NOTIFICATION

New Delhi, the…………

PETROLEUM AND NATURAL GAS REGULATORY BOARD

In exercise of the powers conferred by section 61 of the Petroleum and Natural Gas Regulatory Act, 2006 (19 of 2006), the Petroleum and Natural Gas Regulatory Board hereby makes the following regulations, namely: -

1. Short title and commencement

(1) These regulations may be called the Petroleum and Natural Gas Regulatory Board (Integrity Management System for Petroleum and Petroleum Products Pipelines) Regulations, 2014.

(2) They shall come into force on the date of their publication in the Official Gazette.

2. Definitions

(1) In these regulations unless the context otherwise requires, -

(a) "Act" means the Petroleum and Natural Gas Regulatory Board Act, 2006;

(b) "Board" means the Petroleum and Natural Gas Regulatory Board established under sub-section (1) of section 3 of the Act;

(c) petroleum and petroleum products pipeline" means the pipelines as defined under Petroleum and Natural Gas Regulatory Board (Authorizing entities to Lay, Build, Operate or Expand Petroleum and Petroleum Product Pipelines) Regulations, 2010:

(d) "operator" means an entity that operates Petroleum and Petroleum Product Pipelines with the authorization of the Board;

(e) "Risk" is the measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences

(f) "Risk analysis" "see risk assessment";

(g) "Risk assessment" means systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and can be performed at varying levels of detail depending on the operator's objectives;

(h) "Risk management" means overall program consisting of identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved;

(i) "Right of User (RoU)" means the area or portion of land with which the pipeline operator or owner has acquired the right through the relevant Statutory Acts or in accordance with the agreement with the land owner or agency having jurisdiction over the land to lay and operate the Petroleum and Petroleum Products Pipelines;

(j) "Subject Matter Expert (SME)" means an individual who possesses knowledge and experience in the process or discipline one represents as per ASME B 31 Q".

(k) "Integrated surveillance system" means the pipeline surveillance for third party encroachment activities along ROU. This may use optical fiber cable, microwaves, and satellite as communication systems and could integrate SCADA's data;

(l) intermediate pump station" means the installation located at any place between starting point and the terminal point having pumps to enhance the pressure of the fluid to achieve desired flow rate;

(m) "originating pump station" means facilities installed at the start of the pipeline system for developing required fluid pressure so as to achieve desired flow rates in the pipeline system;

(n) "terminal station" means a facility to receive products at the end of the pipeline and this may include the tankage for storage of petroleum and petroleum products;

(o) "Shall" indicates mandatory requirement;

(p) "Should" indicates a recommendation or that which is advised but not mandatory;

(2) Words and expressions used and not defined in these regulations, but defined in the Act or in the rules or regulations made there under, shall have the meanings respectively assigned to them in the Act or in the rules or regulations, as the case may be. Other definitions / terminologies used for integrity assessment like anomaly, defect, MAOP etc. which are not defined above, shall be as defined in ASME B31.4/API 1160.

3. Applicability

These regulations shall apply to all the entities engaged in laying, building, operating or expanding petroleum & petroleum products pipelines.

4. Scope

(1) These regulations shall cover all the existing and new petroleum & petroleum products pipelines including High Vapour Pressure (HVP) liquids. This includes the associated facilities required for transportation of petroleum & petroleum product through pipelines such as storage facilities, delivery stations / terminals, intermediate pigging facilities, pumping stations, sectionalizing valves etc. of pipeline installations.

(2) The design, layout, maintenance, inspection etc. of petroleum installations connected with pipeline system shall be in accordance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for petroleum installations) Regulations, 2020.

(3) The materials and specifications followed shall be in accordance with Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for petroleum & petroleum products pipeline) Regulations, 2016.

5. Objective

(1) These Regulations outline the basic features and requirements for developing and implementing an effective and efficient Integrity Management Plan (IMP) for Petroleum and Petroleum Products Pipeline system.

(2) These regulations are intended to-

- (a) Evaluate the risk associated with petroleum & petroleum product pipeline and effectively allocate resources for prevention, detection and mitigation activities;
- (b) Improve the safety of petroleum & petroleum product pipeline so as to protect the personnel, property, public and environment;
- (c) minimize the probability of failure of petroleum & petroleum product pipeline for streamlined and effective operations

6. Integrity Management System

The development and implementation of Integrity Management System for the petroleum & petroleum product pipeline shall be as described in SCHEDULE-1 to SCHEDULE-9 of these regulations.

7. Default and consequences

(1) Compliance to the provisions of these regulations shall be done

through implementation schedule as described in these regulations at Schedule-7, Schedule-8 and Schedule-9 in conjunction to Appendix-II.

(2) In case of any shortfall in achieving the implementation schedule and compliance of Integrity Management System as specified in these Regulations, the entities shall be liable to face the following consequences, namely: -

(a) The entity shall be required to complete each activity within the specified time limit and if there is any deficiency in achieving in one or more of the activities, the entity(s) shall submit a mitigation plan with time schedule and make good all short comings within the time schedule. If the entity fails to complete activities within the specified time schedule, relevant penal provisions of the Act shall apply

(b) In case the entity fails to implement the approved Integrity Management System, the Board may issue a notice to defaulting entity allowing it a reasonable time to implement the provisions of Integrity Management System. In case the entity fails to comply within the specified time, the relevant provisions of the Act and regulations shall apply.

8. Requirement under other statutes

It shall be necessary to comply with all statutory rules, regulations and Acts in force as applicable and obtain requisite approvals from the relevant competent authorities for the Petroleum and Petroleum Product Pipelines.

9. Miscellaneous

(1) Through these regulations the uniform application of Integrity Management System is to be ensured for all petroleum & petroleum product pipelines;

(2) Entity operating and maintaining Petroleum and Petroleum Product Pipeline shall have a written plan / philosophy of deploying qualified and trained manpower at the installations based on activities required for compliance to this regulation.

(3) These regulations either on suo-motu basis or on the recommendation of concerned sub-committee of petroleum & petroleum product pipelines shall be reviewed by the board from time to time;

10. Power to remove difficulties

In the event of the problem faced by the entity in implementing the provisions contained in these Regulations, the entity may approach Board for necessary dispensation.

SCHEDULES

(See regulation 6)

SCHEDULE – 1

OBJECTIVE

The objective of Pipeline Integrity Management System (PIMS) is to maintain integrity of petroleum & petroleum products pipelines at all times to ensure public safety, protect environment and ensure availability of pipeline to transport petroleum & petroleum product without interruptions and minimize risks associated with accidents and losses. The availability of the Integrity Management System shall allow personnel engaged in integrity tasks to have clearly established work aims and targets in the short, medium and long term, which undoubtedly will enhance their efficiency and satisfaction to attain them.

