STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-40, SUB 142

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Frontier Natural Gas Company – Violations of)
Title 49, Part 192, Subpart O, Code of)
Federal Regulations)

COMMISSION PIPELINE SAFETY SECTION DIRECT TESTIMONY OF JOHN S. HALL, HARRY C. BRYANT, III AND STEPHEN P. WOOD

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A: My name is John S. Hall, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am a contract Pipeline Safety Engineer for the Pipeline Safety Section of the Operations Division, North Carolina Utilities Commission. My qualifications and experience are provided in Appendix A.

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

A: My name is Harry C. Bryant, III and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am a Pipeline Safety Engineer for the Pipeline Safety Section of the Operations Division, North Carolina Utilities Commission. My qualifications and experience are provided in Appendix B.

Q: PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND PRESENT POSITION.

My name Is Stephen P. Wood, and my business address is 430 North Salisbury Street, Raleigh, North Carolina. I am the Director of the Pipeline Safety Section of the Operations Division, North Carolina Utilities Commission. My qualifications and experience are provided in Appendix C.

Questions

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of our testimony is to present background information and the results of our February 2017, pipeline safety inspection of Frontier Natural Gas Company's Integrity Management Program pursuant to Subpart O of 49 Code of

Federal Regulations (CFR), Part 192, to present other relevant information learned subsequent to the integrity management inspection, and to present our recommendations for actions to be taken by the Commission.

Q: WHAT AUTHORITY DOES THE COMMISSION HAVE TO ENFORCE GAS PIPELINE SAFETY STANDARDS?

A: Pursuant to provisions in 49 United States Code Sec. 60105, North Carolina General Statutes 62-50 and other authorities, the Commission has entered into an agreement with the United States Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) that grants the Commission the authority to enforce federal pipeline safety standards with regard to all natural gas pipelines subject to PHMSA jurisdiction located within the State of North Carolina. Pursuant to the statute and the agreement, the Commission is authorized to enforce the PHMSA pipeline safety standards under 49 CFR, Parts 191, 192 and 193 (PHMSA regulations). The PHMSA regulations create extensive, detailed guidelines for building, maintaining, operating and inspecting gas pipelines.

Pursuant to Commission Rule R6-39(b), the Commission has adopted and made applicable to all North Carolina pipeline operators the safety standards in 49 CFR, Part 192, except where North Carolina law is more stringent than the PHMSA regulations.

Q: IS FRONTIER NATURAL GAS COMPANY A GAS PIPELINE OPERATOR SUBJECT TO PHMSA REGULATIONS?

A: Yes. Under the PHMSA regulations, Frontier Natural Gas Company (Frontier) is a gas pipeline operator.

Q: PLEASE GIVE A GENERAL OVERVIEW OF THE COMMISSION's PIPELINE SAFETY SECTION.

A: The Pipeline Safety Section consists of a Director and five field Pipeline Safety Engineers. The Director and one engineer/inspector are stationed in Raleigh. The other four engineers/inspectors are stationed around the State. The Section currently has one contract employee.

Q: FOR AN APPLICANT TO BE HIRED AS A PIPELINE SAFETY ENGINEER, WHAT ARE THE MINIMUM EDUCATION AND EXPERIENCE REQUIREMENTS?

A: An applicant must have a bachelor's degree in engineering or equivalent combination of training and experience.

Q: WHAT SPECIALIZED TRAINING DO PIPELINE SAFETY ENGINEERS RECEIVE?

A: To be qualified to be the lead inspector on a Standard inspection, engineers/inspectors are required to take and pass seven week-long courses at PHMSA's Inspector Training and Qualification Division (T&Q) located in Oklahoma City, Oklahoma. Additional courses are taught on specialized subjects, including transmission integrity management.

Q. WHAT SPECIALIZED TRAINING IS REQUIRED FOR AN ENGINEER/INSPECTOR TO CONDUCT AN INTEGRITY MANAGEMENT AUDIT?

A: Currently there are thirteen courses that PHMSA requires an engineer/inspector to successfully complete before leading an Integrity Management (IM) inspection. The first seven are the basic courses that all inspectors are required to take when they start. The next six focus on the IM rule. Five of the six IM courses require travel to T&Q. These are: (1) Fundamentals of Integrity Management, (2) Gas integrity Management (IM) Protocol, (3) Fundamentals of (SCADA) System Technology and Operations, (4) Safety Evaluation of Inline Inspection (ILI)/Pigging Programs, and (5) External Corrosion Direct Assessment (ECDA) Field Course. In addition to these courses, there is one web-based training course on Investigating and Managing Internal Corrosion of Pipelines.

Q: WHAT IS SUBPART O OF 49 CFR, PART 192?

A: Subpart O prescribes the minimum requirements for an integrity management program on any gas transmission pipeline covered in Part 192. It was promulgated by PHMSA on December 13, 2003.

Q: WHAT IS PHMSA's UNDERLYING PHILOSOPHY BEHIND SUBPART O?

A: Risk management is the underlying philosophy. PHMSA maintains an online fact sheet that states, "Risk assessment is a process used to evaluate unwanted consequences and the likelihood of those consequences occurring. The purpose of risk assessment is to develop information that allows organizations to make decisions that reduce or eliminate unwanted consequences by changing their likelihood, their adverse impacts, or both." Operators are required to establish an Integrity Management Program (IMP) for their transmission lines, survey their systems and identify High Consequence Areas (HCAs) where human activity falls within specific guidelines in the regulations. Operators are then required to assess the risk to their transmission pipelines and choose one of three methodologies to evaluate the integrity of those lines.

Q: WHAT ELEMENTS DOES SUBPART O REQUIRE AN INTEGRITY MANAGEMENT PROGRAM TO CONTAIN?

A: §192.911 describes sixteen elements of an IMP. These include, in summary:

(a) The identification of HCAs,

(b) A Baseline Assessment Plan,

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment,

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed,

(e) Provisions meeting the requirements of §192.933 for remediating conditions found during an integrity assessment,

(f) A process for continual evaluation and assessment meeting the requirements of §192.937,

(g) If applicable, a plan for confirmatory direct assessment,

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the HCAs,

(i) A performance plan meeting certain industry standards,

(j) Record keeping provisions,

(k) A management of change process,

(l) A quality assurance process,

(m) A communication plan, (n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to State and federal regulators,

(o) Procedures for ensuring that each integrity assessment is being conducted in a manner that minimizes environmental and safety risks, and

(p) A process for identification and assessment of newly-identified high consequence areas.

Q: WHAT WAS THE FIRST REQUIREMENT FOR PIPELINE OPERATORS UNDER SUBPART O?

A: In § 192.907, Subpart O requires a gas pipeline system operator to develop and follow a written Integrity Management Program no later than December 17, 2004.

Q: DOES FRONTIER HAVE A WRITTERN INTEGRITY MANAGEMENT PROGRAM?

A: Yes. Frontier adopted an IMP in 2004. A copy of the most recent Frontier IMP that has been provided to Pipeline Safety is attached to our testimony as Commission Staff Exhibit 1.

Q: WHO OWNED FRONTIER WHEN THE IMP WAS WRITTEN?

A: Sempra Energy, one of the largest corporations in the country involved with natural gas distribution.

Q: DOES THE IMP DEFINE ANY STAFF POSITIONS AND LIST QUALIFICATIONS?

A: Yes. Table 1.1 lists an Integrity Management Program Manager, a Data Analyst, a Compliance Coordinator, General Manager, and a Vice President. There are additional staff positions and qualifications listed in other subparts of the IMP.

The IMP Manager is required to be a degreed engineer or have equivalent training, and have five or more years of pipeline experience, a working knowledge or specific training in 49 CFR, Part 192, Subpart O, and a detailed understanding of Frontier's organization.

The Data Analyst must have a working knowledge or specific training in applicable Company data management systems and two years of GIS experience.The Compliance Coordinator must have five or more years of pipeline industry experience in the regulatory arena and demonstrated project management skills including detailed documentation.

The General Manager and Vice President are both required to have education, training and experience commensurate with the General Manager position.

Q: PURSUANT TO 49 CFR, SECTION 192.911(b), A PIPELINE OPERATOR IS REQUIRED TO HAVE A BASELINE ASSESSMENT PLAN AS PART OF ITS IMP. PLEASE EXPLAIN THE PURPOSE OF THIS REQUIREMENT.

A: The PHMSA regulations require that a pipeline operator's IMP begin with a framework. The idea is that it will evolve into a more detailed and comprehensive plan as information and experience are gained. A Baseline Assessment Plan (BAP) is part of the framework to make sure that the operator understands the structural and operational characteristics of the operator's pipeline.

Q: WHAT MUST A BASELINE ASSESSMENT PLAN INCLUDE?

A: It must include, (1) identification of the potential threats to each covered pipeline segment and the information supporting the threat identification; (2) the methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected; (3) A schedule for completing the integrity assessment of all covered segments; and (4) a procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

Q: DOES FRONTIER'S IMP INCLUDE A BASELINE ASSESSMENT PLAN?

A: Yes. Section 5.3 covers the BAP.

Q: HAS FRONTIER CONDUCTED a BASELINE ASSESSMENT PURSUANT TO §192.911(b) AND SECTION 5.3 OF ITS IMP?

A: It has performed baseline assessments on all covered segments in which the assessment method chosen is an ECDA. However, Frontier's BAP included two covered segments that were to be assessed using Internal Corrosion Direct Assessment (ICDA). Frontier did not have documentation showing that an ICDA had been done.

Q: WHAT ARE THE THREE METHODOLOGIES CURRENTLY APPROVED BY PHMSA REGULATIONS TO CONDUCT A BASELINE ASSESSMENT?

A: §192.921(a) specifies that an operator choose one or more of three assessment methods. These are (1) the use of an internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible, (2) a pressure test, or (3) direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking, conducted in accordance with the relevant provisions of Subpart O.

Q: WHICH METHOD DID FRONTIER EMPLOY?

A: External Corrosion Direct Assessment.

Q: IS IT ACCEPTABLE UNDER PHMSA REGULATIONS FOR FRONTIER TO USE ECDA EXCLUSIVELY AND NOT CONDUCT ICDA?

A: No. Table 5.2 in Frontier's BAP identifies two covered segments in which both ECDA and ICDA should have been used to assess the segment.

Q: AS A PART OF ITS IMP, DOES FRONTIER HAVE A WRITTEN EXTERNAL CORROSION DIRECT ASSESSMENT PROTOCOL?

A: Yes.

Q: HOW DOES THE EDCA PROTOCOL DEFINE EXTERNAL CORROSION DIRECT ASSESSMENT?

A: ECDA is a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity. ECDA seeks to proactively prevent external corrosion defects from growing to a size that affects the structural integrity of the inspected pipeline segments.

Q: WHAT IS THE ECDA METHODOLOGY?

A: The ECDA methodology is a four-step process requiring integration of pre-assessment data, data from multiple indirect field inspections, and data from pipe surface examinations. The four steps of the process are:

Pre-Assessment: The Pre-Assessment step utilizes historic and recent data to determine whether the ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions. The required data are typically available at Frontier's Gas Division office located in Elkin, North Carolina.

Indirect Inspection: The Indirect Inspection step utilizes above ground inspections to identify and define the severity of coating faults, diminished cathodic protection, and areas where corrosion may have occurred or may be occurring. A minimum of two indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. Indications from indirect inspections are categorized according to severity.

Direct Examination: The Direct Examination step includes analyses of pre-assessment data and indirect inspection data to prioritize indications based on the likelihood and severity of external corrosion. This step includes excavation of prioritized sites for pipe surface evaluations resulting in validation or re-ranking of the prioritized indications. During the Direct Examination step, high priority areas with corrosion damage are re-evaluated for further action.

Post-Assessment: The Post-Assessment step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process and determine reassessment intervals.

Q: DOES FRONTIER'S ECDA PROTOCOL DEFINE ANY STAFF POSITIONS AND LIST QUALIFICATIONS?

A: Yes. It specifies that there will be an Integrity Management Program Manager, an ECDA Project Coordinator, a Project Engineer, a Data Integration Specialist and ECDA Field Personnel.

Q: DOES THE FRONTIER ECDA PROTOCOL INCLUDE PERSONNEL QUALIFICATION REQUIREMENTS, INCLUDING EDUCATION, TRAINING AND EXPERIENCE?

A: Yes, in Table 2.1 of the ECDA Protocol.

Q: WHAT ARE THE EDUCATION, TRAINING AND EXPERIENCE REQUIREMENTS?

A: With regard to the IMP Manager position, some of the requirements are the same as those listed in Table 1.1 of the IMP. However, Table 2.1 of the ECDA Protocol also calls for the IMP Manager to have a working knowledge or specific training in National Association of Corrosion Engineers (NACE) Standard Procedure 0502, training or experience in buried piping corrosion mechanisms and training or experience in indirect inspection techniques. The ECDA Project Coordinator must have five or more years of pipeline industry experience or cathodic protection experience, successfully attended Frontier's ECDA training program, and demonstrated project management skills, and other training that is deemed necessary by the Project Engineer or Program Manager. The Project Engineer must be a degreed engineer with two or more years of pipeline experience in corrosion related field, have successfully attended Frontier's ECDA training program, received corrosion-related training and have a working knowledge of burst pressure calculations. The Data Integration Specialist must have a working knowledge or specific training in applicable Company data management systems and two years GIS experience. ECDA Field Personnel are required to have training and compliance with specific Company Operator Qualification task requirements and be trained on ECDA procedures.

Q: DID THE COMMISSION'S PIPELINE SAFETY SECTION CONDUCT INSPECTIONS OF FRONTIER TO DETERMINE IF FRONTIER'S IMP WAS IN COMPLIANCE AND THAT FRONTIER WAS OPERATING IN ACCORDANCE WITH ITS IMP?

A: Yes. In October 2009, Stephen F. Hurbanek and John S. Hall of the Pipeline Safety Staff performed an Integrity Management inspection of Frontier. Mr. Hurbanek had attended the required PHMSA courses and was qualified to be an Integrity Management lead inspector. In November 2010, Mr. Hurbanek and Mr. Hall conducted a follow-up inspection. In February 2017, Mr. Hall and Harry C. Bryant, III conducted an Integrity Management inspection of Frontier.

Q: WHO OWNED FRONTIER WHEN THE OCTOBER 2009 INTEGRITY MANAGEMENT INSPECTION WAS CONDUCTED?

A: In 2007, Frontier was purchased from Sempra Energy by Energy West, which is now known as Gas Natural, Inc.

Q: WHAT WAS THE OUTCOME OF THE OCTOBER 2009 INSPECTION?

A: From October 26 through October 29, 2009, Mr. Hurbanek and Mr. Hall conducted an inspection that included a review of the required records and field inspections.

The focus was on the IMP itself. The inspection revealed that Frontier had developed and implemented a program for integrity management, however, a considerable number of potential issues were raised during the inspection.

Q: DID THE PIPELINE SAFETY SECTION RECOMMEND THAT A CIVIL PENALTY BE IMPOSED AFTER THAT INSPECTION?

A: No. It was recognized that this was a complex new rule and Pipeline Safety was committed to working with operators in North Carolina to get their IMPs established. During the inspection, it was agreed that Frontier would address all of the deficiencies in their IMP and record keeping within eight months. After that period, Pipeline Safety would conduct a follow-up inspection.

Q: WHO WAS MANAGING FRONTIER AT THAT TIME AND RECEIVED FORMAL NOTIFICATION OF THE INSPECTION'S FINDINGS?

A: On November 9, 2009, Mr. Christopher Isley, who was then the Director of Pipeline Safety, sent a letter to Mr. Raymond Fisher, the Vice President and General Manager of Frontier, with a copy of the inspection form. A copy of that letter is attached to our testimony as Commission Staff Exhibit 2.

Q: WAS A FOLLOW-UP INSPECTION CONDUCTED?

A: Yes. From November 15 through 17, 2010, Mr. Hurbanek and Mr. Hall returned to Elkin for a follow-up inspection. At a meeting on November 17, 2010, it was agreed that Frontier would correct all deficiencies in its IMP and record keeping within eight months.

Q: WHAT WAS THE RESULT OF THAT INSPECTION?

A: In a letter sent by Mr. Isley to Mr. Fisher dated December 1, 2010, Mr. Isley stated that Frontier had corrected most of the potential issues identified in the 2009 inspection.

However, nine specific protocols in Frontier’s IMP were identified as still having potential issues. A copy of that letter is attached to our testimony as Commission Staff Exhibit 3.

Q: A FOLLOW-UP INSPECTION OF FRONTIER’S IMP THAT WAS PLANNED FOR 2011 DID NOT OCCUR. WHY NOT?

A: An inspection of Frontier's IMP that took place in 2009 and 2010 indicated potential issues, particularly with the Internal Corrosion Direct Assessment element. A follow up inspection did not occur because Mr. Hurbanek, the Pipeline Safety Section’s lead Integrity Management inspector resigned, and Raymond W. Fisher, Frontier’s Integrity Management Program Manager also left around the same time.

Q: HOW OFTEN DOES PIPELINE SAFETY INSPECT INTEGRITY MANAGEMENT PROGRAMS?

A: IN 2015, PHMSA established a minimum inspection interval at five years.

Q: WHEN DID PIPELINE SAFETY CONDUCT ITS MOST RECENT REVIEW TO DETERMINE WHETHER FRONTIER IS IN COMPLIANCE WITH ITS IMP?

A: Mr. Bryant and Mr. Hall met with Mr. Fred Steele, Frontier’s General Manager and President, Mr. Josh Wagoner and Ms. Regina Davis at Frontier's Offices in Elkin, North Carolina, on February 8 and 9, 2017.

Q: DID PIPELINE SAFETY PROVIDE FRONTIER WITH ADVANCE NOTICE OF WHEN PIPELINE SAFETY WOULD CONDUCT THE 2017 INSPECTION?

A: Yes, we sent an email to Mr. Wagoner on Thursday, January 12, 2017 and informed him that we would be coming to conduct the IMP review on Monday, February 6, 2017. The email included a copy of the PHMSA's Integrity Management Inspection Protocols. Mr. Steele called back later that week and asked for a lengthy extension but we were not able to accommodate him. We did agree to schedule the inspection to begin February 8.

Q: HOW DID PIPELINE SAFETY STAFF CONDUCT ITS FEBRUARY 2017 INSPECTION?

A: Our inspection of Frontier's transmission Integrity Management Program began by following the PHMSA Gas Integrity Management Protocols inspection form. The inspection is a process, and there are fourteen protocol areas with criteria to verify plan and implementation of program elements to evaluate operator integrity management programs. The protocol inspection process began with verifying individuals responsible for the IMP. Mr. Steele indicated that Mr. Wagoner is IMP Manager, Ms. Davis is the Centralized Workload Manager, and he (Mr. Steele) was President/General Manager. These individuals make up the primary Frontier IMP team. We inquired about staff qualifications and the responsibilities of IMP roles and Mr. Steele indicated the decision to assign IMP roles was recent, and that training was needed for staff. We asked if Mr. Mickey Grewal had been involved with the Frontier IMP, and Mr. Steele said that Mr. Grewal was not directly involved. Mr. Steele said Frontier was in the process of hiring two engineers that would be involved with the IMP.

Q: WHO IS MICKEY GREWAL AND WHY DID YOU ASK ABOUT HIS ROLE?

A: Pipeline Safety Staff was aware that Adam Theriault, for a time, was the only degreed engineer working for Frontier in Elkin. He was Frontier's Regulatory Compliance Engineer. He left Frontier in February 2015. Commission Staff had questioned Frontier over a period of time about the lack of a degreed engineer. Frontier's response, in part, was that it was attempting to recruit an engineer and that, until an engineer was hired to work in Elkin, GNI would provide engineering support. In the fall of 2015, Frontier introduced Mr. Grewal to Commission personnel as a new GNI engineer who would support Frontier and the other GNI subsidiaries. His duties included providing oversight and direction in regulatory compliance with Part 192, and explicitly included compliance with IMP.

Q: HAVE YOU SEEN MR. GREWAL'S RESUME?

A: Yes, I have. It is very impressive. His career goes back to 1994 and includes twelve years of experience with Nicor, a large natural gas local distribution company. His qualifications include "Working knowledge of 49 CFR, Part 192, 195, API, ASME, ANSI."

Q: WHAT WAS HIS JOB TITLE?

A: Director of Engineering, System Planning and Regulatory/Safety Compliance.

Q: WHAT OTHER DUTIES WERE ASSIGNED TO MR. GREWAL BY GNI?

A: An email from Mr. Steele dated September 23, 2015, contained a description of Mr. Grewal's duties. This email stated that he would provide direction and oversight as it relates to: "(1) Engineering design and standardization, (2) Regulatory compliance with Part 192, including DIMP, IMP, Public Awareness and etc., (3) Compliance warehousing, GasOps, GIS, etc., (4) System Planning including, sizing, expansion, system layout (headers), peak degree day planning, peak day model development, (4) Estimate of gas supply requirements to meet peak day, (5) IT support, including Itron systems, GIS systems, GasOps, etc., and (6) Overall safety compliance in operations."

Q; HOW MANY REGULATED NATURAL GAS UTILITIES DOES GNI HAVE?

A: According to the "Newly Proposed Structure" provided to the Commission in Docket No. G-40, Sub 136, GNI has a subsidiary, PHC Holdings Inc., that holds eight regulated utilities, including two in Montana, one each in North Carolina and Maine and four in Ohio.Q: IS IT YOUR UNDERSTANDING THAT MR. GREWAL WAS SUPPOSED TO PROVIDE ALL OF THOSE SERVICES FOR ALL OF THOSE COMPANIES?

A: That is our understanding.

Q: WHAT ARE YOUR OBSERVATIONS WITH REGARD TO HOW WELL IT WORKED FOR MR. GREWAL TO HAVE THAT TYPE OF EXTENSIVE RESPONSIBILITY FOR EIGHT PIPELINE OPERATORS?

A: Correspondence concerning Mr. Grewal's hiring makes it very clear that both GNI and Frontier were well aware of the existence of PHMSA's Integrity Management regulation. However, given the scope and scale of his job, it is not a surprise that we saw no evidence of Mr. Grewal being directly involved in implementing the Integrity Management Program at Frontier. For example, Pipeline Safety never received a telephone call or email from Mr. Grewal, did not observe any written communications from him among Frontier's IMP records, and he was not present at any time during the 2017 inspection. Based on Frontier's IMP staffing and the

2017 inspection results described below, a reasonable conclusion is that GNI failed to support Frontier while Frontier attempted to hire a replacement for Mr. Theriault because GNI was also too thinly staffed to do the job.

Q: WHAT INFORMATION DID YOU ASK FOR REGARDING THE FRONTIER IMP?

A: We asked to see current maps showing HCAs. We inquired if program reviews were being performed as part of the Frontier IMP Quality Control Plan. Mr. Steele indicated they were still locating records, and that some record keeping may be missing or not available. Mr. Steele indicated the IMP related activities performed by former Frontier personnel were being internally questioned. We inquired about record keeping to document assessments that had been performed as a follow-up to those that had not been performed as of the 2009/2010 IMP inspection, but Mr. Steele stated that these records were not available. We asked to review Frontier's current BAP schedule and were provided with a copy that indicated plans for conducting a Confirmatory Direct Assessment (CDA). The dates for performing the CDA's in twenty HCA's were proposed to begin in February 2017 and finish in March 2017. One pipeline is scheduled for a CDA in calendar year 2018.

Q: WHAT WERE THE MAIN AREAS OF INTEREST THAT PIPELINE SAFETY REVIEWED WITH REGARD TO FRONTIER'S IMPLEMENTATION OF ITS IMP?

A: The recent appointment of IMP staff was of interest due to their apparent lack of familiarity with Subpart O of PHMSA regulations and with Frontier's written IMP. When record keeping was not available to verify that IMP reviews were being performed, or when record keeping was not available to verify the last ECDA, and when the Baseline Assessment Plan schedule indicated performing Confirmatory

Direct Assessment on overdue segments, we realized that Frontier's IMP was not being implemented.

Q: WHAT CONCLUSIONS WERE DRAWN FROM THIS INFORMATION?

A: Frontier staff was not familiar with Subpart O of PHMSA regulations or with the Frontier Integrity Management Program. Documentation of the Quality Control (QC) Plan process was not available. The Baseline Assessment Plan schedule indicated that Frontier had not performed integrity reassessments on time and they were indicated that Frontier had not performed integrity reassessments on time and they were overdue.

Q: WHAT CONCLUSIONS ARE DRAWN FROM THE ADDITIONAL INFORMATION LEARNED FROM YOUR 2017 INSPECTION?

A: Frontier's IMP has not been maintained since approximately 2011, and is being administered by staff that has not had the training or experience to carry out an IMP.

Q: SPECIFICALLY, WHAT DID YOU FIND DURING THE 2017 INSPECTION WITH REGARD TO FRONTIER'S ANNUAL REVIEWS OF ITS HCAs?

A: We asked for record keeping to show that the HCAs were being reviewed (audited) one time each year, per the IMP's Quality Control Plan in Section 9, but Frontier did not have any records available to demonstrate this was being done. Mr. Steele said he didn't know where all the records were, and he was questioning the actions of prior personnel regarding the IMP. The HCA mileage being reported on PHMSA Form 7100.2-1 was the same since at least 2010, which is 14.2 miles. If the annual

HCA reviews had been conducted by Frontier, it would be expected that this HCA mileage would have changed in the period between 2011 and 2017.

Q: DURING THE 2017 INSPECTION, WHAT DID YOU FIND WITH REGARD TO FRONTIER'S PERFORMANCE OF THE BASELINE ECDAS THAT WERE REQUIRED TO BE PERFORMED BEFORE DECEMBER 17, 2012?

A: Record keeping for the baseline ECDAs that was due to be completed before PHMSA's December 17, 2012 deadline was not available during the inspection. However, adequate documentation was provided during our meeting in June.

Q: DURING THE 2017 INSPECTION, WHAT DID YOU FIND WITH REGARD TO FRONTIER'S IMP STAFFING?

A: We asked who was responsible for Frontier's IMP, and Mr. Steele stated that he, Mr. Wagoner and Ms. Davis were the IMP team. Revisions being made to the Frontier IMP written plan just before the February inspection indicate the 2017 IMP team as replacing the 2010 Frontier IMP staff.

Q TO YOUR KNOWLEDGE, DID FRONTIER OBTAIN APPROVALS FOR ITS LACK OF COMPLIANCE WITH ITS IMP STAFFING REQUIREMENTS THROUGH THE EXCEPTION PROCESS DESCRIBED IN SETION 7.0 OF ITS ECDA PROTOCOL?

A: Frontier staff was completely unfamiliar with the ECDA Protocol at the time of the inspection. An exceptions report was not asked for, but would have been an element of the Quality Assurance process that was not occurring.

Q: DURING THE 2017 INSPECTION, WHAT DID YOU FIND WITH REGARD TO FRONTIER'S IMP RECORDKEEPING, IN ADDITION TO THE LACK OF

RECORDS FOR ANNUAL HCA REVIEWS AND PERFORMANCE OF ECDAS THAT YOU HAVE ALREADY DISCUSSED?

A: To our understanding, based on the discussions with Mr. Steele and the other Frontier staff, implementation of the IMP had not been occurring, and therefore there was not any record keeping to indicate the IMP was being maintained.

Q: DOES FRONTIER HAVE A QUALITY CONTROL PLAN?

A: Yes. Section 9 of Frontier's IMP is its Quality Control Plan (QCP). The objective of the QCP is to assure that the Company has documented proof that all requirements of the IMP are met. The QCP indicates that an audit of specific IMP elements will occur annually (Table 9.3).

Q: WAS FRONTIER IN COMPLIANCE WITH ITS QUALITY CONTROL PLAN?

A: No. Recordkeeping was requested that would show the IMP was being reviewed, but there wasn't any recordkeeping available. Mr. Steele stated he didn't know where all the recordkeeping was, and he was questioning the activities of the prior IMP staff.

Q: WHAT IS AN ECDA AND A CDA, AND WHAT IS THE DIFFERENCE?

A: ECDA and CDA are Direct Assessment methods used for assessing the integrity of a pipeline that is vulnerable to the threat of corrosion. Another direct assessment method is Internal Corrosion Direct Assessment (ICDA), which is used for the threat of internal corrosion. ECDA follows criteria in ASME/ANSI and NACE SP0502[1] and requires, among other things, using a minimum of two different,

[1] American Society of Mechanical Engineers (ASME) / American National Standards Institute (ANSI); National Association of Corrosion Engineers, Standard Practice 0502.

complimentary tools to conduct the indirect examination step. CDA allows using one tool and is an interim measure until an ECDA is performed at the interval determined appropriate by the operator using information obtained during the ECDA process. However, some type of Direct Assessment must occur by year seven following the previous assessment. The initial baseline ECDA assessments were completed before December 17, 2012. Frontier was unable to provide any documentation to show that the reassessments were performed.

Q: WHY WAS FRONTIER PLANNING TO CONDUCT A CDA RATHER THAN AN ECDA?

A: Based on observations of Frontier's lack of adequate staff and training, and the lack of knowledge of the PHMSA regulations and Frontier's IMP, Pipeline Safety Staff concluded that Frontier's IMP staff did not have sufficient knowledge to understand that a CDA was inadequate.

Q: DID FRONTIER PERFORM AN ICDA?

A: Although Subpart O and Frontier's IMP call for an ICDA, record keeping has not been produced to indicate that Frontier ever performed an ICDA.

Q: WHAT CONCLUSIONS DID YOU DRAW FROM THIS?

A: Implementation of the IMP was not occurring.

Q: HOW DID YOU CONCLUDE YOUR INSPECTION?

A: Mr. Steele and Frontier's IMP staff were informed that Frontier was in a condition of noncompliance; and we would report inspection results to Stephen P. Wood, the Director of Pipeline Safety. The Director of Pipeline Safety would officially notify Frontier of the IMP inspection in writing.

Q: DID FRONTIER ACKNOWLEDGE THE NONCOMPLIANT CONDITION?

A: Yes. They understood that assessments had not been performed as needed.

Q: DID PIPELINE SAFETY PROVIDE FRONTIER WITH WRITTEN NOTICE OF FRONTIER'S NONCOMPLIANCE WITH ITS IMP?

A: Yes. On February 23, 2017, Mr. Wood sent a Letter of Violation to Fred A. Steele, President and General Manager of Frontier. A copy of the Letter of Violation is attached to our testimony as Commission Staff Exhibit 4.

Q: HAVE YOU LEARNED ADDITIONAL INFORMATION SUBSEQUENT TO THE IMP INSPECTION IN FEBRUARY 2017?

A: Yes. We met with the Frontier IMP team in June to review their responses to the Letter of Violation, and to learn what has occurred since the IM inspection.

Q: WHAT DID YOU LEARN FROM THIS MEETING?

A: IMP training was still being sought out. Recordkeeping to document the ECDA process on pipeline T-1 had been located, but no records documenting an implementation of the ICDA process were provided by Frontier. A new engineer with gas industry experience has been hired and another engineer is in the process of being hired pending graduation. A verification of HCAs had been performed, and bid requests were made for assessing HCA segments. Frontier also mentioned that it was reducing the number of HCA miles.

Q: WAS THE ECDA DOCUMENTATION FOR THE PIPELINE FULLY IN COMPLIANCE?

A: We reviewed recordkeeping that indicated the ECDA assessments for T-1 were completed before the PHMSA deadline of December 17, 2012.

Q: WHAT JUSTIFICATION DID FRONTIER OFFER FOR REDUCING THE NUMBER OF MILES OF HCAS?

A: Frontier indicated reduced HCA miles was the result of two factors. First, it recalculated the Potential Impact Radius on certain segments of pipe. Mr. Steele also stated that there were fewer miles of transmission line because the specified minimum yield strength (SMYS) of some segments was less than the threshold for a transmission pipeline.

Q: HAS FRONTIER FOLLOWED THE MANAGEMENT OF CHANGE PLAN IN SECTION 12.0 OF ITS IMP TO PROPOSE REDUCING ITS HCA MILEAGE.

A: No.

Q: DO YOU HAVE AN OPINION WITH REGARD TO THE NATURE, CIRCUMSTANCES AND GRAVITY OF THE VIOLATIONS OF FRONTIER'S IMP?

A: Yes. These are very serious violations. This Commission has a long-standing policy of addressing non-compliances by working with companies to get them into compliance. However, Frontier essentially failed to implement Subpart O of Part 192 over an extended period of time. While we have not established the time period with precision, it goes back for at least five years. Furthermore, when questioned about its thin staff, Frontier assured the Commission that it was receiving help from its parent company on pipeline safety compliance and explicitly mentioned Integrity Management. As the Commission is aware from pipeline ruptures and explosions in other parts of the United States, pipeline safety involves the protection of lives and property. Consequently, the lack of attentiveness and due diligence demonstrated by Frontier in implementing its IMP is a very serious matter.

Q: WHAT WAS THE DEGREE OF FRONTIER'S CULPABILITY?

A: Frontier and its parent company were entirely to blame for its failures. In Pipeline Safety's February 23, 2017 Letter of Violation it was recognized that there had been an unforeseen departure of key personnel having IMP and other safety compliance responsibilities. During that five-year period, Frontier had three different General Managers. Two of them left or were terminated as a result of the management turmoil at GNI. That turmoil included the Chairman of the GNI Board of Directors, Richard Osborne, being removed from the Board. Frontier has also seen turnover in its professional staff. However, while GNI may have failed to provide continuity, that does not excuse Frontier's failure to implement Subpart O. Pipeline Safety's Letter of Violation noted that it remains the responsibility of Frontier to comply with State and federal safety regulations.

Q: PLEASE DISCUSS FRONTIER'S HISTORY OF PRIOR OFFENSES.

A: Going back to the time of the original Integrity Management inspections, Frontier has a history of non-compliances in various inspections including the IMP inspections, Standard inspections and a Public Awareness inspection, some of which were fairly serious. Since the beginning of 2009, when the first Integrity Management inspection was conducted, Pipeline Safety personnel have found non-compliances or issues that required follow-ups in eleven different inspections out of a total of twenty-one formal inspections.

Q: PLEASE DESCRIBE THE INSPECTIONS AND NON-COMPLIANCES.

A: In September 2009, the Pipeline Safety Staff's inspection of Warren County revealed an unacceptable cathodic protection reading.

As already discussed, in the October 2009 Integrity Management Inspection, it was observed that Frontier had developed and implemented an IMP, but, as stated in the November 9, 2009 Letter of Violation (Staff Exhibit 2), there are "a considerable amount of potential issues." These were addressed during the inspection, with the understanding that Frontier would correct them within eight months, after which a re-inspection would be scheduled. When the re-inspection of Frontier's IMP was conducted in October 2010, it was noted that Frontier had corrected most of the potential issues. However a list of nine IMP protocols were listed as having "potential issues outstanding." Also in October 2010, a standard inspection of Frontier revealed that performance standards for excess flow valves (EFVs) and a procedure for installing EFVs needed to be added to its Procedures Manual. In October 2011, an inspection in Warren County revealed a serious non-compliance. The design and installation of pressure regulating equipment failed to include overpressure protection at two locations. In November and December 2011, nine pipeline pressure regulators were found in the Elkin Region that also lacked overpressure protection. In October 2012, the inspection interval for cathodic protection rectifiers was exceeded twice. Significantly, Frontier's response to the notice of non-compliance noted that personnel changes caused one rectifier inspection to be skipped and the other inspection was not conducted in a timely manner because of vacation scheduling. These explanations speak to both a lack of continuity planning and a staff that was either not adequate for the job or was not efficiently utilized. In September 2012, a Public Awareness inspection was conducted. Four issues were identified: (1) an annual audit was not specified in the written Public Awareness plan, (2) a process for determining the need for languages other than English has not been performed, (3) no Public Awareness program implementation audits had been documented, and (4) Frontier asserted that an effectiveness evaluation was performed, but documentation was not available.

Q: WHO WERE THE EXECUTIVES IN CHARGE OF OPERATING FRONTIER DURING THE PERIOD WHEN THESE NON-COMPLIANCES WERE FOUND?

A: Ray Fischer was the General Manager of Frontier. Dave Shipley was the Vice President of East Coast Operations for GNI and the President of Frontier.

Q: AND WHO WAS THE CHAIRMAN OF GAS NATURAL, INC?

A: Richard M. Osborne.

Q: DID MR. SHIPLEY CONTINUE ON AS THE PRESIDENT OF FRONTIER?

A: No. He was abruptly terminated by Richard Osborne in June 2013.

Q: WHO REPLACED MR. SHIPLEY IN FRONTIER’S LEADERSHIP ROLE?

A: Darryl Knight became the General Manager in June 2013.

Q: WHAT WAS MR. KNIGHT’S EDUCATIONAL BACKGROUND?

A: According to his testimony in a docket before the Public Utilities Commission of Ohio, he is a graduate of Fairport Harding High School in Fairport Harbor, Ohio.

Q: AND WHAT WAS MR. KNIGHT’S PROFESSIONAL EXPERIENCE?’

A: According to his testimony in Docket No. G-40, Sub 119, he worked for Orwell Natural Gas in Ohio or its affiliates since 2002.

Q: DID FRONTIER'S PIPELINE SAFETY RECORD IMPROVE UNDER MR. KNIGHT?

A: No. In September 2013, during a field inspection in Boone, three violations were found at one site. A construction crew was observed installing two-inch plastic main incorrectly because it was (1) in a trench that allowed for less than minimum cover requirements, (2) being installed with rocks in the trench, and (3) in contact with a telephone conduit. Also, a 5/8-inch plastic service line was observed at another location in Boone containing a bend that exceeded the bending radius specified in Frontier's procedures. In Wilkesboro, 19 volts of Alternating Current were measured on transmission line T-7, which exceeds the shock hazard level set in NACE standards and may also harm the pipeline. In July 2014, an inspection of Frontier's Distribution Integrity Management Program (DIMP) pursuant to Subpart P of 49 CFR 192 was conducted. It revealed that Frontier had developed a written DIMP plan, but it had not been fully implemented and validated.

Q: HOW LONG DID MR. KNIGHT REMAIN AS FRONTIER'S GENERAL MANAGER?

A: Mr. Knight was the General Manager for less than a year and a half. He was made General Manager of Frontier by Richard Osborne. On May 1, 2014, Mr. Osborne stepped down from the Chairmanship of GNI. He was not nominated for re-election to the Board and was replaced as Chairman by his son, Gregory J. Osborne. With Gregory as Chairman, Mr. Knight was replaced as General Manager by Fred Steele in October 2014.

Q: AFTER MR. STEELE BECAME GENERAL MANAGER, DID PIPELINE SAFETY PERSONNEL CONTINUE TO FIND NON-COMPLIANCES?

A: Yes. In August and September 2016, it was determined that Frontier lacked a program to track and monitor leaks as required by its Operation and Maintenance Manual. Work orders for three grade three leaks at two locations were closed without repair. Also in 2016, Pipeline Safety Staff observed a major road relocation project and found that Frontier had failed to submit a Form G-2 pursuant to Commission Rule R6-5(10) and the October 12, 2012 Order Requiring Filings in Docket Number G-100, Sub 92.

Q: OF ALL OF THE VARIOUS INSPECTIONS PERFORMED BY PIPELINE SAFETY PERSONNEL ON FRONTIER SINCE 2009, HOW MANY WERE THERE IN WHICH NON-COMPLIANCES OR OTHER ISSUES WERE FOUND?

A: Out of twenty-one inspections, eleven -- more than half -- had issues that needed to be addressed. That does not count the failure to file a G-2.

Q: IS THAT TYPICAL OF OPERATORS INSPECTED BY THE COMMISSION'S PIPELINE SAFETY STAFF?

A: No, it is not. Looking at the inspections made on various divisions of the two large gas companies in the State in 2016, Pipeline Safety Staff conducted twenty-three inspections of Piedmont Natural Gas Company and did not find any non-compliances or issues that required follow-up on eighteen of those inspections. It conducted seventeen inspections of PSNC Energy and, in twelve of those, inspectors found no problems. Looking back to 2009 as we did with Frontier, our largest municipal operator, the Greenville Utilities Commission, was inspected nineteen times and no issues were cited on fifteen of those inspections. A medium-sized municipal, the City of Wilson, was inspected twelve times and had ten inspections that required no action. A small municipal operator, the City of Kings Mountain, was inspected eleven times since the beginning of 2009, with eight inspections revealing no issues.

Q: WHAT DO YOU CONCLUDE FROM THAT?

A: Frontier’s record of having a non-compliance or other issues in over half of its inspections is easily the worst record in the State.

Q: DO PHMSA REGULATIONS PROVIDE GUIDANCE ON THE AMOUNTS OF CIVIL PENALTIES THAT SHOULD BE LEVIED?

A: Yes. 49 CFR 190.225 is entitled “Assessment Considerations” and lists in paragraph (a) things that PHMSA will consider and in paragraph (b) things that it can consider. PHMSA will consider (1) the nature, circumstances and gravity of the violation, including adverse impact on the environment; (2) the degree of the respondent's culpability; (3) the respondent's history of prior offenses; (4) any good faith by the respondent in attempting to achieve compliance; and (5) the effect on the respondent's ability to continue in business. Furthermore, PHMSA may consider: 1) the economic benefit gained from violation, if readily ascertainable, without any reduction because of subsequent damages; and (2) such other matters as justice may require.

Q: PLEASE ADDRESS THE CRITERIA REGARDING THE EFFECT OF A CIVIL PENALTY ON FRONTIER’S ABILITY TO CONTINUE IN BUSINESS.

A: The Commission has before it evidence in Docket No. G-40, Sub 136 that two highly knowledgeable outside parties, First Reserve and BlackRock, were made aware that there were pipeline safety violations at Frontier [T-156] and that those violations could result in a civil penalty. Yet First Reserve still chose to pay a 71% market premium for Frontier's parent company, GNI. The maximum penalties available pursuant to 49 CFR 190.223 are a matter of public record. The Commission's authority to impose penalties up to those levels is stated in G.S. 62-50(d). It is reasonable to assume that a large equity management firm, in conducting its due diligence before a merger, having been pointedly made aware of a potential problem, inquired as to the worst case scenario. It certainly would not have paid $13.10 per share for a stock that was trading at $7.68 per share if it thought that a major subsidiary -- and a subsidiary that was touted as a growth vehicle -- was about to be put out of business by a civil penalty.

Q: DID FRONTIER GAIN ANY ECONOMIC BENEFITS FROM NOT IMPLEMENTING ITS IMP?

A: Yes. By not having qualified people on staff, by not doing the field work and keeping the necessary records, by not hiring outside contractors to both conduct specialized inspections and to excavate to examine the pipe and remediate as necessary, Frontier undoubtedly saved a great deal of money.

Q: IS IMPLEMENTING SUBPART O EXPENSIVE?

A: It is well understood that Subpart O is an expensive regulation to implement. Both of the large local distribution companies in North Carolina, Piedmont Natural Gas and PSNC Energy, came to the Commission and asked for and received regulatory asset treatment of expenses incurred to comply with federal pipeline safety regulations, specifically, their integrity management expenses.

Q: WHAT IS REGULATORY ASSET TREATMENT?

A: Piedmont and PSNC recognized that they would incur material and extraordinary expenses implementing Subpart O, and asked that they be allowed to accrue those expenses and amortize them in their next general rate case.

Q: DID THE COMMISSION GRANT REGULATORY ASSET TREATMENT?

A: It did, and, in subsequent rate cases, the Commission approved the continuation of regulatory asset treatment for pipeline integrity management expenses.

Q: WHAT ABOUT CAPITAL COSTS TO IMPLEMENT SUBPART O?

