SCC A PROBLEM IN THE INDUSTRY AND ONE WAY TO MANAGE IT

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BACKGROUND

Stress Corrosion Cracking (SCC) is a phenomenon that occurs in buried carbon steel pipelines used for gas and oil transmission. It is usually found in colonies of thin, long and deep cracks in the external surface of the pipeline. These cracks eventually reach a critical size, which lead to system failures.

Transportadora de Gas del Sur S. A. (TGS), a leading gas transportation company in Argentina, which operates the longest and oldest pipeline system in Latin America, is not beyond the reach of this problem.

SCC in buried natural gas pipelines is a well-known phenomenon which has been under study for many years. There are two basic kinds of SCC to which gas pipelines are vulnerable: SCC which occurs at high levels of pH (9 and 12) and SCC which appears in near- neutral pH solutions (5.5 to 8.5).

TGS has had 4 ruptures in services, 2 leaks in services and 3 failures while doing hydrostatic test. Furthermore we have found a lot of colonies doing excavations (these colonies were found after running EMAT tool and after using a susceptibility model of SCC). In all cases the SCC colonies were classified as high pH SCC.

In order to identify locations where external pipeline SCC is most likely to exist, there are three methods: internal inspection, hydrostatic test and susceptibility model for SCC.

After the first case of SCC in the TGS system (August 1998) appeared, we have used the 3 detection methods, above mentioned. The method to mitigate SCC en each system was selected after the analyses of the following aspects: risk, economy, environment, and business.

Because of these TGS has a good experience in the SCC detection methods. We can remark that each of the 3 methods has advantages and disadvantages and the best method is a good combination of all existing ones.

For that reason in the last years TGS has invested a lot of time and money in order to develop a tool capable of detecting SCC in the gas pipeline system, and also in field investigation. With this information it has been possible to create a specific susceptibility model for TGS and to develop a new spreadsheet for SCC.

After the last rupture in January 2011 caused by SCC in the gas pipeline system we used this approach (combination of existing methods) with good results. It was possible for us to restore the safe condition of the pipeline in a short time and to develop a future plan to detect SCC giving priority to risk areas.

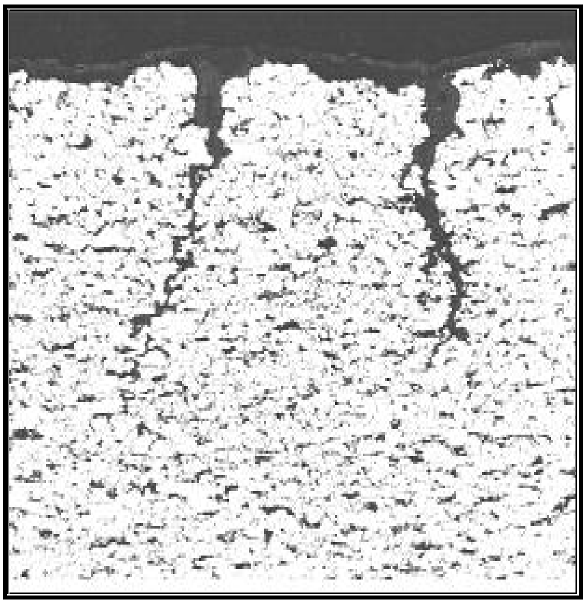
Because of this, the first step of the plan consists in ranking the segments of the pipeline system in terms of probability of failure by SCC and consequence of failure, that is to say ranking by risk.

Then depending on risk results a specific plan is created for each pipeline system to mitigate SCC.

AIMS

Stress Corrosion Cracking (SCC) is a problem for buried pipelines. SCC in pipeline is a type of environmentally assisted cracking (EAC). It describes the formation of cracks caused by various factors combined with the environment surrounding the pipeline.

SCC appears in colonies of small cracks on the external surface of the pipeline. There are two types of SCC: high pH and low pH. At this moment, there are several theories about the combination of factors that cause SCC (initiation and crack growth). Furthermore the reasons for the identification of SCC sites are different if we analyse high or low pH causes.

High-pH SCC (electrolite pH between 8.5 and 11) *Intergranular*	Low-pH SCC (electrolite pH between 6.0 and 8.5) *Transgranular*
 (Magnified 250 times)	 (Magnified 250 times)
Figure N°1 High pH SCC	**Figure N°2 Low pH SCC**

The first task when you implement a plan to SCC control is to conduct a detailed risk analysis of the lines involved: population risk, environmental risk and business risk.

These risks are different for each pipeline system (diameter, pressure, flow, whether there is a loop or not) in each geographic region. It is difficult to establish a single method of analysis.

Before defining a mitigation overhaul and repair plan it is necessary to study the feasibility of each of the three alternatives proposed by ASMEB31.8s : internal inspection, hydrostatic test, or direct assessment. There is no single recipe to apply.

The various actions taken by the industry are a clear evidence that the issue of SCC control is complex.

Here are some examples:

- **New research papers published**
  - *Development of Guidelines for Identification of SCC Sites and Estimation of Re-inspection Intervals for SCC Direct Assessment.*
  - *Stress Corrosion Cracking. Recommended Practices, 2nd Edition, by CEPA.*
  - *Integrity Management Program Delivery Order DTRS56-02-D-70036 Stress Corrosion Cracking Study FINAL REPORT Submitted by: Michael Baker Jr., Inc.*
  - *Integrity management of SCC in HCAs*

- **New high resolution in- line inspection tool incorporating Electro Magnetic Acoustic Transducer (EMAT) technology**

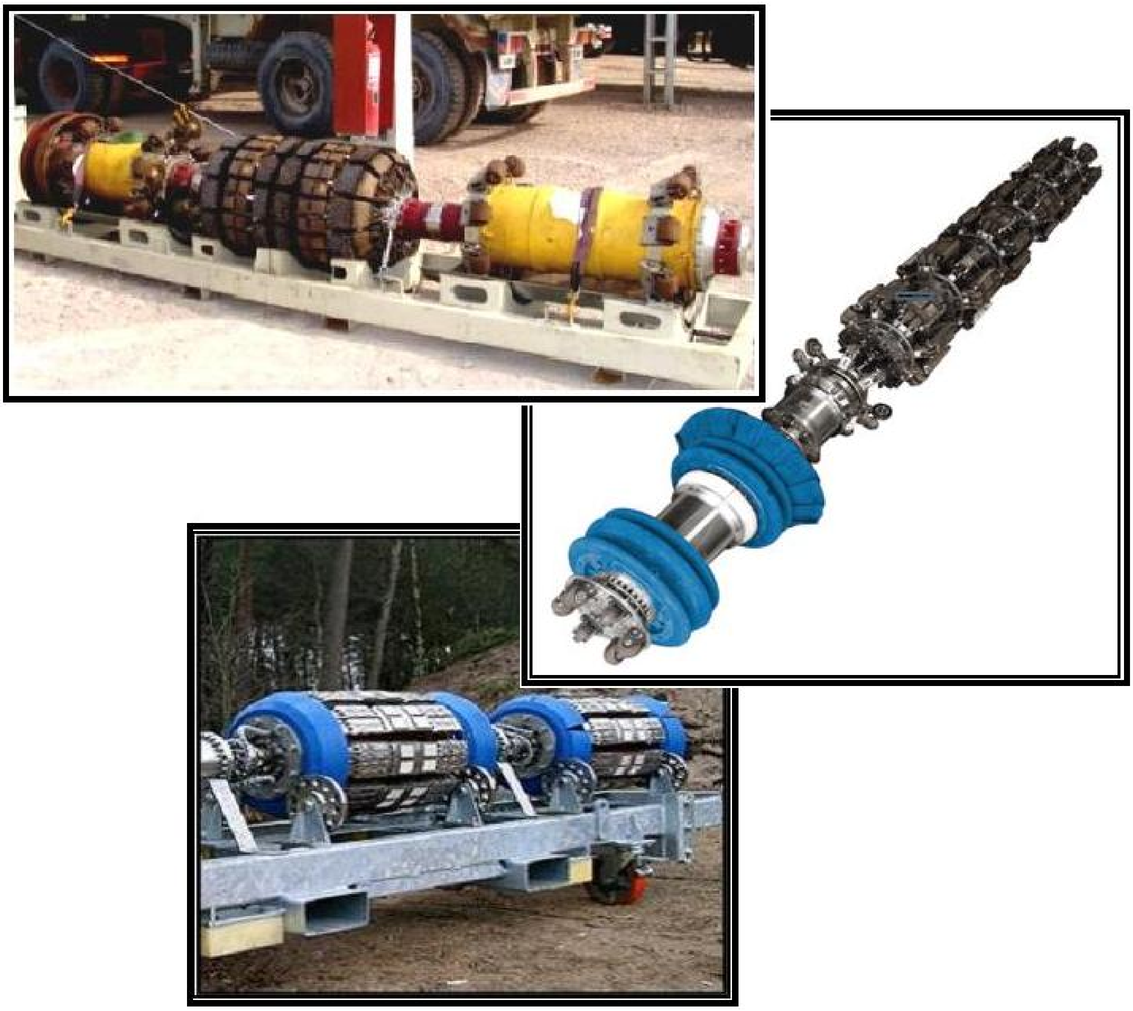


Figure N°3 EMAT tools of different suppliers

○ **The participation of companies that come together to share their experience.**

- *The Northern American Market initiated an EMAT user group, in which many more operators are listed. The Joint Industry Project (JIP) Team was established to develop a common approach to managing SCC.*

In the last 2 years, TGS had two high pH SCC failures in two different pipeline systems, but close to each other in a short time.

