23rd World Gas Conference, Amsterdam 2006

Integrity Management for old Pipeline System

Main author

E. Espiñeira

Co-author

D. Falabella

Argentina

ABSTRACT

Argentina has a large natural gas transportation system, extending from production wells areas to main cities throughout the country.

This system is mainly conformed by 24 and 30” diameter trunk lines, which have been in service for more than 30 years and had originally been coated with asphalt materials. These coatings have undergone severe deterioration during these years in service and the lack of alternative transportation lines have prevented them from being taken out of service for rehabilitation.

TGS (Transportadora de Gas del Sur – Argentina) performs a variety of tasks within its integrity plan in order to operate its pipeline system at the highest level of reliability, optimizing human and material resources, and reducing potential environmental, personal or business impacts.

This Paper comprises the experience acquired by Transportadora de Gas del Sur S.A. (TGS) in Argentina in the implementation of a Natural Gas Pipeline Integrity Plan, using worldwide latest technology.

TABLE OF CONTENTS

1. Introduction

Transportadora de Gas del Sur (TGS) is an Argentine company that renders natural gas transmission and processing services. It started operations in 1992 as a result of the privatization of Gas del Estado S.E. (GDE), state company whose operations had included both transportation and distribution of natural gas.

TGS operates a 8000 km long pipeline system, mainly conformed by 36, 30 and 24 inches diameter pipes, with an average age of 35 years and mainly coated with asphalt materials. These features have resulted in the deterioration of the structural pipeline integrity, mainly in the oldest pipelines.

An Integrity Plan has been developed with the purposes of controlling the structural integrity of the pipelines, avoiding pipeline failures and extending the pipelines´ useful life, thus minimizing Impacts on the Environment, Population and Business in compliance both with international standards and Argentine regulations.

2. Devolpment

The first stage involves the identification of the potential threats to which a buried pipeline system is exposed. These threats have been assessed and classified by the “Pipeline Research Committee International (PRCI) in 9 categories - depending on the kind of failure, nature and growth features.

According to the PRCI, threats to pipeline integrity may be identified as follows:

- Time Dependent
  - External Corrosion
  - Internal Corrosion
  - Stress Corrosion Cracking
- Stable
  - Manufacturing Related Defect
  - Welding / Fabrication related
  - Equipment
- Time Independent (Unforeseen)
  - Third Party / Mechanical Damage
  - Incorrect Operations
  - Weather Related and Outside Force

As far as TGS´s system is concerned, the main identified threats to pipeline integrity are: External Corrosion (1) and Stress Corrosion Cracking (SCC) (2).

In connection with the first threat (1) the implementation of an intensive program which comprised in-line inspection, pipeline replacements, repairs and recoating (which will be discussed in detail below), enables us to assert that external corrosion (1) is a controlled threat.

The second (2) threat has grown in the last years and is affecting all gas and oil duct operators in Argentina to the same extent. The phenomenon is a combination of both environmental and operative factors, which added to the age of the pipeline results in the development of SCC.

Below you will find a description of the program undertaken by TGS for the mitigation of threats to the pipeline system integrity and the methodologies applied.

2.1. External Corrosion

Corrosion damage may be reduced even before pipeline failures through cathodic protection control, pipeline in-line inspection or an External Corrosion Direct Assessment method (ECDA).

TGS has combined all these methodologies in order to control the advance of corrosion. This led to Rehabilitation Programs: pipeline replacement, installation of sleeves, recoating, installation of rectifiers, etc.

In-line Inspection

When in 1993 an in- line inspection method had to be selected two main issues were considered: the need to get an accurate assessment of the condition of the pipelines and the selection of the tool that provided the greatest degree of reliability.

In that moment the market offered only two alternatives: low and high - resolution tools, and by that year only low- resolution tools had been run in Argentina. We prioritized a reliable and safe operation over the related costs, and decided to run the high-resolution tool.

The result of in-line inspections showed that the pipeline with the greatest number of defects and failures - and also the pipeline in which GDE had performed the greatest number of repairs- was the General San Martín (GSM) pipeline (Figure 1). This 30 " and 3,750 km long pipeline links Argentina´s southern basins to the greatest gas consumption centers located in Buenos Aires.

