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LEAK DETECTION USING PRESSURE TRANSMITTERS FOR PIPELINE NETWORKS CARRYING MULTI-PHASE FLUIDS

MICHAEL ROXAS[2], MATTHEW GIRARD[1] PRAKASH GUNASEKARAN[1], SATYA MOKAMATI[2]
[1]VERMILION ENERGY INC.
[2]VANMOK LEAK DETECTION TECHNOLOGIES INC.,

ABSTRACT

With increasing environmental concerns, regulatory and CSA Z662-23 standard requirements, leak detection in all pipelines has become a top priority for the energy industry in recent years. Real time leak detection on the upstream pipeline gathering networks carrying emulsions from oil wells to separation facilities is very challenging due to the presence of multiple fluid phases in the pipelines. Due to the unavailability of minimum required instrumentation, SCADA/telemetry on the gathering pipeline network and operational complexity, conventional leak detection methods such as volume balance or real time transient modeling are not possible to implement on these pipelines. In addition, the cost-effectiveness of these technologies doesn't make it economically feasible to implement them. In this paper, an approach to monitor the emulsion pipeline networks for leak detection using a pressure-based machine learning algorithm is presented. The machine learning-based algorithm uses the pressure data from the beginning and end points of the network to form a closed system that supports creating a decision on whether there is a leak within the pipeline or not.

This paper will demonstrate that with pressure transmitters at the beginning and end points of the pipeline network carrying emulsions, it is feasible to monitor the state of the emulsion pipelines and measure its effectiveness using leak sensitivity, algorithm reliability and robustness during abnormal and degraded operating conditions as the key metrics. The paper will delve into the intricacies of high-frequency data transmission IoT devices to a private cloud system, which plays a pivotal role in continuously monitoring pipeline networks for leaks. The application of this algorithm will be shown for three different pipeline networks with each pipeline containing fluids that have different phase compositions. The paper describes the performance of this algorithm for incidents ranging from small leaks equivalent to a quarter inch leak hole and a full-bore pipeline rupture, which equates to a loss of volume approximately equal to 5-50% of the nominal pipeline flow rate.

Keywords: Multiphase, emulsion, Machine Learning, Neural networks, IoT, Internet of Things, API 1130, Upstream

1. INTRODUCTION

The oil production wells are connected by a network of pipelines to transport production fluids which mainly consist of a mixture of oil, gas and water. This multiphase fluid is also known as "emulsion". The fraction of these three phases varies depending on the life of the well and well formation. The gas fraction in these emulsions can range from negligible amount (~0%) to 90% by volume.

A typical gathering pipeline network is shown in Figure 1. The pipelines from oil wells are connected to a header, from there the emulsions are transported to a processing facility where the emulsions are separated into individual oil, gas and water phases.

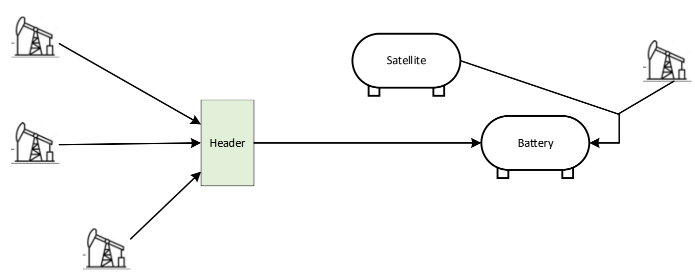

Figure 1 Typical upstream pipeline gathering network.

A common problem for upstream oil and gas producers is the detection of pipeline leaks in their wellhead gathering pipeline networks and network of pipelines connecting processing facilities. These pipeline networks can be adjacent to water bodies, road crossings such as highways, railways, and can be situated closer to public infrastructure, which means that a leak in such high consequence areas could cause devastating impacts. Due to the high number of pipelines in upstream gathering networks, operators are not able to physically attend to all the pipelines in the network on a regular basis. This can be further complicated for those pipelines operating in remote locations.

Upstream companies can benefit from an autonomous, real-time and cost-effective monitoring solution for their emulsion pipeline networks to meet regulatory requirements and maintain reputation in their operating areas.

Efforts to minimize pipeline leakage are crucial not only for environmental reasons, but also for ensuring the safety of operating personnel and the general public, along with the reliability of the pipeline infrastructure. Regulatory authorities and industry stakeholders work together to establish and enforce standards aimed at preventing and addressing pipeline leaks.

Since methane is the major gas fraction component in emulsion pipelines, early detection of leaks in pipelines significantly reduces methane and other greenhouse gas emissions and mitigates the negative economic and environmental impacts of climate change [1].

Gathering pipelines that connect well heads and processing facilities typically lack proper instrumentation such as SCADA and flow meters. Typically, Real-Time Transient Model (RTTM) as well as Volume balance-based leak detection methods require the use of flow meters and pressure transmitters. Due to the cost of the flowmeters themselves, piping modifications, calibration and annual maintenance required, the total installed cost of the solution can be excessive considering the high number of lateral pipeline connections in the upstream gathering network.

Additionally, obtaining SCADA/telemetry communication at remote sites to obtain process signals can drive project costs higher. Flow assurance related issues from emulsions (such as wax formation in turbine flow meters) make it difficult for instruments to measure flow accurately; sometimes they clog the turbine flowmeters which are commonly used in the upstream industry due to their relatively low cost.