A: It was recognized that significant capital costs might be incurred implementing Subpart O and, since these investments would not be revenue-producing, there could be a reluctance on the part of regulated utilities to make these expenditures. In response, the General Assembly passed G.S. 62-133.7A.

Q: WHAT DOES G.S. 62-133.7A DO?

A: In short, it allows local distribution companies to petition the Commission in a general rate case to establish a mechanism that would allow the LDC to begin recovering a return and related costs from capital investments made to comply with federal pipeline safety regulations without waiting for the next general rate case.

Q: HAVE PIEDMONT AND PSNC APPLIED FOR AND RECEIVED PERMISSION TO PUT SUCH A MECHANISM IN PLACE?

A: Yes, they have.

Q: TO DATE, HOW MUCH HAVE PIEDMONT AND PSNC REPORTED IN CAPITAL EXPENDITURES UNDER THEIR INTEGRITY MANAGEMENT MECHANISMS?

A: Piedmont applied for and received permission to implement its Integrity Management Rider (IMR) before PSNC did. It was granted permission to implement its IMR on December 17, 2013, in Docket No. G-9, Sub 631. Since then, as reported in Docket No. G-9, Sub 642, its cumulative integrity management plant investment has totaled over $767 million.

Q: AND HOW MUCH CAPITOL HAS PSNC INVESTED IN INTEGRITY MANAGEMENT?

A: Since receiving permission to implement an Integrity Management mechanism in the October 28, 2016 order in Docket No. G-5, Sub 565, PSNC reports spending about $25 million in capital on integrity management.

Q: IS IT REASONABLE TO DIRECTLY COMPARE PIEMDONT'S AND PSNC'S INTEGRITY MANAGEMENT SPENDING TO FRONTIER'S?

A: No, a direct comparison is not reasonable. Piedmont and PSNC are both much larger and they have much older systems. However, the sheer amount spent, as well as the extraordinary regulatory treatments, makes clear that complying with Subpart O is an extremely expensive proposition for an LDC of any size.

Q: HAS FRONTIER REQUESTED EITHER REGULATORY ASSET TREATMENT FOR EXTRAORDINARY PIPELINE SAFETY EXPENSES OR A MECHANISM TO PASS THROUGH CAPITAL COSTS RELATED TO COMPLYING WITH SUBPART O?

A: No.

Q: DO YOU HAVE AN OPINION AS TO WHY FRONTIER HAS NOT MADE SUCH REQUESTS?

A: Frontier has never filed a general rate case. Gas Natural, Inc. purchased Frontier from its previous owner, Sempra Energy, at an extremely deep discount. Frontier's balance sheet reflects about $108 million of impairments incurred by Sempra Energy. In Docket No. G-40, Sub 136, Frontier and Gas Natural's acquisition by First Reserve, Frontier stipulated that it would not attempt to include any of that $108 million impairment in its rate base in a future rate case. That means that Frontier has had an extremely low rate base, and, if it had filed a general rate case, might well have seen a rate reduction.Q: WITHOUT THE OPTION OF PASSING EXPENSES AND THE RETURN AND RELATED COSTS ON CAPITAL COSTS THROUGH TO RATEPAYERS IN A GENERAL RATE CASE, WHAT IMPACT WOULD COMPLYING WITH SUBPART O HAVE ON FRONTIER?

A: Frontier would have to absorb the costs, and would have to invest capital without earning a return.

Q: DID THE ORDER IN DOCKET NO. G-40, SUB 136 FURTHER ADDRESS A FUTURE RATE CASE BY FRONTIER?

A: Yes. In Regulatory Condition 10, it was further stipulated that neither Frontier nor the Public Staff will request a change in Frontier's margin rates until after December 31, 2021, with an important exception. Regulatory Condition 10 allows that, "Should Frontier or the Public Staff believe that Frontier should implement a pipeline safety rate adjustment mechanism pursuant to G.S. 62-133.7A, either party shall have the right to apply to or petition the Commission to initiate a general rate case proceeding."

Q: WOULD YOU AGREE THAT BY NOT PERFORMING THE ECDAS AS REQUIRED IN 2011, AND WAITING UNTIL 2018 TO PERFORM THEM, FRONTIER

Q: WOULD YOU AGREE THAT BY NOT PERFORMING THE ECDAS AS REQUIRED IN 2011, AND WAITING UNTIL 2018 TO PERFORM THEM, FRONTIER HAS AVOIDED THE COST OF ONE 7-YEAR ROUND OF ECDAs?

A: Yes.

Q: CAN YOU ESTIMATE THE TOTAL COST OF THE ECDAS THAT FRONTIER DID NOT INCUR AS A RESULT OF NOT PERFORMING THE ECDAS AS REQUIRED IN 2011?

A: No. However, an ECDA requires two different tools be used such as a Direct Current Voltage Gradient and a Close Interval Survey. Both of those require hiring outside contractors to walk the length of the pipeline to be inspected with specialized instruments and then to analyze the data and recommend excavations. The number of excavations that need to be made depend on the findings. The excavations, including remediation of problems found, can each cost thousands of dollars. The costs for 14.2 miles of pipeline can be in the hundreds of thousands of dollars. Furthermore, company personnel involved with these efforts cannot be performing their usual duties such as working on system expansion and customer additions.

Q: WHAT OTHER ECONOMIC BENEFITS DID FRONTIER GAIN BY NOT EFFECTIVELY IMPLEMENTING ITS IMP?

A: By not staying fully staffed with qualified people, Frontier saved a great deal of money. After Adam Theriault resigned in early February, 2015, Frontier was without a degreed engineer on staff in Elkin for two and a half years. That savings alone was likely in excess of $200,000. Mr. Gary Moore, who was Frontier's Technical Services Manager, and was in a higher position than Mr. Theriault, left the company last year. Mr. Theriault and Mr. Moore apparently have both been replaced by Mr. Wagoner, who was under them both in salary and Ms. Davis who is Frontier's Centralized Workforce Manager.In addition to staffing issues, no records can be found to show that the IMP's ICDA requirements were ever performed, Integrity Management monitoring did not occur, records were not kept, personnel were not trained. All of these things represent costs that Frontier did not incur.

Q: HAVE YOU SEEN ANY GOOD FAITH SHOWN BY FRONTIER IN ATTEMPTING TO ACHIEVE COMPLIANCE.

A: The February 23, 2017 Letter of Violation asked for Frontier to come back in thirty days with Frontier's plan and schedule for assessing pipe in HCAs. In addition, it required Frontier to do six things as soon as possible, but no later than sixty days from the date of the Letter of Violation. These six things were: (1) Appropriate personnel must become acquainted with the IMP rule and Frontier's IMP plan and processes; personnel qualifications per 192.915, (2) Review the transmission system per requirements of the Frontier IMP written plan to update and verify

HCAs, (3) Verify applicable threats and the risk analysis, and develop a schedule for assessing pipe in HCAs. Overdue segments require an accelerated full assessment, (4) Implement the Geographic Information System (GIS) and any software necessary to support IMP processes including program documentation, (5) Provide the appropriate resources to support the requirements of Frontier IMP including any staff, tools and training, and (6) Develop a Continuity Plan to ensure that safety plans and program processes such as the Frontier IMP will be carried out when key personnel transition away from program roles.

Frontier responded on March 23, 2017, that it had accomplished in thirty days much of what Pipeline Safety had asked it to accomplish in sixty days. Frankly, based on Frontier's lack of qualified IMP staff, that did not seem possible. Mr. Bryant and Mr. Hall met with Frontier on June 21, 2017 and went over the shortcomings in Frontier's response. While Frontier certainly displayed a great deal of effort, it was done in the context of an open docket in which Frontier's parent company was requesting permission to be acquired. Its efforts to engage contractors to perform necessary work was encouraging. Significantly, Frontier has now hired a degreed engineer, Mr. Drew Waravdekar, and has plans to hire another. However, Frontier has a great deal left to do and now that the order has been issued approving the merger in Docket No. G-40, Sub 136, Pipeline Safety will be watching to see if this effort continues. Frontier personnel stated that they did not verify all 14.2 miles of HCA, but rather the reduced number based on the reduction in PIR and the contention that some pipeline classified as transmission was actually operating below 20% of SMYS. Frontier was reminded that it cannot arbitrarily change the classification of transmission lines that have been reported to the Commission (G-2/G-3 Reports) and to PHMSA (Form F 7100.2-1), rather, such changes require following a process, including written notification to the Commission before such changes are made. Frontier's action in this regard was discouraging because it followed a pattern of taking actions to hold down costs as well as a lack of knowledge of pipeline safety regulations. Subsequently, Frontier has notified the Commission that it has verified the HCAs in all 14.2 miles.

Finally, although Frontier stated in its March 23, 2017 response letter that it would submit to Pipeline Safety "a monthly report that will be entitled Monthly Pipeline Safety and Compliance Report until December 31, 2018 or a mutually agreed upon date," Pipeline Safety has not received any such reports from Frontier.

Q: WHAT ACTION DOES THE PIPELINE SAFETY SECTION TAKE WHEN AN INSPECTION TURNS UP A NON-COMPLIANCE?

A: At the time of the inspection, the Pipeline Safety Staff will conduct an exit interview and notify the natural gas system operator's personnel of the problem. Then the Director of Pipeline Safety will send a letter to the responsible person at the operator to inform that person of the problem found and ask that they respond within 30 days with either a report on what has been done to address the problem or a plan of action to bring the operator into compliance.

Q: DOES THE PIPELINE SAFETY SECTION USUALLY RECOMMEND THAT THE COMMISSION IMPOSE CIVIL PENALTIES.

A: Usually, we do not.

Q: WHY NOT?

A: Because we view the Commission's authority to impose civil penalties as a tool to compel compliance. It is our experience that operators in the State promptly and willingly bring their systems into compliance whenever a deficiency is noted. The Commission and the operators have a shared goal of maintaining a safe, reliable gas system in North Carolina.

Q: WHY IS A PEANLTY BEING RECOMMENDED IN THIS DOCKET?

A: This is an extremely serious violation. Frontier effectively failed to implement Subpart O or 49 CFR, Part 192 over an extended period. And, as noted earlier, Frontier over the years has been given the benefit of the doubt and has been given the opportunity to bring itself into compliance when violations were found, but Pipeline Safety Staff continues to find violations. The turnover in personnel is an explanation, but not an excuse. Frontier had an obligation to comply with Subpart O. In light of the turnover, GNI had an obligation to ensure that Frontier had the resources to meet its safety responsibilities. As discussed, Frontier's unique situation resulted in Frontier not using a general rate case to pass through IMP expenses and to earn on any capital expenditures made to comply with Subpart O. With regard to the implementation of its IMP, Frontier and GNI intentionally led the Pipeline Safety staff to believe that it had adequate personnel or, alternatively, was receiving adequate help from GNI.

Q: SPECIFICALLY, WHAT VIOLATIONS HAVE YOU ALLEGED?

A: The Commission's Order Scheduling Show Cause Hearing cited § 192.13(c) which states: "Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part." Frontier wrote an IMP, and it was inspected and improvements were suggested. However it then failed to follow its Plan over an extended period of time.

The Order more specifically cites § 192.911 which requires an operator to make continual improvements to its plan. This cannot be done without qualified people and without adequate record-keeping. More specifically, § 192.911(l) requires a quality control plan. Frontier was unable to demonstrate that it has been maintaining record keeping necessary to document a quality control plan.

§ 192.915 deals with the knowledge and training needed to carry out an integrity management program. Frontier's IMP specifies qualifications for various positions. Nevertheless, the Company has not had qualified people assigned to implement its IMP. Frontier did not have trained supervisory personnel and/or staff qualified to carry out an IMP, in violation of § 192.915. § 192.937 deals with a continual process of evaluation and assessment to maintain a pipeline's integrity. Frontier failed to carry out a continual process of evaluation and assessment to maintain the integrity of its transmission pipelines, in violation of § 192.937.

Q: WERE OTHER FACTORS CONSIDERED IN RECOMMENDING A CIVIL PEANALTY?

A: Yes. During this period, Frontier's parent company, Gas Natural Inc., was under unusual financial stress. In 2012, it was forced to go to regulators in the states in which it operates, including North Carolina, for approval of an unusual debt refinancing. It was subject to formal proceedings before the Public Utilities Commission of Ohio to investigate dealings between regulated utilities in Ohio and companies privately owned by GNI's then-Chairman, Richard Osborne. On

December 16, 2013, its independent accounting firm resigned. In North Carolina, it ran up an unprecedented Gas Cost Deferred Account debit during cold weather event during the winter of 2013-2014. To resolve that situation, it entered into a Stipulation with the Public Staff in Docket Number G-40, Sub 124 that required it to place $2.45 million into a regulatory asset to be amortized over 60 months. In March 2015, the Securities and Exchange Commission notified GNI that it had opened an investigation regarding: (1) audits initiated by the Ohio PUC, (2) the determination and calculation of the gas recovery costs, (3) GNI's financial statements and internal controls and (4) various entities affiliated with GNI's former chief executive officer, Richard M. Osborne. The SEC issued two subpoenas. It has since closed the investigation, but not before GNI had to devote efforts to respond to it. In April 2016, GNI cut its dividend from $0.54 per share to $0.30 per share.

Q: WERE COST-CUTTING MOVES BY FRONTIER OBSERVED DURING THIS PERIOD?

A: Yes. For example, in the summer of 2015, Frontier General Manager Fred Steel was asked to meet with the Commission to explain a significant reduction in Frontier's workforce. In a relatively short period, Frontier's workforce was reduced by a quarter, mostly as a result of personnel being terminated. Mr. Steele explained the workforce reduction largely as a reaction to slowing growth. Adam Theriault, the only degreed engineer, was not replaced until just recently. Gary Moore, another experienced operations employee, was not replaced by someone with equivalent experience.

Q; WHAT DID FRONTIER'S EARNINGS RECORD LOOK LIKE DURING THE LAST FIVE YEARS? WAS IT LOSING MONEY?

A: No. In fact, in four of the five years, its earnings were better than a regulated natural gas utility in North Carolina would be expected to earn.

Q: WHAT DO YOU BASE THAT STATEMENT ON?

A: In 2016, Frontier had a return on equity (ROE) for the year of 13.4%, calculated using Frontier's reported income for the year divided by the average of the reported thirteen-month end-of-month equity balances (from December of 2015 through December 2016). It had a difficult year in 2015, with a return on equity of 8.1%. But for the four preceding years, Frontier showed a return on equity of 13.8% in 2014, 17.8% in 2013, 17.7% in 2012 and 13.6% in 2011. To put that in perspective, in the last two general rate cases for gas companies in North Carolina, the Commission authorized ROEs of 10.0% for Piedmont Natural Gas in Docket No. G-9, Sub 631, and 9.7% for PSNC Energy in Docket No. G-5, Sub 565. Furthermore, Frontier's returns were earned on a much thicker equity percentage of total capitalization.

Q: WHY DOES THE EQUITY SHARE OF TOTAL CAPITALIZATION MATTER?

A: Because if a utility can borrow money and invest at a profit, the borrowing does not increase its equity and the increased profit results in a higher return on the same equity.

Q: DID YOU DETERMINE THAT SPENDING ON SAFETY WAS INTENTIONALLY CURTAILED BY FRONTIER BECAUSE OF GNI'S PROBLEMS?

A: No. Pipeline Safety has not attempted to investigate whether GNI's financial needs led to Frontier neglecting spending on safety. Many of the key people are no longer with the Company. We simply observe that GNI needed cash, that Frontier was run on a very lean basis and that Subpart O was not effectively implemented.

Q: WHAT RECOMMENDATION DOES THE PIPELINE SAFETY STAFF HAVE AS TO THE SIZE OF A CIVIL PENALTY?

A: Taking into consideration all of the factors laid out in 49 CFR 190.225, we recommend that the maximum civil penalty allowed of $2,090,022 be assessed pursuant to 49 CFR 190.223 and G.S. 62-50(d).

Q: DO YOU HAVE ANY OTHER RECOMMENDATIONS FOR THE COMMISSION?

A: Yes. The Commission's August 1, 2017 Order Approving Merger Subject to Regulatory Conditions in Docket No. G-40, Sub 136, Regulatory Condition 14 dealt with pipeline safety. Regulatory Condition 14 laid out a timeline for Frontier to submit certain information to the Commission Staff and the Public Staff. Within ninety days after the close of the merger, Frontier is to submit,

> The scope of a review, critique, and report on the Frontier pipeline system policy and procedures, integrity management program, and staffing, inclusive of operational and safety personnel, along with a list of independent third-party consultants to provide such services.

Then:

> Within 30 days after such submission and after conferring with the Public Staff Natural Gas Division and the Commission Staff, Frontier will seek requests for proposals from those on an approved list of consultants and

> will select from the respondents and retain a consultant to conduct and prepare the review, critique, and report.

Regulatory Condition 14 does not specify how long the consultant will have to perform the necessary work. Within seven days of the issuance of the consultant's report, Frontier will file the report with the Commission. Within 60 days of the issuance of the report, Frontier will meet with the Public Staff Natural Gas Division and the Commission Staff to determine how the recommendations in the report will be addressed. Pipeline Safety strongly supports the hiring of a consultant to assist Frontier, however, this timeline extends for over half a year, not including the time that the consultant will need. The Commission's order stated:

> With regard to Regulatory Condition 14, the Commission recognizes the efforts by Frontier and the Public Staff to draft a framework and a schedule to improve pipeline safety. However, the Commission makes clear that the timetable and actions established and agreed to in Regulatory Condition 14 in no way supersede the Commission's authority pursuant to G.S. 62-50 to enforce pipeline safety regulations. Regulatory Condition 14 does not take precedent over, nor does it relieve Frontier of the obligation to meet any timetable or action imposed by the Commission.

The Commission should make clear that Frontier is currently not in compliance with Subpart O. Nothing in the Commission's Order in Docket No. G-40, Sub 136 grants Frontier a grace period. Frontier should move to get itself into compliance as quickly as it possibly can. To that end, Pipeline Safety believes that Frontier should engage an outside expert to assist it with getting into compliance immediately, perhaps in addition to the consultant required by Regulatory Condition 14. Of the three methods of establishing the integrity of a transmission pipeline, Frontier has chosen Direct Assessment. Direct Assessment depends in large measure on the gathering and analysis of information over time. Given that there is a significant gap in Frontier's efforts in data gathering and analysis, Pipeline Safety believes that another method should be used on at least some portion of Frontier's system to calibrate and verify its Direct Assessment efforts. It recommends that Frontier be required to conduct an inline inspection on at least some portion of its system and to correlate the results with its Direct Assessment findings. PHMSA's Integrity Management regulations focus on high-risk areas. All of Frontier's gas is delivered into ten-inch line in Davie County off of Transcontinental Gas Pipe Line (Transco). Given how thinly Frontier has been staffed with technical personnel and how little support it has apparently gotten from GNI, Pipeline Safety and Commission Staff have been deeply concerned over Frontier's ability to effectively manage a break in its ten-inch line. However, for most of its length, the ten-inch line up from Transco is not in an HCA and therefore is not subject to closer scrutiny under Frontier's IMP. G.S. 62-50(c) authorizes the Commission to settle actions for civil penalties with the utility. Given that, we recommend that Frontier be required to pay a meaningful fine. We also recommend that the penalty be reduced from the total $2,090,022 and the difference be used to help defray the costs of installing the necessary equipment and running an instrumented inline inspection tool (a "smart pig") from near the

Transco take-off to some part of the Frontier system, to be determined through negotiations with the Public Staff and Pipeline Safety.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes, although we note that the Commission Staff has several discovery questions outstanding. We would like to reserve the right to supplement our testimony, if necessary, based on Frontier's discovery responses.

APPENDIX A

John S. Hall

I was employed by Mississippi Valley Gas Company, Jackson, Mississippi, from September 1978 to October 1985. I served as an engineer aide, and later as technical assistant. While at Mississippi Valley Gas I participated in a broad range of gas system operating activities including corrosion control, a critical valve program, and system expansion.

I was employed by Hare Pipeline Construction, Apex, North Carolina, from February 1986 to February 1991. I served as Construction Coordinator for distribution and transmission pipeline construction projects, and I was also responsible for the utility damage prevention program.

I began working for the North Carolina Utilities Commission as a pipeline safety inspector in March, 1991. I have successfully completed pipeline safety training courses taught by US DOT instructors at the Pipeline and Hazardous Materials Safety Administration (PHMSA), Training and Qualifications Division in Oklahoma City, Oklahoma. My course training includes: Safety Evaluation of Gas Pipeline Systems, Pipeline Safety Application and Compliance Procedures, Accident Investigation, and distribution and transmission Integrity Management programs, among other required training courses.

I was a member of National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Pipeline Safety for many years. In 2003, I represented the National Association of Pipeline Safety Representatives (NAPSR) on the Integrity Management Direct Assessment Committee.

I have more than 23 years of experience inspecting natural gas operators for compliance with state and federal pipeline safety regulations, including Integrity Management Programs. I have performed evaluations of operator Integrity Management Programs using the training and guidance material provided by PHMSA.

I was promoted to Pipeline Safety Section Director in October 2013, and directed the day-to-day operations of the Pipeline Safety Section until I retired in January 2016. I am currently working as a pipeline safety inspector contractor for the NCUC, Pipeline Safety Section.

APPENDIX B

Harry C. Bryant III

In 1984, I received an Associate in Applied Science Degree in Mechanical Drafting and Design Technology from Guilford Technical Community College in Jamestown, North Carolina.

In 1996, I received a Bachelor of Science Degree in Industrial Technology Manufacturing Systems from North Carolina Agricultural and Technical State University in Greensboro, North Carolina.

I Served in the U.S. Army as a Squad Leader of an Infantry Mortar Platoon from 1977 through 1981 and then as a Chemical and Biological Specialist in the NC National Guard from 1981 through 1992. I completed the first tour of Desert Storm in 1992.

I had 19 years of experience in the gas industry, working for Pennsylvania and Southern Gas, an NUI Company in Reidsville, North Carolina. I began work for the Company in 1984 as a Mechanical Draftsman. I then became a Technical Supervisor assisting the company in various methods of recording new and existing drawings within the areas of Rockingham and Stokes County, North Carolina. I was promoted to Operations Manager in 1991.

I began my career for the North Carolina Utilities Commission as a pipeline safety inspector in June 2002. While with the Pipeline Safety Section I have successfully completed pipeline safety training courses taught by US DOT instructors at the Pipeline and Hazardous Materials Safety Administration (PHMSA), Training and Qualifications Division in Oklahoma City, Oklahoma. My course training includes: Safety Evaluation of Gas Pipeline Systems, Pipeline Safety Application and Compliance Procedures, Accident Investigation, and, distribution and transmission Integrity Management programs, among other required training courses.

APPENDIX C

Stephen P. Wood

I attended East Carolina University from September 1975 through August 1977.

On November 14, 1977 I started work at North Carolina Natural Gas. I was a crewman, a draftsman and an operations technician until December 1979 when I became a measurement technician. In 1984, I became Measurement Division Supervisor. In July 1992, I became Assistant Division Superintendent over the Wilmington Division. In April 1997, I moved to Fayetteville to assume the duties as Assistant Division Superintendent of the largest division in the company.

In November of 1999, I started working with the North Carolina Utilities Commission Pipeline Safety Section as an inspector. In March of 2016, I was promoted to Director of the Pipeline Safety Section. While with the Pipeline Safety Section I have successfully completed pipeline safety training courses taught by US DOT instructors at the Pipeline and Hazardous Materials Safety Administration (PHMSA), Training and Qualifications Division in Oklahoma City, Oklahoma. My course training includes: Safety Evaluation of Gas Pipeline Systems, Pipeline Safety Application and Compliance Procedures, Accident Investigation, and, distribution and transmission Integrity Management programs, among other required training courses.

FRONTIER NATURAL GAS COMPANY

NC'S GREEN ENERGY CHOICE

Frontier Natural Gas Company
Integrity Management Program

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REVISION CONTROL SHEET

Document Number: 04-101

Title: IMP Program

Client: Frontier Natural Gas Company

SI Project Number: FRON-01

Section	Pages	Revision	Date	Comments
All	All	0	12/13/04	Initial Issue
6.7.5	6-5 and 10	1	2/13/05	Added Root Cause Form
9.6	9.4	1	2/13/05	Added QC requirements for Perf. Management and MOC in Table 9.2
All	All	2	01/26/2017	Recalculated SMYS

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Preface

Frontier Natural Gas Company is dedicated to ensuring the safe and reliable delivery of natural gas to its customers through diligent operation and maintenance of its facilities. The safety of the community, employees, and environment is our top priority. Frontier Natural Gas Company believes that safety and reliability are ensured through properly applied integrity management principles and a commitment to continuous system improvement which extends beyond the requirements of regulatory compliance. This commitment will allow us to be a recognized leader in energy delivery and by enhancing our customers' quality of life and our team's well-being.

The goal of this Integrity Management Plan is to provide a consistent and comprehensive application of Frontier Natural Gas Company's principles.

Fred Steele
General Manager/ President

1.0 INTRODUCTION

1.1 Company Overview

Frontier Natural Gas Company head quartered in Elkin North Carolina operates and maintains an estimated 140 miles of transmission pipeline in North Carolina and provide services to approximately 3500 meters. The transmission systems are composed of pipe diameters ranging from 4.5-inches to 10.75-inches in diameter and are between sixteen and eighteen years old. The piping system has a maximum allowable pressure of 1,000 psi at stress levels ranging from 26% to 51% SMYS. [RD1]

Frontier Natural Gas Company's system is maintained by employees located in three district offices located in cities Elkin, Deep Gap and Warrenton.

1.2 Plan Objective

This Integrity Management Program was developed to be compliant with 49 CFR Part 192 and is applicable to all gas transmission owned by the Company that may affect High Consequence Areas. It is structured to provide the processes, guidance, and documentation requirements for Company personnel to manage integrity of covered pipe segments.

1.3 Responsibility

The Integrity Management Program Manager has overall responsibility and authority for the implementation, compliance and enforcement of the Safety & Environmental Procedure Plan. If he/she becomes aware that the Company is not in compliance with this program or with 49 CFR Part 192 (Rule) and is unable to implement corrective actions to become compliant he/she is required to notify in writing Frontier's General Manager/President within 60 days of not being compliant.

1.4 Integrity Management Framework

Integrity management is a comprehensive and continuous process that requires the integration of a multitude of data, processes, and operation knowledge regarding transmission pipelines. To effectively implement and manage the pipeline system consistent with integrity management principles, the Company has developed a framework of the integrity management process. This framework, shown in Figure 1.1, highlights the major elements of the Program, the interdependencies of the elements and the overall integrity management process. Frontier Natural Gas Company has chosen to follow the Prescriptive based approach instead of the performance based approach.

The program is divided into four major areas - Segment Identification, Risk Assessment, Integrity Management Plan, and Supporting Processes. Each of those areas and their corresponding Program elements are discussed below.

1.4.1 Segment Identification

The objective of this major area of the Integrity Management Program is to identify what pipe segments are covered under the Integrity Management Rule. It has two program elements that are described in the following sections.

1.4.1.1 Determination of Impact Radius Process

This element determines the Impact radius if a rupture occurred on the pipeline. This analysis is to determine the area that could potentially be affected from a pipeline rupture. It is an empirical derivation that utilizes the equation below for pipelines that are carrying natural gas.

$$r = 0.69 * d\sqrt{p}$$

Where:

r = radius of impact circle in feet

d = outside diameter of the pipeline in inches

p = pipeline segment's MAOP in psig

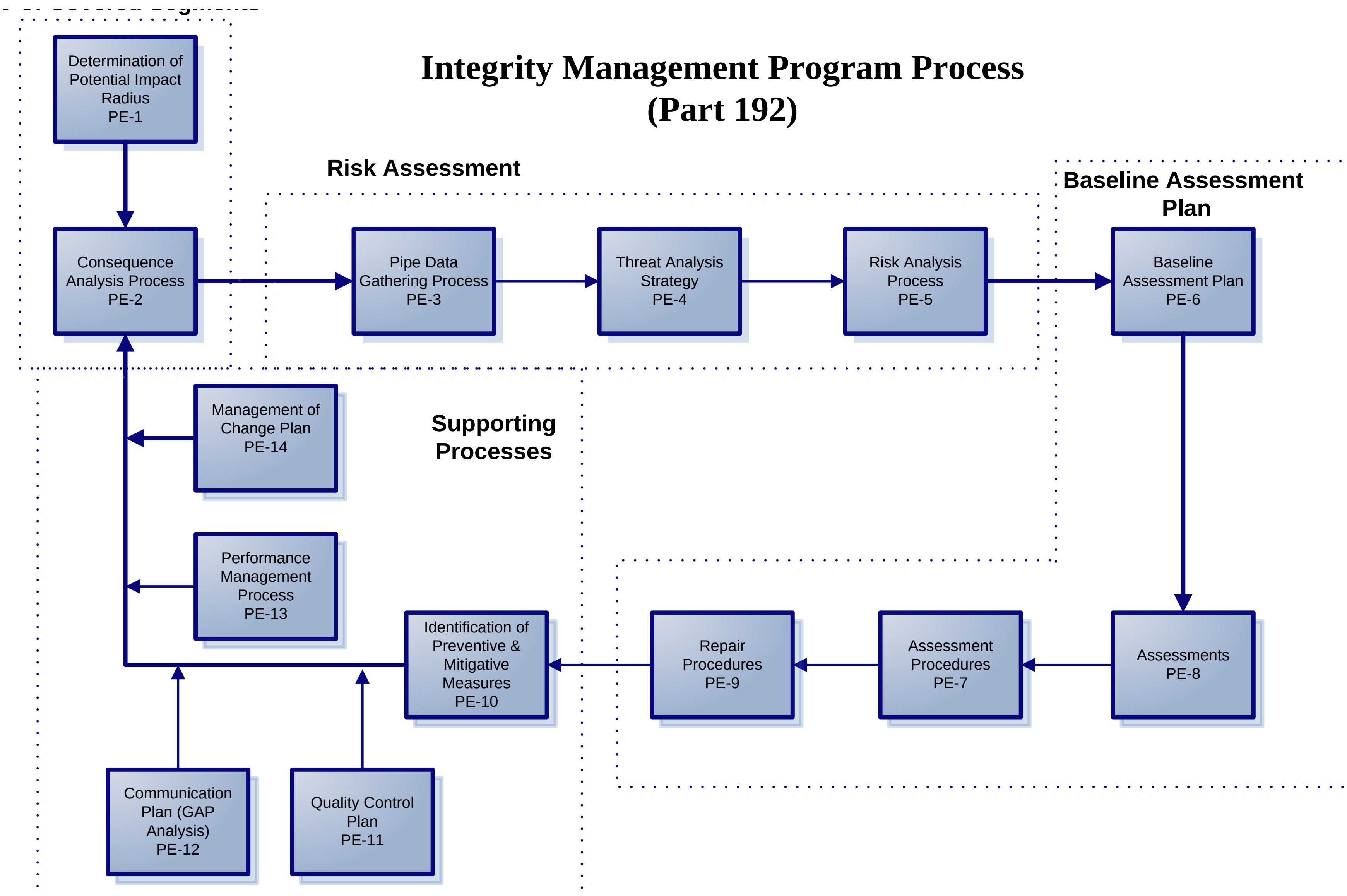


Figure 1.1: Integrity Management Framework

1.4.1.2 Consequence Analysis Process

This element describes the collection of population data along the pipeline right-of-way to determine the location and size of high consequence areas (HCA's). In summary if any of the following structures or places is within an impact circle of a pipeline segment then that area is an HCA:

- Residences: 20 or more buildings intended for human occupancy,
- Outside Gathering Places: An outside area or open structure that is occupied by twenty or more persons on at least 50 days in any twelve month period.
- Businesses: A building that is occupied by twenty or more persons on at least five (5) days a week for ten weeks in any twelve-month period.
- Impaired Mobility Facilities: A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

1.4.2 Risk Assessment

The objective of this major area is to gather and analyze all pipeline data, identify potential threats to the pipeline integrity and to conduct risk assessments for each identified HCA. The risk assessment phase has three program elements, as described in the following subsections.

1.4.2.1 Pipe Data Gathering Process

This program element assures that covered segment data is appropriately identified, collected, and organized into the necessary databases for threat evaluation and risk analysis. It also contains provisions to assure the data is updated and maintained over time. The requirements of this program element are further described in Section 2

1.4.2.2 Threat Analysis Strategy

The Company evaluates each of the 21 potential threats that are identified in ASME B31.8S to determine if the associated pipe segments require assessments for the threats. To evaluate potential threats and to determine if the pipeline segment should be assessed the Company utilizes a three step approach. The three steps are outlined below, and the overall process diagram to evaluate the threat is shown in Figure 1.2.

- What is the Likelihood of the threat?
- What measures have been taken to mitigate the threat?
- What factors could activate the threat?

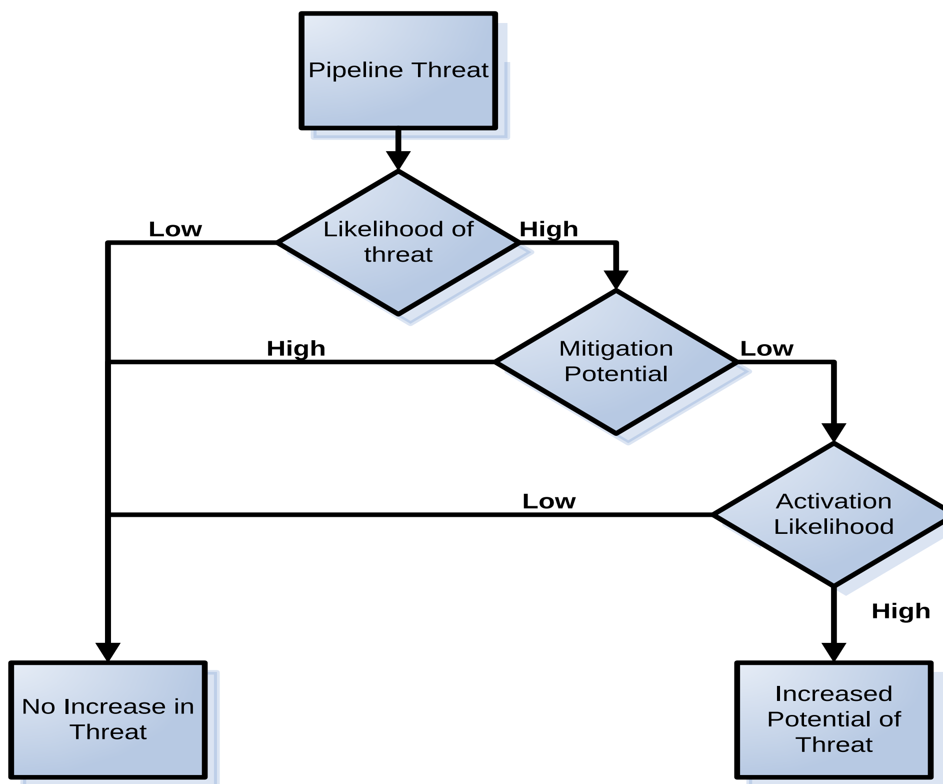


Figure 1.2: Threat Analysis Strategy

1.4.2.3 Risk Analysis

The objective of this program element is to analyze the likelihood and consequences of pipe failures in each HCA and rank order the HCA based on risk. The rank ordering will prioritize the HCA's and facilitate assessment scheduling in the Integrity Management Plan to ensure that the highest risk areas are assessed first.

To conduct the risk analysis, the Company utilizes a relatively risk ranking model called RiskPro, from Structural Integrity Associates, Inc.

1.4.3 Integrity Management Plan

The Integrity Management Plan contains multiple program elements to assure that each covered pipe segment is assessed for identified threats, damage detected during the assessment is repaired and the threat is mitigated to minimize future damage. Each of the program elements are further discussed below.

1.4.3.1 Baseline Assessment Plan

This program element is the plan for assessment of each HCA. The plan contains the following information for each HCA:

- Identification of threats
- Risk ranking
- Assessment method
- Basis for selection of assessment method
- Schedule of when the assessments will be completed

Details on this plan are provided in Section 5 of this program.

1.4.3.2 Assessment Procedures

To conduct assessments the Company has and developed detailed procedures for each assessment method. Section 7 of this program provides a listing of procedures the company uses to conduct the integrity assessments. Although the procedures are a part of the IMP they are contained in their own binders and not within this document.

1.4.3.3 Assessments

This program element consists of conducting the baseline and subsequent assessments of each HCA to evaluate the threats identified in the risk analysis. Details regarding the assessments and the results produced are described in Section 6.

1.4.3.4 Repair

Pipe segments that do not meet existing design criteria will be repaired in accordance with Company standards and procedures. Section 7 of this program provides further details regarding repairs and a listing of repair procedures that are used in the integrity management process.

1.4.4 Supporting Processes

For the IMP to be effective over time, a number of supporting processes have been developed that will account for change within the Company and measure the Program effectiveness. These processes are further described in the following paragraphs:

1.4.4.1 Preventative and Mitigative Measures

This program element describes the process and requirements to evaluate and implement further preventative measures to pipeline damage and mitigative measures to reduce the consequences of a pipeline rupture or leak. Details regarding preventative and mitigative measures are provided in Section 8 of this Program.

1.4.4.2 Quality Control Plan

The objective of the quality control plan (QCP) is to assure that the Company has documented proof that all requirements of the IMP are met. Documentation requirements and processes are an integral part of each program element. The following is included in this project element:

- Identification of the process that will be QC Audited
- Description of the sequence and interaction of the processes
- Establishment of processes and criteria and methods to assure effective execution of the processes
- Establishment of how processes will be monitored, and measured
- Identification of responsibilities and authority of personnel involved in the QCP
- Methodology for internal auditing of the program

Further details and requirements are provided in Section 9.

1.4.4.3 Performance Management Plan

The objective of the Performance Management Plan is to provide a means to measure, communicate, and improve the Integrity Management Program. The plan consists of both metrics and processes to measure the operation and effectiveness of the IMP. The plan contains the following metrics listed below:

- Process Activity Measures: Such as the number of assessments completed on time, number of miles of assessments, exceptions taken with procedures or processes.
- Operational Measures: Includes the trends of the number of 3^{rd} party damage, leaks, cathodic protection performance.
- Assessment Measures: These measures include the results of assessment such as the number of indications requiring repair, the number of immediate, scheduled and monitor indications.

Further details and requirements of this plan are provided in Section 10 of this document.

1.4.4.4 Communication Plan

The objective of the Communication Plan is to inform appropriate company personnel, jurisdictional authorities, and the public informed of integrity management efforts and results of integrity management activities. This program element includes the integration of several existing communication processes that have been modified and integrated for this IMP. Further information on the Communication Plan is provided in Section 11.

1.4.4.5 Management of Change Plan

The objective of this program element is to provide a formal process that allows the consideration and analysis of pipeline integrity before changes are made to technical, physical, procedural, and organizational areas of the Company. The plan also specifies how new pipeline data is incorporated into the Company's Integrity Management Program.

This plan addresses the following:

- Documentation of the reason for the change
- Who can approve what changes
- Analysis of possible consequences of changes
- Communication of change
- Identification of changes to the Integrity Management Program
- Documentation requirements

Further details regarding the Management of Change plan are provided in Section 12.

1.5 Roles and Responsibilities

The Integrity Management Program Manager has overall responsibility for the IMP. Table 1.1 lists the overall responsibilities and qualifications for personnel conducting integrity management activities. The responsibilities and qualifications for conducting assessment shall be listed in the assessment procedure.

Table 1.1: Responsibilities and Qualifications

Position	Responsibilities	Skills & Capabilities	Education, Training & Experience
Integrity Management Program Manager	• Over all program oversight and responsibility • Assures program is in compliance with the Rule and ASME B31.8S • Directs data gathering efforts and reviews results • Enters data into risk model and analyzes and reviews results. • Develops Base Line Assessment Plan by reviewing threat and risk scores and assigning assessment methods • Assures that assessments are conducted in accordance with established procedures. • Facilitates and evaluates the adoption of preventative and mitigative measures • Directs the Quality Control activities and notifies the Director of Operations of audit requirements • Assembles and monitors performance measures • Assures that integrity of the pipeline is considered before changes are made to pipeline segments or supporting structures	• Managerial skills • Communications skills • Setting expectations • Understanding of company data sources and structure • In depth understanding of 49 CFR §Part 192 Subpart O • Technical understanding of structural and remaining life evaluation	• Degreed engineer or equivalent • Five or more years of pipeline experience • Working knowledge or specific training in 49 CFR §Part 192 Subpart O • Detailed understanding of Frontier organization
Data Analyst	• Responsible for the development, maintenance, and security of the integrity database including data collection, data integration, quality checks, and risk model analysis. • The Data Analyst is responsible for all integrity related listings, and overseeing updates to the appropriate listings. The Data Analyst is the SME for risk model analysis and operation.	• Working knowledge of company data sources and structure • Database management skills including, scheduling, tracking and reporting	• Working knowledge or specific training in applicable Company data management systems • Two years GIS experience
Compliance Coordinator	• Issues information request letters annually to public agencies requesting information regarding identified sites • Organize and collect feedback from public agencies • Leads in communication activities	• Project management skills including, scheduling, clarifying expectations, tracking and reporting • Understanding of regulatory rules and codes • Relationship skills to deal with public agencies •	• Five or more years of pipeline industry experience in the regulatory arena • Demonstrated project management skills including detailed documentation. •
General Manager	• Assigns QC audit personnel to audit high level processes • Review QC audit findings and approves corrective actions • Provides budget approvals for integrity management issues	• Managerial skills • Communications skills • Understanding of 49 CFR §Part 192 Subpart O	• Education, training and experience commensurate with the General Manager position.
Vice President	• Annual review of the Integrity Management Program • Overall responsibility to assure IMP has adequate funding and staffing to meet regulatory requirements and the elements in the program	• Managerial skills • Communications skills • Understanding of 49 CFR §Part 192 Subpart O • Other skills and capabilities commensurate with the vice president position.	• Education, training and experience commensurate with the vice president position.

2.0 COVERED SEGMENTS

2.1 Definition of Covered Segments

Segment of pipes covered under this Integrity Management Plan are those transmission line segments that could affect a high consequence area (HCA). The definition and how to determine HCA's are defined per 49 CFR §192.905.

2.2 Identification of Covered Segments

This section of the IMP describes the process of how HCA's are determined, and provides instructions, guidance and requirements to assure the identification is performed in accordance with §192.905.

2.3 Timing and Responsibility

The Manager of Integrity Management Program shall have the transmission system analyzed and identify all segments of transmission pipeline that are within HCA's at least once every calendar year. This analysis shall begin on the first Monday of February and be completed by the first Monday in July. These portions of pipeline shall be referred to as covered segments.
As part of the annual risk and integrity assessment the "monitored conditions" will be evaluated to determine if any changes have occurred that would require additional remediation.

The Manager of Integrity Management Program shall have the transmission system analyzed and identify all segments of transmission pipeline that are outside of the current HCA's at least once every calendar year. The Form-HCA-1 Public Agency Letter and Form-HCA-2 Field Survey will be used to gather data to be evaluated to determine if any new HCA's exist. This analysis shall also begin on the first Monday of February and be completed by the first Monday in July.

If any new potential HCA's are identified the procedures outlined in Section 1.4 of Frontier Natural Gas Company IMP Plan will be implemented.

2.4 Identification Process

Figure 2.1 shows the process flow for the HCA Designation Process. Each step is described in the following sections.

