Fuels Safety Program	Ref. No.: FS- 087- 06	Rev. No.:
DIRECTOR'S ORDER	Date: August 15, 2006	Date:

IN THE MATTER OF:
THE TECHNICAL STANDARDS AND SAFETY ACT, 2000, S.O. 2000, c. 16

- and -

ONTARIO REGULATION 223/01 (Codes and Standards Adopted by Reference)
- and –
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ONTARIO REGULATION 210/01 (Oil and Gas Pipeline Systems)

Subject: Amendment to the Oil and Gas Pipeline Systems Code Adoption Document
Sent to: Gaseous Fuels Advisory Council, Pipeline RRG, Posted on TSSA's Web-Site

The Director of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems) pursuant to section 8 of Ontario Regulation 223/01 (Codes and Standards Adopted by Reference) hereby provides notice that the Oil and Gas Pipeline Systems Code Adoption Document published by the Technical Standards & Safety Authority and dated June 1, 2001, as amended, is amended as follows:

All sections of the Oil and Gas Pipeline Systems Code Adoption Document (Sections 1 to 5) are revoked and replaced with the following:

Section 1

REFERENCE PUBLICATIONS

1.(1) The reference publications as set forth herein are approved by the Director and adopted as part of this Document and the standards, procedures and requirements therein, as applicable to this Document, shall be complied with by operating companies as well as anyone engaged in the design, construction, erection, alteration, installation, testing, operation or removal of a pipeline, for the transmission of oil or gas or the distribution of gas.

Government of Ontario

Technical Standards & Safety Act, 2000, Ontario Regulation 220/01 (Boilers and Pressure Vessels)

Canadian Standards Association

Service Regulators for Natural Gas, CSA 6.18-02

Section 2

GENERAL REQUIREMENTS

2. (1) The Standards issued by the Canadian Standards Association entitled Oil and Gas Pipeline Systems Z662-03, as amended by this Director's Order, and CSA Z276-01 Liquefied Natural Gas (LNG) – Production, Storage and Handling and the standards, specifications, codes and publications set out therein as reference publications insofar as they apply to the said Standards are adopted as part of this Document, with the following changes for the CSA-Z662-03 Standard:

(2) Clause 1.2 is amended by adding the following item:

(g) pipelines that carry gas to and from a well head assembly of a designated storage reservoir.

(3) Clause 1.3 is amended by adding the following items:

(p) digester gas or gas from landfill sites
(q) multiphase fluids
(r) gathering lines
(s) offshore pipeline systems
(t) oil field steam distribution pipeline systems oil field water services
(u) carbon dioxide pipeline systems.

(4) Clause 4.1.6 is revoked and the following substituted:

4.1.6 Subject to prior review by the Director, it shall be permissible for steel oil and gas pipelines to be designed in accordance with the requirements of Annex C, provided that the designer is satisfied that such designs are suitable for the conditions to which such pipelines are to be subjected.

(5) Clause 7.10.2.2 is revoked and the following substituted:

7.10.2.2 For HVP and for sour service pipeline systems, all butt welds shall be inspected by radiographic or ultrasonic methods, or a combination of such methods, for 100% of their circumferences, in accordance with the requirements of clause 7.10.4.

(6) Clause 10.4.10 is amended by adding the following clauses:

10.4.10.7 Operating companies shall inform agencies to be contacted during an emergency, including the police and fire departments about the hazards associated with its pipelines.

10.4.10.8 Operating companies shall prepare an emergency response plan and make it available to local authorities.

(7) Clause 10.5 is amended by adding the following clause:

10.5.5 Right-of-Way Encroachment

10.5.5.1 It shall be prohibited to install patios or concrete slabs on the pipeline right-of-way or fences across the pipeline right-of-way unless written permission is first obtained from the operating company.

10.5.5.2 It shall be prohibited to erect buildings including garden sheds or to install swimming pools on the pipeline right-of-way. Storage of flammable material and dumping of solid or liquid spoil, refuse, waste or effluent, shall be also forbidden.

10.5.5.3 Operating companies shall be allowed to erect structures required for pipeline system operation purposes on the pipeline right-of-way.