Due to difficulty in flow measurements Baptista et. Al [2] used acoustic leak detection systems on multiphase pipelines. However, these systems required SCADA which is not available in upstream areas, also this technology needs installation of pressure sensors to measure a wave signal. However, pipelines in the upstream sector are intertwined underground as a gathering network and it is not possible to install a pressure transmitter at each pipeline intersection. At these intersections, the waves signal would be compromised to do the leak detection.

Gathering pipelines are large in numbers and are typically spread across operating areas of the company. Due to short its length and large numbers, it is very important for the pipeline company to deploy a technology that is scalable and cost-effective while achieving regulatory compliance. In this paper, we presented a technology that uses Internet of Things (IoT) and Cloud to harness the pressure sensors data which becomes the only source of data to machine learning algorithms that monitor multiphase pipelines for leaks autonomously in real-time.

2. LEAK DETECTION FOR MULTIPHASE PIPELINES

The leak detection solution for the multiphase pipeline presented in this paper requires high frequency pressure data as the only source for machine learning algorithms to do real-time and autonomous monitoring and identification of leaks.

2.1 Internet of Things (IoT) technology to harness high frequency data from pressure transmitters:

High frequency data acquisition system presented in this paper uses IoT technology. These data acquisition boxes (IoT Gateways) are connected to pressure transmitters at each end of the pipeline (or pipeline network) to form a closed system within which it is monitored for leaks. The IoT gateways scan pressure transmitters at 50ms sampling and communicate this data via cellular modem to the nearest cellular tower and from there to a Cloud System.

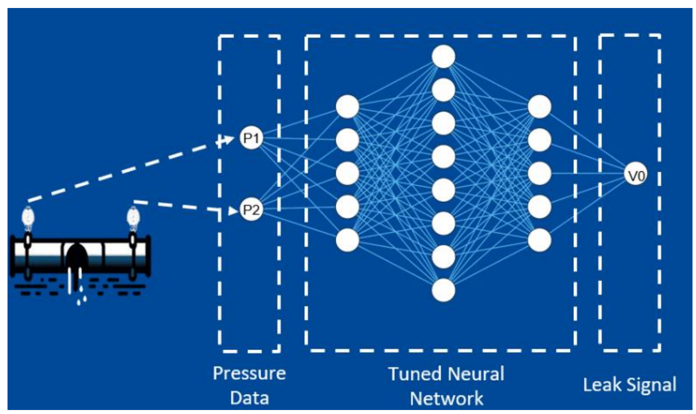

Figure 2 Harnessing pressure transmitter data at a high sampling rate using IoT technology.

2.2 Leak detection technology framework:

The technology presented in this paper uses proprietary leak detection algorithms using neural networks. These algorithms run in real-time on Cloud System (either private Cloud infrastructure or off the shelf 3rd party Cloud platforms) to identify anomalies in the pipeline using pressure data received from IoT Gateways. In the event of a leak, the system can direct alarm notifications to customers' smartphones, emails or both. Figure 3 shows the outline of the technology framework and Figure 4 shows the typical installation of IoT Gateway devices.

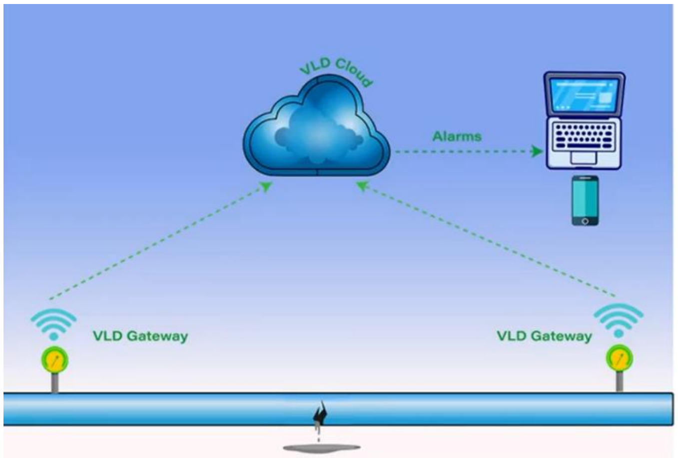

Figure 3 Technology framework showing communication of pressure data from pipeline to Cloud using IoT Gateway devices and alert notifications from Cloud to the end user.

Figure 4 Typical installation of IoT Gateway connected to a pressure transmitter.

2.3 Technology deployment:

As shown in Figure 5, it requires six distinct steps to roll out the leak detection technology:

- Pressure data gathering
- Leak detection model tuning
- Model verification
- Performance evaluation as per API 1130 metrics [2]
- Internal system monitoring
- Production system deployment

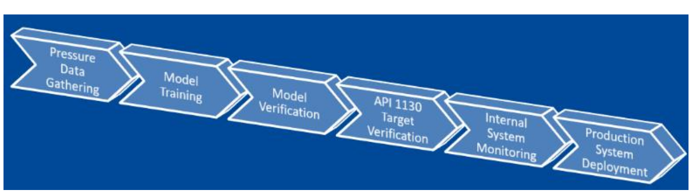

Figure 5 Technology deployment workflow.