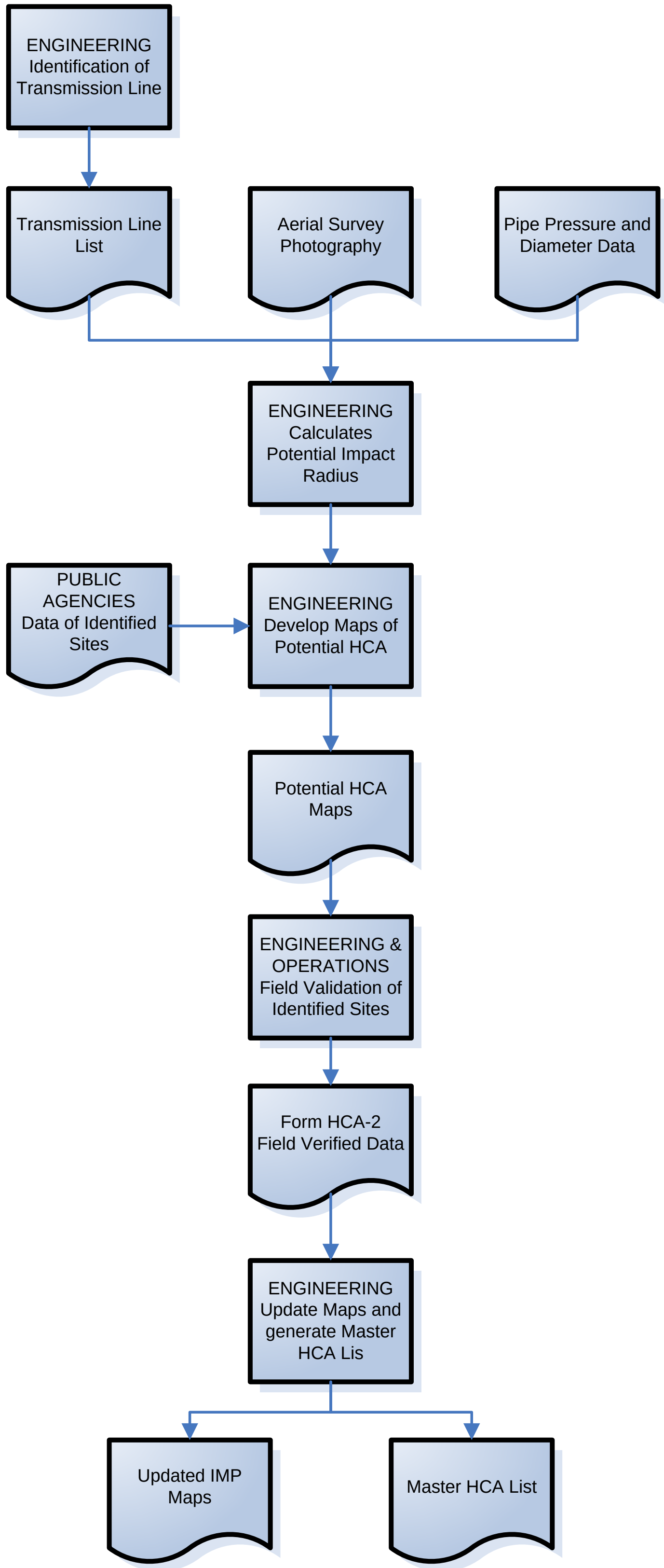


Figure 2.1: HCA Identification Process

2.4.1 Engineering Identification of Transmission Lines

Transmission Lines shall be identified and defined in accordance with 49 CFR §192.3. A master list of transmission lines is located in the mapping index book located in the mapping section of the engineering department. Transmission lines are designated on the maps by the use of a T in front of the line number, i.e. T-7.

2.4.2 Calculation of Potential Impact Radius

The Engineering Department shall calculate or review Potential Impact Radius, (PIR) for each transmission line in each district utilizing the equation below:

$$r = 0.69 * d\sqrt{p}$$

Where:

r = radius of impact circle in feet

d = outside diameter of the pipeline in inches

p = pipeline segment's MAOP in psig

To provide some allowance for mapping tolerance and possible scaling errors, the calculated radius shall be rounded up to a distance referred to as the "default radius". This default radius will be shown on maps for each pipeline segment.

2.4.3 Identified Sites from Public Agencies

The Compliance Coordinator shall annually request information regarding impaired mobility and other identified sites. If local public officials cannot provide information for any category of identified site, other sources must be pursued. The sources of information for identified sites will depend on the category of the site. For example, county or state websites may list recreational facilities, or local licensing agencies may have records for nursing homes, etc.

Frontier will be using the following public agencies and data to solicit information to identify locations that meet the criteria for HCA's:

- Emergency Management
- Fire Marshall
- Building & Permitting License Agencies

If the public agencies are not able to provide adequate information the following sources will be used as alternates:

- One-Call
- GIS Maps
- New Business Request
- Department of Economic Development
- Local Town and Township officials

The following internal methods will also be used:

- Patrols
- Leak Surveys
- Locate & Mark
- Sales
- ROW Maintenance

A sample letter is listed in the Appendix under Form HCA-1 – Public Agency Letter.

2.4.4 Identification of Potential HCA's Based on Population Density

Engineering shall determine the number of houses or building residences are within a sliding mile of the PIR on the Potential HCA pipeline maps. The HCA's shall be determined in accordance to the following sections.

2.4.5 Identification of HCA's Based on Identified Sites

Frontier Natural Gas Company uses method #2 as defined in 192.903. The following definitions shall be used to identify potential HCA's.

2.4.5.1 Outdoor Gathering

An outside area or open structure that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)- month period. (The days need not be consecutive.) Examples include but are not limited to, beaches, playgrounds, recreational facilities, camping grounds, outdoor theaters, stadiums, recreational areas near a body of water, or areas outside a rural building such as a religious facility;

2.4.5.2 Businesses

Building that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples include, but are not limited to, religious facilities, office buildings, community centers, general stores, 4-H facilities, or roller skating rinks;

2.4.5.3 Impaired Mobility Facilities

A facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples include but are not limited to hospitals, prisons, schools, day-care facilities, retirement facilities or assisted-living facilities.

2.4.5.4 Identified Site Proximity

Identified sites that are within the PIR or in very close proximity to the PIR shall be located on the maps distributed by Engineering for this purpose. Electronic rangefinders should be used in the field to locate the site on the map. The site type and name shall be recorded on Form HCA-1 or similar document.

For every identified site, the dimension of that portion of the site that encroaches into the "default radius" and is parallel to the pipeline should also be recorded on the map.

2.4.6 Develop Maps of Potential HCA Sites

The Integrity Management Program Manager shall prepare transmission facility maps showing potential HCA's. These maps will be used by the Operations and Engineering departments to field-confirm Identified Sites. The maps shall have the estimated centerline of the pipeline as well as the potential impact radii.

2.4.7 Field Verification of Identified Sites

Engineering and Operations shall field verify the identified sites on all transmission lines. Form HCA-2 shall be used to document the location and the type of site.

2.4.8 Submittal of Data to Engineering

The completed HCA-2 Forms shall be submitted to the Data Analyst within 90 days of the start of the HCA Identification process.

2.4.9 Creation or Update of Master HCA List

The Data Analyst shall develop or update the Master HCA List. The list shall have the following information:

- Unique Identification Number Name
- Line Number
- Map Number
- Potential Impact Radius
- Start Station Point

- End Station Point
- Number of Buildings
- Number of Identified Sites
- Date HCA was Identified

2.5 Covered Transmission Lines

Table 2.1 shows the current transmission lines that have identified HCA's and are included in this plan. This table shall be updated once each calendar year which shall not exceed 18 months from the last update.

Table 2.1 Transmission lines with HCA's (11/04)

Trans. Line	OD	MAOP	% SMYS	PIR	Year Installed	# HCA's	Total Length of HCA's
T1	10.75	1000	51	287	1998	21	4.9
T2	6.625	1000	39	177	1999	1	0.6
T3	10.75	1000	51	287	1999	3	2
T7	10.75	1000	51	287	2000	8	4.8
T8	6.625	1000	39	177	2001	3	0.7
T10	6.625	1000	39	177	2000	1	0.2
T12	4.50	1000	26	120	1999	1	0.2
T13	6.625	1000	39	177	2000	3	0.8

2.6 Responsibility

The Integrity Management Program Manager is responsible to assure that the HCA's and covered segments in the Integrity Management Plan be updated every calendar year which does not exceed 18 months from the last update.

3.0 THREAT IDENTIFICATION STRATEGY

3.1 Threat Overview

ASME B318.S defines three major categories of defect types – time dependent, stable, and time independent. These defect types are further subdivided into 21 separate root causes, (consider adding the nine categories of related failure types – pg. 3 ASME B31.8S-2004) each of which are considered a potential threat and are evaluated in this program. Each of the defined threats and the Company's approach to those threats are discussed in the following sections. The Integrity Management Program Manager is responsible for identifying threats on all covered segments, and documenting those threats on the Data Integration Table.

3.2 Threat Analysis Strategy

To evaluate potential threats and to determine if the pipeline segment should be assessed for the threats the company uses a three step approach. The three steps are outlined below and the overall process to evaluate the threat is shown in Figure 3.1.

- What is the likelihood of the threats?
- What measures have been taken to mitigate the threat?
- What factors could activate the threat?

At each threat evaluation step, pipeline data as well as subject matter expert knowledge is integrated. This data collection and integration process is described extensively in Section 3 of this program.

Each of these evaluation steps is utilized in the following sections to help frame a description of each threat on the Company's system. This evaluation process is integrated with the Risk Assessment model results to determine the need to assess for a particular threat.

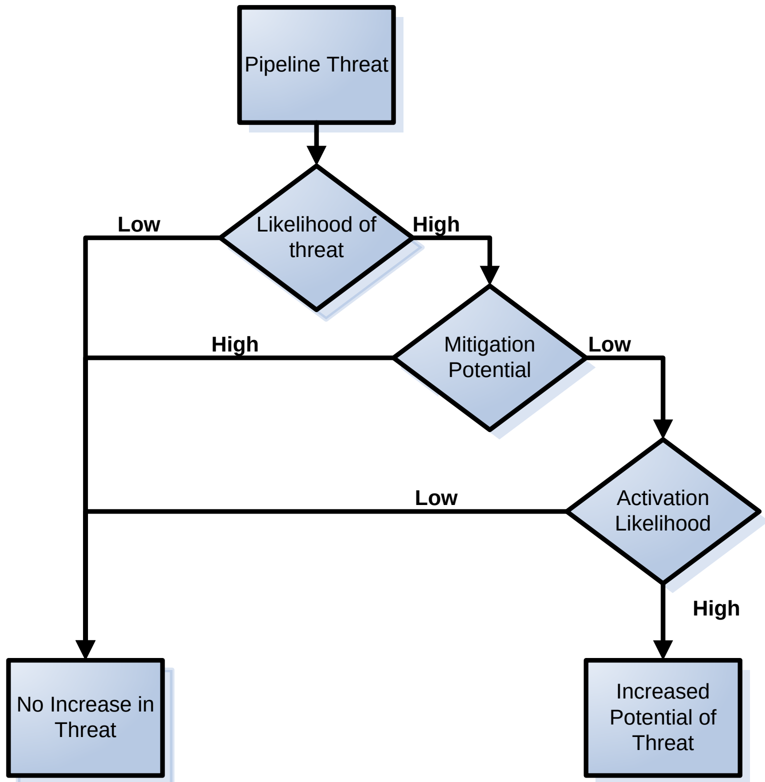


Figure 3.1: Threat Evaluation Process

3.3 Threat Analysis Summary

3.3.1 Industry Threat Summary

Table 3.1 shows the listing of pipeline threats and the number of reportable incidents over a 15 year period from 1985 to 2000. The table is ranked in order showing the threat with the highest frequency of occurrence at the top of the table.

3.3.2 Summary of Company Threats

Table 3.2 shows a summary of the threats for the Company with specifics regarding the likelihood of the threat, mitigative measures taken, and assessments for the given threats. Since Frontier Natural Gas Company's entire pipeline is only between sixteen to eighteen years old many of the threats are extremely low.

Table 3.1: Industry Reportable Incidences per Integrity Management Threat[1]

Classification	1985 through 2000	Percent of Total	Average per Year	1998	1999	2000
Third Party	364	27.60%	22.75	24	15	17
Internal Corrosion	169	12.80%	10.56	15	9	15
External Corrosion	131	9.90%	8.19	7	3	12
Incorrect Operation	92	7.00%	5.75	3	6	4
Miscellaneous	89	6.80%	5.56	6	2	8
Unknown	77	5.80%	4.81	11	3	9
Heavy Rains/Floods	63	4.80%	3.94	1	4	0
Previously Damaged Pipe	43	3.30%	2.69	1	1	1
Threads Stripped, Broken Pipe Coupling	40	3.00%	2.5	3	1	2
Earth Movement	35	2.70%	2.19	10	0	1
Defective Girth Weld	30	2.30%	1.88	4	1	2
Malfunction of Control/Relief Equipment	29	2.20%	1.81	1	0	1
Defective Fabrication Weld	27	2.00%	1.69	3	3	1
Defective Pipe Seam	25	1.90%	1.56	1	0	0
Lightning	22	1.70%	1.38	5	1	2
Gasket or O-ring Failure	20	1.50%	1.25	4	1	0
Defective Pipe	18	1.40%	1.13	0	2	1
Stress Corrosion Cracking	14	1.10%	0.88	0	1	2
Cold Weather	11	0.80%	0.69	0	0	2
Wrinkle Bend or Buckle	9	0.70%	0.56	1	1	0
Vandalism	6	0.50%	0.38	0	0	0
Seal or Pump Packing Failure	4	0.30%	0.25	0	0	0
Total	**1318**	**100.10%**	**82.4**	**100**	**54**	**80**

[1] Analysis of DOT Reportable Incidents For Gas Transmission and System Pipelines 1985 Through 2000, Paul Zelenak, etal., April 2004

Table 3.2: Summary of Frontier Natural Gas Company Integrity Management Threats

Sec.	Threat	Threat Score (weighted)	Likelihood	Mitigative Measures	Activation and Assessment
3.4	External Corrosion	0.06-0.12	Very low likelihood. Pipe is eighteen years old or less. Has FBE and Cathodically protected	• CP Surveys • CP Maintenance	• Will assess
3.5	Internal Corrosion	0	Very low likelihood. Pipe is only eighteen years old. Previous gas quality reports indicate that periodic slugs of water vapor, originating from the gas supplier, have passed through the system in the past.	Gas quality specifications written into supplier contracts.	• Will assess
3.6	Stress Corrosion Cracking	0	Not an active threat. All covered pipe segments have less than 60% SMYS, is less than eighteen years old, and is greater than 20 miles from a compressor station	No mitigative actions	Not an active threat and no assessment necessary
3.7	Defective Pipe Seams	0	Not an active threat. All covered segments are either seamless pipe or post 1972 ERW pipe		• Not active • No assessment necessary
3.8	Welding Fab. Defects	0	Not an active threat. Pipe was manufactured with the latest industry standards utilizing arc welding processes with filler metal additions. Review of records did not find any reports of defects or failures	• Latest welding standards	• Not active threat • No assessment necessary
3.9	Wrinkle Bends	0	Wrinkle bends do not exist in the system.		• Not active • No assessment necessary
3.10	Control. & Relief Valve Mal- function	0	There have been six regulator failures out of an approximate 144 regulators.	• SCADA monitoring • Leak surveys • Routine maintenance	• Conduct an analysis of failure looking for trends of equipment, location etc. • Develop long term plan to mitigate future failures.
3.11	Gasket/O Ring/Seals/Packing Failure	0	Review of company records does not find any documentation of gasket, seals or packing failures. This is a low likelihood event.	• Leak surveys • Routine maintenance	Annual leak surveys
3.12	Third Party Damage	0.27-0.48	Highest Existing Threat	• SCADA monitoring • Encroachment	• Direct Assessment if

Sec.	Threat	Threat Score (weighted)	Likelihood	Mitigative Measures	Activation and Assessment
				monitoring • NC One-Call promotion and involvement. • Damage prevention and emergency readiness seminars.	indications are found. • Prevention activities.
3.13	Incorrect Operations	0	Review of company records has not found any instances of incorrect operations.	• SCADA monitoring • Employee Training • OQ Program • Procedural Audits	• Prevention activities will be conducted in lieu of assessments
3.14	Vandalism	0	Review of company records has not found any instances of vandalism.	• SCADA monitoring • Encroachment monitoring	• Annual leak surveys. • Prevention activities.
3.15	Earth Movement	0	Examination of company records show that no failures or reports of earth movement effecting the pipe.	The system does not have girth weld joints or pipe material susceptible to earth movement	Not active threat; No assessment necessary.
3.16	Weather Related	0.2	Weather related threats are very low. Lightning strike damage has been minor and has only damaged SCADA related equipment.	SCADA systems have independent grounding. SCADA system has an automatic call in system.	Failure of the SCADA system to report in a timely fashion will result in an operational inquiry.

3.4 External Corrosion Threat

3.4.1 Required Data Elements for External Corrosion

The following data elements are required for the evaluation of the external corrosion threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated and analyzed to evaluate the external corrosion threat. This activity will be completed through the risk assessment model.

Table 3.3: Required Data Elements for External Corrosion Threat

• Year of installation	• Years without CP	• Wall thickness
• Coating type	• Soil Characteristics	• Diameter
• Coating condition	• Pipe Insp. Reports	• % SMYS

• Years with adequate CP	• MIC Detected	• Past hydro test info.
• Years with questionable CP	• Leak history	

3.4.2 Likelihood of External Corrosion

External corrosion is a very low likelihood threat on the Company's transmission lines since the transmission lines are only sixteen to eighteen years old. The likelihood of failure score (weighted) ranges from external corrosion ranges from 0.06 to 0.12.

3.4.3 Mitigative Measures for External Corrosion

The buried transmission lines in the company system have had cathodic protection applied to them since they were in service. The Company takes bimonthly rectifier readings and annual pipe-to-soil readings.

3.4.4 Activation and Assessment of External Corrosion

Although external corrosion is unlikely Frontier Natural Gas Company is planning assessment of all covered segments. The Integrity Management Program Manager will utilize the relative risk scores to determine the schedule of assessments. Most segments will be assessed with ECDA unless it is proven to be infeasible. Another assessment technique will be utilized in those cases.

3.5 Internal Corrosion

3.5.1 Required data elements for the Internal Corrosion Threat

The data elements shown in Table 3.4 are required for the evaluation of the internal corrosion threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the internal corrosion threat. This activity will be completed through the risk assessment model.

Table 3.4: Required Data Elements for Internal Corrosion Threat

• Liquids analyzed	• Drying Operation Conducted
• Liquid drains present	• Internal Corrosion Detected
• Frequency of drain checks	• Internal MIC or corrosive detected
• History of liquids	• Upstream source of liquids

3.5.2 Likelihood of Internal Corrosion History

The Company has not identified any internal corrosion and does not have electrolytes entering the system. The likelihood of failure score is 0.0 for all pipeline segments.

3.5.3 Mitigative Measures for Internal Corrosion

The Company has supplier contracts that specify that gas content cannot exceed 7 lbs. of water vapor per MMCF. /mmcf contracts. The company also periodically analyzes its gas quality through sampling.

3.5.4 Activation and Assessment of Internal corrosion

Internal corrosion has not been an identified active threat since the pipeline system does not have electrolytes entering it and there has not been any internal corrosion found in the system and that the system is relative new. The Company plans to conduct ICDA for segments that may catch and hold up liquids.

3.6 Stress Corrosion Cracking (SCC)

3.6.1 Required data elements for the SCC Threat

The following data elements are required for the evaluation of the SCC threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the SCC threat. This activity will be completed through the risk assessment model.

Table 3.5: Required Data Elements for SCC Threat

• Year of installation	• Operating Temperature	• Coating Type
• Outside diameter	• Wall thickness	• MAOP
• SMYS	• Distance from compressor station	• Compressor discharge temperature

3.6.2 Likelihood of SCC

Three conditions must be present for either near neutral or high pH SCC to occur:

- A susceptible material
- Exposure to a critical environment
- Application of critical tensile stresses.

The following is specific criteria to determine if SCC is a threat. All the elements must be true for SCC to be a threat.

- Operating Stress >60% SMYS
- Distance from compressor station ≤ 20 miles
- Age ≥10 years
- Coatings other than Fusion Bonded Epoxy (FBE)
- Operating Temperatures > 100˚F (for high pH SCC only)

The Company system has been designed to a Class Location 3 safety factor, with a MAOP of 50% SMYS or less. All of the covered segments have fusion bonded epoxy and are greater than 20 miles away from a compressor station. None of the covered segments has any of the criteria for the stress corrosion cracking threat. The likelihood of failure score is 0.0 for all the identified segments.

3.6.3 Mitigative Measures for SCC

Since the Company system does meet all of the criteria for SCC, all piping is Fusion Bonded Epoxy (FBE)and no SCC has been identified there are no mitigative measures to implement.

3.6.4 Activation and Assessment of SCC

Activation of SCC is unlikely due to the low stress level throughout the system. No SCC specific assessments will be planned until a segment of pipe meets the B31.8S Appendix A 3.3 criteria for SCC. The criteria for SCC will be reviewed on annual bases to determine if changes in Frontier Natural Gas Company's pipeline have identified the potential for SCC. Also during the investigation of any anomalies if disbanded coating is identified then consideration will be given to removing the disbanded coating and the surface inspected for SCC using magnetic particle inspection (MPI).

3.7 Defective Pipe Seams

3.7.1 Required data elements for the Defective Pipe Seam Threat

The data elements listed in Table 3.6 are required for evaluation of the defective pipe seam threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the defective pipe seam threat. This activity will be completed through the risk assessment model.

Table 3.6: Required Data Elements for Defective Pipe Seam Threat

• Seam type	• Test pressure	• 5 Yr. Max Op Pressure
• Year of installation	• MAOP	

3.7.2 Likelihood of Defective Pipe Seam

The company has ERW pipe that was purchased in 1998 and later. No defective seams are expected.

3.7.3 Mitigative Measures for Defective Pipe Seams

There are no mitigative measures.

3.7.4 Activation and Assessment of Defective Pipe Seams

There will be no assessments.

3.8 Field Fabrication Defects

3.8.1 Required data elements for Field Fabrication Defect Threat

The Field Fabrication Defect threat is compose of the following individual threats:

- Defective Pipe Girth Welds
- Threads/Pipe/Coupling
- Wrinkle Bends

The following data elements are required for the evaluation of the field fabrication defect threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the welding fabrication defect threat. This activity will be completed through the risk assessment model.

Table 3.7: Required Data Elements for Welding/Fabrication Defects Threat

• Defective pipe girth weld	• Test pressure	• Number of wrinkle bends
• Stripped threads/couplings	• MAOP	
• Year installed	• 5 yr. max. op pressure	

3.8.2 Likelihood of Field Fabrication Defects

The Company sets minimum material specifications, mill hydro test requirements, construction specifications, and inspection procedures to reduce the size and number of defects present in the pipeline during construction and installation. Research of Company records has found that the pipeline system has not had any defects associate with field fabrication. The likelihood of having leaks related to fabrication flaws is low.

The system was constructed in 1998 or later and was constructed to meet ASME B31.8. ASME B31.8 does not permit buckling of field bends. It is believed that the system does not have any wrinkle bends.

3.8.3 Mitigative Measures of Field Fabrication Defects

The mitigative measure for the detection of defective welding fabrication defects is the original pressure test of the line. Leak survey identifies other field fabrication defects.

3.8.4 Activation and Assessment of Field Fabrication Defects

Annual leak surveys are conducted over the transmission segments of the system. Field bends will be evaluated during the direct examination phase of ECDA.

3.9 Equipment

3.9.1 Required data elements for Equipment Threat

The Equipment Failure Threat includes the following individual threats:

- Gasket O-Ring Failure
- Control/Relief Malfunction
- Seal/Pump Packing Failure
- Miscellaneous

3.9.2 Gasket/O Ring and Seal/Pump Packing Failure

3.9.2.1 Required data elements for Gaskets, Seals and Packing Threat

The following data elements listed in Table 3.7 are required for the evaluation of the threat of gaskets, O rings, seals and packing failures. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 3.7: Required Data Elements for Gaskets, Seals, and Packing Threat

• Year of installation of failed equipment	• O Ring failure information
• Flanged gasket failure information	• Seal Packing failure information

3.9.2.2 Likelihood of Gasket/O Ring and Seals/Pump Packing Failure

All of the HCA's do not have gaskets, O rings, seals and pump packing to cause leakage. Company records show that only minor leaks have resulted from these failures.

3.9.2.3 Mitigative Measures for Gasket/O Rings and Seal/Pump Packing Failure

Gaskets, O Rings, Seals and Pump packing are maintained and leak tested annually.

3.9.2.4 Activation and Assessment of Gasket/O Rings and Seal/Pump Packing Failure

Maintenance records for each HCA have been reviewed. HCA's with past leakage of gaskets, O rings and seals and pump packing leakage will be further assessed to mitigate the possibility of future failures.

3.9.3 Equipment Related Threats

The following data elements listed in Table 3.8 are required for the evaluation of equipment related threats. The Integrity Management

Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 3.8: Required Data Elements for Control and Relief Valve Threat

• Above ground equipment present	• Control/relief malfunction
• Failed O-Ring	• Seal/pump packing failure

3.9.3.1 Likelihood of Malfunction

Control and relief equipment are designed with a working monitor and double regulation, when possible, to address potential malfunction. Review of Company records has found there has been six regulator or monitor failures with none of those failures resulting in an over pressurization of the pipeline. The likelihood of over pressurization from this threat is very low.

3.9.3.2 Mitigative Measures of Equipment Malfunction

The system is continuously monitored with SCADA for over pressure situations. Regulator and monitor valves are maintained in accordance with Company maintenance and operating procedures at least once per year per PHMSA Part 192.739. Any chronic maintenance issue with regulator and monitor valves is addressed.

3.9.4 Activation and Assessment of Control and Relief Valve Malfunction

Control and Relief Valve maintenance history will be reviewed as part of the risk assessment of each HCA segment. Segments with chronic maintenance and performance problems will be rated high risk and corrected

3.10 Third Party Damage (TPD)

3.10.1 Required data elements for TPD Threat

The following data elements listed in Table 3.9 are required for the evaluation of the TPD threat. The Integrity Management Program

Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 3.9: Required Data Elements for Third Party Damage Threat

• Vandalism incidents	• Incidences involving previous damage
• Pipe Inspection Reports	• One Call Records
• Leak Reports	• Encroachment Records

3.10.2 Likelihood of TPD

Third party damage resulting from excavation activity is the most likely threat to the Company system. It has likelihood of failure scores that range from of 0.27 to 0.48.

3.10.3 Mitigative Measures for TPD

As a result, the Company has implemented aggressive programs to prevent, detect, and mitigate TPD on the system. The ROW is inspected annually. The Company participates in the North Carolina One Call program, monitors 3rd party excavations near transmission lines, provides damage prevention/emergency readiness classes and conducts public awareness meetings in accordance with API 1162.

3.10.4 Activation and Assessment of TPD

Third Party Damage is the greatest threat to Company buried facilities. The Company focus is on the prevention and detection of TPD. Specific assessment for TPD will be initiated from the Patrolling program.

3.11 Incorrect Operations

3.11.1 Required data elements for Incorrect Operations Threat

The data elements listed in Table 3.10 are required for the evaluation of the Incorrect Operations threat. The Integrity Management Program

Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 3.10: Required Data Elements for Incorrect Operations Threat

• Procedure review Information
• Audit information
• Failures caused by incorrect operations

3.11.2 Likelihood of Incorrect Operations

An incorrect operation is an on-going threat to the system integrity. Review of Company records has found there have been no failures resulting from incorrect operation of the pipeline system. The likelihood of this threat is considered low.

3.11.3 Mitigative Measures regarding Incorrect Operations

Prevention is the main measure employed at the Company to mitigate the threat of incorrect operations. Employees are required to attend training and re-certify their understanding of how to perform critical operational tasks. The Company's Operator Qualification program has also been implemented to ensure that employees are qualified to perform the duties outlined in their job responsibilities.

To mitigate the effects of incorrect operation, the system is continuously monitored with SCADA for over pressure situations.

Any deficiencies discovered through procedural review and audits are corrected and implemented into employee training programs and procedures.

3.11.4 Activation and Assessment of Incorrect Operations

Preventative activities are the most appropriate alternative to the threat of incorrect operations. On-going employee training and adherence to Operator Qualification Program requirements will be utilized in lieu of assessment.

3.12 Vandalism

3.12.1 Required data elements for the Vandalism Threat

The following data element is required for the evaluation of the Vandalism threat. The Integrity Management Program Manager shall assure that the data elements is collected, integrated, and analyzed to evaluate the vandalism threat. This activity will be completed through the risk assessment model and Subject Matter Experts.

Table 3.11: Required Data Elements for Vandalism Threat

- Vandalism Incidents

3.12.2 Likelihood of Vandalism

The frequency and extent of vandalism on the company's system has been low and relatively minor. It remains an on-going minor threat to above ground facilities.

3.12.3 Mitigative Measures for Vandalism

The routine patrols are also utilized to detect and report any vandalism to the system. Damaged facilities are noted and reported to the local field operators for maintenance.

3.12.4 Activation and Assessment for Vandalism

Vandalism is a low frequency threat. The routine patrol assesses, identifies and mitigates this threat.

3.13 Earth Movement

3.13.1 Required data elements for Earth Movement Threat

The following data elements listed in Table 3.12 are required for the evaluation of the earth movement threat. The Integrity Management Program Manager shall assure that the data elements are collected, integrated, and analyzed to evaluate the threat. This activity will be completed through the risk assessment model.

Table 3.12: Required Data Elements for Earth Movement Threat

• Joint method	• Profile of ground acceleration	• Earthquake fault
• Topography	• Depth of frost line	• Pipe characteristics
• Earthquake fault	• Year of installation	

3.13.2 Likelihood of Earth Movement

The Company has no history of failures due to geotechnical causes such as earth movement. The pipeline system has suffered from washouts in non-HCA's. These washouts were in remote areas and therefore the likelihood of failure do to earth movement is low, and will not be evaluated as a threat to pipeline integrity.

3.14 Weather Related Threats

3.14.1 Likelihood of Weather Related Threats

Weather related threats are low for the pipeline system. Flooding is the only moderate threat and it is monitored with the right of way patrols. Lightning threats are identified with external corrosion direct assessments.

Lightning strikes have occurred that causes SCADA equipment failure. The system automatically calls the on-call supervisor when the equipment fails. Weather related likelihood of failure scores are 0.2.

4.0 RISK ASSESSMENT

4.1 Objective

This section describes the process of integrating pipeline data to identify, measure, and evaluate threats. The evaluation will be used to determine the risks that the pipeline poses to high consequence areas, and the assessment and mitigating responses to those risks. This process is comprised of three major tasks:

- Data Gathering
- Threat and Risk Analysis
- Assessment Plan

4.2 Time Requirements

The Integrity Management Program Manager shall at least annually conduct the risk assessment analysis to evaluate threats that may affect HCA's. This analysis shall not exceed 18 months from the last Risk Assessment Analysis.

4.3 Data Gathering

The Integrity Management Program Manager shall gather all pertinent data for each covered segment listed in Form RA-1. The data that shall be evaluated for the threats listed in Table 4.1 and used to provide an overall relative risk ranking.

4.3.1 Sources of Data

The data shall be collected from the Company's engineering and construction records, operational and condition reports, and interviews with subject matter experts.

4.3.2 Data Input

The Integrity Management Program Manager shall assure that the data for each pipe segment identified in Form A is inputted into the risk ranking model to evaluate the covered segments of the line.

Table 4.1: RiskPro Data Element Table

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
	Equation Fixed References	**1**	**4**	**7**	**9**	**9**	**6**	**15**	**3**	**6**			**4**
1	Unique ID												
2	Segment Name												
3	Line												
4	Start Point												
5	End Point												
6	Section Length		**1**										
100	***** SEGMENT DATA *****												
101	Potential Impact Radius												
102	Residential	**1**											
103	ID Locations	**1**											
104	Class Location									**1**			
105	HCA Comments												
200	*** PIPE DATA ***												
201	Material Spec												**1**
202	Material Toughness									**1**			
203	SMYS		**1**			**2**							
204	Outside Diameter		**1**			**2**							
205	Wall Thickness		**1**			**2**				**1**			
206	Seam Type						**2**						
207	Factory Coating Type			**2**		**3**							
208	Pipe Comments												
300	***** CONSTRUCTION DATA *****												
301	Year Installed			**2**		**1**	**1**	**1**					**1**
302	Test Pressure						**1**	**1**					
303	Number of Casings												
304	Backfill Construction			**1**									
305	Depth of Cover									**1**			
306	Girth Weld Type												**2**
307	Girth Weld Quality							**1**					
308	Field Coating Type			**2**		**1**							
309	Pipeline Crossing									**1**			
310	Water Crossing												**1**
311	# of Wrinkle Bends							**1**					
312	Wrinkle Result of Move							**1**					

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
313	Wrinkle >3 degrees							1					
314	WB Aspect Ratio <3							1					
315	Above Ground Equipment Present								3				
316	Susceptible to Land Movement					1							1
317	Susceptible to Weather												1
318	Construction Comments												
400	***** SOIL & ENVIRONMENT *****												
401	Soil Type							1					
402	Soil Wetness			1		2							
403	Soil Resistivity			1		1							
404	Water pH					1							
405	Land Use									2			
406	Historical Construction Activity									1			
407	Right of Way Condition									1			
408	Soil & Environment Comments												
500	***** CORROSION CONTROL *****												
501	Coating Condition			2		3							
502	Cathodic Protection Criteria			1									
503	Months Below CP Criteria			1									
504	Years Without CP			1									
505	Stray Current History			1									
506	Casing Contact			1									
507	External Corrosion Detected			1		1							
508	External MIC Detected			1									
509	Internal Corrosion Detected				4								
510	Internal MIC or Corrosives Detected				2								
511	Upstream Source of Liquids				4								
512	History of Liquids				6								
513	Liquid Drains Present				5								
514	Drains Checked Frequently				3								
515	Liquids Analyzed				3								
516	Drying Operation Conducted				1								
517	Corrosion Control Comments												
600	***** OPERATIONAL DATA *****												
601	MAOP		1			2	2	2					
602	5Yr Max Op Pressure						1	1					

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
603	Weekly (Pmin/Pmax)					**1**		**2**					
604	Previous Leaks / mile / year			**1**									
605	Distance From Compressor					**1**							
606	Compr Discharge Temp					**1**							
607	Average Pipe Temp												**1**
608	Pipe Tmax-Tmin							**2**					
609	History of Incorrect Operations											**1**	
610	History of Pipe Seam Failure						**1**						
611	Defective Pipe												
612	Defective Pipe Seam						**1**						
613	Defective Fabrication Weld												
614	Prior Wrinkle Failures							**1**					
615	Stripped Threads / Couplings							**1**					
616	Failed O-Ring								**1**				
617	Control / Relief Malfunction								**1**				
618	Seal / Pump Packing Failure								**1**				
619	# 3rd Party Damage Reports									**1**			
620	# Vandalism Reports										**1**		
621	Operational Comments												
700	***** ECDA Indications *****												
701	Immediate		**2**										
702	Scheduled		**1**										
703	Monitored		**1**										
800	*** CIS Indications ***												
801	**CIS Severe**		**1**										
802	CIS Moderate		**1**										
803	CIS Minor		**1**										
900	***** DCVG/PCM Indications *****												
901	DCVG Severe		**1**										
902	DCVG Moderate		**1**										
903	DCVG Minor		**1**										
Sys1	**Time Stamp**												
	Totals	**3**	**19**	**26**	**37**	**34**	**15**	**32**	**9**	**16**	**1**	**1**	**12**

4.4 Risk Analysis

The objectives of the risk analysis are to integrate a wide range of pipeline data to facilitate identification of threats to the covered segments, generate a ranking of covered segments in order of highest risk, and determine mitigation responses to those risks.

4.5 Risk Model – RiskPro™

To evaluate the risks on the identified pipe segments, the Company shall use RiskPro™, a relative risk ranking model developed by Structural Integrity Associates, Inc. This model utilizes the universal risk formulation of:

Risk = LOF X Consequences

Where:

LOF = Likelihood of Failure

Consequences = An assigned weighting to each type of HCA

4.5.1 Likelihood of Failure Score and Threats

The Likelihood of Failure (LOF) is a relative qualitative measure that is used to assign a likelihood of failure score (expressed as a range from 0 to 1) for a given covered pipeline segment. A zero score indicates that the likelihood of failure is very low, where a score of 1 indicates a high likelihood of failure.

To determine the LOF, the antecedents of each threat are identified. The RiskPro model utilizes scoring algorithms to assign weightings and interdependencies for over 30 data elements related to the nine threats listed below.

- External Corrosion (EC)
- Internal Corrosion (IC)
- Stress Corrosion Cracking (SCC)
- Manufacturing (M)

- Field Fabrication (FF)
- Equipment (E)
- 3rd Party Damage (TPD)
- Vandalism (V)
- Weather and Outside Forces (WOF)

A LOF score is first calculated for each threat, and then specific weightings are applied to each threat as determined by the Company. The average weighted LOF for all threats combined is used to determine the overall LOF for the segment. The general formulation of the LOF is:

$$LOF = (EC*ECwt)+(IC*ICwt)+(SCC*SCCwt)+(M*Mwt)+(FF*Fwt) \\ +(E*Ewt)+(TPD*TPDwt)+(V*Vwt)+(WOF*WOFwt)$$

4.5.2 Data Input

Data is placed into Form A in the RiskPro model for each covered segment. The program populates the model with data from Form RA-1 and determines threat specific LOF scores in addition to the total LOF for the covered segment.

4.5.3 Data Requirements and Documentation

Table 4.2 specifies what data elements are required and what to do in the case the data element is missing. The Integrity Management Program Manager shall assure that the data element input into the model meets these requirements. Data will be documented in the model as well as in the baseline assessment report.

Table 4.2: Data Element Requirements

#	Data Element	Major Contrib. To Threat ID	Need	Action Required When Data is Missing
1	Unique ID		R	Create a number
2	Segment Name	*[Not used in calcs]*	D	Optional
3	Line	*[Not used in calcs]*	D	Optional
4	Start Mile Point	*[Not used in calcs]*	R	Required to specify a geographical reference. Does not have to be mile points
5	End Mile Point	*[Not used in calcs]*	R	Required to specify a geographical reference. Does not have to be mile points
6	Section Length		R	Required to specify length in feet
101	Potential Impact Radius	*[Not used in calcs]*		
102	Residential		R	Required to identify the type of HCA's the segment may affect. Refer to the HCA Identification process.
103	Identified Locations		R	Required to identify the type of HCA's the segment may affect. Refer to the HCA Identification process.
104	Class Location		R	Required to identify the class location of the segment of pipe
201	Material Spec	Yes	R	If no documentation or SME knowledge exists excavate the pipe to determine material properties
202	Material Toughness			
203	SMYS	Yes	R	If no documentation exists assume 24,000 psi or follow sampling program in §193.107
204	Outside Diameter	Yes	R	If no documentation or Subject Matter Expert (SME) knowledge exists excavate the pipe to determine dimensions
205	Wall Thickness	Yes	R	If no documentation or SME knowledge exists excavate the pipe to determine dimensions
206	Seam Type	Yes	R	If no documentation or SME knowledge exists excavate the pipe to determine dimensions
207	Factory Coating Type	Yes	R	Excavate to determine
301	Year Installed	Yes	R	If year installed is not known, assume earliest possible date the pipeline could have been constructed. Document the basis of your assumption.
302	Test Pressure		R	Re-hydrostatically test pipe segment to reestablish MAOP
303	Number of Casings	*[Not used in calcs]*		
304	Backfill Construction		D	If there is not specific data or understanding of the backfill utilize SME most likely estimate of backfill type
305	Depth of Cover		D	If depth of cover is not known provide best estimate from SME
306	Girth Weld Type	Yes	D	If girth weld type is not known provide best conservative estimate for the vintage of pipe from SME. Conservative would be the more brittle or less axial strength joint.
307	Girth Weld Quality			
308	Field Coating Type			
309	Pipeline Crossing		D	If specific information is not available utilize SME most likely estimate
310	Water Crossing			
311	# of Wrinkle Bends		D	If the presence or number of wrinkle bends are not known provide best estimate from SME.
312	Wrinkle Result of Move			
313	Wrinkle >3 degrees			
314	WB Aspect Ratio <3			
315	Above Ground Equipment Present	Yes	R	Survey line to determine
316	Susceptible to Land Movement	Yes	R	Survey the right of way to determine
317	Susceptible to Weather	Yes	R	Survey facilities to determine
401	Soil Type			

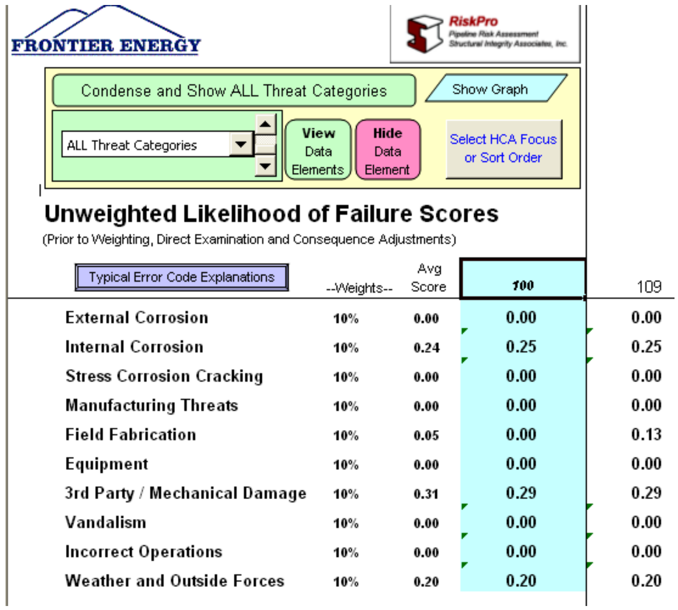
#	Data Element	Major Contrib. To Threat ID	Need	Action Required When Data is Missing
402	Soil Wetness		D	If the soil condition not known assume conditions are seasonally wet and dry
403	Soil Resistivity		D	If soil resistivity is not known and there is no SME knowledge of soils resistivity assume less than 1,000 Ω-cm.
404	Water pH			
405	Land Use	Yes	R	Survey the right away to determine
406	Historical Construction Activity		D	If specific information is not available utilize SME most likely estimate
407	Right of Way Condition		R	Survey right of way to determine
501	Coating Condition		D	If specific information is not available utilize SME most likely estimate
502	Cathodic Protection Criteria		R	Required
503	Months Below CP Criteria		R	Research and analyze CP records for the past ten years
504	Years Without CP	Yes	R	Research records. If SME believes the segment has been without CP then utilize conservative estimate and document basis for estimate
505	Stray Current History	Yes	R	If specific information is not available utilize SME most likely estimate
506	Casing Contact		R	Research records and take electrical measurements
507	External Corrosion Detected	Yes	R	Required to collect all documents and SME knowledge of identified historical external corrosion damage on the pipe segment. If no damage has been identified then that will be noted in the model
508	External MIC Detected			
509	Internal Corrosion Detected	Yes	R	Required to collect all documents and SME knowledge of identified historical internal corrosion damage on the pipe segment. . If no damage has been identified then that will be noted in the model
510	Internal MIC or Corrosives Detected			
511	Upstream Source of Liquids			
512	History of Liquids			
513	Liquid Drains Present			
514	Drains Checked Frequently			
515	Liquids Analyzed			
516	Drying Operations Conducted			
601	MAOP		R	If MAOP cannot be established the Company must reestablish it through the hydro process
602	5Yr Max Op Pressure		R	If the maximum operating pressure over the last five years cannot be established than the Company must assume the highest recorded operating pressure over the last five years be used which may be the existing operating pressure.
603	Weekly (Pmin/Pmax)			
604	Previous Leaks / mile / year		R	Must include any reports of leaks that might be associated with the covered segment. Also include SME knowledge in this data element
605	Distance From Compressor		R	If it can be documented that no compressor station is within 20 miles use greater than 20 miles. If a compressor station is within 20 miles then the actual miles must be determined.
606	Compressor Discharge Temp			
607	Average Pipe Temp		R	
608	Pipe Tmax-Tmin			
609	History of Incorrect Operations		R	Must include any documentation that indicates incorrect operation of the pipe segment. This includes operational, maintenance, or engineering errors. Also include SME knowledge in this data element
610	History of Pipe			

#	Data Element	Major Contrib. To Threat ID	Need	Action Required When Data is Missing
	Seam Failure			
611	Defective Pipe	*[Not used in calcs]*		
612	Defective Pipe Seam			
613	Defective Fabrication Weld	*[Not used in calcs]*	R	Must utilize any company reports or SME understanding if pipe girth weld seams have a tendency to be defective. If no evidence exists that they are defective then assume they are fit for service
614	Prior Wrinkle Failures			
615	Stripped Threads / Couplings	Yes	R	Must utilize any company reports or SME understanding if there have been any coupling failures. If no evidence exists that there has been failures or the failures have been remediated then assume fit for service
616	Failed O-Ring	Yes	R	Must utilize any company reports or SME understanding if there has been any O ring failure. If no evidence exists that there has been failures or the failures have been remediated then assume fit for service.
617	Control / Relief Malfunction	Yes	R	Must utilize any company reports or SME understanding if there has been any control or relief valve malfunctions. If no evidence exists that there has been failures or the failures have been remediated then assume fit for service
618	Seal / Pump Packing Failure	Yes	R	Must utilize any company reports or SME understanding if there has been Seal / Packing failures. If no evidence exists that there has been failures or the failures have been remediated then assume fit for service
619	# 3rd Party Damage Reports			
620	# Vandalism Reports		R	Must include any reports or documentation of vandalism. Also include SME knowledge in this data element
700 to 900	Assessment Results		R	Must include the results of any assessments that have been conducted on the covered segment

4.6 Data Review Requirements

The Integrity Management Program Manager shall review the inputted data and the resulting score using the “Unweighted Likelihood of Failure Score” risk model screen (Figure 4.1). The Integrity Management Program Manager shall select each pipe segment and compare the data and LOF scores with other segment averages to assure the data is correct, and to understand the factors contributing to various in a particular covered pipe segment. The data and LOF scores may also be viewed in graphical format (Figure 4.2) to assist in the review and analysis.