The Integrity Management System shall enable the pipeline operator or transporter to select and identify system for implementation such that the Integrity Management System shall be uniform for all petroleum & petroleum products pipelines entities within the country.

An effective Integrity Management System should aim to:

- Ensure petroleum & petroleum products pipelines integrity in all areas which have potential for adverse consequences;
- Promote a more rigorous and systematic management of petroleum & petroleum products pipelines integrity and mitigate the risk;
- Enhance the general confidence of the public in the operation of petroleum & petroleum products pipelines;
- Enhance the life of the petroleum & petroleum products pipelines with the inbuilt incident investigation and data collection including review by the entity.

SCHEDULE – 2

INTRODUCTIONS TO THE INTEGRITY MANAGEMENT SYSTEM (IMS)

2.1 Every petroleum & petroleum products pipelines operator's primary focus shall be on operation and maintenance of petroleum & petroleum products pipelines in such a way that it would continuously provide un-interrupted services to customers with utmost reliability and safety without any untoward incident which can adversely impact the environment.

2.2 A Pipeline Integrity Management System shall provide a comprehensive and structured framework for assessment of pipeline condition, likely threats, risks assessment and mitigation actions to ensure safe and incident free operation of the pipeline system.

2.3 Such a comprehensive integrity management system shall essentially comprise the following elements:

- **Integrity Management Plan (IMP):** This encompasses collection and validation of data, assessment of spectrum of risks, risk ranking, assessment of integrity with respect to risks, risks mitigation, updating data and reassessment of risk.
- **Performance evaluation of IMP:** This is a mechanism to monitor the effectiveness of integrity management plan adopted and for further improvement.
- **Communication Plan:** This covers a structured plan to regulate information and data exchange within and amongst the internal and external environment.
- **Management of Change:** This is the process to incorporate the system changes (technical physical, procedural and organization changes) into integrity management plan to update the integrity management plan.
- **Quality Plan:** This is the process to establish the requirements of quality in execution of the processes defined in the integrity management plan.

These elements are covered in details in Schedule-6.

SCHEDULE – 3

DESCRIPTION OF PETROLEUM AND PETROLEUM PRODUCTS PIPELINES SYSTEM

3.1 **PHYSICAL DESCRIPTION:** Description of Petroleum and Petroleum products pipeline shall include specific description of the pipelines, pumping stations, valves stations and major installations such as:

- 3.1.1 Steel Pipeline networks
- 3.1.2 Storage facilities/ tanks- atmospheric/low pressure/high pressure
- 3.1.3 Pumping Stations / Intermediate Pump stations
- 3.1.4 Sectionalizing Valve Stations
- 3.1.5 Dispatch Terminal / Receiving Terminal
- 3.1.6 Control Rooms
- 3.1.7 Safety Equipment
- 3.1.8 Intermediate Pigging Stations
- 3.1.9 Tap-Off Stations
- 3.1.10 Electrical System
- 3.1.11 Cathodic Protection System
- 3.1.12 Telecom / SCADA or Data Transfer System
- 3.1.13 Spur-pipelines

3.2 **OTHER DESCRIPTION:**

- 3.2.1 ROU Details-ROU width and constraints, if any
- 3.2.2 Interfaces with other operators' facilities or pipelines, if any;
- 3.2.3 Historical background of the pipeline and major modifications and additions carried out in the system, if any;

SCHEDULE – 4

SELECTION OF APPROPRIATE INTEGRITY MANAGEMENT SYSTEM

4.1 Integrity Management System for Petroleum and Petroleum products pipelines could employ either a Performance based Integrity Management System or a Prescriptive type Integrity Management System. Whereas, petroleum and petroleum products pipeline industry has gathered a reasonably good experience of pipeline operations and such pipeline industry is fairly mature, a Performance based Integrity Management System are appreciated globally. However, where pipeline systems are in developing stage, a Prescriptive type Integrity Management System is recommended. Whereas, the Performance based Integrity Management System recognizes the experience of the entity which has been operating the pipeline but the Prescriptive type Integrity Management System is more rigorous as it considers the worst-case scenario of the failures in the pipeline systems and therefore worst-case scenario for mitigation.

4.2 Though subsequent schedule in these Regulations apply to both prescriptive and performance-based type of Integrity Management System, present regulations mainly focus on prescriptive aspects in absence of adequate historical Integrity Management System IMS data.

4.3 A prescriptive type of Integrity Management System mandates the implementation of an established process for addressing the risks, their consequences and proven methods for mitigation. It also mandates the in- house development of Integrity Management Plan IMP, Management of Change process pertaining to technical aspects. However, Entity may adopt more rigorous IMP within a prescriptive IMP based on their in-house assessment.

SCHEDULE – 5

INTEGRITY ASSESSMENT, MONITORING AND SURVEYS

Some of the tools for Integrity assessment, surveys, monitoring & surveillance are provided below. The operator shall employ at least one integrity assessment tool, and should use all applicable surveys, monitoring & surveillance tools necessary to achieve the IMS for petroleum and petroleum product pipeline. It may be noted that the baseline data for specific measurement should be available with the operator.

The operator of a pipeline system shall develop a chart of most suited integrity assessment tool, surveys, monitoring & surveillance and interval for each applicable threat/risk and further develop appropriate specifications and quality control plan for such assessment. After establishing effectiveness of assessment, the interval of assessment may be further modified subject to any other code requirement such as Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for petroleum & petroleum product pipeline) Regulations 2016. A suggested chart is placed at APPENDIX –III

5.1 INTEGRITY ASSESSMENT TOOLS

5.1.1 In-Line Inspection

In-line inspection (ILI) is an integrity assessment method used to locate and characterize indications, such as, metal loss due to internal / external corrosion & other mechanical damage or deformation.

Internal inspection tool shall have capability of detecting corrosion and deformation anomalies viz. dents, gouges, grooves etc. Instrumented Pigging (Intelligent Pigging) or any other technology that can provide a level of integrity assessment equivalent to In-line Inspection in accordance with provisions of Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for petroleum & petroleum product pipeline) Regulations 2016 may be employed as Integrity Assessment Method.

5.1.2 Hydro / Pressure Testing of In-service Pipelines

Hydro / Pressure testing is appropriate for integrity assessment when addressing certain threats at the pre-commissioning stage itself at test pressure specified in the Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum products Pipelines) Regulations, 2016. Hydro Testing / Pressure testing can also be employed as an integrity assessment tool during service life.