The data gathering process involves configuring each pipeline as a closed system on Cloud System. Once IoT gateways are deployed and start sending data, the leak detection model requires four weeks of pressure data to establish typical operating conditions.

Following data gathering, proprietary automation tools tune the leak detection model using neural network methods.

The tuned model undergoes verification for leak detection performance, with sensitivity, reliability, and robustness established for each pipeline based on API 1130 metrics.

Pre-deployment system monitoring is conducted to validate performance over a selected period.

Upon meeting performance metrics, the system is deployed into production. Post-deployment, the system continuously learns pipeline operating conditions and automatically re-tunes the leak detection model on a weekly basis. False positive alarms may occur during this phase, which are investigated and used to refine the algorithm to eliminate future false alarms. Customers receive alarms that are investigated and if deemed false positive, the auto-tuning system learns these false positive alarms and tunes the algorithm so that any future false positive alarms can be avoided under similar circumstances.

3. FIELD TESTING

We chose to validate and evaluate the technology on selected emulsion pipelines based on the Complexity of the pipeline network, percentage gas fraction in emulsion, and length of pipeline stretch.

- Case 1: Long Emulsion pipeline network (~12 km) with 10% gas fraction
- Case 2: Complex Emulsion pipeline network with 13% gas fraction
- Case 3: Emulsion pipeline with highest gas fraction (~80%)

Table-1 Summary of emulsion pipelines considered.

Case	Pipeline Diameter	Gas Fraction	Pressure (Psig)	Oil Flow Rate (m^3/day)	Gas Flow Rate (m^3/day)	Water Flow Rate (m^3/day)	Length (km)	# of Pipeline Segments
1	6”	10%	200-300	1.25	100	61.45	12	3
2	3”	13%	30-120	7.20	220	250	2.5	4
3	4”	80%	100-150	29.7	4.61×10^3	90.5	4	1

3.1 Test Setup

Equipment used in testing includes a trailer mounted blowdown tank, H_2S scrubber, a pipe run with a flow meter and valves and high-pressure hoses. For systems with over 10% H_2S content, a dual scrubber setup is utilized. A 1” access point, typically located at the top of the pipe, is established for fluid removal.

Emulsion withdrawal from the pipeline is facilitated through a correctly sized flow meter and proper valving connected to an access point in the header/piping. The meter run is secured to a frame and linked via high-pressure hoses to a trailer-mounted blowdown tank and an H_2S scrubber.

Dealing with gas in the fluid during withdrawal tests is addressed by acknowledging the liquid turbine meter's inability to accurately measure the gas rate. However, high leak rates (15-20% of line flow) ensure the removal of gas from the system. The spent scavenger chemical confirms gas passage through the scrubber system. Also, the fluid access point at the top of the emulsion pipe ensured that the gas was removed from the multiphase system as the majority of the emulsion pipeline system encounters a stratified flow regime (i.e. gas phase on top of the pipe).

Leak rate control involves pre-calculating it based on the total flow through the line. Valves are opened, and the flow rate is manually set to the desired level, monitored, and adjusted throughout the testing period. In scenarios where access points are challenging, testing may occur outside the leak detection system boundaries, yet successful simulation of leaks in these systems has been achieved.

(a) Test setup showing the fluid withdrawal access point

(b) Test setup showing the blowdown tank and H_2S scrubber

(c) Fluid withdrawal test setup showing the metering run

Figure 6 Fluid withdrawal test setup showing the equipment used at the test site.

3.2 Case 1: Long Emulsion pipeline network (~12 km) with 10% gas fraction

As shown in Figure 7, the group line transfers about 7 m^3/day of oil from a satellite site to a battery. A producing well tie-in underground to this 6” group line coming from a satellite which is 3 km upstream of well. This well produces about 1.25 m^3/day of oil, 100 m^3/day of gas and 61.45 m^3/day of water with a variable gas composition of up to 10% fraction by volume. Up until the tie-in point the pipeline was single-phase oil and after the tie-in point it is a multiphase fluid. The distance from the tie-in point to the battery is about 9 km.

The company tried other leak detection solutions including the installation of flowmeters to perform volume balancing. These proved to be costly to install (pipe modifications plus lost production), costly to maintain and in the end were highly unreliable. Once installed, the flowmeters would wax at either end of the pipeline, increasing production losses and adding ongoing maintenance costs.

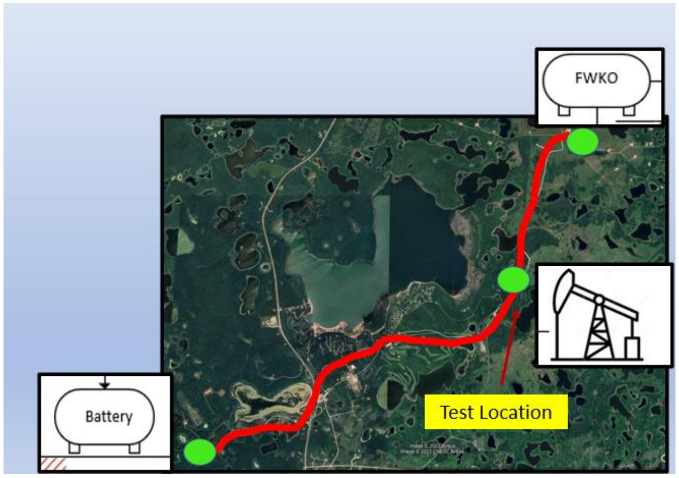

Figure 7 Pipeline Network considered for Case-1.

