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Pipeline Leak Detection, Location and Monitoring systems Past and Future

Marcelino Guedes Gomes
Director
PIPELINEBRAZIL

When people from other industries ask us about the most important activities in pipelines, we usually mention three areas. The first is Operational Risk Management, the second is Pipeline Integrity, and the third is Instrumentation and Process Control. The first is justified by being the one that tells us whether we can operate a pipeline or not; the second is the one that shows us the condition of the pipeline structure including the pipe wall which maintains the product inside the pipeline, and the third is the one that gives us the conditions to monitor the operation.

Without wanting to debate which is most important, we have no doubt that leak detection, location and monitoring systems are among the most important disciplines and all pipeliners from the control room are aware of this. We can classify detection systems into three groups: a) visual systems include degradation and discoloration of grass, line walkers, sniffer dogs and cameras giving local and satellite images; b) variable tracking systems including metering and SCADA tools and c) Sensory Equipment and Systems considering fiber optics, accelerometers and acoustics devices.

Recent technologies will be utilized increasingly to detect, locate, monitor and forecast the effects of any leaks or accidents. The future is coming. Sensing engineering, satellite imaging systems are a reality in theory and will shortly be put into practice to accelerate detection and consequence prediction.

Line Pipe manufactured with inbuilt nano-sensors such as: Temperature, Strain, Pressure, Density, Flowrate, will be affixed inside the pipe wall. We have to considerer new materials – Silicon, Polymers and Nanostructured materials in combination with layers of steel.

Visualization, multi and hyperspectral data from satellites or autonomous drones and aerial imagery are just starting to provide the control room with essential information from the ROWs.

Data Science, Artificial Intelligence, Machine Learning, Big Data and other new methodologies will recommend actions to be taken following an incident. Smart Technology and IoTs, Intelligent Fiber Cables, mesh of different kinds of sensor installed along the ROW will link the pipelines to the authorities, services and the general public.

YPPs – Young Pipeline Professionals will be responsible for designing and implementing the pipelines of the future, considering the new technologies and boundary conditions: No Leaks, No Accidents, No Loss of Life, Fewer Operators, Automatic Pilot, Data Engineering, Sensor Engineering etc. The pipeline industry has been a conservative industry but will change very fast with digital engineering and the new generation.

Leaks and Accidents will only be seen in museums and in chapters on pipeline history.

I am happy that this issue of the Pipeline Technology Journal will shed a light on latest developments in pipeline leak detection and monitoring.

Yours,

Marcelino Guedes Gomes, Director. PIPELINEBRAZIL

THIS ISSUE'S COMPLETE CONTENT

JUNE 2021

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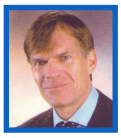

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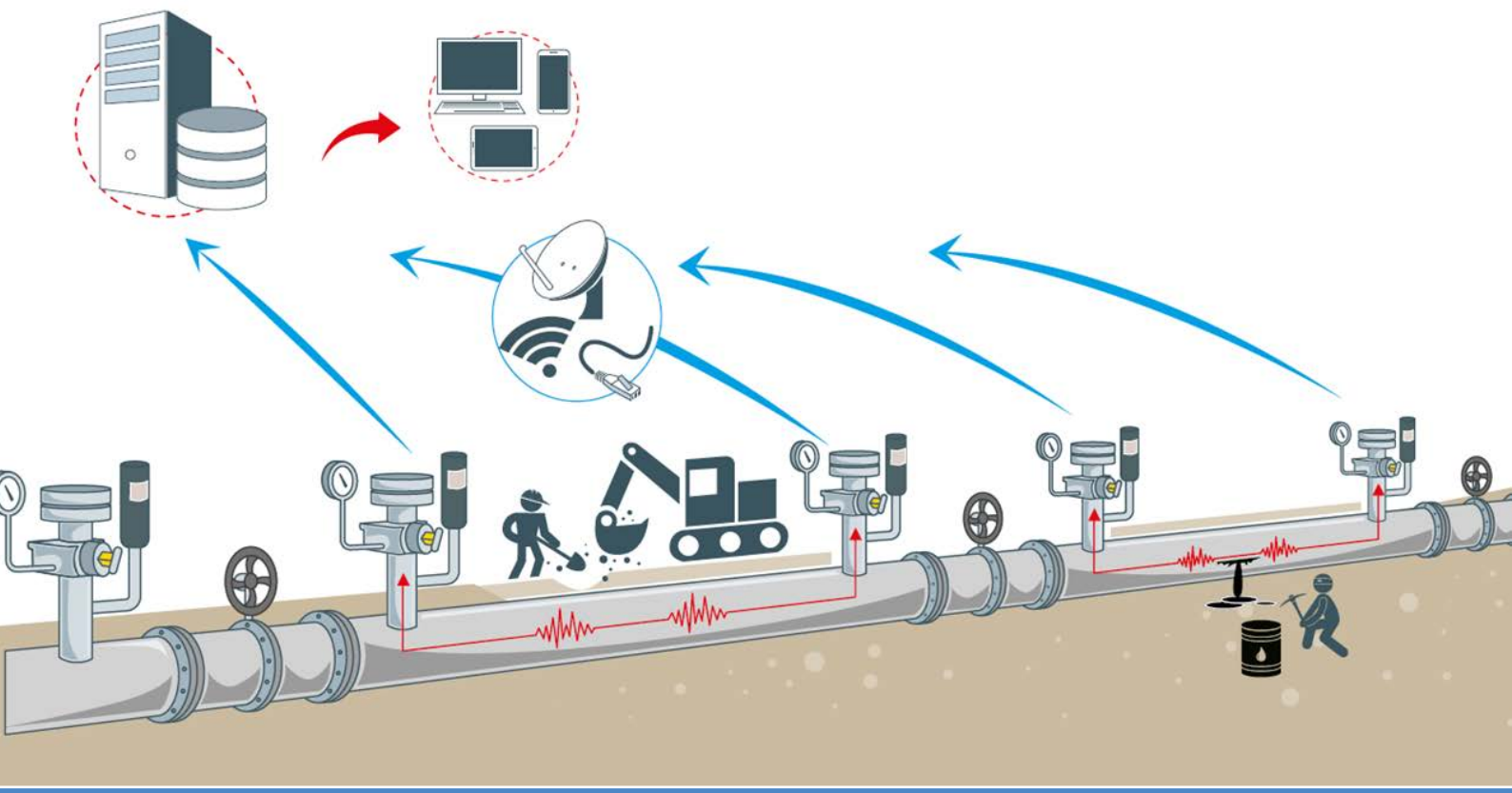
Winner Photo

Albania, TAP project, 215km, 48“, cross country crossing the mountains of Albania.

Wilko Koop, A.Hak International BV, Netherlands.

Flexible asset integrity capabilities by means of the vibroacoustic technology framework



Fabio Chiappa, Marco Marino, Silvio Del Giudice; Simone Cesari, Giuseppe Giunta > SolAres; Eni S.p.A

Abstract

The vibroacoustic system (e-vpms®) was designed by Eni S.p.A to detect and accurately localize spillages/leakages in crude oil and finite product pipelines, although has shown over the years the capability of detecting a wide class of Third Party Interferences phenomena. The reason of this high sensitivity is ascribable to the physical-acoustic properties of the pressurized fluid in the pipeline. Events of spill generates a negative pressure transient into the fluid (i.e. acoustic signal) able to travel for tenths of kilometers inside the conduit.

Moreover, the interaction between an impact and the inner fluid is not direct; impacts are mainly responsible for the transmission of elastic energy to the metallic shell in terms of mechanical vibrations. The elastic wave-field travelling into the solid is transmitted to the internal fluid undergoing an acoustic conversion. Once converted in an acoustic perturbation, the signal can travel for several kilometers inside the pipeline.

Similar considerations can be done also in case of the vibration noise produced by a digging activity over the buried pipeline, right on top or nearby. The mechanical energy of the operation is transferred to the soil in terms of vibrations, towards the pipe shell and finally to the fluid. The energy transfer between soil and inner fluid follows a decay not simple to explain through standard attenuation models. To date, the e-vpms® has achieved a very high level of maturity, nevertheless R&D engineers are constantly working to improve the integrity monitoring system and to find new applicative scenarios.

1. INTRODUCTION

The vibroacoustic technology (e-vpms®) was developed by Eni S.p.A mainly to cope the issue of leakages, although has shown the capability of detecting Third Party Interference, i.e. impacts, illegal tapping precursor events [1-6] and illegal digging operations [19].

The current installations of the e-vpms® more than 1,400 km of pipelines in many regions of South America, Nigeria and Italy; in this country the Vibroacoustic platform protects the 100% of the whole refined products pipeline network [7, 8] and important assets of crude oil in Val d'Agri, southern Italy. The vibroacoustic technology is not invasive and cost-effective. This is due to the ease of installation and the capability of retrofitting existing transport lines. In fact, with few sensors, the e-vpms® can protect pipelines long up to 100 km, against the events which can undermine the asset integrity [9, 10].

In the last years, new technological requirements and challenges have pushed Eni S.p.A to make investments in the research and development, to increase the operating range of the e-vpms®. New underwater sensors have been developed to protect offshore pipelines and several tests were performed to protect gas pipelines. To date, the vibroacoustic system boasts a large spectrum of applications, which go far beyond the detection of illegal events. The use of machine learning techniques on e-vpms® historical data break new ground, like the prediction of obstructions or pump failures.

The system features and the proven performances of detection and event localization makes the Vibroacoustic technology the ideal candidate for supporting the oil company in challenging field of asset integrity.

In fact, the resilience assessment is a current challenge which needs a multidisciplinary approach, integrated management solutions, advanced models and novel technologies. Asset integrity management and operational requirements shall be able to detect and monitor physical threats (e.g. third-party interference, leak, sabotage, failure, anomalies), to protect the surrounding environment, the safety of personnel and the local communities involved in the regions [1, 2]. In this paper we present the following technology improvements and applications:

- the novel shallow-water sensing group, to acquire data underwater in offshore scenarios
- the application of impact detection to gas pipeline
- data-driven machine learning approaches to predict pigging operations in oil pipelines and to remotely monitoring the health of centrifugal pumps.

2. BASICS OF E-VPMS® TECHNOLOGY

The e-vpms® is composed of a multipoint array of vibro-acoustic sensors, placed along a pipeline, telecommunication systems for data transferring and a central processing server. In particular, the sensing groups are devoted to the detecting of the complete elastic-dynamic wave-field; static/dynamic pressures and vibrations contribute to provide deep information on the physical phenomena responsible for the generation of the elastic perturbation (Figure 1).

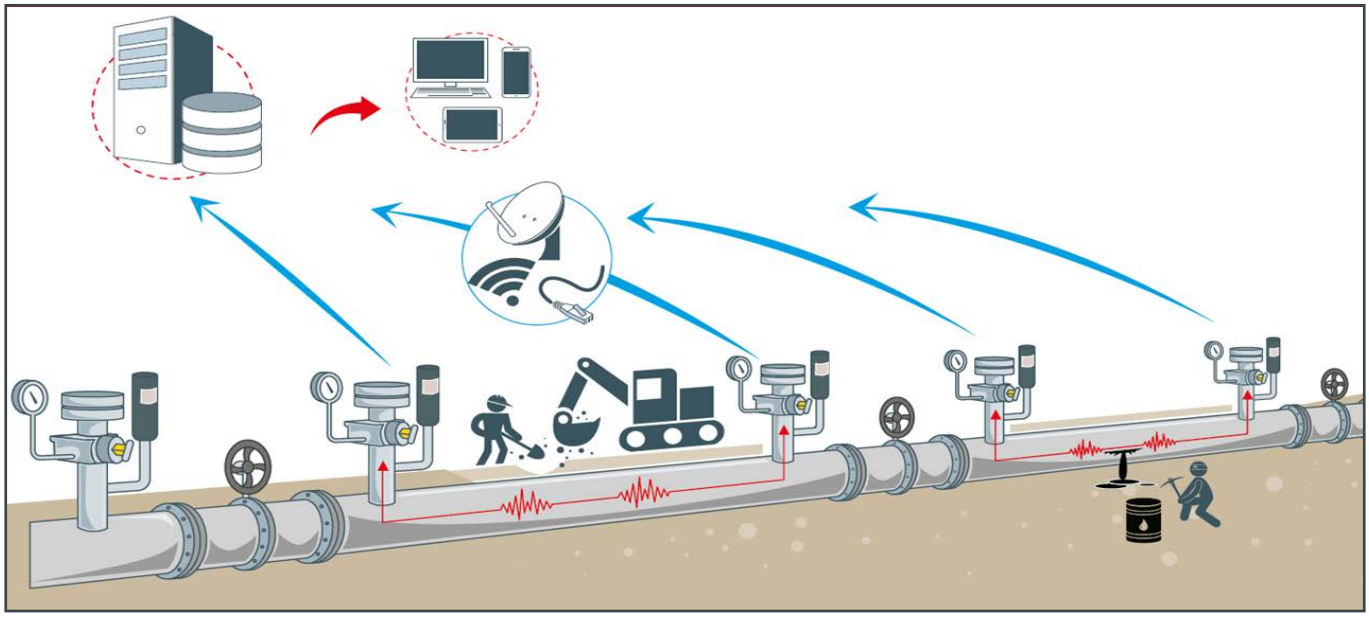


Figure 1: The sketch of the whole e-vpms® hardware. When any kind of mechanical perturbation (such as a spillage, an impact, a digging operation) interacts with the pipeline, a propagating vibro-acoustic wave-field is produced. The anomaly reaches the sensors, which are also responsible of sending data to a central processing unit.

Acoustic and elastic waves are produced from the physical source whenever something happens and travel in both directions at the speed of waves in the crossed media; the e-vpms® sensors detect such waves and a multichannel recording unit transfer continuously data chunks to a processing server. This central unit is responsible for the application to data of advanced digital processing chains, such as non-linear filters, real-time noise estimation, channel estimation, adaptive noise attenuation, detection/localization algorithms and multi-channel localization.

The processing system primarily processes pressure waves, which are commonly used in many applications in the industry to detect leakages. In fact, dynamic pressure information makes it possible to identify and accurately locate an anomalous source of noise, but also the elastic components propagation, carrying on information on second order events. In order to detect such weak and informative vibrations, the developed e-vpms® equipment is very sensitive and the signal processing algorithms are highly advanced.

From the point of view of wave physics, the pipe is a very effective wave-guide system. The dynamic pressure field can travel for kilometers inside the fluid if the pressure is at least 1 barg, while vibrations propagate through the solid shell according to the elastic-dynamic laws. These features give to the e-vpms® system a level of detection performance, that cannot be reached by a simple pressure-based system.

As mentioned before, the e-vpms® uses special and advanced digital processing algorithms. In particular, the noise produced by the operating pumps is used as acoustic source to perform unique tasks (such as PIG tracking) or to perform the patented noise removal routine, which ensures a very high SNR (Signal to Noise Ratio) and a consequent performance enhancement in event detection.

3. SHALLOW WATER SENSOR GROUP

As mentioned before, the e-vpms® is composed of a multipoint array of vibro-acoustic sensors, placed along a pipeline. The e-vpms® sensor group was originally designed for onshore scenarios, but to meet the recent market demands, our R&D engineers develop a new device capable of working underwater. This crucial update of the sensor group opens new operational opportunities, such as the monitoring of offshore flowlines or pipelines that cross area subjected to swamp inundations.

The key idea is to enclose the sensor group into a lid made of carbon steel, resistant to pressure and corrosion by an external epoxy coating. The steel lid is removable to carry out the maintenance and fasten to a welded bead. The sensing group is composed by two sensors (1 accelerometer and 1 hydrophone) to reduce clutter.

4. IMPACT DETECTION IN GAS PIPELINES

Because natural gas is flammable and potentially poisonous, the transportation system must consist of a sophisticated network of pipelines in order to reach the goal safely. Aside from security, speed and efficiency are also critical. In gas transportation, the gathering system is made up of low-pressure, small-diameter tubes. It carries natural gas from the wellhead to the processing plant in a safe and efficient manner. If a component of natural sour gas needs to be removed (i.e. hydrogen sulfide or carbon dioxide), a non-corrosive specialized collection line must be

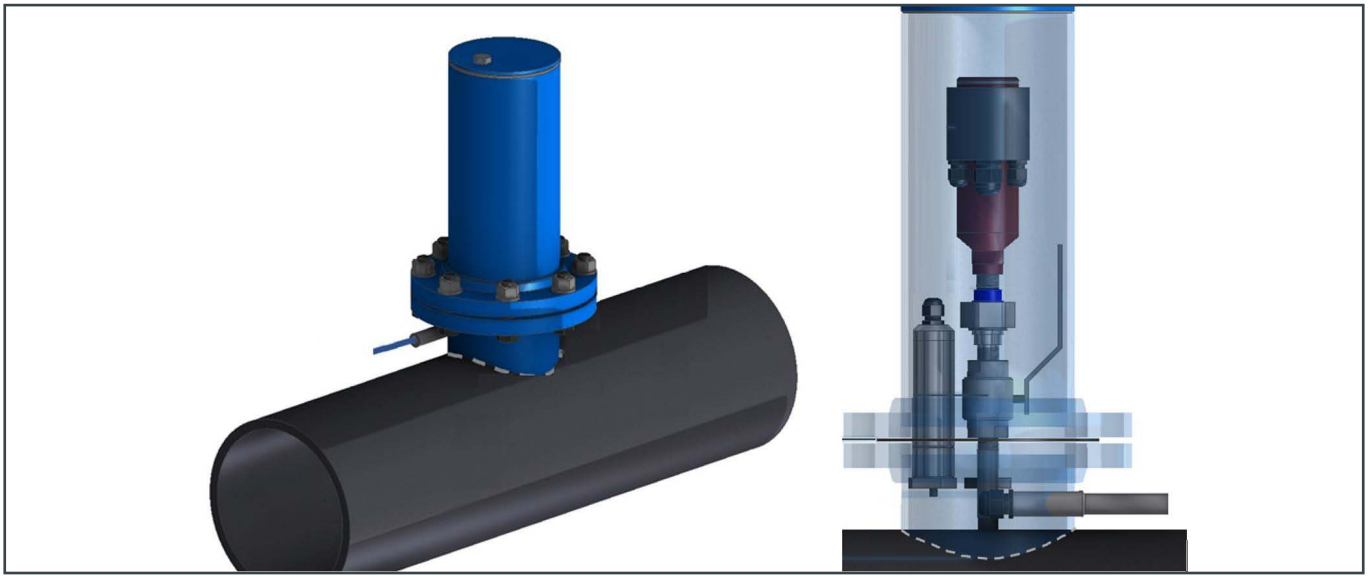


Figure 2: On the left, the pipeline with the sensor case made by a welded bead and a steel lid. On the right, the interior of the case, in which accelerometer and hydrophone layout is shown.

Figure 3: A picture of pendulum device taken "in situ". Before the mass release, the distance a is precisely measured, to make feasible the energy calculation.

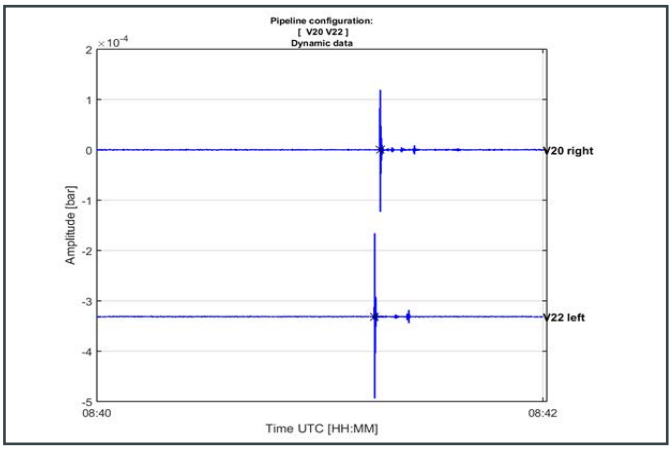


Figure 4: Acoustic signals produced by the hit of the pendulum registered by e-vpms® stations placed at a distance of about 2.5 km.

built. From this point, the product is transported from the processing plant to the centers of consumption by means of intrastate/interstate pipeline system and then to the distribution for delivering to gas the end-user.

The escalating worldwide demand for natural gas has resulted increasing investment into this area to extend the operational service life of existing rigs. The asset integrity of the whole gas transportation system becomes crucial to cope these needs. In fact, several damages can occur to a gas pipeline, due to corrosion, geohazards events or third-party interference. One of the extremely dangerous events is the impact, because it can cause leaks or a localized plastic deformation (dent&gouge) responsible for the triggering of corrosive processes. In case of impact/dent event, it is necessary to react as soon as possible so that to act.

From a physical point of view, the impact with pipeline shell shakes the gas generating a pressure wave which can travel inside the fluid for several kilometers. The e-vpms® can cope with this issue, providing an early detection system capable of localizing such events with very high accuracy.

During the last quarter of 2020, Eni S.p.A performed impact test on pipeline, no longer operational. The Eni's infrastructure to be used for the full-scale tests is a 16" ID gas pipeline, stand-still, 100 km long, in North Italy. During the full-scale test campaigns, the pipeline will be filled with a gas mixture (Nitrogen/Air), pressurized at about 6 barg, in stand-still condition. The pipeline is fully operative with several valve sections, power supply, fiber optic cable and property facilities area to be used for technologies installations and to perform the Third Party Interferences (TPI) tests.

The impact tests were performed by means a 100 kg calibrated pendulum equipment (see Figure 2). The pendulum is released (from rest) at a certain distance measured from the pipe armor to the pendulum itself. Given that this distance is known, it is possible to compute the potential energy of all tests. Supposing that the potential energy is transferred to the pipe in a single stroke, the impact energy can be computed as $m.g.a^2/2l$, where m is the mass of the pendulum, g is the gravitational acceleration, a is the measured distance for each test, and l is the pendulum arm length (1.5m).

For the sake of completeness, plot in Figure 4 shows an example of registrations during an impact test. Data traces refer to two recording stations placed at about 2.5 km; they show an evident amplitude response, which makes feasible the accurate detection and localization of the vibro-acoustic source of impulsive noise. The experimental tests lead to draw up the following performance specifications for the TPI impact pendulum with energy in the range 15÷1300 J:

- Event detectability: 100%
- Localization precision: 20 m by impact energy > 300 J
- Propagation distance: 3.1÷27 km by impact energy > 300 J

5. A MACHINE LEARNING APPROACH TO THE PREDICTION OF PIGGING OPERATIONS

Machine learning approach was presented in [13] and refers to a method able to predict the need to perform pigging by means the data driven machine-learning (ML) analysis of e-vpms® measurements. In particular, the solution makes use of pressure measurements, collected by the recording stations in different locations along the pipeline. Eni S.p.A collected vibroacoustic historical data for two years in the crude oil transportation pipeline connecting the Eni R&M Logistic terminals of Chivasso (Turin) and Pollein (Aosta). The conduit under test is 100 km long and has an inner diameter of 16", whereas the relative distance between the measure stations is about 30-40 km.

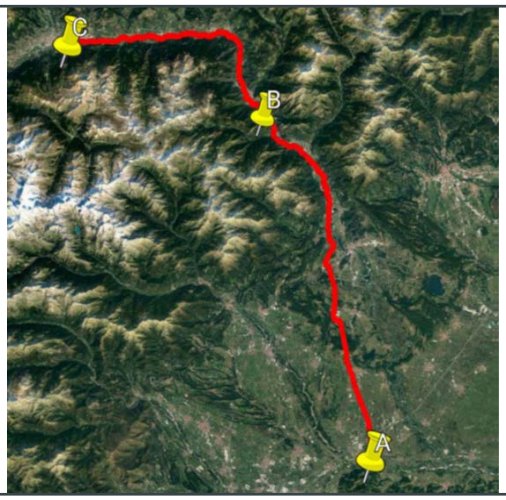


Figure 5: Satellite map of under-test pipeline (red curve) and location of the e-vpms® measurement stations in North Italy (yellow pins) [13].

The classificatory is based on a decision tree regressor, properly fed by supervised information gathered by validated field data sets. Several rolling statistics features are derived the e-vpms® dataset; one of the most significant features is the head loss between couples of measurement stations. These are used to estimate the probability of the need for pigging the pipeline segment. In particular the expert system associated the anomalous features with the occlusion level for each segment suggesting the clean-up operations.

Head losses can be trivially calculated through the differences between pressures at different recording stations, even though must be compensated by removing the effects of the hydraulic head and normalized with respect to distance. Lower head losses are indicative of cleaner pipe sections; in these conditions, a pumping terminal can operate with a lower service pressure.

Such a dataset can be used to perform the descriptive analysis and train the ML algorithm. As shown in Figure 6, if the time evolution of the head loss for three different line segments is compared with the pigging campaigns, it can be noted that after pigging operations important drops in head loss occur.

We have manually built a target function, named a "PIG indicator" to be learned by the supervised regressor, and it corresponds to a pigging probability measure (see Figure 7). This measure is trivially obtained by normalizing the historical head-loss between 0 and 1, where 0 stands for the optimal status of the pipeline, whereas 1 represents the need to clean up because the level of obstruction is high.

The model accuracy is assessed by evaluating the RMS error (Root Mean Square) between the PIG indicator and the estimated PIG probability (see Figure 8). The training dataset is the period from July 2013 and May 2014 only for the AC line segment, whereas the test dataset is the period from May 2014 to November 2014 of the AC segment and the whole historical period for the AB and BC segments. As depicted in Figure 8, the predictions (real lines) are superimposed on the PIG indicators, showing a very high accuracy. The system use the machine learning model derived from the historical observations and the current real-time pressure value to predict the probability of pigging about 10minutes in the future.

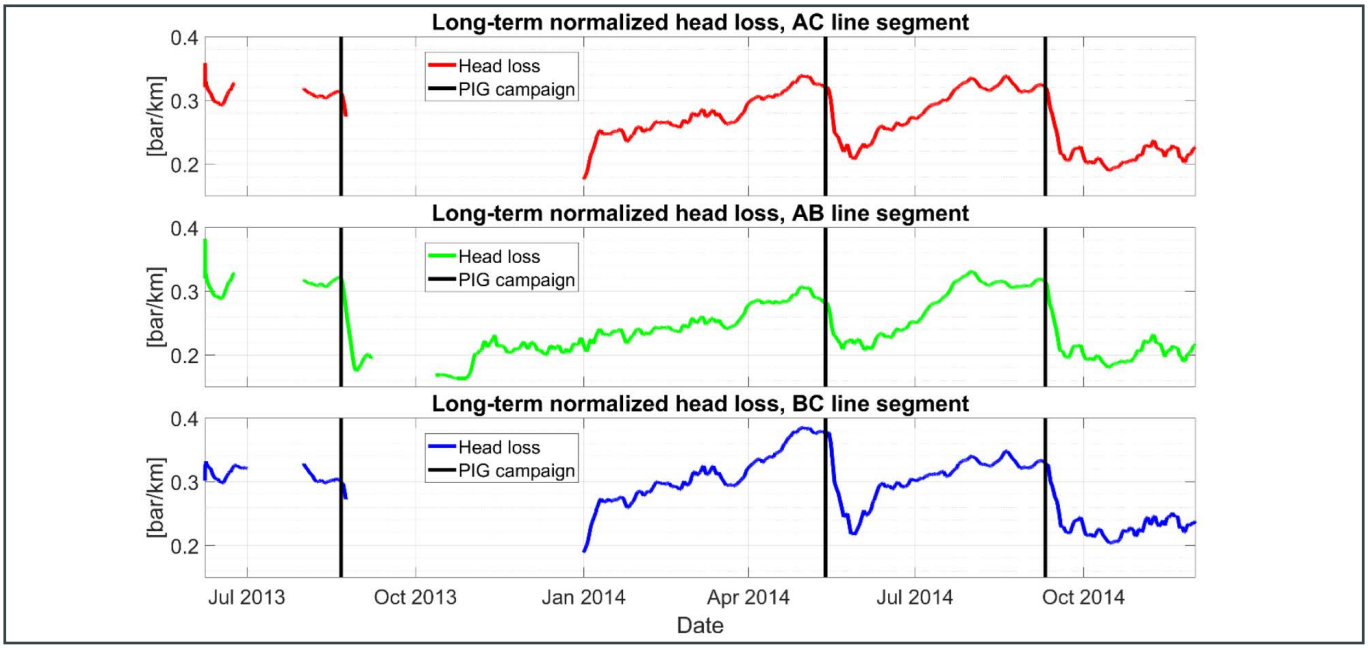


Figure 6: Normalized pressure head loss (red, green and blue lines) for three different line sections and markers (black vertical lines) indicating three main PIG campaigns [13].

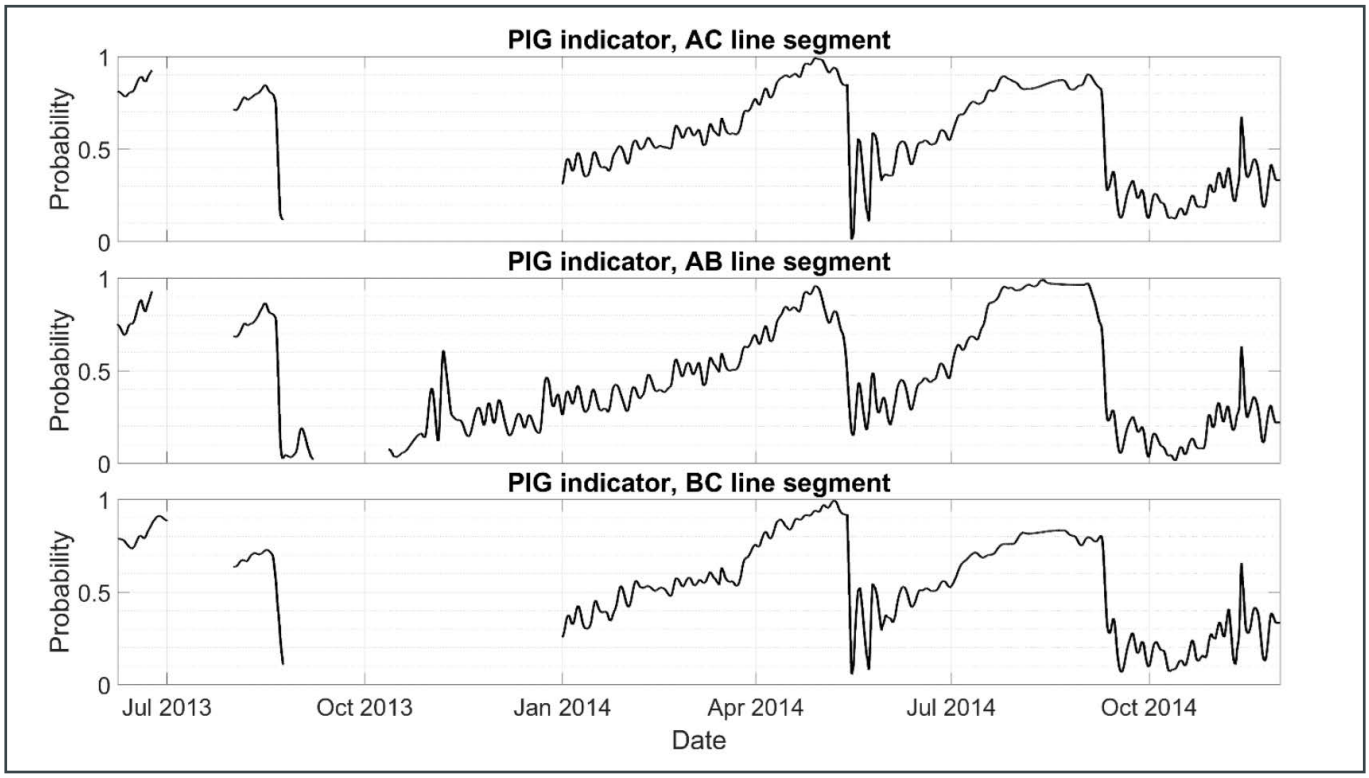


Figure 7: PIG indicators for three different line sections.

