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TRANSMISSION INTEGRITY MANAGEMENT PROGRAM PLAN

Gill Ranch Storage

Transmission Integrity Management Program Plan

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Introduction

The objective of Gill Ranch Storage's (GRS's) Transmission Integrity Management Program (TIMP) is to provide enhanced protection for defined High Consequence Areas (HCAs), establish and continuously improve integrity management systems within GRS and provide increased public assurance of pipeline safety. This section presents the scope and applicability of this program for gas pipelines and its correlation with other GRS programs and documentation.

GRS is a gas storage and transmission pipeline business activity owned solely by Northwest Natural Gas (dba NW Natural) headquartered in Portland, Oregon. The Gill Ranch Storage (GRS) facilities are co-owned by GRS and Pacific Gas & Electric headquartered in San Francisco, California. GRS operates the Gill Ranch Storage facilities on behalf of both owners. The GRS TIMP Plan will be administered by the NW Natural (NWN) Integrity Management Group (IMG). To the extent applicable, the GRS TIMP Plan will share certain NW Natural resources.

Plan Scope

On December 17, 2002, the United States Department of Transportation (DOT) adopted the final rule on Gas Transmission Pipeline Integrity Management (49 CFR Part 192 subpart O). This Integrity Management Rule ("the rule") specifies regulations to assess, prioritize, evaluate, mitigate, and validate the integrity of natural gas transmission lines that, in the event of a leak or failure, could affect high consequence areas (HCAs).

In accordance with the requirements of the rule, this document represents GRS's written TIMP Plan for natural gas transmission pipelines owned and/or operated by GRS and provides guidelines for continual assessment of all pipelines that could impact HCAs as defined in the rule.

This integrity assessment of GRS's pipelines and facilities will be achieved through instrumented internal inspection, direct examination (possibly in the future), hydrostatic pressure testing, or other equally effective means supported by sound engineering practices and approved by the DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA).

Transmission Line Definition

GRS defines transmission lines as those with a maximum allowable operating pressure (MAOP), equal to or greater than 20% of the Specified Minimum Yield Strength (SMYS). This definition is consistent with the annual federal reporting requirements. It is well below the generally accepted threshold of catastrophic failure of 30% SMYS (Gas Research Institute Report-00/0232).

Prescriptive versus Performance-Based Plans

Initially, the GRS Plan will be a prescriptive-based program until a comprehensive integrity management database is developed. Later, as more definitive data becomes available, the GRS Plan may change to a performance-based program.

Covered Systems

Current covered systems include GRS's complete natural gas transmission system in Madera and Fresno Counties of California.

Integrity Management Process and Program Elements

GRS's Integrity Management Program is designed to meet the requirements in 49 CFR 192 Subpart O - Transmission Integrity Management. The Program also includes segments of the following documents that are incorporated by reference:

- ASME/ANSI B31.8S-2004 – Managing System Integrity of Gas Pipelines
- NACE RP0502-2002 – Pipeline External Corrosion Direct Assessment Methodology

Each of the 16 elements of the integrity management program identified in §192.911 are addressed in the GRS IMP plan in the same order that they appear in the PHMSA Inspection Protocols, as shown in Table 1.

Table 1. IMP Plan Organization

Protocol Section	GRS Sections	IMP Element	Description
A	1	Identifying HCAs	Identify all pipeline segments that could affect HCAs
B	2	Baseline Assessment Plan	Schedule assessments of HCA segments according to risk
C	3	Threat Identification, Risk Analysis, and Data Integration	Analyze and integrate all information about threats to pipeline integrity and failure consequences
D	4	Direct Assessment Plan	Conduct of direct assessments for scheduled HCA segments (not initially planned for use on GRS pipelines)
E	5	Remediation	Repair criteria and processes
F	6	Continual Evaluation	Establish a process for continual integrity assessment/evaluation
G	7	Confirmatory Direct Assessment	Identify damage resulting from external and internal corrosion (not initially planned for use on GRS pipelines)
H	8	Preventive and Mitigative Measures	Analyze actions to prevent and/or reduce the risk to HCA segments

Protocol Section	GRS Sections	IMP Element	Description
I	9	Performance Measures	Establish performance effectiveness measures for the integrity management program
J	10	Record Keeping	Establish guidelines for maintaining required pipeline records
K	11	Management of Change	Establish guidelines for making changes to the TIMP
L	12	Quality Assurance	Establish quality assurance guidelines for the TIMP
M	13	Communication Plan	Establish plan to communicate externally and internally.
N	14	Submittal of Program Documents	Establish process for documenting that documentation has been submitted to the proper state and local authorities

IMP Key Team Members

Integrity management involves the GRS organization and selected NWN personnel. The NW Natural Integrity Management Group (IMG) is charged with the development of the TIMP Plan and for the accomplishment of its processes. The key team members involved in the development and distribution of this program are listed in Table 2.

Table 2. TIMP Organization Chart

Name	Title	Function
	Chief Operating Officer, NW Natural Energy	Chief Executive
	President, NW Natural Gas Storage	President
	Vice President, Engineering and Operations, GRS	Project Sponsor & Chief Engineer
	Director, Deliver Gas Process, NWN	Steering Committee Member
	Manager, Engineering, NWN	Steering Committee Member
	Supervisor of Integrity Management, NWN	Project Manager, Steering Committee Member
	Integrity Management Engineer, NWN	Integrity Management Engineer
	Integrity Management Engineer, NWN	Integrity Management Engineer
	Integrity Management Specialist, NWN	Integrity Management Specialist

Correlation with Other GRS Documentation

This TIMP plan describes the processes of GRS's program for integrity management but does not repeat elements of the program that are already in place as existing procedures. Certain GRS Operator Qualification Procedures are relevant to some of the processes and procedures of the TIMP.

1. Identifying HCAs

The final rule on Transmission Integrity Management in High Consequence Areas directs transmission line operators to identify high consequence areas (HCAs) along covered pipelines by either of two methods:

- Method 1, primarily based on class locations
- Method 2, based on the contents of areas within potential impact circles

The method used can be different for different pipelines or for different segments of the same pipeline, but the method used for each segment of each pipeline must be described.

GRS pipeline and gas processing facilities are located in a geographically compact rural area. Only method 2 will be used to identify HCAs. Should conditions change or additional pipelines be added in other more populated areas, NW Natural's Integrity Management Group (IMG), on GRS's behalf, may use Method 1.

1.1 HCA Identification Process

The IMG's HCA identification process for the GRS pipeline and processing facilities is not complex due to the relatively short intertie pipeline between the processing facilities and the PG&E mainline. Injection/withdrawal wells are less than a mile from the processing facilities. The IMG physically examines the high resolution aerial photos of the system for potential HCAs.

All GRS transmission pipeline segments and gas processing facilities located in potential high consequence areas were installed during the spring and summer of 2010. Therefore, HCAs could not be identified prior to December 17, 2004. Documentation of HCAs discovered are located in the NWN IMG GRS office files.

1.2 Potential Impact Radius

A potential impact circle (PIC) defines an area within which a transmission pipeline failure could have a significant impact on people or property. The size of the circle is a function of a segment's nominal pipe diameter, a factor related to type of gas transported, and the certified MAOP of the pipeline. GRS transports only natural gas with a gross heat content less than 1100 BTU/cu. ft.; therefore, the factor for natural gas was used. The potential impact radius (PIR) is calculated using the following formula:

$r = f\sqrt{(pd^2)}$	
where	r = radius of the circle from the center line of the transmission line (ft)
	f = 0.69 (the gas factor for natural gas with a gross heat content less than 1100 BTU/cu.ft.)
	p = maximum allowable operating pressure (MAOP) of the pipeline segment (psig)
	d = nominal outside diameter of the pipeline (in)

The calculated PIR will include an addition of 10% to the radius to account for the possibility of minor variations between aerial or satellite photography and actual pipeline locations.

The potential impact radius is used in several ways:

- The PIR defines the distance the potential impact zone extends on each side of a covered pipeline for the length of the segment.
- For an identified site, the PIR determines the length of the HCA along the pipeline.

To define the HCA for an identified site:

1. The PIR is calculated using the above formula.
2. The point on the centerline of the pipeline that equals the length of the PIR from the left side of an identified site, such as the school in Figure 1-2-, becomes the center of the potential impact circle on the left.
3. The point on the pipeline that is the length of the PIR from the right side of the identified site becomes the center of the potential impact circle on the right.
4. The HCA, shown at the bottom of Figure 1-3, extends along the pipeline from the outermost edge of the left circle to the outermost edge of the right circle.

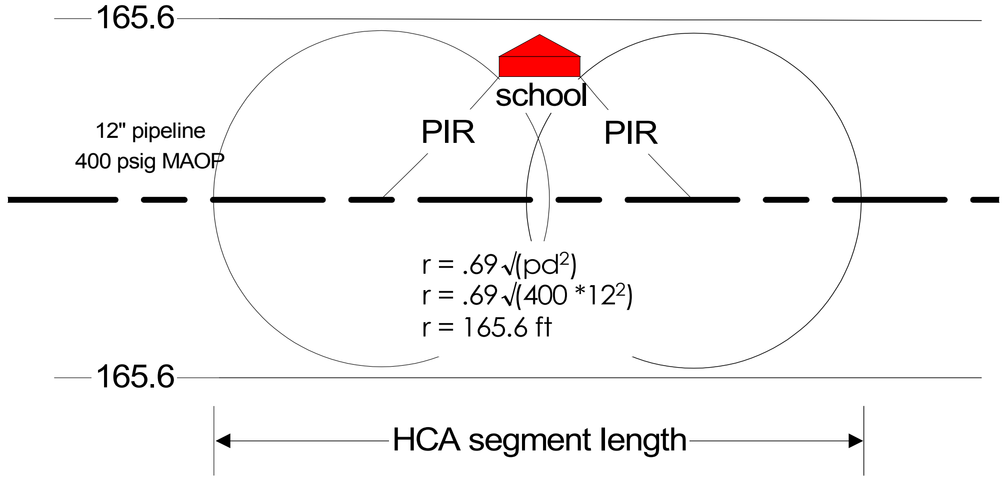


Figure 1-2: The HCA extends along the pipeline between the outer edges of the PICs.

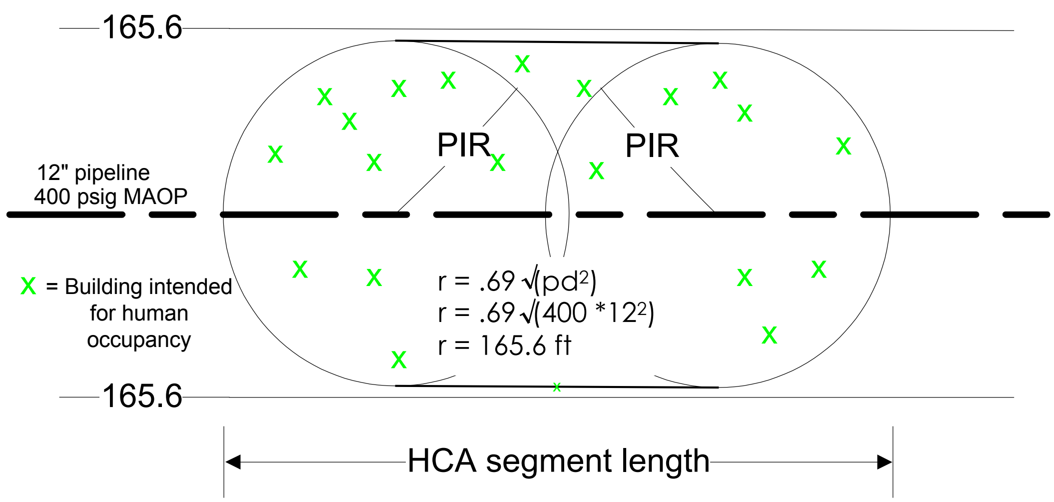


Figure 1-3. The HCA extends along the pipeline between the outer edges of the PICs.

1.3 Identified Sites

Both Method 1 and Method 2 of HCA identification require operators to evaluate identified sites within the PIC. Identified sites meet one of the three criteria described in Table 1-1.

Table 1-1. Identified Sites

Type of Site	Occupants	Occupation during any 12-month Period*	Examples (but not limited to:)
Outside area or open structure	20 or more persons	At least 50 days	Beaches, playgrounds, recreational facilities, campgrounds, outdoor theaters, stadiums, areas outside a rural building such as a religious facility
Building	20 or more persons	At least 5 days a week for 10 weeks	Office buildings, community centers, religious facilities, general stores, 4-H facilities or roller skating rinks
Facility	Persons who are confined or difficult to evacuate	—	Hospitals, prisons, schools, daycare facilities, retirement facilities or assisted living facilities

*Days and weeks need not be consecutive.

The IMG uses the following sources, as appropriate, to find identified sites:

- Routine operation and maintenance activities. (See section1.6)
- Public officials involved in safety, emergency response, and planning, such as the local emergency planning commission, fire marshals or chiefs, or Native American tribal officials. A record of contact will be maintained in the NWN IMG GRS office files.
- Visible marking (e.g., a sign observed during the quarterly patrols. (See section 1.6).
- Facility licensing or registration data available from private or government agencies available from sources such as the National Center for Education Statistics, the American Hospital Association, and the Topologically Integrated Geographic Encoding and Reference system (US Census Bureau or Visual Risk).

Structures or gathering sites that meet the criteria in Table 1-1, and are within the PIC along GRS's pipeline facilities, are included among the identified sites. A record of the source of an identified site is maintained in the NWN IMG GRS office files. GRS pipelines and gas processing facilities are located in rural areas. As such, roads are not subject to daily or repeated traffic stand stills that could be interpreted as identified sites. Should conditions change, this evaluation of roads in PIR will be reviewed for change to an identified site.

1.4 Identification Using Class Locations (Method 1)

GRS pipeline and gas processing facilities are located in a rural area. Only method 2 will be used to identify HCAs. If a decision is made to use method 1, explanations in this section will be expanded and completed.

1.5 Identification Using PIR (Method 2)

GRS pipeline and gas processing facilities are located in a rural area. The IMG will apply Method 2 to GRS's pipelines and facilities. For Method 2, an HCA is defined as the area within a potential impact circle containing 20 or more buildings for human occupancy or an identified site. See section 1.2, Potential Impact Radius for the detailed explanation of determining an HCA.

1.5.1 Prorating the Number of Buildings

The section of the code allowing the use of a prorated number of buildings if the PIR for a pipeline is over 660 feet was allowed until December 17, 2004. Since all of GRS pipelines were installed in 2010 with the possibility of later installation of additional pipelines, this portion of the code was not applicable and not used.

1.6 Identifying New and Modifying Existing HCA Segments

When the IMG obtains information that the area near a pipeline segment might meet the criteria for an HCA, it evaluates the segment using method 2. If the evaluation identifies a new HCA on the segment, the IMG incorporates the segment into the baseline assessment plan and completes the baseline assessment of pipe in the newly identified HCA per the timeline stated in §2.5 of this plan.

Any employee or GRS contractor may submit information of changes along the route of a transmission line that could result in a new HCA or changes in an existing HCA at any time by completing a "Potential High Consequence Area Notification" form (see Appendix C). The form is initially submitted to the GRS Plant Manager for a field audit (see following section 1.7). The forms will be forwarded to the NWN Supervisor of Integrity Management as a new HCA or not meeting the definition of an HCA. Forms will then be maintained in the NWN IMG GRS office files or a secure network server. A list of examples of typical identified sites will be included on the form.

The GRS Plan analyzes changes for impacts on pipeline segments that could affect HCAs such as the following:

- Changes in the pipeline MAOP.
- Modifications affecting the diameter of the pipe.
- Changes in the commodity transported in the pipeline.
- Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites.
- Changes in use of existing buildings.
- Installation of new pipeline.
- Change in class location or class location boundary.
- Pipeline rerouting.
- Corrections to pipeline platted location.
- Field design changes affecting pressure, diameter, or pipeline location.

1.7 1.7 HCA Field Audit Process

The IMG has the option of performing an HCA Audit on pipeline sections to assure that the HCAs identified either internally or by a third party vendor are accurate and meet the definition of HCA as specified earlier in this section. Any member of the IMG may start the HCA Audit process. The process is typically performed prior to an integrity assessment. The HCA Audit process is not required for all covered pipeline sections.

The HCA Audit process starts by examining the initial reason for identifying a segment of pipe as an HCA or non-HCA. The HCA Audit process then requires additional research on the pipeline segment, such as site visits, telephone investigation, or interviews with people knowledgeable of the area, to determine the actual usage of the land or building within the Potential Impact Circle. The results of the additional research are documented in memo form and submitted to the Supervisor of Integrity Management for approval. Upon approval the results are filed in the NWN IMG GRS file and the appropriate changes are made to the risk model and the Baseline Assessment Plan. The process is outlined in the flow chart below.

HCA Audit Process

The purpose of the HCA Audit Process is to provide a method of assuring that HCAs identified internally or by third party vendor, are accurate and meet the definition of HCA provided in GRS's Integrity Management Program.

1. Choose pipeline to audit.

2. Gather the current HCA data to identify the segments within the pipeline that are currently within an HCA.

3. Research the reason for identifying a segment of pipe as an HCA or non-HCA.

4. Perform additional research on the pipeline segment to compliment the aerial photographs and plat sheets originally used to identify HCAs. Additional research methods may include but are not limited to, site visits, phone calls, and interviews with people knowledgeable with the area. The purpose of this step is to identify, as accurately as possible, what exists within the potential impact circle.

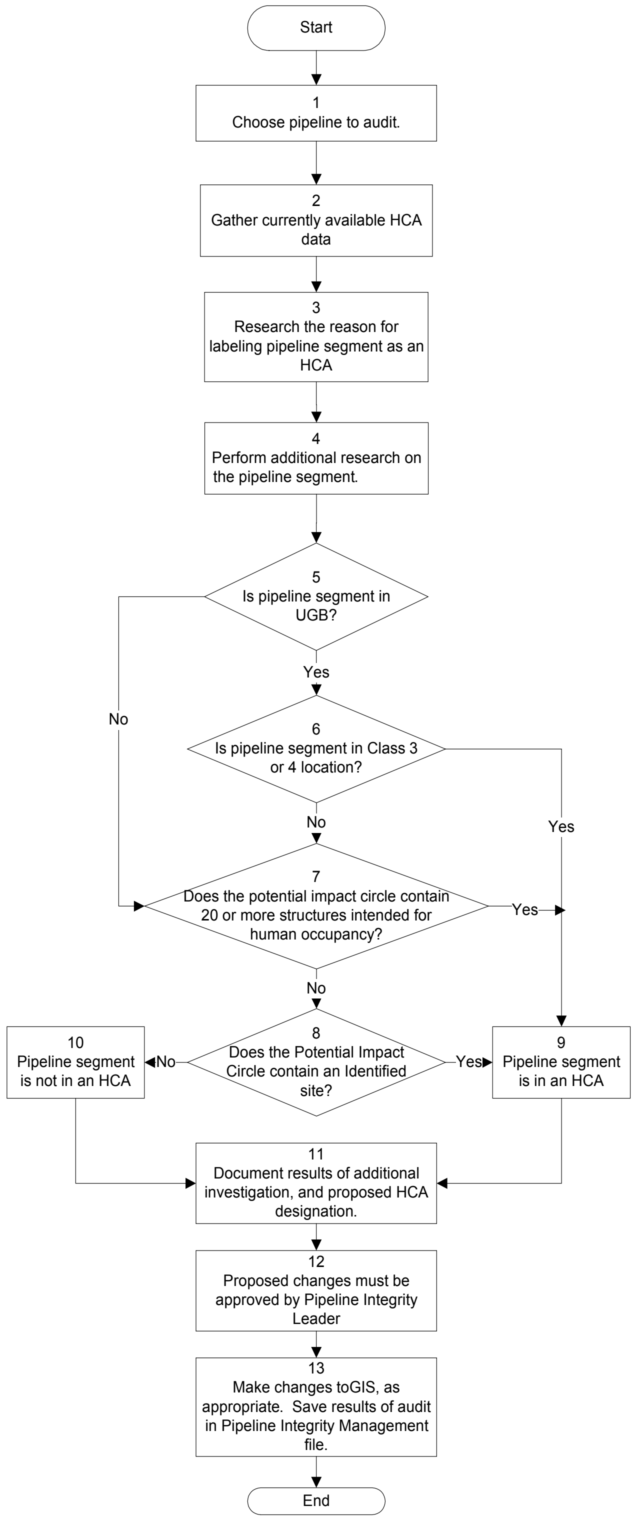
5-8. These steps identify HCA and are based on the definitions in GRS's Integrity Management Program.

9-10. Appropriately classify the pipeline segment as either within an HCA or outside an HCA based on the additional research performed.

11. Document results of audit in memo form. Include all pertinent information including but not limited to maps, photos, and interview results.

12. Submit written conclusions to the NW Natural Integrity Management Supervisor to approval.

13. Make changes, as appropriate, to GIS. Also file copy of audit results in Pipeline Integrity Management file.



2. Baseline Assessment Plan

This section describes GRS's plan and schedule for conducting a baseline assessment. Section 192.921(g)) specifies that operators of newly installed pipe may conduct a pressure test, per Subpart J, to satisfy the requirement for a baseline assessment. The GRS Plan's Baseline Assessment Plan (BAP) is to utilize the initial pressure test of all GRS pipelines and interconnecting pipe segments at facilities as its baseline assessment. All GRS gas transmission pipelines and gas processing plant piping were newly installed in the spring and summer of 2010. The IMG will use the initial hydrostatic (water pressure) tests of: the 30 inch diameter transmission line between the gas processing plant and PG&E line 401 tie-in site; all the injection/withdrawal lines; and the appropriate plant piping for the baseline assessment.

Requirements

The rule identifies five required elements of the Baseline Assessment Plan.

5. Identification of potential threats and the supporting documentation (GRS TIMP Section 2.6).
6. The method(s) selected to assess the integrity of the pipeline, including an explanation why the assessment method(s) were selected.
7. A schedule for completing the integrity assessment of all covered segments.
8. A direct assessment plan, if applicable (GRS TIMP section 4).
9. A procedure addressing environmental and safety risks (GRS TIMP section xx).

2.1 Assessment Methods

To assess the integrity of a transmission pipeline segment, the federal code prescribes one or more of the following methods:

- In-line inspection (ILI),
- Hydrostatic pressure tests (also called hydrotests or pressure tests)
- Direct assessment (not intended to be used on GRS pipelines), and/or
- Any other method, with 180-day advance notice to OPS and the applicable state PUC, that gives equivalent understanding of the condition of the pipe.

The IMG selects the assessment method for each pipeline segment based on the applicability of the method to address the potential threats to the integrity of that segment. The potential threats to transmission pipeline integrity are discussed in section 3. The methods the IMG may use for each mode of integrity threat, shown in Table 2-1, are based on the types of assessments outlined in ASME/ANSI B31.8S, section 6.

More than one method may be needed to assess the integrity on a given segment of a pipeline. A selected assessment method can yield insights into integrity threats other than those it was intended to address. For example, an in-line inspection may reveal a third-party damage threat if dents are discovered on a pipe segment.

This process outlines the steps that the IMG takes to create its Baseline Assessment Plan (BAP). The process can be implemented by any person in the IMG or his/her designee. The goal of this process is to create assessment schedules based on identified threats and risk factors.

