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March 3, 2014

VIA RESS, EMAIL and COURIER

Ms. Kirsten Walli
Ontario Energy Board
2300 Yonge Street
Suite 2700
Toronto, Ontario
M4P 1E4

Re: EB-2012-0459 - Enbridge Gas Distribution Inc. ("Enbridge")
2014 – 2018 Rate Application
Undertaking Responses

Further to Enbridge Gas Distribution's filing of February 28, 2014, enclosed please find the following undertaking responses:

Exhibit J1.2;
Exhibit J3.2
Exhibit J4.3;
Exhibits J5.1, J5.6, J5.8;
Exhibit J6.4; and
Exhibit J7.3.

This submission was filed through the Board's RESS and is available on the Company's website at www.enbridgegas.com/ratecase.

Yours truly,

(original signed)

Lorraine Chiasson
Regulatory Coordinator

cc: Mr. F. Cass, Aird & Berlis
EB-2012-0459 Intervenors

UNDERTAKING J1.2

UNDERTAKING

TR 19

To file Enbridge Gas Distribution’s Utility Financial Results.

RESPONSE

Please see tables on the following pages.

Witness: K. Culbert

UTILITY REVENUE SUFFICIENCY CALCULATION
AND REQUIRED RATE OF RETURN
2013 HISTORICAL YEAR

Line No.		Col. 1 Principal Incl. CC/CIS	Col. 2 Component	Col. 3 Cost Rate	Col. 4 Return Component
		($Millions)	%	%	%
1.	Long and Medium-Term Debt	2,411.1	56.16	5.84	3.280
2.	Short-Term Debt	236.5	5.51	1.11	0.061
3.		2,647.6	61.67		3.341
4.	Preference Shares	100.0	2.33	2.40	0.056
5.	Common Equity	1,545.6	36.00	8.93	3.215
6.		4,293.2	100.00		6.612
7.	Rate Base	($Millions)			4,293.2
8.	Utility Income	($Millions)			306.8
9.	Indicated Rate of Return				7.146
10.	Sufficiency in Rate of Return				0.534
11.	Net Sufficiency	($Millions)			22.9
12.	Gross Sufficiency	($Millions)			31.2
13.	Revenue at Existing Rates	($Millions)			2,566.2
14.	Revenue Requirement	($Millions)			2,535.0
15.	Gross Revenue Sufficiency	($Millions)			31.2
	Common Equity				
16.	Allowed Rate of Return				8.930
17.	Earnings on Common Equity				10.414
18.	Sufficiency in Common Equity Return				1.484

Witness: K. Culbert

REVENUE REQUIREMENT
AND SUFFICIENCY
2013 HISTORICAL VERSUS BOARD APPROVED

Line No.		Col. 1 2013 Historical	Col. 2 2013 Board Approved	Col. 3 Variance
		($Millions)	($Millions)	($Millions)
	Cost of Capital			
1.	Rate base	4,293.2	4,162.0	131.2
2.	Required rate of return	6.61%	6.80%	-0.19%
3.		283.8	283.2	0.6
	Cost of Service			
4.	Gas costs	1,522.8	1,342.8	180.0
5.	Operation and maintenance	415.5	414.9	0.6
6.	Depreciation and amortization	278.0	279.3	(1.3)
7.	Fixed financing costs	2.4	2.3	0.1
8.	Municipal and other taxes	40.0	39.3	0.7
9.		2,258.7	2,078.6	180.1
	Miscellaneous operating and non operating revenue			
10.	Other operating revenue	(41.2)	(44.3)	3.1
11.	Interest and property rental	-	-	-
12.	Other income	(1.6)	(0.7)	(0.9)
13.		(42.8)	(45.0)	2.2
	Income taxes on earnings			
14.	Excluding tax shield	86.2	90.9	(4.7)
15.	Tax shield provided by interest expense	(38.0)	(39.0)	1.0
16.		48.2	51.9	(3.7)
	Taxes on sufficiency			
17.	Gross sufficienc -incl. CC/CIS	31.2	-	31.2
18.	Net sufficiency -incl. CC/CIS	22.9	-	22.9
19.		(8.3)	-	(8.3)
20.	Sub-total Revenue Requirement	2,539.6	2,368.7	170.9
21.	Customer Care Rate Smoothing Variance Account A	(4.6)	(4.6)	-
22.	Revenue Requirement	2,535.0	2,364.1	170.9
	Revenue at existing Rates			
23.	Gas sales	2,250.7	2,043.8	206.9
24.	Transportation service	314.0	318.6	(4.6)
25.	Transmission, compression and storage	1.6	1.7	(0.1)
26.	Rounding adjustment	(0.1)	-	(0.1)
27.	Total	2,566.2	2,364.1	202.1
28.	Gross revenue sufficiency	31.2	-	31.2

Witness: K. Culbert

UTILITY INCOME
2013 HISTORICAL VERSUS BOARD APPROVED

Line No.		Col. 1 2013 Normalized Utility Income ($Millions)	Col. 2 2013 Board Appvd Utility Income ($Millions)	Col. 3 Variance ($Millions)	Col. 4 Reference Expl. on page 4
1.	Gas sales	2,250.7	2,043.8	206.9	a)
2.	Transportation of gas	314.0	318.6	(4.6)	a)
3.	Transmission, compression and storage reve	1.6	1.7	(0.1)	a)
4.	Other operating revenue	41.2	44.3	(3.1)	b)
5.	Interest and property rental	-	-	-	
6.	Other income	1.6	0.7	0.9	
7.	Total operating revenue	2,609.1	2,409.1	200.0	
8.	Gas costs	1,522.8	1,342.8	180.0	a)
9.	Operation and maintenance	415.5	414.9	0.6	
10.	Customer Care Rate Smoothing	(4.6)	(4.6)	-	
11.	Depreciation and amortization expense	278.0	279.3	(1.3)	
12.	Fixed financing costs	2.4	2.3	0.1	
13.	Municipal and other taxes	40.0	39.3	0.7	
14.	Other interest expense	-	-	-	
15.	Cost of service	2,254.1	2,074.0	180.1	
16.	Utility income before income taxes	355.0	335.1	19.9	
17.	Income tax expense	48.2	51.9	(3.7)	c)
18.	Utility income	306.8	283.2	23.6	

Witness: K. Culbert

Pg. 3 Ref.	$Millions	Explanations of major utility income variances	
a)	202.2	Sales, transportation & trans. compr. / storage revenue increases	
	180.0	Gas cost increases mainly resulting from higher PGVA ref. price	
	22.2	Margin increase	
		The margin increase is mostly resulting from the following;	
		-higher number of average unlock customers	4.8
		-increase in gas in storage carrying costs from higher PGVA ref. price	3.1
		-lower transmission and storage related fuel cost charges	10.4
		-higher contract demand volumes	1.9
		-stale date cheques and other	2.0
			22.2
b)	(3.1)	Other operating revenue	
		The decrease in other operating revenue is mainly the result of lower LPP, new account and red lock charges.	
c)	(3.7)	Income tax expense	
		The reduction in income taxes is mainly the result of increased tax deductions arising from higher costs of retirements and removals and from increases in CCA, partly offset by an increase in taxable income of $19.9 million from variances in margin and other revenue / cost items.	

CALCULATION OF UTILITY TAXABLE INCOME AND INCOME TAX EXPENSE
2013 HISTORICAL YEAR

Line No.		Col. 1 Federal ($Millions)	Col. 2 Provincial ($Millions)	Col. 3 Combined ($Millions)
1.	Utility income before income taxes	355.0	355.0	
	Add			
2.	Depreciation and amortization	278.0	278.0	
3.	Accrual based pension and OPEB costs	42.8	42.8	
4.	Other non-deductible items	1.1	1.1	
5.	Total Add Back	321.9	321.9	
6.	Sub-total	676.9	676.9	
	Deduct			
7.	Capital cost allowance	238.2	238.2	
8.	Items capitalized for regulatory purposes	68.6	68.6	
9.	Deduction for "grossed up" Part VI.1 tax	2.9	2.9	
10.	Amortization of share/debenture issue exper	3.8	3.8	
11.	Amortization of cumulative eligible capital	0.3	0.3	
12.	Amortization of C.D.E. and C.O.G.P.E	0.1	0.1	
13.	Cash based pension and OPEB costs	41.6	41.6	
14.	Total Deduction	355.5	355.5	
15.	Taxable income	321.4	321.4	
16.	Income tax rates	15.00%	11.50%	
17.	Provision	48.2	37.0	85.2
18.	Part VI.1 tax			1.0
19.	Investment tax credit			-
20.	Total taxes excluding interest shield			86.2
	Tax shield on interest expense			
21.	Rate base	4,293.2		
22.	Return component of debt	3.34%		
23.	Interest expense	143.4		
24.	Combined tax rate	26.500%		
25.	Income tax credit			(38.0)
26.	Total utility income taxes			48.2

Witness: K. Culbert

UTILITY RATE BASE
2013 HISTORICAL VERSUS BOARD APPROVED

Line No.		Col. 1 2013 Rate Base	Col. 2 2013 Board Appvd Rate Base	Col. 3 Variance	Col. 4 Reference Expl. on page 7
		($Millions)	($Millions)	($Millions)	
	Property, Plant, and Equipment				
1.	Gross propery, plant and equipment	6,749.3	6,749.4	(0.1)	a)
2.	Accumulated depreciation	(2,755.9)	(2,804.1)	48.2	b)
3.	Net property, plant, and equipment	3,993.4	3,945.3	48.1	
	Allowance for Working Capital				
4.	Accounts receivable merchandise finance plan	-	-	-	
5.	Accounts receivable rebillable projects	4.1	1.3	2.8	
6.	Materials and supplies	40.6	31.9	8.7	
7.	Mortgages receivable	0.2	0.2	-	
8.	Customer security deposits	(63.7)	(68.7)	5.0	
9.	Prepaid expenses	1.2	1.8	(0.6)	
10.	Gas in storage	320.0	248.4	71.6	c)
11.	Working cash allowance	(2.6)	1.8	(4.4)	
12.	Total Working Capital	299.8	216.7	83.1	
13.	Utility Rate Base	4,293.2	4,162.0	131.2	

Witness: K. Culbert

Page 6 Ref.	$Millions	Explanations of major rate base variances
a)	(0.1)	Gross P.P. & E. The slight change in gross pp&e is mostly due to the impact of the following; -higher 2012 actual versus 2012 estimated retirements mainly from cast iron and bare steel replacement programs and replace vs. repair meter exchanges -offset by increases in 2013 additions to plant in service mainly within mains, services and software asset categories
b)	48.2	Accumulated depreciation The reduction in accumulated depreciation is mainly due to the following; -higher 2012 actual versus 2012 estimated retirements mainly from cast iron and bare steel replacement programs and replace vs. repair meter exchanges -an unfavourable or higher cost of removals / abandonment work for system integrity / replacements
c)	71.6	Gas in storage The increase in value of gas in storage is predominantly due the higher average PGVA reference price throughout 2013 versus the price embedded in the 2013 Board Approved results.

Witness: K. Culbert

UNDERTAKING J3.2

UNDERTAKING

TR 12

To review Exhibit K3.1 and confirm that I-X would have to be 4.55 percent to accord with EGDI's application.

RESPONSE

Mr. Coyne confirms that the average of the annual growth rates in line 12 of Exhibit K3.1 is 4.55%. Mr. Coyne notes that this escalation factor is only representative of a case where:

- GTA is not Y factored
- Pension cost of $43 million in the base year is escalated at the I-X level as opposed to a pass-through item.

Alternative scenarios for Y factors with pension pass-through, with resulting revenue escalation and implied X factors, are presented in response to Vice Chair Chaplin’s question in J4.3.

Witness: J. Coyne - Concentric

UNDERTAKING J4.3

UNDERTAKING

TR 58

To derive the implied TFP Rate of Change for 2014 to 2019.

RESPONSE

Mr. Coyne assumes the intent is to calculate the implied X factor as a compound growth rate from a base of 2013 to 2018, the final year of the plan. In order to calculate the X factor, assumptions must be made concerning the revenues subject to I-X escalation vs. those subject to Y factor or pass-through treatment. The following table illustrates X factors for a range of scenarios. Scenario 1 incorporates the Company's current assumptions regarding Y factors; the resulting X factor is -0.4%.

Implied X Factor Under Alternative Assumptions

Y Factor					**Compound annual growth rate (%)**				
Scenario		GTA	Ottawa	WAMS	Revenues subject to escalation	Customer Growth	I-X factor	Less Inflation factor	Implied X
1	**GTA,Ottawa and WAMS as Y factor, No SRC**	**X**	**X**	**X**	**4.7%**	**1.7%**	**2.9%**	**2.5%**	**-0.4%**
2	GTA & Ottawa as Y factor, No SRC	X	X		4.9%	1.7%	3.1%	2.5%	-0.6%
3	GTA as Y factor, No SRC	X			5.1%	1.7%	3.3%	2.5%	-0.8%
4	No Y factor, No SRC				6.4%	1.7%	4.6%	2.5%	-2.1%

Site Restoration Cost effects are removed from this analysis.

SRC impact includes the effect of the Constant Dollar Net Salvage Adjustment (CDNSA) and the lower depreciation rate for 2014-2018.

Inflation is based on the three-factor I projection from Concentric's IR report, A2, Tab 9, Sch. 1, P. 48.

Witness: J. Coyne - Concentric

UNDERTAKING J5.1

UNDERTAKING

TR 14

To provide the results of the initial distribution System Integrity Management Program implementation.

