CORROSION CONTROL'S LINES OF DEFENCE

Cal Chapman and Mike Ames, Chapman Engineering, USA, analyse the risks and consequences of internal and external pipeline corrosion.

Industry-recognised standards, some dating from the 1950s or earlier, address many important oil and gas pipeline integrity concerns. One commonly applied list of integrity risks includes:

- Multiple types of corrosion damage.

- Third-party damage to existing pipelines (especially by excavations).
- Problems with manufacturing, fabrication or joining of line pipe, fittings, valves, etc.
- Various types of incorrect operations, weather forces and environmental forces.

Control of corrosion for oil and gas pipelines must include study, measurement, maintenance and prediction of external and internal corrosion processes, and risks related to cracking, local stress and other damage to pipeline metals. Many physical and electrochemical processes are in play.

External corrosion of pipelines

External corrosion, usually to carbon steel pipeline metal, happens when exposed steel pipe is put into direct contact with water and soils, and the various chemical constituents they contain. When steel is put in soil and water contact, natural electrochemical reactions take place. These are driven by the huge amounts of energy put into the steel, when manufactured from iron ore, carbon and other additives. The metal refining process, the milling, machining and welding of pipe, all put energy into the steel. When that steel is put into the environment, corrosion begins and will continue until all the steel is converted back into iron ore/rust. That is the lowest stable energy state for iron, in Mother Nature's eyes.

Figure 1. A 2 in. steel oil pipeline in the Bakken Formation of North Dakota, USA, with mostly degraded external coating (a second pipeline is directly underneath).

Figure 2. A corroded 8 in. flange face on emulsion pipeline at isolation kit, with CP current transfer through produced water fraction (combination of emulsion water content and stray CP current).

Coating protection

The first protection against external corrosion is a good quality coating. For a new pipeline, this is a given, and coatings in today's world can do exceptional work for reasonable costs. For existing pipelines, however, coatings might be old and deteriorated, or might not have even been used. A common problem, whether pipeline is old or new, relates to coatings applied in the field, to girth welds or to fittings. The same happens when coating application is undertaken with high humidity or water-wetting of metal surfaces. Backfill operations can further damage coatings.

One good practice is holiday testing (a holiday being a failed coating section, tiny or large) on new pipeline during burial. Often called 'jeep' testing (high voltage DC power applied to a rolling coil around pipe causes an electrical short circuit 'jeep' sound at detected holidays), this is typically required by job specifications as part of pipeline installation processes. But standards are only followed when the interested parties (pipeline owner representative, construction contractor, and construction inspector) all want to 'do it right the first time.' Unless follow-up testing is carried out using such techniques as direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other coating conductance survey, the already-backfilled coating issues will not be found. One strong recommendation is to have a trusted third-party corrosion survey firm carry out the DCVG or ACVG while pipeline construction contractor is still in warranty period, then make that contractor undertake digs and coating remedial work as significant defects are found. However, a common practice is to have the pipeline construction company provide this survey work as part of the contract. This may mean the corrosion survey contractor is serving the interest of the pipeline contractor, and not the pipeline owner/operator. A better approach is for the owner to retain a good third-party vendor for the needed survey work, avoiding the chances for conflicts of interest.

Surface preparation

Good surface preparation, the right coatings and trained applicators are the best 'first' investment anyone can make against external corrosion. When selected properly and put on a clean, prepared metal surface using the right procedures, coatings provide great protection to 98%, 99.5%, or even more of that external metal surface. Coatings must not be damaged during transport, fabrication, installation or burial. But every subsurface metal structure also needs cathodic protection. NACE International, a leading corrosion protection organisation, specifies that both coatings and cathodic protection are required for external corrosion

Figure 3. A foreign pipeline (green coating) crossing the client's pipeline. Light-coloured spots on the red line are coating damage from CP interference.

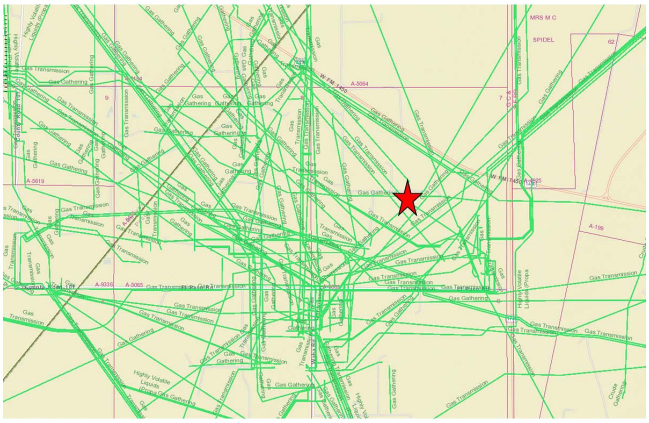

Figure 4. Railroad commission of Texas pipeline mapping, near Coyanosa, Texas. Client line crossed 42 times in 2.5 miles by other pipelines with a star at photo location of Figure 3.

control. Think of these as a good preventive maintenance programme, and as very inexpensive life extension insurance.