5.1.3 Direct Assessment

Direct assessment is an integrity assessment method utilizing a structured process through which the operator is able to integrate knowledge of the physical characteristics and operating history of a pipeline system or segment with the results of inspection, examination, and evaluation, in order to determine the integrity.

External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA) and Stress Corrosion Cracking Direct Assessment (SCCDA) are the available tools for direct assessment and evaluation.

5.1.3.1 External Corrosion Direct Assessment (ECDA) can be used for determining integrity for the external corrosion threat on pipeline segments. While implementing External Corrosion Direct Assessment if the pipe is exposed, the operator is advised to conduct examinations for threats other than that for external corrosion also (like mechanical and coating damages).

5.1.3.2 Internal Corrosion Direct Assessment (ICDA) can be used for determining integrity for the internal corrosion threat on pipeline segments.

5.1.3.3 Stress Corrosion Cracking Direct Assessment (SCCDA) can be used for determining integrity for the stress corrosion threat on pipeline segments.-

Each of these assessments are carried out in four steps as below-

(a) Pre-assessment- incorporating various data gathering, database integration and analysis

(b) Indirect Inspection- using either tools or calculations to flag possible corrosion sites, or calls, based on the evaluation or extrapolation of the database

(c) Direct/Detailed Examination- excavation and examination to confirm corrosion at the identified sites and remediation as provided in Schedule 6 of these regulations.

(d) Post-assessment - to determine the fitness for service of pipeline, re-assessment interval and effectiveness of Direct Assessment.

5.1.4 Other Integrity Assessment Methodology

Other proven integrity assessment methods for pipeline may exist for use in managing the integrity of pipeline. For the purpose of these regulations, it is acceptable for an operator to use these inspections as an alternative to pressure testing or direct assessment and where ILI is not feasible due to operational or other constraints.

5.2 MONITORING AND SURVEYS

5.2.1 Cathodic Protection (CP) System Monitoring

Following cathodic protection monitoring methods are available:

(i) Pipe to Soil Potential Survey

(ii) Transformer Rectifier Unit / Cathodic Protection Power Supply Module - current and voltage monitoring method

(iii) Closed Interval Potential Logging Survey

(iv) Coating Health Surveys (Current Attenuation Test, Direct Current Voltage Gradient survey and Alternating Current Voltage Gradient Survey)

(v) Pipeline AC & DC Interference Survey including survey at Foreign Pipeline Crossings, Power Transmission line crossings or parallelism and other Stray current sources. It shall be obligatory on all the entities involved to facilitate conduct studies or surveys and take mitigation measures.

5.2.2 Internal corrosion monitoring should be done through Corrosion coupon or ER Probe, debris analysis from cleaning pigging, quality monitoring at source etc. The quality of fluids transported through pipeline shall be monitored especially with respect to moisture etc. to prevent the internal corrosion.

5.2.3 Thickness assessment and periodic review against baseline values

For all sections of the pipelines above ground, all pipeline skids and pressure vessels, a periodic thickness assessment and comparison with baseline values may be done and employed as Integrity Assessment tool. Possibility of thickness survey should be explored whenever underground portion of the pipeline is exposed for whatsoever reasons.

5.2.4 Pipeline equipment Health Monitoring

Pipeline equipment such as main line sectionalizing valves, other valves, pig launching and receiving facilities etc. may be checked periodically for their operation.

5.3 Surveillance of Pipelines

Various effective surveillance methods are being used as direct integrity assessment tools. Based upon the experience and resource management, one or multiple tools may be followed by the operator; some of them are detailed as under:

5.3.1 Patrolling / Ground Survey of the Right of User which includes Line Walk for ensuring clear visibility of Right of User, access to maintenance crew along the Right of User, valve locations and other pipeline facilities. This also helps to observe surface conditions, leakage, construction activity performed by external agencies, encroachments, washouts and any other factors affecting the safety and operation of the pipeline. Also, patrolling ground survey may be done for maintenance of all pipeline markers, kilometer posts and other specific indication marks along the pipeline. This may also include:

(i) Night patrolling by Line walkers or alternative security surveillance system where the pipeline location is vulnerable from security point of view

(ii) Right of User tracking through satellite imaging methods for critical stretches of pipeline system

(iii) Aerial survey of Right of User at critical and in-accessible stretches e.g. hilly regions and Ghat sections etc.

(iv) Identify the vulnerable locations from pilferage point of view.

5.3.2 Integrated Surveillance System for critical stretches

The above system may use various types of detection systems such as:

1. Fiber Optics System
2. Ground Censor System
3. Radar based detection system
4. Fence secure data access system

5.3.3 Awareness Program:

Villagers and general public along the right of way shall be made aware of the possible consequence of hydrocarbon leaks by providing a list of Do's and Don'ts. Safety awareness among the administration and local public may be created as per disaster management plan in accordance with the provisions of Petroleum and Natural Gas Regulatory Board (Codes of Practices for Emergency Response and Disaster Management Plan), Regulations, 2010.

SCHEDULE – 6

DESIGNING APPLICABLE INTEGRITY MANAGEMENT SYSTEM FOR PETROLEUM AND PETROLEUM PRODUCT PIPELINES

All operators of existing and new petroleum and petroleum product pipelines shall develop an integrity management program comprising the necessary plans, implementation schedule and assessment of its effectiveness in order to ensure safe and reliable operation of the pipelines. It is recognized that the comprehensive pipeline integrity management program is based on continuous exercise of extensive data collection, assimilation and analysis. Further, an integrity management program should be devised on specified methods, procedures and time intervals for assessments and analyses or on the basis of performance of the program with regard to efficacy of integrity assessment plan, its results and mitigation efforts. For operators implementing an integrity management program in the absence of base line and performance data, it may become imperative to adopt a prescriptive integrity management program initially.