RESPONSE

Please see attached the initial “2008 Distribution System Integrity Management Program Annual Report”.

Please also see the response to Undertaking J5.11 for additional context.

Witness: L. Lawler

2008 Distribution System Integrity Management Program Annual Report

Prepared by:

Graham Campbell

Integrity Management

July 2009

Table of Contents

1.0 Introduction

In 2007, the Technical Standards and Safety Authority issued a Director's Order that requires Gas Distribution Operators in the province of Ontario to have a plan for and to implement a Distribution System Integrity Management Program (DSIMP) by April 30th 2008. The guidelines for the DSIMP are given in CSA Z662-07, Annex M.

Enbridge Gas Distribution (EGD) has created a plan to meet this order. The intent of this report is to show the progress of EGD's Distribution System Integrity Management Program to date. This report will outline how the company has developed the program and will present the findings therein.

As outlined in the company's Integrity Management Program Manual, data will be collected, integrated and analyzed to establish the cause and frequency of failure and damage incidents in the distribution system. This information is to be used for the purposes of identifying potential threats and risks to the distribution system and to establish grounds for possible mitigation of these threats. The timeline for the data in this report is from 1 Jan 2008 to 31 Dec 2008 inclusive.

A discussion is presented on how the data is gathered and stored for analysis purposes.

The findings will be presented in tables and graphical formats with a commentary associated with each.

2.0 Data Gathering

In order for the required data to be gathered, the data set had to be identified. It was determined that the information requirements for the DSIMP can be obtained by investigating the repair work carried out on the distribution system. In the company's work management system (STORMS) there are pieces of work that relate to the repairs carried out on the assets. For the purposes of collecting data for the DSIMP, the following work request types were identified.

Job Type	**Job Description**
MRMEINSP	Measurement Inspection
MRTC	M&R Trouble Call
LRI	Leak Repair Investigation
LSI	Leak Survey Investigation
MAMNPPLC<8	Main Repair <8m
MAMRPR	Main Repair >8m
MAMRPR	Main Repair For Leak
MACR	Main coating repair
MAJR	Main Joint Repair
MAJR	Joint-Repair-LIR
SMRPRAB	Service Maintenance Above Ground Repair

SMRPRBL	Service Maintenance Below Ground Repair
SMRPRBL	Below Ground Repair - LIR
COFI	Corrosion Fault Investigation
VLRPR	Valve Repair
VLRPR	Valve Repair - Leak

The above job types have been identified as the work which leads to identifying the cause of the fault or failure that required the asset to be repaired. These job types identify the type of asset that required attention.

The data is extracted through the use of a Hyperion Reporting Tool created by EGD's IT Dept in conjunction with Integrity Management. A report is run monthly and the data can be extracted to a MS Excel workbook. The data is grouped into similar work packets and the components are shown in Table 2.1.

Table 2.1: Groupings for Similar Work Packets

Condition Monitoring Activity	Description	Data Source	Report Format
Leak Management			
LSI	Leak Survey Investigations	Hyperion Tool	Excel
LRI	Leak Repair Investigations	Hyperion Tool	Excel
Leak Repairs	Leak Repairs - Below Ground - Mains, Services, Joints, Valves	Hyperion Tool	Access
SMRPRAG	Repairs - Above Ground	Hyperion Tool	Excel
Damages			
EMERD	Emergency Damages	ENV Damages Report	Access
Corrosion Management			
COFI	Corrosion Fault Investigations	Hyperion Tool	Access
RRRPR	Rectifier Repairs	Hyperion Tool	Access
RERPR	Regulator Repair	Hyperion Tool	Access
MATPRPR	Test Point Repair	Hyperion Tool	Access
MACRPR	Coating Repair	Hyperion Tool	Access

LSI and LRI extracts are left in Excel and the rest of the data is imported into a central MS Access database to improve the search and leak identification capabilities. These groups of data are analyzed and put into the tables and graphs that are shown in this report.

Damages are captured in a separate Hyperion Report, owned and maintained by the Damage Prevention Department. The report's data is extracted by Integrity Management and is imported into the central DSIMP Access database.

3.0 Data Discussion

Some explanation is required to present the issues associated with the gathering of data as it relates to the requirements of the DSIMP. Recommendations for corrective actions for these issues are given in Section 8. The following is a summary of the issues:

3.1 LSI and Repairs

An LSI work request is a Leak Survey Investigation. The purpose of this job type is to establish a record of a below ground leak through the creation of a unique identification number, LIR_ID and to give the ability for that leak to be classified as outlined in Section 3.0 of the Operating and Maintenance Manual.

In STORMS, each repair type i.e. MAJR, MAMRPR, SMRPRBL and VLRPR has a specific job code and Compatible Unit (CU) for leak repairs that allow the capture of a Leak Indication Report (LIR_ID) which will establish a relationship between the leak record and the associated repair. The repair will also be associated with a physical asset such as a service, main or station. Without an LIR_ID this will not happen.

During the data gathering process, it was found that not all below ground leaks are assigned through the LSI work request process and therefore do not have a leak asset record and LIR_ID. If a below ground leak is not assigned an LIR_ID then no PMTS record is created for the leak, its classification cannot be recorded against the leak asset and does not have the leak monitoring work requests generated by STORMS. The business process supporting this function is now under review to ensure compliance is being met.

3.2 Above or Below Ground Repairs

It would be helpful if the decision point for classifying a leak as above or below ground was defined as upstream or downstream, respectively of the outlet of the service valve. Currently, it is understood by IM that the transition is at the downstream piping after the outlet of the service valve.

3.3 Leaks Vs LIRS

The data in Section 4.0 makes reference to Leaks and LIRs. A Leak, in this case, is an unplanned release of gas from the distribution system that has not been identified through the LSI process as described in Section 3.1. A leak that is identified through the LSI process has an LIR_ID. A leak that is not identified through the LSI process does not have an LIR_ID and cannot be tracked in PMTS. The business process supporting this function is now under review to ensure compliance is being met

3.4 Free Form Fields

In many cases, field staff use free form comment fields to enter leak cause information into their field devices. Information in comment fields cannot be searched electronically which means that data extraction can only be done by reading every comment field in every work request. There are up to five comment fields in each work request and there were more than 10,000 work requests for repair and inspection work gathered for DSIMP analysis in 2009. This is a very labour intensive activity. Furthermore, field staff often use short forms and abbreviations to minimize the number of key strokes to enter the information. This makes interpretation of the data during manual data searches very difficult and it also makes the interpretation of the notes subjective.

The information in the DSIMP database was enhanced to include new fields to capture relevant data, such as leak reporting method, AMP fitting leak and consequence score. Two of the drop down menus in a work request contain information related to leaks, i.e. Leak Cause and Leak Repair Pipe Condition. However, they are not mandatory fields and they are only available if the correct work requests and job codes have been created. Steps are being taken to review the leak management process to determine the necessity for these fields to be made a mandatory requirement.

3.5 Asset Issues

The DSIMP requires that all pipelines and components are included in the data. This can be summarized as mains, services and stations. It also includes all fittings associated with the pipe. Within EGD's asset data base there are some circumstances where there are difficulties in associating incidents in the system to actual recorded assets. Examples are: the network, high and low nodes of the main are not determined at the time of repair, a service address is not known, a station does not relate to a particular main or service fitting.

The above issues are examples of where the data gathered may not necessarily have a relationship back to a particular asset. The analysis of the data attempts to ignore any outlying "one of's" in this regard, while highlighting where there are deficiencies in records reporting.

The capture of this information is dependent on many factors. There are situations where the work generated to repair a leak can be issued when the asset affected is not yet known. Recommendations for training and process review have been made. There have also been some discussions with Quality Acceptance to measure the leak management work output.

3.6 Third Party Damages Data

The data gathered through the Damage Prevention Hyperion Report is in a different format from the leak and repair information. This report does not give asset ID or main leg information and therefore the damage occurrence is not recognized in the report as being associated to a physical asset.

The Asset Health Review runs a similar Hyperion Report to the DSIMP. This data contains EMERD work and this data set is under evaluation to better capture damage related data.

4.0 Condition Monitoring Data

4.1 Threat Categorization

Table 4.1.1 shows the correlation between the threat categories from each incident and the condition monitoring activities carried out. Each incident that is recorded will be assigned one of the threat categories and where the threat cannot be identified, the term “unknown” is used.

Table 4.1.1: Condition Monitoring Activities vs Threat

	Corrosion/ Degradation	Manufacturing/ Construction Defects	Equipment Malfunction	Third Party Damages	Operator Error	Natural Forces
Leak Management	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit	Detect - Survey	Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit
Corrosion Management	Detect - Survey Mitigate - Repair		Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit		Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit
Damage Prevention				Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit	Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit
Pipeline Patrol Inspections				Detect - Survey Investigate - Circumstance Mitigate - Potential Damages		Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit
Valve Inspections		Detect - Survey Investigate - Failure Mode	Detect - Survey Investigate - Failure Mode		Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	
Bridge and River Crossing Inspections	Detect - Inspection Mitigate - Repair / Maintenance	Detect - Survey Investigate - Failure Mode	Detect - Survey Investigate - Failure Mode		Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit
Material Fault Report Program	Investigate - Failure Mode	Investigate - Failure Mode	Investigate - Failure Mode		Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Investigate - Failure Mode
Measurement and Regulation Inspection	Detect - Inspection Mitigate - Repair / Maintenance	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit		Detect - Procedure Investigate - Failure Mode Mitigate - Correct Process/ Procedure	Detect - Survey Investigate - Failure mode Mitigate - Repair or Revisit

4.2 Leak Management Data

Leak management data is presented in two parts. The first part represents new leak records created from Leak Survey Investigation work requests. The second component addresses all below ground repairs completed during the data period. Leaks investigated include mains, services and valves. Above ground leaks are also considered and the information can be reviewed in Section 4.2.3.

4.2.1 Leak Survey Investigations

Table 4.2.1.1 shows all of the new leaks that were assigned an LIR_ID in 2008. They do not correlate directly with the repairs in Section 4.2.2 of this report as they may not be required to be repaired depending on the leak classification. The information about a leak cannot be recorded until it is repaired. The total is not the same as the number of leaks that were repaired in the reporting period. For example, a B leak can be monitored for up to 15 months before it is repaired. The table shows that 83 % of these leaks were found by leak survey activities.

Table 4.2.1.1: The number of LSIs created and the reported source of the leak report.

Leak Report Source	**Number**	**Percentage of Total**
20% RESIDENTIAL WALKING SURVEY	601	64
COPPER SERVICE SURVEY	32	3
MOBILE	179	19
OTHER GAS COMPANY PERSONNEL	57	6
PUBLIC\ HOMEOWNER	37	3
WALK XHP/HP SERVICES	2	<1
WALKING WTW SURVEY	20	2
THIRD PARTY DAMAGE	1	<1
SPECIAL SURVEY ALDYL A PIPE	1	<1
LEAK SURVEY CONTRACTOR	2	<1
VALVE INSPECTION	3	<1
Grand Total	**935**	

4.2.2 Below Ground Leak Repairs - Mains, Services and Valves

The following section gives the findings from the below ground leak repair data extracted from STORMS using the Hyperion reporting tool.

Table 4.2.2.1: The number of repaired below ground leaks per month for leaks that were assigned an LIR_ID and leaks that were not assigned an LIR_ID.

Month	**Assigned LIR**	**LIR not Assigned**	**Month Total**
Jan	25	45	70
Feb	14	39	53
Mar	25	46	71
Apr	19	61	80
May	19	38	57
Jun	47	67	114
Jul	44	92	136
Aug	40	77	117
Sep	34	62	96
Oct	27	54	81
Nov	41	58	99
Dec	22	57	79
Totals	**357**	**696**	**1,053**

Figure 4.2.2.1 shows the data from Table 4.2.2.1. Leaks that have not been recorded as LSI's and assigned an LIR_ID do not have a PMTS Leak Indication Asset record. 696 of the 1,053 leaks, 66 %, were not assigned an LIR_ID and therefore cannot be tied to an asset in PMTS. This severely limits the ability to analyse the leak data for trends. Ideally, this graph should show a majority of leaks as LIRs. This data is broken down using the three categories of repairs: mains, services and valves. The outcome is shown in Figures 4.2.2.2 - 4.2.2.5.

Figure 4.2.2.1: The number of leaks captured through the LIR process compared to the number of leaks detected in the data that did not have an LIR, data label Y. The two columns combine to give the estimated total number of leaks from below ground repairs each month.