The GSM Pipeline was constructed in three stages: the first in 1964 – when Pico Truncado in the Province of Santa Cruz was linked to Buenos Aires. The second and third construction stages took place in 1975 and 1978 - the latter including the offshore crossing of the Magellanes Strait.

The pipeline constructed in 1964 is coated with poor quality asphalt and it shows the worst conditions is the one that links Pico Truncado - Province of Santa Cruz - to Cerri, in the Province of Buenos Aires. The other sections are also coated with asphalt. However, they are in good condition compared with the first section.

When the in-line inspection program was launched, the first surprise arose when running a cleaning tool previous to the in-line inspection: a pipeline rupture was produced, which was later attributed to a decrease of the pipe wall thickness due to corrosion.

Further to that, with the in-line inspection preliminary results, TGS conducted the repairs of the most severe defects.

The severity and number of reported failures compelled TGS to ensure safety by reducing operating pressure by 20% in roughly 1000 kilometers of the San Martín Pipeline, until the repair and replacement tasks could be implemented.

To illustrate this, Figure 2 shows the ASME B31G curves of the 148 km long sections Conesa – Colorado, in which the inspection tool recorded over 27.000 defects due to metal loss.

Most pipelines presented overall corrosion, with many severe defects, including defects along the transversal welding. This information had not been detected by low resolution tools, or even by some of the so-called second- generation tools.

The performance of the in- line inspections and the obtained results initiated a Repairs Program, which comprised pipeline replacements, and installation of full circumvallation reinforcements.

Figure 3 shows the replacements and installed sleeves conducted by TGS.

To conclude, in the midst of our pipeline repair and replacement program, we had a second pipeline rupture, also attributable to a decrease in pipe wall thickness due to corrosion, which confirmed the severity of the problem.

Further to the performed program - and in line with the outlined monitoring methodologies- three years after the first in-line inspection, a second running of the in-line inspection tools was carried out. The results obtained showed the improvement achieved by the Integrity Plan implemented in 1997. Figures 4 and 5 show the state of the defects for the section Conesa - Colorado in the second and third running. Afterwards we continued with five-year inspection intervals.

The results of the several in-line inspections carried out indicated that in a first stage the massive advance of the external corrosion was constrained. However the last in-line inspection pointed out at a new increase in the threat of external corrosion. This led to the implementation of new analysis, such as the assessment of corrosion speed rates.

To determine corrosion rates, in 2002 the existing inspection reports were compared, relating the recorded defect depth differences to the time intervals between one inspection and the other (Figure 6). This calculation involved an error, characteristic of defect sizing. On the other hand, for the comparison of this kind of defects, many variables should have been normalized, (odometry, orientation) .

In order to avoid measurement obstacles, we chose a new method to determine corrosion speed rates, known as RunCom (Figure 7). This new method, supplied by in-line inspection personnel, consists in the comparison of tool runnings, not considering the quantified values, but directly the magnetic signals of the running tool. Thus, the obstacles involved in the previous method would be avoided and it would be easier to discriminate new defects from the ones which were growing. This discrimination was not possible in the previous method as there was no certainty when determining whether a defect was new or not.

The results of these new surveys facilitate the monitoring of these defects, and their discrimination between active and non-active faults by following their evolution in time. This allowed us to minimize the threat attack field.

Cathodic Protection

The Argentine Code for Pipeline Safety N.A.G.-100 (based on the Safety Regulations for Pipelines by the United States Department of Transport) requires the compliance of a criterion of –850 mV "OFF" potentials to consider a pipeline as "fully protected". Pipelines with coating in poor conditions may find this criteria hard to meet.

In late 1996, the three main gas transmission pipelines complied with the exchange criteria of 100 mV of cathodic protection, and most sections in the three pipeline systems met the criterion of –850m V "Off" potentials of cathodic protection. In late 1996, the compliance with the –850m V "Off" potentials - after maintenance programs further to the first high- resolution in-line inspection- showed variations in different segments of the pipeline. This prompted the comparison between the status of compliance with the criterion of–850m V "Off" potentials and the change in defects numbers reported between the in-line inspections - which led to the conclusion that the cathodic protection system had faults.

The main cause of this was the bad condition of the original asphalt coating, which had to be replaced to improve the cathodic protection system and to hold back the advance of corrosion detected in the last in-line inspection.

Figure 8 shows the Recoating executed to date, and the quantity of cathodic protection equipments installed by TGS. Up to this date, we recorded 315 km of coating change and installed 178 cathodic protection units.