1. Gather the calculated Risk of Failure (ROF) scores from the Risk Model.

2. Group the discrete pipeline segments that are outputted from the Risk Model into operational pipeline segments. Operational pipeline segments group contiguous pipeline segments together to create a pipeline with a logical start and end point. Examples of start and end points include a gate station, beginning of branch lateral, and terminus of the pipeline.

2a. Verify if the pipeline segment will utilize a preactivation Subpart J test.

3. Assign the highest ROF score from the discrete pipeline segments to the entire operational pipeline segment.

4. Rank all pipeline segments based on ROF scores from highest ROF to lowest ROF. This will provide a relative risk raking for all pipeline segments.

5. Using the relative risk ranked pipeline segments, create a Baseline Assessment Plan (BAP) that details the year of assessment for each pipeline segment.

6. Verify that the BAP schedule meets all of the schedule requirements of Subpart O, including inspecting all of the pipeline segments by December 17, 2012. Additional rules for scheduling are detailed in section 2.3.

7. IMG selects the assessment method for each pipeline segment based on the applicability of the method to address the potential threats to the integrity of that segment. The potential threats are discussed in Section 3. The methods that IMG may use for each integrity threat is shown in Table 2-1.

8. In Line Inspection includes, but is not limited to Magnetic Flux Leakage (MFL) metal loss tools, and Multi-channel caliper/deformation tools. Additional technologies are discussed in section 2.1.1

9. Direct Assessment is not initially to be used on the GRS system.

10. Hydrostatic test refers to a DOT 192 Subpart J qualifying hydrostatic test as discussed in section 2.1.2.

11. If IMGI intends to use a method other than the above it will notify PHMSA and appropriate state agencies at least 180 days prior to start of the assessment.

12. Verify that the selected inspection method is appropriate for identified threats.

13. Conduct assessments as scheduled.

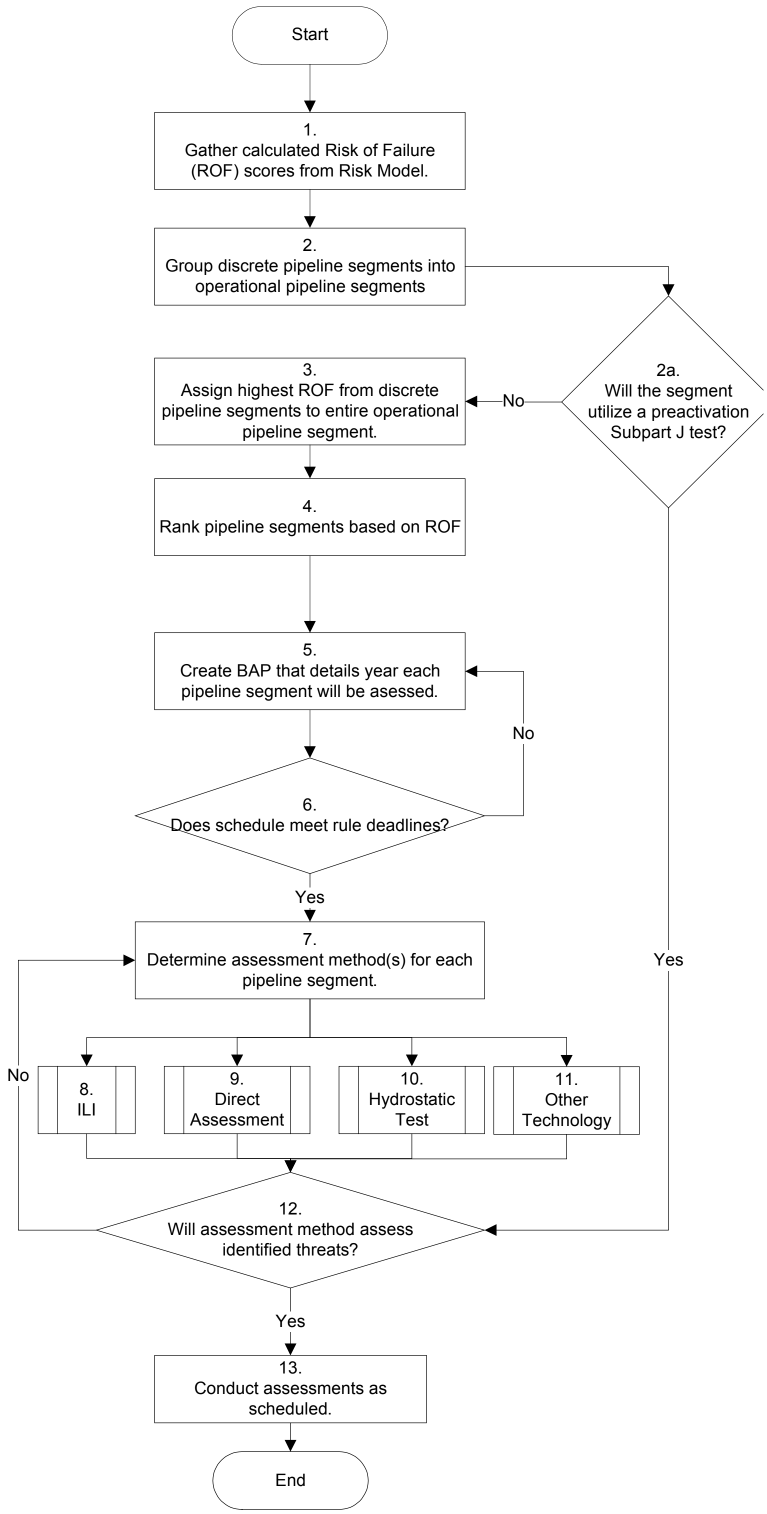


Figure 2-1 Flowchart of the Baseline Assessment Process

Table 2-1. Assessing Integrity for Modes of Threat

• Time Factor	• 9 Failure Categories[1]	• 21 Root Causes[2]	• Possible Assessment Method
Time-dependent	• External corrosion • Internal corrosion • Stress corrosion cracking (SCC)	• External corrosion • Internal corrosion • Stress corrosion cracking (SCC)	• In-Line Inspection • Direct Assessment • Hydrostatic Test
Stable	Manufacturing-related defects[3]	• Defective pipe seam • Defective pipe	• ILI • Hydrostatic test
	Welding-, fabrication-, or construction-related defects	• Defective pipe girth weld • Defective fabrication weld • Wrinkle bend or buckle • Stripped threads/broken pipe/coupling failure	• ILI • Hydrostatic test
	Equipment failures	• Gasket or O-ring failure • Control/relief equipment malfunction • Seal or pump-packing failure • Miscellaneous	• Discovered and remediated in the course of scheduled maintenance • Hydrostatic test.
Time-independent	Third-party or mechanical damage	• Damage inflicted by 1st, 2nd, or 3rd parties (instantaneous/ immediate failure) • Previously damaged pipe (delayed failure mode) • Vandalism	• Preventative measures (ROW inspection, responding to one-call requests, etc). • In-Line Inspection • Direct Assessment
	Incorrect operations; human error	Incorrect operational procedure	Not detectable by ILI, DA or hydrostatic test. Discovery only possible by direct observation, review of data, or admission by the person involved.

• Time Factor	• 9 Failure Categories[1]	• 21 Root Causes[2]	• Possible Assessment Method
	Weather-related and outside force damage	• Cold weather • Lightning • Heavy rains or floods • Earth movement	• Direct observation and interpretation of ground features by trained personnel. • Preventative measures (proper design using company standards)
Other	Cyclic fatigue; other loading conditions	All other potential threats (unknown[4])	Integrity Management Supervisor or his designee to evaluate on individual basis.

[1] Must be used when applying the prescriptive integrity management method (ASME B31.8S, section 2.2 and Appendix A.)

[2] Must be used when applying the performance-based integrity management method. (ASME B31.8S, section 2.2)

[3] Including the use of low-frequency ERW and lap-welded pipe, or other pipe potentially susceptible to manufacturing defects.

[4] References to 22 root causes include a category identified as "unknown."

2.1.1 In-Line Inspection

In-line inspection is used to locate and quantify anomalies in the pipe such as internal and external corrosion, SCC, or mechanical damage. ILI tools can be either product-driven or cable-pulled.

The IMG Integrity Engineers select in-line inspection tools to match factors known about the pipeline and expected anomalies with the capabilities and performance of the ILI tool. The IMG shall consider the following prior to selecting an ILI tool for assessment:

- Detection sensitivity sufficient to identify the predetermined minimum defect size
- Classification of the types of anomalies to be identified
- Sizing accuracy to enable prioritization of GRS's response
- Location accuracy
- Result reporting needed for defect assessment

The Integrity Engineer provides the ILI vendor a pipeline questionnaire with the significant parameters and characteristics of the pipeline segment including, but not limited to:

- Pipeline characteristics and known impediments such as valve bore and bend radius
- Launcher and receiver design information
- Pipe cleanliness
- Proposed flow rate, pressure, and temperature for the inspection

Potential ILI vendors are evaluated based on the following:

- Confidence level of the ILI method they employ
- Performance history of their ILI method/tool
- Success rate of their surveys
- Ability of their tool to inspect the full length and full circumference of the pipeline section, specifically considering the operating pressures of GRS's transmission pipeline system
- Ability to indicate the presence of multiple cause anomalies
- Ability to conform with API 1163, ASNT ILI PQ, and NACE 35100

The following types of ILI tools have been identified for possible assessment. Typical allowable tool specifications are detailed for each technology. The Integrity Engineer reserves the right to deviate from the specifications when necessary.

Magnetic Flux Leakage (MFL) Tools

An instrumented in-line inspection tool designed to record metal loss by inducing a longitudinally oriented magnetic field in a pipe wall between two poles of a magnet. Sensors record changes in the magnetic flux (flow) that can be used to evaluate metal loss. MFL tools may be used to assess pipelines with the following threats:

- external corrosion
- internal corrosion
- third party/mechanical damage
- Typical Detection Specifications
- Isolated Metal Loss (Anomaly area <3t x 3t)
    - Minimum depth for sizing accuracy 0.2t
    - Sizing Accuracy (depth) +/-0.1t
    - Sizing Accuracy (length) +/-0.40"
- Area-type Metal Loss (Anomaly area <3t x 3t)

- Minimum depth for sizing accuracy 0.1t
- Sizing Accuracy (depth) +/-0.1t
- Sizing Accuracy (length) +/-0.80”

- Location Accuracy
  - Axial +/-0.1%
  - Circumferential +/-15° (30 minutes of clock orientation)

Multi-Channel Caliper/Deformation Tools

An instrumented in-line inspection tool designed to record conditions, such as dents, wrinkles, Ovality, bend radius and angle by sensing the shape of the internal surfaces of the pipe. Multi-channel caliper tools may be used to assess the following threats:

- third party/mechanical damage
- outside force damage

Typical Detection Specifications

- Reporting Threshold, 2%
- Deformation (depth), +/-0.14”
- Ovality (depth), +/-0.14”
- Location Accuracy
  - Axial +/-0.1%
  - Circumferential +/-15°

Transverse Flux Tools

A transverse flux tool is an instrumented in-line inspection tool that magnetizes the pipe wall circumferentially to optimally detect longitudinally oriented narrow anomalies such as narrow axial corrosion. It can also detect additional metal loss anomalies. Transverse Flux tools may be used to assess pipelines with the following threats:

- external corrosion
- internal corrosion
- Manufacturing related defects (specifically low-frequency ERW pipe anomalies)(N/A)

Ultrasonic Tools – Shear Wave

An instrumented in-line inspection tool designed to find longitudinal cracks in pipelines. Transducers emit ultrasonic signals either through a liquid couplant or a wheel couplant angularly to assess for cracks. Because a liquid couplant will require a shutdown of a pipeline for an extended period of time and wheeled coupled tools are not commercially available for small diameter pipelines, this technology has limited usefulness for GRS. Ultrasonic tools may be used to assess pipelines with the following threats:

- Fatigue cracks
- SCC
- Manufacturing related defects.

In-Line Inspection Process

The following process outlines the steps that the IMG takes to assess a GRS's pipelines using ILI technology. The process is valid for both cable pulled and product driven inspection tools. An Integrity Engineer typically implements the process.

1. Identify pipeline segments for inspection with ILI technology based on anticipated threats.
2. Select an ILI technology and vendor. Factors to consider include the type and size of predicted anomalies, pipeline flow characteristics, and pipeline construction (i.e. bend radius, appurtenances, diameter changes, off takes…)
3. Pipeline maps, "as-builts", and other historical records are analyzed for potential worksites that may reduce the likelihood of a successful inspection.
4. Clean the pipeline using a suite of cleaning pigs. A typical cleaning plan will include a poly-coated foam pig, a solid urethane cup pig, and a steel mandrel brush/magnets cleaning pig. The cleaning pigs should be run in order of least aggressive to most aggressive, and some cleaning pigs may need to be run multiple times. The Integrity Engineer will determine when the pipeline is adequately clean for the ILI tool. Typically the pipeline is clean enough for the ILI tool when the cleaning pigs are received from the pipeline lightly coated in debris and not pushing a slug of debris.
5. Run vendor supplied gauge plate pig to assure the ILI tool can safely navigate the entire pipeline segment.
6. Inspect the pipeline with the ILI tool(s). Efforts will be made to run the ILI tool at a constant speed and within the speed range supplied by the vendor.
7. Verify that the ILI tool recorded acceptable data for the entire pipeline segment. If necessary rerun the ILI tool.

ILI Report Acceptance and Validation

The following process on next page will be used to accept and validate all ILI reports.

Process for accepting and validating an ILI Report

This process outlines the steps that the IMG takes to accept and validate ILI results. The process is typically implemented by an Integrity Management Engineer This process shall be performed after receiving either a preliminary or final ILI report.

1. The Integrity Management Engineer will receive the ILI report from the inspection vendor. The Integrity Management Engineer should record the date that the ILI report was received.

2. The ILI report shall be reviewed for completeness. The final report should meet the Inspection Vendor's published specification. Data should be collected for the entire length. Any deviation from the above shall be approved by the Supervisor of Integrity Management.

3. For pipelines that have been inspected by ILI previously, compare the new ILI report to the historical ILI report. Also compare field measurements from previous digs to reported anomalies in new ILI report. A complete analysis is not required. Spot checking to review accuracy is adequate.

4. Does the report appear to be complete and accurate? Items that may make a report incomplete or inaccurate include missing data, inability to correlate data to previous excavations, and conflicting reported data (i.e. spreadsheet states a metal loss depth of X and the viewing software states a metal loss depth of Y). The Integrity Management Engineer may accept lower quality data (i.e. data from a speed excursion) if additional analysis is to be performed.

5. Accept report. The report at this time is considered to be accurate, and the invoice can be paid.

6. All anomalies called out by the ILI report must be evaluated for Immediate Repair Condition. See Section 5.1.5 of this plan for Immediate Repair Conditions.

7. Were any anomalies found to meet the immediate repair condition?

8. Lower the pressure to a level not to exceed 80% of the operating pressure at the time of the immediate repair condition discovery.

9. Classify all remaining anomalies as either scheduled or monitor conditions. Select anomalies for visual inspection. Document process and results.

10. Excavate all anomalies chosen for visual inspection. Record and document results of digs on Pipeline Integrity Anomaly Report form.

11. Compare dig results with reported anomaly depth, length, and orientation.

12. Verify that anomalies meet ILI vendor's published tool specification.

13. If the dig results meet the ILI vendor's published tool specs the results are validated. Document results. Share excavation results with ILI vendor.

14. If the ILI results do not meet the published tool specifications, the ILI report should be re-issued. The new report must be reanalyzed to assure all anomalies are appropriately classified and if necessary excavated.

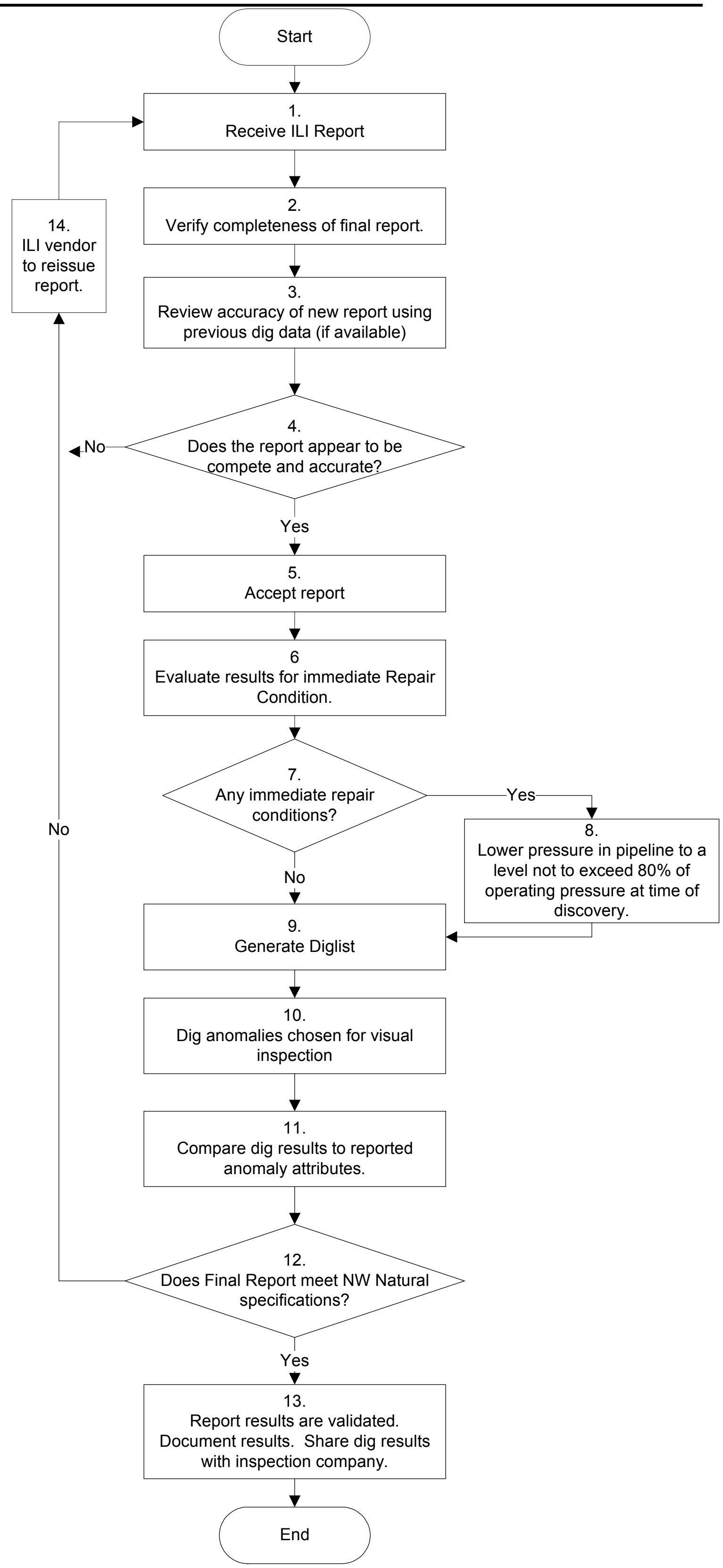


Figure 2-2. Process for accepting and validating an ILI Report

2.1.2 Pressure Testing

Pressure Testing (also referred to as Hydrostatic Testing or Hydrotesting) can be both a strength test and a leak test. Pressure testing conducted in accordance with the requirements in Part 192, Subpart J, and ASME B31.8S-2004 may be used to assess the following threats (note: if the language in the rule and ASME B31.8S-2004 conflict, the rule takes preferences):

- Time-dependent threats such as external corrosion, internal corrosion, or SCC.
- Manufacturing-related threats such as faulty pipe seams.

Any section of pipe that fails a pressure test will be examined to determine whether or not the failure was really due to the assumed threat. If it was due to some other threat, that information must be integrated into the TIMP database and the segment reassessed for risk relative to the other threat.

GRS's hydrostatic pressure test procedure is detailed in procedure CT37 of the GRS Operator Qualification Program and GRS Standard Practice (Appendix B).

2.1.3 Direct Assessment

Direct assessment (DA) is another acceptable method for a baseline assessment of pipe for the threats of external corrosion, internal corrosion, and SCC. Since All GRS pipelines and pipe segments are pigable or may be pressure tested, the IMG does not intend to use DA for GRS pipelines. Should the IMG determine the use of DA is appropriate a plan will be developed in Section 4 of this Program Plan.

2.1.4 Inspection Method for Low-Frequency Electric-Resistance-Welded (ERW) Pipe

All GRS's pipelines were constructed of new pipe, fabricated many decades after low frequency manufacturing methods ceased. No GRS pipelines were constructed of low-frequency pipe that meets the criteria established in Section 3.1.3, Electric-Resistance-Welded (ERW) Pipe.

GRS does not have any lap welded pipe in its transmission pipeline system.

2.1.5 Inspection Method for Plastic Transmission Pipeline

GRS has no plastic transmission pipelines at this time. If plastic transmission lines are added in the future, a program will be developed.

2.1.6 Other Methods and PHMSA Notification

If the IMG intends to use a method other than in-line inspection, pressure testing, or direct assessment as a baseline assessment method, the IMG will notify PHMSA and the appropriate state pipeline safety authority, at least 180 days before conducting the assessment. Section 14 of this Program Plan describes how the company communicates with PHMSA, in accordance with §192.949.

2.2 Choosing Integrity Assessment Methods

The integrity threats to each pipeline segment will be analyzed and the appropriate assessment method to detect the effect of that threat will be selected NWN Supervisor of Integrity Management or his designee will review and approve. The following guidelines are used to determine the appropriate assessment method:

Pipeline gas flow driven ILI technology will be used, if applicable, on covered transmission lines that meet the following criteria:

- Pipeline segments that have sufficient pressure and flow to meet ILI tool vendor requirements,
- Pipeline segments that are currently pigable or can be modified to become pigable within resource limitations and time constraints, and
- Pipeline segments of continuous significant length (generally greater than one mile),

Pipeline segments selected for ILI inspection will typically be inspected with a multi-channel caliper tool and a high resolution MFL metal-loss tool. The multi-channel caliper tool will be used to measure the depth, length, width, and orientation (o'clock) position of deformation anomalies on the pipe. A high-resolution magnetic flux leakage (MFL) tool will be used to characterize the length, depth, and width of metal loss anomalies such as corrosion. Pipeline segments that do not meet the above criteria for gas driven ILI assessment will be evaluated for cable pulled ILI, or hydrostatic testing to assess the pipeline threats.

Pipeline segments selected for cable pulled ILI will typically be inspected with a multi-channel caliper tool and a high-resolution MFL metal-loss tool. The multi-channel caliper tool is used to measure the depth, length, width, and orientation (o'clock) position of deformation anomalies on the pipe. A high-resolution MFL tool is used to characterize the length, depth, and width of metal loss anomalies such as corrosion. If a caliper tool is not available for the cable pulled pipeline segment, the MFL tool can be used to locate Deformation Anomalies. Pipeline segments selected for hydrostatic test will be by a pressure test in accordance with 49 CFR, subpart J, and to a pressure specified by table 3 of section 5 of ASME B31.8S.

Newly constructed pipeline segments will use hydrostatic test for baseline assessment. Hydrostatic tests will be completed using the GRS Standard Practice (see Appendix B).