Figure N°4 SCC sites

The occurrence of these two faults determined the development of a specific plan to mitigate SCC and ensure the integrity of the pipes involved.

For the construction of such plan, the experience gained in previous years was used, focusing on:

1) Detailed risk analysis.

2) Advantages and disadvantages of the three methods presented: Internal inspection, hydrostatic test and SCC direct assessment.

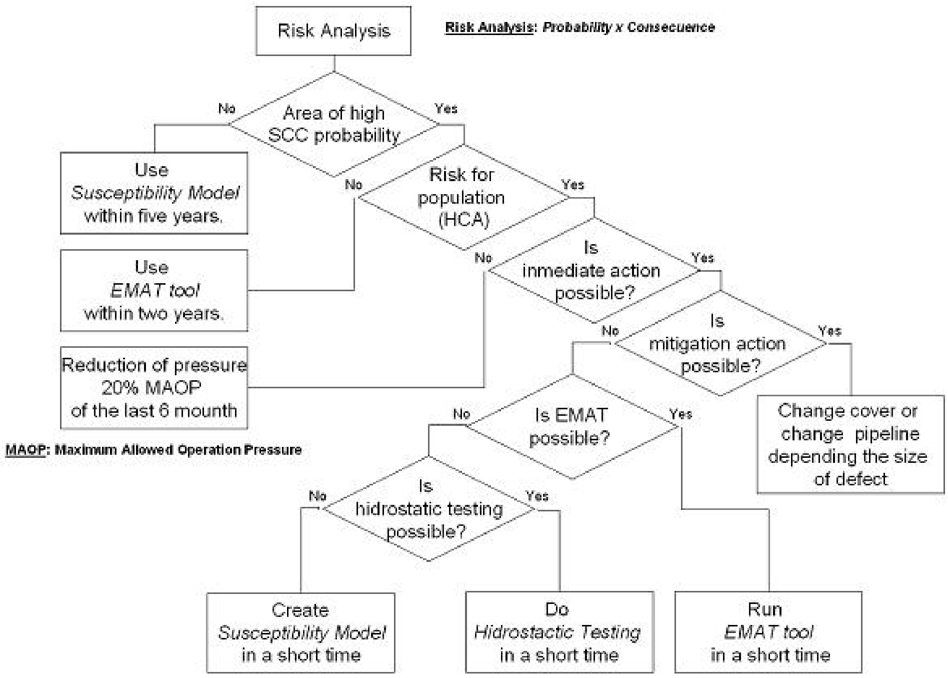


Figure N°5 :SCC mitigation plan

The SCC mitigation plan implemented as shown in Figure 5 uses a combination of: Internal inspection, hydrostatic test and SCC direct assessment, which (in a short time) allowed TGS to optimise technical and financial resources, to operate the pipeline system affected in a safe and reliable way.

This paper does not seek to be cover all the possible situations that may occur in the industry to study an SCC mitigation plan, but only to explain the solution used by TGS in a complex pipeline system.

METHODS

Transportadora de Gas del Sur S. A. is the leading gas transportation company in Argentina. TGS operates one of the longest and oldest pipeline systems in Latin America 9010 km of pipeline, 723.000 HP compression power, 92 MMm3/d of contracted capacity).

It performs a variety of tasks within its integrity plan in order to operate its pipeline system at the highest level of reliability, optimising human and material resources and reducing environmental, personal and business impacts.

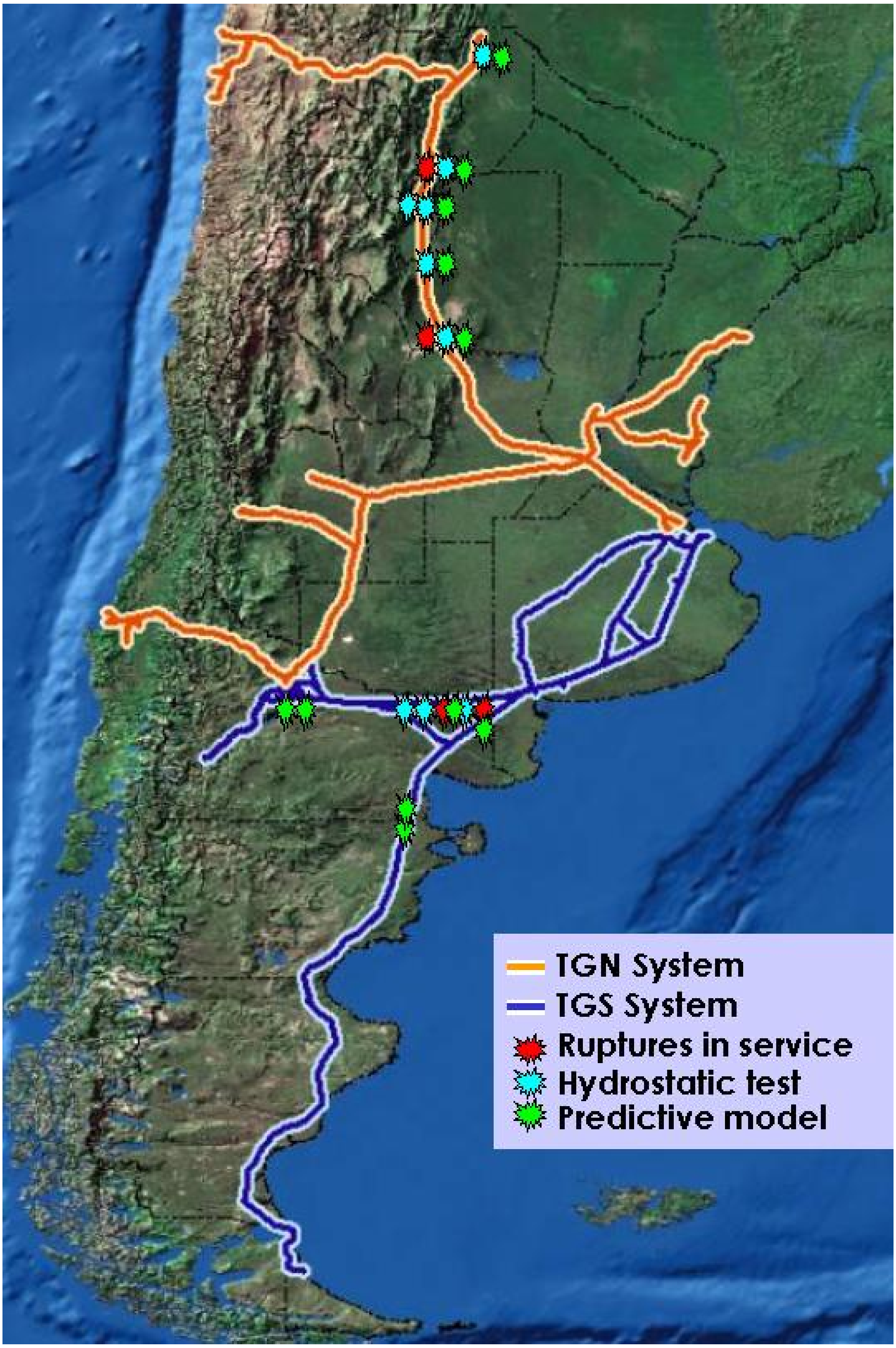


Figure N°6: TGS and TGS Pipeline System

The design of buried pipelines for the transport of both Oil and Gas involves important safety factors that make them safer and more reliable. The different building codes in the world contain different safety factors that take into account population density.

These codes are based on the principle that: *"the design requirements are intended to be adequate for public safety under all conditions encountered in the gas industry".*

But despite these precautions pipes often fail.