6.1 Pipeline Integrity Management Plan

All petroleum and petroleum product pipelines and associated facilities installed as a part of pipeline shall be covered in pipeline integrity management plan. The cycle of basic processes of integrity management Plan is illustrated (Figure-1) and further detailed hereunder:

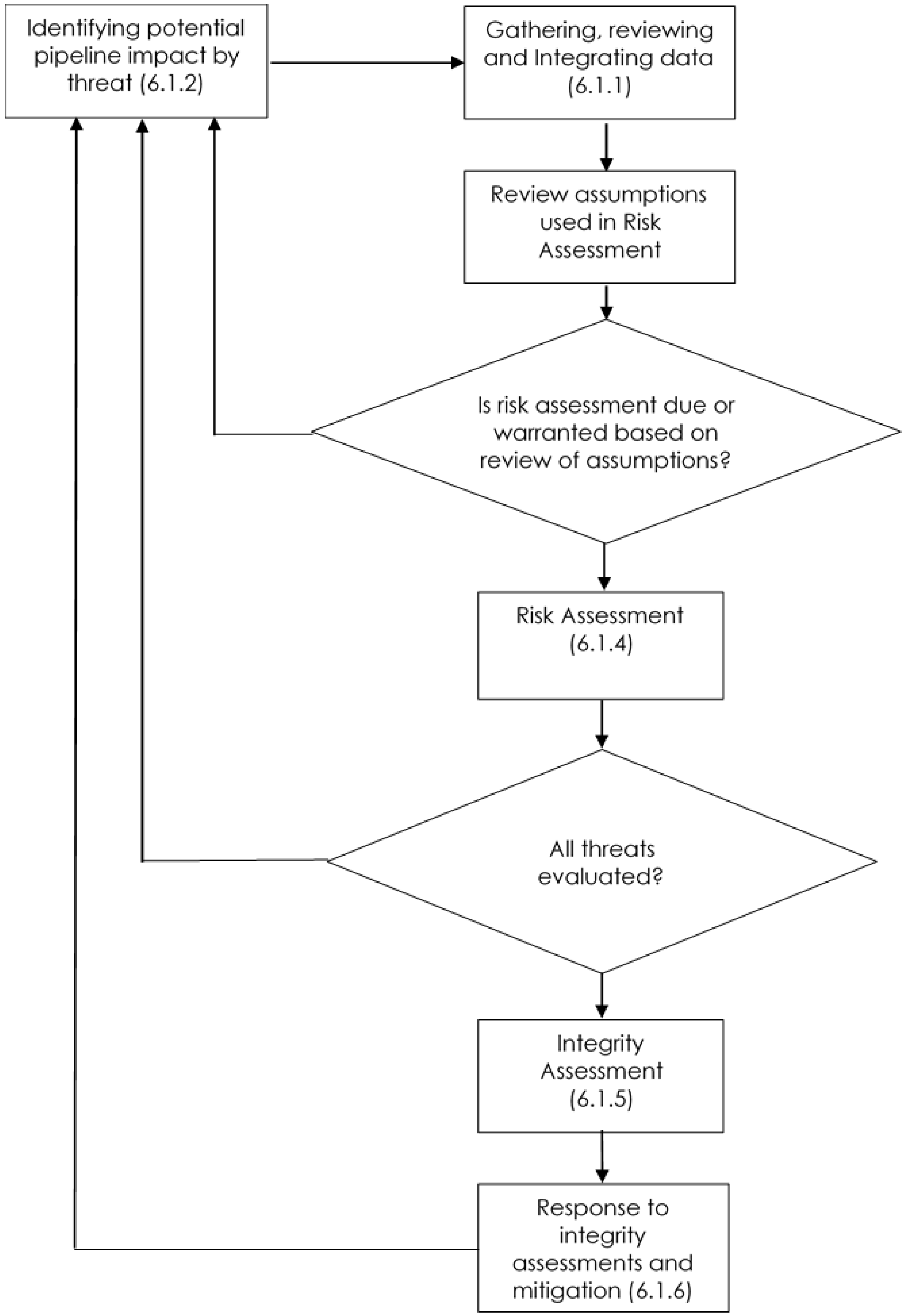

Figure-1: Pipeline Integrity Management Plan - Flow Diagram

6.1.1 Initial Data gathering, review and integration

Data related to design and engineering, construction, pre-commissioning and commissioning of pipeline assets, operation and maintenance shall be gathered and reviewed along with post-construction operational and integrity assessment data gathered to identify the potential threats along the pipeline system. Operational and integrity assessment data will be continuously updated while performing various activities along the pipeline such as patrolling, aerial surveillance, Cathodic Protection (CP) monitoring, monthly maintenance of equipment etc. and records maintained either hard or soft options.

6.1.2 Threats Identification:

Pipeline incident data analyzed and classified by Pipeline Research Committee International (PRCI) represents 22 root causes for threat to pipeline integrity. One of the causes reported by the operator is "unknown". The remaining 21 threats have been grouped into three groups based on time dependency and further in to nine categories of related failure types according to their nature and growth characteristic as below:

(I) <u>Time Dependent Threats</u>:

1) External Corrosion

2) Internal Corrosion

3) Stress Corrosion Cracking

(II) <u>Stable Threats:</u>

4) Manufacturing related defects

i. Defective pipe seam

ii. Defective pipe

5) Welding /fabrication related

i. Defective pipe girth weld

ii. Defective fabrication weld

iii. Wrinkle bend or buckle

iv. Stripped threads /broken pipe /coupling failure

6) Equipment

i. Gasket O-ring failure

ii. Control/relief equipment malfunction

iii. Seal pump packing failure

iv. Miscellaneous

(III) <u>Time independent Threats:</u>

7) *<u>Third party /mechanical damage:</u>*

i. Damage inflicted by first, second or third party (instantaneous /immediate failure)

ii. Previously damaged pipe (delayed failure mode)

iii. Vandalism

8) ***Incorrect operational procedure***

9) ***Weather related and outside force:***

i. Weather related

ii. Lightening

iii. Hydro technical: water-related threats including, but not limited to, liquefactions, flooding, channeling, scouring, erosions, floatation, breaches, surges, inundations, tsunamis, ice jams, frost heaves, and avalanches, creek area effects, river meandering, river bed / bank movement

iv. Geotechnical: earth movement threats including, but not limited to, subsidence, extreme surface loads, seismicity, earthquakes, fault movements, mining, and mud and landslides, muddy land effects

v. High wind

6.1.3 Consequence and Impact Analysis

Once the hazardous events are identified, the next step in the risk analysis is to analyze their consequences i.e., estimate the magnitude of damage to the public, property and environment of all the identified threats. These consequences may include leak, fire, explosion, vapour cloud, pollution of water courses/ground water, pollution of soil to oil spillage etc.

(i) Leak

(ii) Mass release/Continuous release

(iii) flash fire/Jet fire

(iv) explosion

(v) UVCE (unconfined vapour cloud explosion)

(vi) CVCE (confined vapour cloud explosion)

(vii) Gas cloud

(viii) Fireball

(ix) Pool fire

(x) Tank fire

Consequence estimation can be accomplished by using mathematical models (consequence modelling), which can be at various levels of detail and sophistication.