2.3 Prioritized Schedule

Section 192.921(g) specifies that operators of newly installed pipe may conduct a pressure test, per Subpart J, to satisfy the requirement for a baseline survey. All GRS gas transmission pipelines and gas processing plant piping was newly installed in the spring and summer of 2010. GRS will use the initial hydrostatic tests of: the 30 inch diameter transmission line between the gas processing plant and PG&E line 401 tie-in site; all the injection/withdrawal lines; and the appropriate plant piping for the baseline assessment plan (BAP). All applicable elements of the GRS will be included in the BAP.Thus all priorities are essentially the same.

The IMG prioritizes the covered pipeline segments for subsequent assessments according to a risk analysis that considers the potential threats to each segment. Pipeline segments that contain both HCA and non-HCA sections, only the HCA impact segments will be used to prioritize pipeline segments.

Each pipeline segment will be given an integrity priority score that is calculated using data from the risk model. Segments of a continuous pipeline that have different risk scores may be grouped together in the BAP to allow for assessment efficiency. Grouped segments that contain multiple non-contiguous HCA impact segments will use the HCA impact segment with the highest relative risk for prioritizing. The final HCA schedule will meet the deadlines as reported in table 2-3.

Table 2-3. Baseline Assessment Due Dates

Category of Pipe	Due Date for Assessment
All pipe covered by §192.901	December 17, 2012
Pipe in newly discovered HCAs	Within 10 years of identification
Newly installed pipe	Within 10 years of installation (Post-installation pressure test is acceptable)

2.4 Use of Prior Assessments

Section 192.921(e) of the federal code was written to allow the use of assessments prior to December 17, 2002 for the baseline assessment. It does not apply to GRS since all of its pipelines are constructed in 2010 or later.

2.5 Newly Identified HCAs and Newly Installed Pipe

GRS will meet the following schedule for assessing covered pipeline segments where new HCAs have been identified or new pipeline segments have been installed.

For applicable pipeline segments in newly identified HCAs:

- Gather data, identify threats, assess risk, and include in the Baseline Assessment Plan within 1 year from the date of identification of the new HCAs.

- Complete the baseline assessment of the applicable segments within 10 years from the date the area is identified.

For newly installed pipe segments that impact a previously identified HCA:

- Gather data, identify threats, assess risk, and include in the Baseline Assessment Plan within 1 year from the date of installation of the new pipe.
- Complete the baseline assessment of the applicable segments within 10 years from the date the new pipe is installed.

2.6 Consideration of Environmental and Safety Risks

GRS has procedures to ensure that it conducts its baseline assessments in a manner that minimizes environmental and safety risks.

This section refers to current company operator qualification procedures, which promote safety and environmental best practices.

2.6.1 Minimizing Environmental and Safety Risks during Baseline Assessments and Reassessments

In-Line Inspection

In-line inspection will be performed as described in the GRS Operator Qualification procedures appropriate for performing an inline inspection.

- CT41, Operate Pressure Relieving Devices for Launching and Receiving Facilities
- CT60.3, Recognize and Respond to Physical Damage to the Pipeline System.
- CT60.6, Prevention of Accidental Ignition

Direct Assessment

- GRS is not using ECDA, ICDA, or SCCDA and will develop fully documented plans to minimize environmental and safety risks prior to electing to use these methods.

2.6.2 Hydrotesting

Hydrotesting will be performed as described in the GRS Operator Qualification procedure CT37, “Conduct Pressure Test”.

2.7 Changes to Baseline Assessment Plan

The Baseline Assessment Plan will be updated once each calendar year, not to exceed 15 months, to incorporate new information obtained that affects threats, consequences, changes in HCA’s, addition or removal of pipeline segments, and the completion of pipeline assessments or other minor changes.

BAP updates will conform to the Management of Change requirements described in section 11 and include the following information:

- Reason for the change.
- Authority for approving the change.
- Analysis of any implications.
- Communication of the change to the affected parties.

3. Threat Identification, Data Integration, & Risk Assessment

This section describes the process by which the NWN IMG identifies and analyzes the risk of potential threats to the integrity of covered segments located in the HCAs on the pipeline. Figure 3-1 Diagrams this process.

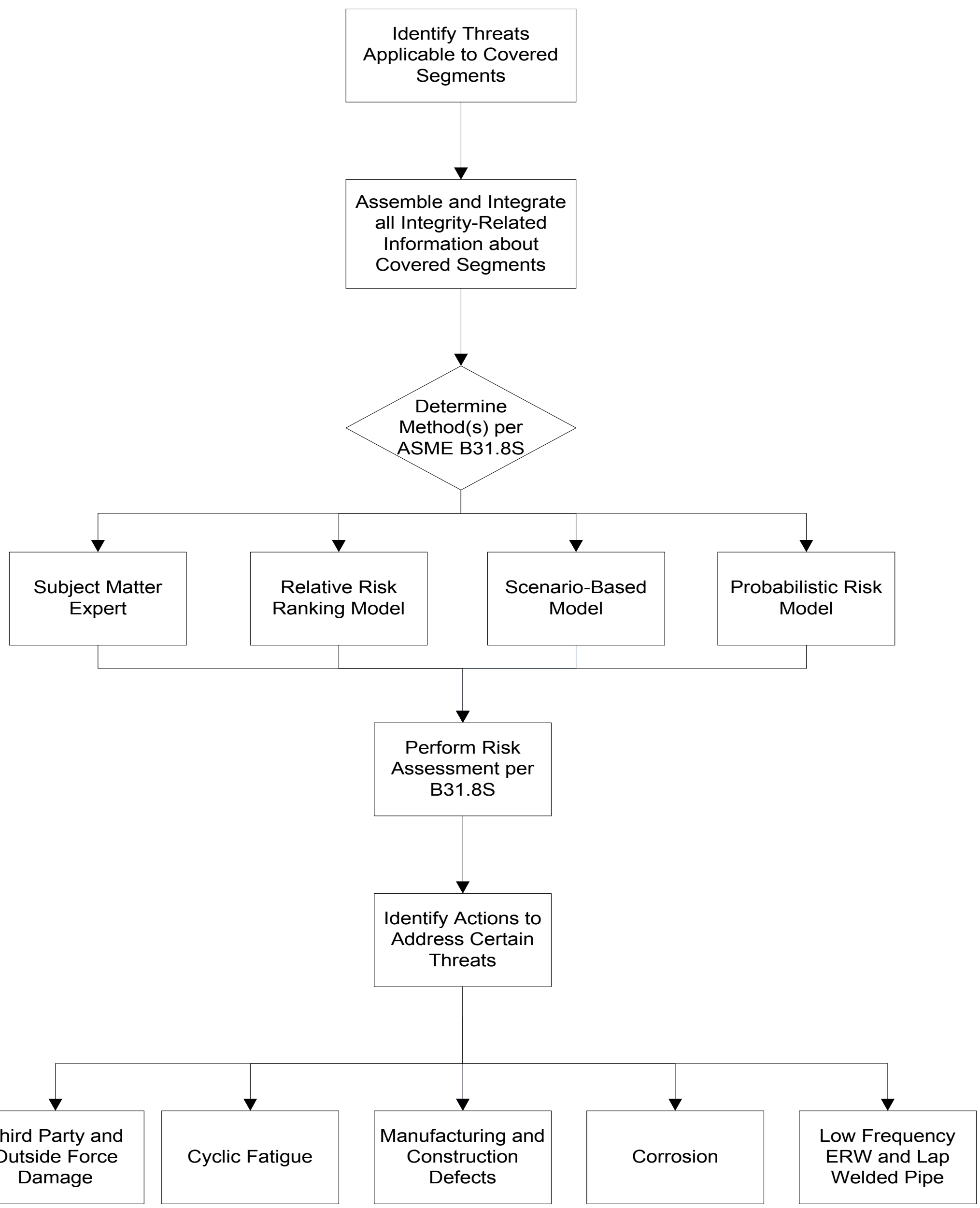


Figure 3-1. Flowchart of Threat Identification and Risk Assessment

3.1 Threat Identification

The IMG will identify the threats for each covered pipeline segment in each HCA and perform a risk assessment of those threats. This identification and assessment of threats is the first element in the baseline assessment plan (Section 2 in this Program Plan).

Table 3-1 lists the classifications of integrity threats according to time factors, as identified in ASME B31.8S, section 2.2.

Table 3-1. Integrity Threat Classification

<table>
<tr><th>Time Factor</th><th>9 Failure Categories[1]</th><th>21 Root Causes[2]</th></tr>
<tr><td>Time-dependent</td><td>• External corrosion
• Internal corrosion
• Stress corrosion cracking (SCC)</td><td>• External corrosion
• Internal corrosion
• Stress corrosion cracking (SCC)</td></tr>
<tr><td rowspan="3">Stable</td><td>Manufacturing-related defects[3]</td><td>• Defective pipe seam
• Defective pipe</td></tr>
<tr><td>Welding-, fabrication-, or construction-related defects</td><td>• Defective pipe girth weld
• Defective fabrication weld
• Wrinkle bend or buckle
• Stripped threads/broken pipe/coupling failure</td></tr>
<tr><td>Equipment failures</td><td>• Gasket or O-ring failure
• Control/relief equipment malfunction
• Seal or pump-packing failure
• Miscellaneous</td></tr>
<tr><td>Time-independent</td><td>Third-party or mechanical damage</td><td>• Damage inflicted by 1st, 2nd, or 3rd parties (instantaneous/immediate failure)
• Previously damaged pipe (delayed failure mode)
• Vandalism</td></tr>
</table>

Time Factor	9 Failure Categories[1]	21 Root Causes[2]
	Incorrect operations; human error	• Incorrect operational procedure
	Weather-related and outside force damage	• Cold weather • Lightning • Heavy rains or floods • Earth movement
Other	Cyclic fatigue; other loading conditions	• All other potential threats (unknown[4])

[1] Must be used when applying the prescriptive integrity management method. (ASME B31.8S, section 2.2 and Appendix A.)

[2] Must be used when applying the performance-based integrity management method. (ASME B31.8S, section 2.2)

[3] Including the use of low-frequency ERW and lap-welded pipe, or other pipe potentially susceptible to manufacturing defects.

[4] References to 22 root causes include a category identified as "unknown."

3.1.1 Prescriptive Approach

Initially, the GRS Plan will use only the prescriptive approach to integrity management. When using this method, nine categories of failure types must be considered in the threat assessment for each covered pipeline segment. These threats are listed in the "9 Failure Categories" column in Table 3-1.

Covered pipeline segments may be subject to more than one threat category at the same time. The interaction of some threats may cause more risk than each of the risks considered separately. In such cases, GRS considers the possible interaction of these multiple threats and adjusts the risk priority. It should be noted that no reference information to estimate the multiplier for combined risk are given in ASME B31.8S. The threat interaction algorithm is contained within the risk model.

3.1.2 Performance-Based Approach

As the IMG develops a more extensive GRS database of information, the GRS Plan may change to a performance-based method. If it is determined to use the performance-based method, a process will be developed at that time.

3.1.3 Action to Address Particular Threats

Some threats require specific action to assess and mitigate the cause. The IMG will address the following threats, if found, in accordance with §192.917(e):

Third-Party Damage

Comprehensive preventive measures must be taken for any covered pipeline segment for which third-party damage is identified as a potential threat. To determine the susceptibility of any segment to the threat of third-party damage, the IMG will integrate data from additional sources with the results from the applicable threat assessment. Examples of these additional sources include those listed in ASME B31.8S, Section A7.2:

- Reports of vandalism.
- Pipe inspection reports indicating the pipe has been damaged by probable 3rd-party activity.
- A leak report indicating the pipe has been damaged by probable 3rd-party activity.
- Reported Incidents caused by existing mechanical damage.
- In-line inspection reports for dents and gouges on the top half of the pipe.
- One-call locate records.
- Encroachment records.

The IMG also considers historically high-risk areas of third-party damage when assessing the third-party damage threat. In addition, aerial and surface patrols can indicate an increase in construction or development activity and a consequent higher risk for third-party damage.

The IMG integrates third party damage information with assessment results using the following process. The process is typically implemented by an IMG Integrity Engineer and is performed during the dig-list generation.

- Integrity Engineer to obtain an ILI report from the vendor.
- Integrity Engineer will review, prioritize and locate all anomalies (see Section 5, Remediation).
- Anomalies that could be caused from third party damage (such as top side dents) are matched to company pipeline information for records of: possible pre-existing damages, foreign line crossings, repair documentation, or other information to potentially explain the presence of an anomaly.
- If necessary, the Integrity Engineer will visit anomaly site to search for field information that may explain the cause of the anomaly. The site inspection should look for signs of utility crossings, landowner encroachments, or land disturbances.

- An anomaly that does not meet the requirements of monitor, scheduled or immediate repair condition may be upgraded in priority by the Integrity Engineer due to possibility of third party damage.

Section 5, Remediation, describes how the GRS Plan responds to discoveries of damage, including third-party damage.

Cyclic Fatigue

Covered pipeline segments located in places or on structures where anticipated physical movement or external loading could cause failure or leakage requires additional analysis. The IMG will also evaluate the threat of cyclic fatigue for covered pipe segments that have a history of significant pressure cycles.

Such segments will be evaluated to determine if the presence of other threats such as the failure due to a dent, gouge, or other defect could be exacerbated by cyclic fatigue.

GRS will integrate data from these evaluations and the results from the applicable threat assessments into the Baseline Assessment Plan and adjust the priority of the covered segments' risk accordingly.

Manufacturing and Construction Defects

The IMG will evaluate covered segments that have a known or suspected manufacturing or construction defect, including seam defects, to determine the risk of failure. The results of prior assessments must be included in the analysis.

Such defects can be considered stable if the operating pressure in the covered segment is not greater than the highest operating pressure the segment experienced during the 5 years preceding identification of the HCA, or if the pipeline has a successful Subpart J pressure test.

Any manufacturing and construction defects that survive the Subpart J pressure test are considered to be stable and not subject to failure, unless other threats adversely affect the stability of the residual manufacturing and construction defects. The IMG will conduct its threat identification analysis in sufficient detail to identify if other interacting threats could adversely affect the stability of residual manufacturing and construction defects.

The IMG will examine any changes in the operating conditions and assign the segment a high-risk priority in the baseline assessment, or subsequent reassessment, if it finds any of the following conditions:

- Increase in the operating pressure above the historical operating pressure (highest pressure recorded in the preceding 5 years),

- Increase in MAOP, or
- An increase in stresses that lead to cyclic fatigue.

Electric-Resistance-Welded (ERW) Pipe

The IMG will select an assessment method capable of assessing seam integrity and seam corrosion anomalies if a covered pipeline segment is susceptible to seam related integrity threats. The criteria for seam integrity assessment of pipeline segments containing ERW are: 1) if a covered or non-covered segment of the pipeline system has experienced a seam failure ; or 2) if the operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. To be excluded from a seam integrity assessment plan, any seam related service failure must be entirely explainable as a non-time related event. GRS pipe was produced decades after the last Low Frequency ERW and Lap Welded pipe was manufactured. Therefore, the process established in OPS TTO5 “Low Frequency ERW and Lap Welded and Longitudinal Seam Evaluation” to determine susceptibility of seam related integrity threats does not apply.

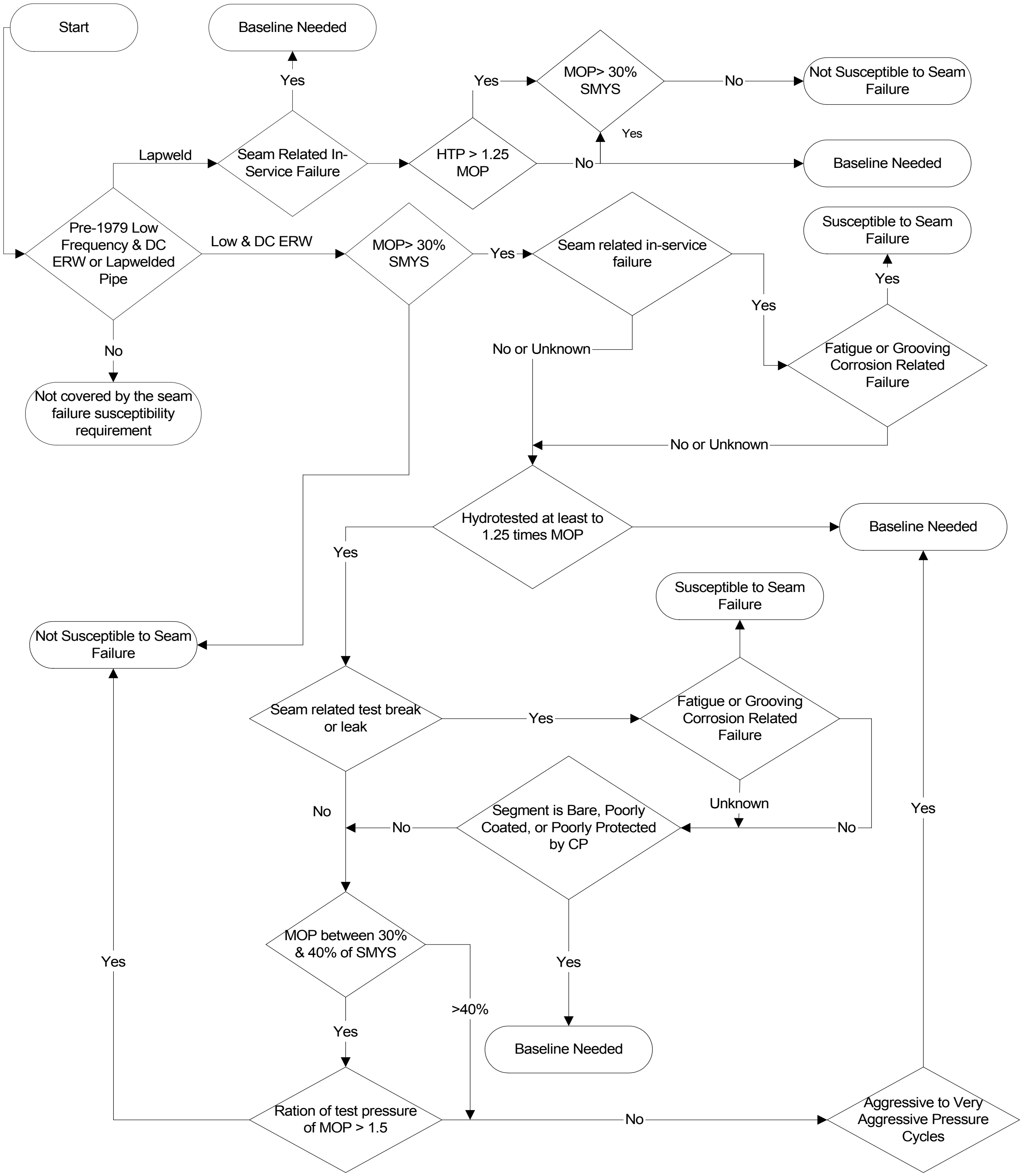


Figure 3-2 – Process flow chart from OPS TT05 for Low Frequency ERW seam evaluation

The results of this analysis will be documented for each transmission pipeline segment and saved in the NWN IMG GRS files.

GRS has no lap-welded pipe in the transmission pipeline system.

Corrosion

If the IMG finds a corrosion condition that could affect integrity on a segment covered by the rule, it will establish a schedule for evaluating all pipeline segments, both covered and non-covered, with similar material coating and environmental characteristics and makes remediation as necessary. The IMG interprets a corrosion condition to mean an immediate repair corrosion condition.

Internal Corrosion

The internal corrosion threat on pipelines carrying gas that is usually “dry” is that it may occasionally be subject to an upset that introduces an electrolyte or other corrosion-inducing agent that could accumulate in low points or inclines in the pipeline. The IMG assess the potential for this threat by obtaining and analyzing data that includes but it not limited to:

- Location of all gas input and withdrawal points on the pipeline
- Location of all low points on the covered segments, including sags, drips, inclines, valves, manifolds, dead legs, and traps
- Elevation profile of the pipeline with enough detail to calculate an angle of inclination for all pipe segments.
- Pipeline diameter, with any changes in diameter noted
- Pipe wall thickness
- Operational parameters
- Range of expected gas velocities
- Areas of reduced velocity downstream of draw-off
- Identification of pipelines where gas flow changes directions
- Periods where there is no flow
- Pressure
- Operating stress level (% SMYS)
- Historical pipeline data:
- Year of installation
- Pipe inspection reports (bell hole)
- Past hydrotest information

- Gas, liquid, and solid analyses (particularly hydrogen sulfide, carbon dioxide, free water, and chlorides)
- Results from bacteria culture tests
- Analyses of corrosion detection devices (such as coupons or probes) if devices are available
- Date, area, and nature of upsets and leaks

Stress Corrosion Cracking

The threat of Stress Corrosion Cracking (SCC) results from a combination of a corrosive soil environment and stress. The IMG assesses for an SCC threat if all of the following elements are present:

- MAOP greater than 60% SMYS, and
- Temperature of >100°F, and
- 20 miles or less from a compressor station, and
- Age of pipe is at least 10 years
- All coatings with the exception of Fusion Bond Epoxy (FBE)
- A segment is also assessed for an SCC threat if the segment has a history of SCC and if SCC-inducing conditions have not been corrected:
- One or more service incidents or leaks caused by SCC
- One or more hydrotest failures caused by SCC
- Bell hole inspection that discovers SCC

There are two types of SCC, distinguished by the alkalinity under the coating in which it develops: high pH and near-neutral pH. Both are found only in coatings other than FBE. It should be noted that all GRS pipelines are coated with FBE.

3.1.4 Elimination of Threats from Consideration

If a particular threat appears to not be applicable for a pipeline segment, the IMG reviews pipeline failure history, design, manufacturing, construction, operation and maintenance information for relevance. If the review does not change the applicability of the potential threat, the IMG documents the engineering justification for the elimination of the threat.

3.1.5 Threat Interaction

The presence of multiple threats from different categories can heighten the risk of a pipeline release if the threats can interact with one another. The IMG's risk assessment process evaluates threat interaction and increases the risk rating of a pipeline where the potential of interacting threats exists.

IMG raises the risk score for a threat if interaction with another threat is present using the following steps: The risk algorithm evaluates the potential effect of an interacting threat and derives a risk value for it based on probable occurrence indicated by the pipeline input data. The risk value is multiplied by a weighting factor determined by GRS subject matter experts for the interacting threat. The resultant becomes an additive component of the overall risk score for the threat influenced by the interacting threat. Examples from the risk assessment algorithm include the effect of weather and outside forces (such as land movement) on construction threats, and the effect of pressure cycling on manufacturing related threats. The IMG's assessment of risk will also account for any secondary effects from a pipeline incident, such as an incident occurring in the area of a chemical factory.

3.2 Data Gathering and Integration

The IMG gathers all the data that could be relevant to each pipeline segment, including other covered and non-covered segments that have similar characteristics to the segment being evaluated. The data is evaluated for level of definition or "granularity". The aggregated data is added to the proprietary risk assessment application. It is assigned to each unique segment by station so it can later be retrieved for review or updating. The types of data used depend on the threat being assessed.

Appendix A lists the data elements for a prescriptive transmission pipeline integrity program and the categories of threats that each data element can help assess.

Sources of data may include, but are not limited to, the following:

A. As per §192.917 consider the following:

- Past Incident history
- Corrosion control records
- Continuing surveillance records
- Patrolling records
- Maintenance history
- Internal inspection records
- Any other information specific to a pipeline

B. As per ASME B31.8S, consider the following:

- Process and instrumentation drawings (P&ID)
- Pipeline alignment drawings
- Facility drawings and maps

- As-built drawings
- Original construction inspector notes/records
- Pipeline route aerial photography
- Materials certifications
- Survey reports and drawings
- Safety-related condition reports
- Operator standards and specifications
- Industry standards and specifications
- Operations and maintenance procedures
- Emergency response plans
- Inspection records
- Test reports and records
- Compliance records
- Design and engineering reports
- Technical evaluations
- Manufacturer equipment data
- Data on pipeline conditions and environments
- Root cause analysis of previous failures (once they are available)
- All other conditions specific to each pipeline.