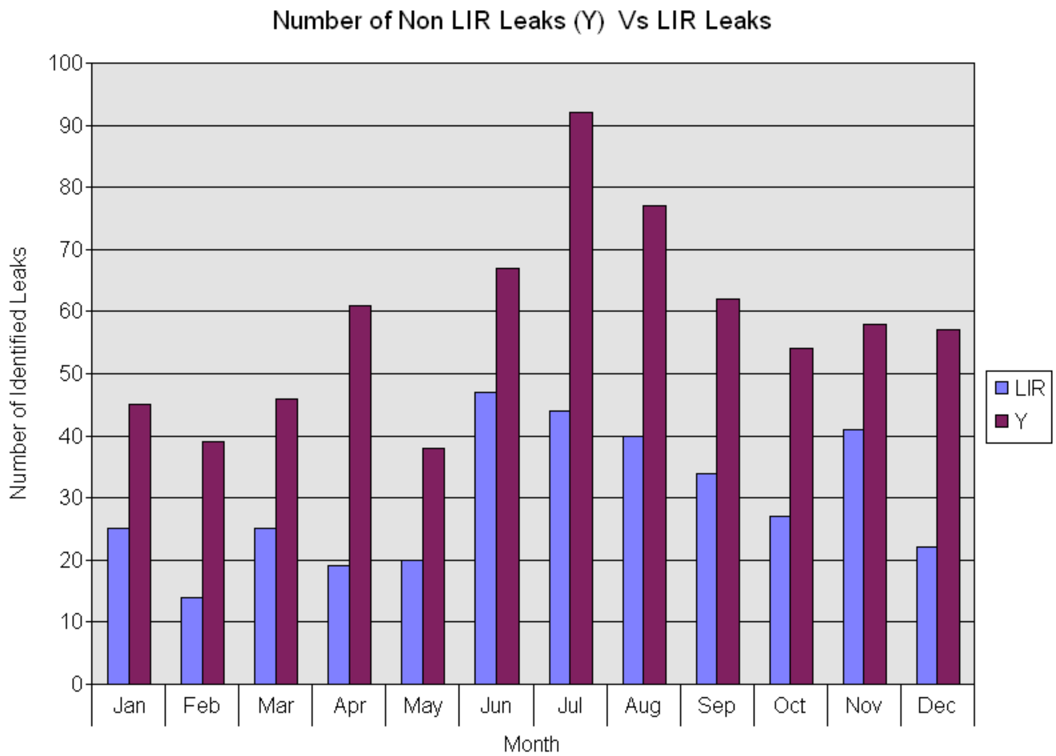


Figure 4.2.2.2: Main Leak Repairs by Area

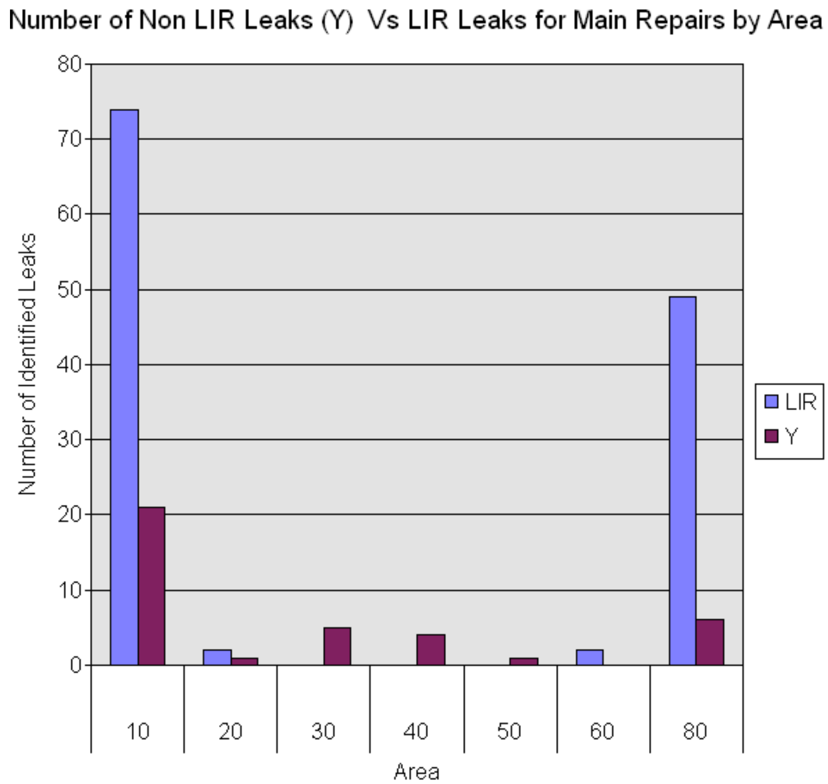


Figure 4.2.2.3: Below Ground Service Leak Repairs by Area

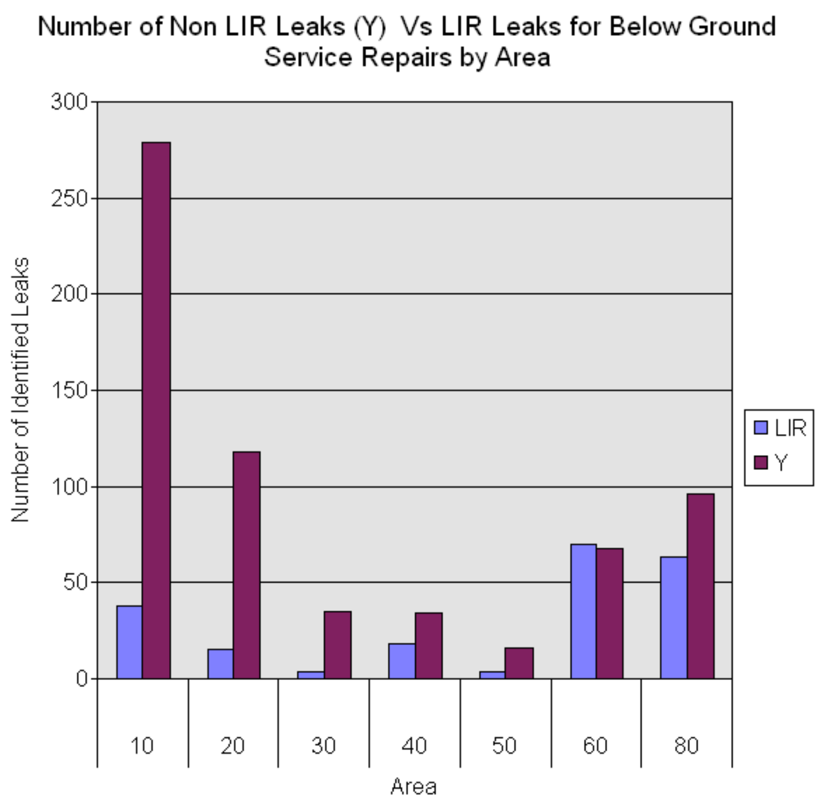
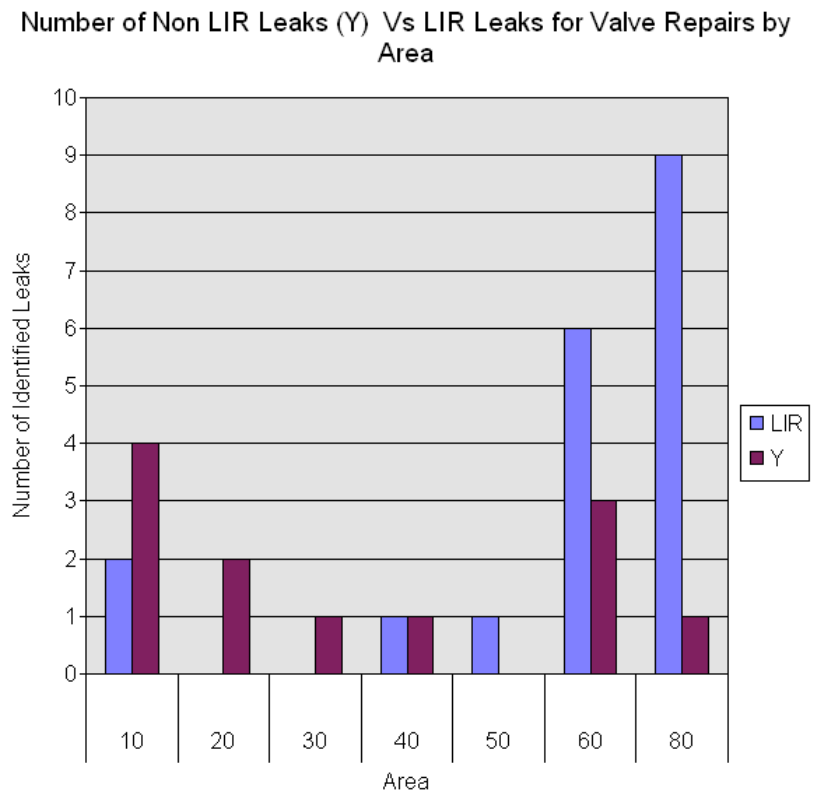


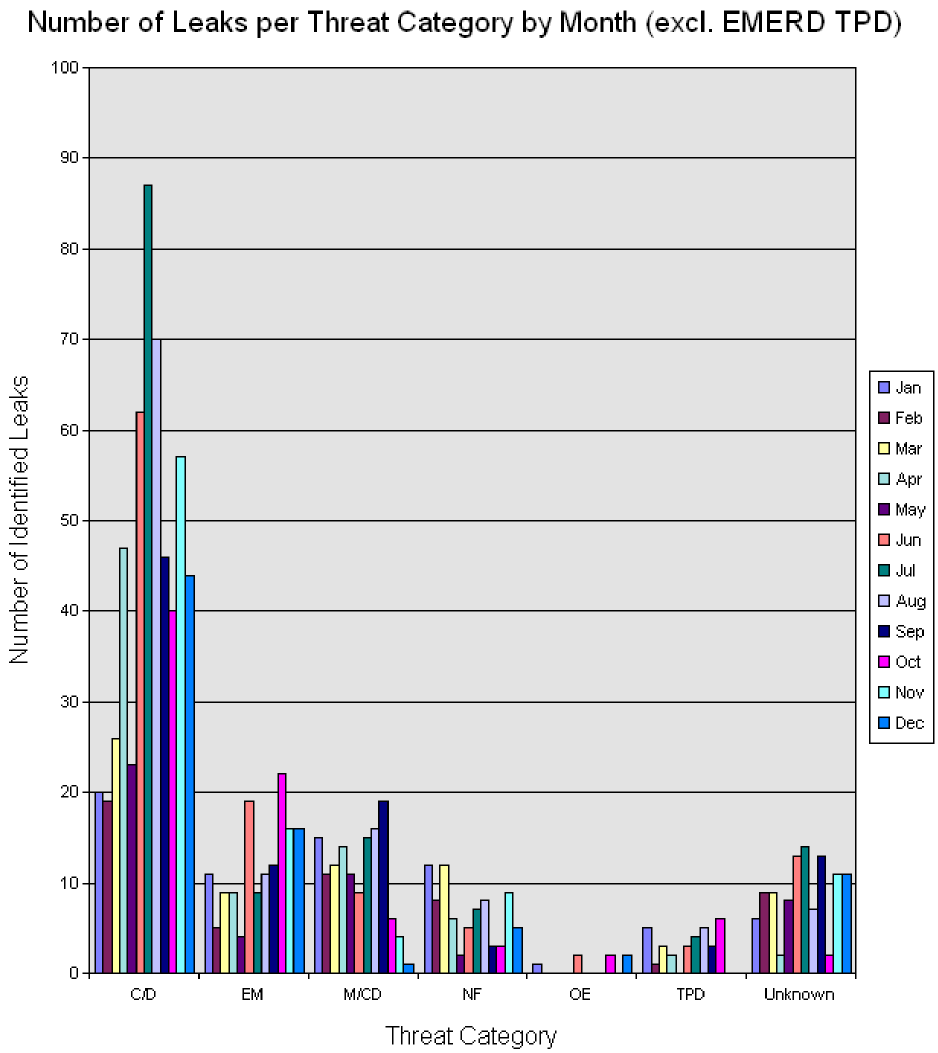
Figure 4.2.2.4: Valve Leak Repairs by Area



Figures 4.2.2.2 – 4.2.2.4 show the breakdown of Figure 4.2.2.1 for main repairs, below ground service repairs and valve repairs separately. It is worth noting that the proportion of non-LIR leaks for mains is significantly reduced. This is in direct contrast with the below ground service repair. This highlights the issue with the leak management process showing the difficulty in recognizing and recording the leak on a service when it is determined to be a below ground repair. The figures also highlight regional differences in leak management with Areas 10 to 50 showing a higher proportion of non LIR leaks compared with Areas 60 and 80. This may be in part due to the different work management practices in Ottawa and Niagara.

Figure 4.2.2.5 shows the threats to the distribution system as interpreted by the Integrity Management Department using the MS Access data base from data that established if there was a leak, the mode of failure and the most likely threat associated to it.

Figure 4.2.2.5: The number of identified below ground leaks per month by threat category, regardless of whether an LIR_ID existed or not.



The threat categories are:

C/D	Corrosion/Degradation
EM	Equipment Malfunction
M/CD	Manufacturing/ Construction Defect
NF	Natural Forces
OE	Operator Error
TPD	Third Party Damages

Figure 4.2.2.6: The number and type of threat associated with main repairs.

