2012-2015 Triennium Work Reports

# Pipeline Integrity Management System

## Study Group 3.2

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## 1.0 Executive Summary

In the Triennium 2012 to 2015 IGU Working Committee 3's (WOC3) Study Group 3.2 (SG3.2) has been assigned to study on enhancement of Pipeline Integrity Management Plans (IMPs) to reduce risk of failures and incidents based on Pipeline Integrity Management System (PIMS) approach.

The scopes of the study are as follows:

- To define Pipeline Integrity Management System Approach.
- To provide information on new development to reduce the gaps in integrity threat management.
- To propose strategies to prolong the life of ageing pipelines or to reclassify the ones in use.
- To describe what governments, companies and suppliers are doing to improve "Third party damage prevention" (including the application of new rules).
- To identify the critical tasks that affect integrity management.
- To provide appropriate competency for personnel performing critical tasks.

In addition, the SG 3.2 is assigned to build and maintain a pipeline database of IGU Member Transmission Systems, containing information on transmission network (physical data)

This document reports the respective findings.

During the investigations, SG3.2 has developed a series of questionnaires which addressed the following sub-topics based upon the above scopes:

i. Sub-topic 1 – PIMS
Investigation into PIMS approach by focussing into following aspects:
a. Policy and strategy
b. Data review / procedure
c. Risk assessment
d. Geographic information system (GIS)
e. Improvements and audits
f. Emergency procedure

ii. Sub-topic 2 - Pipeline database :
Building and maintaining a Pipeline database of the WOC 3, based on the following data :
a. Total length
b. Material grade
c. Nominal Diameter
d. Nominal wall Thickness
e. Operating Pressure
f. Cover Depth
g. Coating type

iii. Sub-topic 3 –Threats identification

Analyses of existing mitigations in managing integrity threats and identifications of any gaps by focussing into following aspects :

a. Threat Categories
b. System Audits
c. Country Regulations on Pipeline Inspection
d. In-line Inspection

iv. Sub-topic 4 – Third Party Damage

Studying on possible technological and/or procedural improvements in preventing third party damages, by focussing into following aspects :

a. Pipe design legislation
b. Type of communications between TSO, and Public
c. Claim management.
d. Survey and proactive control
e. Emergency plan
f. New solutions to manage third party damage
g. Abandoned pipelines

v. Sub-topic 5 – Managing Ageing Pipelines

Investigation into procedures used by Transmission System Operators (TSOs) in managing aging pipelines and establishing common grounds or best practices, by focussing into following aspects :

a. Design Life
b. Assessment of the pipeline technical current state
c. Pipeline replacement, downgrade or rehabilitate
d. Use of a decision procedure or a tool
e. Basis of assessment (Technical or technical and financial tool).
f. Basis of assessment (Financial or technical- financial tool).
g. Replacement program

A total of 21 countries which correspond to 23 companies/TSOs provided their answers to the surveys.

Most of TSOs subscribed to PIMS in addressing (i) policy and strategies, (ii) data management and related procedures, (iii) conducting risk assessment in analyzing risk of pipelines to prioritize inspections and maintenance activities, (iv) utilizing GIS to aid in decision making, (v) performing audits/reviews for continuous improvement, and (vi) having comprehensive emergency response management particularly in managing failures and incidents.

Pipeline integrity management is becoming more mature; and threats are being managed through various mitigations. Nevertheless, there is some room (issues) for improvement particularly in utilizing advanced technologies e.g. real time remote monitoring system or satellite imaging for third party intrusion/damage; ultra-high resolution in-line inspection tools for accurate measurement of corrosions and mechanical damages (dents, gouges); to name a few.

Most of TSOs have procedures and strategies when dealing with aging pipelines. This is done via a combination of technical and financial aspects. Technical aspects mainly cover the condition of coating and pipe wall i.e. defects or damages; and financial aspects refer to comparison between CAPEX and OPEX. Ultimately, either pipeline or sectional replacement and/or repairs being employed.

As to third party damage prevention, all TSOs are maintaining the typical mitigations which are proven to be effective i.e. designing the pipeline based on safety factors and; and having various controls for pipelines in operation (safety distances between pipeline and other facilities, safety signs, surveillance, communicating with stakeholders, inspections etc.).

PIMS or managing pipeline integrity requires competent personnel; and competent personnel can only be realized through formal and on-job trainings. Most of TSOs have training programs for their employees; but lack in structured technical capability development program.
There are two categories of people who deal with critical tasks. Engineers deal with assessing pipeline risks, identifying and evaluating inspection technologies, evaluating and assessing inspection reports to determine repair decisions, identifying and evaluating appropriate repair technologies or methods, and updating relevant data and information into PIMS database. Field technicians that deal with day-to-day or routine inspections and maintenance e.g. operational pigging, cathodic protection, surveillance, internal corrosion monitoring, product sampling and analysis, rectifier stations etc.

In conclusion, SG3.2 noted that a comprehensive Pipeline Integrity Management System (PIMS) should encompass critical elements which have been described above; and that those elements shall be customized to address specific requirements of each TSO. Utilisation of advanced technologies in managing pipeline integrity should be enhanced further in the areas of third party damage prevention, geotechnical hazards management and corrosions management; and that the technologies must give technical and commercial benefits. Investment on ‘rejuvenating’ ageing pipelines is also part of managing the overall integrity and that technical and commercial aspects are also taken into account in making such decision.

For TSOs to have an effective PIMs they should have competent personal and ensure the continuous development of their technical capabilities

# 2.0 Introduction

## 2.1 Scope & Purpose

For Triennium 2012-2015, the International Gas Union (IGU) has entrusted Working Committee 3's (WOC 3) Study Group 3.2 (SG3.2) to study on enhancement of Pipeline Integrity Management Plans (IMPs) to reduce risk of failures and incidents based on Pipeline Integrity Management System (PIMS) approach.

The scope of the study as shown in the executive summary were broken down into five sub-topics as follows to provide more focus and clarity into the study topics.

i. Sub-topic 1 – PIMS

Investigation into PIMS approach by focussing into following aspects:
a. Policy and strategy
b. Data review / procedure
c. Risk assessment
d. Geographic information system (GIS)
e. Improvements and audits
f. Emergency procedure

ii. Sub-topic 2 – Gaps in Integrity Threats

Analyses of existing mitigations in managing integrity threats and identifications of any gaps pertaining to the following threats:

a. Third Party Interference
b. External Corrosion
c. Geotechnical Hazards
d. Operator Error
e. Manufacturing Defects
f. Welding and Fabrication Defects/ Construction Errors
g. Stress Corrosion Cracking
h. Internal Corrosion

iii. Sub-topic 3 – Strategies for Aging Pipelines

Investigation into procedures used by Transmission System Operators (TSOs) in managing aging pipelines and establishing common grounds or best practices.

iv. Sub-topic 4 – Third Party Damage Prevention

Studying on possible technological and/or procedural improvements in preventing third party damages.

v. Sub-topic 5 – Critical Tasks and Competencies

Benchmarking with TSOs and codes/standards pertaining to personnel competencies in performing critical integrity management tasks.

## 2.2 Methods

The method that WOC 3 employed to conduct the investigation was via survey of its member countries and/or transmission system operators (TSOs). Questionnaires were designed for the five sub-topics, reviewed and accepted by the SG members and distributed to all WOC 3 members for responses. Responses from member countries and/or TSOs were then evaluated and assessed and clarifications were sought from the relevant member countries and/or TSOs for detailed explanations if necessary. General information from each member country and/or TSO such as pipeline length and mean age together with company and contact details were also sought for reference purposes.

For Sub-topic 1 - PIMS, twenty (21) questions were developed to gain information and data on PIMS and its practices by TSOs. The questions were generally focusing on six areas:

i. Policy and strategy
ii. Data review / procedure
iii. Risk assessment
iv. Geographic information system (GIS)
v. Improvements and audits
vi. Emergency procedure

The complete questionnaire on PIMS can be found in Appendix I.

Sub-topic 2 - Pipeline database : Eight (08) questions were developed to gain information and data on pipeline data operated by TSOs. The questions were focusing on:

h. Total length
i. Material grade
j. Nominal Diameter
k. Nominal wall Thickness
l. Operating Pressure
m. Cover Depth
n. Coating type

The complete questionnaire can be found in Appendix II.

Sub-topic 3 –Threats identification, twelve (12) questions were developed for the purpose of analyzing the following threats and possible gaps in ensuring future management of pipeline integrity would be more effective, efficient and cost optimum:

i. Third Party Interference
ii. External Corrosion
iii. Geotechnical Hazards
iv. Operator Error
v. Manufacturing Defects
vi. Welding and Fabrication Defects/ Construction Errors
vii. Stress Corrosion Cracking
viii. Internal Corrosion

The complete questionnaire can be found in Appendix III.

Sub-topic 4 – Third Party Damage fifty (50) questions were developed aimed to gather the followings:

i. The regulations that affect the design, construction and operation of buried pipelines, are being reviewed and modified periodically in such a way that the number of third party accidents decrease.
ii. Requirements on any civil engineering work with respect to buried pipelines.
iii. Requirements on pipeline surveillance and proactive control measures.
iv. Emergency response procedures and planning.
v. Any new technological solutions in controlling third party damage.
vi. Legal requirements for abandoning pipelines.
vii. Other best or good practices.

The complete questionnaire can be found in Appendix IV.

Sub-topic 5 - Managing Ageing Pipelines, twenty-two (22) questions had been designed to gather information and data on the followings:

i. General information i.e. technical and economic design life, pipeline age and coating type, and replacement program.
ii. Assessment of pipeline technical current state.
iii. Decision on replacement, downgrading and rehabilitation.

The complete questionnaire can be found in Appendix V.

**Respondents**

The responses were gathered from WOC 3 members i.e. total of twenty (21) countries which corresponds to twenty (23) companies/TSOs. Please refer to Table 1 below for the complete list of countries and companies.

Table 1: Overview of respondents

| No. | Company | Country | Continent |
|---|---|---|---|
| 1 | PTT | Thailand | Asia |
| 2 | GRTG, Spa | Algeria | Africa |
| 3 | TGS | Argentina | South America |
| 4 | Eustream | Slovakia | Europe |
| 5 | Tokyo Gas | Japan | Asia |
| 6 | KOGAS | Korea | Asia |
| 7 | Gassco | Norway | Europe |
| 8 | Snam Rete Gas | Italy | Europe |
| 9 | GRTgaz | France | Europe |
| 10 | TIGF | | |
| 11 | N.V. Nederlandse Gasunie | The Netherlands | Europe |
| 12 | STEG | Tunisia | Africa |
| 13 | SERGAZ | | |
| 14 | Energinet.dk | Denmark | Europe |
| 15 | Transportadora de Gas del Perú | Perú | South America |
| 16 | Gasum | Finland | Europe |

| | | | |
|---|---|---|---|
| 17 | The Hong Kong and China Gas Company | Hong Kong | Asia |
| 18 | Fluid systems | Poland | Europe |
| 19 | AusNet Services | Australia | Australia |
| 20 | TBG | Brazil | South America |
| 21 | PETRONAS | Malaysia | Asia |
| 22 | Net4Gaz | Czech Republic | Europe |
| 23 | Sweden. | Swedgas | Europe |

# 3.0 Pipeline Integrity Management Systems

## 3.1 PIMS – Pipeline Integrity Management System

### 3.1.1 Summary

In order to measure the degree of maturity in the field of PIMS within the gas industry (mainly for gas transmission operators) and suggest some recommendations, a questionnaire was specially designed by the IGU WOC 3.2 which includes 21 questions covering items regarding strategy/policies, data, GIS, risk assessment and audit/control. Twenty gas transmission operators from all over the world replied. An analysis of those replies was made by the same WOC3.2. Some trends were pointed out which led to some recommendations. A four step procedure to follow is therefore addressed:

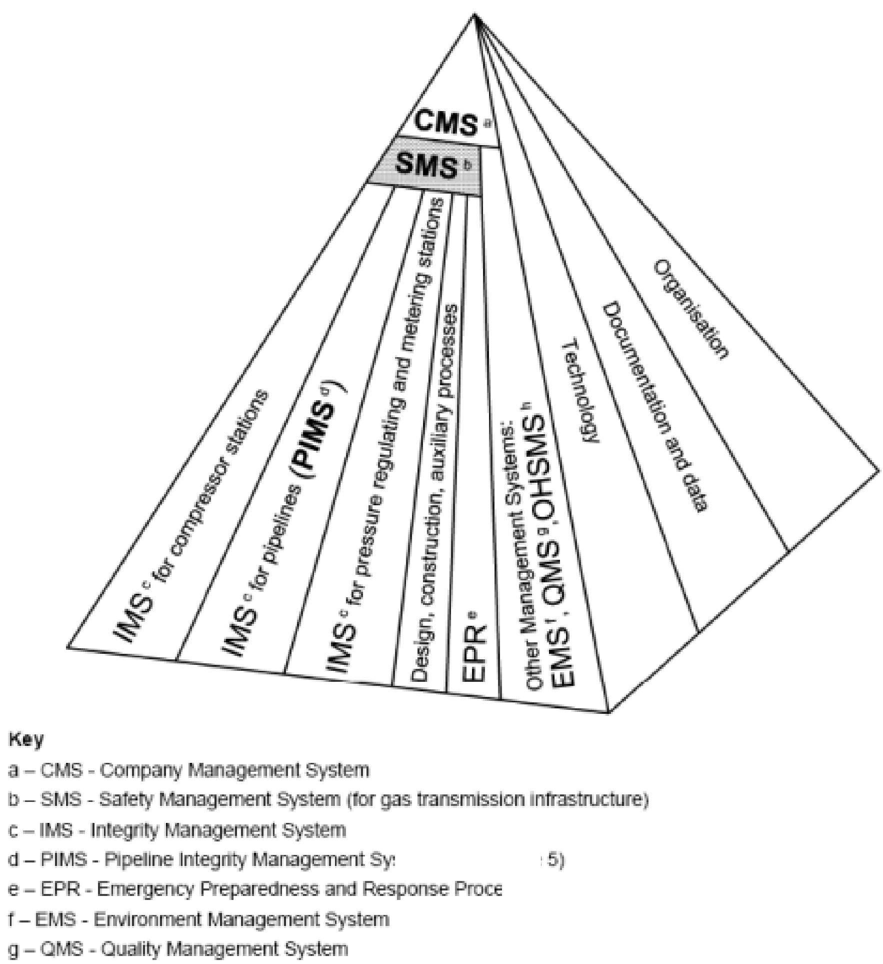
- **Step 1**: integrated data base including pipeline geographical position, technical characteristics, environment, maintenance acts history and recorded incidents/accidents.
- **Step 2**: risk assessment based on the data described in step 1 for the identification as well as the classification of the threats that the gas transmission company is facing.
- **Step 3**: definition of appropriate action plans in order to mitigate the associated risk of the identified threats.
- **Step 4**: control and review for estimating the improvements and the appropriateness of the decided corrective or preventive action plans.

A “Plan Do Check Act” procedure completes the aforementioned recommendation.

### 3.1.2 Introduction

The PIMS is a relatively new concept having the ambition to organize all the activities related to safety and reliability of gas pipeline networks. The qualification of “relatively new” is due to the fact that the corresponding standard is recent: August 2013 for the first edition of EN 16348. However, despite this context, pipeline integrity was and is still the first target that transmission operators are working on. The present paper has the intention to give, by means of a questionnaire (see appendix), some data and relevant analysis showing the level of maturity of Gas Transmission Companies in this field. Moreover, some recommendations are addressed.

For comprehensive reasons, it is necessary to recall some PIMS notions. According to EN 16348, the PIMS is a part of the SMS (Safety Management System[1]) of any Gas Transmission Company as shown in the following diagram:




The PIMS starts once a transmission pipeline is commissioned. Its first objective is to “preserve the integrity of the pipelines through the management of the relevant safety aspects. By this, PIMS contributes to the safety and availability of the gas transmission

[1] EN definition of the SMS : *“set of appropriate activities and practices by which a transmission system operator preserves a safe and reliable gas transmission system and mitigates the consequences of incidents”.*

pipelines. In particular, the PIMS shall take into account the fact that transmission pipelines can be located in an open environment where the public can access the pipeline route.

The second objective of the PIMS is to demonstrate the integrity of the pipelines during their operational life to stakeholders."

The questionnaire includes 21 questions related to pipeline integrity. The designated sub-group, who took in charge the reply analysis, decided to gather those questions into 6 sections as following:

| | Section title | Questions |
|---|---|---|
| 1 | Policy & strategy | 1, 2, 3, 9 & 10 |
| 2 | Data review / procedure | 4, 4a, 5, 6 & 17 |
| 3 | Risk assessment | 14, 15 & 16 |
| 4 | Geographic information system (GIS) | 18, 19, 20 & 21 |
| 5 | Improvements and audits | 7 & 8 |
| 6 | Emergency procedure | 11, 12 & 13 |

Section "Emergency procedure" was transferred to the sub-group having in charge the scope on "Threats and Gaps" where this subject is already tackled. Hereafter, all the other sections are developed. The detailed statistics issued from the questionnaire are displayed in the appendix.

### 3.1.3 Policy, strategy

Almost 75% of the replying Gas Transmission Operators (GTO) had written their own integrated policy regarding pipeline reliability. This first step of integration is fundamental for any company willing to implement a Pipeline Safety Management System. Among the remaining companies (25%) there is a trend to integrate the different reliability policies in a whole safety system. Here is a sample of written policies given by some companies as an illustration:

- Quality manual , internal manual
- Operating / technical procedure
- Annual review of Operation and Maintenance plans
- Pipeline survey and maintenance guidelines

It is important to underline that, most of the companies (~ 85%) refer to either legislation, code or standard pertaining to pipeline integrity management system as listed hereafter:

- ASME
- European Norm
- DNV
- Each country's legislation, code or standard
- Internal standard or code

In addition to this integrated policy, most of the companies (66%) establish short, medium and long term strategic objectives with regard to pipeline safety and integrity. The following list gathers all those strategic objectives that those companies are dealing with:

- Maintain the rate of failure below a value (benchmarked)
- There are objectives in the Strategic Plan aiming the operational excellence, KPI and metrics used to assess the results
- Establish PIMS as company's technical criteria
- No leaks, no third party damages
- Short term: survey and cathodic protection, mid and long term inspection
- Short term : trouble shooting in facilities and temporary repair, mid-term: replacement of the troubled valves actuators, long term: trend analysis of the reliability and integrity
- Rehabilitation programs. Recounting task and cathodic protection improvement. In-line inspection. Hydraulic test.

According to some companies, it is recognized that PIMS helps to improve the current conditions of the integrity management system by referring to those strategic objectives. However, only 50% of the replying companies hold specific Key Performance Indicators (KPI) pertaining to pipeline reliability and integrity. It is quite a low rate regarding the important issue of the network reliability. The most relevant ones are given by the following list:

- Pipeline failure rate / number of pipeline incidents
- Illegal digging works within the pipeline safety zones / Number of non-authorized excavations in the ROW
- Leakage incident
- Cathodic protection

<u>Lesson learnt</u>: Safety and reliability are nowadays for most gas transmission operators the object of a structured policy/strategy which may be considered as a fundamental step before dealing with an integrity management tool such as PIMS.

### 3.1.4 Data review / procedure

When collecting data, it is relevant to gather those issued from the proper feedback of the transmission operator. However, it is even more relevant to evaluate them in comparison with other transmission operators. Therefore, exchanges, benchmarking, etc... are the best way to proceed. According to the questionnaire, in the extent of approximately 80%, most of the replying companies have either internal or external forums where they discuss questions related to reliability and integrity. The forum form differs from one company to another and may be divided into 4 main groups:

- Internal workshops and meetings (53%)
- External meetings or forums (42%)
- External audits or regulatory meetings (10%)
- External service provider (5%)

There is an overlap especially from companies that have internal forums and are represented in external associations or forums related to reliability and integrity.
The frequency of meetings in the forums varies from every two months to every year. One company has meetings and evaluations related to each pipeline section.

On the other hand and concerning its own proper data, it may be noticed that most of the companies, in the extent of approximately 80%, have periodic reviews of their own pipeline integrity feedback. The frequency of those reviews differs from a continuous process to eight year spans. Periods could be divided into 3 groups.

- Once a year (51%)
- More than once a year (22%)
- Less than once a year (5%)

From the answers, one can see that the extent varies a lot on how reviews are performed. This is probably depending on the status of the pipeline system and of course on the regulatory requirements.

Moreover, according to the questionnaire, most of the companies created a special organization which has to handle pipeline reliability and integrity matters, starting from the job of data collecting and analysing. There is a wide range of titles given to such an organization whose importance depends on the company size (from a simple section to a large department). The most common departments/sections mentioned in the replies are listed hereafter:

- Operation department
- Maintenance department
- Technical department
- Engineering department
- HSEQ department

There are as well specific names as Pipeline integrity dep. /management, department of protection, disaster management and diagnostic management. The scope of such a department is not limited of course to data but it is closely related to maintenance and operation, engineering and environmental matters also.

Concerning the level of liability of such organizations handling safety and reliability, the questionnaire shows that only 50% of the companies have authority or internal procedures for endorsing or approving any technical deviations with respect to pipeline integrity management:

- All these companies (50%) have a system on how to handle deviations or defect related to the pipeline.
- Half of these companies (25%) seem to have internal procedures and systems in place for handling of deviations from internal regulations and authority regulations. Among these, only one company refers to the fact that they have a risk based system issued from an industry standard. Another one is directly referring to ASME standard for evaluation of defects. And one other company does not allow the use of routine methods and have instead an in house expert group that evaluate deviations. Interesting to underline, in one country, the national authority has an ongoing work developing rules how to handle deviations.

As a final step for data acquisition and analysis, the questionnaire tackles the way that a transmission operator informs the stakeholders about all activities/matters related to pipeline integrity reliability. Quite 80% of the replying companies produce periodic integrity reports:

| Frequency | % of replies |
|---|---|
| 8 years | 8% |
| 5 years | 15% |
| 3 years | 8% |
| 1 year | 46% |
| 6 months | 8% |
| 3 months | 8% |
| 1 month | 8% |

Out of 10 companies that specified if it is done internally or externally, there are 6 that do it internally, 3 externally and one both internally and externally.

Lesson learnt: A solid PIMS must lean on a strong data basis in order to assess all the technical issues in which a transmission operator is involved. Most of the companies are already following this principle and the remaining ones are on their way to do so.

### 3.1.5 Risk assessment

For almost 60% of the replying companies, risk assessment is taken into account in the field of pipeline reliability and integrity. This reveals the effort of the companies to base their PIMS on such an approach which is more and more considered as fundamental when identifying and classifying the threats that a gas transmission operator is coping with. Standards like EN 16348 or activities related to an Asset Management approach will undoubtedly incite the remaining 40% of the replying companies to adopt progressively such a risk assessment approach.

It is useful to recognize that a risk assessment remains however empirical and is based on a subjective risk matrix. Perform qualitative or quantitative risk analysis are two processes within the risk management of a pipeline. While qualitative risk analysis could be performed in every situation, quantitative risk analysis has a more limited use, based on the type of pipeline and the availability of data to use in order to conduct the quantitative analysis.

A qualitative risk analysis prioritizes the identified risks using a pre-defined rating scale. Risks will be scored based on their probability or likelihood of occurring and the impact on the pipeline. Probability/likelihood is commonly ranked on a zero to one scale.

A quantitative risk analysis is a further analysis of the highest priority risks where a numerical or quantitative rating is assigned in order to develop a probabilistic analysis. In the case of a quantitative risk analysis, high-quality data and a well-developed risk model are needed.  The availability of data is discussed on the Chapter 3 of this report (Data review & procedure).

It is important to point out that, among the companies who refer to a risk assessment in their PIMS, most of them use quantitative assessments as a base for their system. Almost 15% are using a combination of semi-quantitative and quantitative assessments. Less than 10% of the companies are still using qualitative assessments.

If a risk assessment is used, thresholds are to be fixed. The ideal level of risk to reach is of course zero, however, for financial reasons, it is quite accepted nowadays that the risk level

should be as low as reasonable, i.e. non zero. This is the ALARP principle. Using “ALARP” allows us to fix goals for duty-holders. It has great advantages but it has also its drawbacks. Deciding whether a risk is ALARP can be challenging because it requires exercising the judgment. In most of cases, we can refer to existing ‘good practices’. For critical threats, it is important to use more formal decision making techniques, including cost-benefit analysis.
The answers have shown that the concept of ALARP is not widely spread in the industry. Half of the replying companies still does not consider this concept for their pipeline integrity plans.

<u>Lesson learnt</u>: The notion of risk assessment is totally assimilated by gas transmission operators. Even if the questionnaire shows that not all of them are prepared to perform risk assessments but it is clear that the situation is moving towards the principle of risk evaluation in order to identify and classify all the threats that any company is coping with.

### 3.1.6 Geographic Information System - GIS

Almost 70% of the replying companies do record all data related to pipeline integrity in their Geographical Information System. The score climbs to quite 90% if we take into account the companies who intend in the next future to do so. This means that GIS is considered as a key element regarding PIMS.

It is useful to underline that the nowadays trend is to develop an in-house GIS based on PIMS. Some companies did not yet take a decision whether to buy a GIS based on PIMS on shelf or to develop internally such a system. Nevertheless, it may be pointed out that more than 50 % of the Gas Transmission Operators are already aware of the important issue of possessing an internal PIMS. It is clear that this score will rapidly increase since, as mentioned at the very beginning of the paper, PIMS as a whole is a quite new notion reflected by the very recent published standard EN 16348 in August 2013.

<u>Lesson learnt</u>: Linear assets like pipeline networks must undoubtedly be managed by a GIS. Not only characteristic data are to be targeted in such a system, but all the needed data in order to perform a risk assessment or even a safety study. Therefore GIS should be enriched by other relevant data: environment, maintenance acts, incidents, technical documentation, inspection reports.

### 3.1.7 Improvements & Audits

Many ways are available to improve the performance of a PIMS. The questionnaire investigated on two basic issues for such improvements: training and audits.

It is relevant to mention that, although dedicated organizations as well as sophisticated assessment tools are important in the process of maintaining gas network reliability, high levels of integrity can be reached better and faster by competent personnel/engineers. This seems to be quite understood by all Gas Transmission Operators.

In addition, it is acknowledged that controlling safety/reliability/integrity by audits, checks… is an issue phase in order to earn experience and feedback. Even if the score should be higher (around 60 % of the replying Gas Transmission Companies), the present situation is acceptable and by anticipation, the trend should undoubtedly increase.

Lesson learnt: Any management system needs to be continuously improved. Improving requires competent personnel as well as periodic reviews to measure the global performance. Audits contribute to such improvements.

### 3.1.8 Recommendations

According to the previous analysis, one may consider 4 fundamental steps that a PIMS should include:

**Step 1**:

Large data basis covering not only the geographic localization as well as the technical characteristics (MOP, OD, wall thickness, yield stress…) of the network but also all recorded operational data: maintenance acts, incidents, accidents. Moreover, for risky activities as the one that Gas Transmission Operators are dealing with, it is relevant to acquire all environmental data like built up areas and population density living beside the network system. All the aforementioned data may be gathered within one data base: Geographical Information System (GIS).

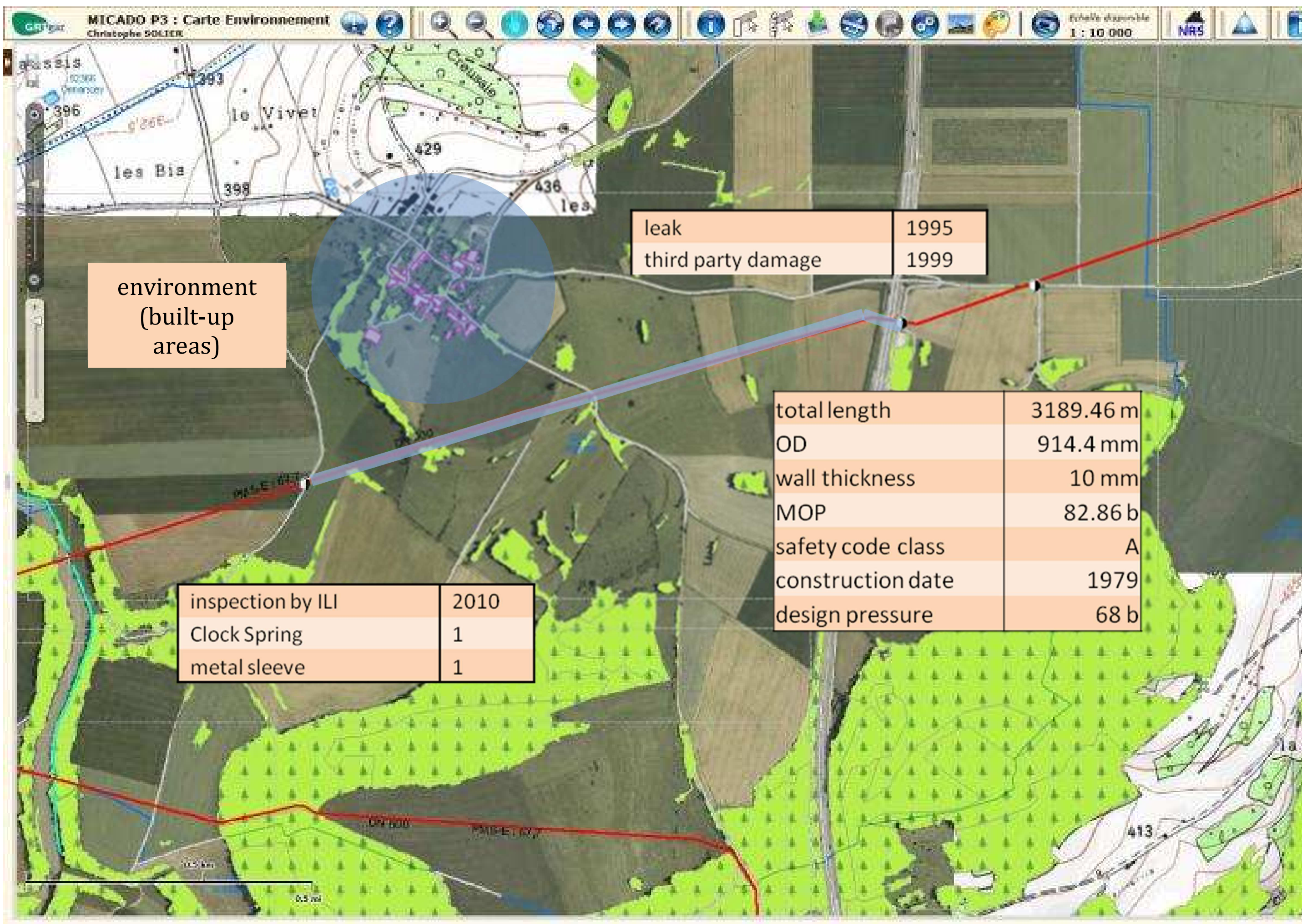



Illustration: GIS displaying relevant data for a risk assessment of a pipeline portion (highlighted in blue)

**Step 2**:

Risk assessment in order to identify and classify threats that the transmission operator is coping with. For this purpose, step 1 gathers all the required data for performing an objective risk assessment. Since risk is usually defined as the combination of two components: the probability or frequency of undesired events and their consequences on persons and properties; those two components are therefore extracted from the previous step. In addition, safety studies may be performed (failure scenario: a leak followed by an ignition with high thermal radiations defining for instance lethal zones). Once risk assessment achieved, it is usually noticed that the threats are common to all gas transmission companies like for instance: third party interference, corrosion, mill defects, landslide area, etc…

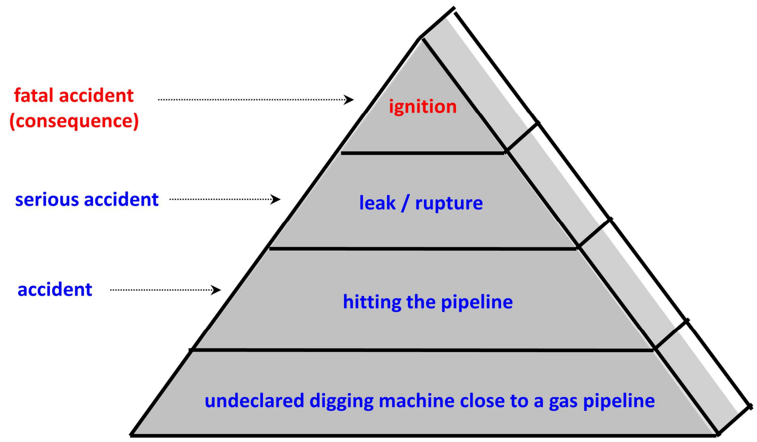



Illustration: risk assessment based on Bird pyramid

**Step 3**:

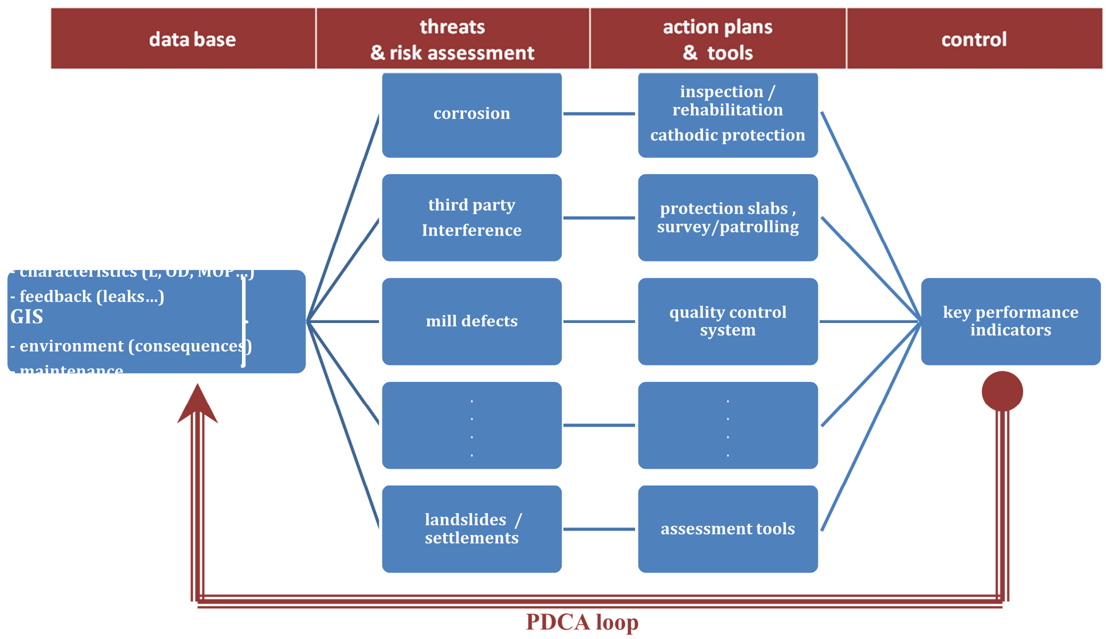
Once threats are identified and classified according to their risk level, preventive and/or corrective action plans are decided and carried out in order to mitigate the corresponding risk level. Such action plans exist and are standardized within the gas industry, e.g. preventing third party interference, inspection and rehabilitation, cathodic protection. Innovative action plans are also possible (unmanned surveillance/patrolling like for instance the use of drones).

Action plans - illustration: inspection by ILI (preventive) and a cut off repair operation (corrective)

**Step 4**:

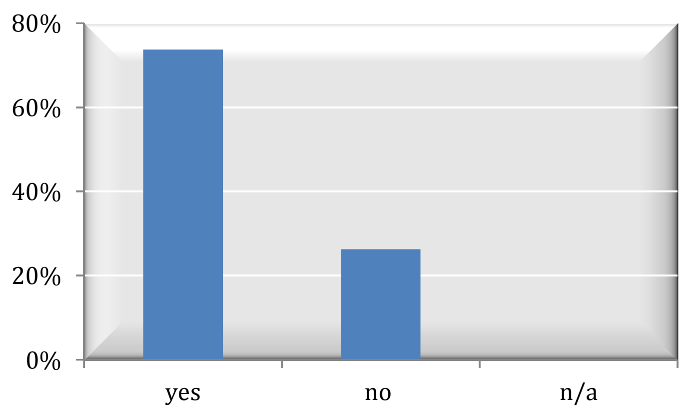
This last step is dedicated to perform evaluation in order to check whether the decided action plans are appropriate. Therefore some key performance indicators (KPI) are defined and periodically reviewed.

The PIMS procedure is usually completed by the common PDCA loop (Plan, Do, Check, Act). The following diagram summarizes the overall procedure which is recommended to follow.

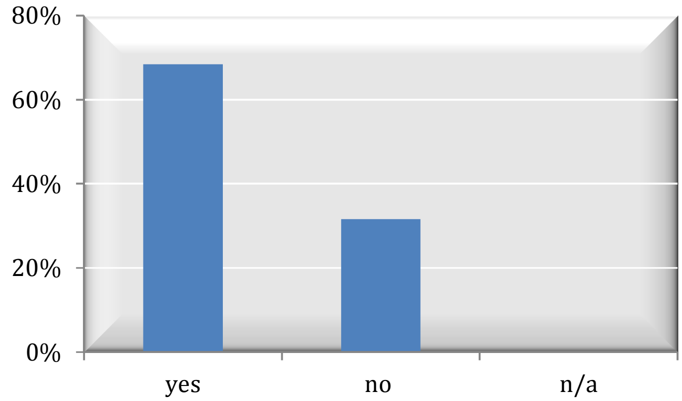



## Appendix – Questionnaire & relevant statistics

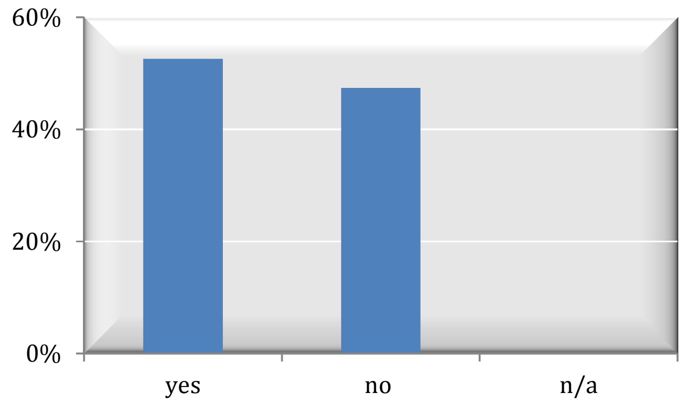
**Q 1**: Does Gas Transmission Company have written policy and/or philosophy pertaining to pipeline reliability and integrity?