Potential Impact Area: Generally, these are high-population-density areas, difficult-to- evacuate facilities (such as hospitals or schools), and locations where people congregate (such as churches, office buildings, or fields), water ways / water bodies etc.

6.1.4 Risk assessment specific to pipeline system.

6.1.4.1 Developing a Risk Assessment Approach: Risk assessment process identifies the location-specific events or conditions, or combination of events and conditions that could lead to loss of pipeline integrity, and provides an understanding of the likelihood and consequences of these events.

The risk assessment has the following objectives:

i) Prioritization of pipeline sections/segments for scheduling integrity assessment and mitigation plan

ii) Assessment of the benefits derived from mitigation actions

iii) Determination of the most effective mitigation measures for the identified threats

iv) Assessment of the integrity impact from modified inspection intervals

v) Assessment of the use of or need for alternative inspection methodology

vi) More effective resource allocation

Pipeline sections may be prioritized for integrity assessment based on severity of composite risk due to all threats. The composite risk value for particular pipeline section is product of relative likelihood of failure and consequences altogether due to all applicable threats. Risk priority shall be established for pipeline sections observed with high risk to organize the integrity assessment. The risk may simply be categorized as high, medium, low (or 1, 2, 3) or larger range, to differentiate the priorities among various sections.

Following approaches for risk assessment and prioritization may be adopted as deemed suitable to the Operators:

a) Utilizing the services of Subject Matter Experts (SMEs)

b) Relative Assessment Model

c) Scenario –Based Model

d) Probabilistic Models

The risk assessment models mentioned above have following common features:

(a) They identify potential events or conditions that could threaten system integrity;

(b) They evaluate likelihood of failure and consequences;

(c) They permit risk ranking and identification of specific threats that primarily influence or drive the risk;

(d) They lead to the identification of integrity assessment and/or mitigation option;

(e) They provide for a data feedback loop mechanism;

(f) They provide a structure and continuous updating for risk reassessments

Risk assessment considering the likelihood and consequences through risk assessment approaches may not consider the extent of failure that is leak or rupture. If failure cannot be identified as leak or rupture while assessing the risk through any of the above models, a worst case scenario may be considered.

6.1.4.2 Risk Assessment for the pipeline system:

The risk assessment is continuous and repetitive process. System wide risk assessment shall be carried out every year by pipeline operators through any of the methodology mentioned above after incorporating and updating the recently captured data in risk model such as:

i) Increase in Operating Pressure.

ii) Changes in Right of Use conditions like development of encroachments, increase in third party activities/ population density, major washouts.

iii) Pipeline Leak/rupture history.

iv) Addition of new /expansion of the existing railway/road/waterway crossings.

v) Changes to pipeline Cathodic protection levels due to external interference problems.

vi) Any other issues which may affect the integrity of pipeline.

vii) The results of previous integrity assessments.

The risk assessment may be performed earlier if any new threat is perceived. The risk assessment process and method shall be reviewed and updated periodically to achieve the objective of pipeline integrity management plan consistently.

The result of risk assessment shall be arranged in descending order for each section for prioritizing the section for conducting integrity assessment after selecting the appropriate integrity assessment method based on most significant threats to particular section.

6.1.5 INTEGRITY ASSESMENT

A plan shall be developed to address the most significant threats and risks as per previous section and determine appropriate integrity assessment methods to assess the integrity of the pipeline segment. The following methods can be used for Integrity Assessment:

i) Pressure testing

ii) Inline inspection (ILI)

iii) Direct Assessment (ECDA, ICDA & SCCDA)

iv) Any other Integrity Assessment methodology.

Brief description of various Integrity Assessment methods has been also provided in Schedule-5 of these regulations.

Selection of appropriate integrity assessment method shall be based on most significant threats to which particular segment are susceptible. One or more integrity assessment methods can be used depending upon the threats to particular segment of pipeline.

The operator of a pipeline system shall develop a chart of most suited integrity assessment method and assessment interval, prevention and mitigation measures for each applicable threat and risk. The operator shall further develop appropriate specifications and quality control plan for such assessment. After establishing effectiveness of assessment, the interval of assessment may be further modified subject to the requirements under the Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum Products Pipeline) Regulations, 2016 and other relevant Regulations. A suggestive chart is placed at Appendix –III.

While carrying out risk assessment and selecting the integrity assessment methods and monitoring techniques & surveys and their intervals, special care shall be taken to address specific threats in respect of offshore sections of predominantly onshore pipelines (such as free-span survey), High Vapor Pressure Liquid Pipelines (such as special attention to failure consequences) and ageing pipelines (such as to increase monitoring / inspection frequencies).

6.1.6 Mitigation and Responses (Repair and Prevention)

After the completion of integrity assessment and monitoring / surveys, like inline inspection and, Direct Assessment, coating health surveys etc., the results shall be evaluated, and the necessary repairs and preventive actions shall be undertaken to eliminate the threat to pipeline integrity.

Immediately upon completion of integrity assessment, a comprehensive schedule of repair shall be prepared. All anomalous conditions discovered through the integrity assessment shall be evaluated and classified under the following three categories based on severity of defect. Mitigation action (repair and prevention) shall be undertaken to eliminate any unsafe condition to the integrity of a pipeline or to ensure that the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment. The entity shall have a plan for ensuring safety of personnel and pipelines by suitable means such as pressure reduction, wherever warranted

(A) <u>Mitigation through Repair Actions:</u>

All anomalies reported in ILI shall be categorized as per their significance with respect to the safe operation of the pipeline.

At the time of establishing schedules, responses shall be divided in to three groups and repair actions shall be as follows:

(a) **Immediate repair conditions:** Such indication shows that defect is at failure point this shall include but not limited to any corroded area having

i) Metal loss equal to or more than 80% of nominal wall thickness regardless of dimensions.

ii) Predicted failure pressure less than equal to 1.1 times the maximum allowable operating pressure (MAOP) as determined by ASME B31G or equivalent. Safety Factor, tool tolerance are not taken into consideration while calculating predicted failure pressure.

iii) Metal loss indication affecting a detected longitudinal seam, if that seam was formed by direct current or low frequency electric resistance weld or by electric flash welding.

iv) Crack or Crack like anomalies greater than 70 % of nominal wall or of an indeterminate depth that exceeds the maximum depth sizing capabilities of the tool used in integrity assessment or Verified cracks except shallow crater cracks or star cracks in girth welds unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity or all indications of stress corrosion cracks (SCC).

v) A combination of dent with gouge/possible crack/ Stress riser unless an industry recognized engineering analysis shows that it does not pose an immediate threat.

vi) A dent located on the top of the pipeline (above the 4 o'clock and 8 o'clock positions) with a depth greater than 6 % of the nominal pipe diameter unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity.

vii) Any indication of adverse impact on the pipeline expected to cause immediate or near-term leaks or ruptures which include dents with gouges etc.

(b) **Scheduled conditions:** – Such indication shows that defect is significant but not at failure point. Following indications shall be examined within one year of discovery:

i) An area of general corrosion, Selective Seam Weld Corrosion, area of widespread circumferential corrosion, area of girth weld, area located at another pipeline crossing with a predicted metal loss greater than 50 % of nominal wall.

ii) Predicted failure pressure less than equal to 1.25 times the maximum allowable operating pressure (MAOP) as determine by

ASME B31G or equivalent (Safety Factor, tool tolerance are not taken into consideration while calculating predicted failure pressure)

iii) Crack or Crack like anomalies with depth greater than 50 % of nominal wall

iv) A gouge or groove greater than 12.5 % of nominal wall resulting from mechanical damage.

v) A dent falling under any of the following criteria, unless an industry recognized engineering analysis shows that it poses minimal risk to pipeline integrity:

  (a) Located on the bottom of the pipeline (below the 4 o'clock and 8 o'clock positions) with a depth greater than 6 % of the pipeline's diameter;

  (b) That affect ductile girth or seam welds if the depth is more than 2% of the nominal pipe diameter (0.250 inch in depth for a pipeline diameter less than NPS 12);

  (c) Located on the top of the pipeline (above 4 and 8 o'clock position) with a depth greater than 2 % of the pipeline's diameter (0.250 in. in depth for a pipeline diameter less than NPS 12);

  (d) Located anywhere on the pipeline with corrosion;

  (e) Dents of any depth that affect non-ductile welds such as acetylene girth welds or seam welds that are prone to brittle fracture

vi) Maximum depth of metal loss feature including corrosion growth and tool tolerances predicted to be greater than 80%

vii) A lamination that intersects a girth weld or seam weld, that lies on a plane inclined to the plane of the pipe surfaces, or that extends to the inside or outside surface of the pipe

* For details, para 451.4 of ASME 31.4 : "*Repair Procedures for Steel Pipelines*" may be referred.

(c) Monitored conditions

Monitored conditions indications shows that defect will not fail before next inspection. Such indications are the least severe and will not require examination and evaluation until next scheduled integrity assessment, interval provided that they are not expected to grow to critical level prior to the next scheduled assessment.

(B) <u>Mitigation through Preventive Actions:</u>

The pipeline operator shall develop scheduled program for monitoring the integrity of the pipeline to prevent from time dependent and independent threats to support the integrity assessment and mitigation plan.

The monitoring scheme and frequency should be decided by the pipeline operator subject to compliance of Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum products pipeline) Regulations, 2016. Few schemes are as follows:

(a) Patrolling of pipelines and associated facilities

(b) Maintenance of Right of User and inspection of Crossings

(c) Pipeline Cleaning Pigging

(d) Inspection of cathodic protection system

(e) Coating Survey (Closed Interval Potential Logging / Direct Current Voltage Gradient / ACVG / Pearson/Current Attenuation Test)

6.1.7 Update, integrate and review data:

After the initial integrity assessments are completed, the results shall be maintained in soft / hard or both versions which will be used for future risk and integrity assessments in addition to operational information that is recorded on continuous basis for assessments and implementing risk mitigation plan.

6.2 Performance Evaluation Plan

Every pipeline operator shall define suitable performance indicators which can be monitored to give a picture of the integrity levels of various aspects of the operator's pipeline assets. Monitoring of these indicators on a periodic basis against pre-defined targets helps to assess the effectiveness of Integrity Management program. Performance indicator measures should be selected carefully to ensure that they can reasonably indicate the effectiveness of program and health of the assets.

An operator can evaluate a system's integrity management program performance within their own system and also by comparison with other systems on an industry-wide basis.

Such performance evaluation should consider both threat-specific and aggregate improvements. Threat-specific evaluations may apply to a particular area of concern, while overall measures apply to all pipelines under the integrity management program.

Performance indicator may measure either or all of the below as applicable:

(i) Process measures e.g. Number of damages per excavation notification received

(ii) Operational measures e.g. No. of significant In-line Inspection anomalies

(iii) Direct integrity measures e.g. No. of damages per km. of pipeline length

A performance indicator may be either leading or lagging indicator. Lagging measures are reactive in that they provide an indication of past integrity management program performance. Leading measures are proactive in that they provide an indication of how the plan may be expected to perform.

6.2.1 Performance Measures

Performance measures serve as a tool for evaluating the success of the Pipeline Integrity Management System. The performance measures have been developed as a method to gauge the extent to which the Pipeline Integrity Management System goals have been met. Performance results demonstrate whether integrity management activities are appropriate or require improvements. The results may be evaluated annually by the pipeline operators, at which time the appropriateness of each performance measure may be assessed. Some of the goals as part of performance measures are illustrated below for reference. The operator may set their own goals depending on priorities & specific problems.

Goals	Performance Measure
To maintain pipeline Pipe-to-Soil Potential (PSP) within acceptable limits	PSP Level
Execution of In-line Inspection	As applicable
Leakage and ruptures	Number
Development, Training and Awareness program	Number of training and awareness program conducted in a year
No Right of Use encroachments	Number of encroachments

In addition to the above performance measures, the Pipeline Integrity System Monitoring Report includes the following:

i) Patrolling undertaken vs. Planned.

ii) Key Integrity issues such as encroachments, restoration, constructional deficiencies, mitigation plan and any operational issues.

iii) The number of Integrity Management System required activities completed.

iv) The number of defects found requiring repair or mitigation.

v) The number of leak reported.

For performance measures relating to damage events, the following points are documented in the Operator's Damage Prevention Report:

i) The number of third-party damage events and near misses.

ii) The number of pipeline hits by third parties due to lack of notification.

iii) Aerial surveillance and patrolling reports.

6.2.2 Continuous Improvement

The Integrity Management System shall be continuously evaluated and modified to accommodate changes in pipeline design and operation, changes in both the physical and regulatory environment in which the system operates and new operating data or other integrity related information. Continuous evaluation is required to make sure that the program takes appropriate advantage of improved technology and that the program remains integrated with the operator's business practices and effectively supports the operator's integrity goals.

Integrity Management System shall be evaluated and reviewed as per the frequency described in Schedule-9 of these regulations. Issues that would typically be reviewed may include, but are not limited to:

- Performance measures.
- Testing and inspection successes and failures.
- New threat identification.
- Root causes analysis of pipeline breakdowns & accidents.
- Process enhancement / changes (Management of Change).
- Recommended changes for the Integrity Management System.
- Additional training requirements necessary to support Integrity Management System.
- Public awareness program.
- Inspection tool performance (whenever applicable).
- Inspection tool vendor performance.
- Alternative repair methods.
- Staffing for inspections, testing and repairs.
- Past and present assessment results.
- Data integration and risk assessment information.
- Additional preventive and mitigating actions.
- Training needs of O&M personnel.
- Additional items as necessary to aid in the success of the IMP program.

Based on results of the internal reviews, integrity assessment & mitigation program shall be improved & documented.

6.3 Communication

This provides a framework for developing and implementing a written internal and external communication program for operators of Petroleum and

Petroleum products pipelines. All pipeline operators shall develop and implement a communication plan to disseminate the integrity management efforts undertaken by pipeline operator and also to receive internal and external information or input. This program must address intended audiences, message content, communication, frequencies and methods and program evaluation. The information received through external/internal communication should be considered for risk assessment, integrity assessment and mitigation. The communication plan typically comprises, establishment of external and internal communication system as follows:

6.3.1 External Communication:

This should cover the communication plan with external agencies, which are not directly related with operator's business, for propagating information regarding presence of pipeline location, damage preventing actions, company contact information for reporting leakage and informing before carrying out any excavation etc. The various means such as web site, warning boards, pamphlet distribution, street plays etc. can be utilized by operators for this purpose. The following external agencies may be targeted:

(I) land owner and tenants along the Right of Use

(II) General Public / Public institutions like schools, hospitals etc. near pipeline route

(III) Public officials and statuary bodies other than emergency responders

(IV) Local and regional emergency responders

6.3.2 Internal Communications:

This should cover the dissemination of the information to employees and persons involved in operation and maintenance of pipeline system regarding integrity management program to understand and comply with the program objectives and requirements. Such a plan is also expected to fully cover the flow of information and controls in response to emergencies.

6.4 Management of Change Plan

Pipeline systems and the surrounding environment in which pipelines operate are often dynamic and need changes depending upon operational or any other requirement. Prior to implementation of any changes to pipeline system, a systematic process shall be adopted to ensure that prospective changes (such as design, operation, or maintenance) are evaluated for their potential risk impacts to pipeline integrity including impact on environment. All Petroleum and Petroleum product pipeline operators shall define a Management of Change Plan in integrity management program to at least address the following:

(1) Reason for change

(2) Authority for approving changes

(3) Analysis of implications (threat and risk analysis)

(4) Documentation

(5) Communication of change to affected parties

After implementation of changes, they shall be incorporated, as appropriate, into future risk assessment to ensure that the risk assessment process addresses the systems as currently configured, operated, and maintained. The results of the Integrity Management Plan's mitigation activities should be used as feedback for systems and facilities design and operation.

Changes to the pipelines could affect the priorities of the pipeline Integrity Management Plan and the risk mitigation measures employed. Any change in design basis, process or operational issue that can affect the risk rating has to be routed through Management of Change.

6.5 Quality Plan

All the entities shall prepare and maintain documented procedure and records as per the requirement of this standard which can also be made part of existing Quality Management Program (e.g. ISO-9001) maintained by the entities. The following activities shall be made part of quality control program:

(i) Identifying and maintaining the documents required for Integrity management plan, procedures and records. This includes both controlled and uncontrolled documents.

(ii) Defining Roles & responsibilities for implementation of program, documentation etc.

(iii) Reviewing of Integrity management plan and implementation of recommendation at predefined interval.

(iv) Training and awareness of persons implementing the Integrity management plan

(v) Periodic internal Audit of integrity management plan and quality plan.

(vi) Documentation of corrective actions taken or required to be taken to improve the integrity management plan or quality plan

6.6 Manpower

Entity shall have a written plan / philosophy for deploying personnel of adequate experience and expertise in preparation & development of integrity management plan of pipeline systems and manning the installations based on activities required for compliance to this regulation. Entity shall address the requirement of manpower for different stages of project, namely: Design, construction, commissioning, operation and maintenance in the above plan.

SCHEDULE 7

APPROVAL OF INTEGRITY MANAGEMENT SYSTEM (IMS):

Pipeline Integrity Management System is a management plan in the form of a document that explains to operator's employees, customers, regulatory authorities, etc., as to how the operator and its assets are managed, by stating:

(i) who is responsible for each aspect of the asset and its management;

(ii) what policies and processes are in place to achieve targets and goals;

(iii) how they are implemented;

(iv) how performance is measured and;

(v) how the whole system is regularly reviewed and audited.

For the first time the approval of the IMS document shall be done by the Board of the entity. While during review, to be done every three years, the approval shall be done by CEO / Full time Director of the company and all levels of management shall comply with its contents. Necessary awareness shall also be created within and outside the company regarding benefits to the society for up keeping of the pipeline system for all times to come.

Preparation of the document shall be done in following three stages and six steps:

7.1 MANAGEMENT APPROVAL:

Step#1: Prepared by In-house team or Consultant

Step#2: Checked by In-house team Head or Consultant head

Step#3: Provisionally approved by Head of Operation / Maintenance of the entity

Step#4: Verification of Conformity of IMS document with the Regulation by Third Party Inspection Agency (TPIA)

Step#5: Approval of Integrity Management System document for implementation by the Board of the entity for the first time and approval of subsequent periodic review by CEO or Full-time Director of the entity

Step#6: Approved IMS document along with confirmation from entity of its implementation shall be submitted to the Board.