A pressure transmitter was installed at the beginning of the crude oil pipeline from the separator at the satellite and another pressure transmitter was installed at the wellhead header. A third transmitter was installed at the battery to make it a closed system as shown in Figure 8.

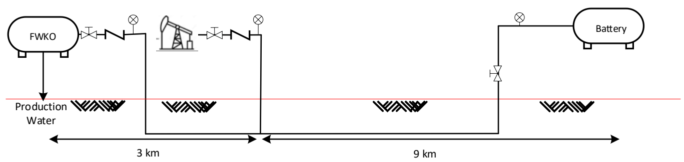

Figure 8 Pipeline from Wellhead/battery showing the location of pressure transmitters.

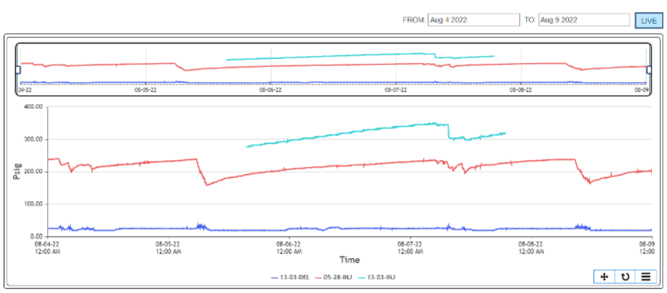

Figure 9 Typical operating pressure in the pipeline over a week. (Red - Wellhead pressure, Cyan – Satellite pressure, Blue - Header pressure (battery))

Table-2 shows the leak tests performed at the leak location marked in Figure 7. Four tests were performed starting with a 1.1 m^3/hr leak rate. However, this leak rate is very close to the threshold leak rate (1 m^3/hr) that the system can detect. Therefore, the system did not generate a leak alarm for this test. The equivalent hole size to generate a leak in the first test was a pinhole of size 2.8 mm. The second leak test was conducted at 2 m^3/hr leak rate through an equivalent hole size of 3.8 mm, which is also a pinhole. A leak alarm was generated by the system after 20 minutes. The third test was performed by decreasing the leak rate to 1.6 m^3/hr through an equivalent pinhole size of 3.5 mm. The system generated a leak alarm after 21 minutes. The last test was conducted by further lowering the leak rate to 1.3 m^3/hr through an equivalent pinhole size of 3.3 mm. The system took 74 minutes to alarm which is more than 3 times longer in duration.

From these tests, the sensitivity of the leak detection system for this emulsion pipeline was considered to be 1.3 m^3/hr leak rate and 3.3 mm pinhole. The percentage leak size based on the oil and water flow rate in the pipeline is in the order of 30% to 50% for the four tests conducted. This value is based on liquid production as the gas content cannot be measured. However, the higher order of magnitude of the percentage leak rate is misleading due to the fact that the leak hole sizes are pinholes (~3 to 4 mm). During the performance evaluation period of one year, no false alarms were generated.

Table-2 Fluid withdrawal test data for Case-1.

Test Number	Leak Rate (m^3/hr)	Leak Hole Diameter (inch)	Nominal Leak Rate (%)	Leak Detected	Time to Alarm (Minutes)
1	1.10	0.11	30.0	N	N/A
2	2.00	0.15	54.4	Y	20
3	1.60	0.14	43.6	Y	21
4	1.30	0.13	35.5	Y	74

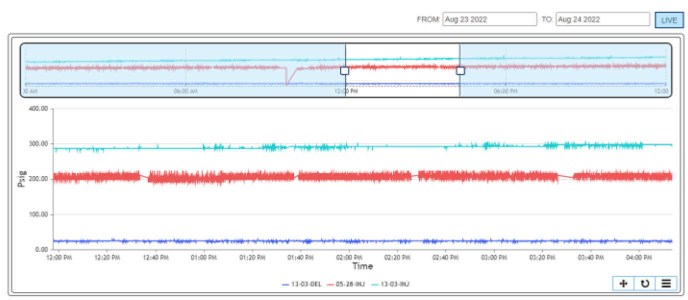

Figure 10 Pressure trends during the leak tests.

3.3 Case 2: Complex Emulsion pipeline network with 13% gas fraction

As shown in Figure 11, this is a 3” diameter and 2.5 km long group pipeline that transfers about 250 m^3 produced water/day, 7.2 m^3 oil/day and 220 m^3 gas /day from four producing wells to a battery. This pipeline is built around a lake; therefore, a leak results in immense environmental impacts on this high consequence area. The average daily volumetric gas fraction in emulsion received at the battery is ~13% (at 73 psi and 40ºC).

