DIMP IMPLEMENTATION
"What gets measured, gets done."

National Association of Pipeline Safety Representatives

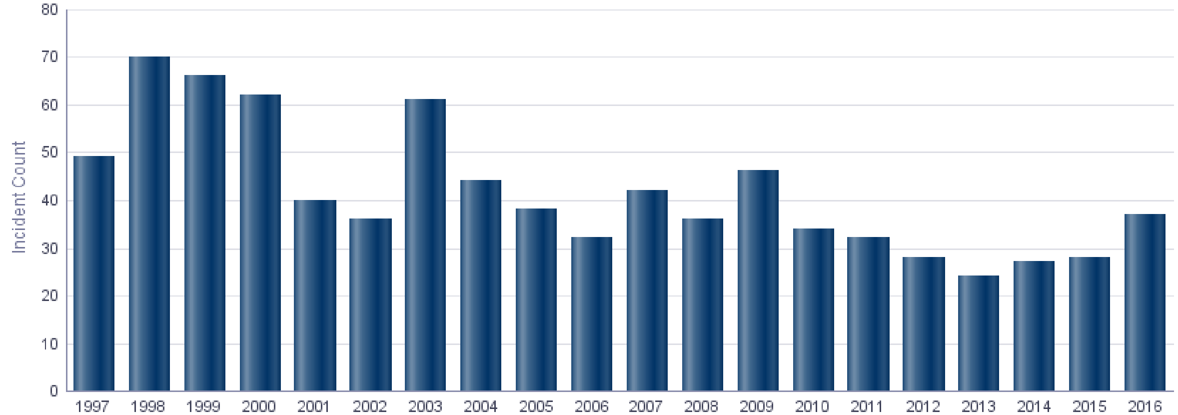
&

US DOT PHMSA Office of Pipeline Safety

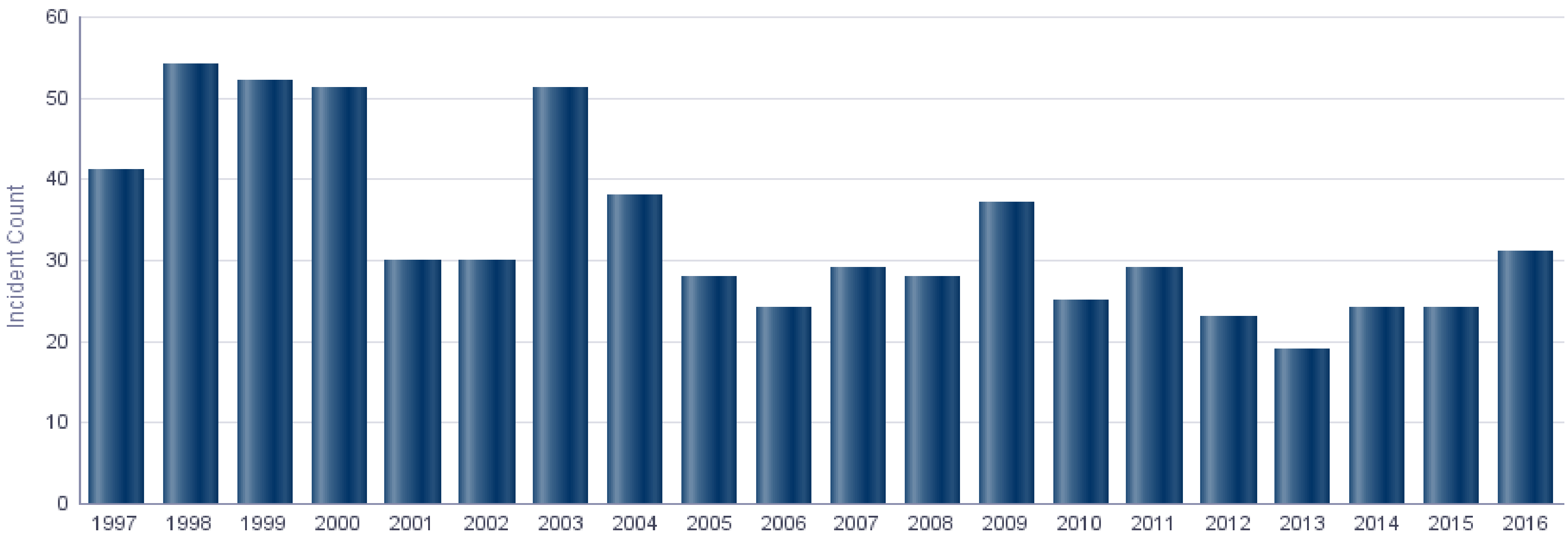
Serious Incidents (fatalities, multiple injuries)