10.5.5.4 No person shall operate a vehicle or mobile equipment except for farm machinery and personal recreation vehicles across or along a pipeline right-of-way unless written permission is first obtained from the operating company or the vehicle or mobile equipment is operated within the traveled portion of a highway or public road.

10.5.5.5 Operating companies shall develop written procedures for periodically determining the depth of cover for pipelines operated over 30% of SMYS. Such written procedures shall include a rationale for the frequency selected for such depth determinations. Where the depth of cover is found to be less than 60 cm in lands being used for agriculture, an engineering assessment shall be done in accordance with clause 10.11.2 and a suitable mitigation plan shall be developed and implemented to ensure the pipeline is adequately protected from hazards.

(8) Clause 10.11.2 is amended by adding the following items:

10.11.2.6 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under subsections 18.(1) 1, 18(1) 3 and 16 (6) of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems).

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause
- i. a hazard to the safety of the public or to the employees of the operating company
- ii. an adverse effect to the environment or to property, or

c) the Director wishes to assess the operating company's pipeline integrity management program.

10.11.2.7 For the protection of the public, the pipeline, and the environment, an operating company shall develop a pipeline integrity management program for steel pipelines with a MOP of 30% or more of the SMYS. The pipeline integrity management program shall contain:

a) a management system,
b) a working records management system,
c) a condition monitoring program, and
d) a mitigation program.

10.11.2.8 When developing the pipeline integrity management program, an operating company shall consider Z662S1-05 Supplement No. 1 to CAN/CSA-Z662-03, Oil and Gas Pipeline Systems, Annex N, Guidelines for Pipeline Integrity Management Programs. The implementation of this program based on Annex N must be completed no later than June 30, 2007. In the interim, the requirements outlined in Appendix 2 shall apply.

(9) Clause 10.11.3.1 is revoked and the following substituted:

10.11.3.1 Prior to a change in service fluid, including sweet to sour, the operating company shall conduct an engineering assessment to determine whether it would be suitable for the new service fluid. The assessment shall include consideration of the design, material, construction, operating, and maintenance history of the pipeline system and be submitted to the Director for approval.

(10) Clause 10.13.1.2 is amended by adding the following items:

(e) maintain warning signs and markers along the pipeline right-of-way,
(f) maintain existing fences around above ground pipeline facilities, and
(g) empty tanks and purge them of hazardous vapours.

(11) Clause 12.4.8.1 is renumbered as clause 12.4.8.1.1. Clause 12.4.8 is amended by adding the following clauses:

12.4.8.1.2 All new and replacement natural gas service regulators shall comply with the requirements of CSA 6.18-02 standard, Service Regulators For Natural Gas, including the Drip and Splash Test contained in Appendix A of the said Standard. Where a regulator – meter set installation or supplemental protective devices that is providing equivalent protection against regulator vent freeze up, passes a successful test in accordance to Appendix C of the said Standard, the requirements of Appendix A (Drip and Splash Test) and those contained in Clause 14.15 (Freezing Rain Test) of the Standard are waived. Evidence of test made in accordance with Appendix C, shall be kept by the operating Company as permanent records.

12.4.8.1.3 Regulator-meter set configurations shall be included in the operating company's operating and maintenance procedures.

(12) Clause 12.4.10.6 is amended by replacing the second sentence with the following:

…Clearances from building openings shall be commensurate with local conditions and the volume of gas that might be released, but shall not be less than those required by CSA B149.1 clause 5.5.9 as amended by Item 1.12 of the Gaseous Fuels Code Adoption Document…

Note: The amendment to clause 5.5.9 of CSA B149.1 by the Gaseous Fuels Code Adoption Document adds a new column to the "Table 5.2 – Pipe Threshold Stress Values", found in the CSA B149.1, that states: "The discharge clearances from relief device openings with capacities under 50 cf/h (1.5 m^3 /h) will be 1 ft. (.3 m) to a building opening, appliance vent outlet, appliance air intake or source of ignition, and 3 ft. (1 m) to a mechanical air intake".

(13) Clause 12.10.9 is amended by adding the following:

12.10.9(e For polyethylene piping installed in Class 1 and Class 2 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of Clause 12.4.2.1; and

12.10.9(f) For polyethylene piping installed in Class 3 and Class 4 location, the upgraded maximum operating pressure shall not exceed the design pressure calculated in accordance with the requirements of clause 12.4.2.1.1 with a combined design factor and temperature derating factor (F x T) of 0.32.

