GUIDELINES
ON
INSPECTION OF ON LAND NON-PIGGABLE PIPELINE

OISD - Guidelines - 233

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Preamble

Indian petroleum industry is the energy lifeline of the nation and its continuous performance is essential for sovereignty and prosperity of the country. As the industry essentially deals with inherently inflammable substances throughout its value chain – upstream, midstream and downstream – Safety is of paramount importance to this industry as only safe performance at all times can ensure optimum ROI of these national assets and resources including sustainability.

While statutory organizations were in place all along to oversee safety aspects of Indian petroleum industry, Oil Industry Safety Directorate (OISD) was set up in 1986 Ministry of Petroleum and Natural Gas, Government of India as a knowledge centre for formulation of constantly updated world-scale standards for design, layout and operation of various equipment, facility and activities involved in this industry. Moreover, OISD was also given responsibility of monitoring implementation status of these standards through safety audits.

In more than 25 years of its existence, OISD has developed a rigorous, multi-layer, iterative and participative process of development of standards – starting with research by in-house experts and iterating through seeking & validating inputs from all stake-holders – operators, designers, national level knowledge authorities and public at large – with a feedback loop of constant updation based on ground level experience obtained through audits, incident analysis and environment scanning.

The participative process followed in standard formulation has resulted in excellent level of compliance by the industry culminating in a safer environment in the industry. OISD – except in the Upstream Petroleum Sector – is still a regulatory (and not a statutory) body but that has not affected implementation of the OISD standards. It also goes to prove the old adage that self-regulation is the best regulation. The quality and relevance of OISD standards had been further endorsed by their adoption in various statutory rules of the land.

Petroleum industry in India is significantly globalized at present in terms of technology content requiring its operation to keep pace with the relevant world scale standards & practices. This matches the OISD philosophy of continuous improvement keeping pace with the global developments in its target environment. To this end, OISD keeps track of changes through participation as member in large number of International and national level Knowledge Organizations – both in the field of standard development and implementation & monitoring in addition to updation of internal knowledge base through continuous research and application surveillance, thereby ensuring that this OISD Standard, along with all other extant ones, remains relevant, updated and effective on a real time basis in the applicable areas.

Together we strive to achieve NIL incidents in the entire Hydrocarbon Value Chain. This, besides other issues, calls for total engagement from all levels of the stake holder organizations, which we, at OISD, fervently look forward to.

Jai Hind!!!

Executive Director
Oil Industry Safety Directorate
FOREWORD

Oil Industry in India is more than 100 years old. Over years, a variety of practices have been in vogue because of collaboration / association with different foreign companies and governments. Standardisation in design, operating and maintenance practices was hardly in existence at a national level. This lack of uniformity, coupled with feedback from some serious accidents that occurred in the recent past in India and abroad, emphasised the need for the industry to review the existing state of art in designing, operating and maintaining oil and gas installations.

With this in view, the Ministry of Petroleum & Natural Gas in 1986 constituted a Safety Council assisted by the Oil Industry Safety Directorate (OISD) staffed from within the industry in formulating and implementing a series of self-regulatory measures aimed at removing obsolescence, standardizing and upgrading the existing standards to ensure safer operations. Accordingly, OISD constituted a number of functional committees comprising of experts nominated from the industry to draw up standards and guidelines on various subjects.

The present document on “Cross-country LPG Pipelines” was prepared by the Functional Committee on ‘Cross-country LPG Pipelines’. This document is based on the accumulated knowledge and experience of functional committee members and various national and international codes and practices. This document is meant to be used as supplement and not as a replacement for existing codes and practices.

This standard in no way supercedes the statutory requirements of bodies like IBR, CCE, Factory Inspectorate or any other Government Body which must be followed as applicable.