data as-of 2/6/2017

All System Types rise in 2016



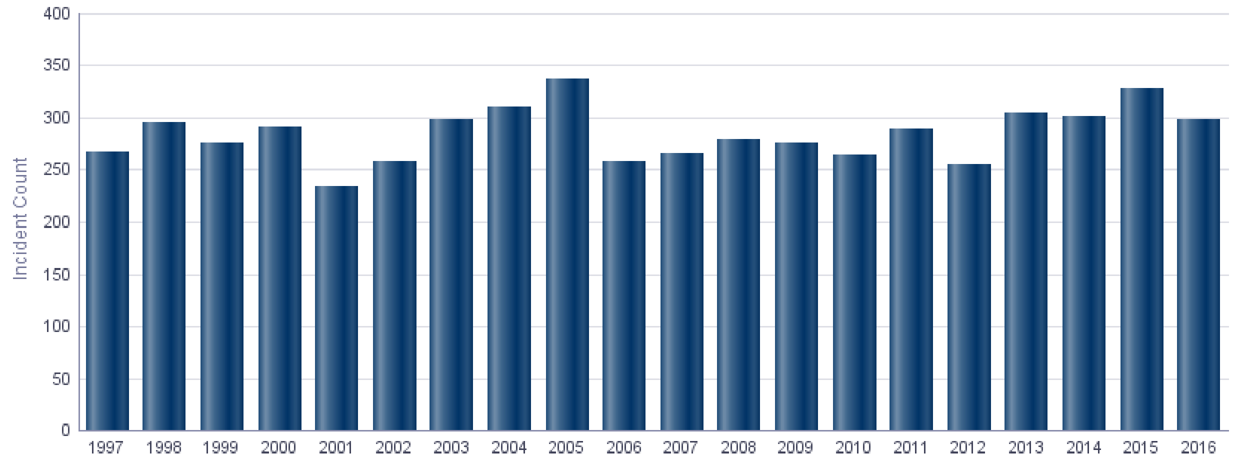
Gas Distribution rise in 2016



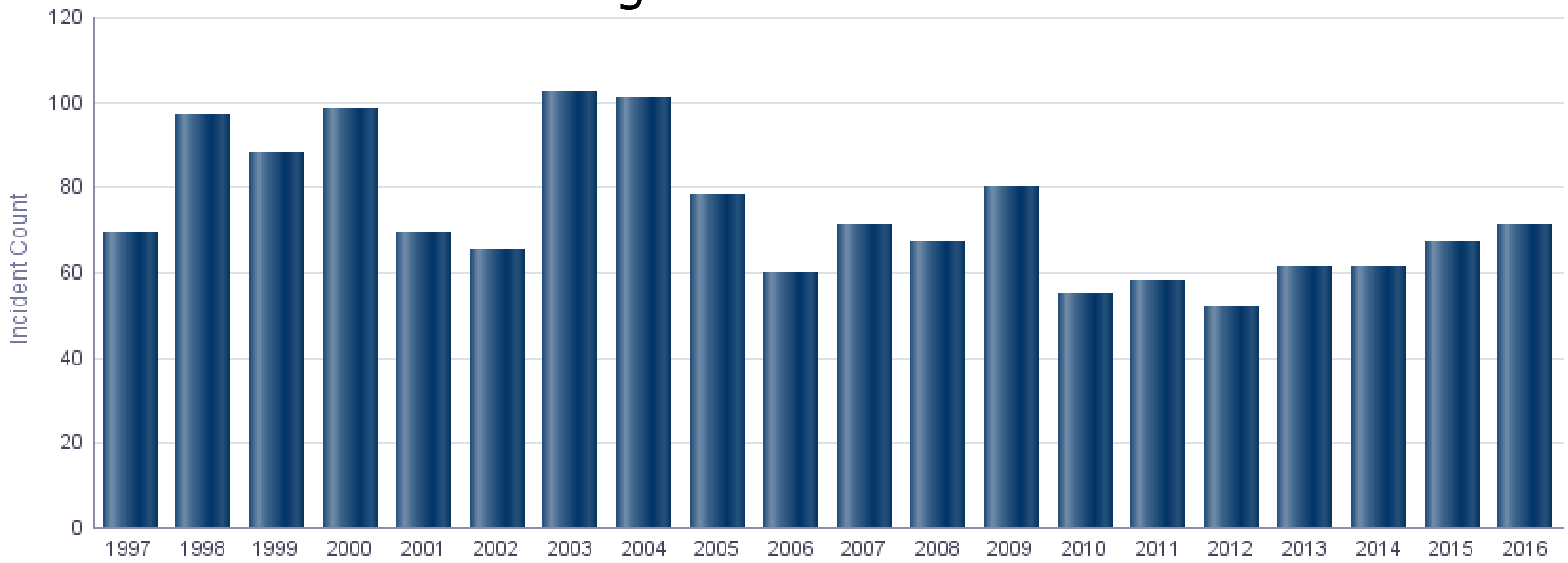
Significant Incidents

