DAKOTA
GASIFICATION
COMPANY
A BASIN ELECTRIC POWER
COOPERATIVE SUBSIDIARY

October 5, 2018

Mr. Allan Beshore
901 Locust Street, Suite 462
Kansas City, MO 64106

RE: CPF **3-2018-5003M**, Notice of Amendment

Dear Mr. Beshore,

The Pipeline and Hazardous Materials Safety Administration (**PHMSA**) inspected Dakota Gasification Company's (**DGC**) carbon dioxide pipeline procedures for operations, maintenance, public awareness, operator qualification, integrity management, corrosion and control room at the Great Plains Synfuels Plant near Beulah, ND on various dates from January to May of 2017. DGC received a Notice of Amendment dated May 29, 2018. On June 22, 2018, PHMSA granted an extension in order for DGC to more thoroughly review its programs and procedures. DGC is not contesting the allegations contained in the Notice of Amendment and provides the following amended procedures.

Amendment 1
PHMSA alleges DGC's procedural manual did not include procedures for operating, maintaining and repairing the pipeline system in accordance with each of the requirements of subpart F and subpart H of Part 195. 49 CFR §195.575(e). DGC has updated Procedure 044, attached hereto as Exhibit 1 to address the mitigation of fault currents and to provide guidelines for mitigation of corrosion on the pipeline.

Amendment 2
PHMSA alleges that at the time of the inspection, DGC's Procedure 74-004 Cathodic Protection Survey was missing procedures for identification and mitigation of interference events. Subsequent to the inspection, DGC staff produced Procedure 74-004 and it was tentatively approved by PHMSA staff on March 29, 2018, pending approval by management in the PHMSA Complaints Resolution Office. Procedure 74-004 is attached hereto as Exhibit 2.

Amendment 5
PHMSA alleges that DGC's integrity management program (**IMP**) did not describe the elements in enough detail to provide criteria for remedial action to address integrity issues raised by the

assessment methods and information analysis. DGC's Procedure 028 did not contain sufficient detail to address the requirements of code section 49 CFR §195.452(f)(4). DGC submits revised Procedure 028, attached hereto as Exhibit 3.

Amendment 6
PHMSA alleges that DGC's IMP failed to include methods to measure the program's effectiveness and were therefore inadequate to measure program effectiveness. Specifically, DGC's IMP procedures did not clearly define the use of performance metrics in evaluating program performance. Attached as Exhibit 4 is the IMP Program Evaluation and attached as Exhibit 5 is an analysis of the IMP's performance metrics.

Amendment 7
PHMSA alleges that DGC's IMP failed to include a procedure to analyze all available information about the integrity of the entire pipeline and the consequences of a failure. Specifically, DGC did not have a procedure for assessing the risk factors of its aboveground facilities in HCAs, namely, the Tioga Pump Station. DGC has added Procedure 22 for assessing the risk factors at the Tioga Pump Station, attached as Exhibit 6 and developed a risk assessment for the Tioga Station, attached hereto as Exhibit 7.

Amendment 8
PHMSA alleges that DGC's procedures did not include a process for identifying which pipeline segments could affect a HCA. DGC must amend its IMP plan to define, justify and document unusually sensitive areas (**USA**) and other types of HCAs. Staff has revised Procedure 29, Identification of HCAs along the CO_2 Pipeline, attached hereto as Exhibit 8.

Please contact Dale Johnson with any questions at 701-873-2100 or dalej@bepc.com.

Best Regards,

David J. Sauer
Senior Vice President & Chief Operating Officer

Cc: Dale Johnson
Jeff Graney
Trinity Turnbow
Claude O'Berry
Christopher Breiner
Charles Roy
Mark D. Foss
Anine Merkens

am/sw

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	Procedure No.:	Revision No.:
12/11/06	044	4

Affected Area(s):	Originating Department:	
5900, 7400, and 7500 CO2 Pipelines	Reliability Engineering	
	Final Approval:	**Date:**
	/s/ Dale Johnson	7/9/2018

Procedure Description:
CO2 Pipeline Corrosion Control

I. PURPOSE

A. The purpose of this procedure is to provide guidelines for the protection and repair of the CO2 pipeline from corrosion.

II. SCOPE

A. Provide direction for corrosion control according to federal regulations.

III. REFERENCES

A. 49 CFR 195 Subpart F – Pipeline Integrity Management

B. 49 CFR 195 Subpart H – Corrosion Control

C. CSA Z662 Clause 9 – Corrosion Control

D. CSA Z662 Clause 10 – Pipeline System Integrity Management Program

E. NACE Standard SP0169-2007 – Control of External Corrosion on Underground or Submerged Metallic Piping Systems

F. ASME B31G – Manual for Determining the Remaining Strength of Corroded Pipelines

G. DGC Procedure No. EIP-261 – Cathodic Protection Rectifier Inspection

IV. DEFINITIONS

A. Buried - covered or in contact with soil.

B. Direct assessment - an integrity assessment method that utilizes a process to evaluate certain threats (i.e. external corrosion, internal corrosion, and stress corrosion cracking) to a pipeline segment's integrity. The process includes the gathering and integration of risk factor data, indirect examination or analysis to identify areas of suspected corrosion, direct examination of the pipeline in these areas, and post assessment evaluation.

C. Electrical survey - a series of closely spaced pipe-to-soil potential measurements over a pipeline that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

D. External corrosion direct assessment (ECDA) - a four-step process that combines pre-assessment, indirect inspection, direct examination, and post-assessment to evaluate the threat of external corrosion to the integrity of a pipeline.

E. Pipeline environment - includes soil resistivity (high or low), soil moisture (wet or dry), soil contaminants that may promote corrosive activity, and other known conditions that could affect the probability of active corrosion.

V. RESPONSIBILITIES

A. The pipeline engineer shall establish inspection requirements, provide corrective action, and verify the corrosion control measures are sufficient for the Dakota Gasification Company (DGC) CO2 pipelines.

B. Maintenance shall make all coating repairs in accordance with the guidelines established by the pipeline engineer.

C. Inspection shall perform the required inspection at the interval established by the pipeline engineer.

D. E&I Maintenance shall perform all cathodic protection inspections and repair/rework any deficiencies.

E. Mechanical and Civil Engineering shall be responsible for determining the strength of as found pipeline.

VI. INSTRUCTIONS

A. Verify that supervisors maintain a thorough knowledge of their portion of the corrosion control procedures.

B. Buried or submerged pipeline must have an external coating for external corrosion control.

C. Coating material for external corrosion control must:

1. Be designed to mitigate corrosion of the buried or submerged pipeline
2. Have sufficient adhesion to the metal surface to prevent under film migration of moisture.
3. Be sufficiently ductile to resist cracking.
4. Have enough strength to resist damage due to handling and soil stress.
5. Support any supplemental cathodic protection.
6. If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.

D. All external pipe coating must be inspected just prior to lowering the pipe into the ditch or submerging the pipe.

E. Coating damage discovered must be repaired.

F. Buried or submerged pipeline must be cathodically protected. Cathodic protection must be in operation not later than one year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable.

G. Buried or submerged pipeline must be protected from fault current and/or unusual risks of lightning strikes.

1. Maintain a minimum 30' distance from;

   a. Electrical transmissions tower footings

   b. Ground cables

   c. Counterpoises

2. Solid State Decouplers will be considered at insulation flanges for protection from fault currents and/or lightning strikes.

H. General – Each buried or submerged pipeline or segment of pipeline under cathodic protection must have electrical test leads for external corrosion control.

I. Installation

1. Locate the leads at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

2. Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead shall otherwise remain mechanically secure and electrically conductive.

3. Prevent lead attachments from causing stress concentrations on pipe.

4. For leads installed in conduits, suitably insulate the lead from the conduit.

5. At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire.

J. Maintenance

1. Maintain the test lead wires in a condition that enables an electrical measurement be made to determine whether the cathodic protection system complies with one or more of the applicable criteria and other conditions for cathodic protection contained in paragraphs 6.2 and 6.3 of NACE Standard SP0169-2007.

K. If any portion of a buried pipeline is exposed, examine the exposed portion for evidence of external corrosion if the pipe is bare or if the coating is deteriorated. If external corrosion is found requiring corrective action, you shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion control is required in the vicinity of the exposed portion.

L. Monitor external corrosion control:

1. Protected pipeline

   a. Conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively

coated pipelines, testing may be done at least once every three calendar years, but with intervals not exceeding 39 months.

b. Identify the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of paragraph 10.1.1.3 of NACE Standard SP0169-2007.

2. Unprotected pipeline

a. Re-evaluate unprotected buried or submerged pipe and cathodically protect the pipe in areas in which active corrosion is found.

(1) At least once every three calendar years, but with intervals not exceeding 39 months.

3. Rectifiers and other devices

a. Rectifier – at least six times each calendar year, but with intervals not exceeding 2½ months.

b. Other interference bond – at least once each calendar year, but with intervals not exceeding 15 months.

4. Coupons

a. Examine coupons at least twice each calendar year with intervals not exceeding 7½ months.

M. Corrective Action

1. Identified deficiencies in corrosion control must be corrected in a timely manner; not to exceed the next inspection cycle.

2. A pipeline that is part of the Integrity Management Program shall be corrected as required by 49 CFR 195.452 (h), or CSA Z662, clause 10.3.1.

N. Removal of Pipe

1. Pipe removed from the pipeline shall have the internal surface inspected for evidence of corrosion.

2. If you find internal corrosion requiring corrective action you must investigate circumferentially and longitudinally beyond the removed pipe to determine whether additional corrosion deficiencies requiring remedial action are present.

O. Above Ground Pipeline

1. Pipeline exposed to atmospheric corrosion shall be clean and coated.

2. Coating material shall be as determined by the pipeline engineer, and must be suitable for the prevention of atmospheric corrosion.

3. Pipeline exposed to the atmosphere shall be inspected every three calendar years with intervals not exceeding 39 months.

P. Corroded Pipe Corrective Action

1. General Corrosion

   a. Pipe that is generally corroded that the remaining wall thickness is less than that required for the maximum operating pressure of the pipeline must be replaced; however, you need not replace the pipe if:

      (1) The maximum operating pressure is reduced commensurate with the strength of the pipe needed for serviceability based on actual remaining wall thickness; or

      (2) Repair the pipe by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.

2. Localized Corrosion Pitting

   a. Pipe having localized corrosion/pitting to a degree that leakage might result, must be replaced or repaired unless the maximum operating pressure is reduced commensurate with the strength of the pipe based on actual remaining wall thickness in the pits.

3. ASME B31G manual for determining the remaining strength of corroded pipelines.

Q. Corrosion Control Information Retention

1. Maintain current records or maps to show the location of:

   a. Cathodically protected pipelines

   b. Cathodic protection facilities, including galvanic anodes

   c. Neighboring structures bonded to cathodic protection system

2. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

3. Maintain a record of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test required by this subpart H in sufficient detail to demonstrate the adequacy of corrosion control measures or that corrosion requiring control measures does not exist. Retain these records for at least five years, with the exception of records pertinent to sections of 49 CFR 195 and CSA Z662, 195.569, 195.573 (a) and (b), 195.579 (b)(3) and (c), which must be retained for as long as the pipeline remains in service.

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY SOURIS VALLEY PIPELINE LIMITED PROCEDURE

Origination Date:	Procedure No.:	Revision No.:
	74-004	4

Affected Area(s):	Originating Department:	
7400, 7500 Areas CO2 Pipeline Facilities	Operations	
	Final Approval: /s/ Claude O'Berry	**Date:** 3/29/2018
	SVPL Representative: /s/ Wade Borschowa	**Date:** 3/29/2018

Procedure Description:
Cathodic Protection Survey

I. PURPOSE

The purpose of this procedure is to provide detailed steps for performing Cathodic Protection (CP) surveys of the CO_2 pipeline. This procedure includes operations of the CP system.

II. RESPONSIBILITY

Pipeline Operations is responsible for maintaining and implementing this procedure. The electrical department staff collect readings and document findings on PLR-04.

CAUTION

Abnormal Operating Condition is a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operation that may.

- Indicate a condition exceeding design limits
- Result in a hazard(s) to person(s), property, or the environment.

ABNORMAL OPERATING CODITION

1. AOC: Low readings cathodic protection.
   Reaction: Notify Supervision- Adjust settings as required- document changes.

III. DISCUSSION

Pipe-to-soil potential measurements obtained along the pipeline route are used to adjust the rectifier units to satisfy the -850 millivolts or more negative pipe-to-soil potential criterion for cathodic protection established in the NACE Standard Practice SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." For an FBE type coating, the pipe to soil (off) potential should not be more negative than -1250 millivolts to prevent damaging the coating. If possible, the (on) potentials should be maintained between -850 and -1500 millivolts. The potential must account for IR-drop, (current/resistance drop) as well as the native soil test readings. IR drop is calculated using Ohm's Law which uses the readings taken across the shunt located between the resistors and the anode bed.

The rectifier units are adjusted such that the pipe to soil criterion for cathodic protection is satisfied. The current and voltage outputs and the tap settings of the rectifier units shall be recorded each time adjustments are made.

Failure to achieve pipe to soil criterion during survey may be the result of stray current interference. Observations indicating stray current interference may include changes or fluctuations in pipe to soil potentials caused by a nearby foreign source, or changes or fluctuations in the line current magnitude or direction when testing Type C test stations. In areas where stray currents are suspected, coordination with all affected parties are required to evaluate threats of external corrosion due to stray current interference. Tests may include measurement or correlations of pipe to soil potentials or current flowing on the structure with recording or indicating instruments to determine the source(s) and extent of stray current pickup and discharge. In some cases, it may be required to complete a Close Interval survey to identify precise locations of stray current pick up and discharge. Mitigation of stray interference currents may include but is not limited to the installation of interference bonds, anode current drains, and/or recoating of the current pickup areas.

Another type of cathodic protection survey is the close interval survey. This survey records a pipe to soil potential at approximate 3-5 -foot intervals over the entire pipeline to provide a complete picture of the cathodic protection system. It will indicate areas of variations in the potential that may be caused by coating holidays, interference, soil conditions, stray current, etc. This type of survey is usually conducted, unless not practicable, on sections of the pipeline where the potential readings are not being met to satisfy NACE SP0169-2007 criteria for cathodic protection.

The forms used while implementing the monthly rectifier unit monitoring (PLR-04) are found in the electronic file system.

IV. PROCEDURE

A. Monitor the CP System

The voltage and current outputs of the impressed current systems shall be measured on a monthly basis and a record shall be maintained of these readings. The voltage output of the systems should remain constant while the current output may vary with the resistance of the anode bed. The anode bed resistance may vary with soil moisture. The current output should, in general, be maintained within ± 10 percent of the original reading. The current output may decrease as the pipeline polarizes (usually two to three months after start-up). Pipe-to-soil potential measurements will indicate whether a satisfactory level of cathodic protection is being maintained at the reduced current output. Appendix A contains a sample sheet that would be maintained for each rectifier unit. A change in the current output outside of the above parameters should be investigated, the cause determined and appropriate corrective actions taken.

B. Perform an annual survey of the cathodic protection system. The survey shall consist of the following, as a minimum:

- Measure pipe-to-soil potentials at test stations, valves sites, and insulating joints.

- Measure of pipe voltage drop at Type C test stations.
- Determine effectiveness of the insulating joints.
- Inspect the rectifier units and test stations.
- Record current and voltage outputs of the rectifier units.
- Adjust output of cathodic protection system, as required, to satisfy NACE SP0169-2007 criteria for cathodic protection.

Attached to this procedure is a copy of the form that will be used for the annual testing. The test station readings will be maintained in a database such that the pipe to soil potentials are plotted versus the pipeline distance. The readings from year to year can then be easily compared and trends noted that could indicate potential problem areas.

C. The pipe-to-soil potential measurements are obtained using a high impedance DC voltmeter (10 megohms minimum) and a copper/copper sulfate reference electrode. For Type A test stations, the reference electrode is placed on the soil over or adjacent to the pipeline and is connected to the negative terminal of the voltmeter. The positive terminal of the voltmeter is connected to the pipeline under test either through a test station or by direct contact. The DC voltage between the pipe and the reference electrode is then recorded. It should be negative.

D. The Type C test stations are also called 4-wire test stations or current measurement test stations. The purpose of these test stations is to be able to measure the direction and the current flow in the pipeline in addition to measuring a pipe to soil potential. This information is used to evaluate the relative effectiveness of the pipeline coating, the distribution of current from the rectifier units, determine the presence of stray current and future troubleshooting of the cathodic protection system. Any one of the four wires can be used to obtain a pipe to soil potential measurement to evaluate the cathodic protection system.

Four wires are required to determine the resistance of the pipeline (calibration) between the two sets of test leads. The voltage and polarity between the red and white wires would be measured during the regular testing. The positive terminal of the voltmeter would be connected to the red wire and the negative terminal to the white wire. A positive reading would indicate that the current flow is in the same direction as the product flow. The voltage reading would be divided by the calculated resistance to determine the current. The current should be very small before the cathodic protection system is energized.

The calibration of the test span is only required to be determined once. The resistance is then used during the future testing. The calibration of the test span is accomplished as follows:

1. Connect DC voltmeter between the red and white wires. Positive terminal of voltmeter to red and negative to white. Record voltage and polarity.

2. Connect a 6 volt lantern battery, DC ammeter, a switch and 1 ohm resistor between the black and blue wires. Connect positive terminal of the battery to the black wire in the test station. Connect the blue wire to one side of the 1-ohm resistor and connect the other side of the resistor to the positive terminal of the DC ammeter. Then connect the negative terminal of the battery to the negative terminal of the DC ammeter. Close the switch, measure and record the current and at the same time record the voltage and polarity between the red and white wires. Disconnect the battery. Calculate resistance of the pipe span by dividing the change in voltage (battery connected and disconnected) between the red and white leads by the current flow from the battery. This resistance is then used during cathodic protection surveys to measure the cathodic protection current flow.

E. The effectiveness of the insulating joints can be determined by a meter specifically made for this purpose or by measuring pipe-to-soil potentials at a Type D test station. A potential measurement is made using the white lead in the test station and then using the black lead in the test station. The reading being the same or nearly the same indicates that the insulating joint is not effective. An appreciable difference between the readings indicates that the insulating joint is effective. When the cathodic protection system is operating, the voltage difference will usually be greater than 50 millivolts.

F. For crossing pipeline, use the Type B test station. Place reference electrode on surface of ground over DGC pipeline. Measure pipe to soil as for Type A (step C, above) with connections to each pipeline. Record the values for each pipeline. If crossing is not at the test station location, the reference electrode should be placed over the foreign pipeline for measurement of its potential

G. The outputs of the impressed current systems can be read at the panel meters on the rectifier units. Annually the panel meters shall be checked using a portable voltmeter connected across the output terminals to measure the voltage and compared to the panel voltmeter. The current panel meter is checked by measuring the voltage across the meter shunt. The shunt rating will be stamped on the side (50 mv – XX A). The current through the shunt is the ratio of the measured millivolts to 50 millivolts times the current rating. A shunt rated at 50 mv – 30 A with 20 mv measured across it indicates that 12 amperes is flowing through the shunt.

Records of the monthly readings and the annual potential measurements shall be maintained by the E & I department. These readings are necessary to evaluate the effectiveness of the cathodic protection system, to aid in future troubleshooting, and to determine when components of the cathodic protection system require replacement. These records are also required by the federal regulations and are made available during inspections.

To ensure adequate Cathodic Protection, the CO2 pipeline is equipped with eleven rectifiers located as follows.

1. 14" CO2 pipeline locations

- MLV # 1- 50V 28A system 10 deep well anodes and 4 surface anodes
- MLV # 3- 40V 5A system 3 surface anodes
- MLV # 4- 50V 28A system 10 deep well anodes and 2 surface anodes
- MLV # 5- 40V 5A system 3 surface anodes
- MLV # 6- 40V 5A system 9 deep well anodes and 3 surface anodes
- MLV # 7- 40V 5A system 10 deep well anodes and 5 surface anodes
- TIOGA - 50V 28A system 10 deep well anodes and 2 surface anodes

2. 12" CO2 pipeline locations
   - MLV # 8- 40V 5A system 3 surface anodes
   - MLV # 9- 40V 5A system 3 surface anodes
   - MLV # 11- 50V 28A system 10 deep well anodes and 2 surface anodes
   - Good water – 60V 12A system 4 surface anodes

Test stations are provided along the entire pipeline route at approximately one-mile increments for the purpose of taking pipe-to-soil potential readings.

DEVELOPED/REVIEWED BY	SIGNATURE	DATE
Engineer:		
♦ Chris Breiner	/s/ Chris Breiner	3/28/2018
Supervisor:		
♦ Kurt Dutchuk	/s/ Kurt Dutchuk	3/27/2018
♦ Dave Knoll	/s/ Dave Knoll	3/27/2018
♦		
♦		
Technician:		
♦ Craig Mattheis	/s/ Craig Mattheis	3/27/2018
♦ Lewis Hinckley	/s/ Lewis Hinckley	3/27/2018
♦		
♦		

Procedure No.: 74-004 Revision No.: 4

Summary of Revision: Changes to verbiage to address stray current and mitigation

Revision Requested By: Claude O'Berry

The attached procedure is safe, accurate, and meets the Operating Procedure Guidelines for PSM affected operating areas.

Risk Assessment Review: /s/ Charles J. Roy 3/29/2018
Process/Reliability/Section Engineer Date

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	Procedure No.:	Revision No.:
2/11/03	028	5

Affected Area(s):	Originating Department:	
All	Engineering	
	Final Approval:	Date:
	/s/ Dale Johnson	10/02/18

Procedure Description:

Integrity Management Program Assessment Results Review

I. PURPOSE

A. This procedure will be utilized to assess the results from an integrity assessment for the carbon dioxide (CO_2) pipeline.

II. SCOPE

A. This procedure will be utilized as part of the Integrity Management Program per the Department of Transportation (DOT) 49 CFR 195. This procedure shall be used to ensure the results from any type of assessment of the carbon dioxide pipeline are assessed and documented correctly.

III. REFERENCES

A. 49 CFR 195 – Transportation of Hazardous Liquids by Pipeline

B. 49 CFR 195.452 – Pipeline Integrity Management in High Consequence Areas

C. API 1160 – Managing System Integrity for Hazardous Liquid Pipelines

D. API 570 – Piping Inspection Code

E. API Standard 1163 – In-line Inspection Systems Qualification

F. NACE SP0102-2010 – In-line Inspection of Pipelines

G. ASME B31G - Manual for Determining the Remaining Strength of Corroded Pipelines

H. DGC Procedure No. 129 – Pipeline Inspections

I. Form PLR-87 (DGC 1684) – ILI Acceptance Criteria

IV. DEFINITIONS

A. High consequence area (HCA)

1. *Commercially navigable waterway* – A waterway where a substantial likelihood of commercial navigation exists.

2. *High population area* – An urbanized area, as defined and delineated by the Census Bureau that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

3. *Other populated area* – An area, as defined and delineated by the Census Bureau that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

   a. *Office of Pipeline Safety (OPS) identified* – Areas the OPS has identified as meeting the criteria of an other populated area.

B. Unusually sensitive area (USA) – A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release as defined in 49 CFR 195.6.

C. Discovery of a condition – Discovery of a condition occurs when adequate information about the condition to determine the need for repair. Depending on circumstances, adequate information may be corroboration between any two of the following:

1. Preliminary internal inspection report
2. Integrated data from other sources
   a. Cathodic protection surveys
   b. Right-of-way inspections
   c. Other types of inspections
3. Excavation and verification of condition
4. Final internal inspection report

The date can be no later than the date of the final report or integrity assessment results.

V. RESPONSIBILITIES

A. Plant Management

1. Responsible for allocating appropriate resources for completing integrity assessments.

B. Pipeline Superintendent

1. Responsible for overseeing the implementation of this procedure to ensure compliance with 49 CFR Part 195.
2. Provide operational support and resources for completing integrity assessments.

C. Pipeline Engineer

1. Issue a yearly report detailing the results of the annual cathodic protection (CP) survey.
2. Issue a report detailing the results of piping inspections.
3. Issue a report detailing the results of corrosion coupon inspections.

D. Maintenance Engineering

1. Perform, or contract to perform, an annual test of pipe to soil potentials.
2. Responsible for identifying all anomalies that will need to be investigated further.
3. Responsible for calculating corrosion growth rates based on the previous runs and applying those rates to all critical anomalies.
4. Responsible for coordinating an evaluation of all the assessment results to identify potential corrective actions.

E. E&I Maintenance

1. Ensure cathodic protection is operating at acceptable levels to adequately protect the pipeline.
2. Perform, or contract to perform, an annual test of pipe to soil potentials.

VI. INSTRUCTIONS

A. Data Retention

1. All reports and documentation required or produced by this procedure shall be filed in the appropriate folder (identified by work order number, assigned description, or pipeline location) located in Altien under *DGC / Pipelines / Integrity Management*.
2. All reports are to be kept for the life of the pipeline.

B. Types of Assessments

1. Hydrostatic Test
   a. Hydrostatic tests, other than pre-service hydrostatic tests, shall not be allowed on the CO_2 pipeline. This is due to the possibility of the formation of carbonic acid.
2. Corrosion Control
   a. Cathodic Protection
      (1) It is the responsibility of E&I Maintenance to ensure the cathodic protection is operating at acceptable levels to adequately protect the pipeline without causing damage to the pipeline coating and also assured corrosion control and compliance with 49 CFR 195 subpart “H”
      (2) It is the responsibility of E&I Maintenance and/or Maintenance Engineering to perform or contract to perform an annual test of pipe to soil potentials. This data will be trended year to year and any modifications to the system will be noted with this data.
         (a) The pipeline engineer shall issue a yearly report detailing the results of the annual survey and compliance with 49 CFR 195 Subpart H. This report is to include a summary of the survey and note any potential problems as well as any necessary repairs or additions to the cathodic protection system. This report will also

identify if any further investigation, such as a close interval survey, is required. This report will be issued to Process Operations and Maintenance.

(b) If any additional cathodic testing is done on the pipeline the results and interpretations will be issued in a report distributed to Process Operations and Maintenance.

b. Piping Inspection

(1) It is the responsibility of the pipeline engineer to perform piping inspection per DGC Procedure No. 129.

(a) The pipeline engineer shall issue a report detailing the results of the inspection. This report is to include a summary of the inspection and note any potential problems as well as any areas of concern, such as increased corrosion rate. This report shall l be issued to Process Operations and Maintenance.

c. Corrosion Coupon

(1) It is the responsibility of the pipeline engineer to inspect the corrosion coupon. The results and interpretations shall be issued in a report distributed to Process Operations and Maintenance.

d. CO_2 Sampling

(1) Samples are collected daily and analyzed in the chemistry laboratory for CO_2 quality and moisture content. Any time the moisture content is greater than 25 ppm, the process operations section manager is notified, and the source of the moisture or high reading is identified and resolved. A follow-up sample is taken to verify the moisture issue has been corrected.

3. Electronic Inspection

a. It is the responsibility of Maintenance Engineering to write the specifications for the equipment to be used for the internal inspection of the pipeline.

(1) Maintenance Engineering shall ensure that the latest technology is used for the internal inspection of the pipeline.

(2) Maintenance Engineering shall ensure that the tools are capable of detecting metal loss as well as any dent or other geometric anomalies.

(3) Maintenance Engineering shall ensure that the tools utilize the latest means of Global Position System (GPS) technology for anomaly location.

b. Process Operations and Maintenance shall coordinate the actual inspection of the pipeline.

C. Survey acceptance criteria shall be evaluated according to Form PLR-87 (DGC 1684) to ensure a successful in-line inspection (ILI) tool run.

a. The contractor shall furnish a preliminary report to Maintenance Engineering when the tool run is complete and the data is analyzed. Maintenance Engineering shall forward a copy to Pipeline Process Operations for review and comments. This report will note any significant anomaly that will require immediate attention and further analysis.

b. A final report from the tool run shall be furnished to Maintenance Engineering for analysis.

(1) The data from the vendor is to be analyzed as follows:

(a) The clustering criteria is to be 6t x 6t.

(b) The formulas for calculating remaining strength are to be per ASME B31G modified.

(c) The software supplied by the vendor shall have the option for the user to select different clustering rules as well as different remaining strength calculations.

(d) The location of the anomaly will be reported in GPS coordinates.

(e) The final report shall be issued no later than 150 days after completion of the ILI tool run.

(2) Copies of this report shall be issued to management, Process Operations, and Maintenance for their review.

c. Once the final report is reviewed and accepted, the following process will be used for validating the ILI tool unless DGC justifies not performing validation digs and documents the justification.

(1) Dig selection shall include any that meet the defined response time criteria per 49 CFR 195. If no predicted features meet the defined response criteria, dig locations shall be selected to validate the magnetic flux leakage (MFL) and Caliper tools, as applicable.

(a) Features used for validation must meet the detection and sizing specifications established by the ILI vendor.

(b) Depending on the type of feature, the appropriate type of measurement shall be selected. (i.e. ultrasonic testing for internal corrosion, pit gauge for external corrosion)

(2) Document dig site location using GPS and chainage from a known position using ILI tool data.

(3) Confirm any dig and anomaly locations, inspect and examine defect and coating, and document findings. Remaining strength calculations are completed based on the direct inspection results.

(4) Validation is an analysis of predicted data and actual measurements to evaluate tool accuracies. Perform three validation points to obtain a high confidence in the ILI data.

(5) Document the validation process for each dig selection, and return to the ILI vendor to update the final report if necessary.

(6) If the measured data is within the acceptable limits pre-established by the ILI vendor and the predicted data reflects the conditions of the pipeline, then the tool run is acceptable.

(7) Guidance on this topic can be found in API Standard 1163 and NACE SP0102-2010.

g. Maintenance Engineering shall identify all anomalies that will need to be investigated further.

(1) This shall be done through integration of all pertinent data. This data may include:

(a) Cathodic protection data

- Test post readings
- Close interval surveys
- Direct current voltage gradients

(b) Right-of-way inspections

(c) Other ILI tool data

(d) Visual inspections

(e) Soil data

(f) Crossing records

h. For corrosion anomalies, Maintenance Engineering shall calculate a corrosion growth rate based on the previous runs and apply that rate to all critical anomalies.

(1) The anomalies shall be broken down into the following categories:

(a) Those of significant size that do not meet the criteria for remaining strength

(b) Those that will reach a significant size before the next scheduled assessment

i. Maintenance Engineering will issue a report after all the data is analyzed. This report shall list the number of the anomalies to be remediated, the repair method to be used to restore the serviceability of the pipe, and the date by which each anomaly will need to be repaired. This report shall be issued to Process Operations, Maintenance, and plant management.

2. External Corrosion Direct Assessment

a. Conduct External Corrosion Direct Assessment (ECDA) of all high consequence areas that cannot be inspected with intelligent inline inspection tools. Testing is to be done in accordance with 49 CFR 195.588 and all applicable NACE requirements listed in 195.588.

b. Contractor will furnish a final report with recommendations for potential excavations to back up findings of the ECDA.

3. Other Types of Assessments

a. Other types of assessments such as directional ultrasonic, acoustic, or any other new technology that could prove beneficial in the assessment of the pipeline will be utilized as necessary

b. If another type of assessment is utilized in the place of the ILI tool a notice to the Office of Pipeline Safety is required 90 days prior to conducting the assessment.

(1) A report will be issued upon completion of any type of new assessment. This report will contain:

(a) The results of the assessment

(b) Any problems or concerns with the data

(c) The applicability of the data to the integrity of the pipeline

4. HCA Inspection for Aboveground Piping (5900 Area and MLV Station)

a. Visual inspection – every three years (coating, insulation, etc.).

b. Ultrasonic thickness reading – every three years (location of thickness reading designated by a degreed mechanical engineer.

c. Inspection to be done by maintenance engineering personnel certified as piping inspectors per API 570 – Piping Inspection Code.

5. HCA Inspection for Below Grade Piping

a. Required every five years, unless through engineering analysis it can be proven that the time frame can be extended.

b. This may not exceed a maximum of seven years.

(1) If a time frame longer than five years is justified, the pipeline engineer shall notify the Office of Pipeline Safety at least nine months prior to the five-year time frame expiring.

c. If the technology doesn't exist, notification to the Office of Pipeline Safety must be sent to inform them and an alternate plan for inspection proposed.

(1) The Office of Pipeline Safety must be notified 180 days before the five-year interval expires.

D. Evaluation

1. The pipeline engineer will be responsible for coordinating the evaluation process on comparing all the assessment reports listed in part VI.B.

a. This comparison is to include corroboration between reports that would indicate a concern about condition of the pipeline or coating.

b. Qualification of review personnel shall be per Appendix A of this procedure.

2. Maintenance Engineering may request assistance from any department or outside contractor in the evaluation process.

3. All data in the reports shall be trended by Maintenance Engineering to identify any areas that may be experiencing abnormal rates of changes in condition.

4. If an area of concern is identified, Maintenance Engineering, or another department designated by Maintenance Engineering, shall issue a memo stating where the area is, what the concern is, what type of further investigation is required, and what type of remediation is required.

5. A work order with tasks for all affected departments shall be generated and the work completed in accordance with the memo.

`

APPENDIX A

QUALIFICATION REQUIREMENTS FOR QUALIFIED PERSONNEL TO REVIEW IN-LINE INSPECTION REPORTS, EXTERNAL CORROSION DIRECT ASSESSMENT (ECDA) AND OTHER DOCUMENTS CONCERNING THE MECHANICAL INTEGRITY OF THE PIPELINE

A. Mechanical Engineer (Bachelor of Science)

B. Attend risk assessment analysis training

C. Knowledgeable in 49 CFR Part 195 requirements

D. Knowledgeable of ASME B31.4 and API 1160

E. Knowledgeable in reviewing in-line inspection reports

F. Knowledgeable in defect assessment

G. Knowledge of pipeline operations

QUALIFICATION REQUIREMENTS FOR QUALIFIED PERSONNEL TO REVIEW CATHODIC PROTECTION DATA, INTERNAL INSPECTION REPORTS, AND EXTERNAL CORROSION DIRECT ASSESSMENT

A. Metallurgical/Corrosion Engineer (Bachelor of Science) with a minimum of NACE cathodic protection level II certification

B. Knowledgeable in NACE Recommended Practice RP0502-2002

C. Knowledgeable in stress corrosion cracking

QUALIFICATION REQUIREMENTS FOR QUALIFIED PERSONNEL TO REVIEW CIVIL/STRUCTUAL DOCUMENTATION

A. Civil/Structural Engineer (Bachelor of Science), OR

B. Geotechnical Soil Engineer (Bachelor of Science) consultant

QUALIFICATION REQUIREMENTS FOR QUALIFIED PERSONNEL TO REVIEW CIVIL/STRUCTUAL DOCUMENTATION

A. Vendor training (on installed leak detection system) on how to program, operate, and detect leaks

B. Knowledge of Computer Flow Modeling / Computational Pipeline Monitoring (CFM/CPM)

C. Knowledge of Supervisory Control and Data Acquisition (SCADA) system

D. Knowledge of API 1130, 1149, 1155, 1113

E. Knowledge of 49 CFR Part 195 as it relates to leak detection systems

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	Procedure No.:	Revision No.:
2/11/03	031	4

Affected Area(s):	Originating Department:	
All	Engineering	
	Final Approval:	Date:
	/s/ Dale Johnson	10/02/18

Procedure Description:

Integrity Management Program Evaluation

I. PURPOSE

A. This procedure will be utilized to evaluate and assess the Integrity Management Program for the carbon dioxide (CO_2) pipeline.

II. SCOPE

A. This procedure will be utilized as part of the Integrity Management Program (IMP) per the Department of Transportation (DOT) 49 CFR 195.452. This procedure shall ensure the program is run efficiently and correctly.

III. REFERENCES

A. 49 CFR 195 – Transportation of Hazardous Liquids by Pipeline

B. 49 CFR 195.452 – Pipeline Integrity Management in High Consequence Areas

C. API 1160 – Managing System Integrity for Hazardous Liquid Pipelines

D. "Consolidated Format Integrity Management Inspection Protocols", US Department of Transportation, Research and Special Projects Administration, and Office of Pipeline Safety

E. API RP 754 – *Process Safety Performance Indicators for the Refining and Petrochemical Industries*

F. "*Guidance for Strengthening Pipeline Safety Through Rigorous Program Evaluation and Meaningful Metrics*", Pipeline and Hazardous Materials Safety Administration (PHMSA)

IV. DEFINITIONS

A. <u>High consequence area (HCA)</u>

1. *Commercially navigable waterway* – A waterway where a substantial likelihood of commercial navigation exists.

2. *High population area* – An urbanized area, as defined and delineated by the Census Bureau that contains 50,000 or more people and has a population density of at least 1,000 people per square mile.

3. *Other populated area* – An area, as defined and delineated by the Census Bureau that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

a. *Office of Pipeline Safety (OPS) identified* – Areas the OPS has identified as meeting the criteria of an other populated area.

B. Unusually sensitive area (USA) – A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release as defined in 49 CFR 195.6.

V. RESPONSIBILITIES

A. Plant Management

1. Responsible for allocating appropriate resources for completing IMP effectiveness evaluations.
2. Responsible for approving IMP performance goals.

B. Pipeline Superintendent

1. Responsible for overseeing the implementation of this procedure to ensure compliance with 49 CFR Part 195.
2. Provide operational support and resources to perform IMP effectiveness evaluations.
3. Responsible for communicating established goals and the results of the IMP evaluation to appropriate stakeholders.

C. Pipeline Engineer

1. Responsible for periodic maintenance of metrics established to support the IMP effectiveness evaluation.

D. Maintenance Engineering Supervisor

1. Provide support and resources to the pipeline engineer.

VI. INSTRUCTIONS

A. Establishment of safety performance goals – The following outlines the steps for selection, documentation, and communication of safety performance goals.

1. Safety performance goals – Safety performance goals should be documented and reviewed periodically as part of DGC's required program evaluation. These goals should support the short and long-term organizational objectives of Dakota Gasification Company (DGC).
2. System specific safety performance goals – Additional safety performance goals should be established for unique system configurations or situations, such as:

a. Piping systems transporting highly volatile liquids,

b. Piping systems having unique operating parameters (e.g. piping system that is susceptible to liquid entrainment),

c. Piping systems having unique threat profiles (e.g. located in areas having high population density, industrial, or construction activities).

3. Senior management commitment – Senior management should be engaged in the development and review of the safety performance goals.

4. Safety performance goal communication – Safety performance goals should be routinely communicated as well as performance to goals should be communicated to appropriate stakeholders by the pipeline engineer.

5. Safety performance goal review – Safety performance goals should be established or reaffirmed on a periodic basis. Previously established goals should be affirmed or redefined/revised as needed to maintain effectiveness.

B. Identification of required performance metrics

1. At a minimum, DGC shall measure and track the metrics that DGC is required to submit annually to PHMSA per 49 CFR Part 195.

2. DGC may identify other required metrics as appropriate. Other required metrics may be selected from 49 CFR Part 195 or API 1160.

C. Selection of other required metrics and additional meaningful metrics

1. DGC should select other required metrics and additional meaningful metrics that effectively monitor and measure the performance to the established safety goals.

D. Performance metrics collection and recording

1. The pipeline engineer and pipeline superintendent are responsible for collecting data for the required performance metrics.

2. The data supporting all established metrics should be recorded in a centralized file, such as a managed Microsoft Excel spreadsheet or a technical report.

3. Recorded data should be reviewed and validated to identify potential errors.

E. Program evaluation using metrics

1. The pipeline superintendent, or designee, is responsible for measuring the effectiveness of the IMP annually and communicating relevant information to affected personnel.

2. As a guide, an effective program should have the following characteristics:

a. Assessment of program effectiveness – A review of relevant inputs to measure IMP effectiveness. Periodic self-assessments, internal audits, external audits, management reviews, or other self-critical evaluations may be used to assess the program effectiveness.

b. Metric trends – Program effectiveness is determined through the analysis of established performance metrics. Performance metrics are reviewed to identify trends in the data and risk reduction measures are implemented to correct

negative trends. The metrics review should include an assessment of the success in meeting the established safety goals.

c. Program evaluation reviews – The Pipeline Superintendent should approve program evaluations and provide resources to address adverse performance trends identified by the program evaluation.

d. Performance feedback – Lessons learned, insights from the performance metric trends, and best practices, should be provided to appropriate personnel responsible for the different aspects of the IMP.

e. Corrective actions – Corrective actions from the performance evaluation should be formally tracked in EXP-DIR incident reporting system until completion and should have designated timeframes that are commensurate with the action's importance to safety. Corrective actions resulting in significant organizational change should be managed through DGC's management of change process. Corrective actions should be revisited in subsequent performance evaluations to determine proper implementation of the action.

f. Threat identification and risk analysis updates – A review of the IM threat assessment and risk analysis process that considers the outcomes, insights, and identified trends. This helps ensure that the risk analysis tools used to support future safety and integrity decisions accurately reflect the operational history, asset condition, and program experience.

g. Program evaluation process reviews – The program evaluation process itself should be reviewed annually as part of the IMP effectiveness evaluation. This evaluation attempts to identify opportunities for improvement for the performance evaluation.

h. Safety performance goals confirmation – Based on results of the performance evaluation, new safety performance goals should be established or the current set of goals should be reaffirmed. Goals may be redefined or revised if they are not positively affecting safety performance.

i. Metric updates – Metrics should be updated to address any improvements identified by the program evaluation and updated safety performance goals. DGC should eliminate non-useful metrics.

VII. RECORDS

A. All reports and documentation required or produced by this procedure shall be considered records, and shall be filed for the life of the pipeline in the appropriate electronic folder located in Altien under DGC / Pipelines / Integrity Management.

Exhibit 5

Third Party Damage

One Calls	Number of One Calls	0	Number of Overdue One Calls	One Call Follow-up Ratio	Goal (%)	Number of One Call (or lack of) Near Misses / Encroachments	# of Incidents with One call (or lack of) as a factor	One Call Ratio	Goal
January	94	3	2	100	100	1	1	1	2
February	50	0	0	100	100	0	0	#DIV/0!	2
March	58	2	2	100	100	0	0	#DIV/0!	2
April	124	2	3	100	100	1	0	#DIV/0!	2
May	194	0	0	100	100	1	0	#DIV/0!	2
June	194	0	0	100	100	0	0	#DIV/0!	2
July	186	1	1	100	100	0	0	#DIV/0!	2
August	185	1	0	100	100	0	0	#DIV/0!	2
September				#DIV/0!	100			#DIV/0!	2
October				#DIV/0!	100			#DIV/0!	2
November				#DIV/0!	100			#DIV/0!	2
December				#DIV/0!	100			#DIV/0!	2

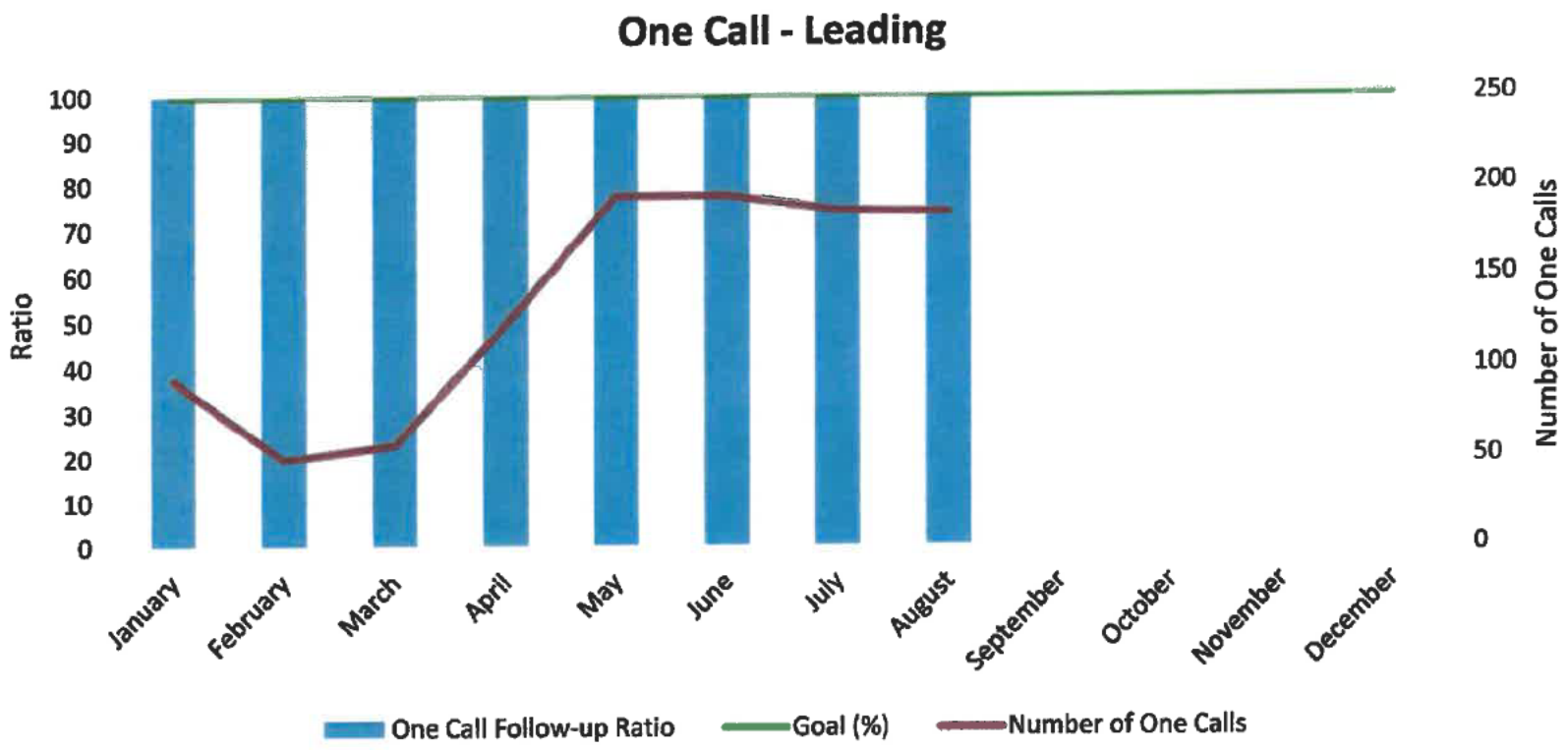
Third Party Damage

Public Awareness Metrics	Number of mailers sent	Number of mailers received	Mailers Received Ratio	Goal	Number of near misses with public awareness (or lack of) as a factor	# of incidents with public awareness (or lack of) as a factor	Public Awareness Ratio	goal
January	0	0	#DIV/0!	100%	0	0	#DIV/0!	1
February	0	0	#DIV/0!	100%	0	0	#DIV/0!	1
March	1445	1367	95%	100%	0	0	#DIV/0!	1
April	16	12	75%	100%	0	0	#DIV/0!	1
May	0	0	#DIV/0!	100%	0	0	#DIV/0!	1
June	0	0	#DIV/0!	100%	0	0	#DIV/0!	1
July	3	3	100%	100%	0	0	#DIV/0!	1
August	0	0	#DIV/0!	100%	0	0	#DIV/0!	1
September			#DIV/0!	100%			#DIV/0!	1
October			#DIV/0!	100%			#DIV/0!	1
November			#DIV/0!	100%			#DIV/0!	1
December			#DIV/0!	100%			#DIV/0!	1

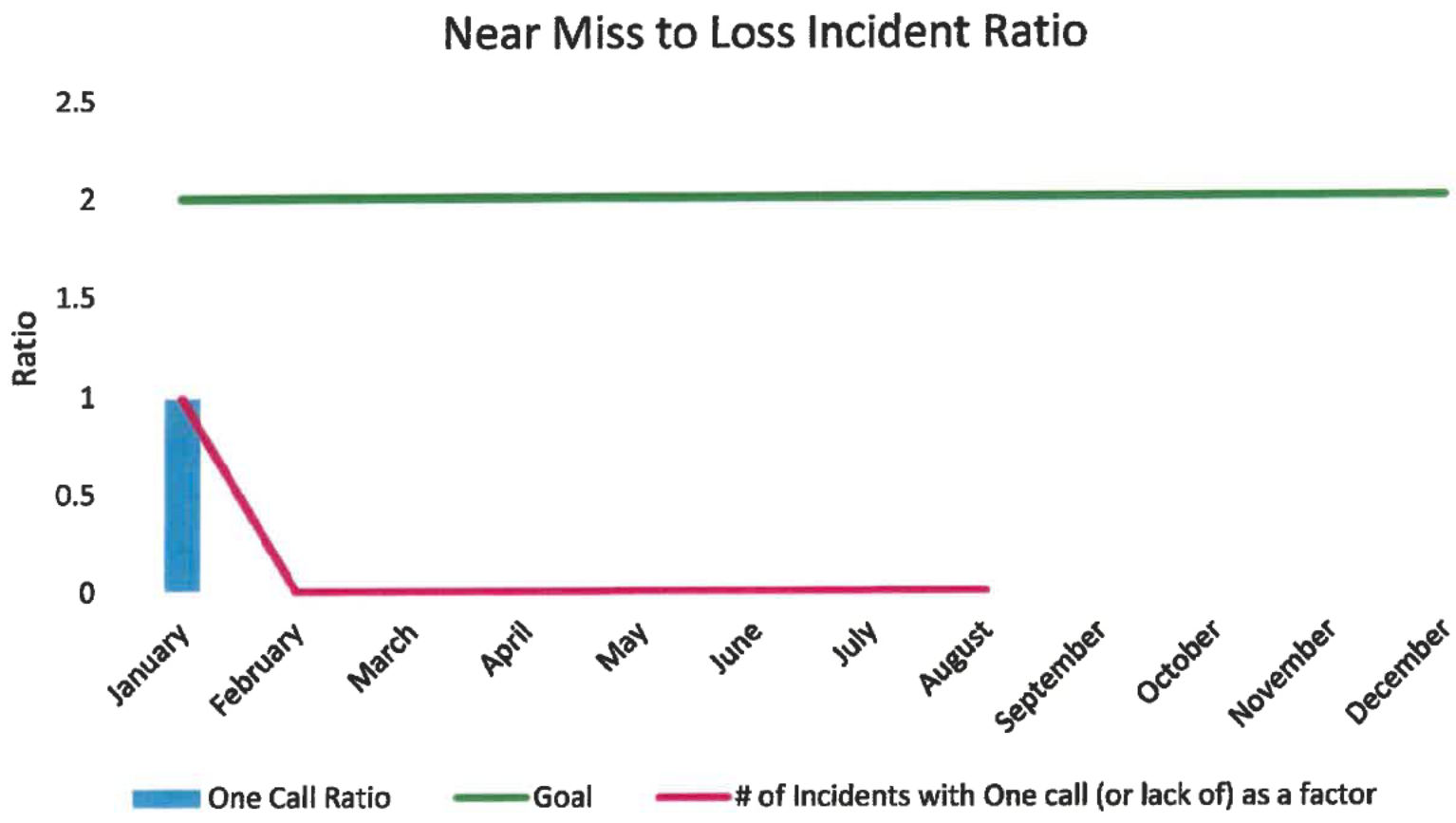
Third Party Damage

Aerial patrol detections	Aerial patrols scheduled	Aerial patrols Completed	Ratio	Goal (100%)	Number of Aerial Patrol Detections
January	2	2	100	100	2
February	2	2	100	100	2
March	2	2	100	100	0
April	2	2	100	100	1
May	2	2	100	100	1
June	2	2	100	100	3
July	3	3	100	100	0
August	2	2	100	100	2
September			#DIV/0!	100	
October			#DIV/0!	100	
November			#DIV/0!	100	
December			#DIV/0!	100	

Third Party Damage



Third Party Damage



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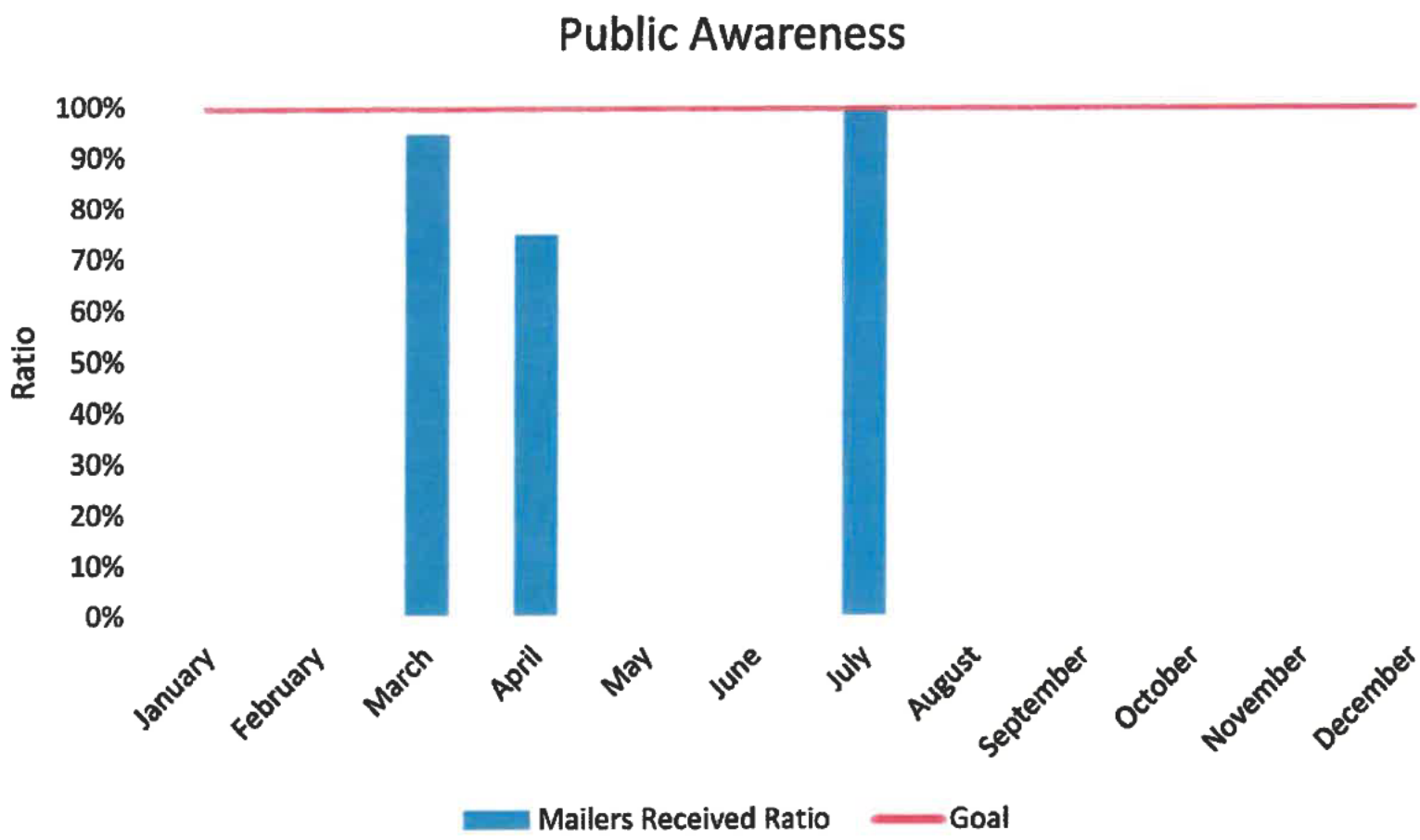
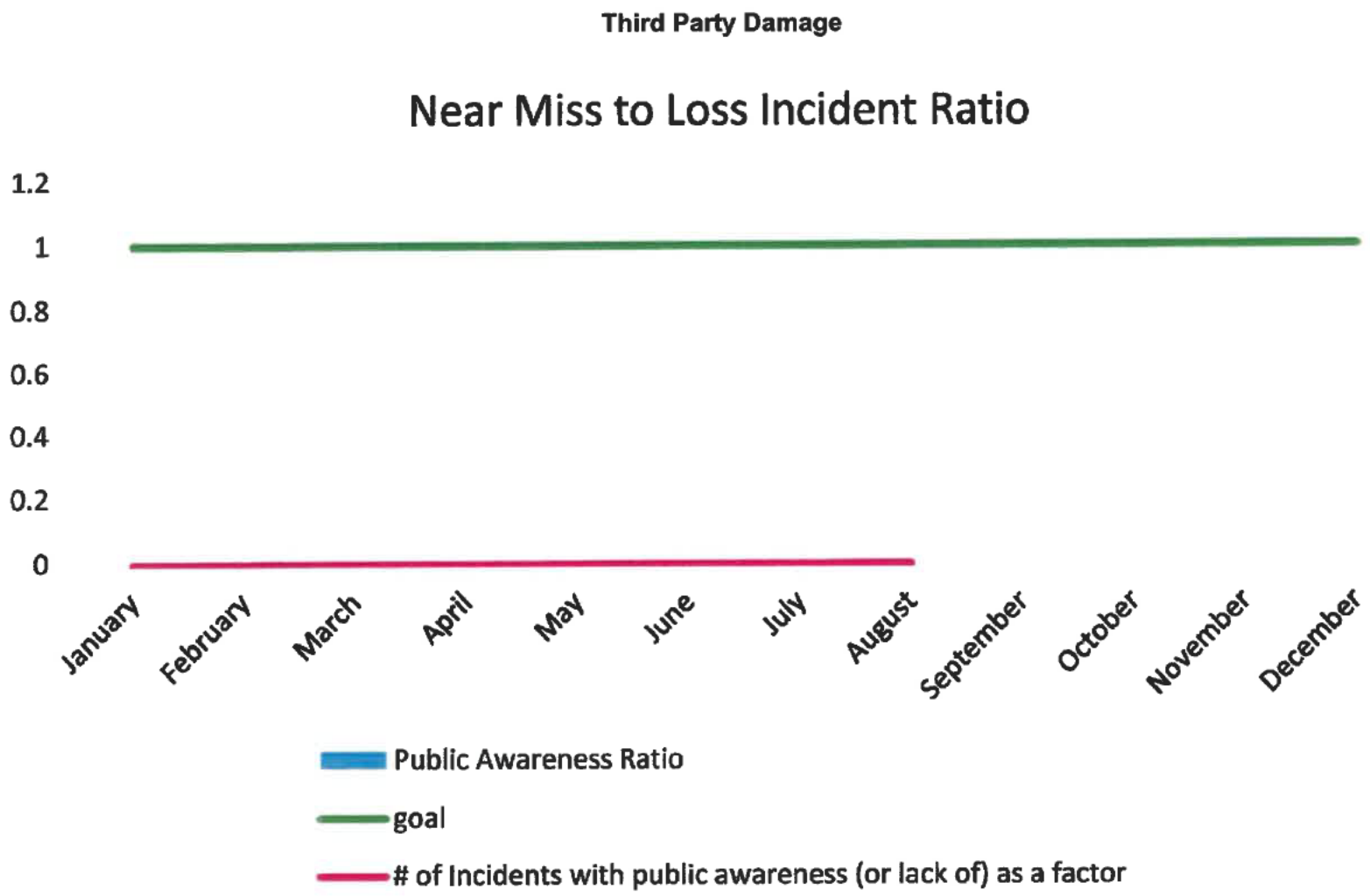
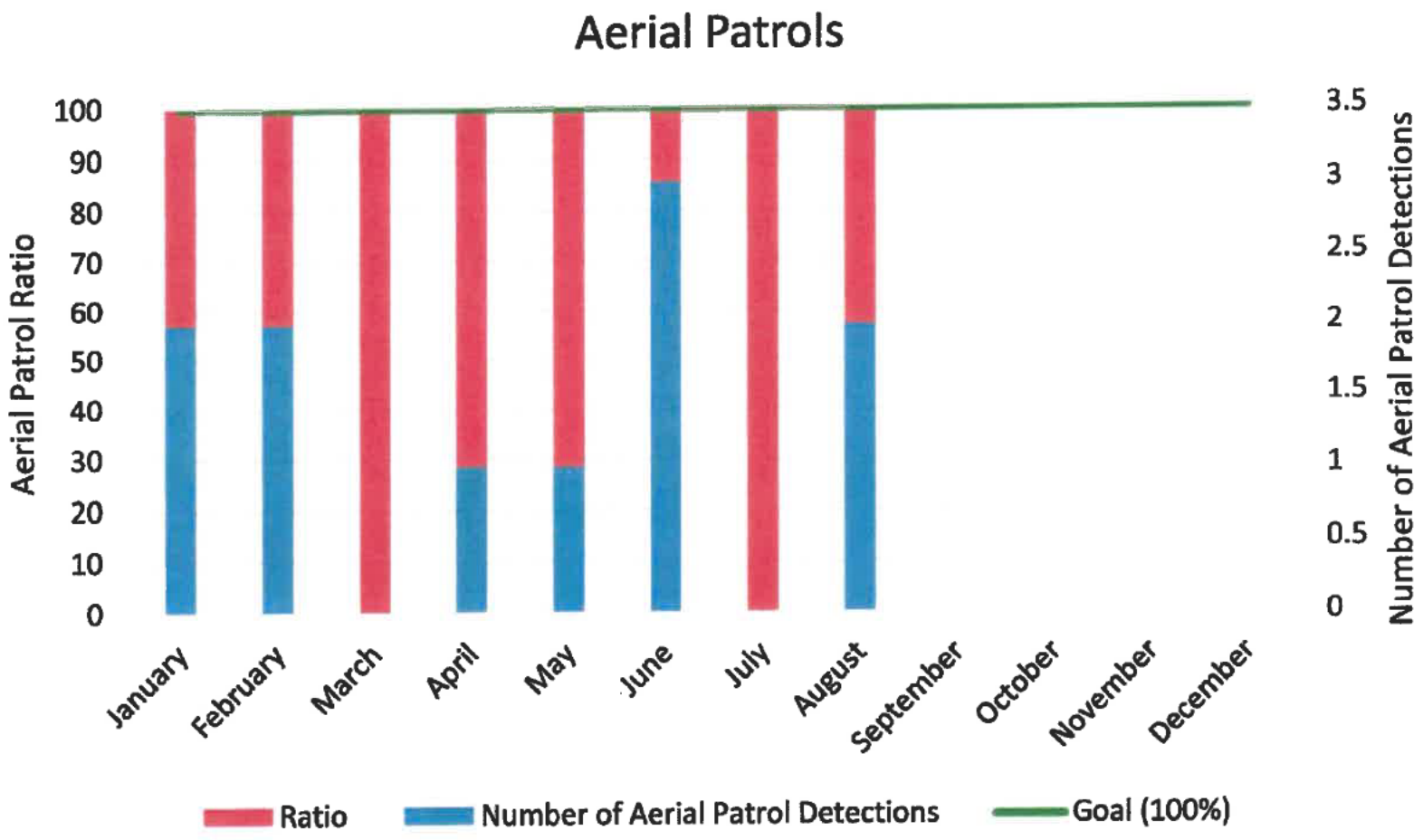