This document will be reviewed periodically for improvements based on the new experiences and better understanding. Suggestions may be addressed to:

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Committee on Inspection of Non-piggable Pipeline,
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These documents are intended only to supplement and not to replace the prevailing statutory requirements.
FUNCTIONAL COMMITTEE MEMBERS
ON
GUIDELINES
ON
INSPECTION OF ON LAND NON-PIGGABLE PIPELINE
(2013)

<table>
<thead>
<tr>
<th>S.No.</th>
<th>Name</th>
<th>Designation &amp; Organization</th>
<th>Position in the Committee</th>
</tr>
</thead>
<tbody>
<tr>
<td>(1)</td>
<td>Shri D.B. Basu</td>
<td>ED (LT), IOCL (R&amp;D)</td>
<td>Member</td>
</tr>
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<td>Shri Kamal Pande</td>
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<td>(3)</td>
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<td>(4)</td>
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<td>CE (P), CHSE, ONGC, New Delhi</td>
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</tr>
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<td>(5)</td>
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<td>S.E. (PLF), OIL, Dulijan</td>
<td>Member</td>
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<td>(7)</td>
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<td>Additional Director (Engg &amp; Pipelines), OISD, Noida</td>
<td>Member Co-ordinator</td>
</tr>
</tbody>
</table>
GUIDELINES ON INSPECTION OF ON LAND NON-PIGGABLE PIPELINE

1.0 Introduction:
In the past few years there has been significant increase in number of major incidents in non-piggable pipeline in hydrocarbon industry. The lessons learnt from fires, explosion, fatalities and accidents emphasizes the need for developing a guidelines specially for non-piggable pipelines which can be implemented for assessing the integrity of these pipelines through a systematic health integrity assessment methods. These guidelines outline a process of related activities that a pipeline operator can use to plan, organise and execute for pipeline integrity management.

2.0 Scope:
2.1 This guideline shall be applicable in all hydrocarbon industry in upstream and downstream sector for all sizes (2” diameter and above) of underground and over ground non-piggable pipelines (excluding pipelines within Refineries, Petro-chemicals manufacturing, Gas processing plants, POL and LPG, LNG terminals) laid for transfer of Crude oil / Petroleum product/ Natural gas / Liquefied Petroleum Gas (LPG) and any other liquid or gaseous hydrocarbon from one point to another point including well flow lines and water injection lines and are non piggable.

2.2 For piping, valves and fittings within the installation, OISD-Std-130 shall be followed.

2.3 These guidelines shall be applicable to all existing and new pipelines with immediate effect.

2.4 These guidelines are not applicable for piggable pipeline. For piggable pipeline provisions given in OISD-Std-141, OISD-Std-214 and OISD-Std-226 shall be followed.

3.0 Definition:

Non Piggable Pipeline:
A pipeline that does not have required facility to pig or a pipeline that cannot be pigged with currently available pigs (1.5 x D, where ‘D’ outer
diameter of the pipe) due to presence of tight bends or multiple diameter or other such restriction that is likely to prevent passage of a normal cleaning pig. Length of such pipeline can be long or short (less than 1 km), large or small diameter operating at high pressure or low pressure.

**Low Stress pipeline**: Any pipeline operating at a pressure that can produce a stress on pipe material less than 30% of SMYS (Specified Minimum yield strength) of the pipe is generally considered as low stress pipeline.

**High Stress pipeline**: Any pipeline operating at such a pressure that is likely to produce a stress on pipe material more than 30% of SMYS (Specified Minimum yield strength) of the pipe is generally considered as high stress pipeline.

4.0 **Inspection Procedure**:

4.1 Pipeline Integrity Management (PIM) procedures as per the extant OISD standards for cross country pipelines permit three inspection methods pipelines: (i) internal inspection, also known as instrument/ intelligent or smart pigging or In-line inspection (ILI), (ii) pressure testing, such as hydrotesting, or (iii) combination of (i) and (ii). However, hydro testing, or current instrumented / intelligent / ILI or smart pigging technology, may not be suitable, or cost effective, on certain pipelines. For example, some pipelines cannot be smart pigged, and removal from service for hydro testing may not be a viable option for some critical pipelines.

4.2 For non piggable pipelines, primary assessment method like External Corrosion Direct Assessment (ECDA) and Internal Corrosion Direct Assessment (ICDA), and Stress Corrosion Cracking Direct Assessment (SCCDA) can be used to identify potential threats based on applicability and service of the pipeline. However, use of ECDA and ICDA addresses only certain general corrosion threats to transmission pipeline that can cause failures. These are worldwide accepted procedure.