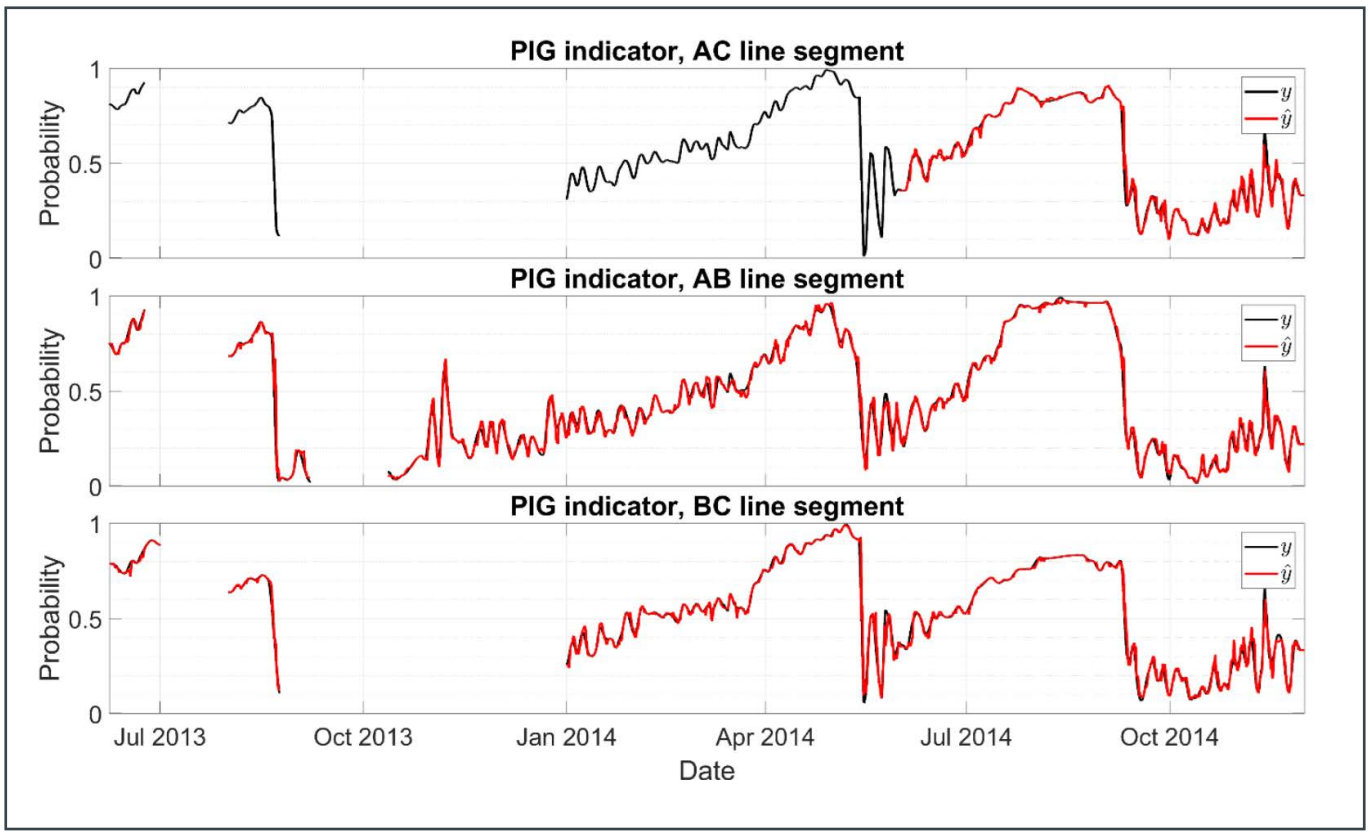


Figure 8: Ground truth (black lines) and predicted (red lines) values of the PIG indicators for three different line segments.

6. DATA-DRIVEN PIPELINE PRESSURE PROCEDURE FOR REMOTE MONITORING OF CENTRIFUGAL PUMPS

Pumping systems are an important part of oil and gas pipeline transportation facilities, and monitoring their integrity is a critical issue in terms of safety and efficiency.

As deeply described in [12], it is possible to perform a predictive maintenance by means of unsupervised machine learning technique by using the remote e-vpms® pressure time series (gathered by pressure transducers and hydrophones). This innovative solution overcomes the limitations imposed by standard approaches of local pump monitoring, which require the installation of several sensors on the pump itself; these solutions are not often applicable especially in offshore remote facilities.

The e-vpms® smart monitoring technique is validated and proven on pressure signals gathered by Eni over several years on a crude oil transportation pipeline in North Italy.

Pressure data are processed to derive a collection of rolling statistics features over appropriate window lengths; these statistical features are used as dataset to feed an unsupervised Gaussian mixture model and to get an automatic clustering. The descriptive analysis and the human interpretation of the obtained clusters show four main operational regimes:

- Regular pumping operations (high level stationary pressure noise)
- Pumps off (low level stationary pressure noise)
- Flow regulation (pressure noise variations, according to specific patterns)
- Anomalous (high amplitude peaks in features)

According to pump maintenance logs, the anomalous regime is associated to damaged roller bearing movements, which disappear after the activation of the pump backup system. One of the most interesting features of this failure phenomenon is that such anomalies in rolling statistics are detectable several days before; the smart monitoring proposed by us makes possible the implementation of an early alert system for preventive maintenance.

As for the previous case, the data used to develop the smart pump monitoring are gathered by the proprietary multi-point vibroacoustic monitoring system [10]. Each data recording station is equipped with the following instrumentation:

- A dynamic hydrophone, which measures pressure variations within the fluid. These transients propagate along the whole conduit in the form of acoustic waves;
- A static hydrophone, which provides the absolute pressure of the transported fluid.

By way of example, we show a descriptive cluster analysis performed on sensors placed at about 3.5 km from the pump group. The cluster analysis is presented in form of statistical frequency cross-plots (see Figure 9), but the same feature dataset is used for the automated clustering

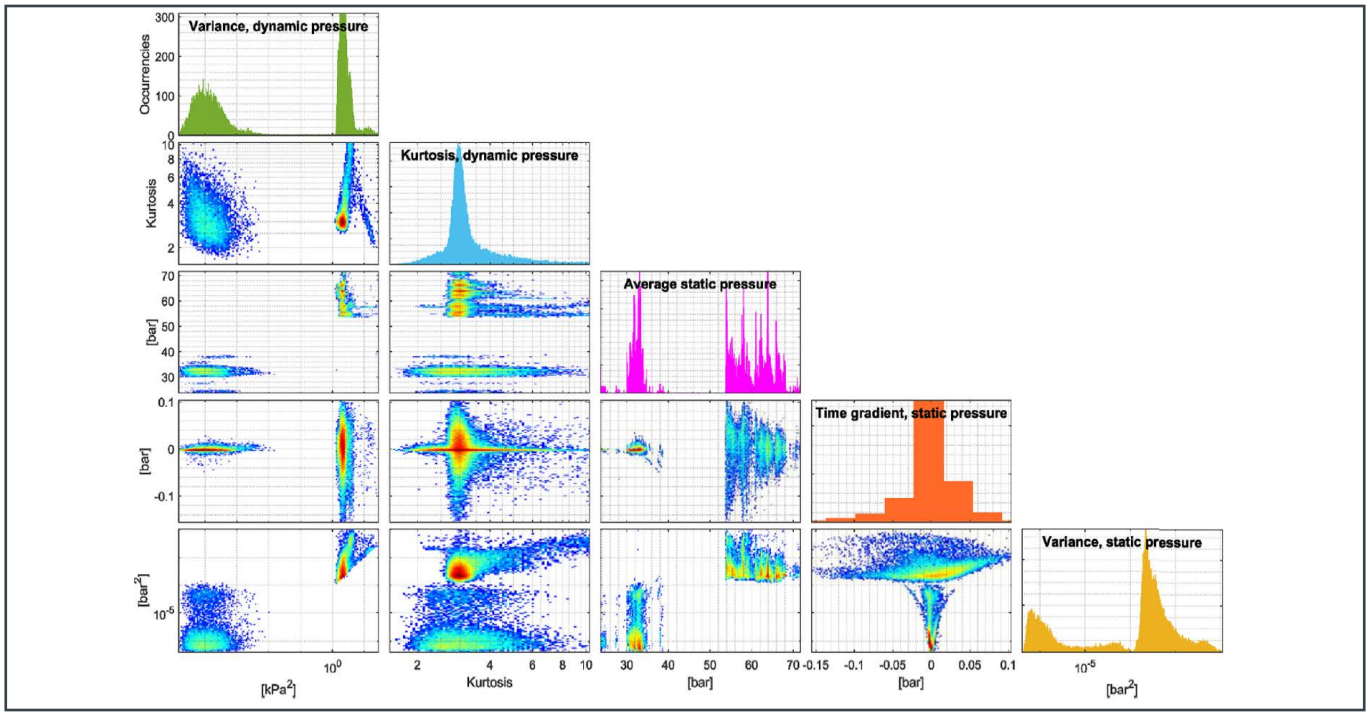


Figure 9 – Density plot between pairs of features (lower triangular part) and individual probability distributions (main diagonal) [12].

based on Gaussian mixture model. The rolling statistics (variance, average, kurtosis, time gradient) show well separated clusters, easy to detect by the automated model.

Figure 10 shows the automated cluster analysis on a dataset containing the typical behavior of healthy pumping equipment; three regimes (steady state, flow regulation and regular functioning, respectively tagged with black, blue, and green lines) are properly recognized. Instead, maintenance logs report that the pump fault occurred on February 15th, 2015. In Figure 11, the automated clustering technique is able to recognize an abnormal behavior several days before the failure events. This suggests that a precursors can be detected by the automated system.

The model implementation consists in the real-time analysis of pressures at the recording station by the Gaussian mixture model, properly trained with the large volume e-vpms® dataset. Each test data point is given as input to the model and is assigned to a specific cluster and in case of anomalous behavior an early warning is provided to the pipeline operator.

7. CONCLUSIONS

To date, the e-vpms® system is a mature technology able to cope with several issues that can undermine the asset integrity management. Although the vibroacoustic platform was born to detect and localize spillages/leakages in liquid fluids, over the years has demonstrated that can be applied

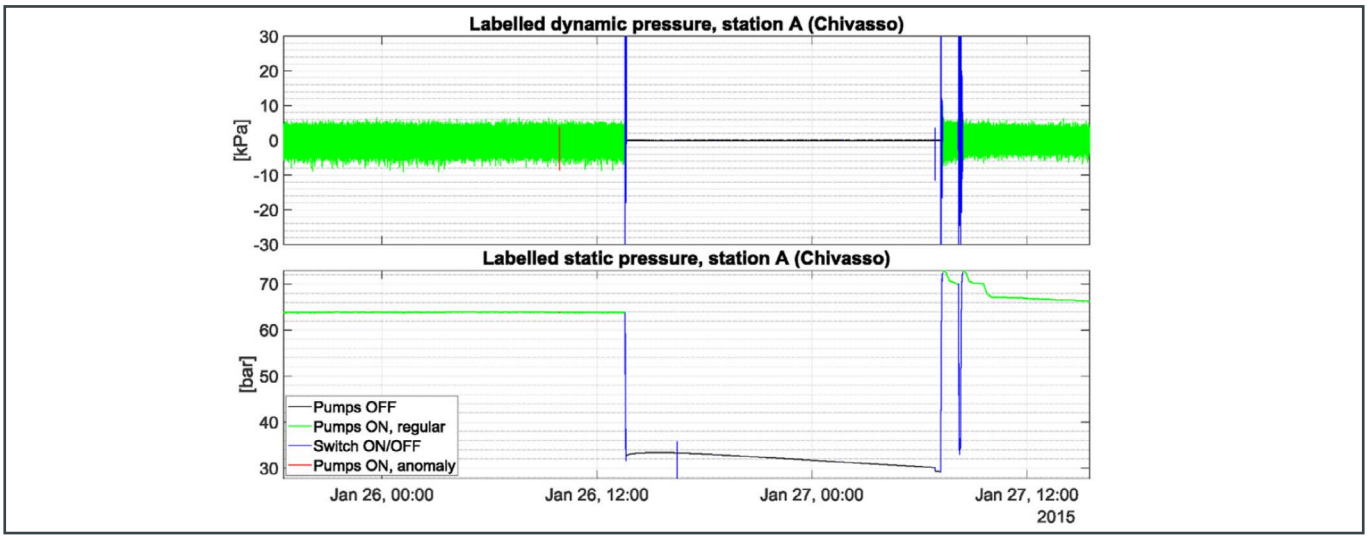


Figure 10: Density plot between pairs of features (lower triangular part) and individual probability distributions (main diagonal) [12].

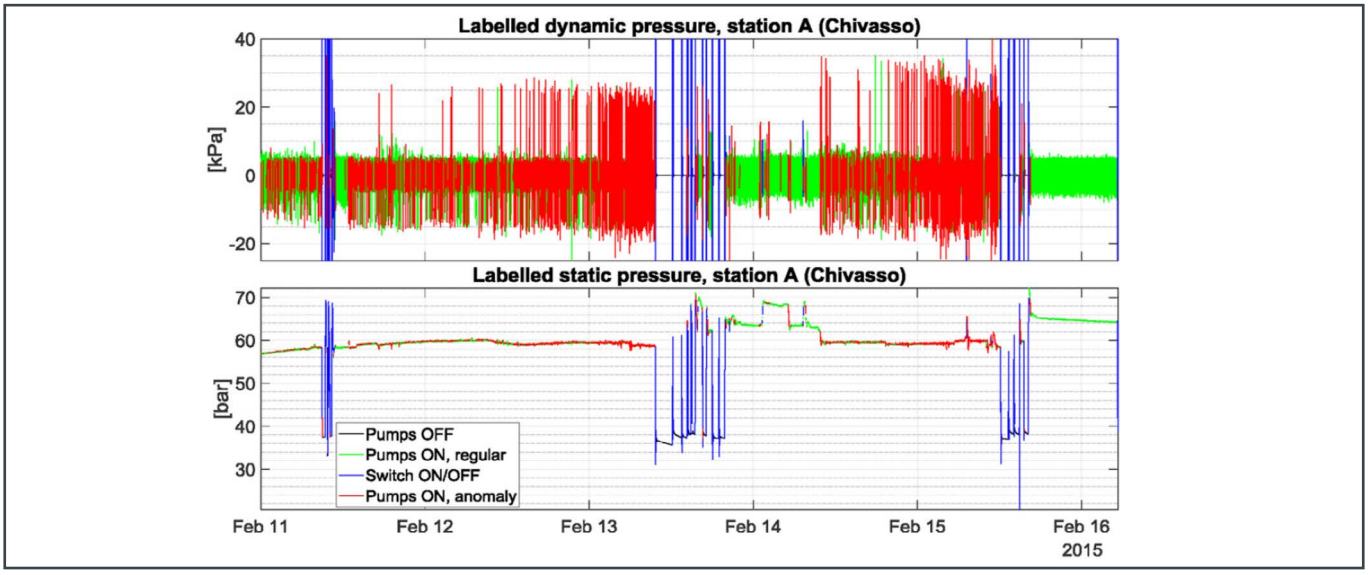


Figure 11: Density plot between pairs of features (lower triangular part) and individual probability distributions (main diagonal) [12].

with success to a wide class of Third-Party Interference phenomena, from illegal digging to impact detection. The system was accurately tested on gas scenario, demonstrating the ability to detect and localize impact events.

The e-vpms® system is evolving continuously, to promptly give technological answers to the challenging requirements of integrated asset integrity in new operative scenarios (i.e. gas transport), the monitoring system based on data-driven machine learning techniques are some of the novel features presented in this paper. Moreover, to achieve new operative scenarios an underwater sensing group has been developed to protect offshore pipelines or assets subjected to swamp inundations.

The use of data-driven machine learning techniques on e-vpms® historical and legacy static/dynamic pressure data sets break new ground. The prediction of obstruction/deposit level in pipeline and the continuous monitoring of health of pumps are two of the main application based on artificial intelligence, which can be used as predictive maintenance tools by asset operators. The system features, the proven performances of detection and event localization, the wide spectrum of operative scenarios and the novel tools based on machine learning makes the vibroacoustic technology the ideal candidate for supporting the energy company in challenging field of asset integrity management.

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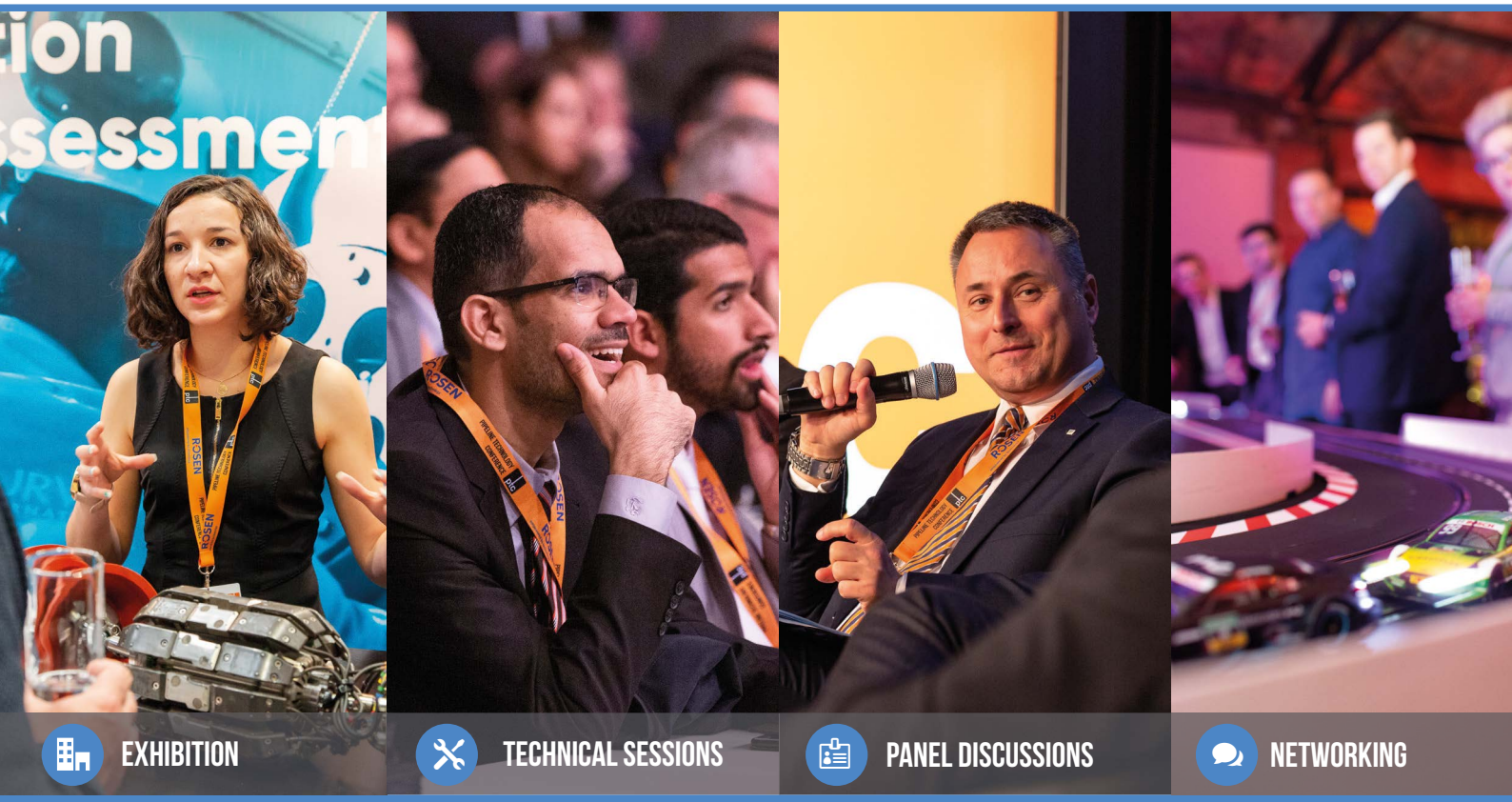

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A Case Study for Application of Nonintrusive Scraper Passage Indicators in Oil and Gas Industry

Husain Al-Muslim, Ibraheem Alsokairan > Saudi Aramco

Abstract

Pipelines are an important part of the Oil and Gas Industry, as they are the most economical method to transport different products through long distances to various consumers. These pipelines are cleaned and inspected — without interrupting their operations — using utility scrapers and smart instrument scrapers, respectively. To track the scraper tool and ensure full travel through the pipeline, scraper passage indicators (SPIs) are installed at several points along the pipeline; mainly downstream the scraper launcher, upstream the scraper receiver, and at selected points in between. Conventional mechanical SPIs involve mechanical means where a probe protrudes through a 1 to 2" branch connection into the pipeline, giving a signal when hit by the passing scraper.

This arrangement requires welding the branch to the pipe, introducing a weak point that may fail resulting in gas release or oil spills, which is a safety and environment concern, and demand costly repairs. Recently, nonintrusive scraper passage detection techniques, including magnetic and ultrasonic technologies are being deployed as an alternative where direct contact with the process is not required, to detect scraper passage and therefore the branch connection is avoided. This paper will discuss a case study of mechanical scraper detection branch failure. The failure occurred due to improper welding procedure for the sour service environment where it was installed. The recommendations after the failure included better control of welding specification, qualification and control. Furthermore, it was recommended to evaluate the nonintrusive technologies. The paper also discussed the deployment of the two technologies of the scraper passage indicator, i.e,. the magnetic based and ultrasonic based.

The paper will present the concept of each technology, followed by the challenges and advantages of each technique based on field deployment. The paper concludes with guidelines to help end-users select between the intrusive vs. nonintrusive scraper passage indicators.

1. INTRODUCTION

Pipelines are both cleaned and inspected without interrupting their operations, using utility scrapers and smart instrument scrapers, respectively. Tracking a scraper from launch to reception is an important part of a successful scraping run. To track the scraper tool and ensure its full travel through the pipeline, scraper passage indicators (SPIs) are installed at several points along the pipeline; mainly downstream the scraper launcher, upstream the scraper receiver, and at selected points in between. Conventional mechanical SPIs (Figure 1) involves mechanical means, where a probe is protruded through a 1 to 2" branch connection into the pipeline, which gives a signal when hit by the passing scraper. This arrangement requires welding the branch to the pipe, introducing a weak point that could fail, which is a safety and environment concern, and may result in costly repairs.

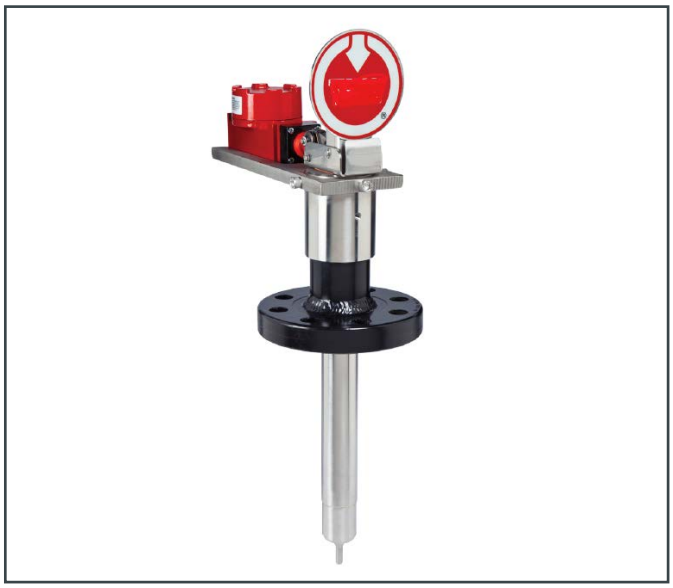

Figure 1: Conventional (Intrusive) Scraper Passage Indicator (SPI)

One example of failure occurred due to an improper welding procedure for the sour service environment, where it was installed (Figure 2 and Figure 3). The recommendations after the failure included better control of welding specification and qualification. This was a drive to evaluate new technologies of tracking scrapers. There was an increased interest in utilizing nonintrusive SPIs (Figure 4), due to the clear advantage of no hydrocarbon release, compared to conventional intrusive detection methods. In this paper, a comparison will be made between these technologies to illustrate the benefits of using nonintrusive types.

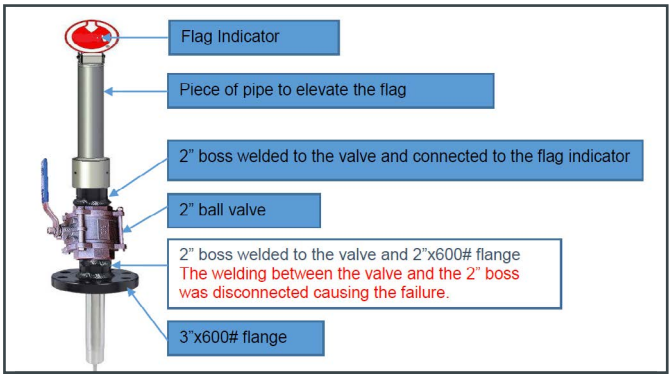

Figure 2: Conventional SPI Elements

This will be followed with an assessment of the different nonintrusive detection systems available; passive acoustic, active ultrasonic and magnetic nonintrusive units, including why Saudi Aramco chose to adapt the magnetic detection type alone as an alternative to conventional detection in its facilities. The materials provided herein are not intended to favor any specific vendor for the technology. References from vendors herein are only used for illustrative purposes.

Figure 3: Fracture at the valve to flange weld

Figure 4. NonIntrusive SPI Mounted on a Pipe

CHALLENGES WITH INTRUSIVE SPIS

Conventional Scraper Passage Indicators (SPIs) are the standard selection in most pipelines and have been used successfully for decades. Still, many challenges are presented by utilizing the probe, including the probe getting stuck or damaged after being hit by a passing scraper, which cannot be fixed without cost to the operation. Table 1 lists the main challenges with intrusive SPIs.

COMPARISON BETWEEN SPIS, INTRUSIVE VS. NONINTRUSIVE

In the past decade, a lot of advancement took place in the nonintrusive SPIs technologies. These units provide many advantages that can help minimize usage of conventional passage indicators, including:

- Fail-safe installation where no intrusion to the pipeline is required.
- Eliminating the need for welding and associated specification and qualification.

Table 2 below elaborates more on the differences between the intrusive vs. the nonintrusive SPIs.

TYPES OF NONINTRUSIVE SIGNALING PASSAGE INDICATORS (NI SPIS)

All nonintrusive units are similar in the way they are mounted on the pipe and do not require specialized installation to commission them online. Three types were identified that are available in the market; passive acoustic, active ultrasonic and magnetic units. The advantages and limitations of each type are detailed in the following sections.

1. PASSIVE ACOUSTIC

Passive acoustic nonintrusive indicators are very effective in acoustically quiet areas for both gas and liquid service. Once the unit memorizes both pipeline and passing scraper acoustic signals, the unit is ready to work. Unfortunately, the need to memorize signals of the pipelines and scraper, leads to many limitations:

Challenge	Consequence	Remedy
1. Weld failure for branch connection for scraper detector probe	Product leak, operation disruption, and ultimate shutdown of the pipeline to repair the leak.	Utilize butt welds instead of threaded or socket welding joints OR incorporate NonIntrusive Scraper Passage Indicator (NI SPI).
2. Damaged/Stuck scraper detection probe	Impair scraping operations if passage cannot be determined. May require product flow isolation before it can be repaired.	Utilize SPIs that can be removed from the line while in service OR Utilize NI SPI.
3. Need to install a branch to insert the probe to the pipeline.	Inherent impact to the pipeline integrity due to the resulting localized stresses on the pipeline.	Utilize NI SPI.

Table 1: Summary of challenges with intrusive SPIs

SPI Type	Conventional (Intrusive)	Nonintrusive
Pipe Intrusion	Yes	No
Hot Work	Yes	No
NDE Requirement	Yes	No
Installation Time	Few Days	One Hour
Manpower	Multiple crews for welding, NDE, Coordination, etc.	Only one crew (two workers) for placement.
Mobility	Require repeating installation	Require only fit up of strands and proper instrument mounting plate size.
Safety	Installation effects pipe integrity and failure results in a leak.	Fail safe

Table 2: Comparison between intrusive vs. the nonintrusive SPIs

- The unit is susceptible to faulty indication if there are other acoustic noise sources nearby, e.g., inside a running plant. Also, it is not suitable to locate it near frequently operated equiment, for example, a pipeline's operating control valve.
- Changing the pipeline or scraper type will trigger the need to recalibrate the unit to capture the signals again. This adds cost and time on its setup every time a change is made.
- The pipeline may undergo operational changes, upgrades, or corrosion. These may impact the acoustic indicators ability to trigger leading to missing recording of scraper passage events.

Due to these limitations, this technology did not qualify for field deployment.

2. ACTIVE ULTRASONIC

These units detects scraper passage by simply detecting the change in bouncing back of the pulsing ultrasonic wave. While it is online, the reading gives the internal diameter of the pipe. When a scraper passes through, the unit detects the bouncing wave from the scraper surface, which give a smaller reading than the pipe diameter as shown in Figure 5. The new reading becomes the trigger to log a new event for the scraper passage.
This capability can be expanded for detection of the exact location of the scraper and measurement of rough debris profile collected in front of the scraper after it reaches the receiving station. As it measures the internal diameter of the pipe, it can detect buildup of wax and changes to pipe diameter, due to corrosion and erosion issues. It does not need calibration nor any special retrofit to the selected scraper, which makes it highly reliable in liquid service.

Active ultrasonic technology has significant limitations:

- It cannot be used in gas or multiphase flow service pipelines. Also, if the liquid flowline has air pockets or solids, faulty readings may occur.
- The unit typically needs to be mounted either on the minor barrel, or on a straight section of the pipeline to ensure its effectiveness.
- When mounted on the pipe, direct coupling is required between the instrument sensor and the pipe service. A form of grease is applied at the sensor tip touching the pipe to ensure full contact. Even insulation needs to be cut and removed. Therefore, it is not practical for hot pipes.

Due to these limitations, this technology was not prioritized for field deployment.

3. MAGNETIC

The magnetic NI SPI was found to be preferable as an alternative to the conventional intrusive type. This technology has no major limitations when compared to the previous two types. This device indicates passage by measuring the change in magnetic flux due to a fitted magnet on the scraper. The device is not affected by change in scraper type, pipe roughness or local acoustic noise. Moreover, it does not matter if the pipe is coated or insulated. Furthermore, the instrument has no location restriction. Another feature is that the threshold to trigger the unit needs to be adjusted to a certain value. This value should not be too low —causing a faulty trigger due to surrounding magnetic noise; nor should the value be too high — resulting in missing the passing scraper due to the magnetic flux not reaching the threshold limit. Due to the apparent advantages of this technology, it was deployed in the field succesfully. Nevertheless, the user needs to be aware about its setup requirements, to ensure that the threshold value is properly selected. Also, it is recommended to have equispaced circumferentially vendor-fitted magnets on the scraper itself, to ensure that the vendor warrants that the product has the right magnets to be used with the device. Attaching an axial magnet to the rear of the scraper introduces the risk of losing the magnet, due to the possibility of hitting the sides of the pipe during turns within elbows or tees.

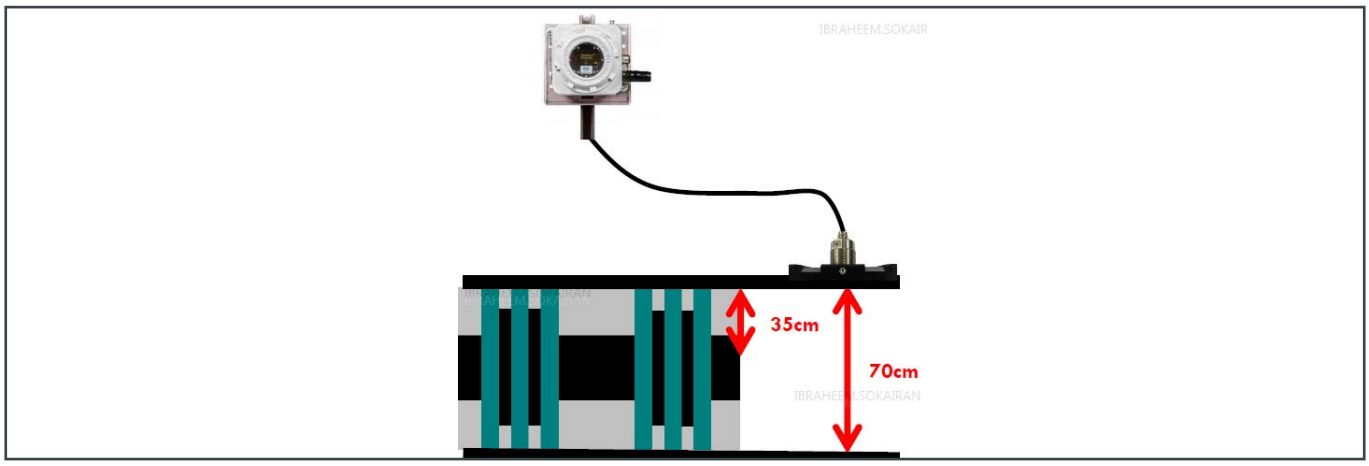

Figure 5: Depth measurement as detected by the active ultrasonic sensor

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CONCLUSION AND RECOMMENDATIONS

NI SPIs can be used successfully as an alternative to conventional (intrusive) SPIs. They have the clear advantage of avoiding release of hydrocarbons, due to failure of the weld attachments of the intrusive SPIs. Understanding of the functionality of the specific NI SPIs, and developing user-experience by working closely with the vendor, is important for successful application of SPIs.

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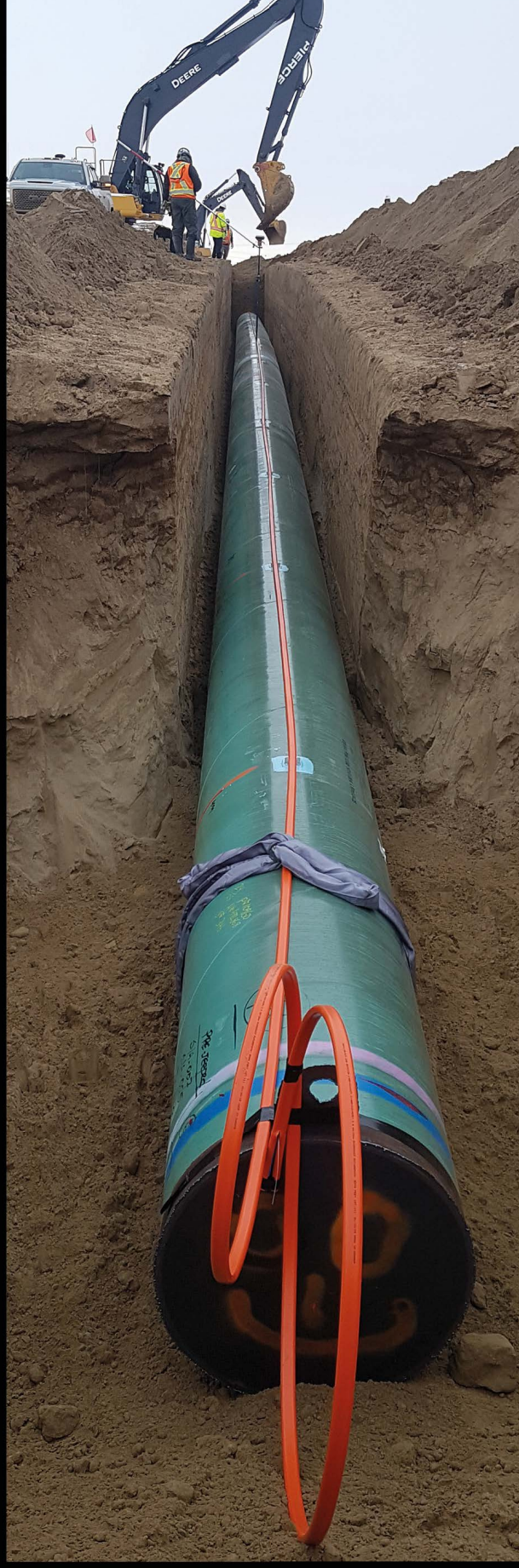

Early Leak Detection and TPI Monitoring for Pipelines – Presenting a Practical Experience with Distributed Optical Fiber Sensing

Edward Tapanes, Li Xiaotong > Fibersonics Inc.

Abstract

The Oil & Gas pipeline industry is facing a very serious challenge in assuring spill and accident-free operations of pipeline infrastructure, which is distributed across many thousands of miles in both remote and populated areas. In recent years, however, the occurrences of high-profile spills and incidents have spiked, further escalating the safety concerns. [1] [2] For example, the San Bruno, California, explosion or the huge area of contamination by crude oil in Michigan's Kalamazoo River (a 4.3 million liter crude oil spill from a pipeline that is estimated to have cost $820 million to clean up). In Alberta, Canada, spills have occurred on average twice daily since 1975, at times resulting in high-profile large gas explosions and oil spills. [3] To help meet the challenge of a zero-incident target, the Oil & Gas industry must improve its range of technologies and ability to monitor their systems for safety in real-time – permanently and distributed along the length of the pipeline network. [4] One particularly promising technology involves the use of distributed optical fiber sensing cables. Over the past twenty years, several first and second-generation monitoring technologies were developed using fiber optic sensing cables for detection and location of leaks and third-party interference (TPI) events involving physical disturbance to the pipeline. [4] [5] [6]

To address the urgent need of the Oil & Gas industry for improved technology for securing and monitoring pipelines, Fibersonics has developed and patented a new generation of fiber optic technology – the technology is named "Long Ranger™". This technology can be very effective in the prevention of oil spills and/or gas explosions due to its unique ability to utilize an ordinary optical fiber cable to both detect, locate and classify vibrations caused by physical activity (such as TPI), while simultaneously monitoring for early-stage leaks, along the entire length of the pipeline in real-time. Over the past 5 years, Fibersonics has been working together with their regional partner in the P.R. China to implement several pipeline monitoring systems with local operators. This paper briefly presents some of the cases of implementing this technology on operational pipelines in P.R. China.

1. BACKGROUND

According to the analysis and statistics of pipeline accidents for the past 50 years, the main types of incidents involving the safe operation of oil and gas pipelines are leakage, TPI, blockages, displacement, and geological disasters, etc. The causes of these events are varied, and the resulting losses can often be huge. [2] [3] In order to maintain a safe and efficient operation, it is necessary to carry out real-time monitoring of operational pipelines to detect, find, analyze and treat all kinds of hazardous events as early as possible.

At present, manufacturers and scientific research institutions around the world have developed a variety of equipment to detect pipeline leaks and TPI. There is a vast multitude of products in the market. [4] Distributed optical fiber sensors are one promising type of technology to have emerged over the past 20 years. [6] Several first and second-generation monitoring technologies were developed using fiber optic sensing cables for detection and location of leaks and TPI events involving physical disturbance to the pipeline. [4] Earlier versions of this technology were able to monitor pipelines for many miles, but there were some significant drawbacks. These technologies may be broadly classified as follows:

1. First-generation locating interferometers, otherwise known as transmissive distributed fiber-optic vibration sensing (DVS) systems. [7] [8] [9] [10] [11] While providing unprecedented levels of sensitivity and locating, these systems proved to be prone to a significant level of nuisance alarming and lack of sensitivity at low frequencies. This resulted in poor detection of excavating machinery. In addition, the need for a stable temperature environment for the equipment made it difficult and expensive to operate with consistent and reliable results. It's expensive. A minimum cost for the DVS system is $150,000 USD for a 40km run of cable, plus the need for an expensive temperature-controlled rack to house the system. Any loss of control of temperature, or hard physical contact with the cable, will destabilize the polarization of the light, thus rendering the locating part of the system highly unreliable. It is limited in frequency bandwidth, usually to 10-20kHz. However, the leaks of interest for gas occur around 80kHz and oil/water around 40kHz when the leak is small. [12] This kind of detection is at a late-stage leak, heading for catastrophic failure.
2. Coherent-OTDR or Distributed Acoustic Sensor (DAS) technology is a second generation of distributed interferometer that operates in a reflective (Rayleigh backscatter) configuration. [13] [14] The technology has a significantly lower frequency bandwidth, usually up to a maximum range of 1-10kHz. This is a useful frequency range for large, gross movements/acoustics, but it is also where nearly all environmental nuisance alarms are generated. Also, this technology is not capable of early leak detection since gas leaks occur around 80kHz and oil leaks around 40kHz [12], well beyond the 1-10 kHz maximum bandwidth limitations of DAS systems. The cable for this technology needs to be installed quite deeply, otherwise, it will generate many nuisance alarms. In areas of high background noise, i.e., road crossings, highways, near rail lines, populated areas, etc., it will be susceptible to significant nuisance alarming. It is also critical to understand that, since DAS systems are based on an optical time-domain reflectometer (OTDR) architecture, their resolution and frequency bandwidth diminishes significantly and rapidly with distance. For a 1-2km long system, they can achieve 1m locating resolution and 10kHz frequency bandwidth. However, for a 40-50km system, they would achieve 20m locating resolution and only a 1-2kHz bandwidth at best, rendering DAS systems unsuitable for long pipelines and most early leak detection applications.
3. Distributed temperature sensing (DTS) [15] is another fiber optic sensing technology marketed for leak detection in pipelines. DTS technologies measure static or very low-frequency changes in temperature or strain, which is particularly useful for geotechnical applications (ground movement/settling, soil stability/erosion, pipeline deformation, integrity monitoring, etc.) and the indirect detection of leaks by measurement of temperature differentials (via the Joule-Thomson effect). However, this technology cannot be used effectively for TPI nor acoustic (or ultrasonic) detection of leaks. While initially, it appears simple and effective, particularly when an existing fiber-optic communications cable can be used, the correct installation of the sensor to detect leaks could be very difficult and expensive. Its performance, especially the detection time, depends on ground conditions, the correct placement of the optical fiber cable relative to the pipeline, as well as, on the leak dynamics of the pipeline contents. Actually, owing to their complimentary capabilities, DTS and DVS technologies are highly synergistic, rather than competing. The synergy is not so strong with DAS, however, as they both operate in the low frequency domain, so there is no capability or benefit of detecting early-stage, ultrasonic pin-hole leaks. In spite of this, a combined detection system will become more complex and significantly increase the cost.

In conclusion, conventional DVS and DAS technologies have limited frequency bandwidth, which does not allow the direct detection of small (pin-hole) leaks occurring on an operational pipeline. They are expensive to implement and limited to only detecting TPI events and ground

movements from major leaks, offering little potential for a combined early TPI warning and leak detection system.

To address the urgent need of the Oil & Gas industry in monitoring pipelines, Fibersonics developed and patented a new generation of fiber optic technology – the technology is named "Long Ranger™". This technology can be very effective in the prevention of oil spills and/or gas explosions due to its unique ability to detect, locate, and classify (ultra-high frequency bandwidth) vibrations caused by physical activity (such as TPI), while simultaneously monitoring for early-stage leaks, along the entire length of the pipeline in real-time.

2. LONG RANGER™ INTRUSION DETECTION SYSTEM

The Long Ranger™ Intrusion Detection System provides an automated pipeline monitoring solution for prevention and corrective control of the most undesirable and dangerous events that can occur to pipelines, such as leaks and spills, as well as tapping and TPI. The Long Ranger™ operates in real-time and should be considered as a preventative monitoring system since it has the potential to detect the early stages of these events without the cable being directly/physically impacted or damaged. The Long Ranger™ systems can also be potentially effective in the detection of dynamic geo-hazard movements caused by landslides, earthquakes or floods, or excavating activity (by equipment or hand) anywhere within the vicinity of a pipeline, and in some cases before the excavating operation.

The Long Ranger™ technology is based on the fact that light waves propagating in a fiber optic cable are extremely sensitive to any movement, vibration, and acoustic-type noise that may be generated in its nearby environment. These disturbances create microscopic stresses or vibrations in the surrounding soil that are mechanically coupled into the buried cable. These forces on the cable in turn generate highly-sensitive optical phase changes within the fibers. The amount of optical phase change is determined by the strength of the disturbance. Amplitude (strength) and frequencies, as well as several other parameters, are detected. Proprietary software is used to interpret and classify these changes to determine if the signal is a true event or standard ambient/environmental conditions. When a security/safety event is detected, an appropriate alarm is triggered and then transmitted to the mapping software (graphical user interface).

The core Long Ranger™ technology acts as a continuous microphone designed to "monitor" over a quasi-DC to

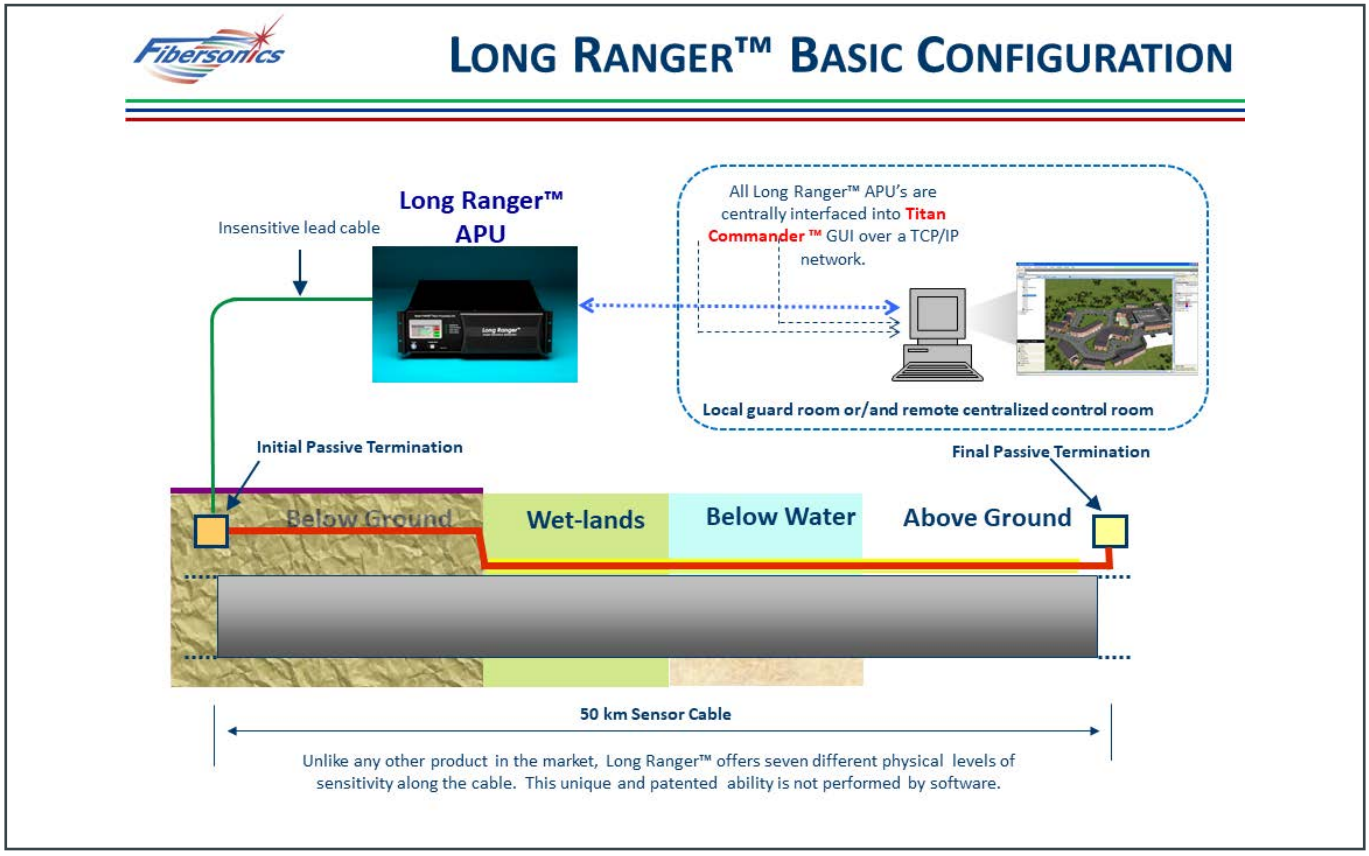

Figure 1: Long Ranger™ System Configuration.

500kHz bandwidth, to very distinctive frequencies generated by TPI and leak events, while discriminating between normal and ambient conditions. TPI events occur largely in the low-frequency range of quasi-DC to 2kHz. Leaks of interest occur around 80kHz for gas pipelines and around 40kHz for oil/water pipelines, when the leak is small (pinhole leak). [12] As the hole increases in size, the frequency lowers to a point where audible sound is made and physical vibrations can be felt.

All other currently available fiber optic-based technologies are limited to a 10-20kHz range, which makes it impossible to detect early, small leaks of pipelines. The Long Ranger™ technology, with its 500kHz bandwidth, is uniquely designed for early leak detection (before audible sounds and physical vibrations are generated). This is by far the widest frequency bandwidth available for any distributed fiber optic sensing technology and is the world's first distributed fiber optic ultrasonic sensor. Consequently, this technology is capable of monitoring far beyond the normal frequency bandwidth of conventional DVS or DAS systems.

Another significant differentiating advantage of this transmissive, hybrid interferometer technology is that its frequency response and location resolution/accuracy are not degraded with increasing distance, unlike conventional DAS systems.

The system consists of an optical fiber cable installed in close proximity, above or near the pipeline, and a dedicated, custom-built controller installed near the pipeline section to be monitored. The controller consists of ultra-high-speed FPGA and DSP microprocessors, electro-optical hardware, and signal processing firmware. The system can be remotely monitored via Fibersonics' Command and Control software Titan Commander™.

Incorporating the Long Ranger™ system into a pipeline's operational control center can provide automated pipeline safety monitoring. The system is designed to quickly and accurately detect and locate any anomaly or breach on the system at any point over the entire length of a pipeline and its networks, enabling the ability to include automation feedback to the SCADA system. The basic system configuration is shown in Figure 1.

For long-haul pipeline applications, additional controllers can be placed every 100km of cable, usually coinciding with compression or pump stations along the pipeline, as shown in Figure 2.

Due to a higher signal to noise (SNR) and a continuous-wave (CW) laser signal, the system can process detected signals at very high speeds, without the need for signal averaging or the need to wait for pulses or echoes to disappear (inherent in DTS and DAS systems). It takes only 10ms for an event to be processed. Furthermore, the system can detect a large number of multi-target dynamic events at the same time.

With the use of high-performance and high-speed device processing, the sensor has a very wide frequency response range from 3Hz to 500kHz, covering the spectrum range of all incidents of interest, including TPI, pigging, leaks,

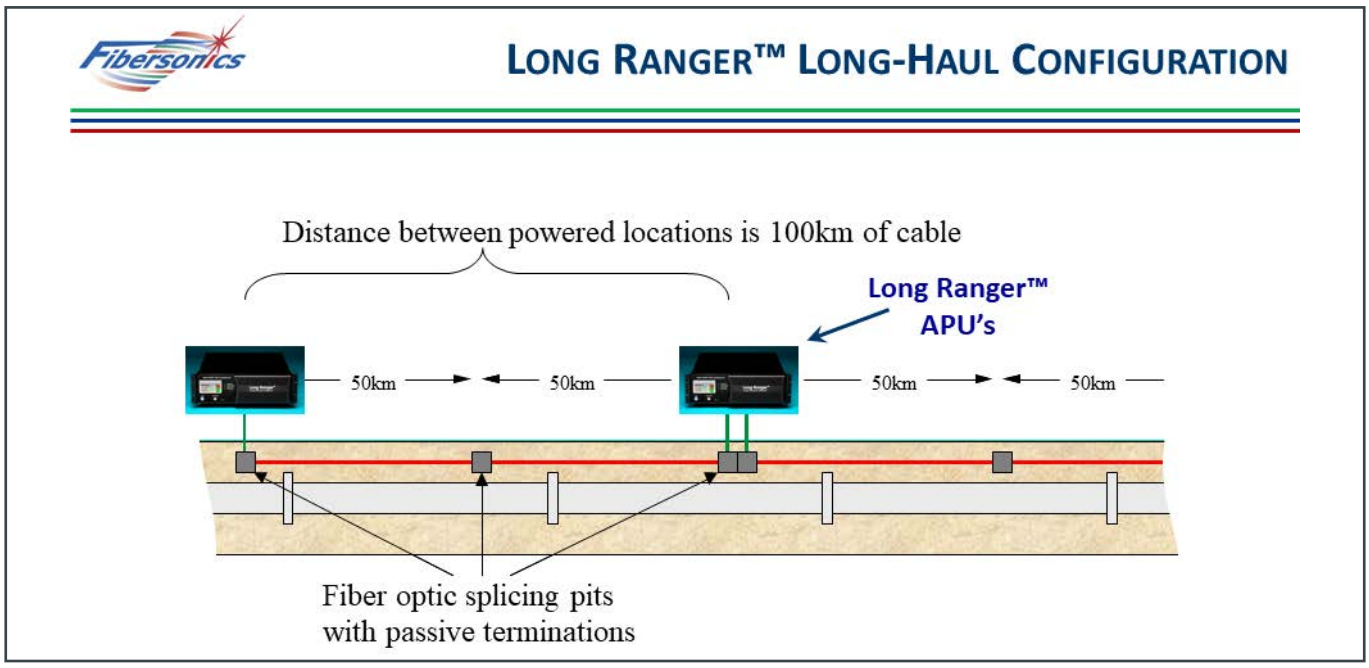

Figure 2: Long Ranger™ Long-Haul Configuration.

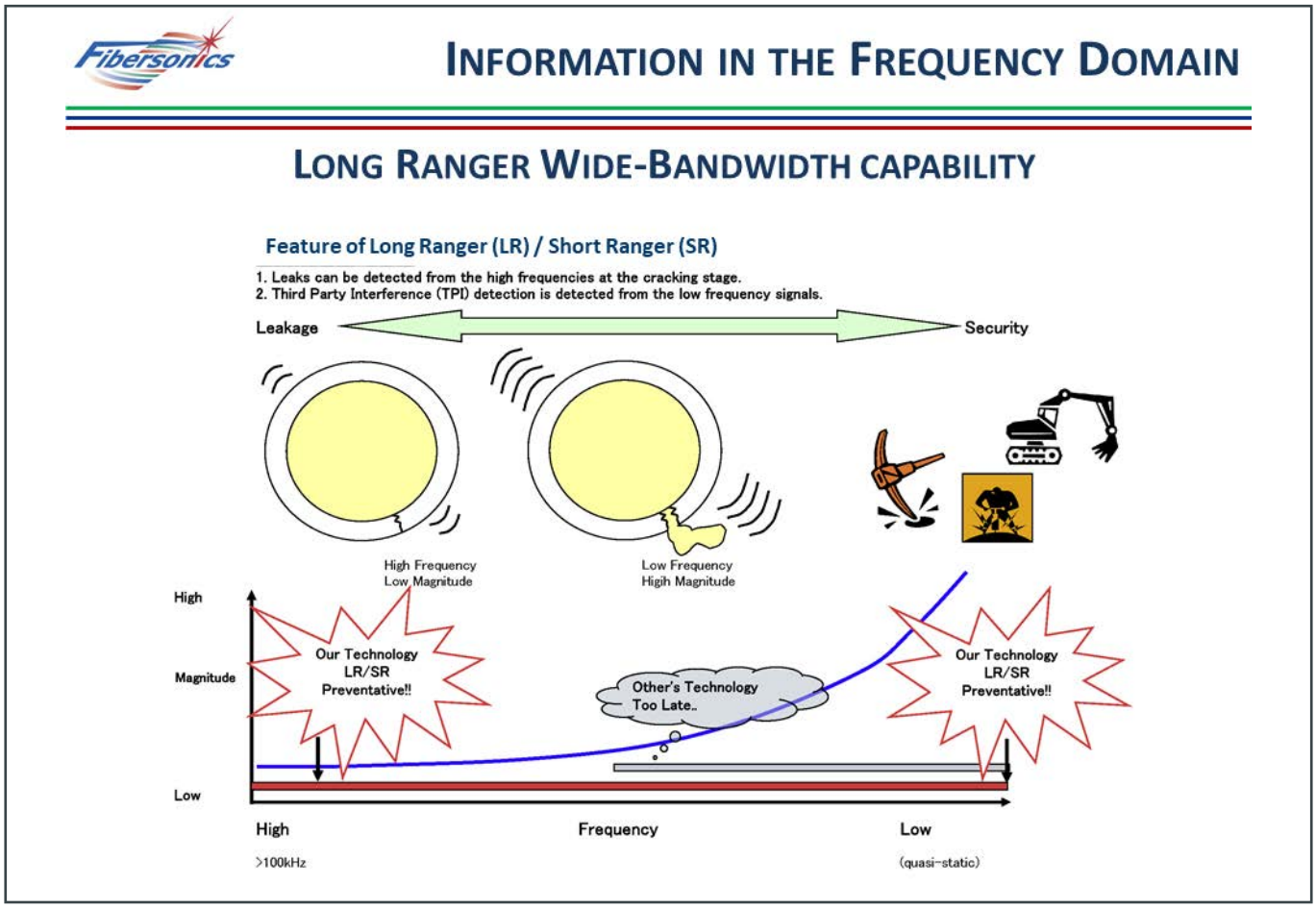

Figure 3: Incidents of interest in the Frequency Domain.

blockages, and pipeline displacement. Figure 3 illustrates the relevance of the ultra-wide frequency bandwidth to incidents of interest.

A multi-parameter, behavior pattern analysis method is used to analyze the signals of various events, including leaking, TPI, pigging, and blockages. It can effectively identify and locate the various types of events of interest while reducing the nuisance alarm rate. Many companies with distributed fiber optic sensing products claim to have developed intelligent databases of event "signatures" that they detect and classify alarms from. However, because so many uncontrolled project/site factors impact on the characteristics of a signal (ie., soil type, rock content, moisture content, temperature, distance from cable, cable design, etc.), we believe their method is unreliable since the signatures will be different from site to site.

Fibersonics has developed a different method for event classification. The proprietary methodology, known as the Unified Algorithms (UA), are a structured, layered approach to event classification and alarming, consisting of algorithms that look at staged data sequentially, applying user-defined parameters and algorithms that maximize the probability of detection (PD) while minimizing the nuisance alarm rate (NAR). We are having great success with this approach. Table (1) illustrates how factors are interrelated in the behavior pattern analysis.

3. VALIDATION OF THE CORE TECHNOLOGY

The core Long Ranger™ technology was developed between the years of 2010-2014. During the years of 2013-2016, the system underwent considerable independent field testing and validation on a number of test and operational pipelines. The system has also undergone independent testing in a Joint Industry Program (JIP) leak detection program. Figures (4) to (9) illustrate some of the results from the independent studies.

In Figure 5, the 0.125in orifice leak is seen at a frequency of 30kHz for a pipeline pressure of 119psi. As shown in Figure (6), when the pressure was increased to 558psi, the detected frequency increased to approximately 120kHz. At 1,063psi, the detected frequency increased to approximately 230kHz. All of these ultra-high frequencies are impossible to detect without an ultrasonic capability.

Events	Amplitude	Energy	Duration	Repetition	Frequency	Location
Hand tools	*	*	*	*	*	**
Backhoe	***	***	**	**	**	***
HDD	**	**	***	***	*	**
Blockage	**	**	***	***	**	***
Leak	*	**	***	***	***	**
Pipe Displacement	*	**	***	**	*	**
...	...	...	...	...	...	...

Table 1: Multi-parameter, behavior pattern analysis.

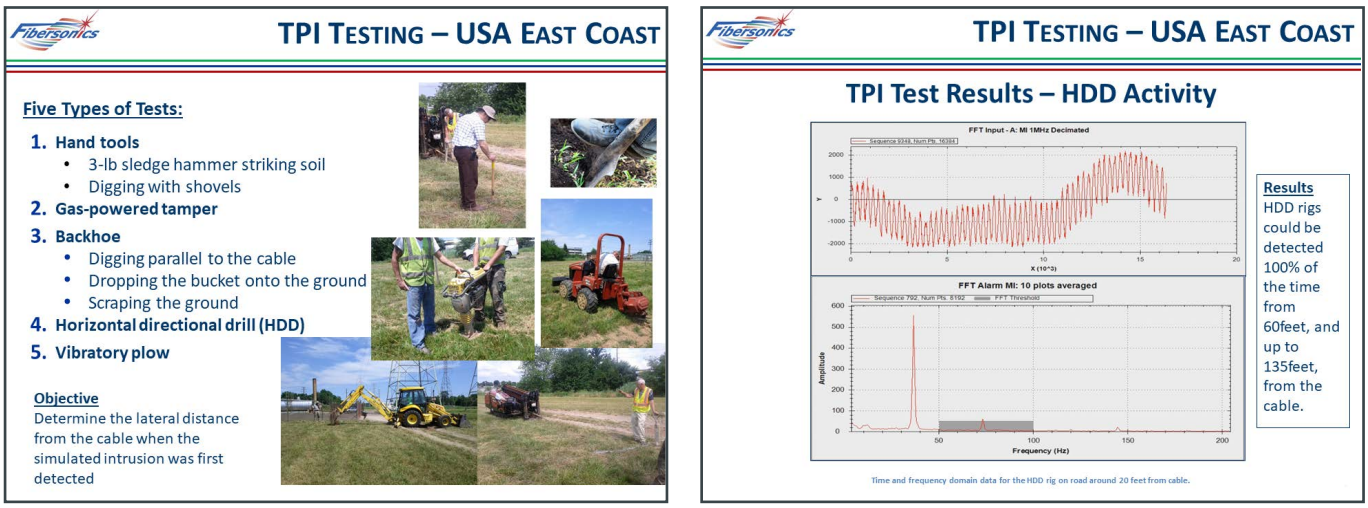

Figure 4: Independent TPI Validation in 2013 with Northeast Gas Association, NYSearch [16]. Various types of equipment were tested. Result shown is for HDD detection.

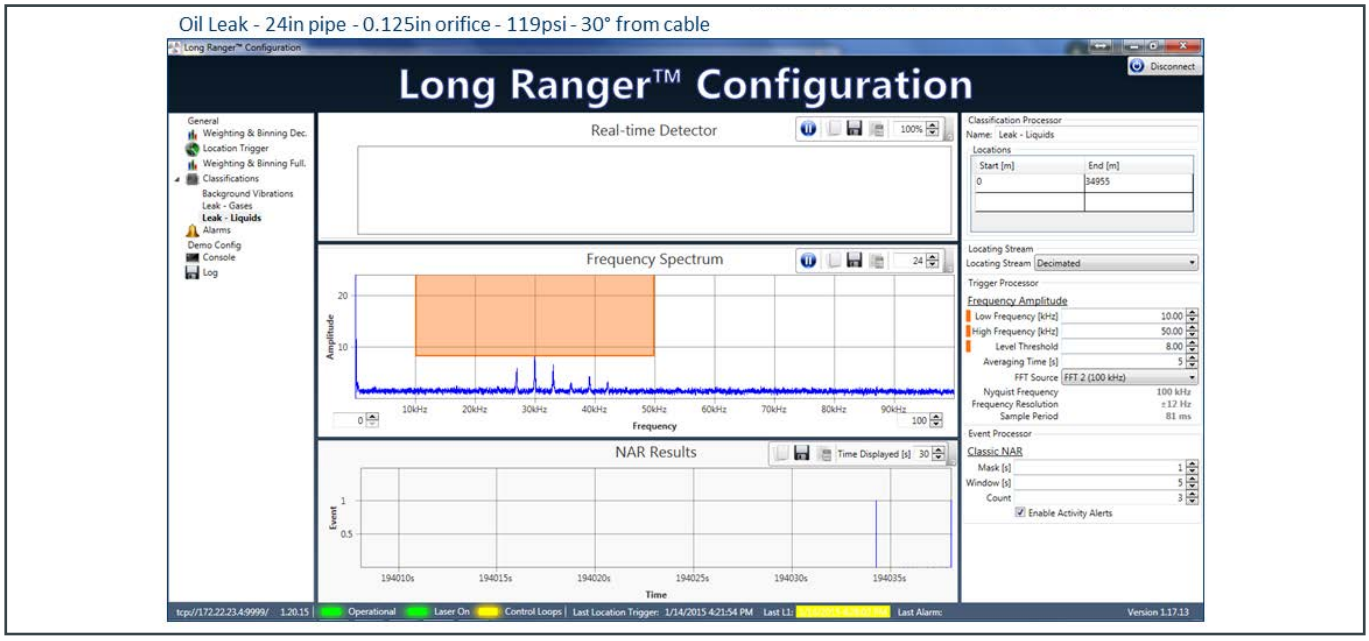

Figure 5: Result from Independent JIP Leak Study in 2015.

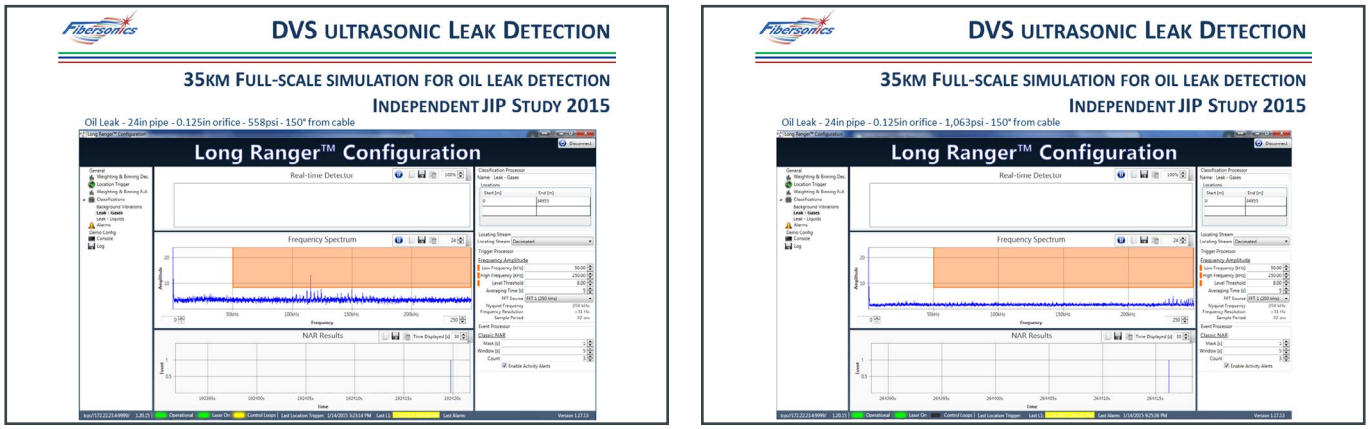

Figure 6: Results from Independent JIP Leak Study in 2015 at higher pressure.

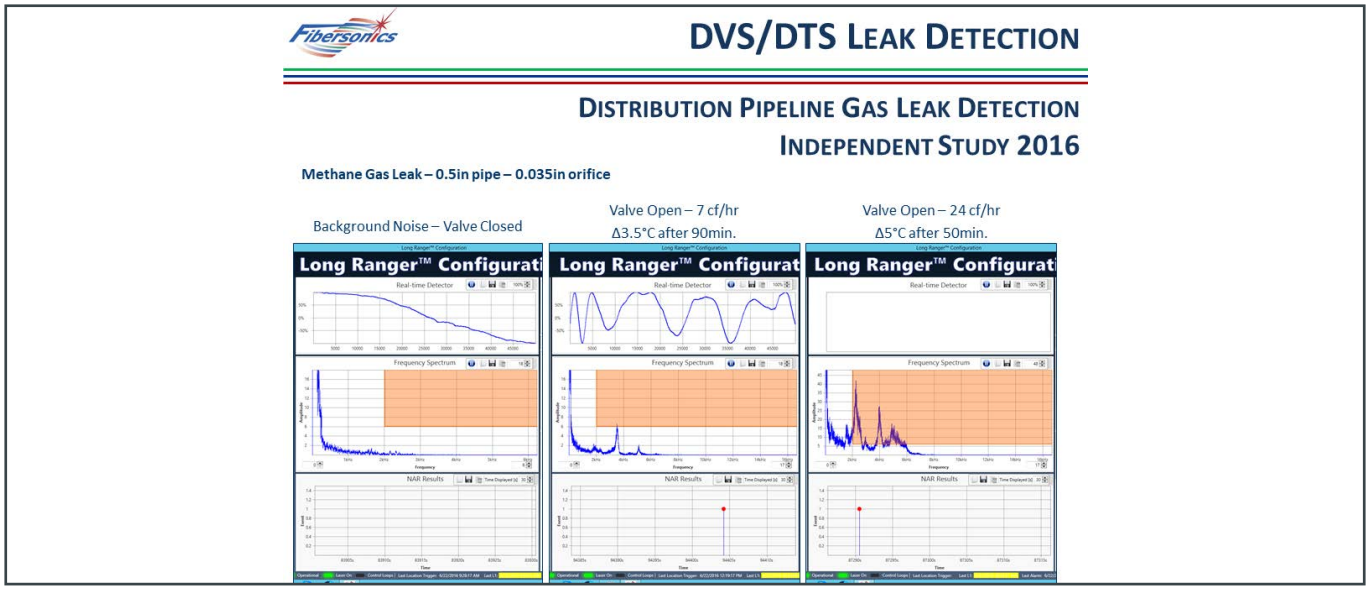

Figure 7: Result from Independent Leak Validation in 2016.

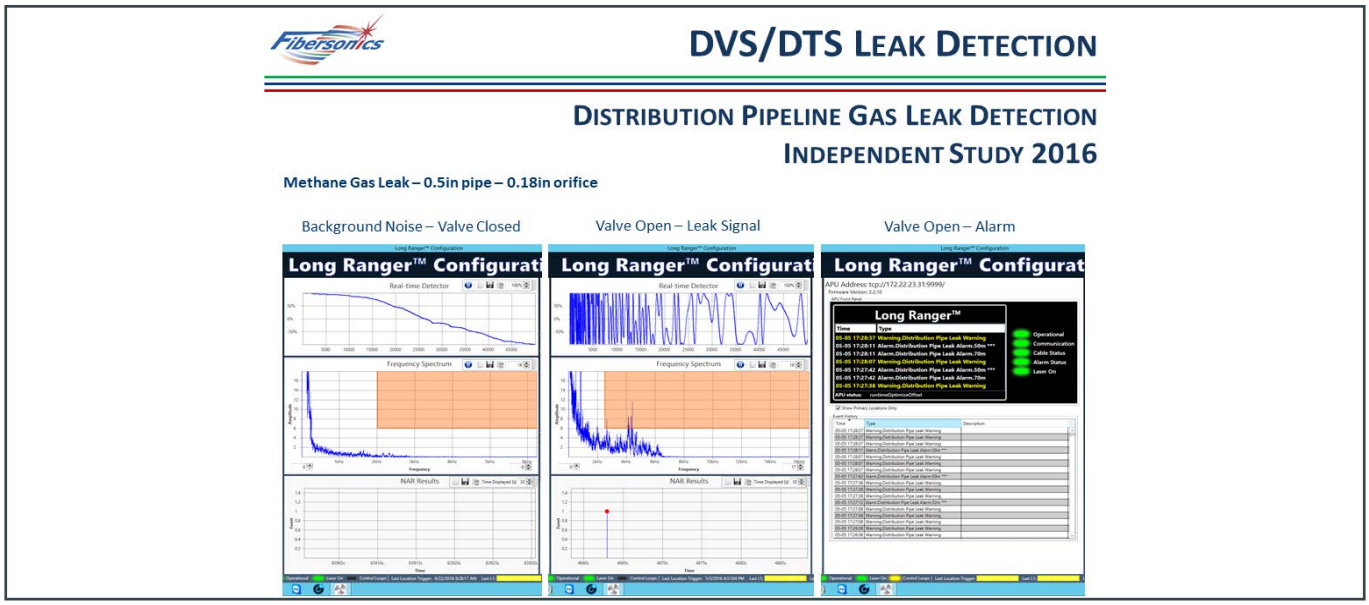

Figure 8: Result from Independent Leak Validation in 2016.

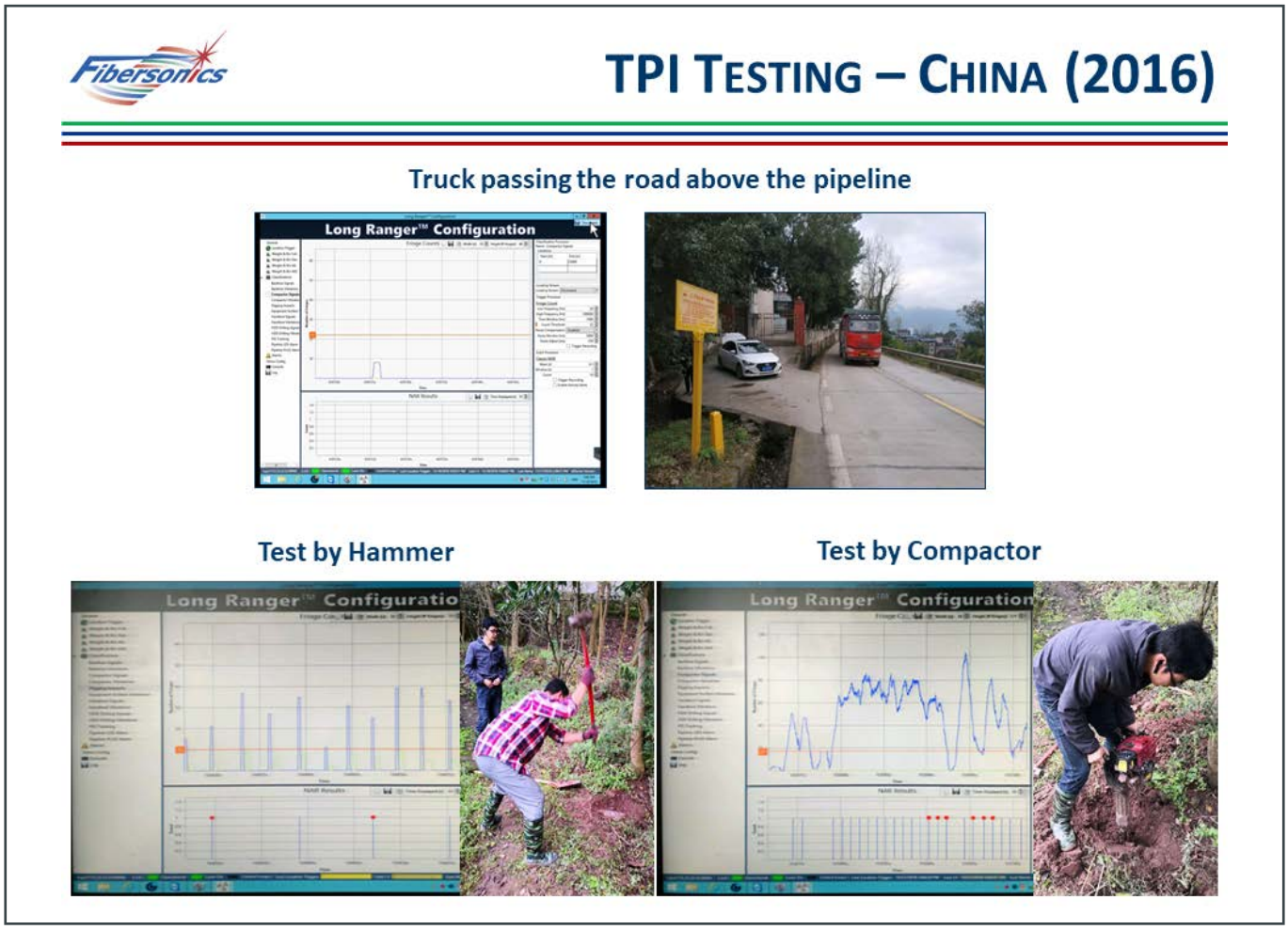

Figure 9: Result from independent TPI Validation in P.R. China in 2016.

4. PROJECT EXPERIENCE IN P.R. CHINA

Since the launch of Long Ranger™ solution in 2015, dozens of successful projects have been implemented around the world, including in the United States, South America, the Middle East, Europe, Asia, and P.R. of China. In 2014, the P.R. China made a commitment to invest significantly in this area. [17] To date, we have provided operators in the P.R. China with a complete set of pipeline leakage and safety early warning solutions. This opportunity has enabled us to obtain considerable amounts of field data and experience in different environments and field conditions. We would like to share some of our experience, as follows.

CASE NO.1, IN THE NORTH OF P.R.CHINA:

Pipeline conditions: gas, diameter 1,016mm, working pressure 5MPa, buried depth 1.5-2m. Geological conditions: flat area, clay, and sandy soil, the water content of soil 15%. Fiber cable: communications cable, loose tube, 12 cores, buried 0.5-2m to the side of the pipeline.

There are a lot of peaks in the displayed screenshot. The peaks have a narrow width, low amplitude, and appear at intervals. Each peak represents one digging activity. It fits logically with the action characteristics of manual digging activities.

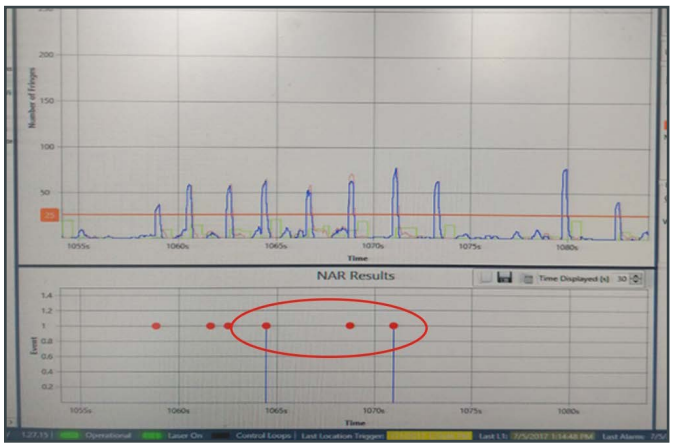

Figure 10: Hand tools activity.

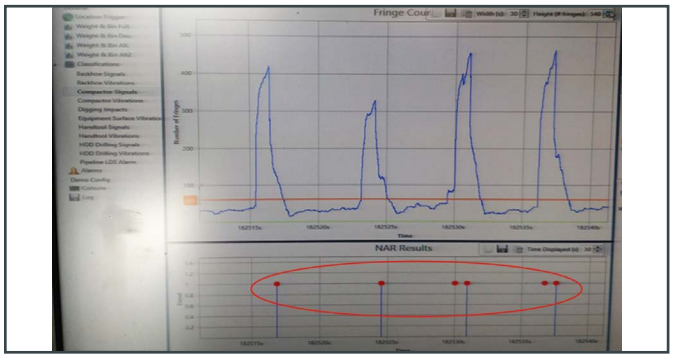

Figure 11: Backhoe activity

The peaks in the displayed screenshot have a wider (time) width, higher amplitude, and longer gaps compared with Figure 10. There is an alarm at each peak. It fits logically with the action characteristics of backhoe digging activities.

Mechanical activities are shown in the following figures.

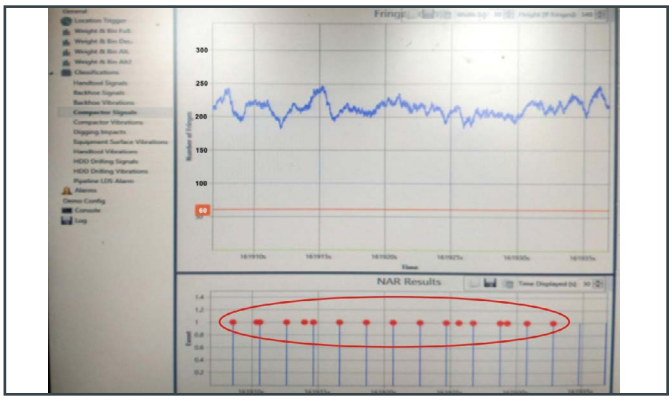

Figure 12: Rock drill

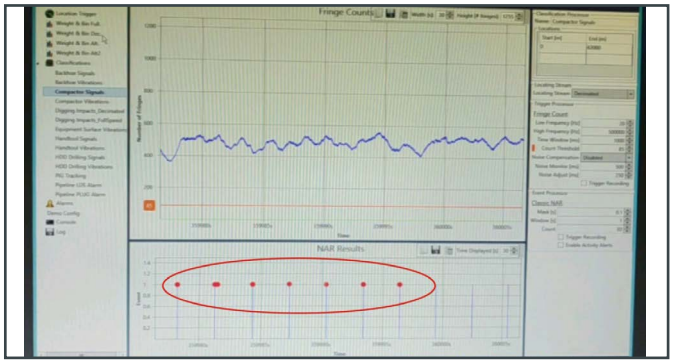

Figure 13: HDD Activity

Figures 12 and 13 illustrate a different kind of response. There are no transient peaks in the signals since these represent and are detected as continuous signals. Also, the amplitude of the continuous signal is high, meaning it is a strong and constant activity. Accordingly, the alarms occur continuously. This is a typical signal generated by a rotating type of machine, operating at constant high speed. As can be seen, they have similar waveforms. However, the difference between them can be seen clearly in the frequency content of their signals, as they rotate at different speeds.

CASE NO.2, IN THE NORTH OF P.R.CHINA:

Pipeline conditions: gas, diameter 1,016mm, working pressure 6MPa, buried depth 1.5-2m. Geological conditions: flat area, clay, and sandy soil, the water content of soil 15%. Fiber cable: communications cable, loose tube, 24 cores, buried 0.5-2m to the side of the pipeline.

a) Air Compressor operating on the pipeline:

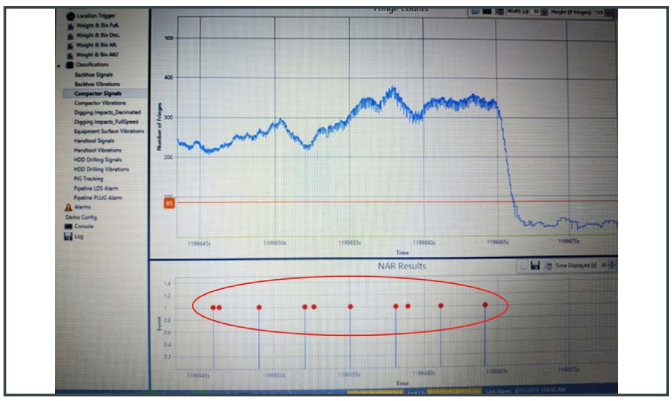

Figure 14: The acoustic echo.

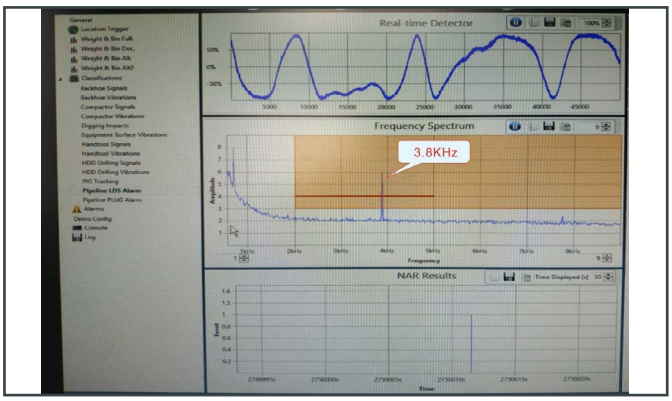

Figure 15: The frequency spectrum

Figure 14 illustrates the signal generated by the internal acoustic echo of the air compressor. Figure 15 displays the frequency spectrum of the signal. In Figure 14, the signal can be seen to be strong (high amplitude) and continuous. Also, the alarms occur continuously. It is clear that the signal suddenly drops, representing that the air compressor operation was stopped after reaching the predetermined pressure. Figure 15 illustrates the corresponding frequency spectrum, clearly showing a strong vibration frequency

during operation of 3.8kHz. In this scenario, the system can be programmed to not alarm on such types of signal/ event characteristics, if desired.

b) Pipeline maintenance:

Maintenance work is often carried out in the pipeline operation. Often, personnel use grinding equipment at the pipeline weld joints. Figure 16 further below displays a site photo of such a scenario. Figure 17 illustrates the signals and alarms generated in the Long Ranger™ system during this maintenance operation. There are two very large peaks seen in Figure 17, each peak has a wide width and a vibratory type of oscillation is evident riding on the main signal peaks. There is also a long interval between the two peaks. Figure 17 shows the operating characteristics of the grinding equipment operated by the maintenance personnel.

Figure 16: Site Maintenance

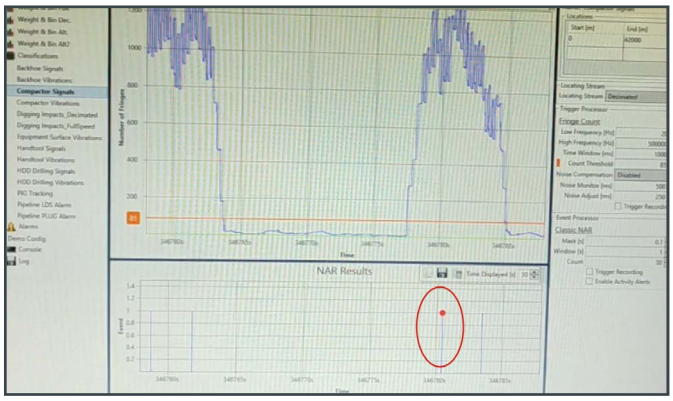

Figure 17: Grinding Signals

c) Pipeline displacement:

On one occasion, a very strange type of signal was detected, as illustrated below in Figure 18. As you can be seen, the signal waveform is continuous and wavy, with relatively large amplitude but very low frequency. By measurement, the frequency is approximately 10Hz. This alarm activity lasted about two minutes at position 5km. After physically checking at the position of the alarm, at the corresponding position on the pipeline, we found that there was several tons of construction rubbish that had been dumped directly on top of the pipeline. Also, fresh truck tire tracks were found at the site. This confirmed that the alarm was caused by the ground/pipe deformation caused by the pressure of a heavy object placed over the pipeline. When the trucks were unloading the rubbish, the weight of the rubbish fell slowly, producing continuous pressure on the ground, due to which the pipeline experienced a weak elastic displacement. However, when the dumping process was completed, the pipe returned to its normal position.

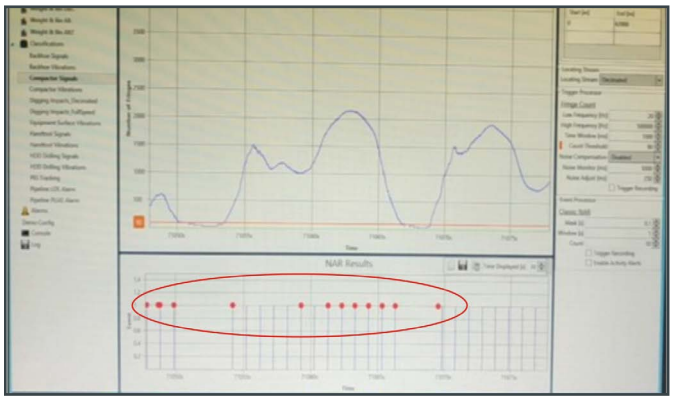

Figure 18: Pipeline displacement signal.

The whole process lasted only about 2 minutes and was detected by the sensor completely. This signal characteristic is highly consistent with the above events.

CASE NO.3, IN THE NORTH OF P.R.CHINA:

Pipeline conditions: gas, diameter 1,219mm, working pressure 8MPa, buried depth 4m. Geological conditions: hilly area, sandy soil, the water content of soil 10%. Fiber cable: communications cable, loose tube, 24 cores, cable in conduit, buried at 5 o'clock position 0.5m from the pipe.

a) Blockage in the pipeline:

Sometimes, ice blockages (plugs) occur in the oil and gas pipeline during operation. When the blockage occurs, the inner diameter of the pipe effectively becomes smaller and the local gas velocity increases at the blockage area. Under the influence of the high pressure, it causes the vibration (like a turbulence noise) of the pipeline. The vibration signals leak out through the metal tube wall and are detected by the optical fiber cable, generating alarms by the system. Figures 19 to 22 illustrate the system response to one such incident that was detected.

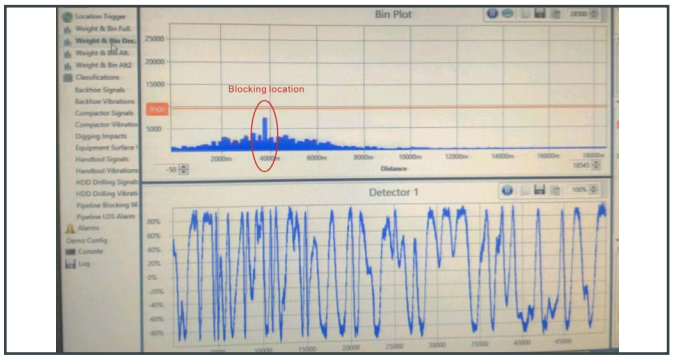

Figure 19: Blockage signal (before treatment).

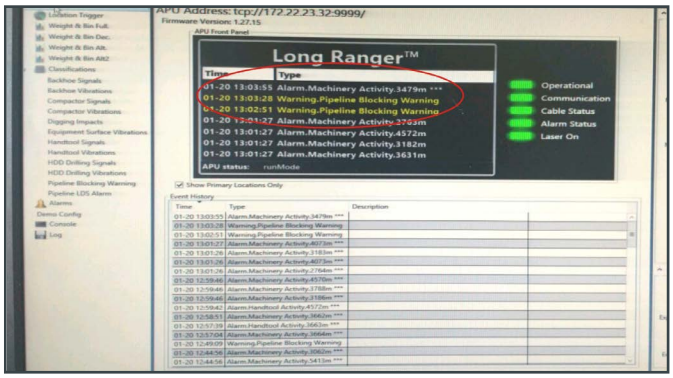

Figure 20: Blockage alarm and location

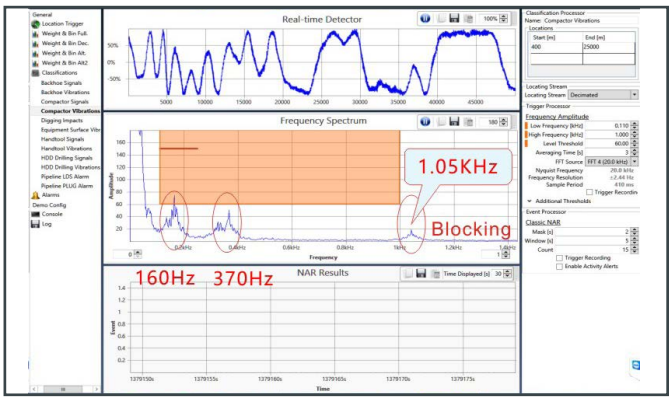

Figure 21: The blockage spectrum.