If pipe information is either missing or of poor quality, the IMG follows the processes described in ASME B31.8S, Non-mandatory Appendix A.

1. All the applicable threats will be identified for each covered segment, regardless of whether or not substantiating data is available.
2. If sufficient data is not available for a pipeline segment, the risk assessment for that segment will be based on conservative assumptions or the segment is given a higher priority than might otherwise be the case.
3. The use of any unsubstantiated data will be documented so the impact on the variability and accuracy of the assessment results can be considered.
4. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.

3.2.1 Reviewing Data

The IMG will, once each calendar year, review the data in the risk algorithm to verify the quality and consistency of the data. Records shall be maintained throughout the process that identify where, and how unsubstantiated data is used in the risk assessment process so its potential impact on the variability and accuracy of the assessment results can be considered.

The IMG's review process includes the following features:

- A record of where and how unsubstantiated data is used in the risk assessment process.
- Assurance of a consistency in units.
- Actual data is used rather than assumptions.
- Discounting of the reliability of older data pertaining to time-dependent threats, such as corrosion and Stress Corrosion Cracking (SCC).
- An assumption that unavailable data elements increase the considered risk of a threat.
- Provisions for additional inspections and field data collection for important but missing data elements.

3.2.2 Factoring in Missing Data

Threats with missing data are assumed to be present. The IMG's process for actions when data is missing is interviewing subject matter experts for their knowledge related to the missing data. Conservative values shall be used when assigning values for the missing data from subject matter experts thus erring to the side of greatest risk.

If there is no historical data of the threat resulting in compromised integrity of pipeline, the IMG uses industry data to assess the risk of the threat.

3.2.3 Incorporating New Information

As new information is acquired, the company will incorporate any applicable data into the program in a timely and effective manner, as described in section 11, Management of Change.

3.2.4 Integrating Data

The IMG integrates risk data using proprietary risk management software to consider the synergistic effect of multiple and/or independent facts or data to calculate relative risk for pipeline segments. It gives each segment a unique alphanumeric name and stationing that aligns the risk data in the risk management software.

The combination of the unique name and the stationing gives GRS's system a common reference system. After completing an integrity assessment, GRS will integrate ILI or DA (if used) results with data such as encroachments or foreign line crossings to define areas of potential third-party damage.

3.2.5 Performance-Based Integrity Management Program

As GRS's Integrity Management Program matures, some portions of it may be conducted as a performance-based program. This method uses a more sophisticated risk-assessment process that may include more data elements than those listed in Appendix A of this Program Plan. The results will meet or exceed the results of the prescriptive method.

3.3 Risk Assessment

Risk assessments are used to prioritize integrity management activities and help organize data and information for making accurate and timely decisions. They provide a basis for evaluating the potential impact of different incident types and balancing the results with the likelihood that such events may occur. Risk assessments are also used to identify locations for integrity assessments and the resulting mitigative action.

GRS's TIMP Plan's objectives for risk assessment are as follows:

- Prioritize operational pipeline segments for scheduling integrity assessment and/or reassessment and mitigation.
- Assess the benefits derived from mitigating actions.
- Determine the most effective mitigation measures for the identified threats.
- Assess the integrity impact from any modified inspection intervals. Assess the use of, or need for, alternative inspection methods.
- Allocate resources more effectively by placing resources on the highest risk ranked, non-assessed pipeline segment.
- Facilitate decisions to address risks along a pipeline or within a natural gas facility, used in collaboration with the site-specific technical information.

3.3.1 Risk Assessment Approaches

For GRS the IMG will use the relative assessment approach to risk. It is a comparative approach based on accumulated data for the GRS system.

Relative Assessment Model

A relative assessment model is a data based method used to identify and quantify known threats and consequences relevant to historical pipeline operations. This is a relative-risk model because the risk results of each segment are compared with the results generated from existing data using the same model. For GRS the IMG uses this model.

Other Risk Assessment Models

Subject Matter Experts (SME) – An approach based on company personnel or contractor expertise. The IMG does not intend to use this model for GRS.

Scenario-Based Model – An approach based on an analysis of an expected course of events. The IMG does not intend to use this model for GRS.

Probabilistic Risk Model – An approach based on the probability that an event will occur. The IMG does not intend to use this model for GRS.

3.3.2 Risk Model Characteristics

The IMG's relative risk assessment approach for GRS was selected to:

- Identify potential events or conditions that could threaten system integrity,
- Evaluate likelihood of failure and consequences,
- Permit risk ranking and identification of specific threats that primarily influence or drive the risk,
- Lead to the identification of integrity assessment and/or mitigation options,
- Provide for a data feedback loop mechanism, and
- Provide structure and continuous updating for risk reassessments.

Attributes

The IMG's relative risk assessment approach for GRS contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk.

Operating/Mitigation History

As a history of operation is established, GRS's relative risk assessment considers the frequency and consequences of past events and account for any corrective action that was taken to prevent recurrence. The risk assessment will incorporate the results of pipeline assessments as they are obtained. Other industry data may be used initially if sufficient GRS data is not available.

Predictive Capability

The IMG selected a relative risk assessment method for GRS that would be able to identify transmission pipeline integrity threats not considered previously, based on pipeline inspections and trend analyses of data collected over time.

Risk Confidence

The IMG will verify and check the data used in the risk assessment for accuracy. The use of any default values used in place of missing or questionable data will be documented. Default values should conservatively reflect the values of other similar pipeline segments. Such substitutions of data may elevate the risk for the segment and will be replaced with actual data as it becomes available.

Feedback

See section 3.3.3, Updating the Risk Assessment.

Documentation

The risk assessment process will be carefully documented to provide a history of the work that was performed and the justification for the decisions that were made.

"What if" Determinations

GRS's relative risk assessment method will, where feasible, perform "what if" calculations to enhance the ability to estimate the effects of changes over time and the potential for risk reduction.

Weighting Factors

GRS's relative risk assessment process includes a structured set of weighting factors to indicate the relative level of influence of each risk assessment component.

Structure

GRS's relative risk assessment process has the ability to compare and rank the risk result to support the IMP decision process.

Segmentation

GRS's relative risk assessment process incorporates sufficient resolution of pipeline segment size to analyze data, as it exists along the pipeline. This analysis will facilitate location of local high-risk areas that may need immediate attention. Segment lengths can range from units of feet to miles, depending on the pipeline attributes, its environment, and other relevant data.

3.3.3 Updating the Risk Assessment

To provide continuous improvement in the accuracy of the results, the risk assessment will be updated annually. When new information is obtained or conditions change that will have a significant impact on pipeline segments the risk model will be updated.

- The risk for each segment will be recalculated to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions.

- The IMG integrates the risk assessment process into existing field reporting, engineering, facility mapping, and other appropriate company processes to ensure regular updates to the risk model.
- The risk assessment process will be revised if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments.
- The IMG uses a feedback mechanism (periodic IMP review) to ensure that the risk model is subject to continuous validation and improvement.

3.4 Validation of the Risk Assessment

The IMG performs a validation of the Risk Model typically after each update to the Risk Model, such as a data update or an algorithm change. The process can be initiated by any member of the IMG and is outlined in Figure 3-2.

3.5 Plastic Transmission Pipeline

GRS has no plastic transmission pipelines at this time. If plastic transmission lines are added in the future, the Integrity Management Supervisor shall evaluate the pipelines to determine a need and develop a program as required.

This process outlines the steps that the Integrity Management Group takes to validate the results from the Risk Model. The process can be implemented by any person in the Pipeline Integrity Group or his/her designee (tasks typically performed the Integrity Management Engineer). The process typically starts after each update to the Risk Model (either an algorithm change or a data update).

1. Evaluate overall Risk of Failure (ROF) scores. The ROF scores offer the best overview of the Risk Model. The ROF scores can be evaluated either as raw data from the Risk Model or after compiling into the Baseline Assessment Plan (BAP). Recommended practices include looking at the data for drastic changes from a previous update or for pipelines with a noticeable deviation from the core group of scores. Small changes to the risk model will be evaluated internally by the IMG.

2. The Integrity Management engineer will evaluate a selection of pipeline segments identified in the previous step to understand the risk drivers. The Integrity Management Engineer will verify the risk algorithm properly calculated the risk score. The number of segments to evaluate depends on the magnitude of the changes.

3. Were any problems identified during the data drill down? Problems can include but are not limited to missing data, incorrectly entered data, and formula error.

4. Correct errors and rerun the Risk Model.

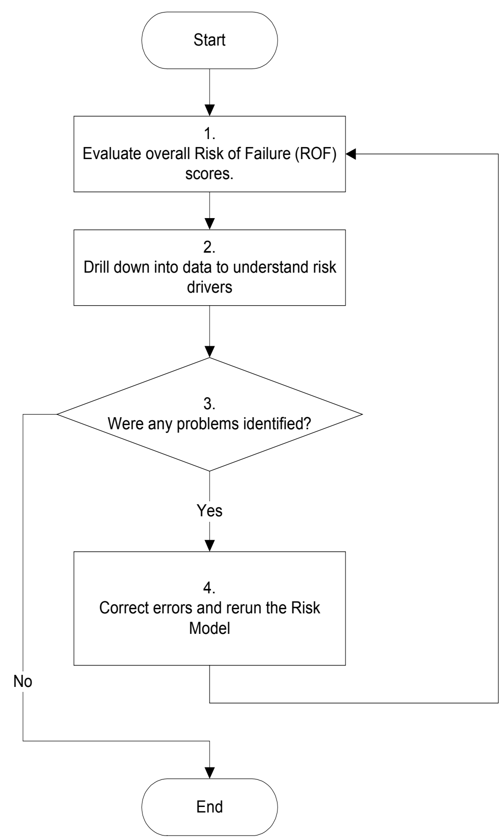


Figure 3-2 Flowchart for the validation of the risk model

4. Direct Assessment Plan

The IMG intends to use Inline Inspection or Hydrotesting for assessing the GRS transmission pipelines. The IMG will not initially use ECDA, ICDA or SCCDA. Should these methods become appropriate, the IMG will develop a process for these direct assessment methods.

5. Remediation

This section describes the process for the remediation of any anomalous conditions found during integrity assessments. NWN's IMG will manage the remediation process for GRS. The IMG and field teams will, at a minimum,

- Evaluate all anomalous conditions and remediation in a timely manner, those that could reduce a pipeline's integrity,
- Select a remediation method that will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment,
- Generate and maintain records that document these processes, and
- Follow guidelines to protect workers, the public, and the environment.

Throughout this IMP Program Plan, the term "remediation" is used to describe the addressing of a defect through

- Repair, replacement, or operating pressure reduction, or
- Operating pressure reduction in combination with repair or replacement.

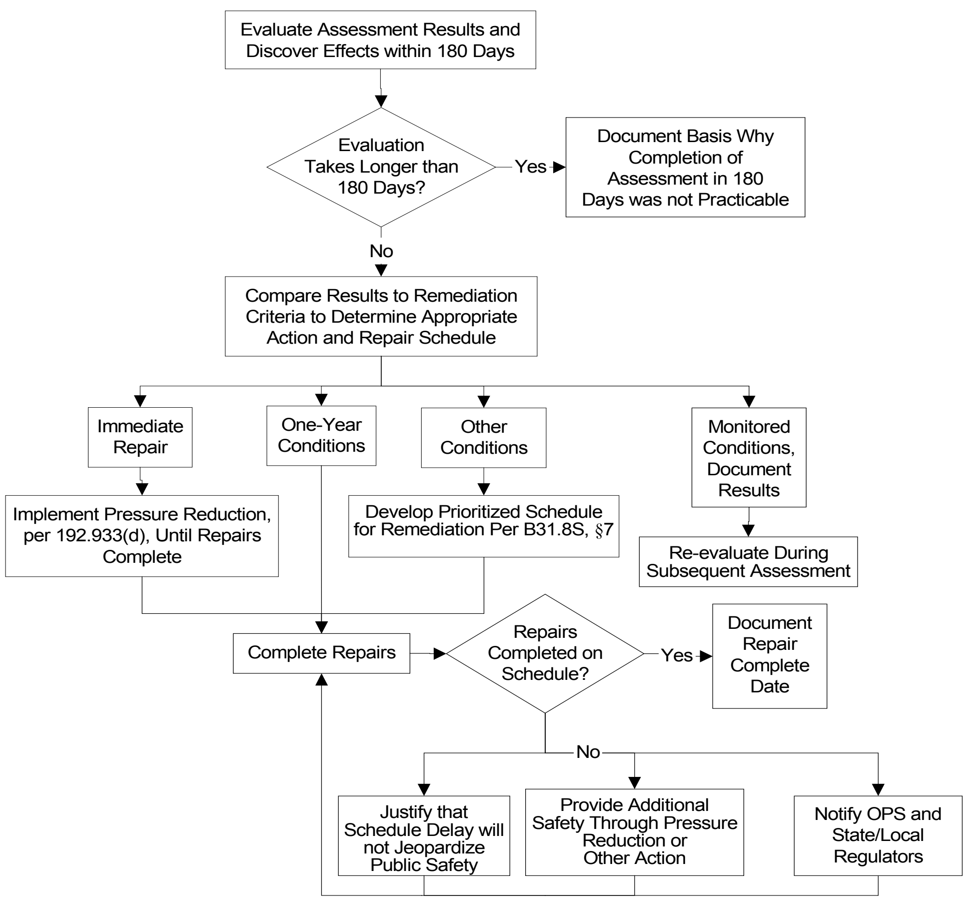


Figure 5-1. Overview of the Remediation Process

5.1 Program Requirements for Discovery, Evaluation, and Remediation Scheduling

Discovery of condition occurs when the IMG has adequate information to determine that the condition presents potential threat to the integrity of the pipe. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring. Discovery of a condition can occur through a scheduled integrity assessment or though any other means, such as an aerial or ground patrol, or routine maintenance.

The IMG promptly reviews assessment reports for any immediate response indications. The reviews for other indications may occur during the initial review of the results of the integrity assessment data, or after historical, site related, operational, and maintenance records are integrated with assessment data. ILI vendors are required to notify the IMG promptly on discovery of likely immediate conditions.

All review and analysis processes leading to the discovery of a known condition must be complete no later than 180 days from the completion date of the integrity assessment data gathering. The completion date of an integrity assessment data gathering is defined as:

- For assessment by ILI – the date the ILI tool successfully records credible, complete data for the entire pipeline segment. For pipeline segments assessed using multiple ILI tools run within a few days of each other, the date is defined as the date the final ILI tool successfully records credible complete data for the entire pipeline segment. If there are more than a few days between multiple runs, then each run has a separate 180-day timeline.
- For assessment by direct assessment – the date the final indirect assessment is completed.
- For assessment by hydrostatic test – the date that the 49 CFR 192, subpart J hydrostatic test is completed.

Documentation of discovery dates along with other data such as pipeline anomalies, visual inspection results, and final reports of pipeline assessment will be contained in pipeline project file(s). Electronic project files will be kept on a secure network drive. Paper project files will be kept in the NWN IMG GRS office files. Specific details of GRS's TIMP Plan documentation can be found in section 10 of this Program Plan.

5.1.1 Scheduling Remediation

The IMG schedules GRS pipeline repairs and/or emergency reductions in operating pressure according to the types and locations of the condition. Moreover, it prioritizes the schedule based on evaluation and remediation of anomalous conditions.

For indications on the pipeline discovered during integrity assessments, routine inspection or other events, the remediation criteria has been established with three priority levels. These priority levels correspond to the different "conditions" described in the integrity management rule, and are immediate repair conditions, scheduled response conditions, and monitored conditions. Scheduling of remediation may be subject to change until all conditions are discovered.

The IMG uses the definitions as provided in table 5-1 to describe these three conditions:

Table 5-1. Repair Definitions

Severity Group	Definition	Required Actions
Immediate repair condition	Indication of a defect at the calculated failure point	The operating pressure must be reduced promptly to a level not exceeding 80% at the time of discovery until the defect is examined. The defect will be promptly examined within a period not to exceed 5 days and promptly repaired.
Scheduled response condition	Indication of a defect that is significant but not at the calculated failure point	• Must examine and remediate within response time of figure 5-2. • Conditions identified in figure 5-3 must be examined and remediated within 1 year of discovery
Monitored condition	Indication of a defect that will not fail before the next inspection	Does not need to be scheduled for remediation Must record and monitor during subsequent risk assessments and integrity assessments for any change that might require remediation

With exception of the anomalies identified in section 5.1.4 of the GRS Plan, scheduled conditions are examined and remediated based on the response time in figure 5-2. If the scheduled reassessment for the pipeline segment is prior to the deadline established by the response time, the anomaly will be reevaluated by the subsequent integrity assessment. Example: if the schedule is determined to be 8 years and the reassessment is scheduled for 7 years, then the anomaly will be re-evaluated at 7 years.

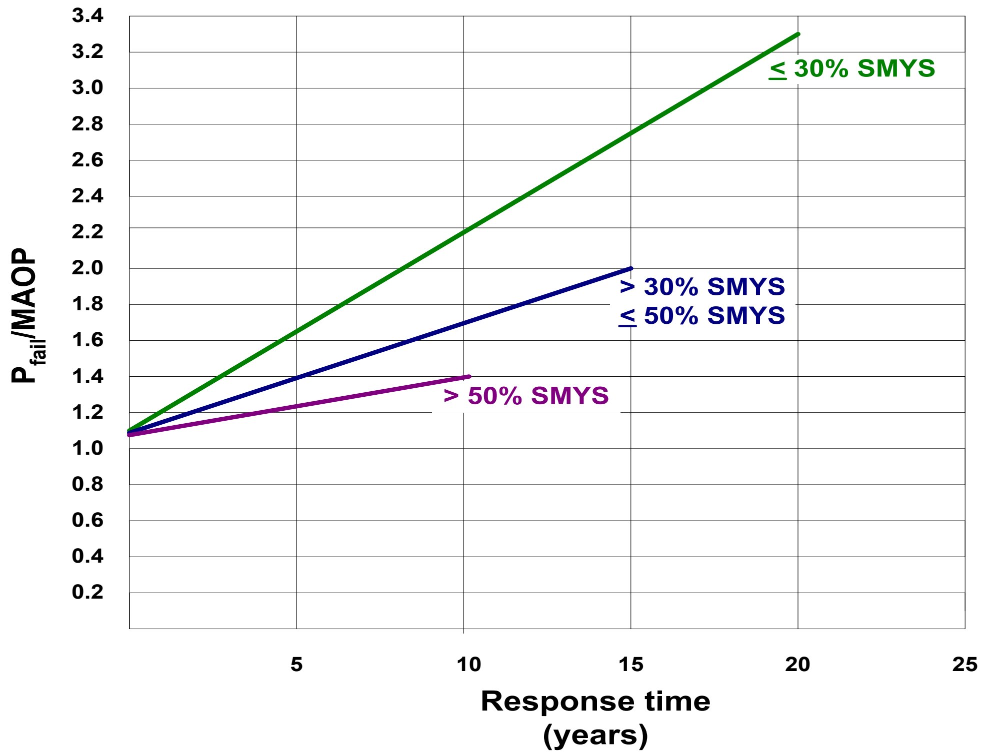


Figure 5-2. Maximum Allowed Response Times for Non-Specified, Scheduled Conditions (Source ASME B31.8S, Figure 4)

5.1.2 Response to Pressure Testing

Any defect that fails a pressure test will be promptly remediated by repairing the defect or replacing the failed section of pipe.

5.1.3 Response to Immediate Repair Conditions

If the IMG discovers an immediate repair condition, it will promptly implement a temporary reduction in operating pressure to a level not exceeding 80% of the pressure at the time the anomaly was discovered or will shut down the pipeline (note: “promptly” means as soon as the pressure reduction can be safely implemented and without undue delay). Pressure at the time of discovery is to be obtained from online pressure monitoring information located at the GRS Operations facility. An IMG Integrity Engineer will use ASME B31G or "RSTRENG." to calculate the appropriate pressure reduction except in situations with metal loss exceeding 80% of wall thickness, which requires repair or replacement. The anomaly will be promptly examined. If it is not possible to complete a remediation of an immediate condition, reduce the pressure or shut down the pipeline within 5 days of discovery, the IMG will notify PHMSA and the California Public Utility Commission (CPUC). The IMG will document the basis for concluding the delay will not impact pipeline safety in the notification.

5.1.4 Deviation from Remediation Timelines

Section 192.193 allows deviation from remediation timelines only for a Performance-based program. GRS is using a Prescriptive-based program. Should GRS move to a Performance-based program in the future, a process will be developed at that time.

5.1.5 Special Requirements for Scheduling Remediation

Figure 5-3 shows the conditions listed in §192.933 and in sections 7.2.1, 7.2.2, and 7.2.3 of ASME B31.8S as requiring immediate repair, scheduled repair, or monitored treatment.

In addition to the conditions shown in Figure 5-3, the IMG also considers conditions under which pipelines operate and gives priority for evaluation and remediation to pipelines in high consequence areas.