The efficiency of the cathodic protection enhancement works has been monitored by new in-line inspection reports, which have shown a slow- down in the growth of defects as compared to previous runnings. This and the corrosion evolution studies let us arrive to the conclusion that growth rates are lower. Another indication of the achieved progress is the increase of protected pipelines percentage according to the criteria –850m V.

After the performed tasks, we conclude that corrosion behavior in TGS pipelines as described in the last in-line inspections, is typical of well-protected pipelines. We have also verified that corrosion growth rates have not increased, and have in most cases decreased.

ECDA

The External Corrosion Direct Assessment (ECDA) is a method devised to assess the integrity of buried pipelines in order to control the impact of external corrosion. The process integrates data from current facilities with historical data, field inspection data, testing results and pipeline system - related information.

This method consists basically in indirect inspections conducted aboveground to estimate the efficiency of the cathodic protection process.

The process involves digging in determined sites for the verification of the indirect inspection results and the confirmation of the accuracy to find areas with active and passive corrosion in the pipeline as well as coating faults where corrosion might occur.

Inspection methodologies used in ECDA and which TGS used in its pipeline system comprise measurements of pipe-to-soil potentials such as CIS (close interval survey) and DCVG (direct current voltage gradient). Thus, TGS has performed to date over 2.000 km of CIS and 80 km of DCVG measurement surveys.

2.2. Stress Corrosion Cracking (SCC)

In August 1998, a rupture was produced in the Pipeline Neuba I, located in the Province of La Pampa, while it was in service. Integrity studies were conducted to provide insight into the causes of the fracture and it was concluded that the failure was produced by Stress Corrosion Cracking (SCC). This fracture was the first SCC case recorded in TGS pipeline system, and it brought about detailed analysis of the other potential sites for SCC . Furthermore, a methodology was outlined for the identification and mitigation of this threat to the system integrity before the occurrence of another rupture of a pipeline in service and for avoiding impacts on the Transportation service, Population and the Environment.

Nevertheless, in February 1999, along the same pipeline and over 30 kilometers upstream from the first case, there was another rupture while the pipeline was in service. After the rupture had been repaired, integrity surveys were carried out on the pipeline sections to identify the causes and it was concluded that it was a further case of SCC.

This concurrence of ruptures separated by barely a six-month interval and in such a confined area, alerted TGS and triggered an immediate Corrective Plan for the mitigation of potential cases of SCC in the Neuba Pipeline in order to avoid further ruptures.

Hydrostatic Test

The first inspection methodology used by TGS to identify and mitigate SCC was the application of hydrostatic test on the pipelines affected by the SCC ruptures. The areas selected in the Neuba I Pipeline comprised the compressor plants discharge areas, which combined the most unfavorable conditions in connection with SCC susceptibility. Three sections were affected by this testing (Figure 9).

- Chelforo – Fortín Uno
- Fortín Uno – Gaviotas

- Gaviotas – Gral. Cerri

Performed hydrostatic test totaled an extension of 134 kilometers with the outcome of three (3) cases of SCC at the discharge of the Compressor Plants in Gaviotas (2) and Fortín Uno (1).

This testing technique presents two disadvantages for the pipelines business. Although it has a high efficiency rate in the identification of critical size flaws, it is not good for identifying sub-critical cracks. Besides it has an adverse effect on the gas transportation business since the service must be interrupted during the fluency testing.

Predictive SCC Susceptibility Model (Canadian)

In 1999 a Predictive SCC Susceptibility Model was applied in order to identify SCC sites. This model was developed by a Canadian company specialized in the study of SCC phenomenon.

With the implementation of this model, 8.63 km inspection diggings were conducted and 7 SCC cases were identified.

This inspection methodology has no impact on the gas transportation service. However, its efficiency to identify SCC is very low compared to hydrostatic test.

Inspection tools

Although the use of in-line inspection tools for the detection of SCC cracking has not been perfected yet, it is currently under development as it is being supported by gas pipeline operators due to the comparative advantages that they involve for the eradication of SCC.

The main advantage of the methodology is the little impact it has over the rendering of the gas transportation service and the high efficiency rate expected to be obtained in the identification of both critical size flaws and sub-critical cracks.