(14) Clause 12.10.11.1 is revoked and the following substituted:

12.10.11.1.1 Operating companies shall establish effective procedures for managing the integrity of pipeline systems with a MOP less than 30% of SMYS (Distribution Systems) so that they are suitable for continued service. The integrity management program shall contain:

a) a management system;
b) a working records management system;
c) a condition monitoring program, and
d) a mitigation program.

12.10.11.1.2 When developing the distribution system integrity management program (DSIMP), an operating company shall consider Appendix 1, Guidelines for Gas Distribution System Integrity Management Programs (DSIMP).

12.10.11.1.3 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if:

a) the operating company or person makes an application to the Director under Section 18.(1) 1 and 18(1) 3 of Ontario Regulation 210/01 (Oil and Gas Pipeline Systems).

b) the Director has reasons to believe that the design, construction, operation or abandonment of a pipeline, or any part of a pipeline is or may cause

i. a hazard to the safety of the public or to the employees of the operating company
ii. an adverse effect to the environment or to property, or

c) the Director wishes to assess the operating company's DSIMP.

12.10.11.1.4 The implementation of DSIMP shall be completed no later than April 30, 2008.

Section 3

POLYETHYLENE PIPE CERTIFICATION

3. (1) Polyethylene piping and fittings that are used in a polyethylene gas pipeline shall be certified by a designated testing organization accredited by the Standards Council of Canada as conforming to the CAN/CSA-B137.4-99 - Polyethylene Piping Systems for Gas Services.

Section 4

WELDER QUALIFICATION

4. (1) Welds shall not be made in any steel pipe that forms or is intended to form a part of a steel oil or gas pipeline or a component of a steel oil or gas pipeline unless the welder is qualified to make the weld in accordance with the requirements of the CSA Z662 Standard as adopted under section 2 of this document and is the holder of the appropriate authorization issued under Ontario Regulation 220/01 (Boilers and Pressure Vessels), made under the *Technical Standards & Safety Act, 2000*.

Section 5

In the event of a conflict between any provision of a standard, specification, code or publication adopted in this document, this document shall prevail.

Any person involved in an activity process or procedure to which this document applies shall comply with this document.

The said amendments are effective immediately.

Dated at Toronto this 15th_day of August, 2006.

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Roland Hadaller
Statutory Director
Ontario Regulation 210/01 (Oil and Gas Pipeline Systems)
made under the *Technical Standards & Safety Act, 2000*

Appendix 1

Guideline for gas distribution system integrity management programs (DSIMP)

1.0 Introduction

1.1 This Appendix provides guidelines for developing, documenting, and implementing an integrity management program (DSIMP) for gas distribution systems. The purpose of a DSIMP is to prevent or mitigate conditions leading to failure incidents with significant consequences, so that distribution systems are capable of providing safe and reliable service.

1.2 The major components in a DSIMP are detailed in this Appendix.

2.0 Definitions

"Failure incident" – means an unplanned release of gas due to failure of a pipe or component.

"Damage incident" – means an event that results in a pipe, component or coating defect, without release of service fluid.

"Hazard" – includes any condition that might cause a failure or damage incident.

3.0 Integrity management program scope

3.1 A gas DSIMP should include methods to collect, integrate, and analyze information related to:

(a) design and construction;
(b) maintenance and repair;
(c) operating conditions;
(d) failure incidents with significant consequences;
(e) damage incidents, and
(f) damage and deterioration.

3.2 Gas distribution companies should document the facilities included in the DSIMP. When parts of the distribution system are not included in the DSIMP, reasons for such exclusions should be stated.

4.0 Corporate policies, objectives, and organization

4.1 Gas distribution companies should have statements of integrity-related corporate policies, values, and objectives, and performance indicators.

4.2 Gas distribution companies should document the types of consequences they consider to be significant and the rationale for determining their significance.

4.3 Gas distribution companies should document those positions responsible for key integrity-related activities.

5.0 Integrity management program records

5.1 Gas distribution companies should prepare and manage records related to gas distribution system design, construction, operation, and maintenance that are needed to perform the activities included in a DSIMP.

