Mitigating external corrosion failures in buried petroleum pipelines in Nigeria: A review

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Citation

Abstract
Most transmission pipelines are buried underground to minimize their contact with external influences. The soils usually contain deleterious chemicals and microbes that accelerate the deterioration of the pipe steel through corrosion. Thus making corrosion is one of the leading in-service defects resulting in pipeline failures. The various mechanisms of external corrosion found in underground pipelines are reviewed. The primary methods for mitigating/preventing corrosion are discussed. Pipelines are usually coated to isolate the pipe steel from direct contact with the soil. Because of the inherent imperfection of coatings and their degradation over time, cathodic protection is used as a secondary protection. Emphasis is made on the need to establish a proper maintenance program for the pipelines. An appropriate repair option must be chosen in the case of a defect arising in a pipe material. The study concludes that petroleum pipeline failure, with its attendant environmental and human cost can be prevented or greatly mitigated with a consistent monitoring and maintenance program.

1. Introduction
Petroleum pipelines are the main artery of the oil and gas transportation system [10]. They are important for transportation, storage and marketing of crude oil, natural gas and refined petroleum products.

The Nigerian geographical space is traversed by a network of oil and gas pipelines most of which are buried underground. These pipeline infrastructures are exposed to diverse climatic and soil conditions. The performance reliability of the pipeline decreases with age. It can be observed from Table 1 below that most of the main pipelines in Nigeria are over 30 years old. They are thus prone to failures [1]. There have been various incidents of pipeline failure in Nigeria in recent years. Achebe et al (2012) reported a total of 137 pipeline failures across six states in the Niger Delta region of Nigeria in the period 1999-2005. Corrosion accounted for 18% of these failures. In the US, 25% of transmission pipeline failures between 1994 and 1999 were due to corrosion. For liquid product transmission pipelines most of the corrosion accidents were due to external corrosion [4].

A 2011 Amnesty International report highlighted the devastating effect of two successive oil spills in Bodo, a town in Ogoniland inhabited by 69000 people – all dependent on the environment for their survival. The first of the spills occurred in
August 2008 as a result of a fault in a section of the Trans-
Niger pipeline. According to the company operating the
pipeline, this spill was caused by a ‘weld defect’. Another
spill followed in December of the same year and
investigations by the company attributed it to ‘equipment
failure as a result of natural corrosion’.

Table 1. Age and performance rating of Nigerian main pipelines as at the
year 2000

<table>
<thead>
<tr>
<th>Age (years)</th>
<th>Year 2000</th>
<th>% reliability</th>
<th>% total network length</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt;20</td>
<td>46</td>
<td>27</td>
<td></td>
</tr>
<tr>
<td>20-30</td>
<td>29</td>
<td>32</td>
<td></td>
</tr>
<tr>
<td>&gt;30</td>
<td>25</td>
<td>41</td>
<td></td>
</tr>
</tbody>
</table>

Source: Achebe et al, (2012)

Considering the implications of oil pipeline failure and the
role played by corrosion in these failures, it is obvious that
proper and adequate corrosion control can have a significant
effect on the safety, environmental preservation and
economics of pipeline operations.

2. Pipeline Design Considerations
   and Pipeline Failure Modes

2.1. Pipeline Design Considerations

The vast majority of oil and gas transmission pipelines are
made of carbon steel [5]. The American Petroleum Institute
API 5L specification specifies the maximum composition
limit of carbon, phosphorus, manganese and sulphur.
Nevertheless, other alloying elements may be added to
improve on some mechanical properties of the steel for
specific applications.

Carbon steels have inadequate corrosion resistant
properties thus undergo various corrosion failure modes in
underground environments [4].

Because of the level of hazard posed by their products to
the environment, pipelines are designed to well-established
standards. These standards ensure operational safety,
compliance to legislation, security of supply and cost
effectiveness [10]. These criteria are met by designing to
prevent failure as a result of burst, puncture, overload,
buckling, fatigue and fracture. Preventing failure of pipelines
therefore begins with good design, which will eliminate most
of the above potential failure modes. However, since
pipelines operate in adverse environments (underground),
they are constantly threatened by defects and damages that
occur during service. These in-service defects are the major
culprits in pipeline failures.

2.2. Pipeline Failure Modes

These in-service defects can be broadly outlined into two
categories:

- External force – third party damages, mechanical
damages and outside interference

- Corrosion of the pipe wall, either internally by the
  product conveyed or externally by the interaction
  with the surrounding environment.

External damages occur as a result of sabotage or
mechanical damages. Sabotage occurrences are underpinned
by the existence socioeconomic inequality. It occurs more
often in regions of economic deprivation and perceived social
injustices. Mechanical damages result from impact from e.g.
earth moving equipment in excavation sites.

Other causes of failure could be attributed to defects in
materials and construction. Material defects may originate
during pipeline fabrication. They cause non-uniformity in the
pipeline material creating sites for differential cell formation
which accentuates the oxidation-reduction reaction that leads
to corrosion. Construction defects include scratches and dents.

They can serve as sites for extreme corrosion attacks.

This paper aims to discuss the mechanisms of external
corrosion in pipelines and measures of preventive
maintenance. This is because of the limited effect of internal
corrosion in petroleum transmission pipelines as a result of
the low percentage of water in and non-corrosive nature of
the fluid [3; 4].

3. External Corrosion Mechanism in
  Underground Pipelines

Steel pipelines undergo a variety of corrosion failure
mechanisms in underground environment. The most
important of these include differential cell corrosion and
stress-corrosion cracking (SCC) [4].

Source: Dawotola, (2012).

Fig 3.1. External corrosion in underground pipeline

3.1. Differential Cell Corrosion

In underground environment, the pipeline material does
not undergo a uniform metal loss along its surface. Rather
there is an uneven metal loss over localized areas in the pipe
surface. The mechanism that gives rise to this is the
differential corrosion cell. Corrosion is basically an
oxidation-reduction reaction. Existence of a significant
difference in potential between two points in the metal
surface creates an anodic and a cathodic site between the
points. This causes an exchange of electrons (redox reaction)
between the points. It is this electron exchange that leads to
corrosion. Various pipe surface and environmental conditions
can give rise to a difference in potential in the surface of
buried pipelines.
Underground pipelines corrosion is predominantly due to the existence of differential corrosion cells. Differential corrosion cells may arise as a result of different oxygen concentration levels in the soil (differential aeration cell), varying soil properties, presence of dissimilar metals (galvanic corrosion), presence of surface films etc [4; 9].

### 3.1.1. Differential Aeration Cells

This form of differential cell is set up in an underground structure when one end of the pipeline line is exposed to a higher oxygen concentration, while the other is situated in an oxygen deficient area. The part of the structure in the higher oxygen concentration region becomes the cathode and the oxygen deficient end forms the anode. Electrons flow from the metal surface in the anodic site to the oxygenated cathode. The flow of current increases the corrosion rate in the anode. Two consequences of this electrochemical reaction tend to promote the continuation of the cells. The first is the hydrolysis of the metallic ions produced by the corrosion reactions in the anode. This reduces the local pH. The second consequence is the migration of corrosive halide ions to the anodic sites to maintain charge neutrality. Both of the processes increase the corrosion rate at the anode. On the other hand, the reduction reactions at the cathode increase the pH and improve the formation of corrosion protective films on the metal surface [4].

### 3.1.2. Varying Soil Properties

Variation in soil properties as a result of difference in moisture content, pH, soil type, presence of microbes and aggressive ions in the soil can set up differential corrosion cells [9].

### 3.1.3. Galvanic Corrosion

#### Table 2. Practical galvanic series and redox potentials of metals and alloys in neutral soils and water

<table>
<thead>
<tr>
<th>Material</th>
<th>Potential (CSE)(a), V.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Most Noble</td>
<td></td>
</tr>
<tr>
<td>Carbon, graphite, coke</td>
<td>+3</td>
</tr>
<tr>
<td>Platinum</td>
<td>0 to -0.1</td>
</tr>
<tr>
<td>Mill scale on steel</td>
<td>-0.2</td>
</tr>
<tr>
<td>High silicon cast iron</td>
<td>-0.2</td>
</tr>
<tr>
<td>Copper, brass, bronze</td>
<td>-0.2</td>
</tr>
<tr>
<td>Low-carbon steel in concrete</td>
<td>-0.2</td>
</tr>
<tr>
<td>Lead</td>
<td>-0.5</td>
</tr>
<tr>
<td>Cast iron (not graphitized)</td>
<td>-0.5</td>
</tr>
<tr>
<td>Low-carbon steel (misted)</td>
<td>-0.2 to -0.5</td>
</tr>
<tr>
<td>Low-carbon steel (clean and shining)</td>
<td>-0.5 to -0.8</td>
</tr>
<tr>
<td>Commercially pure aluminum</td>
<td>-0.8</td>
</tr>
<tr>
<td>Aluminum alloy (5% Zn)</td>
<td>-1.05</td>
</tr>
<tr>
<td>Zinc</td>
<td>-1.1</td>
</tr>
<tr>
<td>Magnesium alloy (Mg-6Al-3Zn-0.15Mn)</td>
<td>-1.6</td>
</tr>
<tr>
<td>Commercially pure magnesium</td>
<td>-1.7</td>
</tr>
<tr>
<td>Most Active</td>
<td></td>
</tr>
</tbody>
</table>

(a) Measured with respect to copper sulphate reference electrodes (CSE).


This form of corrosion results from the coupling of two dissimilar. Metals can be arranged according to their redox potentials as shown in Table 2 below. The metal with the more positive potential forms the cathode (reduced corrosion rate), while the negative potential member of the couple becomes the anodic site, increasing its corrosion rate. Although, galvanic corrosion can be detrimental to structures, it is also useful as a means of corrosion control through cathodic protection (CP) [12].

### 3.2. Stress-Corrosion Cracking (SCC)

Stress corrosion cracking occurs when metallic structures are subjected to static, tensile stresses and are exposed to corrosive environments. In such situation induced cracks are propagated by the combined effect of the surface stress and the environment in which the pipeline is buried [7]. The primary component of tensile stress in a pipeline is in the hoop direction and results from the operating pressure.

Two forms of SCC are known to exist in underground pipeline: the high pH SCC and the low or near-neutral pH SCC. A common characteristic of both forms of SCC is the formation of colonies of cracks in the body of the pipe that link up to form long, shallow flaws [4].

![Fig 3.2. SCC in external surface of an underground pipeline.](image)

Source: Beaver and Thompson, (2008)

Usually three factors contribute to cracking. They are:

- Potent environment developing at the pipe surface
- Susceptible pipe material
- Tensile stress

The development of a suitable environment at the pipe surface is necessary for the inauguration of both forms of SCC. For the low pH SCC, the environment is a dilute solution of CO$_2$ in groundwater. The cracking occurs under a condition of little cathodic protection current reaching the pipe surface. This may be due to high resistivity soil, presence of shielding coating or inadequate CP design [8]. The CP current collecting on the pipe surface at disbandment, in conjunction with dissolved CO$_2$ in groundwater creates the environment for high-pH SCC.

### 4. Corrosion Control

Preventing or mitigating pipeline failures has become more important than ever. This need is not unconnected with the ever growing anxiety to curb environmental degradation due to spillage of petroleum products. The best approach is to develop methods of detecting potential failure defects before they occur, and effecting necessary repairs. We cannot expect the same or enhanced performance from our ageing pipeline infrastructures without some engineering intervention. Therefore, continued operational safety will require pipeline management systems that reduce failures either by
4.1. Coatings

Pipe coatings are materials laid along the pipe surface to isolate it from the environment. Poor performance of the coating is a major contributing factor to underground corrosion. The ability of the coating material to withstand degradation is a key to its selection and long term performance. It is therefore important that the coating material must be carefully selected. Beavers et al (2006) listed some characteristics desired in an effective coating material. They include:

- Effective electrical insulation
- Effective moisture barrier
- Good adhesion to pipe surface
- Ability to resist damage during handling, storage and installation
- Resistance to disbonding
- Resistance to chemical degradation
- Ease of repair
- Nontoxic to the environment etc.

Many forms of materials are available for coating underground pipelines. When first installed these coatings are able to meet their basic requirements i.e. isolate the external pipe surface from underground environment, minimize CP requirement and enhance CP current distribution. The prime consideration in their selection is the ability to resist degradation over time, and the ability of the coating to minimize shielding should it fail. The engineer will ultimately rely on field reports on performance of coatings to aid in selection. However, guidelines for such selection have been developed by professionals over time (CEPA, 1997). Uses of polyethylene and multilayer coatings have been reported to have longer service life [1].

4.2. Cathodic Protection

Corrosion is basically an electrochemical process involving an oxidation-reduction reaction. Two sites are setup in this process - the cathode (reduction site) and the anode (oxidation site). This reaction results in the formation of metallic oxides. The oxides formed by most metals form a protective film over them preventing further attack. However, the oxide of iron (which is the base metal in steel) is readily broken down, and in the presence of moisture will undergo further deterioration.

By altering the electrochemical nature of the corroding surface, the process of corrosion can be prevented or mitigated. In theory, this involves making the external pipe surface the cathode of the electrochemical cell by applying a negative potential to the system. The rate of corrosion (oxidation) of the pipe surface is thus reduced or prevented. CP also alters the pipe environment in such a way as to mitigate corrosion. The pH of any electrolyte on the pipe surface is increased, oxygen concentration is reduced and deleterious ions migrate away from the pipe surface [4].

There are two approaches to applying CP systems: sacrificial anode CP and impressed-current CP systems.

4.2.1. Sacrificial anode CP

The sacrificial anode technique utilizes a metallic material that has a more negative potential in relation to the pipe steel. When both metals are coupled together the pipe steel becomes the cathode. Oxidation is reduced at the pipe surface preventing or slowing down the rate of corrosion of the pipe. At the anode, the rate of corrosion is increased. The negative potential metal thus corrodes at the expense of the pipe steel. Common sacrificial anode materials utilized in underground pipeline are zinc and magnesium.

4.2.2. Impressed-current CP

The most common method of cathodic protection in underground pipeline is by using impressed-current [9]. This method utilizes an external power source to control the voltage between the pipe and an anode in such a way that the pipe becomes the cathode, mitigating corrosion.

It is noted that CP increases the pH of the electrolyte on the pipe surface. This can create the potential environment for high pH SCC initiation. But high pH SCC propagates only within a limited potential range. Thus by maintaining the potential of the pipe surface outside this range, by proper CP control can mitigate the propagation of high pH SCC.

5. Pipeline Inspection and Maintenance

Most often, failure due to corrosion in pipelines can be attributed to failure of the corrosion control systems installed [10]. These failures do not occur suddenly. There are usually telltale signs to their eventually occurrence. With diligent maintenance programs, corrosion defects can be assessed, evaluated and proper intervention made before they result in failure. This preventive maintenance approach is vital when one considers the myriad consequences that can result from a petroleum pipeline failure.

 Pipelines are required to be routinely inspected to ascertain their integrity. Corrosion monitoring is an integral part of this integrity management program. Various methods exist for
monitoring/detection of corrosion in pipelines. The methods aim to ensure that pipelines do not become defective and that defects are detected before they can cause damage.

The methods commonly employed to detect corrosion in underground pipelines are hydrostatic testing, direct assessment and in-line inspection.

### 5.1. Hydrostatic Testing

Pipelines should be periodically hydro-tested in-service to prove their integrity. The process involves pressure testing the pipeline with water at higher pressures than the pipeline operating pressure, typically 110% of specified minimum yield strength (SMYS) [10]. Any defect larger than a critical size will fail at this hydrostatic test pressure.

### 5.2. Direct Assessment

In direct assessment field inspection programs the overall condition of the pipeline corrosion system and its coating is determined using above ground measurements. The data is then used to prioritize the system for direct examination, hydrostatic testing, in-line inspection, recoating or pipe replacement.

### 5.3. In-line Inspection

Pipelines can be monitored from the inside without disrupting the product flow by using in-line inspection tools, also called intelligent pigs. The pigs are sophisticated devices that travel with the product and via array of sensors record data about the condition of the pipe. They can measure metal loss (due to corrosion and cracking) and geometric abnormalities (e.g. dents). There are two basic types of in-line tools for measuring metal loss: magnetic flux leakage tools and ultrasonic tools.

### 5.4. Maintenance and Repair

In pipeline maintenance, two options are available to the engineer: repair or replace. Once corrosion or crack is detected, the size of the defects must be measured. Assessment of the defect size will determine the appropriate intervention. The defect size is usually ascertained by direct examination i.e.by direct measurement in the field. The length of crack is ground out to establish the maximum crack depth. Burst pressure models or fracture mechanics techniques can be used to determine the failure pressure of the affected sections. If the burst pressure (usually 100% SMYS) is within acceptable limit the pipe is recoated. However, if it is less than the acceptable limit the pipe is replaced or repaired using steel or composite sleeves and recoated.

If failure occurs in hydrostatic testing, the only option is to replace the failed sections. Replacement is also recommended when there is an extensive corrosion localized within an area in the pipeline.

Improvement of the CP system to reduce corrosion or crack growth is also an option in areas where the growing crack is not an immediate threat to pipeline integrity.

Generally, the maintenance or repair option is decided by the engineer after a careful assessment of the information gotten from the inspection tools. Other factors like cost, urgency and engineering considerations are also important in the choice of repair options [10].

### 6. Conclusion

One major challenge to pipeline engineers is that our pipelines are growing old. This becomes a real problem when one considers that Nigeria still has a proven oil reserve of over 30 billion barrels as reported by OPEC, 2013. At the present production rate of just over 2 million barrels/day, this figure translates to over 40 years of proven oil supplies. And most of this is expected to be carried by the existing pipeline infrastructures.

To ensure a stable industry and the security of supply, the integrity of the pipelines must be maintained within an acceptable safety limit. Though, this work has focused on the problem of corrosion (which is basically an engineering problem), the need to ensure the overall safe operation of our pipelines must be a concern for all.

Importantly, pipeline operators must develop a consistent and reliable approach to pipeline integrity management. They must realize that the human and environmental cost associated with petroleum pipeline failures can never be adequately compensated. Therefore, no cost is too much to ensure the protection of the pipelines against in-service defects.

### References