The Integrity Management Program Manager should review the data input with subject matter experts to better understand the analysis and identify potential anomalies in the data.



	--Weights--	Avg Score	100	109
External Corrosion	10%	0.00	0.00	0.00
Internal Corrosion	10%	0.24	0.25	0.25
Stress Corrosion Cracking	10%	0.00	0.00	0.00
Manufacturing Threats	10%	0.00	0.00	0.00
Field Fabrication	10%	0.05	0.00	0.13
Equipment	10%	0.00	0.00	0.00
3rd Party / Mechanical Damage	10%	0.31	0.29	0.29
Vandalism	10%	0.00	0.00	0.00
Incorrect Operations	10%	0.00	0.00	0.00
Weather and Outside Forces	10%	0.20	0.20	0.20

Figure 4.1: RiskPro "Unweighted Likelihood of Failure Score" Screen

4.6.1 Data Review Documentation

The Integrity Management Program Manager shall document his/her review on Form RA-2 by initialing the threat category for each covered pipeline segment where he/she has:

- Reviewed the data for accuracy
- Reviewed the data in comparison with other covered pipe segments
- Reviewed the data with the threat scoring to assure the data and the individual threat score is rational
- Compare the threat score with other covered pipe segments
- Compared the threat score of the covered segment with the average threat score for the other pipe segments.

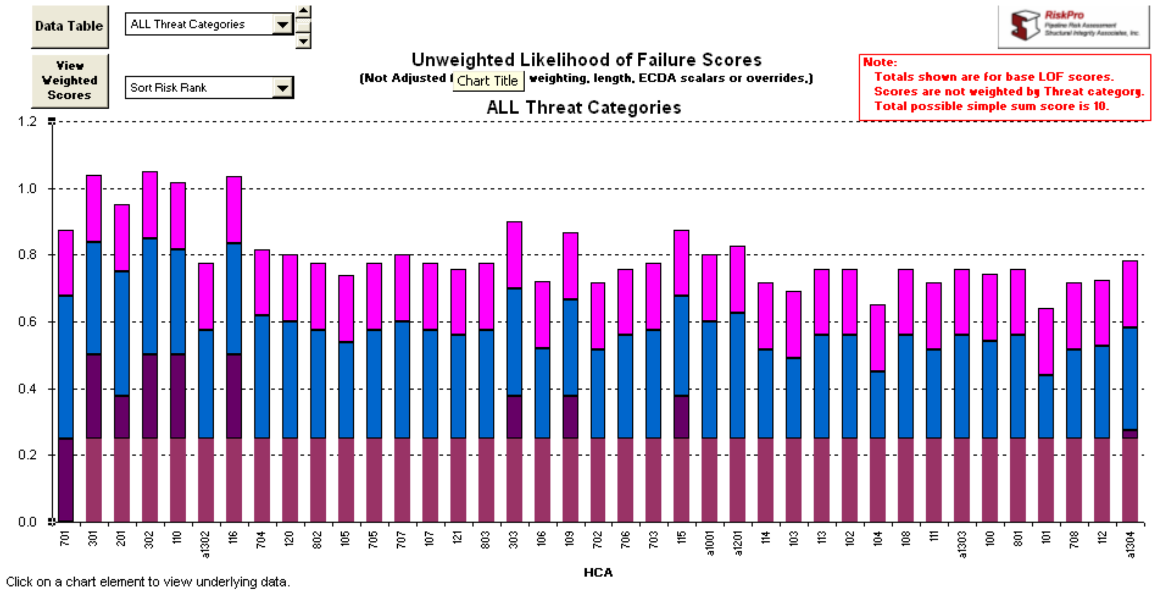


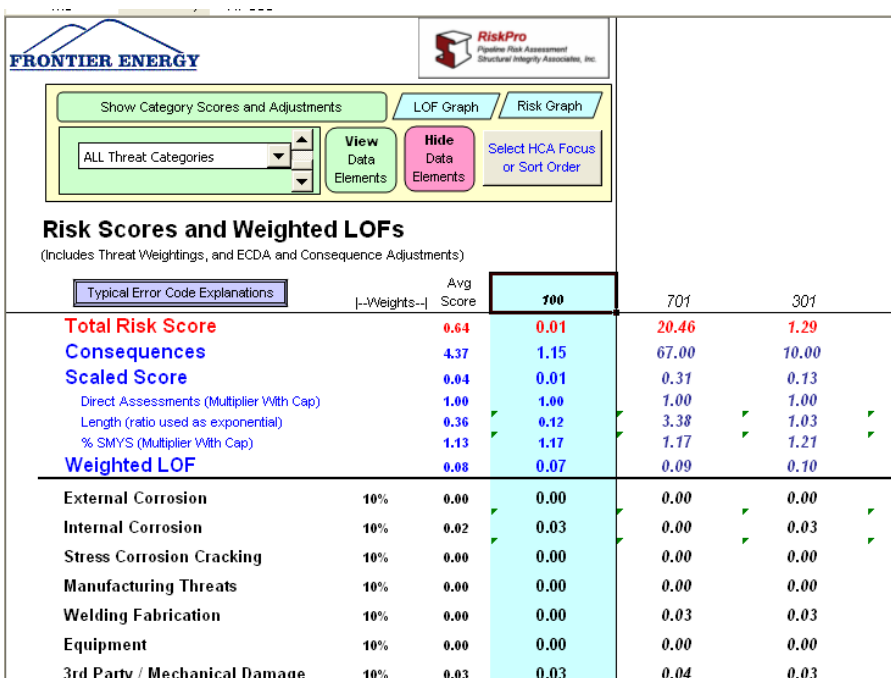
Figure 4.2: Un-weighted Likelihood of Failure Chart

4.6.2 Consequence and Final Risk Score

The final risk score is the product of the weighted LOF score and the consequence score. The consequence score is determined by the number of identified sites in the HCA and the number of residences divided by 20.

4.6.3 Analysis Review Requirements

Once the data has been inputted and analyzed, the Integrity Management Program Manager shall review the risk scores for each covered segment to assure they appear rational and are complete.



	|--Weights--|	Avg Score	700	701	301
Total Risk Score		0.64	0.01	20.46	1.29
Consequences		4.37	1.15	67.00	10.00
Scaled Score		0.04	0.01	0.31	0.13
Direct Assessments (Multiplier With Cap)		1.00	1.00	1.00	1.00
Length (ratio used as exponential)		0.36	0.12	3.38	1.03
% SMYS (Multiplier With Cap)		1.13	1.17	1.17	1.21
Weighted LOF		0.08	0.07	0.09	0.10
External Corrosion	10%	0.00	0.00	0.00	0.00
Internal Corrosion	10%	0.02	0.03	0.00	0.03
Stress Corrosion Cracking	10%	0.00	0.00	0.00	0.00
Manufacturing Threats	10%	0.00	0.00	0.00	0.00
Welding Fabrication	10%	0.00	0.00	0.03	0.03
Equipment	10%	0.00	0.00	0.00	0.00
3rd Party / Mechanical Damage	10%	0.03	0.03	0.04	0.03

Figure 4.3: Risk Scores and Weighted LOF's Screen

5.0 BASELINE ASSESSMENT PLAN PROCESS

5.1 Baseline Assessment Plan Documentation

5.1.1 Baseline Assessment Form

The Integrity Management Program Manager shall utilize Form RA-3, Baseline Assessment Plan for each covered segment. Completion of this form is mostly automated in RiskPro. The threat, the assessment method, and assessment schedule require manual input by the Integrity Management Program Manager. This information may be entered through the RiskPro program.

5.1.2 Threat Identification

The Likelihood of Failure Score (LOF) for each threat (unweighted) is listed on the Baseline Assessment Form. As a guideline, threat scores 0.25 or greater should be closely reviewed by the Integrity Management Program Manager potential assessment. The Integrity Management Program Manager has the responsibility to review the data and risk analysis as specified in Section 3.5 of this plan and identify threats that will be assessed. A minimum of one threat must be assessed to satisfy the Baseline Assessment Plan requirements. The Integrity Management Program Manager shall list the threats to be assessed on Form D at Location A.

5.1.3 Assessment Method

The Integrity Management Program Manager shall specify the assessment method in Form RA-3 at Location B. The Integrity Management Program Manager shall explain the rationale for his assessment selection in the comment section on Form RA-3 at Location C.

5.1.4 Assessment Schedule

The Integrity Management Program Manager shall specify the schedule of assessment on each identified pipe segment on Form RA-3 at Location D. The Integrity Management Program Manager shall consider the risk ranking of the identified segment, the assessment time requirements specified in and operational logistic issues when determining the schedule for assessments.

The Integrity Management Program Manager shall explain the rationale for the schedule in the comment section in Form RA-3 at Location C.

5.1.5 Signature Requirement

The Baseline Assessment Plan shall be printed after completion of threat identification, assessment method selection, and assessment scheduling. The Integrity Management Program Manager shall sign and date the printed Baseline Assessment Plan (Form C) for each covered pipe segment indicating review and approval.

5.2 Record Keeping

5.2.1 Filing

The completed Baseline Assessment Plans will be filed in the Company's Integrity Management Program. There shall be one plan for each covered pipe segment. A copy of each plan shall be placed in Section 5.3 of this document.

5.2.2 Record Retention

Baseline Assessment Plan shall be kept on file for as long as the Company operates the covered segment. If the plan changes, the Company shall retain the original Baseline Assessment Plan and all revised versions of the plan for the life of the covered segment.

5.2.3 Revising the Baseline Assessment Plan

If the plan changes the Integrity Management Program Manager shall document all changes from the previous version, the reasons for the change, and the date the change was implemented. This documentation shall be accomplished by highlighting revisions on a copy of the previous Baseline Assessment Plan and recording the reasons for the revisions. The documentation shall be kept on file for the life of the covered pipeline segment.

5.3 Baseline Assessment Plans

5.3.1 BAP Structure

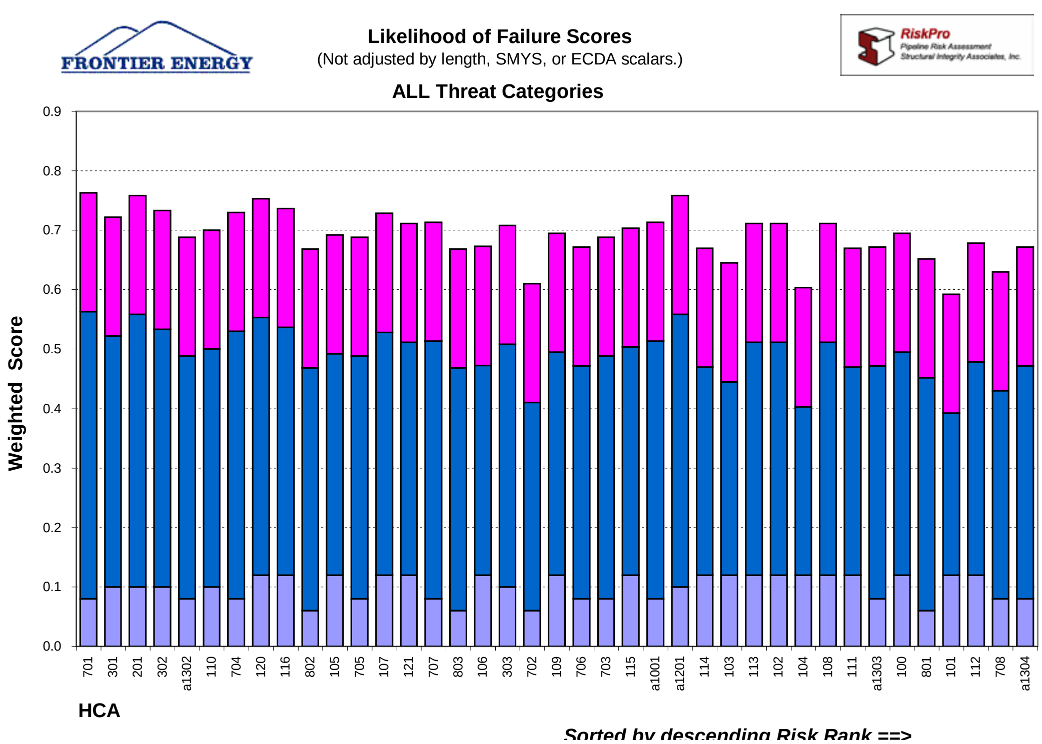
Each HCA has a BAP that provides the entire pipeline related data, consequence data, likelihood of failure scores, risk scores, as well as the assessment plans. These plans are provide in Section 5.3.6 of this document.

5.3.2 Time Sensitive Data

Unlike most sections of the IMP this section contains time sensitive data that will need to be updated by the IMP Manager at least semi-annually.

5.3.3 Identified Threats

Figure 5.1 shows the likelihood of failure score for the Company's covered segment.



Legend: **Pink: Weather and Outside Forces**, **Dark Blue: 3rd Party Damage**, **Light Blue: Ext. Corrosion**

Figure 5.1: Likelihood of Failure Score

From this chart it can be recognized that the following are the identified threats.

Table 5.1: Identified Threats

Threat	LOF Score Weighted
3rd Party Damage	0.27 – 0.48
Weather and Outside Forces	0.2
External Corrosion	0.06 - 0.12

5.3.4 Risk Scores

Figure 5.2 shows the relative ranking of the HCA's based on risk. This risk score was derived from the product of the likelihood of failure and consequences.

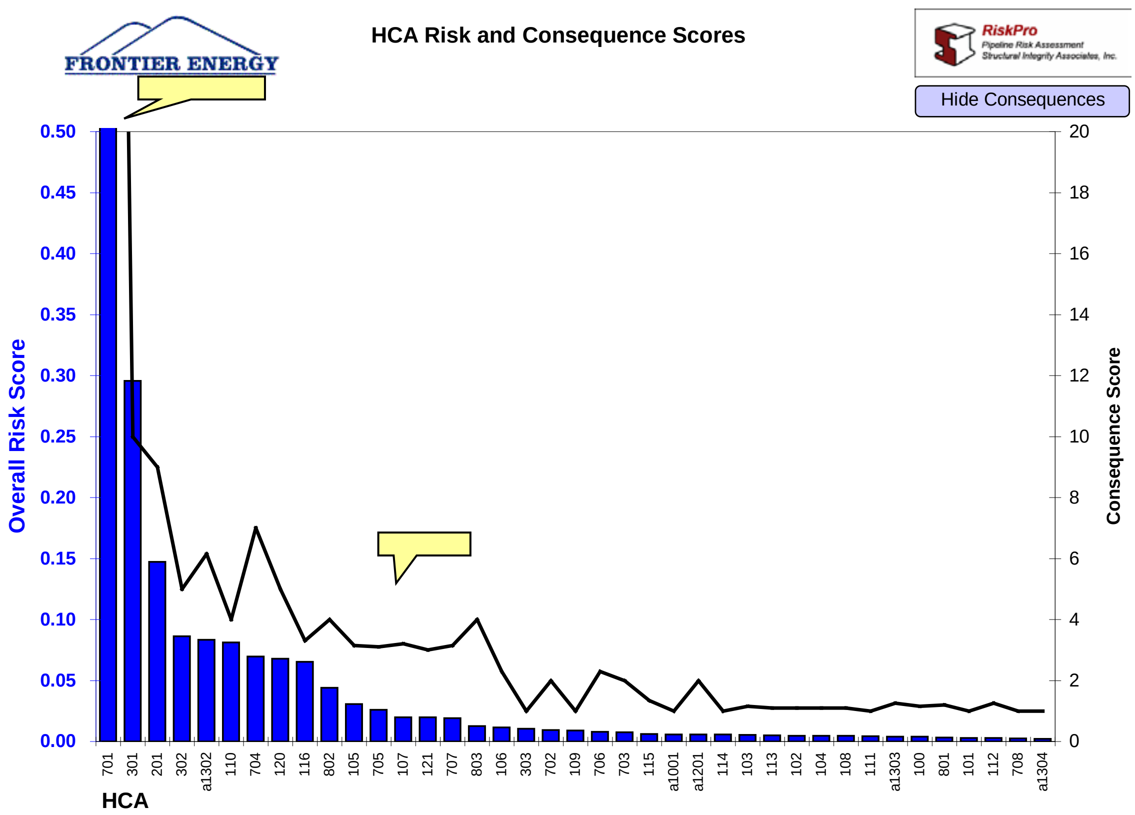


Figure 5.2: Relative Risk Ranking

5.3.5 Summary Baseline Assessment Plan

Table 5.2 is a summary of the baseline assessment plans showing the schedule date and the assessment planned for each HCA.

Table 5.2: Summary BAP

HCA ID	HCA Name	Line	Immediate Classification	Total Risk Score	Consequence Score	Scaled LOF	Threat Addressed	Assessment Method	Start Date
704	Holbrook	T-7		0.1	7.0	0.01	Ext. Corrosion	ECDA	20-Jul-05
705	Logger Shop	T-7		0.0	3.1	0.01	Ext. Corrosion	ECDA	20-Jul-05
707	Jester's Auto	T-7		0.0	3.2	0.01	Ext. Corrosion	EDCA	20-Jul-05
702	Maple Springs	T-7		0.0	2.0	0.00	Ext. Corrosion	ECDA	20-Jul-05
706	Shephard's	T-7		0.0	2.3	0.00	Ext. Corrosion	ECDA	29-Jul-05
703	J.C. Greene	T-7		0.0	2.0	0.00	Ext. Corrosion	ECDA	29-Jul-05
708	Zion Church	T-7		0.0	1.0	0.00	Ext. Corrosion	ECDA	29-Jul-05
701	Westpark	T-7		6.0	67.0	0.09	Ext. Corrosion	ECDA	1-Mar-05
201	Mt. Airy Industrial	T-2		0.1	9.0	0.02	Ext. Corrosion	ECDA	14-Mar-07
302	Smoot Park	T-3		0.1	5.0	0.02	Ext. Corrosion	ECDA	3-Oct-06
303	VFW 1142	T-3		0.0	1.0	0.01	Ext. Corrosion	ECDA	16-Oct-06
a1001	Hays	T-10		0.0	1.0	0.01	Ext. Corrosion	ECDA	12-Apr-05
a1201	NC Foam	T-12		0.0	2.0	0.00	Ext. Corrosion	ECDA	1-Mar-07
301	Greenway	T-3		0.3	10.0	0.03	Ext. Corrosion	ECDA	5-Oct-06
a1302	Carrol Leather	T-13		0.1	6.2	0.01	Ext. Corrosion	ECDA	1-Jan-06
110	Eklin Industrial	T-1		0.1	4.0	0.02	Ext. Corrosion	ECDA	1-Jan-11
802	Emmanuel Church	T-8		0.0	4.0	0.01	Ext. Corrosion	ECDA	1-Jan-06
803	221 Produce	T-8		0.0	4.0	0.00	Ext. Corrosion	ECDA	1-Jan-06
a1303	Nazarene Church	T-13		0.0	1.3	0.00	Ext. Corrosion	ECDA	1-Jan-06
801	Gap Creek Church	T-8		0.0	1.2	0.00	Ext. Corrosion	ECDA	1-Jan-06
a1304	Pepsi	T-13		0.0	1.0	0.00	Ext. Corrosion	ECDA	1-Jan-06
116	West Yadkin Church	T-1		0.1	3.3	0.02	Ext. Corrosion	ECDA	1-Jan-11
109	21 Motors	T-1		0.0	1.0	0.01	Ext. Corrosion	ECDA	1-Jan-11
115	21 BP	T-1		0.0	1.4	0.00	Ext. Corrosion	ECDA	1-Jan-11
112	Lone Hickory	T-1		0.0	1.3	0.00	Ext. Corrosion	ECDA	1-Jan-11
120	Sheffield	T-1		0.1	5.0	0.01	Ext. Corrosion	ECDA	1-Jan-11
105	Jericho	T-1		0.0	3.2	0.01	Ext. Corrosion	ECDA	1-Jan-11
107	Center	T-1		0.0	3.2	0.01	Ext. Corrosion	ECDA	1-Jan-11
121	Hwy 64 Rex Exxon	T-1		0.0	3.0	0.01	Ext. Corrosion	ECDA	1-Jan-11
106	Hwy 64 Four Brothers	T-1		0.0	2.3	0.01	Ext. Corrosion	ECDA	1-Jan-11
114	Gunter's Store	T-1		0.0	1.0	0.01	Ext. Corrosion	ECDA	1-Jan-11

HCA ID	HCA Name	Line	Immediate Classification	Total Risk Score	Consequence Score	Scaled LOF	Threat Addressed	Assessment Method	Start Date
103	Woodleaf	T-1		0.0	1.2	0.00	Ext. Corrosion	ECDA	1-Jan-11
113	Turkey Foot	T-1		0.0	1.1	0.00	Ext. Corrosion	ECDA	1-Jan-11
102	Ijames Church	T-1		0.0	1.1	0.00	Ext. Corrosion	ECDA	1-Jan-11
104	Davie Academy Road	T-1		0.0	1.1	0.00	Ext. Corrosion	ECDA	1-Jan-11
108	Hanes Church	T-1		0.0	1.1	0.00	Ext. Corrosion	ECDA	1-Jan-11
111	Joyner Community Center	T-1		0.0	1.0	0.00	Ext. Corrosion	ECDA	1-Jan-11
100	Roxanne	T-1		0.0	1.2	0.00	Ext. Corrosion	ECDA	1-Jan-11
101	Rumor's	T-1		0.0	1.0	0.00	Ext. Corrosion	ECDA	1-Jan-11
701	Westpark	T-7		6.0	67.0	0.09	3rd Party Damage	Damage Prevention Plan	On-going
701	Westpark	T-7		6.0	67.0	0.09	Int. Corrosion	ICDA	
301	Greenway	T-3		0.3	10.0	0.03	Int. Corrosion	ICDA	
301	Greenway	T-3		0.3	10.0	0.03	3rd Party Damage	TPD Prevention Program	

5.3.6 Baseline Assessment Plans

The following are individual baseline assessment plans for the covered segments.

6.0 PIPELINE ASSESSMENTS

6.1 Objective

This Program Element describes the process and basic requirements for performing integrity assessments of covered segments under the IMP. The goals of this section are to:

- Systematically classify and schedule assessment findings for further evaluation and remediation.
- Perform root cause analysis to identify the source of the integrity issue and facilitate mitigation of the anomalous condition or threat.
- Schedule covered segments for reassessment

6.2 Assessment Process

The assessment process is described in each assessment procedure that is part of the IMP. The overall Integrity Management Program assessment process is described in this section and shown in Figure 6.1

6.3 Responsibility and Schedule

The Integrity Management Program Manager is responsible for assuring that assessments are conducted following the established assessment procedures and protocols. The assessments shall be conducted in accordance with the schedule established in the baseline assessment plan or the reassessment schedule.

6.4 Conducting Assessments

6.4.1 Procedures

Integrity assessments for identified threats shall be conducted in accordance with Company written procedures. These procedures shall be in compliance with the applicable requirements of the Integrity Rule, OPS FAQ's, industry standards. Table 6.1 below is a list of assessment procedures and their status of development.

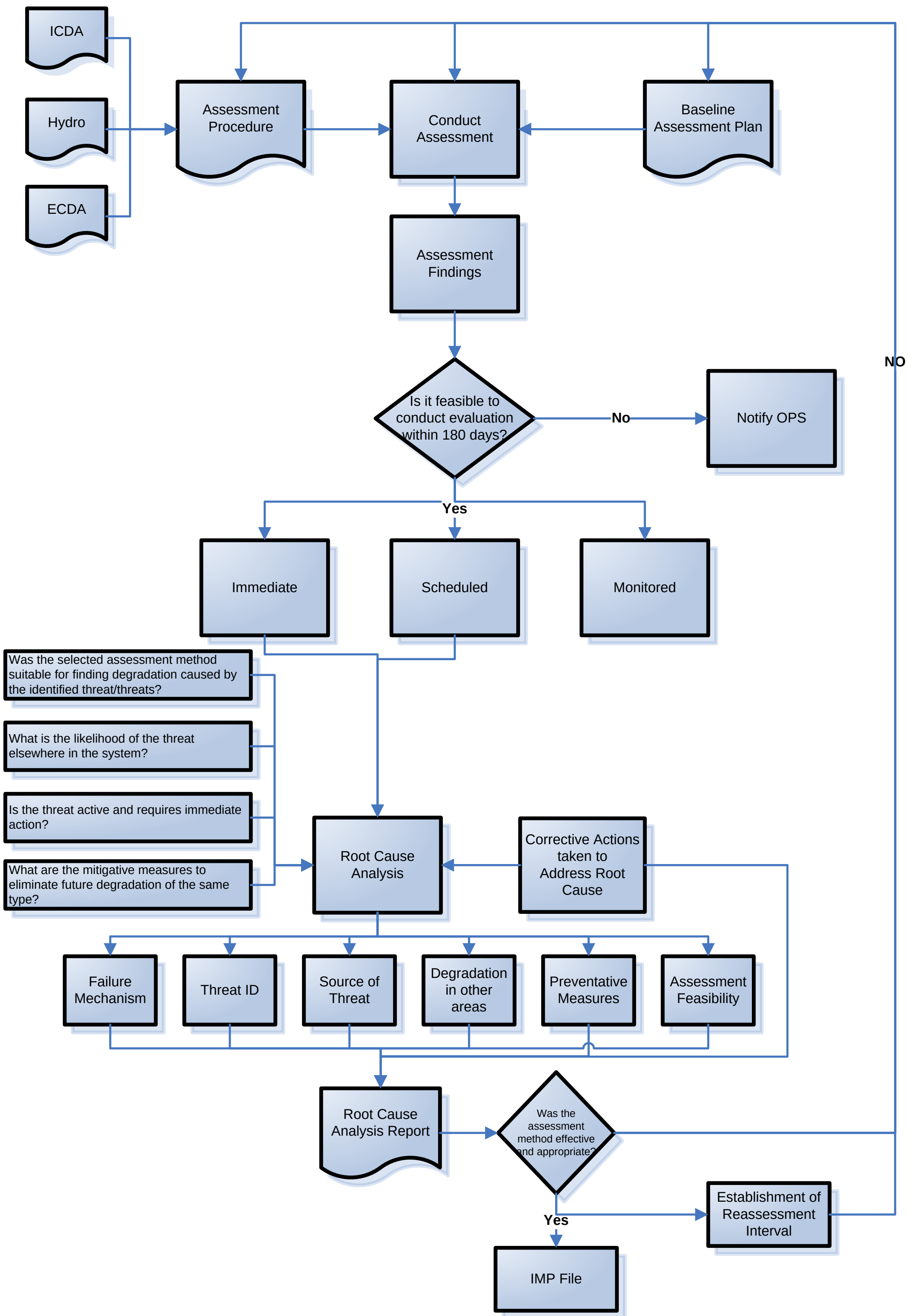


Figure 6.1: Assessment Flow Chart

Table 6.1: Assessment Procedures and Status[1]

Procedure Name	Number	Status
ECDA		Developed and in place
ICDA		Adopted the Northeast Gas Association ICDA Plan
SCCDA		No current plans to be developed
ILI		Not yet developed
Pressure Test		No current plans to be developed
Guided Wave		Not yet developed

[1] As of November 2010

6.5 Responsibilities

The Integrity Management Program Manager shall assure that the assessments are conducted in accordance with the established written procedures and within the baseline assessment plan schedule.

6.6 Time Requirements

The time requirements for the evaluation and disposition of assessment indication shall be specified in the assessment procedure. **In all cases the response to integrity assessments shall occur within 180 days from the date the assessment is completed.** For direct assessments the 180 days is from the completion of the Direct Examination Phase.

If the 180 day timeframe is impracticable to make a determination regarding the assessment results, justification for a time extension shall be submitted to OPS and to state and local agencies if appropriate. The engineering judgment and rationale used in the analysis of the baseline assessment data shall be documented on the Form NOE, Notification of Integrity Schedule Exceedance.

6.6.1 **Classify & Categorize anomalies**

i. Immediate Repair Conditions (Conditions requiring immediate remediation actions)

1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP;
2. A dent having any indication of metal loss, cracking, or a stress riser;

3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action.

4. Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding;

5. All indications of stress corrosion cracks;

6. Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline.

ii. One-Year Conditions (Conditions requiring remediation within one year of discovery).

1. A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; or,

2. A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld.

iii. Monitored Conditions (Conditions which must be monitored until the next assessment).

1. A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe;

2. A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; or,

3. A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded.

6.7 Integrity Assessment Root Cause Analysis

6.7.1 Responsibility

The Integrity Management Program Manager shall assure that a root cause analysis is conducted for each integrity assessment performed on a given covered segment that has identified scheduled or immediate indications.

6.7.2 Procedure and Documentation

The method of how the root cause is conducted as well as the necessary documentation shall be specified in the individual assessment procedure.

6.7.3 Objective

The analysis is to determine the likely causes for the identified anomalies to determine the following:

- Was the selected assessment method suitable for finding degradation caused by the identified threat/threats?
- The likelihood of the threat elsewhere in the system.
- Determination if the threat is active and requires immediate action.
- Identify mitigative measures to eliminate future degradation of the same type.

6.7.4 Analysis Content

The analysis should discuss the following aspects:

6.7.4.1 Threat Identification

An overview of the types of threats observed, and the ability to detect and identify them from the inspection data.

6.7.4.2 Failure mechanism

For each threat a discussion of the potential failure mechanism, presence of factors which may exacerbate failure, and an assessment of its relative activity/passivity.

6.7.4.3 Source of the threat

Identify the factors which contributed to the initiation of the threat and its growth.

6.7.4.4 Degradation in other areas

Discuss the likelihood and location characteristics of where similar threats may be present.

6.7.4.5 Preventative Measures

Identify potential prevention measures to arrest the failure mechanism at the particular location, and at all other similar locations on the pipe.

6.7.4.6 Assessment Feasibility

Discuss the suitability of the integrity assessment selected on identifying similar areas of degradation.

6.7.5 Documentation

The Integrity Management Program Manager shall assure that the root cause of each Immediate and Scheduled indication excavated be documented and placed in the project file. A root cause analysis can cover multiple anomalies provided that they are similar in all the characteristics listed in Section 6.7.3. Form RC root cause analysis may be used to document the analysis.

6.7.6 Integrity Assessment Evaluation

If the root cause analysis identifies degradation mechanisms that the assessment process is not well suited to detect then it shall be documented in the analysis. A suitable assessment method shall then be identified to re-assess the segments of pipe exposed to that particular degradation mechanism.

6.7.7 Corrective Action

If corrective action was taken to address the root cause during the assessment, than it shall be noted in the analysis and documented through the Prevention and Mitigation Measures (Section 8).

6.8 Reassessment

Reassessment intervals must be established for all covered segments upon completion of assessment, evaluation, and prioritization activities. The reassessment interval shall be established from the date the original integrity assessment was completed. The Integrity Management Program Manager shall be responsible for performing and documenting the requirements of this section.

6.9 Pipelines operating at or above 30% SMYS.

The maximum allowable reassessment interval is seven years. If a reassessment interval greater than seven years is established, confirmatory direct assessment must be conducted over the covered segment within the seven-year period, followed by reassessment at the originally established interval. A reassessment carried out using CDA must be performed in accordance with § 192.931. Table 6.2 sets forth the maximum allowed reassessment intervals.

Table 6.2: Maximum Reassessment Interval

Assessment method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
ILI, Pressure Test, or DA	10 years[1]	15 years[1]	20 years[2]
Confirmatory DA	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years plus ongoing actions specified in § 192.941

[1] A confirmatory DA as described in §192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15 year interval.
[2] A low stress reassessment or Confirmatory DA shall be conducted by years 7 and 14 of the interval

6.9.1 Pressure test, ILI, or other equivalent technology.

If pressure testing, ILI, or other equivalent technology is used as the original assessment method, the reassessment interval for a covered pipeline segment shall be established by either:

(i) Basing the interval on the identified threats for the covered segment and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment,

or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table3.

6.9.2 External Corrosion Direct Assessment

If ECDA is used as the original assessment method, the reassessment interval for a covered pipeline segment shall be determined by the reassessment interval process established in the ECDA procedure (developed in accordance with the requirements in paragraphs 6.2 and 6.3 of NACE RP0502-2002).

6.9.3 ICDA or SCCDA

If ICDA or SCCDA are used as the original assessment methods, the reassessment interval for a covered pipeline segment shall be determined by the following method:

- Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil, and protection conditions;

- Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and

- Estimate the reassessment interval as half the time required (half-life) for the largest defect to grow to a critical size

Note: The reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

6.10 Operating Below 30%SMYS

The maximum allowable reassessment interval is seven years. The reassessment interval must be established by at least one of the following methods:

6.10.1 Pressure test, ILI, or other equivalent technology.

If pressure testing, ILI, or other equivalent technology is used as the original assessment method, the reassessment interval for a covered pipeline segment shall be established by either:

(i) Basing the interval on the identified threats for the covered segment and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment,

or

(ii) Using the intervals specified for different stress levels of pipeline (operating below 30% SMYS) listed in ASME/ANSI B31.8S, section 5, Table 3.

If a reassessment interval greater than seven years is established, CDA or low stress reassessment must be conducted over the covered segment within the seven-year period.

6.10.2 External Corrosion Direct Assessment

If ECDA is used as the original assessment method, the reassessment interval for a covered pipeline segment shall be determined by the reassessment interval process established in the ECDA procedure (developed in accordance with the requirements in paragraphs 6.2 and 6.3 of NACE RP0502-2002).

6.10.3 ICDA or SCCDA

If ICDA or SCCDA are used as the original assessment methods, the reassessment interval for a covered pipeline segment shall be determined by the following method:

- Determine the largest defect most likely to remain in the covered segment and the corrosion rate appropriate for the pipe, soil, and protection conditions;
- Use the largest remaining defect as the size of the largest defect discovered in the SCC or ICDA segment; and
- Estimate the reassessment interval as half the time required (half-life) for the largest defect to grow to a critical size

7.0 REPAIRS

7.1 General Requirements

This Program Element describes the basic response requirements for remediation and repair of anomalous conditions discovered during integrity assessment of covered segments performed in accordance with Section 6. The Company shall take prompt action to address all anomalous conditions, and remediate those which could affect pipeline integrity. The Integrity Management Program Manager shall be responsible to ensure overall Company compliance through adherence to the requirements listed in this section. The Integrity Management Program Manager shall have the authority to delegate responsibility for ensuring technical analyses are conducted and remedial actions are implemented.

7.2 Objectives

This section describes the process for conducting minimum repair and remediation actions in order to:

- Ensure prompt action to address all anomalous conditions discovered through integrity assessments
- Systematically evaluate the repair response for anomalies
- Remediate anomalies that pose an immediate threat to pipeline integrity
- Demonstrate that the pipeline condition after remediation is unlikely to pose a threat to pipeline integrity before reassessment.

7.3 Response Time Requirements

7.3.1 Exceedance of specified time limits

If the Company is unable to respond to discovered conditions within the time limits specified in this section, one of the following actions shall be taken:

7.3.1.1 Reduction of Pressure

Pressure shall be reduced to a minimum safe level determined in accordance with ASME B31G, RSTRENG, or KAPA

-OR-

80% of the pressure at the time of discovery

Other response actions shall be evaluated and implemented that ensures the safety of the covered segment.

7.3.1.2 Pressure Reduction Time Limit

Pressure reduction may not exceed 365 days without written technical justification ensuring that continued pressure reduction will not jeopardize pipeline integrity. Form NOE, Notification of Integrity Schedule Exceedance shall be provided to the Integrity Management Program Manager by the Integrity Engineer.

7.3.2 Notification of Management

If the Company cannot meet the remediation schedule for any discovered condition, the Integrity Management Program Manager must immediately notify the Vice President. Additionally, the Integrity Management Program Manager must complete the Form NOE to document the justification for why the schedule cannot be met, and to demonstrate that the change in schedule will not jeopardize public safety.

7.3.3 Notification of Regulatory Agencies

As soon as possible but no later than 10 days after receiving notification of the delay, the Integrity Management Program Manager shall notify OPS (in accordance with § 192.949), if both of the following conditions are present:

- The remediation schedule cannot be met
- The Company cannot ensure safety through a temporary reduction in operating pressure or other action.

Copies of the OPS notification shall be sent to the following State or local authorities in according to the area where the pipeline condition exists:

North Carolina – North Carolina Utilities Commission

7.4 Discovery of Condition

7.4.1 Definition

Discovery of condition used within the context of the IMP is defined as the date when the Company has adequate information about the pipeline condition to make a determination that a condition presents a potential threat to pipeline.

7.4.2 Time Requirements

The Integrity Management Program Manager shall undertake all reasonable efforts to promptly obtain sufficient information regarding the pipeline condition to make a determination, but no later than 180 days after completion of integrity assessments.

If this time requirement cannot be met the Integrity Management Program Manager shall follow the instructions in Sections 7.3.2 and 7.3.3

7.5 Repair/Remediation of Discovered Conditions

- The interval between discovery and repair or remediation of anomalous conditions shall be specified in the assessment procedure.

8.0 PREVENTATIVE AND MITIGATIVE MEASURES

8.1 Objective

In compliance with Part §192.935[2] Frontier will evaluate additional preventative and mitigative measures to prevent a pipeline failure and to mitigate the consequences of a failure to a HCA. This plan specifies the method of how to evaluate additional measures based on the risk assessment of the pipeline segments.

8.2 Measures to be Evaluated

The measures that shall be evaluated, but not limited to the activities listed in Table 8.1.

8.2.1 Description of Table Headings

The following defines the heading descriptions in Table 8.1

8.2.1.1 P&M

This number is referenced to in the Preventative and Mitigative Measures as short hand to discuss the requirement.

8.2.1.2 Type of Measure

This column characterizes whether the measure is preventative or mitigating

8.2.1.3 Associated Threat

This column refers to the threat(s) that the measure applies. In some cases the measures applies to specific threats.

[2] There are no requirements for Preventative and Mitigative measures in ASME B31.8S-2001

8.2.1.4 Measure Description

This column describes the description of the measure. The description is a paraphrasing of the rule.

8.2.1.5 Implementation Requirements

This column describes whether the measure can be evaluated for its relative effectiveness or is required irrespective of its effectiveness. Implementation of evaluated measures is dependent on the evaluation.

Table 8.1: Alternative Preventative and Mitigative Measures

P&M #	Type of Measure	Associated Threat	Measure Description	Implementation Requirement
1	Preventative	General	Pipe replacement with greater wall thickness	Evaluate
2	Preventative	General	Implementing additional inspection and maintenance programs	Evaluate
3	Mitigative	General	Automatic Shut-off Valves	Evaluate
4	Mitigative	General	Remote Control Valves	Evaluate
5	Mitigative	General	Computerized Monitoring	Evaluate
6	Mitigative	General	Leak detection systems	Evaluate
7	Mitigative	General	Providing additional training on response procedures	Evaluate
8	Mitigative	General	Conducting drills with local emergency responders	Evaluate
9	Preventative	3rd Party	Use of qualified personnel for work that could adversely affect the integrity of a covered segment: marking, locating,	Required
10	Preventative	3rd Party	Direct supervision of known excavating work	Required
11	Preventative	3rd Party	Collecting location specific excavation damage in a central data base	Required
12	Preventative	3rd Party	Root cause analysis for additional preventative and mitigative measures	Required
13	Preventative	3rd Party	Participation in one-call systems	Required
14	Preventative	3rd Party	Conduct above ground assessments of areas of unmonitored excavations in accordance with the ECDA procedure	Required
15	Mitigative	3rd Party Below 30%	Perform quarterly leak surveys	Required
16	Preventative	Outside Force	Take action to reduce the potential damage from outside force when it can affect the integrity of the segment. Actions include: • Increasing frequency of patrols • Adding external protection • Reducing external loads • Relocating the line	Evaluate

8.3 Responsibility

The Integrity Management Program Manager shall be responsible for assuring that the requirement of this plan be met. The Program Manager may delegate the tasks but still remains responsible for the completion and effectiveness of implementation.

8.4 Schedule Requirements

Form P&M-1 shall be used to document the schedule of completing P&M evaluations and plans. All covered segments shall have their P&M Evaluations completed by December 17, 2007[RD2]. Revaluations shall occur every ten calendar years after the initial evaluation or when an integrity assessment is completed.

8.5 Mitigation Evaluation Process

The Integrity Management Program Manager shall follow the process outlined below (Figure 8.1) for each covered segment under the IMP.

8.5.1 Step 1: Develop P&M Evaluation Plan

The Integrity Management Program Manager shall develop and maintain a schedule when each covered segments will be evaluated. The schedule shall have the following information:

- Segment Name and other ID
- Likelihood of Failure score
- Risk Score
- Month and year the segment will be evaluated
- Departments or groups that will be a part of the evaluation
- Evaluation Facilitator

8.5.1.1 Evaluation Order

In general the evaluation plan should be based on the relative risk and/or likelihood of failure of each pipe segment. Plan developer may group like or adjacent segments together for continuity considerations of the evaluation process.