5.2 The methods and results for the activities described in this Appendix should be documented.

5.3 Gas distribution companies should document the methods used for managing DSIMP records. Items that should be considered include:

(a) responsibilities and procedures for the creation, updating, retention, and deletion of records;
(b) evidence of past activities, events, changes, analyses, and decisions; and
(c) an index describing the types, forms, and locations of records.

6.0 Competency and training

6.1 Gas distribution companies shall utilize personnel that have appropriate knowledge and skills to perform tasks associated with the development and implementation of the DSIMP.

6.2 Gas distribution companies should consider documenting the methods used to evaluate the integrity management knowledge and skills of their personnel.

6.3 Where evaluation of the knowledge and skills indicates that development is required, training should be arranged. Such training should include:

(a) formal training courses provided by educational institutions or industry organizations;
(b) workshops and conferences related to gas distribution system integrity;
(c) technical committees of industry and standards development organizations;
(d) research and development projects related to gas distribution system integrity; and
(e) supervised work experience.

7.0 Change Management

7.1 Gas distribution companies should have a documented change management process to manage changes that may affect the integrity of the gas distribution system.

7.2 The change management process should have procedures in place to address and document, where applicable, items such as:

(a) monitoring to identify anticipated and actual changes that may affect gas distribution system integrity;
(b) responsibilities for approving and implementing changes;
(c) analysis of implications and effects of the changes;
(d) communication of changes to affected parties;
(e) timing of changes; and
(f) reasons for the changes.

8.0 Hazard identification and control

8.1 Gas distribution companies should identify and document hazards that can lead to a failure or damage incident with significant consequences.

8.2 The methods and data used for hazard identification should be documented, taking into consideration the primary causes and any additional failure or damage incident causes that are relevant.

8.3 Where hazards that may lead to a failure or damage incident with significant consequences are identified, the gas distribution company should:

(a) assess and document the risks associated with such hazards in accordance with the provisions of sections 9.0 to 9.4 of this Appendix.
(b) implement and document actions to monitor for conditions that can lead to failures or damage incidents; and
(c) implement and document actions to eliminate or mitigate conditions that can lead to failure or damage incidents.

9.0 Risk assessment

Gas distribution companies should consider incorporating risk assessment in a DSIMP. This section provides guidance to distribution companies for conducting risk assessments. For further guidance see Annex B of CSA Z662-03.

9.1 Risk analysis approach

When selecting an appropriate approach for performing risk analysis, gas distribution companies should consider:

(a) the features that are unique to the design, construction and operation of the gas distribution system;
(b) existing screening and analysis approaches;
(c) the availability of procedures, models, and information needed to perform the analysis; and
(d) how the results of the risk assessment will be used.

9.2 Risk analysis refinement

Gas distribution companies should consider methods to refine its risk analysis including the following options:

(a) a review of its risk analysis approach; and
(b) additional observations and analysis of the operating conditions.

9.3 Risk Evaluation

Gas distribution companies should have methods to evaluate gas distribution system risk. This may include:

(a) establishment of various risk levels; and
(b) methods or approaches to screen and, where appropriate, further refine risk analysis.

9.4 Risk reduction validation

The risk analysis and risk evaluation should be repeated to establish that the options selected reduce the estimated risk to a level that is considered to be not significant.

10.0 Options for hazard control and risk reduction

10.1 Operator errors

Options that can be used to reduce the frequency of failure incidents associated with operator error should include items such as:

(a) personnel training;
(b) improved system monitoring methods;
(c) modified operating and maintenance practices; and
(d) improvements or modifications to piping and equipment.

10.2 External interference

Options that can be used to reduce the frequency of failure incidents associated with external interference include items such as:

(a) participation in one-call utility location organizations;
(b) improved public awareness and education of the presence of the gas distribution system;
(c) additional vegetation control, markers and signs to identify the presence of gas distribution facilities;
(d) improved procedures for gas distribution system location and excavation; and
(e) installation of structures or materials to protect the gas distribution system from damage.

10.3 Gas distribution system defect~~s~~ or malfunction~~s~~

Options that can be used to reduce the frequency of failure or damage incidents associated with gas distribution system defects or malfunctions include, where applicable, items such as:

(a) improved quality measures for manufacturing, design, construction and operations;
(b) improved failure detection measures;
(c) temporary or permanent reductions in the established operating pressure; and
(d) assessment, repair rehabilitation and replacement measures.