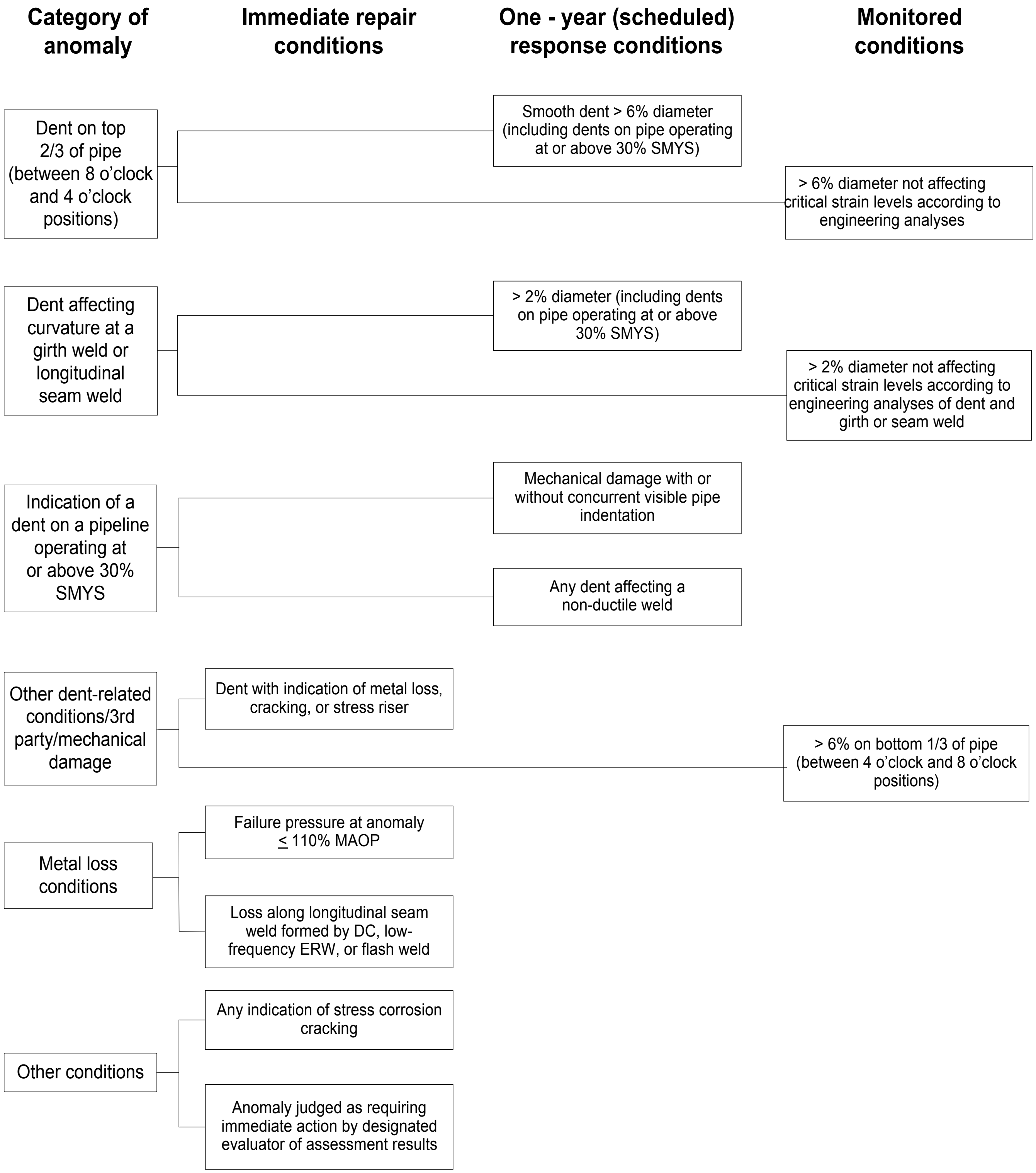


Figure 5-3. Special Conditions for Remediation

5.2 Program Requirements for Identifying Anomalies

Pipeline anomalies that meet the definition in Table 5-1 and the special condition defined in Figure 5-3 will be identified by an IMG Integrity Engineer and listed in a dig list file. Each pipeline segment will have its own dig list file and will be kept in the NWN IMG GRS office files, or on a secure network drive. The dig list file will contain the following information for each anomaly:

- Distance (in feet) to nearest known pipeline measurement reference or appurtenance
- Date of discovery
- Deadline for examination and remediation
- Reported anomaly dimensions and/or values
- Date of visual examination
- Date of remediation
- Remediation performed

The dig list file will be kept for the life of the pipeline.

5.2.1 Reassessment of Monitored Conditions

During reoccurring evaluation of pipeline segments, as described in section 6, GRS reviews any monitored conditions for change in their status that would require remediation. Any anomaly identified as a “Monitor” condition on the dig list file will be reevaluated by each subsequent integrity assessment. If the new integrity assessment data shows a change in priority status, the anomaly will be reclassified and examined per the schedule established in section 5.1.

5.3 Documentation of Pipeline Anomalies

The Anomaly Report (AR) shall be used for the required visual examinations (excavation) of pipelines covered by the GRS Plan. The AR details the information that should be gathered from the pipeline during a visual inspection of the pipe. The AR form is broken into four sections, the Excavation Location, Pipe Description, ECDA (N/A), and Pipe Anomalies. There is additional room on the form for a sketch of the coating and the pipe as found. Each pertinent section of the AR form should be filled out as completely as possible. Additional items, such as NDE reports and photos, should be included with the completed AR. Completed AR shall be filed in the NWN IMG GRS office files for the life of the pipe. The Integrity Engineer or designee typically fills out this form. See Appendix G for the Pipeline Integrity Anomaly Report Form and instructions for completing the form.

5.4 Operator Response when Timelines for Evaluation and Remediation Cannot be Met

If the IMG cannot make complete its evaluation of assessment data and effect the necessary remedial actions within the 180-day timeframe, it creates a report with the reason for the delay, a revised schedule, and justification for why the changed schedule will not jeopardize public safety. The IMG initiates a pressure reduction not to exceed 80% of the level at the time the condition was discovered or other action that ensures the safety of the covered segment when it is unable to respond within the required timeframes. The appropriate pressure reduction will be determined using ASME B31.8G or “RSTRENG”, or the pressure reduced to 80% of the level at the time the condition was discovered.

If the IMG on behalf of GRS cannot meet the schedule and cannot provide safety through a temporary reduction in operating pressure or other action, it will notify PHMSA and the CPUC, as described in section 14.1.2 of this Program Plan.

If the IMG perceives that a temporary pressure reduction will exceed 365 days, the NWN Supervisor of Integrity Management creates a report that explains the reason for the remediation delay and how pipeline integrity is not compromised by continued operation in this manner and will notify PHMSA and CPUC as described in sections 14.1.1 and 14.1.2.

5.4.1 Calculating the Remaining Strength of Pipe

Section 192.933 specifies the use of ASME B31.G, RSTRENG, or an equivalent method to find remaining strength of pipe. For small signs of corrosion, ASME B31.G uses measurements of length and maximum metal-loss depth to assume a bowl-shaped area of metal loss. If the corrosion takes the form of pitting, ASME B31.G can estimate a metal-loss condition as being more severe than it actually is. The RSTRENG method allows for making individual calculations of the effective area of metal loss in clusters and within sections of each cluster. The IMG Integrity Engineer will select the appropriate calculation method based on the characteristics of the anomaly.

5.4.2 Discovery of a Corrosion Condition

If the IMG Integrity Engineer finds a corrosion condition that could affect the integrity of a pipeline on a segment covered by the rule (which the IMG interprets as meaning an immediate repair corrosion condition), it will establish a schedule for evaluating all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics (i.e., CP, CP interference, age of construction) and make remediation as necessary.

For corrosion defects that fall into the scheduled response and monitored corrosion severity groups, the IMG follows the guidelines of GRI-00/0230, Determining Periodic Inspection Intervals for High Consequence Areas, for predicting growth rates of the defects so that they do not reach a critical level before the next inspection.

5.4.3 Prescriptive and Performance-Based Programs

Section 192.193 allows deviation from remediation timelines only for a Performance-based program. GRS is using a Prescriptive-based program.

Should GRS move to a Performance-based program in the future, a process will be developed at that time.

5.5 Record Review for Discovery, Repair, and Remediation Activities

Upon completion of defect remediation for the pipeline segment, an IMG Integrity Engineer evaluates the entire remediation process to assure that all potential threats to pipeline integrity are unlikely to pose a threat to the integrity of the pipe before the next scheduled assessment. This process will include, but is not limited to, ensuring that:

- The assessment method provided results within contract tolerances and specifications.
- All anomalies that met the criteria in section 5.1.1 and 5.1.4 were identified and documented.
- The correct pipeline anomaly identified for visual inspection was inspected.
- All past deadlines were met.
- If the defect required remediation the proper remediation occurred.
- Future deadlines are identified and are scheduled for completion.
- Monitor conditions are recorded on the dig list file.

If any of the above criteria were not met, the IMG Integrity Engineer will determine if any additional work needs to be completed before the assessment is finished. The IMG Integrity Engineer will take action to complete the necessary work in a timely fashion.

5.6 Engineering Critical Assessments

ASME B31.8S defines an engineering critical assessment as a rigorous evaluation of the data, which reassesses the criticality of the anomaly and adjusts the projected growth rates based on site-specific parameters. The IMG Integrity Engineer will examine all anomalies from an integrity assessment to determine the priority level of the anomaly. Methods of analysis may include, but are not limited to:

- B31.G, RSTRENG, or an equivalent method for metal loss anomalies
- Strain analysis of deformation anomalies
- Integration of multiple ILI assessments
- Integration of current integrity assessment with past integrity assessments.
- Examination of previously excavated defects with integrity assessment
- Integration of integrity assessment results with items such as third party activity, landowner data, and leak surveys

6. Continual Evaluation and Reassessment

After a covered segment has undergone a baseline assessment, the IMG will reevaluate the segment prior to the next re-assessment interval. This evaluation includes updating and re-running the risk model to identify any new or remaining threats or risks.

The reassessment intervals for each covered pipeline segment and method for integrating any new data, along with justifications for each decision, are documented in individual pipeline segment files stored in the NWN IMG GRS office files or on a secure network drive. The reassessment process and/or schedule may be revised based on a review of the risk model output.

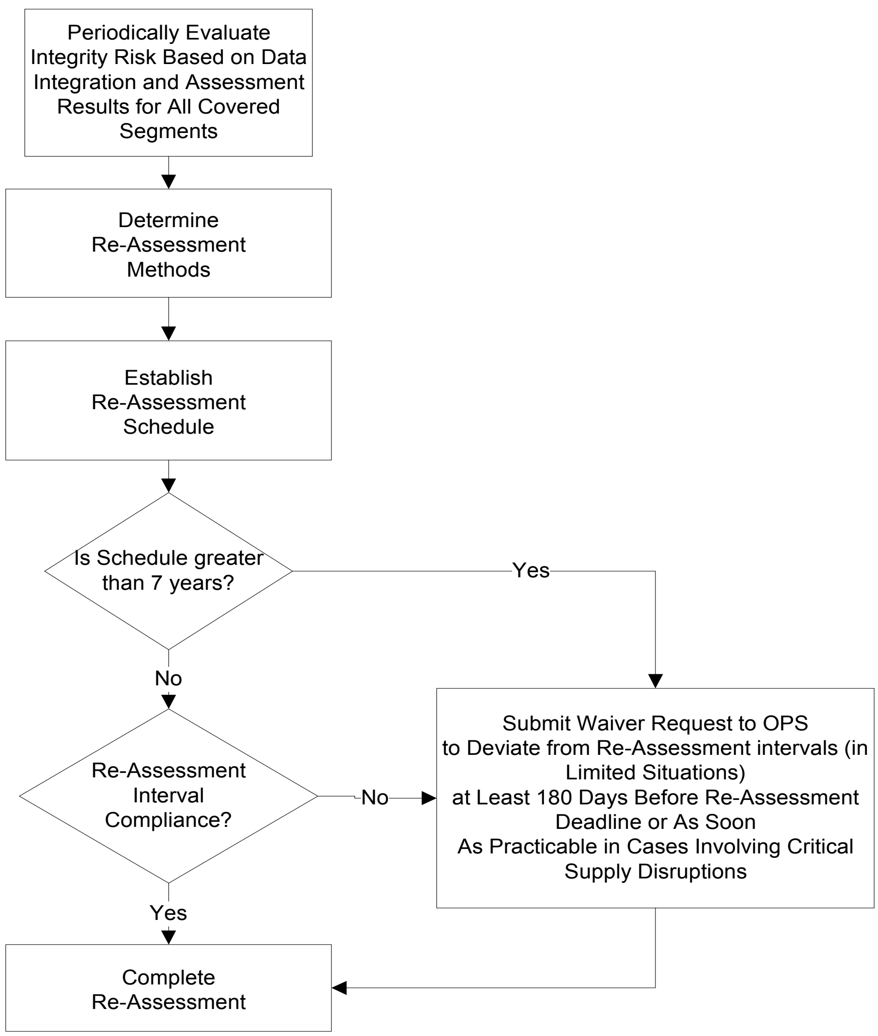


Figure 6-1. Flowchart of Continual Evaluation and Reassessment Process

6.1 Periodic Evaluations

The IMG bases its reassessment method on data integration and risk assessments for the entire transmission pipeline system, with identification of threats specific to each pipeline segment. Re-evaluation of the system will be conducted on an annual basis, or more frequently based on the frequency and importance of data modifications. To establish the reassessment intervals after the baseline assessment of each segment is complete, the following data sources are considered:

- Past and present integrity assessment results to determine if new information warrants changes to the reassessment intervals.
- Data integration and risk assessment to address threats and pipeline conditions.
- Decisions about remediation.
- Additional preventive and mitigative measures taken to reduce risk.

In general, the IMG plans to reassess GRS pipelines on an interval not to exceed 7 years; however, the IMG will conduct a re-evaluation in response to certain events, such as significant ground movement or floods or other critical events that may impact pipeline safety.

6.2 Reassessment Methods

The following methods are considered for reassessing each pipeline segment:

- In-line inspection capable of detecting corrosion and any other threats to which the segment is susceptible.
- Pressure test conforming to the requirements in Subpart J of 49 CFR 192 and using the test pressures specified in ASME B31.8S, section 5, table 3.
- Direct assessment for threats of external or internal corrosion, or SCC
- Other technology that provides an equivalent understanding of the condition of the pipe (with justification to the applicable federal and state agencies 180 days before doing the assessment, as described in section 14).
- Confirmatory direct assessment for all segments for which the reassessment period is longer than seven years.
- Low Stress reassessment for pipelines operating at less than 30% SMYS.

The IMG will reevaluate each pipeline segment prior to reassessment to assure that the proper methodology is used to assess all the potential integrity threats. If GRS chooses in the future to assess pipelines with either Low Stress Reassessment or Confirmatory Direct Assessment, complete assessment methodologies will be established and they will be performed on intervals not to exceed the deadlines established in this section.

6.3 Low Stress Reassessment

GRS does not intend to use this method at this time. If GRS chooses to use this method, a process will be developed per rule guidelines.

6.4 Reassessment Intervals

All covered segments will be reassessed no later than 7 "actual" years (not calendar years) after their baseline assessment is complete unless special conditions are discovered that could require an earlier reassessment. The reassessment intervals for pipelines operating at, above, or below 30% SMYS can be determined from Table 6-1.

Table 6-1. Integrity Assessment Intervals for Time-dependent Threats (Prescriptive Method)

Inspection Technique	**Maximum[a] Interval (years)**	Criteria		
		≥ 50% SMYS	≥ 30% SMYS < 50% SMYS	<30% SMYS
Pressure test	5	P_{test}[b] ≥ 1.25 × MAOP	P_{test} ≥ 1.4 × MAOP	P_{test} ≥ 1.7 × MAOP
	10	P_{test} ≥ 1.39 × MAOP	P_{test} ≥ 1.7 × MAOP	P_{test} ≥ 2.2 × MAOP
	15	Not allowed	P_{test} ≥ 2.0 × MAOP	P_{test} ≥ 2.8 × MAOP
	20	Not allowed	Not allowed	P_{test} ≥ 3.3 × MAOP
In-line inspection	5	P_{fail}[c] >1.25 × MAOP	P_{fail} >1.4 × MAOP	P_{fail} >1.7 × MAOP
	10	P_{fail}[c] >1.39 × MAOP	P_{fail} >1.7 × MAOP	P_{fail} >2.2 × MAOP
	15	Not allowed	P_{fail} >2.0 × MAOP	P_{fail} >2.8 × MAOP
	20	Not allowed	Not allowed	P_{fail} >3.3 × MAOP
ECDA	7	See section 4.5.1	See section 4.5.1	See section 4.5.1
	10	See section 4.5.1	See section 4.5.1	See section 4.5.1
	15	Not allowed	See section 4.5.1	See section 4.5.1
	20	Not allowed	Not allowed	See section 4.5.1
		Number of Indications Examined that must be Reassessed		
ICDA or SCCDA	5	Sample	Sample	Sample
	10	All	Sample	Sample
	15	Not allowed	All	All
	20	Not allowed	Not allowed	All

Inspection Technique	Maximum[a] Interval (years)	Criteria		
		≥ 50% SMYS	≥ 30% SMYS < 50% SMYS	<30% SMYS
CDA	7			
Low-stress reassessment		N/A	N/A	7 years[d]

[a] The maximum interval may be less depending on repairs, preventive measures, and aggressiveness of the threat. Occurrence of a time-dependent threat requires immediate reassessment of the interval.

[b] P_{test} = maximum hydrostatic test pressure.

[c] P_{fail} = predicted failure pressure. See section 4.5.1.

[d] Seven years with consideration of ongoing actions specified in §192.941.

6.4.1 Reassessment Using Pressure Testing or ILI

If the segment is being reassessed with a pressure test or ILI, the IMG will select one of the following options to set the reassessment schedule:

- Basing the intervals on the identified threats for the segment, on the last integrity assessment, and on a review of the data integration and risk assessment, or
- Using the intervals listed in table 3 of ASME B31.8S for different pipeline stress levels (for pipelines where the risk drivers are time-dependent threats or manufacturing or other related threats). Table 6-1 relates the reassessment intervals described in ASME B31.8S and the reassessment mandates in §192.939.
- If the predicted failure pressure ratio or test pressure ratio falls in-between the values listed in Table 6-1, the ratio will be interpolated.

The IMG will follow Section 7.3.2 of ASME B31.8S, which covers reassessment intervals for segments that are pressure tested for SCC, and mandates a documented pressure retest program with a technically justifiable interval.

6.4.2 Reassessment Using Direct Assessment

The GRS Plan does not initially intend to use ECDA, ICDA or SCCDA and will develop fully documented plans for ECDA and/or ICDA and/or SCCDA prior to electing to their use for extending the re-assessment intervals per the rule guidelines.

6.4.3 Reassessments for Segments with Prior Assessments

Per 192.937(a), any segment, for which an assessment conducted before December 17, 2002 was used in the baseline assessment plan, must be reassessed no later than December 17, 2009. Since all GRS's system was installed in 2010 or later, this section does not apply.

6.4.4 Confirmatory Direct Assessment

The GRS Plan does not intend to use Confirmatory Direct Assessment (CDA) and will develop fully documented plans for CDA prior to electing to use of those methods for extending the re-assessment interval per rule guidelines.

6.4.5 Maximum Reassessment Intervals

Table 6-2 lists the maximum reassessment intervals for each option described in this section.

Table 6-2. Maximum Reassessment Intervals (in Years Following a Baseline Assessment)

Assessment Method	Operating Pressure		
	≥ 50% SMYS	≥ 30% SMYS < 50% SMYS	< 30% SMYS
ILI, pressure test, or DA (with confirmatory DA)	10 years (CDA at Year 7)	15 years (CDA at Year 7, CDA at Year 14)	20 years (CDA at Year 7, CDA at Year 14)
ILI, pressure test, or DA (without confirmatory DA)	7 years	7 years	7 years
Low-stress reassessment	N/A	N/A	7 years + ongoing actions

6.5 Deviation from Reassessment Requirements

GRS is following the Prescriptive Plan at this time. If GRS chooses to use the Performance Based Plan in the future to deviate from reassessment requirements, a process will be developed at that time.

6.6 Waiver from Reassessment Interval

If the required internal inspection tools are not available to conduct a required reassessment or if the reassessment would interrupt service to our customers, GRS will apply for a waiver from PHMSA and appropriate state and local pipeline safety authorities, if applicable, at least 180 days before the reassessment is due. Such a request must demonstrate that a longer re-inspection interval would not jeopardize public safety and contain the following information:

- A demonstration that GRS cannot obtain the internal inspection tools within the required inspection period or maintain the local supply of product if it conducts the reassessment within the required interval, and
- A description of the actions GRS is taking to ensure the integrity of the pipeline segment in the interim.

If the application for waiver is based on an interruption in local supply, and it cannot be submitted 180 days before the reassessment is due, it will be filed as soon as the need for a waiver is known.

The NWN Supervisor of Integrity Management completes and files with PHMSA a waiver that meets the requirements established above.

6.7 Consideration of Environmental and Safety Risks

GRS implements precautions to protect workers, members of the public, and the environment from safety hazards during reassessments. Operator qualification procedures promote safety and environmental best practices.

6.7.1 Minimizing Environmental and Safety Risks during Reassessments

In-Line Inspection

In-line inspection will be performed as described in the GRS Operator Qualification procedures appropriate for performing an inline inspection.

- CT41, Operate Pressure Relieving Devices for Launching and Receiving Facilities
- CT60.3, Recognize and Respond to Physical Damage to the Pipeline System.
- CT60.6, Prevention of Accidental Ignition

Direct Assessment

- Not applicable

Hydrotesting

Hydrotesting will be performed as described in the GRS Operator Qualification procedure CT37, “Conduct Pressure Test”.

7. Confirmatory Direct Assessment

The IMG does not intend to use CDA. Should this decision change, the IMG will develop a fully documented CDA plan for ECDA and/or ICDA prior to the use of either of those methods for extending the assessment interval per rule guidelines.

8. Preventive and Mitigative Measures

This section describes the process by which the GRS Plan provides additional protection for HCAs and enhances public safety by selecting and implementing preventive and mitigative (P&M) measures beyond those already required by Part 192.

8.1 Identification of Additional Preventative and Mitigative Measures

The GRS Plan's process for the development of additional P & M Measures is made with input from the GRS P & M Measures Team. Team members include: The NW Natural Supervisor of Integrity Management, the GRS Plant Manger, and others as required for specific conditions. The GRS P & M Measures Team meets at least annually or sooner, if a need to do so is realized, and utilizes the following process:

1. The IMG reviews the risk model developed in Section 3 to determine the predominant threats to individual line segments. Threats will be classified as time-dependent, stable, or time-independent.
2. The IMG forwards the threat information to the P & M Measures Team.
3. The Team proposes P & M measures based on the predominant threats.
4. The Team evaluates the likely effectiveness of each proposed P & M measure.
5. If the proposed P & M measure offers a substantial reduction in the threat or consequence level, the Team will develop an implementation plan and budget.
6. The Team will forward the plan and request funding in the next Capital Budget submission. Once approved, the additional P & M measure will be implemented in a timely fashion.
7. Additional preventative and mitigative alternatives are considered:
    a. Installing automatic shut-off valves or remote control valves.
    b. Additional response training.
    c. Drills with local emergency responders
    d. Enhanced inspection and maintenance schedules
    e. Replacement of pipe segments with pipe of heavier wall thickness
    f. Installing computerized monitoring and leak detection systems
    g. Other prevention activities
8. A record of the GRS P & M Measures Team meeting will be kept on the GRS Preventive and Mitigative Measures Review form (see Appendix F).

The GRS Plan retains preventive measures that have a record of success and examines new prevention measures for potential effectiveness.

8.2 Third-Party Damage

The GRS Plan has implemented the following enhancements to its existing damage prevention program:

- Using qualified personnel when doing work that could affect the integrity of a covered segment, such as locating, marking, and stand-bys for known excavation work. (See the qualifications for workers employed for locating, marking and stand-by in the contractor specifications located in the NWN IMP GRS office files).
- Collecting location-specific information on excavation damage on the "Report of Damage to Gill Ranch Storage Property" (See Appendix K) into a central database. This database would contain information on both covered and non-covered transmission line segments and would include root cause analyses that support the selection of P&M measures that target HCAs. The damage information in the database must include damage not defined as an incident under Part 191. Copies of the completed "Report of Damage to Gill Ranch Storage Property" document retained for the life of the pipeline in the NWN IMP GRS office file or a secure network server.
- Participating in one-call systems where covered segments are present. Monitoring known or discovered excavations of covered pipeline segments. If physical evidence of an unmonitored encroachment is found near a covered segment, GRS will initiate an excavation of the area near the encroachment. If discovered conditions warrant remediation, they will be made in a timely fashion.

GRS mitigates third-party damage by two means:

- Repair or replacement of damage (See section 5, Remediation.)
- Ensuring that third-party damage prevention programs are in place and functioning

8.3 Pipelines Operating below 30% SMYS

Table 8-1 describes additional P&M measures that IMG considers for use to address the third-party damage threat for covered pipeline segments operating below 30% SMYS, both inside HCAs and outside HCAs but inside Class 3 or Class 4 locations.

The IMG evaluates the method or methods that will most likely mitigate the threat caused by third party damage. It considers the likelihood of the threat, the consequence of the potential failure, resource availability and other factors in selecting the means to mitigate the potential hazard

.