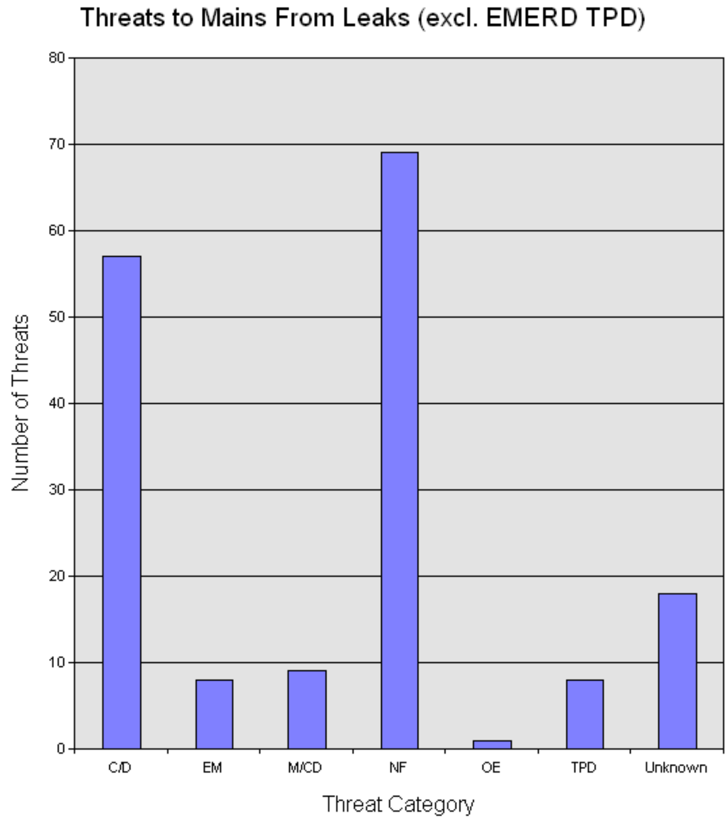
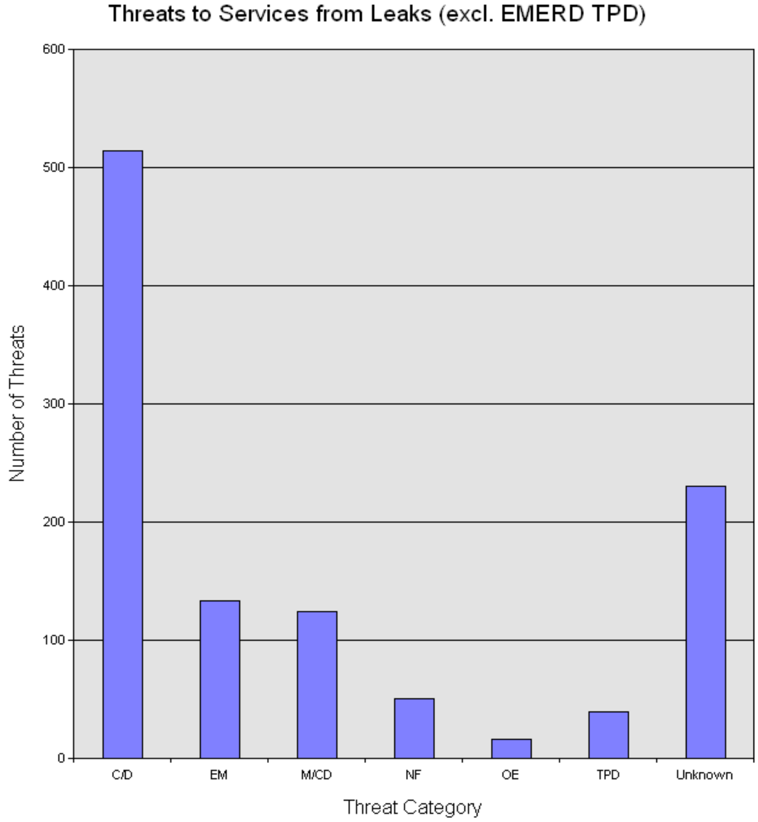


Figure 4.2.2.7: The number and type of threat associated with service repairs.



Each of the above figures shows the number of leaks by threat type, excluding all third party damages. Third party damages are managed as EMERD Jobs, which are discussed in Section 4.4.

Figure 4.2.2.8 and Table 4.2.2.2 show the reported condition of the pipe at locations where below ground repairs were completed. This data can be correlated to the main leg in PMTS should an investigation be warranted. The data in Table 4.2.2.2 shows only those repairs where the network, low node and high node are available and have corrosion identified. i.e. those incidents recorded as having “slight corrosion”, ”uniform corrosion”, “heavy corrosion” and “deep pits”. The label of the first column is “-“, an option in the Leak Repair Pipe Condition drop down menu in eField.

Figure 4.2.2.8: The estimated condition of the pipe where noted at the time of repair from the Leak Repair Pipe Condition facility attribute.

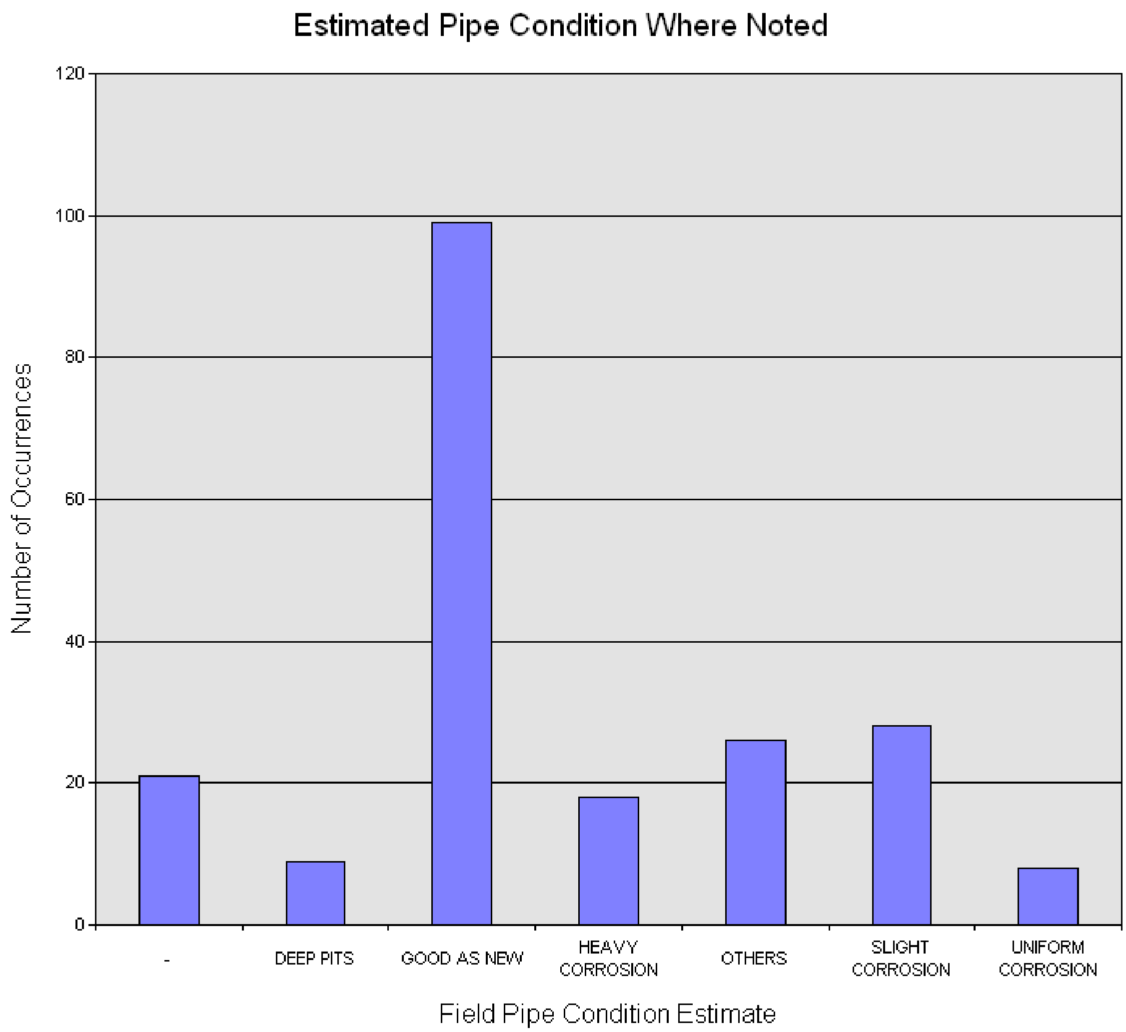


Table 4.2.2.2: Main leg identification of estimated pipe condition

Network	Lownode	Highnode	LeakRepPipecondition	Job Type	Number of Occ.
102	176	183	SLIGHT CORROSION	MAMRPR	1
103	481	488	SLIGHT CORROSION	MAJR	1
106	647	648	SLIGHT CORROSION	MAMRPR	1
	844	1888	SLIGHT CORROSION	MAJR	1
108	263	273	UNIFORM CORROSION	MAJR	1
110	1146	1147	SLIGHT CORROSION	MAJR	1
180	190	567	DEEP PITS	SMRPRBL	1
336	10	11	DEEP PITS	MAMRPR	1
			SLIGHT CORROSION	MAMRPR	1
520	345	320	HEAVY CORROSION	MAJR	1
6549	4040	4281	SLIGHT CORROSION	SMRPRBL	1
6566	0098	0099	HEAVY CORROSION	SMRPRBL	1
8103	0308	0351	HEAVY CORROSION	SMRPRBL	1
	0352	0353	HEAVY CORROSION	MAMRPR	1
8106	0662	0697	UNIFORM CORROSION	MAMRPR	1
8120	0557	2467	HEAVY CORROSION	MAMRPR	1
	0566	1059	DEEP PITS	MAMRPR	1
			HEAVY CORROSION	MAMRPR	2
	0637	0650	UNIFORM CORROSION	MAMRPR	1
8320	0889	3351	SLIGHT CORROSION	MAMRPR	1
8321	0279	0407	HEAVY CORROSION	MAMRPR	1
8520	0248	0506	SLIGHT CORROSION	MAMRPR	1
	0308	1149	UNIFORM CORROSION	MAMRPR	1
	0859	0860	HEAVY CORROSION	MAMRPR	2
8720	1092	6393	SLIGHT CORROSION	MAMRPR	1
	1131	3712	SLIGHT CORROSION	SMRPRBL	1
	6342	6343	DEEP PITS	MAMRPR	1
	8702	8703	UNIFORM CORROSION	SMRPRBL	1
8926	0951	0952	DEEP PITS	MAMRPR	1

4.2.2.1 Below Ground Leaks on Mains

The number of below ground leaks that were repaired on mains is shown in Table 4.2.2.1.1, broken down by material type. The table also shows the leak rate per kilometre of main per year for each material type.

Table 4.2.2.1.1: Main Leak Data by Material Type.

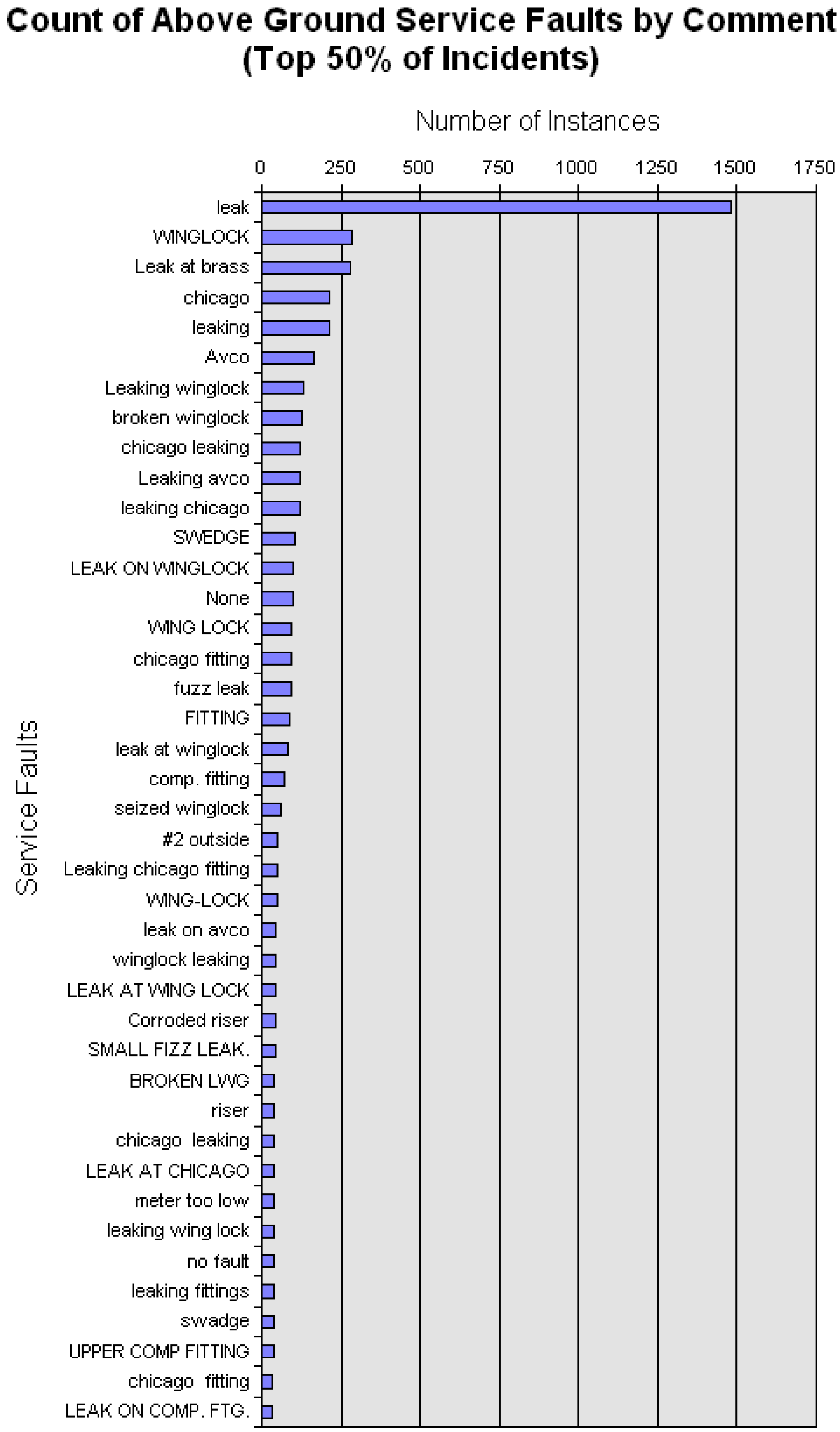
Main Material	Number of Repairs	Length of Main (km)	Leaks / km-yr
Cast Iron	64	350	0.1828
Bare Steel	17	43	0.3967
Coated Steel	48	12,028	0.0040
Polyethylene	25	20,080	0.0012

The table clearly shows that the highest leak rates are on bare steel and cast iron mains. The leak rate for cast iron mains is more than 150 times that of polyethylene mains and more than 45 times that of steel mains.