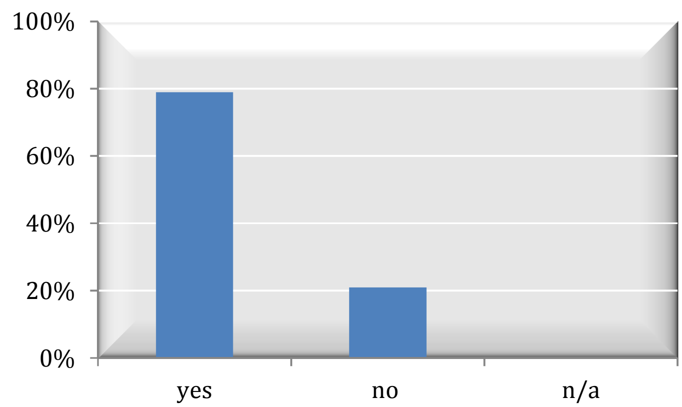
**Q 2**: Does Gas Transmission Company establish short, medium and long term strategic objectives with regard to pipeline integrity and reliability? If Yes, please deliberate briefly on the objectives.



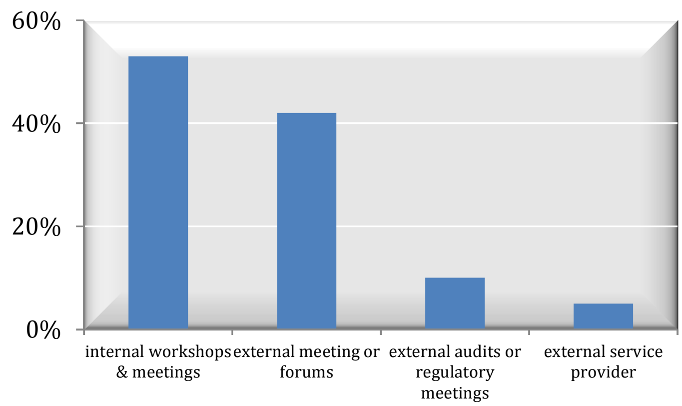

**Q 3**: Does Gas Transmission Company head or respective heads hold specific KPI/s pertaining to pipeline reliability and integrity? If Yes, state the KPI/s.



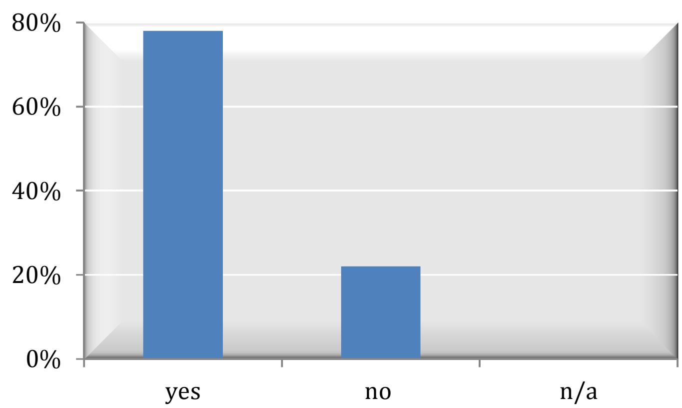

**Q4**: Does the Gas Transmission Company have a specific forums (Internal / External) to discuss/reports matters pertaining to pipeline reliability and integrity?



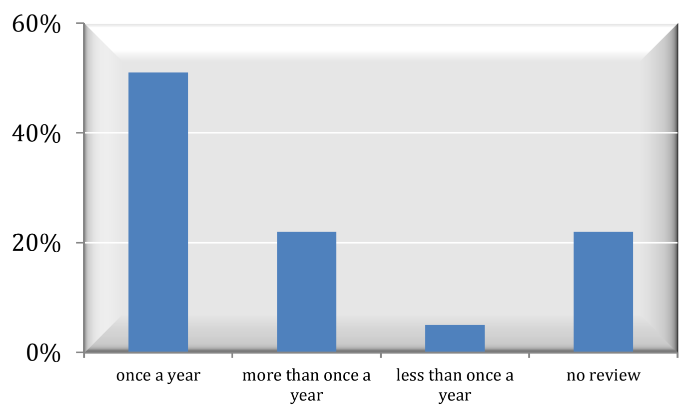

If yes, name and describe the forums. Also provide information on topics discussed and their frequency.



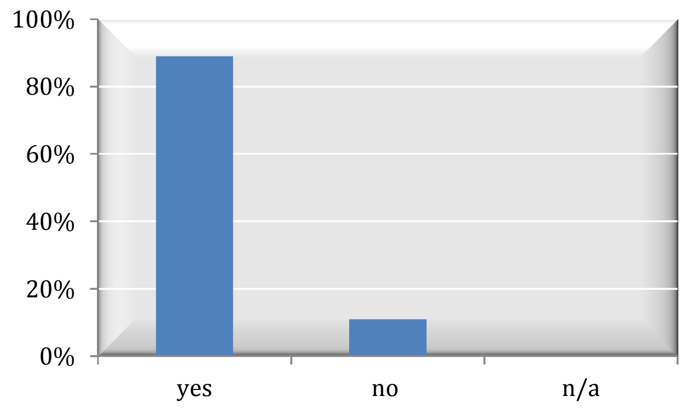

**Q4a**: Does your company perform periodic review of the asset integrity data?



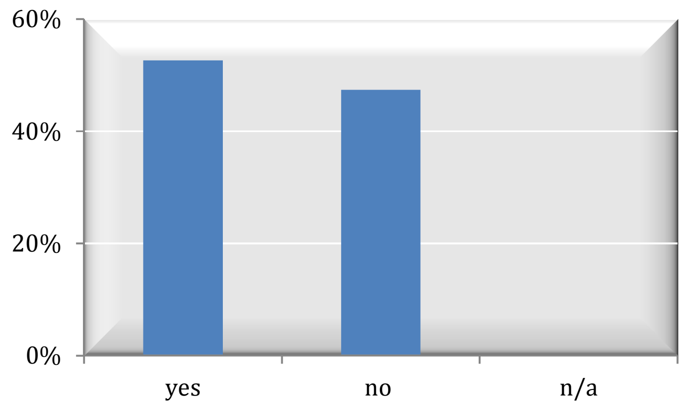

If yes ; what is the frequency?



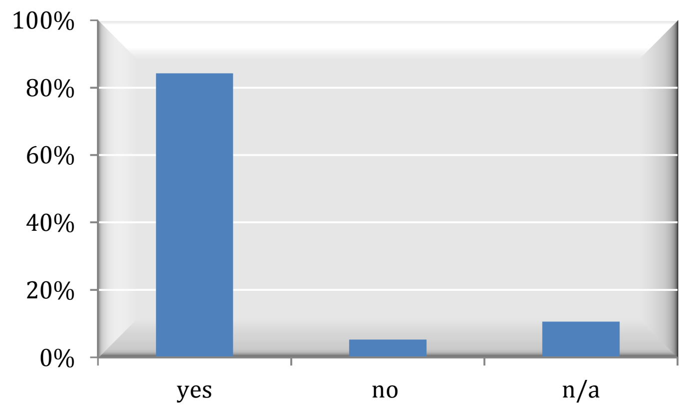

**Q5**: Does the Gas Transmission Company have specific department or section or unit that look into matters pertaining to pipeline reliability and integrity?



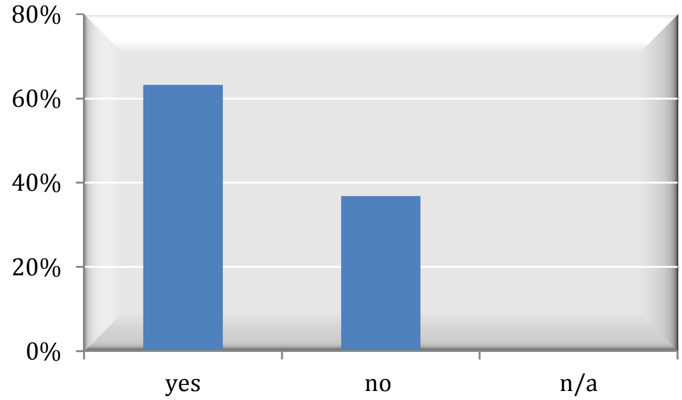

**Q6**: Does Gas the Transmission Company has an authority or procedure for reviewing, endorsing or approving any technical deviation with respect to pipeline integrity management?



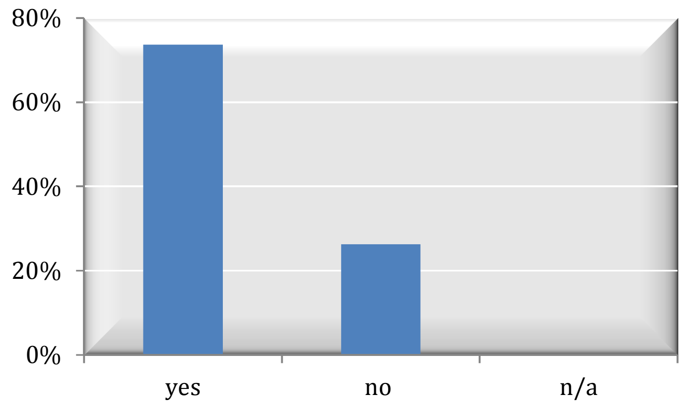

**Q 7**: Does the Gas Transmission Company support technical capability development of its pipeline integrity engineers?



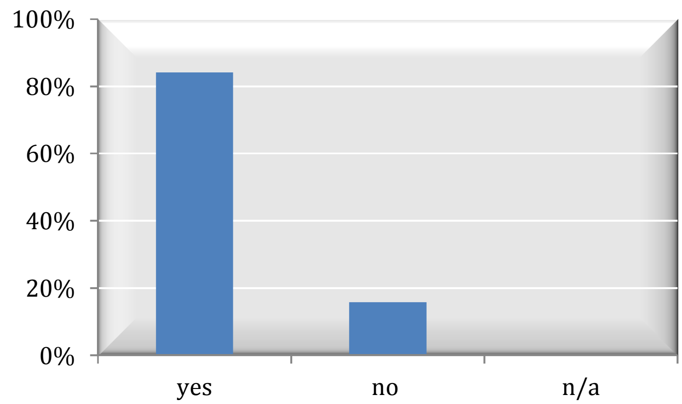

**Q 8**: Does the Gas Transmission Company has specific audit or assessment plan or program for pipeline integrity management ?



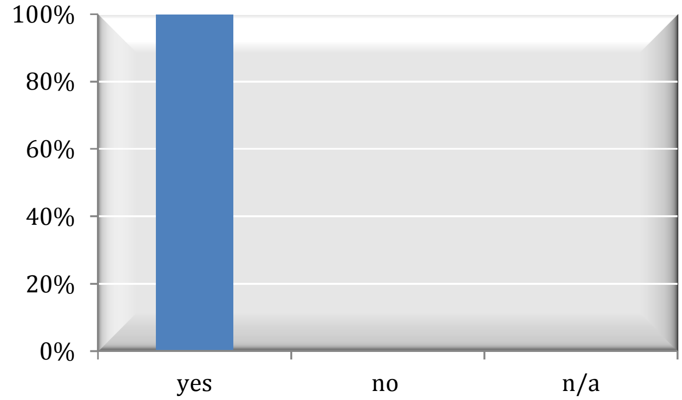

**Q 9**: Does Gas Transmission Company has written guidelines, plans or procedures to support management of the pipeline integrity management system?



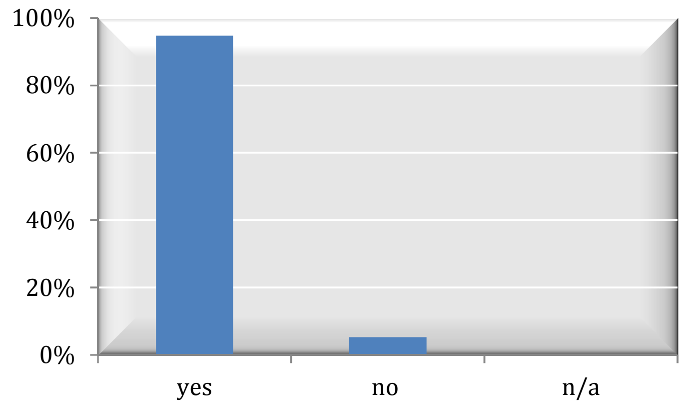

**Q 10**: Does Gas Transmission Company referring to any principal legislation, code and standard pertaining to pipeline integrity management system? If Yes, state the legislation, code and standard.



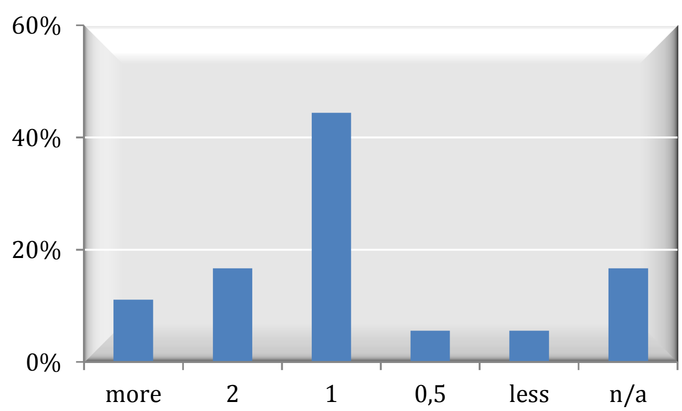

**Q 11**: Does Gas Transmission Company have written Emergency Response Plan?



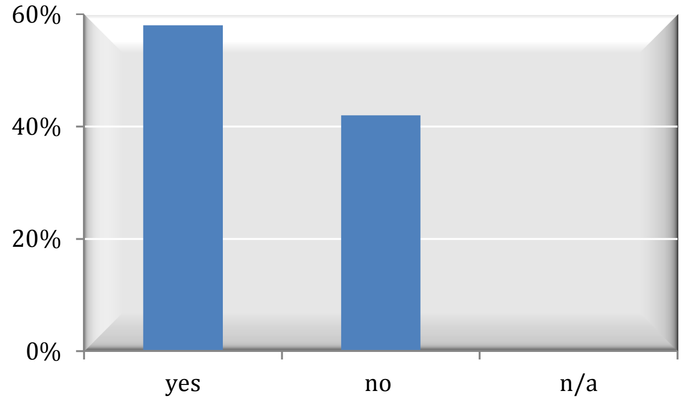

**Q 12**: If above answer is Yes, does the Gas Transmission Company conducts emergency drill?



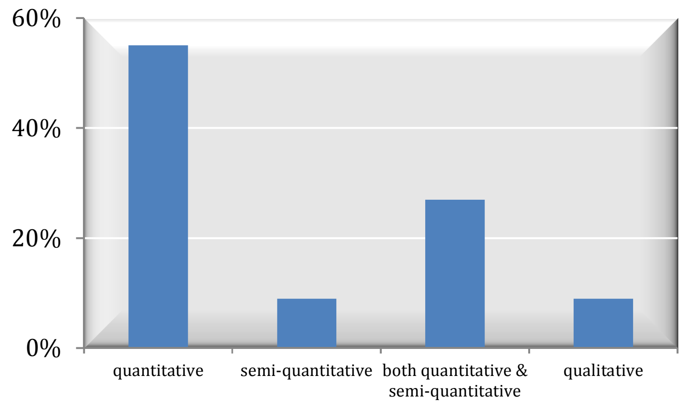

**Q 13**: How frequent do you have an Emergency Response drill?



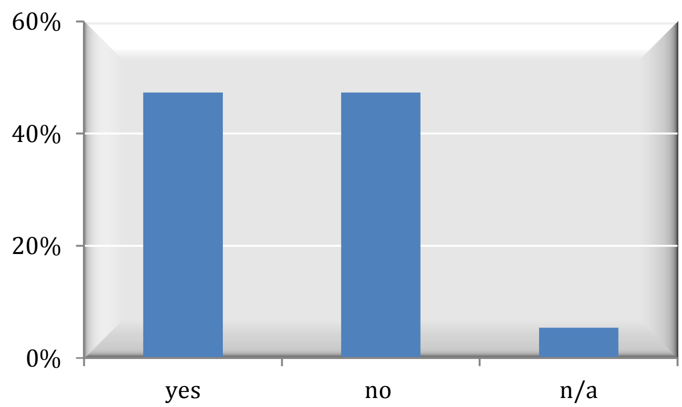

**Q 14**: Does the Gas Transmission Company use Risk Assessment Approach for PIMS?



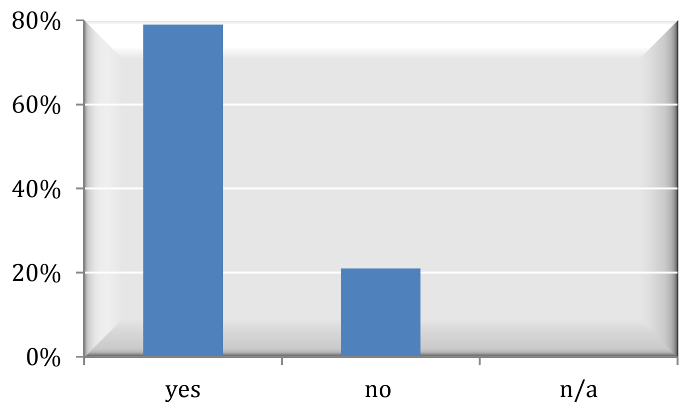

**Q 15**: If answer to the above is YES, how is the risk assessment methodology based (Quantitative or Qualitative)?



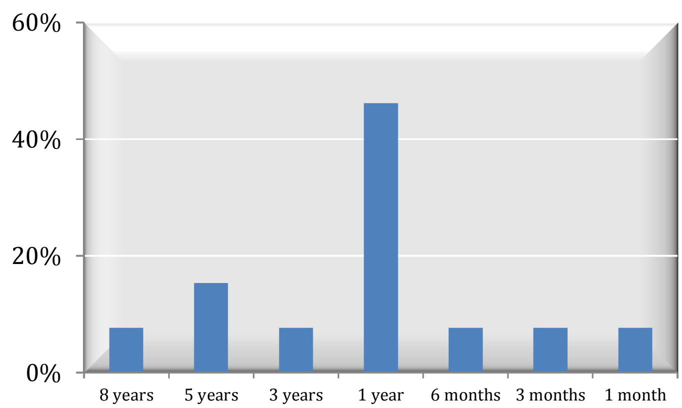

**Q 16**: Does your PIMS consider ALARP (As Low As Reasonably Practicable) approach in creating pipeline integrity related plans.



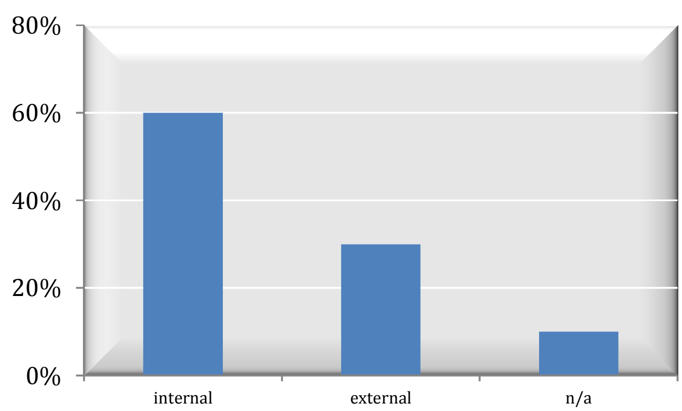

**Q17**: Does the Gas Transmission Company produce any periodic/annual pipeline integrity report?



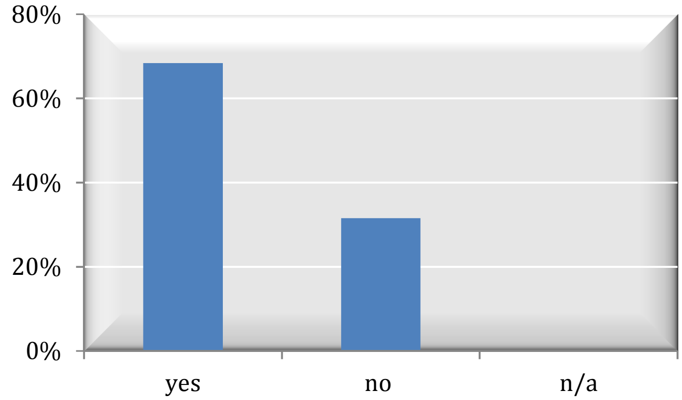

If YES, please state the frequency,



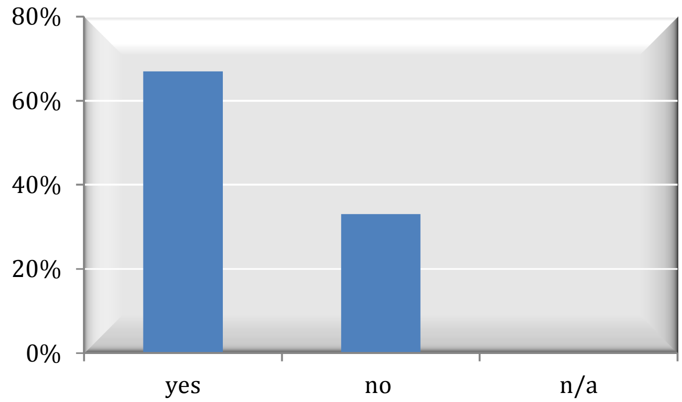

& specify whether it is internal or external.



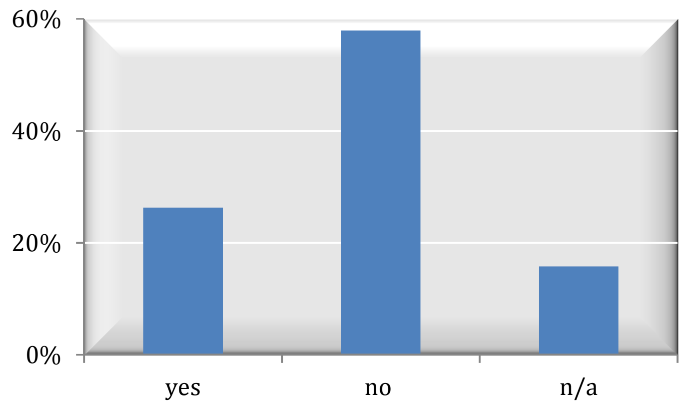

**Q 18**: Does the Gas Transmission Company record integrity data in Geographic Information System (GIS).




**Q 19**: If no, is the gas transmission company planning to implement GIS in PIMS in future ?




**Q 20**: Does your company have or intend to buy off the shelf GIS based PIMS ?



## 3.2 Pipeline database

### 3.2.1 Summary

One of the targets of the WOC 3 during the 2012-2015 triennial Work Program is to gather data on the gas transmission systems of the participant TSOs, for building and maintaining a database of the transmission systems.

To carry out this assignment, a questionnaire limited to onshore pipelines, was established by the study group 3.2, including 08 questions.

Presently, 22 TSOs representing 20 countries coming from the 05 continents transmitted their gas transmission data.

The obtained WOC 3's 2014 database is valuable source of information and reference that is used to help TSOs when utilizing the different results gotten from the PIMS's report.

### 3.2.2 Introduction

As said previously, in order to permit TSOs interested in using the different results gotten from the PIMS's report, a database of the transmission systems of the Europe, Africa, Asia, South America and Australia's TSOs, which participated to elaborate the final report, is very useful reference.

The WOC 3's 2014 transmission system database, fulfill the following gas pipeline conditions:

- Made of steel
- Onshore
- High pressure

And include the following main information:

- Nominal Diameter
- Material grade
- Year of construction
- Nominal wall Thickness
- Cover Depth
- Operating Pressure
- Coating type

### 3.2.3 General data

#### *3.2.3.1 Total length*

The total length of the 22 TSOs, which participated and answered the questionnaire of the WOC 3 during the year 2014, is 175 551 Km.

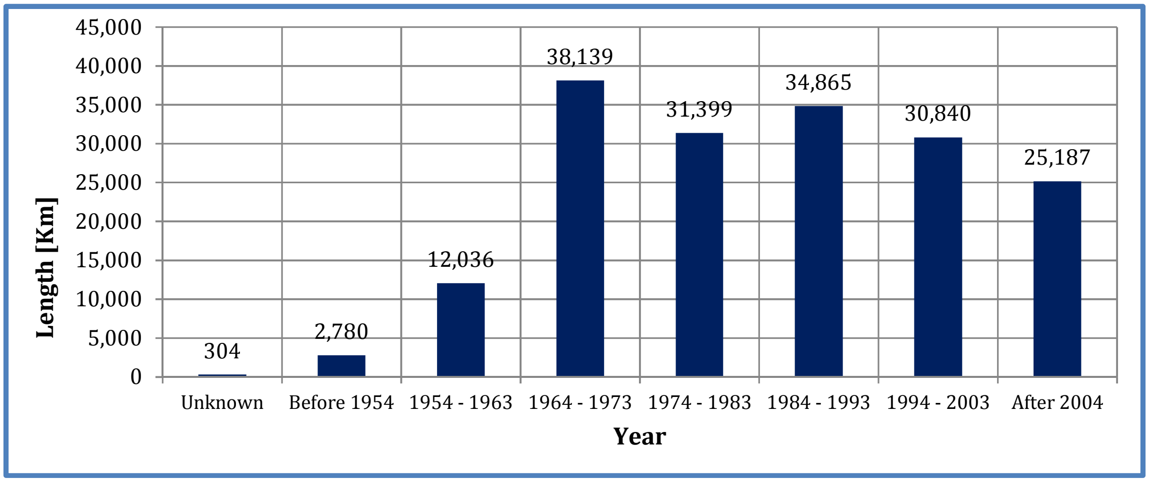



Fig. 1

Figure 1 shows that more than 20 % of the gas network system was built in the sixties period, and in term of year gas pipeline operation we have:

| Part [%] | Operation period [year] |
|---|---|
| 9 % | ≥ 50 |
| 40 % | between 30 and 50 years |
| 30 % | between 10 and 30 years |

#### *3.2.3.2 Material grade*

The most commonly material grades used are X 52 (24 %), X60 (17%) and X65 (15% ) as shown in figure 2.

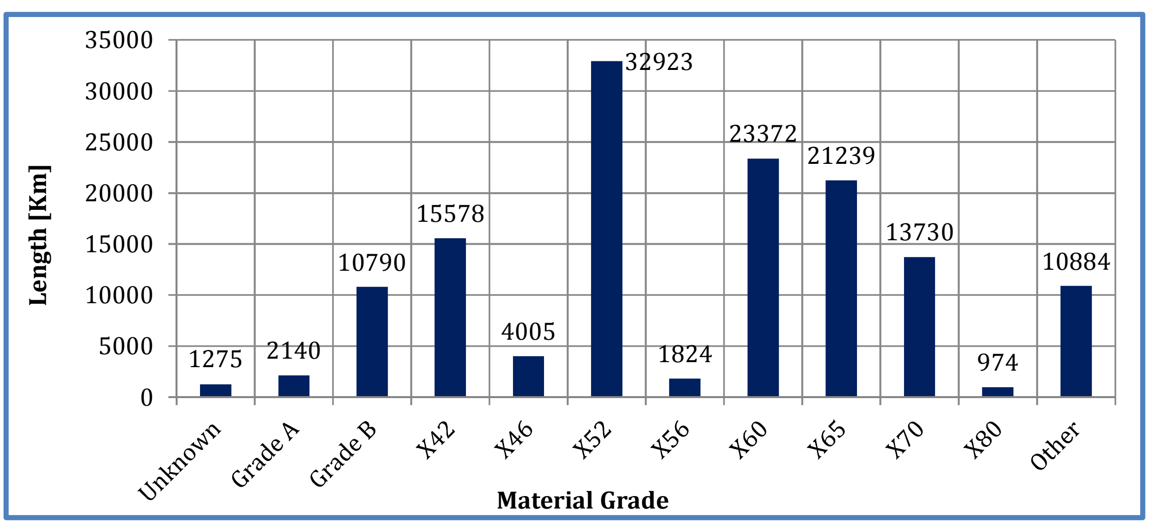



Fig. 2

#### 3.2.3.3 Nominal Diameter

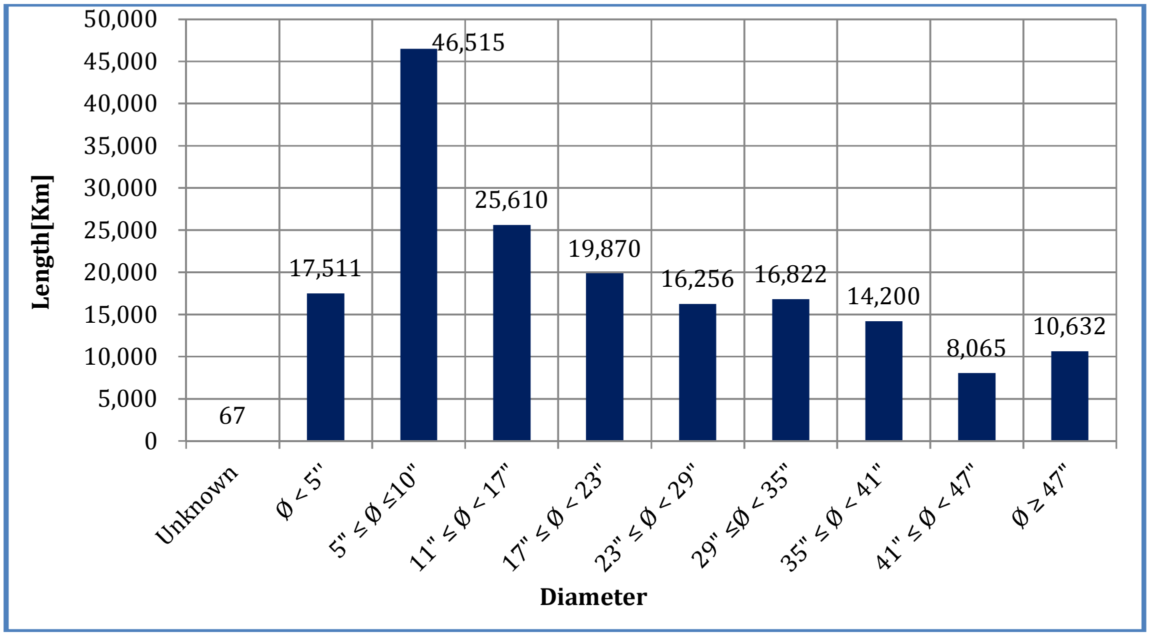



Fig. 3

#### 3.2.3.4 Nominal wall Thickness

The most commonly wall thickness class used are 5-10 mm and 10 -15 mm, as shown in figure 4.

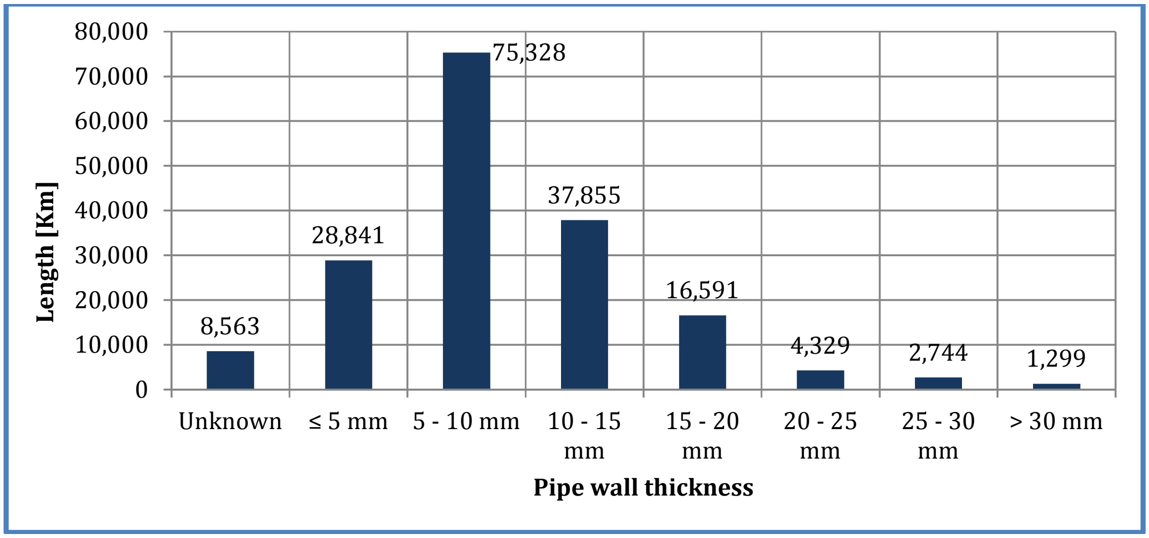



Fig. 4

#### 3.2.3.5 Operating Pressure

More than 70 % of the total gas pipeline length is operating above 50 bars as shown in the fig 5.

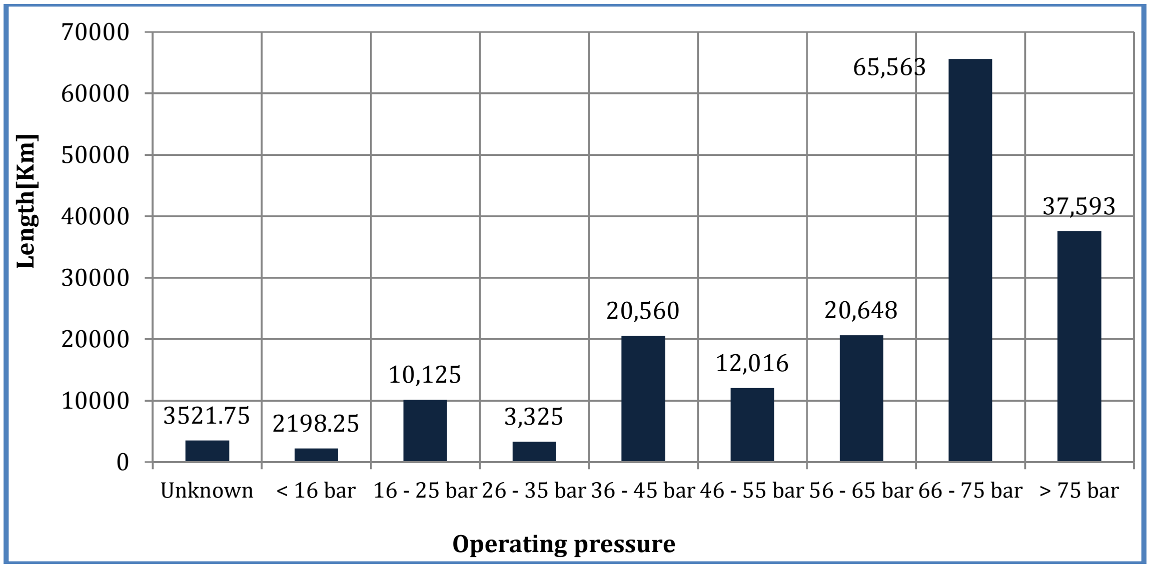



Fig. 5

#### 3.2.3.6 Cover Depth

The most commonly depth cover (C) used are 80 cm ≤ C ≤ 100 cm [40 %] and C > 100cm [44%] as shown in figure 6.

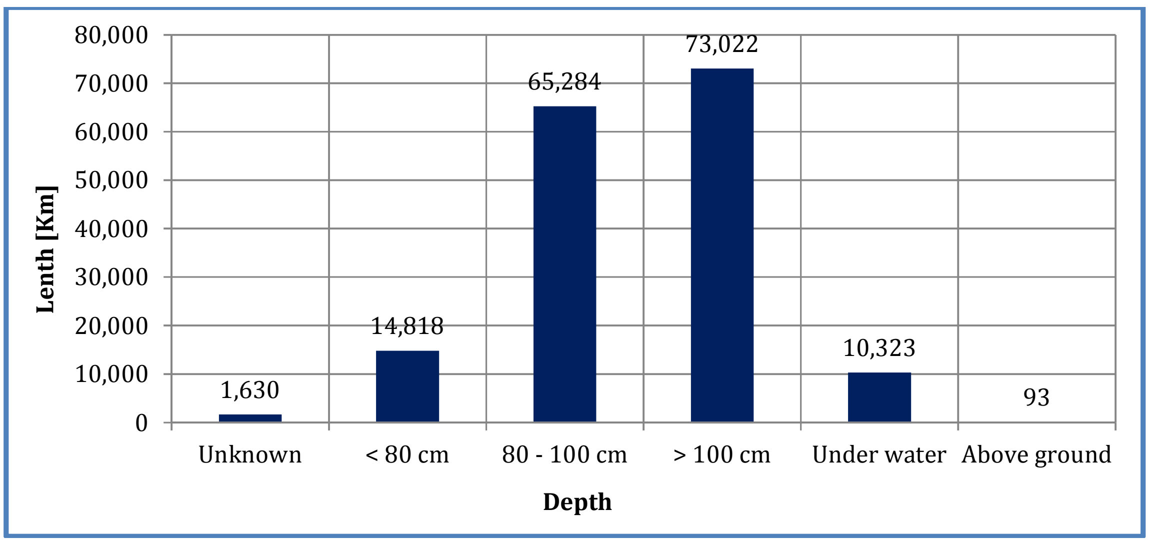



Fig. 6

#### 3.2.3.7 Coating type

More than 70 % of the total gas pipeline length is coated with Bitumen (35 %) and Polyethylene (36%) as show in figure 7.