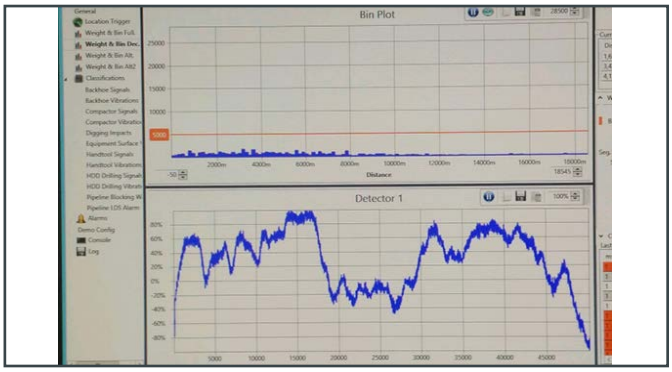

Figure 22: The blockage cleared (after treatment).

Figure 19 illustrates that the maximum amplitude is located at the center of the pipe blockage area, at position 3,479m, and spreads to the both sides for thousands of meters. By analyzing the spectrum of Figure 21, the vibration signals have three frequency components. The component at 160Hz is background noise, 370Hz is the friction signal between the gas and pipeline and 1.05kHz is the high-frequency vibration signal caused by the blockage (plug) in the pipeline. With the increase of blockage, the inner diameter of the pipe and the vibration frequency will both change. The more blockage, the higher the frequency of the vibration. By observing the changes, the development trend of the pipeline blockage can be monitored in real-time, while providing technical support for maintenance and emergency teams.

When this activity was first detected and alarmed by the Long Ranger™ system, a 30m long trench was carefully dug over the pipeline at the determined location of 3,479m. When the depth of the ditch reached about 2m, the personnel in the trench found that the ground under their feet was trembling distinctly. Once the pipeline was exposed, it was possible for them to feel a strong vibration on the pipeline surface.

The position with the maximum vibration was determined to be the location of the blockage, and this position was only 10m from where the Long Ranger™ system had alarmed. Afterward, with the continuous injection of methanol into the pipeline, the development trend of the pipeline blockage was monitored continuously using the Long Ranger™ system. After 72 hours, the system showed that the pipeline blockage became significantly weaker, as illustrated in Figure 22. The operator of the pipeline was impressed with the performance of the system, which had saved them countless hours and cost in this scenario.

b) Leaking detection:

With long-distance pipelines, normally, there is a pressure station along the line every certain distance, which has a relief port inside. When the pressure in the line exceeds a certain limitation, the relief port can be opened to reduce the pressure in the main pipeline. The relief port is connected to the main pipeline by a smaller diameter pipe. When the discharge occurs, the discharged gas will produce friction with the nozzle and the air, causing a high frequency (turbulent) vibration. The vibration frequency is so high that only a high-frequency hissing can be heard by humans. Sometimes, the frequency is even too high for humans to hear. The Long Ranger™ system, however, can detect the vibration easily thanks to its ultrasonic frequency bandwidth and then generate alarms, if desired. One such scenario was detected during the blockage event that was described above. The system detected the discharge several times, even though the port was located 150m

away from the main pipeline. Figure 23 illustrates the discharge signal and frequency spectrum. The discharge vibration frequency was at 42.4kHz.

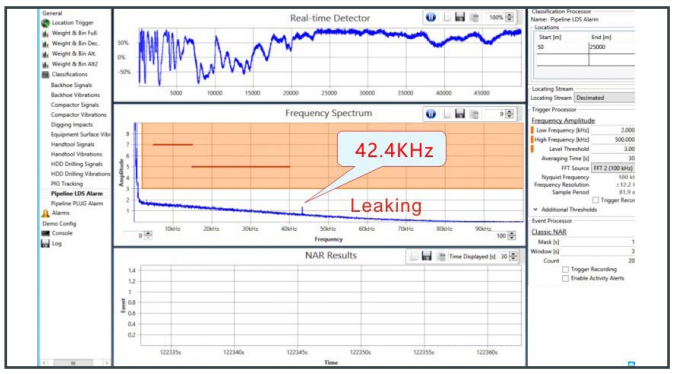

Figure 23: Discharge frequency spectrum.

5. SUMMARY

The Long Ranger™ technology and system have been briefly presented. It is distinguished by the following main operational capabilities:

1. It operates over an extremely broad frequency range (3Hz to 500kHz) and is the world's first and only distributed ultrasonic detector. As a result, it can detect and locate many difficult or complex types of signals, directly and much earlier than other cable-based systems.
2. It is effective at discriminating different patterns of interferences and environmental/traffic noises from potentially dangerous operational events/threats. By reducing nuisance alarms, it alarms for events of true concern with an increased degree of confidence and thus allows for automatic response mechanisms with a practical degree of responsibility.
3. It offers completely uniform sensitivity and performance over the entire length of the optical fiber cable. Most other systems are non-uniform and their performance diminishes with distance.

This technology can be very effective in the prevention of oil spills and/or gas explosions due to its unique ability to utilize an ordinary optical fiber cable to both detect, locate and classify vibrations caused by physical activity (such as TPI), while simultaneously monitoring for early-stage leaks, along the entire length of the pipeline in real-time.

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Selection Criteria for Pipeline Leak Detection Methods using Distributed Fiber Optic Sensing

Alex de Joode > AP Sensing

Abstract

Distributed Fiber Optic Sensing (DFOS) has expanded current pipeline leak detection technologies (LDS), providing a significant set of new capabilities. This paper briefly reviews the main types of DFOS technologies used for pipeline monitoring. There are different types of Distributed Acoustic Sensing (DAS) and Distributed Temperature Sensing (DTS) that make LDS selection somewhat complex for a specific application.

The DFOS LDS selection process must take into consideration the correlation between the "leak signature" of a particular pipeline and the LDS methods provided by different DFOS technologies. DFOS LDS can play a significant role in modern pipeline leak management, improving performance, and regulatory compliance.

1. INTRODUCTION

Special optical technologies and software can transform fiber optic cables into sensing cables, solving the main challenge of monitoring long assets such as pipelines, power cables, tunnels, and train lines. With a fiber optic sensor cable, the sensing capability is always close to the asset where a potential leak event or external threat occurs. **Figure 1** illustrates Distributed Fiber Optic Sensing (DFOS) technology. An interrogator sends a laser pulse through the fiber optic cable and the associated backscattered light travels back to the interrogator. The backscattered light can be analyzed at certain wavelengths, bringing back acoustic/vibration and thermal information.

Distributed Fiber Optic Sensing (DFOS) is better known as an external pipeline leak detection method that detects effects on the external environment of the pipeline caused by leaks. These effects include changes in temperature, noise, or vibration. However, leak-related **events occurring inside the pipe can also be sensed**, like Negative Pressure Waves (NPW) and other internal acoustic signals. Similarly, DFOS detects internal events including PIG/scrapper tracking, liquid accumulations in gas pipelines, slugs, and flow constrictions caused by waxing, solid accumulations, or hydrate formation.

Today the use of **DFOS**-based pipeline **Leak Detection Software** is well established, covering a wide variety of pipeline applications. LDS systems using data provided by **Distributed Acoustic Sensing (DAS)** and **Distributed Temperature Sensing (DTS)** are already installed in hundreds of projects across tens of thousands of kilometers of pipelines.

In this paper, we discuss the criteria for the selection of the best DFOS-based LDS technology, taking into consideration the following:

- **Suitability of DFOS** technologies for pipeline applications
- **DFOS** role in Pipeline Leak Detection Management
- How pipeline characteristics affect **leak signature** characteristics
- **DAS and DTS** leak detection methods and performance
- Additional **DFOS** functionalities

2. DFOS TECHNOLOGIES

DFOS technologies use laser interrogators which can present risks to eyes or skin, and fire/explosive hazards. Lasers are classified according to the laser power in four classes and subclasses; **Laser Class 1** is the safest, while Class 3B poses risks to eyes and skin, also presenting a fire hazard in certain conditions. For many different reasons, **Laser Class 1** is recommended for pipeline applications.

There are many different DFOS technologies in the market addressing specific applications. Pipeline leak detection tends to focus on the detection of thermal and acoustic signatures. In the first stage of the selection process, the

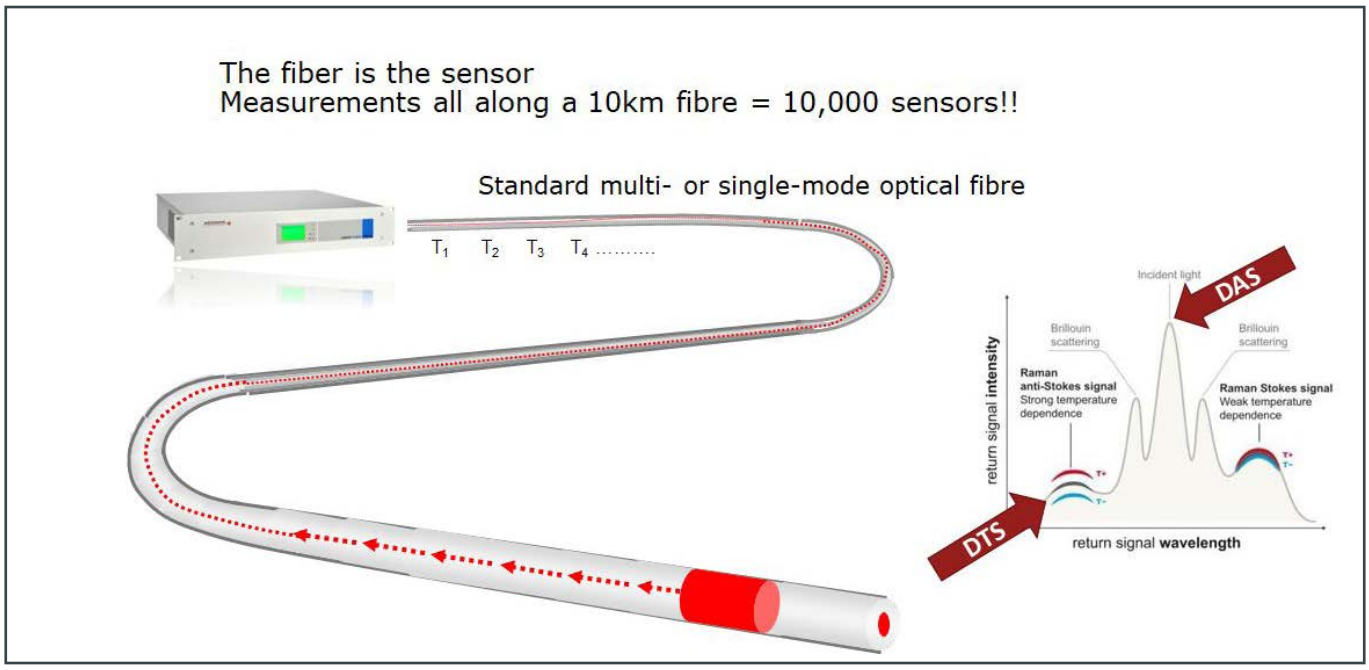

Figure 1: DFOS Backscattering

DFOS technologies can be grouped according to thermal and acoustic capabilities. The ability to use different types of standard fiber optic cables is also considered.

Detection of thermal signals:

- **Raman DTS – Distributed Temperature Sensing**
  Measures accurate temperature values with no cross-talk between temperature and strain.
  Raman DTS can be used with Single Mode (SM) or Multimode (MM) fibers. MM fibers provide a stronger scattering signal, thus achieving better accuracy and can be used up to 50 km.
- **Brillouin DTS – Distributed Temperature Sensing**
  Measures strain and temperature values with possible cross-talk between temperature and strain. Brillouin DTS has a stronger backscatter signal than Raman. It is often used in a loop configuration requiring a return fiber and halving the monitoring range. Special cables should be considered to avoid cross-talk between strain and temperature.
  Brillouin DTS uses SM fibers only.
- **DTGS – Distributed Temperature Gradient Sensing** – as part of Quantitative DAS (also known as Phase-Based DAS) or DFBG (Distributed Fiber Bragg Gratings). Measures temperature gradients very quickly over finite timespans with very high resolution (0.001K) without measuring absolute temperatures.
  DTGS, when part of Quantitative DAS, uses SM fibers. When part of DFBG, DTGS uses specially-treated FBG sensing fibers.
- **eDTS – Enhanced Distributed Temperature Sensing** – uses DTGS Quantitative DAS + Raman DTS.
  eDTS uses absolute temperature measurements from the Raman DTS with fast temperature variation measurements of DAS-DTGS to provide enhanced and faster DTS leak alarms.
  eDTS uses SM fibers or a combination of SM and MM fibers.

Detection of acoustic/vibration signals:

- **Non-Quantitative DAS (Amplitude-Based) – Distributed Acoustic Sensing**
  These are simpler DAS systems that only detect the presence of a vibration signal, but not the true signal amplitude or phase of the acoustic signal. Amplitude DAS is mainly used for perimeter protection, does not provide DAS-DTGS, and has difficulty in classifying acoustic events among other shortcomings for pipeline applications.
  Non-Quantitative DAS uses **SM** fibers.
- **Quantitative DAS (Phase Based) – Distributed Acoustic Sensing**
  Quantitative DAS is suitable for applications that require DAS-DTGS and delivers the high-quality acoustic signal (low–fading, quantifiable, high repeatability) required for event classification. Quantitative DAS provides the true signal amplitude or phase of the acoustic signal and is sometimes called "True-Phase DAS" systems. In addition to multi-LDS detection methods, Quantitative DAS includes additional functionalities such as PIG tracking and Third-Party Interference Monitoring.
  AP Sensing's Quantitative DAS uses 2 polarizations, enabling quantitative measurement with superior quality over extended distances of the sensor cable.
  Quantitative DAS uses **SM** fibers.
- **DVS – Distributed Vibration Sensing**
  Unlike DAS that is using a "Coherent-Optical Time Domain Reflectometry" concept, DVS is based on a hybrid interferometer technology (Michaelson/Mach-Zender Interferometer). Similar to Non-Quantitative DAS, DVS is often used for simpler applications such as perimeter protection. It does not provide DTGS and has difficulty in classifying acoustic events among other shortcomings for pipeline applications.
  DVS uses **SM** fibers.
- **DFBG – Distributed Fiber Bragg Grating Sensing**
  Some types of DFBG are occasionally called DAS, but must use special types of fiber and are heavily dependent on the fiber composition, fiber complex manufacturing processes, and variation of specific FBG optical fiber properties. DFBG can provide DTGS.
  DFBG **cannot** use standard **SM or MM** fibers. DFBG requires specially-treated FBG fibers.

From the summary above, the selection of **Raman DTS** (absolute temperature measurement) and **Quantitative DAS** (superior event classification and DTGS) results in a better fit for most pipeline leak detection applications. Brillouin DTS could be considered as a compromise in some specific circumstances where higher signal strength or strain monitoring is required. Standard fiber optic cable is available with suitable **SM** and **MM** fibers or a combination of **SM** + **MM** fibers in a single cable.

3. RAMAN DTS & LEAK DETECTION SOFTWARE CAPABILITIES

Figure 1 illustrates a laser pulse traveling through the fiber optic cable and the associated backscattered light traveling back to the interrogator. At the **Raman** Anti-Stokes wavelength, the intensity of the backscattered light is only strongly correlated with the temperature; this effect can be calibrated to provide absolute temperature readings along the fiber optic cable length. Thanks to the RADAR-like OTDR measurement concept, the location of the temperature readings can be calculated with an accuracy of 0.5 meters to a few meters, depending on the measurement time required and length monitored by the fiber optic cable.

One of the main advantages of Raman DTS is its insensi-

Figure 2: RAMAN DTS

tivity to any acoustic and strain inputs, delivering reliable temperature readings even in noisy conditions. Raman DTS is widely used for fire detection in car/train tunnels and metros where noise and vibration are a concern. For pipeline leak detection applications, LDS software uses DTS measurements together with smart algorithms to calculate if the temperature variations around the pipe are consistent with a leak event, disregarding normal temperature changes caused by the weather, day-night variations, pipeline operations, and other causes of thermal transients.

Raman DTS provides a powerful external LDS method for liquid leaks that cause significant temperature changes to the environment. DTS is widely used as the primary LDS method in hot or cold applications involving insulated pipes where the fiber optic cable is attached to the outside of the thermal insulation. Leaks from insulated pipes result in a localized, fast, and sharp change of the temperature outside the insulation and can be detected rapidly, even in the case of small leaks. Thermally insulated applications include cryogenic tanks, LNG/LPG tanks and associated pipelines, as well as liquid ammonia, liquid hydrogen hot sulfur, bitumen, and heavy crude.

Leaks from non-insulated pipes transporting hot liquids can also cause significant temperature changes in the adjacent environment. By placing the sensor cable a few centimeters away from the pipe, it is possible to measure changes in temperature due to a leak as the ground itself acts as insulation. For small diameter pipelines, ground temperature variation due to a leak can be detected relatively quickly.

DTS is used for high-pressure natural gas, CO2 and LPG. In these cases, the temperature of the transported fluid is not necessarily different from the ambient. The depressurization causes a cooling effect due to the gas expansion (Joule-Thomson effect) or change phase (liquid/gas phase transition).

DTS is often used as a secondary method to detect seeping leaks that can cause a suspicious temperature discontinuity which can be confirmed by advanced LDS software. Seeping leaks are very small leak rates usually detected by periodic inspections (aerial or foot patrol) which rely on a much larger total spill volume to be detected when compared to DTS.

The unique capabilities of DTS allow leak detection in situations when flow metering is unreliable or impossible, such as in open channel waterways or partially filled low-pressure sewage systems.

4. QUANTITATIVE DAS & LEAK DETECTION SOFTWARE CAPABILITIES

Pipeline leak detection software, when used together with Quantitative DAS, can provide three leak detection methods:

- Negative Pressure Wave (NPW)
- Acoustic and Orifice Noise
- DTGS - Distributed Temperature Gradient Sensing

NEGATIVE PRESSURE WAVE

NPWs are rarefaction waves generated during the onset of the leak. NPWs propagate in the fluid at the speed of sound in both directions away from the leak origin. API 1130 NPW CPM (Computational Pipeline Monitoring) software has historically relied on instrumenting multiple locations with two sensor-like pressure meters to detect the presence and direction of the propagation of such waves. DAS of NPWs brings several benefits for the sensing of NPWs:

- **Resilience to obstacles to the NPW path**
  Point sensors are normally installed many kilometers apart and NPW propagation can be interfered with or stopped entirely by obstacles. Pressure-regulating

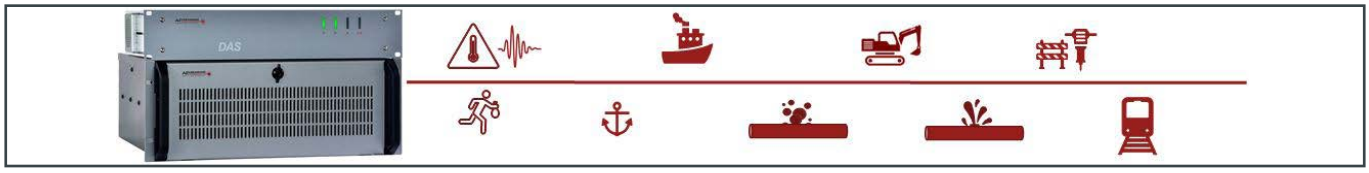

Figure 3: Quantitative DAS

valves, pigs, slack flow vapor pockets, changes in diameter, booster stations, and other factors can interfere with or stop the arrival pressure pulse at a remote sensor. Distributed sensing ensures sensitivity on all segments of the pipeline.

- **Pressure wave attenuation**
  Pressure wave attenuation is a limiting factor that restricts the maximum distance between pressure sensors. Distributed sensing delivers the sensor at closer proximity to the leak origin and therefore provides high sensitivity even with DAS interrogators placed 120 km apart.
- **Event duration and confirmation**
  AP Sensing's enhanced Quantitative DAS can monitor not only the onset of NPWs, but also the progress of the NPWs as they travel over many kilometers. NPW monitoring time using DAS is a thousand times longer than using point sensors, clearly showing travel direction and point of origin. DAS can also provide further leak confirmation at the leak location by acoustic and DTGS LDS methods.

NPW sensing is an important leak signature of high-pressure pipelines. This method is particularly important for the detection and location of high-pressure liquid pipelines and the NPW leak signal will be detected before thermal effects change the temperature around the fiber.

ACOUSTIC AND ORIFICE NOISE

Continuous flow through the leak orifice generates noise and vibrations outside the pipe, and produces pressure instabilities within the fluid. API 1130 Acoustic CPM (Computational Pipeline Monitoring) can benefit from DAS sensors. Acoustic/Orifice Noise signals are present during the duration of the leak but are weaker than signals from NPWs and attenuate faster. Acoustic signals from small leaks do not travel long distances inside the fluid and require specialized transducers capable of detecting the frequencies. The proximity of the sensor cable provides a much greater probability of detection of acoustic leak signals compared to sensors placed kilometers apart.

Orifice noise detected outside the pipe is an important leak signature of high-pressure pipelines. This method is particularly important for the detection and location of high-pressure gas leaks in buried, above ground, and underwater conditions. The acoustic leak signal will be detected before thermal effects change the temperature around the fiber.

DTGS – DISTRIBUTED TEMPERATURE GRADIENT SENSING.

DTGS is an external leak detection method provided by DAS, detecting thermal variations similarly to DTS. Using

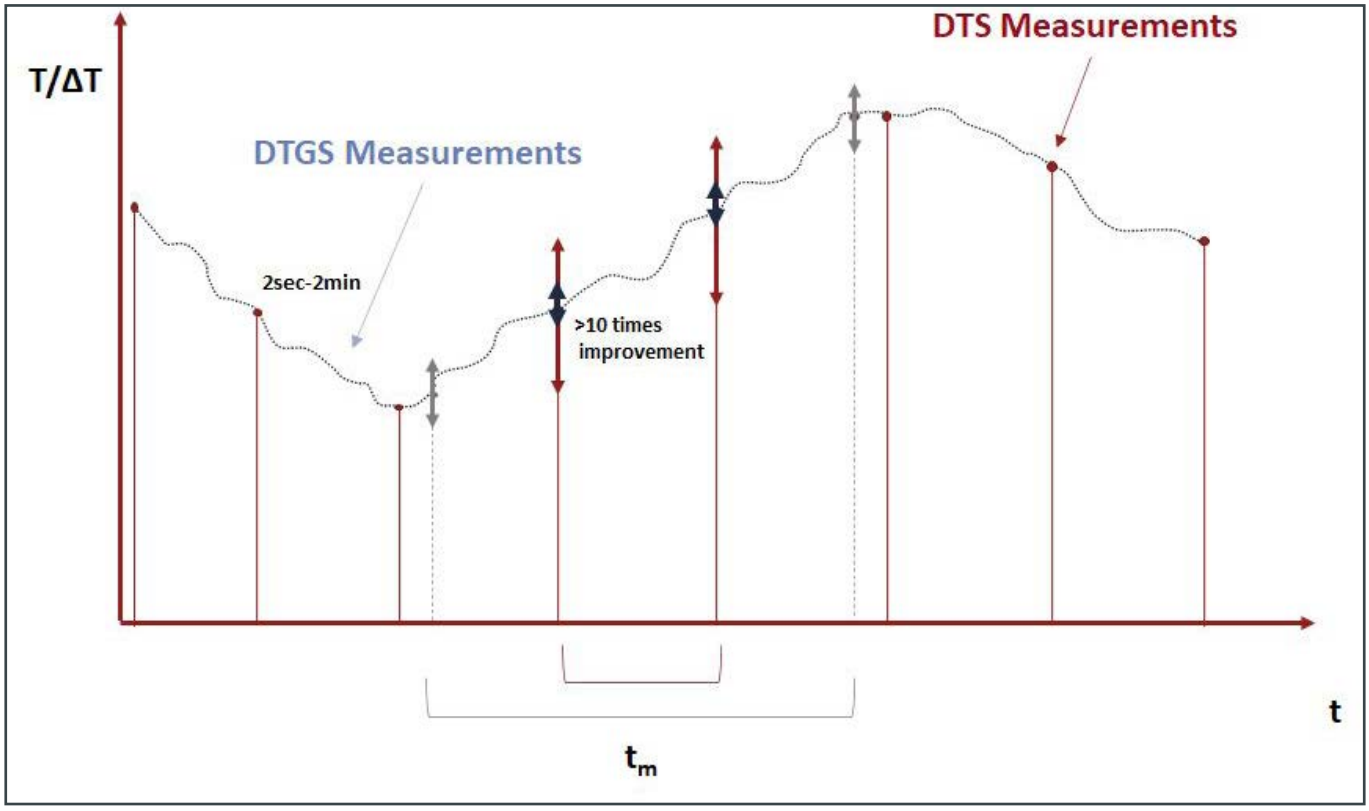

Figure 4: eDTS – merging DTS and DTGS measurements

the same DAS interrogator, the data provided by a Quantitative DAS can be analyzed to determine temperature variations. DTGS can detect very small changes in temperature with very high resolution.

The selection between DTS or DTGS takes into consideration the other DAS LDS methods, as well as additional functionalities provided by DAS and their relevance for the leak signature being considered. The DTGS leak detection method is particularly important for the confirmation of leak alarms from Acoustic/Orifice Noise and NPW from high pressure gases, LPG, and LNG pipelines.

EDTS – ENHANCED DISTRIBUTED TEMPERATURE SENSING

DAS and DTS technologies can be used on their own or together on the same cable, each bringing unique benefits for pipeline leak detection and pipeline monitoring. DAS and DTS used together allow synergies like eDTS, where the fast and sensitive response of DTGS is used to improve the temperature monitoring accuracy of DTS.

The decision between DAS and DTS does not always involve excluding one system, as DTS can be selected as the primary LDS and DAS selected for TPI capabilities. DTS is often used together with DAS, either as a complimentary LDS or as a redundancy. In these cases, the DTGS capabilities of DAS can be used to improve DTS in a unique way. The DTSs capability to measure accurate temperature values is augmented with the DAS system's capability to quickly measure small temperature variations. The result is very sensitive, fast, and accurate DTS measurements with improved performance that is particularly useful for pipeline leak detection among other applications.

5. DFOS ROLE IN THE PIPELINE LEAK DETECTION PROGRAM

DFOS can support the Pipeline Leak Detection Program Management as a primary LDS, secondary LDS, or one component of a multi-LDS system.

DFOS systems are normally used as real-time applications providing continuous LDS monitoring even when used as an external method to detect seeping leaks. Table 1 shows an example where DFOS is used as part of a Leak Detection Program Analysis using different LDSs for different leak rates. Industry best practices recommend that a combination of internal and external leak detection methods should be considered to improve the leak size detection threshold, reduce the time to detect a leak, and/or define the leak location more accurately. Both DAS and DTS can be used together or on their own as external LDS methods and will, in most cases, extend the capabilities of CPM (Computational Pipeline Monitoring) LDSs.

DTS is often considered as a primary LDS for pipeline applications where leak events generate a fast and strong thermal signature. In these cases, and especially for small diameter pipes, the DTS-based LDS software alarms are easy to understand and can provide a very sensitive, reliable method with unparalleled performance. DTS monitoring solutions can be engineered to provide fast alarm response with the accurate temperature and location readings required from a primary LDS.

Quantitative DAS-based Leak Detection Software can be used as an internal LDS method for both CPM Acoustic and CPM Negative Pressure Wave methods. The Fiber Optic Cable is the sensor capable of monitoring conditions inside the pipe using DAS. AP Sensing NPW software

	Continuous LDS			Non-Continuous LDS			
Leak Rate Type	SCADA Monitoring	CPM	Continuous DFOS LDS	Public Awareness	Aerial Surveillance	Non- Continuous DFOS LDS	In-line Inspection
Rupture	●	●	●	●	●	●	N/A
Medium Leak	O	●	●	●	●	●	●
Small Leak	X	O	●	O	O	●	●
Seep	X	X	O	O	O	O	●

X Detection improbable
● Detection probable
O Detection possible

Table 1: Example of a Leak Detection Program including DFOS

uses the input from DAS to analyze the wave propagation direction, calculate the wave speed and the wave point of origin, and determine if the patterns are consistent with a pipeline leak.

6. CONCLUSIONS

The selection process of a DFOS LDS technology for pipelines considers the different DFOS technologies, their suitability to the specific application, and performance requirements. Some of the main aspects to evaluate are:

- Fiber Optic Cable Considerations: standard fiber optic cables using single-mode fibers are suitable for DAS and DTS. Standard fiber optic cable using multi-mode fibers can enhance the performance of Raman DTS.
- Laser Class Type: DAS and DTS using Laser Class 1 should be preferred.
- Type of DAS or DTS technology: Quantitative DAS and Raman DTS should be considered preferred choices in most cases.
- Correlation between Leak Signature type and DFOS Technology:
- Thermal: If the leak causes a significant temperature change in the external environment, the LDS selection should consider DTS, Quantitative DAS-DTGS, and eDTS. LDS software incorporating "Machine Learning" should also be considered to improve performance.
- Acoustic: If the pipeline is pressurized, a leak will generate Acoustic and NPWs signals that can be detected and classified by Quantitative DAS and suitable LDS software. Thermal + Acoustic: If both leak signals are present, Quantitative DAS with DAS-DTGS should be the primary choice. Often Raman DTS is selected in conjunction with DAS for redundancy and independent confirmation
- DFOS role in the LDS Program: Depending on pipeline characteristics, DFOS can be used as a primary, secondary, or single component of a multi-LDS system. Industry best practices recommend that a combination of internal and external LDSs should be considered to improve sensitivity, detection time, and location accuracy.

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Using simulation to overcome operational challenges caused by the COVID-19 pandemic

Glen Tyson > Atmos International

Abstract

Atmos International (Atmos) is continuously working with the pipeline industry to develop solutions to overcome operational challenges. Atmos Simulation (SIM) Suite is an operational tool that users can trust to help operators run their pipelines safely, efficiently and with clarity and visibility.

Atmos SIM Online, working in real-time, performs a hydraulic simulation allowing pipeline operators to monitor all pipelines without the limitations of instrumentation availability. With Atmos SIM, operators benefit from fast and accurate simulations, providing meaningful information that operations teams can act upon quickly and with confidence.

The COVID-19 pandemic has caused additional challenges to pipeline operators and left some of them with reduced staff sizes. Operations teams with reduced members have used Atmos SIM to quickly identify faults with critical instrumentation. Atmos SIM enables them to isolate the issues by overriding the values with trusted simulated values. This helps users to continue to operate their pipelines with confidence while a maintenance team is dispatched and the problem is resolved.

Operating pipelines can be difficult, particularly if the product doesn't remain in the optimum region for efficient transport which is especially true when transferring varying grades of crude oil. Atmos Batch is an additional Atmos SIM module that allows operators to track, merge and blend their products while retaining and providing the information of the various component fractions of the batches and calculating its new physical properties itself to ensure the product reaches its destination safely and efficiently.

Atmos continuously innovate and improve its solutions including Atmos SIM and provide excellent customer care to our global customer base.

1. PIPELINE SIMULATION

The discipline of pipeline simulation can be summarized as the use of computational modelling to create an accurate representation of an actual pipeline system. This virtual replication of a pipeline is a powerful tool that has numerous applications in design, operations, training and management for the user's pipeline assets to enable them to operate their pipelines more safely and confidently while reducing costs.

Atmos SIM is an operational tool that users can trust to help operators run their pipelines safely, efficiently and with clarity and visibility. Atmos SIM is comprised of various software products and modules like Atmos SIM Online, Atmos SIM Offline, look-ahead modelling, Atmos Batch, Atmos Trainer and others.

Atmos SIM Online is capable of modelling either liquid or gas pipelines using real-time data available from DCS and SCADA systems. It enables operators to monitor areas where there is limited or no instrumentation and can complete forecasting calculations which allow operators to view the future pipeline conditions based on current or simulated (what-if) conditions and assess the safety of the schedule.

From exploring the initial pipeline design and providing justifications or validations to specific design decisions, simulation systems are commonplace in the early stages of pipeline construction or expanding existing systems. When working from a blank canvas, pipeline design specialists can work quickly to explore different ideas and virtually experience the different operational and commercial effects from their varying designs, allowing them to deliver justifications and validations to the recommended designs. Pipeline simulation software accelerates this entire process, enabling a wider range of design trials that will ultimately yield significant cost reductions.

Simulation offers pipeline operators in a live environment an amazing tool that enables them to explore the effect of operational changes and measure their impact in a virtual environment without having to risk implementing changes to an active pipeline system. Utilities help optimize pump/compressor operating plans to minimize running costs and reduce emissions. From an operational standpoint, operators can see the effect that any unplanned maintenance will have on the system and be able to respond effectively to any resulting negative impact.

Where pipelines are transporting multiple products with the same asset, the operator can monitor the status and properties of their products with Atmos Batch. Atmos Batch is widely regarded as the most accurate batch-tracking tool in the market, uniquely effective for long pipelines with large elevation changes and prominent vapor pockets. The batch tracker provides a rich and accurate visual display reporting all relevant details of value helping the operations team to optimise the process.

Simulation also offers a powerful training tool to improve operator onboarding to allow them to gain the experience required through a simulated pipeline.

Atmos SIM pipeline modelling software, in general, has various applications, the focus of this paper is its ability to improve pipeline operations and to share how Atmos SIM systems are helping those in the control rooms, throughout the world, utilize pipeline simulation to deal with the additional challenges presented by the COVID-19 pandemic.

COVID-19 has changed how organizations operate by restricting the way we work to maintain a safe working environment. The current reality is that operational teams are having to work with a smaller amount of resources and are expected to deliver the same level of services as before the pandemic. The solution for Atmos SIM users has been to place more focus on their real-time models and some have begun to integrate them more closely within the operating process. This is a trend we expect all users of pipeline simulation software to be doing for those fortunate to have it available. Doing this enables operators to make informed decisions faster, reducing time to resolution of quickly evolving situations, it provides an extra pair of eyes overlooking the system and automates some of the more time-consuming tasks.

Figure 1 shows an example of the simulation results in time and distance-based profile of flow, pressure and temperature.

2. INSTRUMENTATION ANALYSIS

One of the key benefits Atmos SIM customers are reporting is the instrumentation analysis functionality. This feature is standard for Atmos SIM to ensure the model is always returning accurate results. Atmos SIM achieves this by comparing real-time data acquired from field instrumentation with the calculated results which are returned from the simulated pipeline model. When this comparison returns a difference, Atmos SIM can determine if the field instrumentation has developed a fault as it can benefit from the surrounding instrumentation values and not focus on the difference in isolation and identify the value as an outlier. An example of this can be seen in Figure 2.

It is this comparison that Atmos SIM users have taken to the next level. Following the identification of faulty instrumentation in the field, it is not always possible to

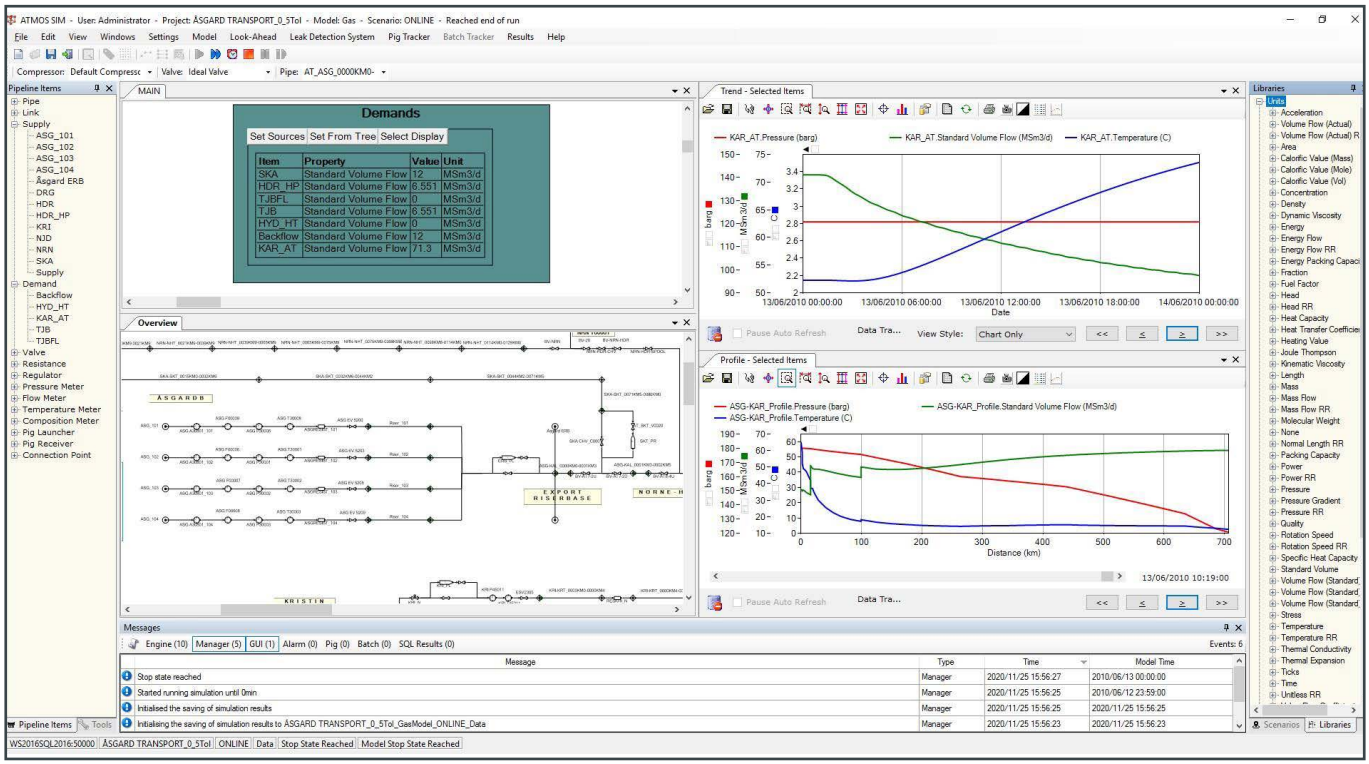

Figure 1: Real-time simulation results of a pipeline network

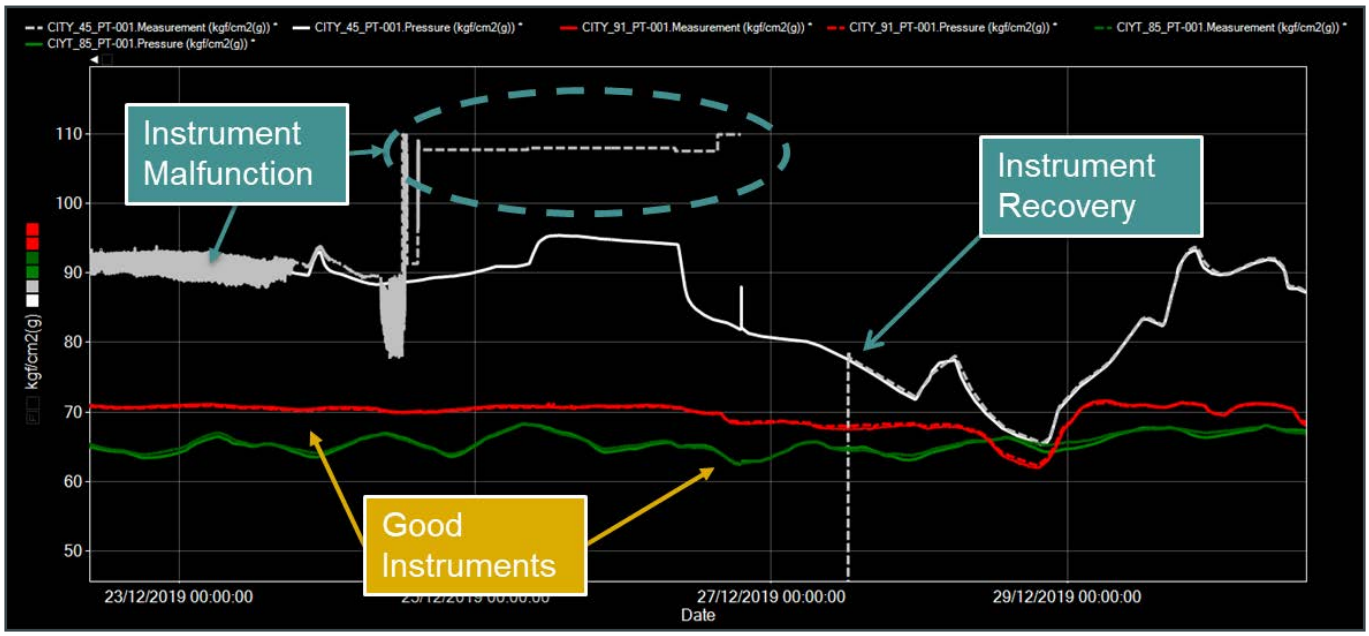

Figure 2: Real example of a trend showing three different pressure meters with the SIM calculation shown in a continuous line and measurement shown in a dashed line

Figure 3: An example showing the measured values are replaced by simulated ones (inside the red rectangle)

dispatch a repair team promptly due to availability or even having the essential equipment to complete the repair. In this circumstance, users have been able to integrate the simulated values into the SCADA/DCS and override them in human-machine interface (HMI) displays to enable the operations team to safely operate without the need to constantly note which values are unreliable. In the example in Figure 3, a redacted image of one of our user's systems is shown, where the unreliable values from the field have been replaced with simulated values and highlighted to provide that visual cue to remind them of its source.

This process also allows the operations team in the control room to easily prioritize the dispatch of the maintenance personnel to quickly resolve high impact issues. Before this integration, the control room would have been reliant on the systematic approach to the maintenance of each instrument which would have been done on a schedule rather than this proactive approach to the issue documented above. Figure 4 below illustrates how being able to compare the modelled and actual data provides a clear indication that some maintenance is required.

3. ISSUE PREVENTION/PROBLEM AVOIDANCE (LOOK-AHEAD)

Atmos International is known within the industry for the leading leak detection solutions and it is sometimes easy to overlook the value of pipeline simulation as an element of leak prevention. Atmos SIM can foresee developing issues and provide early warnings hours before any action is required to avert a crisis with the 'look-ahead' feature. With a real-time model in operation, the simulation software can take a 'snap-shot' of the current pipeline state and calculate what will happen in the future if the operating conditions remain the same and return alerts if pipeline limits are to be exceeded and a predicted time when this would occur. Similarly, it can forecast if a nominated schedule is feasible by running look-ahead modelling. This type of operation can be manually triggered but it is typically automated to run as frequently as every 15 minutes for short term calculations in the region of 4-6 hours ahead to every hour for longer-term calculations. Results are returned within minutes and using the latest technologies Atmos SIM can process multiple simulation scenarios simultaneously so that the operators have fast accurate information that they can act upon proactively with confidence rather than making reactive decisions to an unfolding disaster.

4. PIPELINE TRACKING INFORMATION

Pipeline simulation delivers added benefits when used in conjunction with operational tracking needs such as real-time batch tracking. With the use of the simulation model, Atmos Batch can handle complex calculations such as batch blending and compute changes in the product properties as they happen, such as the changes in viscosity from two different crudes and also continue to track the makeup of the composition of this newly blended batch. Even if further batches are injected, the simulation can automate the calculation of all the components for the new batch and continue to compute new properties for this.

The ability of the model to optimize itself to ensure its results are accurate as operating conditions change, such as large elevation differences, varying pipe diameters and low-pressure sections means that the batch tracking system can reliably predict a batch arrival within a small window of time ensuring the operators are ready to deliver

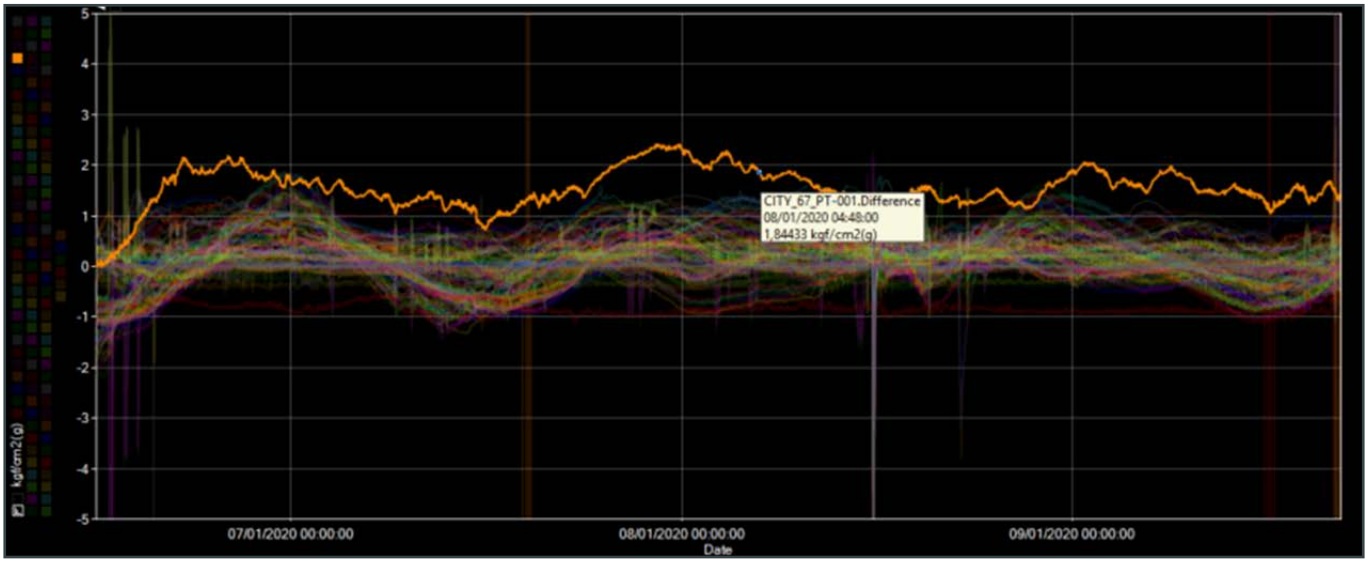

Figure 4: Difference between measured and calculated pressure indicating a need for instrument maintenance

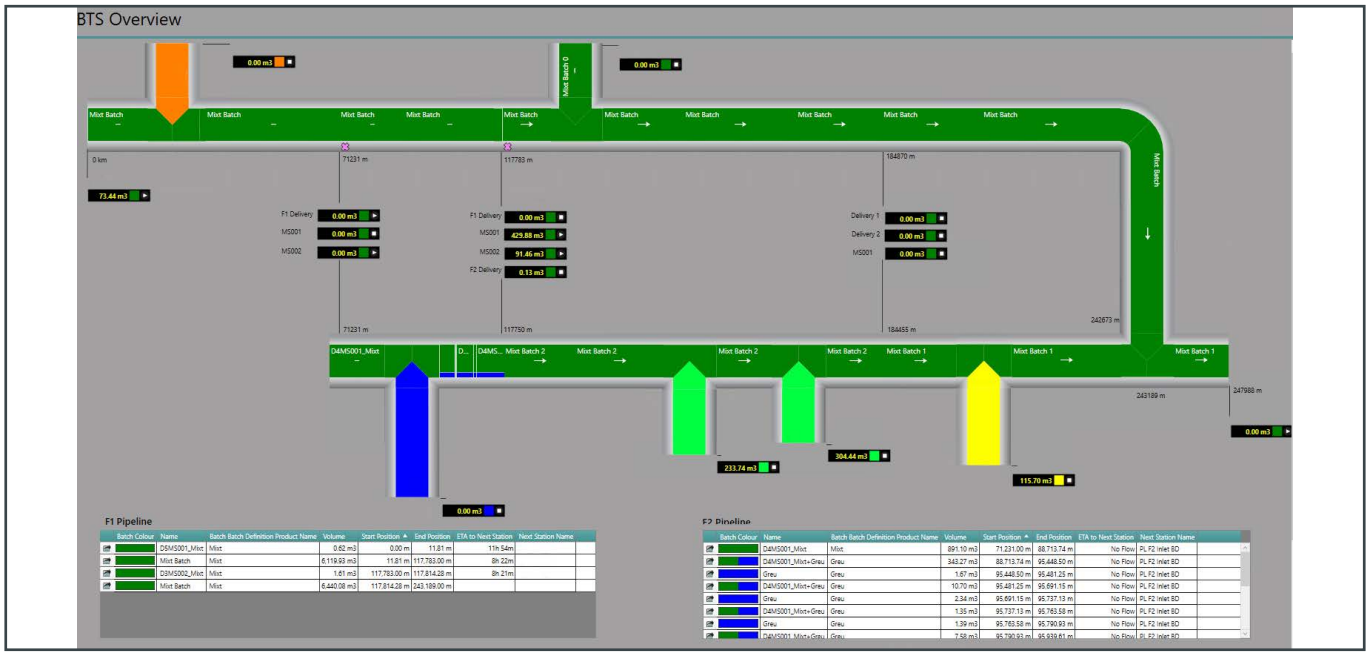

Figure 5: Batch tracking in two parallel pipelines

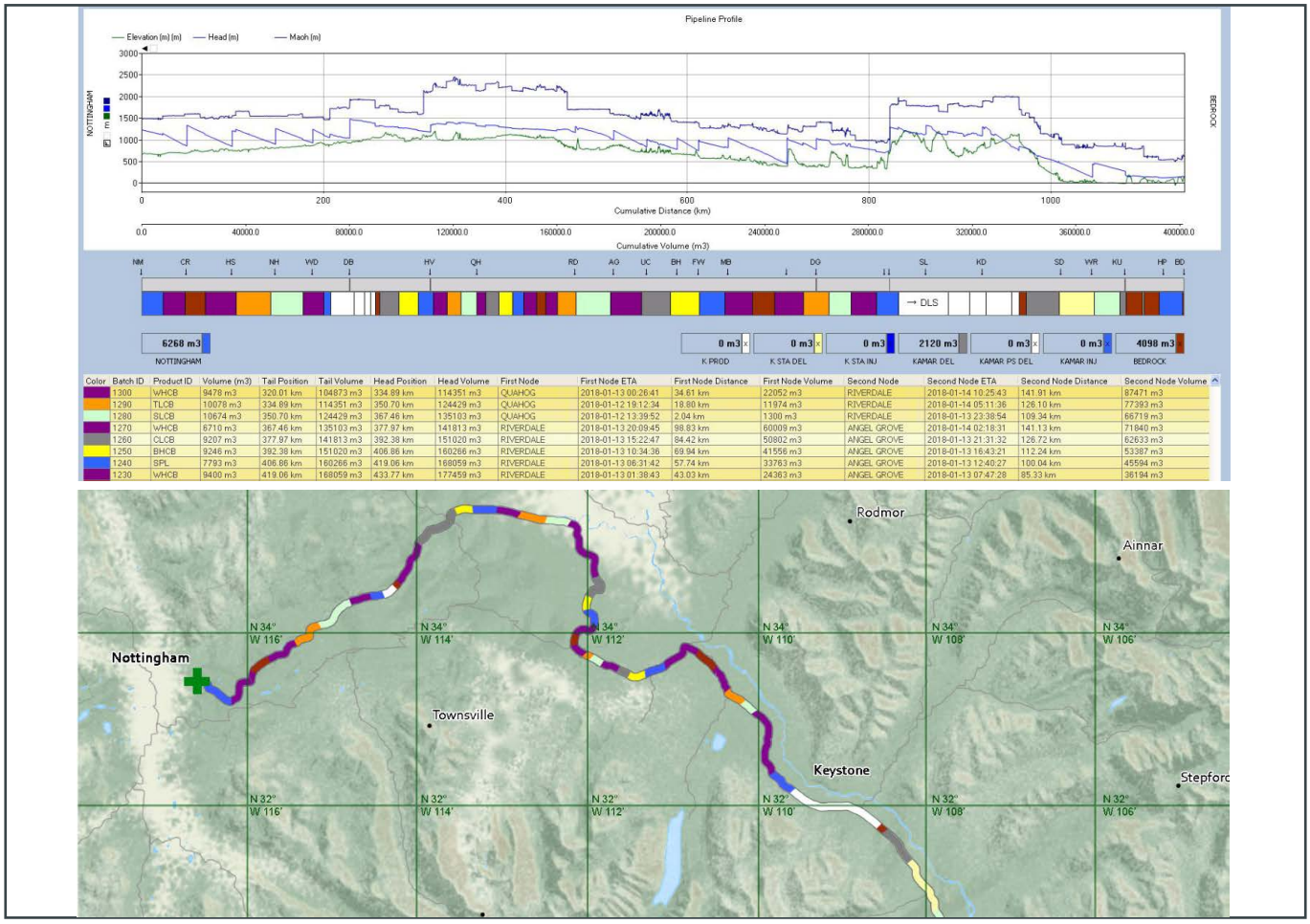

Figure 6: The details of a batch tracking system for a 1400 km long multi-product pipeline

the batch to the right storage tank minimizing the mixing and waste.

All of this results in less time and resources spent on manually tracking these elements with the flexibility of auto adapting to changing operating conditions and also reduces the time needed to be allocated to managing batch arrivals due to accurate ETAs. Figure 5 shows an example of batch tracking in two parallel pipelines. Figure 6 includes the details of a batch tracking system for a long multi-product pipeline.

5. CONCLUSIONS

What has traditionally been a tool for a specialized simulation department (with its dedicated experts) has shown how critical pipeline simulation is for pipeline operation and control. It is clear how entire pipeline operation teams could benefit from an 'extra pair of eyes' in the form of simulation with Atmos SIM. Atmos instrumentation analysis aids the fast identification of instrumentation faults that have developed in the pipeline network. This enables operators to make an easy assessment of the issue and provides them with more options when deciding what action is required. Atmos SIM also supports the integration of the simulated values into the SCADA/DCS to allow further flexibility to overwrite poor quality data in the interim period it takes to fix the instrument.

Other features such as 'look-ahead' and Atmos Batch help provide a single source of truth for what is happening over every inch of the pipeline. These tools also automate certain tasks ultimately providing operators with more time to dedicate to the other necessary tasks while giving them the confidence that they are operating the pipeline efficiently and safely. None of this can be achieved without having a capable system that the users can trust. This trust is built on the foundation of a robust, accurate model that is extremely reliable that supports user's day-to-day needs. Without Atmos SIM an operator's job becomes harder, slower and considerably more stressful in these already challenging times.

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Overcoming the Challenges and Increasing Value in Fiber Optic Monitoring

Steven Koles, Ehsan Jalilian, John Hull > Hifi Engineering

Abstract

Distributed fiber optic sensing has been gaining significant momentum in pipeline industry adoption. The primary application of this technology has been in preventative leak detection, but intelligent new applications such as pipeline flow rate monitoring are now emerging and promise to deliver extra value to the pipeline operators.

We present a high fidelity dynamic sensing system (HDS), which is capable of sensing acoustics, temperature, strain, and vibration over long distances in, on, or near a pipeline. We will discuss the practical considerations and challenges of deploying this technology in the field, including long distance fiber jetting, on and off the pipe placement, deployment in existing conduits, placement underneath riverbeds and roads, internal deployment, and micro-trenching. An overview of conduit sizing and thickness design tradeoffs and their impact on sensitivity will also be provided.

Case studies will be provided to showcase the value of using artificial intelligence and machine learning to explore new frontiers in pipeline monitoring. A variety of "value added" applications such as flow anomaly detection, flow rate, pressure, and density estimation will be discussed in detail. Other applications such as pig, vehicle, and train detection and tracking will also be presented.

A discussion of the critical design criteria for the creation of scalable client notification and data delivery platforms will also be provided. Design considerations include the diversity of customer personas and the associated requirement of interface customizability, the need for scalability to accommodate the always-growing volume of data, future-proof design to permit on-the-fly addition of new events and data streams with minimal core platform modifications, and intuitive user interface design requirements.

1. INTRODUCTION

Pipeline safety is a top concern for the general public, governments, and energy companies. Leaks can be caused by integrity failures due to sudden ruptures, accumulated strain, ground movement, etc. Pipeline companies rely on a number of technologies such as mass balance systems, aerial surveillance, and inline inspection tools to monitor the integrity of their pipelines on a regular basis.

Fiber optic pipeline monitoring has the advantage of continuous monitoring in both time and space. Deploying the fiber optic cable on, near, or inside the pipe effectively transforms it into a powerful suite of distributed sensors. Hifi Engineering's HDS technology utilizes the power of high fidelity fiber optic dynamic sensing to detect small changes in the optical path length between two adjacent fiber bragg gratings (FBGs), which are used as low angle wavelength reflectors. These perturbations are representative of the strain, vibration, acoustic, and thermal energy which is applied to the fiber optic sensor.

A variety of independent event identification algorithms are applied to the data acquired from the fiber optic sensors to detect the occurrence of pipeline integrity related events such a leaks, flow anomalies, or excessive strain. Further algorithms are also used to track pigs in the pipeline, estimate flow rate and pressure, etc.

2. DEPLOYMENT CONSIDERATIONS AND CHALLENGES

Fiber optic deployment methods may be divided into three categories of on the pipe external placement, off the pipe external placement, and internal placement. On the pipe placement (see Figure 1) is ideal for new constructions as it maximizes acoustic and strain sensitivity, though in some cases the client may prefer to place the fiber a short distance away from the pipe due to deployment considerations, or in an effort to monitor multiple parallel pipes. It is best practice to keep the fiber optic cable no more than one meter away from the pipe.

Due to the fragile nature of fiber optics, it is imperative that the sensors be deployed inside a protective housing such as stainless steel tubing or HDPE conduits. From a practical perspective, deploying in multi-duct HPDE conduits provides the greatest level of flexibility during the deployment while allowing the operator to deploy extra fiber optics, control cables, etc. in the future if needed.

Conduit based deployments generally involve the placement of an empty or pre-loaded conduit on or near the pipe during construction, and using splice enclosures to connect the conduit segments. Depending on the specific deployment, the splice enclosure can be anywhere from a few hundred meters to a few kilometers apart. For on the pipe placement, pipeline tape, special clamps, pipeline grade adhesives, or sandbags can be used to secure the conduit to the pipe prior to backfilling the trench. A placement in the 11 o'clock to 1 o'clock range is optimal as it provides high sensitivity while reducing the chances of the conduit getting crushed by the pipe during the backfill process. Sufficient slack allowances must be made to prevent excessive strain on the conduit in case of thermal expansion of the pipe.

Figure 1: On the pipe fiber installation

Burying pre-loaded conduit during the construction phase is a possibility. In some cases the operator may prefer to simply deploy an empty conduit during the construction phase and use specialized fiber injection equipment (see Figure 2) to jet the fiber into the conduit after the completion of this phase and the backfilling of the trench. This option has the added advantage of minimizing the number of required fiber splices.

In some deployment cases such as placement underneath riverbeds and roads, sections of the pipe must be placed using horizontal directional drilling (HDD). Using redundant conduits minimizes the chances of all conduits being damaged throughout the drilling and pull back process. In such cases, multiple conduits (see Figure 3) can be attached to the pipe near the pull-head and then pulled alongside the pipe in the bore (see Figure 4). It is recommended that the conduit not be taped to the pipe to allow it to rotate and move around freely while being pulled inside the bore, otherwise the conduit may experience excessive strain and be damaged during the process of boring.

Practical considerations regarding conduit sizing include crush rating, the number of fiber optic strands to be fitted inside, and the transportability of the conduit spool. Of great importance is the thickness of the conduit as it directly bears on crush rating and preventing compromising the conduit (see Figure 5), however the increased thickness also results in higher levels of acoustic signal attenuation. Mechanical models have been developed to calculate the optimal inner and outer diameters of the conduit to strike the proper balance between sensitivity and robustness.

Figures 6 and 7 below show the relationship between conduit thickness and crush rating and acoustic attenuation.

Existing pipelines pose a challenge to the deployment of fiber optic sensors. Generally, two approaches are possible. The first involves micro-trenching near the pipe to allow the conduit placement. This approach works in some cases, but can pose a safety risk to the pipeline. In some cases, hydro-vacuuming may be used to expose short pipe segments in order to deploy the fiber optic sensor. In some cases of existing pipelines such as river crossings, internal deployment may be the most suitable choice.

Internal deployment is often accomplished by inserting the fiber optic conduit into the pipe at a valve or other ingress location (see Figure 8) and using a tow pig (see Figure 9) to pull the fiber along with the flow inside the pipe. A dislodgement mechanism such as using mechanical sheer force will need to be used to separate the fiber from the pig once the cable is laid inside the pipe. It's also possible to use degradable pigs that dissolve over time with the pipeline flow.

Figure 2: Fiber injection at into buried conduit at a hand-hole site

Figure 3: A multi-duct HDPE conduit

Figure 4: HDD pull

3. DATA PROCESSING AND EVENT IDENTIFICATION

Machine Learning and Artificial Intelligence are rapidly gaining prominence as the preferred methods of choice for event detection. Supervised learning approaches such as classification algorithms are powerful tools that can utilize a large database of known events, for instance simulated leaks, to train a monitoring system to detect events such as pipeline leaks, pig runs, and flow anomalies. Decision Tree and Support Vector classifiers are particularly useful for event detection, however the classification outcomes may be impacted if adequate data conditioning, feature extraction, and labeling is not performed. The risk of overtraining the data must be taken seriously and appropriately mitigated by dividing the data into training, test, and validation datasets. It's also good practice to train and test the event detection algorithms using data from various different deployments to ensure robustness and avoid overtraining.

Unsupervised learning methods such as cluster analysis are useful in cases where sufficient training data for the event of interest is unavailable, or the available training data, e.g. simulated leaks, is not relevant to the specific deployment environment. Algorithms can be trained to analyze the data to 'learn' baseline activity such as the ambient acoustics or frequent events, e.g. train crossings. The extracted features are divided into various clusters of previously observed events, without a need for the clusters to be labeled. If the features of a future event fall outside these known clusters, they will be flagged as anomalies which need to be further processed.

