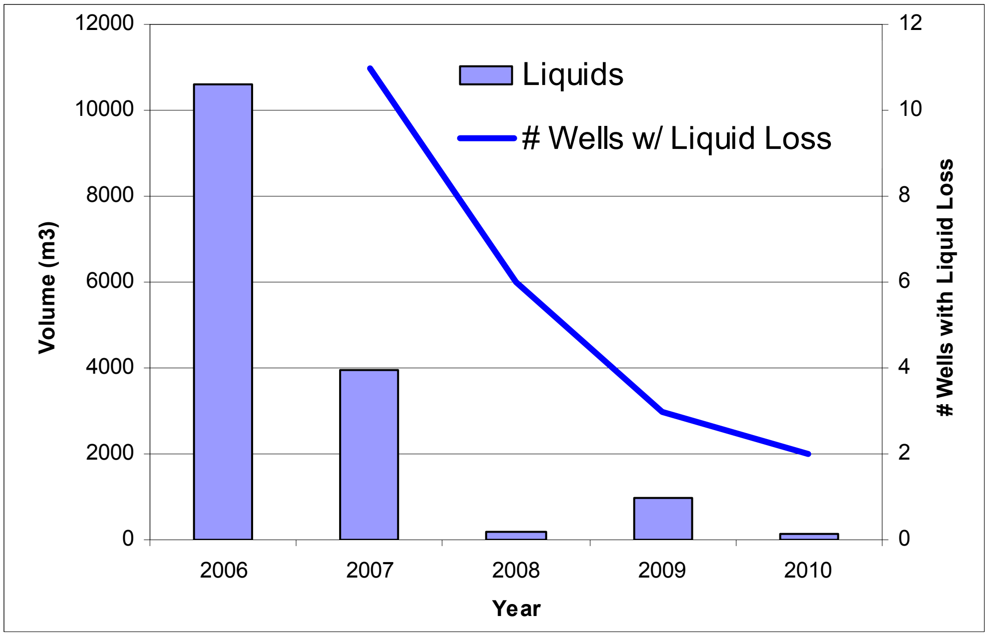

Figure 6: Intermediate Failure Fluid Loss by Year

The number and frequency of primary intermediate casing failures for the commercial casing design in Cold Lake are summarized in Figure 7 and Figure 8. The number and frequency of failures increased slightly above 2009 levels, however remained below 2007 and 2008.

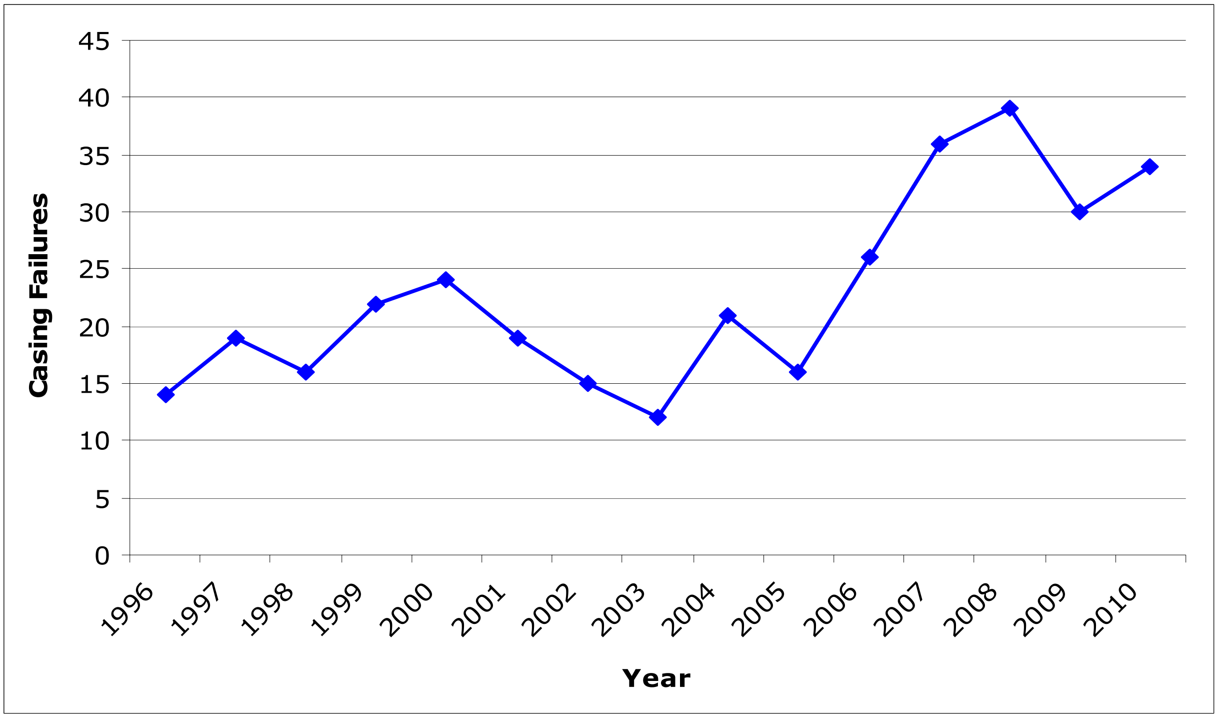

Figure 7: Primary Intermediate Commercial Failure Count

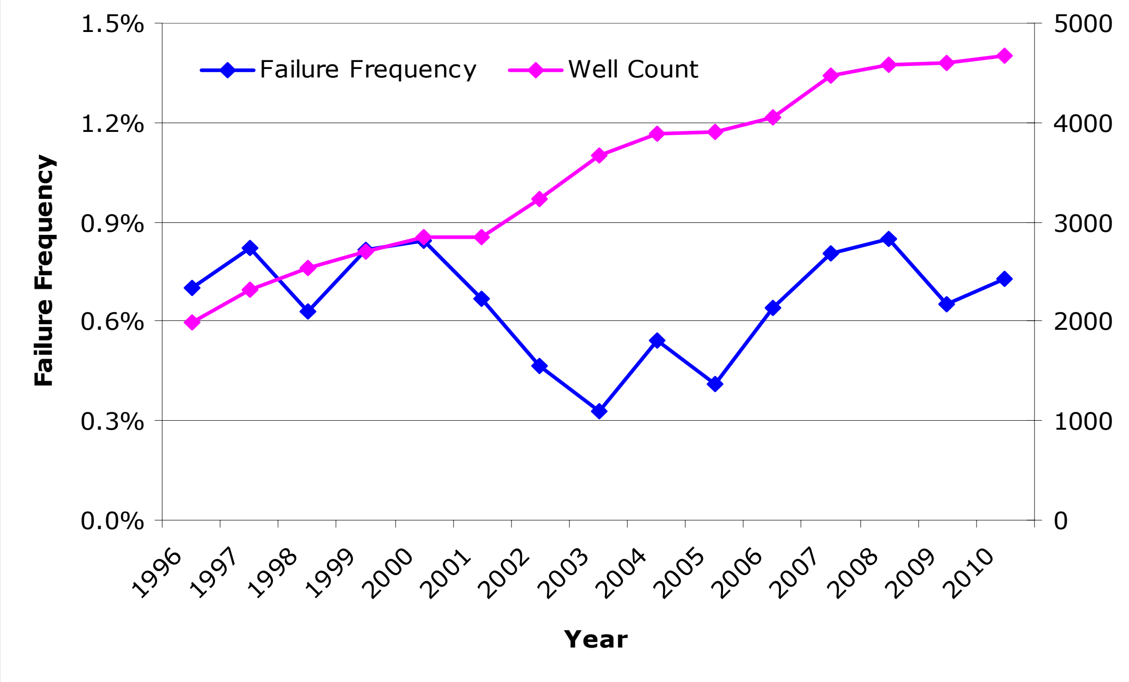

Figure 8. Primary Intermediate Commercial Failure Frequency and Well Count

In Figure 9, the primary intermediate casing failures for the commercial casing design in Cold Lake data is stacked into early (1-4), mid (5-7), and late (8-12) cycle classifications. The number of early cycle failures has historically been lower than mid and late cycle failures and continues to be so. Mid cycle failures have generally been increasing since 1996; however, a significant decrease was observed in 2009 and 2010. Four failures in 2010 were second failures in wells that were pressure tested as part of the 5 year integrity check of suspended wells.