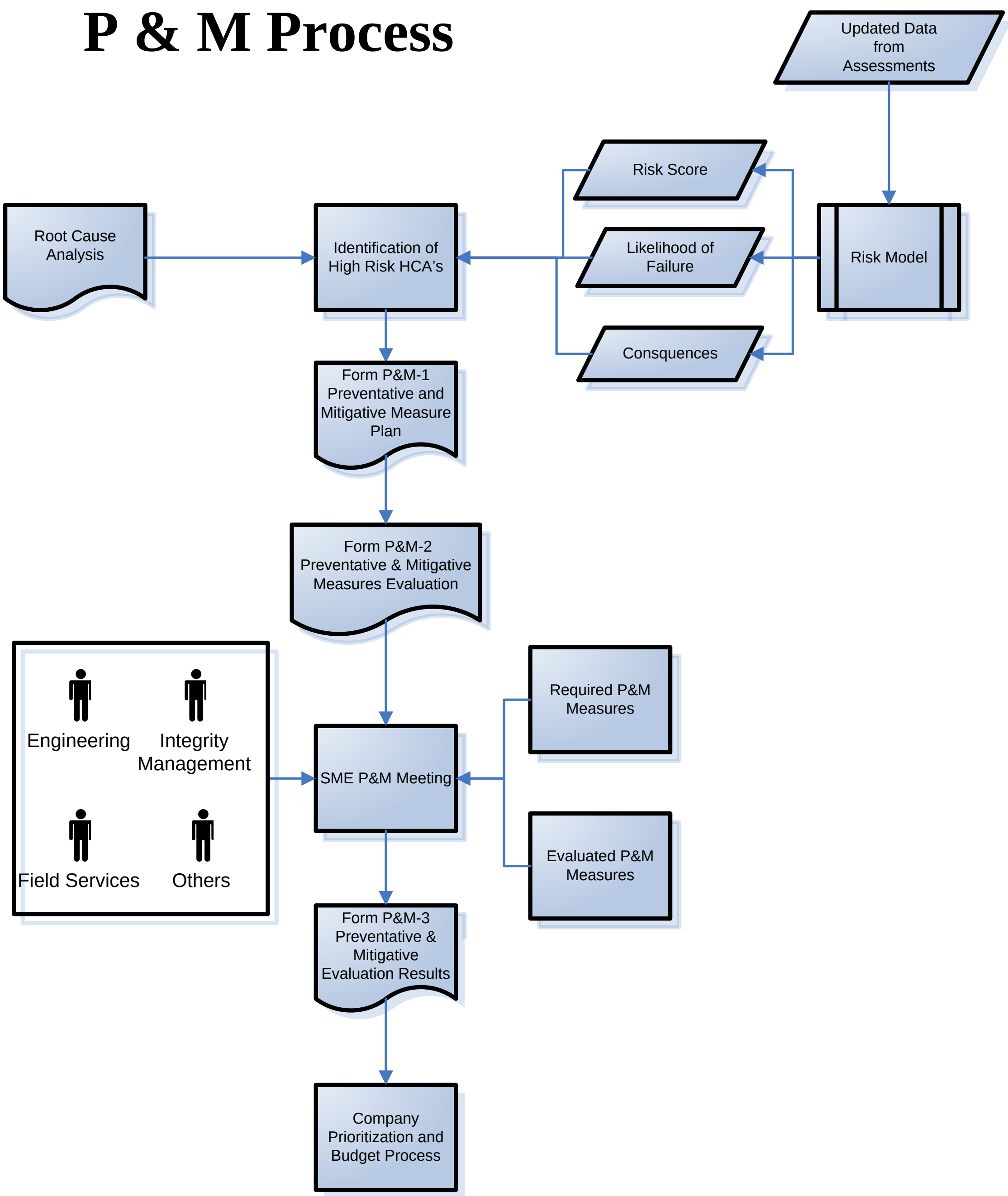


Figure 8.1: Preventative and Mitigative Process Flow Chart

8.5.1.2 Documentation

Form P&M 1 may be used to develop the P&M Schedule. The schedule shall be dated and signed by the preparer and filed in the IMP documentation files.

8.5.2 Step 2: Assembling of Data

The objective of this process step is to assemble as much pertinent information for the evaluation as possible. As a minimum the Facilitator shall assemble the following information:

- Assessment plan data sheet (see Figure 8.2 shows the necessary data)
- Pipeline drawings
- Assessment results (if any)
- Corrective action from assessments
- Leak and failure history

Integrity Management Plan

HCA ID:	**01_0012 Cb**	HCA Name:	**McAllister Dr/PNG Regulato**	Starting Station:	C-1-6.86	**Total Risk Score:**	**7.4**
Scoring Date:	**17-Oct-04**	Line Name:	**Cb**	Ending Station:	B-6-1.34	**Risk Ranking:**	**6**
		PIR:	**200 ft.**	Length:	4,940 ft.	% SMYS	35%

Threats	LOF Score	Wgt
Time Dependent		
External Corrosion	0.50	10%
Internal Corrosion	0.00	10%
Stress Corrosion Cracking	0.00	10%
Stable		
Manufacturing	1.00	10%
Field Fabrication	0.00	10%
Equipment	0.00	10%
Time Independent		
3rd Party Damage	0.35	10%
Vandalism	0.00	10%
Incorrect Operations	0.00	10%
Weather and Outside Forces	0.00	10%
Weighted LOF Score	0.19	100%

Consequence Drivers	
Residential	324
ID Locations	24
Class Location	3

LOF-to-Risk Rank Adjustments	
SMYS Scalar	1.06
Length Exponent	0.94
ECDA / CIS / DCVG Scalar	1.00
Consequence Multiplier	**40.2**

Main Threats	Assessment Method	WBS #	Start Date	Finsh Date

Reviewed by: ______________________ Date: ________

Number	Description	Value	Number	Description	Value
100	***** SECTION DATA *****	**********	**500**	***** CORROSION CONTROL *****	**********
102	Residential	324	507	Years Without CP	9
104	ID Locations	24	508	Casing Contact	No
105	Class Location	3	509	External Corrosion Detected	No
200	***** PIPE DATA *****	**********	511	Liquid Drains Present	No
201	Material Spec	API-5L	512	Drains Checked Frequently	Not Applicable
204	Outside Diameter	8.625	514	History of Liquids	No
205	SMYS	25000	513	Upstream Source of Liquids	No
206	Wall Thickness	0.322	515	Liquids Analyzed	Not Applicable
207	Seam Type	Lap Weld	516	Drying Operation Conducted	No
209	# of Wrinkle Bends	0	517	Internal Corrosion Detected	No
210	Above Ground Equipment Present	No	518	Internal MIC or Corrosives Detected	No
300	***** CONSTRUCTION DATA *****	**********	**600**	***** OPERATIONAL DATA *****	**********
301	Year Installed	1952	601	MAOP	650
303	Depth of Cover	48	603	5Yr Max Op Pressure	545
304	Girth Weld Type	SMAW	604	Average Pipe Temp	32 <= T < 100 F
305	Test Pressure	1109	605	Compr Discharge Temp	125
311	Defective Pipe Girth Weld	No	606	Distance From Compressor	18.7
315	Backfill Construction	Good	606	Previous Leaks / mile	0 - <0.1
400	***** SOIL & ENVIRONMENT *****	**********	607	Stripped Threads / Couplings	No
406	Soil Wetness	Seasonally Wet/Dry	608	Failed O-Ring	No
407	Soil Resistivity	>15,000	609	Control / Relief Malfunction	No
409	Land Use	Residential	610	Seal / Pump Packing Failure	No
410	Pipeline Crossing	None	611	History of Pipe Weld Failure	No
413	Historical Construction Activity	Light	612	# Vandalism Reports	0
414	Right of Way Condition	Good	613	History of Incorrect Operations	No
415	Susceptible to Weather	No	**700**	***** DIRECT ASSESSMENT *****	**********
416	Susceptible to Land Movement	No	702	Immediate	NA
500	***** CORROSION CONTROL *****	**********	703	Scheduled	NA
501	Factory Coating Type	Unknown	704	Monitored	NA
502	Coating Condition	Good	801	CIS Severe	NA
504	Stray Current History	No apparent issues	802	CIS Moderate	NA
505	Cathodic Protection Criteria	-850 mV On	803	CIS Minor	NA
506	Months Below CP Criteria	0	901	DCVG Severe	NA
			902	DCVG Moderate	NA
			903	DCVG Minor	NA

Figure 8.2: Sample integrity management plan showing the required data

8.5.3 Step 3: Preliminary Evaluation

The Facilitator [RD3]shall conduct a preliminary evaluation of the data for the segments that he/she is responsible for. The Facilitator may use P&M Form-2 to document the evaluation. The following are descriptions of the evaluation steps.

8.5.3.1 Risk and Threats

Record the current relative risk score and Likelihood of Failure Score. Record the active threats and associated weighted score. Include details describing the source of reason for the threat and if any P&M measures have been taken.

8.5.3.2 Implemented P&M Measures

Document for each P&M Measure in Table 8.1 if it has been implemented. For each implemented P&M measure provide details regarding of what was implemented.

8.5.3.3 Population Characteristics

Record the population characteristics as shown on Form P&M-2. These include the following data:

- # of Bldgs. for Human Occupancy
- # Outside area 20 or more people
- # of Bldgs. with 20 or more people
- # of Confined or impaired mobility

Provide further details of the population characteristics to assist in the evaluation.

8.5.3.4 Leak Detection Characteristics

Determine and record the characteristics of detecting a leak. The following items shall be documented:

- Time for leak detection

- Time to shut down pipe
- Distance of nearest response personnel
- Potential for ignition

Record further details describing the characteristics and reasons for the time it takes to detect a leak and the possible sources of ignition.

8.5.4 Step 4: Finalize arrangements for the Evaluation Meeting

After collecting, reviewing and analyzing the data the Facilitator shall assure that the appropriate Subject Matter Experts (SME's) are invited and attend the meeting. The SME's should consist of appropriate members of Engineering, Field Operations, outside company experts, and Integrity Management Personnel. The Facilitator shall provide the SME's completed copies of Form P&M-2 and other supporting documentation and drawings prior to the meeting. The meeting shall be scheduled and SME's notified of the date and time.

8.5.5 Step 5: Conduct the P&M Evaluation Meeting

The objective of the meeting is to determine what P&M measures can be effectively implemented. The Facilitator shall lead the SME's in the review of the data and requirements of this section of the IMP as well as the Rule. SME's shall collectively determine which measure evaluated measures shall be implemented. They shall document their decisions on Form P&M-2 or similar document. If the SME's determine that the required P&M measures are not effective they shall prepare an exception in accordance with Section 13 of the IMP.

8.5.6 Step 6: Submitting Recommendations for Funding

The Facilitator shall meet and discuss the outcome of the Evaluation meeting with the IMP Process Manager. The Integrity Management Program Manager may not change the outcome of the Evaluation Meeting.

The Integrity Management Program Manager shall make arrangements to present the outcome for review, approval and funding of the projects to implement the P&M measures. The Integrity Management Program Manager may update or change the date of implementation based on the funding timing decisions. Those dates shall be recorded on Form P&M-2 or similar documentation.

8.5.7 System Wide P&M Measures

A number of P&M measures are policy, or system wide type programs that may be implemented prior to the individual P&M Evaluation meetings. Those measures are listed in Table 8.2 below:

Table 8.2: P&M Measures that may be implemented on system wide basis

Mitigative Measure #	Type of Measure	Type of Threat Mitigation	Description	Requirement
1	Preventative	General	Pipe replacement with greater wall thickness	Evaluate
7	Mitigative	General	Providing additional training on response procedures	Evaluate
8	Mitigative	General	Conducting drills with local emergency responders	Evaluate
9	Preventative	3rd Party	Use of qualified personnel for work that could adversely affect the integrity of a covered segment: marking, locating,	Required
10	Preventative	3rd Party	Direct supervision of known excavating work	Required
11	Preventative	3rd Party	Collecting location specific excavation damage in a central data base	Required
12	Preventative	3rd Party	Root cause analysis for additional preventative and mitigative measures	Required
13	Preventative	3rd Party	Participation in one-call systems	Required
14	Preventative	3rd Party	Conduct above ground assessments of areas of unmonitored excavations in accordance with the ECDA procedure	Required
15	Mitigative	3rd Party Below 30%	Perform leak surveys	Required

8.5.7.1 System Wide Measure Plan Development

A plan shall be developed for measures that will be implemented system wide. Those measures that are already implemented system wide do not need a plan. The plan shall contain the following elements:

- The name of the measure that will be implemented
- Person responsible for the measure
- Key tasks that need to be completed for the measure to be implemented.
- A schedule for implementation.

8.5.7.2 Documentation

The plan shall be documented and filed in the IMP files. As the key steps are completed the accompanying documentation should be included in the IMP files with the System Wide P&M Plan.

9.0 QUALITY CONTROL PLAN

9.1 Objective

The objective of the Quality Control Plan (QCP) is to assure that Integrity Management Program is being conducted as described in this document and that there is documentation which demonstrates the Company's compliance with the IMP requirements.

9.2 General Requirements

The following tasks list details of the QCP:
Identification of the responsibilities and authority of personnel responsible for the execution of the QCP:

- Identification of the Processes subject to the QCP
- Documentation of the sequence and interaction of these processes
- Implementation of criteria and methods for internal auditing to assure effective execution of the covered processes is maintained
- Implementation of measures to monitor each covered process

Implement actions necessary to achieve planned results and continued improvement

9.3 QC Framework

For QC review purposes the processes of the IMP is divided into the two following groups.

9.3.1 Routine IMP Processes

Routine IMP Processes are internal sub-processes or task in the IMP that are well suited to have IMP or other personnel to ensure that they are being conducted correctly and in accordance with the IMP.

9.3.2 High Level IMP Processes

High Level IMP processes are critical steps or activities to the overall effectiveness of the IMP. These processes are intended to serve as overall indicators that the IMP as a whole is implemented and functioning properly. These processes will be evaluated by a person outside the IMP group assigned by the President.

9.3.3 Criteria for Routine and High Level Processes

Table 9.1 provides the general criteria in determining whether a task or process is Routine or High Level.

Table 9.1: QC Criteria for Routine and High Level Tasks and Processes

Characteristics of Evaluation	Routine	High Level
Nature of Element	Task	Process
Complexity	Relatively straight forward	Multiple tasks, higher complexity
Evaluation Difficulty	Easy to determine compliance	Greater difficulty in determining compliance. Less clear criteria
Specific Rule Requirements	Applies to specific and non-specific Rule requirements	Applies to specific and non-specific Rule requirements
Impact on IMP Effectiveness	All levels of impact	High levels of impact
Sensitivity of evaluation	Straight forward, not sensitive	Higher level of sensitivity due to system impact, costs, or higher level positions
Frequency	As necessary	Annual

9.4 Responsibilities

9.4.1 IMP Manager

The IMP Manager is the QC Plan owner. The IMP Manager shall be responsible for evaluating and implementing the overall QC process, identifying necessary changes to the plan, identifying and implementing changes to the plan to ensure continuous improvement. The IMP Manager tasks can be broken down to three key categories:

- Assure that the Routine IMP processes are being quality controlled checked in accordance with this plan.
- Assure that the President assigns parties to conduct the QC audits for High Level IMP processes.
- Assure that any outside resources used on any IMP processes follow the Frontier IMP plan and hold all required qualifications.

9.4.2 President

The President shall assign the responsibility to QC Audit High Level IMP processes or tasks to qualified personnel, including independent third party auditors. To maintain objectivity throughout the QC review process, the President should select individuals that are independent of the process or element under evaluation. Audits may be performed by internal staff, preferably not by personnel directly involved in the administration of the integrity management program.

9.4.3 Quality Control Auditor

The QC Plan Auditor is responsible for applying the QC Plan to the element assigned for evaluation. These reviews may be of the Routine or the High Level processes.

9.4.4 Approving Authority

The IMP Manager is the Approving Authority of the results from the QC activities of the Routine Process. He/she shall periodically review the QC related information and take corrective action as appropriate.

The President is the Approving Authority of the QC audits of the High Level Processes. He/she shall direct corrective action to the IMP Manager based on the audit findings and further analysis and discussions with the IMP Manager.

9.5 Timing

The IMP Manager shall assure that the IMP Program is reviewed under the QC Plan at frequencies specified in this section. He shall notify in writing the President to assign personnel to review High Level Processes at least once per calendar year but not to exceed 18 months. The IMP Manager shall provide the President names of potential reviewers.

9.6 Quality Control Plan Scope

The IMP elements subject to the scope of the QC Plan are listed below in Table 9.2. For each IMP element, specific documentation requirements are listed which ensure that key IMP objectives are achieved and documented. Those documents are used as control and monitoring points for application of the QC Plan, and serve as the basis for ensuring that the IMP is implemented and maintained.

Table 9.2: Processes Subject to the Quality Control Plan Requirements

IMP Element	IMP Document Section		QC Items	QC Process	Review Freq.
IMP Management	1.5	Roles & Responsibilities	Qualifications, Resumes, Training, Certifications	High Level	Annual
Segment Identification	2.2	Schedule		High Level	Annual
	2.3.1	PIR Calculation	Formulation and correct input into model	Routine	Semi-Annually
	2.3.3	ID of Population Density HCA's	Process, methodology and documentation for the identification of HCA's based on population density	High Level	Annual
	2.3.4	ID of Identified Sites HCA's	Process, methodology and documentation for the identification of HCA's based on identified sites.	High Level	Annual
	2.3.6	Submittals to GIS	HCA's and their characteristics are being effectively placed into GIS	Routine	Semi-Annually
Baseline Assessment Plan	4.3	Data Gathering	Form A, Baseline Assessment Plan has appropriate data for all HCA's	Routine	Semi-Annually
	4.5.5	Data Review	Data has been reviewed and signed off in accordance with this Section on Form B	Routine	Semi-Annually
	5.1.2	Threats Identified in BAP	High level threats are identified in the Baseline Assessment for each HCA.	High Level	Annual
	5.2.4	Notification of alternative technology	OPS is notified with time requirements that alternative technology will be used for assessments	High Level	Annual
	5.3	Assessment Schedule	Assessment schedule has been developed, the schedule meeting the 50% and 100% schedule requirements	High Level	Annual
	5.4	Record keeping	Baseline assessment plans are on file	Routine	Semi-Annually
	5.5	Revision of baseline assessment plans	Plan revisions have been documented and revisions have been kept on file	Routine	Annual
Assessments	6.3	Responsibilities and Schedule	Evaluate if assessments are conducted within the schedule of the baseline assessment plan	Routine	Annual
	6.4	Conducting Assessments	Evaluate if assessments were conducted in accordance with company procedures	High Level	Cyclical
	6.5	Time Requirements	Evaluate if the assessments steps were performed within time requirements and if they complied with the 180 day time requirement	High Level	Annual
	6.6	Integrity Assessment Root Cause	Evaluate if the root cause analysis was conducted to the prescribed process in the assessment procedure.	Routine	Semi-Annually
	6.7	Reassessment	Evaluate if the correct interval for re-assessment was conducted.	Routine	Annually

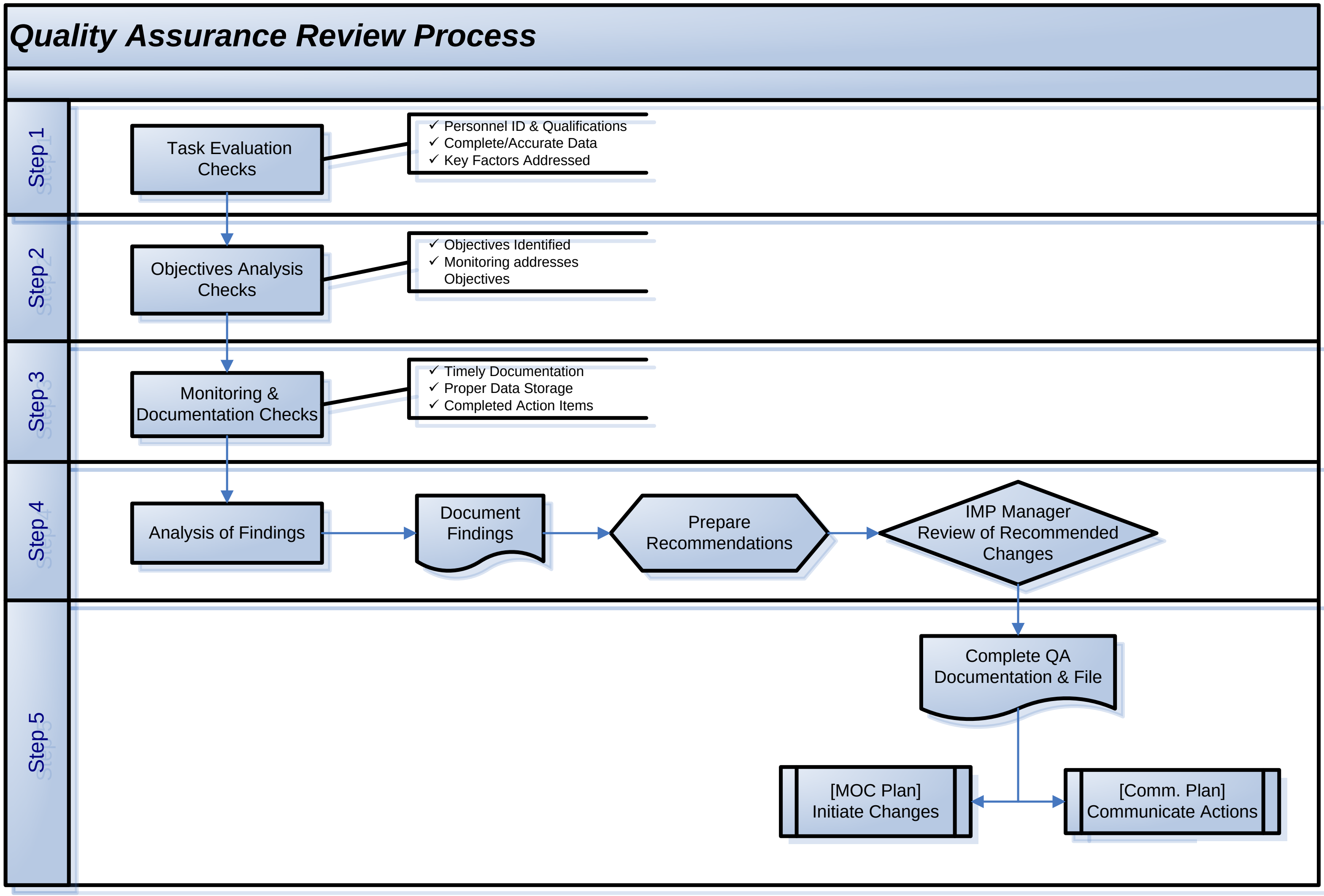
IMP Element	IMP Document Section		QC Items	QC Process	Review Freq.
Repairs	7.3	Response Time Requirements	Evaluate if the repairs were conducted within the specified response times.	High Level	Annually
Prevention and Mitigation	8.2	Prevention and Mitigation Process	Evaluate to determine if the prescribed process was followed	Routine	Semi-Annually
	8.3	Additional Preventative	Evaluate if the additional requirements have been met	High Level	Annual
Performance Management Plan	10.4-10.6	Performance Metrics	Review of performance metrics to see if they meet the IMP.	High Level	Annual
	10.7	Review and Analysis	Determine if the review of the performance metrics have been performed and the trends in effectiveness recognized.	High Level	Annual
Communication Plan	11.0				
Management of Change	12.5.4	MOC Process Inventory	Review inventory table and check for updates	High Level	Annual
	12.6.2	Schedule for Re-engineering	Check if a realistic schedule has been established	High Level	Annual
	12.6.3	Communication of MOC	The preliminary principles and requirements of MOC has been communicated.	High Level	Annual
	12.6.2	MOC Process Requirements	The MOC related processes meets the requirements of the IMP	High Level	Annual

Note: Newly identified HCA's will follow all elements of the QC plan in Table 9.2. Initial HCA's will only utilize elements applicable.

9.7 Quality Control Plan Methodology

The quality control review process outlined below consists of five steps which are shown in Figure 9.1. Each evaluation step of the QC process contains criteria to assure reviewed IMP Elements are completed, adequate, and documented. The assigned QC Auditor shall evaluate the processes listed in Table 7.1 by applying the five steps of the QC evaluation. Each one of the elements shall be evaluated for acceptability, and in the event that deficiencies are discovered, comments shall be recorded outlining those deficiencies.

Figure 9.1 – Quality Control Process Flow Chart



9.8 Routine Quality Control Audit Process

9.8.1 Objective

The Routine QC Audit process is to check and document that the assigned task or process is being conducted in accordance with the IMP or related procedure. It is also designed to identify any improvements in the process to make it more effective at assuring pipeline integrity or reducing costs. Conducting the audits should be relatively straight forward and will not normally take a great deal of time.

9.8.2 Responsibilities

9.8.2.1 IMP Manager

The IMP Manager will assign Routine QC audits to personnel as required. IMP Manager is responsible to review the audit results, take corrective or process improvement action and document the results. The IMP Manager shall resolve disputes over record access if necessary.

9.8.2.2 QC Auditor

The person conducting the audit is referred to as the QC Auditor in this plan. The QC Auditor has the responsibility to conduct the audit truthfully, accurately, and completely. The QC Auditor has the authority to have access to those records that are necessary to conduct the audit.

9.8.3 Frequency of Routine QC Audits

Each IMP process identified to have Routine QC audits is designated in Table 9.2 The Frequency of QC reviews is dependent upon the type of task. The IMP Manager has authorization to change the frequency of the Routine QC audits, but they cannot exceed one year.

9.8.4 Classification of Audit Findings

9.8.4.1 Objective

The objective of the classification of QC Audit findings is to provide easier overview of the findings and to facilitate reporting to the IMP Performance Management Plan.

9.8.4.2 Classifications

The QC Auditors shall classify their findings into one of the following categories.

- **Immediate Findings:** Those findings that resulted in errors of determining key Integrity Management factors, such as identification of HCA's, Identification of Threats, ineffective assessment methods, inaccuracy in assessing assessment results. These findings require immediate response to correct.

  Specifically:

  1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP;
  2. A dent having any indication of metal loss, cracking, or a stress riser;
  3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action.
  4. Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding;
  5. All indications of stress corrosion cracks; or
  6. Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the

pipeline.

- **Scheduled Findings:** Those findings that could lead to systemic errors in determining key Integrity Management Factors such as identification of HCA's, Identification of Threats, ineffective assessment methods, and inaccuracy in assessing assessment results. These findings require eventual remediation response to correct.
  Specifically:
  1. A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; or,
  2. A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld.

- **Monitored Findings:** Those findings that are errors in documentation, protocol, and improvements in the process that should continue to be monitored in and out of the QC Audit process. These findings will be evaluated by the IMP Manager to determine disposition
  Specifically:
  1. A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe;
  2. A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; or,

3. A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded.

9.8.5 Documentation

The QC Auditor shall document the audit findings on the specified form of the IMP or other appropriate document. The completed audit documentation shall be submitted for review and signature to the IMP Manager. The signed documentation shall be filed in the QC Plan documentation section of the IMP files.

9.8.6 Requirements and Steps for Conducting a Routine QC Audit

Table 9.3 provides pertinent information for those tasks and steps that are classified as Routine QC Audit items. The QC Auditor shall review Table 9.3, acquire the appropriate form for the given process or task that will be audited, and complete the audit.

Table 9.3: Routine QC Audit Information

	IMP #	Process Description	Audit Objective	Audit Process	Frequency	Sample Size	Auditor Qualifications	Form Number
Segment Identification	2.3.1	PIR Calculations	Check for PIR calculations being completed correctly with correct data input.	Documentation correctly completed Documentation is filed Responsible person identified Qualifications are met Results are checked by hand calcs. Correct units are used	Annual	10% of new HCA's identified from each operating company, but not less than three for 1-10 new HCA's	Engineer Trained or has experience with PIR calculation	QCP-1
	2.3.6	Submittals to GIS	Check if the data is correctly being placed into GIS	Documentation correctly completed Documentation is filed Responsible person identified Qualifications are met	Annual	10% of new HCA's identified from each operating company, but not less than three for 1-10 new HCA's	Person familiar with PNG mapping and GIS system but not directly involved	QCP-2
Baseline Assessment Plan	4.3 4.6.4	Data Gathering and Data Review	All required data has been collected for the new HCA's and it is correct. The data, LOF and Risk Scores have been reviewed and rationalized	Documentation correctly completed Documentation is filed Responsible person identified Qualifications are met	Annual	10% of new HCA's identified from each operating company, but not less than three for 1-10 new HCA's	Person familiar with the operation of RiskPro but not directly involved in the data gathering	QCP-3
	5.5 5.6	Record Keeping	Assure that the completed BAP are properly filed and any revision have also been filed	Documentation is correctly filed.	Annual	All BAP's since last QC check	Person familiar with the Integrity Management program but not directly involved in the creation and filing of the BAP	QCP-4
Assessments	6.3 6.6 6.7	Schedule Root Cause Analysis Reassessment Interval	Evaluate if the assessments are completed within the schedule of the BAP and that root cause analyses are being conducted on damage pipe	Review schedule dates for assessments and compare with dates on assessment forms Identify any damage pipe found in assessments. Look for corresponding root cause analysis and if the analyses are complete Review all reassessment intervals to be compliant with IMP	Annual	All assessments since the last QC review	Integrity Management Engineer familiar with assessment technology and root cause but not directly involved in conducting or managing the assessment.	QCP-5

	IMP #	Process Description	Audit Objective	Audit Process	Frequency	Sample Size	Auditor Qualifications	Form Number
Preventative and Mitigative Measures	8.4 8.5	Scheduling of P&M Evaluation Conducting P&M Evaluations	Determine that the P&M Evaluation Schedule has been developed and kept updated. Determine if the evaluation process in the IMP has been followed and documented	Review the P&M Schedule, compare it with completed assessments to determine if it has been updated Check for the collection of data, that the implemented measures have been documented, the meetings have been conducted, the results documented and recommendations submitted for funding approval	Annual	All P&M activities since the last QC review	Person familiar with the IMP but not directly involved in the P&M measure implementation	QCP-6
	8.7	P&M measures that can be implemented system wide by policy and procedure	Determine the level of effectiveness of system wide application and the degree of implementation	Identify what P&M measures have been selected for system wide application. Check to see the if the plan has been developed. Determine if the System Wide Plan has been developed	Annual	All P&M activities since the last QC review	Person familiar with the IMP but not directly involved in the P&M measure implementation	QCP-7
Performance Plan	10.4 - 10.6	Generation of performance metrics that indicates the IMP effectiveness	Determine the level of compliance with the Performance Management Plan requirements	Review the metrics that have been generated and determine if they are compliant with the IMP	Annual	All Metrics	Person that could match requirements with reports generated	QCP-8
	10.7	Review and analysis of the performance metrics to evaluate the IMP effectiveness and identification of improvement opportunities	Determine if the review of the performance metrics have been performed and if any trends in effectiveness was appropriately recognized.	Audit the Review and Analysis reports and determine if they were completed in a timely manner and if any trends were recognized.	Annual	All reports since last audit	Person that is familiar with the IMP but not directly involved with the development of the Performance Management Plan	QCP-8
Communication Plan	11.0							QCP-9

	IMP #	Process Description	Audit Objective	Audit Process	Frequency	Sample Size	Auditor Qualifications	Form Number
Management of Change Plan	12.5.4	MOC Process Inventory identifies those process that need to integrate MOC requirements into them	Establish that the Inventory has been established and updated per the plan requirements	Review the inventory table and check for changes since last audit	Annual	The current and last inventory table	Person knowledgeable of the Company's processes	QCP-10
	12.6.2	A schedule for reengineering of the identified processes in the inventory table	To assure a realistic and effective schedule to implement MOC requirements into process that affect integrity	Check to see if schedule has been completed and the schedule is not unreasonable long.	Annual	The current schedule	Person knowledgeable of the Company's processes	QCP-10
	12.6.3	Communicate MOC requirements to process owners that have processes that do not yet have MOC requirements integrated into them.	Determine if the notifications were made and if they were in compliance with the plan.	Compare notification letters with MOC Process Inventory Table.	Annual	Current Inventory Table and Notification letters since last audit	Person capable of matching letters with Inventory table	QCP-10
	12.6.2	A process to implement MOC requirements into process that affect pipeline integrity	To determine if the processes are being evaluated and reengineered according to the established schedule	Review implementation schedule with process documents to determine if the processes have adopted the MOC requirements	Annual	Current schedule with process documents	Person capable of matching letters with Inventory table	QCP-10

9.8.7 Audit Process Steps

9.8.7.1 Step 1- Task Evaluation

- Ensure that critical/responsible personnel are identified and qualified
- Ensure that the process information requirements are accurate and complete
- Ensure that appropriate key factors are addressed in the process document

The QC Auditor shall verify that the section of the IMP adequately addresses the personnel involved in the IMP Process and their qualifications. The section shall be checked for accuracy and completeness as well as evaluated to ensure that key factors contained in the section requirements are captured in the documentation associated with the process.

9.8.7.2 Step 2 - Objectives Analysis

- Ensure that the plan identifies IMP element objectives
- Ensure that the monitoring measures adequately address the objectives

The Reviewer shall verify that the section of the IMP identifies the objectives and clearly addresses those objectives.

9.8.7.3 Step 3 - Monitoring & Documentation

- Ensure that the documentation requirements are completed with prescribed timeframes and appropriately stored
- Ensure that implementation of data or findings are completed, or that awareness of action items is assured.

The QC Auditor shall verify that the section of the IMP is documented according to established guidelines, that the documentation is appropriately stored, and that the data or findings are communicated and implemented appropriately.

9.8.7.4 Step 4 - QC Findings & Recommendations

- Classify each of the findings in accordance with the definitions described in Section 7.7.4, "Classification of Audit Findings".
- Provide analysis of findings for each IMP Element.
- Document recommendations on the appropriate form

The QC Auditor shall provide an analysis of the QC elements designated as unacceptable or requiring action from steps 1-3 of the QC evaluation process. Discussion shall include a description of the deficiency, and options for process improvement.

9.8.7.5 Step 5 – Documentation and Hand-off

Completed QC Forms shall be stored in the IMP Management file.

9.9 Audits of High Level Processes

9.9.1 Objective

High Level Processes provide overall management of each major IMP element to ensure that effective execution of the IMP is maintained.

9.9.2 Responsibilities

9.9.2.1 IMP Manager

The IMP Manager is to provide in writing notification to the President that personnel needs to be assigned to conduct the QC Audits of high level processes. The IMP Manager can make recommendations to the President on qualified and objective personnel to conduct the audits.

Once the audits are completed the IMP Manager needs to meet with the QC Audit personnel to go over findings, identify corrective actions and implement those actions.

9.9.2.2 President

The President shall assign the responsibility to QC Audit High Level IMP processes or tasks to qualified personnel, including independent third party auditors. To maintain objectivity throughout the QC review process, the President should select individuals that are independent of the process or element under evaluation. Audits may be performed by internal staff, preferably not by personnel directly involved in the administration of the integrity management program.

9.9.3 Frequency of High Level Process Audits

Audits of the High Level processes shall be conducted at least once every calendar year, not to exceed 18 months from the last evaluation.

9.9.4 Documentation

The QC Auditor shall document the audit findings for each step that is outlined in Section 9.7.6, "Audit Process Steps". The documentation shall have recommendations and supporting rationale based on the process improvement options.

9.9.4.1 Distribution of Audit Reports

The Audit Reports of High Level process shall be distributed to the following:

- Vice President by the IMP Manager for review and consideration.
- The Management of Change File for evaluation
- The IMP QC file

9.10 Performance Measures

9.10.1 Objectives

QC Audit findings, recommendations and process improvements will be monitored through the performance measurement process. This section describes the elements that will be monitored in the performance measurement process.

9.10.2 QC Audit Performance Metrics

The following items shall be monitored by the IMP Performance Metrics:

- Number of Routine QC Audits
- Number of High Level QC Audits
- Number of Immediate Findings
- Number of Scheduled Findings
- Number of Monitored Findings
- Number of Immediate Findings still not resolved and closed
- Number of Scheduled Findings still not resolved and closed

10.0 PERFORMANCE MANAGEMENT PLAN

10.1 Performance Management Plan

The objective of the Performance Management Plan is to provide a means to measure, communicate, and improve the Company Integrity Management Program. The plan contains both metrics and processes to measure the operation and effectiveness of the Integrity Management Program over time. The measures shall provide a basis for implementing continuous improvement efforts which support the overall goal of the integrity management process.

10.2 Objectives

This Section describes the Performance Management Plan process in order to ensure that the following objectives are met:

- Ensure all IMP objectives are accomplished
- Ensure pipeline integrity and safety is effectively improved through adherence to the IMP.

10.3 Responsibilities

The Integrity Management Program Manager shall assure that these reports are prepared, correct and distributed. The Integrity Management Program Manager shall review the report in detail and take corrective and continuous improvement actions as indicated by the metrics and subsequent evaluation.

10.4 Reporting Frequency

The Integrity Management Program Manager shall assure that these reports are prepared, analyzed and distributed on an annual basis. The regulatory metrics (SAR-0 to SAR-04) shall be reported semi-annually to the Office of Pipeline Safety.[RD4]

10.5 Performance Metrics

10.5.1 Regulatory and Code Requirements

The Performance Management Plan is developed to meet the requirements listed in the following sections of §192, Subpart O and ASME B31.8S-2001.

- § 192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?
- §Part 192.945, What methods must an operator use to measure program effectiveness?
- §Part 192.951, Where does an operator file a report?
- ASME B31.8S, Section 9.4
- ASME B31.8S, Appendix A

Frontier Natural Gas Company has chosen to use the performance management plan. If Frontier chooses to use exceptional performance in the future in order to deviate from certain requirements of the rules, a plan will be developed at that time.

10.5.2 Required Metrics

Table 10.1 specifies the required metrics to be reported to monitor the performance of the Integrity Management Program. These metrics are required either in the Rule or by reference in the Rule. These measures are reported in reference to the threats that they cover as well as the type of indicator.

10.5.2.1 Activity

These metrics measure the level of integrity activity in the program. Examples include the number of assessments completed on time, number of miles assessed, number of exceptions taken with procedures or processes, etc.

10.5.2.2 Operational

These metrics measure the level of integrity being found through assessments and plans. Examples of these measures are the number of immediate and scheduled indications, the number of repairs made as a result of assessment identifying damage, and the risk scores for the system.

10.5.2.3 Integrity

These metrics measure integrity issues such as leaks, ruptures, and equipment failures.

10.5.3 Discretionary Metrics

Table 10.1 also lists the discretionary metrics that the Integrity Management Program Manager shall report.

Table10.1 Required and Discretionary Metrics

Metric Category	Metric #	Metric Description	Measure Type: Activity	Measure Type: Operational	Measure Type: Integrity	Measure Type: General	Threats: External Corrosion	Threats: Internal Corrosion	Threats: SCC	Threats: Manuf.	Threats: Const.	Threats: Equipment	Threats: 3rd Party	Threats: Vandalism	Threats: Incorrect Operations	Threats: Weather
Semi Annual Reporting to OPS	SAR-01	Number of pipeline miles inspected vs. program requirements	x			x										
	SAR-02	Number of immediate repairs completed as a result of IMP assessments		x		x	x	x	x	x	X	x	x			
	SAR-03	Number of scheduled repairs completed as a result of IMP assessments		x		x	x	x	x	x	X	x	x			
	SAR-04	Number of leaks, failures, and incidents (classified by cause)			x	x	x	x	x	x	X	x	x	x	x	x
ASME B31.8S Appendix A	A-01	Number of hydrostatic test failures by threat		x			x	x	x	x						
	A-02	Number of repair actions taken due to ILI assessments (immediate and scheduled)		x			x	x								
	A-03	Number of repair actions taken due to direct assessments (immediate and scheduled)		x			x	x								
	A-04	Number of leaks or failures classified by threat			x		x	x	x	x	X	x	x	x	x	x
	A-05	Number of girth welds/couplings reinforced or removed		x							X					
	A-06	Number of wrinkle bends inspected	x								X					
	A-07	Number of wrinkle bends removed		x							X					
	A-08	Number of fabrication welds repaired/removed		x							X					
	A-09	Number of regulator failures			x							x				
	A-10	Number of relief valve failures			x							x				
	A-11	Number of gasket and O-ring failures			x							x				
	A-12	Number of repair/replacements classified by cause			x				x							x
	A-13	Number of leaks or failures caused by vandalism			x									x		
	A-14	Number of findings per audit/review classified by severity		x											x	
	A-15	Number of changes to procedures due to audits/review		x											x	
	A-16	Number of audits/reviews conducted													x	
	A-17	Number of repairs implemented prior to leak or failure											x			

10.6 Documentation

The reporting shall be completed on PPR-01 “Performance Management Plan Report” or similar documentation at the discretion of the Integrity Management Program Manager.

10.7 Review and Analysis

The Integrity Management Program Manager shall review the metric and analyze the trends and document the following for each Metric Category on Form PPR-02, Continuous Improvement Analysis of Performance Metrics.

10.7.1 Significant Events

Events that measurably impact the integrity of the pipeline shall be noted. These can include both adverse and advantageous integrity events. Such things leaks, ruptures, pressure reduction, line relocations should all be reported.

10.7.2 Integrity Trends

The general performance trends for each Metric Category shall be noted. These trends can be the lowering of average risk or likelihood of failure, as well as improvement or decline in making schedule requirements.

10.7.3 Opportunities for Improvements

The Integrity Management Program Manager shall identify analyses and tasks that can be conducted to improve trends, scores and compliance.

10.8 Semi Annual Reporting to the Office of Pipeline Safety

The Company must submit the results of the four overall performance measures (SAR-01 through SAR-04) to OPS on a semi-annual frequency. The reports must include complete performance information through two report periods – January 1st through June 30th, and July 1st through December 31st of each year. Each semi-annual report shall be submitted within 60 days from the closing date of the report period (June 30th and December 31st).

10.8.1 Reporting Process to OPS

The Company's Communications Manager, under the direction of the Integrity Management Program Manager, shall submit performance measure results to OPS by any of the following means:

Sending notification to:

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
Room 7128
400 Seventh Street, SW
Washington, DC 20590

Facsimile:

Sending notification to the Information Resources Manager by facsimile to (202) 366-7128

Internet:

Entering the information directly to the Integrity Management online reporting system website at http://ops.dot.gov.

10.8.2 State Communication Requirements

The Company must also notify the North Carolina Utility Commission of any change that may substantially affect the IMP's implementation or may significantly modify the IMP or schedule for completion of the IMP elements.

11.0 COMMUNICATION PLAN

11.1 Objectives and Benefits

11.1.1 Objective

The objective of this plan is to keep appropriate company personnel, jurisdictional authorities, and the public informed about the Company's integrity management efforts and the results of integrity management activities.

11.1.2 Benefits

This Communication Plan provides significant value to the IMP by increasing public safety, improving pipeline safety and environmental performance, building trust and better relations with the public along the rights-of-way (ROW), improved preservation of ROWs, enhanced emergency response coordination, and upholding Company reputation.

11.1.3 Scope Limitations

This Plan is not intended to cover communications necessary for emergency response, reporting incidences, or establishment of new pipelines. These communications are unique and are covered by other regulations and Company plans.