10.4 Natural hazards

Options that can be used to reduce the frequency of failure or damage incidents associated with natural hazards include where applicable, items such as:

(a) the design and location of facilities and materials that eliminate or mitigate the potential for failure incidents;
(b) the design and installation of structures or materials to protect the gas distribution system from external loads;
(c) programs to monitor pipe or soil movement;
(d) increased monitoring and inspection measures;
(e) excavation and reburial to relieve loads on the facilities; and
(f) relocation of facilities.

10.5 Consequence reduction

Options that can be used to reduce the consequences associated with failure or damage incidents include, where applicable, items such as:

(a) improved system and facility design;
(b) improved measures for early detection of a failure or damage incident;
(c) improved public awareness and education; and
(d) improved emergency response procedures.

11.0 Gas DSIMP planning

11.1 Gas distribution companies should develop and document plans for completion of activities related to their gas distribution integrity management.

11.2 DSIMP planning should include, in addition to other clauses in this Appendix, consideration of the following:

(a) failure and damage incident history of the gas distribution company;
(b) recommendations from previous integrity reviews and activities;
(c) the presence or potential growth of known conditions that may lead to failure incidents; and
(d) industry experience.

11.3 DSIMP plans should include steps to review completed integrity activities in order to:

(a) verify that the relevant methods and procedures for such activities were properly performed;
(b) determine if the intended objectives were achieved;
(c) identify incomplete work and unresolved issues;
(d) develop recommendations and plans for future work; and
(e) verify that the relevant records were created or revised.

12 DSIMP implementation

12.1 Gas distribution companies should document and implement methods and procedures to inspect, test, patrol, and monitor in accordance with the requirements of Clauses 9, 10, and 12 of CSA Z662-03.

12.2 The rationale used to determine the timing or frequency should be documented. Consideration to both indirect and direct assessment methods should be made.

12.3 Gas distribution companies should consider the need for supplemental inspections using more direct methods, where an inspection is performed using indirect methods.

12.4 Records of inspections, testing, patrols, and monitoring activities should include:

(a) dates when performed;
(b) equipment used;
(c) results and observations; and
(d) evaluation of the acceptability of the results and observations.

13.0 Evaluation of results

13.1 Where apprised of conditions that may lead to a failure incident with significant consequences, gas distribution companies should:

(a) perform an engineering assessment as specified in Clause 12.10.11.2 of CSA Z662-03; and
(b) perform corrective action as specified in Clause 10.11.2.3 of CSA Z662-03.

13.2 Portions of the gas distribution system with indications of imperfections shall be subject to detailed visual inspection, mechanical measurement, non-destructive inspection as deemed appropriate by the gas distribution company. Evaluation shall be as specified in Clause 10.8 limited by Clauses 12.10.6 and 13 of CSA Z662-03.

14.0 Mitigation

14.1 Gas distribution companies should document the types of corrective actions that will be considered for anticipated conditions that may cause a failure incident with significant consequences.

15.0 Failure and damage incident investigations

15.1 Gas distribution companies should develop procedures for investigating and reporting failure and damage incidents. Failure incidents shall be addressed in accordance with the requirements specified in Clause 12.10.2.2.3 of CSA Z662-03.

15.2 Such procedures should include, where applicable an analysis to determine the need for changes to improve the effectiveness of the DSIMP.

16.0 Program review and evaluation

16.1 Gas distribution companies shall periodically review and evaluate their DSIMPs to determine if it is in accordance with the provisions of this Guideline and be revised, as necessary. Such review shall give consideration to the root causes of failure incidents. The methods and responsibilities for review and evaluation and the results of such reviews shall be documented. Gas distribution companies shall also consider having audits performed on their DSIMPs.

Appendix 2

Pipeline Integrity Management for Pipelines with a Maximum Operating Pressure (MOP) over 30% SMYS

(Interim requirements until June 30, 2007)

1.0 The Director may require operating companies or a person to submit a design, specification, program, manual, procedure, measure, plan or document to the Director if the Director wishes to assess the operating company's pipeline integrity management program (IMP).