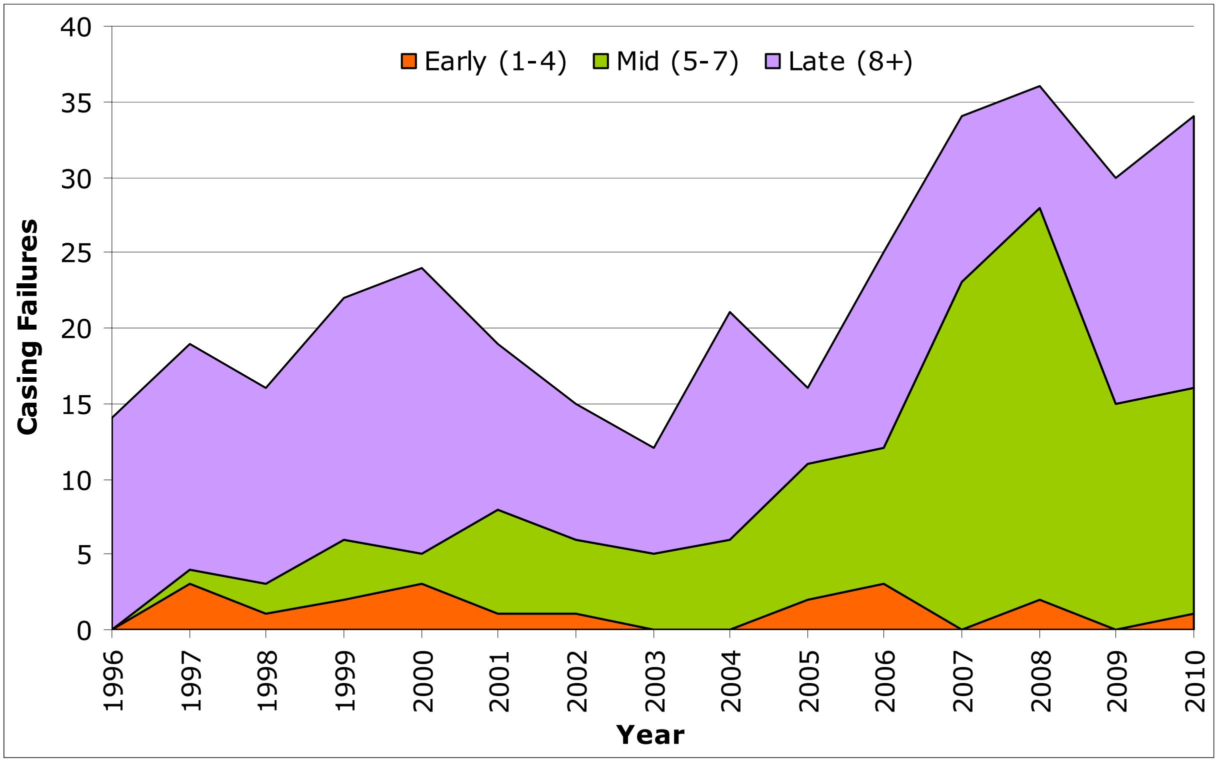

Figure 9: Primary Intermediate Commercial Failures by Cycle Range

In Figure 10, the primary intermediate failure frequency for the commercial casing design the data is, again, divided into early (1-4), mid (5-7), and late (8-12) cycle classifications. Early cycle failure frequency peaked in 2006 and has continued to decrease since. Mid cycle failure frequency steadily increased between 2004 and 2008; however, 2009 saw a marked reduction which is believed to be the result of many casing integrity initiatives underway since 2006. Mid cycle failures are in a similar range to 2007 - 2008 levels.

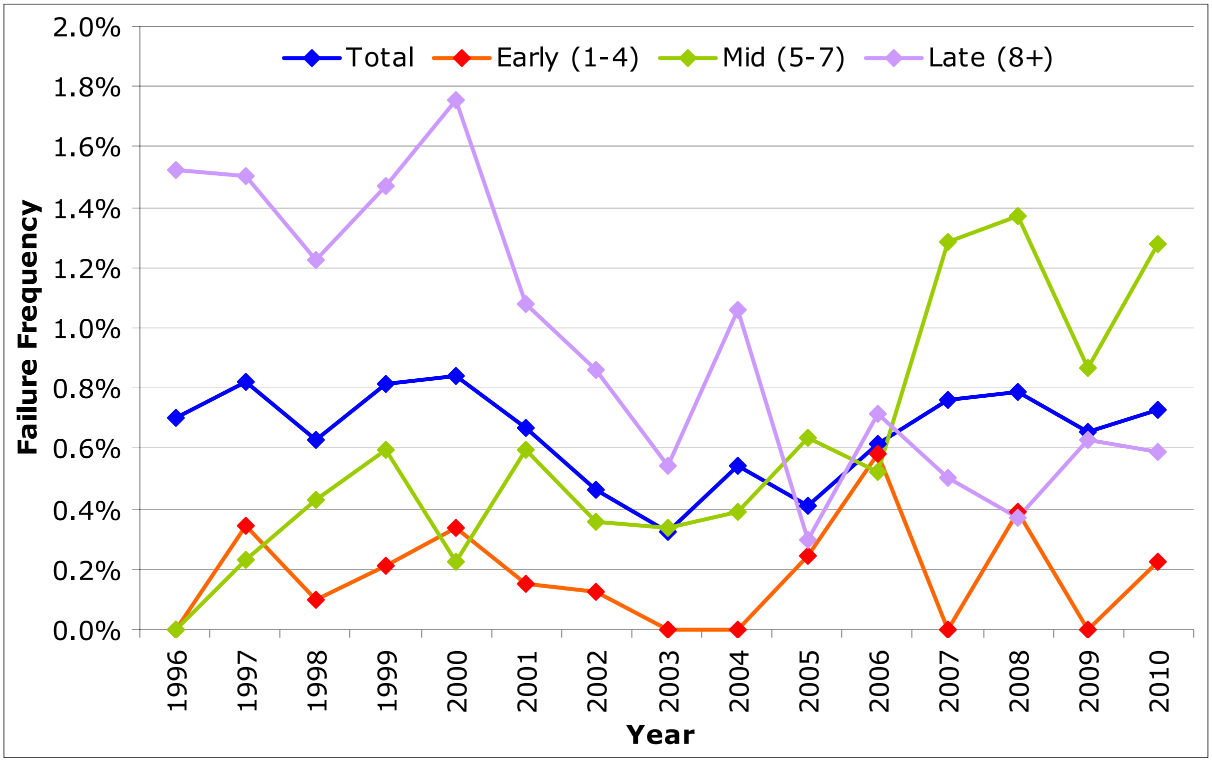

Figure 10: Primary Intermediate Commercial Failure Frequency by Cycle Range

Primary intermediate failure detection method is displayed in Figure 11. The pre-steam casing integrity process has detected a significant portion (approximately 65%) of the casing failures at Cold Lake since its inception in 1996. The percentage of operationally detected casing failures has generally increased since 2002, primarily due to the increased detection capabilities and enhancements with passive seismic and the nitrogen soak monitoring program. The number of casing integrity checks performed since 2001 is displayed in Figure 14, which is provided later in this report.

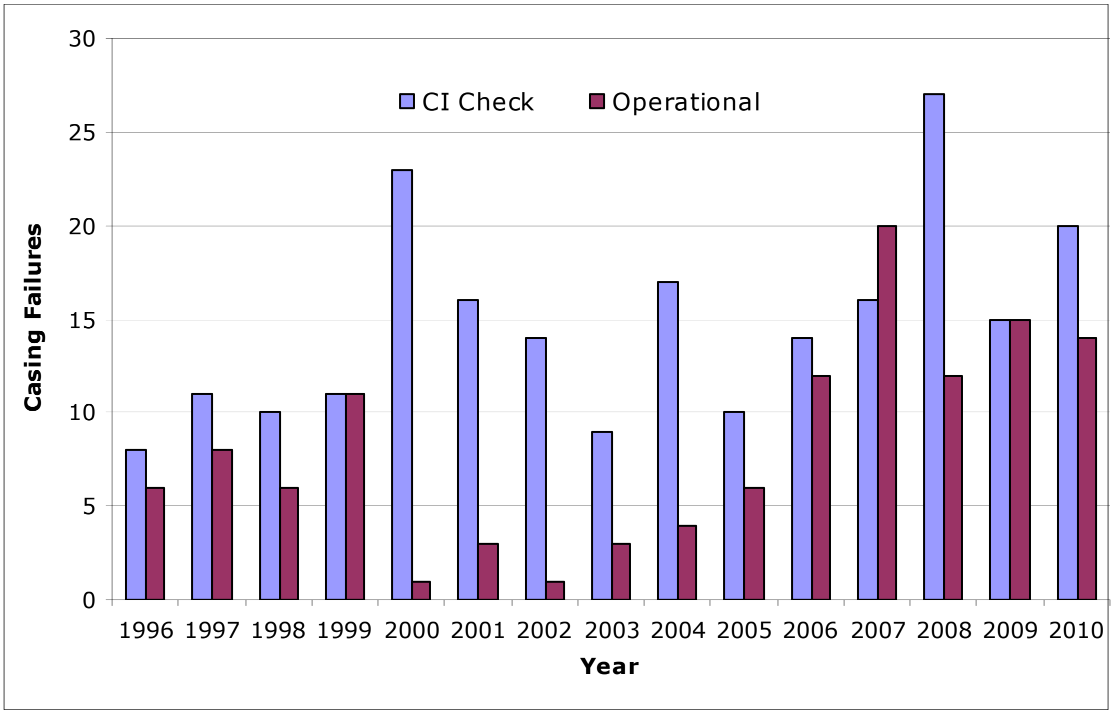

Figure 11: Primary Commercial Intermediate Failures by Detection Method

The 34 intermediate casing failures in 2010 were managed the following way:

- 11 wells were repaired using casing patch technology
- 9 wells were zonal abandonments
- 8 wells were suspended
- 4 wells were the 2nd failure of a zonally abandoned well, no action was taken, Not considered secondary failures or related to initial failure
- 1 well was repaired by slimhole
- 1 well waiting for reservoir pressure to decrease before taking action, nitrogen blanket on annulus keeping fluid level below break

A breakdown of the management of each intermediate casing failure is found in Table 6. There are a number of wells that have been suspended with future plans to repair.