Among the value added applications of pipeline fiber optic monitoring are pig tracking and flow, pressure, and density

Figure 5: A compromised conduit

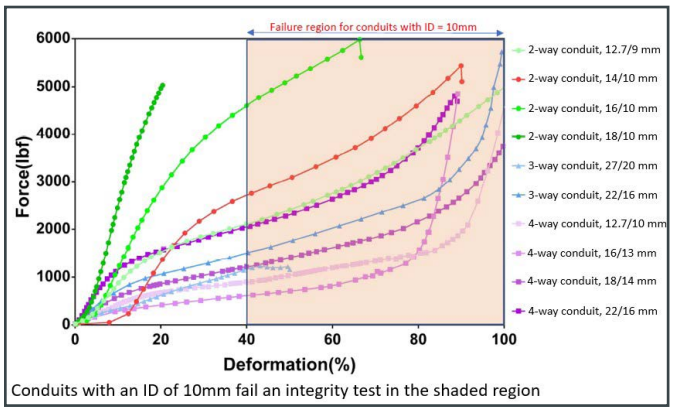
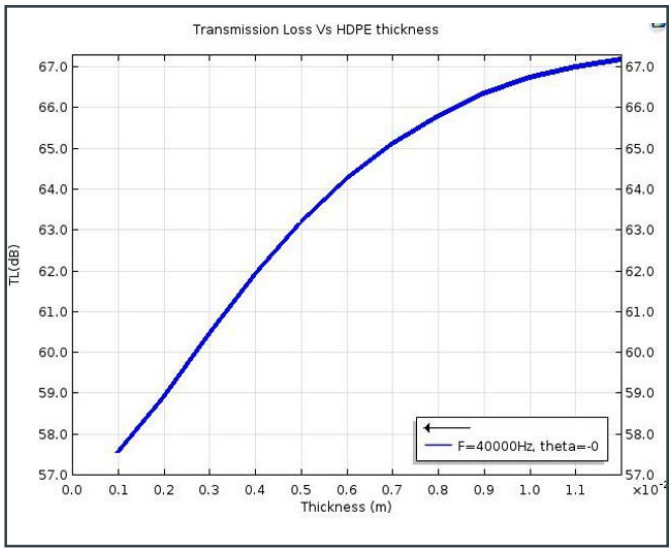


Figure 6: Conduit sizing impact on crush rating



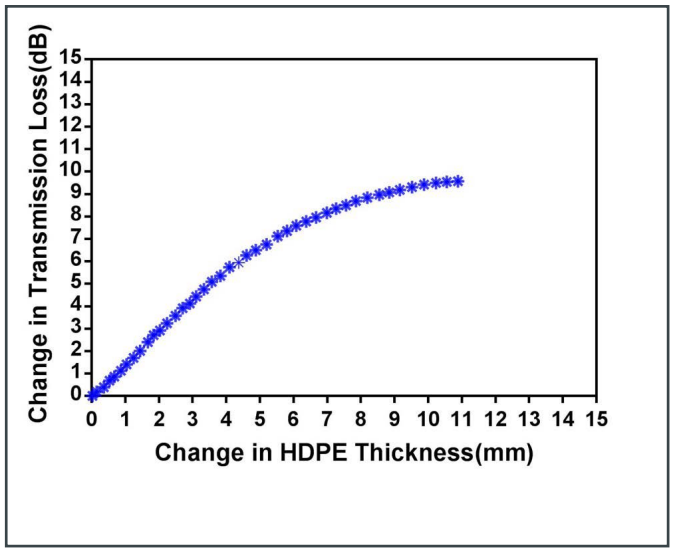


Figure 7: Conduit sizing impact on acoustic attenuation

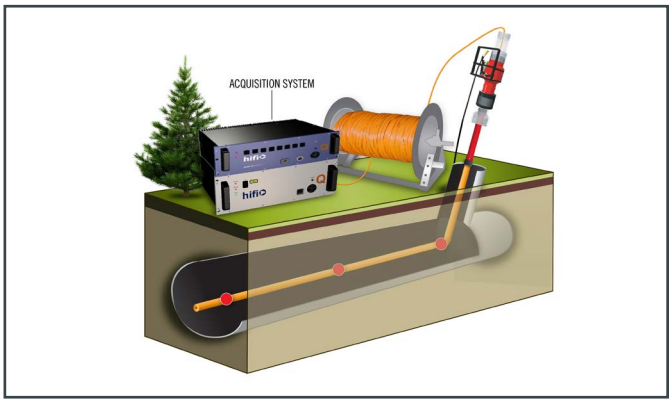


Figure 8: Internal deployment schematics

Figure 9: Fiber optic cable attached to tow pig for internal deployment

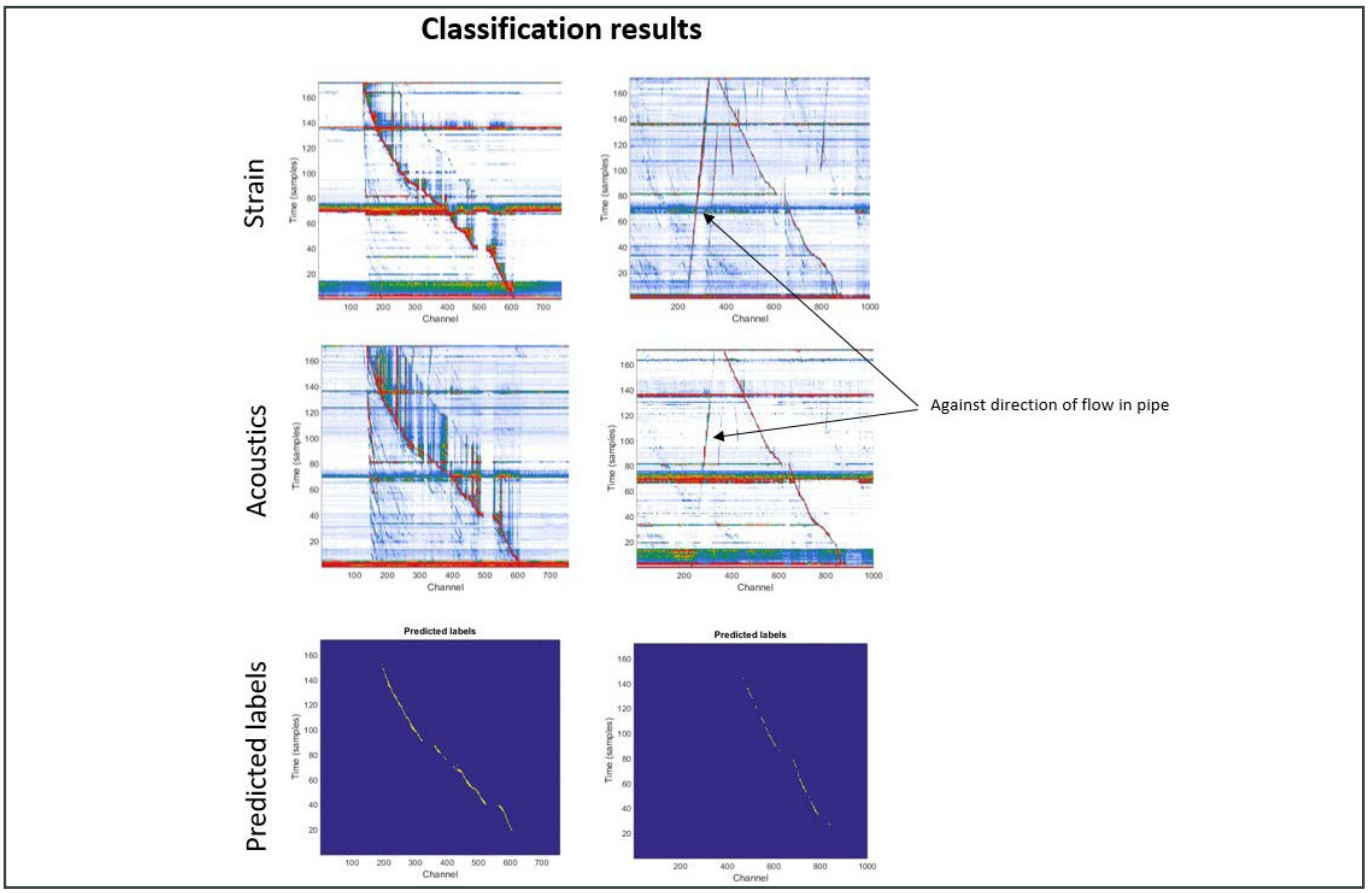


Figure 10: Pig tracking data

estimation. Pig tracking enables pipeline companies to know the exact location of the pig, along with its speed and arrival time at the next pig catching station. Strain and acoustic data collected from previous pig runs (see Figure 10) can be used to train classification algorithms. Imposing post-classification selection criteria such as acceptable direction and speed bounds can be used to reject events such as cars traveling on roads parallel to the pipeline right of way.

The flow of fluids in pipelines creates an acoustic signature which varies with changes in operational parameters such as flow rate, pressure, and density. The estimation of these operational parameters may be accomplished using regression analysis. Independently measured operational parameters (for example data recorded from flow and pressure meters), can be correlated to the acoustic data collected using fiber optic sensors (see Figure 11). The regression equation can subsequently be used to predict future operational parameters from the acquired acoustic data.

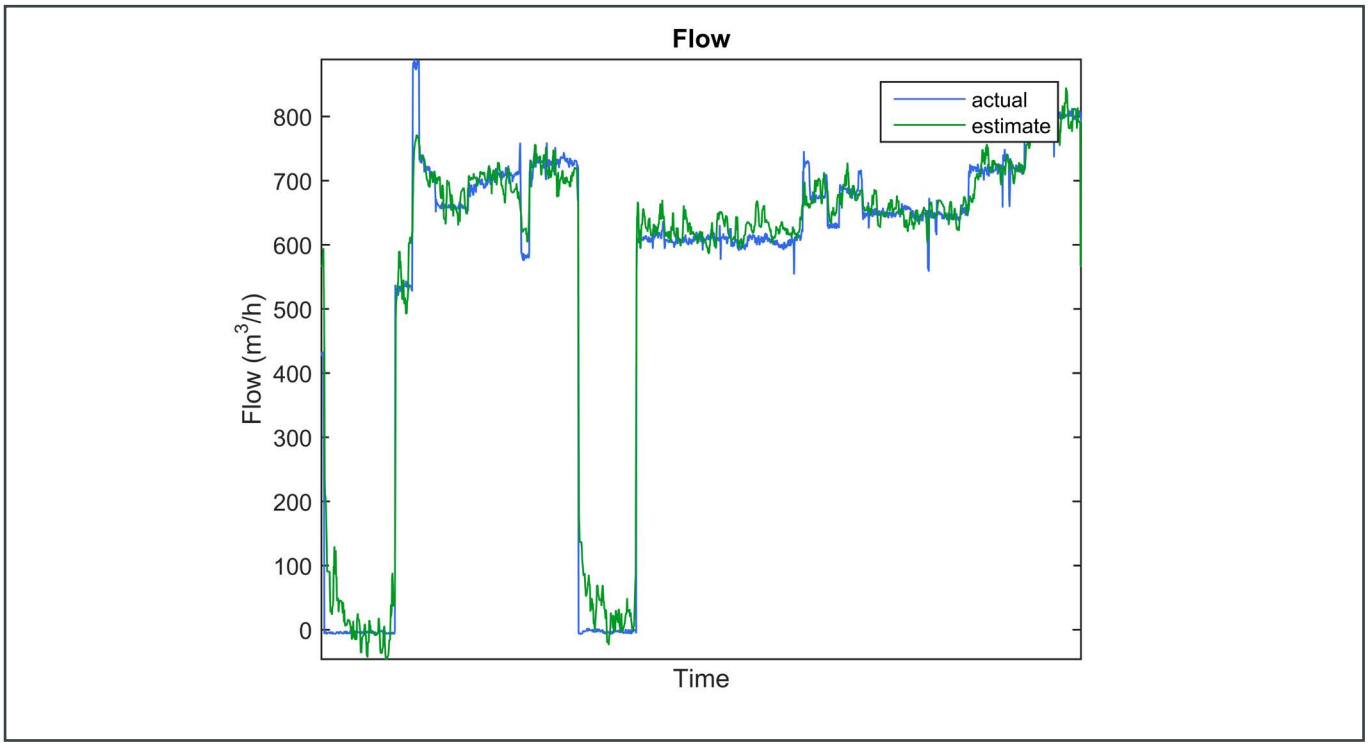


Figure 11: Flow estimation using fiber optic data

4. USER INTERFACE

A well designed and intuitive user interface is an important component of all critical asset monitoring systems. As the majority of pipeline control room operators are pre- conditioned to SCADA-based alarm interfaces, it's imperative that the fiber optic monitoring system's user interface be designed in such a way that feels intuitive and familiar to the users. While there are many benefits to making a feature rich UI, it's best to create layered designs with different features targeted to the different client personas. For instance, UI features targeted to control room operators must minimize the usage of bright colors unless they're used to indicate alarms. Similarly, due to the fast paced nature of control room operations, informational and non-actionable notifications must be suppressed.

For non-control room operators such as integrity managers, the UI design can incorporate more long term information that may be of a preventative nature. For example, an integrity dashboard summarizing the number of events (real or simulated) detected to date, the calibration status of the system, etc. can be an effective way to provide insights into the readiness of the monitoring system.

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Digital Integrated Pipeline Integrity Assurance System (i-PIMS)

Mohd Nazmi bin Mohd Ali Napiah, Ahmad Sirwan bin Mat Tuselim, Mohd Hisham Abu Bakar, Sani bin Sualiman, M Masduki bin Abu Samah, M Shahrustami bin M Nadzeri > PETRONAS

Abstract

In PETRONAS, there are on-going initiatives at petrochemical plants, gas processing plants, Upstream's well engineering and retail business in pursuing the digitilisation in line with the Industrial Revolution (IR) 4. The aim of the initiatives is basically to improve the efficiency of critical processes thus at the end will reduce overall cost and improve production margin and revenue /profitability.

This paper will present the initiative of PETRONAS' Pipeline fraternity consisting of pipeline experts, managers and engineers in the development of intelligent and integrated pipeline integrity management system. The system is designed to have minimal people intervention as data will be automatically uploaded by Inspection & Maintenance (I & M) vendors and field technicians through interface software and utilising artificial intelligence/ machine learning for descriptive, predictive and prescriptive analytics. It is envisaged that by having the system, critical decision-making pertaining to integrity, safety and reliability of pipeline system could be done in 'split seconds' extending the asset's life and eliminating unwanted incidents i.e. leak/rupture.

Furthermore, standardisation of pipeline risk and integrity software/tools among Operating PETRONAS Units (OPU)/regions will provide cost savings in the long term compared to current practice of having off-the-shelf software/tools. Integration of relevant corporate software/tools and the intended software/tools will further provide cost savings in terms of database management and enhanced efficiency.

1. INTRODUCTION

To eliminate pipeline leak/rupture, PETRONAS adopts 14 elements in its Pipeline Integrity Management System (PIMS) and critical elements such as Element 5: Risk & Integrity management where Risk-based Integrity planning and Fitness for Sevices assesments are conducted using PIMS software. Three options were explored whether to enhance current PIMS software, purchase off-the-shelf software or develop in-house software that suit the company requirements. This include identifying functional and non-fuctional requirements, identify gaps, flexibility to incorporate new needs, support for maintenance and licensing requirements. Findings from the analysis show that current software is based on outdated technology, risk of no future support and performance issue of current software, outshine the strengths of the software. In addition, the availability of up-to-date and comprehensive pipeline data in centralised database that can be utilised for trending analysis and data analytics are also one of the major findings.

PETRONAS' goal is to develop intelligent and digitally-abled pipeline integrity management software that can be used across PETRONAS. Previously, every OPU/subsidiary have its own PIMS system and the software/systems is not integrated to other corporate systems such as maintenance management system, plant information, geographical information system etc. thus posed inefficiency in overall integrity management i.e. Inspection and Maintenance (I&M) planning; I&M execution; integrity analyses and assessments; repair & rehabilitation; and activities progress tracking.

The new digital PIMS or i-PIMS is designed to have minimal people intervention as data will be automatically uploaded by I&M vendors and field technicians/operators through interface software and utilise artificial intelligence/machine learning for descriptive, predictive and prescriptive analytics. It is envisaged that by having the system, critical decision-making pertaining to integrity and reliability of pipeline system could be done in immediately thus extending the asset's life and eliminating unwanted incidents i.e. leak/rupture. Pipeline leak/rupture are catastrophic which impacting people, environment, assets and reputation. Pipeline operators are not only required to repair as quick as possible but also to clean-up the spillage which affected the environmental surrounding.

The i-PIMS is designed to be an efficient and user-friendly software that will enable good user experience and high utilisation. Pipeline integrity data can be accessed, gathered and verified faster and effectively. This will result in efficient identification of issues/risk prior to escalation to unwanted situation; and can be acted upon to mitigate the issue/risk proactively. An efficient PIMS, not only provided quick solution for assessment/analysis but will also greatly enhance operator's ability to eliminate unwanted incidents i.e. leak/rupture. The massive and various database from I&M records are fit for trending purposes and utilization of artificial intelligent and machine/deep learning can be employed for various data analytics purposes.

In parallel with i-PIMS development, few other initiatives using machine/deep learning are also being embarked to detect anomalies using advanced acoustic emission technology as well as corrosion, free span and 3rd party impact analytics. Once completed, the above will be integrated to i-PIMS and the final product of i-PIMS total solution will be eventually able to be accessed via mobile apps.

2. PETRONAS' PIMS SITUATIONAL ASSESSMENT

Currently, relevant OPU/subsidiaries have their dedicated PIMS software which have its own strengths and limitations. The standalone software is not integrated thus posed inefficiency in overall integrity management i.e. Inspection and Maintenance (I&M) planning; execution; integrity analyses and assessments; repair & rehabilitation; and activities progress tracking. The integrity management process is extremely tedious and requires huge efforts to develop inspection, maintenance, monitoring and repair plans for > 400 nos. of pipelines. Data integrity is also at risk due to possible human errors. Currently it requires minimum 4-6 months to develop an inspection, monitoring, maintenance and repairs plans yearly for these pipelines.

In the spirit of IR4.0, current PIMS software is lacking 'intelligence' and analytics:

- Manual data uploading and analyses.
- Require full human intervention during crisis/emergency.
- No 'split-second' and 'real-time' capability to analyse pipeline conditions.
- No 'self-learning' for critical analyses and enhancement of 'historical' database.

Thus, internal consultant i.e. PETRONAS' Group Digital i.e. ICT team was requested to undertake a situational assessment of the current system landscape and assess available enhancement options together with comparison against other pipeline integrity software identified by the OPUs. The situational assessment involved studying and analysing on existing PIMS software including new vision and mission. This included assessing and identifying possible options for existing PIMS improvements and propose way forward to support for new PIMS software vision and mission.

Three options were explored whether to enhance current PIMS software, purchase off-the-shelf software or develop in-house software that suit the company requirements. This include identifying functional and non-fuctional requirements comparison, identify gap findings, flexbility to incorporate new needs and cost comparison in term of total development, support & maintenance & licensing.

SWOT (Strengths, Weakness, Opportunities, Threats) analysis was also conducted for current PIMS software. Findings from the analysis show that significant threat findings on outdated technology, risk of no future support and performance issue of current software, outshine the strengths of the software. The situational assessment also discovered that developing a totally new digital PIMS incorporating all relevant users' requirements would be the most cost effective way forward rather than enhancing current software or purchase off-the shelf software.

In-house developer i.e. PETRONAS' Group Digital i.e. ICT team and PETRONAS' Group Technical Data team were engaged based on defined criteria and commercial viability. Several workshops were organized among relevant parties in PETRONAS i.e. Upstream Assets (Sarawak, Sabah and Peninsular Malaysia), Gas and New Energy (PETRONAS Gas Berhad) and PETRONAS Group Technical Solutions that have interest in utilising and maintaining of PIMS software.

The workshops discussed on the following requirements:

- Capabilities/functionalities to cater for current and near term future (e.g. within 5 years) needs.
- Integration of the risk & integrity software & other corporate software/tools shall eliminate multiple needs of data uploading i.e. only single data uploading platform.
- Deliberation of existing risk assessment methodologies and develop single Risk-based Integrity plan (RBIP) methodology for PETRONAS.
- Explore readily available in-house software for seamless integration.
- Prepare road map for 10 years plan (big data, probabilistic, predictive, robotic).
- Custodian of the software, which will be the focal in liaising the in-house developer, in term of addressing any 'bug" issues, maintenance services and future enhancement.

The technical and operational requirements were discussed for software development and captured in System Requirements Specification (SRS). The development is divided into Phase 1 and 2 based on OPUs' prioritization. Migration of data from previous software/system is part of the scope and conducted in several stages.

3. KEY FEATURES AND FUNCTIONALITIES OF PETRONAS' I-PIMS

The PETRONAS Integrated Pipeline Integrity Assurance Solutions (i-PIMS) houses severals functionalities & databases in a single system. The overall system architecture comprises of database module with asset registration in the database hierarchy, assessment module which further link to My Task and task manager module. i-PIMS also serve as a platform to integrate with existing databases such as PI for operating data, SAP and PiriGis. The design had minimizes pipeline engineer involvement to gather, clean and upload data in the system as most of these features are readily integrated to i-PIMS. Having this advantages, pipeline engineer are able to focus on analyzing the assessment outcome and create value creation by recommending fit for purpose mitigation action to maintain pipeline integrity.

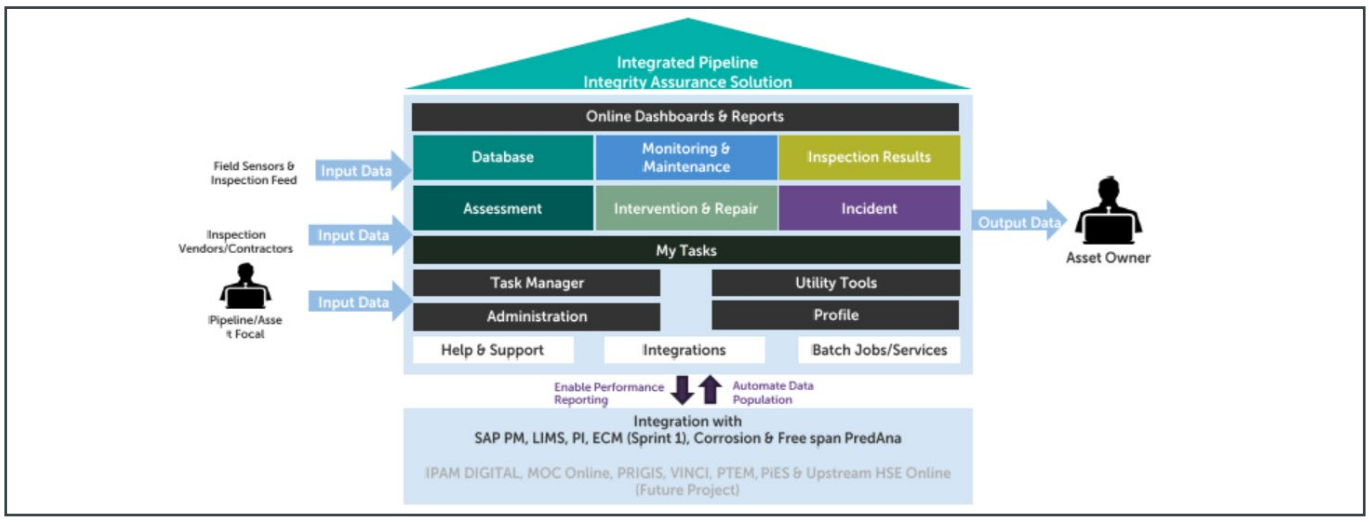

Figure 1: i-PIMS overview of system architecture (Courtesy of PETRONAS)

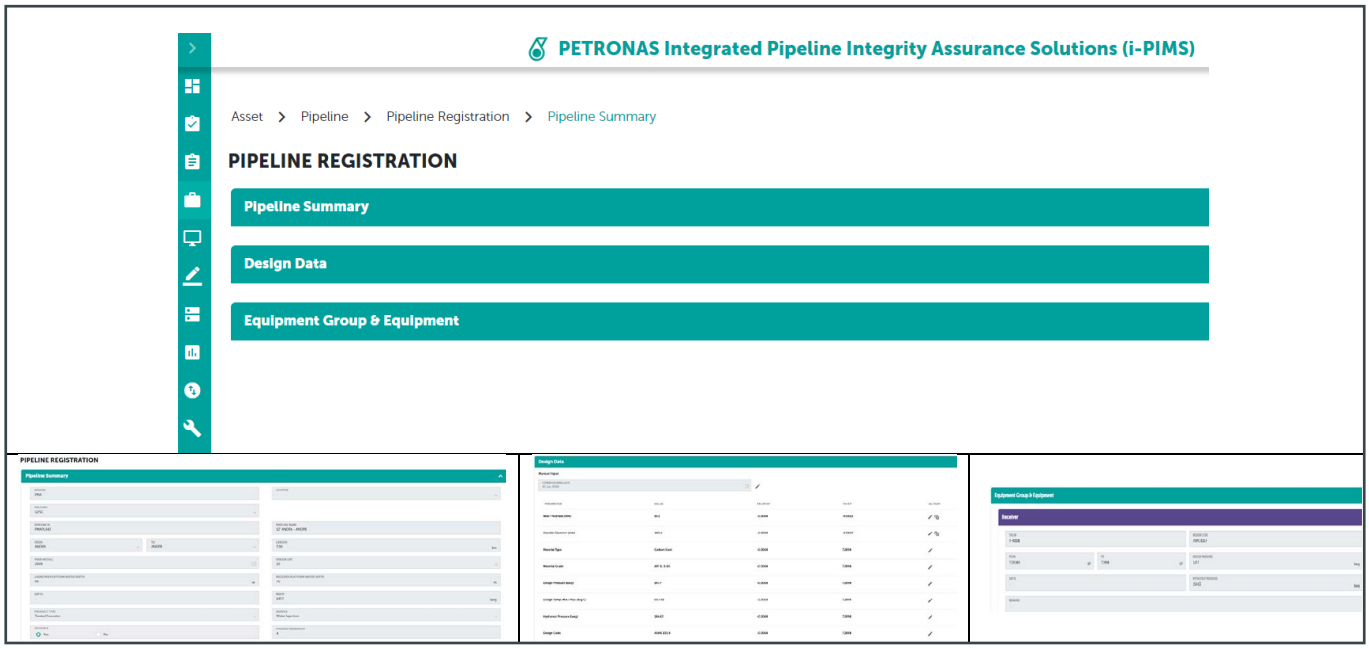

Figure 2 : Example GUI for Asset Sub-Modules (Courtesy of PETRONAS)

Data Harvest module was officially go-live on 26th December 2019 of which its the key functionalities are further discussed in subsequent section.

4. DATA HARVEST MODULE

Data harvest module comprises of several sub-modules which includes asset registration (pipeline summary, design data and equipment group), monitoring & maintenance (corrosion monitoring, CP, OP, CI and sampling analysis) and inspection (CP survey, UTTG, IP, Underwater survey and MTM). The intent of this module is to clean, store & contiunously update the informations. It is PETRONAS aspiration & core focus to ensure data integrity and data accuracy in which data harvest module serves as a platform to realize this aspiration.

Figure 2 depicts some of the examples of typical parameters required as part of the input for Asset sub-modules. Each of the input parameters plays a crucial role in the subsequent modules especially RBIP & FFS in which asset registration information were directly link to assessment module in order to produce risk and integrity assessment report. This information will also automatically populated in Dashboard modules to provide management team with clear asset visualization and its integrity, risk and operating status. More elaborative pipeline information in terms of monitoring, maintenance and inspection can be interactively uploaded and visualize in this sub modules as per example given in Figure 3. In this sub modules, PETRONAS grants inspection & maintenance vendor an access to upload respective inspection or maintenance activity into i-PIMS. Inspection and maintenance finding can be reviewed online by asset owner to ensure that all uploaded data are clean and meet the desired quality and standard. This feature enhances process cycle efficiency to 67% in which report submission can be completed in 2 weeks/pipeline instead of 6 weeks/pipeline.

The system also fueled by live operating data captured by field sensors, feeding near realtime data to i-PIMS system through integration with PI. As each asset is tagged to SAP, integration with SAP system will enable i-PIMS system generate specific tasks. Obviously, this can only happen with the capability of the Assessment sub-modules comprise of RBIP and FFS, capable to anlayze various pipeline threats stipulated in API 1160 and ASME B31.8S.

5. RISK ASSESSMENT MODULE

Risk assessment is an analytical process by which a pipeline operator determines the types of adverse events or conditions that might impact pipeline integrity during operational stage. It also determines the likelihood or probability of those events or conditions that will lead to a loss of pipeline integrity, the nature and the severity of the consequences that might occur following a pipeline failure.

This process involved the integration of information from design, construction, operating, maintenance, testing, inspection, and other related information about a pipeline system. The entire process of risk assessment and management for pipeline are administer through the system and according to API1160 and B31.8S guideline requirements.