Experimentally, TGS has tried Russian tools for the detection of SCC cracking. Two magnetic flux tools, MFL magnetic flux leakage and TFI, were run in two sections of the Neuba I Pipeline, the pipeline which has presented most SCC cases.

Unfortunately, there was not a positive outcome in the in-line inspections, and the use of them is subject to the adjustment and enhancement of the tools.

Predictive SCC Susceptibility Model developed by TGS

In March 2003, during recoating works on Gral San Martin Pipeline the discovery of a leakage triggered mitigation works. When an field study was carried out to assess the flaw that caused the leakage, it was concluded that the cracking was caused by SCC phenomenon. Once the existence of the phenomenon was verified in the pipeline, TGS proceeded to repair the fault, replacing the affected pipeline segment.

These last two SCC cases were found along a main pipeline that has the characteristic of not being apt for the performance of hydrostatic tests (the most effective methodology for finding SCC) as they can not be out of service. This finding, added to some incompatibilities of the SCC factors found in this site with the factors outlined in SCC literature, motivated TGS to develop its own Predictive SCC Susceptibility Model.

One month after having found the first SCC case, following the outlines of the susceptibility model in progress, a second SCC cracking was found in the recoating works of the same pipeline. This led to the hypothesis that there might be more SCC cases in San Martín pipeline.

For the development of the susceptibility model, TGS conducted soil studies in areas where TGS pipeline system extends and recorded the operating features of all the sites where SCC had been found, with the aim to identify environmental and operating variables that generate conditions promoting SCC and – based on those variables- - define the characteristics of potential sites with significant SCC and their likely location

Prompted by the Predictive Susceptibility Model under way, 80 inspection diggings were conducted. No SCC case has been found so far, but the model is still in progress with studies carried out jointly with Universities and geological research entities.

2.3. Data Integration (GIS)

The main asset of an integrity management program is the ability to combine and use data from different sources. For the application of an integrity program one of the first steps consists in the introduction of a common reference system, which allows to combine data from different sources.

Besides, it is generally acknowledged that the first step in the assessment of potential threats to a pipeline system is the collection of data and required information that classifies the segment and the potential threats to which it is exposed.

Given the age of TGS system and its extension, collected data was in several different formats and it was often incomplete. Besides, data proceeded from a variety of sources, each one with its own reference system in connection with the pipeline. This undoubtedly demanded a huge effort from us when we undertook the task to relate and integrate all the data.

Considering the variety, complexity and volume of the data, it was essential the use of an efficient database to look up, retrieve and analyze the information. A Geographical Information System (GIS) was implemented to visualize the data in a user- friendly and simple way, with the possibility of making geographical cross- references with the information required for the plan.

Another reason for our selection of this Geographical Information System (GIS) lies in the connectivity that this system has with other database management systems in the company, such as the CPDM (cathodic protection), IAP (Risk analysis in pipelines), and Easements (legal-real estate ownership data). This feature avoids the duplication of data, while it facilitates its easy maintenance and permits access to the same information by all company members.

The main advantages in the use of the integrated data system to store information are:

- The GIS structure allows the combination -within a single system- of information with diverse origins and formats, which results in data integration.
- The tools allow to manage and look- up the database, ensuring the obtaining of relevant, timely and suitable information
- Flexibility to link to other database management systems, which allows an efficient interaction and a dynamic connectivity with the company´s systems.
- The inclusion of cartography, satellite images and photograph in the database provide additional information for monitoring the pipeline integrity and achieving safe operations.

3. Conclusions

The Integrity Management Plan provides operators with a single data base which comprises all the technical parameters required in decision making for correctly performing long time integrity analysis.

With this kind of information pipeline operators will be able to generate long term Maintenance Programs, budgets and contracts, which will derive in cost reduction.

This type of plan provides information about the potential risk areas, preventing future environmental and safety hazards.