data as-of 2/6/2017

All System Types



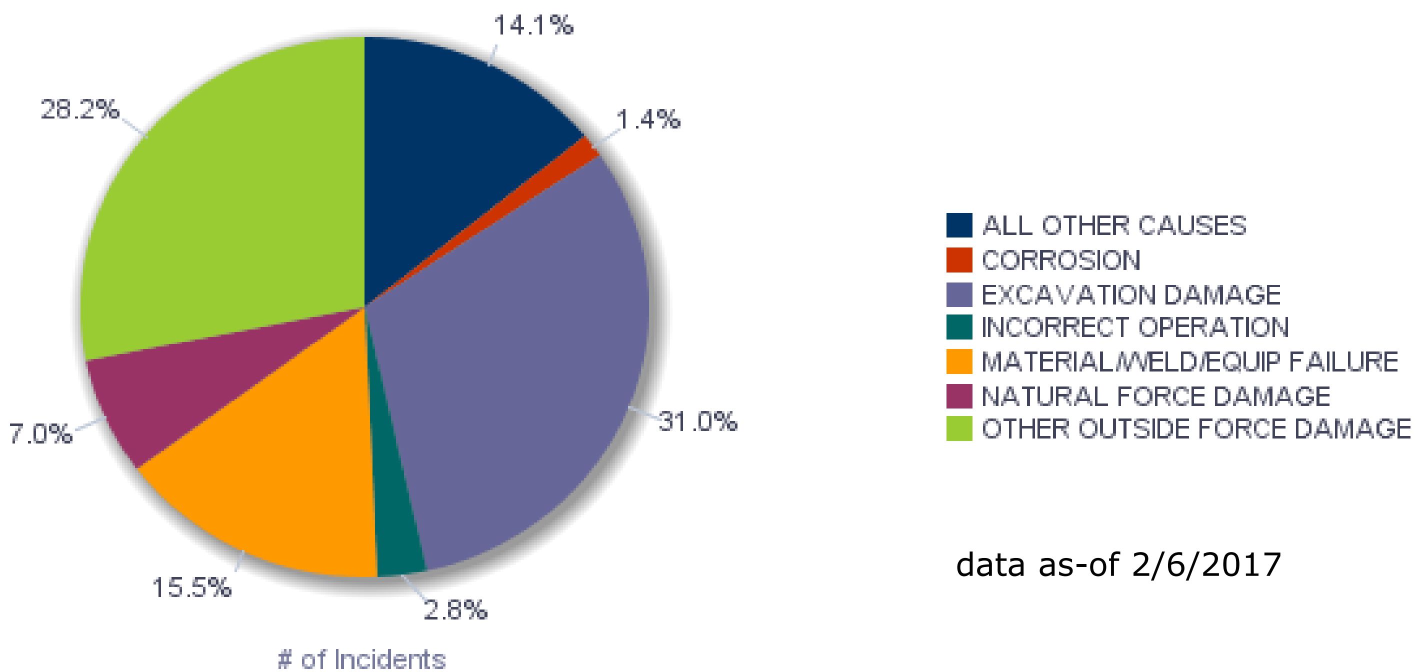
Gas Distribution slight rise in 2016



Gas Distribution Significant Incidents

CY 2016 Leading Causes:

Excavation Damage
Other Outside Force Damage
Material/Weld/Equip Failure



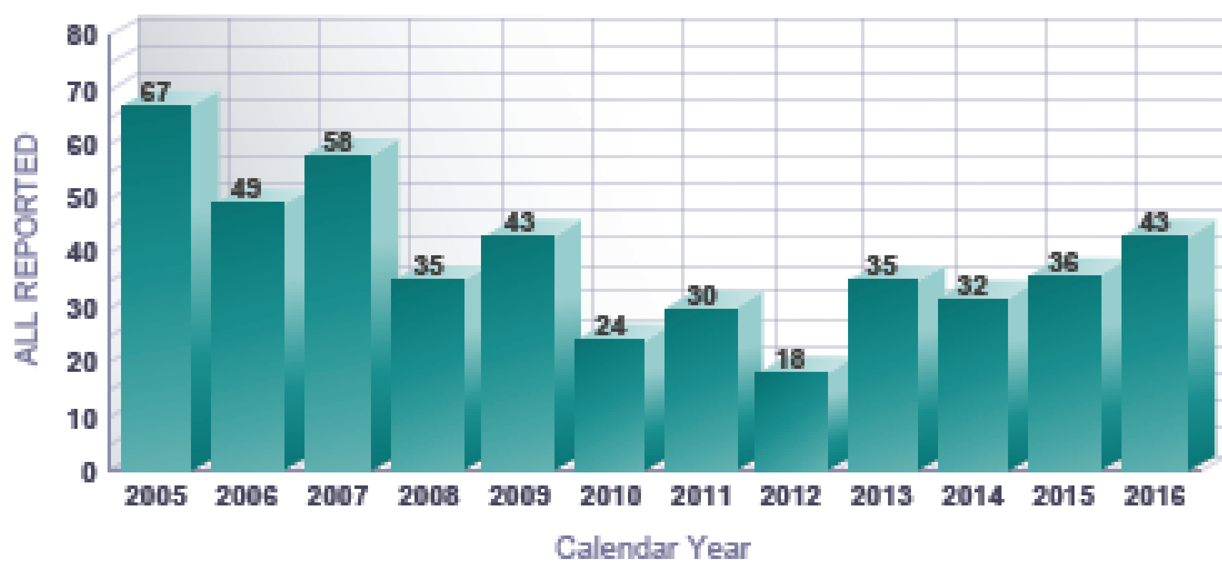
data as-of 2/6/2017

Trends in GD Incidents by Cause

Geo Region: ALL Geo State: ALL

	ALL REPORTED												Total
Incident Cause Type	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	
ALL OTHER CAUSES	15	23	22	16	21	16	14	7	10	13	13	17	187
CORROSION	2	3	1	5	2	5	4	3	1	2		2	30
EXCAVATION DAMAGE	67	49	58	35	43	24	30	18	35	32	36	43	470
INCORRECT OPERATION	7	4	1	6	5	9	9	7	4	8	2	7	69
MATERIAL/WELD/EQUIP FAILURE	11	7	13	9	12	8	13	11	16	12	8	14	134
NATURAL FORCE DAMAGE	15	11	12	11	13	9	12	5	5	8	14	6	121
OTHER OUTSIDE FORCE DAMAGE	51	43	41	62	60	49	35	39	34	34	30	31	509
Grand Total	**168**	**140**	**148**	**144**	**156**	**120**	**117**	**90**	**105**	**109**	**103**	**120**	**1,520**

Incident Cause Type EXCAVATION DAMAGE

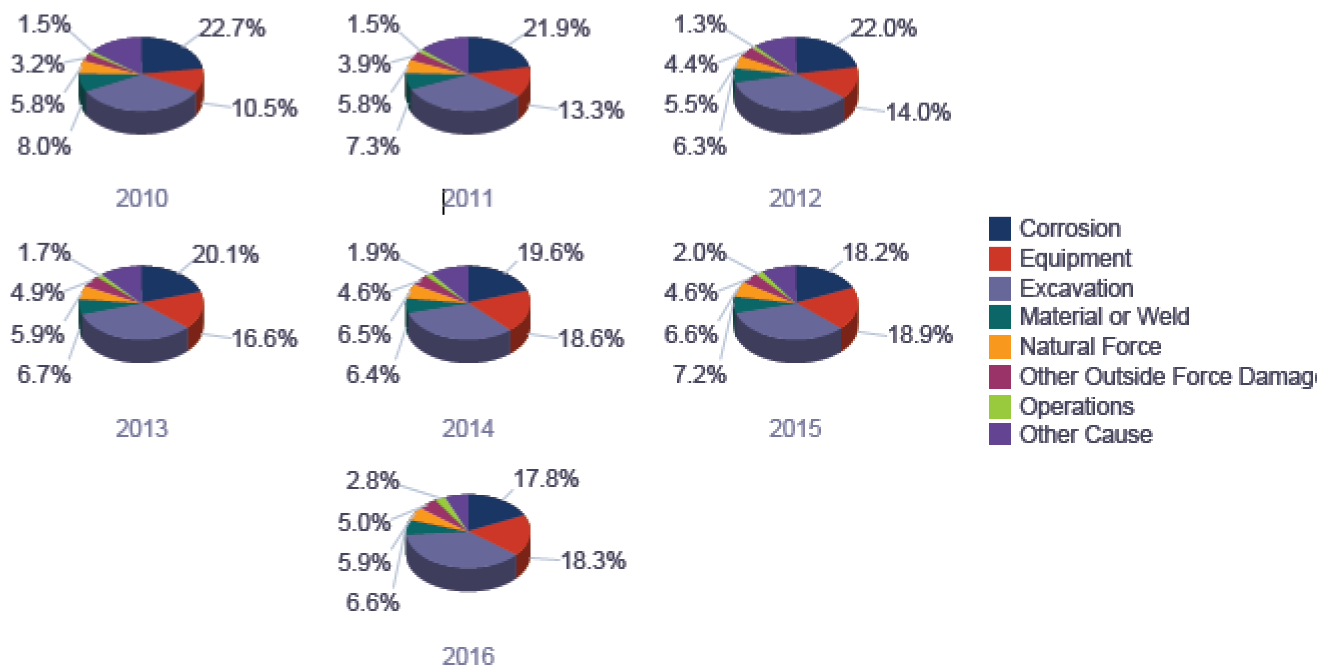


data as-of 8/18/2017

Trends in GD Hazardous Leaks by Cause

Geo Region: ALL Geo State: ALL

	2010	2011	2012	2013	2014	2015	2016
Leak Cause							
Corrosion	42,180	41,988	41,260	38,308	40,385	39,000	37,287
Natural Force	10,855	11,187	10,250	11,322	13,322	14,120	12,421
Equipment	19,500	25,474	26,218	31,729	38,344	40,485	38,256
Material or Weld	14,977	13,971	11,828	12,733	13,093	15,340	13,792
Excavation	63,699	63,470	66,255	63,718	66,925	71,752	78,896
Operations	2,740	2,962	2,491	3,224	3,836	4,363	5,932
Other Outside Force Damage	5,925	7,429	8,194	9,264	9,399	9,819	10,567
Other Cause	26,346	25,149	20,702	20,492	20,566	18,952	12,440