11.2 Communication Network

Figure 11.1 shows the network of agencies, organizations, and departments that this Plan addresses. This chart shall be updated annually to reflect changes to the list of organizations covered by the Communication Plan.

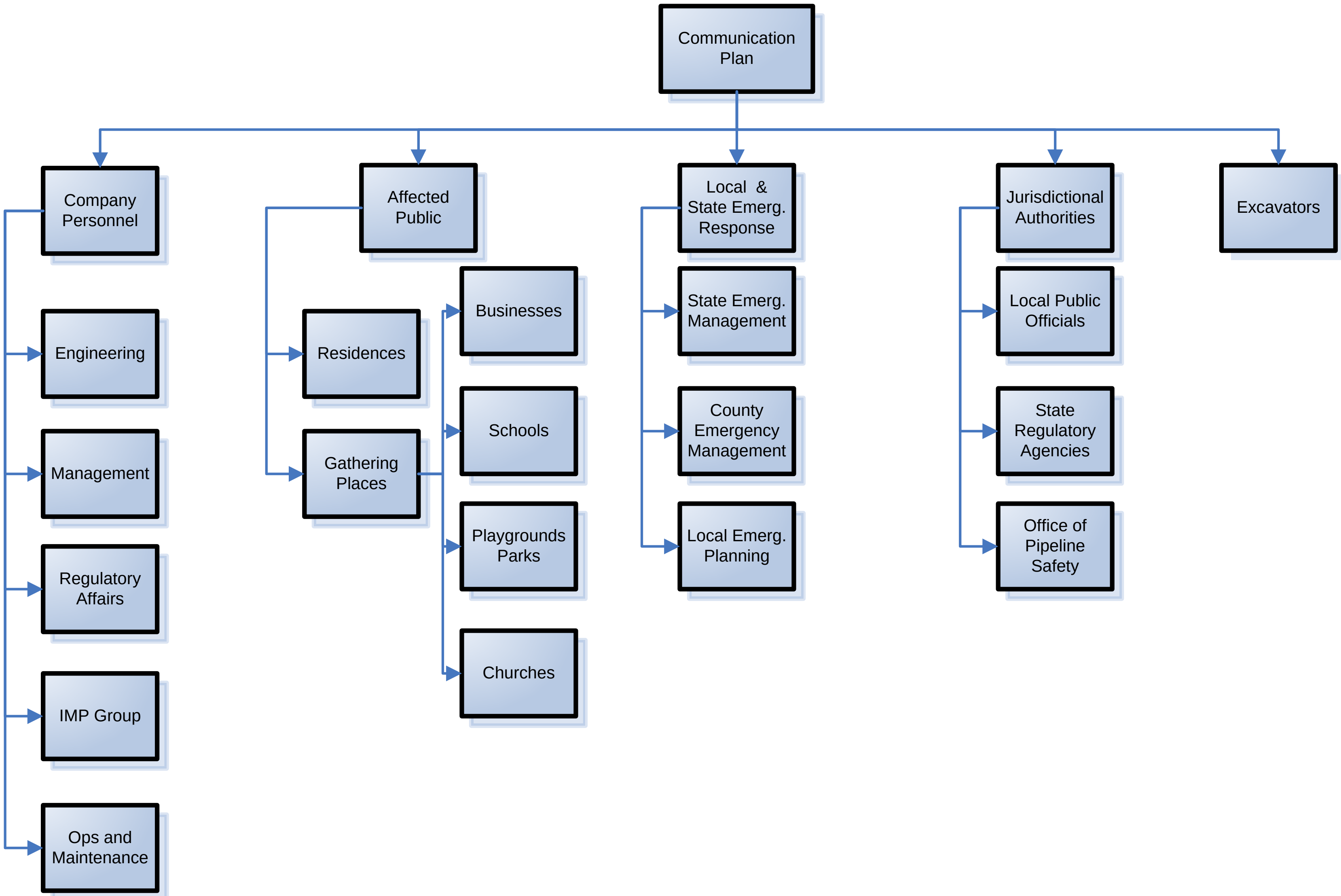


Figure 11.1: Agencies, organizations, and departments addressed by the Communication Plan.

11.3 Responsibilities

11.3.1 Integrity Management Program Manager

The Integrity Management Program Manager has the overall responsibility to assure that this Plan is effective and that activities specified within this Plan are conducted in accordance with the Plan requirements.

11.3.2 Regulatory Communications Coordinator

Many of the activities that are specified in this plan are the responsibility of the Regulatory Communications Coordinator. Specific communication responsibilities based on the affected agency or organizations are outlined in Table 11.1. The Regulatory Communications Coordinator shall assure that the Plan activities are conducted and documented. If Company communication activities deviate from the requirements of this Plan, the Regulatory Communications Coordinator shall notify the Process Manager.

Table 11.1: Specific Communication Plan Responsibilities

Agency Type	Responsible Department
Company Internal Communications	Regulatory Communications Coordinator
Affected Public Residences Along ROW and Places of Congregation	
State and Local Emergency Agencies	
Jurisdictional Agencies	
Excavators/ Contractors	
One Call Centers	

11.4 Pipelines Covered

This plan applies to all covered segments identified in Section 2 of the IMP. It may have applications to non-covered segments and may be applied at the discretion of the responsible manager.

11.5 Communication Plans

11.5.1 Plans

Tables 11.2 list the agency, organization, or department that shall receive integrity management communications. The tables provide a summary of information for each organization, the frequency of communication, and the process for delivery of information. Tables 11.2 shall be reviewed and updated by the Regulatory Communications Coordinator on an annual basis.

Table 11.2: Communication Plan By Agency – Transmission Pipelines

Agency Type	Stakeholders	Message Type/ Information Content	Frequency	Delivery Process	Status	Comments
Company	• Engineering • Operations and Maintenance • Regulatory Affairs • Management • Integrity Management Program Personnel		Annual			
Affected Public Residences Along ROW and Places of Congregation	• Businesses • Schools • Churches • Parks and Outdoor Gathering Places • Residences	Pipeline Purpose and reliability	Every 2 Years		Materials need to be reviewed for content and updated	
		Awareness of hazards and prevention measures undertaken	Every 2 Years		Brochures need to be reviewed for content and updated	
		Damage Prevention Awareness	Every 2 Years		An overview needs to be added to our brochures	
		One Call Requirements	Every 2 Years		Members of Dig Safe	
		Leak Recognition and Response	Every 2 Years		In the AGA and BGC brochure The Firefighter . . . And the Gas Company	
		Pipeline Location Information	Every 2 Years		Pipeline markers in place - our brochures need to explain size, shape, and placement of signs.	
		How to get additional information	Every 2 Years		Contact sheets should be included in Targeted Mailings	

Agency Type	Stakeholders	Message Type/ Information Content	Frequency	Delivery Process	Status	Comments
		Availability of list of pipeline operators through NPMS - National Pipeline Mapping System	Every 2 Years			
State and Local Emergency Agencies	• State Emergency Management • County Emergency Management • Local Emergency Planning • Police Departments • Fire Departments	Pipeline Purpose and reliability	Annual	Personnel Contact	Mailings	Need to revise meeting agendas to ensure proper understanding of hazards and prevention measures. Need to identify audience: Fire, police, sheriff, LEPC, EMA, Homeland Security
		Awareness of hazards and prevention measures undertaken	Annual	Targeted Distribution of print materials including Brochures, Flyers., Letters OR	Print materials need to be reviewed for content and updated - AGA Fire & Rescue is primary	
		Emergency Preparedness Communications	Annual	Group Meetings OR	Brochures need to be reviewed for content and updated	
		Potential Hazards	Annual	Telephone Calls with Targeted distribution of print materials	In current Brochure	
		Pipeline Location Information and availability of NPMS	Annual		Pipeline Markers in place and monitored. NPMS not in place	
		How to get additional information	Annual		Contact sheets should be included in Targeted Mailings and meeting handouts (get e-mail addresses)	
Jurisdictional Agencies	• Local Public Officials • State Regulatory Agencies • Federal Regulatory Agencies	Pipeline Purpose and reliability	Every 3 years	Targeted Distribution of print materials including Brochures, Flyers, or Letters	Print materials need to be reviewed for content and updated	enforcement
		Awareness of hazards and	Every 3 years		Brochures need to be reviewed for	

Agency Type	Stakeholders	Message Type/ Information Content	Frequency	Delivery Process	Status	Comments
		prevention measures undertaken			content and updated – AGA Fire & Rescue is primary	
		Emergency Preparedness Communications	Every 3 years		Brochures need to be reviewed for content and updated	
		One Call Requirements	Every 3 years		Members of Dig Safe	
		Pipeline Location Information and availability of NPMS	Every 3 years		In Brochure	
		How to get additional information	Every 3 years		Contact sheets should be included in Targeted Mailings (get e-mail addresses)	
Excavators/ Contractors	• Construction Contractors • Public Works Officials	Pipeline Purpose and reliability	Annual	Targeted Distribution of print materials including	Print materials need to be reviewed for content and updated	
		Awareness of hazards and prevention measures undertaken	Annual	Brochures, Flyers., Letters	Brochures need to be reviewed for content and updated – we have a number of choices	
		Damage Prevention Awareness	Annual	One-Call Center outreach AND	Brochures need to be reviewed for content and updated	
		One Call Requirements	Annual	Pipeline Markers	Members of Dig Safe and participate in educational outreach to excavators	

Agency Type	Stakeholders	Message Type/ Information Content	Frequency	Delivery Process	Status	Comments
		Leak Recognition and Response	Annual		In Brochure	
		How to get additional information	Annual		Contact sheets should be included in Targeted APWA, Municipal associations Land Developers, Builders Mailings (get e-mail addresses)	
One Call Centers			Annual	Maps	KeySpan provides GIS information to Dig Safe with monthly updates	This reduces unnecessary No Gas Dig Safe requests

11.5.2 Contact Information

Contact Information for the affected stakeholders shall be documented in Table 11.3. This information shall verified annually by the Regulatory Communications Coordinator.

Table 11.3 Contact List of Outside Businesses and Agencies

Agency Type	Stakeholders	Organization Name	Contact Position	Contact Person	Phone Number	Address	email	Website
Company	Engineering							
	Operations and Maintenance							
	Regulatory Affairs							
	Management							
	Integrity Management Program Group							
Affected Public	Businesses							
	Schools							
	Churches							
	Parks and Outdoor Gathering Places							
	Residences							
Local and State Emergency Responses	State Emergency Management							
	County Emergency Management							
	Local Emergency Planning							

Agency Type	Stakeholders	Organization Name	Contact Position	Contact Person	Phone Number	Address	email	Website
	Police Departments							
	Fire Departments							
Jurisdictional Authorities	Local Public Officials							
	State Regulatory Agencies							
	Federal Regulatory Agencies							
Excavators								
One Call Centers								

11.5.3 Communication Content

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

11.5.3.1 Company Internal Communications

Company communications for the various integrity activities shall be conducted in accordance with the specific requirements outlined in this IMP. These include the results of integrity assessments, quality assurance audits, and performance measures.

11.5.3.2 Affected Public along the rights-of-way

1. Company location, and contact information
2. General location information and where more specific location information may be obtained
3. How to recognize, report and respond to a leak
4. Contact phone numbers both routine and emergency
5. General information regarding prevention, integrity measures, emergency preparedness, and how to obtain a summary of Integrity Management Plans
6. Damage prevention information, including excavation notification numbers and excavation notification center requirements.

11.5.3.3 Local and State Emergency Responders

Emergency responders include local emergency planning commissions, regional and area planning committees, jurisdictional emergency planning offices, etc.

1) Company contact numbers both routine and emergency
2) Local maps
3) Facility description

4) How to recognize, report and respond to a leak
5) General information regarding prevention and integrity measures.
6) Station locations and descriptions
7) Summary of Company emergency capabilities

11.5.3.4 Jurisdictional Authorities

Periodic distribution to each municipality of maps and company contact information, including a summary of emergency preparedness and Integrity Management Program

11.5.3.5 Excavation Contractors

Information regarding Frontier's efforts to support excavation notification and other damage prevention initiatives, including Company contact and emergency reporting information.

11.5.4 Communication Frequency

The frequency of communications shall follow the timeframes specified in Tables 11.2 . Communications should be conducted as often as necessary to ensure that appropriate individuals and authorities have current information about the Company's system and integrity management efforts. Changes to the frequency of communication with stakeholders may be made at the discretion of the Regulatory Compliance Manager.

11.5.5 Communication Delivery Process

The methods used to convey Company integrity information are specified by message type and information content in Tables 11.2. Changes to the method of communication with stakeholders may be made at the discretion of the Regulatory Compliance Manager based on the most appropriate or effective methods for a given audience or message content. Established communication methods include but are not limited to:

- Print Materials: letters, mailings, brochures, bill inserts
- Electronic Media: e-mail, websites
- Public Media: public service announcements, paid advertising
- Other: pipeline markers, maps, public meetings.

12.0 MANAGEMENT OF CHANGE PLAN

12.1 Overview

The Management of Change Plan (MOC) is a formal procedure that facilitates the consideration of pipeline integrity **before** changes affecting the technical, physical, procedural, and organizational areas of the Company are implemented. The MOC plan specifies how new information is incorporated into the Company's Integrity Management Program, and assures that integrity management systems are updated, changes are documented, and that appropriate approvals, communication and training take place.

The process is intended to be flexible enough to accommodate both major and minor changes, and transparent to ensure that it is easily understood by affected personnel (an overview of the process is shown in Figure 12.1).

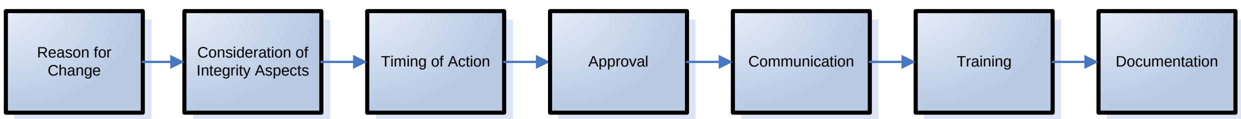


Figure 12.1: Management of Change Process

A number of Company processes need to integrate MOC requirements and practices. This plan describes the process of implementing MOC in the company processes. Figure 12.2 is a flow chart of the implementation process.

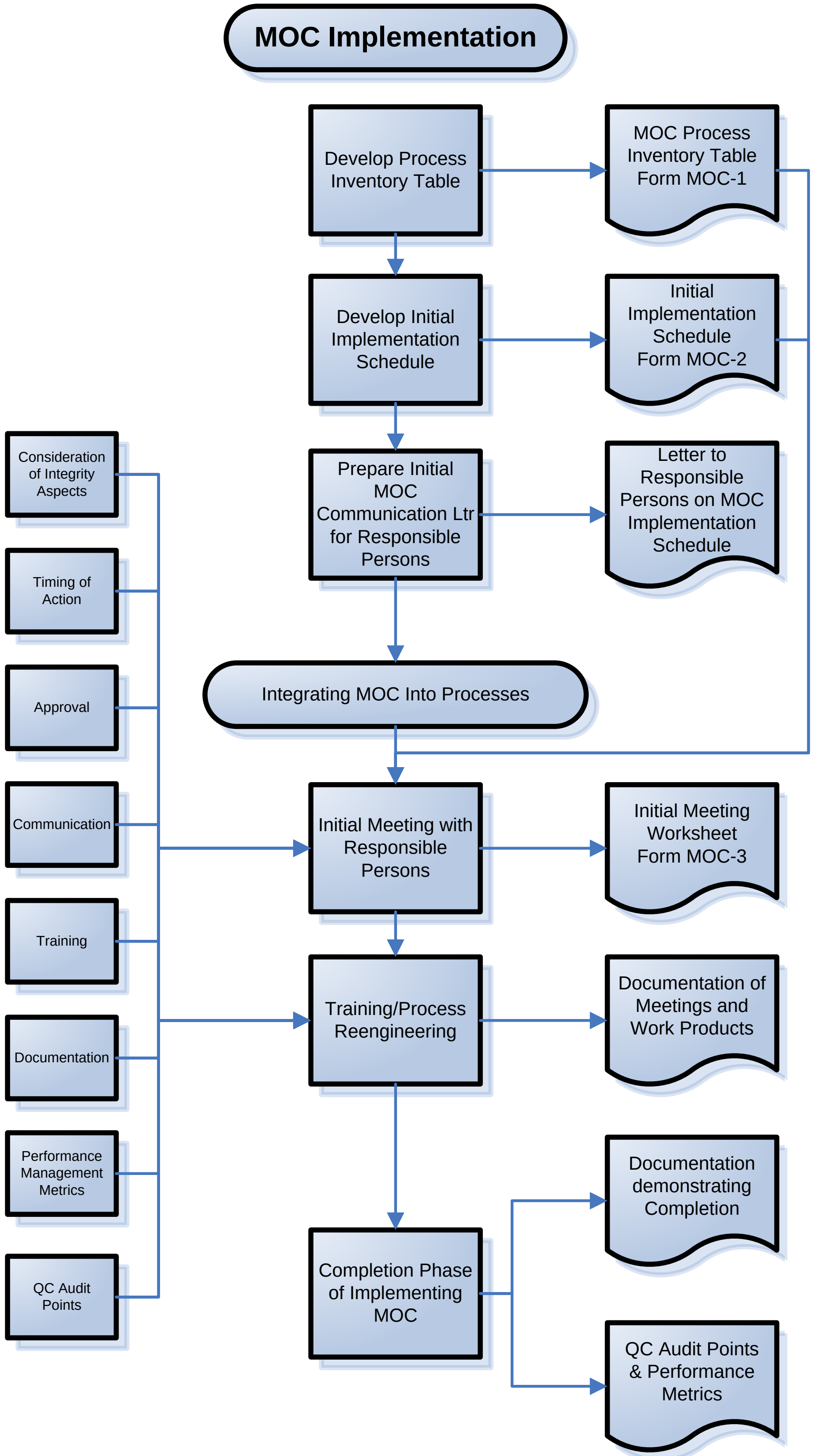


Figure 12.2: Flow Chart of MOC Implementation Process

12.2 Objectives

This Section describes the MOC process in order to ensure that the following objectives are met:

- Assure the Integrity Management process remains viable throughout changes in the physical, technical, procedural, and organizational aspects of the Company
- Recognize, analyze, and approve changes to the above areas prior to implementation
- Assure the integration of changes (including newly discovered conditions) to allow for adjustments in maintenance, operation and IM processes.
- Provide guidance for documentation and tracking of changes
- Assess the safety impact of system changes
- Identify resulting training requirements
- Ensure communication of changes to affected parties
- Communicate new technologies impacting the Integrity Management area to appropriate personnel

12.3 Responsibilities

12.3.1 Integrity Management Program Manager

The Integrity Management Program Manager is the MOC process owner. The Integrity Management Program Manager shall be responsible for evaluating and implementing the overall MOC process and plan, identifying necessary changes to the plan, and implementing those changes to ensure continuous improvement. The Integrity Management Program Manager has the authority for approval of modifications to the MOC Plan. Revisions to the MOC Plan shall be reviewed and authorized by the Integrity Management Program Manager. The Integrity Management Program Manager shall review the MOC Plan at least once every calendar year, not to exceed 18 months from the last Plan evaluation.

12.3.2 Affected Process Owner

Application of the MOC Process to individual Company processes shall be the primary responsibility of the process owner. The affected process owner is responsible for evaluation of the change, determination of its overall impact on the process, development of an action plan, and communication of the outcome. Each process covered under the scope of the MOC Plan shall be reviewed by the process owner at least once every calendar year, not to exceed 18 months from the last Plan evaluation.

12.4 Implementation Process

The implementation of the MOC process consists of six overall steps. Steps 1 through 3 provide for the identification and development of short term responses to MOC requirements. Steps 4 through 6 provide a three phase approach toward integration of MOC processes into the Company operating systems. The MOC plan shall be implemented by applying the steps outlined in the following sections.

12.5 MOC Process Inventory

12.5.1 Description

Table 12.1 provides an inventory of the processes that are subject to the MOC plan. Processes are designated into broader categories, and each covered process lists the associated change, trigger event, and process owner responsible for changes that may affect the integrity of the pipeline.

12.5.2 Purpose

The MOC Process Inventory (Table 12.1) provides a summary of activities that could potentially affect the integrity of the pipeline. The Integrity Management Program Manager and others involved with the Integrity Management Program are required to assure that the people, processes, and tasks involved with these activities consider the MOC Process with specific regard for the following items:

- Reason for change
- Authority for approving change
- Analysis of implications
- Acquisition of required work permits
- Documentation
- Communication of change
- Time limitations
- Qualifications
- Staff reviews the changes to assess the safety impact
- Assurance that the Integrity Management Process continues to be viable throughout the change process
- A system that tracks changes
- Communication of changes to interested parties
- Identifies new training requirements as a result of changes
- Communicates new technologies in the Integrity Management area to appropriate personnel

12.5.3 MOC Process Inventory - Definitions

Integrity Category: A broad designation of various activities that may affect the integrity of the pipeline.

Integrity Changes: Integrity aspects that could be affected by the trigger events

RiskPro Data Element: The related data elements in the RiskPro model.

Trigger Event For Changes: Events that result in changes that may affect the integrity of the pipeline

Responsible Organization: The Company department or division that is primarily responsible for evaluation of the trigger event, and hence responsible for the assuring that integrity is considered.

Responsible Position: The specific position that is accountable for, and approves the trigger event, and hence is responsible for assuring that integrity considerations are evaluated prior to the change.

Process: The Company procedure, methodology, or practice governing the implementation of the trigger event. In some cases there is not a definitive consistent process for these events.

Table 12.1: Management of Change Process Inventory

Category	Ref Number	Change	Responsible Position	Process
HCA	101	Number of Residences and Identified sites	Compliance Coordinator	Annual Pipeline ROW Surveys
Pipe Related Change	102	Material, Grade, Seam Type	Operations Manager	New Services, uprates, and replacements
	103	Diameter	Operations Manager	New Services, uprates, and replacements
	104	Addition or removal of equipment	Field Supervisor	Addition and removal of plant
Construction Related Changes	201	Replacement of pipe	Operations Manager	Company pipe standards
	202	Addition or removal of casings	Operations Manager	Addition or removal of plant
	203	Depth of cover	Field Supervisor	Annual Pipeline ROW Surveys and other ROW activities
	204	Pressure Test	Field Supervisor	Company's Pressure Test Procedure
	205	Addition or removal from waterways	Operations Manager	Addition or removal of plant
Soil and Environmental Changes	300	Inclination of pipe	Operations Manager	Pipe replacement and reroute process
	301	Soil Subsidence	Field Supervisor	Annual Pipeline ROW Surveys
	302	Addition, removal or movement nearby pipelines	Field Supervisor	Annual Pipeline ROW Surveys
	303	Addition or removal of paving	Field Supervisor	Pipe replacement and reroute process
	304	Construction activity	Field Supervisor	Annual Pipeline ROW Surveys
Corrosion Control Changes	401	Encroachment or change in ROW conditions	Field Supervisor	Annual Pipeline ROW Surveys
	402	Coating condition including refurbishment, direct examination, and type	Field Supervisor	Pipe Excavation Report
	403	CP criteria	Operations Manager	Cathodic Protection Criteria
	404	Level of polarization	Operations Manager and Field Supervisor	Quarterly CP Reads plus review and sign off

Category	Ref Number	Change	Responsible Position	Process
	405	Conductance of non IMP assessments	Operations Manager and Field Supervisor	Expense Projects
	406	Casing contact	Operations Manager and Field Supervisor	Casing Contact
Operational Changes	501	Presence of liquids	Operations Manager and Field Supervisor	Gas Quality Monitoring
	502	MAOP (up or down)	Operations Manager and Field Supervisor	Re Rate Process
	503	Pressure cycling	Field Supervisor	Unlikely event. No specific process
	504	3rd Party Damage or Leak Reports	Field Supervisor and Compliance Coordinator	3rd Party Damage Leak Reports
	505	Pipe Inspection Reports	Field Supervisor and Compliance Coordinator	Pipe Excavation Reports
	506	Gas Quality	Field Supervisor	Gas Quality Monitoring
IMP Assessment Activities	601	ECDA Assessments	Operations Manager and Field Supervisor	ECDA Procedure
	602	Hydro tests	Operations Manager and Field Supervisor	Pressure Test Procedure
	603	ILI Assessments	Operations Manager and Field Supervisor	ILI Procedure
	604	Other Assessments	Operations Manager and Field Supervisor	Specific procedure for assessment of carrier pipes in casings
	605	Remediation Activities	Operations Manager and Field Supervisor	Remediation procedures
Integrity Management Process	700	HCA Identification	Operations Manager	IMP
	701	Risk Analysis Process	Operations Manager	IMP
	702	Baseline Assessment Plan	Operations Manager	IMP
	703	Assessment Methods	Operations Manager	ECDA, ICDA, Casings
	704	Assessment Procedures	Operations Manager	ECDA, ICDA, Casings

Category	Ref Number	Change	Responsible Position	Process
	705	Communication Plan	Compliance Coordinator	Communication Plan
	706	Management of Change Plan	Operations Manager	Management of Change Plan
	707	QA Plan	Operations Manager	QA Plan
	708	Performance Management Plan	Operations Manager	Performance Management Plan
Maintenance Processes	**801**	Frequency of patrols	Field Supervisor	Patrol Procedure
	802	Valve Maintenance	Field Supervisor	Valve Maintenance Procedure
	803	Others		
Organizational	**901**	Reorganization	Vice President	No specific procedure
	902	Personnel changes	Vice President	No specific procedure

12.5.4 Updating Table and Documentation

The Integrity Management Program Manager shall review the process inventory at least once per year not to exceed 18 months from the last review. The Integrity Management Program Manager shall document his/her review on Form MOC-1. This form shall be filed in the IMP files.

12.6 Initial MOC Plan Implementation

12.6.1 Objective

The Integrity Management Program Manager shall arrange training for the responsible persons and/or organizations listed in Table 12.1 (Form MOC-1) to assure that all the identified processes integrate the MOC plan tasks and objectives. This section describes the process of how the IMP MOC will be implemented in the Company.

12.6.2 Initial Management of Change Implementation Schedule

The Integrity Management Program Manager shall develop an initial implementation schedule on Form MOC-2 by **February 28, 2005**[RD5]. The Integrity Management Program Manager shall indicate the initial meeting date, the training date, and the date for completion of the MOC implementation for each Responsible Organization and/or person.

12.6.3 Initial Communication of MOC

Changes that affect pipeline integrity may occur at any time, prompting the need to immediately implement MOC principles on an ad hoc basis as soon as possible. The framework for communication of MOC requirements is outlined below.

12.6.3.1 Communication Content

The Integrity Management Program Manager shall communicate the following items to the Responsible Organizations and Positions identified in Table 12.1:

- Requirements of the integrity management rule for the development of MOC processes within the IMP.
- Explanation of the MOC process
- The intent to further communicate, train, and adjust the processes to incorporate MOC process elements
- The meeting schedule outlining the Integrity Management Program Manager's plan for MOC training.
- Interim plans for applying the MOC process in an ad hoc manner.
- Items and processes under the control of the responsible person that may affect the integrity of the pipeline.

12.6.3.2 Documentation Requirements

The initial communication of MOC requirements shall be conducted in writing to the responsible persons. The letters shall be filed in the MOC section of the IMP file system.

12.6.3.3 Date Requirements

The Integrity Management Program Manager shall complete this communication no later than February 28, 2005[RD6].

12.7 Incorporating MOC Elements into Company Processes

12.7.1 Objective

This section describes the principles and general requirements that the company processes must adopt to satisfy the MOC requirements. It is provided as guidance to the Integrity Management Program Manager for reference when developing or reengineering processes for MOC purposes. The following sections discuss the individual MOC Process steps shown in Figure 12.1.

12.7.2 Reason for Change

The process shall have methods and requirements for documenting the reason for change. This documentation should indicate if the change is temporary, and if so when will be changed again. Documentation of the reason for change should also list alternatives that were considered, and the rational for not proceeding with the alternatives.

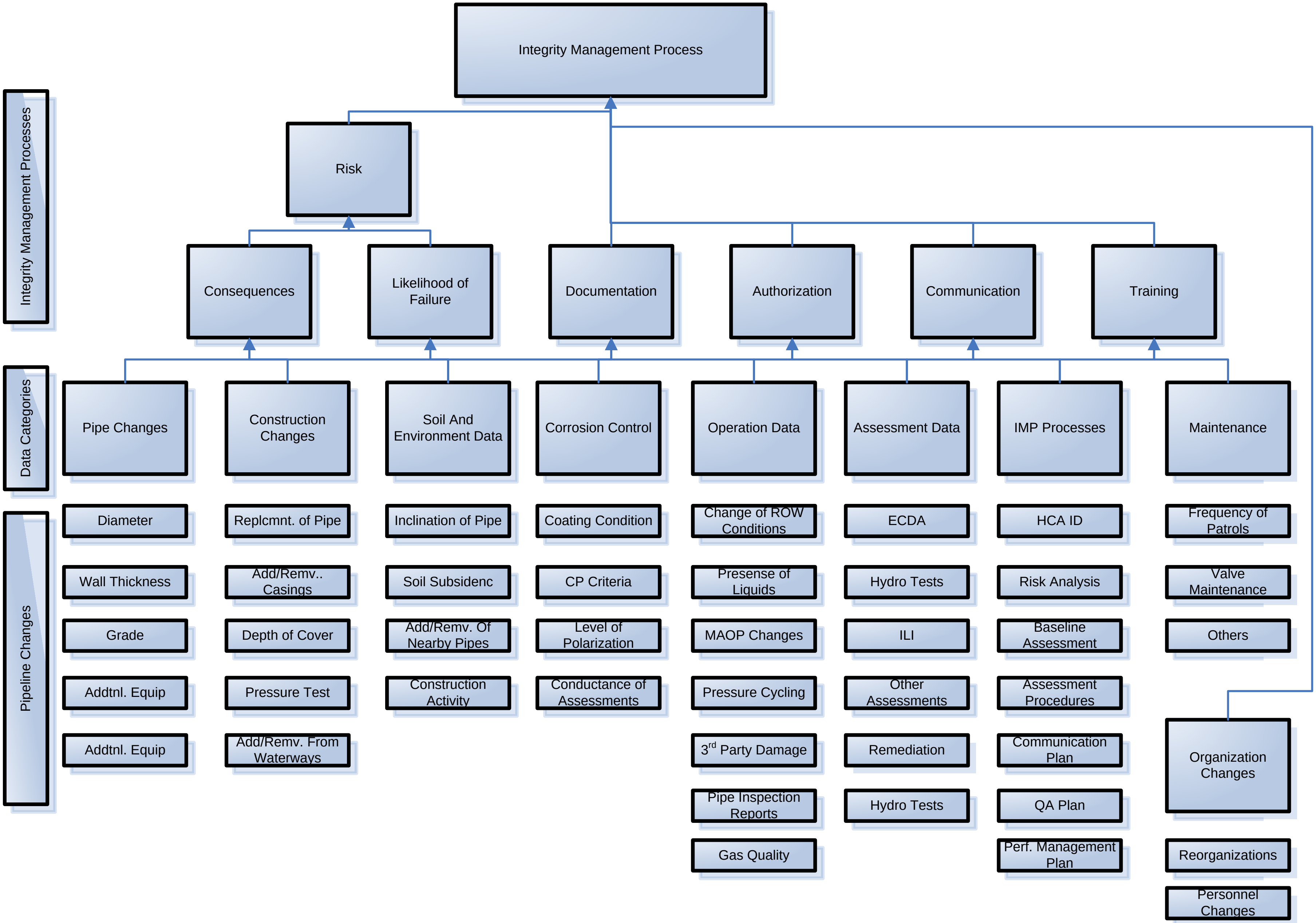


Figure 12.3: Management of Change Data Element Map

Table 12.2: RiskPro Data Element Vs Integrity Threat

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
	Equation Fixed References	**1**	**4**	**7**	**9**	**9**	**6**	**15**	**3**	**6**			**4**
1	Unique ID												
2	Segment Name												
3	Line												
4	Start Point												
5	End Point												
6	Section Length		**1**										
100	***** SEGMENT DATA *****												
101	Potential Impact Radius												
102	Residential	**1**											
103	ID Locations	**1**											
104	Class Location									**1**			
105	HCA Comments												
200	***** PIPE DATA *****												
201	Material Spec												**1**
202	Material Toughness									**1**			
203	SMYS		**1**			**2**							
204	Outside Diameter		**1**			**2**							
205	Wall Thickness		**1**			**2**				**1**			
206	Seam Type						**2**						
207	Factory Coating Type			**2**		**3**							
208	Pipe Comments												
300	***** CONSTRUCTION DATA *****												
301	Year Installed			**2**		**1**	**1**	**1**					**1**
302	Test Pressure						**1**	**1**					
303	Number of Casings												
304	Backfill Construction			**1**									
305	Depth of Cover									**1**			
306	Girth Weld Type												**2**
307	Girth Weld Quality							**1**					
308	Field Coating Type			**2**		**1**							
309	Pipeline Crossing									**1**			
310	Water Crossing												**1**
311	# of Wrinkle Bends							**1**					
312	Wrinkle Result of Move							**1**					

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
313	Wrinkle >3 degrees							1					
314	WB Aspect Ratio <3							1					
315	Above Ground Equipment Present								3				
316	Susceptible to Land Movement					1							1
317	Susceptible to Weather												1
318	Construction Comments												
400	***** SOIL & ENVIRONMENT *****												
401	Soil Type							1					
402	Soil Wetness			1		2							
403	Soil Resistivity			1		1							
404	Water pH					1							
405	Land Use									2			
406	Historical Construction Activity									1			
407	Right of Way Condition									1			
408	Soil & Environment Comments												
500	***** CORROSION CONTROL *****												
501	Coating Condition			2		3							
502	Cathodic Protection Criteria			1									
503	Months Below CP Criteria			1									
504	Years Without CP			1									
505	Stray Current History			1									
506	Casing Contact			1									
507	External Corrosion Detected			1		1							
508	External MIC Detected			1									
509	Internal Corrosion Detected				4								
510	Internal MIC or Corrosives Detected				2								
511	Upstream Source of Liquids				4								
512	History of Liquids				6								
513	Liquid Drains Present				5								
514	Drains Checked Frequently				3								
515	Liquids Analyzed				3								
516	Drying Operation Conducted				1								
517	Corrosion Control Comments												
600	***** OPERATIONAL DATA *****												
601	MAOP		1			2	2	2					
602	5Yr Max Op Pressure						1	1					
603	Weekly (Pmin/Pmax)					1		2					

Seq. #	SI Name	Consq	Scale	EC	IC	SCC	Mnfg	Cnstr	Equip	3P	Vand	Ops	Out For
604	Previous Leaks / mile / year			**1**									
605	Distance From Compressor					**1**							
606	Compr Discharge Temp					**1**							
607	Average Pipe Temp												**1**
608	Pipe Tmax-Tmin							**2**					
609	History of Incorrect Operations											**1**	
610	History of Pipe Seam Failure						**1**						
611	Defective Pipe												
612	Defective Pipe Seam						**1**						
613	Defective Fabrication Weld												
614	Prior Wrinkle Failures							**1**					
615	Stripped Threads / Couplings							**1**					
616	Failed O-Ring								**1**				
617	Control / Relief Malfunction								**1**				
618	Seal / Pump Packing Failure								**1**				
619	# 3rd Party Damage Reports									**1**			
620	# Vandalism Reports										**1**		
621	Operational Comments												
700	***** ECDA Indications *****												
701	Immediate		**2**										
702	Scheduled		**1**										
703	Monitored		**1**										
800	*** CIS Indications ***												
801	**CIS Severe**		**1**										
802	CIS Moderate		**1**										
803	CIS Minor		**1**										
900	***** DCVG/PCM Indications *****												
901	DCVG Severe		**1**										
902	DCVG Moderate		**1**										
903	DCVG Minor		**1**										
Sys1	**Time Stamp**												
	Totals	**3**	**19**	**26**	**37**	**34**	**15**	**32**	**9**	**16**	**1**	**1**	**12**

12.7.3 Impact to Pipeline Integrity

This aspect of the MOC process is to assure that pipeline integrity impacts are considered prior to implementation of the change. This step should be carried out in an analysis framework where the impact of safety and the implications on integrity management are considered. To frame the analysis, the Integrity Categories shown in Figure 12.3 may be used. Each data element may affect an Integrity Category. Table 12.2 provides information regarding RiskPro data elements that may influence a particular pipeline threat. This figure and table may be used as guidance when evaluating the impact of a change on pipeline integrity.

12.7.4 Timing of Action

The timing of the change should be evaluated for potential impacts to the integrity of the pipeline. For example, coordinating the change with assessments or other integrity aspects should be considered to maximize improvements to pipeline integrity. The consideration should include the time required to obtain work permits, and consideration of more expedient alternatives (OPS FAQ 139 is currently under development that may provide further insight and requirements to this aspect of the MOC process).[RD7]

12.7.5 Approval

Approval for the change shall be provided at a position level that has the experience base and process insight necessary to determine that integrity issues have been sufficiently considered and correctly analyzed. The process shall have the position and/or person clearly identified as the approving authority. The process shall specify the approving authority responsibilities and list specific considerations that the approving authority must consider.

12.7.6 Communication

Communication of potential and actual changes is important not only for consideration of additional pipeline activities, but also for collecting critical input and developing wide spread agreement as appropriate. The Integrity Management Program Manager shall assure that the process identifies specific communication requirements referenced to company positions. The process should identify those positions that should be solicited for information and insight prior acceptance and implementation of critical changes.

12.7.7 Regulatory Notification

The process shall identify any situations requiring notification of regulatory agencies and describe the process of how the notification shall occur.

12.7.7.1 Federal Notification

The Company must provide notification to the Office of Pipeline Safety of any change that may substantially affect the IMP's implementation or may significantly modify the IMP or schedule for completion of the IMP elements. This notification must occur within 30 days after adopting a substantial change affecting the IMP. The notification shall be made to

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
U.S. Department of Transportation
Room 7128
400 Seventh Street, SW
Washington, DC 20590

Or by Fax to the Information Resources Manager at (202) 366-7128

Or by entering the information directly on the Integrity Management Database (IMDB) website at http://primis.rspa.dot.gov/gasimp/.

12.7.7.2 State Notification

The company also needs to notify the North Carolina Public Utility Commission of any change that may substantially affect the IMP's implementation or may significantly modify the IMP or schedule for completion of the IMP elements.

12.7.8 Training

List or describe any new training or qualification requirements that must be considered in association with the change. Does new equipment mandate the implementation of a training course? Is a regularly scheduled refresher course required for a specific task?

12.7.9 Documentation

The process shall list the documentation requirements for the elements of the MOC process described in sections 1.4.4.5. The documentation of the MOC elements shall have sufficient detail to allow tracking and review at a later date. Documentation shall also identify systems and databases that require updates with the changes.

12.7.10 Performance Management Metrics

The Performance Management Plan shall monitor and report on the implementation of the MOC Plan as well as on-going MOC activities. Performance monitoring metrics shall be identified during integration of the MOC objectives into the process. The metrics shall measure the degree of MOC implementation into processes, and the number of changes subject to the MOC process.

12.7.11 QC Audit Points

During the implementation phase of the MOC, Quality Control (QC) audit points shall be identified. These audit points shall be identified as either

"High Level" process issues (that should be audited by individuals who are independent of the Integrity Management Program) or as "Routine" process points (see the Quality Control Plan in the IMP for further details).

12.8 Implementation Process

The implementation of the MOC process into company systems is divided into three phases. Each phase is described below:

12.8.1 Phase I - Initial Implementation Meeting

The Integrity Management Program Manager shall meet with the Responsible Person to determine the most effective means to implement MOC into the affected process. The following items shall be determined:

- The processes or activities that may affect the integrity of a pipe segment
- The extent the process needs to be reengineered to accommodate the objectives of the MOC process.
- The most effective way to implement the MOC steps into the processes
- The need for the second phase of training or group problem solving
- The date for the second phase to begin, if appropriate
- The date the process reengineering will be completed.

12.8.1.1 Documentation

The discussion and the decisions from the initial meeting shall be documented on Form MOC-3, Initial Meeting Worksheet

12.8.2 Phase II - Training/Process Reengineering

This phase covers training of personnel on the MOC requirements of MOC and/or reengineering a process to integrate MOC requirements. If this phase is not warranted, it may be bypassed by agreement of both the

Integrity Management Program Manager and the Responsible Person during the Initial MOC Implementation Meeting.

12.8.2.1 Documentation

The following shall be documented for the Training/Process Reengineering Phase:

- Meeting attendance list with date and title of the meeting
- Work products and decisions from the meeting

12.8.3 Phase III - Completion and Documentation

This phase implements and documents the identified changes necessary to integrate MOC requirements and steps into the process.

12.8.3.1 Reconcile Requirements

Check the process to assure that it has instructions and/or criteria that address each of the six steps in the MOC processes shown in Figure 1.2 and listed below.

- Consideration and Evaluation of Integrity Aspects
- Timing Requirements and Considerations
- Approval
- Communication
- Training
- Documentation

12.8.3.2 Communication and Training

The Responsible Person shall communicate and/or train personnel as appropriate on the changes and requirements of the process modifications.

12.8.3.3 Documentation

The process shall have documentation that supports each of the three process phases listed above. Documentation shall be placed in the IMP files that demonstrates that the MOC objectives and steps have been integrated into the process.

13.0 EXCEPTION PROCESS

13.1 Expectations

It is expected that the requirements of the integrity management program are followed to the extent possible. However, exceptions may be taken by obtaining approval and documenting the exceptions as prescribed in this section.

13.2 Objective

This process is to provide control and consistent documentation of exceptions to the program. Control and consistent documentation are necessary to maintain the integrity of the program through continuous process improvement, feedback, audits, and compliance with this procedure.

13.3 Exception Requirements

The following process is required for deviating from the program. It shall be documented on Form EX: Exception Report:

13.3.1 Section of Procedure

State the specific paragraph number where the exception is being taken. Briefly state or paraphrase the requirements of the paragraph.

13.3.2 Alternative Plan

State the proposed exceptions to the program.

13.3.3 Reason

Provide the reason for the exception.

13.3.4 Recommendation

Indicate if this is a project specific exception, or if the program should be changed.

13.3.5 Approval

Obtain approval from the Section Manager.

13.4 Documentation

Form EX; Exception Report shall be used to document the Exception Process. Form EX shall be reviewed and signed by the Section Manager. All exception reports shall be stored in the Integrity Management Program file.

FORMS

Form HCA-1 – Sample Public Agency Letter

Dear Public Safety Official:

Federal Legislation enacted in December 2002, commonly referred to as the "Pipeline Safety Improvement Act of 2002," created requirements for pipeline operators and their Federal regulators to undertake additional activities in the area of Integrity Management Programs for gas pipelines.

You may have heard the term "High Consequence Area," or "HCA" used in conjunction with Hazardous Liquid Pipelines operators, and their management of environmentally sensitive areas, particularly in the areas of drinking water supplies. Natural Gas Pipeline operators are now required to evaluate areas called HCA's based upon different criteria. The primary criteria for gas pipeline HCA's involve population density and areas of congregation.

As a public safety official, we need your help to supplement our identification of the sites we will evaluate as HCA's. In an advisory bulletin issued by the federal Office of Pipeline Safety on ___________________, natural gas pipeline operators received guidance on working with public safety officials to identify sites that meet specific criteria defined by pending Federal regulations. Some of these "identified sites" are locations that are not easily identified through a pipeline operator's normal operation and maintenance activities. Because of this difficulty we need your help.