SCHEDULE-8

IMPLEMENTATION SCHEDULE of Integrity Management System

Sr. No.	Activities	Time Schedule
1	Compliance with Petroleum and Natural Gas Regulatory Board (Technical Standards and specifications including Safety Standards for Petroleum and Petroleum products pipelines) Regulations, 2016.	Confirmation to be submitted to PNGRB along with submission of approved IMS document.
2	Preparation of Integrity Management System document and approval by Head of Operation / Maintenance team of the entity.	1 year from date of notification of these regulations*
3	Conformity of Integrity Management System document with regulation by Third Party Inspection Agency.	3 months from the approval by the Head of Operation/Maintenance of the entity.
4	Approval for implementation by the Board of the entity for the first time and approval subsequent periodic review by CEO or Full-time Director of the entity	Within 3 months from the conformity assessment by Third Party Inspection Agency (TPIA).
5	Start of Implementation	Immediately after approval at Sr. No. 4 above
6	Submission of Integrity Management System Document to Petroleum and Natural Gas Regulatory Board	One month from the approval as mentioned at Sl. 4 above.
7	Submission of Compliance Statement to Petroleum and Natural Gas Regulatory Board	Shall be submitted every year to Petroleum and Natural Gas Regulatory Board

Note: Steps for implementation to be followed as described in Schedule-7

* - For new pipelines, the above shall be complied within one year of date of commissioning

SCHEDULE- 9

REVIEW OF THE INTEGRITY MANGEMENT SYSTEM

10.1 Periodicity of review of Integrity Management System

Entities may review their existing Integrity Management System from time to time but not exceeding an interval of every 3 years and update the same if required in accordance with the provisions of Schedule 7 based on the performance of Integrity Management Program and /or changes if any in the statutory / regulatory requirements. However, changes of dynamic nature such as addition, deletion, modification of assets, key personnel, interfaces with other utilities etc. may not require revision in the IMS and the same can be kept updated periodically by the concerned entity.

10.2 Integrity Management System Audit

Audit of the Pipeline Integrity Management System shall be performed on a regular basis. The purpose of the audits is to ensure compliance with the policies and procedures as outlined in these regulations. Recommendations and corrective actions taken shall be documented and incorporated into the Pipeline Integrity Management System.

The following essential items will be focused for any internal and external audit of the entire Integrity Management System:

(i) IMS document is developed, approved and is valid.
(ii) Activities are performed in accordance with the Integrity Management System.
(iii) Verify if annual performance measures have been evaluated
(iv) All action items or non-conformances are closed in a timely manner.
(v) The risk criteria used have been reviewed and documented.
(vi) Prevention, mitigation and repair criteria have been established, met and documented.

10.3 Frequency of Internal and External Audit

There shall be a system for ensuring compliance to the provision of these regulations by conducting following audits during operation phase:

(a) Internal Audit - Every year.

(b) External Audit - Every 3 years in-line with the approved IMS by third party empaneled by the Board.

APPENDIX-I

REFERENCES

Reference documents of Standard Operation and Maintenance procedures related to Pipeline Integrity may be developed for use of O&M personnel. Some of them are mentioned below for reference:

1) Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum products pipelines) Regulations, 2016;
2) Petroleum and Natural Gas Regulatory Board (Codes of practices for Emergency Response and Disaster Management Plan) Regulations, 2010;
3) ASME B31.4- Pipeline Transportation Systems for Liquid Hydrocarbons and other Liquids.
4) ASME B31.8S – Managing System Integrity of Gas Pipelines;
5) API 1160 - Managing System Integrity for Hazardous Liquid Pipelines
6) ASME B31Q – Pipeline Personnel Qualification
7) ASME B31G – Manual for Determining the Remaining Strength of Corroded Pipelines

APPENDIX-II

CRITICAL ACTIVITIES IMPLEMENTATION SCHEDULE

S/N	CRITICAL ACTIVITY	TIME SCHEDULE
1	Cathodic Protection (CP) Inspection	As per Petroleum and Natural Gas Regulatory Board (Technical Standards and Specifications including Safety Standards for Petroleum and Petroleum products pipelines) Regulations, 2016
2	Pigging/Intelligent Pigging	
3	Surveillance	
4	Coating Survey	
5	Hydro-testing	
6	GIS Mapping Implementation	2 years from the commissioning of pipeline or within 2 years from the notification of this regulation
7	Leak Detection System Implementation	2 years from the commissioning of pipeline or within 2 years from the notification of this regulation

APPENDIX-III

Suggestive Chart for selection of Integrity Assessment OR Management Method* with respect to specific threat

Threat Group	Threat	Integrity Assessment /Management Methods*	Interval
(A) Time-Dependent			
	External Corrosion	Inline inspection /External Corrosion Direct Assessment (ECDA) / Pressure Testing / Any other Integrity Assessment Methodology	Max. 10 year**
	Internal Corrosion	Inline inspection /Internal Corrosion Direct Assessment (ICDA) / Pressure Testing / Any other Integrity Assessment Methodology	Max. 10 year**
	Stress Corrosion cracking	Inline inspection / Stress Corrosion Cracking Direct Assessment (SCCDA) / Pressure Testing / Any other Integrity Assessment Methodology	Max. 10 year**
(B) Stable			
a) Manufacturing related defects	Defective Pipe Seam	Inline inspection/ Pressure Testing / Any other Integrity Assessment Methodology	Before commissioning or as and when required
	Defective Pipe		
b) Welding / Fabrication related	Defective Pipe Girth Weld		
	Defective fabrication Weld		

Threat Group	Threat	Integrity Assessment /Management Methods*	Interval
	Wrinkle bend or buckle	Caliper Pigging / Electronic Gauging Pigging (EGP)	
	Stripped threads/broken pipe	Visual Examination / Leakage Survey	
c) Equipment	Gasket / O-ring Failure	Visual Examination / Leakage Survey	
	Control / Relief equipment malfunction	Visual Examination / Leakage Survey	
	pump Seal packing failure	Visual Examination / Leakage Survey	
(C) Time-Independent			
a)Third Party / Mechanical Damage	Damage inflicted by first, second, or third parties (Instantaneous / Immediate failure)	Public Education (See Communication Plan & preventive actions), Patrolling, ROU maintenance, External Protection	Monthly /quarterly
	Previously damaged pipe (delayed failure mode)	Above + Leakage Survey, Rehabilitation	
	Vandalism	All above	
	Change in geometry	EGP survey (Once in three years)	

Threat Group	Threat	Integrity Assessment /Management Methods*	Interval
b)Incorrect Operations	Incorrect Operational procedure	Compliance Audits	
c) Weather Related and Outside Forces	Weather related	Leakage survey, Surveillance	As and when required
	Lightning	Inspection of Surge diverters	
	Heavy rains or floods	Inspection, Surveillance	
	Earth Movements	Strain monitoring, Leakage survey.	
	Creek Area Effects	Surveillance, Leakage survey, Inspection	
	Muddy/Marshy area effects	Surveillance, Leakage survey, Cathodic Protection monitoring	
	River Bed Movements	Surveillance, Leakage survey, Inspection	

* Some of the important Integrity Assessment / Management Methods have been mentioned in Schedule-5 of these regulations.
** Inline inspection frequency to be as per PNGRB (Technical Standards and Specifications including Safety Standards for Petroleum & Petroleum product Pipelines) Regulations, 2016