Figure N° 7: pipeline failure

This is because the pipes are exposed to a range of threats. ASME B31.8S says in chapter 2: Quote *"The first step in managing integrity is identifying potential threats to integrity. All threats to pipeline integrity shall be considered. Gas pipeline incident data has been analysed and classified by the Pipeline Research Committee International (PRCI) into 22 root causes. Each of the 22 causes represents a threat to pipeline integrity that shall be managed. One of the causes reported by operators is "unknown"; that is, no root cause or causes were identified. The remaining 21 threats have been grouped into nine categories of related failure types according to their nature and growth characteristics, and further delineated by three time-related defect types. The nine categories are useful in identifying potential threats. Risk assessment, integrity assessment, and mitigation activities shall be correctly addressed according to the time factors and failure mode grouping.*

(a) Time-Dependent

(1) external corrosion

(2) internal corrosion

(3) stress corrosion cracking

(b) Stable

(1) manufacturing-related defects - a) defective pipe seam, b) defective pipe)

(2) welding/fabrication related -a) defective pipe girth weld (circumferential) including branch and T joints, b) defective fabrication weld, c) wrinkle bend or buckle, d) stripped threads/broken pipe/coupling failure

(3) equipment: (a) gasket O-ring failure (b) control/relief equipment malfunction (c) seal/pump packing failure (d) miscellaneous

(c) Time-Independent

(1) third party/mechanical damage (a) damage inflicted by first, second, or third parties (instantaneous/immediate failure) (b) previously damaged pipe (such as dents and/ or gouges) (delayed failure mode) (c) vandalism

(2) incorrect operational procedure

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

The interactive nature of threats (i.e., more than one threat occurring on a section of pipeline at the same time) shall also be considered. An example of such an interaction is corrosion at a location that also has third party damage. The operator shall consider each threat individually or in the nine categories when following the process selected for each pipeline system or segment." Unquote.

According to this description, in the last years, the principal cause of failure in the TGS pipeline system has been pH SCC.

- **HIGH pH SCC CHARACTERISTICS**

High pH SCC usually occurs in pipes coated with asphalts which have deteriorated.

High pH SCC requires the formation of FeCO3 on the steel surface, and is therefore related to the formation of concentrated solutions of CO3-2 / HCO3- and pH levels > 9.0 in contact with the pipes.

FeCO3 is known to form in the narrow potential range of -0.75 V < Eoff < -0.60 V where it coexists with Fe3O4 according to the following reactions:

$$Fe + CO_3^{2-}{}_{aq} = FeCO_3 + 2e \qquad [1a]$$

$$Fe + HCO_3{}_{aq}^{-} + OH^- = FeCO_3 + H_2O + 2e \qquad [1b]$$

$$3\,Fe + 8\,OH^- = Fe_3O_4 + 4\,H_2O + 8e \quad [1c]$$

As does every corrosion process, SCC in buried pipelines depends on the interaction between a metallic surface and the medium (water and dissolved ions) in direct contact with it. This can only be due to the damaging of the protective pipeline coating found on specific points, failure of the cathodic protection system (inability to effectively reach the required level of -0.85 V), and a susceptible metal.

Potential levels ranging between -0.75 V < Eoff < -0.60 V may be reached spontaneously in areas where the metal is exposed to the medium with inadequate cathodic protection. In other cases, these potential levels may be reached even when cathodic protection levels are –1.2 < Eoff < -0.9 V, as a consequence of the shielding effect that occurs on the inside of the crevices formed between the corroded coating and the metal. This shielding effect is common in low-conductivity soils.

Another effect that can cause the shielding of cathodic protection current takes place in conductive soils with levels of Eoff < -1.1 V, especially in high-temperature areas such as those found near compressor plants. In this case, hydrogen bubbles are formed, possibly causing unmanageable potential within the crevices, or precipitates caused by the alkalinisation due to cathodic protection.

High pH SCC is strongly Influenced by pipe surface temperatures. This explains why 80% of cases are detected in the first 20 km from the compressor plants, where temperatures can range between 40°-60° C. Temperature increases fissure growth rate (v) according to

$$v = K\exp(-Ea/RT)$$

Where Ea denotes Activation Energy, and K and R are constants. An increase in temperature not only increases fissure growth rate, but also increases wetting and drying cycles that concentrate HCO_3^- and CO_3^{-2} until the required critical level is attained for SCC (1N).

○ SUMMARY OF THE TGS SCC CASES

Over the last 12 years TGS has detected the following sites with SCC in our pipeline system:

- Ruptures in services: 4
- Ruptures by hydrostatic test: 3
- Leaks in services: 2
- Sites detected by internal inspection tools: 5
- Sites detected by SCCDA: 26

Figure Nº 8 SCC colonies found in TGS pipeline system

○ DETECTON AND ASSESMENT METHODS

1. ***Stress corrosion cracking direct assessment (SCCDA)***

Stress corrosion cracking direct assessment (SCCDA) is a formal process to assess a pipe segment for the presence of SCC. It is a structured process that contributes to improve safety by reducing the impact of SCC on pipeline integrity

- Step 1: Pre – Assessment
- Step 2: Indirect Inspections

- Step 3: Direct examinations
- Step 4: Post Assessment

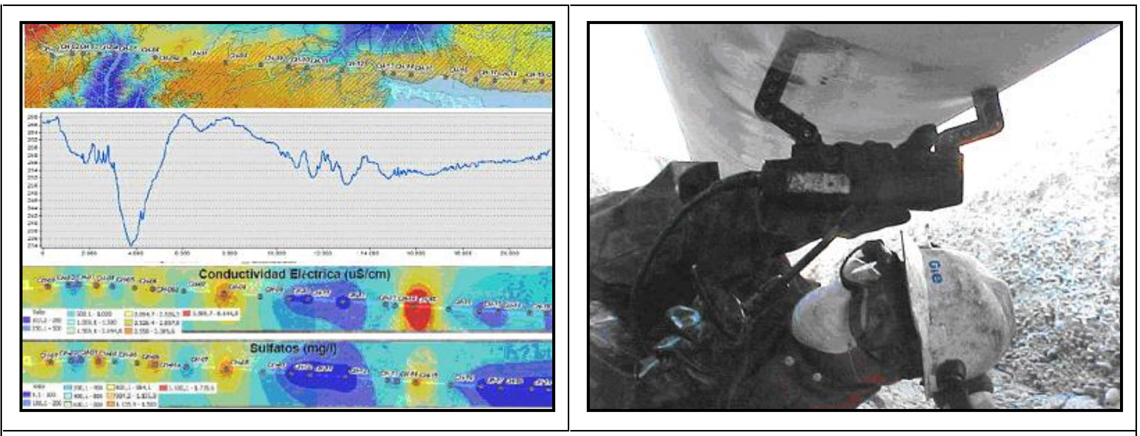
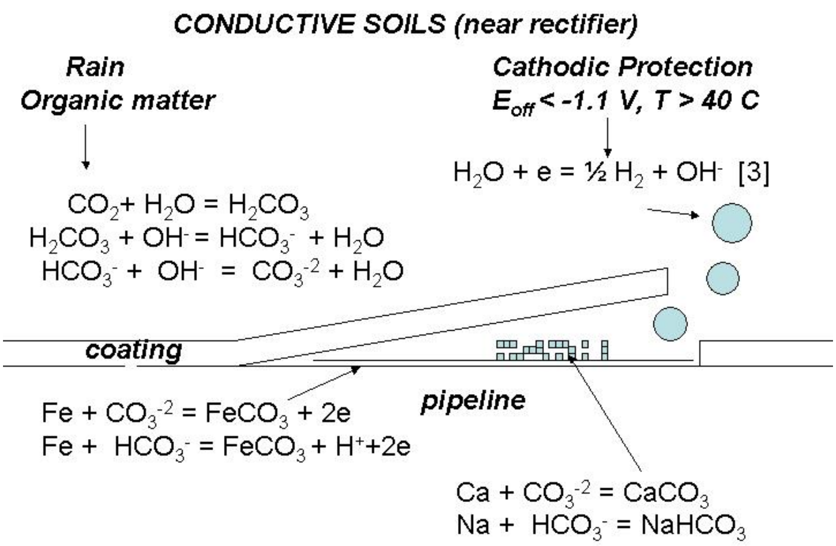


Figure N°9 SCCDA

- **Pre – Assessment. Proposed Model.**

In order to create their owner SCCDA TGS has decided to develop a susceptibility model to detect high pH SCC.

The following is a diagram of the processes that take place in SCC sites.