Third Party Damage
Near Miss to Loss Incident Ratio
1.2
1
0.8
0.6
0.4
0.2
0
January
February
March
April
May
June
July
August
September
October
November
December
Public Awareness Ratio
goal
# of Incidents with public awareness (or lack of) as a factor

Third Party Damage



Threats - Corrosion, SCC, Fatigue

Chemical content	# of H20 excursions	Goal	# of H2S excursions	Goal	# of C02 excursions	Goal
January	0	0	5	0	1	0
February	0	0	8	0	0	0
March	0	0	13	0	0	0
April	0	0	22	0	0	0
May	0	0	7	0	2	0
June	0	0	2	0	0	0
July	0	0	15	0	0	0
August	0	0	26	0	16	0
September		0		0		0
October		0		0		0
November		0		0		0
December		0		0		0

Threats - Corrosion, SCC, Fatigue

Overdue	Inspections	PMs	Recommendations	Goal
January	0	1	0	0
February	0	0	0	0
March	0	0	0	0
April	0	0	0	0
May	0	12	0	0
June	0	0	0	0
July	0	0	0	0
August	0	1	51	0
September				0
October				0
November				0
December				0

Threats - Corrosion, SCC, Fatigue

Number of Integrity Assessment Findings	Due to ILI	Due to Pressure	Due to ECDA
January	1	0	0
February	0	0	0
March	0	0	0
April	0	0	0
May	0	0	0
June	2	0	0
July	2	0	0
August	0	0	0
September			
October			
November			
December			

Threats - Corrosion, SCC, Fatigue

# of ILI Anomalies:	Excavated	Repaired inside	Repaired Outside HCA
January	1	0	0
February	0	0	0
March	0	0	0
April	0	0	0
May	2	0	2
June	2	0	0
July	0	0	0
August	0	0	0
September			
October			
November			
December			

Threats - Corrosion, SCC, Fatigue

Leaks	# near misses due to corrosion issues	# Incidents due to corrosion issues	Corrosion ratio	Goal	# near misses due to gasket / packing issues	# Incidents due to gasket / packing issues	Gasket / packing ratio	Goal
January	0	0	#DIV/0!	1	1	0	#DIV/0!	1
February	0	0	#DIV/0!	1	0	0	#DIV/0!	1
March	0	0	#DIV/0!	1	0	0	#DIV/0!	1
April	0	0	#DIV/0!	1	0	0	#DIV/0!	1
May	0	0	#DIV/0!	1	0	0	#DIV/0!	1
June	0	0	#DIV/0!	1	0	0	#DIV/0!	1
July	0	0	#DIV/0!	1	0	0	#DIV/0!	1
August	0	0	#DIV/0!	1	0	0	#DIV/0!	1
September			#DIV/0!	1			#DIV/0!	1
October			#DIV/0!	1			#DIV/0!	1
November			#DIV/0!	1			#DIV/0!	1
December			#DIV/0!	1			#DIV/0!	1

Threats - Corrosion, SCC, Fatigue

Material Properties	Number of pipeline materials with Question	Goal	# near misses due to material properties issues	# incidents due to material properties issues	Material Properties ratio	Goal
January	0	0	0	0	#DIV/0!	1
February	0	0	0	0	#DIV/0!	1
March	0	0	0	0	#DIV/0!	1
April	0	0	0	0	#DIV/0!	1
May	0	0	0	0	#DIV/0!	1
June	0	0	0	0	#DIV/0!	1
July	0	0	0	0	#DIV/0!	1
August	0	0	0	0	#DIV/0!	1
September					#DIV/0!	1
October					#DIV/0!	1
November					#DIV/0!	1
December					#DIV/0!	1

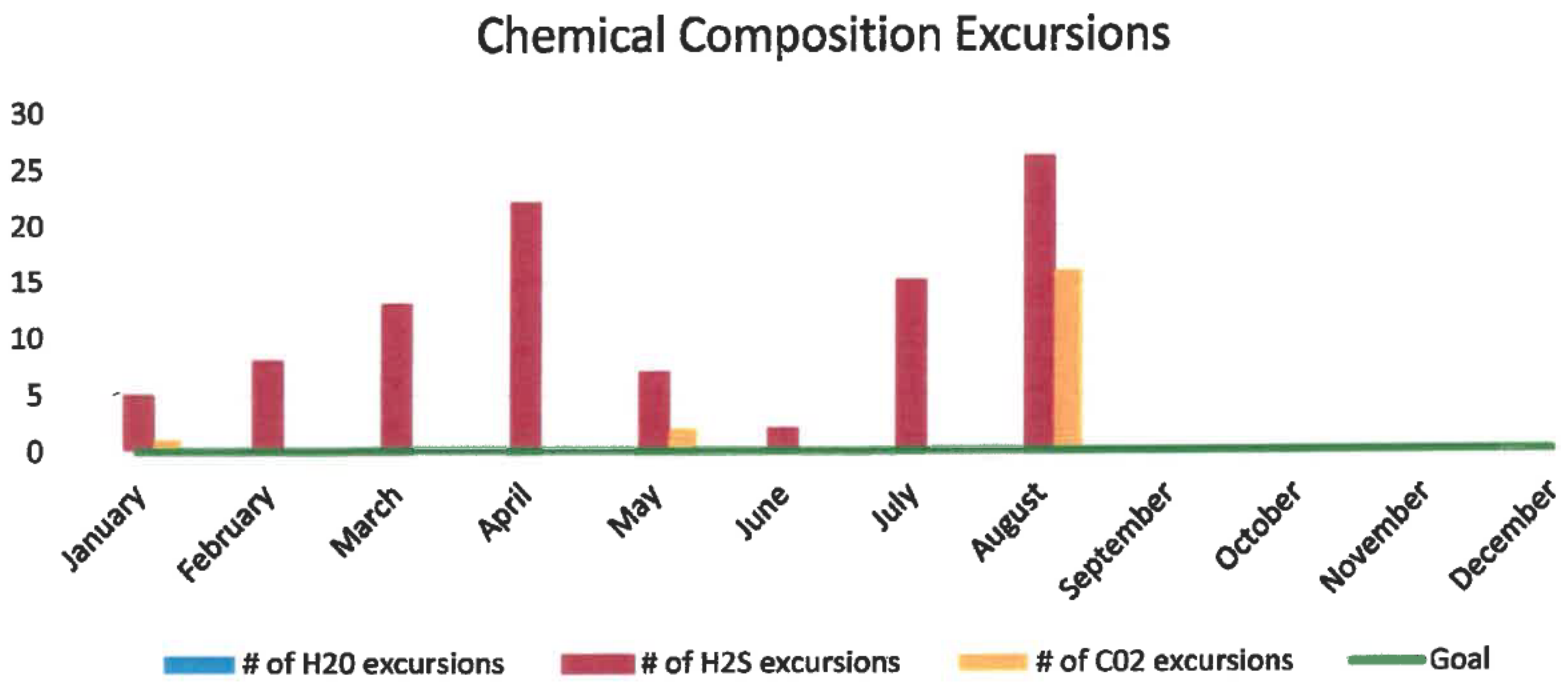
Threats - Corrosion, SCC, Fatigue

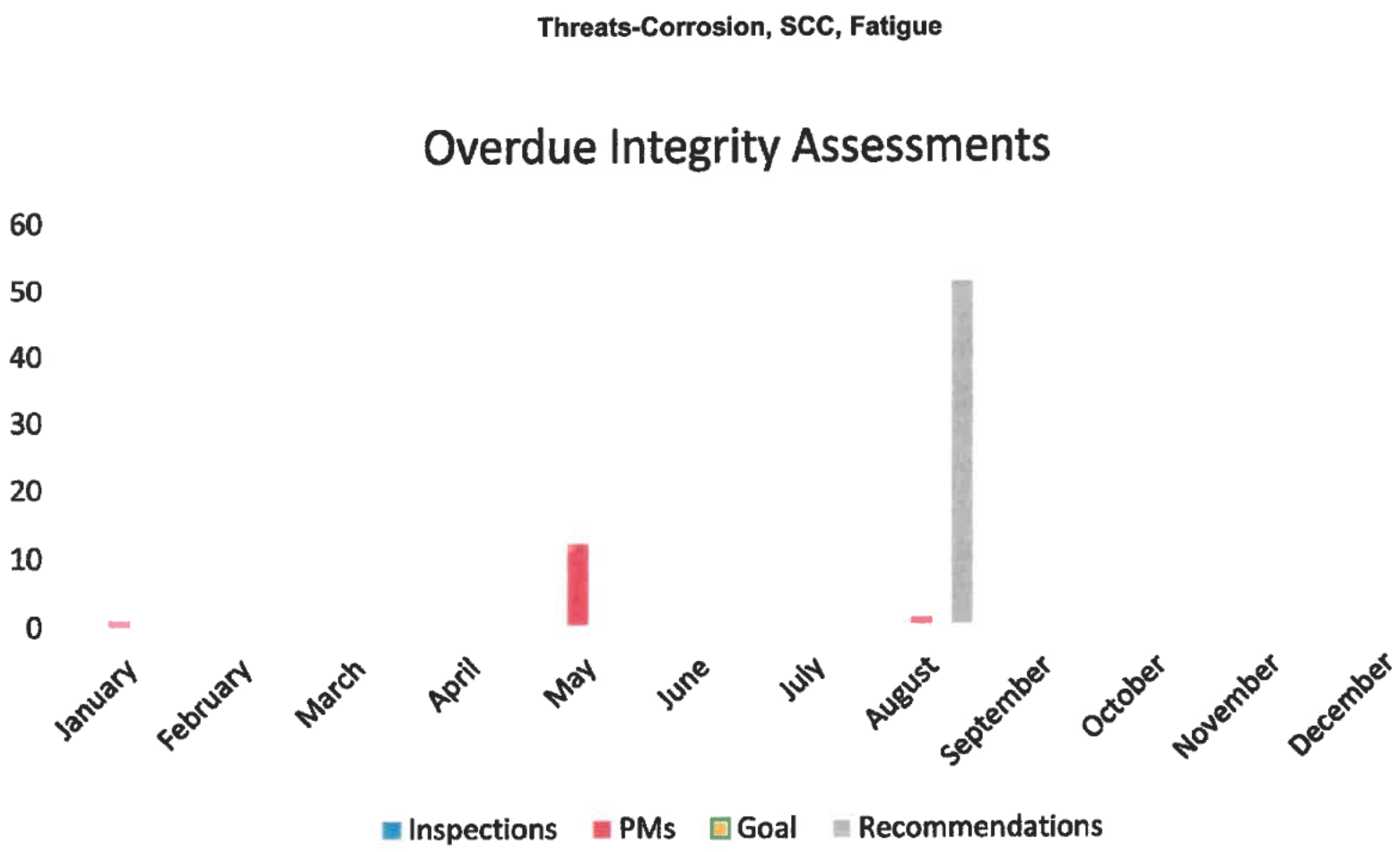
# of Completed Repair Conditions per IMP:	Immediate Repair conditions	60 day repair conditions	180 day repair conditions	Other Conditions
January	0	0	0	0
February	0	0	0	0
March	0	0	0	0
April	0	0	0	0
May	0	0	1	1
June	0	0	0	0
July	0	0	0	0
August	0	0	0	0
September				
October				
November				
December				

Threats - Corrosion, SCC, Fatigue

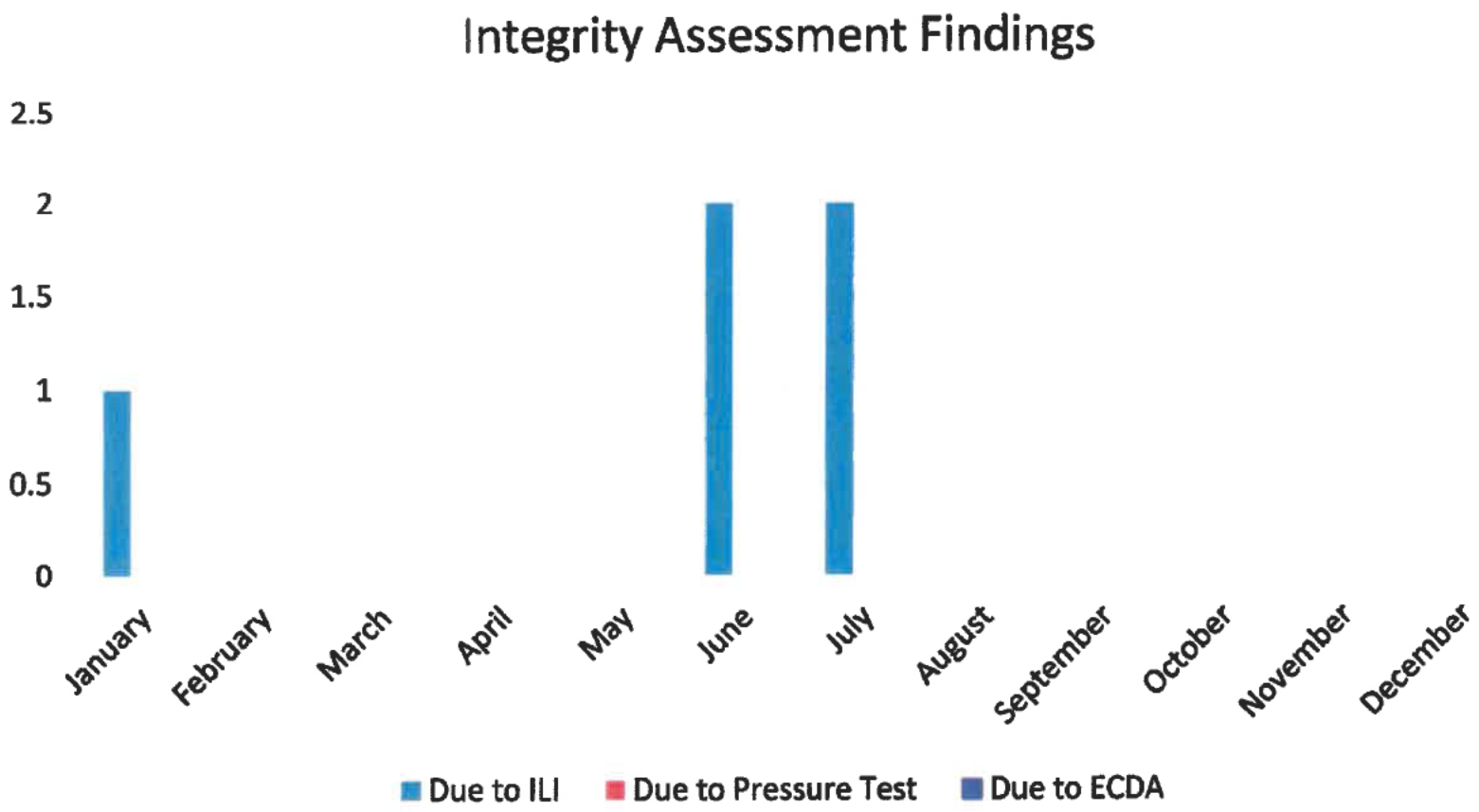
# of miles inspected	Planned	Actual	Ratio	Goal (%)
January	0.0075	0.0075	1	100%
February	0	0	#DIV/0!	100%
March	0	0	#DIV/0!	100%
April	0	0	#DIV/0!	100%
May	0.015	0.015	1	100%
June	0.015	0.015	1	100%
July	0	0	#DIV/0!	100%
August	0	0	#DIV/0!	100%
September			#DIV/0!	100%
October			#DIV/0!	100%
November			#DIV/0!	100%
December			#DIV/0!	100%

Threats-Corrosion, SCC, Fatigue

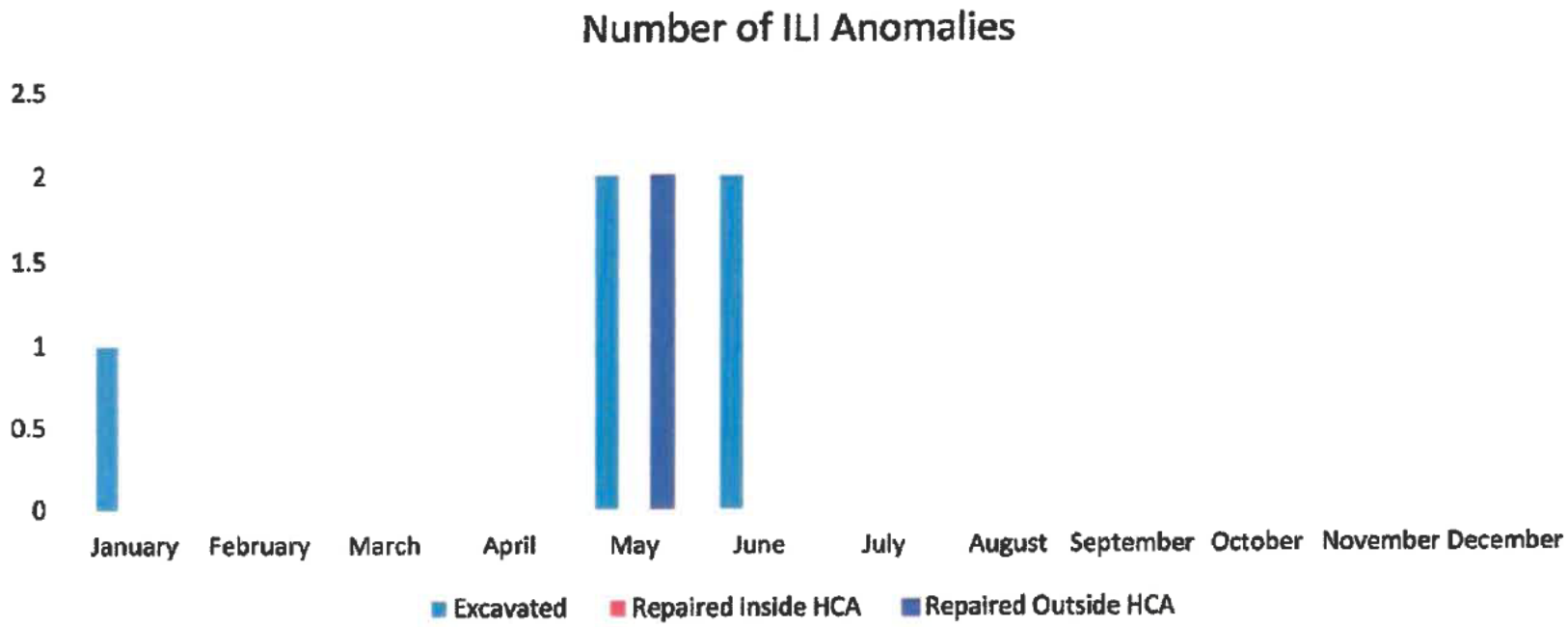



Threats-Corrosion, SCC, Fatigue
Overdue Integrity Assessments
60
50
40
30
20
10
0
January
February
March
April
May
June
July
August
September
October
November
December
Inspections
PMs
Goal
Recommendations

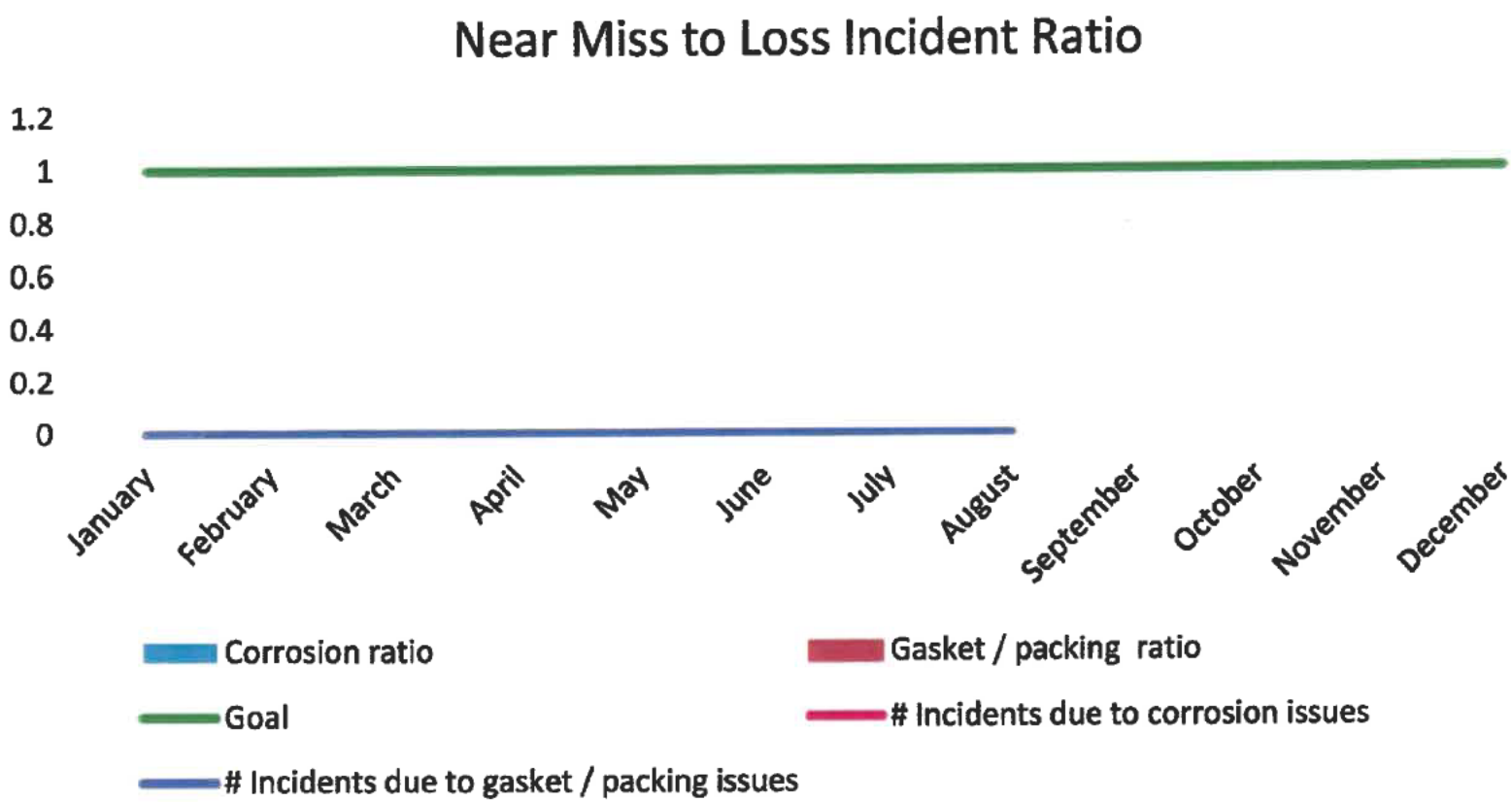
Threats-Corrosion, SCC, Fatigue



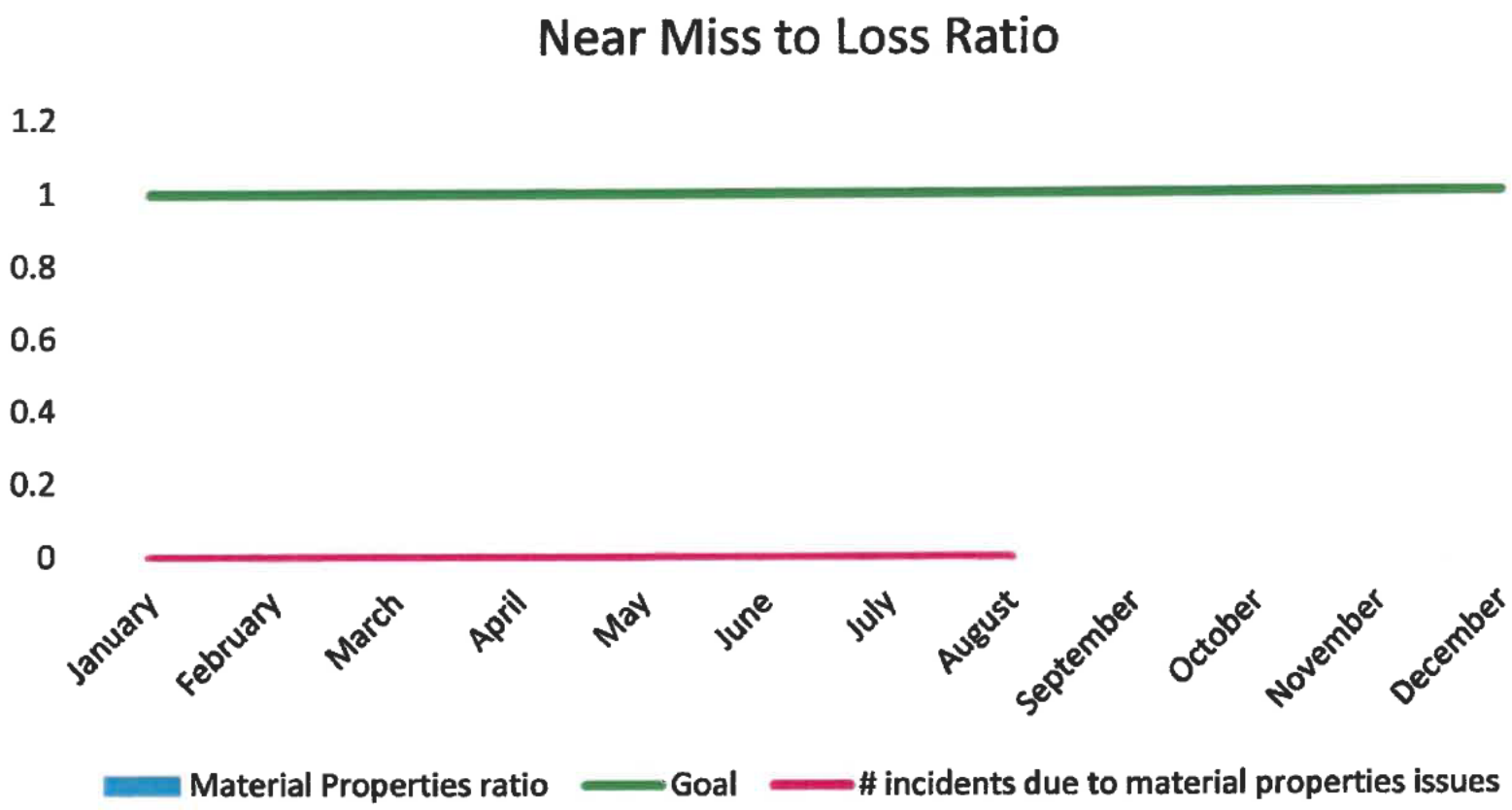
Threats-Corrosion, SCC, Fatigue



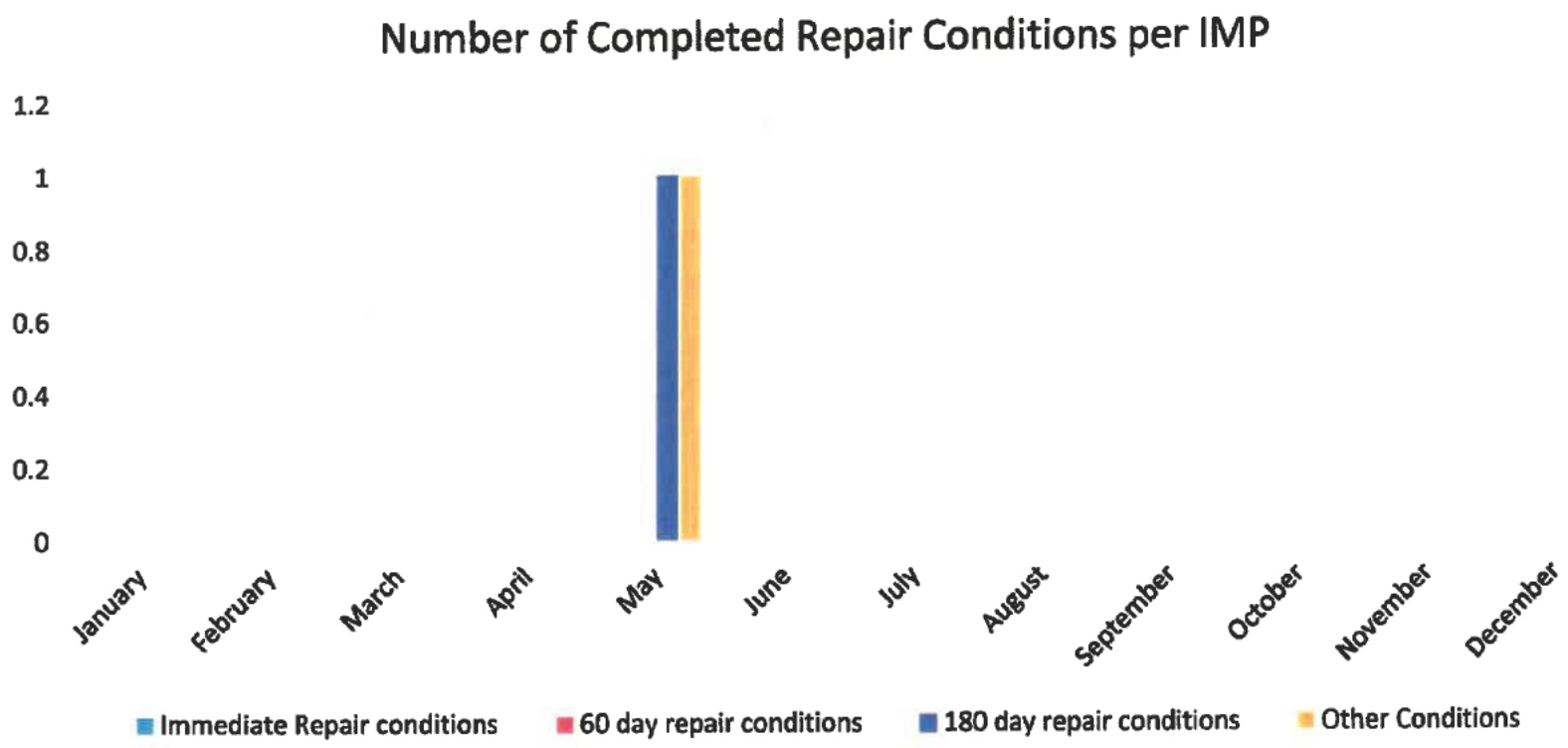
Threats-Corrosion, SCC, Fatigue



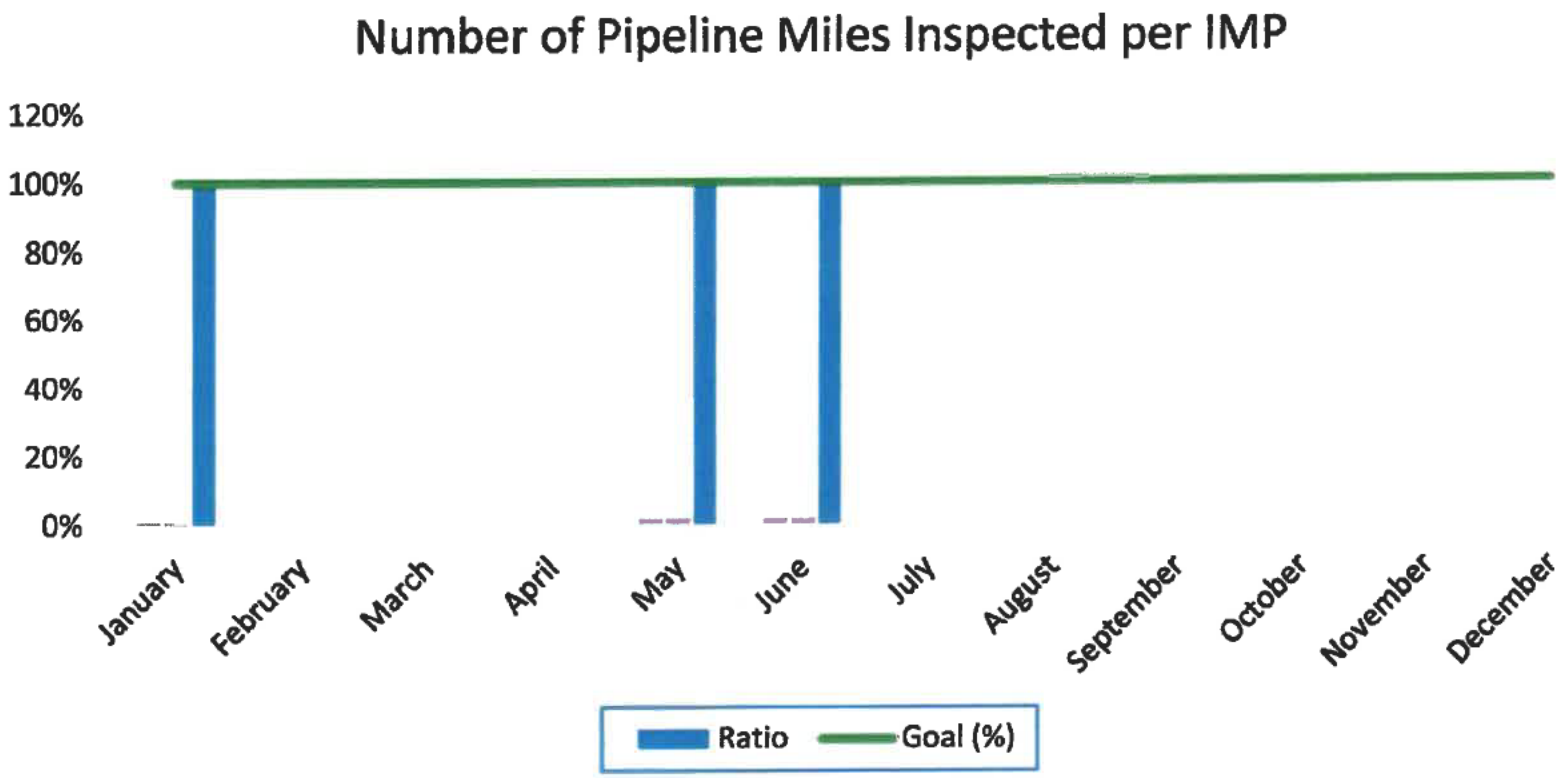
Threats-Corrosion, SCC, Fatigue



Threats-Corrosion, SCC, Fatigue



Threats-Corrosion, SCC, Fatigue



Operational Discipline *

Training	# of overdue Operator Qualification trainings	Goal	# near misses with OQ training / performance / experience as a factor	# incidents with OQ training / performance / experience as a factor	Training Ratio	Goal
January	0	1	0	0	#DIV/0!	1
February	0	1	0	0	#DIV/0!	1
March	1	1	0	0	#DIV/0!	1
April	1	1	0	0	#DIV/0!	1
May	0	1	0	0	#DIV/0!	1
June	0	1	0	0	#DIV/0!	1
July	2	1	0	0	#DIV/0!	1
August	0	1	0	0	#DIV/0!	1
September		1			#DIV/0!	1
October		1			#DIV/0!	1
November		1			#DIV/0!	1
December		1			#DIV/0!	1

SWP	Number of SWP/Internal Compliance audits/DIR Observations conducted	Goal	# near misses with SWP as a factor	# incidents with SWP as a factor	Training Ratio	Goal
January	1	5	0	0	#DIV/0!	1
February	16	5	0	0	#DIV/0!	1
March	9	5	0	0	#DIV/0!	1
April	2	5	0	0	#DIV/0!	1
May	2	5	0	0	#DIV/0!	1
June	3	5	0	0	#DIV/0!	1
July	0	5	0	0	#DIV/0!	1
August	0	5	0	0	#DIV/0!	1
September		5			#DIV/0!	1
October		5			#DIV/0!	1
November		5			#DIV/0!	1
December		5			#DIV/0!	1

Operational Discipline*

Safety system isolation	# of times safety system isolated (or exceeding time)	Goal
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September		0
October		0
November		0
December		0

Alarm mgmt	# near misses with AM as a factor	# incidents with AM as a factor	Alarm Mgmt Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Operational Discipline *

O&M Manual Review	# of O&M Manuals Reviewed	# of Overdue O&M Manual Reviews	Goal	# near misses with procedure as a factor	# incidents with procedure as a factor	Alarm Mgmt Ratio	Goal
January	1	0	0	0	0	#DIV/0!	2
February	0	0	0	0	0	#DIV/0!	2
March	0	0	0	0	0	#DIV/0!	2
April	0	0	0	0	0	#DIV/0!	2
May	0	0	0	0	0	#DIV/0!	2
June	0	0	0	0	0	#DIV/0!	2
July	0	0	0	0	0	#DIV/0!	2
August	0	0	0	0	0	#DIV/0!	2
September			0			#DIV/0!	2
October			0			#DIV/0!	2
November			0			#DIV/0!	2
December			0			#DIV/0!	2

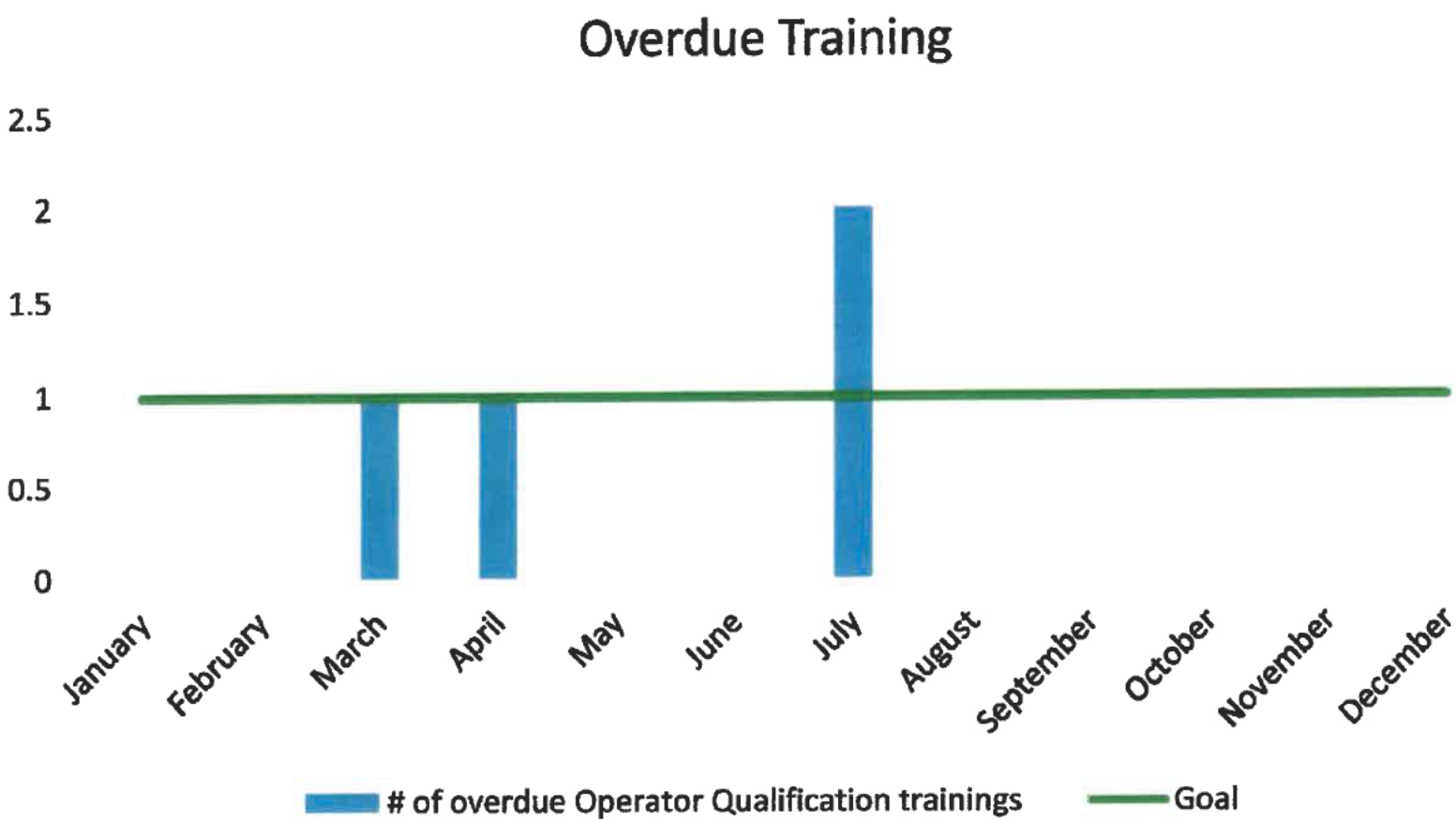
Specs review	# of outdated spec reviews	Goal	# near misses with spec as a factor	# incidents with spec as a factor	Specification ratio	Goal
January	0	0	0	0	#DIV/0!	2
February	0	0	0	0	#DIV/0!	2
March	0	0	0	0	#DIV/0!	2
April	0	0	0	0	#DIV/0!	2
May	0	0	0	0	#DIV/0!	2
June	0	0	0	0	#DIV/0!	2
July	0	0	0	0	#DIV/0!	2
August	0	0	0	0	#DIV/0!	2
September		0			#DIV/0!	2
October		0			#DIV/0!	2
November		0			#DIV/0!	2
December		0			#DIV/0!	2

Operational Discipline *

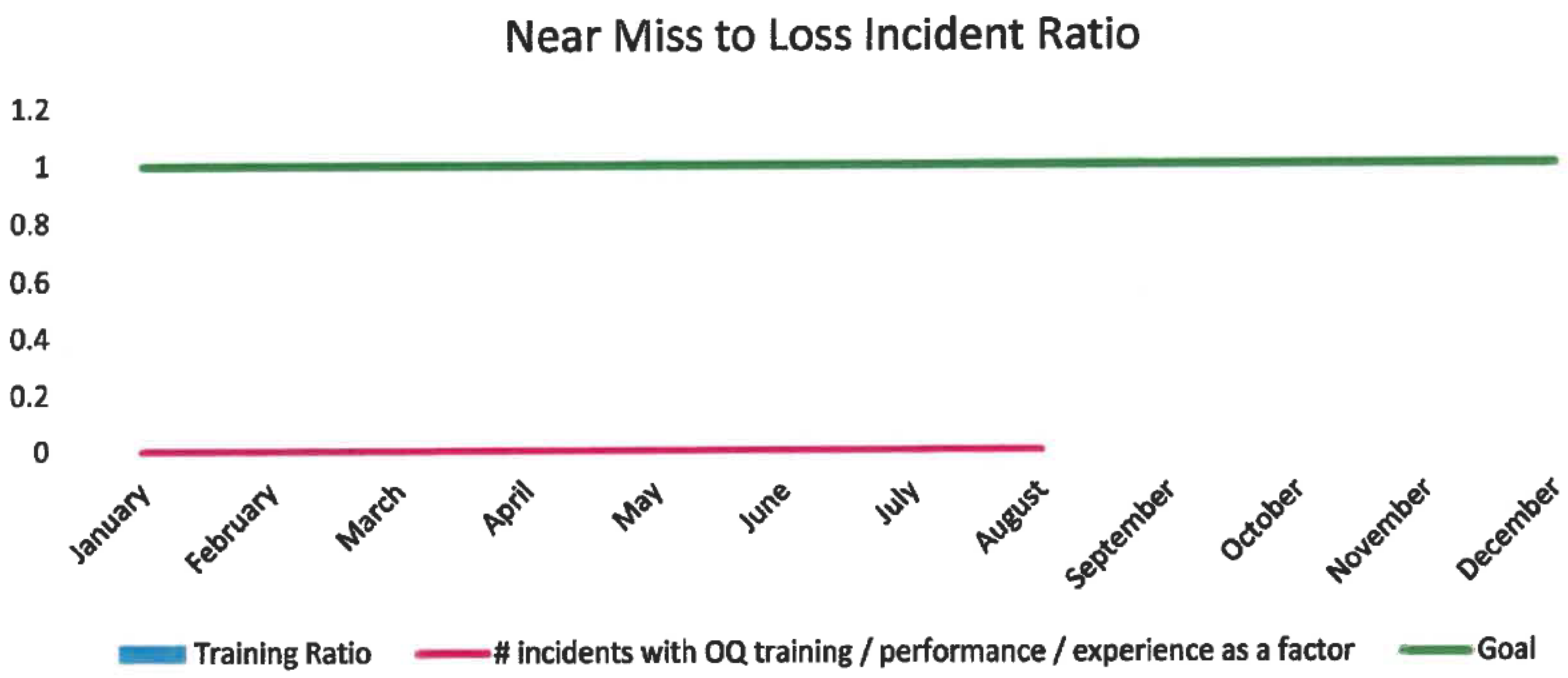
Construction/ mfg	# of hydrostatic failures / near misses due to construction/mfg defects	# incidents with construction/ mfg defects as a factor	Construction / mfg Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

***Crews: Boiler Maintenance, Gas Processing, CO2 Pipeline, Maintenance Engr, E&I (all crews), Inspection, 5900 (all crews), Inspection, Shift Supts. & Step ups, Protection Services >3 years**

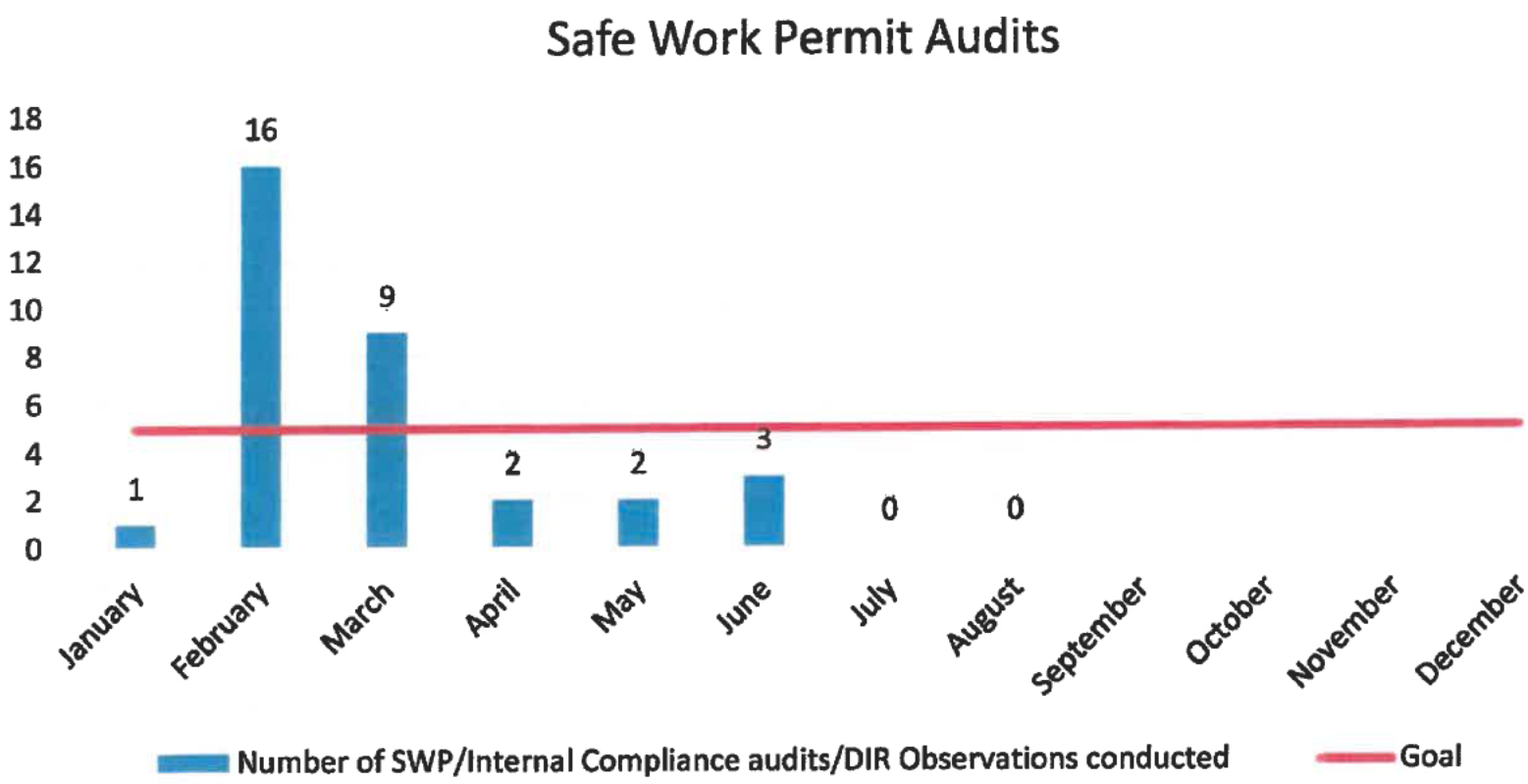
Operational Discipline



Operational Discipline



Operational Discipline



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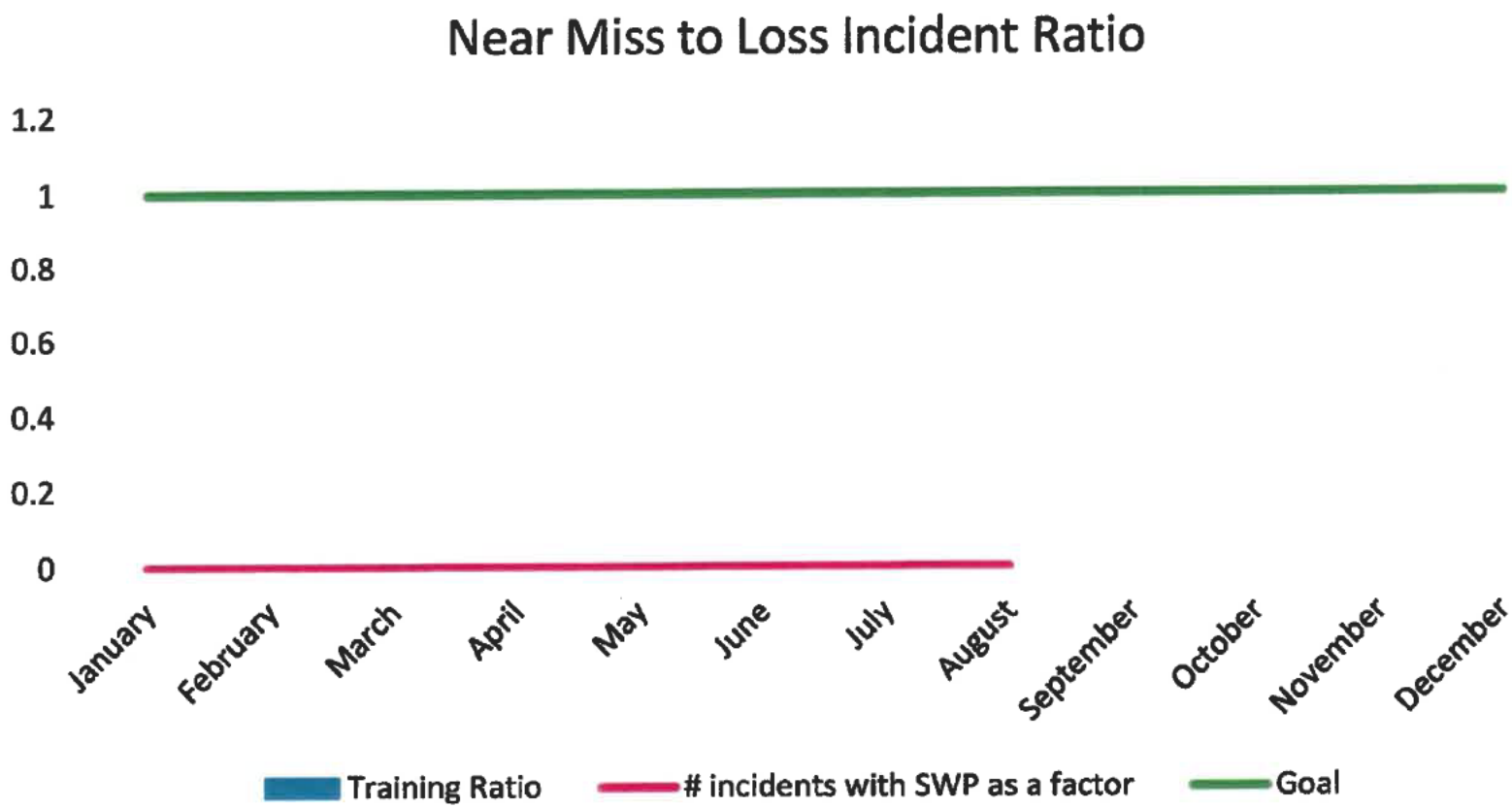

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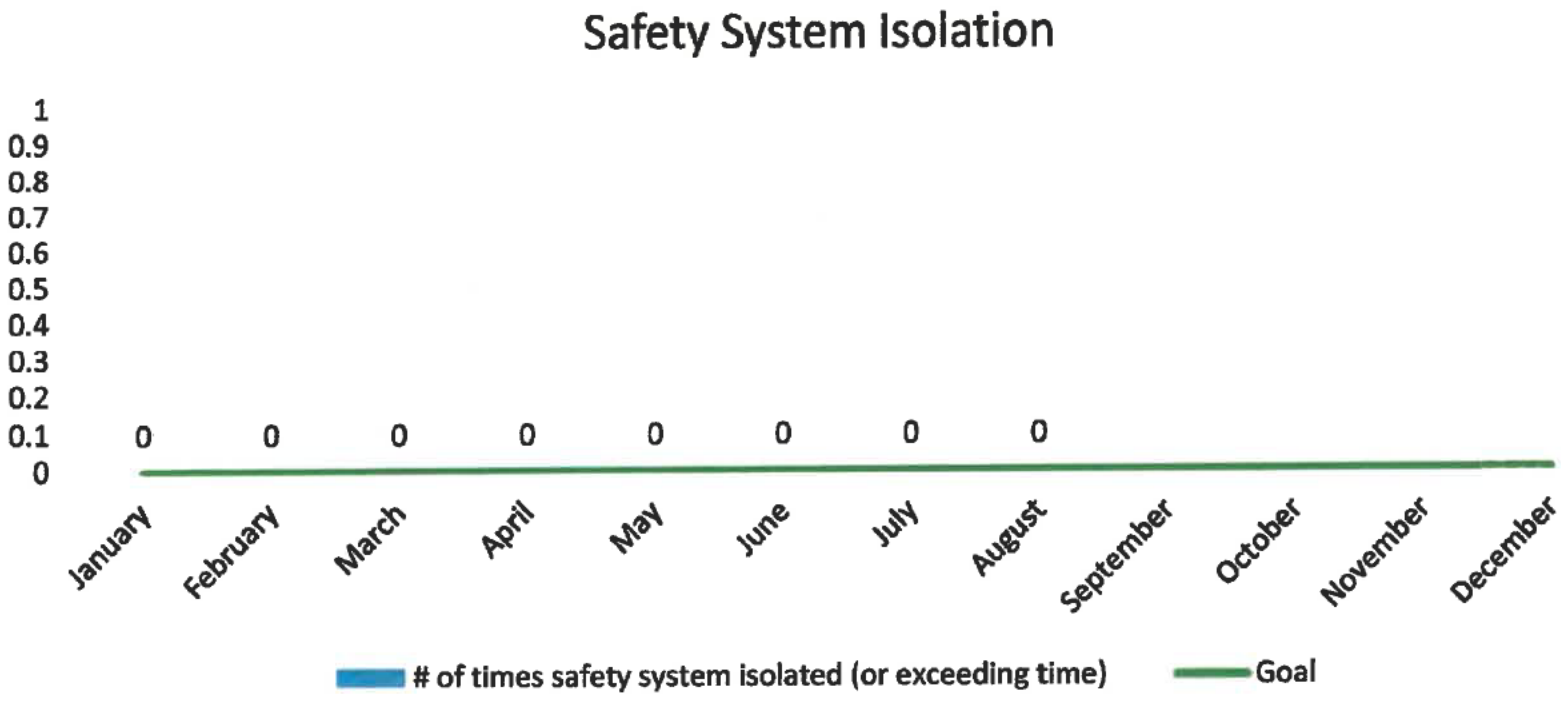

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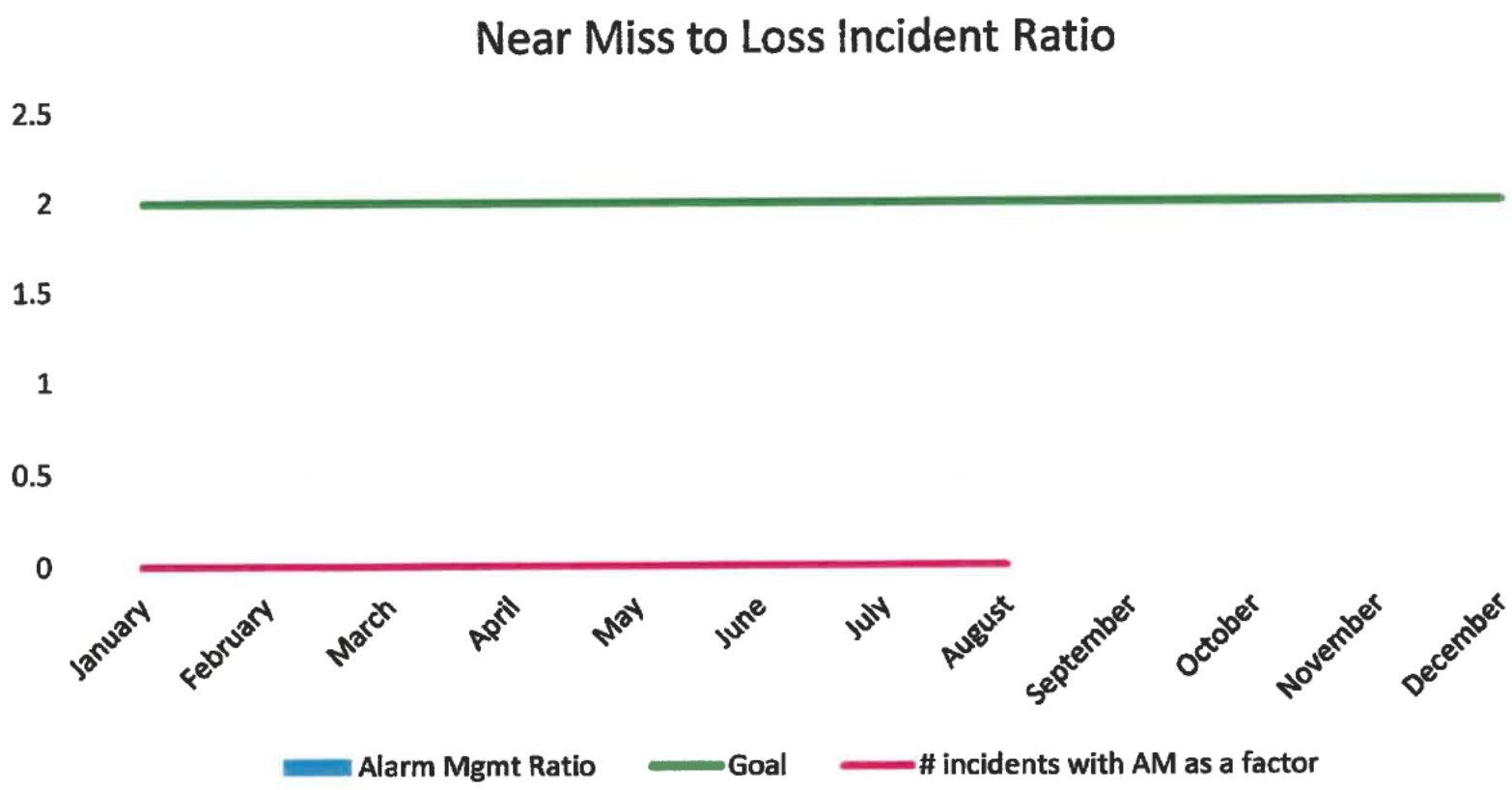

