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LEAK DETECTION SYSTEMS FOR MULTIPHASE FLOW – MOVING FORWARD

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ABSTRACT

Multiphase flow is one of the most difficult situations for leak detection in pipelines, due to several reasons: the existence of two different and independent flow rates at each phase, five or more possible flow patterns, different fluid velocities at the phases, and sometimes a non-Newtonian associated behavior, due to the formation of an oil-water emulsion.

There are two main groups for leak detection techniques: the models (or CPM, as stated in [API_1130]) which monitor the flow in real time (CVB, RTTM, PPA, etc.) from inside the pipeline (the instrument sensor is actually in physical contact with the fluid), and try to model the flow using a state estimator; and those based on dedicated external sensors (thermal, mass dispersion, etc) along the pipeline. Most of the technologies at the first group rely entirely on volumetric flow rate measurements, which turn them quite ineffective for multiphase flow.

It is also relevant to consider that in some multiphase flow pipelines, the flow pattern changes quite random and intensively, allowing from a bubble pattern, to a slug pattern. There is sometimes the situation where a gas slug is big enough to fill entirely a short line and allow it to behave similarly to a gas pipeline, during a certain time (in fact, this was the case of one of the field tests this work will describe). This will bring unpredictability to those lines, in opposition to a regular single-phase line. Within this frame, the systems based on prediction approaches (hydraulic, statistical, etc, i. e., CPM's), will show a good probability to be unreliable, inaccurate and not sensitive.

The acoustic system is an exception to those two groups of technologies previously mentioned. It has, on one hand, a sensor that really touches the fluid (which would suggest it to be within the first group), but there's no flow model behind it, on the other hand, but an acoustic sign analysis algorithm, acting somewhat like a piece of hardware.

This paper will describe, discuss and report data for tests using an acoustic leak detection system at three different multiphase flow pipelines in Brazil, managed by PETROBRAS Production & Exploration Department.

INTRODUCTION

Pipelines carrying crudes directly from oil fields do not have their operational conditions easily determined. Their scenarios vary constantly due to a diversity of factors, such as: variation in transport properties, caused by the fact that the wells may produce from different reservoirs. The gas to oil ratio (GOR) for the same reason is not a well-known and stable variable. Considering these pipelines are submitted to substantial temperature variation (for instance: submarine transportation), this variable also has considerable effect on the flow behavior.

As mentioned before, any leak detection option that considers the use of flow measurement was discarded due to the intrinsic multiphase flow difficulties. Once considered this premise, efforts were made to identify a technology based on alternative methods, leading to the use of acoustic as a prime attempt.

To make sure this would be an effective technology for leak detection under the above conditions, a first trial was accomplished in a complex multiphase pipeline network, located in the Amazon rain forest. After two rounds of tests, with adequate results, and the adoption of this technology for using in other PETROBRAS production areas, two other pipelines were chosen to receive the same system, and, tests were once again implemented.

THE ACOUSTIC TECHNOLOGY

Acoustic leak detection operates by detecting and processing a very low frequency part of the pressure signals generated by a leakage. Any pipeline has its own pressure noise pattern, which shall be discarded by filtering techniques within local (or site) stations located along the pipeline. It is up to these units to condition the signal for the processing of a so-called master station.

A station is a piece of hardware composed by a processor unit (a main board with TI processor), a GPS device and a firmware ROM memory. It is able to communicate with the other stations using the common communication approaches like radio links or even to link with SCADA, and let to the SCADA to manage the communication task.

As far as location goes, due to a random distribution of the two phases within the pipeline, an uncertainty associated with the leak location determination occurs. Significant if compared to single-phase pipelines where the acoustic velocity is relatively constant. So as to minimize this loss of accuracy, on-line leak tests are a tool to verify the actual acoustic wave velocity, and thus mitigate this drawback.

Once the leak location is based upon the monitoring of the time taken by the site stations to sense it, all nodes which are parts of the leak detection system shall operate under synchronous time, which is accomplished by the use of external GPS devices.

The attached figure 1 illustrates the adopted system architecture for the first test implemented at Urucu Field, located in the Amazon Forest, Amazonas, Brazil.