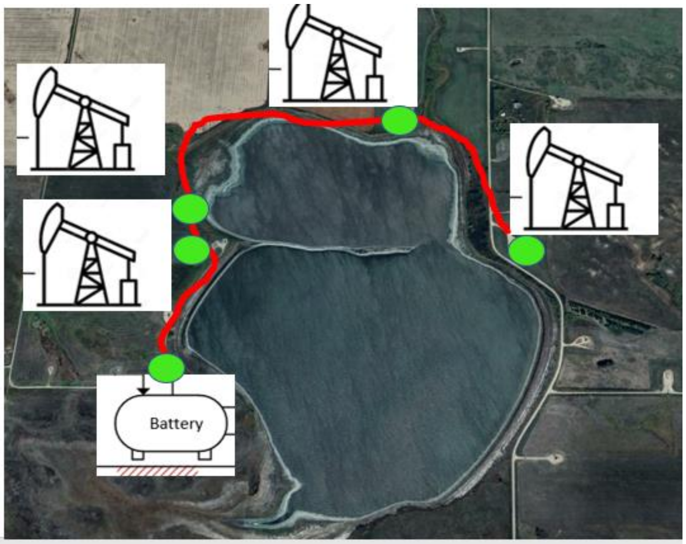

Figure 11 Pipeline Network considered for Case-2 showing pipeline carrying emulsions from four producing wells to a separator.

The pressure transmitters were installed at the beginning of emulsion pipeline from each producing well and at the battery end of the pipeline as shown in Figure 12.

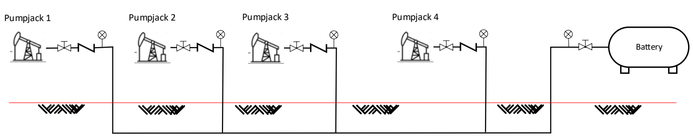

Figure 12 Pipeline from Wellhead/battery showing the location of pressure transmitters.

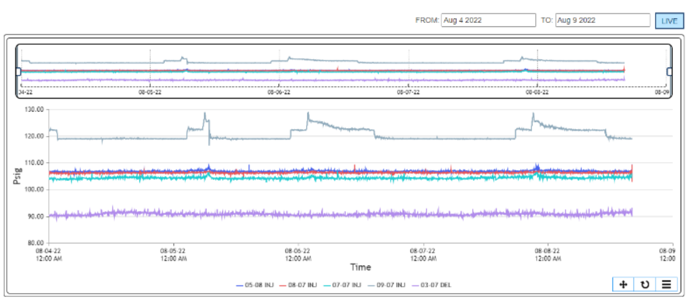

Figure 13 Typical operating pressure in the pipeline over a week. (Blue – Pumpjack 1 pressure, Grey – Pumpjack 2 pressure, Red – Pumpjack 3 Pressure, Teal – Pumpjack 4 pressure, Purple – Battery pressure)

Table-3 shows the leak tests performed at the delivery location of the emulsion pipeline near the separator. Three tests were performed starting with the highest leak flow rate of 3.6 m^3/hr. The equivalent hole size to generate a leak in the first test was 6.35 mm. The leak detection system generated alarms after 21 minutes. The second leak test was conducted at 2.1 m^3/hr leak rate through an equivalent hole size of 4.8 mm. The system took the same time to generate a leak alarm as the previous test (21 minutes). The third test was performed by decreasing the leak rate to 1.2 m^3/hr through an equivalent pinhole size of 3.5 mm. The system generated a leak alarm after 69 minutes which is more than 3 times longer in duration.

From these tests, the sensitivity of leak detection system for this emulsion pipeline was considered to be 1.2 m^3/hr leak rate and 3.5 mm pinhole. The percentage leak size based on the flow rate in the pipeline is in the order of 20% to 60% for the four tests conducted. However, the higher order of magnitude of the percentage leak rate is misleading due to the fact that the leak hole sizes are pinholes (~3.5 to 6 mm). During the performance evaluation period of one year, no false alarms were generated.

Table-3 Fluid withdrawal test data for Case-2.

Test Number	Leak Rate (m^3/hr)	Leak Hole Diameter (inch)	Nominal Leak Rate (%)	Leak Detected	Time to Alarm (Minutes)
1	3.60	0.25	61.3	Y	21
2	2.10	0.19	35.8	Y	21
3	1.20	0.14	20.4	Y	69

Figure 14 Pressure trends during the leak tests.

3.4 Case 3: Emulsion pipeline with highest gas fraction (~80%)

As shown in Figure 15, the emulsion pipeline considered was a 4" diameter and 3.88 km long steel group line that transfers about 30 m^3/day oil from two satellite sites to a header. The second satellite ties into this line ~0.8 km from the beginning of the pipeline. The distance from this tie-in point to the header is ~3.1 km. The total fluid breakdown for this group line is 29.68 m^3/day oil, 90.45 m^3/day water, and 4.61 x 103 m^3/day gas. This pipeline has a variable gas fraction of approximately 80%.

Figure 15 Pipeline Network considered for Case-3 showing pipeline carrying emulsions from two satellite sites to a separator.

The pressure transmitters were installed at the beginning of the emulsion pipeline from each satellite facility and the field header end of the pipeline as shown in Figure 16.