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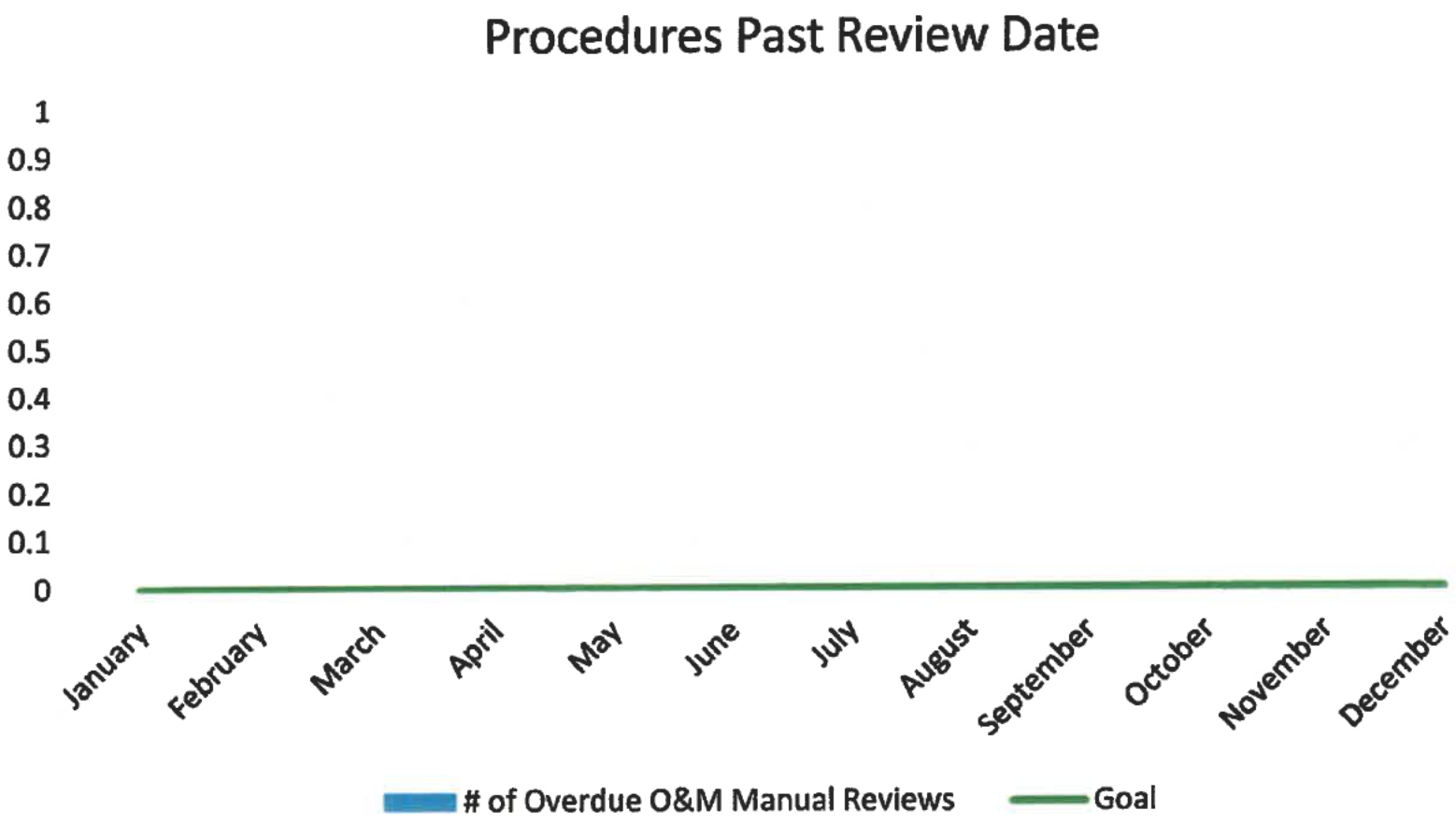

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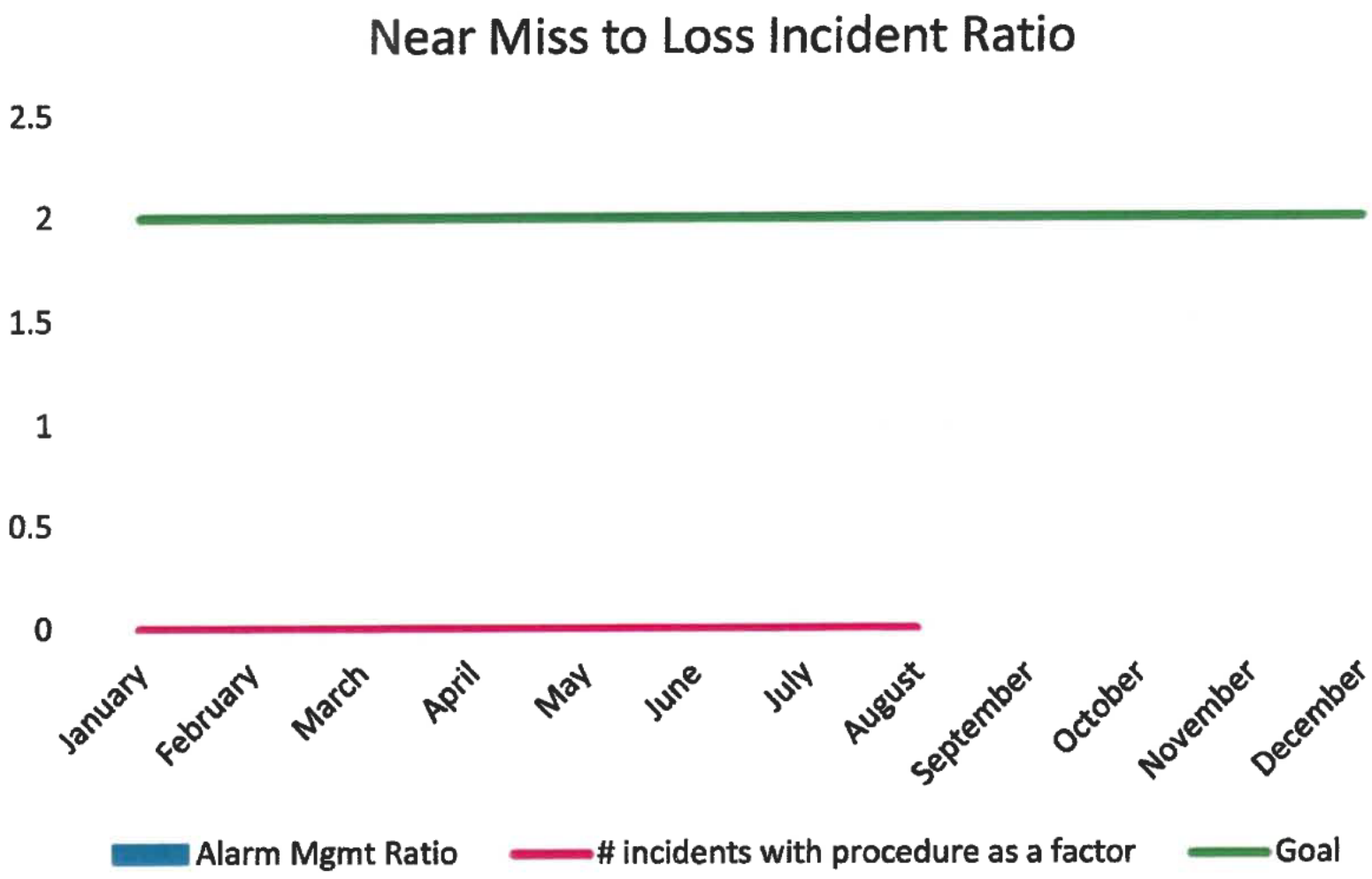

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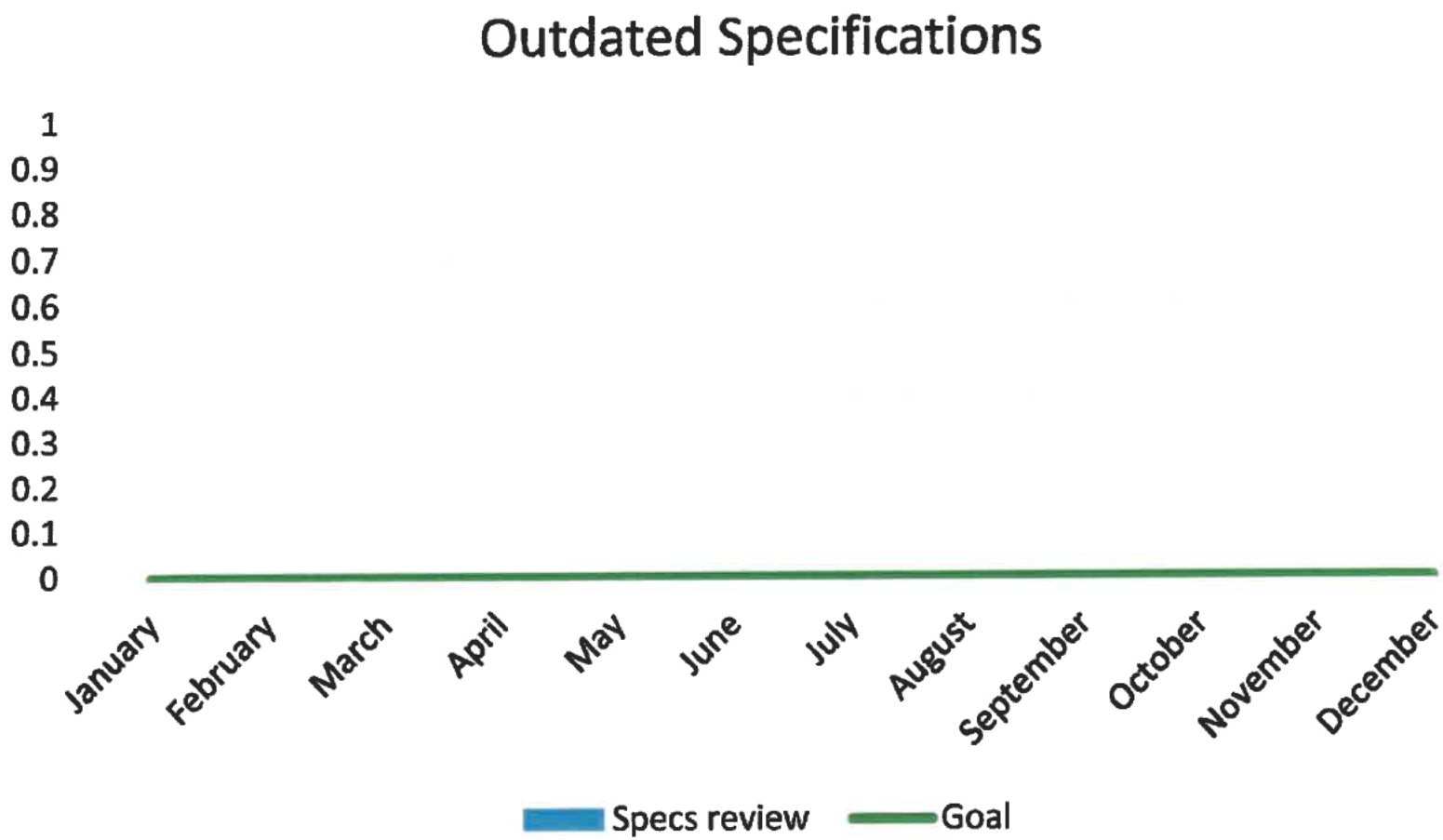
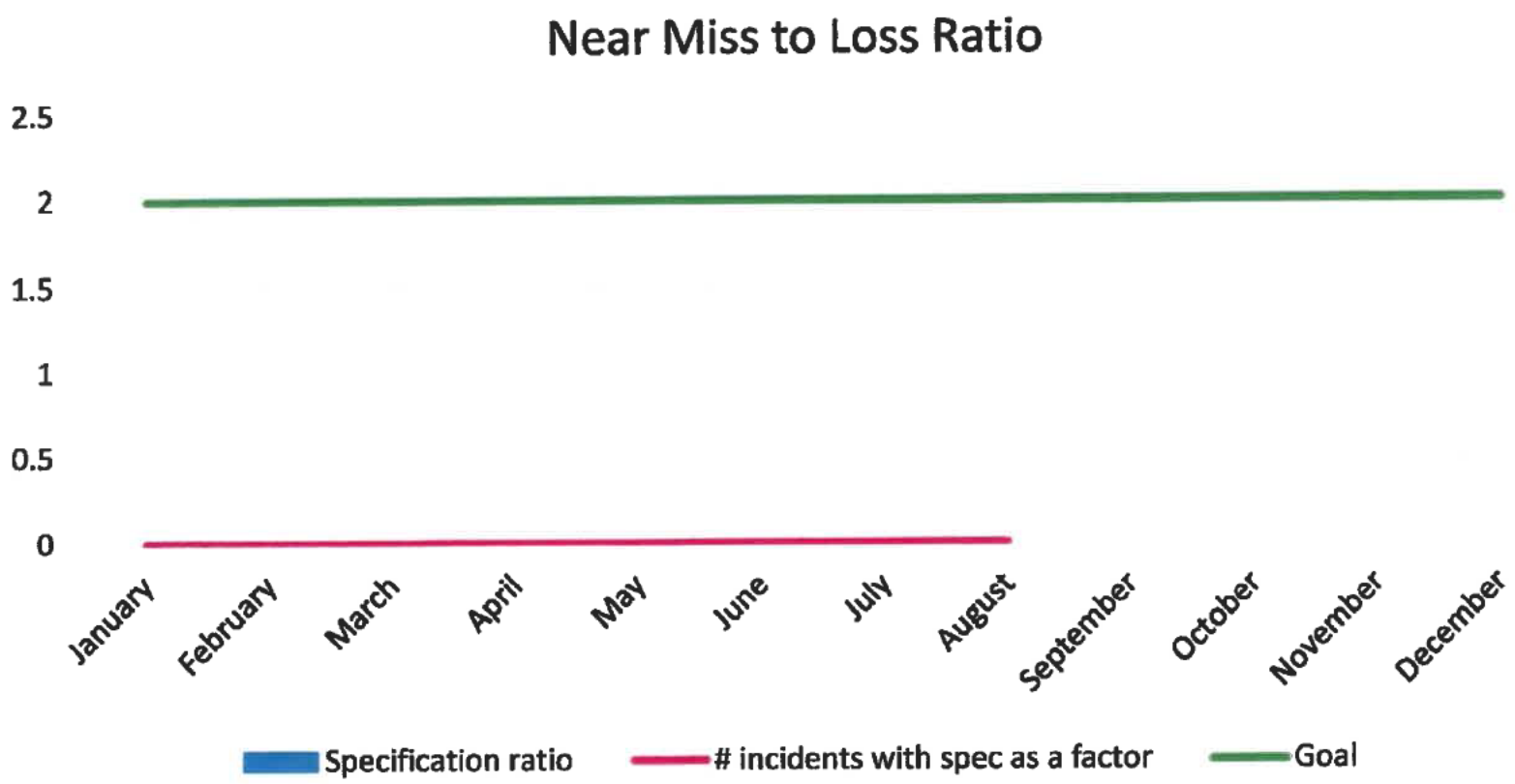


Operational Discipline



Operational Discipline

Natural Forces

Cold Weather	# near misses with cold weather as a factor	# incidents with cold weather as a factor	Cold Weather Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Exposed pipe / Earth Movement / Landslides	# near misses with exposed pipe / washout as a factor	# incidents with exposed pipe / washout as a factor	Exposed Pipe / Washout Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Lightning	# near misses with lightning as a factor	# incidents with lightning as a factor	Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	1	1	1	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

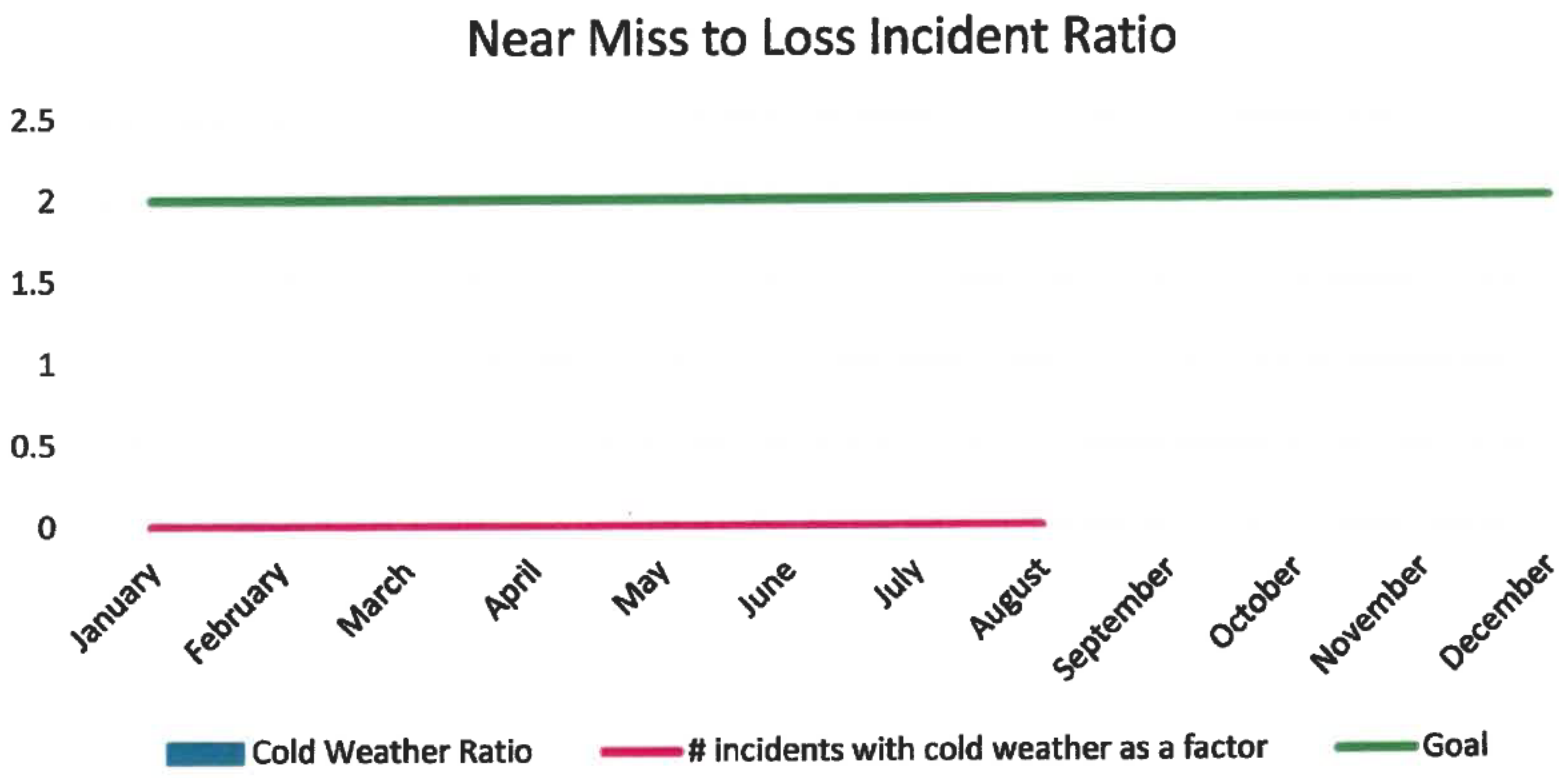
Natural Forces

Tornado	# near misses with tornado as a factor	# incidents with tornado as a factor	Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Flooding	# near misses with flooding as a factor	# incidents with flooding as a factor	Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Fire	# near misses with fire as a factor	# incidents with fire as a factor	Ratio	Goal
January	0	0	#DIV/0!	2
February	0	0	#DIV/0!	2
March	0	0	#DIV/0!	2
April	0	0	#DIV/0!	2
May	0	0	#DIV/0!	2
June	0	0	#DIV/0!	2
July	0	0	#DIV/0!	2
August	0	0	#DIV/0!	2
September			#DIV/0!	2
October			#DIV/0!	2
November			#DIV/0!	2
December			#DIV/0!	2

Natural Forces



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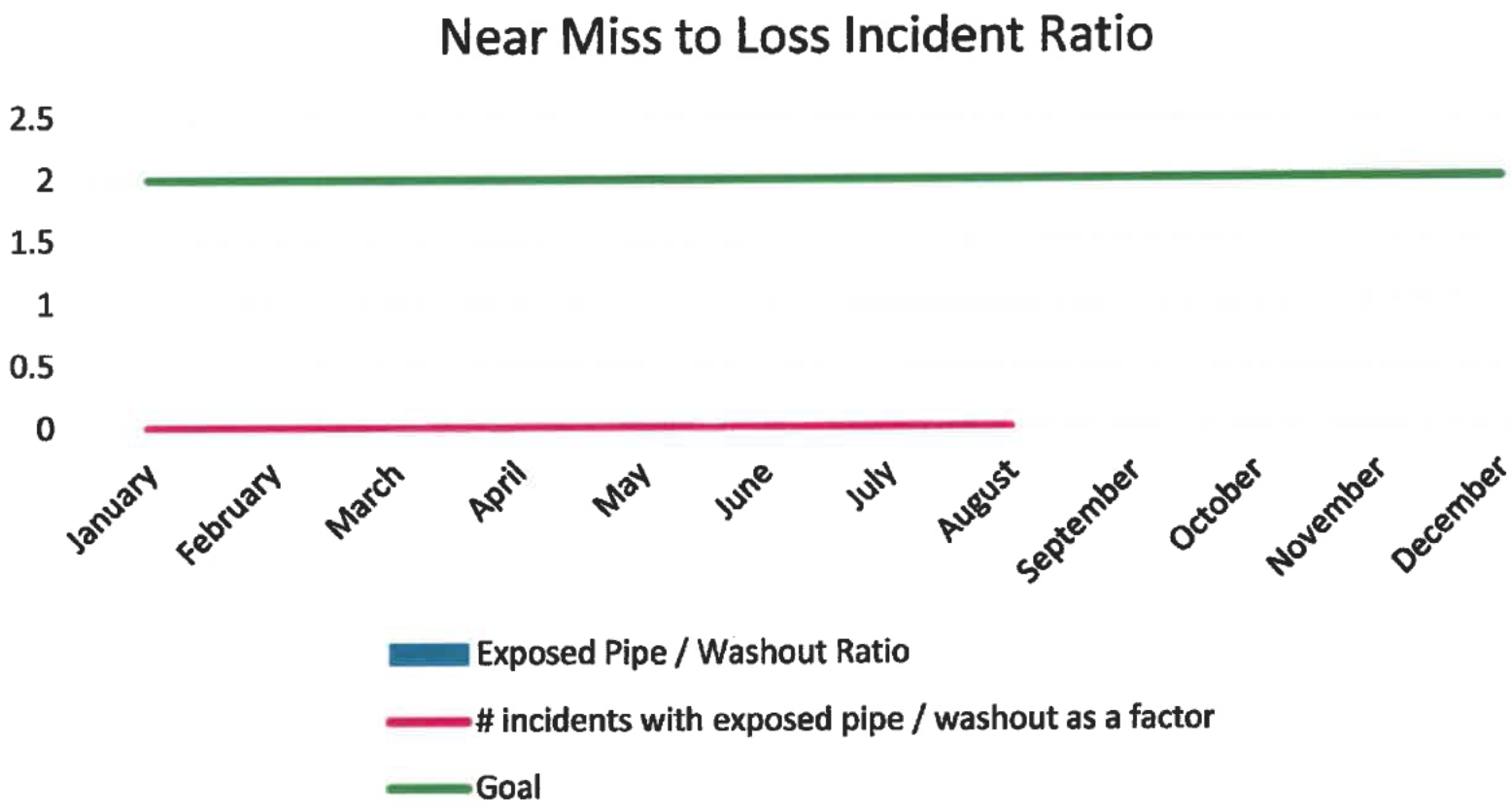

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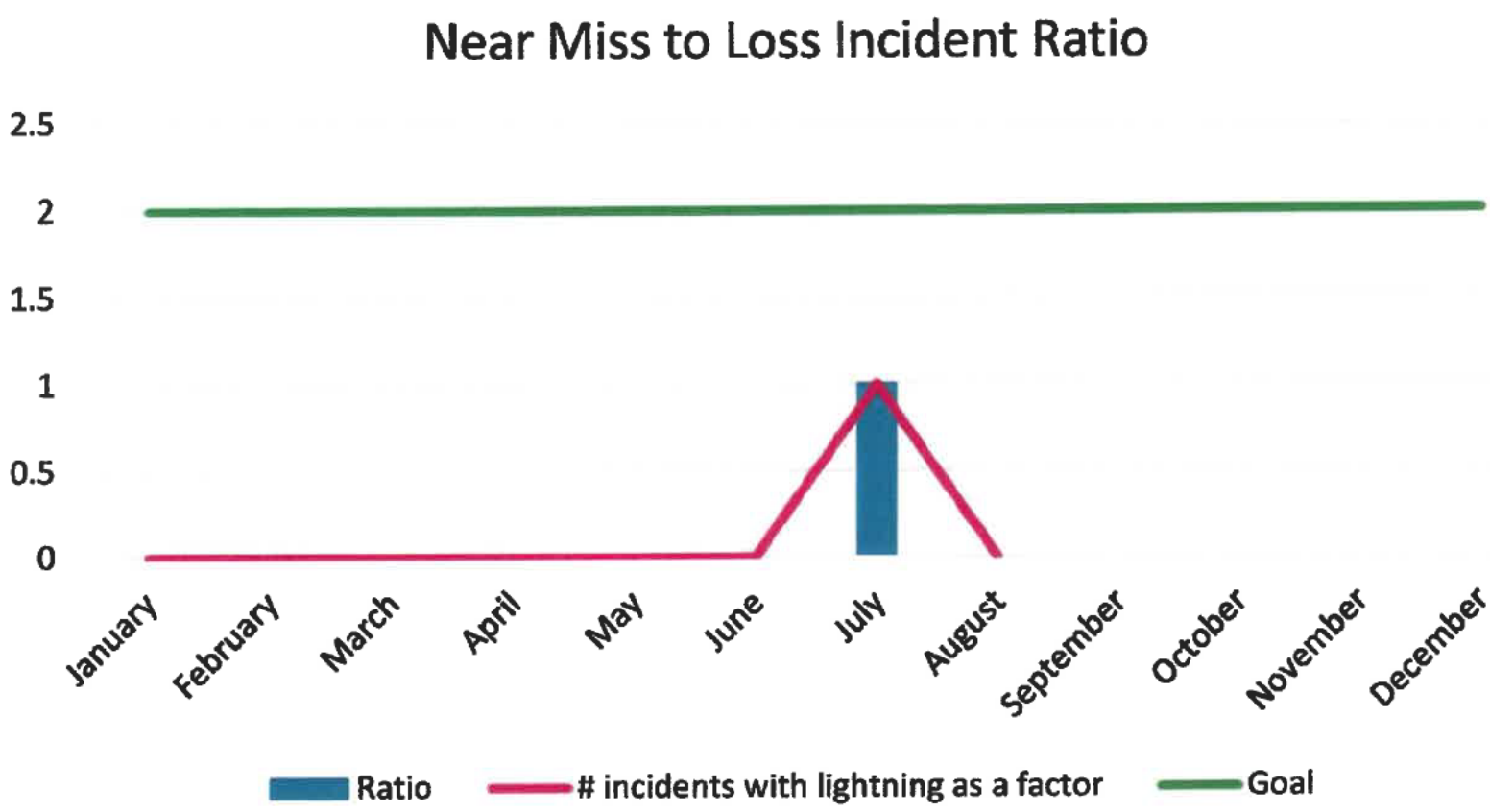
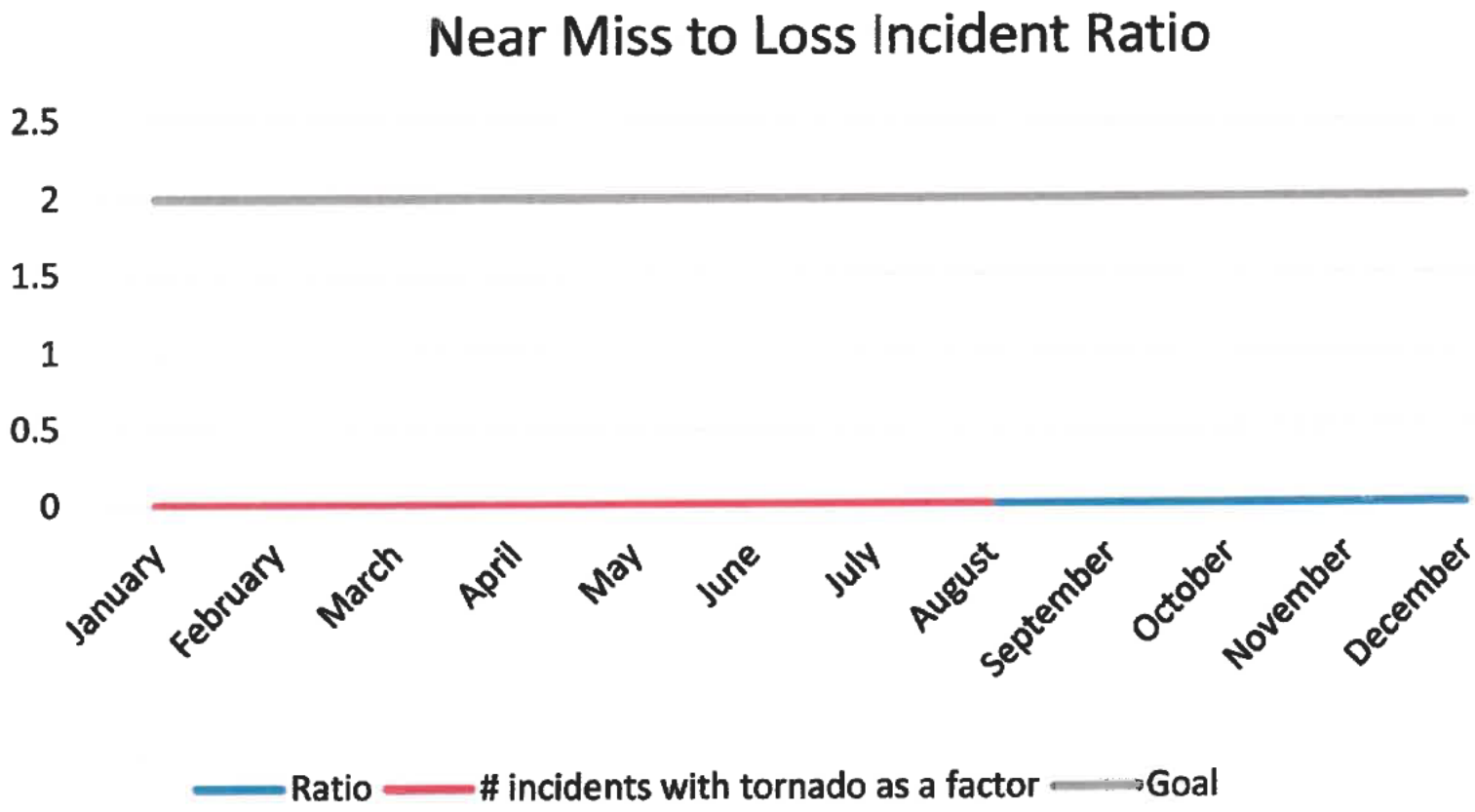
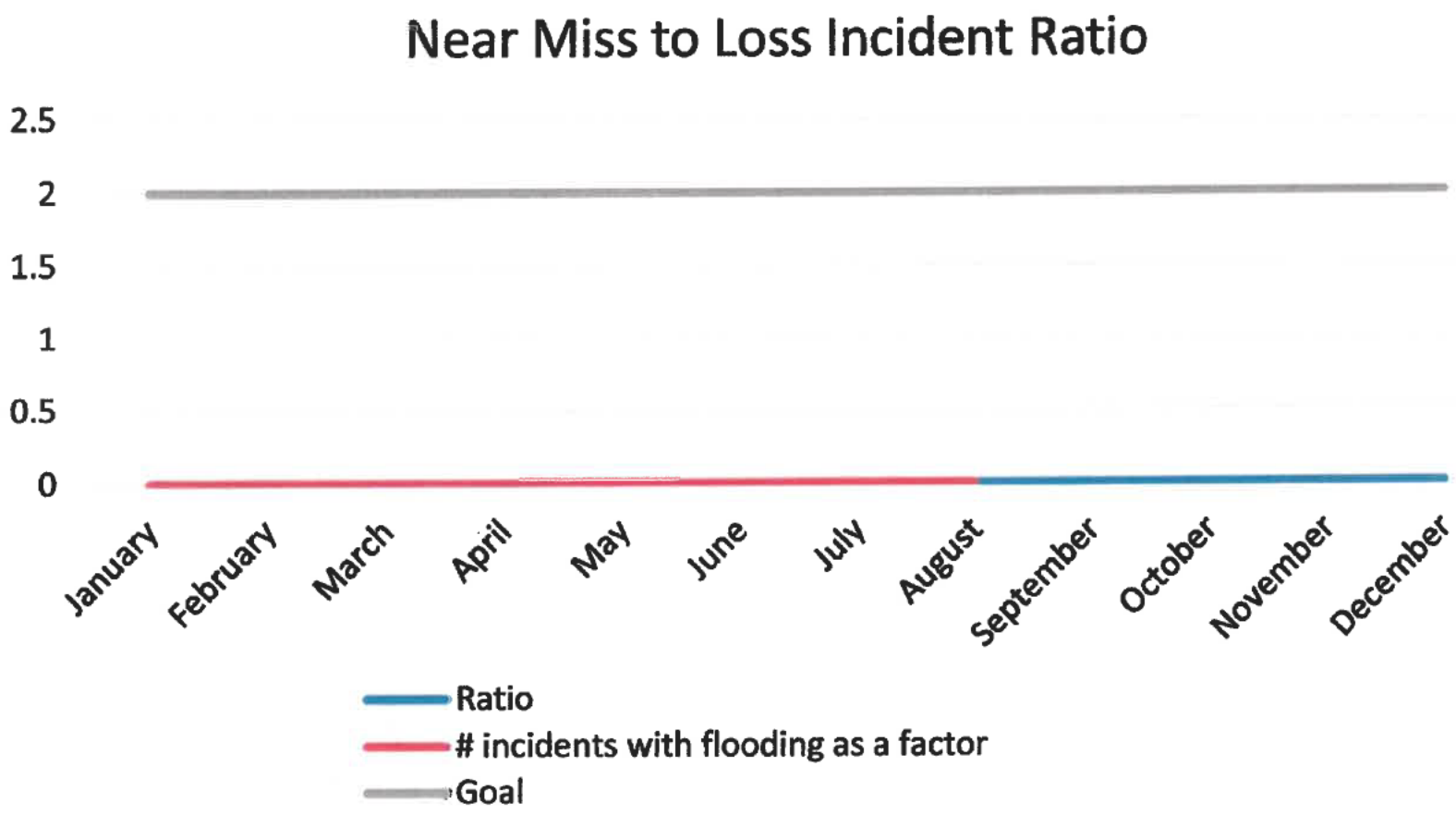
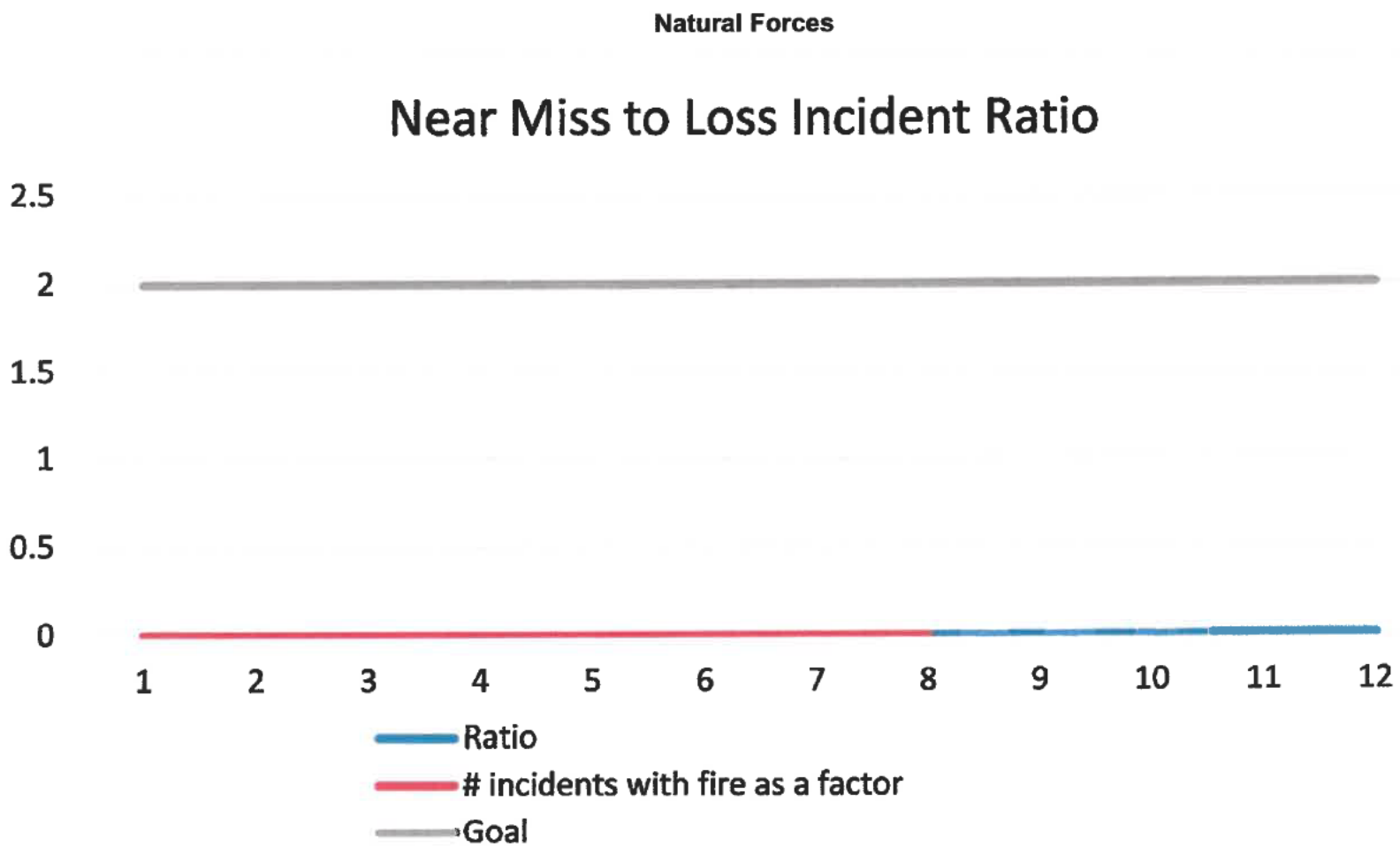


Natural Forces



Natural Forces




Natural Forces
Near Miss to Loss Incident Ratio
2.5
2
1.5
1
0.5
0
1
2
3
4
5
6
7
8
9
10
11
12
Ratio
incidents with fire as a factor
Goal

IMP Effectiveness

Preventive and Mitigation identified and implemented	Preventive and Mitigation Measures identified	Preventive and Mitigation Measures implemented	Goal
January	0	0	3
February	3		3
March	3		3
April	0	0	3
May	0	0	3
June	0	0	3
July	0	0	3
August	2	2	3
September			3
October			3
November			3
December			3

IMP Effectiveness

Reviews	# of overdue annual reviews; IMP Evaluation, Annual DOT Report, HCA Survey, Compliance Audit (Performance Evaluation), Preventive & mitigative measures analysis (PLR-68)	Goal
January	0	0
February	0	0
March	0	0
April	0	0
May	0	0
June	0	0
July	0	0
August	0	0
September		0
October		0
November		0
December		0

IMP Effectiveness

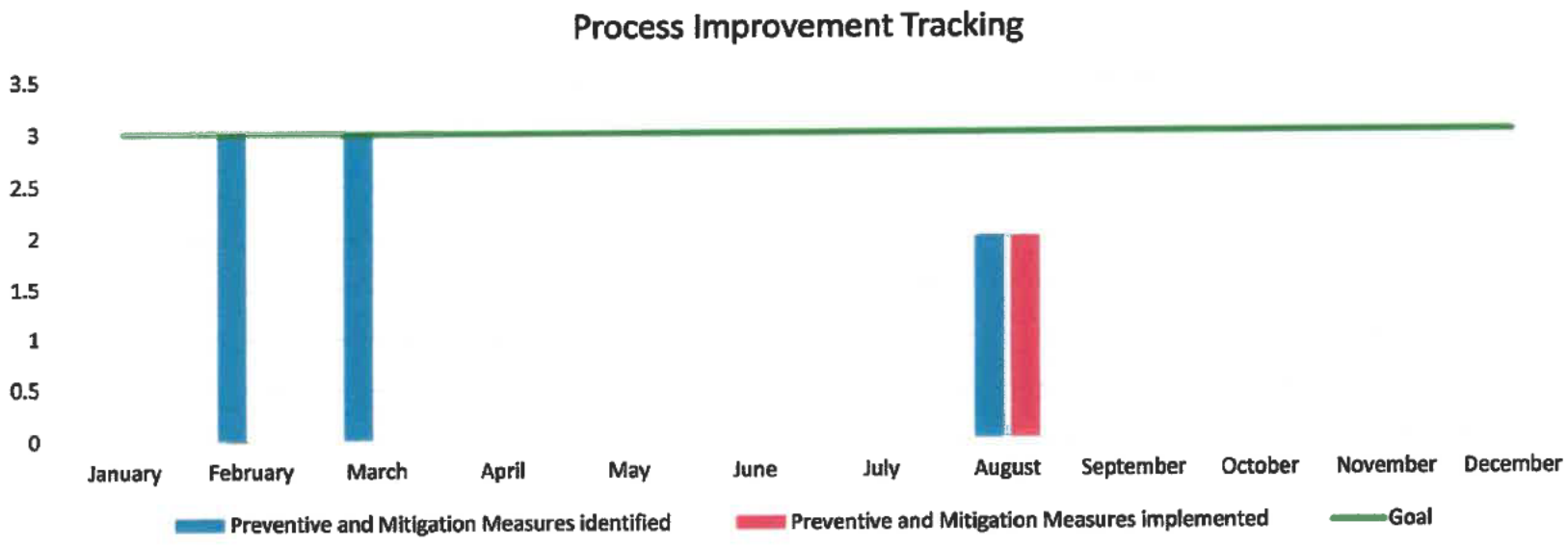
Integrity assessments	# of inspections/PMs Forecasted	# of inspections/PMs completed	Forecasted to Completed Ratio	Goal (%)
January	16	15	93.75%	100.00%
February	3	3	100.00%	100.00%
March	3	3	100.00%	100.00%
April	4	4	100.00%	100.00%
May	17	5	29.41%	100.00%
June	12	12	100.00%	100.00%
July	7	7	100.00%	100.00%
August	5	4	80.00%	100.00%
September			#DIV/0!	100.00%
October			#DIV/0!	100.00%
November			#DIV/0!	100.00%
December			#DIV/0!	100.00%

Integrity mgmt work	# of open WOs past need date	# of open WOs > 1 year old	Goal
January			100
February			100
March			100
April			100
May			100
June			100
July			100
August	170	125	100
September			100
October			100
November			100
December			100

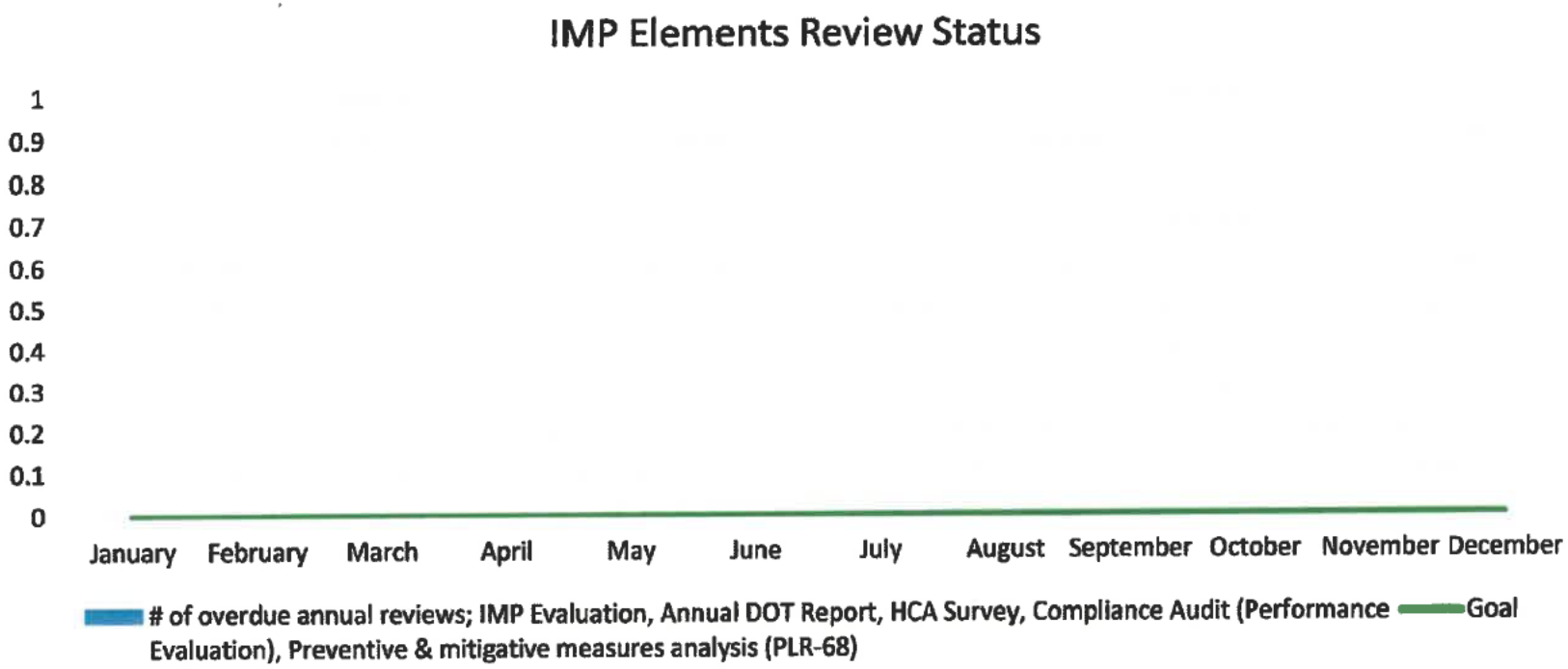
IMP Effectiveness

LDS issues	Total Leak Detection System Alarms	Alarms due to Leak	Alarms due to Adjusting Pipeline Pressure	Alarms due to PM Work	Alarms due to Scada Issues	Goal
January	3	0	1	0	1	0
February	1	0	0	0	1	0
March	3	0	0	0	3	0
April	14	0	1	13	0	0
May	12	0	4	2	6	0
June	7	0	6	0	1	0
July	11	0	0	0	11	0
August	12	0	8	0	4	0
September	1	0	0	1	0	0
October						0
November						0
December						0

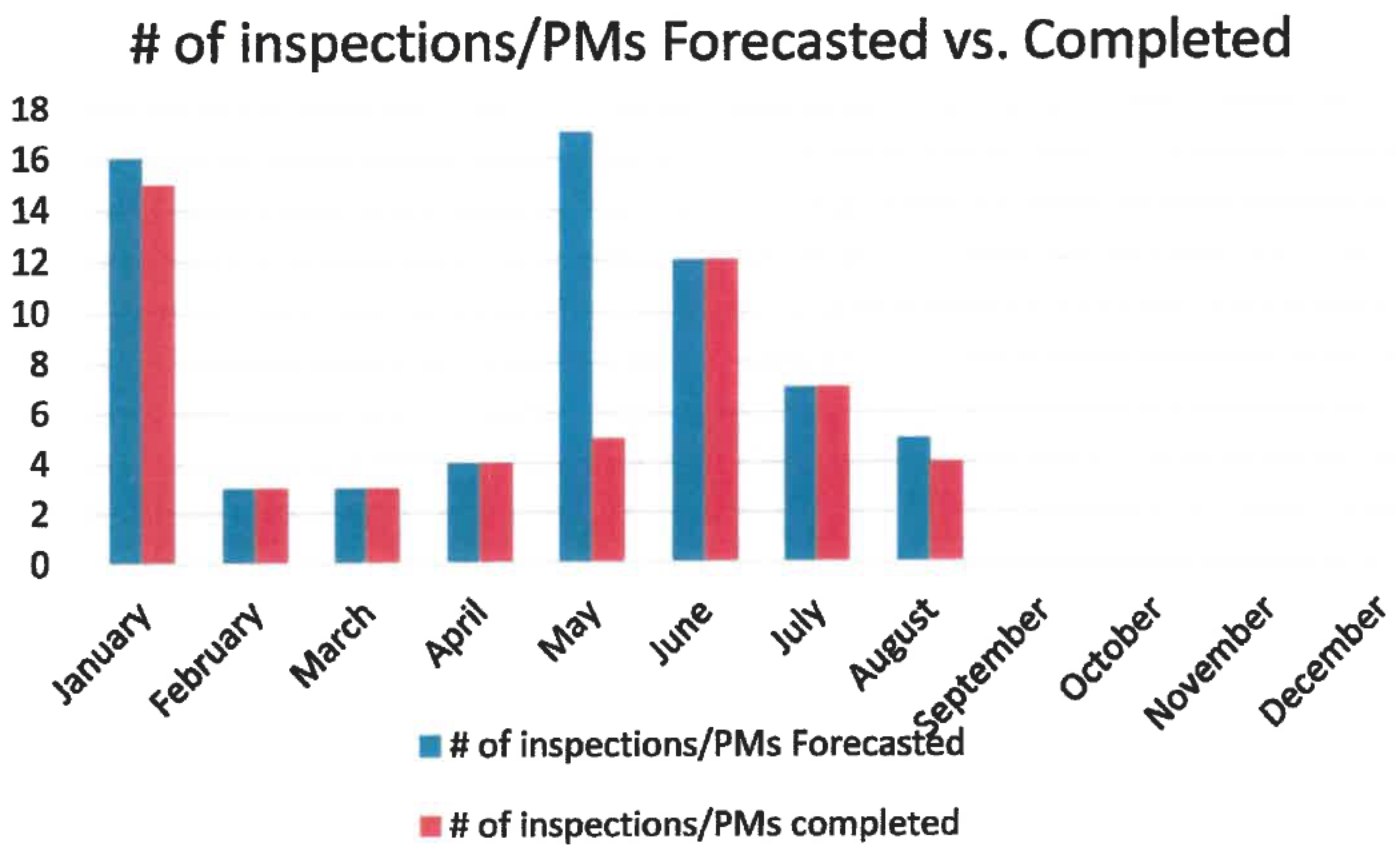
IMP Effectiveness



IMP Effectiveness



IMP Effectiveness



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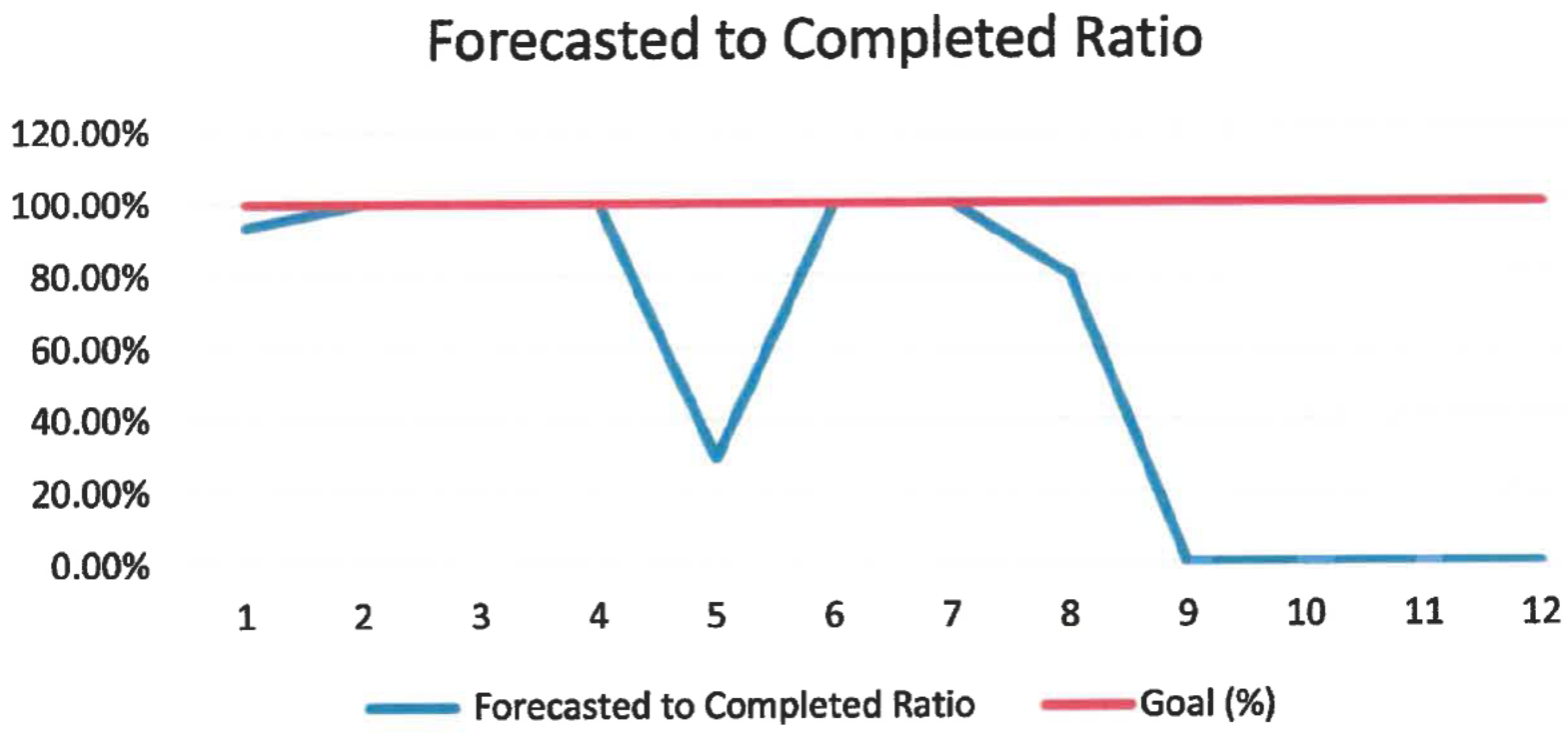
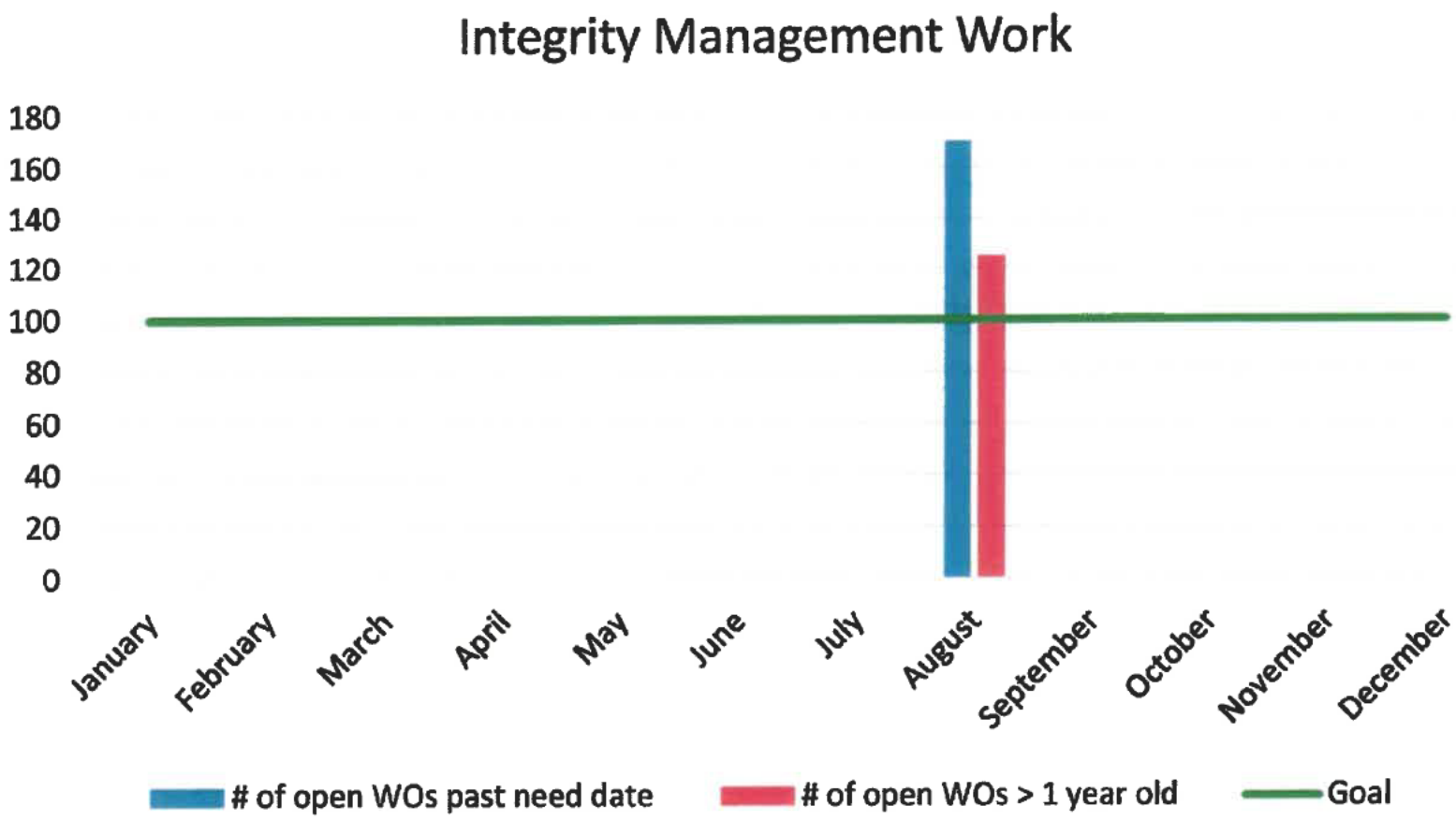
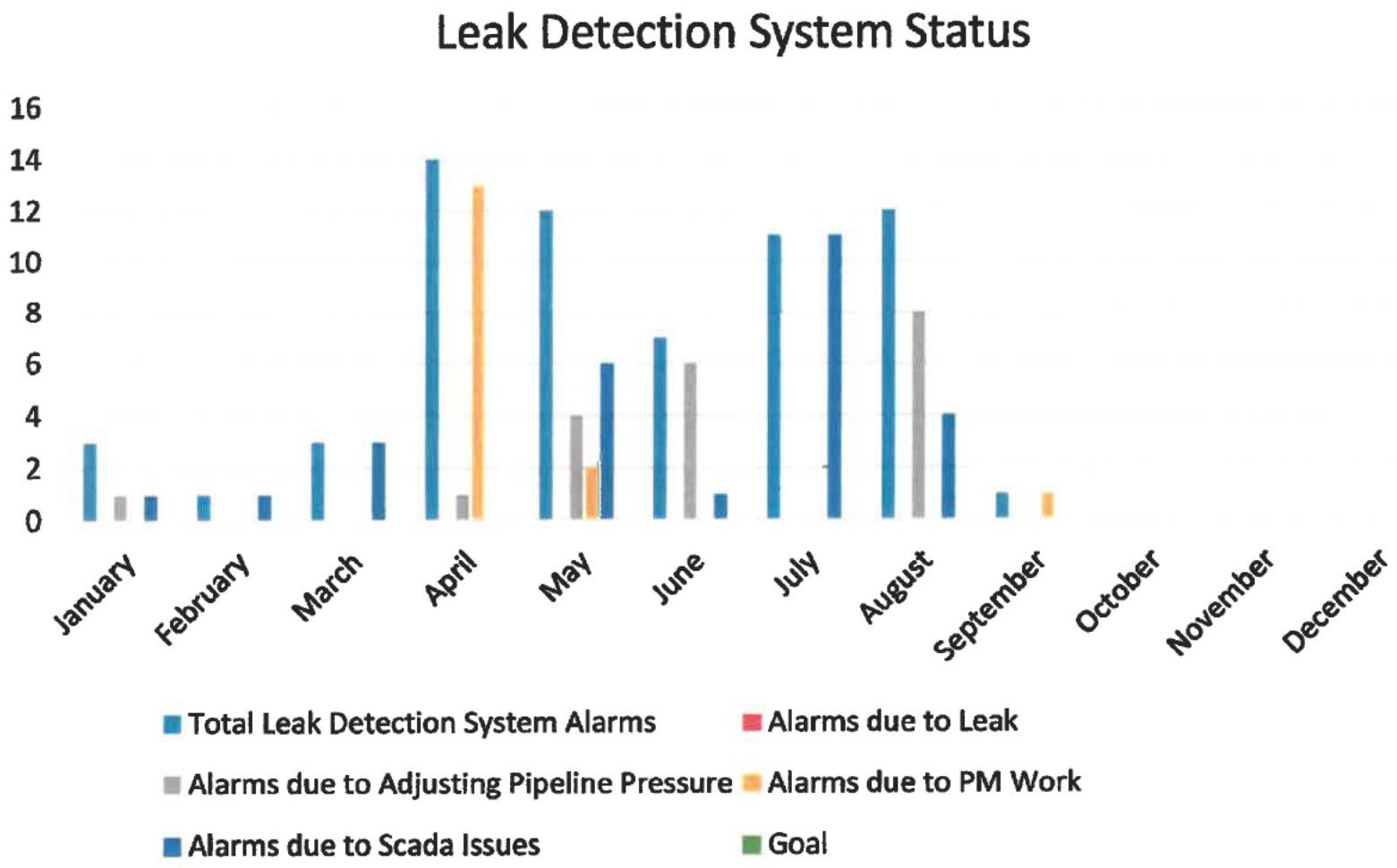