4.2.3 Above Ground Repairs

The number of above ground repairs by each reported fault type is shown in Figure 4.2.3.1. The data is sorted by the number of occurrences of each fault description in descending order. It is important to note that not all fault descriptions are leaks.

Figure 4.2.3.1: Above Ground Service Faults



4.3 Damage Incidents

In CSA Z662-07 – Annex M a “Damage Incident” is defined as – “an event that results in a defect in a pipe, component, or coating **without release of gas**”.

In an effort to capture these incidents, the below ground repair data was evaluated for such incidents and recorded where appropriate. The number of occurrences of each threat category is shown in Figure 4.3.1. The threat category for most of the incidents, 157 of 267 could not be determined from the records. This data records events that are indirect threats to the distribution system. They do not cause a leak immediately but they may indicate a problem that could lead to future incidents.

Figure 4.3.1: Damage Incidents per threat category

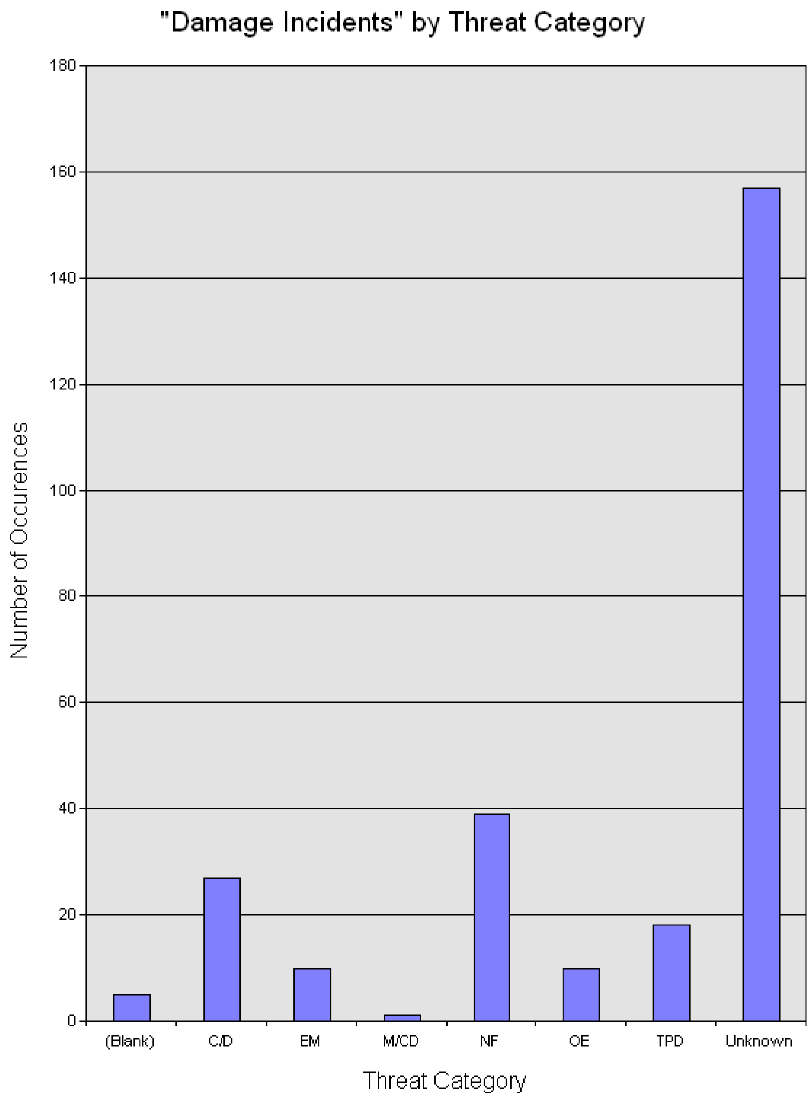
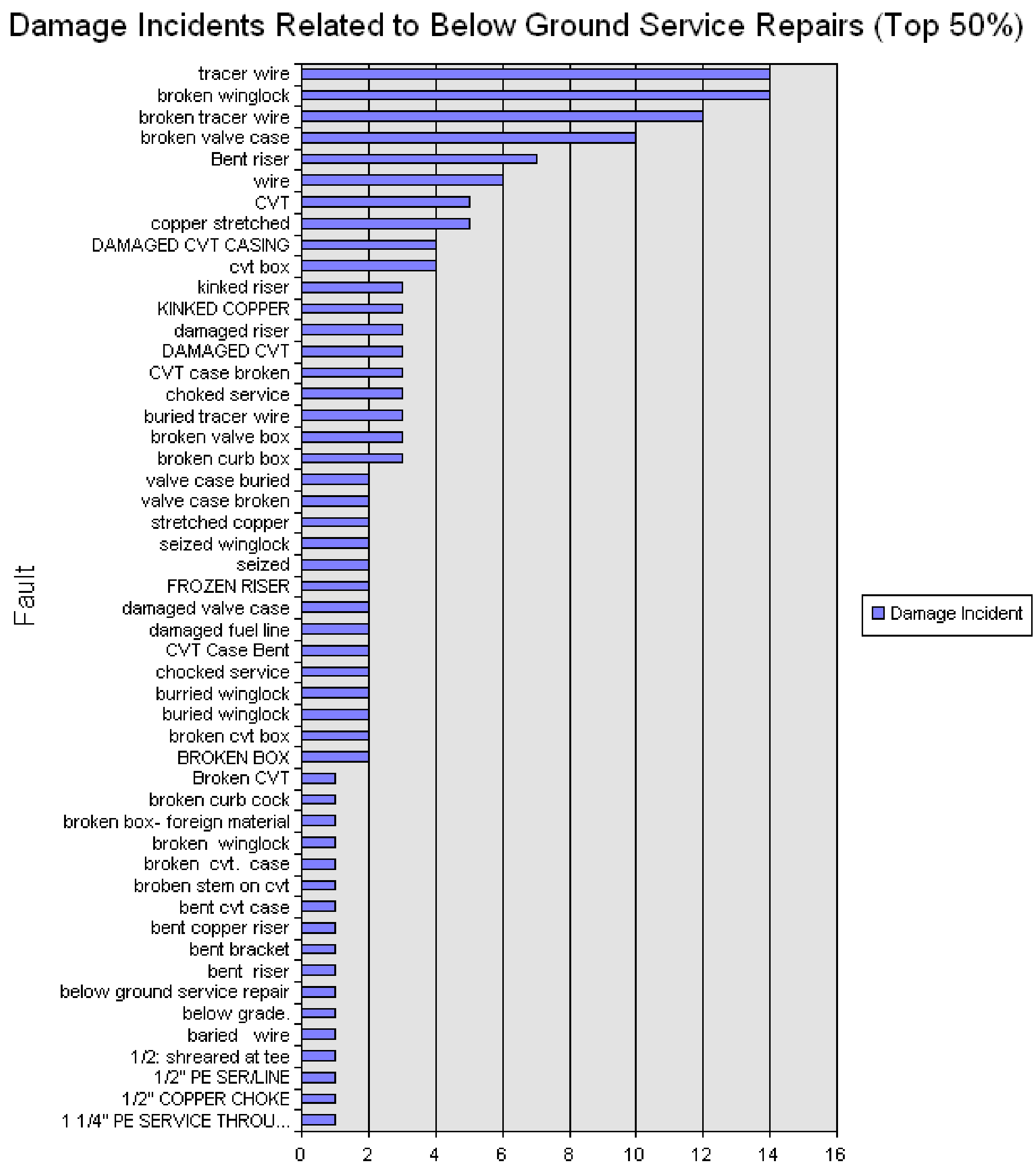


Figure 4.3.2 shows the top 50% of faults due to damage incidents. The data provided is limited to below ground service repairs. There are a small number of damage incidents associated to mains and valves but the data is insufficient to draw any conclusion of trends. This graph highlights the type of hazards that are being recorded in the field. The free form nature of the fault description limits the ability to count the number of individual fault types. As is seen from the graph.

31 of the 49 fault descriptions were used either once or twice. This highlights the difficulty of collecting data with free form comments.

This data can be used to keep an overview of the typical damage incidents that occur in the distribution system and over time may identify a need for further assessment.

Figure 4.3.2: Top 50% of faults related to Damage Incidents on Services



4.4 Third Party Damages

Third Party Damages are recorded by the Damage Prevention group and this data is extracted from the Hyperion ENV Damages Report.

Figure 4.4.1: Third Party Damages to services, mains and stations by month

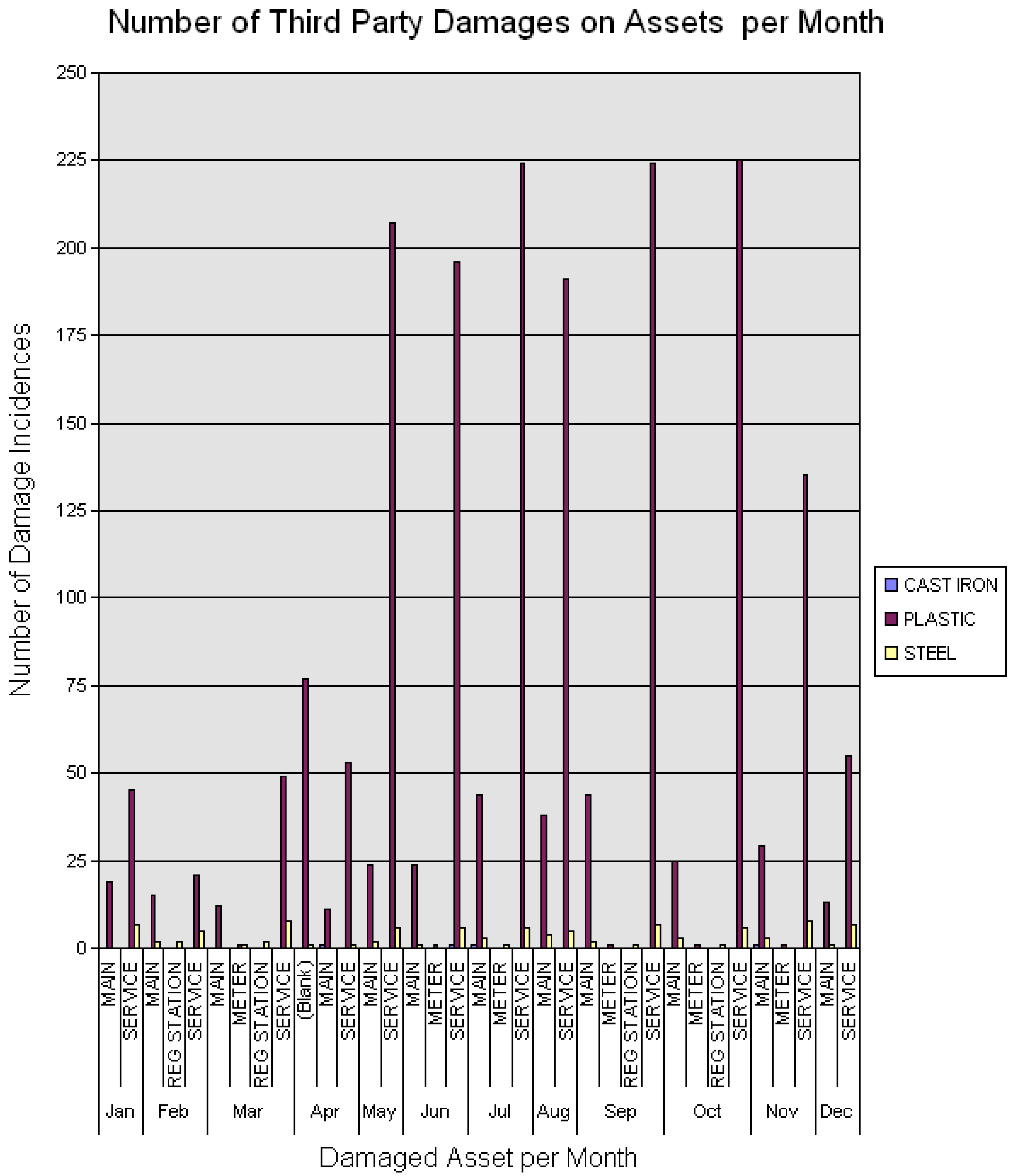
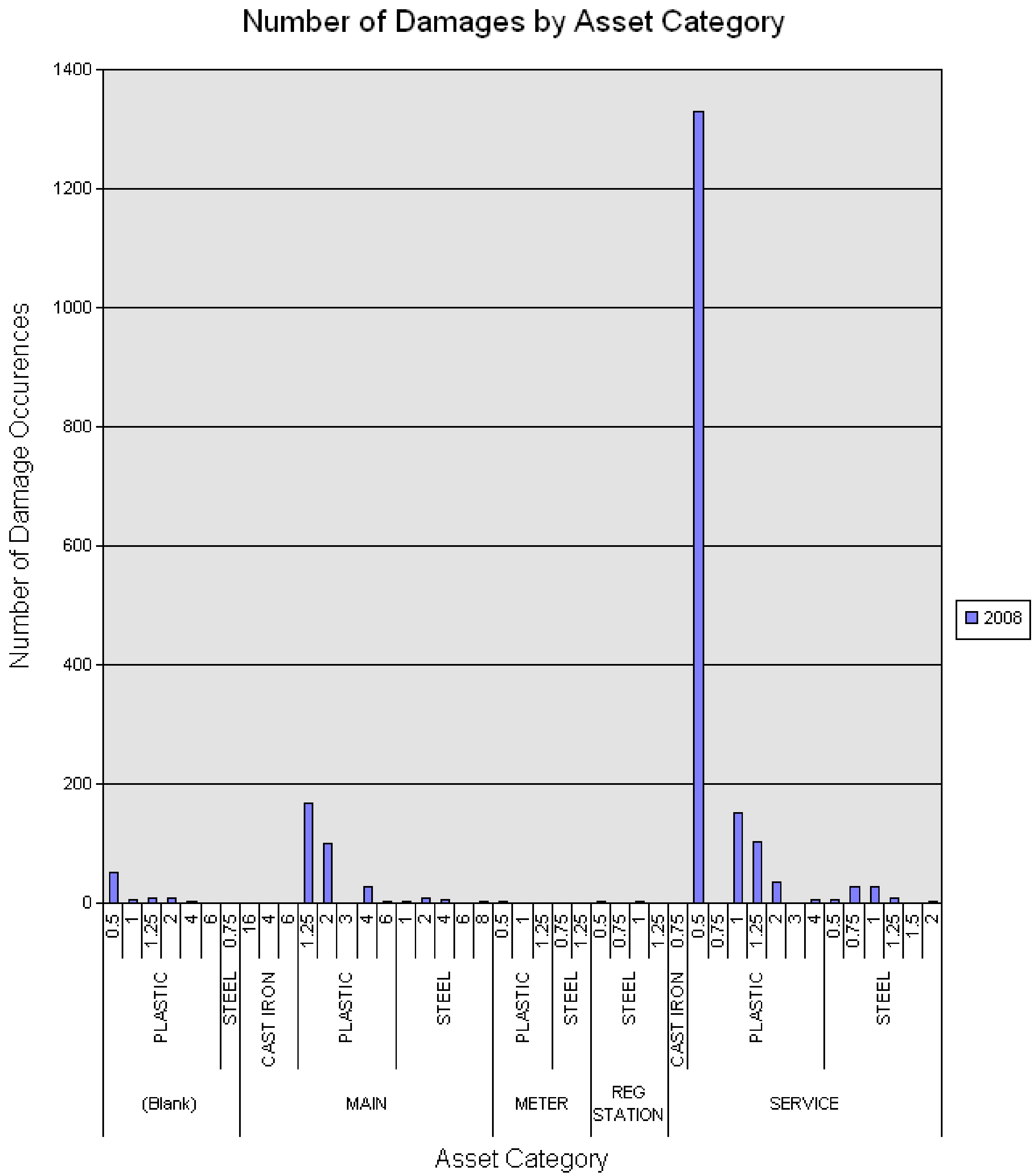