Table 6: 2010 Primary Intermediate Repair Techniques

No.	WELL INFORMATION			FALURE INFORMATION					Failure Managament
	Well	License	Unique Well Identifier	Detection Date	Depth		Depth Class	Cycle	Repair Technique
				mm/dd/yy	mKB	mTVD			
1	D62-09	157796	100/11-36-064-04W4	01/14/10	280.1	277.6	Westgate Fm	9	Repaired - Casing Patch
2	V04-17	291598	106/02-34-064-03W4	01/24/10	254.9	254.9	Fish Scale Fm	6	Suspended
3	R03-13	131567	105/13-14-065-04W4	02/06/10	294.0	292.0	Joli Fou Fm	9	Repaired - Casing Patch
4	D54-02	127200	102/13-35-064-04W4	02/07/10	324.4	297.5	Joli Fou Fm	11	Suspended
5	D54-04	127202	105/14-35-064-04W4	02/27/10	316.0	296.0	Joli Fou Fm	11	Repaired - Casing Patch
6	Y16-19	256883	106/13-31-064-03W4	03/03/10	335.6	331.4	Joli Fou Fm	7	Repaired - Casing Patch
7	G01-15	221373	109/09-08-065-03W4	03/05/10	315.2	305.5	Joli Fou Fm	9	Repaired - Casing Patch
8	L08-23	276378	105/06-29-065-04W4	03/18/10	296.5	287.9	Joli Fou Fm	8	Repaired - Casing Patch
9	D55-13	127639	104/06-35-064-04W4	03/26/10	262.0	261.0	Westgate Fm	11	Zonal abandonment
10	D26-07	114962	103/01-02-065-04W4	04/24/10	282.3	280.5	Fish Scale Fm	9	Well already zonally abandoned
11	E10-03	189356	111/14-25-064-04W4	04/21/10	126.3	125.7	Upper Colorado Shale	7	Well already zonally abandoned
12	H05-09	110184	106/15-22-065-04W4	04/24/10	259.1	258.3	Westgate Fm	7	Zonal abandonment
13	H04-01	111140	102/04-27-065-04W4	05/01/10	304.2	278.3	Westgate Fm	10	Well already zonally abandoned
14	D33-14	225549	110/14-02-065-04W4	05/03/10	297.4	284.2	Fish Scale Fm	8	Suspended
15	D65-15	188552	107/03-36-064-04W4	05/11/10	281.6	268.8	Westgate Fm	8	Repaired - Casing Patch
16	U02-22	273354	103/02-03-065-03W4	06/10/10	363.5	352.7	Joli Fou Fm	6	Zonal abandonment
17	F07-30	221727	106/01-17-065-03W4	06/28/10	294.4	285.9	Westgate Fm	7	Zonal abandonment
18	H58-09	323674	102/16-09-066-04W4	07/17/10	216.5	216.5	Fish Scale Fm	4	Zonal abandonment
19	F07-14	221709	104/15-08-065-03W4	08/13/10	281.8	270.8	Westgate Fm	7	Suspended
20	J13-20	125663	100/15-10-065-04W4	08/18/10	291.5	272.1	Westgate Fm	10	Repaired - Casing Patch
21	F07-20	221715	104/08-17-065-03W4	08/26/10	325.3	307.7	Joli Fou Fm	7	Repaired - Casing Patch
22	Y16-07	256868	107/04-06-065-03W4	08/25/10	258.1	257.1	Fish Scale Fm	7	Repaired - Casing Patch
23	H42-13	285599	105/04-34-065-04W4	09/10/10	223.0	223.0	Fish Scale Fm	6	Suspended
24	H47-20	302905	102/04-10-066-04W4	09/14/10	202.0	200.0	Fish Scale Fm	6	Slimhole - In progres as of Feb 7 2011
25	H47-12	302912	105/03-10-066-04W4	09/18/10	210.0	210.0	Fish Scale Fm	6	HP mud kill. Waiting for pressure to decrease
26	E01-02	291793	100/06-12-065-04W4	09/19/10	294.8	294.2	Joli Fou Fm	7	Suspended
27	E08-05	189038	102/08-36-064-04W4	10/20/10	218.2	213.0	Belle Fourche Fm	8	Suspended
28	J05-04	112749	102/09-22-065-04W4	10/21/10	236.0	234.0	Westgate Fm	12	Well already zonally abandoned
29	D25-03	115011	105/12-01-065-04W4	11/17/10	221.0	216.1	Fish Scale Fm	13	Repaired - Casing Patch
30	D51-08	127836	104/16-35-064-04W4	11/27/10	222.0	221.5	Fish Scale Fm	9	Zonal abandonment
31	T07-20	248856	102/01-33-064-03W4	12/12/10	601.0	469.7	Lloydminster Member	7	Zonal abandonment
32	D51-06	127834	102/16-35-064-04W4	12/15/10	225.8	219.2	Fish Scale Fm	9	Zonal abandonment
33	U01-15	253509	103/01-04-065-03W4	12/16/10	270.9	269.5	Fish Scale Fm	7	Suspended
34	E03-03	199234	102/15-01-065-04W4	12/20/10	311.5	300.3	Joli Fou Fm	8	Zonal abandonment

Despite the few slimhole repairs completed on 2010 intermediate casing failures, it remains a common repair technology for Imperial Oil. There are currently 210 slimhole wells within Cold Lake, representing just over 4% of the total well count. To date, 12 slimhole wells have failed (5.7% of all slimhole wells), 4 of which were near surface failures and repaired using the surface dig out technique. The 8 remaining slimhole failures were either suspended or abandoned after failure as there is currently no repair technology available for 4.5" intermediate failures.

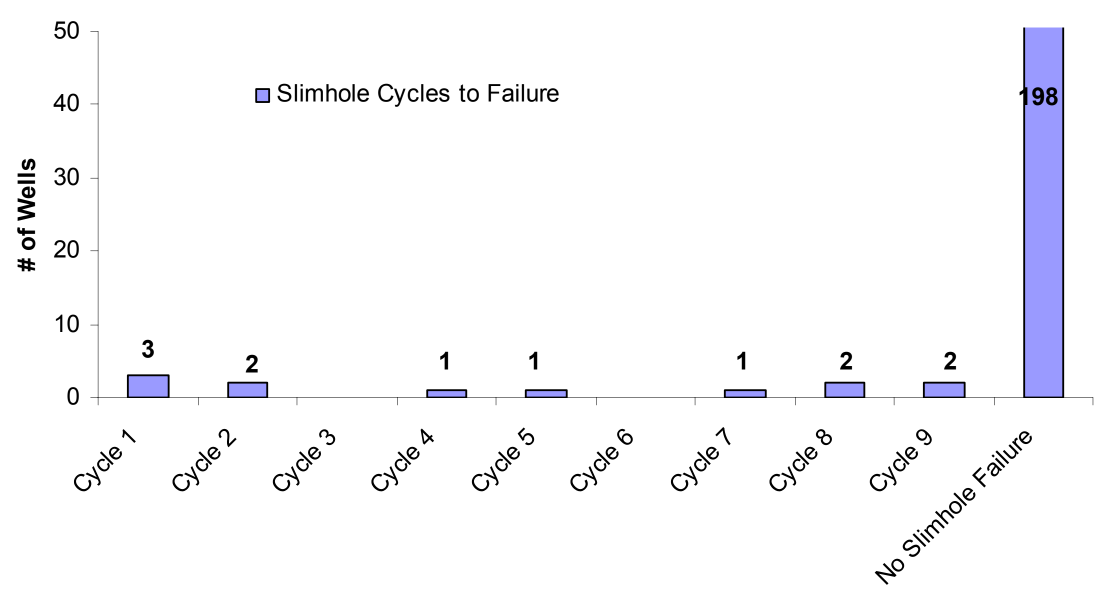

Figure 12: Slimhole Failures

2.3 Clearwater Casing Integrity Data

In 2010, 15 Clearwater casing failures were detected. Details of these failures are provided in Table 7.