IMP Effectiveness



IMP Effectiveness

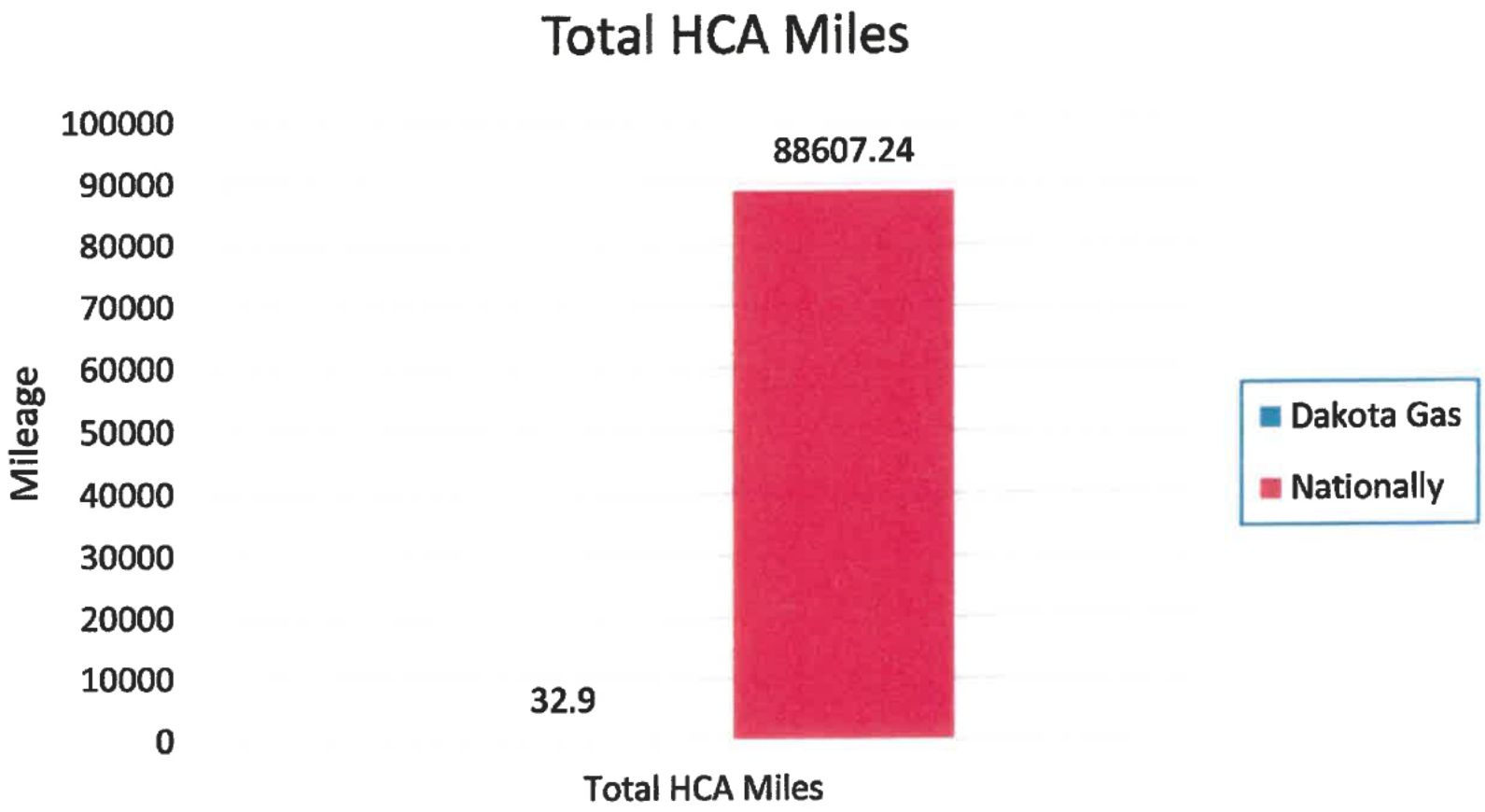


Calendar Year 2017

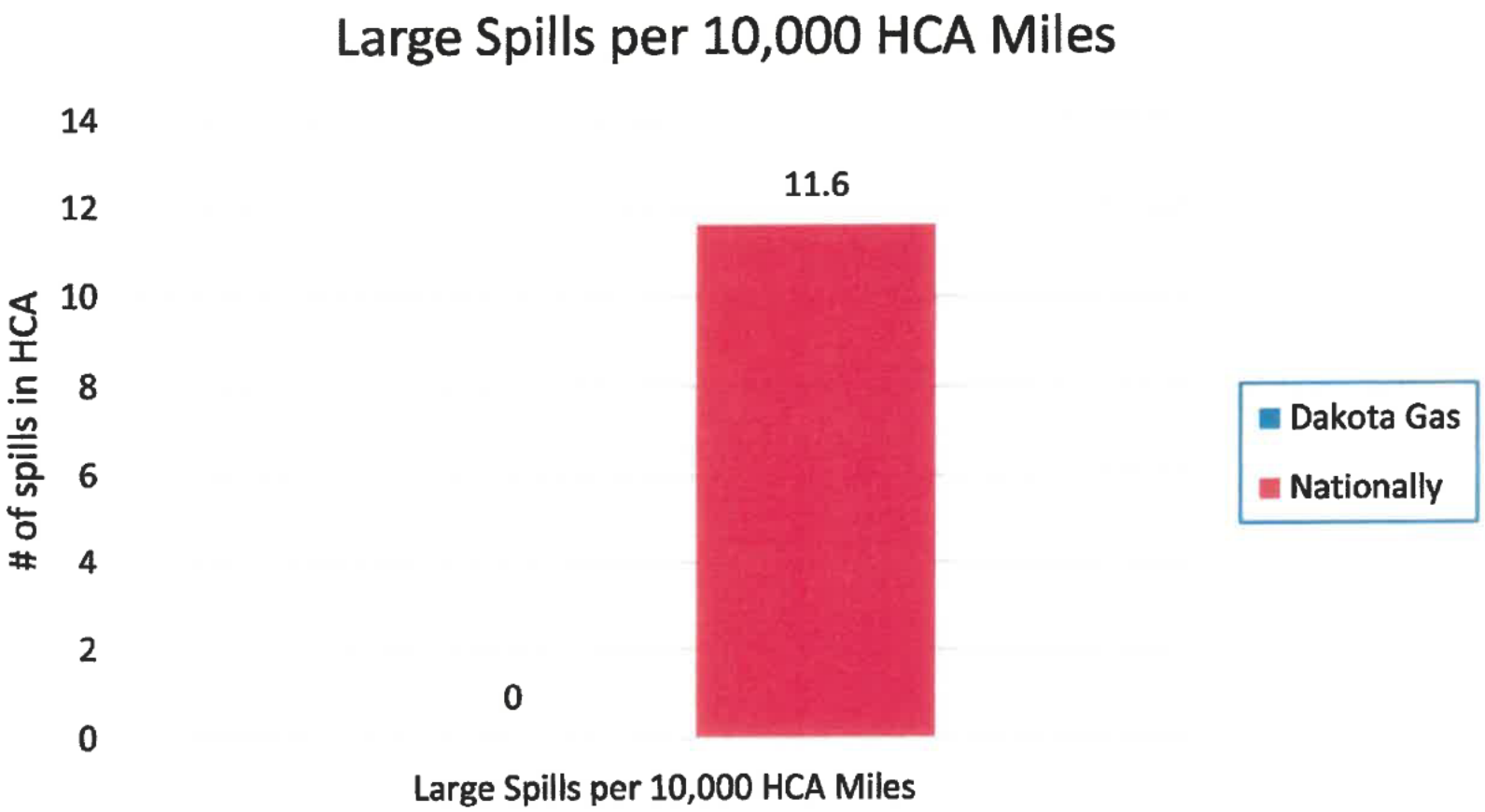
** National Data found at https://www.phmsa.dot.gov/pipeline/hazardous-liquid-integrity-management/hl-im-performance-measures

	Dakota Gas	Nationally
Total HCA Miles	32.9	88607.24
Large Spills in HCA	0	103
Large Spills per 10,000 HCA Miles	0	11.6
Baseline Miles per 10,000 HCA Miles	0	142.2
Reassessment Miles per 10,000 HCA Miles	3.71	2796.4
Total HCA Repairs per 10,000 HCA Miles	0	728
HCA Immediate Repair per 10,000 HCA Miles	0	77.98
HCA 60 Day Repair per 10,000 HCA Miles	0	45.03
HCA 180 Day Repair per 10,000 HCA Miles	0	601.76
HCA Pressure Test Failure Repairs per 10,000 HCA Miles	0	3.61
Total Miles Inspected (Both HCA and non-HCA) per 10,000 HCA Miles	18.85	11991.46
ILI Corrosion Tool per 10,000 HCA Miles	0	4442.75
ILI Dent Tool per 10,000 HCA Miles	0	4320.64
ILI Crack Tool per 10,000 HCA Miles	0	1754.94
ILI Other Tool per 10,000 HCA Miles	0	813.59
Pressure Test per 10,000 HCA Miles	0	462.94
ECDA per 10,000 HCA Miles	0	22.23
Other Method per 10,000 HCA Miles	18.85	174.48

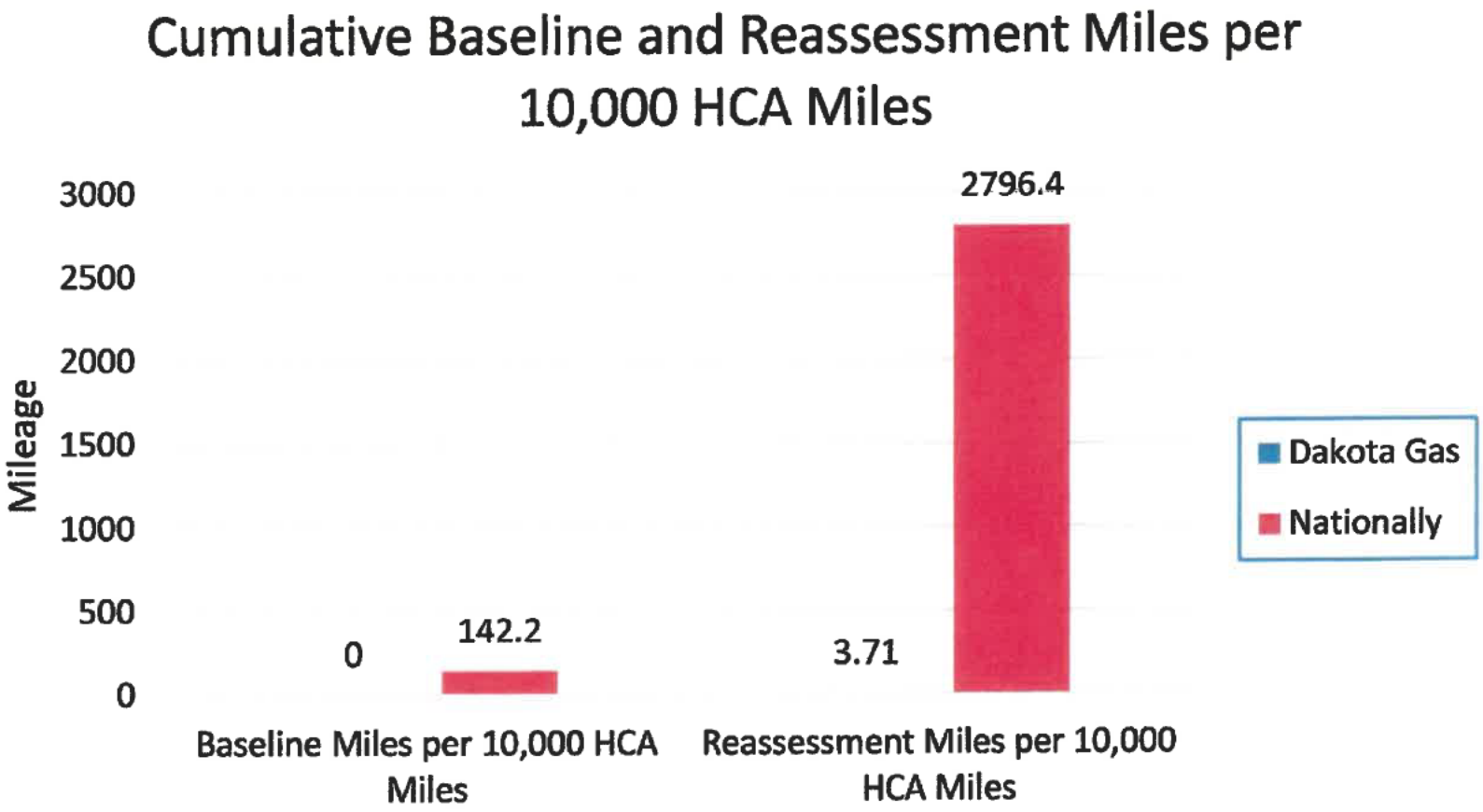
Benchmarking Metrics



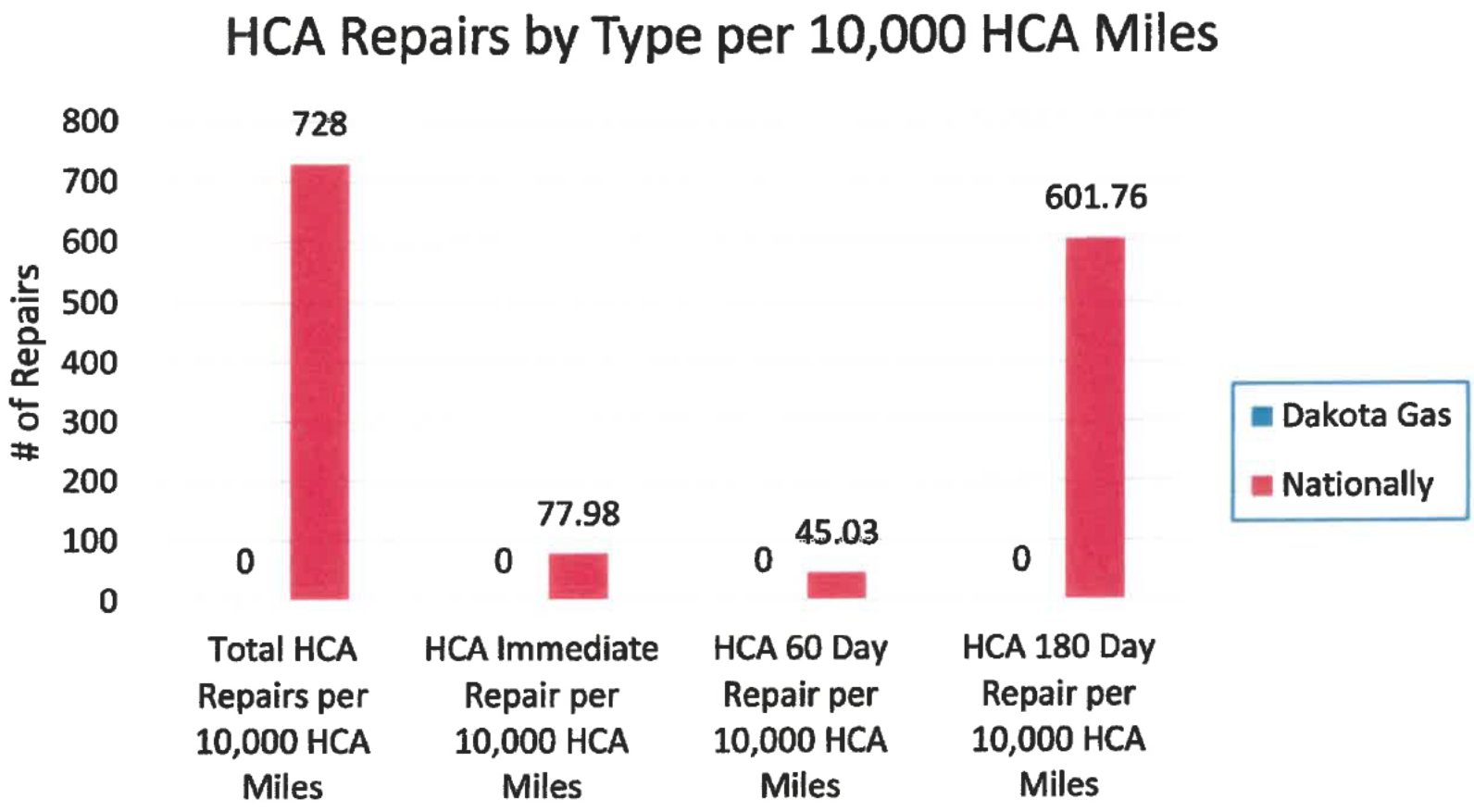
Benchmarking Metrics



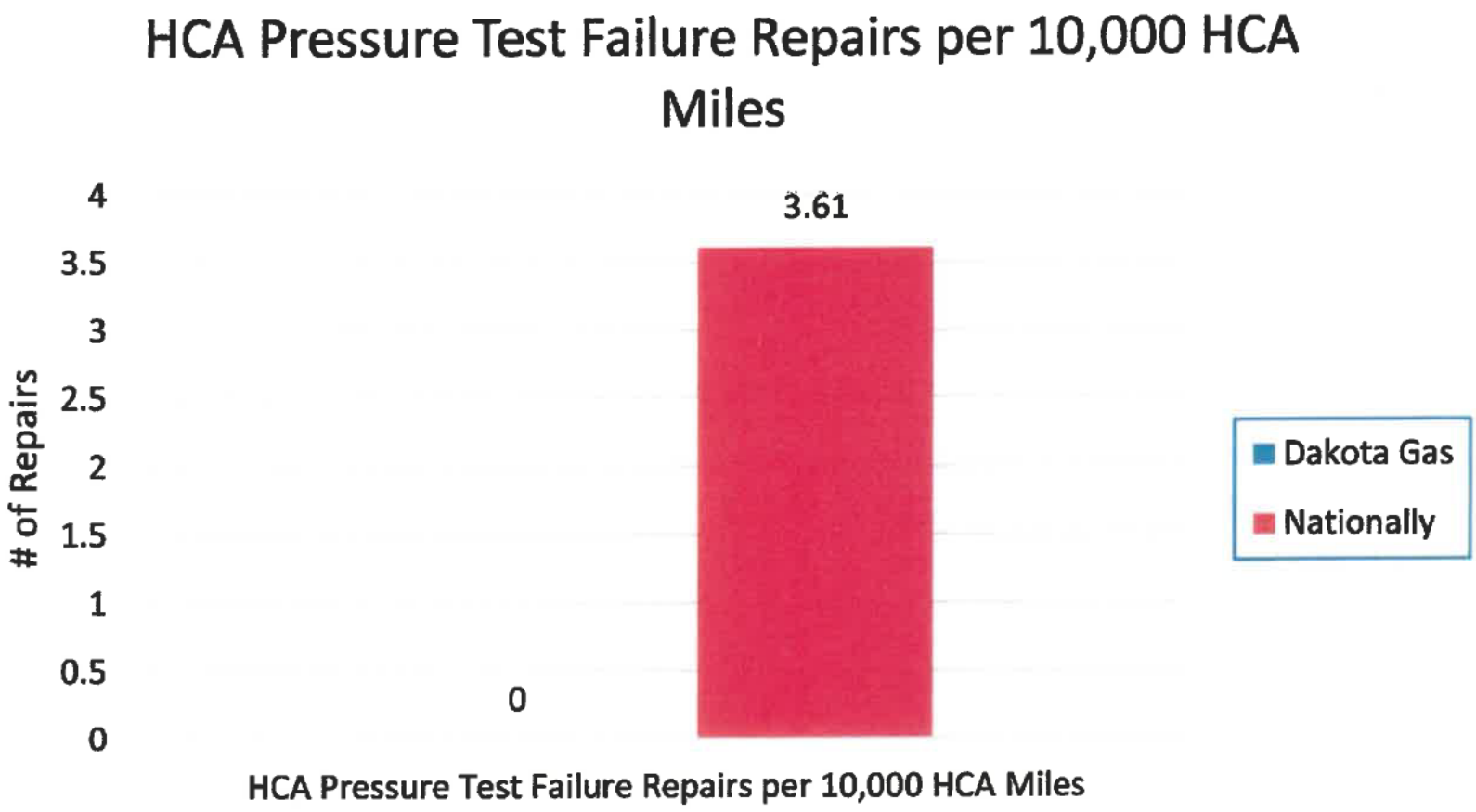
Benchmarking Metrics

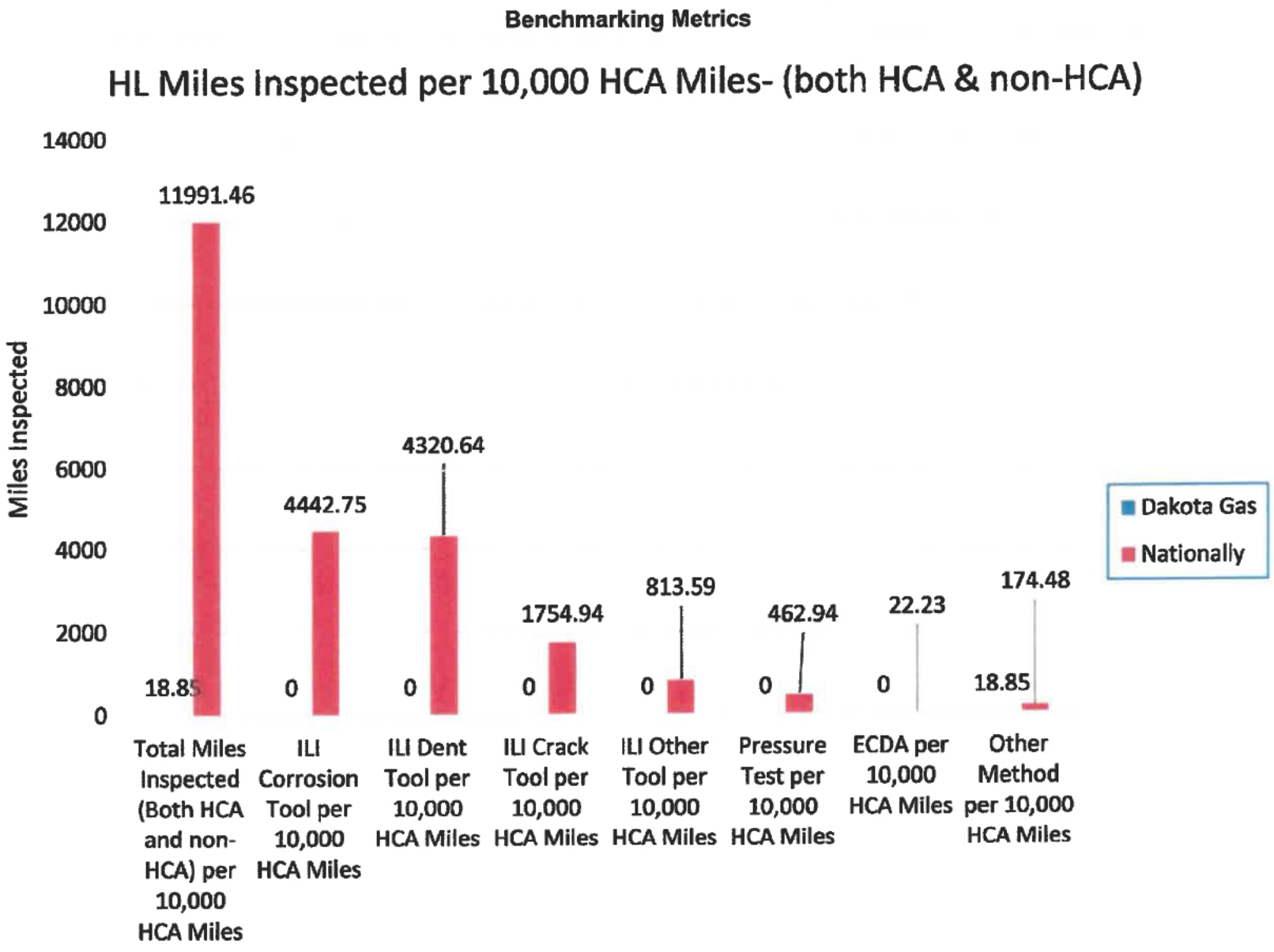


Benchmarking Metrics



Benchmarking Metrics




Benchmarking Metrics
HL Miles Inspected per 10,000 HCA Miles- (both HCA & non-HCA)
Miles Inspected
14000
12000
10000
8000
6000
4000
2000
0
11991.46
18.85
4442.75
0
4320.64
0
1754.94
0
813.59
0
462.94
0
22.23
0
174.48
18.85
Total Miles Inspected (Both HCA and non-HCA) per 10,000 HCA Miles
ILI Corrosion Tool per 10,000 HCA Miles
ILI Dent Tool per 10,000 HCA Miles
ILI Crack Tool per 10,000 HCA Miles
ILI Other Tool per 10,000 HCA Miles
Pressure Test per 10,000 HCA Miles
ECDA per 10,000 HCA Miles
Other Method per 10,000 HCA Miles
Dakota Gas
Nationally

Automated Info

Able to be automated	Not automated
Number of One Call (or lack of) Near Misses / Encroachments	Number of mailers sent
# of Incidents with One call (or lack of) as a factor	Number of mailers received
Number of near misses with public awareness (or lack of) as a factor	Number of mailers followed-up
# of Incidents with public awareness (or lack of) as a factor	Number of One Calls
Overdue:	Number of One Call Follow-ups within timeframe of the law
Inspections	Aerial patrols scheduled
PMs	Aerial patrols Completed
Recommendations	Number of Aerial Patrol Detections
Number of Integrity Assessment Findings:	# of H20 excursions
Due to ILI	# of H2S excursions
Due to Pressure Test	# of C02 excursions
Due to ECDA	# of ILI Anomalies:
Repairs scheduled as a result of the IMP	Excavated
Scheduled Repairs completed as a result of the IMP	Repaired inside HCA
# near misses due to corrosion issues	Repaired Outside HCA
# Incidents due to corrosion issues	# of:
# near misses due to gasket / packing issues	Immediate Repair conditions
# Incidents due to gasket / packing issues	60 day repair conditions
Number of pipeline materials with Q#	180 day repair conditions
# near misses due to material properties issues	# of miles inspected:
# incidents due to material properties issues	Planned
# near misses with training / performance / experience as a factor	Actual
# incidents with training / performance / experience as a factor	# of overdue trainings
Number of SWP audits conducted	# of times safety system isolated (or exceeding time)
# near misses with SWP as a factor	# of overdue procedure reviews
# Incidents with SWP as a factor	# of outdated spec reviews
# near misses with AM as a factor	Process Improvements identified
# incidents with AM as a factor	Process Improvements implemented
# near misses with procedure as a factor	Original Risk
# Incidents with procedure as a factor	New Risk
# near misses with spec as a factor	# of overdue annual reviews; Integrity Evaluation, Annual IM Report, HCA, Audit (Performance Evaluation), Risk Assessment, IMP, Preventive & mitigative measures analysis, OQ, AM
# Incidents with spec as a factor	# of inspection report / PM followed-ups

Automated Info

# of hydrostatic failures / near misses due to construction/mfg defects
incidents with construction/mfg defects as a factor
near misses with cold weather as a factor
incidents with cold weather as a factor
near misses with exposed pipe / washout as a factor
incidents with exposed pipe / washout as a factor
near misses with lightning as a factor
incidents with lightning as a factor
of inspections/PMs needed
# of inspections/PMs scheduled
# of inspection reports / PM completed
# of inspection reports / PM approved
# of open WOs past need date
# of open WOs > 1 year old
# of open T/A WOs past T/A time
# of Leak Detection System issues

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	**Procedure No.:** 022	**Revision No.:** 0
Affected Area(s): All	**Originating Department:** Plant Management	
	Final Approval: /s/ Dale Johnson	**Date:** 10/04/18
Procedure Description: Risk Assessment of Facilities Potentially Affecting High Consequence Areas		

I. PURPOSE

A. To define the process utilized for performing a risk analysis of facilities that may affect high consequence areas (HCAs) along the carbon dioxide (CO_2) pipeline. Additionally, to evaluate relevant risk factors at facilities, including those factors that may be unique or specific to facilities.

II. SCOPE

A. This procedure shall be utilized as part of the Integrity Management Plan per the Department of Transportation (DOT) 49 CFR 195.452. This procedure provides guidance for prioritizing threats posed from facilities that potentially affect HCAs.

III. REFERENCES

A. 49 CFR 195 – Transportation of Hazardous Liquids by Pipeline

B. 49 CFR 195.452 – Pipeline Integrity Management in High Consequence Areas

C. API 1160 – Managing System Integrity for Hazardous Liquid Pipelines

D. DGC Form 1642 - Process Hazard Analysis Recommendation Resolution

E. DGC Pipeline Safety Risk Matrix

IV. DEFINITIONS

A. High consequence area (HCA) − An HCA can be defined as any of the following:

1. *Commercially navigable waterway* − A waterway where commercial navigation exists.

2. *High population area* − An urbanized area, as defined and delineated by the Census Bureau, which contains 50,000 or more people, and has a population density of at least 1,000 people per square mile.

3. *Other populated area* − A place, as defined and delineated by the Census Bureau, which contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

   a. *Office of Pipeline Safety (OPS) identified* – Areas the OPS has identified as meeting the criteria of an other populated area.

B. Unusually sensitive area (USA) − A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release as defined in 49 CFR Part 195.6.

C. Active safeguard – Safeguards which detect and then respond to process deviations. These safeguards directly prevent hazards from occurring, provide notification so that a human may respond to a condition, or may mitigate the hazard.

D. Administrative controls – A procedural requirement for directing and/or checking engineered systems or human performance associated with plant operations (i.e., operating procedures, lockout/tagout/training, car seal system, and safety procedures).

E. Basic Process Control System – A control system, generally within the Distributed Control System, that safeguards against hazards or maintains a system within a safe operating envelope.

F. Catastrophic release – A major uncontrolled emission, fire, or explosion, involving one or more highly hazardous chemicals that presents serious danger to workers, the public, or the environment.

G. Cause – Actions or events that could result, directly or indirectly, in the initiation of an undesirable process condition.

H. Consequence – Direct, undesirable result of a deviation. Typically measured in health and safety effects, environmental impacts, loss of property, and business interruption costs.

I. Credible scenario – A cause/consequence pairing with a reasonable and documented/validated probability of occurring (e.g. an overpressure event leading to injury to personnel when the pump curve indicates the pump is capable of achieving a pressure over design).

J. Deviation – Departure from the intended operation/function of a process or pre-established operating or design limit.

K. Double jeopardy – Concurrent incidence of multiple, independent, and unrevealed initiating events.

L. Escalation event – An event with cascading failures. An example would be a catastrophic failure of a piece of rotating equipment resulting in the failure of another piece of equipment due to a secondary event such as a fire spreading.

M. Engineering Controls – A hardware or software system designed to maintain a process within safe operating or design limits, to safely shut it down during a process upset, or to reduce human exposure to the effects of an upset (e.g. pressure relief devices, interlocks, and control valve failure positions).

N. EXP-DIR – Electronic software/database system used to review, manage, communicate, document, and approve an action item from a risk assessment.

O. Guideword – Words such as high, low, no, more, or less, which are used in conjunction with parameters to analyze deviations.

P. Hazard and Operability (HAZOP) Analysis – Qualitative risk assessment technique utilizing guidewords and deviations to systematically assess process risks.

Q. Node – A small portion of a process identified for process hazard analysis.

R. Operability – Ability to operate a process within its design intention.

S. Parameter – Measurable process conditions such as pressure, temperature, and level, which when combined with guidewords, are utilized to identify and analyze process deviations.

T. Passive safeguard – Safeguards based on design features and do not require any external input to function. Generally, passive safeguards mitigate a consequence to a less severe event; an example would be a dike wall or drainage designed for a specific consequence.

U. Procedural safeguard – Safeguards that utilize human response to mitigate or prevent a consequence. Examples include procedural checks, administrative checks, operator checks, and corrective actions.

V. Risk – The resulting intersection of severity and frequency in the risk matrix utilized to measure potential loss (human, environmental, economic).

W. Risk matrix – A chart that shows the event frequency ranges versus the consequence ranges, along with likelihood and consequence categories, to determine the tolerability of risk in a given category. The risk matrix is used to standardize judgments about risks.

X. Safeguard – A device, system, or action for reducing the frequency and/or severity of the consequences of a deviation.

Y. What–if analysis – A risk assessment technique that utilizes brainstorming based on a list of questions or concerns addressing hazards, hazardous situations, or specific accident events that can produce an undesirable consequence in a system or process and qualitatively judges the adequacy of existing safeguards.

V. RESPONSIBILITIES

A. Plant Management

1. Provides the necessary resources to maintain the facility risk assessment process.
2. Provides the necessary resources to implement approved preventive and mitigative measures.

B. Pipeline Superintendent

1. Review recommended preventive and mitigative measures and determine if the recommended measures should be implemented.

C. Compliance, Safety, and Industrial Hygiene Superintendent

1. Provides personnel knowledgeable in risk assessment methodologies.
2. Responsible for ensuring a risk analysis report is produced and distributed to appropriate stakeholders.

VI. INSTRUCTIONS

A. General considerations

1. The goals of risk assessment are as follows:

   a. Identify the threats to facility integrity.

   b. Determine the risk represented by these threats and the consequences to critical locations.

   c. Rank facilities in the order of greatest need for integrity assessment or mitigative action, if applicable.

   d. Compare different integrity assessment or mitigation options in terms of the risk reduction benefits and costs.

   e. Facilitate reassessment and re-ranking once the integrity assessments and mitigative actions have been completed.

2. Risk assessments are not static and do not deliver absolute certainty with regard to scheduling integrity assessments or other preventive and mitigative activities. However, it does offer a methodology with which to start an integrity assessment program, and if allowed to evolve with experience, it becomes a tool for continual planning of integrity assessments.

3. Risk assessments for facilities potentially affecting HCAs shall be conducted if one of the following conditions are met:

   a. Prior to startup of a new facility potentially affecting HCAs

   b. Within six months of a change that requires a revised risk assessment

   c. Within six months of a change that requires a revised consequence analysis (e.g. new process, new facility, operational change, HCA changes, equipment changes).

4. Team composition

   a. Risk assessments for facilities shall be performed by an experienced team knowledgeable in the process technology and operations. The team shall be comprised of essential personnel who are required to be present for the entire duration of the risk assessment and support personnel who shall be available for the duration of the risk assessment.

      (1) *Essential personnel* – The following roles are considered essential. A risk assessment shall not proceed without representation of at least the following competencies:

         (a) *Process knowledgeable representative* – Shall have detailed technical experience and knowledge of the process technology being assessed. This experience should include knowledge of the

chemistry, engineering, equipment, and safety equipment utilized within the process being analyzed.

(b) *Process operations representative* – Shall have operational knowledge of the process technology being assessed. This experience should include working knowledge of the safety equipment, controls, history, physical layout, and procedures utilized within the process being analyzed.

(c) *Pipeline engineer* – Shall have detailed technical experience and knowledge of the process technology being assessed. This experience should include knowledge of the engineering, equipment, pipeline integrity management activities, and safety equipment.

(d) *Person knowledgeable of the risk assessment technique* – Shall have detailed experience and knowledge of the risk assessment technique being utilized as well as a knowledge of the process sufficient to understand the plant processing operations being discussed, capture relevant details, and to control the discussion.

(e) *Mechanical engineer/maintenance engineer (fixed equipment) or inspection representative* – Shall have detailed experience and working knowledge of mechanical integrity threats specific to facilities (e.g. external corrosion, internal corrosion, manufacturing defects, construction defects, equipment failure, and cycle induced fatigue).

(f) *Maintenance engineer (rotating equipment)* – Shall have detailed experience and working knowledge of pumps, compressors, and/or fans associated with facilities.

(2) *Support personnel* – Additional personnel may be required and shall be identified during the planning phase of the risk assessment.

5. Acquiring and integrating data in risk assessment

a. The data to be gathered and integrated shall be of sufficient quality and breadth so that it can be used in the risk assessment to help identify relevant threats that could affect the integrity of the facility. Examples of data include:

(1) Attributes of each facility that bear on the susceptibility to various integrity threats

(2) Construction factors that could affect the susceptibility to various integrity threats

(3) Operating parameters that could affect the susceptibility to various integrity threats

(4) Assessment histories that may indicate susceptibility to various integrity threats

(5) Release history

B. Risk assessment approach

1. A combination of the following risk assessment methods may be used to determine and evaluate the risks posed by facilities:

   a. Hazard and Operability (HAZOP) Analysis

   b. What-if Analysis

   c. Appropriate equivalent methodology that evaluates specific risks of facilities

2. HAZOP analysis methodology

   a. HAZOP methodology may be used to provide an analysis of threats posed from incorrect operations and equipment failure.

   b. HAZOP methodology is not suitable for analyzing all threats posed to facilities. Additionally, planning for certain non-credible scenarios is not reasonable. Therefore, the following scenarios are excluded from the HAZOP methodology:

      (1) Double jeopardy events.

      (2) Occupational, health, and safety events – Events such as slips, trips, falls, ergonomics, and walking/working surfaces shall be addressed via the Safety Management System and are not covered by facility risk.

      (3) Events initiated by failure of control of work practices – Failure of control of work practices (i.e. safe work permitting, hot work permitting, lock out - tag out, confined space entry, and the bolted joint procedure) shall not be considered initiating events.

      (4) Engineering design errors – It shall be assumed that the process being evaluated has been designed in accordance with good engineering practices.

      (5) Escalation events – The development of a credible scenario shall terminate at the loss event caused from the process deviation.

      (6) Initiating events that do not cause a loss event within 24 hours may be excluded at the discretion of the team. This is intended to exclude events that are progressive in nature such as corrosion/erosion/seal damage and are generally identified and corrected prior to a catastrophic failure. Failures that will result in a sudden catastrophic failure and are unrevealed are not exempted. “What-if” methodology is more suitable for these scenarios.

      (7) Events initiated by natural disasters, terrorism, sabotage, or a third-party. “What-if” methodology is more suitable for these scenarios.

c. HAZOP workflow – Facility risk assessment using HAZOP follows the following seven step process:

(1) Establishment of node boundaries

(a) Nodes shall be developed prior to HAZOP and shall be identified with highlighted piping and instrumentation diagrams (P&IDs).

(b) Safe operating limits for the node under analysis shall be reviewed during the risk analysis. These limits are the critical parameters that define when a deviation occurs. Generally, these consist of the following design parameters: pressure, temperature, flow rates, and stream compositions. These parameters effectively describe the process safe operating limits.

(2) Deviations

(a) Deviations consist of a guideword/parameter pair, such as “high” and “pressure.” This pairing results in the deviation “high pressure.” Additionally, generic deviations may be specified to review specific risks associated with a node (e.g. relief systems, management of change, abnormal operations, and previous incidents).

(b) Table 1 lists examples of how parameters and guidewords may be combined to form deviations.

TABLE 1: GUIDEWORD-PARAMETER COMBINATIONS

GUIDEWORD / PARAMETER	No Not None	Less Low Short	More High Long	As well as / Misdirected	Other than	Reverse
Pressure	N/A	Low Pressure	High Pressure	N/A	N/A	Vacuum
Temperature	N/A	Low Temperature	High Temperature	N/A	N/A	N/A
Level	N/A	Low Level	High Level	High/Low Interface	N/A	N/A
Flow	No Flow	Low Flow	High Flow	Misdirected Flow	N/A	Reverse Flow
Reaction	N/A	Low Reaction Rate	Runaway Reaction	Partial Reaction	Side Reaction	Decomposition
Composition	N/A	N/A	Extra Material	Impurities	Wrong Material	N/A
Procedure	Skipped Step	Too Short/Little	Too Long/Much	Additional Action	Incorrect Action	Opposite Action
Speed	Stopped	Too Slow	Too Fast	N/A	Out of Sync	Reverse Direction
Other	Utility Failure Sampling	Leak/Rupture	Startup Shutdown	Maintenance Previous Incidents	N/A	N/A

(3) Causes

(a) Causes are brainstormed and identified for each deviation. Only credible causes are to be evaluated and documented.

(b) Where a single cause may fall under multiple deviations, the cause shall only be documented a single time. For example, a pressure control valve failing open may result in high pressure as well as high flow, but shall only be recorded under one location or the other.

(c) Deviations with no credible causes shall be documented as “no credible cause identified” and deviations with no unique causes (all causes captured by other deviations) shall be documented as “no additional causes identified.”

(4) Consequence evaluation

(a) Each cause shall have consequences developed globally without regard to node boundaries.

(b) Consequences are only fully developed into scenarios where the cause results in a safe operating limit potentially being exceeded. A cause that results in no significant consequence would be documented as “scenario considered, but no consequence of interest identified.”

(c) Consequence developed shall assume that all active safeguards fail. Passive safeguards may be assumed to still function at the discretion of the team.

(d) Consequences shall reference equipment tags.

(e) Scenario consequence are to be developed by the immediate consequence of interest (no escalation of event). Team should base severity on the most severe plausible outcome.

(f) Risks that are associated with economic or environmental consequences are outside the scope of the risk assessment.

(5) Safeguards

(a) Active safeguards shall be identified and reviewed against process safety information (PSI) for effectiveness. For example, a relief valve protecting against a blocked outlet case is to be reviewed against the relief device sizing documentation and found to be sized adequately for the blocked outlets scenario, a temperature alarm is to be confirmed to be set below safe operating limits.

(b) Active safeguards shall have adequate response time to safeguard against the scenario developed. For example, an alarm that affords credit for an operator to respond, includes adequate time for an operator to notice the alarm, determine appropriate action, and complete any tasks required. These durations shall be based on team judgment and experience for HAZOP assessments.

(c) Administrative or procedural safeguards (e.g. procedures or manuals) shall be documented.

(6) Scenario frequency evaluation

(a) Frequencies shall be developed by the likelihood adjustment method. This method takes an initial estimate for the frequency based on team judgment or published data and then adjusts the frequency based on the probability of failure of safeguards designed to mitigate or prevent the scenario.

(7) Risk ranking

(a) Based on the results of the consequence evaluation and the scenario frequency evaluation, scenarios are to be risk ranked to determine a risk priority level. The risk priority level is defined by the DGC Pipeline Safety Risk Matrix.

3. What-if methodology

a. What-if methodology may be used to provide an analysis of the threats posed from facilities that may not be adequately analyzed using HAZOP. Generally, HAZOP takes the cause of the scenario into account when calculating risk,

severity, and likelihood of the scenario. The what-if analysis simply considers what the outcome would be if the given scenario were to occur. This allows the what-if analysis to cover a range of scenarios that could be overlooked using the HAZOP analysis.

b. In this method, a scenario is described by asking what the consequences of a facility threat would be. For example, "*What if* the facility experiences external corrosion at the soil-to-air interface?" or "*What if* there was localized soil movement that exposed the pipe?"

c. What-if workflow – Facility risk assessment using what-if methodology follows the following six-step process:

(1) Topic/Guideword

(a) A list of relevant threats to the integrity of the facility shall be identified for discussion.

(2) What-if/Causes

(a) The team shall develop scenarios identified as having a reasonable probability of occurring by asking, "*What if* X occurred?".

(3) Consequence evaluation

(a) The team shall determine the consequences of the scenarios which have a reasonable probability of occurrence and document the severity of the outcome.

(4) Safeguards

(a) A list of safeguards used to prevent or mitigate scenario consequences is to be developed.

(5) Scenario frequency evaluation

(a) Frequencies shall be developed by the likelihood adjustment method. This method takes an initial estimate for the frequency based on team judgment or published data and then adjusts the frequency based on the probability of failure of safeguards designed to mitigate or prevent the scenario.

(6) Risk ranking

(a) Based on the results of the consequence evaluation and the scenario frequency evaluation, scenarios shall be risk ranked to determine a risk priority level. The risk priority level is defined by the DGC Pipeline Safety Risk Matrix.

C. Recommended preventive and mitigative measures from risk assessments

1. Risk assessment shall continually identify preventive and mitigative measures to be considered for implementation. As integrity assessments, remediations, and

mitigative actions are carried out, the particular risk assessment method used can be validated, improved, or replaced if necessary to conform with the experience gained through integrity management activities

2. Preventive and mitigative measures for facilities shall be identified and prioritized based on the results of risk assessments.

3. Recommended preventive and mitigative measures for facilities shall be reviewed by the pipeline superintendent.

   a. If the pipeline superintendent determines preventive and mitigative measures recommended from the risk assessment are required, the preventive and mitigative measures shall be implemented.

      (1) Preventive and mitigative measures to be implemented shall be tracked with the EXP-DIR system.

   b. The pipeline superintendent may justifiably decline to adopt a recommendation where the reason is documented in writing and adequate evidence given that one or more of the following are true:

      (1) The analysis upon which the recommendation is based contains material factual error.

      (2) The recommendation does not significantly reduce risk posed to the health and safety of employees, employees of a contractor, or the public.

      (3) An alternative measure would provide a sufficient level of protection.

      (4) The recommendation is unfeasible.

   c. Should the pipeline superintendent determine to justifiably decline a recommendation, the reason is documented and signed in the Process Hazard Analysis Recommendation Resolution form (DGC 1642). The signed form shall be attached to the recommendation in EXP and the recommendation is closed.

VII. RECORDS

A. Results of risk assessments shall be documented and distributed to appropriate stakeholders by the compliance, safety, and industrial hygiene superintendent, or designee.

B. All reports and documentation required or produced by this procedure shall be considered records, and shall be filed for the life of the facility in the appropriate electronic folder located in Altien under *DGC / Pipelines / Integrity Management.*

Exhibit 7

Dakota Gasification Company

Technical Report

To: Claude O'Berry

From: Chris Breiner

Date: October 4, 2018

Subject: Tioga Station Risk Assessment

To evaluate relevant threats posed by operations at Tioga station, Dakota Gasification Company (DGC) personnel performed a risk assessment of the facility on September 28th, October 1st, 2018. Due to recommendations from PHMSA, the team evaluated the risk reduction benefit and prioritized the recommendations on October 4th, 2018. The risk assessment methodologies outlined in DGC Procedure 022 R0 were used to complete the analysis.

During the risk assessment, the following preventive and mitigative measures were recommended:

No.	Recommended P&M Measure	Worksheet Reference	Current Estimated Risk Level	Estimated Risk Level with P&M Measure Implemented	Recommended P&M Measure Relative Priority
1	It was noted by the team that CV74114 and FYV74056 are not on a PM schedule. Consider adding CV74114 and FYV74056 to a PM schedule.	Node 3.6	S4-L3 (Acceptable)	S4-L3 (Acceptable)	4 of 4
2	Evaluate if the set point for PSV74050 and PSV74051 are appropriate for the limits of class F5AB piping. The PSVs are set at 3,260 psig and the DGC defined operating limit of pipe spec F5AB is 2,964 psig.	Node 3.10	S4-L5 (Undesirable)	If PSV set point is appropriate, the scenario is not credible. (Acceptable)	1 of 4
3	During the risk analysis there was some uncertainty about the potential failures associated with manufacturing defects so the team did not have a good understanding of the risk. Ensure appropriate documentation has been provided during the construction of the Tioga station so the risk can be appropriately derived.	Node 7.1	S7-L3 (Unacceptable)	S7-L2 (Undesirable)	2 of 4

No.	Recommended P&M Measure	Worksheet Reference	Current Estimated Risk Level	Estimated Risk Level with P&M Measure Implemented	Recommended P&M Measure Relative Priority
4	Evaluate benefit of adding a camera that can be monitored remotely. The team believes installation of a camera would mitigate or prevent threats posed by unauthorized access to the facility.	Node15.1	S4-L4 (Undesirable)	S4-L3 (Acceptable)	3 of 4

The table above presents the current estimated risk level, the estimated risk level if the P&M measure was implemented, and the recommended priority of the recommended P&M measures. The current estimated risk level is the estimated risk at the time of the risk analysis and is based on the information that was available to the team at the time of the analysis. The estimated risk level with P&M measure implemented is the team's estimated risk level if the recommended P&M measure was implemented. The recommended P&M measure relative priority is based on the recommendation's impact to the estimated risk. If the P&M measure significantly changed the estimated risk, then the recommendation was given a higher priority when compared to the other recommendations.

Refer to Attachment 1 for the completed risk assessment worksheets.

Refer to Attachment 2 for process flow diagrams as well as P&IDs defining node boundaries. All the node boundaries are located at the Tioga facility. Since Tioga is the only facility operated by DGC that affects an HCA, a ranking of priority of the Tioga facility over other facilities is not required.

Refer to Attachment 3 for supporting documentation used to aid in estimating scenario consequences. Attachment 3 also contains the corresponding threat assessment report.

Refer to Attachment 4 for supporting documentation used to aid in estimating scenario frequency.

Refer to Attachment 5 for DGC Procedure 022.

cc: Dale Johnson
Mike McKinzie
Chuck Fritel
Brian Dillman
Isaac Michaelson
Tim Rogness
Jeff Graney
Trinity Turnbow
Aaron Marquart
Dan Pillar
Charles Roy
Robin Braun
Troy Borud
A.T. Funkhouser
Rick Volk
Rory Hochsprung
Kurt Dutchuk
Mark Degenstein
Tim McEvers

Attachment 1

Risk Assessment Worksheets

Team Members

First Name	Last Name	Job Title	Role	Experience
Robin	Braun	Section Engineer	Operations Engineering	9
Chris	Breiner	Section Engineer	Risk Analyst	4
Mark	Degenstein	Inspection Supervisor	Mechanical Integrity Specialist	29
Kurt	Dutchuk	Pipeline Supervisor	Operations	25
Isaac	Michaelson	Rotating Equipment Engineer	Rotating Equipment Specialist	5
Claude	O'Berry	Pipeline Superintendent	Operations	32
Tim	Rogness	Inspection Specialist	Mechanical Integrity Specialist	24
Charles	Roy	Pipeline Engineer	Pipeline Engineering	3.5

List of Sections

No.	Type	Name	Description	Design Intent	Highlight	Folder	Drawings
1		GA7411 Suction, including portable launcher	GA7411 Suction, including portable launcher	Piping: F5AB - 12" 2964 psig @ -50°F to 120°F	Orange		D7400-001-F Sheet 1 D7400-033-P D7400-036-P D7400-001-F Sheet 2
2		GA7411/M	GA7411/M	Piping: F5AB - 12" 2964 psig @ -50°F to 120°F	9875200		D7400-001-F Sheet 1 D7400-033-P D7400-036-P TM2853003 D7400-001-F Sheet 2
3		GA7411 Discharge Line	GA7411 Discharge Line	Piping: F5AB - 12" 2964 psig @ -50°F to 120°F	Blue		D7400-001-F Sheet 1 D7400-033-P D7400-036-P TM2853003 D7400-001-F Sheet 2
4		Enclosed Flare	Enclosed Flare	Piping: F5AB - 12" 2964 psig @ -50°F to 120°F A5A - TEMP (°F) -50 to 100 200 300 400 500 600 650 PSIG 252 235 215 195 170 140 125	Yellow		D7400-001-F Sheet 1 D7400-033-P TM2853003 070503-PID D7400-001-F Sheet 2
5		External Corrosion	External Corrosion				
6		Internal Corrosion	Internal Corrosion				
7		Manufacturing Defects (Defective Pipe Seams & Defective Pipe)	Manufacturing Defects (Defective Pipe Seams & Defective Pipe)				
8		Construction Defects (Defective Girth Welds, Fabrication Welds, Installation Damage, Wrinkle Bends & Buckles, Fitting Failure)	Construction Defects (Defective Girth Welds, Fabrication Welds, Installation Damage, Wrinkle Bends & Buckles, Fitting Failure)				

No.	Type	Name	Description	Design Intent	Highlight	Folder	Drawings
9		Equipment Failure (Gasket or O-Ring Failure, Seal/Pump Failure)	Equipment Failure (Gasket or O-Ring Failure, Seal/Pump Failure)				
10		Mechanical Damage (Immediate Failure)	Mechanical Damage (Immediate Failure)				
11		Mechanical Damage (Delayed Failure)	Mechanical Damage (Delayed Failure)				
12		Pressure Cycle Induced Fatigue	Pressure Cycle Induced Fatigue				
13		Weather & Outside Forces (Cold Weather, Landslides, Earth Movement, Lightning, Tornado, Flooding, Fire)	Weather & Outside Forces (Cold Weather, Landslides, Earth Movement, Lightning, Tornado, Flooding, Fire)				
14		3rd Party Damage	3rd Party Damage				
15		Sabotage/Vandalism/Unauthorized Access	Sabotage/Vandalism/Unauthorized Access				

No.: 1	**Description:** GA7411 Suction, including portable launcher									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
1.1	High Pressure	1. No credible cause identified.								
1.2	Low / No Pressure	1. No credible cause identified.								
1.3	High Temperature	1. No credible cause identified.								
1.4	Low / No Temperature	1. No credible cause identified.								
1.5	High Flow	1. No credible cause identified.								
1.6	Low / No Flow	1. XV74050 fails closed	2. Loss of flush to the seal, resulting in seal failure. Seal failure leads to a gas discharge to the flare. The flare will be snuffed and a release to atmosphere occurs.	1. PALL74055 PSIG - set at 1200 - trip GA7411 2. PDALL74052 PSIG - set at 120 - trip GA7411 3. PAL74055 - 1500 PSIG - results in operator action - not enough time for operator to respond - no credit taken 4. XZSC74055 manually closed from the board - must be set in auto in the field for this to function 5. Flare auto ignitor - TSL74050 - ignites flare - no credit taken		Safety	S4	L3	S4-L3	
		2. Plugged strainer	1. Blocks instrumentation lines to seals resulting in a pump trip. Scenario considered, but no consequence of interest identified							
1.7	Misdirected / Reverse flow	1. No credible cause identified.								
1.8	Utilities	1. Power loss	1. Leads to shutdown of pump and powered valve actuators. Hydraulic system retains control.							

No.: 1	**Description:** GA7411 Suction, including portable launcher									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
			Scenario considered, but no consequence of interest identified.							
1.9	Abnormal Operations	1. Loss of containment while prepping for maintenance	1. Valves leak occasionally which may result in release during line breaking. Potential impact to people in the immediate area.	1. Hydrogen sulfide fixed building monitors 2. Personal hydrogen sulfide monitors 3. DGC Procedure #2350 - Line breaking procedure 4. DGC Procedure #74-058 - Shutdown of GA7411 - Procedure for routing bleed valve to safe location		Safety	S3	L3	S3-L3	
1.10	Changes - MOC	1. No MOCs originating in of affecting this area.								
1.11	Previous Incidents	1. No previous incidents originating in or affecting this area.								
1.12	Pressure Relief Systems	1. PSV74002A/AS - Block valve upstream of relief device closed - vents to atmosphere - Capacity is 9250 SCFM	1. If relief device is block in, then loss of pressure protection for the launcher and receiver during a fire case.	1. Relief device is maintained yearly, per DOT reg.		Safety	S1	L3	S1-L3	
			2. If relief device discharges to atmosphere, then potential for exposure.			Safety	S4	L3	S4-L3	
		2. PSV74000B/BS - Block valve upstream of relief device closed - vents to atmosphere - Capacity is 9250 SCFM	1. If relief device is block in, then loss of pressure protection for the launcher and receiver during a fire case.	1. Relief device is maintained yearly, per DOT reg.		Safety	S1	L3	S1-L3	
			2. If relief device discharges to atmosphere, then potential for exposure.			Safety	S4	L3	S4-L3	

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
2.1	High Pressure	1. No credible cause identified.								
2.2	Low / No Pressure	1. No credible cause identified.								
2.3	High Temperature	1. No credible cause identified.								
2.4	Low / No Temperature	1. No credible cause identified.								
2.5	High Flow	1. No credible cause identified.								
2.6	Low / No Flow	1. No credible cause identified.								
2.7	Misdirected / Reverse flow	1. No credible cause identified.								
2.8	Utilities	1. Power failure	1. Leads to shutdown of pump and powered valve actuators. Hydraulic system retains control. Scenario considered, but no consequence of interest identified.							
2.9	Abnormal Operations	1. No credible cause identified.								
2.10	Pressure Relief Systems	1. Breather cap on lube oil tank	1. Scenario considered, but no consequence of interest identified.							
2.11	Changes - MOC	1. 7400_2_2016_1 - Implement monthly PM for GA7411 to turn motor/pump shafts and to perform a visual inspection instead of the monthly vibration route collection. The pump will be ran every 6 months to obtain Vibration data. The need to run the booster pump is very limited currently and the electrical cost of	1. The team reviewed the change and has no further recommendations for implementing the change.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		running the pump for a few hours to obtain monthly vibration readings is ~$6200. Establishing the modified preventive/predictive maintenance strategy will reduce annual operating costs and prevent false brinelling of the pump bearings due to lack of operation.								
		2. 7400_2_2013_4 - SI74059, GA7411 speed, limit to a maximum speed of 3450 rpm. The week of 9/3 the GA7411 thrust chamber was replaced due to high vibrations. A trend of the speed versus thrust chamber vibrations shows that in early August, the pump was run over 3500 rpm and after that the vibrations slowly started climbing. The signature of the vibration changed also indicating ball bearing deterioration. Past history has proven that operating this pump over 3500 rpm causes the bearings in the thrust chamber to fail. It happened in March 2006, again in November 2010, March 2013 and now in August. Every instance has shown the same vibration signature of bearing deterioration after being run above 3500 rpm. Rotating Equipment recommendation is to limit the speed to 3450 rpm in order to prevent the thrust chamber from failing	1. The team reviewed the change and has no further recommendations for implementing the change.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		rapidly.								
2.12	Previous Incidents	1. DIR-2017-00237 - GA7411 Tioga pump shutdown with no first out alarm. A high DP came into alarm on the seal after the pump tripped but did not seen to be the cause of the trip. E & I did not have anything to go off of since the first out never came in, and pipeline operators checked out the pump to verify no problems. When it was test ran there was no problems found.	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							
		2. DIR-2015-00652 - Tioga pumped tripped from the oil pump stopping. Pump motor went bad. The Tioga pumped tripped like it was supposed to do when the oil pump stops. No action that occurred with the Tioga pump shutting down due to the oil pump shutting off. Is the correct operation. The motor failed due to normal wear and fatigue. Motor failing wasn't caused by anything different then normal fatigue. Corrective Action - We need to have a life expectancy assessment done for this motor and have it changed out on a set up rotation. DIR 2015-00652 documented a lube oil cooler/pump motor trip, for equipment tag number GA7412M. The trip was due to a motor failure. The	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		event was scored 5. An action item was created and asked for a life expectancy assessment and regularly scheduled motor replacements. Maintenance Engineering does not believe an assessment or regularly motor replacements are warranted, and requests the action item be closed, because: • The GA7412M motor is a consumable. Run to failure for this item is the low cost maintenance plan intent. • Regularly replacing the motor per a schedule while it is still functional would waste remaining motor life, and increase the life cycle cost of the motor. • The trip had no adverse consequences, such as a release or spill. • The Tioga CO2 booster pump GA7411 automatically and safely shut down as per design when GA7421/M tripped. • Operations provides a secondary source of additional monitoring when they walk down the area. • There was no CO2 production loss, (Apache and Cenovus nominations were below budgeted expectations at the time).								
		3. DIR-2015-00280 - At 7:00 A.M. an alarm came in stating that the temperature in the electrical room was over 99 degrees and rising, it	2. This was a reoccurring incident that was resolved once a new HVAC system was installed.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		was 65 degrees ambient temperature. I notified pipeline personnel and my supervisor. They were going to work on getting someone to go up and check out the A/C unit for possible failure. Throughout the day the temperature reached 83 degrees outside and caused the room to reach a high temp scale of 120 degrees causing the pump to trip. - New HVAC unit has been installed. No issues since.								
		4. DIR-2015-00062 - seal failure - Corrective Action - The CO2 flare for GA7211 went out when the seal failed. This has happened before, please make sure the flare is sized properly and gas to flare is sized properly. - Open action pending.	3. Open action item pending for this incident.							
		5. DIR-2014-00384 - GA7411 started but did not have flow. The flow control valve FV74056 was opened from the control board but the valve did not open in the field.	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							
		6. DIR-2014-00248 - Tioga pump GA7411 tripped - cause unknown	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							
		7. DIR-2014-00169 - Tioga Pump Fail - Possible air conditioner fail lead to high building temp causing pump VFD failure. We reset the VFD and tried for	2. This was a reoccurring incident that was resolved once a new HVAC system was installed.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		a restart. Everything started good, however due to the excessive heat within the Tioga pump building, we had decided not to compromise the equipment any further due to rising temps. We shut the pump down manually and submitted an E work order for the current day. - New HVAC unit has been installed. No issues since.								
		8. DIR-2014-00131 - GA7411 Tioga pump tripped ,Electrical building temp high was in alarm,HVAC not working properly causing Rack room to over heat,VFD had to be reset,had to wait for control system to cool down before restarting GA7411,the alarm on VFD reset was inverter heat system overtemp,fault 69 - New HVAC unit has been installed. No issues since.	2. This was a reoccurring incident that was resolved once a new HVAC system was installed.							
		9. DIR-2013-00654 - Tioga pump GA7411 tripped. MLV 8 was being stroked at the time. - Suspect pressure backed up while pipeline crew stroked MLV 8 - Team noted that the bypass valve at MLV was not opening. Valve was replaced.	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							
		10. DIR-2013-00608 - GA7411 tripped VFD fault. - Elec building temp high TAH74065A was in alarm. Suspect the A/C is not working - New HVAC unit	2. This was a reoccurring incident that was resolved once a new HVAC system was installed.							