4. Figures

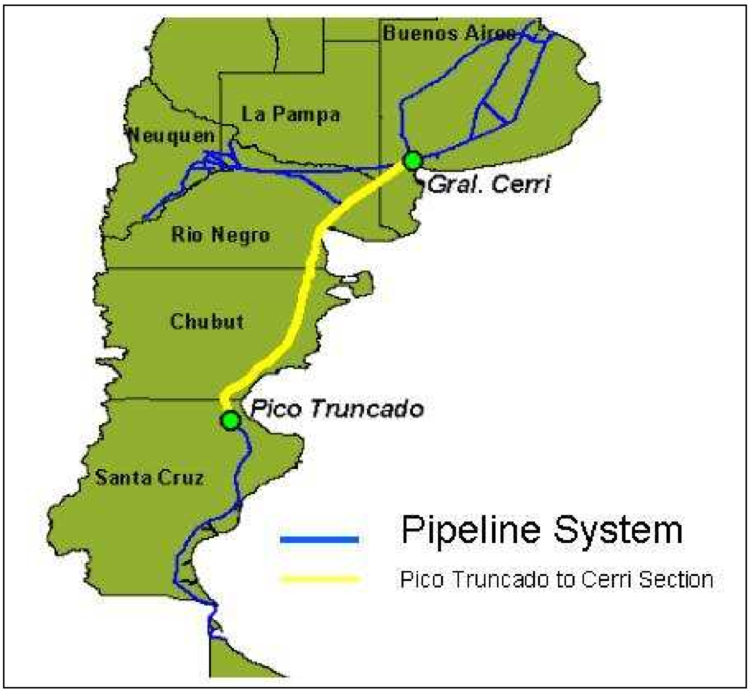

Figure 1: San Martin Pipeline – Pico truncado to Cerri section

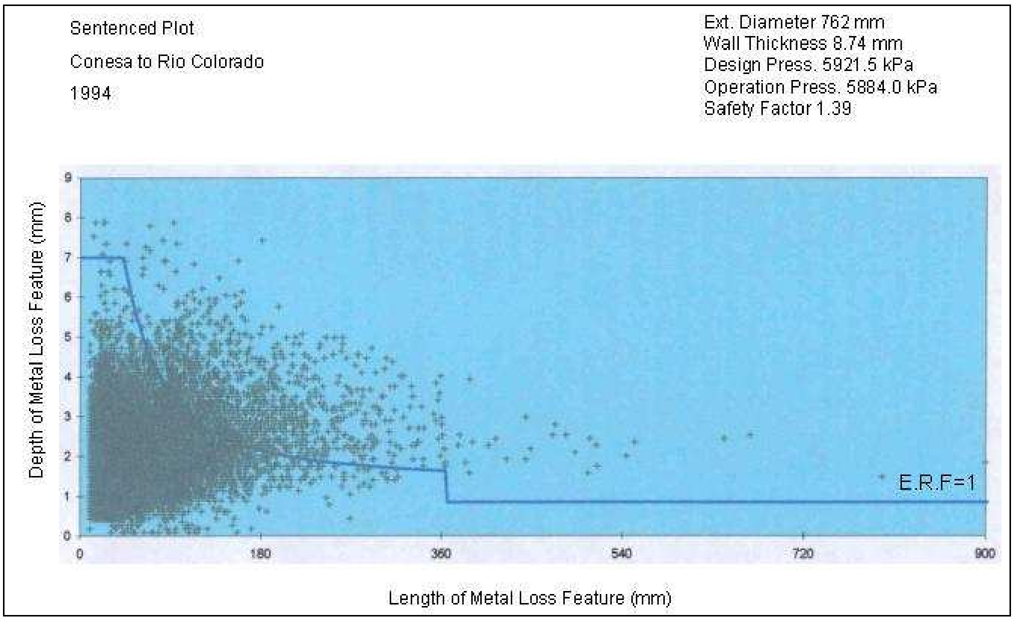

Figure 2: 1994 ILI Results (ASME B31G Curve)