data as-of 8/18/2017

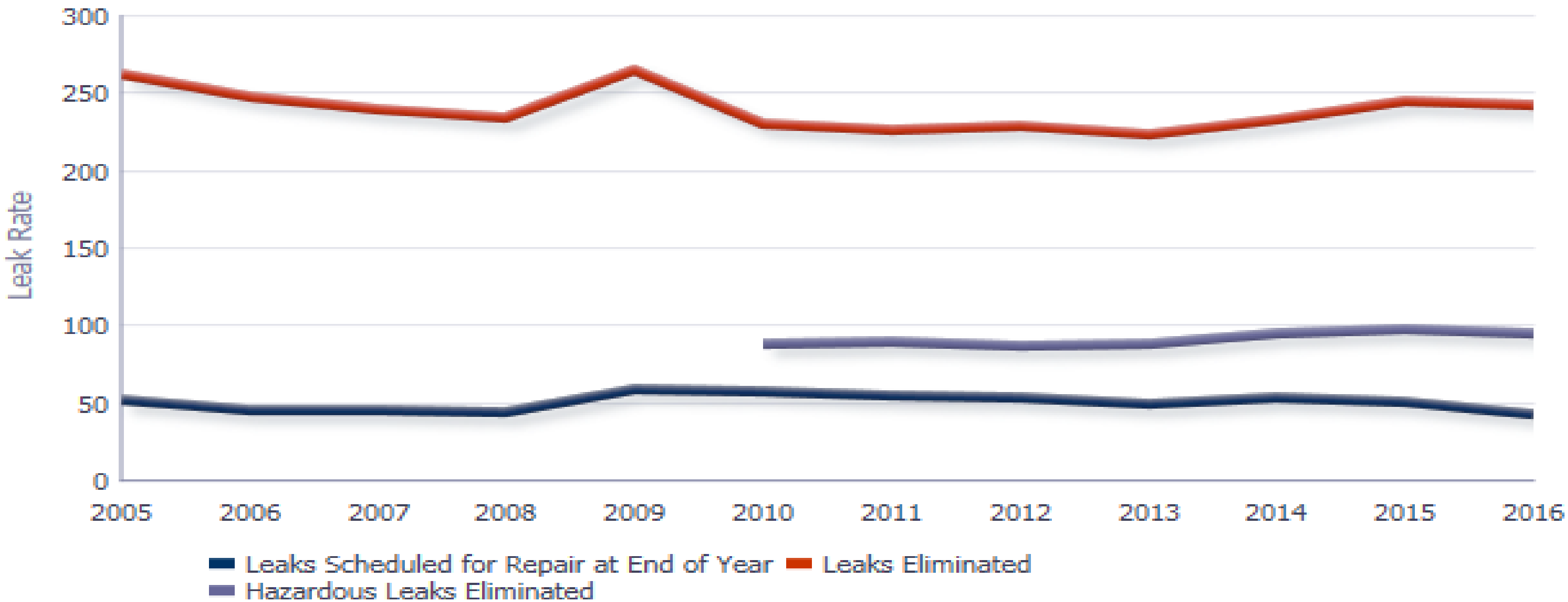
Performance Measurement

- Gas Data Quality & Analysis Team posted Gas Distribution and Gas Transmission Performance Measures on the OPS website at https://www.phmsa.dot.gov/pipeline/library/data-stats/performance-measures
- Key Performance Indicators (KPIs)

Gas Distribution Performance Measures

- Serious Incident per Mile - trend & cause pie chart
- Significant Incident per Mile - 3 trends
- Leaks per Mile - 3 trends & 2 cause pies
- Excavation Damage - 2 trends
- Cast and Wrought Iron - 2 trends
- Steel Miles (Bare and Unprotected) - 3 trends
- Miles by Decade Installed - 6 trends

Trends in Gas Distribution Leaks



PHMSA began collecting the number of **Hazardous Leaks Eliminated** in 2010. The rate per 1,000 mile for Hazardous Leaks Eliminated has increased 7% since 2010. The effective date for PHMSA's gas distribution integrity management (DIMP) regulations was 2011. PHMSA expects an eventual decrease in the rate as pipeline operators identify integrity threats and implement measures to reduce risk.

The rate per 1,000 mile for all **Leaks Eliminated** has decreased 8% since 2005.

The rate per 1,000 mile for **Leaks Scheduled for Repair at End of Year** has decreased 17% since 2005.