No.: 2	**Description:** GA7411/M									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		has been installed. No issues since.								

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
3.1	High Pressure	1. Refer to low/no flow for blocked pump discharge cases.								
3.2	Low / No Pressure	1. No credible cause identified.								
3.3	High Temperature	1. No credible cause identified.								
3.4	Low / No Temperature	1. No credible cause identified.								
3.5	High Flow	1. No credible cause identified.								
3.6	Low / No Flow	1. FYV74056 fails closed	1. Deadhead GA7411. The deadhead pressure is 3586, which is greater than the listed limits of pipe spec F5AB. Potential flange resulting in minor release of process to atmosphere.	1. PAH74056 - set at 2900 PSIG - operator action to shutdown pump - off same tap as trip - no credit taken 2. PAHH74056 - set at 3100 - automatically trips the pump 3. VAHH74060 - vibe trips GA7411 - set at 0.4 in/s 4. VFD Pump - unlikely to be operating at maximum deadhead conditions 5. PSV74050 set at 3260 PSIG discharges to pump suction 6. PSV74051 set at 3260 PSIG discharges to pump suction 7. TAHH74056 - set at 150 F - Trips GA7411 - process temperature would increase as fluid is spun	2. It was noted by the team that CV74114 and FYV74056 are not on a PM schedule. Consider adding CV74114 and FYV74056 to a PM schedule.	Safety	S4	L3	S4-L3	
		2. XV74051 fails closed	1. Deadhead GA7411. The deadhead pressure is 3586, which is greater than the listed limits of	1. PAH74056 - set at 2900 PSIG - operator action to shutdown pump - off same tap as trip - no credit		Safety	S4	L3	S4-L3	

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
			pipe spec F5AB. Potential flange resulting in minor release of process to atmosphere.	taken 2. PAHH74056 - set at 3100 - automatically trips the pump 3. VAHH74060 - vibe trips GA7411 - set at 0.4 in/s 4. VFD Pump - unlikely to be operating at maximum deadhead conditions 5. PSV74050 set at 3260 PSIG discharges to pump suction 6. PSV74051 set at 3260 PSIG discharges to pump suction 7. TAHH74056 - set at 150 F - Trips GA7411 - process temperature would increase as fluid is spun						
		3. CV74114 fails closed	1. Deadhead GA7411. The deadhead pressure is 3586, which is greater than the listed limits of pipe spec F5AB. Potential flange resulting in minor release of process to atmosphere.	1. PAH74056 - set at 2900 PSIG - operator action to shutdown pump - off same tap as trip - no credit taken 2. PAHH74056 - set at 3100 - automatically trips the pump 3. VAHH74060 - vibe trips GA7411 - set at 0.4 in/s 4. VFD Pump - unlikely to be operating at maximum deadhead conditions 5. PSV74050 set at 3260 PSIG discharges to pump suction 6. PSV74051 set at 3260 PSIG discharges to pump suction	2. It was noted by the team that CV74114 and FYV74056 are not on a PM schedule. Consider adding CV74114 and FYV74056 to a PM schedule.	Safety	S4	L3	S4-L3	

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
				7. TAHH74056 - set at 150 F - Trips GA7411 - process temperature would increase as fluid is spun						
3.7	Misdirected / Reverse flow	1. No credible cause identified.								
3.8	Utilities	1. Power failure	1. Leads to shutdown of pump and powered valve actuators. Hydraulic system retains control. Scenario considered, but no consequence of interest identified.							
3.9	Abnormal Operations	1. No credible cause identified.								
3.10	Pressure Relief Systems	1. PSV74050 - Set at 3260 PSIG - Discharges to GA7411 suction	1. PSV74050 is set higher than DGC's internally defined operating limits. The team believes a leak may occur if pipeline pressure reaches the range between the PSV set point (3260 psig) and the defined piping limits (2964 psig).		1. Evaluate if the set point for PSV74050 and PSV74051 are appropriate for the limits of class F5AB piping. The PSVs are set at 3,260 psig and the DGC defined operating limit of pipe spec F5AB is 2,964 psig.	Safety	S4	L5	S4-L5	
		2. PSV74051 - Set at 3260 PSIG - Discharges to GA7411 suction	2. PSV74051 is set higher than DGC's internally defined operating limits. The team believes a leak may occur if pipeline pressure reaches the range between the PSV set point (3260 psig) and the defined piping limits (2964 psig).		1. Evaluate if the set point for PSV74050 and PSV74051 are appropriate for the limits of class F5AB piping. The PSVs are set at 3,260 psig and the DGC defined operating limit of pipe spec F5AB is 2,964 psig.	Safety	S4	L5	S4-L5	
3.11	Changes - MOC	1. No MOC originating in this area.								
3.12	Previous Incidents	1. DIR-2018-00051 - While pressuring up GA-7411 Tioga CO2 pump with diesel to line it back up for	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		service, Discharge PSV 74050 started leaking at the bottom and out the weep hole. system pressure was at 2300 LBS. - Who discovered the incident? Dale with Adler Hot Oil How was the incident discovered? while pressuring up CO2 pump with diesel to put in service PSV74050 started leaking out weep hole and bottom of PSV. Who was affected by the incident? Pipeline Operations How did the incident occur? Pressuring up with diesel to line up GA 7411 for Service Immediate corrective actions taken: PSV 74050 was isolated and bled down and tagged and locked out								
		2. DIR-2017-00244 - PSV74050 body leak at 1/2" plug - CO2 leaked out the blowdown adjustment screw/plug which is a threaded connection. The lock wire was still in tact which would prevent screw from being tampered with or backing out. There is also a lock nut on adjustment screw to prevent it from backing out. This PSV also has a teflon blowdown adjustment screw/plug seal. This seal may have failed and caused the leak, but the receiving and disassembly inspections did not indicate condition of valve parts. Teflon	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		blowdown seal cat id 175878 was replaced WO#41108343 after failure. - Gather photos and timelines to attach								
		3. DIR-2017-00089 - While using diesel from Adler's Hot Oiler truck, to pressure up PSV 74051, to check for leaks prior to putting back in service. the pressure indication on Adler's truck reached 3000 psi. PSV 74051 set pressure is 3260 psi. - During the pressure test of the PSV piping, the truck tri-plex pump discharge spiked to 3000 psi. Adler documented that the PSV on the hot oil truck was set and tested at 2700 psi and "worked good" Adler also documented that the Maximum operating pressure during the operations was 2500 psi. See Adler doc. attached. DGC piping should of not seen any pressure spikes higher then 2700 psi. The 3000 psi spike would of lifted the Hot oil truck PSV and vented right back to the truck. - Corrective Action - While pressure testing PSVs prior to putting in service, the pressure of the pump discharge spiked quickly to 3000psi.The 3000 psi only showed off the truck. Unsure if the truck PSV lifted (releasing back into the truck), or if the pressure went to our	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		piping. DGC piping should not seen any pressure spikes higher then 2700 psi.They were pressure testing a very small portion of piping and the contractor used a larger pump to do this job.Operations Supervisor working with the contractor to only used certain sized hot oil trucks and tri-plex pumps for our work.								
		4. DIR-2014-00287 - Leak developed on PSV74051 at fitting. PSV on Tioga pump GA7411. - Tube fitting on side of PSV 74051 failed after pump was shut down, tried replacing but could not stop. Appears failure is in threaded area on body of PSV. - Corrective Action - investigate/repair failure mechanism - This valve has devloped cracks around one of the ports. This can't be repaired. Needs to be sent off for annaylisis. No further action is needed by the valve shop. - investigate cause of failure and recommendations for repair - The vendor was not of any help in determining what caused the failure. I also had slightly conflicting accounts of what the operations folks thought happened and the sequence of events. One thought was there was a	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 3	**Description:** GA7411 Discharge Line									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, **Piping Plan:** D7400-036-P, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		fitting leak that blew very cold CO2 onto the valve body which made it crack due to brittle fracture. The valve manufacturer claimed the valve body was not defective as it passed hydrotesting before it was installed. Unable to come up with a clear root cause of failure.								

No.: 4	**Description:** Enclosed Flare									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, 070503-PID, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
4.1	High Pressure	1. No credible cause identified.								
4.2	Low / No Pressure	1. No credible cause identified.								
4.3	High Temperature	1. No credible cause identified.								
4.4	Low / No Temperature	1. No credible cause identified.								
4.5	High Flow	1. PCV74050 fails open	1. Scenario considered, but no consequence of interest identified.							
		2. SOV74050 fails open	1. Scenario considered, but no consequence of interest identified.							
		3. Bypass around SOV74050	1. Scenario considered, but no consequence of interest identified.							
		4. TIC74054 fails open	1. Scenario considered, but no consequence of interest identified.							
		5. XV74052 fails open	1. Scenario considered, but no consequence of interest identified.							
		6. XV74055 fails open	2. XV74055 is always all the way open. The seal leakage from GA7411 would be sent to the flare. The flare is adequately sized to handle normal seal leakage. Scenario considered, but no consequence of interest identified.							
4.6	Low / No Flow	1. PCV74050 fails closed	1. Failure of this valve would result in a loss of fuel to the flare. The flare would go out and the normal seal leakage from GA7411 would be released	1. TAL74054 alarms at 1200 F - prompts operator action 2. Personal hydrogen sulfide monitors		Safety	S3	L3	S3-L3	

No.: 4	**Description:** Enclosed Flare									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, 070503-PID, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
			to atmosphere. The normal vent flow rate for process gas is 60 SCFH. The low release rate would result in a localized impact area.	3. Hydrogen sulfide fixed building monitors - no credit taken due to building typically being closed						
		2. SOV74050 fails closed	1. Failure of this valve would result in a loss of fuel to the flare. The flare would go out and the normal seal leakage from GA7411 would be released to atmosphere. The normal vent flow rate for process gas is 60 SCFH. The low release rate would result in a localized impact area.	1. TAL74054 alarms at 1200 F - prompts operator action 2. Personal hydrogen sulfide monitors 3. Hydrogen sulfide fixed building monitors - no credit taken due to building typically being closed		Safety	S3	L3	S3-L3	
		3. TIC74051 fails closed	1. Failure of this valve would result in a loss of fuel to the flare. The flare would go out and the normal seal leakage from GA7411 would be released to atmosphere. The normal vent flow rate for process gas is 60 SCFH. The low release rate would result in a localized impact area.	1. TAL74054 alarms at 1200 F - prompts operator action 2. Personal hydrogen sulfide monitors 3. Hydrogen sulfide fixed building monitors - no credit taken due to building typically being closed		Safety	S3	L3	S3-L3	
		4. XV74052 fails closed	2. Failure of this valve would result in a loss of air to the flare. The flare may go out and the normal seal leakage from GA7411 would be released to atmosphere. The normal vent flow rate of process gas is 60 SCFH. The low release rate would result in a localized impact area.	1. TAL74054 alarms at 1200 F - prompts operator action 2. Personal hydrogen sulfide monitors 3. Hydrogen sulfide fixed building monitors - no credit taken due to building typically being closed		Safety	S3	L3	S3-L3	
		5. XV74055 fails closed	3. Potential seal damage that would result in a	4. PAHH74053 trips the pump. Seal vent pressure.		Safety	S3	L4	S3-L4	

No.: 4	**Description:** Enclosed Flare									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, 070503-PID, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
			minor seal leak to atmosphere inside the building.	Set at 30 psig.						
4.7	Misdirected / Reverse flow									
4.8	Utilities	1. Loss of power	1. Results in loss of air blower for flare. Refer to deviation 4.6.							
		2. Loss of natural gas fuel line	2. Results in low flow deviation 4.6.							
4.9	Abnormal Operations	1. Loss of containment while prepping for maintenance	1. Valves leak occasionally which may result in release during line breaking. Potential impact to people in the immediate area.	1. Hydrogen sulfide fixed building monitors 2. Personal hydrogen sulfide monitors 3. 2350 - Line breaking procedure 4. 74-058 - Procedure for routing bleed valve to safe location						
4.10	Changes - MOC	1. No MOC originating in this area.								
4.11	Previous Incidents	1. DIR-2017-00583 - Tioga pump GA7411 tripped on Seal Vent line pressure and snuffed the flare out. Who discovered the incident? Board Operator How was the incident discovered? Flare came into Alarm Who was affected by the incident? 5900 How did the incident occur? Failed Seal on GA7411 Immediate corrective actions taken: Block the seal vent line to the flare and isolate GA7411 - Corrective Action - Talked with the crew on what happened and how we isolated the Tioga	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 4	**Description:** Enclosed Flare									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, 070503-PID, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		compressor and communicating with Canada about possible rate cuts to them.								
		2. DIR-2017-00105 - Tioga Flare CB7421 tripped and would not relight automatically. Who discovered the incident? Pipeline Controller Chris Iverson How was the incident discovered? Tioga flare tripped and alarmed into the Control room. Who was affected by the incident? NA How did the incident occur? Winter storm in the Northern part of ND, High winds and blowing snow, near zero visibility and 60-65 mph winds. Blowing snow and zero visibility may have given the fire eye a false indication that the flare pilot was out and tripped the flare. Immediate corrective actions taken: Attempted restarting the Flare, was able to get it lit, but it would go out fairly quickly due to the high winds. Pipeline Techs stayed the night and successfully restarted the flare the next morning after the wind went down.	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							
		3. DIR-2016-00047 - Tioga Flare went out and did not relight. Blocked in XV74055, and notified Shift Superintendent, Supervisor, MIS and sent a notice to Environmental - Flare at Tioga booster	1. The team reviewed the incident and has no further recommendations for preventing reoccurrence.							

No.: 4	**Description:** Enclosed Flare									
PFD: D7400-001-F Sheet 1, D7400-001-F Sheet 2, **P&ID:** D7400-033-P, 070503-PID, **Performance Curve:** TM2853003										
Item	**Deviation**	**Causes**	**Consequences**	**Safeguards**	**Action Items**	**Matrix**	**S**	**ML**	**MR**	**Comment**
		station went out. Blower for flare was down. Didn't have combustion air to light flare. Part failure on blower, new parts on ordered. It's not normal for flare to go out. Possibly only went out once before. - Corrective Action - work order 41033640 was generated. A crew was sent up there and got the flare and blower going again. New parts ordered to repair the problem on the blower. Work order was generated, crew was sent to booster station and got the flare to relight. New parts ordered to repair it right to prevent this from happening again. generate a PM work order for CD7421, specifically addressing PM on the blower motor. PM work order to PM CD7421 and vent blower motor annually.								

What-if				
Robin Braun, Chris Breiner, Kurt Dutchuk, Isaac Michaelson, Tim Rogness, Charles Roy				

No.: 5	External Corrosion

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
5.1	External Corrosion	If unmanaged, potential leak of process to atmosphere impacting off site.		Safety	S4	L3	S4-L3		Coatings and wrap Guided wave inspection Leak detection system Above ground 3 year visual external inspection - dig 12 inches down around every soil-to-air interface 3 year ultrasonic thickness testing	
		If unmanaged, potential leak of process to atmosphere impacting off site.		Safety	S4	L3	S4-L3		Guided wave inspection Leak detection system Above ground 3 year visual external inspection - dig 12 inches down around every soil-to-air interface Coatings 3 year ultrasonic thickness testing	
		If unmanaged, potential leak of process to atmosphere impacting off site.		Safety	S4	L3	S4-L3		Coatings and wrap Guided wave inspection Leak detection	

No.: 5	External Corrosion									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
									system	

What-if				
Robin Braun, Chris Breiner, Kurt Dutchuk, Isaac Michaelson, Tim Rogness, Charles Roy				

No.: 6	Internal Corrosion									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
6.1	Internal Corrosion	If unmanaged, potential leak of process to atmosphere impacting off site.		Safety	S4	L3	S4-L3		3 year ultrasonic thickness testing Daily moisture monitoring in process gas Corrosion coupons	

What-if				
Robin Braun, Chris Breiner, Kurt Dutchuk, Isaac Michaelson, Tim Rogness, Charles Roy				

No.: 7	Manufacturing Defects (Defective Pipe Seams & Defective Pipe)									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
7.1	Manufacturing Defects (Defective Pipe Seams & Defective Pipe)	Failure of piping system resulting in potential rupture of the above ground piping. A rupture could potentially result in a large impact area.	3. During the risk analysis there was some uncertainty about the potential failures associated with manufacturing defects so the team did not have a good understanding of the risk. Ensure appropriate documentation has been provided during the construction of the Tioga station so the risk can be appropriately derived.	Safety	S7	L3	S7-L3		Original hydrotest results MTR certs	

What-if				
Robin Braun, Chris Breiner, Kurt Dutchuk, Isaac Michaelson, Tim Rogness, Charles Roy				

No.: 8	Construction Defects (Defective Girth Welds, Fabrication Welds, Installation Damage, Wrinkle Bends & Buckles, Fitting Failure)									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
8.1	Construction Defects (Defective Girth Welds, Fabrication Welds, Installation Damage, Wrinkle Bends & Buckles, Fitting Failure)	Failure of piping system resulting in potential rupture of the above ground piping. A rupture could potentially result in a large impact area.		Safety	S7	L3	S7-L3		Original hydrotest results Qualified construction personnel Inspection per applicable codes	

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

No.: 9	Equipment Failure (Gasket or O-Ring Failure, Seal/Pump Failure)

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
9.1	Equipment Failure (Gasket or O-Ring Failure, Seal/Pump Failure)	If a double seal failure occurred, process gas would be released into the building. Some process gas would be vented. The localized impact area.		Safety	S3	L4	S3-L4		Hydrogen sulfide fixed building monitors PAHH74053 trips GA7411 at 30 psig. PDALL74052 set at 120 psi. Trips GA7411. VAHH74060 trips GA7411 at 0.4 in/s.	
		If a double seal failure occurred, flow to the flare would exceed the limits of the flare and potentially cause the flare to be snuffed. The process gas would be released through the flare to atmosphere.		Safety	S3	L4	S3-L4			
		Gasket or O-ring failure would result in a minor leak that is localized to the release source.		Safety	S3	L4	S3-L4		Material verification by independent personnel	
		Gasket or O-ring failure would result in a minor leak that is localized to the release source.		Safety	S3	L4	S3-L4		Replace of O-rings and gaskets during line breaks. Internal visual during line breaking Personal hydrogen sulfide monitors Hydrogen sulfide fixed building monitors Carbon dioxide leak detection camera is periodically used to identify leaks at the	

No.: 9	Equipment Failure (Gasket or O-Ring Failure, Seal/Pump Failure)									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
									aboveground facility	

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

No.: 10	Mechanical Damage (Immediate Failure)

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
10.1	Mechanical Damage (Immediate Failure)	Refer to Node 14 for potential causes.								

What-if				
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No.: 11	Mechanical Damage (Delayed Failure)									
Item	**What if...?**	**Responses**	**Action Items**	**SOE**	**S**	**L**	**R**		**Safeguards**	**Comment**
11.1	Mechanical Damage (Delayed Failure)	Earth movement resulting in aboveground pipe stress. Potential leaks from flange.		Safety	S3	L4	S3-L4		Above ground 3 year visual external inspection	
		Refer to nodes 5 through 9 for additional potential causes.								

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

No.: 12	Pressure Cycle Induced Fatigue

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
12.1	Pressure Cycle Induced Fatigue	No credible cause identified.								

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

No.: 13	Weather & Outside Forces (Cold Weather, Landslides, Earth Movement, Lightning, Tornado, Flooding, Fire)

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
13.1	Weather & Outside Forces (Cold Weather, Landslides, Earth Movement, Lightning, Tornado, Flooding, Fire)	Scenario considered, no consequence of interest.								
		Scenario considered, no consequence of interest.								
		Refer to Node 4.11 for weather related incident.								
		Potential for significant release impacting area. Risk was not assessed as there are limited safeguards available. Also, the team believed that possibility of the Tioga Station being hit was unlikely.								
		Scenario considered, no consequence of interest.								

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

No.: 14	3rd Party Damage

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
14.1	3rd Party Damage	Refer to node 15 for potential causes.								

What-if				
Robin Braun, Chris Breiner, Mark Degenstein, Kurt Dutchuk, Isaac Michaelson, Claude O'Berry, Charles Roy				

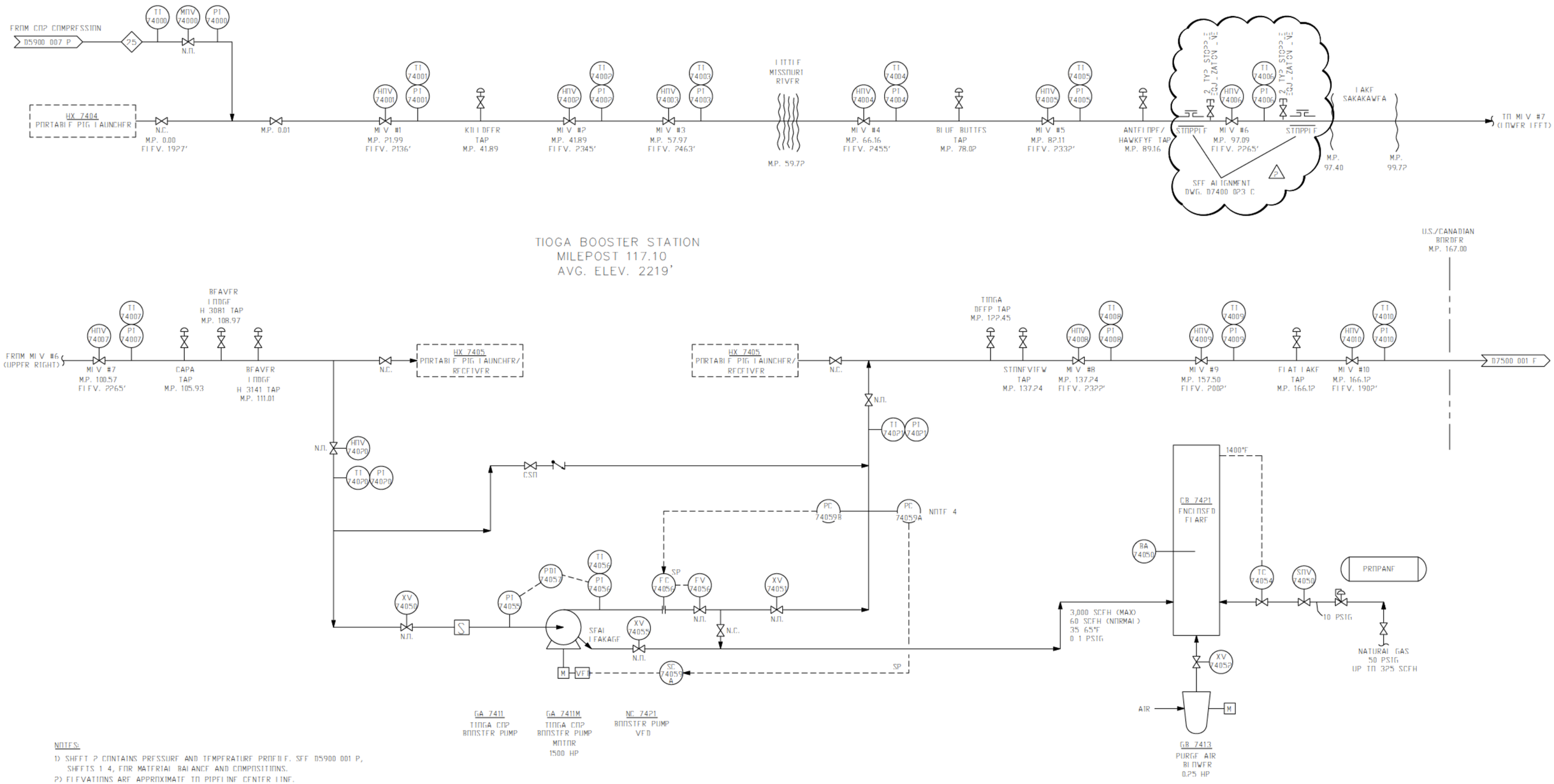
No.: 15	Sabotage/Vandalism/Unauthorized Access

Item	What if...?	Responses	Action Items	SOE	S	L	R		Safeguards	Comment
15.1	Sabotage/Vandalism/Unauthorized Access	Potentially close valves and isolate pipeline. No release would occur. Scenario considered, but no consequence of interest identified.	4. Evaluate benefit of adding a camera that can be monitored remotely. The team believes installation of a camera would mitigate or prevent threats posed by unauthorized access to the facility.						Perimeter fence locked Building locked Warning signs HOV74020 - board notification that pipeline has been isolated Multiple flow and pressure transmitters along the pipeline	
		Trip power to aboveground facility. Scenario considered, but no consequence of interest identified.								
		Potentially damage pump. Potential localized release.		Safety	S4	L4	S4-L4			
		Potentially open bleed or vent valves.	4. Evaluate benefit of adding a camera that can be monitored remotely. The team believes installation of a camera would mitigate or prevent threats posed by unauthorized access to the facility.	Safety	S4	L4	S4-L4		Perimeter fence locked Building locked Warning signs LDS alarms to board operator.	

Attachment 2

Supporting Documentation

Process Flow Diagrams
Piping and Instrumentation Diagrams



NOTES:

1) SHEET 2 CONTAINS PRESSURE AND TEMPERATURE PROFILE. SEE D5900 001 P, SHEETS 1-4, FOR MATERIAL BALANCE AND COMPOSITIONS.
2) ELEVATIONS ARE APPROXIMATE TO PIPELINE CENTER LINE.
3) PI'S AND TI'S ARE SHOWN TOGETHER TO ELIMINATE CLUTTER. THEY ARE NOT PHYSICALLY CONNECTED.
4) THERE ARE 4 BASIC MODES OF PUMP CONTROL.
   A) PRESSURE TO SPEED CASCADE (NORMAL FOR CASE 3).
   B) PRESSURE TO FLOW CASCADE (NORMAL FOR CASE 1).
   C) FLOW SETPOINT IN AUTOMATIC (EXTENDED STARTUP MODE).
   D) MANUAL SPEED AND FLOW OUTPUTS (INITIAL STARTUP).

REV	DATE	DESCRIPTION	DWN	CHK	APP	APP	APP
2	07/10	ADDED STOPPLE WO# 4053669	DTF	JN	RW		
1	10/08	CHANGED FUEL FOR TIOGA FLARE TO SNG WO# 4050,3584	C.JA	M.JM	MAI	GGB	
0	07/06	ORIGINAL DESIGN	C.JA	DKF	GGB	DRW	

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PO BOX 1149
BISMARCK, ND 58502

CO_2 PIPELINE – 7400 AREA PROCESS FLOW DIAGRAM

DWG. NO: D7400 001 F SHEET: 1 OF 2 REV NO: 2

LOC NO: D0002064B

D0002064B

7400/7500 PFD MATERIAL BALANCE TABLE

	CASE 1 SUMMER	CASE 1 WINTER	CASE 1A SUMMER	CASE 1A WINTER	CASE 2 SUMMER	CASE 2 WINTER	CASE 3 SUMMER	CASE 3 WINTER	CASE 4 SUMMER	CASE 4 WINTER
PIPELINE FLOW	120 MMSCFD	120 MMSCFD	105 MMSCFD	105 MMSCFD	95 MMSCFD	95 MMSCFD	165 MMSCFD	165 MMSCFD	200 MMSCFD	200 MMSCFD
# 5900 COMPRESSORS OPERATING	2	2	2	2	2	2	3	3	4	4
TIOGA BOOSTER PUMP OPERATING	YES	YES	NO	NO	NO	NO	YES	YES	YES (UPGRADED)	YES (UPGRADED)
GOODWATER STATION FLOW (SEE NOTE 2)	110 MMSCFD	110 MMSCFD	95 MMSCFD	95 MMSCFD	90 MMSCFD	90 MMSCFD	137.5 MMSCFD	137.5 MMSCFD	137.5 MMSCFD	137.5 MMSCFD
MIDALE STATION FLOW (SEE NOTE 2)	10 MMSCFD	10 MMSCFD	10 MMSCFD	10 MMSCFD	5 MMSCFD	5 MMSCFD	27.5 MMSCFD	27.5 MMSCFD	27.5 MMSCFD	27.5 MMSCFD
FLOW DELIVERED UPSTREAM OF TIOGA (SEE NOTE 2)									35 MMSCFD	35 MMSCFD

INSTRUMENT	LOCATION	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F	PSIG	°F
PI/TI 74000	PLANT DISCHARGE	2270	125	2585	120	2690	125	2680	120	2640	125	2625	120	2690	125	2690	120	2690	125	2690	120
PI/TI 74001	MLV #1	2143	96	2464	87	2585	96	2574	87	2536	96	2524	87	2533	96	2539	87	2470	96	2477	87
PI/TI 74002	MVL #2	2000	81	2328	68	2461	81	2451	68	2422	81	2403	68	2336	81	2349	68	2214	81	2233	68
PI/TI 74003	MLV #3	1909	74	2243	58	2384	74	2374	58	2350	74	2330	58	2210	74	2228	58	2043	74	2074	58
PI/TI 74004	MLV #4	1881	71	2220	56	2364	71	2357	56	2338	71	2313	56	2155	71	2180	56	1959	71	2000	56
PI/TI 74005	MLV #5	1880	67	2231	50	2377	67	2377	50	2358	67	2337	50	2114	67	2151	50	1877	67	1935	50
PI/TI 74006	MLV #6	1857	63	2217	46	2371	63	2375	46	2356	63	2334	46	2056	63	2104	46	1758	63	1835	46
PI/TI 74007	MLV #7	1839	63	2202	45	2361	63	2366	45	2350	63	2327	45	2030	63	2081	45	1706	63	1790	45
PI/TI 74020	TIOGA STATION INLET	1800	60	2178	41	2332	60	2344	41	2338	60	2314	41	1922	60	1991	41	1570	60	1677	41
PI/TI 74056	PUMP DISCHARGE	2479	70	2785	50	BYPASSED		BYPASSED		BYPASSED		BYPASSED		2856	70	2763	50	2841	70	2738	50
PI/TI 74021	TIOGA STATION OUTLET	2474	65	2416	46	2331	60	2343	41	2337	60	2313	41	2851	65	2758	46	2836	65	2733	46
PI/TI 74008	MLV #8	2345	59	2291	41	2215	59	2234	41	2237	59	2221	41	2636	59	2558	41	2628	59	2538	41
PI/TI 74009	MLV #9	2370	59	2334	39	2264	59	2299	39	2298	59	2291	39	2575	59	2524	39	2562	59	2503	39
PI/TI 74010	MLV #10	2365	59	2339	39	2266	59	2308	39	2304	59	2303	39	2523	59	2484	39	2521	59	2475	39
PI/TI 75001	MLV #11	2272	58	2255	36	2192	58	2242	36	2238	58	2234	36	2354	58	2332	36	2347	58	2322	36
PIC 6014/TI 75002	GOODWATER STATION INLET	2200	58	2200	35	2141	58	2200	35	2200	58	2200	35	2200	58	2200	35	2200	58	2200	35
PIC 6013 (NOTE 3)	GOODWATER STATION OUTLET	2121	58	2130	35	2077	58	2140	35	2145	58	2155	35	2050	58	2065	35	2069	58	2065	35
PC 75032	MIDALE STATION INLET	2200	58	2200	35	2141	58	2200	35	2200	58	2200	35	2200	58	2200	35	2200	58	2200	35
PC 75033 (NOTE 4)	MIDALE STATION OUTLET	2195	58	2195	35	2136	58	2195	35	2195	58	2195	35	2195	58	2195	35	2195	58	2195	35

CASE DESCRIPTIONS:

CASE 1 SUMMER	LOWER PLANT DISCHARGE PRESSURE TO HELP OFFLOAD COMPRESSORS.
CASE 1 WINTER	HIGHER PLANT DISCHARGE PRESSURE WITH TIOGA PUMP THROTTLED.
CASE 1A SUMMER	MAXIMUM CO2 EXPORT WITH TIOGA PUMP DOWN.
CASE 1A WINTER	MAXIMUM CO2 EXPORT WITH TIOGA PUMP DOWN.
CASE 2 SUMMER	MAXIMUM CO2 EXPORT AT 1/2 PLANT RATES.
CASE 2 WINTER	MAXIMUM CO2 EXPORT AT 1/2 PLANT RATES.
CASE 3 SUMMER	MAXIMUM CO2 DELIVERY TO CANADA WITH 3 COMPRESSORS AND TIOGA PUMP RUNNING.
CASE 3 WINTER	MAXIMUM CO2 DELIVERY TO CANADA WITH 3 COMPRESSORS AND TIOGA PUMP RUNNING.
CASE 4 SUMMER	THEORETICAL CASE WITH 175 MMSCFD PLANT RATE, 4 COMPRESSORS AND A TIOGA PUMP UPGRADE.
CASE 4 WINTER	THEORETICAL CASE WITH 175 MMSCFD PLANT RATE, 4 COMPRESSORS AND A TIOGA PUMP UPGRADE.

NOTES:

1) SEE DRAWING D5900 001 P, SHEETS 1 4 FOR DETAILED MATERIAL BALANCE AND COMPOSITIONS.
2) CUSTOMER FLOWS SHOWN ARE FOR A "TYPICAL" DAY. CONTRACTUAL OBLIGATIONS MAY DICTATE A DIFFERENT SPLIT.
3) GOODWATER STATION DP IS DICTATED BY PIPING CONFIGURATION.
4) MIDALE STATION DP IS DICTATED BY FLOW CONTROL VALVE POSITION.

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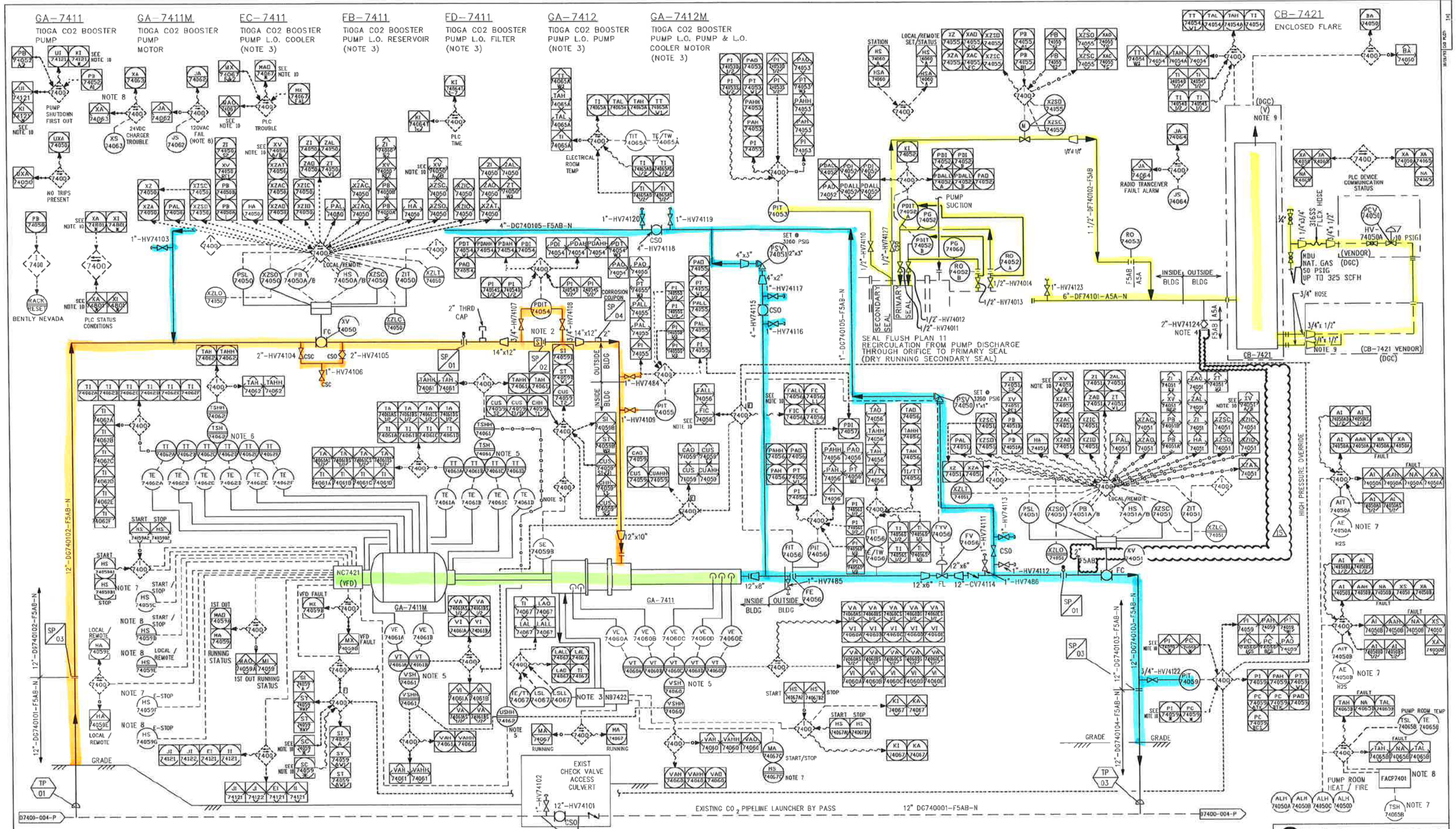
BEULAH, ND 58523

CO_2 PIPELINE 7400/7500 AREAS
PRESSURE & TEMPERATURE PROFILE
PROCESS FLOW DIAGRAM

REV	DATE	DESCRIPTION	DWN	CHK	APP	APP	APP
0	12/28/16	ORIGINAL DESIGN AS-BUILT	CJA	DKE	GGE	MAL	

DWG. NO: D7400 001 F SHEET 2 OF 2
REV. NO: 0
LOC. NO: D00020649

D00020649



NOTES:

1. REPLACE CULVERT WITH RECTANGULAR ACCESS.
2. INSTALL STRAINER WITH 90° ELL DOWNSTREAM FOR EASY REMOVAL.
3. SEE SCHLUMBERGER DWG. NO. 3909357 & 3909384 FOR DEPICTION OF LUBE OIL SYSTEM
4. LOCATE VENT VALVES AS CLOSE AS POSSIBLE TO FLARE HEADER
5. BENTLY NEVADA RACK / EQUIPMENT. SEE INSTRUMENT LOOP DIAGRAMS FOR DETAILS ON ALARM & TRIP SET POINTS.
6. T-538 CONTROLLER / T-538 INDICATION
7. LOCATED IN PUMP ROOM
8. LOCATED IN ELECTRICAL ROOM
9. SEE "MRW TECHNOLOGIES, INC." DRAWING# 070503-PID FOR PILOT / BURNER CONTROL SYSTEM.
10. SEE INSTRUMENT LOOP DIAGRAM FOR ASSOCIATED TAGS.

Node 1
Node 2
Node 3
Node 4

REVISION APPROVAL RECORD				REV	
DISCIPLINE	BY	DATE	DISCIPLINE	BY	DATE
ARCH.			MECHANICAL		
CIVIL			I & C		
ELECTRICAL			PIPING		
ENVIRON.			PROCESS		
GEN. ARRANG.			QA / QC		
HVAC			STRUCTURAL		

REFERENCE DRAWINGS	
DESCRIPTION	DRAWING NO.
TITLE	NO

REV	DATE	DESCRIPTION	EVN	CHK	APP	APP	APP
15	07/07	REMOVED 2"DG740106 NDCH BOT-155	EDH	JRN	JMH	SJC	
14	07/05	ASBUILT, ADDED MAGELIS DISPLAY	KIM	JJD	DRW	SJC	
13	6/05	AS BUILT, WDR 4070366 MODIFY SEAL FLUSH PIPING	CJA	HJM	KAL	SJC	
12	1/01	AS BUILT, REPLACED SWITCHES WITH TRANSMITTERS	SJD	DRW	DRW	DMP	SJC
11	3/01	ADDED TE/TT/TT/LSL/LAL74067 WDR40266691	KIM	NDF	DMP	MAJ	
0	10/96	APPROVED FOR CONSTRUCTION	AGD	RKB	RAS		

APPROVAL

DRAWN AGD	DATE 05/06/05
CHECKED RKB	DATE 7/22/05
SIZE	DATE
PCN	DATE 7/22/05
DN	DATE
CLIENT	DATE

Washington Group International
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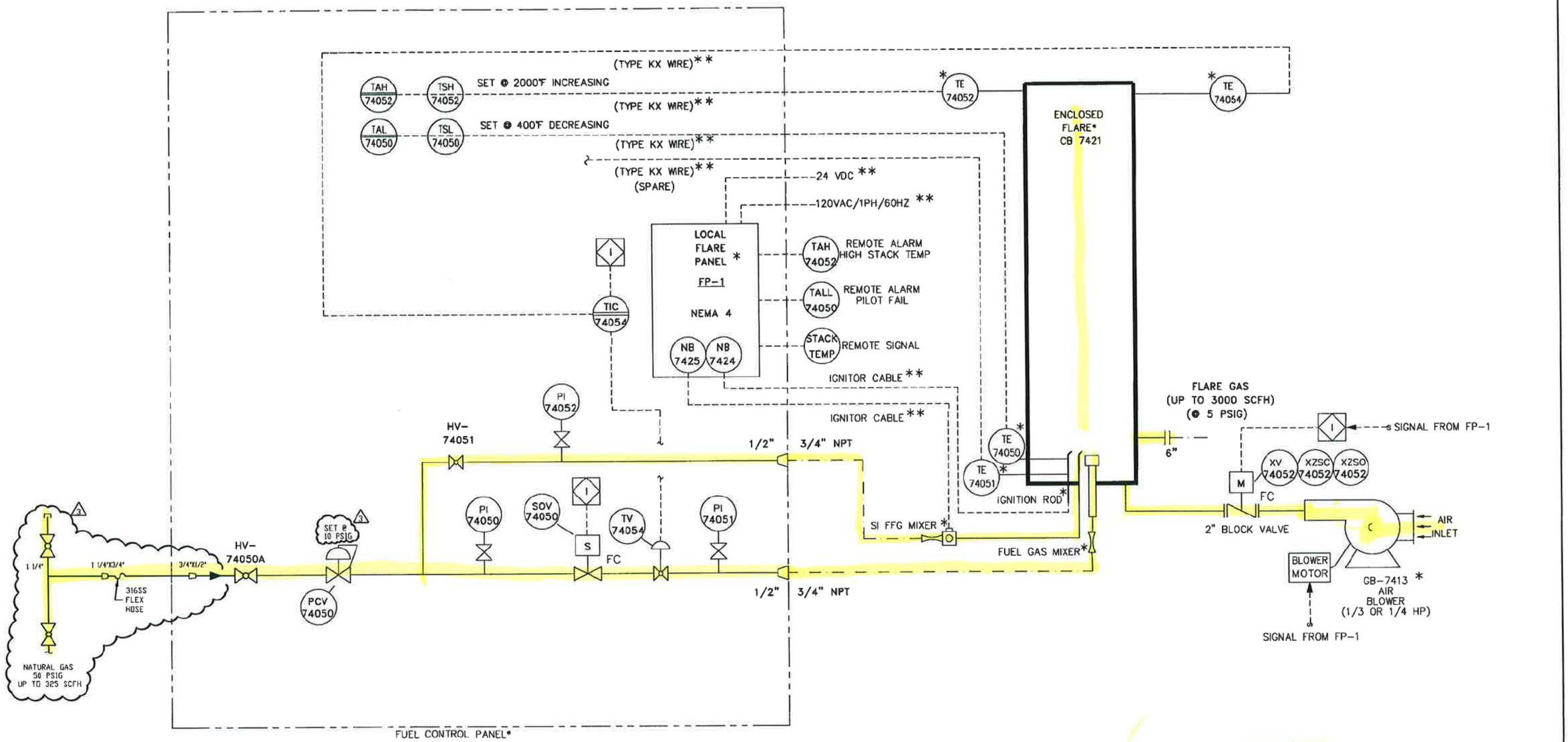
BISMARCK, ND 58503

CO_2 COMPRESSION - 7400 AREA
BOOSTER PUMP
PIPING & INSTRUMENTATION DIAGRAM

DWG. NO. D7400-033-P
REV. NO. 15
LOC. NO. D00018191

D00018191



Node 4

NOTES:

PIPING BY OTHERS
ELECTRICAL SIGNAL
RACK BOUNDARY LIMITS

* SHIP LOOSE FOR FIELD INSTALLATION BY OTHERS

** BY OTHERS

ELECTRICAL AREA CLASSIFICATION: UNCLASSIFIED
SOV-100 & TSL-001 ARE 24 VDC

No.	Date	By	Chk'd	Appr'd	Appr'd	Description	Drawing No.	Subject
3	09-29-08	CJA	MJN	MAL	GGB	CHANGED FUEL FOR TIOGA FLARE TO SNG, WO# 40503384		
2	10-04-05	CD	MRD			FOR CONSTRUCTION		
1	09-02-05	CD	MRD			REVISED PER CUSTOMER COMMENTS		
0	7-25-05	CD	MRD			FOR APPROVAL		

REVISIONS — Reference Drawings

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Customer: DAKOTA GASIFICATION CO.

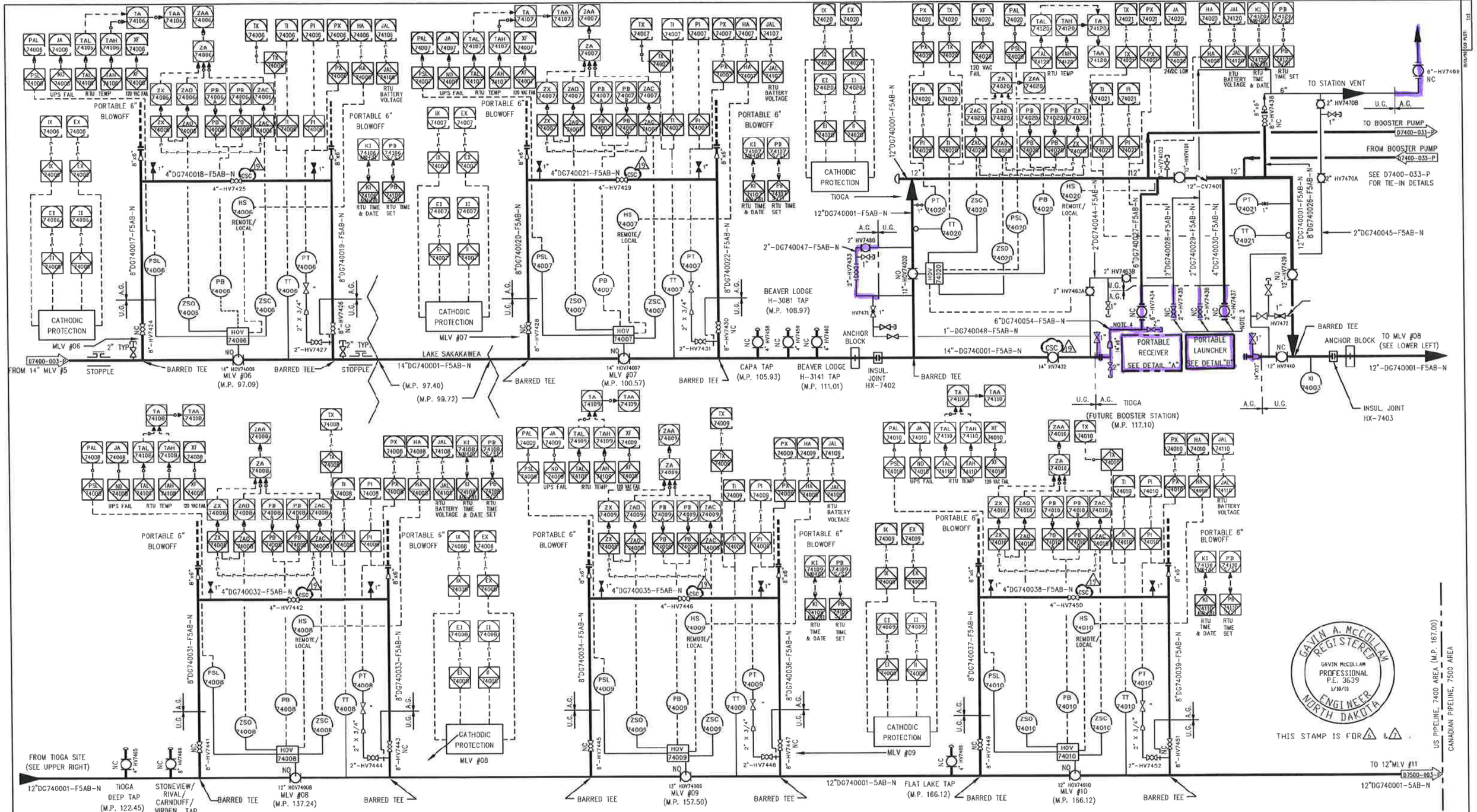
Drawn: CD
Date: 7/25/05
Scale: NTS
Checked: MRD
App'd:

ENCLOSED FLARE
PIPING AND INSTRUMENTATION DIAGRAM

MRW technologies, inc. Tulsa, Oklahoma

P.O. No. 381209
Jobsite: BEULAH, ND
Revision No. 3
Drawing No. 070503-PID
Sheet 1 Of 1

D00008658



NOTES:
1) THE 6" BLOWOFFS AT THE MAINLINE VALVES ARE NORMALLY BLINDED. THE PORTABLE 6" BLOWOFFS FOR EACH SITE ARE STORED IN THE VALVE SITE BUILDING.
2) HX7404 PORTABLE RECEIVER ON 14" LINE USE PSV74002A/AS, 2970 PSI ON 12" LINE USE PSV74002B/BS, 3260 PSI
3) 1" BLEED VALVE ADDED TO BLIND FLANGE. BLIND FLANGE USED WHEN LAUNCHER/RECEIVER NOT IN PLACE. SEE DETAIL 3 ON DWG D7400-008P.
4) 6" BYPASS (DG740054) USED WHEN PORTABLE RECEIVER IS NOT IN PLACE.

Node 5

REFERENCE DRAWINGS		REV	DATE	DESCRIPTION	DRWN	CHK	APP	APP	APP
DESCRIPTION	DRAWING NO.	15	9/9/98	FOXBORO MIGRATION VD040357222	RKS	TVT	DRW	GGB	
P&I SYMBOLS & LEGENDS	D-7400-002-P	18	9/9/98	OPERATION REDLINE, CAR SEAL & REMOVED V17402	JEB	CJR	RLB	RLS	
PIPELINE P&ID	D-7400-003-P	17	7/7/01	REMOVED DG740050, ADDED NOTE 4 & DG740054	JEB	CJR	RLB	RLS	
PIPELINE P&ID	D-7500-003-P	16	6/5/01	ADD STOPPLE - VD040536669	DTF	JN	LRW		
				HX & PSV # VD040630822	JEB	MJH	MAL	TJT	
		REV	ISSUE DATE	DESCRIPTION	DWN	CHK	APP	APP	APP
		0	6/8/98	ISSUED FOR CONSTRUCTION	R.B.	BWR	GAT	WMD	WLR

HOUSTON, TEXAS

APPROVAL

	DATE
DRAWN R.B.	11/24/97
CHECKED R. SADIGH	3/15/98
PROJECT ENGINEER G.A. TENCER	9/3/98
PROJECT MANAGER W.H. OLSON	9/3/98
CLIENT V.L. RICKERD	9/3/98

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BEULAH, ND 58523

CO_2 COMPRESSION U.S. - 7400 AREA
PIPELINE SCHEMATIC
PIPING & INSTRUMENTATION DIAGRAM

DWG. NO: D7400-004-P
REV. NO: 19
LOC. NO: D00020104

D00020104

Dakota Gasification Company

Technical Report

To: C. O'Berry

From: C.Roy

Date: December 6, 2017

Subject: CO2 Pipeline Threat Assessment

Attached is the documentation from the November 20th, 2017 meeting that addressed the CO2 Pipeline Threat Assessment. These threats, preventative measures, and mitigative measures will be incorporated into the IMP and applicable procedures.

Please contact me at extension 6629 with any questions or comments.

cjr

ATTACHMENTS

1) Meeting Notes & Action Log
2) CO2 Pipeline Threat Assessment Spreadsheet
3) Referenced API 1160
4) CO2 IMP Appendix L
5) ArcGIS Mapping Printouts

cc: C. Breiner
K. Dutchuk
D. Knoll
N. Schroetlin
C. O'Berry

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

MEETING NOTES & ACTION LOG

Meeting Topic: CO2 Threat Assessment		Date: 11/20/2017	Time: 12:30 PM
Facilitator: Charles Roy		Location: DGC Field Office Building	

Attendees	Department	Present	Attendees	Department	Present
Charles Roy	Reliability Engr.				
Dave Knoll	OPS Pipeline				
Paul Remnick	OPS				
Kurt Dutchuk	Pipeline OPS				
Eric Hyttinen	E&I				
Chris Breiner	Process Engineering				
Neil Schroeder	Reliability Eng. Supervisor				
Claude O'BERRY	OPS Pipeline				

No.	Topic/Action/Issue	Responsibility	Due Date	Status
	- Question asked if any other threats besides IR in API 1160 Section 4.2? None			
	Check pressure cycling on CO2 Pipeline	Charles Roy		
	Weather Related Incidents in AOC & Training	Dave Knoll		
	Check inspections for above ground piping with SCC. (Wet Mag)	Charles Roy		
	Technical Report	Charles Roy		

RESPONSIBLE CARE®

CO2 Pipeline Threat Assessment

Threat	Consequence	Preventative/Mitigative Measures
External Corrosion	Leak due to corrosion	• Coating • Cathodic Protection • In-Line Inspections • Close Interval Survey • Guided Wave Testing • Leak Detection System • AC Interference Testing
Internal Corrosion	Leak due to corrosion	• ILI Inspections • Corrosion Coupons • Gas sampling to monitor H20 levels
Selective Seam corrosion	Leak due to corrosion	• Coating • Cathodic Protection • ILI Inspections
Stress Corrosion Cracking (SCC)	Leaks or ruptures	• Fusion Bonded Epoxy Coating • Wet Mag Particle Inspection • ILI Inspections • Investigating new ILI technologies
Manufacturing Defects (defective pipe seams & defective pipe)	Leaks or ruptures	• Original Hydrotest • ILI Inspections
Construction Defects (defective girth welds, fabrication welds, installation damage, wrinkle bends & buckles, fitting failure)	Leaks or ruptures	• Original Hydrotest • Original 100% X-Ray • ILI Inspections • Pipe Movement Analysis for Stress

CO2 Pipeline Threat Assessment

Equipment Failure (gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, & miscellaneous)	Leaks or ruptures	• Periodic Inspections • Preventative Maintenance Program
Mechanical Damage (Immediate Failure)	Leak due to Third Party Damage	• One-Call System • Locating & Marking • Monitoring Excavations • Public Awareness Program • Aerial & Ground Surveillance • Secured Aboveground Assets
Mechanical Damage (Delayed Failure)	Leak due to Third Party Damage	• ILI Inspections • Notification of pipeline damage from TPD • Aerial & Ground Surveillance
Incorrect Operations	Leaks, Overpressure, or Pipe Damage	• Proper Training & OQ • Operating & Maintenance Manual • Monitoring
Weather & Outside Force (Cold weather, landslides, earth movement, lightning, tornado, flooding, fire)	Leaks or ruptures	• Aerial & Ground Surveillance after severe weather • Aerial Surveillance to locate landslides • Aerial Surveillance to monitor river crossings • Removing trees where roots could impinge on the pipeline • Pipe Movement Analysis • Emergency Response Procedure • County notifications of inclement weather in the area
Pressure Cycle Induced Fatigue	Leaks or ruptures	• ILI Inspections to track anomaly growth

4 Integrity Management Program

4.1 General Considerations

A pipeline integrity management program should facilitate appropriate and timely actions on the part of a pipeline operator to assure that a pipeline system is continually operated in a manner that minimizes risk to the public/ employees, the environment, or the customers. It is the intent of this document to provide a guideline for pipeline operators to use in developing their pipeline integrity management plans (IMPs).

In simplest terms a pipeline integrity management program should:

— identify threats to pipeline integrity,

— identify potential consequences to the public and the environment in the event of a release,

— rank segments of the pipeline system according to the risk each poses,

— provide for assessment of the integrity of each segment in a timely manner based on identified threats and the risk to minimize the possibility of a release,

— specify repairs or mitigative actions to carry out in a timely manner to prevent releases,

— establish reassessment frequencies,

— define preventive and mitigative measures to address relevant threats including those not covered by integrity assessments,

— use the findings of integrity assessments to update and improve the integrity management process.

The program process flow shown in Figure 2 provides a common structure upon which to develop an operator-specific integrity management program [4]. As implied by the feedback loop in Figure 2, an integrity management program involves a continuous cycle of monitoring pipeline condition, identifying and assessing risks, and taking action to minimize the most significant risk. Risk assessments should be periodically updated and revised to reflect current conditions so operators can most effectively use their finite resources to achieve the goal of error-free, spill-free operation.

4.2 Elements of Integrity Management

Identify Potential Pipeline Impacts to Critical Locations—This program element involves the identification of pipeline segments that could affect critical locations in the event of a release. Identification of critical locations involves evaluating populated, environmentally sensitive and navigable water areas information, integrating this information with pipeline mapping data, and determining at which locations a release could impact these areas. The identified critical locations may change with time or with changes to the pipeline system. Therefore, critical locations need to be reviewed from time to time. Guidance for making these determinations is provided in Section 5 of this RP.

Data Gathering, Review, and Integration—To understand the potential threats to the integrity of a pipeline segment and to determine the extent to which the segment could affect a critical location, should a spill occur, an operator needs to gather, review, and integrate relevant information. Such information generally consists of the design of the pipeline, the attributes of the pipeline, the operational history including operating pressure ranges and past releases if any, the results of prior inspections and assessments including any in-line inspections (ILIs) or hydrostatic tests, previously made repairs or other mitigative responses, corrosion and cathodic protection surveys, and measures taken to prevent releases or the effects of a release. An operator should also consider gathering, reviewing, and

[4] Operators may access the essential elements of integrity management required by 49 *CFR* 195.452 at http://primis.phmsa.dot.gov/iim/flowchart1.htm.

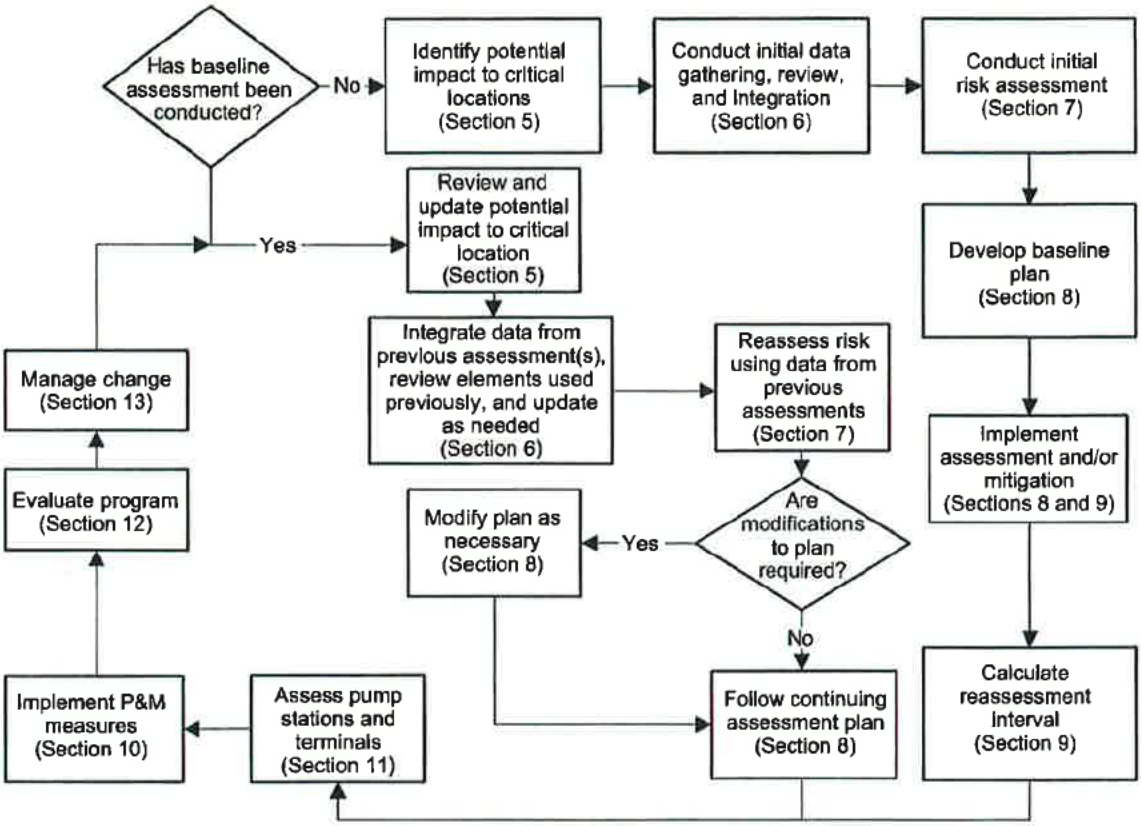


Figure 2—Process Flow for an Integrity Management Program

integrating applicable industry trends, regulatory notices, and other operators' experiences where applicable. Section 6 provides a summary of the data sources, common data elements that are typically used in risk analyses, and approaches to data review and integration.