Figure 4.4.2 shows that the most frequent damage occurs to residential NPS ½ polyethylene services.

Figure 4.4.2: Characteristics of assets damaged by third parties



The Damage Prevention Department produces an annual report and develops damage prevention programs based on this data. This strategy has reduced the number of 3rd party damages per 1,000 locate requests from greater than 13.0 in 2003 to 5.4 in 2008.

4.5 Corrosion Control

The function of the corrosion control department is to minimize corrosion of the entire steel pipe in the distribution system. This section outlines issues related to maintenance of the cathodic protection system and will summarize faults and repairs to the system.

As is seen in Table 4.5.1, there is clearly insufficient information to establish any meaningful analysis from this data. This is data from a sample of 439 lines of data from Jan – June 2008 inclusive. The quality of the information gathered in the field is expected to improve in 2009 with the introduction in March of the Cathodic Protection Data Management, CPDM, system to control and record the work and the use of handheld Allegro devices to record data in the field.

Table 4.5.1: All corrosion repairs and comments using corrosion repair work requests.

Job Type	Job Code	CU	TP Reading	E Action	E Repair
MACR	COREPC	COATINGREPAIR	(Blank)	(Blank)	(Blank)
MATPRPR	CTPREP	TPREPAIR	(Blank)	broken case	replaced
				GOOD READING	REPAIRED
				installed	installed
				raise	extened wires
				removed 4x4 testpoint	install flushmount testpoint in sidewalk
				REPLACED	replaced
				REPLACED TEST POINT	replaced
			-0.15	broken 4x4 test point	replace 4x4 test point
			-1.20	(Blank)	(Blank)
			-1.27	BROKEN TEST POINT	REPAIR TOP OF TEST POINT CHEEK OKAY
			1.3	Repaired fallen post	dig up & repaired post
RERPR	REREPR	MNRREGREP	(Blank)	(Blank)	(Blank)
RRRPR	COREP	RECTMNT	(Blank)	(Blank)	(Blank)

Table 4.5.2 shows that there were a total of 18,500 inspections. Of 12,724 initial pipe to soil measurements there were 631 “60 day follow ups” along with 1,061 “fault investigations”. Of 3,180 rectifier inspections, there were 524 maintenance inspections to follow up on repairs.

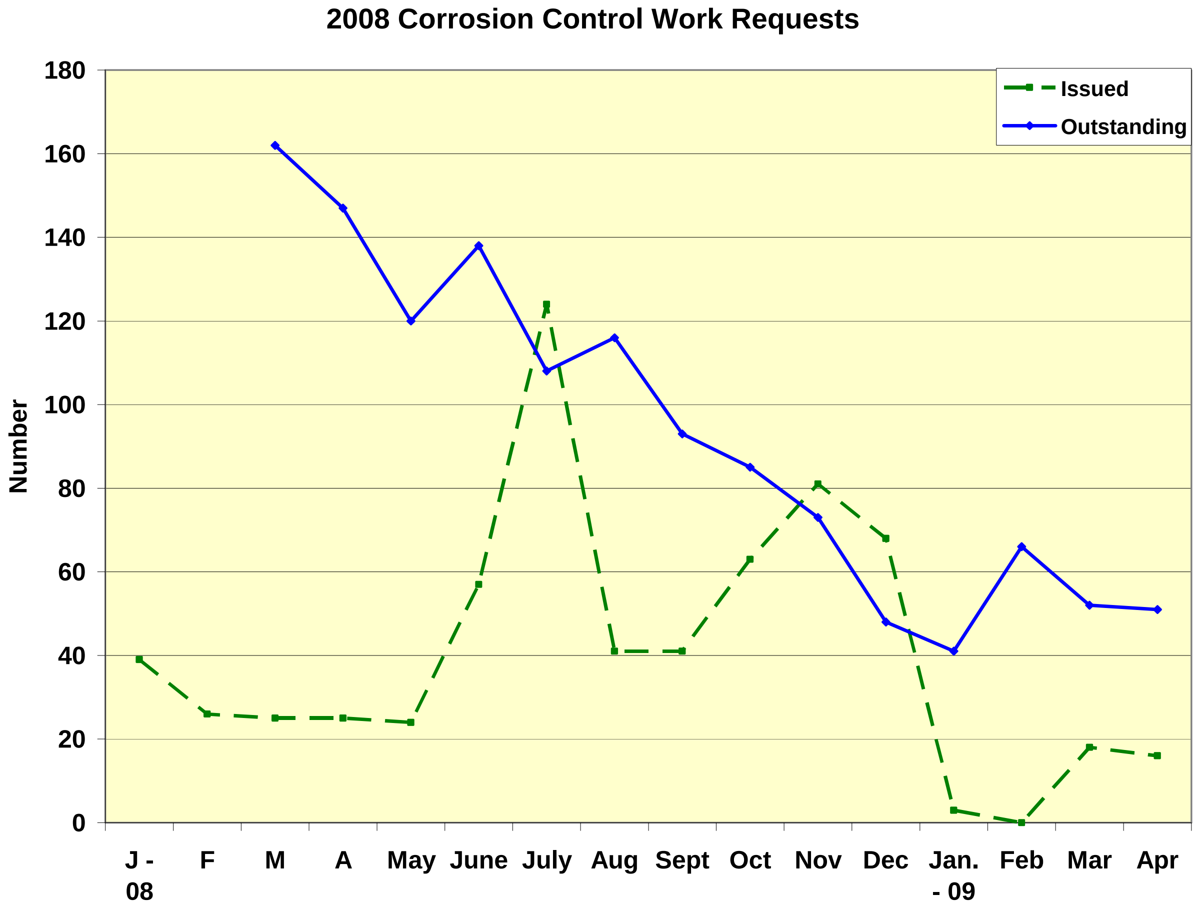
Table 4.5.2: The number of inspections in 2008 obtained from data gathered for the Corrosion Control Program.

TOTAL INSPECTIONS	**ADMIN AREA**								
INSPECTION TYPE	**10**	**20**	**30**	**40**	**50**	**60**	**80**	**90**	Grand Total
INITIAL PIPE-TO-SOIL	3,286	1,259	756	1,225	797	1,944	3,167	290	12,724
60 DAY FOLLOW-UP	249	106	64	92	32	88	0	0	631
FAULT INVESTIGATION	289	124	80	78	37	155	261	37	1,061
RECTIFIER INSPECTION	1,601	97	66	127	98	869	93	229	3,180
RECTIFIER MAINTENANCE INSPECTION	337	17	13	29	22	76	10	20	524
Grand Total	**5,772**	**1,623**	**1,009**	**1,591**	**1,036**	**3,192**	**3,611**	**666**	**18,500**

A thorough review of the corrosion control management system is currently being undertaken by Integrity Management and Technical Services. The 2008 Corrosion Department Review that discusses the current state and makes recommendations for future improvements to the program.

The 2007 Asset Health Review noted that work requests generated by the corrosion control technicians were often not completed within the times required in the O & M manual. The completion of these requests was tracked in 2008 and dramatic improvements were made in reducing the number of outstanding work requests, as shown in Figure 4.5.1 below.

Figure 4.5.1: Outstanding Corrosion Control Generated Work Requests.



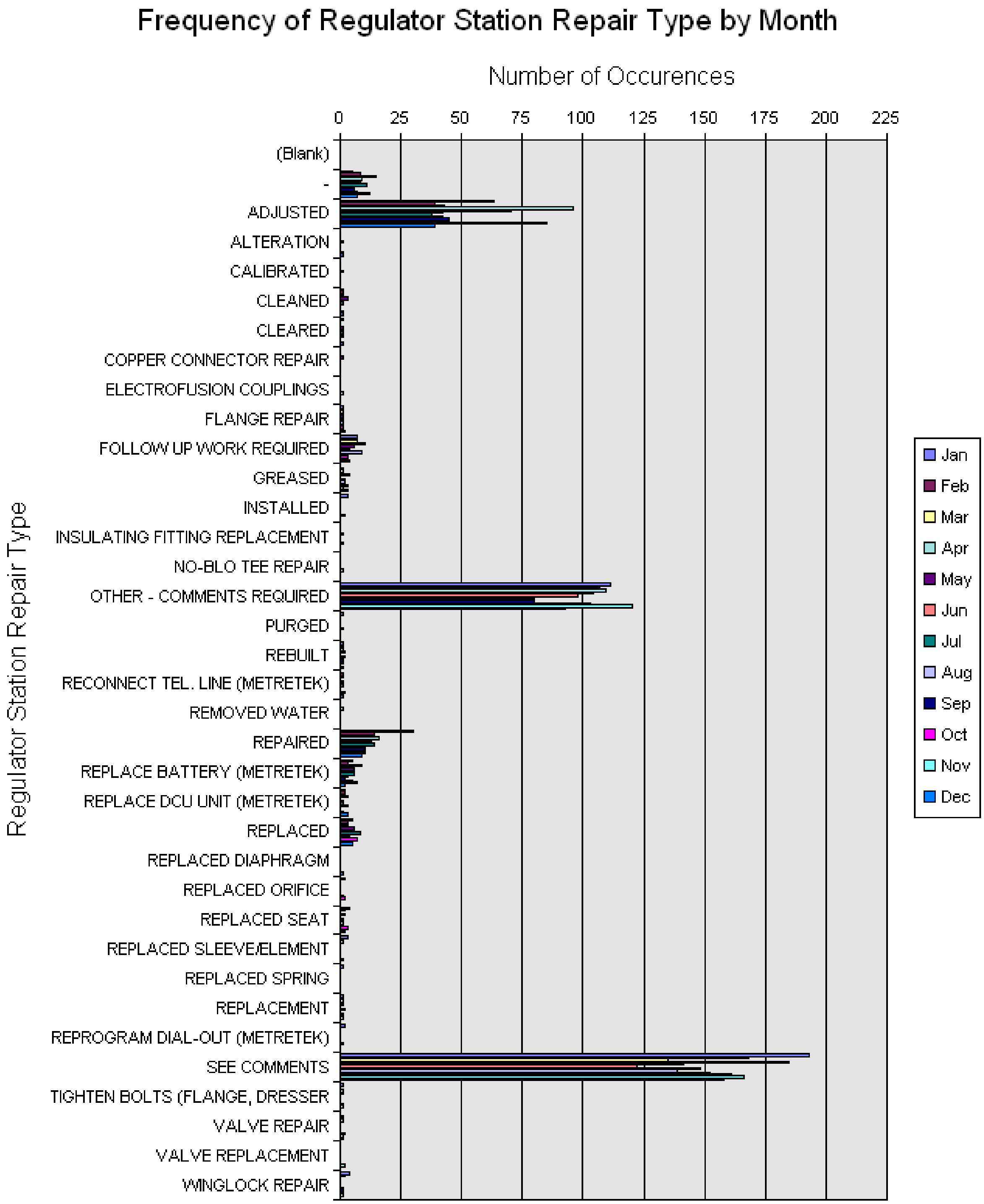
4.6 Measurement & Regulation

The majority of issues that occur with regulators and meter sets are handled by MRTC (Meter Trouble Call) work requests and the repair is completed.

