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Internal Repair of Pipeline Leaks Using Pressure-Activated Sealant

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Abstract

A cost-effective method of internally repairing pipeline leaks has been developed that – in many instances – eliminates the need for expensive and risky external mechanical repairs.

By delivering a pressure-activated sealant between two pigs to a leak site and pressure activating the sealant to polymerize as a flexible solid within the leak path, it is possible to internally repair pipeline leaks without the need for excavating or replacing defective sections with minor leaks.

Introduction

According to Department of Transportation's Office of Pipeline Safety, there are over 326,000 miles of natural gas transmission pipelines and over 1,923,000 miles of natural gas distribution pipelines presently in the United States. With natural gas consumption projected to increase by 50% over the next seventeen years, a major focus will be placed on pipeline integrity management, particularly pipe and joint leak repair systems.

The conventional methods of curing pipeline leaks is to either perform an external mechanical repair of the leak or install an internal patch or sleeve that reduces the inside diameter of the pipe. What is needed is a cost-effective method of internally repairing the pipeline leaks without the need for expensive and risky external mechanical repairs.

The paper will describe the use of a pressure-activated sealant technology to effect internal repair of pipeline leaks. This sealant technology has been successfully applied in the oil and gas industry for nine years, including offshore gathering lines and pipeline applications. These upstream industry case histories will be outlined.

The described technology is unique in that a differential pressure through the leak site activates a polymerization process that solidifies the liquid sealant and seals the leak paths. The availability of this technology can result in a significant reduction in the long-term risks and economics of repairing pipeline leaks.

Pursuant to a Cooperative Agreement with the United States Department of Energy (DOE) - Office of Fossil Energy - National Energy Technology Laboratory - Strategic Center for Natural Gas - Delivery Reliability Program, Seal-Tite is extending the capabilities of the pressure-activated sealant technology to cure leaks in natural gas distribution and transmission systems. Preliminary results of the DOE project will be available for the Eastern Regional Meeting.

The DOE section of the paper will review: (i) leak data used as a benchmark to develop new sealant formulas and procedures, and (ii) laboratory leak sealant operations on simulated pipeline leaks. The DOE Project has not been completed. A status report on the project will be distributed at the Conference.

Traditional Pipeline Repair Options

Although existing methods of curing leaks can be effective in curing leaks and restoring the integrity of the pipeline, there are limitations to the existing methods.

External Repairs

External repairs have an advantage of restoring pipe strength, but require excavation and cleaning of the external pipe surface. The two oldest methods, spot welding directly onto the external surface of the pipe to build up wall loss, and cutting and removing a damaged pipe section and installing a replacement section, are proven, but time consuming methods that have been replaced by welded full-encirclement split sleeve.

Welded Full-Encirclement Split Sleeve The welded sleeve, the most common and simplest method for external repair of gas pipelines, is usually utilized to spot repair welded steel liners. The leak site is excavated and the exterior of the pipe is cleaned. A full-encirclement steel sleeve is positioned around the circumference of the pipe encasing the leak site. The sleeve is then welded longitudinally and at the ends. A similar repair method is the ***Bolt-On Repair Sleeve***. The same procedure is generally followed for excavation and cleaning but then a rubber lined, stainless steel sleeve is bolted in place across the leak site.

Fiber Reinforced Composite Repair Composite repair, in general, consists of woven fiberglass in an epoxy resin material bonded to the pipe using an adhesive. This method, as an alternative to Welded Full-Encirclement Split Sleeves, has the advantage of eliminating the need for welding but still requires excavation and cleaning. Examples of this technology include Armor Plate® Pipe Wrap, Clock Spring®, and StrongBack®.

Epoxy Sleeve Repair® Epoxy sleeve repair comprises two oversized steel half-shells which are joined together to encircle the damaged area, leaving an annular gap. The annulus is sealed at each end of the sleeve using a fast-setting material, and then filled at very low pressure with a stiff epoxy-based compound. The epoxy grout cures, forming a bond at both steel interfaces, providing both hoop and axial support.

PETROSLEEVE® Petrosleeve® is a Steel Compression Reinforcement Sleeve Repair system, comes standard in 36" lengths for pipe diameters from 2" to 60". The damaged pipe area is grit blasted, epoxy is applied, and the sleeve is assembled, brought to the required compression, and then welded together.

Internal Repairs

Internal repairs have the advantage of precluding the need to excavate, but are generally used to restore leak tightness and not to restore pipes strength. Additionally, most internal repairs cause a reduction in the inside diamter of the pipeline.

Remote/Robotic Welding Repairs This method was developed primarily for the nuclear power industry and presently exists in varying stages of development from prototypes to field trials to fully operational units. Generally, the units fall under three categories based on locomotive capability; stationary, self-propelled and towed.

Self-propelled units on wheels or tracks, receive power and control via umbilical cables, while the power supply for the welding module remains at the entry point. The ability of the units to pull the umbilicals, along with the welding power supply remaining at the point of entry, limits the working range. The working range for the self propelled welding units vary from 135 ft to 500 ft in pipe sizes from 12" to 24", with one unit, comprised of separate modules connected by flexible coupling, able to service 6" to 40" pipe. All of the self propelled units can transverse 90° bends.

Towed units, which can reach lengths of 1,000 ft in 12" to 18" pipe, are operational in straight pipe only.

Stationary units, for obvious reasons, have a very short working range of only 12 ft.

Fiber Reinforced Composite Repair There are two composite repair methods that can be utilized for internal repairs; Cured-In-Place Pipe Liners and Fold-And-Form Liners. As with all internal liner systems there is a reduction in host pipe internal diameter that may hinder the ability to clean / inspect using traditional inspection tools (PIGs).

Cured-In-Place Pipe Cured-In-Place systems consist of a flexible reinforced non-woven felt liner with the outermost layer coated with polyethylene and the inside diameter saturated with liquid thermosetting resin. The liner is installed by using water pressure to propel the liner through the pipe and turn it "inside-out" so that the saturated resin side is pressed tightly against the host pipe section to be repaired. Once in place heat is applied to cure the resin. Sections of up to 1,000 ft can be lined depending on diameter and number of bends. While this method is primarily used to restore leak tightness, several companies are working with utilizing glass fibers and braided tubing for restoring pipe strength.

Fold-and-Form Liners Liners involve manufacturing a thermoplastic pipe into a folded "C" shape which , after being pulled into the host pipe via a winch, is expanded with pressure and heat. The liners, which are made from polyethylene or polyethylene reinforced with polyester fiber, achieve a close fit after expansion to restore leak tightness. Due to the pull-in requirements this technology is limited to smaller pipe sizes.

Expandable Metal Patch Patches have been successfully used in the oil and gas industry for several years and with modification can be applied to gas pipelines. A fixed sized metal liner is deployed via coiled tubing with expandable metal seals at the top and bottom of the assembly. The metal seals are energized and expanded hydraulically via a hydraulic setting tool. The setting tool is pulled from the pipeline along with the coiled tubing after the setting process is completed. The Expandable Metal Patch is presently available for sizes up to 9-5/8" with a minimum burst pressure rating of 3,560 psi. The disadvantage of this method is the necessity of coiled tubing deployment. Although vibration tool technology enhances the ability of the coiled tubing to reach extended lengths, the working range may still be inadequate for many of the applications. Another disadvantage of this method is the size reduction through the patch. Generally, the patch will reduce the pipe internal diameter by 1".

Internal Repair Sleeve Internal Sleeve is basically a combination of fiber reinforced composite repair and expandable liner patch repair. It consists of a stainless steel sleeve surrounded by an outer sleeve of felt liner that is saturated with liquid resin immediately prior to installation. The sleeve can be deployed on coiled tubing, carried by robots or pulled by cable. Once in place an inflatable bladder expands the sleeve out to the host pipe internal diameter. Locking barbs on the exterior wall of the sleeve lock the sleeve in place while the resin cures. At present, this system is available in sizes from 4" to 54". Typically, the sleeve will reduce the pipe internal diameter by approximately 1-1/2".