1.1 For the protection of the public, the pipeline and the environment, an operating company shall develop a IMP for steel pipelines operating at 30% or more of the SMYS. The IMP shall contain:

a) a management system;

b) a working records management system;

c) a condition monitoring program, and

d) a mitigation program.

1.3 When developing the pipeline IMP, an operating company shall consider the following:

a) **In the management system:**

(i) the program scope, including a description of facilities, goals and objectives;
(ii) the organizational lines of responsibility for the IMP, including the reporting requirements to senior management;
(iii) the training of management and staff required to develop and execute the IMP;
(iv) the qualifications of consultants and contractors required to develop and execute the IMP;
(v) the methods of keeping abreast of industry practice and current research activities;
(vi) the methods to be used to manage change in respect of the design, construction and operation of the pipeline; and
(vii) the methods to be used to measure the effectiveness of the program.

b) **In the working records management system (RMS):**

The maintenance of an RMS that would allow timely access by sections to records regarding the pipeline system. Where practicable, the RMS should include information on the original pipe and all repairs such as:

(i) pipe material, manufacturer and date of manufacture, category, seam and girth weld type, grade, welder identification, non-destructive examination records, heat number, weld maps (e.g. weld number, non-destructive examination type and number);
(ii) coating type for line pipe, joints and tie-ins, manufacturer, application method and weather condition at the time of application;

(iii) repair history (e.g. location and type of repair, type and specification of sleeves, hot taps, grinding, cut-outs and replacements, type of defects, cut out or repaired, major coating repairs, and re-coating specifications);
(iv) mapping (e.g. location of pipelines including class location, depth of cover, location of buried valves and flanges, and geotechnical data);
(v) all pressure test data and records, maximum operating pressure, construction drawings, in-line inspection (ILI) tool data and reports, corrosion control and cathodic protection records including design and survey results;
(vi) inspection records of pressure relieving and emergency shutdown devices;
(vii) valve inspection records;
(viii) documentation of condition monitoring and mitigation programs and past condition monitoring and mitigation decision analyses; and
(ix) review of IMP effectiveness as outlined in 10.11.2.8 a).

c) **In the condition monitoring program:**

An internal inspection with ILI tools (e.g. caliper, metal loss), where such tools are commercially available, an engineering assessment (EA) of pipeline segments to address pipeline integrity. Both time dependent (e.g. corrosion, stress corrosion cracking, hydrogen induced cracking and fatigue) and non-time dependent (e.g. manufacturing defects, third party damage and geotechnical (slope stability, and stream washout) hazards that are to be considered and investigated in the EA. The EA should consider the results of such methods as pressure testing, use of ILI tools and investigative digs. The risk assessment (RA) method to be used when assigning priorities for integrity evaluations of facilities or line segments. Factors to be included in the RA are items such as: pipeline age and condition, coating age and condition, cathodic protection data and ILI data. Consideration should be given to determining the area affected (consequence) by a product release, where appropriate, monitoring and surveillance programs for slope movement, river crossing, depth of cover, frost heave and thaw settlement; a program to minimize third party damage, including line patrols; the methods used to evaluate and maintain pipeline integrity and the criteria for their application, which may include:

(i) the use of the appropriate ILI tool technology and the methods used to verify ILI findings;
(ii) the hydrostatic retesting procedure;
(iii)the corrosion control monitoring methods and cathodic protection survey documentation;
(iv) the method used to evaluate remaining life where defects exist;
(v) the methods used to verify the coating type and condition; and
(vi) any other method utilized for defect detection.
(vii) the procedures used to track, analyze and trend the condition of the pipeline and its coating; and
(viii) the steps to be taken to evaluate the cause of the line or facility failure including the minimum investigation and requirements (e.g. cut-out, metallurgical analysis).

d) **In the mitigation program:**

(i) the criteria and procedures for evaluation of imperfections and repairs of piping containing defects;
(ii) the procedures for performing consequence analysis to establish repair priorities;

(iii) the criteria and procedures for consideration of such measures as pipe replacement (e.g. cut-out), repair (e.g. grinding, sleeving (steel or fiberglass), hot taps, hot work, excavation procedures, maintenance welding, recoating, hydrostatic retesting and reduction in operating pressure (temporary or permanent); and
(iv) an outline of the short term (e.g. 1 to 3 year(s)) and long term (e.g. 4 to 10 years) IMP plans and priorities.