Cathodic protection systems

Once a new pipeline is put in service, cathodic protection (CP) systems are then used as the second line of defence against external corrosion, with the coatings being 'first line.' CP is an electrochemical process which forces the steel pipeline metal to always be a cathode, meaning it is more electronegative than any other metals, soils, or moisture around the pipe. But this automatically means that another metal body must be sacrificed over time as an anode. With time, replacement anodes must be installed as anodes are consumed.

CP is undertaken one of two ways. For short pipeline segments that are kept electrically separate from other metal (such as facility structures or other pipelines), galvanic anodes (sacrificial anodes) are attached to the pipeline. Industry practices strongly recommend that these anodes be attached through test stations with dedicated bond wires to the pipeline, and not by direct connection of anode lead wires to pipe metal. Direct-connected anodes do not allow later CP survey work to be carried out applying NACE-standard requirements.

The most commonly used galvanic anode for carbon steel sub-surface pipelines is made of magnesium. This metal is very electrochemically active, and is a strong anode compared to steel. Another common choice is zinc, somewhat less active than magnesium, but appropriate in a broad range of uses. In brackish or salt water environments, aluminium anodes are used for CP on carbon steel. Galvanic anodes generate their own driving voltage and do not require external power.

Galvanic anode CP approaches are limited, however, in the amount of protective DC current that can be applied to steel structures, and in the distance or reach that protection may be delivered. For these reasons, many practitioners use the second approach, impressed-current CP systems. These systems require external power supplies, with the most common power source being a transformer rectifier unit – often simply called a rectifier. Other power sources might be solar panels with batteries, thermoelectric generators or wind turbines, for remote areas without AC power.

Impressed-current CP has four major pieces, the first being the rectifier or other outside power supply. Think of that as equivalent to a DC battery, with positive and negative terminals. From the positive terminal, a heavy wire connects to the anodes, each capable of delivering a large positive DC current. The next circuit piece is less obvious. It is the soil, water and rock matrix that connects the anode bed, as an electrical current flow path, to the pipeline(s) being protected. The pipeline is then connected by another heavy wire back to the rectifier negative terminal. By adding an on-off switch, the CP system is ready to work.

Measurement of CP system effectiveness must be done after each new CP system is energised, and regularly thereafter. It requires well-trained personnel following standardised procedures, obtaining sufficient data, then evaluating data to see if adequate protection is applied. As seasons change, as coatings age, and as other structures come in around the subject line, CP behaviour can change. One risk from other structures is high-voltage AC power interaction with well-coated pipelines, bringing both safety and AC-induced corrosion risks into consideration.

External corrosion control can be readily measured, through bimonthly or more frequent checks of rectifiers and annual surveys of pipe-to-soil voltages on pipelines. Those measurements should include both CP system current applied (system on) and current-interrupted (instant-off) data, with comparison of all voltages made to the three different criteria specified by NACE International Standard Practice SP-0169. Measurements of unprotected pipeline voltages (called 'native' or 'depolarised' readings) are also high-value, allowing the study of electrochemical polarisation shift on the structure.

Internal corrosion of pipelines

Internal corrosion is a far different and often insidious set of issues, compared to external corrosion. External corrosion processes on steel and cast iron/ductile iron pipelines received technical attention beginning in the 1920s and 1930s. Internal corrosion issues, including biological and corrosiverelated properties, did not receive major attention until 30 to 50 years later.

For internal corrosion, the biggest risks usually come from water. If allowed to get inside a pipeline and collect, water is always a source of trouble. Some steel pipelines move emulsion product streams, which keep crude oil, natural gas and produced water (typically very salty in nature) all mixed together. Others may be moving treated crude oil, natural gas liquids (NGLs) or natural gas. Treatment steps remove basic sediment and water (or BS & W) from the product stream, so the water content is greatly reduced. But that often does not eliminate all water from getting into pipelines, and then dropping out/collecting inside.