An Alternative to Conventional Repair Methods

As an alternative to conventional repair methods, Seal-Tite, in cooperation with the DOE, organized a project to attempt to expand the capabilities of an existing pressure-activated sealant technology to allow internal repair of pipeline leaks without reducing the internal diameter of the pipe and without the need for excavation or replacement of defective sections.

The Pressure-Activated Sealant Concept

Background Critical to the success of internally sealing pipeline leaks is a new formulation of an existing pressure activated sealant technology that is specifically designed to seal leaks in severe environment hydraulic systems. The sealant is unique in that a pressure drop through a leak site causes the sealant fluid to polymerize into a flexible solid seal only at the leak site.

Pressure Activated Traditional sealants are activated by temperature, time or simply by clogging a leak with particulates. The sealant reaction is analogous to blood coagulating at a cut. The sealants remain fluid until the sealant is released through a leak site. Only at the point of differential pressure, through the leak site, will the sealant reaction occur.

The basic pressure-activated sealant formula consists of a super-saturated mixture of short-chain polymers, monomers and polymerizing chemicals in a carrier fluid. The sealant formula is adjusted with additional components based on temperature, pressure, system fluids and leak rate. The monomers and polymers in the formula are cross-linked by the polymerizing chemicals. As the reaction proceeds, the polymerized sealant plates out on the edges of the leak site and, simultaneously links across the leak site to seal the leak. The resulting seal is a flexible bond across the leak. The remainder of the sealant will remain fluid and will not clog the hydraulic system or pipeline.

Contrasted to conventional particulate sealants, a true pressure activated sealant does not contain any significant particulate materials (component size of less than four microns). The problem with particulate sealants is that they can plug vital components of the system.

The likelihood of pressure activated sealants providing a long-term seal is dependent on the severity of the original leak and the stress placed on the seal after the treatment. On moderate leaks, the sealant, once cured for two weeks, has the same longevity as an 80 durometer elastomer in the same service. For leaks within their capabilities, pressure activated sealants are very cost-effective compared to the alternatives.

The methods of delivering the sealant are very flexible. In pipelines it is expected that the sealant will be delivered between isolating media such as foam, gel or smart pigs. Because the sealant never hardens except in the presence of a differential pressure, concerns about the time to deliver the sealant and pipeline temperature have been eliminated. If the sealant can be delivered to the leak site and a differential pressure created through the leak, there is a high probability of sealing the leak.

Pipeline Sealant Repairs (Pre-DOE Project)

As stated in the Introduction, the DOE and Seal-Tite have entered into a Cooperative Agreement by which the parties share the funding of research necessary to extend the capabilities of the pressure-activated sealant concept. Prior to entering into the Cooperative Agreement, the sealant technology had been used only on applications where the seal was not exposed to damage by a passing pig. In the prior applications, the sealant was polymerized in connection threads or joints. The technology had not been successfully used on the types of leaks that are experienced in welded pipe such as found in the large diameter, long distance transmission and distribution pipelines that are the main conduits of transporting oil and gas to the industrial and consumer markets of the United States.

Some examples of the pre-DOE applications of the predessessor sealant technology are as follows:

Pipeline Swivel Connection The 12”, 8.5 mile, 1415 Maximum Allowable Operating Pressure (MAWP) Pacific Ocean Pipeline Company (POPCO) pipeline was originally installed with two “Swivel Joint Connectors” in 800 ft water depth. With an operating pressure of 1050 psi, a continuous stream of gas bubbles was escaping to the sea from each connector. The conventional repair procedure would include complete depressurization and flushing of the pipeline prior to cutting out, removal and replacement of the faulty section. This would have resulted in a significant expense as well as several days of production downtime.

Utilizing a Dive Support Vessel and an atmospheric diving suit commonly refered to as a “WASP”” diver suit, access was gained to the void for each Swivel Joint Connector. A work umbilical was lowered to the sea floor and tied-in by the WASP. After determination of the leak characteristics, a custom-blended sealant was prepared and pumped in to the void space of each connector. The internal pressure was slowly staged up to 1350 psi and allowed to cure. The void pressure was then bled off to allow room for thermal expansion.