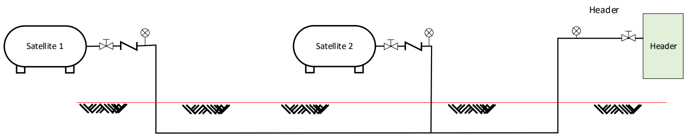

Figure 16 Pipeline from two satellites to header at a battery showing the location of pressure transmitters.

Instrument Accuracy:

Figure 17 shows the typical operating pressure in the pipeline over 12 days period.

In comparison to the pressure trends in the other two cases, this data displays a larger amount of noise. The noise in this data is due to the instrument's accuracy. The instrument procured for leak detection on this pipeline has 1% on full-scale accuracy. The line operating pressure is about 100 psig, however the transmitter full scale range is 0 to 1000 psig.

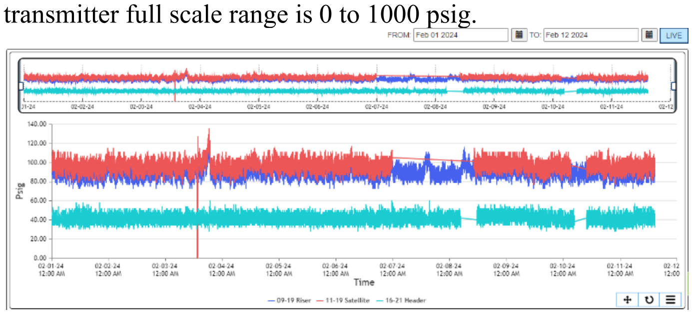

Figure 17 Typical operating pressure in the pipeline over 12 days. (Blue – Satellite 2 pressure, Cyan - Header pressure (battery), Red – Satellite 1 pressure)

Table-4 shows the leak tests performed at the leak location marked in Figure 15. Three tests were performed starting with 0.75 m^3/hr leak rate. Even though this leak rate is below the system threshold leak rate (1 m^3/hr), the system generated a leak alarm after 2 hours (131 minutes). The equivalent hole size to generate a leak in the first test was a pinhole of size 2.8 mm. The second leak test was conducted by increasing the leak rate to 1 m^3/hr through an equivalent hole size of 3.8 mm, which is also a pinhole. A leak alarm was generated by the system after 36 minutes. Third test was performed by decreasing the leak rate to 0.5 m^3/hr to check the lowest possible sensitivity for a pinhole leak. The leak rate of 0.5 m^3/hr was too far below the system threshold (1m^3/hr) which is why our system did not alarm.

From these tests, the sensitivity of the leak detection system for this emulsion pipeline with 80% gas fraction was considered to be 0.75 m^3/hr leak rate and 2.8 mm pinhole. The percentage leak size based on the flow rate in the pipeline is in the order of 15% to 20% for the three tests conducted. However, the higher order of magnitude of the percentage leak rate is misleading due to the fact that the leak hole sizes are pinholes (~2 to 4 mm).

During the performance evaluation period of 10 months, 10 false positive alarms were generated. All of those 10 false positive alarms were generated over two days after the leak test was completed. The only operation that occurred after the leak test was that the operator sent and received a maintenance pig. But they have been doing this every 2 weeks, as the pigging is on a bi-weekly frequency and we have not received any false positive alarm in the past. The alarm stopped after 2 days of leak test. We are still sending and receiving pigs with no alarms. We suspect a process upset in the field header piping to cause the false alarms after the leak test.

There were no other false positive alarms since the system rolled other than alarms received on June 6th and June 7th.

Table-4 Fluid withdrawal test data for Case-3.

Test Number	Leak Rate (m^3/hr)	Leak Hole Diameter (inch)	Nominal Leak Rate (%)	Leak Detected	Time to Alarm (Minutes)
1	0.75	0.11	15.0	Y	131
2	1.00	0.15	20.0	Y	36

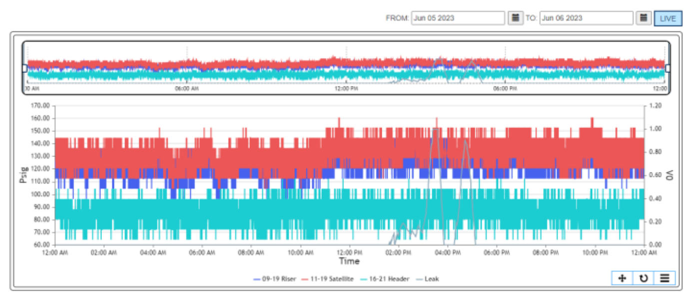

Figure 18 Pressure trends during leak tests.

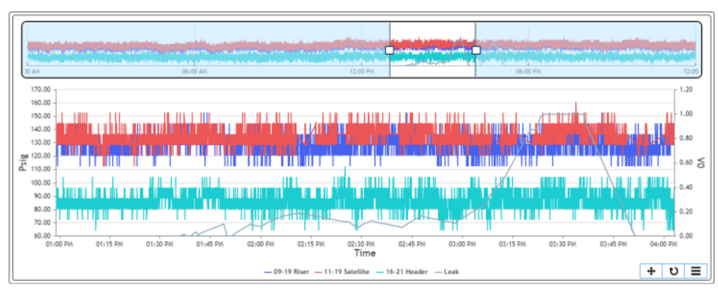

Figure 19 Test 1 | Pressure trends for 15% leak test.