4.3 ECDA addresses general external corrosion caused by lack of coating, usually from certain types of holes / damages in the external coating
of pipelines. These holes / damages are normally associated with coating penetrations from rocks, poor pipe installation, coating deterioration with time, and from many types of third party damage, such as cuts, damage during construction by third party, pilferage etc., ECDA is inappropriate for use where external pipeline coating has disbonded from the pipeline external steel surface. A coating is considered disbonded when there is a loss of adhesion between the external protective coating and the outer pipe wall surface for various reasons. Coating disbonding creates annular space between pipe outer surface and the coating where reactants e.g., water may accumulate and starts corrosion.

4.4 ICDA, address internal corrosion on gas transmission pipelines / liquid petroleum pipelines having the presence of an electrolyte (i.e. water / condensate) which serves as the driving mechanism for this general internal corrosion. Normally the electrolyte settles out, or drains, on the inner lower surface of a pipe whenever a certain critical angle of inclination is exceeded for a flow velocity. The use of ICDA, however, does not exclude wet gas operations that can generate higher risks of failure from internal corrosion (especially for pipelines that don’t utilize an effective cleaning pig / analysis program). It is the responsibility of pipeline operator to demonstrate effective internal corrosion monitoring in wet gas service.

4.5 An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. Therefore, it is necessary that ICDA Regions be identified (for underground segments). At least three field inspections are required for each ICDA region. One location must be at a low point at the beginning of the covered segment, the second location could be at a location where there is likelihood of change in soil resistivity property around the pipeline (like pipeline crossing effluent drains, water body nallahs etc..) and the third location should be further downstream from this site near the end of the underground segment for which ECDA should also be carried out. If any industrial effluent is flowing over the Right of Way (ROW) / Right of User (RoU) or any environmental changes is noticed on the ROW / RoU,
the soil samples should be tested and recorded once in six months. Inspection measurements are performed using accepted industry techniques for pipe thickness measurement. If internal corrosion is discovered, the operator must evaluate the potential in all pipeline segments (both underground and above ground) where similar characteristics to the ICDA Region for underground segments are found.

4.6 Internal Corrosion:

Internal corrosion is a function of what the pipeline contains and transports. Presence of corrosive constituents and other contaminating impurities in the transported fluid may lead to internal metal loss in the pipeline resulting in general corrosion or pitting type of corrosion. Such constituents could be due to salinity of sea water, presence of carbon-dioxide together with moisture etc., safeguarding against internal corrosion could be by providing lining on the inner wall of pipeline with an inert protective material compatible with the fluid transported.

The following schedules / activities shall be followed to monitor internal corrosion:

4.6.1 Effectiveness of corrosion mitigation measures should be checked once in a six months by analysing the corrosion coupon.

4.6.2 Electrical resistance probes (ER) / Electrochemical noise technique (ECN probes) or Linear polarisation technique (LPR probes), should be installed at the stations (originating and terminating) to monitor the internal corrosion. If the rate of corrosion is more than 1 mpy (mills per year), suitable doses of corrosion inhibitor shall be used. Monitoring the effectiveness on corrosion mitigation measures and reading should be checked once in a quarter.

4.6.3 Whenever replacement to the pipeline are carried out, internal visual inspection shall be done to supplement ultrasonic thickness readings taken externally.

4.7 Stress Corrosion Cracking (SCC):
Presence of H₂S (Hydrogen Sulphide) can lead to serious sulphide stress cracking of steels which is essentially not a metal loss, but causes stepwise cracking in steel. For this type of corrosion, its mitigation can be done by injecting chemical inhibitors along with the product flow. The sulphide stress cracking can be mitigated by treating steel with certain alloying elements and controlling its hardness.