Prior to job completion, a one-hour observation period showed no leaks from either Swivel Joint Connection, indicating a successful seal had been established. The pipeline was returned to operation with no further evidence of leaks.

Load Limiting Connector An offshore 6”, 800 psi working pressure bulk oil pipeline sustained a leak 300 feet from the platform near the Load Limiting Connector (LLC). Observations by divers and video cameras indicated leakage past the seals between the inner and outer barrels of the LLC.

The conventional repair method is a risky and expensive clamp procedure in 300 feet of water. Instead, the operator chose to use a sealant solution in an attempt to cure the leak.

First, the pipeline was flushed and filled with saltwater. A train consisting of pressure-activated sealant between two foam pigs was launched from the platform and down the pipeline until the front edge of the sealant had reached the leak site. The pipeline was then shut-in and pressure cycled between 200 psi and 1000 psi to push the sealant through the leak site and polymerize the sealant within the leak site. Pressure testing of the pipeline indicated that the leak rate had been decreased, but not eliminated.

A second sealant operation was performed using the same procedure with a different sealant formula. With this second operation, the leak was fully sealed and tested to Minerals Management Service specifications at a pressure of 1000 psi.

Pipeline Connections Overpressuring of an 8”, 1400-psi working pressure bulk oil pipeline resulted in multiple connection leaks along the entire length of the 11.5 mile onshore pipeline.

The conventional alternative was to dig up the entire pipeline to identify and repair each of the estimated fifty (50) leaks in the pipeline. The operator chose to use a sealant solution in an attempt to cure the leak.

A train consisting of sealant between two foam pigs was pumped down the pipeline at a pressure of 1400 psi and at a speed sufficient to allow exposure of the sealant to each leak site for a minimum of one hour. As the sealant train passed each leak, the pressure drop through the release site activated the sealant. The sealant polymerized within each location to repair the subject leak.

All leaks in the pipeline were fully sealed and the pipeline was hydro-tested to a pressure of 1400 psi

Extension of the Sealant Technology
(The DOE Cooperative Agreement Project)

The deliverables outlined in the DOE Cooperative Agreement were as follows:

1. Collect and review data on leak incidents for gas transmission and gathering system pipelines.
2. Analyze leak incident data.
3. Attempt to develop leak sealant technology to address the types of leaks experienced on gas transmission and gathering system pipelines.
4. Conduct tests of the developed leak sealant technology.
5. Perform leak sealant operations on in-service pipelines.

Collection of Current Field Data

Collection of field data started with the report titled "Analysis of DOT Reportable Incidents for Gas Transmission and Gathering System Pipelines, 1985 through 1997" [1].

This 13-year period was chosen because this was the time frame with the most complete data available. Additional data from the Office of Pipeline Safety reports as well as operator and service company input was added to aid in identifying candidates for the pressure activated sealant technology. The report listed a total of 1,084 incidents during the period. Initially, all catastrophic incidents were eliminated as clearly being beyond the capability of the sealant technology. Of the remaining 354 incidents, 205 incidents were identified as having leak characteristics (leak size, geometry and flow rate) that might be within the capability of the technology.

The 205 candidates out of the total universe of candidates affirms that pressure activated sealant technology is a viable option to traditional external leak repairs.

In identifying these candidates, we not only focused on incidents where Seal-Tite's technology could have been utilized, but where it would have been the optimum repair method. A database of the 205 incidents and the leak characteristics that defined them as applicable candidates for sealant technology was prepared and submitted to the DOE. This data included types of defects, areas of defects, pipe sizes and materials, incident and operating pressures, ability of pipeline to be pigged and corrosion states. This data will be available in the final DOE Report.

Analysis of Current Field Data

The database constructed during the collection of current field data was used as a basis in constructing applicable sealant test modeling.