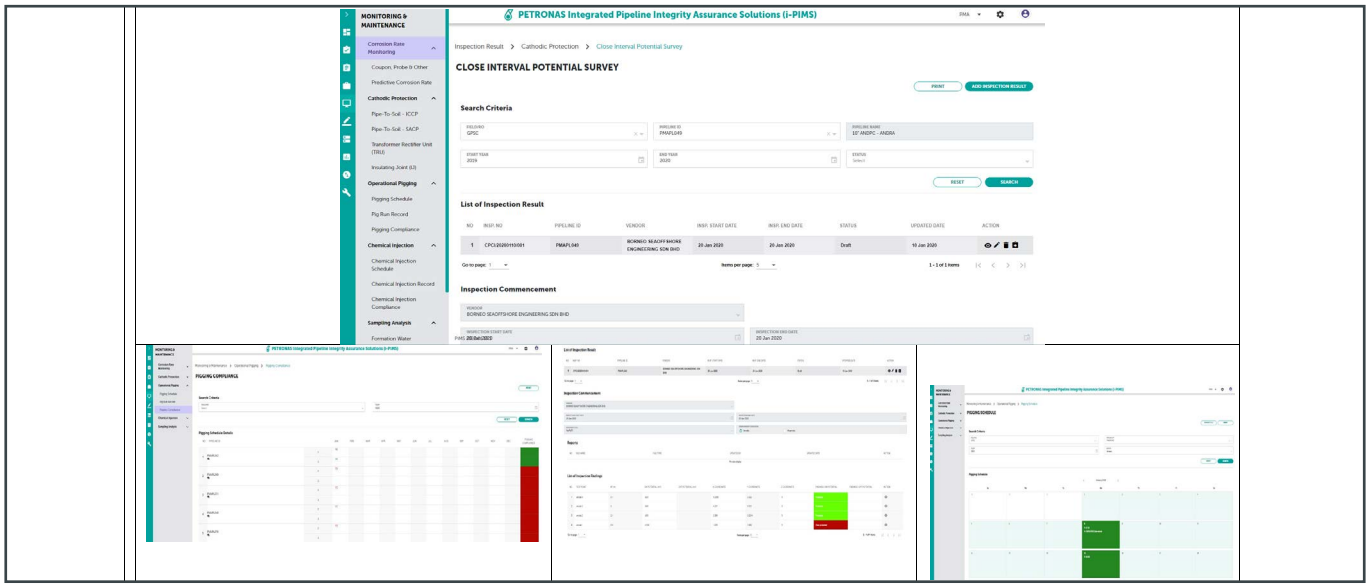

Figure 3 : Example GUI for Monitoring, Maintenance & Inspection sub-modules (Courtesy of PETRONAS)

Figure 4 : Example of integration with other systems (i.e. PI & SAP) (Courtesy of PETRONAS)

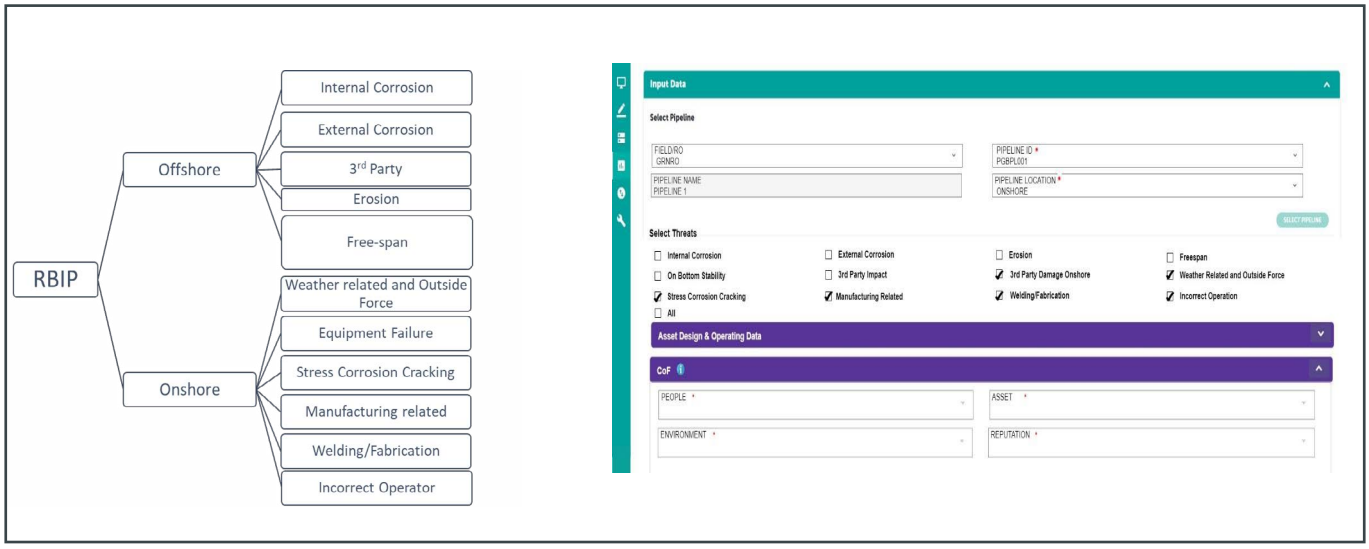

Figure 5: i-PIMS overview of RBIP threats selection (Courtesy of PETRONAS)

THREATS	PIPELINE SECTION	LAST INSPECTION YEAR	INSPECTION YEAR			ANALYSIS YEAR			SOURCE	INSPECTION PLAN		RECOMMENDATION
			PoF	CoF	Risk Rating	PoF	CoF	Risk Rating		Next Inspection Year	INSPECTION/REPAIR TYPE	
Internal Corrosion	subsea pipeline	20 Nov 2014	A	4	A4	A	4	A4	RBI Detailed	04 Sep 2031	Magnetic Flux Leakage (MFL)	To comply with CMP compliance To perform IP in 2024 (10 years from last inspection)
External Corrosion		20 Nov 2014	A	4	A4	A	4	A4	RBI Initial	20 Nov 2020	Magnetic Flux Leakage (MFL)	To monitor in next IP inspection
Erosion	subsea pipeline	20 Nov 2014	A	4	A4	A	4	A4	RBI Detailed	04 Sep 2031	Magnetic Flux Leakage (MFL)	To monitor sand in next pigging activity
Freespan		24 Jun 2015	A	4	A4	A	4	A4	RBI Initial	24 Jun 2035	Underwater Inspection (UW)	To monitor in next UWI inspection
On Bottom Stability		24 Jun 2015	A	4	A4	A	4	A4	RBI Initial	24 Jun 2035	Side Scan Sonar (SSS)	To monitor in next SSS/UWI inspection
3rd Party Impact		30 Sep 2019	A	4	A4	A	4	A4	RBI Initial	30 Sep 2039	Underwater Inspection (UW)	To monitor in next UWI inspection

Figure 6: Overview of system IMP (Courtesy of PETRONAS)

Risk Based Inspection Plan (RBIP) which is the very foundation of an integrity management program can vary in scope or complexity and used different methods or techniques. The ultimate goal of assessing risk is to identify the most significant risk so that an operator can develop an effective and prioritized prevention/ detection/ mitigation plan by Integrity Management Plan IMP to address the risk within ALARP level, display transparently through dashboard and send the outcome to Task Manager for systematic coordination and tracking.

Risk module was developed into two sections and based on user's select location (Offshore, Onshore or both) with pre-defined threats and extended not only pipeline but also station level designed by B31.4 or B31.8 through integration with multiple Petronas's risk and integrity software (PRBI and PiriGIS). Two methodologies were used for assessing risk based on Codes & Standards and best practices by pipeline operators worldwide either from FFS assessment (time -based) to integration data from GIS portal (surveillance and geohazard) event based.

I. QUALITATIVE RISK ASSESSMENT (INITIAL ASSESSMENT).

In general, the qualitative method involves defining the various threats, determining the extent of weaknesses and devising counter measures should the event occur. The assessment shall be conducted with the presence of subject matter expert (SME) supported by expert's judgement, experience and historical data.

II. SEMI – QUANTITATIVE RISK ASSESSMENT (DETAILED ASSESSMENT)

The purpose of the detailed analysis is to perform a more in-depth (quantitative) assessment of the risk level, probability and consequence of failure assessment, as compared to the initial assessment. The detailed risk analysis covers pipeline systems, components and damage modes that are identified in the Initial Assessment as items with unacceptable risk.

Semi-Quantitative Risk Assessment (semi - QRA) is a mechanism that is using combination of qualitative input of the pipeline system and numerical approach for the pipeline operator to conclude the probabilities of adverse events and the likely extend of the losses if a particular event takes place.

RBIP summary results shall be extracted from pipeline latest assessment date based on governing threats (either Initial or Detail assessments) and shall be visually displayed for systematic action plan and task manager prioritization.

6. FITNESS FOR SERVICE ASSESSMENT MODULE

Fitness For Service (FFS) module enables users to identify integrity of the pipeline system deterministically, produce repair list, determines pipeline remaining life which in turns link to task manager and other modules. As each pipelines are registered as per SAP asset registration, any verificaiton or repair activity can be easily monitor to ensure its full compliance against codes and standard. For this, the system had adopted response category as outlined by prominent codes and standards such as ASME B31.8S and API 1160 in managing or prioritizing resources in response to anomalies reported from inspection reports.

The module was designed to provide more flexiblity with the aims to minimize engineers extensive effort of data sorting and uploading as per traditional PIMS approach. These includes standardization of pipeline inspection data by IP vendors which eventually to be uploaded by the vendors into the system directly. In addition, if the FFS results reveals unsatisfactory findings from injurious anomalies, pipeline operator are allowed to validate the results through dig up verification and the results can be updated directly into the system to reduce assessment conservatism.

PETRONAS Integrated Pipeline Integrity Assurance Solutions (i-PIMS)

NORTHERN

Assessment > RBI for Pipeline > Initial Assessment

INITIAL ASSESSMENT

PRINT

Input Data

Output Data

ASSESS

CoF

PEOPLE
2

ASSET
3

ENVIRONMENT
2

REPUTATION
3

FINAL COF CATEGORY
3

3rd Party Damage Onshore

CRITERIA (SUB CRITERIA)	PoF INSP YEAR	FINAL CoF CATEGORY	RISK AT INSP YEAR	PoF ANALYSIS YEAR	RISK AT ANALYSIS YEAR	YEARS FOR 1-UNIT INCREASE IN PoF	NEXT INSP YEAR	ACTION
Pipeline Description (NA)	C	3	C3	C	C3	5	1 Jan 2025	
Location Class and Level of Activity (NA)	C	3	C3	C	C3	5	1 Jan 2025	
Inspection Findings (ROW Surveillance)	C	3	C3	C	C3	5	1 Jan 2025	

FINAL RISK AT INSPECTION YEAR
C3-MEDIUM

FINAL RISK AT ANALYSIS YEAR
C3-MEDIUM

RECOMMENDATIONS
Description of recommendation for this threat

Weather Related and Outside Force

CRITERIA (SUB CRITERIA)	PoF INSP YEAR	FINAL CoF CATEGORY	RISK AT INSP YEAR	PoF ANALYSIS YEAR	RISK AT ANALYSIS YEAR	YEARS FOR 1-UNIT INCREASE IN PoF	NEXT INSP YEAR	ACTION
Inspection Findings (EML Ground Survey)	C	3	C3	C	C3	5	1 Jan 2025	
Geohazard (NA)	D	3	D3	C	C3	5	1 Jan 2030	

FINAL RISK AT INSPECTION YEAR
D3-HIGH

FINAL RISK AT ANALYSIS YEAR
C3 - MEDIUM

RECOMMENDATIONS
Description of recommendation for this threat

Stress Corrosion Cracking

COATING TYPE

CP CONDITION

SCC REPORTED?
○ YES ○ NO

INSPECTION CONDUCTED?
○ YES ○ NO

PRESSURE TRENDING

CRITERIA	PoF INSP YEAR	FINAL CoF CATEGORY	RISK AT INSP YEAR	PoF ANALYSIS YEAR	RISK AT ANALYSIS YEAR	YEARS FOR 1-UNIT INCREASE IN PoF	NEXT INSP YEAR	ACTION
Pipeline Description	C	3	C3	C	C3	5	1 Jan 2025	
Historical SCC	A	3	A3	A	A3	10	1 Jan 2030	
With IP Indication	A	3	A3	D	A3	3	1 Jan 2030	

FINAL RISK AT INSPECTION YEAR
C3-MEDIUM

FINAL RISK AT ANALYSIS YEAR
C3-MEDIUM

RECOMMENDATIONS
Description of recommendation for this threat

Figure 7: i-PIMS overview of Initial RBIP (Courtesy of PETRONAS)

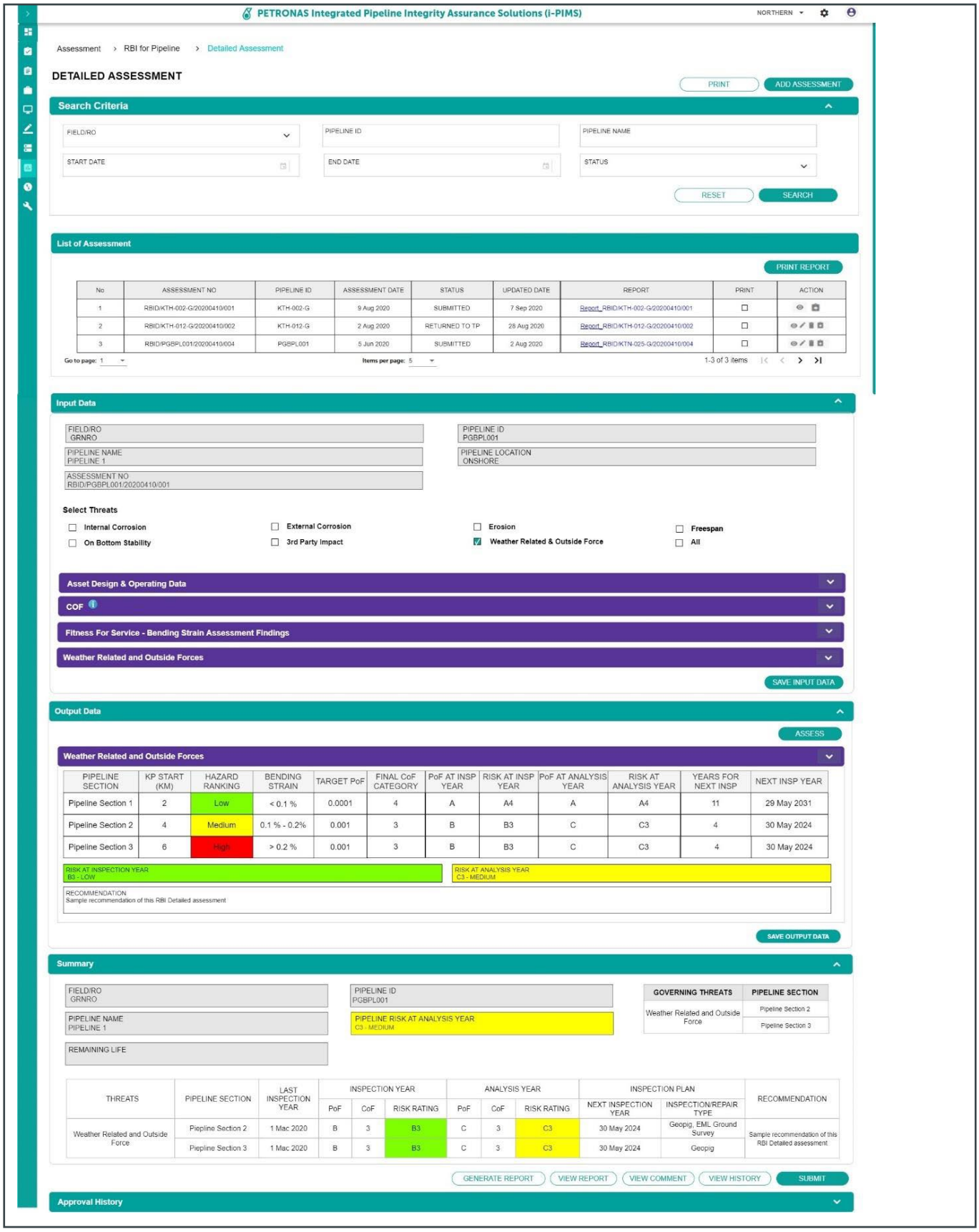

Figure 8: Overview of detailed RBIP (Courtesy of PETRONAS)

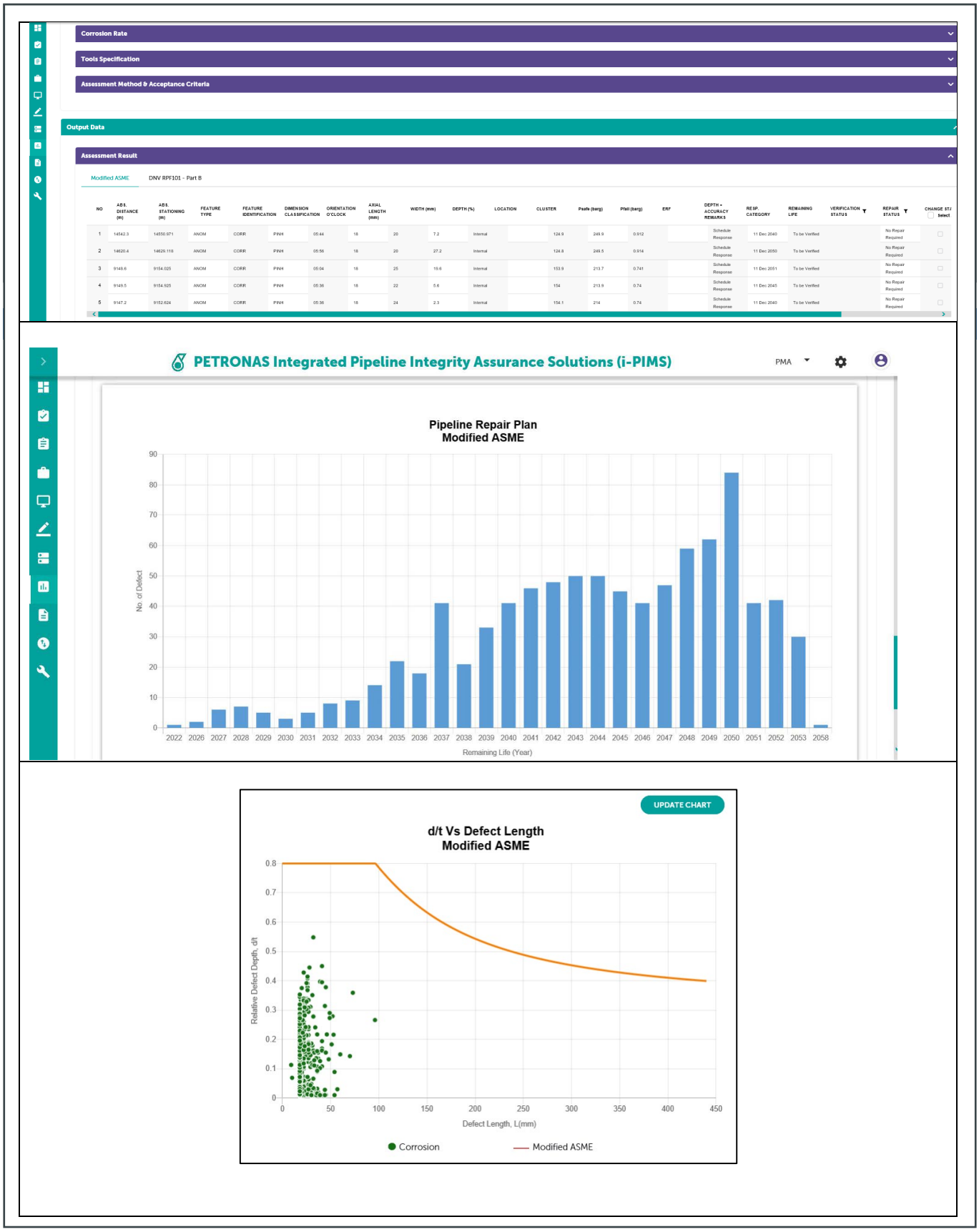

Figure 10: Overview of FFS results and repair plan (Courtesy of PETRONAS)

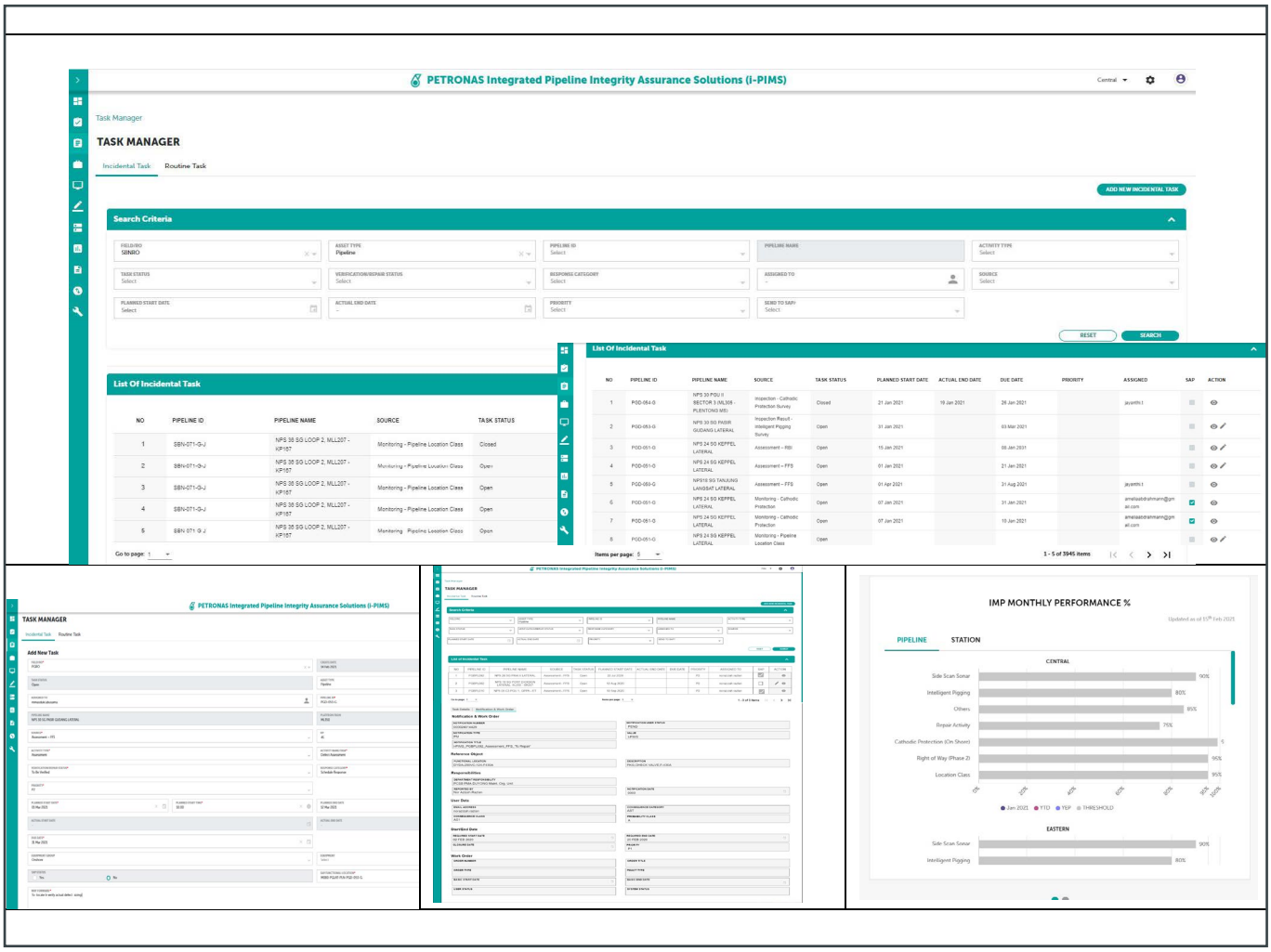

Figure 11 : Example GUI for Task Manager Module (Courtesy of PETRONAS)

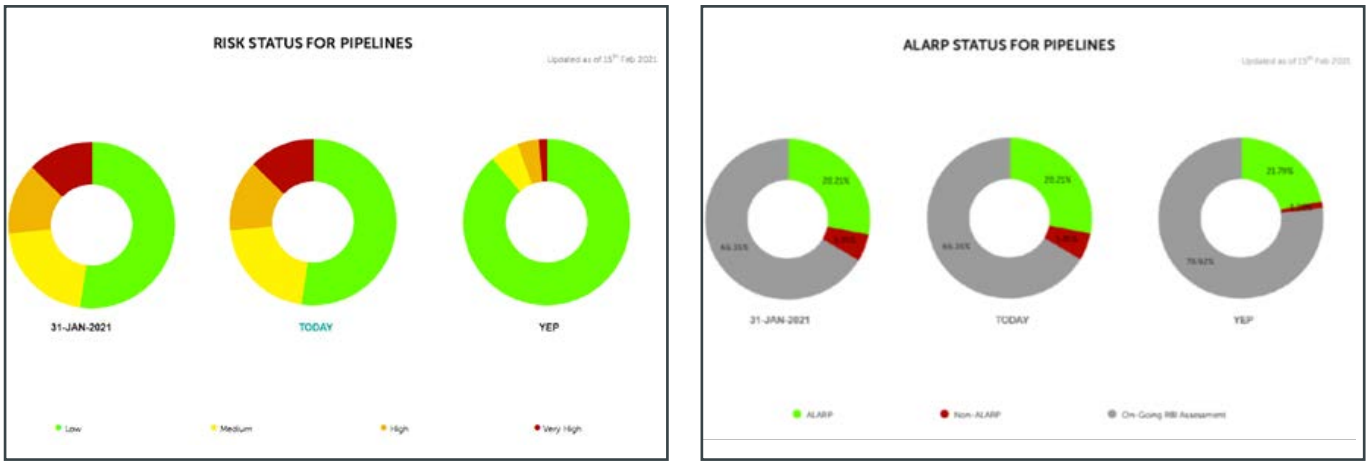

Figure 12: Snapshots of Pipeline Risk and ALARP status for Pipelines (Courtesy of PETRONAS)

Figure 13: Snapshots of Pipeline Statistics (Courtesy of PETRONAS)

The quality assurance of the FFS outcome can be performed seamlessly as the software will generate FFS report which undergone online review/approval by Technical Authority to preserve its authenticity & traceability for future references.

7. TASK MANAGER MODULE

Task Manager helps to plan, co-ordinate and track all integrity plan activities created in I-PIMS which includes risk-based inspection tasks, repair&mitigation action, and routine maintenance work.

The Task Manager module able to handle "Routine" such as operational pigging, product sampling, CI Injection, etc. and "Incidental" Task e.g. advance assessment, NDT&visual inspection, temporary or permanent repairs are scheduled in systematic process flow from initiation till approval of the task execution. For tracking and audit purposes, inspection and maintenance personnel to record actions taken, time expended, date completed, and any pertinent remarks concerning findings when the task was done.

Figure 11 shows example of the list of tasks created for an onshore pipeline section. For Incidental task, the Task Manager is designed to publish automatically task generated by the Assessment module. Obviously, this only happened with the capability of the Assessment sub-modules comprise of RBIP and FFS, capable to analyze various pipeline threats stipulated in API 1160 and ASME B31.8S.

As each asset is tagged to SAP, integration with SAP system enable tasks from i-PIMS to be incorporated into well-defined work-order management system in dealing with financial, resources and work scheduling. This module also link with the Dashboard module, which make it easier for relevant stakeholders to monitor performance of the tasks completion as well as Integrity Management Plan (IMP) compliancy status.

8. DASHBOARD MODULE

One of the main interesting yet the most informative features of i-PIMS is the dashboard. This most seek features of i-PIMS particularly by the management sets as the backbone of i-PIMS and becomes the first page of i-PIMS interface whenever users log in into i-PIMS. It pulls all the data from various modules including Asset Register, Risk Based Inspection, Fitness for Service and Task Manager and will be automatically updated each time there is updates on respective modules that it connected with.

One of the main interests of the dashboard that it reports pipelines and stations risk as well as ALARP (As Low As Reasonably Practicable) status, indicating numbers and which pipelines that make up each risk cateogries as well as its governing threats. This information of risk is crucial for pipeline engineers to monitor and gauge pipelines and stations planned risk reduction program progress, as further depicted in several other sections of the dasboard, as well as their effectiveness in reducing the pipeline risk for a given year.
This risk and ALARP status of pipelines and stations are real time, where the data is taken from the Risk Ranking module in i-PIMS and will be automatically updated once Risk Based Inspection Assessment of respective pipelines updated.

As mentioned above, pipeline engineers will also be able to monitor overall progress of integrity management program assigned to their pipelines from the dashboard. Inspection and maintenance activities performance shows all major inspection and maintenance program for the pipelines which are tied to the closure of work orders of respective activities as listed in Task Manager modules. Meanwhile, Corrosion Management Plan (CMP) performance shows status of routine corrosion management activities on monthly basis including maintenance pigging and chemical injection program against monthly target.

Another informative feature of the dashboard is that it displays pipelines and stations statistics. This provides a quick overview to users numbers of pipelines that are in operations, preserved and abandoned so that more focused and resources can be put more to those pipelines in operations. Meanwhile, pipeline operating ages and remanining life will enable pipeline engineers to cross check with the pipeline risk and ALARP status in the respective section of the dashboard so that more resources and focus can be allocated to high risk pipelines.

9. CONCLUSIONS

Fully integrated PIMS solution and together integrated with external and in-house software i.e. PETRONAS i-PIMS for total pipeline integrity management for managing pipeline information, including pipeline risk and healthcare status, inspection and maintenance program, resources planning, execution and monitoring is to support for the operationalization of data-driven and analytic-based re-inspection, maintenance and repairs.

Having standardized and integrated PIMS software will realise critical decision-making pertaining to integrity and reliability of pipeline system to be done in 'split seconds' extending the asset life and eliminating unwanted incidents i.e. leak/rupture. The availability of up-to-date and comprehensive pipeline data in centralised database which can be utilised for trending analysis and various data analytics will lead to faster decision and optimization for I&M activities.

It is PETRONAS' aspiration that eventually, descriptive analytic of i-PIMS i.e. critical pipeline integrity performance indicators and critical processes can eventually able to be accessed via mobile apps which will be a 'pace-setter' in overall pipeline integrity management scheme i.e. 'effectively managing pipeline at fingertips'.

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EXHIBITOR UPDATES

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H2-readiness of European pipeline grids: Effects of hydrogen developments on the European pipeline networks

Q: Dr. Schorling, in your presentation at this year's ptc, you were talking about the current European developments in the use of hydrogen, its admixture, and transport in existing pipeline grids. Summarized in one-two sentences, what needs to be considered when planning on transporting hydrogen in such networks?

A: It is assumed that your question refers to the admixture of hydrogen to natural gas, i.e., a case where the hydrogen concentration is small compared to natural gas. We would recommend that the pipeline system considered should be carefully reviewed regarding technical aspects, i.e., materials, lining, flow regimes, etc. - similar as shown in our paper - an activity that ILF is very interested in supporting. In addition, the following is noted: Many of the current European gas pipelines are designed according to EN 1594, EN 12732, etc., i.e., all standards, which currently do not yet consider relevant concentrations of hydrogen. It is understood that these standards are currently updated to reflect as well admixture of hydrogen, an important step to formally regulate the admixture of hydrogen.

Q: What impact does the current hydrogen development have on the pipeline market in Europe?

A: We see that new pipeline projects usually include the requirement for "H2 – Readiness". In many cases, studies shall be prepared to verify that the primary selected process materials are suitable for an admixture of hydrogen. Moreover, the studies shall identify and recommend optional pre-investments. In several cases, existing pipeline systems shall be assessed as well in respect to "H2 – Readiness", where assessments need to be taken to consider as well the life cycle of the installed materials.

Q: "H2-readiness" of existing networks will be the key to minimize the required investments for future transport of hydrogen. Which are the critical elements that determine the degree of H2-compatibility?

A: When speaking about "H2-readiness of existing gas networks", we should really only consider small concentrations of hydrogen compared to natural gas, where "small concentrations" may mean up to 10 Vol.-%. The existing pipeline gas networks have usually been designed for the medium Natural Gas. The physical properties of H2 are significantly different from Natural Gas, and hence, we should not expect that the originally designed systems will be suitable for a very different medium. Last but not least, a maximum concentration of H2 in the natural gas will be driven to a large extent by the gas consumers, which in many cases have restrictions on the composition.

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