SCC is a selective external corrosion attack resulting from a combination of disbonded coating, tensile stress, and certain environmental factors. There are two types of SCC that transmission pipelines have experienced, “high pH” and “near-neutral.” Industry recommended practices largely focuses on high pH SCC factors and recommends hydro testing if SCC has resulted in failure. Hydrostatic testing of a pipeline affected with SCC may or may not result into pipeline rupture. Failure after a hydro test or pig evaluation can be highly unpredictable for both gas and liquid transmission pipelines for various reasons unique to SCC. Though SCC can fail as leaks, most SCC failures result in pipeline rupture. ECDA, though is inappropriate for corrosion associated with disbonded coatings, some of the indirect (above ground) tools or techniques may prove appropriate for identifying areas of coating disbondment that might assist in identifying possible SCC sites for further consideration. While not all disbonded coating sites are areas of concern for SCC, SCC is known to have occurred under disbonded coating.

4.8 Direct Assessment (DA):

The DA methods for external and internal corrosion consist of following a four-step structured process:

(i) A pre-assessment stage incorporating various data gathering, database integration, and analysis,

(ii) An identification phase using either above ground tools or calculations to identify possible corrosion sites based on the evaluation or extrapolation of the database(s).

(iii) Field examinations by excavation / dig site verification and direct
assessment to confirm corrosion at the identified sites and rectifications.

(iv) Post-assessment evaluation to determine if dig site verifications are true representative on a pipeline segment.

(v) Based on the field verifications or dig site verifications, feedback is collected to tune various assessment approaches on the pipeline, further predict where similar conditions may exist that are conducive to such corrosion, and perform additional field verification. For pipeline systems where general external or internal corrosion or SCC may be a risk of concern, DA may be a more cost effective and rational approach to hydro testing or smart pigging.

5.0 Inspection Steps:

5.1 For each pipeline following data should be gathered or collected in the format given below:

<table>
<thead>
<tr>
<th>S. No.</th>
<th>Type of Data</th>
<th>Details</th>
</tr>
</thead>
</table>
| 1      | Historical Data | (i) Name of the Pipeline  
         |               | (ii) Date of Commissioning  
         |               | (iii) Hydro test Pressure  
         |               | (iv) Failure History  
         |               | (v) De-rating history (if any)  
         |               | (vi) Replacement of Pipe or pipe section.  
         |               | (vii) Soil Type |
| 2      | Pipeline Maps & Geo Details | (i) Pipeline Route map  
         |               | (ii) Burial depth  
         |               | (iii) Land profile  
<pre><code>     |               | (iv) Crossing Details |
</code></pre>
<table>
<thead>
<tr>
<th>S. No.</th>
<th>Type of Data</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.</td>
<td>Basic Technical Data</td>
<td>(i) Pipe Diameter, wall thickness, length</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(ii) Grade of pipe</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(iii) Service (Crude / product/ LPG/ Natural Gas/ water injection / has lift/ condensate etc.)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(iv) Flow rate, operating temperature</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(v) Design Pressure</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(vi) Operating pressure range (maximum-minimum)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(vii) Coating type</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cathodic Protection data including line protection, C.P. Parameters, current density etc.</td>
</tr>
<tr>
<td>4</td>
<td>Presence of Liquid water</td>
<td>Whether the hydrocarbon being transported through the pipeline contains water? If so, location at which water has been collected.</td>
</tr>
<tr>
<td>5</td>
<td>Presence of hydrogen sulphide (H₂S), Carbon dioxide (CO₂) or Oxygen</td>
<td>Chemical analysis data of the hydrocarbon being transported at lab to know typical content of hydrogen sulphide (H₂S), Carbon dioxide (CO₂) or Oxygen (O₂).</td>
</tr>
<tr>
<td>6</td>
<td>Corrosion monitoring data</td>
<td>Corrosion monitoring data including type of monitoring (e.g., coupons, electric resistance, linear polarization probe etc.), if so, rate of corrosion calculated. Information about corrosion inhibitor injection location, chemical type, dosing rate etc.,</td>
</tr>
<tr>
<td>7</td>
<td>Pipeline Survey Data</td>
<td>Pipeline Soil resistivity data, coating survey data (Pearson/ CAT/ DCVG) CIPS etc.,</td>
</tr>
</tbody>
</table>

**5.2** Review and analyse the above data and prepare a report and identify gaps in data. Based on the data prioritise the requirement for each group of pipelines. Following priorities are suggested.