Figure 4.6.1 shows that it is clear that the users prefer to use comments to describe the work that was carried out for each work request. Given that there are over 3,000 WR for this Job Type in 2008, it is not helpful to try to compile and analyse the data. Most of the repairs were of a trivial nature. Examples of the more common repairs are:

ADJ PRESSURE, ADDED OIL TO MTR
BLDG VACANT
CLEARED EVC ALARMS
GATE WEEKLY ODOURANT CHECK
DID RESYNCH
INSTALL STUBY & PAINT
INSTRUMENT EXCHANGE
LOWERED PRESSURE

Figure 4.6.1: The number of each station repair type per month.



As a method of estimating, Integrity Management determined there are indications of Leaks among these comments and these can be seen in Figure 4.6.2. This is achieved by filtering the repair comments for the word “leak”. The total is 244 for the period.

Figure 4.6.2: Regulator Station Estimated Number of Leaks

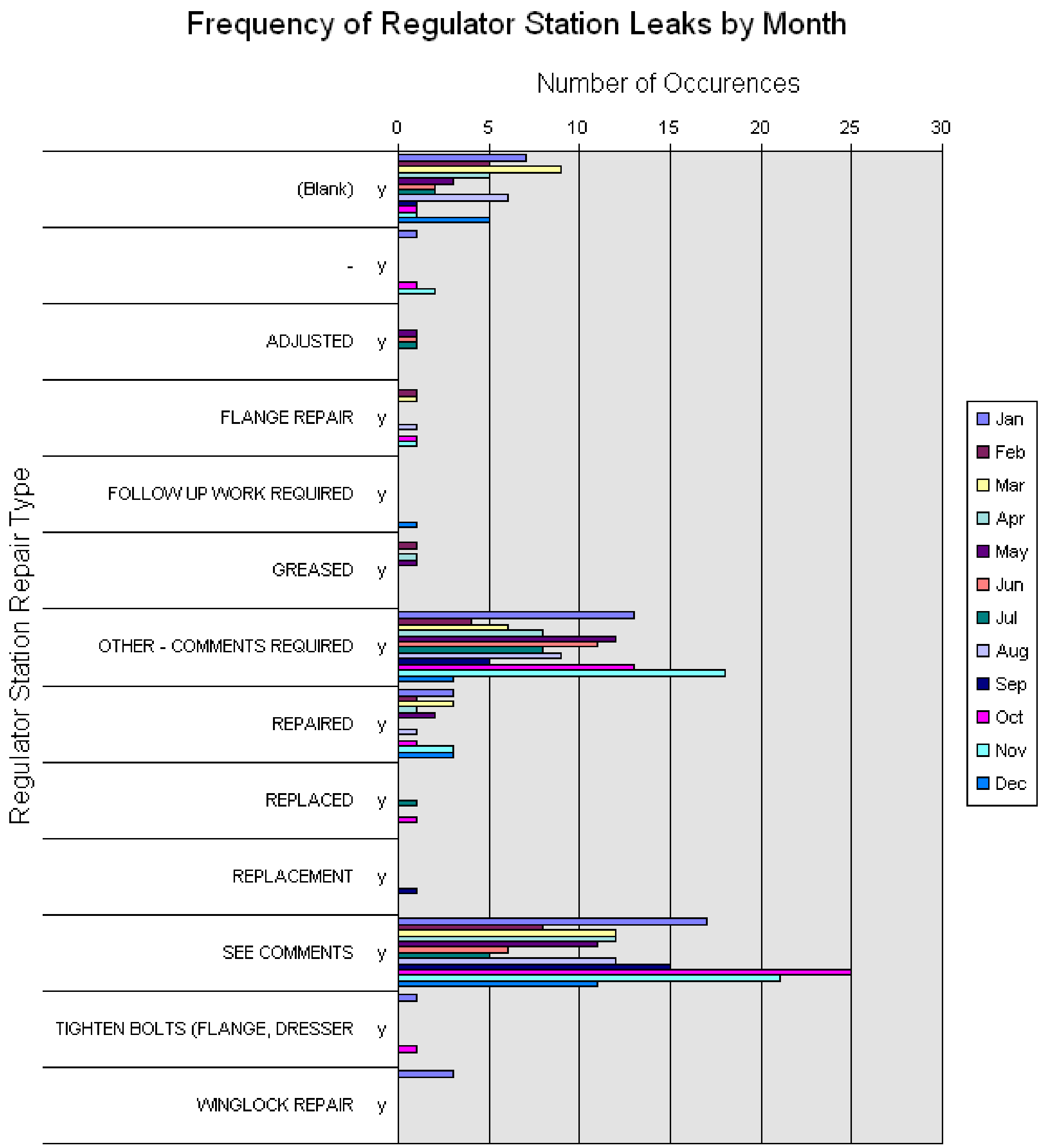
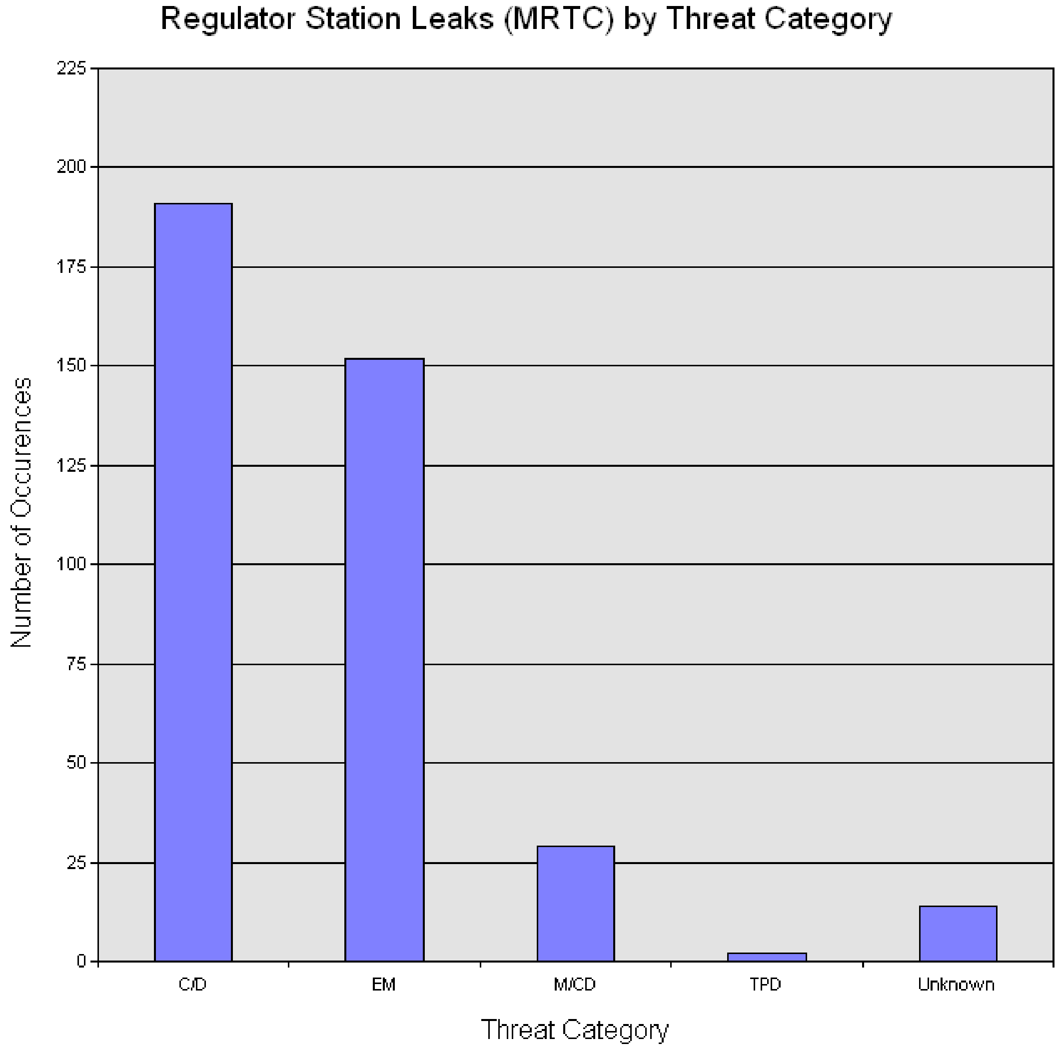


Figure 4.6.3: Regulator Station Estimated Leaks by Threat Category.



Each of the leaks was assigned to a threat category to attempt to establish any trends in failures. The data is formatted this way to be incorporated into the Summary of Threats in Section 5.0.

4.7 Bridge Crossings

Integrity Management has received copies of all bridge crossing inspections completed in 2008 and upon review can conclude that there were no significant incidents due to leaks found. Table 4.7.1 shows that there were conditions found that required action and will be repaired and rectified as per the Operating and Maintenance Manual Section 3.5.1.3.

Table 4.7.1: 2009 Bridge Crossing Inspection Summary

2008 Bridge Crossings					
	Type A	**Type B**	**Type C**	**Type N**	**Other**
Niagara 12 total	1 No hangers - recommended abandonment	3 moderately corroded	0 N/A	5 No faults	2 Abandonded and removed pipelines 1 pipe not one Bridge - replaced?
Gazifere 3 total	0 N/A	0 N/A	2 Minor Surface/support corrosion	1 No faults	0 N/A
Toronto 7 total	0 N/A	0 N/A	3 Minor Surface/support corrosion	1 No faults	3 Abandonded
Central 20 Total	0 N/A	0 N/A	5 Minor Surface/support corrosion	9 No faults	1 abandonded 1 pipe never energized 3 pipe encased in bridge concrete (unable to inspect) 1 pipe removed replaced with river crossing
Ottawa 32 Total	4	1	2	16	9 Detailed (3A, 1B, 5C, 3N)

4.8 River Crossings

Integrity Management has received copies of all bridge crossing inspections completed in 2008 and upon review can conclude that there were no significant incidents due to leaks found. Table 4.8.1 shows that there were conditions found that required action and will be repaired and rectified as per the Operating and Maintenance Manual Section 3.5.1.3.

Table 4.8.1: 2009 River Crossing Inspection Summary

2009 River Crossings					
	Type A	**Type B**	**Type C**	**Type N**	**Other**
Niagara Total 21	0 N/A	1 Pipe exposed at river	19 Requires proper	1	0 N/A
Gazifere Total 5	0 N/A	0 N/A	1 Crossing markers are in	4 Recently installed/No	0 N/A
Toronto 13 Total	0 N/A	0 N/A	11 Crossing markers not	2 No faults	0 N/A
Central 72 Total	0 N/A	4 Pipe exposed at bottom of crossing (no markers) Erosion on East Bank	48 No markers , markers require updating	20 No faults	0 N/A
Ottawa	0 N/A	0 N/A	13	7 No faults	0 N/A

4.9 Pipeline Patrol Inspections

A Technical Announcement to the Operating and Maintenance Manual was created in 2008 to clarify and enhance the process for carrying out these inspections and documenting findings. Integrity Management will follow up on this process in 2009 to ensure that the requirements set out in Section 3.3 of the Operating and Maintenance Manual are being met.