Table 7: 2010 Clearwater Failures Summary

No.	WELL INFORMATION			FAILURE INFORMATION			
	Well	License	UWI	Detection	Cycle	Depth	
				mm/dd/yy		mKB	mTVD
1	D39-31	354044	108/05-12-065-04W4	01/27/10	4	487.0	419.0
2	V09-14	291597	107/04-35-064-03W4	03/26/10	5	513.0	441.4
3	E01-19	291810	110/02-12-065-04W4	04/06/10	6	493.0	419.6
4	T12-17	268225	102/03-29-064-03W4	04/29/10	6	558.0	466.2
5	H46-09	314344	106/13-03-066-04W4	05/13/10	4	427.7	408.5
6	U02-10	273342	104/04-03-065-03W4	05/24/10	6	434.0	429.8
7	L08-12	276366	104/07-29-065-04W4	05/28/10	6	450.0	423.6
8	D39-18	354025	109/11-12-065-04W4	06/13/10	4	569.6	421.1
9	H14-10	272986	107/03-27-065-04W4	06/17/10	8	460.3	420.4
10	D39-17	354021	113/11-12-065-04W4	07/13/10	4	491.9	421.0
11	T02-12	237106	1W0/05-33-064-03W4	08/10/10	8	628.0	477.0
12	J03-17	109725	104/03-22-065-04W4	09/27/10	8	480.2	424.4
13	T11-22	268195	103/12-28-064-03W4	09/29/10	6	539.5	476.0
14	T11-08	268183	105/16-29-064-03W4	09/30/10	7	609.7	478.5
15	H40-08	315033	104/09-28-065-04W4	10/01/10	6	880.6	460.3

The number and frequency of Clearwater casing failures for the commercial casing design in Cold Lake are summarized in Figure 10. The frequency of failures reduced in 2010. Work is ongoing to determine potential reasons for the decrease in Clearwater failures.

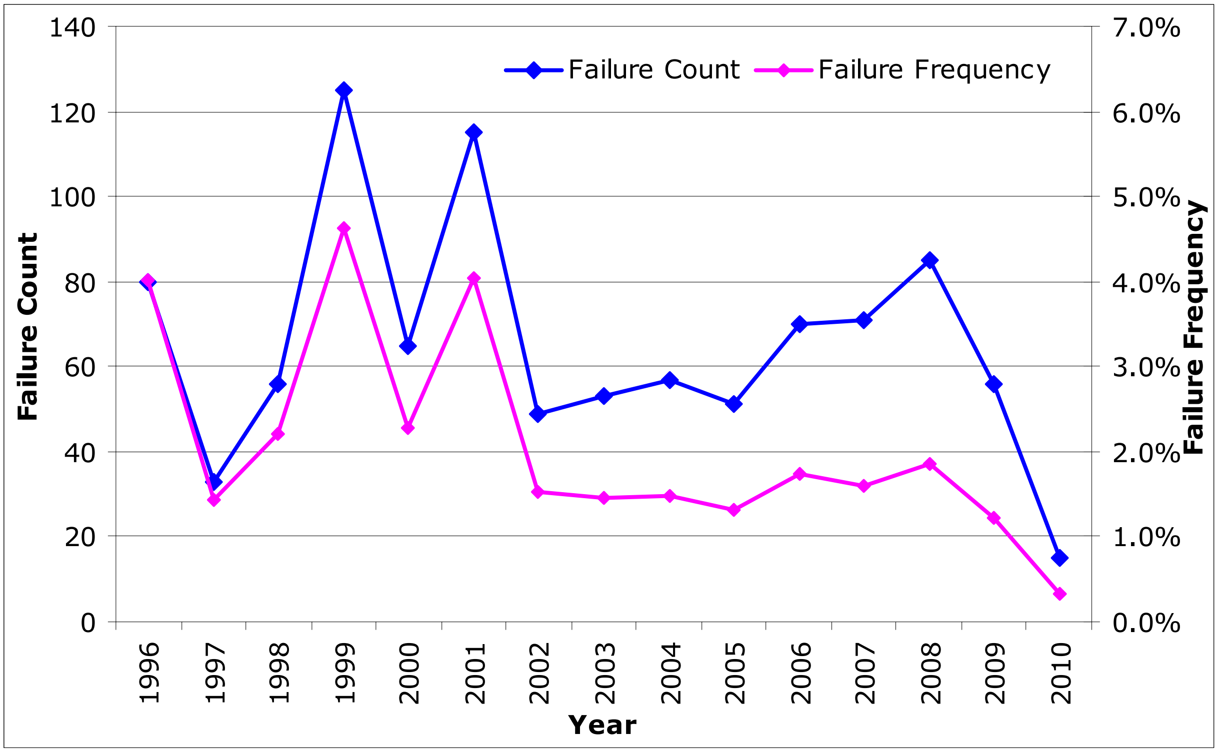

Figure 13: Commercial Clearwater Failures and Failure Frequency

3.0 COLD LAKE CASING INTEGRITY MANAGEMENT

Casing integrity is a critical component of the Operations Integrity Management System in Cold Lake. Continuous improvement with respect to casing integrity has been made throughout the history of Cold Lake Operations. Failure mechanisms that have been identified in Cold Lake wells are external corrosion (near surface failures), stress corrosion cracking (SCC), and sulphide stress cracking (SSC) with contributing factors such as metal fatigue (high strain – low cycle) and formation movement. The Cold Lake Casing Integrity Operating Practices were formally introduced in 1996 providing improvements in three major areas – prevention and detection of, 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. The Casing Integrity Operating Practices are reviewed and updated annually.

Improvements and initiatives in detection and prevention of (with respect to the three depth classifications), and response to casing failures relevant to 2010 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 during steam injection
- Nitrogen Soak pressure and fluid level monitoring during soak and shut-in
- Steam trend analysis
- Passive seismic monitoring
- Groundwater monitoring
- Casing integrity check process

Current initiatives and recent improvements in detection methods 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 passive seismic alarms and responded to immediately in order to confirm the potential casing failure.

A new method of filtering DFP events to reduce the number of false alarms and streamline casing failure detection was developed in 2009; a prototype test is currently in progress to verify its' validity. If the test proves successful, full implementation is planned for Q2 2011.

The nitrogen soak and fluid shot program is the primary monitoring system for casing failure detection for shut-in and soaking wells. After steam or during shut-in periods wells are purged with nitrogen to eliminate an environment susceptible to SSC, and to provide a liquid free annulus to enable casing pressure and fluid level monitoring. Real time wellhead pressures are monitored with the N2SOAK program for all wells across the district every half-an-hour. An adaptive alarm trigger was developed in 2009 further enhancing the failure detection capability of the N2SOAK system; the new trigger is now operational across the district. The N2SOAK program calculates the hourly average wellhead pressure (Pnew) and compares it with the hourly average from 3-hours ago (Pold). If the change in pressure (Pold – Pnew) is greater than the alarm trigger limit, an alarm is generated and the operator is alerted. The alarm trigger limit is automatically calculated by the program, between 25 kPa and 90 kPa, depending on the historical pressure profile of the well. Fluid levels are also taken 1 hour, 24 hours, 3 days, 7 days, and every 28 days thereafter the initial purge to monitor for casing failures on soaking wells. All alarms and/or rises in the fluid level are investigated and potential casing failure events are responded to immediately in order to confirm the potential casing failure

3.1.2 Passive Seismic Monitoring

Passive seismic alarm coordination was implemented in 2007, triggering immediate action on potential intermediate casing failures. If the well with a potential casing failure is at low pressure (< 4 MPa), the well is checked with a service rig within 60 days of the event. If the well is at high pressure, the well is immediately put on nitrogen soak to confirm integrity. Beginning in 2007 additional geophones have been added within the Glacial Till on all new Passive Seismic installations to enhance casing failure detection within the upper portion of the wellbore.

Imperial Oil has been utilizing the passive seismic system to aid in the detection of Clearwater top (CWT) failures. When a medium to high probability Clearwater top passive seismic event (within 30 mTVD of CWT) is detected, the well is operated below the fracture pressure until a casing integrity check is performed (required prior to the next steam cycle). No action is required for low probability Clearwater top passive seismic events.