For ease of reference, excerpts from the original Technical Topical Report, "Analysis of Current Field Data" [2] are included in Table 1.

Candidates for pressure activated sealant technology were identified on the basis of several criteria: Accessibility / Economic Advantage, Leak Severity, Leak Geometry, and Leak Cause.

Accessibility/Economic Advantage: The more inaccessible the leak site, the greater the economic advantage. Our database focuses on leaks where accessibility is difficult, time-consuming and costly. 198 incidents (96.6% of our 205 incident base) were either underground, under pavement or underwater.

Leak Severity and Geometry: While no actual leak rates were collected, we know through previous field experience and testing that we can cure leaks up to approximately 50 scf per minute. Our incident base focused on cracks & pinholes, not ruptures, punctures or tears, which may be out of the range for sealant technology. Narrow leaks, which have more surface area to open area, are easier to seal and have longer seal longevity than circular leaks.

Leak Cause: Weld and corrosion leaks accounted for 75.6% of our incident base and 43.8% of all 354 leaks. By focusing our testing on weld and corrosion leaks we will be testing a representative sampling of the majority of leaks that are applicable candidates for pressure activated sealant technology.

Table 1: Leaks By Cause [3]

	Number of Leaks by Cause	% of 205 Incident Base	% of All 354 Leaks
DFW	9	4.4%	2.5%
DGW	16	7.8%	4.5%
DPS	12	5.9%	3.4%
EC	41	20.0%	11.6%
IC	77	37.6%	21.8%
	155	75.6%	43.8%

Testing of the Sealant Formulas

The previously developed sealant formulas polymerize into a flexible seal at the point of differential pressure through a leak site. For the pipeline sealant, a more rigid sealant formula is necessary. A number of different formulas were developed based on the desired result of creating a sealant that would polymerize into a more rigid seal. These various sealant formulas were lab tested as follows:

General Lab Test Procedure:

1) Build four interchangeable removable sections of pipe. These will be the "Defect Sections".
2) Damage each Defect Section with one of the four typical types of leaks.
3) Set each Defect Section standing vertical with a blind flange on bottom and a blind flange tapped for nitrogen charge and gauge on top end. (Actual leak is on bottom to reduce the chance of pushing the top of the sealant column pass the leak site)
4) Fill each Defect Section completely with sealant
5) Pressure to 1440 psi.
6) Monitor bleed off every 30 minutes.
7) Once there is 0 bleed off after 30 minutes start clock for curing time as follows:
   a) External Corrosion – 48 hours
   b) Internal Corrosion – 96 hours
   c) Pinhole – 144 hours
   d) Weld 192 hours

   (The different cure times were used to analyze the effects of cure time on the durability of the seal.)
8) After designated curing time bleed pressure and drain sealant

9) For each Defect Section, pump various types of pigs through the test fixture.

Pipeline Test Fixture

Based on a review of pipeline failure histories, 6-5/8", 12-3/4", 16" and 20" pipe accounted for 56.1% of the incidents. Based on preliminary testing, it was our opinion that, in these larger diameter pipes, the technology could be tested in any of the listed pipe sizes. To reduce costs and facilitate ease of handling, we utilized 6-5/8" pipe for our test model.

Schedule 80 XS steel was utilized as the pipe material since 204 of the 205 incidents occurred on steel material [1]. This pipe has a wall thickness of 0.432", an internal diameter of 5.761" and a Maximum Operating Pressure of 1,793 psi MAOP.

Two valves were incorporated into the test model to simulate pressurizing against a closed downstream valve or plug in proximity of the leak site in non-piggable pipeline applications.

Twelve 1" nipples were placed in the system to allow for placement of pressure gauges, bleed-off valves, pressure pop-off valves, and ball valves for the injection and discharge of nitrogen, air, water and sealant.