**Priority 1:** All pipelines above 15 years old i.e., pipelines operated more
than 15 years after commissioning and operated at more than 30% of SMYS.

**Priority 2:** All pipelines above 10 years old and operated at more than 30% of SMYS.

**Priority 3:** All pipelines above 15 years old i.e., pipelines operated more than 15 years after commissioning and operated at less than 30% of SMYS.

**Priority 4:** Pipelines less than 10 years old having incident of leak / burst due to corrosion / material defect or where reasons of failures are not established, more than 3 number since commissioning.

**Priority 5:** All pipelines above 10 years old and operated at less than 30% of SMYS.

**Priority 6:** All pipelines less than 10 years old and operated at more than 30% of SMYS.

**Priority 7:** All pipelines less than 10 years old and operated at less than 30% of SMYS.

5.3 **Inspection procedure for Pipeline having external coating but without cathodic protection system (impressed current based or sacrificial current based).**

5.3.1 Pipeline route if not known shall be identified using pipe locator. Subsequently route marker shall be installed on the pipe route as per clause 11.15 of OISD-Std-141. In case in-house expert or equipment is not available, Subject Matter Expert (SME) should be deployed.

5.3.2 In case coating survey has not been carried out before, Current Attenuation Test (CAT) survey followed by Direct Current Voltage Gradient (DCVG) Survey to pin point the location of coating damage shall be done. Considering the fact that some low pressure lines can be of small length, it is recommended to carry out DCVG survey at the earliest.

5.3.3 Location of site shall be identified for dig site verification to check the efficacy of coating survey as per para 5.3.2 above.

5.3.4 Soil resistivity survey to be carried out to find out probable location of high,
medium or low soil resistivity area.

5.3.5 Locations that are predicted to have highest susceptibility to accumulation of corrosion causing substance and for longest residence time are assessed to have highest likelihood of experiencing internal corrosion. Those locations where probability of water and/or solid accumulation is more are to be identified or flagged. This should be the basis for selecting these sites for detailed inspection. Similarly, based on pipeline survey data i.e., soil resistivity, coating survey, location for external corrosion probable site can be identified.

5.3.6 After identifying these locations, at least 3 pipe sections per site are to be excavated in full and visual inspection of coating shall be carried out. In case the coating condition is found reasonable good, random peel test at least 3 Nos. per pipe (at three different locations, where at least one location shall be a weld joint, and at different clock position) to be carried out to check the coating adhesiveness or disbondment. Also, 5 m section of the coating on pipe to be peeled off in totality, clean (not sand blast) the surface, to check the condition of external surface of the pipe. After preparation of the pipe surface, Ultrasonic thickness measurement shall be taken continuously at all locations by making suitable and convenient grid of appropriate size (taking 1 reading in each square of 1”x 1”) as per requirement so that thickness scanning can be performed by the technician properly to detect any significant thickness loss of pipe/elbow. Any thickness loss of piping circuit shall not be overlooked while carrying out ultrasonic thickness survey. All thickness readings are to be recorded in the following format. Minimum number of final assessment site per pipeline length shall be as under:

<table>
<thead>
<tr>
<th>Continuous pipeline length</th>
<th>Minimum number of assessment site</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.05 Km to 10 Km</td>
<td>4</td>
</tr>
<tr>
<td>More than 10 Km to 50 Km</td>
<td>6</td>
</tr>
</tbody>
</table>

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More than 50 Km to 100 Km 8
More than 100 Km to 500 Km 10
More than 500 Km 14

(i) Name of the Pipeline: ........ from ............. to...........

(ii) Length of the Pipeline................. Mtr / Km

(iii) Location of thickness measurement............. Km from originating point.

(iv) Design Pressure...PSI (Pound per square inch) / Kg per cm²

(v) Operating Pressure........ PSI / Kg per cm²

(vi) Pipe Dia / Nominal Thickness / Grade ..............