As shown on the above-mentioned figure and previously mentioned, the system is composed of:

Master Station: this component runs all the leak location and detection functionalities using a similar hardware to those used for the site stations (remote units), but with a more complex firmware and applicative programs. Whenever there is a detection of an event the master station waits for a second site station to raise a flag for the same event. If so happens, then the location calculation is carried out. Otherwise, a warn of a non confirmed leakage is issued at the HMI (operator's interface).

Site Station: it is up to these stations to run the time stamping and signal filtering functions. As far as filtering goes, different filters are used (which will be later commented) so as to wipe all inherent installation noise and send a cleaner signal to the master station. Follow some description of the system.

Sensors: Special pressure transmitters, dedicated to sense pressure wave signals, directly in contact with the fluid transported by the pipeline, providing 4-20 mA output signals to the site stations, are used.

Detection time

The required leak detection time is the sum of two parcels: the time required for an acoustic wave to travel to a monitored site, which is calculated dividing the distance between the leak and the adjacent upstream/ downstream monitor sites by the acoustic velocity in the fluid pipeline medium; the second parcel is the time required for the master station to scan all local stations and calculate the leak location.

False alarms handling

The local stations employ the briefly described techniques for reducing false alarm rates: dual element acoustic sensors at the boundaries of the monitored pipeline segment; matched filters, which use the signature of a leak from a database as a mask against which real-time pressure data are compared. This database was built using a comprehensive set of field data, including both field leak data as well experimental leak test data for various pipeline operating conditions, several fluids, and different degrees of dissipation and dispersion. The technique uses a fingerprint matching active identification on the true leak signal which attempts to reduce the false alarm rate, seeking to increase the location accuracy and sensitivity. Among the filtering techniques, there are: digital high pass and low pass filters with auto-adjust roll-off frequencies; moving average filter with a tuned dynamic adjusted window to filter out noise; dynamic threshold logic, using an auto-adjust algorithm to distinguish random noise and other events from true leak signals (It continuously scans, computes, and verifies all incoming data and automatically adjusts the dynamic thresholds); repetitive filters: several types of repetitive filters were built to suppress other various unusual noise sources.

False alarm rate is a function of frequency of activity (sudden pressure changes on the pipeline associated with operating changes.) The use of the previously cited filters is an attempt to reduce them significantly.

<u>Leak location</u>

When a leak occurs, the GPS times are recorded. The master station uses acoustic parameters that describe the pipeline operating conditions. It also uses the distance between site stations along with GPS arrival time to confirm the occurrence and determine the location of a supposed leak.

The accuracy of leak location is affected by two principal types of errors: timing errors associated with communications and synchronization; and changes in sound velocity due to changes in temperature, pressure and other operating parameters. In case of loss of communication or communication faults, the leak signal will still be detected by the local sensor and registered with GPS time stamp at the corresponding local station. This information will be used to compute leak location when communication resumes. Tuning of acoustic velocity parameters during commissioning will attempt to reduce location errors due to changes in sound velocity.

THE TESTS

The following section of this paper describes three different applications where leak detection based on acoustic technology was successfully tested.

In all three cases, detectors were installed in the pipeline, after a detailed study of each case sensors, which allowed the customization the acoustic detection system to each application, by defining the adequate quantity and location of sensors, considering the existence of secondary branches, process vessels and equipments like pumps and valves, as well as allowed the mitigation of the excessively long sections effect, thus improving the response of the complete system.

In some cases as further described in this paper the use of sensors in the middle of the length was not possible, considering the application involved a sub-sea pipeline, thus, effecting the accuracy of the final results as it will be shown when detailing this specific application.

As communication medium, used to transmit data from the site stations to the master one, for all three cases the choice was the use of half-duplex radio-modems, modulating in frequency, transmitting in a band of 500 to 542 MHz, with output transmitting power of up to 5W. The chosen communication rate was 9600 bps.

So as to provide the same time base for all nodes of each network, necessary to adequately run the location routines, GPS devices were installed and connected to all remote and master stations, equalizing the time base used by all nodes of the same system.

All tests were implemented producing an actual leak, by opening valves previously installed along the length of the pipeline for this purpose, and bleeding the content of the pipeline to accumulation tanks.

For all three applications it was necessary the development of specific filters, to eliminate the effects of the typical noise of each application. This was accomplished by setting acoustic detection threshold higher than the noise level detected in each application, based upon acoustic records of the mentioned existing noise.