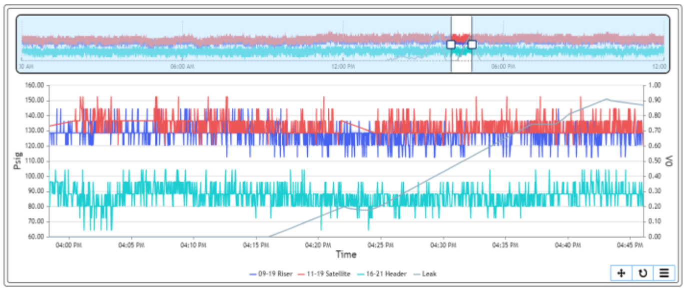

Figure 20 Test 2 | Pressure trends for 20% leak test.

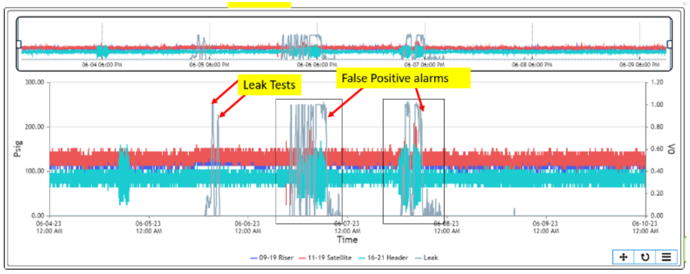

Figure 21 Pressure trends showing the leak test and false positive alarms generated on the day after the leak test.

Figure 22 Pressure trends during the false positive leak alarms

4 LEAK DETECTION PERFORMANCE AND DISCUSSION

The leak detection system performance was evaluated as per API 1130 metrics--Sensitivity, Reliability and Robustness. Even though Accuracy (leak localization accuracy and leak size accuracy) is one of the metrics of the leak detection performance, it was not considered due to the following two reasons.

1. In a network of pipelines, the system has limitation to localize the leak location. However, the system can detect leak location? in a single-segment pipeline with no other segments tie-in. The length of pipeline networks is less than few kilometers. Therefore, identification of segments will allow the company to isolate the network and prepare for spill response.
2. Flow rate in the pipeline at the inception of leak is required to estimate the percentage leak size. Due to the lack of flow meters on the pipeline networks, the leak size accuracy cannot be obtained. However, the pipelines that were considered in this paper have flow meters on the test pipe run, but leak size estimation by the system was not considered. It was manually calculated using a flow meter installed on the leak test apparatus and a flow meter on the pipeline.

Sensitivity:

Leak detection system performance based on sensitivity shows how small a leak the system can detect and the time it takes to send alarm alert notifications. The sensitivity is typically expressed based on the % leak rate compared to the average flow rate in a pipeline. However, in this paper we attempted to present sensitivity based on leak hole size and leak flow rate.

As shown in Figure 23, for emulsion lines with gas fractions 10% and 15%, the leak response time is in the same order of magnitude even though the leak hole size varied from 3.8-6.4mm. Emulsion pipeline with an 80% gas fraction took a relatively longer time to alarm for approximately the same leak hole size. As the leak hole diameter decreased by 0.04”, the alarm time increased significantly from 36 minutes to 131 minutes. The data shows that the leak response time increased for the emulsion pipeline as the gas fraction increased.

From Figure 23 (sensitivity based on leak hole diameter), Figure 24 (sensitivity based on % leak rate) and Figure 25 (sensitivity based on leak rate(m^3/h), it can be observed that the leak detection system responded 27 minutes earlier for emulsion pipeline with 80% gas fraction compared to pipelines with 10% and 13% gas fraction for the same leak size of 20%.

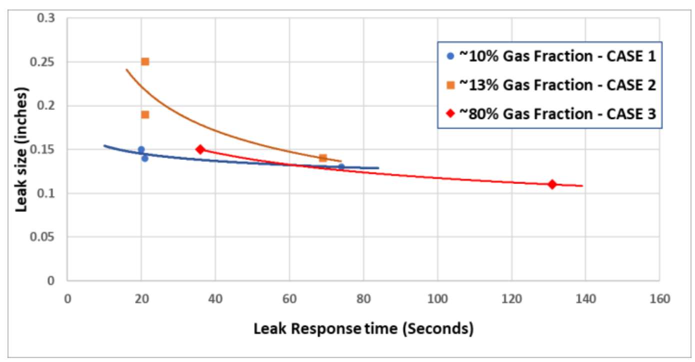

Figure 23 Leak detection system sensitivity with respect to leak size based on leak hole diameter for various gas fractions in the emulsion pipelines.

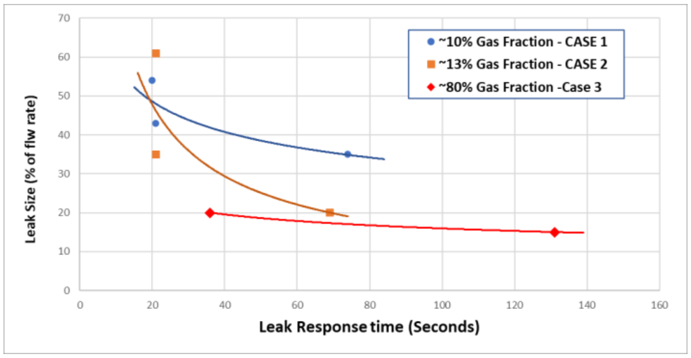

Figure 24 Leak detection system sensitivity with respect to leak size based on % leak rate for various gas fractions in the emulsion pipelines.