3.1.3 Casing Integrity Check Process

Since the inception of the Casing Integrity Operating Practices in 1996, casing integrity checks have been conducted pro-actively to detect casing failures. A basic casing integrity check consists of both a 21 MPa pressure test and a gauge ring/scraper run to at least the top of the Clearwater formation. If the gauge ring/scraper combination identifies a new impairment or casing deformation, or there is a previously identified severe impairment requiring follow-up, a multi-sensor caliper is run to determine the extent of the deformation. Although a well may pass a 21 MPa pressure test, the information from the gauge ring/scraper combination can trigger additional diagnostics, which are used to confirm whether or not the wells integrity is adequate for steaming operations. Corrosion inspection logs in the top 50 meters of the wellbore are performed in later cycles on wells that were installed prior to 1996. Also, if a near surface failure is detected, all remaining wells on the pad require a corrosion assessment or inspection log in the current or next casing integrity check.

The number of 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. The casing integrity check frequencies were increased in 2007 for wells with metal-to-metal connections (called “upgraded” commercial casing) and for pads without passive seismic wells to enhance pre-steam confirmation of well integrity. 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.

A risk-based decision process is used to select wells that should be checked prior to being placed on steam. In 2007 phase 1 of our Targeted Selection process was implemented to select which wells should receive casing integrity checks, as well as to identify wells that should be checked incremental to the minimum standard. Targeted Selection phase 1 is aimed at reviewing data indicating a potential casing failure and includes a mandatory review and close-out of passive seismic casing events, suspect 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 steam injection. Targeted Selection phase 2 is currently being developed and is aimed at reviewing data that may be a contributing factor in casing failures including such things as drilling documents noting any problems (mud rings, overpressure, lost circulation, difficulty running casing to final depth), connection make-up plots, and nitrogen purge compliance.

The number of wells in Cold Lake and the frequency of casing integrity checks required have generally increased over time. Figure 14 shows the number of casing integrity checks performed each year since 2001 as well as the percentage of casing integrity checks that found near surface or intermediate depth failures. 2010 total number of casing integrity checks was lower than previous years due to a higher number of early cycle wells being steamed, a higher number of injector only infill wells being steamed, and a larger region of the field under steam flood.

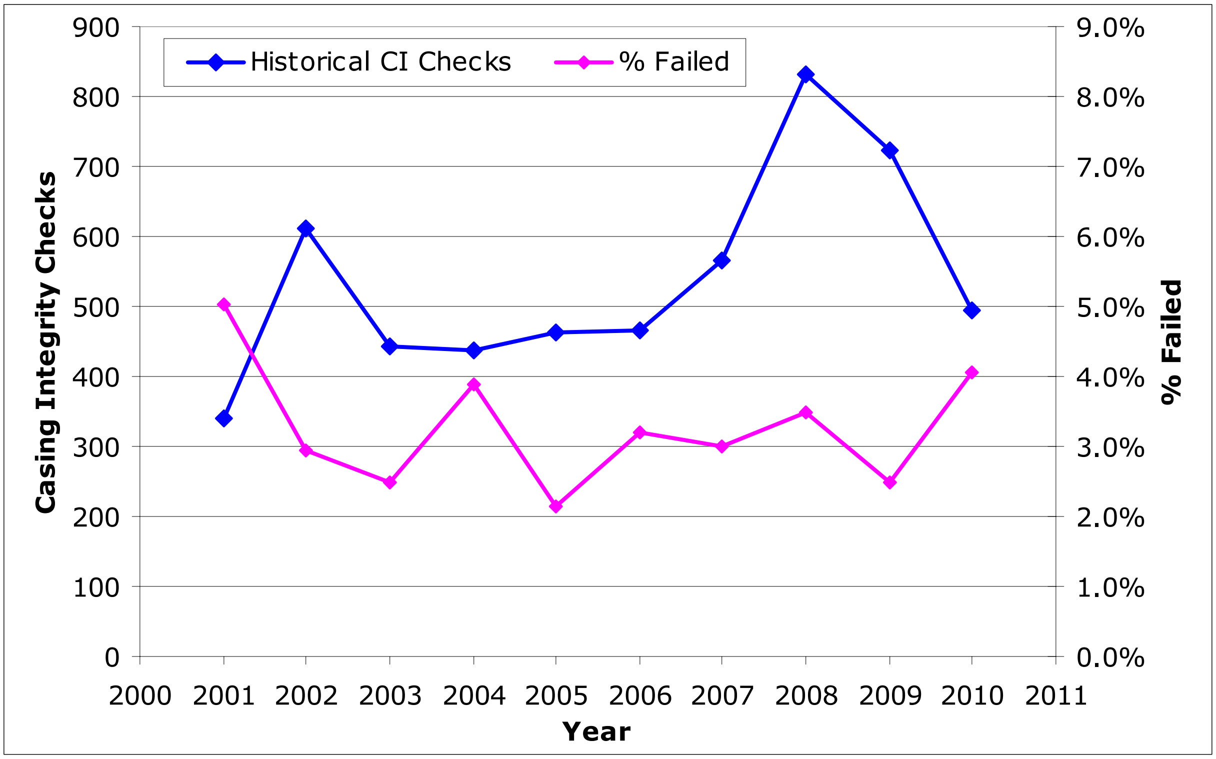

Figure 14: Casing Integrity Check History

3.2 Near Surface Casing Integrity Management

The primary mechanism for near surface casing failures is external corrosion. Minor wellhead packing leaks and surface water run-off collect in the conductor pipe - production casing annulus forming a corrosion cell. Water typically accumulates in the conductor annulus due to cement slumping (after primary cementing) or cement degradation over time.

Corrosion inspection logs (electromagnetic flux leakage) and casing pressure tests are completed as part of the Casing Integrity Operating Practices. Wells identified with corrosion concerns are either pressure tested to ensure suitability for service, repaired, or taken out of steam service. Improved primary cementing practices for new wells enhance the ability to achieve and maintain cement tops at surface. However, if the cement quality is not adequate in the production casing, the well will be repaired or taken out of steam service. Wells that have cement tops near surface are topped up with bentonite during the first steam cycle; the bentonite top-ups are maintained throughout the life of the wellbore. Wells that have cement tops below the conductor pipe setting depth are repaired by running wash pipe down over the production casing to the top of cement and cementing it in place.

Imperial Oil'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 a high pressure (capable of flow to surface) casing failure where there is the potential for environmental impact. Since the implementation of the Casing Integrity Operating Practices in 1996 there have been no surface depth casing failures of consequence, and Imperial Oil is confident that current practices will continue to confirm well integrity prior to steam.

The majority of failures in 2010 occurred on older, late cycle, low pressure wells. The consequence associated with a near surface casing failure is low as these wells are not capable of flow to surface. In order to reduce corrosion rates and thus the number of near surface failures, several initiatives have been implemented or are being progressed. Details on these initiatives are described in the following subsections.

3.2.1 2010 Bentonite Top-up Program

A field wide inspection conducted in early spring of 2009 revealed that bentonite top-up degradation is occurring at a higher than expected rate due to rainfall, well work and operational activities including thawing wellheads in winter months (top few inches of bentonite washed away with water). As a result, the existing top-up program was enhanced to complete bentonite top-ups on all applicable wells this year. Excluding approximately 1000 below grade wells where bentonite top-ups are not able to be completed, 3808 of 3808 wells have been assessed and received bentonite top-ups. The Casing Integrity Operating Practices were updated as a result of our learnings; for these pads go forward, top-ups will be completed annually and before each steam cycle. It is believed that effective maintenance of bentonite tops and shrouds will mitigate corrosion thus reducing the surface depth failure frequency over time.

Results and top-up compliance are now stewarded quarterly to ensure all requirements within the top-up program are met. This is expected to enhance compliance with our established practices over the long term.

There are approximately 1000 late cycle wells where bentonite top-ups are not able to be completed as conductor pipes are at or below grade level. All wells in this category are operated at low pressure thus the risk associated with a surface failure is low, and all wells in this category require casing integrity checks to confirm integrity prior to steam. Imperial Oil conducted tests of infrared camera technology and found it was an inconclusive measurement for detecting leaks. Another technology was tested which utilized filtered infrared methane detection. This tool detects methane concentrations down to ppm values. As a result of the assessment, the following forward strategy will be tested in 2011:

- Conduct helium purging to confirm integrity of suspect wells identified during the methane detector tests.

  The purpose of the helium test is to differentiate between methane present as a result of a casing leak from methane present as a result of gas migration or other sources.

Note that there are no below grade wells in the 'new' well category. Also, go forward all new drills are required to have a minimum of 6" (0.15 m) conductor or surface casing stick up at pad turnover to allow for bentonite top-up maintenance throughout the life of the pad.

3.2.2 Casing Shroud Installation

As a result of the increased surface failures and visual inspection confirming that top-up degradation is occurring at a higher than acceptable rate, a casing shroud was designed, tested, and installed on a number of wells. Casing shrouds prevent water accumulation in the conductor pipe thus increasing the longevity and effectiveness of bentonite top-ups. A prototype was designed and a successful 150 well trial was completed in the summer of 2009. In 2010 a assessment of the trial program was completed and as a result all wells with a conductor above grade level (3808) now have a casing shroud installed. The casing shrouds will be monitored annually in conjunction with the bentonite top-up program to ensure that they are effective in preventing excessive bentonite top-up degradation.