Just the presence of water causes steel to corrode, as most pipelines have bare steel as the internal wall surfaces. If there is hydrogen sulfide or carbon dioxide available, the water turns more acidic and corrosion rates increase. Another bad internal corrosion driver is oxygen. If atmospheric air is leaked into the pipeline product stream, oxygen causes exposed steel surfaces to change from cathodes to anodes, greatly increasing corrosion rates. To manage oxygen-driven internal corrosion, pipeline operators are encouraged to keep oxygen concentrations below 20 ppb in the product mix. Considering that Earth's atmosphere has almost 21% oxygen, oxygen removal is of huge importance for the insides of pipelines.

Along with water, bacteria and other micro-organisms get introduced to pipeline internals. Many microbes use hydrocarbons and water as food, and proliferate. Some 'bugs' move with product flow and are referred to as planktonic. Not attaching to pipe walls, they are often of less concern. But those that do attach, called sessile (or fixed) microbes, are of great concern. All bacteria produce acid wastes, and some make very potent acids. Some produce hydrogen sulfide and other noxious waste chemicals. Because they stay in one place on the pipe internal surface, they can cause very aggressive, deep pitting into the pipe wall. Where a pipeline has low points as it runs overland or undersea, water and bugs tend to collect because water is much denser than the typical crude oils, NGLs and natural gas. Once the water collects, product flows keep riding right over the top, with bugs and food and water all staying put. Without regular pipeline cleaning and chemical treatments, risks are huge.

Pipeline cleaning

For pipelines, maintenance pigs should be used regularly to sweep debris, water and other chemicals (such as paraffin) out of the pipeline. This maintenance pigging work is critical to remove waste products or deposits that cause aggressive internal corrosion. When this type of pigging is carried out effectively, chemical treatments will work far better.

Pipelines must be designed and constructed to allow the proper use of pigs. Materials removed from the pipeline, on a regular basis, need to be evaluated. Valuable information is learned by characterising the material, including what types of corrosion risks are present and how various internal treatments are performing. Many experienced pipeline operators call maintenance pigging a science and an art, as every pipeline and its product stream is a unique system.

Many companies use chemical and biocide treatments in their pipelines. Chemical corrosion inhibitors and oxygen scavengers get added to product flows, in concentrations intended to neutralise the various corrosion-causing reactions. Measurements of residual chemical presence, at downstream points, are made to monitor effectiveness and make process improvements. These chemicals perform best when pipe internal walls are kept clean by good maintenance pigging operations.

To monitor for internal corrosion, metal coupons may be inserted into the pipeline. After known exposure periods, coupons are removed and then tested. The amount of weight loss over time, surface appearance changes, and other measurements can indicate how aggressive internal corrosion issues may be. A standard goal calls for "internal pipe wall loss to be less than one mil (0.001 in.) per year." Coupons may also be swabbed for samples then analysed for microbes present and active. Other internal devices, such as electrical resistance (ER) probes, may be placed in pipeline flow and checked for periodic read-outs of metal loss vs time. These coupons and probes should be placed where water collects. High points such as pig traps and skids may not represent the significant corrosion locations.

Gouges, dents, stress corrosion cracking

Any time a pipeline receives damage, multiple risks come into play. A gouge, a corrosion pit or a dent each represent places where uneven stresses are applied to pipe metal, as well as coating damage. At any concentrated stress area, more energy is available for locally accelerated corrosion. In addition, any thinning of pipe wall may cause a decrease in strength, and greater chance for pipe failure. For a pipe in service, these issues are often discovered only when a smart pig (or inline inspection, ILI, tool) run is performed, or when pipe is exposed. Whenever a pipeline is uncovered, detailed inspection by a qualified professional is highly recommended, no matter the regulatory status.

Specialised ILI tools can often call out crack-like indications or defects, dents, gouges, internal or external pitting, and other concerns on a pipeline. Bear in mind, however, that these data sets are usually considered high-quality but not 100% accurate. Other inspection work must be undertaken in correlation with pig data, to raise confidence in the overall integrity assessment of a pipeline.

Cathodic protection interference

In congested oil and gas production regions, as well as in urban congestion areas involving natural gas distribution, public water systems, public transit systems using DC power, etc., regular and open co-operation among these asset operators is needed to minimise electrical interference effects among the various buried assets. CP systems can be a major cause of stray current interference. The physical corrosion damage done to buried metal assets by interference effects represents big risk, with large potential consequences (Figure 4).