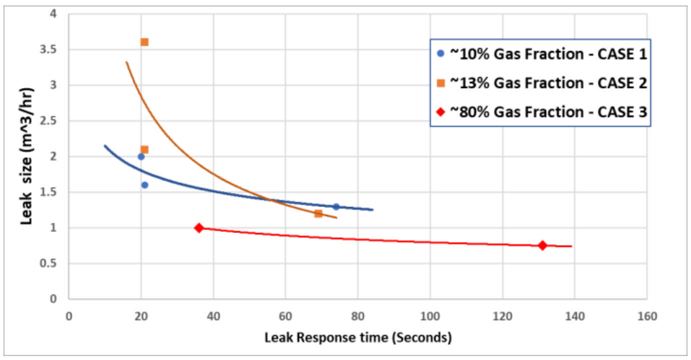

Figure 25 Leak detection system sensitivity with respect to leak size based on leak rate m^3/h for various gas fractions in the emulsion pipelines.

Reliability:

Leak detection system performance based on reliability is evaluated by the number of false positive alarms received per week/quarter/month or year. No false positive alarms were received for emulsion pipelines described in Case 1 and Case 2 over a period of 11 months.

The process upset at the field header piping for Case 3 caused 10 false positive alarms over two days. No other false positive alarms were reported during the rest of the days over 10 months of pipeline operation.

Robustness:

The leak detection system should demonstrate its robustness by maintaining the leak detection performance (sensitivity and reliability) during the abnormal and degraded operating conditions of the emulsion pipeline. The leak detection system maintained its performance in pipelines described in Cases 1,2 and 3 in spite of the presence of multiphase fluids with gas fractions ranging from 10% to 80% (which already degraded the conditions for leak detection). The robustness was also maintained during abnormal operating conditions, such as transients in the pipeline, and degraded conditions, such as noisy data from the instruments. Even though there were frequent cellular network communications interruptions, the robustness was maintained by the leak detection system by autonomously restarting the leak detection system after communication was established. The leak detection system maintained its performance by continuously learning and auto-tuning every week.

5 TECHNOLOGICAL CHALLENGES, CONTINUOUS IMPROVEMENTS AND FUTURE WORK

5.1 Technological challenges, continuous improvements

Cellular Network Connectivity:

Cellular network connectivity in remote areas of the oil fields is a challenge. The challenges are attributed to the availability of cellular towers in the nearby area and the cell signals blocked by the tree lines and oil field facility buildings. Some of these issues were addressed by mounting antennas (with high gain) on a mast up to 20 feet high. The cellular network issues in the low signal strength areas were also resolved by making continuous improvements to the hardware and firmware of the IoT Gateway. We are planning our future work to address poor cellular connectivity or no connectivity at all by implementing LoRaWAN technology.

Off Grid Power Source:

IoT gateways were powered by solar where there is no access to grid power. During extreme winter weather conditions and cloudy days with no sunlight for extended periods, the batteries were deep cycled with power interruptions to the IoT gateway. The issues related to solar power were resolved by increasing the battery capacity and solar panel power rating.

5.2 Future work

We plan to further evaluate the performance of the technology for leak detection on emulsion pipelines with gas fractions higher than 80% and reaching 100% gas fractions. The limit of the technology presented in this paper will be tested for pipelines longer than 12 km.

6 CONCLUSION

The study presented in this paper addresses a critical need in the upstream sector: leak detection in pipeline networks carrying multiphase fluids. Traditional methods prove inadequate due to operational complexities and cost constraints. Leveraging pressure transmitters and machine learning algorithms, the paper demonstrates a novel approach to real-time leak detection. Through extensive field testing across various pipeline configurations, the system's effectiveness, sensitivity, reliability, and robustness as per API 1130 metrics were evaluated.

The results indicate promising performance across different scenarios, showcasing the system's ability to detect leaks accurately and autonomously. Sensitivity analyses based on leak hole size, percentage leak rate, and leak flow rate reveal consistent performance across pipelines with varying gas fractions. Moreover, the system exhibits reliability, with minimal false positive alarms observed during extended operational periods.

Robustness assessments highlight the system's capability to maintain performance under adverse conditions, including multiphase fluid compositions and transient pipeline states. Continuous learning and auto-tuning mechanisms ensure adaptability and ongoing optimization, enhancing system resilience.

Despite technological challenges such as cellular network connectivity and off-grid power sources, continuous improvements have been made to address these issues. Future work aims to expand the system's capabilities to handle higher gas fractions and longer pipeline lengths, further enhancing its utility and applicability.

In conclusion, the study underscores the efficacy of pressure transmitter-based leak detection augmented by machine learning algorithms in addressing critical environmental and operational concerns in the upstream energy sector. This innovative approach offers a cost-effective and scalable solution, aligning with regulatory requirements and industry standards, thus enhancing pipeline safety and integrity while mitigating environmental risks.

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