<table>
<thead>
<tr>
<th>Sl. No.</th>
<th>Nominal pipe wall Thickness in mm</th>
<th>Measured Thickness in mm</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Pipe No- 1 / 2 / 3</td>
</tr>
<tr>
<td></td>
<td>Location-1 (L-1)</td>
<td>L-2</td>
</tr>
<tr>
<td></td>
<td></td>
<td>L-3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>L-4</td>
</tr>
<tr>
<td></td>
<td></td>
<td>L....n</td>
</tr>
</tbody>
</table>

Based on the above, assessment results will be tabulated as follows:

% Metal Loss = \( \frac{(Nominal \ pipe \ wall \ thickness - measured \ pipe \ wall \ thickness) \times 100}{Nominal \ pipe \ wall \ thickness} \)

<table>
<thead>
<tr>
<th>Locations</th>
<th>Metal loss &lt;20%</th>
<th>Metal loss &lt;21%- 40%</th>
<th>Metal loss &lt;41%-60%</th>
<th>Metal loss &gt;60%</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
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</tr>
</tbody>
</table>

Calculation of safe operating pressure shall be done as per “ASME B 31 G-Manual for determining the remaining strength of corroded Pipelines”. Repair of
the pipe section shall be done as per the requirement of OISD –Standard-141/214/226/ ASME B 31.4/31.8.

**Note:**

1. Metal loss of 21% to 40% is considered moderate
2. Metal loss of 41% to 60% is considered high
3. Metal loss of more than 60% is considered severe.

Subject Matter Expert (SME) advise (in house / external) shall be sought while working in this area for assessment for repair / replacement.

**5.3.7** Measurement of pipe wall thickness shall be done by Ultrasonic testing (UT), the techniques based on ultrasound to measure wall thickness of steel elements, pipelines, vessels and tanks. For continuous internal corrosion features, **LFET (Low Frequency Electromagnetic Test) tool** may be used along with UT. Alternatively, there are new / latest proven techniques available like long range ultrasonic testing (LRUT) for measurement of underground overall pipe thickness with the help of ultrasound methods on continuous basis for about 50 m on both sides of the location of the instrument installed for straight pipeline having no coating. Coating and bends on the pipeline will reduce the inspection length of pipeline by LRUT.

For the above ground portion of any underground pipeline, thickness measurement shall be taken at 4 locations (i.e., 12, 3, 6 and 9 O'clock positions) at the exits, bends and at every ten metre interval of the pipeline. Underground section of the pipeline where pipes are cased, it shall be ensured that casings are free of water and muck.

**5.3.8** All survey results to be Collated and analysed by the subject matter expert (SME).

**5.3.9** In case the coating condition is not found satisfactory upon bell hole inspection at site identified through coating survey, defect location based on para 5.3.2 shall be immediately taken up for coating repair.

**5.3.10** Post repair, the 1\textsuperscript{st} coating survey shall be carried out immediately, and 2\textsuperscript{nd}
coating survey shall be carried out after 3 years. Subsequent survey shall be carried out based on assessment of in house expert or SME, the frequency of survey shall not exceed 5 years.

5.3.11 Based on the above, pipeline should be concluded for fit for use purpose by in house or external subject matter expert (SME).

5.4 Inspection procedure for Pipeline having external coating with cathodic protection system (impressed current based or sacrificial current based):

5.4.1 Pipeline route, if not known shall be identified using pipe locator. Subsequently route marker shall be installed on the pipe route as per clause 11.15 of OISD-Std-141. In case in-house expert or equipment is not available, Subject Matter Expert (SME) should be deployed.

5.4.2 In case coating survey has not been carried out before, Pearson/ Current Attenuation Test (CAT)/ Close Interval Potential survey (CIPS) or Continuous Potential Logging (CPL) “On” & “Off” survey for every meter of pipeline Right of Way (ROW) / Right of Users (ROU) shall be carried out immediately to cover the entire pipeline for establishing efficacy of the CP system. For pipeline length more than 100 KM but less than 300 KM CPL survey may be done to cover the entire pipeline in 2 years.

5.4.3 Notwithstanding above, 1st CPL survey of cathodically protected pipeline shall be carried out immediately, and 2nd CPL survey shall be carried out after 3 years. Subsequent survey shall be carried out based on assessment of in house expert or SME, the frequency of survey shall not exceed 5 years.