4.10 Material Fault Reports

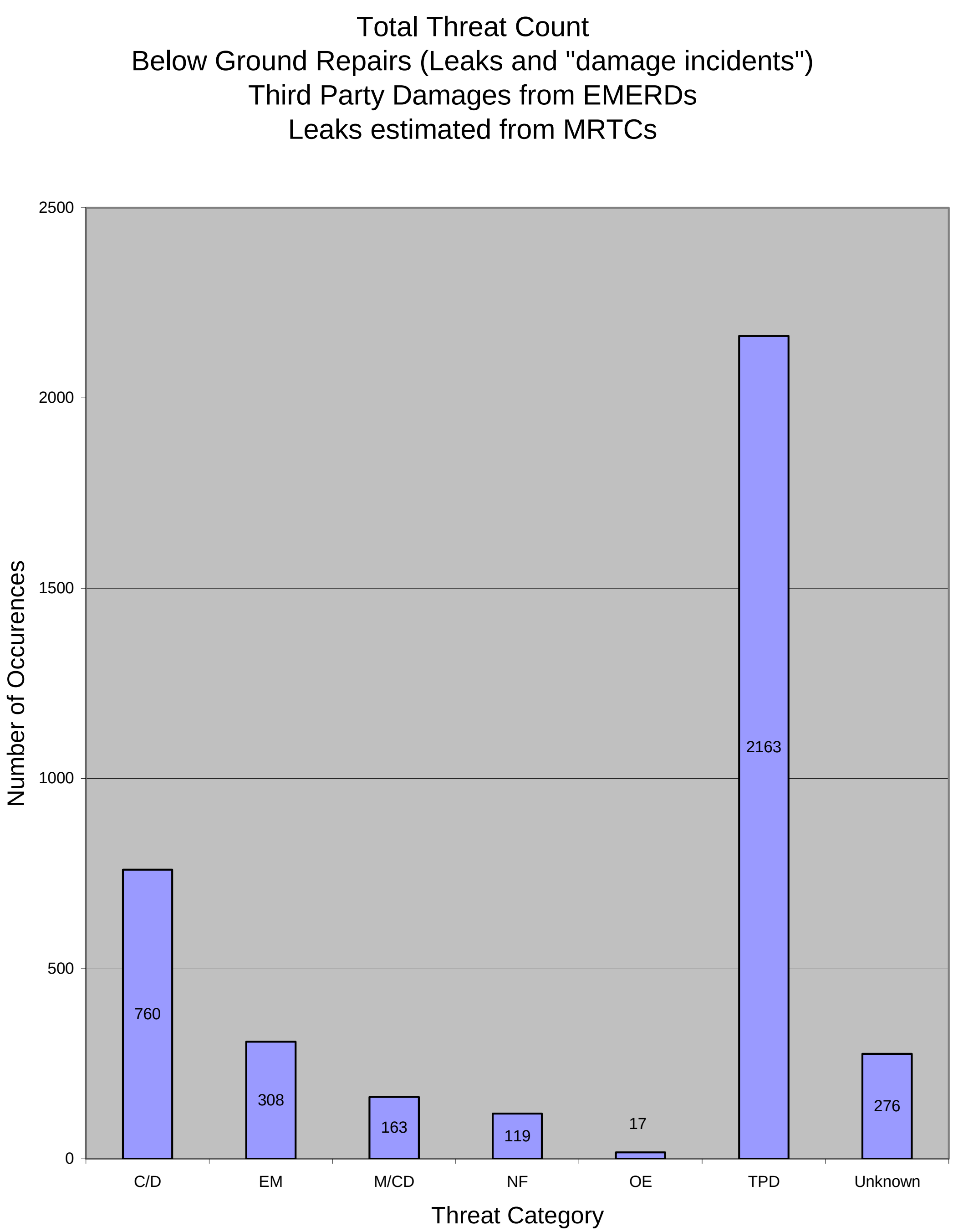
The Material Fault Reporting Program has been operating as normal. There are several highlights that are noted in the 2008 Material Fault Report Summary. The report outlines the faults recognized for action by the POLE committee and describes the action taken to mitigate immediate and future threats. This illustrates the necessity for the Material Fault Reporting Program and IM fully supports its ongoing activities. In terms of incident trending, IM has concluded that the annual Material Fault Report Summary shows no significant indications of any failure or damage incidents from new issues that are trending in a negative direction. It does highlight however, that reported AMP fitting related repairs are still on the increase which supports the information presented in Section 7.1.

5.0 Summary of Threats

For all the data gathered, there is not one single source for integrity data. This summary section attempts to pull all the basic threat analyses together to provide a picture of the distribution of threats in the distribution system.

Figure 5.1: Summary of Threats - The graph below shows the total count of threats for the following categories.

- Below Ground Repairs (Leaks and "damage incidents")
- Third Party Damages from EMERDs
- Leaks estimated from MRTCs



6.0 Consequence Analysis

As part of the risk model, consequences related to failure and damage incidents are assessed on a scale from 1 to 5 with 5 being the most severe. The rating of consequence is intended to be assessed using a scale created by a CGA Task Force on Distribution Integrity for both business and safety impacts.

The measurement of consequences was originally intended to be obtained by examining the actual consequence of each incident in the distribution system. After a period of assessment, the likelihood of determining consequences in this manner has reduced. Going forward, the assessment of potential consequences as measured by previous risk assessments is being evaluated. This method may require consultation with a risk specialist such as Dynamic Risk Assessment Systems.

7.0 Risk Assessment and Mitigation

An attempt has been made to create an overall risk assessment based on frequencies of failure of each failure type and a selection of the more frequent failure modes and components. There is some work required to establish a common equivalency between each failure category.

Once a risk assessment approach has been finalized, there will be recommendations made to outline the potential mitigation strategies required to reduce the overall risk in the distribution system.

7.1 AMP Fitting Related Failures

Integrity Management is tracking the number of failures due to internal corrosion of copper risers in the distribution system. The table below presents the findings from the Hyperion Tool extraction for above and below ground repairs. Data for this particular mode of failure has been gathered from 2007 as well as from Jan-Sept 2008. There are a growing number of failures from this asset type.

Table 7.1.1: Amp Fitting Related Failures

Year	Month	Count of AMP Related Failure			Year	Month	Count of AMP Related Failure			Trend Year over Year
		Below	Above	Total			Below	Above	Total	
2007	Jan	12	1	13	2008	Jan	3	1	4	-9
	Feb	9	0	9		Feb	10	1	11	2
	Mar	13	2	15		Mar	9	1	10	-5
	Apr	20	0	20		Apr	17	6	23	3
	May	32	4	36		May	18	1	19	-17
	Jun	31	2	33		Jun	37	5	42	9
	Jul	26	3	29		Jul	47	5	52	23
	Aug	24	1	25		Aug	51	5	56	31
	Sep	12	2	14		Sept	25	4	29	15
	Oct	13	5	18		Oct	23	1	24	6
	Nov	13	3	16		Nov	26	1	27	11
	Dec	11	0	11		Dec	12	4	16	5
	Total	**216**	**23**	**239**		**Total**	**278**	**35**	**313**	**74**

8.0 Observations and Recommendations

Below is a discussion of observations and recommendations that Integrity has determined as issues that should be addressed to aid in improving the DSIMP moving forward for 2009.

1. The existing process for leak management does not meet the requirements for data gathering and reporting for Integrity Management purposes. Integrity Management has created a recommendation for a proposed leak management workflow to allow the required data to be gathered. There are no required changes to Envision for this workflow to occur. There are several benefits to this proposed process: there will be a leak asset created for every below ground leak in the system, there will be the correct recording and classification of the leak for records and traceability purposes and leak cause and pipe condition near the leak will be recorded at the source and provide enhanced reporting. The adoption of this workflow and training are required for the implementation of the above.

2. An RMT needs to be created to change two facility attributes in the LIR CU to mandatory fields (i.e. Leak Cause, Leak Repair Pipe Condition). This will require field staff to populate those fields upon completion of a leak repair. This will be even more effective if the proposed leak management workflow in Item 1 above is adopted.

3. There is a need to establish a definition of above to below ground transition and for it to be used consistently. Currently, it is understood by IM that the

transition is at the downstream piping after the outlet of the service valve. IM recommends that this be the definition.

4. In several work requests, the staff completing the work are using the term “SEE REMARKS” and completing work descriptions in the work request remarks field. The Hyperion reporting tool is not currently set up to include remarks fields. The potential solutions are to advise operations to use the CU fields for work descriptions and/or Integrity Management to include remarks in the Hyperion reporting tool.

5. Integrity Management recommends a training program for field staff on the completion requirements for leak management activities. Further, it would be beneficial to train the field staff on the ability to understand the variety of job codes available and to master the functionality of “raising related work”. When a repair to a leak is underway. The field personnel would benefit from the understanding that the leak is an asset and has its own unique Asset ID and the leak asset needs to be managed through to completion.

6. The damage prevention data does not provide the network, low and high node of the asset that is damaged, or in the case of a service, valve or station, the main it is associated with. If it is possible, gathering this information will allow association of damages to local assets and allow GIS mapping to take place. This is one step in integrating our integrity management data for analysis purposes. The Asset Health Review runs a similar Hyperion Report to the DSIMP. This data contains EMERD work and this data set is under evaluation to better capture damage related data

7. The risk assessment approach is not fully developed at this point. An evaluation will take place to establish an equivalency for all failure and damage incidents threats and hazards in order that system issues can be ranked on a risk basis. This will be developed ongoing into 2009.

8. Services that are being relayed due to leaks in the system, such as copper, will need to be tracked more closely moving forward. Service cut offs and relays may have to be included in the Hyperion reporting tool and investigated. Should the relay arise out of a repair or LRI, then this should be captured by the leak management data.

9. Above ground service repairs work requests include several indications of leaking assets. Given that there were around 12,000 of these repairs from Jan. to Dec. 2008, the analysis is limited to the graph shown in Section 4.2.3.

10. While the data gathered is as accurate as possible, there is a significant amount of interpretation that is undertaken in order to establish the number of leaks. Integrity Management considers this approach as a best fit and is looking to utilize that data for trending analysis. Statistical

outliers are not considered in isolation unless the incident is of a significant or unique nature.

11. Corrosion Control or namely cathodic protection of the steel assets in the distribution system was originally out of scope for EGD's work management system. Technical Services, Operations and Integrity Management are working together to provide a comprehensive update to EGD's current corrosion management capabilities. As this solution progresses, the DSIMP will incorporate corrosion management information into the analysis.

12. Bare steel and cast iron mains clearly have the greatest frequency of main leaks in the distribution system. The replacement programs for these two types of mains should be completed to eliminate this threat to the system.

9.0 Conclusions

The data presented in this report is the first iteration of the data gathering process for the purposes of the Distribution System Integrity Management Program. There is an expectation as the development of the program continues that the data set will improve and become more refined.

From the data gathered to this point, it is clear that the largest threat to the distribution system is from third party damages. EGD's Damage Prevention group is focused on preventing the third party damages and continues to develop new programs and initiatives to continue to reduce the number of third party damages to the system. The group works with locate service providers to improve the accuracy and timeliness of locates, with excavators to encourage them to call before they dig and is part of the Ontario Common Ground Alliance and Ontario One Call to publicize the need for anyone planning to excavate to contact Ontario One Call for a locate.

Corrosion and degradation are the second largest threat to the system. This is generally due to wear and tear and aging of pipe and components. The analysis of the data was not able identify any trends or patterns in the occurrences of leaks and repairs caused by this threat.

Most of the failures by natural forces are accounted for in cast iron repairs. The Cast Iron Replacement program remains a priority for the organization. This threat will be completely eliminated when the last of the cast iron mains have been replaced in 2011.

The remaining bare steel mains in Niagara Region have the highest leak rate of any piping in the system and there is a prioritized program underway to replace the remaining bare steel mains.

A 2009 planned objective is in place to attempt to improve the data gathering from the leak management process. In relation to items 1 and 2 in Section 8, IM is working closely with Asset Management and in particular the Asset Health Review Report recommendations along with the findings from the Maintenance Optimization pilot program. The intent is to revise the work flow model and create an RMT to ensure that the required data fields are mandatory and to revisit and advise on the overall leak management process from DMS to departmental procedures. This is imperative to ensure that asset leak history is improved, that every leak is tied to a main, service or valve and that the leak cause is determined.

UNDERTAKING J5.6

UNDERTAKING

TR 46

To explain when the Board of Directors approves a capital budget for operation purposes.

RESPONSE

The annual budgets for Enbridge Gas Distribution Inc. are approved by Enbridge Gas Distribution Inc. Board of Directors in February of that respective year.

Witness: P. Squires

UNDERTAKING J5.8

UNDERTAKING

TR 51

To confirm whether the Board of Directors has approved anything for an Operations Capital Budget for each year of the period 2014 – 2018.

RESPONSE

The Enbridge Gas Distribution 2014 capital budget of $659 million (including WAMS, GTA and Ottawa reinforcements, as filed with the Ontario Energy Board in the current proceeding) was presented for approval by the EGD Board of Directors (as part of the enterprise-wide budget) at the February 10, 2014 Board meeting, with recognition that the EB-2012-0459 proceeding was still underway and an OEB decision not expected for several months.

Capital budgets for the years 2015 through 2018 were not presented for approval by the Board of Directors.

Witness: P. Squires

UNDERTAKING J6.4

UNDERTAKING

TR 24

To provide any history of cost sharing with municipalities or the province.

RESPONSE

No examples of cost sharing between EGDI and municipalities or the province for the purposes of system expansion were found.

It appears that discussions between EGDI and the Town of Deep River in the late 1980s and early 1990s may have included the topic of municipal cost sharing; however, as documented in the Board's decision with reasons for EBLO 231, the Company instead opted for and was permitted to collect contributions from individual customers.

Union Gas' expansion to Red Lake is an example of a municipality providing a lump sum contribution to a natural gas system expansion project. Details of the arrangements are available in EB-2001-0040/41/42.

Witness: R. Murray

UNDERTAKING J7.3

UNDERTAKING

TR

To provide evidentiary references for areas raised in the Other O&M Panel's Evidence-in-Chief (where not identified in Exhibit K7.1).

RESPONSE

Mr. Lapp: The two uses of GPS Technology (EIC pp. 4 and 5)

- GPS in field & in vehicles – Exhibit D1, Tab 13, Schedule 1, pages 17.
- GPS Asset Location – Exhibit B2, Tab 5, Schedule 5, Attachment 2, pages 19 to 21.

Locates (EIC pp. 6 and 7)

- Exhibit D1, Tab 17, Schedule 1, pages 8 to 10

Ms. Torriano: Contractor Rates (EIC pp. 7 and 8)

- Exhibit D1, Tab 13, Schedule 1, pages 13 to 16
- Exhibit D1, Tab 14, Schedule 1, pages 3 to 8

Bad Debt (EIC 8)

- Exhibit I.B17.EGDI.SEC.68, Line Item 16

Ms. Trozzi: Human Resources Embedded Productivity (EIC p. 8)

- Exhibit D1, Tab 3, Schedule 2, pages 1 to 10
- Exhibit D1, Tab 16, Schedule 1

Witnesses: D. Lapp
M. Torriano
S. Trozzi