Identified Sites

There are two types of identified sites we have difficulty identifying. For the following types we need your input:

1) A small, well-defined outside area that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12) month period (the days need not be consecutive), or
2) A facility that is occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate, and
    a. is visibly marked, or
    b. is licensed or registered by a Federal, State or local agency; or
    c. is on a list or map maintained by, or available from a Federal, State, or local agency.

You are not being requested to conduct a search to identify these sites. The guidance clearly instructs us to consult with the appropriate officials who indicate "they know the location of sites" that meet this description. The guidance further lists "good examples" as schools, elder care, assisted living and nursing facilities that you may be aware of in the communities in which you serve.

If you know of facilities or areas that fit these definitions, XXXX would like to receive location information from you about these sites.

You may provide this information to us by any of the following methods, listed in order of preference by Intermountain Gas Company;

1) In writing to:

2) By fax to:

3) By e-mail to:

4) By phone to:

The information to be supplied is as follows:

1) facility or area name
2) Street address or physical location
3) description of facility and its use or special needs.

If you have any questions concerning this input, please contact Jxx Sxxxx at xxxxxxxxx.

Thank you for your assistance as we try to ensure our pipelines continue to be the safest form of transportation.

FORM HCA-2 – HCA FIELD SURVEY

Line Designation	
Map Number	
Potential Impact Radius	
Survey Start Station Point	
Survey End Station Point	
Number of Buildings	
Number of Identified Sites	
Date of Survey	
Surveyor	

Engineering Department Use Only

Area to be classified as HCA? ☐ Yes ☐ No   If yes, HCA #:________________
HCA Start Station:_______________   HCA Name: ________________
HCA End Station:_______________

Comments:

____
____
____
____
____

FORM RA-1 – DATA ELEMENT INPUT FORM

INSTRUCTIONS: Complete this form within the RiskPro program

Instructions

RiskPro
Pipeline Risk Assessment
Structural Integrity Associates, Inc.

Integrity Management
Data Element Work Sheet

#			
0	***** Pipe Segment Identifiers *****		
1	Unique ID	B2-002	
2	Segment Name.	Star	text
3	Line.	Boise #2	text
9	Start Point.	5+00	text
10	End Point.	25+00	text
11	Section Length	2000	feet
100	***** SEGMENT DATA *****		
101	Potential Impact Radius	152	feet
103	Residential	0	count
105	ID Locations	7	count
106	Class Location	3	number
200	***** PIPE DATA *****		
201	Material Spec	API-5L	text
204	Outside Diameter	12.75	inches
205	SMYS	42000	psi
206	Wall Thickness	0.25	inches
207	Seam Type	ERW	text
209	# of Wrinkle Bends	0	count
210	Above Ground Equipment Present	Yes	text
300	***** CONSTRUCTION DATA *****		
301	Year Installed	1964	year (yyyy)
302	.Number of Casings		count
303	Depth of Cover	36	inches
304	Girth Weld Type	SMAW	text
305	Test Pressure	330	psi
307	.Field Coat Method		text
308	.Length of Water Crossing		feet
311	.Defective Pipe Seam		text
312	.Defective Pipe		text
313	Defective Pipe Girth Weld	No	text
314	.Defective Fabrication Weld		text
319	Backfill Construction	Medium	text
400	***** SOIL & ENVIRONMENT *****		
405	.Soil Type		text
406	Soil Wetness	Seasonally Wet/Dry	text
407	Soil Resistivity	1,000-15,000	ohm-cm
409	Land Use	Commercial	text
410	Pipeline Crossing	None	text
413	Historical Construction Activity	Moderate	text
414	Right of Way Condition	Average	text
415	Susceptible to Weather	No	text
416	Susceptible to Land Movement	No	text
500	***** CORROSION CONTROL *****		
501	Factory Coating Type	Coal Tar Enamel	text
502	Coating Condition	Fair	text
505	Stray Current History	No apparent issues	text
506	Cathodic Protection Criteria	-850 mV On	text
507	Months Below CP Criteria	5	months
508	Years Without CP	0	years
510	Casing Contact	No	text
511	External Corrosion Detected	No	text
512	.External MIC Detected		text
513	Liquid Drains Present	No	text
514	Drains Checked Frequently	Not Applicable	text
515	History of Liquids	No	text
516	Upstream Source of Liquids	No	text
517	Liquids Analyzed	No	text
518	Drying Operation Conducted	No	text
519	Internal Corrosion Detected	No	text
520	Internal MIC or Corrosives Detected	No	text
600	***** OPERATIONAL DATA *****		
601	MAOP	330	psi
602	5Yr Max Op Pressure	330	psi
603	Average Pipe Temp	32 <= T < 100 F	° F
604	Compr Discharge Temp	120	° F
605	Distance From Compressor	17	miles
606	Previous Leaks / mile	0.4 - <0.8	text
607	Stripped Threads / Couplings	No	text
608	Failed O-Ring	No	text
609	Control / Relief Malfunction	No	text
610	Seal / Pump Packing Failure	No	text
611	History of Pipe Weld Failure	No	text
612	# Vandalism Reports	0	count or "NA"
613	History of Incorrect Operations	No	text
620	.# 3rd Party Damage Reports		Number
700	***** ECDA Indications *****		
702	Immediate	0	count or "NA"
703	Scheduled	0	count or "NA"
704	Monitored	0	count or "NA"
800	***** CIS Indications *****		
801	CIS Severe	0	count or "NA"
802	CIS Moderate	0	count or "NA"
803	CIS Minor	0	count or "NA"
900	***** DCVG/PCM Indications *****		
901	DCVG Severe	0	count or "NA"
902	DCVG Moderate	0	count or "NA"
903	DCVG Minor	0	count or "NA"

FORM NOE: NOTIFICATION OF INTEGRITY SCHEDULE EXCEEDANCE *(1 OF 2)*

OFFICIAL COPY

Aug 25 2017

DATE:______________________________
INTEGRITY ID:_________________________
START MP: ___________________________
END MP: _____________________________

PIPELINE NUMBER:____
PIPELINE NAME:____
PROJECT MANAGER:____
PROCESS MANAGER.:_______________________________________

PIPE DATA:
DIA.:_________ WALL THICKNESS:___________ MATERIAL:__________ SMYS:_________ MAOP:_________ CLASS LOCATION:_______

DATE INTEGRITY ASSESSMENT WAS COMPLETED:______________ DATE OF DISCOVERY (IF APPLICABLE):______________

REASON FOR NOTIFICATION:
☐ EXCEEDANCE OF 180 DISCOVERY WINDOW
☐ EXCEEDANCE OF PRESSURE REDUCTION 365 DAY LIMIT
☐ EXCEEDANCE OF REMEDIATION SCHEDULE → HAS PRESSURE BEEN REDUCED? ☐ YES ☐ NO

EXCEEDANCE OF 180 DAY DISCOVERY WINDOW:

Reason/s for Condition Discovery Delay (state whether 180 day window is impracticable): ______________________________________
____
____
____
____
____

Corrective Action and anticipated date of Discovery: ____
____
____
____
____
____

Project Manager ________________________________ Date of Notification: ____/____/____

Process Manager:______________________________________Date of Review: ____/____/____

EXCEEDANCE OF PRESSURE REDUCTION 365 DAY LIMIT:

Reason/s for Initial Pressure Reduction and Exceedance: ____
____
____
____
____
____

Justification that continued reduction will not jeopardize pipeline integrity (justification must include technical evaluation, and conclusively determine safety is assured. Attach additional sheets as necessary): ________________________________
____
____
____
____
____

Anticipated Re-pressurization Date: _______________

Project Manager ______________________________________Date of Notification:_______

Process Manager:______________________________________Date of Review:___________

Form NOE: Notification of Integrity Schedule Exceedance *(2 of 2, continued)*

EXCEEDANCE OF 180 DAY DISCOVERY WINDOW:

PARAGRAPH REFERENCE NUMBER OF TIMING REQUIREMENT WHICH HAS BEEN EXCEEDED: ______________________

Summary of anomalous condition: ____

____

____

____

____

____

____

Reason/s for Exceedance of Remediation Schedule: ____

____

____

____

____

____

____

Summary of Actions taken to ensure of safety of covered segment: ____

____

____

____

____

____

____

Justification that continued exceedance will not jeopardize pipeline integrity (justification must include technical evaluation, and conclusively determine safety is assured. Attach additional sheets as necessary): ____

____

____

____

____

____

____

____

CONCLUSION REGARDING CONTINUED SAFETY:

□ *Yes, the pipeline is safe*

□ *No, safety cannot be ensured* → **OPS NOTIFICATION REQUIRED**

Project Manager ____ Date of Notification: _______

Process Manager: ____ Date of Review: ___________

FORM RA-2 – RISK ANALYSIS REVIEW DOCUMENTATION

START DATE OF ANALYSIS:_____ LINE NAME:_____
COMPLETION DATE OF ANALYSIS:_____ LINE NUMBER:_____
INTEGRITY MANAGEMENT PROGRAM MANAGER:______

INSTRUCTIONS PROVIDED IN PARAGRAPH 4.6.2
RISK REVIEW DOCUMENTATION TABLE

HCA #	Data	EC	IC	SCC	M	FF	E	TPD	V	Comments

FORM RA-3 – SAMPLE INTEGRITY MANAGEMENT

FRONTIER ENERGY

RiskPro
Pipeline Risk Assessment
Structural Integrity Associates, Inc.

Integrity Management Plan

HCA ID: **701**	HCA Name: **Westpark**	Starting Station: 0		Total Risk Score:	**20.5**
Scoring Date: **13-Sep-04**	Line Name: **T-7**	Ending Station: 17834.7		Risk Ranking:	**1**
	PIR: 250 ft.	Length: 17,835 ft.		% SMYS	44%

Threats	LOF Score	Wgt
Time Dependent		
External Corrosion	0.00	10%
Internal Corrosion	0.00	10%
Stress Corrosion Cracking	0.00	10%
Stable		
Manufacturing	0.00	10%
Field Fabrication	0.25	10%
Equipment	0.00	10%
Time Independent		
3rd Party Damage	0.43	10%
Vandalism	0.00	10%
Incorrect Operations	0.00	10%
Weather and Outside Forces	0.20	10%
Weighted LOF Score	0.09	100%

Consequence Drivers	
Residential	0
ID Locations	67
Class Location	3

LOF-to-Risk Rank Adjustments	
SMYS Scalar	1.17
Length Exponent	3.38
ECDA / CIS / DCVG Scalar	1.00
Consequence Multiplier	**67.0**

Main Threats	Assessment Method	WBS #	Start Date	Finsh Date
Internal Corrosion	ICDA		9/1/2004	12/31/2004
Field Fabrication	ECDA		9/1/2004	12/31/2004
Third Party Damage	Damage Prevention Plan		9/1/2004	12/31/2004
External Corrosion	ECDA		9/1/2004	12/31/2004

Reviewed by: Allen Casstevens Date:

Number	Description	Value
100	***** SECTION DATA *****	**********
103	Residential	0
105	ID Locations	67
106	Class Location	3
200	***** PIPE DATA *****	**********
201	Material Spec	API-5L
204	Outside Diameter	10.75
205	SMYS	60000
206	Wall Thickness	0.203
207	Seam Type	ERW
209	# of Wrinkle Bends	141
210	Above Ground Equipment Present	Yes
300	***** CONSTRUCTION DATA *****	**********
301	Year Installed	2000
303	Depth of Cover	42
304	Girth Weld Type	SMAW
305	Test Pressure	1500
313	Defective Pipe Girth Weld	No
319	Backfill Construction	Medium
400	***** SOIL & ENVIRONMENT *****	**********
406	Soil Wetness	Seasonally Wet/Dry
407	Soil Resistivity	>15,000
409	Land Use	Commercial
410	Pipeline Crossing	Few
413	Historical Construction Activity	Moderate
414	Right of Way Condition	Average
415	Susceptible to Weather	Low
416	Susceptible to Land Movement	No
500	***** CORROSION CONTROL *****	**********
501	Factory Coating Type	Fusion Bonded Epoxy
502	Coating Condition	Good
505	Stray Current History	No apparent issues
506	Cathodic Protection Criteria	-850 mV On
507	Months Below CP Criteria	0

Number	Description	Value
500	***** CORROSION CONTROL *****	**********
508	Years Without CP	0
510	Casing Contact	No
511	External Corrosion Detected	No
513	Liquid Drains Present	No
514	Drains Checked Frequently	Not Applicable
515	History of Liquids	No
516	Upstream Source of Liquids	No
517	Liquids Analyzed	No
518	Drying Operation Conducted	Yes
519	Internal Corrosion Detected	No
520	Internal MIC or Corrosives Detected	No
600	***** OPERATIONAL DATA *****	**********
601	MAOP	1000
602	5Yr Max Op Pressure	620
603	Average Pipe Temp	32 <= T < 100 F
604	Compr Discharge Temp	120
605	Distance From Compressor	35
606	Previous Leaks / mi.	0 - <0.1
607	Stripped Threads / Couplings	No
608	Failed O-Ring	No
609	Control / Relief Malfunction	No
610	Seal / Pump Packing Failure	No
611	History of Pipe Weld Failure	No
612	# Vandalism Reports	0
613	History of Incorrect Operations	No
700	***** DIRECT ASSESSMENT *****	**********
702	Immediate	0
703	Scheduled	0
704	Monitored	0
801	CIS Severe	0
802	CIS Moderate	0
803	CIS Minor	0
901	DCVG Severe	0
902	DCVG Moderate	0
903	DCVG Minor	0

FORM RC: ASSESSMENT ROOT CAUSE ANALYSIS REPORT (1 OF 2)

DATE:______________________________ PIPELINE NUMBER:______________________________
INTEGRITY ID:______________________________ PIPELINE NAME:______________________________
START MP: ______________________________ INTEGRITY ENGINEER:______________________________
END MP: ______________________________ CORROSION CONTROL FOREMAN.:______________________________

PIPE DATA:
DIA.:__________ **WALL THICKNESS:**____________ **MATERIAL:**___________ **SMYS:**__________ **MAOP:**__________ **CLASS LOCATION:**________

DATE INTEGRITY ASSESSMENT WAS COMPLETED:_______________ DATE OF DISCOVERY (IF APPLICABLE):_______________

Description of Damage: (For Example – Pitting, Wall Loss, Coating Damage, Dents, Gouges, etc.)

Extent of Damage: (For pipe steel and coating determine extent of damage in depth direction as well as axial and circumferential directions).

Review of Pipeline Maintenance History (Review GIS and Division records and evaluate the historical maintenance and repair history to determine if there are trends that can be identified that may assist in the quantification & understanding of the extent of damage. Consider all factors which may be integrated to contribute to the cause of the damage, e.g. third party encroachment and dent damage)

Review of Existing Damage Mitigation Measures:(Is the CP, Pipe Line Markers, Coating, etc. adequate? If External Corrosion, was it reviewed by a Corrosion Engineer? If Land Movement issues where involved does a Geologist need to be consulted activities) ________________

FORM RC: ASSESSMENT ROOT CAUSE ANALYSIS REPORT (2 OF 2, CONTINUED)

DATE:______________________________ PIPELINE NUMBER:______________________________________

INTEGRITY ID:__________________________ PIPELINE NAME:______________________________________

Root Cause of Damage: (For Example Coating Damage, Inadequate CP, Low Soil Resistivity, Shielding, Third Party Dig-Ins, or a combination of these or other causes?)____

Review of Damage Mitigation Measures Taken

____

Additional Testing and/or Analysis Needed For Long Term Risk Mitigation: (Did the Direct Examination results indicate that additional testing would be prudent to identify the extent of damage or better evaluate a damage condition for which the inspection method used is not the most appropriate? For example, if there damage to coating caused by Third Party Dig-Ins in an agricultural area, would DCVG testing be appropriate? Were hard spots identified and another inspection method would be more appropriate to evaluate the condition? Does the CP system need to be upgraded? Does a new ILI run need to be commissioned?)

____

CAN THE ASSESSMENT METHOD RELIABLY DETECT DAMAGE RESULTING FROM THE ROOT CAUSE? ☐ YES ☐ NO

IS REPRIORITIZATION OF INDICATIONS RECOMMENDED? ☐ YES ☐ NO

ARE REPEAT OR ALTERNATIVE ASSESSMENTS REQUIRED? ☐ YES ☐ NO

Integrity Engineer:________________________________Date of Review:__________

IMP Manager:____________________________________Date of Review:__________

FORM P&M-1: PREVENTATIVE & MITIGATIVE MEASURES PLAN

DATE:__________________ **IMP PROCESS MANAGER:**_______________________

Instructions for completion of this form is provided in Section 10.4 of the IMP

Segment Name or ID	LOF Score	Risk Score	Evaluation Date	Departments or Position in Evaluation Meeting	Evaluation Facilitator

Completed By:______________________________

FORM P&M-2: PREVENTATIVE & MITIGATIVE MEASURES EVALUATION

PIPE SEGMENTS:____ FACILITATOR:__________________

Instructions for completion of this form is provided in Section 8.5 of the IMP

RISKS AND THREATS

Risk Score:________ **LOF Score:______**

Active Threat	Score	Assessment Date	Detail About Threat/P&M Measures Taken

IMPLEMENTED P&M MEASURES

REQUIRED			EVALUATED□		
Imp Yes/No	**P&M**	**P&M Measure**	**Imp Yes/No**	**P&M**	**P&M Measure**
	9	Use of qualified personnel		**1**	Pipe replacement greater wall thickness
	10	Direct supervision of know excavating work		**2**	Additional inspection and maintenance
	11	Excavation damage stored in central database		**3**	Automatic Shut Off Valves
	12	Root cause analysis for additional P&M measures		**4**	Remote Control Valves
	13	Participation in One Call systems		**5**	Computerized Monitoring
	14	Conduct above ground assessments of areas w/unmonitored excavations		**6**	Leak Detection Systems
	15	Perform quarterly leak surveys		**7**	Providing additional training on response
				8	Conducting drills with local emergency responders
				16	Taking action to reduce damage from outside forces, (see Table 10.1)

Comments and details about each of the P&M measures implemented

P&M	Details and Comments Regarding Measure

POPULATION CHARACTERISTICS

of Bldgs. for Human Occupancy:
Outside area 20 or more people:
of Bldgs. With 20 or more people:
# of Confined or impaired mobility:

Details:____
____
____
____

LEAK DETECTION CHARACTERISTICS

Time for leak detection:
Time to shut down pipe:
Distance of nearest response personnel:
Potential for ignition:

Details:____
____
____
____

FORM P&M-3: PREVENTATIVE & MITIGATIVE MEASURES EVALUATION MEETING RESULTS

PIPE SEGMENTS:____ FACILITATOR:__________________

P&M PLAN

P&M #	Measure Description	Action Planned Yes/No	Response. Person	Start Date	Finish Date	Description of Action
1	Pipe replacement with greater wall thickness					
2	Implementing additional inspection and maintenance programs					
3	Automatic Shut-off Valves					
4	Remote Control Valves					
5	Computerized Monitoring					
6	Leak detection systems					
7	Providing additional training on response procedures					
8	Conducting drills with local emergency responders					
9	Use of qualified personnel for work that could adversely affect the integrity of a covered segment: marking, locating,					
10	Direct supervision of known excavating work					
11	Collecting location specific excavation damage in a central data base					
12	Root cause analysis for additional preventative and mitigative measures					
13	Participation in one-call systems					
14	Conduct above ground assessments of areas of unmonitored excavations in accordance with the ECDA procedure					
15	Perform quarterly leak surveys					
16	Take action to reduce the potential damage from outside force when it can effect the integrity of the segment. Actions include: Increasing frequency of patrols Adding external protection Reducing external loads Relocating the line					

Form QCP-1: Routine Process QC Audit - PIR Calculation

Assigned Date:______________ Operating Region:__________________________ QC Auditor:_____________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP
Number of New Lines or HCA's since last audit: _______ Number to be audited:_________
Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Recorded Results	Audited Results[3]	Classification Of Finding	Comments/Actions
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							

Could any errors result in systematic miscalculation of PIR's?: ________________ If so all suspected PIRs shall be recalculated

Audit Results and Conclusions

Was calculation appropriately documented, complete and filed correctly? ____

____

Did the person who conducted the calculation have the correct training, education, and experience?______________________

____

Were the results of the calculations correct? ____

____

Are there any recommendations to improve the PIR calculation process?

____

Reviewed by IMP Manager:____________________________ Date:________________

[3] Attach calculations to this form

FORM QCP-2: ROUTINE PROCESS QC AUDIT - GIS UPDATING

ASSIGNED DATE:______________ OPERATING REGION:__________________________ QC AUDITOR:_____________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP

Number of New Lines or HCA's since last audit: _______ Number to be audited:_________

Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Classification of Finding	Comments/Actions
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Audit Results and Conclusions

Was the HCA information documented, complete and filed correctly? ____

____

Was the GIS updated correctly? ____

____

Are there any recommendations to improve the GIS update process?______________________________________

____

____

____

Reviewed by IMP Manager:____________________________ Date:________________

FORM QCP-3: ROUTINE PROCESS QC AUDIT - DATA GATHERING AND DATA REVIEW

ASSIGNED DATE:_______________ OPERATING REGION:____________________________ QC AUDITOR:_______________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP
Number of New Lines or HCA's since last audit: _______ Number to be audited:_________
Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Classification of Finding	Comments/Actions
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Audit Results and Conclusions

Was all data correctly identified, entered into RiskPro and filed correctly? ____

____

Was the data and results of RiskPro reviewed and documented? ____

____

Are there any recommendations to improve the data gathering and update process? ________________________________

____

____

____

Reviewed by IMP Manager:_____________________________ Date:________________

FORM QCP-4: ROUTINE PROCESS QC AUDIT - RECORD KEEPING

ASSIGNED DATE:_______________ OPERATING REGION:____________________________ QC AUDITOR:_______________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP
Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Classification of Finding	Comments/Actions
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Audit Results and Conclusions

Was all the BAP correctly filed correctly? ____

____

Was all revisions of the BAP correctly identified and filed? ____

____

Are there any recommendations to improve the Record Keeping process? ____

____

____

____

Reviewed by IMP Manager:______________________________ Date:_________________

FORM QCP-5: ROUTINE PROCESS QC AUDIT – ASSESSMENT SCHEDULE, ROOT CAUSE, AND REASSESSMENT INTERVAL

ASSIGNED DATE:______________ OPERATING REGION:__________________________ QC AUDITOR:_____________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP
Number of New Lines or HCA's since last audit: _______ Number to be audited:_________
Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Recorded Results	Audited Results[4]	Classification of Finding	Comments/Actions
1							
2							
3							
4							

Audit Results and Conclusions

Were the assessments conducted on schedule? ____
____

Was Root Cause Analysis Completed on all areas that was found to have damaged pipe? ______________________
____

Was the Reassessment Intervals in accordance with the IMP Assessment Procedure?_____________________________
____
____
____

Are there any recommendations to improve the Assessment process? ______________________________
____
____

Reviewed by IMP Manager:____________________________ Date:________________

[4] Attach calculations to this form

FORM QCP-6: ROUTINE PROCESS QC AUDIT – SCHEDULING AND EVALUATION OF P&M MEASURES

ASSIGNED DATE:______________ OPERATING REGION:__________________________ QC AUDITOR:_____________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP

Number of Assessments since last audit: _____________ Number to be audited:_________

Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	Record Name	HCA Name	Responsible Person	Classification of Finding	Comments/Actions
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					

Audit Results and Conclusions

Was the P&M Evaluation Schedule followed ____

____

Was data collected for the P&M and was the P&M evaluation meeting held? ____

____

Was the P&M meeting results documented and appropriately submitted for distribution?____

____

____

Are there any recommendations to improve the P&M process?____

____

____

____

Reviewed by IMP Manager:_____________________________ Date:________________

FORM QCP-7: ROUTINE PROCESS QC AUDIT – SYSTEM WIDE P&M MEASURE IMPLEMENTATION

ASSIGNED DATE:______________ OPERATING REGION:__________________________ QC AUDITOR:_____________________________

Instructions for completion of this form are provided in Section 1.7 of the IMP
Number of P&M Measure to be implemented System Wide: _________ Number to be audited:__________
Finding Classifications (1.7.4.2): **Immediate:** Error **Scheduled:** Potential Error **Monitor:** Process Improvement

Description of Audited Records and Results

Line Item	P&M Measure	Schedule of Implementation	Responsible Person	Classification of Finding	Comments/Actions
1					
2					
3					
4					
5					
6					

Audit Results and Conclusions

Does the P&M Measures that were identified to be implemented system wide have an implementation plan? ____
____

Is the implementation plan and schedule being followed? ____
____

Are there any recommendations to improve the P&M process?____
____
____
____

Reviewed by IMP Manager:_____________________________ Date:________________

FORM PPR-1: PERFORMANCE METRICS REPORT

DATE:__________________ **IMP MANAGER:**________________________________

Instructions for completion of this form is provided in Section 1.6 of the IMP

Metric Catego...	Metric #	Metric Description	Report Data		
			Last Report	Current	Since Inceptions
Semi Annual Reporting to OPS	SAR-01	Number of pipeline miles inspected vs. program requirements	**Planned**	**Actual**	
	SAR-02	Number of immediate repairs completed as a result of IMP assessments			
	SAR-03	Number of scheduled repairs completed as a result of IMP assessments			
	SAR-04	Number of leaks, failures, and incidents (classified by cause)			
ASME B31.8S Appendix A	A-01	Number of hydrostatic test failures by threat			
	A-02	Number of repair actions taken due to ILI assessments (immediate and scheduled)			
	A-03	Number of repair actions taken due to direct assessments (immediate and scheduled)			
	A-04	Number of leaks classified by threat			
	A-05	Number of girth welds/couplings reinforced or removed			
	A-06	Number of wrinkle bends inspected			
	A-07	Number of wrinkle bends removed			
	A-08	Number of fabrication welds repaired/removed			
	A-09	Number of regulator failures			
	A-10	Number of relief valve failures			
	A-11	Number of gasket and O-ring failures			
	A-12	Number of leaks caused by previously damaged pipe			
	A-13	Number of leaks or failures caused by vandalism			
	A-14	Number of findings per audit/review classified by severity			
	A-15	Number of changes to procedures due to audits/review			
IMP Monitoring	IMP-01	Number of HCA's			
	IMP-02	Risk Score (High)			
	IMP-03	Risk Score (Average)			
	IMP-04	Risk Score (Low)			
	IMP-05	LOF (High)			
	IMP-06	LOF (Average)			
	IMP-07	LOF (Low)			
My...	QC-01	Number of Routine Audits conducted			

Metric Catego…	Metric #	Metric Description	Report Data		
			Last Report	Current	Since Inceptions
	QC-02	Number or Immediate Findings from Routine Audits			
	QC-03	Number of Schedule Findings from Routine Audits			
	QC-04	Number of High Level Audits conducted			
	QC-05	Number or Immediate Findings from High Level Audits			
	QC-06	Number of Schedule Findings from High Level Audits			
ECDA Effectiveness	DA-01	Number of feet of CIS			
	DA-02	Number of feet of DCVG			
	DA-03	Number of feet of PCM			
	DA-04	Number of Immediate Excavations			
	DA-05	Number of Scheduled Excavations			
	DA-06	Number of Monitored Excavations			
	DA-07	Remaining Life Of Immediates			
	DA-08	Remaining Life of Scheduled			
	DA-09	Number of Reprioritizations			
	DA-10	Number of Immediate Repairs			

FORM PPR-2: CONTINUOUS IMPROVEMENT EVALUATION OF PERFORMANCE METRICS

DATE:__________________ **IMP MANAGER:**______________________________

Instructions for completion of this form is provided in Section 1.6 of the IMP

Metric Category	Significant Events	Integrity Trends	Opportunity for Improvements
Semi Annual Reporting to OPS			
ASME B31.8S, Appendix A			
IMP Monitoring			
Quality Control			
ECDA Effectiveness			

PREPARED BY:_______________________________ **DATE:**________________

APPROVED BY:_______________________________ **DATE:**________________

FORM MOC-1: MOC INVENTORY

REVISION DATE:________________ PERSON UP DATING INVENTORY:___________________________ FORM REVISION DATE:_____________

Instructions for completion of this form are provided in Section 12.4.4 of the IMP

MOC Inventory

Category	Reference Number	Change	Trigger Event	Responsible Organization	Responsible Position	Process
HCA	**101**	Number of Residences and Identified sites				
Pipe Related Change	**102**	Material, Grade, Seam Type				
	103	Diameter				
	104	Addition or removal of equipment				
Construction Related Changes	**201**	Replacement of pipe				
	202	Addition or removal of casings				
	203	Depth of cover				
	204	Pressure Test				
	205	Addition or removal from waterways				
Soil and Environmental Changes	**300**	Inclination of pipe				
	301	Soil Subsidence				
	302	Addition, removal or movement nearby pipelines				
	303	Addition or removal of paving				
	304	Construction activity				

Category	Reference Number	Change	Trigger Event	Responsible Organization	Responsible Position	Process
Corrosion Control Changes	**401**	Encroachment or change in ROW conditions				
	402	Coating condition including refurbishment, direct examination, and type				
	403	CP criteria				
	404	Level of polarization				
	405	Conductance of non IMP assessments				
	406	Casing contact				
Operational Changes	**501**	Presence of liquids				
	502	MAOP (up or down)				
	503	Pressure cycling				
	504	3rd Party Damage or Leak Reports				
	505	Pipe Inspection Reports				
	506	Gas Quality				
IMP Assessment Activities	**601**	ECDA Assessments				
	602	Hydro tests				
	603	ILI Assessments				
	604	Other Assessments				
	605	Remediation Activities				

Category	Reference Number	Change	Trigger Event	Responsible Organization	Responsible Position	Process
Integrity Management Process	**700**	HCA Identification				
	701	Risk Analysis Process				
	702	Baseline Assessment Plan				
	703	Assessment Methods				
	704	Assessment Procedures				
	705	Communication Plan				
	706	Management of Change Plan				
	707	QA Plan				
	708	Performance Management Plan				
Maintenance Processes	**801**	Frequency of patrols				
	802	Valve Maintenance				
	803	Others				
Organizational	**901**	Reorganization				
	902	Personnel changes				

Reviewed by IMP Manager:_____________________________ Date:________________

FORM MOC-2: MOC IMPLEMENTATION SCHEDULE

REVISION DATE:________________ PERSON UP DATING INVENTORY:__________________ FORM REVISION DATE:____________________

Instructions for completion of this form are provided in Section 12.6.2 of the IMP

MOC Inventory

Category	Reference Number	Process	Responsible Organization	Responsible Person	Initial Meeting		Training		Completion		Comments
					Plan	Actual	Plan	Actual	Plan	Actual	
HCA	101										
Pipe Related Change	102										
	103										
	104										
Construction Related Changes	201										
	202										
	203										
	204										
	205										
Soil and Environmental Changes	300										
	301										
	302										
	303										
	304										
Corrosion Control Changes	401										
	402										
	403										
	404										
	405										
	406										
era tion al Ch an	501										

Category	Reference Number	Process	Responsible Organization	Responsible Person	Initial Meeting		Training		Completion		Comments
					Plan	Actual	Plan	Actual	Plan	Actual	
	502										
	503										
	504										
	505										
	506										
IMP Assessment Activities	601										
	602										
	603										
	604										
	605										
Integrity Management Process	700										
	701										
	702										
	703										
	704										
	705										
	706										
	707										
	708										
Maintenance Processes	801										
	802										
	803										
Organizational	901										

Category	Reference Number	Process	Responsible Organization	Responsible Person	Initial Meeting		Training		Completion		Comments
					Plan	Actual	Plan	Actual	Plan	Actual	
	902										

Reviewed by IMP Manager:_____________________________ Date:________________

Form MOC-3: Initial Meeting Worksheet

Meeting Date:____________ Meeting Facilitator:_____________________________________

MOC Ref.:_______________ Change Type:________________________ Process Owner:_________________________________

Instructions for completion of this form are provided in Section 12.8.1 of the IMP. Complete this worksheet for each MOC Ref. and/or Change Type.

Process Evaluation Phase

This section of the Initial Meeting is to provide an overview discussion and documentation of the change and some of the MOC steps that need to be implemented. It is not intended to be an extensive problem solving session.

Consideration: How can changes that the process implements affect the integrity of the pipeline? (Refer to Figure 12.2 and Table 12.2)____

Timing: Are there any timing issues of when the change occurs: _______________________________

Approval: What position/person is responsible for approving the change? ______________________

Communication: What type of communication should occur for the change? ____________________

Training: What training should occur when the change is implemented? _______________________

Documentation: What documentation should occur with the change? __________________________

Reengineering Evaluation Phase

Process Changes: Considering the answers above what steps in the process needs to be changed to integrate MOC objectives and requirements?____

Approach: What would is the best approach to implement those changes? (Fiat, assigned to individual or team, larger group to include training)_____________________________________

Reengineering Planning Phase

Next Step: What is the next step for the implementation? __________________________________

Preparation for Next Step: What action items are needed to occur before the next step? _____________

Schedule: When will the next step occur?____

Implementation Phase

Schedule: When will the process changes be complete and the MOC objectives and steps implemented in the process?___

Process Owner:________________________________ Section Manager:______________________________

FORM EX: EXCEPTION REPORT

INSTRUCTIONS: Completing this form is described in Section 7.0

DATE OF REPORT:______________________________ ECDA REGION NUMBER:___________________________________
LINE NUMBER:_________________________________ EPC:____

Paragraph Number of Exception: ___________

Requirements of paragraph (Briefly state or Paraphrase): ____

Alternative Plan: ____

Reason for Exception: ____

Recommendation: Should the procedure be changed? ☐ **YES** ☐ **NO**
COMMENTS: ____

EPC:______________________________**Date:**__________

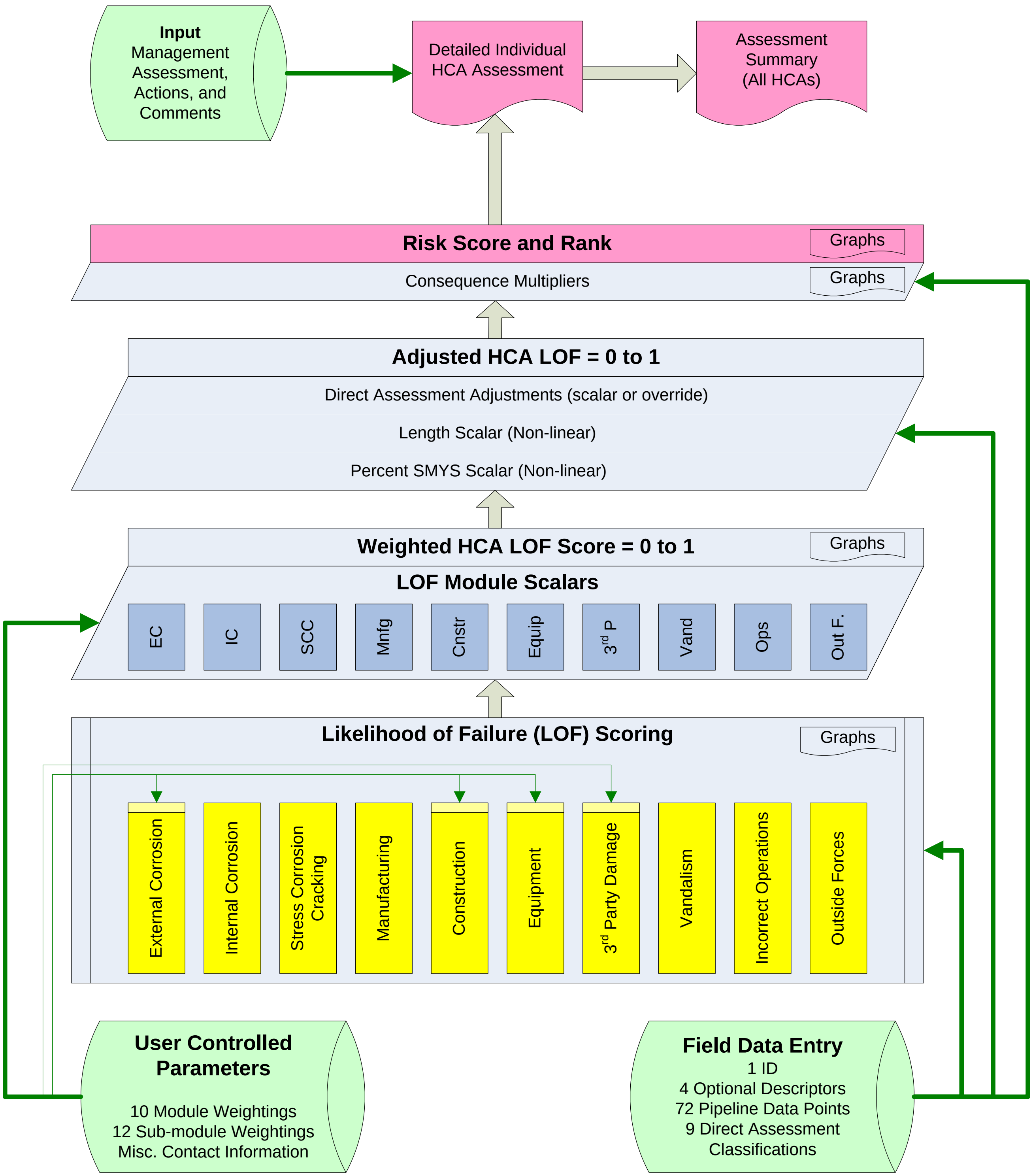
EPE:______________________________**Date:**__________

IMPM:_____________________________**Date:**__________

RISKPRO DOCUMENTATION

RiskPro Structure

Version 2(2a)

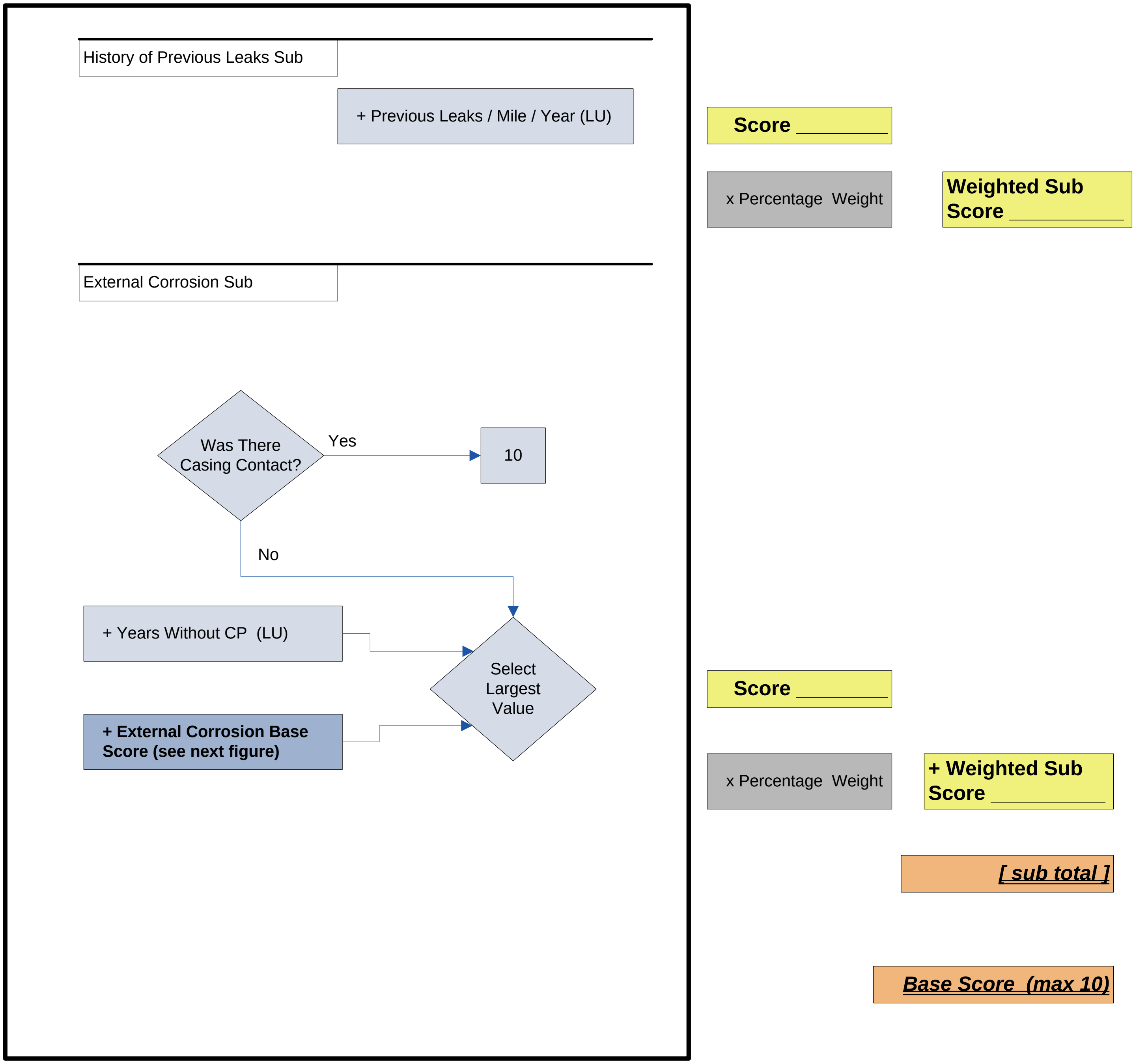


OFFICIAL COPY

Aug 25 2017

External Corrosion Module

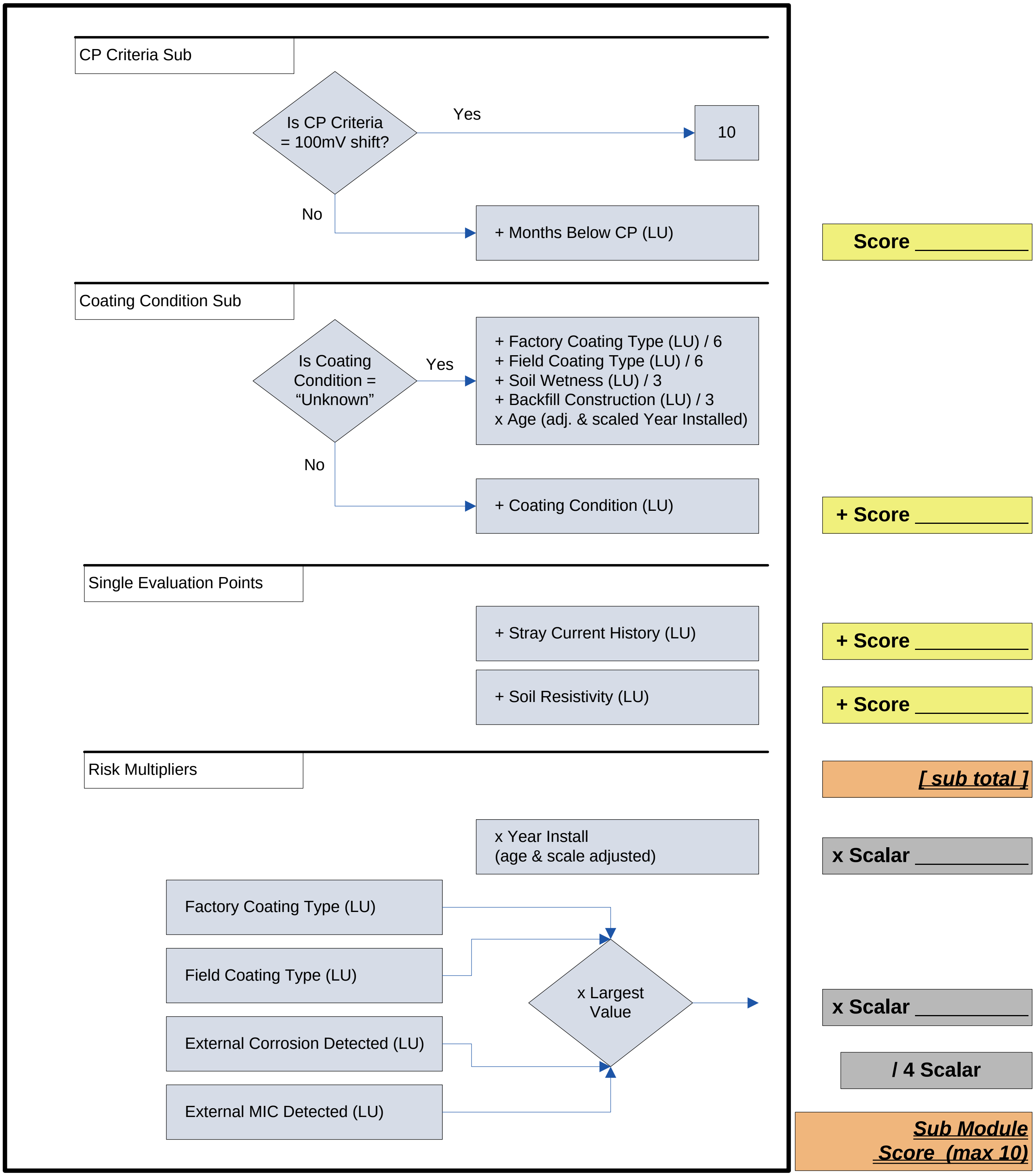
RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