Trends in Gas Distribution Leaks Operator Level

Gas Distribution Leaks – Operators with 10,000 miles or more
Time run: 8/19/2017 9:45:15 AM

Data Source: US DOT Pipeline and Hazardous Materials Safety Administration
Data as of: 08/18/2017

Operator ID	Operator Name	5 Year Average Hazardous Leaks Eliminated (leaks per 1,000 miles)	10 Year Average Leaks Eliminated (leaks per 1,000 miles)	5 Year Average Leaks Eliminated (leaks per 1,000 miles)	10 Year Average Leaks Scheduled for Repair (leaks per 1,000 miles)	2016 Miles
1640	BOSTON GAS CO	377.24	780.11	674.57	24.03	10,784.32
1088	BALTIMORE GAS AND ELECTRIC COMPANY	217.18	514.52	579.26	80.03	13,569.59
2364	DUKE ENERGY OHIO	193.69	508.81	440.38	85.43	11,396.25
21349	VIRGINIA NATURAL GAS	169.17	414.87	388.48	40.34	10,974.47
18532	TEXAS GAS SERVICE COMPANY, A DIVISION OF ONE GAS, INC.	167.56	340.35	401.37	102.67	15,781.19
4499	CENTERPOINT ENERGY RESOURCES CORPORATION	155.73	440.76	405.81	85.08	66,113.22
12350	CENTERPOINT ENERGY RESOURCES CORP., DBA CENTERPOINT ENERGY MINNESOTA GAS	154.77	289.11	281.27	14.66	25,577.47
180	ALABAMA GAS CORPORATION	149.54	368.99	291.97	70.56	23,813.98
2596	COLUMBIA GAS OF OHIO INC	147.56	392.49	375.05	133.59	41,683.39
603	CENTERPOINT ENERGY RESOURCES CORP.	141.28	376.70	332.59	158.42	30,587.93

Rows 1 - 10

Gas Transmission Performance Measures

- Serious Incident per Mile - trend & cause pie
- Onshore Significant Incident per Mile - 3 trends, also HCA and non-HCA trends & cause pies
- HCA Immediate Repair per Mile - trend
- HCA Leaks & ILI Detectability - 2 trends & cause pie charts
- Steel Miles (Bare and Unprotected) - 2 trends
- Miles by Decade Installed - 5 trends
- Onshore Pipeline Significant Incident Rates per Decade - rate chart and cause chart

Integrity Management Systems Performance Measurement

- ADB 2014-05 - Guidance for Meaningful Metrics
    - ➢ ADB–2012-10 Using Meaningful Metrics in Conducting Integrity Management Program Evaluations
- ADB 2014-02 - Lessons Learned from the Marshall, Michigan, Release

NTSB Failure Investigation Report of San Bruno, CA incident

NTSB concluded that the company's self-assessments were ''superficial and resulted in no improvements to the integrity management program.''

As a result, NTSB recommended: "Assess every aspect of your integrity management program, paying particular attention to the areas identified in this investigation, and implement a revised program that includes, at a minimum, .."

Recommendation P–11–29 .. (4) an improved self-assessment that adequately measures whether the program is effectively assessing and evaluating the integrity of each covered pipeline segment

ADB – 2012-10

- Remind operators of their responsibilities, under Federal IM regulations, to perform evaluations of their IM programs using meaningful performance metrics. Program evaluation is a required integrity management program element as established in §192.911(i)
- A critical program element of an operator’s integrity management program is the systematic, rigorous evaluation of the program’s effectiveness using clear and meaningful metrics.
- When executed diligently, this self-evaluation process will lead to more robust and effective integrity management programs and improve overall safety performance.
- This process is critical to achieving a mature IM program and a culture of continuous improvement and learning.

ADB – 2012-10

- Metrics that measures and provide insights into how well an operator’s processes associated with the various IM program elements are performing.
- Specific threats that include both leading and lagging indicators for the important integrity threats on an operator’s systems, including:
  - ➢ Activity Measures that monitor the surveillance and preventive activities that are in place to control risk
  - ➢ Deterioration Measures that monitor operational and maintenance trends to indicate if the program is successful or weakening despite the risk control activities in place
  - ➢ Failure Measures that reflect whether the program is effective in achieving the objective of improving integrity.

NTSB Failure Investigation Report of San Bruno, CA incident

NTSB Findings 25 & 26

25 - Effective and meaningful metrics were not incorporated as part of performance-based pipeline safety management programs, neither the operator nor regulator was able to effectively evaluate or assess the integrity of the operator's pipeline system

26 - Because PHMSA has not incorporated the use of effective and meaningful metrics as part of its guidance for effective performance-based pipeline safety management programs, its oversight of state public utility commissions regulating gas transmission and hazardous liquid pipelines needs improvement.

NTSB Failure Investigation Report of San Bruno, CA incident

NTSB Recommendation P-11-19-1 to PHMSA

(1) Develop and implement standards for integrity management and other performance-based safety programs that require operators of all types of pipeline systems to regularly assess the effectiveness of their programs using clear and meaningful metrics, and to identify and then correct deficiencies

ADB – 2014-05

- PHMSA developed guidance on the elements and characteristics of a mature program evaluation process that uses meaningful metrics
- Major topic areas addressed in the guidance document include:
  - Establishing Safety Performance Goals
  - Identifying Required Metrics
  - Selecting Additional Meaningful Metrics
  - Data Collection and Metric Monitoring
  - Program Evaluation Using Metrics

ADB – 2014-05 Guidance

- Tables 1 & 2 are lists of metrics required by Part 192 and ASME B31.8S-2004 **TO BE USED!**

Table 2 - Other Required Metrics for Gas Transmission and Distribution Systems

Required by §192.945 and ASME B31.8S-2004, Table 9 for Gas Transmission Pipelines:

Threat	Performance Metrics for Prescriptive Programs
External corrosion	Number of hydrostatic test failures caused by external corrosion
	Number of repair actions taken due to in-line inspection results
	Number of repair actions taken due to direct integrity assessment results
	Number of external corrosion leaks
Internal corrosion	Number of hydrostatic test failures caused by internal corrosion
	Number of repair actions taken due to in-line inspection results
	Number of repair actions taken due to direct integrity assessment results
	Number of internal corrosion leaks

ADB – 2014-05 Guidance

Table 3 - IM Programmatic Performance Metrics

Table 3 - IM Programmatic Performance Metrics

	Leading ---Indicators--- *Lagging*		
Program Element	**Selected IM Process, Operational or Activity Metrics**	**Operational Deterioration Indicators**	**Failure or Direct Integrity Metrics**
1. Identification of pipeline segments that could impact HCAs	• Frequency of updates to segment identification analysis • Frequency and nature of reviews conducted to identify new HCAs • Frequency of field district surveys or ROW inspections identifying new HCAs – or segments that could affect HCAs • Frequency and nature of review of procedures and assumptions made in identifying segments that could affect HCAs • Frequency of updates to aerial photography used for HCA segment analysis • Frequency of contacts with public safety officials and others having local knowledge for information on potential "identified sites" or could affect segments	• No. of newly acquired or newly identified assets not incorporated within the IMP within the required timeframe • No. of previously mis-identified HCAs identified as HCAs in updates to the segment identification analysis • No. of PIR calculations using an inappropriate formula for product transported (Gas Trans) • No. of new HCAs or could affect segments identified due to changing conditions (pipeline modifications, new public construction, change in public use of existing buildings, etc.) • No. of abnormal weather conditions (e.g., stream flow rate) that exceed assumptions used in HCA or could affect segment identification	• No. of releases which reached an HCA from pipe that was not determined to be a "could affect" segment (Haz Liq) • No. of releases with adverse impacts beyond the PIR (Gas Trans) • No. of releases which had different impacts to HCAs than determined by the "could affect" analysis • No. of releases which reached different HCAs than determined by the "could affect" analysis • No. of releases that exceeded the highest estimated volume that could be released in a segment (Haz Liq)

ADB – 2014-05 Guidance

Table 4 - System and Threat-Specific Performance Measurement

Table 4 - System and Threat-Specific Performance Measurement

	Leading ------------------------Indicators------------------------*Lagging*		
Failure Mechanism	**Selected Process or Operational Activities for Threat Prevention or Management**	**Deterioration Indicators**	**Failure or Direct Integrity Metrics**
Mechanical Damage			
First-party (operator) and second-party (contractor) damage	• Operator procedures for excavation on or near its own pipeline • Contractor procedures for excavation on or near the pipeline • Use of current system / facility maps	• No. of improper locates • No. of excavations outside locate area • No. of incidents / accidents where procedures were not followed or where appropriate care was not exhibited • No. of damages not reported • No. of enforcement actions taken by enforcement authority • Increase in frequency of damage	• Releases due to first or second party damage

DIMP Inspection Results and Findings

High Level Observations

- DIMPs must Mature and be Continuously improved to mature to fit the operator's unique operating environment - a learning experience
- DIMP Rule is a performance based regulation to be flexible and allow operators to implement their DIMP in the most efficient and effective manners to improve pipeline safety.

High Level Observations

- Treat DIMP as a tool to analyze needs and progress, not as a regulatory exercise.
- The Plan should culminate in a ranked/prioritized list of threats, risk reduction measures, and performance measures – Table in Inspection Form.

Measures to Address Risks (Threats)

- Table 1 in DIMP Inspection Forms 22 & 23 provide an overview of risk reduction and monitoring methods

	Primary Threat Category	Threat Subcategory, as appropriate	Measure to Reduce Risk implemented	Performance Measure
1	Corrosion	External Corrosion on Copper Service Lines	Replace approximately 100 copper service lines each calendar year	Track number of leaks caused by external corrosion per 1000 copper service lines annually
2	Excavation Damage	Third Party Damage	Conduct pre-construction meetings or Monitor locate for life of ticket	Track frequency of failures per 1000 excavation tickets annually
3	Equipment Failure	Mechanical Fittings, Couplings or Caps/Seals	Repair or replace problem materials as found	Track frequency of failures by equipment type annually

Concerns

- Training of All personnel regarding DIMP requirements
- Awareness of DIMP by all personnel – not just at the headquarter or compliance level
- Data quality is a common concern, and an appropriate level of resource allocation is required;
    - Outdated Field data acquisition forms
    - Incomplete Forms with obvious errors
    - Outdated data systems difficult to use or sort
    - Data cleanup and scrubbing is often required

DIMP Inspections

- Vacancies created by an aging workforce (turn-over) have created voids in operating knowledge of pipeline systems, and trained personnel have not always been available for inspections.
- Procedures are required in 192.1007, and plans must contain adequate procedural documentation.
- Procedure means a fixed, step-by-step sequence of activities or course of action (with definite start and end points) that must be followed in the same order to correctly perform a task.