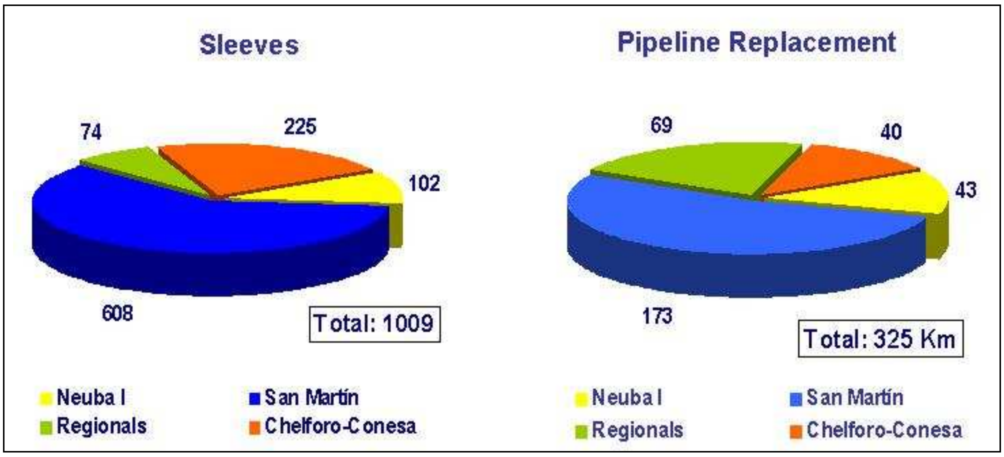

Figure 3: Maintenance Tasks made by TGS

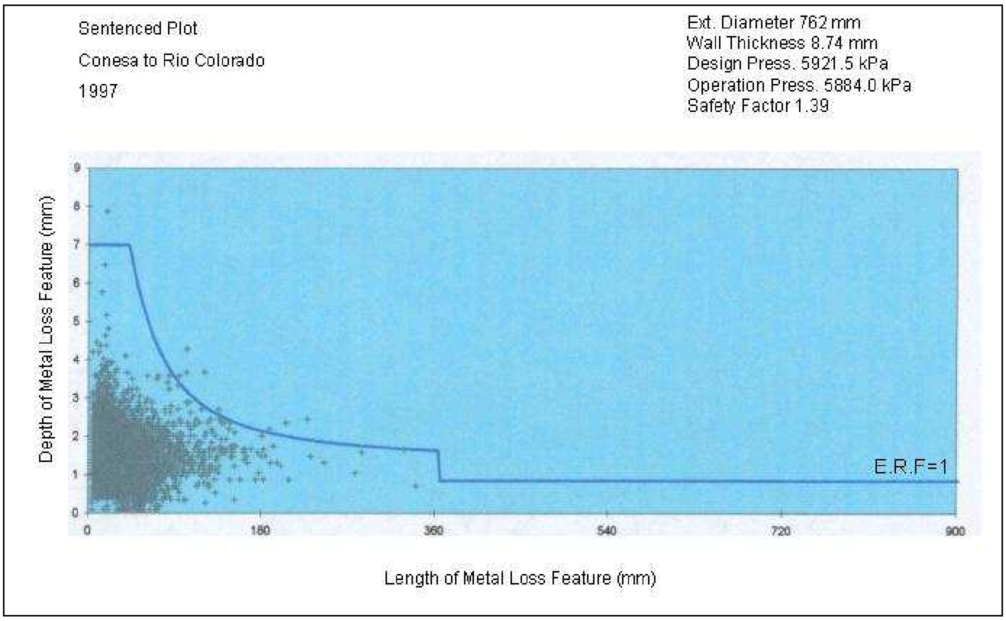

Figure 4: 1997 ILI Results (ASME B31G Curve)