External Corrosion Sub-Module - RiskPro v2(2a)

External Corrosion Base

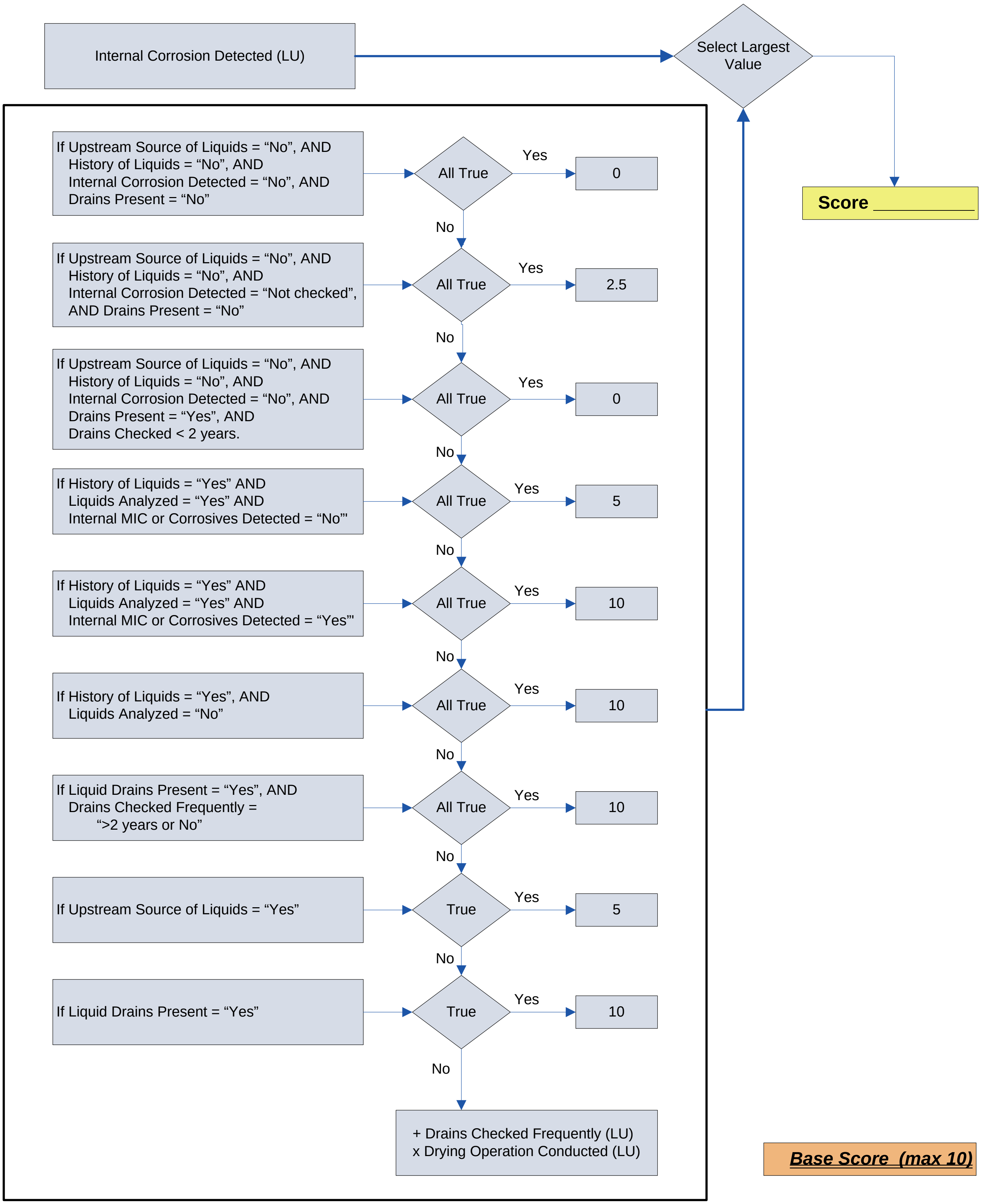


Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Structural Integrity Associates

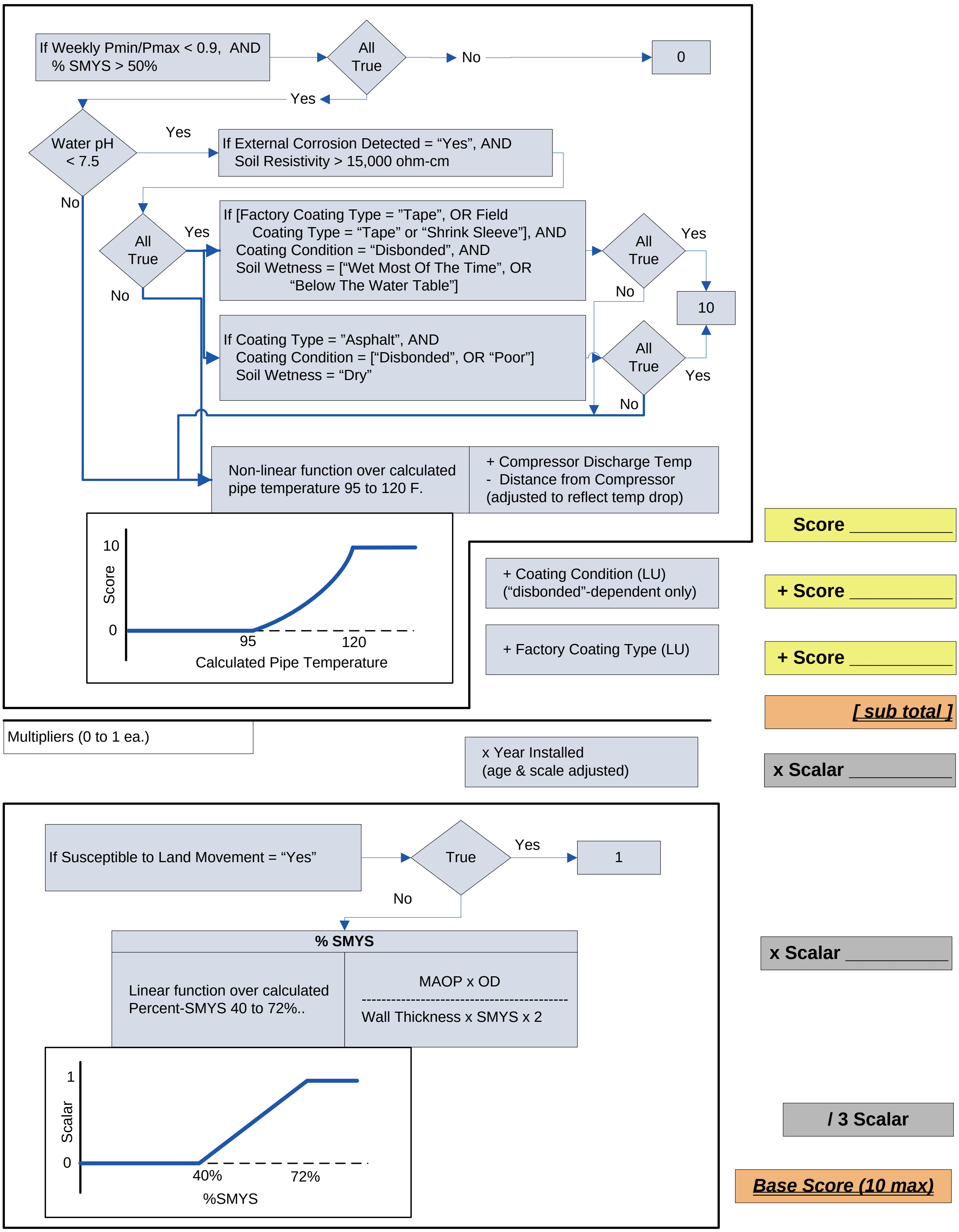
Internal Corrosion Module

RiskPro v2(2a)



Stress Corrosion Cracking Module

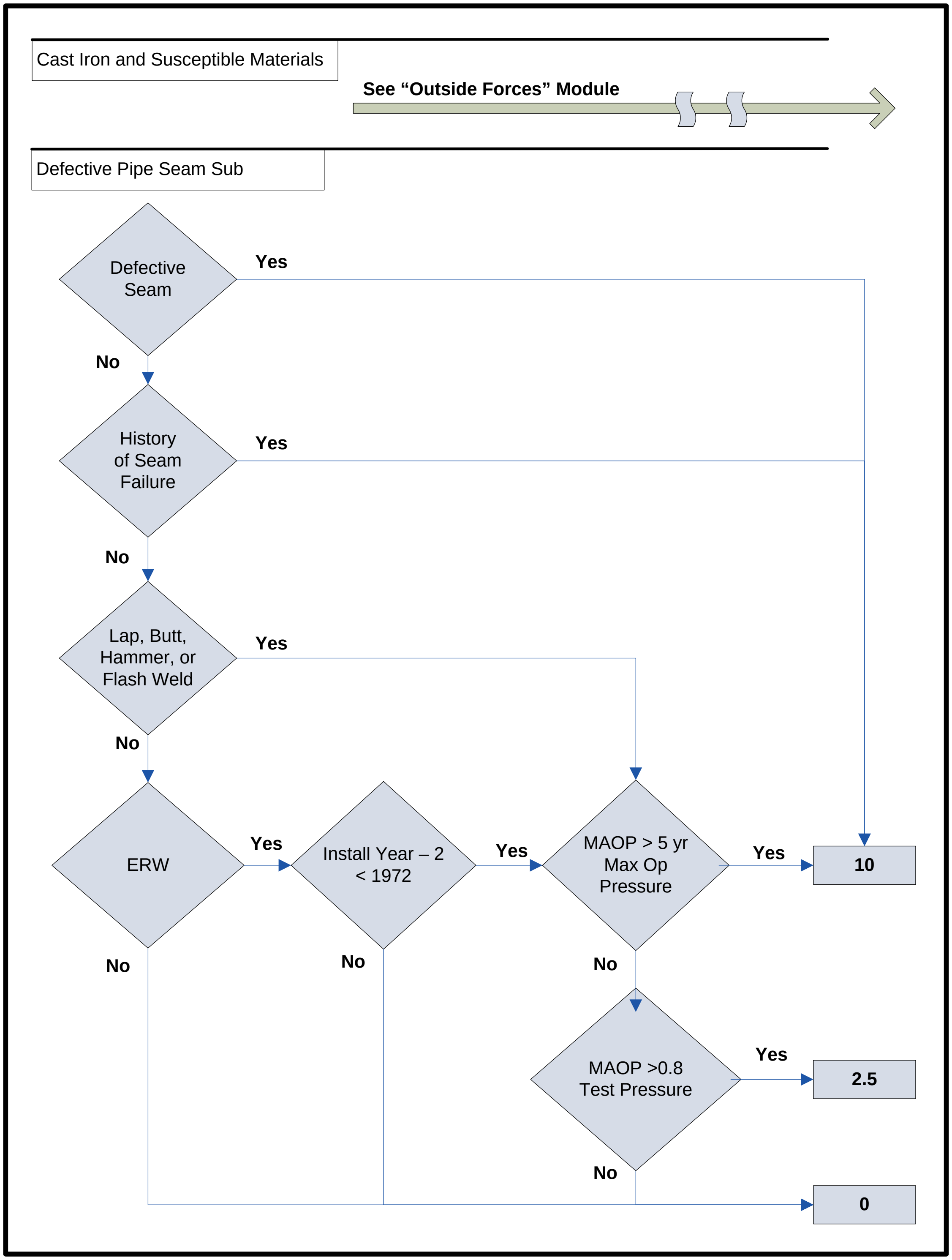
RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Manufacturing Module

RiskPro v2(2a)



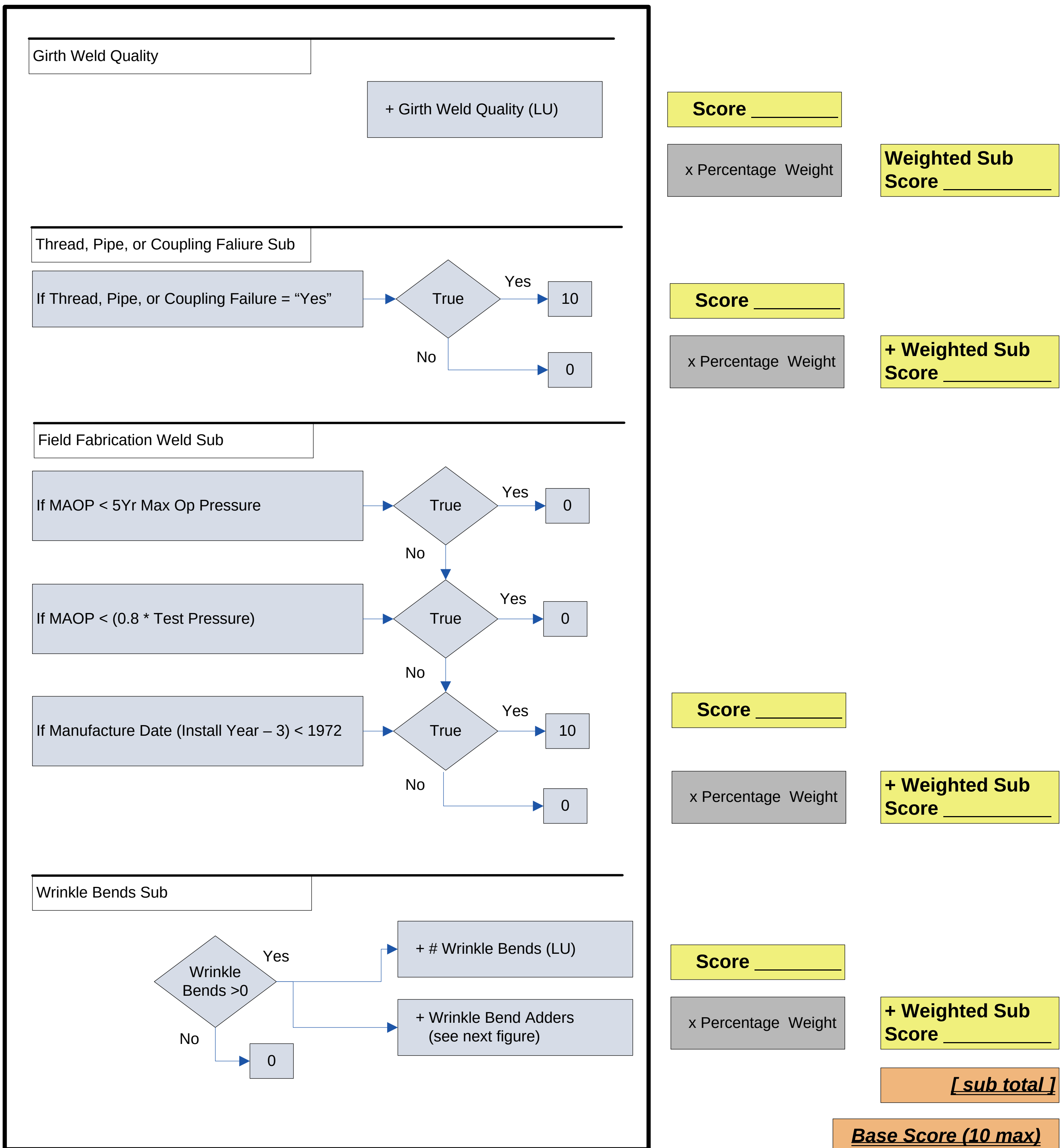
Score ________

Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Base Score (10 max)

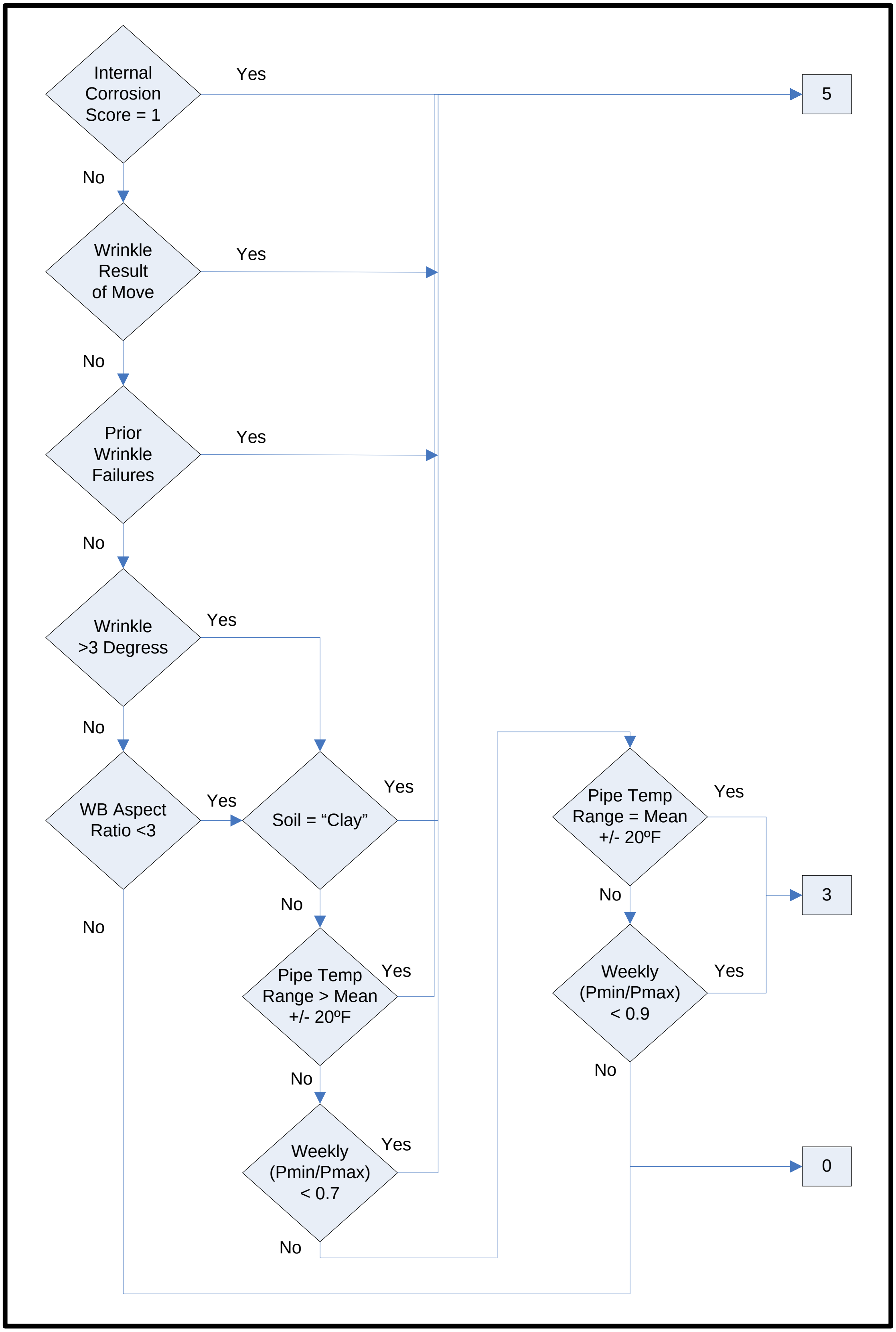
Construction Module

RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

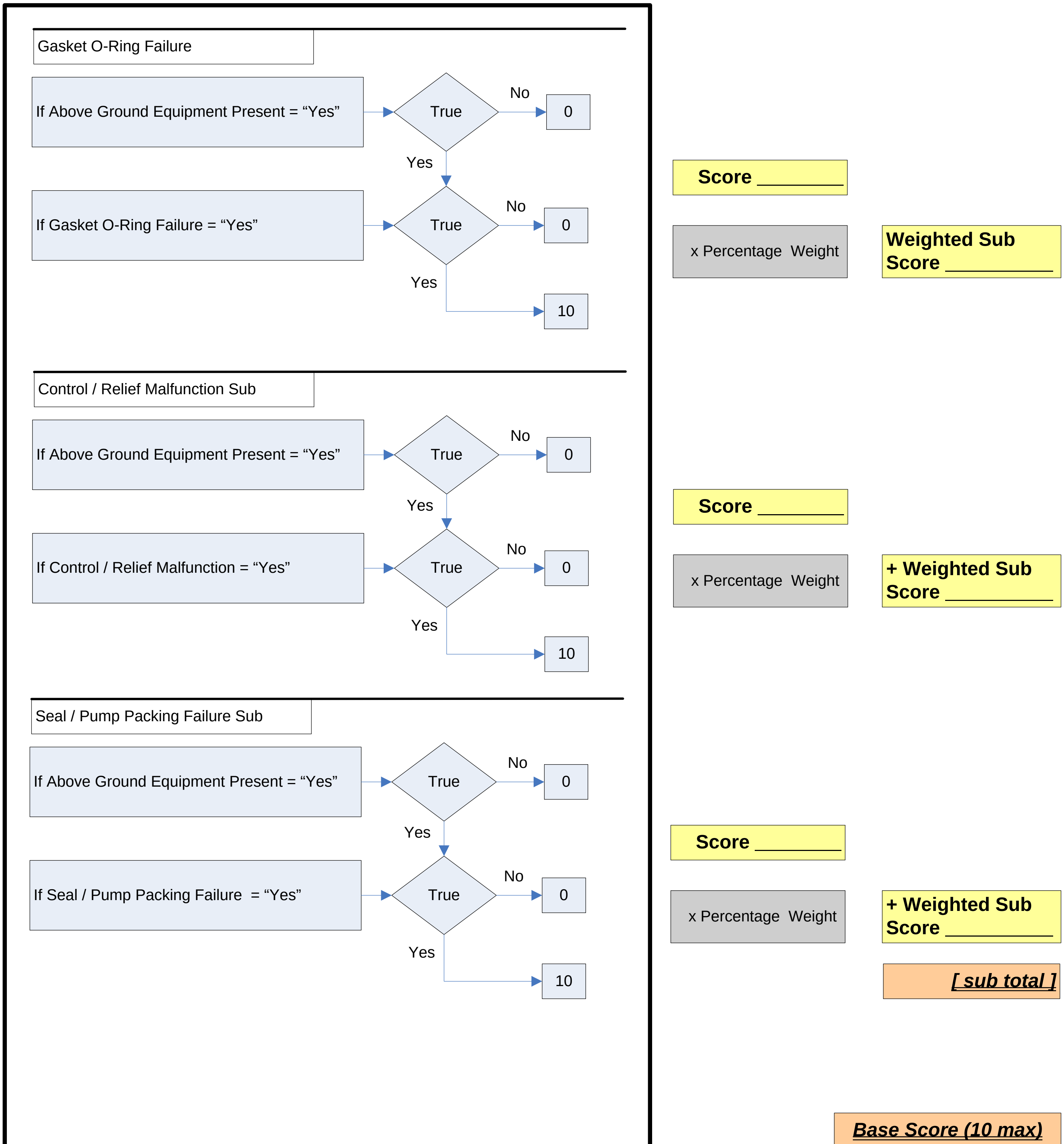
Wrinkle Bend Adders



Score ________

Equipment Module

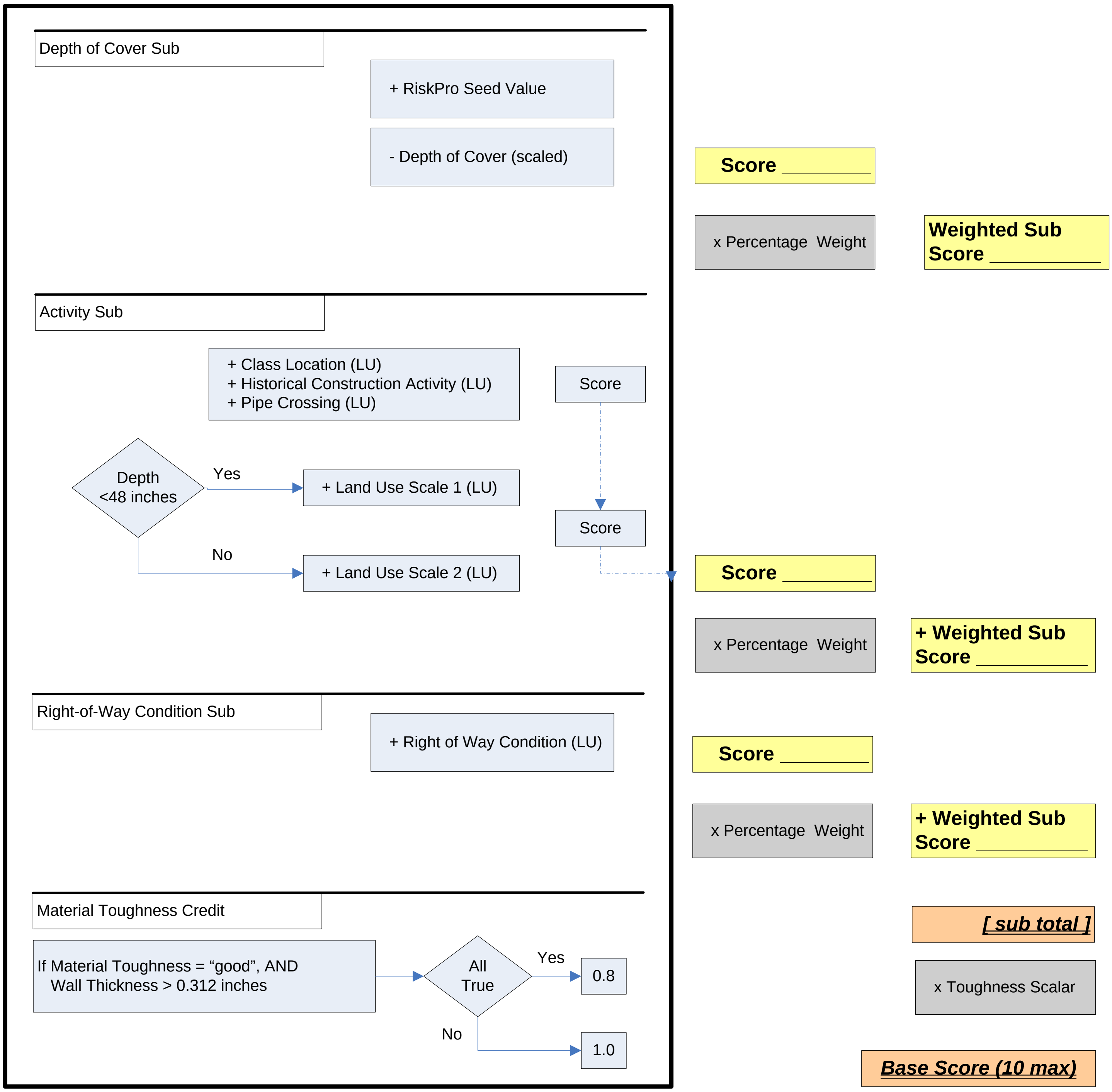
RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

3rd Party / Mechanical Damange Module

RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Vandalism Module

RiskPro v2(2a)

Vandalism

+ Vandalism (LU)

Score ________

Base Score (10 max)

Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Incorrect Operations Module

RiskPro v2(2a)

Operations

+ History of Incorrect Operations (LU)

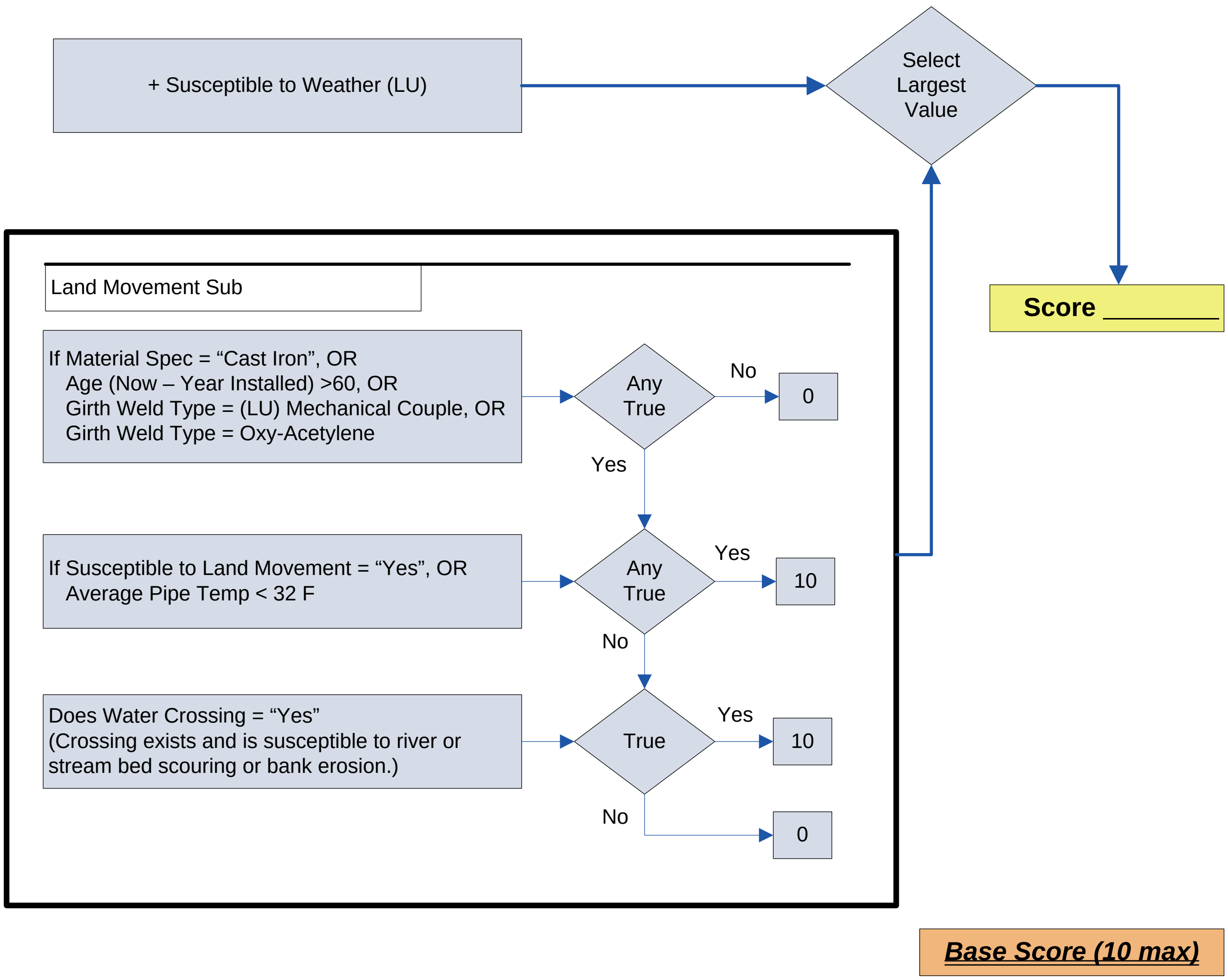
Score ________

Base Score (10 max)

Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Outside Forces Module

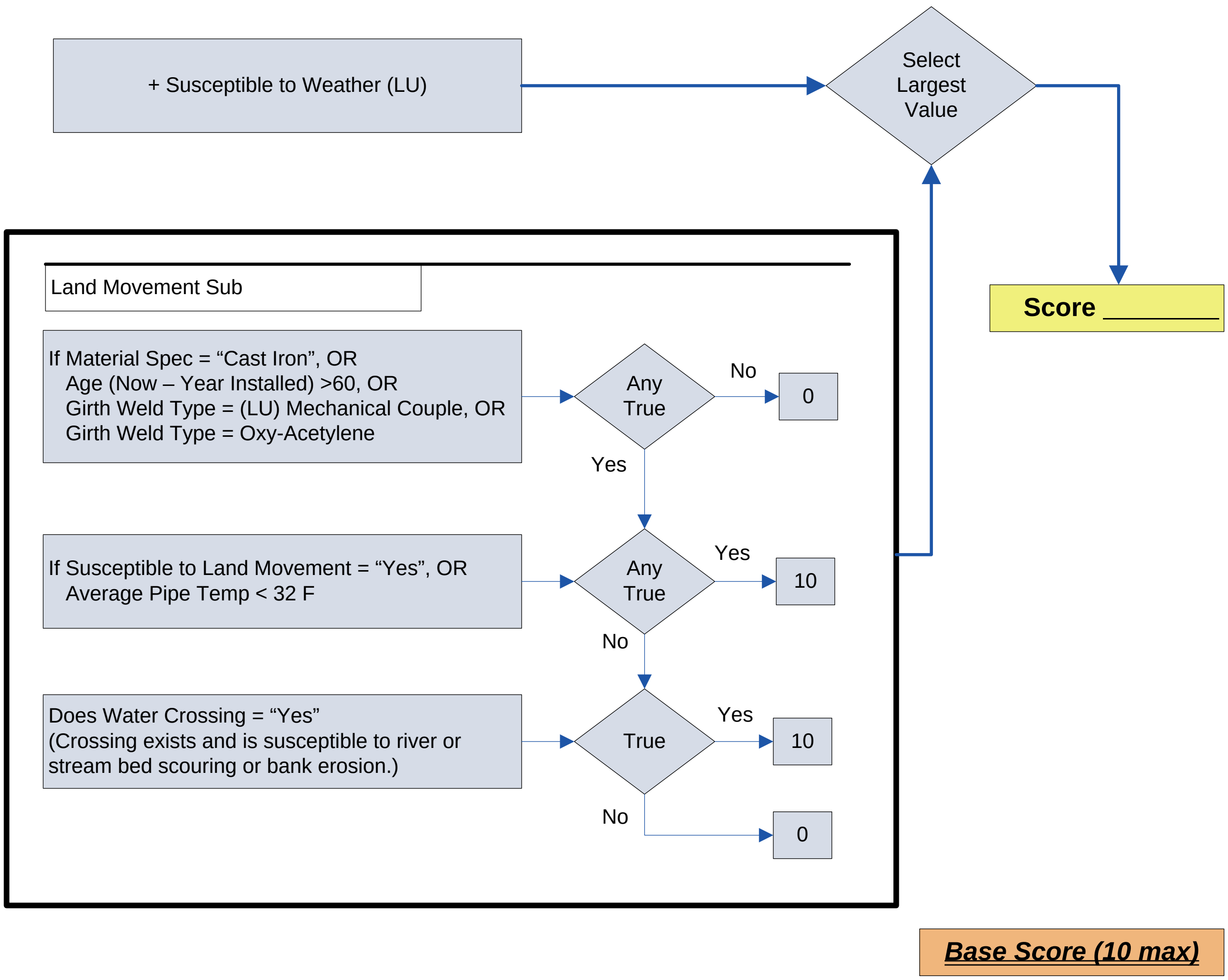
RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Outside Forces Module

RiskPro v2(2a)



Notes:
(LU) indicates the value used is the result of a look-up function.
+, -, /, and x indicate the general or most predominant use of a value.

Consequences Module

RiskPro v2(2a)

Note: Consequence values are open-ended.

Consequences

Consequences
(Residential / 20) + ID Locations

Multiplier ________

09 Report

F-up 7/10/2010

State of North Carolina
Utilities Commission

4325 Mail Service Center
Raleigh, NC 27699-4325

November 9, 2009

Mr. Raymond Fischer
Vice President and General Manager
Frontier Natural Gas.
1927 North Bridge Street
Elkin, North Carolina 28621

Dear Mr. Fischer:

Enclosed is a copy of the Integrity Management inspection report for the natural gas transmission facilities operated by Frontier Natural Gas Company in North Carolina. The inspection was conducted by Mr. Stephen F. Hurbanek, and Mr. John Hall, October 26 thru 29, 2009 and was in reference to 49 CFR, Part 192. The inspection included a review of required record keeping and inspections performed in the field to determine compliance with the Code.

A review of the report indicates that Frontier Natural Gas has developed and implemented an Integrity Management Program, however; there were a considerable amount of potential issues that were addressed during the inspection. At a meeting with Mr. Hurbanek and Mr. Hall on October 28' it was agreed that Frontier would correct all the deficiencies in their Integrity Management Program and record keeping within 8 months of this inspection. At that time Mr. Hurbanek and Mr. Hall will conduct a follow-up inspection.

We appreciate the cooperation during this inspection, and if you have any questions concerning the inspection or the report, please contact our office at 919-733-6000.

Sincerely,

Chris Isley

Chris Isley, Director
Pipeline Safety
CI:SH

430 North Salisbury Street • Raleigh, North Carolina 27603
Telephone No: (919) 733-4249
Facsimile No: (919) 733-7300
www.ncuc.net

2010 Report
File Copy
f-up 7/20/11

State of North Carolina
Utilities Commission

4325 Mail Service Center
Raleigh, NC 27699-4325

December 1, 2010

Mr. Raymond Fischer
Vice President and General Manager
Frontier Natural Gas.
1927 North Bridge Street
Elkin, North Carolina 28621

Dear Mr. Fischer:

Enclosed is a copy of the Integrity Management inspection report for the natural gas transmission facilities operated by Frontier Natural Gas Company in North Carolina. The inspection was conducted by Mr. Stephen F. Hurbanek, and Mr. John Hall, November 15 thru 17, 2010 and was in reference to 49 CFR, Part 192. The inspection included a review of required record keeping and inspections performed in the field to determine compliance with the Code.

A review of the report indicates that Frontier Natural Gas has corrected most potential issues identified in the 2009 inspection. However this inspection revealed that Frontier has potential issues in the following areas:

The following Protocols have potential issues outstanding:

D.06 a-c ICDA Programmatic Requirements
D.07 a-e Dry Gas ICDA, Preassessment, Region Identification and use of model
D.08 Dry Gas ICDA Direct Exam a-e
D.09 Dry Gas ICDA Post Assessment a-d
D.10 Wet Gas ICDA Programmatic Requirements a-b
F.01 Periodic Evaluations b-d
H.07 Automatic Shut Off Valves or Remote Controlled Valves a
K.02 Attributes of Change Process a
L. Quality Assurance b-c

At a meeting with Mr. Hurbanek and Mr. Hall November 17, 2010 it was agreed that Frontier would correct all the deficiencies in their Integrity Management Program and record keeping within 8 months of this inspection. At that time Mr. Hurbanek and Mr. Hall will conduct a follow-up inspection.

We appreciate the cooperation during this inspection, and if you have any questions concerning the inspection or the report, please contact our office at 919-733-6000.

Sincerely,

Chris Isley

Chris Isley, Director
Pipeline Safety Section

CI:sh
Enclosure

State of North Carolina
Utilities Commission

4325 Mail Service Center
Raleigh, NC 27699-4300

February 23, 2017

Mr. Fred Steele
President and General Manager
Frontier Natural Gas Company, LLC
110 PGW Drive
Elkin, North Carolina 28621

Dear Mr. Steele:

Please take notice that this is a letter of Violation from the North Carolina Utilities Commission (NCUC) Pipeline Safety Section.

On February 8 and 9, 2017 Mr. Harry Bryant and Mr. John Hall of the NCUC Pipeline Safety Section met with you and Mr. Josh Waggoner and Ms. Regina Davis to review Frontier Natural Gas Company, LLC's (Frontier's) Integrity Management Program (IMP) to ascertain compliance with the Minimum Federal Safety Standards, specifically 49 CFR, Part 192, Subpart O.

As a result of our meeting we learned that many activities of the IMP either have not been occurring, have not been consistently occurring, or have not been documented adequately. Further, some of the IM program record keeping may be missing, and assessment of transmission gas pipelines located in High Consequence Area's (HCA's) are past due.

The information obtained indicates a serious failure on the part of Frontier to carry out a Gas Transmission Integrity Management Program, and represents significant violation(s) of the Pipeline Safety Regulations, notably Part 192.13(c) which states: "Each operator shall maintain, modify as appropriate, and follow the plans, procedures, and programs that it is required to establish under this part". Other violations may apply.

The NCUC Pipeline Safety Section recognizes there has been an unforeseen departure by key personnel having IMP and other safety compliance program responsibilities. However, it remains the responsibility of Frontier to comply with State and Federal Safety Regulations.

As a starting point in responding to this Letter of Violation, Frontier should verify applicable threats and the risk analysis, and within (30) days of the date of this Letter of Violation provide the NCUC Pipeline Safety Section with Frontier's plan and schedule for assessing pipe in HCA's.

In addition, Frontier should take the following steps as soon as reasonably possible, but no later than (60) days from the date of this Letter of Violation:

- Appropriate personnel must become acquainted with the IMP rule and Frontier's IMP plan and processes; personnel qualifications per 192.915.
- Review the transmission system per requirements of the Frontier IMP written plan to update and verify High Consequence Areas.
- Verify applicable threats and the risk analysis, and develop a schedule for assessing pipe in HCA's. Overdue segments require an accelerated full assessment.
- Implement the Geographic Information System (GIS) and any software necessary to support IMP processes including program documentation.
- Provide the appropriate resources to support the requirements of Frontier IMP including any staff, tools and training.
- Develop a Continuity Plan to ensure that safety plans and program processes such as the Frontier IMP will be carried out when key personnel transition away from program roles.

Within thirty (30) days of the date of this Letter of Violation, provide the NCUC Pipeline Safety Section with a comprehensive and detailed plan for completing the actions listed above including a timeframe for each item listed. A further determination of appropriate action will be made by NCUC Pipeline Safety Section following Frontier's response to the requirements set forth in this Letter of Violation.

If you have any questions concerning this Letter of Violation or the inspection of Frontier's IMP please contact our office at 919.733.6000.

Sincerely,

Steph Wood

Stephen Wood, Director
Pipeline Safety Section

Certificate of Service

The undersigned counsel for the North Carolina Utilities Commission Staff hereby certifies that the forgoing Commission Staff's testimony and exhibits were served on the attorney for Frontier Natural Gas Company by electronic service, as follows:

Frontier Natural Gas Company
Attention: M. Gray Styers, Jr., Attorney at Law
Smith Moore Leatherwood LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601
Gray.styers@smithmoorelaw.com

This the 25 day of August, 2017.

/s/Leonard G. Green
Leonard G. Green
Senior Staff Attorney
North Carolina Utilities Commission
430 North Salisbury Street
4325 Mail Service Center
Raleigh, North Carolina 27699-4300
(919) 733-0834
lgreen@ncuc.net