Figure 1: Test Fixture

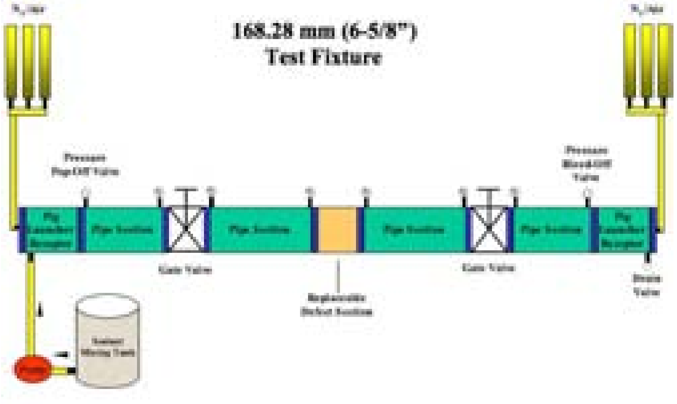

Table 2: Test Fixture Dimensions

Pipe OD, in.	6.625
Pipe ID, in.	5.761
	Length, in.
Pig Launcher	21.375
Pipe Section	70.125
Valve	22.250
Pipe Section	99.500
Test Section	39.500
Pipe Section	99.500
Valve	22.250
Pipe Section	70.125
Pig Receptor	21.375
Total Fixture Length	466 inches 38 ft 10 in.

Figure 2: Overview of Test Model

Figure 3: Close-up of Test Model

Figure 4: Pig Launcher / Receptor Assembly

Our test model includes a replaceable 3-foot Defect Section. Each Defect Section simulates a type of defect identified during the analysis stage; Defective Fabrication Weld (DFW), Defective Girth Weld (DGW), Defective Pipe Seam (DPS), External Corrosion (EC) and Internal Corrosion (IC). These defects accounted for 75.6% of the incidents.

The DFW, DGW and DPS defects will simulate common irregularities associated with welds including cracks and wormholes. Since 68.3% of the externally corroded pipe and 64.1% of the internally corroded pipe is described as either “localized pitting”, “pinhole” or “pinhole with localized pitting”, the EC and IC defects will simulate localized pitting with pinholes.

The dimensions of the various defects created in the Defect Sections are shown in Table 3.

Figure 5: Overview of Replaceable Defect Section

Figure 6: Overview of External Corrosion with Pinhole

Figure 7: Close-up of External Corrosion with Pinhole

Figure 8: Overview of Internal Corrosion Defect Section

Figure 9: External Pinhole

Table 3: Defect Dimensions

Defect Section	Corrosion			Pinhole 1		Pinhole 2	
	Length	*Width*	*Depth*	*OD*	*Depth*	*OD*	*Depth*
External Corrosion							
Defect 1	4.00	2.00	0.315	0.063	0.432	na	na
Defect 2	3.25	1.25	0.315	na	na	na	na
Internal Corrosion							
Defect 1	4.00	3.00	0.120	0.063	0.432	na	na
Defect 2	3.50	3.00	0.120	0.063	0.432	na	na
Pinhole Defect (2)	na	na	na	0.063	0.432	0.063	0.432
Weld Defect							
Crack	2.00	0.063	0.432	na	na	na	na
Wormhole	xx	xx	0.432	na	na	na	na

Leak Rates

Liquid leak rates were established by filling the test model with water, establishing maximum rate (determined either by maximum pressure allowed or maximum output of double diaphragm pump) and recorded maximum leak rate at X psi. The leak rate was then incrementally reduced and once it stabilized at each increment the corresponding pressure was recorded. We continued this process until a representative amount of data points was collected. The Weld Defect only has 2 data points due to the extremely small leak rate.

Nitrogen leak rates were established by pressuring test model to maximum psi (limited either by pipe strength or nitrogen tanks) and recording pressure drop over time. The leak rate was then calculated by first solving for V1 (the amount of N2 to pressure test model at a given psi) by using:

$$P1*V1*Z1 = P2*V2*Z2$$

$$V1 = (P2*V2*Z2) / (P1*Z1)$$

We then solved for the change in volume due to pressure drop by utilizing the same formula. Complete leak rate data both tabular and by chart will be published in the final DOE report. Some selected data points are shown in Table 4.