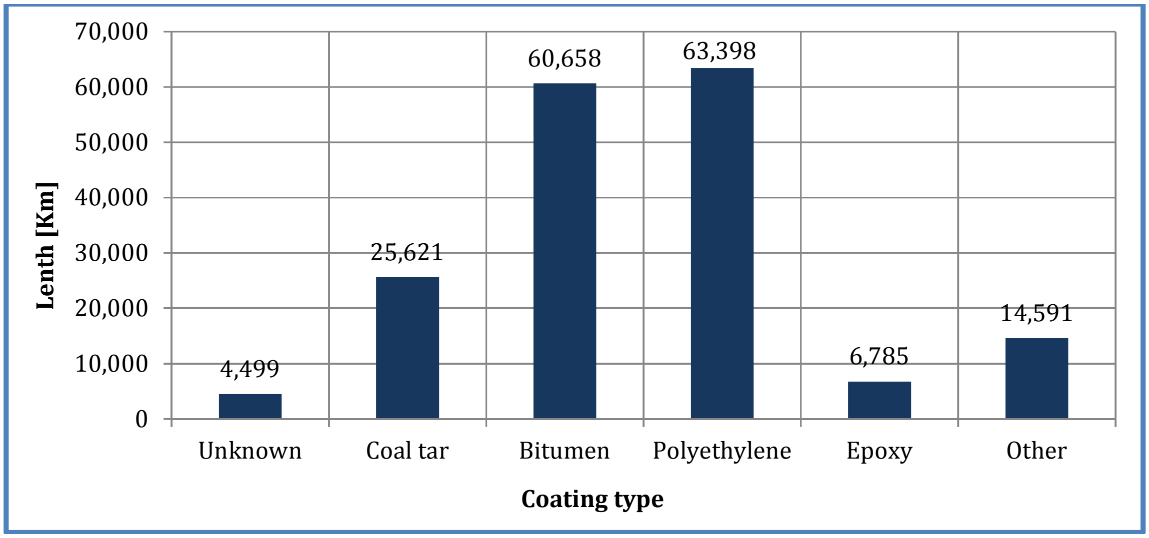



Fig. 7

### 3.2.4 Conclusion and Recommendation

175 551 Km is the total gas pipeline length of the 22 TSOs' which participated and answered the questionnaire during the 2012-2015 triennials Work Program in WOC 3, to carry out not only PIMS but also New transmission projects and Public acceptance & new technologies.

The 2014 built database gives information and reference for the TSOs which are interested to use the different results gotten from the PIMS's report.

As far as WOC 3 will still produce reports for the next triniums, it's suitable to:

1. Continuous gathering data on the gas transmission systems of the participant TSOs, to build a database.
2. Enrich the database by including more questions to the questionnaire, in order to get tendencies of the TSOs in using material grade, coating, pipe cover depth.

## 3.3 Threat Identification

### 3.3.1 Summary

The analysis carried out in the triennium of 2012-2015 has identified that the third party interference is the biggest cause of the pipeline failures. The study indicated that the TSOs recognize the seriousness of the various pipeline threats and manage the risk of pipelines by implementing cohesive integrity management systems where a mix of one or multiple controls are utilised to manage several pipeline threats. It is evident from the analysis that TSOs prefer using traditional threat mitigation measures over the new generation smart systems.

The industry can be benefitted by adopting new technology such as intelligent and remote systems for monitoring the pipeline's real time performance. The integrated and intelligent systems will enable sustainable and effective asset management. It is felt that further advancements are required to develop cost effective systems. The requirement of industry advocacy groups to encourage TSOs and clarify the operational feasibility of intelligent systems is also observed.

The key findings of the study are:

- Third Party Interference and External Corrosion has been identified as the major threats to the pipelines.
- All TSOs around the world implement of Pipeline Integrity Management System.
- Use of smart systems, remote technology and incident database system is not yet fully exploited. Real time remote operations are not widely used in managing pipeline threats.
- Only 66% of survey respondents use in-house databases with other depend on industry data base for risk ranking or industry standards for implementing Integrity Management controls.

### 3.3.2 Introduction

The objective of this study is to identify opportunities to strengthen the current threat mitigation practices for managing pipeline integrity. The analysis involved validating the type of threats to transmission pipelines and TSO's preference for particular maintenance practices in mitigating the threats is also investigated.

A questionnaire was prepared and the information was collected by the members of the 'Working Committee 3 – IGU'. The questionnaire comprised of twelve questions and was completed by nineteen global TSOs.

Effectiveness of any integrity management system is underpinned by the robustness of a process to identify threats and implement measures for those threats in order to prevent pipeline failures. Therefore, it is very important for TSOs to develop a process to identify threats, rank the threats based on their seriousness, plan the integrity processes and implement those processes to prevent the pipeline failure.

Best results, in terms of structural integrity of a pipeline depend upon the appropriate resource allocation for the treatment of the identified threats. Some of the pipeline threats are mitigated during the design phase for example by providing extra wall thickness as allowance for corrosion management, depth of soil cover, suitable alignment to prevent third party encroachment and to carry out maintenance activities.

Proactive threat treatments for pipeline integrity which are implemented during the life of the pipeline include routine patrolling, cathodic protection, coating survey, coating repair, stake holder consultation, Right-of-Way management, in-line inspection, pipeline pressure management etc.

TSOs based on their function, size, feasibility and competency use various methodologies to identify and rank threats in order to develop an optimal integrity management system.

To understand this diversity in threat identification and identify an opportunity to further strengthen the PIMS, a survey has been undertaken by the Transmission Working Committee of the International Gas Union. The following lists the main aim of this study:

- How global TSOs identify and determine pipeline threats.
- Which threats are deemed most critical for pipelines.
- What controls are implemented to prevent these threats.
- Opportunities to further enhance the integrity management.

#### 3.3.3 Threat Categories

A comprehensive understanding of pipeline threats and potential gaps in current integrity management systems is critical to propose a best practice system in managing pipelines.

Data related to pipeline threats is collected by surveying the members of Working Committee-3 of the IGU. Members of the committee come from 18 countries and 5 continents, hence bring diverse experience in managing the pipelines.

Threats to the pipeline can be distinguished into three main categories namely; *Time Dependent, Stable and Time Independent*.

Time dependent threats arise during the life of the pipeline and their risk of failure propagates with the age of the pipeline (For example: External Corrosion, Stress Corrosion Cracking, Internal Corrosion).

Stable threats are the ones which do not grow over time unless acted upon by another condition or failure mechanism (for example: Manufacturing Faults, Welding and Fabrication Defects/ Construction Errors).

Time Independent threats are the ones whose risk profiles do not change with the age of pipeline (for example: such as third party interference, Geotechnical Issues, Operators Errors and Lightening).

The following analysis focuses on the aforementioned threats and aims to highlight the currently used integrity management practices by the TSOs. Gaps in the current practices and potential opportunities to further reduce threats are also discussed.

Following is the list of the pipeline threats which have been discussed in the chapter within:

i. Third Party Interference
ii. External Corrosion
iii. Geotechnical Hazards
iv. Operator Error
v. Manufacturing Defects
vi. Welding and Fabrication Defects/ Construction Errors

#### 3.3.3.1 Third Party Interference

Third Party Interference (TPI) has been deemed as the biggest threat to the pipelines by global TSOs in the survey of 2013.77% of TSOs classified “Third Party Interference” as one of the top five threats to their pipelines.

TPI related threats to pipelines are not dependent on the age of the pipelines. The most common factor determining the likelihood and the consequence of this threats the location of a pipeline. The pipelines are in remote area have lesser risk both in terms of likelihood and consequence in comparison to the ones in the urban area.

Five most common controls or mitigations implemented by global TSOs to prevent the threat of TPI are listed below in order of their preference (from top-to-down):

i. Patrolling (Ground and Aerial)
ii. Stakeholder and Community Consultation
iii. Warning Signage and Marker Posts
iv. Protection by separation (depth of cover, concrete slab, conduit)
v. Design (pressure regulation, wall thickness)

Other common controls to prevent threat of TPI are:

i. Supervision of external works within pipeline corridor
ii. One Call System
iii. In-line Inspection (to identify and repair any wall loss)
iv. Local Regulation
v. Contractor training and permit to work system
vi. Warning Tape

The analysis of the survey results indicate that approximately 80% TSOs rank patrolling and stake holder consultation as the major controls in preventing TPI.

Patrolling enables monitoring of Right-of-Way and prevents unauthorised excavation, directional drilling, blasting operations etc. Where effective stakeholder engagement enables reduction in unauthorised activities around pipeline corridor, it also facilitates better planning and more informed integrity management programs.

Potential gap identified by the committee was the utilisation of real time and remote TPI detection systems. According to the analysis none of the survey respondents use such systems. The real time remote detection systems are proven technology and can be used to reduce pipeline damages and improve pipeline integrity.

Possible reasons of low utilisation of smart technologies could be that the existing controls are considered effective in managing TPI threats; and that to strike a balance between installation, operation and maintenance cost of such systems versus TPI risk reduction. This issue could be further studied in the next triennium.

### 3.3.3.2 External Corrosion (EC)

EC is identified as the second biggest risk to pipeline integrity. EC results in gradual reduction of pipe's wall thickness, consequently leading to the pipe failure. EC could occur by both natural processes i.e. when the pipe surface gets exposed to oxygen and atmospheric moisture and also by stray current activity which corrodes pipe surface by instigating an electrochemical process.

Typically, the industry uses external coated line-pipe in order to prevent the direct contact between the pipe and the surrounding soil or moisture, thus preventing the oxidation process. However, three most common controls implemented by global TSOs to prevent EC are listed below in order of their preference (from top-to-down):

i. Cathodic Protection and Close Interval Potential Survey
ii. In-line inspection
iii. Indirect Inspection (DCVG, Pearson)

The survey indicated that all of the respondents use multiple controls to prevent external corrosion. Figure 8 highlights other controls and the ratio of TSOs implementing these controls to prevent EC.

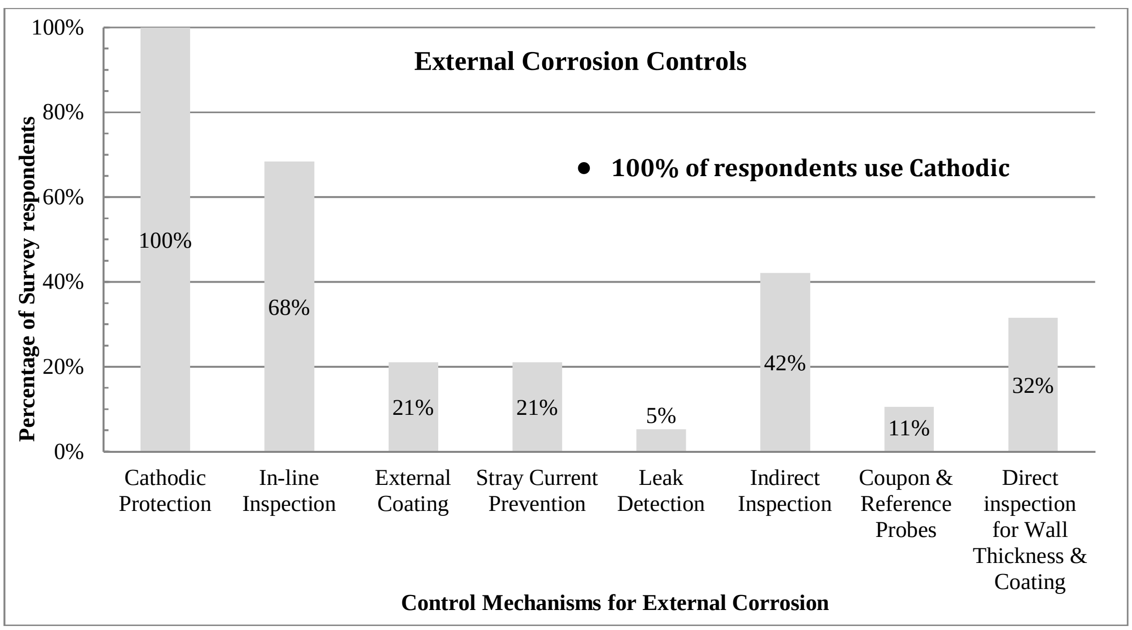



Fig. 8

Although the current controls used by TSOs are deemed adequate, opportunity to adopt real-time remote monitoring of cathodic current has been observed. The real time monitoring provides capability to ensure 100% reliability of the protective currents. Real time monitoring systems will enable TSOs to reduce response time in eliminating the faults which in traditional systems is dependent on the next visit by technical personnel.

Advancement of in-line inspection technology by having more precise defect detection can enable TSO's to detect and remediate the defects in early stages and reduce the costs of expensive repairs. It is envisaged that the scope of these technologies and their usability will be explored in future WOC studies.

#### 3.3.3.3 Geotechnical Hazards (GH)

Gas transmission pipelines are subjected to various GH. Different integrity approaches ranging from pipeline design, monitoring of pipeline strain, monitoring of the ground movement are implemented by TSOs. The most common controls implemented by global TSOs to prevent issues pertaining to ground movement, soil movement, landslide, erosion, rock fall and alike are listed below in order of their preference (from top-to-down):

i. Patrolling (Ground and Aerial)
ii. Monitoring of compressive and tensile stresses by Strain Gauges
iii. Containment of slope or erosion prevention by Gabion
iv. Inline inspection for monitoring wrinkle or ovality
v. Route Selection
vi. Erosion Prevention by Plantation
vii. Leakage Survey
viii. Expansion Loop
ix. Pipeline Renewal
x. Rainfall Monitoring

The survey indicated that all of the survey respondents use multiple controls. Figure 9 highlights the controls or mitigations and the ratio of TSOs implementing these controls to prevent GH.

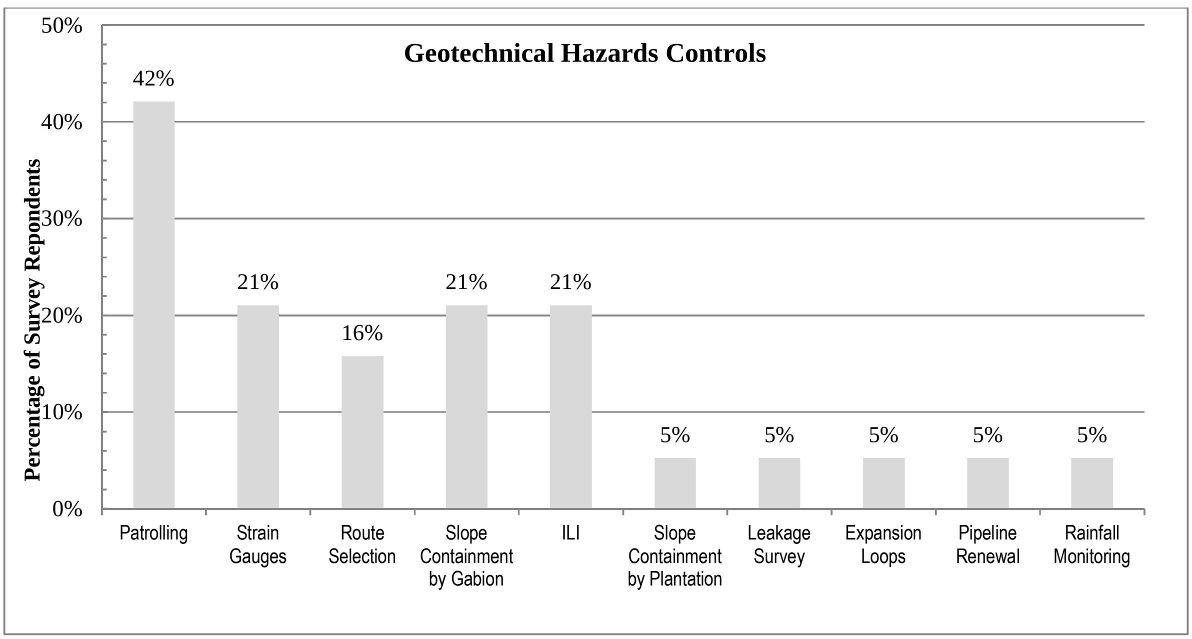



Fig. 9

Early detection of signs of GH is paramount in managing pipeline's integrity. Relying alone on patrolling which is conducted at pre-determined frequency might not be sufficient.

The committee also believes that the usage of smart technologies such as real time remote monitoring integrated with strain gauges can benefit the industry in managing GH proactively. Real Time Satellite imaging for tracking the gradual erosion or earth movement could also be explored.

Unmanned Aerial Vehicle (UAV) equipped with high definition digital camera and/or LIDAR technology can be beneficial it can save overall cost of managing the GH as well as TPI.

#### 3.3.3.4 Operator Error (OE)

TSOs confirmed that personnel competency is an important factor for maintaining integrity of pipeline assets and achieving optimal returns. TSOs acknowledged that inadequate personnel management introduce threats to pipeline integrity and therefore TSOs implement controls pertaining to human resource management as part of their integrity management system.

The most common controls implemented by global TSOs to prevent threats pertaining to OE are listed below in order of their preference (from top-to-down):

i. Personnel Training
ii. Work Procedures and Instructions
iii. Permit to Work System
iv. Job Safety Analysis
v. Auto Operated Control Systems
vi. Remote Monitoring
vii. Asset Proving before Works
viii. Review of Personnel Competency

The survey indicated that all of the TSO respondents use multiple controls. Figure 10 highlights other controls and the ratio of operators implementing these controls to prevent threats pertaining to human / operator errors.

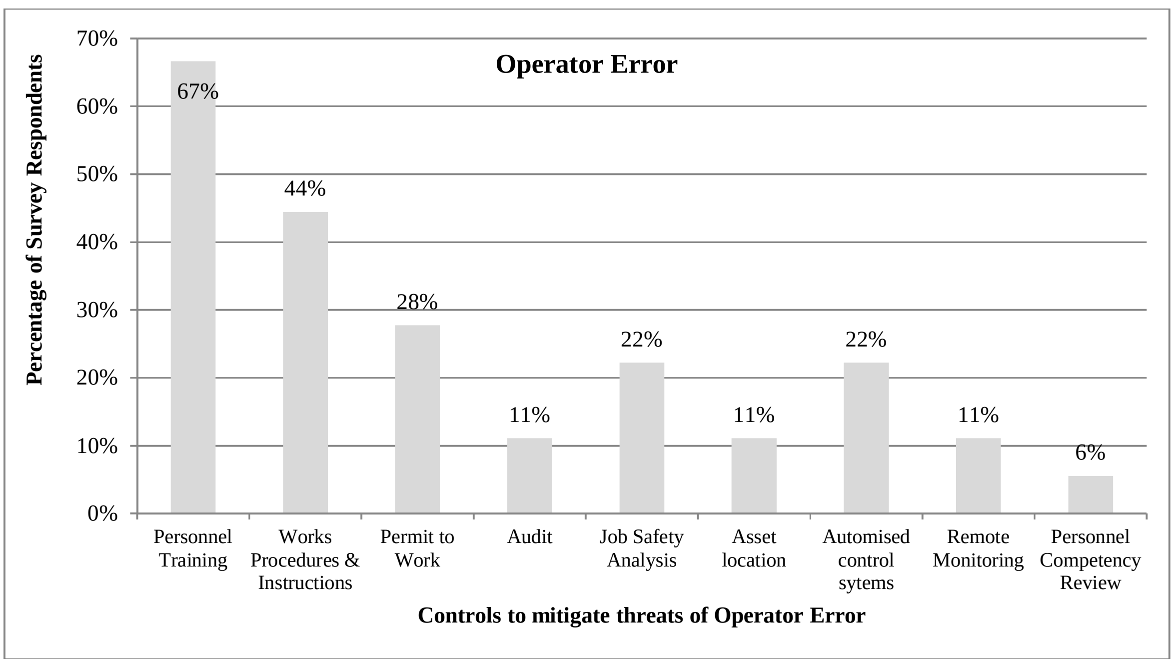



Fig. 10

It is observed through the analysis that there is scope to develop a standardised training program for managers, engineers and technicians/operators to ensure sustenance in personnel development thus would prevent any pipeline failure due to OE.

A need to further strengthen the process of developing succession plans to replace ageing workforce and appropriate knowledge transfer is also identified through the analysis.

#### 3.3.3.5 Manufacturing Defects (MD)

Manufacturing related defects or material defects are one of the common causes for failures in old pipelines. Early steel-making processes allowed more impurities to remain. Newer and improved processes have reduced this threat vastly because of improved manufacturing process and the quality of the steel used. However, material defects are still existent and have potential to result failures.

The most common controls implemented by TSOs to prevent and mitigate issues related to manufacturing defects or material defects are listed below in order of their preference (from top-to-down):

i. Quality control program at manufacturer or supplier plant by company witness
ii. Hydrostatic testing of manufactured products
iii. Use qualified material according to standards or guidelines
iv. Non-destructive testing or In-line inspection
v. Base material testing
vi. Use approved or qualified manufacturer or supplier program
vii. Construction supervision
viii. Increase safety margin during design
ix. Periodical product exchange

The survey indicated that all of the survey respondents use multiple controls. Figure 11 highlights the controls implemented by global pipeline operators and their ratio of utilisation of these controls by TSOs.

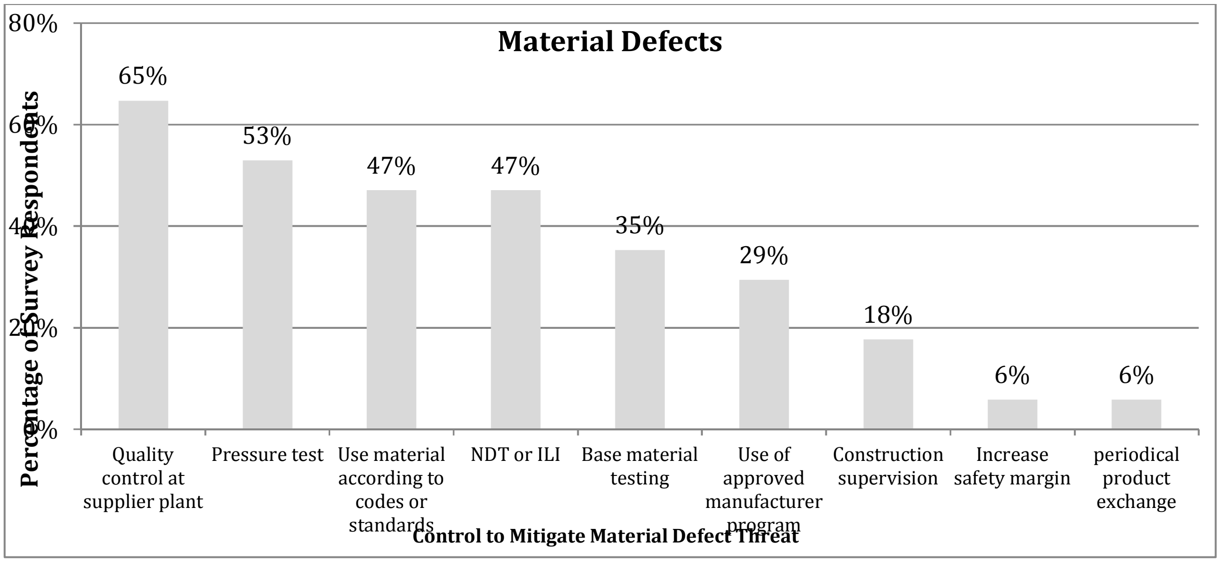



Fig. 11

The scope for industry to promote the development of new technologies for material testing is observed as an opportunity to reduce the threats of material failure.

#### 3.3.3.6 Welding and Fabrication Defects/ Construction Error (CE)

Welding or fabrication defects cause of a lot of pipeline failures. Quality issues such as, disintegration of pipeline coating during backfilling, failure of field welds during hydro testing are commonly experienced issues during pipeline construction.

The most common controls implemented by global pipeline operators to prevent and mitigate issues pertaining to construction errors are listed below in order of their preference (from top-to-down):

i. Operator represents onsite to supervise during construction
ii. In-line Inspection after construction
iii. Welds inspection with NDT
iv. Use of Quality control program or procedure to control quality
v. Training or qualified personnel related to construction works
vi. Design and construction according to international standards or company guideline
vii. Use quality control procedure during construction
viii. Pressure test after construction
ix. Use qualified or competent contractors
x. Indirect inspection (CIPS/DCVG) to confirm construction quality

The survey analysis indicated that all of the survey respondents use multiple controls. Figure 12 highlights the controls implemented by TSos.

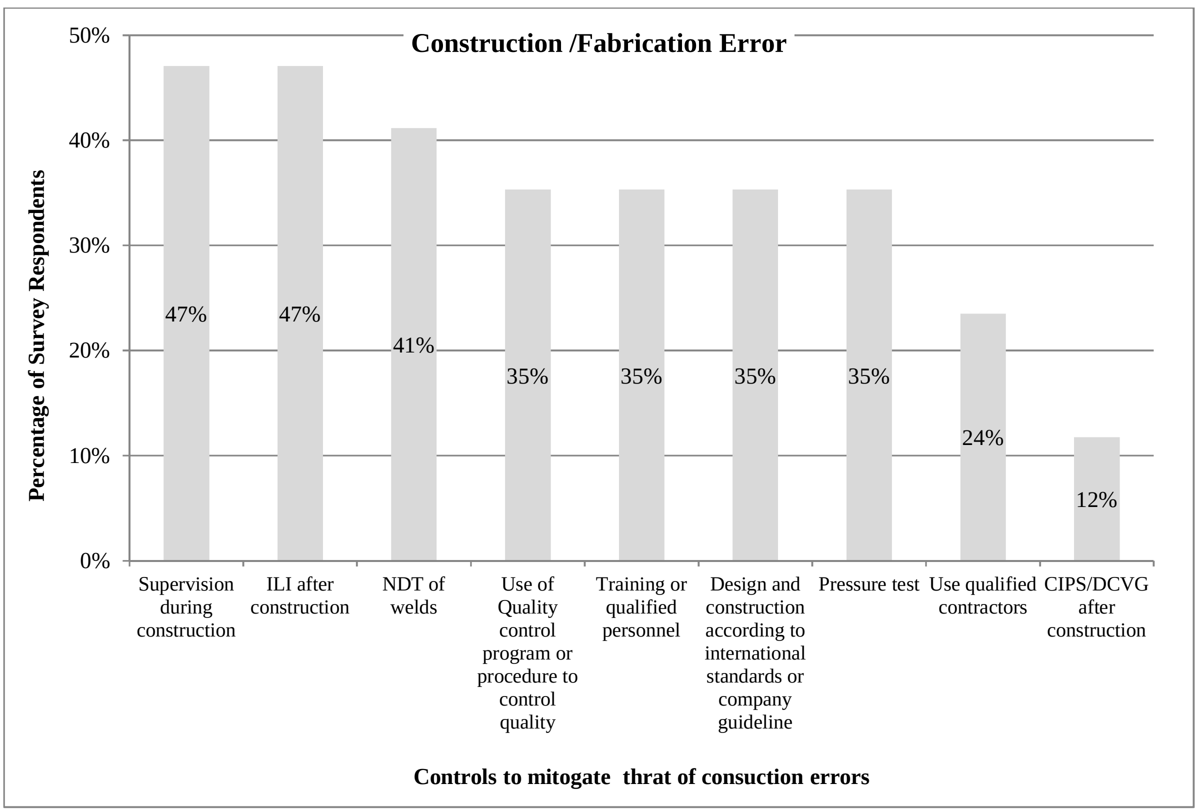



Fig. 12

One of the survey respondents (TSO) informed that they experienced multiple pipeline failures due to welding defects during construction. Competency of welding inspectors and the efficacy non-destructive tests i.e. radiography test technicians were identified as potential causes behind the weld failures.

It is envisaged that an automated and enhanced non-destructive testing technology (such as automated ultrasonic testing and computerised radiographic testing) may help the industry by providing greater efficiency in detecting weld and fabrications defects.

##### 3.3.3.7 Other Threats

In addition to the above mentioned threats, there are other threats that global TSOs see the need to be addressed. These threats are, for example, Microbiological Influenced Corrosion (MIC), Stress Corrosion Cracking (SCC), Internal Corrosion, Sabotage etc. The likelihood of these threats is very low and therefore the committee have decided to combine these threats in ‘other’ category.

These threats are generally mitigated by implementation of combination of integrity management practices such as Patrolling, Direct Inspection of Coating and Pipeline, Operators Training, CP Surveys, Interference Monitoring, Evaluation of Susceptibility to SCC, Using more stringent material specification, Sampling Gas Quality, Online monitoring of corrosive contaminants (CO2, H2S).

The periodic review of the implemented practices, their performance evaluation and trend analysis of defects and threats; allows TSOs to improve integrity plans and achieve long term asset management efficiencies.

Evidently, TPI is still the top most threat to transmission pipelines. A detailed analysis for managing TPI can be referenced in section 3.3.3.1.

#### 3.3.4 System Audits

Periodic audits enable TSOs to validate the effectiveness of their pipeline integrity management systems and quality systems. Audits help in ensuring that these systems have been implemented in accordance with the policies and standards.

Auditing regime provides opportunity for TSOs to evaluate performance of the implemented methodologies and introduce changes where required. Benchmarking with the industry practices and standards enable TSOs to identify industry best practices.

Audits can be performed by internal staff, preferably by personnel not directly involved in the administration of the integrity management program, or external experts.

Audit results can be utilized to modify the integrity management program as part of a continuous improvement process. The analysis showed that many TSOs are using internal or external audit as performance measure to evaluate effectiveness in addition to other measures stipulated in the integrity management program.

The survey result in figure no. 13 shows that most of gas pipeline operator performing audit of their PIMS or Quality Systems. However, 2 out of 12 survey respondents audit only on their quality system not PIMS.

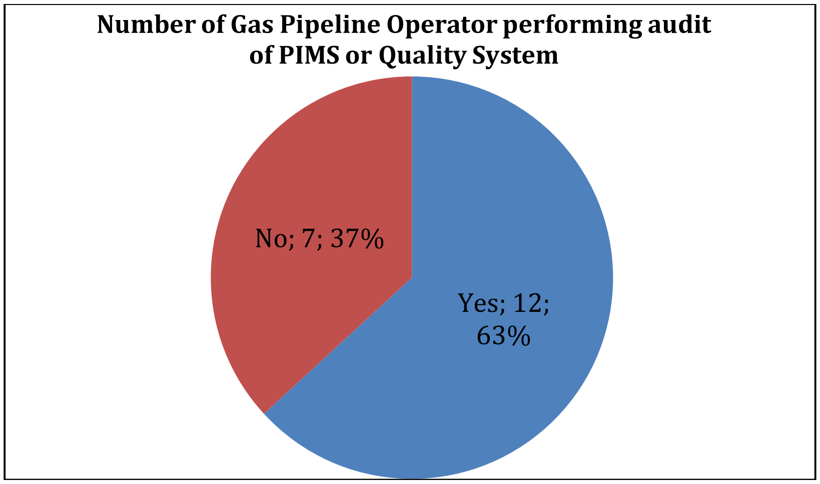


Fig.13

The survey also reflected that TSOs have different audit frequency. The audit frequency varies depending on the policies of each operator. The pie chart below Figure no. 14 shows that most of the survey respondents are conducting surveys at least once a year.

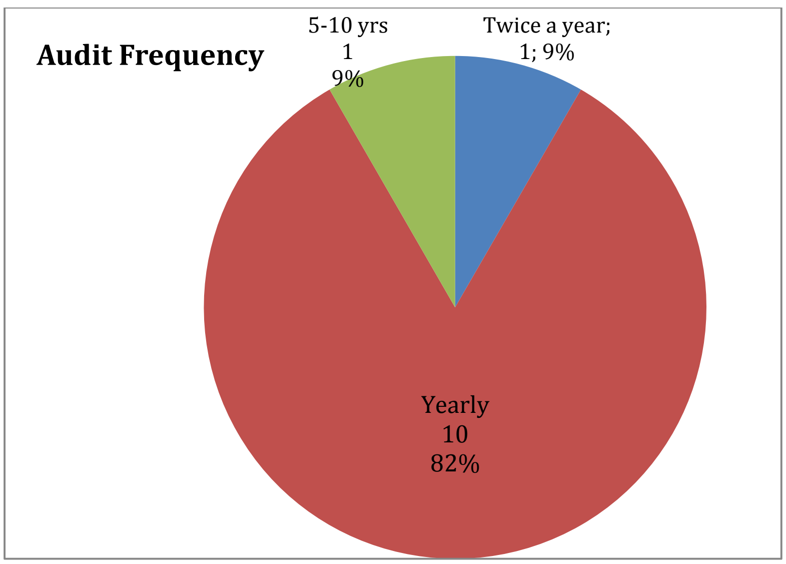


Fig.14

### 3.3.5 Country Regulations on Pipeline Inspection

In addition to pipeline codes and standards that pipeline industry conforms to many countries have specific regulatory requirements for pipeline inspection and management. The survey analysis demonstrated, Figure 15, that almost half of the survey respondents (TSOs) have country regulations on pipeline inspection.

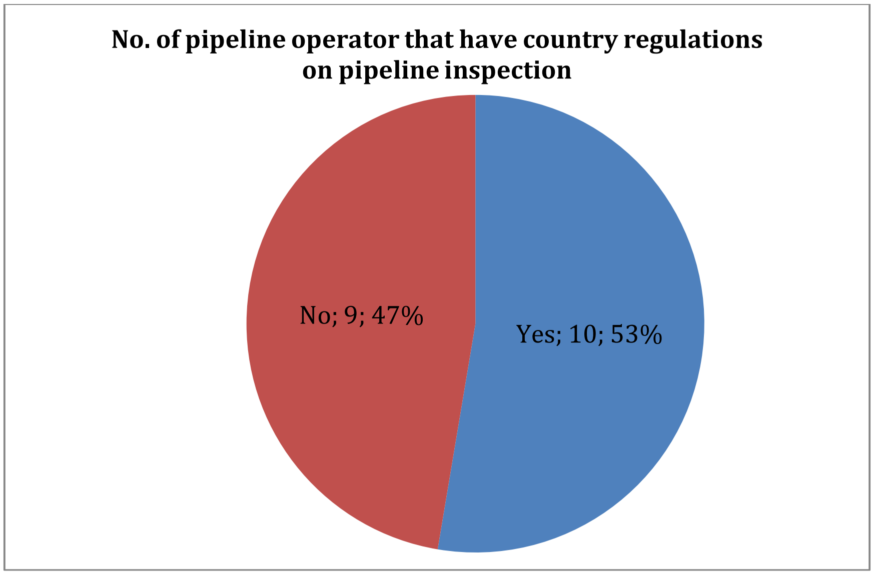


Fig.15

Analysis showed that many countries have distinct regulations for pipeline management and operation. Below are some of the observations from the survey:

- Some country regulations only require maintaining pipeline in accordance with their preferred engineering standards. For example, Pipelines Act of Victoria (Australia) requires compliance with AS2885.1 or Thailand Pipelines Act requires compliance with ASME B 31.8. These acts do not prescribe any particular integrity management practices.
- Some countries have laws stating technical requirements for integrity measures.
- Some country regulations mandate frequency of inspection for transmission pipelines.
- Some country regulations enforce conditions on the construction of new pipelines for example; Pipeline exceeding specific parameters (Diameter, Length and Pressure) shall be built with pig traps.

### 3.3.6 In-line Inspection

One of the most efficient methods to assess the integrity of pipeline is In-Line Inspection (ILI, aka Pigging). ILI assist in not only cleaning the pipeline' internal surface, it also helps in gathering information about the condition, features and integrity of the pipeline.
ILI methodology is well proven and is available with different technologies such as Magnetic Flux Leakage (MFL) and ultrasonic to inspect pipeline. Some Intelligent pigs also use callipers to measure the inside geometry of the pipeline.

Survey analysis and group discussions revealed that TSOs intelligently inspect pipelines before commissioning to detect construction defects and to develop base line integrity data for future trend analysis.

The analysis of the survey, figure no. 16, showed that ILI is not a regulatory requirement in most of the countries.

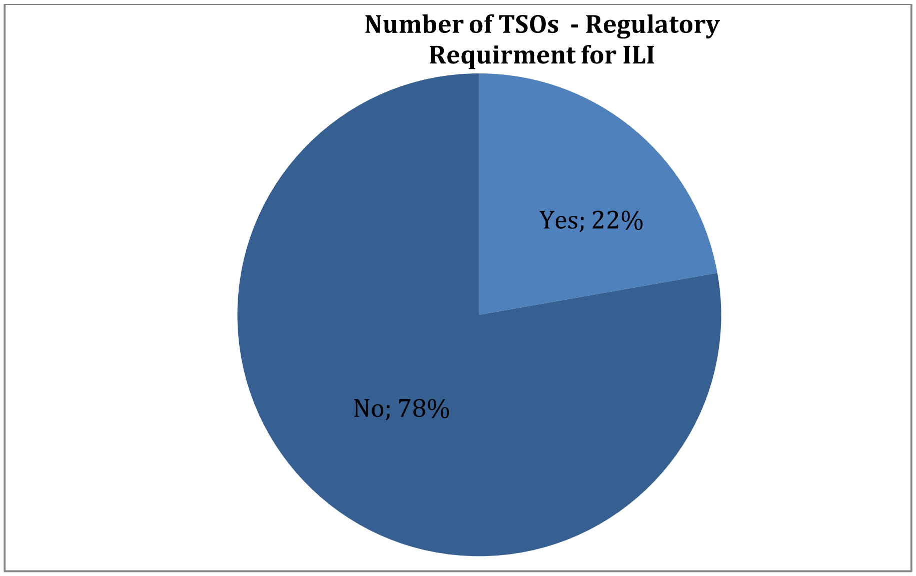



**Fig.16**

The countries with regulatory requirement have inspection frequency in between 5-10 years.

Nevertheless, TSOs worldwide use ILI methodology to inspect and ascertain the integrity of gas transmission pipelines. The reasons for using ILI technology varies amongst TSOs. The below list highlights some of the main reasons for using ILI inspection:

- To confirm quality after pipeline construction
- To comply with company' guidelines, practices or PIMS policy
- To assess the pipeline condition
- Access to integrity-data for the whole length of the pipeline
- Proven and reliable methodology
- Does not require flow interruption

The survey analysis, Figure no. 17, showed that TSOs without regulatory obligation also differ in ILI frequency. It is discovered that most of the TSOs undertake ILI once in every 5-10 years.

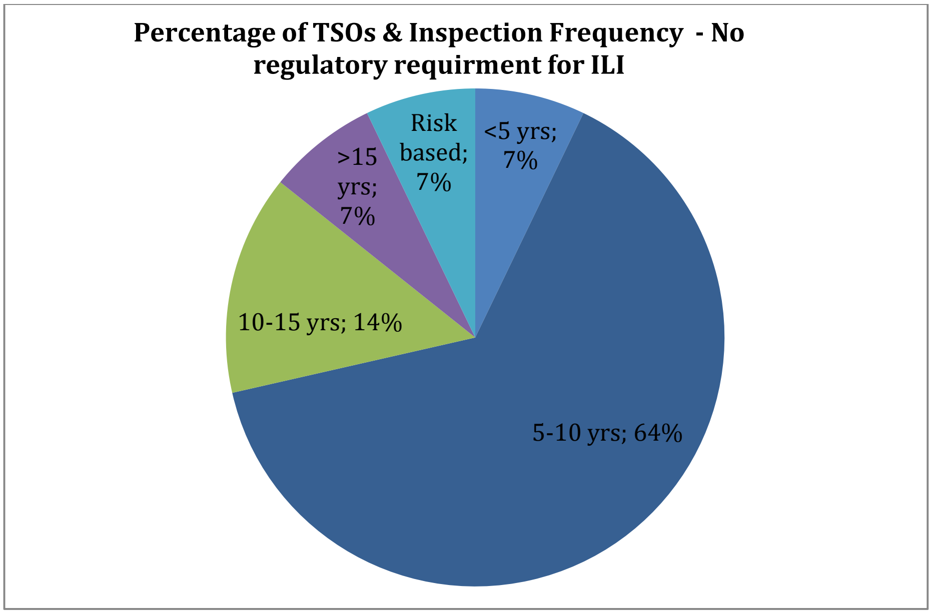



Fig.17

The analysis of the survey identified some of the main reasons considered by TSOs to establish the ILI frequency:

- Based on the current condition of the pipeline
- As per technical standards or industry practices
- Company Policies
- Risk Assessment
- Cost Benefit Analysis
- Expertise Recommendation

The graph below, figure no. 18, shows the ratio of survey respondents (TSOs) and their reasons which they consider most important to ascertain the ILI frequency:

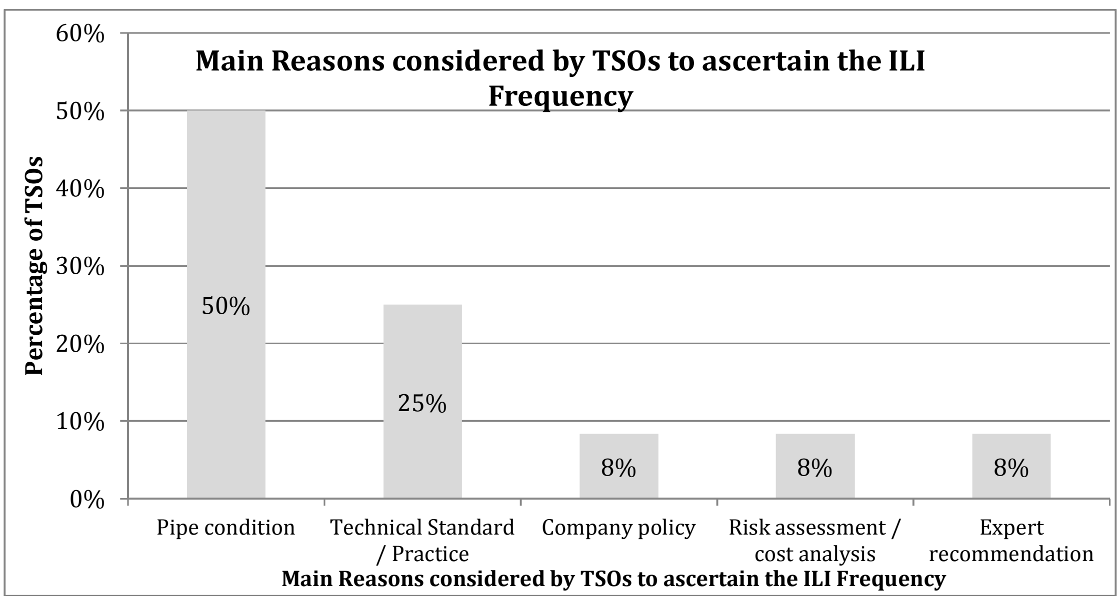



Fig. 18

### 3.3.7 Conclusions

The analysis of the survey carried out by Transmission Working Committee of the International Gas Union highlighted that Third Party Interference and External Corrosion are the top two threats to pipeline integrity.

The analysis showed that most TSOs rely on traditional methods of pipeline integrity management. The threat mitigations measures which are common across the board are Patrolling, Cathodic Protection, Pipeline coating, Right-of-Way Management, ILI and Stake holder consultation.

These practices are deemed adequate but a need to further strengthen the reliability of these practices is identified. Use of automated and remote technology is seen as a way in future and to reduce the pipeline failures.

It is no surprise that Real-Time monitoring of Right-of-Way, Real-Time Cathodic Protection monitoring and use of intelligent and automated weld-defect detection systems may help the industry in bringing the number of defects down.

However, the utilisation of the smart technologies is very limited in the industry. It is possibly because of TSOs resistance to create a need of additional skills and the workforce to maintain smart systems. The other reason which the committee think is the understanding of commercial viability of the innovative technologies.

There is no silver bullet, hence more work is required to further investigate threat mitigation measures and engage industry players to promote research and development in developing cost effective threat mitigation systems.

## 3.4 Third Party Damage

### 3.4.1 Summary

Third Party Damage (TPD) has been deemed to be the biggest threat to pipelines by global Transmission System Operators (TSO) as shown in the below histogram (results of the survey undertaken by the Working Committee 3 – Study Group 3.2- during the 2009-2012 Triennium).

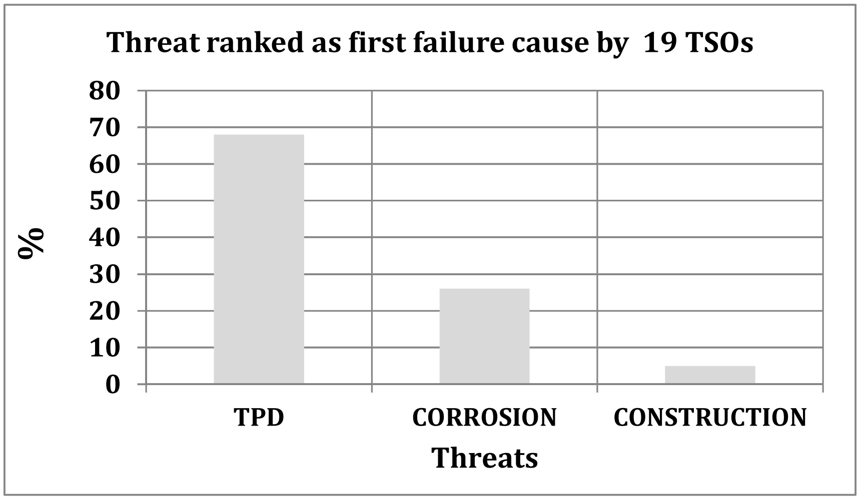



Fig. 19

For the triennium 2012-2015, a new survey has been undertaken in order to identify the most commonly used measures by TSO to reduce TPD.
This report covers the following points:

- Pipe design legislation
- Requirement of civil engineering work
- Survey and proactive control
- Emergency plan

This chapter also gives an overview of the abandoned pipelines.

### 3.4.2 Introduction

TPD is a major risk to public safety because of the proximity of people to the pipeline when these incidents occur.
The excavating equipment can accidentally strike and cause damage to buried pipelines. Several damages can cause the pipeline to leak or rupture. Even damage which appears to be minor can, over time, weaken a pipeline, causing a leak or rupture in the future.
Damage caused by TPD around pipelines is one of the most common causes of leaks and explosions on transmission pipelines.
The potential consequences of damage to pipelines by TPD range from service disruptions to catastrophes including loss of life, serious injury, and/or significant environmental impact.
The risks of pipeline damage are rising as the population grows - more people means more construction which means more excavation.
The good news is: pipeline damage caused by excavation and construction around pipelines is generally preventable.

Even though there are so many factors that endanger pipeline safety, TPD is the primary cause of loss to buried gas pipeline integrity.
In this document TPD is known as damage due directly to acts of man such as the damage by contacting with excavators.
Damage to pipelines caused by construction and excavation activities poses a significant risk to public safety but is generally avoidable. Damage prevention is all about pipeline companies working with those who routinely dig and excavate to reduce the risk of damage to the pipeline.
In order to put the focus on TPD a questionnaire was created and distributed to participating members of WOC3 in order to know the principal aspects of TPD, and current measures which are being carried out by TSO to prevent TPD .

#### 3.4.2.1 Pipe design legislation

The first barriers to prevent TPD are the *general design data for pipeline* **construction**, such as route selection, diameter, length, design factor, burial depth of the gas pipeline, distances between gas pipelines and other infrastructure utilities, safety/warning signs, restricted zones.
A good design can predict TPD failures. We will describe what TSOs are doing at this point.

##### 3.4.2.1.1 Design factor

*Design Factor*, also known as safety factor, is a term describing the structural capacity of a system beyond the expected loads or actual loads. This is, essentially, how much stronger the system is than it usually needs to be for an intended load. Safety factors are often calculated using detailed analysis because comprehensive testing is impractical on many projects, such as bridges and buildings, but the structure's ability to carry load must be determined with a reasonable degree of accuracy.
Pipeline systems are purposefully built much stronger than needed for normal usage to allow for emergency situations, unexpected loads, misuse, or degradation.
Pipeline standards have wall-thickness requirements for pressure containment. In most pipeline-design standards or recommendations, the basic wall-thickness design requirement is based on limiting the pipe hoop stress due to internal pressure to an allowable stress, which equals the SMYS multiplied by a design factor. This is implemented using the familiar Barlow equation:

$$\sigma_h = \frac{pD_{code}}{2t_{code}} \leq \phi_{code}\sigma_y$$

in which:

- $\boldsymbol{\sigma_h}$ is the hoop stress,
- **p** is the internal pressure,
- $\boldsymbol{\sigma_y}$ is the specified minimum yield stress,
- $\mathbf{D}_{code}$ is the diameter,
- $\mathbf{T}_{code}$ is the wall thickness, and
- $\mathbf{F}_{code}$ is the design factor.

Operating pressure introduces circumferential tension, which is the main cause of pipeline tensions. The maximum allowable operating pressure (MAOP) must now be determined.
The TSO operate pipelines with different MAOP, as shown in the table below:

| Number of country | MAOP's range | Remarks |
|---|---|---|
| 11 | ≥ 75 bars | Two companies answered 250 |
| 06 | 55 – 70 bars | |
| Others | - | Unspecified |

As we know the class location is then determined by counting the houses in a specified area near the pipeline. In all answers there is more than one class location. The analysis of the answers shows a diversity of the number of the class used by the countries varying from 1 to 5 as shown in the following figure.

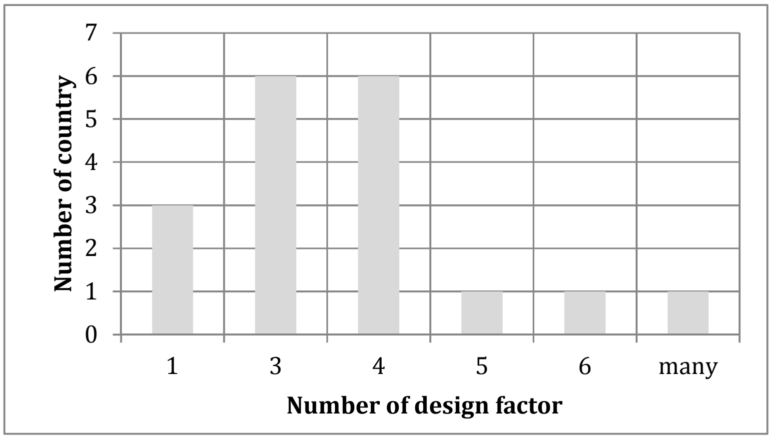



Fig. 20

The associated design factors range from a minimum value of 0.3 to 0.73 for the maximum value as shown in the below table.

| Design factor | | | | |
|---|---|---|---|---|
| Minimum | Mean Minimum | Mean Intermediate | Maximum | Mean Maximum |
| 0.3 | 0.42 | 0.55 | 0.73 | 0.64 |

We have not received answers in which the design factor exceeds 0.73considering that there are a number of pipeline codes that allow operation of transmission pipelines at stress levels up to, or over, 80% of the specified minimum yield strength.

- ✓ Canada - Canadian Standards Association
- ✓ Z662
- ✓ USA - ASME B31.8
- ✓ International - ISO 13623
- ✓ UK - BS PD 8010-1
- ✓ Australian Standard

###### 3.4.2.1.2 Burial depth of gas network

The 2013 survey shows that except two countries, the rest obey the specific burial depth of gas pipeline fixed by the national legislation:

**Burial depth of the gas pipeline [m]**

| Under | Minimum | Maximum | Average |
|---|---|---|---|
| Road | 0.8 | 3.5 | 1.4 |
| Pavement | 0.8 | 2.0 | 1.3 |
| Railways | 0.8 | 3.5 | 1.5 |
| Canal | 0.6 | 3.0 | 1.5 |

#### 3.4.2.1.3 Distances between gas network and other infrastructure utilities

The 2013 survey shows that except five countries, fourteen respect the specific distance fixed by the national legislation. Among the five countries, three use the same range values and two didn't specify the adopted distances.
The table below summarizes the minimum and maximum distances adopted by the different countries.

**Distances between gas pipelines and other infrastructure utilities [m]**

| Infrastructure utilities | | Minimum | Maximum |
|---|---|---|---|
| Electricity cable | Parallel horizontal | 0.3 | 8 |
| | Parallel vertical | 0.3 | 1.5 |
| | Crossing | 0.3 | 3 |
| Water pipes | Parallel horizontal | 0.3 | 10 |
| | Parallel vertical | 0.3 | 1 |
| | Crossing | 0.3 | 1.5 |
| Telecom wiring | Parallel horizontal | 0.3 | 6 |
| | Parallel vertical | 0.3 | 1.5 |
| | Crossing | 0.3 | 1.5 |
| Sewage | Parallel horizontal | 0.3 | 6 |
| | Parallel vertical | 0.3 | 1.5 |
| | Crossing | 0.3 | 1.5 |
| Other* | Parallel horizontal | 0.3 | 6 |
| | Parallel vertical | 0.3 | 1 |
| | Crossing | 0.25 | 1 |

Countries which have national legislation: 10 consider those distances to be safety distances, two for the design and construction purposes and one did not specify. For the 5 remaining countries, two consider those to be safety distances, one as clearances for the other assets within the vicinity of the gas transmission pipeline and the two others did not specify.

#### 3.4.2.1.4 Installation of safety /warning sign

17 of the 19 countries have national legislation which requires the installation of safety/warning signs. The below table summarizes the different types of warning signs used by the 19 TSO:

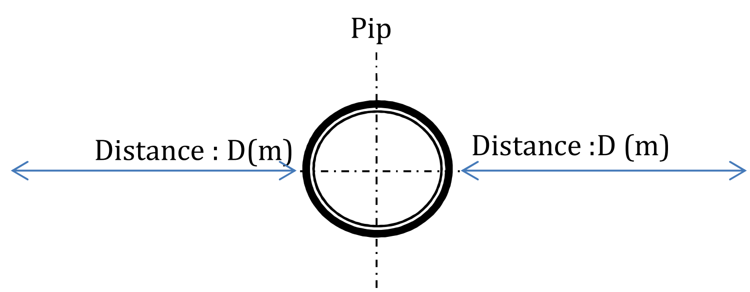
| Type of warning signs | Having national legislation : 17 | | | | Without national legislation : 02 | | |
|---|---|---|---|---|---|---|---|
| | Yes | No | Not answered | Remarks | Yes | No | Not answered |
| Passive buried strips | 10 | 05 | 02 | 01 warning foils | 01 | | |
| Passive buried strips with metal cable | | 14 | 03 | | | 01 | 01 |
| Active buried strips (for surface detection) | | 14 | 03 | | | 01 | 01 |
| Surface sign posting / overhead markers | 15 | 02 | | | 01 | | 01 |

Most warning signs used by the TSO's are the passive buried strips and surface sign posting / overhead markers.
The survey also showed us the use of other types of warning signs:

- ✓ TSO's having national legislation (04) use: warning mesh, signal buoys in navigable rivers, sign balls at overhead power line crossings, markers.
- ✓ TSO's without legislation (01) use: concrete slabs


##### 3.4.2.1.5 Restricted zones in the vicinity of gas network

17 of the 19 countries have national legislation which imposes restricted zones in the vicinity of the gas network. The above table summarizes the different restricted zones used by the 19 TSO:



| Zone where | Having national legislation : 17 | | | | | Without national legislation : 02 | |
|---|---|---|---|---|---|---|---|
| | D[m] | | | Remarks | | D[m] | |
| | min | max | Average | | | min | max |
| mechanical works are forbidden | 0.3 | 25 | 8.5 | One TSO answered 0 | *For the average we didn't take into account the distance of 200 m given by 04 TSOs.* | *1* | 1.5 |
| the gas company must be informed for any kind of works | 2.5 | 200 | 14.4 | *Two TSO answer a minimum of 0* | | 0 | 2.5 |
| a systematic removal of trees in the pipeline right of way is performed | 2 | 15 | 5.7 | One TSO answered 0 | | - | 3 |

The different restricted zones used by the 19 TSO, depends on many parameters and the predominant one is the geographic area of the country (availability of various pipe laying corridors).

#### 3.4.2.1.6 Requirement of civil engineering work

When a civil engineering/infrastructure projects are undertaken, a pre-investigation about the underground utilities is required. 17 TSOs adhere to a national legislation which assigns in 12 cases the excavation company to inform directly all concerned utilities before digging starts. For the rest of the cases the assignment is obtained from:

- The local authorities.
- Coordination meeting between interested companies
- the use of referrals service "Dial Before You Dig" for obtaining information and locating underground utilities .

### 3.4.2.2 Type of communications between TSO and Public

Communication between TSO and public is considered an important factor in preventing TPD. it starts with the preliminary plan, then the way and the duration of exchanging information and the precautions undertaken before starting any work beside the gas pipelines.

#### 3.4.2.2.1 Ways for exchanging information between TSO and utilities.

There are different channels used by the company to be informed by the digging company before work starts. 20 TSOs answered the questionnaire survey, and the summaries are given in the following histograms and tables which summarize the different ways and duration of exchange of information between TSOs and utilities:

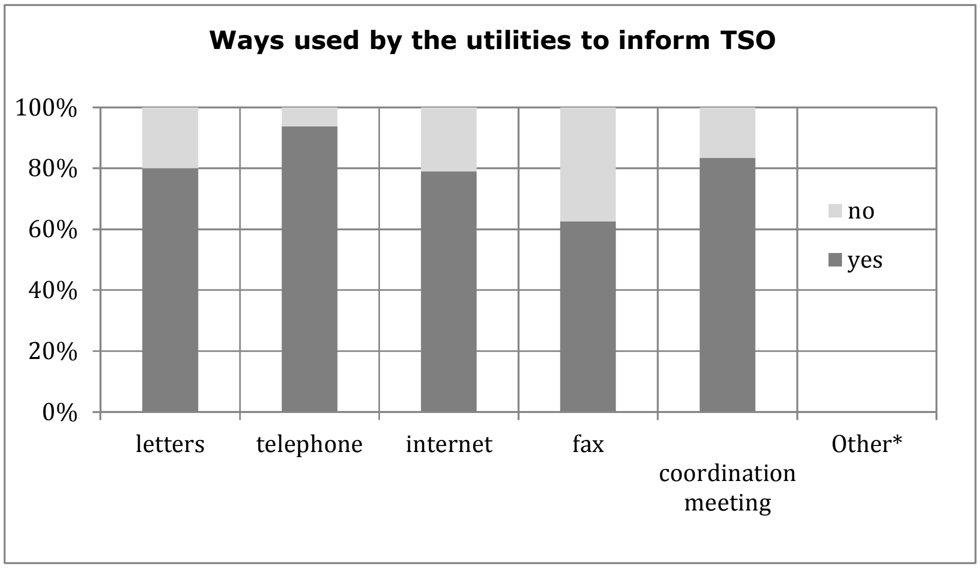



Fig. 21

Most of the utilities, mainly a dedicated telephone number as a way to exchange information with TSO. On other hand most of the TSO use official letters to reply as shown in the below figure.

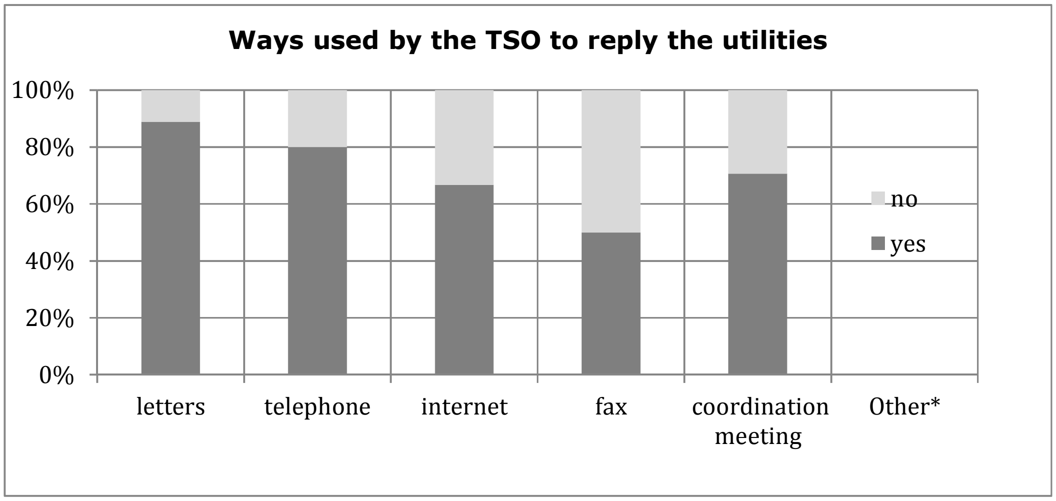



Fig. 22

One Call system/web based system, was also a subject of the 2013's survey. It's a free service to inform underground utilities or pipeline owners of any called-in excavation activities that could potentially affect their underground facilities. The facility owner, in turn, provides specific location information to the excavator and marks the underground facility.

The 2013's survey shows that only 8 countries use this channel for exchanging information between TSO and utilities. It is required by the national legislation for three countries. For the rest, only 3 countries are undertaking studies to create this type of channel.
When replying the utilities, TSO use many types of Information content, as shown in the below histogram, maps and notification, are the predominant information's content that TSO give to the utilities

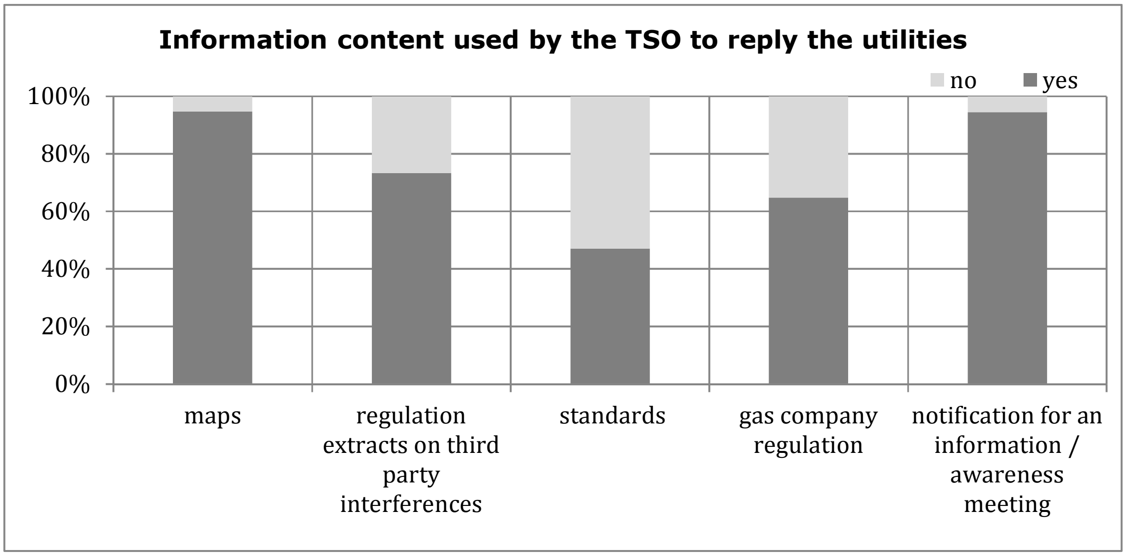



Fig. 24

#### 3.4.2.2.2 Duration for exchanging information between TSO and utilities.

Concerning the deadline used by the utilities to inform TSO and the duration to do a reply, before starting any work in the neighboring of the vicinity of the gas pipeline, different answers were given as shown in the following table :

| Deadline | Used by the utilities | |
|---|---|---|
| | To inform TSO before digging starts | To reply |
| 3 days before | 4 | 3 |
| 7 days before | 3 | 4 |
| 10 days before | 2 | 2 |
| Other* | not defined/ As early as possible/ 15 days/ 1 month/ | not defined/ As early as possible/ 15 days/ 1 month/ |

The utilities use various deadlines to inform TSO, and in any case they cannot start digging before getting TSO`s authorization.

For the one call system/web based system, a call center is set up so that anyone who will be digging or excavating using any kind of equipment from shovels to mechanized equipment (i.e. commercial contractors, road maintenance crews, telephone pole installers, fence builders, landscape companies or home owners) can make one telephone call to give notice of their plans to dig in a specific area up to 72 hours prior to any excavation activity. The person doing the project must wait the specified time during which the marking of the facilities is accomplished before beginning the project. Everyone has to cooperate so that the project can be completed as planned and the underground facilities are marked and protected during the work.

#### 3.4.2.2.3 Certification of third party information procedure

Third party certifications are the most trusted form of TPD verification. The process of having a product third-party certified requires the hiring of an independent auditing firm. It means that the processes and the organization are audited and verified by an independent third-party certification body. Therefore, once a product has successfully undergone the review process and the audit claims are verified, a product can make the claim that it is level certified.

Although it is a good rule to have a process audited by an external source, in many companies this is not implemented.

Measures of complementary prevention set up voluntarily by gas companies in order to reduce third party damages.

Most of them use periodic information meetings intended for third parties. Only half use special training intended for third parties and signed agreements for genuine relationships among all stakeholders.

The 2013's survey showed that 8 out of 19 TSOs have third party information procedure certified by an external auditor

#### 3.4.2.2.4 Additional measure that TSO adopt to prevent TPD

In order to reduce TPD, TSOs frequently adopt complementary prevention measures, set up voluntarily. The below histogram shows the different prevention measures used by the TSOs.

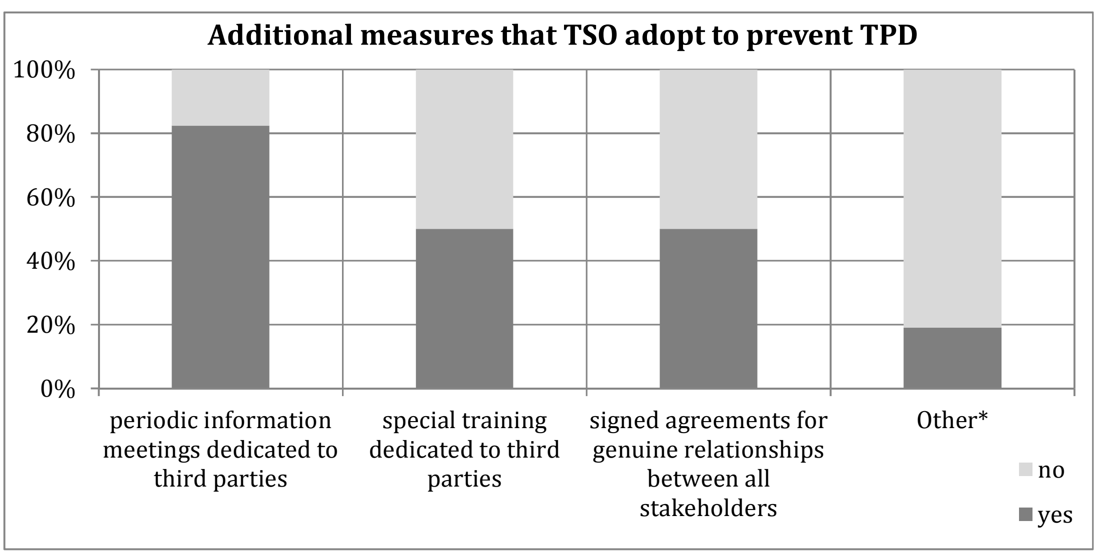



Fig. 25

Periodic information meeting dedicated to Third Party is the predominant measure used by TSO to prevent TPD. Other measures are used by the TSOs such as folders, pamphlet……

#### 3.4.2.2.5 Pipeline Detection before digging

When digging is projected in the vicinity of the gas pipeline, 10 TSOs use detectors for locating the axis laying of the pipe, among which 7 adhere to a national legislation. The 2013 survey shows that radio frequency is the most used equipment as shown in the below table:

| **kind of detectors used by TSO** | **Number of TSO** |
|---|---|
| Magnetic field detector | 4 |
| Radio frequency detector | 6 |
| Transmitter and detector | 5 |
| Radar | 1 |

Among the 19 TSOs, 12 proceed to in situ test probes before digging.

### 3.4.2.3 Claim management.

Impact damage to a pipeline from excavators and mini diggers can lead to a significant gas leakage, loss of supply and incur a significant financial cost with considerable environmental damage and could be potentially tragic.

For this reason, TSOs carry out statistics over the number of interferences with third parties and network damages per year.
The 2013 survey shows the different records done on the TSO's gas network during the last 5 years:

| Total number of | Given by TSOs | | | Remarks |
|---|---|---|---|---|
| | min | max | Average | |
| received notification about digging works per year | 9 | 400 000 | >150 | *For the average we didn't take into account the answers of two TSOs : 400 000 and 1 500.* |
| network damages per year without leakage | 0 | 22 | 3,5 | |
| network damages per year with leakage | 0 | 10 | 1,3 | |

When damage to the gas network happens, the company responsible for the damages should make financial compensation. The following table shows in what percentage of cases, financial compensation is claimed from the company responsible of the caused damages to the gas network:

| Number of TSO | % of damage claims made |
|---|---|
| 6 | 100 |
| 2 | 22 and 10 |
| 9 | 0 |

On other hand 15 TSOs over the 19 take different kinds of repressive measures against the accused third party as shown in the following table :

| kind of repressive measures | Number | Remarks |
|---|---|---|
| Fine or penalty | 8 | |
| Inform Health and Safety authority | 8 | |
| Inform civil engineering federation | 4 | |
| Removal from the gas company approved contractors/suppliers list | 7 | |
| Other* | 1 | -Sending notification letter through judicial officer.<br>-Visit to the leaders of the digging company for clarifications about safety procedures. |

### 3.4.2.4 Survey and proactive control

#### 3.4.2.4.1 Means of survey

In order to reduce third party damages, various means of pipe survey are used according to the need of each company, pipe characteristics and localization (urban, suburban, rural areas).
The 2013 survey gives the different means and frequency of the gas network's survey and specifies whether it is mandatory or not:

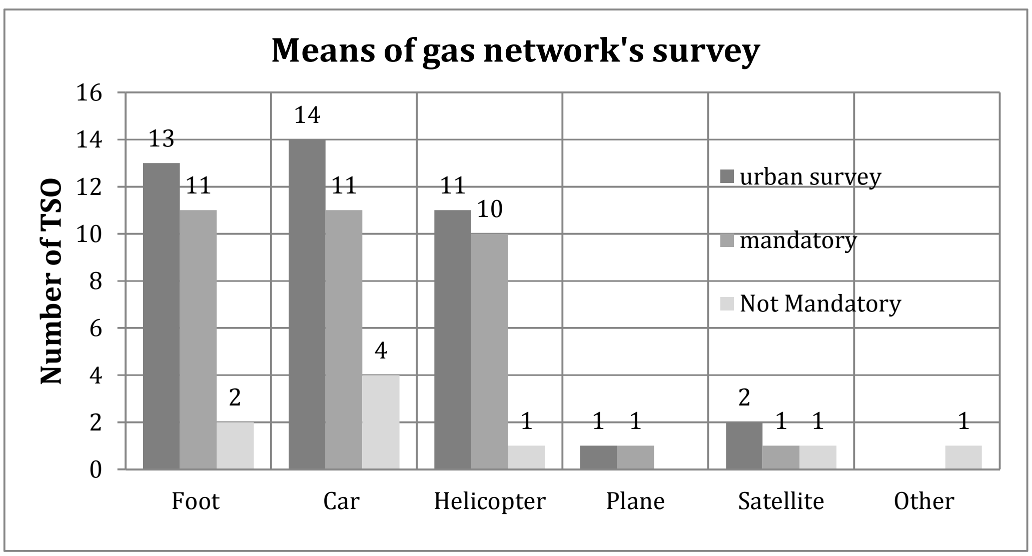



Fig. 26

The most frequent operations performed are (most of them are mandatory):

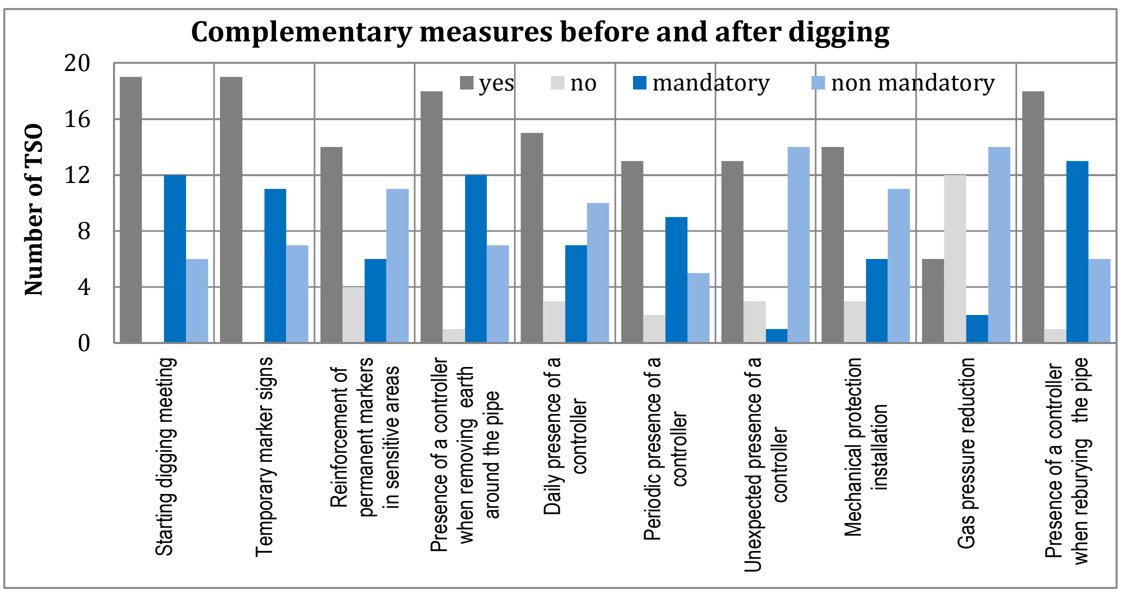
- on-foot inspection
- car patrol
- aerial survey by helicopter

The different frequencies used by the TSOs for each means of survey are given in the following table :

| Means of survey | Most used urban frequency | Other TSOs |
|---|---|---|
| Foot | yearly : 06 TSOs | daily, biweekly, weekly, 12-3 -2 times /year |
| Car | daily : 07 TSOs | daily, biweekly, weekly, 52-4 -2 times/year |
| Helicopter | yearly : 04 TSOs | 20-12-7 times /year |
| Plane | 12 times /year : 01 TSO | |
| Satellite | yearly : 01 TSO<br>1time / 05 years : 01 TSO | |

#### 3.4.2.4.2 Work permit

TSOs take particular complementary measures before and after digging in the vicinity of pipes in order to perform this operation in a safe way and to avoid pipe damage. The following histogram gives these complementary measures and specifies whether thy are mandatory or not:




The most frequent complementary measures are (most of them are mandatory):

- Starting digging meeting
- Temporary marker signs
- Presence of a controller when removing earth around the pipe
- Daily presence of a controller
- Presence of a controller when reburying the pipe

#### 3.4.2.4.3 Damage investigation after the end of works

Even if controllers of the TSOs are present when removing earth around the pipe and when reburying it, damage investigations are carried out just after the end of works, as shown in the following histogram:

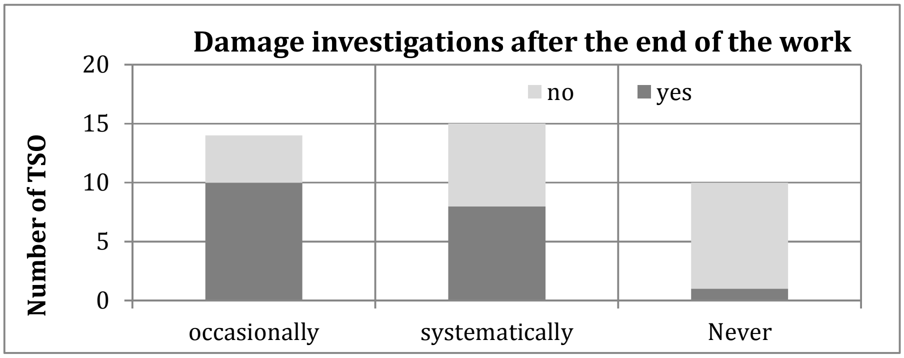



Fig. 27

More than 40 % of the TSOs undertake systematic damage investigations just after the end of works, consisting mainly in cathodic protection measuring, gas detection and pigging as shown in the following histogram:

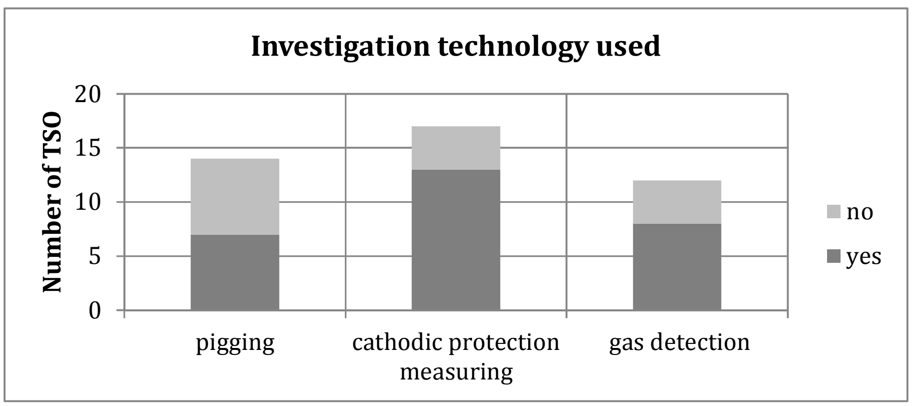



Fig. 28

When damage investigations are undertaken just after the end of works, cathodic protection measuring is the most used technology.