Risk Assessment—Data assembled from the previous steps are used to conduct a risk assessment of the pipeline system. The risk assessment begins with a systematic and comprehensive consideration of potential threats to the integrity of the pipeline or facility.

The pipeline industry through the Pipeline Research Council International (PRCI) has classified pipeline incidents into 22 categories, each of which represents a threat to pipeline integrity. Pipeline integrity management entails addressing each of these 22 threats and taking appropriate measures to mitigate those that are found relevant to any particular pipeline segment. The 22 categories are:

1) external corrosion;

2) internal corrosion;

3) SCC;

4) defective pipe seam;

5) defective pipe;

6) defective pipe girth weld (circumferential including branch and T joints);

7) defective fabrication weld;

8) wrinkle bend or buckle;

9) stripped threads/broken pipe/coupling failure;

10) gasket or O-ring failure;

11) control/relief equipment malfunction;

12) seal/pump packing failure;

13) miscellaneous (failure of valve or other component);

14) damage inflicted by first, second, or third parties (instantaneous/immediate failure);

15) previously damaged pipe such as dents and/or gouges (delayed failure);

16) vandalism;

17) incorrect operational procedure;

18) cold weather;

19) lightning;

20) heavy rains and floods;

21) earth movement;

22) unknown (root cause of failure was not determined).

ASME B31.8S recommends that pipeline operators address in their IMPs the first 21 of these 22 threats. The category of "unknown" [Threat 22)] is not included in the list of threats to be addressed for the obvious reason that prevention and mitigation of an unknown threat is not possible. Per ASME B31.8S, the 21 threats are grouped as time dependent, stable, or time independent, and certain failure modes are grouped under one heading as follows.

Time-dependent threats:

— external corrosion,

— internal corrosion,

— SCC.

Stable threats:

— defective pipe seams;

— defective pipe;

— welding/fabrication related threats: defective pipe girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure;

— equipment threats: gasket or O-ring failure, control/relief equipment malfunction, seal/pump packing failure; and

— miscellaneous.

Time-independent threats:

— third-party/mechanical damage threats: damage inflicted by first, second, or third party (instantaneous/immediate failure);

— previously damaged pipe;

— vandalism;

— incorrect operational procedure;

— weather-related and outside force threats: cold weather, lightning, heavy rains or floods, and earth movement.

Operators of hazardous liquid pipelines should address these threats as well in their IMPs. However, the fact that there are both physical and regulatory differences between gas and liquid pipelines makes it necessary to alter the threat categories to some extent. For one thing, the potential for pressure-cycle-induced fatigue is much greater for liquid pipelines than it is for gas pipelines. The threat of any one of several types of defects becoming enlarged by pressure-cycle-induced fatigue becomes an additional threat category for liquid operators to consider. In addition, 49 *CFR* 195 requires special consideration of seam integrity assessment for certain types of seams. As a result selective seam corrosion, which is a subset of the external and internal corrosion threats identified in ASME B31.8S, becomes a separate threat category in this RP. Lastly, the threat of "transit fatigue" is added because of its being historically a problem in some hazardous liquid pipelines due to pressure-cycle-induced fatigue.

The threats for hazardous liquid pipelines that operators should address can be characterized as follows:

1) external corrosion;

2) internal corrosion;

3) selective seam corrosion (external or internal);

4) SCC;

5) manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots);

6) construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken pipe/coupling failure);

7) equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous);

8) mechanical damage (causing an immediate failure or from vandalism);

9) mechanical damage (previously damaged pipe causing a delayed failure or vandalism);

10) incorrect operations;

11) weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement);

12) the growth of an initially noninjurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue).

Fire, Tornado

WET Mag Testing

Threats 1), 2), 3), 4), and 12) are clearly time-dependent threats that should be addressed by periodic assessment and monitoring. Threats 5), 6), and 9) are considered possibly time-dependent threats because of the potential for their enlargement by pressure-cycle-induced fatigue. For the latter threats, the pipeline operator will be called upon to judge the need for continuing assessments or monitoring. Threats 7), 8), 10), and 11) are considered time independent because they involve random events for which the time of occurrence is usually not predictable. Management of the latter class of threats involves employing preventive and mitigative measures.

It is recognized that not all 12 may apply to every hazardous liquid pipeline and that pipeline operators may want to customize their approach to considering these threats. These 12 threats are discussed in detail in Annex A of this RP.

Next the possible consequences of a release should be assessed. Consequences include impacts to critical locations. Risk is generally taken to be the combination of probability of an event and the consequence of such an event. Both the threats and the consequences may vary from point to point along a pipeline, so risk assessment should be done either incrementally along the pipeline or by discrete segments of the pipeline. The risk analysis for each segment can be used to prioritize or rank the segments. Risk should be reassessed periodically and prior to reassessment of pipeline integrity. Information gathered, analyzed, and acted upon during any previous assessments of pipeline integrity should also be taken into account in the risk reassessment. Section 7 provides guidance for developing and implementing a risk assessment approach.

Development of a Pipeline Integrity Assessment Plan—The pipeline operator should develop a plan to assess the integrity of the pipeline system, or modify as appropriate, an existing plan that has been followed previously. The order of assessment should be based as nearly as practical on the results of the risk rankings established during risk assessment, starting with the most significant risks. For pipeline segments that could affect critical locations, the pipeline operator's plan should identify the internal inspection technique(s), pressure testing, or other technology that will be used to assess the integrity of the pipeline. It should also establish the schedule for conducting these assessments, the justification for the integrity assessment method(s) selected, and mitigative measures that will be employed. Section 8 provides guidance for conducting integrity assessments, and Annex B provides a description of the various internal inspection techniques available and guidance to assist operators in selecting an integrity assessment method.

Inspection, Mitigation, and/or Remediation—The pipeline operator should implement the pipeline integrity assessment plan, evaluate the results, and make any necessary repairs, all in a timely manner, to assure that anomalies that pose an integrity threat are eliminated or remediated. For pipeline segments that could affect critical locations, the operator should establish reasonable and technically justifiable time limits for the examination of several classes of anomalies detected by ILI. This schedule should consider applicable regulatory statutes. Section 8 provides guidance for prioritizing features identified by ILI for examination and repair. Annex C provides a description of commonly used repair techniques to address the different types of defects that might be discovered during integrity assessment.

Revise Integrity Assessment Plan and Continue to Assess Periodically—The pipeline operator should conduct integrity assessment on a periodic basis. The pipeline operator should develop a schedule for reassessments that considers items such as the rates of deterioration, the consequences of an event, and other risk factors. Section 9 provides guidelines for scheduling reassessments. Examples of how one might go about calculating reassessment intervals are presented in Annex D.

Establish and Implement Preventive and Mitigative Measures—A pipeline operator should establish and implement a process to evaluate the need for additional measures to protect pipelines. The following list provides some examples of potential measures.

— Preventing mechanical damage. Generally, this involves participating in "one-call" systems, locating and marking a pipeline segment when excavation is to take place on the right-of-way, monitoring contractors working on the right-of-way, establishing and maintaining a public awareness program, maintaining visible rights-of-way, and conducting periodic aerial and/or ground surveillance of the rights-of-way.

— Establishing and maintaining a corrosion mitigation program.

— Installing emergency flow restriction devices (EFRDs) at appropriate locations.

— Developing emergency response plans to limit the amounts of unrecovered product in the event of a release.

The various preventive and mitigative measures are described in Section 10.

Evaluate Program—The pipeline operator should identify, collect, and periodically evaluate metrics that indicate the effectiveness of the integrity management program. For pipeline segments that could affect critical locations, pipeline operators should develop a process for assessing the effectiveness of their integrity management programs. Section 12 provides guidance for developing performance measures to evaluate program effectiveness and for conducting audits of integrity management programs.

Manage Change—Pipeline systems and the environment in which they operate are not static. A systematic process should be used to ensure that changes to the pipeline system design, operation, or maintenance are evaluated for their potential risk impacts prior to implementation and to ensure that changes in the environment in which the pipeline operates are evaluated. Furthermore, after these changes have been made, they should be incorporated, as appropriate, into future risk assessments to be sure the risk assessment process addresses the system as it is currently configured, operated, and maintained. Section 13 discusses the important aspects of managing changes as they relate to integrity management.

Update, Integrate, and Review Data—After an integrity assessment has been performed, the operator should add the information acquired through the assessment to the database of information used to assess risk. In addition, as the system continues to be operated, the accumulated operating, maintenance, and surveillance data should be collected for input into the next scheduled reevaluation of risk prior to the next integrity assessment. As part of this process, the operator should determine whether any circumstances have changed that would either add or remove pipeline segments from the population of segments that could affect critical locations.

Reassess Risk—Risk reassessments should be performed at established intervals to factor in recent operating data and to consider changes to the pipeline system design (e.g. new valves, newly replaced pipeline segments or rehabilitation projects, etc.) and operation (e.g. a change in flow or the hydraulic pressure profile). Changes in population, changes that could alter the segments that could affect critical locations, and the results of previous integrity assessments and the impacts of repairs and mitigative measures should be taken into account in these risk reassessments as well. The aim should be to assure that the analytical process reflects the latest understanding of pipe condition.

Integrity Management of Pipeline Pump Stations and Terminals—Section 11 of this RP identifies attributes of pipeline system facilities other than line pipe such as pump stations and terminals that should be considered in developing a comprehensive system-wide integrity management program. While the program depicted in Figure 2 applies to these facilities, the specific aspects of integrity assessment applicable to these facilities tend to be somewhat unique.

5 Identifying Critical Locations with Respect to the Consequences of a Release

5.1 General

Because the main goal of pipeline integrity management is to minimize risk to the public/employees, the environment, and the customers, a pipeline operator should place a high priority on the inspection, evaluation, and maintenance of pipeline segments in areas where the consequences of a spill would be most likely to affect a critical location. Note that commercial software including geographic information system (GIS) technology is available to perform many of the tasks described in the following sections. This technology is available from numerous commercials service providers. Information about pipeline segments and facilities that could affect critical locations is used in several key elements of an integrity management program, such as:

— data gathering,

— risk assessment,

The examples described herein indicate that a pipeline operator should establish a Figure 5 for the specific circumstances of wall thickness, anomaly growth rate, MOP, and minimum failure-pressure-to-MOP ratio achieved by the current assessment in order to determine either when reassessment is needed or when it is necessary to remediate a particular anomaly. The process can be applied to corrosion-caused metal loss, SCC, and selective seam corrosion (i.e. to any time-dependent anomaly growth mechanism where it is safe to assume a constant anomaly growth rate). For each particular type of threat other than corrosion-caused metal loss in the body of the pipe, however, the user should account for the effect of material toughness on the sizes of defects that will fail at particular benchmark pressure levels.

9.4 Reassessment Times for Cracks That Grow by Pressure-cycle-induced Fatigue

To calculate times for reassessment for cracks that grow by fatigue, the pipeline operator should determine the appropriate C and n values to represent the maximum rate of fatigue crack growth in the segment and the pressure-cycle spectrum for a representative period for the location of the anomaly (usually a full year's worth of data is required). Cycle counting by the "rain-flow" method [see ASTM E1049-85, *Standard Practices for Cycle Counting in Fatigue Analysis* (reapproved in 1997)] is strongly recommended. If the last assessment was by means of a hydrostatic test, the operator should analyze a family of anomalies with different length/depth combinations each having the same failure pressure as the hydrostatic test pressure. This may be done on the basis of a model such as that represented in Figure D.3 taking the toughness of the material into account and using the length corresponding to the point of intersection of each d/t curve and the horizontal line representing the test pressure. The operator should assume that the family of anomalies is located at a point along the pipeline where it will experience the maximum pressure range (usually but not always the discharge of a pump station). If the analysis is based on an anomaly located by ILI, the operator may use the dimensions determined by ILI (considering the possibility of tool error), the toughness of the material, and the pressure cycle spectrum representative of the location of the anomaly. The operator should then apply the cycles to representative anomalies using an appropriate fatigue-crack growth model to ascertain the time it takes for each analyzed anomaly to grow from the size that it was at the time of the last assessment to the size that will cause a failure at the MOP. The reassessment interval should be one-half to one-quarter of the shortest calculated time to failure or less. When the safety factor for reassessment is being considered, the accuracy of known measurements, the risk of the pipeline segment and the accuracy of cycle counting should be considered.

10 Preventive and Mitigative Measures to Assure Pipeline Integrity

10.1 General

The preceding sections, Section 8 and Section 9, are focused primarily on integrity assessment and reacting to what is found through integrity assessment to address the time-dependent degradation threats such as corrosion, SCC and pressure-cycle-induced fatigue growth of pipe manufacturing flaws. In addition to conducting integrity assessments, a pipeline operator should implement preventive and mitigative measures that would tend to reduce the probability of a release and/or the consequences of a release from these time-dependent threats and from random (time-independent) threats such as third-party damage, equipment failure, and incorrect operations. Section 10 provides guidance for establishing and implementing preventive and mitigative measures to reduce the probabilities of releases and the consequences of releases from all threats.

The process of establishing and implementing preventive and mitigative measures begins with data gathering, data integration, and informational analysis as outlined in Section 6. Data integration and the analysis of the information developed through data gathering often reveal aspects of an operator's operations and maintenance that allow the operator to address the threats to pipeline integrity and reduce the consequences of potential releases. Most importantly, the incident history associated with certain components or circumstances should be considered. One or more incidents associated with any component or circumstance may indicate the need for enhanced preventive and mitigative measures associated with the particular component or circumstance. Some examples are shown in Table 5 and Table 6.

Table 5—Examples of Preventive Measures to Address Pipeline Integrity Threats

Threat	Problems Identified through Data Gathering and Integration	Preventive Measures
Weather/outside force	River crossing inspections identify exposed pipe due to river scouring.	Install protective mats in some cases or replace crossings with directional drills.
Internal corrosion	Internal MFL anomalies discovered at low spots in the pipeline.	Inject inhibitor. Run cleaning pigs more frequently.
Third-party damage	Near hits from landowners not making one-calls.	Install line-of-sight markers, trim rights-of-way more frequently, enhance contacts with landowners, or establish agreements not to cultivate.
Equipment failure	Seeps or stains in facilities at fittings or flanges.	Increase frequency of inspections. Replace gasket materials at specific intervals or when inspections indicate gasket deterioration. Develop flange torque procedures.
Mechanical damage with delayed failure	Alignment of MFL anomalies with geometric anomalies reveals locations of previous damage to pipelines.	Increase frequency of aerial and foot patrols in areas of frequent new construction.
External corrosion	MFL anomalies and/or low cathodic protection readings.	Increase cathodic protection. Conduct more frequent close-interval P/S potential surveys.
Incorrect operations	Surges caused by poorly coordinated start-ups and unexpected shutdowns from power failures.	Conduct advanced hydraulic studies to optimize start-up procedures and train operators to use the new procedures. Install improved electrical gear at remote stations to minimize power outages.

Table 6—Examples of Mitigative Measures to Address Consequences

Consequences	Mitigative Measures
Contamination of drinking water aquifer.	Install hydrocarbon detection cable next to pipeline across the aquifer recharge area. Conduct spill drills aimed at rapid containment.
Ignition of vapor cloud in populated area.	Educate the public as to the danger of a vapor cloud. Provide emergency phone number to residents. Increased frequency of ILI. Improve emergency response criteria.
A release results in large drain-down.	Install EFRDs. Increase frequency of ILI. Improve emergency response criteria.
Small leak over time accumulates into large release.	Improve leak detection; increased frequency of ILI; enhanced patrol technology.

In addition to their application to specific problems identified by data analysis and integration, preventive and mitigative measures are needed to address all threats to pipeline integrity, including those that can be assessed as described in Section 8 and Section 9. Threats that cannot be addressed by integrity assessment methods include:

— manufacturing anomalies (hard heat-affected zones in ERW pipe);

— equipment failure;

— mechanical damage (causing an immediate failure);

— incorrect operations;

— weather and outside force (floods, landslides, subsidence, earthquakes, etc.).

The threat of mechanical damage causing an immediate failure and the threat of failure from weather and outside force are threats that potentially affect all pipelines. The threats of hard spots and hard heat-affected zones affect

pipelines constructed with certain older, easily recognized materials that are susceptible to these phenomena. The measures for preventing and mitigating these are addressed in Section 10. In addition, this section presents minimum requirements for preventing corrosion, and it presents guidance for limiting consequences of pipeline releases by means of leak detection programs, flow restriction devices, and emergency response planning. Lastly, this section discusses the use of reducing operating pressure as a means to assure pipeline integrity. The preventive and mitigative measures for the threats of equipment failure and incorrect operations can be defined based on data gathering as shown in Table 5. Prevention of equipment failure is a subject to be addressed in a pipeline operator's operating and maintenance procedures. Prevention of incorrect operations should be covered in pipeline operator's operating procedures and operator training practices.

10.2 Prevention of Third-party Damage

10.2.1 General

To protect a pipeline system from immediate failures caused by mechanical damage, a pipeline operator should establish a program to detect and prevent unauthorized encroachments on the rights-of-way of the pipeline system. A damage prevention program should contain the following elements:

— maintaining adequate, up-to-date maps of the system;

— participating in a one-call system;

— providing for timely temporary marking of any portion of the operator's system that falls within the location scope of a one-call "ticket";

— establishing written guidelines for excavators authorized to work on the right-of-way stating what procedures an excavator should follow;

— providing a full-time observer while excavation is in progress on, or in proximity to the pipeline;

— establishing and continuing a public awareness program with land occupants, excavators, and contractors;

— maintaining adequate permanent pipeline-identifying markers along the rights-of-way and trimming and mowing the rights-of-way, where permissible, so that they remain identifiable and visible from the air;

— conducting periodic aerial and/or ground-based surveillance of all rights-of-way;

— installing continuous markers or physical barriers where appropriate on new or reinstalled segments or providing for deeper burial where appropriate;

— documenting all detected hits or near misses associated with either authorized or unauthorized encroachments on rights-of-way and investigating the causes for the hits or near misses;

— minimizing impacts to critical locations and/or designated high consequence areas.

See API 1166 for additional guidance on excavation monitoring and observation.

Implementation of an effective damage prevention program requires adequate resources and adequately trained personnel to execute it. Therefore, a pipeline operator should establish a team of personnel that is responsible for the damage prevention program and should provide the training necessary to assure that the personnel have adequate knowledge and skills to understand the elements of damage prevention in order to be able to execute the program effectively. At a minimum the damage prevention personnel should:

— be familiar with the pipeline system so that one-call "tickets" will be screened in a timely manner;

— be able to communicate easily with the appropriate one-call centers;

— be trained in locating underground facilities;

— be able to communicate with excavators, land occupants, emergency response personnel, and the public;

— be trained to monitor excavation and are familiar with the pipelines to which they are assigned;

— be familiar with pipeline surveillance techniques and have the opportunity to communicate with patrol pilots.

10.2.2 Mapping

A pipeline operator should create and maintain an up-to-date map of each pipeline facility. The maps of appropriate parts of the system should be provided to all one-call centers whose coverage includes those pipeline segments. Alternatively, the operator should indicate to all one-call centers covering regions containing segments of the operator's pipelines, the "grid squares" through which those segments pass (see 10.2.3). Preferably, electronic maps should be provided which show each of the operator's pipelines within a corridor of suitable width (e.g. 500 ft on either side of the centerline of the pipeline).

10.2.3 One-call Systems

Many states within the United States and many countries require operators of underground utilities to participate in a "one-call" system. The United States has established 811 as a nationwide one-call number. The purpose of the one-call system is to accept calls from potential excavators and to relay the location, scope, and time of the excavation to each utility having a facility located within a particular square of the "grid" covered by the one-call system (a typical grid square might be 1000 ft by 1000 ft). The information provided by the excavator is recorded on a document commonly referred to as a "ticket." Copies of the ticket are sent to each of the participating utilities to notify them of the location, scope, and time of the excavation. Each notified utility is then responsible for locating and marking their facilities located within the square that could be affected by the excavation. A pipeline operator should participate in a one-call system in every area in which the operator has facilities. The operator should either indicate which of the system's grids contain segments of the operator's pipelines and/or supply the one-call center with up-to-date maps of the pipeline segments.

10.2.4 Locating and Marking

Upon receipt of a ticket from a one-call center, a pipeline operator should attempt to determine whether or not the excavation could affect one of the operator's pipelines. If the operator is certain that the excavation will not encroach upon any of the operator's facilities, the ticket should be "cleared," that is, the operator should notify the one-call center that none of the operator's facilities will be impacted or make contact with the excavator directly if the one-call center does not have positive response capability. If, however, the excavation will be on or close to the operator's right-of-way, the operator should promptly locate the pipeline that could be affected and mark its location with temporary markings. The markings should indicate the location of the centerline and size of the pipeline or the sides of the pipeline (or pipelines if it is a multiple-pipeline right-of-way). The operator should renew the markings if they become displaced by excavation or if they become degraded with the passage of time until all excavation activity has ceased.

10.2.5 Communication with an Excavator and Monitoring an Excavation

The pipeline operator, besides locating and temporarily marking the pipeline, should establish a communication link with the excavator that may involve the following:

— exchange of names of contacts and phone numbers;

— issuance of a written procedure for the excavator to follow that includes a distance-to-the-pipeline limit within which nonmechanical excavating techniques should be used, a description of how any exposed pipe should be

supported, and a procedure for back-filling that will avoid damaging the coating on the pipeline or any cathodic protection attachments;

— agreement on a start time and the fact that the operator's observer should be present when excavation is approaching within a specified distance of the pipeline.

Pipeline operators may obtain detailed guidance on monitoring and observing excavations in API 1166.

10.2.6 Public Awareness

Because not every potential excavator may be aware of the dangers of excavating near a hazardous liquid pipeline, a pipeline operator should establish a public awareness program. Pipeline operators may obtain detailed guidance on establishing and maintaining a public awareness program in API 1162.

10.2.7 Right-of-way Maintenance and Surveillance

As a defense against unauthorized encroachments, a pipeline operator should clear the rights-of-way of underbrush, tall weeds, trees, and canopy (where permissible). Keeping the rights-of-way clear in this manner facilitates aerial surveillance, alerts land occupants and others to presence of a pipeline corridor and increases the likelihood that anyone happening onto a right-of-way will see one or more permanent markers indicating the presence of an underground pipeline.

A pipeline operator should regularly conduct surveillance of each right-of-way, either by aerial patrol or other means such as ground patrol. When using aerial patrols, operators should consider the use of a separate observer in addition to the pilot in order to improve the effectiveness of this type of right-of-way surveillance.

Alternatively, a pipeline operator may decide to patrol certain rights-of-way on foot or by means of a vehicle.

10.2.8 Permanent Markers, Warning Techniques, and Physical Barriers

A pipeline operator should install permanent markers to alert anyone approaching a pipeline right-of-way that a pipeline is present. For guidance on the appropriate design of pipeline markers including where to put them and the types of information that should be provided on the markers, the operator should consult API 1109.

A pipeline operator may consider installing physical barriers such as concrete slabs above the pipeline to protect it. Alternatively, the operator may elect to bury a warning tape or plastic mesh above the pipeline to alert an excavator to the presence of a buried pipeline. These measures, if desired, can usually only be taken in conjunction with the construction of a new pipeline or the relocation of an existing pipeline. A pipeline operator may also consider lowering an existing pipeline by exposing and reburying it at a deeper depth. This may be necessary where a new road or railroad is being built over an existing pipeline. Another option is performing a depth of cover survey and proactively lowering shallow pipe in actively tilled land or areas where significant construction activity is occurring, planned or expected.

10.2.9 Documenting Hits and Near Misses

In order to determine which damage prevention techniques are the most cost effective, it is helpful to study and evaluate past mechanical damage hits and near misses. By understanding how these hits or near misses occurred, pipeline operators will be able to focus resources on the preventive techniques that are the most effective. In North America, the Common Ground Alliance has establish a formal, but voluntary, Damage Incident Reporting Tool (DIRT). An operator of an underground facility who wishes to participate in this effort is asked to document each hit or near miss in conjunction with any excavation that takes place on, above, or immediately adjacent to the facility whether authorized or unauthorized. Analyses of these data have helped to identify when and how preventive measures either work as intended or fail to do their job. As this effort continues, it is reasonable to expect that pipeline operators will learn which preventive measures are the most effective.

10.3 Preventing Releases Associated with Hard Spots and Hard Heat-affected Zones in Line Pipe

Pipeline operators have dealt successfully with round or oval hard spots in the body of the pipe by locating them with ILI magnetic tools and eliminating them or shielding them from cathodic protection. Unfortunately, to date no ILI technique has emerged that is capable of locating the narrow hard zones adjacent to some ERW bondlines. Pipeline operators experiencing the latter phenomenon generally have had to resort to barring the transport of sour crude or to monitoring cathodic protection levels and limiting them to levels that are adequate to prevent corrosion but not so high as to generate excessive amounts of hydrogen at coating holidays.

10.4 Preventing or Mitigating Releases Associated with Weather and Outside Force

A pipeline operator should attempt to prevent or mitigate the damage from weather events such as extreme cold, high winds, and flooding and from geophysical events such as earthquakes, landslides, land erosion, or subsidence that could cause releases. Preventive or mitigative activities that an operator should consider are:

— inspecting drain valves and pipe extensions before cold weather arrives to eliminate water that will freeze and could cause breakage;

— shutting down and, if feasible, purging pipeline segments that could be damaged by impending hurricanes or floods;

— providing for movement of the pipeline to occur without damaging the pipeline at seismic fault crossings, seismic fault crossings, unstable slopes, or areas of subsidence;

— training patrol pilots to spot areas of developing soil instability, landslides, and subsidence;

— conducting patrols as soon as feasible after the passage of severe weather, flooding, or an earthquake;

— monitoring river crossings for exposed pipe in crossings or at riverbanks;

— routinely gather updated GIS data regarding fault zones, land use, etc.

10.5 Control of Corrosion

10.5.1 External Corrosion

All new pipelines should be protected from external corrosion by the installation of a protective external coating and an adequate cathodic protection system. NACE SP0169 provides minimum criteria for applying cathodic protection to mitigate external corrosion of a buried steel pipeline. Cathodic protection should be applied to an existing pipeline as well whether it is coated or bare. Pipeline operators should also follow NACE SP0169 with regard to the minimum level of protection that should be maintained on an existing pipeline. Cathodic protection levels should be monitored at least once every 12 months. The levels of protection should be determined by making pipe-to-soil potential measurements at test leads typically located at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection.

At areas where the potentials fall below the levels indicated by NACE SP0169, the operator should investigate the cause of the low potentials and mitigate them. Mitigation should consist of bringing the cathodic protection levels into compliance with the levels specified in NACE SP0169 either by making sufficient repairs to the coating and/or by increasing the current outputs of existing anodes or adding anodes to increase the current output necessary to achieve the recommended levels. A pipeline operator may also find it useful to employ one or more of the ECDA techniques described in 8.5 to enhance the mitigation of external corrosion of a given pipeline segment.

Induced AC corrosion has become better understood and should be controlled. For information on mitigating induced AC corrosion, see NACE 35110 and also NACE SP0177.

10.5.2 Internal Corrosion

If the fluid being transported in a pipeline has the potential to corrode the internal surface of the pipeline, the operator should determine the nature of the corrosion that could occur and should take adequate steps to mitigate it. The most common form of internal corrosion arises in conjunction with the holdup of water and/or the deposition of sediment. These phenomena are a function not only of the fluid characteristics but also of the flow velocity and the elevation profile. The operator can monitor critical locations by installing coupons or resistance-change devices or by measuring wall thickness to detect loss of metal. Mitigative steps include:

— the injection of a suitable inhibitor or biocide,

— frequent cleaning with cleaning pigs to remove sediment and water,

— maintaining a minimum flow velocity to minimize water and sediment entrainment,

— flushing dead-legs or valve bodies.

A pipeline operator may also find it useful to employ one or more of the internal corrosion direct assessment (ICDA) techniques described in 8.5 to enhance the mitigation of internal corrosion of a given pipeline segment. See also NACE SP0208 and NACE SP0106.

10.6 Detecting and Minimizing the Consequences of Unintended Releases

10.6.1 General

An IMP should contain protocols for detecting leaks and for limiting the consequences in the event of an unintended release. Elements of the plan should describe the means and procedures for:

— minimizing the time required for detection of a release,

— minimizing the time required to locate a release,

— minimizing the volume that can be released,

— minimizing emergency response time,

— protecting the public and limiting adverse effects on the environment.

10.6.2 Reducing the Time to Detect and Locate Unintentional Releases

A pipeline operator should select, install, and maintain a leak detection system or systems appropriate for the length and size of the pipeline, the type of products within the pipeline, and the spill scenarios for critical locations developed in Section 5 of this RP. The abilities to detect a leak of a certain minimum size and to locate where such a leak has occurred depend on the type of leak detection system or systems employed. The leak detection methods and their characteristics are summarized in Table 7. Brief descriptions of leak detection methods are presented below.

A pipeline operator may find it advantageous to employ a combination of these methods. For example the computational methods could be augmented by a volume balance approach and/or tracer chemicals or a stand-up test could be used on occasion as a check on the real-time methods. In any case all real-time leak detection systems should be tied to the SCADA system, and the operating personnel should be well-versed as the nature, characteristics, and operation of each leak detection system.

Table 7—Leak Detection Methods

Method	Locates Leak	Availability	Beneficial Feature	Biggest Limitation
Periodic auditory, visual, and olfactory inspections	Yes	Periodic	Simplicity	Delayed recognition of leak between intervals
Volume balance	No	Intermittent based on comparison time	Simplicity	Transients tend to cause false alarms
Dynamic flow modeling	Yes if analysis is done	Continuous even when transients are present	Best method to detect small leak rapidly	Complexity and cost
Tracer chemical	Yes	Can be either continuous or one time	Accurately locates small leaks	Must add something to the product and requires air sampling
Release detection cable	Yes	Continuous	Accurately locates small leaks	Next to impossible to retrofit to an existing pipeline
Shut-in leak detection	No	Periodic	Simplicity	Requires shutting off flow and accurate pressure monitoring
Pressure point analysis	Yes, if multiple points used	At the sampling rate except during transient operation	Simplicity	Not suitable for large pipelines or compressible fluids
Acoustic leak detection	Yes	Continuous		

10.6.3 Isolation and Control of a Release

Once a release has been confirmed the pipeline should be shut down. An exception to this would be leaving a pump station in operation if it is pulling product away from the release site. Shutting down the system and/or pumping product away from the release limits the subsequent volume of the release to the gravity drain-down volume (or vaporization of a HVL). The pipeline operator should locate and isolate the release as rapidly as possible to further limit the quantity of the release by minimizing gravity drain-down (or the size of the vapor cloud in the event of the release of a HVL).

Manually closing block valves may aid in limiting the gravity drain-down volume. Operators should consider installing block valves or check valves in appropriate locations to minimize spills. EFRDs such as remotely actuated, automatic valves, or check valves can be employed to further limit the gravity drain-down volume. Automatic valves should be employed only in situations where normally expected transients will not cause them to close when there is no leak.

It should be noted that adding additional valves to a pipeline right-of-way may increase the risk of certain threats. The potential increase in risk should be considered in a manner consistent with considering other risk factors. When determining whether to install additional remote or check valves, an overall risk reduction would be needed to justify such installations.

10.6.4 Emergency Response

A very important means to limit the consequences of a release is for the operator to provide a timely and sufficient response to a leak. Note that the need for an emergency response may not arise as the result of the operator's leak-detection system. Sometimes releases are discovered by the operator's personnel or a third party. Even when a release has occurred, the consequences of a release can be significantly reduced if the operator is adequately prepared to deploy personnel and equipment who can install or erect physical barriers to limit the spread of released

product and to recover as much of the spilled product as possible. The operator's emergency response plan should provide for:

— establishing lines of responsibility for an emergency response to an unintended release;

— training for all personnel responsible for mitigation of an unintended release;

— communication with law enforcement and firefighting agencies who can limit access to the site and to protect the public;

— isolation of the leak to limit the volume released;

— limiting the spread of the released product by deploying booms on water or by erecting soil berms on land;

— recovery of as much released product as possible;

— temporary accommodation of members of the public displaced by the release;

— providing potable water if drinking water supplies are at risk.

On a longer term basis the operator should also provide for:

— mitigation of contaminated soil or water,

— restoration of the site.

Response drills should be carried out periodically to train response personnel, to test response equipment, and to improve procedures if possible. It is a good practice for operators to evaluate their response after the exercise to identify opportunities for improved performance. Outside agencies such as law-enforcement and firefighting agencies should be informed of and included in response drills. Pipeline operators in the United States are bound by 33 *CFR* Chapter 40, Oil Pollution (otherwise known as OPA 90) with regard to unintended release that could cause substantial harm to the waters of the United States.

10.7 Reducing Pressure

A reduction in operating pressure can be used to reduce the risk associated with threats to pipeline integrity that are hoop stress related (i.e. corrosion-caused metal loss, SCC, mechanical damage, or the growth of an anomaly through pressure-cycle-induced fatigue). A pressure reduction can be either permanent or temporary. If operators are unable to meet repair or reassessment deadlines, they should implement a temporary pressure reduction. An operator wishing to employ a pressure reduction can assess the value of a given amount of pressure reduction in the same manner as the test-pressure-to-operating-pressure ratio of a hydrostatic test by consulting Annex D.

11 Integrity Management of Pump Stations and Facility Piping

11.1 General Considerations

Because the piping and operation of facilities are distinctly different from that of mainline pipe, the threats to piping at facilities such as pump stations, terminals, and loading facilities are characterized and grouped in a different manner than they are for mainline pipe. Experience suggests that facilities piping incidents typically involve small leaks. Large-volume releases in facilities piping are rare. The attributes of facilities piping that distinguish it from mainline piping and need to be considered in the management of its integrity are:

— relatively low operating stresses,

APPENDIX L

CO2 Pipeline Data

CO_2 Pipeline Data

Design Material and Construction Data

A. Pipeline segment name/id

1. 14" CO_2 Pipeline
   a. Section 1 (DGC-MLV1)
   b. Section 2 (MLV1-MLV2)
   c. Section 3 (MLV2-MLV3)
   d. Section 4 (MLV3-MLV4)
   e. Section 5 (MLV4-MLV5)
   f. Section 6 (MLV5-MLV6)
   g. Section 7 (MLV6-MLV7)
   h. Section 8 (MLV7-Tioga)
2. 12" CO_2 Pipeline
   a. Section 9 (Tioga-MLV8)
   b. Section 10 (MLV8-MLV9)
   c. Section 11 (MLV9-MLV10)
   d. Section 12 (MVL10-MLV11)
   e. Section 13 (MLV11-Goodwater)

B. Pipeline route coordinates

1. Drawing numbers
   a. United States Side
      - D7400-001-C to D7400-037-C
   b. Canadian Side
      - D7500-001-C to D7500-009-C

C. Pipe specifications

1. DGC to Tioga
   a. Mainline
      - 14" OD x .375" WT Grade X-70 ERW
   b. Fabrication, Roads, Rivers, Lakes
      - 14" OD x .500 WT Grade X-65 SMLS
   c. Stations, Railroads
      - 14" OD x .625 WT Grade X-65 SMLS
2. Tioga to Goodwater

a. Mainline

- 12 3/4" OD x .375" WT Grade X-70 ERW

b. Fabrication, Roads, Rivers, Lakes

- 12 3/4" OD x .500 WT Grade X-65 SMLS

c. Stations, Railroads

- 12 3/4" OD x .625 WT Grade X-65 SMLS

D. Design Maximum Allowable Operating Pressure

1. Due to the pipeline crossing the border, both the US and Canadian Code were looked at, and the code with the highest safety factor was applied to the entire pipeline. This resulted in a safety factor of .72 for the mainline, .6 for uncased road crossings and MLV stations, .5 for uncased railroad crossings and compressor, pump, and meter facilities. These factors result in the following MAOP's on the pipeline.

   a. DGC to Tioga

   - 2700 PSIG
   - Minimum hydrotest pressure – 3375 PSIG

   b. Tioga to Goodwater

   - 2964 PSIG
   - Minimum hydrotest pressure – 3705 PSIG

E. Pipe manufacturer and production dates

1. Sumitomo Metal Industries Ltd., Wakayama Steel Works, 1850 Minato, Wakayama, Japan
2. Manufactured between August 18, 1998 and November 13, 1998
3. See Pipeline Job Book Volume II Book 1 located in DGC records department under location number M00004169 for mill test reports and inspection reports on the pipe.

F. Construction date

1. Construction of the pipeline started May 12, 1999 and completed December 1, 1999.

G. Weld quality and inspection

1. Welder certifications, welding procedures, welder qualification tests, and radiographic inspection reports are located in Pipeline Job Book Volume I Book 2 located in DGC records department under location M00004161.
2. A report on the failure of a seam weld during the hydrotest can be found in DGC records location number M0004027.

H. Coating type

1. The coating is a 17 mil fusion bonded epoxy (FBE) applied by Bredero Shaw. Pipe for the bored crossings is also coated with FBE and also an abrasion resistant coating to prevent damage to the coating during the installation process. The field welds are coated with 50 mil of Protal 7000 epoxy and Raychem shrink sleeves on the US side. In Canada Specialty Polymers SP-2888 was used on the field welds.

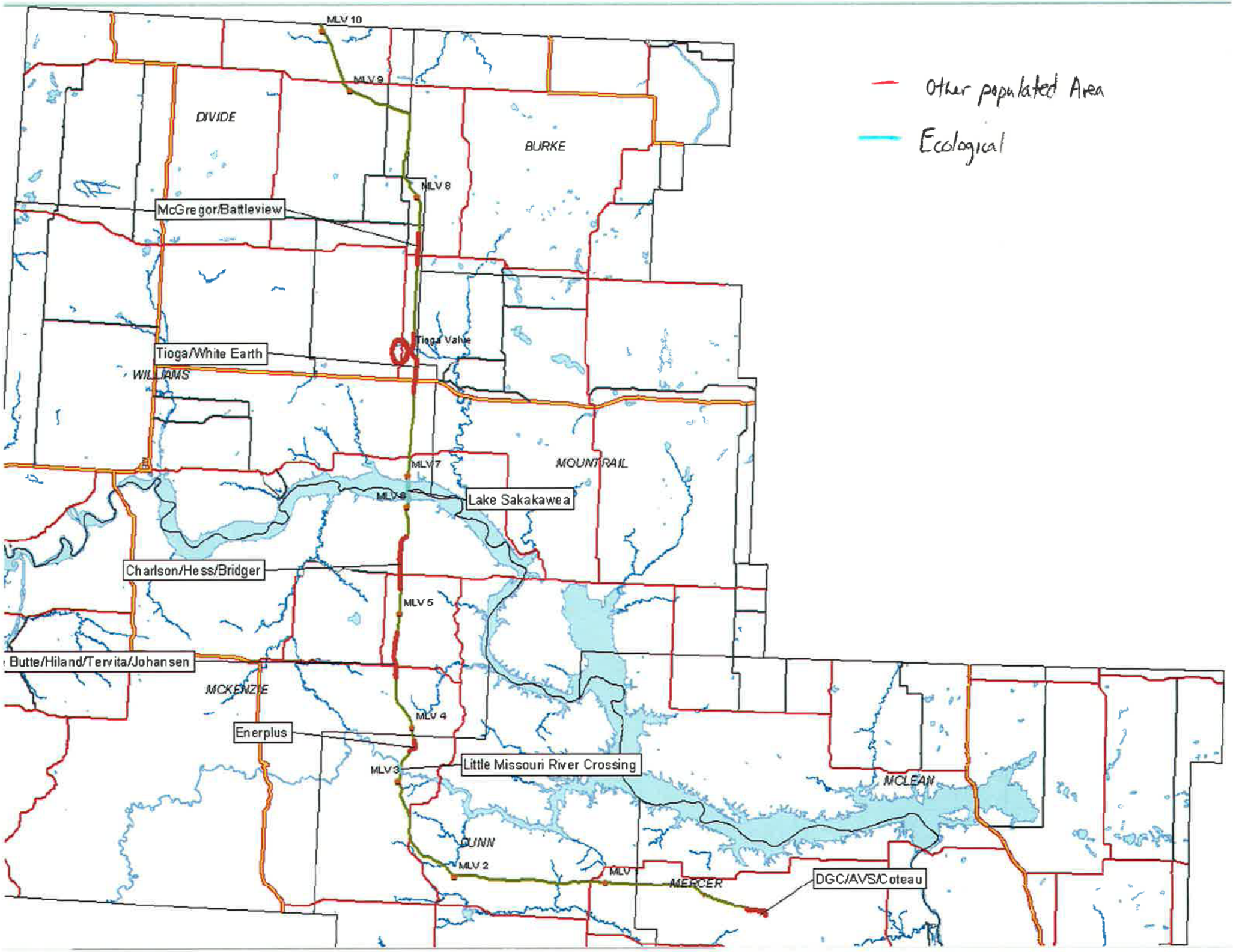
All above ground piping is painted in accordance with DGC specification 80-III "Painting Materials and Application Requirements"

I. Cathodic Protection

1. 14" CO2 Pipeline
   a. MLV #1: 50V 28A system consisting of 10 deepwell anodes and 4 surface anodes
   b. MLV #3: 40V 5A system consisting of 3 surface anodes
   c. MLV #4: 50V 28A system consisting of 10 deepwell anodes and 2 surface anodes
   d. MLV #5: 40V 5A system consisting of 3 surface anodes
   e. MLV #6: 40V 5A system consisting of 3 surface anodes
   f. MLV #7: 40V 5A system consisting of 5 surface anodes
   g. Tioga: 50V 28A system consisting of 10 deepwell anodes and 2 surface anodes
2. 12" CO2 Pipeline
   a. MLV #8: 40V 5A system consisting of 3 surface anodes
   b. MLV #9: 40V 5A system consisting of 3 surface anodes
   c. MLV #11: 50V 28A system consisting of 10 deepwell anodes and 2 surface anodes
   d. Goodwater: 60V 12A system consisting of 4 surface anodes

J. Charpy V-Notch

1. 14"
   a. .375" – 100 ft/lb
   b. .500" – 250 ft/lb
   c. .625"
2. 12"
   a. 375" – 100 ft/lb
   b. .500" – 250 ft/lb
   c. .625"


Other populated Area
Ecological
MLV 10
MLV 9
MLV 8
MLV 7
MLV 6
MLV 5
MLV 4
MLV 3
MLV 2
MLV 1
DIVIDE
BURKE
WILLIAMS
MOUNTRAIL
MCKENZIE
DUNN
MCLEAN
MERCER
McGregor/Battleview
Tioga/White Earth
Tioga Valve
Lake Sakakawea
Charlson/Hess/Bridger
Butte/Hiland/Tervita/Johansen
Enerplus
Little Missouri River Crossing
DGC/AVS/Coteau

MLV 4
22
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MLV 3
MLV 2
DUNN
MLV 1
1806
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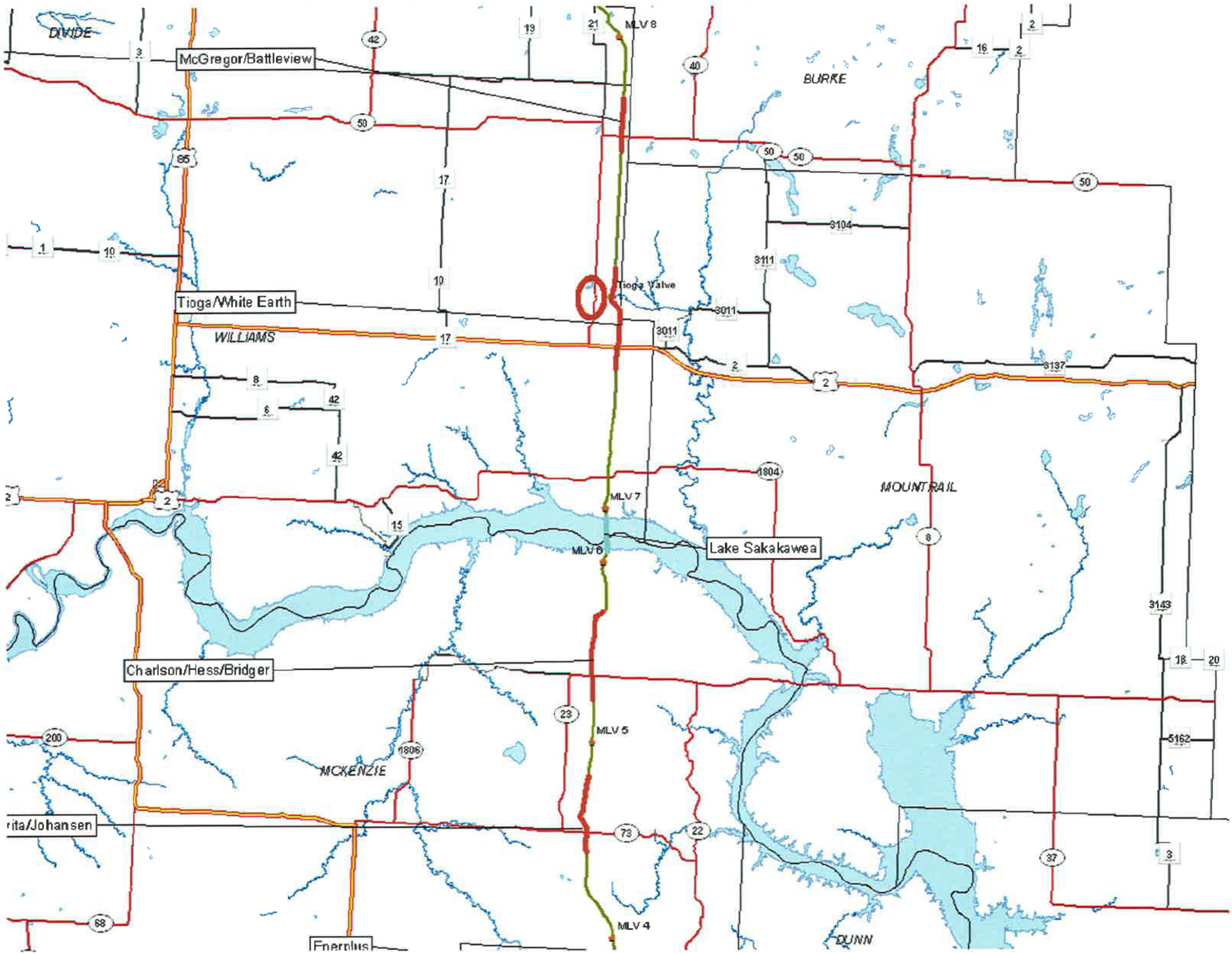
MERCER
8
43
MCLEA
3
9


DIVIDE
McGregor/Battleview
BURKE
Tioga Valve
Tioga/White Earth
WILLIAMS
MOUNTRAIL
Lake Sakakawea
Charlson/Hess/Bridger
MCKENZIE
rita/Johansen
Enerplus
DUNN
MLV 8
MLV 7
MLV 6
MLV 5
MLV 4

Attachment 3

Supporting Documentation

Release Impact Analysis
Receptor Map
Receptor Population Survey

This section summarizes the techniques used to estimate the consequence severity of a credible scenario. The following criteria were used to predict consequences of interest:

1. Each cause will have consequences developed globally without regard to node boundaries.

2. Consequences are only fully developed into scenarios where the cause results in a safe operating limit potentially being exceeded. A cause that results in no significant consequence would be documented as “Scenario considered, but no consequence of interest identified”.

3. Consequence developed shall assume that all active safeguards fail. Passive safeguards may be assumed to still function at the discretion of the team.

4. Scenario consequence should be developed to the immediate consequence of interest (no escalation of event). Team should base severity on the most severe plausible outcome.

In order to estimate the possible impact area for a release occurring at the Tioga facility, an impact analysis completed by Quest Consultants Inc. was used. Additionally, operating experience was also used. DGC’s pipeline risk matrix has varying levels of severity that are based on the magnitude of a release and the number of pipeline receptors that may be impacted. The Quest report, the pipeline receptor map, and the receptor population surveys form the basis for the team to estimate how many receptors may be impacted if a catastrophic release scenario was evaluated. If smaller release scenarios were evaluated, such as flange leaks or a pump seal failure, the impact area was based on operating experience.

RELEASE AND DISPERSION CALCULATIONS FOR THE DAKOTA GASIFICATION COMPANY CARBON DIOXIDE PIPELINE NEAR TIOGA, NORTH DAKOTA

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RELEASE AND DISPERSION CALCULATIONS FOR THE DAKOTA GASIFICATION COMPANY CARBON DIOXIDE PIPELINE NEAR TIOGA, NORTH DAKOTA

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RELEASE AND DISPERSION CALCULATIONS FOR THE DAKOTA GASIFICATION COMPANY CARBON DIOXIDE PIPELINE NEAR TIOGA, NORTH DAKOTA

1.0 INTRODUCTION

Quest Consultants Inc. was retained by Dakota Gasification Company (DGC) to perform a series of release and dispersion calculations in an effort to quantify the hazards associated with an accidental release from a pipeline located just east of the town of Tioga, North Dakota transporting carbon dioxide (CO_2) and trace amounts of other materials. This material is classified as a highly volatile liquid (HVL) by the U.S. Department of Transportation (DOT), which regulates the pipelines transporting these materials. Releases of HVLs are modeled to estimate the potential worst-case consequences in the event of a pipeline rupture in or near a high-consequence area (HCA). If affected by a pipeline release, all or part of the city of Tioga would be considered a HCA.

The consequence analysis calculations were performed under worst-case operating and atmospheric conditions in order to provide a credible upper limit when defining the potential impact area. A release location was selected just east of Tioga, where the pipeline route crosses a shallow valley. Releases from the pipeline in the shallow valley entering Tioga from the east were modeled using a computational fluid dynamic (CFD) model. This type of model accounts for the lack of expansion and mixing along the sides of the plume as it travels in the valley.

The size of the calculated hazard zones as they approach Tioga, will be used to complete Phase 1 of the consequence analysis potion of a protocol developed to satisfy the Pipeline Integrity Management Program for HVL pipelines. A description of this protocol is presented in Appendix A.

1.1 Meteorological Conditions

Meteorological data for wind speed, wind direction, and Pasquill-Gifford atmospheric stability class used in this study were gathered from the Tioga Municipal Airport for the years 2013 through 2017 [NCEI, 2017]. A summary of the meteorological data used in this study is presented as wind roses in Figure 1-1. Figure 1-1 presents the annual wind rose data for the areas near Tioga, ND. The length and width of a particular arm of the rose define the frequency and speed at which the wind blows from the direction the arm is pointing. As an example, reviewing Figure 1-1 shows that the most common winds blow from the west and northwest quadrant.

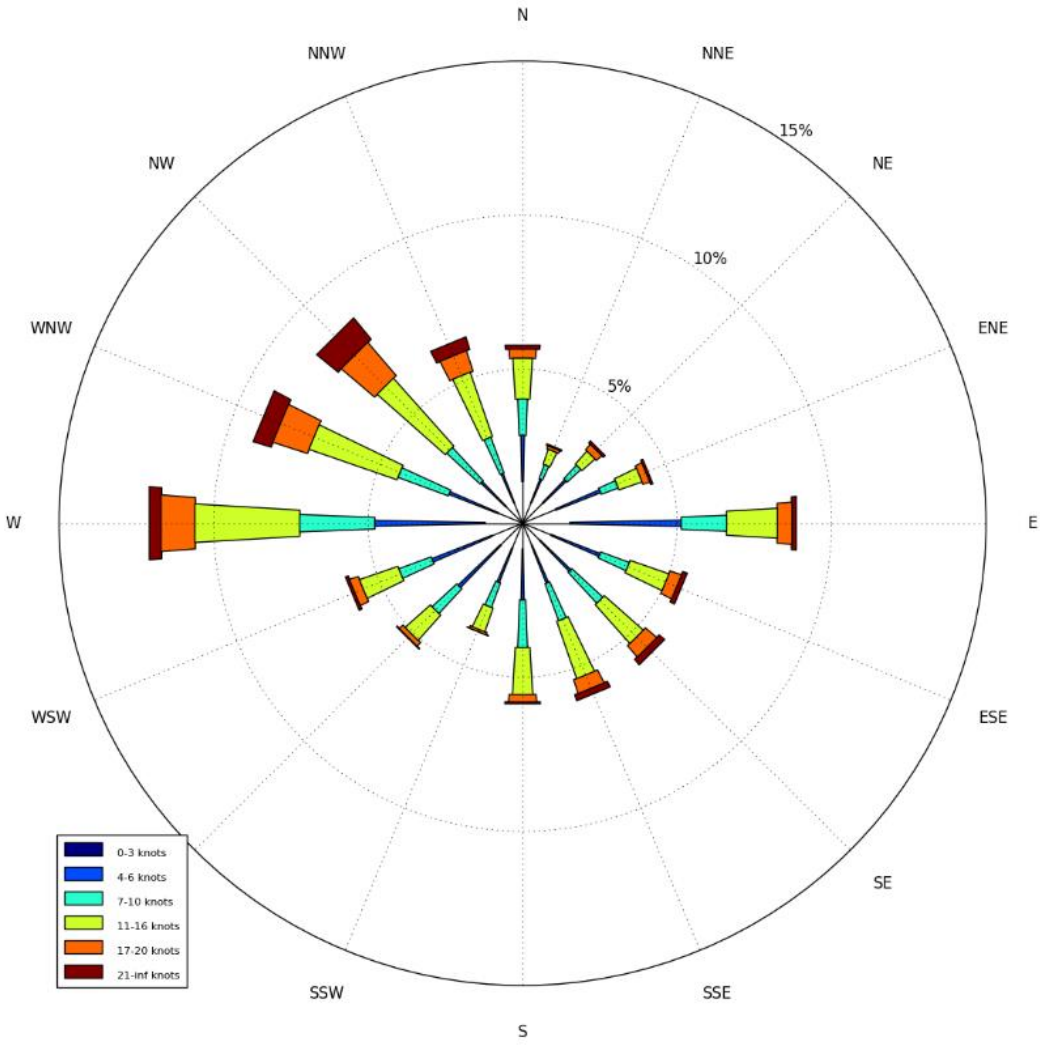

Figure 1-1
Windrose for Tioga, ND

2.0 PIPELINE PARAMETERS

The pipeline is made up of 13 segments. Eight of these pipeline sections are between the DGC plant and the Tioga Pump Station and five of these sections are between the Tioga Pump Station and Goodwater. Table 2-1 lists several parameters of the pipeline. The operating pressure of the upstream section of the pipeline is defined to be a maximum of 2,700 psig (at the Dakota Gasification Plant) and 2,964 psig when boosted at the Tioga Pump Station. The release location that is the subject of this study is just before the Tioga Pump Station (Pipeline Section 8).

Table 2-1
DGC Pipeline Parameters

Pipeline Section Number	Start	End	Pipeline Mile Marker at End of Section	Section Length [miles]	Pipeline Internal Diameter [inches]	Pump Discharge Operating Pressure [psig]
1	DGC Plant	MLV1	21.99	21.99	13.25	2,700
2	MLV1	MLV2	41.86	19.87	13.25	-
3	MLV2	MLV3	57.87	16.01	13.25	-
4	MLV3	MLV4	66.06	8.19	13.25	-
5	MLV4	MLV5	82.01	15.95	13.25	-
6	MLV5	MLV6	96.99	14.98	13.25	-
7	MLV6	MLV7	100.47	3.45	13.25	-
8	MLV7	Tioga Pump Station	117.02	16.55	13.25	-
9	Tioga Pump Station	MLV8	137.19	20.17	12.	2,964
10	MLV8	MLV9	157.40	20.21	12.	-
11	MLV9	MLV10	166.02	8.62	12	-
12	MLV10	MLV11	185.75	19.73	12	-
13	MLV11	Goodwater	204.86	19.11	12	-

The composition of the pipeline fluid was approximated by the mixture shown in Table 2-2.

2.1 Calculation of Release Rates Following a Pipeline Rupture

The calculation of pipeline release rate in this study was accomplished with the release model contained in the CANARY by Quest® modeling package. This model predicts the time-varying flow of vapor, aerosol, and liquids following a breach of the pipe. While calculating the release rates and pressure drop along the pipeline, the model accounts for multiphase thermodynamic behavior, including two-phase flow due to flashing in the pipe and varying vapor/aerosol production.

Table 2-2
Composition of Pipeline Fluid

Component	Mole Percent
Methane	0.9
Carbon Dioxide	95.66
Ethane+	2.
Hydrogen Sulfide	1.
Nitrogen	0.4
Oxygen/Argon	0.01
Mercaptans	0.03
Total	**100.00**

Once an HVL pipeline rupture occurs, the response time to isolate a pipeline section may not be an important factor in determining how far the cloud travels. This is due to the rapid deinventory of the pipeline following a rupture. For example, a rupture near the end of the pipeline entering the Tioga Pump Station results in the exiting mass flow rate versus time plot presented in Figure 2-1. As can be seen from Figure 2-1, the rate of mass leaving the pipeline drops dramatically within seconds of the rupture. Within one minute, the escaping mass rate has dropped to less than one-tenth of the rate seen in the initial few seconds. The rate of mass loss (through the rupture) is significantly higher than the normal flow through the pipe. For this pipeline, the maximum normal flow rate is 150 million standard cubic feet per day (150 MMSCFD), or about 200 lb/s. Comparing this normal flow rate to the escaping release rate depicted in Figure 2-1 shows that the normal flow through the system only modestly adds to the escaping mass rate during the first few minutes following a rupture. As the release continues, the mass rate exiting the pipe will continue to drop as the pressure driving force is lost. If the normal flow at the upstream end of the pipeline is shut off, the exiting flow will decay more quickly, because mass is no longer being added to the pipeline. In the case of a pipeline rupture just before the Tioga station, the amount of pipeline fluid "back flowing" from the station to the rupture point would be insignificant. For this analysis, it was assumed that the normal flow through the pipeline would be terminated within 30 minutes after the rupture occurs.

The high mass release rate during the first few moments establishes the maximum extent of the vapor cloud. Fluid trailing out of the pipe at later times will only pose a local hazard close to the rupture point. For this reason, the maximum extent of the defined component concentration limits does not vary if the time required to stop the normal flow is more than a few minutes. Thus, for ruptures of pipelines that transport HVLs, the isolation time is not a critical parameter when defining the maximum extent of the cloud.

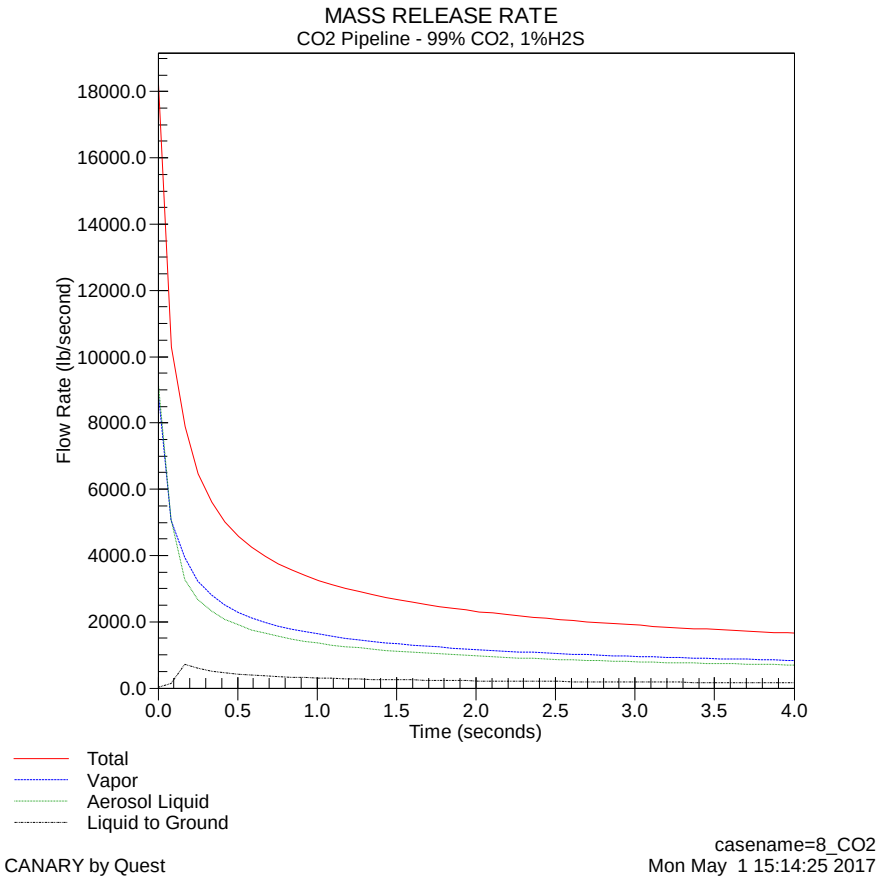

Figure 2-1
Mass Release Rate Decay for Rupture at
End of Section 8 as Pipeline Enters Tioga Pump Station

2.2 Potential Hazards

This analysis involved the evaluation of several potential impacts following an HVL release. Each potential release may result in one or more of the following hazards:

- Exposure to low temperatures due to the expansion of the CO_2 fluid as it reaches equilibrium.
- Exposure to high concentrations of CO_2 such that asphyxiation occurs.
- Exposure to the immediately dangerous to life and health (IDLH) of 40,000 ppm CO_2.
- Exposure to hydrogen sulfide (H_2S) such that fatality occurs within 30 minutes of exposure.
- Exposure to H_2S that defines the "onset of fatality" after 30 minutes of exposure (lower concentrations of H_2S and/or shorter exposure times do not result in fatality).
- Exposure to IDLH for H_2S of 100 ppm.