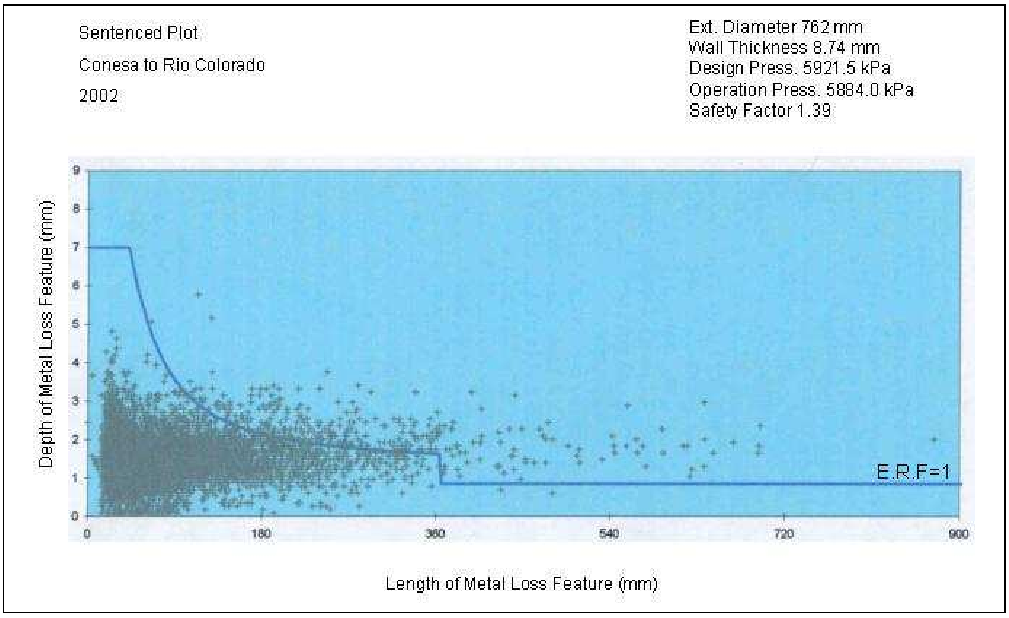

Figure 5: 2002 ILI Results (ASME B31G Curve)