Bentonite top-ups continue to be evaluated as the most effective solution in mitigating near surface depth corrosion. They are completed after cycle 1 steaming, and then monitored and maintained on an annual and per cycle basis.

3.2.3 New Well Corrosion Assessments

Through detailed data analysis, Imperial Oil has determined that uphole casing failures are related to time only and there is no correlation between uphole corrosion and cycle number. Based on this analysis, the operating practices have been revised to trigger vertilog inspections of wells based on well age. Imperial Oil continues to apply a 3.5% corrosion rate when assessing wells.

3.2.4 Alternative Corrosion Measurement Technologies

Imperial Oil has used Baker Atlas' Digital Vertilog (DVRT) for conducting corrosion assessments since the mid 1990's. During numerous reviews it has been deemed the most effective technology at identifying external corrosion near surface, however, changes in metal thickness, interference from the top of the conductor pipe, and changes in logging speed near surface affect the complexity and accuracy of the interpretation. The Weatherford Corrosion Inspection Tool (CIT) was tested in 2009 and evaluated in 2010. The evaluation determined the CIT is not a feasible tool for this service. Imperial Oil continues to evaluate potential alternatives to the Baker Atlas Digital Vertilog.

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3.2.5 Alternative Casing Repair Technologies

Imperial Oil's current repair practice for wells with near surface failures is a surface dig out repair. This work involves suspending the well, excavating to below the failure depth, replacing the failed section of casing with new, and reactivating the well. Imperial Oil will continue to evaluate alternative casing repair technologies for near surface casing failures including a near surface casing patch for low pressure steaming operations. A pilot installation of this technology is being considered for 2011, pending ERCB approval.

3.2.6 New Well Installations

Imperial Oil is currently investigating high temperature external coatings to be applied to the top joint of production casing prior to cementing as an additional means of mitigating near surface corrosion for new wells. Laboratory testing of the coating and study of feasibility is underway in 2011.

3.3 Intermediate Depth Casing Integrity Management

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

- Improved nitrogen purge management
- Producing well annulus gas testing
- Enhanced shear stress management on pads of special interest
- Adjusted steam strategy
- Targeted selection criteria for casing integrity checks

Imperial has an ongoing research program to investigate root causes and develop changes to operating practices and well construction techniques to reduce the number of intermediate depth casing failures. These initiatives are discussed in the following subsections.

3.3.1 Casing Retrieval

Imperial conducted operations to retrieve sections of casing on four wells (T11-09, E02-04, T07-15, and D33-10) with intermediate depth casing failures. Sample size and quality varied between wells due to the complexity of this type of workover operations. All samples were sent for analysis to ExxonMobil's Upstream Research Company, who conducted metallurgical examination of the samples. Techniques used in the examination included microscopic analysis, X-Ray diffraction, scanning electron microscopy, and bulk chemical analysis.

The casing retrieval program was completed in 2010 and reported to the ERCB on October 14, 2010.

Based on the results from examination of samples, there is evidence of both embrittlement and ductile overload. The improvements made to nitrogen purging practices will reduce the likelihood of additional H_2S exposure on existing wells, which is the most likely cause of embrittlement. However, some failures associated with embrittlement may continue to occur if wells have undergone SSC prior to the improvements to purging practices. The results of the casing retrieval program also confirmed the validity of Imperial Oil's Root Cause Failure Analysis process and the results will provide information to the research groups studying a new fatigue resistant connection.

3.3.2 Material Testing

Imperial began evaluating higher strength casing material for use in Cold Lake as a means of reducing casing failures. A series of tests using T95 grade material were completed to determine the onset of SSC as a function of temperature and H_2S partial pressure. The tests were based on a modified version of the NACE TM0198 slow strain rate test (SSRT) to better simulate the thermal well casing environment. The tests were commensurate with an identical program performed on L80 casing earlier. The objective is to quantify performance of higher strength material in sour well environments. The modifications included:

- The specimen was pre-strained in air to simulate joint make-up (3% strain).
- The specimen was soaked in a test environment for 3 hours to charge with hydrogen.
- The specimen was cyclically loaded such that 1% plastic strain was added for each cycle up to a total of 6 cycles. The final strain of 9% was chosen to simulate the maximum strain expected in a connection based on previous finite element analysis studies.

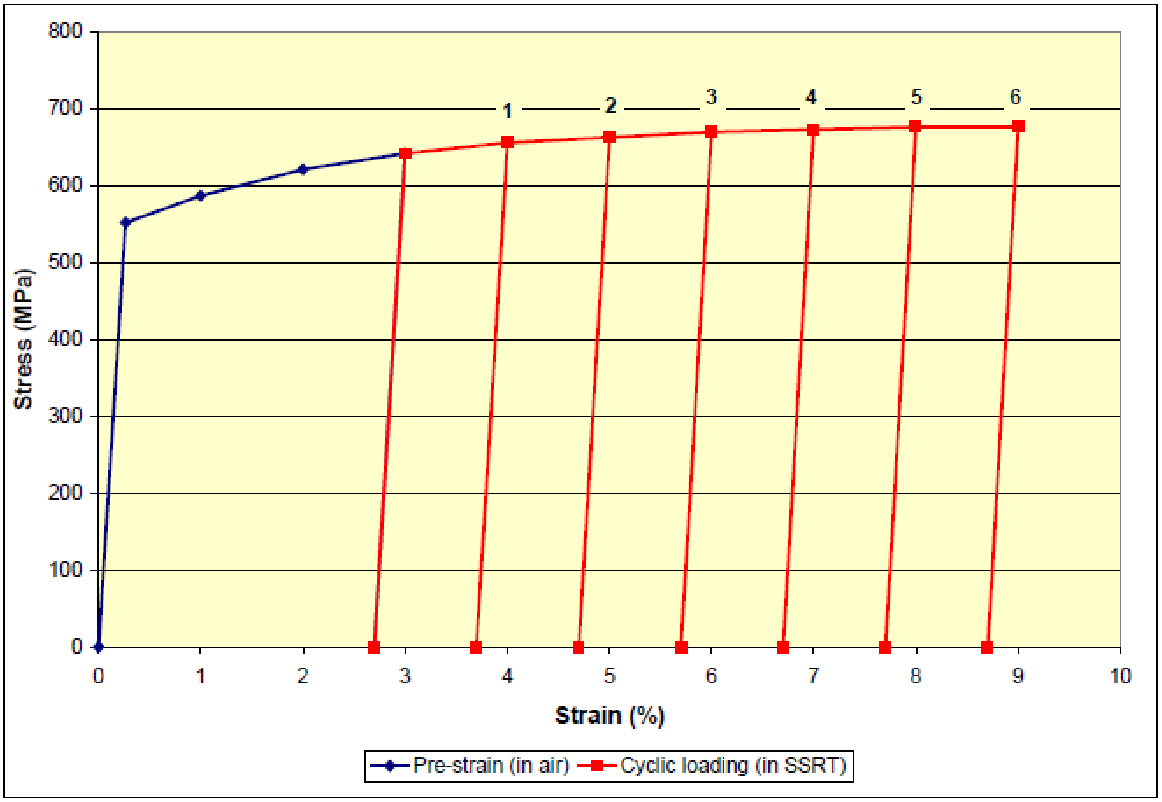

Figure 15: Strain Loading History for Slow Strain Rate Test

At the end of each test, the samples were removed and a metallurgical examination was conducted. The specimens were classified as follows:

- Failed (specimen parted) – the specimen parted prior to completion of the slow strain rate test.
- Failed (specimen micro-cracked) – the specimen remained intact, but evidence of micro-cracks were observed on the specimen.
- Scale micro-cracking – at higher temperatures, formation of an iron sulphide scale and subsequent cracking of that scale.
- Pass – no evidence of micro-cracking.

Results from the testing are summarized in Figure 16. The area below and to the right of the dashed line indicates the onset of SSC as opposed to scale micro-cracking. The scale micro-cracking is believed to be a laboratory phenomenon. Due to practical limitations of the laboratory equipment and the time required to conduct the testing, the rate of strain during the test is an order of magnitude higher than would be expected in the field. The higher rate of strain can lead to scale cracking and crack propagation due to anodic film dissolution. Higher temperature scale micro-crack propagation would not be expected to occur in the field at slower strain rates due to reformation of scale products.