Reactions that take place on the Fe surface at temperatures over 40º C and (Eoff) potential below -1.1 V are

$$H2O + e = ½ H2 + OH- \ [3]$$

The OH^- produced by reaction [3] leads to the formation of partially soluble bicarbonates and insoluble carbonates in the cracks, according to the following reactions

$$CO_2 + H_2O = H_2CO_3 \quad [4a]$$

$$H_2CO_3 + OH^- = HCO_3^- + H_2O \quad [4b]$$

$$HCO_3^- + OH^- = CO_3^{-2} + H_2O \quad [4c]$$

After some time the deposits appearing in the cracks (reaction [4c]) may shield protection, which would fall to levels within the risk zone. In addition, the hydrogen bubbles produced by protection in the cracks may shield protection, as found in lab tests.

In these conditions (shielded CP, Eoff between -0.75 V/-0.60 V) the bicarbonates/carbonates resulting from reaction [4] may lead to the formation of $FeCO_3$ according to reactions [1a-b] described in the introduction.

The reagents in these reactions, carbonic acid and bicarbonates, are produced by the reaction between the CO_2 contained in the rainwater and the carbonates found in the soil or by the decay in organic matter and soil rich in carbonates (found throughout the soil around the oil pipelines).

The production of HCO_3^- would explain the appearance of soluble bicarbonates like sodium and potassium bicarbonates that have been found in contact with the pipelines and corroded coating in the SCC zones. These are often considered to be indicators of possible SCC.

During the development of our model we found some unusual features with reference to available literature on the subject. While some classic patterns remain the same (cracking type mostly intergranular, proximity to compressor plants, good soil drainage, topographic location in slopes, etc) failures were observed near the rectifying equipment and low resistivity soils.

TGS has developed a research about SCC. This research has been implemented in cooperation with INIFTA institute, which depends on CONICET and Universidad Nacional de La Plata, INGEIS institute, which depends on Universidad Nacional de Buenos Aires and AEROTERRA, a private company.

The investigation included:

INIFTA Institute Research:

- Electrochemical tests carried out in stress and environmental simulated operative conditions. It was possible to obtain SCC cracks in labs -In addition to this, CO_2 influence was studied and it was determined that the presence of CO_2 is always necessary for the formation of cracks, as well as $CaCO_3$ and a low level of cathodic protection Figures N° 10 and Figure N°11.

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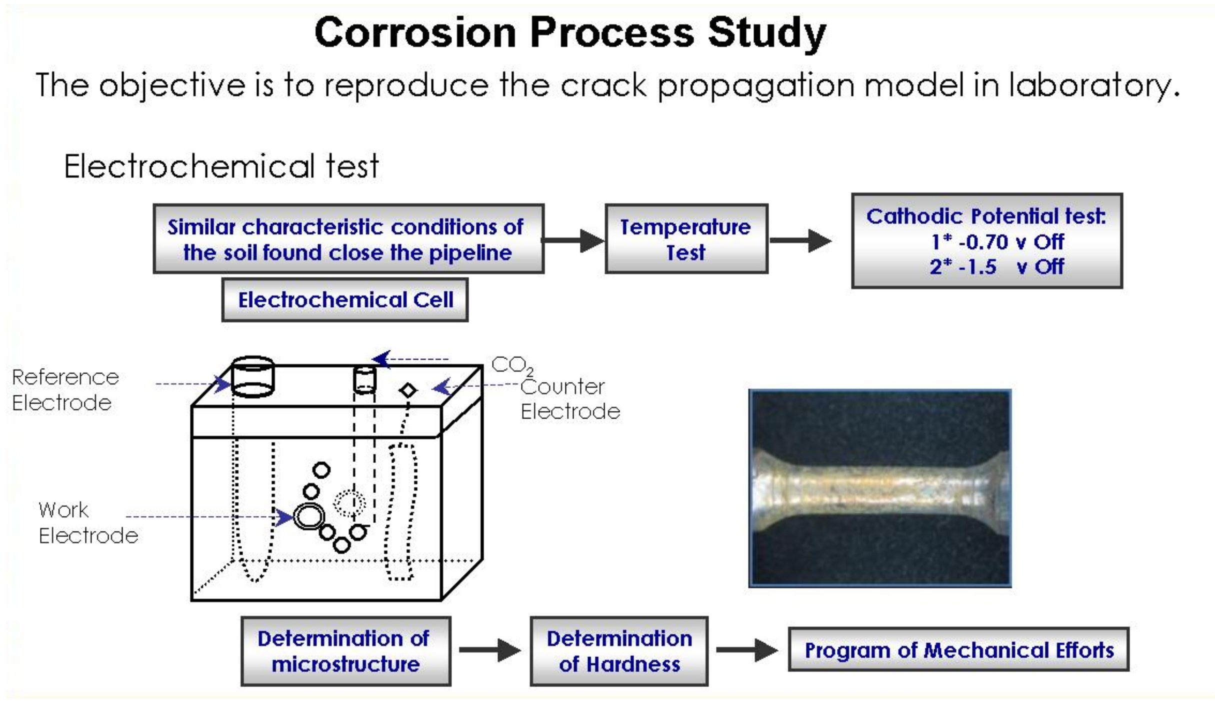

Figure N° 10 Corrosion Process Study

With Cathodic protection Potential OFF –1.28V		**Without Cathodic protection Potential OFF –1.28V**	
Sol. "Pipe/coating" pH sol decrease ↓ pH shielding coat increase ↑ NO CRACK		Sol. "Pipe/coating" Oxide Pits NO CRACK	
CO_2 + Sol. "Pipe/coating" pH sol decrease ↓ TRANSGRANULAR CRACKS		CO_2 + Sol. "Pipe/coating" pH sol decrease ↓ SMALL CRACKS	
CO_2 + $CaCO_3$ + Sol. "Pipe/coating" pH range between 8-10 NO CRACKS		CO_2 + $CaCO_3$ + Sol. "Pipe/coating" pH range between 8-10 INTERGRANULAR CRACKS	

Figure N° 11 Result of electrochemical test under applied stress

- We simulated the cathodic protection level below the holyday coating (Figure N° 11), and it was found that the cathodic protection level decreased more abruptly near the rectifying equipment due to the formation of H2, clearly the formation of H2 shields the cathodic protection level. Besides, statistic research was carried out into operative variables and it was concluded that the electrolyte chemical solution which is formed between pipe and coating depends on cathodic protection and not only on soil composition as it was supposed.

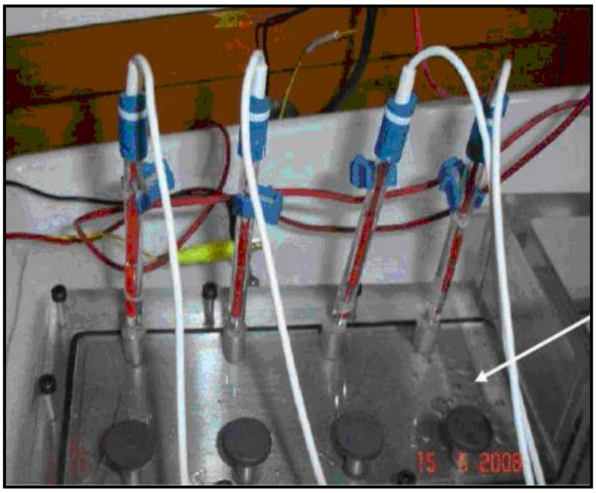

Figure N° 11 Result of electrochemical test under applied stress

INGEIS Institute Research:

- Study of the abnormal presence of CO2 flow in the place where the cracks occurred. Figure N° 12
- Measurement of the soil conductivity change and development of a specific model of soil resistivity in two-dimensions. It was possible to detect important changes of soil resistivity in SCC areas.
- Soil laboratory tests were performed to determine physical and chemical parameters which were used by AEROTERRA to construct isovalue maps
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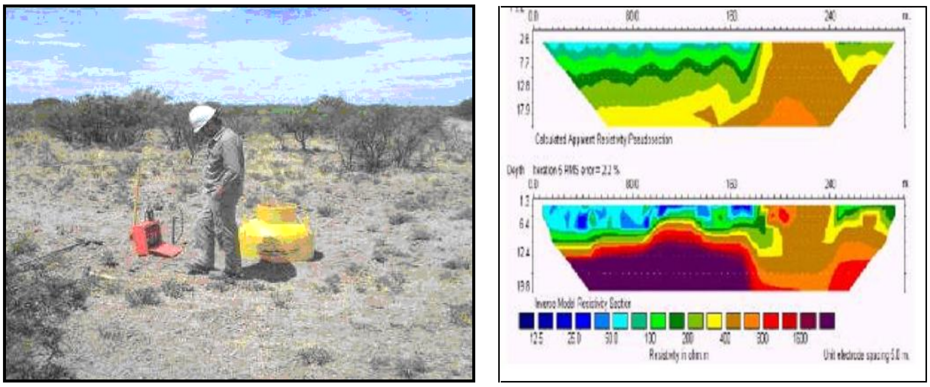

Figure N°12 Study of CO_2 flow in soils.