The transported fluid does not present a flammable hazard.

2.3 Pipeline Release Scenarios

When a pressurized fluid is released from a buried pipeline, a significant amount of energy is transferred to the overburden. In some cases, the momentum of the escaping fluid is sufficient to move the overburden away from the release point and create a crater. If the momentum of the release is not great enough to move the overburden (due to insufficient pressure in the pipeline or small release hole size or both), the released material spreads through the overburden and is released into the atmosphere by diffusion through the soil.

An evaluation of historical data for releases from liquefied gas lines was conducted in order to better understand the mechanisms by which liquefied gases could be released to the atmosphere. This evaluation found several instances of liquefied gas releases, but no consistent reporting of crater formation, crater size, or release behavior as a function of pipeline size or operating pressure. Due to the lack of reliable historical data, several assumptions were made regarding the behavior of releases from this pipeline.

All ruptures from the pipeline were assumed to remove the overburden. The crater formed following a rupture of the buried pipeline was assumed to be approximately 12 feet in diameter. This size formed the basis for the release of CO_2 evolving from the crater following a rupture.

3.0 PHYSIOLOGICAL EFFECTS OF CARBON DIOXIDE

3.1 Asphyxiant Hazard

Carbon dioxide is a colorless, odorless gas. The major hazard associated with CO_2 is asphyxiation. At low concentrations CO_2 may only produce mild effects to people. At high concentrations, CO_2 can cause nausea, vomiting, asphyxiation, and even death. The acute effects are due to displacement of oxygen by CO_2 resulting in reduced oxygen. Table 3-1 describes the various effects of reduced oxygen (O_2) concentrations on people.

Table 3-1
Effects of Different Concentrations of Oxygen

Oxygen Concentration	Effects and Symptoms (Due to Depleted Oxygen Content in Air)*	Required Carbon Dioxide Concentration
20.9 %	Normal.	--
19 %	Some adverse physiological effects occur, but they are unnoticeable.	9.09 % 90,909 ppmv
16 %	Increased pulse and breathing rate. Impaired thinking and attention. Reduced coordination.	23.4 % 234,500 ppmv
14 %	Abnormal fatigue upon exertion. Emotional upset. Faulty coordination.	33.0 % 330,000 ppmv
12.5 %	Very poor judgment and coordination. Impaired respiration that can cause permanent heart damage. Nausea and vomiting.	40.2 % 402,000 ppmv
< 10 %	Inability to perform various movements. Loss of consciousness. Convulsions. Death.	>52.1 % >521,000 ppmv

* Compressed Gas Association Safety Bulletin [SB-2, 2007]

The physiological effects of airborne toxic materials depend on the concentration of the toxic vapor in the air being inhaled, and the length of time an individual is exposed to this concentration. The combination of concentration and time is referred to as "dosage." In risk studies that involve toxic gases, probit equations are commonly used to quantify the expected rate of fatalities for the exposed population. Probit equations are based on experimental dose-response data and take the following form.

$$Pr = a + b\ ln(C^n \cdot t)$$

where: Pr = probit
C = concentration of toxic vapor in the air being inhaled (ppm)
t = time of exposure (minutes) to concentration C
$a, b,$ and n = constants

The product $C^n \cdot t$ is often referred to as the dose factor. According to probit equations, all combinations of concentration (C) and time (t) that result in equal dose factors also result in equal values for the probit (Pr) and therefore produce equal expected mortality rates for the exposed population.

A probit equation for the asphyxiant affects caused by CO_2 uses the values of -90.80, 1.01, and 8 for the constants $a, b,$ and n, respectively [HSE, 2009]. Substituting these values into the general probit equation yields the following probit equation for CO_2.

$$Pr = -90.80 + 1.01\ ln(C^8 \cdot t)$$

Using this probit equation, the CO_2 concentration that equates to a one percent mortality rate is 63,340 ppm for 60 minutes exposure, 69,073 ppm for 30 minutes exposure, or 75,325 ppm for 15 minutes exposure, etc., as shown in Table 3-2. Table 3-2 presents the mortality rates, dosage levels, and CO_2 concentrations for various exposure times, while Figure 3-1 presents the same information in graphical form.

Table 3-2
Hazardous CO_2 Concentration Levels for Various Exposure Times Using the HSE [2009] CO_2 Probit

Exposure Time [minutes]	Probit Value	Mortality Rate* [percent]	CO_2 Concentration [ppm]
5	2.67	1	86,413
	5.00	50	115,296
	7.33	99	153,833
15	2.67	1	75,325
	5.00	50	100,502
	7.33	99	134,094
30	2.67	1	69,073
	5.00	50	92,160
	7.33	99	122,965
60	2.67	1	63,340
	5.00	50	84,511
	7.33	99	112,759

*Percent of exposed population fatally affected.

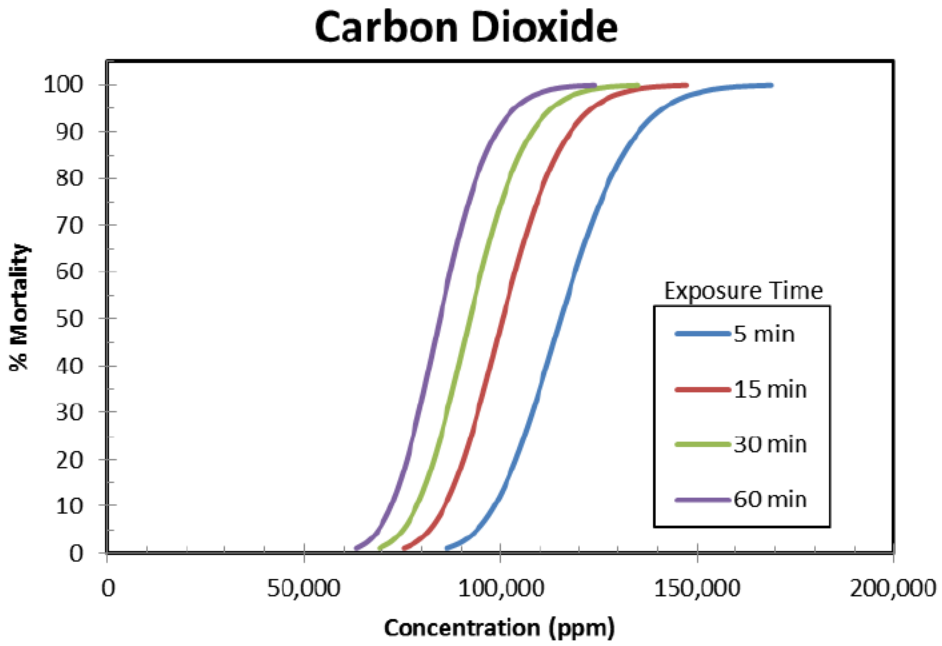

Figure 3-1
Carbon Dioxide Probit Functions

Probit relationships such as the one presented above are often used in risk analysis studies when the risk of fatality to the exposed population is to be determined. The CO_2 concentrations in the report titled "*Design and Operation of CO_2 Pipelines*" [Det Norske Veritas, 2010] are clearly identified as those pertaining to occupational exposure. These concentrations, reproduced in Tables 3-3 and 3-4, should be applied to the workers in the facility where CO_2 may be present in an intermittent or continuous manner. The low CO_2 concentrations (e.g., 0.5, 1, and 2 mol %) for long exposure times (e.g., over one hour) have little meaning when evaluating the potential exposure of the public to CO_2 exposure following an accidental release. The reasons for this conclusion can be summarized as follows.

- Few large (e.g., ruptures) accidents release CO_2 at a steady rate for more than one hour.
- The wind does not blow steadily at the same speed and direction for more than one hour.
- The atmospheric conditions (e.g., stability, temperature, etc.) do not remain the same for more than one hour.
- Members of the public who are outside are generally mobile and do not remain in the same location for more than one hour.

Table 3-3
Acute Health Effects of High Concentrations of Inhaled CO_2

CO_2 Concentration in Air [% v/v]	Exposure	Effects on Humans
17 - 30	Within 1 minute	Loss of controlled and purposeful activity, unconsciousness, convulsions, coma, death
>10 - 15	1 minute to several minutes	Dizziness, drowsiness, severe muscle twitching, unconsciousness
7 - 10	Few minutes	Unconsciousness, near unconsciousness
	1.5 minutes to 1 hour	Headache, increased heart rate, shortness of breath, dizziness, sweating, rapid breathing
6	1-2 minutes ≥ 16 minutes Several hours	Hearing and visual disturbances Headache, difficult breathing (dyspnoea) Tremors
4 - 5	Within a few minutes	Headache, dizziness, increased blood pressure, uncomfortable breathing (Equivalent to concentrations expired by humans)
3	1 hour	Mild headache, sweating, and difficult breathing at rest
2	Several hours	Headache, difficult breathing upon mild exertion
0.5 - 1	8 hours	Acceptable occupational hazard level

In general, the only CO_2 pipeline releases that may continue to exist in the eight to ten hour time frame with a reasonably constant release rate would be small leaks. While these releases may occur, the impact zones would be smaller than the larger accidental releases modeled in this study and it would still require members of the public to remain at a specific location for an eight to ten hour period. For these reasons, dispersion calculations to the low CO_2 concentrations at the eight and ten hour time markers are not of significant value when assessing the potential hazards and risks associated with the proposed pipeline.

Table 3-4
Occupational Exposure Limits

Exposure Time	% CO_2	Comment	Reference
10 hours	0.50 %	Time weighted average	NIOSH (US)
8 hours	0.50 %	Time weighted average	OSHA (US)
	0.50 %	Occupational Long Term Exposure Limit (LTEL)	COSHH HSE (UK)
60 min	4 %	Emergency Exposure Level for submarine operations	USA Navy
	2.5 %	Emergency Exposure Level for submarine operations	National (US) Research Council
	5 %	Suggested Long Term Survivability Exposure Limit	HSE (UK)
	2 %	Maximum exposure limit	Compressed Gas Association 1990
20 min	3 %	Maximum exposure limit	Compressed Gas Association 1990
15 min	1.5 %	Occupational Short Term Exposure Limit (STEL)	COSHH HSE (UK)
	3 %	Short Term Exposure Limit (STEL)	Federal occupational safety and health regulations (US)
10 min	4 %	Maximum exposure limit	Compressed Gas Association 1990
7 min	5 %	Maximum exposure limit	Compressed Gas Association 1990
5 min	5 %	Suggested Short Term Exposure Limit (STEL)	HSE (UK)
	6 %	Maximum exposure limit	Compressed Gas Association 1990
3 min	7 %	Maximum exposure limit	Compressed Gas Association 1990
1 min	15 %	Exposure limit	NORSOK (Norway)
<1 min	4 %	Maximum Occupational Exposure Limit	Federal occupational safety and health regulations (US)

3.2 Low Temperature Hazard

A release of supercritical carbon dioxide from a pipeline results in an expanding flashing fluid. This flashing process produces a low fluid temperature. As the CO_2 mixes with the air, the temperature of the CO_2/air mixture slowly increases from the minimum temperature achieved after flashing. In the limit, the temperature of the air mixture with small concentrations of CO_2 will approach that of the surrounding air. One way to represent this behavior is presented in Figure 3-2. This figure shows how the CO_2/air mixture warms as the CO_2 is diluted with air following a release from the pipeline. The following points are taken from Figure 3-2.

30 mol % CO_2 (70 mol % air) corresponds to a CO_2/air temperature of - 4°C
20 mol % CO_2 (80 mol % air) corresponds to a CO_2/air temperature of 3°C
15 mol % CO_2 (85 mol % air) corresponds to a CO_2/air temperature of 8°C

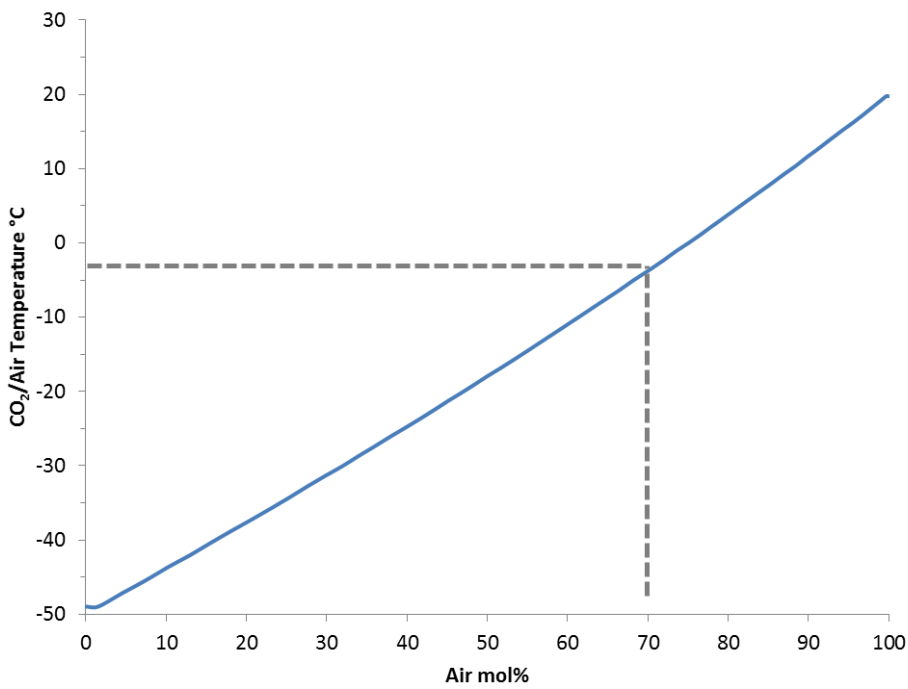

Figure 3-2
Carbon Dioxide/Air Cloud Temperature as a Function of Air Concentration

In order to determine the potential hazards associated with exposure to cold CO_2/air temperatures, a relationship between air temperature, exposure time, and wind speed (air movement) must be used. Work completed by Tikuisis and Frim [1994] developed a correlation between these three parameters for people. A summary of part of this work is presented in Figure 3-3. The basis of the work was to define the survival time associated with exposure to cold temperatures. In this sense, the work is focused on long term exposure (e.g., exposure times on the order of hours) while the accidental release modeling that is the subject of this study focused on exposure times less than one hour. Thus, using the survival time approach (hours of exposure) will produce a conservative result since persons near the pipeline would not be expected to remain stationary in the cold cloud more than a few minutes.

A review of Figure 3-3 finds that if a person is exposed to 10 to 20 km/h winds with an air temperature of -20°C, they would be expected to survive for more than eight hours. Since the CO_2 concentration associated with a temperature of -20°C is greater than 30 mol % CO_2 (i.e., less than 70 mol % air in Figure 3-2), the low temperature hazards associated with an accidental release from the pipeline will always be smaller than the asphyxiant hazard associated with 30 mol % CO_2. Another way to view the relationship between cold CO_2/air and CO_2 concentration is to note that -20°C is equivalent to a CO_2 concentration of 53 mol %. Thus, in every scenario, the hazard zone associated with low temperature exposure is smaller than the hazard zone associated with the equivalent CO_2 concentration level necessary to cause fatality by asphyxiation.

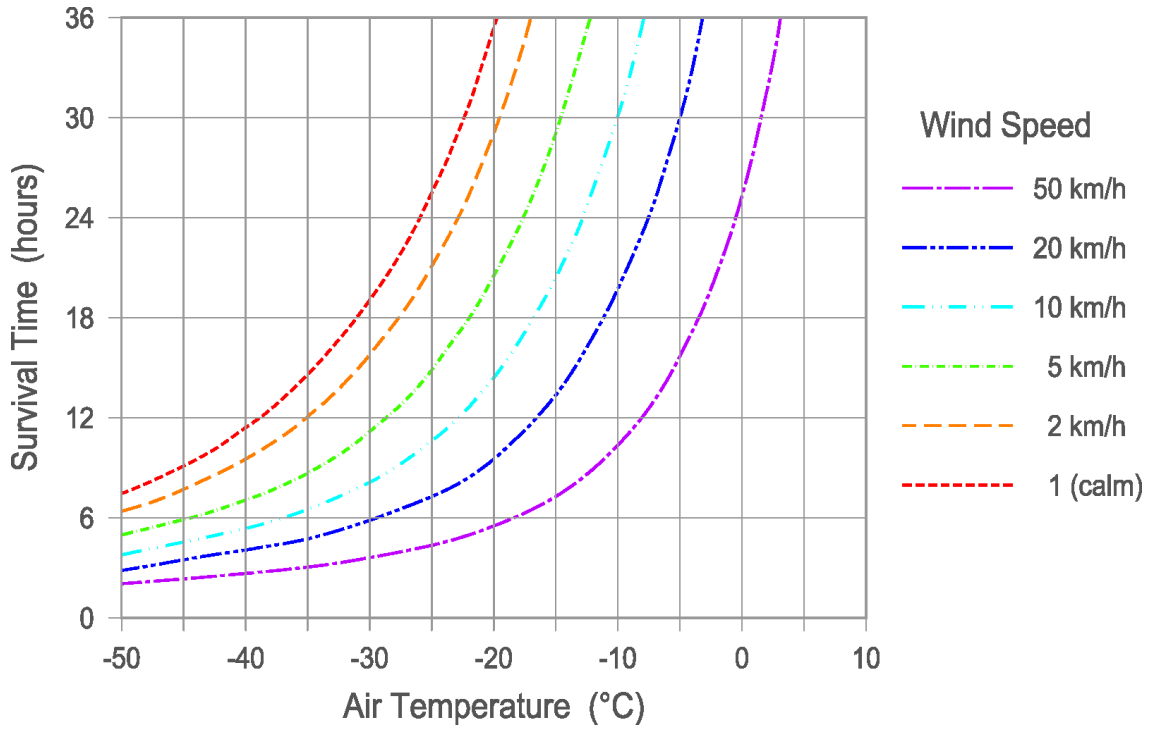

Figure 3-3
Survival Time as a Function of Air Temperature

3.3 IDLH

Immediately dangerous to life or health (IDLH) concentrations are "likely to cause death or immediate or delayed permanent adverse health effects or prevent escape from such an environment." For concentrations above the IDLH, self-contained breathing apparatus (SCBA) is required. Below the IDLH, air purifying respirators may be used, if appropriate. The IDLH for CO_2 is 40,000 ppm (4 mol %) with an exposure time of 30 minutes [NIOSH, 1994].

4.0 PHYSIOLOGICAL EFFECTS OF HYDROGEN SULFIDE

Hydrogen Sulfide (H_2S) is a colorless, flammable gas with a strong, irritating odor. H_2S has a low threshold limit value (TLV) and is detectable by odor at concentrations significantly lower than those necessary to cause physical harm or impairment (odor detectable as low as 0.13 ppm). The most serious hazard presented by H_2S is exposure to a large release from which escape is impossible. Table 4-1 describes various physiological effects of H_2S. The physiological effects of airborne toxic materials depend on the concentration of the toxic vapor in the air being inhaled, and the length of time an individual is exposed to this concentration.

4.1 H_2S Probit Relation from Perry and Articola

A probit equation for H_2S has been presented by Perry and Articola [1980]. This probit uses the values of -31.42, 3.008, and 1.43 for the constants *a*, *b*, and *n*, respectively. Substituting these values into the general probit equation yields the following probit equation for H_2S.

$$Pr = -31.42 + 3.008\, ln(C^{1.43} \cdot t)$$

Dispersion calculations are often performed assuming a 60-minute exposure to a toxic gas. This is particularly true when dealing with air pollution studies since they are typically concerned with long-term exposures to low concentration levels. For accidental releases of toxic gases, shorter exposure times are warranted since the durations of many accidental releases are less than an hour. In this study, calculations were performed for various exposure times and concentration levels.

When using a probit equation, the value of the probit (Pr) that corresponds to a specific dose factor must be compared to a statistical table to determine the expected mortality rate. If the value of the probit is 2.67, the expected mortality rate is one percent. Using this probit equation, the H_2S concentration that equates to a one percent mortality rate is 157 ppm for 60 minutes exposure, 256 ppm for 30 minutes exposure, or 416 ppm for 15 minutes exposure, etc. Table 4-2 presents the probit values, mortality rates, and H_2S concentrations for various exposure times, while Figure 4-1 presents the same information in graphical form.

A summary of the hazard endpoints employed in this study are presented in Table 4-3.

Table 4-1
Physiological Response to Various Concentrations of Hydrogen Sulfide (H_2S)

H_2S Concentration [ppm]	Duration of Exposure						
	0-2 min	2-15 min	15-30 min	30 min to 1 hr	1-4 hr	4-8 hr	8-48 hr
5-100				Mild conjunctivitis, respiratory tract irritation.			
100-150		Coughing, irritation of eyes, loss of sense of smell.	Disturbed respiration, pain in eyes, sleepiness.	Throat irritation.	Salivation and mucous discharge, sharp pain in eyes, coughing.	Increased symptoms.*	Hemorrhage and death.*
150-200		Loss of sense of smell.	Throat and eye irritation.	Throat and eye irritation.	Difficult breathing, blurred vision, light shy.	Serious irritating effect.*	Hemorrhage and death.*
250-350	Irritation of eyes, loss of sense of smell.	Irritation of eyes.	Painful secretion of tears, weariness.	Light shy, pain in eyes, difficult breathing.	Hemorrhage and death.*		
340-450		Irritation of eyes, loss of sense of smell.	Difficult respiration, coughing, irritation of eyes.	Increased irritation of eyes and nasal tract, dull pain in head, weariness, light shy.	Dizziness, weakness, increased irritation, death.	Death.*	
500-600	Coughing, collapse, and unconscious-ness.	Respiratory disturbances, irritation of eyes, collapse.*	Serious eye irritation, light shy, palpitation of heart, a few cases of death.	Severe pain in eyes and head, dizziness, trembling of extremities, great weakness and death.*			
600 or greater	Collapse, unconscious-ness, death.*						

*Data secured from experience on dogs that have a susceptibility similar to man.
Source: National Safety Council data sheet D-chem 15.

Table 4-2
Hazardous H_2S Concentration Levels for Various Exposure Times Using the Perry and Articola[1980] H_2S Probit

Exposure Time [minutes]	Probit Value	Mortality Rate* [percent]	H_2S Concentration [ppm]
5	2.67	1	897
	5.00	50	1,542
	7.33	99	2,652
15	2.67	1	416
	5.00	50	715
	7.33	99	1,230
30	2.67	1	256
	5.00	50	440
	7.33	99	758
60	2.67	1	157
	5.00	50	271
	7.33	99	467

* Percent of population fatally affected.

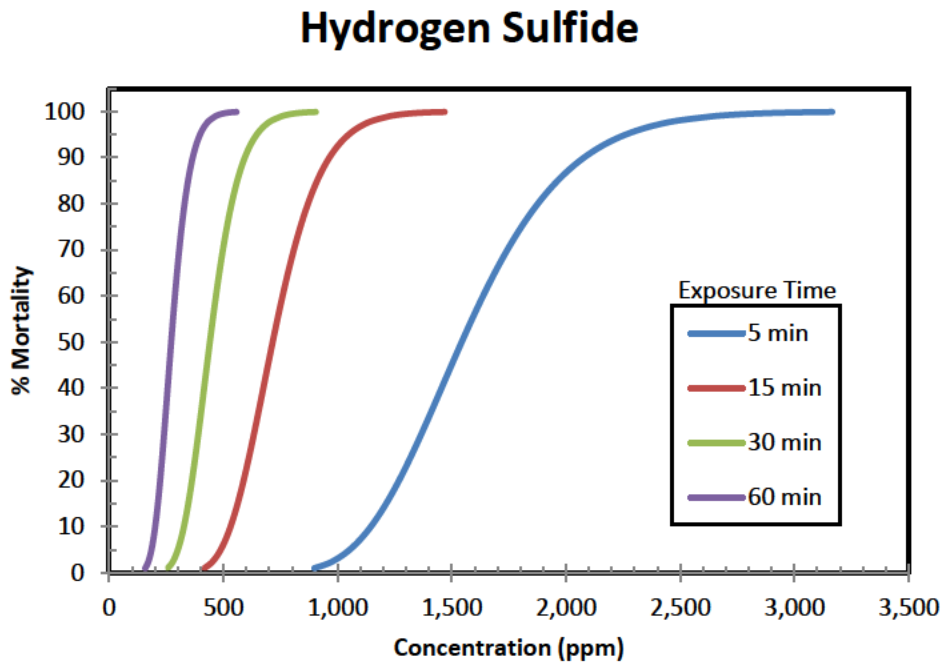

Figure 4-1
Hydrogen Sulfide Probit Functions

Table 4-3
Endpoint Criteria for Consequence Analysis

Hazard Type	Concentration [ppm]	Exposure Duration [min]	Consequence	Reference
CO_2 Exposure	530,000	480	Freezing Temperatures	Tikuisis and Frim [1994]
	69,073	30	1 % Fatality	HSE [2009]
	40,000	30	IDLH	NIOSH [1994]
H_2S Exposure	758	30	100 % Fatality	Perry and Articola [1980]
	256	30	1 % Fatality	
	100	30	IDLH	NIOSH [1994]

5.0 MODELING PARAMETERS

The following parameters were applied to the modeling for the HVL pipeline.

Product Temperature	60°F (underground in pipeline)
Product Flowrate	10 to 150 MMSCFD (150 MMSCFD used in modeling)
Pipeline Diameter	13.25 inches (I.D.) upstream of Tioga
Air Temperature	80°F
Relative Humidity	70 %

Pipeline releases were modeled as a full rupture of the pipeline. Vapor dispersion releases were modeled at two wind speeds and atmospheric stability combinations: 4.5 mph and "F" and 11 mph and "D." Atmospheric stability is defined by the Pasquill-Gifford rating scale of A through F. The most unstable atmosphere is characterized by Stability Class A. Stability A would correspond to an atmospheric condition characterized by strong solar radiation and moderate winds. This combination of radiation and winds allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by partial to full cloud cover during both daytime and nighttime. The atmospheric turbulence is not as great during D conditions as during A conditions; thus, the gas will not mix as quickly with the surrounding atmosphere. Stability D is often considered as representative of "average" conditions. Stability F corresponds to the most stable atmospheric conditions. Stability F generally occurs during the early morning hours before sunrise (thus, no solar radiation) and under low winds. The combination of low winds and lack of solar heating allows for an atmosphere which appears calm or still and thus restricts the mixing ability of a released gas. Modeling the releases under 4.5 mph winds and F Stability generally results in the longest downwind dispersion distances.

5.1 Hazards Calculations

Each hazard calculation was performed until the defined concentration endpoints were reached.

When performing site-specific consequence analysis studies, the ability to accurately model the release, dilution, and dispersion of gases and aerosols is important if an accurate assessment of potential exposure is to be attained. For this reason, Quest uses a modeling package, CANARY by Quest, that contains a set of complex models that calculate release conditions, initial dilution of the vapor (dependent upon the release characteristics), and the subsequent dispersion of the vapor introduced into the atmosphere. The models contain algorithms that account for thermodynamics, mixture behavior, transient release rates, gas cloud density relative to air, initial velocity of the released gas, and heat transfer effects from the surrounding atmosphere and the substrate. The release and dispersion models contained in the QuestFOCUS package (the predecessor to CANARY by Quest) were reviewed in a United States Environmental Protection Agency (EPA) sponsored study [TRC, 1991] and an American Petroleum Institute (API) study [Hanna, Strimaitis, and Chang, 1991]. In both studies, the QuestFOCUS software was evaluated on technical merit (appropriateness of models for specific applications) and on model predictions for specific releases. One conclusion drawn by both studies was that the dispersion software tended to overpredict the extent of the gas cloud travel, thus resulting in too large a cloud when compared to the test data (i.e., a conservative approach).

A study prepared for the Minerals Management Service [Chang, et al., 1998] reviewed models for use in modeling routine and accidental releases of flammable and toxic gases. CANARY by Quest received the highest possible ranking in the science and credibility areas. In addition, the report recommends CANARY by Quest for use when evaluating toxic and flammable gas releases. Specific models contained in the CANARY by Quest software package have also been extensively reviewed.

Model descriptions for CANARY and validation are presented in Appendix B.

5.2 Vapor Cloud Dispersion

A full rupture of the pipeline was modeled to determine the maximum distances to the CO_2 and H_2S concentrations of interest as the cloud traveled in the shallow valley toward Tioga.

5.3 Computational Fluid Dynamics Using FDS

The results of the CO_2 transient release analysis are one of the primary inputs to the computational fluid dynamic model employed for this work. Quest uses the Fire Dynamics Simulator (Version 6.0, FDS6) model for this type of application. The FDS model is described in the FDS User's Guide [McGrattan, 2014] as follows.

> Fire Dynamics Simulator (FDS), is a computational fluid dynamics (CFD) model of fire-driven fluid flow. FDS solves numerically a form of the Navier-Stokes equations appropriate for low-speed, thermally-driven flow with an emphasis on smoke and heat transport from fires.
>
> FDS solves numerically a form of the Navier-Stokes equations appropriate for low-speed, thermally-driven flow with an emphasis on smoke and heat transport from fires. The core algorithm is an explicit predictor-corrector scheme, second order accurate in space and time. Turbulence is treated by means of Large Eddy Simulation (LES). It is possible to perform a Direct Numerical Simulation (DNS) if the underlying numerical mesh is fine enough. LES is the default mode of operation.

The FDS model was employed when the pipeline rupture occurred just before the Tioga station where the terrain effects of the shallow valley could affect the dispersion behavior of the CO_2 cloud. Releases in this shallow valley leading toward Tioga were modeled with FDS with the wind blowing toward Tioga from the point of pipeline rupture (east to west). This valley is defined by the dimensions as well as how it meanders before reaching Tioga.

The meandering nature of the valley can be seen in Figure 5-1. Figure 5-1 presents the depiction of the valley leading to Tioga. The top of the valley ranges from 55 to 95 feet above the valley floor. In Figure 5-1, the darker the green, the lower the elevation. The valley slopes slightly downward from east to west. Figure 5-2 presents the same shallow valley near Tioga using an aerial picture.

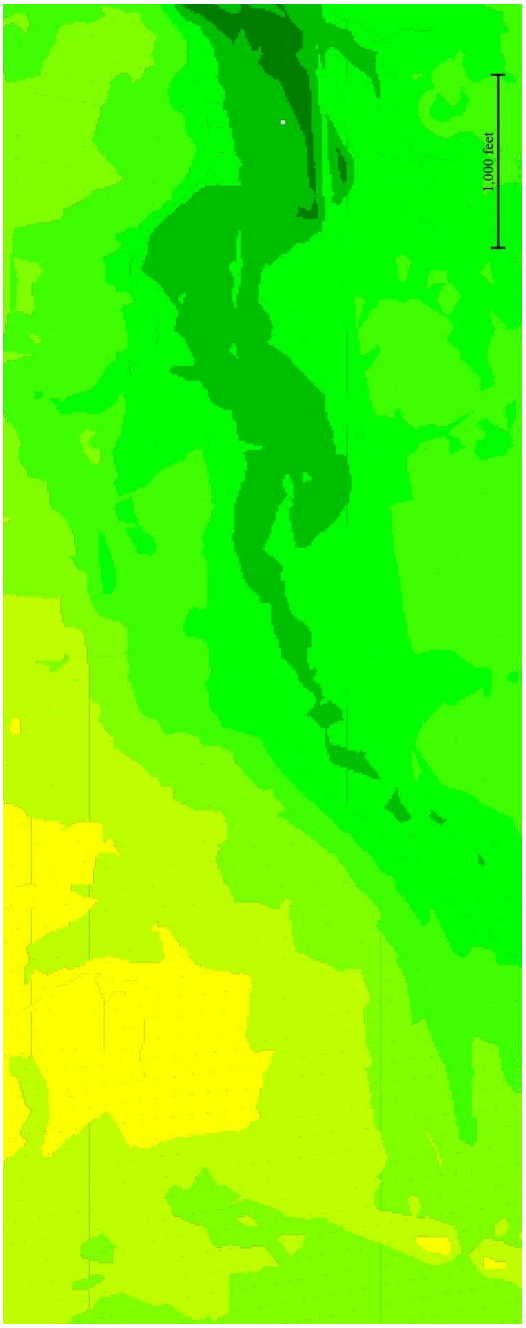

Figure 5-1
Elevation Drawing of Tioga Valley – 4 meter contours

Figure 5-2
Elevation Drawing of Tioga Valley Overlaid on Aerial Map

The dispersion results for the CO_2 and H_2S gas concentration endpoints selected are presented in Table 5-1. As can be seen in Table 5-1, the shallow Tioga valley produces shorter dispersion distances to the specified gas concentration endpoints than the narrow and wide valleys of a previous study [Quest, 2017]. As the valley becomes wider and wider, the dispersion results will begin to approach those on flat terrain. In addition, the worst case results presented in Table 5-1 are for the atmospheric condition when the winds are blowing parallel to the valley's direction. Any other condition where the winds are blowing any other direction will result in shorter dispersion distances to the gas concentration endpoints chosen.

It is important to note the effect of exposure time on the dispersion results. In Table 5-1, results for two exposure times are presented; one and five minutes. The one minute exposure time results do not mean much when it comes to exposure to CO_2 or H_2S, when the concentrations chosen are representative of longer exposure (e.g., 30 minute exposure for IDLH). Even the use of a five minute exposure time is conservative as it represents the distance achieved by the cloud for a five minute exposure instead of a longer exposure time. For this reason the use of the five minute exposure time results should be used when evaluating the dispersion results.

Table 5-1
CFD Modeling Results for the CO_2 Pipeline – Rupture

Terrain	Wind Speed [mph]	Exposure Time [minutes]	Maximum Downwind Distance to Carbon Dioxide Concentration[ft]			Maximum Downwind Distance to Hydrogen Sulfide Concentration [ft]		
			530,000 ppm	69,073 ppm	40,000 ppm	758 ppm	256 ppm	100 ppm
Tioga Shallow Valley	4.5	1	70	750	1,250	720	2,490	6,430
	4.5	5	30	430	850	330	1,880	5,430
Tioga Shallow Valley	11	1	70	850	1,190	750	2,170	4,590
	11	5	30	460	660	390	1,120	2,600

6.0 SUMMARY

The purpose of this analysis was to define the maximum extent of potential hazards following a rupture of a 14-inch pipeline entering the Tioga station when the winds were blowing toward Tioga. The subject pipeline is transporting a mixture containing primarily carbon dioxide. It was conducted in support of Phase 1 of a protocol developed to satisfy the consequence analysis portion of a pipeline integrity management program. Vapor dispersion of CO_2 and H_2S, following a full-bore rupture of the pipeline, were modeled to a concentration endpoint equal to the IDLH for each material. All releases were modeled under worst-case conditions, identified as low winds (4.5 mph) and stable atmosphere (Stability Class F) as well as more "average" conditions of moderate winds (11 mph) and neutral atmosphere (Stability Class D).

For releases in the shallow valleys leading to Tioga, the maximum extents of H_2S IDLH (6,430 feet for a one-minute exposure and 5,430 feet for a five-minute exposure) and CO_2 IDLH (1,250 feet for a one-minute exposure and 850 for a five-minute exposure) are greater than on the flat land sections. This is due to the inability of the vapor cloud to freely entrain air on its sides (less mixing with the atmosphere).

When these dispersion results are used to identify any high consequence areas along the pipeline route, the population distribution along the pipeline route must be taken into consideration. Single dwellings along the pipeline route do not constitute a high consequence area according to 49 CFR 195 [DOT, 2000]. In the same manner, in order for portions of shallow valley leading to Tioga to be considered a high consequence area, multiple dwellings must be located in the valley or be reached by the dispersing cloud within the dispersion distances defined. If the area (the shallow valley east of Tioga) is not populated by multiple dwellings, it is not classified as a high consequence area. Visual representations of the maximum cloud travel are presented in Figures 6-1 through 6-4.

A review of Figures 6-2 and 6-4 show that the five minute exposure dispersion distances to the carbon dioxide and hydrogen sulfide concentrations do not reach any dwellings. Thus, an accidental release from the carbon dioxide pipeline approaching the Tioga station does not reach the town of Tioga above the concentration levels defined.

Figure 6-1
40,000 ppm CO_2 – 1 Minute Exposure

Figure 6-2
40,000 ppm CO_2 – 5 Minute Exposure

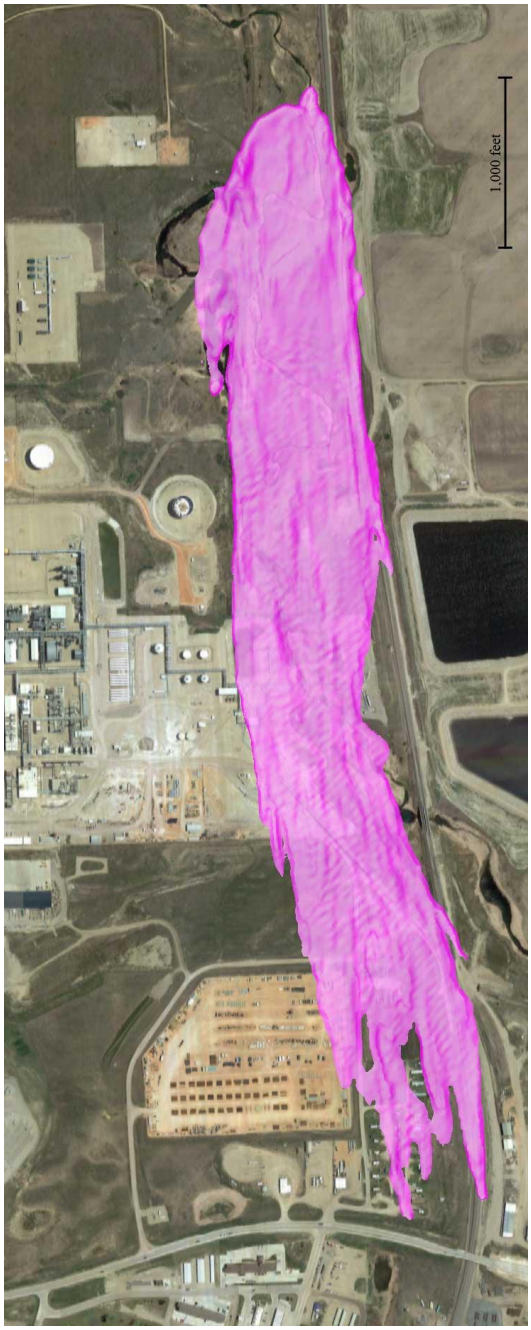

Figure 6-3
100 ppm H_2S – 1 Minute Exposure

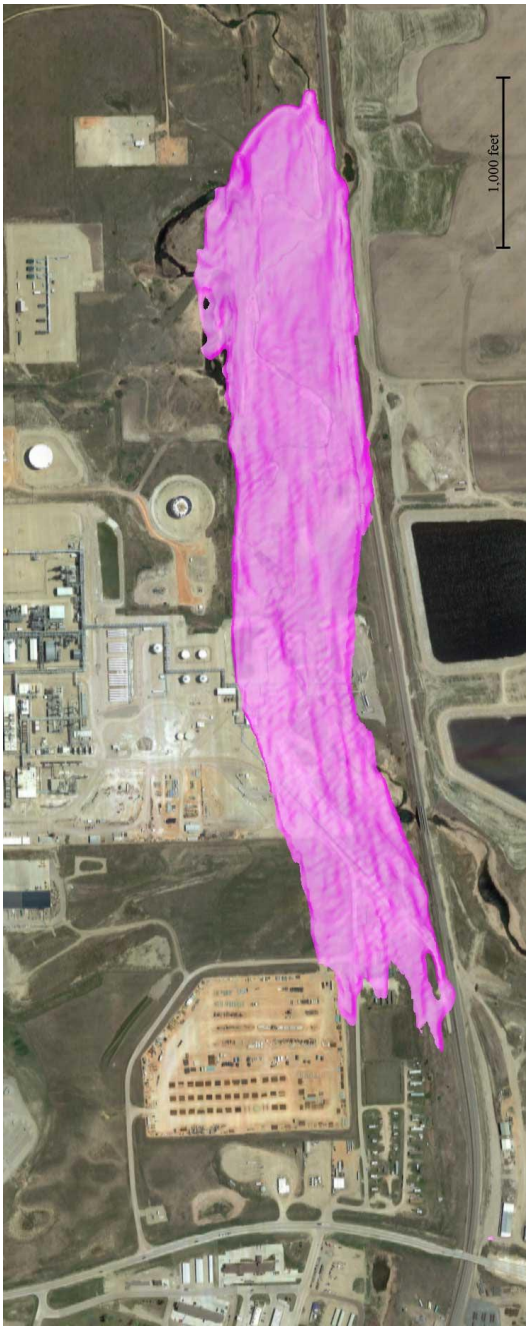

Figure 6-4
100 ppm H_2S – 5 Minute Exposure

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APPENDIX A

PROTOCOL FOR COMPLYING WITH THE CONSEQUENCE ANALYSIS REQUIREMENT WITHIN DOT'S INTEGRITY MANAGEMENT PROGRAM FOR HAZARDOUS LIQUID PIPELINES

The following is a brief description of Quest's protocol for complying with the consequence analysis portion of DOT's Integrity Management Program (IMP) for hazardous liquid pipelines (44 CFR 195.452). The protocol is divided into three phases, although it will not be necessary to conduct all three phases for each pipeline. At the completion of each phase, the analysis can be stopped if the results of the analysis up to that point indicate that High Consequence Areas (HCAs) along the pipeline route cannot be affected by a release from the pipeline. This option is clearly illustrated by the use of STOP signs in Figure A-1.

Phase 1 - Worst-Case Consequence Analysis Using Conservative Assumptions

Using our state-of-the-art consequence modeling software, CANARY by Quest®, define the hazard footprints for worst-case releases (e.g., full-bore ruptures) along the pipeline route. The hazards of interest are:

For people
- Exposure to a toxic gas cloud
- Exposure to a flammable gas cloud
- Exposure to explosion overpressure
- Exposure to radiant heat from torch or pool fire

For waterways and the environmentally sensitive areas
- Ingress of hazardous pipeline fluids into commercial waterways
- Ingress of hazardous pipeline fluids into environmentally sensitive areas

Conservative assumptions are used in the analysis in order to define the maximum hazard footprint associated with each pipeline.

Determine if one or more of the hazard zones could reach an HCA along the pipeline route—at a hazard level capable of severely impacting the public or the environment.

A. No - Document results for the pipeline. Analysis complete.
B. Yes - Proceed to Phase 2.

Phase 2 - Incorporation of Site-Specific Factors into Consequence Modeling

For those sections of a pipeline that affect one or more HCAs, determine if any site-specific factors can be incorporated into a refined consequence analysis. Examples of site-specific factors could include local terrain, local weather patterns.

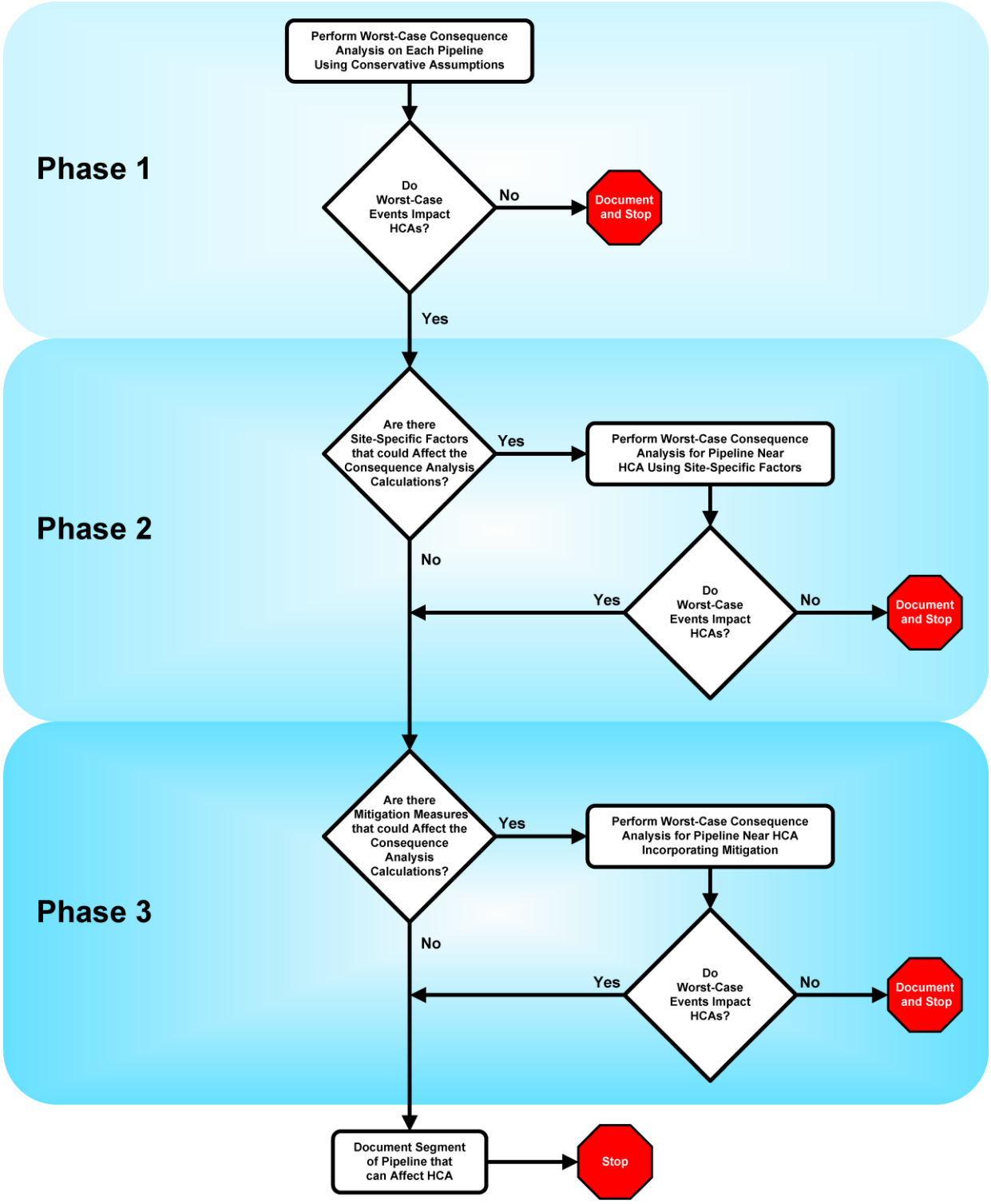

Figure A-1
HCA Evaluation Flowchart

Re-run the consequence analysis incorporating the site-specific factors. Using the same hazard impact criteria, determine whether the pipeline sections affect HCAs along the route.

A. No - Document results for the pipeline. Analysis complete.
B. Yes - Proceed to Phase 3.

Phase 3 - Review of Potential Mitigation Options

At this point in the analysis, one or more sections of the pipeline have been identified as being able to impact an HCA at a hazard level that could severely affect the public and/or the environment. A review of potential mitigation measures may be warranted, depending on the site-specific nature of each HCA impact.

Incorporate mitigation measures into the consequence analysis to determine the effect of active mitigation on the extent of potential hazard footprints. Using the same hazard impact criteria, determine whether the pipeline sections affect HCAs along the route.

A. No - Document results for the pipeline with active mitigation. Analysis complete.
B. Yes - Document results for the pipeline and potential impacts on HCA.

APPENDIX B
CONSEQUENCE MODEL DESCRIPTIONS

The consequence models used in this study include those found in the CANARY by Quest® modeling package, as well as the QMEFS vapor cloud explosion model. CANARY uses fluid properties and fluid release sub-models to supply information for vapor dispersion, vapor cloud explosion, and fire radiation models. The consequence models provide a simulation of potential hazardous material release scenarios so that the inherent hazards can be quantified. The following models are used:

- Engineering Properties
- Fluid Release Model
- Pool Spreading and Vaporization Model
- Momentum Jet Dispersion Model
- Heavy Gas Dispersion Model
- Pool Fire Radiation Model
- Torch Fire and Flare Radiation Model
- Fireball Model
- QMEFS Vapor Cloud Explosion Model

A brief description of the capabilities, requirements, and correlations used within each model is presented below. A more detailed description of the models is available upon request.

ENGINEERING PROPERTIES

The purpose of this model is to provide an accurate means of computing physical and thermodynamic properties of a wide range of chemical mixtures using a minimum of initial information. The Peng-Robinson cubic equation of state (EOS) is combined with van der Waals quadratic mixing rules and pure component data (e.g., normal boiling point) for the computation of thermodynamic properties.

The model is implemented using a properties database of approximately 250 single components which can be applied to mixtures of up to 10 components. The user supplies composition, temperature, and pressure, and the model provides thermodynamic properties (such as density, enthalpy, entropy, etc.) for liquid, vapor, and two-phase systems. These properties are used as inputs to the release and hazard models.

FLUID RELEASE MODEL

The purpose of the fluid release model is to predict the rate of mass release from a breach of containment. Specifically, the model predicts the rate of flow and the physical state (liquid, two-phase, or gas) of the release of a fluid stream as it enters the atmosphere from a breach in a pipe or vessel wall. The model also computes the amount of gas, or liquid or aerosol produced and the rate at which liquid reaches the ground.

The fluid release model takes into account the composition, temperature and pressure of the fluid before the release and identifies flow regime within the closed system before and during the release event. User-defined parameters such as normal flow rate of fluid, pipe and vessel sizes, area of the orifice, angle of release relative to horizontal, and release elevation provide a physical description of the system from which the release occurs. The model tracks the pressure profile in the system, computing the flow conditions stepwise in time until the mass is depleted or an end time is reached, while accounting for the system inventory and head pressure available. The system flow can be all vapor, all liquid, or two-phase, with checks made to determine if the fluid flow is realistic (e.g., velocity has not exceeded the sonic velocity). An orifice equation is used to calculate the time-varying velocity and mass flow rate from the breach during the release event.

The prediction of aerosol formation and amount of liquid rainout is based on the theoretical work performed for the Center for Chemical Process Safety (CCPS) by CREARE. CREARE's work has been corrected and extended by Quest. The extension to the model computes the non-aerosol drop evaporation. An example validation plot for this portion of the model is given in Figure B-1, for chlorine (Cl_2), methylamine (MMA), CFC-11, and cyclohexane aerosol test data compared to values computed by the CANARY aerosol model.

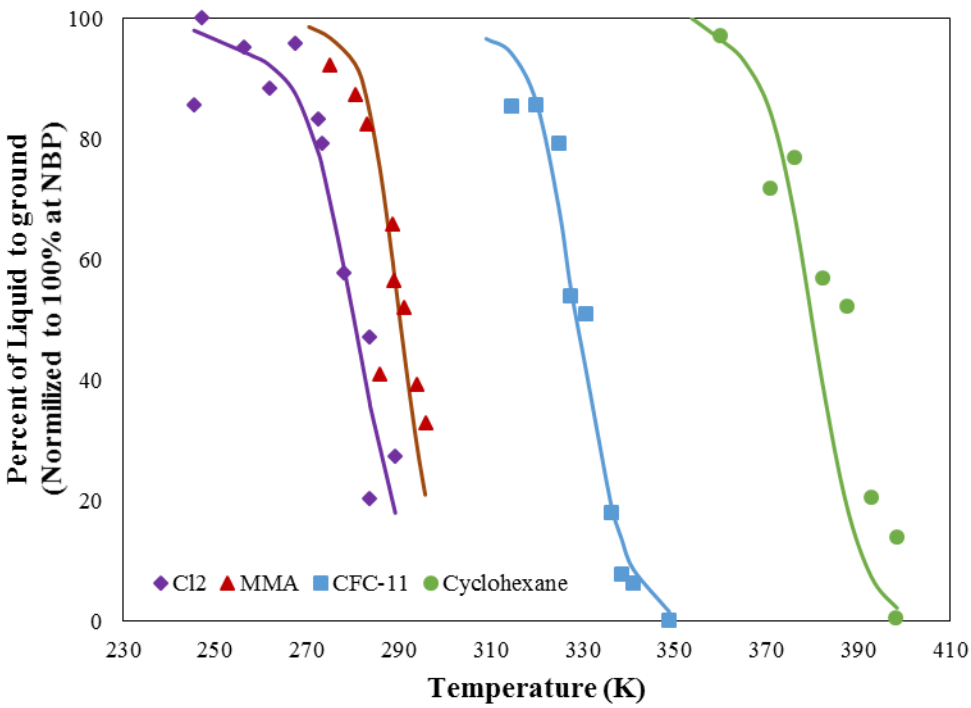

Figure B-1
Aerosol Predictions Compared to Experimental Data

Figure B-2 compares the computed and experimental gas discharge rates for the complete breach of two pipelines. Experiments included pipeline with two different internal diameters 6.2 inches (0.157 m), and 12 inches (0.305 m) respectively. These pipes were initially pressurized to 1,000 psia with air and then explosively ruptured. The experimental values were reported in a research paper for Alberta Environment, authored by Wilson [Wilson, 1981].

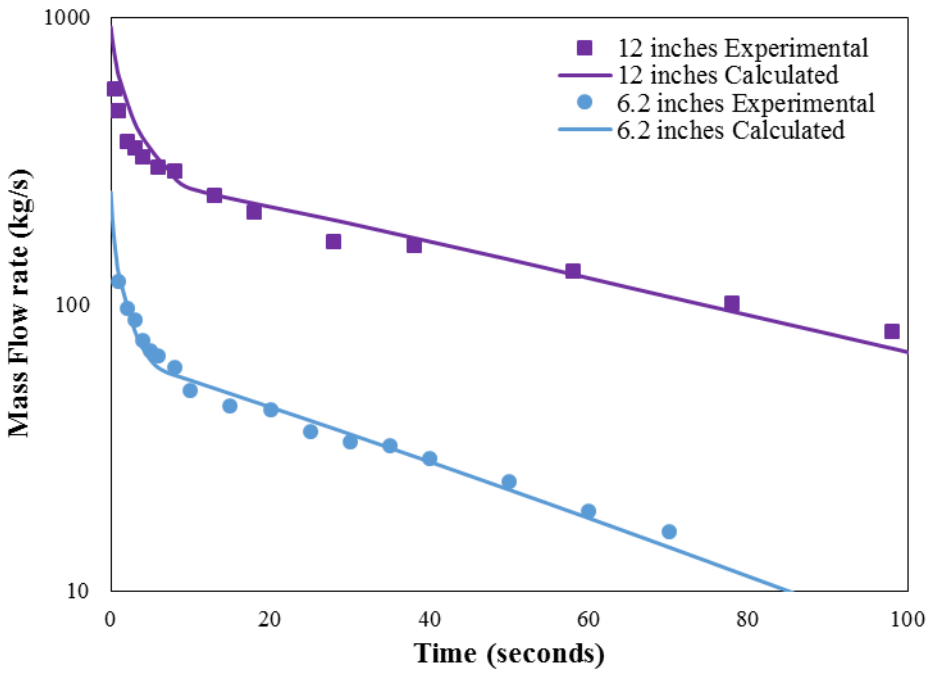

Figure B-2
Mass Release Rate Predictions Compared to Experimental Data

POOL SPREADING AND VAPORIZATION MODEL

The purpose of this model is to describe the spreading and mass vaporization rate of spilled liquids. For spills of refrigerated liquids on water, the model accounts for the presence of a potential obstacle that the liquid must overcome the local wave action.

The pool spreading and vaporization model uses information about impoundment systems provided by the user (and can also model the unconfined case) as well as liquid flow rate information from the release model. Coupled with the material's thermodynamic properties, the time-varying pool size and vaporization rate are predicted. The output from this model is used for input as a source term in the heavy gas dispersion model.

For refrigerated liquid spills on water, the liquid will spread radially and unconfined from the release point until the liquid reaches some minimum thickness that diminishes the liquid's ability to spread due to hydrodynamic head. The speed at which the liquid pool spreads is a function of the spill rate, liquid vaporization rate, physical properties of the liquid, radius of the liquid pool, and the nature of the spill surface. For this model the viscosity and surface tension effect are considered to have negligible effects on the rate of spread. This later simplification allows the rate of liquid spreading to be found at any instant in time, by use of a simple hydrodynamic model in which the rate of spread becomes a function of spill, vaporization rate, and pool radius. Finally the numerical solution of the differential equations permits the computation of the pool size, height of the liquid pool, and the transient evaporated mass rate.

MOMENTUM JET DISPERSION MODEL

The purpose of this model is to predict the dispersion of a jet release into ambient air. It is used to predict the downwind travel of a momentum-based jet of flammable or toxic gas or aerosol.

The momentum jet dispersion model incorporates the composition and properties (temperature, pressure, composition, density, etc.) of the released materials, the mass rate of release, and some geometric parameters such as angle of release relative to horizontal, height of release, and area of release. Environmental and atmospheric conditions such as wind speed, Pasquill-Gifford stability class, ambient air temperature, and surface roughness are taken into account. Velocity, concentration, and density profiles are assumed to be cylindrically symmetric about the plume axis and Gaussian in shape. Entrainment along the jet is calculated while applying equations for conservation of mass and momentum.

The momentum jet dispersion model used in CANARY was validated by comparing results obtained from the model with experimental data from field-scale tests. Data used for this comparison and the conditions used in the model were taken from an American Petroleum Institute (API) study [Hanna, 1991]. Comparisons were made with the Desert Tortoise, Goldfish, and Prairie Grass series of dispersion tests. Results of these comparisons are shown in Figure B-3.

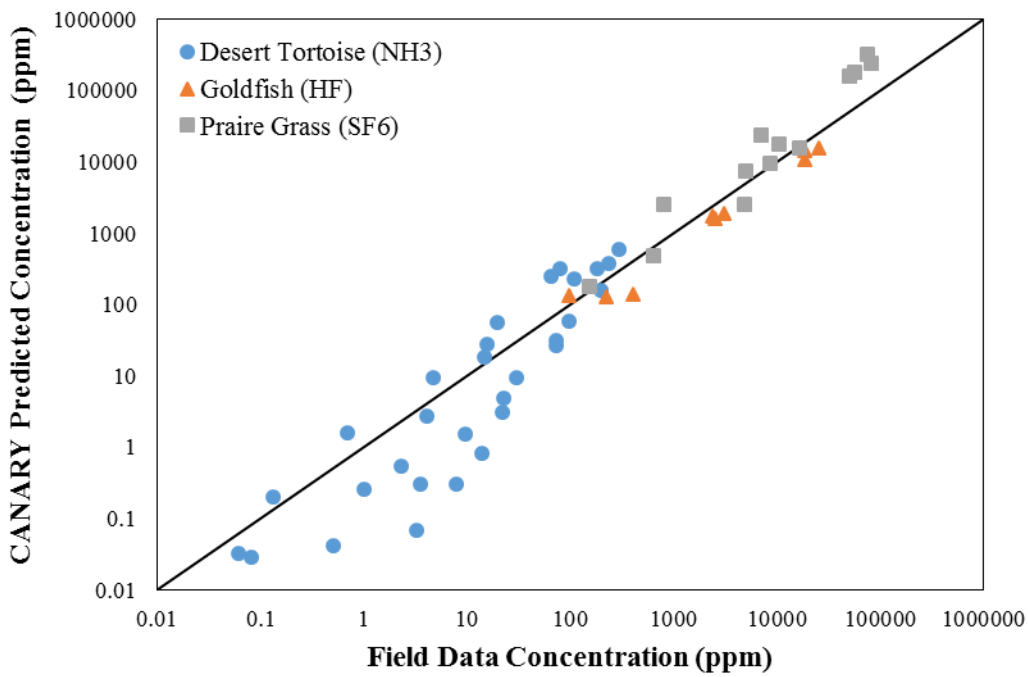

Figure B-3
Momentum Jet Dispersion Predictions Compared to Experimental Data

HEAVY GAS DISPERSION MODEL

The purpose of this model is to predict the dispersion and gravity flow of heavier-than-air gases evolving from liquid pools. The model is also employed when an initially momentum-dominated release involving heavier-than-air gases loses its momentum, and impacts grade. The model is used to predict the downwind travel of a flammable or toxic vapor cloud.

The heavy gas dispersion model incorporates the properties of the source vapor, as well as its mass rate and the size of the source area. Environmental and atmospheric conditions such as wind speed, Pasquill-Gifford stability class, ambient air temperature, and surface roughness are taken into account. Concentration and density profiles are applied about the plume axis. Entrainment along the dispersing cloud is calculated while applying equations for conservation of mass and momentum.