5.4.4 Direct Current Voltage gradient (DCVG) Survey shall be carried at probable coating defect location identified by CPL survey (para 5.4.2 above). The type of survey should be decided based on coating condition. In case CAT survey is selected, it shall be done at intervals of 50 m.

5.4.5 PSP (Pipe to soil potential) reading at feeding locations shall be recorded and monitored fortnightly.

5.4.6 The PSP readings at test lead points (TLPs) for entire pipelines shall be
taken quarterly. The minimum pipe to soil potential PSP shall be more negative than -0.85 volts with respect copper/copper sulphate half-cell. The areas where anaerobic bacterial are active minimum PSP shall be more negative than (-) 0.95 volts instead of (-) 0.85 volts. Over protection of coated pipelines shall be avoided by ensuring that polarisation potential is below (-) 1.2 volts with respect to copper/copper sulphate half-cell.

5.4.7 Instant pipe to soil “OFF” potential readings at test lead points of entire pipeline shall be taken immediately (in case such readings have not been taken earlier) and subsequently once in six months. For the purpose of logging the instant OFF PSP, care shall be taken to minimize the effect of polarization decay, by logging the reading within the first 1 or 2 second of simultaneous switching off all Cathodic protection station affecting that section of the pipeline.

5.4.8 The ON / OFF PSP survey data along with soil resistivity data shall be plotted graphically in one page / sheet to identify coating holidays.

5.4.9 Based on the Pipe to Soil Potential profile generated through CPL survey stretches are to be selected for coating condition assessment in the following order:

- Carry out Current Attenuation Test (CAT) survey to assess the condition of CAT broadly. In case of CAT survey signals are to be collected at every 50 m.
- Based on CAT survey findings carry out Direct Current Voltage Gradient (DCVG) Survey to pin point the location of coating damage. Alternatively, for pipelines length less than 10 KM, entire line can be surveyed by DCVG to assess the coating condition.

5.4.10 Location of site shall be identified for dig site verification to check the efficacy of coating survey as per para 5.3.2 / 5.4.2 above.

5.4.11 All survey results to be collated and analysed by the subject matter expert (SME).

5.4.12 Identified coating defect location to be immediately taken up for coating repair. Before coating repair, UT measurement for at least 2 m continuous
section of the pipe shall be taken after making 1”x 1” grid and record tabulated and analysed as per para 5.3.6 above.

5.4.13 Based on the above, pipeline should be concluded for fit for use purpose by in house or external subject matter expert (SME).

5.5 For all pipelines laid in more or less flat terrain (where it is difficult to locate a particular site for inspection and no coating defects could be found in coating survey as per para 5.3.2 / 5.4.2 above), the 1st three (3) full pipes segment (from originating point) outside the boundary wall limit of installation to be exposed and coating condition to be checked and analysed. At four locations per pipe coating to be peeled off and pipe surface to be checked, UT measurement shall be taken continuously at four locations for the pipe. It is recommended that UT measurement should include locations at 12, 3, 6 and 9 O’clock positions. Recording and evaluation of data to be carried out in line with para 5.3.6. This exercise shall be carried out once in 5 years or earlier as deemed fit by the pipeline owner.

6.0 Hydro testing:

In case it is feasible to carry out hydro test in the existing operating pipeline, one must carry out the same, as hydro test is the destructive method of establishing the integrity of a pipeline system. A successful hydro test will ensure failure free operation for a considerable period of time provided further corrosion in the pipeline is restrained. Hydro test pressure needs to be selected carefully considering next date of testing. A higher test pressure will ensure that failures do not take place for a longer period of time.

6.1 It is recommended that those pipelines which have a failure record in the form of rupture and or burst in any pipe must be hydro tested to establish integrity of the pipeline system.

6.2 Hydro testing a pipeline at higher pressure and then operating it at a lower pressure will provide the operator a higher safety cushion and longer
interval for next hydro test. However, it must be kept in mind that hydro test is no guarantee against time based failure like corrosion leaks.