Table 8-1. Addressing the Third-Party Damage Threat for Low-Stress Pipelines

Additional P&M Measures
Case 1 Transmission pipelines, either in an HCA or not in an HCA but in a Class 3 or Class 4 location, any of the following: • Participation in a state one-call system • Use of qualified employees and contractors to perform locating buried facilities and directly observing excavation work • Either monitoring of known excavations near transmission pipelines, or bi-monthly patrol of transmission pipelines in HCAs or Class 3 and Class 4 locations l • Indications of unreported construction activity would require a follow-up investigation to determine if mechanical damage occurred **Case 2 (in addition to the above)** Transmission pipelines not in an HCA but in a Class 3 or Class 4 location (Note: GRS has no transmission pipelines that meet this criteria): • Semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical)

8.4 Plastic Transmission Pipeline

GRS has no plastic transmission lines and has no plans to install them in its system.

8.5 Outside Force Damage

The IMG, in coordination with NWN Engineering Services, selects a method or methods listed below that will most likely mitigate the threat caused by the particular weather- and outside force- related occurrence or occurrences. It considers the likelihood of the threat, the consequence of the potential failure, resource availability and other factors in selecting the timing and the means to mitigate the potential hazard.

- Stabilization of the soil
- Stabilization of the pipe or pipe joints
- Relocation or lowering of the pipeline
- Lowering of the pipeline below the frost line
- Providing lightning protection
- Line patrolling
- Monitoring movement progress in areas of ongoing subsidence and slides.

8.6 Corrosion

If the IMG becomes aware of a corrosion condition that could affect the integrity of a pipeline on a segment covered by the rule (which the IMG interprets as meaning an immediate repair corrosion condition), it will establish a schedule for evaluating all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics (i.e., CP, CP interference, age of construction), and makes remediation as necessary.

For corrosion defects that fall into the scheduled response and monitored corrosion severity groups, the IMG follows procedures outlined in the IMP Plan, Chapter 5. Determining Periodic Inspection Intervals for High Consequence Areas, for predicting growth rates of the defects so that they do not reach a critical level before the next inspection.

8.7 Automatic Shutoff Valves or Remote Control Valves

GRS will install Automatic Shutoff Valves (ASVs) or Remote control Valves (RCVs) if an evaluation concludes that such valves should be installed. The prospect of installing ASVs or RCVs on existing or proposed new transmission line valve is reviewed as part of the annual GRS P&M Team meeting.

The GRS P&M Team’s process for considering the installation of ASVs or RCVs is outlined as follows:

1. Existing valves are considered for replacement based on the risk score for line segments listed in the Baseline Assessment Plan.
2. Proposed new valves will be considered in the design stage prior to final equipment selection.
3. Factors considered for the use of ASVs/RCVs are:
    - Swiftness of leak detection and pipeline shutdown capabilities
    - Operating pressure
    - Rate of potential release
    - Pipeline profile
    - Potential for ignition
    - Location of nearest response personnel
    - Natural gas as the transported material
4. Metrics are applied to the above factors on the “ASV/RCV Evaluation Matrix” form (see Appendix J).
5. If an ASV or RCV is determined to be appropriate for a given site, the recommendation is forwarded to the NW Natural Manager of Engineering for inclusion in the next annual Capital Budget submission.
6. The assigned project engineer selects the appropriate ASV or RCV for the site and originates a Work Order for its installation.
7. Installation is accomplished by the assigned work crews.
8. The completed Work Order is returned to the Engineering Department and a copy forwarded to the ASV/RCV Evaluation Team.

9. Performance Measures

The IMG measures elements of the GRS Integrity Management Program Plan to assure the effectiveness of the program and to reveal processes that need improvement. Performance measures focus attention on the integrity management program results that demonstrate that the GRS Plan has attained improved safety. Performance measure evaluation and trending can also lead to recognition of unexpected results that may include the recognition of threats not previously identified.

9.1 General Performance Measures

The IMG compiles information for the four performance measures listed below and forwards to PHMSA semi annually. Procedures for submittal of documentation are located in section 14.1. Performance measures are to be completed through June 30 and December 31 of each year. The Supervisor of Integrity Management submits them within 2 months after those dates. (Copies of the documents are located in the NWN IMG GRS office files).

1. Number of miles of pipeline inspected versus program requirements
2. Number of immediate repairs completed as a result of integrity management inspection program
3. Number of scheduled repairs completed as a result of the integrity management inspection program
4. Number of leaks, failures, and incidents (as defined in ASME B31.8S-2004, Section 13), classified by cause on covered pipeline segments

9.2 Threat Specific Performance Measurement

The IMG gathers relevant GRS data on a semi-annual basis and compares it to current baseline data or to a rolling average.

9.2.1 Prescriptive Plans

For the GRS Plan's prescriptive program, performance measures include all of the threat-specific metrics for each threat as summarized in Table 9-1.

9.2.2 Performance-Based Plans

The GRS Plan is following the prescriptive plan at this time. If IMG on behalf of GRS chooses to use performance based plans in the future, additional performance measures will be developed.

Table 9-1. Performance Metrics

Threats	Performance Metrics for Prescriptive Programs
External Corrosion	Number of hydrostatic test failures caused by external corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of external corrosion leaks
Internal Corrosion	Number of hydrostatic test failures caused by internal corrosion Number of repair actions taken due to in-line inspection results Number of repair actions taken due to direct assessment results Number of internal corrosion leaks
Stress Corrosion Cracking	Number of in-service leaks or failures due to SCC Number of repair replacements due to SCC Number of hydrostatic test failures due to SCC
Manufacturing	Number of hydrostatic test failures caused by manufacturing defects Number of leaks due to manufacturing defects
Construction	Number of in-service leaks or failures due to construction defects Number of girth-weld/couplings reinforced/removed Number of wrinkle bends removed Number of wrinkle bends inspected Number of fabrication welds repaired/removed
Equipment	Number of regulator valve failures Number of relief valve failures Number of gasket or O-ring failures Number of leaks due to equipment failure
Third-party damage	Number of leaks or failures caused by third-party damage Number of leaks or failures caused by previously damaged pipe Number of leaks or failures caused by vandalism Number of repairs or replacements implemented as a result of third-party damage
Incorrect operations	Number of leaks or failures caused by incorrect operations Number of regulatory or internal audits/reviews conducted Number of findings per audit/review classified by severity Number of changes to procedures due to audits/reviews
Weather related and outside force	Number of leaks that are weather related or due to outside force Number of repair, replacement, or relocation actions due to weather-related or outside-force threats

10. Record Keeping

The primary objective of this section is to describe the methods the IMG on behalf of GRS uses to maintain the required integrity management related documentation and where the records are retained.

10.1 Records Maintained by GRS

The IMG on behalf of GRS maintains records that demonstrate compliance with the requirement of subpart O of the Gas Integrity Management Rule for the useful life of the pipeline. Compliance records include:

- A written integrity management program.
- Documentation supporting the threat identification and risk assessment.
- HCA Identification Records.
- A written baseline assessment plan.
- Documentation to support policy decisions, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements.
- Documents that demonstrate that GRS or NWN's IMG on GRS's behalf, and/or contractor personnel have the required training. (See section 10.6)
- A schedule that prioritizes probable conditions found during an inspection for evaluation and remediation, including technical basis documentation.
- Documentation to carry out the requirements of the direct assessment (if used in the future).
- Documentation to carry out the requirements of confirmatory direct assessment (if used in the future).
- Verification the IMG on behalf of GRS has provided documentation or notification required by subpart O of the rule to be provided to PHMSA, and when applicable, with the pipeline safety inspection department of the California Public Utility Commission.

10.2 Written Integrity Management Plan

The IMG maintains the written GRS Integrity Management Plan in the NWN IMG GRS office files and on a secure network server. Superseded copies of the integrity management plan are archived, with revisions and dates. (See section 13.1.2 for internal communication of plan updates.)

10.3 Threat Identification and Risk Assessment Documentation

The IMG maintains GRS's pipeline records in the NWN IMG GRS office files and on a secure network server for threat identification, historical pipeline operations and maintenance data gathered, interviews with subject matter experts (SMEs), weighting of risk factors, risk assessment documentation and risk scores. (See also section 2.)

10.4 Baseline Assessment Plan

The Baseline Assessment Plan (BAP) is kept in the NWN IMG GRS office files and on a secure network server. Superseded copies of the BAP are archived with revisions and dates in the NWN IMG GRS office files and on a secure network server.

10.5 Training

A description of the GRS Plan's training program appears in section 12, Quality Assurance. GRS training documentation is maintained in the NWN IMG GRS office files.

10.6 Evaluation and Remediation Schedules

A description of the GRS Plan's Evaluation and Remediation program appears in Section 5 Remediation.

10.7 Direct Assessment Plan Documentation

The GRS Plan does not intend to initially use ECDA, ICDA or SCCDA and will develop fully documented plans for ECDA and/or ICDA and/or SCCDA prior to electing to use of these methods for extending the assessment interval per rule guidelines.

10.8 Confirmatory Direct Assessment Documentation

The GRS Plan does not intend to use CDA to assess GRS pipelines at this time. It will develop fully documented CDA plans for ECDA and/or ICDA prior to electing to use either of those methods for extending the assessment interval per rule guidelines.

10.9 Notification Documentation

The IMG maintains records of notices submitted on behalf of GRS to PHMSA and State authorities in the NWN IMG GRS office files.

10.10 Other Documentation

GRS pipeline and facility drawings and documentation not required for the TIMP Plan are maintained in the GRS office files and/or in the GRS area of a secure network server.

11. Management of Change (MOC)

The GRS Plan has a management of change (MOC) process as part of its TIMP. This controlled process identifies and considers the impact of proposed changes to pipeline systems and their integrity prior to implementation.

11.1 Types of Changes Considered in MOC

The MOC process manages the following types of proposed changes, whether permanent or temporary:

- Program changes
- Technical changes
- Physical changes to the covered pipeline, such as:
  - Equipment changes
  - Pipeline material changes
  - Pipeline route changes
  - Pipeline size changes
- Procedural changes relevant to transmission line operations and maintenance
- Organizational changes relevant to transmission line operations and maintenance

11.2 Attributes of the Change Process

System changes shall be properly reflected in the TIMP and the risk assessment process and outputs will include changes to applicable data.

The GRS Plan's MOC process includes the following elements:

1. Reason for change.
2. Authority for approving changes.
3. Analysis of implications.
4. Acquisition of required work permits.
5. Documentation of the change.
6. Communication of change to affected parties.
7. Time limitations.
8. Qualifications of staff (see section 10, Record Keeping, and section 10.6, Job Requirements and Training).

11.2.1 The MOC Process

The GRS Plan recognizes that system changes can precipitate changes in the integrity management program, and conversely, results from the program can necessitate system changes.

Steps in the MOC Process:

- The need for change is recognized
- An MOC Form (see Appendix H) is prepared by the change initiator
- The MOC Form is reviewed by NWN"s Supervisor of Integrity Management and others of his choosing, to determine the impacts of the proposed changes
- The proposed change is accepted, denied or sent back to the initiator for revision by NWN"s Supervisor of Integrity Management
- Upon approval training is implemented if necessary
- The change is communicated (see section 11.2.4)

When a change that meets the requirements of this section is communicated, a member of the Integrity Management group will initiate the MOC process.

The IMG maintains a presence on NWN committees that manage change to evaluate and provide input on NWN originated changes that may impact GRS pipeline integrity prior to implementation. The IMG maintains contact with GRS operations to evaluate and provide input on GRS originated changes that may impact GRS pipeline integrity prior to implementation.

11.2.2 Data Integration of MOCs

All changes that will impact the risk to a covered pipeline or may cause a transmission pipeline to become a covered pipeline will be added to the risk assessment update, as needed, during the periodic review process.

11.2.3 MOC Documentation and Review

The Management of Change (MOC) Form shall be used to document changes to covered pipelines. The MOC form includes a detailed explanation of the situation precipitating the change, the condition before the change, condition after the change, the impacts of the change to pipeline systems and their integrity, and the justification for the change. Completed MOC forms shall be filed in the IMG office files for the life of the pipeline system. See Appendix H for the MOC form and instructions for completing the form.

11.2.4 MOC Notification and Communication

Notification to PHMSA and State and Local Authorities

For significant changes to the program, program implementation, or schedule, the IMG on behalf of GRS notifies PHMSA and the appropriate state and local pipeline safety authorities, if applicable, within 30 days of adopting the change. GRS uses the notification guidelines in section 14.

Internal Communication

The IMG and members GRS communicates changes to each covered pipeline segment and to the integrity management plan to affected parties by memos, intranet updates, meetings, refresher training or by other means.

The GRS Plan's MOC process includes communication of the change to affected personnel:

- A change in land use would affect either the consequence of an incident or change in likelihood of an incident
- A change to a covered pipeline segment as a result of an integrity assessment, such as a change to cathodic protection or permanent reductions in maximum allowable operating pressure
- Changes to policies or procedures impacting the transmission pipeline system
- Changes to GRS organization that affects the pipeline system or affects transmission pipeline integrity management

11.2.5 New Technologies

If IMG identifies new technologies that could improve the integrity of the GRS pipeline systems, it will provide the necessary information and training to appropriate personnel and stakeholders prior to implementing the new technology.

12. Quality Assurance

This section describes the GRS Plan's process meeting the quality assurance requirements for the TIMP Plan including documentation, qualifications and training. Developing accurate processes for those tasks is an iterative activity. Review and critique of those processes is an essential part of the continuous improvement effort.

12.1 Integrity Management Program Responsibilities and Authorities

The flow of authority through the organization in descending order is: COO, NW Natural Energy; President, NW Natural Gas Storage; Vice President, Engineering and Operations GRS; Director of NWN's Deliver Gas Process; Manager, NWN Engineering; NWN Supervisor of Integrity Management; and NWN Integrity Engineers. The primary responsibility for implementing and administering the GRS TIMP Plan is the IMG. The GRS organization is committed to providing the resources and information necessary to support the operation and monitoring of the TIMP processes.

12.2 Quality Assurance Process

The process for assuring the quality of GRS's integrity management consists of examining each required activity on a specified frequency. The quality of each activity is verified by the responsible party to determine if the criteria of validation have been accomplished. Table 12-1 at the end of this section lists Activities, Frequency, Methods, Criteria, and the Responsible Party for conducting the audits of the TIMP. Results of each activity audit are documented on the Quality Assurance Audit Form (see Appendix D). Results of the review will be forwarded to the Supervisor of Integrity Management for follow-up action if required or filing in the NWN IMG GRS office files or on a secure network server.

12.2.1 Plan for Improving Performance

The Responsible Party uses the Quality Assurance Audit Form to document recommended changes to the TIMP that result from an audit. The Supervisor of Integrity Management assigns the recommended changes to an appropriate individual or team to be accomplished by a specified date

12.3 Invoking Non-Mandatory Statements in Standards

The IMG has reviewed all "should" statements in the documents incorporated by reference in Part 192, relating to Subpart O. Where non-mandatory statements apply, the GRS IMP Plan accepts those "should" statements. They are incorporated in the Plan as "shall", "will", or "must" as appropriate.

12.4 Program Documentation Requirements for the QA Process

The IMG maintains the Quality Assurance Audit Forms in the NWN IMG GRS office files or on a secure network server for the life of the pipeline.

12.5 Integrity Management Program Reviews

The GRS Plan shall be reviewed once each calendar year for code compliance and appropriateness. Subject matter experts may be called upon to make recommendations for improvement to the manual. Regulatory audits will be reviewed to evaluate if the content of the manual needs updating as well. The reviews are performed to determine the appropriateness and adequacy of the policy used in normal operation and maintenance during pipeline integrity tasks. New or revised contents require the approval of the Supervisor of Integrity Management or designee.

As part of that review the IMG:

- Evaluates necessary program documentation,
- Reviews the qualifications and lines of reporting of personnel making decisions and performing integrity management activities,
- Reviews the choices of performance measures for each integrity management activity to make sure that the performance measures accurately and thoroughly track the effectiveness of the activities,
- Reviews current vendor records to make sure that vendors are maintaining GRS standards for documentation, operator qualification, and other quality issues.

12.6 Personnel Qualification and Training Requirements

The IMG maintains specific job descriptions and organizational charts for integrity management positions that outline the specific responsibilities and lines of reporting for personnel that perform integrity management activities.

12.6.1 Integrity Management Staff Qualifications

Qualifications: The TIMP Plan requires supervisory personnel to have the appropriate training or experience for their assigned responsibilities. The Supervisor, Integrity Engineers and Pipeline Integrity Specialist are evaluated and selected by a technical interview team. The qualifications for each position are specified in the Position Descriptions that are on file in the NWN IMG GRS office files or Secure network server. Selection of an individual to the Integrity Management Team is an acknowledgement by the Technical Interview Team that the individual satisfies the required qualifications.

Training: To maintain high standards of its integrity management personnel, members of the IMG will participate in periodic training or attend conferences/seminars relative to Pipeline Integrity. The record of this training will be kept in the NWN IMG GRS office files or secure network server.

The qualifications of personnel performing integrity management activities, including decision-making, changes to the program, changes impacting pipeline integrity or those that carry out assessments and who evaluate assessment results are available in the NWN IMG GRS office files or secure network server.

12.6.2 Integrity Management Contractor Qualifications

Each contractor must submit the training requirements and qualifications of their personnel for review and acceptance by IMG Integrity Engineers. Indirect Inspection contractors will have a NACE CP Level 1 or equivalent in-house certification program. Non Destructive Testing (NDT) staff performing ultrasonic or magnetic particle testing is required to have Level II NDT certification. In-line inspection tool operators and graders will be required to meet ASNT ILI – PQ -2005 or equivalent in-house certification program. Proprietary tool operators (Guided Wave Ultrasonic) are required to be certified by the Original Equipment Manufacturer. The qualification documents and review /acceptance documents will be retained in the Contractor Qualification File or in the final inspection report appendix.

12.7 Performance Metrics

The GRS Plan's performance metrics, reviewed semi-annually, is discussed in section 9.

12.8 Version/Issue Control

The IMG tracks any changes to this Program Plan in the Revision Log located in the front of the document. Additionally, the version number and date in the document footer can distinguish different versions of this document. The Supervisor of Integrity Management is responsible for the compiling of changes, for releasing new versions of the document, for archiving legacy versions of the document, and for assuring the latest version of the document is available on GRS's intranet site.

The Supervisor of Integrity Management is responsible for making sure that all personnel responsible for making integrity management decisions and for performing integrity management activities are aware of the latest version of this document and notifies all personnel of plan changes via email.

12.9 Vendor Responsibilities

The GRS Plan requires the same level of quality control in processes, personnel qualifications and training, and documentation from vendors contracted to perform integrity management services, as it requires of its own personnel. These requirements are written into vendor contracts and enforced either by field personnel or by the Supervisor of Integrity Management or designee. (See sample Purchase Order located in NWN IMG GRS office files or secure network server).

Table 12-1. Quality Assurance of Integrity Management Processes

Audit Activity	Audit Frequency	Methods for Assuring Quality	Criteria Of Validation	Responsible Party
Identifying High Consequence Areas Process				
HCA Identification	As frequently as necessary but at least once every 3 years	Verified process identified in figure 1-1 was utilized.	HCAs are identified for each gas transmission pipeline segment	IMG or Consultant
Identified New and Modifying Existing HCAs	Annual before an integrity assessment	Documentation of patrol activity and MOC Submissions to IMG	Record review of materials submitted	IMG or Consultant
HCA Field Audit Process	As needed or before integrity assessment	Verify process identified in figure 1-2 was utilized.	Add / remove HCAs as field verified.	IMG or Consultant
Baseline Assessment Plan Processes				
Assessment Methods & Assessment Schedule	As frequently as necessary but at least once every 3 years	Verify process identified in figure 2-1 was utilized.	Assessment methods are selected by the risks and feasibility for each pipeline segment	IMG or Consultant
Assessment Progress	Annual	Assessment schedule review	GRS is to assess all covered segments by December 17, 2012	IMG or Consultant
BAP Update	Annual not to exceed 15 months	BAP review	BAP is updated with newly identified HCAs, newly installed pipe, completed assessments and other new pipeline risk information	IMG or Consultant
Threat Identification/Data Integration/Risk Assessment Processes				
Threats Identification	Annual	Verify new or changed threats identified.	Covered pipeline segments are evaluated for each of the nine categories threats listed in ASME B31.8S	IMG or Consultant
Risk Model Data	Annual	Verified process identified in figure 3-2 was utilized.	Latest available pipeline data is ready for Risk Model.	IMG or Consultant
Assessment Processes				
Hydrotest	Each Use	Audit of hydrotest records	Hydrotest assessments conform to Section 2 of this IMP Plan	Transmission Supervisor

Audit Activity	Audit Frequency	Methods for Assuring Quality	Criteria Of Validation	Responsible Party
ILI Process	Annual for pipelines completed in prior year	a) Tool selection process. b) Data accuracy c) Anomaly grading	a) Tool selection process conformed to section 2.1.1 b) Data acceptance per Figure 2-2 c) Anomaly grading conformed to Figure 5-3	IMG or Consultant
ECDA Process (not used)				
ECDA Post Assessment Effectiveness (not used)				
ICDA Process (not used)				
SCCDA Process (not used)				
Remediation Processes				
Anomaly Discovery	Annual	Review of vendor reports against NWN Diglist.	Discoveries made within 180 days of assessment	IMG or Consultant
Anomaly Remediation	Annual	Review of the previous year's Diglists.	Immediate and schedule prioritized anomalies remediated within timeframes; Monitored conditions documented for re-evaluation in future assessments	IMG or Consultant.

Audit Activity	Audit Frequency	Methods for Assuring Quality	Criteria Of Validation	Responsible Party
Immediate Condition Pressure Reduction	Annual	Review of the previous year's Diglist.	Immediate conditions had pressure reduced 80% of the pipeline pressure at time of discovery	IMG or Consultant
Pressure Reductions Exceeding 365 days	Annual	Review of the previous year's Diglist.	Pressure reductions exceeding 365 days had written justification	IMG or Consultant.
Preventive and Mitigative Measures Processes				
Additional P&M Measure Implementation	Every 2 years	Review of P&M records	Effectiveness of implemented P&M measures are tracked and re-evaluated	IMG or Consultant
Additional P&M Measure Budget	Annual	Review of P&M records to ensure that all proposed P&M measures submitted for approval for the following budget cycle.	P&M process is integrated into budget process	IMG or Consultant
Additional P&M Measure Implementation	Annual	Review of P&M records to ensure that all proposed P&M measures were implemented following budget approval.	Additional P&M Measures Implemented	IMG or Consultant
Record Keeping and Quality Assurance Processes				
Pipeline Records	Annual	Check randomly selected pipeline records	Maintaining required records for the useful life of the pipeline	IMG or Consultant
Training Records	Annual	Training records review	Training records of NW personnel and contractors are up to date	IMG or Consultant
Agency Notification	Annual	Records review	All notifications required by subpart O of the rule to be provided to OPS; or to OPUC; or the WUTC have been made on time.	IMG or Consultant
Quality Assurance Process				
Audit Activity	Annual	Review the conduct of the Audit Process	Was the Audit Process an effective means of evaluating the TIMP requirements?	IMG or Consultant

13. Communication Plan

The GRS Plan addresses safety concerns raised by PHMSA, state and local authorities, and the public through its communication plan. The plan includes a process for keeping company personnel up-to-date on the integrity management plan. The plan addresses both routine communications as well as responses to requests for information.