### 3.4.2.5 Emergency plan

To manage a gas transportation system, TSOs have developed and implemented an emergency plan that defines procedures and instructions particularly regarding the evacuation plan and mission of the permanent intervention squad, information of the authorities, the fire brigades and the public and the way of cooperation with the external bodies.

All the 19 TSOs which participated to the 2013 survey have an internally tested emergency plan in case of accidents. The content of this emergency plan is given in the following histogram:

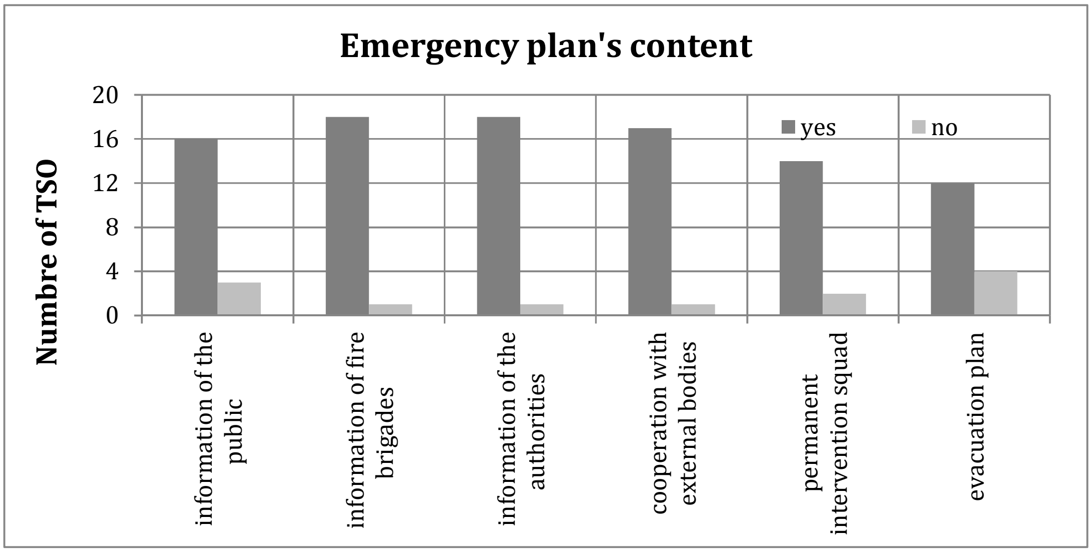



Fig. 29

Among the 19 TSOs, 13 have an external emergency plan with different levels as shown in the following histogram:

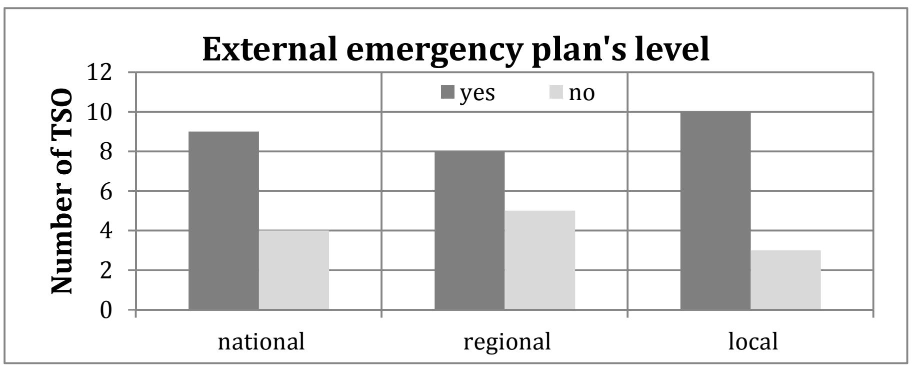



Fig. 30

50 % of these emergency plans include evacuation perimeter distances to be used by the fire brigades in case of incident on a pipeline:

- "hot zone" depending on pipeline pressure and diameter according to risk assessment criteria (3kW/m² radiation).
- Decreasing from 2 km
- 200 m distances

#### 3.4.2.6 New solutions to manage third party damage

Around fifty per cent of TSOs are studying new solutions to reduce third party damage, **in order to be more efficient and cost effective**:

- new leak detection technologies-satellite survey
- pipe remote survey by satellite

- Future Fiber Optic Technology (FFT) for third party excavation detection (Un-notified excavation is expected to be detected).
- Fiber cable, automatic recognition of construction equipment by satellite
- vibration detection by optical fiber cable
- remote alarm
- ultrasonic gas detection
- use of new Media's way of communication (web, free call..)
- call before you dig campaign

Maintaining excellent relationship with the interested parties, such as land owners and farmers, people living around the pipe path, is also a key for preventing the most possible risks due to entropic activity.
TSOs can also:

- Develop sustainability policies and social activities such as local entrepreneur development supporting, sport and cultural events financing etc.,
- Contribute to satisfy fundamental human rights to health, fresh water, education, etc..
- Develop an environmental policy to reduce an activity's impact on the local communities.

Generally speaking, address the real needs of population living around pipe, this activity can be developed in coordination with local authorities and population representatives.
Sustainability policy targets to create a new relationship between TSOs and local countryside population based on mutual interest to safeguard the pipe.

#### 3.4.2.7 Abandoned pipelines

Abandoned pipelines could be a serious problem for the TSOs which made pipeline rehabilitation (replacement), the 2013 survey shows that 12 TSOs have legal obligations applicable to pipelines either out of service or abandoned, by undertaking actions as shown by the following histogram:

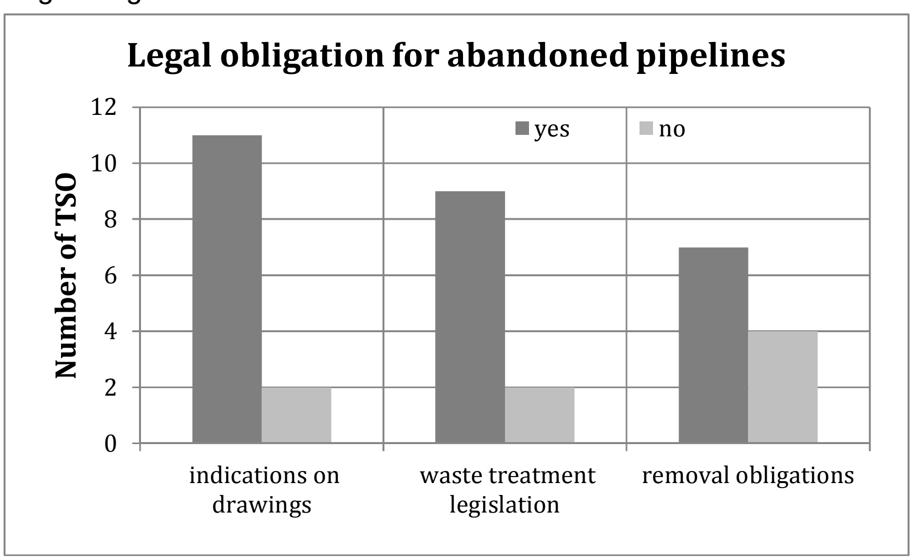


Fig. 31

### 3.4.3 Best practices

Third party damage can be made by external public/private companies or by land owners, to operate in the best environmental conditions; a good relationship with local authorities should be pursued and maintained

Throughout this relationship a cooperation with public companies (water, electricity, road and public building etc.) should be ensured in order to share own plan of activity to avoid possible interferences with third party infrastructures (road, track etc.), new constructions (farm facilities, wall and barrier etc.),farmers , or other surrounding activity on pipeline integrity.

### 3.4.4 Conclusion

To avoid third party damage, pipe construction should be done in the safest way (design factor, coating, pipe depth, safety distances and restrictive area, cathodic protection, pipe markers, major protection crossing rivers, roads, rails, etc.)

A maintenance plan has to be implemented (pipe survey on foot, by car, plane and/or satellite, pipe inspection by intelligent pig, cathodic protection measuring, real time remote control and monitoring of the gas transmission system parameters, leak detection, abandoned pipes treatment, etc.)

There should be emergency plans testing and also free advice to people working near a pipeline. A communication system with third companies, subcontractors, land owners and local authorities should be developed and meetings should be organized under the aegis of local authorities, with the attendance of all the above mentioned entities and stakeholders' representatives.

It is important to point out that the prevention of third party damage is not entirely the responsibility of TSOs. Stakeholders, real estate owners and local governments should also get involved.

***Furthermore, a deficit of legislation is relieved in many countries specially to protect existing pipes against urban extension and to delimit safety distances that new constructions have to respect in the vicinity of existing pipelines.***

The best method to prevent TPD is the "Swiss Cheese Model", by which a lot of barriers should be implemented. An increase in the number of barriers will reduce the probability of TPD failure.

## 3.5 Managing Ageing Pipelines

### 3.5.1 Summary

The gas transmission network is based essentially on steel pipelines which connect the different gas sources to the delivery points. Pipelines vary on lengths, diameters, type of coating and many other characteristics.

Steel pipelines for gas transmission are buried underground; they could be onshore or offshore, they could cross many countries, through rivers, lakes, mountains. Their design life and operating life differ from company to another, where considerations to operating are different. Many parameters affect their life.

Today, a big part of transmission network exceeds 30 years old and for some areas it is even more than 50 years. The life of a steel pipeline is affected by the way on which it is designed, constructed, operated, maintained and inspected.

Transmission system operators TSOs are facing the problem of ageing steel pipelines, hence they will be requiring network upgrade or pipeline replacement which could be very expensive. Safety, reliability as well as cost efficiency are obvious driving issues. However, no adequate systems are available enabling GTCs to plan, schedule and decide whether to replace or rehabilitate or downgrade a steel gas pipeline.

This report intends to extract some basic TSOs internal procedures which are deployed locally in order to reach as much as possible an objective decision related to steel pipeline rehabilitation, replacement or downgrading. It may hopefully lead to establish a list of ideas for a prospective approach for managing aging pipelines.

### 3.5.2 Introduction

The gas transmission network is composed of a big number and complicated cross linked pipes that are different in age, length, diameters and even gas quality composition; pipelines are also laid in different types of soils.

Today many pipelines are old and their integrity is affected not only by their age but by some other factors. Some criteria are stated to describe the situation of a pipeline, but also Inline Inspection methods are considered.

Adding to that all the financial aspects which decide about the way to construct, operate and repair the pipeline.

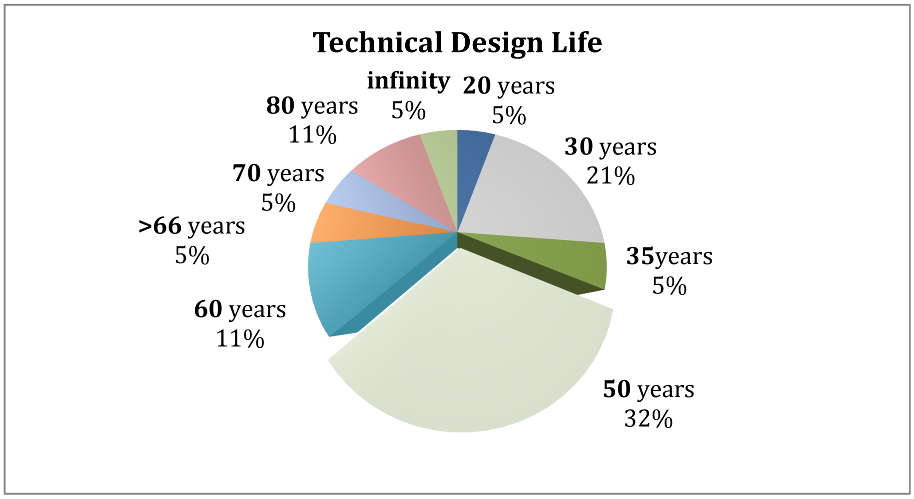
In order to put the focus on Ageing pipelines a questionnaire was created and distributed to participating members of WOC3 in order to know how TSOs are managing them.

### 3.5.3 Design life

#### 3.5.3.1 Technical

The technical design Life is the life that a pipeline is designed for; it varies from one company to another, from analyzing the answers of 19 TSOs; the design life varies from 20 years to infinity , Only 2 of the 19 TSOs have national legislation which imposes the technical design life (50 and 60 years) and third of the TSOs consider 50 years as a technical design life.

The below figure summarizes the different technical design life values used by the 19 TSO




#### 3.5.3.2 Economical

It is the economical life of a pipeline, the 20 TSOs use an economical design life varying from 13 years to more than 100 years (3 TSOs have national legislation which imposes the economical design life (13, 20 and 50 years)). This wide range depends mainly on the economical conditions of each company, the capex and opex and also the way of operating, most of the companies (21%) considered 30 years as an economical design life. The below figure summarizes the different technical design life values used by the 20 TSO

Fig. 32

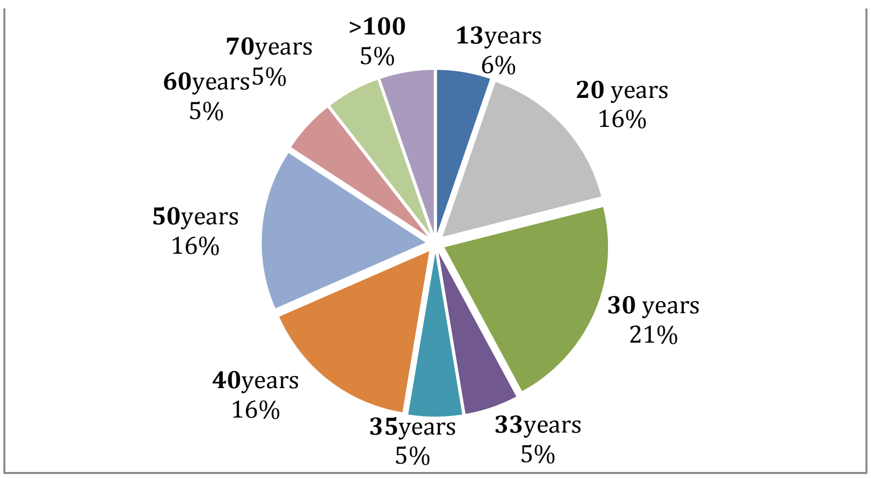



Fig. 33

### 3.5.4 Assessment of the pipeline technical current state

The main objective of this assessment is to show how TSOs perceive pipeline ageing and what are the TSOs different key decisions For Replacing, downgrading or rehabilitating…?

### 3.5.4.1 What is an aged pipeline?

The 2013 survey shows that the TSOs do not use the age of the pipelines as a main criterion for classifying them as ageing ones, but their perceptions converge when they record:

a- Significant increase of maintenance cost

b- Excessive distribution, kind and density per length of metal defects

c- Excessive distribution, type and density per length of coating defects.

Other understanding of Ageing pipeline was given by some TSOs:

- Defective girth welds

- Renew concession period

- Company strategy to divert it for distribution pipelines

The below figure summarizes the different TSOs perception of an ageing pipeline.

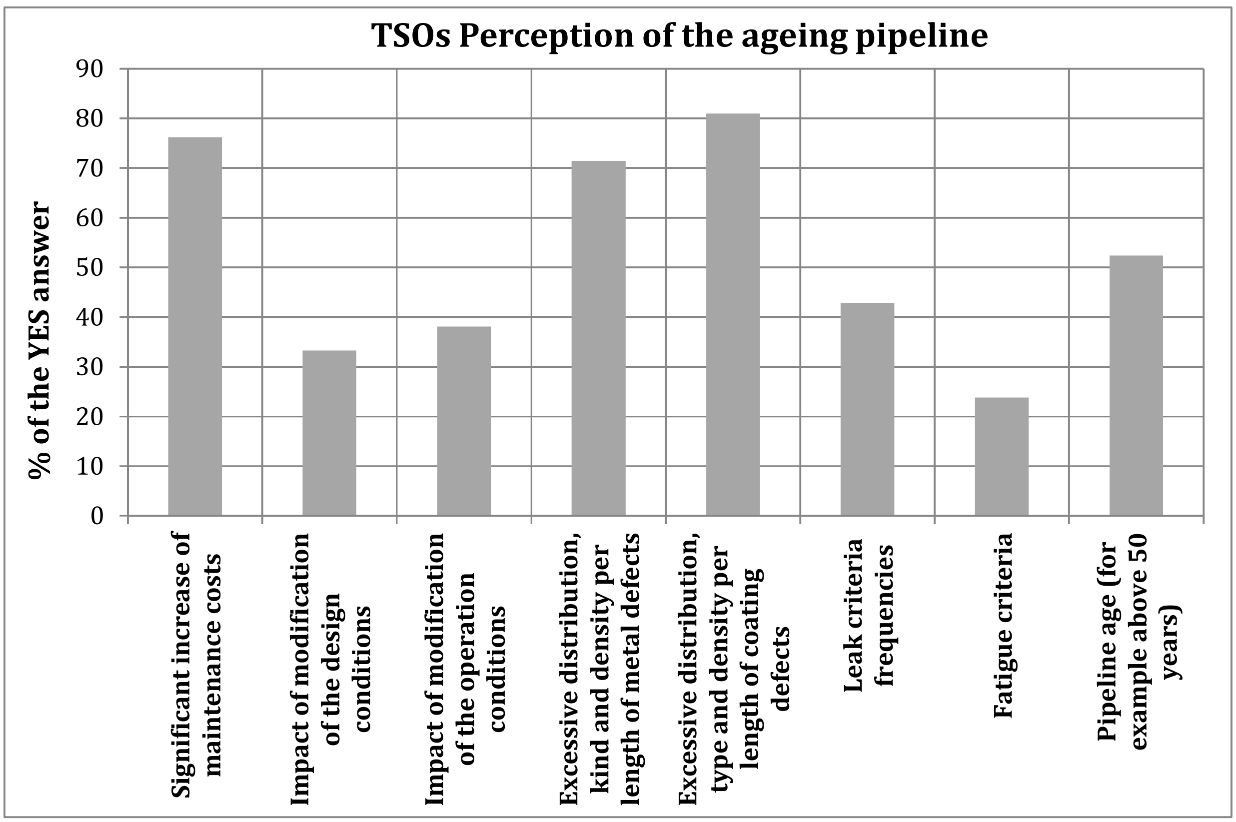



Fig. 34

### 3.5.4.2 Type of pipeline inspection technique used by TSOs

TSOs use mainly two ways of pipeline inspection, the inline inspection (ILI) and On line inspection.

The ILI consists of launching an intelligent tool into the pipeline and inspect the state of the pipe, there are the standard techniques such as MFL, IFI, etc. which are used by almost all the TSOs.
The On line consists of undertaking electrical field survey methods: ON/OFF CIPS-DCVG for detecting defects on a buried pipeline.
Other new techniques such as EMAT tool are used by a few TSOs. There are some other tools less effective which mainly used to detect some other defects related to of the pipeline such: INS, Geometric Toll, Geo pig, US wall thickness measurement, Geometrical and Inertial PIG.
The below figure summarizes the type of pipeline inspection technique used by TSOs:

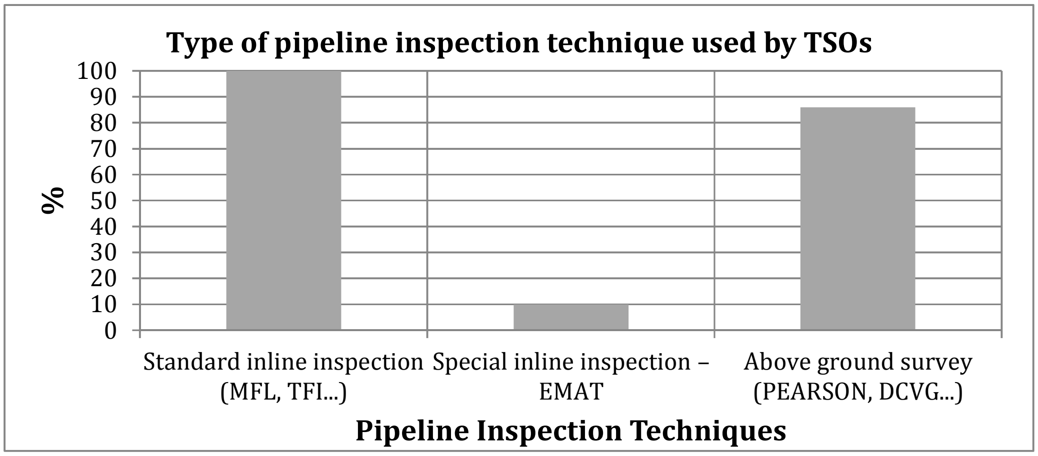



Fig. 35

The most used pipeline inspection techniques by the TSO are ILI and On line.
The 2013 survey also shows that 77 % of the TSOs, consider that "old/aging" pipelines which cannot be inspected by an ILI technology would be a source of worry / trouble, for divers reasons as shown in the below figure:

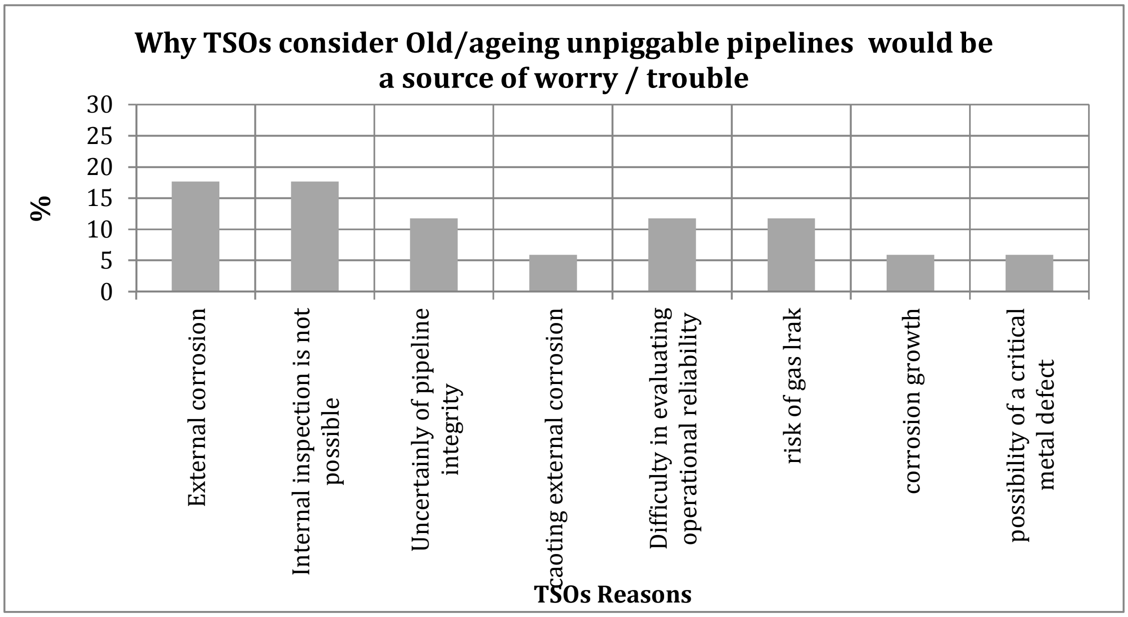



Fig. 36

#### 3.5.4.3 Comparing technologies

The 2013 survey shows that the 58 % of TSOs undertook technologies comparison by inspecting some pipelines with ILI and On line techniques. For the ones which undertook simultaneously the two inspections, only 3 TSOs deduced a correlation between metal defects and coating ones. The others have different visions and interpretations.

#### 3.5.4.4 Deterioration defects related to Ageing

The 2013 survey shows that most of the TSO deduced a correlation between coating defects and ageing, among them 53 % did the same correlation with the metal loss.
The below figure summarizes the correlation between deterioration defects related to ageing:

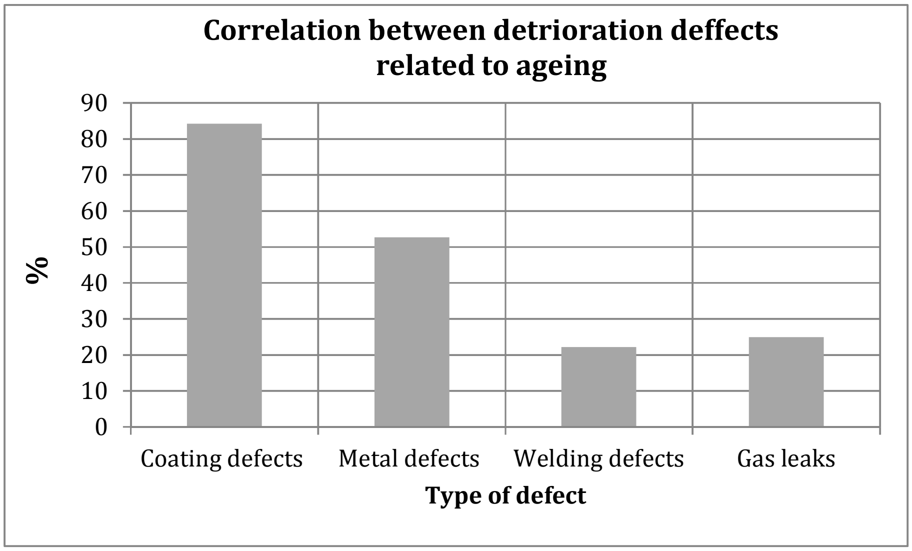



Fig. 37

#### 3.5.4.5 Pipeline repairs

##### 3.5.4.5.1 Metal defects

TSOs use different techniques for repairing a metal defect in a pipeline, it could be from a simple operation (grinding) to a complicated one which is cutting and replacing a part of a pipe. These reparation techniques are as follows:

- Local cut and replacement: it consists of cutting the damaged part of the pipe and replacing it by a new spool, this method is made off gas and a stop of the gas flow is needed, almost all the TSOs use this type of reparation when cutting gas is possible.
- Composite reinforcement: It can be done on operated gas pipeline (hot reparation), a kind of composite material is pooled which makes reinforcement to the defected part.
- Metallic sleeve: It's a rapid way to repair a defect and to reinforce a pipe, by applying a metallic sleeve, which could be fixed by bolts or by welding it on the pipe.
- Grinding: this type of reparation could be made for a pitting on the metal but this way is only used when the defect is small and not deep.
- Internal strong plastic coating: It's a way to protect the pipe from internal corrosion; it could be done as a preventive way to avoid corrosion.
- Recoating: when needed and when detected, recoating a pipe is a way to prevent the pipe from corrosion and then from metal defects.

- Hot tapping: these techniques are used to repair a pipe even if it's still in operation, by using a hot tapping to divert gas from the original pipe to a temporary by passed pipe, in order to empty the defected pipe and repair it (stoppel).
- Deposit welding: the metal defect could be replaced by deposing a weld on a defected part.
- There are some other alternatives used, a reduction on the MAOP could be done in case of a pipe which has a lot of defects along the pipeline causing a reduction in the pipe wall thickness and where the repairs will be difficult to achieve.

The below figure summarizes the different way used by TSOs for metal defects reparation.

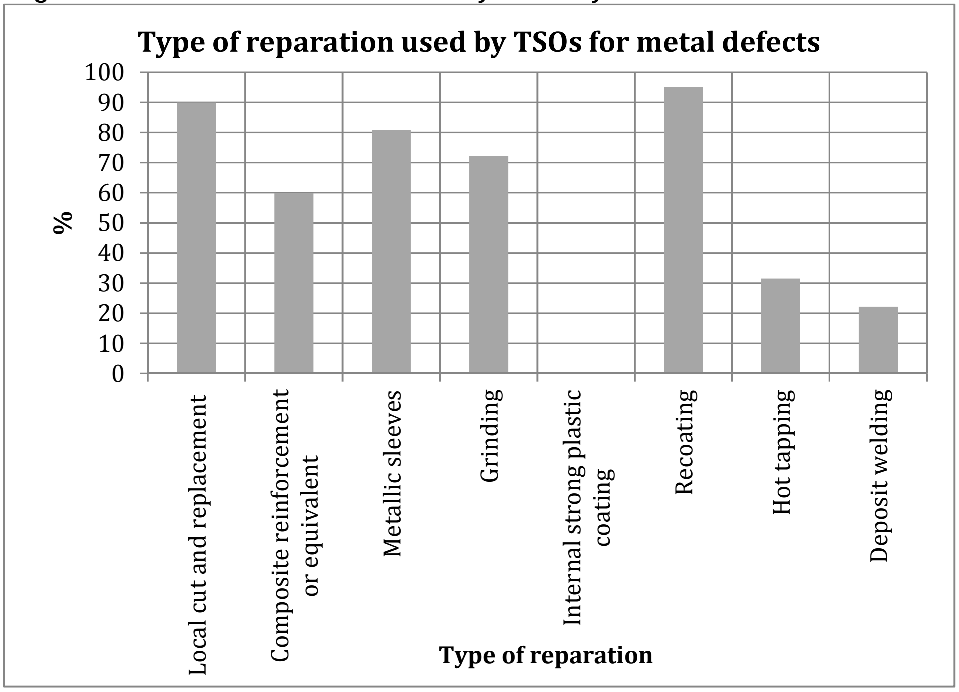



Fig. 38

Instead of metal defect reparation, 4 TSOs use, in some cases the reduction of the MAOP.

In practice, not all metal defects detected are repaired, considering the type of defects, the soil conditions, the state of CP, the operating pressure, etc… some defects could be disregarded.

#### 3.5.4.5.2 Coating defects

The 2013 survey shows that TSOs use mainly two ways to deal with coating defects, either by acting on the coating or on the cathodic protection:

- Coating reparations could be done by reinforcing the existing coating or recoating the defect itself is used. Most of the TSOs use a recoating.
- Adjusting the cathodic protection parameters in order to overcome the coating defect.

The below figure summarizes the different way used by TSOs for metal defects reparation.

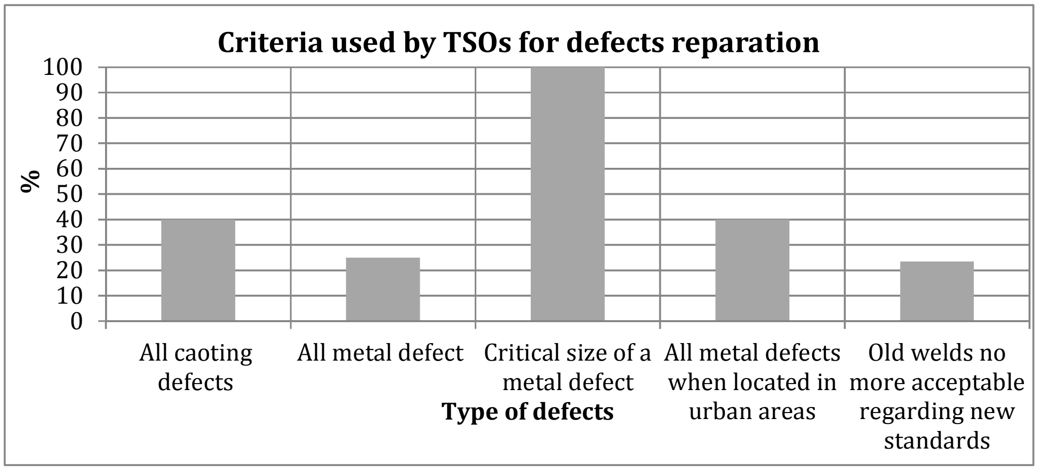



Fig. 39

#### 3.5.4.5.3 Criteria used to repair metal and coating defects

The 2013 survey shows that all the TSO have one common criterion to undertake pipeline reparation: critical size of a metal loss. For the rest of defects, the results denote that TSOs differ in the reparation decision.

Some TSOs use other criteria such as:

- Standards criteria (ASME and API)
- Critical size of a coating defect
- Procedure to assess seriousness of the defects.
- corrosion growth
- geometrical defects
- SCC defects

The below figure summarizes the criteria used by TSOs for defects reparation.

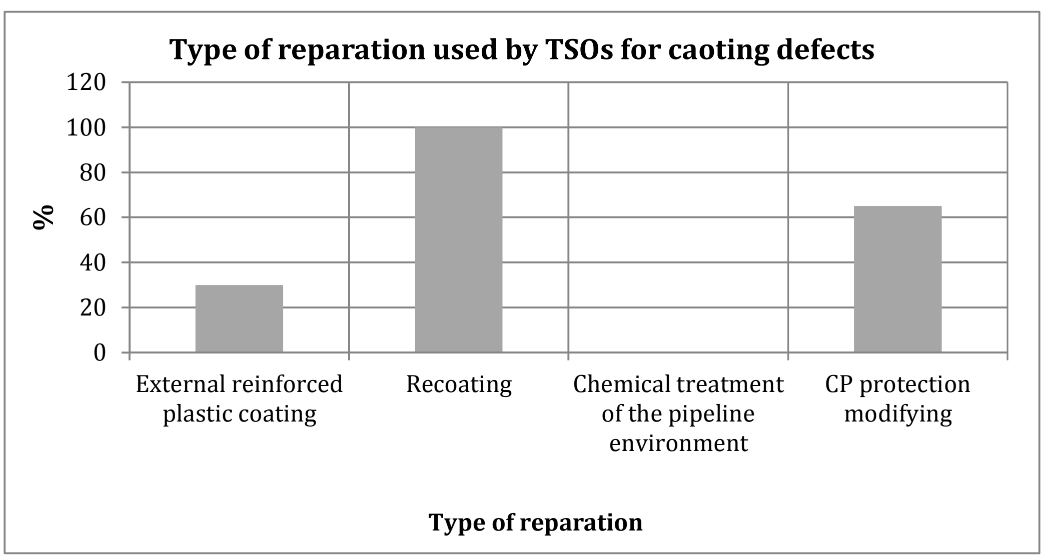



Fig. 40

The below figures summarize the ratio used by TSOs for metal/coating defects reparation with respect to the total detected defects

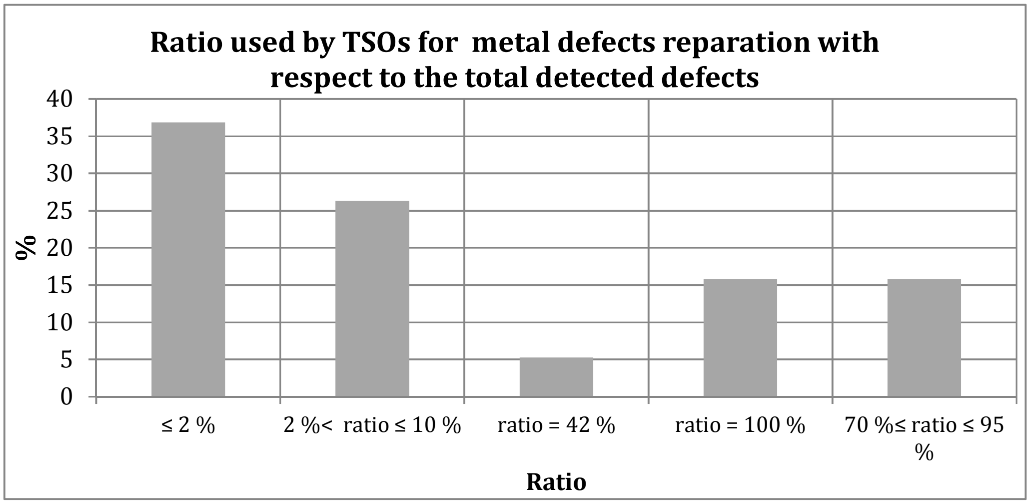



Fig. 41

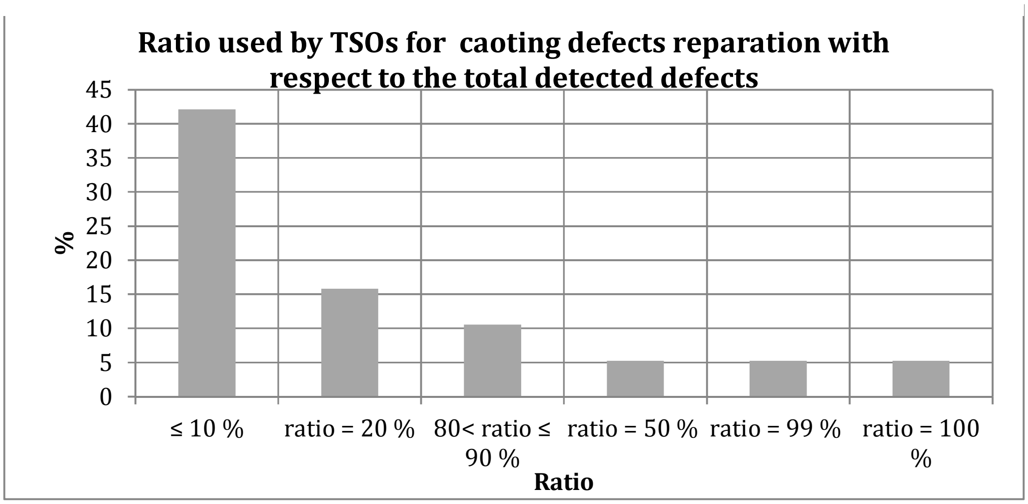



Fig. 42

### 3.5.5 Pipeline replacement downgrade or rehabilitate

One of the most care of TSO is to decide whether or when it is appropriate to replace, rehabilitate or downgrading a steel gas pipeline. The 2013 survey shows how TSOs proceed in order to take decisions.