The heavy gas dispersion model used in CANARY was validated by comparing results obtained from the model with experimental data from field-scale tests. Data used for this comparison and the conditions used in the model were taken from the Burro, Coyote, and Maplin Sands series of dispersion tests. Results of these comparisons are shown in Figure B-4.

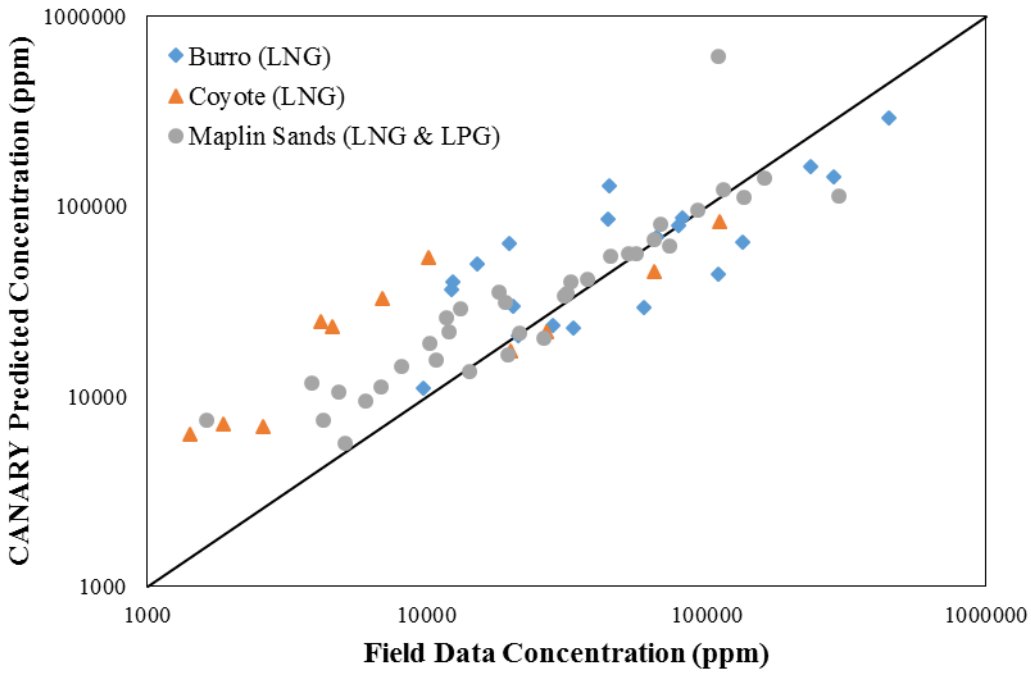

Figure B-4
Heavy Gas Dispersion Predictions Compared to Experimental Data

POOL FIRE RADIATION MODEL

The purpose of this model is to predict the impact of fire radiation emitted by flames fueled by vapors emanating from liquid pools. Specifically, the model predicts the maximum radiant heat flux incident upon a target as a function of distance between the target and the flame. Thermal radiation hazard zones can be then determined for any radiant end points of interest.

The pool fire model incorporates the composition and temperature of the liquid pool, atmospheric conditions such as wind speed, air temperature, and relative humidity. Variables such as elevation of the target, elevation of the pool, and dimensions of the free surface of the pool (rectangular or circular) are accounted for. The dimensions and tilt of the flame (due to wind) are determined using correlations based on thermodynamic properties of the pool and air as well as the size of the pool. A pool fire is divided into two zones: a clear zone in which the flame is not obscured by smoke, and a smoky zone in which a fraction of the flame surface is obscured by smoke. The Surface Emissive Power (SEP) for the clear zone

can be determined by material properties, while the average SEP of the smoky zone is an area-weighted average of the surface fluxes for smoke and the clean-burning areas within the smoky zone. The model defines the flame geometry as a tilted elliptical cylinder over the pool. The surface of the flame is divided into numerous differential areas and the total radiant heat flux to a target is calculated using the SEP, view factors, and atmospheric transmittance.

One of the most notable test series was the Montoir large liquefied natural gas (LNG) pool fires, which involved pools up to 35 meters in diameter [Nédelka, 1989]. Figure B-5 compares the radiation isopleths predicted by CANARY with the actual measurements taken in Test 2 of the Montoir series.

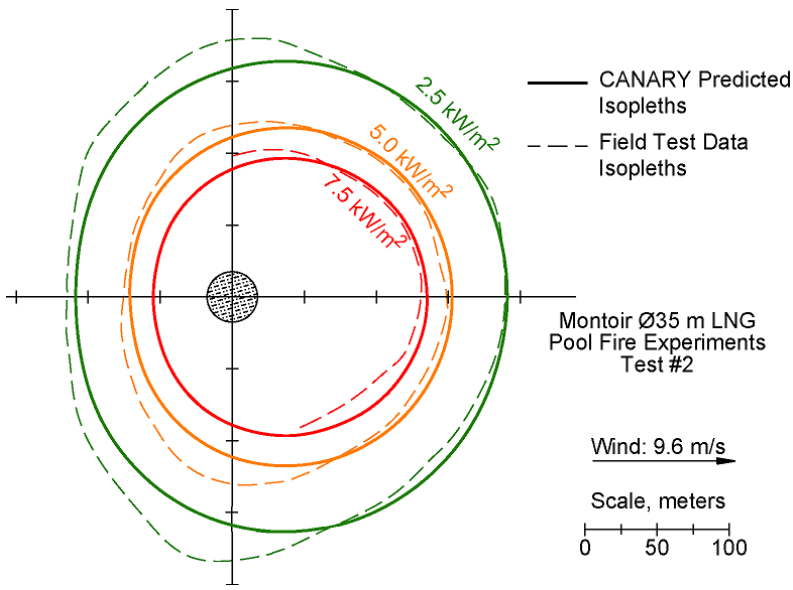

Figure B-5
CANARY Pool Fire Radiation Comparison to Montoir Test #2

TORCH FIRE AND FLARE RADIATION MODEL

The purpose of this model is to predict the extent of fire radiation emitted by burning jets of vapor (jet fire, torch fire, flare fire). Specifically, the model predicts the maximum radiant heat flux incident upon a target as a function of distance between the target and the point of release.

The torch fire and flare radiation model incorporates the composition of the release material, the temperature and pressure of the material before release, the diameter of the release orifice, and the mass flow rate of the release. Environmental factors of wind speed, air temperature and relative humidity are accounted for, as well as geometric factors such as elevation of the target, elevation of the release point, and the angle of release.

Correlations for the length of the flame and flame path are applied to the user-defined parameters. These correlations account for the effects of composition of the released material, diameter of the exit hole, release rate, release velocity, wind speed, and plume buoyancy. The geometric shape of the flame is defined as a frustum of a cone with a hemisphere at the large end of the frustum. The surface of the flame is divided into numerous differential areas and the total radiant heat flux to a target is calculated using the surface emissive power, view factors, and atmospheric transmittance.

Comparisons of experimental data and CANARY model predictions for incident heat flux was done for available data sources. One source of such test data is a report by Chamberlain [1987] concerning test ran by Shell. It contains data from seven flare tests involving natural gas releases from industrial-sized flares. Variables that were examined during these tests include release diameter (0.203 and 1.07 m), release rate, exit velocity, and wind speed. Figure B-6 compares the predicted values of incident heat flux with experimental data from the seven flare tests.

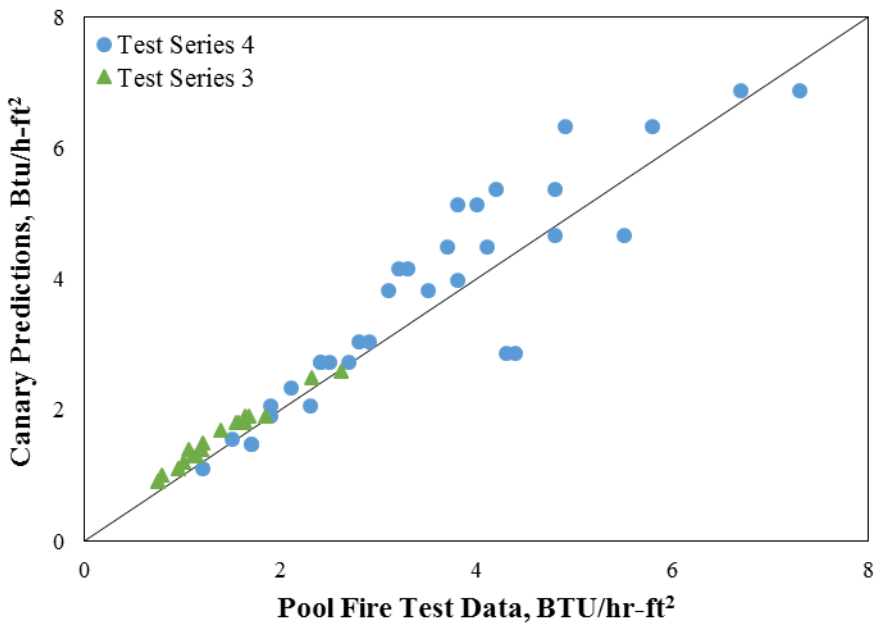

Figure B-6
CANARY Torch/Flare Fire Radiation Comparison to Shell Tests

FIREBALL MODEL

The purpose of the fireball model is to predict the impact of thermal radiation emitted by fireballs that result from catastrophic failures of pressure vessels containing superheated liquids. This event is called a Boiling Liquid Expanding Vapor (BLEVE). Specifically, the model predicts the average radiant heat flux incident upon a grade-level target as a function of the horizontal distance between the target and the center of the fireball.

The fireball model incorporates the composition, mass, temperature and pressure of the flammable liquid contained in the pressure vessel before release. Air temperature and relative humidity are also incorporated to determine the radiant heat flux reaching a target.

The maximum diameter and the duration of the fireball can be calculated from the mass of fuel using empirical correlations. The maximum SEP is computed using the heat of combustion and adjusted for the pressure at the point of the release. The model simulates the fireball as a sphere that grows in time, then lifts off from grade level, with a decreasing SEP as it moves upwards vertically. The view factor between the fireball and a target is determined analytically. The radiant heat flux at a target location is computed using the SEP, view factor, and atmospheric transmittance. Impacts from the fireball are expressed as absorbed energy, average incident flux, and integrated dosage over the duration of the fireball.

Comparisons of experimental data and model predictions for average incident heat flux, absorbed energy, or dosage are needed for model validation. Unfortunately, very few reports on BLEVEs contain the level of detail required to make such comparisons, and no such data are available for large-scale experiments. One of the most complete sources of test data for medium-scale fireball tests is a report by Johnson, Pritchard, and Wickens [Johnson, 1990]. It contains data on five BLEVE tests that involved butane and propane, in quantities up to 2,000 kg. Figure B-7 compares the CANARY predicted values of absorbed energy with experimental data from those five BLEVE tests.

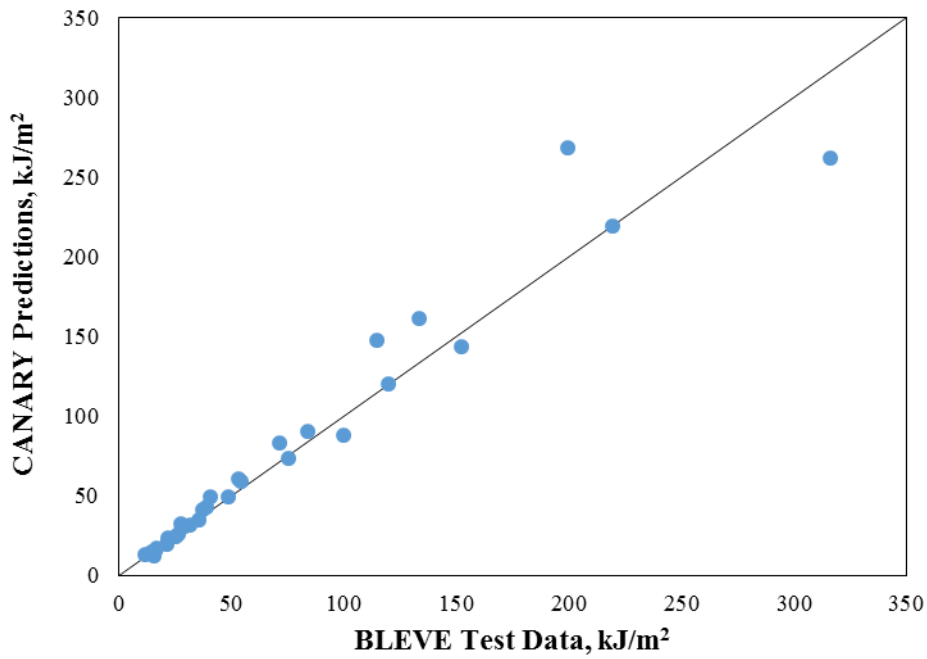

Figure B-7
CANARY Absorbed Energy Comparison to Johnson, Pritchard, and Wickens [1990]

QMEFS VAPOR CLOUD EXPLOSION MODEL

The purpose of this model is to predict the overpressure field that would be produced by the explosion of a partially confined and/or obstructed fuel-air cloud. QMEFS [Marx & Ishii, 2017] is based on experimental data involving vapor cloud explosions, and is related to the amount of confinement and/or obstruction present in the volume occupied by the vapor cloud. The model is based on the Baker-Strehlow-Tang (BST) methodology, and predicts the magnitude of the peak side-on overpressure and specific impulse as a function of distance from the source of the explosion.

In this model the combustion energy is estimated with the mass of fuel in the flammable cloud and its heat of combustion. A stoichiometric mixture of air and fuel is assumed. The fuel properties, volume blockage ratio, obstacle density, confining planes, run-up distance, and volume are provided by the user and used by the model to calculate a flame speed. The peak side-on overpressure and specific impulse at any scaled distance are determined from the calculated flame speed and the BST model blast curves [Baker, 1999].

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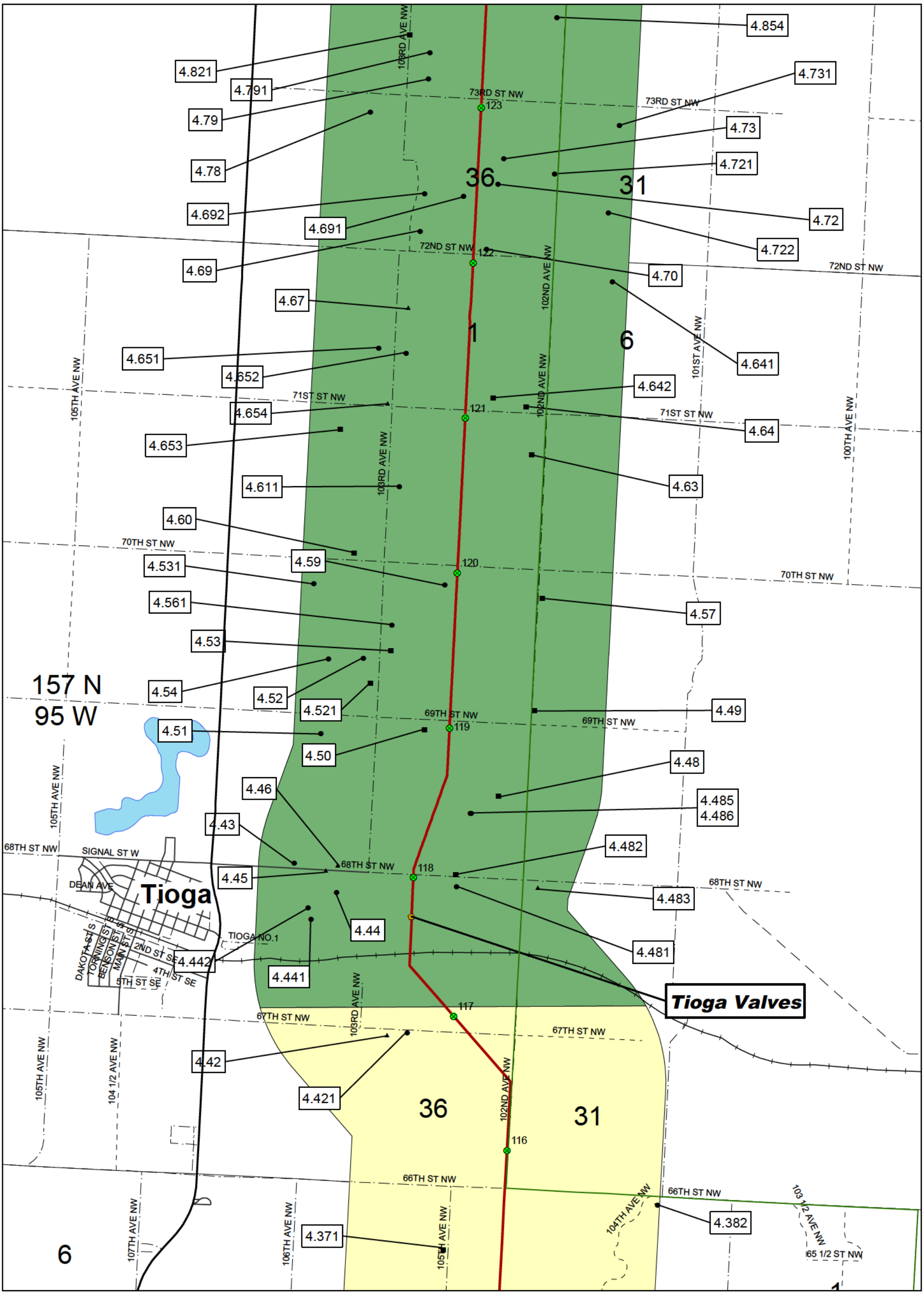

CO2 PIPELINE RECEPTORS WITHIN 1 MILE MAP 11 OF 14

Updated November 27, 2017

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

PLR-28 POPULATION SURVEY INFORMATION

OFFICIAL PIPELINE DOCUMENT

☐ SNG ☒ CO2

Date of Survey: 4/19/18

Receptor number (if already assigned; if not, leave blank): 4.42

Map number (if applicable): 11 of 14

County: Williams Section: 36

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 116

Approximate distance from pipeline (1/10 mile): 0.5

Direction from pipeline (North, South, East, West): Southwest

GPS reading (latitude): 48.386389 (longitude): -102.90361

Name of resident(s):

Name of business, church, school or public use area: Tioga Airport

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): PO Box 428
Tioga, ND 58852

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-641-3417 (Steven Jensen - cell)
- Alternate number (home, work, cell-phone): 507-649-0831 (Chris Nogard)

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: People coming and going during the day; 701-664-2220 (office)
Steven is airport board member & Chris is chairman of the board. Steven is the primary contact and Chris is secondary.

RESPONSIBLE CARE® OUR COMMITMENT TO SUSTAINABILITY

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

PLR-28 POPULATION SURVEY INFORMATION

OFFICIAL PIPELINE DOCUMENT

☐ SNG ☒ CO2

Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.43

Map number (if applicable): 11 of 14

County: Williams Section: NE 26

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 117.2

Approximate distance from pipeline (1/10 mile): 0.7

Direction from pipeline (North, South, East, West): West

GPS reading (latitude): 48.401944 (longitude): -102.91778

Name of resident(s):

Name of business, church, school or public use area: Hess Bakken Investments II

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 3015 - 16th Street SW Suite 20 (land office)
Minot, ND 58701

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: 84 employees Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Occupants are for the plant and north gathering; 1-800-406-1697 (emergency)
10384 - 68th Street NW, Tioga, ND 58852 (plant)

Contact person: Chad Zubke 701-648-9829 (cell); czubke@hess.com

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Date of Survey: 5/3/18

Receptor number (if already assigned; if not, leave blank): 4.44

Map number (if applicable): 11 of 14

County: Williams Section: 26

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 117.2

Approximate distance from pipeline (1/10 mile): 0.5

Direction from pipeline (North, South, East, West): West

GPS reading (latitude): 48.399444 (longitude): -102.91167

Name of resident(s):

Name of business, church, school or public use area: Tesoro High Plains Pipeline - Tioga Station

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 2972 - 108S Avenue SW, PO Box 1207
Dickinson, ND 58601

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-641-1103 (Monica); 701-641-8567 (Andy)
- Alternate number (home, work, cell-phone): 1-866-283-7676 (24 hours)

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Truck facility - trucks coming and going all day; Dickinson main office 701-225-8973 Dennis Hartsoch (field specialist Tioga station) 701-641-1881; Andy Huseby (technical specialist Tioga station) 701-641-8567; Mike Orluck (field specialist Tioga station) 701-641-1124

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Date of Survey: 4/19/18

Receptor number (if already assigned; if not, leave blank): 4.45

Map number (if applicable): 11 of 14

County: Williams Section: SE 23

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 117.3

Approximate distance from pipeline (1/10 mile): 0.6

Direction from pipeline (North, South, East, West): West

GPS reading (latitude): 48.401389 (longitude): -102.91333

Name of resident(s):

Name of business, church, school or public use area: Montana-Dakota Utilities - Substation

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 121 - 8th Avenue West
Williston, ND 58802-1406

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-572-1600; 701-546-7101 (McGregor)
- Alternate number (home, work, cell-phone): 1-800-638-3278 (after hours)

Number of occupants: varies Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: 101 North Main Street, Tioga, ND 58852

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Date of Survey: 5/3/18

Receptor number (if already assigned; if not, leave blank): 4.48

Map number (if applicable): 11 of 14

County: Williams Section: 24

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 118

Approximate distance from pipeline (1/10 mile): 0.3

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.409167 (longitude): -102.88972

Name of resident(s): Kathy Neset

Name of business, church, school or public use area:

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 6853 - 102nd Avenue NW
Tioga, ND 58852

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-664-3563 (home)
- Alternate number (home, work, cell-phone): 701-641-0004 (cell)

Number of occupants: 1 Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience): None

Access instructions (best routes, etc.): Driveway access

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped): None

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: 12 month dwelling; owner of Neset Consulting; Email: kathleenneset@nesetconsulting.com

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Date of Survey: 4/19/18

Receptor number (if already assigned; if not, leave blank): 4.421

Map number (if applicable): 11

County: Williams Section: 36

Township: 157 Range: 95

Approximate distance along pipeline from DGC (1/10 mile): 117.3

Approximate distance from pipeline (1/10 mile): 0.4

Direction from pipeline (North, South, East, West): Southwest

GPS reading (latitude): 48.386731 (longitude): -102.900780

Name of resident(s): (vacant) Used for airplane hangers

Name of business, church, school or public use area: Energyview, LLC

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 10280 67th St NW
Tioga, ND 58852

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-664-1492
- Alternate number (home, work, cell-phone): Kathy Neset 701-664-3563 or 701-641-0004

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.): 67th St NW, just east of Tioga Airport

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Also lot 19, 10270 67th St NW, Tioga (Knutson)
4 large white sheds/shops used for airplane hangars. Neset has 3 shops, Knutson has 1 shop
Mailing address is 6844 Highway 40, Tioga, ND 58852 Kathleen neset@nesetconsulting.com

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Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.441

Map number (if applicable): 11 of 14

County: Williams Section: SWNE 26

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 117.7

Approximate distance from pipeline (1/10 mile): 0.6

Direction from pipeline (North, South, East, West): West

GPS reading (latitude): 48.396802 (longitude): -102.915047

Name of resident(s): _____

Name of business, church, school or public use area: Hess Bakken Investments II or Hess Tioga Gas Plant, LLC

Hours of operation if church, school or public use area (CST/MST): _____

Mailing address (including zip code): 3015 - 16th Street SW Suite 20 (land office)
Minot, ND 58701

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 1-800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: _____ Number of children: _____

Most likely or nearest evacuation center (emergency planning or owner's experience): _____

Access instructions (best routes, etc.): _____

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped): _____

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language? _____

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: _____ Date: _____

Remarks: Well name - Plant Disposal 1; Field name - Tioga; #1078; active
1-800-406-1697 (emergency); 10384 - 68th Street NW, Tioga, ND 58852 (plant)
Contact person: Chad Zubke 701-648-9829 (cell); czubke@hess.com

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Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.442

Map number (if applicable): 11 of 14

County: Williams Section: 26

Township: 157 Range: 95

Approximate distance along pipeline from DGC (1/10 mile): 117.8

Approximate distance from pipeline (1/10 mile): 0.7

Direction from pipeline (North, South, East, West): West

GPS reading (latitude): 48.397857 (longitude): -102.915554

Name of resident(s):

Name of business, church, school or public use area: Hess Corporation

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 10384 - 68th Street NW
Tioga, ND 58852

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 1-800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Control room manned 24/7 (best contact); survey covers Hess gas plant expansion; GPS taken from street address; 3015 - 16th Street SW Suite 20, Minot, ND 58701 (land office) 701-420-6900

Chad Zubke 701-648-9829(cell) czubke@hess.com 701-664-6277 (Tioga Office)

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Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.481

Map number (if applicable): 11 of 14

County: Williams Section: NWNE 25

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 117.9

Approximate distance from pipeline (1/10 mile): 0.3

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.400528 (longitude): -102.894941

Name of resident(s):

Name of business, church, school or public use area: Hess Bakken Investments II

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 3015 - 16th Street SW Suite 20 (land office)
Minot, ND 58701

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 1-800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: TI-Larson-157-95-2536H-1; #16709; active; 1-800-406-1697 (emergency)
10384 - 68th Street NW, Tioga, ND 58852 (plant)
Contact person: Chad Zubke 701-648-9829 (cell); czubke@hess.com

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Date of Survey: 4/23/18

Receptor number (if already assigned; if not, leave blank): 4.482

Map number (if applicable): 11 of 14

County: Williams Section: 24

Township: 157N Range: 95W

Approximate distance along pipeline from DGC (1/10 mile): 118

Approximate distance from pipeline (1/10 mile): 0.3

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.401683 (longitude): -102.89515

Name of resident(s): Arlene Stone (trustee) and Robert Stone (manager)

Name of business, church, school or public use area:

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): Box 488
Eaton, CO 80615

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 303-483-8003 (Arlene - cell)
- Alternate number (home, work, cell-phone): 303-483-8002 (Robert - cell)

Number of occupants: 2 Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience): Basement

Access instructions (best routes, etc.): County 10 - 10249 - 68th Street NW

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped): None

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Arlene lives in Colorado but comes back in the summer; owned by Betty Neset Family Trust; both managers occupy this property about 6 months (May-Oct); Arlene & Robert also have gated farmstead to the east on 68th and 102nd (north side); GPS 48.2418/-102.53143

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Date of Survey: 4/19/18

Receptor number (if already assigned; if not, leave blank): 4.483

Map number (if applicable): 11 of 14

County: Mountrail Section: 30

Township: 157N Range: 94W

Approximate distance along pipeline from DGC (1/10 mile): 118

Approximate distance from pipeline (1/10 mile): 0.8

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.40082 (longitude): -102.88357

Name of resident(s):

Name of business, church, school or public use area: Estvold Oil Field Services

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): PO Box 1191
New Town, ND 58763

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 701-898-8533 (Mike Borgechatz) best #
- Alternate number (home, work, cell-phone): 701-627-2777 (office - dispatch)

Number of occupants: 10+ Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: Arlene Stone is the landowner; Joey Long - Safety Supervisor; 701-897-1809 (Joe - cell)
3962 - 84th Avenue NW, New Town, ND 58763

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Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.485

Map number (if applicable): 11 of 14

County: Williams Section: NWSE 24

Township: 157 Range: 95

Approximate distance along pipeline from DGC (1/10 mile): 118.7

Approximate distance from pipeline (1/10 mile): 0.3

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.40742693 (longitude): -102.8933906

Name of resident(s):

Name of business, church, school or public use area: Hess Bakken Investments II

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 3015 - 16th Street SW Suite 20 (land office)
Minot, ND 58701

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 1-800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: TI-Arlene Stone 157-95-2419H-2; Field name - Tioga; #28723
1-800-406-1697 (emergency); 10384 - 68th Street NW, Tioga, ND 58852
Contact person: Chad Zubke 701-648-9829 (cell); czubke@hess.com

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Date of Survey: 5/5/18

Receptor number (if already assigned; if not, leave blank): 4.486

Map number (if applicable): 11 of 14

County: Williams Section: NWSE 24

Township: 157 Range: 95

Approximate distance along pipeline from DGC (1/10 mile): 118.7

Approximate distance from pipeline (1/10 mile): 0.3

Direction from pipeline (North, South, East, West): East

GPS reading (latitude): 48.40742674 (longitude): -102.8935265

Name of resident(s):

Name of business, church, school or public use area: Hess Bakken Investments II

Hours of operation if church, school or public use area (CST/MST):

Mailing address (including zip code): 3015 - 16th Street SW Suite 20 (land office)
Minot, ND 58701

Phone numbers (include area codes and extensions):

- Primary number (home, work, cell-phone): 1-800-406-1697
- Alternate number (home, work, cell-phone): 281-536-9170 Ben Badon Cell

Number of occupants: Number of children:

Most likely or nearest evacuation center (emergency planning or owner's experience):

Access instructions (best routes, etc.):

Assistance required or special conditions (vehicle/wheelchair needed; physically handicapped):

Is English your primary language? ☒ Yes ☐ No

If not, what is your primary language?

Signature of Receptor *(DGC agrees that the information contained in this survey form will only be used in preparing for and providing emergency response assistance and subject to such utilization, will be maintained on a confidential basis.)*

Signature: Date:

Remarks: TI-Arlene Stone 157-95-2423H-1; Field name - Tioga; #28724
1-800-406-1697 (emergency); 10384 - 68th Street NW, Tioga, ND 58852
Contact person: Chad Zubke 701-648-9829 (cell); czubke@hess.com

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Attachment 4

Supporting Documentation

Process Flow Diagrams
Piping and Instrumentation Diagrams

This section summarizes the technique used to estimate the likelihood of a credible scenario. Frequencies were developed by the likelihood adjustment method. This method takes an initial estimate for the frequency based on team judgment or published data and then adjusts the frequency based on the probability of failure of safeguards designed to mitigate or prevent the scenario. This technique is summarized with the following equation:

$$\text{Likelihood} = IEL \times P_{OCP} \times P_{EC} \times PFD_1 \times PFD_2 \times PFD_3 \times \ldots \times PFD_n$$

Where:

- IEL - Initiating Event Likelihood (failure/year)
- P_{OCP} – Occupancy Factor (probability)
- P_{EC} – Enabling Condition (probability)
- $PFD_1 \ldots PFD_n$ – Probability of Failure on Demand for each safeguard

For the IEL, the below table may be utilized to estimate a general failure rate in events/year for equipment failures:

Equipment Failure Initiating Event Likelihood	
Description	**IEL_L (per year)**
BPCS control loop	1.0×10^{-1}
Pressure regulator failure	1.0×10^{-1}
Pump, compressor, fan or blower failure	1.0×10^{-1}
Localized loss of power	1.0×10^{-1}
Single check valve failure (clean service)	1.0×10^{-1}
Failure of check valves in series (clean service)	1.0×10^{-2}
Pump seal leak (leakage associated with normal seal wear and operation)	1.0×10^{-0}
Complete primary pump seal failure	1.0×10^{-1}
Hose failure, leak and rupture	1.0×10^{-2} to 1.0×10^{-1}
Spurious lift of pressure relief device	1.0×10^{-2}

For the IEL, the below table may be utilized to estimate a general failure rate in events/year for human errors:

Human Error Initiating Event Likelihood		
Description	**IEL**	**Basis**
Human error during a task performed more often than once per week	1.0×10^{-0}	per year
Human error during a task performed only once per week up to once per month	1.0×10^{-1}	per year
Human error during a task performed less than once per month	1.0×10^{-2}	per opportunity

For safeguards, the following table may be used to estimate the probability of failure on demand:

Description	PFD
BPCS control loop	$1.0x10^{-1}$
Safety instrumented system	$1.0x10^{-1}$ to 1.0×10^{-4}
Pressure relief device (PSVs, PRVs, RDs) in clean service	$1.0x10^{-2}$
Multiple redundant pressure relief devices In clean service	$1.0x10^{-3}$
Pressure relief device in plugging, fouling, or polymerizing service	$1.0x10^{-0}$ to $1.0x10^{-2}$
Conservation and vacuum vents	$1.0x10^{-2}$
Frangible roof on tank	$1.0x10^{-2}$
Explosion isolation valves	$1.0x10^{-1}$
Explosion panels	$1.0x10^{-2}$
Excess flow valve	$1.0x10^{-1}$ to $1x10^{-2}$
Restriction orifice	$1.0x10^{-2}$
Single check valve failure (failure to close when required)	$1.0x10^{-1}$ to $1.0x10^{-0}$
Multiple check valves	$1.0x10^{-1}$
Pressure reducing regulators	$1.0x10^{-1}$
Continuous pilot	$1.0x10^{-1}$
Managed valve (captive key/lock system)	$1.0x10^{-2}$
Tandem pump seal	$1.0x10^{-1}$
Mechanical overspeed trip on turbine	$1.0x10^{-1}$
Automated fire suppression systems	$1.0x10^{-1}$
Human response to abnormal condition/alarm	$1.0x10^{-1}$
Human response to abnormal condition/alarm with greater than 24 hours to respond	$1.0x10^{-2}$
PPE	$1.0x10^{-1}$

During the risk analysis, various databases that contain inspection reports, component specification sheets, alarm set points, procedures, incident reports, and MOCs were used to validate the inputs for the frequency analysis. For example, if a PSV was being credited as a safeguard for a blocked outlet case, the operations engineer would be assigned a task to validate the design case.

Attachment 5

DGC Procedure 022 R0

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	Procedure No.: 022	Revision No.: 0
Affected Area(s): All	Originating Department: Plant Management	
	Final Approval: /s/ Dale Johnson	Date: 10/04/18
Procedure Description: Risk Assessment of Facilities Potentially Affecting High Consequence Areas		

I. PURPOSE

A. To define the process utilized for performing a risk analysis of facilities that may affect high consequence areas (HCAs) along the carbon dioxide (CO_2) pipeline. Additionally, to evaluate relevant risk factors at facilities, including those factors that may be unique or specific to facilities.

II. SCOPE

A. This procedure shall be utilized as part of the Integrity Management Plan per the Department of Transportation (DOT) 49 CFR 195.452. This procedure provides guidance for prioritizing threats posed from facilities that potentially affect HCAs.

III. REFERENCES

A. 49 CFR 195 – Transportation of Hazardous Liquids by Pipeline

B. 49 CFR 195.452 – Pipeline Integrity Management in High Consequence Areas

C. API 1160 – Managing System Integrity for Hazardous Liquid Pipelines

D. DGC Form 1642 - Process Hazard Analysis Recommendation Resolution

E. DGC Pipeline Safety Risk Matrix

IV. DEFINITIONS

A. High consequence area (HCA) − An HCA can be defined as any of the following:

1. *Commercially navigable waterway* − A waterway where commercial navigation exists.

2. *High population area* − An urbanized area, as defined and delineated by the Census Bureau, which contains 50,000 or more people, and has a population density of at least 1,000 people per square mile.

3. *Other populated area* − A place, as defined and delineated by the Census Bureau, which contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.

   a. *Office of Pipeline Safety (OPS) identified* – Areas the OPS has identified as meeting the criteria of an other populated area.

B. Unusually sensitive area (USA) − A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release as defined in 49 CFR Part 195.6.

C. Active safeguard – Safeguards which detect and then respond to process deviations. These safeguards directly prevent hazards from occurring, provide notification so that a human may respond to a condition, or may mitigate the hazard.

D. Administrative controls – A procedural requirement for directing and/or checking engineered systems or human performance associated with plant operations (i.e., operating procedures, lockout/tagout/training, car seal system, and safety procedures).

E. Basic Process Control System – A control system, generally within the Distributed Control System, that safeguards against hazards or maintains a system within a safe operating envelope.

F. Catastrophic release – A major uncontrolled emission, fire, or explosion, involving one or more highly hazardous chemicals that presents serious danger to workers, the public, or the environment.

G. Cause – Actions or events that could result, directly or indirectly, in the initiation of an undesirable process condition.

H. Consequence – Direct, undesirable result of a deviation. Typically measured in health and safety effects, environmental impacts, loss of property, and business interruption costs.

I. Credible scenario – A cause/consequence pairing with a reasonable and documented/validated probability of occurring (e.g. an overpressure event leading to injury to personnel when the pump curve indicates the pump is capable of achieving a pressure over design).

J. Deviation – Departure from the intended operation/function of a process or pre-established operating or design limit.

K. Double jeopardy – Concurrent incidence of multiple, independent, and unrevealed initiating events.

L. Escalation event – An event with cascading failures. An example would be a catastrophic failure of a piece of rotating equipment resulting in the failure of another piece of equipment due to a secondary event such as a fire spreading.

M. Engineering Controls – A hardware or software system designed to maintain a process within safe operating or design limits, to safely shut it down during a process upset, or to reduce human exposure to the effects of an upset (e.g. pressure relief devices, interlocks, and control valve failure positions).

N. EXP-DIR – Electronic software/database system used to review, manage, communicate, document, and approve an action item from a risk assessment.

O. Guideword – Words such as high, low, no, more, or less, which are used in conjunction with parameters to analyze deviations.

P. Hazard and Operability (HAZOP) Analysis – Qualitative risk assessment technique utilizing guidewords and deviations to systematically assess process risks.

Q. Node – A small portion of a process identified for process hazard analysis.

R. Operability – Ability to operate a process within its design intention.

S. Parameter – Measurable process conditions such as pressure, temperature, and level, which when combined with guidewords, are utilized to identify and analyze process deviations.

T. Passive safeguard – Safeguards based on design features and do not require any external input to function. Generally, passive safeguards mitigate a consequence to a less severe event; an example would be a dike wall or drainage designed for a specific consequence.

U. Procedural safeguard – Safeguards that utilize human response to mitigate or prevent a consequence. Examples include procedural checks, administrative checks, operator checks, and corrective actions.

V. Risk – The resulting intersection of severity and frequency in the risk matrix utilized to measure potential loss (human, environmental, economic).

W. Risk matrix – A chart that shows the event frequency ranges versus the consequence ranges, along with likelihood and consequence categories, to determine the tolerability of risk in a given category. The risk matrix is used to standardize judgments about risks.

X. Safeguard – A device, system, or action for reducing the frequency and/or severity of the consequences of a deviation.

Y. What–if analysis – A risk assessment technique that utilizes brainstorming based on a list of questions or concerns addressing hazards, hazardous situations, or specific accident events that can produce an undesirable consequence in a system or process and qualitatively judges the adequacy of existing safeguards.

V. RESPONSIBILITIES

A. Plant Management

1. Provides the necessary resources to maintain the facility risk assessment process.
2. Provides the necessary resources to implement approved preventive and mitigative measures.

B. Pipeline Superintendent

1. Review recommended preventive and mitigative measures and determine if the recommended measures should be implemented.

C. Compliance, Safety, and Industrial Hygiene Superintendent

1. Provides personnel knowledgeable in risk assessment methodologies.
2. Responsible for ensuring a risk analysis report is produced and distributed to appropriate stakeholders.

VI. INSTRUCTIONS

A. General considerations

1. The goals of risk assessment are as follows:

   a. Identify the threats to facility integrity.

   b. Determine the risk represented by these threats and the consequences to critical locations.

   c. Rank facilities in the order of greatest need for integrity assessment or mitigative action, if applicable.

   d. Compare different integrity assessment or mitigation options in terms of the risk reduction benefits and costs.

   e. Facilitate reassessment and re-ranking once the integrity assessments and mitigative actions have been completed.

2. Risk assessments are not static and do not deliver absolute certainty with regard to scheduling integrity assessments or other preventive and mitigative activities. However, it does offer a methodology with which to start an integrity assessment program, and if allowed to evolve with experience, it becomes a tool for continual planning of integrity assessments.

3. Risk assessments for facilities potentially affecting HCAs shall be conducted if one of the following conditions are met:

   a. Prior to startup of a new facility potentially affecting HCAs

   b. Within six months of a change that requires a revised risk assessment

   c. Within six months of a change that requires a revised consequence analysis (e.g. new process, new facility, operational change, HCA changes, equipment changes).

4. Team composition

   a. Risk assessments for facilities shall be performed by an experienced team knowledgeable in the process technology and operations. The team shall be comprised of essential personnel who are required to be present for the entire duration of the risk assessment and support personnel who shall be available for the duration of the risk assessment.

      (1) *Essential personnel* – The following roles are considered essential. A risk assessment shall not proceed without representation of at least the following competencies:

         (a) *Process knowledgeable representative* – Shall have detailed technical experience and knowledge of the process technology being assessed. This experience should include knowledge of the

chemistry, engineering, equipment, and safety equipment utilized within the process being analyzed.

(b) *Process operations representative* – Shall have operational knowledge of the process technology being assessed. This experience should include working knowledge of the safety equipment, controls, history, physical layout, and procedures utilized within the process being analyzed.

(c) *Pipeline engineer* – Shall have detailed technical experience and knowledge of the process technology being assessed. This experience should include knowledge of the engineering, equipment, pipeline integrity management activities, and safety equipment.

(d) *Person knowledgeable of the risk assessment technique* – Shall have detailed experience and knowledge of the risk assessment technique being utilized as well as a knowledge of the process sufficient to understand the plant processing operations being discussed, capture relevant details, and to control the discussion.

(e) *Mechanical engineer/maintenance engineer (fixed equipment) or inspection representative* – Shall have detailed experience and working knowledge of mechanical integrity threats specific to facilities (e.g. external corrosion, internal corrosion, manufacturing defects, construction defects, equipment failure, and cycle induced fatigue).

(f) *Maintenance engineer (rotating equipment)* – Shall have detailed experience and working knowledge of pumps, compressors, and/or fans associated with facilities.

(2) *Support personnel* – Additional personnel may be required and shall be identified during the planning phase of the risk assessment.

5. Acquiring and integrating data in risk assessment

a. The data to be gathered and integrated shall be of sufficient quality and breadth so that it can be used in the risk assessment to help identify relevant threats that could affect the integrity of the facility. Examples of data include:

(1) Attributes of each facility that bear on the susceptibility to various integrity threats

(2) Construction factors that could affect the susceptibility to various integrity threats

(3) Operating parameters that could affect the susceptibility to various integrity threats

(4) Assessment histories that may indicate susceptibility to various integrity threats

(5) Release history

B. Risk assessment approach

1. A combination of the following risk assessment methods may be used to determine and evaluate the risks posed by facilities:

   a. Hazard and Operability (HAZOP) Analysis

   b. What-if Analysis

   c. Appropriate equivalent methodology that evaluates specific risks of facilities

2. HAZOP analysis methodology

   a. HAZOP methodology may be used to provide an analysis of threats posed from incorrect operations and equipment failure.

   b. HAZOP methodology is not suitable for analyzing all threats posed to facilities. Additionally, planning for certain non-credible scenarios is not reasonable. Therefore, the following scenarios are excluded from the HAZOP methodology:

      (1) Double jeopardy events.

      (2) Occupational, health, and safety events – Events such as slips, trips, falls, ergonomics, and walking/working surfaces shall be addressed via the Safety Management System and are not covered by facility risk.

      (3) Events initiated by failure of control of work practices – Failure of control of work practices (i.e. safe work permitting, hot work permitting, lock out - tag out, confined space entry, and the bolted joint procedure) shall not be considered initiating events.

      (4) Engineering design errors – It shall be assumed that the process being evaluated has been designed in accordance with good engineering practices.

      (5) Escalation events – The development of a credible scenario shall terminate at the loss event caused from the process deviation.

      (6) Initiating events that do not cause a loss event within 24 hours may be excluded at the discretion of the team. This is intended to exclude events that are progressive in nature such as corrosion/erosion/seal damage and are generally identified and corrected prior to a catastrophic failure. Failures that will result in a sudden catastrophic failure and are unrevealed are not exempted. “What-if” methodology is more suitable for these scenarios.

      (7) Events initiated by natural disasters, terrorism, sabotage, or a third-party. “What-if” methodology is more suitable for these scenarios.

c. HAZOP workflow – Facility risk assessment using HAZOP follows the following seven step process:

(1) Establishment of node boundaries

(a) Nodes shall be developed prior to HAZOP and shall be identified with highlighted piping and instrumentation diagrams (P&IDs).

(b) Safe operating limits for the node under analysis shall be reviewed during the risk analysis. These limits are the critical parameters that define when a deviation occurs. Generally, these consist of the following design parameters: pressure, temperature, flow rates, and stream compositions. These parameters effectively describe the process safe operating limits.

(2) Deviations

(a) Deviations consist of a guideword/parameter pair, such as “high” and “pressure.” This pairing results in the deviation “high pressure.” Additionally, generic deviations may be specified to review specific risks associated with a node (e.g. relief systems, management of change, abnormal operations, and previous incidents).

(b) Table 1 lists examples of how parameters and guidewords may be combined to form deviations.

TABLE 1: GUIDEWORD-PARAMETER COMBINATIONS

GUIDEWORD / PARAMETER	No Not None	Less Low Short	More High Long	As well as / Misdirected	Other than	Reverse
Pressure	N/A	Low Pressure	High Pressure	N/A	N/A	Vacuum
Temperature	N/A	Low Temperature	High Temperature	N/A	N/A	N/A
Level	N/A	Low Level	High Level	High/Low Interface	N/A	N/A
Flow	No Flow	Low Flow	High Flow	Misdirected Flow	N/A	Reverse Flow
Reaction	N/A	Low Reaction Rate	Runaway Reaction	Partial Reaction	Side Reaction	Decomposition
Composition	N/A	N/A	Extra Material	Impurities	Wrong Material	N/A
Procedure	Skipped Step	Too Short/Little	Too Long/Much	Additional Action	Incorrect Action	Opposite Action
Speed	Stopped	Too Slow	Too Fast	N/A	Out of Sync	Reverse Direction
Other	Utility Failure Sampling	Leak/Rupture	Startup Shutdown	Maintenance Previous Incidents	N/A	N/A

(3) Causes

(a) Causes are brainstormed and identified for each deviation. Only credible causes are to be evaluated and documented.

(b) Where a single cause may fall under multiple deviations, the cause shall only be documented a single time. For example, a pressure control valve failing open may result in high pressure as well as high flow, but shall only be recorded under one location or the other.

(c) Deviations with no credible causes shall be documented as “no credible cause identified” and deviations with no unique causes (all causes captured by other deviations) shall be documented as “no additional causes identified.”

(4) Consequence evaluation

(a) Each cause shall have consequences developed globally without regard to node boundaries.

(b) Consequences are only fully developed into scenarios where the cause results in a safe operating limit potentially being exceeded. A cause that results in no significant consequence would be documented as “scenario considered, but no consequence of interest identified.”

(c) Consequence developed shall assume that all active safeguards fail. Passive safeguards may be assumed to still function at the discretion of the team.

(d) Consequences shall reference equipment tags.

(e) Scenario consequence are to be developed by the immediate consequence of interest (no escalation of event). Team should base severity on the most severe plausible outcome.

(f) Risks that are associated with economic or environmental consequences are outside the scope of the risk assessment.

(5) Safeguards

(a) Active safeguards shall be identified and reviewed against process safety information (PSI) for effectiveness. For example, a relief valve protecting against a blocked outlet case is to be reviewed against the relief device sizing documentation and found to be sized adequately for the blocked outlets scenario, a temperature alarm is to be confirmed to be set below safe operating limits.

(b) Active safeguards shall have adequate response time to safeguard against the scenario developed. For example, an alarm that affords credit for an operator to respond, includes adequate time for an operator to notice the alarm, determine appropriate action, and complete any tasks required. These durations shall be based on team judgment and experience for HAZOP assessments.

(c) Administrative or procedural safeguards (e.g. procedures or manuals) shall be documented.

(6) Scenario frequency evaluation

(a) Frequencies shall be developed by the likelihood adjustment method. This method takes an initial estimate for the frequency based on team judgment or published data and then adjusts the frequency based on the probability of failure of safeguards designed to mitigate or prevent the scenario.

(7) Risk ranking

(a) Based on the results of the consequence evaluation and the scenario frequency evaluation, scenarios are to be risk ranked to determine a risk priority level. The risk priority level is defined by the DGC Pipeline Safety Risk Matrix.

3. What-if methodology

a. What-if methodology may be used to provide an analysis of the threats posed from facilities that may not be adequately analyzed using HAZOP. Generally, HAZOP takes the cause of the scenario into account when calculating risk,

severity, and likelihood of the scenario. The what-if analysis simply considers what the outcome would be if the given scenario were to occur. This allows the what-if analysis to cover a range of scenarios that could be overlooked using the HAZOP analysis.

b. In this method, a scenario is described by asking what the consequences of a facility threat would be. For example, "*What if* the facility experiences external corrosion at the soil-to-air interface?" or "*What if* there was localized soil movement that exposed the pipe?"

c. What-if workflow – Facility risk assessment using what-if methodology follows the following six-step process:

(1) Topic/Guideword

(a) A list of relevant threats to the integrity of the facility shall be identified for discussion.

(2) What-if/Causes

(a) The team shall develop scenarios identified as having a reasonable probability of occurring by asking, "*What if* X occurred?".

(3) Consequence evaluation

(a) The team shall determine the consequences of the scenarios which have a reasonable probability of occurrence and document the severity of the outcome.

(4) Safeguards

(a) A list of safeguards used to prevent or mitigate scenario consequences is to be developed.

(5) Scenario frequency evaluation

(a) Frequencies shall be developed by the likelihood adjustment method. This method takes an initial estimate for the frequency based on team judgment or published data and then adjusts the frequency based on the probability of failure of safeguards designed to mitigate or prevent the scenario.

(6) Risk ranking

(a) Based on the results of the consequence evaluation and the scenario frequency evaluation, scenarios shall be risk ranked to determine a risk priority level. The risk priority level is defined by the DGC Pipeline Safety Risk Matrix.

C. Recommended preventive and mitigative measures from risk assessments

1. Risk assessment shall continually identify preventive and mitigative measures to be considered for implementation. As integrity assessments, remediations, and

mitigative actions are carried out, the particular risk assessment method used can be validated, improved, or replaced if necessary to conform with the experience gained through integrity management activities

2. Preventive and mitigative measures for facilities shall be identified and prioritized based on the results of risk assessments.

3. Recommended preventive and mitigative measures for facilities shall be reviewed by the pipeline superintendent.

   a. If the pipeline superintendent determines preventive and mitigative measures recommended from the risk assessment are required, the preventive and mitigative measures shall be implemented.

      (1) Preventive and mitigative measures to be implemented shall be tracked with the EXP-DIR system.

   b. The pipeline superintendent may justifiably decline to adopt a recommendation where the reason is documented in writing and adequate evidence given that one or more of the following are true:

      (1) The analysis upon which the recommendation is based contains material factual error.

      (2) The recommendation does not significantly reduce risk posed to the health and safety of employees, employees of a contractor, or the public.

      (3) An alternative measure would provide a sufficient level of protection.

      (4) The recommendation is unfeasible.

   c. Should the pipeline superintendent determine to justifiably decline a recommendation, the reason is documented and signed in the Process Hazard Analysis Recommendation Resolution form (DGC 1642). The signed form shall be attached to the recommendation in EXP and the recommendation is closed.

VII. RECORDS

A. Results of risk assessments shall be documented and distributed to appropriate stakeholders by the compliance, safety, and industrial hygiene superintendent, or designee.

B. All reports and documentation required or produced by this procedure shall be considered records, and shall be filed for the life of the facility in the appropriate electronic folder located in Altien under *DGC / Pipelines / Integrity Management.*

DAKOTA GASIFICATION COMPANY
A BASIN ELECTRIC POWER COOPERATIVE SUBSIDIARY

DAKOTA GASIFICATION COMPANY PROCEDURE

Origination Date:	**Procedure No.:** 029	**Revision No.:** 4
Affected Area(s): CO_2 Pipeline	**Originating Department:** Engineering	
	Final Approval: /s/ Dale Johnson	**Date:** 10/02/18
Procedure Description: Identification of High Consequence Areas Along the Carbon Dioxide Pipeline		

I. PURPOSE

A. To define the process utilized to identify the high consequence areas (HCAs) along the carbon dioxide (CO_2) pipeline. This procedure shall be used to support the Integrity Management Plan.

II. SCOPE

A. HCAs shall be identified for the Integrity Management Plan using technically justified methods that conform with the requirements of 49 CFR Part 195.452.

B. This procedure covers the Dakota Gasification Company (DGC) carbon dioxide pipeline that runs from DGC near Beulah, ND, to the oil fields near Goodwater, Saskatchewan. Active and idle lines are covered by this procedure.

III. REFERENCES

A. 49 CFR Part 195 − Transportation of Hazardous Liquids by Pipeline

B. 40 CFR Part 141 − National Primary Drinking Water Regulations

C. 40 CFR Part 143 − National Secondary Drinking Water Regulations

D. "*Impact Probability Analysis of Accidental Carbon Dioxide and Hydrogen Sulfide Exposures Associated with the Dakota Gasification Company CO_2 Pipeline Project*", ENSR and TetraTech EM, January 1998

E. "*Environmental Assessment Study*", ENSR, June 1998

F. "*Release and Dispersion Calculations for the Dakota Gasification Company Carbon Dioxide Pipeline*", Quest Consultants Inc., September 2017

G. "*Updated Dispersion Modeling for the CO_2 Pipeline*", File-9450-CCB-17-019

H. "*PHMSA Corrective Action: Carbon Dioxide Pipeline Topographic Assessment*", File-9450-CCB-18-002

I. National Waterways Network (NWN) database

J. CO2 Pipeline Integrity Management Plan

K. DGC Procedure No. 038 − CO_2 Pipeline Annual Report

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IV. DEFINITIONS

A. High consequence area (HCA) − An HCA can be defined as any of the following:

1. *Commercially navigable waterway* − A waterway where commercial navigation exists.
2. *High population area* − An urbanized area, as defined and delineated by the Census Bureau, which contains 50,000 or more people, and has a population density of at least 1,000 people per square mile.
3. *Other populated area* − A place, as defined and delineated by the Census Bureau, which contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area.
   a. *Office of Pipeline Safety (OPS) identified* – Areas the OPS has identified as meeting the criteria of an other populated area.

B. Unusually sensitive area (USA) − A drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release as defined in 49 CFR Part 195.6.

V. RESPONSIBILITIES

A. Pipeline superintendent

1. Responsible for overseeing the implementation of this procedure to ensure compliance with 49 CFR Part 195.
2. Provide operational support and resources to perform inspections and population surveys to identify potential changes to HCA list.
3. Responsible for informing pipeline engineer if potentially new HCAs are identified during routine pipeline right-of-way (ROW) ground inspections, aerial inspections, or population survey.

B. Pipeline engineer

1. Responsible for the positive identification of an HCA.
2. Responsible for keeping the HCA list and map up to date.
3. Responsible for submitting an annual report identifying all HCAs.

C. Reliability engineering supervisor

1. Provide support and resources to pipeline engineer.

VI. INSTRUCTIONS

A. HCAs shall be identified through the creation of a pipeline corridor. The pipeline corridor shall be established by defining an impact zone using technically justifiable methods. Refer to "*Updated Dispersion Modeling for the CO2 Pipeline*" (File-9450-CCB-17-019) and "*PHMSA Corrective Action: Carbon Dioxide Pipeline Topographic Assessment*" (File-9450-CCB-18-002) for technical documentation used to establish the pipeline corridor.

B. In the event of a leak or a rupture on the pipeline, four hazard zones shall be considered around the pipeline.

1. First zone − This zone is a physically disturbed zone. This is an area where the force of the pressurized fluid escaping causes the earth around it to be physically moved. This zone is important for any USAs that include archeological finds. Prior to the pipeline route selection, an environmental assessment study was done and any area found to have any cultural significance was avoided. Because of this there will be no HCAs physically disturbed by a release. This information can be found in the Environmental Assessment Study done by ENSR and located in Records Management System (RMS) M00004424.

2. Second zone − This zone is a cold zone due to the immediate cooling around the leak area due to the Joule-Thompson effect of the depressurizing carbon dioxide (CO_2). This will only be of significance for large leaks or ruptures. This phenomenon will freeze anything in the local vicinity of the leak/rupture.

3. Third zone − This zone is the area affected by a CO_2 release. This is an area where the concentration of CO_2 is above the immediately dangerous to life or health (IDLH) level established by Occupational Safety and Health Administration (OSHA). This zone is presented in the air dispersion report done by ENSR and TetraTech, as well as the air dispersion report done by Quest Consultants Inc.

4. Fourth zone − This zone is the area affected by a hydrogen sulfide (H_2S) release. This will be the largest zone and is presented in the air dispersion report done by ENSR and TetraTech, as well as the air dispersion report done by Quest Consultants Inc. Since this zone has the largest impact distance, this zone shall be the governing factor in determining if a release can affect an HCA.

C. Engineering is responsible for the initial identification of an HCA, as well as maintaining the list of HCAs.

1. Methods of identifying HCAs include, but are not limited to, the following:

a. National Pipeline Mapping Service (NPMS)

(1) This is a service of the Department of Transportation (DOT), Research and Special Programs Administration (RSPA), and the Office of Pipeline Safety (OPS). It can be found at http://www.npms.rspa.dot.gov/. This site shall be checked periodically for updates, or when a change to OPS-identified HCA areas is known to have happened.

b. Pipeline patrol

(1) Routine pipeline patrol as required by 49 CFR Part 195.412 shall be utilized to identify potential HCAs.

c. Receptor Survey

(1) Per requirements set forth by 49 CFR Part 195, DGC is required to conduct a population survey.

d. National Waterways Network

(1) National Waterways Network (NWN) database is the basis the Pipeline and Hazardous Material Administration (PHMSA) uses to identify commercially navigable waterways. PHMSA's use of this database replaced the use of the prior United States Coast Guard (USCG) designation. http://www.navigationdatacenter.us/data/datanwn.htm

2. All newly identified HCAs shall be added to the high consequence areas map of the CO_2 pipeline.

D. Types of HCAs

1. Commercially navigable waterway

a. There are no commercially navigable waterway HCAs currently in North Dakota.

2. Unusually sensitive area (USA)

a. Drinking Water

(1) There will be no affect in the event of a leak or rupture. The carbon dioxide poses no pollution threat to drinking water according to the letter from the Office of Pipeline Safety (OPS) to Mr. Wayne Rickard of DGC located in the CO_2 Pipeline Integrity Management Plan (Appendix K).

(2) The Environmental Protection Agency (EPA) has set both primary and secondary national drinking water standards in accordance with the Safe Drinking Water Act (SDWA). Primary drinking water standards set legally enforceable limits on certain contaminants that could threaten public health. Secondary drinking water standards are set for certain contaminants that may impact the aesthetics of drinking water quality, but do not pose a risk to human health. Primary drinking water standards can be found in Title 40 of the Code of Federal Regulations (40 CFR) 141 and the secondary drinking water standards can be found in 40 CFR 143. There are no primary or secondary national drinking water standards set for hydrogen sulfide (H_2S).

b. Ecological

(1) If an area is identified as an ecological resource area, it must be determined as to what is the ecological reason it has been identified. The type of resource it is shall determine what affect a pipeline leak or rupture will have on it.

c. Highly populated areas

(1) There are currently no highly populated areas within the established pipeline corridor.

d. Other populated areas

(1) If the pipeline or pipeline corridor pass through a populated area, that area is considered an HCA.

(2) All water crossings of the pipeline including lakes, rivers, streams, creeks and dry creeks, must be identified not only where they cross the pipeline, but also when they are located in the pipeline corridor. These are areas where a release could be constrained by banks and travel at a slow rate and not dissipate as quickly as anticipated. Refer to "*Updated Dispersion Modeling for the CO2 Pipeline*" (File-9450-CCB-17-019) and "*PHMSA Corrective Action: Carbon Dioxide Pipeline Topographic Assessment*" (File-9450-CCB-18-002) for technical documentation used to establish the pipeline corridor.

(3) The gas released would have a higher vapor density than air so it could travel downhill or channel in valleys. Due to this, topography was taken into account while establishing the pipeline corridor. Refer to "*Updated Dispersion Modeling for the CO2 Pipeline*" (File-9450-CCB-17-019) and "*PHMSA Corrective Action: Carbon Dioxide Pipeline Topographic Assessment*" (File-9450-CCB-18-002) for technical documentation used to establish the pipeline corridor.

3. Documenting the HCA

a. When the OPS issues new HCA information on their website, the information shall be downloaded and overlaid on the current HCA map to determine if any changes impacting the established pipeline corridor have been made.

b. If a new HCA is identified during the routine pipeline ROW inspections and aerial surveys, Process Operations shall inform Engineering about the location(s). Process Operations shall furnish the latitude and longitude of the HCA, as well as the type of HCA (i.e. population, environmental, etc).

(1) This information could include:

(a) New residences along the pipeline

(b) Changes in terrain or environment along the pipeline

(c) Third party activity along the pipeline

(d) Any other type of physical changes that could have an impact on an HCA

c. Engineering shall input all data into the HCA map for analysis.

d. Any new locations that meet the criteria for high consequence area shall be added to the list of HCA's located in the Integrity Management Program document for the CO_2 pipeline. The name of the HCA and the date it was added shall be documented. The Pipeline Engineer shall be responsible for keeping the HCA list and map up to date.

e. The pipeline engineer shall issue an annual report identifying all high consequence areas along the pipeline. This report shall be issued to the plant manager, the operations manager, the pipeline superintendent, the maintenance manager, and the engineering manager.

VII. RECORD RETENTION

A. All reports and documentation required or produced by this procedure shall be considered records, and shall be filed for the life of the pipeline in the appropriate electronic folder located in Altien under *DGC / Pipelines / Integrity Management*.