13.1 External and Internal Communications Requirements

13.1.1 External Communication

The GRS Plan maintains a Public Safety Awareness Policy, Customer and Public Education, and an annual Public Safety Awareness Program Plan that addresses the external communication elements outlined in RP1162 and ASME B31.8S. The Public Safety Awareness Program Plan is maintained by the NWN Director Consumer Information & Internet Services.

The following items will be considered for external communication to the various interested parties as outlined below:

A. Landowners and Tenants along the Rights-Of-Way

1. Company name, location and contact information.
2. General location information and where more specific location information or maps can be obtained.
3. Commodity transported.
4. How to recognize, report, and respond to a leak.
5. Contact phone numbers both routine and emergency.
6. General information about pipeline operator's prevention, integrity measures, emergency preparedness and how to obtain a summary of Integrity Management Plans.
7. Damage prevention information, including excavation notification numbers and excavation notification center requirements and who to contact if there is any damage.

B. Public Officials Other Than Emergency Responders

1. Periodic distribution to each municipality of maps and company contact information.

2. Summary of GRS emergency preparedness and TIMP Plan.

C. Local and Regional Emergency Responders.

1. GRS will maintain continuing liaison with all emergency responders, including local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc. GRS shall provide:
    a. Company name and contact numbers both routine and emergency.
    b. Local maps.
    c. Facility description and commodity transported.
    d. How to recognize, report, and respond to a leak.
    e. General information about pipeline operator's prevention and integrity measures and how to obtain summary of Integrity Management Plans.
    f. Station locations and descriptions.
    g. Summary of operators' emergency capabilities.
    h. Coordination of operators' emergency preparedness with local officials.

D. General Public.

1. Information regarding GRS's efforts to support excavation notification and other damage prevention initiatives.
2. Company name, contact, and emergency reporting information including general business contact.

13.1.2 Internal Communication

The IMG and GRS communicate internally to establish understanding of and support for the GRS Plan in the following ways:

1. Integrity Management intranet website
2. Email of information to appropriate company personnel
3. Integrity Management Group meetings

4. Scheduled program evaluations
5. Meetings with Upper Management

The Supervisor of Integrity Management determines when information needs to be communicated to others in the GRS organization and then determines the most effective method of communication. The NWN Public Affairs and Communication Services Department may assist in disseminating the information.

A semiannual Communications Committee meeting is held with representation from across the company to review the safety information being distributed to customers and a strategy to inform employees.

Integrity Management Website

The following information is available at all times on the GRS corporate intranet:

- Integrity Management Plan
- Useful forms
- Semi-annual program reviews
- Other information as appropriate and needed

Email

The IMG and GRS staffs handle much of its internal communication via email or on its corporate intranet. The IMG and GRS staffs are responsible for determining what information needs to be communicated and to whom, and who maintains pertinent e-mail communication.

Integrity Management Group Meetings

The IMG meets periodically. During these meetings, the team will determine if new or additional information needs to be communicated to other divisions within the organization. The Supervisor of Integrity Management communicates any issues, concerns, or updates to applicable personnel.

Periodic Program Evaluations

As part of its performance measures, the IMG conducts periodic program evaluations of the GRS Plan. Those evaluations will be posted on the intranet website.

13.2 Addressing Safety Concerns

PHMSA and/or state or local authorities' safety concerns will be addressed by contacting:

GRS
220 NW Second Avenue
Portland, OR 97209

Attention:

Or:

Upon receipt of safety concerns, they will be evaluated to determine if they are specific to GRS. If specific to GRS, an acknowledgement of receipt will be made. The appropriate individual will research the concern and a written response made to the originator in a timely fashion. If the concern is general in nature, such as a Pipeline Safety Advisory, the directions will be followed and the actions documented.

14. Submittal of Program Documents

This section details the provisions to submit documentation to PHMSA or state authorities tasked with pipeline safety inspection.

14.1 Procedures for Submittal of Documentation

14.1.1 Submittal to Pipeline Hazardous Materials Safety Administration (PHMSA)

PHMSA Notifications

The IMG notifies PHMSA by one of the following methods: The Supervisor of Integrity Management, by mail, or electronically. A copy of the communications will be given to the NWN Code Compliance department and may be sent by fax or through the PHMSA Integrity Management Database (IMDB) website as well (PHMSA prefers electronic submittal of data).

Mail to:

Information Resources Manager

Pipeline and Hazardous Materials Safety Administration
U.S. Department of Transportation
Room 2103
400 Seventh Street, SW
Washington, DC 20590

3. Fax to: Information Resources Manager; 202.366.7128

4. Enter the information directly on the IMDB website:
http//primis.phmsa.dot.gov/gasimp

The IMG notifies PHMSA of any major changes to the GRS TIMP Plan or its related procedures, including a 25% or greater change in HCA mileage or a major change in the risk model.

Performance Reports

The IMG submits GRS performance reports to PHMSA as detailed above. A copy of the submission will be given to the NWN Code Compliance department.

1. Mail to:

   Pipeline and Hazardous Materials Safety Administration
   U.S. Department of Transportation
   Room 7128
   400 Seventh Street, SW
   Washington, DC 20590

2. Fax to: Information Resources Manager; 202.366.7128

3. Enter the information directly on the online reporting system for electronic reporting: http://primis.phmsa.dot.gov/gasimp/

14.1.2 State and Local Document Submittal

GRS submits its risk analysis or integrity management program to state or local authorities upon request. Table 14-1 lists the contact information for state or local agency with jurisdictional authority over any segment of GRS's gas pipelines. Notifications to PHMSA should also go to appropriate state and local pipeline safety authorities.

Table 14-1. State and Local Agencies

Agency Name	Jurisdictional Authority	Addressee	Fax	Mail
California Public Utilities Commission (CPUC)	California	Chief, Pipeline Safety		Mr. Raffy Stepanian, Chief 505 Van Ness Avenue, Room 2005 San Francisco, CA 94102-3298

Appendix A – Data Element/Threat Matrix

Note: This table is based on the following ASME B31.8S data:

- Table 1, Data Elements for Prescriptive Transmission Integrity Program, and
- Section 2.2, Integrity Threat Classification

Class of Element	Data Element	IntegrityThreat Classification								
		Time Dependent			Stable Defects			Time-Independent		
		External	Internal	SCC	Manu-facture	Weld/ Fabrication	Equip-ment	3rd Party	Incorrect Operations	Weather/ Outside Force
Attribute	Pipe wall thickness	X	X							X
	Diameter	X	X							X
	Seam type				X					
	Joint factor				X					
	Manufacturer				X		X			
	Manufacturing date				X		X			
	Pipe material and properties				X	X				
	Equipment properties						X			
	Pipe grade									Internal stress + pipe loading <100% SMYS
	Manufacturing process*				X					
	*If pipe data is unknown, can use "History of Line Pipe Manufacturing in North America", by Keifner and Clark 1996 ASME, for age of manufacture.									
Construction	Year of installation	X	X		X		Failed eqpmt			X
	Bending method					X				
	Joint method, process and inspection results							X		
	Depth of cover					Wrinkle bends				
	Crossings/casings	X								
	Pressure test				X	X	X			
	Field coating methods	X								
	Soil/backfill characteristics	X				Wrinkle bends				
	Inspection reports				X					
	Cathodic protection installed	X								
	Coating type	X		X						
	Age of pipe			X						
	Coupling identification					X				

Class of Element	Data Element	IntegrityThreat Classification								
		Time Dependent			Stable Defects			Time-Independent		
		External	Internal	SCC	Manu-facture	Weld/ Fabrication	Equip-ment	3rd Party	Incorrect Operations	Weather/ Outside Force
	Post construction coupling reinforcement					X				
	NDT information on welds					X				
	Number of girth welds/ couplings reinforced/removed					X				
Construction (cont)	Number of wrinkle welds removed					X				
	Number of fabrication welds repaired/removed					X				
	Topography and soil/backfill conditions (unstable slopes, water crossings, water proximity, soil liquefactions susceptibility)							X		
Operational	Gas quality		X							
	Flow rate		X	X						
	Normal max and min operating pressures/ Operating stress level (%SMYS)	X	X	X						
	Leak/failure history	X	X			Due to const. defects				
	Coating condition	X								
	Cathodic Protection system performance	X								
	Operating temperature/Pipe wall temperature			X						
	Pipe inspection reports	X		X		X	X	X		
	OD/ID corrosion monitoring	X	X							
	Pressure fluctuations		X	X						
	Regulator valve failure information						X			
	Relief valve failure information						X			
	Flange gasket failure information						X			
	Regulator set point drift (outside of manufacturer's tolerances)						X			
	Relief set point drift						X			
	Encroachment records							X		

Class of Element	Data Element	IntegrityThreat Classification								
		Time Dependent			Stable Defects			Time-Independent		
		External	Internal	SCC	Manu-facture	Weld/ Fabrication	Equip-ment	3rd Party	Incorrect Operations	Weather/ Outside Force
	Repairs	X	X	X	X	X	X	X		X
	Vandalism incidents							X		
	External forces					X				
	MIC detected	X								
	Years with adequate cathodic protection	X								
	Years with questionable cathodic protection	X								
	Years without cathodic protection	X								
	Leak reports resulting from immediate damage							X		
	Leak reports resulting from previous damage							X		
Operational (cont)	Operating parameters (pressure, flow velocity, periods of no flow)		X							
	Distance of segment from a compressor station			X						
	O-ring failure information						X			
	Operating pressure history				X					
	Wrinkle head identification					X				
	One-call records							X		
	Earthquake fault							X		
	Profile of ground acceleration near fault zones (> 0.2 g acceleration)							X		
	Depth of frost line							X		
	Seal/packing information						X			
	Failures caused by incorrect operation							X		
Inspection	Past hydrostatic test information	X	X	X	X					
	In-line inspections	X	X					X		
	Geometry inspections							X		
	Bell hole inspections	X	X			X	Where pipe was hit			

Class of Element	Data Element	IntegrityThreat Classification								
		Time Dependent			Stable Defects			Time-Independent		
		External	Internal	SCC	Manu-facture	Weld/ Fabrication	Equip-ment	3rd Party	Incorrect Operations	Weather/ Outside Force
	CIS CP inspections	X								
	DCVG coating condition inspections	X								
	Procedure review information							X		
	Audit information							X		
	Gas, liquid, or solid analysis (hydrogen sulfide, CO2, oxygen, free water, and chlorides)		X							
	Bacteria culture test results		X							
	Corrosion detection devices (coupons, probes, etc.)		X							
	Number of wrinkle bend inspections					X				
	In-line inspection results for dents and gouges at top half of pipe							X		

Appendix B – Standard Practice for Pressure Testing of Steel Pipelines

Appendix B Standard Practice for Pressure Testing of Steel Pipelines

Revision: 0

1. SCOPE

This standard practice establishes the required pressures and duration for testing all new steel pipelines (mains, services and fabricated units) designed to be operated at pressures in excess of 60 psig. Subsequent retesting of existing pipelines follows the same procedures for testing as all new steel pipelines.

2. POLICY

Prior to actual pipeline operation all new pipelines or fabricated units that will be operated at pressures greater than 60 psig, regardless of whether they are mains, services, or fabricated units shall be pressure tested. Exceptions to this policy require the approval of NW Natural's Manager of Engineering, or designee.

3. PROCEDURE

3.1 General Requirements

Perform pressure tests for all new or replacement pipeline and fabricated unit installations.

Pre-tested fabricated units may be used as an alternative to an on-site pressure test.

Pre-tested pipe can be installed as a single component in a pipeline segment as an alternative to an on-site pressure test.

Perform soap tests at the tie-in joints not subjected to pressure test or nondestructive testing at not less than the current operating pressure of the pipeline.

3.2 Test Pressures, Durations, and Disposal of the Testing Medium

Pressure test all steel pipelines and fabricated units as specified by the Engineering department in accordance with state and federal safety regulations (Part 192 Subpart J) . Testing criteria is based on the Percent Specified Minimum Yield Strength (%SMYS) of the pipe at the certified MAOP and at test pressure. The Engineering department will determine the %SMYS based on the following equation:

%SMYS = Hoop Stress/Minimum Specified Yield Strength of pipe

Hoop Stress = PD/2t

Where: P = Certified MAOP of the pipeline or assembly (psig)
D = Nominal outside diameter of the pipe (in.)
T = Nominal wall thickness of the pipe (in.)

Minimum test pressure, test media and test duration will be based on certified MAOP and length of pipeline to be tested in accordance to the chart below. Any exceptions to this chart must be approved by Manager of Engineering, Principal Compliance Engineer or designee:

Certified MAOP	Pipe Diameter	Test Length	Test Media	Minimum Test Pressure	Test Duration
Greater than 400 psig	No diameter restrictions	No length restrictions	Water	1.5 times MAOP	8 hours2

In special circumstances with the approval of Manager of Engineering, Principal Compliance Engineer, or designee, minimum test pressure may be lower than 600 psig to a minimum of 1.5 times MAOP.

For fabricated units and short sections of pipe where a post installation test is impractical, a pre-installation strength test must be conducted by maintaining the pressures at or above the test pressure for at least 4 hours.

3.2.1 Maximum Test Pressure with Water as a Test Medium

For mains, services and fabricated units that do not include pressure rated components, the maximum test pressure is 90% SMYS. For pipelines that include components carrying a pressure rating, the maximum test pressure will be limited by the test pressure rating of the lowest-rated component.

For components:

Pipelines with Rated Components	Maximum Test Pressure
150 ANSI	425 psig
300 ANSI	1100 psig
600 ANSI	2175 psig

For testing of components with WOG or CWP rating, consult with manufacturer on appropriate maximum test pressure.

3.2.2 Disposal of Test Water

After the hydrostatic test, dispose of the water in accordance with applicable regulations.

3.3 Test Failures

If the test pressure drops below the specified minimum test pressure during the duration of the test for any reason, retest the main, service or fabricated unit for the full test duration after necessary modifications are made. Require a successful test for the specified duration before the main, service or fabricated unit is placed in operation.

3.4 Pressure Test Equipment

Maintain, test for accuracy, or calibrate pressure-testing equipment in accordance with the manufacturer's recommendations. When there are no manufacturer's recommendations, test the pressure-testing equipment for accuracy at an appropriate schedule determined by NW Natural.

Tag test equipment with the calibration or accuracy check expiration date. Apply the requirements of this section to equipment such as pressure charts, gauges, dead weights, or other devices used to test, monitor, or check system pressures or setpoints.

3.5 Pressure Test Records Required for Pipelines
(Mains, Services, Fabricated Units)

All pressure tests records shall be retained for the life of the pipeline and shall document the following information:

Operator's name

Contractor's name, if applicable

Employee's name, if applicable

Test medium used

Test pressure

Test duration

Pipe size and length

Dates and times

Test results

For pipelines that will operate at 20% SMYS or higher, retain a record of the test pressure, method, and duration on form 8161NS (example as the last page of this Standard Practice)with the attached Recorder Chart for the lifetime of all pipe. In addition, records for pre-tested pipe will also include form 8162NS once the pipe has been installed.

For pipelines that will operate below 20% SMYS document the test pressure using a Recorder Chart or a calibrated pressure gauge with readings recorded at a minimum of 15 minute intervals. Retain records for the life of the pipeline.

Where multiple pressure tests are performed on a single installation, maintain a record of each test. An example of a single installation with multiple tests would be any continuous ongoing job or installation such as a new plat or long main installation where more than one pressure test was conducted during construction.

4. REFERENCE CODES AND STANDARDS

49 CFR 192.105 – Design formula for steel pipe

49 CFR 192.503 – General requirements

49 CFR 192.505 – Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS

49 CFR 192.507 – Test requirements for pipelines to operate at a hoop stress less than 30 percent of SMYS and at or above 100 p.s.i. gage

49 CFR 192.515 – Environmental protection and safety requirements

49 CFR 192.517 – Records

49 CFR 192.619 – Maximum allowable operating pressure: Steel or plastic pipelines

Appendix C – Potential High Consequence Area Notification Form

POTENTIAL HIGH CONSEQUENCE AREA NOTIFICATION FORM

Your Name ____Date_____________________

Description of the potential High Consequence Area (HCA)____________________________________

____

____

Address or Pipeline Location (mile post)____

____

____

Which HCA criteria below do you think it meets? Circle all that apply:

1. Within 780 feet of the 30" Pipeline

2. Outside Area or Open Structure occupied by 20 or more persons at least 50 days in any 12 month period (NOTE: Days need not be continuous). Examples: Beaches, playgrounds, recreational facilities, campgrounds, outdoor theaters, stadiums, areas outside of a rural building such as a religious facility, or other similar areas or structures.

3. Building occupied by 20 or more persons at least 5 days per week for 10 weeks in any 12 month period (NOTE: Days or weeks need not be continuous). Examples: Office buildings, community centers, religious facilities, general stores, 4-H facilities, roller skating rinks, or other similar buildings.

4. Facility occupied by persons who are confined, are of impaired mobility, or difficult to evacuate. Examples: Hospitals, prisons, schools, daycare facilities (licensed or unlicensed), retirement facilities, assisted living facilities, or other similar facilities.

<u>SEND THIS FORM TO: Gill Ranch Storage Plant Manager</u>

GRS Plant Manager Comments: ____

____

___________________ (date)

Received by the Supervisor of Integrity Management on ___________________ (date)

Action(s) as a result of this notification ____

____

Appendix D – Quality Assurance Audit Form

QUALITY ASSURANCE AUDIT FORM

Audit Activity ____

Person conducting the Audit ______________________ Date____________

Audit Frequency______________________ Last Audited______________

Quality Assurance Method____________________________________

Critria____

Result of Audit/Comments____________________________________

____

____

Recommended Action____

____

____

Recommended Action sent to______________________ Date____________

Recommended Actions Received by__________________Date____________

Action(s) as a result of the Recommendations__________________________

____

____

____

Assigned to______________________________ Date ____________

For Completion by__________________ Charge Number______________

Receipt of Assignment by______________________Date____________

Completion Date______________

Was the Recommended Action Effective? Yes / No

Are Additional Actions Recommended? Yes / No Describe__________________

____

____

Additional Recommendations Sent to__________________ Date____________

Receipt of Additional Recommendations by______________ Date____________

Action(s) Taken as a Result of Additional Recommendations__________________

____

____

Appendix E – Preventive and Mitigative Measures Meeting Typical Agenda

Agenda item	Topics within agenda
Candidate pipe segments for preventive or mitigative measures	Location, risk levels, and threats of the following: • Segments with greatest overall risk • Segments exhibiting a trend of increasing risk, including segments with increasing risk because of previously unidentified threats • Segments in which a leak could cause secondary effects or pose another unusually high danger • Segments with unreduced risk despite implementation of P&M measures • Segments that have undergone an integrity assessment since the last P&M meeting • Other segments chosen by Project Manager
Effectiveness review of previously implemented P&M measures	• P&M measures from previous P&M meeting
Third party damage prevention review	• Implications of time-independent threat • Qualifications of personnel who locate and mark lines and who supervise excavations • Development of excavation damage database • One Call participation • Excavation or above-ground survey/direct examination of unmonitored encroachments • Remediation of damage found by inspections, examinations, and tests • Third-party damage prevention programs • Low-stress P&M activities • Other means of preventing third-party damage for high-risk segments
Corrosion prevention review	• Implications of time-dependent threat • Discovered immediate repair corrosion damage • Plan for evaluating and remediating corrosion on all segments (covered and non-covered) with similar coating and environmental characteristics • Other means of preventing external corrosion, internal corrosion, and Stress Corrosion Cracking for high-risk segments
Prevention of stable threats on high-risk segments	Discussion of possibility of failure and means of prevention regarding the following threats: • Manufacturing-related threat • Construction threat • Equipment-related threat

Agenda item	Topics within agenda
Prevention of incorrect operations threat	Discussion of possibility of failure and means of prevention regarding incorrect operations
Prevention of outside force/weather-related damage threat	Discussion of possibility of failure and means of prevention regarding outside force/weather damage
Valve placement review	Discussion of whether Automatic Shut-off Valves and Remote Control Valves are adequately protecting HCAs based on • Distance from HCA to ASV/RCV • Pipeline profile • Response time • Distance from ignition source • Shutdown time • MAOP
Mitigative measures for segments where consequence is the primary risk driver	• Response training • Drills with emergency responders • Inspection and maintenance schedules • Replacement of thin-walled pipe with thicker-walled pipe • Monitoring and leak detection systems
Other changes to pipe, operation, or program	Discussion of possible changes in equipment, pipeline components, pipeline operations, or procedural changes
Review of assessment/ reassessment schedule	Discussion of whether assessment dates and intervals are appropriately set based on updated levels of risk
Candidate pipe segments for preventive or mitigative measures	Location, risk levels, and threats of the following: • Segments with greatest overall risk • Segments exhibiting a trend of increasing risk, including segments with increasing risk because of previously unidentified threats • Segments in which a leak could cause secondary effects or pose another unusually high danger • Segments with unreduced risk despite implementation of P&M measures • Segments that have undergone an integrity assessment since the last P&M meeting • Other segments chosen by the Project Manager
Effectiveness review of previously implemented P&M measures	• P&M measures from previous P&M meeting

Appendix F – THE GRS Preventive and Mitigative Measures Review Form

GRS PREVENTIVE & MITIGATIVE MEASURES REVIEW FORM

P & M Meeting Chair: ______________________ Meeting Date: ___________________

Attendees: ____

____

Pipeline to be evaluated: ____

Between start: ____________________________ & end: _________________________

Note: Use additional forms for other segments to be evaluated.

Predominant threat information for the pipeline: ______________________________

____

____

____

____

_______New P & M measures proposed to reduce the predominant threats and an evaluation of their effectiveness: ____

____

____

____

____

_______ P & M measure(s) proposed for the inclusion in the next Capital Budget Request:_______________

____

____

____

____

_______Proposed new P & M measure(s) implementation plan: ______________________

____

____

____

____

Appendix G - Anomaly Report

This section provides a reduced sample of the Pipeline Anomaly Report and the instructions for completing the form.

I. Instructions

1. Excavation Location

This section is required for all digs and records information pertaining to the location of the excavation.

- Pipeline Name – Write the complete Pipeline Segment name. Include alphanumeric name (i.e. P-72) and title (i.e. South Mist Transmission). Optionally include the start and end of the operational pipeline segment (i.e. Bacona to Rock Creek)
- Report (WMIS) Number – Record the WMIS number for the dig. The WMIS number will allow for the Anomaly Report to be matched with other construction documentation.
- Plat – Record the plat that the dig occurs in.
- Date of Examination: Record the date that the pipe was examined.
- Physical Location of Pipe (address) – Record any additional information that could help identify the location of the dig from above ground. Possible measurements include, physical address or distance to property line or cross street.
- U/S Reference – Record the Upstream Reference from either the ILI or Direct Assessment report (i.e. a valve, bend, or starting location).
- Distance to U/S Ref – Record the reported distance from the ILI or Direct Assessment report between the dig and the upstream reference
- D/S Reference – Record the Downstream Reference from either the ILI or Direct Assessment report (i.e. a valve, bend, or ending location).
- Distance to D/S Ref – Record the reported distance from the ILI or Direct Assessment report between the dig and the downstream reference
- GPS Northing – Record the GPS Northing if available
- GPS Easting – Record the GPS Easting if available
- Reason for Excavation – Record the method of assessment that identified the location for a visual examination.
- Excavation Priority – Record the priority of the excavation using the definitions in Section 5.1.1 of this plan.
- Length of Pipe Exposed – Record the total length of pipe exposed in the ditch.
- Length of Coating Removed – Record the length of coating removed.