6.3 Underground section of the flow pipelines shall be pressure tested at minimum 1.25 times the maximum allowable operating pressure or design pressure or 1.25 times of highest operating pressure experienced in last 3 years. Hydro test shall be repeated every 5 years. Pressure hold period shall be for 24 hrs. Unaccounted pressure drop should not be more than 0.3 bar.

6.4 Above ground section of the flow Pipelines shall be pressure tested at minimum 1.25 times the maximum allowable operating pressure or design pressure or 1.25 times of highest operating pressure experience in last three years. Hydro test shall be repeated every five years. Pressure hold period shall be for minimum 6 hrs. During the hold period, thorough checking of weld joints shall be done for wetness and sweating. Pressure drop due to temperature variations is allowed. However, reasons for such pressure drop shall be analysed and recorded. During the hold period, if the hold pressure exceeds the limit, liquid bleeding quantity from the pipe to be recorded.

6.5 An operator can use the fluid transported as the medium of test provided the test is done once in 2 years with a test pressure 10 % higher than the maximum operating pressure achieved during last 24 months. Generally most of the crude / petroleum products / Natural gas / LPG/ water and gas injection lines can be tested at 10 % higher than maximum operating pressure for 6 hrs of hold period.

In case of any specific liquid other than above, exemption can be sought.

7.0 **Inspection of Valves**: The valves on the flow pipelines shall be checked and serviced once in a year in-situ condition.

8.0 **Rail / Road Bridge Crossing**: Rail Bridge, Road Bridge, Suspended crossings shall be inspected once in a quarter to check wear and tear of supports/structures and condition of coatings at the points where
pipe exits and enters the ground. Ultrasonic thickness measurements shall be taken on exposed sections of the pipeline once in three years for the crude and gas pipelines.

Thickness measurement shall be taken at 4 locations (i.e. 12, 3, 6 and 9 O'clock positions) at the exits, bends and at every ten metre interval of exposed piping. Where pipes are cased it shall be ensured that casings are free of water and muck.

9.0 Cased Road and Highway Crossing:
Road and Highway crossings shall be inspected once in a quarter for following:

a) Presence of water/ mud in the annular space.
b) For any shorting of the casing.

10.0 Submerged crossing and Inter-tidal zone:
Submerged crossing locations shall be inspected for erosion/washouts twice in a year i.e., prior to and after monsoon and topographic changes, if any, shall be recorded for corrective actions. Exposed length of pipeline, if any, falling in Inter-tidal Zones shall be inspected once in a quarter for checking the condition of coating and wrapping for taking corrective action.

11.0 Pipeline Patrolling:
Each operating company shall maintain a periodic pipelines patrol programme to observe surface conditions on and adjacent to the Pipeline right of way, indications of leak, construction activity other than performed by the company and other factors affecting the safety and operation of the pipeline. Ground patrolling of flow pipelines shall be carried out once in a week.

12.0 After bean pressure (ABP) of flowing wells should be monitored on daily basis. If there is an abnormal reduction or increase in ABP, investigation shall be carried out to ascertain the reason for the same.
13.0 Extra care should be taken for high pressure gas wells / high GLR (Gas Liquid ratio) wells. High / low pressure protection device should be installed on the pipelines connected with high pressure / high GLR wells.

14.0 If there is abnormally high number of leakages in the pipeline as compared to other similar pipeline in same service, then the pipeline should be planned for replacement on priority.

15.0 Villagers should be made aware of the hazards associated with the pipeline and actions to be taken in case leakage of oil/gas is observed.

16.0 Reference:

(i) ANSI/NACE SP-0502-2008: Pipeline External Corrosion Direct Assessment Methodology.

(ii) NACE SP-0206-2006: Internal Corrosion Direct Assessment Methodology for pipelines carrying normally Dry Natural Gas.

(iii) NACE SP-0208-2008: Internal Corrosion Direct Assessment Methodology for liquid petroleum pipelines.

(iv) NACE SP-0110-2010: Wet Gas Internal Corrosion Direct Assessment Methodology for pipelines.

(v) NACE SP0204-2008 Stress Corrosion Cracking (SCC) Direct Assessment Methodology.