Downstream these valves, calibrated orifice plates and pairs rupture disks were installed, the firsts intended to make possible variation of the hole size, and the seconds to emulate the typical noise generated by the abrupt rupture of a pipeline wall, as it happens in accidents, as well as to provide means of controlling the start of the leak, by depressurizing the interchamber formed by the mentioned pair of disks, previously kept at an intermediary pressure value using nitrogen which once removed by bleeding the chamber caused the immediate rupture of both disks.

During the sequence of tests these plates were changed, decreasing the orifice size, until the limit sensitiveness of the system was reached.

A test was only considered as valid once it had its occurrence confirmed by more than a detector, and its location determined as well.

An important point to be highlighted regarding to the use of this technology is about its limitations. As any other leak detection system, it also has its application range and events where its inherent characteristic does not allow and effective detection. For this sort of system, limitations are regarded to the accurate determination of leak rate. As an option, this system will provide an estimated leak rate (~ 2 to 10% accuracy) based on signal strength. Becaue there is no flowmeter used in this system, it is not easy to accurately calculate the leak flow rate. However, considering all possible leak accidents in a pipeline, and the existence of other methods to detect the degradation of wall thickness, this method still presents big advantages over others regarding to the fast response, and accurate location, once regarded the above mentioned restrictions.

Test #1: Urucu pipeline

As mentioned before, the first set of tests of this acoustic leak detection technology was implemented in a very environmentally sensitive crude oil pipeline, e.g. located in the middle of the Brazilian Rain Forest.

This pipeline which was equipped with a detection system as shown on the figure, deals with a very light crude (API degree 38-40), and collects production of over 40 wells distributed along its total length of approximately 36 km, taking it to a gathering station named Polo Arara at its end.

Pressure along this pipeline experiences substantial decreases along its route, starting at the farthest end from its final destination at values around 74 kg/cm^2g and arriving at around 14 kg/cm^2g. The combination of these factors favors the change of phase from liquid to gas as pressure and temperature experience changes along the pipeline length. To mitigate this scenario, along its route, here are six separation stations, where the gas formed by pressure losses and temperature variations is removed and sent via a second pipeline also to the above-mentioned gathering station.

After the tests were implemented, analysis of the obtained data showed the system had capability of detecting and locates holes ranging from 0.2 to 0.5 inches. The average error on the leak location was of +/- 200m, which compared to the total length of 35900m, was considered as within the range of expected and acceptable results.

These tests were implemented in two sets, being the first round implemented in July/2001, and the last one carried out in October/2001. Since the first tests, the system was left in operation, so as to evaluate its stability to spurious alarms. Since then, no false alarms were generated by this system, proving its stability regarding to this subject.

Test #2: PGA-3 / EPA pipeline

The figure 2 shows the architecture implemented for the second test, where a sub-sea pipeline which links a platform named PGA-3 to a on-shore treatment station in Aracajú/SE/Brazil named EPA, received the same acoustic leak detection system.

This 16", pipeline works with an inlet pressure of 12,6 kgf/cm^2g and output pressure of 1.3 kgf/cm^2g, carrying crude produced in a complex of platforms where PGA-3 is the central one. Once again, a case where the oil is very light, and the pressure losses along the pipeline cause changes in the physical state of the fluid, from liquid to gas, generating a multiphase flow.

As shown in the figure, at the side of the platform only one sensor was used. The reason for using two sensors is to eliminate noise generated upstream the segment to be monitored, but measurements at the platform indicated a very low inherent noise level, thus, not justifying a second sensor. Still about the use of two sensors, so as to allow a perfect filtering of the existing noise, it is necessary to keep a distance of at least 60 meters between both of them.

After implementing tests according to the same procedure described for the Urucu pipeline, the final results indicated this system was able to detect holes with initial diameters equal or bigger than 0.5 inches, which according to the results given by process simulators corresponds to a leak of 0.53% of the flow handle by this pipeline.

Once this test was carried out during a big gas slug, it was possible to track the volumetric flow rate at both boundaries of the segment being monitored. Thus, through the use of a numerical flow simulator, it was possible to convert a hole diameter to an actual leakage volumetric flow rate, and to raise the sensitivity curve show on figure 3. Even for a short monitored segment (15,7 km), those results were considered relevantly positive, as we were talking about a gas pipeline, and a 0.5% flow rate leakage was detected and located properly, in a very small time.

As an average, the time taken from the beginning of the test to its detection was smaller than 15 seconds, and the accuracy on the leak location was around +/- 300m, a small error, if compared to the pipeline total length of 15731 m.

Test #3: PCA-02 / Fazenda Cedro pipeline

This third test was implemented in a pipeline 18537m long, which connects an offshore platform (PCA-02) to a treatment station (Fazenda Cedro), in Espirito Santo – Brazil. Of the total length, 9794 m runs undersea and the remainder 8743 m are onshore.

This 6" pipeline handles a crude heavier than in the two previous cases (API 36), and has an inlet pressure of approximately 9,7 kgf/cm^2g, and output pressure of 2,3 kgf/cm^2g.

The architecture used was exactly the same used in the PGA-3 / EPA case, and the results obtained with tests indicated the system is able to detect holes with initial diameter of 0,35" or bigger, and the accuracy on the location was around +/- 40m, for a testing point located 9644 m away from the zero reference (location of the onshore second sensor).

Comparing these two last cases we can see the effect of the proximity of a leakage point to the zero reference, due to errors in the measurement of the time delays used to calculate the position of the leak point. In the first case where the leak was emulated only 194 m away from the zero reference, the obtained accuracy on the location (+/- 300m) was almost ten times the one obtained for the last case (+/- 40m).

DISCUSSIONS

Considering the probable worst condition for leak detection, using a technology usually not familiar to the one who handles flow analysis, some issues may be analyzed, initially in a general approach independently from the field results, but with a strong operational approach, as follows.

Signal range for good performance

A question usually comes: what would happen, if the pressure signal goes to a low level, e.g., something closer to the atmospheric pressure, or even vacuum? In a practical sense, there would have a point where the signal would be lost by attenuation at the other boundary of the monitored segment. What would be this number? Similarly to the CPM's, it would depend on a sort of reasons, but mainly the distance between measurement takes and the nature of the inventory. As a rule of thumb, field data has shown us that this technology works better in a flow where the pressure is 3 kgf/cm^2 or higher.

Noise filtering

Valves, pumps, compressors, physical filters, and some other line equipments are natural noise generators. All those equipments must have their noise filtered, i. e., during the commissioning (tuning), in order to get the flow properly tuned.

Deep-water offshore lines

Imagine a pipeline laid over the deep of the sea, in a 2000 m water dept. This would bring something like 200 kgf/cm^2 as external pressure. If a leak happens, probably, it will cause the water to invade the pipeline, i. e., a "negative" leakage. Even for not that hard external pressure, probably special care must be taken in order to approach submarine leakages. Two special water column leak tests were perfomed to verify the capability of this system in detecting leaks in a pipeline laid over the the deep of the sea. Both leaks were detected with leaks initiated under a column of water of different height. These tests positively proved that this method is suitable for detecting leaks in a sub-sea pipeline.

Sensitivity analysis "a priori"

What could be done, in a way to obtain an estimate of the system performance, a priori (i. e., with no field experiments, for instance, to be put in an environmental study)? The answer is, a study may be carried out, given the pipeline configuration and fluid data, to determine a similar sensitivity curve, but, instead of a leakage volumetric flow rate percent, there is a hole size against the detection time. Hydraulic simulations may be accomplished in order to convert from hole size to actual flow rate, if an estimate of operational data (especially flow rate) is available.

Detection time

The initial results from the field have suggested a first impression that the detection time doesn't vary against the hole size, which has shown to be false, as new data was coming. Actually the time varies in a not that much sensible way, but it does vary. The sensitivity curve, hole size against detection time is pretty much inclined than the usual RTM/RTTM expected curve, but it is not a vertical line. Again, given some hydraulic actual operational data, it is possible to convert from hole to flow rate.

Distance between measurements

Even considering that the used pressure wave sensors are non conventional PT´s (they are actually a more sensitive pressure transmitter, in the sense of a scan rate of some thousands of reliable data within a second), the maximum distance between two sensors are, similarly to the CPM´s, a function of the type of inventory within the pipeline. But there´s a difference: in CPM´s, with a big distance, there´s still leak detection functionality, in a degraded way; in this case, a similar behavior will be obtained, until a certain limit, from which the leak detectability will no longer be available.

CONCLUSIONS

Performance considerations

Since this technology is not exactly based on a flow hydraulic considerations, some of the usual parameters shown on API 1155, were not easy to raise, forcing us to go through some adapting procedures in order to properly match to that parameters.

Reliability

This is one of the key issues of this technology. Some companies rely on it to perform automatic leak combat directly from the software intelligence, without human interference for shutting down the turbo machinery and closing the block valves, for instance. This surprising high reliability comes essentially from the filtering techniques and dual sensing approach. However, the old balance between reliability and sensitivity is also present, and it is quite relevant.

Sensitivity

This was a positive discover from this tests. The system is very sensitive, even for multiphase flow. In equal conditions, it tends to overcome CPM's for single-phase gas pipeline, as verified in test #2, shown in fig. 3. It was plotted the actual results using acoustic technology (full line), and the best theoretical result a model (CPM) hyperbola could achieve, considering that it would be possible to have a gas flow meter to allow the same performance for the upper point (a very unrealistic assumption – dotted line). Once this test #2 has had the leaked point quite closer to one of the site stations, it has initially suggested that, in a leakage located closer to the center of the monitored segment, the sensitivity would fall. That premise has shown to be false, as the sensitivity in test #3 has remained in a higher level. Plese consider the flow rate percent shown in figure 3, as the ratio between the leaked flow rate and the pipeline nominal operational flow rate.

Accuracy

Leak location was the single variable that could be assessed under the accuracy point of view. Respecting the spacing between measurements takes, and the problem of a leakage happening in point close to one of the boundaries, it has also shown a positive behavior, especially given the circumstances of a multiphase approach.

Robustness

This technology is an example of high robustness being provided by putting dual equal devices (the site stations sensors) given different functionalities to each of them. The first is indeed used to sense the sign which will be analyzed,the second one is to filter. The robustness is much better than the one present in RTTM models.
If you lose one of the flow channels at that technology, you still have leak detection, but in a degraded way. In this acoustic example, depending on the signal noise, you can lose one of the sensors without any big impact on leak detectability. However, in this case, the common decision in not to install the second one due to non-technical reasons.

Impact on leak location

Similarly to other techniques (e. g., RTTM's and CVB's), leak location has degradation if the leak is very close to one of the boundaries. It was properly verified at the test #2. This method has better location accuracy than others.

Suitability

Not only multiphase flow pipelines are suitable for this technology. Probably almost all lines may use this technique, especially gas pipelines, observing some constraints, and other non-technical issues. Initially, there are elements to imagine that this technology would not be at best performance in a line with slack flow or column aperture, due to signal attenuation in vacuum, As to information gathered so far, this assumption was incorrect. The effect was small after the data properly analyzed.

Some final remarks

Similarly to the CPM's, this technology degrades performance as the spacing between measurements increases, as well as when the inventory compressibility gets higher. However, in a different way: it is far more sensitive, and there will have a point where the leak detectability will simply be toggled off, as the CPM's will monotonically decrease performance. To find out this point is an issue.

REFERENCES

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American Petroleum Institute - API, 1995, "Evaluation Methodology for Software Based Leak Detection Systems", publication #1155, First Edition.

PETROBRAS URUCU MULTIPHASE PIPELINE

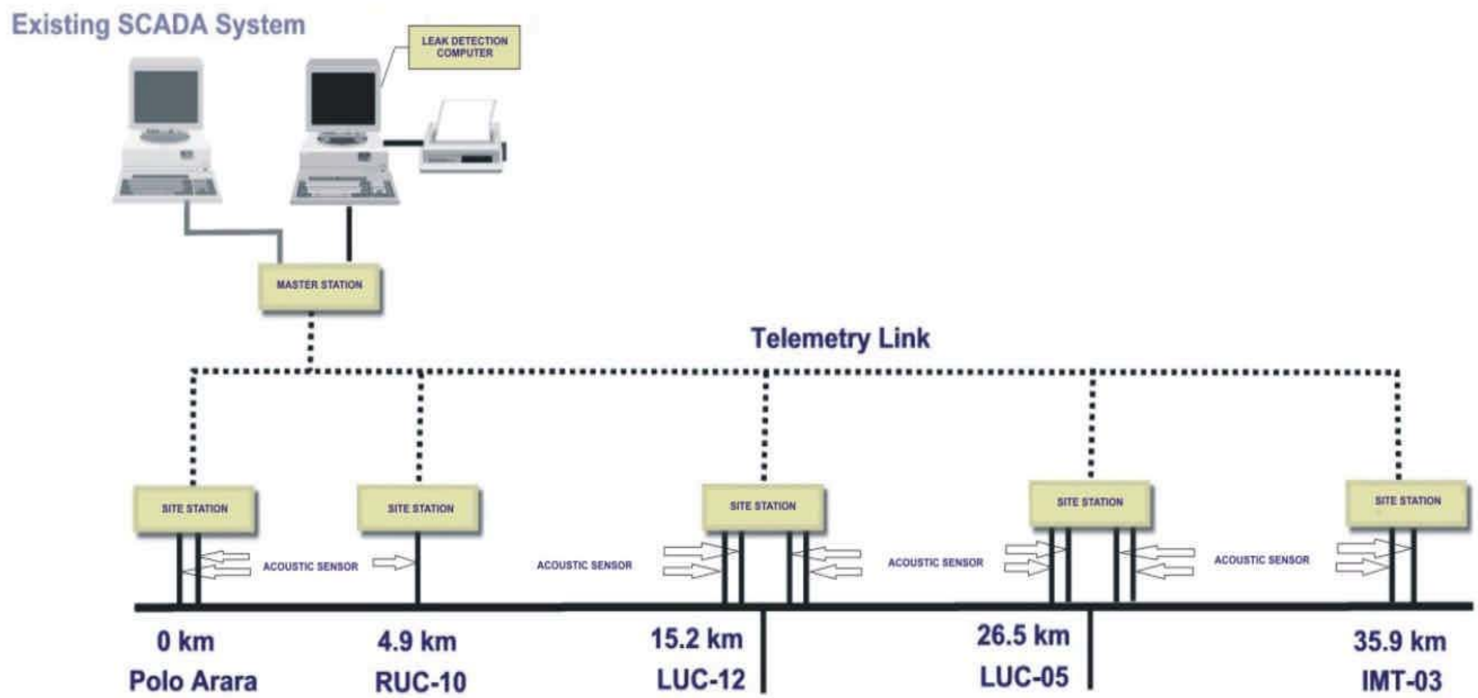

Figure 1 - The facilities at Urucu location

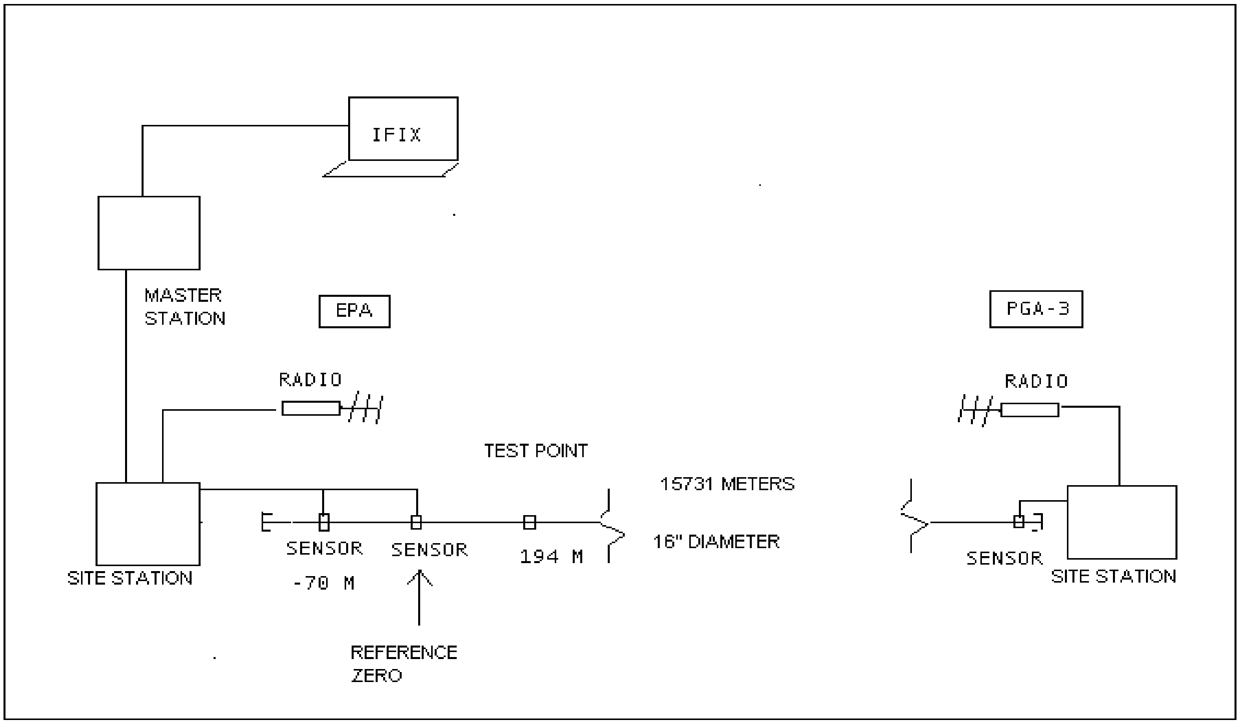

Figure 2 - The facilities at Aracaju location

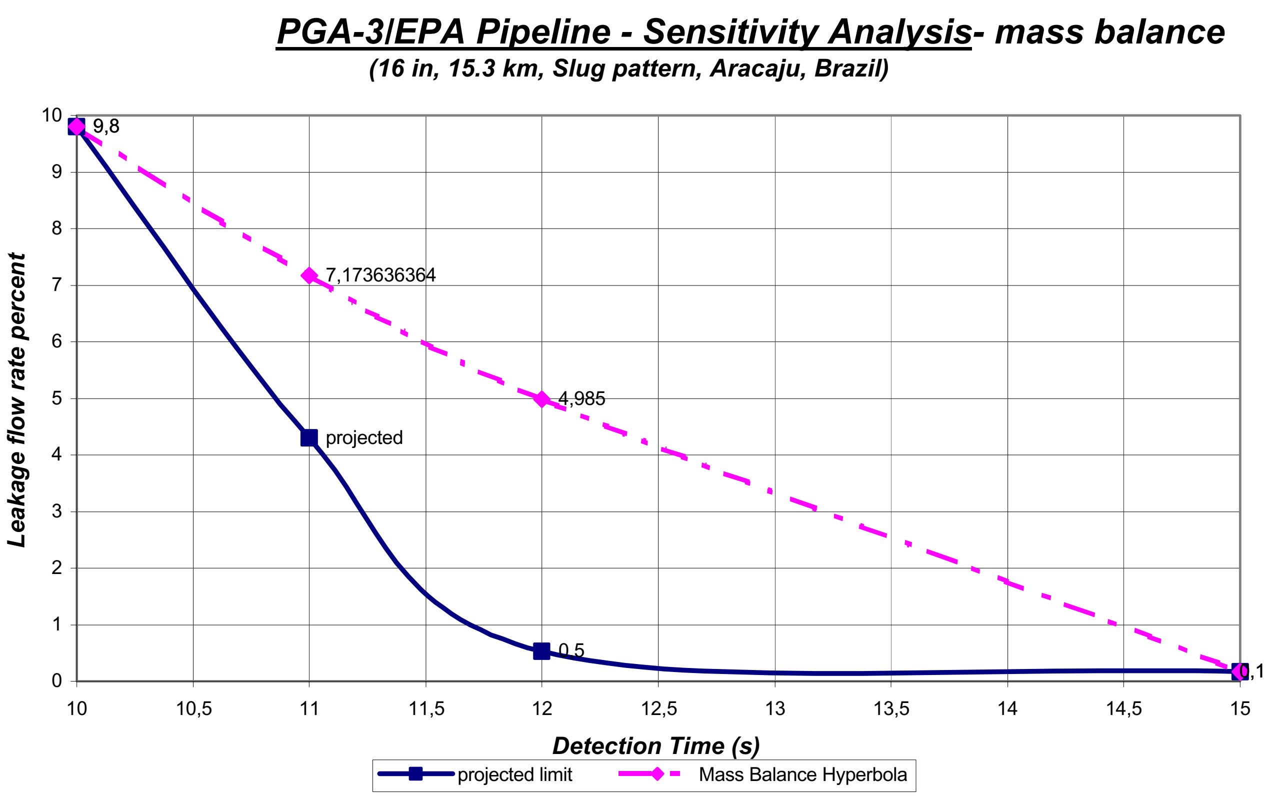

Figure 3 – The sensitivity curve for PGA-3/EPA pipeline