Table 4: Leak Rates

Defect Section	Water l/min	Water Gpm	Water ΔP	Nitrogen scf/min	Nitrogen ΔP
External Corrosion	8	2.11	985	48	987
Internal Corrosion	9	2.38	1,005	56	1,052
Weld Defect	0.2	0.05	985	2	1,077
Pinhole Defect	13	3.43	455	96	937

Experimental Procedures

Since the data collected in reference to the ability of the pipelines to be pigged was considered inconclusive, we tested delivery methods that included piggable, semi-piggable (multi-diameter) and non-piggable pipelines.

The testing of sealant delivery between Polly Pigs represents delivery procedures in pipelines that are piggable. To date, no tests have been conducted using Gel Pigs or Gel Spacers. In the actual applications, (i) the Foam Pigs would be used for multi-diameter pipelines and (ii) Gel Pigs or Gel Spacers would be used in pipelines where the restrictions would not allow even the compressibility of the foam pig to transverse.

We also tested against a closed valve to simulate delivery of the sealant to the leak site by pressuring against a downstream closed valve or plug. Again, we followed the representative solution with polly, foam and gel pigs for the reasons previously described. The main purpose of the tests was to evaluate the different delivery methods in delivering sealant to the leak site with the least amount of fluid bypass. A short outline of the delivery testing procedures is as follows:

Delivery Methods

Between Polly Pigs
Between Foam Pigs
Between Gel Pigs/Spacers

Against downstream Plug/Closed Valve

Followed by Polly Pig
Followed by Foam Pig
Followed by Gel Pig

For each type of defect we attempted to establish a low pressure and, after a cure time, a high pressure seal; then, retest the integrity of each seal after exposure to wire brush cleaning pigs. Since no leak rate data was collected in the collection phase of this project, we will work our way up by establishing a leak rate, test, and establish a larger leak rate and test, and so on until the maximum leak rate that we can seal for each type of defect is determined. A short outline of the sealant testing procedures is as follows:

General Test Model Procedure

1. Insert two pigs into test model.
2. Close launcher side gate valve and launcher ball valve
3. Inject sealant between the two pigs using nipples in the test model.
4. Pressure system from receptor side to 200 psi
5. Open launcher side ball valve and let pressures equalize
6. Move pigs/sealant train by regulating Nitrogen pressure on receptor side through needle valve. Approximately 20 psi less on receptor side than launcher side moves pigs/sealant train.
7. When lead pig is across leak site (indicated by sealant coming out of defect in early tests – indicated by electronic pig indicator on latter tests) open receptor needle valve fully to maintain equal pressure on upstream and downstream side of pigs.
8. Increase pressure until initial seal is formed. Shut in both receptor and launcher ball valves SIMUTANEOUSLY to keep sealant train from moving pass leak site
9. Hold for designated time and then open both receptor and launcher ball valves simultaneously and increase pressure. Increase & hold in increments until final 1440 – 1450 psi pressure seal is achieved.
10. Let cure for approximately 20 hours.
11. Note test model pressure. If pressure is less than final shut-in pressure then re-pressure system to previous pressure from both ends.
12. Open needle valve on receptor side and bleed pressure down (20 psi differential) to move pigs and sealant to receptor.
13. Close receptor gate valve.
14. Re-pressure system to final shut-in pressure to confirm trailing wiper pig did not destroy seal integrity. If seal maintained integrity proceed to Step 15. If seal broke End Test.
15. Bleed pressure off launcher end.
16. Insert 2 wiper pigs. Open a ball valve upstream of Defect Section.

17. Pressure behind pigs and move pigs pass defect section.
18. Close upstream ball-balve.
19. Re-pressure system to final shut-in pressure. If seal maintained integrity proceed to Step 20. If seal broke End Test.
20. Insert scrapper/wiper pig configuration.
21. Re-pressure system to final shut-in pressure. Record if seal maintained integrity or if seal broke. End Test.