#### 3.5.5.1 Tool / Procedure

The 2013 survey shows that the TSOSs decisions to replace, downgrade or rehabilitate a pipeline, are based on either technical or financial or both technical/financial.
The technical tool/procedure is a group of a technical characteristics that define the state of the pipe, it could include the pipe and steel characteristics, the coating type, the age, the PMS, the PWT, the area where it is laid etc…
The economic tool is a tool that include the costs (capex and opex) the economical design life, repair cost etc..

The below figure summarizes the different tool/procedure used by the TSOs, to make a final decision to replace, downgrade or rehabilitate a pipeline

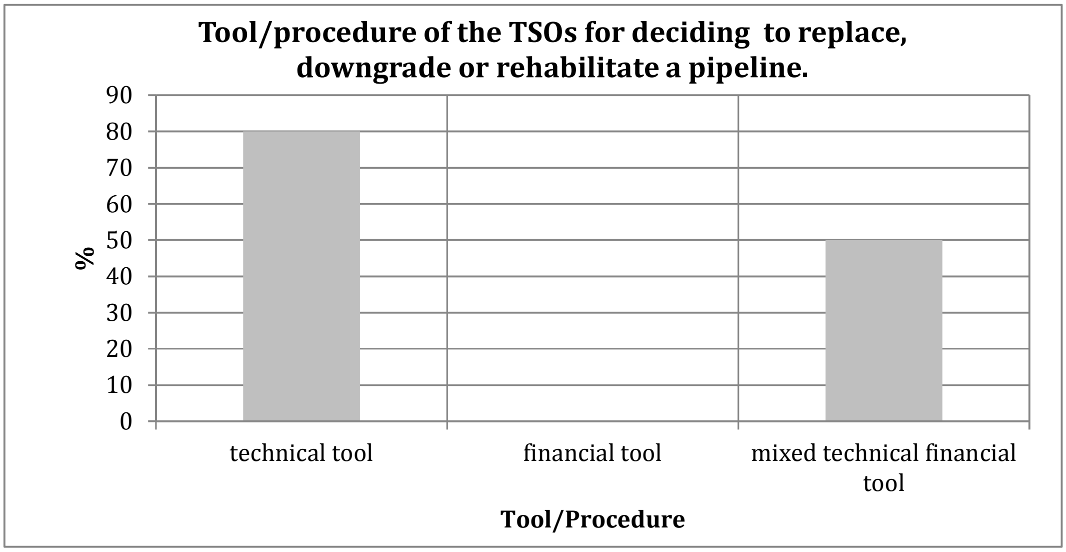



Fig. 43

2 of the TSOs don't have tools to make decision, and only one will develop technical and mixed technical financial tool/procedures.
Technical Procedure / tool is the most used by TSOs.

#### 3.5.5.2 Basis of assessment (Technical or technical and financial tool).

When a technical tools or a mixed technical-financial tool is used by TSOs the following basis of assessments are used:

##### 3.5.5.2.1 Risk failure assessment

Risk analysis is identifying the risk drivers, assessing their likelihood of occurrence and their potential consequences and about finding ways to monitor and then mitigate the risks. The risk failure could be based on:

- Deterministic risk assessment: events completely determined by cause-effect-chains (causality) and analyze of the effects of assumed causes.

- Probabilistic risk assessment: events can be identified by the probability of occurrence and the use of observations on the level of components.

The below figure shows what TSOs used to for failure risk assessments:

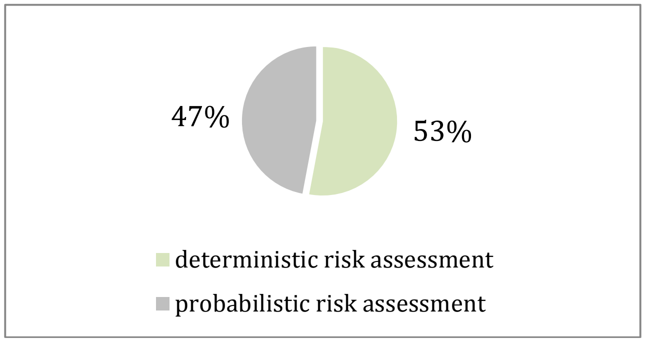



Fig. 44

### 3.5.5.2.2 Ageing pipeline basis

The 2013 survey shows that TSOs do assessments for old/aging pipelines based mainly for the unpiggable pipelines, the ones which are close to urban area and the ones which were designed and constructed with obsolescent
The below figure shows the different reasons which lead TSOs doing assessments

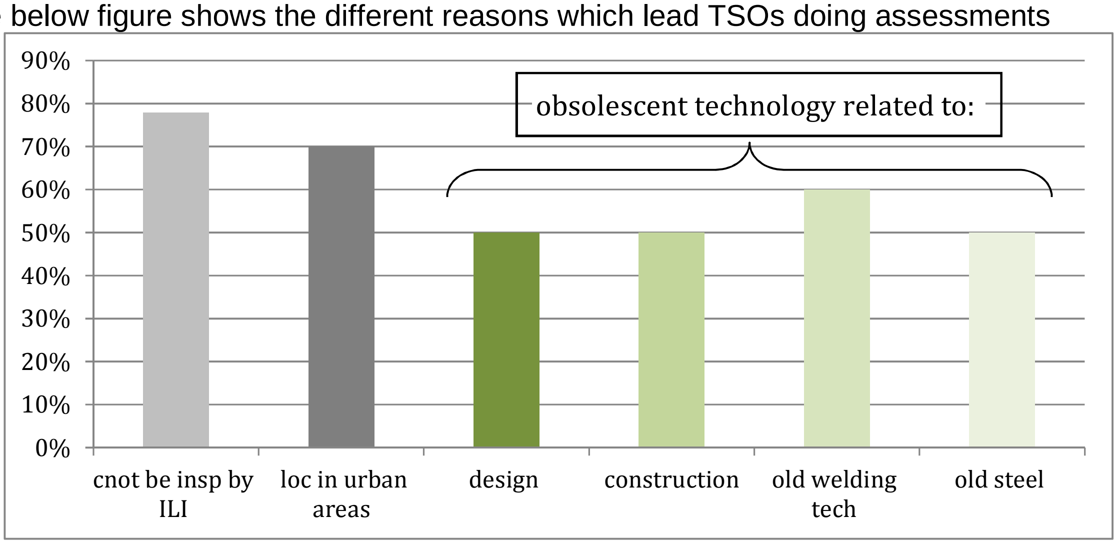



Fig. 45

### 3.5.5.2.3 Steel defects density

The 2013 survey shows that TSOs undertake Deterministic and Probabilistic assessment when they are faced to pipeline steel defects density (No. of defect per km).
The below figure summarizes the obtained results:

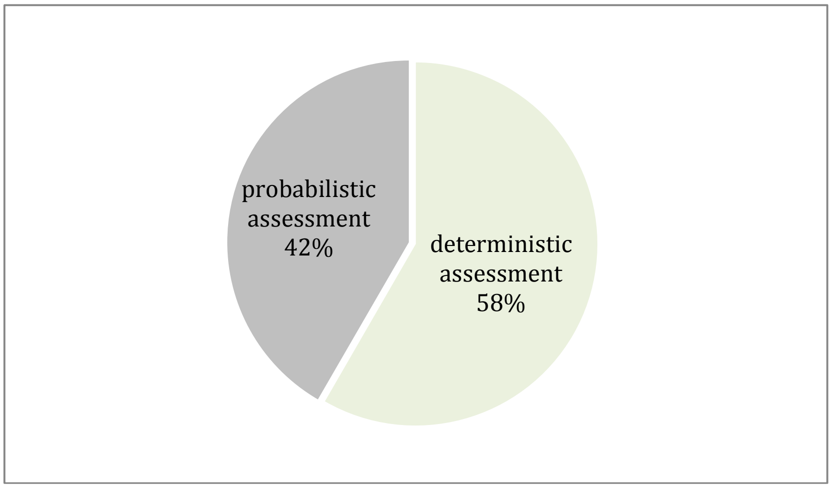



Fig. 46

Deterministic assessment is slightly the most used by TSOs (2TSOs use the two assessment type).

##### 3.5.5.2.4 Expert knowledge based on preventive assumption

The 2013 survey show that's 8 out of 11, use it as basis to undertake assessment

##### 3.5.5.2.5 Coating deterioration

For the Coating deterioration case, 9 TSOs out of 13 use it to undertake assessment

##### 3.5.5.2.6 Aggressive environment

60% of the TSOs undertake assessment when they consider an aggressive environment such as Electric currents, biological effect on soil, chemical…

##### 3.5.5.2.7 Other Basis

02 TSOs consider other basis to undertake assessment:

- Insufficient depth of cover
- Soil resistivity

#### 3.5.5.3 Basis of Assessment (Financial or technical- financial tool).

When a financial tools or a mixed technical-financial tool is used by TSOs the following basis of assessments are used:

- Opex versus Capex
- Capex versus Capex or
- Some other assessment could be considered depending on the type of defect that could be detected by any inspection method, for that a special budget could be included depending upon the ILI results or any other inspection method.

The below figures summarizes the obtained results:

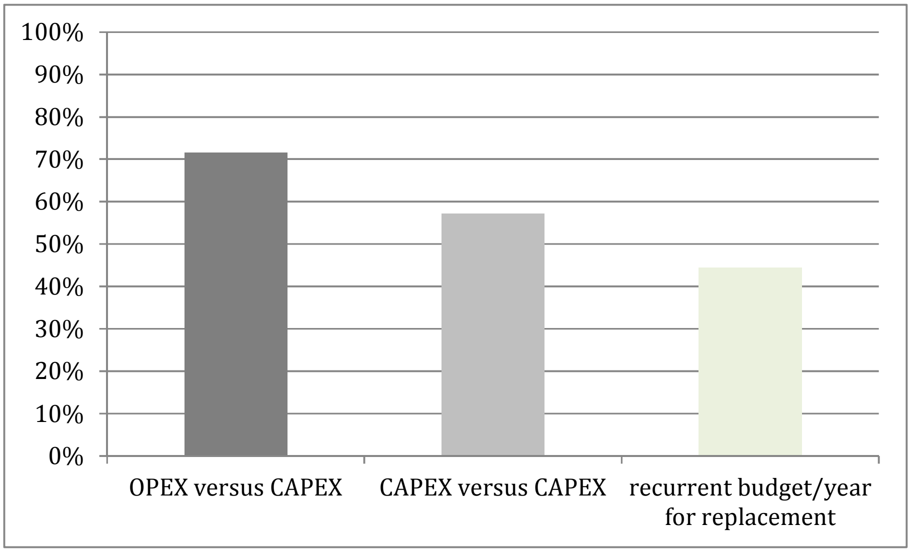



Fig. 47

Opex versus Capex is the most used by TSOs and 45% of the TSOs have a recurrent yearly budget for pipe replacement

#### 3.5.5.4 Replacement program

The 2013 survey shows that only 5  TSOs out of 21 have a replacement program, the others are not even intending to replace aged pipeline. Through the 143 306 km only 1 280 km have been replaced from 2009 to 2013 and 380 km are to be replaced in 2014 and 2015.

### 3.5.6 Conclusion

Ageing pipelines is one of the major care that TSOs have to face in preserve pipeline integrity. The decision related to steel pipeline rehabilitation, downgrading or replacement, with ageing pipeline, differs from one TSO to another depending on their technical, financial and economical situation. TSOs don't share the same way of design, construction and operating for that some differences appear in considering operating parameters.
There is neither a typical life time nor an economical life time for a pipeline; this varies from one company to another.
For major criteria defining an aged pipeline, we can consider the excessive coating defects, metal defects, a significant increase of maintenance cost and the age of the pipeline itself.
Most of the companies don't have a replacement program of aged pipelines and they deal with ageing by repairing the defects or in some cases by acting on the reasons causing ageing (coating, aggressive environment, metal defects etc..)
All companies use Inline Inspection as a method to survey pipelines and then to decide what to do. However, some pipelines are not piggable, for that, some other techniques are to be considered to inspect pipelines. According to the defects, decisions are to be taken to repair, replace or downgrade and again depending on the company procedures, decisions are taken differently.
The use of decision tools( including capex and opex) as a way to decide on the pipeline defects is still not common, companies which are not using tools take the decision upon

their own experience and according to the way of operating and maintaining pipelines. 60% of the companies using tools relay on a technical decision tools and 40% on a mixed technical-financial tools.
As a result, dealing with aged pipelines differs from one company to another. The decision related to steel pipeline rehabilitation, downgrading or replacement depends mainly on TSOs. Experiences, procedures and also financial situation are the major factors that affect decisions regarding ageing pipelines.

## 4.0 Conclusions & Recommendations

Pipeline Integrity Management Plan (IMP) or integrity plan are crucial documents in overall integrity management of a pipeline system aimed to manage pipeline risks and eliminate failures and incidents. As minimum, it contains integrity threats, risk levels corresponding to the threats, mitigation measures to be employed i.e. inspection, maintenance, repair etc., frequency or schedule of inspection, maintenance or repair, and person-in-charge or organization-in-charge responsible to execute the activities, as well as key performance indicators.
IMP is resulting from the implementation of Pipeline Integrity Management System (PIMS); and the survey suggested that TSOs in WOC 3 are implementing PIMS anchored on six critical elements i.e. policy and strategies, data management and establishment of related procedures, conducting risk assessment of pipelines to prioritize inspections and maintenance activities, utilizing GIS to aid in decision making, performing audits/reviews for continuous improvement, and having comprehensive emergency response management particularly in managing failures and incidents. The survey also noted that PIMS concept is relatively new to European TSOs i.e. with the establishment of EN 13648 in 2013. Nevertheless, PIMS is more mature in Asia and South America. Perhaps in the future, PIMS would be made through an intelligent system using artificial intelligence (AI) as welle as “big data” (i.e.e data mining) that should bring balanced benefits to all stakeholders.

PIMS addresses pipelines’ risks; and those risks come from integrity threats. Typical integrity threats include third party interference, external corrosion, geotechnical hazards, operator error, manufacturing defects, welding and fabrication defects/ construction errors, stress corrosion cracking and internal corrosion. Results from the survey pointed out that the TSOs are already mature in implementing various mitigation and control measures in managing the integrity threats. Nevertheless, gaps can be seen where utilization of advanced technologies are relatively low. For example, technologies such as real-time remote monitoring system for third party interference, cathodic protection, and geotechnical hazards are available in the industry for more than five years and yet its utilization in managing pipeline integrity threats by TSOs are rather low. Perhaps separate study should be commissioned within next triennium to learn more on this matter.

Managing aging pipelines must be part of overall pipeline integrity management through PIMS. Aging pipelines typically is due to one or combinations of external coating damage, defects on pipe wall i.e. external and/or internal, and decreasing of fatigue life i.e. due to mechanical damages. Survey showed that TSOs evaluate any pipeline technically and economically before arriving to decision of replacement or downgrading or rehabilitation/repair. Although technical evaluation can be considered mature and established, survey results found out that economic evaluation using CAPEX and OPEX i.e. life cycle cost analysis (LCCA) is still un-common to TSOs. This could be further studied and enhanced in next triennium.

One cannot deny the importance of human factor in PIMS i.e. competent engineers; field and control room technicians/operators are the ‘KEY’ success factor in overall pipeline integrity management. For critical tasks pertaining to PIMS, review of ASME B31Q yielded that the day-to-day or routine inspection, maintenance and monitoring activities should be regarded as ‘critical’ since they are the ‘basic’ or ‘fundamental’ things to do to ensure safe and reliable pipeline system. In addition, the role that engineers play in assessing and evaluating inspection technologies or methods; inspection and maintenance results and findings; decisions on replacement or downgrading or rehabilitation/repair; and keeping PIMS database updated and current should also be considered as critical tasks. The subject on competency is also looked upon that formal and on-job trainings are the 'tools' used by TSOs. The absence of structured competency or technical capability development program among TSOs should be the starting point or push factor of implementing such program.

In addition to above, append in the Appendix section some of best practices pertaining to pipeline technologies and practices that are used by SG 3.2 member companies that can be emulated by other pipeline operators/TSOs.

Having concluded the above, we would like to make several recommendations for further improvement of PIMS that can be beneficial both technically and commercially to worldwide TSOs:

i. To conduct conceptual study for utilizing artificial intelligence in overall pipeline integrity management from data acquisition, analysis, decision support, repair and rehabilitation.

ii. To perform situational assessment or gap analyses on the low utilization of real-time remote monitoring of third party interference and life cycle cost analysis (LCCA) tool as one of decision making tools for aging pipeline management.

iii. To study to establish standardized framework on structured technical capability to develop program for pipeline engineers and technicians.

## 5.0 Questionnaires

### 5.1 PIMS

| No | Questionnaire |
|---|---|
| 1 | Does Gas Transmission Company have written policy and/or philosophy pertaining to pipeline reliability and integrity? |
| 2 | Does Gas Transmission Company establish short, medium and long term strategic objectives with regard to pipeline integrity and reliability? If YES, please deliberate briefly on the objectives. |
| 3 | Does Gas Transmission Company Head or respective heads hold specific KPI/s pertaining to pipeline reliability and integrity? If YES, state the KPI/s. |
| 4 | Does Gas Transmission Company have a specific forums (Internal / External) to discuss/report matters pertaining to pipeline reliability and integrity? If YES, name and describe the forums. Also provide information on topics discussed and their frequency. |
| | Does your company perform periodic review of the asset integrity data ? If yes; what is the frequency? |
| 5 | Does the Gas Transmission Company have specific department or section or unit that look into matters pertaining to pipeline reliability and integrity? If YES, name the department and its scope. |
| 6 | Does Gas the Transmission Company has an authority or procedure for reviewing, endorsing or approving any technical deviation with respect to pipeline integrity management? If YES, please deliberate briefly its scope. |
| 7 | Does the Gas Transmission Company support technical capability development of its pipeline integrity engineers? If YES, please describe. |
| 8 | Does the Gas Transmission Company has specific audit or assessment plan or program for pipeline integrity management? If YES, please describe the structure of the department responsible for the audits. |
| 9 | Does Gas Transmission Company has written guidelines, plans or procedures to support management of the pipeline integrity management system? |
| 10 | Does Gas Transmission Company referring to any principal legislation, code and standard pertaining to pipeline integrity management system? If YES, state the legislation, code and standard. |

| | |
|---|---|
| **11** | Does the Gas Transmission Company have written Emergency Response Plan? |
| **12** | If Yes, does the Gas Transmission Company conducts emergency drill? |
| **13** | How frequently do you have an Emergency Response drill |
| **14** | Does the Gas Transmission Company use Risk Assesment Approach for PIMS? |
| **15** | If answer to the above is YES, how is the risk assessment methodoly based (Quantitative or Qualitative)? |
| **16** | Does your PIMS consider ALARP (As Low As Reasonably Practicable) approach in creating pipeline integrity related plans. |
| **17** | Does the Gas Transmission Company produce any periodic/annual pipeline integrity report? If YES, please state the frequency and specify whether it is internal or external. |
| **18** | Does the Gas Transmission Company record integrity data in Geographic Information System (GIS). |
| **19** | If No, is the Gas Transmission Company planning to implement GIS in PIMS in future. |
| **20** | Does your company have or intend to buy off the shelf GIS based PIMS.  Please specify. |
| **21** | If No, does your company have or intend to develop the GIS based PIMS inhouse. |

## 5.2 Pipeline Database

| |
|---|
| **Nominal diameter**<br>Nominal diameter [inch] |
| Unknown |
| diameter < 5" |
| 5" <= diameter <= 10" |
| 11"  <= diameter < 17" |
| 17"  <= diameter < 23" |
| 23"  <= diameter < 29" |
| 29"  <= diameter < 35" |
| 35"  <= diameter < 41" |
| 41"  <= diameter < 47" |
| diameter >= 47" |
| **Material grade**<br>Material grade |
| Unknown |
| Grade A |
| Grade B |
| X42 |
| X46 |
| X52 |
| X56 |
| X60 |
| X65 |
| X70 |
| X80 |
| Other |
| **Construction year**<br>Year of construction |
| Unknown |
| Before 1954 |
| 1954 - 1963 |
| 1964 - 1973 |
| 1974 - 1983 |
| 1984 - 1993 |
| 1994 - 2003 |
| After 2004 |
| **Nominal wall thickness**<br>Nominal wall thickness [mm] |
| Unknown |
| ≤ 5 mm |
| 5 - 10 mm |
| 10 - 15 mm |
| 15 - 20 mm |
| 20 - 25 mm |
| 25 - 30 mm |
| > 30 mm |

| |
|---|
| **Cover depth**<br>Depth of cover [cm] |
| Unknown |
| < 80 cm |
| 80 - 100 cm |
| > 100 cm |
| Under water |
| Above ground |
| **Design pressure**<br>Design pressure [bar] |
| Unknown |
| < 16 bar |
| 16 - 25 bar |
| 26 - 35 bar |
| 36 - 45 bar |
| 46 - 55 bar |
| 56 - 65 bar |
| 66 - 75 bar |
| > 75 bar |
| **Coating type**<br>Type of coating |
| Unknown |
| Coal tar |
| Bitumen |
| Polyethylene |
| Epoxy |
| Other |
| **In line inspection**<br>In line inspection |
| Yes |
| No |

## 5.3 Threat Identification

| N° | Questionnaire |
|---|---|
| 1) | What approach does your Gas Transmission Company use to determine the different threats or failure causes? Is it industry incident data (like EGIG, or US DOT, etc.), own incident data, or both, or failure cause analysis, etc? Please describe the specific approaches used and the corresponding data sources. Is there any gap you identify, or an unsolved issue? |
| 2) | Based on the approach described in Question 1, present :<br>a. the threats to pipeline integrity/failure causes and its ranking for a particular Gas Transmission Company in your country.<br>b. the percentage attributable to each cause, on one hand for damage and on the other hand for failures.<br>c. the period for which this data is relevant (1, 5 years, etc.) |
| 3) | What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *external interference*? Please list at least the five (5) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 4) | What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *external corrosion*? Please list at least the three (3) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 5) | What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *geotechnical problems* i.e. ground subsidence, slope erosion/failure etc.? Please list at least the three (3) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 6) | What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *human/operator error*? Please list at least the three (3) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 7) | 7) What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *materials defects*? Please list at least the three (3) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 8) | What .are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *construction errors*? Please list at least the three (3) main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 9) | What are the actions and/or activities undertaken to mitigate the risk of pipeline failure (leak/rupture) or damage due to *other causes which are not listed above*? Please specify the cause(s) and list the main actions. Is there any gap (scope for improvement) you identify, or an unsolved issue? |
| 10) | Does your company perform independent reviews/audits of PIMS and quality systems? If yes, how often are these audits/reviews being conducted? |

| | |
|---|---|
| **11)** | Does your country have specific regulations on pipeline inspections procedures/technologies/methodologies? If yes, please describe briefly. |

## 5.4 Third Party Damage

| General data and Requirementes | | |
|---|---|---|
| 1 | Total network length (km) | |
| 2 | Pipe diameter range (mm) | |
| 3 | Number of design factors | |
| 4 | List of design factors | |
| 5 | Maximum operating pressure (bars) | |
| | Different MOP levels (per grid) | |
| 6 | Is there national legislation specifying the burial depth of gas networks ? | |
| 7 | What is the minimum burial depth of gas networks ("Good practice") ? | |
| | Pressure | |
| | Mains under road | |
| | Mains under pavement | |
| | Mains under railways | |
| | Mains under canals | |
| | 8 – Is there national legislation specifying minimum distances between gas networks and other infrastructure utilities (electricity, water, sewage, telecom…) ? | |
| | 9 – Are those distances considered as safety distances ? | |
| 10 | If no, what are they used for ? | |
| 11 | What are those minimum distances ? | |
| | Electricity cable | Parallel (Horizontal)<br>Parallel (Vertical)<br>Crossing |
| | Water pipes | Parallel (Horizontal)<br>Parallel (Vertical)<br>Crossing |
| | Telecom wiring | Parallel (Horizontal)<br>Parallel (Vertical)<br>Crossing |
| | Sewage | Parallel (Horizontal)<br>Parallel (Vertical)<br>Crossing |
| | Other* | Parallel (Horizontal)<br>Parallel (Vertical)<br>Crossing |
| 12 | Does national legislation require the installation of safety/warning signs ? | |
| 13 | What kind of safety/warning signs is used (many answers are possible)? | |
| | passive buried strips | |
| | passive buried strips with metal cable | |

| | |
|---|---|
| | active buried strips (for surface detection) |
| | surface sign posting / overhead markers |
| | other |
| 14 | Does national regulation impose restricted zones in the vicinity of the gas network ? |
| 15 | Please, give a description of these restricted zones (many answers are possible) |
| | (X) zone where mechanical works are forbidden D(meter) |
| | (X) zone where no existing or new construction can be present without official agreement D(meter) |
| | (X) zone where the gas company must be informed for any kind of works D(meter) |
| | (X) zone where a systematic removal of trees in the pipeline right of way is performed D(meter) |
| | ¨ other* D(meter) |
| **Special requirements for civil engineering/infrastructure works** | |
| 16 | At the early stage of a civil engineering/infrastructure project, does the national legislation require a pre-investigation about concerned utilities? |
| 17 | When shifting from civil engineering/infrastructure project phase to civil engineering/infrastructure realization phase, does the national legislation assign the excavation company to inform directly all concerned utilities before digging starts? |
| 18 | If no, who informs the utilities? |
| 19 | Is one call/web-based system used? |
| 20 | If yes, is it required by legislation? |
| 21 | If you don't have a one call/web-based system, is setting one up under study nowadays? |
| 22 | How is your company informed by the digging company before work starts? (many answers are possible)? |
| | by letters |
| | by telephone |
| | by internet |
| | by fax |
| | by an organized coordination meeting |
| | Other* |
| 23 | What is the deadline to inform your company before digging starts? |
| | 3 days before |
| | 7 days before |
| | 10 days before |

| | |
|---|---|
| | Other* |
| 24 | How long do utilities take to reply? |
| | 3 days before |
| | 7 days before |
| | 10 days before |
| | Other* |
| 25 | How does your gas company reply (many answers are possible)? |
| | by letters |
| | by telephone |
| | by internet |
| | by fax |
| | by an organized coordination meeting |
| | Other* |
| 26 | What is the information content of your gas company reply (many answers are possible)? |
| | maps |
| | regulation extracts on third party interferences |
| | standards |
| | gas company regulation |
| | notification for an information / awareness meeting |
| | Other |
| 27 | Is your third party information procedure certified by an external auditor? |
| 28 | What are the complementary prevention measures set up voluntarily by your gas company in order to reduce third party damages (many answers are possible)? |
| | periodic information meetings dedicated to third parties |
| | special training dedicated to third parties |
| | signed agreements for genuine relationships between all stakeholders |
| | Other* |
| 29 | Does the national legislation require the use of detectors before digging starts? |
| 30 | If yes, what kind of detectors is used (many answers are possible)? |
| | magnetic field detector |
| | radio frequency detector |
| | transmitter and detector |
| | radar |
| | Other* |
| 31 | Does your gas company proceed to in situ test probes before digging? |
| 32 | What are your records on your gas network damages due to third party interferences for the last 5 years? |
| | Total number of received notification about digging works per year |

| | | |
|---|---|---|
| | Total number of network damages per year without leakage : | |
| | Total number of network damages per year with leakage : | |
| 33 | In what percentage of cases is financial compensation claimed from the company responsible of the caused damages to the gas network? | |
| 34 | Does your gas company take repressive measures against the accused third party?<br>.. yes | |
| 35 | If yes, what kind of repressive measures is taken (many answers are possible)? | |
| | fine or penalty | |
| | inform Health and Safety authority | |
| | inform civil engineering federation | |
| | removal from your gas company subcontractors list | |
| | Other* | |
| **Survey and proactive controls** | | |
| 36 | What kind of survey does your gas company carry out? | |
| | By foot | Mandatory (Yes / No) |
| | | Urban frequency |
| | By car | Mandatory (Yes / No) |
| | | Urban frequency |
| | By helicopter | Mandatory (Yes / No) |
| | | Urban frequency |
| | By plane | Mandatory (Yes / No) |
| | | Urban frequency |
| | By satellite | Mandatory (Yes / No) |
| | | Urban frequency |
| | Other* | |
| 37 | Does your gas company take complementary measures when digging is about to begin and after? | |
| | Starting digging meeting | Yes / No |
| | | Mandatory : Yes / No |
| | Temporary marker signs | Yes / No |
| | | Mandatory : Yes / No |
| | Reinforcement of permanent markers in sensitive areas | Yes / No |
| | | Mandatory : Yes / No |
| | Presence of a controller when removing earth around the pipe | Yes / No |
| | | Mandatory : Yes / No |
| | Daily presence of a controller | Yes / No |
| | | Mandatory : Yes / No |
| | Periodic presence of a controller | Yes / No |
| | | Mandatory : Yes / No |
| | Unexpected presence of a controller | Yes / No |
| | | Mandatory : Yes / No |
| | Mechanical protection installation | Yes / No |
| | | Mandatory : Yes / No |

| | | |
|---|---|---|
| | Gas pressure reduction | Yes / No |
| | | Mandatory : Yes / No |
| | Presence of a controller when reburying the pipe | Yes / No |
| | | Mandatory : Yes / No |
| | Other* | |
| 38 | Does your gas company carry out damage investigations just after the end of works? | |
| | occasionally | |
| | systematically | |
| | Never | |
| 39 | If yes, what is the investigation technology used? | |
| | pigging | |
| | cathodic protection measuring | |
| | gas detection | |
| | Other* | |
| **Emergency Plan** | | |
| 40 | Does your gas company have an internal emergency plan in case of accidents? | |
| 41 | What is the content of this emergency plan (many answers are possible)? | |
| | information of the public | |
| | information of fire brigades | |
| | information of the authorities | |
| | cooperation with external bodies | |
| | permanent intervention squad | |
| | evacuation plan | |
| | Other* | |
| 42 | Is this emergency plan tested: | |
| 43 | Are there any external emergency plans? | |
| 44 | If yes, on which level is that external emergency plan? | |
| | national | |
| | regional | |
| | local | |
| | Other* | |
| 45 | Does the emergency plan include evacuation perimeter distances to be used by the fire brigades in case of incident on a pipeline? | |
| | 46 – If yes, please give some details (i.e. distances…) | |
| **New Solution to Reduce Third Party Damages** | | |
| | 47 – Is your gas company studying a new approach to reduce third party damages (new technology, a dedicated management system, use of mechanical protection such as concrete slabs, a new procedure, other…? | |

| | |
|---|---|
| | 48 – If yes, can you give a brief description of the expected solution? |
| **Abandoned Pipelines** | |
| | 49 – Are there any legal obligations applicable to pipelines either out of service or abandoned? |
| | 50 – If yes, in which field? |
| | indications on drawings |
| | waste treatment legislation |
| | removal obligations |
| | Other* |

## 5.5 Ageing Pipelines

| General data | | | |
|---|---|---|---|
| 1 | What is in years the "technical design life" used currently in your company for a pipeline? | Technical design life (yrs) | |
| | | is it a company rule | |
| | | is it a legislation rule | |
| 2 | What is in years the "economical design life" used currently in your company for a pipeline? *Economical design life = Expected period when pipeline is fully depreciated. | Economical design life (yrs) | |
| | | is it a company rule | |
| | | is it a legislation rule | |
| 3 | Steel transmission network total length (km please specify): | | |
| 4 | Please, split this total length into elementary lengths regarding the pipeline age (based on the year of construction): | | |
| | ***Age*** | | |
| | Less than 15 years | | |
| | Between 15 and 30 years | | |
| | Between 30 and 50 years | | |
| | Between 50 and 70 years | | |
| | Between 70 and 90 years | | |
| | More than 90 years | | |
| 5 | Please, split this total length into elementary lengths regarding the type of coating: | | |
| | ***Coating type*** | | |
| | Plastic coating (PE…) | | |
| | Tapes | | |
| | FBE (fusion bounded epoxy) | | |
| | hydrocarbon (asphalt, bitumen…) | | |
| | Other (please precise) | | |
| 6 | Do you have already a pipeline replacement program? | | |
| | if no, are you expecting to prepare one in the near future? | | |
| 7 | Can you specify the total lengths of replaced pipelines during the last recent years as well as those to be replaced in the future: | | |
| | ***Year*** | | |
| | 2015 | | |
| | 2014 | | |
| | 2013 | | |
| | 2012 | | |
| | 2011 | | |
| | 2010 | | |
| | 2009 | | |
| **Assessment of the pipeline technical current state**<br>( goal: replace, downgrade or rehabilitate decision basis) | | | |

| | |
|---|---|
| 8 | What do you understand by "Ageing of pipelines"? |
| | Significant increase of maintenance costs |
| | Impact of modification of the design conditions |
| | Impact of modification of the operation conditions |
| | Excessive distribution, kind and density per length of metal defects |
| | Excessive distribution, type and density per length of coating defects |
| | Leak criteria frequencies |
| | Fatigue criteria |
| | Pipeline age (for example above 50 years) |
| | Others |
| 9 | What type of inspection technique do you use: |
| | Standard inline inspection (MFL, TFI...) |
| | Special inline inspection – EMAT |
| | Above ground survey (PEARSON, DCVG...) |
| | Other technology (precise the type) |
| 10 | What percentage of the network is piggable? |
| 11 | Did you notice deterioration effects related to ageing (i.e. observed correlation): |
| | - coating defects |
| | - metal defects |
| | - welding defects |
| | - gas leaks |
| | - other (please precise) : |
| 12 | What type of criteria do you use to decide to repair? |
| | - All coating defects<br>- All metal defect |
| | - Critical size of a metal defect |
| | - All metal defects when located in urban areas |
| | - Old welds no more acceptable regarding new standards |
| | - Other criteria (please precise): |
| 13 | To compare technologies, do you inspect some pipelines by internal (such as ILI) and non-intrusive external (such as DCVG, Pearson, CIPS) technologies? |
| | Is there any correlation between internal and external technologies? |
| | If yes, what correlation you deduced between metal defects and coating ones? |
| 14 | In general, do you consider that “old/aging” pipelines which cannot be inspected by an ILI technology would be a source of worry / trouble? |
| | If yes, what is the main reason? |
| 15 | 0 |
| | - Local cut and replacement |
| | - Composite reinforcement or equivalent |
| | - Metallic sleeves |

| | | | |
|---|---|---|---|
| | - Grinding | | |
| | - Internal strong plastic coating | | |
| | - Recoating | | |
| | - Hot tapping | | |
| | - Deposit welding | | |
| | - Other (please precise, for example: MAOP reduction) | | |
| 16 | What types of repair do you use for coating defects? | | |
| | - External reinforced plastic coating | | |
| | - Recoating | | |
| | - CP protection modifying | | |
| | - Chemical treatment of the pipeline environment | | |
| 17 | What is the ratio (in%) of repaired metal defects with respect to the total detected defects? | | |
| 18 | What is the ratio (in %) of repaired coating defects with respect to the total detected defects? | | |
| | **Pipeline replacement, downgrade or rehabilitate** | | |
| 19 | Is there a tool/procedure within your company on which is based the final decision to replace, downgrade or rehabilitate a pipeline? | | |
| | If yes, is it a: | technical tool | |
| | | financial tool | |
| | | mixed technical financial tool | |
| | If no, are you developing or on the way to develop such a tool/procedure? | | |
| | Will it be a | technical tool | |
| | | financial tool | |
| | | mixed technical financial tool | |
| 20 | If a technical or mixed technical financial tool is used; what are the basis of assessments? | | |
| | a - failure based on | deterministic risk assessment | |
| | | probabilistic risk assessment | |
| | b - Criteria for old/aging pipelines based on following reasons: | cannot be inspected by ILI | |
| | | located in urban areas | |
| | | obsolescent technology related to: | |
| | | design | No |
| | | construction | No |
| | | old welding technology | Yes |
| | | old steel | Yes |
| | c - steel defect density (No. of defect per km) | deterministic | |

| | | |
|---|---|---|
| | assessed by a | assessment |
| | | probabilistic assessment |
| | d - expert knowledge based on preventive assumption | |
| | e - coating deterioration | |
| | f - aggressive environment (electric currents, biological, chemical… ) | |
| | g - other (please precise) | |
| 21 | If a financial or mixed technical financial tool is used; what are the basis of assessments? | |
| | OPEX versus CAPEX | |
| | CAPEX versus CAPEX | |
| | you have a recurrent dedicated budget per year for replacement | |
| | other (please precise) | |
| 22 | Any additional comments (***developments you are undertaking in this field, expert opinion...***) | |

# 6.0 Appendices

## 6.1 Remaining life prediction using statistical analysis of ILI pigging data 1], 2], 3], 4] 5]

### 6.1.1 Introduction

In general, the prediction of pipeline residual life can effectively assist pipeline operators to evaluate future safe operating strategies including re-inspection and appropriate maintenance schedule. As a result, it can minimize the possibility of pipeline failures until it reaches its designed lifetime.
Corrosion is an imperative form of pipeline deterioration due to aggressive environments. As pipeline ages, it can be affected by a range of corrosion mechanisms, which may lead to a reduction in its structural integrity. Without practical and effectual corrosion prevention strategy, corrosion will continue to progress and the cost of repairing a deteriorating pipeline will escalate. Significant savings are possible by optimizing the inspection and corrosion prevention strategies. The objective of an effective corrosion management program is to identify and mitigate corrosion anomalies before they reach critical limit states.
The optimization of the inspection interval and the selection of anomalies to mitigate depend on understanding of corrosion growth. In order to make specifications of different vendors and for different inspection technologies comparable standardized rules need to be established. Prediction of corrosion growth is challenging because growth with time is non linear and highly location specific. These characteristics make simplistic approaches such as using maximum growth rates for all defects impractical. Therefore, it is important to understand the salient aspects of corrosion growth so that appropriate decisions on excavation and re-inspection can be made without compromising safety or undertaking undue amounts of mitigation activities.
The aim of this report is to describe the statistical method used in ILI (In-line inspection) data analysis for pipeline remaining life prediction in a comprehensive manner backed up by practical examples of one ILI run. If the statistical analysis conducted using result of twice ILI run to same pipeline, more accurate life prediction is possible. Many types of run-comparison have been used in the past. Run-comparisons, comparing two consecutive ILI runs, measures actual growth experienced by the pipeline. These measured growth values do contain measurement errors or uncertainties. These errors depend on many factors such as time interval between consecutive runs, compatibility of technology and vendor used for each ILI. In the current state the analytic theory on the multiple run-comparisons performed at the same section of the pipeline has not been fully established, which was omitted from this report. The detail statistical concepts and analysis method for pipeline ILI data are referred to reference.