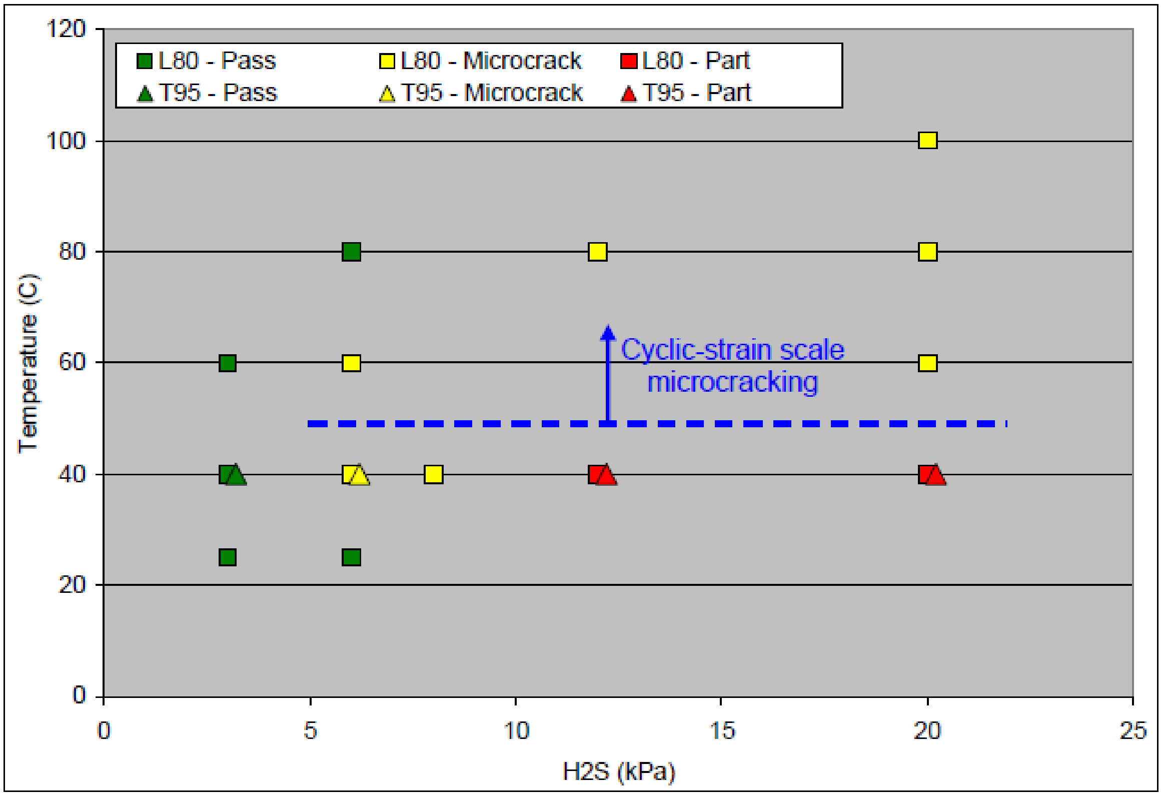

Figure 16: SSRT Results for T95 and L80

Based on the SSRT program for T95, the following conclusions were made:

1. No evidence of SSC was observed at H_2S partial pressures of 3 kPaa and 40°C.
2. SSRT results show that T95 is susceptible to SSC at H_2S partial pressures of 6 kPaa or greater at 40°C (identical conditions to L80).
3. At H_2S partial pressures of 12 kPaa or greater at 40°C, specimen parting (fracture) was observed.

Further to the SSRT program, comparative monotonic tests of L80 and T95 were completed in Standard NACE A solution at 25°C, in order to obtain a comparative SSC performance basis in standard loading conditions. The results are summarized in Table 8.

Table 8: Comparative SSC Resistance of L80 and T95 under Monotonic Conditions

Casing Material Property	**L80**	**T95**
Upper Yield Stress (MPa)	557	677
Ultimate Tensile Stress (MPa)	638	768
Nominal Strain at UTS (%)	6.2	7.8
Nominal Strain at Failure (%)	6.8	8.2

The results indicated that T95 has slightly higher SSC resistance compared to L80 under monotonic conditions.

While the T95 exhibited superior SSC resistance compared to L80 under standard loading conditions, its performance was similar to L80 in the cyclical loading environment. This result indicates that cyclic loading has a dominant effect of a material regardless of NACE A monotonic behavior. Further testing is planned in 2011 to compare the low cycle fatigue characteristics of T95 vs. L80 as well as some elevated temperature characteristics of T95.

3.3.3 Instrumented Well / Wellbore Environment Model

Previous material testing concluded that L80 grade casing can from micro-cracking at H_2S partial pressure above 3 kPaa and temperatures below 60°C. Most Cold Lake CSS wells produce at temperatures above 60°C, thus are not expected to be at risk of SSC. In late 2009 Imperial Oil implemented a program to identify wells producing at 70°C or lower and obtain gas samples from these wells. The purpose of the program is to identify, shut in and nitrogen purge producing wells at risk of SSC (T<60°C and H_2S partial pressure > 3 kPaa). Wells below 70°C which have a H_2S partial pressure between 1 kPaa and 3 kPaa are re-sampled monthly to monitor for any changes in the H_2S partial pressure. To date, 904 samples have been taken and 7 wells have been identified as having a temperature below 60°C and H_2S partial pressure > 3 kPaa. These 7 wells have been shut in and purged with nitrogen.

Analysis of the data from the T06-09 instrumented well assisted in the development of a numerical model to determine downhole H2S partial pressures based on surface sampling data. The validated numerical model computes that the downhole H2S concentration is 1.45 times higher than surface. This correction factor will be applied going forward to determine when to shut in wells expected to be at risk of SSC.

3.3.4 Geological Study of the Colorado Shales

Imperial has completed the geological review of the Colorado Group which began in 2008. The review examined detailed stratigraphy and depositional environment of the shales at a number of pads in an attempt to correlate casing failures and deformations to the geology of the Colorado Group. The presence of small-scale normal faults would appear to be a contributing factor to well deformations and failures. In addition, a detailed study of the Fish Scales formation has been completed. A large number of casing failures have been correlated to specific geological markers in the Fish Scales. The large majority of failures within the Fish Scales occur within 2m on either side of these markers. Figure 17 identities to two specific markers with a green and orange indicator. The conclusion of this study has lead to the implementation of a new drilling practice which connections are not placed within 2m of the Fish Scales markers. Geoscience commences an offset study prior to drilling and identifies the depth of the markers to avoid placing connections. Actual field results are then stewarded internally. In 2010, 72 wells, (82% of wells drilled in 2010), had casing collars spaced out to avoid a connection within 2m of the specified markers.

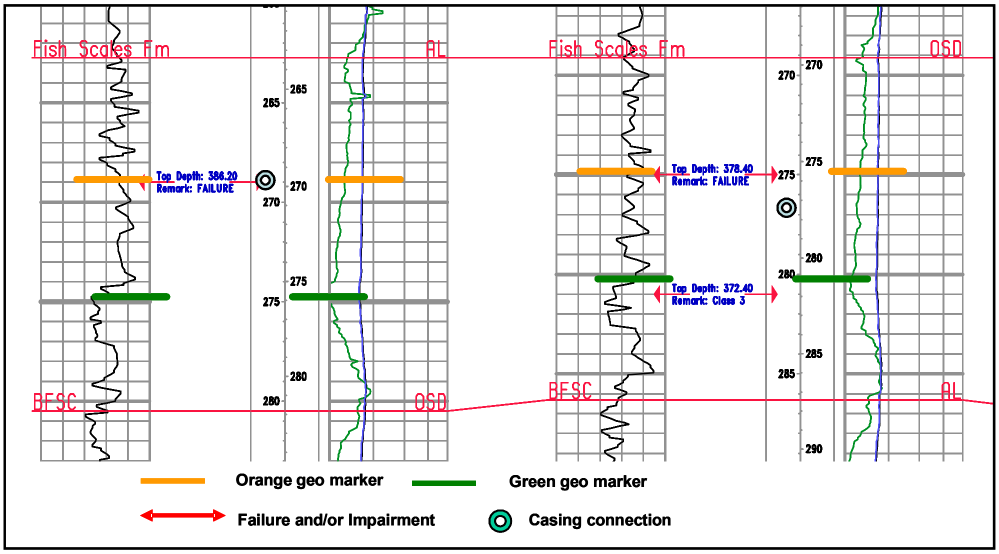

Figure 17: Fish Scales Green Geological Markers Correlating to Casing Failures

3.3.5 Well Load and Resistance Studies

On behalf of and working closely with Imperial, ExxonMobil Upstream Research Company (URC) continued model studies using a coupled numerical model. The earth model uses geomechanical rock properties and Clearwater top dilation due to steam injection and fluid production to predict shear slip in the overburden. This model is then coupled with well and connection sub-models incorporating the metallurgical properties of the casing body and connections to predict the distribution and magnitude of plastic strain in the casing and estimate when the material will fail. A series of sensitivity studies were conducted to assess the impact of different steam strategies and wellbore configurations, and additional pad models were constructed to relate model predictions to actual failures.