Some all too Common Observations

- The inspection revealed the operator did not identify additional information needed and a plan for gaining missing information over time through normal activities conducted on the pipelines even though Design and Construction records were unavailable for the operator's high pressure distribution main and town’s original pipeline.
- DIMP must provide adequate details and specificity to address specific potential and existing threats and risks in the Operator’s unique operating environment

Addressing Risks to Improve Safety

- **§192.603(c) Abnormal operation. (4)** Periodically reviewing the response of operator personnel to determine the effectiveness of the procedures controlling abnormal operation and taking **corrective action where deficiencies are found**.
- **192.613 Continuing surveillance** (a) Each operator shall have a procedure for continuing surveillance of its facilities to determine and **take appropriate action** concerning changes in class location, failures, leakage history, corrosion, substantial changes in cathodic protection requirements, and other unusual operating and maintenance conditions. …
- **192.617 Investigation of failures** Each operator shall establish procedures for analyzing accidents and failures, including the selection of samples of the failed facility or equipment for laboratory examination, where appropriate, for the purpose of determining the causes of the failure and **minimizing the possibility of a recurrence**.
- **192.1007 What are the required elements of an integrity management plan? … (b) Identify threats & (d) Identify and implement measures to address risks.**

Potential Threats For Consideration

- Over pressurization events
- Regulator malfunction or freeze-up
- Cross-bores into sewer lines
- Materials, Equipment, Practices, etc. with performance issues
- Vehicular or Industrial activities
- Incorrect maintenance procedures or faulty components
- Mechanical fitting failures (Vintage Plastic and Steel)
- Operator error/quality of workmanship
- Age of system and equipment
- Electrical arcing onto the gas systems
- Other potential threats specific to the operator's unique operating environment

Move from Compliance to Choice

- Our world must move from a "checkbox" mentality to understanding the health of our pipeline systems by analyzing and understanding data and information and promptly acting to reduce risks
- Safety Management Systems provide a platform from which to drive continuous improvement in the safe operation and integrity of a pipeline system.
- Continuous improvement is a requirement to meet the minimum safety regulations for integrity management programs – TIMP & DIMP.

Where Management Systems will take us

Reactive –> Proactive -> Predictive

"What gets measured, gets done."

DIMP Home

PHMSA
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration

Pipeline Technical Resources

Return to Pipeline Safety Community

Home	Alternative MAOP	Cased Crossings and GWUT	Class Location	CRM	DIMP	Gas IM

HL IM	High Volume EFV	Low Strength Pipe	OQ	Pipeline Construction	R&D	LNG Facility Siting	Public Meetings

Gas Distribution Integrity Management Program

DIMP Menu

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- Feedback

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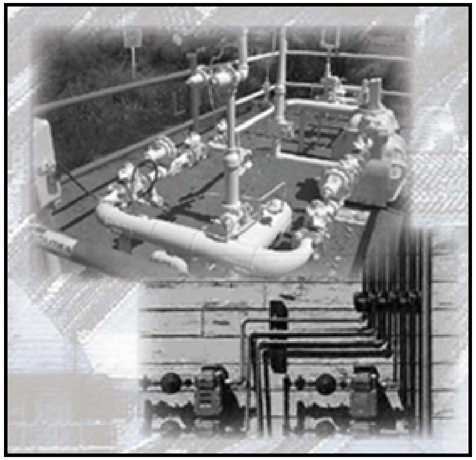

The Pipeline and Hazardous Materials Safety Administration (PHMSA) published the final rule establishing integrity management requirements for gas distribution pipeline systems on December 4, 2009 (74 FR 63906). The effective date of the rule is February 12, 2010. Operators are given until August 2, 2011 to write and implement their program.

PHMSA previously implemented integrity management regulations for hazardous liquid and gas transmission pipelines. These regulations aim to assure pipeline integrity and improve the already admirable safety record for the transportation of energy products. Congress and other stakeholders expressed interest in understanding the nature of similarly focused requirements for gas distribution pipelines. Significant differences in system design and local conditions affecting distribution pipeline safety preclude applying the same tools and management practices as were used for transmission pipeline systems. Therefore, PHMSA took a slightly different approach for distribution integrity management, following a joint effort involving PHMSA, the gas distribution industry, representatives of the public, and the National Association of Pipeline Safety Representatives to explore potential approaches.

http://primis.phmsa.dot.gov/dimp/index.htm

PHMSA Websites

Please regularly use PHMSA websites as they are a primary form of communication with Stakeholders

PHMSA Office of Pipeline safety

http://phmsa.dot.gov/pipeline

DIMP Home Page

http://primis.phmsa.dot.gov/dimp/index.htm

Pipeline Safety Stakeholder Communications

http://primis.phmsa.dot.gov/comm/

Pipeline Replacement Updates

http://opsweb.phmsa.dot.gov/pipeline_replacement/

Assessing Maturity

Questions and Comments?

Thank you for your participation in Pipeline safety!