AEROTERRA contribution:

- Acquisition of digitalized high resolution IKONOS images and development of a digital elevation model. These images proved of great help to determine landscape units.
- Studies into the physical and chemical conditions of the soil, classifying and describing the kind of soil of each area for the preparation of isovalue maps with the system variables (Conductivity, Sulfate, Sodium, Potassium, Calcium, Magnesium, Chloride, Carbonate, Bicarbonate, pH) Figure N° 13 a) b) c) d) e)

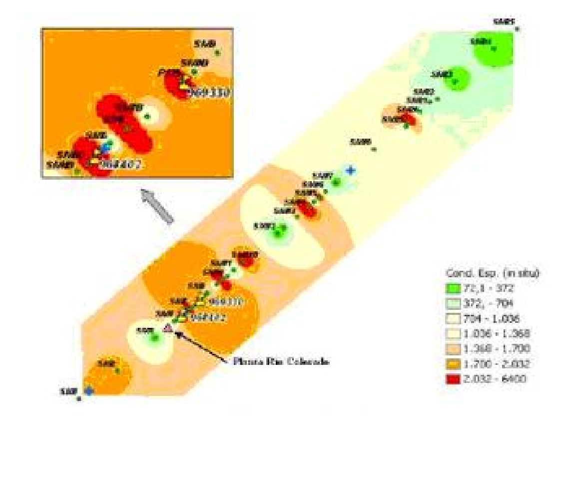

Figure N° 13 a) Specific Conductivity Distribution (uS/cm)

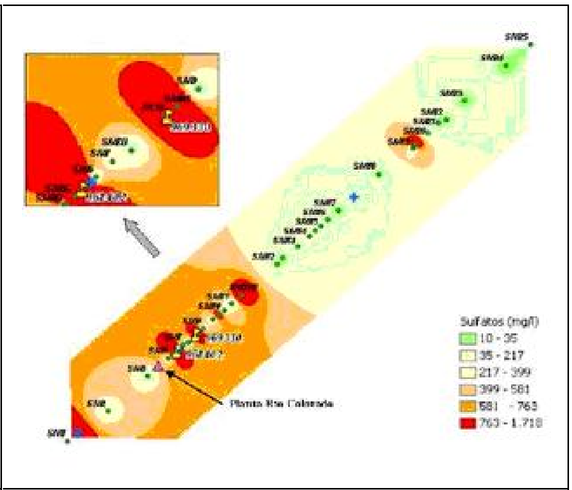

Figure N° 13 b) Sulphate Distribution (mg/l)

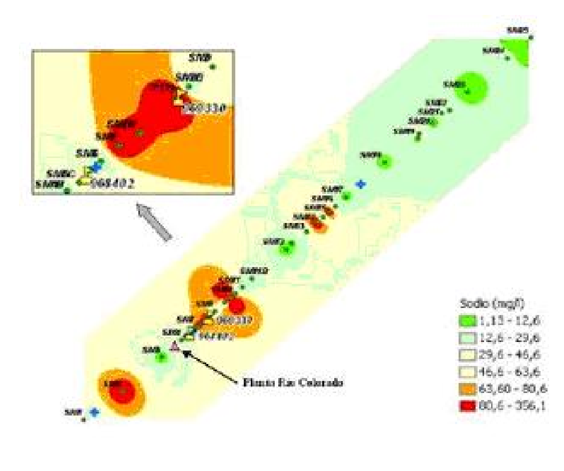

Figure N° 13 c) Sodium Distribution (mg/l)

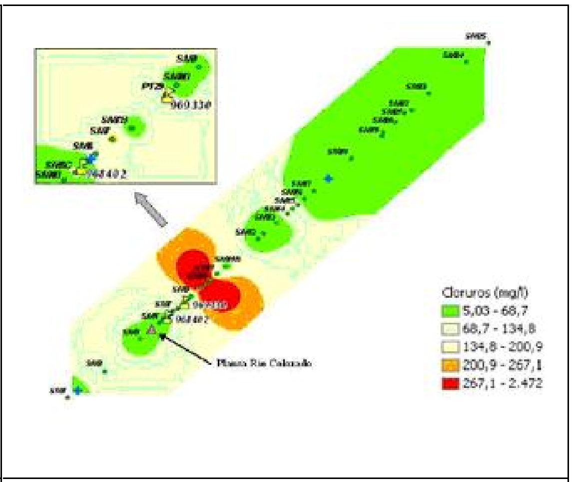

Figure N° 13 d) Chloride Distribution (mg/l)

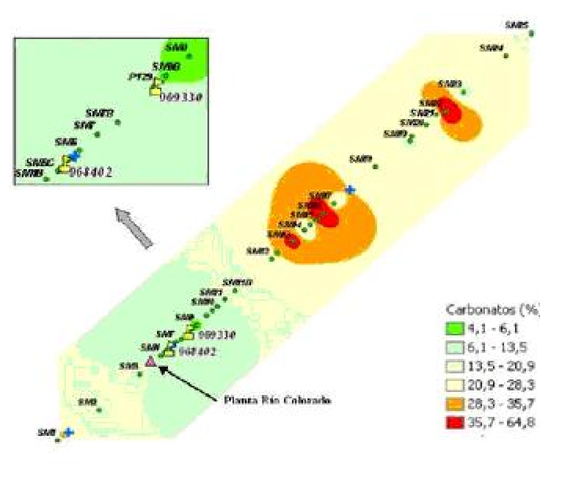

Figure N° 13 e) Carbonate Distribution (mg/l)

- **Soil classification in research areas**

TGS has carried out a thorough study on the environment of sites where SCC has been detected. The investigation includes climate, topography, drainage and soil-type analysis. The information provided by this study is comprehensive and valuable.

Research included research on land conditions in the sites mentioned, as well as in their area of influence. Satellite information and topographical data, as well as traditional field techniques and laboratory tests were used for this purpose.

The study consisted of the following tasks:

- Provision and digital processing of high-resolution satellite images. High resolution IKONOS images (1 metre) in stereoscopic format were acquired and processed in order to analyse them in 3D. The processing included the following steps:
  - Ground control point measuring using GPS technology.
  - Creation of a digital elevation model.
  - Image orthorectification
  - Creation of a digital mosaic
- Detailed scale analysis of researched areas. This analysis was based on IKONOS images, the digital land model and the slope map, combined with a detailed review of previous research (including soil research and geological studies). An example of a satellite image of one of the sites and its geo-morphologic analysis can be seen in Figure 14. The image covers a 3 km distance, with the pipeline right of way in the centre.
- Field work for the classification and detailed description of soils in researched areas. This research was carried out through test pits, well studies and natural cracks in the ground. The sites where research holes were excavated for terrain description can be seen in Figure 15.

Figure N°14 Satellite image

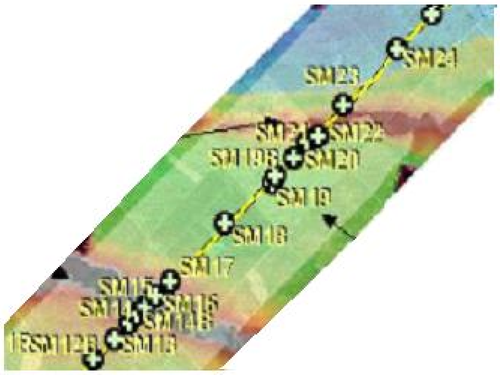

Figure N°15 Soil Model

A study of physical land characteristics was carried out, which included:

- Relief and micro-relief
- Natural drainage
- Superficial drainage
- Flooding
- Surface flora
- Surface lithology
- Human influence.

The edaphic profile was also studied, including:

- Horizon description
- Texture
- Structure
- Permeability
- Effective depth
- Porosity
- Stoniness
- Rock outcrop proportion
- Organic material content.
- Colour
- Soil-pH reaction
- Calcium carbonate content
- Internal drainage
- Permeability
- Consistency
- Soil instability and flood risk.

Physical-chemical “in situ” parameters were also studied, in relation to the following:

- Hydrogen potential (pH)
- Specific conductivity

Soil/sediment samples were also collected for future chemical lab analysis and for X-ray detection of mineral composition. All samples were collected at pipe base depth (approximately 1.5 m), although in some cases, samples were collected from upper horizons.

- Analytical lab description. It included mineralogical composition and crystalline substance description of researched soils/sediments, as well as chemical-analytical description in the aqueous phase.

- **Site Selection Model Variables**

Based on the studies described above, the following model has been made for the detection of high pH SCC in buried pipelines coated with asphalt.

- SOIL VARIABLES

- Topographic pattern: Undulating, and Declining.
- Drainage Type: Incomplete Drainage
- Profile humidity: dry
- Proximity to waterways
- Elevation
- Chemical data
    - pH levels on site
    - Specific conductivity (salinity measurement) > 2000 uS/cm.
    - Calcium carbonates.
    - Sodium carbonates.
- Soil resistivity (< 1000 ohm/cm). We focus on the point where soil changes resistivity

- OPERATIONAL VARIABLES

- Historical temperature on exiting plant (> 50° C)
- Pressure cycles
- Rank of cathodic protection potential (CIS) (-650 to -850 mv)
- No defects from corrosion (ILI)
- Distance from rectifier (0 to 5 km)
- Distance from compressor plant
- Pipeline age (> 10 years)
- Age of coating (> 10 years)
- Age of rectifier (>10 years)
- Age of compressor plant (> 10 years)
- Rectifier Equipment (> 15 years)
- High density of current applied by rectifier equipment
- Availability time of Rectifier Equipment

- **Spreadsheet for SCC**

The results of this research has enable TGS to understand the behaviour of SCC in the TGS system and allowed the development of a model for the identification of susceptible areas where investigation digs are to be made.

With the above information it has been possible to create a specific susceptibility model for TGS and to develop a new spreadsheet for SCC.

The following is an example of this SCC spreadsheet.

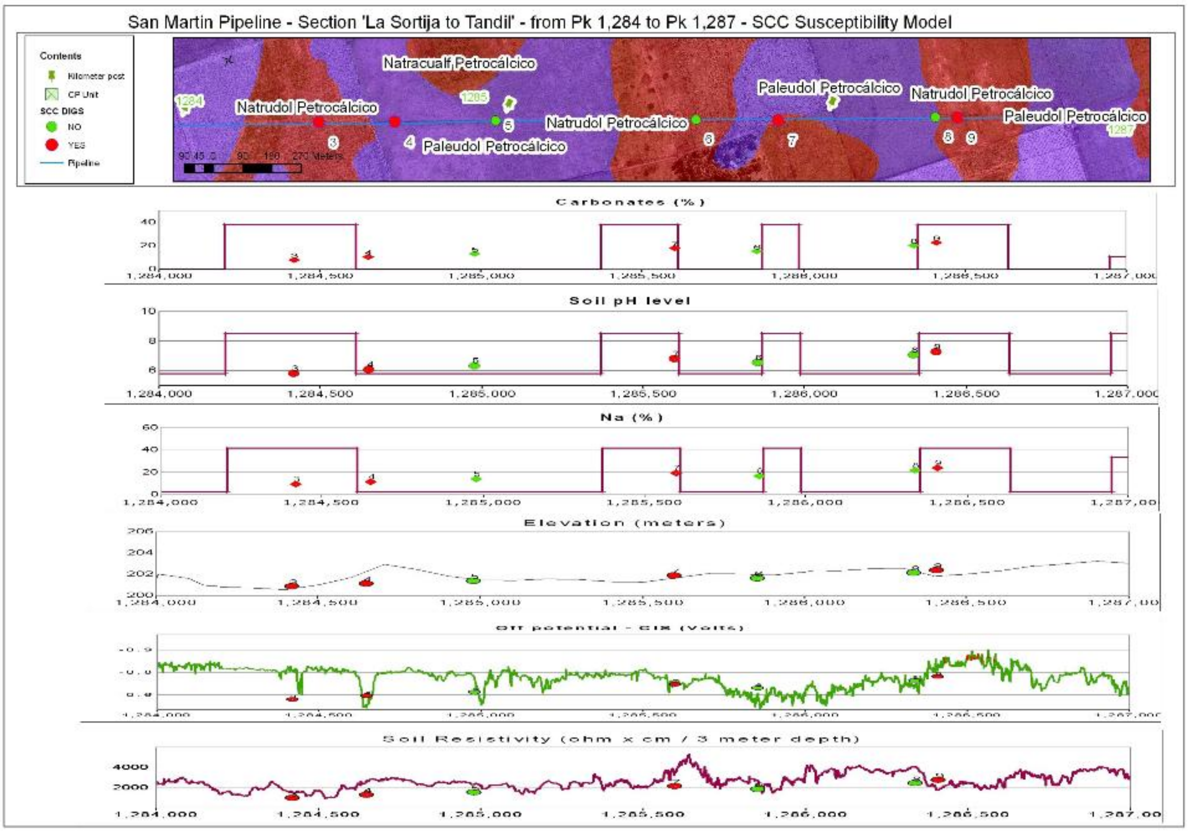

Figure N° 17 Example of SCC spreadsheet

This model was developed and applied in the main pipelines of TGS system.

Using this model SCC places were found. The results were very favourable for TGS.

The field results are continually being used to carry out new investigation and to allow us to further understanding.

Last year with similar SCC spreadsheet we defined 26 potential sites susceptible to SCC. In 8 of them it was possible for us to find SCC, that is to say we had 30% accuracy.

2. Hydrostatic test

The hydrostatic test is performed to determine if the line is able to operate at Maximum Allowable Operating Pressure (MAOP), without risk of failure attributable to the SCC phenomenon.

The test is carried out at a pressure that produces a hoop stress in the wall of the pipe 110% of specified minimum yield stress (SMYS) of the pipe in the section under test (Figures N° 18).

Figures N° 18 Hydrostatic test

Furthermore, this method reduces the rate of crack growth because the high level of pressure produces the plastification on the edge of the crack.

For this reason a Hydrostatic Test is a valid way to locate critical size cracks by SCC because the critical SCC cracks fail at the time of the test pressure.

The Hydrostatic Test is the most common technique to ensure the integrity of the pipeline when SCC appears.

However, if there is not a failure, it is impossible to conclude that the line under analysis does not have SCC (small SCC cracks could have no critical dimensions).

The use of liquid in the test has advantages and disadvantages. The principal advantage is that liquid does not propagate failures because it is not compressible. The disadvantage is that the line needs to be out of service during the Hydrostatic Test.

The following Figure (Figure N° 19), which appears in the document: "**Stress Corrosion Cracking. Recommended Practices,2nd Edition**" , by CEPA, explains the expression: "BUY TIME WITH HYDROSTATIC TEST"

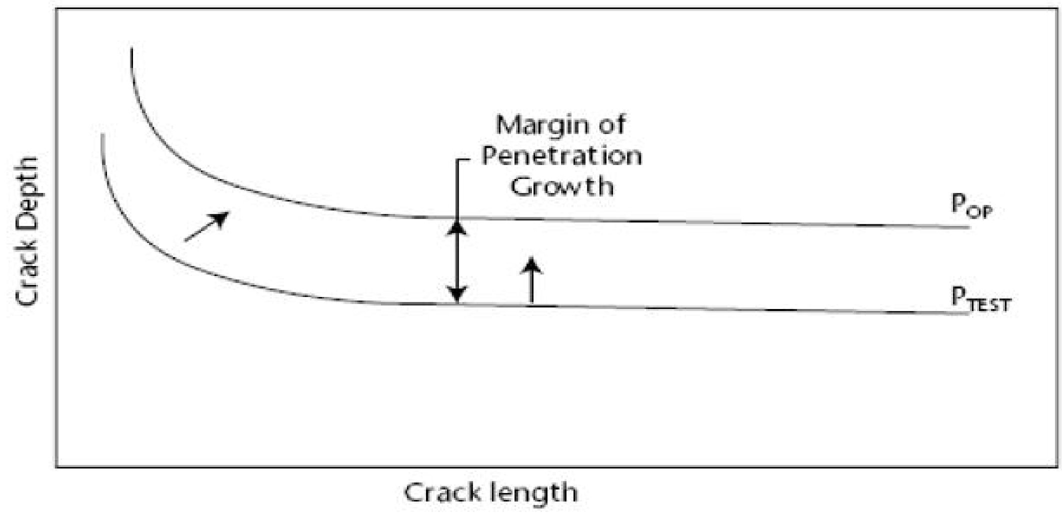

Figure N° 19 Hypothetical Critical SCC dimensions at Hydrotest and Operating Pressure

In the graph there are 2 curves: hydrostatic test pressure (P_{TEST}), and the pipeline operating pressure (P_{OP}). After the Hydrotest Test, it can be safely assumed that all surviving SCC features have dimensions below the P_{TEST} curve. Quote *" The greater the difference between the test and the operating pressures the longer the expected life of any surviving SCC feature. The time between these two periods is simply the difference in SCC dimensions divided by the growth rate determined for this SCC feature. The retest or re – inspection interval is this calculated time less a period that provides a safety factor at* P_{OP}*."* Unquote.

3. ***Internal Inspection tool***

Internal inspection is another SCC Detection and Assesment method to that the operator of pipeline can use.

There are three types of technologies available in the market for internal inspection to detect SCC: In line inspection (ILI)Tools Ultrasound Tools (UT) and Electro-Magnetic Acoustic Transducer (EMAT) Tools.

The ILI tools, that include two different techniques: magnetic flux leakage (MFL) + transverse field magnetic flux leakage (TFI), are useful to evaluate the integrity of gas line. The combination of MFL + TFI is a good one to detect low pH SCC, but not for the high pH SCC. In this case the cracks are closed and do not produce significant variation in the magnetic field. For this reason, this combination of tools is only used to detect low pH SCC.

Figure N° 20 MFL + TFI tool

The UT tools are useful to evaluate the integrity for gas line. But in this case it is necesary to introduce a liquid in the pipeline to couple the sensor with the internal surface of the pipeline. For this reason it is not communly used in gas line.

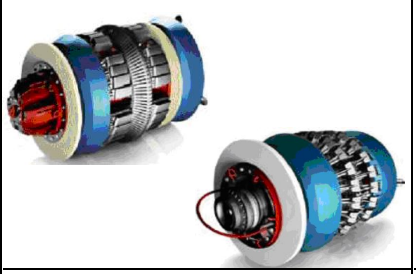	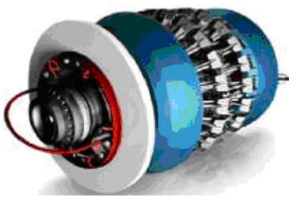	
Figure N° 21 MFL + TFI	**Figure N°22 UT**	**Figure N° 23 EMAT**

In the last years a tool with a new technology has been developed. This tool is based on a novel concept of an induced ultrasonic wave electromagnetic that makes the detection of both stress corrosion cracking and disbonded coating possible.

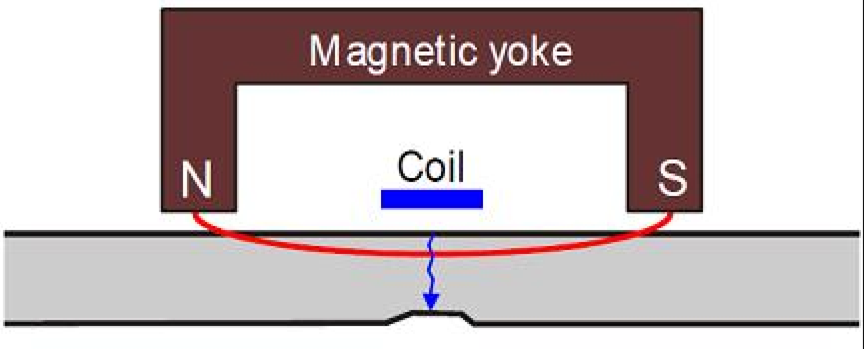

Figure 24 shows the basic sensor arrangement of the new EMAT design.

Coating disbondment is understood to be a precursor to SCC by increasing the susceptibility of the pipeline to corrosion.

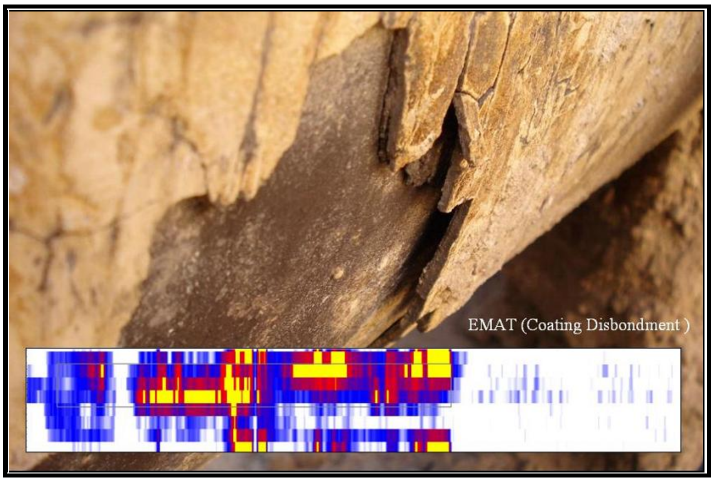

Figure N° 25 Disbondment in pipeline

- A magnetic field must be applied in the steel,
- The transducer coil must be very close (approximately 1 mm) to the surface of the steel plate during the inspection, and
- The receiver must be extremely sensitive.

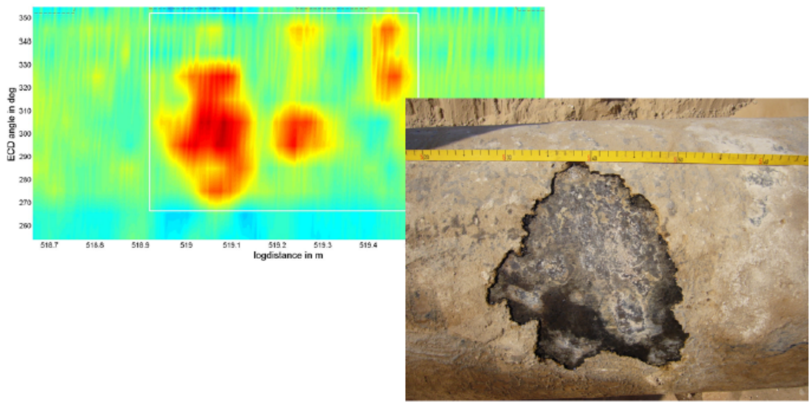

Figure 26: Detection of Coating Disbondment. (Left) Multi-channel view of transmission signal. (Right) Corresponding coating damage.

The characteristic features of the crack detection tool are:

- Dry coupled ultrasonic technology

- Inspection of gas and liquid lines
- High Resolution EMAT sensor
- Superior SCC sensitivity
- Versatile guided shear wave technology
- Coating disbondment detection

TGS has used two different technologies of EMAT principle. In one case, we inspected 500 km and was possible to find critical colonies of SCC. With the second company we ran 300 km and at the time of writing this paper we have not received the results of the EMAT tool runs.

Advantages and Disadvantages

We summarise the advantages and disadvantages of the Detection and Assessment method to detect SCC we developed above.

DETECTION OF SCC

Advantages and disadvantages between options

Detection / Comparative Characteristics	Inspection tool EMAT	Inspection tool ULTRASONIC	Hydrostatic Testing	Susceptibility Model
Reliability	Medium At present this tool has problem to discriminate cracks from exfoliations.	High The problem appears when the pipeline presents exfoliations.	High (for critical cracks) It does not supply information about subcritical cracks.	Low
Operation	It needs a lot of run to clean the internal surface of the pipeline.	This tool needs liquid batch. It is difficult to control the speed of the tool, specially in sloping areas. Other sources of gas have to be used by consumers while running this tool.	Other sources of gas have to be used by consumers during the execution of the test.	It is necessary to reduce 20% of the MAOP during visual examination tasks
Effect on Transport	It is low in general because the tool has variable by pass.	Total closure of pipeline 1 week per section	Total closure of pipeline 1 month per section between valves (around 30 km)	Low
Cost of Service	High There are not enough tools available	High	Moderate	Low

Figure Nª 27 Advantages and Disadvantages about SCC Detection and Assessment Methods

Although the conclusion seems to be that there is not one ideal method, the experience of TGS is the following: the best method is a good combination of all existing ones.

RESULTS

In the last years TGS has invested a lot of time and money in order to develop a tool capable of detecting SCC in the gas pipeline system and also in field investigation. With this information it has been possible to create a specific susceptibility model for TGS and to develop a new spreadsheet for SCC.

After the last rupture in January 2011 caused by SCC in the gas pipeline system we used this approach explained above (combination of existing methods) with good results. It was possible for us to restore the safe condition of the pipeline in a short time and to develop a future plan to detect SCC giving priority to risk areas.

The first step to implement an SCC mitigation plan consists in ranking the segments of the pipeline system in terms of probability of failure by SCC (according to "Site Selection Model Variables" above) and consequence of failure (business, environment, population), that is to say ranking by risk. One example the risk areas we can see in the figure N° 28

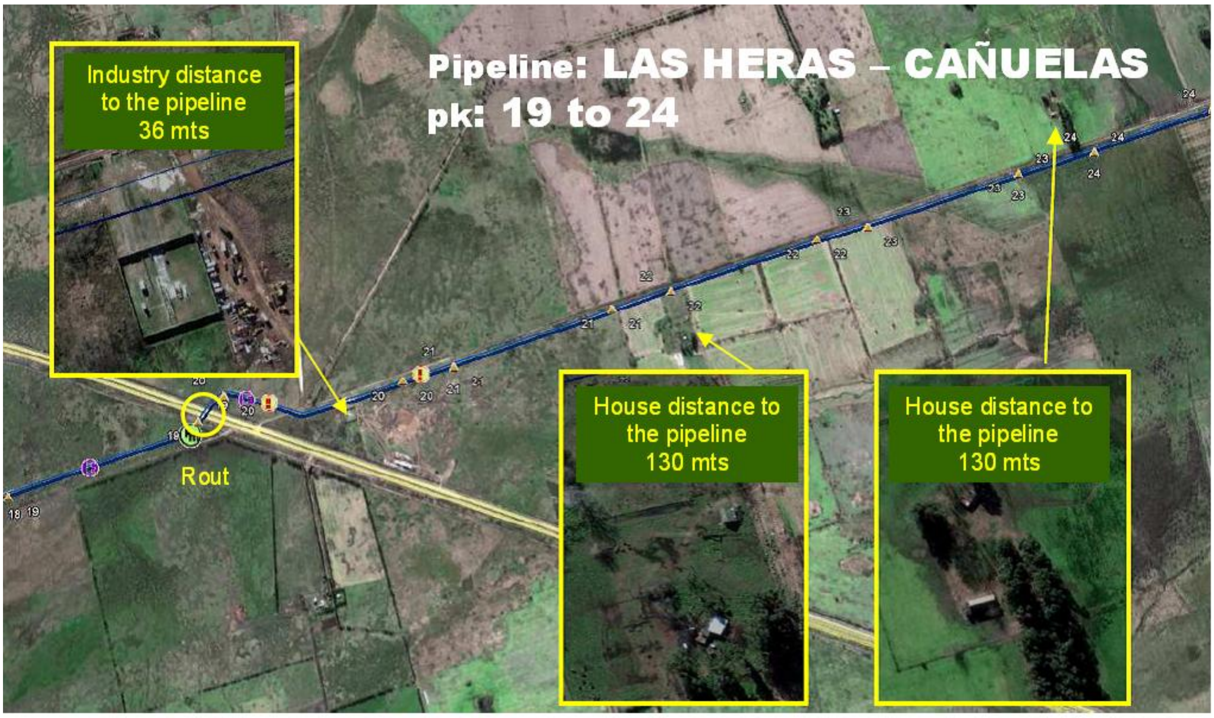

Figure N° 28 Risk Evaluation

Then depending on risk results and analysis of the information shown in Figure N° 27 (Advantages and Disadvantages of the detection and Assesment method), a specific plan is created for the corresponding system. This plan includes activities from 2011 to 2014

The following is an example, used in TGS.

After the two failures at the beginning of 2011, Integrity Area developed the following plan:

- **Short-term plan (2011)**

  - Hydrostatic test in both sections affected by SCC failure.
  - Run EMAT tool in three sections (2 because they are the most densily populated areas, and one in the area with failure of SCC). At the time of writing this paper we have not receive the results of the EMAT tool runs.
  - Exploratory excavation using Susceptibility model explained above. We made 28 digs and we found SCC in 7 sites.

Furthermore, TGS has decided to engaje an international company to carry out an audit of our SCC program.

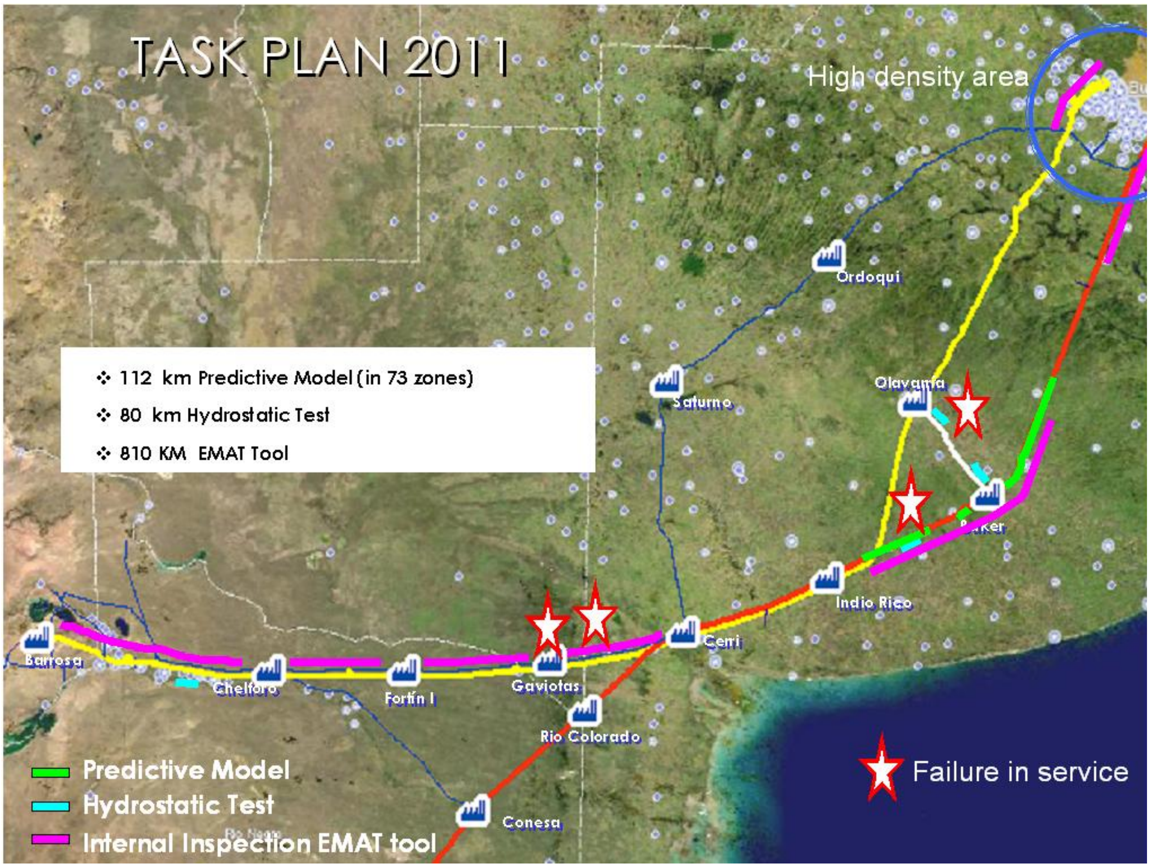

Figure N° 29 Task Plan 2011

- **Long-term Plan**

Furthermore, TGS has elaborated a long term plan for the rest of the system doing a mix in accordance with the risk of the section and the best and the most economical technology available on the market.

SUMMARY / CONCLUSIONS

Stress corrosion cracking is one of the threats to the time-dependent defects which can affect gas transportation lines.

In the TGS gas transportation system this phenomenon appeared in August 1998. Since then TGS has carry out an important number of research and field tasks to detect this phenomenon.

In January last year, two failures ocurred in the pipeline system. For that reason TGS made the decision to review the principles used in the past to define their SCC Management program.

Studies have been carried out on the environmental and operational factors producing the micro-environment found in the coating failure zones for different sites where high pH SCC has been detected in the TGS gas pipeline system.

SCC levels have been taken into account on each site in order to obtain a profile of "possible significant SCC sites" for the gas pipelines. This profile contradicts some aspects of the information on SCC provided by previous research but coincides with others. The differences can be rationally explained without challenging previous perceptions on the mechanisms which lead to high pH SCC.

A different model from that established by previous research for the localization of these sites along the pipeline course has been created on the basis of the results obtained from the research on soils and operational variable analysis.

This model has resulted in new guidelines for the localization of high pH SCC in buried pipelines coated with asphalt.

New spreadsheets from digging will make it possible to create a model for accurate forecasts on possible significant SCC sites.

This document details the Management Program implemented by TGS.

The implemented plan involved the following tasks

1) The first step was to define the study zone.
2) We spotted the risk areas in the study zone .
3) We evaluated the 3 methods for Detection and Prevention of SCC : Excavation based on Susceptibility Model, In Line inspection, Hydrostatic test., advantages and disadvantages .
4) TGS developed a short to long term plan, using the best option combining kinds of risk (business, people, environment) and the best technology.
5) This plan was audited by external people

The plan implemented allowed TGS to operate the system to its maximum operating pressure with high reliability and a low budget.

Furthermore, it was possible to use new tools of SCC based on EMAT principle with good results.