In the Coyanosa area seen in Figure 4, some pipelines are over 30 years old. They require large per mile protective CP currents, having very old coatings now in place. New pipelines should have high-quality coatings in use, allowing for much smaller CP system current needed. Where coating defects are present, foreign pipeline CP currents can get onto another pipeline, travel in that pipe's metal wall for a distance, then exit that pipe to go back home to the original pipeline and CP system. Where this current leaves that other pipeline, corrosion can occur from this unintended current path.

Figure 3 shows a client's large diameter pipeline with external fusion-bonded epoxy (FBE) coating (the red colour) that was bubbled and disbonded due to foreign pipeline CP system interference (note the light-coloured spots on an otherwise uniform, red coating surface). The foreign line with green FBE was five to six years old, while the client pipeline (red) was less than three years old. One external corrosion pit showed 30% wall loss, due to foreign CP current leaving the client pipeline at this close approach. When many pipelines come into such close proximity, some line portions will be over-protected by stray CP current for a period of time, and this causes coating damage. As operators change CP levels, or more new pipes come into service, a formerly over-protected region may become under-protected – with aggressive corrosion being the result. Also, whenever DC current leaves a pipe surface, just that process causes very rapid corrosion of the metal.

Some companies with old transmission pipeline systems and poor-quality coatings are trying to use large CP currents to meet the NACE Criterion 2 protection standard (-850 mV instant off). Results are often showing that this approach creates new CP interference issues. This reinforces the need for co-operative CP operator groups who understand and apply CP to minimise interference issues. They co-ordinate detailed CP surveys and design/performance comparisons for mutual benefits and proper protection to pipelines in congested areas.

Figure 5. First pipeline rupture after 45 min. of blowdown, Midland County, Texas, USA.

Figure 6. One result of second pipeline rupture and explosion, Midland County, Texas, USA.

Summary

A great approach is to treat all assets as regulated, and then use good or best management practices (BMPs) to care for them. Keep in mind that a standard is not necessarily the BMP, and might not even be an average management practice. Rather, just as regulations often state, the standard sets a bar at the minimum threshold for an operator to properly care for assets. Is meeting the minimum safe enough? Is it risk-minimising enough? NACE International published a study in March 2016 which clearly illustrated the substantial return on investment asset owners receive when corrosion control work is properly performed.

An asset owner should use due diligence when choosing corrosion control providers. Many practitioners try to use one-size-fits-all approaches. They may not pay attention to the nuances of project geography, topography, geology, soil science, and construction plans. To install a US$50 million plant or pipeline, for instance, and give the company and investors a 30-year service life (or longer), one must assure that good coatings and surface preparations are selected, and then applied. Hire good contractors, with qualified inspectors overseeing all the work, documenting how job requirements are truly met.

Think about the cost of any one pipeline release incident. There is shutdown time, doing de-inventory and repair. What is the cost of making the news? What if there is a fire, or injuries, or worse? Figure 5 is an August 2018 natural gas pipeline leak/burn after most of the pressure was 'blown/burned down.' Figure 6 shows the results of an adjacent pipeline rupture/explosion, moments after Figure 5 was taken. Note the firefighting brush truck in the foreground of Figure 5, parked about 300 ft away from the initial rupture point.

Corrosion control and other vital pipeline integrity management functions must be done using the continual 'plan, do, check, act' cycle on these assets. Regulations may require paper trail, but the responsible persons must perform the real work that backs up what is put on paper.

So what does it cost to 'do it right the first time?' And what does it cost to 'do it right the second time?' Spend a little more time and money at the front end, please.

30 PLUS YEARS

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Company Profile

Chapman Engineering, Inc., a Texas USA corporation founded in 1989, offers corrosion control and engineering, environmental engineering, subsurface environmental assessment and corrective action, ground-water availability studies, and specialty construction and survey related to corrosion control. Starting in underground fuel storage tank (UST) release detection and cathodic protection of steel USTs, Chapman Engineering has worked in the corrosion protection marketplace since the mid-1990s. It designs, constructs and manages cathodic protection systems for water, sewer and
electrical utilities and infrastructure, oil and gas production and transportation systems, and refining/petrochemical complexes.
The firm's multifaceted engineering team has over three decades of experience in corrosion control design, installation of cathodic protection (CP), coating quality and AC power interaction evaluations with pipelines, and review of existing asset integrity, as well as CP system commissioning,
testing and optimizing across the industries. Our team has a proven track record of effectively mitigating the corrosion risk for steel, ductile iron, concrete pressure pipe, storage tanks, and other metal assets across North America.