Testing Status

As of the submission date of this paper (July 1, 2004), the testing program is ongoing. The goals that have been achieved to date are as follows:

1. Sealant formulas have been developed that are capable of sealing the leaks created in the test fixture.
2. The sealant can be delivered to the leak site between two pigs.
3. A differential pressure can be created at the leak site by stopping the sealant train at the leak site and increasing pressure on the line to approximately 1440 psi.
4. The sealant polymerized in each of the leaks and created a polymer seal that was able to hold a pressure of 1440 psi.
5. The polymer seals established in Internal Corrosion & Weld Leaks withstood wiper pigs but failed when subjected to scraper pigs.
6. The polymer seals established in External Corrosion and Pinhole Leaks failed when subjected to wiper pigs
7. Seals created at higher pressures are more durable and resistant to pigging operations.

Further testing is necessary to develop sealant formulas and polymerization methods that will create polymer seals that are resistant to all pigging operations. At the conference, an updated report on the status of testing will be distributed.

Benefits of the Technology

The benefits realized by development of this technology for curing pipeline leaks include:

- Repair of inaccessible pipeline leaks
- Repair of pipeline leaks without a need to excavate
- Significant reduction in pipeline downtime
- Elimination of environmental problems caused by pipeline leakage and excavation
- Significant reduction in the cost of pipeline leak repairs
- Internal repair of pipeline leaks without restricting the host pipe ID

Conclusion

Through research of current state of the art pipeline repair methods and the collection of current field data, we conservatively concluded that there is a need and an opportunity for sealant repair technology. Through analysis of the data collected we have identified a representative sampling of the type of leaks and their characteristics that are experienced in gas transmission pipelines. This representative sampling will be the basis for our test modeling

Significant work has been completed in developing sealants and sealant delivery procedures to address the types of leaks and their characteristics previously identified.

Developing sealants to address the types of leaks and their characteristics previously identified will be accomplished by comparing existing formulas to the types of leaks that were identified as applicable candidates and if necessary, modify existing sealants. New formulas will be developed if needed. Analyzing job files and communicating with service companies and operators will aid in the development of piggable and non-piggable sealant delivery methods. These methods will focus on efficiently delivering the sealant to the leak site in an optimized concentrated form.

Sealing simulated leaks will be concluded with the issuance of a test summary report summarizing all test scenarios used in determining optimum formulas and procedures.

Finally, we anticipate evaluating the optimized sealant formula and delivery procedures in an operational pipeline. Field data will be correlated to laboratory data to evaluate the effectiveness of sealant technology as well as delivery methods on pipeline leaks.

If we are successful in our attempts at sealing these simulated leaks then we will be confident in our ability to repair similar leaks experienced in natural gas transmission pipelines.

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SPE Metric Conversions

psi x 6.894 757	E+00 = kPa
in x 2.54*	E-02 = m
ft x 3.048*	E-01 = m
mi x 1.609344	E+00 = km

All SI Metric Conversion Factors can be found at:
www.spe.org/spe/jsp/basic/0,,1104_1732,00.html

Acronyms and Abbreviations

DFW	Defective Fabrication Weld
DGW	Defective Girth Weld
DOE	Department of Energy
DOT	Department of Transportation
DPS	Defective Pipe Seam
EC	External Corrosion
ft	foot
GPM	gallons per minute
IC	Internal Corrosion
ID	Internal Diameter
in.	Inches
km	kilometer
kPa	kilopascal
LLC	Load Limiting Connector
l/m	liters per minute
m	meter
MAOP	Maximum Allowable Operating Pressure
mi	mile
Min.	Minimum
mm	Millimeters
MPa	Megapascal
N_2	Nitrogen
na	Not Applicable
OD	Outside Diameter
ΔP	Pressure differential
P1, P2	Inital pressure and final pressure
psi	Pounds Per Square Inch
POPCO	Pacific Ocean Pipeline Company
scf	Standard Cubic Feet
scf/min	Standard Cubic Feet per minute
V1, V2	Initial volume and final volume
XS	Extra Strong
”	Inches
Z1, Z2	compressibility coefficient factor

References

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