This has lead to the development of the Production Injection Management Fatigue Estimate Toolkit (PIMFET), a new software tool that applies single well superposition and the Ultra Low Cycle Fatigue (ULCF) algorithm to predict shear slip and fatigue life of a casing connection during CSS operation. The software user inputs historical injection and production and PIMFET will calculate shear slip history and current casing fatigue life in each well. The user can then optimize the planned steam cycle by modifying various input variables and come up with a solution to minimize shear stress and casing fatigue damage while maintaining bitumen recovery. The PIMFET software is approaching the end of the testing phase and planned for full production release in early 2011.

In addition to performing in-house modeling studies, Imperial is participating in a joint industry project (JIP) led by Noetic Engineering to study synergistic thermo-mechanical and environmental loads on casing. Project work is currently underway and Imperial has provided input to the scope of the project.

3.3.6 Well Environment

Since 1996, Imperial Oil's operating practices have specified wellbore operating conditions that prevent corrosive environments within the wellbore. In the course of the soaking or shut-in portions of a cycle, the wellbore annulus is purged with nitrogen, mitigating the potential for SSC.

Since implementing this standard, Imperial has purged all wells that have completed their steam cycle and gone into the soak portion of the cycle.

Enhancements to the wellbore environment control standards were implemented April 2007, requiring all wells to be purged within 48 hours of being shut-in. Nitrogen purging is used to reduce the presence of H_2S in the casing - tubing annulus during shut-in periods, which helps to mitigate the occurrence of failures due to SSC. Through a continuous improvement approach, a sustainable improvement in purge compliance has been observed since the revised purging standards were first implemented. Improved nitrogen purge management will aid in the detection of low-rate casing failures. Nitrogen purge compliance for 2010 is displayed in Figure 18; it can bee seen that current performance was at or near 100% throughout the year.

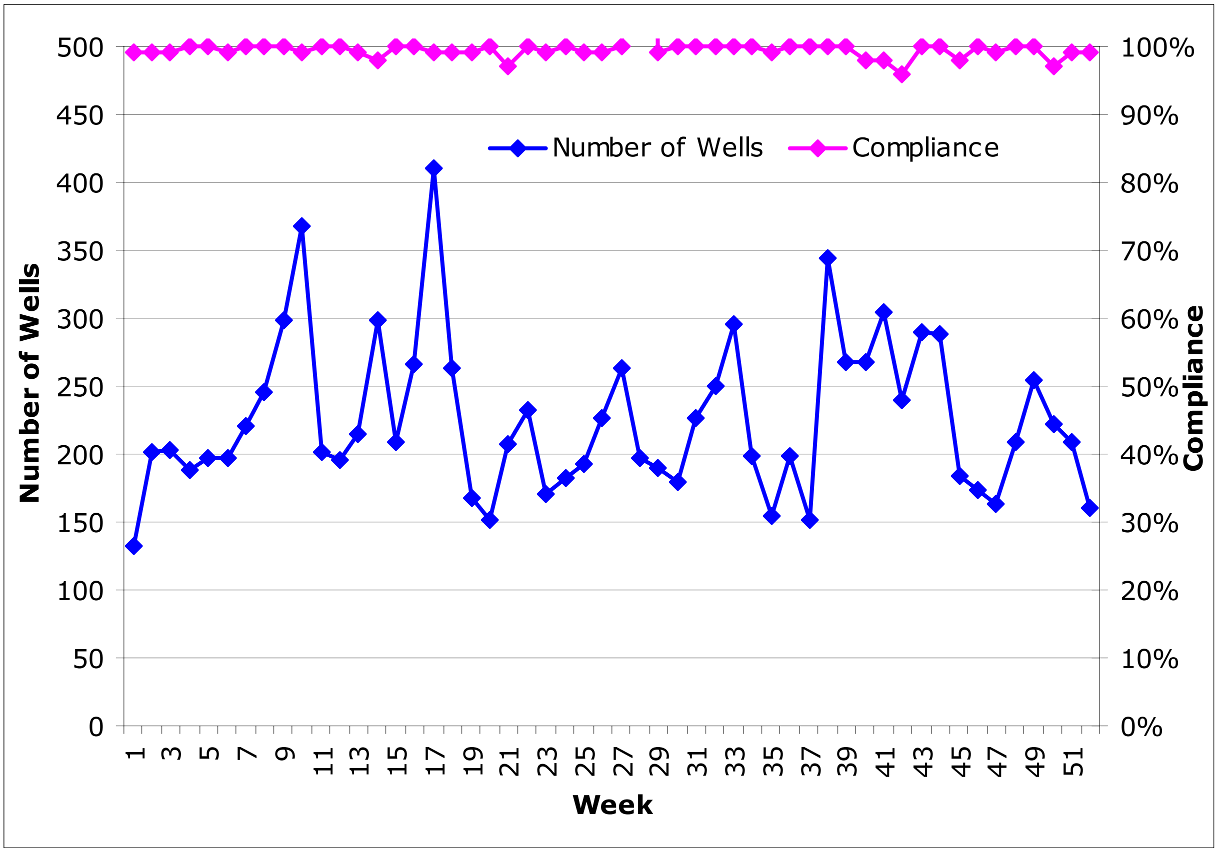

Figure 18: Weekly Nitrogen Purge Compliance

3.3.7 *Well Design*

To date, Imperial Oil has invested significantly in the design and testing of various types of casing connections for use in cyclic steam stimulation (CSS) service. Full-scale testing confirmed that metal-to-metal seal connections improve connection seal ability and, in turn, casing integrity. Since September 1999, metal-to-metal connections have been installed on all new CSS wells drilled in Cold Lake, minimizing the potential for future failures as a result of stress corrosion cracking.

Imperial believes that the use of L80 steel is the optimum casing material to balance post-yield material properties and SSC resistance. However, as previously mentioned, further testing is ongoing to study the use of higher strength T95 casing for Cold Lake operations. This work will be ongoing through 2011.

On behalf of Imperial, ExxonMobil Upstream Research Company (URC) has conducted model studies to vary connection grade and geometry to determine if there are any connection design improvement opportunities. Finite element analysis has shown that by selectively reducing the coupling length or outer diameter the fatigue life could be prolonged. Based on these promising results, a new connection design concept is being considered for CSS operations in Cold Lake. URC, on behalf of Imperial Oil are currently designing physical tests to further study this new design concept and will be progressing throughout 2011.

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, serviceability of the well can be restricted. 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 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 into the overlying formation (Grand Rapids). Occasionally, Clearwater failures (or larger Clearwater impairments) are mitigated through the installation of shear liners for structural support. A new Clearwater Top stabilization liner is being developed with plans to test in 2011.

3.5 Casing Integrity Response

Currently, Imperial maintains the following equipment and materials on-site: 2 pre-mix tanks, a return tank, 240 tonnes of barite, 360 tonnes of hematite, and all necessary kill fluid additives in order to respond to high pressure casing failures quickly.

In 2010, emergency response was initiated 7 times due to high pressure casing failures and only one barite mud kill was required.

ATTACHMENT 1: CASING INTEGRITY CHECK FREQUENCY

Casing Checks by Cycle and Design

Beginning Cycle # %	Commercial Old %	Commercial New/Upgraded w/o PS %	Commercial New/Upgraded w/ PS %	Environmental Old %	Environmental New/Upgraded %
1	0	0	0	0	0
2	0	0	0	0	0
3	0	0	0	0	0
4	0	0	0	0	0
5	33	33	0	100	50
6	33	33	33	100	50
7	33	33	33	100	100
8	100[1]	100	33	100[1]	100
9	100[2]	100	50	100[2]	100
10	100[2]	100	50	100[2]	100
11	100[2]	100	100	100[2]	100
12	100[2]	100	100	100[2]	100
12+	100[2]	100	100	100[2]	100

Notes:

1. Wells require a Vertilog at or before this cycle.
2. Corrosion assessment (incremental 3.5%/yr from last Vertilog to projected steam in date) to be applied to determine operating strategy unless a current Vertilog is run to confirm.

Additional Notes:

If a surface failure is detected all remaining wells in the current or next CI check require Vertilogs or a corrosion assessment to assess pad condition.

Horizontals and Infill wells are included in the above designs.

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.
Water Bodies:	Leming Lake, McDougal Lake, Bourque Lake, Un-named Lake in sec 35-64-04W4.
Upgraded Commercial:	New casing design coming out in 1998 with NSCC-M phosphate coated 'metal-to-metal' connections (VAM SWNA, Tenaris Blue, NSCCM, NSCC, QB2).
Known Surface Failures:	Wells located on a pad which have had corrosion related surface failures (0-25m).