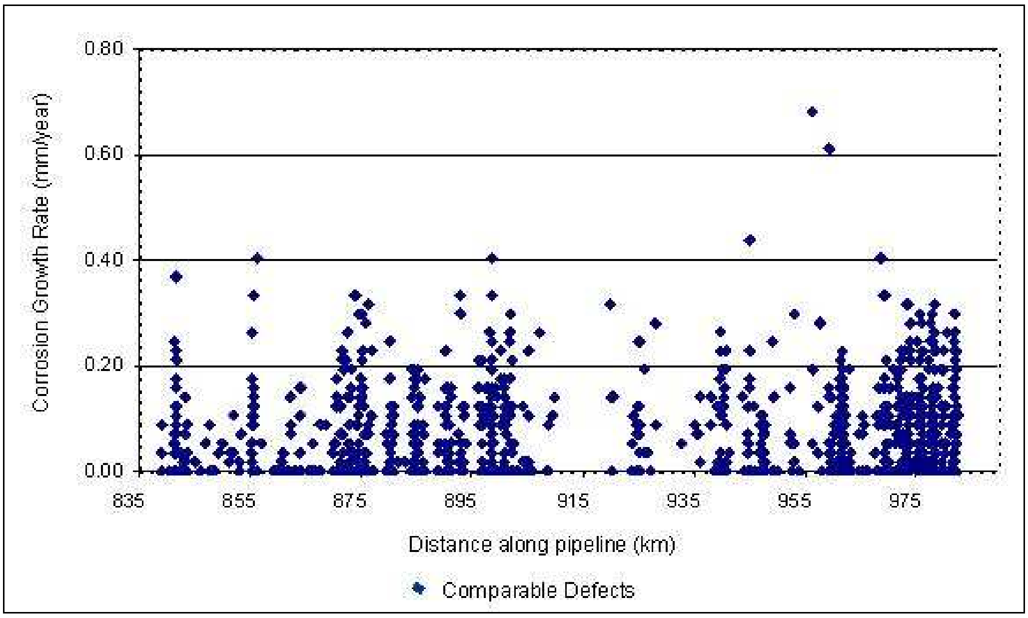

Figure 6: Corrosion Rates

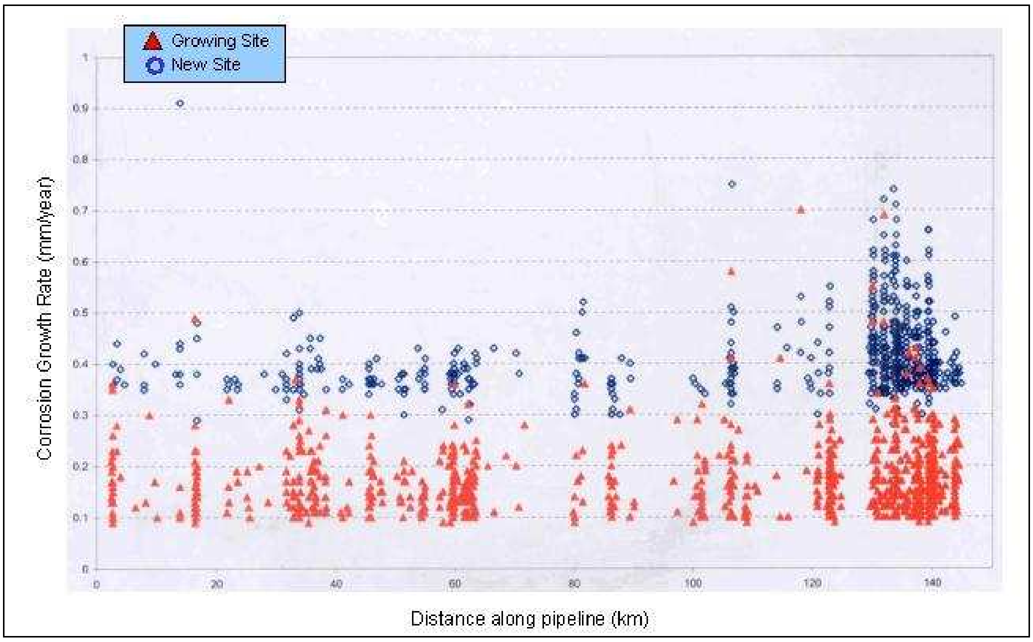

Figure 7: RunCom Analysis

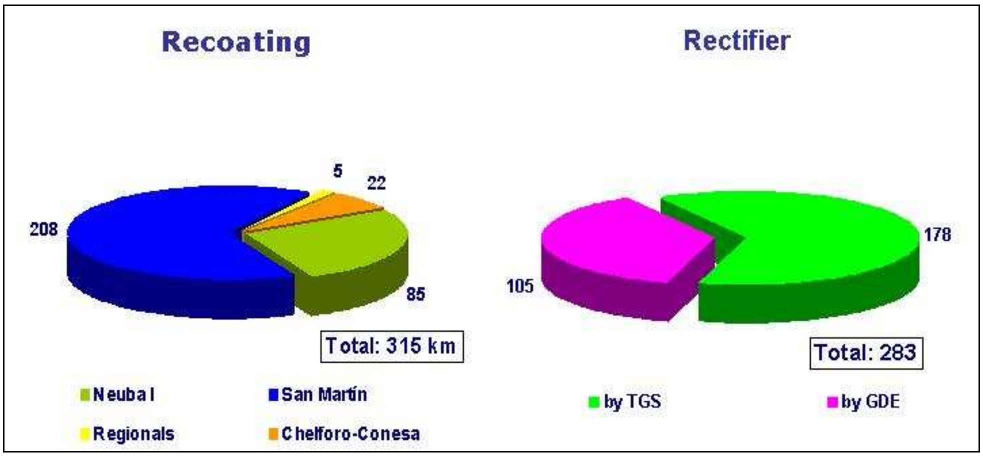

Figure 8: Recoating and New Rectifiers installed by TGS

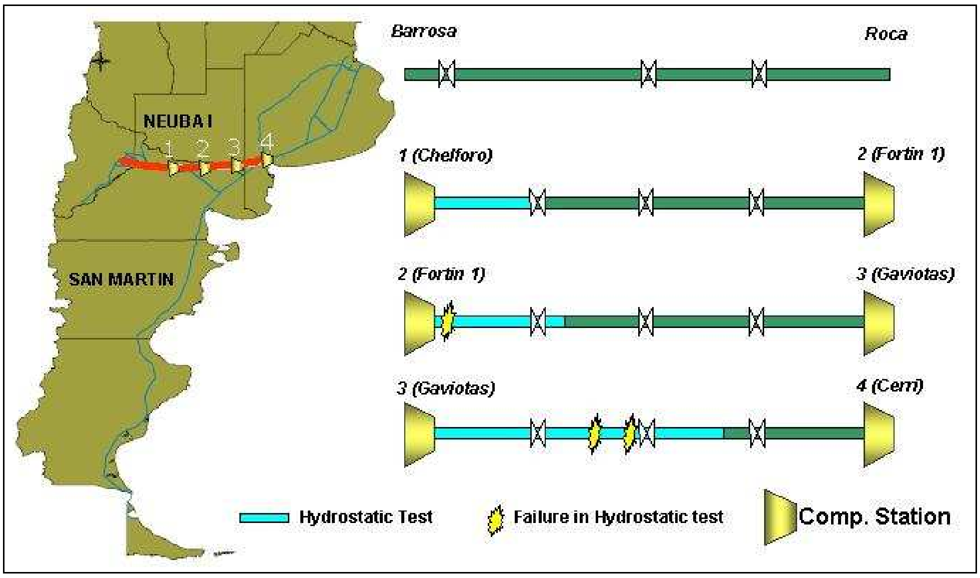

Figure 9: Hydrostatic Tests made by TGS