### 6.1.2 ILI (In-line Inspection)

#### 6.1.2.1 ILI data

In line inspection (ILI) based integrity programs have been used for many decades to manage corrosion in oil and gas pipelines. Over the last two decades the performance of inline inspection tools has impressively improved. This equally refers to the detection capability as well as to the sizing accuracy of the different methods applied. The results of inline inspections can directly be used as input parameters for defect assessment. High resolution in-line inspection technology is an increasingly important component of pipeline integrity management.

Running an ILI tool in the pipeline provides the operator with a description of the internal and external corrosion located along the line. The ILI inspection report will also provide depth, length and width measurements for each corrosion feature. It is therefore possible to determine corrosion rates based upon the maximum defect depth detected in the pipeline and the difference between the corrosion initiation time and the time of the inspection. In the determination of external corrosion rates, it is important to identify the reason corrosion has begun (such as coating damage) and estimate when corrosion may have started by considering other data as evidence that corrosion resulted from a known incident of 3rd party damage or known incidents of CP under-protection on the pipeline.
The application of the corrosion growth rate models appropriates for external corrosion conditions may result in non-conservative conclusions for remaining life due to the non-uniform nature of some types of corrosion. As a result, it is important to understand the possible corrosion mechanisms together with inspection tool tolerances in order to estimate the most appropriate corrosion growth rate and remaining life. Because it is often not possible to immediately repair all anomalies identified during a pipeline inspection, predicting potential corrosion growth allows a pipeline operator to prioritize repairs based on both current severity and probable future severity and establish re-inspection intervals.

Corrosion growth assessment is an essential part of an effective integrity assessment and used in planning a safe and cost-efficient rehabilitation strategy. The critical component for corrosion management is a prediction or estimation of the corrosion growth rates. An effective estimation of corrosion growth rates heavily depends on the type of corrosion (internal or external) and the type of information available. External corrosion is influenced by a number of factors including the water content of the soil, the soluble salts present, the pH of the corrosion environment and the degree of oxygenation, therefore the prediction of external corrosion rates is complex and there is no method for estimating corrosion rates using empirical equations. ASME B31.8S contains an external model of corrosion correlating soil Resistivity with the rate of corrosion growth. The same kind of relation between the external corrosion rate and soil Resistivity is presented by Peabody. NACE and Shell Global Solutions have information and guidance on this subject.
For pipelines that have repeated ILI runs over a period of time, a quantitative comparison of a representative sample of defects can be used to “measure” corrosion growth (both internal and external). The advantage of this method for corrosion growth determination is that the raw ILI signal inspection data is compared to each of the defects, and the differences due to tool technologies and analysis methods to be identified and the effects minimized. In addition, more ILI vendors are offering a raw signal comparison service. The run comparison allows obtaining the variation of the corrosion growth rate along the length of the pipeline.

#### 6.1.2.2 ILI performance

The performance of in-line inspection tools employed for integrity assessments has significant impact on the reliability of assessment results, the extent of required remediation, and justification of re-inspection intervals. Verification measurements of in-line inspection results, including anomaly sizes and characteristics, are an essential part of the pipeline integrity assessment. A clear understanding of ILI tool performance should be used to justify rehabilitation strategies and re-inspection intervals, regardless of whether the techniques are deterministic or probabilistic. Statistical methods such as comparisons of

distributions, confidence intervals and other methods for hypothesis testing are referenced in API 1163 for the purposes of determining the size of a sample.
Corrosion is a time-dependent threat to pipeline integrity. Assessment of future integrity involves the application of a corrosion growth rate to predict a time interval where have a calculated failure pressure less than the “safe operating pressure”, which considers some value of the safety factor. The predicted date where either criterion will be exceeded establishes the re-inspection interval or the remaining life of the pipeline. The estimation of corrosion growth from multiple in-line inspection runs represents the most accurate source of corrosion rates. With only one ILI inspection available, external corrosion growth rates can also be modelled from cathodic protection data, measurements of condition of pipeline coatings and from the physical properties of surrounding soil.
The inline inspection detects and measures the defects at a point in time. However, in following year corrosion growth needs to be accounted for and the pipeline industry has estimated this growth using many different techniques. As corrosion growth is extremely variable from defect to defect, the challenge in managing corrosion is to understand which defects will grow to a critical level and which defects will be dormant.

### 6.1.3 Case study for one ILI run

#### 6.1.3.1 Introduction

Corrosion growth is highly variable between defects. Within a segment the vast majority of the defects hardly grows while a few defects are growing quite aggressively. This leads to a highly peaked corrosion growth distribution among defects of a segment with a low value mode and a thick long tail. Consequently corrosion growth in a segment of pipe with many defects is modelled by a Gumbel, Weibull, or Lognormal distribution.
Corrosion data obtained from in-line inspection can be applied to assess present integrity as well as to predict the future integrity of gas pipeline by using a statistical probability analysis. In deterministic method, the failure model like ASME B31G include just the criteria of "Safe or Fail" for corroded pipeline. However the probability method can offer "Probability of failure" as using the same failure model. It is used to estimate the maximum allowable operating pressure of the corroded pipeline based on a series of ILI pigging data, which represents the corrosion pit location and dimension. In this case study, it is focused to look for the POF (Probability of Failure) from hypothetical data on the gas pipeline.
POF can be derived by statistical methods like MCS (Monte Carlo Simulation), FOSM (First Order Second Moment), FORM (First Order Reliability Method), and SORM (Second Order Reliability Method). POFs by MCS, FORM and SORM are commonly applied to LSF (Limit State Function), however POF by FOSM is simply obtained from mean and variance of allowable pressure. The LSF is a border between allowable and failure pressure with main parameters of corrosion depth/length, pipe diameter/thickness and tensile strength of pipeline material.
The MCS method is carried out by inputting corrosion data (depth, length) into the LSF, and the POF is calculated by counting fail cases divided by total input cases. However, the FORM is carried out with a tangent line of LSF PDF (Probability Density Function), and the POF is obtained from the shortest distance to the tangent line of LSF PDF as shown in Figure 1.
The POF and remained life of gas pipeline were investigated by statistical methods of MCS, FOSM and FORM. POF results obtained by each method were compared, and POF sensitivities of COV were inspected with parameter's variance.

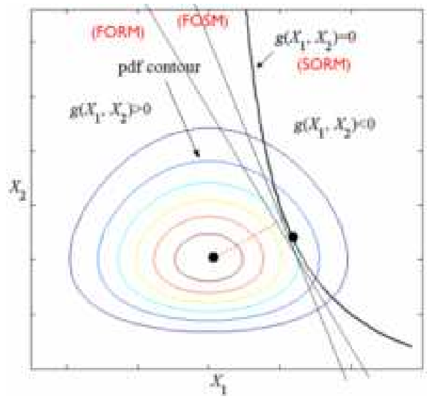



Figure1 LSF and PDF Counter by FOSM/FORM/SORM

#### 6.1.3.2 Statistical Procedure

Statistical methods carried out by "ten steps procedure" like below using hypothetical ILI data of the gas pipeline.

1) Taking over corrosion data from ILI result
2) Dividing section and selection
3) Extreme data treatment of LCOT and HCOT
4) Statistical treatment of corrosion data
5) Inputting parameters of pipeline specification and operation pressure
6) Application of corrosion growth rate
7) Application LSF of Pipeline Company or international code
8) Performing MCS, FOSM and FORM by MATLAB code
9) Analysing POF Sensitivity by comparison of COV
10) Estimation of remaining life with target POF in BS 7910, API 579 and ISO 2394.

#### 6.1.3.3 Results

Distributions and histograms of hypothetical corrosion pit (depth, length) were shown in Figure 2. Mean and variance of corrosion pits (depth, length) were Amm and Bmm respectively, and the COV of B/A was 50%.

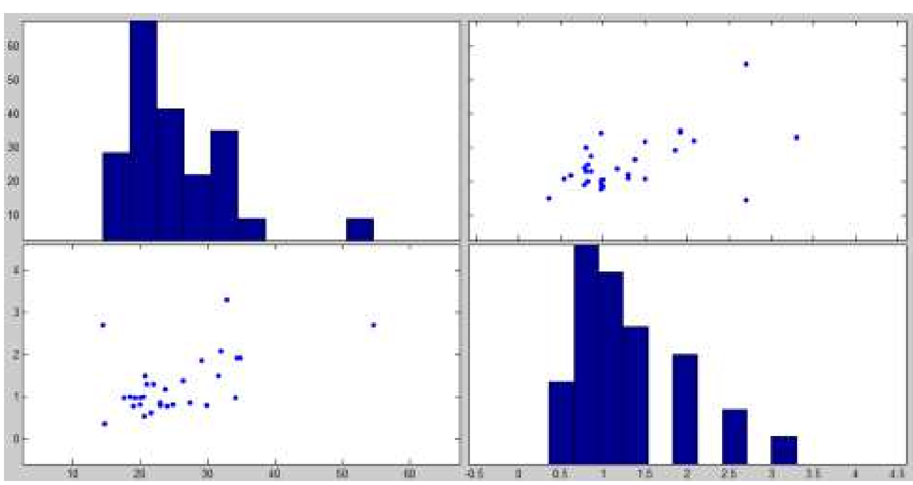


Figure 2 Distributions and histograms of corrosion pit (depth, length)

The LSF of Battelle Code (equation 1) was used in the statistical methods of MCS, FOSM and FORM.

$$P_f = \frac{2UTSt}{D}\left(1 - \frac{d(T)}{t}M\right)$$

$$M = 1 - \exp\left(-0.157\frac{L(T)}{\sqrt{D(t-d(T))/2}}\right)$$

$$d(T) = d_0 + V_r(T - T_0)$$

$$L(T) = L_0 + V_a(T - T_0) \qquad \text{-------------------} \quad (1)$$

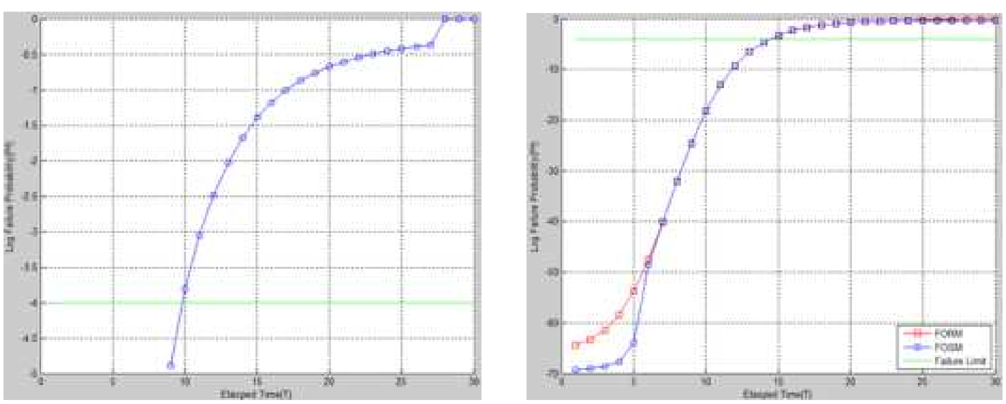
Here, $P_f$: failure pressure, UTS: ultimate tensile strength, D: pipe diameter, t: pipe thickness, d: corrosion depth, L: corrosion length, M: Folias factor, d(T): time function of corrosion depth, L(T): time function of corrosion length

Parameters, distribution, mean and COV (%) used in this case study were in Table 1. The corrosion growth rate was assumed to be a simple linear behaviour as an ILI result of pipeline to be operated for 12 years.

Table 1 Input parameters

| Parameter | Distribution | Mean | COV%(1) | COV%(2) |
|---|---|---|---|---|
| Diameter (D) | Normal | A mm | 0.1 | 0.2 |
| Thickness (t) | Normal | B mm | 1.0 | 2.0 |
| Pop | Normal/Weibull | C MPa | 6.2 | 12.4 |
| UTS | Normal | D MPa | 4.2 | 8.4 |
| Depth, d0 | Normal/Exponential | as measured | 40 | 20 |
| Length, L0 | Normal/Exponential | as measured | 40 | 20 |
| Corrosion rate (depth) | Normal/Exponential | d0/12 | 40 | 20 |
| Corrosion rate (length) | Normal/Exponential | L0/12 | 40 | 20 |

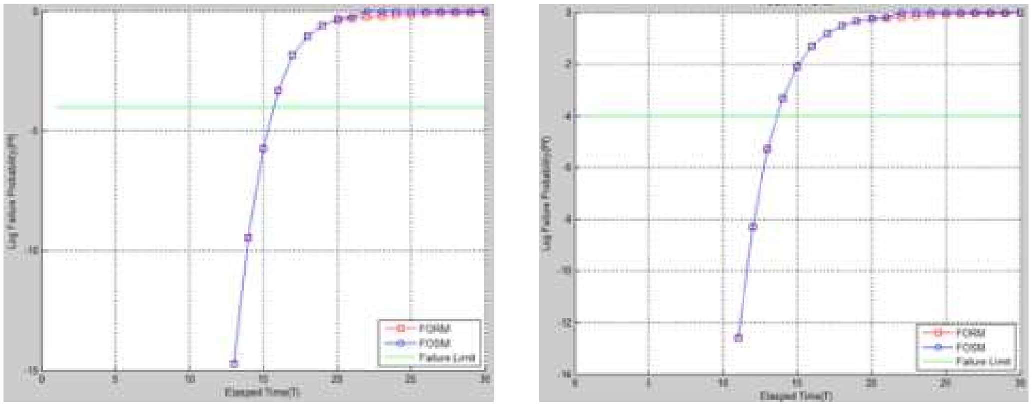
The POF results of MCS and FORM/FOSM with all the ILI data were shown in Figure 3. The figure presented that the POFs of MCS and FORM/FOSM are $10^{-1}$ and $10^{-2}$ respectively after operating 15 years of gas pipeline.




(a) MCS (b) FORM/FOSM

Figure 3 POF results by MATLAB code

POF sensitivity with 50% COV of corrosion pits (depth, length) was shown in Figure 4. The figure presented that the POF of FORM/FOSM was seriously affected by corrosion depth, not by corrosion length.




(a) Corrosion depth (b) Corrosion length

Figure 4 POF sensitivities of 50% COV

Remained life prediction of gas pipeline was calculated with a target of POF in codes like BS 7910, API 579 or ISO 2394. As one example, the remained life obtained from the target POF in $10^{-4}$ was shown in Table 2. The table presented that the remained life of MCS was shorter than that of FORM/FOSM. The smaller COV% induced the longer remained life, especially in corrosion depth.

Table 2 Remained life variation with COV at the target POF of $10^{-4}$

| Statistics | COV(1) | COV(x2)<br>D, T, Pop, UTS | COV(x1/2)<br>Corrosion Depth(d) |
|---|---|---|---|
| MCS | 8 years | - | - |
| FORM/FOSM | 14 years | 13 years | 16 years |

### 6.1.3.4 Reference

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4] Shahani Kariyawasam and Hong Wang, "Useful Trends for Predicting Corrosion Growth", Proceedings of the 2012 9th International Pipeline Conference, IPC2012-90539
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## 6.2 External Corrosion Threat Management (TGS Argentina)

### 6.2.1 Summary

Controlling the External Corrosion (EC) effects in buried pipelines is a challenging task not only when a new gas pipeline is designed but also when its maintenance is planned.

In order to mitigate the EC effects, the pipelines are installed with external coating system as a primary control system and a cathodic protection system as a secondary one. Furthermore gas pipelines are constructed in a piggable way so that internal inspection tools can be run to detect critical defects that should be repaired.

During the pipeline's lifespan, its external coating loses its original properties, so the cathodic protection system grows in importance. This is the reason why both current injection levels by the cathodic protection system and the amount of equipment increase as time passes. Therefore, the primary system at design time (external coating) becomes secondary and the secondary system at the moment of design (cathodic protection system) becomes the primary one.

As mentioned above, the aims of monitoring the effects of external corrosion differ depending on the age of the pipeline system.

ASME B31.8S **Managing System Integrity of Gas Pipelines** describes the following methods to control this threat in point 6 *Integrity Assessment*:

- Pipeline In-Line Inspection
- Pressure Testing
- Direct Assessment
- Other Integrity Assessment Methodologies

What this standard does not specify is under what circumstances each method is to be used.

For external corrosion defect to appear, some basic correlation effects should occur:

- The coating should break or disband
- The cathodic protection system should be insufficient
- The medium around the pipeline should be aggressive
- Time should pass.

For a new pipe, control of external corrosion must focus on analyzing the good condition of the external coating. In these circumstances, Direct Assessment is the most strongly recommended method to apply. This methodology detects failures in external coating, but no metal losses are manifested by operation of the cathodic protection system. Once the fault in the coating is found and repaired, the effect of external corrosion is mitigated. For that reason, we can agree that this method is often proactive.

For an old pipe, the most convenient method to detect defects by corrosion is to run an Internal Inspection tool (ILI). The problem is that this method detects the loss of material when it has already happened. This is why we say that this method is reactive. In general, when the cover of the pipe is old, it is very difficult to use the Direct Assessment method.

In order to have a productive method to control external corrosion threat, we have developed an analytical methodology to detect critical defects by external corrosion, namely a **Susceptibility Analysis of External Corrosion**. With its implementation, we use internal inspection runs to monitor good performance and to improve our Susceptibility Method.

In this paper we will develop the concepts expressed here in detail.

### 6.2.2 Introduction

Pipelines with External Corrosion Threat Management have a low percentage of failures in the world because they have been designed with enough safety margin. Nevertheless, there might be failures, as we have seen in the last years, because the integrity of buried pipelines is affected.

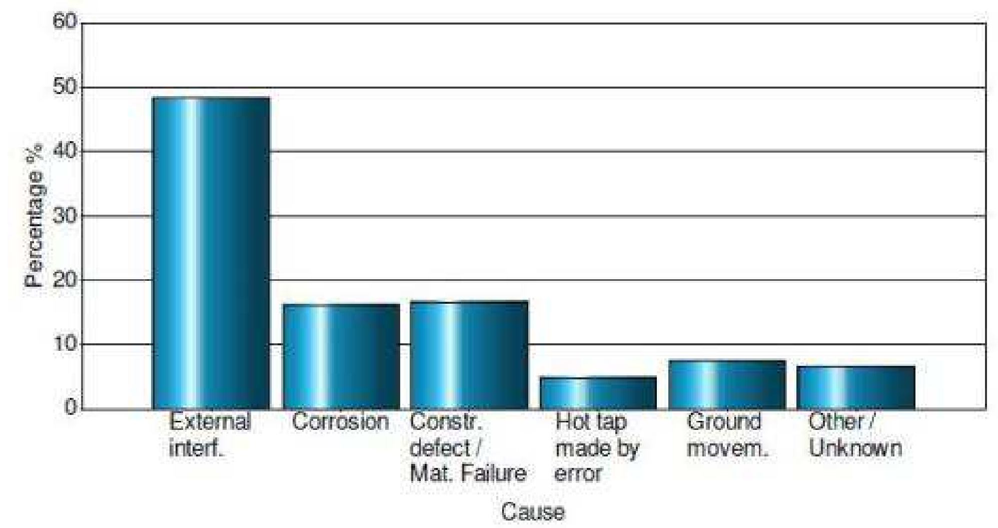


*Image 1: Distribution of incidents per cause*

Gas pipeline incident data has been analyzed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. One of the causes reported by operators is “unknown”, i.e. no root cause or causes were identified. The remaining 21 threats have been grouped into 9 categories of related failure types in accordance with their nature and growth characteristics, and further delineated by three time-related defect types.

The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment, and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.

**(a) Time-Dependent**

(1) External corrosion
(2) Internal corrosion

(3) Stress corrosion cracking

**(b) Stable**

(1) Manufacturing related defects
 *(a) Defective pipe seam*
 *(b) Defective pipe*

(2) Welding / fabrication related
 *(a) Defective pipe girth weld*
 *(b) Defective fabrication weld*
 *(c) Wrinkle bend or buckle*
 *(d) Stripped threats / broken pipe / coupling failure*

(3) Equipment
 *(a) Gasket O-ring failure*
 *(b) Control / relief equipment malfunction*
 *(c) Seal / pump packing failure*
 *(d) Miscellaneous*

**(c) Time-Independent**

(1) Third party / mechanical damage
 *(a) damage inflicted by first, second, or third parties (instantaneous / immediate failure)*
 *(b) previously damaged pipe (delayed failure mode)*
 *(c) vandalism*

(2) incorrect operational procedure

(3) weather-related and outside force
 *(a) cold weather*
 *(b) lightning*
 *(c) heavy rains or floods*
 *(d) earth movements.*

Depending on the age, material manufacturing specifications, procedures of line construction, design, operation, and protection systems applied, some of the threats mentioned above are likely to occur in the pipeline.

World statistics of failures clearly show three main causes: External Corrosion, Third Party Damage and SCC.

In order to control Third Party Damage the operators have important prevention tasks, but in order to control External Corrosion, the efforts involve detection, evaluation and mitigation tasks.

For that reason all the operators have to invest a lot of money, time and resources to control External Corrosion.

In this paper we will deal with the principal activities to prevent, detect, evaluate, and mitigate External Corrosion in both old and new pipelines.

### 6.2.3 Integrity Assessment Methods

When a new gas transportation system is designed, design engineers perform a careful analysis in order to prevent external corrosion defects from appearing in the future.

This analysis is based on the definition of two external corrosion barriers :

- External Coating
- Cathodic Protection system

Therefore a primary objective of external coating in buried pipelines is corrosion control. In addition, coating systems can be designed to provide mechanical protection during installation and operation. Many types of coating and wrapping are applied. The external coating is defined in accordance with soil characteristic.

Furthermore a CP system is installed to provide sufficient current to the structure.

To sum up, in order to control an external corrosion threat, coating supplemented with CP should be provided in the initial design and maintained during the service life of the pipeline system. When first installed, most pipeline coatings are effective in meeting their required function: to isolate the external surface of an underground pipeline from the environment and to reduce the CP current required. But in some cases both barriers fail and external corrosion defects appear.

ASME B31.8 establishes three methods to detect corrosion defects in pipelines.

- Pipeline In Line Inspection
- Direct Assessment
- Pressure Testing
- Other

Each method has advantages and disadvantages when applied.

A description of each method will be mentioned below.

#### 6.2.3.1 Pipeline in Line Inspection

This methodology is widely used to detect External Corrosion. It can be used when the pipeline has been constructed to run pig. This methodology gives us a lot of information about the construction and integrity of the pipelines such as:

Construction:
Valves
Width

Defects:
Metal Loss (External / Internal)
Crack detection
Dents
Corrosion in circumferential Weld
Manufacturing defects

This technique consists in introducing a special pig (instrumental pig) with a body of sensors and electronic components in the pipelines. This pig moves in the pipeline with the gas flow, identifying defects. This technique is called in line inspection (ILI).

*Image 2: ILI tool*

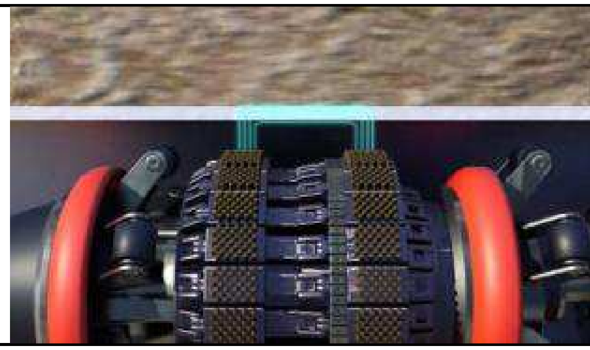

*Image3: Tool moves by gas*

There are different tools for ILI. Each tool detects a different kind of defect and is used for specific gas flow.

Magnetic tools are used in gas pipelines transporting dry gas and to detect external corrosion. These are tools equipped with strong magnets and sensor rings. Magnets saturate the walls of the pipeline with magnetic flow so that magnetic lines deviate if there is external or internal defect along the pipeline. Sensor rings detect the magnetic line deviation and further analysis determines the kind and characteristics of the defect.

There are 2 kinds of tools using magnetic technology, namely MFL (Magnetic Flux Leakage) and TFI (Transverse Field Inspection), both of which will be described below.

MFL tool creates magnetic flow field in axial direction of the pipeline and it is used to detect generalized metal loss. (Image 4)

TFO tool creates magnetic flow field in transversal direction of the pipeline and it is used to detect axially oriented metal loss. (Image 5)

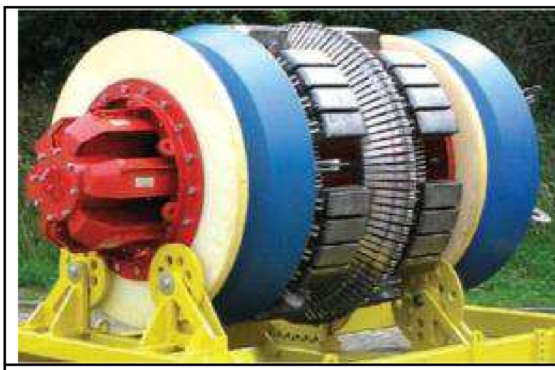

*Image 4: MFL tool*

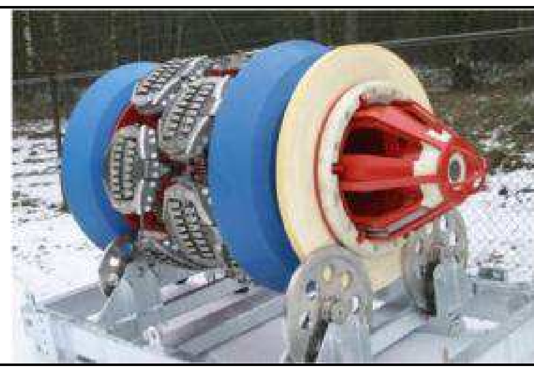

*Image5: TFI tool*

#### 6.2.3.2 Direct Assessment

This methodology is an organized integrity evaluation process to detect and prioritize pipeline segments which are found to be susceptible to external corrosion after revision of data concerning operation, maintenance and design; desk study and inspection with indirect methods, evaluation through test digs; revision of methodology, intervals of inspection and continuous evaluation of the process. Such methodology is also used to evaluate Internal Corrosion and SCC.

The above mentioned process has four stages, whatever threat is being evaluated. (Image 6)

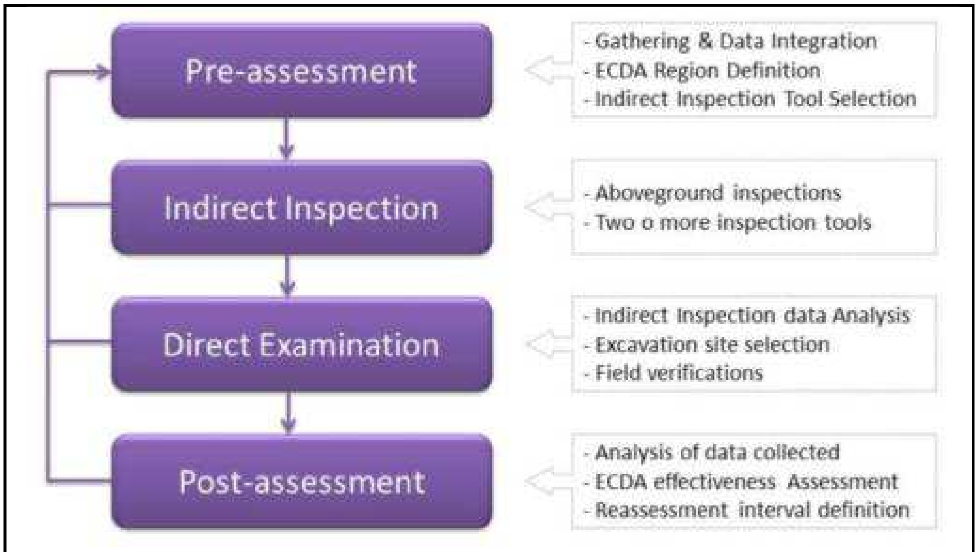


*Image 6: ECDA Structure*

#### 6.2.3.3 Pressure Testing

Pressure testing is performed in order to see if the pipeline is capable of operating at MAOP without the risk of corrosion or SCC, in the manufacture or construction of new pipeline and/or pipeline that cannot be inspected. Pressure testing also aims at preventing the spread of non-significant cracks.

Pipeline internal pressure is exerted from 1.1 to 1.25 MAOP. For SCC flow test, pressure against the wall of the pipeline is increased to 110% of minimum yield strengt .(Images 7 and 8) .

*Image  7: IMG Pressure Testing*

*Image 8: IMG Pressure Testing*

As opposed to internal inspection, this method only makes sure that critical defects have been mtigated through collapse. However, it does not provide any information about non-critical anomalies still remaining in the pipeline.

#### 6.2.3.4 Other: Susceptibility Analysis of External Corrosion

TGS has a big experience in controlling external corrosion threats with a lot of records on external corrosion defects with many operating, soil, and construction variables, plus a lot of information about internal inspection and CP data. This number of variables enables the company to integrate all this information to understand the corrosion process in order to define tendency and a mitigation plan.

When using this methodology it is necessary to have a strict and carefuly process of data collection to guarantee the result quality.

This methodology consists in creating a Study Sheet that includes the information to obtain the following results:

- Metal failures that requiere immediate or programmed action
- Cathodic protection defects which must be repaired
- Corresponding mitigation action such us: recoating, cathodic protection increase, etc.
- Risk analysis frame

### 6.2.4 Advantages and Disadvantages of using these methods

Each of the evaluation methods mentioned above must follow specific requirements before they are used, and there are advantages and limitations in their use both in the practical sense and concerning the kind of failure they can detect. If the requirements are not complied with, this might derive in the failure of integrity evaluation.

We found the following factors to be considered when choosing gas pipeline assessment technology:

- Inherent to defect characteristics.
    - Galvanic or microbiological type of corrosion
    - Corrosion in the body or the seam of the pipeline
    - Position of defect (axial or transversal)
- Inherent to transportation system
    - Existence of transportation
    - Feasibility of floor reconditioning
    - Pipeline availability
- Inherent to pipeline design
    - Characteristics of pipeline material
    - Variability of pipeline diameter
    - Existence of pig launcher and receiver
    - Existence of full port ball valves
    - Accessories that block the run of tools
- Inherent to applicability of methodology
    - Number of defects expected to be found
    - Detection capacity
    - Efficiency and practicality
    - Risk on pipeline segment

Each of these factors will determine the possibility of using one methodology or another.

#### 6.2.4.1 Pipeline in Line Inspection

Inspection tools require the following for their use:

- ✓ Fluid to run the tool
- ✓ Pig launcher and receiver
- ✓ If there are ball valves they should be full port
- ✓ Only in special projects is it possible to inspect pipelines with changing diameters, and there are limitations.
- ✓ Strict control of gas speed
- ✓ Availability of the right tools at the right time

The above mentioned elements create the major premises that determine the possibility of inspection or not. One of them is pipeline usefulness. If there are no facilities or correct pipeline design, operating cost and time will make reconditioning impossible.

Type of transportation is another premise. Reconditioning gas pipeline speed and/or flow is not always possible because of the season or the location of the gas pipeline in the system. In order to attain suitable gas speed, gas transportation and gas operator’s service may be restricted. Although there are variable speed controls for inspection tools, if the range in which they work is not respected, pipeline inspection might fail. Moreover, this kind of tool has a measuring error specification like any other kind of indirect measuring technology. Errors might increase if speed conditions are not attained and the report will thus contain wrong information.

Finally, tools should be available in time. Operators usually analyze transportation conditions and program tasks for the most adequate time, which means the moment transportation should be minimally affected. This service is provided by foreign companies whose work is in high demand and which have complex logistics, which does not always comply with the operators’ plans.

Despite the conditioning factors described above, this assessment methodology can be used and has the advantages listed below:

- ✓ Highly developed technology
- ✓ Wide market availability
- ✓ Inspection of total extension of the gas pipeline as well as its internal and external surface
- ✓ It is independent from the number of anomalies existing in the pipeline
- ✓ Methodology validation is not conditioned by field testing
- ✓ It informs location and size of each anomaly reported
- ✓ It shows not only anomalies but identification, location and characteristics of each event under study (seams, accessories, objects near or touching the pipeline, others)
- ✓ Quick implementation and attainment of results

#### 6.2.4.2 Direct Evaluation

The implementation of this methodology does not require any intervention and/or changes in transportation conditions. It requires at least two separate studies in order to detect and identify anomalies in pipeline protection systems, which will then be integrated in a process of analysis. We might mention the following studies:

- CIS (close interval survey), a method to identify cathodically unprotected areas.
- DCVG/ACVG, a method to identify coating defects
- PCM, gas flow mapping to detect coating defects and unwanted contact with buried pipelines.

These methods are complemented by other special studies to segment and focus on areas of importance such as:

- ✓ Soil model
- ✓ Gas flow modeling and critical angle
- ✓ Resistivity and Conductivity
- ✓ Corrosion coupons or corrosion test pieces
- ✓ MIC detection

This methodology requires the following stages:

- ✓ Execution and combination of 2 different study methods to detect and locate abnormality
- ✓ Development of a specific analysis model in order to assess the threat
- ✓ Field testing is required to validate the analysis model developed
- ✓ Process of methodology reassessment and validation
- ✓ Permanent or temporary existence of cathodic protection system

Nevertheless, this method is difficult to be used in old pipelines or those with a large number of anomalies, which will result in much detection rendering the application of this method impractical.

Another disadvantage of this methodology is that it does not show the existence, characteristics or size of anomalies in the walls of the pipeline.

The analysis and definition process might take a long time.

On the other hand, there are advantages and the use of this method has good results in the following cases:

- ✓ Used in new pipelines
- ✓ Pig launcher and receiver are not required
- ✓ Independent from the characteristics of pipeline material and existing facilities
- ✓ Transportation reconditioning is not required
- ✓ Low operational costs

#### 6.2.4.3 Pressure test

This is the most complex and least utilized assessment method, mainly due to application requirements and impact on transportation, operation, costs and loss of profits.

Another characteristic of this methodology is that it does not assess or diagnose the condition of the anomalies found in the pipeline. This methodology is based on the principle of taking critical anomalies affecting normal operation to the point of collapse. In the case of non critical anomalies which do not collapse, the method generates a deformation process which lengthens its passivity for a limited period of time (cracks). However, this method does not show the size of possibly existing anomalies or clues of their growth rate.

To sum up, we can mention the following disadvantages of this methodology:

- ✓ Total interruption of service of the pipeline under test
- ✓ Long time test
- ✓ Using fluid material (water) for the test

Before testing, removal of possible breaking points during tests, such as existing saddles or severe defects which will not withstand the test

- ✓ Big crew and equipment are required
- ✓ Drying up and water removal tasks are required
- ✓ Gas pipeline pressurization and gas quality adjustment controls
- ✓ Costs and loss of profits

On the other hand, some advantages can be mentioned, and the use of this method has good results in the following cases:

- ✓ This method removes all critical anomalies
- ✓ It does not require pig launcher and receiver
- ✓ It is independent from the characteristics of pipeline material or existing facilities

However, in order to decide on the choice of this methodology, it is necessary to analyze the Cost/Profit element as compared with other methodologies.

#### 6.2.4.4 Other: Susceptibility Analysis of External Corrosion

In order to use this methodology a large amount of information is required, as follows:.

- More than one Internal Inspection using the same technology
- History of cathodic protection data.
- On/Off potential
- Electric survey such as: soil resistivity, CIS, DCVG
- Electric test
- Corrosion growth rates.
- Record of mitigation tasks: recoating, defect repairs and dig verification results
- Records of ruptures and leaks
- Pressure profile & historic records of operation
- Location of facilities, crosses, railways
- Records of Buildings around pipeline

Here is a brief description of the structure of Susceptibility Analysis Model and its advantages.

The study sheet starts with a chart comparing all in line inspections. This chart describes the behaviour and tendency of the corrosion process and after some subsequent analysis, it enables the company to decide on the best alternative for corrosion risk mitigation tasks (Image 9).

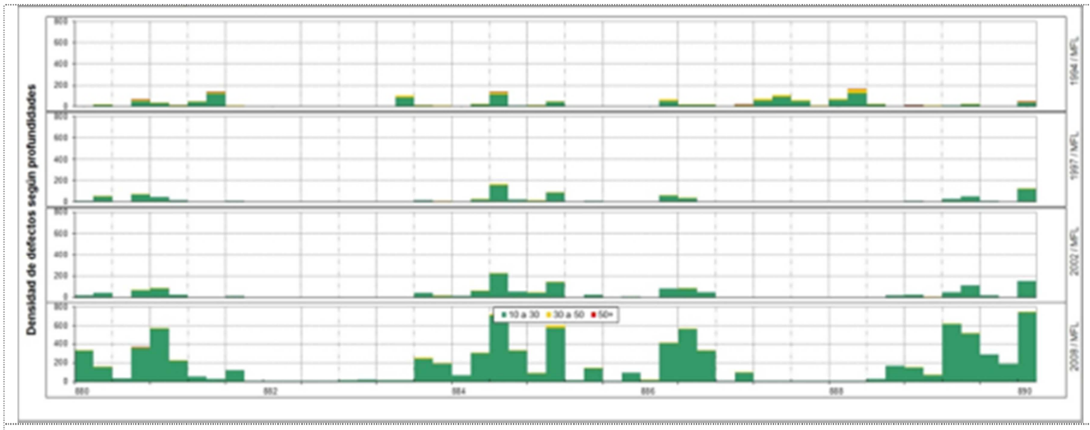

*Image 9 - ILI comparison: runs of 1994, 1997, 2002 and 2008. Intevals of 200 meters*

Another chart of the model describes the results of the latest in line inspection. Defects are shown under two indices: ERF (Estimated Repair Factor) and maximum Depth. In this way it is possible to detect special and critical defects which require either immediate or programmable action. (Image 10)

The same model shows a corroded area chart. In this way, there is indirect assessment of cover damage and of the connection between pipeline segment and cathodic protection.

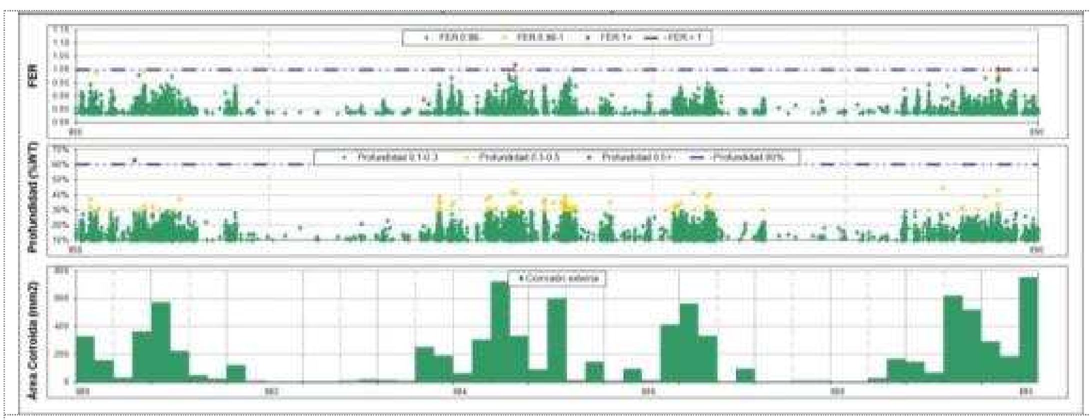

*Image 10 – Latest ILI run: FER and Depth visualization + Corroded area chart every 200 meters*

Soil characteristics are also described in this model. Charts show resistivity measurement, elevation profile and detection of pipeline sections affected by soil salinity (Image 11). This information enables the company to analyze the performance of the cathodic protection system, soil aggressiveness and the effects on existing defects.

*Image 11: Soil resistivity measurement, elevation profile and soil salinity*

Another important model is the condition of the cathodic protection system (Image 12).

- o The latest survey of On/potential
- o The three latest surveys of Off/potential
- o Existing CIPS and DCVG surveys
- o Location and kind of ICCP
- o Availability and Scope of each ICCP
- o Corrosion rates
- o Historical Off/ potential on each Test point

The integration of information enables the company to assess the following:

- o The level of cathodic protection in the system, its evolution and tendency
- o Detection of unprotected areas of pipeline due to low potential or inadequate distribution of ICCP'S
- o Correlation between areas of high corrosion rates and poor cathodic protection

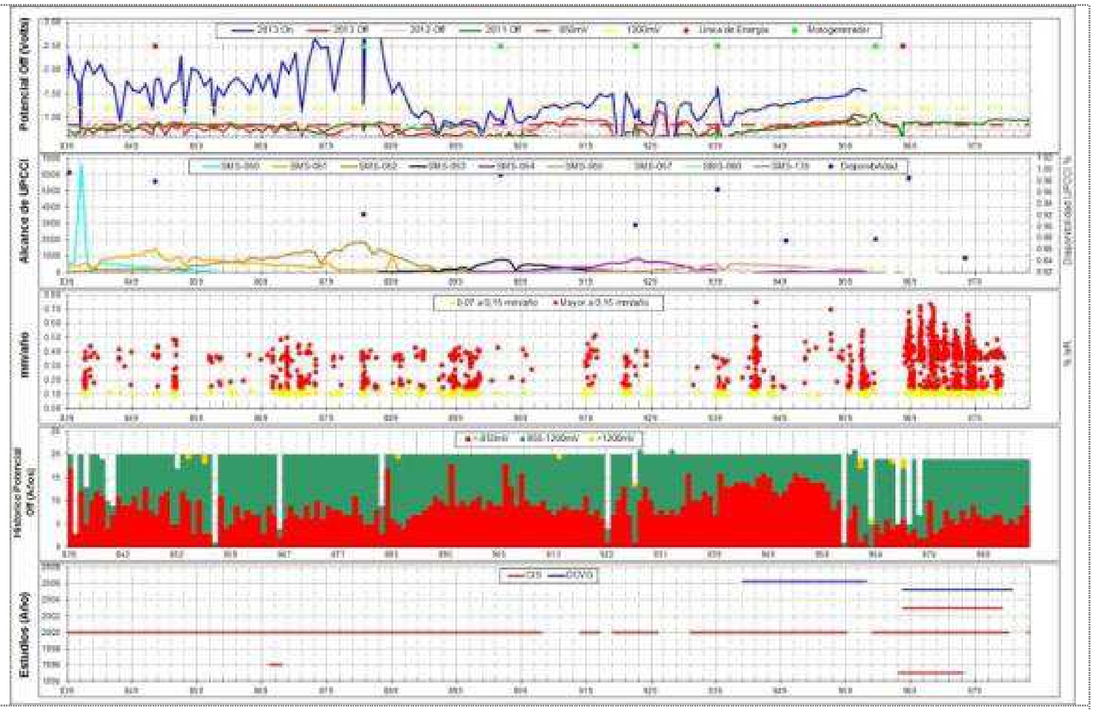

*Image 12: Cathodic Protection System*

Some other relevant information in the model is Mitigation task records such as pipeline replacement, recoating, total surrounding repairs, etc. They complement the analysis and detect already passivized areas (Image12). This chart also shows the history of failure, leaks and damages caused by External Corrosion. This also describes the serious condition of the area.

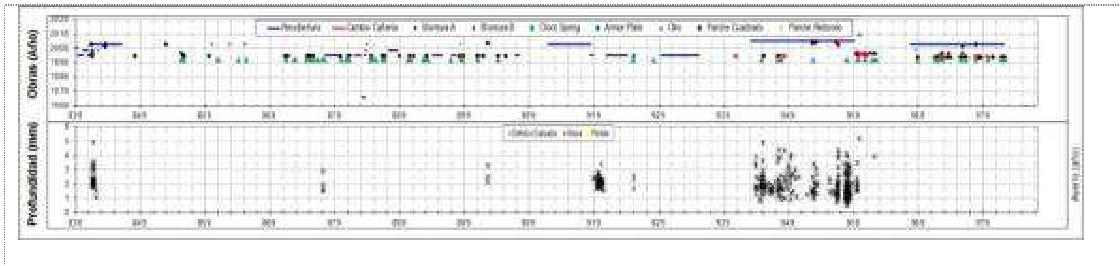


*Image 13: Mitigation task records*

Another important piece of information in the model is the detection of sensitive areas (Image 14), which are defined as high consequence areas when the failure occurs.

The following chart shows:

- Location of junctions, whether they are crossroads, access roads, rivers or railways
- Crossings with other pipelines
- Buildings within the radius of danger
- Pipeline ground surface facilities (valves, bypasses, compressors, and so on)
- Kinds of pipeline layout
- Private areas such as sport fields, natural reserves and any open air area where people might gather

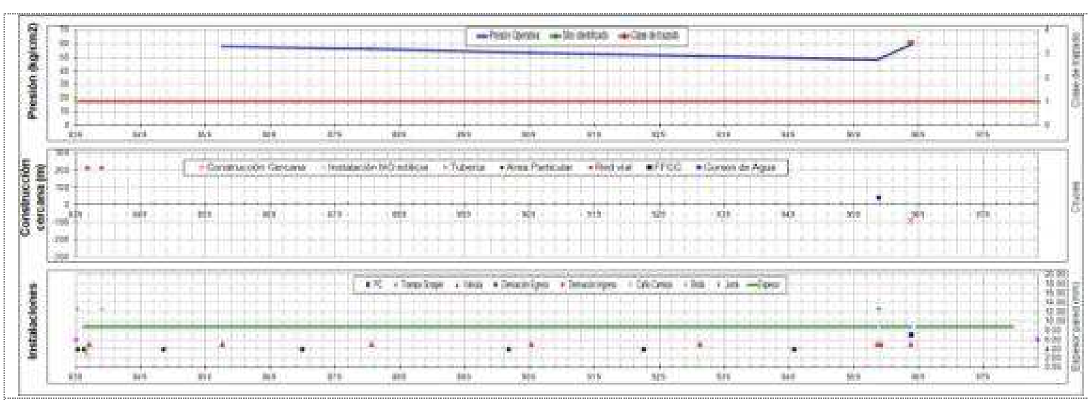


*Image 14: High Consecuences Areas*

Finally, after the analysis of the above mentioned information, it is possible to determine the levels of qualitative external corrosion risks. Assessment, change or mitigation tasks will be defined in accordance with such risk level (Image15).

*Image 15: Risk levels and Actión Plan*

### 6.2.5 Old Pipelines

Old pipelines are expected to have damaged coating, a number of anomalies and to have been repaired with totally surrounding saddles, the definition and applicability of the most appropriate methodology is a complex process in which it is necessary to evaluate a number of elements such as the possibility of pipeline inspection, the effectiveness of the method to choose, loss of profits for reconditioning and restarting the pipeline, staff and time needed for tasks.

After reviewing the characteristics of the methods described above, we can remark the following:

| **Aspects of Evaluation** | **Internal Inspection** | ***ECDA*** | **Pressure testing** |
| --- | --- | --- | --- |
| Pig launcher and receiver | Necessary | Unnecessary | Unnecessary |
| Ground level ball valve and renoval of obstructions in pipeline segments | Necessary | Unnecessary | Unnecessary |
| Gas transportation affected and/or gas flow cut off | Moderate | No | High |
| Transported product affected and reconditioning of gas pipeline system required | No | No | High |
| Crew | Minimum | Moderate | Maximum |
| Duration of tasks | Minimum | Long | Very Long |

| | | | |
|---|---|---|---|
| Gas pipeline reconditioning and/or adjustments required | Minimum | Minimum | High |
| Detection capacity and/or inference of anomalies | High | Minimum | None |
| Capacity to analyze the whole gas pipeline | High | Minimum | None |
| Method's pipeline analysis performance level | High | Low | None |
| Cost of method per gas pipeline length | Moderate | Low | High |

The comparative grid above clearly shows that Pressure Testing is not only the least efficient and most complex method to implement but also the most expensive and the longest to execute. This is why it has been least used and avoided by operators.

Direct assessment (ECDA) is the most highly recommended assessment method for new pipelines or those with few flaws in their anticorrosion protection or few anomalies. This is why this method is not recommended for old pipelines or long pipeline segments. The method's low performance and complex process makes such assessment impossible. On the other hand, the method's low performance and complexity would prove less costly in terms of money and time for the operator.

Internal Inspection appears to be the best alternative for the above mentioned pipelines since this method can detect all the defects within a reasonable period of time, with minimum crew and reasonable costs.

However, an old gas pipeline usually has damaged coating, cathodic protection, high concentration of defects. This is why it is convenient to implement more than one assessment method, such as internal inspection as basic, complemented by ECDA method on important pipeline segments.

The combination of two assessments methods is based on two premises:

- ✓ Different performance of the methods
- ✓ Monitoring capacity of active anomalies throughout time
- ✓ Internal inspection shows the size of a defect but it does not indicate how the defect has evolved or how it will evolve.

Direct assessment, on the other hand, does not characterize gas pipeline anomalies but it can describe the protection status of the pipeline and corrosive behavior of one point in particular.

Thus, the combination of methodologies, i.e. identifying the existent anomalies with Internal Inspection and monitoring the status of protection with Direct Assessment, results in optimum monitoring and control of the corrosion process, learning how it develops, when it can become critical and also enabling the use of an alternative mitigation method to control threats without the need of digs or direct verification.

### 6.2.6 Conclusions

- There are several methodologies and Technologies to assess gas pipeline integrity. However, not all of them have the same scope or performance.
- Using each of them requires (to a certain extent) operating restrictions, investment of resources and equipment or adaptation of gas pipeline design for the method to be used.
- Pressure Testing has practically been abandoned by the industry to control this threat because of its low performance and high cost as well as the operator's loss of profits.
- Direct Assessment is being more widely used because it does not require pig launcher or receiver or intermediate surface facilities. However, it should be used on new pipelines or those with few anomalies. This is proactive methodology because we can detect problems in the cover, although the corrosion has not yet occurred.
- Internal Inspection is the assessment methodology of best performance and capacity to detect anomalies. Nevertheless, if the pipeline has not been designed and constructed to run tools, adapting pipelines might be costly. This is the most efficient methodology, but it is reactive because the loss of material by corrosion has already occurred at the time of detection
- In the case of old pipelines, with high concentration of defects and with reported failures of their anticorrosion system, a combination of assessment methodologies is recommended, starting with the basis of Internal Inspection and using Direct Assessment in some parts.
- Finally, the implementation of a Susceptibility Model to detect defects by external corrosion with the combination of variables, aligned with different graphs, will enable us to control this threat safely.

### 6.2.7 Reference


*ASME B31.8-2012*

*NACE SP 0502-2011*

*ASME B31 G*

*API 579*

*API 1163*

*NACE RP 010202*

*POF Specifications for ILI*

*NACE SP0169-2007*

## 6.3 Composite Repair Clamp for Pipeline & Piping Leak Repairs (PETRONAS)


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### Table of Contents



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# 1.0 Background/ Introduction

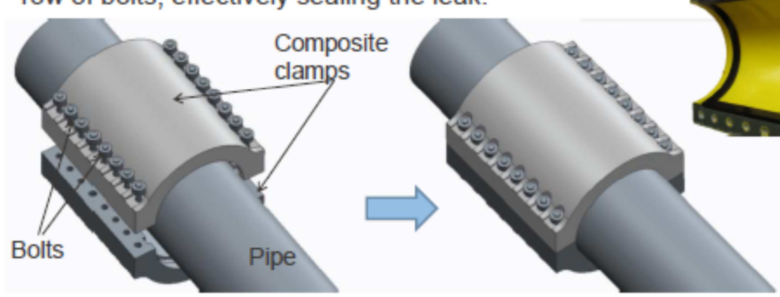




## Introduction

### Composite Repair Clamp

- The Composite Repair Clamp consist of two fiber reinforced composite half-shells. Each half-shell will have a perimeter seal on the inner surface.
- These half-shells shall be brought together over the corroded/leak area of the pipe. The shells shall be secured by the two longitudinal row of bolts, effectively sealing the leak.




## 2.0 Design & Testing





## Main Codes/Standards

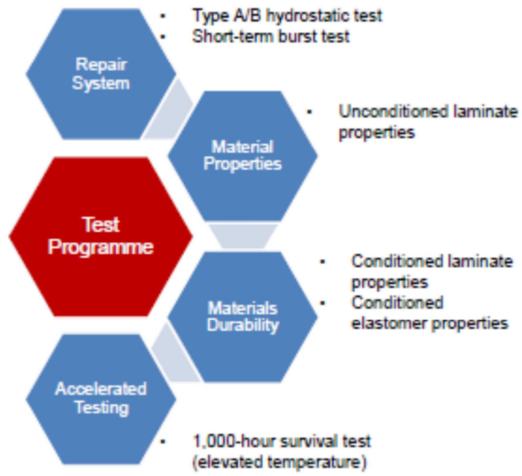
- **ASME Post Construction Committee (PCC-2)** and **ISO/TS 24817**
  - Specifies composite testing criteria (ASME PCC-2, Part 4)
  - Basis of short-term hydrostatic and long-term survival (1,000 hours) tests

- **ASME B31.4 & .8**
  - Repairs may be made to both leaking and non-leaking defects by the installation of a mechanically applied clamp.
  - Mechanical bolt-on clamps can be used for several types of defects (see Table 451.6.2.9-1 in ASME B31.4), including corrosion.
  - Shall not be used to repair circumferentially oriented defects unless designed to withstand the axial load.
  - A mechanical clamp shall have a design pressure of not less than that of the pipe being repaired.

# Test Program

## Overview

- **ISO/TS 24817**
  - Petroleum, petrochemical and natural gas industries - Composite repairs for pipework - Qualification and design, installation, testing and inspection
- **ASME PCC-2**
  - Repair of Pressure Equipment and Piping
- **ISO 14692**
  - Petroleum and natural gas industries - Glass-reinforced plastics (GRP) piping - Part 2: Qualification and manufacture
- **PTS 31.40.10.19**
  - Glass-fibre Reinforced Plastic Pipeline and Piping Systems
- **PTS 30.10.02.13**
  - Non-metallic Materials - Selection & Application








# Repair Clamp Material Selection

## Clamp Body

- Selection based on **PTS 30.10.02.13**, "Non-metallic Materials - Selection & Application" (see extract)
- Material = **Fibre reinforced vinyl ester resin**
  - Covers a variety of chemicals to a least 80°C:
    - Sulphuric 40% up to 90°C
    - Sulphuric 60% up to 80°C
    - Water up to 80°C
    - Crude oil up to 100°C
- Alternative material, epoxy, can be used for greater temperature resistance

5.4 VINYL ESTER RESINS

Compared to Polyester, Vinyl Ester resins are less brittle and have improved corrosion resistance, especially in fluids containing high concentrations of chlorine. Vinyl Esters come in many forms and have good chemical resistance to a broad range of acids, alkalis and hydrocarbons. High temperature resistant Vinyl Esters resins are also available, e.g., Epoxy-Novolac. Compared to Epoxy resin, the resistance of Vinyl Ester against acids is better, but is less against solvents, alkalis and hydrocarbons. The minimum operating temperature for Vinyl Ester resin is –50 °C.

Table 5.4a lists the maximum operating temperature as a function of various service fluid compositions for Glass fibre Reinforced Vinyl Ester (GRVE).

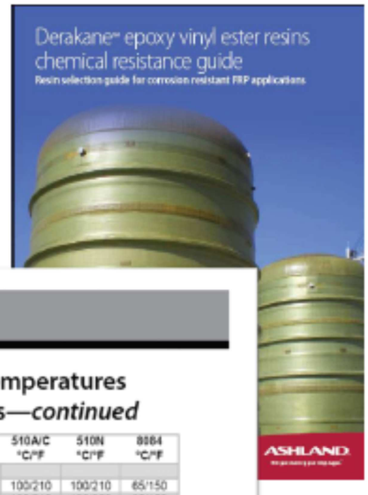
**Table 5.4a Maximum operating temperature as a function of application for GRVE**

| Typical applications | T (max) (°C) post-cured system | Typical applications | T (max) (°C) post-cured system |
|---|---|---|---|
| Water (fresh, salt, sea, brackish) | 80 | Water, chlorinated < 100 mg/kg | 80 |
| Acetic acid, < 50 % | 80 | Acetone, 5 % to 10 % | 20 |
| Acetic acid, 50 % to 75 % | 65 | Allyl chloride | 25 |
| Air | 100 | $CO_2$ gas | 90 |
| Alcohol, methyl < 5 % | 50 | Condensate | 80 |
| Butane gas | 35 | Gasoline | 65 |
| Citric acid | 80 | Heptane | 60 |
| Gas, natural | 90 | HCl < 37 % | 80 |
| Glycol, ethylene | 90 | Crude oil | 100 |
| Hexane | 60 | Sodium hydroxide, < 50 % | 80 |
| Jet Fuel (kerosene) | 70 | | |
| Petrol; sour, refined | 60 | | |
| Sodium hypochlorite, pH >11 | 60 | | |

# Repair Clamp Material Selection

## Clamp Body (cont.)

- Selected **Derakane 411 vinyl ester**
- Resin has good chemical resistance to wide range of chemicals, including sour crude, up to 100ºC (see extract below).
- Resin has long track record in OG&P industry, supply and technical support readily available.




Derakane Chemical Resistance Guide

**Chemical Resistance Table: Maximum Service Temperatures for Derakane and Derakane Momentum™ Resins—*continued***

| Chemical Environment | Concentration % | 411 °C/°F | 441 °C/°F | 470 °C/°F | 510A/C °C/°F | 510N °C/°F | 8084 °C/°F |
|---|---|---|---|---|---|---|---|
| Corn Sugar/Syrup (Glucose) <18> | All | 80/180 | 80/180 | | | | |
| Cottonseed Oil <18> | 100 | 100/210 | 100/210 | 100/210 | 100/210 | 100/210 | 65/150 |
| Crude Oil, Sweet, Sour | 100 | 100/210 | 120/250 | 120/250 | 100/210 | 120/250 | 65/150 |





# Repair Clamp Material Selection

## Clamp Body (cont.)

- Many factors affect permeability e.g. diffusants, temperature, pressure, filler, reinforcement & loading. Furthermore, it is difficult to compare as permeation are often reported in different units and conditions. Table below converts all units to a common coefficient for comparison purpose (source: Nuclear Decommission Agency, UK, www.nda.gov.uk)
- Barrier properties of vinyl ester is generally good against non-polar molecules (e.g. hydrocarbons).

| Materials | $CO_2$ | | Toluene | | Gasoline | | Moisture | |
|---|---|---|---|---|---|---|---|---|
| | Permeation coef. ($\times 10^{-10}$) | Temp. (ºC) | Permeation coef. ($\times 10^{-10}$) | Temp. (ºC) | Permeation coef. ($\times 10^{-10}$) | Temp. (ºC) | Permeation coef. ($\times 10^{-10}$) | Temp. (ºC) |
| Vinyl Ester | 6.32-22.20 | 42 | 0.001 | 37 | 0.001 | 37 | 0.013 | 37 |
| Epoxy | 0.14-0.24 | 43 | 0.001 | 37 | 0.001 | 37 | 0.013 | 37 |
| Nylon 6 | 0.16 | 45 | - | - | - | - | - | - |
| PVDF | 0.034 | 33 | - | - | - | - | - | - |

Permeability coefficients are specified in units of $\frac{cm^3(STP).cm}{cm^2.s.(cmHg)}$

## Repair Clamp Material Selection

### Perimeter Seals

- Selection based on **PTS 30.10.02.13**, "Non-metallic Materials - Selection & Application" (see extract)
- Material: **NBR (Buna-N)**
  - Temperature range -40 to 100°C
  - Suitable for variety of chemicals:
    - Sulphuric 40% up to 80°C
    - Alkalis up to 60°C
    - Water up to 90°C
- Alternative material, Viton® can be used for greater temperature and chemical resistance.

6.7 NITRILE BUTADIENE RUBBER (NBR, HNBR)

The solvent resistance of NBR, also known as Buna-N, is superior to most rubbers and therefore it is widely used for gaskets, seals and mouldings in the petrochemical industry. NBR has high resistance to aliphatic hydrocarbon oils and fuels. It has high resilience and wear resistance.

However, NBR is susceptible to Explosive Decompression. It has limited weathering resistance, and poor resistance against aromatics. The typical operating temperature range for NBR rubber is from –40 °C up to 100 °C.

Hydrogenated Nitrile rubber (HNBR) has higher temperature resistance and strength than NBR. HNBR has good oil resistance and resistance to amines. HNBR is suitable for use in methanol and methanol/hydrocarbon mixtures. Resistance against water and steam is good.

The typical operating temperature range for HNBR rubber is from –40 °C up to 180 °C. HNBR can be specified with appropriate hardness (Shore A nominal hardness of 90) and compounding to obtain excellent explosive decompression resistance.

Table 6.7a lists the maximum operating temperature as a function of fluid composition.

**Table 6.7a Maximum operating temperature as a function of application for NBR**

| Typical applications OP and Chemicals | T (max) (°C) | Typical applications EP | T (max) (°C) |
|---|---|---|---|
| Fuel oil, kerosene | 100 | Water | 90 |
| | | Oil/water mixture | 90 |





## Repair Clamp Manufacturing

**Composite:**

- Derakane Vinyl ester resin with Fibre glass reinforcement
- RT cure, 80°C post cure in oven

**Composite manufacture:**

- Vacuum bag resin infusion (VBRI)
- Low setup cost and scalable (similar process used to manufacture super yacht and wind turbine blades).
- Semi-skilled labour force

**Seals/grooves:**

- Conventional machining
- NBR (Buna-N) seals for maximum applicability. This are commonly used in commercial clamps.

## Test Results

### Composite Materials - Unconditioned

| Test | Results at Temperature | | Standards | Remarks |
|---|---|---|---|---|
| | RT | 80°C | | |
| **Longitudinal tension** | Modulus: 24.6GPa<br>Strength: 427.1MPa | Modulus: 23.0GPa<br>Strength: 395.9MPa | ASTM D3039 | Strength limits are more than sufficient for the function of clamp at either RT or 80°C |
| **Transverse tension** | Modulus: 28.0GPa<br>Strength: 501.6MPa | Modulus: 26.7GPa<br>Strength: 438.6MPa | ASTM D3039 | |
| **Interlaminar shear** | Modulus: 4.15GPa<br>Strength: 30.0MPa | Modulus: 3.13GPa<br>Strength: 18.8MPa | ASTM D5379 | |
| **Tg** | 110°C | | ASTM E1640 | Tg = 110°C; Max temperature for clamp: 80°C |

- Actual measured materials data used in the design of the clamp.
- Upper temperature limit is based on Tg-30ºC convention used for composite structures.

## Test Results

### Composite Materials - Conditioned

| Test | Test condition | Results at Temperature | | Standards | Remarks |
|---|---|---|---|---|---|
| | | RT | 80°C | | |
| **Longitudinal tension** | Hot/wet conditioned at 80°C for 1000 hrs (ISO/TS 24817) | Modulus: 23.2GPa<br>Strength: 186.7MPa | Modulus: 23.2GPa<br>Strength: 147.5MPa | ASTM D3039 | Conditioned properties used in FEA; Stresses in clamp are still well below the strength limits. |
| **Interlaminar shear** | | Modulus: 3.27GPa<br>Strength: 10.2MPa | Modulus: 5.58GPa<br>Strength: 7.4MPa | ASTM D5379 | |
| **Tg** | | 97°C | | ASTM E1640 | |

- Based on accelerated test, design safety factors sufficient for long term operation of clamp, *i.e.* stresses in clamp are still well below the **reduced** long term materials property limits.

# Test Results

## Perimeter NBR Seals

| Test | Test condition | Test Temperature | | | Standards | Remarks |
|---|---|---|---|---|---|---|
| | | RT | 65°C | 80°C | | |
| Compression Set | As manufactured | 9.2% | 18.9% | 32% | ASTM D395 | Meets manufacturer's specifications and function of clamp |
| Proof loading tests | Seals loaded at 15 MPa for approximately 5 days | - | ✓ | - | Custom test | Test on seal shows robustness at >2 times MAOP of clamp |
| Hardness Test | 1,000 hours of conditioning at 65°C | ✓ | - | - | Custom test | No significant difference in hardness of seal after long-term conditioning |

- Testing validated materials properties of seals.
- Additional testing accelerated and long term testing showed no seal degradation.



# Test Results

## System test

| Test | Test condition | Temperatures tested | | | Standards | Remarks |
|---|---|---|---|---|---|---|
| | | RT | 65°C | 80°C | | |
| Hydrostatic test (Defect Type A) | 105 bar pressure | ✓ | ✓ | ✓ | ISO/TS 24817; ASME PCC-2; ASTM D1599 | MAOP = 70 bar |
| Hydrostatic test (Defect Type A/B) | 105 bar pressure | ✓ | ✓ | - | ISO/TS 24817; ASME PCC-2; ASTM D1599 | |
| Short-term Burst (Defect Type A) | 190 bar pressure at 80°C | - | - | ✓ | ASTM D1599 | Safety Margin = 2.7 MAOP |
| 1,000-hour Survival test at 65°C (Defect Type A/B) | Elevated temperature 65°C (ISO 14692) for 1,000 hours at 105 bar | - | ✓ | - | ISO/TS 24817; ASME PCC-2; ISO 14692 | Estimated Lifetime = 3 yrs; can be designed to 20 yrs |

- Clamp successfully held pressure up to 2.7 times design pressure.
- 1,000-hr survival test completed and witnessed by Lloyd's Register.

# Test Results

## 1000hr Survival Test

- 8" repair clamp sustained pressure of 105 Bar on a Type A/B defect. Test spool was submerged in 65ºC bath.
- No leak detected at end of 1000hr.
- Using a conservative regression gradient from ISO 14692, the 1000hr survival produces an estimated minimum lifetime of 3 yrs.

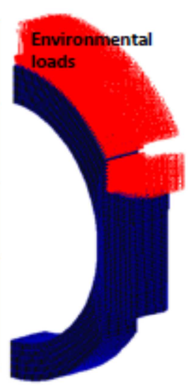

Defect: 70% wall thinning with 5 mm hole

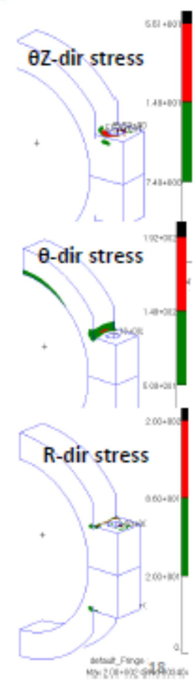


# FEA using Long-term Conditioned Properties

- FEA assumes **Environmental loading** equivalent to the pressure of **100 metres of water** (acting on top half), in addition to **Temperature** (80°C) and internal **Pressure** (105 bar) effects on the clamp
  - Composite material was tested at 80°C after 1000-hour conditioning at 80°C
  - These material properties were used in FE analyses to predict strength of clamp after long-term conditioning effects
  - Clamp was subjected to internal test pressure 105 bar
- **<u>Clamp meets all criteria</u>: All stresses are predicted to be below the conditioned material strength limit in the bulk of the clamp**

| FE Analyses | Criteria (using measured properties of material at after 1000-hour at 80°C) | FE Predictions |
|---|---|---|
| Shear stress (θZ-dir) | Not exceeding average strength = 7.4 MPa | Shear stresses are MPa limit ✓ |
| Hoop stress (θ-dir) | Not exceeding average strength = 147.5 MPa | Tensile stresses are MPa ✓ |
| Interlaminar stress (R-dir) | Vinyl-ester tensile strength MPa. A nominal 50 MPa interlaminate tensile was chosen as a design value. | Stresses are generally <20 MPa ✓ |

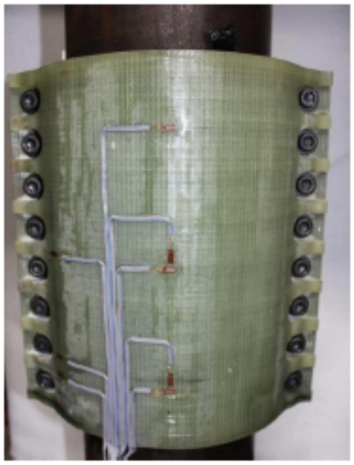


# 8” Prototype Repair Clamp

## Physical and Technical Characteristics

- **Dimension of Prototype:**
  - For 8-inch diameter pipe
  - 350 mm length
- **Pressure (can be designed for higher pressures):**
  - Design pressure: 105 bar
  - MAOP: 70 bar
  - Safety Margin 2.7 times MAOP
- **Temperature:**
  - Maximum working temperature: 80°C
- **Estimated Lifetime:**
  - 3 years for MAOP of 70 bar
- **Weight:**
  - 26 kg installed (23 kg composite, 3 kg bolts + seal) for 350 mm length, density 2200 kg/m$^3$
  - 30% to 40% the weight of an equivalent metal clamp

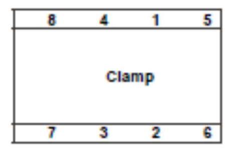




# 3.0 Installation Procedure

# Summary of Installation Procedure

- Prior to installation of the clamp, the pipe shall be inspected, cleaned and free of loose corrosion deposits in the vicinity of the repair area, in particular the area where the sealing surfaces will contact the pressure component. Any irregular surface should be smoothened with suitable tools.
- Grease the pipe surface where seals will contact. Apply grease to the seals on the two clamp halves.
- Remove the plugs from the pressure ports of both clamps
- Position the two clamp halves onto the pipe, one at the top (12 o'clock) and one at the bottom (6 o'clock). Ensure that the clamp sits entirely over the intended repair area.
- Insert 180 mm length locking bolts at four extreme corners of the clamp and manually tighten the locking bolt, just strong enough to close the two halves to within 15 mm. Ensure that tightening is done alternatingly between the four bolts, so that the clamps remain horizontal as they come together.
- Insert the bolts into the remaining holes. Manually tighten all the bolts until the clamp is fully closed.
- Use a torque wrench to tighten the bolts to the required torque (120 Nm) in the order as shown in the figure below. Repeat the process.
- Fasten the pressure ports for each clamp half.






# Installation Procedure – Mitigation Plan

The following are some steps to mitigate leak failures caused by installation:

- Inspect the gaps between clamp and pipe to ensure the seal has not extruded or is not displaced.
- Check that all pressure ports have been fastened correctly.
- Ensure torque wrench is set to the correct torque; Re-torque all the bolts.
- If clamp is still leaking, undo all bolts, remove the clamps and inspect the repair area for uneven surfaces; Replace the seals on the clamp with the spare seals and reinstall as per installation procedure.

# 4.0 Summary and Conclusion

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## Summary and Conclusion

| Functionality | Design & Engineering | Manufacture |
|---|---|---|
| • Corrosion resistant and do not add excessive loads to repaired structures<br>• Strengthen pipe in addition to leak repair through the option of grouting<br>• Target 20% lower price than metal clamp<br>• MAOP = 70 bar;<br>• Max Temperature = 80°C | • Developed design methodology for composite clamp<br>• Materials and clamp has undergone static and long term testing<br>• Clamp has passed 1000-hr long term test<br>• Margin for clamp = 2.7 x MAOP<br>Design of clamp complies to ASME B31.4 & B31.8 requirements i.e. design pressure and loadings | • Low CAPEX process<br>• Can be executed by semi-skilled workforce<br>• Manufacturing process is scalable |

**The current prototype clamp is competitive in price, whilst providing corrosion resistance and lightweight advantages, compared to similar specification metal clamps. The design method has been verified through extensive testing, including static and long-term testing (as per ASME PCC-2, ISO/TS 24817 and ASTM D1599), and materials testing (e.g. ASTM D3039, D5379, E1640, D395). In addition, testing has demonstrated that the clamp can withstand up to 2.7 x MAOP and complies to ASME B31.4 & 8 (see pg 9) and "Petroleum (Safety Measures) (Transportation of Petroleum by Pipelines) Regulations 1985" (Regulation 4: ASME B31.4 & 8).**


Thank You
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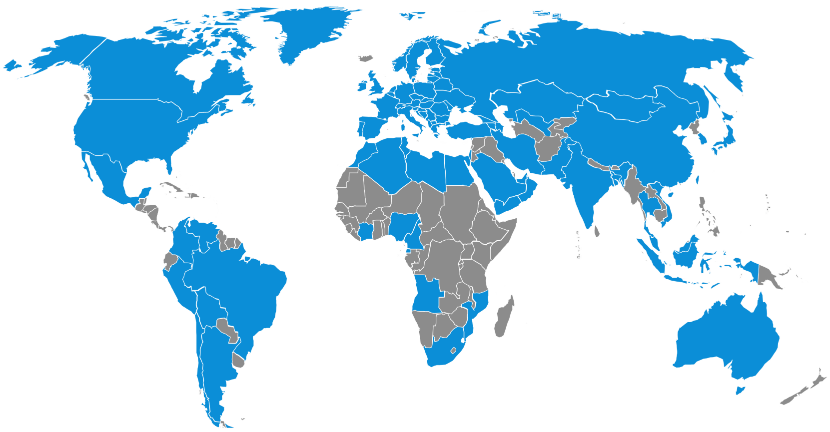
# NOTES



The International Gas Union (IGU) was founded in 1931 and is a worldwide non-profit organisation promoting the political, technical and economic progress of the gas industry with the mission to advocate for gas as an integral part of a sustainable global energy system. The IGU has more than 142 members worldwide and represents more than 97% of the world's gas market. The members are national associations and corporations of the gas industry. The working organisation of IGU covers the complete value chain of the gas industry from upstream to downstream. For more information please visit **www.igu.org**

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