2. Pipe Description

This section is required for all digs. This section records information pertaining to the pipe as installed.

- Diameter – Record the outer diameter of the pipe to be examined. (i.e. 10.75”)
- Nominal wall thickness – Record the nominal wall thickness of the pipe to be examined (i.e. 0.219”wt)
- Grade – Record the grade of the pipe to be examined (i.e. API5L-X42)
- Long Seam Type – Record the long seam type of the pipe to be examined. Options include Electric Resistance Weld (ERW), Double Submerged Arc Weld (DSAW), Seamless, Lap Welded, and Spiral Weld.
- Long Seam Orientation – Record the o’clock position of the long seam for ERW and DSAW pipe.
- Depth of Cover – Record the depth of the pipe measured from the top of the pipe to the surface of the ground.
- Existing Coating – Record the type of existing coating on the excavated pipe
- New Coating – Record the type of new coating installed on the pipe.
- Coating Condition –Record the percentage of the existing coating that is adhered to the pipe.
- Average Coating Thickness – Record the average thickness of the existing coating using a magnetic pull off gauge prior to the coating being removed, or calipers once the coating has been removed.
- UT Wall thickness – Record the actual wall thickness all the way around the pipe using a compression wave ultrasonic wall thickness meter. If additional UT wall thickness measurements are taken, attach an additional sheet.
- Comments – Record any other pertinent information here.

3. Direct Assessment

- GRS intends to use only Hydrotesting or Inline Inspection for assessing GRS transmission pipelines. This section will be completed should the GRS Plan propose to use Direct Assessment in the future.

4. Pipe Anomalies

This section is required for all digs. This section records information pertaining to the pipe as found.

- Metal Loss Present – Record if metal loss is present on pipe
- Orientation – Record o’clock position of the metal loss found on pipe
- Deepest Pit Depth (in) – Record the depth of the deepest metal loss pit in inches. Use properly calibrated pit gauge.
- Deepest pit Length (in) – Record the longitudinal length in inches of deepest metal loss pit

- Deepest pit Width (in) – Record the circumferential width in inches of the deepest metal loss pit
- Largest Pit Depth (in) – Record the depth of the largest metal loss pit in inches
- Largest pit Length (in) – Record the longitudinal length in inches of largest metal loss pit
- Largest pit Width (in) – Record the circumferential width in inches of the largest metal loss pit
- Interacting Depth (in) – Record the deepest pit of the interacting metal loss. Individual metal loss pits are considered interacting if they are within 1" longitudinally and 6t (where t = wall thickness) circumferentially.
- Interacting Length (in) – Record the length of the interacting metal loss. Individual metal loss pits are considered interacting if they are within 1" longitudinally and 6t (where t = wall thickness) circumferentially.
- Distance to Girth Weld – Record the distance of the metal loss anomalies from the nearest Girth Weld (if a girth weld was exposed)
- Dent/Deformations Present – Record if a dent or deformation is present on the pipe
- Orientation - Record o'clock the position of dent/deformation found on pipe
- Depth (in) – Record the depth of the dent/deformation found on the pipe. Measure the depth using a long straight edge ruler to bridge the deformation and measure the deepest deviation from round pipe.
- Distance from Girth Weld – Record the distance of the deformation anomaly from the nearest Girth Weld (if a girth weld was exposed)
- Length (in) – Record the length of the dent/deformation found on pipe. Measure the length by using a long straight edge ruler to bridge the deformation and measure the length of pipe that deviate from round pipe.
- Interacting with Other Anomalies – Record if the dent/deformation is interacting with other anomalies (i.e. metal loss in a dent, or a gouge in a dent…)
- Cracks/Gouge Present - Record if a crack or gouge is present on pipe
- Orientation – Record o'clock position of the crack or gouge found on pipe
- Depth (in) – Record the depth of the crack or gouge in inches.
- Distance from Girth Weld – Record the distance of the crack or gouge from the nearest Girth Weld (if a girth weld was exposed)
- Length (in) – Record the length of the crack or gouge found on pipe. .
- Interacting with Other Anomalies – Record if the crack or gouge is interacting with other anomalies (i.e. gouge in dent, cracks with metal loss)
- Additional NDE Performed – Record if any additional NDE was performed on the anomaly such as automated ultrasonic inspection, wet magnetic particle, and shear wave ultrasonic. Record pertinent information in comment section, and if possible, attach written report to Anomaly Report Form.
- Anomaly/NDE Comments – Record general comments on anomaly here. If necessary attach additional pages.

- Repair/Evaluation Criteria – Record the evaluation/repair criteria used to determine if a repair is necessary. If "Other" is selected, document criteria used.
- Repair Required – Record if evaluation/repair criteria mandates a repair to the pipeline to return the pipe to full operational capability. For locations where an industry code does not require a repair, but a repair is installed for added insurance, mark this section as "no"
- Repair Used – Record the repair installed on the pipe.
- Repair comments – Record general comments on repair here. If necessary attach additional pages.

5. Sketches, Attached Sheets, and Report Approval

The sketches should be filled out for every dig, but are not mandatory. The attached sheets sections should be used to denote additional pages that are attached. The Report Approval blocks must be filled out for every form.

- Coating Diagram – Sketch the coating as found here. Note any coating damages or anomalies. If necessary attach additional pages.
- Pipe Diagram – Sketch the anomalies and nearby references (such as exposed welds) as found on the pipe here. If necessary attach additional pages.
- Attached Sheets – Record if the following additional documents were created for this excavation, Coating damage log, metal loss log, photo log, and additional NDE reports.
- Report Prepared By – Record the name of the person who prepares the report.
- Report Approved By – A member of either the GRS Integrity Management Team or GRS Pipeline Services Department must approval all Anomaly Reports. The person who generates the Anomaly report may approve the Anomaly Report.
- Date – Record the date the Anomaly Report was completed.

II. Report Form

The Pipeline Integrity Anomaly Report form is shown on the following page (reduced size).

GRS
Pipeline Integrity - Anomaly Report

Excavation Location

Pipeline Name:________________ Report (WMIS) Number:________________

Plat:________________ Date of Examination: ________________

Physical Location of Pipe (address)________________

U/S Reference:________________ Distance to U/S Ref:________________

D/S Reference:________________ Distance to D/S Ref:________________

GPS Northing:________________ GPS Easting:________________

ILI odo:________________ ILI Report:________________

Reason for Excavation: [ ]DA [ ]ILI [ ]Recoat [ ]Leak [ ]Other ________________

Comments:________________

Excavation Priority: [ ]Immediate [ ]Scheduled [ ]Monitor [ ]Other

Length of Pipe Exposed:________________ Length of Coating Removed:________________

Pipe Description

Diameter	Nominal Wall Thickness	Grade	Long Seam Type	Long Seam orientation	Depth of Cover (in)

Existing Coating: [ ]Bare [ ]Coal Tar [ ]Tape [ ]Wax [ ]FBE [ ]Other________________

New Coating: [ ]Powercrete [ ]Polyken Tape [ ]Wax Tape [ ]Other________________

Coating Condition: [ ]Excellent - Fully Adhered to Pipe [ ] Good - 75%-99% Adhered to pipe [ ] Fair - 50%-75% Adhered to pipe [ ] Poor - Less than 50% Adhered to pipe

Average Coating Thickness:________________

UT Wall thickness:

12:00	1:00	2:00	3:00	4:00	5:00	6:00

7:00	8:00	9:00	10:00	11:00

Comments:________________

Direct Assessment

Holiday Testing Performed: [ ]Yes [ ]No Voltage Used:________________

Pipe to Soil Potentials in Ditch (-mV):________________

Comments:________________

Soil Resitivity in Ditch (p-cm):________________ Soil Samples Collected: [ ]Yes [ ]No

Ground Water Present? [ ]Yes [ ]No Samples Collected: [ ]Yes [ ]No

Liquid Underneath Coating? [ ]Yes [ ]No If yes, pH of Liquid:________________

Corrosion Product Present? [ ]Yes [ ]No If yes, sample taken? [ ]Yes [ ]No

Comments:________________

Soil Type:________________ Soil PH:________________

ECDA Comments:

Pipe Anomalies

Metal Loss Present: [ ]Yes [ ]No | Orientation:____

Deepest Pit Depth (in)	Deepest Pit Length (in)	Deepest Pit Width (in)	Largest Pit Depth (in)	Largest Pit Length (in)	Largest Pit Width (in)	Interacting Depth (in)	Interacting Length (in)	Distance to Girth Weld

Dent/Deformation Present: [ ]Yes [ ]No Orientation:____________________

Depth (in):__________ Distance from Girth Weld:____________

Length (in):____________ Interacting with other Anomalies?:_________

Cracks/Gouges Present: [ ]Yes [ ]No Orientation:____________________

Depth (in):__________ Distance from Girth Weld:____________

Length (in):____________ Interacting with other Anomalies?:_________

Additional NDE Performed? (Wet-mag, UT…) [ ]Yes [ ]No

NDE Comments:________________________________

Anomaly/NDE Comments:

Repair/Evaluation Criteria: [ ]ASME B31.G [ ]RSTRENG [ ]NWN Criteria [ ]Other

Repair Required: [ ]Yes [ ]No (^if other explain____________)

Repair Used: [ ]Clockspring [ ]Weld Band [ ]Other__________________

Repair Comments:

Coating Diagram <------ Flow

6:00									
3:00									
12:00									
9:00									
6:00									

Pipe Diagram <------ Flow

6:00									
3:00									
12:00									
9:00									
6:00									

Attached Sheets:

Coating Damage Log (Y/N)		Metal Loss Log (Y/N)		Photo Log (Y/N)	
NDE Reports (Y/N)					
Report Prepared By:		Report Approved By:		Date:	

Appendix H – Management of Change Report

This section provides a reduced sample of the Management of Change (MOC) report and the instructions for completing the form.

I. Instructions

- MOC Title – Document the general nature of the change.
- Date – Document the date the MOC form is initiated
- Initiator – Record the name of the person or department that is requesting the change.
- Contact # - Document the phone number of the initiator.
- Title – Documents the title of the initiator
- Email – Document the email address of the initiator.
- Description of Proposed Change – Document a complete description of the proposed change. Include the reason for the change and an analysis of implication. If necessary, attach additional sheets.
- Duration of Change – Document if the change is permanent or temporary. If temporary, document the dates of the temporary change.
- Communicated/Distributed To – Document the departments and people that the change has been communicated/distributed to.
- Other Notification or Approval Required – Document departments and people outside Pipeline Integrity that may need to be notified or approve of the change.
- Approved/Acknowledged – Documents the acceptance/awareness of the change by the Pipeline Integrity Program Manager or his/her designee.
- Date – Record the date of acceptance of the change by the Pipeline Integrity Manager.

II. Report Form

The Management of Change form is shown on the following page.

Appendix H
GRS - Management Of Change

MOC Title: ______________________________ Date: ______________

Initiator: ______________________________ Contact #: ______________

Title: ______________________________ Email: ______________

Description of Proposed Change (including Reason for Change and Analysis of Implication):

Proposed Change:

*Required Work Permits are the Responsibility of the Initiator and are handled with normal GRS work processes. Document extra and extraordinary permit requirements.

Duration of Change: ☐ Permanent ☐ Temporary - From ________________ To ______________________

Communicated/Distributed to:____

Other Notification or Approval Required:____

Approved/Acknowledged:________________________________ Date:__________________________

Appendix I – Resources Used by the GRS Integrity Management Group

DOQQ – Digital Ortho Quarter Quads – National Dataset

A digital orthophoto quadrangle (DOQ) is a computer-generated image of an aerial photograph in which image displacement caused by terrain relief and camera tilts has been removed. It combines the image characteristics of a photograph with the geometric qualities of a map.

The standard DOQ's produced by the U.S. Geological Survey (USGS) are either grayscale or color-infrared (CIR) images with a 1-meter ground resolution; they cover an area measuring 3.75- minutes longitude by 3.75-minutes latitude, approximately 5 miles on each side or a quarter of a USGS 7.5 minute quad. Each DOQ has between 50 and 300 meters of overedge image beyond the latitude and longitude corner crosses embedded in the image. This overedge OK facilitates tonal matching and mosaicing of adjacent images. All DOQ's are referenced to the North American Datum of 1983 (NAD83) and cast on the Universal Transverse Mercator (UTM) projection. Primary (NAD83) and secondary (NAD27) datum coordinates for the upper left pixel are included in the header to allow users to spatially reference other digital data with the DOQ. From: http://www.usgsquads.com/prod_doqq.htm

GNIS – Geographic Names Information System – National Dataset

The Geographic Names Information System (GNIS), developed by the U.S. Geological Survey in cooperation with the U.S. Board on Geographic Names, contains information about physical and cultural geographic features in the United States and associated areas, both current and historical (not including roads and highways). The database holds the federally recognized name of each feature and defines the location of the feature by state, county, USGS topographic map, and geographic coordinates.

The GNIS is the official vehicle for geographic names use by the Federal Government and the source for applying geographic names to Federal maps & other printed and electronic products. The system supports the U.S. Board on Geographic Names, a Federal body created in 1890 and established in its present form by Public Law in 1947. The Board serves the Federal Government, other government agencies, and the public as the central authority to which name inquiries, name issues, and new name proposals may be directed. From: http://nhd.usgs.gov/gnis.html

LULC – Land Use and Land Cover – National Dataset

Land Use and Land Cover (LULC) vector data consists of land classifications that were based primarily from manual interpretation of 1970's and 1980's aerial photography. Secondary sources included land use maps and surveys. There are 37 possible categories of cover type using the Anderson level II classification system. From: http://www.mapmart.com/Vector/LULC/LULC.htm

NCES – National Center for Educational Statistics – National Dataset

The National Center for Education Statistics (NCES), located within the U.S. Department of Education and the Institute of Education Sciences, is the primary federal entity for collecting and analyzing data related to education.

The data(sic) comes directly from the 30,000 plus private schools that responded to the 2001-2002 Private School Universe Survey (PSS) conducted by the National Center for Education Statistics. From: http://www.nces.ed.gov/

Tiger – Topologically Integrated Geographic Encoding and Referencing system – National Dataset

The Census 2000 TIGER/Line shapefiles were created from the Topologically Integrated Geographic Encoding and Referencing (TIGER) database of the United States Census Bureau. The shapefiles contain data about the following features

- Line Features—roads, railroads, hydrography, and transportation and utility lines.
- Boundary Features—statistical (e.g., census tracts and blocks); government (e.g., places and counties); and administrative (e.g., congressional and school districts).
- Landmark Features—point (e.g., schools and churches); area (e.g., parks and cemeteries); and key geographic locations (e.g., apartment buildings and factories). From: http://www.esri.com/data/download/census2000_tigerline/description.html

VRisk – Visual Risk – National Dataset

Visual Risk Technologies provides a standard set of databases with all VRiskMAP™ projects. The data is custom-produced for each specific jurisdiction and includes not only the immediate area but also surrounding areas. In order to offer the user a detailed coverage of all critical facilities, lifelines, and infrastructure within the area, the data is derived from a variety of sources. All applicable databases include phone number information for contact and notification in the event of an emergency.

In addition to the provided datasets, VRiskMAP™ can also be used to display and query any existing ESRI shapefiles maintained by the local GIS department. Using local data in conjunction with the VRisk data bundle allows the emergency planner to have access to the most detailed and up-to-date data available for the jurisdiction. Also, by means of the

VRiskMAP™ interface with Microsoft Access, any Access table with lat/long coordinates or a physical street address may be used to incorporate existing information into the mitigation plan. From: http://www.vrisk.com/stafforddata.htm

Appendix J – Automatic Shutoff Valve or Remote Control Valve Evaluation

General Instructions

Before attending the evaluation meeting:
Print the Cap Sheet before attending the meeting to review the potential replacement(s).
The sheet will allow some entries electronically.
Print the Form (it will not allow electronic entry).
Take these two forms to the evaluation meeting.

Instructions for Automatic Shutoff Valve or Remote Control Valve Evaluation Matrix

This form is used for evaluating a covered transmission line segment for installation of an automatic shutoff valve or remote control valve (ASV or RCV.
It was created from the ANSI Z380 Gas Piping Technology Committee paper.
One person records the consensus of the group on the form.

The Matrix is arranged from minimum potential risk or consequence on the left to maximum potential risk or consequence on the right side of the form. A value of 1 is selected for the least value and a value of 5 is selected for the greatest value.

Circle only one numeric value per line.
Add the circled numeric values in each column and record those values in the row labeled Sub Total.
Add the numeric values in the Sub Total row and divide by 90.
The integer value needs to be represented as a percentage on the form.
The minimum percentage is 20% for risk or consequence reduction, on the given covered transmission line segment, when a ASV or RCV is installed on the given Covered Pipeline Segment.
The maximum percentage is 100% for risk or consequence reduction on the given covered transmission line segment.

Instruction for finalizing the ASV or RCV Evaluation Record

Record the potential percent decrease on the Cap Sheet.
A value of 80% or greater will require the recommendation of installation of an ASV or RCV.
Fill out the box with the group’s recommendation.
Submit to Engineering.

Automatic Shutoff Valve (ASV) or Remote Control Valve (RCV) Evaluation Form

Valve Location: ________________________________ Date: ______________

Plat Sheet: ______________________ Size: _____ Completed by: ______________________

	MINIMUM		**MODERATE**		**MAXIMUM**
FACTOR					
	1	**2**	**3**	**4**	**5**
Gas control Operations	Not necessary		Necessary		Very necessary
System Implications	Dual feed or no customers in this segment		Single source with few customers	Single source with a lot of customers	Provides service to residential and non-interruptible customers
Ability to detect decreased pressure by SCADA	Easy to detect	75% chance of detection	50% chance of detection	25% chance of detection	Not readily detectable
Pressure fluctuations affecting ability to sense damage	Never	Isolated events	Seasonal and frequent	Daily and frequent	Customer driven frequency
Proximity to a high consequence area (HCA) or an identified site	Far from Potential Impact Radius (PIR)	Somewhat beyond the PIR	Near the PIR	Within the PIR	Very close to the pipeline
Potential for third party damage	Not likely at all	Remote potential	Potential	More likely	Likely potential
Potential for nearby source of ignition	Not likely at all	Remote potential	Reasonable potential	Likely potential	Expected
Known source of ignition	No source	Source beyond 500 feet	Source at about 200 feet	Source at about 50 feet	Source very close
Pipe diameter	6” or smaller	8” and 10”	12”	16” to 20”	Larger than 20”
Pipeline MAOP	250 to 400	400 to 499	500 to 599	600 to 899	900 and greater
Time to respond during normal work hours from notification of a problem until crew is at site.	Within 15 minutes	Up to 60 minutes	Within 2 hours	Within 4 hours	> four hours
Time to respond during non-work hours from notification of	Within 60 minutes	Within 2 hours	Within 4 hours	Within 8 hours	> 8 hours

Automatic Shutoff Valve (ASV) or Remote Control Valve (RCV) Evaluation Form

Valve Location: ______________________________ Date: ______________

Plat Sheet: ______________________		Size: ______	Completed by: ______________________		
	MINIMUM		**MODERATE**		**MAXIMUM**
FACTOR					
	1	**2**	**3**	**4**	**5**
a problem until crew is at site.					
Seasonal weather	Hardly ever	Occasionally	Days/ Year	Weeks/ Year	Months/ Year
Geographical restrictions to shutoff access	No restriction likely	Can get within 50 feet with vehicle	Can get within 500 feet with vehicle	Can get within half a mile with vehicle	Access is one mile or greater
Able to shut off line using an existing STOPPLE fitting, or Mueller Line Stopper, or other.	Fitting already on the pipeline and readily accessible		Fitting already on pipeline but not readily accessible		No fitting on the line
Potential for damage by nature, vandalism, etc.	No damage expected	Not too likely	Could be damaged	Readily damaged	Expect damage
Other constraints	No public or financial impact		Moderate profile or expense if shut in		High profile or large expense if shut in
Potential risk reduction of an ASV or RCV is installed: TOTAL / 90 =					

Appendix K – Report of Damage to Gill Ranch Storage (GRS) Property

Address of Damage ______________________ Today's Date

Pipeline mile (nearest) ______________________ County ____________

Date of Damage ____________ Time ____________ Time made gas safe ____________

Damaging Party ______________________

Damaged by: ☐ Landowner ☐ Municipality ☐ Contractor ☐ Unknown

Property of Another Utility Damaged During this Incident? ☐ Yes ☐ No
If Yes Name of Utility

Did Excavator Call One Call Center? ☐ Yes ☐ No
Was the Locate Request Marked in White? ☐ Yes ☐ No
Were the markings within the Reasonable Accuracy Zone? ☐ Yes ☐ No
Did the damaging party hand-dig around the locates? ☐ Yes ☐ No
Did the damaging party wait two (2) business days? ☐ Yes ☐ No

LOCATE REQUEST TICKET NO	REQUESTED DATE	REQUESTED TIME	PERFORMED DATE	PERFORMED TIME	LOCATED BY	METHOD OF LOCATE
NONE REQUESTED						

Were the Markings Within Reasonable Accuracy Zone? ☐ Yes ☐ No
Did Damaging Party Wait Two (2) Business Days? ☐ Yes ☐ No

Photos Taken? ☐ Yes ☐ No If "Yes", please attach copies to this form.

TYPE OF WORK BEING PERFORMED WHEN FACILITY WAS DAMAGED (check appropriate box)

☐ Sewer	☐ Electric/Power	☐ Street Light	☐ Landscaping	☐ Vehicle
☐ Water	☐ Cable	☐ Fence	☐ Road Improvement	☐ Grading/Site Development
☐ Curb/Sidewalk	☐ Telephone	☐ Home Yard Work	☐ Signs	☐ R.O.W. Maintenance
☐ Driveway	☐ Irrigation	☐ Building Construction	☐ Building Demolition	☐ Other (describe below)

DAMAGE MEDIA (check appropriate box)

☐ Backhoe/Trackhoe	☐ Hand Equipment	☐ Vertical Boring	☐ Settlement	☐ Erosion
☐ Grader/Dozer	☐ Moving Vehicle	☐ Horizontal Boring	☐ Cave In	☐ Other (describe below)

ROOT CAUSE DESCRIPTION (check appropriate box)

☐ No Locate Request	☐ Careless Operations	☐ No 'no response' Call	☐ Improper Installation
☐ Locator Failed to Mark	☐ Locator Mislocated	☐ Incomplete Locator's Locate	☐ Unlocatable Facility
☐ Failed to Maintain Marks	☐ Wrong Locate Info Provided	☐ Miscommunication	☐ Insufficient Locate Time
☐ Incomplete/Inaccurate Records	☐ Previous Damage	☐ Homeowner	☐ No Pot-Hole/Hand Dig
☐ Excavator Outside Locate Area	☐ Missing/Broken Trace Wire	☐ Short Notice Locate	☐ Depth Issues
☐	☐	☐	☐ Other (describe below)

Report of Damage to Gill Ranch Storage (GRS) Property
ATTACH A SKETCH OF DAMAGE AREA BELOW

Supervisor on Scene? ☐ Yes ☐ No Supervisor's Initials ____________________

Prepared by: ______________________________ Approved by: ____________________ Date: __________

COMMENTS REGARDING DAMAGES:

COMMENTS REGARDING REMEDIATION OF DAMAGES:

DAMAGE PHOTOS: