LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 252

Responding Witness: Lonnie E. Bellar

Q-252. Identify and provide a copy of the Company's most current Transmission Integrity Management Plan.

A-252. See attached.

PPL companies

Integrity Management Program

For Gas Transmission Pipelines

As Required by:

49 CFR 192 Subpart O
Pipeline Integrity Management

Prepared By:

Pipeline Integrity Group
(502) 364-8462

Developed By Gulf Interstate Engineering

1 INTRODUCTION

In This Section

Referenced Protocols

Appendix 1A – Cross Reference Table – IMP Section to Protocol Regulation A

1 INTRODUCTION

1.1 MAP OF THE INTEGRITY MANAGEMENT PROGRAM

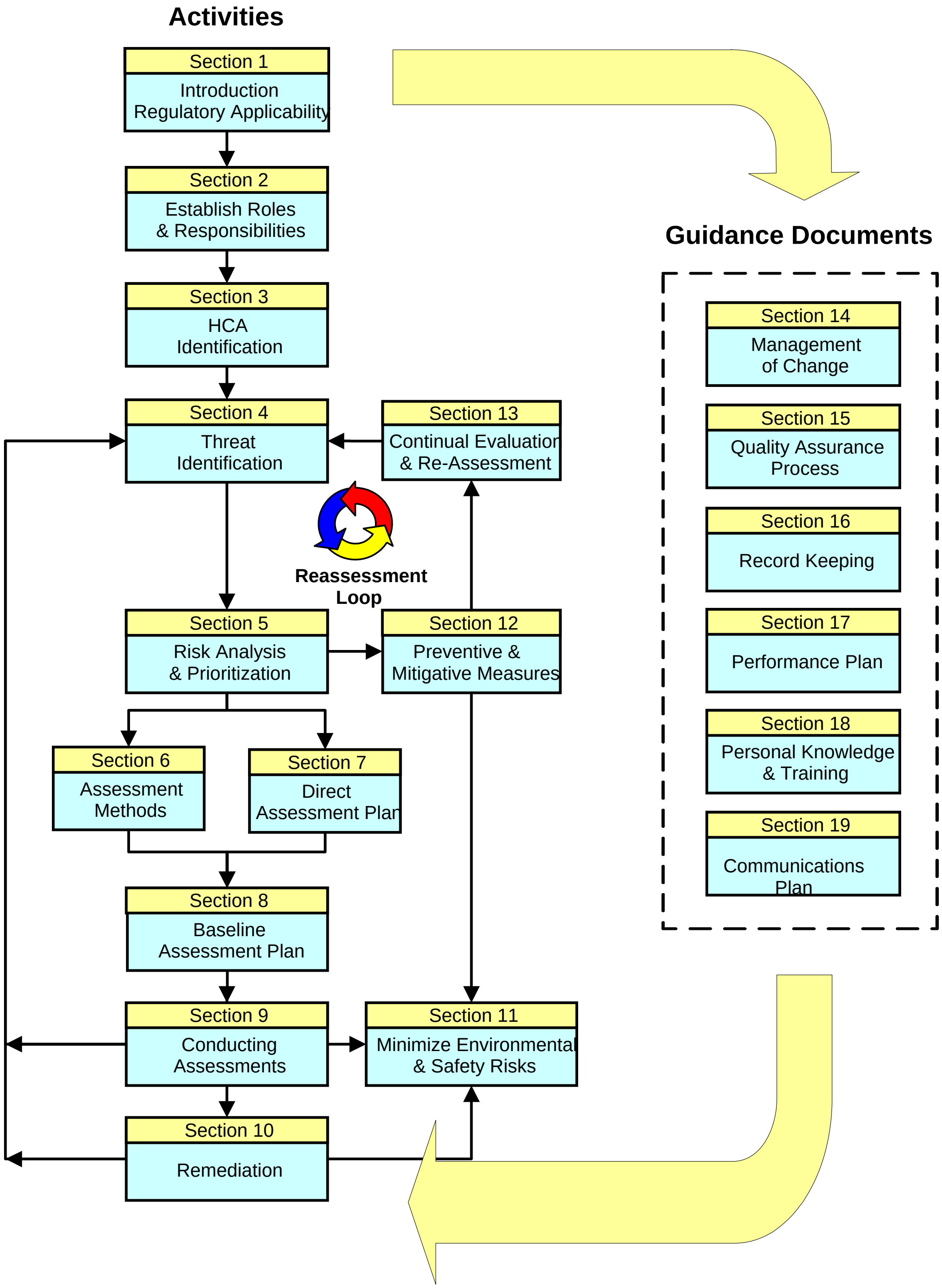

Figure 1-1: Map of the IMP

1.2 HOW TO USE THIS INTEGRITY MANAGEMENT PROGRAM

The Integrity Management Program (IMP) document is divided into major section headings as reflected in the Table of Contents. Each section represents a required program element or other significant function or activity of the IMP.

The first page of each section reflects the contents of the section under the heading "***In This Section***". A list of PHMSA (OPS) inspection protocols referenced within the section is also provided on the first page. These "***Referenced Protocols***" have been used and referenced to ensure compliance with 49 CFR Part 192 Subpart O – Gas Transmission Pipeline Integrity Management, as well as to assist regulatory agencies in their review of this document.

A comprehensive regulatory Cross Reference Table has been provided in **Appendix 1-A**. It cross references the regulations and regulatory inspection protocols listed below to ensure that all requirements have been considered and addressed in the IMP document. This regulatory reference is part of the overall Quality Assurance Process [Refer to **Section 15**].

- Written IMP Section Reference
- Regulatory Reference – CFR Part 192 – Subpart O
- PHMSA (OPS) Inspection Protocol Document

1.3 PURPOSE

This section, Section 1, provides an introduction to the IMP and its regulatory applicability. This IMP framework was developed in accordance with the requirements of the Department of Transportation's (DOT) Integrity Management Rule, 49 CFR Part 192 Subpart O – Gas Transmission Pipeline Integrity Management (Referred to as "**Subpart O**" and provided in **Appendix 1-C**).

This IMP document is applicable to Louisville Gas & Electric / Kentucky Utilities (the company) and subsidiary companies named herein.

Louisville Gas and Electric Company	(PHMSA Operator Identification Number 11824)
Kentucky Utilities Company	(PHMSA Operator Identification Number 30054)

These operators will collectively be referred to as "**the company**" throughout the remainder of the document. An overview of the natural gas systems is available within the company's Geographic Information System (GIS.)

1.4 IMP PROGRAM DEVELOPMENT

This section describes the process used to develop the overall structure of the IMP as well as the topics listed in each section. It is intended to provide additional insight into the logic and methods used to ensure compliance with the Pipeline Integrity Management rule.

The overall structure of the IMP was an iterative process which considered several factors and sources of information. The process started with a review of the following key information sources to develop a Table of Contents:

- Required Program Elements (§192.911)
- Natural Gas Integrity Management Flow Charts – PHMSA (OPS) website
- Gas Pipeline Integrity Inspection Protocols (Topical Index Listing)
- ASME B31.8S Managing System Integrity of Gas Pipelines

From these sources, the IMP was divided into logical topics or break points that became sections within the IMP. These sections were then mapped to show the overall flow, process, and inter-relationships of each section within the IMP. This map became the "Map of the IMP" as reflected in **Section 1.1**. It distinguishes between those sections that are "activity related" versus those that are "guidance documents" for the overall IMP.

Having completed the process Map of the IMP on a macro level, additional detail was developed for each section on a micro level. Each "activity related" section was mapped to reflect the process within the section as well its overall relationship to the Map of the IMP. In addition, using the regulations of Subpart O, PHMSA (OPS) flow charts, PHMSA (OPS) Inspection Protocols, and ASME B31.8S, a more detailed table of contents was developed for each section. The table of contents is reflected on the first page of each section under "In This Section".

1.5 PIPELINE SAFETY IMPROVEMENT ACT OF 2002

The 107th Congress passed bill H.R. 3609 known as the "Pipeline Safety Improvement Act of 2002" into law on **December 17, 2002**. Upon passing the bill into law, it became Public Law 107-355 and can be found in its entirety at https://www.govinfo.gov/.

The Pipeline Safety Improvement Act of 2002 introduces several new requirements for Pipeline Operators including those specifically addressing Pipeline Integrity Management. Section 14 of the Act titled "Risk Analysis and Integrity Management Programs for Gas Pipelines" mandates several new pipeline integrity related requirements. Among these requirements are the following:

- Each Operator shall adopt and implement a written Integrity Management Program
- The [DOT] Secretary (Office of Pipeline Safety) shall issue regulations prescribing standards within **12 months** of the date of enactment [**December 17, 2003**].
- The regulations shall require an Operator to conduct a risk analysis and adopt an Integrity Management Program within **24 months** of the date of enactment [**December 17, 2004**].
- Each Operartor of a gas pipeline facility shall begin a baseline integrity assessment within **18 months** of the date of enactment [**June 17, 2004**].
- The Operator shall complete a baseline integrity assessment within 10 years of the date of enactment [**December 17, 2012**], with 50 percent of such facilities being assessed within 5 years of the date of enactment [**December 17, 2007**].

1.6 REGULATORY APPLICABILITY - SCOPE

The pipeline integrity regulations of 49 CFR Part 192 Subpart O, prescribe the minimum requirements for an IMP on any gas transmission pipeline covered under 49 CFR Part 192. These pipelines are defined in part 192.3 "Definitions" as follows:

> "Transmission Line means a pipeline, other than a gathering line, that:
>
> (a) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not downstream from a distribution center;
>
> (b) Operates at a hoop stress of 20 percent or more of SMYS; or
>
> (c) Transports gas within a storage field.
>
> A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas."

However, the pipeline integrity regulations of 49 CFR Part 192 Subpart O do **not** include those pipelines classified as Gathering or Distribution Lines. Per 192.3 a Gathering Line "means a pipeline that transports gas from a current production facility to a transmission line or main." The pipelines within LG&E storage fields commonly called "gathering lines" by company employees are **not** gathering lines by this definition, but **are** transmission lines because they transport gas within a storage field.

To determine which segments of a gas pipeline transmission system are covered by 49 CFR Part 192 Subpart O, an Operator must identify its high consequence areas (HCA).

Regulatory jurisdiction may reside with a state or local pipeline safety authority when a covered segment is located in a state where PHMSA (OPS) has an interstate agent agreement in place.

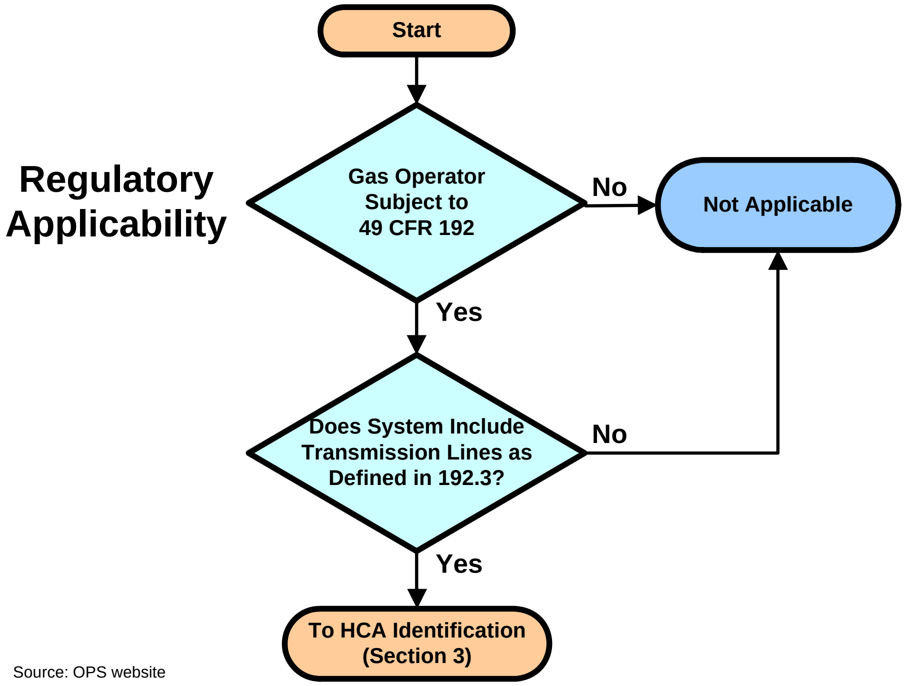

Figure 1-2: Regulatory Applicability

1.6.1 Steel Transmission Pipelines

For gas transmission pipelines constructed of steel, all sections of Subpart O must be considered for their applicability.

1.6.2 Low Stress Pipelines – Less Than 30% SMYS

For gas transmission pipelines operating at less than 30% Specified Minimum Yield Stress (SMYS), all sections of Subpart O must be considered for their applicability. However, the following paragraphs contain requirements that are specific to transmission pipelines operating at less than 30% SMYS.

192.935(d)	Preventive and Mitigative Measures	Ref. IMP Section 12
192.939(b)	Reassessment Intervals	Ref. IMP Section 13
192.941	Low Stress Reassessment	Ref. IMP Section 13

1.6.3 Plastic Transmission Pipelines

For gas transmission pipelines constructed of plastic, only the following sections apply.

192.917	Threat Identification	Ref. IMP Section 4
192.921	Baseline Assessment Plan	Ref. IMP Section 8
192.935	Preventive and Mitigative Measures	Ref. IMP Section 12
192.937	Continual Evaluation and Reassessment	Ref. IMP Section 13

1.7 IMP PROGRAMS - PRESCRIPTIVE VS. PERFORMANCE BASED

The pipeline integrity regulations of 49 CFR Part 192 Subpart O provide for two types of Integrity Management Programs:

- Prescriptive Approach
- Performance Based Option [§192.913]

Prescriptive Approach

The prescriptive approach must conform to the requirements of 49 CFR Part 192 Subpart O without deviation. This approach includes those minimum requirements incorporated by reference in ASME B31.8S and NACE RP 0502-2002. Operators shall not deviate from timeframes for reassessment without PHMSA (OPS) granting a formal waiver [§192.943]. The company uses this approach for the basis of its IMP.

Performance Based Option [§192.913]

Under this approach the Operator may deviate from certain requirements provided exceptional performance can be demonstrated under its Integrity Management Program by having a performance-based program that meets or exceeds the performance based requirements of ASME B31.8S and includes at a minimum the following elements:

- A comprehensive Process for risk analysis;
- All risk factor data used to support the program;
- A comprehensive data integration process;
- A Procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;
- A Procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;
- A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;
- Annual performance measures beyond those required in §192.945 that are part of the Operator's performance plan. An Operator must submit these measures, by electronic or other means, on an annual frequency to PHMSA (OPS) in accordance with §192.951; and
- An analysis that supports the desired integrity reassessement interval and the remediation methods to be used for all covered segments.

Once an operator has demonstrated that it has satisfied the requirements of §192.913(b), the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances:

- Time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer that seven years[§192.913 (c)(1)];

- Time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment. [§192.913 (c)(2)]

1.8 INTEGRITY MANAGEMENT REGULATION DEFINITIONS

The following terms are used in the integrity management regulations and the definitions provided below will apply throughout the document.

1.8.1 Integrity Management Program (IMP)

As used in this document, an Integrity Management Program (IMP) is a set of documents that collectively will systematically define, control, and implement the requirements for Integrity Management. It will be developed to take advantage of existing company policies, procedures, plans, and programs whenever practical. The IMP addresses the requirements, processes, plans, schedules, and activities of Integrity Management. An IMP is "process focused" and contains the following required elements as indicated in §192.911.

- HCA Identification
- Baseline Assessment Plan
- Threat Identification
- Direct Assessment Plan, if applicable
- Remediation
- Continual Evaluation and Assessment
- Confirmatory Direct Assessment
- Preventive and Mitigative Measures
- Performance Plan
- Record Keeping
- Management of Change
- Quality Assurance
- Communication Plan
- Submittals to Regulatory Agencies
- Minimizing Environmental & Safety Risks
- Newly Identified High Consequence Areas

1.8.2 Plans

A Plan is a written approach or methodology that defines who, what, where, when, and how a specific activity will be conducted. It is used to provide consistent implementation, accountability, documentation, and performance measurements. A plan should address the following:

- Responsibilities
- Required Activities

- Locations
- Schedules
- Processes and Procedures

The requirements of 49 CFR 192.911 refers to the following plans.

- Baseline Assessment Plan
- Direct Assessment Plan
- Performance Plan
- Communications Plan

1.8.3 IMP Framework

An IMP Framework is an initial or basic form of the IMP that describes the following:

- The process for implementing each required IMP element;
- How relevant decisions are made and by whom;
- A time line for completing the work to complete each Program element; and
- How information gained from the experience will be continuously incorporated into the Program.

The IMP Framework is intended to be developed from its initial form into a more mature program over time. The expected degree of maturity for individual elements of the IMP Framework depends on the required timing for the particular program elements. Activities that must be completed earlier such as HCA Identification should reflect a more mature program than later activities such as Continual Evaluation and Reassessments. The company must make continuous improvements to the initial IMP Framework so that it evolves into a more detailed and comprehensive IMP.

1.8.4 49 CFR Part 192 Subpart O – Definitions

Several other terms and definitions are introduced in 49 CFR Part 192 Subpart O. These terms are listed below along with the section of the document that discusses them in more detail.

• High Consequence Area	Section 3
• Identified Site	Section 3
• Potential Impact Radius	Section 3
• Potential Impact Circle	Section 3
• Covered Segment or Covered Pipeline Segment	Section 3
• Assessment	Section 6
• Direct Assessment	Section 7
• Confirmatory Direct Assessment	Section 7

- Discovery of Condition — Section 10
- Remediation — Section 10

Additional industry terms, definitions and acronyms are listed in **Appendix 1-B** of this document.

1.9 KEY IMP IMPLEMENTATION DATES

1.9.1 Congressional Mandates

The Pipeline Safety Improvement Act of 2002 introduced several new requirements for Pipeline Operators including those specifically addressing Pipeline Integrity Management. The following requirement is listed in the Pipeline Safety Improvement Act of 2002, but is not listed in 49 CFR Part 192 Subpart O – Pipeline Integrity Management.

June 17, 2004

Section 14 of the Pipeline Safety Improvement Act of 2002 titled "Risk Analysis and Integrity Management Programs for Gas Pipelines" mandates several pipeline integrity related requirements. Among these requirements are the following:

- Each Operator of a gas pipeline facility shall begin a baseline integrity assessment within **18 months** of the date of enactment [**June 17, 2004**].

OPS Advisory Bulletin No. ADB-03-07 [Federal Register Vol. 68, No. 221 November 17, 2003] states:

Prior to June 17, 2004, each operator must have begun to –

- Identify segments that are located in high consequence areas;
- Integrate available data on those identified segments;
- Prioritize the highest risk segments from available data on those identified segments; and
- Select the assessment method best suited to assess (pressure-test, internal inspection device, direct assessment, or alternative method) each high-risk segment.

An Operator must have begun its preparation to conduct a baseline assessment on at least one high risk segment that the operator has already identified. Preparing to conduct a baseline assessment means that:

- An Operator has scheduled for assessment the segments identified prior to **June 17, 2004**; **and**
- An Operator has started to contract or has entered into a contract with a tool vendor to assess the identified segments; **or**
- An Operator has started to assess the first scheduled segment.

PHMSA (OPS) also considers any of the following actions as meeting the intent of the statute.

- An Operator has installed launchers or receivers for ILI inspections
- An Operator has set up a segment for a pressure test; or
- An Operator has completed the pre-assessment step for Direct Assessment.

These are not the only actions PHMSA (OPS) will accept, and an Operator should contact PHMSA (OPS) for any additional clarifications.

1.9.2 Regulatory Requirements

In accordance with the requirements of 49 CFR Part 192 Subpart O – Pipeline Integrity Management, the following key implementation and compliance dates were to be met by each Operator.

August 31, 2004 An Operator must report to PHMSA (OPS) indicating the company has begun its preliminary baseline assessments. Thereafter, the semi-annual reports must be submitted within 2 months of June 30 and December 31 each year. The semi-annual reports were later eliminated and transmission integrity management data was added to the annual report for natural gas transmission systems.

December 17, 2004 An Operator of a covered pipeline segment must develop and follow a written Integrity Management Program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment.

The initial Integrity Management Program must consist, at a minimum, of a framework that describes for each of the 16 elements identified in §192.911:

- The process for implementing each program element
- How relevant decisions will be made and by whom
- A schedule for completing the work to implement each program element
- How the information gained from experience will be continuously incorporated into the Program.

This framework will evolve into a more detailed and comprehensive program.

December 17, 2004	Complete the initial HCA identification of the pipeline system. Refer to FAQ 14 on the PHMSA (OPS) Integrity Management website that indicates all High Consequence Areas (HCAs) must be identified as part of this initial framework completion.
March 15, 2005	An Operator must submit its first full reporting to PHMSA (OPS) of the 4 overall performance measures.
December 17, 2006	An Operator's ability to use a prorated building count to determine High Consequence Areas expires per §192.903.
December 17, 2007	An Operator must assess at least 50% of the covered segments beginning with the highest risk segments. An Operator must prioritize all the covered segments for the Baseline Assessment in accordance with §192.917(c) and paragraph §192.921(b).
December 17, 2009	An Operator must re-assess a covered segment on which a prior assessment is credited as the Baseline Assessment under §192.921(e)
December 17, 2012	An Operator must complete the Baseline Assessment of all covered segments.

1.10 POTENTIAL INTERRUPTIONS TO GAS SUPPLY

The IMP Rule attempts to minimize potential interruptions to gas supply by providing an Operator multiple assessment methods. These methods include Direct Assessment (DA) that can typically be performed without supply interruptions.

Under §192.943(a)(2) of the rule an Operator may be able to justify a longer reassessment period for a covered segment if the Operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval, and that a waiver of the requirement would not threaten pipeline safety. An Operator must seek a formal waiver of the required reassessment interval.

1.11 REFERENCED STANDARDS

The IMP Rule references several industry standards that have been incorporated by reference. Some of these documents are incorporated in total where others have only incorporated specific referenced sections into the rule.

Should a conflict exist between the rule [49 CFR Part 192 Subpart O] and a referenced industry standard, the rule shall control in all cases. Also, all "Shall" or "Must" statements in any referenced portion of an industry standard will be a mandatory requirement under the rule. In addition, all "Should" statements in any referenced portion of an industry standard will be considered a recommended practice under the rule. However, if these recommended practices are not adhered to, the company's justification for the decision will be documented.

1.12 PROGRAM REVIEW AND MODIFICATIONS

This IMP will be reviewed each calendar year as part of the continual improvement process, with modifications being made as necessary.

Revision Log

Date	Description	Revised By
11/16/2004	Changed NGA logo to LG&E Energy logo	MTS
11/16/2004	Changed the work "Manual" to "Integrity Management Program" or IMP	MTS
11/16/2004	Modified Figure 1-1 by eliminating Section 20. Section 20 is being combined with Section 19	MTS
11/16/2004	Deleted all "Note to Operator"	MTS
11/16/2004	Formatted text and made minor grammerical changes	MTS
11/16/2004	Changed the color of the headings from blue to green	PID
11/16/2004	Stated that LG&E Energy will be using the prescriptive approach for the IMP	MTS
11/16/2004	Defined LG&E Energy LLC as the "Company" and listed its subsidiary companies	MTS/PID
11/16/2004	Changed the Pipeline Integrity Management Plan title in the footer to Integrity Management Program	MTS
11/16/2004	Included title block for signatures	MTS
11/17/04	Revised Appendix numbers	lco
11/17	Accepted changes to date, saved as new file revised_11_19_04	lco
11/19/04	**11/19/04 Version Approved by Management**	**LCO**
5/9/08	Changed Logos, signature blocks, and updated formats.	lco
5/9/08	Changed LG&E Energy to LG&E/KU and "the company"	lco
5/9/08	Minor revisions to appendicies	lco
5/9/2008	**5/9/2008 Version Approved by Management**	**LCO**
6/1/09	Corrected IMP form reference to Form 8-1 for Protocol B.2e in Appendix 1A	lco
6/2/09	Updated protocol descriptions/No., added and checked IMP and Regulation numbers to protocols A and B only	JJB
6/8/09	Updated protocol descriptions/No. for protocols C, D, E, F	JJB
6/9/09	Updated remaining protocols/No., checked/added regulations refs where needed	JJB
6/10/09	Checked and added IMP sections where needed	JJB
7/20/09	Checked Intro, Appendix 1B Terms-Acro-Def, and Appendix 1C Gas IMP Rule, made revisions to Introduction to match 49CFR 192 more closely	JJB
10/19/2010	Reviewed the Introduction, 1A, 1B, and 1C and found no changes to be made	JJB
6/13/2011	Changed company logos	JJB
11/6/12	Noted that semi-annual performance measures report has been eliminated and TIMP data has been added to the annual transmission report.	PJC
11/30/2013	Updated regulatory references to post base-line assessment phase and made general clerical changes.	JRG
12/15/2015	Made minor clerical corrections.	JRG
11/17/2016	Updated hyperlink and H.R. code reference in section 1.5.	TAD

APPENDIX 1-A

OPS Protocols (August 2013)
Cross Referenced to IMP Document

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
		A.1	**A.1 Program Requirements** Verify that the methods defined in §192.903 High Consequence Area (1) and/or §192.903 High Consequence Area (2) are applied to each pipeline for the identification of high consequence areas. [§192.905(a)]
3.5, 3.6	192.905(a)	A.1a	a. Verify the operator's integrity management program includes documented processes on how to implement methods (1) and (2) in order to identify high consequence areas. [§192.905(a)]
3.6.2, Form 8-1	192.905(a)	A.1b	b. Verify that the operator's process requires that the method used for each portion of the pipeline system be documented. [§192.905(a)]
Form 8-1, GIS	192.905(a)	A.1c	c. Verify that the operator's integrity management program includes system maps or other suitably detailed means documenting the pipeline segment locations that are located in high consequence areas. [§192.905(a)]
Archived BAB From 12-17-2004	192.907 192.911(a)	A.1d	d. Review HCA records to verify that the operator completed identification of pipeline segments in high consequence areas by December 17, 2004. [§192.907, and §192.911(a)]
		A.2	**A.2 Potential Impact Radius** Verify that the definition and use of potential impact radius for establishment of high consequence areas meets the requirements of §192.903. [§192.905(a)]
3.3.2, 3.3.5, 3.6	192.903 192.905(a) B31.8S-2004, 3.2	A.2a	a. Verify that the operator's formula for calculation of the potential impact radius is consistent with §192.903 requirements ($r = 0.69*(p*d^2)^{0.5}$) and that the pressure used in the formula is based on maximum allowable operating pressure (MAOP). i. For gases other than natural gas, verify that the operator has documented processes for the use of ASME B31.8S-2004, Section 3.2 to calculate the impact radius formula. [§192.903 Potential Impact Radius, §192.905(a)]
3.3.5, 3.6.2	192.903	A.2b	b. In cases where potential impact circles are used to identify high consequence areas, verify that the program requires that high consequence areas include the area extending axially along the length of the pipeline from the outermost edge of the first potential impact circle to the outermost edge of the last contiguous potential impact circle for those potential impact circles that contain either an identified site or 20 or more buildings intended for human occupancy. [§192.903 High Consequence Area (3)]
		A.3	**A.3 Identified Sites** Verify that the operator's identification of identified sites includes the sources listed in §192.905(b) for those buildings or outside areas meeting the criteria specified by §192.903, and that the source of information selected is documented. [§192.903 Identified Sites, §192.905(b) and §192 Appendix E, I(c)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
3.3.4	192.903 192.905(b)	A.3a	a. Identified sites must include the following: [§192.903 Identified Sites, §192.905(b)] i. Outside areas or open structures occupied by 20 or more people on at least 50 days in any 12 month period (days need not be consecutive), ii. Buildings occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12 month period (days and weeks need not be consecutive), and iii. Facilities occupied by persons who are confined, have impaired mobility, or would be difficult to evacuate.
3.4.1,3.4.2, 3.4.4, 3.7.1, Form 3-1	192.905(b)	A.3b	b. Identified sites must be identified using the following sources of information: [§192.905(b)] i. Information from routine operation and maintenance activities and input from public officials with safety or emergency response or planning responsibilities ii. In the absence of public official input, the operator must use one of the following in order to identify an identified site: 1. Visible markings such as signs, or 2. Facility licensing or registration data on file with Federal, State, or local government agencies, or 3. Lists or maps maintained by or available from a Federal, State, or local government agency and available to the general public.
		A.4	**A.4 Identification Using Class Locations (Method 1)** If the operator's integrity management program relies on §192.903 High Consequence Area definition (1) for identification of high consequence areas, verify compliance with the following:
3.6.1	192.903	A.4a	a. Verify the integrity management program includes Class 3 and Class 4 piping locations as high consequence areas consistent with the criteria of §192.5(b)(3) and §192.5(b)(4), and §192.5(c). [§192.903 High Consequence Area (1)(i) and (ii)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
3.3.5, 3.5.1,3.6.1	192.903	A.4b	b. For Class 1 and Class 2 locations with the potential impact radius greater than 660 feet, verify the integrity management program includes piping locations as high consequence areas if the area within the associated potential impact circle contains 20 or more buildings intended for human occupancy.[§192.903 High Consequence Area (1)(iii)] i. As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)] Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]^2 or Building Count within 200 meters = 20 x [200 (m) / PIR (m)]^2 1. If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. [§192.903 High Consequence Area (4)]
3.3.5, 3.6.1	192.903	A.4c	c. Verify the program includes as a high consequence area, any area in Class 1 and Class 2 piping locations where the potential impact circle contains an identified site. [§192.903 High Consequence Area (1)(iv)]
		A.5	**A.5 Identification Using Potential Impact Radius (Method 2)** If the operator's integrity management program relies on §192.903 High Consequence Area definition (2) for identification of high consequence areas, verify compliance with the following:
3.3.5, 3.5.1, 3.6.1, 3.6.2	192.903	A.5a	a. Verify the integrity management program includes piping locations as high consequence areas if the area within a potential impact circle contains 20 or more buildings intended for human occupancy: [§192.903 High Consequence Area (2)(i)] i. As an option for PIRs greater than 660 feet, the definition of high consequence area may be based on a prorated building count for buildings intended for human occupancy within a distance of 660 feet (200 meters) from the centerline of the pipeline as calculated using the following formula: [§192.903 High Consequence Area (4)] Building Count within 660 feet = 20 x [660 (ft) /PIR (ft)]^2 or Building Count within 200 meters = 20 x [200 (m) / PIR (m)]^2 1. If the option for use of a prorated number of buildings has been used for identification of high consequence areas, verify that the program acknowledges that use of the prorated allowance is only available to operators until December 17, 2006. [§192.903 High Consequence Area (4)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
3.3.5, 3.6.1, 3.6.2	192.903	A.5b	b. Verify the program includes piping locations as high consequence areas if the area within the potential impact circle contains an identified site. [§192.903 High Consequence Area (2)(ii)]
		A.6	**A.6 Identification and Assessment of Newly Identified HCAs, Program Requirements** Review the operator's integrity management program to verify processes are in place for evaluation of new information that may show that a pipeline segment impacts a high consequence area. [§192.905(c)]
3.7, 3.7.1,Fig 3-4, 3.7.2, 3.7.3, 3.7.4, Section 14	192.905(c)	A.6a	a. Verify the operator's integrity management program includes documented processes for how new information that shows a pipeline segment impacts a high consequence area is identified and integrated with the integrity management program. The program is to identify and analyze changes for impacts on pipeline segments potentially affecting high consequence areas. Issues the program must consider include but are not limited to: [§192.905(c)] i. Changes in pipeline maximum allowable operating pressure (MAOP), ii. Pipeline modifications affecting piping diameter, iii. Changes in the commodity transported in the pipeline, iv. Identification of new construction in the vicinity of the pipeline that results in additional buildings intended for human occupancy or additional identified sites, v. Change in the use of existing buildings (e.g., hotel or house converted to nursing home). vi. Installation of new pipeline. vii. Change in pipeline class location (e.g., class 2 to 3) or class location boundary, viii. Pipeline reroutes ix. Corrections to erroneous pipeline center line data
		B.1	**B.1 Assessment Methods** Verify that the operator's Baseline Assessment Plan (BAP) specifies an assessment method(s) for each covered segment that is best suited for identifying anomalies associated with specific threats identified for the segment. [§192.919(b), §192.921(a), §192.921(c), and §192.921(h)]
Form 6-1	192.921 192.919(b) B31.8S-2004, 6	B.1a	a. Verify that the operator followed ASME B31.8S-2004, Section 6 and that the methods selected for each covered segment address all of the threats identified for the segment. More than one assessment tool may be necessary to address all applicable threats to a covered segment. [§192.919(b), §192.921(a), §192.921(c), and §192.921(h)]
6.4, 9.2, Table 9B-2	192.921(a)(1) B31.8S-2004, 6.2	B.1b	b. If internal inspection tools are selected, verify that the operator followed ASME B31.8S-2004, Section 6.2 in selecting the appropriate internal inspection tool for the covered segment. [§192.921(a)(1)] i. Verify that the operator has evaluated the general reliability of any in-line assessment method selected by looking at factors including but not limited to: detection sensitivity; anomaly classification; sizing accuracy; location accuracy; requirements for direct examination; history of tool; ability to inspect full length and full circumference of the section; and ability to indicate the presence of multiple cause anomalies. Refer to ASME B31.8S-2004, Section 6.2.5. [§192.921(a)(1)]

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6.3, 6.5, Assesment Report pg. 4	192.921(a)(2)	B.1c	c. If a pressure test is specified, verify that the test is required to be conducted in accordance with Part 192, Subpart J requirements. Verify that the operator followed ASME B31.8S-2004, Section 6.3 in selecting the pressure test as the appropriate assessment method. [§192.921(a)(2)]
6.3 Fig. 6-2, 6.7	192.921(a)(4)	B.1d	d. If the operator specifies the use of "other technology," verify that notification to PHMSA is required in accordance with Part 192.949, 180 days before conducting the assessment. Also, verify that notification to a State or local pipeline safety authority is required when either a covered segment is located in a State where PHMAS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [§192.921(a)(4)]
4.8.2, 6.3 Fig 6-2, 6.4, 6.5	192.917(e)(4)	B.1e	e. If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW) or lap welded pipe that satisfies the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004, Appendix A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years verify that the selected assessment method(s) are proven to be capable of assessing seam integrity and detecting seam corrosion anomalies. [§192.917(e)(4)]
4.4.3, 4.4.4, 6.3.2, Form 6-1	192.921(h)	B.1f	f. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, verify that the operator documents an acceptable justification for the use of an alternative assessment method that will address the identified threats to the covered segment. [§192.921(h)]
		B.2	**B.2 Prioritized Schedule** Verify that the BAP contains a schedule for completing the assessment activities for all covered segments; and that the BAP appropriately considered the applicable risk factors in the prioritization of the schedule. [§192.917(c), 192.919(c), and 192.921]
Form 8-1	192.921(a)	B.2a	a. Verify that the BAP schedule includes all covered segments not already assessed. [§192.921(a)]
8.4, Section 4, Section 5, Form 8-1	192.917(c) 192.921(b)	B.2b	b. Verify that the BAP schedule prioritizes the covered segments based on potential threats and applicable risk analysis, and that the risk ranking is appropriate. [§192.917(c) and 192.921(b)]
4.8.2	192.917(e)(4) 192.917(e)(3)	B.2c	c. Verify that covered segments meeting the following conditions are prioritized as high-risk segments. i. Segments that contain low frequency resistance welded (ERW) pipe or lap welded pipe that satisfy the conditions specified in ASME B31.8S-2004, Appendix A4.3 and ASME B31.8S-2004, A4.4, and any covered or non-covered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years. [§192.917(e)(4)] ii. Covered segments that have manufacturing or construction defects (including seam defects) where any of the following changes occurred in the covered segment: operating pressure increases above the maximum operating pressure experienced during the preceding five years; MAOP increases; or the stresses leading to cyclic fatigue increase. [§192.917(e)(3)]

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Fig. 8-2, 8.4, Form 8-1	192.921(d)	B.2d	d. Verify that the BAP schedule requires 50% of the covered segments, beginning with the highest risk segments, to be assessed by December 17, 2007; and that baseline assessments shall be completed for all covered segments by December 17, 2012. [§192.921(d)]
Form 8-1	192.921 192.933	B.2e	e. Review the operator's implementation progress to date and verify that: [§192.921] i. Assessments scheduled for completion by the date of the inspection were in fact completed. ii. Assessment methods used for completed assessments were as described in the plan. iii. The date assessment field activities were completed is recorded [so the operator understands the time frame allowable for compliance with the provisions of §192.933].
		B.3	**B.3 Use of Prior Assessments** If prior assessments are used in the BAP, verify that the assessment methods used meet the requirements of §192.921(a) and that remedial actions have been carried out to address conditions listed in §192.933. Prior assessments are those that were completed prior to December 17, 2002. [§192.921(e)]
Section 4 and Section 6	192.919(a)	B.3a	a. Verify that threats to these pipeline sections were identified as required under §192.919(a).
8.2	192.919(b) 192.919(d)	B.3b	b. Verify that the methods used for these prior assessments were appropriate for the threats per ANSI B31.8S as required under §192.919(b) and §192.919(d).
Section 10	192.933	B.3c	c. Verify that anomalies satisfying the requirements of §192.933 were repaired.
		B.4	**B.4 New HCAs/Newly Installed Pipe** Verify that the operator updates the baseline assessment plan for new HCAs and newly installed pipe. [§192.905(c), §192.921(f), and §192.921(g)]
Fig. 8-2, 8.7.1, 8.7.3, Form 8-1, Form 3-3	192.905(c)	B.4a	a. If new HCAs have been identified or new pipe has been installed that is covered by this subpart, verify that applicable segment(s) have been incorporated into the operator's baseline assessment plan within one year from the date the area or pipe is identified and assessments have been appropriately scheduled and/or completed. [§192.905(c)]
Fig. 8-2, 8.7.1, Form 8-1	192.921(f)	B.4b	b. For new HCAs, verify that the operator completes a baseline assessment for the applicable segment(s) within ten (10) years from the date the area is identified. [§192.921(f)]
Fig. 8-2, 8.7.1, Form 8-1	192.921(g)	B.4c	c. For newly installed pipe that is covered by this subpart and impacts an HCA, verify that the operator completes a baseline assessment within ten (10) years from the date the pipe is installed. [§192.921(g)]
Section 4, Form 8-1	192.919(a) 192.921(b)	B.4d	d. Verify that threats to these pipeline sections were identified as required under §192.919(a). [§192.921(b)]
Section 6, Fig 6-2, Form 6-1	192.919(b) 192.919(d) B31.8S-2004	B.4e	e. Verify that the assessment methods used were appropriate for the threats per ASME B31.8S-2004 as required under §192.919(b) and 192.919(d).

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		B.5	**B.5 Consideration of Environmental and Safety Risks** Verify that the operator addresses requirements for conducting the integrity assessments (baseline and reassessment) in a manner that minimizes environmental and safety risks. [§192.919(e) and §192.911(o)]
9.6, Section 11, Forms 11-1 thru 11-4	192.919(e)	B.5a	a. Verify that precautions were implemented to protect workers, members of the public, and the environment from safety hazards (such as an accidental release of gas) during assessments. [§192.919(e) and §192.911(o)]
		B.6	**B.6 Changes** Verify that the operator keeps the BAP up-to-date with respect to newly arising information. Also refer to Protocol K. [§192.911(k) and ASME B31.8S-2004, Section 11]
8.7, 3.7.1, Form 8-2	192.911(k) B31.8S-2004, 11	B.6a	a. Verify that the operator's process has requirements to keep the BAP up-to-date with respect to newly arising information, applicable threats, and risks that may require changes to the segment prioritization or assessment method. [§192.911(k) and ASME B31.8S-2004, Section 11]
8.7, 8.8 (Form 8-2), Section 14	B31.8S-2004, 11(a)	B.6b	b. Verify that required BAP changes have been made and that for all changes, the following are documented: [ASME B31.8S-2004, Section 11(a)] i. Reason for change ii. Authority for approving change iii. Analysis of implications iv. Communication of change to affected parties
		C.1	**C.1 Threat Identification** Verify that the operator identifies and evaluates all potential threats to each covered pipeline segment. [§192.917(a)]
Section 4.3, 4.4.2, 4.8, 5.3.2	192.917(a) 192.917(e)(4) B31.8S-2004, 2.2	C.1a	a. If the operator is following the prescriptive or performance-related approaches, verify that the following categories of failure have been considered and evaluated:,[§192.917(a) and ASME B31.8S-2004, Section 2.2] i. external corrosion ii. internal corrosion iii. stress corrosion cracking; iv. manufacturing-related defects, including the use of low frequency electric resistance welded (ERW) pipe or lap welded pipe or other pipe potentially susceptible to manufacturing defects [§192.917(e)(4) and ASME B31.8S-2004, Appendix A4.3]; v. welding- or fabrication-related defects, vi. equipment failures; vii. third party/mechanical damage [§192.917(e)(1)], viii. incorrect operations (including human error), ix. weather-related and outside force damage, x. cyclic fatigue or other loading condition [§192.917(e)(2)

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			xi. all other potential threats.
N/A, 4.3, 5.3.2	192.917(a) B31.8S-2004, 2.2	C.1b	b. If the operator is following the performance-based approach, verify that all 21 of the threats associated with the nine categories listed above have been evaluated. [§192.917(a) and ASME B31.8S-2004, Section 2.2]
, Section 4, 4.4.1, 4.4.2, 5.6.8.3	192.917(a) 192.917(e)(2) B31.8S-2004, 2.2	C.1c	c. Verify that the operator's threat identification has considered interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) [ASME B31.8S-2004, Section 2.2].
N/A, 4.9	B31.8S-2004, 5.10	C.1d	d. Verify that the approach incorporates appropriate criteria for eliminating a specific threat for a particular pipeline segment. [ASME B31.8S-2004, Section 5.10]
4.4.4	192.917(a)	C.1e	e. Verify that the approach appropriately considers industry data and experience.
4.4.2		C.1f	f. Verify that the records indicate that all potential threats to each covered pipeline segment have been identified and evaluated. Adequate records that demonstrate all potential threats to each covered segment have been identified and evaluated should: i. Show consideration and evaluation of categories of threats summarized in 192.917(a), 192.917(e), and ASME B31.8S-2004. ii. If performance-based approach is utilized, show that all 21 of the threats associated with 192.917(a) and ASME B31.8S-2004 are considered. iii. Show interactive threats from different categories (e.g., manufacturing defects activated by pressure cycling, corrosion accelerated by third party or outside force damage) are considered. iv. Show appropriate criteria for eliminating a specific threat for a particular pipeline segment. v. Show that industry data and experience was appropriately considered in the identification of potential threats.

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		C.2	**C.2 Data Gathering and Integration** Verify that the operator gathers and integrates existing data and information on the entire pipeline that could be relevant to covered segments, and verify that the necessary pipeline data has been assembled and integrated. [§192.917(b)]
4.5.1, 4.6	B31.8S-2004, 4.2 B31.8S-2004, 4.4	C.2a	a. Verify that the operator has in place a comprehensive plan for collecting, reviewing, and analyzing the data. [ASME B31.8S-2004, Section 4.2 and ASME B31.8S-2004, Section 4.4]
4.6, Table 4-1, 4.5.2	192.917(b) B31.8S-2004, 4.2 B31.8S-2004, 4.3 B31.8S-2004, 4.4	C.2b	b. Verify that the operator has assembled data sets for threat identification and risk assessment according to the requirements in ASME B31.8S-2004, Section 4.2, and ASME B31.8S-2004, Section 4.3 and ASME B31.8S-2004, Section 4.4. At a minimum, an operator must gather and evaluate the set of data specified in ASME B31.8S-2004, Appendix A (summarized in ASME B31.8S-2004, Table 1) and consider the following on covered segments and similar non-covered segments [§192.917(b)] i. Past incident history ii. Corrosion control records iii. Continuing surveillance records iv. Patrolling records v. Maintenance history vi. Internal inspection records vii. All other conditions specific to each pipeline.
Section 4, 4.5	B31.8S-2004, 4.3	C.2c	c. Verify that the operator has utilized the data sources listed in ASME B31.8S-2004, Table 2, for initiation of the integrity management program. [ASME B31.8S-2004, Section 4.3]
4.7	B31.8S-2004, 4.1 B31.8S-2004, 4.2.1 B31.8S-2004, 4.4 B31.8S-2004, 5.7	C.2d	d. Verify that the operator has checked the data for accuracy. If the operator lacks sufficient data or where data quality is suspect, verify that the operator has followed the requirements in ASME B31.8S-2004, Section 4.2.1, and ASME B31.8S-2004, Section 4.4, and ASME B31.8S-2004, Appendix A [ASME B31.8S-2004, Section 4.1, ASME B31.8S-2004, Section 4.2.1, ASME B31.8S-2004, Section 4.4, ASME B31.8S-2004, Section 5.7(e), and ASME B31.8S-2004, Appendix A]: i. Each threat covered by the missing or suspect data is assumed to apply to the segment being evaluated. The unavailability of identified data elements is not a justification for exclusion of a threat. ii. Conservative assumptions are used in the risk assessment for that threat and segment or the segment is given higher priority. iii. Records are maintained that identify how unsubstantiated data are used, so that the impact on the variability and accuracy of assessment results can be considered. iv. Depending on the importance of the data, additional inspection actions or field data collection efforts may be required.
N/A	B31.8S-2004, 11(b) B31.8S-2004, 11(d)	C.2e	e. Verify that the operator's program includes measures to ensure that new information is incorporated in a timely and effective manner, as addressed in Protocol K. [§192.911(k), ASME B31.8S-2004, Section 11(b) and ASME B31.8S-2004, Section 11(d)]

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4.5	B31.8S-2004, 4.5 §192.917(e)(1)	C.2f	f. Verify that individual data elements are brought together and analyzed in their context such that the integrated data can provide improved confidence with respect to determining the relevance of specific threats and can support an improved analysis of overall risk. [ASME B31.8S-2004, Section 4.5]. Data integration includes: i. A common spatial reference system that allows association of data elements with accurate locations on the pipeline [ASME B31.8S-2004, Section 4.5]; ii. Integration of ILI or ECDA results with data on encroachments of foreign line crossings in the same segment to define locations of potential third party damage [§192.917(e)(1)].
4.7	192.917, B31.8S-2004, 4 B31.8S-2004, Appendix A	C.2g	g. Verify that the operator's program includes a procedure for ensuring the accuracy and completeness of information and data used in the identification of potential threats and the risk analysis.
4.5	192.917, B31.8S-2004, 4 B31.8S-2004, Appendix A	C.2h	h. Verify that the operator's program includes plans for additional inspection activities or field data collection efforts as needed to ensure data completeness and accuracy.
4.5	192.917, B31.8S-2004, 4 B31.8S-2004, Appendix A	C.2i	i. Verify that the records indicate that all existing data and information on the entire pipeline, that could be relevant to covered segments, has been gathered. Adequate records that demonstrate all data and information has been gathered should: i. Show that comprehensive collection, review and analyzing of data was performed. ii. That data sets for threat identification and risk assessment were assembled in accordance with the requirements in ASME B31.8S-2004, Sections 4.2, 4.3 and 4.4. iii. Show that data sources listed in ASME B31.8S-2004, Table 2, were utilized for initiation of the integrity management program. iv. Show that new information was incorporated in a timely and effective manner. v. Show that controls to provide assurance of the completeness and accuracy of input information in accordance with the operator's procedure were properly applied. vi. Show additional inspection or field data collection activities to improve the accuracy and completeness of the data were conducted.
		C.3	**C.3 Risk Assessment** Verify that the operator has conducted a risk assessment that follows ASME B31.8S-2004, Section 5, and that considers the identified threats for each covered segment. [§192.917(c)] [Note: Application of the risk assessment to prioritize the covered segments for the baseline assessment is covered in Protocol B, continual reassessments in Protocol F, and additional preventive and mitigative measures in Protocol H.]

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5.6.4	B31.8S-2004, 5.3 B31.8S-2004, 5.4	C.3a	a. Verify that the operator's risk assessment supports the following objectives [ASME B31.8-2004, Section 5.3, and ASME B31.8S-2004, Section 5.4]: i. prioritization of pipelines/segments for scheduling integrity assessments and mitigating action ii. assessment of the benefits derived from mitigating action iii. determination of the most effective mitigation measures for the identified threats iv. assessment of the integrity impact from modified inspection intervals v. assessment of the use of or need for alternative inspection methodologies vi. more effective resource allocation vii. facilitation of decisions to address risks along a pipeline or within a facility
5.6, Form 8-1	B31.8S-2004, 5.5	C.3b	b. Verify that operator utilizes one or more of the following risk assessment approaches [ASME B31.8S-2004, Section5.5] i. Subject matter experts (SMEs), ii. Relative assessment models, iii. Scenario-based models, or iv. Probabilistic models
5.4, 5.6.2, 5.6.10, 5.6.11	B31.8S-2004, 3.1 B31.8S-2004, 3.3 B31.8S-2004, 5.2 B31.8S-2004, 5.3 B31.8S-2004, 5.7	C.3c	c. Verify that the risk assessment explicitly accounts for factors that could affect the likelihood of a release and for factors that could affect the consequences of potential releases, and that these factors are combined in an appropriate manner to produce a risk value for each pipeline segment. [ASME B31.8S-2004, Section 3.1, ASME B31.8S-2004, Section 3.3, ASME B31.8S-2004, Section 5.2, ASME B31.8S-2004, Section 5.3 and ASME B31.8S-2004, Section 5.7(j)] Verify that the risk assessment approach includes the following characteristics: i. The risk assessment approach contains a defined logic and is structured to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, Section 5.7(a)]; ii. The risk assessment considers the frequency and consequences of past events, using company and industry data [ASME B31.8S-2004, Section 5.7(c)]; iii. The risk assessment approach integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S-2004, Section 5.7(d)]; iv. The risk assessment process includes a structured set of weighting factors to indicate the relative level of influence of each risk assessment component [ASME B31.8S-2004, Section 5.7(i)]; v. The risk assessment process incorporates sufficient resolution of pipeline segment size to analyze data as it exists along the pipeline [ASME B31.8S-2004, Section 5.7(k)].
4.6,5.5, 5.6.4, 5.6.5,	§192.917(c) B31.8S-2004, 5.4 B31.8S-2004, 5.7 B31.8S-2004, 5.11 B31.8S-2004, 5.12	C.3d	d. Verify that records demonstrate that the risk analysis data is combined in an appropriate manner to produce a risk value for each pipeline segment. Verify that the records: i. Show a defined logic and structure to provide a complete, accurate, and objective analysis of risk [ASME B31.8S-2004, Section 5.7(a)];

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			ii. Show the frequency and consequences of past events, using company and industry data is considered[ASME B31.8S-2004, Section 5.7(c)]; iii. Shows the risk assessment approach integrates the results of pipeline inspections in the development of risk estimates [ASME B31.8S-2004, Section 5.7(d)]; iv. Show how factors with missing or unsubstantiated data was used in the risk analysis [ASME B31.8S-2004, Section 5.7(e)] v. Show that conservative assumptions are used whenever inadequate or unsubstantiated data was used in the risk analysis [ASME B31.8S-2004, Section 5.7(e)] vi. Shows a structured set of weighting factors to indicate the relative level of influence of each risk assessment component [ASME B31.8S-2004, Section 5.7(i)]; vii. Shows that sufficient resolution of pipeline segment size was used to analyze data as it exists along the pipeline [ASME B31.8S-2004, Section 5.7(k)].
5.5, 5.6.12	B31.8S-2004, 5.7(b)	C.3e	e. Verify that adequate time and personnel have been allocated to permit effective completion of the selected risk assessment approach. [ASME B31.8S2004, Section 5.7(b)]
		C.4	**C.4 Validation of the Risk Assessment** Verify that the integrity management program identifies and documents a process to validate the results of the risk assessments. [§192.917(c) and ASME B31.8S-2004, Section 5.12]
5.6.5	§192.917(c) B31.8S-2004, 5.12	C.4a	a. Verify that the validation process includes a check that the risk results are logical and consistent with the operator's and other industry experience. [§192.917(c) and ASME B31.8S-2004, Section 5.12]
5.6.12	§192.917(c) B31.8S-2004, 5	C.4b	b. Verify that the operator's process provides for revisions to the risk assessment if new information is obtained or conditions change on the pipeline segments. Verify that the provisions for change to the risk assessment address the following areas: i. the risk assessment plan calls for recalculating the risk for each segment to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions. [ASME B31.8S-2004, Section 5.11, and ASME B31.8S-2004, Section 5.7(c)] ii. the operator integrates the risk assessment process into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. [ASME B31.8S-2004, Section 5.4] iii. the integrity management plan calls for revision to the risk assessment process if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments. [§192.917(c) and ASME B31.8S-2004, Section 5.12] iv. the operator uses a feedback mechanism to ensure that the risk model is subject to continuous validation and improvement. [§192.917(c) and ASME B31.8S-2004, Section 5.7(f)]

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			v. the use of a mechanism to ensure the risk model is subject to continuous validation and improvement vi. leak, failure, and incident history is used to validate the risk model.
5.6	192.917, B31.8S-2004, 5	**C.4c**	4c. Verify that records demonstrate that the risk assessment was revised as necessary as new information was obtained or conditions changed on the pipeline segments. Verify that the records address the following: i. The risk for each segment was recalculated to reflect the results from an integrity assessment or to account for completed prevention and mitigation actions. ii. The risk assessment process was integrated into field reporting, engineering, facility mapping, and other processes as necessary to ensure regular updates. iii. The risk assessment process was revised if pipeline maintenance or other activities identify inaccuracies in the characterization of the risk for any segments. iv. The risk model is continually being validated and improved. v. The operator uses its leak, failure, and incident history to validate the risk model. vi. The operator captures actions such as installing new pipe, new coating, repairs, etc. into the pipeline system in and outside of HCA's.
		C.5	**C.5 Plastic Transmission Pipeline** If the operator has plastic transmission pipelines, verify that the operator assesses applicable threats to each covered segment of plastic line. [§192.917(d)]
4.4.3, 4.8	192.917(d) B31.8S-2004, 4 B31.8S-2004, 5	C.5a	a. If the operator has plastic transmission lines, verify that the information in ASME B31.8S-2004, Section 4 and ASME B31.8S-2004, Section 5, and any unique threats to the integrity of plastic pipe have been considered when assessing the threats to each covered segment of plastic pipeline. [§192.917(d)]
		D.1	**D.01 ECDA Programmatic Requirements** If the operator elects to use ECDA, verify that the operator develops and implements an ECDA plan in accordance with §192.925.
Section 7A	192.925(b)	D.1a	a. Verify that the operator developed a documented ECDA plan, and developed procedures to implement the plan. [§192.925(b)]
		D.2	**D.02 ECDA Pre-Assessment** Verify that the ECDA Pre-assessment process complies with ASME B31.8S-2004, Section 6.4 and NACE SP0502-2008 to (1) determine if ECDA is feasible for the pipeline to be evaluated, (2) identify ECDA regions and (3) select Indirect Inspection Tools. [§192.925(b)(1)]

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Section 7A, 7A.3.4.3, Form 7A.1, Form 7A.2	SP0502-2008, 3.2	D.2a	a. Verify that the operator **identifies and collects adequate data** to support ECDA pre-assessment. [NACE SP0502-2008, Section 3.2]
Section 7A, 7A.3.8, Form 7A.3	SP0502-2008, 3.3	D.2b	b. Verify that the operator conducts an ECDA **feasibility assessment** by integrating and analyzing the data collected. [NACE SP0502-2008, Section 3.3]
Section 7A, 7A.3.9, Form 7A.4	192.925(b)(1) SP0502-2008, 3.4 SP0502-2008, Table 2 §192.925(b)(1)(ii)	D.2c	c. Verify that the operator complies with all requirements for appropriate indirect inspection **tools selection**: [SP0502-2008, Section 3.4, NACE SP0502-2008, Table 2, and §192.925(b)(1)(ii)] i. A minimum of 2 complementary tools must be selected such that the strengths of one tool compensate for the limitations of the other tool. (Note: The operator must consider whether more than two indirect inspection tools are needed to reliably detect corrosion activity.) ii. Tools are able to assess and reliably detect corrosion activity and/or coating holidays. iii. Verify that the operator documents the basis for its tool selection. iv. If the operator utilizes an indirect inspection method not listed in NACE SP0502 -2008, Appendix A, verify that the operator justifies and documents the method's applicability, validation basis, equipment used, application procedure, and utilization of data. [§192.925(b)(1)(ii)]
Section 7A, 7A.3.10, Form 7A.5	SP0502-2008, 3.5	D.2d	d. Verify that the operator **identifies ECDA Regions** based on the use of data integration results applied to specified criteria. [NACE SP0502-2008 Section 3.5]
Table 7A.4.8 Section 7A, Table 7A.3.1, 7A3.9.3	§192.925(b)(1)(i)	D.2e	e. Verify that the operator applies more restrictive criteria when conducting ECDA pre assessment for the first time on a covered segment. [§192.925(b)(1)(i)]
		D.3	**D.03 ECDA Indirect Examination** Verify that the ECDA Indirect Examination process complies with ASME B31.8S-2004, Section 6.4 and NACE SP 0502-2008, Section 4 to identify and characterize the severity of coating fault indications, other anomalies, and areas at which corrosion activity may have occurred or may be occurring, and establish priorities for excavation. [§192.925(b)(2)]

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Section 7A, 7A.4	SP0502-2008, 4.2.1 SP0502-2008, 4.2.2 SP0502-2008, 4.2.3	D.3a	a. Verify that the operator **conducts indirect examination measurements** in accordance with NACE SP0502-2008, Section 4.2. i. Verify that the operator identifies and clearly marks the boundaries of each ECDA region. [NACE SP0502-2008, Section 4.2.1] ii. Verify that the operator performs indirect inspections over the entire lengths of each ECDA region and that the inspections conform to generally accepted industry practices. [NACE SP0502-2008, Section 4.2.2] iii. Verify that the operator specifies and follows generally accepted industry practices for conducting ECDA indirect inspections and analyzing results. [NACE SP0502-2008, Section 4.2.2] iv. Verify that the operator specifies the physical spacing of readings (and the practices for changing the spacing as needed) such that suspected corrosion activity on the segment can be detected and located. [NACE SP0502-2008, Section 4.2.3]
Section 7A, 7A4.9, 7A4.10, 7A.4.12, 7A.4.13	SP0502-2008, 4.3 SP0502-2008, 5.2 192.917(b) 192.917(e)(ii) 192.925(b)(2)(iii)	D.3b	b. Verify that the operator properly aligns indications and compares the data from each indirect examination to characterize both the severity of indications and urgency for direct examination in accordance with NACE SP0502-2008, Section 4.3 and NACE SP0502-2008, Section 5.2. i. Verify the operator specifies criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum criteria include 1. Known sensitivities of assessment tools 2. The procedures for using each tool 3. The approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected. [§192.925(b)(2)(ii) and NACE SP0502-2008, Section 4.3.1.1] ii. Verify that the operator specifies and applies criteria for classification of the severity of each indication. [NACE SP0502-2008, Section 4.3.2], 1. Verify that the operator considers the impact of spatial errors when aligning indirect examination results. [NACE SP0502-2008, Section 4.3.1.2] 2. Verify that the operator compares the results from the indirect inspections and determines the consistency of indirect inspections results to resolve conflicting or differing indications by the primary and secondary tools. [NACE SP0502-2008, Section 4.3.3] 3. Verify that the operator compares indirect inspection results with pre-assessment results to confirm or reassess ECDA feasibility and ECDA Region definitions. [NACE SP0502-2008, Section 4.3.4] iii. Verify that the operator specified and applies criteria for defining the urgency level (i.e., immediate, scheduled, or monitored) with which excavation and direct examination of indications will be conducted based on the likelihood of current corrosion activity plus the extent and severity of prior corrosion. [§192.925(b)(2)(iii) and (iv) and NACE SP0502-2008, Section 5.2] iv. Verify that the operator's ECDA procedures have a process to address pipeline coating indications. The procedures must provide for integrating ECDA data with encroachment and foreign line crossing data to evaluate the covered segment for the threat of third party damage, and to address this threat as required by §192.917(e)(1) (See Protocol C.02 and Protocol C.03). [§192.917(b), §192.917(e) and §192.925(b)]

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Table 7A.4.8 Section 7A, Table 7A.3.1, 7A3.9.3		D.3c	c. Verify that the operator applies more restrictive criteria when conducting ECDA indirect examinations for the first time on a covered segment. [§192.925(b)(2)(i)]
		D.4	**D.04 ECDA Direct Examination** Verify that the ECDA Direct Examination process complies with ASME B31.8S-2004, Section 6.4 and NACE SP0502-2008, Section 5 to collect data to assess corrosion activity and remediate defects discovered. [NACE RS0502-2008, Section 5.1.1 and §192.925(b)(3)]
Section 7A5.5	SP0502-2008, 5.3 SP0502-2008, 5.4 SP0502-2008, 5.10 SP0502-2008, 6.4.2	D.4a	a. Verify that the operator performs excavations and data collection in accordance with NACE SP0502-2008, Section 5.3, NACE SP0502-2008, Section 5.4, NACE SP0502-2008, Section 5.10 and NACE SP0502-2008, Section 6.4.2. i. Verify that the operator makes excavations based on priority categories described in NACE SP0502-2008, Section 5.2. [NACE SP0502-2008, Section 5.3.1] ii. Verify that the operator identifies and implements minimum requirements for data collection, measurements, and recordkeeping, to evaluate coating condition and significant corrosion defects at each excavation location. [NACE SP0502-2008, Section 5.3, NACE SP0502-2008, Section 5.4, NACE SP0502-2008, Appendix A, NACE SP0502-2008, Appendix B, and NACE SP0502-2008, Appendix C] iii. Verify that the number and location of direct examinations complies with NACE SP0502-2008, Section 5.10 and NACE SP0502-2008, Section 6.4.2
Section 7A	192.925(b)(3) SP0502-2008, 5.5 192.933	D.4b	b. Verify that the operator determines the remaining strength at locations where corrosion defects are found. Any corrosion defects discovered during direct examinations must be remediated in accordance with §192.933. [§192.925(b)(3)(ii), §192.933, and NACE SP0502-2008 Section 5.5]
Section 7A	SP0502-2008, 5.9.3 SP0502-2008, 5.6.2 192.925(b)(3)	D.4c	c. Verify that the operator identifies the root cause of all significant corrosion activity, [NACE SP0502-2008, Section 5.6] and identifies and reevaluates all other indications that occur in the pipeline segment where similar root-cause conditions exist. [NACE SP0502-2008, Section 5.9.3] i. Verify that the operator considers alternative methods of assessing the integrity of the pipeline segment if the operator's root cause analysis uncovers problems for which ECDA is not well suited. [NACE RP0S02-2008, Section 5.6.2 and §192.925(b)(3)(ii)(b)]
Section 7A	SP0502-2008, 5.7 192.933	D.4d	d. Verify that the operator mitigates or precludes future external corrosion resulting from significant root causes. [NACE SP0502-2008, Section 5.7]

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Section 7A	SP0502-2008, 5.7 SP0502-2008, 5.8 192.933	D.4e	e. Verify that the operator performs an evaluation of the indirect inspection data, the results from the remaining strength evaluation and root cause analysis to evaluate the criteria and assumptions used to: [NACE SP0502-2008, Section 5.7, NACE SP0502-2008, Section 5.8, and §192.933] i. Categorize the need for repairs ii. Classify the severity of individual indications
Section 7A	SP0502-2008, 5.9 192.925(b)(3)	D.4f	f. As appropriate, verify the basis upon which the operator may reclassify and reprioritize indications in accordance with any of the provisions that are specified in NACE SP0502-2008, Section 5.9. [§192.925(b)(3)(iv)]
Section 7A	192.925(b)(3) 192.909 192.911(k)	D.4g	g. Verify the operator establishes and implements criteria and internal notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications. [§192.925(b)(3)(iii), §192.909, and §192.911(k)]
Section 7A	SP0502-2008, 5.1.5 192.933	D.4h	h. Verify that the operator has a process to consider the use of assessment methods other that ECDA (i.e., ILI or Subpart J pressure test) to assess the impact of defects other than external corrosion (e.g., mechanical damage and stress corrosion cracking) discovered during direct examination. [NACE SP0502-2008, Section 5.1.5 and §192.933]
Section 7A	192.925(b)(3)(i)	D.4i	i. Verify that the operator applies more restrictive criteria when conducting ECDA direct examination for the first time on a covered segment. [§192.925(b)(3)(i)]
		D.5	**D.05 ECDA Post-Assessment** Verify that the ECDA Post assessment process complies with ASME B31.8S-2004, Section 6.4 and NACE SP0502-2008, Section 6, to (1) define reassessment intervals and (2) assess the overall effectiveness of the ECDA process. [§192.925(b)(4) and §192.939]
Section 7A	SP0502-2008, 6.2 SP0502-2008, 6.3	D.5a	a. Verify that the operator determined **reassessment intervals** in accordance with NACE SP0502-2008, Section 6. i. Verify the adequacy of the operators remaining life calculations. [NACE SP0502-2008, Section 6.2] ii. Verify that the maximum re-assessment intervals for each region are one half the calculated remaining life. [NACE SP0502-2008, Section 6.1.3and NACE SP0502-2008, Section 6.3]

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Section 7A, Section 13	192.939 192.925(b)(4)	D.5b	b. Verify that the reassessment intervals are adjusted if required in accordance with special provisions in Subpart O, as follows: i. Verify that reassessment intervals do not exceed the maximum intervals (refer to Protocol F) established in §192.939, as follows: 1. 10 years for pipeline segments operating at SMYS levels greater than 50% 2. 15 years for those segments operating between 30 and 50% SMYS 3. 20 years for those segments operating below 30% SMYS ii. Verify that the operator specifies and applies criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in §192.939. [§192.925(b)(4)(ii)]
Section 7A	192.925(b)(4) 192.945(b) SP0502-2008, 6.4	D.5c	c. Verify that performance measures for ECDA effectiveness have been defined and are monitored. [§192.925, §192.945(b) and NACE SP0502-2008, Section 6] i. Verify that at least one additional, randomly selected anomaly location has been excavated for process validation. [NACE SP0502-2008, Section 6] ii. Verify that additional criteria have been established and monitored to evaluate long-term program effectiveness such as those identified in NACE SP0502-2008, Section 6.4.3. [§192.945(b) and NACE SP0502-2008, Section 6.4.3]
Section 7A	192.907 SP0502-2008, 6.5	D.5d	d. Verify the operator's process has incorporated feedback at all appropriate opportunities throughout the ECDA process to demonstrate feedback and continuous improvement. [192.907(a) and NACE SP0502-2008, Section 6.5]
		D.6	**D.06 Dry Gas ICDA Programmatic Requirements** If the operator elects to use ICDA, verify that the operator develops and implements an ICDA plan in accordance with §192.927.
Section 7B	192.927(c)	D.6a	a. Verify that the operator developed a documented ICDA plan [§192.927(c)]
Section 7B	192.927(c)(5) 192.933	D.6b	b. Verify that the operator's plan contains provisions for carrying out ICDA on the entire pipeline in which covered segments are present, except that application of the remediation criteria of 192.933 may be limited to covered segments. [§192.927(c)(5)(iii)]
Section 7B	192.927(c)(5)	D.6c	c. Verify that the operator implements the ICDA plan. [§192.927(c)]
		D.7	**D.07 Dry Gas ICDA Pre-Assessment, Region Identification, Use of Model & Indirect Inspection** For dry gas systems, verify that the operator gathers, integrates and analyzes data and information to accomplish pre-assessment objectives. [§192.927(c)(1) and ASME B31.8S-2004, Section 6.4.2 ASME B31.8S-2004, Appendix A2 and ASME B31.8S-2004, Appendix B2]

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Section 7B	192.927(c)(5)(i)	D.7a	a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., region identification, feasibility determinations) in implementing the pre-assessment stage of the ICDA process. [§192.927(c)(5)(i)]
Section 7B	192.927(c)(1)	D.7b	b. Verify that the operator collects, as a minimum, the following **data and information**: i. All data elements listed in ASME B31.8S-2004, Appendix A2 [§192.927(c)(1)(i)] ii. Information needed to support use of a model to identify areas where internal corrosion is most likely, including locations of all 1) gas input and withdrawal points, 2) low points such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, 3) elevation profile in sufficient detail for angles of inclination to be calculated, and 4) the range of expected gas velocities within the pipeline; [§192.927(c)(1)(ii)] iii. Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions [§192.927(c)(1)(iii)] iv. Information where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes. [§192.927(c)(1)(iv)]
Section 7B	192.927(c)(1) 192.927(c)(2)	D.7c	c. Verify that the operator integrates the data collected and uses the integrated data analysis to evaluate and document the following: i. Feasibility of performing ICDA on its pipe segments [§192.927(c)(1)] ii. Identification of ICDA Regions and the location of each region. [§192.927(c)(1) and §192.927(c)(2)] iii. Support use of a model to identify the locations along the pipe segment where electrolyte may accumulate [§192.927(c)(1)] iv. Identify areas within the covered segment where liquids may be potentially entrained. [§192.927(c)(1)]
Section 7B	[§192.927(c)(2)] GRI 02-0057	D.7d	d. Verify the operator's plan uses the model in GRI 02-0057 ICDA of Gas Transmission Pipelines- Methodology (or equivalent acceptable model) to define critical pipe angle of inclination above which water film cannot be transported by the gas, and that the model considers, as a minimum: [§192.927(c)(2)] i. Changes in pipe diameter, [§192.927(c)(2)] ii. Locations where gas enters a line, [§192.927(c)(2)] iii. Locations down stream of gas draw-offs. [§192.927(c)(2)] iv. Other conditions that may result in changes in gas velocity. [§192.927(c)(2) and GRI 02-0057]
Section 7B	192.927(c)(5)(ii)	D.7e	e. Verify that the operator's plan contains provisions for applying more restrictive criteria for pre-assessment and region identification when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

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		D.8	**D.08 Dry Gas ICDA Direct Examination** For dry gas systems, verify that the operator (1) identifies locations where internal corrosion is most likely in each ICDA region and (2) performs direct examinations of those locations. [§192.927(b), §192.927(c)(3), ASME B31.8S-2004, Section 6.4 and ASME B31.8S-2004, Appendix B2]
Section 7B	192.927(c)(5)(i)	D.8a	a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., identifying locations most likely to have internal corrosion, selection of tools) in implementing the direct assessment stage of the ICDA process. [§192.927(c)(5)(i)]
Section 7B	192.927(c)(3) B31.8S-2004, 6.4.2 Appendix B2.3	D.8B	a. Verify the operator has identified locations where internal corrosion is most likely to exist in each ICDA region and where electrolyte accumulation is predicted. [§192.927(c)(3), ASME B31.8S-2004, Section 6.4.2 and ASME B31.8S-2004, Appendix B2.3]
Section 7B	192.927(c)(2) B31.8S-2004, 6.4.2 Appendix B2.3 Appendix B2.4	D.8c	c. Verify the operator requires a direct examination for internal corrosion using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique of those covered segment locations where internal corrosion is most likely to exist, and includes as a minimum, the following: [§192.927(c)(3), ASME B31.8S-2004, Section 6.4.2, ASME B31.8S-2004, Appendix B2.3, and ASME B31.8S-2004, Appendix B2.4] i. A minimum of two (2) locations within each ICDA region within a covered segment, ii. At least one location must be the low point nearest the beginning of the ICDA region and iii. The second location must be further downstream within a covered segment near the end of the ICDA Region (The end of the ICDA region is the farthest downstream location where the ICDA model predicts electrolytes could accumulate based on the critical angle of inclination above which water film cannot be transported by the gas). [§192.927(c)(2) and ASME B31.8S-2004, Appendix B2.3]
Section 7	192.933 192.927(c)(3)	D.8d	d. If internal corrosion exists at any location directly examined, verify that the operator: [192.927(c)(3)] i. Evaluates the severity of the defect and remediates the defect per §192.933 (see Protocol E) [§192.927(c)(3)(i)], and ii. Either performs additional excavations or performs additional assessment using an allowed alternative assessment method [§192.927(c)(3)(ii)], and iii. Evaluates the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found and remediates the conditions per §192.933. [§192.927(c)(3)(iii)]
Section 7B	192.927(c)(5)(ii)	D.8e	e. Verify that the operator's plan contains provisions for applying more restrictive criteria for the direct examination when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]

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		D.9	**D.9 Dry Gas ICDA Post-Assessment** For dry gas systems, verify that the operator performs post-assessment evaluation of ICDA effectiveness and continued monitoring of covered segments where internal corrosion has been identified. [§192.927(c)(4)]
Section 7B	192.927(c)(5)(i)	D.9a	a. Verify that the operator's plan defines criteria to be applied in making key decisions (e.g., reassessment interval determination, techniques for monitoring internal corrosion) in implementing the post-assessment stage of the ICDA process. [§192.927(c)(5)(i)]
Section 7B	192.927(c)(4) Appendix B2.5 192.939	D.9b	b. Verify the operator has a process for **evaluating the effectiveness** of ICDA as an assessment method and **determining reassessment intervals**. [§192.927(c)(4)(i) and ASME B31.8S-2004, Appendix B2.4] i. Verify that if corrosion is found in areas where the pipeline inclination is greater than the estimated critical inclination, that the operator re-evaluates the critical inclination angle and additional new areas are selected for direct examination. [ASME B31.8S-2004, Appendix B2.4] ii. Verify the operator's process determines whether a segment must be reassessed at intervals more frequently than those specified in §192.939 using the largest defect most likely to remain in the covered segment as the largest defect discovered in the ICDA segment and estimating the reassessment interval as half the time required for the largest defect to grow to critical size. Verify that this evaluation is to be carried out within one year of completion of the assessment. [§192.927(c)(4)(i) and §192.927(a)(3)] iii. Verify the operator's reassessment intervals comply with the following maximum allowed intervals in accordance with 192.939 (see Protocol F). [§192.939(b)] 1. 10 years for segments operating at SMYS levels greater than 50% 2. 15 years for segments operating between 30 and 50% SMYS 3. 20 years for segments operating below 30% SMYS
Section 7B	192.927(c)(4) 192.933 Appendix A2.2	D.9c	c. Verify the operator continually monitors each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing them for corrosion products. [§192.927(c)(4)(ii)] i. Verify the operator has a process to determine the frequency for monitoring and liquid analysis based on all integrity assessments results conducted in accordance with 192 Subpart O and risk factors specific to the covered segment. [§192.927(c)(4)(ii), ASME B31.8S-2004 Appendix A2.2] ii. Verify the operator's process requires that if any evidence of corrosion products is found in the covered segment, prompt action must be taken including, as a minimum: [§192.927(c)(4)(ii)] i. Remediate the conditions the operator finds in accordance with §192.933, and ii. Implement one of the two following required actions: (1) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe, or (2) assess the covered segment using another integrity assessment method allowed by Subpart O.

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Section 7B	192.927(c)(5)(ii)	D.9d	d. Verify that the operator's plan contains provisions for applying more restrictive criteria for the post-assessment when conducting ICDA for the first time on a covered segment [§192.927(c)(5)(ii)]
		D.10	**D.10 Wet Gas ICDA Programmatic Requirements –** If the operator elects to use ICDA to assess a covered segment operating with electrolyte present in the gas stream (wet gas), verify that the operator develops and implements an ICDA plan in accordance with §192.927 which addresses the following. [§192.927(b)]
Section 7	192.927(c)	D.10a	a. Verify that the operator developed a documented ICDA plan which demonstrates how the operator will conduct ICDA on the entire pipeline in which covered segments are present to effectively address internal corrosion. [§192.927(c)]
Section 7	192.921(a)(4) 192.937(c)(4) 192.927(b)	D.10b	b. Verify the operator has provided notification to PHMSA, and applicable state or local safety authorities, of an ICDA wet gas "other technology" application in accordance with §192.921 (a) (4) or §192.937 (c) (4). [§192.927(b)]
		D.11	**D.11 SCCDA Data Gathering & Evaluation** If the operator elects to use SCCDA, verify that the operator's SCCDA evaluation process complies with ASME B31.8S-2004, Appendix A3 in order to identify whether conditions for SCC of gas line pipe are present and to prioritize the covered segments for assessment. [§192.929(b)(1)]
Section 4	192.929(b)(1) Appendix A3	D.11a	a. Verify that the operator has a process to **gather, integrate, and evaluate data** for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. [§192.929(b)(1)] i. Verify that the operator's process gathers and evaluates data related to SCC at all sites it excavates during the conduct of its pipeline operations (not just covered segments) where the criteria indicate the potential for SCC. [§192.929(b)(1) and ASME B31.8S-2004, Appendix A3.3] ii. Verify that the data includes, as a minimum, the data specified in ASME B31.8S-2004, Appendix A3. iii. Verify that the operator addresses missing data by either using conservative assumptions or assigning a higher priority to the segments affected by the missing data, as required by ASME B31.8S-2004, Appendix A3.2.
		D.12	**D.12 SCCDA Assessment, Examination, & Threat Remediation** Verify that covered segments (for which conditions for SCC are identified) are assessed, examined, and the threat remediated. [§192.929(b)(2)]
N/A	B31.8S-2004, Appendix A3	D.12a	a. Verify that, if conditions for SCC are present, that the operator **conducts an assessment** using one of the methods specified in ASME B31.8S-2004, Appendix A3.

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Section 7	B31.8S-2004, Appendix A3.4	D.12b	b. Verify that the operator's plan specifies an acceptable **inspection, examination, and evaluation plan** using either the Bell Hole Examination and Evaluation Method (that complies with all requirements of ASME B31.8S-2004 Appendix A3.4 (a)) or Hydrostatic Testing (that complies with all requirements of ASME B31.8S-2004, Appendix A3.4 (b)). i. Verify, that the operator's plan requires that for pipelines which have experienced an in-service leak or rupture attributable to SCC, that the particular segment(s) be subjected to a hydrostatic pressure test (that complies with ASME B31.8S-2004, Appendix A3.4 (b)) within 12 months of the failure, using a documented hydrostatic retest program developed specifically for the affected segment(s), as required by ASME B31.8S-2004, Appendix A3.4.
Section 7	192.939(a)(3)	D.12c	c. Verify that assessment results are used to determine **reassessment intervals** in accordance with §192.939(a)(3); (see Protocol F). [§192.939(a)(3)]
		E.1	**E.1 Program Requirements for Discovery, Evaluation and Remediation Scheduling** Verify that provisions exist to discover and evaluate all anomalous conditions resulting from integrity assessment and remediate those which could reduce a pipeline's integrity. [§192.933(a)]
10.3	192.933(b)	E.1a	a. Verify a definition of discovery is provided. [§192.933(b)]
10.4; Forms 9B.2, 9C.2, 7A.10	192.933(b)	E.1b	b. Verify a requirement exists to document the actual date of discovery. [§192.933(b)]
10.4; Forms 9B.2, 7A.7, 7A.8	192.933(c)	E.1c	c. Verify a requirement exists to develop a schedule that prioritizes evaluation and remediation of anomalous conditions. [§192.933(c)]
N/A	192.933 192.913(b) 192.913(c)	E.1d	d. If the operator desires to deviate from the timelines for remediation as provided in Section 192.933 by demonstrating exceptional performance, verify that the requirements of Section 192.913(b) have been met and the safety of the covered segment is not jeopardized. [§192.913(c)(2)](See Protocol F.5)
		E.2	**E.2 Program Requirements for Identifying Anomalies** Inspect the operator's program to verify that provisions exist for the classification and remediation of anomalies that meet the criteria for: (1) Immediate repair conditions; (2) One-year conditions; (3) Monitored conditions; or (4) Other conditions as specified in ASME B31.8S-2004, Section 7 . [§192.933(c) and §192.933(d)]
10.4, 10.5.1, Form 10-1	192.933(d)(1)	E.2a	a. Verify the program requires a temporary pressure reduction or the pipeline to be shut down upon discovery of all immediate repair conditions. [192.933(d)(1)]

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10.4.1	192.933(d)(1) 192.933(d)(2) 192.933(d)(3) B31.8S-2004, 7.2.1 B31.8S-2004, 7.2.2 B31.8S-2004, 7.2.3	E.2b	b. Verify provisions exist to classify and categorize anomalies meeting the following criteria: i. Immediate Repair Conditions (Conditions requiring immediate remediation actions) 1. Calculated remaining strength indicates a failure pressure that is less than or equal to 1.1 times MAOP; [§192.933(d)(1)] 2. A dent having any indication of metal loss, cracking, or a stress riser; [§192.933(d)(1)] 3. An indication or anomaly that is judged by the person designated by the operator to evaluate assessment results as requiring immediate action. [§192.933(d)(1)] 4. Metal-loss indications affecting a detected longitudinal seam if that seam was formed by direct current or low-frequency electric resistance welding or by electric flash welding; [ASME B31.8S-2004, Section 7.2.1] 5. All indications of stress corrosion cracks; [ASME B31.8S-2004, Section 7.2.2]; or 6. Any indications that might be expected to cause immediate or near-term leaks or ruptures based on their known or perceived effects on the strength of the pipeline. [ASME B31.8S-2004, Section 7.2.3] ii. One-Year Conditions (Conditions requiring remediation within one year of discovery). 1. A smooth dent located between the 8 and 4 o'clock positions (upper 2/3 of the pipe) with a depth greater than 6% of the pipeline diameter; [§192.933(d)(2)] or, 2. A dent with a depth greater than 2% of the pipeline's diameter, that affects pipe curvature at a girth weld or at a longitudinal seam weld. [§192.933(d)(2)] iii. Monitored Conditions (Conditions which must be monitored until the next assessment). 1. A dent with a depth greater than 6% of the pipeline diameter located between the 4 and 8 o'clock position (lower 1/3) of the pipe; [§192.933(d)(3)] 2. A dent located between the 8 and 4 o'clock position (upper 2/3) of the pipe with a depth greater than 6% of the pipeline diameter, and engineering analysis to demonstrate critical strain levels are not exceeded; [§192.933(d)(3)]or, 3. A dent with a depth greater than 2% of the pipeline diameter, that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analysis of the dent and girth or seam weld to demonstrate critical strain levels are not exceeded. [§192.933(d)(3)]
10.5.2	192.933(d)(3)	E.2c	c. . Verify provisions exist to record and monitor anomalies that are classified as "monitored conditions" during subsequent risk or integrity assessments for any change in their status that would require remediation. [§192.933(d)(3)]

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10.4, 10.5.2	B31.8S-2004, 7 192.933(c)	E.2d	d. Verify that program requirements exist to meet the provisions of ASME B31.8S-2004, Section 7, Figure 4 for scheduling and remediating any other threat conditions that do not meet the classification criteria of Protocol E.02.b, above. [§192.933(c)]
		E.3	**E.3. Operator Response when Timelines for Evaluation and Remediation Cannot be Met** Verify that provisions exist to respond appropriately when the operator is unable to meet time limits for evaluation and remediation. [§192.933(a)].
10.10, 10.5	192.933(a) B31G	E.3a	a. Verify a requirement exists to take a temporary operating pressure reduction or other action that ensures safety of the covered segment in the event the operator is unable to respond within the timeframes required by 192.933. [192.933(a)] i. Verify a requirement exists to determine the appropriate pressure reduction using ASME B31G, or "RSTRENG", or reduce pressure to a level not exceeding 80% of the level at the time the condition was discovered. [§192.933(a)] ii. Verify a requirement exists that when a pressure reduction is to exceed 365 days, a documented technical justification is developed that explains the reason for remediation delay and demonstrates continuation of the reduction will not jeopardize pipeline integrity. [§192.933(a)]
10.9, 10.10	192.933(a) 192.933(c)	E.3b	b. Verify a requirement exists to document the justification, when a remediation activity cannot be completed within established timeframe requirements, that includes the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety. [§192.933(a) and §192.933(c)]
10.9,10.10, 10.11.1	192.949 192.933(a) 192.933(c)	E.3c	e. Verify a requirement exists to notify PHMSA in accordance with Section §192.949 and the State pipeline safety authority, if applicable, when: i. the operator cannot meet the evaluation and remediation schedule and cannot provide a temporary reduction in operating pressure or other action [§192.933(a)(1) and §192.933(c)], and ii. a pressure reduction exceeds 365 days. [§192.933(a)(2)] The notification is to include the documented justification under protocols E.03.a and E.03.b.
		E.4	**E.4. Record Review for Discovery, Repair and Remediation Activities** Inspect operator repair and remediation records to verify that remediation activities have been conducted in accordance with program requirements. [§192.933]
10.2, 10.4, 10.5, 10.6	192.933(c) 192.933(d)	E.4a	a. Verify a prioritized schedule exists for evaluation and remediation of anomalies identified during assessment or reassessment activities. The prioritized schedule must document which of the criteria specified in §192.933(d) and/or ASME B31.8S-2004 were used as the basis for the schedule. [§192.933(c) and §192.933(d)]
10.2.1, Forms 10-1, 9B.2, 7A.8, 7A.10,	192.933(b)	E.4b	b. Verify anomaly discovery was documented within 180 days of completion of the assessment or reassessment, or else that compliance with the 180-day period was impracticable. [§192.933(b)]

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7B.12			
10.2, 10.5.2, 10.6	192.933(a)	E.4c	c. Verify any remediation activities taken are sufficient to ensure that the anomaly is unlikely to threaten the integrity of the pipeline before the next scheduled reassessment. [§192.933(a)]
10.4, 10.5.1.2, Figs. 10-2 & 10-3, Form 10-1	192.933(a) B31G	E.4d	d. Verify, for any immediate repair anomalies, a temporary pressure reduction is taken by the operator on the pipeline and the reduced pressure is determined in accordance with ASME B31G, or "RSTRENG", or that the reduced pressure does not exceed 80% of the level at the time the condition was discovered. [§192.933(a)]
10.4.2, 10.4.4, 10.5.1	192.933(d)(1) B31.8S-2004,7	E.4e	e. Verify immediate repair conditions have been evaluated and remediated on a schedule established in accordance with the provisions of ASME B31.8S-2004, Section 7. [§192.933(d)(1)]
10.4,10.5.1.2, 10.10	192.933(a) 192.949	E.4f	f. Verify any pressure reduction taken has not exceeded 365 days from the date of discovery unless: i. a technical justification has been developed to demonstrate that continuation of the pressure reduction will not jeopardize the integrity of the pipeline [§192.933(a)], and ii. PHMSA and the State pipeline safety authority, if applicable, have been notified in accordance with §192.949. [§192.933(a)]
Forms 10-1, 9B.2, 7A.8, 7A.10, 7B.12	192.933(c) 192.933(d)	E.4g	g. Verify that remediation activities were completed in accordance with scheduled timeframes. [§192.933(c) and §192.933(d)]
10.2.1, 10.4, Froms 9B.2, 7A.8, 7A.10, 7B.12	192.933(d)	E.4h	h. Verify that anomalies meeting any of the criteria of §192.933(d)(3) as "monitored conditions" are evaluated during subsequent risk and integrity assessments to identify any change that may require remediation and that any required remediation is scheduled and implemented in accordance with the applicable requirements of §192.933 and ASME B31.8S-2004. [§192.933(d)]
10.4, 10.9, 10.10, 10.11, Form 10-1	192.933(c)	E.4i	i. Verify any remediation activities that have not been completed in accordance with §192.933 timeframes, and the operator has not provided safety through a temporary pressure reduction: i. have technical justifications that include the reasons why the schedule cannot be met and the basis for why the changed schedule will not jeopardize public safety, and ii have been reported to PHMSA and appropriate State authorities in accordance with the requirements of §192.933(c) of the rule. [§192.933(c)]
		F.1	**F.1 Periodic Evaluations** Verify the operator conducts a periodic evaluation of pipeline integrity based on data integration and risk assessment to identify the threats specific to each covered segment and the risk represented by these threats. [§192.917 and 192.937(b)]

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13.2, 13.3, Fig 13-2, Fig. 13-5, Fig. 4-6	192.937(b) 192.917 192.933 192.935	F.1a	a. Verify that periodic evaluations are conducted based on a data integration and risk assessment of the entire pipeline as specified in §192.917. The evaluation must consider the following: [§192.937(b) and §192.917] i. Past and present assessment results ii. Data integration and risk assessment information [§192.917] iii. Decisions about remediation [§192.933] iv. Additional preventive and mitigative actions [§192.935]
4.7	192.937(b)	F.1b	b. Verify that periodic evaluations of data are thorough, complete, and adequate for establishing reassessment methods and schedules. [§192.937(b)]
13.4, Form 3-1	192.937(b)	F.1c	c. Verify that an appropriate interval is established for performing required periodic evaluations of threats and pipeline conditions following completion of the baseline assessment. [§192.937(b)]
Section 13	192.937	F.1d	d. Verify that the operator periodically reviews the evaluation results to determine if the new information warrants changes to reassessment intervals and/or methods, and makes changes as appropriate. [§192.937]
		F.2	**F.2 Reassessment Methods** Verify that the approach for establishing the reassessment method is consistent with the requirements in §192.937(c). [§192.937(c) and §192.941]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
Section 13, Section 6, Section 9B, 9C,	192.937(c)(1) 192.937(c)(2) 192.937(c)(3) 192.937(c)(4) 192.937(c)(5) 192.949 B31.8S-2004, 5 B31.8S-2004, 6.3	F.2a	a. Verify that one or more of the following assessment methods (depending on the applicable threats) are specified: i. An internal inspection tool(s) capable of detecting corrosion and any other threats that the operator intends to address using this tool(s). The process must follow ASME B31.8S-2004, Section 6.2, in selecting the appropriate inspection tool. [§192.937(c)(1)] ii. A pressure test conducted in accordance with subpart J. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939. Pressure test is appropriate for threats as defined in ASME B31.8S-2004, Section 6.3. [§192.937(c)(2)] iii. Direct assessment – refer to Protocol D. [§192.937(c)(3)] iv. Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the pipe. If other technology is the method selected, the process should require that the operator notify PHMSA at least 180 days before conducting the assessment, in accordance with §192.949. Also, verify that notification to a State or local pipeline safety authority is required when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State. [§192.937(c)(4)] v. Confirmatory direct assessment when used on a covered segment that is scheduled for a reassessment period longer than seven years. Refer to Protocol G. [§192.937(c)(5)] vi. If the operator is using "low stress reassessment" method, evaluate the process using protocol question F.03.
Form 6-1		F.2b	b. Review the methods selected for reassessments and verify that they are appropriate for the identified threats.
		F.3	**F.3 Low Stress Reassessment** For pipelines operating at < 30% SMYS, the operator may choose to use a "low stress reassessment" method to address threats of external and internal corrosion. If this method is used, verify that the operator addresses the following requirements [§192.941]:
Appendix 8-A	192.941(a)	F.3a	a. Verify that the operator completes a baseline assessment on the covered segment prior to implementing the "low stress reassessment" method. [§192.941(a)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
13.5	192.941(b)(1)	F.3b	b. If used to address external corrosion, verify that the operator has incorporated the following: i. If the pipe is cathodically protected, electrical surveys (i.e., indirect examination tool/method) must be performed at least every 7 years. The operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for covered segments. This evaluation must consider, at a minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)] ii. If the pipe is unprotected or cathodically protected where electrical surveys are impractical, the operator must require (1) the conduct of leakage surveys as required by 192.706, at 4-month intervals; and (2) the identification and remediation of areas of active corrosion every 18 months by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe records, and the pipeline environment. [§192.941(b)(1)]
Section 13.5	192.941(c)(1) 192.941(c)(2) 192.941(c)(3)	F.3c	c. If used to address internal corrosion, verify that the operator has incorporated all of the following: i. Gas analysis for corrosive agents must be performed at least once each calendar year. [§192.941(c)(1)] ii. Periodic testing of fluids removed from the segment must be conducted. At least once each calendar year the operator must test the fluids removed from each storage field that may affect a covered segment. [§192.941(c)(2)] iii. At least every seven (7) years, the operator must integrate data from the analysis and testing required by c.i and c.ii above with applicable internal corrosion leak records, incident reports, and test records, and define and implement appropriate remediation actions. [§192.941(c)(3)]
		F.4	**F.4 Reassessment Intervals** Verify that the requirements for establishing the reassessment intervals are consistent with section §192.939 and ASME B31.8S-2004. [§ 192.937(a), 192.939(a), 192.939(b), 192.913(c), ASME B31.8S-2004, Section 5, Table 3]
Section 13	192.921(d) 192.937(a)	F.4a	a. Verify that the operator reassesses covered segments on which a baseline assessment was conducted during the baseline period specified in subpart §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the reassessment evaluation (refer to question F.01) indicates an earlier reassessment. [§192.937(a)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
Section13	192.913(c) 192.917 192.939(a) 192.937(a) B31.8S-2004, 5, Table 3	F.4b	b. For pipelines operating at or above 30% SMYS, verify that the operator meets the following requirements: i. If the operator establishes a reassessment interval greater than seven (7) years, a confirmatory direct assessment (refer to Protocol G) must be performed at intervals not to exceed seven (7) year intervals followed by a reassessment at the interval established by the operator (refer below). [§192.939(a)] ii. Unless a deviation is permitted under 192.913(c), the maximum reassessment interval shall not exceed the values listed in the §192.939(b) table. [§192.937(a)] iii. If the reassessment method is a pressure test, ILI, or other equivalent technology, the interval must be based on either: (1) the identified threat(s) for the covered segment (see §192.917) and on the analyses of the results from the last integrity assessment, and a review of data integration and risk assessment; or (2) using the intervals specified for different stress levels of pipeline listed in ASME B31.8S-2004, Section 5, Table 3. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939. [§192.939(a)(1)] iv. If the reassessment method is external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment refer to Protocol D for evaluating the operator's interval determination.
Section13	192.939(b)(1) 192.939(b)(2) 192.939(b)(3) 192.939(b)(4) 192.939(b)(5) ASME B31.8S-2004, 5, Table 3	F.4c	c. For pipelines operating < 30% SMYS, verify that the operator selects one of the following reassessment approaches: i. Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph §192.939(a)(1) except that the stress level referenced in §192.939(a)(1)(ii) would be adjusted to reflect the lower operating stress level. However, if an established interval is more than seven (7) years, the operator must conduct at seven (7) year intervals either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941. An operator must use the test pressures specified in ASME B31.8S-2004, Section 5, Table 3, to justify an extended reassessment interval in accordance with §192.939.[§192.939(b)(1)] ii. Reassessment by external corrosion direct assessment, internal corrosion direct assessment, or SCC direct assessment. Refer to Protocol D for evaluating the operator's interval determination. [§192.939(b)(2), §192.939(b)(3), and §192.939(b)(4)] iii. Reassessment by confirmatory direct assessment at seven year intervals in accordance with subpart §192.931, with reassessment by one of the methods listed in §192.939(b)(1) – (b)(3) by year 20 of the interval. [§192.939(b)(4)] iv. Reassessment by the "low stress method" at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in §192.939(b)(1) through (b)(3) by year 20 of the interval. [§192.939(b)(5)]
13.4.2, Fig. 13-3	192.921(e) 192.937(a)	F.4d	d. Verify that a covered segment on which a prior assessment was credited as a baseline assessment under subpart §192.921(e) is required to be reassessed by no later than December 17, 2009. [§192.937(a)]
13.4		F.4e	e. Verify that reassessment intervals are appropriate and that adequate documentation and technical bases support the intervals selected.

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		F.5	**F.5 Deviation From Reassessment Requirements** If the operator elects to deviate from certain requirements listed in §192.913(c), verify that the operator uses a performance based approach that satisfies the requirements for exceptional performance as follows: [§192.913, ASME B31.8S-2004]
13.9, N/A	192.911(i) 192.913(a) 192.943	F.5a	a. Verify that the operator has a performance based integrity management program that meets or exceeds the performance-based requirements of ASME B31.8S-2004 and includes, at a minimum, the following elements: [§192.913(a)] i. A comprehensive process for risk analysis; ii. All risk factor data used to support the program; iii. A comprehensive data integration process; iv. A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart; v. A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program; vi. A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments (Refer to Protocol I); vii. Semi-annual performance measures beyond those required in §192.943 that are part of the operator's performance plan. [See §192.911(i)] Refer to Protocol I. viii. An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.
13.9, N/A	192.913(b)(2)(i)	F.5b	b. Verify that the operator has completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach and is able to demonstrate that each assessment effectively addressed the identified threats on the covered segments. [§192.913(b)(2)(i)]
13.9, N/A	192.913(b)(2)(ii) 192.933	F.5c	c. Verify the operator has remediated anomalies identified in the more recent assessment per the requirements of §192.933. [§192.913(b)(2)(ii)]
13.9, N/A	192.913(b)(2)(ii)	F.5d	d. Verify the operator has incorporated the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment. [§192.913(b)(2)(ii)]
13.9, N/A	192.913(c)(1) 192.939	F.5e	e. Verify that deviations are allowed only for the timeframe for reassessment as provide in §192.939 except that reassessment by some method allowed by Subpart O (e.g., confirmatory direct assessment) must be completed at intervals not to exceed seven (7) years. [§192.913(c)(1)]

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		F.6	**F.6 Waiver from Reassessment Interval** Verify that the operator's program requires that it apply for a waiver, should it become necessary, from the required reassessment interval. The waiver request must demonstrate that the waiver is justified as specified in the rule. Such a waiver request may only be made in the following limited situations: [§192.943]
Section13	192.943(a)(1)	F.6a	a. Lack of internal inspection tools. [§192.943(a)(1)]
Section13	192.943(a)(2)	F.6b	b. Cannot maintain local product supply. [§192.943(a)(2)]
Section13	192.943(b)	F.6c	c. Application must be made at least 180 days before the end of the required reassessment interval. (Exception: If local product supply issues make the 180 day submittal impractical, an operator must apply for the waiver as soon as the need for waiver becomes known). [§192.943(b)]
		G.1	**G.1 Confirmatory Direct Assessment, CDA** If using confirmatory direct assessment (CDA) as allowed in §192.937, verify that the operator's integrity management plan meets the requirements of §192.931, §192.925 (ECDA) and §192.927 (ICDA). [§192.931]
Section13, Section 7	192.931(b)	G.1a	a. Verify that the operator's CDA plan for external corrosion complies with all of the requirements contained in §192.925 (See Protocols D.1 ~ D.5) with the following exceptions, [192.931(b)] i. The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application ii. The procedures for direct examination and remediation must provide that all immediate action indications and at least one scheduled action indication are excavated for each ECDA region.
Section 13, Section 7	192.931(c) 192.927	G.1b	b. Verify that the operator's CDA plan for internal corrosion complies with all of the requirements contained in §192.927 (See Protocols D.6 ~ D.10) except that procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.[§192.931(c) and §192.925]
Section13, Section 7	192.931(d) 192.933	G.1c	c. When using CDA carried out under §192.931(b) or (c), if an operator discovers any defect requiring remediation prior to the next scheduled assessment, verify that the operator evaluates the need to accelerate the schedule for the next assessment. If the schedule is accelerated, verify that the new assessment scheduled is determined using the methodology documented in NACE SP0502-2008, Section 6.2 and NACE SP0502-2008, Section 6.3. [§192.931(d)] i. If the defect requires immediate remediation, verify the operator reduces pressure consistent with §192.933 (See Protocol E) until the operator has completed reassessment using one of the assessment techniques allowed in §192.937 (See Protocol F). [§192.931(d)]
		H.1	**H.1 General Requirements (Identification of Additional Measures)** Verify that a process is in place to identify additional measures to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. [§192.935(a)]

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12.1.1, 12.2	192.917 192.935(a)	H.1a	a. Verify that the process for identifying additional measures is based on identified threats to each pipeline segment and the risk analysis required by §192.917. [Note: Protocol H.8 addresses the implementation decision process for additional preventive and mitigative measures.] [§192.935(a)]
12.3.1	192.935(a)	H.1b	b. Verify that additional measures evaluated by the operator cover a spectrum of alternatives such as, but not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs. [§192.935(a)]
		H.2	**H.2 Third Party Damage** Verify that the following preventive and mitigative requirements regarding threats due to third party damage have been addressed: [§192.935(b)(1) and §192.935(e)]
12.3.2	192.935(b)(1) 192.915(c) B31.8S-2004,7.5 SP0502-2008	H.2a	a. Verify implementation of enhancements to the §192.614-required Damage Prevention Program with respect to covered segments to prevent and minimize the consequences of a release, and that the enhanced measures include, at a minimum: [Note: As noted in Protocol H.03 and Protocol H.04, a subset of these enhancements are required for pipelines operating below 30% SMYS and for plastic transmission pipelines.] [§192.935(b)(1)] i. Using qualified personnel (see Protocol L.02 - §192.915(c)) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [§192.935(b)(1)(i)] ii. Collecting, in a central database, location-specific information on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under Part 191. [§192.935(b)(1)(ii)] iii. Participating in one-call systems in locations where covered segments are present. [§192.935(b)(1)(iii)] iv. Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. 1. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE SP0502-2008 must be conducted. [§192.935(b)(1)(iv)] A. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ASME B31.8S-2004, Section 7.5 and §192.933. [§192.935(b)(1)(iv)]
12.3.2, Forms 12-2	192.917(e)(1)	H.2b	b. If the threat of third party damage is identified by results of the §192.917(b) (Protocol C.02) and ASME B31.8S-2004, Appendix A7 data integration processes, verify that comprehensive additional preventive measures are implemented. [§192.917(e)(1)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
		H.3	**H.3 Pipelines Operating Below 30% SMYS** Verify that the following preventive and mitigative requirements for pipelines operating below 30% SMYS have been addressed:
12.3.5	192.935(d) 192.935(d)(1) 192.935(d)(2)	H.3a	a. For pipelines operating below 30% SMYS located in a high consequence area: i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [§192.935(d) and §192.935(d)(1)] [Note: This requirement is also contained in Protocol H.02.a.i for pipelines operating above 30% SMYS.] ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d) and §192.935(d)(1)] [Note: This requirement is also contained in Protocol H.02.a.iii for pipelines operating above 30% SMYS.] iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d) and §192.935(d)(2)] 1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2)]
12.3.5	192.935(d) 192.935(d)(1) 192.935(d)(2) 192.935(d)(3) Table E.II.1	H.3b	b. For pipelines operating below 30% SMYS located in a class 3 or 4 area but not in a high consequence area: i. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [§192.935(d), §192.935(d)(1) and §192 Table E.II.1] [Note: This requirement is also contained in Protocol H.02.a.i for pipelines operating above 30% SMYS.] ii. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(d), §192.935(d)(1) and §192 Table E.II.1] [Note: This requirement is also contained in Protocol H.02.a.iii for pipelines operating above 30% SMYS.] iii. Verify that excavations near the pipeline are monitored, or patrols are conducted of the pipeline at bi-monthly intervals as required by §192.705. [§192.935(d), §192.935(d)(2) and §192 Table E.II.1] 1. If indications of unreported construction activity are found, verify that required follow up investigations are conducted to determine if mechanical damage has occurred. [§192.935(d)(2) and §192 Table E.II.1] iv. Verify that the operator performs semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical). [§192.935(d)(3)and §192 Table E.II.1]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
		H.4	**H.4 Plastic Transmission Pipeline** For plastic transmission pipelines, verify that applicable third party damage requirements have been applied to covered segments of the pipeline. [§192.935(e)]
12.3.2.1	192.935(e)	H.4a	a. Verify that the operator's processes for damage prevention program enhancements include requirements for the use of qualified personnel (see Protocol L.02 - §192.915(c)) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work. [§192.935(e)] [Note: This requirement is also contained in previous Protocol H.02.a.i for non-plastic pipelines operating above 30% SMYS.]
12.3.2.3	192.935(e)	H.4b	b. Verify that the operator's processes for damage prevention program enhancements include participating in one-call systems in locations where covered segments are present. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iii for non-plastic pipelines operating above 30% SMYS.]
12.3.2.4	192.935(e) SP0502-2008	H.4c	c. Verify that the excavations on covered segments are monitored by pipeline personnel. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.] i. When there is physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, verify that the area near the encroachment must be excavated or that an above ground survey using methods defined in NACE SP0502-2008 must be conducted. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.] 1. If an above ground survey is conducted, verify that any indication of coating holidays or discontinuities warranting direct examination must be excavated and remediated in accordance with ASME B31.8S-2004, Section 7.5 and §192.933. [§192.935(e)] [Note: This requirement is also contained in Protocol H.02.a.iv for non-plastic pipelines operating above 30% SMYS.]
		H.5	**H.5 Outside Force Damage** Verify that the operator adequately addresses threats due to outside force (e.g., earth movement, floods, unstable suspension bridge). [§192.935(b)(2)]
12.3.3	192.935(b)(2)	H.5a	a. Verify that if the operator makes a determination that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment (e.g., via Protocol C.01 activities), measures have been taken to minimize the consequences to the covered segment. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line. [§192.935(b)(2)]
		H.6	**H.6 Corrosion** Verify that the operator takes required actions to address corrosion threats. [§192.917(e)(5)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
Section 10, 4.8, Form 9-6	192.917(e)(5)	H.6a	a. Verify that the operator makes a determination of whether or not corrosion exists on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933). [§192.917(e)(5)] i. If such corrosion is identified, then verify: 1. The corrosion is evaluated and remediated, as necessary, for all pipeline segments (both covered and noncovered) with similar material coating and environmental characteristics. [§192.917(e)(5)] 2. A schedule is established for evaluating and remediating, as necessary, the similar segments consistent with the operator's established operating and maintenance procedures under Part 192 for testing and repair. [§192.917(e)(5)]
		H.7	**H.7 Automatic Shut-Off Valves or Remote Control Valves** Verify that the operator has a process to decide if automatic shut-off valves or remote control valves represent an efficient means of adding protection to potentially affected high consequence areas. [§192.935(c)]
12.3.4	192.935(c)	H.7a	a. Verify that the operator establishes an adequate risk analysis-based process to determine if an automatic shut-off valve or remote control valve should be added. [§192.935(c)] i. Verify that, as a minimum, the following factors were considered: [§192.935(c)] 1. swiftness of leak detection and pipe shutdown capabilities 2. the type of gas being transported 3. operating pressure 4. the rate of potential release 5. pipeline profile 6. the potential for ignition 7. location of nearest response personnel
		H.8	**H.8 General Requirements (Implementation of Additional Measures)** Verify that the operator has identified and implemented (or scheduled) additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area: [§192.935(a)]
12.2, 12.4.1, Form 12-1, Form 12-2	192.935(a)	H.8a	a. Verify that a systematic, documented decision-making process is in place to decide which measures are to be implemented, involving input from relevant parts of the organization such as operations, maintenance, engineering, and corrosion control. [§192.935(a)]

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
Section 12, 12.3.4, Form 8-1	192.935(a)	H.8b	b. Verify that the decision-making process considers both the likelihood and consequences of pipeline failures. [§192.935(a)]
Section 12, Form 12-1	192.935(a)	H.8c	c. Verify that additional measures are identified and documented and have actually been implemented, or scheduled for implementation. [§192.935(a)]
		I.1	**I.1. General Performance Measures** Inspect the operator's program to verify that, as a minimum, provisions exist for measuring integrity management program effectiveness in accordance with the four elements of ASME B31.8S-2004, Section 9.4 and each identified threat in ASME B31.8S-2004, Appendix A. [§192.945(a) and ASME B31.8S-2004, Section 12(b)(5)]
15.4, 17.4, 17.6, Form 17-1	192.945(a) B31.8S-2004, 9.4 B31.8S-2004, Appendix A	I.1a	a. Verify the process for measuring IM program effectiveness includes the elements necessary to conduct a meaningful evaluation. An adequate process for measuring IM program effectiveness should have the following characteristics: • Includes the use of periodic self-assessments, internal and/or external integrity management program audits, management reviews, or other self-critical evaluations to measure program effectiveness. • Includes a clear description of the scope, objectives, and frequency of these program evaluation methods. • Includes bench-marking performance metrics using data from inside or outside the company. • Clearly defines the use of performance metrics in evaluating program performance. • Provides for feedback to corrective action programs, preventive and mitigative measures decisions, and the threat and risk analysis processes? Does this feedback include communicating lessons learned and noteworthy practices to the appropriate individuals/organizational units. • Assures management awareness and commitment, including the resources required to address integrity program improvements identified through performance measurement. • Includes provisions for the review and follow-up of program effectiveness evaluation results, findings, and recommendations, etc., with appropriate company managers. • Includes provisions for the assignment of responsibility, by organization, group, or title, for implementation of required actions. • Requires evaluation of the effectiveness of programs to address specific threats in accordance with ASME B31.8S-2004 Appendix A. •
17.3, 17.4, Form 17-1	B31.8S-2004, 9 B31.8S-2004, Appendix A	I.1b	b. Verify the process to evaluate IM program effectiveness includes an adequate set of performance metrics to provide meaningful insight into IM program performance. A process for identifying an adequate set of performance measures should have the following characteristics:

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			• Includes a description of the performance metrics to be used and the frequency for data collection. • Defines metrics that: o Provide an overall measure of program effectiveness such as number of leaks or ruptures, etc., o Reflect the accomplishment of the program's objectives such as number of miles of pipeline assessed; number of anomalies found requiring repair or mitigation; number of right-of-way encroachments, and o Provide threat-specific insight in accordance with ASME B31.8S – 2004, Appendix A. Examples include: the number of leaks caused by each threat (e.g., internal/external corrosion, third party damage, etc.); number of repair actions taken for each threat, etc. • Includes performance metrics developed in accordance with ASME B 31.8S-2004 Section 9 including: o Process/Activity Metrics that monitor the surveillance and preventive activities that are in place to control risk. These metrics indicate how well an operator is implementing the elements of its integrity management program. o Operational Measures that monitor operational and maintenance trends to indicate if the program is effective or ineffective, or the desired outcome is being achieved or not, despite the risk control activities in place. o Direct Integrity Metrics that reflect whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure the number of leaks, ruptures, injuries, fatalities, etc. • Includes trending of metrics over time and an analysis of these trends? The process for trending should include: o A method to establish the magnitude of trends that represent normal fluctuations versus significant deviations (e.g., significant enough to warrant corrective action). o The trending of equipment or material failures (e.g., valve gaskets or pump seals) as a means to evaluate pipeline deterioration (an indicator of the end of useful life of materials and components). o The trending of leading indicators such as inadvertent over-pressurization, right-of-way encroachments without one-call notification, SCADA outages, operation of overpressure or other safety devices, or other abnormal operating conditions such as those listed in 192.605(c). (Leading indicators measure the effectiveness of proactive activities to control risk. These indicators can uncover weaknesses before they develop into full-fledged problems.) • Provides for the periodic review and revision (if needed) of performance metrics to assure they are providing useful information about the effectiveness of IM Program activities. • Includes procedures to ensure the completeness and accuracy of performance measure data – both for metrics reported to PHMSA and the metrics used internally. • Defines performance goals, including segment-specific issues related to the operator's unique operating environment such as a

IMP Sec.	Regulation	Protocol No.	Protocol Description (Version 8/1/2013)
			decrease in the number, and depth, of corrosion related anomalies, a decrease in the threat of mechanical damage due to a decrease in one-calls, a decrease in the number of crack anomalies, etc. • Provides for the periodic review of performance goals and their revision (if needed) based on the results of program evaluations. • Includes comparing leak, failure, and incident metrics to risk model results, and uses these comparisons to modify the risk model if necessary.
17.3.2	B31.8S-2004, 9.4	I.1c	c. Verify that performance is measured annually (completed through December 31st of each year) for each of the following: [ASME B31.8S-2004, Section 9.4] • Number of miles of pipeline inspected versus program requirements • Number of immediate repairs completed as a result of the integrity management inspection program • Number of scheduled repairs completed as a result of the integrity management program • Number of leaks, failures and incidents (classified by cause).
Form 17.1	B31.8S-2004, Appendix A B31.8S-2004, Table 9	I.1d	d. Verify that performance is measured annually in accordance with the threat-specific metrics of ASME B31.8S-2004, Appendix A (See ASME B31.8S-2004, Table 9 for a summary listing).
		I.2	**I.2 Performance Measures Records Verification** Inspect operator records to verify: [192.945(a)]
	192.945(a)	I.2a	a. The methods to measure program effectiveness provide effective evaluation of IM program performance and result in program improvements where necessary. The records to demonstrate IM program effectiveness should have the following characteristics: • The records show that periodic self-assessments, internal and/or external audits, management reviews, or other self-critical program evaluations have been performed at the established frequency. • The records indicate that the process has been implemented consistent with its scope and objectives, and at the established frequency. • The records show that these program evaluations provided a comprehensive and in-depth examination of performance, and effectively used the established performance metrics in this process. • The records show bench-marking performance using data from inside or outside the company. • The records show evidence of feedback to corrective action programs, preventive and mitigative measures decisions, and the threat

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			and risk analysis processes. • The records show that lessons learned and best practices have been communicated to the appropriate individuals and organizational units. • The records show evidence of management awareness and commitment, including providing resources to address improvements identified by the program evaluation. • The records include the review and follow-up of program evaluation results, findings, and recommendations, etc., by appropriate company managers. • The records include the assignment of responsibility, by organization, group, or title, for implementing required actions. • The records show that deficiencies identified in program evaluations and recommended improvements have been implemented in a timely manner.
Form 17.1	192.605(a) B31.8S-2004, Appendix A B31.8S-2004, 9	I.2b	b. That performance metrics are providing meaningful insight into integrity management program effectiveness. Records to demonstrate that performance metrics are providing meaningful insights into IM program effectiveness should have the following characteristics: • The records show the performance measure data is being collected and at the frequency established in the program evaluation process. • The records show that overall metrics have been defined and data collected for: o Overall measures of program effectiveness such as number of leaks, or ruptures, etc., o Metrics that reflect the accomplishment of the program's objectives, and o Threat specific metrics as established in ASME B31.8S-2004, Appendix A. • The records show that the performance metrics developed in accordance with ASME B 31.8S-2004 Section 9 were implemented. Specifically, o Process/Activity Metrics that monitor the surveillance and preventive activities that are in place to control risk. These metrics indicate how well an operator is implementing the elements of its integrity management program. o Operational Measures that monitor operational and maintenance trends to indicate if the program is effective or I.2aineffective, or the desired outcome is being achieved or not, despite the risk control activities in place. o Direct Integrity Metrics that reflect whether the program is effective in achieving the objective of improving integrity. These are typically lagging indicators that measure the number of leaks, ruptures, injuries, fatalities, etc.

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			• The records show the trending of metrics over time and an analysis of these trends. Specifically, o Do records show the trending analysis includes method(s) to establish the magnitude of trends that represent normal fluctuations versus significant deviations (e.g., significant enough to warrant corrective action). o Do records show trending of equipment or material failures as a means to evaluate pipeline equipment deterioration. o Do records show trending of leading indicators such as inadvertent over-pressurization, ROW encroachments without one-call notification, SCADA outages, operation of overpressure or other safety devices, or other abnormal operating conditions such as those listed in 192.605(c). (Leading indicators measure the effectiveness of proactive activities to control risk. These indicators can uncover weaknesses before they develop into full-fledged problems.) • The records show that the performance metrics have been reviewed and updated if needed to assure they are providing useful information about the effectiveness of IM Program activities. • The records show that the operator has implemented its program to assure the completeness and accuracy of the data used to measure performance. • The records show that the IM performance measures reported to PHMSA are complete and accurate. • The records show any data quality concerns that might exist. • The records show that the operator has established specific performance goals, including segment specific issues related to the operator's unique operating environment such as the number, and depth, of corrosion related anomalies, the threat of mechanical damage due to one calls, the number of crack anomalies, etc.. • The records show that the performance goals have been reviewed and revised based on the results of program evaluations. • The records show the leak, failure, and incident metrics have been compared to the risk model, and that changes to the risk model have been made when the data indicates such changes are necessary.
17.3.5, GTAR	192.951 B31.8S-2004, 9.4	I.2c	**c.** The four overall performance measures of ASME B31.8S-2004, Section 9.4 have been submitted to PHMSA annually in accordance with §192.951.
		I.3	**I.3 Exceptional Performance Measurements** For operators that choose to demonstrate exceptional performance in order to deviate from certain requirements of the rule, verify the following.
N/A	192.913(b)	I.3a	a. Additional performance measures beyond those required in §192.945 (see Protocol I.01) are part of the operator’s performance plan. [§192.913(b)(vii)]

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N/A	192.913(b)	I.3b	b. All performance measures (all measures required by §192.945 and the additional performance measures) are submitted to PHMSA on a semi-annual frequency in accordance with §192.951. [§192.913(b)(vii)]
		J.1	**J.1 Records to be Maintained by the Operator** Verify that the following records, as a minimum, are maintained for the useful life of the pipeline: [§192.947, ASME B31.8S-2004, Section 12.1 and ASME B31.8S-2004, Section 12.2(b)(1)]
16.4.1All sections Section 3, Section 4, 16.4.2 Section 8, 16.4.3 16.4.4 Section 18, 16.4.5 Form 9-2, 16.4.6 Section 7, 16.4.7 Section 7, 16.4.8 16.4.9	192.947(a) thru 192.947(i)	J.1a	a. i. A written integrity management program [§192.947(a)] ii. Threat identification and risk assessment documentation per §192.917 [§192.947(b)] iii. A written baseline assessment plan per §192.919 [§192.947(c)] iv. Documents to support any decision, analysis, and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements [§192.947(d)] v. Training program documentation and training records per §192.915 [§192.947(e)] vi. Remediation schedule and technical basis documentation per §192.933 [§192.947(f)] vii. Direct assessment plan documentation per §192.923 through §192.929 [§192.947(g)] viii. Confirmatory assessment documentation per §192.931 [§192.947(h)] ix. Documentation of Notifications to PHMSA or State/Local Regulatory Agencies. [§192.947(i)]
		K.1	**K.1. Documentation and Notification of Changes to the Integrity Management Program** Verify that changes to the integrity management program have been handled in accordance with §192.909 of the rule.
Revision Logs	192.909(a)	K.1a	a. Verify that the reasons for program changes have been documented prior to implementation of the change(s). [§192.909(a)]
19.3	192.909(b)	K.1b	b. Verify, that for significant changes to the program, program implementation, or schedules, PHMSA or the State or local pipeline safety authority, if applicable, has been notified within 30 days after operator has adopted the change. [192.909(b)]
		K.2	**K.2 Attributes of the Change Process** Verify that the integrity management program meets the requirements of ASME B31.8S-2004, Section 11 for a management of change process. [§192.911(k)]
Section 14	B31.8S-2004, 11(a)	K.2a	a. Verify the existence of procedures that consider impacts of changes to pipeline systems and their integrity. [ASME B31.8S-2004, Section 11(a)]
Section 14.4.4	B31.8S-2004, 11(a)	K.2b	b. Verify change procedures address technical, physical, procedural, and organizational changes. [ASME B31.8S-2004, Section 11(a)]

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Section 14.1.2.4, Section 2	B31.8S-2004, 11(a)	K.2c	c. Verify the following are provided for by the change procedures: [ASME B31.8S-2004, Section 11(a)] i. Reason for change ii. Authority for approving changes iii. Analysis of implications iv. Acquisition of required work permits v. Documentation vi. Communication of the change to affected parties vii. Time limitations viii. Qualification of staff
14.4.12	B31.8S-2004, 11(b)	K.2d	d. Verify that integrity management system changes are properly reflected in the pipeline system and that pipeline system changes are properly reflected in the integrity management program. [ASME B31.8S-2004, Section 11(b)]
	B31.8S-2004, 11(d)	K.2e	e. Verify that equipment or system changes have been identified and reviewed before implementation. [ASME B31.8S-2004, Section 11(d)]
		L.1	**L.1 Program Requirements for the Quality Assurance Process** Verify that a quality assurance process exists that meets the requirements of ASME B31.8S-2004, Section 12. [§192.911(l)]
Section 2, Table 2-1, Section 18	B31.8S-2004, 12.2(b)(2)	L.1a	a. Verify that responsibilities and authorities for the integrity management program have been formally defined. [ASME B31.8S-2004, Section 12.2(b)(2)]
Section 2.4.3, Section 15.4.3, Section 17	B31.8S-2004, 12.2(b)(3)	L.1b	b. Verify that reviews of the integrity management program and the quality assurance program have been specified to be performed on regular intervals, making recommendations for improvement. [ASME B31.8S-2004, Section 12.2(b)(3)]
Section 17, Form 17-1, Form 15-1	B31.8S-2004, 12.2(b)(7)	L.1c	c. Verify that corrective actions to improve the integrity management program and the quality assurance process have been documented and are monitored for effectiveness. [ASME B31.8S-2004, Section 12(b)(7)]
15.4.9, Form 10-5	B31.8S-2004, 12.2(c)	L.1d	d. Verify that when an operator chooses to use outside resources to conduct any process that affects the quality of the integrity management program, the operator ensures the quality of such processes and documents them within the quality program. [ASME B31.8S-2004, Section 12.2(c)]
		L.2	**L.2 Personnel Qualification and Training Requirements** Verify that personnel involved in the integrity management program are qualified for their assigned responsibilities. [§192.911(l), §192.915 and ASME B31.8S-2004, Section 12(b)(4)]

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Section 2, Section 18.2.1, Form F2-1	192.915(a)	L.2a	a. Verify that the Integrity Management Program requires supervisory personnel to have the appropriate training or experience for their assigned responsibilities. [§192.915(a)]
Section 2, 18.2.2, Form F2-1	192.915(b)	L.2b	b. Verify the qualification of personnel that carry out assessments and who evaluate assessment results. [§192.915(b)]
Section 2, 18.2.3, Form F2-1	192.915(c) B31.8S-2004, 12(b)(4)	L.2c	c. Verify the qualification of personnel who participate in implementing preventive and mitigative measures including: [§192.915(c)] i. Personnel who mark and locate buried structures. ii. Personnel who directly supervise excavation work. iii. Other personnel who participate in implementing preventive and mitigative measures as appropriate. [ASME B31.8S-2004, Section 12(b)(4)]
Section 2, Section 15, 18.22.4, Form F2-1	B31.8S-2004, 12.2(b)4 B31.8S-2004, 11(a)(8)	L.2d	d. Verify that the personnel who execute the activities within the integrity management program are competent and properly trained in accordance with the quality control plan. [ASME B31.8S-2004, Section 11(a)(8) and ASME B31.8S-2004, Section 12.2(b)(4)]
		L.3	**L.3 Invoking Non-Mandatory Statements in Standards** Verify that non-mandatory requirements (e.g., "should" statements) from industry standards or other documents invoked by Subpart O (e.g., ASME B31.8S-2004 and NACE SP0502-2008) are addressed by one of the following approaches: [§192.7(a)]
, 15.4.6		L.3a	a. Incorporated into the operator's plan and implemented as recommended in the standard; or
		L.3b	b. An equivalent alternative method for accomplishing the same objective is justified and implemented; or
		L.3c	c. A documented justification is included in the plan that demonstrates the technical basis for not implementing recommendations from standards or other documents invoked by Subpart O.
		M.1	**M.1 External and Internal Communication Requirements** Verify that an integrity management communication plan exists that meets the requirements of ASME B31.8S-2004, Section 10. [§192.911(m)]

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19.3		M.1a	a. Verify that the operator has submitted its API-1162 external communications plan to the PHMSA clearinghouse for approval..
19.5	B31.8S-2004, 10.3	M.1b	b. Verify provisions for operator internal organizational communication exist to establish understanding of and support for the integrity management program. [ASME B31.8S-2004, Section 10.3]
		M.2	**M.2 Addressing Safety Concerns** Verify that provisions exist to address safety concerns raised by:
19.4.3, 19.6	192.911(m)(1) 192.911(m)(2)	M.2a	a. PHMSA and State or local pipeline safety authorities (when a covered segment is located in a State where PHMSA has an interstate agreement). [§192.911(m)(1) and §192.911(m)(2)].
		N.1	**N.1 Integrity Management Program Document Submittal** Verify that the operator includes provisions in its program to submit, upon request, the operator's risk analysis or integrity management program to: [§192.911(n)]
19.4.4	192.911(n)	N.1a	a. PHMSA and State or local pipeline safety authorities, as applicable. [§192.911(n)]

APPENDIX 1-B

Terms, Definitions, and Acronyms

1-B APPENDIX 1-B

In This Section

Referenced Protocols

None

A TERMS, DEFINITIONS, AND ACRONYMS

A.1 TERMS, DEFINITIONS, AND ACRONYMS

The following are terms, definitions, and acronyms that may be used within this document as provided by Integrity Management regulations. The prefix symbol denotes the regulations that provides the respective definition.
-Definition means a definition from 49 CFR §192.3 Definitions – Revision 03/2015.

*****Definition*** means a definition from 49 CFR 192 Subpart O – Gas Transmission Pipeline Integrity Management, primarily §192.903– Revision 03/2015.

+Definition: A definition from ASME B31.8S-2004

-Abandoned means permanently removed from service.

-Active Corrosion means continuing corrosion that, unless controlled, could result in a condition that is detrimental to public safety.

-Administrator means the Administrator, Pipeline and Hazardous Materials Safety Administration or his or her delegate.

-Alarm means an audible or visible means of indicating to the controller that equipment or processes are outside operator-defined, safety-related parameters.

*****Assessment*** is the use of testing techniques as allowed in this subpart [49 CFR 192–Subpart O] to ascertain the condition of a covered pipeline segment.

+Bell hole: an excavation that minimizes surface disturbance yet provides sufficient room for examination or repair of buried facilities.

+Cathodic Protection (CP): a technique by which underground metallic pipe is protected against deterioration (rusting and pitting).

+Close Interval Survey (CIS): an inspection techniques that includes a series of aboveground pipe-to-soil potential measurements taken at predetermined increments of several feet (i.e. 2-100 feet) along the pipeline and used to provide information on the effectiveness of the cathodic protection system.

+Composite repair sleeve: a permanent repair method using composite sleeve material, which is applied with an adhesive.

*****Confirmatory direct assessment*** is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

+Consequence: the impact that a pipeline failure could have on the public, employees, property and the environment

-Control room means an operations center staffed by personnel charged with the responsibility for remotely monitoring and controlling a pipeline facility.

-Controller means a qualified individual who remotely monitors and controls the safety-related operations of a pipeline facility via a SCADA system from a control room, and who has operational authority and accountability for the remote operational functions of the pipeline facility.

*****Covered segment or covered pipeline segment*** means a segment of gas transmission pipeline located in a high consequence area (HCA). The terms gas and transmission line are defined in §192.3 (and in this Appendix).

-Customer meter means the meter that measures the transfer of gas from an operator to a consumer.

+Defect: an imperfection of a type and magnitude exceeding acceptable criteria.

*****Direct assessment*** is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered 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.

+Direct Current Voltage Gradient (DCVG): inspection technique that includes above ground electrical measurements taken at predetermined increments along the pipeline and is used to provide information on the effectiveness of the coating system.

-Distribution Line means a pipeline other than a gathering or transmission line.

+Double Submerged-Arc Welded pipe (DSAW pipe): pipe that has a straight longitudinal or helical seam containing filler metal deposited on both sides of the joint by the submerged-arc welded process.

*****ECDA Region*** a section or sections of a pipeline that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and in which the same indirect inspection tools are used [NACE SP0502].

+Electric resistance welded pipe (ERW Pipe): pipe that has a straight longitudinal seam produced without the addition of filler metal by the application of pressure and heat obtained from electrical resistance. ERW pipe forming is distinct from flash welded pipe and furnace butt-welded pipe as a result of being produced in a continuous forming process from coils of flat plate.

-Electrical survey means a series of closely spaced pipe-to-soil readings over pipelines which are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline.

+Evaluation: the analysis and determination of the facilities fitness for service under the current operating conditions.

+Examination: the direct physical inspection of the pipelines by a person and may also include the use of nondestructive examination (NDE) techniques.

-Exposed underwater pipeline means an underwater pipeline where the top of the pipe protrudes above the underwater natural bottom (as determined by recognized and generally accepted practices) in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

*****External Corrosion Direct Assessment (ECDA)*** is a four-step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline [§192.925].

+Failure: a general term used to imply that a part in service has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that is has become unreliable or unsafe for continued use.

+Fracture Toughness: the resistance of a material to failure from the extension of a crack.

-Gas means natural gas, flammable gas, or gas which is toxic or corrosive.

+Gas: any gas or mixture of gases suitable for domestic or industrial fuel and transmitted or distributed to the user through a piping system. The common types are natural gas, manufactured gas, and liquefied petroleum gas distributed as a vapor, with or without the admixture of air.

-Gathering Line means a pipeline that transports gas from a current production facility to a transmission line or main.

+Geographic Information System (GIS): a system of computer software, hardware, data, and personnel to help manipulate, analyze, and present information that is tied to a geographic location

+Global Positioning System (GPS): a system used to identify the latitude and longitude of locations using GPS satellites.

***-Gulf of Mexico* and its inlets** means the waters from the mean high water mark of the coast of the Gulf of Mexico and its inlets open to the sea (excluding rivers, tidal marshes, lakes, and canals) seaward to include the territorial sea and Outer Continental Shelf to a depth of 15 feet (4.6 meters), as measured from the mean low water.

-Hazard to navigation means, for the purpose of this part, a pipeline where the top of the pipe is less than 12 inches (305 millimeters) below the underwater natural bottom (as determined by recognized and generally accepted practices) in water less than 15 feet (4.6 meters) deep, as measured from the mean low water.

*****High Consequence Area*** means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as-

(i) A Class 3 location under § 192.5; or

(ii) A Class 4 location under § 192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact radius contains an identified site.

(2) The area within a potential impact circle containing-

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in Appendix E. of Subpart O)

(4) If in identifying a high consequence area under paragraph (1) (iii) of this definition or paragraph (2) (i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (i.e., the prorated number of buildings intended for

human occupancy is equal to 20 x (660 feet [or 200 meters]/ potential impact radius in feet [or meters])**2]).

$$B_{prorated} = 20\left(\frac{660}{PIR}\right)^2$$

-High pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

+Hydrogen Induced Cracking (HIC): a form of hydrogen induced damage consisting of cracking of the metal.

+Hydrogen induced damage is a form of degradation of metals caused by exposure to environments (liquid or gas) that cause absorption of hydrogen into the material. Examples of hydrogen induced damage are formation of internal cracks, blisters, or voids in steels; embrittlement (i.e. loss of ductility); high-temperature hydrogen attack (i.e., surface decarbonization and chemical reaction with hydrogen).

*****ICDA Region*** is a region that extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed [§192.927].

+Incident: an unintentional release of gas due to the failure of a pipeline.

*****Identified site*** means each of the following areas:

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

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

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

+Indication: a finding of a nondestructive testing technique. It may or may not be a defect.

+In-line Inspection (ILI): a pipeline inspection technique that uses devices known in the industry as "smart pigs". These devices run inside the pipe and provide indications of metal loss, deformation, and other defects.

+Inspection: the use of a nondestructive testing technique.

+Integrity Assessment: is a process which includes inspection of pipeline facilities, evaluating the indications resulting from the inspections, examining the pipe using a variety of techniques, evaluating the results of the examinations, and characterizing the evaluation by defect type and severity and determining the resulting integrity of the pipeline through analysis.

*****Internal Corrosion Direct Assessment (ICDA)*** is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO2, O2, hydrogen sulfide or other contaminants present in the gas [§192.927(a)].

+Leak: an unintentional Escape of gas from the pipeline. The source of the leak may be holes, cracks (include propagating and non-propagating, longitudinal, and circumferential), separation or pullout, and loose connections.

-Line section means a continuous run of transmission line between adjacent compressor stations, between a compressor station and storage facilities, between a compressor station and a block valve, or between adjacent block valves.

-Listed specification means a specification listed in section I of Appendix B of this part [49 CFR 192].

+Location Class: an onshore area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. Class location units are categorized as Class 1 through 4. Class 1 locations are more rural and Class 4 locations are more urban.

-Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

+Magnetic Flux Leakage (MFL): a type of in-line inspection technique that induces a magnetic field in a pipe wall between two poles of a magnet. Sensors record changes in the magnetic flux (flow) which can be used to evaluate metal loss.

-Main means a distribution line that serves as a common source of supply for more than one service line.

+Management of Change: a process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural or organizational nature that can impact system integrity.

-Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

-Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part [49 CFR 192]

+Maximum Allowable Operating Pressure (MAOP): the maximum pressure at which a gas system may be operated in accordance with the provisions of ASME B31.8 Code.

+Mechanical Damage: a type of metal damage in a pipe or pipe coating caused by the application of an external force. Mechanical damage can include denting, coating removal, metal removal, metal movement, cold working of the underlying metal, and residual stresses, any one of which can be detrimental.

+Microbiologically Influenced Corrosion (MIC): is corrosion or deterioration of metals resulting from the metabolic activity of microorganisms. Such corrosion may be initiated or accelerated by microbial activity.

+Mitigation: the limitation or reduction of the probability of occurrence or expected consequence for a particular event.

-Municipality means a city, county, or any other political subdivision of a State.

+Nondestructive Examination (NDE): an inspection technique that does not damage the item being examined. This technique includes visual, radiography, ultrasonic, electromagnetic and dye penetrant methods.

-Offshore means beyond the line of ordinary low water along that portion of the coast of the United States that is in direct contact with the open seas and beyond the line marking the seaward limit of inland waters.

-Operator means a person who engages in the transportation of gas.

+Operator: the entity that operates and maintains the pipeline facilities and has fiduciary responsibility for such pipeline facilities.

-Outer Continental Shelf means all submerged lands lying seaward and outside the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

+Performance Based Integrity Management Program: an integrity management process that utilizes risk management principles and risk assessments to determine prevention, detection and mitigation actions and their timing.

-Person means any individual, firm, joint venture, partnership, corporation, association, State, municipality, cooperative association, or joint stock association, and including any trustee, receiver, assignee, or personal representative thereof.

-Petroleum gas means propane, propylene, butane, (normal butane or isobutanes), and butylene (including isomers), or mixtures composed predominantly of these gases, having a vapor pressure not exceeding 208 psi (1434 kPa) gage at 100 °F (38 °C).

+Pig: a device run inside a pipeline to clean or inspect the pipeline, or to batch fluids.

+Piggability: the ability of a pipeline or segment to be inspected by an ILI device.

-Pipe means any pipe or tubing used in the transportation of gas, including pipe-type holders.

+Pipe Grade: a portion of the material specification for pipe, which includes specified minimum yield strength.

-Pipeline means all parts of those physical facilities through which gas moves in transportation, including pipe, valves, and other appurtenance attached to pipe, compressor units, metering stations, regulator stations, delivery stations, holders, and fabricated assemblies.

+Pipeline: all parts of physical facilities through which gas moves in transportation, including pipe, valves, fittings, flanges (including bolting and gaskets), regulators, pressure vessels, pulsation dampeners, relief valves, and other appurtenances attached to pipe, compressor units, metering stations, regulator stations, and fabricated assemblies. Included within this definition are gas transmission and gathering lines, transporting gas from production facilities to onshore locations and gas storage equipment of the closed pipe type, which is fabricated or forged from pipe or fabricated from pipe and fittings.

-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.

-Pipeline facility means new and existing pipelines, rights-of-way, and any equipment, facility, or building used in the transportation of gas or in the treatment of gas during the course of transportation.

*****Potential Impact Circle*** is a circle of radius equal to the potential impact radius (PIR).

*****Potential Impact Radius (PIR)*** means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula

$$r = 0.69\sqrt{pd^2}$$

where 'r' is the radius of a circular area in feet surrounding the point of failure, 'p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and 'd' is the nominal diameter of the pipeline in inches.

> **Note:** 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. For other gases refer to ASME/ANSI B31.8S–2004 Section 3.2.

+Prescriptive Integrity Management Program: is an integrity management process that follows preset conditions that result in fixed inspection and mitigation activities and timelines.

+Pressure Test: a measure of the strength of a piece of equipment (pipe) in which the item is filled with a fluid, sealed, and subjected to pressure. It is used to validate integrity and detect construction defects and defective materials.

+Probability: the likelihood of an incident occurring.

*****Remediation*** is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

+Rich gas: a gas that contains significant amounts of hydrocarbons or components that are heavier than methane and ethane. Rich gases decompress in a different fashion than pure methane or ethane.

+Right of Way (ROW): a strip of land on which pipelines, railroads, power lines, and other similar facilities are constructed. It secures the right to pass over property owned by others and ROW agreements only allow the right of ingress and egress for the operation and maintenance of the facility, and the installation of the facility. The width of the ROW can vary and is usually determined based on negotiation with the affected landowner or by legal action.

+Risk: a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.

+Risk Assessment: is a systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and be performed at varying level of detail depending on the operator's objectives.

+Risk Management: an overall program consisting of: identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.

+Root Cause Analysis: a family of processes implemented to determine the primary cause of an event. These processes all seek to examine cause-and effect relationship through the organization and analysis of data. Such processes are often used in failure analyses.

+Rupture: a complete failure of any portion of the pipeline.

+SCADA System: a supervisory control and data acquisition system

+Segment: a length of pipeline or part of the system that has unique characteristics in a specific geographic location.

-Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

-Service regulator means the device on a service line that controls the pressure of gas delivered from a higher pressure to the pressure provided to the customer. A service regulator may serve one customer or multiple customers through a meter header or manifold.

+Smart pig: the industry term for a type of ILI device.

-SMYS means specified minimum yield strength is:

(a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or

(b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

+Specified Minimum Yield Strength (SMYS): is the minimum yield strength of the steel in pipe as required by the pipe product specifications expressed in pounds per square inch,.

-State means each of the several States, the District of Columbia, and the Commonwealth of Puerto Rico.

+Stress Concentrator: a discontinuity in a structure or change in contour that causes a local increase in stress.

+Stress Corrosion Cracking (SCC): is a form of environmental attack of the metal involving an interaction of a local corrosive environment and tensile stresses in the metal resulting in formation and growth of cracks.

*****Stress Corrosion Cracking Direct Assessment (SCCDA)*** A process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment [§192.929(a)].

+Subject Matter Experts: individuals that have expertise in a specific area of operation or engineering.

-Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

+System: refers to either the operator's entire pipeline infrastructure or large portions of that infrastructure that has definable starting and stopping points.

+Third Party Damage: damage to a gas pipeline facility by an outside party other than those performing work for the operator. For the purposes of this document [ASME B31.8S – 2004] it also includes damage caused by the operator's personnel or the operators contractors.

-Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

Note: A large volume customer may receive similar volumes of gas as a distribution center, and includes factories, power plants, and institutional users of gas.

+Transmission System: one or more segments of pipeline usually interconnected to form a network that transports gas from a gathering system, the outlet of a gas processing plant, or a storage field to a high- or low-pressure distribution system, a large-volume customer, or another storage field.

-Transportation of Gas means the gathering, transmission, or distribution of gas by pipeline or the storage of gas, in or affecting interstate or foreign commerce.

+Transportation of Gas: gathering, transmission, or distribution of gas by pipeline or the storage of gas.

+Ultrasonic: high frequency sound. Ultrasonic examination is used to determine wall thickness and to detect the presence of defects.

-Welder means a person who performs manual or semi-automatic welding.

-Welding operator means a person who operates machine or automatic welding equipment.

+Wrinkle bend: a pipe bend produced by field machine or controlled process which may result in abrupt contour discontinuities on the inner radius.

APPENDIX 1-C

49 CFR 192 Subpart O -

Pipeline Integrity Management

03/2015 Revision

Note – Changes made in this revision of the regulations are shown highlighted for deletions and underlined for additions.

Subpart O—Gas Transmission Pipeline Integrity Management

§192.901 What do the regulations in this subpart cover?

This subpart prescribes minimum requirements for an integrity management program on any gas transmission pipeline covered under this part. For gas transmission pipelines constructed of plastic, only the requirements in §§ 192.917, 192.921, 192.935 and 192.937 apply.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003]

§192.903 What definitions apply to this subpart?

The following definitions apply to this subpart:

Assessment is the use of testing techniques as allowed in this subpart to ascertain the condition of a covered pipeline segment.

Confirmatory direct assessment is an integrity assessment method using more focused application of the principles and techniques of direct assessment to identify internal and external corrosion in a covered transmission pipeline segment.

Covered segment or covered pipeline segment means a segment of gas transmission pipeline located in a high consequence area. The terms gas and transmission line are defined in §192.3.

Direct assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion and stress corrosion cracking) to a covered 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.

High consequence area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

(i) A Class 3 location under §192.5; or

(ii) A Class 4 location under §192.5; or

(iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or

(iv) Any area in a Class 1 or Class 2 location where the potential impact circle contains an identified site.

(2) The area within a potential impact circle containing—

(i) 20 or more buildings intended for human occupancy, unless the exception in paragraph (4) applies; or

(ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. (See Figure E.I.A. in appendix E.)

(4) If in identifying a high consequence area under paragraph (1)(iii) of this defini-

tion or paragraph (2)(i) of this definition, the radius of the potential impact circle is greater than 660 feet (200 meters), the operator may identify a high consequence area based on a prorated number of buildings intended for human occupancy within a distance 660 feet (200 meters) from the centerline of the pipeline until December 17, 2006. If an operator chooses this approach, the operator must prorate the number of buildings intended for human occupancy based on the ratio of an area with a radius of 660 feet (200 meters) to the area of the potential impact circle (*i.e.*, the prorated number of buildings intended for human occupancy is equal to [20 x (660 feet [or 200 meters]/potential impact radius in feet [or meters]$)^2$]).

Identified site means each of the following areas:

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

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

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

Potential impact circle is a circle of radius equal to the potential impact radius (PIR).

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula r = 0.69* (square root of (p*d^2)), where `r' is the radius of a circular area in feet surrounding the point of failure, `p' is the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch and `d' is the nominal diameter of the pipeline in inches.

Note: 0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. An operator transporting gas other than natural gas must use section 3.2 of ASME/ANSI B31.8S–2001 (Supplement to ASME B31.8; incorporated by reference, see § 192.7) (incorporated by reference, *see* § 192.7) to calculate the impact radius formula.

Remediation is a repair or mitigation activity an operator takes on a covered segment to limit or reduce the probability of an undesired event occurring or the expected consequences from the event.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-95C, 69 FR 29903, May 26, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-103c, 72 FR 4655, Feb. 1, 2007; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.905 How does an operator identify a high consequence area?

(a) *General.* To determine which segments of an operator's transmission pipeline system are covered by this subpart, an operator must identify the high consequence areas. An operator must use method (1) or (2) from the definition in §192.903 to identify a high consequence area. An operator may apply one method to its entire pipeline system, or an operator may apply one method to individual portions of the pipeline system. An operator must describe in its integrity management program which method it is applying to each portion of the operator's pipeline system. The description must include the potential impact radius when utilized to establish a high consequence area. (*See* appendix E.I. for guidance on identifying high consequence areas.)

(b)(1) *Identified sites.* An operator must identify an identified site, for purposes of this subpart, from information the operator has obtained from routine operation and maintenance activities and from public officials with safety or emergency response or planning responsibilities who indicate to the operator that they know of locations that meet the identified site criteria. These public officials could include officials on a local emergency planning commission or relevant Native American tribal officials.

(2) If a public official with safety or emergency response or planning responsibilities informs an operator that it does not have the information to identify an identified site, the operator must use one of the following sources, as appropriate, to identify these sites.

(i) Visible marking (*e.g.*, a sign); or

(ii) The site is licensed or registered by a Federal, State, or local government agency; or

(iii) The site is on a list (including a list on an internet web site) or map maintained by or available from a Federal, State, or local government agency and available to the general public.

(c) *Newly identified areas.* When an operator has information that the area around a pipeline segment not previously identified as a high consequence area could satisfy any of the definitions in §192.903, the operator must complete the evaluation using method (1) or (2). If the segment is determined to meet the definition as a high consequence area, it must be incorporated into the operator's baseline assessment plan as a high consequence area within one year from the date the area is identified.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003]

§192.907 What must an operator do to implement this subpart?

(a) *General.* No later than December 17, 2004, an operator of a covered pipeline segment must develop and follow a written integrity management program that contains all the elements described in §192.911 and that addresses the risks on each covered transmission pipeline segment. The initial integrity management program must consist, at a minimum, of a framework that describes the process for implementing each program element, how relevant decisions will be made and by whom, a time line for completing the work to implement the program element, and how information gained from experience will be continuously incorporated into the program. The framework will evolve into a more detailed and comprehensive program. An operator must make continual improvements to the program.

(b) *Implementation Standards.* In carrying out this subpart, an operator must follow the requirements of this subpart and of ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) and its appendices, where specified. An operator may follow an equivalent standard or practice only when the operator demonstrates the alternative standard or practice provides an equivalent level of safety to the public and property. In the event of a conflict between this subpart and ASME/ANSI B31.8S, the requirements in this subpart control.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.909 How can an operator change its integrity management program?

(a) *General.* An operator must document any change to its program and the reasons for the change before implementing the change.

(b) *Notification.* An operator must notify OPS, in accordance with §192.949, of any change to the program that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State. An operator must provide the notification within 30 days after adopting this type of change into its program.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004]

§192.911 What are the elements of an integrity management program?

An operator's initial integrity management program begins with a framework (*see* §192.907) and evolves into a more detailed and comprehensive integrity management program, as information is gained and incorporated into the program. An operator must make continual improvements to its program. The initial program framework and subsequent program must, at minimum, contain the following elements. (When indicated, refer to ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) for more detailed information on the listed element.)

(a) An identification of all high consequence areas, in accordance with §192.905.

(b) A baseline assessment plan meeting the requirements of §192.919 and §192.921.

(c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§192.917) and to evaluate the merits of additional preventive and mitigative measures (§192.935) for each covered segment.

(d) A direct assessment plan, if applicable, meeting the requirements of §192.923, and depending on the threat assessed, of §§ 192.925, 192.927, or 192.929.

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

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

(g) If applicable, a plan for confirmatory direct assessment meeting the requirements of §192.931.

(h) Provisions meeting the requirements of §192.935 for adding preventive and mitigative measures to protect the high consequence area.

(i) A performance plan as outlined in ASME/ANSI B31.8S, section 9 that includes performance measures meeting the requirements of §192.945.

(j) Record keeping provisions meeting the requirements of §192.947.

(k) A management of change process as outlined in ASME/ANSI B31.8S, section 11.

(l) A quality assurance process as outlined in ASME/ANSI B31.8S, section 12.

(m) A communication plan that includes the elements of ASME/ANSI B31.8S, section 10, and that includes procedures for addressing safety concerns raised by—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

(n) Procedures for providing (when requested), by electronic or other means, a copy of the operator's risk analysis or integrity management program to—

(1) OPS; and

(2) A State or local pipeline safety authority when a covered segment is located in a State where OPS has an interstate agent agreement.

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

(p) A process for identification and assessment of newly-identified high consequence areas. (See §192.905 and §192.921.)

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.913 When may an operator deviate its program from certain requirements of this subpart?

(a) *General.* ASME/ANSI B31.8S (incorporated by reference, *see* §192.7) provides the essential features of a performance-based or a prescriptive integrity management program. An operator that uses a performance-based approach that satisfies the requirements for exceptional performance in paragraph (b) of this section may deviate from certain requirements in this subpart, as provided in paragraph (c) of this section.

(b) *Exceptional performance.* An operator must be able to demonstrate the exceptional performance of its integrity management program through the following actions.

(1) To deviate from any of the requirements set forth in paragraph (c) of this section, an operator must have a performance-based integrity management program that meets or exceed the performance-based requirements of ASME/ANSI B31.8S and includes, at a minimum, the following elements—

(i) A comprehensive process for risk analysis;

(ii) All risk factor data used to support the program;

(iii) A comprehensive data integration process;

(iv) A procedure for applying lessons learned from assessment of covered pipeline segments to pipeline segments not covered by this subpart;

(v) A procedure for evaluating every incident, including its cause, within the operator's sector of the pipeline industry for implications both to the operator's pipeline system and to the operator's integrity management program;

(vi) A performance matrix that demonstrates the program has been effective in ensuring the integrity of the covered segments by controlling the identified threats to the covered segments;

(vii) Semi-annual performance measures beyond those required in §192.945 that are part of the operator's performance plan. (See §192.911(i).) An operator must submit these measures, by electronic or other means, on a semi-annual frequency to OPS in accordance with §192.951; and

(viii) An analysis that supports the desired integrity reassessment interval and the remediation methods to be used for all covered segments.

(2) In addition to the requirements for the performance-based plan, an operator must—

(i) Have completed at least two integrity assessments on each covered pipeline segment the operator is including under the performance-based approach, and be able to demonstrate that each assessment effectively addressed the identified threats on the covered segment.

(ii) Remediate all anomalies identified in the more recent assessment according to the requirements in §192.933, and incorporate the results and lessons learned from the more recent assessment into the operator's data integration and risk assessment.

(c) *Deviation.* Once an operator has demonstrated that it has satisfied the requirements of paragraph (b) of this section, the operator may deviate from the prescriptive requirements of ASME/ANSI B31.8S and of this subpart only in the following instances.

(1) The time frame for reassessment as provided in §192.939 except that reassessment by some method allowed under this subpart (e.g., confirmatory direct assessment) must be carried out at intervals no longer than seven years;

(2) The time frame for remediation as provided in §192.933 if the operator demonstrates the time frame will not jeopardize the safety of the covered segment.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.915 What knowledge and training must personnel have to carry out an integrity management program?

(a) *Supervisory personnel.* The integrity management program must provide that each supervisor whose responsibilities relate to the integrity management program possesses and maintains a thorough knowledge of the integrity management program and of the elements for which the supervisor is responsible. The program must provide that any person who qualifies as a supervisor for the integrity management program has appropriate training or experience in the area for which the person is responsible.

(b) *Persons who carry out assessments and evaluate assessment results.* The integrity management program must provide criteria for the qualification of any person—

(1) Who conducts an integrity assessment allowed under this subpart; or

(2) Who reviews and analyzes the results from an integrity assessment and evaluation; or

(3) Who makes decisions on actions to be taken based on these assessments.

(c) *Persons responsible for preventive and mitigative measures.* The integrity management program must provide criteria for the qualification of any person—

(1) Who implements preventive and mitigative measures to carry out this subpart, including the marking and locating of buried structures; or

(2) Who directly supervises excavation work carried out in conjunction with an integrity assessment.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003]

§192.917 How does an operator identify potential threats to pipeline integrity and use the threat identification in its integrity program?

(a) *Threat identification.* An operator must identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 2, which are grouped under the following four categories:

(1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking;

(2) Static or resident threats, such as fabrication or construction defects;

(3) Time independent threats such as third party damage and outside force damage; and

(4) Human error.

(b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

(c) *Risk assessment.* An operator must conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), and to determine what additional preventive and mitigative measures are needed (§192.935) for the covered segment.

(d) *Plastic transmission pipeline.* An operator of a plastic transmission pipeline must assess the threats to each covered segment using the information in sections 4 and 5 of ASME B31.8S, and consider any threats unique to the integrity of plastic pipe.

(e) *Actions to address particular threats*. If an operator identifies any of the following threats, the operator must take the following actions to address the threat.

(1) *Third party damage.* An operator must utilize the data integration required in paragraph (b) of this section and ASME/ANSI B31.8S, Appendix A7 to determine the susceptibility of each covered segment to the threat of third party damage. If an operator identifies the threat of third party damage, the operator must implement comprehensive additional preventive measures in accordance with §192.935 and monitor the effectiveness of the preventive measures. If, in conducting a baseline assessment under §192.921, or a reassessment under §192.937, an operator uses an internal inspection tool or external corrosion direct assessment, the operator must integrate data from these assessments with data related to any encroachment or foreign line crossing on the covered segment, to define where

potential indications of third party damage may exist in the covered segment.

An operator must also have procedures in its integrity management program addressing actions it will take to respond to findings from this data integration.

(2) *Cyclic fatigue.* An operator must evaluate whether cyclic fatigue or other loading condition (including ground movement, suspension bridge condition) could lead to a failure of a deformation, including a dent or gouge, or other defect in the covered segment. An evaluation must assume the presence of threats in the covered segment that could be exacerbated by cyclic fatigue. An operator must use the results from the evaluation together with the criteria used to evaluate the significance of this threat to the covered segment to prioritize the integrity baseline assessment or reassessment.

(3) *Manufacturing and construction defects.* If an operator identifies the threat of manufacturing and construction defects (including seam defects) in the covered segment, an operator must analyze the covered segment to determine the risk of failure from these defects. The analysis must consider the results of prior assessments on the covered segment. An operator may consider manufacturing and construction related defects to be stable defects if the operating pressure on the covered segment has not increased over the maximum operating pressure experienced during the five years preceding identification of the high consequence area. If any of the following changes occur in the covered segment, an operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(i) Operating pressure increases above the maximum operating pressure experienced during the preceding five years;

(ii) MAOP increases; or

(iii) The stresses leading to cyclic fatigue increase.

(4) *ERW pipe.* If a covered pipeline segment contains low frequency electric resistance welded pipe (ERW), lap welded pipe or other pipe that satisfies the conditions specified in ASME/ANSI B31.8S, Appendices A4.3 and A4.4, and any covered or noncovered segment in the pipeline system with such pipe has experienced seam failure, or operating pressure on the covered segment has increased over the maximum operating pressure experienced during the preceding five years, an operator must select an assessment technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies. The operator must prioritize the covered segment as a high risk segment for the baseline assessment or a subsequent reassessment.

(5) *Corrosion.* If an operator identifies corrosion on a covered pipeline segment that could adversely affect the integrity of the line (conditions specified in §192.933), the operator must evaluate and remediate, as necessary, all pipeline segments (both covered and non-covered) with similar material coating and environmental characteristics. An operator must establish a schedule for evaluating and remediating, as necessary, the similar segments that is consistent with the operator's established operating and maintenance procedures under part 192 for testing and repair.

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§192.919 What must be in the baseline assessment plan?

An operator must include each of the following elements in its written baseline assessment plan:

(a) Identification of the potential threats to each covered pipeline segment and the information supporting the threat identification. (See §192.917.);

(b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment. The integrity assessment method an operator uses must be based on the threats identified to the covered segment. (See §192.917.) More than one method may be required to address all the threats to the covered pipeline segment;

(c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule;

(d) If applicable, a direct assessment plan that meets the requirements of §§ 192.923, and depending on the threat to be addressed, of §192.925, §192.927, or §192.929; and

(e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003]

§192.921 How is the baseline assessment to be conducted?

(a) *Assessment methods.* An operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment (See §192.917).

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, and stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with, as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Prioritizing segments.* An operator must prioritize the covered pipeline segments for the baseline assessment according to a risk analysis that considers the potential threats to each covered segment. The risk analysis must comply with the requirements in §192.917.

(c) *Assessment for particular threats.* In choosing an assessment method for the baseline assessment of each covered segment, an operator must take the actions required in §192.917(e) to address particular threats that it has identified.

(d) *Time period.* An operator must prioritize all the covered segments for assessment in accordance with §192.917 (c) and paragraph (b) of this section. An operator must assess at least 50% of the covered segments beginning with the highest risk segments, by December 17, 2007. An operator must complete the baseline assessment of all covered segments by December 17, 2012.

(e) *Prior assessment*. An operator may use a prior integrity assessment conducted before December 17, 2002 as a baseline assessment for the covered segment, if the integrity assessment meets the baseline requirements in this subpart and subsequent remedial actions to address the conditions listed in §192.933 have been carried out. In addition, if an operator uses this prior assessment as its baseline assessment, the operator must reassess the line pipe in the covered segment according to the requirements of §192.937 and §192.939.

(f) *Newly identified areas.* When an operator identifies a new high consequence area (see §192.905), an operator must complete the baseline assessment of the line pipe in the newly identified high consequence area within ten (10) years from the date the area is identified.

(g) *Newly installed pipe.* An operator must complete the baseline assessment of a newly-installed segment of pipe covered by this subpart within ten (10) years from the date the pipe is installed. An operator may conduct a pressure test in accordance with paragraph (a)(2) of this section, to satisfy the requirement for a baseline assessment.

(h) *Plastic transmission pipeline*. If the threat analysis required in §192.917(d) on a plastic transmission pipeline indicates that a covered segment is susceptible to failure from causes other than third-party damage, an operator must conduct a baseline assessment of the segment in accordance with the requirements of this section and of §192.917. The operator must justify the use of an alternative assessment method that will address the identified threats to the covered segment.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, Apr. 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.923 How is direct assessment used and for what threats?

(a) *General.* An operator may use direct assessment either as a primary assessment method or as a supplement to the other assessment methods allowed under this subpart. An operator may only use direct assessment as the primary assessment method to address the identified threats of external corrosion (ECDA), internal corrosion (ICDA), and stress corrosion cracking (SCCDA).

(b) *Primary method.* An operator using direct assessment as a primary assessment method must have a plan that complies with the requirements in—

(1) Section 192.925 and ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7); section 6.4, and NACE SP0502 (incorporated by reference, *see* § 192.7), if addressing external corrosion (ECDA).

(2) Section 192.927 and ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 6.4, appendix B2, if addressing internal corrosion (IC).

(3) Section 192.929 and ASME/ANSI B31.8S (incorporated by reference, see

§ 192.7), appendix A3, if addressing stress corrosion cracking (SCCDA).

(c) *Supplemental method.* An operator using direct assessment as a supplemental assessment method for any applicable threat must have a plan that follows the requirements for confirmatory direct assessment in §192.931.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-114, 74 FR 48593, Aug 11, 2010; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.925 What are the requirements for using External Corrosion Direct Assessment (ECDA)?

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

(b) *General requirements.* An operator that uses direct assessment to assess the threat of external corrosion must follow the requirements in this section, in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4, and in NACE SP0502-2008 (incorporated by reference, *see* §192.7). An operator must develop and implement a direct assessment plan that has procedures addressing pre-assessment, indirect inspection examination, direct examination, and post-assessment. If the ECDA detects pipeline coating damage, the operator must also integrate the data from the ECDA with other information from the data integration (§192.917(b)) to evaluate the covered segment for the threat of third party damage, and to address the threat as required by §192.917(e)(1).

(1) *Preassessment.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 3, the plan's procedures for preassessment must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment; and

(ii) The basis on which an operator selects at least two different, but complementary indirect assessment tools to assess each ECDA Region. If an operator utilizes an indirect inspection method that is not discussed in Appendix A of NACE SP0502, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect inspection examination.* In addition to the requirements in ASME/ANSI B31.8S, section 6.4 and NACE SP0502–2008, section 4, the plan's procedures for indirect inspection examination of the ECDA regions must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for identifying and documenting those indications that must be considered for excavation and direct examination. Minimum identification criteria include the known sensitivities of assessment tools, the procedures for using each tool, and the approach to be used for decreasing the physical spacing of indirect assessment tool readings when the presence of a defect is suspected;

(iii) Criteria for defining the urgency of excavation and direct examination of each indication identified during the indirect examination. These criteria must specify how an operator will define the urgency of excavating the indication as immediate, scheduled or monitored; and

(iv) Criteria for scheduling excavation of indications for each urgency level.

(3) *Direct examination.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 5, the plan's procedures for direct examination of indications from the indirect examination must include—

(i) Provisions for applying more restrictive criteria when conducting ECDA for the first time on a covered segment;

(ii) Criteria for deciding what action should be taken if either:

(A) Corrosion defects are discovered that exceed allowable limits (Section 5.5.2.2 of NACE RP0502), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE RP0502);

(iii) Criteria and notification procedures for any changes in the ECDA Plan, including changes that affect the severity classification, the priority of direct examination, and the time frame for direct examination of indications; and

(iv) Criteria that describe how and on what basis an operator will reclassify and reprioritize any of the provisions that are specified in section 5.9 of NACE SP0502.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502, section 6, the plan's procedures for post assessment of the effectiveness of the ECDA process must include—

(i) Measures for evaluating the long-term effectiveness of ECDA in addressing external corrosion in covered segments; and

(ii) Criteria for evaluating whether conditions discovered by direct examination of indications in each ECDA region indicate a need for reassessment of the covered segment at an interval less than that specified in § 192.939. (See Appendix D of NACE SP0502.)

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§192.927 What are the requirements for using Internal Corrosion Direct Assessment (ICDA)?

(a) *Definition.* Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas.

(b) *General requirements*. An operator using direct assessment as an assessment method to address internal corrosion in a covered pipeline segment must follow the requirements in this section and in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4 and appendix B2. The ICDA process described in this section applies only for a segment of pipe transporting nominally dry natural gas, and not for a segment with electrolyte nominally present in the gas stream. If an operator uses ICDA to assess a covered segment operating with electrolyte present in the gas stream, the operator must develop a plan that demonstrates how it will conduct ICDA in the segment to effectively address internal corrosion, and must provide notification in accordance with §192.921 (a)(4) or §192.937(c)(4).

(c) *The ICDA plan.* An operator must develop and follow an ICDA plan that provides for preassessment, identification of ICDA regions and excavation locations, detailed examination of pipe at excavation locations, and post-assessment evaluation and monitoring.

(1) *Preassessment*. In the preassessment stage, an operator must gather and integrate data and information needed to evaluate the feasibility of ICDA for the covered segment, and to support use of a model to identify the locations along the pipe segment where electrolyte may accumulate, to identify ICDA regions, and to identify areas within the covered segment where liquids may potentially be entrained. This data and information includes, but is not limited to—

(i) All data elements listed in appendix A2 of ASME/ANSI B31.8S;

(ii) Information needed to support use of a model that an operator must use to identify areas along the pipeline where internal corrosion is most likely to occur. (See paragraph (a) of this section.) This information, includes, but is not limited to, location of all gas input and withdrawal points on the line; location of all low points on covered segments such as sags, drips, inclines, valves, manifolds, dead-legs, and traps; the elevation profile of the pipeline in sufficient detail that angles of inclination can be calculated for all pipe segments; and the diameter of the pipeline, and the range of expected gas velocities in the pipeline;

(iii) Operating experience data that would indicate historic upsets in gas conditions, locations where these upsets have occurred, and potential damage resulting from these upset conditions; and

(iv) Information on covered segments where cleaning pigs may not have been used or where cleaning pigs may deposit electrolytes.

(2) *ICDA region identification*. An operator's plan must identify where all ICDA Regions are located in the transmission system, in which covered segments are located. An ICDA Region extends from the location where liquid may first enter the pipeline and encompasses the entire area along the pipeline where internal corrosion may occur and where further evaluation is needed. An ICDA Region may encompass one or more covered segments. In the identification process, an operator must use the model in GRI 02-0057, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines—Methodology," (incorporated by reference, *see* §192.7). An operator may use another model if the operator demonstrates it is equivalent to the one shown in GRI 02-0057. A model must consider changes in pipe diameter, locations where gas enters a line (potential to introduce liquid) and locations down stream of gas draw-offs (where gas velocity is reduced) to define the critical pipe angle of inclination above which water film cannot be transported by the gas.

(3) *Identification of locations for excavation and direct examination.* An operator's plan must identify the locations where internal corrosion is most likely in each ICDA region. In the location identification process, an operator must identify a minimum of two locations for excavation within each ICDA Region within a covered segment and must perform a direct examination for internal corrosion at each location, using ultrasonic thickness measurements, radiography, or other generally accepted measurement technique. One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the covered segment nearest to the beginning of the ICDA Region. The second location must be further downstream, within a covered segment, near the end of the ICDA Region. If corrosion exists at either location, the operator must—

(i) Evaluate the severity of the defect (remaining strength) and remediate the defect in accordance with §192.933;

(ii) As part of the operator's current integrity assessment either perform additional excavations in each covered segment within the ICDA region, or use an alternative assessment method allowed by this subpart to assess the line pipe in each covered segment within the ICDA region for internal corrosion; and

(iii) Evaluate the potential for internal corrosion in all pipeline segments (both covered and non-covered) in the operator's pipeline system with similar characteristics to the ICDA region containing the covered segment in which the corrosion was found, and as appropriate, remediate the conditions the operator finds in accordance with §192.933.

(4) *Post-assessment evaluation and monitoring.* An operator's plan must provide for evaluating the effectiveness of the ICDA process and continued monitoring of covered segments where internal corrosion has been identified. The evaluation and monitoring process includes—

(i) Evaluating the effectiveness of ICDA as an assessment method for addressing internal corrosion and determining whether a covered segment should be reassessed at more frequent intervals than those specified in §192.939. An operator must carry out this evaluation within a year of conducting an ICDA; and

(ii) Continually monitoring each covered segment where internal corrosion has been identified using techniques such as coupons, UT sensors or electronic probes, periodically drawing off liquids at low points and chemically analyzing the liquids for the presence of corrosion products. An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted in accordance with the requirements of this subpart, and risk factors specific to the covered segment. If an operator finds any evidence of corrosion products in the covered segment, the operator must take prompt action in accordance with one of the two following required actions and remediate the conditions the operator finds in accordance with §192.933.

(A) Conduct excavations of covered segments at locations downstream from where the electrolyte might have entered the pipe; or

(B) Assess the covered segment using another integrity assessment method allowed by this subpart.

(5) *Other requirements.* The ICDA plan must also include—

(i) Criteria an operator will apply in making key decisions (e.g., ICDA feasibility, definition of ICDA Regions, conditions requiring excavation) in implementing each stage of the ICDA process;

(ii) Provisions for applying more restrictive criteria when conducting ICDA for the first time on a covered segment and that become less stringent as the operator gains experience; and

(iii) Provisions that analysis be carried out on the entire pipeline in which covered segments are present, except that application of the remediation criteria of §192.933 may be limited to covered segments.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.929 What are the requirements for using Direct Assessment for Stress Corrosion Cracking (SCCDA)?

(a) *Definition.* Stress Corrosion Cracking Direct Assessment (SCCDA) is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe having similar operational characteristics and residing in a similar physical environment.

(b) *General requirements*. An operator using direct assessment as an integrity assessment method to address stress corrosion cracking in a covered pipeline segment must have a plan that provides, at minimum, for—

(1) Data gathering and integration. An operator's plan must provide for a systematic process to collect and evaluate data for all covered segments to identify whether the conditions for SCC are present and to prioritize the covered segments for assessment. This process must include gathering and evaluating data related to SCC at all sites an operator excavates during the conduct of its pipeline operations where the criteria in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), appendix A3.3 indicate the potential for SCC. This data includes at minimum, the data specified in ASME/ANSI B31.8S, appendix A3.

(2) Assessment method. The plan must provide that if conditions for SCC are identified in a covered segment, an operator must assess the covered segment using an integrity assessment method specified in ASME/ANSI B31.8S, appendix A3, and remediate the threat in accordance with ASME/ANSI B31.8S, appendix A3, section A3.4.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.931 How may Confirmatory Direct Assessment (CDA) be used?

An operator using the confirmatory direct assessment (CDA) method as allowed in §192.937 must have a plan that meets the requirements of this section and of §§ 192.925 (ECDA) and §192.927 (ICDA).

(a) *Threats.* An operator may only use CDA on a covered segment to identify damage resulting from external corrosion or internal corrosion.

(b) *External corrosion plan.* An operator's CDA plan for identifying external corrosion must comply with §192.925 with the following exceptions.

(1) The procedures for indirect examination may allow use of only one indirect examination tool suitable for the application.

(2) The procedures for direct examination and remediation must provide that—

(i) All immediate action indications must be excavated for each ECDA region; and

(ii) At least one high risk indication that meets the criteria of scheduled action must be excavated in each ECDA region.

(c) *Internal corrosion plan.* An operator's CDA plan for identifying internal corrosion must comply with §192.927 except that the plan's procedures for identifying locations for excavation may require excavation of only one high risk location in each ICDA region.

(d) *Defects requiring near-term remediation.* If an assessment carried out under paragraph (b) or (c) of this section reveals any defect requiring remediation prior to the next scheduled assessment, the operator must schedule the next assessment in accordance with NACE RP 0502 (incorporated by reference *see* §192.7), section 6.2 and 6.3. If the defect requires immediate remediation, then the operator must reduce pressure consistent with §192.933 until the operator has completed reassessment using one of the assessment techniques allowed in §192.937.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-114, 74 FR 48593, Aug 11, 2010; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.933 What actions must be taken to address integrity issues?

(a) *General requirements.* An operator must take prompt action to address all anomalous conditions the operator discovers through the integrity assessment. In addressing all conditions, an operator must evaluate all anomalous conditions and remediate those that could reduce a pipeline's integrity. An operator must be able to demonstrate that the remediation of the condition will ensure the condition is unlikely to pose a threat to the integrity of the pipeline until the next reassessment of the covered segment.

(1) *Temporary pressure reduction*. If an operator is unable to respond within the time limits for certain conditions specified in this section, the operator must temporarily reduce the operating pressure of the pipeline or take other action that ensures the safety of the covered segment. An operator must determine any temporary reduction in operating pressure required by this section using ASME/ANSI B31G (incorporated by reference, *see* §192.7) Pipeline Research Council, International, PR-3-805 (R–STRENG) (incorporated by reference, *see* § 192.7); or by reducing the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. An operator must notify PHMSA in accordance with § 192.949 if it cannot meet the schedule for evaluation and remediation required under paragraph (c) of this section and cannot provide safety through a temporary reduction in operating pressure or through another action. An operator must also notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement or an intrastate covered segment is regulated by that State.

(2) *Long-term pressure reduction.* When a pressure reduction exceeds 365 days, the operator must notify PHMSA under §192.949 and explain the reasons for the remediation delay. This notice must include a technical justification that the continued pressure reduction will not jeopardize the integrity of the pipeline. The operator also must notify a State pipeline safety authority when either a covered segment is located in a State where PHMSA has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(b) *Discovery of condition.* Discovery of a condition occurs when an operator has adequate information about a condition to determine that the condition presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, those conditions that require remediation or monitoring listed under paragraphs (d)(1) through (d)(3) of this section. An operator must promptly, but no later than 180 days after conducting an integrity assessment, obtain sufficient information about a condition to make that determination, unless the operator demonstrates that the 180-day period is impracticable.

(c) *Schedule for evaluation and remediation.* An operator must complete remediation of a condition according to a schedule prioritizing the conditions for evaluation and remediation. Unless a special requirement for remediating certain conditions applies, as provided in paragraph (d) of this section, an operator must follow the schedule in ASME/ANSI B31.8S (incorporated by reference, see §192.7), section 7, Figure 4. If an operator cannot meet the schedule for any condition, the operator must explain the reasons why it cannot meet the schedule and how the changed schedule will not jeopardize public safety.

(d) *Special requirements for scheduling remediation*.—(1) Immediate repair conditions. An operator's evaluation and remediation schedule must follow ASME/ANSI B31.8S, section 7 in providing for immediate repair conditions. To maintain safety, an operator must temporarily reduce operating pressure in accordance with paragraph (a) of this section or shut down the pipeline until the operator completes the repair of these conditions. An operator must treat the following conditions as immediate repair conditions:

(i) A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. Suitable remaining strength calculation methods include ASME/ANSI B31G (incorporated by reference, *see* § 192.7), PRCI PR-3-8-5 (R-STRENG) (incorporated by reference, *see* § 192.7), or an alternative equivalent method of remaining strength calculation.

(ii) A dent that has any indication of metal loss, cracking or a stress riser.

(iii) An indication or anomaly that in the judgment of the person designated by the operator to evaluate the assessment results requires immediate action.

(2) *One-year conditions.* Except for conditions listed in paragraph (d)(1) and (d)(3) of this section, an operator must remediate any of the following within one year of discovery of the condition:

(i) A smooth dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12).

(ii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

(3) *Monitored conditions.* An operator does not have to schedule the following conditions for remediation, but must record and monitor the conditions during subsequent risk assessments and integrity assessments for any change that may require remediation:

(i) A dent with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than NPS 12) located between the 4 o'clock position and the 8 o'clock position (bottom ⅓ of the pipe).

(ii) A dent located between the 8 o'clock and 4 o'clock positions (upper ⅔ of the pipe) with a depth greater than 6% of the pipeline diameter (greater than 0.50 inches in depth for a pipeline diameter less than Nominal Pipe Size (NPS) 12), and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

(iii) A dent with a depth greater than 2% of the pipeline's diameter (0.250 inches in depth for a pipeline diameter less than NPS 12) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-104, 72 FR 39012, July 17, 2007; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.935 What additional preventive and mitigative measures must an operator take?

(a) *General requirements.* An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (*See* §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.

(b) *Third party damage and outside force damage*—(1) *Third party damage.* An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—

(i) Using qualified personnel (*see* §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.

(ii) Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.

(iii) Participating in one-call systems in locations where covered segments are present.

(iv) Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE SP0502 (incorporated by reference, *see* §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.

(2) *Outside force damage*. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.

(c) *Automatic shut-off valves (ASV) or Remote control valves (RCV).* If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.

(d) *Pipelines operating below 30% SMYS.* An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.

(1) Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and

(2) Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.

(3) Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).

(e) *Plastic transmission pipeline*. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-114, 74 FR 48593, Aug 11, 2010; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.937 What is a continual process of evaluation and assessment to maintain a pipeline's integrity?

(a) *General.* After completing the baseline integrity assessment of a covered segment, an operator must continue to assess the line pipe of that segment at the intervals specified in §192.939 and periodically evaluate the integrity of each covered pipeline segment as provided in paragraph (b) of this section. An operator must reassess a covered segment on which a prior assessment is credited as a baseline under §192.921(e) by no later than December 17, 2009. An operator must reassess a covered segment on which a baseline assessment is conducted during the baseline period specified in §192.921(d) by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment.

(b) *Evaluation.* An operator must conduct a periodic evaluation as frequently as needed to assure the integrity of each covered segment. The periodic evaluation must be based on a data integration and risk assessment of the entire pipeline as specified in §192.917. For plastic transmission pipelines, the periodic evaluation is based on the threat analysis specified in 192.917(d). For all other transmission pipelines, the evaluation must consider the past and present integrity assessment results, data integration and risk assessment information (§192.917), and decisions about remediation (§192.933) and additional preventive and mitigative actions (§192.935). An operator must use the results from this evaluation to identify the threats specific to each covered segment and the risk represented by these threats.

(c) *Assessment methods.* In conducting the integrity reassessment, an operator must assess the integrity of the line pipe in the covered segment by any of the following methods as appropriate for the threats to which the covered segment is susceptible (*see* §192.917), or by confirmatory direct assessment under the conditions specified in §192.931.

(1) Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible. An operator must follow ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.2 in selecting the appropriate internal inspection tools for the covered segment.

(2) Pressure test conducted in accordance with subpart J of this part. An operator must use the test pressures specified in Table 3 of section 5 of ASME/ANSI B31.8S, to justify an extended reassessment interval in accordance with §192.939.

(3) Direct assessment to address threats of external corrosion, internal corrosion, or stress corrosion cracking. An operator must conduct the direct assessment in accordance with the requirements listed in §192.923 and with as applicable, the requirements specified in §§ 192.925, 192.927 or 192.929;

(4) Other technology that an operator demonstrates can provide an equivalent understanding of the condition of the line pipe. An operator choosing this option must notify the Office of Pipeline Safety (OPS) 180 days before conducting the assessment, in accordance with §192.949. An operator must also notify a State or local pipeline safety authority when either a covered segment is located in a State where OPS has an interstate agent agreement, or an intrastate covered segment is regulated by that State.

(5) Confirmatory direct assessment when used on a covered segment that is scheduled for reassessment at a period longer than seven years. An operator using this reassessment method must comply with §192.931.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006]

§192.939 What are the required reassessment intervals?

An operator must comply with the following requirements in establishing the reassessment interval for the operator's covered pipeline segments.

(a) *Pipelines operating at or above 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating at or above 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. If an operator establishes a reassessment interval that is greater than seven years, the operator must, within the seven-year period, conduct a confirmatory direct assessment on the covered segment, and then conduct the follow-up reassessment at the interval the operator has established. A reassessment carried out using confirmatory direct assessment must be done in accordance with §192.931. The table that follows this section sets forth the maximum allowed reassessment intervals.

(1) *Pressure test or internal inspection or other equivalent technology*. An operator that uses pressure testing or internal inspection as an assessment method must establish the reassessment interval for a covered pipeline segment by—

(i) Basing the interval on the identified threats for the covered segment (see §192.917) and on the analysis of the results from the last integrity assessment and from the data integration and risk assessment required by §192.917; or

(ii) Using the intervals specified for different stress levels of pipeline (operating at or above 30% SMYS) listed in ASME/ANSI B31.8S (incorporated by reference, *see* § 192.7), section 5, Table 3.

(2) *External Corrosion Direct Assessment.* An operator that uses ECDA that meets the requirements of this subpart must determine the reassessment interval according to the requirements in paragraphs 6.2 and 6.3 of NACE SP0502 (incorporated by reference, *see* §192.7).

(3) *Internal Corrosion or SCC Direct Assessment.* An operator that uses ICDA or SCCDA in accordance with the requirements of this subpart must determine the reassessment interval according to the following method. However, the reassessment interval cannot exceed those specified for direct assessment in ASME/ANSI B31.8S, section 5, Table 3.

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

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

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

(b) *Pipelines Operating Below 30% SMYS.* An operator must establish a reassessment interval for each covered segment operating below 30% SMYS in accordance with the requirements of this section. The maximum reassessment interval by an allowable reassessment method is seven years. An operator must establish reassessment by at least one of the following—

(1) Reassessment by pressure test, internal inspection or other equivalent technology following the requirements in paragraph (a)(1) of this section except that the stress level referenced in paragraph (a)(1)(ii) of this section would be adjusted to reflect the lower operating stress level. If an established interval is more than seven years, the operator must conduct by the seventh year of the interval either a confirmatory direct assessment in accordance with §192.931, or a low stress reassessment in accordance with §192.941.

(2) Reassessment by ECDA following the requirements in paragraph (a)(2) of this section.

(3) Reassessment by ICDA or SCCDA following the requirements in paragraph (a)(3) of this section.

(4) Reassessment by confirmatory direct assessment at 7-year intervals in accordance with §192.931, with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(5) Reassessment by the low stress assessment method at 7-year intervals in accordance with §192.941 with reassessment by one of the methods listed in paragraphs (b)(1) through (b)(3) of this section by year 20 of the interval.

(6) The following table sets forth the maximum reassessment intervals. Also refer to Appendix E.II for guidance on Assessment Methods and Assessment Schedule for Transmission Pipelines Operating Below 30% SMYS. In case of conflict between the rule and the guidance in the Appendix, the requirements of the rule control. An operator must comply with the following requirements in establishing a reassessment interval for a covered segment:

Maximum Reassessment Interval

Assessment Method	Pipeline operating at or above 50% SMYS	Pipeline operating at or above 30% SMYS, up to 50% SMYS	Pipeline operating below 30% SMYS
Internal Inspection Tool, Pressure Test or Direct Assessment	10 years(*)	15 years(*)	20 years(**)
Confirmatory Direct Assessment	7 years	7 years	7 years
Low Stress Reassessment	Not applicable	Not applicable	7 years + ongoing actions specified in §192.941

(*) A Confirmatory direct assessment as described in § 192.931 must be conducted by year 7 in a 10-year interval and years 7 and 14 of a 15-year interval.
(**) A low stress reassessment or Confirmatory direct assessment must be conducted by years 7 and 14 of the interval.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-114, 74 FR 48593, Aug 11, 2010; Amdt. 192-119, 80 FR 168, January 5, 2015]

§192.941 What is a low stress reassessment?

(a) *General.* An operator of a transmission line that operates below 30% SMYS may use the following method to reassess a covered segment in accordance with §192.939. This method of reassessment addresses the threats of external and internal corrosion. The operator must have conducted a baseline assessment of the covered segment in accordance with the requirements of §§ 192.919 and 192.921.

(b) *External corrosion.* An operator must take one of the following actions to address external corrosion on the low stress covered segment.

(1) *Cathodically protected pipe*. To address the threat of external corrosion on cathodically protected pipe in a covered segment, an operator must perform an electrical survey (i.e. indirect examination tool/method) at least every 7 years on the covered segment. An operator must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(2) *Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.* If an electrical survey is impractical on the covered segment an operator must—

(i) Conduct leakage surveys as required by §192.706 at 4-month intervals; and

(ii) Every 18 months, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

(c) *Internal corrosion.* To address the threat of internal corrosion on a covered segment, an operator must—

(1) Conduct a gas analysis for corrosive agents at least once each calendar year;

(2) Conduct periodic testing of fluids removed from the segment. At least once each calendar year test the fluids removed from each storage field that may affect a covered segment; and

(3) At least every seven (7) years, integrate data from the analysis and testing required by paragraphs (c)(1)-(c)(2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004]

§192.943 When can an operator deviate from these reassessment intervals?

(a) *Waiver from reassessment interval in limited situations.* In the following limited instances, OPS may allow a waiver from a reassessment interval required by §192.939 if OPS finds a waiver would not be inconsistent with pipeline safety.

(1) *Lack of internal inspection tools.* An operator who uses internal inspection as an assessment method may be able to justify a longer reassessment period for a covered segment if internal inspection tools are not available to assess the line pipe. To justify this, the operator must demonstrate that it cannot obtain the internal inspection tools within the required reassessment period and that the actions the operator is taking in the interim ensure the integrity of the covered segment.

(2) Maintain product supply. An operator may be able to justify a longer reassessment period for a covered segment if the operator demonstrates that it cannot maintain local product supply if it conducts the reassessment within the required interval.

(b) *How to apply.* If one of the conditions specified in paragraph (a) (1) or (a) (2) of this section applies, an operator may seek a waiver of the required reassessment interval. An operator must apply for a waiver in accordance with 49 U.S.C. 60118(c), at least 180 days before the end of the required reassessment interval, unless local product supply issues make the period impractical. If local product supply issues make the period impractical, an operator must apply for the waiver as soon as the need for the waiver becomes known.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004]

§192.945 What methods must an operator use to measure program effectiveness?

(a) *General*. An operator must include in its integrity management program methods to measure whether the program is effective in assessing and evaluating the integrity of each covered pipeline segment and in protecting the high consequence areas. These measures must include the four overall performance measures specified in ASME/ANSI B31.8S (incorporated by reference, see §192.7 of this part), section 9.4, and the specific measures for each identified threat specified in ASME/ANSI B31.8S, Appendix A. An operator must submit the four overall performance measures as part of the annual report required by §191.17 of this subchapter.

(b) *External Corrosion Direct assessment.* In addition to the general requirements for performance measures in paragraph (a) of this section, an operator using direct assessment to assess the external corrosion threat must define and monitor measures to determine the effectiveness of the ECDA process. These measures must meet the requirements of §192.925.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004; Amdt. 192-103, 71 FR 33402, June 8, 2006; Amdt. 192-115, 75 FR 72878, Nov 26, 2010]

§192.947 What records must an operator keep?

An operator must maintain, for the useful life of the pipeline, records that demonstrate compliance with the requirements of this subpart. At minimum, an operator must maintain the following records for review during an inspection.

(a) A written integrity management program in accordance with §192.907;

(b) Documents supporting the threat identification and risk assessment in accordance with §192.917;

(c) A written baseline assessment plan in accordance with §192.919;

(d) Documents to support any decision, analysis and process developed and used to implement and evaluate each element of the baseline assessment plan and integrity management program. Documents include those developed and used in support of any identification, calculation, amendment, modification, justification, deviation and determination made, and any action taken to implement and evaluate any of the program elements;

(e) Documents that demonstrate personnel have the required training, including a description of the training program, in accordance with §192.915;

(f) Schedule required by §192.933 that prioritizes the conditions found during an assessment for evaluation and remediation, including technical justifications for the schedule.

(g) Documents to carry out the requirements in §§ 192.923 through 192.929 for a direct assessment plan;

(h) Documents to carry out the requirements in §192.931 for confirmatory direct assessment;

(i) Verification that an operator has provided any documentation or notification required by this subpart to be provided to OPS, and when applicable, a State authority with which OPS has an interstate agent agreement, and a State or local pipeline safety authority that regulates a covered pipeline segment within that State.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-95B, 69 FR 18227, April 6, 2004]

§192.949 How does an operator notify PHMSA?

An operator must provide file any notification report required by this subpart by– electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with §191.7 of this sub-chapter.

(a) Sending the notification by electronic mail to *InformationResourcesManager@dot.gov*; or

(b) Sending the notification by mail to ATTN: Information Resources Manager, DOT/PHMSA/OPS, East Building, 2nd Floor, E22–321, 1200 New Jersey Ave. SE., Washington, DC 20590.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-100, 70 FR 11135, Mar. 8, 2005; Amdt. 192-103c, 72 FR 4655, Feb. 1, 2007; Amdt. 192-[106], 73 FR 16562, Mar. 28, 2008; Amdt. 192-[109], 74 FR 2889, January 16, 2009; Amdt. 192-115, 75 FR 72878, Nov 26, 2010; Amdt. 192-120, 80 FR 12762, March 11, 2015]

§192.951 Where does an operator file a report?

An operator must file any report required by this subpart electronically to the Pipeline and Hazardous Materials Safety Administration in accordance with §191.7 of this subchapter.

[Amdt. 192-95, 68 FR 69777, December 15, 2003 as amended by Amdt. 192 95A, 69 FR 2307, December 22, 2003; Amdt. 192-100, 70 FR 11135, Mar. 8, 2005; Amdt. 192-103c, 72 FR 4655, Feb. 1, 2007; Amdt. 192-[106], 73 FR 16562, Mar. 28, 2008; Amdt. 192-[109], 74 FR 2889, January 16, 2009; Amdt. 192-115, 75 FR 72878, Nov 26, 2010]

2 ROLES AND RESPONSIBILITIES

In This Section

Referenced Protocols

Not Applicable

2 ROLES AND RESPONSIBILITIES

2.1 PURPOSE

This Section describes the organizational structure of the Company's personnel fulfilling Integrity Management (IM) functions and their respective IM responsibilities and qualifications. This Section also provides the criteria for qualification of key IM personnel as required by 49 CFR § 192.915.

2.2 KEY FUNCTIONAL ROLES AND RESPONSIBILITIES

The primary IM functions are provided in Table 2-1 along with the current Company job title for the person responsible for providing that function. These functions are assigned "function codes", e.g. (F)ield Level F5 function code includes field oversight and inspection of pipeline repairs. Table 2-1 also indicates the applicability of the IM Rule requirement for knowledge and training for specific functions (§192.915). For ease of reference during regulatory compliance inspections, Table 2-2 is a direct cross reference of the Company personnel positions with §192.915.

As the Company's IM Program develops, the IM functions provided within a designated function code may change as well as the job titles. Similarly, functions may shift across personnel categories. For example, the Qualified Individual (QI) function for making Immediate Repair determinations (currently an M1 function) may be transferred or shared with personnel in a field office providing a F2 function).

2.3 DOCUMENTATION OF PERSONNEL QUALIFICATIONS

The Company's corporate database, i.e. PeopleSoft or similar software, will be used to record formal education, training, certifications and Company experience for Company Personnel. In addition, the Integrity Management Section may retain training support documentation (i.e. class syllabus/outlines and class certificates) on their departmental share drive or other location deemed appropriate. Relevant non-company experience may be documented using the Personnel Qualification Record Form (Form F2-1 or other similar form). This form is provided at the end of this Section for ease of reference. The documentation of personnel qualifications for each employee will be stored in accordance with company procedures and Section 16 (Recordkeeping) for audit and regulatory compliance inspection purposes.

Table 2-1 - Key Personnel Requirements

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
E1 **Vice President Gas Distribution**	• Corporate officer responsible for IM Program performance Program • Ensure Program Management and Field Level functions have adequate support to perform their responsibilities. • Monitor IM Program performance. • Communicate IM Program performance and support needs to Company officers as appropriate.	• Writing and verbal communication • Interface with senior officers	• Working knowledge of or training on the operations and management of gas pipeline systems.
M2 **Director - Gas Control and Storage**	• Ensure Field Level functions have adequate support to perform their IM responsibilities. • Monitor IM Program performance. • Ensure qualifications and requisite training of Regional subordinates. • Provide IMP reviews as a member of the Integrity Management Review Team.	• Technical writing and verbal communication. • Interpretation and application of published engineering calculation procedures and regulatory standards for pipeline systems. • Application of regulatory knowledge and compliance interpretations. • Supervision of technical staff. • Interface with senior management.	• BS degree in engineering, physical sciences, or physics or equivalent experience. • Experience and/or training in the design, inspection and repair of gas pipeline systems including: ➢ Design and specification of pipe for procurement and installation utilizing ASME and ANSI standards. ➢ Inspection, repair and preventative maintenance programs for line pipe. • Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
M4 **Manager – Gas Regulatory Compliance**	• Oversee the performance of functions M1 and M3. • Provide technical and non-technical guidance on transmisison integrity management tasks to subordinates and others within M4's area of knowledge. • Ensure Program Management and Field Level functions have adequate support to perform their responsibilities. • Ensure participation in and performance of Damage Prevention and Public Education Programs • Ensure qualifications and requisite training of subordinates. • Review and/or approve safe operating pressure for immediate repair conditions. • Co-chair Integrity Management Review Team meetings for evaluation of IM Program performance.	• Technical writing and verbal communication. • Interpretation and application of published engineering calculation procedures and regulatory standards for pipeline systems. • Application of regulatory knowledge & compliance interpretations. • Supervision of technical staff. • Interface with senior management.	• BS degree in engineering. • Experience and/or training in the design, inspection and repair of gas pipeline systems including: ➢ Design and specification of pipe for procurement and installation utilizing ASME and ANSI standards. ➢ Calculation of safe operating pressure for pipe anomalies using B31G, RSTRENG or similar methodology. ➢ In line inspections, direct assessments, and pressure tests. ➢ Preventative maintenance programs for pipelines. • Familiarity with one-call notification and public education programs. • Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192. • Specific knowledge or training on DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
M1 **Group Leader – Integrity Management** **(may be referred to as Program Manager – Integrity Management)**	• Oversee the performance of functions F3 and F5. • Provide technical and non-technical guidance on transmisison integrity management tasks to subordinates and others within M1's area of knowledge. • Approve and maintain ILI, DA, and pressure test assessment specifications and procedures. Approve vendor selections and qualifications. • Serve as default Qualified Individual (QI) for discovery of Immediate Repair Conditions; assigns QI responsibility to subordinates. • Review and/or approve safe operating pressure for immediate repair conditions. • Oversee of anomaly repair selection procedures and implementation. • Co-chair Integrity Management Review Team meetings for evaluation of IM Program performance.	• Interpretation and application of published engineering calculation procedures and regulatory standards for pipeline systems. • Knowledge of metallurgical characteristics pertaining to yield strength, ductility and chemical composition. • Knowledge of metal corrosion principles and prevention practices. • Supervision of technical staff	• BS degree in engineering. • Licensed Professional Engineer • Experience and/or training in the design, inspection and repair of gas transmission systems including: ➢ Design and specification of pipe for procurement and installation utilizing ASME and ANSI standards. ➢ Calculation of safe operating pressure for pipe anomalies using B31.G, RSTRENG or similar methodology. ➢ In line inspections, direct assessments, and pressure tests. ➢ Preventative maintenance programs for pipelines. • Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192. • Specific knowledge or training on DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience

M3
Group Leader – Gas Regulatory (Corrosion)
or
Corrosion Analyst
	• Review relevant assessment data to identify corrosion trends and areas for corrosion control upgrades when a cathodic protection system is suspected of being ineffective on a macro level.
	• Develop short-range and long-range plans for upgrades to cathodic protection systems.
	• Serve as a technical advisor for the company direct assessment program.
		• Reading comprehension and analysis of technical specifications and regulatory standards.
		• Verbal communication and written documentation of field activities.
		• Application of metal corrosion principles and prevention practices.
			• High school degree and continuing education related to corrosion control.
			• Experience and/or training in the application and evaluation of corrosion prevention systems for gas pipelines including:
			  • Cathodic protection system installation and repair.
			  • Close interval surveys
			  • Direct Current Voltage Gradient surveys
			• Working knowledge of DOT regulations 49 CFR § 192 Subpart I and familiarity with DOT regulations 49 CFR § 192 Subpart O.
			• NACE CP Level II or higher.

M5 **Group Leader – Gas Regulatory Services**	• Oversee contract services related to marking and locating buried structures.	• Reading comprehension and analysis of technical specifications and regulatory standards. • Verbal communication and written documentation of field activities.	• High school degree and continuing education related to location of buried structures. • Experience and/or training in the application of techniques used in the location of buried structures.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
F1 **Manager – Gas Storage Operations**	• Identify actions and resources necessary to resolve deficiencies in the performance of Regional IM activities. • Participate in integration and analysis of pipeline inspection data with all other pipeline operation issues. • Ensure IM qualifications and training of subordinates. • Oversee anomaly repair selection procedures and implementation.	• Supervision of technical staff • Technical writing and verbal communication. • Interpretation and application of published engineering calculation procedures and regulatory standards for pipeline systems • Supervision of technical staff. Interface with senior management.	• Experience and/or training in the operation and repair of gas pipeline systems. • Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192. • Familiarity with DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience

F2
 	
Engineer (Gas Storage)
	• Manage pipeline installations and pressure testing.
	• Manage repairs of gas pipeline and non-pipe facilities.
	• Determine safe operating pressure for immediate repair conditions.
	• Manage preventative maintenance programs for line pipe and non-pipe facilities.
		• Technical writing and verbal communication.
		• Interpretation and application of published engineering calculation procedures and regulatory standards for pipeline systems.
		• Application of metal corrosion principles and prevention practices.
			• BS degree in engineering, physical sciences, or physics or equivalent experience.
			• Experience and/or training in the design, inspection and repair of gas pipeline systems including:
			  ◦ Design and specification of pipe for procurement and installation utilizing ASME and ANSI standards.
			  ◦ Calculation of safe operating pressure for pipe anomalies using B31.G, modified B31.G, RSTRENG or similar methodology.
			  ◦ Direct participation in inspection, repair and preventative maintenance programs for line pipe and non-pipe facilities (e.g. compressor stations.)
			• Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192.
			• Familierity with DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience

F3
 	
Engineer (Integrity Management)
	• Maintain integrity management data including pipeline strength attributes, pressure test history, historical HCAs, historical risk analysis, historical preventative & mitigative measures implemented, and historical integrity assessments and associated repairs.
	• Identify necessary changes in type of data collected and/or methodology of integrity data collection.
	• Calculate HCA locations and class locations.
	• Conduct Risk Assessment modeling of pipeline segments and identify threats.
	• Implement preventative and mitigative measures.
	• Maintain baseline and continual re-assessment plan/schedule.
	• Conduct integrity assessments, evaluate results and oversee related repairs.
	• Support M1 in Quality Control reviews of IM data.
	• Determine safe operating pressure for immediate repair conditions.
		• Technical writing and verbal communication.
		• Interpretation and application of industry and regulatory standards for gas pipeline systems.
		• Computer database operation.
			• BS degree in engineering, physical sciences, physics or mathematics or equivalent experience.
			• Experience and/or training in the design, inspection and repair of gas pipeline systems including:
			  ◦ Design and specification of pipe for procurement and installation utilizing ASME and ANSI standards.
			  ◦ Calculation of safe operating pressure for pipe anomalies using B31.G, modified B31.G, RSTRENG or similar methodology.
			  ◦ Direct participation in inspection, repair and preventative maintenance programs for line pipe.
			• Working knowledge of or specific training on DOT regulations 49 CFR § 191 and 192.
			• Specific knowledge or training on DOT Integrity Management regulations 49 CFR § 192 Subpart O.

F4 **Team Leader,** **Distribution Crew Leader,** **or Pipeline Inspector**	• Manage regional assets related to maintenance activities.	• Verbal communication and written documentation of field activities. • Application of metal corrosion principles and prevention practices.	• High school diploma or equivalent • Experience and/or training in the application of corrosion prevention systems for gas pipelines. • Familiarity with DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience

F5
 	
Pipeline Specialist
	• Field oversight of integrity assessments.
	• Field oversight of repairs of line pipe and non-pipe facilities.
	• Field oversight of preventative and mitigative measure activities.
		• Reading comprehension and analysis of technical specifications and regulatory standards.
		• Verbal communication and written documentation of field activities.
		• Interpretation and application of published procedures and regulatory standards for pipeline systems.
			• High school diploma or equivalent.
			• Experience and/or training in the inspection and repair of gas pipeline systems including:
			  ◦ Installation of pipeline systems utilizing ASME or ANSI standards.
			  ◦ Direct participation in inspection, repair and preventative maintenance programs for line pipe.
			• Familiarity with DOT Integrity Management regulations 49 CFR § 192 Subpart O.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
F6 **Corrosion Technician**	• Perform field corrosion surveys. • Collect requested corrosion data. • Perform visual inspections for corrosion. • Perform coating repairs on transmission pipelines.	• Verbal communication and written documentation of field activities. • Application of metal corrosion principles and prevention practices.	• High school diploma or equivalent • Experience in the application of corrosion prevention systems for gas transmission pipeline facilities including cathodic protection system inspection and repair. • Operation Qualification Requirements • NACE CP Level I or higher or equivalent knowledge and experience.

Table 2-1 - Key Personnel Requirements (Continued)

Function Code /Title	Responsibilities	Job Tasks Analysis	Education, Training and Experience
F7 **Geologist**	• Oversight of internal corrosion efforts in Storage Fields. • Manage regional assets related to maintenance activities.	• Verbal communication and written documentation of field activities. • Application of metal corrosion principles and prevention practices.	• BS degree in engineering, physical sciences, physics or mathematics or equivalent experience. • Experience in the application of internal corrosion prevention systems for gas transmission pipeline facilities. • Familiarity with DOT Integrity Management regulations 49 CFR § 192. • Operation Qualification Requirements

Table 2-2 – Cross Reference of Company IM Positions with §192.915

Function Code /Title		§ 192.915 (a) Supervisory Personnel	§ 192.915(b)(1) Persons Who Conduct Assessments	§ 192.915(b)(2) Persons Who Review and Analyze Results From Assessments	§ 192.915(b)(3) Persons Who Make Decisions on Actions to Take Based on Assessments	§ 192.915(c)(1) Persons Who Implement Preventive and Mitigative Measures, *Including Marking and Locating Buried Structures*	§ 192.915(c)(2) Persons Who Directly Supervise Excavation Work in Conjunction With Integrity Assessments
M1	Group Leader – Integrity Management	X		X	X		X
M2	Director - Gas Control and Storage	X					
M3	Group Leader – Gas Regulatory (corrosion) or Corrosion Analyst	X				X	
M4	Manager – Gas Regulatory Compliance	X			X		
M5	Group Leader – Gas Regulatory	X				X	
F1	Manager –Gas Storage Operations	X					
F2	Engineer (Gas Storage)	X				X	X
F3	Engineer (Integrity Management)	X	X	X	X	X	X
F4	Team Leader, Distribution Crew Leader or Pipeline Inspector	X	X			X	X
F5	Pipeline Specialist		X	X	X	X	X

Table 2-2 – Cross Reference of Company IM Positions with §192.915 (Continued)

Function Code /Title		§ 192.915 (a) Supervisory Personnel	§ 192.915(b)(1) Persons Who Conduct Assessments	§ 192.915(b)(2) Persons Who Review and Analyze Results From Assessments	§ 192.915(b)(3) Persons Who Make Decisions on Actions to Take Based on Assessments	§ 192.915(c)(1) Persons Who Implement Preventive and Mitigative Measures, *Including Marking and Locating Buried Structures*	§ 192.915(c)(2) Persons Who Directly Supervise Excavation Work in Conjunction With Integrity Assessments
F6	Corrosion Technician		X			X	
F7	Geologist	X					

2.4 ORGANIZATION STRUCTURE AND DECISION MAKING

Figure 2-1 describes the Company's Key IM Personnel organization structure.

2.4.1 Operation (Field Operations) Personnel

Figure 2-1 depicts the Company's personnel at the field operations level by job title and IM Function code defined in Table 2-1. These personnel are largely responsible for implementing the assessment, repair, and preventive/ mitigative activities of the IM Program.

2.4.2 Corporate Services Personnel

As indicated in Figure 2-1, the Company's corporate offices have personnel that provide executive (E) and program management (M) support to the field operations IM activities. See Table 2-1 for a detailed description of the roles and responsibilities of the Corporate Services personnel. These personnel are primarily responsible for ensuring adequate resources for the overall IM Program.

2.4.3 IM Program Review Team

The Integrity Management Program Review Team is responsible for periodically performing a quality assurance review of the IM programas detailed in Section 15.4.3.1. As indicated in Figure 2-1, the IMP Review Team normally consists of representatives from each operating region and is normally co-chaired by the M4 and M1 personnel.

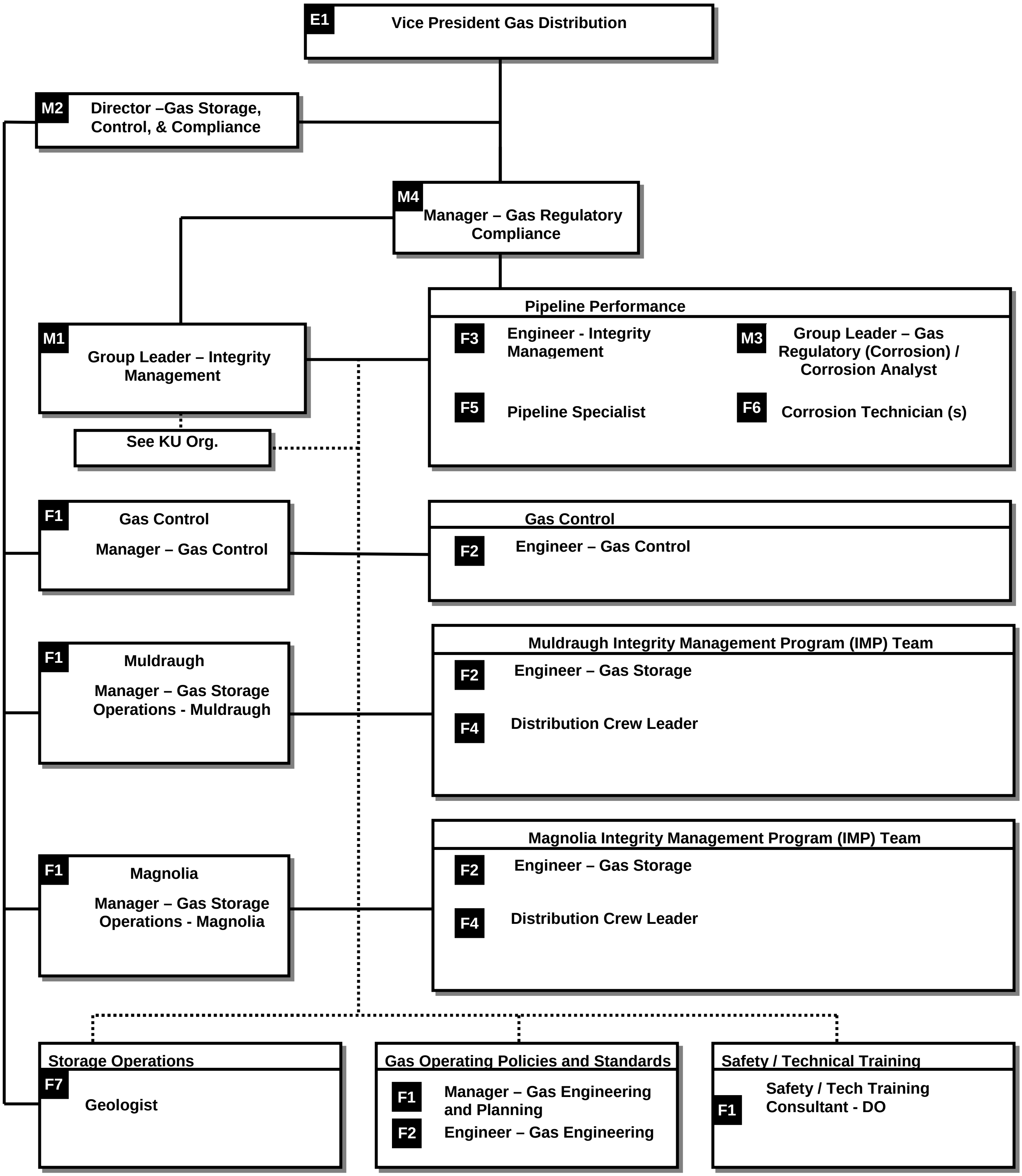


Figure 2-1 Key Personnel Organization Chart – LG&E

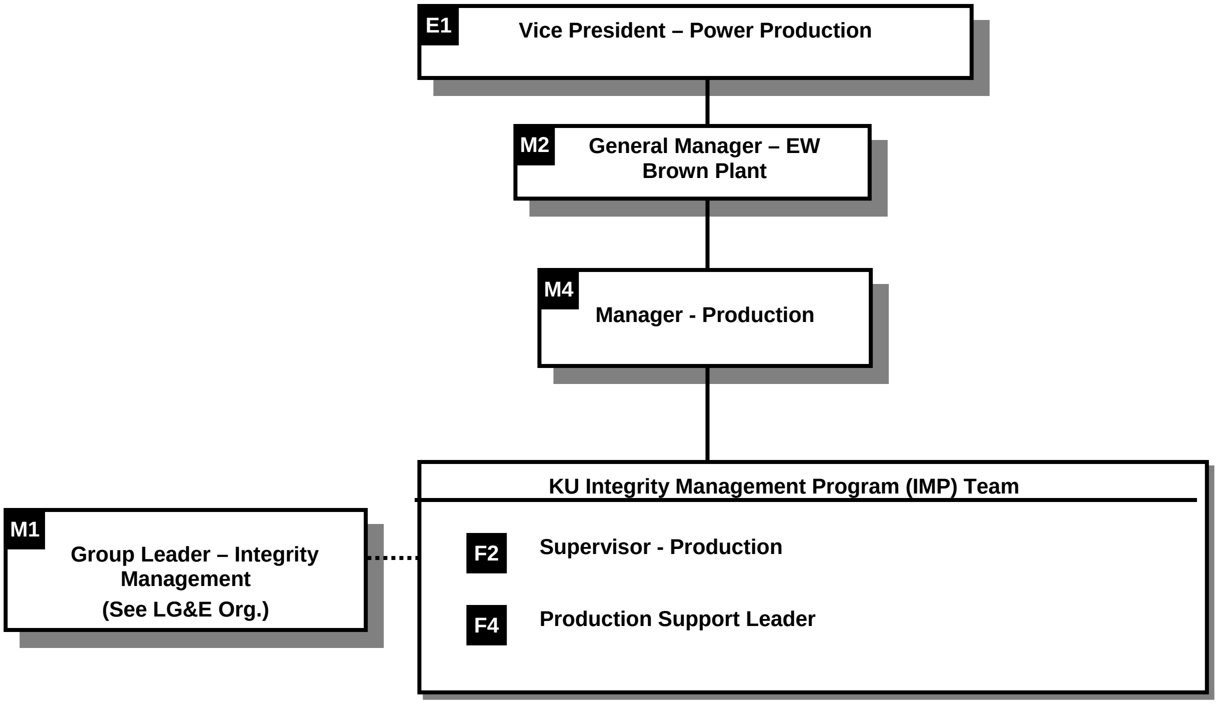


Figure 2-1 (Continued) - Key Personnel Organization Chart – KU

2.5 FORMS

Form F2-1: Personnel Qualfications Record Form

Personnel Qualifications Record Form

Form F2 – 1
Rev. December 21, 2012

Employee Name: ________ *(last)* ________ *(MI)* ________ *(first)*

Relevant Non-LG&E Experience

No.	*Company / Firm*	*Relevant Experience per Sec. 2.2*	*Experience Time From*	*Experience Time To*
1				

Relevant Non-LG&E Training Completed

List training relevant to Personnel Requirements, Table 2-1 of Section 2 in the IM Plan (include industry workshops, seminars, courses, self-study, etc.). Include training certificates and training descriptions in file as appropriate.

Date(s) (mm/dd/yyyy)	*Training*	*Hrs of Training*

Revision Log:

Date	Description	Revised By
11/15/04	Customized template to reflect LG&E organization	lco
11/15/04	11/15/04 Version Approved by Management	lco
6/27/2007	Replaced company logo from “LG&E Energy” to “LG&E” E.ON|US logo.	CMA
9/27/2007	Added KU logo	CMA
12/15/2008	Annual Regulatory Review for completed.	lco
12/28/2010	Revised company logo by removing “an Eon Company” subscript.	JRG
12/28/2010	Designated corporate personnel database as documentation site for personnel training records.	JRG
12/28/2010	Designated Form F2-1 for recording suppplemental outside experience and training for personnel in Integrity Management Group.	JRG
12/28/2010	Modified review and approval procedure for Form F2-1.	JRG
12/28/2010	Modified personnel functions listed in Table 2-1.	JRG
12/28/2010	Deleted “Planned Training to be Completed” from Form F2-1.	JRG
12/28/2010	Modified key personnel functions listed in Table 2-2.	JRG
12/28/2010	Modified “Cross Reference of Company IM Positions with Section 192.915”.	JRG
12/13/2011	Made minor corrections to changes made on 12/28/2010.	JRG
12/13/2011	Made corrections in Form F2-1 both in Section 2 and in the form document itself.	JRG
5/25/2012	Updated “Key Personnel Requirements”, “Cross Reference of Company IM Positions with Section 192.915”, IM Program Review Team information, personnel titles and Form F2-1.	PJC
11/6/2012	Deleted Table 2-1 since it was redundent with Table 2-2. Deleted unused F8 Compliance Specialist function. Updated position responsibilities and function education, training, and experience. Revised Form 2-1 to cover only non-LG&E experience and training.	PJC
11/20/2013	Corrected responsibilities due to organization change, inserted a job function for M5 for marking and locating buried structures into Table 2-1 and 2-2, corrected organization chart Figure 2-1 and general clerical corrections.	JRG
11/30/2015	Deleted parts of Section 2.4.3 IM Program Review Team and reinserted it into Section 15 Quality Assurance Process.	JRG

3 HCA IDENTIFICATION §192.905

In This Section

Referenced Protocols

3 HCA IDENTIFICATION PROCESS

3.1 OVERVIEW

3.1.1 Purpose

This Section describes **Louisville Gas & Electric / Kentucky Utilities'** (**the company(s)**) process for identifying High Consequence Areas (HCAs) on its pipeline system. These HCAs are mapped along the pipeline system to determine the "covered segments" per the definition in §192.903.

The methods, data sources, and processes used to identify those covered segments are described in this section. This section also contains the procedures for quality assurance; and the correction and updating of results.

3.1.2 Responsibility

The **Program Manager – Integrity Management** M1 is responsible for the implementation and maintenance of the procedures in this Section. The **Pipeline Integrity Engineer** F3 has specific assignment responsibilities as described within this section. This includes correction and updating of the current pipeline system HCA analyses and quality control review of data inputs and results of the identification process. The **Engineers** F2 are also responsible for quality assurance review of data inputs relating to engineering aspects of the pipeline system (e.g., flow rate, pressure).

3.2 GENERAL

✓ ***Referenced Protocol:*** ***A.1 Program Requirements***

This section contains the documented processes used by **the company** to implement the HCA identification process for Method 1 and 2. Although **the company** may select either method 1 or 2 in determining HCAs along the pipeline system, **the company** may also choose a combination of method 1 and 2 on the pipeline system. Alternatively, **the company** may choose to identify the entire pipeline system as an HCA.

The company maintains system maps and documentation of all HCA segments and their selection methods electronically.

The company has completed the initial HCA identification for all pipeline segments prior to the **December 17, 2004** deadline.

3.3 DEFINITIONS

3.3.1 Class Locations

The following are federal definitions under 49 CFR 192. State or local pipeline authorities with delegated authority may vary somewhat from the federal definitions and requirements. Agencies with delegated authority may be more stringent, but they cannot be less stringent. Kentucky gas safety regulations describe the same criteria for determination of class locations, 807 KAR 5:022 Section 1 (3).

Class Location Unit:

A ‘‘class location unit’’ is an onshore area that extends 220 yards (660 feet) on either side of the centerline of any continuous 1-mile length of pipeline. [Also referenced in Appendix 1B of this Integrity Management Program]

Dwelling Unit / Building:

Each separate dwelling unit in a multiple dwelling unit building is counted as a separate building intended for human occupancy. Each store or business unit in a multi-unit commercial building, such as a mall or shopping center, shall be counted as a separate unit intended for human occupancy. Multi-unit and subdivided buildings will be mapped within the company's GIS as a single building matching the exterior footprint and the number of units intended for human occupancy will be recorded as a building characteristic. Buildings connected by breezeways, conveyors, awnings, or similar may be mapped separately.

Garages, storage sheds, barns, and other utility buildings intended for the storage of vehicles, equipment, materials, or shelter of animals, and in which human occupation is transient and short term under normal conditions shall not be considered as buildings intended for human occupancy. However, if such buildings are inhabited by humans during their normal use, such as a commercial garage or a distribution center warehouse, they shall be considered as being intended for human occupancy.

Individual suites within a hotel or motel are not to be considered as separate dwelling units.

Class 1:

A Class 1 location is:

(i) An offshore area; or

(ii) Any class location unit that has 10 or fewer buildings intended for human occupancy.

Class 2:

A Class 2 location is any class location unit that has more than 10 but fewer than 46 buildings intended for human occupancy.

When a cluster of buildings intended for human occupancy requires a Class 2 location, the class location ends 220 yards (660 feet) from the nearest building in the cluster.

Class 3:

A Class 3 location is:

(i) Any class location unit that has 46 or more buildings intended for human occupancy; or

(ii) An area where the pipeline lies within 100 yards (300 feet) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)

When a cluster of buildings intended for human occupancy requires a Class 3 location, the class location ends 220 yards (660 feet) from the nearest building in the cluster.

Class 4:

A Class 4 location is any class location unit where buildings with four or more stories above ground are prevalent.

A Class 4 location ends 220 yards (660 feet) from the nearest building with four or more stories above ground.

3.3.2 Potential Impact Radius

✓ ***Referenced Protocol:*** ***A.2 Potential Impact Radius***

Potential impact radius (PIR) means the radius of a circle within which the potential failure of a pipeline could have significant impact on people or property. PIR is determined by the formula:

$$PIR = 0.69\sqrt{pd^2}$$

where:

PIR = the radius of a circular area in feet surrounding the point of failure
p = the maximum allowable operating pressure (MAOP) in the pipeline segment in pounds per square inch
d = the outside diameter of the pipeline in inches.

Note:	0.69 is the factor for natural gas. This number will vary for other gases depending upon their heat of combustion. For other gases refer to ASME B31.8S-2004 Section 3.2.

[Also referenced in Appendix 1B of this Integrity Management Program]

3.3.3 Potential Impact Circle

Potential impact circle is a circle with a radius equal to the potential impact radius (PIR). [Also referenced in Appendix 1B of this Integrity Management Program]

3.3.4 Identified Sites

✓ ***Referenced Protocol:*** ***A.3 Identified Sites***

Identified site means each of the following areas:

(a) An **outside area or open structure** that is occupied by twenty (20) or more persons on at least 50 days in any twelve (12)-month period. (The days need not be consecutive.) Examples may include but are not limited to:

- Beaches
- Playgrounds
- Recreational Facilities
- Camping Grounds
- Wedding Venues
- Farmers Markets
- Outdoor Theaters
- Stadiums
- Recreational Areas near a body of water
- Areas Outside a Rural Building such as a Religious Facility

or;

(b) A **building** that is occupied by twenty (20) or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12)-month period. (The days and weeks need not be consecutive.) Examples may include, but are not limited to:

- Religious Facilities
- Office Buildings
- Community Centers
- Restaurants
- General Stores
- 4-H Facilities
- Roller Skating Rinks
- Gymnasiums

or;

(c) A **facility** occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate. Examples may include but are not limited to:

- Hospitals
- Prisons
- Schools
- Day-Care Facilities
- Retirement Facilities
- Assisted-Living Facilities

Note that each identified site may be evaluated to whether it actually meets the occupancy requirements of its definition as deemed appropriate. The company may elect to conservatively classify other building or outside area types as identified sites. [Also referenced in Appendix 1B of this Integrity Management Program]

3.3.5 High Consequence Area (HCA)

High Consequence Area means an area established by one of the methods described in paragraphs (1) or (2) as follows:

(1) An area defined as—

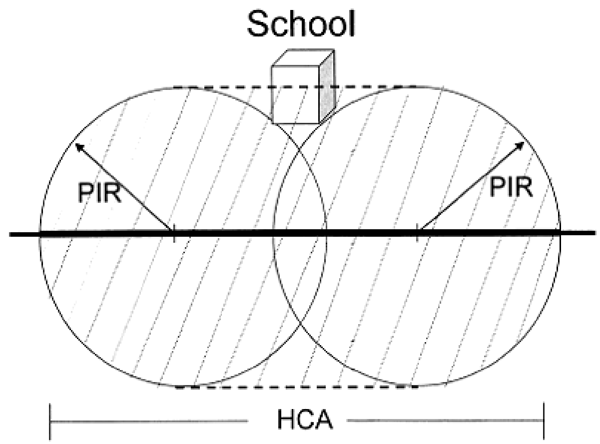
- (i) A Class 3 location under § 192.5; or
- (ii) A Class 4 location under § 192.5; or
- (iii) Any area in a Class 1 or Class 2 location where the potential impact radius is greater than 660 feet (200 meters), and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
- (iv) Any area in a Class 1 or Class 2 location where the potential impact radius contains an identified site.

(2) The area within a potential impact circle containing—

- (i) 20 or more buildings intended for human occupancy; or
- (ii) An identified site.

(3) Where a potential impact circle is calculated under either method (1) or (2) to establish a high consequence area, the length of the high consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy to the outermost edge of the last contiguous potential impact circle that contains either an identified site or 20 or more buildings intended for human occupancy. The company may elect to merge multiple separate HCAs into a single continuous HCA for analytical efficiencies.

(See Figure E.I.A. in appendix E. of Subpart O, reproduced below)
[Also referenced in Appendix 1B of this Integrity Management Program]



3.3.6 Covered Segment or Covered Pipeline Segment

Covered Segment or Covered Pipeline Segment means a segment of gas transmission pipeline located in a high consequence area (HCA). [Also referenced in Appendix 1B of this Integrity Management Program]

The terms gas and transmission line, are defined in §192.3 and Appendix 1-B of this IMP.

3.4 DETERMINING IDENTIFIED SITES

3.4.1 Initial Identified Site Inventory

The company's initial approach to determining HCAs was based upon using the existing Geographic Information System (GIS). The GIS used was Smallworld ENOM and was the primary data repository for storing building data using the BUILDING and RESTRICTED AREA objects and their respective attributes. To enable determination of the HCAs using the GIS, the buildings and defined outside areas around the pipeline were digitized into the GIS. Aerial photography taken in March 2003 inside of Jefferson County and December 2003 for the balance of the gas transmission system outside of Jefferson County was used for the initial HCA identification process. It was determined that the maximum that a main was offset (mapping error) from the actual location was 90 feet. Using the class location corridor, 660 feet (§192.5), as a starting base, 90 feet was added to the 660 feet for a total of 750 feet. This 750 feet was used as the radius to create a buffer area around the pipeline within which all buildings and defined outside areas would need to be digitized.

The images of any buildings or defined outside areas that appear on the aerial photos within 750 feet of the digitized pipelines were digitized. While digitizing the buildings and areas, it was in the best effort of each employee to identify each building and area and populate data describing the building or area by name, number of stories, occupancy patterns, and normal function as described in Section 3.4.3

After the buildings and defined outside areas were digitized, meetings were set up with the responsible centers to make a first pass at identifying the buildings and areas using the aerial photography. Upon the completion of those meetings, maps were printed and distributed to field crews to go out and identify any buildings or areas that had not yet been identified. These maps were returned to the Pipeline Integrity group and employees entered the data into the GIS.

If the building was identified as a business, the name of the business and the number of people that occupy the business were populated. This data was needed to determine the HCAs. If this data was not available, public officials, such as fire chiefs, were contacted to help provide information to determine if these businesses could be classified as identified sites. **The company** determined the fire jurisdictions through which transmission lines passed. Meetings were scheduled and held with the respective fire chiefs. At these meetings, the fire chiefs were educated on the definition of an identified site, maps with transmission lines and buildings were reviewed as needed, and the fire chiefs provided information pertaining to potential identified sites within their jurisdiction. If additional time for review was needed, the maps were left with the fire chiefs with the request to note relative information and return the maps to the proper **company** employee. If the public officials could not provide additional information, the businesses themselves were contacted for additional information.

3.4.2 Current Identified Site Inventory - Defining Potential Impact Zones

To enable determination of identified sites that could be potentially impacted by a pipeline failure, the affected zone, or buffer zone, adjacent to each side of transmission pipelines shall be identified and mapped. Digital technology utilizing applicable software and hardware shall be employed wherever practical for mapping pipelines and land data.

The total width of each buffer zone surrounding each pipeline must be at least as great as the diameter of the potential impact circle. Additional distance may be added to compensate for possible mapping error where applicable. **The company** has elected to maintain the original buffer radius of 750 feet from the pipeline when determining which buildings and defined outside areas are reviewed.

3.4.3 Current Identified Site Inventory - Determining Identified Sites Within Zones

Locating Potential Sites

Pre-existing maps, aerial photography, field surveillance, and other means as applicable shall be used to locate buildings, roadways, railroads, ball playing fields, and other land based features that may have an effect upon the determination of identified sites within the potential impact zones identified and mapped. To the greatest extent practical buildings and open outside areas that may constitute an identified site or may collectively constitute a high consequence area shall be digitized and entered into the mapping database.

All buildings labeled as the following “Type” in the GIS will automatically be defaulted to identified sites in the risk analysis:

- School
- Hospitals
- Day Cares
- Nursing/Retirement Facility
- Prisons

Identification Methodology

To the greatest extent practical each building, structure, defined outside area shall be identified as to its functional classification, usage, inhabitation schedule, etc. Internal and external resources may be used to the extent which they are effective and at the discretion of the company.

Internal resource responsibilities may include but are not limited to the following:

- Audit of maps by employees familiar with geographical areas and pipeline routes in question.
- Field surveillance and visual observation of buildings and outside areas in question.
- Query of **company** customer information databases to determine identity and classification of gas and/or electric accounts.

External **resources may include** but are not limited to the following:

- Software analysis of annual aerial photography.
- Public officials with emergency response or community planning responsibilities. This may include local emergency management, fire fighting and law enforcement agencies.
- Local, State, or Federal licensing agencies.
- Lists or maps available from local, State, and Federal agencies, and available to the public.
- Owners and occupants of buildings or properties in question.

Pertinent Data and Assumptions:

The following data shall be collected for buildings and outside areas as applicable:

- Name of business or institution
- Type of building or outside area
- Number of stories above ground
- Number of dwelling or occupied units
- Days per week occupied by more than 20 people
- Intended for human occupancy, yes or no.
- Occupants difficult to evacuate, yes or no.
- Identified site, yes or no.

Buildings shall be classified as follows:

- Business
- Fire department
- Hospital
- Multi-family dwelling
- Nursing/retirement facility
- Daycare
- Place of public assembly
- Police station
- Religious facility
- School
- Single family dwelling
- Barn
- Prison
- Other
- Unknown

Defined Outside Areas shall be classified as follows:

- Cemetery
- Correctional Facility
- Golf Course
- Historic Landmark
- Military Installation
- Miscellaneous
- Park
- Recreation Area

- Wildlife Area

Buildings located within residential neighborhoods, and which have similar appearance as single family dwellings within the same area shall be assumed to be single family dwellings unless there is some indication of other usage. Likewise, buildings within residential neighborhoods having similar appearance as multiple family dwellings within the same area shall be assumed to be multiple family dwellings unless there is some indication of other usage. A listing of all new buildings shall be delivered to Pipeline Integrity following each aerial inventory for verification of usage and occupancy.

3.4.4 Current Identified Site Inventory – Overall Process

The overall process of identified site identification and confirmation shall be managed and coordinated by **Pipeline Integrity Engineer** F3 under review of **Program Manager – Integrity Management** M1. Qualified personnel, including contractors, may be utilized as available to perform software programming, surveillance, and administrative duties.

The identified site inventory process consists of both annual and triennial processes. An example workflow is shown in Figures 3-1, 3-2, 3-3, 3-4, and 3-5.

Continual surveillance of the LG&E transmission pipeline system shall include awareness and observation of new structures or open air developments, or changes in use of existing structures or land usage that may result in additions or deletions of identified sites within 220 yards of each pipeline. Any such changes outside of normal identified site inventory processes shall be documented on Form 3-1, "Louisville Gas and Electric – Pipeline Integrity – New Building / Outside Area Form" and routed to the Integrity Management department for update into the appropriate systems per Section 3.7 of this document and Figure 3-6 below. The **Pipeline Integrity Engineer** F3 will review these changes periodically to ensure they are still applicable.

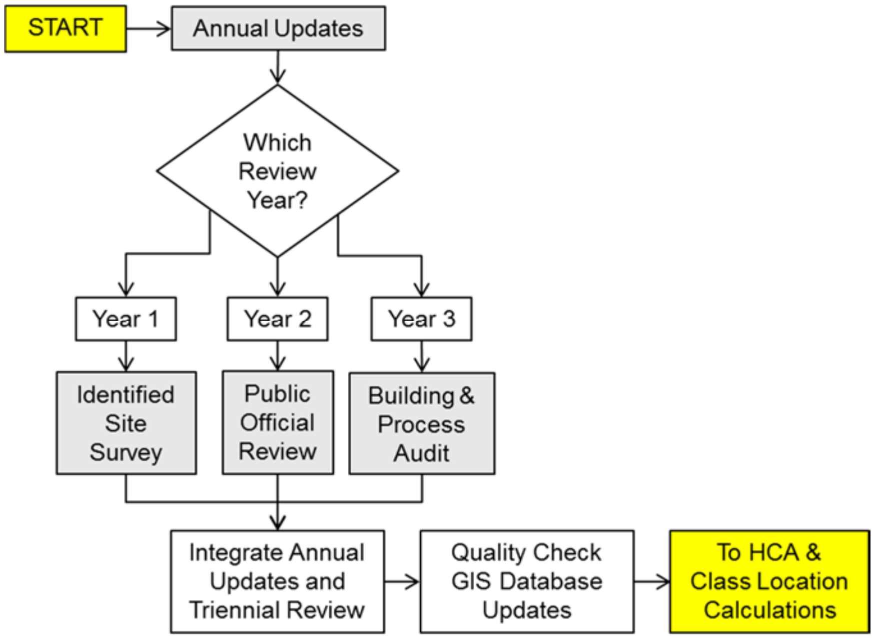


Figure 3-1: Example Overall Identified Site Inventory Process

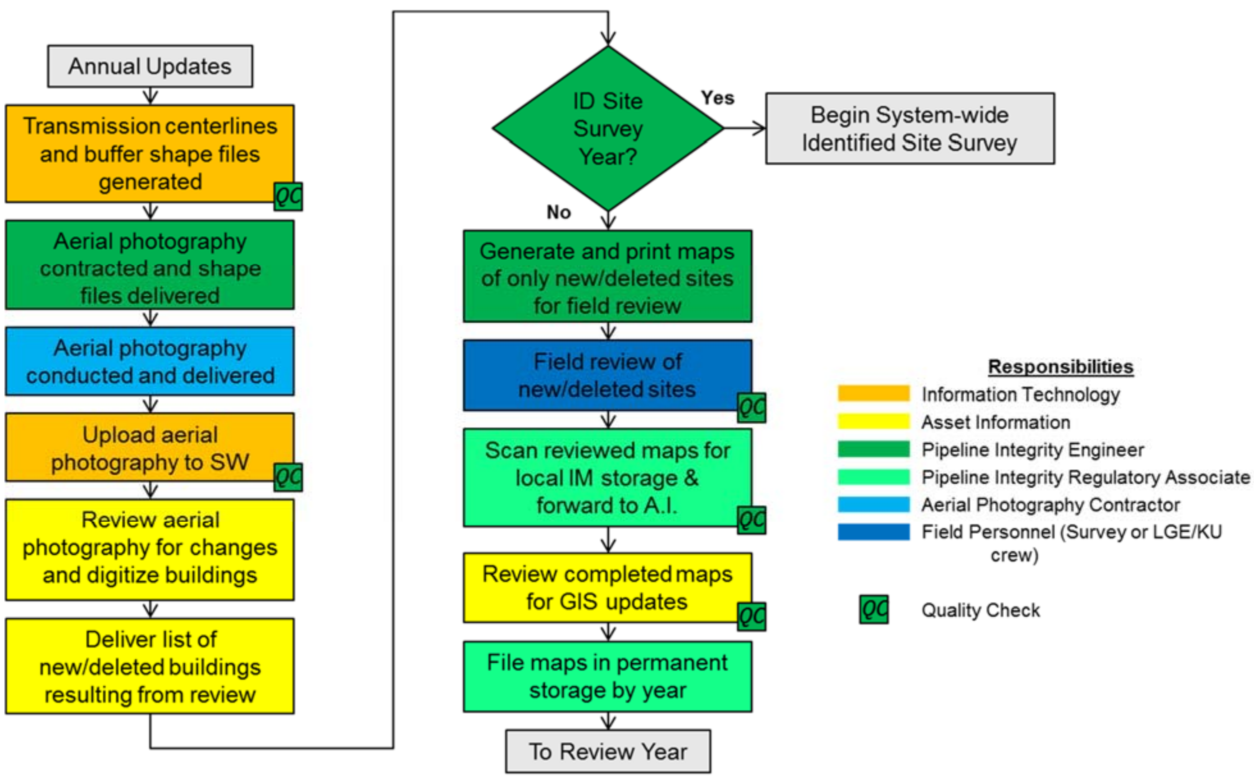


Figure 3-2: Example Annual Updates to Identified Site Inventory

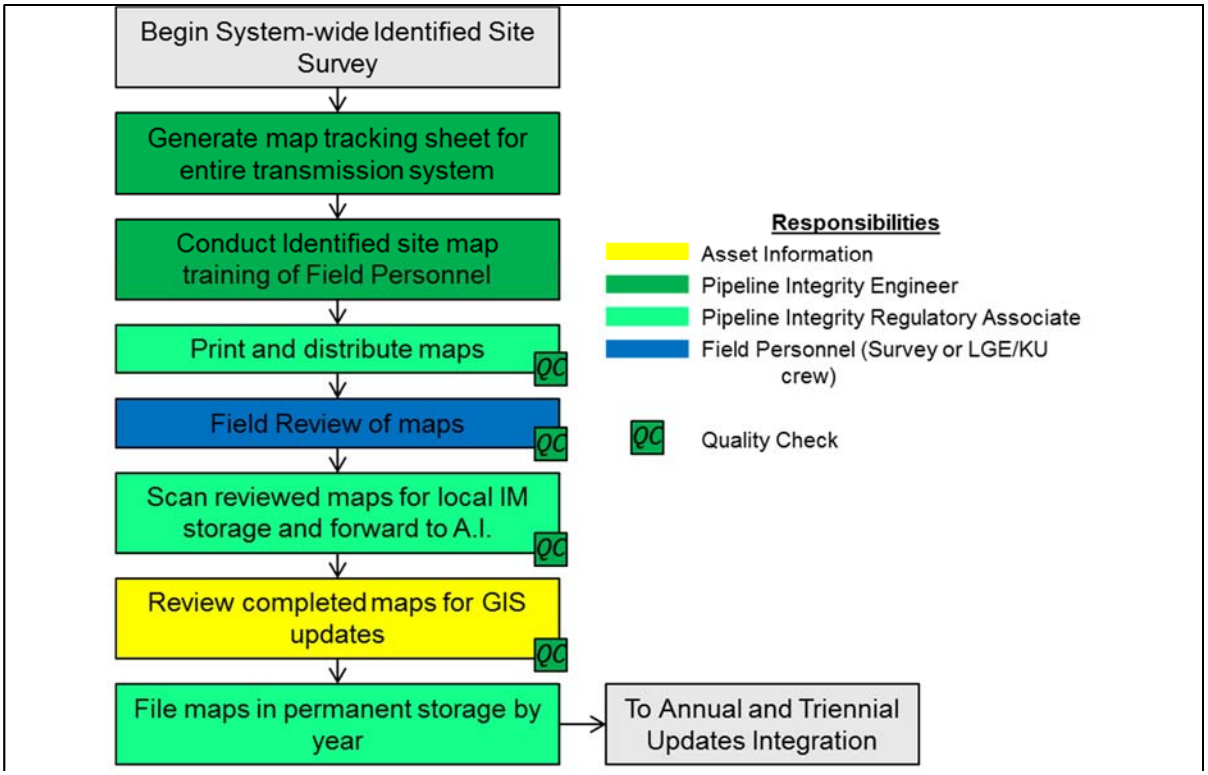


Figure 3-3: Example Year 1 – System-wide Identified Site Suvey

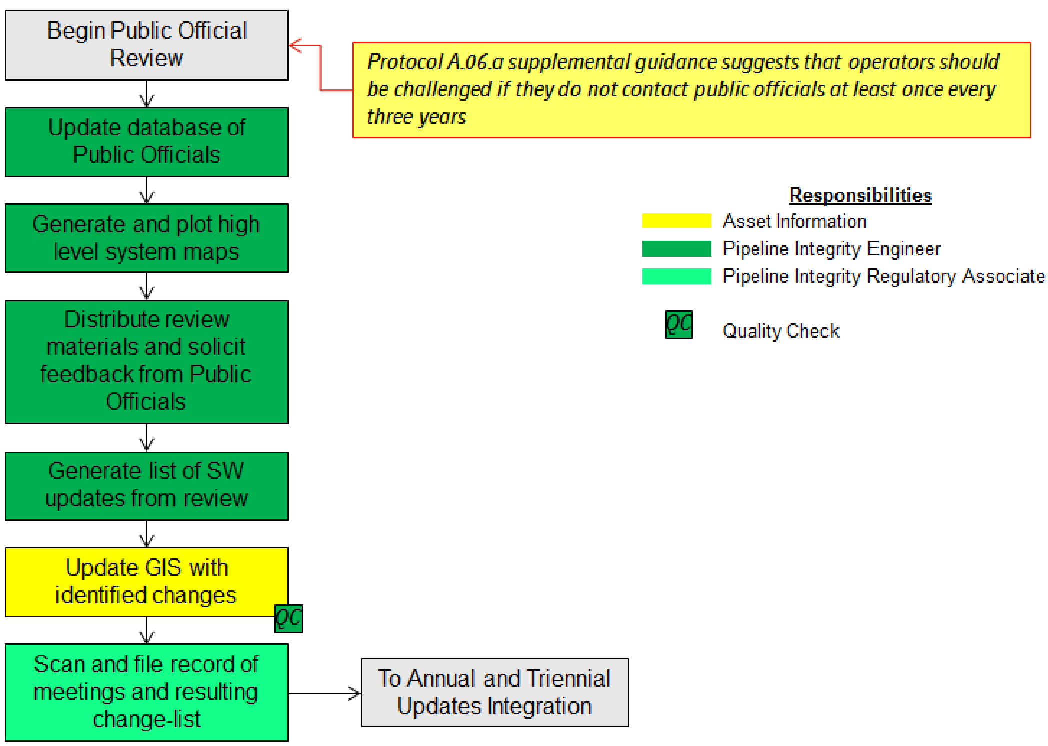


Figure 3-4: Example Year 2 – Public Officials Review

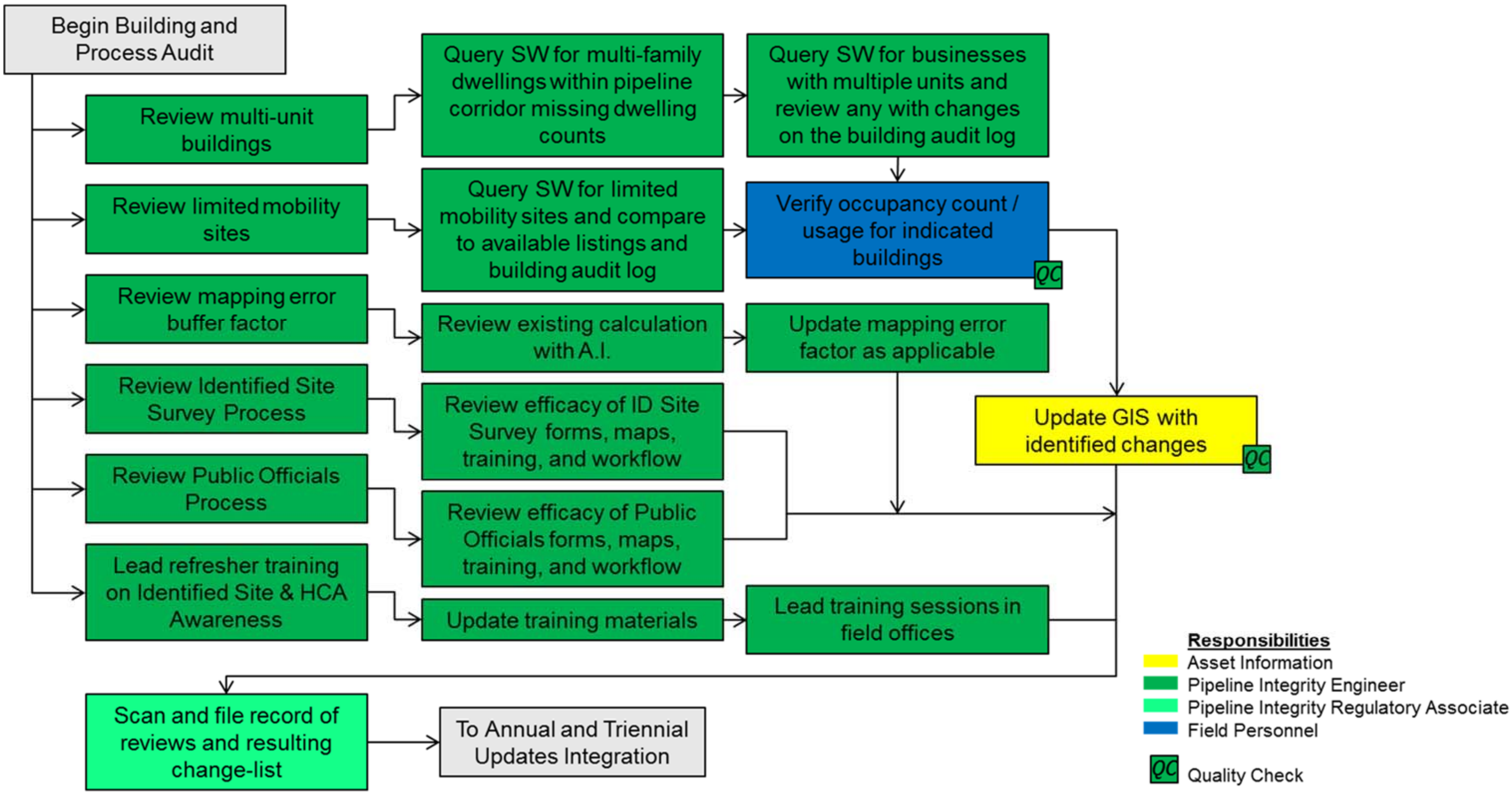
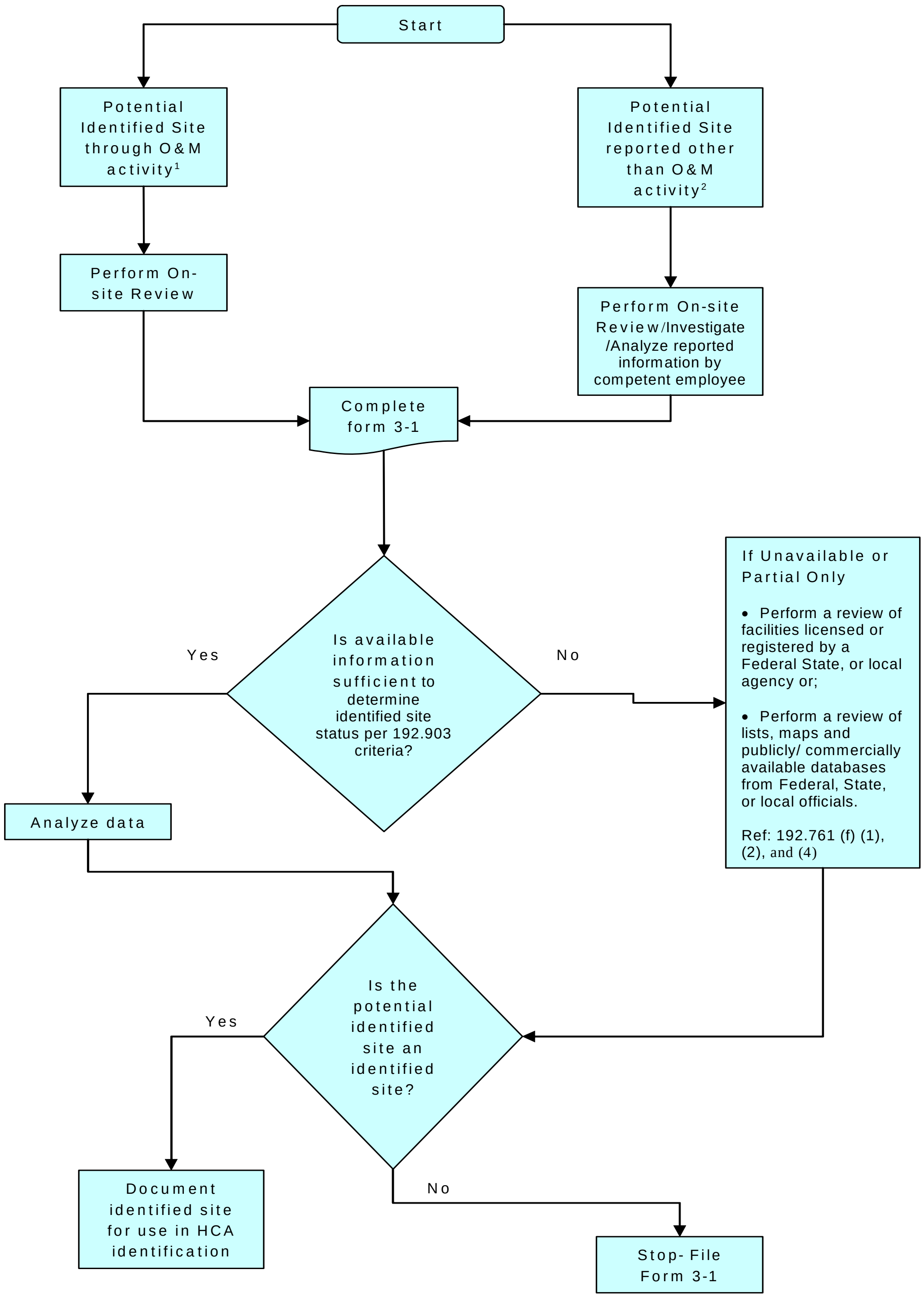


Figure 3-5: Example Year 3 – Building and Process Audit



[1]O&M Activities- Leak Survey, Surveillance, Corrosion Control activities, etc.
[2]Non-O&M Activities- Public Liaison Meetings, Maps & Records Updates, Random Field Observations

Figure 3-6: Process Sequence for Locating Identified Sites

3.5 SELECTING A HCA METHOD

3.5.1 Data Considerations

Although **the company** may select a single HCA Identification Method to determine the HCA's along the entire pipeline system, **the company** may also choose to alternate between Method 1 and Method 2 within the same pipeline section and/or among various sections within a system.

The company has based the selection of its HCA selection method in part on the availability and quality of HCA related data.

A review includes the availability and quality of the following data:

- Building data for Class 1 & 2 Locations
- Building data for Class 3 & 4 Locations
- Building data for buildings intended for human occupancy with a PIR greater than 660 feet

If the required data is unavailable to perform a PIR HCA Identification (Method 2) on a covered segment, the **company** may consider performing a Class Location Identification (Method 1) based upon available data. In accordance with §192.903, the prorated option of Method 1 may not be used after December 17, 2006. The **company** elected to **not** use the prorated option at any time during its applicability. Accordingly, the prorated methodology has been removed from this plan.

3.6 HCA IDENTIFICATION METHODS

Natural gas is the only gas transported by **the company** on its pipeline system and thus the 0.69 factor has been used for the PIR equation.

Should **the company** change service from natural gas to another gas covered under 49 CFR 192, **the company** shall use the appropriate factor for the type of gas being transported. The process to determine the appropriate factor for gases other than natural gas is to follow ASME B31.8S-2004 Section 3.2 to determine the appropriate factor.

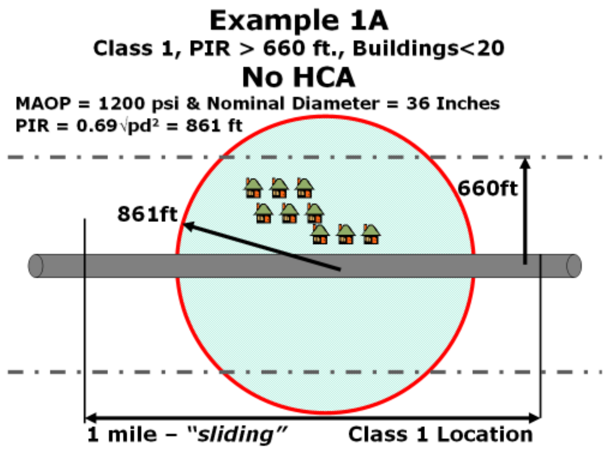
Any changes to the product service from one gas to another will require the PIR calculation to be performed using the factor of the new gas unless the original factor is more conservative. The product service change will also require the existing HCA maps to be modified based upon the new PIR circle unless the existing HCA segments represent a more conservative approach. Any change in product service must be documented as part of the Management of Change Process [Section 14].

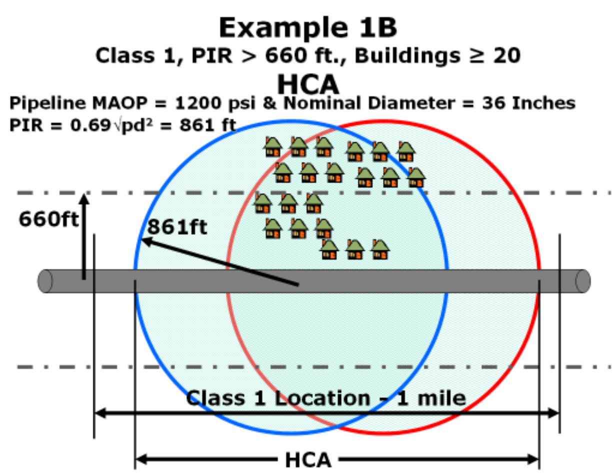
3.6.1 Method 1: Class Location Method

✓ ***Referenced Protocol:*** ***A.4 Identification Using Class Locations - Method 1***

The following table and associated figures provide examples of the HCA identification process under Method 1.

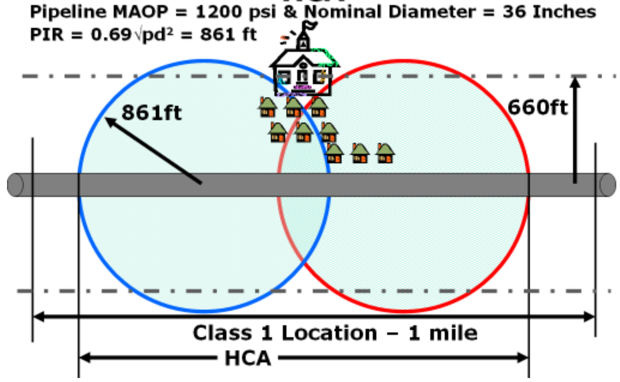
Example	HCA Identification: Method 1	HCA
1A	Class 1, PIR >660 ft., Buildings <20	No
1B	Class 1, PIR >660 ft., Buildings ≥20	Yes
1C	Class 1, Identified Site in PIC	Yes
1D	Class 2, PIR > 660 ft., Buildings ≥20	Yes
1E	Class 2, Identified Site in PIC	Yes
1F	Class 3	Yes
1G	Class 4	Yes





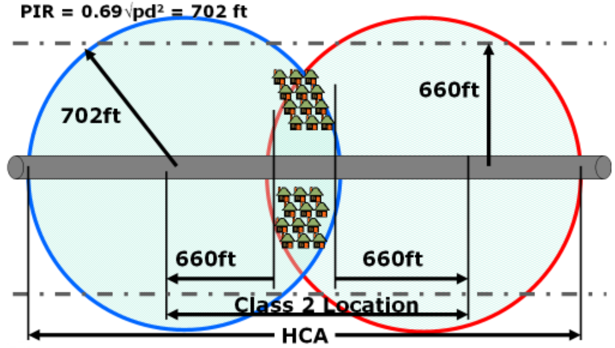
Example 1C
Class 1 Line, Identified Site in PIC

HCA
Pipeline MAOP = 1200 psi & Nominal Diameter = 36 Inches
PIR = 0.69√pd² = 861 ft



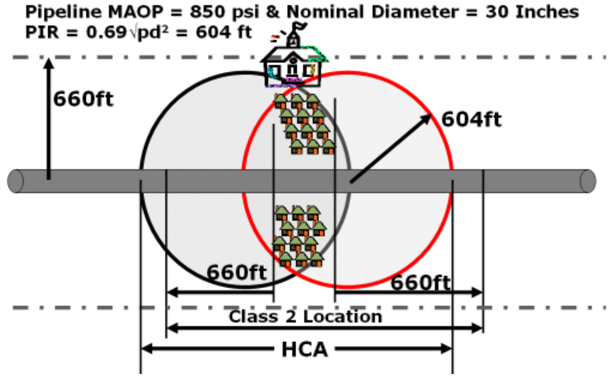
Example 1D
Class 2 Line, PIR > 660 ft., Buildings ≥20

HCA
Pipeline MAOP = 1150 psi & Nominal Diameter = 30 Inches
PIR = 0.69√pd² = 702 ft



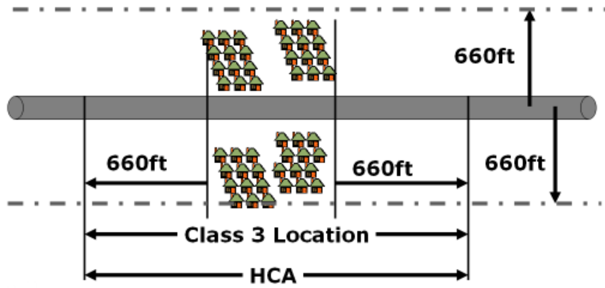
Example 1E
Class 2, Identified Site in PIC

HCA
Pipeline MAOP = 850 psi & Nominal Diameter = 30 Inches
PIR = 0.69√pd² = 604 ft



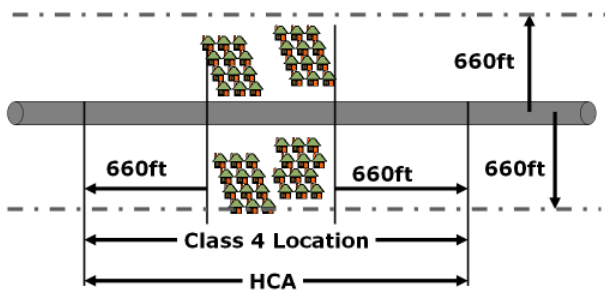
Example 1F
Class 3
HCA

Pipeline MAOP, Nominal Diameter, & PIR Are Not Relevant



Example 1G
Class 4
HCA

Pipeline MAOP, Nominal Diameter, & PIR Are Not Relevant

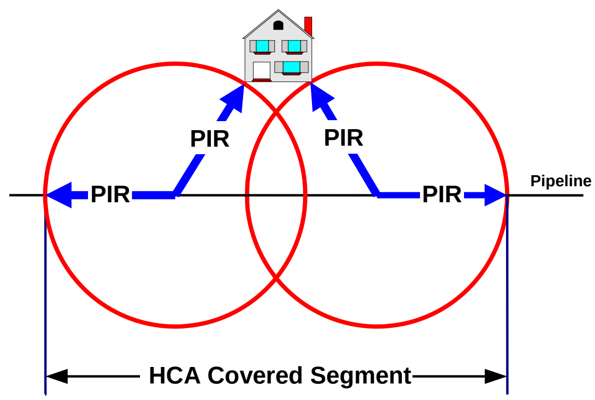


3.6.2 Method 2: Potential Impact Circle Method

✓ ***Referenced Protocol:*** ***A.5 Identification Using Potential Impact Radius***

The Potential Impact Circle Method is based upon the PIR equation from paragraph 3.3.2.

In cases where the PIR is used to identify HCAs and (i) an identified site or (ii) 20 or more buildings intended for human occupancy, are located within the Potential Impact Circle, the HCA segment shall extend from the outermost edge of the first Potential Impact Circle to the outermost edge of the last contiguous Potential Impact Circle.

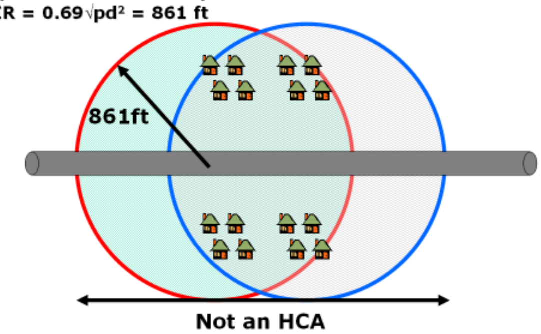


The following table and associated figures provide examples of the HCA identification process under Method 2.

Example	HCA Identification: Method 2	HCA
2A	PIC Contains <20 Buildings	No
2B	PIC Contains ≥20 Buildings	Yes
2C	PIC Contains Identified Site	Yes

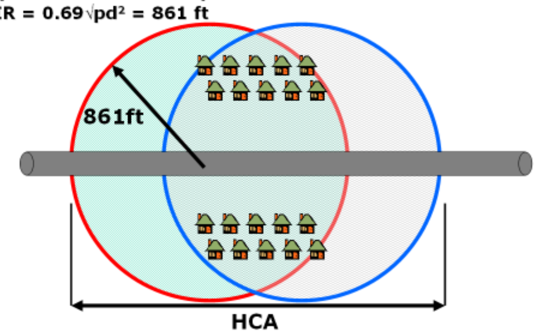
Example 2A
PIC Contains <20 Buildings
No HCA

Pipeline MAOP = 1200 psi & Nominal Diameter = 36 Inches
PIR = 0.69√pd² = 861 ft



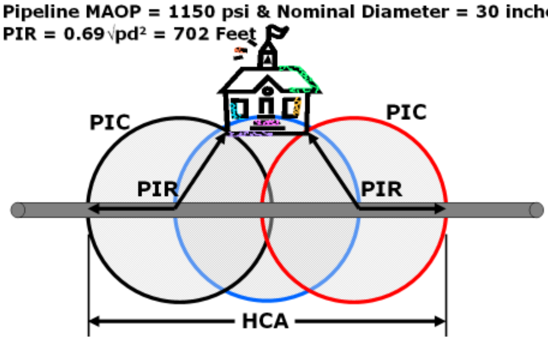
Example 2B
PIC Contains ≥20 Buildings
HCA

Pipeline MAOP = 1200 psi & Nominal Diameter = 36 Inches
PIR = 0.69√pd² = 861 ft



Example 2C
PIC Contains Identified Site
HCA

Pipeline MAOP = 1150 psi & Nominal Diameter = 30 inches
PIR = 0.69√pd² = 702 Feet



3.6.3 Methodology for Data Analysis

The company uses Method 2: Potential Impact Circle Method as the HCA identification method. To the greatest extent practical the Company shall utilize computer technology to analyze a digital database for residences, commercial and other buildings, commonly occupied open areas, and other features that individually or collectively may be within a potential impact circle to constitute an HCA. The company may elect to apply a mapping error factor to the buffer or a HCA extension factor to the calculation of HCA lengths. The software shall be designed to produce a report listing each segment of transmission pipeline and locations thereof that fall within High Consequence Areas per the method of HCA identification selected. HCA locations may be described by line station number, GPS coordinates, or other means compatible with mapping in a manner that will enable positive field location. Locations of covered segments (HCAs) are mapped in the Company's GIS database.

On December 17, 2008 the mapping error factor for the Potential Impact Radius was reduced from 13.6% to 9.1%. This reduction was recalculated to reflect spatial improvements to Smallworld gas and land objects. In cases where a study or field survey can more accurately determine the location of the pipe and the PIR in relation to the surrounding area, this mapping error factor may be reduced or eliminated.

3.7 NEWLY IDENTIFIED OR CHANGED HCA'S

✓ ***Referenced Protocols:*** ***A.6 Identification and Assessment of Newly Identified HCA's***
P.1 Identification and Assessment of Newly Identified HCA's
B.4 Newly Identified HCA's / Newly Installed Pipe

Figure 3-7 shows the procedural steps required for updating current HCA analysis for a pipeline segment. Updating the current HCA analysis can be triggered for the following reasons:

- Identification of new potential HCAs or changes impacting existing HCAs that are not in the current HCA analysis database;
- Correction of errors or modification of current HCA analysis inputs;
- Operational changes to new, existing, or idle pipelines that may affect HCA analysis;
- Acquisition of a new pipeline system.

Specific considerations or activities associated with these updates are described below.

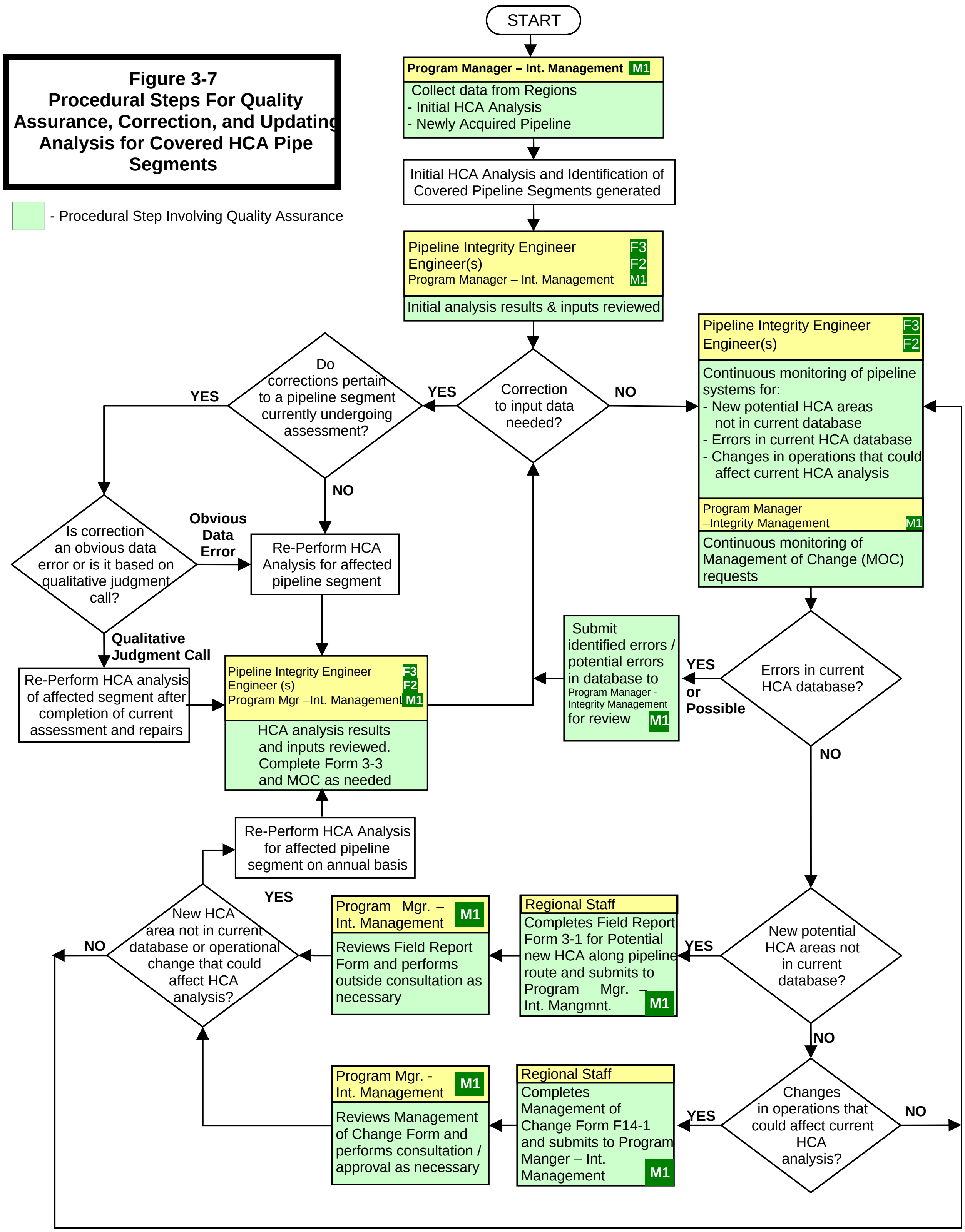
3.7.1 New Potential HCA Areas or Changes Impacting Existing HCA Areas Discovered by Field Personnel

The **Pipeline Integrity Engineer** F3 will be responsible for training appropriate field operations personnel about HCA awareness so that these personnel will be able to identify new potential HCAs along the pipeline route (e.g., new construction of a building or identified site). Any sightings of new potential HCAs will trigger the following actions.

- The completion of Form 3-1 entitled "Louisville Gas and Electric New Building/Outside Area Form" (attached to the end of this Section 3.0 for reference). Form 3-1 describes the following information:
  - New construction in the vicinity of the pipeline that could result in additional buildings intended for human occupancy or additional identified sites;
  - Change in use of existing buildings.
- The **Pipeline Integrity Engineer** F3 will review and approve the completed form and forward to the **Program Manager – Integrity Management** M1 for review and incorporation into the current HCA analysis database as appropriate.
- Actions taken by the **Program Manager – Integrity Management** M1 will be recorded on Form 3-1 which will be archived in the permanent system records.

Figure 3-7
Procedural Steps For Quality Assurance, Correction, and Updating Analysis for Covered HCA Pipe Segments

- Procedural Step Involving Quality Assurance



Attachment to Response to AG Q252
Page 147 of 770
Bellar

3.7.2 Errors In HCA Analysis or Desired Modifications

Figure 3-7 indicates the steps for processing errors identified in the current HCA analysis or if changes in the analysis assumptions are needed or desired. **Pipeline Integrity Engineer** F3 will complete HCA Correction Form 3-3 and a Management of Change Request Form (see section 14) as needed.

3.7.3 Changes in Operations That Could Affect HCA Analysis

The **Pipeline Integrity Engineer** F3 and **Engineer(s)** F2 are responsible for identifying any operational changes that could affect the current HCA analysis, or the current Risk Assessment analysis. Examples of these changes include:

- Changes in assumptions or conditions used in either Method 1 or Method 2 to determine covered HCA segments.
- Changes in pipeline maximum allowable operating pressure (MAOP).
- Pipeline modifications affecting piping diameter.
- Changes in the commodity transported in the pipeline.
- Pipeline reroutes or new pipeline.
- Reactivation of an idle pipeline.

> **Note:** Operational changes that could affect an HCA must be identified before the change is made or the new or rerouted pipeline is placed in service.

Where such changes occur, the Management of Change Request Form (see Section 14.0) will be completed by the **Pipeline Integrity Engineer** F3 or **Engineer(s)** F2 and forwarded to the **Program Manager – Integrity Management** M1 for review and appropriate follow-up actions.

3.7.4 Acquisition of New Pipeline Systems

The **Program Manager – Integrity Management** M1 will be responsible for incorporating new pipeline system acquisitions into the current Integrity Management Program, including any revisions to HCA analyses performed by the previous owner. These acquisitions may not have been adequately modeled for HCA impacts or may need to be normalized to **the company's** methodologies of HCA analysis.

3.7.5 Time Schedule Requirements for Re-Performing HCA Analyses

The company's Program Manager – Integrity Management M1, or appropriate designees, will be responsible for reviewing and identifying any new potential HCAs from the sources listed above on at least an annual basis. Potential new HCAs will be confirmed within this time period using either Method 1 or 2 described above.

Results of this review will be documented and stored in the IMP database for integration with other procedures.

Any newly identified HCAs will be incorporated into **the company's** Baseline Assessment Schedule within one year of the date it is identified in accordance with §192.905(c).

As indicated in Section 8.0 (Baseline Assessment Plan), newly identified covered HCA line pipe segments will be assessed within 10 years of the date they are identified.

On a three (3) year frequency, Company will re-perform identified site inventory and modeling analyses described in Sections 3.4 and 3.5. Any additional HCAs identified from these re-analyses will be incorporated into the BAP schedule within one year.

3.8 FORMS

Form 3-1: New Building / Outside Area Form

Form 3-2: HCA Correction Form

Form 3-3: IDS Annual Updates Checklist

Form 3-4: Identified Site Survey Completion

Form 3-5: Public Officials Review Checklist

Form 3-6: Building and Process Audit Checklist

Revision Log:

Date	Significant Changes	Revised By
August 25, 2004	Reformatted page numbers	
October 28 Thru November 25, 2004	Initial changes to GIE / Northeast Gas written program, includes: • Formatting, including Table of Contents page for section • Rename responsible positions per Section 2 • Replace "Company" with "LG&E Energy" • Rename appendices • 3.3.1 – KYPSC class location criterion added, building count criterion added, note to operator removed • 3.4 – Entire subsection replaced • Figure 3.2 – process flow revised • 3.6.3 – New subsection • 3.7.2 – Note to operator removed • 3.8 – Form replace with LG&E form for Potential Building / Outside Area / Identified Site form	Oelker Augustine Eder
12/17/2004	12/17/04 Version Approved by Management	LCO
6/27/2007	Replaced "LG&E Energy" Logo with "LG&E", E.ON|US logo.	CMA
6/27/2007	Replaced the company name "LG&E Energy" with "Louisville Gas & Electric/Kentucky Utilities" and referenced as "the company" throughout.	CMA
6/27/2007	Inserted the updated version of form 3-1	CMA
7/29/2008	Inserted verbage that all buildings listed within 192.903- Identified Site definition (c) will be default to Identified sites in the company's GIS.	CMA
8/8/2008	Updated table and screen captures in appendix 3A.	CMA
8/21/2008	Added the identification of new construction activity and change in the use of an existing building to Form 3-1.	ENE
8/21/2008	Added verbage similar to protocol for data required for identification of new HCAs into section 3.7. Inserted the updated version of Form 3-1.	ENE
8/22/2008	Added "Daycare" and "Prison" to Form 3-1	CMA
8/8/2008	8/8/2008 Version Approved by Management	LCO
9/14/2009	Form 3-2: Identified Site Inventory added to Section	CMA
9/14/2009	3.4.3 Defining Potential Impact Zone. Paragraph added to document the reduction of PIR error factor from 13.6% to 9.1%	CMA
9/14/2009	Section 3.6.3 – Indicated that the company chose Method 2 for HCA analysis	CMA
9/14/2009	Changed "Assessment Deadline" Column to "Discovery Date" in Appendix 3-A	CMA
9/14/2009	Updated Table in Appendix 3-A for 2009 HCAs	CMA
9/14/2009	Updated HCA Integrity Screen Shots in Appendix 3-B	CMA
10/1/2010	Inserted HCA Correction Form	CMA
10/1/2010	Removed Appendix 3-A	CMA
10/1/2010	Removed Appendix 3-B	CMA
10/24/2011	Corrected logos, table of contents, and spacing of images.	WJN
10/24/2011	Included a recommendation for individual evaluation of automatically labeled identified sites and use of automated aerial image change analysis software	WJN
11/03/2011	Replaced references to removed appendices with references to electronically maintained databases of identified segments and their identification methods	WJN

Date	Significant Changes	Revised By
11/12/2012	Removed section referring to the prorated HCA methodology since its availability for use expired in 2006. Added language clarifying that the prorated option was not used by the company.	WJN
11/12/2012	Added language to allow for the option of applying a mapping error factor or HCA extension factor to HCA calculation	WJN
11/12/2012	Updated images of the forms to latest revisions	WJN
11/27/2012	Updated section on changes to HCA analysis for clarity and to reference form 3-3. Also corrected the workflow in Figure 3-4	WJN
11/13/2013	Moved PIR buffer calculation and added correction language to section from 3.4.2 (formerly 3.4.3) to section 3.6.3	WJN
11/13/2013	Clarified multi-unit mapping policiy in definition of Dwelling Unit / Building	WJN
11/13/2013	Major revision of Section 3.4 “Identified Site Inventory” to clarify historical context (initial survey and inventory process) as well as clarify the annual and triennial survey processes. Created example workflows for identified site inventory processes. Created forms 3-3 through 3-6.	WJN
11/13/2013	Updated form images (minor updates to existing forms)	WJN
11/13/2013	Fixed formatting errors in table of contents	WJN
10/24/2015	Clarified in section 3.4.4 that changes to HCAs and identified sites outside of the usual annual processes will be periodically reviewed for applicability.	WJN
10/24/2015	Clarified new HCAs on line pipe witll be assessed within 10 years of the date they are identified.	WJN
10/24/2015	Updated screenshots of forms	WJN
11/15/2016	Added cross-references to Appendix 1B for terms defined in Appendix 1b and in Section 3. Minor clerical changes.	WJN

3.8.1 Form 3-1: New Building/ Outside Area Form

PPL companies

Louisville Gas and Electric - Pipeline Integrity
New Building/Outside Area Form

Transmission Line Data:

Name of Line ______________________ Segment Number _____________
MAOP (Psig) ______________________ SYS ID ____________________
Diameter (Inches) ___________________

Site Information:

Site Description (type of site)
___ Business (__##__Units) ___ Hospital ___ Multi-Family (__##__Units)
___ Nursing/Retirement Facility ___ Place of Public Assem. ___ Police Stat.
___ Religous Facility ___ School ___ Fire Dept. ___ Single Family
___ Correctional Facility ___ Golf Course ___ Historic Landmark
___ Military Installation ___ Park ___ Recreation Area ___ Cemetary
___ Other ______________________________

Name: ______________________________
Street Address: ______________________________
City or Town: ______________________________

Identified Site? ☐ Yes ☐ No

If yes, choose one:

☐ An Outside or Open Area that is occupied by 20 or more persons on at least 50 days in any twelve (12) month period. (Days need not be consecutive.)

☐ A building is occupied by 20 or more persons on at least five (5) days a week for ten (10) weeks in any twelve (12) month period.
The days and weeks need not be consecutive.

☐ A Facility occupied by persons who are confined, are of impaired mobility, or would be difficult to evacuate.

Location Information (Use back of page for drawing space if needed)

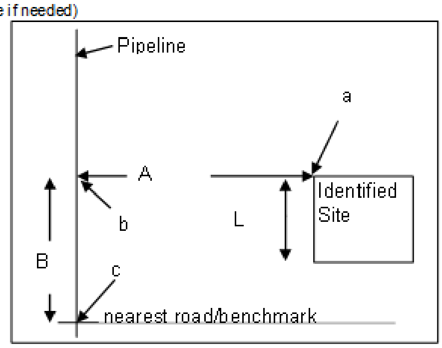
Map Page# ____________________

Measurements (Feet)

A (nearest point of identified site to pipeline point (b))	
B (pipeline point (b) to nearest road/benchmark)	
L (Length of Site)	

GPS Data

Point	Lat.	Long.
a		
b		
c		
GPS Unit:		



Name: ____________________ Employee ID# _____________ Date and Time: ___________

Please Forward to Bill Norton - Pipeline Integrity - AOC FORM 3-1

3.8.2 Form 3-2: HCA Correction Form

PPL companies

Louisville Gas and Electric - Pipeline Integrity
HCA Correction Form 3-2

Transmission Line Data:

BAP Version ____________________

SYS ID	Segment Name	Segment Number	HCA Number	HCA Length	Begin	End

Description

Give a detailed description of the correction and attach supporting information where applicable

Sketch

Provide a sketch or GIS Screen Capture of the HCA being corrected. Include actual measures to structures.

Employee Name and Number	Date

3.8.3 Form 3-3: IDS Annual Updates Checklist

Louisville Gas and Electric - Pipeline Integrity
Form 3-3: IDS Annual Updates Checklist

Time Frame

Annual update start date: ____________ Annual update end date: ____________

Update Year (check one):
___ Year One (Identified Site Survey)
___ Year Two (Public Officials Review)
___ Year Three (Building and Process Audit)

Job Duties

Integrity Management Lead: ______________________
Name Title/Company

Aerial Photography Lead: ______________________
Name Title/Company

Field Identification Peformed by: ______________________
Company

Smallworld Updated by: ______________________
Name Title/Company

Annual Update Checklist

Task:	Completed By:	Date:
Transmission centerlines and buffer shape files generated		
Aerial photography contracted		
Centerline shape files delivered		
Aerial photography conducted		
Aerial photography uploaded to Smallworld GIS		
Aerial photography reviewed and changes digitized		
List of new or deleted buildings delivered		
Complete if Year Two or Year Three is checked above, otherwise complete Form 3-3:		
Generate and print maps of new/deleted sites for field review		
Field review of new/deleted sites complete		
Reviewed maps scanned for IM storage and forwarded to AI		
GIS updates complete		
Maps filed in permanent storage		

Signatures

Pipeline Integrity Engineer: ______________________

Program Manager - Integrity Management: ______________________

3.8.4 Form 3-4: Identified Site Survey Completion

Louisville Gas and Electric - Pipeline Integrity
Form 3-4: Identified Site Survey Completion

Time Frame

Date of Previous Inventory: ______________________

Current Inventory
Start Date: ______________________
End Date: ______________________

Job Duties

Integrity Management Lead: ______________________
Name Title/Company

Maps Printed by: ______________________
Name Title/Company

Field Identification Peformed by: ______________________
Company

Smallworld Updated by: ______________________
Name Title/Company

Pipeline Systems Covered

	Pipeline System	Inventoried By	Date Completed
____	Ballardsville System		
____	Calvary		
____	Cane Run, CR 7 & Riverport		
____	Center Pipeline		
____	Center Storage		
____	Distribution City Gate Stations		
____	Doe Run IN Storage		
____	Doe Run KY Storage		
____	EW Brown Pipeline		
____	Flint Hill Line		
____	Magnolia Lines		
____	Magnolia Storage		
____	Muldraugh Storage		
____	Muldraugh-Piccadilly Line		
____	Penile-Paddys Beltline		
____	Trimble		
____	Western KY Lines		

Signatures

Pipeline Integrity Engineer: ______________________

Program Manager - Integrity Management: ______________________

Form 3-5: Public Officials Review Checklist

Louisville Gas and Electric - Pipeline Integrity
Form 3-5: Public Officials Review Checklist

Time Frame & Job Duties

Review start date: ____________ Review end date: ____________

Integrity Management Lead: ______________________________
Name Title/Company

Public Officials Review Checklist

Task:	Completed By:	Date:
Update database of Public Officials by pipeline system / county		
Generate high-level system maps		
Distribute materials to Public Officials		
Solicit feedback from Public Officials		
Generate list of GIS updates from feedback		
Update GIS with identified changes		
Scan and file record of meetings and change-list		

Pipeline Systems Covered

	System:	Review Completed By:	Date:
	Ballardsville System		
	Calvary		
	Cane Run, CR7 & Riverport		
	Center Pipeline		
	Center Storage		
	Distribution City Gate Stations		
	Doe Run IN Storage		
	Doe Run KY Storage		
	EW Brown Pipeline		
	Flint Hill Line		
	Magnolia Lines		
	Magnolia Storage		
	Muldraugh Storage		
	Muldraugh-Piccadilly Line		
	Penile-Paddys Line		
	Trimble		
	Western KY Lines		

Signatures

Pipeline Integrity Engineer: ______________________________

Program Manager - Integrity Management: ______________________________

3.8.5 Form 3-6: Building and Process Audit Checklist

Louisville Gas and Electric - Pipeline Integrity
Form 3-6: Building and Process Audit Checklist

Time Frame & Job Duties

Review start date: ____________ Review end date: ____________

Integrity Management Lead: ______________________________
Name Title/Company

Review Checklist

Task:	Completed By:	Date:
Review multi-unit buildings		
If field verification required, include name/date of verifier:	____	____
Review limited-mobility sites	____	____
If field verification required, include name/date of verifier:	____	____
Review mapping error buffer factor calculation	____	____
Review Identified Site Survey process	____	____
Review Public Officials review process	____	____
Field personnel training on HCA/Identified Site awarenedd		
Review and update training materials	____	____
Lead refresher training sessions on site		
Muldraugh Compressor Station	____	____
Magnolia Compressor Station	____	____
Other (please specify):____________	____	____
If GIS updates are required, include name/date of update:	____	____

Summary of Changes

Include a brief description of any process changes, and list any attachments included as supporting documentation:

____
____
____
____
____
____
____
____
____
____
____

Signatures

Pipeline Integrity Engineer: ______________________________

Program Manager - Integrity Management: ______________________________

4 THREAT IDENTIFICATION AND EVALUATION §192.917

In This Section

Referenced Protocols

4 THREAT IDENTIFICATION AND EVALUATION

4.1 OVERVIEW

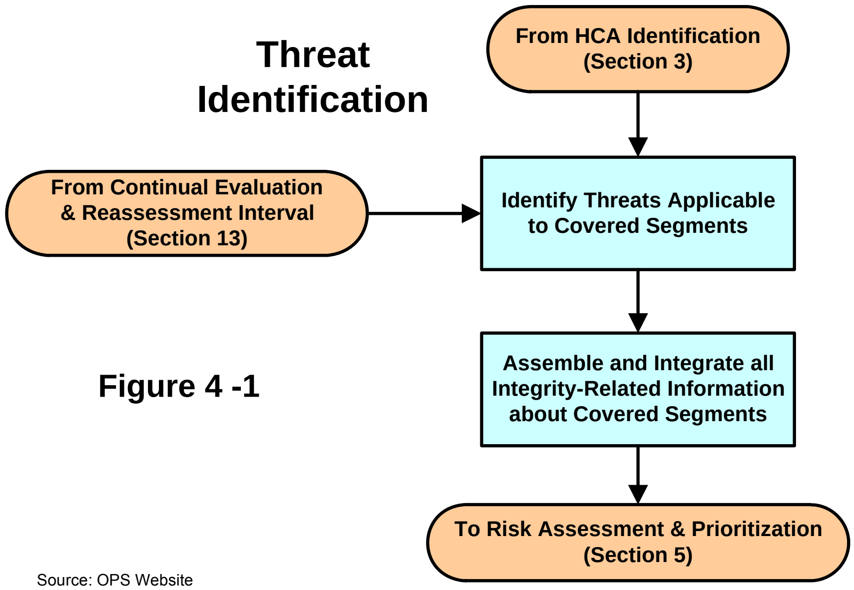


Figure 4 -1

Source: OPS Website

4.1.1 Purpose

This Section describes the types of threats which must be identified and evaluated for each covered pipeline segment, and **Louisville Gas & Electric/ Kentucky Utilities'** (the company('s) methodology for evaluating each threat. It also describes **the company's** gathering, integration, review, and analysis of the data associated with each threat.

4.1.2 Responsibility

The **Program Manager – Pipeline Integrity** M1 is responsible for the implementation and maintenance of the procedures in this Section. The **Pipeline Integrity Engineer** F3 has specific assignment responsibilities as described within this Section. This includes the gathering, correction, and updating of the threat related data accumulated and maintained for each threat. The **Engineer(s)** F2 are also responsible for the quality control review of data inputs relating to the technical and engineering aspects of the pipeline system.

4.2 DEFINITIONS

Potential Threat
A Potential Threat is a threat which has not yet been evaluated using **company** data and methodology for evaluating threats.

Threat of Concern (TOC)
A Threat of Concern (TOC) is a threat which has been evaluated using **company** data and methodology for evaluating threats, and sufficient information exists to determine it

as a viable threat to the pipeline system. A TOC is also a threat in which sufficient data does not exist to reasonably exclude it as a viable threat.

Threats of Concern are the result of a filtering process in which all potential threats are evaluated against the specific data from **the company's** pipeline system. They are a subset of the potential threats, representing those specific threats which are a concern to **the company's** pipeline system.

> **NOTE:** If a Potential Threat is determined not to be a Threat of Concern, it means that particular threat is not a Threat of Concern at the time of evaluation. However, as HCA segments are continuously evaluated (see Section 13), future evaluations may determine it to be a Threat of Concern at a later time.

4.3 PRESCRIPTIVE VS. PERFORMANCE BASED APPROACH

The pipeline integrity regulations of 49 CFR 192 Subpart O provides for two types of Integrity Management Programs, prescriptive and performance based.

Prescriptive Approach [The basis of this IMP Document]
Under the prescriptive approach each "threat category" must be considered. The prescriptive approach enables the threat analysis to be conducted in the context of the 9 threat categories.

Performance Based Approach
Under the performance based option "each threat" must be considered individually, and all 21 threats must be addressed. An operator may also deviate from the reassessment intervals and remediation schedule, if it can be justified under the program. This approach requires a significant amount of data to perform an adequate analysis to justify these extensions. See 49 CFR 192.913 for detailed requirements.

The **company** uses the Prescriptive Approach as the basis of this manual, and has utilized the requirements contained within Appendix A of ASME B31.8S-2004 as appropriate to address each threat category.

4.4 THREAT IDENTIFICATION

✓ ***Referenced Protocol:*** ***C.1 Threat Identification***

4.4.1 Regulatory Citations

The Pipeline Research Committee International (PRCI) has analyzed the historical incident data from gas pipelines and classified each of these incidents into 22 root causes. One cause was characterized as "unknown", meaning no root cause was identified.

The remaining 21 threats were grouped into 9 categories of related failure types according to their nature and growth characteristics. These 9 categories were further delineated by three time related defect types [Ref: ASME B31.8S-2004, Section 2.2]

Per 49 CFR 192.917 (a) all potential threats to each covered pipeline segment must be identified and evaluated by each operator. These threats include as a minimum the twenty-one threats listed in ASME B31.8S-2004 section 2. Additionally, the effects of cyclic fatigue or other loading conditions must be evaluated where applicable per 49 CFR 192.917(e)(2).

Cyclic Fatigue shall be included as Threat Number 22.

4.4.2 Other Potential Threats

As part of the threat identification process, **the company** will also identify and consider any unique threats to its pipeline system which are not specifically listed in the 9 threat categories. Those unique threats which have been determined to be Threats of Concern will also be addressed in subsection 4.8. **The company** has not identified any unique threats beyond the nine categories at this time.

4.4.3 Plastic Transmission Pipeline

✓ ***Referenced Protocol:*** ***C.7 Plastic Transmission Pipeline***

Historically, plastic pipe was first installed as company transmission piping in September 2008, near Laconia, Indiana, .

4.4.4 Applicability Criteria

Any threat prescribed as applicable by specific requirements stated within 49 CFR 192 Subpart O or its incorporated references will be identified as applicable.

Any threat that is possible by functional definition will be identified as applicable even if the probability of occurrence is infinitesimally small. However, if criteria for inclusion of a threat is stated within 49 CFR 192 Subpart O or its incorporated references and the stated criteria is not satisfied, that threat will be identified as not applicable.

The following Table 4-1A lists the threats as designated in ASME B31.8S-2004 Section 2, and identifies those that are applicable to the company gas transmission pipelines. Table 4-1B is used in conjunction with Table 4-1A for the current justification of the threat applicability.

Table 4-1A
Identified Integrity Threats per ASME B31.8S-2004 Section 2

B31.8S Threat Designation	**Applicability**				
B31.8S Category / **Threat Number and Description**	**A** Pipe Segment	**B** Blowdown or Stub	**C** Drip	**D** Equipment	**E** Plastic Pipe
Designation (a) Time Dependent Threats					
Category 1 External Corrosion					
1. External corrosion	Yes	Yes	Yes	Yes	No
Category 2 Internal Corrosion					
2. Internal corrosion	Yes	Yes	Yes	Yes	No
Category 3 Stress Corrosion Cracking					
3. Stress corrosion cracking	Yes	No	No	No	*
Designation (b) Stable Threats					
Category 4 Manufacturing Related Defects					
4. Defective pipe girth weld	Yes	Yes	Yes	No	No
5. Defective pipe (Other than seam)	Yes	Yes	Yes	No	Yes
Category 5 Welding / Fabrication Related Defects					
6. Defective pipe girth weld	Yes	Yes	Yes	No	No
7. Defective fabrication weld	No	No	Yes	Yes	No
8. Wrinkle bend or buckle	Yes	No	No	No	Yes
9. Stripped threads / broken pipe / coupling failure	Yes	Yes	Yes	Yes	Yes
Category 6 Equipment					
10. Gasket / O-ring failure	No	No	No	Yes	No
11. Control / relief equipment malfunction	No	No	No	Yes	No
12. Seal / pump packing failure	No	No	No	Yes	No
13. Miscellaneous Equipment	No	No	No	Yes	Yes
Designation (c) Time-independent Threat					
Category 7 Third Party / Mechanical Damage					
14. Damage inflicted by first, second, or third party instantaneous	Yes	Yes	Yes	Yes	Yes
15. Previously damaged pipe (delayed failure mode)	Yes	Yes	Yes	Yes	Yes
16. Vandalism	Yes	Yes	Yes	Yes	Yes
Category 8 Incorrect Operations					
17. Incorrect operational procedures	Yes	Yes	Yes	Yes	Yes
Category 9 Weather Related and Outside Force					
18. Cold weather	Yes	Yes	Yes	Yes	Yes
19. Lightning	Yes	Yes	Yes	Yes	Yes
20. Heavy rain or flood	Yes	Yes	Yes	Yes	Yes
21. Earth movement	Yes	Yes	Yes	Yes	Yes
Additional Threat Designated in Subpart O					
22. Cyclic fatigue	Yes	Yes	Yes	Yes	Yes

Table 4-1 B Identified Threat Justification		
Integrity Threat Number		
	Applicability Column	
1	**A, B, C, D**	All buried metallic pipe, fittings, components are subject to damage by external corrosion if not properly coated and cathodically protected. Above ground pipe and components are subject to damage from external atmospheric corrosion if not properly coated or otherwise protected from a corrosive environment.
1	**E**	Plastic pipe and fittings are not subject to damage by external corrosion
2	**All**	All metallic pipe and gas carrying components may be subject to damage from internal corrosion if the gas contains liquid water and other corrosive substances. However for dry gas that is always dry the potential for internal corrosion is essentially zero.
1	**E**	Plastic pipe and fittings are not subject to damage by internal corrosion
3	**A**	Near-neutral SCC threat considered if all three conditions are present. High pH SCC not considered a risk as all conditions listed in ASME B31.8S-2004, Section A3.3, are not realized for any one segment of pipe. Fatigue failure which may result from cyclic forces at a point of stress concentration will be addressed as Threat 22.
3	**B**	All conditions required for SCC threat are not realized for blowdowns or stubs as they operate below the operating stress level criteria.
3	**C**	Most drips are shop or field fabricated by pipeline contractors using standard line pipe and fittings. They are typically constructed of heavier wall pipe and operate below the operating stress level criteria for SCC.
3	**D**	SCC not applicable to equipment.
3	**E**	SCC does not apply to plastic pipe but for purposes of this IMP threat identification process Environmental Stress Cracking (ESC) as part of this threat.
4	**A**	Any steel pipe with a seam has some possibility of a seam defect. ERW grade pipe produced using a low frequency AC welding current, typical of pipe manufactured prior to 1970, has a high risk of seam failure from corrosion and shall be regarded as high risk if seam failures of similar pipe have been experienced in any line segment, or if pressure has increased over maximum experienced during preceding five years. Per B31.8S CW grade, lap weld grade, or any grade requiring a .6 longitudinal joint factor shall be regarded as high risk subject to same stipulations as low frequency ERW pipe.
4	**B**	Same as pipe
4	**C**	Same as pipe. Most drips are shop or field assembled using standard pipe and fittings.
4	**D**	For this purpose equipment, even if fabricated partially with pipe, shall not be considered to be pipe
4	**E**	Plastic pipe does not contain a seam and therefore is not susceptible to this threat.
5	**A**	This is applicable to any manufacturing defect in pipe or standard weld end fittings other than defective seam. May be considered stable if the pipeline was successfully tested per Subpart J for MAOP being qualified, or if the operating pressure has not exceed five year historic maximum.
5	**B**	Same as pipe.
5	**C**	Same as pipe. Most drips are shop or field assembled using standard pipe and fittings.
5	**D**	For this purpose equipment, even if fabricated partially with pipe, shall not be considered to be pipe.
5	**E**	Plastic pipe is susceptible to manufacturing defects related to the PE extrusion process. Injection molded plastic fittings are also susceptible to manufacturing defects.
6	**A**	Essentially all transmission pipe segments are predominantly welded construction. Where pipe is welded to a flange, valve, or other component the weld will be considered to be a pipe attribute.
6	**B**	Same as pipe
6	**C**	Same as pipe. Most drips are shop or field assembled using standard pipe and fittings.
6	**D**	Wherever an equipment attribute is welded to a pipeline the girth weld will be considered as an attribute of the pipe.
6	**E**	
7	**A**	Not applicable to pipe segments. Applicable to manufactured or shop assembled components with welded seams.
7	**B**	Same as pipe

Table 4-1 B
Identified Threat Justification

Integrity Threat Number		
7	C	Could be applicable if drip is a factory manufactured component.
7	D	Applicable to weld seams in fabricated equipment
7	E	
8	A	Wrinkle bends have never been used on company gas pipelines. However some field bends may have been made without the use of proper bending shoes or equipment.
8	B	Blow downs are typically straight pipe, or pipe with standard fittings.
8	C	All bends in fabricated drips are made with standard weld end fittings.
8	D	Any pipe bends in manufactured equipment are shop-made under controlled conditions
8	E	Appropriate bend radius for plastic pipe is designed on a case-by-case basis.
9	A	Threaded joints are generally not used on underground transmission piping. However, mechanical couplings may be used.
9	B	Blow down valves, plugs, and caps are liable to be threaded.
9	C	Small blow down valve on drip likely to be threaded body.
9	D	Threaded or bolted connections are common place on equipment.
9	E	Mechanical couplings may be utilized on plastic pipelines.
10	A, E	Pipe not considered being equipment.
10	B	Blow down not considered to be equipment
10	C	Drips not considered to be equipment
10	D	Gaskets and O-rings are common place on some equipment.
11	A, E	Pipe not considered to be equipment.
11	B	Blow down not considered to be equipment
11	C	Drips not considered to be equipment
11	D	Applies to pressure controlling and pressure limiting equipment
12	A, B, E	Pipe not considered to be equipment.
12	C	Drips not considered to be equipment
12	D	Not limited to pumps, shall apply to any component with seal on movable part.
13	A, B, E	Pipe not considered to be equipment.
13	C	Drips not considered to be equipment
13	D	Miscellaneous equipment not covered under threat number 10, 11, or 12.
14	All	Mechanical damage causing instantaneous failure caused by first, second, or third party is a threat to all pipe and components to varying degrees.
15	All	Previous damage caused by first, second, or third party causing delayed failure is a threat to all pipe and components to varying degrees.
16	All	Vandalism is a potential threat to all pipe and components to varying degrees. Sabotage and terrorist activities should be recognized threats.
17	All	Threat of damage to pipe, blow downs, drips, or equipment from improper operation is very small but is in some cases possible.
18	A, B, C, D	Threat of damage from cold weather to pipe, blow downs, drips, or equipment is minimal but possible
18	E	Plastic pipe can be detrimentally affected by either extreme cold or extreme heat outside the manufacturer's tolerance. See also 49 CFR 192.321 for code requirements.
19	A, B, C, E	Threat of damage from lightning to pipe, blow downs, or drips is minimal but possible.
19	D	Electronic control equipment and electric motor operated equipment is susceptible to damage and possible malfunction from lightning.
20	All	Threat of damage from heavy rain or flood cannot be ruled out.
21	All	Threat of damage from earth movement cannot be ruled out
22	All	Principle threat of cyclic fatigue is from outside forces at uncased road crossings, construction sites, etc. from vehicles or equipment crossing pipe. Coincidental to stress rising feature.
22	B	Threat of cyclic fatigue on buried blow down piping only
22	C	Threat of cyclic fatigue if buried under road, construction site, etc

4.5 DATA GATHERING

✓ ***Referenced Protocol:*** ***C.2 Data Gathering***

This subsection addresses the data which must be gathered to adequately evaluate each potential threat on the pipeline system.

4.5.1 Data Requirements

Data gathering requirements are described under 192.917 (b) of the applicable regulations as follows:

> b) *Data gathering and integration.* To identify and evaluate the potential threats to a covered pipeline segment, an operator must gather and integrate existing data and information on the entire pipeline that could be relevant to the covered segment. In performing this data gathering and integration, an operator must follow the requirements in ASME/ANSI B31.8S, section 4. At a minimum, an operator must gather and evaluate the set of data specified in Appendix A to ASME/ANSI B31.8S, and consider both on the covered segment and similar non-covered segments, past incident history, corrosion control records, continuing surveillance records, patrolling records, maintenance history, internal inspection records and all other conditions specific to each pipeline.

The following table, Table 4-2, lists the data to be considered for threat evaluation and risk analysis for the nine major threat categories per requirements of ASME B31.8S Appendix A in compliance with the above regulation:

Table 4-2
Data Collection Requirements for Threat Evaluation and Risk Analysis
(based on ASME B31.8S-2004 Table 1 and ASME B31.8S Appendix A)

	General	Ext. Corr.	Int. Corr.	SCC	Mfr. Defects	Weld / Fab Defects	Equip. Failure	Third Party / Mech. Damage	Incorrect Operations	Weather / Outside Force
	Table 1	A1	A2	A3	A4	A5	A6	A7	A8	A9
Pipe Attribute Data										
Equipment properties	X									
Joint factor	X				X	X				
Manufacturer	X				X					
Manufacturing date	X				X					
Pipe diameter	X	X	X							X
Pipe grade / material specification	X				X	X				X
Pipe Seam type	X				X					
Pipe Wall thickness	X	X	X		X					
Design/Construction Data										
Bending method	X					X				
Coating type	X	X		X						
CP system installation	X	X								
Crossings/casings	X									
Depth of cover	X					X				X
Field coating methods	X									
Hydrostatic pressure test (pre-service)	X				X	X				

Table 4-2
Data Collection Requirements for Threat Evaluation and Risk Analysis
(based on ASME B31.8S-2004 Table 1 and ASME B31.8S Appendix A)

	General	Ext. Corr.	Int. Corr.	SCC	Mfr. Defects	Weld / Fab Defects	Equip. Failure	Third Party / Mech. Damage	Incorrect Operations	Weather / Outside Force
	Table 1	A1	A2	A3	A4	A5	A6	A7	A8	A9
Inspection reports (pre-service, includes weld NDT)	X					X				
Installation year	X	X	X	X	X	X	X			X
Joint method, process & inspection results (inlcudes welding procedures)	X				X	X				X
Proximity to compressor stations				X						
Soil characteristics	X	X		X						X
Operational Data										
Coating condition	X									
Corrosion monitoring, OD/ID	X		X							
CP system performance	X	X								
Encroachments								X		
External forces	X					X				
Flow rate	X		X							
Gas quality	X		X							
Operating pressure history, normal max. & min.	X				X					
Operating stress level (% SMYS)		X	X	X						
Operating temperature				X		X				
Pipe wall temperature	X									
Pressure fluctuations	X									
Repairs & repair methods	X					X				
Inspection Data										
Audits & reviews	X								X	
Coating condition inspections (DCVG)	X									
CP inspections (CIS)	X									
Geometry tool inspections	X									
In-Line Inspection	X									
MIC / bacteria test results (yes/no/unknown)		X	X							
One-Call records								X		
Pipe inspection reports, bell hole inspections	X	X	X	X	X			X		
Pressure tests	X	X	X	X	X	X				
Leak, Failure, Incident History										
Failure history (flange, gasket, o-ring, seal/packing)							X			
Vandalism	X							X		
Regulator/relief performance (includes failures & set point drift)	X						X			
Incidents involving previous damage								X		

NOTE: ASME B31.8S indicates that the operator can perform the initial data collection using only the Attribute and Construction data listed above. As assessments (inspections) are performed, the data from these assessments and similar "Inspection" elements listed above can be collected. Similarly, Operational data may take additional time to collect.

Subsection 4.6 further describes how the company assembles these elements or "data fields" into a working database structure.

4.5.2 Data Sources

The company has identified appropriate sources of information both within the company and from external sources such as industry wide data and technical publications. The data sources located within the company are typically associated with design / construction or operational / maintenance records.

The following sources for the company gas transmission line data are available to varying degree within the company:

Main Reports are documents that contain summary information for transmission pipelines and distribution mains. Main reports may contain any or all of the following data:

- Nominal diameter of pipeline
- Length in feet of original installation. Subsequent reports may show altered lengths as portions of the original pipeline are retired as in a partial replacement.
- Pipe material designation which may reflect coating type
- Date of installation, generally the original date the main was connected to a source of natural gas and put into service.
- Pressure designation by company nomenclature, H.P. for high pressure distribution or transmission line.
- Depth of burial
- Tabular listings of commencement and termination points, fittings used, valve locations, distance from right-of-way or easement lines, etc. Locations are generally referenced to fixed objects such as public road crossings. In many cases property lines or right-of-way lines are referenced.
- Pressure test data. In some cases pressure attained, duration of test and test medium. In other cases only partial information such as pressure alone, or pressure and medium or pressure and time duration.
- Name of contractor if applicable.
- Name of welder.
- Name of company inspector. In most cases the report is signed by the inspector.
- A line drawing or sketch may be provided showing summary location data. Generally will show notations to indicate welds that were radiographed.
- Any other information deemed significant by the inspector making the report.

A signed main report is considered to be a very reliable document as it is generally signed by a person who witnessed the installation and pressure test. However, main reports for transmission lines installed prior to approximately 1982 were completed by Maps and Records personnel rather than by the actual inspector, but with the assistance of the inspector.

Main reports are generally accessible through the document imaging system for viewing or printing. Main reports are filed by and accessed by Main Number only.

Gas Pipeline Data Sheets are documents that provide engineering design data, test data, and weld radiograph inspection data for gas distribution and transmission pipelines. The **Part I** sheet was completed by the design engineer and provided the intended pipe specifications, including size, wall thickness, specification and grade; class location; minimum pressure test requirements; and weld radiograph requirements; as necessary to meet or exceed federal and state regulatory requirements. The **part II** sheet documents the actual test and radiograph inspections performed and lists any deviations from the pipe specifications and design specifications of Part I. The completed Part II document is signed by either the main inspector or a responsible supervisor.

The Pipeline Data Sheet Process was implemented approximately 1970 to assure compliance with record keeping requirements of the newly adopted Federal Department of Transportation gas pipeline safety regulations, Title 49 CFR Part 192. The Part I and Part II Pipeline Data Sheets are required to be retained for the life of the pipeline in the construction project file for each pipeline or main. Gas Pipeline Data Sheets, Part I and Part II, where replaced with the seven part High Pressure Gas Data Sheet in 2013.

Gas Pipeline Data Sheets are filed with the overall job file for each project and are accessible by construction work order number through the document imaging system, microfilm files, and archived paper files located in the Asset Information section.

High Pressure Gas Data Sheets are a seven part document containing design data, as-built drawings, location references, construction data, pipe and pipe-like fittings, miscellaneous fittings, valves, and pressure test documentation. This document replaced the Gas Pipeline Data Sheets in 2013.

Design Drawings represent the proposed construction of a pipeline and may serve as an indication of the scope and location of an installed pipeline. Facility design information is sometimes available, however there are cases the final installation was different from the initial proposal.

Pressure Test Charts if properly labeled serve to confirm initial strength test applied to a pipeline. To the extent retained, pressure charts are filed in the construction project folder accessible through the document imaging system, microfilm files, and archived paper files located in Asset Information. In 2015, the company purchased digital pressure test recorders. All test charts are saved from the digital recorder, in an electronic format, to a designated company shared network drive. Both analog and digital records, meeting the proper test requirements, are acceptable formats for pressure test charts.

Mill Test Reports (MTR) are maintained in the Assets Management files. These files date back to 1952 and contain test certifications reports for pipe purchased. Although the files are incomplete, they represent a sampling of pipe in various sizes purchased by the company over the years. In some cases there are attached letters, hand written notations, mill coating plant summaries, or other documents that link reports to specific projects. These files have enabled **the company** to establish realistic but conservative default values for specification, grade and wall thickness of pipe as a function of size and year installed.

As-Built Drawing are drawings drafted after the completion of job to indicate exactly how the assets were installed. As-built drawing may be updated and changes to the physical configuration take place through normal operations.

Miscellaneous Data Sources

Corrosion Control records, maintained by the **company's** gas Corrosion Control section provide an ongoing record of cathodic protection test readings, maintenance to the C.P. system, dielectric coupling locations, etc. C.P. monitoring test readings were documented on paper from the start of the Corrosion Control section in 1954 through approximately year 2000 at which time a Bass Trigon software package was implemented and a transition took place to electronic filing. The Corrosion control files generally contain sketches or construction drawings, anode installation reports, and other asset information which may be reflected in the work management system**, Maximo,** in main reports, or maintenance reports, dependent upon date and process in time of the activity performed. Paper files are retained in the corrosion control section of the Pipeline Integrity office.

Non-destructive Testing Reports, nearly exclusively radiograph, when available confirm the integrity of girth welds. Radiograph reports may be on a two part form provided by the **company,** with one part summarizing the number of welds made and the number tested each day; and the other part providing the detailed location and results of each test. In some cases the radiograph results are submitted on forms provided by the contractor. Non-destructive test records are to be retained for the life of the pipeline and are filed with the construction project folder accessible through the document imaging system, microfilm files, and archived paper files located in Asset Information.

Invoices are useful to determine or confirm identity of contractors. Invoices for nondestructive testing may confirm that wells were radiographed and may enable a determination of how many welds were tested. Invoices may also confirm specifications for materials or equipment ordered. To the extent retained, invoices are filed in the construction project folder accessible through the document imaging system, microfilm files, and archived paper files located in Asset Information.

Diaries and Notes in some cases provide a record of construction, inspection, testing, etc. as witnessed by the inspector. Hand written diaries and notes are considered to be a credible source of data. Diaries and notes are likely to be found at the transmission system offices located at Magnolia and Muldraugh Compressor Stations.

ACEs (Authorizations for Capital Expenditure) generally describe the broad scope of a project and can be useful to confirm approximate date of a project and construction work order number. The information contained in an ACE may provide preliminary information that is helpful for finding more complete information. Details concerning the description of a project are generally of limited value as it is not unusual for details to change after funds are authorized. ACEs are typically filed with the construction project folder accessible through the document imaging system, microfilm files, and archived paper files located in Asset Information.

Maintenance Reports generally provide information concerning the coating type, location, depth of burial, soil characteristics, and general condition of a pipeline as well as a description of the maintenance or repair performed. In some cases short segments of pipe were replaced on maintenance accounts rather than capital accounts, and were documented only on maintenance reports. Maintenance reports are accessible by main number through the document imaging system.

Archived Transmission Line Maps provide limited data and graphic illustration of older pipelines, including size, locations and construction work order number.

GIS Mapping System provides maps and asset information for gas mains and transmission lines and various attributes thereof. Data normally supported in GIS includes size, material, coating type, CP status, depth of cover, length, installation date, material, transmission line or distribution status, main report number, and construction work order number. The GIS database was created from information documented on main reports and other field generated documents. Within the GIS is a customized data entry interface called the Integrity Management Editor (IME). The IME allows the Integrity Management group to enter integrity related data, not stored elsewhere in the GIS, into database that is located on a network server.

Gas Dispatch and Control Operating Records provide pressure and flow data for city gate stations and certain other critical points within the storage and transmission systems. Electronic filed data can be retrieved for recent years through the gas SCADA system. Data for approximately the past forty years can be retrieved manually from microfiche files retained y the Gas Control office.

The preceding discussion does not preclude the use of other documents that may supply needed data or that may add credibility to other documents. Due to the diverse nature of the transmission system operation combined with administrative changes and record keeping process changes documents other than those described may be located at locations other than those described.

The company has also used subject matter experts and those directly involved in integrity related activities to gain additional insight into the data being collected.

If any assumptions are made in lieu of comprehensive data, **the company** will document those assumptions.

If a threat has been retained due to insufficient data, or if the quality of the data is questionable or unreliable, **the company** may perform specific data gathering activities to acquire the data needed (e.g., field measurements). Upon acquiring this data, the prescriptive-based processes may be re-evaluated to determine if the threat can be excluded as a Threat of Concern from **the company's** pipeline system

4.5.3 Data Collection

4.5.3.1 Initial Data Collection

Prior to the development of this written plan, and prior to issuance of a final pipeline integrity management regulation, **the company** initiated the data collection process necessary to evaluate applicable threats and assess the relative corresponding risks to all transmission line segments of record.

The primary collection tool for collection of pipe data including appurtenance and attribute data is a shared Excel spreadsheet with protected write access limited to authorized users for selected data fields. Development of this worksheet has been an evolutionary process with modifications continuing as additional applications are developed. The original spreadsheet was generated from the GIS (Smallworld ENOM database).

For the initial data collection effort each distinct pipeline has been assigned a name, with each segment assigned a number. To the extent practical names previously used were assigned. Segment numbers have been assigned in ascending order in the direction of normal flow while serving customers during periods of substantial system demand.

In the event that certain pertinent historical data could not be found, default values developed by subject matter experts are used. These default values can be found in Appendix 4A- Pipe Data Default Summary Table. This table provides of summary of minimum specifications for steel pipe used by Louisville Gas and Electric Company for the construction of gas mains and transmission lines. It is based upon pipe mill certification reports that are on file in the Assets Management "Gas Engineering" office. In some cases records were not available for certain sizes and certain years and trends were extrapolated.

For data not addressed in the Pipe Data Default Summary Table, explanations of defaults values are described below.

- Date of Pre-Service Pressure: When this date cannot be found due to missing pressure test records, the date of installation is used, rounded to the nearest month and year. The day will be defaulted to 1.
- Weld Joint/ Fitting Coating- For pipe installed before 2002, defaulted to 'Tape-Cold Applied' if not specified on Main Report based on company practices. Coating type should be listed on all main reports after 2002.

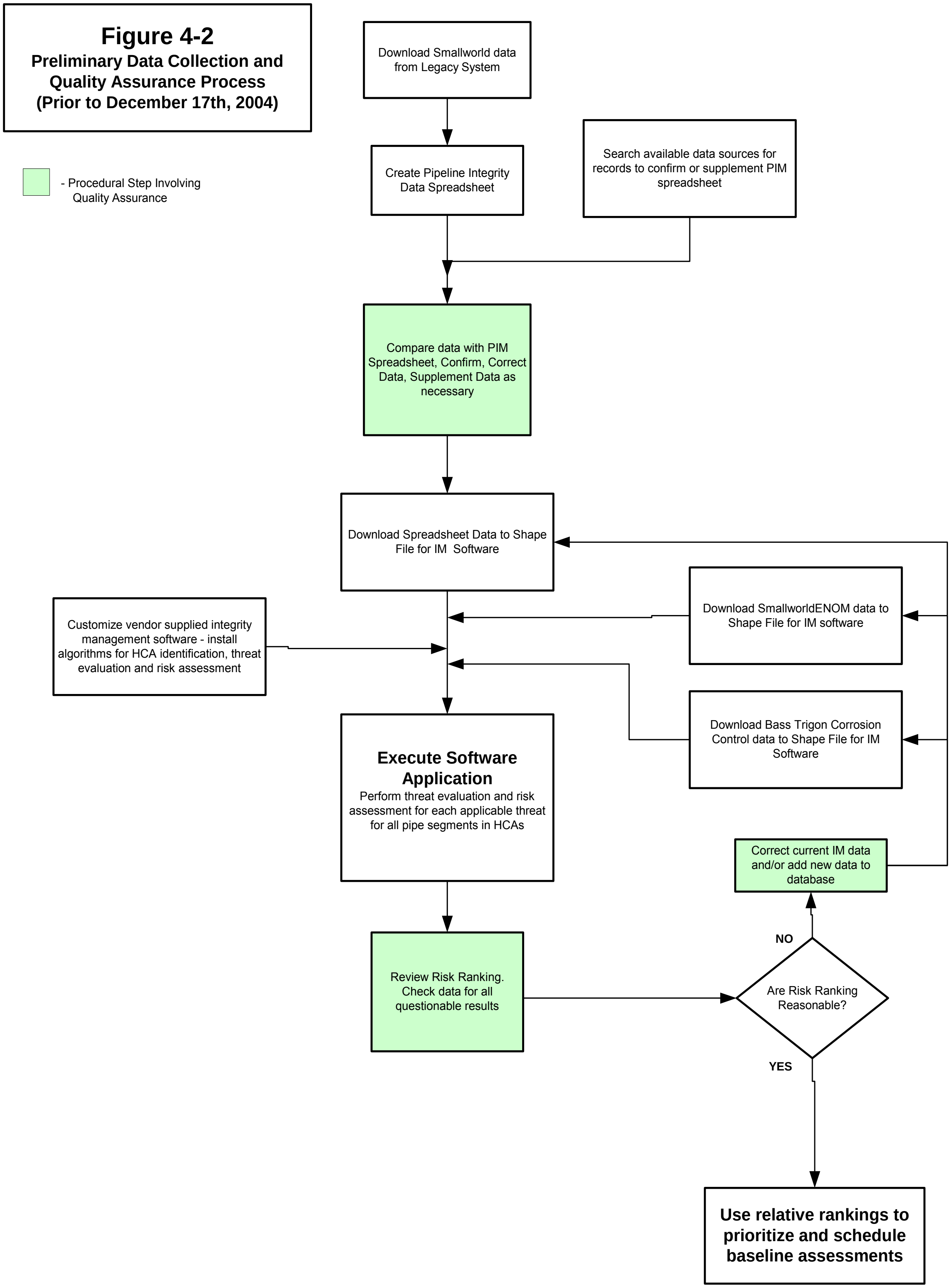
- Weld Process: Defaulted to SMAW because of standard company practice.
- Weld Test/Inspection Method: If no X-ray report can be found, but a signature exists on Main Report, then defaulted to 'Visual' inspection. If no signature is on the Main Report, defaulted to 'Unknown'. Otherwise, the X-ray data should be found in the Construction Reports.
- % Welds Non-Destructively Tested: Defaulted to 0 if unknown.
- Non-Destructive Test Contractor: Defaulted to unknown if unknown.

Forms were developed for field personnel to use for identifying potential identified sites (Form 3-1) and HCAs, and for documentation of direct examinations of pipe using the Direct Examination Form (Form 9-6.)

Figure 4-2 outlines the process used for preliminary data collection and quality assurance process.

In 2011, the aforementioned spreadsheet was retired from use. A tool in the GIS was designed to house the data previously retained in the spreadsheet.

Figure 4-2
Preliminary Data Collection and Quality Assurance Process (Prior to December 17th, 2004)



4.5.3.2 Continuing Data Collection

Collection of transmission pipeline data shall be a continual process. As additional segments of transmission line are identified or discovered, additional information is acquired for currently listed segments, existing segments are retired, or corrections to existing data are discovered the data base shall be updated in a timely manner. Continual updates will be performed for new HCA segments (as identified per Section 3 of this IMP) as well as for existing HCA segments.

If or when additional data fields are discovered or identified as applicable and available the GIS shall be revised as necessary to accommodate the new information. Likewise, if an existing data field is identified as non-applicable or not available the GIS may be modified accordingly.

4.5.3.3 Continuing Data Collection – External Sources

The availability of external data sources referenced in this document are subject to change without notice. Company personnel will make every effort to use the same or similar datasets during their annual review and update. New types or formats of data may also be utilized at the discretion of the **Integrity Engineer**. The **Integrity Engineer** will record the date and source of all external data downloaded and used by the risk program. This information will be reviewed annually and if any changes have occurred, the file will be downloaded and risk model updated.

4.6 DATA INTEGRATION

✓ ***Referenced Protocol:*** ***C.3 Data Integration***

4.6.1 Segment or Attribute Identity

Each segment of main or transmission line, each appurtenance, etc., of record in the GIS data base is identified by a unique system identification number. The system identification number shall be included as a required data field for each identified line segment or other attribute.

This system identification number can be used with the object browser features of the GIS to locate the referenced segment's attribute data and map location.

4.6.2 Pipeline Name and Segment

Each distinct pipeline has been assigned a pipeline system, a pipeline name, and a segment number. Segment numbers have been assigned in ascending order in the direction of normal flow while serving customers during periods of substantial system demand.

4.6.3 Database Assembly

The company has selected **Dynamic Risk's IRAS (risk analysis software)** as its primary software for identification of HCAs and for threat and risk calculations. The risk analysis software transforms exported data from various electronic systems into a database that is useable by the software.

4.6.4 Equipment Data Fields

Threats 10 through 13 address transmission line equipment, which includes piping both above ground and below ground at regulator stations, city gate stations, compressor stations, processing plants, and other applicable facilities. These components of the transmission line system that are considered to be equipment are subject to annual (or more frequent) inspection and maintenance.

4.6.5 Using a Common Distance Measurement Reference System

Since a wide variety of data is acquired based upon different distance measurement systems, it is important to convert this data into a common reference system to be useable for threat evaluations. These different reference systems may include pipeline stationing, mile posts, ILI odometer wheel count, GPS, and other forms of referencing. The company GIS is used as the base for the measurement system and other systems are aligned to it using the available reference.

4.6.6 Leak, Failure, and Safety Related Condition History

DOT Reportable Incidents are documented by **the company**. This information is also input by the **Pipeline Integrity Engineer** into the Pipeline Integrity Database.

Safety Related Condition Reports and Safety Related Condition Investigation Reports are similarly recorded.

Customer-reported leaks and Class 1 company-reported leaks are entered into GIS by company Regulatory Department personnel immediately upon notification. Company-reported Class 2 or Class 3 leaks are entered after completion of necessary forms.

4.6.7 Maintenance and Repair History

Form 9-6 is completed whenever excavation is performed as a direct result of the integrity management program. Depending upon the nature of the work, either a Main Report or Maintenance Report is also completed.

Although Maintenance Reports are entered into GIS by the Mapping Department, these objects do not record enough relevant data to improve the accuracy of the risk calculation. Thus, the Pipeline Integrity Department maintains a separate record of all information recorded on Form 9-6. This information is entered into the Pipeline Integrity Database and, ultimately, into GIS.

4.6.8 Unique Conditions

Company or contractor personnel may inform the Pipeline Integrity Department of any unique physical or operating conditions along the pipeline. This information may be provided verbally, through email, or on forms such as 9-6. Whenever possible the **Pipeline Integrity Engineer F3** will incorporate the data into the risk equation. Some unique conditions may not have a corresponding field in the risk database. In these cases, the information is used at the discretion of the **Program Manager**. For example, the unique condition could prompt a manual override of a specific TAV value if that threat is deemed significantly worse or significantly lessened by the condition.

4.7 DATA QUALITY ASSURANCE

4.7.1 Data Review and Correction Procedure

Data review and quality assurance shall remain an integral part of this plan. Much of the data that is processed for threat evaluation and ultimately risk assessment appears on the GIS which is manually updated and confirmed. As a part of this process suspicious values are to be questioned and corrected or confirmed to the greatest extent practical.

Gas main data in the GIS controlled through an audit logs process. Each day, an automatically generated log indicating the updates, inserts, or deletions of transmission mains in the GIS is sent to the Pipeline Integrity Engineer. The Pipeline Integrity Engineer reviews the log for changes. If there are issues or concerns with the changes, the engineer should discuss them with Asset Information. The Pipeline Integrity Engineer should update the Integrity Management Editor when a new segment is inserted into the GIS.

Data that is downloaded directly from the GIS or Bass Trigon is not visually displayed as an intermediate step within the process. As a part of the quality assurance process the results from each risk analysis performed by the risk analysis software shall be critiqued to discover any apparent discrepancies in risk ranking. For any suspected discrepancies the input data shall be checked and confirmed or corrected. If corrections are made to the data the analysis shall be rerun to reestablish relative risk ranking between covered segments.

Figure 4-3 presents the procedural steps that the company shall follow in assembly and maintenance of the Integrity Management Data. Specific responsibilities and duties of the **Program Manager – Pipeline Integrity** M1 and field personnel are delineated. This includes quality assurance of integrity management data, and quality review of the results of threat evaluations and risk analysis.

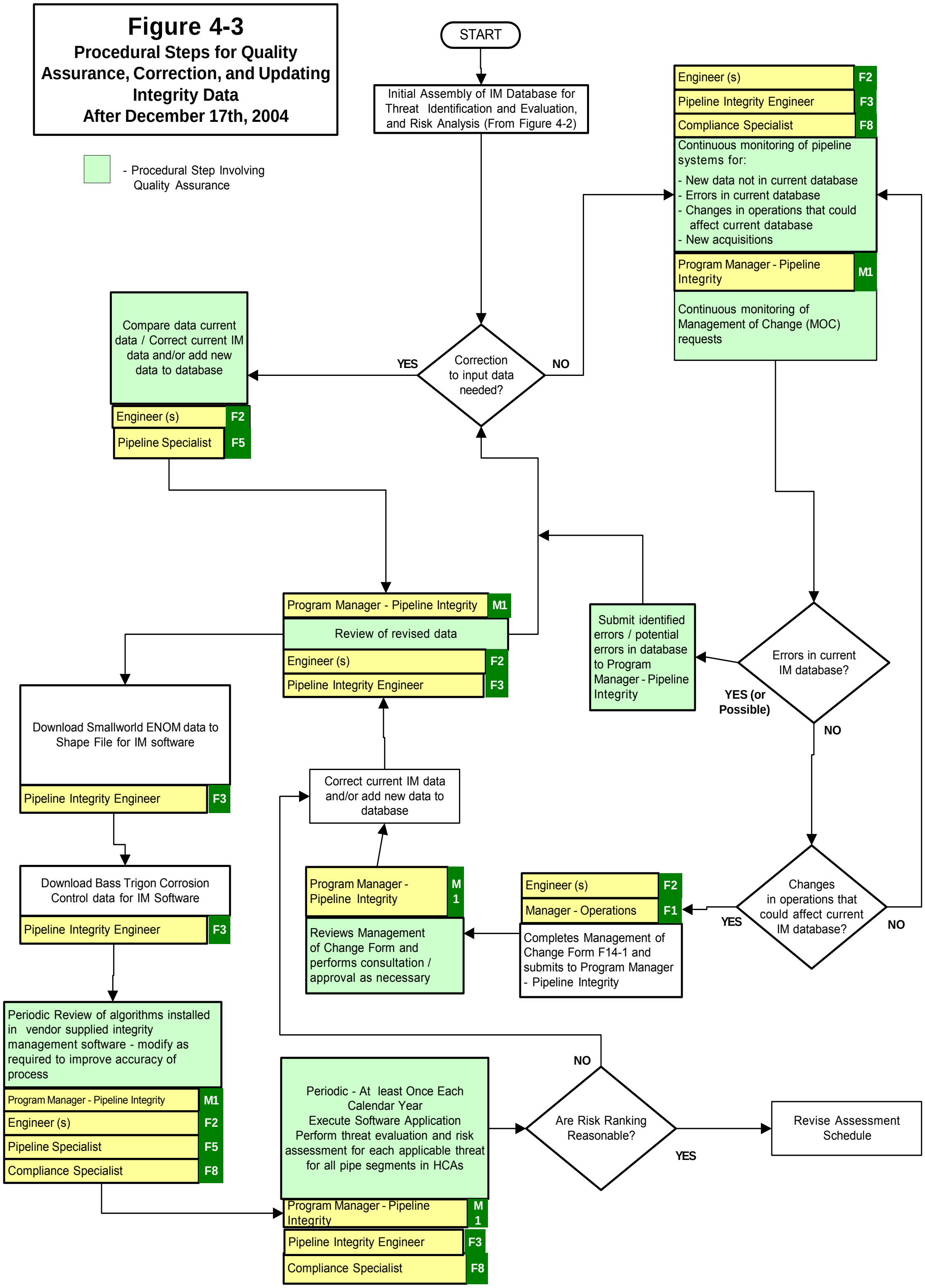


Figure 4-3
Procedural Steps for Quality Assurance, Correction, and Updating Integrity Data After December 17th, 2004
- Procedural Step Involving Quality Assurance
START
Initial Assembly of IM Database for Threat Identification and Evaluation, and Risk Analysis (From Figure 4-2)
Engineer (s) F2
Pipeline Integrity Engineer F3
Compliance Specialist F8
Continuous monitoring of pipeline systems for:
- New data not in current database
- Errors in current database
- Changes in operations that could affect current database
- New acquisitions
Program Manager - Pipeline Integrity M1
Continuous monitoring of Management of Change (MOC) requests
Compare data current data / Correct current IM data and/or add new data to database
Engineer (s) F2
Pipeline Specialist F5
YES
Correction to input data needed?
NO
Program Manager - Pipeline Integrity M1
Review of revised data
Engineer (s) F2
Pipeline Integrity Engineer F3
Submit identified errors / potential errors in database to Program Manager - Pipeline Integrity
Errors in current IM database?
YES (or Possible)
NO
Download Smallworld ENOM data to Shape File for IM software
Pipeline Integrity Engineer F3
Correct current IM data and/or add new data to database
Download Bass Trigon Corrosion Control data for IM Software
Pipeline Integrity Engineer F3
Program Manager - Pipeline Integrity M1
Reviews Management of Change Form and performs consultation / approval as necessary
Engineer (s) F2
Manager - Operations F1
Completes Management of Change Form F14-1 and submits to Program Manager - Pipeline Integrity
YES
Changes in operations that could affect current IM database?
NO
Periodic Review of algorithms installed in vendor supplied integrity management software - modify as required to improve accuracy of process
Program Manager - Pipeline Integrity M1
Engineer (s) F2
Pipeline Specialist F5
Compliance Specialist F8
Periodic - At least Once Each Calendar Year
Execute Software Application
Perform threat evaluation and risk assessment for each applicable threat for all pipe segments in HCAs
Program Manager - Pipeline Integrity M1
Pipeline Integrity Engineer F3
Compliance Specialist F8
NO
Are Risk Ranking Reasonable?
YES
Revise Assessment Schedule

4.8 THREAT EVALUATION PROCESS

4.8.1 General Description of Process

The company approach incorporates an integrated process that combines threat evaluation with risk assessment. The overall process is a three step approach:

Step 1 – Determine Threat Assessment Value

1. For each line segment or attribute determine a Threat Assessment Value for each threat, indicating a relative chance that the threat being addressed is present in that segment or attribute. This calculated variable does not by itself indicate a risk of failure. The process uses dynamic segmentation, meaning that any change in underlying attributes creates a new Threat Assessment Value score.

Variable name: TAVn, where subscript n is the threat identification number

TAVn may be either a real or integer number depending upon the nature of the independent variables determining its value.

TAVs typically range from 0 to 5.0 as follows:

TAV = 0	Threat that is not applicable to the segment being analyzed
TAV => 1.0 < 2.0	Low risk
TAV => 2.0 < 3.0	Intermediate risk
TAV => 3.0	High risk

A threat may be considered not applicable if it cannot physically exist, such as a defective seam in seamless pipe, or if language within the regulations or incorporated references permits the threat to disregarded.

The lowest TAV assigned to an applicable threat is 1.0. Values between 0 and 1.0 may be used as code numbers to indicate special circumstances or conditions.

The remaining two steps describe the risk assessment process and will be described in Section 5 of this program.

4.8.2 Evaluating Individual Threats

Threat Number 1, External Corrosion
(B31.8S designation Time Dependent, category External Corrosion)

External corrosion of metal pipe is a function of pipe coating, cathodic protection, and years of exposure. Coatings such as coal tar and fusion bonded epoxy (FBE) provide protection to the pipeline. An effective cathodic protection program – defined as one meeting minimum pipe-to-soil potential requirements – also reduces the risk of external corrosion. Section 5 of this Integrity Management Plan details the effect of pipe age on risk ranking and prioritization.

In addition to these factors, the threat of external corrosion is also related to leak history for a given segment of pipe. Pipe with prior leaks due to external corrosion may be at greater risk for continued corrosion and future failures.

Plastic transmission pipe is not susceptible to external corrosion.

Therefore,

TAV1 = [(TAVcoating + TAVcp)/1.6] + [TAVcorrosionleaks*2]

Where,

Coating:

Coated pipe	TAVcoating = 1.0
Bare pipe	TAVcoating = 3.0

Cathodic Protection:

CP pipe-to-soil readings	
> (-500mV)	TAVcp = 5.0
≤ (-500 mV) and > (-700mV)	TAVcp = 3.0
≤ (-700 mV) and > (-850mV)	TAVcp = 2.0
≤ (-850 mV)	TAVcp = 1.0
Invalid reading	TAVcp = 0.1
No data (default value)	TAVcp = 5.0

Leaks:

TAVcorrosionleaks = Leak Count (per pipeline segment), up to a maximum of 5.

Threat Number 2, Internal Corrosion
(B31.8S designation Time Dependent, category Internal Corrosion)

The **company** used a Subject Matter Expert approach to determining the internal corrosion threat. SMEs reviewed current gas quality, hydrogen sulfide, and other available data to determine appropriate threat scores for metal pipe. Refer to Section 5 of this Integrity Management Plan for details on how pipe age impacts risk ranking and prioritization. Plastic transmission pipe is not susceptible to internal corrosion.

Gas quality:

Gas quality was determined to be a function of line function as shown in the Table below.

Type	Location	Gas Quality
Pipeline	Ballardsville Line Calvary Line	Always Dry
Storage	All serving storage fields to compressor station inlet	Normally Wet during Withdrawal
Processed from Storage	All not included in Pipeline or Storage	Normally Dry

Hydrogen Sulfide:

Individual lines were grouped according to the storage field which they served. DRI and DRKY fields were combined. Typical values for field during 2000-2001, 2001-2002, 2002-2003 and 2003-2004 withdrawal seasons are shown in the Table below.

Locations	H_2S (ppm)
Center	5 ppm
DRI	80 ppm
Mag Upper	80 to 150
Muld	300 ppm
Mag Deep	360 ppm

Based upon discussions with operating personnel at the August 20, 2004 meeting held at Elizabethtown, the Doe Run complex demonstrates through iron sulfide deposits the greatest indications of active internal corrosion. Based upon that combined with the typical maximum observed field outlet H_2S readings and gas quality the TAV for internal corrosion is assigned as follows:

Ballardsville Line	TAV2 = 1.0
Calvary Line	TAV2 = 1.0
Center storage	TAV2 = 3.0
Mag Upper	TAV2 = 3.5
Muld	TAV2 = 4.0
DRKY or DRI	TAV2 = 5.0
Mag Deep	TAV2 = 5.0

All other (non-plastic) lines	TAV2 = 2.0
Plastic transmission lines	TAV2 = 0.0

Threat Number 3, Stress Corrosion Cracking
(B31.8S designation Time Dependent Threat, category Stress Corrosion Cracking)

Specific language in B31.8S-2004 Section A3.3 rules this threat out if all conditions required are not present.

High pH SCC is a Threat of Concern if all five of the following conditions are present:

- Operating stress level (MAOP) greater than 60% SMYS
- Coating other than Fusion Bonded Epoxy (FBE)
- Age of metal pipe greater than ten (10) years
- Operating temperature greater than 100°F
- Less than twenty (20) miles downstream from a compressor station

The Company uses cooling fans to maintain operating temperatures near approximately 55°F downstream of compressor stations, well below the 100°F threshold. Likewise, locations with heaters are maintained near 40°F. Therefore High pH SCC is not a Threat of Concern for the pipeline system.

Near-neutral SCC is a Threat of Concern if all three of the following conditions are present:

- Operating stress level (MAOP) greater than 60% SMYS
- Coating other than Fusion Bonded Epoxy (FBE)
- Age of pipe greater than ten (10) years

TAV values can be 0, 3 or 5 as follows:

Neither High pH nor Near-neutral SCC is a TOC	TAV3 = 0
Near-neutral SCC only is a TOC	TAV3 = 3
Both High pH and Near-neutral SCC are TOC	TAV3 = 5

At the current time, the Company has not identified SCC as a Threat of Concern. When and if SCC is identified as a Threat of Concern, the Company will develop and approve a written process for assessing / mitigating SCC.

Stress corrosion cracking does not apply to plastic transmission pipelines. However, a somewhat similar mechanism called Environmental Stress Cracking (ESC) has been shown to exist in polyethylene material subject to stress and in the presence of certain chemicals. For threat identification purposes, ESC will be considered as part of TAV3.

All plastic pipe contains some level of residual stress from the manufacturing process. However, transmission pipelines transporting normally dry gas should not contain any significant quantities of alcohols, halogens, or aromatics. Chemical treatment is not likely since internal corrosion is not a concern for these pipelines. Furthermore, the exterior surface would not be exposed to paint or other chemical treatments. Therefore TAV values can be assigned as follows;

Plastic pipe, normally dry gas, no chemical treatment	TAV3 = 0
Plastic pipe, normally wet gas	TAV3 = 1
Plastic pipe, chemical treatment	TAV3 = 3
Plastic pipe, storage field	TAV3 = 3

Threat Number 4, Defective Pipe Seam
(B31.8S designation Stable Threat, Manufacturing Related Defects)

Only pipe that has a seam can have a seam defect. Based upon criteria of B31.8S-2004 A4.3 if the pipe has a joint factor of less than 1.0 (such as lap welded pipe, hammer welded pipe, butt welded pipe), or if the pipe is comprised of low-frequency welded ERW pipe or flash welded pipe a manufacturing threat is considered to exist.

Flash welded seam pipe was produced by A.O. Smith Company from 1930 to 1969, however the company has no record of using A.O. Smith pipe.

Most ERW pipe produced prior to 1965 was made by either low frequency AC or a DC process. Whereas most ERW pipe manufactured in year 1970 or later employed high frequency welding techniques, low frequency AC by Interlake Steel and DC welding by Youngstown Steel continued until approximately 1980.

ERW seam welding process has been identified within the GIS as one of the following:

- LF – Low frequency AC current up to 360 Hz
- HF – High frequency AC current over 360 HZ
- DC – Direct current
- NA – Not applicable for seamless or seam types other than ERW

The company has utilized the ASME Research Report CRTD –Vol. 43, “History of Line Pipe Manufacturing in North America", prepared by Kiefner and Associates, Inc., copyright 1996, to identify the seam welding process used for pipe installed between 1965 and 1980. For ERW pipe installed prior to 1965 low frequency welding is assumed and for pipe installed 1980 or later high frequency seam welding is assumed.

All ERW pipe 8” and smaller of unknown manufacturer installed prior to 1980 is assumed to be of the low frequency process as the company was known to purchase some pipe, 4” through 8” from Interlake during this period., All ERW pipe 12” and larger prior to 1980 of unknown manufacturer is assumed to be of the DC manufacturing process, as records show that the company purchased some pipe 12” and larger from Youngstown during this time period.

Per 49 CFR 192.917(e)(4) any segment of low frequency ERW, lap-welded, hammer-welded, flash-welded or butt-welded pipe (requiring a longitudinal joint factor of less than 1 per 49 CFR 192.113) must be considered high risk for base assessment or subsequent reassessment if any covered or noncovered segment of similar pipe in the system has experienced a seam failure, or if the operating pressure exceeded the maximum pressure experienced during the five years preceding identification of the HCA (5-year P).

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

There is no record or recollection of any ERW seam failure ever occurring on the company's pipe. Therefore, seam failure history is not to be evaluated in this algorithm.

For HCAs originally identified in 2004, the five year operating history base is the five year period ending June 30, 2004. For additional HCAs, the operating history base is the five year period preceding identification as an HCA. The **Integrity Engineer** documents the five-year maximum operating pressure in the Integrity database upon identification of the HCA. This value is used for comparison to determine whether any pipe seam threats have become unstable.

Based upon the above:

Seam type= Seamless pipe	TAV4 = 0
Material = Plastic pipe	TAV4 = 0
Seam type= ERW AND Pipe Installed 1980 to present	TAV4 = 0
Seam type= ERW AND Pipe Installed pre-1980 AND (Max P < 5 year P)	TAV4 = 1
Seam type= ERW AND Pipe Installed pre-1980 AND Subpart J compliant pressure test was conducted	TAV4 = 1
Seam type= ERW AND Pipe Installed pre-1980 AND (Max P > 5 year P)	

AND Subpart J compliant test was not conducted TAV4 = 10

Seam type= ERW
AND Max P > MAOP since most recent Subpart J test TAV4 = 10

Seam type= ERW
AND Pipe Installed pre-1980
AND no other ERW scores are true TAV4 = 5

Seam Type= CW OR Furnace Butt Weld or Lap Weld
AND (Max P < 5 year P) TAV4 = 1

Seam Type= CW OR Furnace Butt Weld or Lap Weld
AND Subpart J Test was conducted TAV4 = 1

Seam Type= CW OR Furnace Butt Weld or Lap Weld
AND (Max P > 5 year P)
AND a Subpart J Compliant test was not conducted TAV4 = 10

Seam Type= CW OR Furnace Butt Weld or Lap Weld
AND Max P > MAOP since most recent Subpart J test TAV4 = 10

Seam Type= CW OR Furnace Butt Weld or Lap Weld
AND no other CW, Furnace Butt Weld, or Lap Weld scores are true TAV4 = 5

Where,

Max P = maximum operating pressure since identification of the HCA
5 year P = maximum historical operating pressure in 5 years preceding HCA identification

Pipe having a TAV4 value of zero (0) does not require assessment for seam failure threat.

Pipe having a TAV4 value of 1.0 is considered stable and therefore need not be assessed for defective seam unless the operating pressure is raised to a level higher than allowed per the Subpart J test of record and higher than the 5 year historic operating pressure. Either of these conditions would trigger a change in TAV4 score from 1.0 to 10.0.

Pipe having a TAV4 value of 10.0 must be assessed for defective seam as a part of its baseline assessment.

Covered segments deemed at high risk of seam failure must be assessed using a proven technology or technologies with a proven application capable of assessing seam integrity and seam corrosion anomalies.

Threat Number 5, Defective Pipe
(B31.8S designation Stable Threat, Manufacturing Related Defects)

This threat includes any manufacturing defect to pipe other than defective seam.

Per 49 CFR 192.917(e)(3), any covered segment containing manufacturing or construction related defects may be considered a high risk segment for baseline assessment or subsequent reassessment if any of the following conditions are met:

- The operating pressure on the covered segment exceeds the maximum operating pressure experienced during the five years preceding identification of the HCA (5-year P)
- The maximum allowable operating pressure increases
- Stresses leading to cyclic fatigue increase

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

The company has no record of failure resulting from pipe manufacturing defects. This threat will have a default TAV of one (1) for all metal pipe. Due to the more limited industry historical evidence, a slightly higher default score of two (2) will be used for all plastic pipe. It will therefore be equal in value for all segments unless a failure attributable to defective pipe occurs.

TAV5 (for metal) = 1+ count of leaks or failures resulting in a DOT reportable incident due to defective pipe

TAV5 (for plastic) = 2+ count of leaks or failures resulting in a DOT reportable incident due to defective pipe

The maximum score for any given pipeline segment will be 5.

Threat Number 6, Defective Pipe Girth Weld
(B31.8S Designation Stable Threat, Welding/Fabrication Related Defects)

Virtually all transmission line pipe currently in use was constructed using SMAW butt welds to join pipe-to-pipe and pipe-to-fittings, and that all welders were certified in accordance with qualified welding procedures in place at the time of construction.

Standard inspection procedures include visual inspection of all girth welds made in the field. Welds made after 49 CFR Part 192 went into effect, fall 1970, were nondestructively inspected by radiograph or other means in compliance with these regulations. Welds prior to the onset of 49 CFR Part 192 may have been subjected to nondestructive testing in some cases.

Plastic transmission pipelines may be constructed using electrofusion, heat fusion methods, or mechanical couplings. Although not strictly a "weld", electrofusion or heat fusion joints in plastic transmission lines will be addressed under TAV6. The same scoring will apply to plastic pipe as for traditional metal pipe. Refer to Threat Number 9 for mechanical couplings.

Per 49 CFR 192.917(e)(3), any covered segment containing manufacturing or construction related defects may be considered a high risk segment for baseline assessment or subsequent reassessment if any of the following conditions are met:

- The operating pressure on the covered segment exceeds the maximum operating pressure experienced during the five years preceding identification of the HCA (5-year P)
- The maximum allowable operating pressure increases
- Stresses leading to cyclic fatigue increase

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

For the purpose of assessing risk of failure from defective girth welds the following assumptions will be made as detailed records of visual weld inspections were not kept.

No record naming pipeline inspector, No visual inspection of welds	TAV6 = 3.5
Signed main report or other inspection document Visual inspection 100% of welds	TAV6 = 2.0

Valid radiograph[1] inspection documents,
Visual inspection 100% of welds,
Radiograph as indicated TAV6 = 2.0 - % X-ray
(% X-ray as decimal value)

Threat Number 7, Defective Fabrication Weld
(B31.8S Designation Stable Threat, Welding/Fabrication Related Defects)

Company Subject Matter Experts identified drips as the most common location for fabrications welds. The threat of defective fabrication welds was the correlated to the age of each location.

In addition to drips, fabrication welds may be found on piping at valves, regulators, pig launchers/receivers or other equipment. A similar threat index to the one used for drips will be applied as follows:

Equipment Age	
<= 10 years	IDXEquipAge = 1
11 - 20 years	IDXEquipAge = 2
21 - 30 years	IDXEquipAge = 3
31 years or more	IDXEquipAge = 5

TAV7 = [Sum of the IDXEquipAge)^2 / Sum of the (IDXEquipAge)] + 0.4 * (count of equipment within the PIC)

Where IDXEquipAge refers to all equipment within the PIC

The company selected a 0.4 weighting factor for equipment counts based on review of various scenarios. This factor, combined with the sum of values squared factor, appropriately rates locations with multiple pieces of equipment higher than a single piece of equipment.

Equipment types covered by this Threat include:
- Regulators
- Compressor
- Drip
- Farm Tap
- Odorizer
- Over Pressure Protection
- Heater
- Separator

Per 49 CFR 192.917(e)(3), any covered segment containing manufacturing or construction related defects may be considered a high risk segment for baseline assessment or subsequent reassessment if any of the following conditions are met:

[1] Radiograph inspections do not apply to plastic transmission pipelines.

- The operating pressure on the covered segment exceeds the maximum operating pressure experienced during the five years preceding identification of the HCA (5-year P)
- The maximum allowable operating pressure increases
- Stresses leading to cyclic fatigue increase

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

Threat Number 8, Wrinkle Bend or Buckle
(B31.8S Designation Stable Threat, Welding/Fabrication Related Defects)

The company has never intentionally installed wrinkle bends in transmission line piping. There is, however, possibility of minor wrinkle, dents, gouges, or other damage where field bends were made during installation of any pipeline. This threat was minimized wherever bends were made using a bending machine capable of properly supporting the pipe and controlling the bending radius.

The company will use a default threat score of 1.0 for all segments unless a wrinkle bend or buckle is found on that pipeline. The presence of one bend or buckle increases the likelihood of additional bends as yet unfound elsewhere on the line.

An acceptable bend radius is defined for each plastic transmission line depending on its dimensions. Current construction practices do not allow field bends more severe than the design parameters. Since no plastic transmission pipe was previously installed, wrinkle bends are not considered a threat on plastic pipelines.

Plastic transmission pipeline	TAV8 = 0
No wrinkle bends / buckles on pipeline	TAV8 = 1
Wrinkle bend or buckle found on pipeline	TAV8 = 2

Per 49 CFR 192.917(e)(3), any covered segment containing manufacturing or construction related defects may be considered a high risk segment for baseline assessment or subsequent reassessment if any of the following conditions are met:

- The operating pressure on the covered segment exceeds the maximum operating pressure experienced during the five years preceding identification of the HCA (5-year P)
- The maximum allowable operating pressure increases
- Stresses leading to cyclic fatigue increase

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

Threat Number 9, Stripped Threads / Broken Pipe / Coupling Failure (B31.8S Designation Stable Threat, Welding/Fabrication Related Defects)

Pipeline drips may contain threads, pipe, and couplings. Therefore the threat of stripped threads, broken pipe, or coupling failure was the correlated to the age of each drip location. The TAV for the threat is an index of the age of the drip as follows:

Drip Age	
<= 10 years	IDXDripAge = 1
11 - 20 years	IDXDripAge = 2
21 - 30 years	IDXDripAge = 3
31 years or more	IDXDripAge = 5

In addition to these drip locations, coupling failures can occur on transmission line pipe where mechanical couplings are in use. Mechanical couplings may be used on either metal or plastic transmission pipe.

Mechanical coupling	TAVcoupling = 3
Reinforcement installed	TAVcoupling = 1

TAV9 = [Sum of the IDXDripAge)^2 / Sum of the (IDXDriipAge)] + 0.4 * (count of drips within the PIC) + TAVcoupling

Where IDXEquipAge refers to all equipment within the PIC

The company selected a 0.4 weighting factor for equipment counts based on review of various scenarios. This factor, combined with the sum of values squared factor, appropriately rates locations with multiple pieces of equipment higher than a single piece of equipment.

The combined maximum score for any given pipeline segment will be 5.

Per 49 CFR 192.917(e)(3), any covered segment containing manufacturing or construction related defects may be considered a high risk segment for baseline assessment or subsequent reassessment if any of the following conditions are met:

- The operating pressure on the covered segment exceeds the maximum operating pressure experienced during the five years preceding identification of the HCA (5-year P)
- The maximum allowable operating pressure increases
- Stresses leading to cyclic fatigue increase

Additionally, PHMSA's answer to FAQ-219 (Frequently Asked Question) states that a successful 49 CFR 192 Subpart J is sufficient to reveal any manufacturing and construction defects that could jeopardize pipeline integrity at any operating pressure less than or equal to its MAOP as of the date of the pressure test. Therefore, if a pressure test is of record commensurate with the table in 192.619, manufacturing and construction defects may be considered to be stable unless other threats adversely affect the stability of residual manufacturing and construction defects.

Threat Number 10, Gasket / O-ring failure
(B31.8S Designation Stable Threat, Equipment)

This threat is not applicable to line pipe segments; however, gaskets and O-rings are commonplace on certain types of equipment.

TAV10 shall apply only to locations in an HCA that contain a flange or valve. Gasket or O-ring failure will not be a Threat of Concern at any other locations. Valve connection type data – flanged versus non-flanged – is stored in the GIS system. Where this information is unknown, a flanged valve is assumed.

Fitting	
Flanged	$TAV_{connectiontype} = 2$
Non-flanged	$TAV_{connectiontype} = 1$
Valve	
Flange x Flange	$TAV_{connectiontype} = 3$
Weld x Flange	$TAV_{connectiontype} = 2$
Weld x Weld	$TAV_{connectiontype} = 1$
Null or Unknown	$TAV_{connectiontype} = 3$

TAV10 = Sum of $TAV_{connectiontype}$ within the PIC; maximum value = 5

Equipment types covered by this Threat includes:

- Fittings
- Valves

Threat Number 11, Control/ relief equipment malfunction
(B31.8S Designation Stable Threat, Equipment)

This threat is not applicable to line pipe segments; however, it applies to pressure controlling and pressure limiting equipment. There has not been a significant history of failures of this type based on DOT reported failures and company leak reports or abnormal operating condition reports. Records of such failures are maintained in accordance with OM&I procedures **GOM&I-GN-GD-001** "Data Gathering for Part 191 Incident Reporting" and **GOM&I-PO-IF-001** "Investigation of Failures". Failure of any control/relief equipment anywhere on the pipeline in question will count toward this TAV score. However, communications failures will not be counted as control/relief equipment failures (i.e. minor power or communication outages).

TAV11 = $Leaks_{cntrl/relief}$ + $Failures_{cntrl/relief}$

Where,

$Leaks_{cntrl/relief}$ = the number of leaks due to equipment failures in on the pipeline in the last 10 years

$Failures_{cntrl/relief}$ = count of the number of leaks or failures resulting in a DOT reportable incident due to equipment failure within the last 10 years

The combined maximum score for any given pipeline segment will be 5.

Leak and failure history more than ten years ago may not be relevant due to equipment or operational changes on the pipeline. Therefore, they are not considered in determining this TAV score.

Equipment types covered by this Threat include:

- Regulators
- Relief Valves
- Over Pressure Protection

Threat Number 12, Seal/pump packing failure
(B31.8S Designation Stable Threat, Equipment)

This threat is not applicable to line pipe segments; however, seals and packing failures may occur on certain types of equipment.

TAV12 shall apply only to locations in an HCA that contain a valve or pump since these contain seals and/or pump packing. Seal or packing failure will not be a Threat of Concern at other locations.

TAV12 = Equipment count within the PIC; maximum value = 5

Equipment types covered by this Threat include:

- Valve
- Compressor
- Regulator

Threat Number 13, Miscellaneous Equipment
(B31.8S Designation Stable Threat, Equipment)

This threat is not directly applicable to line pipe segments; however, it applies to associated equipment that meet the definition of transmission pipeline. This category consists of any equipment other than O-rings, gaskets, seal/pump packing, and control/relief equipment already accounted for in Threat Numbers 10 through 12. Examples of "miscellaneous equipment" include, but are not limited to heaters, compressors, and drips. There has not been a significant history of failures of this type based on DOT reported failures and company leak reports or abnormal operating condition reports. Records of such failures are maintained in accordance with OM&I procedures **GOM&I-GN-GD-001** "Data Gathering for Part 191 Incident Reporting" and **GOM&I-PO-IF-001** "Investigation of Failures".

$TAV13 = Leaks_{othereq} + Failures_{othereq}$

Where,

$Leaks_{othereq}$ = the number of leaks due to equipment failures in on the pipeline in the last 10 years

$Failures_{othereq}$ = count of failures resulting in a DOT reportable incident due to equipment failure within the last 10 years

The combined maximum score for any given pipeline segment will be 5.

Leak and failure history more than ten years ago may not be relevant due to equipment or operational changes on the pipeline. Therefore, they are not considered in determining this TAV score.

Equipment types covered by this Threat include:

- Separators
- Heaters
- Compressors
- Drips

Threat Number 14, Damage inflicted by first, second, or third party, instantaneous (B31.8S Designation Time Independent Threats, Third Party/Mechanical Damage)

The recommended approach to threat evaluation and risk assessment described in ASME B31.8S-2004 Section A7 calls for collection, review, and analysis of statistical data pertaining to vandalism and third party damage that has occurred and pertaining to One-call location request records. One-call records are of little value in that the current dispatching process does not enable each request to be matched with a specific pipeline segment.

A database of underground lines not owned by the company is used to determine proximity of foreign pipelines[2]. Although this database may not include all foreign pipelines, the data points contained within the database are considered reasonably accurate. Therefore, if another underground pipeline crosses or parallels the

[2] http://technology.ky.gov/gis/ Commonwealth of Kentucky, Office of Technology, Division of Graphic Information.

pipeline within 60 feet, there is an increased likelihood of Third-Party Damage due to excavation on that other pipeline.

Government entities have published maps of water and sewer mains to the public;[3] these files are compatible with the company's GIS system. The company will consider the existence of these underground mains within 60 feet of the pipeline to represent a higher risk of Third-Party Damage.

Where such information is currently unavailable, the company considers the threat of third party damage to be directly proportional to the number of building close to each pipeline added to the number of public streets or roads crossing each pipeline. The rational is that for each building near the pipeline and each street crossing there is likely to be one or more underground utility lines crossing or adjacent to the pipeline. Land based data including buildings and road crossings in the proximity of each transmission pipeline is available and reliable. Therefore, building count within 100 feet of the pipeline and road crossings within 60 feet of the pipeline were used to evaluate this threat as follows:

TAV14 = 1 + TAVforeign + TAVroad + TAVbuilding100ft

Where,

TAVforeign = count of pipeline, water, or sewer lines within 60 feet of the pipeline

TAVroad = count of paved roads or highways within 60 feet of the pipeline

TAVbuilding100ft = count of buildings within 100 feet of the pipeline

The combined maximum score for any given pipeline segment will be 5.

Foreign pipelines and other encroachments greater than 60 feet from the pipeline centerline are not considered to increase the threat of Third Party Damage. Standard (non-sub-meter) GPS accuracy is typically +/- 30 feet; therefore, excavation for a facility more than twice this distance from the pipeline is not a great concern.

Although less likely in some areas, Third Party Damage cannot be ruled out as a threat at any location. For this reason, a minimum TAV score of one (1) was assigned.

Third-Party Damage to the high-voltage towers near the pipeline may in turn result in damage to the pipeline. Refer to Threat Number 19 for further explanation regarding electrical ground faults.

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[3] http://kia.ky.gov/wris.data.htm Kentucky Infrastructure Authority, Water Resource Information System (WRIS) Geospatial Data

Threat Number 15, Previously damaged pipe (delayed failure mode)
(B31.8S Designation Time Independent Threats, Third Party/Mechanical Damage)

This threat is a function of number of excavations made over or adjacent to the pipeline and not directly observed by a company gas inspector. This would include utility service line crossings, utility mains and cables, street construction, etc. It would also include land development such as subdivision construction.

For the reasons stated regarding Threat Number 14, the company considers the threat of third party previous damage to be directly proportional to the number of building, pipelines, and underground facilities close to each pipeline added to the number of public streets or roads crossing each pipeline. Therefore, the algorithm used to evaluate the threat of undiscovered previous third party damage is the same numerically as Threat 14. However, a higher TAV score is applied to pipe segments installed prior to 2004 when the Integrity Management Rule took effect. This reflects the less stringent excavation monitoring standards that were in place prior to adoption of current practices.

TAV15 = 1 + (TAVforeign + TAVroad + TAVbuilding100ft) * AgeFactor

Where,

TAVforeign = count of pipeline, water, or sewer lines within 60 feet of the pipeline

TAVroad = count of paved roads or highways within 60 feet of the pipeline

TAVbuilding100ft = count of buildings within 100 feet of the pipeline

Pipeline installed prior to 2004	AgeFactor = 1.5
Pipeline installed 2004 or later	AgeFactor = 1

The combined maximum score for any given pipeline segment will be 7.5.

Threat Number 16, Vandalism
(B31.8S Designation Time Independent Threats, Third Party/Mechanical Damage)

The company will consider any aboveground facility or equipment to have some risk of vandalism. For the purpose of this threat evaluation, “buried pipeline or equipment” refers to facilities that are completely buried and only accessible by excavation. Equipment residing below grade but not completely encased such as a regulator pit would be considered “protected” aboveground equipment.

The company will also consider that any historical vandalism to pipelines or equipment could increase the threat of vandalism occurring again within the same vicinity.

Aboveground pipe or equipment	$TAV_{above/below} = 2$
Buried pipeline or equipment	$TAV_{above/below} = 0$

$Leaks_{vandalism}$ = the number of leaks due to vandalism failures in the pipeline in the last 10 years

$TAV16 = TAV_{above/below} + Leaks_{vandalism}$

Threat Number 17, Incorrect Operational Procedures
(B31.8S Designation Time Independent Threats, Incorrect operations)

This threat addresses operation and maintenance of pipelines to be performed by qualified personnel using O&M procedures that are correct. The company has an effective operator qualification program as prescribed by 49 CFR 192 Subpart N. There are no failures or damages of record to transmission lines attributable to this threat. Any future DOT reportable failures or damages due to Incorrect Operation will affect the TAV score. Records of such failures are maintained in accordance with OM&I procedures **GOM&I-GN-GD-001** "Data Gathering for Part 191 Incident Reporting" and **GOM&I-PO-IF-001** "Investigation of Failures".

TAV17 = 1 + count of leaks or failures resulting in a DOT reportable incident due to incorrect operation

Despite the company's operator qualification requirements, training programs, and track record, accidents and errors cannot be ruled out. Therefore the minimum TAV score for this Threat is 1.0. Because operators are responsible for more than one pipeline within their geographic area, any failures are applied equally for the entire operating center regardless of whether the failure occurred in an HCA.

The Incorrect Operation encompasses both failure to comply with procedures as well as incorrect procedures. However, since incorrect procedures are typically corrected as soon as practical after discovery and since these procedures equally apply to all covered segments, incorrect procedures are not considered in the TAV17 equation.

Threat Number 18, Cold Weather
(B31.8S Designation Time Independent Threats, Weather related and outside force)

Cold weather failures at the company have been limited to regulator failure and operational problems with possible pressure variations but without damage to pipe. There are no failures or damages of record to transmission lines attributable to this threat. However, plastic transmission pipe can be damaged by extreme temperatures outside the manufacturer's specifications or beyond the restrictions in 49 CFR 192.321. Due to the more limited industry historical evidence, a slightly higher default score of two (2) will be used for all plastic pipe.

Frost heave is considered a threat if the pipeline depth is less than or equal to the typical frost line depth. Frost line depths in the area of the Company's pipeline range between two and three feet[4]; therefore, lines with three feet or greater depth of cover are considered not to have a threat due to frost heave.

TAV18 = TAVcold + TAVheave

TAVcold (for metal) = number of reported operational problems due to cold weather on the pipeline in question within the past 5 years.

TAVcold (for plastic) = 2 + number of reported operational problems due to cold weather on the pipeline in question within the past 5 years

Depth of cover < 3 feet	TAVheave = 3
Depth of cover ≥ 3 feet	TAVheave = 0

The combined maximum score for any given pipeline segment will be 5.

Threat Number 19, Lightning
(B31.8S Designation Time Independent Threats, Weather related and outside force)

Lightning damage is generally limited to aboveground equipment and instrumentation. Therefore, the company considers any location with aboveground equipment (i.e. valves, regulators, etc.) at risk.

In addition, based on experiences with downed power lines causing secondary damage to the pipeline and/or pipeline coating, any location within 100 feet of a high-voltage tower will be considered at risk. The company recognizes that electrical ground faults in the vicinity of high-voltage lines are not solely caused by lightning or other weather-related conditions. Third-Party Damage to the tower itself may in turn result in damage to the pipeline. However, since the end result in all cases will be the sudden unforeseen application of very high currents to the pipeline, all threats related to the proximity of high-voltage towers will be handled in this single TAVgf score.

TAV19 = TAVltng + TAVgf

Lightning:

Buried pipelines	TAVltng = 0
Aboveground equipment	
Lightning flash density > 16 flashes per km^2 per year	TAVltng = 5
8 – 16 flashes / year	TAVltng = 3
4 – 8 flashes / year	TAVltng = 2
< 4 flashes / year	TAVltng = 1

[4] Army Corps of Engineers Report EM-1110-1-1905.

Based on five-year flash density maps from the National Weather Service[5], TAVltng will be set equal to 2 for the entire pipeline system. The company considers this five-year average flash density data a more effective benchmark since there can be significant year-to-year variation.

Electrical Ground Faults:

Aboveground equipment	
With a high-voltage tower/pole within 100 feet	TAVgf = 5
Pipelines	
With a high-voltage tower/pole within 100 feet	TAVgf = 2

Threat Number 20, Heavy Rain or Flood
(B31.8S Designation Time Independent Threats, Weather related and outside force)

Those locations in which transmission line segments are vulnerable to damage resulting from heavy rain or flood are inspected frequently during periods of excessive rain or flooding in compliance with 49 CFR 192.705.

Pipeline segments in a flood plain:

Pipeline segments that lie within a High Risk[6] flood plain as determined by the Federal Emergency Management Agency (FEMA):

In flood plain	
Aboveground equipment	TAV20 = 5
Pipeline	TAV20 = 2
Not in flood plain	TAV20 = 0

Pipeline segments that cross a water feature:

Crosses flowing water, river, creek, ditch or stream	TAV20 = 3
With river weights	TAV20 = 1
With cased crossing	TAV20 = 0
Crosses non-flowing water: lake, pond, reservoir or marsh	TAV20 = 2
With river weights	TAV20 = 1

For most water crossings, the heavy rain or flood poses a threat to the pipeline due to stresses from pipe movement. At creeks and ditches, sudden

[5] http://www.lightningsafety.noaa.gov/lightning_map.htm National Weather Service. “U.S. Lightning Map: 5-year flash density (1996-2000)”.
[6] http://www.msc.fema.gov Federal Emergency Management Agency. “FEMA Flood Zone Definitions”.

heavy rains or floods may cause erosion or wash-out conditions which in turn increase the risk of damage to the pipe and coating. A Wash-out or erosion causing plastic pipe to become exposed presents threat as plastic is susceptible to degradation from ultraviolet light. 49 CFR 192.931(g) limits uncased aboveground plastic pipe to a maximum of two (2) cumulative years for this reason. Therefore any unintentional exposures of plastic transmission pipe need to be tracked to ensure code compliance.

If sufficient data exists to prove that a directional bore or other construction method was used to ensure the pipeline is crosses sufficiently below the water feature to eliminate the threat, the **Pipeline Integrity Engineer** may set TAV20 equal to zero (0) for that crossing.

Threat Number 21, Earth Movement
(B31.8S Designation Time Independent Threats, Weather related and outside force)

Appropriate data is not presently available to enable identification of locations in which this threat may present a risk using the integrity management software. However, those locations in which transmission line segments are vulnerable to damage resulting from earth movement are inspected frequently during periods in which excavation is conducted in their proximities, or in periods of excessive rain, flooding, or other natural phenomena that may exacerbate this threat in compliance with 49 CFR 192.705.

TAV21 = TAVquake + TAVblast + TAVsoil

The combined maximum score for any given pipeline segment will be 5.

Earthquakes:

Peak ground acceleration[7]

< 10% g	TAVquake = 0
10 – 20% g	TAVquake = 1
20 – 30% g	TAVquake = 2
30 – 40% g	TAVquake = 3
40 – 60% g	TAVquake = 4
> 60% g	TAVquake = 5

Peak ground acceleration is expressed as a %*g*, with *g* being the gravitational acceleration (32.2 ft/sec^2 or 9.81 m/s^2). Correlations between %g and the Modified Mercalli Intensity Scale were used to determine appropriate TAV levels. The MM scale describes the physical effects of an earthquake. For

[7] http://earthquake.usgs.gov/ U.S.G.S. Earthquake Hazards Program. "National Seismic Hazards Map – 2002: Peak Horizontal Acceleration (%g) with 10% Probability of Exceedance in 50 Years"

example, underground piping will break in a MMIX intensity quake, which correlates to peak accelerations in the range of approximately 65-125% *g*.

Blasting Zones:

TAVblast = count of blasting permits within 500 feet of the pipeline within the past 2 years

Per **GAOP-PO-003** "Blasting in the Vicinity of Pipelines", blasting plans are written and retained for the life of the pipeline for any blasting activities scheduled less than 500 feet from a transmission line. The Company uses recent history (i.e. two years) as a predictor of current and future activity.

Soil Stability:

Sinkhole within 100 feet of the pipeline[8] TAVsoil = 5

All other locations,
TAVsoil = count of Safety Related Condition Reports due to unintended movement

GOM&I-GN-SR-001 "Safety Related Condition Reports" describes requirements for reporting unintended movement or loading that impacts the serviceability of the pipeline. These include the following:

- Cave ins
- Undermining
- Wash outs
- Mud slides
- Mine or other underground void collapse
- Subsidence of the earth

At the discretion of the **Program Manager – Pipeline Integrity** a Safety Related Condition Investigation Report that does not meet the reporting criteria may also be used for this threat evaluation.

Historical Reference: On April 18, 2008 an earthquake of magnitude 5.2 occurred just outside of Mt. Carmel, IL.[9] Tremors could be felt in the Louisville, KY area along with noticeable damage to some above ground structures (i.e. buildings) in the vicinity. Leak Surveys were performed within the HCAs following the earthquake. No leaks caused by earth movement were found.

[8] http://www.uky.edu/KGS/gis/sinkpick.htm Kentucky Geological Survey, University of Kentucky. "Sinkhole Data by County".
[9] http://earthquake.usgs.gov/ U.S.G.S. Earthquake Hazards Program. Earthquake Archives

Threat Number 22, Cyclic Fatigue
(This is not a designated threat in B31.8S)

This is the threat resulting from low frequency internal and external forces acting upon a pipeline. Internal force is the result of gas pressure within the pipeline. External force includes forces transmitted to the pipe through fill dirt at non-encased road crossings, force transmitted through fill in cultivated fields, and forces resulting from thermal expansion or contraction at locations exposed to ambient temperature or varying gas temperature.

Cyclic fatigue may result in cracking if the combined effect of hoop stress from internal pressure and stress from cyclic external loading approach the actual yield strength for the pipe. Dents, gouges, or pipe wall defects that concentrate stress may result in a conservative stress locally approaching or exceeding the yield strength for the pipe material and result in a failure.

Review of leaks and failures and review of operating pressures and resulting stress levels attributed to internal pressure and external loading indicates that cyclic fatigue does not present a significant threat to the integrity of the company's transmission pipelines. The effects of cyclic fatigue have therefore not been incorporated into the risk assessment model used to prioritize baseline assessments for 2004.

The effects of cyclic fatigue will be further evaluated and incorporated into subsequent risk assessment models to the extent applicable based upon Report Number TTO Number 5, "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation", Final Report , Kiefner and Associates, and other recognized authoritative sources as they become identified.

Aside from cyclic fatigue due to internal pressure fluctuations, cyclic fatigue can be attributed to cyclic external stresses. The Company has not identified any features on the system such as suspension bridges which would be susceptible to this threat. Road and railway crossings, whether cased or uncased, are designed to protect the pipeline from cyclic loads. Therefore TAV22 will be set equal to zero (0) for all segments. If a Subject Matter Expert identifies a particular location to be at risk due to cyclic loads exceeding the design parameters, the **Pipeline Integrity Engineer** will override the TAV score for that segment.

4.8.3 Location of Data

Threat	Variable	System	File	Attributes	Quality Control
1- External Corrosion	TAVcoating	Smallworld (Mains)	Gas_Mains.shp	Coating	Audit Log Process
		Smallworld (Mains)	Gas_Mains.shp	Protection	Audit Log Process
	TAVcp	CDPM	CPDM_full_run.xlsx	Structure PS	
	TAVcorrosionleaks	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
2- Internal Corrosion	TAV2	Smallworld (IME)	Oracle Database Connection	Pipeline System	
		Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
3- Stress Corrosion Cracking	TAV3	IRAS		%SMYS	
		Smallworld (Mains)	Gas_Mains.shp	Coating	Audit Log Process
		Smallworld (Mains)	Gas_Mains.shp	Date Installed	Audit Log Process
		Smallworld (IME)	Oracle Database Connection	Operating Temperature	
		IRAS (DataManager)	(via Smallworld)	Within 20mi (Downstream)	
		Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
		Smallworld (IME)	Oracle Database Connection	Pipeline System	
4- Defective Pipe Seam	TAV4	Smallworld (IME)	Oracle Database Connection	Seam Type	
		Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
		Smallworld (Mains)	Gas_Mains.shp	Date Installed	Audit Log Process
		SQL	Server= SQLSCADAHIST, Database= tag_history, table= tag_max_daily	Day	
		SQL	Server= SQLSCADAHIST, Database= tag_history, table= tag_max_daily	TagName	
		SQL	Server= SQLSCADAHIST,	TagID	

Threat	Variable	System	File	Attributes	Quality Control
			Database= tag_history, table= tag_max_daily		
		SQL	Server= SQLSCADAHIST, Database= tag_history, table= tag_max_daily	TagMax	
		Smallworld (IME)	Oracle Database Connection	PT Pressure	
		Smallworld (IME)	Oracle Database Connection	Listed MOP	
5- Defective Pipe	TAV5	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
		Smallworld (IME)	Oracle Database Connection	DefectivePipe	
		Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
6- Defective Pipe Girth Weld	TAV6	Smallworld (IME)	Oracle Database Connection	LGE Inspector	
		Smallworld (IME)	Oracle Database Connection	% Welds ND Tested	
7- Defective Fabfrication Weld	TAV7	Smallworld (Regulators)	Gas_Regulator_Location.shp	Date Installed	
		Smallworld (Compressor)	Gas_Compressor_Location.shp	Date Installed	
		Smallworld (Drip)	Gas_Drip_Siphon_Location.shp	Date Installed	
		Smallworld (Farm Tap)	Gas_Farm_Tap_Location.shp	Date Installed	
		Smallworld (Odorizer)	Gas_Odorizer_Location.shp	Date Installed	
		Smallworld (Over Pressure Protection)	Gas_Over_Pressure_Proctection_Location.shp	Date Installed	
		Smallworld (Heater)	Gas_Pipeline_Heater_Location.shp	Date Installed	
		Smallworld (Separator)	Gas_Separator_Location.shp	Date Installed	

Threat	Variable	System	File	Attributes	Quality Control
8- Wrinkle Bend of Buckle	TAV 8	Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
		Smallworld (IME)	Oracle Database Connection	Wrinkle Bend	
9- Stripped Threads/Broken Pipe/Coupling Failure	IDXDripAge	Smallworld (Drip)	Gas_Drip_Siphon_Location.shp	Date Installed	
	TAVcoupling	Smallworld (Fitting)	Gas_Fitting_Location.shp	Use Class	
10- Gasket/O-ring Failure	TAVconnectiontype	Smallworld (Fitting)	Gas_Fitting_Location.shp	Flanged	
		Smallworld (Valve)	Gas_Valve_Location.shp	Connection Type	
11- Control/relief Equipment Malfunction	Leakscntrl/relief	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
		Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Affected Part	
	Failurecntrl/relief	Smallworld (IME)	Oracle Database Connection	Equip-Regulators	
		Smallworld (IME)	Oracle Database Connection	Equip- Relief Valves	
		Smallworld (IME)	Oracle Database Connection	Equip- OP Protection	
12- Seal/pump Packing Failure	TAV12	Smallworld (Valve)	Gas_Valve_Location.shp	Facility Status	
		Smallworld (Regulators)	Gas_Regulator_Location.shp	Facility Status	
		Smallworld (Compressor)	Gas_Compressor_Location.shp	Facility Status	
13- Miscellaneous Equipment	Leaksothereq	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
		Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Affected Part	
	Failureothereq	Smallworld (IME)	Oracle Database Connection	Equip-Separators	
		Smallworld (IME)	Oracle Database Connection	Equip- Heaters	

Threat	Variable	System	File	Attributes	Quality Control
		Smallworld (IME)	Oracle Database Connection	Equip- Compressor	
		Smallworld (IME)	Oracle Database Connection	Equip- Drips	
		Smallworld (IME)	Oracle Database Connection	Equip- Other	
14- Third Party Damage Immediate	TAVforeign	Smallworld (Foreign Object)	Gas_Foreign_Pipeline_Route.shp	Type	
	TAVroad	Smallworld (Streets)	Land_Street_Route_Line.shp	Classification	
	TAVbuilding100ft	Smallworld (Buildilng_Footprint)	Land_Building_Footprint_Extent.shp	Type	
15- Third Party Damage Delayed	TAVforeign	Smallworld (Foreign Object)	Gas_Foreign_Pipeline_Route.shp	Type	
	TAVroad	Smallworld (Streets)	Land_Street_Route_Line.shp	Classification	
	TAVbuilding100ft	Smallworld (Buildilng_Footprint)	Land_Building_Footprint_Extent.shp	Type	
	Agefactor	Smallworld (Mains)	Gas_Mains.shp	Date Installed	Audit Log Process
16- Vandalism	TAVabove/below	Smallworld (IME)	Oracle Database Connection	Above/Below Ground	
	Leaksvandalism	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
17- Incorrect Operations	TAV17	Smallworld (Gas Leaks)	Gas_Gas_Leaks_Leaks_Location.shp	Cause	
		Smallworld (IME)	Oracle Database Connection	Incorrect Operation	
18- Cold Weather	TAVcold	Smallworld (IME)	Oracle Database Connection	Cold Weather	
		Smallworld (Mains)	Gas_Mains.shp	Material	Audit Log Process
	TAVheave	Smallworld (Mains)	Gas_Mains.shp	Depth	Audit Log Process
19- Lightning	TAVltng	Smallworld (IME)	Oracle Database Connection	Above/Below Ground	

Threat	Variable	System	File	Attributes	Quality Control
		IRAS (RiskAnalyst)	via Flash density map	TAV 19 Threat Assessment Value, Lightning	
	TAVgf	Smallworld (IME)	Oracle Database Connection	Above/Below Ground	
		IRAS (DataManager)	via Electric Tranmission GPS	High Voltage Pole	
20- Heavy Rain or Flood	TAV20	Smallworld (IME)	Oracle Database Connection	Above/Below Ground	
		Federal Emergency Management Agency	fema_q3_FloodPlain.shp	Zone	
		Smallworld (Hydrology Extent)	Land_Hydrology_Extent.shp	Type	
		Smallworld (Hydrology Route)	Land_Hydrology_Route_line.shp	Type	
		Smallworld (casings)	Gas_Casing_Route_Location.shp	Facility Status	
		Smallworld (River weights)	Gas_River_Weight_Location.shp	Facility Status	
21- Earth Movement	TAVquake	USGS Earthquake Hazard Program	5hz10pct_p.shp	PERCENT_G	
	TAVblast	Smallworld (IME)	Oracle Database Connection	Blasting	
	TAVsoil	Kentucky Geological Survey	kentucky_sinkholes.shp	FID	
		Smallworld (IME)	Oracle Database Connection	Soil Stability/Safety	
22- Cyclic Fatigue	TAV22	IRAS (DataManager)	via SME	Integrity Engineer Cyclic Fatigue Score	

4.9 ADDRESSING PARTICULAR THREATS PER §192.917(E)

4.9.1 Initial Threat Evaluation

Regulation 49 CFR 192.917 (e) states specific requirements for addressing the threat categories (1) Third party damage, (2) Cyclic fatigue, (3) Manufacturing and construction defects, (4) ERW pipe, and (5) Corrosion. The software utilized by the company was programmed to group the applicable threats into these categories, applying scaling factors which take into account the prevalence of each threat for each pipeline segment for preliminary threat evaluation and subsequent risk assessment and prioritization for baseline assessment in 2004. The algorithms described in 4.8 of this section were applied for this purpose.

4.9.2 Continuing Threat Evaluation

The initial threat evaluation (and risk analysis) used to prioritize and schedule baseline assessments prior to the completion of this written program were developed based upon the knowledge and resources available to the company at the time. The algorithms and processes used shall be subject to continual review and improvement as additional knowledge and resources become available.

Sources of information and data for continual improvement include but are not limited to the following:

- Codes and standards incorporated by reference in 49 CFR Part 191 as applicable.
- Research reports sponsored by AGA, RSPA, or other organizations recognized and respected by regulatory compliance authorities and gas industry officials.
- Letters of interpretation issued by RSPA in response to frequently asked questions (FAQs) or individual requests for interpretation.
- Feedback from inspections performed as a result of prior threat evaluation and risk analysis.
- Operating experience and related knowledge of employees and contractors pertinent to the threats being considered.
- Professional and academic qualifications of employees and contractors.
- Recognized gas industry consultants.
- Recognized gas service and software vendors.
- Operating data and inspection data accumulated after the start of the PIM program.
- Knowledge and data received from other gas operators.
- Corrosion control data referenced in OM&I Procedures under the Corrosion Control category (AC-001, EC-001, EC-002, EC-003, IC-001, RM-001) and stored in the Pipeline Compliance System software.
- Leak data referenced in OM&I Procedure GOM&I-PO-007 and stored in the Smallworld GIS.

- Continuing Surveillance data referenced in OM&I Procedure GOM&I-PO-CS-001.

Review of the processes, algorithms, and data shall be as frequent as deemed necessary to accommodate changes or noted deficiencies, but typically shall occur at least once each calendar year.

4.9.3 Assessment, Prevention and Mitigation Considerations

See Section 6.0 and 12.0 of this written plan for pipe inspection methods and preventive and mitigative actions respectively.

Revision Log:

Date	Significant Changes	Revised By
Nov 2 Thru Dec 3, 2004	Initial changes to GIE / Northeast Gas written program, includes: • Formatting, including Table of Contents page for section • Rename responsible positions per Section 2 • Replace "Company" with "LG&E Energy" • Add 49CFR Part 192 reference to 4.3 • Remove Table 4-1 • Introductory paragraph 4.4 and 4.4.1 replaced with new 4.4.1 • New Tables 4-1A and 4-1B inserted in 4.4.4 • 4.4.2 renumbered as 4.4.3 • New paragraph 4.4.4 added • Entire subsection 4.5 replaced, including new Figure 4 -2. • Entire subsection 4.6 replaced • Entire subsection 4.7 replaced including Figure 4-3 • Entire subsection 4.8 replaced • Entire subsection 4.9 replaced, process flow diagrams removed, to be inserted later. • Subsection 4.10, Form 3-1 replaced	Oelker Augustine Eder
12/02/2004	Final Section signed and approved by management.	CMA
6/27/2007	LG&E Energy logo replaced with LG&E/ E.ON|US logo	CMA
6/27/2007	Company name "LG&E Energy" changed to "Louisville Gas & Electric/Kentucky Utilities" and referenced as "the company" throughout the section.	CMA
6/27/2007	In section 4.6.3, noted that Plexus changed its name to Plexos International	CMA
8/7/2007	In section 4.5.3, inserted explanation for default values. Inserted 'Pipeline Data Default Summary' as Appendix 4A. Updated TOC	CMA
10/22/07	Revised TAV 4 per recommendation from consultant to include all vintages of ERW pipe, not only pre 1970. Removed calculations related to TAV4 with respect to "a few pounds over MAOP" that was interpreted as 105% of MAOP.	LCO / RNE
3/31/2008	Changes to TAV process including: • Replaced LG&E with "the company" • Updated references from ASME B31.8S-2001 to ASME B31.8S-2004 • Update Tables 4-1-A & 4-1-B to agree with	CMA/ RNE / EN Engineering

	revised threat descriptions in Section 4.8.1 • Replaced Table 4-2 to match ASME B31.8S & ASME B31.8S Appendix A • Added 4.5.3.3 describing data download process for external sources • Revised 4.6.4 to address Equipment threats • 4.8.1, Step 1: Added sentence describing dynamic segmentation of HCA data; eliminated possible TAV score of 1000 since no longer used in equations. • 4.8.2, Threat 1 reworded • 4.8.2, Threat 2 reworded; deleted Figure 4.5 • 4.8.2, Threat 3 revised include both high pH & near neutral SCC. • 4.8.2, Threat 4 revised to include all low-frequency ERW pipe as well as A.O.Smith flash-welded pipe. Eliminated Figure 4.6 • 4.8.2, Threat 5 revised & added TAV equation • 4.8.2, Threat 6 deleted Figure 4.7 • 4.8.2, Threat 7 revised to include fabrication welds other than drips • 4.8.2, Threat 8 added TAV equation and deleted paragraph stating an algorithm will be developed. • 4.8.2, Threat 9 revised to include couplings besides those on drips; revised TAV equation • 4.8.2, Threats 10 through 13 added TAV equations and explanation • 4.8.2, Threats 14 & 15revised to include additional data sources; modified TAV equations to include information other than building counts and road crossings. • 4.8.2, Threats 16 - 21 added TAV equations and explanations. • 4.8.2, Threat 22- Historical reference to April 18, 2008 earthquake inserted. • 4.8.2, Threat 22 included more detailed explanation why TAV22 set to zero. • Added additional data sources to 4.9.2 "Continuing Threat Evaluation"	
11/18/2008	11.18/2008 Final Version signed and approved by management.	LCO
6/19/2009	4.4.3 Reworded section regarding Plastic Transmission Pipe	EN Engineering
6/19/2009	Table 4-1A: added column for Plastic Pipe applicability	EN Engineering
6/19/2009	Table 4-1B: Updated with Plastic Pipe applicability	EN Engineering
6/19/2009	4.5.3.2 Added sentence regarding continual data updates	EN Engineering
6/19/2009	4.8.2 Threats 1, 2, & 3 – specified "metal pipe" and added statement that plastic pipe	EN Engineering

	is not susceptible	
6/19/2009	4.8.2 Threat 3 – added paragraph about Environmental Stress Cracking (ESC) and assigned TAV scoring for plastic pipe. Considered this in the same threat category as SCC on metal pipe.	EN Engineering
6/19/2009	4.8.2 Threat 4 – reworded explanation of 5-yr historical maximum pressure for HCAs and revised TAV scores accordingly.	EN Engineering
6/19/2009	4.8.2 Threat 5 – added separate TAV scoring for metal vs. plastic pipe	EN Engineering
6/19/2009	4.8.2 Threat 6 – considered electrofusion or heat fusion joints on plastic pipe equivalent to traditional girth welds on metal pipe for the purpose of TAV6.	EN Engineering
6/19/2009	4.8.2 Threat 8 – added explanation of acceptable bend radius for plastic pipe	EN Engineering
6/19/2009	4.8.2 Threat 9 – added statement that mechanical couplings can apply to metal or plastic pipe.	EN Engineering
6/19/2009	4.8.2 Threat 18 – added separate TAV18 scoring for plastic pipe along with a brief explanation	EN Engineering
6/19/2009	4.8.2 Threat 20 – added statements regarding code requirements for exposed plastic pipe.	EN Engineering
9/3/2009	4.8.2 Threat 10 – changed IDXGasket to TAVconnectiontype	CMA
9/3/2009	4.9.3 Continuing Threat Evaluation – added a paragraph allowing exceptions to threat and risk equations if software is not capable of performing equations written within the plan.	CMA
9/3/2009	4.4.3- This section changed to indicate that the company has plastic transmission pipe.	CMA
9/3/2009	TAV16- review for potential improvement the algorithm for TAV16 vandalism to count leak objects with the cause code of 612-vandalism.	CMA
9/3/2009	TAV2- Add MAGDEEP TAV2= 5.0	CMA
9/3/2009	Section 4.9.2 - Continuing Threat Evaluation. Added paragraph regarding current status of threat equations within risk analysis software	CMA
9/3/2009	Add “Unknown; TAV=5” to Threat 16-Vandalism	CMA

9/3/2009		Removed the index scores and apply the scores to the connection type. (ie remove "IDXGasket")	CMA
9/3/2009		Added Appendix 4B – Threat Equation Status.	CMA
10/1/2010		Section 4.9.2 - Continuing Threat Evaluation. Removed paragraph regarding current status of threat equations within risk analysis software	CMA
10/1/2010		Removed Appendix 4B – Threat Equation Status.	CMA
11/1/2011		Moved Form 4-1 to section 9 and renamed to Form 9-6.	CMA
10/18/2012		Removed references to the Proper Nouns of software systems and replace with generic names. Specifically, 'Optika', 'Smallworld', and 'Plexos'	CMA
10/18/2012		Removed all references to pipe data being stored in a 'Pipeline Integrity' spreadsheet and database. This spreadsheet was retired in 2011 and all the data is retained in the GIS.	CMA
12/5/2012		Updated section 4.9.2 to indicate that continual evaluation typically occurs each calendar year.	CMA
3/15/2013		Updated Threats 4-9	JRG
10/07/2013		Update TAV16 algorithm.	CMA
9/12/2014		Revised TAV4 for clarity. No changes were made to the algorithm.	CMA
11/10/2015		Section 4.5.2, Inserted "Gas High Pressure Data Sheets" and "As-Built Drawings" as a data sources.	CMA
11/10/2015		Section 4.5.2, reordered the data sources as they appear in the IME (Smallworld). Any data source not specifically listed in the	CMA

		IME was grouped under "Miscellaneous Data Sources"	
11/10/2015		Section 4.5.2, add information about the Integrity Management Editor (IME).	CMA
11/10/2015		Section 4.5.2, removed language about incorporating new data via the MOC process.	CMA
11/10/2015		Section 4.5.3.1, moved paragraph "For the initial…system demand" from section, 4.6.2	CMA
11/10/2015		Section 4.6.2, removed language about station number. Station numbering is no longer used.	CMA
11/10/2015		Section 4.6.3, update section to better describe the database assembly for company risk software.	CMA
11/10/2015		Section, 4.6.4, removed sentence that claimed that data collection for equipment is similar to line. Data collection is performed on equipment but not similar to line pipe.	CMA
11/10/2015		Section 4.6.5, removed paragraph stating that company uses relative stationing.	CMA
11/10/2015		Section 4.7.2, inserted paragraph describing the audit log process.	CMA
12/15/2015		Inserted Section 4.8.3- Location of Data	CMA

4A APPENDIX A

Pipe Data Default Summary

Time Span			Spec.	Grade	Seam	Wall	Press @ 100%	Long Joint Factor	Design Class 3
1" Pipe	**(1.315" O.D.)**								
Unkown			API 5L	A25	CW	0.133	5057	0.6	1517
1951	to	2003	API 5L	A25	CW	0.133	5057	0.6	1517
2" Pipe	**(2.375" O.D.)**								
Unkown			API 5L	A25	CW	0.154	3242	0.6	973
1951	to	2003	API 5L	A25	CW	0.154	3242	0.6	973
4" Pipe	**(4.500" O.D.)**								
Unkown			API 5L	A25	CW	0.237	2633	0.6	790
1951	to	1956	API 5L	A25	CW	0.237	2633	0.6	790
1957	to	1959	API 5L	Class I	CW	0.237	2633	0.6	790
1960	to	1978	API 5L	B	ERW	0.219	3407	1.0	1703
1979	to	2003	API 5L	B	ERW	0.188	2924	1.0	1462
6" Pipe	**(6.625 " O.D.)**								
Unknown			API 5L	B	ERW	0.188	1986	1.0	993
1951	to	1978	API 5L	B	ERW	0.219	2314	1.0	1157
1979	to	1983	API 5L	B	ERW	0.188	1986	1.0	993
1984	to	2003	API 5L	X42	ERW	0.188	2384	1.0	1192
8" Pipe	**(8.625" O.D.)**								
Unknown			API 5L	B	ERW	0.188	1526	1.0	763
1951	to	1953	API 5L	A	ERW	0.277	2698	1.0	1349
1954	to	1955	API 5L	B	ERW	0.277	2248	1.0	1124
1956	to	1957	API 5L	B	ERW	0.250	2029	1.0	1014
1958	to	1959	API 5L	B	ERW	0.188	1526	1.0	763
1960	to	1979	API 5L	B	ERW	0.219	1777	1.0	889
1980	to	1983	API 5L	B	ERW	0.188	1526	1.0	763
1984	to	2001	API 5L	X42	ERW	0.188	1831	1.0	915
12" Pipe	**(12.375" O.D.)**								
Unknown			API 5L	B	ERW	0.250	1373	1.0	686
1951	to	1954	API 5L	B	ERW	0.330	1812	1.0	906
1955	to	1962	API 5L	B	ERW	0.250	1373	1.0	686
1963	to	1982	API 5LX	X42	ERW	0.219	1443	1.0	721
1983	to	2003	API 5L	X42	ERW	0.219	1443	1.0	721
16" Pipe	**(16.000" O.D.)**								
Unknown			API 5L	B	ERW	0.250	1094	1.0	547
1951	to	1966	API 5L	B	ERW	0.250	1094	1.0	547
1967	to	1982	API 5LX	X42	ERW	0.250	1313	1.0	656
1983	to	2003	API 5L	X42	ERW	0.250	1313	1.0	656
20" Pipe	**(20.000" O.D.)**								
Unknown			API 5L	B	ERW	0.250	875	1.0	438
1951	to	1967	API 5L	B	ERW	0.250	875	1.0	438
1968	to	1982	API 5LX	X42	ERW	0.250	1050	1.0	525
1983	to	2003	API 5L	X42	ERW	0.250	1050	1.0	525

5 RISK ASSESSMENT & PRIORITIZATION §192.917(c)

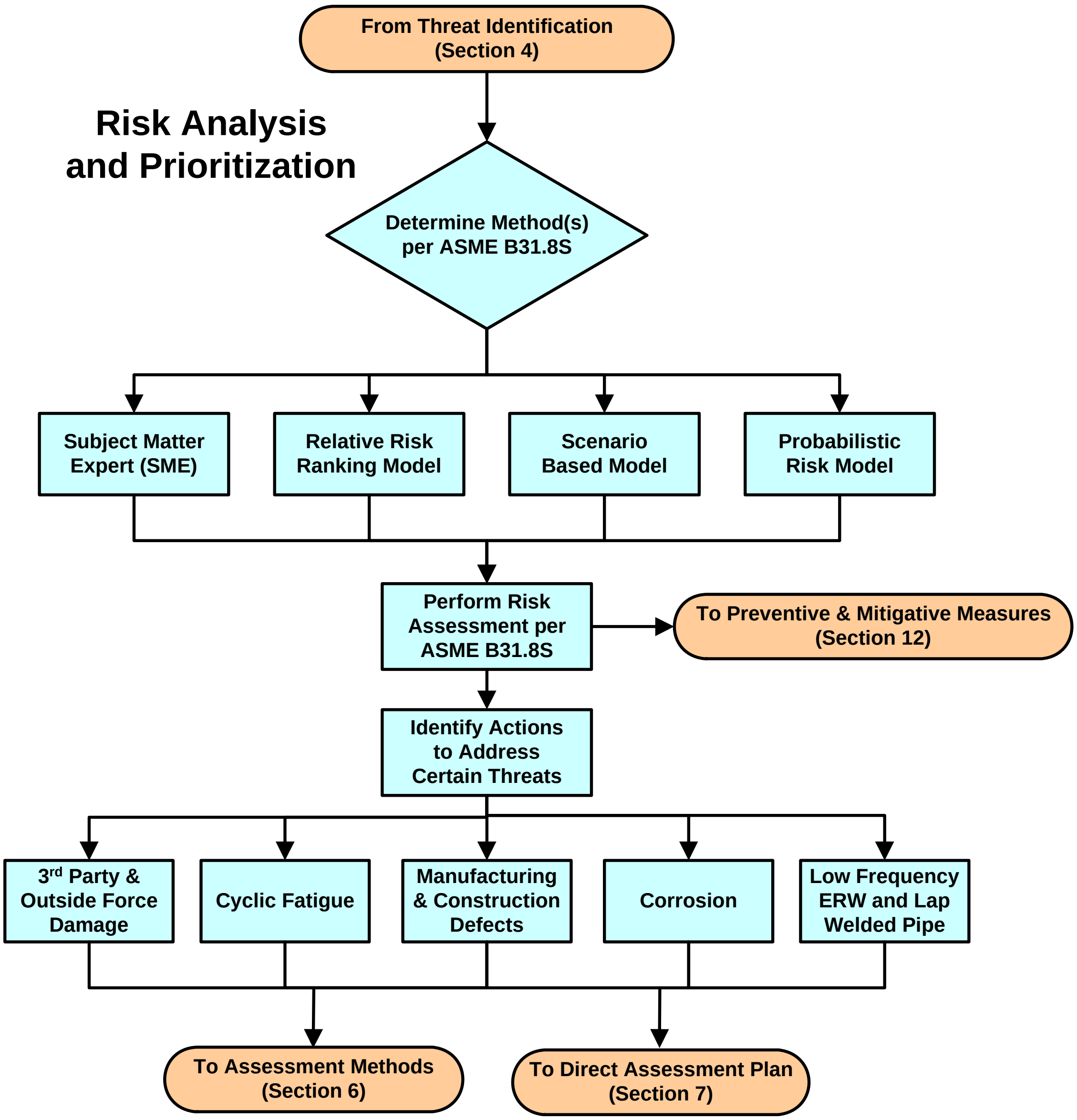
(Reference: ASME B31.8S Section 5)

In This Section

Referenced Protocols

5 RISK ASSESSMENT & PRIORITIZATION

5.1 OVERVIEW



Source: OPS Website

5.1.1 Purpose

This Section describes available risk assessment (risk analysis) approaches under the rule and the method(s) selected by **Louisville Gas & Electric/ Kentucky Utilities** (the company) to satisfy these requirements. It also describes how all identified "threats of concern" from Section 4 will be used in the risk assessment process.

The risk assessment process is used to prioritize the covered segments for use in the Baseline Assessment (Section 8), the evaluation of Preventive and Mitigative Measures (Section 12), and the Continual Assessments (Section 13) in the future.

5.1.2 Responsibility

The **Program Manager – Integrity Management** M1 has overall responsibility for the performance of these procedures and for any modifications to this Section. The **Program Manager – Integrity Management** M1 is also responsible for the development and maintenance of **the company's** selected risk assessment method(s).

5.2 DEFINITIONS

The following defined terms have been used in this Section.

Covered Segment

A Covered Segment means a segment of gas transmission pipeline located in a high consequence area (HCA).
Ref alternate definition in Appendix 1B

Risk

Risk is a measure of potential loss in terms of both the incident probability (likelihood) of occurrence and the magnitude of the consequences.
Ref alternate definition in Appendix 1B

Risk Assessment

Risk Assessment is a systematic process in which potential hazards from facility operation are identified, and the likelihood and consequences of potential adverse events are estimated. Risk assessments can have varying scopes, and be performed at varying level of detail depending on the operator's objectives.
Ref alternate definition in Appendix 1B

Risk Management

Risk Management is an overall program consisting of: identifying potential threats to an area or equipment; assessing the risk associated with those threats in terms of incident likelihood and consequences; mitigating risk by reducing the likelihood, the consequences, or both; and measuring the risk reduction results achieved.
Ref alternate definition in Appendix 1B

Consequence

A Consequence is the impact that a pipeline failure could have on the public, employees, property or the environment.
Ref alternate definition in Appendix 1B

Risk Variable

A Risk Variable is a root cause, contributing cause, or influence of each failure and consequence type.

Attribute

An Attribute is a quality or characteristic which is inherent to the pipeline system or the risk assessment process.

Risk Score

A Risk Score is the relative risk or ranking result, which has been determined from implementing the selected risk assessment method.

Subject Matter Expert

A Subject Matter Expert is an individual that has expertise in a specific area of operation or engineering.
Ref alternate definition in Appendix 1B

5.3 RISK ASSESSMENT

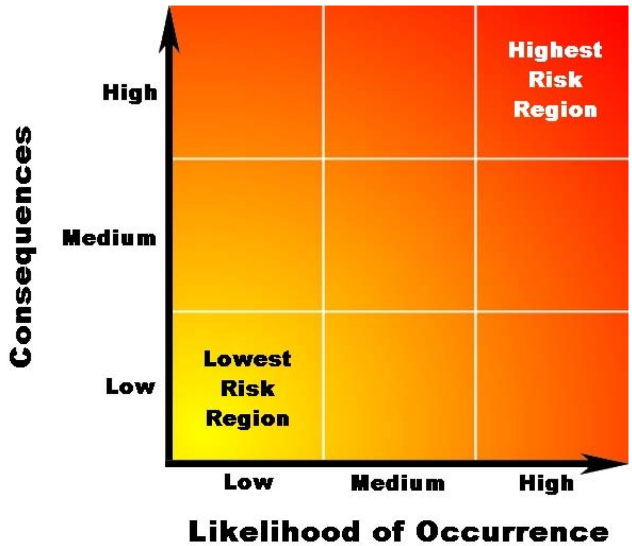
Risk can be characterized as the product of two primary components, the "likelihood" that an adverse event will occur, and the resulting "consequence" if it does. This basic concept can also be reflected in the expression below [Ref: B31.8S Section 5.2].

For a Single Threat $\text{Risk}_{i} = \text{P}_{i} \text{ x } \text{C}_{i}$

For a Covered Segment $\text{Risk} = \sum_{i=1}^{9} (\text{P}_1 \text{ x } \text{C}_1) + (\text{P}_2 \text{ x } \text{C}_2) \ldots. (\text{P}_9 \text{ x } \text{C}_9)$

where:

P = likelihood of failure
C = Consequence of failure
1 to *9* = failure threat category (prescriptive method)



5.3.1 How the Risk Assessment is Used

Information from the risk assessment process is used in the following key sections of this IMP document to prioritize covered segments.

- Section 8: Baseline Assessment Plan
- Section 12: Preventative and Mitigative Measures
- Section 13: Continual Evaluation and Reassessments

5.3.2 Prescriptive vs. Performance Based

The risk assessment and prioritization portion of the IMP can be performed using either a prescriptive based or a performance based approach. **The company** has selected the prescriptive approach which is the basis of this integrity management program.

Prescriptive Approach [The basis of this IMP Document]

A risk assessment performed using a prescriptive based approach is based upon the nine threat “categories” listed in Section 4 which are used to prioritize the covered pipeline segments. The data sets specified in Appendix A of B31.8S are used to perform the prescriptive based risk assessment.

A prescriptive based risk assessment can not be used to increase the prescriptive re-inspection intervals [Ref: Section 13]. The following four risk assessment methods are appropriate when a prescriptive based approach is used with the prescriptive re-inspection intervals.

- Subject Matter Experts (SME) Method
- Relative Risk Assessment Model
- Scenario Based Model

- Probabilistic Model

Performance Based Approach

A risk assessment performed using a performance based approach uses the 22 “individual” threats listed in Section 4 to prioritize the covered pipeline segments. This method will typically require a broader and more complex range of data then those specified in Appendix A of B31.8S. A performance based risk assessment approach must be able to address this expanded data set. This approach may also be used to establish and technically justify re-inspection intervals.

5.4 RISK ASSESSMENT METHODS

Under the rule each operator is responsible for selecting an appropriate risk assessment method(s) which meets the needs of the operator's integrity management program. More than one risk assessment method may be used throughout the pipeline system.

Any risk assessment method considered should include the following key features.

- Ability to match the assessment method to the level of information available
- Ability to thoroughly document data inputs
- Ability to provide a means of "what if" analysis
- Ability to validate risk assessment results

The risk assessment methods discussed in this section all have the following common components which can:

- Identify potential events of conditions that could impact system integrity
- Evaluate the likelihood of failure and the resulting consequences
- Allow risk ranking and identification of specific threats that drive risk
- Lead to the identification of preventive and mitigative options
- Provide a data feedback mechanism
- Provide structure and continuous updating for reassessments of risk

5.4.1 Subject Matter Experts (SME) Method

The Subject Matter Expert Method utilizes the extensive experience and institutional knowledge of the operating company's personnel, contractors, and consultants. This knowledge and experience is then combined with information from relevant technical industry publications.

This approach can be combined with a simple relative risk matrix to determine a relative value. SME's are used to analyze each pipeline segment, and to assign a relative likelihood and consequence to determine a relative risk value for each of the 9 threat categories.

These values are then aggregated to determine a total risk score for the segment. The risk scores from each segment are then used to prioritize all covered segments on the pipeline system.

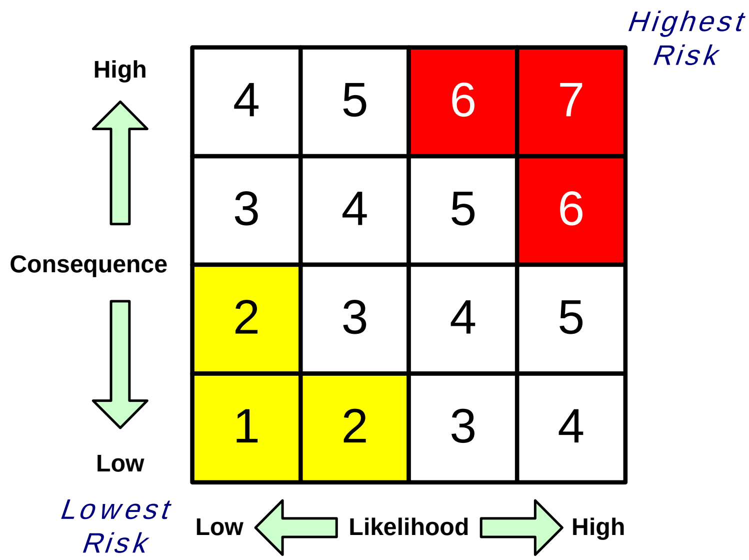


Figure 5-2: Simple Relative Risk Matrix

For a Single Threat: $\text{Risk}_i = P_i \times C_i$

For a Covered Segment: $\text{Risk} = \sum_{i=1}^{9} (P_1 \text{ x } C_1) + (P_2 \text{ x } C_2) \ldots . (P_9 \text{ x } C_9)$

where:

P = likelihood of failure
C = Consequence of failure
1 to *9* = failure threat category (prescriptive method)

An organized, structured, and thoroughly documented process is important to assure a consistent analysis that is reproducible.

Some Operators may consider this method when there are relatively few pipeline segments to consider.

Advantages

The SME approach can be implemented rather easily without an extensive infrastructure for risk assessment.

Disadvantages

The SME approach can be labor intensive for key personnel since they tend to be the most knowledgeable on the pipeline system. The method also introduces subjectivity, which will require a structured and well-documented process to ensure reproducibility.

5.4.2 Relative Risk Ranking Model

The Relative Risk Ranking Model builds on pipeline specific experience and significant data to develop the risk models. These models use algorithms to address known threats on the pipeline system which have historically impacted pipeline operations.

This type of model identifies and quantitatively weights the major threats and consequences relevant to past operations. The weightings are based upon a range of values (minimum to maximum) and the relative importance of each item.

The approach is considered a relative risk model since the results are compared with other results from the same model. The value generated is a unitless number, which can provide a relative comparison to other results from the same model to produce a relative risk ranking. The generated values are only meaningful relative to each other.

The model uses these algorithms to objectively quantify major threats and consequences on the pipeline system.

Operators of medium to larger transmission systems may consider this method when many pipeline segments must be considered, and there is a need for extensive "what if" analysis.

Advantages

A properly tuned Relative Risk Ranking Model tends to be more objective than the SME Method. The model is also well suited for extensive "what if" analysis to determine the impacts of preventive and mitigative measures.

Disadvantages

The Relative Risk Ranking Model is more difficult to implement than the SME method and will require more pipeline specific system data.

LG&E Risk Ranking Model

The analytical model developed by the company, and installed by the company in their integrity management software is a relative risk ranking model. The company maintains the option of utilizing the subject matter expert approach as a primary risk ranking method for segments of an isolated pipeline system, or as a validity check when reviewing relative rankings determined by the integrity management software based upon relative risk ranking algorithms.

5.4.3 Scenario Based Model

The Scenario Based Model generates a description of a hypothetical event or a series of events, which leads to a determined level of risk. This type of model includes the generation of both the likelihood and the consequences of such events based upon input from SME's and system data. This method usually includes the construction of event trees, decision trees, and fault trees from which appropriate risk values can be determined.

Under this method the "most probable" or "most severe" pipeline scenarios are typically envisioned. The resulting damages are then estimated, and preventive and mitigative measures are considered.

Operators of smaller transmission systems may consider this method when there are relatively few pipeline segments to consider, and if the operator has extensive experience utilizing event trees, decision trees, and fault trees. This will typically not be the best choice for most operators.

Advantages

The scenario-based approach typically utilizes event trees, decision trees, and fault trees for those operators with extensive experience with these tools.

Disadvantages

This approach is scenario-based and is dependent upon the operator selecting each appropriate failure mode for every threat combination. Although a very structured method within each scenario selected, it can be subjective based on the scenarios selected by the operator. This method can also produce a large quantity of scenarios that may be difficult to successfully manage, update, and perform "what if" analysis.

5.4.4 Probabilistic Risk Model

The Probabilistic Risk Model is the most complex and demanding of the four methods mentioned with respect to data requirements. Models are constructed to describe the probability of specific events leading to failure. The probabilities of the event occurring are based upon available operating experience and system data.

The results of the Probabilistic Risk Model are provided in a format that is compared to acceptable risk probabilities that have been established by the operator. The results are typically expressed as a probability of the event occurring (e.g. = $1x10^{-6}$)

Advantages

The Probabilistic Risk Model expresses the results in terms of probabilities which may be desired by some operators (e.g. probability of the event occurring = $1x10^{-6}$).

Disadvantages

The Probabilistic Risk Model can be difficult to implement, and is very data intensive.

5.5 CHARACTERISTICS OF AN EFFECTIVE RISK ASSESSMENT

Several general characteristics exist that will contribute to the overall effectiveness of any risk assessment approach. These characteristics were considered during the selection of a risk assessment approach. These characteristics include:

Attributes

Specific attributes which are used to assist in defining the logic and structure of the risk assessment method which assure a complete, accurate, and objective analysis of the risk. Knowledge based systems such as the SME Method are typically easier to apply but they require more time from the Subject Matter Experts.

Resources

Sufficient time, personnel, and funding have been allocated to implement the selected risk assessment method.

Operating / Mitigation History

The frequency and consequences of previous events are considered for the pipeline system, as well as other pertinent industry data. Updates are performed based upon the preventative, mitigative, and corrective actions taken.

Predictive Capability

The risk assessment method can identify integrity threats not previously considered through the integration of data. This integration may also include the trending of various results from inspections, examinations, and evaluations over time to predict future conditions.

Risk Confidence

Risk data used in the risk assessment method is checked for accuracy as part of the program's quality assurance. When missing or questionable data exists, conservative default values are established until more accurate and reliable data can be obtained.

Feedback

A feedback mechanism is used as a process for continual improvement and a validation of the method selected.

Documentation

The approach is thoroughly documented explaining the technical basis for the method, the procedures used, and the impacts on risk determinations.

"What If" Determinations

A structure is in place to perform "what if" determinations to see the potential impacts of preventative and mitigative measures being considered.

Weighting Factors

A structured set of weighting factors exist to indicate the value of each risk assessment component both failure probability and consequences.

Structure

A structure with the ability to compare and rank the risk assessment results to support the IMP decision process and identify the primary risk drivers the most influence on results.

Segmentation

A structure exists which provides sufficient resolution of a pipeline segment to adequately analyze the data along the pipeline. The structure is used to assist in the determination of high risk areas. The ability exists to update segments where preventive and mitigative measures have been taken.

5.6 LG&E'S RISK ASSESSMENT APPROACH

✓ ***Referenced Protocol:*** ***C.4 Risk Assessment***
C.5 Characteristics of an Effective Risk Assessment Approach

This following describes **the company's** objectives in selecting a risk assessment approach which have been used to establish an overall scope and approach.

5.6.1 Objectives

The company has determined it will be using a prescriptive based approach, and has established the following objectives. The method should be able to:

- Address the "threats of concern" identified in section 4
- Accommodate the level of available information
- Provide a structured approach
- Thoroughly document and maintain data inputs and attributes
- Provide objective results which are reproducible
- Determine a relative risk score to be used in risk ranking
- Accommodate pipeline segmentation to evaluate the risks
- Consider frequencies and consequences of previous events
- Perform "what if" analysis based upon preventive and mitigative measures considered
- Provide a means of feedback to validate risk assessment results
- Provide results to be used for risk mitigation and decision making processes

- Assess the impact from modified inspection intervals
- Assess the use or need for alternative inspection methods
- Allow for more effective resource allocation
- Determine the most effective preventive and mitigative measures for the identified threats.

These objectives have been considered in selecting **the company's** risk assessment method.

5.6.2 Selected Risk Assessment Method(s)

The company has reviewed the four risk assessment methods described subsection 5.3.2 of this document and has selected the Relative Risk Ranking approach to analyze and prioritize its risk assessments.

The company uses a pipeline risk analysis software to perform risk assessments on its covered pipeline segments. This software is programmed with the algorithms outlined in section 4 and this subsection of the IMP.

5.6.3 Characteristics of the Risk Method(s)

The purpose of the risk analysis software model as is to provide a framework for **the company** to evaluate and compare the diverse parts the pipeline system on the basis of relative risk. The results of these evaluations can be used to priority rank the covered segments in the baseline assessment plan, evaluate preventative and mitigative measures, and perform continual evaluations and reassessments.

The risk analysis software has been customized for use by the company based on the existing data for its gas transmission lines. **The company** has determined that sufficient data exists to adequately support this risk model. The system data is stored in the GIS, and the Pipeline Compliance System software for documentation. Individual risk algorithms calculate the risk with respect to each threat. An overall risk algorithm for the relative risk for each distinct covered segment within the pipeline system is then computed.

The segments are defined in the GIS with each segment consisting of uniform characteristics or attributes along its length and catalogued uniquely by the GIS System ID number. **The company** has established its segments based upon changes in key attribute data to ensure sufficient resolution exists to perform a meaningful risk assessment.

The Pipeline Integrity Engineer will rank all HCAs by relative risk, determine the factors that drive the risk, and evaluate the effects of risk reduction through preventive and allow for mitigative measures using "what if" analysis.

The risk analysis software model uses custom mathematical equations which utilize the pipeline attributes, environmental factors, and mitigative responses to calculate the relative likelihood of failure. The higher the resulting score, the more likely it is that a failure could occur.

Since the format and weighting factors that characterize the equations are based on a combination of expert judgment, experience, and technical knowledge, the model provides relative risk rankings of the likelihood of failure rather than the true mathematical probability of failure.

When the required data is either missing or questionable, **the company** will use the most conservative value or weighting in the range (minimum to maximum) of values for the parameter. As additional data is obtained these default values will be updated to reflect actual data.

The model uses mathematical equations to represent the degree of exposure of people and property to the potentially damaging effects of a pipeline failure. The consequence equations may also address the impact of loss of service to customers. The risk of failure from any particular threat is assumed to be the likelihood of failure from the threat, times the conceivable consequences of the failure. The total risk of failure for a segment is calculated as the sum of the risks for each threat.

5.6.4 Prioritization

The total risk for each segment is a relative number. The higher the number, the higher the relative risk. This relative risk score assists in the decision making process by allowing the covered segments to be ranked according to relative risk and ultimately developing a prioritized list of covered segments.

Through the use of "what if" analysis, **the model could** determine the impacts of preventive and mitigative measures in terms of relative risk. Since the model considers the benefits of these risk reduction actions, various scenarios can be examined to determine the various degrees of risk reduction achievable.

The company will recalculate and update the risk model to reflect new information obtained (including information from completed integrity assessment or mitigative actions) on the affected covered segments on an annual basis. However, if new pertinent information becomes available, a new risk model may be recalculated at any time.

Once the risk reduction actions have been implemented, **the company** can use the model to re-rank the covered segments based upon the resulting relative risk.

The company also uses the processes described in Section 4 – Threat Identification and Section 14 – Management of Change, to provide regular updates to the risk assessment process. The processes in Section 4 are designed to provide pertinent information from field reports and along with quality assurance of the data from the **Engineer(s)** F2. **The company** captures other changes that could impact the integrity of the pipeline system through the Management of Change process which is employed on a system wide basis.

5.6.5 Validation of the Risk Method(s)

✓ ***Referenced Protocol:*** ***C.6 Validation of the Risk Assessment***

To ensure the successful use of the selected risk assessment method, **the company** will provide adequate data sets, use appropriate structured algorithms, and assure the algorithms are properly tuned and validated. The ability to correctly identify the most critical segments depends on the validity and completeness of the system data, and the extent to which the algorithms reflect the true effects of the controlling factors. Additional fine tuning will occur over time as actual data is used to validate the accuracy of the model.

5.6.6 Risk Considerations of Specific Threats

The risk considerations for the following specific threat categories have been addressed in Section 4 – Threat Identification.

- Third Party and Outside Force Damage
- Cyclic Fatigue
- Manufacturing & Construction Defects
- Corrosion
- Low Frequency ERW and Lap Welded Pipe

The risk analysis software is capable of addressing each of these threat categories, and **the company** has incorporated these parameters into its customized model.

5.6.7 LG&E Relative Risk Ranking Model – General Approach

The analytical model developed by the company utilizes a three step approach to relative risk ranking.

The first step, described in **Section 4** of this written program, is to evaluate identified threat and determine a **Threat Assessment Value** (TAV), where TAV_n is a number from zero to five plus indicating the relative degree to which threat number "n" is considered by the operator as likely to exist. It is a relative ranking, not a mathematical probability. See Section 4.8.1 for further detail pertaining to this step.

The second step of this process is to develop a **Propensity for Failure Index** (PFI_n) for each threat or group of threats to be considered. As with the TAV values, the PFI values represent a relative risk rather than a mathematical probability of failure from a particular threat or group of threats.

To determine the PFI for an individual threat or a group of threats appropriate factors representing phenomena that exacerbate the risk are added to the individual TAV or effective TAV for the group. Typical parameters that exacerbate risks and chance of failure include age of pipe, stress level as percentage of SMYS, pipe coating, and cathodic protection.

The third step of the relative risk ranking process requires application of a **Consequence** of failure factor to the cumulative propensity for failure index for all threats applicable to each covered pipeline segment. The product of the consequence factor and the total propensity for failure index is a numerical representation of **Total Risk** for the pipeline segment. Again, this is a relative ranking rather than a mathematical probability. A higher number represents a higher perceived risk but degree of risk is not mathematically proportional to the total risk calculated value.

5.6.8 Risk Exacerbation Factors

5.6.8.1 Age Index:

Many defects are exacerbated by age. Either directly if time dependent phenomena such as active corrosion, or indirectly though increased numbers of random occurrences for time independent or stable threats. In order to have a value at or near zero for new pipe, and a maximum value of approximately 1.0 for the oldest pipe in the LG&E systems the following equation applies:

AgeIndex = (CurrentDate - InstallDate) / (CurrentDate – MaxInstallDate)

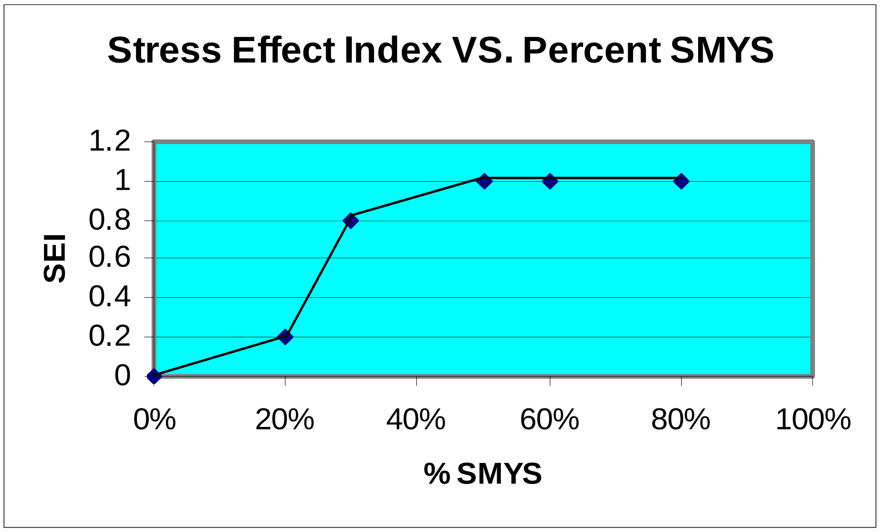
Where
CurrentDate = date risk score calculation is performed
Install Date = pipeline installation date
MaxInstallDate = installation date of oldest pipeline segment in system

5.6.8.2 Stress Effect Index (SEI):

Stress in the pipe wall directly affects most defects. Stress exceeding 60% of SMYS is considered to contribute to stress corrosion cracking, and high cyclic stress concentration at defects and damaged points can cause fatigue failure. Pipe stressed by internal pressure to the point of producing hoop stress of 30% SMYS or more is likely to fail in a rupture mode. For this algorithm stress level of 20% SMYS or less is considered conservative and of little consequence with respect to failure, and stress level of 30% SMYS or more produces a high risk of catastrophic failure.

For this model the following premises shall apply:

Leakage mode failure for up to 20% SMYS	SEI = 0 to 0.2
Increasing chance of rupture 20% to 30% SMYS	SEI = 0.2 to 0.8
Rupture failure likely over 30% SMYS definite at 50%	SEI = 0.8 to 1.00
For greater than 50% SMYS	SEI = 1.0



5.6.8.3 Interactive Threat Index

Certain threats, when present at the same location, have the potential to interact and thereby increase the overall risk to pipeline integrity. These interactive threats are scored and combined to determine an Interactive Threat Index (IATIndex). This index is then included in the Total Risk similar to the Stress Effect Index (SEI) described above.

Not all threats have the potential to interact. For example, internal and external corrosion could be present at the same pipeline coordinate but the mechanisms cannot interact. Even among pairs of threats, the interaction may be one-sided as in the case of Vandalism and External Corrosion. While a vandalism incident could impact the likelihood or rate of corrosion, corrosion can have no affect on the probability for vandalism to occur. Of the twenty-two (22) identified threats, **the company** has identified seventy-eight (78) combinations that could be deemed potentially interactive.

These interactions are described in the table below. Inter-Active Threat (IAT) is numbered to indicate the effect of TAVy acting upon TAVx. For example, IAT 1-4 describes the effect of pipe seam upon external corrosion.

Interactive Threat #	Description / Example of Interaction
IAT 1-4	Preferential seam corrosion
IAT 4-1	Preferential seam corrosion
IAT 5-4	Defective pipe exacerbates defective seam
IAT 5-6	Defective pipe exacerbates defective weld
IAT 5-7	Defective pipe exacerbates defective fabrication weld
IAT 8-1	Increased likelihood for coating defect at wrinkle bend; formation of corrosion cell at wrinkle bend.
IAT 8-3	Stress concentration at wrinkle bend.

Interactive Threat #	Description / Example of Interaction
IAT 8-5	Defect already in the pipe made a more serious threat to integrity at bend/buckle
IAT 10-11 IAT 10-13	Gasket/O-ring failure at control/relief or miscellaneous equipment.
IAT 11-4 IAT 11-5 IAT 11-6 IAT 11-7 IAT 11-9 IAT 11-13	Over-pressurization has negative effect on existing material defects.
IAT 12-11 IAT 12-13	Seal / pump packing failure at control/relief or miscellaneous equipment.
IAT 13-2	Separator failure results in higher than normal water content in the line, increasing internal corrosion.
IAT 13-22	Excessive vibration from compressors results in cyclic fatigue.*
IAT 14-1	Damage to pipeline &/or coating results in corrosion cell.
IAT 14-3	Damage such as a sharp gouge causes a stress concentration. Coating damage leads to possible SCC (if all other conditions are met).
IAT 14-11	Damage to control/relief equipment
IAT 15-1	Damage to pipeline &/or coating results in corrosion cell.
IAT 15-3	Damage such as a sharp gouge causes a stress concentration. Coating damage leads to possible SCC (if all other conditions are met).
IAT 16-1	Damage to pipeline &/or coating results in corrosion cell.
IAT 16-3	Damage such as a sharp gouge causes a stress concentration. Coating damage leads to possible SCC (if all other conditions are met).
IAT 16-11	Damage to control/relief equipment
IAT 16-13	Damage to miscellaneous equipment
IAT 17-1	Incorrect operation of CP system
IAT 17-2	Upsets causing higher than normal levels of water or corrosive constituents in the pipeline; improper application of biocide; failure to maintain drips (Note: Only applies to certain equipment types but the algorithm will apply to all TAV17's equally. Lower interaction factor to accounts for this lower likelihood.)
IAT 17-3	Incorrect operation of CP system
IAT 17-4 IAT 17-5	Over-pressurization
IAT 17-6 IAT 17-7	Incorrect or improperly performed welding procedures
IAT 17-8 IAT 17-9	Incorrect or improperly performed construction procedures
IAT 17-10	Incorrect or improperly performed maintenance or installation procedures
IAT 17-11	Incorrect or improperly performed maintenance or installation procedures; over-pressurization
IAT 17-12	Incorrect or improperly performed maintenance or installation procedures
IAT 17-13	Incorrect or improperly performed maintenance or installation procedures
IAT 17-14	Failure to perform One-Calls, line patrols, etc.
IAT 17-18	Failure to perform preventive measures for cold weather (e.g. heaters)
IAT 17-21	Incorrect or improperly performed construction procedures
IAT 17-22	Incorrect pressurization or flow control*
IAT 18-10	Extreme cold causes brittleness
IAT 18-11	Cold affects control/relief equipment, particularly electronic components
IAT 18-12	Extreme cold causes brittleness
IAT 18-13	Cold affects miscellaneous equipment, particularly electronic components
IAT 19-1	Lightning strike hits CP rectifier; strike causes coating damage
IAT 19-11 IAT 19-13	Lightning strike to control/relief or miscellaneous equipment
IAT 20-1	Coating damage
IAT 20-3	Coating damage; seasonally wet asphalt/tar coating more susceptible to SCC

Interactive Threat #	Description / Example of Interaction
IAT 20-4	Movement of pipeline during flood condition increases stress on any material defects
IAT 20-5	
IAT 20-6	
IAT 20-7	
IAT 20-8	
IAT 20-9	
IAT 20-11	Water damage to control/relief or miscellaneous equipment, particularly electronic components
IAT 20-13	
IAT 21-3	Soil stresses can attribute to coating damage
IAT 21-4	Movement of pipeline increases stress on any material defects
IAT 21-5	
IAT 21-6	
IAT 21-7	
IAT 21-8	
IAT 21-9	
IAT 21-13	Damage to miscellaneous equipment at site of earth movement
IAT 22-3	Cyclic stresses increase potential for SCC if all other conditions are met*
IAT 22-4	Cyclic fatigue increases stress on any material defects*
IAT 22-5	
IAT 22-6	
IAT 22-7	
IAT 22-8	
IAT 22-9	

**Note: Per Section 4, TAV_{22} = 0 for all HCAs therefore these interactive threats will not apply.*

Of these combinations, **the company** considers the probability of interaction to be negligible if the TAV score for either of the threats is less than 3. Furthermore, different factors are applied to interactive threats depending on the likelihood that the two components, if present at the same location, would actually interact.

Appendix 5-1 contains a figure showing the interactions considered in the Interactive Threat Index. Each interaction is further defined as having High, Moderate, or Low probability of interaction.

For each of the interactive threat categories considered, the IAT score is calculated as:

If TAV_A and TAV_B are both at least 3, IAT_{A-B} = Factor x TAV_A x TAV_B

If either TAV_A or TAV_B are less than 3, $IAT_{A-B} = 0$

Where,
TAV_A is the threat assessment value for threat A
TAV_B is the threat assessment value for threat B
IAT_{A-B} is the interactive threat score for threat A exacerbating threat B
Factors are applied as follows:

High probability of interaction	0.50
Moderate probability of interaction	0.10
Low probability of interaction	0.05

The Interactive Threat Index (IATIndex) is then calculated as the sum of all IAT scores

5.6.9 Risk Reducing Factors

5.6.9.1 Assessments:

Although the company considers a successfully completed integrity assessment to reduce the risk of failure due to time-dependent threats – external corrosion, internal corrosion, and stress corrosion cracking - the risk of all time independent threats is unaffected. Therefore no reduction is applied to the total risk.

5.6.9.2 P&M Measures:

Preventative and mitigative measure will be performed on pipelines in order to reduce likelihood of a threat. Please refer to section 12 for the P&M measures and the threats they are applicable to.

Once a permanent P&M measure is performed, the level of the applicable threat can be lowered in the risk model. Some of these reductions are accounted for in specific TAV scores described in Section 4. For example, heightened security measures would lower the TAV value for Vandalism. Any P&M measures which are not directly tracked through TAV values are assigned a risk-reducing score. The P&M Factor (PMF) is calculated as the sum of all the applicable P&M measures for a given pipeline segment.

Because the number and type of Preventive and Mitigative measures is so varied, the company rated each option as having High, Moderate, or Low impact based on Subject Matter Expert opinion. These ratings consider the likelihood and consequence that each P&M measure could potentially reduce the risk of failure on given pipeline segment. P&M measures which address multiple threats are generally given greater weight. Appendix 5-2 lists all of the P&M measures identified in Section 12 of this IMP along with their relative impact.

P&M Ratings (PMR) are applied as follows:

High impact	0.90
Moderate impact	0.50
Low impact	0.10

Time (t) impacts are rated as follows:

Permanent	0.90
Temporary	0.50
Annual	0.10

$$\mathrm{PMF_n} = \prod_{k=1}^{n} \left(1 - (\mathrm{PMR_k})(\mathrm{t_k})\right)$$

5.6.10 Consequence of Failure Index

A consequence of failure coefficient has been developed to apply to the Propensity for Failure Index for each segment to determine the total risk factor for the threat or group of threats being evaluated. This factor, variable name "CONSEQUENCE" estimate the impact upon human life in terms of number of buildings intended for human occupancy, outdoor identified site, and building identified sites.

CONSEQUENCE = Non Identified Site Building Count + 20 X Building Identified Site Count+ 20 X Outdoor Identified Site Count

5.6.11 Determining Total Risk for Prioritizing Baseline Assessments

For each covered line segment the Threat Assessment Values (TAVs) determined as described in **Section 4** of this program are summarized and adjusted as follows:

Where:

Threat Assessment Value	Group	Threat
TAV_1	Group A: Time Dependent	External Corrosion
TAV_2		Internal Corrosion
TAV_3		Stress Corrosion Cracking
TAV_4	Group B: Pipe Manufacturing Defect	Defective Pipe Seam
TAV_5		Defective Pipe
TAV_6	Group C: Pipe Construction Defect	Defective Girth Weld
TAV_7		Defective Fabrication Weld
TAV_8		Wrinkle Bend or Buckle
TAV_9		Welding/Fabrication Related defects
TAV_{10}	Group D: Equipment	Gasket / O-ring failure
TAV_{11}		Control / Relief Equipment malfunction
TAV_{12}		Seal / Pump Packing failure
TAV_{13}		Miscellaneous Equipment
TAV_{14}	Group E: Third Party Damage	Third Party Damage, Instantaneous
TAV_{15}		Third Party Damage, Delayed
TAV_{16}		Vandalism
TAV_{17}	Group F: Incorrect Operation	Incorrect Operational Procedures
TAV_{18}	Group G: Weather and Outside Force	Cold Weather
TAV_{19}		Lightning
TAV_{20}		Heavy Rain or Flood
TAV_{21}		Earth Movement
TAV_{22}	N/A	Cyclic Fatigue (equal to zero for all HCAs)

The following equations apply:

$Group_A$ Threat (Time Dependent)
Time dependent threat scores are adjusted based on the Reassessment Ratio described in section 5.6.9.1.

$$Group_A = ((TAV_1 * PMF_1) + (TAV_2 * PMF_2) + (TAV_3 * PMF_3))$$

$Group_B$ Threat (Pipe Manufacturing Defect)

$Group_B = (TAV_4 * PMF_4) + (TAV_5 * PMF_5)$

$Group_C$ Threat (Manufacturing and Construction Defect)

$Group_C = (TAV_6 * PMF_6) + (TAV_7 * PMF_7) + (TAV_8 * PMF_8) + (TAV_9 * PMF_9)$

$Group_D$ Threat (Equipment)

$Group_D = (TAV_{10} * PMF_{10})+ (TAV_{11} * PMF_{11}) + (TAV_{12} * PMF_{12}) + (TAV_{13} * PMF_{13})$

$Group_E$ Threat (Third Party Damage)

$Group_E = (TAV_{14} * PMF_{14}) + (TAV_{15} * PMF_{15}) + (TAV_{16} * PMF_{16})$

$Group_F$ Threat (Incorrect Operation)

$Group_F = TAV_{17} * PMF_{17}$

$Group_G$ Threat (Weather and Outside Force)

$Group_G = (TAV_{18} * PMF_{18}) + (TAV_{19} * PMF_{19}) + (TAV_{20} * PMF_{20}) + (TAV_{21} * PMF_{21})$

5.6.11.1 Propensity for Failure

Propensity for Failure incorporates the sum off all threats as well as specific risk reducing and risk exacerbating factors outlined above. To determine cumulative Propensity for Failure for all threats:

$PFI_{total} = Group_A + Group_B + Group_C + Group_D + Group_E + Group_F + Group_G + AgeIndex + SEI + IATIndex$

5.6.11.2 Total Risk

To determine the total risk for each covered segment it is necessary to multiply PFI_{total} by the consequence of failure index:

$TotalRisk = PFI_{total} \times CONSEQUENCE$

The total risk is an indication of potential human life impact over the entire length of the segment that is in HCA status. In order to give equal consideration to any short segment that is of high propensity for failure the weighted average for each segment or part thereof within HCA status has been determined:

$TotalRISK_{wtavg} = Weighted\ Average\ (TotalRisk)$

The numerical value of $RISK_{wtavg}$ has been used in the initial prioritization by the company for scheduling baseline assessments of covered pipeline segments.

A project summary report generated by risk analysis software detailing the algorithms used in the threat identification and risk assessment is included as Appendix 5-A.

5.6.12 Verification and Review of Risk Model

The company will recalculate and update the risk model to reflect new information obtained (including information from completed integrity assessment or mitigative actions) on the affected covered segments typically on an annual basis. However, if new pertinent information becomes available, a new risk model may be recalculated at any time.

The PIE will rank each covered segment from highest weighted risk average to lowest and assign a sequential numeric value to each, indicating the risk ranking of each, where 1 is the highest risk, 2 the second highest, and so on. The PIE will compare and contrast the updated risk model with its predecessor and document changes and reasons for change in Form 8-2: Baseline Assessment Plan Revision Form. Changes shall include, but not limited to, risk ranking and covered segment length.

The PIE will also include in the risk model analysis results, the top three Threats of Concern for each covered segment and any interactive threats that appear for each HCA. Upon assessment, the PS will verify that these Threats of Concern are applicable for the covered segment.

Appendix 5-1

The table below describes the effect of Y (y-axis) on X (x-axis). That is, could the presence of Y exacerbate, increase or otherwise negatively impact the likelihood of X.

Threat X

Threat Y		Ext. Corr. TAV1	Int. Corr. TAV2	SCC TAV3	Pipe Seam TAV4	Pipe TAV5	Girth Weld TAV6	Fab. Weld (Equip.) TAV7	Wrinkle Bend / Buckle TAV8	Threads / Coupling TAV9	Gasket / O-ring TAV10	Control / Relief TAV11	Seal / Pump Packing TAV12	Misc. Equip. TAV13	TPD, Immed. TAV14	TPD, Delayed TAV15	Vandalism TAV16	Incorrect Ops TAV17	Cold Weather TAV18	Lightning TAV19	Rain / Flood TAV20	Earth Mvmt. TAV21	Cyclic Fatigue TAV22
Ext. Corr.	TAV1	N/A	N	N	H	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Int. Corr.	TAV2	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
SCC	TAV3	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Pipe Seam	TAV4	H	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Pipe	TAV5	N	N	N	M	N/A	M	M	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Pipe Girth Weld	TAV6	N	N	N	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Fab. Weld (Equip.)	TAV7	N	N	N	N	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Wrinkle Bend / Buckle	TAV8	M	N	M	N	L	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N	N
Threads / Coupling	TAV9	N	N	N	N	N	N	N	N	N/A	N	N	N	N	N	N	N	N	N	N	N	N	N
Gasket / O-ring	TAV10	N	N	N	N	N	N	N	N	N	N/A	M	N	M	N	N	N	N	N	N	N	N	N
Control / Relief Equip.	TAV11	N	N	N	M	M	M	M	N	M	N	N/A	N	M	N	N	N	N	N	N	N	N	N
Seal / Pump Packing	TAV12	N	N	N	N	N	N	N	N	N	N	M	N/A	M	N	N	N	N	N	N	N	N	N
Misc. Equip.	TAV13	N	M	N	N	N	N	N	N	N	N	N	N	N/A	N	N	N	N	N	N	N	N	L
TPD, Immed.	TAV14	H	N	H	N	N	N	N	N	N	N	H	N	N	N/A	N	N	N	N	N	N	N	N
TPD, Delayed	TAV15	H	N	H	N	N	N	N	N	N	N	N	N	N	N	N/A	N	N	N	N	N	N	N
Vandalism	TAV16	H	N	H	N	N	N	N	N	N	N	M	N	M	N	N	N/A	N	N	N	N	N	N
Incorrect Ops	TAV17	L	L	L	M	M	L	L	L	L	L	M	L	L	L	N	N	N/A	M	N	N	M	M
Cold Weather	TAV18	N	N	N	N	N	N	N	N	N	M	M	M	M	N	N	N	N	N/A	N	N	N	N
Lightning	TAV19	M	N	N	N	N	N	N	N	N	N	M	N	M	N	N	N	N	N	N/A	N	N	N
Rain / Flood	TAV20	M	N	M	M	M	M	M	M	M	N	H	N	H	N	N	N	N	N	N	N/A	N	N
Earth Mvmt.	TAV21	N	N	M	M	M	M	M	M	M	N	N	N	M	N	N	N	N	N	N	N	N/A	N
Cyclic Fatigue	TAV22	N	N	L	L	L	L	L	L	L	N	N	N	N	N	N	N	N	N	N	N	N	N/A

Probability of Interaction: H = High, M = Moderate, L = Low, N = None, N/A = Not Applicable

Appendix 5-2

Impact of P&M Measures on Propensity of Failure

P&M Measure	*PMIndex Rating (PMR)*	*Time Frame (t)*	*Length Valid*	*Threat(s) Addressed*
Additional Foot Patrol	Moderate	Annual	1 year	TAV1- External Corrosion TAV 9-Stripped threads/broken pipe/coupling failure TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage TAV 16- Vandalism TAV 18- Cold Weather TAV 19- Lightning TAV 20- Heavy Rain or Flood TAV 21- Earth Movement
Additional IC Monitoring	Moderate	Temporary	1 year	TAV 2- Internal Corrosion
Additional Patrols during construction	Moderate	Temporary	1 year	TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage
Additional Training	Moderate	Temporary	1 year	TAV17- Incorrect Ops
Aerial Patrol	Low	Temporary	1 year	TAV 9-Stripped threads/broken pipe/coupling failure TAV 18- Cold Weather TAV 19- Lightning TAV 20- Heavy Rain or Flood TAV 21- Earth Movement TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage TAV 16- Vandalism
Biocide / Inhibitor	High	Temporary	3 years	TAV 2- Internal Corrosion
CIS	Moderate	Temporary	7 years	TAV 1- External Corrosion
Coating repair	High	Permanent		TAV 1- External Corrosion

P&M Measure	*PMIndex Rating (PMR)*	*Time Frame (t)*	*Length Valid*	*Threat(s) Addressed*
				TAV 3- SCC
Construction Inspection	Moderate	Permanent		TAV 5- Defective Pipe
CP Design / Install	High	Permanent		TAV 1- External Corrosion
CP Maintenance Procedures	Low	Permanent		TAV 1- External Corrosion
DCVG	Moderate	Temporary	7 years	TAV 1- External Corrosion
Design Specs	Low	Permanent		TAV 10- Gasket/O-ring Failure TAV 11- Ctrl/Rlf Equip Malfunction TAV 12- Seal/Pump Packing Failure TAV 13- Misc. Equip.
Heat Tracing	Low	Temporary	3 years	TAV 18- Cold Weather
Increase Depth of Cover	Moderate	Permanent		TAV 8- Wrinkle Bend or Buckle TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage TAV 3- SCC TAV 18- Cold Weather
Increase line marker	Moderate	Permanent		TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage
Increased security (aboveground)	Moderate	Permanent		TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage
Inspection / Maintenance	Moderate	Annual	1 year	TAV 10- Gasket/O-ring Failure TAV 11- Ctrl/Rlf Equip Malfunction TAV 12- Seal/Pump Packing Failure TAV 13- Misc. Equip.
Internal Cleaning	High	Temporary	7years	TAV 2- Internal Corrosion
Leak Control	Moderate	Annual	1 year	TAV 2- Internal Corrosion
Leak Survey after event	High	Permanent		TAV 19- Lightning TAV 20- Heavy Rain or Flood TAV 21- Earth

P&M Measure	***PMIndex Rating (PMR)***	***Time Frame (t)***	***Length Valid***	***Threat(s) Addressed***
				Movement
Lightning Arrestors	High	Permanent		TAV 19- Lightning
Mag Particle / Dye Penetrant	Moderate	Temporary	1 year	TAV 3- SCC TAV 4- Defective Pipe Seam
Maintain ROW	Moderate	Annual	1 year	TAV 21- Earth Movement
Manufacturer Inspection	Low	Permanent		TAV 4- Defective Pipe Seam TAV 5- Defective Pipe
Materials Inspection	Low	Permanent		TAV 4- Defective Pipe Seam TAV 5- Defective Pipe
Pre-Service Hydrotest	Moderate	Permanent		TAV 4- Defective Pipe Seam TAV 5- Defective Pipe TAV 6- Defective Girth Weld TAV 7- Defective Fabrication Weld TAV 8- Wrinkle Ben or Buckle TAV 9- Stripped threads/broken pipe/coupling failure
Procedure reviews	Moderate	Temporary	1 year	TAV 17- Incorrect Ops
Reduce external stress	Moderate	Temporary	1 year	TAV 8- Wrinkle Ben or Buckle TAV 21- Earth Movement
Reduce MAOP	High	Temporary	1 year	TAV 3- SCC TAV 4- Defective Pipe Seam TAV 5- Defective Pipe TAV 6- Defective Girth Weld TAV 7- Defective Fabrication Weld
Reduce Moisture	High	Temporary	1 year	TAV 2- Internal Corrosion
Remote Rectifier Monitor	Low	Permanent		TAV 1- External Corrosion
Repair	High	Permanent		TAV 8- Wrinkle Ben or Buckle
Strain Monitoring	Low	Temporary	1 year	TAV 20- Heavy Rain or Flood TAV 21- Earth

P&M Measure	***PMIndex Rating (PMR)***	***Time Frame (t)***	***Length Valid***	***Threat(s) Addressed***
				Movement
Supplemental public education	Low	Temporary	1 year	TAV 14- Immediate Third Party Damage
Temporary line markers during construction	Moderate	Temporary	1 year	TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage
Thermal Protection	Moderate	Permanent		TAV- 18 Cold Weather
Visual Inspection	Low	Temporary	1 year	TAV 4- Defective Pipe Seam TAV 6- Defective Girth Weld
Visual Inspection after event	High	Permanent		TAV 18- Cold Weather TAV 19- Lightning TAV 20- Heavy Rain or Flood
Wall Thickness	High	Permanent		TAV 1- External Corrosion TAV 2- Internal Corrosion
Warning tape	Moderate	Permanent		TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage
X-ray / UT Inspection	Moderate	Permanent		TAV 6- Defective Girth Weld

P&M Measures Accounted for within Individual TAV Scores
(Refer to Section 4 of the IMP)

P&M Measure	***Threat(s) Addressed***
Casing	TAV 20- Heavy Rain or Flood
Increased security (aboveground)	TAV 16- Vandalism
Maintain stable operating conditions	TAV 4- Defective Pipe Seam TAV 5- Defective Pipe
Relocate	TAV 14- Immediate Third Party Damage TAV 15- Delayed Third Party Damage

P&M Measure	***Threat(s) Addressed***
	TAV 16- Vandalism TAV 18- Cold Weather TAV 20- Heavy Rain or Flood TAV 21- Earth Movement
Remove	TAV 8- Wrinkle Bend or Buckle TAV 9- Stripped threads/broken pipe/coupling failure
Replace	TAV 3- SCC
River Weights	TAV 20- Heavy Rain or Flood

Revision Log:

Date	Significant Changes	Revised By
Dec 6 thru Dec 9, 2004	Initial changes to GIE / Northeast Gas written program, includes: • Formatting, including Table of Contents page for section • Rename responsible positions per Section 2 • Replace "Company" with "LG&E Energy" • 5.3 changed heading to "Risk Assessment" • 5.4 changed heading to "Risk Assessment Methods" • 5.4.1 note To Operators removed • 5.4.2 added paragraph "LG&E Risk Ranking Model" • 5.6.2 first sentence, changed "analysis" to "assessment", second paragraph changed to reflect Plexus software • 5.6.3 revised to reflect LG&E program, Note to Operator removed • 5.6.4 second paragraph "Company" replaced with "the model could", third paragraph replaced • 5.6.5 second paragraph removed • 5.6.6 revised to reference Integrity 2004 software • 5.6.7 added • 5.6.8 added • 5.6.9 added • 5.6.10 added	Oelker Augustine Eder
12/9/2004	Final section approved by management.	
6/27/2007	Changed "LG&E Energy" logo to "LG&E" E.ON logo	CMA
6/27/2007	Changed company name from "LG&E Energy" to "Louisville Gas & Electric/ Kentucky Utilities" and used "The company" throughout.	CMA
7/25/2007	5.6.4 paragraph 3 revised to indicate frequency of recalculation of risk model.	CMA
7/27/2007	Added subsection 5.6.12 'Verification and Review of Risk Model"	CMA
9/21/07	Added bullets to objectives in section 5.6.1 per consultants recommendations.	LCO
8/6/2008	Added subsection 5.6.9 "Reducing Risk Factors" Modified section 5.6.11 "Determining Total Risk for Prioritizing Baseline Assessments" to include all threats as well as additional risk factors.	CMA
11/17/2008	Recommended Changes from EN Engineering: • Age Index Formula updated • Section 5.6.8.3 Interactive Threat Index added • Threat assessment group updated to parallel TAV catagories • Propensity for Failure equation updated to reflect P&M Measure and Interactive Threat equations.	CMA
12/4/2008	Final section approved by management.	LCO

11/3/2009	Section 5.6.9.2 Inserted algorithm to incorporate a risk reducing factor when a P&M measure is performed.	CMA
11/3/2009	Section 5.6.10 Update the Consequence algorithm to correct an error that were double counting identified site buildings	CMA
11/3/2009	Section 5.6.11 Inserted the P&M Measure-Risk reducing factor into each applicable group algorithm	CMA
10/5/2012	Removed all references throughout the section to "Integrity 2004" software and replace with a non-Proper noun term, "risk analysis" software.	CMA
12/5/2012	Updated section 5.6.12 to indicate that verification and review of the risk model typically take place on an annual basis.	CMA
10/03/2013	Updated table 5-2 in the appendix to match the correct applicable P&M Measures found in tables throughout section 12. Also completed table for missing information	CMA

6 ASSESSMENT METHOD SELECTION §192.921(a)

In This Section

Referenced Protocols

6 ASSESSMENT METHOD SELECTION

6.1 OVERVIEW

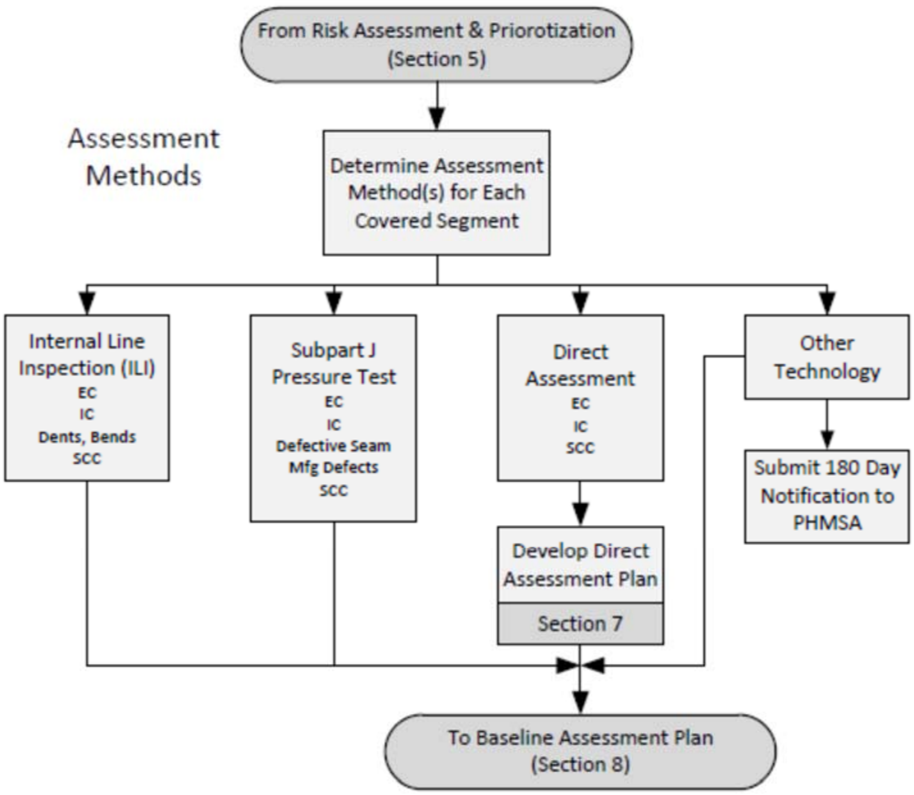


Figure 6-1 – General Process Flow and Inter-Connects to Other Sections

✓ ***Referenced Protocol:*** ***B.1 Assessment Methods***
F.2 Reassessment Methods

6.1.1 Purpose

The Assessment Method Selection Section contains the procedures to follow in selecting the appropriate pipeline inspection (assessment) methods for the Baseline Assessment Plan and any subsequent reassessment of a pipeline segment. As indicated in Figure 6-1, the threat types that must be assessed on a given pipeline segment (e.g., external corrosion, third party damage) must first be determined using the procedures in Section 4.0 - Threat Identification and Evaluation.

6.1.2 Responsibility

The **Program Manager – Integrity Management** M1 will have overall responsibility for the performance of these procedures and for any modifications to this section. The **Manager – Gas Regulatory Compliance** M4 will assign additional staff, as needed, to perform and document the results of these procedures. These staff members will have training and experience in conducting integrity assessments and reviewing and analyzing results as established in Section 2.0 - Roles and Responsibilities.

6.2 DEFINITIONS

Assessment

An Assessment is the use of testing techniques as allowed per 49 CFR §192.903 as referenced in Appendix 1B of this IMP to ascertain the condition of a covered pipeline segment.

6.3 PRIMARY ASSESSMENT METHOD SELECTION PROCEDURE

Figure 6-2 provides the steps to follow in the Primary Assessment Selection Procedure. ***Prior to performing these steps, the threats that must be assessed in each covered pipe segment must be identified using the procedures in Section 4.0. For purposes of selecting assessment methods, these threats are categorized as follows***:

For steel pipelines;

Longitudinal Seam Fatigue Cracking and/ or Corrosion
Stress Corrosion Cracking
General External or Internal Corrosion

For plastic transmission pipelines;

- Any threats that may cause failure other than third party damage

For the threat categories, there are one or more allowable methods prescribed by PHMSA that can be used for assessing pipeline sections as indicated in **Figure 6-2**. Depending on the options selected, additional evaluation steps are performed for Direct Assessment (**Subsection 6.6 and Section 7.0**), ILI tool selection (**Subsection 6.4**), and pressure testing (**Section 6.5**). Comparisons between assessment alternatives are made as applicable and the final method(s) are picked for each pipeline section in the IMP. Multiple inspection methods may be necessary for an individual pipeline section depending on the threats that need to be evaluated. Refer to **Section 6.7** if other inspection technologies not indicated in Figure 6-2 are being considered.

6.3.1 Threats Not Considered in Method Selection – Steel Pipelines

Not every threat applicable to steel pipelines can or should be addressed using a particular one of the three primary assessment methods – Pressure Test, ILI, or Direct Assessment. The following threats are addressed through ongoing inspection, maintenance, surveillance, and preventative and mitigative measures and are not considered during the assessment method selection process:

Third Party Damage
Outside Force
Equipment
Incorrect Operations
Weather Related

It should be noted, however, that indications of Third Party Damage and other previously damaged pipe can be found with ILI caliper tools during integrity assessments. Any anomalies surviving an integrity assessment by pressure test are shown capable to withstand the test pressure. Using an In-Line Inspection assessment method, dents and gouges can be integrated with encroachment and foreign crossing data to identify dents and gouges caused by Third Party Damage. Similarly, integrating encroachment and foreign crossing data with ECDA Indirect Inspection data can identify probable Third Party Damage locations.

For each covered pipeline segment in the IMP, Form 8-1 (Baseline Assessment Plan) is used to record the inspection method(s) chosen and the reason(s) for that selection.

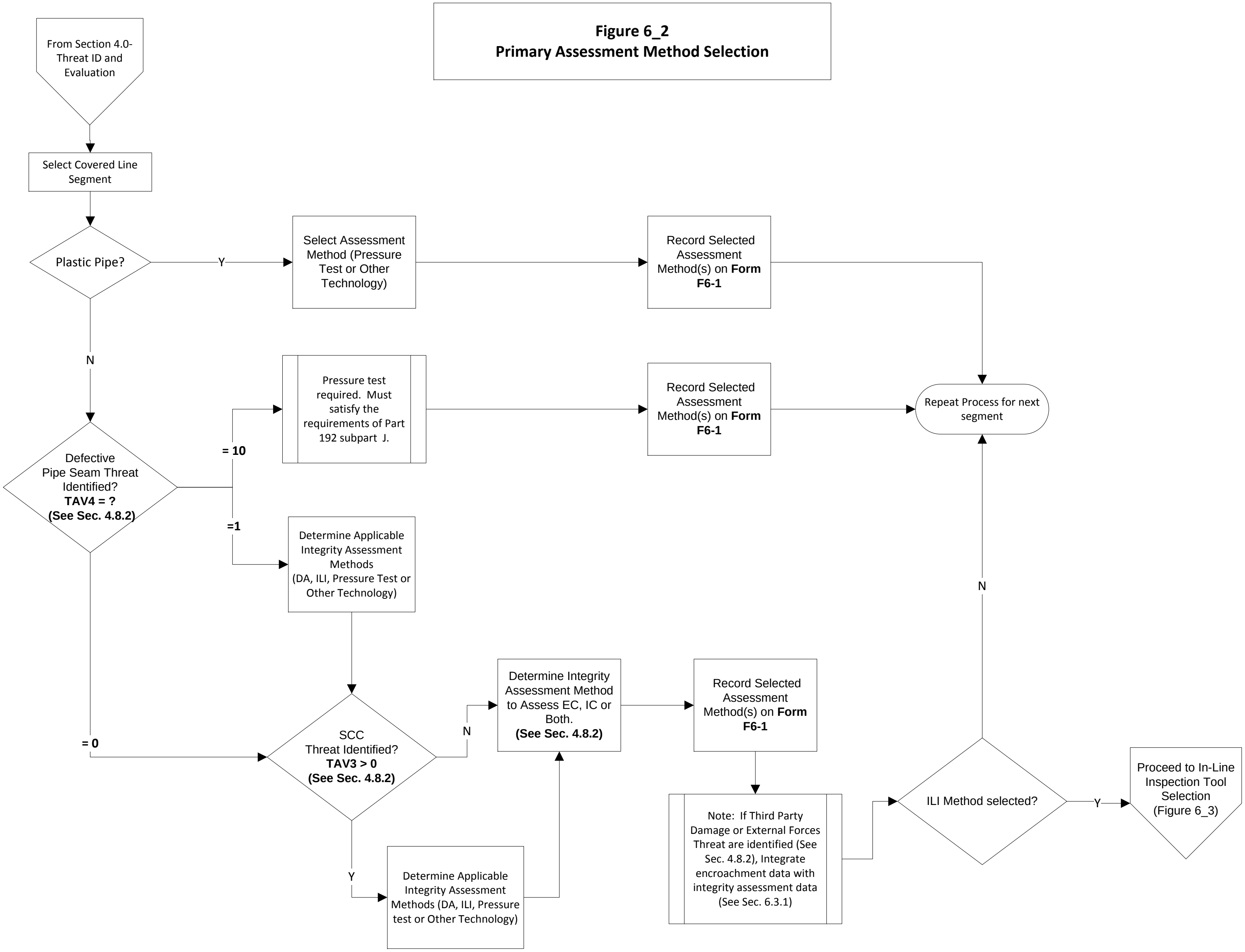
6.3.2 Plastic Transmission Pipelines

Per 49 CFR 192.921, plastic transmission pipelines with an identified threat other than third-party damage require a baseline assessment as outlined in **Section 8** of this Integrity Management Plan.

Pressure testing is the preferred assessment method for plastic transmission pipelines. In-Line Inspection tools are not used on plastic pipelines. Furthermore, since corrosion is not an identified threat for plastic piping, neither ECDA, ICDA, nor SCCDA methodology is applicable. For plastic transmission lines, the company will employ either Pressure Test or Other Technology assessment methods.

Use of other technology assessment methods require justification and advanced regulatory agency approval. Refer to **Section 19.4.5** of this Integrity Management Plan for additional information about submitting other technology notifications.

Figure 6_2
Primary Assessment Method Selection



6.4 INTERNAL LINE INSPECTION (ILI)

Table 6-1 is extracted from ASME B31.8S and should be used to evaluate ILI as a potential option for pipe inspection. **Table 6-1** is a general selection guide for ILI technologies according to their ability to detect each type of anomaly. Standard technologies including Conventional or High Resolution MFL can be used to detect anomalies that have a spatial component oriented circumferentially around the pipe (e.g., corrosion pitting). The Table indicates only two readily available technologies that are considered capable to detect anomalies associated with longitudinal seams or those that are primarily oriented longitudinally with the pipe: 1) Transverse Magnetic Flux Leakage (sometimes referred to as TFI or C-MFL), and 2) Ultrasonic Shear Wave technologies.

Pipe segments that have been previously damaged can be assessed using the caliper and deformation ILI tools. Caliper tools use mechanical caliper arms, touch less electric measurement systems, or a combination thereof to assess geometric anomalies circumferentially within the pipe. The Caliper tool is the only qualified tool capable of assessing dents, buckles, and ovalities, stress-induced geometric features, and bending.

The company's procedure for selecting ILI technologies follows the flowchart in Figure 6-3. This flowchart reflects the requirements of §192.921(a)(1), which references ASME B31.8S, Section 6.2 for ILI tool selection requirements. In addition to technology selection, Section 6.2 of ASME B31.8S requires consideration of the following when evaluating tool and tool vendor options:

- detection sensitivity,
- anomaly classification,
- sizing accuracy,
- location accuracy, and
- requirements for defect assessment.

NOTE that ILI tool tolerances should be considered when determining if a detected anomaly meets repair criteria and when determining reassessment intervals. Refer to Section 10 – Remediation

6.4.1 Special Considerations For Anomalies With Longitudinal Orientation

Because of conflicting reports from operators and vendors concerning tool detection capabilities for anomalies with longitudinal orientation, PHMSA commissioned an independent study on "Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation", dated October 2003[1]. This report evaluates and provides recommendations and guidelines on the use of ILI technology to assess the integrity of LF-ERW and lap-welded pipe seams.

The *PHMSA TT05 Final Report*, Section 9.2 identifies C-UT (Circumferential Ultrasonic Testing or shear wave UT), EMAT (Electro Magnetic Acoustic Transducer), and TFI (Transverse Field Inspection or transverse MFL) as the only methods currently available for accurate detection of crack-like defects, which are the types of defects commonly associated with longitudinal seam

[1] PHMSA TT05 – Low Frequency ERW and Lap Welded Longitudinal Seam Evaluation; Michael Baker Jr., Inc. in association with Kiefner and Assoc., Inc. and CorrMet Enginnering Services, PC, October 2003

integrity. EMAT is a new technology with few inspection runs in pipelines and is still considered to be in the development stage by some ILI vendors. The company does not consider EMAT to be a proven application at this time. Similarly, ET (Eddy Current Testing) appears to be a promising method for crack detection, but has not been proven in gas pipelines.

ILI is an option if the pipe section manufacturing threat is either stable or not present (TAV4 value of 1.0 or 0, refer to Section 4.0). Pipe having a non-stable defective pipe seam threat (TAV4 value of 10.0) can be assessed by pressure testing (Section 6.5) per ASME B31.8S.

When choosing between a UT or MFL tool for assessment of longitudinal seam integrity, the company will give consideration to the benefits and limitations of each type tool. UT has had more use in liquids pipelines because UT requires a liquid coupling medium. Shear wave UT tools can be run in gas pipelines in slugs of liquid or by using tools with liquid filled wheels. When run in a liquid medium, UT typically produces better results than MFL in regard to assessment of long seam issues, but liquid filled wheel UT tools may have difficulty discriminating between internal and external anomalies and have limited sizing ability. TFI tools operate equally well in liquid and gas mediums, but have limited sizing ability and have trouble discriminating between defects. Generally, shear wave UT tools run in a liquid medium are sensitive to a larger number of features than a TFI tool and are capable of sizing anomalies, discriminating between defect types, and indicating external and internal location.

Although circumferential distribution of the magnetic field makes a TFI tool more sensitive to longitudinal anomalies than a high resolution MFL tool, very tight cracks may not alter the magnetic field sufficiently to allow detection. In some instances, the company may use other means of assessment, such as a shear wave UT tool or hydrostatic test to supplement and support TFI data gathered. If a shear wave UT tool is run in a slug of liquid medium, sizing of anomalies typically agrees well with excavated and measured defects. Therefore, a hydrostatic test, other than for reasons of seam failure history or increase in pressure above MAOP per 192.917(e)(4), should not be necessary.

Table 6-1 General Selection Guide for In Line Inspection Method versus Anomaly Type [2]

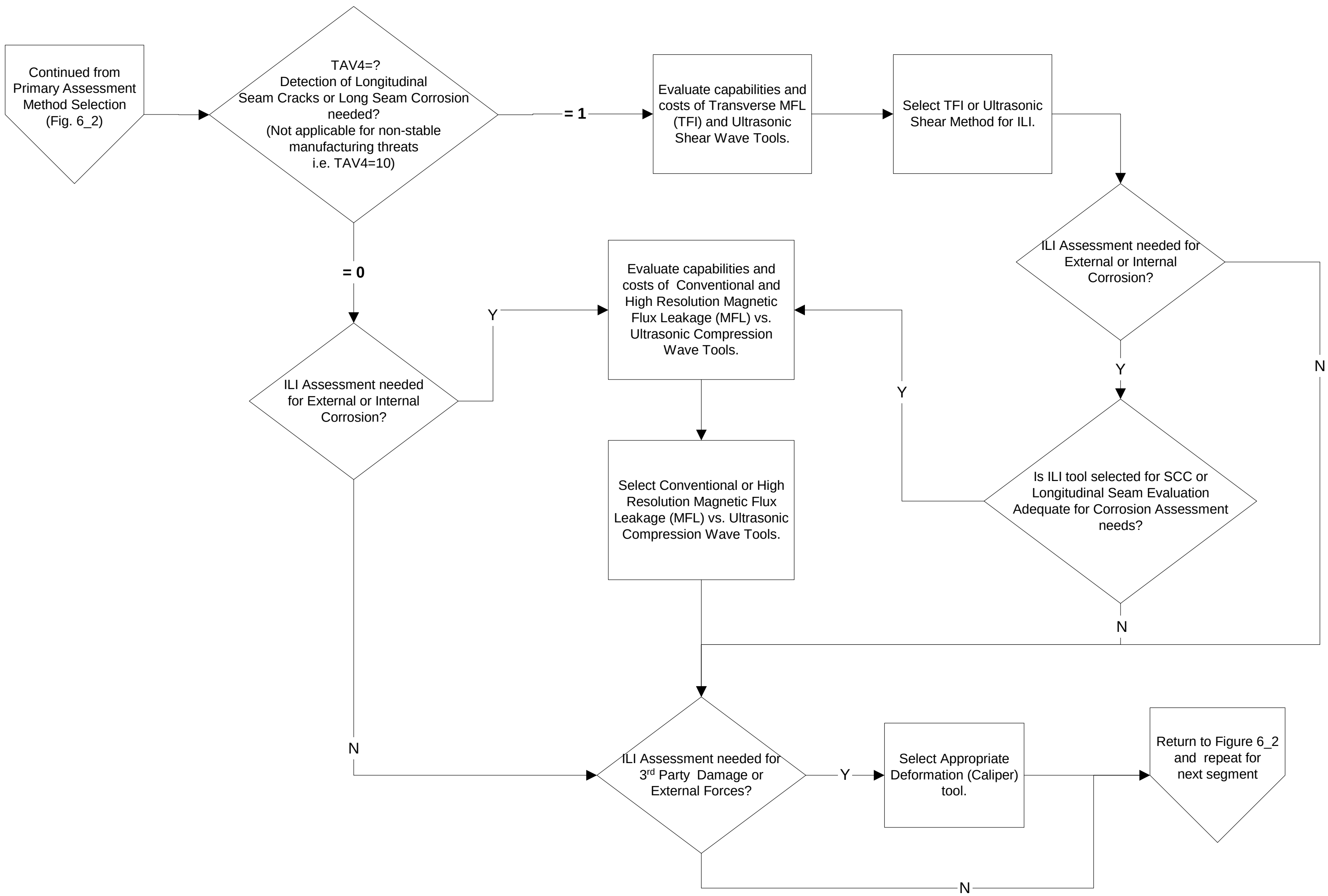
	Candidate ILI Method

[2] Sources: ASME B31.8S -2004, Section 6.2 and NACE RP0102-2002, "Standard Recommended Practice – In-Line Inspection of Pipelines

Pipeline Anomaly Type	High Resolution Magnetic Flux Leakage (MFL)	Conventional Resolution Magnetic Flux Leakage (MFL)	Ultrasonic Compression wave	Ultrasonic Shear Wave	Transverse MFL (TFI Tool)	Caliper Tool
External Corrosion (Non-Axial)	X	X	X	X	X	
Internal Corrosion (Non-Axial)	X	X	X	X	X	
Dents,Buckles, Other Geometric Anomalies*						X
Longitudinal Crack & Seam Defects; Selective Longitudinal Seam Corrosion				X	X	
Stress Corrosion Cracking**				X	X	

*Only Caliper Tool is capable of quantifying dents and buckles and the like.
**TFI has a reduced probability of detection (POD) for tight cracks.

Figure 6_3
In-Line Inspection Tool Selection



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6.5 PRESSURE TESTING

6.5.1 Regulatory Requirements

Pressure tests for a line pipe segment must be conducted in accordance with Part 192, Subpart J requirements (see §192.921(a)(2)). Part 192.921(a)(2) also specifies that test pressures listed in Table 3 of ASME B31.8S (Section 5 of ASME B31.8S) be used in justifying extended reassessment intervals. A copy of Table 3 is provided for reference in **Subsection 6.5.5**.

NOTE: ASME B31.8S Section 6.3.2 specifies that pressure testing shall comply with the requirements of ASME B31.8, which conflicts with the §192.921(a)(2) requirement that pressure tests be conducted in accordance with Subpart J of 49 CFR Part 192. To resolve this conflict, PHMSA has directed that Subpart J requirements shall be followed.

6.5.2 Specifications

The company's **Operating, Maintenance and Inspection Procedures GOM&I-PO-TE-001** contains the company's standard procedures for conducting pressure testing in accordance with 49 CFR 192 Subpart J. Other requirements are included in Section 9C – Pipeline Hydrostatic Testing Procedure.

6.5.3 Pressure Test Considerations

If pressure testing is the method selected for assessment of pipeline integrity, the testing, as a minimum, must be according to Part 192 Subpart J. An optional pressure spike test may be included; (Refer to **Subsection 6.5.6**).

6.5.4 Assurance of Corrosion Control Program

In order for the reassessment intervals stated in Table 3 of ASME B31.8S-2004 to be valid an effective corrosion control program must be in effect (see Company Corrosion Control GOMI Procedures). Compliance with all applicable requirements of 49 CFR 192 Subpart I will ensure an effective corrosion control program. In the event that effective corrosion control cannot be assured the maximum reassessment interval shall be reevaluated based upon the predicted rate of metal loss and estimated time remaining before failure would occur at the MAOP for the pipeline segment being considered. The reassessment time interval may not exceed the interval stated in Table 3, or one half of the remaining time before failure could be expected which ever time period is shortest.

Corrosion control provisions are not required when assessing plastic transmission pipelines since neither external nor internal corrosion are an identified threat.

6.5.5 Selection of Test Pressure

Pressure tests used for integrity assessments must be performed in accordance with Part 192 Subpart J and to prescribed pressure levels (i.e., 1.25 times MAOP in Class 1 and Class 2 locations and 1.50 times MAOP in Class 3 and Class 4 locations). Table 3 of ASME B31.8S may be used to extend reassessment intervals. Consideration should be given to testing to the requirements of Table 3 in order to extend the time interval between pressure tests. The higher the test-pressure-to-operating-pressure ratio, the smaller the remaining defects will be and longer intervals between assessments are achieved.

NOTE: Testing to a higher pressure will increase the chance of test failure. In addition, pressure limitations on pipe, valves, and fittings may exist that preclude higher test pressures.

The following is a partial table from ASME B31.8S Table 3 that has been referenced concerning assessment intervals for time dependent threats.

TABLE 3 - INTEGRITY ASSESSMENT INTERVALS
TIME-DEPENDENT THREATS PRESCRIPTIVE INTEGRITY MANAGEMENT PLAN

Inspection Technique	Interval (Years) **[Note (1)]**	Criteria		
		At or above 50% SMYS	At or above 30% up to 50% SMYS	Less than 30% SMYS
Hydrostatic Testing	5	TP to 1.25 times MAOP **[Note (2)]**	TP to 1.4 times MAOP **[Note (2)]**	TP to 1.7 times MAOP **[Note (2)]**
	10	TP to 1.39 times MAOP **[Note (2)]**	TP to 1.7 times MAOP **[Note (2)]**	TP to 2.2 times MAOP **[Note (2)]**
	15	Not Allowed	TP to 2.0 times MAOP **[Note (2)]**	TP to 2.8 times MAOP **[Note (2)]**
	20	Not Allowed	Not Allowed	TP to 3.3 times MAOP **[Note (2)]**

NOTES:

(1) Intervals are maximum and may be less depending on repairs made and prevention activities instituted. In addition, certain threats can be extremely aggressive and may significantly reduce the interval between inspections. Occurrence of a time-dependent failure requires immediate re-assessment of the interval.

(2) TP is Test Pressure

As indicated in Table 3, the reassessment interval is directly related to the test pressure as a multiple of the MAOP. For example, for a pipeline at or above 50% SMYS, a pressure test of 1.25 times the MAOP will result in a reassessment interval of five years. If that same pipeline were tested to 1.39 or greater multiple of the MAOP, as in Class 3 locations, then the reassessment interval could be ten years (with confirmatory assessment after seven years).

Yield strength as defined in 49 CFR 192.107 applies only to steel pipe. Plastic pipe design pressures are determined per 49 CFR 192.121. Therefore, plastic pipe integrity test pressures and assessment intervals will be based upon the ratio of MAOP to Hydrostatic Design Basis (HDB) rather than percent SMYS.

6.5.6 Use of the Spike Test

Historically, a test pressure to MAOP ratio of 1.5 has been accepted as confirmation of fitness for service of a pipeline. Pipeline failures of low frequency ERW and lap-welded pipe in the 1980's demonstrated that confidence in the safety of pipelines established by a pressure test continues to increase as the test pressure to MAOP ratio increases beyond 1.25. It is now understood that the use of a "spike" test, a brief excursion of test pressures well above the standard test pressure, provides a higher level of assurance on the integrity of a pipeline. The spike test raises the test pressure to a level above 1.25 times

MAOP for a short period of time, typically about one-half hour. After completing the spike test, the pressure can be lowered to the normal pressure test level to complete a “Subpart J” test complying with federal regulations. While there is no defined test pressure to MAOP ratio for a spike test, the ratio of 1.39 is frequently used. This ratio is equal to 100/72, the ratio of 100 percent of SMYS to 72 percent of SMYS, which is the maximum design stress permitted by federal regulations and also the enabling ratio allowing a ten year reassessment period (see Table 3 above) versus the five year period for lower ratios.

A downside to the use of spike test is the increased risk of test failures as the pressure is raised beyond a previously tested level of 1.25 times MAOP. If failures do begin to occur at higher pressures, it will still be necessary to achieve a minimum test pressure of at least 1.25 times MAOP to avoid lowering the established pipeline MAOP. Class 3 and Class 4 areas require at least 1.50 times MAOP. If failures do occur at a higher pressure in the spike test, that pressure level becomes the demonstrated level of integrity for the pipeline. When a successful spike test is conducted, it can be assumed that critical sized defects that would cause pipe failure at the spike pressure are not present. Correlation can be made between the pressure level achieved and the size of any defects present in the pipe. Therefore, a spike test can be very useful in assessing seam issue integrity threats.

NOTE: PHMSA considers an assessment using spike test to be use of "other technology". Therefore, if a spike test, alone, is used as an assessment method, the company will notify PHMSA and Kentucky Public Service Commission (KPSC) and/or the Indiana Utility Regulatory Commission (IURC) at least 180 days in advance. (Refer to **Subsection 6.7**)

6.6 DIRECT ASSESSMENT (EC, IC, AND SCC)

Direct Assessment is a viable option in assessing line pipe for external corrosion, internal corrosion and stress corrosion cracking (refer to §192.921(a)(3)). Procedures for the design and implementation of Direct Assessment are provided in **Section 7.0**. In addition, external corrosion direct assessment (ECDA) can also be used to assess third party damage (TPD) when used in conjunction with additional preventive and mitigative measures. Refer to **Subsection 12.3.1**.

6.7 OTHER TECHNOLOGY

If the company selects the use of "other technology”, notification to PHMSA and KPSC and/or IURC is required 180 days before conducting the assessment in accordance with §192.921(a)(4). Refer to **Section 19** for the company’s procedures for these notifications. As discussed in **Section 6.4.4**, when a spike test is used alone as an assessment method, PHMSA considers that as the use of "other technology".

Form 6-1: Record Form - Assessment Method Selection Results

Assessment Plan Date: ____________

Assessment Year: ____________

Form 6-1 - Decision Answers and Selection Results Based Upon Figure 6-2																													
Segment Data - Plastic and Steel					Plastic Only			Steel Only																			Results of Selection Process		
								Longitudinal Seam				Stress Corrosion Cracking					External Corrosion					Internal Corrosion							
						Applicable Method			Applicable Method				Applicable Method					Applicable Method					Applicable Method					
HCA Identification Number	Segment Name	Segment Number	Diameter (in)	HCA Length (Ft)	Identified Threat Other Than TPD	Pressure Test	Other Technology	Threat Applicable	Pressure Test	ILI	Other Technology	Threat Applicable	Pressure Test	ILI	Direct Assessment	Other Technology	Threat Applicable	Pressure Test	ILI	Direct Assessment	Other Technology	Threat Applicable	Pressure Test	ILI	Direct Assessment	Other Technology	Selected Assessment Method(s)	Preparer / Approver	Comment Number
XX1	Example	54.1	12	165.5	-	-	-	y	y	-	-	N	-	-	-	-	Y	Y	Y	Y	N	Y	Y	Y	Y	N	PTS	ABC/DEF	
XX2	Example	4.1	8	545.5	Y	Y		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	PTS	ABC/DEF	

Note: Excel spreadsheet to contain as many rows as needed

Form 6-1 Record Form - Assessment Selection Method Comments	
Number	**Comment**
	Note: Excel spreadsheet to contain as many rows as needed

Form 6-1 - Assessment Method Codes			
Code	Assessment Method Description	Code	Assessment Method Description
DE	Direct excavation	PT	Standard Subpart J pressure test
DEF	Deformation ILI tool (caliper or geometry)	PTS	Subpart J pressure test plus spike test
ECDA	External corrosion direct assessment (see Section 7)	SCCDA	SCC direct assessment (see Section 7)
HRMFL	High resolution MFL tool	SRMFL	Standard resolution MFL tool
ICDA	Internal corossion direct assessment (see section 7	USCD	Ultrsonic shear tool
NONE	No technologies feasible for this section	USCW	Ultrasonic compression wave tool
OT	Other technology		

Revision Log:

Date	Description	Revised By
12/02/2004	Changed NGA logo to LG&E logo	MTS
	Changed color of sections from blue to green	CA
12/02/2004	Changed font style and size	MTS
12/02/2004	Changed Manager of Engineering to Manager of Pipeline Integrity (Subsection 6.1.2)	MTS
12/02/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/02/2004	Changed Company to LG&E Energy	MTS
12/02/2004	Inserted KPSC and/or IURC for state references	MTS
12/02/2004	Changed Appendix F to Appendix 6-A (pressure test) and 6-B (spike test)	MTS
12/02/2004	Inserted pressure test considerations including benefits and limitiations	MTS
12/02/2004	Reworded Subsection 6.5.4 to state that LG&E Energy will assure that its corrosion control is effective if pressure testing is selected, removed reference to FAQ-49, and added the sentence (i.e., OPS typically requires that operators selecting the pressure test method also provide assurance that their corrosion control program is effective.) per Gulf Interstate Engineering's request.	MTS
12/02/2004	Changes hydrostatic testing to pressure testing	MTS
12/02/2004	Reworded the Note contained in Subsection 6.5.6.	MTS
12/02/2004	Change references to Section 20 to Section 19	MTS
12/14/2004	Section 6 approved by management	CMA
5/4/05	Changed reference to Pressure Test Procedure in 6.5.2 to Appendix 9-A from 6-A	LCO
10/05/2005	Reformatted to match other IMP sections.	CMA
6/27/2007	Changed company logo from "LG&E Energy" to "LG&E" E.ON|US	CMA
1/14/08	Revised 6.7 Other Technology per ENE recommendation	LCO
10/8/2008	Changed all references of OPS to PHMSA	EN Engineering
10/8/2008	Added Section 6.3.1 to address threats that are not used in the Assessment Method Selection Process	EN Engineering
10/8/2008	Added clarification in Section 6.4 for which manufacturing threats that can be assessed by ILI.	EN Engineering
10/8/2008	Updated Table 6-1 to include TFI as a assessment method option for SCC.	EN Engineering
10/8/2008	Updated Primary Assessment Method process in Figure 6_2 to correlate with section 6.	EN Engineering
10/8/2008	Changed Figure 6_3 title to ILI Tool Selection and updated process to correlate with section changes.	EN

		Engineering
10/8/2008	Updated form 6_1 to correlate with changes made to Figure 6_2 (Primary Assessment Method selection).	EN Engineering
11/12/08	11/12/08 Version approved by management	LCO
6/19/09	Added Section 6.3.2 Plastic Transmission Pipelines addressing general integrity assessment requirements for plastic transmission pipelines	EN Engineering
6/19/09	Added statement to Section 6.4 "In-line inspection is not applicable to plastic transmission pipelines.	EN Engineering
6/19/09	Added statement to Section 6.5.4 exempting plastic from corrosion control provisions of pieline integrity managements.	EN Engineering
6/19/09	Section 6.5.5, added expaination of yield strength in steel and hydrostati design base steength in plastic and applicability to test presures and assessment intervals for integrity management.	EN Engineering
12/16/2010	Removed Eon-us reference from logo in heading, changed LG&E Energy to "the company" throughout text	RN Eder
12/16/2010	Removed Eon-us reference from logo in heading on this form	RN Eder
11/23/2011	Updated Figure 6-1, added instructions for use of Form 6-1 in Section 6.8.	RN Eder
10/31/2012	Added subsections 6.3.1, 6.3.2 and 6.4.1 to Table of Contents	RN Eder
11/1/2012	Section 6.3, divided applicable threats into steel and plastic	RN Eder
11/1/2012	Section 6.3.1, added "Steel Pipelines" to heading, inserted steel into text	RN Eder
10/31/2012	Section 6.8, added statement to heading paragraph, "This is a record document ………"	RN Eder
10/31/2012	Replaced Form 6-1, revised form includes plastic pipelines, revised headings, revised appearance	RN Eder
11/08/2012	Correction to Fig 6-2, add "Record Selected Assessment Methods" box to pressure test path	M Stephens
12/12/2013	Correction to 6.5.2 reference to GOM&I-PO-TE-001and general clerical changes.	JRG
12/18/2015	Integrated information from Form 6-1 into Form 8-1 and deleted Form 6-1. Updated list of threats not considered in method selection in Section 6.3.1. Updated section 6.6 with assessment methods for previously damaged pipe. Updated description of an effective corrosion control program in Section 6.5.4,	Craig Meade

7 DIRECT Assessment PLAN §192.923-192.931

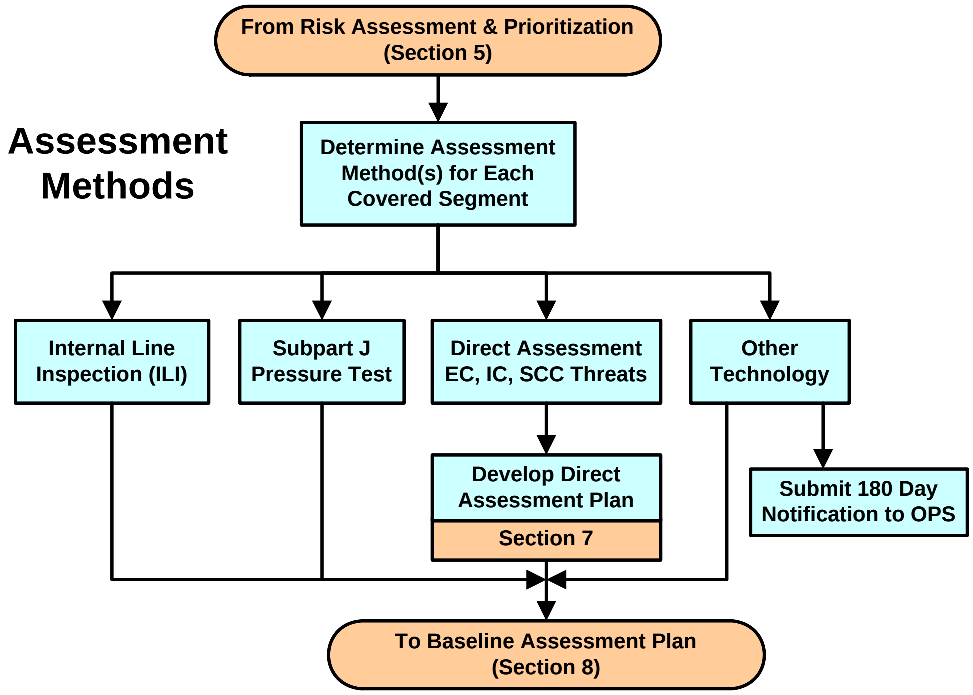
In This Section

Referenced Protocols

Not Applicable

7 DIRECT ASSESSMENT PLAN

7.1 OVERVIEW



7.1.1 Purpose

The Direct Assessment Plan section describes the specific processes and procedures Louisville Gas & Electric/ Kentucky Utilities (**the Company**) will use to implement Direct Assessment as an assessment method. Direct Assessment is an available pipeline integrity assessment method that the company will evaluate during the assessment selection process. The Threats of Concern that must be addressed are identified in Section 4 – Threat Identification and Evaluation. In addition, the selection of appropriate assessment methods is addressed in Section 6 – Assessment Method Selection.

7.1.2 Responsibility

The **Program Manager – Pipeline Integrity** M1 will have the overall responsibility for the performance of these procedures and for any modifications to this section. The **Manager - Gas Regulatory Compliance** M4 responsible ensuring the key personnel described in Section 2 – Roles and Responsibilities, perform their assigned duties as described. The **Program Manager – Pipeline Integrity** M1 has the specific responsibility of managing the pipeline assessments; the **Pipeline Specialist** F5 has the specific responsibility of providing direct oversight of the pipeline assessments.

7.2 DEFINITIONS

7.2.1 Direct Assessment

Direct Assessment is an integrity assessment method that utilizes a process to evaluate certain threats (i.e., external corrosion, internal corrosion, and stress corrosion cracking) to a covered 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. [Appendix 1B and CFR §192.903]

7.2.2 External Corrosion Direct Assessment (ECDA)

External Corrosion Direct Assessment is a four step process that combines preassessment, indirect inspection, direct examination, and post assessment to evaluate the threat of external corrosion to the integrity of a pipeline. [Appendix 1B and CFR §192.903]

7.2.3 Internal Corrosion Direct Assessment (ICDA)

Internal Corrosion Direct Assessment is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas. [Appendix 1B and CFR §192.903]

7.2.4 Stress Corrosion Cracking Direct Assessment (SCCDA)

Stress Corrosion Cracking Direct Assessment is a process to assess a covered pipe segment for the presence of SCC primarily by systematically gathering and analyzing excavation data for pipe process having similar operational characteristics and residing in a similar physical environment. [Appendix 1B and CFR §192.903]

7.3 EXTERNAL CORROSION DIRECT ASSESSMENT (ECDA)

The company's External Corrosion Direct Assessment (ECDA) plan is detailed in Section 7A which follows this Direct Assessment Plan outline.

Section 7Ai contains the procedure for Close-Interval Survey and section 7Aii contains the procedure for Direct Current Voltage Gradient Survey.

7.4 INTERNAL CORROSION DIRECT ASSESSMENT (ICDA)

The company's Internal Corrosion Direct Assessment (ICDA) plan is detailed in Section 7-B which follows this Direct Assessment Plan outline.

7.5 STRESS CORROSION CRACKING DIRECT ASSESSMENT (SCCDA)

The company's Stress Corrosion Cracking Direct Assessment (SCCDA) plan will be developed prior to the use of this assessment method.

7.6 CONFIRMATORY DIRECT ASSESSMENT (CDA)

The company's Confirmatory Direct Assessment (ECDA) plan is detailed in Section 7-C which follows this Direct Assessment Plan outline.

Revision Log:

Date	Description	Revised By
12/02/2004	Changed NGA logo to LG&E logo	MTS
	Removed protocol references. The references should be included with the individual direct assessment plans (i.e., ECDA, ICDA, and SCCDA)	MTS
12/02/2004	Changed font style and size	MTS
12/02/2004	Changed Manager of Engineering to Manager of Gas Regulatory Compliance, Regional Engineer to Program Manager – Pipeline Integrity (Subsection 6.1.2)	MTS
12/02/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/02/2004	Deleted the contents of Subsection 7.3 External Corrosion Direct Assessment and inserted the sentences - LG&E Energy's External Corrosion Direct Assessment (ECDA) plan will detailed in Appendix 7-A. It is scheduled for completion by March 2005 or prior to the use of this assessment method, whichever comes first.	MTS
12/02/2004	Deleted the contents of Subsection 7.4 Internal Corrosion Direct Assessment and inserted the sentence - LG&E Energy's Internal Corrosion Direct Assessment (ICDA) plan will be developed prior to the use of this assessment method.	MTS
12/02/2004	Deleted the contents of Subsection 7.5 Stress Corrosion Cracking Direct Assessment and inserted the sentence - LG&E Energy's Stress Corrosion Cracking Direct Assessment (SCCDA) plan will be developed prior to the use of this assessment method	MTS
12/02/2004	Inserted text for Subsection 7.6 Confirmatory Direct Assessment.	MTS
12/02/2004	Insert signature block	
2/14/06	Section 7, 7A, 7B completed.	CMA
2/23/06	Form 7A.7-1 Updated (this needs to be imported into the document)	CMA
3/1/06	Section 7B.5.4.2 update to read "For every….performed within each DG-ICDA region" Section 7B.5.4.2.3 inserted.	CMA
4/7/06	Section approved by management.	
10/10/2008	Table of Contents updated to included Section 7Ai, 7Aii, 7C	CMA
10/10/2008	All subsections of 7.6 – CDA were removed to indicate that Section 7C – CDA Procedure has been completed.	ENE

7A EXTERNAL CORROSION DIRECT ASSESSMENT §192.921

In This Section

Referenced Protocols

List of Tables

List of Figure

7A.1 PURPOSE

The purpose of this procedure is to describe the process of performing External Corrosion Direct Assessment (ECDA) surveys on identified pipeline segments. This procedure is written in accordance with NACE SP0502, Pipeline External Corrosion Direct Assessment Methodology. It provides instructions, guidance, and requirements to assure and document that ECDA is performed in compliance with the Recommended Practice.

7A.2 INTRODUCTION

✓ ***Referenced Protocol:*** ***D.01 ECDA Programmatic Requirements***

7A.2.1 References

7A.2.1.1 **NACE SP0502**

Standard Recommended Practice, Pipeline External Corrosion Direct Assessment Methodology. (References to NACE SP0502 refer to the most recent revision which is incorporated by reference into 49 CFR Part 192.)

7A.2.1.2 **49 CFR Part 192 Subpart O**

Pipeline Integrity Management in High Consequence Areas.

7A.2.2 Objective

ECDA is a structured process that is intended to improve safety by assessing and reducing the impact of external corrosion on pipeline integrity. ECDA seeks to proactively prevent external corrosion defects from growing to a size that affects the structural integrity of the inspected pipeline segments. Since ECDA is a continuous improvement process, successive applications of ECDA should identify and address locations where corrosion has occurred, is occurring or may occur. When integrated with encroachment and foreign pipeline information, ECDA may be used to evaluate the threat of residual third-party damage.

7A.2.3 Scope

This procedure may be used to evaluate the integrity of pipeline segments that are threatened by external corrosion. During the assessment process other types of damage may be identified. In those cases the damage must be documented and other suitable assessment methodologies used to evaluate the integrity of the pipeline segments ECDA Methodology

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

1. **Pre-Assessment**: The Pre-Assessment step utilizes historic and recent data to determine whether the ECDA is feasible, identify appropriate indirect inspection tools, and define ECDA regions. The required data are typically

available at district offices, transmission and distribution strip maps, GIS, Work management software systems, corrosion control software systems, Distribution Packages, Pipeline Database, and archived files.

2. **Indirect Inspection**: The Indirect Inspection step utilizes above ground inspections to identify and define the severity of coating faults, diminished cathodic protection, and areas where corrosion may have occurred or may be occurring. A minimum of two indirect inspection tools are used over the entire pipeline segment to provide improved detection reliability across the wide variety of conditions encountered along a pipeline right-of-way. Indications from indirect inspections are categorized according to severity. Integrating encroachment and foreign line crossing information with the indirect inspection data allows the use of ECDA to evaluate the threat of residual third-party damage.

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

4. **Post-Assessment**: The Post-Assessment step utilizes data collected from the previous three steps to assess the effectiveness of the ECDA process, determine reassessment intervals, and provide feedback for continuous improvement.

7A.2.4 Roles and Responsibilities

The roles & responsibilities for the personnel executing this ECDA procedure are described in Section 2 of the Louisville Gas & Electric / Kentucky Utilities (**the Company**) pipeline integrity management plan. The positions described within **the Company** pipeline integrity management plan are functional, and may be performed by more than one individual. Likewise, one person may assume multiple functional positions. The principal roles and responsibilities included within this ECDA procedure are as follows:

7A.2.4.1 Program Manager – Pipeline Integrity M1

The Program Manager (PM) is responsible for the overall program oversight, and to assure that this procedure is implemented effectively and fully integrated with **the Company** IMP. This procedure assigns authority for approval of documents, plans, and exceptions to this position. The PM may delegate some or all of these approving responsibilities. Additionally, the PM may assign part or all of the duties or responsibilities for any position included within this procedure to contractors or vendors.

7A.2.4.2 Corrosion Supervisor M3

The Corrosion Supervisor (CS) shall be available for providing technical guidance and assistance regarding the assessment process.

7A.2.4.3 Pipeline Integrity Engineer F3

The Pipeline Integrity Engineer (PIE) is responsible to assure that available and required pipeline and geographical data and available applications software are properly integrated with each ECDA project. The PIE is responsible for data analysis of pre-assessment data and field generated inspection data including, but not limited to sufficient data analysis, ECDA Region Designation, Indirect Inspection results, and remaining strength evaluations. The PIE may also perform direct examinations and indirect inspections for which he or she is qualified.

7A.2.4.4 Pipeline Specialist F5

The Pipeline Specialist (PS) is responsible to assure that all aspects of the assigned ECDA projects are conducted in full compliance with this procedure. The PS is responsible for planning, documenting, and communicating various aspects and stages of the assigned ECDA projects including ECDA Region designations. Additionally, the PS may perform direct examination of pipe coating and pipe surface conditions and other related dig site integrity inspections to the extent that he or she is qualified. This procedure has response time requirements. The PS has point responsibility to assure that those time requirements are met throughout the project.

7A.2.4.5 Corrosion Technician F6

The Corrosion Technician (CT) is responsible for conducting the indirect inspections and assigned direct examinations. They are responsible for conducting the inspections and tests in accordance with this procedure and other testing procedures referenced within the assessment process. In many cases, the CT responsibilities will be assigned to vendors / contractors.

7A.2.5 Qualifications

7A.2.5.1 Objective

The provisions of this procedure shall be applied under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on buried ferrous piping systems.

7A.2.5.2 Specific Qualification Requirements

Table 2-2 in Section 2 of **the Company** IMP lists the key company personnel requirements for each of the roles and responsibilities described in this procedure (see section 2.5 above). If the qualification requirements listed in Table 2-2 are not met, the assigned responsibilities shall be approved through the exception process located in Subsection 7A.7 of this procedure.

Contract personnel and other outside resources must be qualified under the applicable company operator qualification program, or an operator qualification program that has been reviewed and approved by the company as applicable. Refer to Section 15 Quality Assurance for additional information on contract personnel qualifications.

7A.2.6 Definitions

The following are definitions of some key terms used in this procedure:

Considered: "Considered" data (listed in Table 7A.3.1 in the "Usage" column) should be taken into account for the selection of indirect inspection tools, designation of ECDA regions, or analysis of test results. Its omission does not require approval or documentation.

Covered Pipeline: Is a pipeline contained within a High Consequence Area that meets the characteristics specified by the Office of Pipeline Safety requiring it to be included in the company Integrity Management Plan. [See Appendix 1B for an additional definition from CFR §192.903.]

Desired: "Desired" data (listed in Table 7A.3.1 in the "Need" column) should be obtained if reasonably possible or easily measured. Its omission does not require approval or documentation.

ECDA Region: An ECDA region is a portion of a pipeline that has similar physical characteristics, corrosion histories, expected future corrosion conditions, and that uses the same first two indirect inspection tools. ECDA Regions can be discontinuous but must be contained within the same pipeline segment (see below). It is important for the analysis to take into account all of these criteria when establishing ECDA regions. [See Appendix 1B for an additional definition from CFR §192.903.]

High Consequence Area (HCA): High Consequence Areas are locations along the pipeline that meet the characteristics specified by CFR 49, Part 192. [See Appendix 1B for an additional definition from CFR §192.903.]

Project: Projects are ECDA activities that occur in the same relative time frame and where the data is integrated in the ECDA process. Projects can contain multiple ECDA Regions.

Required: "Required" data listed in Table 7A.3.1 are data elements that are required to be taken into account in IIT selection, ECDA Region establishment or during the post assessment step. When accounting for these data elements, The **PS** and / or **PIE** shall integrate all required data elements in making determinations regarding the application of ECDA and assessment of results.

"Required" data is mandatory for the implementation of ECDA. In some cases, if "Required" data is not known, justified assumptions can be made provided the assumption is documented and approved by the **PM**.

Segments: Segments are continuous lengths of pipe. Appendix 1B and ASME B31.8S define segments as a length of pipeline or part of the system that has unique characteristics in a specific geographic location.

Shall: Shall is a requirement that must be complied with, or its exception approved and documented in accordance with subsection 7.0 of this procedure.

Should: Should is a recommendation that is desirable to follow if possible. Not following the recommendation does not require documentation or approval.

NACE SP0502 has been incorporated by reference in it's entirety into Part 192, Subpart O. Therefore, "should" statements listed in SP0502 are addressed in this procedure.

7A.2.7 Special Requirements

In each step of this procedure special requirements are specified when conducting an ECDA over a given piece of pipe for the first time. These requirements provide more extensive data collection, analysis, or other activities when assessing a pipe segment for the first time.

7A.3 PRE-ASSESSMENT

✓ ***Referenced Protocol:*** ***D.02 ECDA Pre-Assessment***

7A.3.1 Objectives

The objectives of the pre-assessment process are to:

- Collect pipeline data to determine the feasibility of conducting an ECDA
- Determine the feasibility of conducting an ECDA of the pipeline
- Select Indirect Inspection Tools (IIT)
- Establish preliminary ECDA regions
- Document pre-assessment results

7A.3.2 Pre-assessment Process

Figure 7A.3.1 shows the process flow chart of the Pre-assessment step.

7A.3.3 Pipeline Segments Requiring ECDA

7A.3.3.1 **Identification of ECDA Projects**

Pipeline segments requiring an ECDA can be identified from multiple sources. Usually the requirement for ECDA analysis will be generated by **the Company's** Integrity Management Program. This procedure does not address the identification or relative risk ranking of pipeline segments requiring ECDA.

7A.3.3.2 **Information Provided with ECDA Request**

The work request for an ECDA shall contain the following information:

- High Consequence Area information
- Starting and ending points of HCA
- Pipeline Number or identification
- Starting and ending mile points of the ECDA region
- Risk Ranking
- Approval of the **PM**

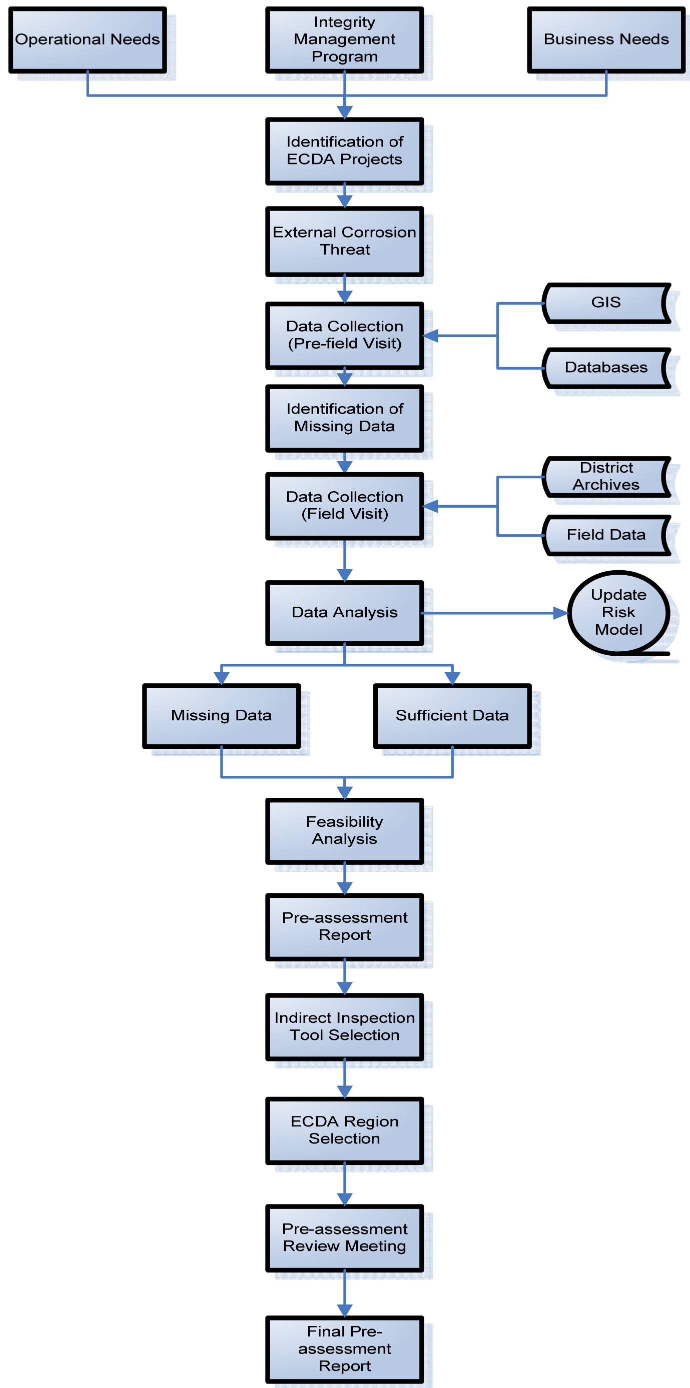


Figure 7A.3.1: Pre-assessment Flow Chart

7A.3.4 Data Collection (Pre-Field Visit)

7A.3.4.1 **Data Collection Objectives**

Key aspects of the Pre-Assessment step include collection of pipeline data, and the consistent use and interpretation of results. Table 7A.3.1 Pre-Assessment Data List provides a checklist of the data elements needed to conduct the ECDA. The data is collected to achieve the following objectives:

- Determine the feasibility of conducting an ECDA
- Selection of Indirect Inspection Tools (IIT)
- Establishment of ECDA regions

The **PIE** should consider these objectives to assure that appropriate and sufficient data is collected.

7A.3.4.2 **Data Collection Phase**

Data collection and analysis is a continuous activity throughout the ECDA process. This procedure divides Pre-assessment data collection into two steps; “Pre-Field Data Collection” and “Field Data Collection”. Pre-Field Data Collection is the process of collecting data from existing files, databases, and subject matter experts. It prepares the **PIE** for understanding what data will need to be collected in the field.

7A.3.4.3 **Data Requirements**

The “Need” for the data elements is identified in Table 7A.3.1 as either “REQUIRED” or “DESIRED”. Data elements identified as REQUIRED shall be obtained in order for the ECDA to be deemed feasible. If a Required data element is not available, but a justified engineering assumption can be made, the ECDA may be feasible upon approval of the **PM**. See Sufficient Data Analysis Subsection 7A.3.7.2 for further details.

“DESIRED” data elements should be obtained if available in existing records or if the data can be easily obtained from measurements or examinations. The **PIE** may consider “DESIRED” data sufficiently important to classify it as “REQUIRED” for a specific ECDA project.

7A.3.4.4 **1st Assessment Requirements**

When conducting ECDA for the first time over a given pipeline segment, all available CP records shall be collected and reviewed to develop a complete understanding of the pipeline corrosion history. This requirement is specified in both Table 7A.3.1 and Form 7A.1 (data element 4.6).

7A.3.4.5 **Data Sources**

Table 7A.3.1 provides guidance regarding possible sources for each data element. If the data element is not available in the listed sources, the **PIE** is responsible for applying good judgment in seeking the data elsewhere.

7A.3.4.6 **Documentation of Data Collection**

The successful collection of information shall be indicated on the "DATA ELEMENT SHEET" (Form 7A.1) or similar document.

7A.3.4.7 **Project Document File**

Each ECDA project shall be maintained using a suitable filing system to house the project documentation - including both hardcopy and electronic media. The system shall be organized to allow the effective storage of correspondence, pipeline data, inspection and analysis results, disposition of findings, and re-inspection intervals.

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage			Data Source					Comments
						Inspection Tool	Region Selection	Interpretation / Analysis	District / Archive Files	GIS	Field Observation	Pipeline Databases	Maps / Other	
1.0 Pipe Related														
1.1	Material and Grade	ECDA is not appropriate for nonferrous materials	Special consideration should be given to locations where dissimilar metals are joined	The SMYS will be used for predicted burst pressure calculations that will influence the remaining life calculations	R	C	C	R	X			X	X	Consider for inspection tools and region selection only when non-ferrous, stainless or cast iron materials are used. Otherwise use only in direct assessment and post assessment phases.
1.2	Diameter	May reduce detection capability of indirect inspection tools		Influences CP current flow and interpretation. Diameter will be used for predicted burst pressure calculations that will influence remaining life calculations.	R	C	C	R	X			X	X	Investigate the affect of diameter on detectability
1.3	Wall thickness			The wall thickness will be used for predicted burst pressure calculations as well as remaining life calculations.	R	N/R	N/R	R	X			X	X	

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Inspection Tool	Region Selection	Interpretation / Analysis	District / Archive Files	GIS	Field Observation	Pipeline Databases	Maps / Other	Comments
1.4	Year manufactured			Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.	D	N/R	N/R	C	X			X	X	Assume the same as year installed
1.5	Seam Type		Locations with pre-1970 low frequency ERW or flash welded pipe with increased selective seam corrosion susceptibility may require a separate region.	Older pipe typically has lower weld seam toughness that reduces critical defect size. Pre-1970 ERW or flash welded pipe may be subject to higher corrosion rates than the base metal.	D	N/R	C	C	X			X		
1.6	Bare pipe	Limits ECDA application. Fewer available tools.	Segments with bare pipe should be in separate regions.	Specific ECDA methods are required.	R	R	R	R	X		X			
2. 0 Construction Related														
2.1	Year installed		Older pipe may have greater damage pipe	Impacts time over which coating degradation may occur, defect population estimates, and corrosion rate estimates.	R	N/R	N/R	R	X			X	R	

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

						Usage			Data Source					
ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Inspection Tool	Region Selection	Interpretation / Analysis	District / Archive Files	GIS	Field Observation	Pipeline Databases	Maps / Other	Comments
2.2	Recent route changes / modifications not reflected in drawings		Changes may require separate regions		D	N/R	C	N/R	X	X	X		As-builts	
2.3	Backfill Construction practices	Backfill with large amount of rock may affect the feasibility of ECDA process	Construction practice differences may require separate regions	May indicate locations at which construction problems may have occurred; e.g., backfill practices influences the probability of coating damage during construction.	D	C	C	C	X					
2.4	Location of major pipe appurtenances such as valves, and taps		Significant drains or changes in CP current should be considered separately; special consideration should be given to locations with dissimilar metals	May impact local current flow and interpretation of results; dissimilar metals may create local corrosion cells points of contact; coating degradation rates may be different from adjacent regions	D	N/R	C	C	X	X	X	X	X	
2.5	Locations of casings	Best assessed with other methodology			R	R	R	C	X		X	X	X	

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage: Inspection Tool	Usage: Region Selection	Usage: Interpretation / Analysis	Data Source: District / Archive Files	Data Source: GIS	Data Source: Field Observation	Data Source: Pipeline Databases	Data Source: Maps / Other	Comments
2.6	Location of bends; including miter bends and wrinkle bends		Presence of miter and wrinkle bends may influence region selection	Coating degradation rates may be different from adjacent regions; corrosion on miter and wrinkle bends can be localized, which affects local current flow and interpretation of results	D	C	C	C	X					
2.7	Depth of cover	Restricts the use of some indirect inspection techniques	May require different ECDA regions	May impact current flow and interpretation of results	D	C	C	C			X		X	
2.8	Underwater sections and river crossings	Significantly restricts the use of many indirect inspection techniques	Requires separate ECDA region	Changes current flow and interpretation of results	R	R	R	C		X	X		X	
2.9	Location of river weights or anchors	Reduces the available indirect inspection tools	May require separate ECDA region	Influences current flow and interpretation of results; corrosion near weights and anchors can be localized which affects local current flow and interpretation results	D	C	C	C	X				As-builts	
2.10	Proximity to other CP structures, HV electric transmission lines, and rail crossing	May preclude the use of some indirect inspection methods	Regions where the CP currents are significantly affected by external sources should be treated as separate ECDA regions.	Influences local current flow and interpretation of results	R	C	C	C			X			

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage			Data Source					Comments
						Inspection Tool	Region Selection	Interpretation / Analysis	District / Archive Files	GIS	Field Observation	Pipeline Databases	Maps / Other	
3.0 Soils / Environmental														
3.1	Soil characteristic s & types including soil contamination	Some soil characteristics reduce the accuracy of various indirect inspection techniques	Influences where corrosion is most likely; significant differences generally require separate ECDA regions	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment	D	C	C	C			X			Soil data may be collected at later stages of the process after review of the ECDA regions for appropriateness
3.2	Drainage		Influences where corrosion is most likely; significant differences may require separate ECDA regions.	Can be useful in interpreting results. Influences corrosion rate and remaining life assessment.	D	N/R	C	C			X			
3.3	Topography	Conditions such as rocky areas can make indirect inspections difficult or impossible.			D	C	C	N/R			X			
3.4	Land use (past / present)	Paved roads, etc., influence indirect inspection tool selection	Can influence ECDA application and selection		R	R	R	N/R			X			Asphalt, concrete, agricultural, residential, industrial, etc.
3.5	Frozen ground	May impact the applicability and effectiveness of some ECDA methods	Pipeline with some frozen areas should be considered in separate regions.	Influences current flow and interpretation of results.	R	C	N/R	C			X			
4.0 Corrosion Control														

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage: Inspection Tool	Usage: Region Selection	Usage: Interpretation / Analysis	Data Source: District / Archive Files	Data Source: GIS	Data Source: Field Observation	Data Source: Pipeline Databases	Data Source: Maps / Other	Comments
4.1	CP system type (anodes, rectifiers and locations)	May effect ECDA tool selection	Pipeline segments with different cp protection (i.e. anodes versus rectifiers) should be considered in separate regions.	Localized use of sacrificial anodes within impressed current systems may influence indirect inspection. Influences current flow interpretation	R	C	C	C	X		X	X	CPDM	
4.2	Known stray current sources / locations		Areas of known stray current issues may require a separate region	Influences current flow and interpretation results	D	N/R	C	C	X		X	X	(See cmts.)	CP Records. Past survey reports
4.3	Test point locations (pipe access points)		May provide input when defining ECDA regions		R	N/R	C	N/R	X		X	X	CPDM	
4.4	CP criteria			Used in post assessment analysis.	R	N/R	C	C	X			X		
4.5	CP maintenance history over past five years		Coating condition indicator	Can be useful in interpreting the results	R	N/R	C	C	X			X		
4.6	**1st Assessment Requirement** - All available CP Maintenance History		Coating condition indicator	Can be useful in interpreting the results	R	N/R	C	C	X			X		First assessment criteria – must include all available CP maintenance history

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Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage: Inspection Tool	Usage: Region Selection	Usage: Interpretation / Analysis	Data Source: District / Archive Files	Data Source: GIS	Data Source: Field Observation	Data Source: Pipeline Databases	Data Source: Maps / Other	Comments
4.7	Years without CP applied		May make ECDA more difficult to apply.	Negatively affects ability to estimate corrosion rates and make remaining life.	D	N/R	C	C	X					
4.8	Coating type-pipe	ECDA may not be appropriate for coatings that cause shielding or disbonded coatings with high dielectric constants resulting in shielding	Different coating types may warrant different ECDA Regions	Coating type may influence time at which corrosion begins and estimates of corrosion rate based on measured wall loss.	R	R	C	C	X		X	X	X	
4.9	Coating type-joints	ECDA may not be appropriate for coatings that cause shielding	Different coating types may warrant different ECDA Regions	Shielding due to certain joint coatings may lead to requirements for other assessment activities.	D	C	N/R	C	X		X			
4.10	Coating condition	ECDA may be difficult to apply with severely degraded coatings	Different coating conditions may warrant different ECDA Regions		D	C	C	C	X		X			
4.11	Current demand		Different current demands may warrant different ECDA Regions	Increasing current demand can indicate areas where coating degradation is leading to more exposed pipe surface area	D	N/R	N/R	C	X		X	X		

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Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage: Inspection Tool	Usage: Region Selection	Usage: Interpretation / Analysis	Data Source: District / Archive Files	Data Source: GIS	Data Source: Field Observation	Data Source: Pipeline Databases	Data Source: Maps / Other	Comments
4.12	CP survey data / history		Different corrosion history may warrant different ECDA Regions	Can be useful in interpreting the results	D	N/R	C	C	X					
5.0 Operational Data														
5.1	Pipe operating temperature		Significant differences generally require separate ECDA areas	Can locally influence coating degradation rates	D	N/R	C	C	X					Consider when within 20 total pipeline miles downstream of compressor station discharge.
5.2	Operating stress level			Impacts critical flaw size and remaining life predictions	R	N/R	N/R	R	X			X		
5.3	Monitoring programs (Coupon, leak patrol, etc.)		May provide input when defining ECDA regions	May impact repair, remediation and replacement schedules.	D	N/R	C	C	X					
5.4	Pipe inspection reports-excavation		May provide input when defining ECDA regions	May provide insight into corrosion rate	D	N/R	C	N/R	X					

Table 7A.3.1: Pre-assessment Data List

R = Required; D = Desired; C = Considered; N/R = Not Required

ID #	Data Element	Indirect Inspection Tool Selection (IIT)	ECDA Region Selection	Use & Interpretation Of Results	Need	Usage			Data Source					Comments
						Inspection Tool	Region Selection	Interpretation / Analysis	District / Archive Files	GIS	Field Observation	Pipeline Databases	Maps / Other	
5.5	Repair history / records (steel / composite repair sleeves, repair locations, etc.)	May affect ECDA tool selection	Repairs (such as anode additions) may influence region selection.	Provide useful data for post assessment analysis	D	C	C	N/R	X					
5.6	Leak rupture history (EC)		Can indicate condition of existing pipe	May assist selecting corrosion rate	R	N/R	C	C	X					
5.7	Evidence of external MIC			MIC may accelerate external corrosion	D	N/R	C	C	X					
5.8	Type and frequency of third party damage		Damage may warrant different ECDA Regions		D	N/R	C	N/R	X					
5.9	Previous above ground survey data		History of corrosion may warrant different ECDA Regions	Essential for pre-assessment and region selection	R	N/R	C	N/R	X				X	Required only if previous surveys have been performed
5.10	Hydrotest date / pressure			Influences inspection intervals	D	N/R	C	C	X			X		
5.11	Prior integrity related assessments – CIS, ILI runs, etc.	May impact ECDA tool selection-isolated vs. larger corroded areas	History of corrosion damage may warrant different ECDA Regions	Useful post assessment data	R	N/R	C	C	X					Required only if previous surveys have been performed

7A.3.5 Identification of Missing Data

Once the Pre-field Visit data is collected the **PIE** shall analyze the data to identify missing elements, and develop a list of data that will need to be obtained in the field. The DATA ELEMENT CHECK SHEET, Form 7A.1, can be used for this purpose.

7A.3.6 Field Visit

7A.3.6.1 **General Description**

Examining the physical locations where the ECDA is to be conducted is a key activity in the gathering of data. It is important to collect available data to achieve the objectives of the Pre-assessment and effectively plan for the Indirect Inspection step of the ECDA process. Hence, preparation is key to conducting an effective field visit. The following data elements that may require field collection or verification in the field are:

Table 7A.3.2: Typical Field Collected Data

ID	Description	ID	Description
2.2	Route changes in the pipeline that are not yet reflected in company documents	**3.3**	Topography where it is extremely rocky or steep or where access is difficult
2.7	Dramatic changes in the depth of cover.	**3.4**	Past and present land use, type of paving, accessibility due to private lands, build-overs, crossings or busy roads or highways
2.8	Details on under water crossings	**3.5**	Possibility of frozen ground
2.10	Proximity to other pipelines, HV transmission lines, and rail crossings	**4.1**	CP systems, location of rectifiers, CP test stations
3.1	Soil characteristics and types	**4.2**	Sources of stray current and their proximity to the pipeline
3.2	Drainage along the pipe line and areas where the pipeline crosses seasonal creeks	**4.3**	Test point locations and access to the pipe

7A.3.6.2 **Documentation Requirements**

All data collected in the field that will be used in the ECDA shall be documented on Form 7A.1.

7A.3.7 Data Analysis

The **PIE** shall analyze the pre-assessment data to identify missing REQUIRED and DESIRED data elements, and conduct a Sufficient Data Analysis. The Sufficient Data Analysis is mandated by NACE RP 0502, and is required for compliance with the recommended practice.

7A.3.7.1 **Missing Data**

The **PIE** shall document missing data. The DATA ELEMENT CHECK SHEET, Form 7A.1, may be used to document the missing data. The pipe segments that are missing data shall be identified. If another list(s) of missing data is developed it shall include the following information:

- HCA Number
- Data Element ID number
- Data Element Description
- Required or Desired data category
- Why the data element was not available

7A.3.7.2 **Sufficient Data Analysis**

The data shall be analyzed by the **PIE** to determine if there is sufficient data to conduct an ECDA. The analysis should include the following:

- **Missing Required Data:** If required data is missing and determined non-essential to the ECDA, the rationale for deviation from normal data collection shall be documented in the SUFFICIENT DATA ANALYSIS REPORT (FORM 7A.2).
- **Missing Desired Data:** If desired data is missing and determined essential to conduct the ECDA, the data should be identified in the analysis and documented in the SUFFICIENT DATA ANALYSIS REPORT (FORM 7A.2).
- **Report:** The **PIE** shall prepare a Sufficient Data report concluding there is sufficient data to conduct an ECDA. This report shall have the analyses described in the two paragraphs above and be signed and dated. The SUFFICIENT DATA ANALYSIS REPORT (FORM 7A.2) of this procedure may be used for this reporting. The PIE shall submit the SUFFICIENT DATA ANALYSIS REPORT (FORM 7A.2) to the PM for review and signature.

7A.3.8 Feasibility Analysis

7A.3.8.1 **Analysis**

The **PIE** shall integrate and analyze the pre-assessment data collected to determine if conditions allow for proper indirect inspections, and if the application of the ECDA is appropriate. The **PIE** shall examine the collected data in each of the five categories in Table 7A.3.1 and assess the following:

- **Indirect Inspection:** Can indirect inspection tools be appropriately applied to the identified pipeline segments and produce meaningful results at locations where the coating is damaged and / or corrosion is possibly occurring?
- **Direct Examination:** Is it feasible to gain access to the pipeline to conduct direct examinations and obtain meaningful data?

- **Post Assessment:** Can reassessment intervals be reasonably determined for the pipe segments given the existing data?

Additionally, the **PIE** shall ensure all "Required" data elements are available. If the "Required" data elements are not available for a line segment, ECDA will be deemed not feasible for the line segment and an alternate assessment technique will be utilized. In some cases, sound engineering justifications can be made for missing "Required" data. Such a circumstance requires the approval of the **PM**.

7A.3.8.2 Specific Feasibility Requirements

In addition to the analyses listed above, the **PIE** shall consider and evaluate the following specific conditions. The following conditions are given as guidance and other conditions may preclude the use of ECDA at the discretion of the **PIE**.

- **Electrical Shielded Coatings:**
  - ECDA is not feasible where a coating type has caused known electrical shielding of cathodic protection or in areas of shielding by disbonded coating
- **Rock**
  - ECDA is not feasible if a rock "cap" resides over the pipeline
  - ECDA is not feasible if the pipeline has been trenched in rock and is lying directly on rock
- **Ground Surfaces**
  - Indirect Inspections are not feasible over frozen ground
  - Indirect Inspections are not feasible in areas of pavement unless holes are drilled through the pavement in order to make contact with the soil/ground.
- **Adjacent Metallic Structures:**
  - ECDA is not feasible in areas where a buried metallic structure is buried over the pipe
- **Inaccessible areas:**
  - Indirect inspections may not be possible at steep inclines
  - Indirect inspections may not be possible in areas where the ground is covered with large rocks
  - Indirect inspections may not be feasible over large bodies of water
  - Direct examinations are not feasible in areas where the pipe may not be accessible (i.e. equipment, permits)

The **PIE** shall consider these conditions to determine if ECDA is suitable for the pipe segments under consideration, and the decision-making rationale shall be documented on Form 7A.3, FEASIBILITY ANALYSIS REPORT.

7A.3.8.3 Pipeline Database Update

The **PIE** shall assure that Pre-assessment data is verified, and that the IMP Pipeline Database is updated with the pre-assessment data element changes if necessary. Updates to the Pipeline Database shall be documented and communicated through **the Company** Integrity Management Plan.

7A.3.8.4 Report

The **PIE** shall prepare a feasibility report and attach Form 7A.3 FEASIBILITY ANALYSIS REPORT. The report shall be reviewed and signed by the **PIE** and the PM. . The following topics shall be addressed in the report:

- Adverse conditions that may make the ECDA infeasible.
- Special considerations or techniques that need to be incorporated in conducting the ECDA to over come the adverse conditions
- A conclusion regarding the feasibility of conducting ECDA for the pipeline segments in the project

7A.3.9 Indirect Inspection Tool (IIT) Selection

7A.3.9.1 Number of IIT's

The **PIE** shall select at least two complimentary tools from Table 7A.3.3 / 7A.3.4 for each pipeline segment in the study area.

The **PIE** may utilize tools other than those listed in Table 7A.3.3 / 7A.3.4, but shall follow the exception process described in Subsection 7A.7 of this procedure. If the exception process is utilized, the following minimum information shall be documented:

- Justification of method's applicability
- Basis of validation methodology
- Type of equipment used
- Procedure for performing indirect inspection
- How data will be utilized / analyzed

Beyond the primary IIT's, the **PIE** may require additional complimentary inspections, data collection, and analysis to gain further information on the pipeline segments.

7A.3.9.2 Selection Basis

The **PIE** shall select IIT's based on their performance reliability under the specific pipeline conditions for each segment. The **PIE** should consider the guidance provided in Table 7A.3.1, Table 7A.3.3, and Table 7A.3.4. The **PIE** shall select tools that are complimentary to one another, i.e. the capabilities of one tool should compensate for the limitations of the other.

7A.3.9.3 **IIT Selection Documentation**

The selection and the basis for the IIT's shall be documented for each pipeline segment. The documentation shall include the name of each technique used, and any special considerations for conducting the inspections. Form 7A.4 Indirect Inspection Tools Selection may be used to document the IIT selections. Each pipeline segment and ECDA Region shall be assigned a sequential alphanumeric identifier (i.e. 1A, 1B, 1C) to allow each portion of pipeline to be uniquely distinguished for the purposes of ECDA data management.

Table 7A.3.3: ECDA Tool Selection Matrix

Conditions	CIS	DCVG/ACVG	Pearson	Electro-magnetic (PCM)	UT Guided Wave
Coating holidays	Yes	Yes	Yes	Yes	No
Anodic zones on bare pipe	Yes	No	No	No	Yes
Near river or water crossings	Yes	No	No	Possible[1]	Yes
Under frozen ground	No	No	No	Yes	Yes
Stray currents	Yes	Yes	Yes	Yes	Yes
Shielded corrosion activity	No	No	No	No	Yes
Adjacent metallic structures	Yes	Yes	No	Yes	Yes
Near parallel pipe lines	Yes	Yes	No	Yes	Yes
Under HVAC electric transmission lines	Yes	Yes	Yes	No	Yes
Shorted casing	No	No	No	No	Yes
Under paved roads	Possible[2]	Possible[2]	No	Yes	Yes
Uncased crossings	Yes	Yes	Yes	Yes	Yes
Cased crossings	No	No	No	Yes	Yes
Wetlands	Yes	Yes	Yes	Yes	Yes
Rock terrain, ledges or backfill	No	No	No	Yes	Yes

[1] Readings can be taken on both sides of smaller water crossings to verify current attenuation consistent with attenuation found upstream and downstream of the crossing. Width of water crossing should be no greater than the standard spacing being used for the inspection.
[2] Survey technique can be utilized when provisions for electrolyte access (i.e. drilling holes in pavement) are made

Table 7A.3.4: Indirect Inspection Tool Guide

Indirect Inspection Tool	Measurement Attributes	Typical Uses	Less Suitable for:	Complimentary Tools
CIS	Measures pipe to soil potentials along the pipeline at typically 3 to 10 foot intervals.	Generally used to assess the performance of CP systems and generally estimate the location of coating holidays. Also can detect interference, shorted casings, electrical or geological shielding, contact with other metallic structures as well as defective electrical isolation joints.	Pipelines that are below paved areas will require holes to be drilled to the soil. Is not effective on coating systems that have disbonded and are shielding.	DCVG, ACVG, Guided wave UT.
Electro-magnetic	Measures the electromagnetic field attenuation emanating from the pipe induced with an AC signal. Qualitatively ranks coating quality and highlights areas with the largest holidays. Spacing is dependent on conditions. 25-50 foot spacing is typical.	Can be used for pipelines under pavement and CP systems that are difficult to isolate	Not indicative of pipe to soil potential or effectiveness of CP. Is ineffective under HV transmission lines. Is not effective detecting coating systems that have disbonded and are shielding.	CIS, Guided wave
DCVG / ACVG	Measures voltage gradients resulting from current pickup and discharge points at holidays at typical 3 to 6 foot intervals for DCVG and 15 to 25 foot intervals for ACVG. Capable of precisely locating holidays on the pipeline.	Generally used to precisely locate large and small coatings holidays on buried pipelines.	Pipelines that are below paved areas will require holes to be drilled to the soil. Is not effective detecting coating systems that have disbonded and are shielding.	CIS, Guided wave
Pearson	Measures AC voltage gradients between two movable electrical ground contacts spaced approximately 20 feet apart along the pipeline.	Used to identify holidays on buried pipelines	Difficult to use for pipelines under pavement. Is not effective detecting coating systems that have disbonded and are shielding.	CIS, guided wave, electromagnetic
Guided Wave Ultrasonic	Uses guided ultrasonic waves to axially locate interior and exterior wall loss. Can potentially estimate the degree and circumferential location of the wastage. Can typically examine 20 to 60 feet of pipe from one bell hole.	Can be used for pipelines under pavement or in casings, pipelines with shielded coatings, or expand the length of pipe examined at a bell holes	Requires direct access to the pipeline and removal of the coating.	Electro-magnetic, CIS

7A.3.10 Establishment of ECDA Regions

7A.3.10.1 Description

ECDA Regions are pipeline segments that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and use the same indirect inspection tools. An ECDA region can be non-contiguous. All pipeline segments being assessed shall be included in an ECDA region.

7A.3.10.2 Criteria

The **PIE** shall analyze all the data collected in the Pre-Assessment step and assign each pipeline segment to an ECDA region. It is important that the **PIE** considers all data categories when establishing ECDA Regions.

7A.3.10.3 ECDA Region Guidance

The **PIE** shall utilize the following minimum guidelines when establishing ECDA regions. An ECDA region change is required at each of the following:

- Material
  - New region defined at pipe material changes
- Coating
  - New region defined at the location where the coating type changes (i.e. FBE to coal tar, coated to bare)
  - Based on line pipe, not joints
- Mechanically coupled pipe
  - Regions are defined by the span of continuously coupled pipe
  - Regions do not encompass individual couplings
- Proximity of parallel external sources in the same ROW influencing CP currents (pipelines, structures, high voltage electric transmission lines, DC transit systems)
  - Define regions as the extents of the area where the foreign structure parallels the subject and / or
  - Define regions as the extents of the area subject to known interference issues
- Unbonded electrical isolation (i.e. flange, monolithic fitting)
  - A region boundary exists at each unbonded isolation point
  - Regions do not encompass individual fittings
- Pipe exposed to the atmosphere
  - Define a new region at each location
  - Perform 100% visual examination
- Underwater sections
  - Define a new region at the boundaries of bodies of water that cannot be traversed on foot
- Casings

7A.3.10.4 Indirect Inspection Methods

Each region shall have the same first and second IIT. Additional inspection tools may be specified as necessary.

7A.3.10.5 Required Data Elements

Table 7A.3.1 lists the data elements that are REQUIRED for the analysis of the ECDA regions. These elements shall be integrated with other data elements to determine which segments of pipe have similar corrosion history and similar predicted degradation.

7A.3.10.6 Considered Data Elements

Data elements that are listed as CONSIDERED in Table 7A.3.1 should be taken into account when establishing the ECDA region.

7A.3.10.7 Documentation

The ECDA Region description shall be defined and kept in the Project File. Form 7A.5: ECDA REGION REPORT should be used for this documentation. Each ECDA region shall have at least two IIT's and one distinguishing characteristic to describe the ECDA Region. A characteristic is anything that affects the assessment of past corrosion that substantially changes the physical characteristic of the pipe, or will affect the current or future degradation of the pipe. The **PIE** shall list all essential characteristics for each region. The ECDA Region Report shall be signed by the PIE, and approved by the **PM**.

7A.3.11 Pre-Assessment Review Meeting

7A.3.11.1 Objective

A Pre-Assessment Review meeting may be held to provide technical insight in conducting the ECDA in the defined area, communicate the plan for how the ECDA will be conducted, and build consensus for the plan. The **PM, PS, CS, PIE**, and any other personnel deemed critical to project success shall be in attendance.

7A.3.11.2 Meeting Results

Updates and changes to the Pre-Assessment data, feasibility analysis, IIT tool selection, and ECDA Regions analysis shall be documented.

7A.3.12 More Restrictive Criteria

49 CFR Part 192.192.925 requires more restrictive criteria for the Pre-Assessment phase of the ECDA process when applying ECDA to a pipeline segment for the first time. The Company utilizes the following more restrictive criteria to meet this requirement:

- Collect and review all available CP records
- Conduct a Pre-Assessment review meeting

The use of more restrictive criteria is documented on form 7A.16: ECDA Pre-Assessment More Restrictive Criteria Form.

7A.3.13 Pre-Assessment Report

7A.3.13.1 **Report**

A Pre-Assessment report shall be prepared with the following information.

- ECDA Identification Information
- Data reports
- Pipeline Maps
- Data Element Check Sheet (Form 7A.1)
- Sufficient Data & Feasibility Analyses Report (Forms 7A.2 & 7A.3))
- Indirect Inspection Tool Selection & ECDA Region Description (forms 7A.4 & 7A.5)
- More Restrictive Criteria – Pre-Assessment (Form 7A.15)

7A.3.13.2 **Approval and Filing**

The report shall be reviewed and approved by the **PM**. A copy shall be stored in the project file.

7A.4 INDIRECT INSPECTION

✓ ***Referenced Protocol:*** ***D.03 ECDA Indirect Examination***

7A.4.1 Objectives

The objective of the Indirect Inspection process is to locate and define the severity of coating faults and areas where external corrosion may have occurred or may be occurring. The primary indirect inspection tasks include:

- Conduct at least two indirect inspections along the entire length of each ECDA Region.
- Align and compare the results from the indirect inspections.
- Identify and classify indications.
- Analyze and report results in preparation for the Direct Examination step.

7A.4.2 More Restrictive Criteria

For the indirect inspection phase, both NACE SP0502 and 49 CFR Part 192 §192.925 require the use of "more restrictive criteria" when applying ECDA to a line segment for the first time. The requirements of Part 192 are above and beyond the requirements of NACE.

7A.4.2.1 NACE More Restrictive Criteria

When ECDA is applied to a line segment for the first time, the Company utilizes one or more of the following techniques:

- Take duplicate readings at random test stations along the indirect inspection survey route with a separate meter and compare the readings
- Repeat an indirect inspection
- When performing close-interval survey, resurvey any areas with structure-to-electrolyte readings more electro-negative than -850 mV
- A Company inspector reviews the indirect inspection survey data
- Other criteria

7A.4.2.2 Part 192 More Restrictive Criteria

When ECDA is applied to a line segment for the first time, the Company utilizes one or more of the following techniques. This is in addition to the technique chosen for the NACE more restrictive criteria.

- Use more than two (2) indirect inspection tools
- Take soil resistivity readings in each ECDA Region or at category I and II DCVG indications
- Perform a depth of cover survey
- Determine a more conservative severity table and apply the increased severity for each tool. Examples may include:
    - For CIS, classify readings more positive than -0.95 volts as a severe indication
    - For PCM, reduce the amount of signal reduction over a set length of pipe (i.e. severe indication greater than 40% signal change over 200 feet)
- Use a closer interval between test point readings for greater possible accuracy and less chance of missing an indication
- Increase the excavation priorities by categorizing the highest two coating indications as “Immediate” and all subsequent indications as “Scheduled” regardless of how minor they appear
- For indirect inspection tool conflicts, even if resolved, redo the indirect inspection for all tools
- Drill holes in pavement in order to reach soil electrolyte
- Other criteria

7A.4.2.3 Documentation

The use of more restrictive criteria will be documented on Form 7A.17: ECDA Indirect Inspection Restrictive Criteria Form.

7A.4.3 Marking of Inspection Areas

7A.4.3.1 Definition

Inspection Areas are sections of pipeline that will be surveyed with the IIT's. Since it is essential that the entire ECDA Region and / or HCA is inspected, the inspection areas boundaries may exceed the ECDA Region Boundaries. The **PS** may also desire to expand the inspection area to evaluate pipe outside the HCA.

A minimum of 100 feet before the start of an HCA and 100 feet beyond the end of an HCA shall be surveyed.

7A.4.3.2 Objective

Prior to conducting indirect inspections, the boundary of each inspection area identified in Form 7A.5: ECDA Region Report shall be clearly marked in the field to eliminate ambiguity regarding the inspection starting and stopping points.

7A.4.3.3 Type of Markings

Both ends of each inspection area shall be identified with one or more of the following methods:

- By a clearly identifiable land mark that has a unique name, such as streets, and buildings
- Painted markings on the roadway or other pavement with arrows pointing towards the center of the inspection area and with the number of the ECDA Region.
- Highly visible stakes, nail markers or other suitable marking device with the ECDA Region number on them and an arrow pointing to the center of the region

7A.4.3.4 Documentation

The location of the inspection area shall be indicated on Form 7A.4: Indirect Inspection Tool Form.

7A.4.3.5 Survey Scheduling

Timing of the survey may depend on land use. In general, perform surveys through farm fields in early spring or late fall, while there are no crops in the field.

7A.4.4 Above Ground Procedure Review

7A.4.4.1 IIT Procedures

Each IIT shall have a corresponding written procedure. **CT** are required to submit their inspection and operating procedures for review. If the company specific procedures are used they shall also be reviewed. The **PIE** shall be responsible for satisfying the review requirements outlined below.

7A.4.4.2 Procedure Content

Each of the procedures shall consider the following:

7A.4.4.2.1 *Numbering*

The procedure shall have a unique alphanumeric number assigned to it with a revision number.

7A.4.4.2.2 *General Description*

The scope of the procedure and the general theory regarding how the IIT works, including what it measures and what it is capable of detecting.

7A.4.4.2.3 *Limitations*

Where the IIT should not be used, what it cannot detect, and its level of sensitivity.

7A.4.4.2.4 *Procedure Qualification*

How the IIT procedure was qualified and where the records exist that document the qualification.

7A.4.4.2.5 *Safety Considerations*

General and specific safety considerations, including adherence to the company safety regulations. Listing of general hazards, and what to do in case of an injury.

7A.4.4.2.6 *Instrumentation*

Types of equipment needed to perform the assessment. The procedure should also include special measurement equipment that will be used in case of special field situations such as stray currents. Any equipment not included on this list must be approved by the **PIE** prior to its use.

7A.4.4.2.7 *Personnel Qualifications*

The qualification requirements of the personnel conducting the exam.

7A.4.4.2.8 *Instructions*

Specific, easy to follow instructions will be used to conduct the survey. These instructions shall include:

- **Calibration:** The calibration of the equipment prior to and during the survey

- **Equipment Connection:** The connection of instrumentation, the set-up interrupters, etc.
- **Pipe Location:** The method of locating the pipe
- **Measurements:** The method of taking measurements and the frequency or interval the measurements should be taken
- **Special Diagnostics:** The techniques and when they are used to address special field situations
- **Distance Measurement:** The method of tracking the distance traveled along the survey. The frequency of geo-references.
- **Recording Data:** The recording of data, and special diagnostic techniques.

7A.4.4.3 Preparation and Approval

The procedure shall document the person who prepared it and the date it was prepared. It shall have been reviewed and approved by a responsible person in the organization that issued it. Both of the above requirements are indicated by signatures and dates.

7A.4.4.4 Procedure Review

The **PIE** shall review each procedure for adequacy. Comments for each IIT procedure shall be recorded on Form 7A.6: IIT Procedure Review.

7A.4.4.5 Frequency of Review and Approval

The procedures shall be reviewed both annually and also when there has been an issued revision to the procedure.

7A.4.4.6 Procedure Filing

Each approved procedure with any amendments shall be kept in the ECDA program management file.

7A.4.5 Indirect Inspection Plan Review

An Indirect Inspection Plan shall be assembled and submitted for review and approval.

7A.4.5.1 Plan Contents

The plan shall have the following documents:

- IIT Selection Form 7A.4
- ECDA Region Analysis Form 7A.5
- More Restrictive Criteria Form 7A.17

7A.4.5.2 **Plan Review**

The **PS and PIE** shall meet to review the plan. This meeting is to review and finalize any new developments or changes in conducting the ECDA. The **PS** and PIE shall review the IIT Selection form (Form 7A.4) and the ECDA Region Analysis (Form 7A.5).

7A.4.6 Survey Preparation

7A.4.6.1 **Right-of-Way**

Perform a visual evaluation of the condition of the right-of-way. Determine of the right-of-way needs to be cleared of trees, brush, or debris prior to commencing the survey. Arrange for the clearing of brush / debris as required.

Ensure all cathodic protection rectifiers and interference bonds affecting the survey segment are functioning properly. Repair rectifiers / interference bonds prior to commencing the survey, as necessary.

Notify landowners / tenants along the right-of-way as appropriate. Ensure the notification includes:

- When survey(s) will be performed
- Who is performing the survey(s)
- A brief description of why the survey(s) are being performed
- LG&E contact information
- Access requirements

7A.4.6.2 **Contractor Coordination**

Coordinate with contractors as necessary. This may include contractors responsible for special survey needs such as drilling holes in pavement.

Coordinate traffic control as required. This may include arranging for signs / barricades for any required lane closures.

Ensure drilling contractors notify One-Call, if applicable.

7A.4.6.3 **Permits**

Obtain appropriate permits. Permits may include but are not limited to:

- Traffic control
- Lane closures
- Drilling holes

Notify Railroad authorities and obtain permits as required. Railroads may require a flagger be present while crossing the tracks.

7A.4.7 Indirect Inspection Crew Preparation

7A.4.7.1 **Indirect Inspection Crew**

Review contractor qualifications and ensure the Indirect Inspection Crew is qualified to perform the survey.

When a crew member is not qualified, request the Contractor (if applicable) provide a qualified replacement. Postpone the survey as necessary.

7A.4.7.2 **Pre-Survey Field Meeting**

The PS shall have a field meeting with **CT** to review the following:

7A.4.7.2.1 *Inspection Areas*

Review first hand the boundaries of each inspection area.

7A.4.7.2.2 *More Restrictive Criteria*

If first time application of ECDA to the line segment, review more restrictive criteria to be used.

7A.4.7.2.3 *Documentation*

Form 7A.4: IIT Selection and Form 7A.5: ECDA Region Report, GIS, strip maps, and other pertinent documents.

7A.4.7.2.4 *Cathodic Protection Equipment*

The location and operation of all associated cathodic protection equipment including **Company** and foreign rectifiers that may affect the survey segment.

7A.4.7.2.5 *Inspection Tools*

Review all the inspection tools that will be used in the ECDA project. The method to achieve contact with the soil if the area is paved. Additional tests for special circumstances.

7A.4.7.2.6 *Access to ECDA Regions*

How the **CT** should access the areas. Contacts, schedule, etc.

7A.4.7.2.7 *Schedule*

Dates and times the CT will conduct the survey.

7A.4.7.2.8 *Landowner Contact*

Protocol if landowners' question field personnel.

7A.4.7.2.9 *Safety & Environmental Hazards*

Discuss safety hazards, such as traffic, overhead lines, rectifier potentials, flora and fauna.

7A.4.7.2.10 *Notification of Abnormal Conditions*

CT shall notify the **PS** when abnormal conditions or situations develop. Discuss what these conditions are; such as extreme data, unusual landowner contact, pipeline safety concerns, inspection tool does not appear appropriate, personnel injury and changes in inspection dates and times.

7A.4.7.2.11 *Changes*

Any changes to the Indirect Inspection Plan shall be documented on one or more of the following forms as appropriate:

- Form 7A.3: Feasibility Analysis Report
- Form 7A.4: Indirect Inspection Tool Selection
- Form 7A.5: ECDA Region Report
- Form 7A.17: ECDA Indirect Inspection More Restrictive Criteria Form

7A.4.8 Indirect Inspections

7A.4.8.1 **Breadth of Inspections**

Each of the primary indirect inspections shall be conducted over the entire ECDA region. The primary indirect inspections include the 1st and 2nd complimentary IIT's.

7A.4.8.1.1 *Supplemental Inspections*

Supplemental indirect inspections (other than the two (2) required primary methods), may be conducted as determined by the **PIE** and documented on Form 7A.4: IIT Selection.

7A.4.8.1.2 *Station Numbering*

Each indirect inspection area shall be designated with a definitive start and stop location (e.g. measurements from landmarks, pipeline stationing, GPS points). Inspection starting points shall be designated with a survey stationing of 0+00 unless otherwise instructed by the **PS**.

7A.4.8.1.3 *Additional Data Collection*

The following data shall be collected for indirect inspections in conjunction with the IIT readings.

Table 7A.4.1: Additional Data Collection Elements

• **Line Identification**	• **Type CP Infrastructure***
• Pipeline Angle Point*	• Description of Land use
• Depth of pipe every 100 feet (optional)*	• Valves*

• Type of Pipeline markers*	• Roadway name*
• Topographical features*	• Foreign Pipeline Crossing*
• Farm Taps*	• Test Stations*
• Flag #	

*GPS readings should be taken for these data elements

7A.4.8.1.4 *Substituting 100% Direct Examination*

100% direct examination of the pipe may be used in lieu of indirect inspection for pipeline segments where indirect inspection is impractical or unnecessary. In such instances, pre-assessment and post-assessment must still be followed.

7A.4.8.2 **Procedures**

The indirect inspections shall be performed strictly in accordance with the approved procedures. Any deviation from the procedure shall be approved and documented in accordance with the Exception Process described in subsection 7A.7.

7A.4.8.3 **Time between Primary Inspections**

The **CT** shall endeavor to have the two indirect inspections conducted as close in time as reasonably possible, but no longer than 60 days apart. If the 60 day window is exceeded, the time between inspections shall be documented through the Exception Process in Subsection 7A.7 of this procedure. If the **PS** does not accept the exceedance, the indirect inspection must be re-conducted within the 60 day timeframe.

7A.4.9 Indirect Inspection Reporting

7A.4.9.1 **Reporting Time Requirement**

The test data shall be submitted to the **PS** in a timely fashion once the indirect inspections are completed - **the Company** targets no later than 90 days after the completion of the last indirect inspection. It is the responsibility of the PS to manage the **CT** to assure timely delivery of data. Reporting time requirements may be included in contract agreements with service providers.

7A.4.9.2 **Report Content**

7A.4.9.2.1 *Location and Dates*

Description of the location where the inspections were performed as well as the dates they were conducted.

7A.4.9.2.2 *Weather Conditions*

Description of the local weather conditions at the time of inspection including temperature and precipitation.

7A.4.9.2.3 *IIT Types*

Description of the indirect inspections performed as well as other tests such as soil resistivity, and depth survey. The testing procedures that were followed as well as the personnel conducting the test shall be listed.

7A.4.9.2.4 *Current Sources*

A table listing the current sources that were interrupted including output and ratings of the rectifiers, and / or bond current values, along with corresponding mileposts and survey stations.

7A.4.9.2.5 *Survey Plots*

All IIT results should be plotted with station distances at 100-foot intervals. Landmarks shall be noted on the chart as well as other test data such as depth surveys, soil resistivities, CP test stations, rectifiers, anodes, mainline valves, markers, and angle points. The period when the tests were conducted shall also be included on the plots.

7A.4.9.2.6 *GPS Coordinates*

GPS coordinates shall be provided every 100 feet along the survey. GPS coordinates shall be taken at each coating holiday indication.

7A.4.9.2.7 *Report Formats*

The report shall be provided in both hardcopy and electronic formats.

7A.4.10 Identification and Classification of Indications

7A.4.10.1 **Objective**

This section describes the process of identifying and classifying indications. Identification is the process of applying criteria to survey results to specify indications. Classification is the process of estimating the likelihood of corrosion occurring at each indication.

7A.4.10.2 **Process**

Figure 7A.4.1 is a flow chart showing the process for identifying, classifying and prioritizing indications. The output of this process is a schedule for direct examinations.

7A.4.10.3 **Identification Criteria**

For each indirect inspection method the data shall be analyzed to identify indications. Table 7A.4.2 under “Minor Indications” provides the minimum qualification criteria for indications based on each indirect inspection technique.

If ECDA is used on bare pipelines, evaluate the classification criteria and verify that it is sufficient to locate anodic regions.

Classifications are defined below:

- Severe - Indications that have the highest likelihood of corrosion activity
- Moderate - Indications that may have corrosion activity
- Minor - Indications that are inactive or have a low probability of corrosion activity

7A.4.10.4 **Classification Criteria**

The severity of each indication shall be initially classified in accordance with Table 7A.4.2.

Different classification criteria may be warranted based upon the capabilities of the Indirect Inspection tool and unique conditions that may be present in a particular ECDA region.

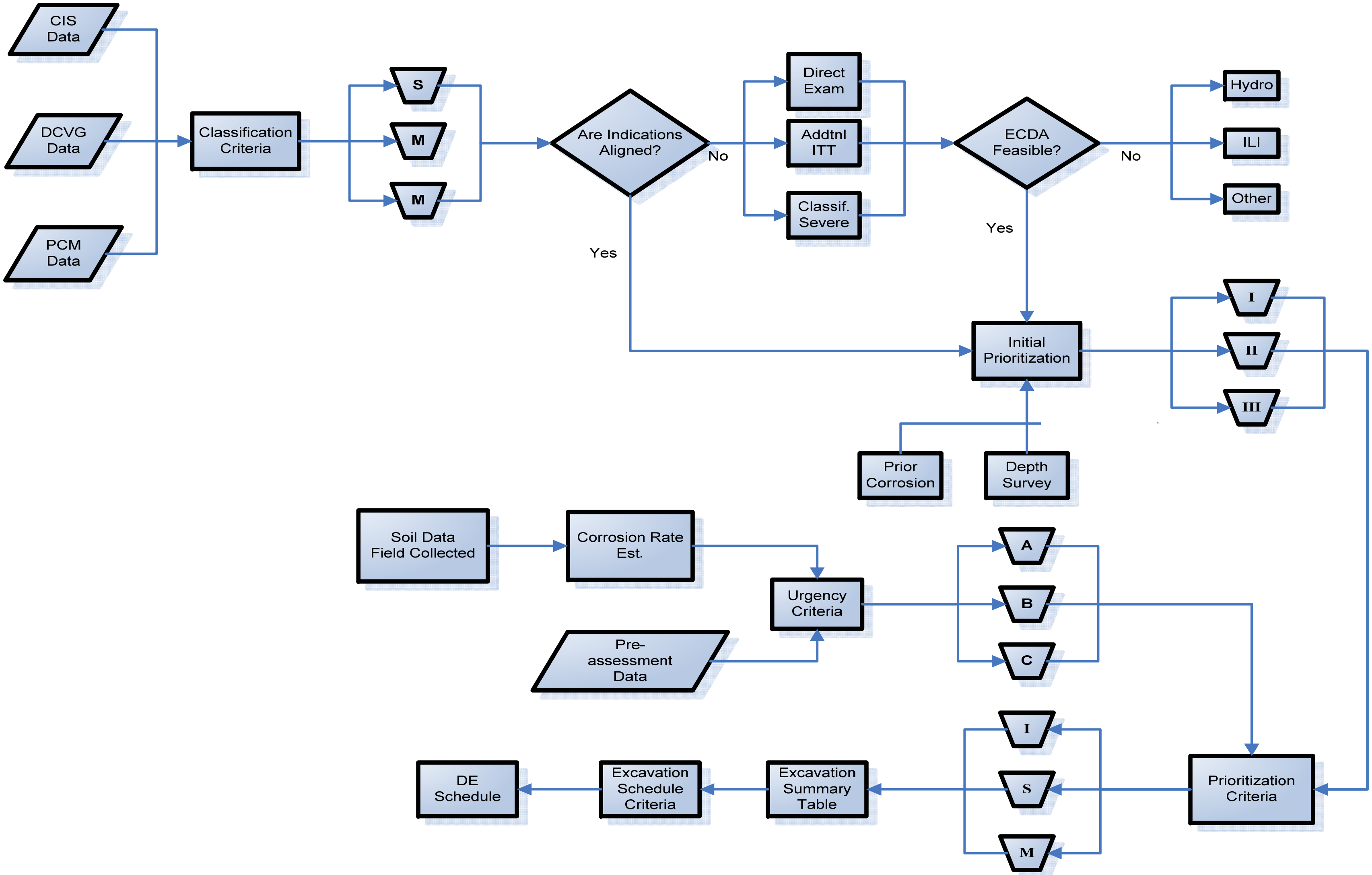
Table 7A.4.2: Indirect Inspection Tool Indications and Severity Guide

Indirect Inspection Tool	Classification Severe Indications	Classification Moderate Indications	Classification Minor Indications
CIS	"On" and "Off" more positive than -850mV -OR- Other condition classified as Severe by the PIE	"On" more negative than -850mV and "off" more positive than -850mV -OR- Both of the following within a 200 ft span: "on" and "off" more negative than -850mV with Convergence of "on / off" potential within a 0mV to 50mV range -OR- Other condition classified as Moderate by the PIE	Both of the following within a 200 ft span: "on" and "off" more negative than -850 mV with convergence of "on / off" potential >50mV -OR- Other condition classified as Minor by the PIE
CIS with Non-Interruptible Galvanic Anodes Attached to the Pipeline	On pipe-to-soil measurements less negative than -0.850 V -AND- A minimum and maximum calculation with a difference of 0.200 V within a 200 feet sample area	On pipe-to-soil measurements less negative than -0.850 V -AND- A minimum and maximum calculation with a difference of 0.150 V within a 200 feet sample area	A minimum and maximum calculation with a difference of 0.100 V within a 200 feet sample area
PCM	Greater than 50% change in 200 feet	Between 30% to 50% change in 200 feet	Between 10% and 29% change in 200 feet
DCVG	61 to 100% IR -OR- Anodic / Anodic	36 to 60% IR -OR- Cathodic / Anodic	1 to 35% IR
ACVG	>5 indications per 100 feet	4 to 5 indications per 100 feet	1 to 3 indications per 100 feet

7A.4.10.5 Classification Time Requirements

The **PIE** should complete the classification of indications in a timely fashion. **The Company** targets data classification within 30 days after receipt of the data. The **PIE** may assign the **CT** to perform the classification of indications. It is the responsibility of the **PIE** to assure timely data classification.

Figure 7A.4.1: Prioritization Process



7A.4.10.6 Documentation

The severity of the indications shall be documented on Form 7A.7: Indication Classification Summary. The following shall be documented on Form 7A.7: Indication Classification Summary or other appropriate document:

- **Inspection Tool:** The IIT used to identify the indication.
- **Location:** The location of the indication along the pipeline.
- **Severity Classification:** Whether the indication is minor, moderate, or severe.
- **Classification Criteria:** Document the need for different criteria based upon the IIT and unique conditions in the ECDA.
- **Additional Surveys or Direct Examinations:** The need for additional surveys or examinations where IIT indications contain unexplainable differences.
- **ECDA Re-assessment:** Document the need for ECDA re-assessment where discrepancies cannot be resolved.

7A.4.11 Aligning Indications

7A.4.11.1 Comparison

The **PIE** shall compare the results from the indirect inspections to determine if they are consistent. The location and severity of the indications from each IIT shall be compared to the indications from other IIT's. The **PIE** shall also consider the impact of spatial errors when comparing the data.

7A.4.11.2 Misalignment

If two (2) or more IIT's indicate significantly different sets of indications at locations that do not align, and if the differences cannot be explained by the inherent capabilities of the tools, specific pipeline features, or local conditions, remedial action is required. The **PIE** shall pursue one or more of the following options:

7A.4.11.2.1 *Direct Examinations*

Direct examinations may be used to resolve discrepancy in the alignment of indications.

7A.4.11.2.2 *Additional Indirect Inspections*

Additional indirect inspections may be used to resolve discrepancies in the alignment of indications.

7A.4.11.2.3 *Classify Indications as Severe*

Any indications where there discrepancy in alignment has not been resolved shall be classified as severe.

7A.4.11.3 ECDA Feasibility Reevaluation

The **PIE** may reevaluate the feasibility of the ECDA and choose to use another integrity assessment technology such as hydro testing or in-line inspection.

7A.4.11.4 Documentation

The **PIE** shall complete Form 7A.8: DA Prioritization Analysis and Direct Examination Form to document any misalignment and its resolution. The **PIE, PS,** and **PM**shall sign Form 7A.8: DA Prioritization Analysis and Direct Examination Form.

7A.4.12 Prioritization of Indications

Objective: Prioritization is the process of ranking the indications based on the integration of corrosion related measurements.

7A.4.12.1 DCVG and PCM Surveys

When both DCVG and PCM surveys are conducted on the same pipe segment the DCVG data and criteria shall be used for the initial prioritization.

7A.4.12.2 Initial Prioritization

The indications shall be initially prioritized into the following categories:

7A.4.12.2.1 *Priority I*

This priority should include indications that have a high likelihood of on-going corrosion activity. Indications included in this priority are:

- **Prioritization Table:** Indications designated as Priority I in Table 7A.4.3 based on integrated inspection results.
- **Multiple Severe Indications:** Multiple severe indications that are in close proximity. Example: Four or more indications within a 200mV or more depressed zone
- **Discrepancies Between IIT:** Indications that seem to have discrepancies between different IIT techniques.
- **Prior Corrosion Zones:** Other severe or moderate indications that are known to have significant corrosion based on historical data.
- **Difficult to Characterize Indications:** Indications where the likelihood of ongoing corrosion cannot be characterized such as indications that are a result of interference with CP current.

7A.4.12.2.2 *Priority II*

This priority includes indications that may have on-going corrosion activity. Indications that fall into this priority are:

- **Severe Indication:** Severe indications that are not in close proximity with other severe indications and were not designated as Priority I. See Table 7A.4.3
- **Moderate Indications:** Moderate indications that had prior significant corrosion likely at or near the indication.

7A.4.12.2.3 *Priority III*

This priority includes indications that exhibit a low likelihood of on-going corrosion that are not designated as Priority I or II. Indications within this category include:

Minor: These indications are minor and have the lowest likelihood of being active. See Table 7A.4.3.

Table 7A.4.3: Prioritization of Indications

		CIS			
		Severe	Moderate	Minor	NRI
PCM	Severe	I	II	II	III
	Moderate	I	II	III	III
	Minor	I	II	III	III
	NRI	II	III	III	NRI
DCVG	Severe	I	I	II	III
	Moderate	I	II	III	III
	Minor	I	II	III	III
	NRI	II	III	III	NRI
Prior Corrosion: Raise the prioritization of indications that have a history of prior corrosion.					
Difficult to Characterize Indications: Indications that are difficult to characterize shall be prioritized as Priority I.					

I = Priority I, II = Priority II, III = Priority III, NRI = Non-relevant indication

7A.4.13 Integrating ECDA Data with Encroachment Data

Integrate the encroachment and foreign line crossing information with the indirect inspection data. This allows for evaluation of the threat of residual third-party damage.

The **PIE** shall review the coating indication and depth of cover data provided by the IIT surveys. The **PIE** should determine if there are foreign line crossings not indicated in the survey data by reviewing records and the GIS. If additional

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crossings are found, the **PIE** should manually integrate the information regarding the crossing(s) with the survey data.

The **PIE** shall document locations where a coating indication corresponds with an encroachment / foreign line crossing on Form 7A.8 DA Prioritization Analysis and Direct Examination Form.

- Document all coating indications within three (3) feet of an encroachment for data that is integrated in the field (i.e. comment about encroachment noted directly in survey comments).

- Document all coating indications within ten (10) feet of an encroachment for locations where the coating survey data and encroachment data is manually integrated. The increased distance will account for any spatial errors.

- Specify in the Comments section details about the encroachment (i.e. company name, type of foreign line crossing).

The **PIE** shall determine the locations to be evaluated for potential third-party damage and schedule the following indications for direct examination:

- “Moderate” or “Severe” DCVG indications within three (3) feet of an encroachment

- “Moderate” or “Severe” DCVG indications within ten (10) feet of an encroachment for manually integrated data

The **PIE** shall reconcile the locations being evaluated for residual third-party damage with locations required for the ECDA process as some locations will be applicable to both processes and should be evaluated at the same time.

These evaluations may not necessarily meet the criteria described in the ECDA Plan for choosing direct examination locations. If not, these evaluations are performed in addition to the direct examinations required by the ECDA Plan.

7A.4.14 Corrosion Rate Analysis

7A.4.14.1 **Objective**

To estimate the corrosion rate of specific pipe segments based on local corrosion characteristics.

7A.4.14.2 **Method 1 – Soil Analysis**

Estimation of the corrosion rate through integration of soils data and cathodic protection data using a corrosion rate model.

7A.4.14.2.1 *Soil Core Samples*

The **PIE** shall designate and arrange for soil core samples of representative Priority I and II indications.

7A.4.14.2.2 *Soil Analysis*

The **PIE** shall arrange to have the soil analyzed for the elements listed in Table 7A.4.4.

Table 7A.4.4: Soil Analysis Data Elements

Soil Resistivity	SO_4
pH	% Gravel
Cl	% Sand
Ca	% Silt
K	% Clay

7A.4.14.2.3 *Estimation of corrosion rates*

The **PIE** shall determine estimated corrosion rates and the relative ranking of the indications based on the soil analysis data results.

7A.4.14.3 **Method 2 – Soil Resistivity**

Estimation of the corrosion rate through the use of soil resistivity data and the corrosion rates related to soil resistivity from Appendix B of ASME B318.S-2004.

7A.4.14.3.1 *Soil Resistivity Measurements*

The **PIE** shall designate and arrange for soil resistivity measurements of representative Priority I and II indications.

7A.4.14.3.2 *Assignment of Corrosion Rate*

The **PIE** shall assign corrosion rates to the Priority I, II and III indications based on resistivity results according to the table below:

Table 7A.4.5: Corrosion Rates Related to Soil Resistivity[3]

Corrosion Rate (mpy)	Soil Resistivity (Ohm-cm)
3	>15,000 + no known active corrosion
6	1,000 – 15,000 or >15,000 + known active corrosion
12	<1,000 (worst case)

[3] ASME B31.8S 2001, *Supplement to B31.8 on Managing System Integrity of Gas Pipelines*, pg. 63, Table B1

7A.4.14.4 **Method 3 – Other Methods**

Estimation of the corrosion rate may be performed using other methods approved by the **PM** in accordance with the requirements set forth in Appendix D of NACE SP0502.

7A.4.14.5 **Estimated Corrosion Rate Documentation**

The **PIE** shall record the estimated corrosion rate for each priority indication (I, II, or III) in each ECDA region on Form 7A.8 DA Prioritization Analysis and Direct Examination Form.

7A.4.15 Urgency Level of Prioritized Indications

7A.4.15.1 **Objective**

This section facilitates the integration of pre-assessment and corrosion related data with the initial prioritization (I, II, III) to determine the final prioritization of indications (Immediate, Scheduled, and Monitored).

7A.4.15.2 **Urgency Criteria**

Table 7A.4.6 defines the Urgency Criteria. The level of urgency (A, B, or C) is defined as an ECDA Region having one or more criteria met for any given level.

Table 7A.4.6: Urgency Criteria[1]

Level	History of Leaks (yes / no)	History of Wall Loss (%)	Years without CP	Est. Corrosion Rate (mpy)
A	Yes	>40%	>4	>12
B	No	20% to 40%	1 to 4	7 to 12
C	No	<20%	<1	<7

[1] The level of urgency for an ECDA region is determined by satisfying one or more criteria in any given row.

7A.4.15.2.1 *Level A*

The ECDA Region shows:

- history of leaks or ruptures due to external corrosion; or,
- has had external corrosion greater than 40% wall loss; or,
- has not had cathodic protection for a cumulative length of four (4) or more years; or,
- An estimated corrosion rate of >12mpy

7A.4.15.2.2 *Level B*

The ECDA Region shows:

- Documented external corrosion between 20% and 40% wall loss; or,
- A history of being unprotected or experienced down CP readings for a cumulative period of one (1) to four (4) years; or,
- An estimated corrosion rate of 7 to 12 mpy

7A.4.15.2.3 *Level C*

The ECDA Region shows:

- No documented external corrosion greater than 20% wall loss; or ,
- A history of being unprotected or experienced down CP readings for a cumulative period <1 year; or,
- An estimated corrosion rate less than 7 mpy

7A.4.15.2.4 *Documentation Requirements*

The **PIE** shall record the urgency level Form 7A.8 DA Prioritization Analysis and Direct Examination Form.

7A.4.15.3 Prioritization of Excavations

The prioritized above ground assessment criteria shall be integrated with the urgency criteria to classify the direct examination as Immediate, Scheduled, or Monitored excavation sites. This integration and prioritization shall be conducted in accordance with Table 7A.4.7.

Table 7A.4.7: Prioritization of Direct Examination Sites

Priority Level	Urgency Level		
	Level A	Level B	Level C
I	Immediate	Scheduled	Monitored
II	Scheduled	Monitored	Monitored
III	Monitored	Monitored	Monitored

Pipeline condition, age, and cathodic protection history may warrant different criteria. Document any additional or different criteria used to prioritize the indications on a separate piece of paper and attach to Form 7A.8 DA Prioritization Analysis and Direct Examination Form.

7A.4.15.4 Prioritization of Excavations for the 1st Time

When conducting and ECDA over a given segment for the first time, the more restrictive criteria in Table 7A.4.8 shall be used.

Table 7A.4.8: Prioritization of Direct Examination Sites - Restrictive

Priority Level	Urgency Level		
	Level A	Level B	Level C
I	Immediate	Immediate	Scheduled
II	Immediate	Scheduled	Monitored
III	Scheduled	Monitored	Monitored

7A.4.15.5 Timing for Direct Examinations

Direct Examinations shall be completed within 180 days of receiving the final indirect inspection data.

7A.4.15.6 Documentation Requirements

Direct Examination prioritization shall be recorded on Form 7A.8 DA Prioritization Analysis and Direct Examination Form.

7A.4.15.7 Insufficient Time to Excavate

As soon as it is determined that the project will not comply with the time requirements in section 7A.4.14.5, the **PS** shall file an exception to the ECDA procedure in accordance with the Exception Process in Section 7A.7 of this procedure.

7A.4.16 Indirect Inspection Analysis

The **PIE** shall compare the results of the indirect inspections with the pre-assessment results and prior history for each ECDA region to see if they rationalize each other. If the assessment results are not consistent with operating history, the **PIE** must reassess the feasibility of the ECDA.

7A.4.17 Indirect Inspection Report

7A.4.17.1 Contents

The **PIE** shall prepare an indirect inspection report. The report shall contain the following elements:

- Form 7A.5: ECDA Region Report
- Form 7A.7: Indication Classification Summary
- Form 7A.8 DA Prioritization Analysis and Direct Examination Form
- Form 7A.17: ECDA Indirect Inspection More Restrictive Criteria Form

7A.4.17.2 Review and Filing

The report shall be reviewed and approved by the PM. This report shall be completed in a timely fashion. **The Company** targets receipt of report within 60 days after the receipt of the IIT test results. A copy shall be kept in the ECDA project file.

7A.5 DIRECT EXAMINATION

✓ ***Referenced Protocol:*** ***D.04 ECDA Direct Examination***

7A.5.1 Overview

7A.5.1.1 Objective

The Direct Examination step is to calibrate and validate the prioritization of indications and their severity.

7A.5.1.2 Tasks

The Direct Examination Step includes the following tasks:

- Scheduling the excavations.
- Excavating the indications and collecting data at areas where corrosion activity is most likely.
- Measurement of coating damage and corrosion defects.

- Evaluation of remaining strength of the pipe segment.
- Root cause analysis.
- Re-prioritization and reclassification of indications if necessary.
- Remedial actions as necessary

7A.5.2 More Restrictive Criteria

For the direct examination phase, both NACE SP0502 and 49 CFR Part 192 192.925 require the use of "more restrictive criteria" when applying ECDA to a line segment for the first time. The requirements of Part 192 are above and beyond the requirements of NACE.

7A.5.2.1 **NACE More Restrictive Criteria**

NACE SP0502 has several requirements for first time applications of ECDA. These criteria have the title "Initial ECDA Projects" throughout section 7A.5. These requirements are in addition to the Part 192 more restrictive criteria described below.

7A.5.2.2 **Part 192 More Restrictive Criteria**

When ECDA is applied to a line segment for the first time, the Company utilized one or more of the following techniques. This is in addition to the NACE more restrictive criteria.

- Resurvey the ECDA region after immediate indications have been repaired to determine if other indications were masked by the large indication
- Perform additional testing to be performed at each excavation location (i.e. magnetic particle testing, X-ray)
- Install coupon test stations at select excavation locations to assist in future monitoring
- Perform a larger excavation to ensure all nearby indications are discovered and to eliminate the potential for smaller indications not be picked-up during the indirect inspection due to masking effects
- Perform additional direct examinations beyond those already required by NACE SP0502
- Other criteria

7A.5.2.3 **Documentation**

The use of more restrictive criteria will be documented on Form 7A.18 ECDA Direct Examination Restrictive Criteria Form.

7A.5.3 Number of Excavations

The number of required excavations is determined by the number of indications, the priority of those indications, and whether the assessment is the first ECDA performed along a given pipeline segment. Table 7A.5.1 provides a summary of the minimum number of excavations required. To ensure that the minimum number of excavations are performed, Form 7A.9: Number of Direct Examination Report will be completed by the PIE and reviewed by the PM.

7A.5.3.1 Immediate Indications

All Immediate indications shall be excavated for direct examination.

7A.5.3.1.1 *Initial ECDA Projects*

For the first assessment of a pipeline segment, Immediate indications shall not be reprioritized.

7A.5.3.1.2 *Reprioritization*

For subsequent assessments, Immediate indications may be reprioritized on a ECDA Region basis to a lower priority as described in subsection 7A.5.10, and shall follow the excavation criteria for the lower priority.

7A.5.3.2 Scheduled Indications

In addition to the Immediate excavations, a minimum of one (1) Scheduled indication shall be excavated per ECDA Region. A minimum of two (2) Scheduled indications shall be excavated per ECDA region for the first ECDA assessment of a pipeline segment.

7A.5.3.2.1 *20% Wall Loss Criteria*

If 20% or more wall loss is found at a Scheduled indication, the **PS** shall continue to excavate Scheduled indications in order of priority until at least two (2) Scheduled indications exhibit less than 20% wall loss.

7A.5.3.2.2 *Initial ECDA Projects*

For the first assessment of a pipeline segment, Scheduled indications shall not be reprioritized.

7A.5.3.2.3 *Reprioritization*

For subsequent assessments, if Scheduled indications are reprioritized as described in Subsection 7A.5.10, then they shall follow the excavation criteria for the new priority. If any Scheduled indications are reprioritized to an Immediate priority, there shall be at least one (1) additional excavation of a Scheduled indication (within that ECDA region) in addition to the requirements listed in 7A.5.3.2.

7A.5.3.3 Monitored

Monitored indications do not require direct examination and can be either monitored or reprioritized. However, if an ECDA Region did not contain any

Immediate or Scheduled indications, then at least one (1) Monitored indication shall be excavated. For initial applications of ECDA, minimum of two (2) direct examinations will be performed.

Additionally, if a Region does not contain enough Scheduled indications to meet the minimum number of dig locations, examinations will be performed at Monitored indications to meet the minimum number of digs.

7A.5.3.3.1 *Multiple ECDA Regions with Monitored Indications*

If multiple ECDA Regions contain monitored indications but do not contain any immediate or scheduled indications, one (1) examination is required is the ECDA Region identified as most likely for external corrosion. For initial applications of ECDA, a minimum of two (2) direct examinations will be performed.

7A.5.3.4 **No Indications in Pipeline Segment**

In the event no indications are identified in the assessment segment, a minimum of one (1) direct examination is required in the ECDA Region identified as most likely for external corrosion.

7A.5.3.4.1 *Initial ECDA Projects*

A minimum of two (2) direct examinations are required in the ECDA Region identified as the most likely for external corrosion. If more than one ECDA Region is determined likely more external corrosion, additional examinations will be considered.

7A.5.3.5 **ECDA Validation Digs**

One (1) additional excavation is required to validate the ECDA process per pipeline ECDA segment. The location shall be at a randomly selected Scheduled indication. If no Scheduled indications remain, the excavation shall be located at a randomly selected Monitored location.

7A.5.3.5.1 *Initial ECDA Projects*

Two (2) additional excavations, Validation Digs, shall be conducted on the first ECDA assessment of a pipeline segment. One (1) excavation shall be located at a randomly selected Scheduled indication, and the other at a random location where no indications were detected.

7A.5.3.5.2 *Evaluation*

The excavation site shall be assessed per the requirements in subsections 7A.5.6 through 7A.5.7.

7A.5.3.5.3 *Documentation*

Document the locations of the Validation Digs on Form 7A.8: DA Prioritization Analysis and Direct Examination Form by indicating "Validation Dig", or similar, in the comments section.

7A.5.4 Selected Indications

Indications that are selected for excavation shall be documented on Form 7A.8: DA Prioritization Analysis and Direct Examination Form (or equivalent document). The selection shall be made by the PIE and reviewed and approved by the **PIE, PS,** and **PM**.

7A.5.5 Scheduling Excavations

Scheduling of the excavations is required to assure that they are performed within the prescribed urgency timeframe in Table 7A.4.8 of this procedure and conducted in the most efficient manner. Form 7A.8: DA Prioritization Analysis and Direct Examination Form may be used to facilitate bellhole inspection scheduling and excavation.

7A.5.5.1 **Order of Excavations**

The **PIE** shall consider the overall risk of the pipeline segments and determine the order of the excavations according to the Urgency Level of the indications and consequences of a rupture.

The **PIE** shall also consider the results of the indication categorization and prioritization (i.e. excavate immediate indications first) when scheduling the direct examinations. Included, but not limited to, the following issues: the availability of personnel, logistics, additional equipment (i.e. shoring, dump trucks) and permitting when determining the order of excavations.

7A.5.5.1.1 *Urgency*

The order of the excavations shall be primarily based on the Urgency Level of the indications; most urgent indication excavated first.

7A.5.5.1.2 *Consequence of Rupture*

In some cases, the consequences of rupture and other related logistics may dictate that prudent action requires scheduled indications to be excavated first.

7A.5.5.2 **Exceptions**

If the project will not be able to comply with the excavation time requirements in Table 7A.4.8, the **PS** shall file an exception to the ECDA procedure in accordance with the Exception Process in subsection 7A.7 of this procedure.

Table 7A.5.1: Excavation Summary Table

<table>
<tr><th colspan="2">For Each ECDA Project</th><th colspan="3">For Each ECDA Region</th><th>Validation Digs per ECDA Project</th></tr>
<tr><th>Indirect Inspection data containing</th><th>Action</th><th>Containing</th><th>Action</th><th>1st Time Application of ECDA</th><th>Action</th></tr>
<tr><td rowspan="6">Mixed Indications including Immediate, Scheduled, and Monitored</td><td rowspan="6">Separate Results by Region & Indication ranking in order to Determine Region Specific Requirements</td><td>Immediate</td><td>Dig all Immediate</td><td></td><td rowspan="6">One excavation per pipeline segment at the next most severe indication[2]</td></tr>
<tr><td rowspan="2">Immediate & Scheduled</td><td>Dig all Immediate</td><td></td></tr>
<tr><td>Add 1 Scheduled dig at the most severe location[1]</td><td>Add an additional examination at next most severe</td></tr>
<tr><td>Scheduled</td><td>Examine one (1) location - Prioritize & dig most Severe</td><td>Add an additional examination at next most severe</td></tr>
<tr><td>Monitored Only</td><td>Examine one (1) location - Prioritize & dig most Severe</td><td>Add an additional examination at next most severe</td></tr>
<tr><td>Multiple Regions with Monitored Only</td><td>Identify Region most likely for external corrosion. Examine one location.</td><td>Add an additional location in the Region most likely for external corrosion</td></tr>
<tr><td>Monitored Only</td><td>Separate Results by Region & Indication Ranking</td><td colspan="2">Identify Region most likely for external corrosion. Dig 1 Monitored indication in most likely corroded region</td><td>Add an additional location in the Region most likely for external corrosion</td><td>One excavation per pipeline segment at the next most severe indication[2]</td></tr>
<tr><td>No Indications</td><td></td><td colspan="2">Identify Region most likely for external corrosion. Dig 1 location in most likely to corrode region</td><td>Add an additional location in the Region most likely for external corrosion</td><td>One excavation per pipeline segment at a randomly selected location[2]</td></tr>
<tr><td colspan="6">[1] If no Scheduled indications remain, perform examination at Monitored indication location.</td></tr>
<tr><td colspan="6">[2] For the first application of ECDA, add a second excavation at a randomly selected location with no indications.</td></tr>
</table>

7A.5.6 Pipe Excavation and Data Collection

7A.5.6.1 **Procedure**

The pipe shall be excavated in accordance with the company excavation procedures. Form 7A.8: DA Prioritization Analysis and Direct Examination Form may be used to facilitate bellhole inspection scheduling and excavation work.

7A.5.6.1.1 ***Location and Size of Excavation***

The location and size of the excavation site shall be identified and recorded on Form 7A.10, Direct Examination Data Excavation Sheet. The location of the center of each excavation or the location of the pipe or appurtenances examined shall be defined with respect to reliable fixed reference points and / or GPS coordinates as necessary to enable accurate mapping and relocation in the field. The length of the exposed pipe shall be physically measured and recorded on Form 7A.10, Direct Examination Data Excavation Sheet.

7A.5.6.1.2 ***Expansion of Excavation***

The **PS** shall have the excavation expanded in length if it appears that the original IIT indication may be contained in the portion of pipeline buried beyond the boundaries of the excavation. The **PS** shall consider the size of the anomaly detected, the tolerance of the IIT used, and the history of the pipeline segment in making this judgment. Coating or external corrosion anomalies extending into the buried portion of pipeline shall be given special consideration. The **PS** shall be contacted if the expansion of the excavation becomes excessive. The expansion shall be documented on Form 7A.10, Direct Examination Data Excavation Sheet.

7A.5.6.1.3 ***Qualified Personnel***

Pipe shall be inspected by personnel that are qualified by the company Operator Qualification Program for the performance of the task (“Examining buried pipe when exposed”). The qualified individual shall complete and sign the Form 7A.10, Direct Examination Data Excavation Sheet.

7A.5.6.1.4 ***Data Collection***

Collecting data on the coating and pipe condition is a key step of the ECDA process. The collection of data shall follow the company bellhole inspection procedures. Required data elements as well as descriptions of the data collection requirements are identified in Table 7A.5.2.

7A.5.6.1.5 *Additional Assessment and / or Inspections*

The direct examination may detect other pipeline integrity threats such as mechanical damage, stress corrosion cracking (SCC), microbiologically influenced corrosion (MIC), etc. When such threats are detected, additional assessments and / or inspections must be performed. The **PS** shall contact the **PIE** or the **PIM** for additional assessment requirements.

The **PIE** or **PIM** will determine the appropriate assessment method such as: ASME(1) B31.4,1; ASME B31.8,2,3; and API(2) 11604.

7A.5.6.1.6 *Notification*

The **PS** shall contact the **PIE** or the **PIM** if conditions found are more severe than the initial classification during the validation digs.

7A.5.6.1.7 *Documentation*

All data collected during a direct examination should be documented on Form 7A.10, Direct Examination Data Excavation Sheet.

Table 7A.5.2: Excavation Data Collection Requirements

Data Element	DATA Type	Required[1]	Description
6.0 Prior To and During Excavation			
6.1	Photographic documentation of original site condition	D	Take photographs documenting the original site condition with a digital camera.
6.2	Coating Type	R	Document the type of coating, if any, observed on the pipe. Types of coating include, but are not limited to: bare, coal tar enamel, extruded polyethylene, FBE, concrete, mastic, paint, hot applied tape, PE tape cold applied, wax, composite, fiberglass, etc.
6.3	Soil Resistivity	R	Obtain soil resistivity readings in the hole at pipe depth. Specify testing method utilized.
6.4	Soil Sample	D	Soil immediately adjacent to the pipe surface shall be collected with a clean spatula or trowel and placed in an 8 oz. plastic jar with a plastic lid. The sample jar should be packed full to displace as much air as possible. Tightly close the jar, seal with plastic tape and using a permanent marker to record the sample location on both jar and lid. Test soil for moisture content, sulfide ion concentration, pH, chloride ion concentration, sulfate ion concentration and conductivity. Test soil in-situ or send to laboratory for analysis.
6.5	Ground Water Samples	D	Take ground water sample if water is present in excavation. Water should always be collected from the open ditch when possible. Completely fill the plastic jar and seal and identify location as described above. Test ground water for: pH, chlorides, sulfates, and nitrates. Perform testing in-situ or send to laboratory for analysis.
7.0 Before Coating Removal			
7.1	Measurement of pipe-to-soil potential	R	These measurements shall be performed in accordance with NACE Standard TM0497. The reference electrode shall be placed in the bank of the excavation at the 12, 3, 6 and 9 o'clock positions. These potentials may help identify dynamic stray currents and prove IR drop considerations.
7.2	Photographic Documentation of coating condition	R	Document the coating condition with digital camera. Photos shall have ruler or other device to determine magnification of photographs showing details of the pipe and coating condition. Macro as well perspective views shall be recorded.
7.3	Under coating liquid pH analysis	R	If any liquid is detected underneath the coating, the pH shall be determined with pH litmus tape.

Data Element	DATA Type	Required [1]	Description
7.4	MIC testing for liquid under coating	R	Perform test in accordance with MIC kit instructions. Use kit that at a minimum tests for aerobic acid producers, anaerobic acid procedures and sulfate reducing bacteria
7.5	Coating Condition	R	Documentation of general coating condition. Document any blisters (with or without fill), delaminations, cracks, areas of erosion, mechanical damage, tenting, or other observed conditions.
7.6	Coating Sample	C	At the discretion of the PS, a sample of the coating shall be obtained if the coating is partially or fully disbonded. This sample will be used to determine the electrical and physical properties of the coating, and to perform microbial tests as directed.
7.7	Coating Thickness	R	Record the coating thickness if the coating is bonded to the pipe using a magnetic or electronic coating thickness gauge. Using calipers, measure thickness of any disbanded coating when applicable.
7.8	Mapping and measurement of coating defects	R	Coating damage shall be measured sufficiently to properly document the area. Use a grid oriented so that columns are circumferentially oriented on the pipe and the rows lie parallel to the longitudinal axis of the pipe. The grid size should be sufficiently fine to document the variation of damage and disbondment, but in no case shall be greater than a one-inch mesh.
8.0 During and After Coating Removal [2]			
8.1	Coating Adherence	R	Documentation of coating condition. Three conditions could exist 1) Coating is in excellent condition and completely adhered to pipe. 2) Coating partially disbonded and / or degraded. 3) The coating is completely missing the pipe surface is bare.
8.2	Corrosion Product	R	Carefully remove any corrosion deposit for possible root cause analysis. Keep sample contamination to a minimum. Perform MIC testing on product when MIC is suspected. This sample may also be used to perform chemical testing for corrosion products, at the discretion of the PS.
8.3	Pipe Temperature	D	Measure the bare pipe surface temperature in the shade. Move to the top and put in methods about solar effect.
8.4	Weld Seam Identification	D	The type of weld seam shall be identified and recorded.
8.5	Other Damage or Defect	R	Other damage or defect to the pipe surface that can be visual detected shall be recorded. Examples of such damage or defect would include gouges, cracking, dents, out of roundness, and / or evidence of third-party damage.

Data Element	DATA Type	Required [1]	Description
8.6	Observe corrosion defects	D	Note if defects have any of the following features: 1) large crater up to 2-3 inches or more in diameter; 2) cup-type hemispherical pits on the pipe surface of in the craters; 3) striations or contour liens in the pits or craters running parallel to longitudinal pipe axis; 4) tunnels sometimes at the end of the craters, running parallel to longitudinal pipe axis. Appearance of these type of defects may indicate microbiologically influenced corrosion (MIC).
8.7	Identification of Active or Inactive Corrosion	R	Careful examination of the corrosion surface shall be conducted after some cleaning to determine if corrosion is active or inactive by visual examination of the corroded surface at low magnifications.
8.8	UT Wall Thickness Measurements	R	Ultrasonic wall thickness shall be taken at every quadrant on the pipe to establish original / nominal wall thickness. Special consideration for internal corrosion shall be taken during measurement and documentation of the wall thickness at the 6:00 position. If a girth weld is exposed, take UT measurements on each side of the weld.
8.9	Photographic documentation of pipe	D	Take pictures with a digital camera documenting the overall condition of the exposed pipe surface.
8.10	Photographic Documentation of Corroded Area and defects	R	The corroded surface shall be photographed, preferable with a digital camera to document the morphology. Additionally, mechanical defects shall be photographed.
8.11	Mapping and measurement of corrosion areas	R	Corrosion damage shall be measured sufficiently to enable accurate remaining strength (RSTRENG) analyses of the corrosion area. Clean and prepare the pipe surface prior to documentation to ensure proper depth and morphology measurements. A grid of wall loss measurements shall be taken over the entire corroded areas. The grid shall be oriented so that columns are circumferentially oriented on the pipe and the rows lie parallel to the longitudinal axis of the pipe. The grid size should be sufficiently fine to document the variation of wall thickness, but in no case shall be greater than a one-inch mesh.
8.12	Pit Depth Map	R	Record the pit depths of the corroded area in a matrix format with mesh spacing no greater than 1-inch.
8.13	Magnetic Particle Inspection	R	Magnetic Particle inspection of the long seam, girth weld, and pipe body shall be taken when the pipe segment is located within 20 miles downstream of a compressor station.
8.14	Photographic documentation of repairs	R	Take digital photographs of repairs made including coating repairs.

Data Element	DATA Type	Required [1]	Description
8.15	Photographic documentation of Site Restoration	D	Take digital photographs of location after site restoration.

[1] R = Required; D = Desired; C = Considered; N/R = Not Required

[2] Note that some activities listed in this section require observation and inspection *during* the coating removal.

7A.5.7 Remaining Strength Evaluation

7A.5.7.1 **Objective**

The objectives of the remaining strength evaluations are three fold:

- **Predicted Burst Pressure:** To determine the predicted burst pressure at the corroded area and assure it meets the Area Class Location Design Requirements.
- **Reprioritization:** Provide input into the reprioritization process to evaluate if the remaining indications are appropriately prioritized
- **Reassessment:** Provide input in setting the reinspection interval in the Post Assessment Step of this procedure.

7A.5.7.2 **Predicted Burst Pressure Procedure**

The **PIE** shall apply the following procedure to calculate the failure pressure for each corroded area. Other analytical techniques such as linear elastic fracture mechanics may be used as appropriate with approval by the **PM**.

7A.5.7.2.1 ***Documentation***

Form 7A.11 “Remaining Strength Evaluation and Root Cause Analysis” or similar documentation shall be completed with the pertinent background data including pipe geometry, pipe material properties, and corrosion mapping data. RSTRENG, KAPA, or B31G analysis (or other recognized remaining strength assessment methodology) results shall also be documented on this form.

7A.5.7.2.2 ***Predicted Burst Pressure (Pf)***

The predicted burst pressure shall be calculated for each corroded area that has been excavated using RSTRENG, KAPA, or B31G methodology.

7A.5.7.2.3 ***Determination of Safety Factor***

The safety factor of the evaluated area shall be reviewed to determine if it meets the minimum safety factor required by the class location.

7A.5.7.2.4 *Analysis*

The **PIE** or other qualified individual to use RSTRENG, KAPA, or B31G methodology shall make the calculations. The qualification records shall be maintained in the Integrity Management Program file.

- **Calculation:** The safety factor shall be determined by:

$$SF_{corr} = \frac{Pf}{MAOP}$$

SF_{corr} = Safety factor of corroded area

MAOP = Maximum allowable operating pressure for a given pipeline segment based upon 49 CFR 192.619.

Pf = Predicted Burst Pressure

- **Comparison to Class Design Requirements:** The safety factor SF_{corr} shall be compared with the safety factor SF_{DR} for the class location of the evaluated area. Table 7A.5.3 provides the corresponding safety factor for each class location.

Table 7A.5.3: Design Requirements by Area Classification

Area Class	% SMYS	SF_{DR}
1	0.72	1.39
2	0.60	1.67
3	0.50	2.00
4	0.40	2.50

SF_{DR} = Design Required Safety Factor

7A.5.7.2.5 *Documentation*

Form 7A.11: Remaining Strength Evaluation and Root Cause Analysis or similar documentation shall be completed with the pertinent background data including pipe geometry, pipe material properties, and corrosion mapping data. RSTRENG or KAPA analysis results shall also be documented on this form. Form 7A.11 Remaining Strength Evaluation and Root Cause

Analysis shall be reviewed and signed by the Program Manager – Integrity Management.

7A.5.8 Required Action for Immediate Response

7A.5.8.1 **Notification**

If SF_{corr} is less than SF_{DR} specified in Table 7A.5.3 for the given class location the **PIE shall immediately contact the following:**

- Program Manager

The date that this determination is made shall be documented on Form 7A.11 Remaining Strength Evaluation and Root Cause Analysis.

7A.5.8.2 **Pressure Reduction**

Pressure shall be reduced in accordance with applicable Integrity Management Program guidance contained in Section 10 of the company integrity management plan.

7A.5.9 Remediation

The **PIE** shall ensure that remedial actions are documented and recorded according of this procedure. Additionally, the PIE shall ensure Form 7A.8: DA Prioritization Analysis and Direct Examination Form is updated to document which indications were repaired.

7A.5.10 Root Cause Analysis

7A.5.10.1 **Procedure**

The **PIE** shall perform a root cause analysis for each area of corrosion associated with an Immediate or Scheduled indication.

7A.5.10.2 **Objective**

The root cause analysis is to identify the likely causes of corrosion to determine:

- If ECDA is suitable for finding degradation caused by external corrosion.
- The likelihood that similar corrosion damage will occur elsewhere in the ECDA region.
- If the degradation is from a historic or active mechanism.
- Recommendations to mitigate the degradation

7A.5.10.3 **Analysis Content**

The analysis should discuss the following aspects:

7A.5.10.3.1 ***Coating Failure***

The extent and cause of coating failure, including discussion regarding whether the damage is localized or widespread.

7A.5.10.3.2 ***Cathodic Protection Ineffectiveness***

Why the CP was ineffective in this area. Include a discussion of CP history in the area, and the reasons for the presence of CP current shielding or stray currents.

7A.5.10.3.3 ***Corrosion Mechanism***

Identify the main drivers for corrosion in the area including soil chemistry, pH, moisture, corrosive microbes, etc. Is the corrosion active or historic?

7A.5.10.3.4 ***Degradation in Other Areas***

Discuss the characteristics of other locations where similar corrosion may be. Discuss the likelihood if the corrosion is active or historic. Refer to section 13.9 of this IMP.

7A.5.10.3.5 ***Mitigative Measures***

Identify potential mitigative measures to arrest corrosion at the particular location.

7A.5.10.3.6 ***ECDA Feasibility***

Discuss the suitability and potential success of applying the ECDA process to similar areas of degradation.

7A.5.10.4 **Documentation**

The root cause of the external corrosion for each Immediate or Scheduled indication shall be documented in the project file and summarized on Form 7A.11: Remaining Strength Evaluation and Root Cause Analysis. A root cause analysis may cover multiple indications provided that they have similar characteristics.

7A.5.10.5 **ECDA Evaluation**

If the root cause analysis identifies a degradation mechanism that the ECDA process is not well suited to detect, the mechanism and its location shall be documented in the same manner as in 7A.5.10.4. Specifically this includes corrosion caused by disbonded and shielding coatings. A suitable assessment method shall then be used to evaluate those segments of pipe that are vulnerable to the identified mechanism.

7A.5.10.6 **Corrective Action**

Corrective actions taken to address the root cause during the Direct Examination shall be documented on Form 7A.11: Remaining Strength Evaluation and Root Cause Analysis.

7A.5.11 Reclassification and Reprioritization of Indications

7A.5.11.1 **Overview**

Figure 7A.5.1 diagrams the overall process of indication reprioritization. The **PIE** shall utilize the additional data collected during direct examination and the resulting analyses of each indication to evaluate the appropriateness of the assigned priority. This evaluation may result in the re-ranking of indications, including classification as non-reportable indications.

7A.5.11.2 **Reprioritization Criteria**

The following describes the requirements for evaluating and reprioritizing indications, and is summarized in Table 7A.5.4. $SF_{corr.}$ SF_{DR} format for the class areas are given in Table 7A.5.3.

7A.5.11.2.1 *Immediate*

Indications in this category have a SF_{corr} less than SF_{DR} given in Table 7A.5.4.

- **1st Assessments:** Immediate indications that are identified in the first assessment of a pipeline segment cannot be reprioritized.
- **Additional Requirement:** If any Immediate indications are validated from direct examinations to meet the criteria in Table 7A.5.4, no other Immediate indications in that ECDA region shall be reprioritized to a lower priority.

7A.5.11.2.2 *Scheduled*

Indications in this category have a SF_{corr} of greater than SF_{DR} and have evidence of inactive or active corrosion.

- **1st Assessments:** Immediate indications that are identified in the first assessment of a pipeline segment cannot be reprioritized.

7A.5.11.2.3 *Monitored*

Indications in this category have no sign of active or inactive corrosion.

7A.5.11.2.4 *Non-Recordable Indications (NRI)*

Indications in this category have no sign of active or inactive corrosion, meet the 100mV cathodic protection criteria, or demonstrate a protective potential of at least -0.850V.

Table 7A.5.4: Reprioritization Criteria by Area Class

Area Class	SF_{corr} Requirements for Priority Categories			
	Immediate	Schedule	Monitored	NRI

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Bellar

1	<1.39	>1.39 w/ corrosion	No corrosion	No corrosion w/ 100mV
2	<1.67	>1.67 w/ corrosion	No corrosion	No corrosion w/ 100mV
3	<2.00	>2.00 w/ corrosion	No corrosion	No corrosion w/ 100mV
4	<2.50	>2.50 w/ corrosion	No corrosion	No corrosion w/ 100mV

7A.5.11.3 Reprioritization Process

The **PIE** shall complete Form 7A.12: Reprioritization for all indications that are direct examined in the following two steps:

7A.5.11.3.1 *Prioritization Evaluation*

The **PIE** shall complete the upper portion of the form with the appropriate information and document the indications that require reprioritization.

7A.5.11.3.2 *Reprioritization Indications*

The **PIE** shall reprioritize all indications as appropriate and document the reprioritization on the lower have for Form 7A. 12: Reprioritization.

7A.5.11.4 Reprioritization Requirements

The following requirements or allowances shall be applied to the reprioritization of indications.

- Reprioritization is required if the above methodologies shows that the corroded area is more severe than its assigned priority.
- When an indication's priority is raised, the **PIE** shall re-evaluate other indications that may have similar root causes in the ECDA region.
- An Immediate indication shall not be reprioritized lower than the Schedule category.
- 1st Assessments cannot be downgraded.
- If direct examinations show corrosion activity is worse then indicated by indirect inspection, determine through root-cause analysis if the corrosion defects are not unique and isolated in nature. If they are not unique, reevaluate the feasibility of the ECDA process.
- If remediation is performed on an Immediate indication it may be revised to Scheduled, provided subsequent indirect inspections justify reducing the severity.

- If remediation is performed on a Scheduled indication it may be revised to Monitored if no corrosion is found, provided subsequent indirect inspections justify reducing the severity.

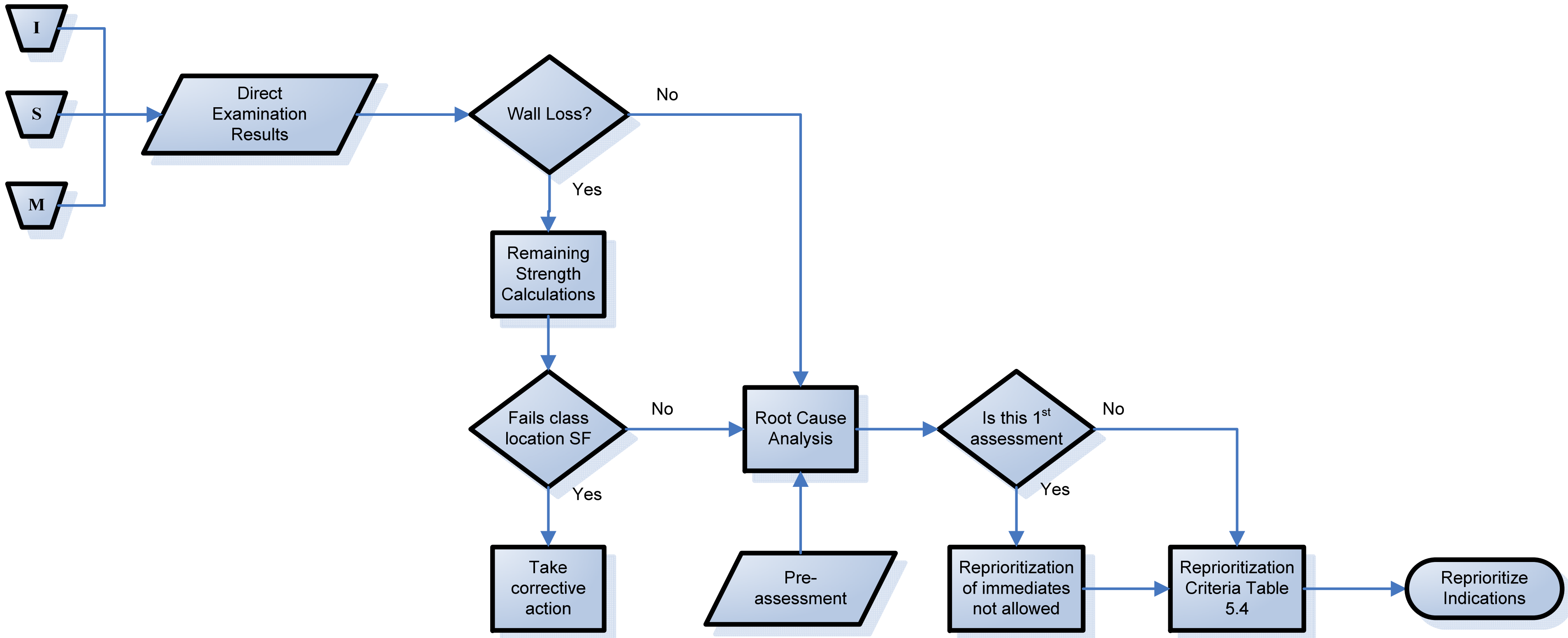

Figure 7A.5.1: Reprioritization Process Diagram

7A.6 POST ASSESSMENT

✓ ***Referenced Protocol:*** ***D.05 ECDA Post Assessment***

7A.6.1 Purpose

The purpose of the Post Assessment is to determine the remaining life and reassessment interval for an ECDA Region, and assess the overall effectiveness of the ECDA process.

7A.6.2 Process

Figure 7A.6.1 is a flow chart showing the process of Post Assessment

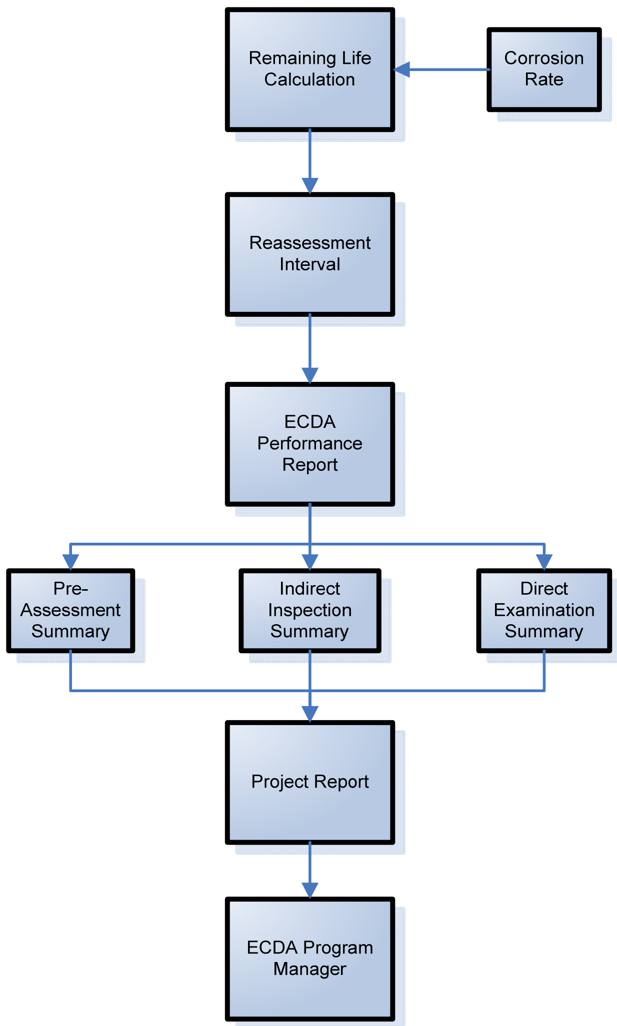

Figure 7A.6.1: Post Assessment Flow Chart

7A.6.3 Remaining Life Determination

The **PIE** shall calculate the remaining life of a corroded area by applying a corrosion rate (either measured or assumed) to the corroded area that exhibits the lowest predicted burst pressure.

7A.6.3.1 **Process**

Figure 7A.6.2 shows the process for determining remaining life.

7A.6.3.2 **Corroded Area Dimensions**

The corrosion anomaly with the lowest burst pressure (Pf) in a given ECDA Region shall be used to determine remaining life.

7A.6.3.2.1 ***Root Cause Exception***

If the root cause analysis shows that the weakest corroded area is unique (and therefore not representative of the dominant degradation mechanism), then the next weakest corroded area may be used to determine remaining life.

7A.6.3.3 **Corrosion Rate**

Corrosion rates from soil analyses, coupon tests, or default values may be used in the remaining life calculation. See subsection 7A.4.14 for soil analysis corrosion rate.

7A.6.3.3.1 ***Default Corrosion Rate with CP***

If the “off” potential of an indication is more negative than -700 mV, and the pipe has not experienced more than one cumulative year without cathodic protection, a corrosion rate of 12 mils per year may be used in the remaining life determination.

7A.6.3.3.2 ***Default Corrosion Rate without CP***

If the “off” potential of an indication is more positive than -700 mV, or the pipe has experienced more than one cumulative year without cathodic protection, a corrosion rate of 16 mils per year shall be used in the remaining life determination.

7A.6.3.3.3 ***Corrosion Rates Exceptions***

Other scientifically supported corrosion rates may be used. The **PM** shall approve use of alternative corrosion rate methods.

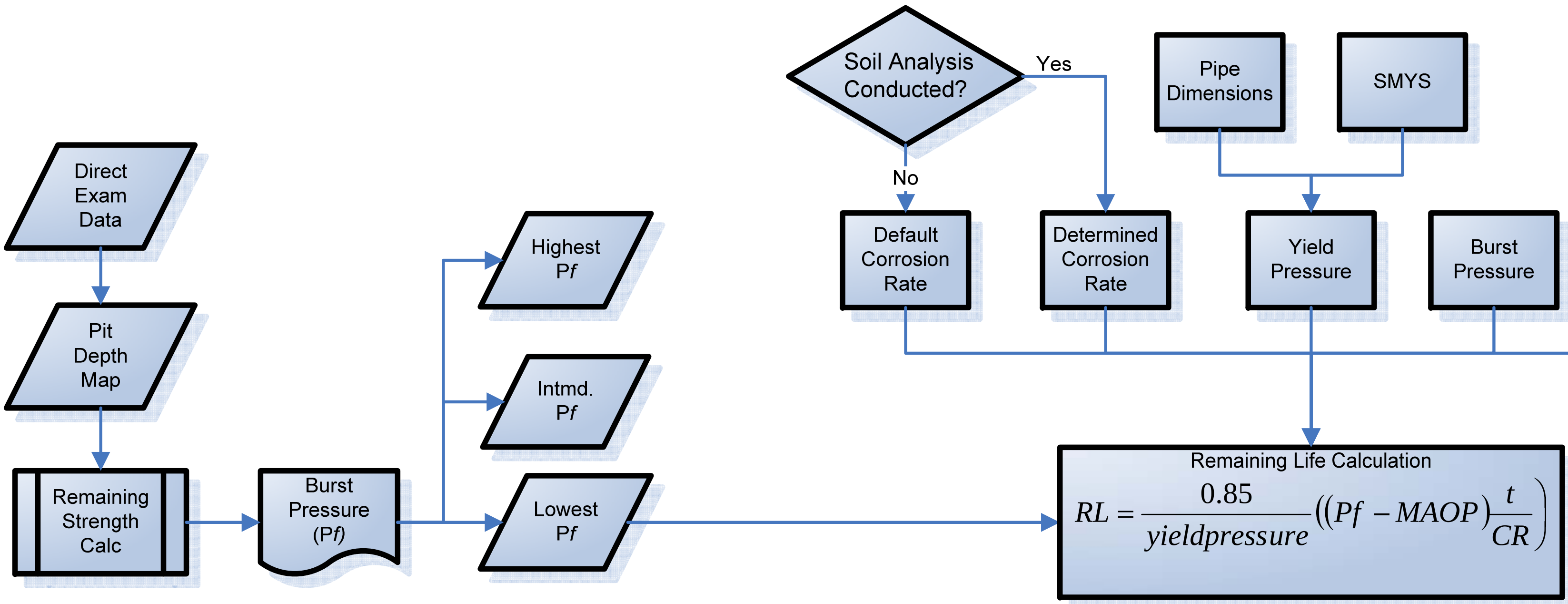

Figure 7A.6.2: Flow chart of Remaining Life Determination process

7A.6.3.4 **Remaining Life Equation**

The equation below shall be used to calculate the remaining life:

$$RL = \frac{0.85}{yieldpressure}\left((Pf - MAOP)\frac{t}{CR}\right)$$

Where:

RL = Remaining Life (years)

Pf = Burst Pressure from RSTRENG (psi)

MAOP = Maximum Allowable Operating Pressure (psi) as determined by the operator in accordance with 49 CFR 192.619.

t = wall thickness (inches)

CR = Corrosion Rate (inches/year)

Yield pressure = $\frac{2*SMYS*t}{OD}$

SMYS = Specified Minimum Yield Strength (psi)

OD = Outer diameter (inches)

7A.6.3.4.1 ***Predicted Burst Pressure***

The *Pf* used in this methodology shall be the "Predicted Burst Pressure" calculated in 7A.5.7.2.

7A.6.3.4.2 ***Calculation***

The largest scheduled indications for ECDA Region after the reprioritization process shall have their remaining life determined.

7A.6.3.4.3 ***Documentation***

The remaining life shall be documented on Form 7A.13: ECDA Remaining Life Determination by the **PIE**.

7A.6.4 Reassessment Intervals

7A.6.4.1 **Remaining Life**

Review the remaining life for an ECDA region calculated in 7A.6.3.4. Calculate ½ the remaining life for each ECDA region.

Determine the Reassessment Interval based upon ½ the Remaining Life or the table below, whichever is **less**.

Table 7A.6.1: Maximum Reassessment Interval

Maximum Reassessment Interval (years)	MAOP at or above 50 % SMYS	MAOP 30% to 50% SMYS	MAOP less than 30% SMYS
10	Maximum Interval [1]		
15	Not allowed	Maximum Interval [2]	
20	Not allowed	Not Allowed	Maximum Interval
[1] A Confirmatory Direct Assessment (CDA) is required by year 7 in a 10-year interval and by years 7 and 14 of a 15-year interval unless a complete reassessment is performed.			
[2] A Low Stress Reassessment or Confirmatory Direct Assessment is required by years 7 and 14 of the interval unless a complete reassessment is performed.			

Determine if it is more feasible to establish one (1) reassessment interval for the entire line segment. Use the **lowest** reassessment interval for all ECDA Regions on the line segment if one (1) reassessment interval will be established.

7A.6.4.2 Review of Reassessment Interval(s)

Review the established Reassessment Interval(s). Determine if a lower Reassessment Interval should be established based upon operating experience including, but not limited to:

- Corrosion defects found on the line segment during non-ECDA related activities.
- Leak history of the line segment.

7A.6.4.3 Other Governing Codes and Regulations

Other documents such as PHMSA regulations may provide further limitations on the reassessment intervals.

7A.6.4.4 Documentation

The reassessment interval for each ECDA Region shall be recorded on Form 7A.13: ECDA Remaining Life Determination and signed by the **PIE**. Also record the reassessment interval per HCA on Form 13.1 “Reassessment Evaluation and Decision Record”.

7A.6.5 ECDA Performance Report

The **PIE** shall complete the Form 7A.20: ECDA Performance Report for each ECDA project. The report shall be reviewed and signed by the **PM**, and filed in both the ECDA project file and the Integrity Management Program file.

7A.6.5.1 Pre-Assessment Summary

Complete the Pre-Assessment table including Direct Examination and other data as appropriate. Where appropriate provide a range of values.

7A.6.5.2 Indirect Inspection Summary

Record the length for each indirect inspection technique used for the project. Record the number of indications by priority after the reprioritization process.

7A.6.5.3 Direct Examination Summary

Record the following Direct Examination results:

7A.6.5.3.1 *Number of Excavations*

Record the number of excavations for each priority indication. If the excavation contained more than one type of priority indication, then record the location at the highest priority indication.

7A.6.5.3.2 *Remaining Life*

Record the remaining life for the scheduled indications. All immediate indications should be assessed and remediate and will not require a remaining life calculation. Monitored indications should not have any corrosion to base a remaining life calculation on.

7A.6.5.3.3 *Immediate Indications*

Record the number of immediate responses found as a result of the direct examinations and remaining strength calculations.

7A.6.5.3.4 *Reprioritization*

Record the number of indications that were reprioritized. Indicate if the priority was raised, lowered, or moved to NRI.

7A.6.5.4 ECDA Effectiveness

The assessment of ECDA effectiveness is accomplished by performing validation digs per the criteria detailed in section 7A.5.3.5 and considering the results of root-cause analysis performed in accordance with section 7A.5.1010.

7A.6.5.4.1 *Confirmation of ECDA Effectiveness*

The **PIE** or **PM** will use the results of the validation digs to provide confirmation of the effectiveness of the ECDA process.

Review results of validation digs for the following:

- No indication found at an “indication” validation examination
- Indication found at a random “no indication” location

If either of the above conditions are found, re-evaluate the effectiveness of the ECDA process.

7A.6.5.4.2 *Documentation*

The **PIE** or **PM** will document the review and include the results of the review in the Post-Assessment documentation Form 7A.20: ECDA Performance Report. The ECDA process will be re-evaluated and repeated, or an alternate integrity assessment method used.

If the performance measures do not show improvement between ECDA applications, the **PM** will reevaluate the applicability of the ECDA process and evaluate alternative methods of assessing the integrity of the pipeline.

7A.6.5.5 **Post Assessment Summary**

The **PIE** or **PM** will record the following post assessment information on Form 7A.20: ECDA Performance Report:

7A.6.5.5.1 *Reinspection Interval*

Record the shortest reinspection interval for the ECDA project.

7A.6.5.5.2 *Missed Deadlines*

Record the number of missed deadlines during the project and provide a brief description of the deadlines missed.

7A.6.5.5.3 *Exceptions*

Record the number or exceptions taken with the procedure and briefly describe the nature of the exception.

7A.6.6 Project Report

The **PS** shall prepare a project report and submit it for approval to the **PM**.

7A.6.6.1 **Contents**

The report shall contain the following information in the suggested order:

- Form 7A.20: ECDA Performance Report
- Form 7A.19: ECDA Feedback and Continuous Improvement
- Form 7A.18: ECDA Direct Examination Restrictive Criteria Form
- Form 7A.17: ECDA Indirect Inspection Restrictive Criteria Form
- Form 7A.16: ECDA Pre-Assessment Restrictive Criteria Form
- Form 7A.15: Contractor Interactions and Decisions
- Form 7A.14 Exception Report
- Form 7A.13: Remaining Life Determination
- Form 7A.12: Reprioritization Reports
- Form 7A.11: Remaining Strength Evaluation and Root Cause Analysis
- Form 7A.10: Data Excavation Sheets
- Form 7A.9: Number of Direct Examinations Reports

- Form 7A.8: DA Prioritization Analysis and Direct Examination Form
- Form 7A.7: Indication Classification Summary Form
- Form 7A.6: IIT Procedure Review Form
- Form 7A.5: ECDA Region Report
- Form 7A.4: Indirect Inspection Tool Report
- Form 7A.3: Feasibility Analysis Report
- Form 7A.2: Sufficient Data Analysis
- Form 7A.1: Data Element Check Sheet

7A.6.6.2 **Documentation**

Upon approval from the **PM**, the report shall be distributed as appropriate and filed in the ECDA project file.

7A.6.7 Internal Communications

The **PM** and **PIE** will ensure that any changes affecting the ECDA Plan are communicated to the appropriate personnel. Changes may include but are not limited to:

- Severity classification
- Priority of direct examinations
- Timeframe direct examinations are performed

Changes will be communicated per the requirements of section 14 “Management of Change”.

7A.6.8 Feedback and Continuous Improvement

Whenever possible, the Company strives to continually improve the ECDA process by incorporating feedback. Areas where feedback may be incorporated include, but are not limited to:

- Identification and classification of indirect inspection results
- Data collected during the direct examinations
- Remaining strength analysis
- Root cause analysis
- Remediation activities
- In-process evaluations
- Validation examinations
- Criteria for monitoring long-term effectiveness
- Reassessment intervals

When deemed appropriate, the **PIE** will host a “lessons learned” meeting to discuss the ECDA process. Items discussed may include:

- Things that went well
- Areas of improvement
- Modifications to ECDA plan or procedures

When such a meeting is held, the **PIE** will document the following on Form 7A.19: ECDA Feedback and Continuous Improvement:

- Date of meeting
- Attendees
- Items discussed
- Action Items

All documentation will be kept in the Integrity Management File.

7A.7 EXCEPTION PROCESS

7A.7.1 Expectations

It is expected that all requirements of this procedure be met when conducting an ECDA. However, exceptions may be taken by obtaining approval and documenting the exceptions as prescribed in this section.

7A.7.2 Objective

To provide control and consistent documentation of exceptions to this procedure. Control and consistent documentation are necessary to maintain the integrity of an ECDA project through continuous process improvement, feedback, audits, and compliance with this procedure.

7A.7.3 Exception Requirements

The following process is required for deviating from this procedure. It shall be documented on Form 7A.14 Exception Report:

7A.7.3.1 **Section of Procedure**

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

7A.7.3.2 **Alternative Plan**

State the proposed exceptions to the procedure.

7A.7.3.3 **Reason**

Provide the reason for the exception.

7A.7.3.4 **Recommendation**

Indicate if this is a project specific exception, or if a procedure change is recommended.

7A.7.3.5 **Approval**

Obtain approval from the **PM**.

7A.7.4 Documentation

Form 7A.14; Exception Report shall be used to document the Exception Process. Form 7A.14: Exception Report shall be reviewed and signed by the **PIE, PS,** and **PM**. All exception reports shall be stored in the ECDA project file.

7A.8 CONTRACTOR INTERACTIONS AND DECISIONS

7A.8.1 Objective

This is a non-mandatory section that intended to facilitate the documentation of discussions, agreements, and decisions between the contractor and the Company when conducting the ECDA process.

7A.8.2 Information

Each issue shall be titled and dated when the entry was made. The individual creating the entry shall initial the document.

7A.8.3 Documentation

The **PIE, PS, CS, PM, CT**, or other Contractor may utilize Form 7A.15: Contractor Interactions and Decisions, to document discussions, agreements, and decision with various parties.

7A.9 ECDA FORMS

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.1: Data Element Check Sheet

Date: ____________ Project Name: ______________________________

Starting Survey Station: ____________ Segment Number/ HCA Number: ______________________________

Ending Survey Station: ____________ Prepared By: ______________________________

Instructions:

This form shall be completed in accordance with Subsection 7A.3.4 of The Procedure. The PIE or designee shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the comment field. This should include, as a minimum the reason required data is not available.

ID #	Data Element Description	Need	District/ Archive Files	GIS	Field	Pipeline Databases	Maps Other	Comments Sys ID ____________	Sign Off
					1.0 Pipe Related				
1.1	Material and Grade	R							CMA
1.2	Diameter	R							
1.3	Wall thickness	R							
1.4	Year manufactured	D							
1.5	Seam Type	D							
1.6	Bare pipe	R							
					2.0 Construction Related				
2.1	Year installed	R							
2.2	Recent route modifications that may not be in GIS	D							
2.3	Construction practices	D							
2.4	Location of major pipe appurtenances such as valves, and taps	D							
2.5	Locations of casings	R							
2.6	Location of bends, including miter bends and wrinkle bends	D							
2.7	Depth of cover	D							
2.8	Underwater sections and river crossings	R							
2.9	Locations of river weight and anchors	D							
2.10	Proximity to other pipelines structures, HV electric transmission lines and rail crossing	R							
					3.0 Soil Environmental				
3.1	Soil characteristics & types (Refer to NACE RP 0502 Appendix B and D).	D							

R= Required, D= Desired, C= Considered, N/R= Not Required

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.1: Data Element Check Sheet

Date: ____________ Project Name: ______________________________

Starting Survey Station: ____________ Segment Number/ HCA Number: ______________________________

Ending Survey Station: ____________ Prepared By: ______________________________

Instructions:

This form shall be completed in accordance with Subsection 7A.3.4 of The Procedure. The PIE or designee shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the comment field. This should include, as a minimum the reason required data is not available.

ID #	Data Element Description	Need	District/ Archive Files	GIS	Field	Pipeline Databases	Maps Other	Comments Sys ID ________	Sign Off
3.2	Drainage	D							
3.3	Topography	D							
3.4	Land use (current/pass)	R							
3.5	Frozen ground	R							
	4.0 Corrosion Control								
4.1	CP system type (anodes, rectifiers and locations)	R							
4.2	Stray Current sources/locations	D							
4.3	Test point locations (pipe access points)	R							
4.4	CP evaluation criteria	R							
4.5	CP maintenance history	R							
4.6	1st **Assessment Requirement:** All available CP Maintenance History	R							
4.7	Years without CP applied	D							
4.8	Coating type-pipe	R							
4.9	Coating type-joints	D							
4.10	Coating condition	D							
4.11	Current demand	D							
4.12	CP survey data/history	D							
	5.0 Operational Data								
5.1	Pipe operating temperature	D							
5.2	Operating stress level	R							
5.3	Monitoring programs (Coupon, patrol leak surveys etc.)	D							

R= Required, D= Desired, C= Considered, N/R= Not Required

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.1: Data Element Check Sheet

Date: ____________ Project Name: ______________________________

Starting Survey Station: ____________ Segment Number/ HCA Number: ______________________________

Ending Survey Station: ____________ Prepared By: ______________________________

Instructions:

This form shall be completed in accordance with Subsection 7A.3.4 of The Procedure. The PIE or designee shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the comment field. This should include, as a minimum the reason required data is not available.

ID #	Data Element Description	Need	District/ Archive Files	GIS	Field	Pipeline Databases	Maps Other	Comments Sys ID ________	Sign Off
5.4	Pipe inspection reports-excavation	D							
5.5	Repair history, steel/composite repair sleeves, repair locations	D							
5.6	Leak rupture history (EC)	R							
5.7	Evidence of external MIC	D							
5.8	Type and frequency of third party damage	D							
5.9	Data from previous over the ground surveys	R							
5.10	Hydro test dates/pressures	D							
5.11	Other prior integrity related activities – CIS, ILI runs, etc.	R							
Field Observations									

PIE: ______________________________ Date: ______________________
Signature

R= Required, D= Desired, C= Considered, N/R= Not Required

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.2: Sufficient Data Analysis

Date: ____________ Project Name: ____________

Starting Survey Station: ____________ Segment Number/HCA Number: ____________

Ending Survey Station: ____________ Prepared By: ____________

Instructions: This Form shall be completed in accordance with Subsection 7A.3.7.2 of The Procedure.

Sufficient Data Analysis

Missing Required Data Elements				
ID# (Form 7A.1)	Data Element Description (Form 7A.1)	Pipe Segments	Reason for missing data	Explanation why the data is not needed

Sufficient Data: Yes ________ PIE: ____________ Date: ____________
Signature

No ________ PM: ____________ Date: ____________
Signature

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LG&E

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.3: Feasibility Analysis Report

Date: ____________________ Project Name: ____________________

Starting Survey Station: ____________________ Segment Number/HCA Number: ____________________

Ending Survey Station: ____________________ Prepared By: ____________________

Instructions: This Form shall be completed in accordance with Subsection 7A.3.8 of The Procedure. Analyze each data category to answer the general questions listed under each ECDA step in the table below. In answering the question include the following:

1) Any adverse conditions that may make the pipe segments infeasible to ECDA. Refer to Table 7A.3.1 for guidance.
2) Any special considerations, techniques that need to be incorporated or considered in conducting the ECDA to overcome the adverse conditions
3) A conclusion on the feasibility of conducting an ECDA for all the pipe segments in the ECDA project

ECDA Feasibility Analysis

ID #	Data Categories	In-direct Inspection Can existing indirect inspection tools be applied to the pipe segments identified and be expected to provide meaningful results on potential locations where the coating is damaged? If any of the conditions listed in subsection 7A.3.8.2 is present an explanation shall be provided here regarding why ECDA is feasible .	Direct Examination Is it feasible to gain access to the pipeline to conduct direct assessment and gain meaningful data?	Post-Assessment Can reassessment intervals be reasonably determined for the pipe segments considering the existing data?
1	Pipe Related			
2	Construction Related			
3	Soils/Environmental			
4	Corrosion Control			
5	Operational Data			

ECDA Feasible: Yes __________ PIE: ______________________________ Date: ______________
Signature

No __________ PM: ______________________________ Date: ______________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.4: Indirect Inspection Tool Selection

Date: ____________ Project Name: ______________________

Starting Survey Station: __________ Segment Number/HCA Number: ______________________

Ending Survey Station: __________ Prepared By: ______________________

Instructions: This Form shall be completed in accordance with Subsection 7A.3.9 of The Procedure.

ECDA Identification			Region Location							Indirect Inspection Tools			Comments
Pipeline Segment Name & Number	ECDA Region ID	HCA Numbers	ECDA Region Start	ECDA Region Stop	GPS Coord. Latitude Start	GPS Coord. Longitude Start	GPS Coord. Latitude Stop	GPS Coord. Longitude Stop	Region Length	1st IIT	2nd IIT	3rd IIT (Required for 1st ECDA)	Region Name, Boundary Marker Type, Additional Inspection Tools, References to Exceptions, Etc.

PIE: ______________________________ Date: ______________
Signature

PM: ______________________________ Date: ______________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.5: ECDA Region Report

Date: ____________ Project Name: ____________

Starting Survey Station: ____________ Segment Number/HCA Number: ____________

Ending Survey Station: ____________ Prepared By: ____________

Instructions: For each ECDA region record the two IIT's and the unique data element(s) that are used to establish the region. The IIT's and at least one other characteristic must be recorded for each region. Bare pipe, casings, and water crossing require separate ECDA regions in addition to the same two primary IIT's.

ECDA Region	First IIT Method	Second IIT Method	Pipe Related Characteristics (incld. Data Element #)	Construction Related Characteristics (incld. Data Element #)	Soils and Environmental Characteristics (incld. Data Element #)	Corrosion Control Characteristics (incld. Data Element #)	Operational Data Characteristics (incld. Data Element #)

PIE: ____________ Date: ____________
Signature

PM: ____________ Date: ____________
Signature

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SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.6: IIT Procedure Review Form

Date: ______________ IIT Method: ______________

Prepared By: ______________ Vendor or Company Organization: ______________

Reviewed By: ______________ Procedure Number: ______________

Requirement: Subsection 7A.4.4.1 in the ECDA Procedure provides the requirement and context for this form.

Procedure Content Review

Acceptable	Not Acceptable		Comments
☐	☐	Procedure Number	
☐	☐	General Description	
☐	☐	Limitations	
☐	☐	Safety	
☐	☐	Instrumentation	
☐	☐	Personnel Qualifications	
☐	☐	Calibration	
☐	☐	Equipment Connections	
☐	☐	Pipe Locator	
☐	☐	Measurements	
☐	☐	Special Diagnostics	
☐	☐	Distance Measurements	
☐	☐	Data Recording	
☐	☐	Approval	

General Comments: ______________

Approved	Not Approved	
☐	☐	Comments: ______________

Reviewer: ______________ Date: ______________
Signature

PIE: ______________ Date: ______________
Signature

Attachment to Response to AG Q252
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SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.7: Indication Classification Summary Form

Date: ________________ Project/HCA Number: ____

Starting Survey Station: ________________ Pipeline Number: ____

Ending Survey Station: ________________ Prepared By: ____

Instructions: Section 7A.4.10 provides instructions on classifying indications. Section 7A.4.12 provides instructions on prioritization of indications.

Beginning Station Number	Ending Station Number	ECDA Region	CIS Severity[1]	DCVG Severity[1]	PCM Severity[1]	Other Severity[1]	Initial Prioritization Category[2]	Comments

PIE: ____ Date: __________________________
Signature

PM: ____ Date: __________________________
Signature

[1] Severity classification: Severe, Moderate, Minor in accordance with Table 7A.4.2
[2] See Table 7A.4.3 for Prioritization

Form 7A.8: DA Prioritization Analysis and Direct Examination Form

Date: ________ Project/HCA Number: ______________________________

Starting Survey Station: ____________ Pipeline Number: ______________________________

Ending Survey Station: ____________ Prepared By: ______________________________

INSTRUCTIONS: Section 7A.4.10 provides instructions on classifying indications. Section 7A.4.11 provides instruction on checking alignment of indications. Section 7A.4.12 provides instructions on prioritization of indications. Section 7A.4.15 provides instructions on Urgency Level and Excavation Date. Subsection 7A.4.14 provides instructions on corrosion rate analysis. Section 7A.4.13 provides information on alight ECDA data with encroachment data.

Pipeline Segment	HCA Number	Item #	Station Begin	Station End	Footage	CIS Severity[1]	PCM Severity[1]	DCVG Severity[1]	Other Severity[1]	Initial Priority[3]	Alignment[2]	Correspond with Encroachment (Y/N)	Comments	Urgency Criteria				Urgency Level	Prioritization of Examination Sites	DE Order	Latest Date of Excavation	Pipe Repair (Y/N)	Notes	Latitude Begin	Longitude Begin	Latitude End	Longitude End
														History of Leaks	History of Wall Loss	Years w/o CP	Est. Corrosion Rate										

PIE: ______________________________ Date: ______________
Signature

PS: ______________________________ Date: ______________
Signature

PM: ______________________________ Date: ______________
Signature

[1] Severity classification: Severe, Moderate, Minor in accordance with Table 7A.4.2

[2] Alignment classification: Yes- IIT Indications align, No- IIT Indication do not algr

[3] See Table 7A.4.3 for Prioritization

Form 7A.9: Number of Direct Examinations Report

Date: ____________ Project/HCA Number: ____________

Starting Survey Station: ____________ Pipeline Number: ____________

Ending Survey Station: ____________ Prepared By: ____________

Segment Indication Priorities				Number of Direct Examinations				
	Indication Severity			Non-Validation Digs		Process Validation		
Region #	Immediate	Scheduled	Monitored	Anytime ECDA Applied	1st Time ECDA	Anytime ECDA Applied	1st Time ECDA	Total Digs
1								0
2								
3								
4								
5								
6								
7								

PIE: ____________ Date: ____________
Signature

PS: ____________ Date: ____________
Signature

PM: ____________ Date: ____________
Signature

Form 7A.9: Number of Direct Examinations Report

For Each ECDA Project		For Each ECDA Region			ValidatioDigs per ECDA Project
Indirect Inspection data containing	Action	Containing	Action	1st Time Application of ECDA	Action
Mixed Indications including Immediate, Scheduled, and Monitored	Separate Results by Region & Indication ranking in order to Determine Region Specific Requirements	Immediate	Dig all Immediate		One excavation per pipeline segment at the next most severe indication[2]
		Immediate & Scheduled	Dig all Immediate		
			Add 1 Scheduled dig at the most severe location[1]	Add an additional examination at next most severe	
		Scheduled	Examine one (1) location - Prioritize & dig most Severe	Add an additional examination at next most severe	
		Monitored Only	Examine one (1) location - Prioritize & dig most Severe	Add an additional examination at next most severe	
		Multiple Regions with Monitored Only	Identify Region most likely for external corrosion. Examine one location.	Add an additional location in the Region most likely for external corrosion	
Monitored Only	Separate Results by Region & Indication Ranking	Identify Region most likely for external corrosion. Dig 1 Monitored indication in most likely corroded region		Add an additional location in the Region most likely for external corrosion	One excavation per pipeline segment at the next most severe indication[2]
No Indications		Identify Region most likely for external corrosion. Dig 1 location in most likely to corrode region		Add an additional location in the Region most likely for external corrosion	One excavation per pipeline segment at a randomly selected location[2]

[1] If no Scheduled indications remain, perform examination at Monitored indication location.

[2] For the first application of ECDA, add a second excavation at a randomly selected location with no indications.

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.10: Direct Examination Data Excavation Page 1 of 3

Date of Excavation: ____________ Line Number: ____________

Excavation Station: ____________ PS: ____________

Excavation Order: ____________ On-Site Manager: ____________

Instructions: Subsection 7A.5.6 provides instructions to complete this form.

Expanded: ☐ Yes ☐ No

Excavation Details: **Expanded Details:**

GPS ____________ ____________

Begin ____________ N° ____________ N°
____________ W° ____________ W°

End ____________ N° ____________ N°
____________ W° ____________ W°

6.0 Prior To and During Excavation

6.1 Photographic documentation of original site condition taken. ☐ Yes ☐ No

6.2 Coating Type ____________

6.4 Soil Resistivity: ____________

Comments: ____________

6.5 Soil Sample Collected? ☐ Yes ☐ No **6.6 Ground Water Sample Collected?** ☐ Yes ☐ No

7.0 Before Coating Removal

7.1 Pipe to Soil Potentials: ____________ Indication of Stray Currents? ☐ Yes ☐ No

Comments: ____________

7.2 Photographic documentation of original site condition taken. ☐ Yes ☐ No

7.3 Under Coating Liquid Present? ☐ Yes ☐ No pH of Under Coating Liquid: ____________

7.4 MIC testing for liquid under coating? ☐ Yes ☐ No

7.5 Coating Condition: ☐ Excellent and adhered to pipe ☐ Coating partially disbonded or degraded
☐ Coating completely missing, pipe bare

7.6 Coating Sample Collected? ☐ Yes ☐ No Comments: ____________

7.7 Coating Thickness: ____________

Map of Coating Degradation: **Axial Length**

Circumferential Length

Clock Pos.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Clock Pos.
12																					12
1																					1
2																					2
3																					3
4																					4
5																					5
6																					6
7																					7
8																					8
9																					9
10																					10
11																					11

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.10: Direct Examination Data Excavation Page 2 of 3

Date of Excavation: ____________ Line Number: ____________

Excavation Station: ____________ PS: ____________

Excavation Order: ____________ On-Site Manager: ____________

8.0 During and After Coating Removal

8.1 Coating Adhereance: ____________

8.2 Corrosion product sample taken? ☐ Yes ☐ No

8.3 Pipe temperature: ______ °F Location Taken: ____________

8.4 Weld seam type: ____________

8.5 Other Damage or Defect: ____________

Evidence of 3rd-Party Damage: ☐ Yes ☐ No PIE or PIM Notified? ☐ Yes ☐ No

Comments: ____________

8.6 Observation of Corrosion Defects:

☐ Large crater up to 2-3 inches or more in diameter

☐ Cup-type hemispherical pits on the pipe surface of in the craters

☐ Striations or contour liens in the pits or craters running parallel to longitudinal pipe axis

☐ Tunnels sometimes at the end of the craters, running parallel to longitudinal pipe axis

8.7 Identification of corrosion: ☐ Active ☐ Inactive Comments: ____________

8.8 UT Wall Thickness Measurements: TDC: ______ 3 o'clock: ______ 6 o'clock: ______ 9 o'clock: ______

Add. UT Msmts: ______ Location: ____________ ______ Location: ____________

______ Location: ____________ ______ Location: ____________

______ Location: ____________ ______ Location: ____________

8.9 Photos Taken of Pipe? ☐ Yes ☐ No Location of Photos: ____________

8.10 Photos Taken of Corroded Area and defects? ☐ Yes ☐ No

Location of Photos: ____________

8.11 See Page 3

8.12 See Page 3

8.13 Magnetic Particle Inspecition Conducted? ☐ Yes ☐ No

Location: ____________

8.14 Photos Taken of Repairs? ☐ Yes ☐ No Location of Photos: ____________

8.15 Photos Taken of Site Restoration? ☐ Yes ☐ No

Additional comments on the Direct Examination: ____________

____

____

____

____

Form 7A.10: Direct Examination Data Excavation Page 3 of 3

Date of Excavation: ____________________ Line Number: ____________________

Excavation Station: ____________________ PS: ____________________

Excavation Order: ____________________ On-Site Manager: ____________________

8.0 During and After Coating Removal Continued

8.11 Map of Corrosion Defects

Axial Length

Circumferential Length

Clock Pos.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Clock Pos.
12																															12
1																															1
2																															2
3																															3
4																															4
5																															5
6																															6
7																															7
8																															8
9																															9
10																															10
11																															11

8.12 Pit Depth Map

Axial Length

Circumferential Length

Clock Pos.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	Clock Pos.
12																															12
1																															1
2																															2
3																															3
4																															4
5																															5
6																															6
7																															7
8																															8
9																															9
10																															10
11																															11

PS: ______________________________ Date: ____________________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.11: Remaining Strength Evaluation and Root Cause Analysis

Date of Evaluation: ____________________ Region Number: ____________________

Indication Station: ____________________ Line Number: ____________________

Prioritization Priority: ____________________ Prepared By: ____________________

Instructions: Subsection 7A.5.7 provides instructions to conduct the remaining strength evaluation. Subsection 7A.5.8 provides instruction for Root Cause Analysis.

PIPE DATA

Dia: ____________ Wall Thickness: ____________ Material: ____________

% SMYS: ____________ MAOP: ____________ Class Location: ____________

PREDICTED BURST PRESSURE DETERMINATION (P_F):

PIT DEPTHS (FORM H, TABLE 7A.7.9, OR OTHER EQUIVALENT DOCUMENTATION MAY BE USED)

Circumferential Length

Clock Pos.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	Clock Pos.
12																					12
1																					1
2																					2
3																					3
4																					4
5																					5
6																					6
7																					7
8																					8
9																					9
10																					10
11																					11

P_F: ________ SF_{com}(P_f/MAOP): ________ SF_{DR}: ____ 1.39 ____ 1.67 ____ 2.00 ____ 2.50

Repair Required: ☐ Yes ☐ No Analyst: ____________________ Date: ____________

People Notified: ____________________ Date of Notification: ____________

____________________ ____________

____________________ ____________

Root Cause Analysis

Cause: ____

Remedial Actions: ____

Is ECDA well suited to identify damage from the cause described above? ☐ Yes ☐ No

Is reprioritization of indications recommended? ☐ Yes ☐ No

Are repeat indirect inspections required? ☐ Yes ☐ No

Comments: ____

Preparer: ____________________ Date: ____________
Signature

PIE: ____________________ Date: ____________
Signature

Signature
PM: ____________________ Date: ____________
Signature

Developed By Mears Group Inc.;
Revised By EN Engineering

Page 1 of 1

INTEGRITY MANAGEMENT PROGRAM

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.12: Reprioritization

Evaluation Date: ____________ ECDA Region Number: ____________

Line Number: ____________ Prepared By: ____________

INSTRUCTIONS: Subsection 7A.5.10 provides instructions on Reclassification and Reprioritization.

Prioritization Evaluation

Station or Station Range of Indication	DE Order (Form 7A.7)	SFcorr	Class Location	SFDR	Corrosion Present	Reprior. Yes/No	Initial Prioritization	Comments

PIE: ____________ Date: ____________

Reprioritized Indications From Above Analysis

Station or Station Range of Indication	Original Priority	New Priority	Comments	MP or MP Range of Indication	Original Priority	New Priority	Comments

PIE: ____________ Date: ____________
Signature

PM: ____________ Date: ____________
Signature

Developed By Mears Group Inc.;
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INTEGRITY MANAGEMENT PROGRAM

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.13: ECDA Remaining Life Determination

ECDA Project Name: ______________________ **Date of Evaluation:** ______________________

Line Number: ______________________ Prepared By: ______________________

Starting Mile Point: __________ **Ending Mile Point:** __________ **Station Discharge:** __________

Class Location: __________ **MAOP:** __________

INSTRUCTIONS: Subsection 7A.6.3, "Remaining Life" provides instructions for this calculation.

Nominal Diameter	*Outside Diameter*
1	*1.315*
2	*2.375*
4	*4.5*
6	*6.625*
8	*8.625*
12	*12.375*
16	*16*
20	*20*

CORROSION RATE CALCULATION:

Soil Resistivity	1000	Estimated Corr. Rate based upon Soil Resistivity	0.006	in/yr
Corrosion Present	Y	Estimated Corr. Rate Based upon Cathodic Protection	n/a	in/yr
CP Data	B			

Select letter from list below:
A - Protected [P/S Off readings more negative than -700mV; 1 year or less cummulative CP off time]
B - Not Well Protected [P/S Off readings less negative than -700mV; >1 year cummulative CP off time]

REMAINING LIFE CALCULATION:

Pipeline Station	Priority	Indication Location	Outside Diameter (in)	Thickness (in)	Yield Strength (psi)	Yield Pressure (psi)	Design Safety Factor (SF_{DA})	Date of Discovery	Pressure Reduction Required?	Reduced Operating Pressure (psi)	Actual Pressure Reduction Date	Predicted Failure Pressure Pf (psi)	Corrosion Rate (in/year)	Remaining Life (years)	1/2 RL (years)
			12	0.5	24000	2000						1800	0.012	31.88	15.94

Shortest Reassessment Interval of all Indications in the HCA: 15.94

Comments: ______________________

PIE: ______________________ **Date:** __________
Signature

PM: ______________________ **Date:** __________

Developed By Mears
Revised By EN Engineering

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INTEGRITY MANAGEMENT PROGRAM

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SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.14: Exception Report

Report Date: ____________ ECDA Region Number: ____________

Line Number: ____________ Prepared By: ____________

Instructions: Completing this form is described in Subsection 7A.7.0

Paragraph Number of Exception: ____________

Requirements of paragraph (Briefly state or Paraphrase): ____________

Alternative Plan: ____________

Reason for Exception: ____________

Recommendation: Should the procedure be changed? Yes No
circle one

Comments: ____________

PIE: ____________ Date: ____________
Signature

PM: ____________ Date: ____________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.15: Contractor Interactions and Decisions

Report Date: ____________________ ECDA Region Number: ____________________

Line Number: ____________________ Prepared By: ____________________

INSTRUCTIONS: Completeing this form as described in Subsection 7A.8 of the procedure

PIE: ______________________________ Date: ______________
Signature

PM: ______________________________ Date: ______________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.16: ECDA Pre-Assessment More Restrictive Criteria Form

Report Date: ________________ Pipeline Name: ______________________________

Line Number: ________________ ECDA Project: ______________________________

Prepared By: ____

INSTRUCTIONS: Subsection 7A.3.12 for additional information.

	Yes	No
Is this the first time to apply the ECDA process to this pipeline segment?	☐	☐
1) Collect and review all available CP records.	☐	☐
2) Hold a Pre-Assessment review meeting to provide technical insight into conducting ECDA on the line segment..	☐	☐
5) Other Criteria Chosen: If yes, describe below:	☐	☐

PIE: ______________________________________ Date: __________
Signature

PM: ______________________________________ Date: __________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.17: ECDA Indirect Inspection More Restrictive Criteria Form

Report Date: ________________ Pipeline Name: ________________________________

Line Number: ________________ ECDA Project: ________________________________

Prepared By: ____

INSTRUCTIONS: Subsection 7A.4.2 for additional information.

	Yes	No
Is this the first time to apply the ECDA process to this pipeline segment?	☐	☐
NACE Criteria choose at least one		
1) Take duplicate readings at random test stations along the indirect inspection survey route with a separate meter and compare the readings	☐	☐
2) Repeat an indirect inspection.	☐	☐
3) When performing close-interval survey, resurvey any areas with structure-to-electrolyte readings more electro-negative than -850 mV.	☐	☐
4) A Company inspector reviews the indirect inspection survey data at the end of each survey day.	☐	☐
5) Other criteria. If yes, describe below:	☐	☐

____

____

____

Part 192 Criteria choose at least one	Yes	No
1) Use more than two (2) indirect inspection tools.	☐	☐
2) Perform depth of cover survey.	☐	☐
3) Take soil resistivity readings in each ECDA Region or at Category I and II DCVG indications	☐	☐
4) Determine a more conservative severity table and apply the increased severity to each to tool.	☐	☐
5) Use a closer interval between test point readings for greater possible accuracy and less chance of missing an indication.	☐	☐
6) Increase the excavation priorities by categorizing the highest two coating indications as 'Immediate' and all subsequent indications as 'Scheduled' regardless of how minor they appear.	☐	☐
7) For indirect inspection tool conflicts, even if resolved, redo the indirect for all tools.	☐	☐
8) Drill holes in pavement to reach electrolyte in order to obtain pipe-to-soil readings.	☐	☐
9) Other criteria. If yes, describe below:	☐	☐

____

____

____

PIE: ____ Date: __________
Signature

PM: ____ Date: __________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.18: ECDA Direct Examination More Restrictive Criteria Form

Report Date: ____________ Pipeline Name: ____________________________

Line Number: ____________ ECDA Project: ____________________________

Prepared By: ____

Instructions: This Form shall be completed in accordance with Subsection 7A.5.2 of The Procedure

	Yes	No
Is this the first time to apply the ECDA process to this pipeline segment?	☐	☐

NACE Criteria

	Yes	No
1) Do not downgrade any classification or prioritization criteria.	☐	☐
2) Do not downgrade any indications that were originally placed in the 'Immediate' or 'Scheduled' priority category to a lower priority category.	☐	☐
3) Other criteria. If yes, describe below:	☐	☐

____

____

____

____

Part 192 Criteria

choose at least one

	Yes	No
1) Resurvey the ECDA region after immediate indications have been repaired to determine if other indications were masked by the large indication.	☐	☐
2) Perform additional testing at each excavation location.	☐	☐
3) Install coupon test stations at select excavation locations to assist in future monitoring	☐	☐
4) Perform a larger excavation to ensure all nearby indications are discovered and to eliminate the potential for smaller indications to not be picked up during the indirect inspection due to masking effects.	☐	☐
5) Perform additional direct examinations beyond those already required by NACE RP0502.	☐	☐
6) Other criteria. If yes, describe below:	☐	☐

____

____

____

PIE: ____ Date: ________
Signature

PM: ____ Date: ________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.19: ECDA Feedback and Continuous Improvement

Report Date: ____________ Pipeline Name: ______________________________

Line Number: ____________ ECDA Project: ______________________________

Prepared By: ____

Instructions: This Form shall be completed in accordance with Subsection 7A.6.9 of The Procedure

Atendees and Titles

Things that went well during the process:

Areas for improvement:

Modifications to the ECDA plan or procedures:

Comments:

PIE: ______________________ Date: ____________
Signature

PM: ______________________ Date: ____________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.20: ECDA Performance Report

Date: ____________________ PIE: ____________________

Line Name: ____________________ PM: ____________________

Segment Numbers: ____________________ IIT Vendor: ____________________

Pre-Assessment Summary

ECDA Identification			Region Location				Indirect Inspection Tools		
Pipeline Segment Name & Number	ECDA Region ID	HCA Numbers	ECDA Region Start	ECDA Region Stop	Region Length	Region HCA Length	1st IIT	2nd IIT	3rd IIT (Required for 1st ECDA)

Indirect Inspection Summary

Previously Inspected? Yes No Year(s)? ____________________

	CIS	DCVG	PCM	Other
Length of Assessed HCA Pipe (Miles)				
Length of Inspected Pipe (Miles)				

	Immediate	Scheduled	Monitored	NRI
# of Indications				

Direct Examination Summary

Region	Dig	Priority Level	Condition	Repaired Needed? (Y/N)	Repair Type	Remaining Strength

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Form 7A.20: ECDA Performance Report

Direct Examination Summary Continued

Region	Dig	Priority Level	Condition	Repaired Needed? (Y/N)	Repair Type	Remaining Strength
Total DE	0					

Reprioritization Summary

	Raising Priority	Lowering Priority	Monitored to NRI
Number of Reprioritizations			

Reassessment Summary

Remaining Life Calculation (From Form 7A.13)	Confirmitory Direct Assessment Deadline	Full Reassessment Deadline

Exceptions Summary

	Pre-assessment	Indirect Inspection	Lowering Priority	Monitored to NRI
Number of Exceptions				

PIE: ______________________________ Date: ______________
Signature

PM: ______________________________ Date: ______________
Signature

SECTION 7A
DIRECT ASSESSMENT PLAN - EXTERNAL CORROSION (ECDA)

Worksheet 7A.21: Contractor Scope

Date(s): ____________________

Line Name: ____________________

Segment Numbers: ______________

Approximate Locations:

____

____

Contact Information

Primary
Name:
Office Phone:
Cell Phone:

Secondary
Name:
Office Phone:
Cell Phone:

Safety

PLEASE REMEMBER TO PERFORM A <u>JOB BRIEFING</u> AT THE BEGINNING OF EACH WORKDAY.

PLEASE REMEMBER TO HAVE YOUR <u>PASSPORT IDS</u> ON YOU AT ALL TIMES.

CIS

Interval Length ________ ft   Interval Length where drilling required ________ ft

Survey Type   ON/OFF   ON Only

DCVG

PCM

Soil Resisvitity

GPS (reverse side)

Worksheet 7A.21: Contractor Scope

GPS

- 100 foot intervals on flat / gently sloping terrain
- 25 foot intervals on hilly terrain
- 5 foot intervals on very hilly terrain
- 10 foot intervals upstream and downstream of features where directional boring may have occurred (i.e. roads, railroads, streams, rivers, lakes, foreign pipelines)
    - Record the crossing type in the survey comments
    - Continue taking readings until the pipeline depth readings become consistent and gently sloping or flat terrain is reached
- Vertical bends
- Points of horizontal inflection (start, center, end)
- Pipeline Inlets / outlets
- Main Line Valves
- Locations where the pipe is above-grade
- Physical features over the pipeline. Physical features may include, but are not limited to:
    - Foreign line crossings
    - Roads
    - Railroads
    - Streams
    - Ditches
- Obtain a depth of cover measurement at each location where an x, y, z coordinate is obtained.

Revision Log:

Date	Description	Revised By
4/7/06	4/7/2006 Version approved by management	LCO
10/10/2008	For all Forms, insert a place for the preparer of the form to be filled out.	ENE
10/10/2008	7A.2.2 Continuous improvement and third party damage evaluation added as objectives.	ENE
10/10/2008	Encroachment and foreign line crossing statement added to 7A.2.4 item 2.	ENE
10/10/2008	The definition of "required" more clearly defined.	ENE
10/10/2008	In section 7A.3.4.3- Data requirements, if required data cannot be obtained, an engineering justification must be made and document in order for ECDA to be feasible.	ENE
10/10/2008	Seam type changed from required pre-assessment data to desired.	ENE
10/10/2008	Frozen ground changed from desired data to required.	ENE
10/10/2008	ECDA region selection described for CP system in the pre-assessment data table list.	ENE
10/10/2008	1st Assessment Requirement changed from R to C in the Interpretation/Analysis usage category.	ENE
10/10/2008	Years w/o CP applied changed from N/R to C in the Interpretation/Analysis usage category.	ENE
10/10/2008	Coating type data element- comments deleted and incorporated into IIT selection.	ENE
10/10/2008	Coating type joints- Need changed from R to D.	ENE
10/10/2008	Monitoring Programs changed from N/R to C in the Interpretation/Analysis usage category.	ENE
10/10/2008	Leak rupture history changed from N/R to C in the Interpretation/Analysis usage category.	ENE
10/10/2008	Evidence of external MIC changed from N/R to C in the Region Selection usage category.	ENE
10/10/2008	Type and frequency of third party damage changed from R to D in the Need category and from C to N/R in the Inspection Tool usage category.	ENE
10/10/2008	Several tasks throughout the ECDA were reassigned from the Corrosion Supervisor to the Pipeline Integrity Engineer. The PIE has been performing these tasks on several past ECDA projects. The Corrosion Supervisor will review for approval/rejection the ECDA process the PIE has selected.	ENE
10/10/2008	In Section 7A.3.8.1- Analysis, if required data cannot be obtained, an engineering justification must be made and documented in order for ECDA to be feasible.	ENE
10/10/2008	In Section 7A.3.8.2, Rock and Ground Surfaces added as conditions in which to consider additional analysis.	ENE
10/10/2008	In Section 7A.3.8.2, bullets points describing situations in which ECDA may not be feasible are lined out for Electrical Shielded Coatings, Adjacent Metallic Structures, or Inaccessible areas conditions.	ENE
10/10/2008	Section 7A.3.9.1, a description of the documentation process inserted if an exception is utilized.	ENE
10/10/2008	Section 7A.3.10.1- Description: Sentence added stated all segments being assessed shall be assigned an ECDA region.	ENE
10/10/2008	Section 7A.3.10.3- ECDA Region Guidance added.	ENE
10/10/2008	All equal level section following 7A.3.10.3 renumbered.	ENE
10/10/2008	Section 7A.3.12- More Restrictive Criteria added.	ENE
10/10/2008	All equal lever sections following 7A.3.12 renumbered.	ENE
10/10/2008	Section 7A.4.2-More Restrictive Criteria, 7A.4.2.1- NACE More Restrictive Criteria, 7A.4.2.2- Part 192 More Restrictive Criteria, and 7A.4.2.3 Documentation added.	ENE
10/10/2008	Section 7A.4.3.1 Definition: The distance before and after and HCA that ECDA is to be surveyed is defined.	ENE
10/10/2008	Section 7A.4.3.5- Survey Scheduling added.	ENE
10/10/2008	Section 7A.4.6- Survey Preparation, 7A.4.6.1- Right-of-Way, Section 7A.4.6.2- Contractor Coordination, and 7A.4.6.3 – Permits added.	ENE
10/10/2008	Section 7A.4.7- Indirect Inspection Crew Preparation added. All other sections on equal levels renumbered.	ENE
10/10/2008	Section 7A.4.10.3- Identification Criteria: Indication classifications for bare pipe defined.	ENE
10/10/2008	Section 7A.4.10.4- Classification Criteria: Clause included to allow for different classification criteria if special conditions are present.	ENE

10/10/2008	Table 7A.4.2 updated for IIT severity guide.	ENE
10/10/2008	Section 7A.4.10.5- Classification Time requirements: Time period and responsibility inserted.	ENE
10/10/2008	Section 7A.4.10.6-Documentation- Bullets added for the documentation of Classification Criteria, Additional Surveys or Direct Examinations, and ECDA Re-assessment.	ENE
10/10/2008	Section 7A.4.11.1- Comparison: Added wording that the PIE shall also consider spatial errors in the comparison.	ENE
10/10/2008	Added Section 7A.4.13- Integrating ECDA Data with Encroachment Data. All at equal levels after this one renumbered.	ENE
10/10/2008	Section 7A.4.15.3- Prioritizations of Excavation: Added statement that other criteria may be used is warranted and documentation process.	ENE
10/10/2008	Section 7A.4.15.5- Timing for Direct Examinations added. All sections past this one at equal levels renumbered.	ENE
10/10/2008	Section 7A.5.2-More Restrictive Criteria, 7A.5.2.1- NACE More Restrictive Criteria, 7A.5.2.2- Part 192 More Restrictive Criteria, and 7A.5.2.3 Documentation added.	ENE
10/10/2008	7A.5.3- Number of Excavation: the word “minimum” added to the number of excavation required.	ENE
10/10/2008	Section 7A.5.3.3- Monitored: Verbage added to this section to explain Direct Examination selected if limited on scheduled indications.	ENE
10/10/2008	Section 7A.5.3.3.1- Multiple ECDA Regions with Monitored Indications added.	ENE
10/10/2008	Section 7A.5.3.4- No Indication in Pipeline Segment added.	ENE
10/10/2008	Section 7A.5.3.4.1-Initial ECDA Project	ENE
10/10/2008	Effectiveness digs renamed to Validation Digs	ENE
10/10/2008	Section 7A.5.4- Selected Indications: PIE shall select indications to excavate and PM and CS shall approve.	ENE
10/10/2008	Section 7A.5.5- Order of Excavation: Inserted paragraph to consider other issues when scheduling the order of excavations.	ENE
10/10/2008	Table 7A.5.1- Excavation Summary Table: Wording in table updated for increased clarity on how to choose the excavation site.	ENE
10/10/2008	Section 7A.5.6.1.5- Additional Assessment and/or Inspections	ENE
10/10/2008	Section 7A.5.6.1.6- Notification	ENE
10/10/2008	Section 7A.5.6.1.7- Documentation	ENE
10/10/2008	Table 7A.5.2- Excavation Data Collection Requirements: Table updated to include any data that might need to be collected during a direct examination along with a description as to how the data is to be collected.	ENE
10/10/2008	Section 7A.5.10.3.4- Degradation in Other Areas- Reference to Section 13.9 of IMP inserted.	ENE
10/10/2008	Section 7A.5.11.2.2-Scheduled: 1st time assessment requirement inserted.	ENE
10/10/2008	Section 7A.5.11.4- Reprioritization Requirements- 3 bullets added to requirements to clarify reprioritization.	ENE
10/10/2008	Section 7A.6.3.2-Corroded Area Dimensions- “Scheduled Indications” changed to “corrosion anomaly”.	ENE
10/10/2008	Section 7A.6.4.1- Remaining Life: Remaining life requirements expanded to include half-life and description of remaining life selection.	ENE
10/10/2008	Table 7A.6.1- Maximum Reassessment Interval inserted.	ENE
10/10/2008	Section 7A.6.4.2- Review of Reassessment Intervals inserted.	ENE
10/10/2008	Section 7A.6.4.4- Documentation- Inserted a note to included that reassessment interval on Form 13-1,	ENE
10/10/2008	Section 7A.6.5.4 ECDA Effectiveness, Section 7A.6.5.4.1- Conformation of ECDA Effectiveness, and 7A.6.5.4.2 Documentation inserted.	ENE
10/10/2008	Section 7A.6.6.1- Contents- Form 7A.13- Form 7A.18 added to the list of Forms to include in the project report.	ENE
10/10/2008	Section 7A.6.7 – Internal Communications inserted.	ENE
10/10/2008	Section 7A.6.8- Feedback and Continuous Improvement inserted.	ENE
10/10/2008	Updated all Form references.	ENE

11/9/2009	7A.2.5- Roles and Responsibilities updated to better match company practices. Updates also made through document to update task responsibilities to company practices.	CMA
11/14/2011	Removed Section 7A.2.1.3 which references a table that was removed several years ago.	CMA
11/14/2011	Section 7A.2.4- Removed Proper names of software systems and renamed to generic names	CMA
10/19/2012	Section 7A.3.11.1- Pre-assessment meetings changed from will be held to may be held.	CMA
12/16/2012	Clarified reference to NACE RP0502 as the latest version incorporated by reference into 49 CFR Part 192.	CMA
4/9/2013	NACE RP0502 changed to SP0502	PJC
11/12/2015	Removed “Compliance Specialist” from section. 7A.5.7.2.5 and replaced with “Program Manager- Pipeline Integrity”.	CMA
11/12/2015	Removed “Compliance Specialist” from Form 7A.11	CMA

7Ai CLOSE INTERVAL SURVEY PROCEDURE §192.921

In This Section

Referenced Protocols

Not Applicable

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7Ai CLOSE INTERVAL SURVEY PROCEDURE

7Ai.1 Preliminary Information

7Ai.1.1 Description

This procedure describes a standardized method for performing a Close-Interval Survey (CIS).

Close-Interval Survey (CIS) applies to buried pipelines with an electrolytic cover. CIS may not be applicable for areas of frozen ground, locations of "shielding" caused by disbonded coating, cased pipeline locations, or paved surfaces. CIS may be used for paved surfaces if additional measures are taken, such as drilling holes, in order to achieve electrolyte access.

CIS measures the potential difference between the structure (pipe) and the electrolyte (soil). For cathodically protected pipelines, CIS is used to assess the effectiveness of the CP system. CIS can also be used to detect stray current interference and metallic shorts.

Timing of the survey may depend on land use. In general, perform surveys through farm fields in early spring or late fall, while there are no crops in the field.

If a Direct Current Voltage Gradient (DCVG) survey is to be performed on the same line segment, perform the close-interval survey prior to the DCVG unless:

- A simultaneous survey will be performed or
- DCVG will be performed without adding temporary groundbeds or adjusting rectifier output or
- Sufficient time has passed to allow the pipe to polarize after the cathodic protection is returned to normal operation

7Ai.1.2 References

1. Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subpart O
2. NACE RP0502-2002 "Pipeline External Corrosion Direct Assessment Methodology"
3. NACE SP0207-2007 "Performing Close-Interval Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipe"

7Ai.1.3 Responsibilities

The Program Manager – Pipeline Integrity (PM) - M1 shall be responsible for maintaining this procedure. Maintenance of this procedure includes periodic review and subsequent revisions as frequently as necessary to maintain the effectiveness thereof.

Pipeline Integrity Engineer - F3 shall have the overall responsibility for implementation of this procedure. The PIE is also responsible for data analysis of pre-assessment data and field generated inspection data

The Corrosion Supervisor (CS) - M3 shall be available for providing technical guidance and assistance regarding the implementation of this procedure.

The Pipeline Specialist (PS) - F5 shall be responsible for overseeing field operations. This includes coordination of operations between contractors, the company, and government agencies.

7Ai.1.4 Safety Considerations

Take appropriate safety precautions when performing the CIS.

Use insulated test clips and terminals to avoid contact with high voltages that may be present.

Use caution when using long lengths of test wire near high voltage alternating current (HVAC) power lines. HVAC lines can induce hazardous voltage levels on the test wire.

Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline being tested.

Use caution when working around roads and railroads. When appropriate, use barricades, sign boards, and / or flag personnel. Wear reflective vests when working in such environments.

7Ai.1.5 Special Tools Required

Perform the CIS using a company approved voltmeter. Use a high input impedance voltage meter (10 MΩ or greater) with 1 mV accuracy in the range of -10 V to +10 VDC as the data collection unit. Use a meter that has AC rejection such that the AC potentials do not influence the DC measurements.

Interrupt all sources of current along the pipeline with GPS synchronized current interrupters. If only one current interrupter is used, the interrupter does not need to be synchronized.

Use copper / copper-sulfate reference electrodes.

Use AWG no. 34 coated copper wire for the survey wire.

7Ai.1.6 Prerequisites

Ensure personnel associated with the inspection are Operator Qualified for the appropriate Covered Tasks or directly supervised by an Operator Qualified individual. Applicable Covered Tasks include:

- Abnormal operating conditions

- Measuring pipe-to-soil readings
- Rectifier readings
- Inspect and test bonds
- Pipeline locating

7Ai.2 PROCEDURE

7Ai.2.1 Survey Preparation

7Ai.2.1.1 Planning

Prepare the area to be surveyed per Section 7 A.4.6 “Survey Preparation”.

Identify locations of test station locations.

Determine the locations of rectifiers required for interruption. Required rectifiers typically include rectifiers within the survey section, the closest two rectifiers downstream of the survey section and the closest two rectifiers upstream of the survey section.

Identify the locations of any bonds and foreign rectifiers.

7Ai.2.1.2 Interrupting Current Sources

Interrupt all sources of current along the pipeline with GPS synchronized current interrupters.

If only one current interrupter is used, the interrupter does not need to be synchronized.

Use an ‘on’ and ‘off’ cycle such that the ‘off’ readings are easily distinguishable from the ‘on’ readings.

Use an ‘on’ and ‘off’ cycle that does not allow significant depolarization.

Common interruption cycles are three (3) seconds ‘on’, one (1) second ‘off’ and 700 milliseconds ‘on’ and 300 milliseconds ‘off’. These are representative cycles and other cycles may be used with the approval of the **PIE**.

Program the current interrupters so the rectifier remains ‘on’ at night, unless night surveying is planned.

Interrupt all known sources of current along the pipeline.

Sources of current include rectifiers, galvanic anode banks, foreign rectifiers, and bonds.

Interrupt all foreign bond connections to the pipeline, unless otherwise directed.

The preferred method for interrupting cathodic protection current through a bond is to interrupt the foreign source(s) that influence the line being surveyed. In such a case, interrupt both the bond and the foreign rectifier(s).

If the bond is non-critical to LG&E (i.e. LG&E is providing cathodic protection current to the foreign company) it is not necessary to interrupt the foreign rectifier(s). Interrupt the bond only.

Record the tap settings and output (current / voltage) at each rectifier prior to setting up the current interrupter. Include this documentation with the final survey data.

Galvanic anodes attached directly to the pipeline cannot be interrupted.

Verify that current interrupters are operating properly at the beginning and ending of each survey day.

7Ai.2.1.3 Marking Regions and Boundaries

Locate and flag and paint the survey segment at 100-foot intervals.

Accurately locate and mark the HCA boundaries if the survey is being performed as part of integrity management.

Locate and mark the boundaries of all ECDA Regions.

7Ai.2.1.4 Line Locating

Accurately locate the pipeline centerline with a radio frequency pipe locator.

The locator may walk in front of the person performing the survey and locate the pipeline while conducting the survey. If this technique is used, the locator should still use marking material to mark the line and the operator should follow the marking material, not the locator. The locator shall ensure the person performing the survey is aware of all points of inflection.

Casing vents or pipeline markers are not adequate for location of the pipeline.

Relocate and resurvey areas that are found to be improperly located.

Mark all points of inflection (PI).

Mark the start, center, and end of each PI.

Remove all marking material at the completion of the job. However, in some cases it may be desirable to leave the marking material intact for the purpose of relocating anomalies. The **PS** will designate when and where material may be left.

If performing additional surveys after the CIS (i.e. DCVG), keep the marking material in-place until the completion of the additional survey(s).

7Ai.2.2 Equipment Preparations

7Ai.2.2.1 Reference Electrodes

Use copper/copper-sulfate reference electrodes.

At the start of each survey day, calibrate the reference electrodes to a value less than five (5) mV.

Rebuild or discard any reference electrodes that do not balance and recalibrate.

Note proof of calibration in the field notebook, field survey records or survey comments.

Reference electrodes that are submerged or placed in an aqueous environment that cover the electrical connection between the electrode and the leads shall have a waterproof connection to prevent erroneous measurements.

7Ai.2.2.2 Meter Accuracy

Check the meter for accuracy by comparing the readings to an independent high input impedance meter.

Document the meter accuracy check in the field notebook, field survey records or survey comments.

7Ai.2.3 Procedures for Close Interval Survey

7Ai.2.3.1 Weather Conditions

Each survey day record the date, weather conditions, and temperature in the field notebook or survey comments.

7Ai.2.3.2 Test Point Connections

Ensure all survey connections are mechanically sound and have low resistance.

Make connections to all above-grade contact points.

Reconnection to another point less than 1,000 feet away is not required.

Do not make connections at rectifier negatives, galvanic anode leads, bonds, or other current-carrying wires.

Note the type of connection (i.e. test station, MLV) in the survey remarks.

Enter the pipeline stationing, as indicated on the alignment sheets, into the comments for each connection.

7Ai.2.3.3 Readings

Take pipe-to-soil potentials at a maximum spacing of three (3) feet, unless otherwise approved by the **PIE**.

Take pipe-to-soil readings directly over the pipeline centerline.

Pipe-to-soil readings are not necessary over cased pipeline crossings.

"Off-set" surveys may be performed in some circumstances.

Do not perform an offset survey more than three (3) feet from the centerline of the pipeline, unless otherwise approved by the **PIE**. Clearly indicate the beginning and end of offset surveys in the survey comments.

Take pipe-to-soil potentials directly over the pipeline centerline at all times.

In select circumstances, conditions on the pipeline right-of-way may not allow measurements to be taken directly over the pipeline. Examples may include large piles of debris over the pipeline. In such a case, enter a remark into the survey comments noting the distance from the centerline of the pipeline the readings are being taken.

Return to the centerline of the pipeline as soon as practical. Note the location in the comments where readings resume over the centerline.

Congested right-of-way conditions do not warrant an offset survey.

The survey crew may need to carry extra equipment such as a machete to clear a path.

If an area is impassable due to poor-right-of way, and the survey crew is unable to clear a path over the pipeline, notify the **PIE** as soon as practical.

Discuss and approve options for completing the survey in this area with the **PIE.**

Take 'on' and 'off' pipe-to-soil potentials and capture the data electronically.

NOTE: Throughout this procedure, references are made to "off" readings. Keep in mind, that references to "off" readings may not be valid if only an "on" survey is being performed.

7Ai.2.3.4 Paved Surfaces

Drill holes in the pavement at ten (10) foot intervals. If indications are identified, additional holes may be required.

Paved surfaces less than ten (10) feet in length may be "skipped".

Obtain approval from **PIE** to "skip" areas larger than ten (10) feet.

As appropriate, utilize alternative methods of obtaining readings for paved right-of-way segments.

Obtain the approval of **PIE** for methods not listed.

7Ai.2.3.5 Readings Across Bodies of Water

Survey across lakes, rivers, and other bodies of water.

Survey across shallow, narrow bodies of water, such as creeks and streams, on foot. However, if the survey crew leader, **PIE**, or **CS** deems it unsafe to walk across the body of water, use alternative methods of obtaining pipe-to-soil readings.

Personal Protective Equipment (PPE) such as flotation vests may be required.

Consider bodies of water that cannot be surveyed across on foot on a case-by case basis.

Discuss and approve options with the **PIE**.

Additional equipment may be necessary to perform the survey, such as watercraft.

7Ai.2.3.6 GPS Coordinates and Comments

Enter all physical references into the data logger as comments. Physical reference points include, but are not limited to:

- Test stations
- Mainline valves
- Aerial markers
- Foreign line crossings
- Roads
- Railroad
- Streams
- Ditches
- Sidewalks
- Driveways
- Fences
- Signs
- Fire hydrants
- Power towers
- Entrance exits to overhead powerline corridors
- Other features deemed significant by the technician

Enter all foreign pipeline crossings / encroachments into the survey comments.

Enter as much information about the encroachment into the survey comments as possible.

For foreign pipelines, this includes the type of crossing and the name of the company, when known.

At concrete and asphalt surfaces such as driveways and roads, reference both edges of the pavement.

Enter the beginning and end of all HCA and ECDA regions into the data logger as comments.

Record GPS coordinates at sub-meter accuracy.

In most cases, this requires an external GPS unit to be used in conjunction with the survey voltmeter.

Record GPS references at the beginning and end of each HCA and ECDA region.

Record a GPS reference at each physical reference point.

Also record GPS coordinates every 100 feet along the pipeline.

Record a GPS reference at all “abnormal conditions” including exposed pipe spans and sinkholes and enter a remark into the survey comments.

Notify **PIE** before the end of the survey day, of such conditions.

7Ai.2.3.7 Far Ground/Near Ground Readings

At each test station, measure and record the metallic IR drop by taking ‘on’ / ‘off’ Near-Ground and ‘on’ / ‘off’ Far-Ground readings.

With the survey wire still connected to the far test station, record the ‘on’ / ‘off’ reading. This is the Far-Ground reading.

With the reference electrode in the same location. Disconnect the test wire from the far test station and connect the test wire to the near test station. Record the on/off reading. This reading is the Near-Ground reading.

The difference between the Far-Ground and Near-Ground reading is the metallic IR drop.

7Ai.2.3.8 Wire Breaks

During a survey, the survey wire can occasionally be broken by outside forces. In some instances, it is not practical to find the break and repair it. In these cases, clearly mark the location of the break and survey back to that point. In such a case, an ‘on’ / ‘off’ far ground reading will not be possible.

Repair survey wire breaks using the following method.

Thoroughly clean the coating off of both ends of the copper wire. This is often accomplished by using sandpaper.

Twist the clean ends of the survey wire together in order to achieve electrical continuity.

Place a piece of electrical tape over the repair / twist.

Place a knot in the survey wire a few inches downstream of the repair.

This will ensure the wire tension is placed at the knot and not the repair.

7Ai.2.4 Clean-Up

At the end of each survey day, clear the right-of-way of debris. This includes, but is not limited to, the removal of all survey wire, road leads, and duct tape that may be used to secure the wire at road crossings.

At the end of the field survey, remove all current interrupters and restore all bonds.

Upon removing each current interrupter, document the tap settings and output (voltage, current) at each rectifier.

Include this information in the final survey documentation.

7Ai.3 DATA QUALITY

7Ai.3.1 Data Review

7Ai.3.1.1 Raw Data

Prior to the next survey day, review the raw data / plots with the **PIE** or appointed personnel.

If the data indicates discrepancies or suspect data, resolve all discrepancies. Discrepancies may include:

- Areas with poor reference electrode contact
- Rectifiers being out of synchronization

7Ai.3.1.1.1 *Resurvey the Suspect Data*

If a resurvey is required, start the resurvey at the test station downstream from the suspect data and end at the test station upstream of the suspect data or a physical reference point.

If the data indicates that not all sources of current have been interrupted, identify additional sources of current.

Interrupt additional sources as applicable.

7Ai.3.1.1.2 ***Resurvey the Entire Line Segment***

Resurvey any areas where the readings are more positive than -850 mV in the reverse direction for verification purposes, unless otherwise approved by the **PIE.**

7Ai.3.1.2 IR Drop Readings

At the end of the survey day, record the 'on' / 'off' pipe-to-soil readings at a test point within the survey segment using the survey equipment.

Before starting the survey on the next day, verify and record the 'on' / 'off' readings at the same test point with the reference electrode in the same location as in the above paragraph.

Calculate the IR drop difference ('on' vs. 'off') for the readings on each day and compare.

If the IR drop difference between the two days is more than 25 mV, investigate and document sources of current change.

At each test station, compare the Near-Ground 'off' and Far-Ground 'off' readings.

When the 'off' potentials do not equal one another, differences should be handled using the following guidelines.

- Normally less than 2%
- 2 - 5%, notify the **PIE** for direction
- 5 - 10%, survey is to be halted until the **PIE** addresses the discrepancy and approves resuming

7Ai.4 DATA PRESENTATION

7Ai.4.1 Data Plots

Present the final data in graphical format.

Develop data plots in color with a separate color used for the 'on' and a separate color used for the 'off' readings.

Include the -850 mV criteria line on the plots.

Include comments on the plots in their approximate stationing location.

Present the data in a downstream or increasing stationing format.

Present a key for the abbreviations used during survey.

7Ai.4.2 Spreadsheet Data

Compile the raw data into an electronic spreadsheet format such as Excel.

Correlate all data strings and represent each in an individual column.

Include the following data:

- Stationing or cumulative footage
- 'On' reading
- 'Off' reading
- Remarks
- GPS coordinates

Compile all data in a single spreadsheet. Therefore, combine all individual data files that may result from multiple runs into one spreadsheet.

7Ai.4.3 Data Classification

Classify indications per table 7A.4.2 in **the Company** ECDA Plan.

If using classification criteria other than those listed in table 7A.4.2 document the criteria and obtain approval from **PM** and **PIE** prior to use.

Include all field notes with the final survey documentation.

7Ai.5 Documentation and Project File

Maintain all information in the Project File. This includes, but is not limited to:

- Data plots
- Raw data in electronic format
- Identified indications and classification
- Survey notes/copy of field notebook

Revision Log:

Date	Description	Revised By
8/20/2008	7Ai.2.1.2- Added a QC task to check interrupters are working properly a the end of each day.	CMA
8/20/2008	7Ai.2.1.3- Added paint as an approved method of marking	CMA
8/20/2008	7Ai.2.2.1- Added calibration requirements for electrodes	CMA
9/25/2008	7Ai.2.3.6- Added 3 physical reference points for GPS surveys	CMA
10/6/2008	7Ai.4.1- Added a requirement for CIS Vendor to submit a list of abbreviations used on the CIS data logger	CMA
10/6/2008	7Ai.4.3- Removed criteria for classifying indication and inserted a reference to another section where these criteria are located.	CMA
10/28/2010	7Ai.1.3- Responsibilities were updated to better reflect the current practices.	CMA
10/28/2010	Throughout the entire document, procedure responsibilities updated to match the changes made in Section 7Ai.1.3- Responsibilities	CMA

7Aii DIRECT CURRENT VOLTAGE GRADIENT PROCEDURE

In This Section

Referenced Protocols

Not Applicable

7Aii DIRECT CURRENT VOLTAGE GRADIENT PROCEDURE

7Aii.1 PRELIMINARY INFORMATION

7Aii.1.1 Description

This procedure describes a standardized method for performing a Direct Current Voltage Gradient (DCVG) survey.

DCVG applies to buried pipelines with and electrolytic cover. DCVG may not be applicable over areas of frozen ground, areas of "shielding" caused by disbonded coating, cased pipeline locations or paved surfaces. DCVG may be used for paved surfaces if additional measures are taken such as coring holes in order to achieve electrolyte access.

DCVG surveys are used to evaluate coating condition on a buried pipeline. The voltage gradient in the electrolyte above the pipeline is measured while an interrupted DC signal is placed on the pipeline. Voltage gradients arise as a result of current pick-up and discharge at coating holiday locations.

Timing of the survey may depend on land use. In general, perform surveys through farm fields in early spring or late fall, while there are no crops in the field.

If a Close Interval Survey will also be performed for the particular line segment, perform the Close Interval Survey prior to the DCVG unless:

- A simultaneous survey will be performed or
- DCVG will be performed without adding temporary ground beds or adjusting rectifier output or
- Sufficient time has passed to allow the pipe to polarize after the cathodic protection is returned to normal operation

7Aii.1.2 References

1. Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subpart O
2. NACE RP0502-2002 "Pipeline External Corrosion Direct Assessment Methodology"
3. NACE SP0207-2007 "Performing Close-Interval Surveys and DC Surface Potential Gradient Surveys on Buried or Submerged Metallic Pipe"

7Aii.1.3 Responsibility

The **Program Manager – Pipeline Integrity (PM) -** M1 shall be responsible for maintaining this procedure. Maintenance of this procedure includes periodic review and subsequent revisions as frequently as necessary to maintain the effectiveness thereof.

Pipeline Integrity Engineer (PIE) - F3 shall have the overall responsibility for implementation of this procedure. The PIE is also responsible for data analysis of pre-assessment data and field generated inspection data

The **Corrosion Supervisor (CS) -** M3 shall be available for providing technical guidance and assistance regarding the implementation of this procedure.

The **Pipeline Specialist (PS) -** F5 shall be responsible for overseeing field operations. This includes coordination of operations between contractors, the company, and government agencies.

7Aii.1.4 Safety Considerations:

Take appropriate safety precautions when performing the indirect inspections.

Use insulated test clips and terminals to avoid contact with high voltages that may be present.

Discontinue the survey when thunderstorms are in the area. Lightning strikes at remote distances can create hazardous voltage surges on the pipeline being tested.

Use caution when working around roads and railroads. When appropriate, use barricades, sign boards and / or flag personnel. Wear reflective vests when working in such environments.

7Aii.1.5 Special Tools Required:

Perform the DCVG survey using a meter approved by the **PIE**. Use a high input impedance voltmeter (10 MΩ or greater). Use a voltmeter that has the ability to deflect, in both the negative and positive direction, from the zero point. If a digital meter is used, the LCD display should be able to distinguish direction / polarity. Deflections of less than one (1) mV shall be distinguishable.

Place a DCVG signal on the pipeline using an existing impressed current rectifier or a temporarily installed ground bed.

Perform the survey using copper/copper-sulfate reference electrodes unless otherwise directed by the **PIE**.

7Aii.1.6 Prerequisites:

Ensure personnel associated with the inspection are Operator Qualified for the appropriate Covered Tasks or directly supervised by an Operator Qualified individual. Applicable Covered Tasks include:

- Abnormal operating conditions
- Measuring pipe-to-soil readings
- Rectifier readings
- Pipeline locating

7Aii.2 PROCEDURE

7Aii.2.1 Survey Preparation

Prepare the area to be surveyed per Section 7A.4.6 “Survey Preparation”.

Identify locations of test stations.

If the survey includes High Consequence Areas (HCA), prior to beginning the survey accurately locate and mark the HCA if the survey is being performed as part of ECDA.

7Aii.2.2 Preparations for DCVG Survey

7Aii.2.2.1 Rectifier

Place a DCVG signal on the pipeline using an existing impressed current rectifier or a temporarily installed ground bed.

If an existing rectifier is used, it may be necessary to increase the output of the rectifier in order to achieve the appropriate signal strength upon approval by Corrosion Supervisor or appropriate company employee in order to prevent excessive pipeline voltages.

Record the tap settings and output (current / voltage) of the rectifier prior to installing the current interrupter and increasing the output.

Include the readings in the final survey documentation.

Upon completion of the survey, return the rectifier to the original setting.

7Aii.2.2.2 Interrupting Current Sources

Place the current interrupter in series with the current source.

It is not necessary to interrupt all sources of current, but enough current needs to be interrupted to achieve the appropriate signal strength (200 mV).

Multiple rectifiers, temporary ground beds, or a combination of both may be required. If multiple current sources are utilized, GPS synchronize the current interrupters.

Set the interrupter(s) to a fast cycle with the ‘on’ time greater than the ‘off’ time.

A common interruption cycle is 700 milliseconds ‘on’ and 300 milliseconds ‘off’.

Program the current interrupters such that the rectifiers are ‘on’ during the night, unless night surveying is planned.

7Aii.2.2.3 Reference Electrodes

Perform the survey using copper / copper-sulfate reference electrodes.

At the start of each survey day, calibrate the reference electrodes to a value less than five (5) mV.

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Bellar

Rebuild or discard any reference electrodes that do not balance and recalibrate the rebuilt electrodes.

Note proof of calibration in the field notebook, field survey records or survey comments.

Reference electrodes that are submerged or placed in an aqueous environment that cover the electrical connection between the electrode and the leads shall have a waterproof connection to prevent erroneous measurements.

7Aii.2.2.4 Field Conditions

At the start of each survey day, record the date, weather conditions and temperature in the field notes.

Check the DCVG signal strength at test points at both ends of the segment to be surveyed prior to commencing the survey.

Document the DCVG signal strength ('on' minus the 'off' pipe-to-soil reading).

The signal strength should be at least 200 mV at both test points.

In rare cases, appropriate signal strengths may not be obtained due to shorted casings or anodes connected directly to the pipeline. Discuss options for completing the survey with the **CS.**

In most cases, if the appropriate signal strength cannot be achieved, an alternate form of survey shall be performed.

7Aii.2.2.5 Marking Regions and Boundaries

Locate and flag the survey segment at 100-foot intervals.

Accurately locate and mark the HCA boundaries if the survey is being performed as part of integrity management.

Locate and mark the boundaries of all ECDA Regions.

7Aii.2.2.6 Line Locating

If the line has not already been marked and flagged, accurately locate the centerline of the pipeline with a radio frequency pipe locator or approved equivalent.

Mark the pipeline with flags or other method of marking.

The locator may walk in front of the person performing the survey and locate the pipeline while conducting the survey. If this technique is used, the locator should still use marking material to mark the line and the operator should follow the marking material, not the locator. The locator shall ensure the person performing the survey is aware of all points of inflection.

Casing vents or pipeline markers are not adequate for location of the pipeline.

Remove all marking material at completion of the job. In some cases, it may be desirable to leave the marking material intact for the purpose of relocating indications.

7Aii.2.3 DCVG Techniques

There are two (2) techniques for performing the survey, the Perpendicular technique and the In-line technique.

7Aii.2.3.1 Perpendicular Survey Method

Place the left-hand cane over the centerline of the pipeline.

Place the right-hand cane perpendicular to the pipeline, at a distance of four (4) to five (5) feet from the left-hand cane.

Walk down the length of the pipeline.

Maintain firm contact with the ground with both electrodes while observing the readings.

Outside of the voltage gradient field of a coating holiday, the voltage difference between the two (2) electrodes should be close to zero (0).

As a coating holiday is approached, the voltage difference between the two (2) reference electrodes will increase in magnitude.

As the coating defect is passed, the voltage difference between the two (2) electrodes will begin to decrease in magnitude.

Locate the epicenter of the coating holiday as described in section 7Aii2.3.3.

7Aii.2.3.2 In-Line Survey Method

While walking along the pipeline, place one electrode over the center of the pipeline and place the second electrode three (3) to six (6) feet ahead of the first, over the centerline of the pipe.

Observe the magnitude and polarity of the reading on the meter.

Maintain firm contact with the ground with both electrodes when the reading is observed.

As a coating holiday is approached, the magnitude of the readings will increase.

Once the holiday has been passed, the readings will shift in polarity.

A zero deflection on the meter indicates the reference electrodes are straddling the defect (i.e. lie on the equipotential line of the gradient field for the defect).

Precisely locate the epicenter of the coating holiday.

Locate the defect as described above (i.e. the location where the maximum voltage reading is observed).

7Aii.2.3.3 Locating the Epicenter

Once the center of the coating holiday has been located, take a series of perpendicular readings towards remote earth.

Begin moving perpendicular to the pipe at three (3) to six (6) foot increments until the readings go to zero (0).

The sum of these perpendicular readings is referred to as the line-to-remote-earth voltage.

Document this reading.

7Aii.2.3.4 Marking

Using a wooden stake and paint, mark the epicenter of the coating holiday and document the GPS coordinates.

Make an effort to root the stake well into the ground such that it can be found several weeks after the end of the survey.

Using a permanent marker, write a unique identifier on the stake (i.e. %IR, stationing).

Indicate the unique identifier in the survey comments.

7Aii.2.3.5 Corrosion States

Determine the corrosion state of the coating indication by comparing the polarity of current flow with the rectifier on and with the rectifier off as indicated below:

- Cathodic / cathodic: Polarity of the readings indicates current flowing to the pipe with the cathodic protection system both on and off
- Cathodic / neutral: Polarity of the readings indicates current flowing to the pipe with the cathodic protection system on; no current flow with the cathodic protection system off
- Cathodic / anodic: Polarity of the readings indicates current flowing to the pipe the cathodic protection system on; current flowing away from the pipe with the cathodic protection system off
- Anodic / anodic: Polarity of the readings indicates current flowing away from the pipe with the cathodic protection system both on and off

Document the classification for each indication.

Some survey meters will automatically determine and document the corrosion state.

Record the signal strength at each test point location.

Record the stationing, as indicated on the alignment sheets, for each test point location.

7Aii.2.3.6 Paved Surfaces

Drill holes in the pavement at ten (10) foot intervals. If DCVG indications are identified, additional holes may be required.

Paved areas less than ten (10) feet may be “skipped”. This means the pavement does not need to be surveyed across using the reference electrodes.

Obtain approval from the **PIE** to "skip" areas larger than ten (10) feet.

In general, parking lots and locations where the pipeline runs parallel and underneath a road may not be skipped and require special survey techniques as discussed below.

"Off-set" surveys may be performed in some circumstances.

Do not perform an offset survey more than three (3) feet from the centerline of the pipeline, unless otherwise approved by the **PIE**.

Clearly indicate the beginning and end of offset surveys in the survey comments.

7Aii.2.3.7 Readings Across Bodies of Water

Survey shallow, narrow bodies of water, such as creeks and streams, across on foot. However, if the survey crew leader or the **PIE, or CS** deems it unsafe to walk across the body of water, use alternative methods of obtaining readings.

Consider alternate survey methods for large bodies of water that cannot be surveyed across on foot on a case-by-case basis.

7Aii.2.3.8 GPS Coordinates and Comments

Record GPS coordinates at all HCA and ECDA region boundaries, when applicable. Enter these coordinates into the survey comments.

Take GPS coordinates at all physical reference points. Enter these coordinates into the survey comments.

Enter all physical references into the data logger as comments. Physical reference points include, but are not limited to:

- Test stations
- Mainline valves
- Aerial markers
- Foreign line crossings
- Roads
- Railroad
- Streams
- Ditches
- Sidewalks
- Driveways
- Fences
- Signs
- Fire hydrants
- Power Towers
- Entrance and exits to overhead powerline corridors.
- Other features deemed significant by the technician.

Take GPS coordinates for all foreign pipeline crossings / encroachments. Enter these coordinates into the survey comments.

Enter as much information about the encroachment into the survey comments as possible. For foreign pipelines, this includes the type of crossing and the name of the company, when known.

Obtain sub-meter accuracy for GPS coordinates.

7Aii.2.3.9 Clean-Up

Congested right-of-way conditions do not warrant an offset survey.

The survey crew may need to carry extra equipment such as a machete to clear a path.

If an area is impassable due to poor-rights-of way and the survey crew is unable to clear a path over the pipeline, notify the **PIE** as soon as practical. Discuss and approve options for completing the survey in this area with the **PIE.**

Record a GPS reference point for all abnormal conditions including exposed pipe spans and sinkholes and enter a remark into the survey comments.

Notify the **PIE** as soon as practical.

At the end of the field activities, remove all current interrupters and temporary ground beds.

Upon removing a current interrupter from an existing rectifier, return the rectifier to the original output (if applicable) and document the tap settings and output (voltage, current) as left.

Include the readings in the final survey documentation.

7Aii.2.4 Data Analysis

Upon completion of the survey, estimate the size and severity of each coating holiday by determining the potential lost from the epicenter of the holiday to remote earth.

Use % IR to characterize the severity of the coating defect

% IR = line-to-remote earth voltage / signal strength *100

Interpolate the signal strength for locations other than test stations (where the signal strength can be directly measured) with the following equation:

Signal Strength(x) = A – (ABS(A-B) / D) x (footage(xA))

Or

Signal Strength(x) = B + (ABS(A-B) / D) x (footage(xB))

Where:

x = location of coating indication
A = Signal strength test point 1 (upstream from indication)
B = Signal strength of test point 2 (downstream from indication)
D = Distance between test point 1 and test point 2
Footage(xA) = Distance from test point 1
Footage(xB) = Distance from test point 2
ABS = Absolute Value

Determine if the signal strength was calculated correctly. If the calculated signal strength is greater than the highest signal strength of test point 1 or 2, or lower than the lowest signal strength of test point 1 or 2, the calculation was not performed correctly.

Document the % IR value for each coating indication.

Note: Depending upon the type of survey meter and survey software used, these calculations may be performed by the survey software.

7Aii.2.5 Data Presentation

Present the final data in graphical format.

Include comments on the plots in their approximate stationing location.

Present the data in a downstream or increasing stationing format.

Compile the raw data into an electronic spreadsheet format such as Excel.

Correlate all data strings and represent each in an individual column.

Provide data for each coating indication including:

- GPS coordinates
- Stationing or cumulative footage
- % IR
- Corrosion state
- Signal strength
- Comments

Compile all data in a single spreadsheet. Therefore, combine all individual data files that may result from multiple runs into one spreadsheet.

Proofread all comments. Clarify in the final data any abbreviations used in the field that may not be understood by others.

7Aii.2.5.1 Coating Classification

Classify all coating indications per table 7A.4.2 in **the Company** ECDA Plan.

If using classification criteria other than those listed in table 7A.4.2 “Survey Preparation”, document the criteria and obtain approval from **PM** and **PIE** prior to use.

Include all field notes with the final survey documentation.

7Aii.2.6 Documentation and Project File

Maintain all information in the Project File. This includes, but is not limited to:

- Data plots
- Raw data in electronic format
- Identified indications and classification
- Survey notes/copy of field notebook

Revision Log:

Date	Description	Revised By
8/20/2008	7Aii.2.2.1- Added approval of corrosion supervisor needed to change rectifier output.	LCO
8/20/2008	7Aii.2.2.3- Changed “balanced” to “calibrate”. Also added verbage to rebuilt electrodes	LCO
8/20/2008	7Aii.2.3.4- Added paint as an approved method of marking.	LCO
8/20/2008	7Aii.2.3.8- 3 physical references added to list of GPS references to record.	LCO
9/7/2008	7Aii.2.5.1- Removed indication classification and replaced with verbiage referencing classification in Section 7A	LCO
10/6/2008	Section 7Aii.2.5- Deleted category classifications	LCO
10/28/2010	7Aii.1.3- Responsibilities updated to better reflect company practices. Also, responsibilities updated throughout this section to reflect company practices	CMA

7B INTERNAL CORROSION DIRECT ASSESSMENT §192.921

In This Section

Referenced Protocols

7B INTERNAL CORROSION DIRECT ASSESSMENT

7B.1 PURPOSE

The purpose of this procedure is to describe the process of performing the Dry Gas Internal Corrosion Direct Assessment (DG-ICDA) methodology on specified pipeline segments carrying normally dry gas. The protocol provides instructions, guidance and requirements to perform and document the DG-ICDA process. The methodology is applicable to buried pipelines that normally carry dry gas but which may suffer from episodic, short-term upsets of liquid water (or other electrolyte).

7B.2 INTRODUCTION

✓ ***Referenced Protocol:*** *D.06 Dry Gas ICDA Programmatic Requirements*

"Internal Corrosion Direct Assessment (ICDA) is a process an operator uses to identify areas along the pipeline where fluid or other electrolyte introduced during normal operation or by an upset condition may reside, and then focuses direct examination on the locations in covered segments where internal corrosion is most likely to exist. The process identifies the potential for internal corrosion caused by microorganisms, or fluid with CO_2, O_2, hydrogen sulfide or other contaminants present in the gas." *

The process to be described in this document (hereinafter named DG-ICDA) applies only for segments of pipeline transporting normally dry natural gas, and not for segments with electrolyte normally present in the gas stream.

In this document, the words "shall" and "must" imply a requirement from 49 CFR Part 192. PHMSA also expects operators to implement "should" statements included in industry standards that are invoked by Part 192. **The Company** has incorporated applicable "should" statements into the ICDA Plan.

In this document, the word "should" represents an activity that, while not mandatory, is recommended. The words "may" "could", and "can" are used to provide an example of how an activity or task is performed. These examples are not to be construed as the only way an activity or task can be performed. They do not indicate a preferred method of conducting the activity or task.

In this document, references to specific requirements of 49 CFR Part §192, and ASME B31.8S are included in brackets "[…]" followed by a paragraph or subparagraph. References to general statements are included in brackets but prefaced with the word "see", as in "see §192.927".

7B.2.1 Scope

This document covers guidelines for the implementation of the methodology termed Internal Corrosion Direct Assessment for pipelines carrying normally dry natural gas (DG-ICDA) that can be used to help ensure pipeline integrity. The methodology is applicable to pipelines that normally carry dry gas, but may suffer from infrequent, short-term upsets of liquid water (or other electrolytes). DG-ICDA applications may

* Superscripts represent references presented in section 7B.2.2.

include but are not limited to assessments of internal corrosion of pipeline segments, drips, and crossovers for which alternative methods may not be practical.

DG-ICDA is intended as a tool to predict most likely areas of internal corrosion, including chemical and microbiologically influenced corrosion, and must be used in conjunction with examination techniques. DG-ICDA focuses the detailed examination on locations where internal corrosion is most likely.

This procedure provides a methodology for implementing a DG-ICDA program. It includes and documents procedures and protocols written to:

- Comply with Title 49 Code of Federal Regulations Part 192 (CFR192) Subpart O, and ASME B31.8S-2004;
- Address the Office of Pipeline Safety's Inspection Protocol for Gas Pipeline Integrity Management (4).
- Define criteria to be applied in making key decisions (e.g., DG-ICDA feasibility, DG-ICDA Region identification, conditions requiring excavation) in implementing each stage of the DG-ICDA process.
- Provide provisions for applying more restrictive criteria when conducting DG-ICDA for the first time on a covered segment and procedures for reassessment.
- Provide provisions for carrying out DG-ICDA on the entire pipeline in which covered segments are present.
- Provide individual procedures for data collection, pre-assessments, indirect inspections, excavations, and post-assessments such that a pipeline company's DG-ICDA program can be audited per the PHMSA Inspection Protocol for DG-ICDA.
- Improve pipeline safety and prevent the future impact of internal corrosion on pipeline integrity.

This procedure is intended to assess the integrity of pipeline segments that are threatened by internal corrosion. However, during the assessment process, other types of damage may be identified, such as mechanical damage, external corrosion, stress corrosion cracking (SCC), etc. In those cases, the damage must be documented and other suitable actions are required in accordance with the Integrity Management Plan.

This procedure shall be applied by or under the direction of competent persons who, by reason of knowledge of the physical sciences and the principles of engineering and mathematics, acquired by education and/or related practical experience, are qualified to engage in the practice of corrosion control and risk assessment on pipeline systems. Such persons may be 1) registered professional engineers, 2) recognized as corrosion specialists by organizations such as NACE International, or 3) professionals (i.e., engineers or technicians) with professional experience including detection/mitigation of internal corrosion and evaluation of internal corrosion on pipelines.

Users of this procedure are assumed to be familiar with applicable pipeline safety regulations and NACE SP0206 on DG-ICDA.

7B.2.2 Regulations, Protocols, Procedures, and Referenced Documents

1. 49 CFR Part 192, Pipeline Safety: Pipeline Integrity Management in High Consequence Areas, Final Rule, Federal Register Vol. 68, No. 240, December 2003. Amended April 6, 2004.
2. NACE SP0206-2006, "Internal Corrosion Direct Assessment Methodology for Pipelines Carrying Normally Dry Natural Gas (DG-ICDA)".
3. ASME B31.8S-2004, Managing System Integrity of Gas Pipelines, Supplement to ASME B31.8.
4. Gas Integrity Management Inspection Protocols "Gas Integrity Management Protocols Areas," Protocol Area D: DA plan. (PHMSA, Revision 5,1/1/2008) http://primis.rspa.dot.gov/gasimp/prolist.gim,
5. ASME B31.8 (latest revision), "Gas Transmission and Distribution Piping Systems" (New York, NY: ASME).
6. ASME B31G (latest revision), "Manual for Determining the Remaining Strength of Corroded Pipelines: A Supplement to B31, Code for Pressure Piping" (New York, NY: ASME).
7. O. Moghissi, L. Norris, P. Dusek, B. Cookingham, and N. Sridhar, "Internal Corrosion Direct Assessment of Gas Transmission Pipelines – Methodology," GRI 02-0057 (Des Plaines, IL, 2002).
8. J. O'Connell, B. Poling, J. Prausnitz, The Properties of Gases and Liquids, 5th ed. (New York, NY: McGraw-Hill, 2001).
9. R. Perry, D. Green, Perry's Chemical Engineers' Handbook, 7th ed. (New York, NY: McGraw-Hill, 1997).
10. API Specification 5L, Forty-Second Edition, "Specification for Line Pipe" (Washington, DC: API, 2000).
11. P.H. Vieth, J.F. Kiefner, RSTRENG2 (DOS Version) User's Manual and Software (Includes: L51688B, Modified Criterion for Evaluating Remaining Strength of Corroded Pipe) (Washington, D.C.: PRCI, 1993).
12. DNV Standard RP-F101 (latest revision), "Corroded Pipelines" (Oslo, Norway: Det Norske Veritas).
13. R. Eckert. "Field Guide for Investigating Internal Corrosion of Pipelines" (Houston, TX: NACE, 2003).
14. NACE Standard RP0502-2002, "Pipeline External Corrosion Direct Assessment Methodology" (Houston, TX: NACE, 2002).

7B.2.3 DG-ICDA Steps

The DG-ICDA methodology is a four-step process requiring integration of pre-assessment and indirect inspection data, with detailed examinations of the internal pipeline surface. The methodology is applicable to natural gas pipelines that normally carry dry gas, but may suffer from infrequent, short-term upsets of liquid water (or other electrolyte).

The basis of DG-ICDA for normally dry natural gas pipelines is that a detailed examination of locations along a pipeline where water would first accumulate provides information about the downstream condition of the pipeline. If the locations along a length of pipe most likely to accumulate water have not corroded, other downstream locations less likely to accumulate water are assumed to be free from corrosion. The DG-ICDA indirect inspection step relies on the ability to identify locations most likely to accumulate water and is applicable to pipelines where stratified film flow is the primary liquid transport mechanism.

The four steps of the process are:

Pre-Assessment – Includes collecting essential historic and current operating data about the pipeline, determining whether DG-ICDA is feasible, and defining DG-ICDA regions. The types of data to be collected are typically available in construction records, operating and maintenance histories, alignment sheets, corrosion survey records, gas and liquid analysis reports, and inspection reports from prior integrity evaluations or maintenance actions.

Indirect Inspections – Covers flow-modeling techniques, developing a pipeline elevation profile, and identifying sites where internal corrosion is considered more likely.

Detailed Examination – Includes prioritizing and performing excavations and conducting detailed examinations of the pipeline to determine whether internal corrosion is present.

Post Assessment – Covers analyzing data collected from the previous three steps to assess the effectiveness of the DG-ICDA process, establishing monitoring, and determining reassessment intervals.

An overview of the DG-ICDA process is shown in Appendix 7B.A. When DG-ICDA is applied for the first time on a pipeline that does not have an adequate history of operating parameters and corrosion protection, more stringent requirements apply (see 49 CFR §192.927). For any portion of pipeline on which DG-ICDA cannot be performed, an acceptable alternative method for assessing internal corrosion, indicated in 49 CFR §192.921 shall be employed.

7B.2.4 Roles and Responsibilities

7B.2.4.1 Program Manager – Integrity Management M1

The Program Manager (**PM**) has the overall responsibility to assure that this procedure is implemented effectively. This procedure assigns authority for the approval of documents, plans, and exceptions to this position. The **PM** may delegate some or all of these approving responsibilities. The **PM** is responsible to assure that all aspects of the assigned DG-ICDA projects are conducted in full compliance with this procedure.

7B.2.4.2 Corrosion Supervisor M3

The Corrosion Supervisor (**CS**) shall be available for providing technical guidance and assistance regarding the assessment process.

7B.2.4.3 Pipeline Integrity Engineer F3

The Pipeline Integrity Engineer (**PIE**) is responsible to assure that available and required pipeline and geographical data and available applications software are properly integrated with each DG-ICDA project. In addition, the **PIE** is responsible for the effective planning, documenting and communicating the various aspects and stages of the assigned DG-ICDA projects. These include, but are not limited to, sufficient data analysis, DG-ICDA Region Designation, Indirect Inspection results, and remaining strength evaluations. The **PIE** is responsible for data analysis of pre-assessment data and field generated inspection data. The **PIE** may also perform direct examinations and indirect inspections for which he or she is qualified.

7B.2.4.4 **Pipeline Specialist** F5

The Pipeline Specialist (**PS**) is responsible for conducting detailed examinations. The responsibility includes conducting the inspections and tests in accordance with this procedure and other testing procedures that have been referenced in the assessment process.

7B.2.5 Qualifications

Company personnel applying this procedure shall comply with the general qualifications described in Section 2 – Roles and Responsibilities of the Integrity Management Program.

Contract personnel and other outside resources must be qualified under the applicable company operator qualification program, or an operator qualification program that has been reviewed and approved by the company as applicable. Refer to Section 15 Quality Assurance for additional information on contract personnel qualifications.

7B.2.6 Definitions

The following are definitions of some key terms used in this procedure:

Considered: A data element that is recommended to be taken into account for the feasibility assessment, designation of DG-ICDA regions, or analysis of test results. Its omission does not require approval or documentation.

Corrosion: The deterioration of a material, usually a metal, that results from a reaction with its environment.

Corrosion Rate: The rate at which corrosion proceeds through the pipe wall.

Covered-segment: See HCA-covered-segment.

Critical Inclination Angle: Angle determined by DG-ICDA flow modeling; the lowest angle at which liquid carryover is not expected to occur under stratified flow conditions.

Defined Length: Any length of pipeline until a new input changes flow characteristics or the potential for water entry.

Desired: A data element that is recommended and should be obtained if reasonably possible or easily measured. Its omission does not require approval or documentation.

Detailed Examination: Examination of the pipe wall at a specific location to determine whether internal corrosion is present utilizing non-destructive evaluation (NDE) methods. This may be performed using ultrasonic, radiographic, or other means.

DG-ICDA Region: A continuous length of pipeline (including weld joints) uninterrupted by any significant change in water or flow characteristics that includes similar physical characteristics or operating history.

DG-ICDA Subregion: A continuous length of pipe (including weld joints) contained in a DG-ICDA region, defined as the pipe length between two inclination angles at which corrosion is found or the start of the region and the first inclination angle that was examined.

Direct Assessment: A structured process for pipeline operators to assess the integrity of pipelines. [See Appendix 1B for an additional definition from CFR §192.903.]

Dry Gas: A gas above its dew point and without condensed liquids.

Dry Gas Internal Corrosion Direct Assessment (DG-ICDA): The internal corrosion direct assessment process as defined in this procedure, applicable to normally dry gas systems.

Electrolyte: A substance through which current is carried by the movement of ions. In DG-ICDA, it refers to the liquid adjacent to and in contact with the internal pipeline surface, including the moisture and other chemicals contained therein. In the electrolyte, the ions present will migrate in an electric field.

Fluid: A substance that does not permanently resist distortion. Both liquids and gases are fluids.

Flow Model: A mathematical approach used to model systems. In DG-ICDA, flow modeling is utilized to find the critical inclination angle(s).

Gathering System: Pipeline and related facilities that collect and move produced gas progressively starting from individual wells to a trunk, common, or main line. Produced gas may not meet gas quality specifications typical of gas transmission systems. [See Appendix 1B for an additional definition from CFR §192.3.]

Geographic Information System (GIS): A system including data, hardware, software, and personnel, for managing information connected with geographic locations. [See Appendix 1B for an additional definition from ASME B31.8S.]

High Consequence Area (HCA): Location along the pipeline that meets the characteristics specified DOT Part 192, Subpart O, i.e., location where a pipeline release might have a significant adverse effect on a particularly sensitive area, or a high population or other populated area. [See Appendix 1B for an additional definition from CFR §192.903.]

Inclination angle: An angle resulting from change in elevation between two points on a pipeline, in degrees.

Indication: Any measured deviation from the norm, as determined using an NDE. [See Appendix 1B for an additional definition from ASME B31.8S.]

Indirect Inspection: Use of an inspection technique that gives information about the condition of a pipeline without performing an excavation. For DG-ICDA, consists of calculating and comparing flow modeling results with a pipeline inclination profile to identify locations where liquid holdup is more likely.

Internal Corrosion: Corrosion occurring on the inside of a pipeline.

In-Line Inspection (ILI): The inspection of a pipeline from the interior of the pipeline using an in-line instrumented inspection tool. The tools used to conduct ILI are known as pigs, smart pigs, or intelligent pigs. [See Appendix 1B for an additional definition from ASME B31.8S.]

Liquid: A substance that tends to maintain a fixed volume but not a fixed shape.

Liquid Holdup: Accumulation of liquid (i.e., input liquid volume is greater than output liquid volume).

Low Point: A location having higher elevations immediately adjacent upstream and downstream; any liquid is expected to preferentially collect at such locations during stagnant flow conditions.

Microbiologically Influenced Corrosion (MIC): Metal corrosion or deterioration which results from or is influence by metabolic activity of microorganisms. [See Appendix 1B for an additional definition from ASME B31.8S.]

Natural Gas: Primarily methane as produced from natural sources.

Nondestructive Evaluation (NDE): An inspection technique that does not damage the item being examined. [See Appendix 1B for an additional definition from ASME B31.8S.]

Potential Liquid Holdup Location: Pipeline locations and features, such as sags, drips, inclines, valves, manifolds, dead-legs, and traps, where liquids can accumulate. In DG-ICDA, corresponds to any low point and associated uphill inclination until critical inclination angle is reached.

Remediation: A repair or mitigation activity that addresses a defect or imperfection to limit or reduce the probability of an undesired event occurring or the expected consequences from the event. [See Appendix 1B for an additional definition from CFR §192.903.]

Required: A data element that must be obtained or its omission must be approved and documented in accordance with Section 7B.8 of this procedure.

Segment: A portion of a pipeline that is (to be) assessed using DG-ICDA. A segment may consist of one or more DG-ICDA regions. [See Appendix 1B for an additional definition from CFR §192.903.]

Shall: A requirement that must be complied with or its exception must be approved and documented in accordance with Section 7B.8 of this procedure.

Should: A recommendation that is desirable to follow. Not following the recommendation does not require documentation or approval.

Stratified Flow: A multiphase-flow regime in which fluids are separated into layers, with lighter fluids flowing above heavier (i.e., higher density) fluids.

Superficial Gas Velocity: The volumetric flow rate of gas (at system temperature and pressure) divided by the cross-sectional area of the pipe.

U.S. Geological Survey (USGS): Organization responsible for providing scientific information to describe and interpret America's landscape by mapping the terrain, monitoring changes over time, and analyzing how and why these changes have occurred.

7B.3 PRE-ASSESSMENT

✓ ***Referenced Protocol:*** *D.07 Dry Gas ICDA Pre-Assessment*

The *Pre-Assessment Step* is used to address the question of whether DG-ICDA is an appropriate integrity assessment method for a particular pipeline. During this step, data are collected and analyzed to establish the operating history of the pipeline and the feasibility of using DG-ICDA to assess the integrity of the pipeline under investigation.

Collecting accurate and complete data at this stage is very important as incomplete data may delay or prevent an accurate assessment of DG-ICDA feasibility. It is also important to capture the experience of field personnel with regard to the pipeline history. Field crews should be consulted for their insight and experience for information in the DG-ICDA Pre-Assessment Data List (discussed below).

Correct alignment and analysis of observations from past years and current inspections will assist in making decisions. In many cases, different stationing systems are used in obtaining data at different times. As part of the *Pre-Assessment Step* and in addition to the inclusion of all original measurements (which should be marked as such), all data are to be aligned under one common form of stationing to enable reference between different reports.

Data to be collected in the *Pre-Assessment Step* are shown in Table 7B.1, Appendix 7B.B "DG-ICDA Pre-Assessment Data List".

Once it has been determined that DG-ICDA is feasible, the next step in the process is to define the DG-ICDA regions. Region definitions are based on locations of possible liquid input and in consideration of cases in which water may condense out of the gas phase.

If flow in the pipeline has been in two directions, regions must be defined for each direction. It is important in this step to know locations of both current and historic inlets and other locations of possible liquid input. Route changes are also considered in region definition, as these may influence locations of liquid hold-up. New regions are defined to start at each location of past or present liquid input into the pipeline. It is also appropriate to begin a new region where a significant amount of water is expected to condense out, such as downstream of compressors.

The process for conducting the Pre-Assessment Step is schematically shown in Figure 7B.1 (Appendix 7B.A). The process consists of:

- Pipeline Segment Selection
- Data collection,
- Assessment of DG-ICDA feasibility, and
- Identification of DG-ICDA regions.

7B.3.1 Pipeline Segments Requiring DG-ICDA

7B.3.1.1 Identification of DG-ICDA Projects: Pipeline segments needing or requiring a DG-ICDA can be identified from multiple sources. Usually the requests for DG-ICDA analysis will come from the Integrity Management, or Risk Management Programs. However, the company may utilize DG-ICDA for other business or operating initiatives. This procedure does not address the identification or ranking processes of pipeline segments requiring DG-ICDA.

7B.3.1.2 Information Provided With DG-ICDA Request: The request for a DG-ICDA shall provide the following information:

- Segment Name and/or Number (if applicable)
- Starting and end points of Segment(s)
- Starting and ending mile points of requested DG-ICDA
- Approval of the Integrity Manager

7B.3.2 Data Collection

7B.3.2.1 **Purpose:** Collect and integrate historical data, current data, and physical information for the segments to be evaluated.

7B.3.2.2 **Requirements:** Data elements are identified as either "Required" or "Desired" in Table 7B.1, Appendix 7B.D. "Required" data elements shall be collected before the *Pre-Assessment* step is completed, in accordance with 49 CFR 192, the PHMSA protocols, and/or ASME B31.8S. The **PIE** may determine that a "Desired" data element is necessary towards assessing a given segment, and thus identify it as "Required"

7B.3.2.3 **Sources:** The data to be collected can be typically found in construction records, operating and maintenance histories, alignment sheets, corrosion survey records, and gas and liquid analysis reports, as well as inspection reports from previous integrity evaluations and maintenance actions. The data collected are usually the same as that collected in an overall pipeline risk (threat) assessment and ECDA programs. Therefore, the **PIE** may decide to conduct the *Pre-Assessment* step in conjunction with an ECDA or other risk assessment effort.

7B.3.2.4 **Alignment:** Data and observations from past years and current inspections shall be aligned. These observations may include, but are not limited to, any GIS measurements, locations of road or stream crossings, locations of any known internal corrosion, and any ILI data.

7B.3.2.5 **Documentation of Data Collection:** All data collected shall be recorded in a Data Collection Form (Form 7B.1 in Appendix 7B.D) or similar document.

7B.3.2.6 **Project Document File:** Each ICDA project shall establish a suitable filing system for both hardcopy and electronic media to house the project documentation. The system shall be organized to allow the effective storage of Pre-Assessment data, Indirect Inspection analysis, Detailed Examination results, and Post Assessment conclusions.

7B.3.3 Data Analysis

7B.3.3.1 All parameters that impact DG-ICDA region definition for initial DG-ICDA process applications on a pipeline segment shall be considered.

7B.3.3.2 If data for a particular category are not available, conservative assumptions may be used based on the operator's experience and information about similar systems. The basis for these assumptions shall be documented as described below.

7B.3.3.3 Accurate flow rate and pressure history are essential to predicting the locations of liquid holdup. In the event that it is determined sufficient data are not available or cannot be collected for some DG-ICDA regions comprising a segment, alternative analyses may be required.

7B.3.3.4 Spatial mapping of the pipeline is of particular importance. A minimum sub-meter GPS survey is required (sub-centimeter is recommended if available) for DG-ICDA (See Section 7B.3.6).

7B.3.3.5 The **PIE** shall analyze the Pre-Assessment data to identify missing Required and Desired data elements, and conduct a Sufficient Data Analysis (see 7B.3.3.8).

7B.3.3.6 The **PIE** shall identify any missing data elements that could be collected during a field visit.

GIS information should be validated from a known reference during this visit to confirm its accuracy. This can be done by looking at a few locations of concern such as road or stream crossings.

Field operators should be consulted regarding pipeline history or other information in the DG-ICDA Pre-Assessment data table.

7B.3.3.7 **Missing Data:** The **PIE** shall document missing data as described below. The Data Collection Form, Form 7B.1 in Appendix 7B.D, can be used to document the missing data. The pipe segments that have missing data shall be identified. If another list(s) is developed it shall include the following information:

- Pipe Segment ID
- Data Element ID number
- Data Element Description
- Required or Desired data category
- Why the data element was not available

7B.3.3.8 **Sufficient Data Analysis:** The data shall be analyzed by the **PIE** to determine if there is sufficient data to conduct a DG-ICDA. The analysis should include the following:

- o **Missing Required Data:** If required data are missing and determined non-essential to the DG-ICDA, the rationale for deviation from normal data collection shall be documented in the Sufficient Data Analysis Report 7B.2 in Appendix 7B.D). In that event, Form 7B.14: Exception Report shall be filled out according to Subsection 7B.8 of this procedure.
- o **Missing Desired Data:** If desired data are missing and determined essential to conduct the DG-ICDA, the data shall be identified in the analysis and documented in the Sufficient Data Analysis Report (Form 7B.2).
- o **Report:** The **PIE** shall prepare a Sufficient Data report concluding there are sufficient data to conduct a DG-ICDA. This report shall have the analyses described in the two paragraphs above and be signed and dated. The Sufficient Data Analysis Report (Form 7B.2) of this procedure can be used for this reporting. The report shall be reviewed and approved by the PM.

7B.3.3.9 In the event that the **PIE** determines that sufficient data are not available or cannot be collected for some DG-ICDA regions comprising a segment to support the pre-assessment step, DG-ICDA shall not be used for those DG-ICDA regions until the appropriate data are obtained.

7B.3.4 Assessment of DG-ICDA Feasibility

7B.3.4.1 **Analysis:** The **PIE** shall integrate the data and information collected above to evaluate DG-ICDA feasibility [§192.927(c)(1)] and determine whether conditions exist that preclude the application of DG-ICDA for the given pipeline segments. Such factors include:

- Indirect inspection tools cannot determine locations where internal corrosion is most probable,
- The pipeline cannot be made accessible for detail examinations, and

- A reliable reassessment interval cannot be determined.

7B.3.4.2 **Criteria:** In order for DG-ICDA to be feasible, all data elements listed as "Required" in Table 7B.1 shall be available. If "Required" data elements are not available for the line segment, ICDA will be deemed not feasible for the line segment and an alternate assessment technique will be utilized.

7B.3.4.2.1 In some cases, sound engineering justification can be made for missing "Required" data. Such a circumstance requires the approval of the **PM**.

7B.3.4.3 Additionally, if any of the following are true, ICDA will be deemed not feasible for the line segment:

7B.3.4.3.1 The pipe normally contains liquids, including glycols or corrosion inhibitors.

7B.3.4.3.2 The pipeline has been previously converted from a service for which DG-ICDA is not applicable (e.g., crude oil or products, normally wet gas).

ICDA is feasible if it is demonstrated that internal corrosion did not occur in the previous service or that previous damage has been separately assessed.

7B.3.4.3.3 The pipeline has an internal coating providing corrosion protection.

7B.3.4.3.4 The pipe has a history of top of the line corrosion (i.e., from condensing water).

7B.3.4.3.5 The pipe is not routinely pigged. If DG-ICDA is applied to a pipeline with a history of pig cleaning, technical justification shall be provided demonstrating the feasibility of ICDA.

7B.3.4.3.6 The pipe has a history of internal corrosion inhibitor use.

If there is any history, technical justification demonstrating the feasibility of ICDA shall be provided. When inhibitors are used, the effectiveness of the inhibitor might not be uniform along the pipeline length and DG-ICDA may not identify the most corroded locations.

7B.3.4.3.7 The pipeline contains or has a history of containing an accumulation of solids, sludge, scale or biofilm/biomass.

If the pipeline does have such a history, the **PIE** shall provide a technical justification demonstrating why ICDA is feasible.

7B.3.4.3.8 There is a pre-1970 low frequency ERW or flash welded pipe seam located on the bottom half of the pipe.

If there is such a weld seam on the bottom half of the pipe, the **PIE** shall provide technical justification demonstrating why ICDA is feasible and discussing specials considerations during the assessment. Actions to be taken are:

a. **Scenario 1** Seam at bottom & no corrosion found → no additional action required
b. **Scenario 2** Seam at bottom & corrosion found → recommend additional dig(s)
c. **Scenario 3** No seam at bottom & corrosion found → proceed with normal ICDA process

d. **Scenario 4** No seam at bottom & no corrosion found → possible additional dig(s) to confirm that bottom-seams (if present) are not experiencing corrosion.

7B.3.4.4 **Report:** The **PIE** shall prepare a report to be reviewed, signed and dated by the **PM**. The following topics will be addressed in the report (see 7B.3: Feasibility Assessment Report, in Appendix 7B.D):

- Any conditions that may make DG-ICDA unfeasible,
- Extra actions that need to be taken to ensure a reliable assessment given these conditions, and
- A conclusion regarding the feasibility of performing DG-ICDA on the given segment.

7B.3.5 Identification of DG-ICDA regions

7B.3.5.1 **Purpose:** Identify DG-ICDA regions based on data collected. These regions are used in the *Indirect Inspection* and *Detailed Examination* steps. Region identification procedures were developed using NACE SP0206, GRI 02-0057, and several other industry documents listed in section 7B.2.2.

7B.3.5.2 A DG-ICDA region is a portion of pipeline with a defined length. A defined length is any length of pipe until a new input introduces the possibility of water entering the pipeline.

7B.3.5.3 DG-ICDA regions shall be defined for each flow direction if flow in a pipeline is bi-directional.

7B.3.5.4 A DG-ICDA region may encompass one or more covered segment.

7B.3.5.5 The **PIE** shall identify DG-ICDA regions, based on the conditions listed under “Identification of DG-ICDA Regions” in Table 7B.1, Appendix 7B.B. Each region should have at least one distinguishing characteristic to describe it. A distinguishing characteristic is anything that significantly affects corrosion rate, mechanism, or location within the pipeline segment (e.g., change in flow direction, temperature, historical inlets).

7B.3.5.6 A new DG-ICDA region shall be identified for each current and historic inlet. Route changes shall also be considered, as these may affect the locations of liquid holdup.

7B.3.5.6.1 **Subsequent Investigations:** After the first assessment is performed, any internal corrosion occurring as a result of past liquid inlets will have been identified.

If no corrosion was found during previous assessments, then future corrosion is assumed to occur only as a result of liquid upsets from current inlets. Therefore, it is only necessary to take into account current inlets, any inlets that were current at the time of the previous DG-ICDA (but are no longer being used), and any historic inlets that have shown internal corrosion during past DG-ICDA assessments.

7B.3.5.7 A new DG-ICDA region shall be identified for each outlet. If the outlet is deemed to have minimal change on the pressure and velocity (less than 10%), it is not necessary to identify a new region boundary.

7B.3.5.8 Compressor and valve locations shall be considered, as they may cause significant changes in superficial gas velocity, affecting the critical inclination angle.

7B.3.5.9 Process changes (e.g., pressure and temperature changes) over the segment length shall be considered, as these changes can induce water condensation or affect the critical inclination angle. Such changes over the segment length either:

- Should be considered as separate DG-ICDA regions, or
- The critical inclination angle (see subsection 7B.4.1) at any point within a region must be based on the local pressure and temperature at that point.

7B.3.5.10 **Documentation:** The start and end locations of all DG-ICDA regions as well as all distinguishing characteristics for each region shall be documented using 7B.4: DG-ICDA Region Report, in Appendix 7B.D. The **PM** and **PIE** shall review and sign this report.

7B.3.6 Pipeline Elevation Profile

7B.3.6.1 Determine if an elevation profile is available for the segment to be assessed. If an elevation profile is not available, arrange for one to be performed.

7B.3.6.2 GPS Survey: Spatial mapping of the pipeline is particularly important in DG-ICDA. The **PIE** may consider performing a Global Positioning System (GPS) survey to collect data with a minimum sub-meter accuracy (sub-centimeter is recommended if available). The accuracy and precision of the data should be documented for uncertainties estimation (see subsection 7B.4.3.3).

If a GPS survey is performed, a high-accuracy and precision method should be used to obtain the information. Tool resolution should accurately measure elevation and horizontal/vertical positioning of inclines. Elevation measurements must be taken at intervals that capture all relevant changes in the inclination profile.

Use the following guidelines when collecting GPS readings. Obtain x, y and z coordinates at the following locations:

- 100 foot intervals on flat / gently sloping terrain
- 25 foot intervals on hilly terrain
- 5 foot intervals on very hilly terrain
- 10 foot intervals upstream and downstream of features where directional boring may have occurred (i.e. roads, railroads, streams, rivers, lakes, foreign pipelines)
  - Record the crossing type in the survey comments
  - Continue taking readings until the pipeline depth readings become consistent and gently sloping or flat terrain is reached
- Vertical bends
- Points of horizontal inflection (start, center, end)
- Pipeline Inlets / outlets
- Main Line Valves
- Locations where the pipe is above-grade
- Physical features over the pipeline. Physical features may include, but are not limited to:
  - Foreign line crossings

- Roads
- Railroads
- Streams
- Ditches

7B.3.6.2.1 Obtain a depth of cover measurement at each location where an x, y, z coordinate is obtained.

7B.3.6.3 USGS Maps: U.S. Geological Survey (USGS) maps with sufficient resolution may also be used, although pipeline elevation changes (such as those at roads and rivers) that would not appear on maps must be considered. The maps used must have sufficient resolution and the depth of cover should be known. In some areas, it may be feasible to assume a constant depth of cover.

When high accuracy data is not available or feasible for the entire segment, one possible option to enhance the inclination profile is to supplement USGS data with GPS field measurements and depth of cover readings at locations of special concern (i.e., near critical angles).

7B.3.7 First Time Application of ICDA Process

7B.3.7.1 When applying ICDA to a pipeline segment for the first time, implement more restrictive criteria during the Pre-Assessment Phase. Options for more restrictive criteria include, but are not limited to:

- Use more specific limiting characteristics to subdivide ICDA regions into smaller, more defined regions
- Collect and analyze a larger data set than the required minimum data set
- Meet with subject matter experts to gather additional information about the operating characteristics of the line segment to be evaluated

7B.3.7.2 Document the use of more restrictive criteria on Form 7B.15 ICDA Preassessment More Restrictive Criteria Form.

7B.3.8 Pre-Assessment Review Meeting

7B.3.8.1 **Purpose:** A pre-assessment review meeting may be held to provide technical insight in conducting the DG-ICDA on the identified segments, communicate the plan of how the DG-ICDA will be conducted, and build consensus for the plan.

7B.3.8.2 **Agenda:** The meeting should address the following information:

- Data reports
- GIS maps
- Feasibility analysis
- DG-ICDA Region Definitions/Locations

7B.3.8.3 **Attendees:** The meeting may be attended by any of the following:

- Program Manager – Integrity Management
- Corrosion Supervisor
- Pipeline Integrity Engineer(s)
- Pipeline Specialist

7B.3.8.4 **Meeting Results:** Updates and changes to the *Pre-Assessment* data, feasibility analysis, and DG-ICDA regions shall be documented in the project file.

7B.3.9 Pre-Assessment Report

All data, actions and decisions pertinent to the *Pre-Assessment* step shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and NACE SP0206 and shall be retained for the useful life of the pipeline.

7B.3.9.1 **Report:** A *Pre-Assessment* report shall be prepared with the following information. All forms shall be signed and dated by either the M1 or the **PIE**.

- Data reports, with the data elements collected for the segment to be evaluated, in accordance with Form 7B.1 Data Collection Form.
- Pipeline Maps
- Methods and procedures used to integrate and align data collected
- Sufficient Data Report
- Feasibility Analyses Report (Form 7B.3: Feasibility Assessment Report)
- Description, characteristics and boundaries of DG-ICDA Regions, including geographically referenced locations of the beginning and ending point of each region (Form 7B.4 DG-ICDA Region Report)
- Documentation on the use of more restrictive criteria

7B.3.9.2 **Approval and Filing**: The report shall be reviewed and approved by the PM. A copy shall be kept in the project file.

7B.4 Indirect Inspection

✓ ***Referenced Protocol:*** *D.08 Dry Gas ICDA Direct Examination*

The DG-ICDA *Indirect Inspection Step* uses multiphase flow modeling results to predict locations most likely to have experienced internal corrosion within each DG-ICDA region.

The DG-ICDA *Indirect Inspection Step* relies on the ability to identify locations most likely to accumulate water and is applicable to pipelines in which stratified film flow is the primary liquid transport mechanism.

The multiphase flow model used must be effective for the pipeline under evaluation. It must define the critical angle past which liquid hold-up is not expected and must be sensitive to changes in diameter, locations where gas enters the pipeline (potential to introduce liquid), and locations downstream of draw-offs (where gas velocity is reduced) [49 CFR Part 192.927].

The process for conducting the *Indirect Inspection Step* is schematically shown in Figure 7B.1 of and consists of the following activities, for each DG-ICDA region:

- Performing multiphase flow modeling calculations using collected data to determine the critical inclination angle of liquid holdup.
- Producing a pipeline inclination profile.

- Identifying sites where internal corrosion may be present by integrating the flow modeling results with the pipeline inclination profile.

7B.4.1 Preliminary Flow Model Determination

7B.4.1.1 **Purpose:** The purpose of performing flow modeling is to identify the critical angle past which electrolyte is not expected to flow.

7B.4.1.2 The **PIE** must identify the most extreme flow conditions (i.e. highest superficial gas velocity) and utilize these in the calculations. Other critical inclination angles for dominant flow conditions may be calculated to provide supplementary data.

7B.4.1.3 The following data and values are required to calculate the critical inclination angle:

- Pipe inner diameter, ID (in)
- Low operating pressure, P (psi)*
- Average temperature, T (^oF)*
- Maximum flow rate, SPT Flow Rate (MMSCF/D)*
- Liquid density, ρ_L (default 62.43 lb/ft^3)
- Molecular weight of gas, MW (typical company gas assumed to be approximately 16.9 lb/lb-mol)
- Compressibility factor, Z, unitless
- Gravity, g = 31.27 ft/s^2
- Universal gas constant, R = 10.73 (psia*ft^3/lb-mol*R)

7B.4.1.4 Determine the value to be used for the Compressibility Factor, Z.

7B.4.1.4.1 For typical ICDA applications, a value of .83 (unitless) can be used.

7B.4.1.4.2 Alternately, the value for Z can be calculated using the following equation:

$$Z = \frac{P * V}{n * R * (T + 460)}$$

7B.4.1.4.3 Values for Z and guidance on non-ideal gas equations can also be found in basic reference texts.

7B.4.1.5 Perform initial calculations as follow:

7B.4.1.5.1 Calculate the gas density, ρ_G

$$\rho_G = \frac{(P + 14.7) * MW}{Z * R * (T + 460)}$$

7B.4.1.5.2 Calculate the operating (OP) flow rate, or the rate for specific conditions if flow rate data are in standard (STP) units

$$\text{OP Flow Rate (MMCF/D)} = (\text{STP Flow Rate}) \frac{Z * P_{STP} * (T + 460)}{(P + 14.7) * T_{STP}}$$

Where P_{STP} = 14.7 psi$_a$, and T_{STP} = 520 R (60^oF)

7B.4.1.5.3 Convert the OP Flow Rate into ft³/s:

$$\text{OP Flow Rate (ft}^3\text{/s)} = \frac{10^6}{24 * 3600} \text{OP Flow Rate (MMCF/D)}$$

7B.4.1.5.4 Calculate the superficial gas velocity, V_g

$$V_g\,(ft/s) = \frac{\text{OP Flow Rate (ft}^3\text{/s)}}{\pi * (ID/12)^2/4}$$

7B.4.1.5.5 Calculate the Critical Angle per the next section.

7B.4.2 Flow Modeling Approaches

7B.4.2.1 Use the *Flow Modeling Fitted Equation Approach* developed for inclusion in NACE SP-0206.

7B.4.2.1.1 Calculate the critical angle, θ

$$\theta = \arcsin\left(.675 \frac{\rho_s}{\rho_l - \rho_s} * \frac{V_g{}^2}{g * (ID/12)} \right)^{1.091}$$

7B.4.2.1.2 This flow model is valid for the following conditions:

- o Nominal pipe diameter between 4 and 48 inches
- o Pressure less than 1100 psi

7B.4.2.1.3 Figure 7B.5 in Appendix 7B.C shows the results from a spreadsheet using the ID, P, T, ρ_L, and Z as input, and ρG is calculated. Critical angle calculations are automated based on these values as a function of gas superficial velocity. These results plotted by gas flow rate are shown in Figure 7B. 7B.6 & 7B.7 of 7B.C.

7B.4.2.2 As an alternative, use the GRI Flow Modeling Iterative Equation Approach to calculate the critical angle.

7B.4.2.2.1 The GRI Flow Modeling Iterative Equation Approach is described in GRI Report 02/0057.

7B.4.2.2.2 As applicable, use the equation below to calculate the critical angle:

$$\theta = \arcsin\left(\frac{\rho_s}{\rho_l - \rho_s} * \frac{V_g{}^2}{g * (ID/12)} * F \right)$$

Where F = dimensionless number, contingent upon degree of angle per the following guidelines:

= 0.35 at θ < 0.5 degrees

= 0.56 at θ > 2 degrees

= [0.29 + (0.13* θ)] for 2 > θ > 0.5 degrees

7B.4.2.2.3 The flow model is valid for the following conditions:

- o Nominal pipe diameter between 4 and 48 inches
- o Pressures between 500 and 1100 psi

- o Velocity 25 ft/s or less

7B.4.2.3 The **PIE** must provide technical justification for selecting an alternative flow model to the ones contained in this procedure.

7B.4.2.4 The critical inclination angle is not necessarily constant within a DG-ICDA region (e.g., changes in internal diameter, flow rates, pressures) and is usually plotted against distance.

7B.4.2.5 The results of the critical angle calculation shall be documented. 7B.5 Flow Modeling, in Appendix 7B.D should be used for this purpose.

7B.4.3 Elevation Profile

7B.4.3.1 The **PIE** shall develop the elevation profile over the defined pipeline length. This step is important to the DG-ICDA process because an inaccurate elevation profile will lead to an incorrect inclination profile.

7B.4.3.2 The elevation should be plotted against distance for each region, as shown in the example in Figure 7B.5 of Appendix 7B.C

7B.4.4 Inclination Profile Calculations

7B.4.4.1 The **PIE** shall calculate the inclination profile using collected pipeline data. The inclination angle at every location can be calculated using the following equation:

$$\theta = \arcsin\left(\frac{\Delta(\text{elevation})}{\Delta(\text{dis tan ce})}\right)$$

Where, distance is the distance along the pipeline (i.e. as determined from GPS coordinates).

7B.4.4.2 The inclination angle should be plotted against distance for each region as shown in the example in Figure 7B.5 of Appendix 7B.C. This figure contains a sample plot showing inclination angles, (calculated moving from North to South) with elevation plotted across the top. Also, critical angles moving North to South and South to North are shown.

7B.4.4.3 The **PIE** shall identify and estimate all uncertainties associated with determining the inclination angles and place a record of these uncertainties in the DG-ICDA project file. The records should be used for screening GPS measurements with respect to DG-ICDA and in consideration with other results during the *Post Assessment* step.

7B.4.5 Selection of DG-ICDA Sites

7B.4.5.1 The **PIE** shall integrate the flow modeling results with the pipeline inclination profile in order to determine sites where internal corrosion may be present. Selection should include consideration of inclination angles at road crossings, rivers, drainage ditches and other locations.

7B.4.5.2 Sites where liquid holdup may possibly occur shall be identified based on a comparison of the calculated critical inclination angle with the inclination profile for a given segment.

7B.4.5.3 Water accumulation is expected to occur on uphill sections of pipeline (in the direction of flow) because shear stress and gravity forces are balanced at this point or at or near low points during stagnant or low velocity conditions.

7B.4.5.4 If collected data include information about the period of time a pipeline experienced velocity ranges, sound technical practice shall be used to determine their significance.

7B.4.5.5 If there has been bi-directional flow through the pipeline, each direction shall be treated separately. Therefore, it may happen that the center area of a pipeline is considered unlikely to have internal corrosion while the two ends are areas of concern.

7B.4.5.6 For each region, the **PIE** shall identify the first upstream inclination angle greater than the largest critical inclination angle determined by the range of operating conditions and the flow-modeling results.

7B.4.5.6.1 If all inclination angles are smaller than the critical inclination angle, the largest inclination angle in the region shall be chosen. If all inclination angles are much smaller than the critical inclination angle, then any liquid upsets may have been transported throughout the entire segment. In such cases, DG-ICDA may not be appropriate for the region.

7B.4.5.7 In some cases, drips or other facility components that accumulate liquid may serve as detailed examination points. If they cannot be used as examination points, they must be assessed separately. The components may be used as DG-ICDA examination points if it can be demonstrated that they meet the following requirements:

- They are located within close proximity upstream of sites selected according to the process outlined in Figure 7B.2 of Appendix 7B.A.
- They have a corrosion environment that either represents or is more severe than the pipeline.

7B.4.5.8 The **PIE** shall compare and analyze the results obtained from this step to determine if they are consistent and if *Detailed Examination* on the selected sites is feasible. The locations shall be compared to prior internal corrosion indications, if available, and with data obtained from field visits. If any inconsistency is found, additional data should be collected and analyzed.

7B.4.6 First Time Application of ICDA Process.

7B.4.6.1 Utilize more restrictive criteria when applying ICDA to a pipeline segment for the first time to ensure that high quality and consistent data is collected. Options for more restrictive criteria include, but are not limited to:

- Calculate the critical angle for “minimum” gas velocity and pressure in addition to the “maximum” gas velocity and pressure conditions.
- Gather pipeline elevation data for the entire line segment
- Collect additional field data to better refine the pipeline inclination angle profile, especially near elevation changes such as river or road crossings

7B.4.6.2 Document the use of more restrictive criteria on Form 7B.16 ICDA Indirect Inspection Restrictive Criteria Form.

7B.4.7 Indirect Inspection Report

7B.4.7.1 All data, flow modeling results, and decisions relevant to the *Indirect Inspection* step shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and NACE SP0206 and shall be retained for the useful life of the pipeline.

7B.4.7.2 The **PIE** shall prepare an *Indirect Inspection* report for each region. It shall include, but is not limited to the following:

- The accuracy of the method(s) used to measure the elevation profile (including consideration of pipeline depth-of-cover).
- The accuracy and precision of the inclination profiles.
- The results of all flow modeling calculations including Form 7B.5: Flow Modeling
- Sites selected for detailed examination, including geographically referenced locations of the beginning and ending points, and each fixed point used for determining the location of each site selected for detailed examination for each ICDA region (Form 7B.6: Site Selection for Detailed Examination) .
- Documentation on the use of more restrictive criteria

7B.4.7.3 The report shall be signed and dated by the **PM** and a copy retained in the project file.

7B.5 DETAILED EXAMINATION

✓ ***Referenced Protocol:*** *D.08 Dry Gas ICDA Direct Examination*

The purpose of the *Detailed Examination Step* is to determine if internal corrosion exists at selected sites, and to use the findings to determine the overall condition of the DG-ICDA region. It focuses examination efforts on identified sites and features most likely to experience internal corrosion. Excavation and subsequent inspection sufficient to identify and characterize internal corrosion in the pipeline are employed.

When the *Detailed Examination Step* is complete for a region, it is considered unlikely that further internal corrosion will be present downstream in the same region (the exception is bi-directional flow, which requires two regions to evaluate for internal corrosion from both ends of the pipeline length).

Defects other than internal corrosion (i.e., external corrosion, stress corrosion cracking, and mechanical damage) may be found during this step; if defects from sources other than internal corrosion are identified, the appropriate procedures must be used to address these threats.

Overlapping with site selections from the *Detailed Examination Step* described in NACE SP0206 and ASME B31.8S are special requirements for HCA locations. 49 CFR Part 192.927 stipulates special regulations for DG-ICDA regions located in HCA areas. The HCA excavation site requirements are described in subsection 7B.5.4. The process for conducting the *Detailed Examination Step* is schematically shown in Figure 7B.2 of Appendix 7B.A, and consists of the following activities, for each DG-ICDA region:

- Selection of sites for detail examination.
- Inspection of other water trapping features (e.g., drains, drips).
- Pipe excavation and inspection.
- HCA special requirements.

These activities are specified below, in subsections 7B.5.1 to 7B.5.4.

7B.5.1 Selection of Sites for Detail Examination

7B.5.1.1 The **PIE** shall follow the process flow diagram shown in Figure 7B.2 and Figure 7B.3 of Appendix 7B.A, and further described in subsections 7B.5.1.3 through 7B.5.1.7, to select the sites for detailed examination in each DG-ICDA region. 100% direct examination of the pipe within a region may be performed in lieu of the multiple dig site process shown in Figures 7B.2 and 7B.3 and described within subsections 7B.5.1.2 through 7B.5.1.7.

7B.5.1.1.1 Any deviation from this deterministic detailed examination process must be justified based on sound technical principles and be approved by the PM. The methodology and assumptions for the alternative approach shall be documented.

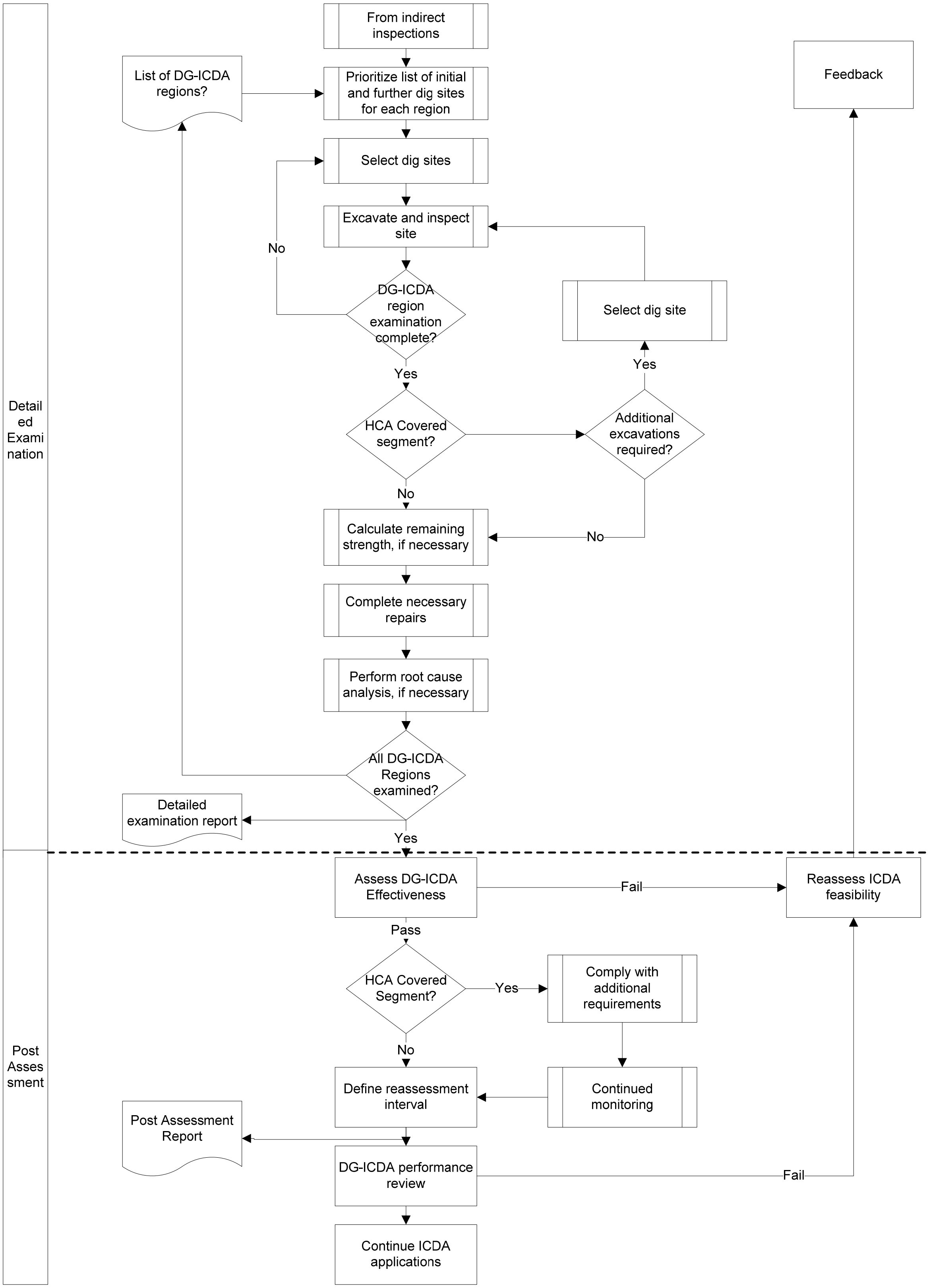


Figure 7B.2 in Appendix 7B.A is inserted above for convenience.

7B.5.1.2 The priority in which excavations and detail examinations are made is determined by a comparison of flow modeling results with the pipeline inclination profile.

7B.5.1.3 The first inspection site in each region shall be the first site downstream from the start of the region with an inclination angle greater than the critical inclination angle, as selected in the *Indirect Inspection* step (Section 7B.4.5.6).

If there are no downstream inclinations greater than the critical inclination angle, select inclination angles from greatest to smallest.

7B.5.1.4 The subsequent inspections shall be conducted in the next location downstream from the previous excavation, with an inclination angle greater than the critical inclination angle.

Two consecutive locations must be found free from internal corrosion to complete the assessment. In addition, a third location serves as a validation.

If no angles greater than critical exist, the largest must be examined. If corrosion is found, the next largest downstream location is selected. If no corrosion is found, one additional (next largest) location serves as validation.

7B.5.1.5 For each DG-ICDA region containing at least one HCA, a minimum of two (2) locations must be examined in an ICDA region HCA. Refer to Section 7B.5.4.2 for the location requirements.

7B.5.1.6 Subregion ‘n’ = 0 shall be identified as the length of pipe between the start of the region and the first site examined (i.e. the first angle greater than the critical inclination angle).

7B.5.1.7 If internal corrosion is identified at more than one site, subregions named ‘n’=1….n, shall be defined for the length between each inspection site where corrosion is found.

7B.5.1.8 At least two (2) inspections shall be performed in each subregion, following the process flow diagram in Figure 7B.3 of Appendix 7B.A, unless there are not enough low points within the subregion.

The first subregion inspection site shall be the site with the largest inclination angle within the subregion.

If no corrosion if found during the first subregion detailed examination, a validation examination shall be conducted at the next largest inclination angle upstream from the previous site examined.

If there is only one inclination upstream of the first site inspected, only one site must be inspected in the subregion. If there are no inclinations in the subregion, no sites need to be inspected in that subregion.

If the low point associated with an inclination angle in a subregion is located outside of the limits of the region being examined, the site must still be examined.

7B.5.1.9 One of the following criteria shall be used for measurements to determine the presence of significant internal corrosion. These criteria are the basis for determining the number of required detailed examinations.

7B.5.1.9.1 Internal corrosion metal loss is considered significant if the wall thickness is less than minimum specified nominal (compensation for metal loss from external corrosion can be made). For example, pipelines operating at less than 72 percent of SMYS would have a criterion of 10% (based on wall tolerance[10]) to indicate the presence of internal corrosion. In this case, additional DG-ICDA excavation sites are triggered when the wall thickness is less than 90% of specified thickness.

7B.5.1.9.2 A pipeline-specific analysis may be performed to develop criteria for significant internal corrosion. The analysis might include consideration of previous metal loss and years of pipeline service.

7B.5.1.9.3 Other technical criteria for significant corrosion may be used with documented technical justification.

7B.5.1.10 The **PIE** may decide to perform additional validation examinations on regions for which the DG-ICDA process has been completed.

7B.5.1.11 Sites selected for detailed examination should be examined within 180 days of their selection.

7B.5.1.12 The sites selected for detailed examination shall be documented and kept within the project file. 7B.6: Site Selection for Detailed Examination, in Appendix 7B.D, can be used for this documentation. The subregions defined for each DG-ICDA region shall also be described and kept in this project file. 7B.7: DG-ICDA Subregion Report, in Appendix 7B.D, can be used for this documentation.

7B.5.2 Inspection of Water Trapping Features

7B.5.2.1 For a given region, any fixture that can trap water (e.g., drip or drain, valve or stub-end) and is located upstream of the furthest downstream validation site shall be identified and examined for internal corrosion.

7B.5.2.2 Water should evaporate before filling and carrying over past a location with an inclination angle greater than the critical angle. However, it is possible for a short term upset with a large liquid volume to occur which fills the accumulation and carries over to a fixture that traps water.

7B.5.2.2.1 If the trap geometry restricts evaporation, it is possible for corrosion to be more severe inside a downstream trap. Therefore, the **PS** shall examine at least one fixture where water can be trapped of similar design directly downstream of a pipe inclination with angle greater than critical. The decision to forgo examination of further downstream fixtures must be justified and documented.

7B.5.3 Pipe Excavation and Inspection

7B.5.3.1 All pipe excavations shall be in accordance with the company OM&I manual and standard operating practices.

7B.5.3.2 Low points (e.g. sags) may be particularly vulnerable to internal corrosion because liquid accumulates at these locations during periods of stagnant flow. Therefore, for each DG-ICDA identified site, excavations should begin at the low point immediately upstream of the critical inclination angle and continue downstream until the critical inclination angle is reached.

7B.5.3.2.1 Excavation length may be shortened if there is a corrosion monitoring device within identified excavation length.

7B.5.3.3 If the pipeline has experienced bidirectional flow, the effect(s) of changing flow direction on corrosion distribution at selected sites shall be considered. This is in addition to treating the reverse directions as separate regions.

7B.5.3.4 The location and size of the excavation site shall be identified and recorded on Form 7B.8: Excavation Data, in Appendix 7B.D. The center and ends of each excavation shall be located and recorded with a GPS instrument. The length of exposed pipe shall be physically measured and recorded on Form 7B.8.

7B.5.3.5 The **PS** shall have the excavation expanded in length if it appears that the internal corrosion may extend beyond the boundaries of the excavation. The expansion shall be performed cautiously and documented on Form 7B.8: Excavation Data.

7B.5.3.6 A pipe level (angle finder with magnetic base) or equivalent shall be used to measure inclination angles. Inclination angles and the stationing at the low point shall be recorded on Form 7B.8: Excavation Data. Detailed data on the pipe condition is also important to record.

7B.5.3.7 The pipe shall be inspected by a person that is qualified by the company Operator Qualification Program to perform the task. The inspector shall complete and sign Form 7B.8: Excavation Data.

7B.5.3.8 Detailed and accurate measurements of the wall thickness and axial length of any wall loss indications shall be performed.

7B.5.3.8.1 Minimum wall thickness within corroded areas must be identified.

7B.5.3.8.2 Ultrasonic thickness measurements, radiography, or another generally accepted technique may be used to make these measurements. Measurements must be performed by individuals qualified by training or experience.

7B.5.3.8.3 Additional testing and monitoring of the pipeline contents may be performed to determine whether corrosive conditions are currently present.

7B.5.3.9 The severity of all internal metal loss defects must be evaluated, and the pipe shall be repaired if necessary according the appropriate company procedures. All remediation of HCA-covered-segments must be conducted in accordance with 49 CFR 192.933.

7B.5.3.10 Indications suspected of having causes other than internal corrosion (i.e. dents) must be investigated using the appropriate company procedures.

7B.5.3.10.1 Remaining strength in locations where corrosion is found shall be calculated or evaluated using the appropriate procedures (i.e., ASME B31G, RSTRENG, KAPA, DnV Recommended Practice RP-F101) (see subsection 7B.5.5)

7B.5.3.11 Improvements for real-time monitoring and future site accessibility may be installed at the time that the excavation is taking place.

7B.5.3.11.1 Once a pipeline is exposed, consider installing a corrosion monitoring device (i.e., electrical resistance probe, corrosion coupon, ultrasonic sensor, electrical resistance matrix, etc.) that may allow the determination of inspection intervals and provide monitoring in the location most susceptible to internal corrosion.

7B.5.3.11.2 Coupons installed at arbitrary locations (e.g., end of pipeline) may not identify the most severe corrosiveness in cases in which corrosion varies with location.

7B.5.3.11.3 See subsection 7B.7.2 for internal corrosion monitoring requirements for HCA-covered-segments.

7B.5.3.12 It may be feasible to use other techniques in concert with DG-ICDA. For instance, data from in-line inspection (ILI) tool runs on upstream portions of pipeline within a DG-ICDA region may provide information that can be used to help assess the downstream condition where a pig cannot be run.

7B.5.3.12.1 Because DG-ICDA predicts that corrosion is more likely upstream than downstream in a given DG-ICDA region, integrity analysis of the upstream locations allows a conclusion to be drawn about downstream locations.

7B.5.3.12.2 In-line inspection data used in integrity assessment must be supplemented by excavation and inspection of specific sites identified in the indirect inspection step of DG-ICDA.

7B.5.3.12.3 Validated data from ILI tools or suitable monitoring devices installed in sites identified in the *Indirect Inspection Step* of DG-ICDA may be used to optimize the required excavations, if they provide equivalent information about the integrity of the pipe. Technical justification must be provided and approved by the PM.

7B.5.3.13 If it is determined that locations most susceptible to internal corrosion due to the presence of water accumulation are free from metal loss, the integrity of a large portion of pipeline mileage is considered to be assured relative to this corrosion threat. If corrosion is found, a potential integrity problem has been identified.

7B.5.3.14 If the detailed examination process identifies the existence of extensive severe internal corrosion, the **PIE** should return to the *Pre-Assessment Step* because the applicability of DG-ICDA is in question.

7B.5.3.15 **Documentation:** The location and size of the excavation site and the results of the *Detailed Examination* shall be documented using Form 7B.8: Excavation Data.

7B.5.3.15.1 The center of each excavation shall be located and recorded with a GPS measurement.

7B.5.3.15.2 An excavation diagram showing the elevation versus distance (or angle) and locations of the low point and critical inclination angle shall be drawn.

7B.5.3.15.3 Detailed wall thickness data should also be noted on the form.

7B.5.4 Detail Examination Requirements for High Consequence Areas

7B.5.4.1 For the purpose of this section, an HCA-is considered any length of pipeline contained within a High Consequence Area that has an internal corrosion threat.

7B.5.4.2 For every DG-ICDA region containing at least one HCA, a minimum of two excavations must take place and detailed examination for internal corrosion must be performed in an HCA. The locations are described in 49 CFR §192.927 and PHMSA Protocol D.8 as follows:

7B.5.4.2.1 One location must be the low point (e.g., sags, drips, valves, manifolds, dead-legs, traps) within the HCA nearest to the beginning of the ICDA Region.

7B.5.4.2.2 The second location must be further downstream, within an HCA, having a slope not exceeding the critical angle of inclination, nearest the end of the ICDA Region.

7B.5.4.3 These HCA required excavations may have already been performed with execution of the DG-ICDA Process flow charts in Appendix 7B.A. If the required excavations within HCA-covered-segments have not already been performed, they must be completed.

7B.5.4.3.1 Detail examination for internal corrosion shall be performed at HCA locations in the same manner as for previously selected sites, utilizing ultrasonic thickness measurements, radiography, or other generally accepted measurement technique.

7B.5.4.3.2 Metal loss due to causes other than internal corrosion must be investigated and remediated using the appropriate procedures in the Integrity Management Plan and in accordance with 49 CFR Part 192.

7B.5.4.4 If internal corrosion is found at either HCA required locations:

7B.5.4.4.1 The severity of the metal loss (remaining strength) shall be evaluated and remediated promptly, and in accordance with 49 CFR Part 192.933. The procedure in Section 10 - Remediation of Integrity Management Plan shall be used for all repairs.

7B.5.4.4.2 As part of the company's current integrity assessment one of the following actions shall be executed: a) perform additional excavations in each HCA with an internal corrosion threat in the DG-ICDA region, or b) assess pipeline in each HCA with an internal corrosion threat within the DG-ICDA region for internal corrosion, using an alternative assessment method allowed by 49 CFR Part 192.

7B.5.4.4.3 The potential for internal corrosion shall be evaluated for all pipeline segments (both HCA and non-HCA) in the pipeline system with characteristics similar to those of the DG-ICDA region containing the HCA in which corrosion was found.

7B.5.4.4.3.1 Each pipeline may be sufficiently unique such that findings in one region do not necessarily apply to other regions.

5.4.4.3.1.1 Each pipeline segment that may be part of an ICDA region may have different producers supplying it.

5.4.4.3.1.2 Product quality and volumes supplied from each producer may not be comparable to other producers.

7B.5.4.4.3.2 As appropriate, remediation will be performed in accordance with 49 CFR Part 192.933, through the company's Integrity Management Plan.

7B.5.5 Remaining Strength Evaluation and Notification of Immediate Response

7B.5.5.1 The purpose of the remaining strength calculations is to determine the predicted failure pressure at corroded areas to assure that it meets the Area Class Location Design Requirements.

7B.5.5.2 The predicted failure pressure shall be calculated using the RSTRENG calculation methodology in all corroded areas with a wall loss greater than 20%. Other methods (e.g., ASME B31G, DNV RP-F101) or analytical techniques (e.g., linear elastic fracture mechanics) may be used as deemed appropriate with approval by the **PM**,

7B.5.5.3 An individual qualified to use RSTRENG shall perform the RSTRENG calculations. The qualification records shall be maintained in the Integrity Management Program file.

7B.5.5.4 The safety factor for the evaluated area shall be determined by:

$$SF_{corr} = \frac{Pf}{MAOP}$$

SF_{corr} = Safety factor of corroded area

MAOP = Maximum allowable operating pressure as determined by operator per 49 CFR 192.619

Pf = Predicted Failure Pressure

7B.5.5.5 An immediate repair is necessary if any of the following conditions are met (according to 49 CFR 192.933 (d)):

7B.5.5.5.1 A remaining strength calculation shows a predicted failure pressure less or equal to 1.1 times the Maximum Allowable Operating pressure at the location of the anomaly, i.e., $SF_{corr} \leq 1.1$

7B.5.5.5.2 The metal loss occurs in proximity of a dent.

7B.5.5.5.3 An indication or anomaly that in the judgment of the qualified person evaluating the assessment results requires immediate action.

7B.5.5.6 If an immediate repair is identified, the pipeline pressure shall be reduced following the procedure in Section 10.4.8 of the company Integrity Management Plan or the line temporarily shut down

7B.5.5.7 **Notification:** If any of the immediate repair conditions are met, the following people shall be contacted:

- Responsible Pipeline Engineer
- Program Manager – Integrity Management
- Responsible Operations Manager

The date that this determination is made shall be documented on 7B.9: Remaining Strength Evaluation, in Appendix 7B.D.

7B.5.5.8 **Documentation:** The results of the remaining strength evaluation and the RSTRENG calculation shall be documented in 7B.9: Remaining Strength Evaluation, in Appendix 7B.D.

7B.5.6 Root Cause Analysis

7B.5.6.1 **Process:** The **PIE** shall perform a root cause analysis for each area of corrosion associated with a location where pipe was removed or its internal surface exposed.

7B.5.6.2 **Objective:** The objective of the root cause analysis is to identify the likely causes of corrosion to determine:

- If DG-ICDA is suitable for finding degradation caused by internal corrosion.
- The likelihood that similar corrosion damage will occur elsewhere in the DG-ICDA region.
- If the degradation is from a historic or active mechanism.
- Recommendations to mitigate the degradation

7B.5.6.3 **Analysis Content:** The root cause analysis should discuss the following aspects:

7B.5.6.3.1 **Corrosion Mechanism:** Identify the main drivers for corrosion in the area including liquid and gas chemistry, solids, corrosive microbes, etc.

7B.5.6.3.2 **Degradation in other areas:** Discuss the characteristics of other locations where similar corrosion may occur. Discuss the likelihood if the corrosion is active or historic.

7B.5.6.3.3 **Mitigative Measures:** Identify potential mitigative measures to arrest corrosion at the particular location.

7B.5.6.3.4 **DG-ICDA Feasibility:** Discuss the suitability and potential success of applying the DG-ICDA process to similar areas of degradation.

The NACE publication, “Field Guide for Investigating Internal Corrosion of Pipelines” 13 is suggested for use in this analysis.

7B.5.6.4 **Documentation:** The root cause analysis of internal corrosion performed shall be documented in the project file and summarized on 7B.10: Root Cause Analysis. A root cause analysis can cover multiple corrosion indications provided that they are similar in all characteristics listed in subsection 7B.5.6.3.

7B.5.6.5 **DG-ICDA Evaluation:** If the root cause analysis identifies a degradation mechanism that the DG-ICDA process is not well suited to detect, the mechanism and its location shall be documented according to subsection 7B.5.6.4. A suitable assessment method shall then be used to evaluate those segments of pipe that are vulnerable to the identified mechanism.

7B.5.6.6 Corrective actions taken to address the root cause during the *Detailed Examination* step shall be documented on 7B.10: Root Cause Analysis.

7B.5.7 First Time Application of ICDA Process

7B.5.7.1 Implement more restrictive criteria during the Direct Examination phase when applying ICDA to a pipeline segment for the first time. Options for more restrictive criteria include, but are not limited to:

- Measure wall thickness around the entire circumference of the pipe
- Apply more conservative “call level” when using LRUT
- Extend the bell hole to assess a greater area of pipe

7B.5.7.2 Document the use of the more restrictive criteria on Form 7B.17 ICDA Direct Examination Restrictive Criteria Form.

7B.5.8 Detailed Examination Report

All data, actions and decisions pertinent to the *Detailed Examination* step shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and NACE SP0206 and shall be retained for the useful life of the pipeline.

7B.5.8.1 The **PIE** shall prepare a *Detailed Examination* report for each DG-ICDA region, based on Form 7B.11: DG-ICDA Detailed Examination Overview Report, in Appendix 7B.D. The report shall be reviewed and approved by the **PM**.

7B.5.8.2 The report shall include, but is not limited to, the following:

7B.5.8.2.1 Characteristics and boundaries of DG-ICDA subregions.

7B.5.8.2.2 Inspection, excavation, and repair procedures.

7B.5.8.2.3 Data collected before and after the excavation:

- Length and actual inclination of the exposed pipe at each location
- Data used to identify other areas that may be susceptible to corrosion
- Data used to estimate corrosion growth rates

7B.5.8.2.4 Documentation pertaining to use of more restrictive criteria

7B.5.8.2.5 If corrosion was found:

- Measured metal-loss corrosion geometries
- Defect analysis, remaining strength, and root cause analysis results
- Planned mitigation activities

7B.6 Dig Site Procedures

7B.6.1 Pipeline Excavation

7B.6.1.1 General

7B.6.1.1.1 All pipe excavations shall be performed in accordance with established company procedures, safety and environmental requirements; federal, state and local regulations.

7B.6.1.1.2 The excavation site should be prepared for safe access by inspection personnel. This may include shoring, pumping out water, terracing, placing skids or pallets in the bottom of the ditch, and so forth. OSHA requires certain inspections of excavations by a competent person initially, daily, and following changes in conditions (such as rain) before entering an excavation.

7B.6.1.2 Location and Size

7B.6.1.2.1 Excavations must be performed at sites selected during the Indirect Inspection step of the DG-ICDA procedure and be sufficiently long that any internal corrosion is captured.

7B.6.1.2.2 An excavation length of at least 20 feet is recommended, usually from the low point where water is expected to accumulate, immediately upstream of the critical inclination angle, to the critical inclination angle (as defined in the dry gas ICDA procedure).

7B.6.1.2.2.1 If the distance between the critical inclination angle and the associate low spot greater than 20 ft, the **PS** may decide to make several excavations (minimum of 10 feet long), to cover the low spot and the critical angle area, as well as intermediate designated areas where water may accumulate during periods of low flow.

7B.6.1.2.2.2 The **PS** shall have the excavation expanded in length if it appears that the internal corrosion may extend beyond the boundaries of the excavation. The expansion shall be performed cautiously and documented on Form 7B.8: Excavation Data.

7B.6.1.2.2.3 Excavation length may be shortened if there is a corrosion monitoring device within the identified excavation length

7B.6.1.2.3 All excavations shall confirm that inclination/ declination angles were correctly calculated (with reasonable uncertainty/error) and that field observations support the site prioritizations.

7B.6.1.2.3.1 A pipe level (angle finder with magnetic base) or equivalent shall be used to measure inclination angles. Inclination angles and the stationing at the low point shall be recorded on 7B.8. Detailed data on the pipe condition is also important to record.

7B.6.1.2.3.2 If there is unsatisfactory error, DG-ICDA as a technique for the pipeline shall be reassessed, or another line survey which resolves the data uncertainties shall be performed on the DG-ICDA region.

7B.6.1.3 Pipe Preparation

7B.6.1.3.1 Pipe preparation includes removal of soil, coating and deposits from the outside of the pipeline so that NDE can be performed. Pipeline characteristics including coating, pipe surface, and soil conditions found should be documented.

7B.6.1.3.2 The minimum surface preparation requirements of the NDE procedure being used must be met.

7B.6.1.3.2.1 In general, all coating in a 3' long (minimum) full circumference band around the pipe shall be removed and the pipe cleaned to bare metal. A longer length of coating may be required to be removed (e.g., 5' of pipe) if automatic ultrasonic equipment is to be used.

7B.6.1.3.2.2 Longer sections may be required to be inspected, depending on the DG-ICDA procedure.

7B.6.1.3.2.3 Some inspection methods will require adjacent pipe to be cleaned as well.

7B.6.1.3.3 Bare or poorly coated pipe that exhibits significant external corrosion may preclude the use of some NDE techniques.

7B.6.1.4 Site Information

7B.6.1.4.1 The following information should be collected for each site and recorded on 7B.8: Excavation Data in Appendix 7B.D:

- Line Identification
- Center and ends of excavation (wheel count, mile post, survey site, GPS, etc.)
- Length of exposed pipe, physically measured
- Pipe Diameter
- Pipe Specified Wall Thickness
- Year of installation
- Rated Maximum Operating Pressure
- Depth of cover
- Distance to adjacent features such as inputs, tie-ins, producers, service feeds, compressor stations, drips, pig traps, etc.
- Normal Flow direction or whether flow is bi-directional
- Local terrain conditions, e.g. slope, low spot, bend or inclination
- Actual pipeline inclination
- Pipe Inspection Report Number
- Person Completing Form
- Date of Inspection

7B.6.1.5 In addition to the pertinent ICDA data, data required for ECDA should also be collected. Minimum data includes but is not limited to:

- Coating type
- Soil resistivity
- Pipe-to-soil readings
- Coating condition
- Mapping of coating and external corrosion defects

7B.6.1.5.1 Refer to the Section 7A Table 7A.5.2 for the complete list of data elements required for ECDA and additional guidance.

7B.6.2 Pipeline Inspection

7B.6.2.1 General

7B.6.2.1.1 The pipe shall be inspected by a person(s) that is qualified by the company Operator Qualification Program to perform the task. The inspector shall complete and sign 7B.8: Excavation Data.

7B.6.2.1.2 Documenting the internal condition of the pipeline during integrity assessments provides important information that can be used to control internal corrosion and manage integrity. Information about the internal condition of the pipe is valuable, regardless of whether internal corrosion is actually present. Examination and documentation must be performed in a consistent manner in order for the data to be useful.

7B.6.2.1.3 Examination of the internal surface of the pipe can be performed from the outside surface, using non-destructive examination methods sufficient to identify and characterize internal defects, or by direct inspection of the internal surface if the pipe is cut.

7B.6.2.1.4 When the internal surface of the pipeline is not exposed, the following tasks shall be performed (see Figure 7B.4 in Appendix 7B.A).

7B.6.2.1.4.1 Collect general site information, as listed in subsection 7B.6.1.4

7B.6.2.1.4.2 Perform nondestructive inspection for internal corrosion as described in subsection 7B.6.3

7B.6.2.1.4.3 Complete 7B.8: Excavation Data

7B.6.2.1.5 When the internal surface of the pipe is exposed during DG-ICDA excavations, the following additional tasks shall be performed (see Figure 7B.4 in Appendix 7B.A):

7B.6.2.1.5.1 Visual and dimensional inspection, as listed in Section 7B.6.2.2

7B.6.2.1.5.2 Solid sampling and field testing, as listed in Section 7B.6.2.3

7B.6.2.1.5.3 Collect liquid samples and conduct field tests, per Section 7B.6.2.4

7B.6.2.1.5.4 Bacteria testing, as listed in Section 7B.6.2.5

7B.6.2.1.5.5 Pipe sampling, if applicable, per Section 7B.6.2.5.5

7B.6.2.1.6 Defects due to causes other than internal corrosion must be investigated and remediated using the appropriate procedures in the Integrity Management Plan and in accordance with 49 CFR Part 192.

7B.6.2.1.7 Once a pipeline has been exposed, the company should consider installing a corrosion monitoring device that may allow the determination of re-inspection intervals by monitoring in the locations most susceptible to corrosion.

7B.6.2.2 Visual and Dimensional Inspection

7B.6.2.2.1 The following requirements apply when internal surfaces of the pipe are visible due to removing a section of pipe or cutting an opening into the pipeline.

7B.6.2.2.1.1 Note the presence of deposits, debris, sludge, scale, oil, water, etc.

7B.6.2.2.1.2 Observe whether the inside of the pipe is wet or dry when cut.

7B.6.2.2.1.3 Determine whether nodules (discrete deposits) are present in the pipe.

7B.6.2.2.1.4 Identify type of corrosion damage that is present, e.g., general, isolated pitting, joined pitting, combination pitting and etching, crevice, etc.

7B.6.2.2.1.5 Note the circumferential and longitudinal extent of the corrosion on the pipe surface. Look for any discernible pattern of attack, such as whether the corrosion is concentrated in one particular area or clock position.

7B.6.2.2.2 Record results of these observations in 7B.8: Excavation Data.

7B.6.2.3 Solid Sampling and Analysis

7B.6.2.3.1 The following requirements apply when internal surfaces of the pipe are visible due to removing a section of pipe or cutting an opening into the pipeline.

7B.6.2.3.2 If solid deposits or scales are found inside the pipe:

7B.6.2.3.2.1 Collect a sample of the material using a clean putty knife or scraper.

7B.6.2.3.2.2 Conduct spot testing for carbonates and sulfides in the field on any internal deposits found in the pipe.

7B.6.2.3.2.3 Place about a tablespoon of the material in a small plastic bag such as a Zip-lock® or WhirlPak® bag. Seal and label the bag. Submit the sample to the appropriate corrosion department personnel.

7B.6.2.3.2.4 Solid sampling is not required when other pipe samples are preserved and being submitted for corrosion inspection as described in subsection 7B.6.2.5.56.

7B.6.2.3.3 Record results of these observations in 7B.8: Excavation Data.

7B.6.2.4 Liquid Sampling and Analysis

7B.6.2.4.1 When the pipe is cut and liquids are present, the liquids shall be sampled for field and laboratory analysis. Liquid composition is an important consideration in assessing the potential for corrosion in a pipeline.

7B.6.2.4.1.1 If water is clearly present or known to exist, collect liquid samples filling two clean Nalgene 250 ml bottles with liquid to the top to eliminate air, and cap each bottle once it is full.

7B.6.2.4.1.2 If fluids are expected to be predominantly hydrocarbon, collect approximately 4 liters of fluid in a disposable plastic container that is fitted with a spigot valve, allow the liquids to settle and the phases to separate, drain water sample into two clean Nalgene 250 ml bottles, filling them to the top to eliminate air, and cap each bottle once it is full.

7B.6.2.4.2 Label each bottle and record the date and time the samples were taken.

7B.6.2.4.3 Keep one bottle sealed for lab analyses.

7B.6.2.4.3.1 Store the bottles in a cool, dark environment if possible.

7B.6.2.4.3.2 A cooler may be used to store multiple samples prior to shipping.

7B.6.2.4.4 Perform the following field tests to the water sample stored in the second bottle.

7B.6.2.4.4.1 Liquid temperature, as soon as possible after sample is taken

7B.6.2.4.4.2 Water pH, using either calibrated pH-meter or pH-paper

7B.6.2.4.4.3 Total Alkalinity, just after measuring pH, using an HACH Alkalinity Test Kit or equivalent

7B.6.2.4.4.4 Dissolved CO_2, using a CHEMetrics Test Kit or equivalent

7B.6.2.4.4.5 Dissolved H_2S, using an HACH or CHEMetrics Test Kit, or equivalent

7B.6.2.4.4.6 Bacteria (see Section 7B.6.2.5)

7B.6.2.4.5 Record results of these observations in 7B.8: Excavation Data.

7B.6.2.5 Bacteria Testing

7B.6.2.5.1 If the inside of the pipe is found to be wet a bacteria fixative sample must be prepared and bacterial culture media inoculated.

7B.6.2.5.1.1 If substantial amounts of deposits, sludge, scale, etc. are present, a small amount of deposits (about the size of a pea) shall be removed from the internal pipe wall at the 6:00 position using new, sterile wood spatula.

7B.6.2.5.1.2 If the inside of the pipe is wet but no substantial amounts of deposits are present, a one-inch square area of the internal pipe wall at the 6:00 position must be swabbed using new, sterile cotton tipped applicator.

7B.6.2.5.1.3 If liquids can be captured when the pipeline is first cut, culture testing shall also be performed on a sample of the liquid as soon as possible after liquid is collected.

7B.6.2.5.2 Prepare a fixative sample

7B.6.2.5.2.1 Open the fixative vial and place the deposits (or break off the tip of the swab) inside the vial. Seal and label the vial of fixative. Shake the vial to fully mix the contents.

7B.6.2.5.2.2 Fixative solution kills and preserves any microorganisms present in the sample so that they may be later identified in the laboratory using microscopic examination.

7B.6.2.5.2.3 Latex gloves should be worn when collecting sterile samples and working with fixative solutions (which contain formaldehyde or glutaraldehyde).

7B.6.2.5.3 Prepare a culture media

7B.6.2.5.3.1 Open the anaerobic diluting solution ADS vial and place the deposits (or break off the tip of the swab) inside the vial. Close the vial of ADS. Shake the vial to fully mix the contents.

7B.6.2.5.3.2 Bacteria culture media should be inoculated with the ADS suspension immediately. If the media cannot be inoculated immediately, the ADS suspension may be stored in a cooler for up to four hours. After four hours the ADS should be discarded.

7B.6.2.5.3.3 Culture testing seeks to identify and enumerate the broad classes of microbes present by allowing them to grow under controlled conditions

7B.6.2.5.4 Submit the fixative and culture samples to the appropriate corrosion department personnel.

7B.6.2.5.5 Bacteria testing per this section should be performed in all cases, regardless of whether or not a pipe sample is being submitted.

7B.6.2.6 Pipe Sampling

7B.6.2.6.1 When a section of pipe is removed during an integrity excavation, a pipe sample may be preserved for subsequent inspection by corrosion personnel or laboratory analysis. The objective of such analysis would be to determine the potential cause of internal corrosion in the pipeline.

7B.6.2.6.2 The size of the sample is often dictated by the type of work being performed.

7B.6.2.6.2.1 Whenever possible, a full circumference pipe section at least 1' long is desired for corrosion inspection. When a full circumference section cannot be made, provide a pipe coupon that contains corrosion typical of that observed in the pipeline.

7B.6.2.6.3 The pipe should be cut to minimize damage to the sample.

7B.6.2.6.3.1 If the pipeline contents allow flame cutting, minimize heat effects and slag by cutting at a location away from the area of interest.

7B.6.2.6.3.2 If it is not possible to avoid damage from flame cutting or if the contents do not allow it, cold cut the pipe.

7B.6.2.6.4 Protect pipe surfaces from foreign materials and keep the corrosion deposits from being contaminated.

7B.6.2.6.4.1 Do not disturb the corrosion deposits or remove any material from the surface of the pipe sample.

7B.6.2.6.4.2 Do not wire brush or scrape material from the internal surface of the sample.

7B.6.2.6.4.3 Field observations and bacteria sampling should be made from the exposed pipe surfaces adjoining the sample section.

7B.6.2.6.4.4 Immediately seal the ends of the sample with nightcap-type plugs, plastic caps or plastic sheeting and duct tape.

7B.6.2.6.4.5 After sealing the pipe avoid rough handling and high temperatures, which can develop from exposure to direct sunlight.

7B.6.2.6.5 Mark the line number, gas flow direction, milepost/station number, and clock position on the O.D. of the pipe sample using a paint marker or similar marking device.

7B.6.2.6.6 The Corrosion Control department shall ensure that examination, testing and documentation of the pipe sample is performed, including as a minimum the following

7B.6.2.6.6.1 Visual examination and photo documentation

7B.6.2.6.6.2 Detailed dimensional examination and wall thickness mapping

7B.6.2.6.6.3 Chemical composition analysis of deposits

7B.6.2.6.6.4 Microbiological analysis of field samples

7B.6.2.6.6.5 Pipe grade verification (chemical and mechanical testing)

7B.6.2.6.7 The results of these tests and examinations shall be permanently retained with the ICDA file for the pipeline region.

7B.6.3 Nondestructive Evaluation Procedures

7B.6.3.1 Selection of Test Methods

7B.6.3.1.1 The required detection limits for corrosion length, width and depth must be determined prior to the selection of appropriate NDE technology and methods.

7B.6.3.1.1.1 Detection limits are based on critical flaw size and criteria defined in the DG-ICDA procedure to determine the presence of significant internal corrosion.

7B.6.3.1.1.2 In general, methods that can provide wall thickness resolution of ± 0.005” and spatial resolution of ± 0.010” are acceptable.

7B.6.3.1.1.3 Other ranges of detection limits may be used if the maximum potential deviation from reported values is factored into remaining strength calculations and significant corrosion criteria.

7B.6.3.1.2 NDE methods used as part of integrity assessment for internal corrosion must be proven to provide adequate sensitivity to identify corrosion features within the required detection limits.

7B.6.3.2 Procedures

7B.6.3.2.1 All nondestructive testing conducted as part of integrity assessments shall be performed in accordance with written, qualified procedures approved by the company.

7B.6.3.2.2 Written procedures shall, at a minimum, contain the following information:

7B.6.3.2.2.1 Scope – Applicability and limitations of the procedure.

7B.6.3.2.2.2 References – List other documents (e.g. ASME, ASTM, NACE) referred to, or incorporated by, the procedure.

7B.6.3.2.2.3 Definitions – List key definitions specific to the procedure.

7B.6.3.2.2.4 Personnel Requirements – The procedure shall address minimum certification levels and/or training requirements of those performing and interpreting the inspections.

7B.6.3.2.2.5 Equipment – This section shall list all equipment necessary to perform the procedure.

7B.6.3.2.2.6 Procedure – The procedure shall detail the inspection in a step-by-step manner. The procedure should include calibration requirements, surface preparation, interpretation of anomalies and detection limits.

7B.6.3.2.3 The test results and procedures used shall become a permanent part of the file for each integrity assessment project.

7B.6.3.2.4 NDE inspection of each assessment site will be performed on an area three feet in length marked on the lower section of the prepared pipe, from the 3-o'clock position to the 9-o'clock position as a minimum. The top of the pipe must also be inspected for internal wall loss in all cases.

7B.6.3.3 Ultrasonic Method - Manual straight beam mapping (D-meter)

7B.6.3.3.1 The length of pipe selected for the ultrasonic thickness inspection shall be based on the company DG-ICDA procedure and subsection 7B.6.1.2.

7B.6.3.3.1.1 For designated dig lengths of 20-feet or less, the area to be inspected shall include the length of pipe between the critical angle and the upstream low point associated with it.

7B.6.3.3.1.2 For designated dig lengths of 20-feet or greater, the area to be inspected shall include the length of pipe between the critical angle and the upstream low point associated with it, as well a designated bell-hole locations between these two points where water may accumulated during periods of low flow.

7B.6.3.3.2 The pipeline surface shall been prepared according to subsection 7B.6.1.3

7B.6.3.3.2.1 If the surface condition of the pipe warrants preparation for thickness readings, a light grinder or "flapper" wheel may be used to clean the surface.

7B.6.3.3.2.2 The surface should be cleaned adequately to allow proper seating of the probe on the pipe's surface.

7B.6.3.3.2.3 Cleaning will not be necessary if the surface condition of the pipe, in it's as-is condition, allows accurate thickness measurements to be taken.

7B.6.3.3.3 A grid three feet in length shall be stenciled on the lower section of the prepared pipe, from the 3-o'clock position to the 9-o'clock position using a 1/2-inch by 1/2-inch pattern. The lowest wall thickness reading at each intersecting line of the grid shall be recorded.

7B.6.3.3.4 The thickness gauge (D-meter) shall be calibrated per the manufacturer's specifications both before and after examination of each 3' long grid. The calibration check results shall be recorded.

7B.6.3.3.4.1 Only dual-element transducers can be used. The diameter of the transducer shall be ¼" or less.

7B.6.3.3.4.2 Calibration typically consists of taking thickness readings on a carbon steel step wedge with five steps ranging from 0.100-inch to 0.500-inch.

7B.6.3.3.4.3 Calibration is achieved when the reading for each step is within +/- 0.002-inch of the actual step thickness.

7B.6.3.3.5 Ultrasonic couplant gel or light, aliphatic oil shall be used as the coupling media for the thickness testing.

7B.6.3.3.6 If internal pitting corrosion* is found on any section of the initial grid, a 1/4-inch by 1/4-inch pattern may be examined in the corroded area and the corrosion re-mapped.

7B.6.3.3.7 The top of the pipe shall also be checked for internal corrosion at 6 inch intervals in the 3' long area of examination. If any internal corrosion is found in the top half of the pipe at any location, the entire circumference shall be inspected using the ½" grid pattern.

7B.6.3.3.8 If the pipe being inspected contains an ERW seam weld that can be visually located and internal corrosion is found anywhere during inspection, the weld seam in the evaluation section must be inspected using an angle beam ultrasonic method to determine whether selective seam corrosion is present. Angle beam inspection may only be performed by personnel qualified to ASNT Level II standards for ultrasonic inspection.

7B.6.3.4 Alternative Ultrasonic Methods

7B.6.3.4.1 The following manual or automated ultrasonic equipment may be used by third party inspectors to document the wall thickness of pipe during integrity investigation excavations, provided the requirements of subsection 7B.6.3.3 are met.

7B.6.3.4.1.1 B-scan

7B.6.3.4.1.2 C-scan

7B.6.3.4.1.3 D-scan

* Internal corrosion is defined in this section as, "an ultrasonic thickness reading measurement below the nominal wall thickness of the pipe by 0.010-inches". External metal loss (if present) should be considered.

7B.6.3.4.2 Particular attention must be paid to personnel qualifications in the use of automated UT methods. Company personnel require specific training and qualifications to conduct this testing.

7B.6.3.5 Radiographic Methods

7B.6.3.5.1 Manual x-ray or gamma ray radiography shall not be used without employing other inspection methods, since it does not provide sufficient resolution of wall loss.

7B.6.3.5.2 Digital radiography shall not be used without employing other inspection techniques. Digital radiography may, in some cases, provide adequate resolution of corrosion detail once it has been determined through other techniques, that internal corrosion is present.

7B.6.3.6 Excavation and Inspection Report

7B.6.3.6.1 All data, actions and decisions of pertinence to the excavation and inspection activities performed within the Detailed Examination step of the company DG-ICDA procedure shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and NACE SP0206 and shall be retained for the useful life of the pipeline.

7B.6.3.6.2 The report shall include, but is not limited to, the following documentation:

7B.6.3.6.2.1 Site information, per subsection 7B.6.1.4

7B.6.3.6.2.2 Inspection procedures

- Detection limits and sensitivity requirements discussed in section 7B.6.3.1.
- Calibration and scale data

7B.6.3.6.2.3 Data collected before and after the excavation:

- Length and actual inclination of the exposed pipe at each location

7B.6.3.6.2.4 Wall thickness profile.

- Graphic representations (maps or scans) of the pipe wall may be provided, however numerical data reporting of the results is still required in all cases.
- In the case of manual straight beam mapping per subsection 7B.6.3.3, all measurements shall be recorded for the inspection grid. Grid rows extending along the length of the pipeline should be given a letter designation, while grid columns extending about the circumference of the pipe should be given a number designation.

7B.7 Post Assessment

✓ ***Referenced Protocol:*** *D.09 Dry Gas ICDA Post-Assessment*

The Post-Assessment step is a critical part of the DG-ICDA Process as it involves integration and analysis of all data from previous steps. The data are analyzed for information that provides support or invalidates DG-ICDA for the particular pipeline. Once it is determined that DG-ICDA has been effective on the pipeline, a continual monitoring program to evaluate locations most at risk for internal corrosion and reassessment intervals must be established (49 CFR Part §192.927). The monitoring plan and reassessment intervals are determined using the appropriate procedures in the Integrity Management Plan and guidance in 7B.7.2 to 7B.7.4.

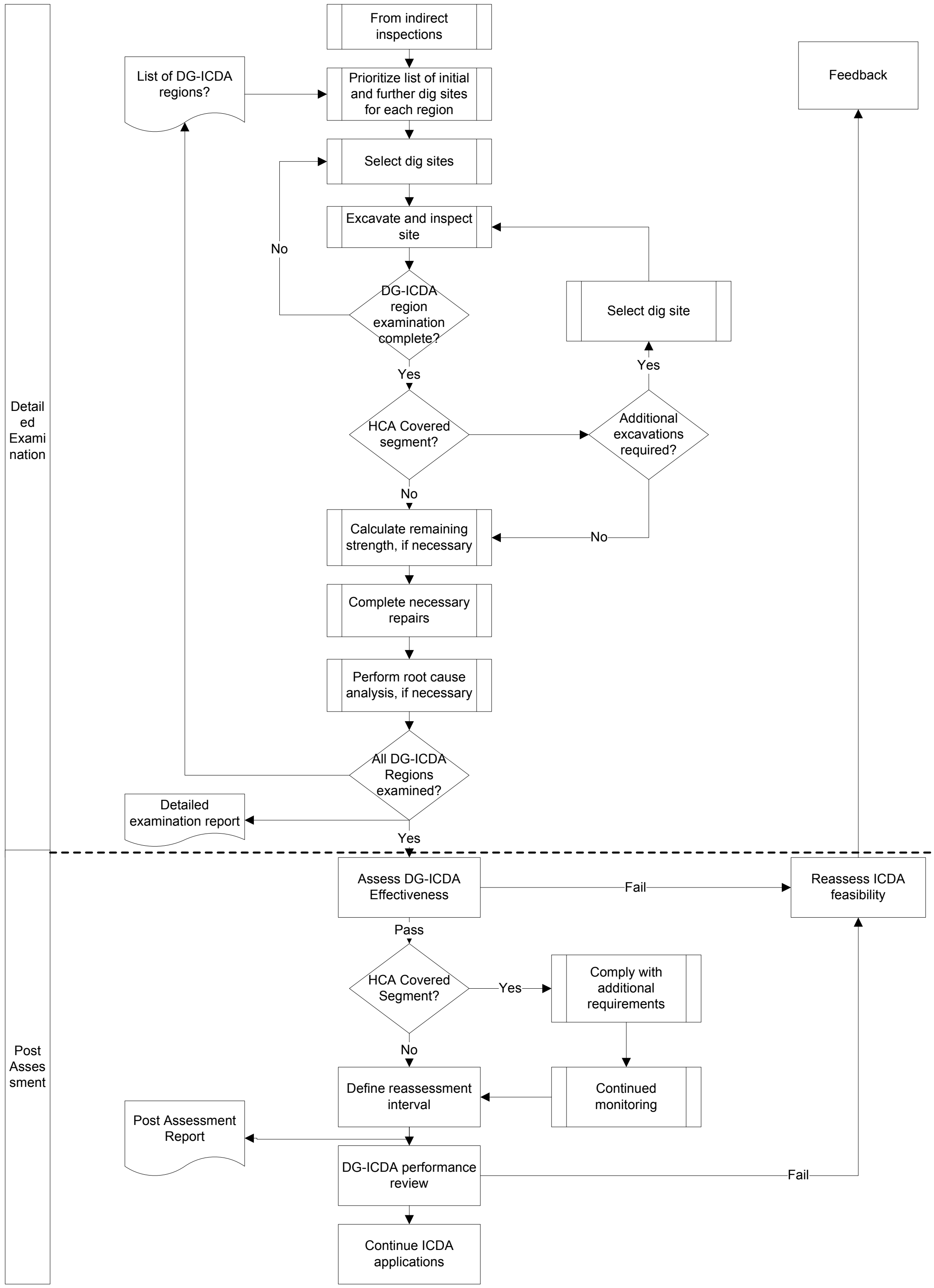


Figure 7B.2 of Appendix 7B.A is inserted above for convenience.

The Post-Assessment step includes the following activities:

- Assess the overall effectiveness of the DG-ICDA process,

- Institute a plan to continually monitor locations where internal corrosion has been identified (required for HCA-covered-segments), and
- Determine remaining life of the pipeline segment and reassessment intervals.

These activities are specified below, in subsections 7B.7.1 through 7B.7.4.

7B.7.1 Assessment of DG-ICDA Effectiveness

7B.7.1.1 Data from the three previous steps shall be analyzed to evaluate the effectiveness of DG-ICDA as an assessment method for addressing internal corrosion threat.

7B.7.1.2 Effectiveness of the DG-ICDA process is determined by the correlation between detected corrosion and the DG-ICDA predicted locations.

7B.7.1.2.1 "If corrosion is found in areas where the pipeline inclination is greater than the estimated critical inclination angle, then the estimate of the critical inclination angle should be reevaluated and additional new areas selected for local examination." [ASME B31.8S Appendix B, B2.4].

7B.7.1.2.2 DG-ICDA for gas pipelines is based on the premise of intermittent upsets. While most such pipelines have little or no corrosion, the presence of extensive corrosion throughout the region or the presence of corrosion on the top of the pipeline suggest that this premise has been violated.

7B.7.1.2.3 Although not a requirement, validation of a DG-ICDA process on piggable lines may be performed by comparing the internal corrosion indications identified using ILI with the predicted locations of internal corrosion on the line as determined by DG-ICDA *Indirect Inspection* procedures. Validation provides additional confidence in the ability of the DG-ICDA program to detect and remediate internal corrosion.

7B.7.1.3 Per 49 CFR Part 192, evaluation of DG-ICDA effectiveness of HCA-covered-segments must be completed in within a year of conducting DG-ICDA. [§192.927(c)(4)(i)]

7B.7.1.4 Per ASME B31.8S-2004 Section 9.4, the following performance measures shall be tracked:

- Number of miles of pipeline inspected versus program requirements.
- Number of immediate repairs completed as a result of the integrity management program.
- Number of scheduled repairs completed as a result of the integrity management program.
- Number of leaks, failures, and incidents (classified by cause).
- Number of repair actions taken due to direct assessment results.
- Number of internal corrosion leaks.

7B.7.2 Continual Monitoring of HCA-Covered-Segments

7B.7.2.1 Continual monitoring of HCA-covered-segments shall be performed anywhere that internal corrosion has been identified, in compliance with 49 CFR Part §192.927.

7B.7.2.2 **Techniques of Monitoring:** There are several monitoring techniques. Some techniques of monitoring require actions if internal corrosion is detected during its process. Continual monitoring techniques may include one or more of the following:

- Coupons
- UT sensors
- Electronic Probes
- Periodically drawing off liquids at low points and chemically analyzing them for presence of corrosion products.

An operator must base the frequency of the monitoring and liquid analysis on results from all integrity assessments that have been conducted and risk factors specific to the covered segment. Each technique requires proper data interpretation. The frequency of monitoring shall be based on root cause analysis and severity of corrosion found.

7B.7.2.3 **Response to Detection of Corrosion Product**. If there is any evidence of corrosion products in an HCA-covered-segment, remediation shall be performed, as described in Section 10 – Remediation of the Integrity Management Plan and 49 CFR Part §192.933, and one of the following two required actions must be conducted:

7B.7.2.3.1 Excavations of HCA-covered-segments at locations downstream from where the electrolyte might have entered the pipe; or

7B.7.2.3.2 Assessment of the HCA-covered-segment using another integrity assessment method allowed by 49 CFR Part 192.

7B.7.3 Determination of Remaining Life

7B.7.3.1 **Corrosion Rate.** The **PIE** shall select, technically justify, and validate the method(s) used for determining the corrosion rate (CR). One or more of the following methods shall be used:

7B.7.3.1.1 Corrosion growth monitoring on the actual pipe, by reexamining specific sites at a prescribed frequency.

7B.7.3.1.2 Continual corrosion rate monitoring, using one or more devices installed at sites of predicted high probability of corrosion, and/or at other representative locations.

7B.7.3.1.3 Corrosion rate prediction, using a corrosion rate model based on operating conditions, gas quality, liquid composition, and other key factors.

7B.7.3.1.4 Corrosion rate measurement in situ or in a laboratory for conditions simulating pipeline operation key factors.

7B.7.3.2 **Remaining Life Determination:** The **PIE** shall calculate the remaining life of all excavation locations containing a corroded area with a wall loss greater than 20% by applying a corrosion rate (see 7B.7.3.1) to the corroded area that exhibits the lowest predicted failure pressure using a sound engineering method, which is properly referenced and documented.

7B.7.3.2.1 If the root cause analysis shows that the weakest corroded area is unique (and therefore not representative of the dominant degradation mechanism), then the next weakest corroded area may be used to determine the remaining life.

7B.7.3.2.2 It is recommended that the conservative method recommended in NACE RP 0502-2002, be used to calculate the remaining life as a start:

$$RL = C \frac{1}{yieldpressure}\left((Pf - MAOP)\frac{t}{CR}\right)$$

Where

- RL = Remaining Life (years)
- C = Calibration Factor = .85
- Pf = Failure Pressure from RSTRENG (psi)
- *MAOP* = Maximum Allowable Operating Pressure (psi) as determined by operator per 49 CFR 192.619
- *t* = Nominal wall Thickness (inches)
- *CR* = Corrosion Rate (inches/year or mpy/1000)
- Yield Pressure or P_100 = pressure that corresponds to the specified minimum yield strength, SMYS (psi)

7B.7.3.3 **Documentation:** The remaining life shall be documented on Form 7B.12: Remaining Life Determination, in Appendix 7B.D.

7B.7.4 Reassessment Intervals

7B.7.4.1 Within one (1) year of completing the last direct examination related to the assessment, determine the reassessment interval for the line segment.

7B.7.4.2 The reassessment interval for a DG-ICDA region shall not exceed one-half of the shortest remaining life calculated in subsection 7B.7.3.2 above. Additionally the reassessment intervals may not exceed the following:

- 10 years for segments operating at SMYS levels greater than 50%
- 15 years for segments operating between 30% and 50% SMYS
- 20 years for segments operating below 30% SMYS

7B.7.4.3 Review the reassessment interval determined above. Determine if a lower reassessment interval should be established based on operating experience including but not limited to:

- Corrosion defects found on the line during non-ICDA related activities
- Leak history of the line segment

7B.7.4.4 According to 49 CFR Part 192.939, the maximum reassessment interval for HCA-covered-segments is seven years.

7B.7.4.4.1 If a reassessment interval greater than seven years is established, a confirmatory direct assessment, in accordance with 193.931, shall be performed on the HCA-covered-segment within the seven-year period. A follow-up reassessment shall then be conducted at the interval established in subsection 7B.7.4.1.

7B.7.4.5 **Documentation:** The reassessment interval shall be documented on Form 7B.12. Also record the reassessment interval per HCA on Form 13.1 “Reassessment Evaluation and Decision Record”.

7B.7.5 Evaluating Similar Segments

7B.7.5.1 If internal corrosion is identified during the assessment, **the Company** will make a determination per the requirements of Section 13 “Continual Evaluation” on whether or not similar pipeline segments (covered and non-covered) need to be evaluated and remediated. Refer to section 13 for additional details.

7B.7.6 First Time Application of ICDA Process

7B.7.6.1 For the first time application of the ICDA process to any segment of pipeline, more restrictive criteria is required per §192.927(5)(ii). Options for meeting this requirement include, but are not limited to:

- Apply the lowest reassessment interval of all ICDA regions for all regions
- Implement additional mitigative measures
- Increase frequency of internal corrosion monitoring (i.e. coupons or probes)
- Increase frequency of liquid sampling and analysis

7B.7.7 Post Assessment Report

All data, actions and decisions pertinent to this step shall be documented in a clear and concise manner. Records shall demonstrate compliance with 49 CFR Part 192 and NACE SP0206 and shall be retained for the useful life of the pipeline.

7B.7.7.1 The PIE shall prepare the *Post Assessment* report. It shall contain, but is not limited to the following:

7B.7.7.1.1 Criteria used to assess DG-ICDA effectiveness and results from assessments.

- Criteria and metrics.
- Data from periodic assessments.
- Correlation between corrosion found and sites predicted by DG-ICDA

7B.7.7.1.2 Remaining life calculation results:

- Maximum remaining flaw size determinations
- Corrosion growth rate determinations
- Method of estimating remaining life
- Results of remaining strength calculations

7B.7.7.1.3 Reassessment intervals and scheduled activities, if any

7B.7.7.1.4 Monitoring records

7B.7.7.1.5 Information of implementation of more restrictive criteria

7B.7.7.1.6 Feedback

7B.7.7.2 The **PIE** shall complete Form 7B.13:DG-ICDA Performance Report, in Appendix 7B.D, for each DG-ICDA project. The report shall be approved by the PM and filed in the project file. The report shall include the following:

7B.7.7.2.1 A summary of the *Pre-Assessmen*t Data Collection Form, including data from detailed examinations and other data as appropriate.

7B.7.7.2.2 A summary of the *Indirect Inspection* results, comparing the results from the calculated inclination angles with the actual values and the predicted corrosion sites with any corrosion observed during excavation.

7B.7.7.2.3 A summary of the *Detailed Examination* results, including the number of excavations performed, the remaining life of the pipe where internal anomalies were found, and the number of repairs or immediate actions.

7B.7.7.2.4 A summary of the *Post Assessment* results, including the shortest calculated re-inspection interval for the DG-ICDA project, the results of the DG-ICDA effectiveness assessment, and feedback for future projects.

7B.8 Exception Process

7B.8.1 Expectations

It is expected that all requirements of this procedure be met when conducting a DG-ICDA. However, exceptions may be taken after obtaining approval and documenting the exceptions as described in this section.

7B.8.2 Objectives

The objective of the exception process is to provide proper documentation of exceptions that are made to this procedure. Documentation of exceptions is necessary to maintain the integrity of the DG-ICDA process by allowing for continued process improvement, feedback, audits and compliance with the procedure.

7B.8.3 Process

The following process is required for deviating from this procedure:

7B.8.3.1 State the specific section number of the procedure where the exception is being taken. Briefly state or rephrase what the section requires.

7B.8.3.2 State the exception to the procedure.

7B.8.3.3 State the reason for the exception.

7B.8.3.4 State if the exception is specific to the current DG-ICDA project, or it is a recommended procedure change.

7B.8.3.5 Document the above items on Form 7B.14: Exception Report, in Appendix 7B.D.

7B.8.3.6 Obtain approval from the Program Manager – Integrity Management

7B.8.3.7 Place signed forms in the project file.

7B.9 DG-ICDA PROJECT REPORTS

7B.9.1 Project Report

The PIE shall prepare a report and submit it for approval to the PM.

7B.9.2 Contents

The report should contain the following information:

- Form 7B.1: Data Collection Form
- Form 7B.2: Sufficient Data Analysis
- Form 7B.3 Feasibility Assessment Report
- Form 7B.4: DG-ICDA Region Report
- Form 7B.5: Flow Modeling
- Form 7B.6: Site Selection for Detailed Examination
- Form 7B.7: DG-ICDA Subregion Report
- Form 7B.8: Excavation Data
- Form 7B.9: Remaining Strength Evaluation
- Form 7B.10: Root Cause Analysis
- Form 7B.11: DG-ICDA Detailed Examination Overview Report
- Form 7B.12: Remaining Life Determination
- Form 7B.13: DG-ICDA Performance Report
- Form 7B.14: Exception Report
- Form 7B.15: ICDA PreAssessment Restrictive Criteria Form
- Form 7B.16: ICDA Indirect Inspection Restrictive Criteria Form
- Form 7B.17: ICDA Direct Examination Restrictive Criteria From
- Form 7B.18: ICDA Post Assessment Restrictive Criteria Form

7B.9.3 Documentation

After the **PM** approves the report it shall be distributed as appropriate and filed in the DG-ICDA project file.

7B.10 APPENDICES

Appendix A: DG-ICDA Process Flow Charts

Appendix B: DG-ICDA Tables

Appendix C: Examples of pipeline inclinations and critical angles calculations

APPENDIX 7B.A

DG-ICDA PROCESS FLOW CHARTS

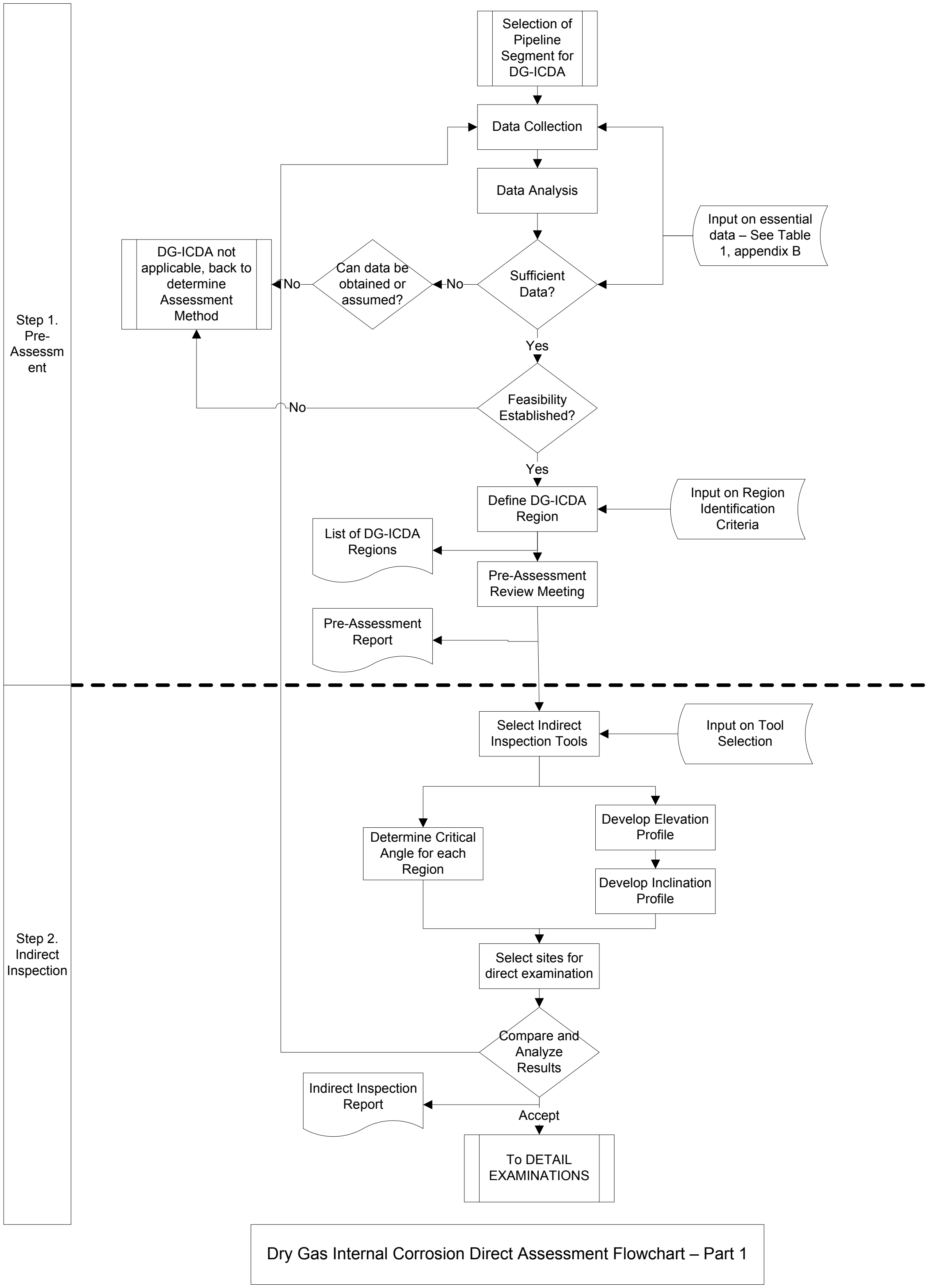


Figure 7B.1. DG-ICDA Flow Chart Part 1: *Pre-Assessment* and *Indirect Inspection* steps

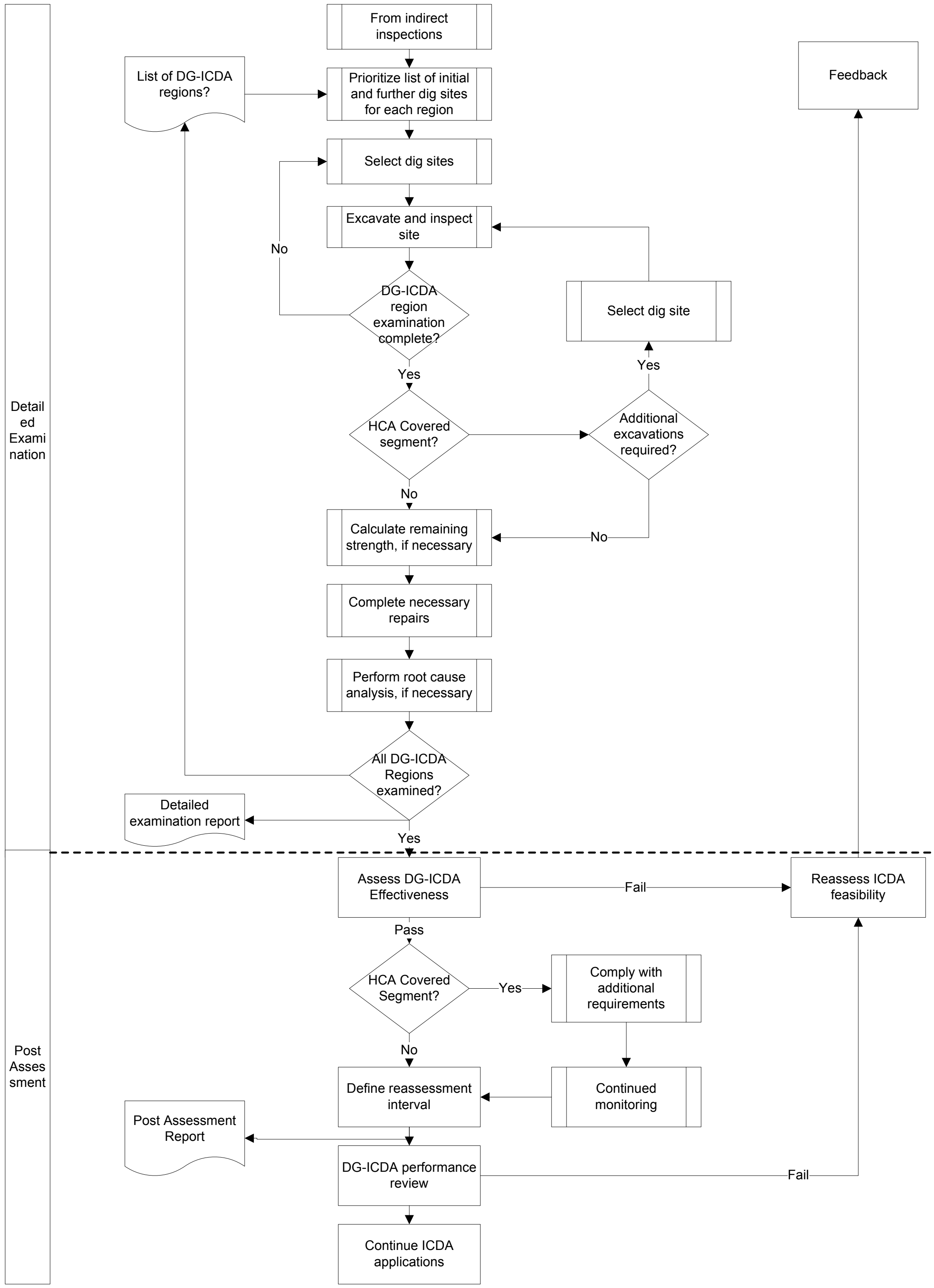


Figure 7B.2. DG-ICDA Flow Chart Part 2: Detailed Examination and Post Assessment steps

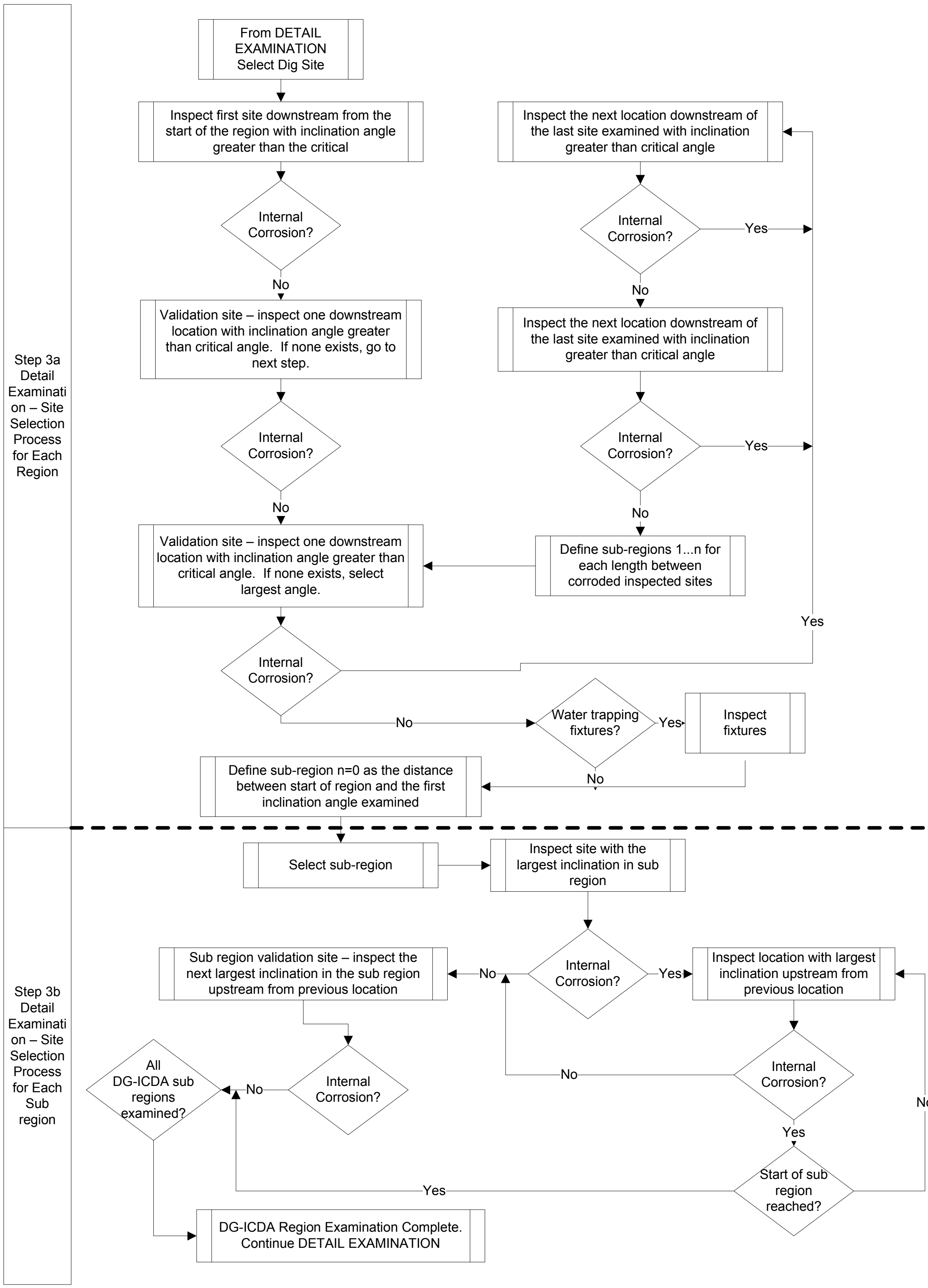


Figure 7B.3. DG-ICDA Flowchart Part 3: Detailed Examination process for each region and subregion

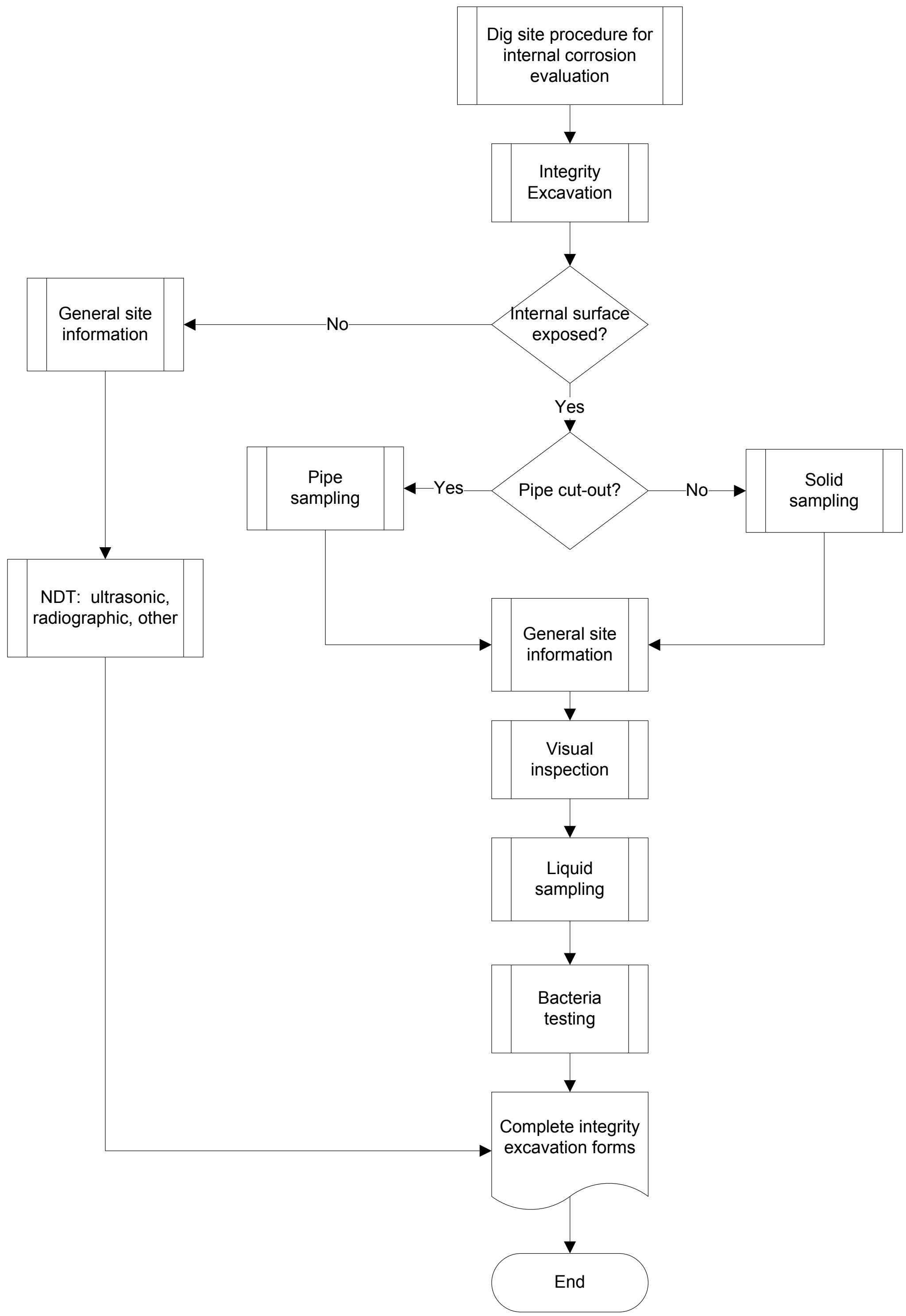


Figure 7B.4. Process Flow Chart for Performing Integrity bell holes.

APPENDIX 7B.B

DG-ICDA TABLES

TABLE 7B.1: DATA FOR USE IN DG-ICDA METHODOLOGY

Date:______________________________

Pipeline Segment Name/Number:___________________________________ Starting-Ending Mile Points:____________________________

DG-ICDA PRE-ASSESSMENT DATA LIST					
ID #	**Data Element**	**REQUIRED/ Desired**	**Feasibility Assessment**	**Identification of DG-ICDA Regions**	**Use & Interpretation of Results**
1.	**PIPE RELATED**				
1.1	Diameter	REQUIRED	Internal diameter must be within flow model range.		Used in flow calculations to determine the critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.
1.2	Wall thickness	REQUIRED			Required to calculate the internal diameter (see 1.1). Also, impacts critical defect size and remaining life prediction of results.
1.3	Internal Coatings	REQUIRED	DG-ICDA not appropriate for locations with internal corrosion protective coatings. The presence of flow coatings should also be considered.		Approved alternative internal corrosion integrity assessment method must be selected for lengths containing internal coatings. For pipelines with discontinuous protective coating, detailed examinations must be performed at non-protective locations within the excavation site (e.g., proximity to welds where coatings are known to be damaged by heat)
1.4	Seam type	REQUIRED	If pre-1970 low-frequency electric resistance welded (ERW) or flash welded pipe located along the bottom half of the pipeline, DG-ICDA not appropriate.		Location with pre-1970 low-frequency electric resistance welded (ERW) or flash welded pipe with increase selective seam corrosion susceptibility may require separate consideration.
1.5	Material and grade	Desired	DG-ICDA may not be appropriate for nonferrous materials.		DG-ICDA methodology assumes uniform material properties along a pipeline segment. Consideration for differences such as weld type and geometry and material defects must be made. Special consideration should be given to locations where dissimilar metals are joined. Can create local corrosion cells when exposed to the environment.
1.6	Year manufactured	Desired			Older pipe materials typically have lower toughness levels, which reduces critical defect size and remaining life predictions.
2.	**CONSTRUCTION RELATED**				
2.1	Year installed	REQUIRED	DG-ICDA will not find corrosion from previous service (e.g., reclaimed pipe).		Impacts corrosion rate estimates.

DG-ICDA PRE-ASSESSMENT DATA LIST					
ID #	**Data Element**	**REQUIRED/ Desired**	**Feasibility Assessment**	**Identification of DG-ICDA Regions**	**Use & Interpretation of Results**
2.2	Type and locations of current and historic (removed) inlets and outlets, tie-ins, taps, insulating joints, drains, drips, cast iron components. Locations, data on any route changes/ modifications.	REQUIRED	1) Consider economic implications of applying DG-ICDA to pipeline with numerous inlets. 2) Locations of drips, drains or other features where liquid hold-up may occur must be identified. 3) Special consideration should be given to locations at which dissimilar metals are connected.	Define new regions at each current or historic inlet. Outlets (current and historic) should also be used in region definition if it is possible there has been liquid input at these locations and to calculate changes in critical angles.	May impact interpretation of results; dissimilar metals may create local corrosion cells at points of contact. Information on orientation of features may assist in identification of those necessary to examine for internal corrosion. Presence of outlets may imply significant changes in flow velocities and/or pressure. Since critical inclination angle is sensitive to differences in pressure and flow velocity, new critical inclination angles are calculated for lengths after each outlet.
2.3	Locations of compressors, and valves	REQUIRED		Should be considered during region definition; significant differences in superficial gas velocity may trigger new region definitions or should be considered in region analysis. Anywhere where water could condense should also be considered.	Use in flow calculations to determine the critical angle past which liquid carry-over is not expected. Because critical inclination angle is sensitive to differences in pressure, new critical inclination angles are calculated for lengths with significant changes in flow velocity.
2.4	Locations of road and water crossings (including roads no longer in service) and any associated casings/ river weights and anchors	REQUIRED	Consider economic and environmental implications of applying DG-ICDA to lengths of pipe containing multiple sites at difficult to access locations. May significantly restrict the *Detailed Examination Step.* Additional tools and other assessment activities may be required.		Special attention should be given to elevation changes at these locations; pipe depth measurements may be necessary to avoid extrapolating nearby results to inaccessible regions, which could introduce unacceptable error for DG-ICDA.
2.5	Route maps/aerial photos	REQUIRED	Assists in pipeline locating; precise location data required.	May provide information about route that would be useful to region definition.	Typically contain pipeline data that facilitate DG-ICDA. Essential to obtain coordinates of precise route location for purposes of elevation profiling with GIS/ USGS.
2.6	Construction practices	Desired	DG-ICDA not desired for pipeline known or suspected to have experienced internal corrosion prior to or during installation. Mechanical damage may preclude use of DG-ICDA.		
2.7	Proximity to other pipelines, structures, high voltage electric transmission lines, and rail crossings	Desired			Affects site selection. Could make detailed examinations difficult. May be associated with pipe depth changes. Provides critical information for use during detailed examinations.
2.8	Locations of exposed pipe, drips and crossovers	REQUIRED			Locations of all exposed pipe, drips and crossovers must be identified. Short sections of exposed pipe could be assessed by a different method.
2.9	HCA #s	REQUIRED			The location of HCAs is necessary to determine what special requirements must be taken for a HCA-covered-segment (i.e. shorter re-assessment interval, continual monitoring, etc)

DG-ICDA PRE-ASSESSMENT DATA LIST					
ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
3.	**TOPOGRAPHICAL DATA**				
3.1	USGS maps or GIS surveys	REQUIRED	An accurate elevation profile (sub-meter) is essential to DG-ICDA. Tool used must be able to discern all important inclination angles. 1) If GIS is used, static or other high accuracy and precision method is required and sufficient data must be collected. Consider economic implications. 2) USGS data must have sufficient resolution. If USGS data are used, it may be necessary to supplement with quality GIS measurements in important locations (i.e., beginning of line to first site).		Locations of ALL low points must be identified. When collecting GIS (Geographic Information System) or USGS (U.S. Geological Survey) data, include marker locations (i.e., road and river crossings) in the comment section of the inclination spreadsheet, for future later reference during detailed examinations.
3.2	Elevation changes at roads, rivers, drains, valves, drips	REQUIRED	An accurate and precise inclination profile is required. If the tool used for data collection does not have sufficient discernment of these features it must be supplemented by pipe depth measurements, static GIS, and/ or another tool which can discern pipeline elevation.		Special attention must be paid to these changes, which are not adequately captured in many topographical surveys. At these locations, pipe depth measurements may be necessary, as the elevation of the pipeline is likely to vary from the surface elevation.
3.3	Depth of cover	DESIRED	Depth of cover measurements are strongly recommended. These must be coordinated precisely with GIS or other data.		May impact success of DG-ICDA. If significant inclinations are not captured, site selections are not expected to be accurate. It is recommended to collect pipe depth measurements simultaneous with GIS to avoid alignment issues.
4.	**OPERATIONAL DATA**				
4.1	Pipeline operating temperature	REQUIRED	Must be within flow model range.	Any significant changes (i.e., frozen ground) require consideration as these could affect liquid hold-up location.	Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.
4.2	Pipeline operating pressures	REQUIRED	Must be within flow model range.	Significant changes in pressure (i.e., due to compressor) may trigger new DG-ICDA regions.	Collect typical minimum and maximum operating pressures. Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change.

DG-ICDA PRE-ASSESSMENT DATA LIST					
ID #	**Data Element**	**REQUIRED/ Desired**	**Feasibility Assessment**	**Identification of DG-ICDA Regions**	**Use & Interpretation of Results**
4.3	Pipeline operating flow rates	REQUIRED	Must be within flow model range.	New regions are defined at current and historic inlets as these locations offer renewed liquid input potential. In case of bi-directional flow, regions are defined for each gas flow direction.	Collect minimum and maximum flow rates at minimum and maximum operating pressures for all inlets and outlets. 1) Use in flow calculations to determine the largest critical inclination angle past which liquid carry-over is not expected. New critical inclination angles should be calculated for any length with a significant change. 2) Range of all gas velocities must be known. 3) Periods of low/no flow must be considered.
4.4	Corrosion inhibitor solubility (water/ oil), carrier (glycol/ aromatic), point of injection, dose rate, years of treatment, monitoring/ detection of inhibitor in any downstream liquids.	REQUIRED	Pipeline should not have a history of internal corrosion inhibitor use. If there is any history, technical justification must be provided.		The use of corrosion inhibitor may preclude application of DG-ICDA because the effectiveness of the inhibitor might not be uniform along the pipeline length. If inhibitor provides partial but incomplete pipeline protection, DG-ICDA may not identify the most corroded locations. In these cases an alternative technique should be used.
4.5	Type of dehydration	REQUIRED	Type of dehydration should be considered.		Some dehydrating agents may encourage formation of sludge and solids or leave other residues. These may increase or decrease corrosion in locations at which they collect.
4.6	Service history. Retired storage fields	REQUIRED	If pipeline has been converted from a service for which DG-ICDA is not applicable (e.g., crude oil, products, normally wet-gas) DG-ICDA is not suitable.		
4.7	Operating stress levels and fluctuations (% SMYS)	REQUIRED			Impacts critical flaw size and remaining life predictions.
4.8	Data on liquid upsets	Desired	1) DG-ICDA is intended for nominally dry gas pipelines. 2) Information on upsets may help anticipate extent of internal corrosion and possibility for any non-stratified flow conditions.	If liquid is known or suspected to have entered the line from outlets, these should be included in region definition.	Collect data on liquid upsets, including frequency (intermittent/ chronic), nature of liquid, volume (if known), location, and potential damage resulting from these upset conditions. History of liquids in the line is useful in assessing likelihood and possible severity of internal corrosion in the pipeline. The DG-ICDA method is based on assumption of stratified flow.
4.9	Water Vapor Dew Point	REQUIRED	DG-ICDA is intended for normally dry gas pipelines, which implies normal operation at temperatures well above water dew point.		Operation of the pipe at temperature close to the water dew point may cause top of the line corrosion in locations not identified by DG-ICDA.
5.	**MONITORING DATA**				
5.1	Corrosion Monitoring	REQUIRED	1) Provides important supplementary information for DG-ICDA. 2) May provide information on presence and rate of internal corrosion. 3) Useful in defining reassessment intervals/ future monitoring.		Collect locations and information from monitoring programs (coupons, electric resistance (ER)/linear polarization resistance (LPR) probes, leak surveys, etc.)

DG-ICDA PRE-ASSESSMENT DATA LIST

ID #	Data Element	REQUIRED/ Desired	Feasibility Assessment	Identification of DG-ICDA Regions	Use & Interpretation of Results
5.2	Gas analyses	REQUIRED	Gas composition factors that may result in accelerated corrosion rate should be evaluated.		Collect gas and liquid analyses, and any bacteria testing results for the pipeline and on shipper and delivery laterals. Establish relationship of gas analyses to pipe location. Presence of bacteria, CO_2, H_2S, or O_2 may accelerate internal corrosion. Their effects must be considered..
6.	**INSPECTION AND REPAIR DATA**				
6.1	Pipeline inspection reports – excavation	REQUIRED	DG-ICDA may not be applicable for pipelines with history of internal corrosion on the top of the pipeline.		May impact repair; remediation, replacement schedules.
6.2	Repair history/ records	REQUIRED			Collect repair history and records – such as steel/ composite repair sleeves, repair locations, etc. Repaired pipeline may mask an internal corrosion problem. For locations which are to be detail examined it is essential to know when excavated pipe has been repaired in the past and its condition previous to repair. Use this information in combination with current detailed examinations in making further site selections.
6.3	Leak/rupture history (internal corrosion)	REQUIRED			Collect location and nature of leaks and failures. This is essential for DG-ICDA site selection. Prior internal (or suspected internal) corrosion leaks must be considered concurrent with detailed examinations in making further site selections.
6.4	Hydrostatic test	Desired			Collect hydrostatic data (dates, pressures, water quality). Provides information on past presence of water.
6.5	Presence of solids, liquids	REQUIRED	Pipelines that contain accumulations of solids, sludge, or scale should not be assessed using DG-ICDA, unless the influence of those materials has been carefully evaluated.		Document presence of solids and liquids in the pipe. If available, include analytical data of all removed sludge, liquids when cleaning pigs were employed or from liquid separators, hydrators, etc. and the analysis performed to determine the chemical properties and corrosivity, including the presence of bacteria, of the removed products. The presence of solids, sludge, and scale may affect the ability to predict where internal corrosion will occur.
6.6	Prior integrity-related activities – maintenance and ILI pigging, etc.	REQUIRED	DG-ICDA is not intended for pipelines that have been or are currently being pigged. Pipelines subjected to regular maintenance pigging (i.e., annual or more frequent basis) should not be assessed using DG-ICDA.		Collect locations, frequency, and dates of other prior integrity-related activities, such as maintenance and ILI pigging (including ILI from mainlines attached to legs on which DG-ICDA is being performed). Maintenance pigging affects where liquids collect, which directly affects the distribution of internal corrosion in a way not predicted by DG-ICDA. The operator must provide technical justification when DG-ICDA is applied to a pipeline that has any history of routine maintenance pigging.

TABLE 7B.2: EFFECTS OF SOLIDS AND SLUDGE ON PIPELINE INTERNAL CORROSION (NACE, SECTION 3.3)

	Action	Effect
1	Retain water inside a porous matrix or under a solid layer	Increases corrosion
2	Attract water through hygroscopic properties and/ or deliquescence	Increases corrosion
3	Formation of a concentration cell (i.e., under deposit corrosion)	Increases corrosion
4	Formation of a protective layer	Decreases corrosion
5	Influence of biofilm/biomass on bacteria growth and corrosion kinetics	Changes corrosion, depending on nature of deposits and prevailing corrosion mechanism

APPENDIX 7B.C

EXAMPLES OF PIPELINE INCLINATIONS AND CRITICAL ANGLES CALCULATIONS

Angle	Velocity, ft/s	MMCF/d @hp	MMSCF/d
0	-	-	0
0.1	3.4	1.4	58
0.2	4.7	1.9	80
0.3	5.7	2.3	97
0.4	6.5	2.6	110
0.5	7.2	2.9	122
0.6	7.8	3.2	133
0.7	8.4	3.4	143
0.8	8.9	3.6	152
0.9	9.4	3.8	160
1	9.9	4.0	168
1.5	11.9	4.8	202
2	13.6	5.5	231
2.5	15.0	6.1	256
3	16.3	6.6	278
3.5	17.5	7.1	298
4	18.6	7.5	317
4.5	19.6	7.9	335
5	20.6	8.3	351
5.5	21.5	8.7	367
5.6	21.7	8.8	370
6	22.4	9.1	382
6.5	23.2	9.4	396
7	24.0	9.7	409
7.5	24.8	10.0	423
8	25.5	10.3	435
8.5	26.3	10.6	447
9	27.0	10.9	459
9.5	27.6	11.2	471
10	28.3	11.4	482
10.5	28.9	11.7	492
11	29.5	11.9	503
11.5	30.1	12.2	513
12	30.7	12.4	523
12.5	31.3	12.7	533
13	31.8	12.9	542
13.5	32.4	13.1	552
14	32.9	13.3	561
14.5	33.4	13.5	570
15	33.9	13.7	578
15.5	34.5	13.9	587
16	34.9	14.1	595

* These Parameters are Input in Predictor Sheet
**** These parameters are Adjustable**

ID * =	**29.3** Inch			
P * =	**500** psi	Gauge Pressure		
T * =	**61** deg F			
rho(liquid) ** =	62.43 lb/ft^3	**1** g/cm^3	Specific Gravity of Water	
Compressibility ** =	**0.83**			
rho(gas) =	1.77 lb/ft^3	2.84E-02 g/cm^3	Gas Law assuming Methane and Compressibility Factor	
g =	32.17 ft/s^2			

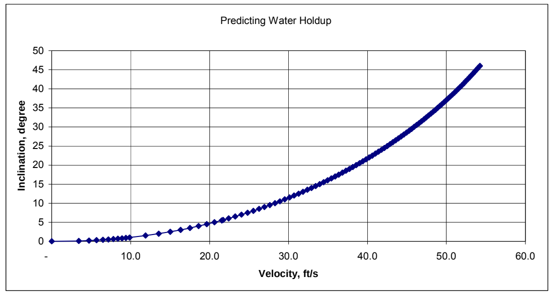


Figure 7B.5. Calculator Example, Determination of the Critical Angle

Pipe Size I.D., Inches	Pressure, psi	Temperature, F
29.3	**500**	**61**

***Based on detailed modeling results within the range of 4 to 48 inch I.D., 50 to 1100 psi, 60 to 120F, and 0 to 25 ft/s gas velocity**

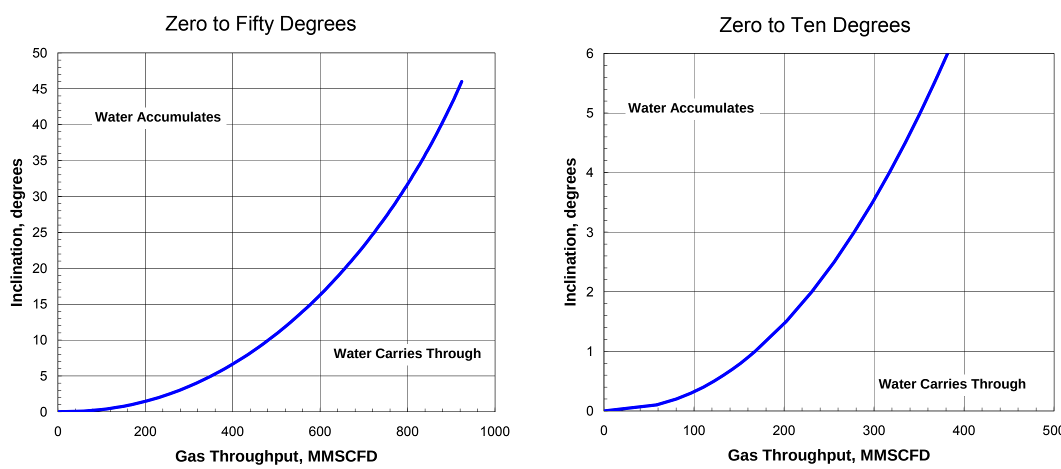


Figure 7B.6. Example, Prediction of Water Holdup

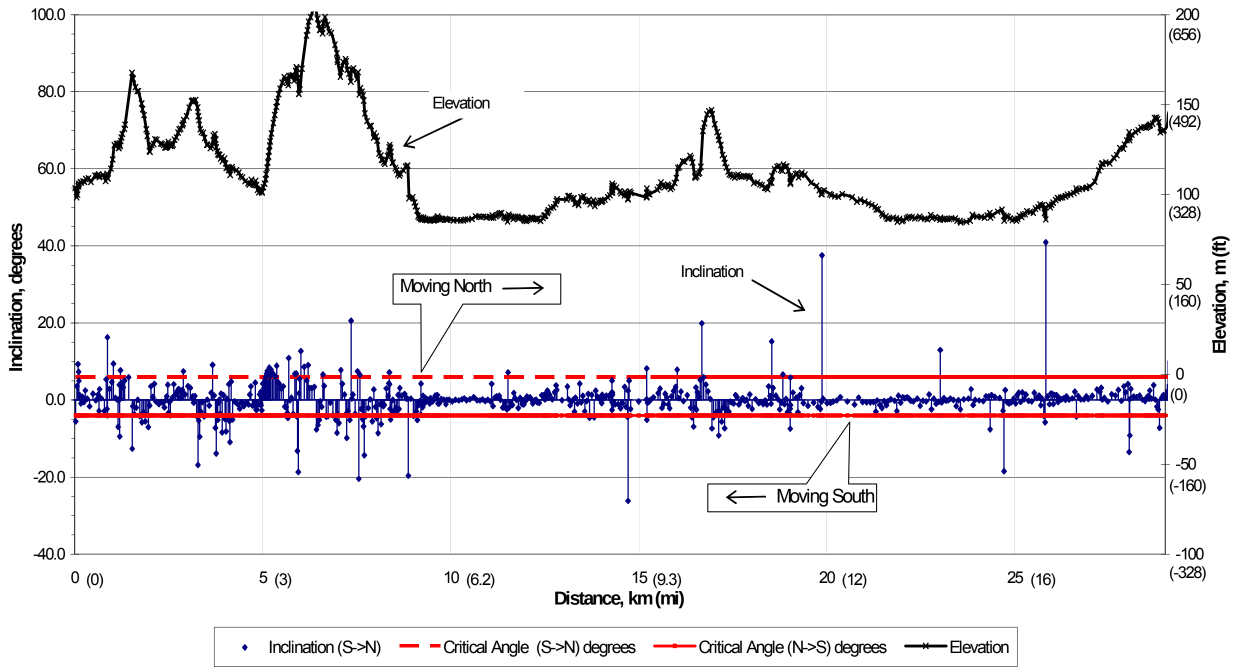


Figure 7B.5: Sample plot of inclination, elevation, and critical angle for a segment of pipe2.

APPENDIX 7B.D

DG-ICDA REPORT FORMS

Form 7B.1: Data Collection Form

ICDA Project Name: **Date of Evaluation:**
Line Name: **PIE:**
Segment Number: **PM:**

Instructions: This form shall be completed in accordance with subsection 7B.3.2 of the procedure. The CS and/or PIE or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Need	Main Report	GIS	Field	Corrosion Control	Maps / Other	Subject Matter Experts	Data Obtained & Comments Sys ID ___________	Sign Off
1.0	PIPE RELATED									
1.1	Diameter	R								
1.2	Wall thickness	R								
1.3	Internal Coatings	R								
1.4	Seam Type	D								
1.5	Material and grade	D								
1.6	Year manufactured	D								
2.0	Construction Related									
2.1	Year installed	R								
2.2	Type and locations of current and historic inlets and outlets, tie-ins, taps, insulating joints, drains, drips, cast iron components. Locations, data on any route changes/ modifications.	R								
2.3	Location compressors and valves	R								
2.4	Locations of road and water crossings and any associated casings/ river weights and anchors	R								
2.5	Route maps/ aerial photos	R								
2.6	Construction practices	D								
2.7	Proximity to other pipelines structures, HV electric transmission lines and rail crossing	D								
3.0	Topographical Data									
3.1	USGS maps or GIS surveys	R								
3.2	Locations of exposed pipe, drips, and crossovers	R								
3.3	Elevation changes at roads, rivers, drains, valves, drips	R								
3.4	HCA #s	R								
3.5	Depth of cover	D								
4.0	Operational Data									
41	Pipeline operating temperature	R								
4.2	Pipeline operating pressures	R								
4.3	Pipeline operating flow rates	R								
4.4	Corrosion inhibitor solubility, carrier, dose rate, years of treatment, monitoring, detection of inhibitor in downstream liquids.	R								
4.5	Type of dehydration	R								
4.6	Service history	R								
4.7	Operating stress levels and fluctuations (% SMYS)	R								
4.8	Data on liquid upsets	D								
4.9	Water Vapor	R								
5.0	Monitoring Data									
5.1	Corrosion monitoring	R								
5.2	Gas analyses	R								
5.3	Bacteria Culture Test Records	R								

Form 7B.1: Data Collection Form

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

Instructions: This form shall be completed in accordance with subsection 7B.3.2 of the procedure. The CS and/or PIE or designate shall indicate the collection of each data elements by initialing the appropriate data element row. Information particular to the individual data element should be recorded in the Data Obtained field. Information in the Comments filed should include, as a minimum the reason required data is not available.

ID #	Data Element	Need	Main Report	GIS	Field	Corrosion Control	Maps / Other	Subject Matter Experts	Data Obtained & Comments Sys ID ___________	Sign Off
6.0	Inspection and Repair Data									
6.1	Pipeline inspection reports-excavation	R								
6.2	Repair history/records	R								
6.3	Leak/rupture history (internal corrosion)	R								
6.4	Hydrostatic test	R								
6.5	Presence of solids, liquids	R								
6.6	Prior integrity- related activities – maintenance and ILI pigging, etc.	R								
6.7	Type/frequency- third party damage	D								

Form 7B.2: Suffiecient Data Analysis

ICDA Project Name: | Date of Evaluation:
Line Name: | PIE:
Segment Number: | PM:

Instructions: This form shall be completed in accordance with subsection 7B.3.3.8 of The Procedure.

SUFFICIENT DATA ANALYSIS

Missing Required Data Elements (or Desired Data Elements Determined Essential for Conducting DG-ICDA)				
ID# (Form A)	Data Element Description (Form A)	Pipe Segments	Reason for missing data	Explanation why it is not needed

Sufficient Data: Yes No

Pipeline Integrity Engineer: ______________________

Project Manager: ______________________

Form 7B.3: Feasibility Assessment Report

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

Instructions: This form shall be completed in accordance with subsection 7B.3.4.3 of the procedure. Place a check mark next to all conditions that apply to the given pipeline segment.

Conditions that may make DG-ICDA unfeasible

__________ The pipe contains liquids.

__________ The pipeline has been converted from a service for which DG-ICDA is not applicable

__________ A corrosion inhibitor has been used.

__________ The pipe has an internal coating that provides corrosion protection.

__________ The pipe has a history of pig cleaning.

__________ The pipe contains an accumulation of solids.

__________ There is pre-1970 low-frequency ERW or flash welded pipe located along the bottom half of the pipe.

__________ Other:

Technical justification for proceeding with DG-ICDA process: ______________________________

Extra actions that must be taken as a result of unfeasible conditions: ____________________

Is DG-ICDA feasible? _______ Yes ________ No

Pipeline Integrity Engineer: ______________________________ Date: ____________________

Program Manager: ______________________________ Date: ____________________

Form 7B.4: DG-ICDA Region Report

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

Instructions: This form shall be completed in accordance with subsection 7B.3.5.7. Refer to Table 7B.1,in Appendix 7B.B for more detailed information regarding Region Distinguishing Characteristics. If the distinguishing characteristic is not contained in the list below, list the characteristic under other, and provide a technical justification for it being used as a region distinguishing characteristic.

Region Distinguishing Characteristics List

1. Current or historic inlet
2. Crossover
3. Drip
4. Exposed pipe
5. Bi-directional flow
6. Significant change in temperature
7. Significant change in pressure
8. Liquid is known or suspected to have entered line from outlets
9. Significant difference in superficial gas velocity (may be caused by compressors and valves)
10. Other*:

Region #	Region Start (geographical reference)	Region End (geographical reference)	Region Distinguishing Characteristic #	Temperature, °F (min/max)	Pressure, atm (min/max)	Flow Rate, mmscf/d (min/max)	ID, in

*Justification for being considered a region distinguishing characteristic (if #10-Other): ______________________

Pipeline Integrity Engineer: ______________________ Date: ______________

Program Manager: ______________________ Date: ______________

Form 7B.5: Flow Modeling

ICDA Project Name: **PIE:**
Line Name: **PM:**
Segment Number: **Contractor:** Company Name
Date of Evaluation: **Flow Modeling Performed by:** Name of person

Instructions: This form shall be completed in accordance with subsections 7B.4.1.3 and 7B.4.1.8 of the procedure.

Flow Model Used: ______________________________

Justification for using flow model if other than the model given in the procedure:

____
____
____
____
____
____
____
____

Comments: ______________________________

____
____
____
____
____
____
____
____

Flow Modeling Results

Region #	ρ_g	OP Flow Rate	V_g	θ (critical inclination angle)	max θ, min θ, or other (specify)

Program Manager: ______________________________ **Date:** ______________

Pipeline Integrity Engineer: ______________________________ **Date:** ______________

Form 7B.6: Site Selection for Detailed Examination

ICDA Project Name: PIE:
Line Name: PM:
Segment Number: Contractor:
Date of Evaluation: Region Number:

Instructions: This form shall be completed in accordance with subsections 7B.4.5.2 of this procedure. These sections provide instructions on determining site selections within each DG-ICDA region. It shall be noted in the Comments field if a site has been selected as a validation inspection. It shall be noted in the Subregion # field if a selected site is not a part of a subregion.

Site #	Subregion #	Critical Inclination Angle	Site Calculated Inclination Angle	Site Start (GPS)	Site Start (geographical reference)	Site Selection Date	Site Selection +180 days	Date Scheduled for Detailed Examination	Comments

Program Manager: ______________________ Date: ______________________

Pipeline Integrity Engineer: ______________________ Date: ______________________

Form 7B.7: DG-ICDA Subregion Report

ICDA Project Name: PIE:
Line Name: PM:
Segment Number: Contractor:
Date of Evaluation: Region Number:

Instructions: For each DG-ICDA region record the sub-regions defined according to subsection 7B.5.1.10 of this procedure.

Region # (Form 7B.4)	Subregion #	Subregion Start (Site #) (Form 7B.6)	Subregion End (Site #) (Form 7B.6)	Subregion Start (geographical reference)	Subregion End (geographical reference)	Comments

Program Manager: ______________________ Date: ______________________

Pipeline Integrity Engineer: ______________________ Date: ______________________

Form 7B.8: Exacvation Data

ICDA Project Name:________________________________ Date of Excavation:___________________
Excavation Mile Point:_____________________________ ICDA Inspector:______________________
Line Number:_____________________________________ ICDA-PM:___________________________
DG-ICDA Region Number(s):____
DG-ICDA Site Number: _____________________________ Subregion Number:___________________

Instructions: Subsection 7B.5.3.15 provides instructions to complete this form.

Excavation Details: GPS Readings:

Location of Low Point (Above Ground) ______________________________ N°
______________________________ W°

Expanded: ☐ Yes ☐ No

Critical Angle: ___________________________

Inclination Angle:

Calculated: ___________________________

Actual: ___________________________

Pipe Data:	Internal Corrosion Damage:
Length of Pipe Excavated:	NDE Contractor:
Diameter:	Wall Thickness (Actual):
Wall Thickness:	Area corroded 0-10% wall thickness (in^2):
Grade:	Area corroded 10-20% wall thickness (in^2):
Pipe Manufacturer:	Area corroded 20-50% wall thickness (in^2):
Longitudinal Seam Weld:	Area corroded 50-100% wall thickness (in^2):
Date Installed:	Photos Taken? ☐Yes ☐No Location of Photos:
Depth of Cover:	Corrosion Product Present? ☐Yes ☐No
MAOP:	Sample taken? ☐Yes ☐No Comments:
Normal Flow Direction:	
(or: bi-directional	

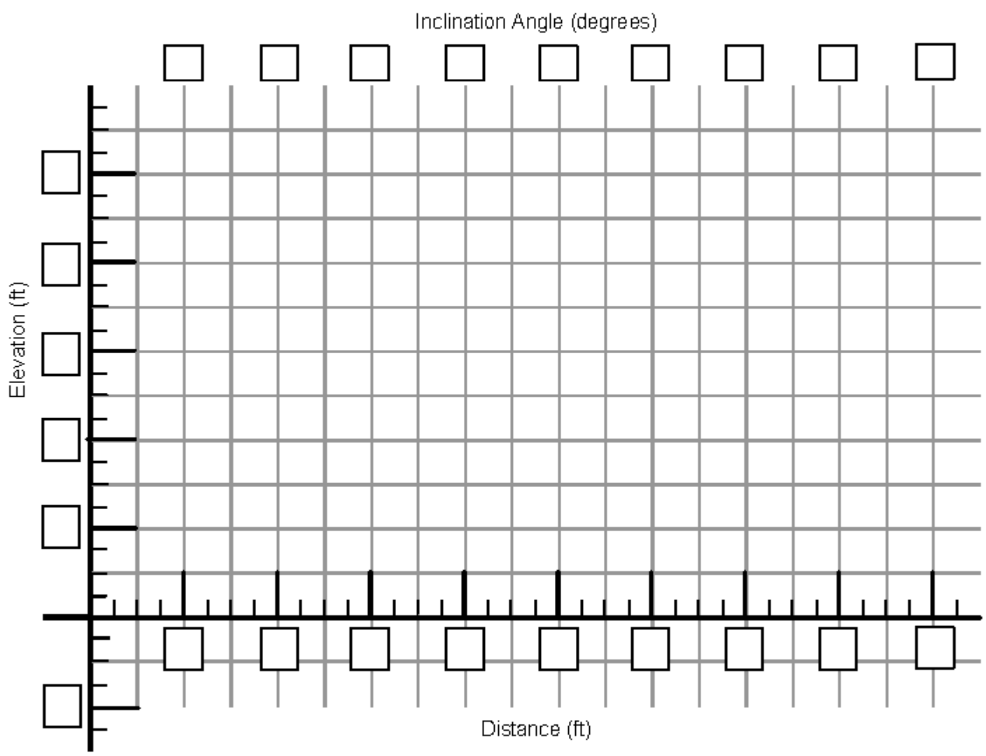
Map of Internal Corrosion (indicate %, size, type, depth, etc):

Excavation Drawing:

At minimum draw pipe elevation profile and indicate stationing of 1) low point and 2) critical inclination angle.

Place an arrow on the drawing indicating direction of gas flow in the region(s).

Other labels may also be added (e.g., "to Station").



STATIONING

STATIONING

Form 7B.9: Remaining Strength Evaluation

DG-ICDA Project Name:____________________ **Date of Evaluation:** ____________________
Evaluation Mile Point:____________________ **PIE:** ____________________
Line Number:____________________ **PM:** ____________________
DG-ICDA Region Number(s): ____________________ **Station Discharge:** ____________________
DG-ICDA Site Number:____________________ **Subregion Number:** ____________________

Instructions: This form shall be completed in accordance with subsection 7B.5.5 of this procedure.

Pipe Information

Diameter: __________ Wall Thickness: __________ Material: __________
SMYS: __________ MAOP: __________ Class Location: __________

Area of corrosion with lowest failure pressure

Length:______ Width:______ Max Pit Depth:_____ RSTRENG Failure Pressure:______

Predicted Failure Pressure Determination (*Pf*)

Pf: __________ SF_{corr} (Pf/MAOP): __________

Pipe Repair Required: __________Yes __________ No

People Notified: ____
____
____
____

Date of Notification: ____________________

Comments:____
____
____
____

Program Manager: ____ **Date:** ____________________

Pipeline Integrity Engineer: ______________________________ **Date:** ____________________

Form 7B.10: Root Cause Analysis

ICDA Project Name:
Line Name:
Segment Number:

Date of Evaluation:
PIE:
PM:

Instructions: This form shall be completed in according with subsection 7B.5.6 of this procedure.

Liquid and Gas Chemistry: ______________________________

Solids Found? ______ Yes ______ No

If yes, Solid Composition: ______________________________

Corrosive Microbes Present? ______ Yes ______ No

Cause of Corrosion: ______________________________

Remedial Actions: ______________________________

Is DG-ICDA well suited to identify damage from the cause described above? _____Yes _____ No

Comments: ______________________________

Program Manager: ______________________ Date: __________

Pipeline Integrity Engineer: ______________________ Date: __________

Form 7B.11: DG-ICDA Detailed Examination Overview Report

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

Instruction: This form shall be completed in accordance with subsection 7B.5.7 of the procedure.

Selected Site					Rationale for Excavation (IC= Internal corrosion)				Results of Excavation								
										Internal Indication							
#	Station #	ICDA Region #	ICDA Sub-region # (or n/a)	Design Wall Thickness (in.)	IC Found at Previous Site OR First Site Examined in Region	No IC Found at Previous Site *	No IC Found at Previous Two Sites #	HCA Location (Min. of 2 required per DG-ICDA Region)	Internal Corrosion Identified? (yes/no)	Minimum Wall Thickness (in.)	Orientation (o-clock)	Inclination Angle at Indication (degrees)	Length (in)	Width (in)	Pipe Repair (Y/N)	Date of Detailed Examination and/or General Comments	Mitigation and/or Scheduled Defect Reassessment Date (from Post-assessment Calculation)

* Subregion Validation Site
# Region Validation Site

Comments

1	
2	
3	
4	

Program Manager: ______________________ Date: ______________________

Pipeline Integrity Engineer: ______________________ Date: ______________________

Form 7B.12: ICDA Remaining Life Determination

ICDA Project Name: ______________________ Date of Evaluation: ______________________

Line Number: ______________________ Project Manager: ______________________

Starting Mile Point: __________ Ending Mile Point: __________
Class Location: _____ MAOP: _____

INSTRUCTIONS: This form shall be filled out in accordance with subsection 7B.7.3 of the procedure.

REMAINING LIFE CALCULATION:

Pipeline Station	Priority	Indication Location	Outside Diameter (in)	Thickness (in)	Yield Strength (psi)	Yield Pressure (psi)	Design Safety Factor (SF_{DA})	Date of Discovery	Pressure Reduction Required?	Reduced Operating Pressure (psi)	Actual Pressure Reduction Date	Predicted Failure Pressure Pf (psi)	Corrosion Rate (in/year)	Remaining Life (years)	1/2 RL (years)

Shortest Reassessment Interval of all Indications in the HCA: 0.00

Method Used to Determine Corrosion Rate: ______________________

Justification: ______________________

Comments: ______________________

Nominal Diameter	*Outside Diameter*
1	*1.315*
2	*2.375*
4	*4.5*
6	*6.625*
8	*8.625*
12	*12.375*
16	*16*
20	*20*

Program Manager: ______________________ Date: __________

Pipeline Integrity Engineer: ______________________ Date: __________

Form 7B.13: DC-ICDA Performance Report

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

INSTRUCTIONS: This form shall be filled out in accordance with subsection 7B.7.5 of the procedure.

Pre-assessment Summary (*Detailed Examination* data can also be used to supplement the requested information below.)

1.0 Pipe Related	Pre-Assessment *(expected)*	Direct Examination *(actual)*	Comments
Material and Grade			
Diameter			
Wall Thinkness			
Seam Type			
Internal Coating			
2.0 Construction Related			
Year Installed			
Inlets and Outlets			
Compressors and valves			
Road and Water Crossings			
3.0 Topographical Data			
USGS maps/ GIS surveys			
Elevation Changes			
Depth of Cover			
Exposed Pipe			
HCA #s			
Crossovers and Drips			
4.0 Operational Data			
Temperature			
Pressure			
Flow Rates			
%SMYS			
Water Vapor			
Corrosion Inhibitor (yes/no)			
Dehydration (type)			
Service History			
5.0 Monitoring Data			
Corrosion Monitoring			
Gas Analyses			
Bacteria Culture Tests			
6.0 Inspection and Repair			
Inspection Records			
Repair History			
Leak/Rupture History			
Hydrostatic Test			
Solids or Liquids (yes/no)			
Prior ILI or Pigging			

Form 7B.13: DC-ICDA Performance Report

ICDA Project Name: Date of Evaluation:
Line Name: PIE:
Segment Number: PM:

INSTRUCTIONS: This form shall be filled out in accordance with subsection 7B.7.5 of the procedure.

Indirect Inspection Summary

DG-ICDA Region #	Critical Inclination Angle	Site #	Site Inclination Angle		Site Corrosion		Comments
			Calculated	Observed	Predicted	Observed	

Detailed Examination Summary

	Corroded Area <10% Nominal Wall Thickness	Corroded Area 10-20% Nominal Wall Thickness	Corroded Area 20-50% Nominal Wall Thickness	Corroded Area >50% Nominal Wall Thickness
Number of Excavations				
Remaining Life (range of years)				
Immediate Responses				
Number of Repairs or Remediation Actions				

Post Assessment Summary

Re-inspection Interval: ____ __________

Exceptions: __________ Yes __________ No

Description: ______________________________

Feedback: ______________________________

Pipeline Integrity Engineer: ______________________ Date: __________

Program Manager: ______________________ Date: __________

Form 7B.14: Exception Report

ICDA Project Name: **Date of Evaluation:**
Line Name: **PIE:**
Segment Number: **PM:**

Instructions: This form shall be completed in accordance with subsection 7B.8 of this procedure.

Paragraph Number of Exception:

Requirements of paragraph (Briefly state or paraphrase): ____________________

____
____
____
____

Alternative Plan: ____________________

____
____
____
____
____

Reason for Exception: ____________________

____
____
____
____
____

Recommendation: Should the procedure be changed? ______ Yes ______ No

Comments: ____________________

____
____
____

Program Manager: ____________________ Date: ____________________

Pipeline Integrity Engineer: ____________________ Date: ____________________

Form 7B.15: ICDA Pre-Assessment Restrictive Criteria Form

Date of Report: ______________ **Line Number:** ______________________________

ICDA Project: ______________________________

Completed by: ______________________________

	Yes	No
Is this the first time to apply the ICDA process to this pipeline segment?	☐	☐

If yes, choose at least one of the following:

	Yes	No
1) Using more specific limiting characteristics to Subdivide the ICDA regions into smaller, more defined regions	☐	☐
2) Collecting and analyzing a larger data set than the required minimum data set	☐	☐
3) Have a pre-assessment meeting with field personnel and Field Subject Matter Experts to gather additional information about the pipeline and the operating characteristics	☐	☐
4) Other Criteria Chosen: If yes, describe below:	☐	☐

____
____
____
____
____
____

Form 7B.16: ICDA Indirect Inspection Restrictive Criteria Form

Date of Report: ____________ **Line Number:** ____________________

ICDA Project: ______________________________

Completed by: ______________________________

	Yes	No
Is this the first time to apply the ICDA process to this pipeline segment?	☐	☐

If yes, choose at least one of the following:

	Yes	No
1) Calculate both "maximum" and "minimum" flow velocity inclination angles	☐	☐
2) Gather elevation profile data over the entire pipeline	☐	☐
3) Gather additional field data to refine pipe inclination profile, particularly near elevation changes	☐	☐
4) Other Criteria Chosen: If yes, describe below:	☐	☐

____
____
____
____
____
____

Form 7B.17: ICDA Direct Examination Restrictive Criteria Form

Date of Report: ________________ **Line Number:** ________________________________

ICDA Project: ____

Completed by: ____

	Yes	No
Is this the first time to apply the ICDA process to this pipeline segment?	☐	☐

If yes, choose at least one of the following:

	Yes	No
1) Measure wall thickness around entire pipe circumference	☐	☐
2) Use more conservative LRUT "call level"	☐	☐
3) Extend bell-hole to assess greater areas of pipe	☐	☐
4) Other Criteria Chosen: If yes, describe below:	☐	☐

____
____
____
____
____
____

Form 7B.18: ICDA Post Assessment Restrictive Criteria Form

Date of Report: ____________ **Line Number:** ______________________________

ICDA Project: ____

Completed by: ____

	Yes	No
Is this the first time to apply the ICDA process to this pipeline segment?	☐	☐

If yes, choose at least one of the following:

	Yes	No
1) Apply the lowest reassessment interval of all ICDA regions as the first reassessment interval for all regions	☐	☐
2) Implement additional mitigative measures	☐	☐
3) Increase frequency of internal corrosion monitoring (i.e. coupons or probes)	☐	☐
4) Increase frequency of liquid sampling and analysis	☐	☐
5) Other Criteria Chosen: If yes, describe below:	☐	☐

____
____
____
____
____
____

Revision Log:

Date	Description	Revised By
4/7/06	4/7/2006 Version approved by management	LCO
11/17/08	Clarified more restricitive criteria for the first time application of ICDA to a line segment. Created four new forms to document more restrictive criteria for each of the four phases of the ICDA process.	ENE
11/17/08	Clarified and added further guidance for determining when ICDA is not applicable to a line segment.	ENE
11/17/08	Clarified and added further guidance for defining ICDA regions.	ENE
11/17/08	Modified and added further guidance for creating the pipeline elevation profile.	ENE
11/17/08	Clarified section on NACE flow modeling equations. Added information on GRI 02/0057 flow modeling equation.	ENE
11/17/08	Added guidance for reviwing the reassessment interval to ensure an interval lower than calculated is not necessary.	ENE
11/17/08	Cross-referenced to Section 13 “Continual Evaluation” for evaluating “like and similar” segments when internal corrosion is found.	ENE
11/17/08	Changed “OPS” to “PHMSA”	ENE
11/9/2009	Section 7B.2.4- Roles and Responsibilities- Updated responsibilities to better reflect company practices. Also, updated task responsibilities throughout this section to reflect company practices.	CMA
3/5/2009	7B.2.5- Contract personnel qualification inserted.	LCO
9/28/2010	Section 7B.3.4.3.8- Developed scenario to verify ERW pipe.	
11/14/11	To reflect the improvement of technology, update GPS requirements to use a minimum sub-meter accuracy equipment but recommend using sub-centimeter accuracy if available.	CMA
10/19/2012	Updated section 7B.3.8 to state that a pre-assessment meeting may be held. Also referenced GRI 02-0057 in Section 7B.3.5.1 for identification of DG-ICDA regions.	CMA

7C CONFIRMATORY DIRECT ASSESSMENT

In This Section

Referenced Protocols

7C CONFIRMATORY DIRECT ASSESSMENT

7C.1 Overview

7C.1.1 Purpose

As noted in Section 13, Confirmatory Direct Assessment (CDA) will be used for external and internal corrosion Threats of Concern (TOC) to extend the reassessment interval for other assessment options beyond **7 years** (e.g. for Direct Assessment, pressure testing, or ILI).

Note that although CDA specifically addresses external and internal corrosion, it satisfies the requirement of §192.939 regardless of whether additional threats have been identified for the HCA in question. The company's Confirmatory Direct Assessment (CDA) Plan meets the requirements of 49 CFR 192.931 (i.e., CDA), 192.925 (i.e., ECDA) and 192.927 (i.e., ICDA).

7C.1.2 Responsibility

The **Program Manager – Pipeline Integrity (PM) -** M1 shall be responsible for maintaining this procedure. Maintenance of this procedure includes periodic review and subsequent revisions as frequently as necessary to maintain the effectiveness thereof.

Pipeline Integrity Engineer (PIE) - F3 shall have the overall responsibility for implementation of this procedure.PIE is also responsible for data analysis or assisting other personnel with analysis of pre-assessment data and field generated inspection data. The PIE may also perform indirect inspections for which he or she is qualified.

The **Corrosion Supervisor (CS) -** M3 shall be available for providing technical guidance and assistance regarding the assessment process

The **Pipeline Specialist (PS) -** F5 shall be responsible for overseeing field operations. This includes coordination of operations between contractors, the company, and government agencies.

7C.2 Procedure

✓ ***Referenced Protocol:*** ***G.1 Confirmatory Direct Assessment, CDA***

7C.2.1 External Corrosion CDA

The methodology for performing a CDA is less restrictive than an ECDA. The methodology described in Section 7A – External Corrosion Direct Assessment will be followed with the following exceptions:

- Only one indirect examination tool suitable for the application is required instead of two complementary tools used for a full ECDA.

- All Immediate Condition indications must be excavated for each ECDA region.

- At least one high risk indication that meets criteria of Scheduled action must be excavated in each ECDA region.

The same documentation forms will be used for External Corrosion CDA as is normally used for ECDA. Refer to Section 7A (External Corrosion Direct Assessment) of this IMP.

7C.2.1.1 Prioritization of Excavations

The classification criteria (7A.4.10.4) for assessment criteria shall be integrated with prior assessments to classify the direct examination as Immediate, Scheduled, or Monitored excavation sites. This integration and prioritization shall be conducted using definitions in this subsection. Table 7C.1 can be used for quick reference.

Immediate action required (immediate)— This priority category should include indications that the pipeline operator considers as likely to have ongoing corrosion activity and that, when coupled with prior corrosion, pose an immediate threat to the pipeline under normal operating conditions.

- Multiple severe indications in close proximity shall be placed in this priority category.
- Isolated indications that are classified as severe by more than one indirect inspection tool at roughly the same location shall be placed in this priority category.
- For initial ECCDA applications, any location at which unresolved discrepancies have been noted between indirect inspection results shall be placed in this priority category.
- Consideration shall be given to placing other severe and moderate indirect inspection indications in this priority category, if significant prior corrosion is suspected at or near the indication.
- Indications for which the operator cannot determine the likelihood of ongoing corrosion activity should be placed in this priority category.

Scheduled action required (scheduled)—This priority category should include indications that the pipeline operator considers may have ongoing corrosion activity but that, when coupled with prior corrosion, do not pose an immediate threat to the pipeline under normal operating conditions.

- Severe indications that are not in close proximity to other severe indications and which were not placed in the immediate action required category shall be placed in this priority category.
- Consideration shall be given to placing moderate indications in this priority category if significant or moderate prior corrosion is likely at or near the indication.

Suitable for monitoring (monitored)—This priority category should include indications that the pipeline operator considers inactive or as having the lowest likelihood of ongoing or prior corrosion activity.

Table 7C.1: Prioritization of Direct Examination Sites

Immediate	Scheduled	Monitored
Severe indications in close proximity regardless of prior corrosion.	All remaining Severe indications	All Remaining indications
Individual Severe indications classified when using 2 or more IITools	All remaining Moderate indication is regions of Moderate prior corrosion	
Groups of Moderate indications in regions of Moderate prior corrosion	Groups of Minor indication in regions of Severe prior corrosion	
Any Moderate indication in regions of Severe prior corrosion		

7C.2.2 Internal Corrosion CDA:

The methodology for performing a CDA is less restrictive than an ICDA. The methodology described in Section 7B – Internal Corrosion Direct Assessment will be followed with the following exception:

- Only one high risk location in each ICDA region must be excavated.

The same documentation forms will be used for Internal Corrosion CDA as is normally used for ICDA. Refer to Section 7B (Internal Corrosion Direct Assessment) of this IMP.

7C.3 Response to Conditions Found During a CDA

If an Immediate Repair Condition is found during the CDA, the company must reduce the operating pressure in accordance with Section 10 of this IMP. The pressure reduction shall remain in place until repair has been performed. Repair must be performed within 365 days.

If, during the CDA, any Immediate Condition, One-Year, or Scheduled Conditions requiring repair prior to the next planned reassessment are found, then the **Pipeline Integrity Engineer F3** must reevaluate the reassessment interval. If the condition is determined to be due to a time-dependent threat, then the previously scheduled reassessment interval must be shortened to ensure that additional repair conditions will not affect the integrity of the pipe prior to reassessment.

The **Pipeline Integrity Engineer F3** provides written justification for why the reassessment interval has or has not changed in response to conditions found during the CDA. The **Program Manager- Pipeline Integrity M1** approves and retains this documentation.

Revision Log:

Date	Description	Revised By
10/19/2011	Prioritization of Excavation for ECCDA added.	CMA

8 BASELINE ASSESSMENT PLAN §192.921

In This Section

Referenced Protocols

8 BASELINE ASSESSMENT PLAN

8.1 OVERVIEW

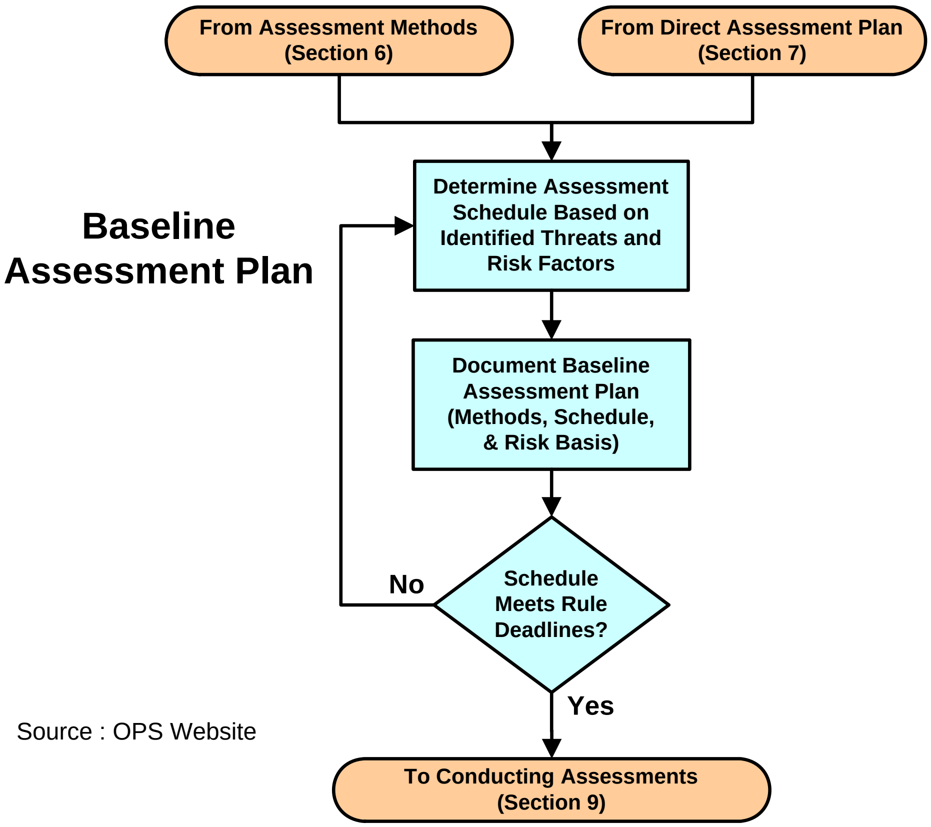


Figure 8-1: Baseline Assessment Plan Development -Process Sequencing

8.1.1 Purpose

The Baseline Assessment Plan section describes Louisville Gas & Electric/Kentucky Utilities' procedures to follow in establishing a baseline schedule for assessing covered pipeline segments that meets the requirements of the Integrity Management Rule. Associated procedures for revising this Baseline Assessment Plan (BAP) are also provided.

Note: In this section, and generally within this IMP, assessment means inspection (e.g., direct assessment, in-line inspection, and pressure testing). This term should not be confused with "Risk Assessment" that is an evaluation of risk factors (refer to Section 5.0). In addition, refer to the Assessment definition located in Section 6 and in Appendix A.

8.1.2 Responsibility

The **Program Manager – Integrity Management** M1 is responsible for generating, maintaining and updating the Baseline Assessment Plan as necessary. The **Program**

Manager – Integrity Management M1 may designate this responsibility to the **Pipeline Integrity Engineer** F3.

The **Pipeline Integrity Engineer** F3 is responsible for maintaining records of BAP revisions / updates as required by this section and Section 16 – Record Keeping.

Compliance Specialist F8 can also be responsible for maintaining records of BAP revisions / updates as required by this section and Section 16 – Record Keeping.

8.1.3 Requirements for Baseline Assessment Plan

To satisfy the requirements of 192.919 this plan provides the following:

a) Identification of potential threats to each covered segment and the information supporting the threat identification, incorporated by reference Section 4 of this written program.

b) The methods selected to assess the integrity of the line pipe, including an explanation of why the assessment method was selected to address the identified threats to each covered segment, incorporated by reference Section 6 of this written program.

c) A schedule for completing the integrity assessment of all covered segments, including risk factors considered in establishing the assessment schedule. Risk Assessment and Prioritization addressed in Section 5 of this written program, scheduling addressed within this section.

d) If applicable a direct assessment plan that meets referenced subpart O regulatory requirements. Direct assessment is incorporated by reference, Section 7 of this written program.

e) A procedure to ensure that the baseline assessment is being conducted in a manner that minimizes environmental and safety risks, incorporated by reference Section 11 of this written program.

8.1.4 General Procedural Steps and Sequencing

Figure 8-2 indicates the procedural steps to follow in developing and maintaining the Baseline Assessment Plan. As indicated in this figure, results from procedures in Sections 3.0 through Section 7.0 of this IMP are utilized in compiling the BAP. The following subsections describe the detailed requirements of compilation and maintaining the BAP.

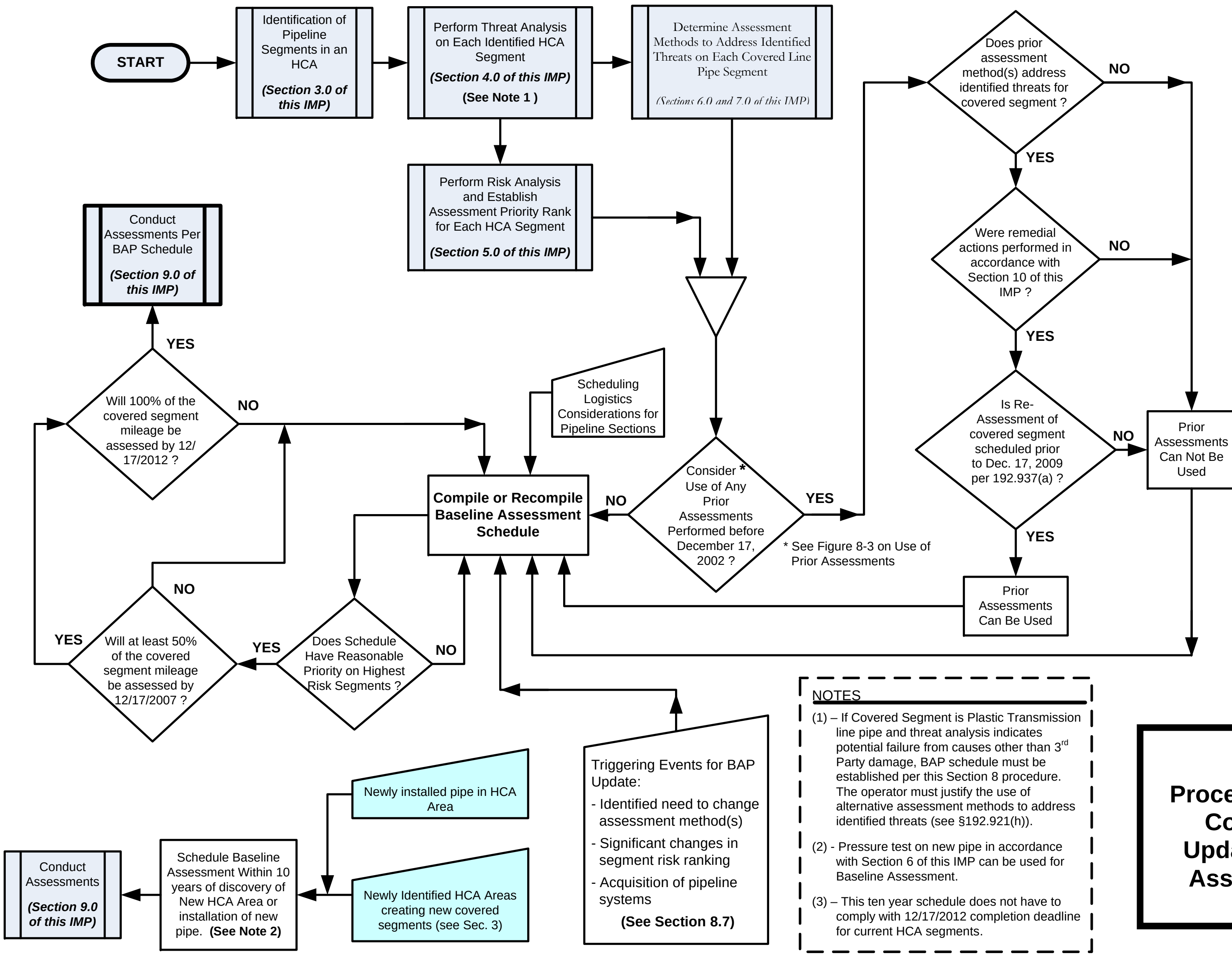


Figure 8-2

Procedural Steps for Compiling and Updating Baseline Assessment Plan

8.2 USE OF PRIOR ASSESSMENTS

✓ ***Referenced Protocol:*** ***B3: Use of Prior Assessments***

As indicated in Figure 8-2, §192.921(e) allows the use of assessments performed prior to **December 17, 2002** as part of the overall BAP.

The company has elected to not utilize assessments performed before **December 17, 2002** to satisfy the baseline assessment requirements, thus additional information on their use has been removed from this plan.

8.3 SELECTED ASSESSMENT METHODS

✓ ***Referenced Protocol:*** ***B1: Assessment Methods***

Section 6.0 of this IMP describes the processes followed in evaluating and selecting the appropriate inspection method for each covered pipeline segment. Detailed documentation of the results of these processes are produced on **Form 6-1**. The BAP schedule is completed using **Form 8-1**.

8.4 PRIORITIZED SCHEDULE FOR ASSESSMENTS

✓ ***Referenced Protocol:*** ***B2: Prioritized Schedule***

As required by 192.921(b), the company has prioritized its baseline assessment schedule based upon relative risk of covered pipeline segments. Section 5.0 of this written program describes the processes used to evaluate the relative risk for each covered segment. The weighted average risk score has been used as the basis for prioritization. Covered segments that are not on line pipe (except crossovers and bypass piping) have been identified as such on **Form 8-1**. These covered segments are not subject to the assessment requirements of Subpart O. They do still require compliance with the risk evaluation, preventative & mitigative measures, and other applicable provisions of Subpart O.

To the extent practical the baseline assessments shall be scheduled based upon relative risk ranking scores for the covered segments, such that the highest scores have priority over lower scores. However, in some cases there may be lower risk segments in the same pipeline vicinity as a high risk segment to be assessed. In such cases the baseline assessment schedule may be manually adjusted to give priority to lower risk segments in conjunction with assessment of one or more high risk covered segments when economics, system operation, and environmental impact are considered.

To be in compliance with 192.921(d) a minimum of 50% of the covered segment footage, beginning with the highest risk segments were assessed by December 17,

2007. Baseline assessment was completed for all covered segments footage by December 17, 2012, except where noted below.

Note:	HCAs created after the original issue date of the IMP need to be assessed within 10 years, which may be beyond the December 17, 2012 deadline.

8.5 ENVIRONMENTAL AND SAFETY CONSIDERATIONS

✓ ***Referenced Protocol:*** ***B.5 Consideration of Environmental and Safety Risks***

In accordance with §192.919(e), The company ensures that all assessments are conducted in a manner that minimizes environmental and safety risks. To aid in minimizing environmental and safety risks, The company developed procedures that are described in Section 11. These procedures consider the following factors:

- Operational conditions of the pipeline, including operating pressure
- Demographic conditions of the area being assessed
- Type of assessment to be performed
- Clean-up and waste disposal
- Worker protection

8.6 DOCUMENTATION OF THE PROCESS

The **Program Manager – Integrity Management** M1 is responsible for documentation of the BAP process. Documentation of the BAP process consists of the following:

- Database and results of risk analyses used in establishing BAP schedule priorities
- Database and results of assessment method selections for each HCA segment
- BAP schedule using the format guideline in **Form 8-1**

Changes to the BAP outside of the annual review are documented on BAP Revision Log **(Form 8-2)** that is discussed in **Subsection 8.7.**

8.7 CHANGES TO THE BASELINE ASSESSMENT PLAN

✓ ***Referenced Protocol:*** ***B.6 Changes***

8.7.1 Triggering Events for Updating Plan

Events that could trigger the need for updating the Baseline Assessment Plan include:

- Ongoing results with inspection methodologies indicates the need to modify or change the assessment method for future inspections.

- Identification of new threats to the integrity of a pipeline segment requires additional inspection methods for a covered line pipe segment.
- Identified changes in risk-ranking data (or risk analysis method) significantly changes the relative risk (and schedule priority) for pipeline segments that could affect an HCA.
- New or improved technologies are developed and proven to provide better evaluation of potential pipeline anomalies with equivalent cost structures.
- Acquisition of new pipeline systems.
- ***New HCA Areas are identified along an existing pipeline route.*** (See Subsection 3.7 of this IMP for evaluation procedures, including the use of **Form 3-1**). This event is specifically covered by §192.921(f) which requires incorporating new HCAs into the baseline assessment plan within 1 year and assessing line pipe within the newly identified area within 10 years of its discovery. (See Figure 8-2)
- ***Newly installed pipe is in an HCA Area.*** This event is specifically covered by §192.921(g) which requires baseline assessment of the newly-installed line pipe within 10 years of its installation. (See Section 8.73 and Figure 8-2). A pressure test performed in accordance with 192 Subpart J (see Section 6) can be used to satisfy this baseline assessment requirement.

> **Note:** New HCA segments created by the last two triggering events listed above (New HCA areas are identified and Newly-installed pipe in an HCA area) do not have to comply with the December 17, 2012 deadline for baseline assessment for existing HCA segments. The only requirement is that the baseline assessment must be completed within 10 years of identification. However, these assessments will be included in the overall **Company** BAP schedule for general tracking purposes.

8.7.2 Responsibilities, Schedule and Documentation

All levels of the company's organization are responsible for recognizing information that could result in a change to the BAP. Any triggering event for BAP change can occur from observations of IMP personnel that are directly communicated to the **Program Manager – Integrity Management** M1. Alternatively, these events can occur through the use of HCA Identification procedures in **Subsection 3.7.1** or the Management of Change (MOC) procedures in Section 14.

The **Program Manager – Integrity Management** M1 is responsible for reviewing requested changes to the Baseline Assessment Plan, determining a need for changes to the BAP, and for implementing those changes. All changes to the BAP will be recorded on the Baseline Assessment Plan Revision Log **(Form 8-2)** that will be maintained by the **Pipeline Integrity Engineer** F3. The Baseline Assessment Plan Revision Log is provided at the end of this Section for reference.

8.7.3 Periodic Review and Assessment

The Baseline Assessment Plan will be reviewed annually. This review will assure the following activities have taken place:

- The BAP is being kept up to date, including newly installed pipe in existing HCAs and newly identified HCAs
- The BAP change log has accurately and completely documented each change to the BAP
- Scheduled assessments are being performed on time

If newly installed pipe requires a change in an existing HCA, the newly defined HCA is required to be incorporated into the baseline assessment plan within 1 year and the line pipe assessed within 10 years of its discovery.

8.8 FORMS

Form 8-1: Baseline Assessment Plan
Form 8-2: Baseline Assessment Plan Revision Log

Form 8-1: Baseline Assessment Plan

Date: SAMPLE

HCA Identification Method - No. 2 (See TIMP Sec. 3.0)

Segment Information						HCA Stationing			HCA Information			
HCA Name (via IRAS)	Pipeline Name	Start Segment Number	End Segment Number	Start Segment ENOM Sys ID	Start Segment ENOM Sys ID	Map Distance begin HCA Station *(ft.)*	Map Distance end HCA Station *(ft.)*	HCA station length *(ft.)*	Earliest Date HCA Identified	Impact circle radius *(ft.)*	Buffer *(ft.)*	Impact Radius w/ buffer *(ft.)*
1	Example 1											
2	Example 2											
3	Example 3											
4	Example 4											

Total Ft	0
Total Miles	0.00
Total Baseline ft	0
Total Baseline Miles	0.00
Total Non-Baseline ft	0.00
Total Non-Baseline Miles	0.00

Risk Calculation Factors															
TAV Factors															
1- External	2- Internal	3-Stress Crossion Cracking	4- Defective Pipe Seam	5- Defective Pipe	6- Girth Weld	7- Defective Fabrication Weld	8- Wrinkle Bend or Buckle	9- Stripped threads/ Broke Pipe/ Coup Fail	10- Gasket/ Oring	11- Control/ Relief Equipment	12- Seal /Pump Packing Fail	13- Miscellaneous	14- Third Party Damage (Immediate)	15- Third Party Damage (Delayed)	16- Vandalism

						Index Factors				Threat & Consequence		Risk Information		Baseline Assessment Information			
17- Incorrect Operational Procedures	18- Cold Weather	19- Lightening	20- Heavy Rain or Flood	21- Earth Movement	22- Cyclic Fatigue	Age Index Factor	Stress Effect (SMYS) Index Factor	Interactive Threat Index	Preventative and Mitigative Measures Score	Total Threat Probability	Consequence	Total Risk (Probability x Consequence)	Weighted Risk Average (Total Risk / HCA length	Date Assessment Required	Date Assessment Complete	Assessment Method	Comments on Baseline Assessments

*Assessment History columns should be verified by the project engineer. They are NOT automatically populated. See comment concerning assessment interval in 2nd Assessment History

Future Assessment Planning					Future Assessment Planning		1st Assessment History (Baseline)				2nd Assessment History			
CDA			Full Reassessment											
Due Date	Planned Date	Completed Date	Due Date	Planned Date	Next Due Date and Reason	Planning Comments	Due Date	Completion Date	Method	Time Permitted to Next Full Assessment (Years)	Due Date	Completion Date	Method	Time Permitted to Next Full Assessment (Years)
#N/A			1900-01-00 - BASELINE DUE		1900-01-00 - BASELINE DUE									
#N/A			1900-01-00 - BASELINE DUE		1900-01-00 - BASELINE DUE									
#N/A			1900-01-00 - BASELINE DUE		1900-01-00 - BASELINE DUE									
#N/A			1900-01-00 - BASELINE DUE		1900-01-00 - BASELINE DUE									

3rd Assessment History				4th Assessment History				5th Assessment History			
Due Date	Completion Date	Method	Time Permitted to Next Full Assessment (Years)	Due Date	Completion Date	Method	Time Permitted to Next Full Assessment (Years)	Due Date	Completion Date	Method	Time Permitted to Next Full Assessment (Years)

SECTION 8
BASELINE ASSESSMENT PLAN

Form 8-2: Baseline Assessment Plan Revision Form

Previous BAP Date:
Revised BAP Date:

		Pipeline Description		Revisions							
				BAP DATA			HCA Length				
Rev. Date	Rev. Code	Segment Name	Segment Number	Previous Rank	Revised Rank		Previous	Revised	Change	Description of Revision	Revision By – Initials

Revision Codes

1. – Change in Risk Ranking and/or Assessment Schedule
2. – Change in Assessment Method
3. – Addition of New Pipelines
4.- Change in length
5- Change in segment numbering
6- New HCA
7- Removed HCA
8- Pipeline Classification Change
9- GIS landbase data changes
10- Other (Describe in comments)
11- GIS landbase geometry changes
12- Addition of new building/IDS
13- HCAs Combined/Merged
14- Addition of pipeline to GIS
15- GIS geometry revisions
16- GIS data revisions

Attachment to Response to AG Q252
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Bellar

Revision Log:

Date	Description	Revised By
12/14/2004	Section 8 Approved by Management	CMA
10/05/2005	Revised formatting to match other IMP Sections (Approved Track Changes)	CMA
02/01/2007	Inserted revised version of Form 8-1	CMA
02/01/2007	Deleted 'LG&E Energy' logo and Replaced it with 'LG&E/E.ON|US' Logo	CMA
7/20/2007	Reclassified Table 8-1 to Form 8-1: Baseline Assessment Form. Renamed Form 8-1: Baseline Assessment Plan Revision Form to Form 8-2: Baseline Assessment Plan Revision Form Removed Table 1 from Section. Revised verbage to reference file 2007_06_14_BAP_2007 for current BAP	CMA
10/13/2008	Removed references to LG&E Energy and replaced with appropriate company name Removed statement "See Appendix 8-A for current baseline Schedule" Sample of updated Forms 8-1 & 8-2 inserted	CMA
10/13/2008	Section 8 Approved by Management v. Section 8 Baseline Assessment Plan FINAL_2008_10_13	CMA
11/25/2009	Added a column to the BAP for "Creation Date" of an HCA. Corrected form reference in CDA and Reassessment columns in Assessment Plan Form. Aligned the Roles and Responsibilities with Section 2.	CMA
12/16/2012	Corrected references to Table 8-1 to Form 8-1. Note that a column for HCA Category was added to Form 8-1.	JRG
11/14/2013	Major revision to Form 8-1 to better incorporate post-baseline assessment tracking, IRAS risk output, etc.	WJN
10/27/2015	Included clarification of the line pipe assessment requirement	WJN

9	CONDUCTING ASSESSMENTS §192.921(a)

In This Section

Referenced Protocols

9 CONDUCTING ASSESSMENTS

9.1 OVERVIEW

✓ *Referenced Protocol:* *BO.1 Assessment Methods*

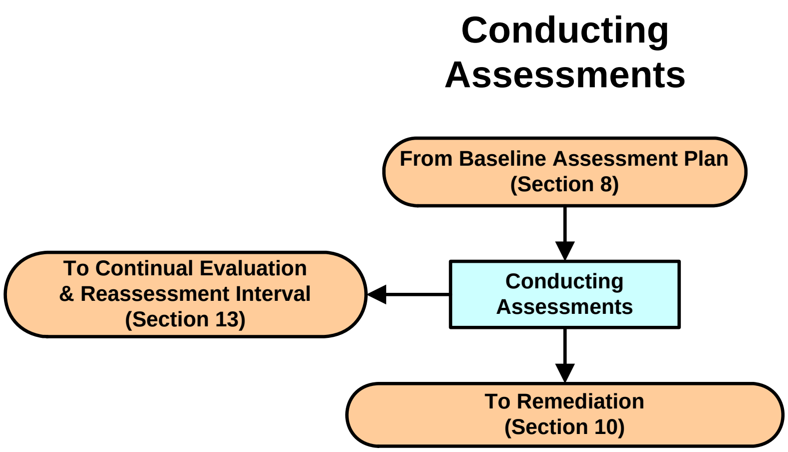


Figure 9-1: General Process Flow Diagram

§192.921(a)	***(a) Assessment methods.*** An Operator must assess the integrity of the line pipe in each covered segment by applying one or more of the following methods depending on the threats to which the covered segment is susceptible. An operator must select the method or methods best suited to address the threats identified to the covered segment.

9.1.1 Purpose

The Conducting Assessments section discusses Louisville Gas & Electric/Kentucky Utilities (the company) requirements to perform the assessments specified in the baseline assessment plan. **The company** has provided the procedures and guidance to be used when performing these integrity assessments.

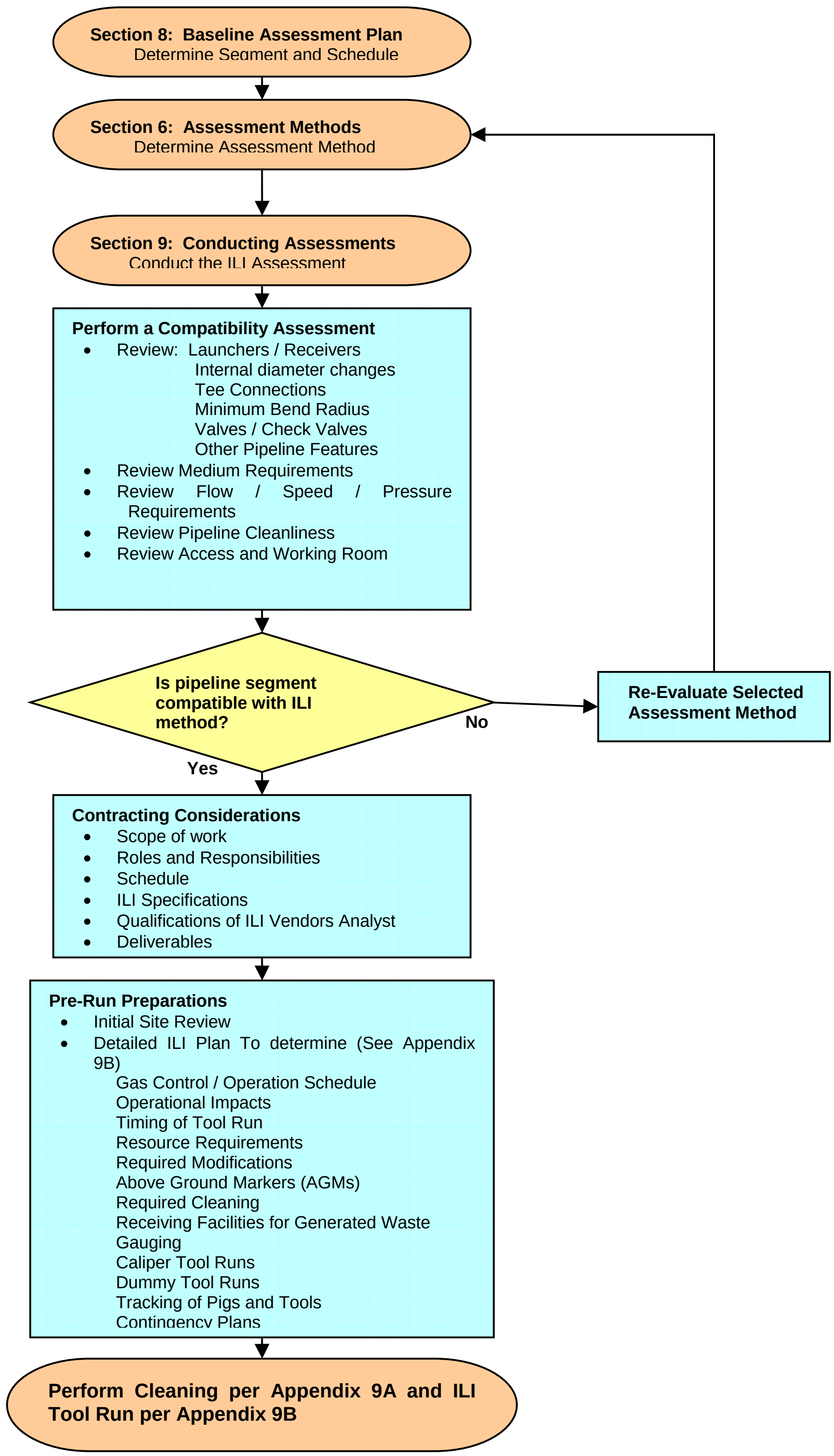
9.1.2 Responsibility

The **Manager – Operations** F1 is responsible ensuring the key personnel described in Section 2 – Roles and Responsibilities, perform their assigned duties as described. The **Program Manager –Integrity Management** M1 has the specific responsibility of managing the pipeline assessments; the **Pipeline Specialist** F5 has the specific responsibility of providing direct oversight of the pipeline assessments.

9.2 IN-LINE INSPECTION (ILI)

When an In-Line Inspection (ILI) assessment method is specified in **the company's** baseline assessment plan, The company will use the ILI Assessment Procedure shown in Figure 9-2.

Figure 9-2: ILI Assessment Procedure



9.2.1 Performing the Compatibility Assessment

Conducting a compatibility assessment is a critical first step in preparing to perform an ILI inspection. **The company** a questionnaire provided by the tool vendor, to facilitate and document the compatibility assessment.

The following are some of the items that should be considered when performing the compatibility assessment on the pipeline.

- Work Space — Review available work space for crane or lifting equipment, ancillary equipment
- Launchers / Receivers: — Review overall length, reducers, valve orientation, isolation capability
- Kicker line sizing — Review kicker line sizing to ensure sufficient to propel the tool
- Pig signals — Review location of pig signals at isolation valves to confirm launch
- Valves: — Review mainline valves - full opening vs. reduced port
- Check Valves: — Review overall length, clamper type - lockable, clamper length vs. ILI tool cups
- Minimum Radius Bends: — Review minimum radius bends, fittings, and the length of straight pipe between bends
- Tee Connections: — Review size and type of tee – barred tee vs. open tee
- Internal Diameter Changes: — Review pipeline wall thickness (WT) changes versus ILI tool tolerances
- Pipeline Probes — Ensure all pipeline probes can be removed
- Other Pipeline Features — Review hot taps, drips, stopples, or any other feature that may affect the ILI run

Upon completing the compatibility assessment, **the company** will review the information with the proposed ILI tool vendor to determine if the proposed ILI tool is compatible with the pipeline segment. If the requirements of the ILI tool are compatible with the pipeline segment, **the company** will continue the project as originally planned.

If the requirements of the ILI tool are not compatible with the pipeline segment, **the company** will determine if any modifications or alterations to the segment are feasible and economically justified to ensure compatibility. If these modifications are not justified, **the company** will review other appropriate assessment methods which may be available in Section 6 – Assessment Methods and/or Section 7 – Direct Assessment.

9.2.2 Contracting Considerations

When an appropriate and compatible ILI tool has been selected for the pipeline segment to be assessed, **the company** will begin the necessary contracting considerations. **The company** will specify the scope of work, schedule, specifications, and deliverables for the project. This process is intended to clearly define the roles and responsibilities of **the company** and the vendor from the inception of the project to the final report.

The process should address such items as resource requirements, specific responsibilities, stages of reporting, milestones, payment schedules, implications of reruns, scheduling changes, standby/downtime charges, demurrage charges, and service interruptions. Since most ILI tools are fully committed several months in advance, the demurrage charges associated with a tool getting lodged in the pipeline can be substantial. In addition, the process should address potential liability issues such as tool damage, tool replacement, and incidental damage versus material damage.

The scope of work should be defined well in advance of any pricing discussions or contracting. The scope should address all aspects of the work including:

- Project Specifications
- Roles and Responsibilities (including transporting of the tool, loading of the tool, cleaning of the segment, placing of AGM's, tracking of the tool, and removing of the tool)
- Resources (Equipment and Manpower)
- Quality Assurance (e.g. tool calibration, certificates, data integrity checks, procedures, qualifications and training of grading personnel)
- Deliverables – Specified in **the company's** specification (e.g. corrosion sizing, shape, detection limits, confidence level, data format, data medium, graded anomalies, preliminary report, final report)
- Any Impacts the Deliverables may have on performing the Data Analysis

When contracting for ILI tool runs, **the company** will provide the ILI Tool vendor with the appropriate **company** or equivalent specifications.

- Geometry Inspection Tool Specification
- Magnetic Flux Leakage (MFL) In-Line Inspection Tool Specification
- Ultrasonic Inspection Tool Specification

9.2.3 Pre-Run Preparations

Detailed planning is extremely important in preparing for an ILI tool run since any delay in the schedule can be very costly. The following pre-run preparations should be performed to ensure a successful ILI tool run:

Request for Shutdown or Operation

A Request for Shutdown or Operation (RSO) shall be prepared, distributed, and approved prior to performing an ILI run, or associated operations that will require a shutdown or deviation from normal pipeline operations. The RSO may be initiated by Pipeline Integrity, SR&O, or other concerned operating entity and shall be subject to approval by Gas Control, RSO, Gas Storage, Gas Distribution, Pipeline Integrity, and other concerned operating entities in accordance with standard operating procedures.

Gas Control

Coordinate with the appropriate company gas control center frequently to assure optimal operating conditions during the ILI tool run. The gas control center should be notified as soon as practical of any schedule changes.

When referenced within this text, gas control means the operating entity within the company that is normally responsible for controlling the flow of gas through the pipeline segments under consideration.

Operational Impacts

Determine the operational impacts of creating an optimal ILI tool run. Determine the impacts to schedules, number of running units, personnel, etc.

Tool Run Schedule

Coordinate with Gas Control, Operations, Maintenance, Contractors, ILI vendor, and other affected parties to establish a detailed and workable schedule. Some of the key activities that should be considered include:

- An assessment of the pipeline’s condition from Subject Matter Experts
- Determination of whether cleaning will be required, and to what degree
- Identification of restrictive bends, fittings, valves or other features which may impair the passage of the tool
- Determination of any modifications needed to perform the tool run
- Determination of whether a caliper tool will be run
- Determination of right-of-way access and landowner permissions
- Establishing above ground markers (AGMs) as reference points
- Determination of the ILI tool availability and committed schedule

- Determination of ILI vendor timing for data review / analysis, preliminary report, final report, and other deliverables
- Determination of a procedure or protocol specific to the vendor's tool
- Scheduling of the dummy tool run
- Determination of how the pigs / tools will be tracked and the amount of resources required
- Development of a contingency plan

Resource Requirements

The resource requirements will be determined from the planning of a detailed schedule. The amount of personnel required will be determined by time and duration of each run, which is also a function of the tool speed and the pipeline segment length. Other factors affecting manpower requirements include the number of cleaning runs, if a caliper pig is run, dummy pig run, specific tool run procedures, establishing AGMs, tool tracking requirements, and environmental and safety requirements. Multiple shifts may be required to address certain aspects of the schedule.

Other resource requirements include the determination of the required equipment at the required locations. Access to heavy equipment such as cranes may be required at launcher and receiver sites.

Right of Way Access / Permits

Any required right-of-way access or permits should be determined during the detailed planning of the ILI tool run. Landowner permissions may be required during the placement of AGMs tool tracking, and potentially launching and receiving operations. **The company** will utilize right-of-way agents to assure the proper right-of-way access has been secured. Access will also be considered later during verification digs and anomaly repairs.

Setting Above Ground Markers (AGMs)

The company will use GPS units whenever practical to establish AGM benchmark locations along the pipeline segment. Readily identifiable permanent appurtenances such as mainline valves are also used as benchmarks. The AGM benchmarks become reference points along the pipeline which are used to correct for measured distance inaccuracies caused by odometer wheel slippage and significant changes in topographic elevations. The closer the AGM spacing, the more accurate the location definition will be.

Pig / Tool Tracking

Personnel trained in the use of pig-tracking equipment and capable of performing tracking calculations will be available to track the various pigs and ILI tool. As the pig passes a reference point, the team jumps ahead several reference points and associated teams to ensure they are in place for the next passing. The pipeline operations control center will be updated at regular intervals as the pig passes various reference points along the pipeline.

Pipeline Cleaning:

Should pipeline cleaning be required prior to the ILI tool run, a specific cleaning plan should be established in consultation with the ILI tool vendor and in accordance with Appendix 9A. Depending upon the condition of the pipeline several progressive cleaning runs may be performed. The pipeline cleaning should be completed prior to a caliper tool or dummy tool run.

Caliper / Geometry Tool

A caliper / geometry tool (also called a deformation tool) is typically run in the pipeline segment prior to a metal loss ILI tool to determine if there are any significant restrictions in the bore and to evaluate the bend radii.

Dummy Tool Run

A dummy tool of similar weight and size may be run prior to a live inspection run to mimic the characteristics of the live tool. The purpose of the dummy tool run is to assure the live tool will be able to successfully traverse the pipeline.

9.2.4 Performing the ILI Tool Run

The ILI Tool Run will be conducted in accordance with a detailed plan as described in Appendix 9-B and ILI vendor protocols.

All pre-run preparations should be checked and verified to be complete prior to the ILI vendor arriving on site with the live tool.

Prior to beginning any work, **the company** will hold a safety meeting to orientate all personnel to the hazards of the work and appropriate **company** safety procedures. **Company** and ILI vendor representatives will review each step of the work with the affected personnel.

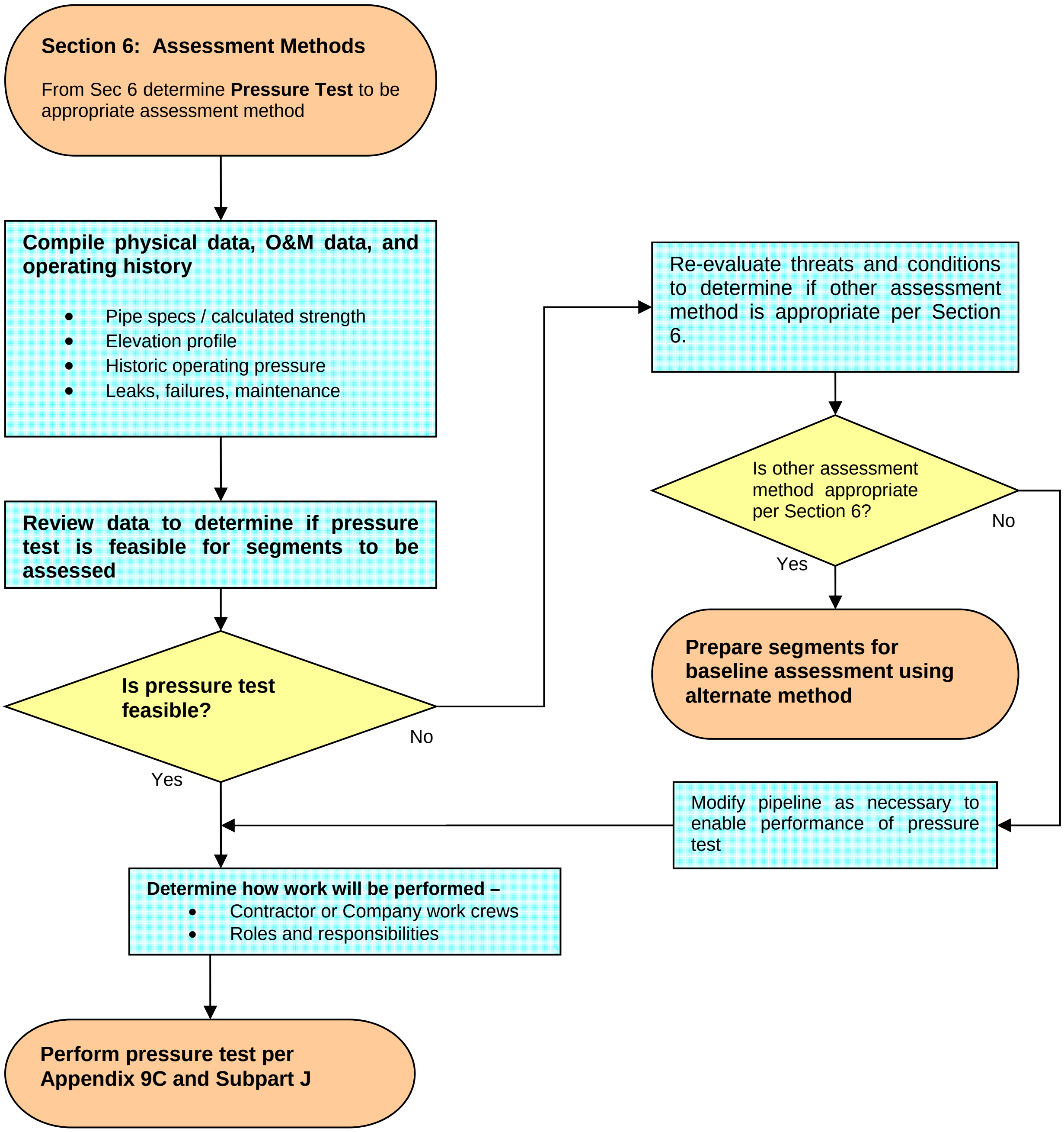
When the orientations have been completed, a **company** representative will contact the appropriate gas control center and notify them they are ready to begin. The ILI tool is then loaded into the launcher, and the gas control is contacted when the crew is ready to launch. As the ILI tool is launched, the time is logged at the gas control center and relayed to those tracking the tool.

When the ILI tool run is complete, the ILI tool is removed from the receiver and inspected by the ILI vendor and **company** personnel for damage. Photographs may be taken to document the condition. A field playback unit may produce an initial printout of the tool run record. Depending upon the contract terms and conditions, preliminary inspection indications may be reviewed within 24 hours. The preliminary report and final report will come later as specified in the contract.

9.3 PRESSURE TEST (SUBPART J)

When a Pressure Test assessment method is specified in **the company's** baseline assessment plan, **the company** will use the process shown in Figure 9-3 along with the Pressure Test Procedure Appendix 9C.

Figure 9-3: Pressure Test Process



9.3.1 Equipment and Materials

When preparing to perform a hydrostatic test, the following equipment and materials should be considered as part of the planning process.

- High Volume Pump
- Water Supply Line Filter
- Injection Pump–Corrosion Inhibitors, Dye
- Meter to Measure Linefill
- Variable Speed Positive Displacement Pump w/ Known Volume per Stroke
- Relief Valve
- Water Source – For Repressuring
- Deadweight Tester
- Pressure Chart Recorder
- Temperature Chart Recorder
- Pressure Gauge / Display
- Temperature Gauge / Display
- Outdoor Thermometer – Ambient Temp
- Shelter to Protect the Recording Equip
- Hydrostatic test manifolds
- Communications Equipment
- Equipment to isolate line segments
- Replacement Pipe
- Equipment to Dewater the Line Segment

Should **the company** use a third party to perform the pressure test, many of these items will be provided by the contractor. The roles and responsibilities of **the company** and Contractor should be clearly defined in the early planning stages.

9.3.2 Project Plan

Company will also consider the following items when preparing the overall Project Plan.

- MAOP anticipated in the future
- Pressure-Volume chart to prevent yielding of the pipe when near SMYS
- List of components & the component that controls the maximum pressure
- Time needed for the test water to stabilize to the ground temperature
- Safety & Environmental Considerations
- Provisions to sample the water quality prior to filling, before discharge, and during discharge
- Requirements for water discharge
- Notifications to landowners or local authorities
- Profile and alignment sheet drawings
- Contingency planning for failures
- Methods for preserving failed specimens of pipe
- Materials available to assist in leak detection

9.3.3 Line Preparation

To minimize the cost of test water disposal and minimize the potential environmental impact in case of a failure the segments to be tested should be thoroughly cleaned per Appendix 9A prior to hydrostatic testing.

9.3.4 Pressure Test Procedure (Subpart J)

The pressure test will be conducted in accordance with **the company's** pressure test procedure Appendix 9C.

9.3.5 Worksheets and Documentation

Pressure testing shall be documented as describe within Appendix 9C**.**

9.4 DIRECT ASSESSMENT

When Direct Assessment is specified as the assessment method in **the company's** baseline assessment plan, **the company** will use the process described in its overall Direct Assessment Plan listed in Section 7 of this IMP.

9.5 OTHER TECHNOLOGY

Other assessment technologies may also be considered provided **the company** can demonstrate that the technology provides an equivalent level of understanding when evaluating the integrity of the pipeline segment. **The company will** notify the Office of Pipeline Safety (OPS) 180 days prior to conducting this assessment (§192.921, §192.949). In addition, **the company** will notify Kentucky Public Service Commission (KYPSC) and/or the Indiana Utility Regulator Commission (IURC). (Refer to Section 19 – Communication Plan).

9.6 ENVIRONMENTAL AND SAFETY RISKS

The company will utilize the processes and procedures located in Section 11 to minimize environmental and safety risks while performing work on the pipeline right-of-way.

Revision Log:

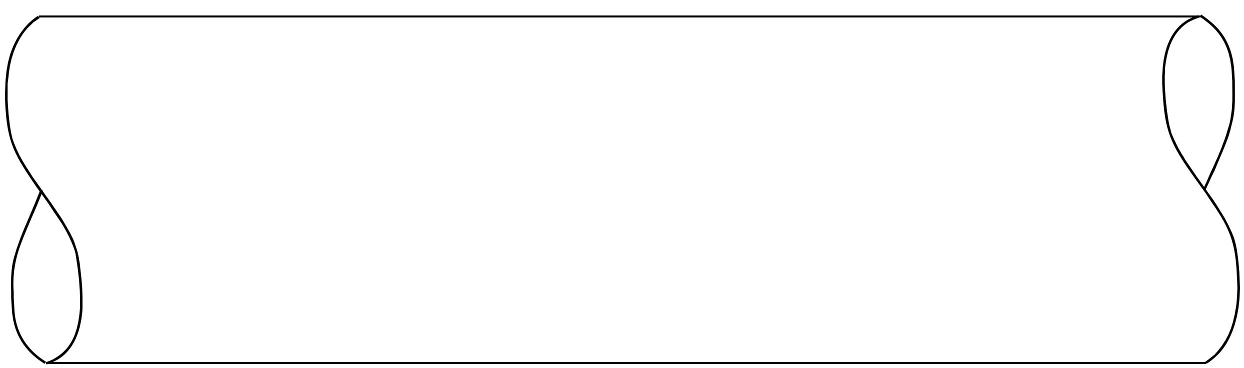
Date	Description	Revised By
01/15/2008	Section 9 Approved by Management (Appendices 9A, B, C added on 9/24/2007)	LCO
01/20/2009	Detailed procedures in appendices for Pipeline Long Range Ultrasonic Testing (Appendix 9D)	RNE
3/18/2009	Section 9 Routed to Management (Appendix 9D added on 1/20/2009)	MLS
7/30/2009	Section 9 Approved by Management (Appendix 9D added on 1/20/2009)	MLS
6/25/2009	Form 9.B.4 – MFL Tool Comparison With Typical Specifications added to 9B	MLS
8/31/2009	Sentence added to 9B.4.1.4 to describe Form 9.B.4	MLS
6/18/2010	Annual review form routed	JRG
9/12/2011	Title changes in responsibilities section	MLS
9/12/2011	Logo changes	MLS
9/12/2011	Annual review form routed in SharePoint	MLS
11/20/12	Added reference to Form 9-2 in section 9.5	WJN
12/15/2015	Minor clerical changes.	JRG
12/17/2015	Deleted Forms 9-1 and 9-2, Added appendixes to replace the forms.	EJB/JRG
11/09/2016	Replaced Form 9B-3 with new version	JRW
11/18/2016	Clarified appendix references for forms 9A-1, 9B-1, and 9C-1	JRW

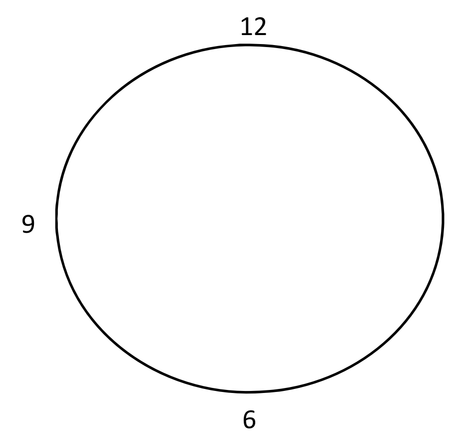
LG&E a PPL company	**Direct Examination Form**	MOC Reference #:		Project Name:		Page # of
		Project #:	Task #:	Drawing #:		Work Order #:
		Location and Project Description:				

Instructions: Use this data sheet to document examinations of material in the high pressure gas system and the condition of any dicovered anomalies (coating holidays, disbondment, 3rd party damage, corrosion, extra metal, exposures, manufacturing defects, etc.).

1. Type or purpose of this direct examination:	
2. Direct examination start Date:	
3. Direct examinatino completion date:	
4. Cathodic Protection?:	If yes, CP Type:
Pipe (Positive Lead) to Soil (Negative Lead) Potential	
Read: ____________	Units (mV or V): ________
Part Tested:	
5. Main # of material being inspected:	
6. Coating type:	
7. Coating condition (disbondment, holidays, etc.):	
8. Internal corrosion found?:	
9. External corrosion found?:	
10. Soil Sample Collected?	
11. Pipe Depth:	Excavation Size:
Length of Pipe Exposed:	

Remarks: ______________________________





Employee Signature:	Printed Name:	Employee ID:	Date:

a PPL company

Direct Examination High Pressure Gas Data Sheet	MOC Reference #:
Project Name:	Page # of
Project #:	Task #:
Drawing #:	Work Order #:
Location and Project Description:	

Instructions: Use this data sheet to document the location of direct examinations and the dispostion of any discovered anomalies. Use roads, property lines, rail roads, waterways, and other similar features as references.

					GPS Coordinates for Item or Feature		
Item or Feature	Distance North/South	of Reference	Distance East/West	of Reference	Lat (North)	Long (West)	Accuracy

Employee Signature:	Printed Name:	Employee ID:	Date:

Appendix 9A-1: Gas Transmission Pipeline Cleaning Field Performance Work Plan (Outline)

Part 1 – Project Information:

1.1 Project name:

1.2 Estimated start date:

1.3 Geographic description:

1.4 Reason for cleaning:

Part 2 – Administrative:

2.1 RSO reference (Request for Shutdown or Operation):

Submitted by: Date:

2.2 Cleaning operation to be performed by: (Company or name of contractor)

2.3 Key personnel (schedule of key personnel including role, employee numbers, contractor affiliation, etc.):

Part 3 – Physical Data:

3.1 Launch site location:

3.2 Propulsion medium:

3.3 Launch site features (schedule of major equipment):

3.4 Drawing or schematic attached (yes or no):

3.5 Receiver site location:

3.6 Receiver site features (schedule of major equipment):

3.7 Drawing or schematic attached (yes or no):

Part 4 – Cleaning Operations:

4.1 General description of process:

4.2 Pig pass / cleaning operation sequence (if applicable, schedule showing pig type, estimated pressure, estimated flow, minimum passes, etc.)

4.3 Acceptance criteria (description of qualitative or quantitative criteria for intermediate and final passes):

Part 5 – Waste Product Removal and Disposal

5.1 Description of waste product removal and disposal plan:

Part 6 – Cleaning Record (completed during and after cleaning)

6.1 Major Operations (schedule of start & finish date/time of any major operations, as well as observed pressure):

6.2 Pipeline length, vent elevations and alignment concerns (for purposes of calculating lost gas during blowdown):

6.3 Listing of Key Personnel involved in the cleaning:

6.4 General description of operations, results, and any problems encountered (including any other information deemed useful):

Part 7 – Signatures

7.1 Writer of report (name, employee number, position per Section 2 of Plan, signature, date):

7.2 Approved and accepted (name, employee number, position per Section 2 of Plan, signature, date):

Appendix 9B-1: Gas Transmission Pipeline Field Performance Work Plan

Part 1 – Project Information:

1.1 **Project name:**

1.2 **Estimated start date:**

1.3 **Geographic description:**

1.4 **Reason for Inspection:**

Part 2 – Administrative:

2.1 **RSO Submitted by:** **Date**

2.2 **Cleaning operation to be performed by:**

2.3 **Key personnel (schedule of key personnel including role, employee numbers, contractor affiliation, etc.):**

LG&E Personnel		
Name	**EMP Number**	**Role Per TIMP Section 2**

Part 3 – Physical Data:

3.1 **Launch site location:**

3.2 **Propulsion medium:**

3.3 **Launch site features (schedule of major equipment):**

3.4 **Drawing or schematic attached (yes or no):**

3.5 **Receiver site location:**

3.6 **Receiver site features (schedule of major equipment):**

3.7 **Drawing or schematic attached (yes or no):**

Part 4 – Pigging Operations:

4.1 **General description of process:**

4.2 **Pig pass / cleaning operation sequence (if applicable, schedule showing pig type, estimated pressure, estimated flow, minimum passes, etc.)**

4.3 Acceptance criteria (description of qualitative or quantitative criteria for intermediate and final passes):

Part 5 – Threats Addressed

5.1 Possible Risks Assessed

Part 6 – Waste Product Removal and Disposal

6.1 Description of waste product removal and disposal plan:

Part 7 – Pigging Record (completed during and after cleaning)

7.1 Major Operations (schedule of start & finish date/time of any major operations, as well as observed pressure):

7.2 Pipeline length, vent elevations and alignment concerns (for purposes of calculating lost gas during blowdown):

7.3 Listing of Key Personnel involved in the cleaning:

LG&E Personnel		
Name	EMP Number	Role Per TIMP Section 2

7.4 General description of operations, results, and any problems encountered (including any other information deemed useful):

Part 8 – Post Assessment

Part 8 – Signatures

7.1 Writer of report (name, employee number, position per Section 2 of Plan, signature, date):

7.2 Approved and accepted (name, employee number, position per Section 2 of Plan, signature, date):

Appendix 9C-1 – Gas Transmission Pipeline Pressure Test Field Performance Work Plan (Outline)

Part 1 – Project Information

1.1 Project name:
1.2 Estimated start date:
1.3 Geographic description:
1.4 Purpose / objective for testing: (PI – baseline assessment, reassessment – include original date, other)
1.5 Threats to be addressed:

Part 2 – Administrative

2.1 RSO reference (Request for Shutdown or Operation) : Submitted by:
Date:
2.2 Cleaning operation to be performed by: (Company or name of contractor)
2.3 Pressure testing to be performed by: (Company or name of contractor)
2.4 Key personnel (schedule of key personnel including role, employee numbers, contractor affiliation, etc.):

Part 3 – Physical Data:

3.1 Locations of end points:
3.2 Locations and functions of operational points:
3.3 Attach Schedule of pipe segments. Include length, diameter, wall thickness, specification , grade, seam type, calculated pressure to produce 100%SMYS, elevation for hydrostatic test, test pressure at lowest elevation, test pressure %SMYS, and volume in cubic feet or gallons as applicable. Include total volume.
3.4 Schedule of equipment and instruments including locations.
3.5 Attach drawings or schematics as necessary to clarify geographic scope, temporary piping configurations, etc.

Part 4 – Pressure Testing Operations:

4.1 General description of process:
4.2 Schedule of pressure plateaus and time durations as applicable

Part 5 – Waste Product Removal and Disposal

5.1 Description of waste product removal and disposal plan:

Part 6 – Signatures

6.1 Writer of report (name, employee number, position per Section 2 of Plan, signature, date):
6.2 Approved and accepted (name, employee number, position per Section 2 of Plan, signature, date):

9A PIPELINE CLEANING PROCEDURE

In This Appendix

9A.1 PURPOSE

The purpose of this procedure is to provide direction for internal cleaning of pipelines in preparation for in-line inspection by means of geometry pigs, magnetic flux leakage pigs, or other instrumented pigs, or in preparation for hydrostatic pressure testing as a baseline assessment tool.

9A.2 INTRODUCTION

9A.2.1 Scope

- This procedure covers internal cleaning of gas transmission pipelines owned and operated by LG&E or KU.
- This procedure is intended for use on pipelines that have been in service. It is not intended to address cleaning of newly constructed pipelines prior to pressure testing or initial operation.
- LG&E meets or exceeds the minimum requirements in-line inspection of gas transmission pipelines as prescribed in US Department of Transportation (DOT) regulations 49 CFR Part 192 Subpart O.

9A.2.2 References

9A.2.2.1 Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subpart O

9A.2.2.2 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-AI-001, "Prevention of Accidental Ignition".

9A.2.2.3 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-PU-001, "Purging Operations."

9A.2.2.4 LG&E Gas Approved Operating Procedure, GAOP-PO-001, "Hazardous Energy Control – Lockout / Tagout Procedure."

9A.2.3 Responsibilities

9A.2.3.1 Gas Regulatory Compliance – Pipeline Integrity Management Section

The Program Manager – Pipeline Integrity - M1 shall be responsible for maintaining this procedure. Maintenance of this procedure includes periodic review and subsequent revisions as frequently as necessary to maintain the effectiveness thereof.

Program Manager - Integrity Management, M1 shall have the overall responsibility for implementation of this procedure when it is used in preparation for internal inspection or hydrostatic pressure testing of a gas transmission pipeline as a part of the company's pipeline integrity management program. This responsibility includes approval of the cleaning method selected and specified acceptance criterion to assure that the cleanliness level achieved is appropriate for the inspection or testing method to be performed.

The Pipeline Specialist - F5 shall be responsible for overseeing field operations. This includes coordination of operations between contractors, the company, and government agencies.

9A.2.3.2 Gas Storage and Control

Gas Storage and Control shall be responsible for the operation of gas transmission pipelines throughout the commencement of cleaning and inspection procedures.

9A.3 DISCUSSION

9A.3.1 Regulatory Requirements

Federal and state gas pipeline safety regulations do not directly address gas pipeline cleaning. It is therefore the responsibility of each operator to adopt procedures that are effective and safe, and to operate each pipeline in accordance with the requirements of all applicable federal and state regulations while performing cleaning operations.

9A.3.2 Design and Installation of Temporary Piping

All temporary piping used for pigging operations shall be designed, tested, and installed in accordance with the requirements of 49 CFR Part 192. Instrument lines, hoses, and other components not specifically addressed in Part 192 shall be designed to safely operate under the pressure and conditions to which they will be subjected.

Pressure vessels shall be designed and tested to safely operate under the maximum pressure to which they may be subjected. Frac tanks or other vessels intended to operate at atmospheric pressure must be adequately vented or otherwise protected against over pressure.

9A.3.3 Environmental Protection

All environmental protection regulations, including LG&E and KU internal procedures must be met when performing pipeline cleaning. Extreme care must be exercised to collect all liquid and solid materials removed from each pipeline. Waste materials shall be sampled and analyzed to determine proper disposal method.

9A.3.4 Cleaning Methods and Procedures

There are various general procedures that have been proven by experience to effectively clean pipelines. Parameters effecting selection of a procedure include composition and quantity of contaminants within the pipeline, operational restraints, environmental restraints, and cost.

In many cases the vendor that will be performing an internal inspection will recommend a particular process based upon experience. It shall be the responsibility of the **Program Manager - Integrity Management,** M1 to review available options and to approve the selected procedure.

9A.3.5 Pipeline Geometry

It is important to know as know as much as possible about the physical geometry of any pipeline to be pigged. Location of such features beforehand can prevent costly delays and minimize down time for the pipeline to be pigged.

9A.3.6 Unpiggable Pipe Segments

Pipe segments that are being prepared for hydrostatic testing but are unpiggable will require alternative cleaning and preparation methods to be considered. The Pipeline Integrity Engineer F3 may coordinate with the Engineer – Gas Storage F2 and Corrosion Supervisor M3 to review available options and approve the selected procedure.

9A.3.7 Worksite Requirements

9A.3.7.1 Launch Site Access

The launch site must be accessible to construction equipment and lifting equipment needed to install and remove the launcher and needed to place pigs in the launcher. Instrumented smart pigs used for in-line inspection are typically longer and heavier than pigs that are used for cleaning operations.

9A.3.7.2 Propulsion Medium

If natural gas is to be used for propulsion of the pigs, there must be sufficient working room to install temporary valves and piping for that purpose. If air or liquid is to be used, there must be a suitable location for air compressors or pumps and liquid supply tanks of sufficient capacity to provide the volume and pressure needed.

9A.3.7.3 Receiving Site Access

The receiving site must be accessible to construction equipment and lifting equipment needed to install and remove the receiver and gas separating and filtering equipment, as well as liquid recovery tanks if wet cleaning is to be used. Additionally, pigs will have to be handled and removed from the site.

9A.3.7.4 Gas, Liquid, and Solids Recovery

If a liquid or gel cleaning process is to be used considerable space will be needed for liquid recovery vessels.

If gas is to be used as the propulsion medium for a dry cleaning process one or more filter–separator vessels will be incorporated in the temporary piping to clean the gas for reentry into a gas pipeline system.

Pipeline liquids, solids, and slurries are likely to be removed in a dry cleaning process and must be captured and returned for safe and proper disposal. Iron sulfide, a black powder present in certain storage field lines, is pyrophoric (may ignite spontaneously in air) and must be handled and transported appropriately to a safe disposal site. Iron sulfide is generally incinerated for disposal.

9A.3.7.5 Gas Blow Down

Any time gas is to be used as propulsion medium there will be a need to blow down the launcher and receiver each time a pig is inserted and removed. Blow down piping must be vented in a manner that does not create a potential hazard to workers, the public, or adjacent property.

9A.4 PROCEDURE

9A.4.1 Field Performance Plan

A field work plan shall be developed for each transmission pipeline cleaning project, and shall be approved by signature of the **Program Manager - Integrity Management,** M1. The Pipeline Integrity Management section shall initiate this written plan which shall include the following elements:

- Description of geographic scope of project
- Statement of purpose and objectives for cleaning the pipeline.
- Request for Shutdown or Operation (RSO) in accordance with established company procedures.
- Pigging operations plan (if applicable)

9A.4.1.1 Pigging operations plan including the following:

- Types of pigs to be run and propulsion medium
- Description of cleaning compounds and solvents if applicable
- Sequence and minimum number of passes for each type of pig. Criteria for determining completion for each type if based upon performance.
- Criteria for determination of acceptance for completion
- Disposition of waste cleaning solutions/ pipeline liquids or solids
- Description of pipeline operation during cleaning process. Include schematic flow diagram if necessary.
- Listing of operating parameters and restraints, MAOPs, flow rates, linear travel velocity, etc.
- Listing of key personnel and responsibilities, including responsible contractors and vendors.
- Listing of internal and external emergency personnel and agencies

An outline for a Gas Transmission Pipeline Cleaning Field Performance Work Plan is provided in Appendix 9A-1.

9A.4.2 Sequence of Pig Runs

Following is a recommended sequence for running pigs when cleaning a pipeline that is believed to be in satisfactory condition without damage or internal attributes, and without excessive debris that would block successful passage of pigs. This procedure does not preclude the use of an alternate procedure subject to the approval of the **Program Manager - Integrity Management,** M1.

9A.4.2.1 Initial Passes

The initial pass serves to confirm that the pipeline is piggable and will provide indications of the internal condition of the pipeline. For this pass a soft or medium density foam pig is recommended.

Upon exit from the pipeline and recovery in the pig receiver, a careful examination of the pig must be made. Excessive wear or damage will indicate possible internal obstructions in the pipeline. Excessive wear or damage accompanied by a large quantity of solid debris may indicate that the pipeline is dirty but not otherwise obstructed.

Subsequent passes should be performed with medium density foam pigs until the level of damage is deemed to be consistent with the expectations for a pig that has traveled through an unobstructed pipeline of the length and diameter in question. If this level of condition can not be attained it will be necessary to analyze and trouble shoot the pipeline to determine the locations of possible damage or obstructions.

9A.4.2.2 Cleaning Passes

Multiple passes will generally be required with cleaning pigs. Cleaning pigs are typically foam pigs with various outer covering, typically in a criss-cross pattern, or mandrel pigs with wire brushes, scrapers, or magnets. Combinations of different types of cleaning pigs can be used such as running two wire brush runs followed by one magnetic pig run

Foam pigs are available with a wire brush incorporated in the covering material. Mandrel pigs are available with combinations of features. Mandrel pigs may incorporate bypass openings to allow gas or liquid to pass and sweep forward loosened debris in order to prevent buildup and blockage in front of the pig.

When a wet or gel process is used it may be necessary to use foam pigs or spherical sealing pigs in conjunction with mandrel pigs to control the movement of the liquid.

The information attained from the initial passes and gauging pass will be valuable for determining the appropriate cleaning pig selection. Qualified vendors can generally assist in the selection of pigs, sequence of runs, etc.

based upon the composition, physical properties, and quantity of internal debris and geometry of the pipeline.

Cleaning passes shall be continued until the quantity and composition of removed debris from each pass meets with the acceptance criteria set by the company or in-line inspection service provider. Whereas acceptance criteria may be set in absolute quantitative terms, if ILI is to be performed, the pipeline must be clean enough that loosened debris from the instrumented pig will not interfere with the performance of the sensors. To the greatest extent practical the ILI vendor's recommendations should be followed. If cleaning is in preparation for a hydrostatic test the residual contaminants in the line should be of small enough quantity to minimize environmental impact and cleanup efforts in the event of a failure.

9A.4.2.3 Final Passes

If in-line inspection is to be performed and a wet cleaning process was performed it will be necessary to remove all residual liquids from the pipeline. Foam pigs or other pigs specifically designed for liquid removal may be used for this purpose. As many passes as necessary to achieve the required degree of dryness shall be utilized.

9A.4.2.4 Gauging Plate Run

If in-line inspection is planned it is advisable to run a mandrel pig with one or more gauging plates. The gauging plates are rigid metal plate, typically aluminum or steel that will bend when passing through an obstruction inside the pipeline. Upon exit from the pipeline and recovery from the receiver the gauging plates shall be examined to determine if any significant restriction exists within the pipeline. Any restriction indicated must be considered before proceeding with an in-line inspection. Major restrictions may have to be located and removed to enable continued cleaning and internal inspection with instrumented pigs.

9A.4.3 System Operation

A "Request for Shutdown or Operation" shall be submitted and approved prior to commencement of cleaning or pigging any LG&E transmission pipeline.

Accurate flow and pressure control must be maintained to control the travel velocity of any pig. Pig manufacturers recommendations should be followed for ideal travel velocity. Recommended travel velocity ranging from 2 to 5 miles per hour is typical.

Records should be kept of all systems operations. A log may be maintained of all valve operations and subsequent pressures with date and time.

Recording pressure gauges are recommended to monitor driving pressure and back pressure during any pig run. Lapsed time when pressure excursions occur may be useful for determining approximate locations of unknown obstacles in a pipeline.

9A.5 SAFETY

9A.5.1 General Safety

All applicable provisions of the LG&E/KU Health and Safety Manual shall be followed. Special attention shall be given to eye protection and hearing protection when pig traps and pipelines are blown down.

All applicable provisions of Section 11 of this written plan, "Procedure to Minimize Environmental and Safety Risks" shall be followed.

9A.5.2 Hose and Tubing Connections

Hoses, instrument piping, and other small diameter temporary piping shall be given special attention to prevent damage from accidental contact or other outside forces. Such appurtenances shall be visually inspected at least once each day, or more frequently if left unattended or if possibly subjected to external force.

9A.5.3 Prevention of Accidental Ignition

All applicable provisions of LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-AI-001, "Prevention of Accidental Ignition" shall be followed.

During blow down operations, including at the launcher and receiver, all normal precautions must be exercised to prevent accidental ignition of gas. Care should be taken to assure that the launcher is purged with gas to clear all air before any pig is put into motion in the pipeline.

Pipelines containing flammable liquid residues should not be pigged using compressed air as the propulsion medium, or with tethered cleaning pigs in an atmosphere containing air.

Special care must be exercised when handling iron sulfide powder removed from a pipeline. Iron sulfide is pyrophoric and may ignite spontaneously following exposure to air. If possible, iron sulfide should be removed to a location where it can be safely incinerated.

Ignition sources shall be kept away from potentially combustible atmosphere locations.

9A.5.4 Purging

All applicable provisions of LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-PU-001 "Purging Operations" shall be followed.

9A.5.5 Lockout / Tagout

LG&E Gas Approved Operating Procedure "Hazardous Energy Control – Lockout/Tagout Procedure", GAOP-PO-001 shall be followed as applicable to prevent accidental release of hazardous energy into isolated portions of the system.

9A.6 ENVIRONMENTAL

9A.6.1 Pipe Cleaning Chemicals

All detergents, solvents, and other pipe cleaning chemicals shall be transported, handled, stored, and utilized in a responsible manner consistent with applicable federal, state, and local environmental protection regulations, and in accordance with the requirements of the company's environmental protection standards.

9A.6.2 Waste Products

All pipeline debris and spent cleaning solutions shall be collected, stored, handled, transported and disposed of in a responsible manner consistent with applicable federal, state, and local environmental protection regulations and in accordance with the requirements of the company's environmental protection standards.

Pigs and filters contaminated with pipeline debris shall be cleaned or disposed of in a manner in which any hazardous waste is collected stored, handled, transported and disposed of in a responsible manner consistent with applicable federal, state, and local environmental protection regulations and in accordance with the requirements of the company's environmental protection standards.

9A.7 TRAINING AND QUALIFICATIONS

9A.7.1 Operator Qualification Program

All gas system operations must be performed by personnel that have been qualified under the applicable LG&E or KU operator qualification program, or an operator qualification program that has been reviewed and approved by LG&E or KU as applicable.

9A.7.2 Drug and Alcohol Control

All gas system operation must be performed by personnel that have qualified under the applicable LG&E or KU drug and alcohol control program or a program reviewed and approved by LG&E or KU as applicable.

9A.7.3 System Operations Experience

The lead person in charge of operating valves on any LG&E or KU gas transmission pipeline shall be knowledgeable and experienced with respect to the pipelines being operated.

9A.8 EQUIPMENT

9A.8.1 Pipeline cleaning pigs

Pipeline cleaning pigs vary in size, material, configuration and features. As there are several qualified providers of pigs and pipeline cleaning services, their recommendations should be evaluated and compared when planning a cleaning operation.

9A.8.2 Pig launcher and receiver

Launchers, receivers, piping, and associated equipment, must be rated to withstand the highest pressure to which the pipeline will be subjected during the time of their installation. If any component to be installed is of lower rating than the MAOP of the pipeline, precautions must be taken to prevent exceeding the rated pressure of that component.

9A.8.3 In-line separator and filter

In-line filters and separators must be rated to handle the maximum pressure to which the pipeline will be subjected, and must be sized to handle the anticipated volumetric flow rates that will occur during all phases of the cleaning operation. Additionally the filter-separator must be able to accommodate the mass quantity and volume of liquids and solid debris that may be encountered during the initial and subsequent cleaning passes.

9A.8.4 Liquid recovery or Frac tank

Liquid recovery vessels, frac tanks, etc. may be required if pipeline liquids are encountered or if liquid cleaning processes are employed.

9A.9 RECORD KEEPING

9A.9.1 Content of Records

Records of gas transmission pipeline cleaning should include the following:

- Time and date of start and finish of each major operation. For this purpose inserting a pig, removing a pig, blowing down a line, etc. constitutes a major operation.
- Observed pressure at start and at intervals during major operation
- Description of line segments isolated during any blow down. This is needed to enable estimation of volume of lost gas and associated cost.
- Identity of personnel performing major operations
- General descriptions of operations performed, results achieved, and problems encountered.
- Any other information that in the opinion of the operating personnel may be helpful when planning future cleaning projects.

This data shall be recorded as part of the Cleaning Record in the Cleaning Field Performance Plan.

9A.9.2 Retention of Records

Records of pipeline cleaning performed in preparation for an in-line inspection or hydrostatic pressure test for integrity management assessment shall be retained as a part of the records for that inspection or assessment. The **Program Manager - Integrity Management,** M1 shall be responsible for records retention.

9B PIPELINE IN-LINE INSPECTION PROCEDURE

In This Appendix

9B.1 PURPOSE

The purpose of this procedure is to provide direction for internal inspection of pipelines by means of geometry pigs, magnetic flux leakage pigs, or other instrumented pigs.

9B.2 INTRODUCTION

9B.2.1 Scope

- This procedure covers in-line inspection of gas transmission pipelines owned and operated by Louisville Gas & Electric/Kentucky Utilities (the company).
- This procedure is intended for use on gas transmission pipelines to perform baseline assessments and reassessment as a part of the pipeline integrity management program as prescribed under US Department of Transportation (DOT) regulations 49 CFR Part 192 Subpart O. It is also applicable to gas transmission and distribution pipelines not covered under this subpart.

9B.2.2 References

9B.2.2.1 Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subpart O

9B.2.2.2 ASME B31.8S-2004, "Supplement to B31.8 on Managing System Integrity of Gas Pipelines"

9B.2.2.3 API Standard 1163, "In-line Inspection Systems Qualification Standards"

9B.2.2.4 LG&E / Procedures

9B.2.2.4.1 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-AI-001, "Prevention of Accidental Ignition".

9B.2.2.4.2 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-PU-001, "Purging Operations."

9B.2.2.4.3 LG&E Gas Approved Operating Procedure, GAOP-PO-001, "Hazardous Energy Control – Lockout / Tagout Procedure."

9B.2.3 Responsibilities

9B.2.3.1 Gas Regulatory Compliance – Pipeline Integrity Management Section

The Program Manager – Integrity Management M1 shall be responsible for maintaining this procedure. Maintenance of this procedure includes periodic review and subsequent revisions as frequently as necessary to maintain the effectiveness thereof.

The Program Manager – Integrity Management M1 shall have the overall responsibility for implementation of this procedure when it is used as a part of the company's pipeline integrity management program. This responsibility includes approval of the inspection methods selected and specified accuracy of the instruments to be used.

The Pipeline Specialist F5 shall be responsible for overseeing field operations. This includes coordination of operations between contractors, the company, and government agencies.

The Pipeline Integrity Engineer F3 shall be responsible for assuring that data is comprehensive and accurate and that records are properly compiled for permanent retention.

9B.2.3.2 Gas Storage and Control

Gas Storage and Control shall be responsible for the operation of gas transmission pipelines throughout the commencement of cleaning and inspection procedures.

9B.3 DISCUSSION

9B.3.1 Regulatory Requirements

9B.3.1.1 Internal Inspection Tool Acceptance Criteria

Federal gas pipeline safety regulations acknowledge the use of "Internal inspection tool or tools capable of detecting corrosion, and any other threats to which the covered segment is susceptible" as an integrity assessment method. An operator must follow ASME/ANSI B31.8S, Section 6.2 in selecting the appropriate inspection tools for the covered segment [§192.921(a)(1)]. It is therefore the responsibility of each operator to adopt procedures that are effective and safe, and that meet the stated regulatory requirements.

ASME/ANSI B31.8S-2004, Section 6.2 is therefore incorporated by reference into this procedure.

9B.3.1.2 Design and Installation of Temporary Piping

All temporary piping used for pigging operations shall be designed, tested, and installed in accordance with the requirements of 49 CFR Part 192. Instrument lines, hoses, and other components not specifically addressed in Part 192 shall be designed to be safely operated under the pressure and conditions to which they will be subjected.

Pressure vessels shall be designed and tested to safely operate under the maximum pressure to which they may be subjected. Frac tanks or other vessels intended to operate at atmospheric pressure must be adequately vented or otherwise protected against over pressure.

9B.3.1.3 Environmental Protection

All environmental protection regulations, including company internal procedures and Section 11 of this written plan must be met when performing pipeline pigging. Extreme care must be exercised to collect all liquid and solid materials removed from each pipeline. Waste materials shall be sampled and analyzed to determine proper disposal method.

9B.3.2 Pipeline Geometry

It is important to know as know as much as possible about the physical geometry of any pipeline to be pigged. Changes in internal diameter, elbows, tees, venturi pattern valves, protrusions into the pipeline may limit the selection of pigs that can be used or may prevent pigging entirely. Location of such features before hand can prevent costly delays and minimize down time for the pipeline to be pigged.

9B.3.3 Worksite Requirements

9B.3.3.1 Launch Site Access

The launch site must be accessible to construction equipment and lifting equipment needed to install and remove the launcher and needed to place pigs in the launcher. Instrumented smart pigs used for in-line inspection are typically longer and heavier than pigs that are used for cleaning operations.

9B.3.3.2 Propulsion Medium

If natural gas is to be used for propulsion of the pigs, there must be sufficient working room to install temporary valves and piping for that purpose. If air is to be used, there must be a suitable location for air compressors of sufficient capacity to provide the volume and pressure needed.

9B.3.3.3 Receiving Site Access

The receiving site must be accessible to construction equipment and lifting equipment needed to install and remove the receiver and gas separating and filtering equipment, as well as liquid recovery tanks if wet cleaning is to be used. Additionally, pigs will have to be handled and removed from the site. If a tethered pig is to be used there must be sufficient room to accommodate the winch truck.

9B.3.3.4 Gas Recovery

If gas is to be used as the propulsion medium for one or more filter–separator vessels will be incorporated in the temporary piping to clean the gas for reentry into a gas pipeline system.

9B.3.3.5 Gas Blow Down

Any time gas is to be used as propulsion medium there will be a need to blow down the launcher and receiver each time a pig is inserted and removed. Blow down piping must be vented in a manner that does not create a potential hazard to workers, the public, or adjacent property.

9B.4 PROCEDURE

9B.4.1 In-line Inspection Tool Minimum Specifications

9B.4.1.1 General Conditions

It is the intent of the company to conduct an effective pipeline integrity management program that meets or exceeds all regulatory requirements while ensuring safe and reliable operation of gas transmission pipelines. The minimum specifications listed within this subsection are based upon established practices, proven technology, and currently available equipment.

The ILI vendor should have documented procedures to provide Quality Assurance (see Section 15) for the following:

- Training and examination procedures for personnel including personnel certification records;
- Safety precautions;
- Procedure for verification of equipment operating condition prior to performing inspections;
- Calibration of equipment;
- Testing and data analysis; and
- Determination of tool tolerance including, depth, length, and confidence level expressed as a percent.

9B.4.1.2 ILI Tool Selection

Selection of the appropriate in-line inspection tool(s) shall be based upon the identified Threats of Concern (TOC) and corresponding Threat Assessment Values (TAV) for the covered pipeline segments to be inspected. TOC and TAV values are determined based upon the algorithms described in Sections 4 and 5 of this plan. The TAV values are reported as described in Section 8 on Form 8- 1 “Baseline Assessment Plan.”

Table 9B-1 summarizes ILI tool selection type based upon ANSI/ASME B31.8S, Section 6.2.

Table 9B-1 ILI Tool Vs. Anomaly Type Pipeline Anomaly Type	ILI Tool Type					
	High Resolution Magnetic Flux Leakage	Standard Resolution Magnetic Flux Leakage	Ultrasonic Compression Wave	Ultrasonic Shear Wave	Transverse Magnetic Flux Leakage	Caliper Tool
External corrosion or metal loss	X	X	X	X	X	
Internal corrosion or metal loss	X	X	X	X	X	
Dents or buckles						X
Longitudinal crack and seam defects, selective seam corrosion				X	X	
Stress corrosion cracking				X		

Whereas standard resolution magnetic flux leakage tools are acceptable under the applicable regulations, it shall be the practice of the company to utilize high resolution tools whenever available and practical. Deviation from this practice shall be subject to the approval of the Program Manager – Pipeline Integrity M1.

9B.4.1.3 Recommended Inspection Tool Minimum Specifications

Table 9B-2 shows typical specifications for high resolution magnetic flux leakage (MFL) in-line inspection tools. The company has accepted these as recommended minimum specifications.

9B.4.1.4 Acceptance of Inspection Tools

Every tool manufactured does not possess the same level of accuracy and sensitivity for all parameters listed. In some cases a proposed tool may have superior qualities in certain areas but be slightly deficient in one or more other areas based upon recommended typical specifications presented in the tables in this subpart. It shall be the responsibility of the **Program Manager – Integrity Management** M1 to review the specifications of the tools proposed by qualified vendors and to note any deficiencies based upon this subsection. Acceptance of any tool with noted deficiencies must be justified on the basis that the noted deficiency will not jeopardize the integrity of the pipeline. It shall be the responsibility of the Program Manager – Pipeline Integrity M1 to review and approve such justification. Form 9.B.4 – MFL Tool Comparison With Typical Specifications has been developed to compare the specifications of proposed tools between vendors.

Table 9B-2 Typical Specifications: MFL Tools - High Resolution (HR)		
Axial sampling distance:	From 2 mm (0.08 in.) If the tool operates with a fixed sampling, the axial sampling distance increases with inspection speed	
Circumferential sensor spacing:	8 to 17 mm (0.3 to 0.7 in.)	
Detection limitations:	Minimum defect depth: 10% of WT Accuracy of measurement of defect depth: 10% of WT	
Minimum inspection speed requirement:	0.5 m/s (~1 mph) (Inductive coils); None (Hall-Effect sensors)	
Maximum inspection speed requirement:	4 to 5 m/s (9 -11 mph)	
Minimum magnetization level:	Minimum magnetic field strength: 10 to 12 kA/m (3 to 3.7 kA/ft) Minimum magnetic flux density: 1.7 T (this requirement should eliminate sensitivity to speed and remnant magnetization)	
Depth sizing accuracy:		
General metal loss:	Minimum depth: Depth sizing accuracy: Length sizing accuracy:	10% of WT ± 10% of WT ± 20 mm (0.8 in.)
Pitting metal loss:	Minimum depth: Depth sizing accuracy: Length sizing accuracy:	10% to 20% of WT ± 10% of WT ± 10 mm (0.4 in.)
Axial grooving metal loss:	Minimum depth: Depth sizing accuracy: Length sizing accuracy:	20% of WT -15 / +10% of WT ± 20 mm (0.8 in.)
Circumferential grooving metal loss:	Minimum depth: Depth sizing accuracy: Length sizing accuracy:	10% of WT -10 / +15% of WT ± 15 mm (0.60 in.)
Axial slotting metal loss:	Minimum depth:	Detectable but not reported
Circumferential slotting metal loss:	Minimum depth: Depth sizing accuracy: Length sizing accuracy:	10% of WT -15 / +20% of WT ± 15 mm (0.60 in.)
Corrosion at girth welds: Adjacent to weld	Minimum depth: Depth sizing accuracy:	10% of WT ± 10 to 20% of WT
On or through weld	Minimum depth: Depth sizing accuracy:	10 to 20% of WT ± 10 to 20% of WT
Length sizing accuracy:	± 10 mm (0.4 in.)	
Width sizing accuracy (circumferential):	± 10 to 17mm (0.4 to 0.7 in.)	
Location accuracy:	Axial (relative to closest girth weld): ± 0.1m (4 in.) Circumferential: ± 5°	
Confidence level:	80%	
High resolution magnetic flux leakage tools must be capable of distinguishing between external and internal metal loss.		
Geometry inspection features incorporated into MFL tools must be capable of detecting any dent with a depth of greater than 2% of the pipe diameter for 12” NPS or more or .250” for pipe smaller than 12” NPS.		

9B.4.1.5 Calibration and Maintenance of Inspection Tools

It shall be the responsibility of the contractor providing the in-line inspection service to adjust, calibrate, and maintain inspection tools as necessary to assure performance in accordance with listed specifications for each tool.

The contractor shall provide documentation of adjustments, calibration, and maintenance of inspection tools.

9B.4.2 Qualification of ILI Contractors Personnel

9B.4.2.1 Job-specific Qualifications

In addition to meeting the applicable requirements of 49 CFR parts 191 and 199 for operator qualification and drug and alcohol control, contractors personnel must be specifically trained and qualified to perform their respective roles in calibrating and maintaining tools, directing operations during inspection runs, analyzing data, etc.

The following documented qualifications and certifications should be provided for Quality Assurance purposes (See Section 15):

Prior training and experience testing with similar inspection technology in accordance with ANSI/ASNT ILI-PQ-2010 “In-Line Inspection Personnel Qualification and Certification Standard”.

Tool Operators performing testing must have a minimum of Level II certification for the inspection technology to be used.

Data Analysts reviewing the data for the final report must be a minimum of Level II certification for the inspection technology to be used. Level III is preferred.

9B.4.2.2 Acceptance of Contractor Employees Qualifications

As a requirement for eligibility to perform an in-line inspection the contractor must submit a written statement of personnel qualifications to the company for review and approval of the **Program Manager – Integrity Management,** M1. Personnel operating in-line inspection tools and analyzing the results must be qualified in accordance with ANSI/ASNT ILI-PQ-2010.

Additionally, as a condition of the contract with the company and in accordance with U.S. Department of Transportation gas pipeline safety regulations the contractor must have a drug and alcohol control program and an operator qualification program that has been approved by the company.

9B.4.3 Preparation and Cleaning

9B.4.3.1 Physical Data and Geometry

Prior to attempting to perform an in-line inspection it is essential to assemble as much physical data as possible. Changes in internal diameter, elbows, tees, venture pattern valves, protrusions into the pipeline may limit the selection of instrumented pigs that can be used or may prevent in-line inspection entirely. Cleaning the pipeline in accordance with Appendix 9A of this written plan will help to ensure, but will not guarantee, that an inspection tool can be successfully run.

It may be necessary to perform an inspection run with a geometry tool independent of and prior to running an MFL or other inspection tool. The recommendations of the in-line inspection contractor should be considered and followed if practical. If not practical, agreement must be reached with the contractor regarding costs for location and removal, and other financial ramifications associated with a tool stuck in the pipeline.

9B.4.3.2 Pipeline Cleaning

Prior to attempting to perform an in-line inspection a pipeline shall have been internally cleaned in accordance with Appendix 9A of this written procedure. The cleanliness criteria set by the in-line inspection tool contractor must be met to assure a successful inspection.

9B.4.4 Field Performance Plan

A field work performance plan shall be developed for each transmission pipeline in-line inspection project, and shall be approved by signature of the **Program Manager – Integrity Management,** M1. This written plan shall be initiated by the Pipeline Integrity Management section and shall include the following elements:

9B.4.4.1 Description of geographic scope of project

9B.4.4.2 Statement of purpose and objectives for inspecting the pipeline including:

- Baseline assessment or reassessment
- Threats to be addressed per B31.8S Section 2.

9B.4.4.3 Request for Shutdown or Operation (RSO) in accordance with established company procedures.

9B.4.4.4 A criterion for assurance pipeline is acceptable for in-line inspection. May reference Gas Transmission Pipeline Cleaning Field Performance Work Plan Appendix 9A-1.

9B.4.4.5 A written pigging operations plan including the following:

- Types of inspection pigs to be run and propulsion medium
- Sequence of passes if more than one pig is to be run. Criteria for determining completion for each type if based upon performance.
- Criteria for determination of acceptance for completion
- Disposition of waste products recovered from receiver, filters, or cleaning of tools.
- Description of pipeline operation during inspection process. Include schematic flow diagram if necessary.
- Listing of operating parameters and restraints, MAOPs, flow rates, linear travel velocity, etc.
- Listing of key personnel and responsibilities, including responsible contractors and vendors.
- Listing of internal and external emergency personnel and agencies.

The pigging operations plan may be designed by a qualified person within the company or a qualified vendor's plan may be incorporated.

9B.4.4.6 Outline

An outline for a Gas Transmission Pipeline In-line Inspection Field Performance Work Plan is provided in Appendix 9B-1.

9B.4.5 Analysis and Reporting

Analysis and reporting of data shall be in accordance with the terms of the contractual agreement, but at a minimum shall include the following:

9B.4.5.1 Data Verification

Upon completion of each instrumented tool run the data shall be reviewed and verified by a qualified technician to assure that meaningful data has been collected and that the run has been successful. This shall be performed before disbandment of the instrumented tools, supporting equipment, and contracted work crews.

9B.4.5.2 Preliminary Data Analysis

A preliminary data analysis shall be performed on site as soon as possible after each instrumented tool is removed from the pipeline to discover immediate repair anomalies including but not limited to:

- Wall loss resulting in a predicted failure pressure less than or equal to 1.1 times the MAOP of the pipeline
- A dent that has any indication of metal loss, cracking, or a stress riser
- Any other indication that in the opinion of the person performing the analysis is unusual or may result in unsafe operation of the pipeline at its MAOP.

A hard copy or electronic copy report of this preliminary analysis must be provided to the company within 30 days of tool removal.

9B.4.5.3 Final Report

A final report must be compiled listing all pipeline features and anomalies detected with the following information:

- Item number
- Pipeline feature description
- Internal/external discrimination
- Odometer reading
- Distance to next feature
- Wall thickness
- Grade
- Outside diameter
- Segment MAOP
- %SMYS at listed system MAOP

- Predicted burst pressure
- Pf /MAOP
- Indicated depth
- Indicated width
- Indicated length
- O'clock orientation
- Nearest upstream reference
- Distance from nearest upstream reference
- Nearest downstream reference
- Distance to nearest downstream reference
- Distance from upstream weld
- Distance to downstream weld

In addition the final report shall list general and specific information pertaining to inspection tools used, analysis processes, failure analysis method, calibration results, and any other information pertinent to the inspection.

The final report shall be submitted to the company within 90 days from the removal of the last tool from the pipeline. The final report shall be submitted to the company in hard copy and electronic format with tabulated data on an Excel spreadsheet or other data base agreeable to the company.

9B.4.6 Data Retained By The Company

9B.4.6.1 System Operating Data

The company shall retain operating data pertinent to the in-line inspection procedure. Such data shall include a listing of system valve operations including time, date and observed pressure.

Flow measurement, including static pressure is recommended for the launching function, and pressure measurement is recommended at the receiving end of the pipeline.

9B.4.6.2 Blow Down Pressure and Volume

In order to estimate lost gas due to blow down of line segment, vessels, or traps it is necessary to know exactly what was isolated, whether a purge was performed, and what the pressure was at the start. A log shall be retained for all blow down and purge operations stating the operation performed (blow down to atmosphere, blow down and purge, purge air with gas, etc.), the pressure at the start, and physical description of segment involved.

9B.4.7 Verification Measurements and Feedback

9B.4.7.1 Verification Measurements

In order to confirm the accuracy of the inspection tools and the validity of the in-line inspection process, it is necessary to verify the validity of the output data. In addition to indicated immediate repair conditions, a minimum of two scheduled indications should be verified. If one or no scheduled anomalies are indicated then verification priority falls to monitored anomalies. Anomaly indications shall be categorized using Section 10.4 of this procedure.

In the event that no anomalies are indicated a minimum of one verification excavation shall be performed at a tap, known anomaly, or other indicated features.

Verification excavations and inspections shall be made within one year of receipt of the final report.

9B.4.7.2 Verification Feedback

The results of direct examination of indicated anomalies or features shall be shared with the in-line inspection contractor in a timely manner. Significant deviations should be promptly reported to the contractor by email or telephone within three working days of discovery. The results of all direct inspections of anomalies or indicated features shall be documented and summarized on Form 9B-2: Assessment Result Worksheet and Form 9B-5: ILI Data Verification Report. Copies of these reports shall be forwarded to the in-line inspection contractor periodically at mutually agreed intervals as work progresses.

9B.4.7.3 Utilization of Verification Data

In the event that direct inspection proves indicated anomalies to be accurate no adjustments to the program are required.

In the event that indicated anomalies are consistently less severe than indicated, the company may elect to re-evaluate indications of remaining anomalies that would require one-year or long term scheduled remediation.

In the event that direct inspection proves that indicated anomalies are consistently more severe than indicated, remaining anomalies that would require one year or long term scheduled remediation shall be re-evaluated.

Re-evaluation may be performed by the in-line inspection contractor or by other means as directed and approved by the **Program Manager – Integrity Management,** M1.

9B.4.8 Operating Responsibilities

9B.4.8.1 Contracted Responsibilities

Respective responsibilities of the company and contractor shall be as defined within the contract.

9B.4.8.2 System Operation

Operation of valves or other equipment that controls the flow of gas through any part of the gas transmission or distribution systems shall be the responsibility of the company, and must be performed by workers qualified under the company operator qualifications program. This does not preclude the operation of a valve or other control by contractor personnel while under the direct supervision and in direct contact with a responsible company qualified worker.

9B.5 SAFETY

9B.5.1 General Safety

All applicable provisions of the LG&E/KU Health and Safety Manual shall be followed. Special attention shall be given to eye protection and hearing protection when pig traps and pipelines are blown down.

All applicable provisions of Section 11 of this written plan, “Procedure to Minimize Environmental and Safety Risks” shall be followed.

9B.5.2 Hose and Tubing Connections

Hoses, instrument piping, and other small diameter temporary piping shall be given special attention to prevent damage from accidental contact or other outside forces. Such appurtenances shall be visually inspected at least once each day; more frequently if left unattended or if possibly subjected to external force.

9B.5.3 Prevention of Accidental Ignition

All applicable provisions of LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-AI-001, “Prevention of Accidental Ignition” shall be followed.

During blow down operations, including at the launcher and receiver, all normal precautions must be exercised to prevent accidental ignition of gas. Care should be taken to assure that the launcher is purged with gas to clear all air before any pig is put into motion in the pipeline.

Pipelines containing flammable liquid residues should not be pigged using compressed air as the propulsion medium, or with tethered cleaning pigs in an atmosphere containing air.

Ignition sources shall be kept away from potentially combustible atmosphere locations.

9B.5.4 Purging

All applicable provisions of LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-PU-001 “Purging Operations” shall be followed.

9B.5.5 Lockout / Tagout

LG&E Gas Approved Operating Procedure "Hazardous Energy Control – Lockout/Tagout Procedure", GAOP-PO-001 shall be followed as applicable to prevent accidental release of hazardous energy into isolated portions of the system.

9B.6 ENVIRONMENTAL

9B.6.1 Waste Products

All pipeline debris and liquids shall be collected, stored, handled, transported and disposed of in a responsible manner consistent with applicable federal, state, and local environmental protection regulations, and in accordance with the requirements of the company's environmental protection standards.

Pigs and filters contaminated with pipeline debris shall be cleaned or disposed of in a manner in which any hazardous waste is collected stored, handled, transported and disposed of in a responsible manner consistent with applicable federal, state, and local environmental protection regulations and in accordance with the requirements of the company's environmental protection standards.

9B.7 TRAINING AND QUALIFICATIONS

9B.7.1 Operator Qualification Program

All gas system operation must be performed by personnel that have been qualified under the applicable company operator qualification program, or an operator qualification program that has been reviewed and approved by the company as applicable.

9B.7.2 Drug and Alcohol Control

All gas system operation must be performed by personnel that have qualified under the applicable company drug and alcohol control program or a program reviewed and approved by the company as applicable.

9B.7.3 System Operations Experience

The lead person in charge of operating valves on any company gas transmission pipeline shall be knowledgeable and experienced with respect to the pipelines being operated.

9B.8 EQUIPMENT

9B.8.1 Pipeline inspection pigs

Pipeline inspection pigs (aka in-line inspection tools) shall be as specified and as required to detect anomalies that may be the result of the threats being addressed. Inspection pigs for gas pipelines are generally driven by gas pressure or pulled by a cable and winch system.

9B.8.2 Pig launcher and receiver

Launchers, receivers, piping, and associated equipment, must be rated to withstand the highest pressure to which the pipeline will be subjected during the time of their installation. If any component to be installed is of lower rating than the MAOP of the pipeline, precautions must be taken to prevent exceeding the rated pressure of that component.

9B.8.3 In-line separator and filter

In-line filters and separators must be rated to handle the maximum pressure to which the pipeline will be subjected, and must be sized to handle the anticipated volumetric flow rates that will occur during all phases of the cleaning operation. Additionally the filter-separator must be able to accommodate the mass quantity and volume of liquids and solid debris that may be encountered during the initial and subsequent cleaning passes.

9B.9 RECORD KEEPING

9B.9.1 System Operations

Records should be kept of all systems operations. At a minimum a log should be maintained of all valve operations and subsequent pressures with date and time.

Recording pressure gauges are recommended to monitor driving pressure and back pressure during any pig run. Lapsed time when pressure excursions occur may be useful for determining locations of unknown obstacles in a pipeline.

9B.9.2 ILI Report

A final hard copy report shall be compiled by the Pipeline Integrity Engineer F3. This report shall include all forms and documents that are pertinent to objective of performing this in-line inspection including but not limited to:

- Form 8-1, Baseline Assessment Plan
- General notes and correspondence related to project planning

- Pertinent main reports, drawings, and system maps
- Request for Proposal
- Materials list, specifications, etc. for temporary piping, pig traps, filtering equipment, etc.
- Procedures for pigging and other line preparation
- Applicable operating data related to preparation or in-line inspection
- Request(s) for Shutdown/Operation
- Management of Change Forms (Form 14-1) for permanent pipeline alterations and for temporary piping and appurtenances
- Pipeline data sheets, pipe mill test reports, vessel certifications, main reports, and other supporting data as applicable for temporary and permanent piping alterations and appurtenances
- ILI contractors reports for cleaning and inspection runs
- Direct inspection results, including main reports, remaining strength calculations, etc.
- Appendix 9B-1: Gas Transmission Pipeline In-line Inspection Field Performance Work Plan
- Form 9B-2: Assessment Results Worksheet
- Dig sheets and pertinent supporting documentation for anomalies addressed (ISFR's, main reports, pictures, etc)
- All forms and documents required by this subsection and other applicable sections of the company written pipeline integrity management plan.
- All other documents appropriate and significant to this in-line inspection, baseline assessment, or reassessment objectives.

Additionally electronic files shall be maintained of the above documents to the extent practical.

9B.9.3 Retention of Records

Records of an in-line inspection for integrity management assessment shall be retained for as long as that pipeline remains in service. The Program Manager – Pipeline Integrity M1 shall be responsible for records retention.

9B.10 FORMS

Form 9B-2 – Assessment Results Worksheet

Form 9B-3 – Pigging Operations Log

Form 9B-4 – MFL Tool Comparison With Typical Specifications

Form 9B-5 – ILI Data Verification Report

Form 9B-2 – Assessment Results Worksheet

Form 9B-3 – Pigging Operations Log

INTEGRITY MANAGEMENT PLAN FORM 9B-3

Form 9B-3 - Pigging Operations Log	
Part 1 - Project Information	
Run Date	
Line	
Operation Being Performed	
Direction	
Length (ft)	
Part 2 - Run Information	
Pig Type and Description	
Pigging Vendor	
Inlet Pressure	
Outlet Pressure	
Differential Pressure Range	
Start Time	
End Time	
Run Duration	
Average Velocity	
Part 3 - Post-Run Information	
Contents Discharged	
Run Details	
Comments	
Immediate Conditions	
One-year Schedule Conditions	
Pigging Related Emergency Line Interruptions	
Total Service Interruptions / Pressure Reductions	

Employee Signature	Date

Form 9B-4 – MFL Tool Comparison Typical Specifications

Form 9B-4 - MFL Tool Comparison With Typical Specifications

References LG&E's IMP section 9B.4.1.4
Typical Specifications taken from Table 9B-2

Project Name: ____

Paramater	Typ. Specifications	Vendor 1	Notes	Vendor 2	Notes
Axial sampling distance:	From 2mm (0.08 in.) [1]				
Circumferential sensor spacing:	8 to 17 mm (0.3 to 0.7 in.)				
Detection limitations:					
Minimum defect depth:	10% of WT				
Accuracy of measurement of defect depth:	10% of WT				
Minimum inspection speed requirement:	0.5 m/s (~1 mph) (Inductive coils); None (Hall-Effect sensors)				
Maximum inspection speed requirement:	4 to 5 m/s (9 to 11 mph)				
Minimum magnetization level:					
Minimum magnetic field strength:	10 to 12 kA/m (3 to 3.7 kA/ft)				
Minimum magnetic flux density:	1.7 T				
(this requirement should eleminate sensitivity to speed and remnant magnetization)					
Depth sizing accuracy:					
General metal loss:					
Minimum depth:	10% of WT				
Depth sizing accuracy:	± 10% of WT				
Length sizing accuracy:	± 20 mm (0.8 in.)				
Pitting metal loss:					
Minimum depth:	10% to 20% of WT				
Depth sizing accuracy:	± 10% of WT				
Length sizing accuracy:	± 10 mm (0.4 in.)				
Axial grooving metal loss:					
Minimum depth:	20% of WT				
Depth sizing accuracy:	-15/+10% of WT				
Length sizing accuracy:	± 20 mm (0.8 in.)				
Circumferential grooving metal loss:					
Minimum depth:	10% of WT				
Depth sizing accuracy:	-10/+15% of WT				
Length sizing accuracy:	± 15 mm (0.6 in.)				
Axial slotting metal loss:					
Minimum depth:	Detectable but not reported				
Circumferential slotting metal loss:					
Minimum depth:	10% of WT				
Depth sizing accuracy:	-15/+20% of WT				
Length sizing accuracy:	± 15 mm (0.6 in.)				
Corrosion at girth welds adjacent to weld:					
Minimum depth:	10% of WT				
Depth sizing accuracy:	± 10 to 20% of WT				
Corrosion at girth welds on or through weld:					
Minimum depth:	10 to 20% of WT				
Depth sizing accuracy:	± 10 to 20% of WT				
Length sizing accuracy:	± 10 mm (0.4 in.)				
Width sizing accuracy (circumferential):	± 10 to 17mm (0.4 to 0.7in.)				
Location accuracy:					
Axial (relative to closest girth weld):	± 0.1m (4in.)				
Circumferential:	± 5°				
Confidence level:	80%				
Battery Life	Minimum 24 Hours				

High resolution magnetic flux leakage tools must be capable of distinguishing between external and internal metal loss.

Geometry inspection features incorporated into MFL tools must be capable of detecting any dent with a depth of greater than 2% of the pipe diameter for 12" NPS or more or 0.25" for pipe smaller than 12" NPS.

1. If the tool operates with a fixed sampling, the axial sampling distance increases with inspection speed.

Noted Deficiencies: ____

Justification of Use: ____

Approved By: ____
Integrity Management Program Manager

Form 9B-5 – ILI Data Verification Report

Form 9B-5 - ILI Data Verification Report

Project Name: ____________________

ILI Run Date: __________ ILI Report Date: __________ Excavation Date: __________

Anomaly Feature List Item Number: ______

Anomaly Feature List Form 9-2	Reported Value ILI Report	Observed Value Direct Inspection	Within Tolerance Yes or No	Comment Number (List Below)
Pipeline Feature				
Int/ Ext				
Odometer				
Ft To Next Pipeline Feature				
Wall Thickness				
Pipe Grade (ksi)				
%SMYS *				
Predicted Burst Press Pf(psig) *				
Pf/MAOP *				
Indicated Depth (%)				
Indicated Depth (in.)				
Indicated Length (in.)				
Indicated Width (in.)				
O'clock Orientation				
Nearest U/S Reference				
Distance From U/S Reference				
Nearest D/S Reference				
Distance From D/S Reference				
Distance From U/S Weld				
Distance From D/S Weld				
Category				
* Features marked with asterisk must be calculated				

Comments:	
1	
2	
3	
4	
5	
6	
7	
8	
9	
10	

Recommended Actions: ____________________

Prepared By: ____________________
Name Signature Tile Date

Attachment to Response to AG Q252
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Bellar

9C PIPELINE PRESSURE TESTING PROCEDURE

In This Appendix

9C.1 PURPOSE

The purpose of this procedure is to provide direction for pressure testing of gas transmission pipelines that have been in service in order to perform baseline assessment or reassessment as required for **the company**'s pipeline integrity management program.

9C.2 INTRODUCTION

9C.2.1 Scope

- This procedure is applicable to all gas transmission pipelines operated by Louisville Gas & Electric/Kentucky Utilities Company (**the company**).
- This procedure is intended for use on gas transmission pipelines to perform baseline assessments and reassessment as a part of the pipeline integrity management program as prescribed under US Department of Transportation (DOT) regulations 49 CFR Part 192 Subpart O. It is also applicable to gas transmission and distribution pipelines not covered under this subpart.
- This procedure includes hydrostatic and pneumatic testing as permitted under Title 49 Code of Federal Regulations Part 192 Subpart J.
- This procedure is intended to provide guidance to ensure compliance with applicable pipeline safety regulations, environment protection regulations, and job site safety standards while optimizing the process of performing baseline assessments as a part of **the company** pipeline integrity management program.

9C.2.2 References

9C.2.2.1 Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subparts J and O

9C.2.2.2 ASME B31.8S-2004, “Supplement to B31.8 on Managing System Integrity of Gas Pipelines”

9C.2.2.4.1 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-AI-001, “Prevention of Accidental Ignition”.

9C.2.2.4.2 LG&E Gas Operations and Maintenance Procedure, GOM&I-PO-PU-001, “Purging Operations.”

9C.2.2.4.3 LG&E Gas Approved Operating Procedure, GAOP-PO-001, “Hazardous Energy Control – Lockout / Tagout Procedure.”

9C.2.3 Responsibilities

9C.2.3.1 General Conditions

When a pressure test is performed on an existing (previously in service) gas transmission pipeline as a means of baseline assessment for pipeline integrity management as required by Title 49 CFR Part 192, Subpart O the roles and responsibilities of personnel overseeing and performing the required tasks shall be in accordance with the requirements of Section 2, "Roles and Responsibilities" of **the company**'s written pipeline integrity management program. The designated responsibilities within this procedure are with reference to Section 2 of the written program.

9C.2.3.2 Gas Regulatory Compliance – Pipeline Integrity Management Section

9C.2.2.3.1 Program Manager

The **Program Manager Pipeline Integrity** M1 has the overall responsibility to assure that this procedure is implemented effectively. Whereas specific responsibilities are designated to specific positions, such responsibilities may be delegated to contractors or other qualified personnel subject to approval by the Program Manager Pipeline Integrity.

9C.2.2.3.2 Pipeline Integrity Engineer

The **Pipeline Integrity Engineer** F3 shall be responsible for assuring that data is comprehensive and accurate and that records are properly compiled for permanent retention.

9C.2.3.3 Gas Storage and Control

Gas Storage and Control shall be responsible for the operation of gas transmission pipelines throughout the commencement of cleaning and inspection procedures.

9C.3.2.3.1 Engineer

It shall be the responsibility of the **Engineer II, III, or Senior**, F2 to determine or approve the test pressure, test medium and time duration for a baseline assessment pressure test.

9C.3 DISCUSSION

9C.3.1 Regulatory Requirements

9C.3.1.1 U.S. DOT Requirements

Federal regulation, 49 CFR 192.921(a)(2) lists a pressure test conducted in accordance with Subpart J of Part 192 as an acceptable assessment and reassessment method.

9C.3.1.2 ANSI/ASME B31.8S Limitations

Section 6.3 of §B31.8S recognizes pressure testing to address time-dependent threats and manufacturing and related defect threats.

Time dependent threats include external corrosion, internal corrosion, stress corrosion cracking, and other environmentally assisted corrosion mechanism.

Manufacturing and related defects include defective pipe and defective pipe seam. It is **the company**'s position to extend this category to include welding/manufacturing related threats. Welding/construction related threats include defective pipe girth weld, defective fabrication weld, and Wrinkle bend or buckle, and stripped threads/broken pipe/coupling failure.

9C.3.1.3 Design and Installation of Temporary Piping

All temporary piping used for pressure testing shall be designed, tested, and installed in accordance with the requirements of 49 CFR Part 192. Instrument lines, hoses, and other components not specifically addressed in Part 192 shall be designed to be safely operated under the pressure and conditions to which they will be subjected.

9C.3.1.4 Environmental Protection

All environmental protection regulations, including company internal procedures must be met when performing pipeline pigging. Extreme care must be exercised to collect all liquid and solid materials removed from each pipeline. Waste materials shall be sampled and analyzed to determine proper disposal method.

9C.3.1.5 Supplementary Procedure

This written procedure is a supplement to basic testing procedures, written or non-written. It is not intended to provide detailed descriptions of each required task and activity normally performed by qualified workers.

9C.4 PROCEDURE

9C.4.1 Collection of Physical Data

Knowledge of the physical properties of a pipeline is essential to conducting a pressure test for baseline assessment or reassessment. To avoid possible damage from excessive test pressure the diameter, wall thickness, specification, grade, and seam type must be known for all segments being tested. Conservative default data shall be assumed in place of any missing data.

Additionally, the maximum and minimum elevation must be known when conducting a hydrostatic test.

9C.4.2 Minimum Test Pressure

9C.4.2.1 Steel Pipe

The test pressure used must be sufficient to justify the MAOP (maximum allowable operating pressure) of the pipeline in accordance with the requirements of 49 CFR 192.619 and to meet the minimum requirements stated within B31.8S Table 3. The table 9C-1 provides factors by which to multiply the MAOP to determine minimum test pressure for the integrity reassessment interval shown.

Table 9C-1 Minimum Pressure Test Requirements for Time Dependent Threat Integrity Assessment Multiply MAOP by Factor Shown			
Maximum Interval Years	Operating Pressure as Percentage of SMYS (Steel pipe only – not applicable to plastic)		
	At or above 50%	At or above 30% < 50%	Less than 30%
5	1.25*	1.4*	1.7
10	1.39*	1.7	2.2
15	Not allowed	2.0	2.8
20	Not allowed	Not allowed	3.3

*Minimum of 1.5 for any portion that is within a Class 3 or Class 4 location, or for which Class 3 or Class 4 design requirements are applicable per §192.109.

9C.4.2.2 Plastic Pipe

To comply with the requirements of 49 CFR 192 Subpart J the minimum permitted test pressure shall be 50 psig or 1.5 times the MAOP, whichever is highest.

The traditional time dependent threats identified in ASME B31.8S – 2001 include only internal corrosion, external corrosion, and stress corrosion cracking which are not applicable to plastic. Furthermore, the stress levels expressed in Table 3 of the same standard are expressed in terms of specified minimum yield stress, a mechanical property that is not clearly defined or published for polyethylene plastic gas pipe.

To assure maximum reassessment time interval in the event that applicable time dependent threats for plastic gas pipe are identified, the maximum test pressure permitted under 49 CFR 192 Subpart J should be considered.

9C.4.3 Maximum Test Pressure

9C.4.3.1 Limiting Factor

The maximum safe pressure may not exceed either of the following:

- Regulator limits stated within 49 CFR Part 192 Subpart J
- Maximum safe test pressure of any pipe, fitting, valve, or other component that will be subjected to that pressure.

Compression couplings, valves, flow control components, line stopper fittings, screw fittings, instrument tubing, etc. shall be limited to maximum test pressures specified by the manufacturer if available. Pressure vessels, separators, process vessels and other processing equipment and components shall be limited to maximum test pressures specified by the manufacturer if available.

Limits specified by applicable referenced codes and standards may be used if manufacturer's limits are not available.

If manufacturer's specified limits are not available and limits are not specified by codes and standards, test pressure should be limited to 1.5 times the cold working pressure rating.

9C.4.3.2 Steel Pipe

The maximum test pressure applied to steel pipe or weld end fittings must not exceed that which would produce a calculated hoop stress of 100% of SMYS based upon the following formula:

$$P_{\max} = \frac{2 \times t \times SYMS}{D}$$

Where: P_{max} = maximum pressure in psig
t = wall thickness in inches
SMYS = specified minimum yield strength in psi
D = outside diameter in inches

Steel pipe that is in place and that is of unknown specification and grade may be hydrostatically tested to the point at which it starts to yield as indicated by deviation from the linear portion of the pressure-volume plot. See ANSI B31.8 Subpart N for specific information.

9C.4.3.3 Plastic Pipe

The maximum test pressure applied to plastic pipe must not exceed 3 times the calculated design pressure under 49 CFR 192.121 at a temperature not less than the pipe temperature during the test. The design pressure formula is as shown:

$$P = \left[\frac{2 \times S \times t}{(D-t)}\right] \times .32 \quad \text{or} \quad P = \left[\frac{2 \times S}{(SDR-1)}\right] \times .32$$

Where: P = design pressure in psig
S = long term hydrostatic design base (HDB)strength per listed specification at temperature 73 F, 100 F, 120 F, or 140 F.
t = wall thickness in inches
D = outside diameter in inches
SDR = standard dimensional ratio

Standard specifications for plastic gas pipe used by Louisville Gas and Electric Company have permitted only polyethylene pipe manufactured and listed in accordance with ASTM Standard Specification D2513. All plastic pipe manufactured in accordance with this standard must be marked showing the word Gas, the designation ASTM D 2513, the manufacturer's name or trademark, the nominal pipe or tubing size including the sizing system used(IPS, CTS, or OD), DR (dimensional ratio) or minimum wall thickness, and material designation. Pipe intended for natural gas service at temperatures greater than 73 F (23 C) shall be marked with additional letters to identify respectively the recommended temperature rating and the HDB at that temperature. The third letter identifies the melt index rating. Table 9C-2 is derived from ASTM D 2513 – 90b.

Table 9C-2 ASTM D 2513 Table 4 PE Pipe Category

Property	Test Method	Category A	Category B	Category C	Category D	Category E	Category F	Category G
Temperature F (C)		100 (38)	120 (49)	140 (60)	160 (71)	180 (82)		
HDB psi (MPa)	D 2837	400 (2.8)	500 (3.4)	630 (4.3)	800 (5.5)	1000 (6.9)	1250(8.6)	1600 (11.0)
Melt index g/10 min	D 1238	>0.5	0.2 – 0.5	0.01 – 0.3	<0.01			

For testing or operation at 73 F or lower temperature the following HBD values may be used. Reference Table A1.2, ASTM D 2513.

Table 9C-3 ASTM D2513 Table A1.2 Long Term Property Requirements (Short term properties not shown)	
PE 2306	HDB = 1250 psi
PE 2406	HBD = 1250 psi
PE 3406	HDB = 1250 psi
PE 3408	HDB = 1600 psi

A typical polyethylene gas pipe may be marked as ASTM D 2513 PE 2406 CEE. This indicates that it has a maximum temperature rating of "C" which is 140 F, and at that temperature it has a specified HDB of "E" which is 1000 psi. Note that this is a material strength rating, not a pressure rating for the pipe.

In the event that a test is to be performed at a temperature that is higher than 73 F and lower than the maximum rated temperature for the plastic pipe the manufacturer may be consulted to determine the HDB value for use in the design pressure formula at that temperature.

9C.4.4 Test Duration

9C.4.4.1 Steel Pipe Subject To Pressure At or Above 100 P_{sig}

Per Subpart J, in order for a test to qualify the pressure must be maintained at or above the minimum level required for at least the following time duration:

- Operate at or above 100 p_{sig} but less than 30% SMYS, steel 1 hour
- Operate at or above 30% SMYS, steel 8 hours*

Exception (*), fabricated units or short sections for which a post installation test is impractical may be strength tested for a minimum of 4 hours prior to installation.

9C.4.4.2 Steel Pipe Less Than 100 P_{SIG} and Plastic Pipe

Subpart J does not specify a minimum time duration for a test applied to steel pipelines intended to operate at less than 100 psig or for plastic pipelines. However, there is a general requirement that the test procedure used must ensure discovery of any potentially hazardous leak for steel pipelines operating at less than 30% SMYS and for plastic pipelines.

A minimum test time of 1 hour is recommended. A shorter time may be used if the entire segment being tested is exposed and may be observed for leaks during the test.

9C.4.5 Test Medium

9C.4.5.1 Permissible Test Mediums

Test medium must be liquid, air, natural gas, or inert gas that is compatible with the material of which the pipeline is constructed, relatively free of sedimentary materials, and with exception of natural gas non-flammable.

A pressure test using liquid as the test medium is referred to as a hydrostatic test. For hydrostatic testing of natural gas pipelines, water is the liquid that is normally used.

For pipeline testing, nitrogen is considered to be an inert gas. Whereas carbon dioxide is frequently used for testing service lines at moderate pressure, carbon dioxide has chemical properties and physical properties that make it undesirable for strength testing transmission pipelines at high pressure

Availability of test medium, disposal of test medium, effective removal from the pipeline, ambient temperature, required test pressure and consequence of failure are to be considered in the selection of test medium.

9C.4.5.2 Test Medium Safety Comparison

Hydrostatic testing presents the lowest consequence of failure when compared with air, inert gas, or natural gas. Water is nearly non-compressible. Once a pipeline is filled with water, it takes only a small additional quantity to attain a high pressure, thus the amount of energy that would be released upon failure is relatively small compared with that for compressible gasses. From the standpoint of safety to personnel, the public, adjacent buildings and other property, hydrostatic is the preferred method of strength testing.

Air, nitrogen, and natural gas are highly compressible. To attain a test pressure of 600 PSIG, approximately 40 times the original pipe volume has to be compressed into the pipeline. In the event of major failure this release of energy would be nearly instantaneous with the capability of producing major damage to the pipeline and its surroundings. When internal pressure produces hoop stress of 30% or more of SMYS the chance of a failure resulting in a rupture as opposed to a leak is much greater than it is at a lower pressure.

Any test failure with natural gas presents the additional risk of fire or explosion from migrating leaking gas. An abrupt failure, as a pipe rupture, with a natural gas test presents the addition risk of spontaneous ignition and explosion.

9C.4.5.3 Pressure Limits for Pneumatic Testing

Table 9C-4, derived from 49 CFR 192 Subpart J, lists maximum allowed air, inert gas, and natural gas test pressures for steel pipelines:

Table 9C-4 Maximum Pneumatic Test Pressures		
Class Location	Maximum hoop stress allowed as percentage of SMYS	
	Natural gas	Air or inert gas
1	80	80
2	30	75
3	30	50
4	30	40

For pipelines subject to operating at hoop stress levels at or above 30 percent of SMYS and within 300 feet of any building intended for human occupancy consult 49 CFR 192.505. Additional restrictions and requirements are applicable and are not addressed in this procedure.

Whereas applicable state and federal regulations may allow higher pressures, **the company** shall limit testing steel pipelines with air or inert gas to pressure levels that will result in less than 30% of SMYS, and plastic pipelines to pressure not in excess of 1.5 times the maximum design pressure based upon the actual pipe specifications at the temperature while testing, unless adequate measures can be taken to protect workers and the public from the consequences of a rupture mode failure.

Testing steel pipelines with natural gas must be limited to that pressure that will produce hoop stress of 30% or less of SMYS. Use of natural gas as test medium for steel or plastic pipelines should be limited to line segments of small internal volume where consequence of failure would be low, even if ignition occurred.

9C.4.5.4 Temperature Considerations – Hydrostatic Testing

Water when freezing expands with sufficient force to cause most pipe and tubing to rupture. Whereas a pipe segment buried in the ground will generally not freeze, test connections, instruments, supply lines, or other components of relatively small mass may freeze and fail if exposed to ambient temperature colder than 32 degrees Fahrenheit. Larger pipe may freeze and fail if exposed for an extended time in severely cold ambient conditions. If hydrostatic testing must be performed in freezing weather, provisions must be made to protect the pipe segment and test components from freezing. Hydrostatic testing must not be attempted if ground temperature at top of pipe depth is below 32 degrees Fahrenheit.

Hydrostatic test sections are subject to significant pressure swings from changing temperature. A segment of pipe pressured with cool water in morning conditions may experience a significant increase in pressure if exposed to afternoon sun. Care must be exercised to prevent the test pressure from exceeding safe limits for the segment being tested.

9C.4.5.5 Elevation Effect – Hydrostatic Testing

Differences in pipeline elevation have a significant effect upon the liquid pressure within a pipeline. For a pipeline completely filled with clean water with no air pockets, each foot of elevation change creates a difference 0.43 psig in the water pressure. The actual pressure within the pipeline will be highest at the lowest elevation and lowest at the highest elevation of the pipeline. The pressure difference will depend upon elevation difference only, and will not depend upon pipe diameter or slope of the hills.

9C.4.6 Liquid Quality – Hydrostatic Testing

The hydrostatic test medium, typically water, must be of acceptable quality. The test medium must not contain substances that are environmentally harmful, corrosive to the pipe, or that will settle or precipitate leaving residual solids in the pipe. Creek or river water must be checked for presence of micro organisms that could start microbially induced internal corrosion. If water is chemically treated, consideration must be given to residual compounds and the possibility of additional environmental requirements for test water disposal.

9C.4.6.1 Environmental Permits and Waste Sampling – Hydrostatic Testing

A Water Withdrawal and Discharge Permit is required when 10,000 gallons or more of water is withdrawn from a stream, lake, or other water body. In addition, Best Management Practices must be used for erosion control when discharged onto the ground.

If a Water Withdrawal and Discharge Permit is required, provide Environmental Affairs (EA) with the exact location of the work (including source and amount of water and location of proposed discharge), an estimate of the size of the pipe to be hydrostatically tested if applicable, maps, photographs, and drawings of the proposed work.

A letter to the DOW KPDES Branch is also required when water is to be discharged. If potable water is used, the water must be de-chlorinated (using sodium thiosulfate or other de-chlorination) prior to discharge. EA prepares and submits this letter.

A letter of intent must be sent to the Indiana Department of Environmental Management when discharging from existing pipe installations. General permit requirements include reporting of discharge points, identification of potentially affected parties, public notice of intent to discharge, and an application fee. EA prepares this permit with assistance from Pipeline Integrity. Wastes may be captured, tested per environmental standards, and upon approval of EA, transported to Kentucky for disposal to avoid the Indiana discharge permit requirements.

All waste liquids and solids must be sampled and disposed in accordance with **the company**'s environmental standards. Hydrostatic test water must be assumed to be environmentally hazardous until it is proven by laboratory analysis to be environmentally safe. Tests for benzene and PCBs are required before discharge of water from used pipe.

In the event that a failure occurs, the spilled water must be sampled and tested, and the volume estimated to enable proper environmental cleanup procedures to be implemented.

9C.4.6.2 Non-hazardous Wastewater Disposal

Non-hazardous wastewater that meets the criteria below may be placed in the Mill Creek Ash Pond for treatment and discharge. Check with EA prior to placement of water that has the potential to contain any other contaminants.

(1) Less than 0.5mg/L of benzene;
(2) No detectable PCBs;
(3) Flash Point greater than 140 degrees F; and
(4) No amines.

The **Pipeline Specialist** F5 or designate shall assure that corporate standards are followed for sampling and disposal of all liquids and solids recovered from the pipeline while implementing this procedure.

9C.4.7 Qualification of Personnel

9C.4.7.1 Job-specific Qualifications

Company employees and contractors personnel must be specifically trained and qualified to perform their respective roles in performing a pipeline pressure test.

9C.4.7.2 Acceptance of Contractor Employees Qualifications

As a requirement for eligibility to perform pipeline pressure test the contractor must submit a written statement of personnel qualifications to **the company** for review and approval by the **Program Manager – Pipeline Integrity** M1.

Additionally, as a condition of the contract with **the company**, and in accordance with U.S. Department of Transportation gas pipeline safety regulations, the contractor must have a drug and alcohol control program and an operator qualification program that has been approved by **the company**.

9C.4.8 Preparation and Cleaning

Each pipeline segment should be cleaned in accordance with Appendix 9A-1 of this procedure prior to hydrostatically testing. Consideration shall be given to the risk that hydrostatic test water could be contaminated and considered a hazardous waste. Failure of the pipeline could result in a hazardous waste spill and require extensive environmental cleanup.

9C.4.9 Field Performance Plan

A field performance work plan shall be developed for each transmission pipeline pressure test project, and shall be approved by signature of the **Program Manager – Pipeline Integrity** M1. This written plan shall be initiated by the Pipeline Integrity Management section and shall include the following elements:

- Description of geographic scope of project
- Statement of purpose and objectives for inspecting the pipeline including:
  - Baseline assessment or reassessment
  - Threats to be addressed per B31.8S Section 2.
- Request for Shutdown or Operation (RSO) in accordance with established company procedures.
- Criteria for assurance pipeline is acceptable for hydrostatic testing. May reference Pipeline Cleaning Field Performance Plan as outlined in Appendix 9A-1.

Acceptance criteria should include maintenance history. A pipeline that has been subject to corrosion leaks may be prone to failure and consequent environmental ramifications from a hydrostatic test.

9C.4.9.1 Pressure test operations plan including the following:

- Purging plan if air or inert gas is to be used as test medium.
- Filling plan for hydrostatic testing. Include source of water or other test medium, description of process utilizing sealing pigs, etc.
- Drawings as necessary to document temporary piping and equipment configuration used for filling, applying pressure, and discharging test medium.
- Description of method for applying pressure to test medium.
- Description of key elements such as gauges, instruments, pumps, or compressors.
- Schedule of pressure increases and observations.
- Criteria for recognition of yield or failure.
- Description of specific safety precautions to be exercised to assure safety of public and personnel while pressure test is being performed.

- Plan for disposal of test liquid or blow down of air, inert gas, or natural gas as applicable for hydrostatic or pneumatic testing.
- Pigging/drying plan for hydrostatic testing.
- Listing of operating parameters and restraints including maximum test pressure.
- Listing of key personnel and responsibilities, including responsible contractors and vendors.
- Listing of internal and external emergency personnel and agencies

9C.4.9.2 Outline

An outline for a Gas Transmission Pipeline Pressure Test Field Performance Work Plan is provided in Appendix 9C-1.

9C.4.10 Performing Test

9C.4.10.1 Filling Considerations – Hydrostatic Testing

The procedure for filling a pipeline for hydrostatic testing must assure that the pipe segment is completely filled with liquid that contains minimal volume of trapped air. Trapped air will compress as the pressure is applied and will store kinetic energy that will increase the potential for damage and injury in the event of a pipe failure or test connection failure.

Use of one or more sealing pigs facing each other ahead of the liquid fill can minimize the quantity of air left entrapped in the test liquid. The source of supply should be capable of maintaining a rapid and continuous flow.

9C.4.10.2 Application of Pressure

All hoses. Fittings, valves, instruments, etc. shall be rated to safely withstand the highest pressure to which they will be subjected. Proper procedures for making tubing connections shall be followed. Tubing should be kept as short as practical and routed such that exposure to accidental contact and damage is minimized.

All end caps on test segments must be standard fittings welded in accordance with approved welding procedures by a qualified welder or must be mechanical fittings designed and certified to contain the test pressure without danger of failure from longitudinal movement. Standard compression couplings shall not be used.

Temperature should be allowed to stabilize between test medium and ground surrounding buried underground pipelines before completion of pressurization process.

Planned test pressure shall be at least as high as the minimum required by Table 9C-1 for steel pipe or 1.5 times MAOP for plastic pipe.

Planned hydrostatic test pressure for steel pipe shall not exceed that pressure that will produce 100% SMYS hoop stress in the pipe wall. Pneumatic test pressure for steel pipe shall not exceed the pressure limitations in Table 9C-4.

Maximum test pressure for plastic pipe shall not exceed 3 times the calculated design pressure as outlined in 9C.6.3.3.

Pressure shall be raised in a steady and continuous manner to not more than 80% of the maximum planned pressure, or to the minimum test pressure required, whichever is lowest. Pressure shall be held at this value while system is observed for leaks. If no leaks are indicated, pressure may be raised to full planned value. Upon reaching full test pressure, a hold period for the required test duration may commence. During this time, test medium may be added if necessary to maintain the minimum test pressure provided declining pressure may be attributed to temperature decrease or other observable stabilization effects.

If at any time during the testing process a leak or yield failure is indicated, the leak or failure must be located, evaluated, and isolated or repaired before continuing.

9C.4.10.3 Indications of Failure

Anytime hydrostatic testing is performed on pipe segments that are buried or otherwise obstructed from view, then consideration should be given to plotting a pressure volume curve as test pressure is applied. For a pipeline completely filled with liquid, the pressure volume curve will be a straight line until such time that yield or failure has occurred. Yield of pipe is considered to have occurred when deviation from the straight line portion of the curve occurs and the volume increase per pressure increment has doubled (ASME B31.8S, Appendix N).

An abrupt drop or steady decline in pressure while pressure is being increased, or during a holding period, will generally indicate a failure.

Any loss of test pressure that cannot be attributed to temperature change or other observed phenomena must be regarded as a leak and a potential failure and must be investigated to determine location and probable cause.

9C.4.10.4 Acceptance Criteria

Any pipeline segment that undergoes a pressure test as prescribed within this procedure without evidence of failure shall be deemed acceptable. To be considered as acceptable, the test pressure must have been maintained continuously at or above the prescribed minimum for the specified time duration.

9C.4.11 Analysis of Failure

9C.4.11.1 Root Cause Analysis

Each failure must be located and examined as necessary to determine the root cause of the failure. The root cause analysis shall be used to determine if additional assessment tools are needed to ensure the integrity of the pipeline.

Form 9C-2: Root Cause Analysis Form shall be used to document root cause analysis.

9C.4.12 Operating Responsibilities

9C.4.12.1 Contracted Responsibilities

If pressure testing is performed by a contractor, the respective responsibilities of **the company** and contractor shall be as defined within the contract.

9C.4.12.2 System Operation

Operation of valves or other equipment that controls the flow of gas through any part of the gas transmission or distribution systems shall be the responsibility of **the company** and must be performed by workers qualified under **the company**'s operator qualifications program. This does not preclude the operation of a valve or other control by contractor personnel while under the direct supervision and in direct contact with a responsible company qualified worker.

9C.5 SAFETY

9C.5.1 General Safety

All applicable provisions of the LG&E-KU Health and Safety Manual shall be followed. Special attention shall be given to eye protection when pipelines are being pressured, and to eye protection and hearing protection when an air test is being blown down.

All applicable provisions of Section 11 of this written plan, "Procedure To Minimize Environmental And Safety Risks" shall be followed.

All excavations shall be barricaded with entry restricted to necessary personnel while the test is in progress and the test pressure is applied. If practical, heavy equipment may be positioned to protect a populated area in case of end cap or other failure.

Workers and the public shall be kept a safe distance away from the discharge of test gases to minimize exposure to potentially harmful noise.

Whereas test gases are generally not toxic, the potential danger of asphyxiation in a confined area must be realized if nitrogen is used.

9C.5.2 Hose and Tubing Connections

Hoses, instrument piping, and other small diameter temporary piping shall be given special attention to prevent damage from accidental contact or other outside forces. Such appurtenances shall be visually inspected at least once each day; more frequently if left unattended or if possibly subjected to external force.

9C.5.3 Lockout / Tagout

LG&E Gas Approved Operating Procedure “Hazardous Energy Control – Lockout/Tagout Procedure”, GAOP-PO-001 shall be followed as applicable to prevent accidental release of hazardous energy into isolated portions of the system.

9C.6 ENVIRONMENTAL

9C.6.1 Waste Test Liquid

All liquids used for hydrostatic testing shall be disposed of in a responsible manner consistent with applicable federal, state, and local environmental protection regulations, and in accordance with the requirements of **the company**’s environmental protection standards.

9C.7 TRAINING AND QUALIFICATIONS

9C.7.1 Operator Qualification Program

All gas system operation must be performed by personnel that have been qualified under the applicable company operator qualification program, or an operator qualification program that has been reviewed and approved by **the company** as applicable.

9C.7.2 Drug and Alcohol Control

All gas system operation must be performed by personnel that have qualified under the applicable company drug and alcohol control program or a program reviewed and approved by **the company** as applicable.

9C.7.3 System Operations Experience

The lead person in charge of operating valves on any company gas transmission pipeline shall be knowledgeable and experienced with respect to the pipelines being operated.

9C.7.4 Pressure Testing Experience

The lead person in charge of performing a pressure test shall be qualified through training and experience to perform the specified procedures.

9C.8 EQUIPMENT

9C.8.1 Pipeline pigs

Spherical pigs, or other sealing pigs may be required to prevent air pockets from being trapped when filling a pipeline with liquid for hydrostatic testing.

Foam pigs, or other pigs intended for liquid removal and drying may be required to clear hydrostatic test medium and to dry a pipeline after hydrostatic testing.

9C.8.2 Liquid Pumps

High volume centrifugal pumps will generally be required to transfer water or other test medium from tank trucks or streams to the pipeline.

Positive displace pumps capable of delivering high pressure are generally required for applying hydrostatic test pressure.

9C.8.3 Gauges and Instruments

Accurate pressure gauges are required to monitor test pressure. Recording instruments are preferred for documentation of a pressure test.

All pressure gauges used to measure and/or document pressure testing shall be accurate within plus or minus one percent of the maximum pressure to be attained.

Paper chart recording gauges shall be checked for accuracy prior to use and recalibrated if necessary. An accurate spring gauge or dead weight gauge may be used in conjunction with a paper chart recording gauge to assure that accuracy is maintained throughout the duration of the test.

Electronic test instruments shall be checked and calibrated by the manufacturer or other certified facility as frequently as needed to assure that their accuracy is maintained.

9C.8.4 Tank Trucks

Tank trucks may be required to supply and for disposal of hydrostatic test liquid.

9C.9 RECORD KEEPING

9C.9.1 Test Report

A test report shall be compiled and shall include at least the following information and data.

- General description of pipeline section or segments being tested
- Method of testing
- Description of pressure measuring instruments including make, model, and serial number if applicable.
- Material descriptions and specifications for end caps, fittings, vessels, etc.
- Calibration certification for pressure measuring/ recording instruments
- Sources of test medium
- Elevation data for hydrostatic testing
- Estimated or measured volume of test medium if other than air
- Log of test pressure versus time and date. Whereas analog or digital recording instruments are preferred, pressure time data may be manually recorded. If manually recorded any irregularities that occur between regular time intervals should be captured.
- Chart of test pressure versus volume for hydrostatic testing (if used).
- Results of test. List failures and subsequent actions.
- Laboratory analysis of discharged hydrostatic liquid.
- Disposition of discharged hydrostatic liquid
- Pigging/drying report if hydrostatic test
- Schedule of pipe segments showing length, diameter, wall thickness, specification, grade, calculated internal pressure at 100% SMYS, and percent of SMYS resulting from applied test pressure.
- Record of any factors that may be pertinent to interpreting test results. Examples include changes in pipe temperature and accompanying pressure swing, loss of pressure due to a leak in a test connection, etc.
- Field Performance Work Plan including supporting documents

9C.9.2 Baseline Assessment / Reassessment Report

A final hard copy report shall be compiled by the **Pipeline Integrity Engineer** F3. This report shall include all forms and documents that are pertinent to objective of performing this in-inspection including but not limited to:

- Form 8-1, Baseline Assessment Plan
- Form 9-1, Assessment Project Worksheet
- General notes and correspondence related to project planning
- Pertinent main reports, drawings, and system maps
- Request for Proposal – if contracted
- Materials list, specifications, etc. for temporary piping, etc.
- Procedures for pigging and other line preparation
- Applicable operating data related to preparation Request(s) for Shutdown/Operation
- Management of Change Forms for permanent pipeline alterations and for temporary piping and appurtenances
- Pipeline data sheets, pipe mill test reports, vessel certifications, main reports, and other supporting data as applicable for temporary and permanent piping alterations and appurtenances
- Pressure test report and supporting documents
- Direct inspection results, including main reports, remaining strength calculations, etc.
- All forms and documents required by this subsection and other applicable sections of **the company**'s written pipeline integrity management plan.
- All other documents appropriate and significant to this pressure test, baseline assessment, or reassessment objectives.
- Additionally electronic files shall be maintained of the above documents to the extent practical.

9C.9.3 Retention of Records

Records of a pressure test for integrity management assessment shall be retained for as long as that pipeline remains in service. The **Program Manager – Pipeline Integrity** M1 shall be responsible for records retention.

9C.10 FORMS

9C.10.1 Form 9C-2 – Root Cause Analysis

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Form 9C-2: Root Cause Analysis - Pressure Test Failure

Part 1 - General Information

Project Name: ______ Test Date: ______
Description of test section: ______
Location of failure, general description: ______
Location of failure, GPS coordinates:

Part 2 - Pipe/Component Data

Did failure occur on pipe? ______ *If yes, provide pipe data below:*
Nominal size: ______ Wall thickness: ______ Seam type: ______
Secification: ______ Grade: ______ Coating type: ______
Did failure occur on other than pipe? ______ *If yes, provide description below:*

Part 3 - Failure Description

Failure pressure: ______ System MAOP: ______ Failure % MAOP: ______
Calculated pressure @ 100% SMYS for pipe or rated pressure other than pipe: ______
Failure pressure % SMYS for pipe or % rated pressure other than pipe: ______
Description of failure: ______

Apparent root cause of failure: ______

Additional testing or analysis to be performed (list): ______

List attachments to this report: ______

Part 4- Remedial Actions and Assessment Evaluation

Remedial actions required: ______

Is Pressure Test well suited to identify damage from the threats indicated as root cause of this failure? ______
If no, list additional assessment tools needed: ______

Part 5 - Signatures and Approval

Prepared by: Pipeline Specialist (if applicable)
Approved by: Program Manager Pipeline Integrity
Pipeline Integrity Engineer

Title Signature Date

9C.11 Supplement

9C.11.1 Supplement: Relationship between Internal Pressure and Percentage of SMYS

There are several references percentage of SMYS or resulting hoop stress as a percentage of SMYS with respect to allowable internal pressures for operation and pressure testing.

To understand SMYS it is necessary to understand stress. Stress is a numeric representation of force with a material, typically expressed in psi (pounds per square inch). It is derived by dividing the total force in pounds by the area in square inches resisting that force. If a tension force of 25000 pounds was applied to a 1 inch by 1 inch steel bar a tensile stress of 25000 psi would result.

SMYS is specified minimum yield strength, which is the specified stress that the steel can carry without failure. For API 5L specification pipe the SMYS is as follows:

Grade A25	25,000 psi
Grade A	30,000 psi
Grade B	35,000 psi
Grade X42	42,000 psi

The above represent the minimum strength that must be met to qualify for that grade.

Hoop stress is the tensile stress in a circumferential direction that results in the wall of pipe from the internal pressure. For code compliance purposes the internal pressure that would produce 100% SMYS is calculated using the design formula in 49 CFR 192.105 with the design factor, longitudinal joint factor, and temperature derating factor each equal to 1.0. To determine the pressure that would create hoop stress of a certain percent of SMYS multiply the 100% SMYS value by the decimal equivalent of the percentage in consideration.

The following table shows the specifications and pressure that will produce 100% SMYS hoop stress for the weakest pipe that will normally be encountered in **the company**’s gas transmission systems based upon the design formula in 192.205.

Internal Pressure to Produce Hoop Stress of 100% in Default Grade LG&E Pipe (All dimensions in inches, SMYS in psi, and pressure in psig)					
Nominal Size	Actual O.D.	Wall Thickness	API 5L Grade	SMYS	100% SMYS Pressure
1	1.315	.133	A25	25,000	5057
2	2.375	.154	A25	25,000	3242
4	4.500	.188	B	35,000	2924
6	6.625	.188	B	35,000	1986
8	8.625	.188	B	35,000	1525
12	12.750	.219	B	35,000	1202
16	16.000	.250	B	35,000	1093
20	20.000	.250	X42	42,000	1050
22	22.000	.250	X42	42,000	955
24	24.000	.250	X42	42,000	875
All pipe 4" and larger is defaulted to ERW (Electric Resistance Weld) seam type. Pipe 2" and smaller is defaulted to CW (continuous weld)					

Whereas the above table may serve as a guideline actual wall thickness and grade should be used to calculate hoop stress values whenever they are known.

9D LONG RANGE ULTRASONIC TESTING PROCEDURE

In This Section

9D.1 OVERVEIW

9D.1.1 Purpose

The purpose of this procedure is to provide direction for use of long range ultrasonic testing as a direct assessment tool, or as a method of baseline assessment of gas transmission in-service pipelines as a part of the company's pipeline integrity management program. Long range ultrasonic testing (LRUT), also known as guided wave is regarded as "other technology" by the Office of Pipeline Safety and is subject to their approval for use as a baseline assessment tool.

9D.1.2 Scope

This procedure is applicable to all steel gas transmission pipelines operated by Louisville Gas and Electric Company and Kentucky Utilities Company.

This procedure is intended for use on gas transmission pipelines to perform baseline assessments and reassessment as a part of the Pipeline Integrity Management Program as prescribed under US Department of Transportation (DOT) regulations 49 CFR Part 192 Subpart O. It is also applicable to gas transmission and distribution pipelines not covered under this subpart. When used as a direct assessment tool, Sections 7 "Direct Assessment, 7A "External Corrosion Direct Assessment" and 7B "Internal corrosion Direct Assessment" shall be referenced.

This procedure is intended to provide guidance to ensure compliance with applicable pipeline safety regulations, environment protection regulations, and job site safety standards, while optimizing the process of performing baseline assessments as a part of the LG&E / KU (the company) pipeline integrity management program.

9D.1.3 References

Department of Transportation, Title 49, Code of Federal Regulations, Part 192, Subpart O

9D.1.4 Responsibility

When a long range ultrasonic test is performed on an in-service gas transmission pipeline as a part of a transmission pipeline integrity inspection, the roles and responsibilities of personnel overseeing and performing the required tasks shall be in accordance with the requirements of Section 2, "Roles and Responsibilities" of the companies written pipeline integrity management program. The designated responsibilities within this procedure are with reference to Section 2 of the written program.

9D.1.4.1 Program Manager

The Program Manager Pipeline Integrity M1 has the overall responsibility to assure that this procedure is implemented effectively. Whereas specific responsibilities are designated to specific positions, such responsibilities may be delegated to contractors or other qualified personnel subject to approval by the Program Manager Pipeline Integrity.

9D.1.4.2 Corrosion Supervisor

The Corrosion Supervisor M3 shall be responsible for review of inspection data and for evaluation of the integrity of each pipeline being inspected. The Corrosion Supervisor shall analyze direct examination inspection data and may perform predicted failure pressure and remaining life calculations.

9D.1.4.3 Pipeline Specialist

The Pipeline Specialist F5 shall be responsible for assuring that field operations are conducted in accordance with the applicable provisions of the company's written pipeline integrity management plan.

9D.1.4.4 Pipeline Integrity Engineer

The Pipeline Integrity Engineer F3 shall be responsible for assuring that data is comprehensive and accurate and that records are properly compiled for permanent retention. The Pipeline Integrity Engineer may perform predicted failure pressure and remaining life calculations.

9D.1.4.5 Manager- Gas Storage

Gas Storage and Control shall be responsible for the operation of gas transmission pipelines throughout the commencement of inspection procedures.

9D.2 DISCUSSION

9D.2.1 Regulatory Requirements

9D.2.1.1 U.S. DOT Requirements

Long range ultrasonic testing is considered by PHMSA to be "other technology" and requires notification to PHMSA and local authorities at least 180 days prior to use as a standalone baseline assessment tool. PHMSA and the pipeline industry are collaboratively involved in extensive research directed towards advancing anomaly detection and characterization capabilities through guided wave ultrasonic testing.

PHMSA has issued an 18 point checklist for use of their authorized inspectors in evaluating an operator's proposal for using guided wave tools as an "other technology". The PHMSA checklist reflects their acceptance criteria based upon their current understanding and may be subject to change. The latest version should be consulted when preparing notification for submittal.

9D.2.2 How LRUT Works

LRUT or guided wave is a process by which a sound wave (mechanical vibration) is produced in a pipeline or other structure in such a manner that the pipe walls channel the travel either longitudinally or torsionally. If at any point the sound wave encounters a change in cross section area, a reflection occurs causing a portion of the sound wave to travel back towards the source of the original wave. Sensors linked to a computer create a graphic display of sound wave amplitudes from which a trained technician is able to calculate the percentage of each cross section change, the extent of the circumference involved, and distance from the source.

The transducers that send and receive the ultrasonic signals are typically in a collar that is placed around the pipe and in turn connected by cables to the computer processing unit. Physical access to the pipeline is required to enable temporary installation of the transducer collar.

9D.2.3 Applications

Long range ultrasonic testing is generally used as a tool to detect metal loss in pipelines that are inside casings, under waterways, or are otherwise impractical to access for conventional ground surface direct assessment surveys, and for which in-line inspection or pressure testing is not a practical option. To perform an LRUT inspection the pipe must be accessible by excavation adjacent to the area being inspected to enable installation of the signal transmitting and receiving collar.

Effective range is affected by several variables including surface roughness, coating conditions, pipe fittings, soil compaction and environment. Maximum range for which a 5% cross section metal loss is detectible is typically between 60 and 100 feet.

9D.2.4 Go-No Go Testing Criteria

The 18 point checklist issued by PHMSA for use by regulatory enforcement agents when evaluating an operator's proposal to utilize LRUT as a baseline assessment tool is based upon a "Go-No Go" remediation requirement. Any indicated metal loss anomaly of 5% CSA or more must be scheduled for direct examination, ILI inspection, pressure testing or replacement prior to completing the integrity assessment on a cased carrier pipe.

9D.2.5 Description of Process

Long range ultrasonic testing is a process in which a mechanical vibration (sound wave) is induced into a structure and in which it propagates along the structure by a transducer. When the guided wave hits a change in cross section it reflects back toward the transducer, to a degree proportional to the extent of the cross section change. Each change in cross section produces a reflected signal which is sensed by the transducer and interpreted by proprietary software. The induced wave may be torsional or longitudinal, or a combination of both. Optimum frequency may vary according to pipe geometry, coating and environment. Testing should be performed at multiple frequencies.

9D.2.6 Selection of Vendor

As LRUT is an advancing technology not all instruments and supporting software have the same limitations, sensitivity, effective range and other features. Care shall be exercised to assure that the service provider selected will utilize instruments and software capable of detecting metal loss anomalies that are of great enough severity to affect the integrity of the pipeline when considering the geometry, operating conditions, and pipeline environment. These instruments and software will be the most up to date and latest versions available at the time of inspection.

9D.2.7 Glossary

CSA – Cross sectional area, the area of a pipe or other object on a plane perpendicular to its longitudinal axis.

DAC Curve – Distance amplitude correction curve. The reflected amplitude from distance features is smaller than for close features. The DAC curve takes into account coating, pipe diameter, wall thickness, and environment at the assessment location and must be set for each inspection. It provides a means of taking apparent attenuation into account along the time base of a test signal and is necessary for interpretation of results.

Dead Zone – a region adjacent to the transducer collar in which the transmitted signal blinds the received signal reducing the ability of producing meaningful results. The dead zone must be identified and documented for each test. It may be necessary to move the collar and perform additional testing to inspect the initial dead zone.

Direct Examination – physical inspection of the wall of a pipeline, fitting, or component to determine and confirm its actual condition. Direct examination may include ultrasonic testing, radiograph, magnetic particle test, penetrating dye test, measurement of surface conditions such as corrosion or dents, visual observation, chemical analysis of corrosion products, or other testing necessary to confirm and analyze an indicated or suspected anomaly.

First Level Equipment Operator – an operator trained and qualified to setup, calibrate, and operate equipment and to collect data and perform interpretations.

LRUT Inspection Site – a general location, usually within a single excavation, from which inspection of a specified region of pipe that is inaccessible to normal excavation is to be inspected by a guided wave test. Minor relocation of a transducer collar needed to overlap a dead zone and near field effects region, or to enable a confirmation shot does not constitute a separate inspection site.

LRUT – Long range ultrasonic testing, also known as guided wave ultrasonic testing (GWUT)

Near Field Effects – a region beyond the dead zone where the receiving signals are ramping up in power and thus is the region before the wave is established properly. The near field must be identified and documented with each test. It may be necessary to move the collar and perform additional testing to inspect the initial near field.

9D.3 PROCEDURE

9D.3.1 Sensitivity

Any long range ultrasonic testing process used as a part of the company's Pipeline Integrity Management Program must be capable of detecting metal loss that produces a 5% or greater reduction in cross section area at any point within the inspection region.

9D.3.2 Collection of Physical Data

Knowledge of the physical properties and attributes of a pipeline is essential to conducting an accurate long range ultrasonic inspection of a pipeline. In addition to pipe diameter and wall thickness it is beneficial to know pipe coating type and condition, properties of soil, presence of wax fill in casing, and physical attributes including girth welds in both directions from the locations where the transducer collar will be placed Complete and accurate data enables proper setup calibration.

All physical data, including existing defects or anomalies, shall be available to the LRUT operator performing the analysis.

9D.3.3 Excavation and Pipeline Preparation

All excavation and pipeline preparation shall be supervised or performed by personnel qualified by virtue of knowledge of the effected pipeline and inclusion in a company approved operator qualification program. All actions and precautions outlined in Section 11, “Procedure to Minimize Safety and Environmental Risk” and in the company “Health and Safety Manual” shall be followed.

The company’s operating department responsible for operation of the pipeline shall be notified in a timely manner prior to any excavation or preparation.

9D.3.4 Equipment

9D.3.4.1 Equipment and Software Generation

For greatest sensitivity and reliability it is recommended that equipment and software should be version 3 or later.

Earlier versions may be used if it can be demonstrated and documented that the required accuracy and sensitivity can be obtained for the segment being inspected, taking into consideration required range, pipe geometry, coating type, pipe environment, etc. A Senior Level operator is required for all non-automated versions, however a First Level operator with appropriate training and experience may be used with oversight by a Senior Level operator.

9D.3.4.2 Traceability

Equipment, including software, must be identifiable and traceable to its manufacturer. The version of guided wave software, brand names and serial numbers of transducer collars, cables, etc., must be documented in the inspection report.

9D.3.4.3 Calibration

Equipment must be maintained and calibrated per manufacturer’s requirements and specifications, and at prescribed time intervals.

9D.3.5 Performing Inspections

9D.3.5.1 Excavation Safety

Any excavation prepared by the company shall be safe and in compliance with OSHA requirements (29 CFR 1926 Subpart P) and Section 11 of the company’s Pipeline Integrity Management Program (Procedure to Minimize Environmental & Safety Risks).

Daily inspections, and inspections after rain storms or other events likely to increase hazards, shall be made by a competent person prior to company or contractor personnel entering an excavation.

The Pipeline Specialist F5 shall assure that excavation safety requirements are met.

9D.3.5.2 Preparation of Pipe Surface

The outside surface of the pipe must be properly prepared and cleaned in the area in which the transducer collar will be placed. The service provider's recommendations shall be followed. This will generally require removal of coal tar coating, cleaning with a wire brush, and pipe wall thickness readings taken in the six o'clock position where the collar will be positioned.

9D.3.5.3 Field Checks and Diagnostics

Diagnostic checks and systems checks shall be performed on-site each time equipment is relocated. Where on-site diagnostics reveal discrepancies with the manufacturer's specifications, the equipment must be restored to proper specifications before testing is performed.

9D.3.5.4 Frequency

Each shot must be run with a minimum of three frequencies in the range specified by the manufacturer of the equipment. Variations of frequency do not change the axial or clock position of detected features or anomalies, however not all will be detected by a single frequency.

9D.3.5.5 Signal Type

Most guided wave equipment can provide both torsional and longitudinal wave signals. Use of both types may be considered. If only one wave form is used it shall be torsional.

9D.3.5.6 Distance Amplitude Correction Curve

A distance amplitude correction curve (DAC curve) must be set for each inspection.

DAC curves provide a means for evaluating the cross section area change of reflections at various distances in the test range by assessing the signal to noise ration.

Accessible welds along or outside the pipe segment to be tested are used in setting the DAC curve. A weld in the access hole (secondary area) is an alternative provided industry accepted guidelines and PHMSA guidelines (PHMSA Checklist 11/01/07) are met. These guidelines include:

- Sufficient distance must be allowed to account for the dead zone and near field.
- Having a weld, in the near field or dead zone, between the transducer collar and the calibration weld is not permitted.
- If the coating is removed from the weld prior to the inspection then the expected attenuation has been changed.
- A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible or version 3 software is being used. If the actual cap height is different from the assumed cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve maybe required. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating.

Alternative means of DAC calibration can be used if justified by sound engineering analysis and evaluation.

9D.3.5.7 Dead Zone and Near Field

Reliable and reproducible test results are difficult to obtain in the dead zone and adjacent near field. The dead zone is adjacent to the transducer collar and is the zone in which the received signal is blinded by the transmitted signal. The near field, which is adjacent to the dead zone is the region in which the receiving amplifiers are ramping up and the wave is not properly established. Some instrument and software manufacturers do not differentiate between dead zone and near field.

The length of the dead zone and near field must be determined and documented for each inspection, and must be accounted for when interpreting results. To properly assess the dead zone and near field it may be necessary to relocate the transducer collar and perform an overlapping inspection.

9D.3.5.8 Inspection Range

The inspection range and sensitivity are set by the signal to noise ratio (S/N ratio). The 5% cross section area criterion for sensitivity with version 3 software and equipment generally requires an S/N ratio of 2.0 or greater for accurate interpretation. At no time should data gathered downstream of a second fitting be considered valid.

Signal to noise ratio is dependent upon several variables including surface roughness, coating, coating condition, pipe fittings, soil compaction, and environment. Maximum range is typically 60 to 100 feet depending upon field conditions for 5% cross section area sensitivity.

9D.3.5.9 Coating Type

Coatings have the effect of attenuating the signal, depending upon their thickness, condition, integrity of bond, and physical properties. LRUT inspections have been successful on pipe coated with coal tar enamel, fusion bonded epoxy, wax, extruded polyethylene, and with taped weld joints and shrink sleeve weld joints. Well bonded concrete coating may be problematic.

9D.3.5.10 Achieving Complete Inspection

To ensure that the entire pipeline is assessed there should be at least a 2 to 1 S/N ratio at all points in the region being inspected. Double ended inspections are recommended whenever practical for crossings, and may be required to cover the required distance. When double ended inspections are used there should be an overlap of at least 5% of the effective range.

If the effective range permits, the collar shall be placed such that the dead zone and near field effects region are outside of the region requiring inspection. When length of the pipe to be inspected requires placement of the collar such that the dead zone and near field fall within the inspection region it will be necessary to perform an additional complimentary inspection with a different collar location to inspect the pipe previously in the dead zone and near field effects region.

If a LRUT inspection is performed and the required sensitivity is not achieved for the entire length of the pipe another type of inspection method must be utilized.

9D.3.5.11 Collection of Data In Two Directions

Data shall be recorded and analyzed both directions from the transducer collar. Known features such as girth welds or elbows shall be used to validate accuracy of the process.

9D.3.5.12 Confirmation Shot

After the initial inspection shot at each location, a second inspection shall be performed with the collar moved back approximately 2 inches or one-half of the effective wavelength. The second inspection shot is to validate indications. Legitimate indications will appear on both shots. Indications that appear on only one shot can be discarded as non-repeatable ghost indications.

9D.3.5.13 End Seal

Industry experience has shown that corrosion anomalies are more likely to occur near end seals than at other points within a casing. Whenever physical access is practical, end seals shall be removed and visual inspection of the carrier pipe shall be performed.

9D.3.5.14 Shorted Casings

Guided waves are stress waves or mechanical vibrations in the pipe and are not affected by electrical interference resulting from a shorted casing. However, if the casing and carrier pipe are in direct contact with high force there may be a signal reflection similar to that which results from a heavily loaded support. If interference other than slight dampening is evident, the shorted casing must be corrected before using LRUT.

Any shorted casings must be corrected in accordance with the company corrosion control procedures.

9D.3.6 Reporting

9D.3.6.1 Field Report

An informal preliminary report shall be made by the guided wave equipment operator to the company representative at the job site at the time each LRUT is performed. This report shall include any information that is significant pertaining to the success of the performance of the inspection or is urgent concerning the integrity and safe operation of the pipeline, and that is immediately apparent to the equipment operator. The informal field report should be electronic either by CD or file copy to thumb drive. It is also recommended that the company request and retain at shots taken at all frequencies.

9D.3.6.2 Written Report

A final written report shall be submitted to the company within one month following completion of each LRUT inspection. The written report shall include at least the following information:

- Name and address and other applicable information identifying contractor performing services.
- Name and brief description of guided wave process performed.
- Scope of inspection work being performed. Multiple pipelines and locations may be included within one report.
- Description of equipment and soft ware used for tests including make, model and serial numbers where applicable. List should include process control units, transducer collars, and other specialized instruments equipment.

- Certification of calibration of instruments. Complete calibration history is not required to be included in report, but should be made available for inspection upon request.
- List of operators and their qualifications. Training and qualifying entity and applicable national standards or guided wave equipment manufacturer's qualification criteria shall be named for each operator.

For each test location at least the following shall be included:

- Location of test site. Description of location should contain pipeline identity and geographic data sufficient to enable a person knowledgeable of the company's transmission systems and mapping systems to locate the testing site. GPS coordinates are recommended but are not required in addition to verbal description. When LRUT is used as a direct assessment tool for isolated segments of an integrity assessment, sufficient location data shall be provided to enable alignment with the overall project.
- List pipe and coating data to extent known.
- List and describe known attributes that will influence performance of inspections, on-site calibrations, and establishing DAC curve. Include welds, fittings, supports, casing starts and ends applicable environmental conditions and other pertinent features.
- Reference to complimentary test locations. Example – test site is on west side of road crossing, complimentary test on east side of road crossing. List extent of overlap with each complimentary test.
- For each test include confirmation of required on site calibrations including establishment of DAC curve.
- For each shot include graphic display and list frequencies and wave type. Include location of zero distance reference direction for positive distance.
- For each test document distance from collar for dead zone and near field effect region.
- For each test location include listing of indicated metal loss anomalies and indicated features such as girth welds.
- For each group of complimentary test locations include listing of indicated metal loss and other features aligned to a common reference.
- Include any remarks pertaining to factors that may affect the accuracy confidence level of any inspection performed.

9D.3.7 Validation Direct Examination

A required validation examination may be of an indication in the pipeline either direction from the transducer collar. It is preferable to examine a metal loss indication of 5% CSA or greater if one is present and accessible. If no metal loss indication of 5% CSA or greater exists in an accessible location a weld, fitting, or other indication may be used.

Measured distance, percent change in CSA, and circumferential extent of an anomaly or feature must correlate within the equipment manufacturers specified tolerances in order for an inspection to be valid.

9D.3.8 LRUT As Primary Assessment Tool

9D.3.8.1 Notice to PHMSA

LRUT is considered as "other technology" by PHMSA. Pursuant to §192.921(a)(4), an operator must notify the Office of Pipeline Safety and the applicable state agency 180 days prior to conducting the assessment. See 9D.12.1 for the Office of Pipeline Safety Notification Template.

In order for other technology to be acceptable to PHMSA, an operator must demonstrate it can provide an equivalent understanding of the condition of the line pipe. The PHMSA checklist that is used to evaluate guided wave notifications is included as an appendix to this section.

9D.3.8.2 Go-No Go Criterion

All metal loss indications in excess of 5% CSA must be directly examined before an integrity assessment is complete. If this is not feasible, an alternate form of assessment, such as ILI or pressure testing must be utilized.

9D.3.8.3 Direct Examination Schedule and Response, Primary Assessment

If LRUT is to be considered as a primary tool for performing a transmission pipeline integrity assessment, the following scheduled responses are required for all metal loss indications in excess of 5% CSA, including those opposite in direction from the crossing subject to inspection. (Source of table, PHMSA checklist)

Table 9D - 1			
	Required Response		
LRUT Criterion	**MAOP Less than 30% SMYS**	**MAOP 30% to 50% SMYS**	**MAOP Over 50% SMYS**
Over 5% CSA and identified for examination	Maximum 12 months	Maximum 6 months	Maximum 6 months
	Leak survey monthly	Limit pressure to MOP at discovery*	Limit pressure to 80% MOP at discovery*

	Perform direct examination	Leak survey monthly	Perform direct examination
		Perform direct examination	
* LG&E considers the MOP (maximum operating pressure) at discovery to be 80% of the historic operating pressure (gauge pressure) that has occurred within the time the apparent anomalies are believed to have existed and within the past ninety days.			

Following direct examination each confirmed anomaly shall be evaluated and repaired or remediated in accordance with Section 10 of this plan.

The provisions of this subsection are applicable to metal loss indications in either direction from the transducer collar, without respect to the HCA status of the pipeline.

9D.3.8.4 Validation Direct Examination

One or more validation direct examinations shall be performed at each LRUT inspection site. The validation examination may be a feature or indicated anomaly either direction from the transducer collar.

9D.3.9 LRUT As Direct Assessment Tool

9D.3.9.1 Direct Inspection and Response

If LRUT is used as a direct assessment tool, direct examination of indications of 5% CSA or more must be performed within 180 days following the last DA inspection. (§192.933(b))

Consideration shall be given to the reflection intensity and circumferential extent to estimate the severity of an indicated metal loss. The following table is presented as a guide for ranking severity of guided wave indications. Subject to the corrosion supervisor’s approval other ranking methods may be used.

Table 9D - 2			
Circumferential Extent	**Intensity of Reflection**		
	5% to 10%	10% to 20%	More than 20%
More than 50%	Minor	Minor	Intermediate
25% to 50%		Intermediate	Severe
Less than 50%	Intermediate	Severe	Severe

Following direct inspection, each confirmed anomaly shall be evaluated and repaired or remediated in accordance with Section 10 of this plan.

The provisions of this subsection are applicable to metal loss indications in either direction from the transducer collar without respect to the HCA status of the pipeline.

When used as a direct assessment tool, all applicable provisions of Section 7A, "External Corrosion Direct Assessment" and Section 7B, "Direct Assessment Plan – Internal Corrosion" must be met.

9D.3.9.2 Pressure Limitation for Severe Indication

Any indicated anomaly ranked as severe shall be subject to pressure reduction or limitation in accordance with Section 10.4.8 of this plan pending direct examination and confirmation.

9D.3.9.3 Validation Direct Examinations

The number and selection of validation examination sites shall be in accordance with the requirements of the respective direct examination written procedures. Additional validation direct examinations shall be performed if necessary in the opinion of the senior level operator responsible for overseeing the inspection(s).

9D.4 SAFETY

9D.4.1 General Safety

All applicable provisions of the LG&E/KU Health and Safety Manual shall be followed and all applicable provisions of Section 11 of this written plan, "Procedure To Minimize Environmental And Safety Risks" shall be followed.

9D.4.2 Job Site Safety

Special attention shall be directed towards excavation safety, traffic control, and other issues directly affecting job site safety.

9D.4.3 Asbestos

Company asbestos abatement procedures must be followed for removal, handling, and disposal of coal tar enamel pipe coating.

9D.5 ENVIRONMENTAL

9D.5.1 Asbestos Removal

All coal tar enamel coating removed from a pipeline must be collected, removed from the excavation, and disposed of in accordance with the company's environmental protection procedures.

9D.6 TRAINING AND QUALIFICATIONS

9D.6.1 LRUT Equipment Operator Training and Experience

All operators of guided wave equipment must have equipment specific training and experience commensurate with the duties which he or she is required to perform. This will typically include equipment operation, field data collection, and data interpretation on cased and buried pipe.

A Senior Level Equipment Guided Wave Operator with pipeline specific experience must provide oversight and approve final reports of a First Level Guided Wave Equipment Operator.

Minimum guided wave equipment operator training and experience requirements include the following:

Table 9D - 3

Accountability	First Level*	Senior Level*
Equipment manufacturer's minimum qualifications for operation and data collection with specific endorsements for casings and buried pipe	X	X
Testing procedures and frequency determination	X	X
Conversion of guided wave data into pipe features and estimated metal loss	X	X
Equipment manufactures minimum qualification with specific for data interpretation of anomaly features for pipe within casings and for buried pipe.		X
** Based upon guidelines presented in PHMSA checklist, revised on 11/01/07. This does not preclude acceptance of a plan using a different operator classification system effectively meeting these requirements.*		

Qualifications of guided wave equipment operators shall be certified by the vendor, documented, and retained with inspection reports.

9D.6.2 Operator Qualification Program

All operators of guided wave equipment must be included in an Operator Qualification Plan that is in compliance with 49 CFR Part 192 and is approved by the company.

9D.6.3 Drug and Alcohol Control

rAll operators of guided wave equipment must be included in a Drug and All operators of guided wave equipment must be included in a Drug and Alcohol Control program that is in compliance with 49 CFR Part 199 and is approved by the company.

9D.7 EQUIPMENT

9D.7.1 LRUT Instrumentation

Specialized equipment intended specifically for performing long range ultrasonic testing is required. This includes but is not limited to the central processing unit, transducer collar, connecting cables, and proprietary software.

9D.8 RECORD KEEPING

9D.8.1 Record Keeping

It shall be the responsibility of the Program Manager Pipeline Integrity M1 to assure that records are maintained in accordance with Section 16, “Record Keeping”, of this written plan.

Records of baseline assessments, reassessments, and other transmission pipeline integrity assessments and records resulting remedial actions are generally required to be maintained for the useful life of the pipeline.

9D.9 FORMS

9D.9.1 Office of Pipeline Safety Notification Template

The following template is available through PHMSA for use in submitting notices that are required under the Gas Integrity management provisions of 49 CFR Part 192, Subpart O. Typical applicable information is shown in right-hand column.

Office of Pipeline Safety
Gas Integrity Management (49 CFR Part 192)
Notification Template

Enter information only in portions of tables with white background. This template covers 3 different types of Notifications. Some sections of this template only apply to specific Notifications types as noted. Any section that does not apply should be left blank. See following web page for methods of submitting notifications to OPS:
http://primis.phmsa.dot.gov/gasimp/Notifications.htm

In addition to completing this template to notify OPS, operators must contact individual states for notifications also required to be submitted to state and local authorities!

Table 1. Operator Identification and Contacts

[tblContact]	Contact Information	*Complete All Applicable Information*
[sbmDate]	*Date Notification Submitted*	MM/DD/YYYY
[oprName]	*Operator Name*	Louisville Gas & Electric or Kentucky Utilities as applicable
[oprID]	*OPS-Assigned Operator ID*	LG&E or KU Operator's Number
[sysSttInter]	*Affected States- Interstate Lines* (2-letter state codes, separate by commas)	
[sysSttIntra]	*Affected States- Intrastate Lines* (2-letter state codes, separate by commas)	Ky or IN as applicable
[sysCommod]	*Commodity Transported*	Natural gas
[sbmName]	*Name of Person Submitting*	Name of Program Manager Pipeline Integrity M1
[sbmTitle]	*Submitter's Job Title*	LG&E or KU job title for above
[sbmEmail]	*Submitter's Email Address*	LG&E or KU Email address for above
[sbmPhone]	*Submitter's Phone Number*	LG&E or KU Office telephone for above
[mgrName]	*Name of Responsible Manager* (if not person submitting)	Name of Manager Gas Regulatory Compliance M4
[mgrTitle]	*Manager's Job Title*	LG&E or KU job title for above
[mgrEmail]	*Manger's Email Address*	LG&E or KU Email address for above

Table 2. Brief Summary Statement

[tblSum]	*Provide a brief summary statement below describing the purpose of the notification.*
[sumText]	*Typical description . . .* LG&E intends to utilize Guided Wave technology to assess the condition of the (nominal size) inch gas carrier pipe inside a casing in a High Consequence Area in (name) Co., KY. This casing is (nominal size) inches in diameter by (known or estimated length) feet long and is under (name of highway or railroad).

Table 3. Selection of Notification Type

[tblType]	Type of Notification	*Type an **X** in the Appropriate Cell*
[type_1]	***Type 1**. Substantial Change to IM Program. (¶ 192.909(b))*	
[type_2]	***Type 2.** Other Assessment Technology. (¶ 192.921(a)(4) or 192.937(c)(4))*	X
[type_3]	***Type 3.** Schedule for Evaluation and Remediation. (¶ 192.933(c))*	

NOTE: The choice of notification type affects the applicability of other tables below.

Table 4. Description of IM Program Change (Type 1 Notifications Only)

[tblPgm]	*For Type 1 notifications, provide a description of the substantive changes and their effect on the IM program.*
[pgmText]	

NOTE: Leave this table blank except for Type 1 notifications.

Table 5. Justification for Use of Other Assessment Technology (Type 2 Notifications Only)

[tblTech]	Technology Information	*Complete All Applicable Information*
[techSch]	*Assessment Schedule Date*	Month/day/year
[techDesc]	*Description of Other Technology to be Used* (Include references to standards, where appropriate)	Long Range Ultrasonic Testing (Guided Wave) Include equipment and software manufacturer and version if known

[techBasis]	*Basis for Concluding that "Equivalent Understanding" of Pipe Condition will be Provided*	Inspection will be performed in accordance with LG&E/KU procedure 09D Pipeline Long Range Ultrasonic Testing which includes the following minimum specifications: Make, model, serial numbers for all major equipment and software shall be documented. All Operator Qualification documentation will be provided and current. LRUT equipment, software, and procedures must be capable of discovering any change in cross section are of plus or minus 5%. Certification of calibration per manufacturers specifications, including time intervals shall be provided. Transducer will be placed such that dead zone and near field effects region are outside of casing or inspection segment. If necessary collar will be relocated to inspect dead zone and near field region. Dead zone and near field effects regions shall be documented. When casing or crossing length exceeds the range of the LRUT equipment being used inspection shall be performed from both ends. A minimum overlap of 5% of the total length shall be required for the inspection to be complete. DAC curve shall be determined and documented for each inspection. Immediate field interpretation of results will be provided. Final report verified. Inspection data will be recorded in the opposite direction of the cased pipeline to be used for validation purposes. A minimum of one (1) indication outside of the casing will be directly inspected to validate results. All indications in excess of 5% CSA in the validation region will be direct examined. All pre-existing pipeline data and conditions will be reported to guided wave technician.

NOTE: Leave this table blank except for Type 2 notifications.

Table 6. Evaluation and Remediation Details (Type 3 Notifications Only)

[tblRpr]	Remediation Information	*Complete All Applicable Information*
[rprImmed]	*Immediate Repair Condition per ¶192.933(d)(1)? (answer Yes or No)*	
[rpr1Year]	*One-Year Condition per ¶192.933(d)(2)? (answer Yes or No)*	

[rprSch]	*Required Response Date per ASME B31.8S, Figure 4 (not applicable if either of above is answered Yes)*	
[rprDefect]	*Description of Defects Requiring Repair*	
[rprRepair]	*Description of Required Remediation*	
[rprReason]	*Reason for Delay (include any factors outside operator's control)*	
[rprPressure]	*Reason Why Pressure Cannot be Reduced*	
[rprBasis]	*Basis for Concluding that Delay will not Jeopardize Public Safety*	
[rprPlan]	*Proposed Schedule for Repair*	
[rprMitigate]	*Other Mitigative Measures Planned*	

NOTE: Leave this table blank except for Type 3 notifications.

Table 7. Description of Affected Pipeline System/Segments (Type 2 and 3 Notifications Only)

[tblSys]	Pipeline Information	*Complete All Applicable Information*
[sysSize]	*Diameter (inches)*	Nominal size
[sysMaterial]	*Material*	Steel, specification, and grade
[sysWeld]	*Weld Type*	Longitudinal seam if known
[sysCoatings]	*Coatings*	Coal tar, FBE, etc.
[sysMfgBy]	*Manufacturer*	Jones and Laughlin
[sysMfgTear]	*Year Manufactured*	If known
[sysInstalled]	*Year Installed*	From records
[sysDesignP]	*Design Pressure*	Per §192.105
[sysMOP]	*MAOP*	400
[sysWall]	*Wall Thickness*	.219

[sysLastPig]	*Date Last Pigged*	
[sysLastHydro]	*Date of Last Hydro Test*	
[sysLastDA]	*Date of Last Direct Assessment*	
[sysPipeline]	*Additional Details about Affected Pipeline*	General description, include length and nominal size of pipe and casing. Include %SMYS at MAOP Statement of leak history Corrosion Control History – Include CP type, coating, CP operating history, casing shorts, etc. Casing ends will be excavated to ensure proper seals, vents, and CC test stations are in place. Air will be used to evacuate any water collected in annular space.
[sysLocation]	*Affected Segment(s) Location* *(milepost, county, state, etc.)*	Include LG&E/KU pipeline name, general description of location(s) for inspecrtion(s).
[sysHcaDesc]	*Nature of HCA: Class 3 or 4, Housing density, Identified Site*	State applicable criterion for pipeline

Table 8. Additional Information

[tblOther]	*Other information relevant for regulatory review. If additional supporting material has been supplied separately, provide a brief description here.*
[otherText]	

[End of Notification.]

9D.10 APPENDIX

Appendix 13-A PHMSA Checklist

Guided Wave UT Target Items for Go-No Go Procedures

These target items are for guidance only and do not require that notifications contain only this material. Where operators have alternatives to this guidance, it is suggested that they include it along with any justification in their notification. PHMSA will review each notification on the merits of the individual submittal.

1. Generation of Equipment and Software

The generation of both the equipment and the computer software is critical to the success of the inspection. Both major equipment vendors are on version 3. Prior versions may be used but require operator specific training and procedures for the earlier versions to achieve manually what later versions can do automatically. A Senior Level GWUT Equipment Operator is required for all equipment and software versions, non-automated, prior to version 3 or First Level GWUT Equipment Operator with experience and training in use of the equipment/software version may be used with oversight by a Senior Level GWUT Equipment operator of all procedures used and interpretation of data prior to completing evaluation of data. Automatic diagnostics, etc., may improve the efficiency of the test and reduce the time taken to collect data, but will not affect the sensitivity or ability to detect defects. This allows the operator to focus on the interpretation of the data rather than the mechanics of the inspection.

2. Inspection Range

The inspection range and sensitivity are set by the signal to noise (S/N) ratio but must still keep the maximum threshold sensitivity at 5% cross sectional area (CSA). Any signal that has an amplitude that is about twice the noise level can be reliably interpreted. The greater the S/N ratio the easier it is to identify and interpret signals from small changes. The signal to noise ratio is dependent on several variables such as, surface roughness, coating, coating condition, associated pipe fittings (T's, elbows, flanges), soil compaction, and environment. Each of these affects the propagation of sound waves and influences the range of the test. It may be necessary to inspect from both ends of the pipeline segment to achieve a full inspection. In general the maximum inspection range can approach 60 to 100 feet depending on field conditions for a 5% CSA. At no time should data downstream of a second fitting be considered valid.

3. Achieving a complete inspection of the pipe

To ensure that the entire pipeline segment is assessed there should be at least a 2 to 1 signal to noise ratio for the required wall loss anomalies to be detected, across the entire pipeline segment that is inspected. This may require multiple GWUT shots. Double ended inspections are expected. These two inspections are to be overlaid to show the minimum 2 to 1 S/N ratio is met in the middle. If possible, show the same near or midpoint feature (if present) from both sides and show an approximate 5% distance overlap.

4. Sensitivity

Sensitivity is defined as the ability to identify a reflection of a specified cross sectional change. The signal to noise ratio determines the detectability at a certain distance and thus sets the range. A sensitivity of 5% of the cross sectional area (CSA) must be achieved. By achieving a 5% sensitivity at the maximum inspection range, a greater sensitivity may be achieved on the segment at locations closer to the inspection equipment. The minimum sensitivity achieved must be able to identify the smallest defects that will fail by rupturing in a hydrostatic test.

The locations and estimated CSA of all metal loss features in excess of the detection threshold shall be determined and reported.

The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe.

5. Frequency

The frequencies used for the inspections must be in the range specified by the manufacturer of the equipment. A sufficient number of frequencies (at least 3) need to be run for each shot as to determine the best frequency for characterizing indications. The frequencies or range of frequencies needs to be documented.

Different frequencies do not change axial position or clock position. If only a single frequency is selected certain defects may not be detected.

6. Signal or Wave Type – torsional and longitudinal

Most GWUT equipment can provide both torsional and longitudinal signals. Although the use of torsional waves may produce the best results, longitudinal waves may also be considered. Where only one wave type is available, it must be torsional. Documentation of the wave type must be provided.

Torsional waves do not couple well with liquids, therefore if liquid is in or around the pipe segment then the operator must consider the use of torsional waves.

7. Distance Amplitude Correction (DAC) curve is required for each inspection

Setting the DAC curve is an important step in establishing the effective range of a GWUT test and must be performed for each inspection. The DAC takes into account coating, pipe diameter, pipe wall and environmental conditions at the assessment location.

DAC curves provide a means for evaluating the cross sectional area change of reflections at various distances in the test range by assessing signal to noise ratio. A DAC curve is a means of taking apparent attenuation into account along the time base of a test signal. It is a line of equal sensitivity along the trace which allows the amplitudes of signals at different axial distances from the collar to be compared.

8. Dead Zone

The Dead Zone is adjacent to the collar. GWUT uses pulse echo testing. The transmitted signal blinds the received signal, thus reducing the ability to obtain reproducible results. Therefore it can be determined from the length of the transmission pulse and the recovery time of the receiver circuits once the transmission burst has ceased.

Inspection procedures need to account for the dead zone. The length of the dead zone must be documented for each inspection.

Different inspections can yield different dead zones. If one is assessing cased crossings, the collar must be placed such that the dead zone does not extend into the casing, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the dead zone.

To properly assess the dead zone the service provider can move the collar and conduct an additional inspection of the dead zone. An alternate method of obtaining valid readings in the dead is to use B-scan ultrasonic equipment and visual examination of the external surface.

It is recognized that not all manufacturers differentiate between the dead zone and the near field/zone.

9. Near Field Effects

The near field is the region beyond the dead zone where the receiving amplifiers are ramping up in power and thus is the region before the wave is established properly. This is not a function of the waveform but rather it is a function of the pulse echo collection method and is affected by pipe geometry. Classification is difficult in the near field due to reduced amplitude.

Inspection procedures need to account for the near field. The length of the near field must be documented for each inspection.

To properly assess the near field, the collar must be placed such that the near field does not extend into the casing, because a majority of indications in casings are typically located within the first few feet. A properly trained service provider can identify and report the near field.

To properly assess the near field the service provider can move the collar and conduct an additional inspection of the near field. An alternate method of obtaining valid readings in the near field is to use B-scan ultrasonic equipment and visual examination of the external surface.

10. Coating type

GWUT inspections that have been conducted on pipe coated with coal tar enamel, FBE, wax, extruded coatings, and some with girth welds coated with tape or shrink sleeves, which have not affected results.

Coatings can have the effect of attenuating the signal. Their thickness and condition are the primary factors that affect the rate of signal attenuation. Due to their variability, coatings make it difficult to predict the effective inspection distance.

Several coating types may affect the GWUT results to the point that they may reduce the expected inspection distance. For example, concrete coated pipe may be problematic when well bonded due to the attenuation effects. If an inspection is done and the required sensitivity is not achieved for the entire length of the cased pipe, then the use of GWUT is not feasible and another type of assessment method must be utilized.

11. End Seal

The end seal does not interfere with the accuracy of the GWUT inspection but may have a dampening effect on the range. The vast majority of indications on carrier pipes in casings occur in the first several feet and this area is critical to the integrity of the pipeline. Operators will remove the end seal from the casing at each GWUT test location to facilitate limited visual inspection. Water and debris can collect at the low point and cause electrolytic shorts. Venting can also be a source of moisture and debris, and are typically located near the casing ends. Operators will be required to observe and collect the corrosion data, if found, under the end seal and process the data to verify the GWUT was correct.

12. Weld Calibration – welds are used to set DAC curve

Accessible welds, along or outside the pipe segment to be inspected, are used in setting the DAC curve. A weld(s) in the access hole (secondary area) is an alternative to set the DAC curve. In order to use these welds in the secondary area, sufficient distance must be allowed to account for the dead zone and near field. Having a weld, in the near field or dead zone, between the transducer collar and the calibration weld is not permitted. If the coating is removed from the weld prior to the inspection then the expected attenuation has been changed. A conservative estimate of the predicted amplitude for the weld is 25% CSA (cross sectional area) and can be used if welds are not accessible or version 3 software is being used. Calibrations (setting of the DAC curve) should be on pipe with similar properties such as wall thickness and coating. If the actual cap height is different from the assumed cap height, the estimated CSA may be inaccurate and adjustments to the DAC curve maybe required. Alternative means of calibration can be used if justified by sound engineering analysis and evaluation.

13. Validation of Operator Training

In the absence of an industry standard for certifying GWUT service providers, pipeline operators must require all guided wave service providers to have equipment specific training and experience for First Level and Senior Level GWUT Equipment Operators which include:

1. equipment operation,
2. field data collection, and
3. data interpretation on cased and buried pipe.

A Senior Level GWUT Equipment Operator with pipeline specific experience must provide oversight and approve the final reports of a First Level GWUT Equipment Operator. A Senior Level GWUT Equipment Operator must have additional training and experience beyond that required for the field data collection level operator, First Level GWUT Equipment Operator. This additional training must be specific to cased and buried pipe, and there must be a quality control program which conforms to Section 12 of ASME B31.8S.

Guided Wave Training and Experience Minimums – for First Level and Senior Level GWUT Equipment Operators

- Equipment Manufacturer's minimum qualification for equipment operation and data collection with specific endorsements for casings and buried pipe
- Training, qualification and experience in testing procedures and frequency determination
- Training, qualification and experience in conversion of guided wave data into pipe features and estimated metal loss (estimated cross-sectional area loss and circumferential extent)
- Equipment Manufacturer's minimum qualification with specific endorsements for data interpretation of anomaly features for pipe within casings and buried pipe – applicable for Senior Level GWUT Equipment Operator.

14. Equipment – should be traceable from vendor to contractor.

The equipment and software must be readily traceable back to the manufacturer. The version of the GWUT software used and the serial number of the other equipment such as collars, cables, etc., must be traceable and documented in the report. Only individuals who have been qualified by the manufacturer or an independently assessed evaluation procedure similar to ISO 9712 (Sections: 5 Responsibilities; 6 Levels of Qualification; 7 Eligibility; and 10 Certification), as specified above, shall operate the equipment.

15. Calibration, Onsite – diagnostic test on site and system check on site.

The equipment must have been calibrated per the equipment manufacturer's requirements and specifications for both performance and time between calibrations prior to being shipped to the service provider. A diagnostic check and system check shall be performed on-site and each time the equipment is relocated. Where on site diagnostics show some discrepancies with the manufacturer's requirements and specifications, the testing shall cease until the equipment can be restored to manufacturer's specifications.

16. Use on shorted (either direct or electrolytic) casings

Shorted casings may not interfere with GWUT assessments. Guided waves are stress waves or mechanical vibrations in the pipe wall. They are not effectively coupled to and hence should not be affected by the electro-magnetic waves. There may be a reflection if the casing and pipe are in direct contact with high contact force, which may affect the GWUT results, but this can and should be addressed with procedures for any heavily loaded support.

Shorted casings may not interfere with the GWUT signal to noise ratio and subsequent results. If GWUT Service Operators see any evidence of interference other than some slight dampening of the GWUT signal from the shorted casing, it must be cleared to use GWUT.

All indications (wall loss anomalies) below the testing threshold (5% of CSA sensitivity) meeting the GWUT "Go-No Go, 18 Point Checklist" criteria, provided that there is no interference or masking of these indications (wall loss anomalies) if the indications are in the area of the short, do not need to be directly examined.

All shorted casings found while conducting GWUT inspections must be addressed by the operator's SOPs and are not to be considered part of a GWUT procedure.

17. Direct examination of all indications above the testing threshold is required.

The use of GWUT in the "Go-No Go" mode requires that all indications (wall loss anomalies) above the testing threshold (5% of CSA sensitivity) be directly examined (or replaced) prior to completing the integrity assessment on the cased carrier pipe. If this can not be accomplished then the use of GWUT is not considered feasible and alternative methods of assessment (such as hydrostatic pressure tests or ILI) must be utilized.

18. Timing of direct examinations of indications above the testing threshold.

All indications (wall loss anomalies) that are identified above the threshold must be scheduled for direct examination. Under a prescriptive plan for these indications, the maximum time frame for each is 6 months for those pipelines operating at greater than 30% SMYS and 12 months for those operating at or below 30% SMYS. For those locations where the operating pressure is greater than 50% SMYS, the pressure must be reduced to 80% of the operating pressure at the time the indication is "discovered" by the GWUT. For those locations where the operating pressure is greater than 30% and less than or equal to 50% SMYS, then the operating pressure shall not exceed the operating pressure at the time of the "discovery" of the indication and the monthly leak survey shall be performed until the indication is directly examined. For those locations where the operating pressure is less than or equal to 30% of SMYS, the casings must be leak surveyed once a month until the indication is directly examined.

	Required Pipeline Response		
GWUT	**Less than 30%**	**Over 30% to 50%**	**Over 50% SMYS**

Criterion		**SMYS**	
Over 5% CSA and identified for examination	Interval < 12 month	Interval < 6 months	Interval < 6 month
	Leak survey once/month	Direct Examination +	Direct Examination +
	Direct Examination	MOP < psi @ discovery	Reduce to 80% MOP @ Discovery
		Leak survey Once /month	

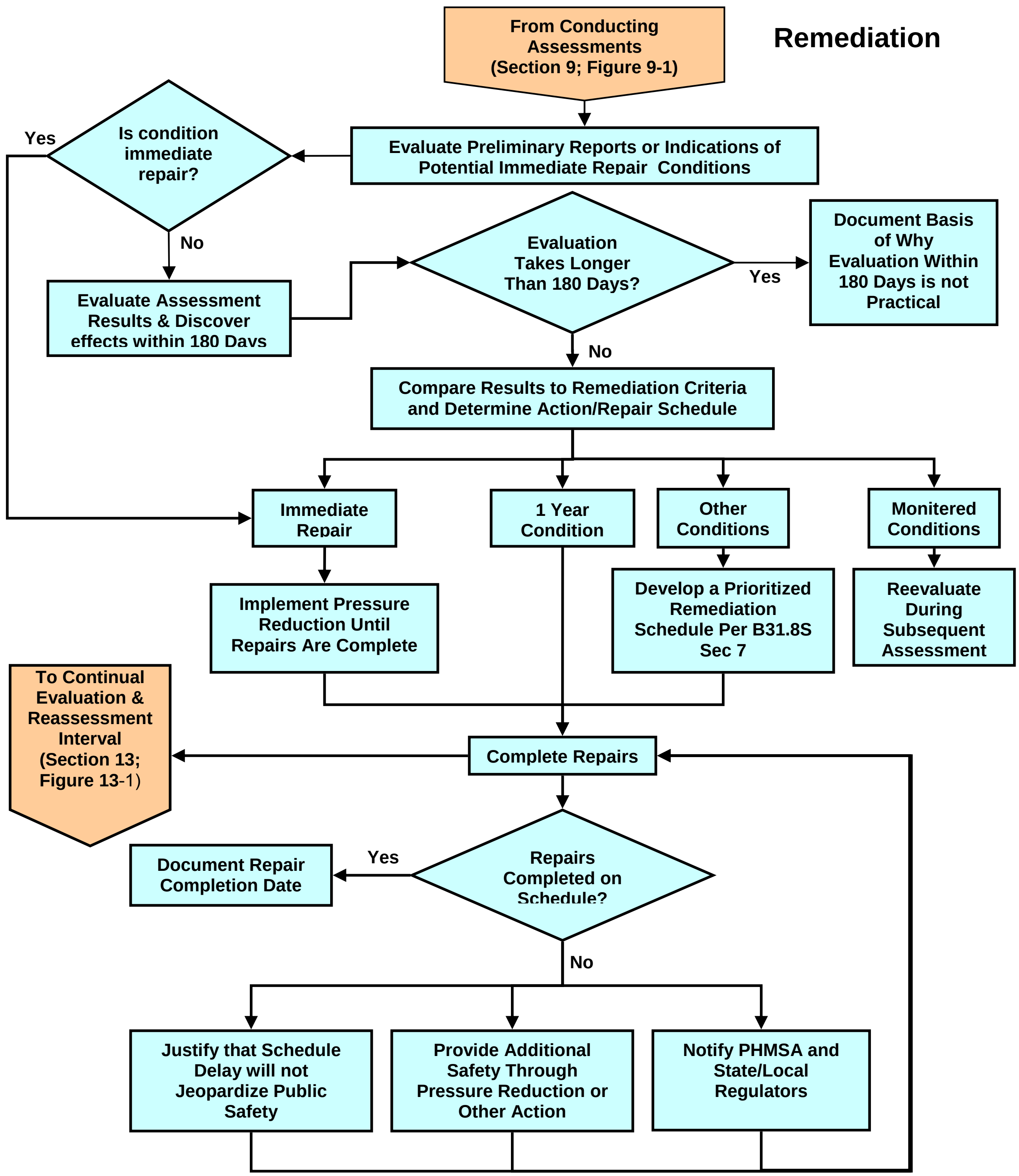
10 REMEDIATION §192.933

In This Section

Referenced Protocols

10 REMEDIATION

10.1 Overview



Source: PHMSA Website

Figure 10-1: Discovery, Evaluation, and Remediation

10.1.1 Purpose

The Remediation section describes **Louisville Gas & Electric/Kentucky Utilities (the company)** program requirements for addressing anomalous conditions discovered through pipeline integrity assessments (Sections 7 and 9). **The company** will evaluate all anomalous conditions and remediate those that could reduce the integrity of the pipeline. This section specifically addresses the evaluation of assessment data, discovery of a condition, responses, prioritized schedule, time limitations, and repair methods.

> **NOTE:** Reassessment intervals for corrosion threats can be directly affected by the level of repairs made beyond the minimum 49 CFR 192 Subpart O's requirements described herein. Refer to Subsection 13.4.1.

10.1.2 Responsibility

Section 2 provides a complete description of the roles, responsibilities, job task analyses, and minimum qualifications for key personnel positions necessary for the implementation of the procedures described in this section.

The **Program Manager – Integrity Management** M1 serves as the default **Qualified Individual (QI)** for determining the discovery of immediate repair conditions regardless of the assessment method used, although this responsibility can be delegated to other qualified personnel. The **Program Manager – Integrity Management** M1 is also responsible for the following tasks: reviewing and approving the safe operating pressure for Immediate Repair Conditions, oversight and approval of the anomaly remediation procedures and implementation, and ensuring that the response time for any Immediate or Scheduled Repair is not exceeded.

The **Manager of Operations** F1 is responsible for determining the safe operating pressure for immediate repair conditions, and manages the remediation of anomalous conditions in mainline pipe and other system facilities.

The **Pipeline Specialist** F5 (PS) is responsible for providing direct field oversight of the remediation of anomalous conditions in mainline pipe and other system facilities.

The **Pipeline Integrity Engineer** F3 (PIE) is responsible for compiling and maintaining all documentation of the Remediation process.

10.2 General

✓ ***Referenced Protocol:*** *E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling*

The company will address all anomalous conditions discovered through pipeline integrity assessments and remediate those that could reduce the integrity of the pipeline. The company will use the processes described in this section and appropriate repair methods to demonstrate that remediation of the condition is unlikely to pose a threat to pipeline integrity before the next assessment cycle.

10.2.1 Evaluation of Assessment Results – Time Limits

Preliminary reports and final reports of assessment results, upon receipt, shall be reviewed as soon as is practical for timely discovery of immediate repair conditions.

The company shall complete the evaluation of the integrity assessment data within 180 days of the completion of the integrity assessment. During this period, sufficient information will be assembled on each potential anomalous condition to determine if it presents a potential threat to the integrity of the pipeline. This applies to any approved assessment method including:

- Direct Assessment
- Inline Inspection
- Pressure Testing (Subpart J)
- Other Approved Technology

The completion date of the integrity assessment and the scheduled evaluation date will be recorded on the appropriate worksheet or form for the assessment method being used. These forms and worksheets are provided in Subsection 9B.10 - Forms for reference.

Those anomalies in covered segments that could pose an immediate threat will be addressed **as soon as practical, and within 5 days of discovery.**

Anomalies in covered segments that do not pose an immediate threat will be properly classified as a scheduled repair or monitored condition. Scheduled anomalies will be addressed in the remediation schedule, and monitored conditions will be recorded for future re-evaluation during the next assessment interval.

Those anomalies in non-covered segments shall be addressed according to the requirements in 49 CFR 192.485, 192.703(b), 192.711, 192.713, 192.715, 192.717 and 192.719 as applicable. In addition, the Company may address anomalies in non-covered segments according to the requirements for covered segments.

10.2.1.1 Evaluation of Assessment Beyond 180 Days

The company will make every reasonable effort to complete evaluation of the integrity assessment data within the required 180 days. However, should this become impractical, **the company** will notify PHMSA and KPSC and/or IURC before the end of the 180 days, and demonstrate why completing the evaluation within the 180 days is impractical. The basis of why the 180 days is impractical will be documented on Direct Examination Form available on the company intranet.

10.2.2 Qualified Individual (QI) – Determination of Immediate Repair Conditions

See Section 10.1.2.

10.3 Definitions

Anomaly
An Anomaly is a possible deviation from sound pipe material or weld. Indication may be generated by non-destructive inspection, such as in-line inspection (NACE SP0102-2010NACE SP0102-2010)

Defect
An anomaly for which an analysis indicates that the pipe is approaching failure as the nominal hoop stress approaches the specified minimum yield strength of the pipe material (NACE SP0102-2010).

A defect is an imperfection of a type or magnitude exceeding acceptable criteria (API 570 and ASME B31.8S as referenced in Appendix 1B of this IMP)

Discovery of a Condition
Discovery of a condition occurs when an Operator has adequate information about an anomaly to determine that the anomaly presents a potential threat to the integrity of the pipeline. A condition that presents a potential threat includes, but is not limited to, the following conditions that require remediation or monitoring:

- Scheduled Repair Conditions for External and Internal Corrosion per B31.8S, Section 7, Figure 4
- Immediate Repair Conditions, per §192.933(d)
- One-Year Conditions per §192.933(d)
- Monitored Conditions per §192.933(d)
- Verification Condition per the company definition
- Other Condition per the company definition

Imperfection
An anomaly in the pipe that will not result in pipe failure at pressures below those that produce nominal hoop stresses equal to the specified minimum yield strength of the pipe material (NACE SP0102-2010). A flaw or other discontinuity noted during inspection that may be subject to acceptance criteria during an engineering and inspection analysis (API 570).

Indication
When used with respect to direct assessment or in-line inspections an indication is an instrument response or observed surface condition that is consistent with the response and/or observed condition that would occur if an anomaly were present. Per NACE SP0502-2010, “Any deviation from the norm as measured by an indirect inspection tool.” A finding of a nondestructive testing technique. It may or may not be a defect (ASME B31.8S as referenced in Appendix 1B of this IMP).

Other Condition
A condition that does not fit the descriptions for immediate repair condition, monitored condition, one-year condition, scheduled repair condition, or verify condition.

Verify Condition
A verify condition is an indication of a physical attribute picked up by in-line inspection or direct assessment line survey that is not consistent with existing records. It is subject to verification if considered significant with respect to the integrity of the pipeline.

10.4 Identifying and Categorizing Anomaly Repair Conditions

✓ ***Referenced Protocol:*** ***E.02 Program Requirements for Identifying Anomalies***

Procedures for categorizing anomaly repair conditions in covered segments, as required by 49 CFR 192 Subpart O, are described in this subsection. These procedures are typically used to categorize anomalies discovered while performing Direct Assessments and In-Line-Inspection (ILI). However, anomalies can be discovered in the course of performing assessments by Pressure Testing or approved “Other Technology”. Repair categorization of any anomalies found in non-covered segments may also be based on these same procedures.

Determination of reassessment intervals, including any adjustments, will be according to Section 13 of this IMP.

10.4.1 Anomaly Repair Categorization

Subpart O (§192.933) specifies that anomalies in covered segments be categorized into the following groups:

Corrosion Anomalies to be Scheduled for Response per ASME B31.8S, section 7, Figure 4. Figure 4 will be used to determine the maximum allowable time for investigation and repair of external and internal corrosion anomalies (excluding Immediate Repair Conditions where the calculated Pf/MAOP is ≤ 1.1). The information from this figure is provided in Section 10.5 of this document for reference.

Immediate Repair Conditions as specified in 49CFR 192.933(d)(1)

- A calculation of the remaining strength of the pipe shows a predicted failure pressure less than or equal to 1.1 times the maximum allowable operating pressure at the location of the anomaly. (Suitable remaining strength calculation methods include ASME/ANSI B31G, RSTRENG, or an alternative equivalent method of remaining strength calculation.)

- Metal-loss indication affecting the long seam of direct current or low-frequency ERW or EFW pipe.

- A dent that has any indication of metal loss, cracking, or a stress riser

- Indication of Stress Corrosion Cracks (SCC)

- An indication or anomaly that, in the judgment of the person designated by the operator to evaluate the assessment results, requires immediate action

One-year Conditions as specified in 192.933(d)(2)

- A smooth dent located between the 8 o'clock and 4 o'clock positions (upper 2 /3 of the pipe) with a depth greater than 6% of the pipeline diameter (or greater than 0.50 inches in depth for a pipeline diameter less than 12-inch Nominal Pipe Size (NPS)).

- A dent with a depth greater than 2% of the pipeline's diameter (or 0.250 inches in depth for a pipeline diameter less than 12-inch NPS) that affects pipe curvature at a girth weld or at a longitudinal seam weld.

Monitored Conditions as specified in 192.933(d)(3)

- A dent with a depth greater than 6% of the pipeline diameter (or greater than 0.50 inches in depth for a pipeline diameter less than 12 NPS) located between the 4 o'clock position and the 8 o'clock position (bottom 1/3 of the pipe).

- A dent located between the 8 o'clock and 4 o'clock positions (upper 2 /3 of the pipe) with a depth greater than 6% of the pipeline diameter (or greater than 0.50 inches in depth for a pipeline diameter less than 12 (NPS),and engineering analyses of the dent demonstrate critical strain levels are not exceeded.

- A dent with a depth greater than 2% of the pipeline's diameter (or 0.250 inches in depth for a pipeline diameter less than 12 NPS) that affects pipe curvature at a girth weld or a longitudinal seam weld, and engineering analyses of the dent and girth or seam weld demonstrate critical strain levels are not exceeded. These analyses must consider weld properties.

The company has designated two additional categories of indicated conditions:

Verification Conditions – ILI Assessments

ILI inspection data will include indications that are consistent with those resulting from physical attributes such as girth welds, line taps, repair clamps, casing ends, etc. In many cases these indications will coincide with known locations of attributes of record and serve as benchmarks to confirm the validity of the survey.

In those cases in which an attribute that is not of record is indicated, additional record searching or excavation and direct examination may be necessary to identify, or confirm the identity of the indicated feature. It shall be the responsibility of the **QI** to determine if an excavation is warranted, and to determine the priority schedule if so.

In cases where a significant attribute (e.g., large bore tee, valve, or flange) is believed to exist but is not indicated by the ILI results, a record search and/or excavation may be necessary to confirm whether the feature is present. It shall be the responsibility of the **QI** to determine if excavation is warranted. This decision should be based on the level of confidence that a particular attribute exists and whether it should have been detected by the ILI tool.

Small line features such as pressure gauge fittings, small diameter taps or fittings, vents and drains may not be detected; therefore, missing such a feature would not require additional research or excavation.

Other Conditions – ILI Assessments

"Other Conditions" include other anomalous conditions which have not been characterized as external or internal corrosion, or as a special requirement under §192.933(d) (e.g., immediate repair condition, one-year condition, and monitored condition). These "Other Conditions" can represent a variety of anomalous conditions found during an ILI assessment. General company procedures will be used in evaluating and responding to these anomalies.

Figures 10-2 and 10-3 present procedural steps for evaluation and repair categorization of anomalies identified in the course of performing an ILI assessment and a direct assessment, respectively.

10.4.2 Discovery and Response to Repair Conditions - ILI

10.4.2.1 Quality Assurance Check of ILI Assessment Data

Discovery and categorization of anomaly repair requirements will not begin until a quality assurance check of the ILI Report has been performed. The **Program Manager – Integrity Management** M1 will be responsible for ensuring this QA check is performed and that the ILI data has been properly validated and qualified in accordance with the Assessment Results Worksheet and Specifications. In performing this QA check, physical and performance data for the pipeline system will be used as appropriate to verify the reasonableness of the ILI data in the Final Report. Results of such data comparisons will be summarized in the Assessment Result Worksheet.

An exception to this guideline is made for any severe indications which are brought to the attention of the **Program Manager – Integrity Management** M1 prior to receipt of the ILI Report. If the ILI vendor provides adequate information to indicate a possible Immediate Repair Condition, excavation and Discovery of Condition is not dependent upon receipt of either the Preliminary or Final ILI Report.

Note:	Operators are expected to review the results of integrity assessments promptly. Discovery of Condition occurs when the operator has adequate information about a condition to determine it may be a potential threat to the integrity of the pipeline. Depending on the circumstances an operator may have sufficient information upon receipt of the preliminary report or receipt of the final report. This information must be obtained no more than 180 days after an integrity assessment, unless the operator can demonstrate that this limit is impractical (refer to FAQ 57 and 58).

10.4.2.2 Immediate Repair Conditions - ILI

The **Qualified Individual (QI)** must make the determination that an Immediate Repair Condition has been discovered.

For in-line inspection, this determination process normally begins with the receipt of the preliminary or final ILI report. The process to determine a potential Immediate Repair Condition is reflected in Figure 10-2 and includes the following:

- **The Company's QI** receives and reviews the preliminary or final ILI report identifying probable immediate repair conditions, constituting discovery of those conditions. As soon as practical, not in excess of five (5) calendar days from discovery if within a covered pipeline segment, a review of operating and physical data shall be made and required follow up actions including possible temporary operating pressure reductions or limitations shall be put into effect and confirmatory excavations or additional assessment inspections shall be performed. Pressure reduction shall be performed as soon as possible after discovery of an Immediate Repair Condition (Pressure reduction includes pressure limitation per Section 10.5.1.2 when used within this section).

- Where the **QI** has a technical basis to question the accuracy of the results of the preliminary assessment report, or if the report has as obvious error or extremely questionable result, the **QI** may wait on commencing pressure reduction until sufficient correlation digs have been performed to verify the preliminary assessment report results. The **QI** will completely document and justify the specific events of each situation where a reduction in operating pressure is delayed due to questionable data and attach the documentation to the Direct Examination Form available on the company intranet..

- **The Company's QI** shall evaluate the results of the field correlation digs typically made while responding to Immediate Repair Conditions and make a determination concerning the accuracy and correlation of the data. Based upon this determination and analysis of the anomalies or defects found; the temporary operating pressure limitations are subject to reevaluation based upon ASME/ANSI B31G, AGA Pipeline Research Committee Project PR-3-805 (RSTRENG), or other established and applicable methods. Normal established operating pressure may be restored where the analysis indicates an Immediate Repair Condition does not exist.

- Any Immediate Repair Condition on a pipeline that is subject to operate at a hoop stress of 20% or more of SMYS may constitute a safety-related condition per 49 CFR 191.23 subject to reporting under the provisions of 191.25. Refer to **GOMI-GN-SR-001 -** "Safety Related Condition Reports".

10.4.2.3 **Non-Immediate Conditions - ILI**

The remaining repair anomalies will be separated into various repair schedules as depicted in Figure 10-2. This process will be performed by the company or by the assessment contractor as appropriate per specific project specifications.

Discovery and categorization of anomaly repair requirements based upon ILI indications will not begin until a quality assurance check of the final ILI Report has been performed. Anomalies indicated by ILI may be categorized and considered to be discovered if following the quality assurance check the data is conclusive in determining the anomaly type without further investigation.

Anomaly indications that are non-conclusive shall be categorized following direct examination or other appropriate investigation to confirm the indicated condition.

Whereas the regulations permit up to 180 days to make a final determination, the apparent risk of failure and likely consequences of failure should be considered when scheduling additional assessments or direct inspections for indications of Immediate

Repair Conditions. Short term operating history, including highest pressure attained during the time period for which the condition is believed to have existed, should be compared with current and intended operating pressure. Higher priority shall be given to evaluation of indicated Immediate Repair anomalies in pipeline segments intended to operate at stress levels approaching or exceeding 30 percent SMYS.

Indications of anomalies that are not categorized as immediate shall be categorized as One-year Condition, Monitored Condition, Other Condition, or Verification Condition as defined in 10.4.1.

A Direct Examination Form available on the company intranet will be used to document the determination (discovery) process for non-immediate Repair Conditions discovered during ILI. This Worksheet will also be used to document the disposition of identified repairs, including pressure reductions. This Worksheet is provided in Section 9B.10 for reference.

Indications of anomalies categorized as Other Condition or Verification Condition can represent a variety of anomalous conditions found during an ILI assessment. Established operating and maintenance procedures shall be followed in response to these indications. It shall be the responsibility of the **QI** to determine if anomalies designated as Other Condition or Verification Condition require direct examination and to schedule them accordingly.

All scheduled responses shall be recorded and tracked on the Direct Examination Form available on the company intranet.

10.4.3 Anomaly Categorization - DA

Section 7 of this IMP describes the procedures for conducting Direct Assessments that includes External Corrosion Direct Assessment (ECDA), Internal Corrosion Direct Assessment (ICDA), SCC Direct Assessment (SCCDA) and Confirmatory Direct Assessment (CDA). In general, these procedures require an initial categorization of potential anomalies found during indirect field examinations into a prioritized excavation schedule for direct examination. For example, an ECDA could produce a listing of anomalies in three excavation priority categories:

- **Immediate excavation** – anomaly indications that are a potential immediate threat
- **Scheduled excavation**– anomaly indications that need to be examined but do not pose an immediate threat
- **Suitable for Monitoring** – excavation generally not required under present conditions. However, written ECDA procedures may call for excavation and direct examination of one or more indicated anomalies classified as suitable for monitoring. This classification includes potential anomaly indications that are considered inactive or having the lowest likelihood of ongoing or prior corrosion activity.

The above categories for ***excavation*** scheduling (i.e., Immediate, Scheduled and Monitoring) **SHOULD NOT** be confused with similar terminology used for ***remediation*** scheduling also described in this IMP Section. As explained in Section 7, sufficient information to determine (discover) what, if any, remediation condition exists for a potential anomaly location is not available until a DA excavation occurs. Upon ***completion of the direct examination (field work) phase of a DA, the company must make a repair category determination, if any is required, for the DA anomaly (refer to FAQ 232).***

The apparent risk of failure and likely consequences of failure should be considered when scheduling additional assessments or direct inspections for indications of immediate repair conditions. Short term operating history, including highest pressure attained during the time period for which the condition is believed to have existed should be compared with current and intended operating pressure. Higher priority shall be given to evaluation of indicated immediate repair anomalies in pipeline segments intended to operate at stress levels approaching or exceeding 30 percent SMYS.

10.4.4 Discovery of Conditions - DA

10.4.4.1 Immediate Repair Conditions - DA

For **Direct Assessment** the determination that an Immediate Repair Condition has been discovered will normally begin with the receipt of field measurements of an anomaly examined during a DA excavation that appears to be an immediate repair condition. The process to determine a potential Immediate Repair condition is reflected in Figure 10-3 and includes:

- The Company's **QI** receives anomaly measurements and any associated field calculations. The **QI** performs the necessary evaluations to verify that an Immediate Repair conditions exists.

Note:	For a Direct Assessment, the necessary excavation and examination of a potential anomaly must first occur to determine the schedule priority for repair (if any) for the anomaly. Such excavations are established on an "Immediate" and "Scheduled" basis as described in Section 7. The operator must determine a repair category, if any, of the DA anomaly after the completion of the examination portion of a DA excavation. (refer to FAQ 232).

- If the **QI** concludes that the anomaly is not an immediate repair condition, it is subsequently classified into one of the non-immediate repair categories and handled accordingly (one-year , monitored, external or internal corrosion, or other condition)
- If the **QI** concludes that the anomaly ***is*** an Immediate Repair Condition, a pressure reduction or limitation is initiated as soon as is practical.
- As soon as practical, not in excess of five (5) calendar days from discovery if within a covered pipeline segment, a review of operating and physical data shall be made and required follow up actions including possible temporary operating pressure reductions or limitations shall be put into effect and confirmatory excavations or additional assessment inspections shall be performed. Pressure reductions shall begin as soon as possible.

The assessment vendor may contact the **QI** prior to the preliminary report in unusual cases where an anomaly is discovered that is deemed to be a potential immediate repair condition for investigation. In such an event, the **QI** will follow the above process requirements as soon as contact has been made by the vendor.

For each assessment, Discovery of Condition date and any required pressure reductions are documented on Form 7A.13 "ECDA Remaining Life Determination" and Form 7B.12 "ICDA Remaining Life Determination". In addition, immediate responses and repairs are summarized on Form 7A.20 "ECDA Performance Report", Form 7B.13 "ICDA Performance Report" and Decision Record" including the required repair date and the actual date of repair. Samples of these forms are provided in Section 7A and 7B respectively.

When an immediate response to Immediate Repair Conditions discovered within covered pipeline segments cannot be achieved, the company will notify PHMSA and KPSC and/or IURC in accordance with Subsection 10.10. This same notification procedure will also be used if reduction of operating pressure exceeds **365 days** without further remedial action.

Complete shutdown of the pipeline segment may be used in lieu of pressure reduction or PHMSA and KPSC/IURC notification. When this option is used all Immediate Repair Condition anomalies must be evaluated and repaired as necessary prior to resuming pipeline segment operation.

For guidelines to determine temporary pressure reduction or pressure limitations see Subsection 10.5.1.2 of this written plan.

10.4.4.2 **Non-Immediate Conditions - DA**

The remaining repair anomalies will be separated into various repair schedules as depicted in Figure 10-3. This process will be performed by the company or by the assessment contractor as appropriate per specific project specifications.

Anomaly indications that are non-conclusive shall be categorized following direct examination or other appropriate investigation to confirm the indicated condition.

Whereas the regulations permit up to 180 days to make a final determination, the apparent risk of failure and likely consequences of failure should be considered when scheduling additional assessments or direct inspections for indications of immediate repair conditions. Following direct examination field work, the company has the required information and the Company must classify the anomalies condition (PHMSA FAQ 234). Short term operating history, including highest pressure attained during the time period for which the condition is believed to have existed, should be compared with current and intended operating pressure. Higher priority shall be given to evaluation of indicated immediate repair anomalies in pipeline segments intended to operate at stress levels approaching or exceeding 30 percent SMYS.

Indications of anomalies that are not categorized as Immediate shall be categorized as One-year Condition, Monitor Condition, Other Condition, or Verification Condition as defined in Section 10.3.

For each assessment, Discovery of Condition date and any required pressure reductions are documented on Form 7A.11 "ECDA Remaining Life Determination" and Form 7B.12 "ICDA Remaining Life Determination". In addition, immediate responses and repairs are summarized on Form 7A.12 "ECDA Performance Report" and Form 7B.13 "ICDA

Performance Report". Samples of these forms are provided in Section 7A and 7B respectively.

10.4.5 Pressure Test Assessments (Subpart J)

Unlike anomalous conditions discovered during an In-Line Inspection that can be categorized as either immediate or scheduled conditions, a pressure test will produce a pass/fail result for anomalous conditions contained in the segment. Any anomaly or defect that fails a pressure test will be promptly remediated by repair or removal.

10.4.6 Other Technology Assessments

Other integrity assessment technologies may also be used provided the company can demonstrate the technology provides an equivalent means of assessment. If the company seeks approval to use this option, appropriate notifications will be required as described in Section 9 and 19. Should the company utilize this option, processes and procedures appropriate to the technology selected will be developed by the company. These processes and procedures will address the discovery, evaluation, and remediation of anomalous conditions when using the Other Technology selected.

10.5 Response to Repair Conditions

✓ ***Referenced Protocol:*** ***E.01 Program Requirements for Discovery, Evaluation and Remediation Scheduling***

10.5.1 Response For Immediate Repair Conditions

10.5.1.1 Response Time

As soon as is practical, and not in excess of five (5) calendar days from discovery if within a covered pipeline segment, a review of operating and physical data shall be made and required follow up actions including possible temporary operating pressure reductions or limitations shall be put into effect and confirmatory excavations or additional assessment inspections shall be performed.

10.5.1.2 Pressure Reduction or Limitation

Pending confirmation of the indicated Immediate Repair Conditions the operating pressure shall be limited as soon as possible to the **lowest** of the following:

a) 0.9 times the failure pressure calculated by ASME/ANSI B31G or AGA Pipeline Research Committee Project PR-3-805 RSTRENG if applicable; or
b) 80% of the operating pressure that occurred at the time of discovery.

Pressure limitations or reductions shall be effective immediately as soon as determined necessary and shall be initiated prior to excavation for direct examination.

Temporary operating pressure reductions or limitations shall remain in effect up to 365 days until repairs are made or direct examination has been performed and maximum safe operating pressure has been reevaluated. A reduction in operating pressure as remedial action cannot exceed 365 days without technical justification by the operator to the effect that continued pressure restriction will not jeopardize the integrity of the pipeline per Section 10.10.

Any Immediate Repair Condition on a pipeline that is subject to operate at a hoop stress of 20% or more of SMYS may constitute a safety-related condition per 49 CFR 191.23, subject to reporting under the provisions of 191.25. Refer to **GOMI-GN-SR-001** "Safety Related Condition Reports".

10.5.1.3 **Verifying Immediate Repair Conditions**

The Company shall verify all Immediate Repair Conditions by excavating the anomaly and performing a direct examination. If an Immediate Repair Condition is verified by direct examination, then the defect will be promptly repaired or replaced unless a reduction of operating pressure mitigates the urgency. If the condition being examined is not an Immediate Repair Condition, then the condition shall be reclassified and be scheduled according to its new classification.

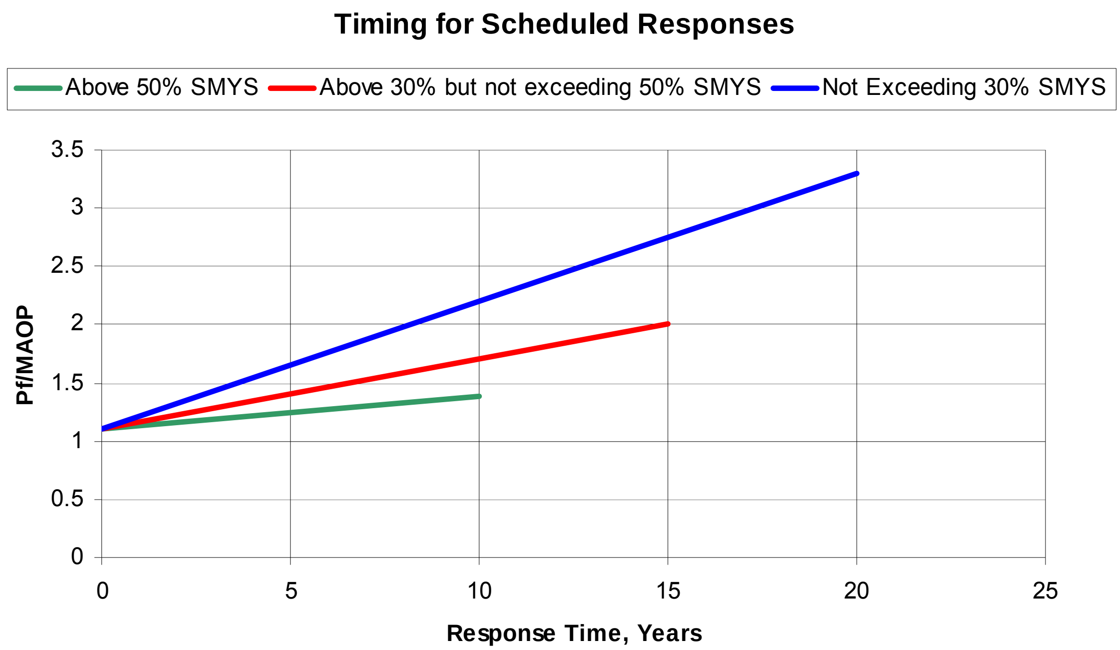
10.5.2 Response For Non-Immediate Repair Conditions

10.5.2.1 **One-Year Conditions**

Conditions meeting the definition of a One-Year Conditions must be repaired within 365 calendar days of discovery.

10.5.2.2 **External and Internal Corrosion Conditions**

For each external and internal corrosion anomaly, the ratio of the predicted failure pressure to the maximum allowable operating pressure shall be calculated. The response schedule will be determined using ASME B31S - Figure 4, as reflected in Graph 10-1 below. The expected growth rate for the anomaly shall be evaluated to determine whether it could grow to an Immediate Repair Condition during the selected response interval, and if so, the response interval will be reduced accordingly. The response to the anomaly will be implemented according to the selected response schedule.



Graph 10-1: Timing of Responses for Corrosion Anomalies. (Source: ASME B31.8S Fig. 4)

10.5.2.3 **Other Repair Conditions**

In the beginning of Section 10.4, the classification of dents and other anomalies and their required response intervals are discussed as referenced in §192.933. Prior to implementing the interval specified by the classification of the condition, it shall be evaluated whether the anomaly in question could grow to an Immediate Repair Condition prior to the next assessment. If so, the response interval will be reduced accordingly. The response to the anomaly will be implemented according to the selected response schedule.

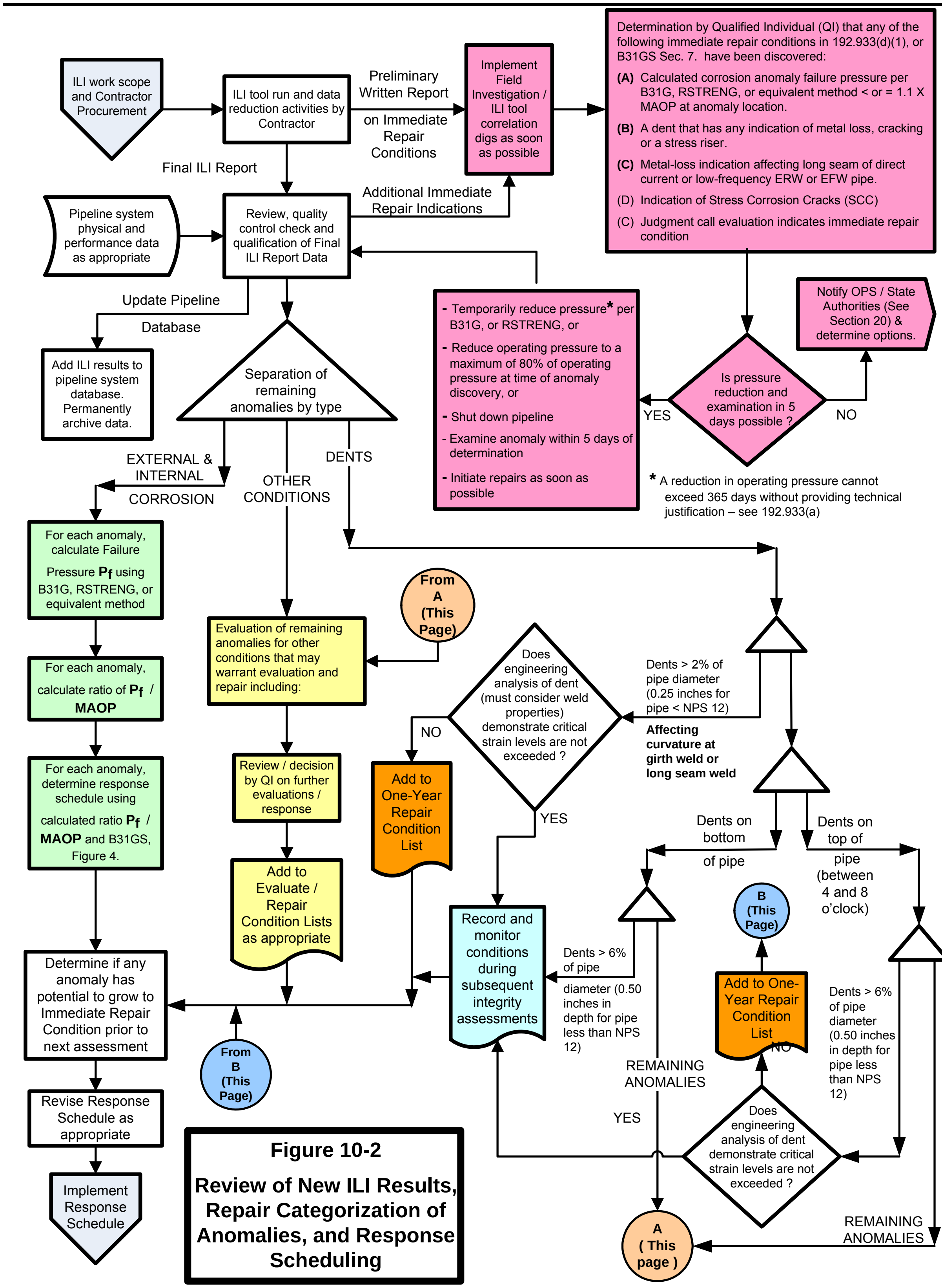


Figure 10-2

Review of New ILI Results, Repair Categorization of Anomalies, and Response Scheduling

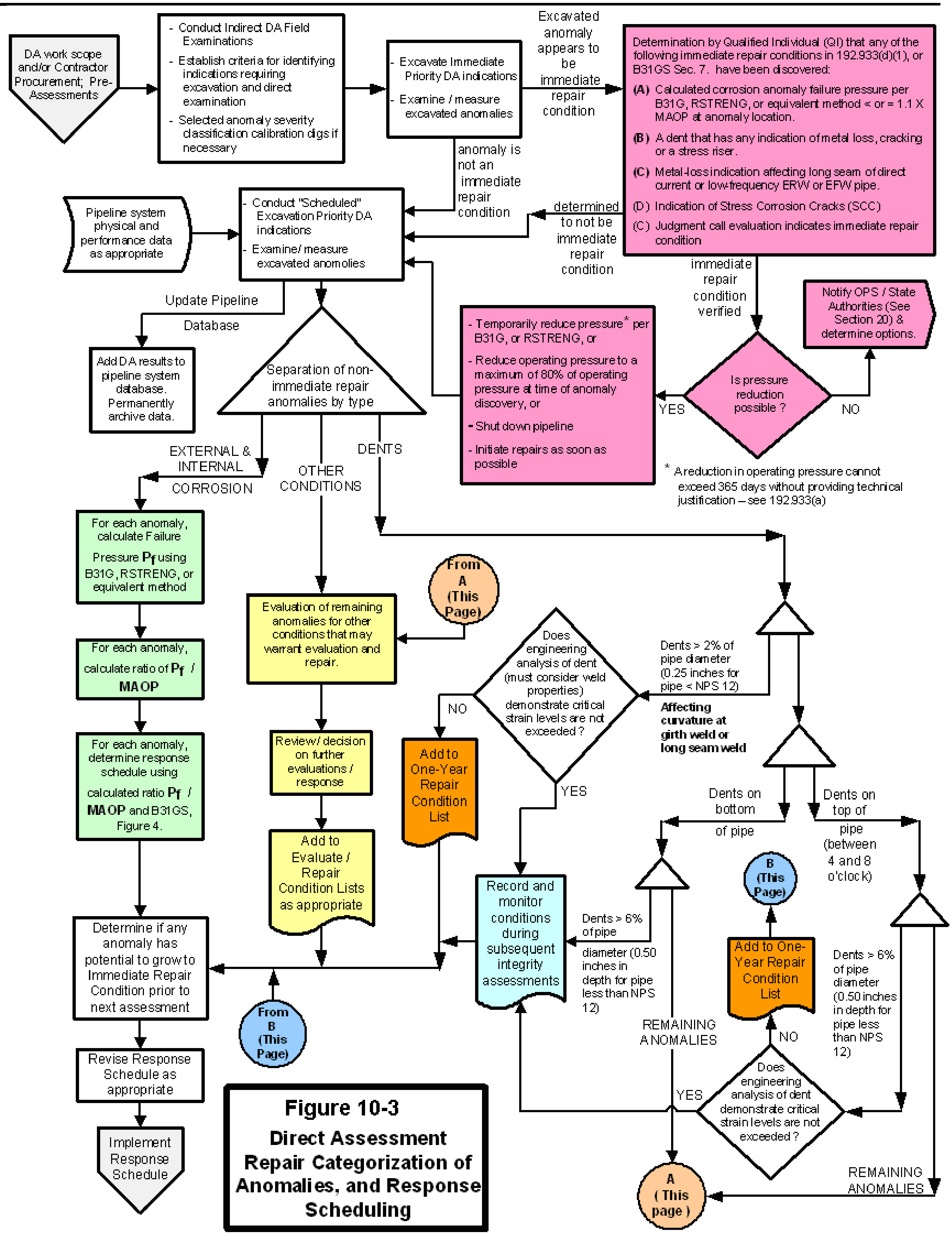


Figure 10-3
Direct Assessment Repair Categorization of Anomalies, and Response Scheduling

10.6 Prioritized Evaluation & Remediation Schedule

The process described within this subsection is presented as an optional guideline for prioritizing remediation and repairs of defects discovered through in-line inspection or direct assessment inspections.

10.6.1 Sequential Location Listing of Repairs Within Each Repair Category

As indicated in Figure 10-4, the repair locations within each repair category will be listed in sequential location order (from beginning to end of pipe segment assessed) using station number, ILI log distance, milepost, joint number, GPS coordinates, or similar reference method. This listing will be generated by either the integrity assessment vendor or the company.

10.6.2 Integration of Risk Factor Data

Section 5 of this IMP describes what risk factor data are collected and how they are weighted to develop a risk-based ranking of pipeline segments to determine the baseline or continuing schedule for integrity assessments.

Integrity assessment inspections reveal potential defects and/or confirmed damage resulting from the various applicable threats. The risk of failure from indicated damage or defects and resulting consequences can be subjectively evaluated to develop a schedule for repairs and remediation.

Repairs prioritized by this method are still subject to any required remediation timeframe as described in Subsection 10.5. For example, One-Year Conditions must be remediated within 365 days regardless of the prioritized schedule.

10.6.3 Risk-Ranking of Repair Locations

For scheduling repairs and remediation the highest priority should be given to the anomalies with the highest risk for failure and resulting consequence.

10.6.4 Finalize Prioritized Repair Schedule

The final schedule for repair may be adjusted as necessary to accommodate operational needs, agricultural usage of right-of-way, proximity of work, accessibility, business impacts, etc.

The **Program Manager – Integrity Management** M1 will have complete discretion in the scheduling provided all regulatory requirements are met. A record of these finalized schedules will be documented along with the actual dates of field investigation and repair comments on the forms provided with the applicable assessment inspections procedures.

Figure 10-4 Process for Prioritizing Repairs

Part 1 – Immediate Repair Conditions

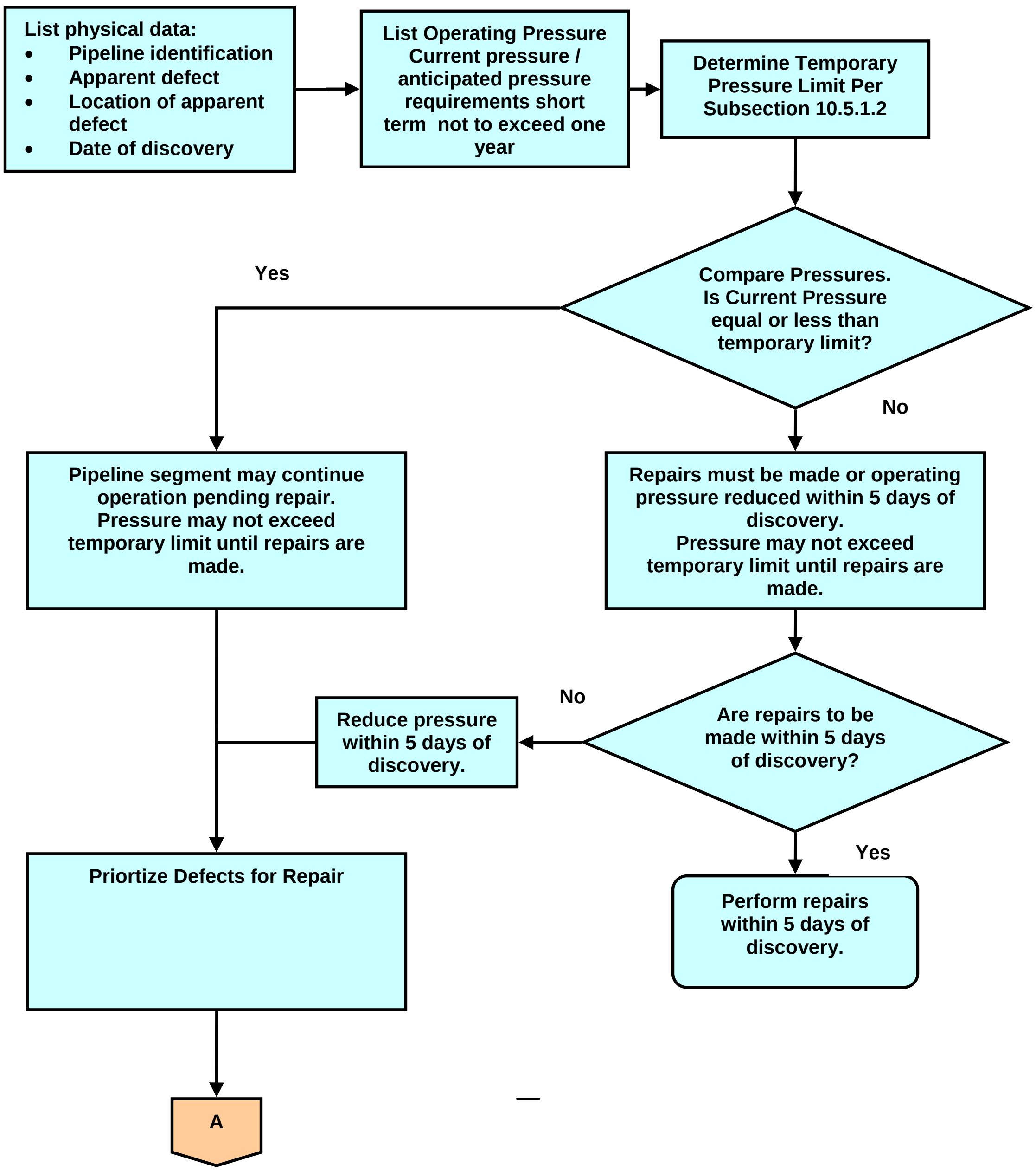
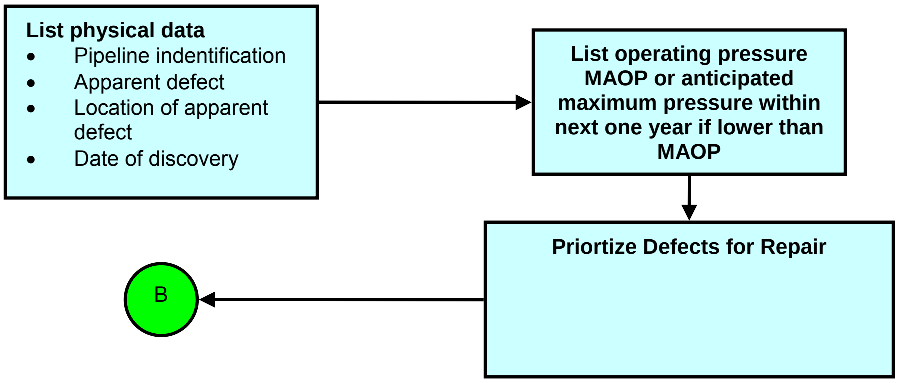


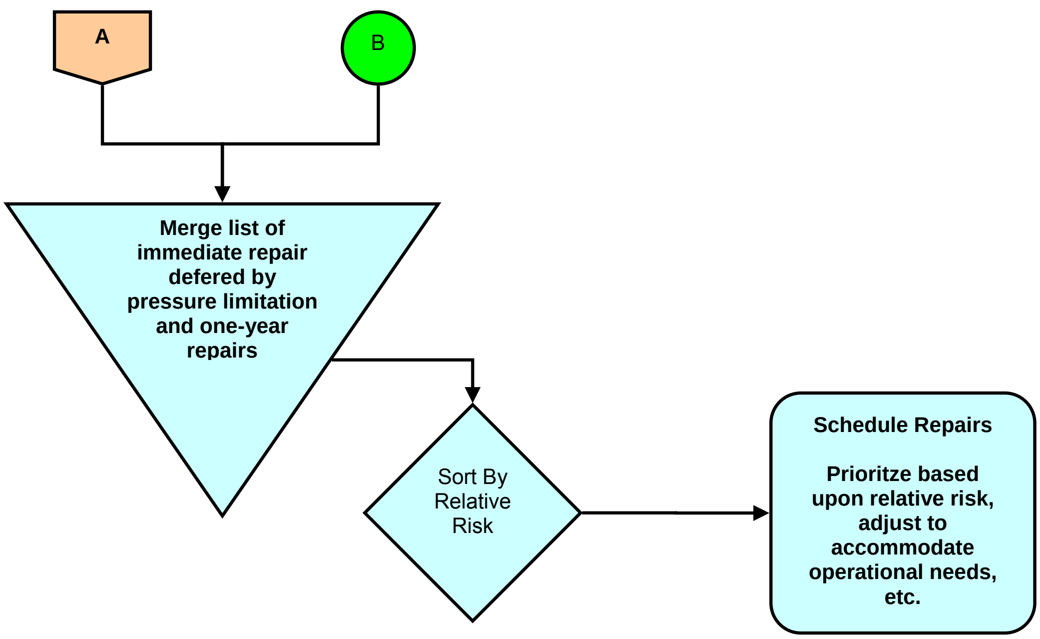
Figure 10-4

Figure 10-4 Process for Prioritizing Repairs

Part 2 – One-year Repair Conditions



Part 3 – Comprehensive Schedule



Note – The process outlined in Figure 10-4 is a recommended guideline, it is not mandatory providing all regulatory requirements and time limits are met.

10.7 Repair Methods

See company Gas Operation, Maintenance and Inspection Procedures – Pipeline Repair, **GOMI-PO-PR-001,** for standard repair methods utilized by the company for repairs to transmission pipelines.

10.8 Environmental and Safety Risks

The company will utilize the processes and procedures designated in Section 11 of this document to minimize environmental and safety risks while performing remediation on the pipeline right-of-way.

10.9 Record Keeping – Documentation of Remediation

The company will maintain all records in accordance with §192.947 and Section 16 of this manual. All inspection and assessment reports, worksheets, schedules, and repair documentation will be kept for the useful life of the pipeline. The **Program Manager – Integrity Management** M1 is responsible for assuring this documentation is maintained. The record keeping requirements stated within this subsection are for the purpose of insuring compliance with 49 CFR Part 192, Subpart O Pipeline Integrity Management Regulations and are not intended to replace existing record keeping processes which shall remain in effect.

10.9.1 Pressure Reduction or Limitation

Temporary pressure reductions or limitations in response to discovery of immediate repair conditions shall be documented using the Temporary Pressure Reduction or Limitation Worksheet, Form 10-1, included in the appendix of this procedure. As a part of this process the **QI** responsible for determining the temporary pressure reduction or limitation shall effectively and immediately communicate the resulting maximum pressure to the Manager responsible for operation of the effected pipeline segment.

10.9.2 Repairs and Remediation

All anomaly investigations will be documented using the appropriate pipeline direct examination forms (for ECDA Form 7A.10, for ICDA Form 7B.8). The **Pipeline Specialist** F5 will forward these forms to the **Pipeline Integrity Engineer** F3 for inclusion in the pipeline segment file.

Immediate repair conditions, scheduled repair conditions, or monitored conditions discovered through pipeline integrity inspections shall be documented in accordance with the specific procedures applicable to the inspections performed using the following forms:

	ILI	ECDA	DG-ICDA
Immediate Repair	Direct Examination Form, 17-1	Forms 7A.9, 7A.11, 7A.12, 17-1	Forms 7B.9, 7B.10, 7B.11, 7B.12, 7B.13, 17-1
Scheduled Repair	Direct Examination Form, 17-1	Forms 7A.9, 7A.11, 7A.12, 17-1	Forms 7B.9, 7B.10, 7B.11, 7B.12, 7B.13, 17-1
Monitor Condition	Direct Examination Form, 17-1	Forms 7A.9, 7A.11, 7A.12, 17-1	Forms 7B-9, 7B-10, 7B-11, 7B.12, 7B.13, 17-1

Table 10-1- DA Forms`

The **QI** as designated by the **Program Manager – Integrity Management** M1 shall be responsible for assuring completion of the applicable record keeping and forms for each assessment performed.

The **QI** shall maintain communication with the **Program Manager – Integrity Management** M1 throughout this process. The **Program Manager – Integrity Management** M1 shall communicate with the **Manager – Operations,** F1**,** and other appropriate operations personnel as necessary to coordinate required operations and anticipated repairs.

10.10 Response When The Schedule Can Not Be Met

The company anticipates completing the remediation and repairs in accordance with a prioritized schedule, and **the company** will make every reasonable effort to meet that schedule. However, should this become impractical, **the company** will make a temporary reduction in operating pressure or take other appropriate action to ensure the safety of the covered segment.

The company will determine temporary reductions in pressure using the methods described in Subsection 10.5 of this written plan.

If the prioritized schedule cannot be met, and a temporary reduction in operating pressure or other appropriate action to ensure the safety of the covered segment cannot be achieved, the **Manager of Gas Regulatory Compliance** M4 will notify PHMSA and KPSC and/or IURC as soon as practical in accordance with §192.949 and Section 19.

Written notification will include:

- The basis of why it is impractical to meet the schedule for a remediation activity
- The basis of why the modified schedule will not jeopardize public safety
- The justification of why a continued pressure reduction beyond **365 days** would not jeopardize pipeline integrity or public safety

10.11 Notifications – Regulatory Authorities

10.11.1 General

Required notifications to the PHMSA and KPSC and/or IURC regarding remediation steps will be submitted for the following reasons and as outlined in **Section 19**:

- Inability to meet 180-day requirement for identifying conditions requiring remediation or monitoring
- Inability to meet required remediation schedule for anomalies in covered segments

The **Manager of Gas Regulatory Compliance** M4 will submit an online notification or a written notification using the procedures in **Section 19**.

The **Program Manager - Integrity Management** M1 and the **Manager of Gas Regulatory Compliance** M4 will also be responsible for ensuring any pressure reductions do not exceed the 365 day limit, or if necessary, will submit written notification using the procedures in **Section 19**.

10.11.2 Safety Related Condition Reporting §191.23

Any defect or condition that constitutes a safety related condition as described in 49 CFR 191.23 must be reported separately to the PHMSA and KPSC and/or IUCR as a safety related condition unless the requirements for exemption stated in 191.23 (b) are met. See **GOMI-GN-SR-001** "Safety Related Condition Reporting."

10.11.3 Notification Schedules

The company will submit its notifications to the PHMSA and KPSC and/or IURC as soon as the company determines it is unable to meet the required repair schedule or other requirements of Subpart O.

10.12 Forms and Worksheets

Form 10-1: Temporary Pressure Reduction or Limitation Worksheet

Revision Log

Date	Description	Revised By
12/10/2004	Changed font style and size	MTS
12/10/2004	Changed the Director of Integrity Management to the Qualifed Individual,	MTS
12/10/2004	Changed responsibilites from Regional Integrity Data Specialist and some Pipeline Specialist to the Manager of Integrity Management	MTS
12/10/2004	Changed responsibilites from Regional Engineer to the Program Manager – Integrity Management	MTS
12/10/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/10/2004	Changed Company to LG&E Energy	MTS
12/10/2004	Inserted KPSC and/or IURC for state references	MTS
12/10/2004	Change references to Section 20 to Section 19	MTS
2/24/06	2/24/06 Version Approved by Management	LCO
6/3/2008	Changed references from OPS to PHMSA where applicable.	EN Engineering
6/3/2008	Deleted note in section 10.2.1.	EN Engineering
6/3/2008	Re-ordered and deleted redundant paragraphs within section 10.4 “Identifying and Categorizing Anomaly Repair Conditons”.	EN Engineering
6/3/2008	Modified note in section 10.4.4.1 to reflect appropriate FAQ.	EN Engineering
6/3/2008	Added pressure reduction discussion to section 10.4.4.3 “Response for Immediate Repair Conditions”.	EN Engineering
6/3/2008	Added response time graph (based on ASME B31.8S-2004) to section 10.4.4.4 “Response for Non-Immediate Repair Conditions”	EN Engineering
12/5/08	Moved pressure reduction & response timeframe information to section 10.5.	EN Engineering
12/5/08	Updated wording to ensure consistent use of terms like Immediate Repair Condition and Verfication Condition	EN Engineering
12/5/08	Added references to forms on which repairs are noted for ILI, ECDA, & ICDA	EN Engineering
12/5/08	Added 10.5.2.1 specifying timeframe for One Year Conditions	EN Engineering
12/5/08	Clarified 10.6.2 to show that regardless of RRP score, must meet required timeframes	EN Engineering
12/5/08	Specified responsibility for notifying authorities if timeframes not met	EN Engineering
12/5/08	12/5/08 Version Approved by Management	LCO
6/19/2009	10.4.4.1 – reference to subsection 10.1.1 changed to 10.4.2	EN Engineering
6/19/2009	Added 2 sentences to 10.7 to address plastic transmission lines	EN Engineering
6/19/2009	Added 2 sentences to Appendix 10-1 to address plastic transmission lines	EN Engineering
8/31/2009	Section 10 Routed to Management	MLS
10/19/2010	Job title corrections throughout document	JRG
10/19/2010	Revised section 10.2.1 to include anomalies in covered and non-covered segments	JRG
10/19/2010	Revised section 10.3 Verify Conditions	JRG
10/19/2010	Revised section 10.4 to include anomalies in covered and non-covered segments	JRG
10/19/2010	Revised section 10.5 to include anomalies in covered and non-covered segments	JRG
10/19/2010	Revised section 10.11.1 to include anomalies in covered segments	JRG
10/19/2010	Section 10 Routed to Management	MLS
11/30/2012	Updated 10.2.2 to remove written requirement	MLS
11/30/2012	Updated section 7 form references	MLS
12-16-2013	Revised a0.5.1.2 pressure reduction or limitation to reflect regulations;Revised Section 10.6 Prioritized Evaluationa and Remediation Schedule including Figure 10-4, Corrections to assigned responsibilities for new organization structure, eliminated Appendix 10-1 Permanent Repair Methods and cross referenced GOMI-PO-PR-001, General clerical revisions.	JRG
10/14/2014	General formatting, grammatical, and punctuation corrections	CLG
10/20/2015	Removed section 10.2.2	CLG

11/12/2015	Deleted Table 10-1 and introductory sentence to Table 10-1	CLG

Form 10-1: Temporary Pressure Reduction or Limitation for Immediate Repair Condition Worksheet

This worksheet is to be maintained to document the process used to determine pressure limitations for pipeline segments in which immediate repair anomalies have been discovered.

I. – Segment Identity, Anomaly Location, Date of Discovery

1.1 Pipeline Name ____________________________ Segment Number _______________

1.2 Date of Discovery ______________________

1.3 a) Anomaly location, pipeline station ____________________________________

b) Anomaly location, GPS coordinates ____________________________________

c) Anomaly location, descriptive ____

____

____

II. – Pipe Data

2.1 a) Size _____ b) Wall thickness ______ c) Specification ________ d) Grade _______

e) Seam type _________________ f) Installation date ______________

2.2 Calculate pressure that will produce hoop stress of 24% SMYS, enter result _________ psig

III – Anomaly Data

3.1 Method of discovery ILI ___ Other ____

3.2 Description of anomaly ____

3.3 a) Is there visible indication, records, or knowledge that excavation or other activity capable of producing damage at the anomaly location may have occurred? _____

b) If yes list known or estimated date _______

3.4 Calculate failure pressure by ________________, enter result ______ psig

IV. – Operating Data

4.1 Enter current established MAOP* _________ psig

4.2 a) List operating pressure at time of discovery

b) List maximum operating pressure that may have occurred within past 90 days or date that damage may have occurred, Line 3.3 (b), whichever is more recent ________ psig

**MAOP in effect prior to discovery of immediate repair condition*

V. – Determine Pressure Limitation

5.1	Multiply calculated failure pressure Line 3.4 by 0.9, enter result	_______ psig
5.2	Enter previously established MAOP from Line 4.1	_______ psig
5.3	a) Multiply historic pressure Line 4.2 by 0.8, enter result	_______ psig
	b) Enter 24% SMYS pressure from Line 2.2	_______ psig
	c) Compare Lines 5.3 (a) and 5.3 (b), enter higher of two	_______ psig
5.4	Compare Lines 5.1, 5.2, and 5.3 (c), enter lowest of three	_______ psig
5.5	Lower limit set by operator, state reason in comment section below	_______ psig

Comments:

____

____

____

____

____

Operating pressure of this segment must be reduced or limited to the value derived on line 5.4, or to the self-imposed limit shown on line 5.5 if lower.

The temporary operating pressure restriction for this pipeline segment pending repairs or reevaluation is therefore determined to be ________ psig.

VI. - Communication

In order to assure implementation of this pressure reduction or limitation the following operations personnel have been notified:

Name and Title	Method of Communication	Date of Communication

VII. - Signature

This worksheet has been compiled by:

____
Name

____
Integrity Management Plan Position

____
Signature

11 PROCEDURE TO MINIMIZE ENVIRONMENTAL AND SAFETY RISKS §192.911(o)

In This Section

Referenced Protocols

Attachment to Response to AG Q252
Page 644 of 770
Bellar

11 PROCEDURE TO MINIMIZE ENVIRONMENTAL & SAFETY RISKS

11.1 OVERVIEW

✓ *Referenced Protocol:* *B5: Consideration of Environmental and Safety Risks*
F.7 Consideration of Environmental and Safety Risks

11.1.1 Purpose

The Procedure to Minimize Environment and Safety Risks section describes the procedures used by **Louisville Gas & Electric/ Kentucky Utilities** (the company) to minimize environmental and safety risks while performing pipeline integrity activities. These procedures will be utilized while performing the following activities:

- Section 9 – Conducting Assessments
- Section 10 – Remediation
- Section 12 – Preventative and Mitigative Measures

Existing environmental and safety procedures have been referenced in this section. Should a conflict exist between existing company procedures and the procedures of this section, the existing company procedures shall control. Procedures in this section have been implemented to protect the company's employees, contract workers, members of the public, and the environment.

11.1.2 Responsibility

The **Program Manager- Integrity Management** M1 is responsible for ensuring that the key personnel described in Section 2 – Roles and Responsibilities adhere to the environmental and safety procedures described in this section. The **Program Manager- Integrity Management** M1 has the specific responsibility of managing the pipeline integrity activities that include these procedures.

The **Pipeline Specialist** F5 has the specific responsibility of providing direct oversight of the pipeline activities and implementing the procedures of this section.

11.2 PLANNING THE WORK

The company will perform significant planning activities prior to arriving on site to perform integrity related work. The requirements of this procedure, and other referenced company environmental and safety procedures, will become an integral part of that planning process. The company's environmental specialists will be consulted early in the planning process to acquire the required environmental permits. These permits frequently have long lead times that could impact integrity related time limits.

11.2.1 Initial Site Review

The **Pipeline Specialist** F5 under the direction of the **Program Manager – Integrity Management** M1 will locate the work site and perform an initial site review as part of the overall planning process. An integral part of that review is the need to address and minimize environmental and safety risks. This initial site review will be performed in conjunction with the following activities:

- Conducting Assessments (ILI, Pressure Tests, and Direct Assessment)
- Remediation
- Preventative and Mitigative Measures

The **Pipeline Specialist** will gather or confirm information about the site that will be used in the planning process. This information will include the proximity of the work to the following areas:

- Homes, apartments, etc.
- Identified Sites (outside areas / open structures, buildings, facilities)
- Streams, rivers, etc. which may require an environmental permit
- Roads / highways which may require a permit
- Wetlands which may require an environmental permit
- Archeological sites
- State Historical Preservation sites
- Construction specific permits including storm-water runoff (disturbed area > 1 acre), removing/disposing of water from a nearby water source, etc.
- Obtain location data for utility locate request

This information is reviewed with the company's environmental and safety specialists who assist in determining the environmental permits required, and the environmental and safety measures to employ. Should additional information be required, environmental or safety specialists may visit the site to acquire that information.

11.2.2 Agency Permitting

Once the required permits have been identified, the company will begin as soon as practical, the permitting process. If the company determines the permitting process will extend beyond the required time limits specified in **Section 10 – Remediation** a notification must be made to OPS and KPSC and/or IURC. Special consideration should be given to remediation. Some of the permits, such as crossing blue-line streams may take up to 6 months. It is also important to determine if there is a creek or drainage area if a hydrostatic test is used. If there is not creek or drainage area, preparation will be required to dispose of water.

11.2.3 Landowner / Public Notifications

Depending upon the nature of the work being performed, the company may contact landowners or members of the public located in close proximity to the work. This notification is typically a courtesy that will be performed in accordance with the requirements of **Section 19 – Communications Plan**. These notifications are intended to inform the public of what to expect during the progression of the work.

11.2.4 Training / Qualification Requirements

The company will assure all personnel are properly trained and qualified for the tasks they are intended to perform. All personnel performing a covered task identified under the company's operator qualification (OQ) program must be qualified for that specific task. The company will also assure all required OSHA related training is performed, and that personnel are trained and qualified for the tasks they will perform. The overall work will be performed within the stated roles and responsibilities of Section 2.

11.2.5 Environmental & Safety Equipment / Materials

Depending upon the nature of the work being performed, the following environmental and safety equipment or materials will be available onsite:

- Communications Equipment
- Combustible Gas Indicator (CGI)
- Fire Extinguishers
- Excavation Protection Equipment
- Barricades (control access to site)
- Isolation Fencing or Marking Tape (establishing hot and safe zones)
- First Aid Kit
- Blood Borne Pathogen Kit
- Personal Protective Equipment (PPE) (hard hat, safety glasses, protective shoes, hearing protection, protective clothing, respirators)
- Water Sample Bottles (Hydrostatic test water)
- Waste Sample Containers (Generated waste, e.g. pigging waste)
- Silt Fencing (control runoff from excavation)
- Cones and signs required for traffic control (as defined in USDOT- FHA Manual on Uniform Traffic Control Devices- Part 6)

NOTE: ILI tools have a strong magnetic field in close proximity, keep any instrumentation that may be affected by a magnetic field a safe distance from the ILI tools.

11.2.6 Communications Equipment

The company will ensure adequate communications equipment exist onsite to communicate to the company's Gas Storage Operations center, Gas Control, and appropriate emergency personnel in the area. If the communications onsite is limited to the company's Gas Storage Operations center, the Gas Storage Operations center will act as a relay station and contact the appropriate emergency personnel.
Appropriate communications equipment may include:

- Company radios

- Cellular phones
- Satellite telephones

11.2.7 Identification of Emergency Centers – Hospitals

Prior to performing the work, the company will identify the appropriate emergency response agencies and emergency centers (e.g. area hospitals). All appropriate contact information including names, telephone numbers, and addresses of the agencies and emergency centers will be recorded in the Environmental & Safety Site Plan described in the following subsection.

11.2.8 Developing an Environmental & Safety Site Plan

The company will develop an Environmental & Safety Site Plan that will be kept onsite at all times. This plan will also incorporate the company's Contractor Safety Management Tool implemented May 1, 2008. This tool can be accessed at the Corporate Health & Safety page on the LG&E KU Intranet Site.

Depending on the nature of work, the plan will address the following topics:

- Worksite(s) description
- Description of known hazards
- List of key personnel onsite (e.g. project supervisor, safety, environmental)
- Subcontractors
- Means to control site access
- Lockout/tagout procedures and training
- Measures employed to minimize environmental and safety risks
- Biological hazards & controls (snakes, ticks, bees, poison ivy, blood borne pathogens)
- Personal protective equipment (PPE)
- Emergency response agencies and emergency centers
- The company's work permits (hot work, trenching & excavation, confined space entry, etc.)
- Agency permit requirements (environmental)
- Right-of-way encroachment work permits
- Signature form – to be signed by all personnel onsite

A copy of Form 11-1: Environmental & Safety Site Plan is located at the end of this section.

11.3 REFERENCED COMPANY SAFETY PROCEDURES

The company will use the following company safety procedures depending upon the nature of the work being performed. The **Pipeline Specialist** F5, or on-site manager, should have working knowledge of any safety procedure referenced in this section. The following are the company's procedures that will be incorporated into this procedure:

Personal Protective Equipment (PPE)

The company's personal protective equipment (PPE) guidelines, as found in the company's Health & Safety Manual, describes the appropriate PPE to be worn while performing work on the company's pipeline system. Although the Health & Safety Manual should be referenced for specific PPE requirements, as a minimum these requirements will include:

- Hard hat
- Flame retardant uniforms
- Safety glasses with side shields or face shield (if applicable)
- Safety toe shoes

Trenching and Excavation

The company's trenching and excavation guidelines, as found in the company's Health & Safety Manual, describes the company's safety requirements to be implemented whenever trenching or excavation is performed. A "Competent Person" will designate to be responsible for the supervision of trenching and excavation operations to ensure worker safety.

The designated "Competent Person" is:

- Someone who has the proper training, experience, and knowledge of:

- soil analysis;
- use of protective systems; and
- the requirements of 29 CFR Part 1926 Subpart P.

- Someone with the ability to detect:

- conditions that could result in cave-ins;
- failures in protective systems;
- hazardous atmospheres; and
- other hazards including those associated with confined spaces

- Someone with the authority to:

- take prompt corrective measures to eliminate existing and predictable hazards; and
- stop work when required

- authorize or deny entry into excavation

Other items addressed in this procedure include but are not limited to:

- Applicability (excavations over 4 ft.)
- Standing water in excavations
- Access and egress
- Surface encumbrances
- Adjacent structures
- Equipment operating nearby
- Hazardous atmospheres in confined spaces
- Determination of soil type
- Soil testing methods
- Spoil placement near excavation
- Excavations over 20 feet deep
- Protective systems
- Sloping of excavations
- Benching or stair stepping of excavation
- Emergency rescue equipment
- Surface crossing of trenches
- Inspection of trenches and excavations

Form 11-4: Excavation Checklist should be used as an aid for following trenching and excavation guidelines.

Hazardous Energy Control – Lockout/Tagout

The company's Lockout/Tagout procedures describes the minimum requirements for the control of hazardous energy during operation, maintenance and inspection of equipment, machines, and/or pipeline facilities within the natural gas transmission, storage, and distribution systems. GAOP-PO-001 should be used to ensure safety and compliance with company, state and federal regulations.

Asbestos Containing Materials (ACM)

The company's asbestos procedure describes the company's safety and environmental requirements when working with asbestos containing materials. The company has determined that small concentrations of asbestos may exist within certain pipeline coatings or gasket materials on the pipeline system. Whenever the potential of asbestos containing materials cannot be eliminated, the company will use the asbestos containing materials procedure.

Blood Borne Pathogens

The company's procedure describes the company's safety requirements to comply with applicable OSHA requirements. Blood Borne Pathogen kits will be available onsite, and the company's employees have received appropriate training on the use of these kits.

First Aid

The company's procedure describes the company's safety requirements to comply with applicable OSHA requirements. First Aid kits will be available onsite, and the company's employees have received appropriate training on the use of these kits.

11.4 REFERENCED COMPANY ENVIRONMENTAL PROCEDURES

The company may use the following environmental procedures depending upon the nature of the work being performed. The **Pipeline Specialist** F5, or on-site manager, should have working knowledge of any environmental procedure referenced in this section.

Environmental Permitting

The Program Manager – Integrity Management M1 or **Pipeline Specialist** F5 will be responsible for notifying the company's environmental scientist in the Environmental Affairs department concerning environmental permits. The environmental scientist will be responsible for acquiring all environmental permits in accordance with existing company procedures.

Generated Wastes

The company will use its existing waste procedures to appropriately characterize any waste generated on site. This waste may be characterized as non-hazardous, hazardous, or special wastes. The company will handle, storage, transport, and dispose of each waste in accordance with the appropriate company procedure.

Sampling

All sampling will be performed in accordance with the company's environmental sampling procedures. These sampling procedures address the following types of sampling:

- Generated wastes (hazardous, non-hazardous)
- Special wastes (e.g. asbestos)
- Hydrostatic test water
- PCBs

11.5 PERFORMING THE WORK

11.5.1 Daily Environmental / Safety Orientation

Each day the **Pipeline Specialist** F5, or on-site manager, will perform a daily environmental /safety orientation prior to commencing the work. During this orientation the **Pipeline Specialist** F5, or on-site manager, will review the Environmental & Safety Site Plan with everyone onsite. Emergency response procedures, PPE, permit requirements, and other safety and environmental mitigative measures will be reviewed in detail.

Upon completion of the initial review, all personnel on site will sign the Environmental & Safety Site Plan indicating they understand the requirements of the plan. Any new personnel arriving onsite, will receive an environmental /safety orientation and will sign the Environmental & Safety Site Plan prior to starting work.

11.5.2 Controlling the Site

The **company** will take appropriate measures to control the work site and ensure the public remains at a safe distance from the work. This may include, but not limited to, the use of road blocks, barricades, fencing, isolation tape, markers, and signage.

If traffic control is needed for controlling the worksite, the **Pipeline Specialist** F5 or designated contractor partner will contact the current traffic control provider and/or local officials as appropriate.

11.5.3 Establishing Hot and Safe Zones

The **Pipeline Specialist** F5 or other qualified individuals (e.g., pipeline inspections, foreman, etc.) will establish "hot" and "safe" zones based upon the hazards of the work. Personnel within the "hot zone" should be limited to those required to perform the work. Anyone not currently required for the task being performed should be staged in the "safe zone" until needed. Whenever the hoop stress of the pipeline being tested exceeds 50% of SMYS, the company will take all practical steps to keep persons not performing the work at a safe distance in the "safe zone".

Note: Reference "Environmental Protection and Safety Requirements" §192.515(a)

11.5.4 Trenching & Excavation

Any trenching or excavation will be performed in accordance with the company's trenching and excavation guidelines found in the company's Health & Safety Manual and under the supervision of a Competent Person. The Competent Person should complete Form 11-4: Excavation Checklist.

11.5.5 Fire Watch

Whenever any welding, cutting, or other hot work is being performed in conjunction with remediation activities on the pipeline a fire watch will be posted at the site. This fire watch will be performed in accordance with the company's fire watch policy, which consists of using fire extinguishers whenever hot work is being performed. Whenever hot work will be performed, Form 11-3: Hot Work Permit must be completed and submitted for approval.

11.5.6 Disposal of Test Medium

Through the use of established company procedures, the company will ensure that the test medium is disposed of in a manner that will minimize damage to the environment.

Hydrostatic test water will be tested prior to the test in its native environment and during any water discharge after the test. All tests will be performed in accordance with water use permits and water discharge permits.

11.6 FORMS: ENVIRONMENTAL & SAFETY PLAN

Form 11-1: Environmental & Safety Plan
Form 11-4: Excavation Checklist

Form 11-1: Environmental and Safety Site Plan

TASK ______________________________

LOCATION ______________________ DATE __________

ON-SITE MANAGER: ______________________________

EMPLOYEES: ______________________________

____

CONTRACTORS: Company ______________________________

Employee ______________________________

Employee ______________________________

Employee ______________________________

PIPELINE INTEGRITY
PART I- MANDATORY JOB BRIEFING AND DOCUMENTATION FORM

Prior to the initiation of any work, the worker, or workers on the job, with or without the supervisor present, **shall review the safety aspects of the job** and ensure that effective actions are taken to protect those involved in the job. The Job Briefing shall always cover at least these key points;

Meet and discuss any key points specific to this briefing.

1) The hazards associated with the job.

2) Work Procedures.

3) Special precautions. (eg: engineering controls)

4) Energy source controls

5) Personal protective equipment requirements

This review **shall** be documented by the employees on the job and placed with the work order.

Where jobs involving the same considerations under the 5 key points are to be undertaken, only one Job Briefing need be held and documented each day. Additional Job Briefings shall be held if significant changes, which might affect the safety of the employees, occur during the course of the work.

Job Briefing must and shall take place prior to the initiation all work.

This standard mandates that all of us **shall think** and take appropriate actions before each and every job to ensure our safety and the safety of those around us.

A.	HAZARDS IDENTIFIED
	____
	____
	____
	____
	____
	____
	____
	____
	____
	____

B.	PERSONAL PROTECTION EQUIPMENT
___ Hard hat ___ Flame retardant uniforms ___ Safety Glasses ___ Face Shield	
___ Hearing Protection ___ Respirators ___ Safety Toe Shoes	

C.	SITE ACCESS CONTROL
___ Barricades ___ Warning Signs ___ Warning Tape ___ Low security fence ___ Cones	
___ Chain link fence ___ Traffic control signs ___ Traffic flag person ___ Security guard ___ Police officer	
Description of site control plan:	
	____
	____
	____
	____
	____
	____

D.	SPECIAL PRECAUTIONS
	_______________________________
	_______________________________
	_______________________________
	_______________________________

E.	SIGNATURES
	_______________________________
	_______________________________
	_______________________________
	_______________________________
	_______________________________
	_______________________________

PART II-	EMERGENCY RESPONSE

(incase of an emergency, call 911.)

Facility Name ______________________________

Address ______________________________

Phone (   ) ______________

Directions ______________________________

____

PART III-	ADDITIONAL KEY POINTS

__Asbestos __Lifting & Carrying __Confined Space __Rigging & Hoisting __Hazardous Energy Isolation

__Welding & Cutting __Ladders & Scaffolding __Emergency Action Plans __Equipment Isolation

__Hand Tools __Fire Prevention __Fall Protection __Housekeeping __Power Tools & Equipment

__Ground Fault Protection __Chemicals & Hazardous Materials

Work Order # Associated with the job (if applicable) ______________________

PART IV-	ENVIRONMENTAL AND SAFETY EQUIPMENT

________ Communication Equipment	________ Combustible Gas Indicator
________ Fire Extinguishers	________ Oxygen Meter
________ First Aid Kit	________ Confined Space Recovering Equipment
________ Blood Borne Pathogen Kit	________ Excavation Protection Equipment
________ Water Sample Bottles	________ Waste Sample Containers
________ Silt Fencing	

PART V-	WORK PERMITS

________ Environmental (Blue Stream, Wetlands, etc.)	________ Traffic
________ Construction	________ Hot Work
________ Trenching & Excavation	________ Confined Space

FORM 11-4: EXCAVATION CHECKLIST

Pipeline Integrity

(Please print legibly.)

GENERAL INFORMATION

1. Location of Job: ____________________
2. Description of Job: ____________________
____
3. Project/Task: ____________________ Work Order No.: ____________________
4. Date of Work: ____________________
5. Highway Permit No.: ____________________
6. Other Utilities: Are "Other" Utilities involved? Yes ( ) No ( )
Overhead ( ) Underground ( )
Have the Utilities been notified? Yes ( ) No ( )
BUD Tracking No.: ____________________
Date: ____________ By: ____________________

PRE-EXCAVATION SAFETY INSPECTION and SURVEY

Roadway---Traffic Hazards:	Yes	No
Congested area?		
Traffic Cones required?		
Barricades required?		
Traffic Vest required?		
Lane and/or Street closures?		
Steel Plating required?		
Traffic Control Officer required?		
Other?		

Sidewalk---Pedestrian Safety:	Yes	No
Congested area?		
Barricade Tape required?		
Lighted Barricades required?		
Fencing required?		
Sidewalk needs to be closed?		
Steel Plating required?		
Other?		

1. Will adjacent structures need to be stabilized? No ________ Yes ________ Identify: ____________________
Describe method to stabilize: ____________________
2. If more than 4 ft deep (by LG&E Procedures), shoring/sloping/benching must be considered:
Benched _____ Shored _____ Sloped _____ Shielded _____ Other _____ Details: ____________________
3. Atmospheric Monitor used? Not Needed ( ) Yes ( )
If Yes, how often? Continuously ( ) Periodically-Every ____________
4. Unusual and/or Special Safety Precautions: ____________________
____

AUTHORIZATIONS

Competent Person Signature ____________________ Date ____________

Note: When complete, return this form to supervisor and retain for one year. Date Returned: ____________

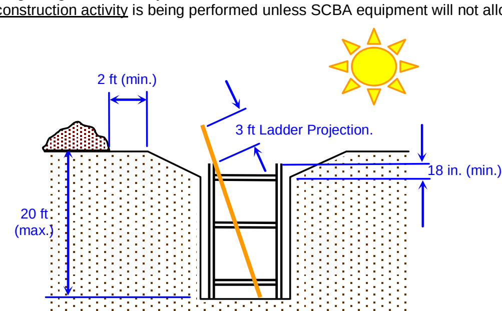
SKETCH OF EXCAVATION

Width: __________ (at bottom).
Width: __________ (at top).
Length: __________
Depth: __________

RULES and REGULATIONS (For further information, refer to OSHA 29 CFR 1926.650 through 1926.652 and LG&E Procedures.)

1. **Competent Person:** A "Competent Person" shall be named and in charge of the excavation and shall inspect the excavation at the beginning of each day and each shift. As hazards increase, the Competent Person should re-inspect the excavation.
2. **Soil Types:**
   a. Stable Rock — Maximum Allowable Slope: Vertical.
   b. Type A Soil: Cohesive soils with an unconfined compressive strength of 3000 pounds per square foot or greater.
   Type A soils cannot be fissured, previously disturbed, or subject to vibration.
   Maximum Allowable Slope: ¾ Horizontal : 1 Vertical.
   Maximum Allowable Slope: ½ Horizontal : 1 Vertical (for simple sloped excavations open 24 hours or less and 12 feet or less in depth).
   Excavations 8 feet or less in depth shall have a lower maximum unsupported vertical side of 3.5 feet.
   c. Type B Soil: Cohesive soils with an unconfined compressive strength between 1000 and 3000 pounds per square foot.
   Granular cohesionless soils such as silt, silty loam, sandy loam, etc.
   Maximum Allowable Slope: 1 Horizontal : 1 Vertical.
   d. Type C Soil: Cohesive soils with an unconfined compressive strength of 1000 pounds per square foot or less.
   Granular soils such as gravel, sand, loamy sand, etc.
   Soil with freely seeping water.
   Maximum Allowable Slope: 1 ½ Horizontal : 1 Vertical.
3. **Spoil Pile:** Keep all excavated material, tools, and equipment at least 2 ft. (min.) from all edges of excavation. The spoil pile should be adequately sloped.
4. **Ladders:**
   a. A ladder shall be provided for entry and exit if the excavation is 4 ft. or more in depth.
   b. The ladder shall extend 3 feet above the ground surface and be secured.
   c. Ladders shall be located such that there is no more than 25 ft. of lateral travel to exit the excavation.
5. **Shoring/Sloping/Shielding/Benching:**
   a. Soil classification for all excavations shall be considered to be Type C for the purpose of designing a shoring system.
   b. A Registered Professional Engineer shall analyze all excavations and shoring systems greater than 20 ft. deep.
   c. Shoring and shielding systems shall extend 18 inches (min.) above the ground surface or the bottom of the sloped or benched portions.
   d. Benching not allowed for cohesionless soils.
6. **Warning Signs:**
   a. Water ingress. Employees shall not work where there is accumulated water, unless adequate precautions have been taken.
   b. Tension cracks in soil.
   c. Nearby surcharge loads or vibrating loads.
7. **Atmospheric Hazards:**
   a. Oxygen: The oxygen level should not be less than 19.5% unless respiratory equipment (SCBAs with fire suits) is used.
   b. Flammability: The Lower Flammability Limit should be less than 20% unless respiratory equipment is used.
   A fire extinguisher shall be available whenever there is a chance of exposure to a flammable atmosphere or when cutting or welding is being performed.
   c. Hydrogen Sulfide: When there is a risk that hydrogen sulfide (H_2S) may be present (i.e. sewers, storage field pipelines, compressor station areas), the atmosphere shall be checked for its presence. Hydrogen sulfide is heavier than air and could settle in the bottom of the trench.
8. **Other Safety:**
   a. Employees shall not be permitted under any suspended load being handled by lifting or digging equipment.
   b. Guardrails shall be provided if there are walkways or bridges crossing over an excavation.
   c. A Job Briefing shall be conducted before beginning each shift or job.
   d. Hardhats should be worn whenever any construction activity is being performed unless SCBA equipment will not allow their use.

GENERAL



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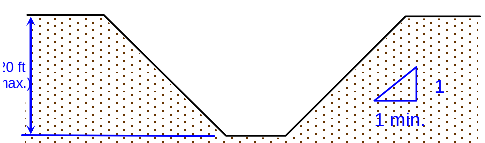
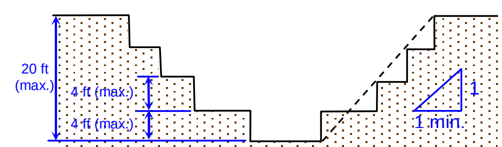
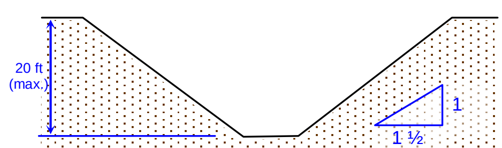


Simple Slope



Multiple Bench
(Allowed in Cohesive Soil only!)

TYPE "C" SOIL



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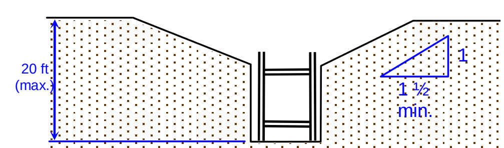

Slope with Shored/Shield

Revision Log:

Date	Description	Revised By
12/10/2004	Changed font style and size	MTS
12/10/2004	Changed Regional Operations Manager to Manager of Pipeline Integrity (Subsection 11.1.2)	MTS
12/10/2004	Changed Regional Engineer to Program Manager - Pipeline Integrity (Subsection 11.1.2 and 11.2.1)	MTS
12/10/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/10/2004	Changed Company to LG&E Energy	MTS
12/10/2004	Changed control center to Gas Storage Operations and added Gas Control	MTS
12/10/2004	Inserted timetable for completion of Environmental and Safety Plan (Subsection 11.2.8)	MTS
12/10/2004	Inserted flame retardant uniforms as a requirement for PPE	MTS
12/10/2004	Inserted requirement that the Program Manager – Pipeline Integrity is responsible for notifying the environment specialists concerning the permits (Subsection 11.4)	MTS
12/10/2004	Insert PCB sampling as a requirement	MTS
12/10/2004	Insert lockout/tagout procedures and training as a topic to be addressed	MTS
12/10/2004	Insert KPSC and IURC noticifiaction	MTS
12/10/2004	Insert text concerning construction specific permits and utility locate request	MTS
12/10/2004	Insert text concerning disposal of water for hydrostatic test	MTS
4/7/2006	4/7/06 Version Approved by Management	LCO
07/30/2008	11.3 – Added Hazardous Energy Control – Lockout/Tagout with description.	SAD
09/20/2008	11.2.8 – Added comment in section introduction making reference to the company Contractor Safety Management Plan	SAD
8/1/2008	8/1/08 Version Approved by Management	LCO
10-29-09	Revised positional titles and function code.	SAD
12-13-10	No Revisions Required	SAD
10-27-11	No Revisions Required	SAD
11-29-12	Paragraph 11.2.8 – Deleted EON-US and replaced with LG&E KU	SAD
12/9/15	Section 11.3 – Added “authorize or deny entry into excavation	SAD
12/9/15	Section 11.3 – Deleted Confined Space Entry language	SAD
12/9/15	Section 11.6 – Deleted Form 11-3 Hot Work Permit Permit	SAD

12/14/14	Section 11.6 – Deleted Form 11-2 Traffic Control Request Form	SAD
12/14/14	Section 11.2.5 – Removed Oxygen Meter and Confined Space Recovery Equipment	SAD
12/14/14	Section 11.5.2 – Changed language in paragraph 2, second sentence.	SAD

12 ADDITIONAL PREVENTIVE & MITIGATIVE MEASURES §192.935

In This Section

Referenced Protocols

12 ADDITIONAL PREVENTIVE & MITIGATIVE MEASURES

12.1 OVERVIEW

12.1.1 Purpose

The Preventive and Mitigative Measures section describes the process and procedures that ***Louisville Gas & Electric/ Kentucky Utilities*** *(the company)* uses to evaluate potential preventive and mitigative (P&M) measures on the gas transmission pipeline system. These measures are selected based upon the identified threats and risk assessment analysis in accordance with the requirements of 49 CFR 192.935, and are intended to prevent or mitigate the consequences of a failure.

12.1.2 Responsibility

The **Program Manager – Integrity Management** M1 will have overall responsibility for the performance of the procedures described within this section, or communication of the required additional preventive and mitigative measures to the responsible **Manager – Operations** F1 as applicable. The **Program Manager – Integrity Management** M1 shall also be responsible for continual review and modifications of this section as necessary.

For each transmission pipeline operated within the scope of this section appropriate additional preventive and mitigative measures, as prescribed by 49 CFR 192.935, will be researched, evaluated, and recommended. The **Program Manager – Integrity Management** M1 will have the overall responsibility with the assistance of the **Pipeline Integrity Engineer- F3**.

The appropriate **Manager – Operations** F1 shall be responsible for implementation of the recommendations submitted by the **Program Manager – Integrity Management** M1.

12.2 General Requirements

✓ ***Referenced Protocol:*** ***H.01 General Requirements (Identification of Additional Measures)***

✓ ***Referenced Protocol:*** ***H.03 Pipelines Operating Below 30% SMYS***

Section §192.935 of 49 CFR 192 Subpart O requires that additional measures be taken beyond those already required in 49 CFR Part 192 to prevent and mitigate the consequences of a pipeline failure. These additional measures apply to both covered pipeline segments (i.e., in an HCA) ***and pipeline segments operating below 30% SMYS that are not in an HCA but are in Class 3 or 4 Areas*** [Ref. §192.935(d)].

For pipeline segments in an HCA (covered pipeline segments), the additional measures are based on the threats identified in Section 4.0 and the risk assessment performed in Section 5.0 of this IMP. For pipeline segments operating below 30% SMYS, that are Class 3 or 4 Areas, but not in an HCA, §192.935(d) has specific prescriptive P&M requirements that are described in this section. Similarly, §192.935(e) also has specific prescriptive P&M requirements for plastic transmission pipeline.

The requirements stated within this section of the company's written Pipeline Integrity Management Program are based upon 49 CFR 192.935 only. These requirements are in addition to, and do not replace other operation and maintenance requirements for transmission lines stated within other sections of 49 CFR Part 192 federal regulations, Kentucky Public Safety Commission gas pipeline safety regulations, or Indiana Underground Regulatory Commission gas pipeline safety regulations.

12.3 SPECIFIC PREVENTIVE AND MITIGATIVE CONSIDERATIONS

12.3.1 Regulatory Requirements

49 CFR Part 192 §192.935 gives specific requirements for gas transmission pipelines of specified materials and operating stress levels.

12.3.2 Third Party Damage Considerations

✓ ***Referenced Protocol:*** ***H.02 Third Party Damage***

The Company complies with the requirements in §192.935 to enhance its' Damage Prevention Program to prevent and minimize the consequences of third party damage. These measures are described in the subparagraphs that follow.

12.3.2.1 Using Qualified Personnel

The Company uses qualified personnel for work being conducted that could adversely affect the integrity of any covered gas transmission line segment.

Activities for which the Company uses qualified personnel include, but are not limited to:

- Line marking
- Line locating
- Supervising excavation work
- Performing maintenance and operations tasks as described in the Company Operator Qualification Program

12.3.2.2 Collecting Excavation Damage in a Central Database

The Company uses the Damage Information Reporting Tool (DIRT) to document third-party damage, including damage that occurs during excavation activities. The information in this database includes damage that is not required to be reported as an incident per 49 CFR Part 192.

This tool is used for all transmission pipelines, regardless of operating stress level, Class Location or presence of HCA. The **Damage Prevention Team Leader** completes a new entry for each occurrence of damage. Information tracked includes but is not limited to:

- Date of event
- Location of event
- Root cause of event
- Name of party responsible for damage

The **Program Manager – Integrity Management** M1 or designee runs a custom query of the DIRT annually. The query downloads the last five (5) years of data, into an Excel spreadsheet.

The **Program Manager – Integrity Management** M1 or designee reviews the data and looks for the following trends:

- Upward trend in a particular root cause from year to year
- High percentage of damage occurrences being attributed to a specific root cause
- High concentration of excavation damage in a particular operating region in relation to other operating regions
- Large percentage of damage occurrences by a specific excavator

Based upon the results of the review, additional P&M measures may be identified. Depending upon the nature of the data and the types of root causes, the additional measures may be applied to:

- High Consequence Areas on a specific line segment
- High Consequence Areas in a specific region or district
- All High Consequence Areas

Once the review is complete, the **Program Manager – Integrity Management** M1 or designee documents the following on the bottom of the Excel spreadsheet:

- Name of person performing review
- Date review performed
- Whether or not additional P&M measures should be implemented
    - If no, a brief statement as to why not

The **Program Manager – Integrity Management M1** or designee saves the file and archives it in the Integrity Management Records.

If additional P&M measures are deemed appropriate, the **Program Manager – Integrity Management M1** or designee documents the P&M measures on **Form 14-1 "Management of Change".** Information documented on Form 14-1 will include:

- Description of proposed change
    - Root causes to be addressed
    - Specific operating areas where root causes need to be addressed (if any)
    - P&M measures to be implemented
    - Date P&M measures will be implemented
- Reason for change (i.e. annual excavation damage P&M review)

As necessary, the **Program Manager – Integrity Management M1** or designee attaches additional sheets to **Form 14-1** and routes and retains the form per the Management of Change process (Section 14.0).

12.3.2.3 One-Call Participation

The Company actively participates in the state wide one-call system for all transmission pipelines, regardless of whether or not a HCA is present. Refer to **GOM&I-PO-005** "Damage Prevention" for further details.

12.3.2.4 Monitoring Excavations

Each line location and marking request meeting the following conditions shall be investigated to determine if proposed excavation may jeopardize the integrity of the pipeline:

In the vicinity of any LG&E or KU gas transmission pipeline that operates below 30% SMYS

- within a class 3 or class 4 area, or
- within any covered segment

"In the vicinity" includes any location within a 100 foot buffer distance on either side of the centerline of the pipeline.

The company commonly elects to, but is not required to, conduct this investigation on other segments as well.

The investigation is documented using the **Locate Request Disposition Ticket** which is generated by e-mail to the applicable LG&E / KU operating center. The top portion of the ticket contains the request as sent by the One-Call Center.

Refer to **Attachment 12-1** for a representative example of the ticket.

Upon receipt of each request, the **Records Coordinator** or other qualified designated agent of the company reviews the information to determine if encroachment of the pipeline may result from the described excavation activity. This review is performed by one of the following:

- Smallworld system maps
- Telephone conversation with the requestor
- Site visit by a qualified company representative
- Other means as deemed appropriate

If it is determined encroachment may result, the **Records Coordinator** or other designated agent prints the ticket and dispatches the appropriate Operations Personnel for monitoring. Upon completion of the work, the Operations representative completes the bottom portion of the ticket. The bottom portion of the ticket contains blank fields for:

- Monitoring Information
- Employee Number
- Signature
- Date
- Yes or No for pipeline encroachment

Refer to **GOM&I-PO-005** "Damage Prevention" for further details.

Upon completion of the excavating project, the field representative documents the requested information at the bottom of the ticket and includes any additional information necessary for clarification. The completed ticket is sent to Integrity Management by email or FAX for inclusion in the Integrity Management file. Additionally an Encroachment Report or Maintenance Report is generated, as applicable, and filed with Asset Records.

In the event that encroachment will not result, the **Locate Request Disposition Ticket** is forwarded by e-mail to the designated Integrity Management mail box. The email states encroachment will not result and the basis for the determination. No entry of data into the fields at the bottom of the form are required if encroachment will not result.

12.3.2.5 Non-Monitored Excavation Activity

The Company considers an encroachment to occur when excavation occurs within a designated transmission pipeline easement or within 15 feet of a transmission pipeline in public right-of-way not within an easement.

Per 49 CFR 192.935(b)(iv), upon discovery of physical evidence of encroachment involving excavation that was not monitored on a covered pipeline segment, the Company has the option of:

- Excavating and examining the pipeline near the encroachment or
- Conducting an above ground electrical survey per NACE SP-0502-2008 standards to determine if damage has occurred.
    - The Company shall excavate, and remediate, in accordance with ANSI/ASME B31.8S and 49 CFR 192.933 any indication of coating holidays or discontinuity warranting direct examination.

Encroachment monitoring is the responsibility of Operations personnel. If evidence of encroachment is found during a patrol or leak survey, the evidence of encroachment is documented on a Maintenance Work Order.

If evidence of encroachment is found during other pipeline activities (i.e. corrosion control survey), personnel notify the District Operations Center of the encroachment.

When an encroachment is found in a class 3 or class 4 area that operates below 30% SMYS or any covered segment, Operations Personnel determine if the excavation activity was monitored by Company Personnel. If not, Operations will investigate the activity. If personnel can conclusively determine that no excavation occurred, no additional follow-up activity will occur. Otherwise, the pipeline near the encroachment is excavated and examined or an above ground electric survey is completed as outlined above.

The company commonly elects to, but is not required to, complete excavations or above ground electrical surveys on other segments where unmonitored excavation activity is identified as well.

Refer to **GOM&I-PO-CS-001** “Continuing Surveillance” and **GOM&I-PO-PA-001** “Patrolling” for further information.

12.3.2.6 District Regulator Stations

Per **GOM&I-PO-RS-001**, district regulator stations served from transmission lines, including pit regulators and above ground assemblies, are visually observed for indications of third party damage as a part of normal operation.

12.3.2.7 Public Awareness Program

The company maintains an effective public awareness communications program based upon API RP 1162 as required by 49 CFR 192.616.

12.3.3 Outside Force Damage

✓ ***Referenced Protocol:*** ***H.05 Outside Force Damage***

For pipelines operating at or above 30% SMYS, if the Company identifies Outside Force Damage as a Threat of Concern (see Section 4.0), the Company will identify P&M measures beyond those already required by 49 CFR Part 192 to minimize consequences to the covered segment. P&M measures to address Outside Force Damage include, but are not limited to:

- Aerial patrol
- Foot patrol
- Strain monitoring

The Company will perform additional inspections as deemed necessary following heavy rain, flood or other outside force conditions that may jeopardize the integrity of transmission line segments in high consequence areas.

Refer also to Section 12.4 for further details on selecting additional P&M measures.

12.3.4 Automatic Shut-Off Valves and Remote Control Valves

✓ ***Referenced Protocol:*** ***H.07 Automatic Shut-Off Valves or Remote Control Valves***

For each steel pipe segment in an HCA, and subject to operation at or above 30% SMYS, consideration must be given for the addition of an automatic shut-off valve (ASV) or remote control valve (RCV). The consideration of the measure is based on the risk analysis performed for the segment (Section 5). For the evaluation of this measure, the factors associated with the consequences of a line failure are of particular importance. The factors for consequence, incorporated in the risk analysis include:

- Swiftness of leak detection
- Pipe shutdown capabilities
- Type of gas being transported
- Operating pressure
- Rate of potential release
- Pipeline profile
- Potential for ignition
- Location of nearest response personnel.

Where the addition of an ASV or RCV would be an efficient means of adding protection to a high consequence area, the ASV or RCV will be installed. Installation schedule will be based upon relative risk and consequence of failure combined with operational and economic considerations.

The **Program Manager – Integrity Management** M1 assigns personnel to complete this study. Once the study is complete, the study documentation is retained in the Integrity Management File.

Every five (5) years, using the date of the original study as the benchmark, the **Program Manager – Integrity Management** M1 or designee reviews the HCAs contained in the study. As necessary, a supplemental study is performed to include HCAs that have been identified since the last study.

12.3.5 Pipelines Operating Below 30% SMYS

✓ ***Referenced Protocol:*** ***H.03 Pipelines Operating Below 30% SMYS***

Section 192.935(d) has specific P&M requirements for:

- Transmission pipe operating below 30% SMYS that is in an HCA
- Transmission pipe operating below 30% SMYS in a Class 3 or 4 Area but not in an HCA.

These requirements are described in the subparagraphs that follow:

12.3.5.1 In a HCA

Transmission pipelines operating below 30% SMYS in a HCA are subject to the following:

- Using qualified personnel per Section 12.3.2.1 of this document
- Collecting excavation damage in a central database per Section 12.3.2.2
- Participating in One-Call per Section 12.3.2.3

12.3.5.2 Not in HCA but in a Class 3 or Class 4

Transmission pipelines operating below 30% not in a HCA but located in a Class 3 or Class 4 location are subject to the following:

- Using qualified personnel per Section 12.3.2.1
- Collecting excavation damage in a central database per Section 12.3.2.2
- Participating in One-Call per Section 12.3.2.3

Additionally, steel pipelines operating at less than 30% SMYS that are not within a HCA but are in either Class 3 or Class 4 locations are subject to a semi-annual leak survey per **GOM&I-PO-007** “Leakage Survey and Leak Classification”.

Unprotected pipelines or cathodically protected pipelines where electrical surveys are not practical are subject to a quarterly leak survey per **GOM&I-PO-007**.

The **Pipeline Integrity Engineer** F3 generates paper maps indicating the aforementioned sections of pipe that are to be leak surveyed. These maps are distributed to compressor station and/or leak survey crews for completion, highlighting the sections of pipe that were leak surveyed. Upon completion of leak surveys, maps are returned to the **Pipeline Integrity Engineer** F3, reviewed for completeness and accuracy, and filed in the Integrity Management File. If leaks are found during the survey they are documented in the Leak Management System.

12.3.6 Plastic Pipe

✓ ***Referenced Protocol:*** ***H.04 Plastic Transmission Pipe***

Plastic transmission pipelines are subject to the following:

- Use qualified personnel when conducting work that could adversely affect the integrity of a covered segment per the requirements of Section 12.3.2.1
- Participate in the One-Call system per the requirements of Section 12.3.2.3
- Monitor excavations per the requirements of Section 12.3.2.4
- Follow-up on non-monitored physical evidence of encroachment per the requirements of Section 12.3.2.5

12.4 SELECTION OF PREVENTIVE AND MITIGATIVE MEASURES

✓ ***Referenced Protocol:*** ***H.01 General Requirements (Identification of Additional Measures)***

12.4.1 General Process for Selecting P&M Measures

Pipelines operating at or above 30% SMYS are subject to P&M measures beyond those already described in this document and beyond what is currently required by Part 192.

The Company uses a SME risk-based approach to select additional P&M measures for each applicable covered segment. During the risk-based process, the **Program Manager – Integrity Management** M1 or designee considers both the likelihood as well as the consequence of pipeline failure when choosing additional P&M

measures. The **Program Manager – Integrity Management M1** may designate SMEs including but not limited to the following to implement this process:

- Operations personnel
- Field personnel
- Engineering personnel
- Integrity Management personnel

If P&M measures above and beyond the requirements of Part 192 have already been implemented, the SME will document the measure(s) on **Form 12-1 Preventive and Mitigative Measures Summary Report**. Next, the SME will determine if the P&M measure(s) is an effective means of preventing, reducing the likelihood, or mitigating the consequence of the identified threat. If so, no further action is required. If not, the SME selects one or more additional P&M measure(s).

12.4.2 Detailed Process for Specific Threats of Concern

The subsections that follow give specific criteria and guidance for selecting P&M measures for each threat. For each threat, applicable P&M measures are given. The measures have been adapted from ASME B31.8S-2004 Table 4 "Acceptable Threat Prevention and Repair Methods". Along with the methods specifically addressed in that table, the Company has identified several additional prevention and mitigation methods.

Upon approval from **Program Manager – Integrity Management M1**, P&M measures other than those listed in this procedure may be used to address a particular threat.

12.4.2.1 External Corrosion

The SME identifies P&M measures for each covered segment where the TAV score for External Corrosion is three (3) or greater. The SME takes both the likelihood and consequences of a pipeline failure into consideration during the decision making process.

The SME reviews existing P&M measures and identifies additional P&M measures as appropriate, using Table 12-1 as guidance.

Table 12-1: Applicable P&M Measures for the External Corrosion Threat

Applicable P&M Measures	**Guidance**
Foot Patrol	Specify frequency and use of instrument; must be above and beyond part 192 requirements
Increased Wall Thickness	Using pipe thicker than required for stress level
CP Monitoring / Maintenance	
• DCVG Survey	Survey to detect coating holidays
• Close-Interval Survey	Survey to identify areas that do not meet NACE criteria for cathodic protection

• Remote Monitoring Units at Rectifiers	Remote monitoring can provide more timely notification and repair of rectifiers (i.e. minimizes amount of time pipeline does not meet NACE criteria for cathodic protection)
• CP Maintenance procedures	Incorporating a timeline for repairing CP equipment reduces the interval that a pipeline segment may have limited Cathodic protection
CP Design and Installation	For segments that do not meet the 850mV CP criteria, installation of new or modifying an existing CP system can lower the threat of external corrosion.
Coating repair	Full encirclement recoat on a segment of pipe (i.e. strip & recoat entire line or several miles). Spot repairs do not constitute a P&M measure. Coating repair improves the efficiency of the cathodic protection system.

Refer to Section 12.4.3 for information on documentation.

12.4.2.2 Internal Corrosion

The SME identifies P&M measures for each HCA where internal corrosion was detected during an integrity assessment or direct examination as well as for each covered segment that is part of a “wet gas” system.

The SME reviews existing P&M measures and identifies additional P&M measures as appropriate, using Table 12-2 as guidance and taking the likelihood and consequence of a pipeline failure into consideration.

Table 12-2: Applicable P&M Measures for the Internal Corrosion Threat

Applicable P&M Measures	**Guidance**
Increased Wall Thickness	Using pipe thicker than required for stress level
Internal Cleaning	Do not use if ICDA will be performed on line Specify frequency – cleaning done in conjunction with a baseline assessment or reassessment is not applicable Frequency should be determined based on condition of pipe and amount of water, sludge, etc. removed during cleaning operations
Reduce Moisture	Installation, upgrade, or increased maintenance frequency of equipment such as scrubbers, moisture separators, or dehydrators.
Leakage Control Measures	Leak detection and control measures can minimize the consequence of a leak.
Biocide / Inhibitor	Type, quantity, and frequency of biocide or corrosion inhibitors must be selected on a case-by-case basis and the effectiveness of any injection program should be monitored.
Monitoring	Routine monitoring of water and/or gas samples ensures an effective Internal Corrosion program. (See also “biocide / inhibitor above.)

Refer to Section 12.4.3 for information on documentation.

12.4.2.3 Stress Corrosion Cracking

The SME selects P&M measures for the covered segment if SCC – either near-neutral or high-pH – is identified as a Threat of Concern. The SME reviews existing P&M measures and identifies additional P&M measures as appropriate, using Table 12-3 as guidance and taking the likelihood and consequence of a pipeline failure into consideration.

Table 12-3: Applicable P&M Measures for the Stress Corrosion Cracking Threat

Applicable P&M Measures	Guidance
Monitoring • Mag Particle testing • Dye Penetrant testing	Perform testing during routine excavations, particularly those done as part of an Integrity Assessment. Document negative test results to show that SCC has not occurred at a particular location.
Replacement	SCC is not a threat of concern for FBE-coated pipe; replace with FBE-coated pipe. SCC is not a concern for pipelines operating below 60% SMYS; replace with different design criteria.
Reduce external stress	
• Reduce MAOP	SCC is not a threat of concern for pipelines operating below 60% SMYS
• Increase Depth of Cover	Increase depth of cover to reduce external stress due to cyclic loads, if applicable.
Coating Repair	SCC is not a threat of concern for FBE-coated pipe. Repair of any coating holidays (i.e. gouges or scratches) helps prevent initial formation of SCC cracks.

Refer to Section 12.4.3 for information on documentation.

12.4.2.4 Manufacturing

The SME will select additional P&M measures for the covered segment if Defective Pipe Seam (TAV 4) or Defective Pipe (TAV 5) score is three (3) or greater.

If both TAV4 and TAV5 have a score of three (3) or greater, the SME will identify the threat with the greatest consequence / likelihood of failure and identify a P&M measure to address that particular threat, using Table 12-4 as guidance.

Table 12-4: Applicable P&M Measures for Manufacturing Threats

Applicable P&M Measures	Pipe Seam	Pipe	Plastic	Guidance
Hydrostatic Testing (pre-service)	X	X	X	These P&M measures address the likelihood of failure for any new (or replaced) sections of pipe; they do not address pre-existing conditions.
Materials inspection	X	X	X	
Manufacturer inspection	X	X	X	
Construction inspection		X	X	
Reduce MAOP	X	X	X	Reducing the MAOP lowers both the consequence and potential

				likelihood of failure.
Monitoring • Mag Particle testing • Dye Penetrant testing • Visual inspection	X			Testing or visual examination of the long seam when pipe exposed.

Refer to Section 12.4.3 for information on documentation.

12.4.2.5 Construction

The SME will select additional P&M measures for the covered segment if any of the following have a score of three (3) or greater:

- Defective Girth Weld (TAV 6)
- Defective Fabrication Weld (TAV 7)
- Wrinkle Bend or Buckle (TAV 8)
- Stripped threads / broken pipe / coupling failure (TAV 9)

If more than one TAV has a score of three (3) or greater, the SME will determine which TAV has the greatest consequence of failure / likelihood of failure and choose a P&M measure to address that threat, using Table 12-5 as guidance.

Table 12-5: Applicable P&M Measures for Construction Threats

Applicable P&M Measures	Girth Weld	Fab Weld	Plastic Fusion	Coupling	Wrinkle Bends	**Guidance**
Hydrostatic Testing (pre-service)	X	X	X	X	X	
Aerial Patrol				X		Specify frequency.
Foot patrol				X		Specify frequency.
Visual inspection	X		X			Inspection of girth welds when exposed.
Reduce MAOP	X	X	X			Reducing the MAOP lowers both the consequence and potential likelihood of failure.
Inspection	X		X			Visual inspection &/or examination (i.e. X-ray, UT) when girth weld exposed.
Reduce external stress					X	
• Increase depth of cover					X	
Removal				X	X	Remove when exposed during routine excavation activities if practical.
Repair					X	Install “pumpkin” type reinforcement over wrinkle bends if removal is not practical.

Refer to Section 12.4.3 for information on documentation.

12.4.2.6 Equipment

The SME will identify additional P&M Measures if any of the following have a score of three (3) or greater:

- Gasket / O-Ring Failure (TAV 10)
- Control / Relief Equipment Malfunction (TAV 11)
- Seal / Pump Packing Failure (TAV 12)
- Miscellaneous Equipment (TAV 13)

If more than one TAV has a score of three (3) or greater, the SME will determine which TAV has the greatest consequence of failure / likelihood of failure and choose a P&M measure to address that threat, using Table 12-6 as guidance.

Table 12-6: Applicable P&M Measures for Equipment Threats

Applicable P&M Measures	Gasket / O-Ring	Control / Relief	Seal / Packing	Misc.	**Guidance**
Inspection and Maintenance	X	X	X	X	Specify frequency
Design specifications	X	X	X	X	Revise specifications if known problems exist for a particular style, model, or manufacturer.

Refer to Section 12.4.3 for information on documentation.

12.4.2.7 Third-Party Damage

The SME will identify additional P&M Measures if any of the following have a score of three (3) or greater:

- Damage inflicted by First, Second, or Third Party / Instantaneous Failure Mode (TAV 14)
- Previously Damaged Pipe / Delayed Failure Mode (TAV 15)
- Vandalism (TAV 16)

If any of the Third Party Damage TAVs have a score of three (3) or higher, the Company will identify the TAV with the highest consequence and likelihood of failure. Upon this determination, the SME will choose an applicable P&M measure, using Table 12-7 as guidance.

Table 12-7: Applicable P&M Measures for Third Party Damage Threats

Applicable P&M Measures	Inst	Del	Van	**Guidance**
Foot Patrols	X	X	X	Specify frequency
Aerial Patrols	X	X	X	Specify frequency
Increasing marker frequency	X	X		Specify locations
Temporary line markers during construction	X	X		Specify locations

Increasing patrols during construction activity	X	X		Specify frequency
Warning tape mesh	X	X		Install whenever pipe is exposed
Line relocation	X	X	X	Consider factors contributing to TPD when designing.
Increasing depth of cover	X	X		Consider increasing depth of cover to address specific concerns such as TPD in plowed field or shallow pipe.
Increased security / protection	X	X	X	Increasing the protection around aboveground facilities can reduce the likelihood of damage.
Supplemental public education	X			Increasing public communications / outreach can reduce the likelihood of an encroachment

Refer to Section 12.4.3 for information on documentation.

12.4.2.8 Incorrect Operations

The SME identifies P&M measures for each covered segment where the Incorrect Operations threat has a score of three (3) or greater.

The SME reviews existing P&M measures and identifies additional P&M measures as appropriate, using Table 12-8 as guidance and taking the likelihood and consequence of pipeline failure into consideration.

Table 12-8: Applicable P&M Measures for the Incorrect Operations Threat

Applicable P&M Measures	Guidance
Additional Training	Additional or improved training reduces the likelihood of failure to comply with procedures. Specify training audience.
Procedure reviews / modifications	Review of existing OM&I and IMP procedures ensures company practices comply with latest industry regulations.

Refer to Section 12.4.3 for information on documentation.

12.4.2.9 Outside Force

The SME will identify additional P&M Measures if any of the following have a score of three (3) or greater:

- Cold Weather (TAV 18)
- Lightning (TAV 19)
- Heavy Rain or Flood (TAV 20)
- Earth Movement (TAV 21)

If any of the Outside Force TAVs have a score of three (3) or greater, the Company will identify the TAV with the highest consequence and likelihood of failure. Upon this determination, the SME will choose an applicable P&M measure, using Table 12-9 as guidance.

Table 12-9: Applicable P&M Measures for Outside Force Threats

Applicable P&M Measures	Cold	Ltng	Rain/ Flood	Mvmt	**Guidance**
Aerial patrol	X	X	X	X	Specify frequency
Foot patrol	X	X	X	X	Patrol after a weather / outside force event
Visual inspection	X	X	X		Inspect after a weather / outside force event
Leak survey		X	X	X	Leak survey after a weather/outside force event
Strain monitoring			X	X	
External protection					
Maintain ROW				X	
Reduce external stress				X	
Heat tracing	X				
Relocate line	X		X	X	
Thermal protection	X				
Lightning arrestors		X			
Increase Depth of Cover	X				Placing the line below frost depth can eliminate this threat of concern.
River weights			X		For pipelines crossing a water feature
Casings			X		For pipelines that cross flowing water

Refer to Section 12.4.3 for information on documentation.

12.4.3 Documentation

✓ ***Referenced Protocol:*** ***H.08 General Requirements (Implementation of Additional Measures)***

Each year, the P&M review is documented on **Form F-14 Management of Change**, regardless of whether new P&M measures are identified or not. This documentation demonstrates that the review was performed. The form is routed and retained per the requirements of Section 14.0.

When P&M measures are identified for a line segment, **Pipeline Integrity Engineer** documents the P&M measures on **Form 12-1 Preventive and Mitigative Measures Summary Report.**

Integrity Management will review the P&M measures for a particular line under the following circumstances:

- Within one (1) year of a baseline assessment
- Within one (1) year of a reassessment
- Within one (1) year of a leak, failure or incident occurring in a HCA
- More frequent as deemed appropriate by the **Program Manager – Integrity Management M1**.

12.5 Document Retention

The **Program Manager –Integrity Management** M1 shall be responsible for assuring that applicable records are created, filed, and maintained.

The **Program Manager - Integrity Management** M1 is responsible for permanent retention of records of location request received and excavations monitored. This includes the **Line Location Disposition Ticket** , daily summaries from the one-call center, and any other records deemed pertinent and essential to maintain compliance with the requirements of 49 CFR 192 Subpart O.

12.6 Forms

The following forms are included within this subsection:

Form 12-1 Preventive and Mitigative Measure Summary Report

Form 12-2 Preventive and Mitigative Measure Documentation

LG&E KU PPL companies

Form 12-1: Preventive and Mitigative Measure Summary Report

Date: SAMPLE

See TIMP section 12 for guidance on applicability and selection of P&M Measures

Segment Information						HCA Stationing			Risk Calculation Factors TAV Scores																					
HCA Name (via IRAS)	Pipeline Name	Start Segment Number	End Segment Number	Start Segment ENOM Sys ID	Start Segment ENOM Sys ID	Map Distance begin HCA Station (ft.)	Map Distance end HCA Station (ft.)	HCA station length (ft.)	TAV 1	TAV 2	TAV 3	TAV 4	TAV 5	TAV 6	TAV 7	TAV 8	TAV 9	TAV 10	TAV 11	TAV 12	TAV 13	TAV 14	TAV 15	TAV 16	TAV 17	TAV 18	TAV 19	TAV 20	TAV 21	TAV 22

\\fs4\Pipe_Integ\Preventative and Mitigative Measures\Form 12-1 PM Summary.xlsx Page 1 of 4 Printed: 11/14/2013

LG&E KU PPL companies

Risk Information		External Corrosion (Group A1)			Internal Corrosion (Group A2)			Stress Corrosion Cracking (Group A3)			Manufacturing (Group B)			
Total Risk (Probability x Consequence)	Weighted Risk Average (Total Risk / HCA length)	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N
		N			N			N			N			N

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Preventive and Mitigative Measures												
Construction (Group C)		Equipment (Group D)			3rd Party Damage (Group E)			Incorrect Operations (Group F)			Weather & Outside Force (Gro	
P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented	Threat Applies?	P&M Measures Selected
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	
		N			N			N			N	

\\fs4\Pipe_Integ\Preventative and Mitigative Measures\Form 12-1 PM Summary.xlsx Page 3 of 4 Printed: 11/14/2013

up G)	Cyclic Fatigue (No Group)		
Date(s) Implemented	Threat Applies?	P&M Measures Selected	Date(s) Implemented
	N		
	N		
	N		
	N		
	N		
	N		
	N		
	N		
	N		
	N		
	N		

\\fs4\Pipe_Integ\Preventative and Mitigative Measures\Form 12-1 PM Summary.xlsx Page 4 of 4 Printed: 11/14/2013

Form 12-2 Preventive and Mitigative Measure Documentation

Pipeline Name/Number: ______________________

Pipeline Description/stationing: ______________________

Date of Review: ____________ Name of reviewer: ____________

Subject Matter Experts (names and titles):

______________________ ______________________

______________________ ______________________

______________________ ______________________

Root Cause: ______________________

____

PREVENTIVE AND MITIGATIVE MEASURES		
Mark all applicable threats and describe P&M Measure associated with each.		
External Corrosion	☐	P&M Measure:
Internal Corrosion	☐	P&M Measure:
SCC	☐	P&M Measure
Manufacturing	☐	P&M Measure:
Construction	☐	P&M Measure:
Equipment	☐	P&M Measure:
Third-Party Damage	☐	P&M Measure:
Incorrect Operations	☐	P&M Measure:
Cold Weather	☐	P&M Measure:
Lightning	☐	P&M Measure:
Heavy Rain or Flood	☐	P&M Measure:
Earth Movement	☐	P&M Measure:

Justification: ______________________

Implementation Date: ____________ Frequency: ____________

Page 1 of 1

Attachment 12-1 *Example Locate Request Disposition Ticket*

-----Original Message-----
From: kupitickets@kydigsafely.org [mailto:kupitickets@kydigsafely.org]
Sent: Thursday, January 17, 2008 5:52 PM
To: Muldraugh Gas Locate Requests
Subject: KUPI 0360 2008/01/17 #00024 0801170649-00A NORM NEW

0360 00024 KUPIa 01/17/2008 17:52:24 0801170649-00A NORM NEW STRT

NORMAL NOTICE

Ticket : 0801170649 Date: 01/17/2008 Time: 17:31 Oper: ARATTERMAN Chan:000

State: KY Cnty: JEFFERSON City: LOUISVILLE
Subdivision:

Address : 1633
Street : STAFFORD AVE
Cross 1 : LONDON DR
Location: FRONT YARD
:
Boundary: n 38.175053 s 38.173748 w -85.817413 e -85.813530

Work type : GAS SERVICE REPLACEMENT
Done for : PROP OWNER
Start date: 01/22/2008 Time: 17:45 Hours notice: 120/48 Priority: NORM
Ug/Oh/Both: U Blasting: NO Emergency: N
Duration : N/A Depth: 18IN

Company : JOHN MCVEY PLUMBING COMPANY Type: CONT Co addr : 9113 OLD BARDSTOWN ROAD
City : LOUISVILLE State: KY Zip: 40291
Caller : JOHN MCVEY Phone: (502)239-5646 Contact : JOHN MCVEY Phone:
Mobile : (502)210-2951

Submitted date: 01/17/2008 Time: 17:31
Members: 0002 0004 0006 0007 0139 0360 5005

Attachment 12-2 *P&M Applicability Table*

Subsection	192.935 Applicability Regulatory Citation	HCA ≥ 30% SMYS, steel	HCA < 30% SMYS, steel	Non HCA ≥ 30% SMYS	Non-HCA < 30% SMYS, Class 3 or 4 Loc, steel	HCA, Plastic Pipelines
(a)	General requirements. An operator must take additional measures beyond those already required by Part 192 to prevent a pipeline failure and to mitigate the consequences of a pipeline failure in a high consequence area. An operator must base the additional measures on the threats the operator has identified to each pipeline segment. (See §192.917) An operator must conduct, in accordance with one of the risk assessment approaches in ASME/ANSI B31.8S (ibr, see §192.7), section 5, a risk analysis of its pipeline to identify additional measures to protect the high consequence area and enhance public safety. Such additional measures include, but are not limited to, installing Automatic Shut-off Valves or Remote Control Valves, installing computerized monitoring and leak detection systems, replacing pipe segments with pipe of heavier wall thickness, providing additional training to personnel on response procedures, conducting drills with local emergency responders and implementing additional inspection and maintenance programs.	X				
(b)	Third party damage and outside force damage -					
(1)	Third party damage. An operator must enhance its damage prevention program, as required under §192.614 of this part, with respect to a covered segment to prevent and minimize the consequences of a release due to third party damage. Enhanced measures to an existing damage prevention program include, at a minimum—	X	X		X	X
(i)	Using qualified personnel (see §192.915) for work an operator is conducting that could adversely affect the integrity of a covered segment, such as marking, locating, and direct supervision of known excavation work.	X	X		X	X
(ii)	Collecting in a central database information that is location specific on excavation damage that occurs in covered and non covered segments in the transmission system and the root cause analysis to support identification of targeted additional preventative and mitigative measures in the high consequence areas. This information must include recognized damage that is not required to be reported as an incident under part 191.	X		X		
(iii)	Participating in one-call systems in locations where covered segments are present.	X	X		X	X
(iv)	Monitoring of excavations conducted on covered pipeline segments by pipeline personnel. If an operator finds physical evidence of encroachment involving excavation that the operator did not monitor near a covered segment, an operator must either excavate the area near the encroachment or conduct an above ground survey using methods defined in NACE RP–0502–2002 (ibr, see §192.7). An operator must excavate, and remediate, in accordance with ANSI/ASME B31.8S and §192.933 any indication of coating holidays or discontinuity warranting direct examination.	X				X
(2)	Outside force damage. If an operator determines that outside force (e.g., earth movement, floods, unstable suspension bridge) is a threat to the integrity of a covered segment, the operator must take measures to minimize the consequences to the covered segment from outside force damage. These measures include, but are not limited to, increasing the frequency of aerial, foot or other methods of patrols, adding external protection, reducing external stress, and relocating the line.	X				

Subsection		192.935 Applicability Regulatory Citation	HCA ≥ 30% SMYS, steel	HCA < 30% SMYS, steel	Non HCA ≥ 30% SMYS	Non-HCA < 30% SMYS, Class 3 or 4 Loc, steel	HCA, Plastic Pipelines
(c)		Automatic shut-off valves (ASV) or Remote control valves (RCV). If an operator determines, based on a risk analysis, that an ASV or RCV would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the ASV or RCV. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel.	X				
(d)		Pipelines operating below 30% SMYS. An operator of a transmission pipeline operating below 30% SMYS located in a high consequence area must follow the requirements in paragraphs (d)(1) and (d)(2) of this section. An operator of a transmission pipeline operating below 30% SMYS located in a Class 3 or Class 4 area but not in a high consequence area must follow the requirements in paragraphs (d)(1), (d)(2) and (d)(3) of this section.		X*		X*	
(d)	(1)	Apply the requirements in paragraphs (b)(1)(i) and (b)(1)(iii) of this section to the pipeline; and		X**		X **	
	(2)	Either monitor excavations near the pipeline, or conduct patrols as required by §192.705 of the pipeline at bi-monthly intervals. If an operator finds any indication of unreported construction activity, the operator must conduct a follow up investigation to determine if mechanical damage has occurred.		X		X	
	(3)	Perform semi-annual leak surveys (quarterly for unprotected pipelines or cathodically protected pipe where electrical surveys are impractical).				X	
(e)		Plastic transmission pipeline. An operator of a plastic transmission pipeline must apply the requirements in paragraphs (b)(1)(i), (b)(1)(iii) and (b)(1)(iv) of this section to the covered segments of the pipeline.					X***

*	192.935(d) does not contain unique requirement, reference to 192.935(d)(1), 192.935(d)(2) and 192.935(d)(3) only
**	192.935(d)(1) does not contain unique requirement, reference to 192.935 (b)(1)(i) and 192.935(b)(1)(iii) only
***	192.935(e) does not contain unique requirement, reference to 192.935(b)(1)(i), 192.935(b)(1)(iii), and 192.935(b)(1)(iv) only

Revision Log:

Date	Description	Revised By
12/09/2004	Changed NGA logo to LG&E logo	MTS
12/09/2004	Changed font style and size	MTS
12/09/2004	Changed Director of Pipeline Integrity to Manager of Pipeline Integrity (Subsection 12.1.2)	MTS
12/09/2004	Changed to Officer of Operations to Director of Pipeline Integrity (Subsection 12.1.2)	MTS
12/09/2004	Assigned the Manager of Pipeline Integrity with the responsibility of scheduling approved P&M recommendations.	
12/09/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/09/2004	Changed Company to LG&E Energy	MTS
12/09/2004	Changed Director of Pipeline Integrity to Manager of Pipeline Integrity (Subsection 12.3.1)	MTS
12/09/2004	Changed Appendix F to Appendix 6-A (pressure test) and 6-B (spike test)	MTS
12/09/2004	Defined electrical survys as indirect inspection tools (e.g., CIS)	MTS
12/09/2004	Added note to clarify pipelines operating below 30% SMYS (Subsection 12.3.4)	MTS
12/09/2004	Required pipelines that are cathodically protected but not in an HCA and are in a Class 3 or Class 4 location to be electrical surveyed on periodic basis not to exceed five years. (Subsection 12.3.4)	MTS
12/09/2004	Added note to claify plastic pipelines (Subsection 12.3.5)	MTS
12/09/2004	Changed Director of Pipeline Integrity to Manager of Pipeline Integrity (Subsection 12.4, 12.4.1, 12.4.3, 12.4.4, 12.4.5, and 12.4.6)	MTS
12/09/2004	Changed to Officer of Operations to Director of Pipeline Integrity (Subsection 12.4.6)	MTS
11/1/07	Major Revisions to entire document including: • Written documentation of Excavation Monitoring Process	LCO / CMA / RNE
07/02/2008	Major revisions to entire document including: • Collecting Excavation Damage Information • Monitoring Excavations • Pipelines Operting <30% SMYS • Selection of P&M Measures • Form 12-1	EN Engineering
08/01/2008	Moved signature box to page 12-1	MDC
8/1/2008	8/1/08 Version Approved by Management	LCO
8/12/2009	Updated section 12.3.6 – Plastic Pipe	MDC
8/12/2009	Updated table 12-4 with applicable plastic P&M measures for manufacturing threats	MDC
8/12/2009	Updated table 12-5 with applicable plastic P&M measures for construction threats	MDC
12/16/2012	Clerical corrections to references to Integrity Management per title names in Section 2.	JRG
12/16/2012	Inserted language related to 192.935(d)(1 &2)	JRG
12/16/2012	Inserted language for plastic pipe in section 12/3/6.	PJC
11/14/13	Updated applicable P&M measures to TPD to ensure matching with section 5	WJN
11/14/13	Updated Form 12-1 P&M Summary to more closely match format of new BAP / IRAS output	WJN
11/10/2016	Updated NACE RP – 0502-2002 to version in CRF 192 – NACE SP 0502-2008	JRW
11/10/2016	Changed RP 1162 to API RP 1162 for clarification	JRW

13 CONTINUAL EVALUATION & REASSESSMENT

§192.937-192.941

In This Section

Referenced Protocols

CONTINUAL EVALUATION & REASSESSMENT PROCESS

13.1 OVERVIEW

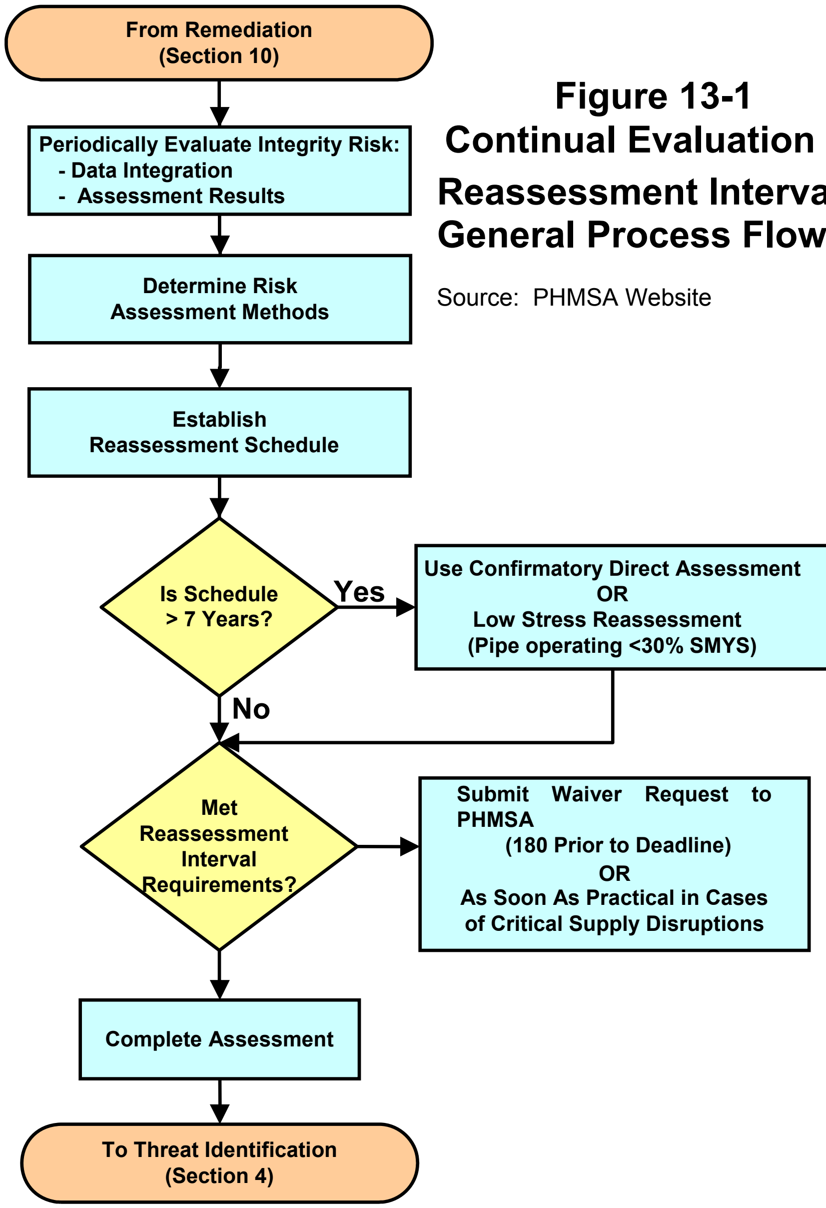


Figure 13-1
Continual Evaluation & Reassessment Interval General Process Flow

Source: PHMSA Website

13.1.1 Purpose

The Continual Evaluation and Reassessment Section describes how and when periodic risk assessments will be performed, and the technical basis for the determination. This section provides the procedures and guidance to be followed in determining the requirements for continuing reassessment of pipe segments after performance of the baseline assessment (refer to **Section 8.0**) or future reassessments. Continuing assessment includes the following activities:

- Identifying the probable failure mechanisms for the pipeline segment after the baseline assessment and repairs are performed:
- Reviewing previously identified monitered conditions during reassessments.
- Applying 49 CFR 192 Subpart O's requirements (§192.937, §192.939, and §192.941) to determine the maximum reassessment intervals, and required reassessment methods.
- Estimating the theoretical time to failure for specific threat mechanisms and applying an appropriate safety factor to estimated theoretical time to failure to determine the time interval for performing the pipeline segment reassessment
- Selecting the appropriate assessment methodology
- Notifying PHMSA and KPSC and/or IURC as necessary to request variances from default time schedules specified in §192.937, §192.939, and §192.941.
- Revising the current reassessment schedule due to the integration of new information about the pipeline system or other factors

13.1.2 Responsibility

Section 2 provides a complete description of the roles, responsibilities, job task analyses, and minimum qualifications for key personnel positions necessary for the implementation of the procedures described in this section.

The **Integrity Management Engineer** F3 has the responsibility for determining reassessment intervals for pipeline segments using the procedures described in this section, and is also responsible for maintenance and revision of these procedures.

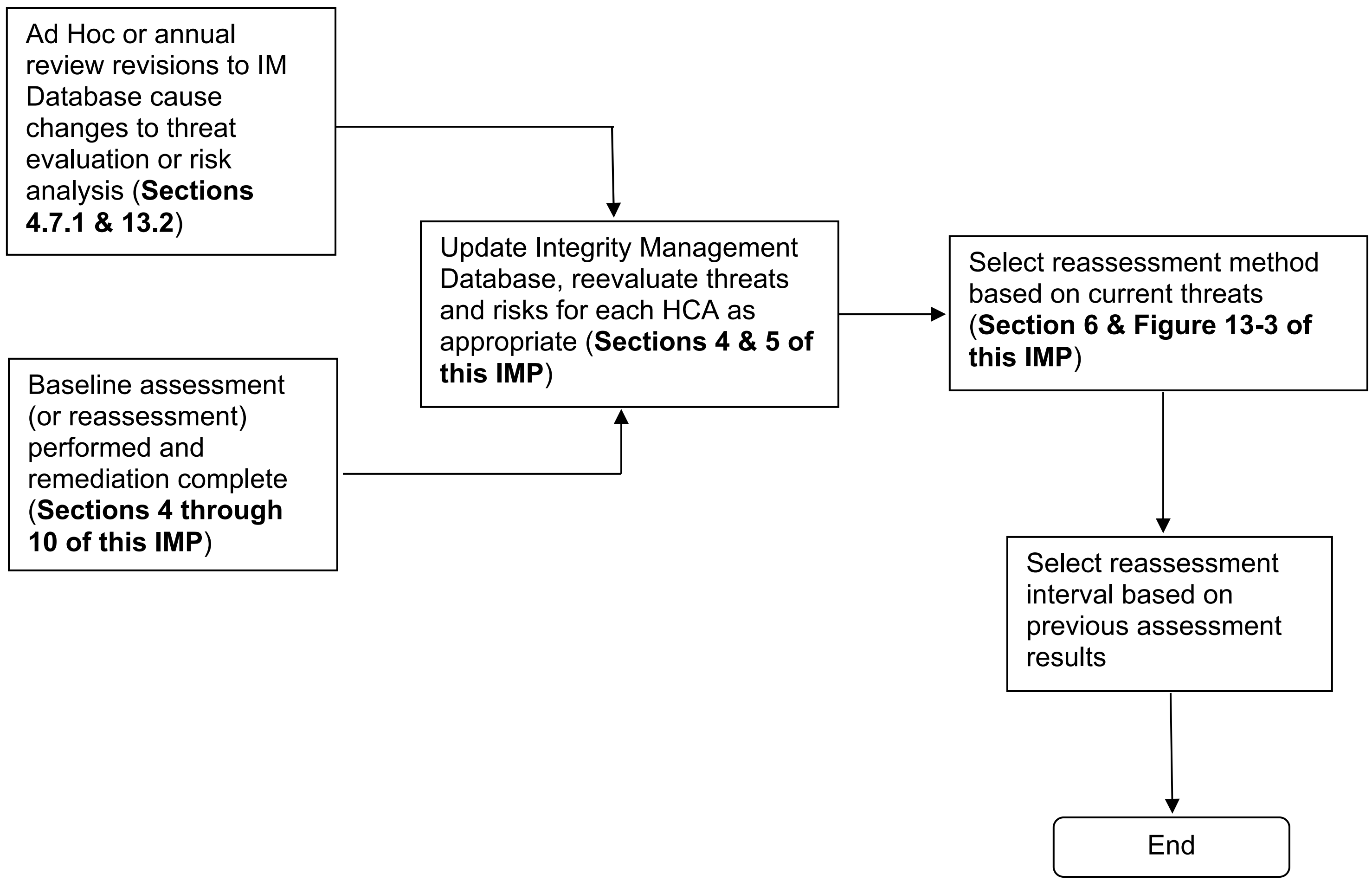
The **Program Manager - Integrity Management** M1 has overall responsibility for approving reassessment intervals as determined by the **Integrity Management Engineer** F3 using the procedures described in this section. The **Program Manager-Integrity Management** M1 is responsible for ensuring that integrity management data that is produced from conducting the procedures in this section are incorporated into the Integrity Management database and Assessment Results spreadsheets as applicable. Furthermore, the **Program Manager - Integrity Management** M1 is responsible for determining the frequency and scope of any re-evaluation of threats and risks (Sections 4 & 5 procedures) for a pipeline segment based on new IM data. The **Program Manager – Integrity Management** M1 may assign responsibilities to other qualified individuals in performing these functions as appropriate.

13.2 PERIODIC RISK ASSESSMENT – DATA INTEGRATION

✓ ***Referenced Protocol:*** ***F.1 Periodic Evaluations***

Figure 13-2 depicts the top-level process for both: 1) ad-hoc and periodic re-evaluations of IM data and risk analysis for Louisville Gas & Electric/Kentucky

Utilities' (The company('s)) pipeline systems, and, 2) establishing an appropriate reassessment interval for covered pipeline segments.


Ad Hoc or annual review revisions to IM Database cause changes to threat evaluation or risk analysis (**Sections 4.7.1 & 13.2**)
Baseline assessment (or reassessment) performed and remediation complete (**Sections 4 through 10 of this IMP**)
Update Integrity Management Database, reevaluate threats and risks for each HCA as appropriate (**Sections 4 & 5 of this IMP**)
Select reassessment method based on current threats (**Section 6 & Figure 13-3 of this IMP**)
Select reassessment interval based on previous assessment results
End

As indicated in **Figure 13-2**, after the baseline assessment or future reassessments are performed on a segment, integrity management data/database(s) will be updated. In addition, the threats and risk to the segment will be reevaluated per Section 4 and 5 of this IMP. Reevaluation of threats and risk will be coordinated with any preventive and mitigative (P&M) evaluations (refer to Section 12) that are performed after a baseline assessment or reassessment. In the process of reevaluating threats, the original assessment method selection (Section 6) may require revision. Previously identified Monitored Conditions must be reviewed and validated during any reassessment. Based on results of the reassessment these Monitored Conditions may require reclassification.

Figure 13-2 also indicates how ad-hoc and periodic reevaluations of threat and risk on an HCA segment are integrated with the reassessment evaluation process. The **Program Manager- Integrity Management** M1 will review all HCA segments in the **Company** systems ***on at least an annual basis*** unless ad-hoc reviews have already been performed in the annual cycle. Any significant changes to the threats or risks that are identified in these reviews will trigger a re-evaluation of reassessment interval in accordance with these procedures.

Section 4.7.1 and **Figure 4-3** of this IMP describe the company's procedures for continuous review and maintenance of the integrity management data by various **company** personnel. This includes the Management of Change (MOC) process (refer to **Section 14)** that notifies the **Program Manager- Integrity Management** M1 of changes that could affect the threats or risk to an HCA segment.

Section 5.6.4 of this IMP describes the **company** commitment to revise the risk analysis for an HCA segment after an integrity assessment or mitigative action.

13.3 REASSESSMENT METHODS

✓ ***Referenced Protocol:*** ***F.2 Reassessment Methods***

The procedures in **Section 6** (Assessment Method Selection) will be used to select the appropriate reassessment inspection method for each HCA segment. The reassessment inspection method(s) may change from the baseline assessment inspection method(s) due to a change in the Threats of Concern (TOC) to a segment, the development of new inspection technologies or if the company decides to request PHMSA and KPSC and/or IURC approval for "Other Technology" (**refer to Section 6**).

If the reassessment interval is determined in Section 13.4 below to be greater than seven (7) years, then an interim reassessment is required prior to a 7 year lapse without a reassessment. For pipe with stress levels greater than or equal to 30%

SMYS[1], a Confirmatory Direct Assessment (CDA) is required. For pipe with stress levels less than 30% SMYS a Low Stress Reassessment (LSR) may be performed in lieu of a CDA. Alternatively, The Company may choose to perform a full reassessment at year 7. CDA is discussed below in Section 13.6; LSR, in Section 13.5 below.

13.3.1 Monitored Conditions

During any re-assessment, CDA, or LSR all previously identified monitored conditions shall be reviewed and validated. In this way, the company ensures that these conditions have not worsened to a point that could impact the integrity of the pipe. The conditions may be reclassified based on results of the reassessment.

13.4 REASSESSMENT INTERVALS

✓ ***Referenced Protocol:*** ***F.4 Reassessment Intervals***

13.4.1 Top-Level Process For Determination of Reassessment Intervals

As previously indicated in **Figure 13-2**, reassessment intervals are determined based on the assessment method performed. The interval is also limited based on whether the HCA segment's operating stress level (% SMYS). Per the requirements of 49 CFR 192 Subpart O segments are split into the following three groups:

- Segments operating at or above 50% SMYS
- Segments operating at or above 30% SMYS and less than 50% SMYS
- Segments operating below 30% SMYS

Note that multiple assessment inspection methods may be necessary for the same segment to address all the Threats of Concern (TOC) for the segment; the selected reassessment interval for each assessment inspection method can also vary for the same segment.

The initial selection of reassessment time intervals in **Figure 13-3** are further evaluated by a Subject Matter Expert to determine whether the interval is sufficient to ensure continued integrity of the pipeline. When appropriate, the initial selection of reassessment time interval may be reduced based on the estimated time-to-failure for corrosion, estimated time-to-failure for long-seam crack growth, or the integrity management data related to Third Party Damage for the segment.

13.4.1.1 Plastic Pipelines

Yield strength as defined in 49 CFR 192.107 applies only to steel pipe. Plastic pipe design pressures determined per 49 CFR 192.121. Therefore, plastic pipe integrity

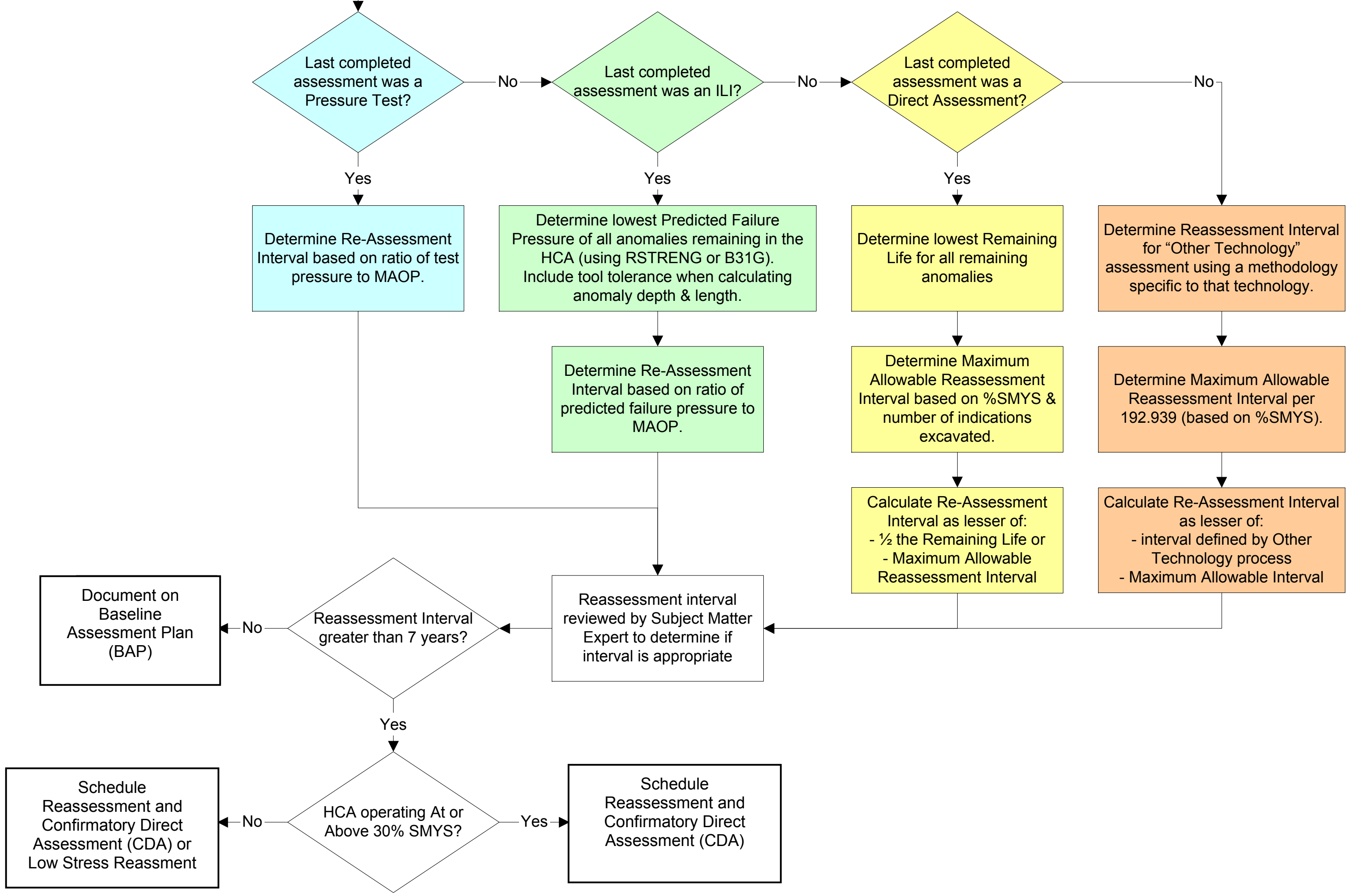
[1] Refer to Section 13.4.1.1.for information regarding stress levels for plastic pipe.

test pressures and assessment intervals will be based upon the ratio of MAOP to Hydrostatic Design Basis (HDB) rather than percent SMYS.

To simplify documentation, all references to % SMYS in this section or on related forms will be taken to mean % HDB when referring to a plastic transmission line.

Figure 13-3

Determination of Re-Assessment Intervals



13.4.2 Determining Reassessment Intervals

Figure 13-3 indicates the procedural steps in determining reassessment intervals for various assessment method options that can be used to address the Threats of Concern for each segment. The reassessment interval is determined based on the method used to assess the pipe. The reassessment interval for each assessment method is as follows:

13.4.2.1 Pressure Test:

When a hydrostatic pressure test is performed as an Integrity Assessment, the **Integrity Management Engineer** F3 determines the reassessment interval based on the ratio of test pressure to maximum allowable operating pressure (MAOP) in accordance with ASME/ANSI B31.8S Table 3.

The **Integrity Management Engineer** F3 may interpolate between the test pressures shown to identify the maximum allowable reassessment interval, provided that the maximum allowable reassessment interval is not exceeded. Refer to **Table 1** for a summary of reassessment intervals for Pressure Test and ILI. A graph is also provided as a visual reference.

The reassessment interval selected shall be reviewed by a Subject Matter Expert to determine if a different interval is more appropriate.

13.4.2.2 In Line Inspection:

When an In-Line Inspection (ILI) is performed as an Integrity Assessment, the **Integrity Management Engineer** F3 determines the reassessment interval based on the ratio of the Predicted Failure pressure (Pf) to MAOP in accordance with Table 3 from ASME/ANSI B31.8S.

The Predicted Failure pressure is determined using ASME B31.G, RSTRENG, or an equivalent method. The lowest calculated Pf for remaining anomalies in the HCA is used to determine the reassessment interval. That is, anomalies which have been repaired are not used when calculating a minimum Pf. Futhermore, only indications in a covered segment (i.e. HCA) need be included when determining the next scheduled integrity assessment.

The **Integrity Management Engineer** F3 may interpolate between the PF pressure shown to identify the maximum allowable reassessment interval, provided the maximum allowable reassessment interval is not exceeded. Refer to **Table 13-1** for a summary of reassessment intervals for Pressure Test and ILI. A graph is also provided as a visual reference (see PHMSA FAQ 231 and PHMSA protocol F04 Reassessment Intervals for guidance on interpolation).

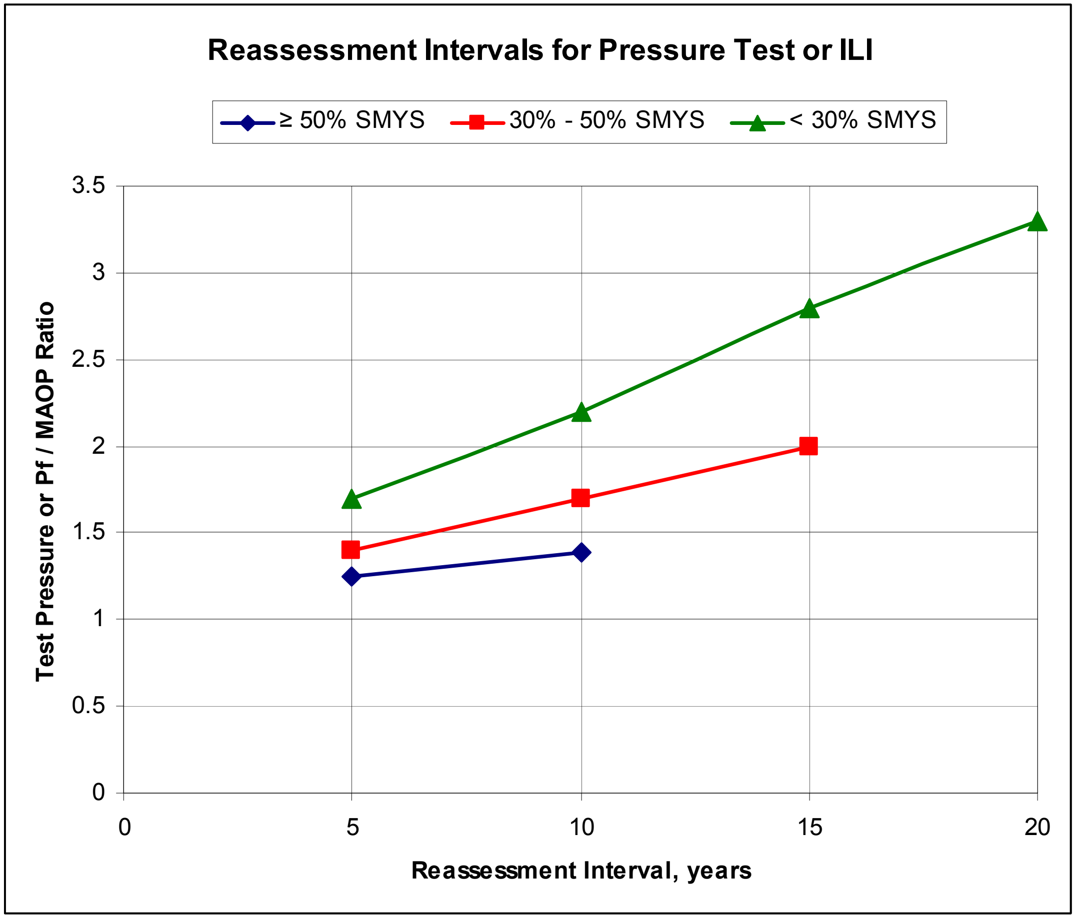
The reassessment interval selected shall be reviewed by a Subject Matter Expert to determine if a different interval is more appropriate.

Table 13-1: Reassessment Intervals for Pressure Test or In-Line Inspection,
Adapted from ASME B31.8S-2004, Table 3 and ASME B31.8S-2004, Figure 4 (below)

Pipeline Operating Pressure:	**Greater Than or Equal to 50% SMYS**	**≥ 30% and < 50% SMYS**	**Less Than 30% SMYS**
Maximum Reassessment Interval	***Ratio of Test Pressure or Predicted Failure Pressure[2]/ MAOP***		
5 years	≥ 1.25 X MAOP	≥ 1.4 X MAOP	≥ 1.7 X MAOP
10 years[3]	≥ 1.39 X MAOP	≥ 1.7 X MAOP	≥ 2.2 X MAOP
15 years[4]	Not Allowed	≥ 2.0 X MAOP	≥ 2.8 X MAOP
20 years[4]	Not Allowed	Not Allowed	≥ 3.3 X MAOP

[2] Minimum Predicted Failure Pressure calculated from ILI results within the HCA.
[3] Interim assessment to be performed by year 7.
[4] Interim assessment to be performed by years 7 and 14.

Adapted from ASME B31.8S-2004, Figure 4 (below)



13.4.2.2.1 Tool Tolerances

Predicted failure pressures – and consequently reassessment interval calculations - are dependent upon remaining wall thickness. Because In-Line Inspection results may not be exact, the tool tolerance is included when classifying indications and when calculating reassessment intervals.

Tool tolerances need not be included in the total if the actual wall measurements from a dig are used; only if the reassessment is based solely on the ILI indications. ILI service providers may not include this margin of error when documenting predicted burst pressures therefore the Pf is calculated in the Assessment Results worksheet (Form 9-2).

13.4.2.3 Direct Assessment:

When External Corrosion Direct Assessment (ECDA) or Internal Corrosion Direct Assessment (ICDA) is performed as an Integrity Assessment, the **Integrity Management Engineer** F3 determines the reassessment interval based on the largest remaining defect in the HCA. Using a corrosion rate appropriate for the pipe, soils, and cathodic protection conditions, calculate the time required for the defect to grow to a critical size. The reassessment interval is then determined to be the lesser of:

- One half of the time required for the largest defect to grow to a critical size.
- The maximum allowable reassessment interval relating the number of indications examined per ASME/ANSI B31.8S, Table 3. (Summarized in **Table 13-2** below.)

The reassessment interval selected shall be reviewed by a Subject Matter Expert to determine if a different interval is more appropriate.

When Stress Corrosion Cracking Direct Assessment (SCCDA) is performed as an Integrity Assessment, the **Integrity Management Engineer** F3 determines the reassessment interval in accordance with that procedure. However, the reassessment interval cannot exceed the maximum allowable per ASME/ANSI B31.8S, Table 3. (Refer to **Table 13-2** below.)

Table 13-2: Maximum Reassessment Intervals for Direct Assessment
Adapted from ASME B31.8S-2004, Table 3

Pipeline Operating Pressure:	**Greater Than or Equal to 50% SMYS**	**Greater Than or Equal to 30% and Less Than 50% SMYS**	**Less Than 30% SMYS**
Maximum Reassessment Interval		***Number of Indications Examined***	

5 years	Sample		
10 years[3]	All	Sample	Sample
15 years[4]	Not Allowed	All	
20 years[4]	Not Allowed	Not Allowed	All

13.4.2.3.1 Corrosion Growth Rates

The **Integrity Management Engineer** F3 determines both external and internal corrosion growth rates based on available data and observations. Refer to Section 7A and Section 7B of this IMP respectively.

13.4.2.3.2 Remaining Life Calculation

It is recommended that the method recommended in NACE SP 0502-2008, be used to calculate the remaining life as also discussed in Section 7A and Section 7B of this IMP. The corrosion rate is either the method discussed in 13.4.2.3.1 above or as calculated in 7A for ECDA or 7B for ICDA. The remaining life calculation is as follows:

Use half the remaining life value calculated above when applying the remaining life as a reassessment intervals as discussed in 13.4.2 above.

13.4.2.4 Subject Matter Expert Review

A Subject Matter Expert reviews the calculated reassessment intervals and may, if warranted, use an alternative criterion to determine a shorter interval. Situations which might warrant a more conservative reassessment interval include but are not limited to:

- Severe localized corrosion indications
- Scheduled conditions that would be difficult to excavate

As an example, the **Integrity Management Engineer** F3 could use external or internal corrosion growth rates to calculate a reassessment interval for a metal loss indication found during In-Line Inspection. (Refer to Section 7A and Section 7B of this IMP respectively for more information regarding corrosion growth rates.)

13.4.3 Determining Interim Reassessment Methods

If the company establishes a reassessment interval that is greater than seven (7) years, the company must, within the seven-year period, conduct an interim reassessment on the covered segment in addition to the follow up reassessment at the interval that the company had established. For pipe with stress levels greater than or equal to 30% SMYS, a Confirmatory Direct Assessment (CDA) is required. For pipe with stress levels less than 30% SMYS a Low Stress reassessment (LSR) may be performed in lieu of a CDA. Alternatively, The Company may choose to perform a full reassessment at year 7. Refer to 13.6 below for CDA procedures.

Figure 13-3 indicates the procedural steps in determining reassessment intervals and for various assessment method options that can be used to address the Threats of Concern for each segment. Assessment methods are selected according to the guidelines presented in Section 6 of this IMP.

13.4.3.1 HCA Segments Operating At or Above 30% SMYS

For HCA segments operating at or above 30% SMYS, a Confirmatory Direct Assessment (CDA) may be performed every seven (7) years as an interim reassessment.

- Confirmatory direct assessment (CDA) can be used every 7 years in lieu of any other assessment method, provided a reassessment is performed using ECDA, ICDA, pressure testing, or ILI at the maximum allowed reassessment interval in accordance with 13.4.2 and §192.939(a)..

13.4.3.2 HCA Segments Operating Below 30% SMYS

For HCA segments operating below 30% SMYS use the same process used for segments at or above 30% SMYS with the following exceptions:

- Confirmatory direct assessment (CDA) can be used every 7 years in lieu of any other assessment method, provided a reassessment is performed using ECDA, ICDA, pressure testing, or ILI at the maximum allowed reassessment interval in accordance with 13.4.2 and §192.939(b).

- Low stress reassessment (LSR) can be used every 7 years in lieu of any other assessment method, provided a reassessment by year 20 is performed using ECDA, ICDA, pressure testing, or ILI (§192.939(b)(5)). The requirements for a Low Stress Re-assessment are described in the following section.

Note: If an interval of longer than seven years is established, then some assessment must be performed no less frequently than every seven years. Confirmatory direct assessment, alone, is sufficient to fulfill this requirement. [PHMSA FAQ-133].

13.5 LOW STRESS REASSESSMENT

✓ ***Referenced Protocol:*** ***F.3 Low Stress Reassessment***

13.5.1 Overview

For HCA segments operating below 30% SMYS, LSR can be used in lieu of CDA every 7 years when the reassessment interval is greater than 7 years (see previous section 13.4). LSR can also be used every 7 years for external or internal corrosion assessment in lieu of any other assessment option provided:

- a baseline assessment in accordance with Section 8 has been performed prior to the use of LSR and,
- a full assessment using ILI, Pressure Testing, or Direct Assessment is performed by year 20 or at the established interval, if less than 20 years.

Low stress reassessment (LSR) can only be used to assess the threats of external or internal corrosion. If required, standard LSR procedures will be established by the company if this assessment method is utilized.

Note: Although LSR specifically addresses external and internal corrosion, it satisfies the requirement of §192.939 regardless of whether additional threats have been identified for the HCA in question. This stance is based on PHMSA guidance related to the other interim assessment method, CDA, which also specifically addressed only external and internal corrosion in its methodology.

Time interval requirements for using LSR are stipulated in **Figure 13-4**.

13.5.2 Responsibility

This section provides a complete description of the roles, responsibilities, job task analyses, and minimum qualifications for key personnel positions necessary for the implementation of the procedures described in this section.

The **Program Manager- Integrity Management** M1 is responsible for ensuring that integrity management data that is produced from conducting the procedures in this section are incorporated into the Integrity Management database and Assessment Results spreadsheets as applicable. The **Program Manager- Integrity Management** M1 may assign responsibilities to other qualified individuals in performing these functions as appropriate.

13.5.3 Methodology

The requirements for Low Stress Re-Assessment are specified in §192. 941 and can be subdivided into external corrosion and internal corrosion assessments as follows:

13.5.3.1 External Corrosion

The Company must take one of the following actions to address external corrosion:

(1) ***Cathodically protected pipe.*** To address the threat of external corrosion on cathodically protected pipe in a covered segment, the company must perform an electrical survey (i.e. indirect inspection tool/method – see Note below) at least every **7 years** on the covered segment. The company must use the results of each survey as part of an overall evaluation of the cathodic protection and corrosion threat for the covered segment. This evaluation must consider, at minimum, the leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

> **Note:** *Electrical survey* means a series of closely spaced pipe-to-soil readings over pipelines that are subsequently analyzed to identify locations where a corrosive current is leaving the pipeline. [192.465]

(2) ***Unprotected pipe or cathodically protected pipe where electrical surveys are impractical.*** If an electrical survey is impractical on the covered segment, the company must perform the following:
(i) Conduct leakage surveys as required by § 192.706 at **4-month intervals**; and
(ii) Every **18 months**, identify and remediate areas of active corrosion by evaluating leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

13.5.3.2 Internal Corrosion

The Company must take the following actions to address internal corrosion:

(1) Conduct a gas analysis for corrosive agents at least **once each calendar year**;
(2) Conduct periodic testing of fluids removed from the segment. At least **once each calendar year**, test the fluids removed from each storage field that may affect a covered segment; and
(3) At least every **seven (7) years**, integrate data from the analysis and testing required by paragraphs (1) and (2) with applicable internal corrosion leak records, incident reports, safety-related condition reports, repair records, patrol records, exposed pipe reports, and test records, and define and implement appropriate remediation actions.

13.6 CONFIRMATORY DIRECT ASSESSMENT

✓ *Referenced Protocol:* *G.1 Confirmatory Direct Assessment, CDA*

As noted in subsection 13.4 above, Confirmatory Direct Assessment (CDA) will be used for external and internal corrosion Threats of Concern (TOC) to extend the reassessment interval for other assessment options beyond **7 years** (e.g. for Direct Assessment, pressure testing, or ILI). In addition, for HCA segments operating below 30% SMYS, CDA can be used every **7 years** for external or internal corrosion assessments in lieu of other assessment options provided the segment is assessed by the prescribed reassessment interval with one of the following assessment methods: Pressure Test, ILI, or Direct Assessment. Note that although CDA specifically addresses external and internal corrosion, it satisfies the requirement of §192.939 regardless of whether additional threats have been identified for the HCA in question.

The company's procedures Confirmatory Direct Assessment are described in **Section 7C** of this IMP. The methodology for performing a CDA is less restrictive than either an ECDA or ICDA.

13.6.1 Response to Conditions Found During a CDA

If an Immediate Repair Condition is found during the CDA, the company must reduce the operating pressure in accordance with Section 10 of this IMP. The pressure reduction shall remain in place until repair has been performed. Repair must be performed within 365 days.

If, during the CDA, any Immediate Condition, One-Year, or Scheduled Conditions requiring repair prior to the next planned reassessment are found, then the **Integrity Management Engineer** F3 must reevaluate the reassessment interval. If the condition is determined to be due to a time-dependent threat, then the previously scheduled reassessment interval must be shortened to ensure that additional repair conditions will not affect the integrity of the pipe prior to reassessment.

13.7 ENVIRONMENTAL AND SAFETY RISKS

✓ *Referenced Protocol:* *F.7 Consideration of Environmental and Safety Risks*

Section §192.911(o) requires that **the company** ensure that any assessments (including CDA, LSR, and reassessments) are conducted in a manner that minimizes environmental and safety risks. **The company** has developed procedures described in **Section 11** of this IMP to ensure that environmental and safety risks are minimized. These procedures consider the following factors:

- Operational conditions of the pipeline, including operating pressure
- Demographic conditions of the area being assessed
- Type of assessment to be performed
- Clean-up and waste disposal
- Worker protection

13.8 PERFORMANCE BASED OPTION

✓ ***Referenced Protocol:*** ***F.5 Deviation From Reassessment Requirements***

The company's current IMP is based on a prescriptive approach and no deviation from reassessment intervals under the performance-based program options allowed by §192.913(c) will be considered. However, the company may elect at a future date to adopt a performance-based IMP and will develop procedures at that time for deviation from the required reassessment intervals that are described in this Section 13.

13.9 RESPONSE TO FINDING CORROSION IN AN HCA

✓ ***Referenced Protocol:*** ***H.6 Corrosion***

The Company complies with the requirements in §192.917(e)(5) to evaluate similar pipeline segments – both covered and non-covered segments – if corrosion that could adversely affect the integrity of the pipeline is found in an HCA. The process is described in the subparagraphs that follow.

13.9.1 Criteria for Corrosion that Could Affect Integrity

Per PHMSA FAQ 135, corrosion conditions that could adversely affect the integrity of the pipeline are those that have a failure pressure to MAOP ratio less than or equal to 1.1. Additionally, the Company will consider corrosion conditions with 80 percent of wall loss or greater to have the potential to adversely affect the integrity of the pipeline.

13.9.2 Identifying Similar Segments

The **Integrity Management Engineer** F3 identifies similar pipeline segments based on shared root cause factors which may include relevant material, coating, and environmental characteristics. Per PHMSA FAQ 224, the identification of similar segments applies only to the pipeline on which the assessment was conducted that resulted in the discovery of corrosion that could adversely affect the pipeline's integrity.

Factors to consider vary depending on the root cause of the corrosion found. Examples of such factors include, but are not limited to:

External Corrosion

- Age of pipe
- Coating type
- Coating condition – disbonded, mechanical damage, etc.
- CP history
- Stray current interference
- Pipeline features – casings, couplings, previous repairs, welds, wrinkle bends, etc.
- Presence of Bacteria (if due to MIC)
- Seam type (if due to preferential seam corrosion)
- Soil conditions – wet, dry
- Soil pH
- Soil type

Internal Corrosion

- Corrosion coupon data
- Flow Conditions – low flow areas
- Gas Quality
- Internal Cleaning Frequency – presence of sludge in line
- Location – drip, low point, inclination angle, etc.
- Operating temperature
- pH
- Presence of Bacteria (if due to MIC)
- Presence of Water / Liquid in line

13.9.3 Measures to Evaluate

Similar segments must be evaluated to determine if corrosion is affecting pipeline integrity at these locations. The type and extent of evaluation necessary depends upon the type, cause, and extent of corrosion found. The **Program Manager – Integrity Management** M1 determines appropriate evaluation measures on a case-by-case basis.

Evaluation methods may include but are not limited to Direct Examination, In-Line Inspection, Long Range UT (LRUT), and aboveground survey (applies to external corrosion only).

If In-Line inspection or aboveground surveys are performed and indicate additional areas of potential corrosion, the most severe indications will be excavated and evaluated. Any corrosion found will be remediated in accordance with standard OM&I procedures.

13.9.4 Timeline to Evaluate and Remediate

The evaluation and any necessary remediation of similar segments will be scheduled and conducted in accordance with standard OM&I procedures. In response to these findings the **Program Manager –Integrity Management** M1 may elect to institute additional preventive and mitigative measures for all similar segments on the pipeline.

Revision Log:

Date	Description	Revised By
12/10/2004	Changed font style and size	MTS
12/10/2004	Changed responsibilities to Manager of Pipeline Integrity and Program Manager – Pipeline Integrity (Subsection 13.1.2)	MTS
12/10/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/10/2004	Changed Company to LG&E Energy	MTS
12/10/2004	Inserted KPSC and/or IURC for state references	MTS
12/10/2004	Added note clarifying the reassessment interval (Subsections 13.4.3 and 13.5)	MTS
6/11/2008	Changed OPS to PHMSA throughout document	EN Engineering
6/11/2008	Reformatted page numbers on page 1	EN Engineering
6/11/2008	Formatted Bullets and Numbering throughout document	EN Engineering
11/07/2008	Major Revisions to entire Document including: • Monitored Conditions • Top-Level Process For Determination of Re-Assessment Intervals • Determining Re-Assessment Intervals • Corrosion Growth Rates • Low Stress Re-Assessment • Performance Based Option	EN Engineering
12/16/08	12/16/08 Version approved by management.	LCO
5/8/2009	Added Section 13.4.1.1. to regarding plastic transmission pipe as well as footnote on page 13-6 referencing this paragraph.	EN Engineering
10/26/2012	Updated company name in text	MDC
09/30/2013	Modified section 13.4.3.1 and 13.4.3.2 to reflect maximum allowed reassessment interval language in 192.939(a) and (b)	JJB
10/2/2013	Added references to FAQ and protocol for section 13.4.2.2	JJB
10/22/2013	Added reference to FAQ 135, 224	JJB
10/22/2013	Corrected criteria for corrosion in section 13.9	JJB
10/22/2013	Added reference to Form 13-2	JJB
10/22/2013	Clarified that similar segments must be on the same pipeline in 13.9.2	JJB
10/22/2013	Changed 13.9.4 to more closely match protocol language	JJB
10/10/2014	Minor formatting and spelling correction	JRW
12/07/2015	Updated document to reflect PPIC audit reccomendations. Removed section 13A – Low Stress Reassessment and transferred important language into section 13. Removed forms 13-1 and 13-2	JRW
11/09/2016	Updated Nace RP 0502-2002 reference to updated version of same standard – Nace SP 0502-2008	JRW

14 MANAGEMENT OF CHANGE PROCESS §192.911(K)

In This Section

Referenced Protocols

14 MANAGEMENT OF CHANGE PROCESS

14.1 OVERVIEW

14.1.1 Purpose

This Section describes the Management of Change (MOC) process that **Louisville Gas & Electric (the Company)** will use to implement Changes which may impact the integrity of the pipeline system or the written Integrity Management Program.

The MOC process is a formal procedure used to manage those Changes. The MOC process ensures the Changes are recognized, formally reviewed, impacts considered, documented, justified, approved, and communicated to affected parties before being implemented.

14.1.2 Responsibilities

The **Program Manager – Pipeline Integrity** M1 is responsible for the maintenance of the MOC procedures and any modifications to this Section. The **Program Manager – Pipeline Integrity** M1 also serves as the Qualified Manager (QM) for any changes to the written Integrity Management Program, and is responsible for communicating those changes to all affected parties.

The **Program Manager – Pipeline Integrity** M1; serves as the default Qualified Manager (QM) for any changes to the pipeline system although this responsibility may also be delegated to the **Manager - Operations** F1 or other Gas Distribution Operations Managers as appropriate (see section 14.1.2.3).

The **Manager - Operations** F1 is responsible for ensuring Changes are communicated to all affected parties within their Responsibility Area.

The **Engineer(s)** F2 is responsible for performing the technical review and impact analysis of any proposed changes, and serves as the default Technical Reviewer for an MOC.

The **Pipeline Integrity Engineer** F3 is responsible for supporting the MOC process, administrating the MOC review and approval process, documenting the technical review and impact analysis and communicating the approved MOC as appropriate.

14.1.2.1 Initiator

An Initiator is an employee that:

- Understands the definition of a “Change” under the MOC process;
- Identifies a potential change as proposed or conceived
- Initiates the MOC process through submitting a completed MOC Form to the Pipeline Integrity Engineer.
- Has the authority to initiate the MOC Process

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An Initiator may include, but is not limited to, employees listed in the key roles and responsibilities of Section 2.

14.1.2.2 Technical Reviewer

The Technical Reviewer is the employee responsible for performing the technical review, which analyzes the implications of the change to the pipeline system and the written Integrity Management Program.
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14.1.2.3 Qualified Manager (QM)

The Qualified Manager is a designated member of management with the ultimate responsibility to determine whether a proposed Change is subject to the MOC process. The role of Qualified Manager(s) may be delegated from the **Program Manager – Pipeline Integrity** M1 to the **Manager - Operations** F1, or other Gas Distribution Operations Managers as appropriate.

The Qualified Manager is responsible for:

- Ensuring the MOC process is followed
- Assigning qualified staff to perform the Technical Review
- Ensuring the Technical Review includes:
  - The reason for the Change
  - An analysis of the implications of the Change
  - Qualified Staff performing the Technical Review
  - Names of the Initiator and Technical Reviewer
- Assessing the staff's qualifications to implement and maintain the Change
- Providing training, as necessary to implement and maintain the Change
- Ensuring the Change is communicated to all affected parties
- Ensuring all required work permits have been acquired
- Ensuring the time limits of the Change are specified
- Ensuring the MOC process is documented using the designated form
- Approving the implementation of the Change

14.2 DEFINITIONS

14.2.1 Management of Change

A process that systematically recognizes and communicates to the necessary parties changes of a technical, physical, procedural or organizational nature that can impact system integrity (ASME B31.8Sas referenced in Appendix 1B of this IMP.

14.2.2 Change

A Change represents any modification to the pipeline system or the written IMP, which may affect system integrity. These changes include technical, physical, procedural, and organizational changes that are either temporary or permanent in nature. See 14.4.2 for examples of a Change.

Operations performed within the established safe operating limits of the pipeline system, and changes classified as "Like Size and Kind" are **not** considered a Change.

14.2.2.1 Like Size and Kind Change

A change that is of "Like Size and Kind", is a replacement in kind, and is not considered a Change under the MOC process. A "Like Size and Kind" change does not alter the technical, physical, procedural or organizational nature of the system and does not impact system integrity. Examples include, but not limited to, flanged valve replacements, screens, and gaskets. Changes that involve replacement of items joined by welding are not considered "Like Size and Kind".

14.2.2.2 Significant Change

Any Change that may substantially affect the program's implementation or may significantly modify the program or schedule for carrying out the program elements is considered a Significant Change. See 14.4.2 for examples of a Significant Change.

14.3 CHANGES TO THE PROGRAM

✓ ***Referenced Protocol:*** ***K.1 Documentation and Notification of Changes to the Integrity Management Program***

14.3.1 General

Under the MOC Process (See Figure 14-1), **the Company** will document any Change impacting the integrity management program prior to implementing the Change (e.g. pipeline system or written IMP program). The MOC documentation will include the process and/or facility design information from before the Changes are put into place. Refer to section 14.5 of this document for emergency changes and changes beyond the control of **the Company**.

All Changes will be documented using **Form F14-1, Management of Change Approval Form,** shown in subsection 14.6.

14.3.2 Agency Notifications

As required in §192.909(b), **the Company** will notify the appropriate jurisdictional authority (PHMSA, state, or local pipeline authority) within 30 days of adopting a "Significant Change" to its integrity management program.

As required in §192.921(a)(4), **the Company** will notify the appropriate jurisdictional authority (PHMSA, state, or local pipeline authority) within 180 days prior to conducting an assessment utilizing an "other technology" that the Company demonstrates can provide an equivalent understanding of the condition of the line pipe.

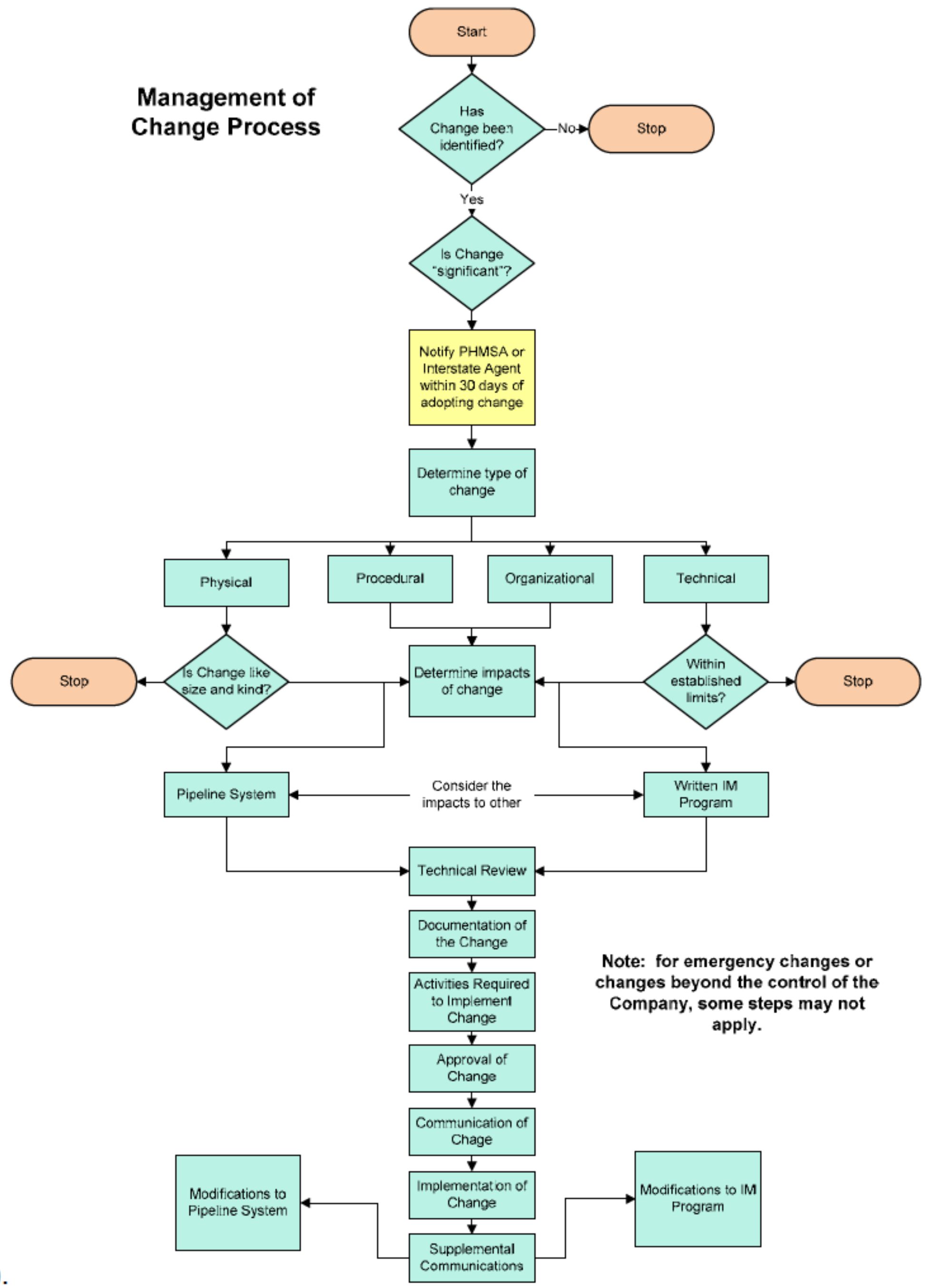

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Figure 14- 1 - Management of Change Process Flow Chart

14.4 IMPLEMENTING THE MOC PROCESS

✓ ***Referenced Protocol:*** ***K.2 Attributes of the Change Process***

14.4.1 Exceptions

The MOC process is not required for the following conditions:

- The change does not affect the Pipeline Integrity Management Program (e.g. pipeline system or written IMP program)
- A "Like Size and Kind" change does not alter the technical, physical, procedural or organizational nature of the system and does not impact system integrity.
- **The Company** is also allowed the flexibility to maintain continuity of operations within established safe operating limits of the pipeline system.

14.4.2 Recognizing a Change

Employees recognize potential Changes or factors that should prompt a change requiring the use of the MOC process. These potential Changes can be identified in several different ways. The following are examples of activities that would trigger the MOC process:

DESCRIPTION OF CHANGE	POTENTIAL IMPLICATIONS TO IM PROGRAM
Change in land use (e.g. increase in population near a pipeline, settlement due to underground mining)	• Identification of new threats • Modifications to written IMP
Assessment results indicate high occurrence of third-party damage	• Modifications to written IMP • Identification of additional Preventive and Mitigative Measures
Increase in operating pressure from its historical level, (e.g. closer to MAOP)	• Identification of new threats • Modifications to written IMP
Change in pipeline operation from a steady state to a more cyclical load (e.g. a daily change in operating pressure)	• Identification of cyclic fatigue threat • Modifications to written MP

Replacement of existing equipment with equipment utilizing updated technology	• Modifications to procedural or OM&I documents • Modifications to Written IMP

14.4.3 Recognizing a Significant Change

The Qualified Manager(s) are responsible for determining if a Change is Significant requiring a formal notification. The following are examples of activities or events that could be considered significant:

DESCRIPTION OF CHANGE	POTENTIAL IMPLICATIONS TO IM PROGRAM
A merger of companies or major pipeline acquisition	• Change in procedural responsibilities • Modifications to written IMP
Determination of susceptibility to SCC when previously considered unsusceptible	• Identification of new threats • Use of different assessment methodologies • Modifications to written IMP
Introduction of an Assessment Methodology not previously used	• Modifications to written IMP • Modifications to Baseline Assessment Plan
Abandoning an Assessment Methodology previously planned for use	• Modifications to written IMP • Modifications to Baseline Assessment Plan
Change to the baseline assessment plan because 50% of HCA footage was not assessed by December 17, 2007	• Modifications to written IMP • Modification to Baseline Assessment Plan
Not meeting deadline for having 100% of HCA footage assessed by December 17, 2012	• Modifications to written IMP • Modifications to Baseline Assessment Plan

Refer to section 14.4.5 of this document for information on reporting a significant change.

14.4.4 Determining the Type of Change

The Qualified Manager(s) or their designee will make a determination of the type of Change proposed (Technical, Physical, Procedural, or Organizational).

Physical Changes will be reviewed to determine if the "Like Size & Kind" exemption applies to the proposed change.

Technical Changes will be reviewed to determine if the proposed change is operating within the established safe operating limits of the pipeline system and thus not considered a change.

The Qualified Manager(s) or their designee will also designate whether the change is temporary or permanent. If the Change is temporary, the anticipated duration should be designated on the form.

14.4.5 Technical Review and Analysis of Implications

The **Engineer** F2 is responsible for performing the technical review and impact analysis of any proposed Changes, and serves as the default Technical Reviewer for the MOC process.

In consultation with the Program Manager – Pipeline Integrity M1 or his designee, the **Engineer** F2 will determine the impacts of the change for both the pipeline system and the written integrity management program.

14.4.6 Documentation of the Change

Upon completion of the technical review and impact analysis, the **Engineer** F2 will document relevant findings and attach it to the Management of Change Form for documentation purposes. Additional documentation requirements can be referenced in Section 16 – Record Keeping of this document.

The **Engineer** F2 will also indicate any required activities necessary to implement the Change.

14.4.7 Activities Required to Implement the Change

The Qualified Manager(s) will evaluate the results of the technical review and any required activities specified. The Qualified Manager(s) will also consider the following items which may be associated with the Change:

- Acquisition of Work Permits
- Environmental / Safety Permits
- Qualifications of Staff
- Additional Training

14.4.8 Approval of a Change – Qualified Manager(s)

Upon a thorough review of the impacts of the Change, the Qualified Manager(s) will determine whether or not to approve the Change.

14.4.9 Communication of the Change to Affected Parties

Upon approval of the Change, the Change is communicated to all affected parties. The term "affected parties" may include internal Company stakeholder, landowners and tenants along pipeline rights-of-way, non-emergency public officials, local and regional emergency responders, the general public, and regulatory agencies. The Qualified Manager(s) are responsible for identifying the parties affected and assuring the Change is communicated to all affected parties.

Additional communication requirements are referenced in Section 19 Communications Plan for internal communications.

14.4.10 Implementation of the Change

Upon completion of the previous procedural steps and the formal approval of the change by the Qualified Manager(s), the implementation of the change will commence. It is the responsibility of the Qualified Manager(s) to ensure the change is implemented.

14.4.11 Supplemental Communications

Supplemental Communications will be provided to all affected parties for the following events:

- Extension of a time frame or limitation (e.g. temporary change)
- Modification of a Change

14.4.12 Modifications to the Program and System

The Company will make the appropriate modifications to the Program and/or System as part of the MOC Process. Changes, such as those listed in subsection 14.4.2, will require a reevaluation of the threats and subsequent risk assessment process.

It is the responsibility of the **Program Manager – Pipeline Integrity** M1 to ensure required modifications are made to the written Integrity Management Plan.

14.5 IMPLEMENTATION OF CHANGE PRIOR TO DOCUMENTATION

Although Changes over which **the Company** has no control are implemented without the MOC review process, applicable Changes are still documented as a MOC. In this case, the MOC is initiated when the Change is identified. Depending on the

Change, a technical review and analysis may still be required, however sections 14.4.7 and 14.4.10 will not apply.

Likewise, Changes such as a pipeline repair in response to an emergency may be implemented prior to completion of the MOC process.

If an MOC cannot be completed prior to implementing the Change, it shall be submitted no later than ten (10) business days after the event.

14.6 FORMS

LG&E KU PPL companies

Management of Change
Approval Form

SECTION 14
MANAGEMENT OF CHANGE
EFFECTIVE DATE -12/19/2014

Form No: F14-1

Change Title		Tracking No.	
Location		Type of Change	
Description of Present Condition (Process or design) *Reference: ASME B31.8S, Section 11(a)*		☐ Permanent ☐ Temporary ☐ Like Size & Kind	
		If Temporary – Duration:	
Description of Proposed Change (Process or design) *Reference: 192.909(a)*			Hours
			Days
			Weeks
			Months
Reason for Change *Reference: 192.909(a)*		Schedule	
		Start:	
		Complete:	
		Actual	
		Start:	
		Complete:	

Does the Change Have the Potential to: *Check all that apply*

Note: Any check below requires Agency Notification within 30 days after adopting the change

- ☐ Substantially affect the Integrity Management Program's Implementation
- ☐ Significantly modify the Integrity Management Program
- ☐ Significantly modify the Schedule to implement Req'd Program Elements

Specific Examples (not limited to):
- ☐ Merger or Major Pipeline Acquisition
- ☐ Determination of SCC as a New Threat
- ☐ Abandoning an Assessment Method Planned for Use

Reference: 192.909(b)

OPS, State, or Local Agency Notified	Person Contacted	Phone	Date

Type of Change: *Any Change that has the "potential" to affect pipeline integrity on the System or the written IMP Program*

Technical	Physical	Procedural	Organizational
☐ Safety Device Settings ☐ SCADA Settings ☐ Programming Logic ☐ ☐ ☐ Other ______	☐ Change of Product ☐ Newly Identified HCA ☐ Newly Identified Threats ☐ New Risk Factors ☐ Replace Safety Device ☐ Replace Valve ☐ Pipeline Acquisition ☐ Other ______	☐ Repair / Remediation ☐ Welding ☐ Pressure Testing / ILI ☐ Direct Assessment ☐ Environmental / Safety ☐ Risk Analysis ☐ HCA Identification ☐ CP Program Changes ☐ Other ______	☐ Roles & Responsibilities ☐ Organizational Structure ☐ Qualified Personnel ☐ Other ______

Technical Review and Analysis of Impacts of the Change: *Attach all supporting documentation*

Technical Review Activity	Assigned To:	Completed

Required activities to Implement the Change:

Internal	External
☐ Qualification of Staff ☐ Additional Training ☐ Communication of the Change	☐ Acquisition of Work Permits ☐ Environmental / Safety Permits

Required Notifications:

		Managers - Operations	
Initiator:		Gas Control	
Technical Reviewer: (Engineer)		Responsible Area	
Program Manager – Pipeline Integrity:		Gas Codes / Standards	

Attach additional documentation as necessary to this form

Integrity Management Program

Figure 14- 2 Management of Change Approval Form

Revision Log:

Date	Description	Revised By
11/29/04	11/29/04 Version Approved by Management	LCO
04/20/2007	Insert sample of Form 14-1 into Section 14 document	CMA
5/30/08	Changed Logos, signature blocks, and updated formats.	LCO
5/30/08	Changed LG&E Energy to LG&E/KU and "the company"	LCO
9/17/08	Updated subsections regarding Agency Notifications, Recognizing a Change, Recognizing a Significant Change, and Communicating Change	EN Engineering
9/17/08	Added a subsection for implementing a change before documentation can be completed	EN Engineering
10/25/2012	Updated Table of Contents page	MDC
3/4/2013	Updated 14.3.1 to document conditions before and after changes.	MDC
3/4/2013	Updated F14-1 to document conditions before and after changes.	MDC
1/13/2015	Updated revised form 14-1	MLS
11/11/2016	Updated the communications process, corrected formatting	CSM

15 QUALITY ASSURANCE PROCESS §192.911(l)

(Reference: ASME B31.8S Section12)

In This Section

Referenced Protocols

QUALITY ASSURANCE PROCESS

15.1 OVERVIEW

15.1.1 Purpose

The Quality Assurance section describes the overall approach to Quality Assurance used by **the company** to address the requirements of 49 CFR 192 Subpart O – Pipeline Integrity Management. **The company** uses the quality assurance process to provide additional confidence that the requirements of 49 CFR 192 Subpart O are being satisfied.

15.1.2 Responsibility

The **Manager – Gas Regulatory Compliance** M4 will have the overall responsibility for the maintenance of the quality assurance process and for any modifications to this section. The **Manager – Gas Regulatory Compliance** M4 will coordinate the review of the Integrity Management Program and the Quality Assurance Process. The **IMP Review Team** members are responsible for assisting the **Manager – Gas Regulatory Compliance** M4 in a **review** of the Integrity Management Program and the Quality Assurance Process.

In addition, each process or procedure detailed within the IMP document also defines the responsibilities of each individual associated with the process or procedure.

15.2 DEFINITIONS

The following definitions have been provided to assist in the discussion of the Quality Assurance Process.

15.2.1.1 Quality

Quality is the degree to which a set of inherent characteristics or distinguishing features fulfill the requirements (Ref: ISO 9000). For integrity management, quality is the degree to which the characteristics or features of an Integrity Management Program meet the requirements of 49 CFR 192 Subpart O.

15.2.1.2 Quality Management

Quality Management is the coordination of activities to direct and control an organization with regard to quality (Ref: ISO 9000).

15.2.1.3 Quality Assurance

Quality Assurance is the part of Quality Management focused on providing the “confidence” that the quality requirements will be fulfilled (Ref: ISO 9000). For integrity management, quality assurance is the systematic approach (e.g. processes, procedures, qualifications, etc.) that provides the company with the confidence that the requirements of 49 CFR 192 Subpart O – Pipeline Integrity Management are being met.

15.2.1.4 Quality Policy

A Quality Policy is a document which states the overall intentions and direction of an organization related to quality as formally expressed by top management (Ref: ISO 9000).

15.2.1.5 Continual Improvement

Continual Improvement is a recurring activity to increase the ability to fulfill requirements (Ref: ISO 9000).

15.2.1.6 Process

A Process is a set of inter-related or interacting activities which transforms inputs into outputs (Ref: ISO 9000).

15.2.1.7 Procedure

A Procedure is a way of carrying out an activity or a process (Ref: ISO 9000).

15.2.1.8 Quality Plan

A Quality Plan is a document specifying which procedures and associated resources shall be applied by whom and when to a specific project or process (Ref: ISO 9000).

15.2.1.9 Organizational Structure

An Organizational Structure is an arrangement of responsibilities, authorities, and relationships between people (Ref: ISO 9000).

15.2.1.10 Preventive Action

A Preventive Action is an action which eliminates the cause of a “potential” nonconformance item or other undesirable potential situation (Ref: ISO 9000).

15.2.1.11 Corrective Action

A Corrective Action is an action which eliminates the cause of a “detected” nonconformance item or other undesirable situation (Ref: ISO 9000).

15.2.1.12 Review

A Review is an activity undertaken to determine the suitability, adequacy and effectiveness of the subject matter to achieve established objectives (Ref: ISO 9000).

15.2.1.13 Self-Assessment

A Self-Assessment is a comprehensive and systematic review of the organization's activities by members of the organization, and is used to determine the degree of conformance to policies, processes, procedures, and requirements.

15.2.1.14 Audit

An Audit is a systematic, independent, and documented process for obtaining records, statements of fact or other information and evaluating it objectively. This objective evaluation is used to determine the extent to which a set of policies, procedures, or requirements are being fulfilled (Ref: ISO 9000).

15.3 ELEMENTS OF A QUALITY ASSURANCE PROGRAM

15.3.1 General

The following topics represent the typical elements of a "quality management system" (Ref: B31.8S §12.2(a), ISO 9004 §4.1).

- Identification of Processes
- Sequence and Interaction of Identified Processes
- Criteria/Methods to Assure Effective Operation and Control
- Adequate Resources and Information
- Monitor, Measure, and Analyze Processes
- Implement Actions to Achieve Planned Results and Continued Improvement

The company has used this information as a guide in the development of the "quality assurance process".

15.3.2 Identification of Processes

The company has identified the following processes as part of its IMP.

- HCA Identification Process — Section 3
- Data Gathering and Data Integration Process — Section 4
- Threat Identification — Section 4
- Risk Analysis & Prioritization (Assessment) — Section 5
- Assessment Method Selection — Section 6
- Direct Assessment — Section 7
- Baseline Assessment Plan — Section 8
- Conducting Assessments (Assessment Evaluation) — Section 9
- Remediation (Corrective Action) — Section 10
- Environmental and Safety Risks — Section 11
- Preventive and Mitigative — Section 12

- Continual Evaluation & Reassessment — Section 13
- Management of Change Process — Section 14
- Quality Assurance Process — Section 15
- Documentation Control (Record Keeping) — Section 16
- Performance Measurement — Section 17
- Personnel Knowledge & Training — Section 18
- Regulatory Reporting (Condition Reporting) — Section 19

15.3.3 Sequence and Interaction of Identified Processes

Subsection 1.1 describes the overall "Map of the Integrity Management Program" which is intended to describe the sequence and interrelationships between each section and the associated processes within the IMP document on a "macro level". Detailed process diagrams are provided within specific sections to describe the specific processes on a "micro level".

15.3.4 Criteria/Methods to Assure Effective Operation & Control

The company uses the following methods to assure the effective operation and control of each process.

- Required Qualifications - Education, Training, & Experience (**Section 2**)
- Personal Knowledge & Training (**Section 18**)
- Roles and Responsibilities (**Section 2**)
- Process Diagrams
- Procedures
- Required Forms and Documentation
- Integrity Management Review Meetings
- Performance Metrics (**Section 17**)
- Management Oversight
- Internal Audits/self-assessments

15.3.5 Adequate Resources and Information

The **Vice President, Gas Distribution** E1 is responsible for ensuring the necessary resources are available and committed to the implementation of the quality assurance process and the overall Integrity Management Program.

15.3.6 Monitor, Measure, and Analyze Processes

The company has developed performance metrics consistent with ASME B31.8S, Section 9.4. These performance metrics are suitable for the evaluation of each "threat specific" category as well as the four overall program measurements required in ASME B31.8S, Section 9.4(b). Additional details associated with these performance metrics are described in **Section 17 –**

Performance Plan.

15.3.7 Actions to Achieve Planned Results & Continued Improvement

The company will implement necessary actions to achieve the planned results and continued improvement of the Integrity Management Program. These actions include:

- Establish Roles and Responsibilities
- Ensure Adequate Training and Qualifications
- Perform Assessments
- Analyze the Data
- Act upon the Data (Remediation, Preventative, & Mitigative Measures)
- Perform Continual Evaluation and Reassessment of processes
- Conduct IMP Review Meetings (Section 2.4)
- Implement Preventive and Corrective Actions
- Consider and Implement appropriate recommendations
- Provide Management Oversight

The company's Continual Evaluation & Reassessment process is more fully detailed in **Section 13.**

15.4 QUALITY ASSURANCE ACTIVITIES

✓ ***Referenced Protocol:*** ***L.1 Program Requirements for the Quality Assurance Process***

15.4.1 Documentation

The company used the PHMSA - OPS Protocol Cross Reference Table (located in Section 1 – Appendix 1A) to document compliance to the regulatory requirements. This table is used to cross-reference the following regulatory requirements and guidance materials to various sections within the IMP document:

- 49 CFR 192 Subpart O – Pipeline Integrity Management
- PHMSA - OPS Inspection Protocols
- PHMSA - OPS posted answers to Frequently Asked Questions (FAQs)

The development of this comprehensive cross reference table is a key quality assurance activity that also serves as an initial self-assessment (refer Subsection 15.4.4). Subsequent reviews and updates of the cross reference table are also self-assessing quality assurance activities.

Additional documentation requirements of the IMP and the quality assurance process are more fully detailed within **Section 16 – Record Keeping**. These requirements include how documents will be controlled, maintained, for what duration, and at what location. The IMP document also indicates the specific documentation to be completed as part of each process or procedure. All IMP documentation should be a value-added activity, and not just an end to itself. The documentation is intended to assist in providing:

- Repeatability
- Traceability
- Objective evidence
- An evaluation of effectiveness

15.4.2 Roles and Responsibilities

The organizational structure of the Integrity Management (IM) personnel and their specific roles and responsibilities under this IMP are clearly and formally defined in **Section 2 – Roles and Responsibilities**.

15.4.3 Review of the Integrity Management Program

The company will review the Integrity Management Program (IMP) each calendar year as part of the overall continual improvement process, and will make appropriate recommendations for improvement. The **Manager – Gas Regulatory Compliance** M4 is responsible for approving changes to the IMP. For the purpose of this review, each individual section within the IMP may be considered as a stand-alone document. This review and approval is documented within the Gas Regulatory SharePoint intranet site.

The reviewer should check for the following items and recommend revisions where appropriate. Situations which may trigger revisions to the IMP include, but are not limited to the following:

- Regulatory changes, either in code or in documents incorporated by reference (e.g. ASME B31.8S);
- Changes in guidance material provided by regulatory authorities;
- New or revised industry specifications (e.g. NACE Standard Practices);
- Organizational changes;
- New or changed pipeline information; and
- Lessons learned during performance of a specific activity (e.g. ECDA or ICDA).

An overall review of the IMP plan as a whole is also conducted to ensure that all required procedures are in place. The reviewer should check to ensure that all required IMP sections are complete and up-to-date. Sections which have not yet been implemented need not be finalized. However, appropriate procedures must be in place before performing an IMP activity.

15.4.4 Self-Assessments

The company will perform self-assessments (i.e., a quality assurance review of the IMP document and the quality assurance process) of the Integrity Management Program to validate the effectiveness of the IMP.

15.4.4.1 Integrity Management Program Review Team

The Integrity Management Program Review Team as addressed in Section 2.4.3 is responsible for periodically performing a quality assurance review of the IM program. The IMP Review Team normally consists of representatives from each operating region and is normally co-chaired by the M4 and M1 personnel. The co-chairs shall name the Integrity Management Program Review Team Members from each region as appropriate. The IMP Review Team shall be convened for meetings typically once a year, but at least once every eighteen months. The co-chairs shall set the agenda for each meeting.

Issues that the Review Team may review at each meeting include, but are not limited to:

- Testing or inspection successes and failures
- Failures resulting from hydrostatic tests
- Inspection tool performance
- Inspection tool vendor performance
- DA performance, recommendations, and conclusions
- Repair methods used
- Alternative repair methods
- Staffing for inspections/testing
- Process enhancement/changes
- Staffing for repairs
- Field activities / performance in identifying potential HCAs
- Recommended changes for the IMP
- Additional training requirements necessary to support IMP
- One-call experience
- Threat identification
- Additional items as necessary to aid in the success of the IMP program

Subsection 15.4.11 Corrective Actions (below) addresses documentation of the IM Review Team Meetings and associated recommendations.

15.4.4.2 Cross Reference IMP with PHMSA Enforcement Guidance

The development of the comprehensive cross reference table in Section 1 – Appendix 1A of this IMP document served as an initial self-assessment. Subsequent reviews and updates of the cross reference table serve as additional self- assessments.

15.4.5 Internal and External Audits

Internal and external audits of the Integrity Management Program will be performed on a periodic basis to validate the effectiveness of the program. The frequency of the internal and external audits will be at the discretion of **the company**. However, an internal or external audit will be performed at a frequency not to exceed ten years. The **Vice President, Gas Distribution** E1 has overall responsibility for the audit process.

15.4.6 Non-Mandatory Statements

In general, **the company** incorporates "should" statements as recommended by the industry standard into the Integrity Management Program. However, **the company** reserves the right to use an equivalent alternative when addressing "should" statements.

15.4.7 Continual Improvement

Continual improvement process requirements are detailed within **Section 13 – Continual Evaluation and Reassessment**. The Management of Change process is detailed within **Section 14 – Management of Change**.

15.4.8 Personnel Knowledge and Training

The company's Training and Operator Qualification programs are referenced in **Section 18 – Personnel Knowledge & Training.**

15.4.9 Control of Outside Resources

The company uses various outside resources to perform pipeline integrity services on the pipeline system. When these services are required, the company, through the **Manager – Gas Regulatory Compliance** M4, assures the quality of the process is maintained and documented as follows:

- Ensuring all personnel performing an OQ covered task are qualified for the task;
- Ensuring all personnel have the knowledge, training and qualifications as required in Section 2, Section 18, and §192.915;
- Ensuring the company's ILI assessment procedures are properly implemented;
- Ensuring the company's pressure test assessment procedures are properly implemented;
- Ensuring the company's direct assessment procedures (ECDA, ICDA, and SCC) are properly implemented; and

- Performing oversight of all outside services and/or resources associated with Integrity Management.

15.4.10 Performance Metrics

The company's performance metrics are detailed in **Section 17 – Performance Plan**.

15.4.11 Corrective Actions

The company will consider appropriate corrective actions to the Integrity Management Program and quality assurance process as identified during an annual (or periodic) Integrity Management Program Review Team Meeting. The final disposition of each recommendation or corrective action will be recorded on Form F15-1. This will serve to document the IMP Review Team meeting and the list of recommendations. The effectiveness of any adopted recommendation or corrective action will be reviewed during the next annual (or periodic) review.

The **Manager – Gas Regulatory Compliance** M4 will ensure each recommendation and corrective action is documented as stated above and will provide the list of recommendations to be considered by the **Vice President, Gas Distribution** E1.

15.5PERSONNEL QUALIFICATION AND TRAINING REQUIREMENTS

✓ ***Referenced Protocol:*** ***L.2 Personnel Qualification and Training Requirements***

15.5.1 Company Personnel

The company's personnel qualification and training requirements are detailed in **Section 2 Roles and Responsibilities** and **Section 18 Personnel Knowledge & Training**.

15.5.2 Outside Resource Personnel

Outside resource personnel are often utilized to perform integrity management assessments and related activities. In addition to the requirements listed in subsection 15.4.9 above, it is the responsibility of the **Qualified Manager** responsible for the activity to be performed by the outside resource to ensure that contractors meet minimum qualification and certification levels appropriate to their task.

15.5.2.1 ILI Inspections

Outside resource personnel performing an In-Line Inspection (ILI) should meet the qualifications and requirements detailed in Subsections 9B.4.1 and 9B.4.2.2.

15.5.2.2 Direct Assessments

Outside resource personnel performing ECDA, ICDA, SCCDA, or CDA inspections should meet the qualifications and requirements detailed in Section 7A.2.5.2, Section 7Ai.1.5, Section 7Aii.1.6, and Section 7B2.5.

15.5.2.3 Nondestructive Testing

Outside personnel performing nondestructive testing such as magnetic particle inspection, dye penetrant inspection, radiography inspection and ultrasonic testing should meet the qualifications and requirements detailed in Section 7A.2.5.2, Section 7Ai.1.5, Section 7Aii.1.6, Section 7B2.5 and Section 9B.

15.6 FORMS

Form F15-1: IMP Document and Quality Assurance Review

SECTION 15
QUALITY ASSURANCE
EFFECTIVE DATE: 11/10/2016

Form F15-1: IMP Document and Quality Assurance Review

Proposed Action	Description	Accept Y/N	Tracking No.	Basis for Acceptance or Rejection	Initiative Owner or Leader	Update	Status

Proposed Actions: CA = Corrective Action PA = Preventative Action RC = Recommendation / Continual Improvement

Revision Log:

Date	Description	Revised By
12/3/2004	Changed NGA logo to LG&E Energy logo	MTS
12/3/2004	Changed the word “Manual” to “Integrity Management Program” or IMP	MTS
12/3/2004	Note: Section 20 for the IMP will need to be deleted.	MTS
12/3/2004	Formatted text and made minor grammatical changes	MTS
12/3/2004	Changed the Integrity Management Plan title in the footer to Integrity Management Program	MTS
12/3/2004	Changed the “foreword” reference to OPS Protocol Cross Reference Table (Subsection 15.4.1)	MTS
12/3/2004	Insert the following language for review of the IMP - LG&E Energy will review the Integrity Management Program (IMP) each calendar year as part of the overall continual improvement process, and will make appropriate recommendations for	MTS

	improvement. The Manager of Integrity Management M2 is responsible for reviewing the IMP.	
12/3/2004	Insert the following language for self-assessment - LG&E Energy will perform a self-assessment (i.e., a quality assurance review of the IMP document and the quality assurance process) of the Integrity Management Program on annual basis to validate the effectiveness of the IMP. The development of the comprehensive cross reference table in the foreword of this IMP document will serve as an initial self-assessment. The IMP Review Team is responsible for performing the self-assessment.	MTS
12/3/2004	Moved the audit subsection from Section 17 to Section 15	MTS
12/3/2004	Insert/modified the following language for internal and external audits - Internal and external audits of the Integrity Management Program will be performed on a periodic basis to validate the effectiveness of the program. The frequency of the internal and external audits will be at the discretion of LG&E Energy. However, an internal or external audit will be performed at a frequency not to exceed five years. The actual audit frequency for internal audits will be determined during by the Audit Services Department. Internal audits will be performed by Audit Services Department. The actual audit frequency for external audits will be determined during the annual review of the IMP Review Team and periodically adjusted based upon established performance metrics and the particular time base. The first external audit will be performed within one year of the implementation of the IMP. External audits will be used as the basis for internal audits. The Officer of Operations E1 has overall responsibility for the external audit process.	MTS
12/3/2004	Change Manager of Engineering to Manager of Integrity Management (Subsection 11.5)	MTS
03/13/2009	Changed “LG&E Energy” to “the Company”	ENE
03/13/2009	Updated job titles to match Section 2: Roles and Responsibilities.	ENE
03/13/2009	Added detail to section 15.4.3 describing the annual IMP review.	ENE
03/13/2009	Deleted redundant description about the IMP Review Team from section 15.4.4.	ENE
03/13/2009	Added section 15.4.6 regarding Non-Mandatory statements (“should” statements) in referenced industry standards.	ENE
03/13/2009	Added detail to section 15.4.11 regarding Corrective Actions.	ENE
03/13/2009	Renamed section 15.5.1 “Company Personnel” and added a separate section 15.5.2 “Outside Resource Personnel”. Included examples of requirements specific to ILI, Direct Assessment, and Magnetic Particle or UT measurements.	ENE
08/05/2009	Section 15 Routed to Management	MLS
11/3/2010	Section 15 Routed to Management (no changes)	MLS
11/11/2011	Updated 15.4.3 – Approvals now being documented on the team SharePoint intranet site rather than on the Annual Review Form. Removed Annual Review Form from the form section of	MLS

	this document.	
11/26/2012	**Title update in 15.4.5**	**MLS**
11/26/2012	**Removed requirement in 15.4.6 to document justification of deviations from "should" statements as it is not required by code.**	**MLS**
4/9/2013	**Revised 15.4.5 to show director has responsibility for audit process rather than just the external audit process.**	**PJC**
4/16/13	**Revised 15.3.5 to reflect organizational restructuring implemented February 18th, 2013**	**BRW**
11/22/13	**Revised titles and responsibilities due to organizational changes. Revised Section 15.5.2 for outside resource personnel to consolidate qualification requirements into Sections 7 and 9 and minor clerical changes.**	**JRG**
10/14/2014	**General formatting, grammatical, and punctuation corrections**	**CLG**
12/19/14	**Made review team language consistent with section 2**	**PJC**
11-30-2015	**Inserted Section 15.4.4.1 detailing the IM Review Team and responsibilities along with other minor edits.**	**JRG**
11/10/2016	**Clerical changes only**	**CLG**

16 RECORD KEEPING §192.947

In This Section

Referenced Protocols

16 RECORD KEEPING

16.1 OVERVIEW

16.1.1 Purpose

This Record Keeping section describes how the Company maintains its records to demonstrate compliance with 49 CFR Subpart O – Pipeline Integrity Management. These records will be maintained for the useful life of the pipeline or as otherwise required by regulations. In addition, certain records referenced in this section will be maintained and available for regulatory review during a compliance inspection of an appropriate jurisdictional regulatory authority.

16.1.2 Responsibility

The **Manager – Gas Regulatory Compliance** M4 will have the overall responsibility for the maintenance of records to demonstrate compliance with 49 CFR Subpart O – Pipeline Integrity Management. The **Program Manager – Integrity Management** M1 will oversee gathering, organizing, and maintaining these records.

16.2 RECORD STORAGE AND ACCESS

The storage and ready access to important records is an essential part of the overall IMP.

The Company has designated the following record locations as the Office of Record for the following records:

Office of Record Location	Record Description
Integrity Management	Written IMP Document (Subsection 16.3.1)
Integrity Management	Supporting Documents for Threat Identification and Risk Assessment (Subsection 16.3.2)
Integrity Management	Written Baseline Assessment Plan (Subsection 16.3.3)
Integrity Management	Decision, Analysis, and Process Documentation (Subsection 16.3.4)
Company Software (PeopleSoft)	Required Training Documentation (Subsection 16.3.5)
Integrity Management	Prioritized Remediation Schedule (Subsection 16.3.6)
Integrity Management	Direct Assessment Plan (Subsection 16.3.7)
Integrity Management	Confirmatory Direct Assessment (Subsection 16.3.8)
Integrity Management	Documentation of Required Notifications (Subsection 16.3.9)

Table 16-1 – Office of Record Locations

16.3 RECORDS MAINTAINED FOR REGULATORY REVIEW

✓ *Referenced Protocol:* *J.1 Record Keeping*

The **Company** maintains the following specific IMP records and will make them available for regulatory review during a compliance inspection by an appropriate jurisdictional regulatory authority.

16.3.1 Written IMP Document

The **Company** maintains this written Integrity Management Program (IMP) document in accordance with the requirements of 49 CFR Subpart O – Pipeline Integrity Management on the Gas Regulatory (Internal) intranet site.

16.3.2 Supporting Documents - Threat Identification & Risk Assessment

The **Company** maintains the supporting documents for threat identification and risk assessment in accordance with §192.917. The methodology and process used to identify Threats of Concern are detailed in **Section 4 – Threat Identification and Evaluation.**

The **Company** uses risk assessment software and the related printouts of its risk model to document the Risk Assessment. The software is continuously updated as new data becomes available. During a regulatory review, the **Company** may show an export of the risk assessment to demonstrate compliance with this documentation requirement. If further investigation is necessary an export of each risk assessment can be exported for the risk software.

16.3.3 Written Baseline Assessment Plan

The **Company** maintains the written baseline assessment plan documentation in accordance with §192.919. The Baseline Assessment Plan is maintained in Form 8-1: Baseline Assessment Schedule. The process for developing the written Baseline Assessment Plan is described in **Section 8 – Baseline Assessment Plan**.

16.3.4 Decision, Analysis, and Process Documentation

The **Company** maintains documentation to support various decisions, analysis and processes developed and used to implement and evaluate elements of the baseline assessment plan and the Integrity Management Program. The documentation includes those documents developed and used in support of the identifications, calculations, amendments, modifications, justifications, deviations, or determinations made. It also includes those actions taken to implement and evaluate IMP elements.

Examples of these documents may include, but are not limited to, the following:

- The HCA identification methods
- Potential Impact Radius / Circle calculations
- HCA proration calculations

- Process and documentation used to determine Identified Sites
- Threat Process technical basis
- Assessment method selection process and documentation (Form 8-1)
- Determination of Immediate Conditions
- Determination of scheduled responses
- Basis and justification when schedules cannot be met
- Determination of preventative and mitigative measures
- Modifications/ amendments based upon continual evaluation and QA process
- Management of Change Process and technical review (Form F14-1)
- Requested waivers and the technical basis and justification

16.3.5 Required Training Documentation

The **Company** maintains the written training documentation in accordance with §192.915 and Section 18 of this IMP. **Form F2-1: Personnel Qualifications Record Form** that is located at the end of Section 2 or similar form will be used to document training for the IMP acquired before employment with the company. The required qualification and training requirements are listed in **Section 18 – Personnel Knowledge and Training** and **Section 2 – Roles and Responsibilities**.

16.3.6 Prioritized Remediation Schedule

The **Company** maintains the prioritized remediation schedule in accordance with §192.933 and Section 10 of this IMP. A prioritized remediation schedule has been developed in accordance with the process detailed in **Subsection 10.6 – Prioritized Evaluation & Remediation Schedule**. The **Company** will maintain this prioritized remediation schedule and have it available for regulatory review by appropriate jurisdictional authorities.

16.3.7 Direct Assessment Plan

The **Company** maintains the documentation associated with Direct Assessment Plan in accordance with §192.923 - §192.929 and Section 7 of this IMP. The process for developing the Direct Assessment Plan is described in **Section 7 – Direct Assessment Plan**. The External Corrosion Direct Assessment (ECDA) Plan is maintained in Section 7A and the Internal Corrosion Direct Assessment (ICDA) Plan is maintained in Section 7B.

16.3.8 Confirmatory Direct Assessment

The **Company** maintains the documentation associated with the Confirmatory Direct Assessment in accordance with §192.931 and Section 7 of this IMP. The Confirmatory Direct Assessment (CDA) process is described in **Section 7C – Confirmatory Direct Assessment**.

16.3.9 Documentation of Required Notifications

The **Company** will maintain appropriate documentation to demonstrate the required submittals and notifications were made to:

- Pipeline and Hazardous Materials Safety Administration (PHMSA)
- The Kentucky Public Service Commission (KPSC)
- The Indiana Utility Regulatory Commission (IURC)

16.4 RECORD RETENTION

The **Company** will maintain those records needed to demonstrate compliance with 49 CFR Subpart O – Pipeline Integrity Management for the useful life of the pipeline or as otherwise required by regulations (Refer to Subsection 16.3).

Revision Log:

Date	Description	Revised By
12/03/2004	Changed NGA logo to LG&E logo	MTS
12/03/2004	Changed font style and size	MTS
12/03/2004	Changed Director of Integrity Management to Manager of Integrity Management (Subsection 16.1.2)	MTS
12/03/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/03/2004	Changed Company to LG&E Energy	MTS
12/03/2004	Inserted the office of record locations (Subsection 16.3)	MTS
12/03/2004	Changed references to Section 20 to Section 19	MTS
12/03/2004	Inserted state regulatory agencies (i.e., KPSC and IURC) (Subsection 16.4.9)	MTS
12/03/2004	Insert signature block	MTS
03/13/2009	Changed "LG&E Energy" to "the Company" and "OPS" to "PHMSA".	ENE
03/13/2009	Updated reference to Baseline Assessment Plan (subsection 16.4.3). Updated reference to Prioritized Evaluation & Remediation Schedule (subsection 16.4.6). Added references to both the ECDA and ICDA plans (subsection 16.4.7). Updated reference to CDA plan (subsection 16.4.8)	ENE
08/05/2009	Section 16 Routed to Management	MLS
11/3/2010	Section 16 Routed to Management (no changes)	MLS
12/14/2012	Updated 16.3 to show PeopleSoft as office of record for corporate training documents.	MLS
12/14/20102	Updated 16.4.2 and 16.4.4 as we do not have a form F4-1 and the flow diagrams have been removed from section 4	MLS
10/8/2013	Changed reference to M2 to M4 for section 16.1.2, changed language in 16.4.4	JJB
12/10/2013	General clerical changes.	JRG
12/21/2015	Deleted sections in Subsection 16.2 that concerned procedures for reviews by regulators. Combined 16.2 and 16.3. Edited Table 16-1 for Office of Record Locations.	JRG
11/11/2016	Clerical changes and clarification of risk assessment software.	CSM

17 PERFORMANCE PLAN §192.945

(Reference ASME B31.8S Section 9.4)

In This Section

Referenced Protocols

17 PERFORMANCE MEASURES

17.1 OVERVIEW

17.1.1 Purpose

The Performance Measures section describes the performance measures **the Company** will use to continually evaluate and monitor the progress of the overall Integrity Management Program as part of the continual improvement process. The section also describes the measurement and reporting frequency of each performance measure.

17.1.2 Responsibility

The **Manager - Gas Regulatory Compliance** M4 has overall the responsibility for the measurement and reporting requirements described in this section. The **Program Manager - Integrity Management** M1 will assist the **Manager - Gas Regulatory Compliance** M4 in the assembly of data necessary to satisfy the requirements of this section. In addition, the IMP Review Team is responsible for self assessment of the Integrity Management Program and the quality assurance process. A review of the performance measures are an integral part of that self assessment.

17.2 DEFINITIONS

The following definitions are listed in PHMSA's **"Instructions for Annual Reporting of Performance Measures"** and have been included in this section for reference. These instructions and the **"Gas Integrity Management Reporting Form"** are located at the end of this section.

Failure

Failure is a general term used to imply that a part in service: has become completely inoperable; is still operable but is incapable of satisfactorily performing its intended function; or has deteriorated seriously, to the point that it has become unreliable or unsafe for continued use (ASME B31.8S as referenced in Appendix 1B of this IMP). If an event involves the unintentional release of gas, it should be reported as an incident or leak.

IMP

IMP means Integrity Management Program as required by 49 CFR Part 192, Subpart O.

Immediate Repair

Immediate repair is defined by 49 CFR 192.933(d)(1). (Note that since an Immediate Repair Condition is not suitable for continued use, it should be reported as a Failure in the performance measures.)

Incident

Incident means any of the following events: [49 CFR 191.3]

(1) An event that involves a release of gas from a pipeline and results in one or more of the following consequences:
   (i) A death, or personal injury necessitating in-patient hospitalization;
   (ii) Estimated property damage of $50,000 or more, including loss to the operator and others, or both, but excluding cost of gas lost;
   (iii) Unintentional estimated gas loss of three million cubic feet or more;

(2) An event that is significant, in the judgment of the operator, even though it did not meet the criteria above.

An incident is an unintentional release of gas due to a failure of a pipeline (ASME B31.8S as referenced in Appendix 1B of this IMP).

HCA

HCA means High Consequence Area, as defined in 49 CFR 192.903 as referenced in Appendix 1B of this IMP.

Leak

Leak means an unintentional escape of gas from the pipeline. The source of the leak may be holes, crack (including propagating and non-propagating, longitudinal, and circumferential), separation and pull-out and loose connections (ASME B31.8S as referenced in Appendix 1B of this IMP). This would include any unintentional release of gas from a pipeline that does <u>not</u> result in an injury, death, or $50,000 in property damage.

Program Requirements

Program Requirements means the number of HCA miles in the IMP program.

Scheduled Repair

Scheduled repair means a repair scheduled in accordance with ASME/ANSI B31.8S, Section 7, Figure 4 as required by 192.933(c) and One-year conditions as identified under 192.933(d)(2) as they are also required to be prioritized for repair according to a schedule. This results in all repairs required by the rule except for immediate repairs being accounted for under the "Scheduled Repairs" category of the "Performance Measure Reports".

17.3 OVERALL PERFORMANCE MEASURES

✓ ***Referenced Protocol:*** *I.1 General Performance Measures*
I.2 Performance Measures Records Verification

17.3.1 General

On an **annual** basis, **the Company** will gather appropriate performance data consisting of overall program measures and threat specific measures. The threat specific measures collected will be associated with those threats which have been identified as a Threat of Concern (Section 4) on the pipeline system.

The Company will review and evaluate the performance data on an **annual** basis to:

- Determine if the Integrity Management Program's objectives are being met
- Determine if the overall pipeline integrity and safety are improving on the pipeline system
- Determine if the IMP Review Team's recommendations, preventative actions, and corrective actions have been effective
- Determine if any new circumstances or trends have developed that should be addressed

Through **the Company's** self-assessment of the IMP document and quality assurance process, **the Company** will periodically review the appropriateness of the performance measures selected and effectiveness of the program.

These performance measures are intended to provide indications of the effectiveness of the overall IMP program; however, there are many factors which can produce misleading results. These factors should be identified and documented on Form F17-1 Annual Performance Measures" during the **annual or periodic** review of the IMP Review Team. After the completion of Form F17-1 for the current year, the information will be inserted into a historical spreadsheet for multiyear tracking purposes.

17.3.2 Reportable Performance Measures

The Company will gather the following overall program measurements as specified by ASME B31.81S, Section 9.4:

- Number of total miles of transmission pipeline excluding gathering lines
- Number of total miles inspected as a result of the IMP rule
- Number of total HCA miles in the IMP Program
- Number of HCA miles inspected via IMP assessments
- Number of immediate repairs completed in HCAs as a result of the integrity management program

- Number of scheduled repairs completed in HCAs as a result of the integrity management program
- Number of leaks in HCA classified by cause
- Number of failures in HCA classified by cause
- Number of incidents in HCA classified by cause

Program Manager - Integrity Management M1 maintains these overall performance measures documented on Form 17-1 for the life of the IMP program.

17.3.3 Reporting Frequency

Reportable performance measures must be submitted to PHMSA in accordance with §191.17. Reportable performance measures for years 2009 and earlier were submitted as required on a semi-annual basis to PHMSA. Beginning with calendar year 2010, the performance measures will be integrated with the Annual Report for Gas Transmission and Gathering Pipeline Systems (F 7100.2.1).

Annual Performance Measures – Overall Measures	
Annual Period	**Submittal Deadline Dates**
January 1 – December 31	March 15

17.3.4 Report Submittal

The Company will submit the overall measures described in this subsection in accordance with §191.17 and LG&E GOM&I-GN-AR-001 Annual Reports & Mechanical Fitting Failure Reports.

17.4 THREAT SPECIFIC PERFORMANCE MEASURES

✓ ***Referenced Protocol:*** *I.1 General Performance Measures*

The Company will gather performance metrics on each of the nine threat categories listed in ASME/ANSI B31.8S, Appendix A as applicable to the pipeline system. The threat specific measures collected will be associated with those threats that have been identified as a Threat of Concern (Refer to Section 4) for the pipeline system. **The Company** will gather the following threat specific program measurements on an annual basis. Beginning with the 2010 reporting year, some of the threat specific measures were incorporated with the Annual Report for Gas Transmission and Gathering Pipeline Systems (F 7100.2.1). Those threat specific measures included on the report are denoted with an asterisk (*) in the list below.

Annual Performance Measures – Threat Specific Measures

Annual Periods	Submittal Dates
January 1 – December 31	March 15 (for threat specific measures with *)

Program Manager - Integrity Management M1 maintains threat specific performance measures documented on Form 17-1 for the life of the IMP program.

17.4.1 External Corrosion

The performance measures that are specific to the external corrosion threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of hydrostatic test failures caused by external corrosion
- Number of repair actions taken due to in-line inspection results
- Number of repair actions taken due to direct assessment results
- Number of external corrosion leaks*

17.4.2 Internal Corrosion

The performance measures that are specific to the internal corrosion threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of hydrostatic test failures caused by internal corrosion
- Number of repair actions taken due to in-line inspection results
- Number of repair actions taken due to direct assessment results
- Number of internal corrosion leaks*

17.4.3 Stress Corrosion Cracking (SCC)

The performance measures that are specific to the stress corrosion cracking threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of in-service leaks or failures due to SCC*
- Number of repair replacements due to SCC
- Number of hydrostatic test failures due to SCC

17.4.4 Manufacturing

The performance measures that are specific to the manufacturing threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of hydrostatic test failures caused by manufacturing defects
- Number of leaks due to manufacturing defects*

17.4.5 Construction

The following performance measures are specific to the construction threat on the pipeline system. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of leaks or failures due to construction defects*
- Number of girth welds or couplings reinforced or removed
- Number of wrinkle bends removed
- Number of wrinkle bends inspected
- Number of fabrication welds repaired or removed

17.4.6 Equipment

The following performance measures are specific to the equipment threat on the pipeline system. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of regulator valve failures
- Number of relief valve failures
- Number of gasket or O-ring failures
- Number of leaks due to equipment failures*

17.4.7 Third Party Damage

The performance measures that are specific to the third party damage threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of leaks or failures caused by third party damage*
- Number of leaks or failures caused by previously damaged pipe*
- Number of leaks or failures caused by vandalism*
- Number of repairs implemented as a result of third party damage prior to a leak or failure

17.4.8 Incorrect Operations

The performance measures that are specific to the incorrect operations (human error) threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of leaks or failures caused by incorrect operations*
- Number of audits or reviews conducted
- Number of findings per audit or review classified by severity

- Number of changes to procedures due to audits or reviews

17.4.9 Weather Related and Outside Forces

The performance measures that are specific to the weather related and outside force threat on the pipeline system are listed below. **The Company** will periodically review the effectiveness of these performance measures and make adjustments as appropriate.

- Number of leaks that are weather related or due to outside force*
- Number of repair, replacement, or relocation actions due to weather related or outside force damage

17.5 ECDA PROGRAM MEASURES

✓ *Referenced Protocol:* *D.5.c ECDA Post Assessment*

The Company has defined the External Corrosion Direct Assessment (ECDA) program measures to be monitored as part of its Direct Assessment Plan (Refer to Section 7). As part of the program measures, **The Company** will perform at least one additional direct examination at a randomly selected anomaly location on the pipeline. This will also serve to validate the ECDA process (See NACE RP0502-2002 - Pipeline ECDA Methodology §6.4.2) In addition, The Company has also developed additional criteria for assessing the long-term effectiveness of the ECDA process that are monitored as part of the Direct Assessment Plan (Refer to Section 7).

> **Note:** For initial ECDA applications, **at least two** additional direct examinations are required for process validation. The direct examinations will be conducted at randomly selected locations, one of which is categorized as scheduled (or monitored if no scheduled indications exist) and one in an area where no indication was detected (See NACE RP0502-2002 - Pipeline ECDA Methodology §6.4.2.1)

Through the application of ECDA, **The Company** intends to identify and address locations where corrosion activity has occurred, is occurring, or may occur. If **The Company** determines the conditions are more severe than those determined through the ECDA process, the process will be reevaluated and repeated. Alternatively **The Company** may also select an alternative integrity assessment method.

17.6 INTERNAL BENCHMARKING

The Company may use internal benchmarking to compare one pipeline segment against an adjacent segment or those from a different area of the same pipeline system. The information obtained may be used to evaluate the effectiveness of prevention activities, mitigation techniques, or performance validation. These comparisons may provide a basis to substantiate metric analyses and identify areas for improvements in the overall Integrity Management Program.

Benchmarking and trending of IMP performance measures from year to year may identify areas for improvement in the overall Integrity Management Program. In addition, benchmarking of other IMP activities may provide useful information on program effectiveness as well as for future planning and budgeting.

The **Program Manager - Integrity Management** M1 will compare the following overall program measurements across several years:

- Number of total miles of transmission pipeline excluding gathering lines
- Number of total miles inspected as a result of the IMP rule
- Number of total HCA miles in the IMP Program
- Number of HCA miles inspected via IMP assessments
- Number of immediate repairs completed in HCAs as a result of the integrity management program
- Number of scheduled repairs completed in HCAs as a result of the integrity management program
- Number of leaks in HCA classified by cause
- Number of failures in HCA classified by cause
- Number of incidents in HCA classified by cause

The **Program Manager - Integrity Management** M1 may benchmark and trend performance of the following activities periodically if determined to be necessary:

- Number of additional Preventive and Mitigative Measures implemented
- Number of digs performed as a result of IMP
- Number of Non-Monitored Excavations identified
- Number of HCA updates made as a result of structure type or location corrections

17.7 PERFORMANCE IMPROVEMENT

The results of the performance measurements, self assessments, and internal and external audits will be considered when making adjustments to the Integrity Management Program and will be part of the continual improvement process. Recommendations from the IMP Review Team for changes or improvements to the Integrity Management Program should consider an analysis of the performance measures and audits performed. The recommendations and accepted changes to the Integrity Management Program will be documented using the forms at the end of Section 12 – Preventive & Mitigative Measures, and Section 15 – Quality Assurance Process.

17.8 FORMS

Form F17-1:	Annual Performance Measures
DOT Form:	F7100.2.1 Gas Transmission and Gathering Annual Report

Revision Log:

Date	Description	Revised By
12/03/2004	Changed NGA logo to LG&E logo	MTS
12/03/2004	Changed font style and size	MTS
12/03/2004	Changed Regional Integrity Data Specialist to Manager of Pipeline Integrity (Subsection 17.1.2)	MTS
12/03/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/03/2004	Changed Company to LG&E Energy	MTS
12/03/2004	Inserted KPSC and/or IURC mailing addresses	MTS
12/03/2004	Changed annual review to self assessment (Subsection 17.1.2)	MTS
12/03/2004	Moved the subsection refering to self assessment and internal audits (i.e., the old Subsection 17.7 Self Assessments and Internal Audits) to Section 15.	MTS
12/03/2004	Add external audits to the informatin that should be considered for adjustments to the IMP. (Subsection 17.7 Performance Improvement)	MTS
10/3/07	Corrected period reporting dates in section 17.3.2 and 17.4 from July 1 – December 31 to January 1st through December 31st.	LCO
10/10/08	Updated Failure, Leak, & Incident definitions to match latest PHMSA guidance. Added definitions for Immediate Repair and Scheduled Repair (subsection 17.2)	ENE
10/10/08	Updated reporting frequency explanation and report submittal instructions to match latest PHSMA reporting instructions. Clarified that end of year submittal should include entire year. (subsection 17.3)	ENE
10/10/08	Added Management Approval requirement per code (subsection 17.3.4)	ENE
10/10/08	Added detail to Internal Benchmarking section (subsection 17.6)	ENE
10/10/08	Changed LG&E references to "the company" and changed "OPS" to "PHMSA".	ENE
10/10/08	Added referenced protocols.	ENE
10/10/08	10/10/08 Version approved by management	LCO
8/5/2009	Fixed minor grammatical errors	JJB
8/5/2009	Changed blue font to black	JJB
8/5/2009	Added /ANSI to all ASME B31.8S references	JJB
10/22/2009	Changed protocol references to match new nomenclature	JJB
12/03/2009	Corrected function code references	JJB
12/03/2009	10/10/08 Version approved by management	JJB
3/15/2010	Adjusted form F-17 to show more recent data from recent years on the left of the sheet	JJB
10/10/2010	Identified possible issues with benchmarking and trending language in Section 17	JJB
12/16/2010	Corrected language regarding benchmarking and trending in section 17.	JJB
4/8/2011	Corrected language regarding semi annual submittal of performance measures.	JJB
11/1/2012	Updated the PHMSA Performance Measures for name to F7100.2.1	JJB
11/28/2012	Modified responsibility for the described measurement and reporting requirements (17.2.2) from Director to Manager level with assistance by IM Program Manager.	PJC
10/7/2013	Modified Management Approval section 17.3.4	JJB
12/18/2015	Modified Form 17-1 for recording annual performance measures.	EB

Date	Description	Revised By
12/12/2016	Edited definitions in Section 17.2 to conform with definitions repeated in Appendix 1B; deleted Section 17.3.4 – Management Approval, and edited Section 17.3.5 – Report Submittal to cross reference GOM&I-GN-AR-001.	PC, EB, JRG

18 PERSONAL KNOWLEDGE & TRAINING §192.915

In This Section

Referenced Protocols

18 PERSONAL KNOWLEDGE & TRAINING

18.1 OVERVIEW

✓ ***Referenced Protocol:*** ***L.2 Personnel Qualification and Training Requirements***

18.1.1 Purpose

The Personal Knowledge and Training section describes the qualifications and training requirements of Louisville Gas & Electric / Kentucky Utilities (the company) key personnel working on the IMP.

18.1.2 Responsibility

The **Manager - Gas Regulatory Compliance** M4 has the overall responsibility for assuring the written IMP document reflects the required personal knowledge and training necessary to implement the company's IMP in accordance with 49 CFR 192 Subpart O.

The **Manager - Gas Regulatory Compliance** M4, and the **Manager – Gas Storage Operations** F1 are each responsible for assuring the key integrity management personnel within their area of responsibility have the required knowledge and training. A list of key integrity management personnel and the associated organizational chart are provided in Section 2 – Roles and Responsibilities.

18.2 INTEGRITY MANAGEMENT QUALIFICATION AND TRAINING

All personnel performing integrity management activities as part of the company's IMP are qualified for the tasks being performed.

The following integrity management responsibilities are described with specific qualification requirements in Section 2, Table 2-1. These responsibilities are also cross referenced to Company titles in Section 2, Table 2-2.

- Supervisory Personnel
- Persons who conduct assessments
- Persons who review and analyze results from assessments
- Persons who make decisions on actions to take based on assessments
- Persons who implement preventive and mitigative measures (including marking and locating buried structures)
- Persons who directly supervise excavation work in conjunction with integrity assessments

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18.2.1 Supervisory Personnel

All supervisory personnel will have the appropriate training or experience for their assigned responsibilities.

The following designated classification is also listed in *Table 2-2: Cross Reference of Company IM Positions with §192.915*:

- Supervisory Personnel [*§192.915 (a)*]

18.2.2 Persons Performing Assessments & Evaluating Results

All personnel that carry out assessments or evaluate assessment results will have the appropriate qualifications for their assigned responsibilities.

The following designated classifications are also listed in *Table 2-2: Cross Reference of Company IM Positions with §192.915*.

- Persons Who Conduct Assessments [*§192.915 (b)(1)*]
- Persons Who Review and Analyze Results from Assessments [*§192.915 (b)(2)*]
- Persons Who Make Decisions on Actions to Take Based on Assessments [*§192.915 (b)(3)*]

The company will use the additional qualification criteria of the Operator Qualification (OQ) Program for those activities which have been designated as a “covered task”.

18.2.3 Persons Who Participate in Preventative & Mitigative Measures

All persons who participate in implementing preventive and mitigative measures will be qualified to perform their assigned responsibilities.

The following designated classifications are also listed in *Table 2-2: Cross Reference of Company IM Positions with §192.915*.

- Persons Who Implement Preventive and Mitigative Measures, Including Marking and Locating Buried Structures [*§192.915 (c)(1)*]
- Persons Who Directly Supervise Excavation Work in Conjunction With Integrity Assessments [*§192.915 (c)(2)*]

The company will use the additional qualification criteria of the company’s Operator Qualification (OQ) Program for those activities which have been designated as a “covered task”.

18.2.4 Personnel Who Execute IMP Activities

All personnel performing activities as part of Company’s IMP are competent, aware of the program, and are trained to perform the activities within their assigned duties.

The company will use the additional qualification criteria of the company's Operator Qualification (OQ) Program for those activities which have been designated as a "covered task" in the company's Operator Qualification Plan.

18.2.5 Changes That Affect Integrity Management

Under the **Management of Change** (MOC) process (**Section 14**); the **Qualified Manager** (defined below) is also responsible for:

- Assigning qualified staff to perform the Technical Review
- Assessing the staff's qualifications to implement and maintain the change
- Providing training as necessary to implement and maintain the change

The **Qualified Manager** is a designated member of management with the ultimate responsibility to determine whether a proposed change is subject to the MOC process.

Qualified Managers include the **Program Manager – Integrity Management M1** and the **Manager – Gas Storage Operations F1**.

18.3 OVERALL COMPANY TRAINING PROGRAM

The company maintains an overall written training program as well as an Operator Qualification Program. The Operator Qualification Program fully complies with the requirements of **49 CFR 192 Subpart N – Qualification of Pipeline Personnel** and all covered tasks have been identified as part of the overall program, including those associated with the IMP.

The company's Operator Qualification Plan is located on the LG&E and KU Intranet site under Gas Regulatory Services.

18.4 DOCUMENTATION

The company maintains written qualifications, knowledge, and training documentation in a corporate database, i.e. People Soft. **Form F2-1: Personnel Qualification Record Form** located at the end of Section 2 or similar form will be used to document qualifications, knowledge, and training for the Integrity Management Group that is not documented in the corporate database.

Revision Log:

Date	Description	Revised By
12/10/2004	Changed NGA logo to LG&E logo	MTS
12/10/2004	Changed font style and size	MTS
12/10/2004	Changed Director of Pipeline Integrity to Manager of Pipeline Integrity (Subsection 18.1.2)	MTS
12/10/2004	Changed the footer from Integrity Management Plan to Integrity Management Program	MTS
12/10/2004	Changed Company to LG&E Energy	MTS
12/10/2004	Inserted Manager of Pipeline Integrity (Subsection 18.2.5)	MTS
07/30/2008	18.1.1 - Changed LG&E Energy's to Louisville Gas & Electric/Kentucky Utilities (the company)	SAD
07/30/2008	18.1.2 – Changed Director of Integrity Management M3 to Director-Gas Storage Control, & Compliance M2	SAD
07/30/2008	18.1.2 – Changed M2 to M4	SAD
07/30/2008	18.2 – Changed LG&E Energy's to the company	SAD
07/30/2008	18.2.2 – Changed LG&E Energy to The company	SAD
07/30/2008	18.2.3 – Changed LG&E Energy to The company	SAD
07/30/2008	18.2.4 – Changed LG&E Energy to The company	SAD
07/30/2008	18.3 – Changed LG&E Energy to The company	SAD
07/30/2008	18.4 – Changed LG&E Energy to The company	SAD
08/01/2008	18.3 – Added "The company's DOT Operator Qualification Plan is located on the E-ON US Intranet site under Gas Engineering & Planning"	SAD
8/1/08	8/1/08 Version Approved by Management	LCO
10-29-09	Page 1 – Corrected signature block.	SAD
10-29-09	18.2 – Changed Form F2-1, Personal Documentation Form	JRG
10-29-09	18.4 – Changed to use corporate database for training documentation.	JRG
12-13-10	18.2.4 – Corrected typo, changed assign to assigned	SAD
10-27-11	No revisions required	SAD
11-29-12	18.3 – Deleted E-ON US and replaced with LGE KU	SAD
11-20-13	18.1 – Corrected titles and responsibilities. 18.2 – Corrected table references 18.3– Corrected location of OQ Plan; deleted reference to Section 15.4.4 18.4 – Corrected name of Form F2-1 Minor clerical corrections throughout Section	JRG
12-16-14	18.2 – Rephrased reference to Section 2 Tables and minor clerical edits.	JRG
11-25-15	Minor clerical corrections throughout Section	JRG

19 COMMUNICATIONS PLAN §192.911(m)

(Reference: ASME B31.8S Section 10)

In This Section

Referenced Protocols

19 COMMUNICATIONS PLAN

19.1 OVERVIEW

✓ *Referenced Protocol:* ***M.1 External and Internal Communication Requirements***

19.1.1 Purpose

This Communications Plan Section was developed by **the company** to ensure that appropriate company personnel, jurisdictional and emergency authorities, and the public are informed about the company's Integrity Management Program (IMP) efforts. In addition, it describes how the company will interact with the regulatory agencies that have jurisdictional authority over the IMP and those circumstances in which they will be contacted. This plan meets the requirements of 49 CFR Subpart O – Pipeline Integrity Management and supplements the company's existing Approved Operating Policy entitled Gas Distribution Operations Communication (GAOP-PO-015), and the company's existing Public Awareness Program, which addresses general natural gas safety for customers and the general public.

The very nature of a "Risk Analysis" and an "Integrity Management Program" has the potential to expose information regarding the most vulnerable and risk sensitive segments of a company's pipeline system. In order to protect its critical infrastructure from the increased risk of terrorism and comply with the Department of Homeland Security, **the company**, like other energy companies, is limited in the amount and type of information that it can share. However, the company also recognizes the need to communicate an appropriate level of information to individuals and authorities concerning its pipeline system and integrity management efforts. This plan helps ensure that each stakeholder receives the appropriate level of information.

19.1.2 Responsibility

The **Program Manager – Integrity Management** M1 will have overall responsibility for maintenance and/or modifications to this plan. In addition, the **Manager - Gas Regulatory Compliance** M4 will have overall responsibility for regulatory interaction.

19.2 GENERAL REQUIREMENTS

This Communications Plan has been developed in accordance with the elements of ASME B31.8S Section 10 – Communications Plan, along with consideration of the recommended practices of API 1162 – Public Awareness Programs for Pipeline Operators. Certain information outlined in this plan will be communicated on a routine basis, while other information will be communicated upon request.

19.3 EXTERNAL COMMUNICATIONS STRATEGY

The external communications strategy is primarily outlined and executed under the company's Pipeline Public Awareness Plan. Information will typically be communicated continuously via the company's website, but could be communicated via an alternate method acceptable per the company's Pipeline Public Awareness Plan.

19.4 EXTERNAL COMMUNICATIONS – REGULATORY INTERACTION

19.4.1 Federal and State Pipeline Authorities

Under the requirements of 49 CFR 192 Subpart O – Pipeline Integrity Management, certain contacts and notifications are required to be made to the Pipeline and Hazardous Materials Safety Administration (PHMSA), Kentucky Public Service Commission (KYPSC) and Indiana Utility Regulatory Commission (IURC).

19.4.2 Changes to the Integrity Management Program

Reference §192.909(b)

The company must notify PHMSA, KYPSC and IURC of any change to the IMP that:

- May substantially affect the IMP's implementation.
- May significantly modify the IMP.
- May significantly modify the schedule to implement required IMP elements.

(See Management of Change Section 14.2.3 for examples of significant changes.)

In addition, the company must provide notification **within 30 days** after adopting this type of change into its program. The company will use the Management of Changes procedures and the "**Management of Change Approval Form F14-1**", or similar form, to document these changes and subsequent notifications (Refer to Section 14).

19.4.3 Addressing Safety Concerns

Reference §192.911(m)

The company has developed this Communications Plan as part of its overall IMP, which addresses potential safety concerns raised by:

- The PHMSA
- The KYPSC and
- The IURC

The procedures for addressing these potential safety concerns are located in **Subsection 19.5.**

19.4.4 Procedure to Provide Documents Upon Request

Reference §192.911(n)

✓ ***Referenced Protocol*** ***N.1 Integrity Management Program Document Submittal***

The following procedure has been developed to describe how copies of the company's "Risk Analysis" or "Integrity Management Program" will be provided to the appropriate jurisdictional agencies upon request. These jurisdictional agencies include the PHMSA, KYPSC and IURC.

a. Request of "Risk Analysis" or "Integrity Management Program"

Any document request received by the company will be directed to the **Manager - Gas Regulatory Compliance** M4 for further processing. The **Manager - Gas Regulatory Compliance** M4 will review the request and ensure the requesting party has the appropriate jurisdictional authority to make the request [Ref: §192.911(m)]. Once the jurisdictional authority of the requesting party has been established, the appropriate documents will typically be prepared for the jurisdictional authority to review while at the company's facility. The documents will stay at the company's facility. Under §192.911(m), the company will provide the following documents:

- Risk Analysis
- Integrity Management Program

The company may, at its discretion, choose to provide the documents to the jurisdictional authority to review at their facility. In such cases, the following process for submitting, designating protections and requesting return of materials will typically be followed.

b. Submittal of Documents

The requested materials will be provided in either printed or electronic media. For printed material, the company will use a postal or messenger service capable of providing a "proof of receipt" for documentation purposes. The company will maintain in-house proof of electronic document submission.

c. Designated Protections and FOIA (Freedom of Information Act) Exemptions

The **Manager - Gas Regulatory Compliance** M4 will assure the proper "document designations" and "FOIA exemptions" are claimed for each agency submittal. The company formally objects to the disclosure of the Risk Analysis and Integrity Management Program documents through any type of Freedom of Information Act (FOIA) request.

(1) Document Designations

The company may designate certain requested documents as "Business Confidential" and/or "Security Sensitive." Any document that has been so designated will be noted in the transmittal letter to the requesting agency and plainly marked on the document.

(2) FOIA Exemption 1: Critical Infrastructure Information

The company has placed a much greater emphasis on the protection of information that could expose the nation's critical infrastructure to an increased risk of terrorism. The very nature of a "Risk Analysis" and an "Integrity Management Program" has the potential to expose information regarding the most vulnerable and risk-sensitive segments of the company's pipeline system. Therefore, the company objects to the disclosure of this Security Sensitive information through any type of FOIA request.

(3) FOIA Exemption 4: Business Confidential and Copyrighted Information

The company may designate certain requested documents as "Business Confidential" due to trade secrets or proprietary business processes. Portions of this IMP document are also protected by copyright of Northeast Gas Association (© Copyright 2004 Northeast Gas Association). The document and all embedded copyright material should be withheld as being exempt under the Freedom of Information Act (FOIA) Exemption 4 Title 5 U.S.C. 552(b)(4) based upon an analysis of the "commercial value" of the work and the effect a FOIA disclosure would likely have on the copyright holder's potential market. Therefore, the company objects to the disclosure of this "Business Confidential" and/or "Copyrighted" information through any type of FOIA request.

d. Requested Return of Materials

Upon completion of the appropriate agency's document review, the **Manager - Gas Regulatory Compliance** M4 will request the submitted documents be returned to the company.

19.4.5 Use of Other Technology–Assessment Method

Reference §192.921(a) (4), §192.937(c)(4)

The company may use any of the following acceptable integrity assessment methods under 49 CFR 192 Subpart O – Pipeline Integrity Management:

- Internal Inspection Tools
- Pressure Testing
- Direct Assessment

The company may also choose to pursue "Other Technology" that it can demonstrate will provide an equivalent understanding of the line pipe condition. If this option is chosen, the PHMSA and KYPSC and/or IURC must be notified within 180 days before conducting an assessment using the "Other Technology" in accordance with §192.949.

19.4.6 When Schedules Cannot Be Met

Reference §192.933(c)

a. Evaluation of Assessment Results

If the company is unable to complete its evaluation of the integrity assessment data within the required **180 days**, the company will notify the OPS, KYPSC and/or IURC

before the end of the 180 days. The company will also demonstrate why completing the evaluation within the **180 days** is impractical. (Refer to Section 10.)

b. **Prioritized Remediation Schedule**
If the prioritized remediation schedule cannot be met, and a temporary reduction in operating pressure or other appropriate action to ensure the safety of the covered segment cannot be achieved, the company will notify the PHMSA, KYPSC and/or IURC **as soon as practical**. (Refer to Section 10.)

c. **Temporary Pressure Reductions**
If a temporary pressure reduction in response to an Immediate Condition will exceed **365 days**, the company will notify the OPS, KYPSC and/or IURC **before the end of the 365 days**. (Refer to Section 10.) In its notification, the company will demonstrate the following:

- Explanation why timeframe exceeded
- Justification why public safety is not endangered
- Additional steps, if any, taken to ensure public safety

19.4.7 Annual Performance Measures

Reference §192.945(a)

✓ ***Referenced Protocol:*** ***I.3 Submitting Results of Performance Measurements to PHMSA***

The company must submit certain overall performance measures, by electronic or other means, on an **annual frequency** to the PHMSA and KYPSC and/or IURC. (Refer to Section 17.) As of the 2010 reporting period, the Performance Measures Report has been incorporated with the DOT Transmission Report.

Annual Performance Measures – Overall Measures	
Period	**Submittal Dates**
January 1 – December 31	March 15

19.4.8 Waiver from Reassessment Interval

Reference §192.943(a)

✓ ***Referenced Protocol:*** ***F.6 Waiver from Reassessment Interval***

PHMSA will consider a waiver from the reassessment interval in limited situations provided it is consistent with pipeline safety. The waiver request will be considered under the following circumstances:

- Lack of internal inspection tools
- Inability to maintain product supply

Under current regulations, if a waiver becomes necessary, the company must apply for the waiver at least **180 days** before the end of the required inspection interval unless local product supply issues make that period impractical. Under current regulations, if local product supply issues do make that period impractical, the company must apply for the waiver **as soon as the need for the waiver is known**.

19.4.9 How to Notify Regulatory Agencies

Reference §192.949

The company will provide any required notification to the PHMSA and KYPSC and/or IURC under the 49 CFR 192 Subpart O – Pipeline Integrity Management by one of the following methods:

a. PHMSA
Notification by mail to:

Information Resources Manager
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration,
East Building, 2nd Floor
1200 New Jersey Avenue SE,
Washington DC 20590

Notification by facsimile to:

Information Resources Manager
(202) 366–3666

Notification by online reporting, by entering the information directly on the Integrity Management Database (IMDB) website at:

http://primis.phmsa.dot.gov/gasimp

Online reporting is PHMSA's preferred method of notification.

b. KYPSC
Notification by mail to:

Kentucky Public Service Commission
Manager, Gas Branch
Division of Engineering
211 Sower Blvd
Frankfort, Kentucky 40601

Notification by e-mail to:

jason.hurt2@ky.gov (Jason Hurt, Gas Branch Manager) or other appropriate KYPSC staff e-mail address.

c. IURC
Notification by mail to:

Indiana Utility Regulatory Commission (IURC)

Indiana Government Center South
302 West Washington Street
Suite E-306
Indianapolis, Indiana 46204

Notification by e-mail to:

WBOYD@URC.IN.GOV (Bill Boyd, Pipeline Safety Program Manager) or other appropriate IURC staff e-mail address.

19.4.10 Where to File A Performance Report

Reference §192.951

The company will submit certain overall measures described in this IMP document (Section 17) by electronic or other means (mail or facsimile) on an **annual frequency** to the PHMSA, KYPSC and IURC. (Refer to Section 17.) As of the 2010 reporting period, the Performance Measures Report has been incorporated with the DOT Transmission Annual Report.

19.4.11 Documentation of Submittals and Notification

Reference §192.947(i)

The company will maintain appropriate documentation to demonstrate the required submittals and notifications were made to:

- PHMSA
- The KYPSC and
- The IURC

This documentation may include the use a postal or messenger service capable of providing a "proof of receipt" for documentation purposes or copy of a sent e-mail. (Refer to Section 16.)

19.5 INTERNAL COMMUNICATIONS

The company has developed its IMP document and this Communications Plan to ensure that the appropriate individuals within the organization receive the appropriate information in a timely manner. These communications occur internally through the GAOP-PO-015 Gas Distribution Operations Communication, Integrity Management review team, budget requests, training request, and various meetings or documentation.

19.6 ADDRESSING SAFETY CONCERNS

✓ ***Referenced Protocol:*** ***M.2 Addressing Safety Concerns***
Reference §192.911(m)

Any safety concerns raised by the Pipeline and Hazardous Materials Safety Administration (PHMSA), Kentucky Public Service Commission (KYPSC) or Indiana Utility Regulatory Commission (IURC) will be directed to the **Manager - Gas Regulatory Compliance** M4.

19.6.1 Verbal Notification of Safety Concerns

Any verbal notification of safety concerns (from PHMSA, KYPSC, or IURC) will be directed to the **Manager - Gas Regulatory Compliance** M4 for response. The **Manager - Gas Regulatory Compliance** M4 will explain the details of the company's overall Integrity Management Program and attempt to resolve any concerns through this discussion.

19.6.2 Written Notification of Safety Concerns

Any written notification of safety concerns will be directed to the **Manager - Gas Regulatory Compliance** M4 for response. Upon receipt the **Manager - Gas Regulatory Compliance** M4 will review the technical and/or regulatory basis of the safety concern and determine if a meeting with the IMP Team is required to properly respond to the concern. Once adequate information has been gathered to properly respond to the concern, the **Manager - Gas Regulatory Compliance** M4 will prepare a written response to the jurisdictional authority addressing the safety concerns and indicate any actions taken as a result of the inquiry.

Revision Log:

Date	Significant Changes	Revised By
Sept. 2004	Appropriately changed references to "Company" to LG&E Energy throughout.	CJH/MS/LO
Sept. 2004	Integrated Section 20, Regulatory Interaction, into the Communications Plan as Section 19.4 - External Communications, as it addresses methods to communicate with the OPS and local regulatory agencies.	CJH/MS/LO
Sept. 2004	Tables on the subjects below, which summarize public awareness communications from API 1162, were included in the original template, but were deleted from this document as they did not address specific requirements of the Pipeline Integrity Communicatins Plan. Howerver, they were considered in the development of this plan. Hazardous Liquids and Natural Gas Transmission Pipeline Operators. Local Natural Gas Distribution (LDC) Companies	CJH/MS/LO
Sept. 2004	Developed and added Table 19-2 External Communications Frequency and Delivery Methods to enable tracking to responsible parties.	CJH/MS/LO
Sept. 2004	Developed and added Table 19-3 Internal Communications from bullet Internal Communications bullet points provided in original template.	CJH/MS/LO
12/8/04	Changed Table 19-2 (04) receiving party from "Emergency Response" to "Landowner/Tenants" to reflect ASME B31.8S.	lco
1/10/05	In Internal Communications Table 19.3, Page 20, changed responsible party for communication to Pipeline Integrity Related Personnel from V.P. Corporate Communications, to Manager, Gas Regulatory Compliance.	CJH / lco
1/10/2005	**1/10/2005 Version Approved by Management**	**LCO**
03/13/2009	Changed "LG&E Energy" to "the Company" and, where appropriate referenced E.On U.S. website and contact information. Changed "OPS" to "PHMSA" where appropriate	ENE
03/13/2009	Subsection 19.3.1 – recreated data tables using current contact information and eliminated redundant information by adding cross-references	ENE
03/13/2009	Subsection 19.4.6 – Added paragraph requiring notification if temporary pressure reductions exceed 365 days.	ENE
12/17/2009	Added reference to Public Awareness program in section 19.3.1	MLS
12/17/2009	Changed title in 19.1.2	MLS
12/17/2009	Section 19 forwarded to management for approval	MLS
3/23/2010	Changed signature block to remove Communications VP and add IM Group Leader	MLS
3/23/2010	Deleted VP of Communications from section 19.1.2	MLS
3/23/2010	Routed revised document to management for approval	MLS
12/16/2010	Section 19 Annual Review Form routed to management	MLS
1/20/2012	Miscellaneous formatting changes and changed OPS to PHMSA	MLS
1/23/2012	Edits to Table 19-3: Internal Communications	MLS
11/8/2013	Changing Director responsibilities to Manager or VP	MLS
11/26/2014	Updated section 19.5, including removing table 19-3, per 2014	MLS

	TIMP audit.	
11/17/2015	Deleted Table 19-1 per 2014 P-PIC audit.	CLG
11/8/2016	Reformatted page numbers to be consistent with rest of TIMP. Cross referenced GAOP-PO-015 Gas Distribution Operations Communication in §19.1.1 and §19.5.	CLG

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 253

Responding Witness: Lonnie E. Bellar

Q-253. Identify all costs, by account, in the base year and, separately, in the forecast period, relating to the Company's Transmission Integrity Management Plan.

A-253. Work related to the Transmission Integrity Management Plan is integrated across various work groups and into employee's daily activity in a way that all costs related to the plan are not captured specifically. However, the table below shows the costs associated with integrity assessments completed as part of the transmission integrity program.

Description	Account	Base Period	Test Period
Transmission Integrity In-line inspections and direct assessments	863	$588,908	$317,000

LG&E is also proposing a Transmission Modernization program that would also directly relate to the Transmission Integrity Management program and is proposed to be recovered through the Gas Line Tracker Mechanism.

Description	Account	Base Period	Test Period
Transmission Modernization Program	107	$87,064	$14,781,488
Transmission Modernization Program	108	$0	$193,800

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 254

Responding Witness: Lonnie E. Bellar

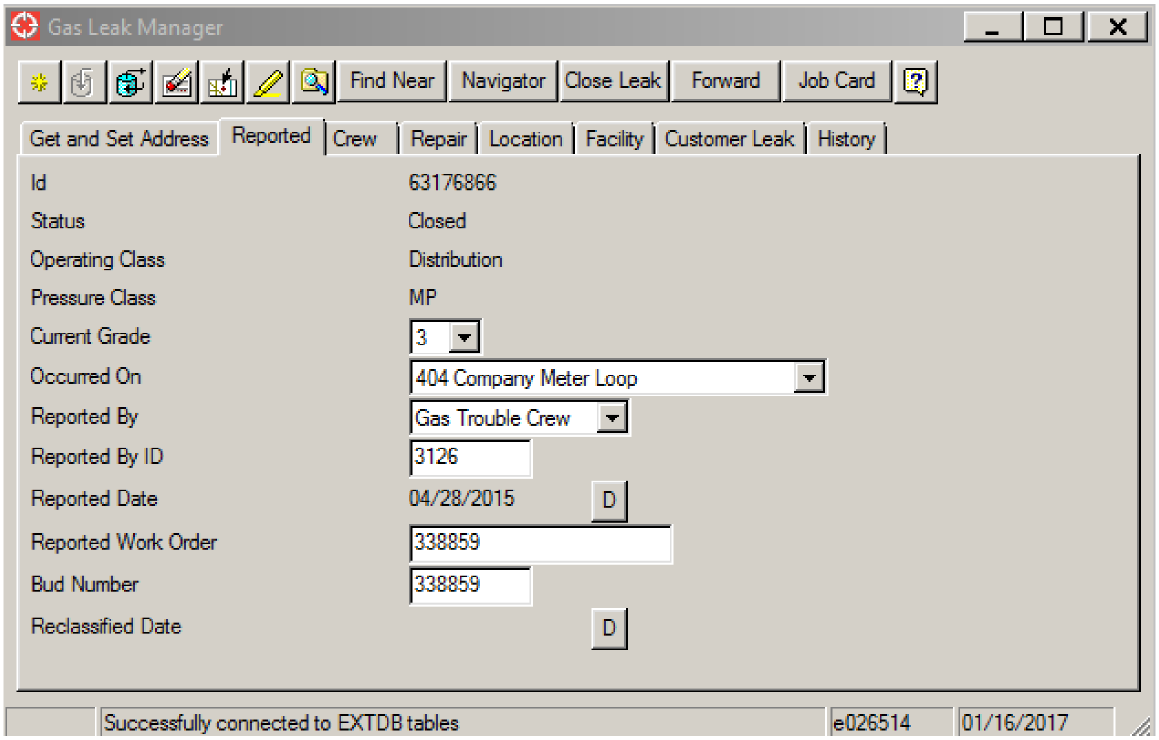
Q-254. How does the Company track and classify gas leaks? Explain fully and provide leak tracking reports used by the Company in 2015 and 2016.

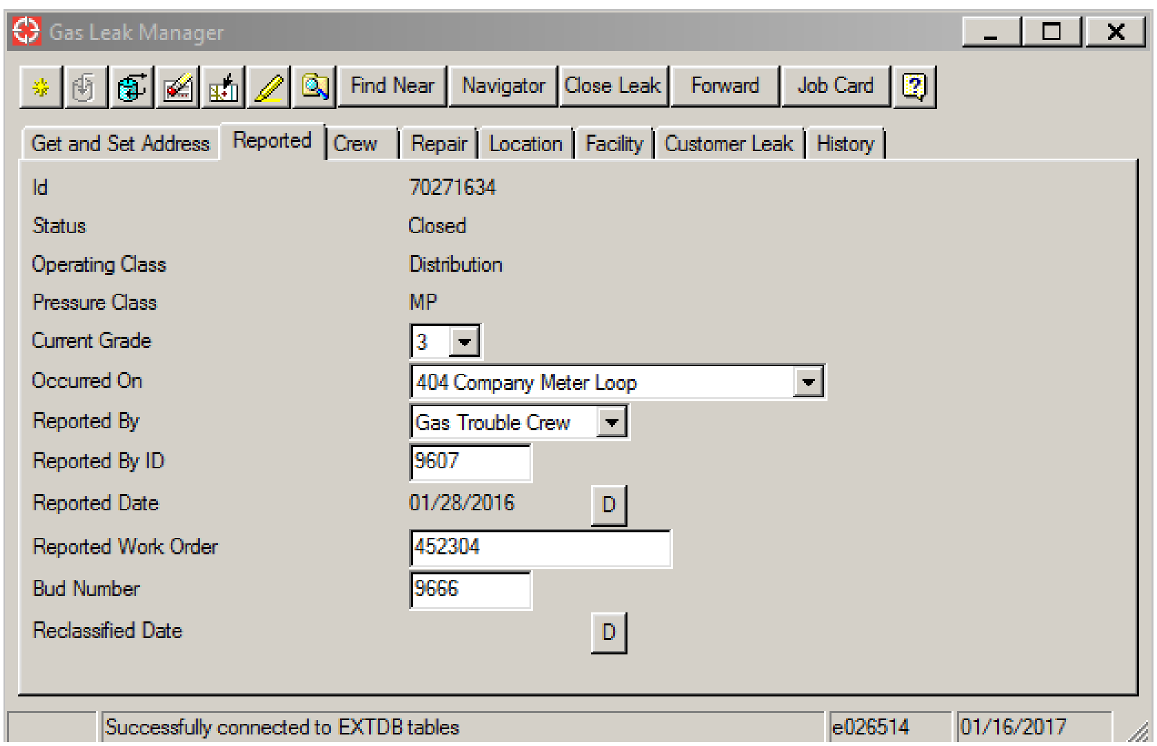
A-254. The Company tracks leaks by mapping them in its Graphical Information System (GIS). Examples of leak objects from the GIS are shown below. From the GIS, data can then be extracted to track details about leaks. A representative sample extraction of relevant information is attached.

This same GIS data is used to compile the Pipeline Hazardous Materials Safety Administration (PHMSA) Annual Report for Gas Distribution Systems. The annual reports are available on PHMSA's website.

The Company classifies leaks based on the guidelines published in The Gas Piping Technology Committee (GPTC) Guide For Gas Transmission and Distribution Piping Systems, Appendix G-192-11.

See attached.


Gas Leak Manager
Find Near
Navigator
Close Leak
Forward
Job Card
Get and Set Address
Reported
Crew
Repair
Location
Facility
Customer Leak
History
Id 63176866
Status Closed
Operating Class Distribution
Pressure Class MP
Current Grade 3
Occurred On 404 Company Meter Loop
Reported By Gas Trouble Crew
Reported By ID 3126
Reported Date 04/28/2015
D
Reported Work Order 338859
Bud Number 338859
Reclassified Date
D
Successfully connected to EXTDB tables
e026514
01/16/2017


Gas Leak Manager
Find Near
Navigator
Close Leak
Forward
Job Card
Get and Set Address
Reported
Crew
Repair
Location
Facility
Customer Leak
History
Id 70271634
Status Closed
Operating Class Distribution
Pressure Class MP
Current Grade 3
Occurred On 404 Company Meter Loop
Reported By Gas Trouble Crew
Reported By ID 9607
Reported Date 01/28/2016
D
Reported Work Order 452304
Bud Number 9666
Reclassified Date
D
Successfully connected to EXTDB tables
e026514
01/16/2017

Sample Leak Report
Gas Mains 12/31/2016

CURRENT GRADE	OCCURRED ON	STREET NUMBER	STREET PREFIX	STREET NAME	STREET SUFFIX	CITY	ZIP CODE	STREET1 INTERSECTION	INTERSECTING STREET SUFFIX	ID	REPORTED DATE	STATUS	PRESSURE CLASS	MAIN PIPE MATERIAL	OPERATING CLASS	REPORTED BY	RECLASSIFIED DATE	LAST SURVEY DATE	DAYAGED
2	408 MAIN			TRURO	CT	LOUISVILLE	40216	SUNFLOWER	AVE	41389837	7/20/2009	ACTIVE	MP	S	Distribution	Leak Survey Crew	12/3/2016	12/6/2016	28
2	408 MAIN	5010		NETHERWOOD RIDGE	DR		40241			71267357	10/31/2016	ACTIVE	MP	PL	Distribution	Gas Trouble Crew			61
2	408 MAIN	2808		JOHNSONTOWN	RD		40272			71478636	11/8/2016	ACTIVE	MP	S	Distribution	Construction Crew			53
2	408 MAIN	5706		JEANINE	DR		40219			71394034	11/11/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			50
2	408 MAIN		S	12TH	ST	LOUISVILLE	40210	ST CATHERINE	ST	70070661	11/15/2016	ACTIVE	MP	PL	Distribution	Gas Trouble Crew	11/16/2016		45
2	408 MAIN	420		MCCREADY	AVE	LOUISVILLE	40206			71479913	11/15/2016	ACTIVE	MP	PL	Distribution	Gas Trouble Crew			46
2	408 MAIN	8300		FREEMONT	RD	BARBOURMEADE	40242			71395599	11/16/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			45
2	408 MAIN	6815		FENWICK	DR		40228			71396154	11/17/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			44
2	408 MAIN			WEISSINGER	RD	LANGDON PLACE	40241	LANGDON	DR	71480328	11/18/2016	ACTIVE	MP	S	Distribution	Construction Crew			43
2	408 MAIN		E	KENTUCKY	ST	LOUISVILLE	40203	BROOK	ST	71528800	12/13/2016	ACTIVE	LP	CI	Distribution	Construction Crew			18
2	408 MAIN	411	N	20TH	ST	LOUISVILLE	40203			71528838	12/13/2016	ACTIVE	MP	PL	Distribution	Construction Crew			18
2	408 MAIN			WOODDALE	DR		40272	PAGES	LN	71529328	12/14/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			17
2	408 MAIN	444		SOUTH	ST	RADCLIFF	40160			71583867	12/21/2016	ACTIVE	MP	S	Distribution	Leak Survey Crew		12/21/2016	10

Sample Leak Report
Gas Mains 12/31/2016

CURRENT GRADE	OCCURRED ON	STREET NUMBER	STREET PREFIX	STREET NAME	STREET SUFFIX	CITY	ZIP CODE	STREET1 INTERSECTION	INTERSECTING STREET SUFFIX	ID	REPORTED DATE	STATUS	PRESSURE CLASS	MAIN PIPE MATERIAL	OPERATING CLASS	REPORTED BY	RECLASSIFIED DATE	LAST SURVEY DATE	DAYAGED
2	408 MAIN			MANSFIELD	LN		40218	GREEN COVE	CIR	70123555	12/22/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			9
2	408 MAIN			ALANADALE	DR		40272	DONERAIL	WAY	71303548	12/22/2016	ACTIVE	MP	S	Distribution	Construction Crew			9
2	408 MAIN			DORRANCE	DR		40258	MOONGLOW	AVE	71304065	12/22/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			9
2	408 MAIN			DORRANCE	DR		40258	MOONGLOW	AVE	71304060	12/22/2016	ACTIVE			unset	Gas Trouble Crew			9
2	408 MAIN			BLUE LICK	RD		40219	SOUTH PARK	RD	71618585	12/28/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			3
2	408 MAIN	5132		MILNER	RD		40216			71304517	12/30/2016	ACTIVE	MP	S	Distribution	Gas Trouble Crew			1

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 255

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q-255. Refer to the testimony of Company witness Bellar. On page 3 (lines 16-19), Mr. Bellar states that LG&E will be investing in (1) a distribution pipeline in Jefferson County, (2) upgrades to city-gate stations and gas regulation facilities, (3) upgrade of its SCADA system, (4) drilling replacement gas storage wells, and (5) compressor station equipment upgrades.

a. Identify the amounts, by account, of cost for each such project that are included in the Company's claimed revenue requirement.

b. Identify and explain where and how the costs for these projects are reflected in the Company's claimed revenue requirement.

A-255.

a. See attached. All amounts in this schedule are in account 107, construction work in progress. The total cost of removal budgeted for all of these projects was $396,000.

The St. Helen Facility (project number 141004) was originally included in the services plant account but has been corrected in the attached schedule to show as measuring & regulating station equipment – general. The Preston Highway City Gate Station (project number 144869) was originally categorized as underground storage equipment but has been corrected in the attached schedule to show as measuring & regulating station equipment – city gates.

b. As referenced on Schedule A (Tab 54 of the Filing Requirements), the costs for these projects are reflected in Schedule J-Capitalization (Tab 63 of the Filing Requirements) and Schedule C-1-Operating Income (Tab 56 of the Filing Requirements).

Amounts by Plant Account for Specified Projects

Project	Description	Plant Account	Spending Prior to July 2017	July 2017 - June 2018 Projected Spending	Total Spending as of June 2018	
(1) Distribution pipeline in Jefferson County						
152546	EAST END REINFORCEMENT	Mains	**199,746**	**3,325,531**	**3,525,276**	(a)
(2) Upgrades to city-gate station and gas regulation facilities						
138019	EMINENCE HIGH PR REG STA	Services	70,557	153,777	224,333	
140968	BELTLINE SEPARATION	Measuring & Regulating Station Equipment - General	1,371,352	295,632	1,666,983	
141004	ST HELEN FACILITY	Measuring & Regulating Station Equipment - General	1,703,208	1,259,205	2,962,412	
144869	PRESTON CITY GATE STATION	Measuring & Regulating Station Equipment - City Gates	-	338,357	338,357	(a)
149403	2016 UPGR PIP SUP CG & REG STA	Measuring & Regulating Station Equipment - City Gates	(3,423)	45,353	41,930	
149405	2017 RPL VLVS CG & DIST REG FC	Industrial Measuring & Regulating Station Equipment	25,080	72,004	97,084	
149406	2018 RPL VLVS CG & DIST REG FC	Industrial Measuring & Regulating Station Equipment	-	25,080	25,080	(a)
149411	2017 UPG CG & LRG REG STA RTU	Measuring & Regulating Station Equipment - City Gates	-	98,564	98,564	
149419	2018 UPG CT STA TRANSMITTERS	Measuring & Regulating Station Equipment - City Gates	-	29,417	29,417	
149432	UPGR MONROE CG FOR WINTER OPS	Measuring & Regulating Station Equipment - City Gates	382,467	68,400	450,867	
CCAPAC451	GAS REG CAPACITY PRO	Industrial Measuring & Regulating Station Equipment	1,392,687	581,971	1,974,658	
CCGUPG451	UPGR FACIL CG STATION 2017	Measuring & Regulating Station Equipment - City Gates	118,437	44,976	163,413	
CCOCNT451	RET/REPL CONTR CG STA 2017	Measuring & Regulating Station Equipment - City Gates	364,271	57,706	421,977	
CREGFC451	GAS REG FAC UPGRADE BLKT 2017	Measuring & Regulating Station Equipment - General	2,092,030	626,486	2,718,516	
CREGST451	UPGR FACIL DIST REG STATIONS	Industrial Measuring & Regulating Station Equipment	154,516	47,560	202,076	
	Subtotal		**7,671,180**	**3,744,487**	**11,415,668**	
(3) Upgrade its SCADA system						
149426	2017 SCADA HARDWARE RPLC	Other Equipment	207,357	1,352,810	1,560,167	
149427	2018 SCADA HARDWARE RPLC	Other Equipment	-	304,269	304,269	(a)
152481	UPRG SCADA & FT SYS DATA COMM	Other Equipment	-	29,392	29,392	
	Subtotal		**207,357**	**1,686,471**	**1,893,828**	
(4) Drilling replacement gas storage wells						
149180	DRILL OBSV WELLS MULD 2018	Gas Storage-Well Drilling	-	390,207	390,207	(a)
149181	DRILL WELLS CENTER 2017	Gas Storage-Well Drilling	537,653	82,647	620,300	
149182	DRILL WELLS CENTER 2018	Gas Storage-Well Drilling	-	413,913	413,913	(a)
149183	DRILL WELLS MAG DEEP 2018	Gas Storage-Well Drilling	-	562,957	562,957	(a)
149185	DRILL WELLS MAG UPPER 2018	Gas Storage-Well Drilling	-	422,657	422,657	(a)
	Subtotal		**537,653**	**1,872,381**	**2,410,034**	

Amounts by Plant Account for Specified Projects

Project	Description	Plant Account	Spending Prior to July 2017	July 2017 - June 2018 Projected Spending	Total Spending as of June 2018	
(5) Compressor station equipment upgrades						
144856	CATHODIC PROTECTION SYS	Gas Storage-Compressor Station Equipment	152,598	503,871	656,468	
144857	MOIST REMOVAL UNIT	Gas Storage-Compressor Station Equipment	-	4,169	4,169	(a)
149264	MULD ENG & COMP UPGR 2017	Gas Storage-Compressor Station Equipment	125,400	32,851	158,251	
149278	MULD VLV INDIC TRANSMITTERS	Gas Storage-Compressor Station Equipment	-	45,351	45,351	
149285	MULD REPL/ADD ENGINE COOLERS	Gas Storage-Compressor Station Equipment	-	57,554	57,554	
149312	COOLER HOUSING/SHROUDS	Gas Storage-Compressor Station Equipment	-	89,687	89,687	(a)
149316	MAG REPLACE MUFFLERS	Gas Storage-Compressor Station Equipment	-	46,740	46,740	(a)
152469	PURCH ATTACH CONSTR EQUIP 2017	Gas Storage-Compressor Station Equipment	15,960	3,990	19,950	
152472	REPL HEAT EXCHANGER 2017	Gas Storage-Compressor Station Equipment	39,900	201,295	241,195	
152476	YARD COOLER AERIAL FAN REPL	Gas Storage-Compressor Station Equipment	-	350,872	350,872	
152477	STATION PIPE REPL MULD	Gas Storage-Compressor Station Equipment	575,998	888,607	1,464,605	
152494	MULD ENG & COMP UPGRADE 2018	Gas Storage-Compressor Station Equipment	-	135,660	135,660	(a)
152495	MULD VALVE INDIC TRANSMITTER	Gas Storage-Compressor Station Equipment	-	48,239	48,239	
152496	MUL STATN & FLD WASTE TANKS	Gas Storage-Compressor Station Equipment	-	39,900	39,900	(a)
152497	PURCH ATTACH CONSTR EQUIP	Gas Storage-Compressor Station Equipment	-	11,400	11,400	(a)
152498	MULD HEAT TRACE IMPROVE 2018	Gas Storage-Compressor Station Equipment	-	20,324	20,324	
152499	MULD STATN PIPE 2018	Gas Storage-Compressor Station Equipment	-	535,933	535,933	(a)
152500	COMPRESSOR ENGINE EQUIP 2018	Gas Storage-Compressor Station Equipment	-	214,806	214,806	
152501	17 BP BOOSTER COMP PHASE 2	Gas Storage-Compressor Station Equipment	-	140,434	140,434	(a)
152515	PAD MOUNTED ELEC SERVICE	Gas Storage-Compressor Station Equipment	-	49,787	49,787	
CDEFEQ447	MULDR FAC IMP/EQ REPLACE	Gas Storage-Compressor Station Equipment	572,871	172,710	745,581	
CDEFEQ448	MAG FAC IMP/EQ REPL	Gas Storage-Compressor Station Equipment	481,534	139,760	621,294	
CSTATN447	MULD STATION BLKT	Gas Storage-Compressor Station Equipment	1,349,206	474,822	1,824,028	
CSTATN448	MAGNOLIA STATION BLKT	Gas Storage-Compressor Station Equipment	1,198,854	261,846	1,460,700	
			4,512,320	**4,470,607**	**8,982,927**	

(a) Total spending as of June 2018 ties to Total Project Expenditures on Schedule B-4.2, tab 55 of the Filing Requirements, pages 3-5.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 256

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q-256. Refer to the testimony of Company witness Bellar as it relates to the planned natural gas pipeline in Bullitt County. On page 4 (lines 6-9) of his testimony, Mr. Bellar states: "The Company plans to commence this project in 2017 with a targeted completion in early 2019. Preliminary cost estimates are approximately $27.6 million, of which approximately $15 million will be expended from July 1, 2017 through June 30, 2018.

a. Provide a breakout of the projected $27.6 million for the cost of this project by plant account by month. Show detailed calculations.

b. Does the Company's claimed revenue requirement include any cost for either the $27.6 million or the $15 million that LG&E projects will be expended between July 1, 2017 and June 30, 2018?

c. If the answer to part "b" is "yes", identify (by account(s) and Company schedule) where the amount (the $27.6 million or the $15 million) for the Bullitt County project is reflected in LG&E's filing.

A-256.

a. See attached. All amounts are in the gas transmission mains plant account, 367. The business plan included $27.8 million for this project, which is reflected in the attached schedule. Testimony referenced $27.6 million due to a slight revision.

b. Yes, $15.8 million of capital investment is included for the forecasted test year and thus included in the determination of revenue requirement.

c. All amounts are in account 107, construction work in progress. See Schedule B-4 and B-4.2, Tab 55 of the Filing Requirements.

Bullitt County Reinforcement Project
Projected Capital Spending by Month

Year	January	February	March	April	May	June	July	August	September	October	November	December	Total
2014	-	-	-	-	-	-	-	-	-	9,043	-	8,048	17,091
2015	5,774	18,266	90	-	3,041	-	13	18,841	13	13	13	13	46,077
2016	47	47	47	47	47	47	47	47	119,798	60,000	60,000	60,000	300,178
2017	-	-	-	50,160	51,300	51,300	104,800	137,300	540,200	1,161,500	1,209,300	1,693,500	4,999,360
2018	502,500	2,013,000	1,450,000	1,225,500	1,845,500	3,363,000	3,321,960	3,307,140	1,881,000	1,852,500	1,026,000	712,500	22,500,600
Total	**508,321**	**2,031,313**	**1,450,137**	**1,275,707**	**1,899,888**	**3,414,347**	**3,426,820**	**3,463,328**	**2,541,011**	**3,083,056**	**2,295,313**	**2,474,061**	**27,863,306**

Project Inception - June 2018 **15,762,206**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 257

Responding Witness: Lonnie E. Bellar

Q-257. Refer to the testimony of Company witness Bellar. On page 4 (lines 12-14) of his testimony, Mr. Bellar states that LG&E anticipates spending $193 million in gas distribution capital investments from July 1, 2016 through June 30, 2018 and that base rate recovery is being sought for $87 million of these investments.

a. Provide a breakout of the gas distribution capital investments, by plant account by month that LG&E anticipates will cost $193 million between July 1, 2016 and June 30, 2018. Within the requested breakout, identify the capital investments that total the $87 million that LG&E will seek recovery through base rates.

b. Explain fully and in detail how the Company determined that it would seek base rate recovery of $87 million of the $193 million of gas distribution investments.

c. Explain how the Company will seek to recover the remaining $106 million of capital investments from July 1, 2016 through June 30, 2018.

A-257.

a. See attached.

b. The capital investments for which base rate recovery is sought are prudent to ensure reliable and safe operations into the future but were not part of specific programs identified for other recovery mechanisms.

c. The Company will seek to recover the remaining $106 million of capital investments through the GLT mechanism.

LG&E Investment in Gas Facilities from July 1, 2016
through June 30, 2018

	2016					
	July	**August**	**September**	**October**	**November**	**December**
Base Rates						
Gas Dist-Industrial Measuring & Regulating Station Equipme	28,281	33,089	162,278	96,692	146,692	43,626
Gas Dist-Mains	333,158	477,798	934,255	1,016,628	855,337	607,591
Gas Dist-Measuring & Regulating Station Equipment City Ga	320,342	234,821	427,574	191,933	84,447	9,000
Gas Dist-Measuring & Regulating Station Equipment-Genera	171,044	222,939	524,094	583,323	394,574	74,742
Gas Dist-Meters	-	-	-	-	-	-
Gas Dist-Other Equipment	-	-	4,000	236,168	34,293	1,333
Gas Dist-Services	153,196	169,408	224,306	189,572	283,294	341,454
Gas General -Power Operated Equipment-Hourly	-	31,969	(4,969)	-	-	-
Gas General -Power Operated Equipment-Other	-	-	36,000	-	-	-
Gas General -Tools,Shop,Garage Equipment	4,406	106,303	22,340	102,854	37,145	6,252
Gas General -Transportation Equipment-Cars/Trucks	-	-	-	-	-	-
Gas General -Transportation Equipment-Heavy Trucks	-	-	139,573	-	-	-
Gas General -Transportation Equipment-Trailers	16,054	17,280	82,779	-	95,693	-
Gas Storage-Compressor Station Equipment	720,391	621,875	1,545,067	1,256,590	506,752	10,457
Gas Storage-Compressor Station Structures	-	54,376	1,351	-	-	-
Gas Storage-Lines	-	-	(4,031)	-	-	-
Gas Storage-Measuring & Regulat Eq	947	6,602	(7,300)	82,038	84,382	10,376
Gas Storage-Other Equip	374,286	493,306	124,403	181,034	75,199	(23)
Gas Storage-Other Structures	18,402	65,054	24,245	14,299	-	-
Gas Storage-Purification Equip	353,555	266,893	228,523	170,591	-	-
Gas Storage-Well Drilling	-	-	-	-	-	-
Gas Storage-Well Equip	294,729	431,570	397,207	255,249	31,522	-
Gas Transmission-Mains	111,901	45,124	586,691	326,460	59,966	59,966
Subtotal - Base Rates	**2,900,690**	**3,278,407**	**5,448,385**	**4,703,431**	**2,689,295**	**1,164,774**
GLT						
Gas Dist-Mains GLT	2,235,155	2,316,708	3,162,471	2,570,982	2,547,564	2,480,805
Gas Dist-Services GLT	2,685,956	3,111,268	3,254,401	3,102,390	2,563,797	2,423,307
Gas Transmission-GLT	-	-	-	-	-	-
Subtotal - GLT	**4,921,112**	**5,427,976**	**6,416,872**	**5,673,372**	**5,111,361**	**4,904,112**
Total	**7,821,801**	**8,706,383**	**11,865,258**	**10,376,802**	**7,800,656**	**6,068,886**

LG&E Investment in Gas Facilities from July 1, 2016
through June 30, 2018

	2017											
	January	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**
Base Rates												
Gas Dist-Industrial Measuring & Regulating Station Equipme	-	-	45,600	45,600	61,242	115,801	146,925	122,004	63,522	85,180	89,582	72,960
Gas Dist-Mains	489,364	533,666	630,183	827,562	964,896	1,123,104	823,912	954,894	945,543	807,837	744,811	567,519
Gas Dist-Measuring & Regulating Station Equipment City Ga	22,800	22,800	36,480	47,633	107,647	96,139	69,134	50,037	25,937	64,574	44,213	-
Gas Dist-Measuring & Regulating Station Equipment-Genera	-	11,400	77,360	84,200	143,320	145,442	314,039	165,592	180,093	68,779	56,522	13,680
Gas Dist-Meters	8,665	43,425	59,043	94,725	94,725	111,825	94,725	89,025	100,425	128,925	83,325	37,725
Gas Dist-Other Equipment	5,700	5,700	62,700	69,293	7,857	295,013	389,633	347,453	353,277	239,400	229,140	126,540
Gas Dist-Services	264,474	248,121	267,993	247,045	402,821	731,751	747,826	565,181	549,098	147,777	143,329	129,836
Gas General -Power Operated Equipment-Hourly	-	-	-	124,260	-	-	-	-	-	-	-	-
Gas General -Power Operated Equipment-Other	-	-	-	-	-	-	-	-	-	-	-	-
Gas General -Tools,Shop,Garage Equipment	-	5,700	57,000	30,780	80,370	29,640	41,040	39,900	5,700	4,560	45,600	14,820
Gas General -Transportation Equipment-Cars/Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Gas General -Transportation Equipment-Heavy Trucks	-	-	-	-	-	-	-	-	-	-	-	-
Gas General -Transportation Equipment-Trailers	-	-	-	323,760	-	-	70,000	-	-	-	-	-
Gas Storage-Compressor Station Equipment	11,898	96,518	388,973	175,644	388,944	626,698	454,743	908,827	602,533	611,193	77,358	18,738
Gas Storage-Compressor Station Structures	-	-	-	-	-	-	-	-	-	-	-	-
Gas Storage-Lines	-	-	-	-	-	-	-	-	-	-	-	-
Gas Storage-Measuring & Regulat Eq	-	-	-	-	-	-	-	-	-	-	-	-
Gas Storage-Other Equip	17	12,377	35,177	241,937	448,483	763,061	776,345	377,997	275,391	577,398	294,020	84,377
Gas Storage-Other Structures	-	-	-	-	-	-	-	-	-	-	-	-
Gas Storage-Purification Equip	35,975	10,359	30,879	28,833	22,307	56,460	154,233	409,912	410,839	223,721	76,920	13,300
Gas Storage-Well Drilling	(333)	(333)	39,853	294,929	531,769	293,789	75,193	37,787	4,227	4,227	(333)	(333)
Gas Storage-Well Equip	-	-	-	22,360	191,146	358,093	366,073	165,679	185,834	60,099	6,057	-
Gas Transmission-Mains	-	-	-	164,160	165,300	192,660	221,742	757,460	588,080	1,161,500	1,209,300	1,693,500
Subtotal - Base Rates	**838,560**	**989,732**	**1,731,241**	**2,822,721**	**3,610,826**	**4,939,475**	**4,745,563**	**4,991,748**	**4,290,498**	**4,185,169**	**3,099,843**	**2,772,662**
GLT												
Gas Dist-Mains GLT	1,115,087	1,225,914	1,391,832	1,397,046	1,373,995	1,506,466	1,593,411	1,627,410	1,452,352	1,214,649	1,058,817	987,779
Gas Dist-Services GLT	2,043,578	1,985,171	2,470,273	2,742,933	3,003,754	2,994,370	2,868,619	3,220,763	2,935,115	3,159,596	2,944,814	2,509,603
Gas Transmission-GLT	37,328	49,736	99,944	215,511	215,511	215,511	215,426	217,513	226,911	191,015	147,111	168,771
Subtotal - GLT	**3,195,993**	**3,260,821**	**3,962,049**	**4,355,490**	**4,593,261**	**4,716,346**	**4,677,457**	**5,065,686**	**4,614,378**	**4,565,260**	**4,150,743**	**3,666,153**
Total	**4,034,554**	**4,250,553**	**5,693,290**	**7,178,211**	**8,204,086**	**9,655,821**	**9,423,020**	**10,057,433**	**8,904,876**	**8,750,429**	**7,250,585**	**6,438,815**

LG&E Investment in Gas Facilities from July 1, 2016
through June 30, 2018

	2018						
	January	**February**	**March**	**April**	**May**	**June**	**Total**
Base Rates							
Gas Dist-Industrial Measuring & Regulating Station Equipme	-	-	45,600	45,600	61,270	118,127	1,629,671
Gas Dist-Mains	1,064,646	1,127,872	1,213,829	1,239,013	1,513,375	1,475,889	21,272,679
Gas Dist-Measuring & Regulating Station Equipment City Ga	-	-	-	-	41,813	59,841	1,957,164
Gas Dist-Measuring & Regulating Station Equipment-Genera	-	11,400	78,516	84,216	143,357	145,486	3,694,116
Gas Dist-Meters	74,067	100,320	110,239	108,870	120,270	120,270	1,580,596
Gas Dist-Other Equipment	5,700	5,700	64,980	120,617	116,169	232,337	2,953,004
Gas Dist-Services	159,086	135,347	148,128	141,891	155,471	139,744	6,686,145
Gas General -Power Operated Equipment-Hourly	-	-	-	-	-	-	151,260
Gas General -Power Operated Equipment-Other	-	-	-	-	-	-	36,000
Gas General -Tools,Shop,Garage Equipment	-	4,560	33,060	25,080	66,120	19,380	782,609
Gas General -Transportation Equipment-Cars/Trucks	-	-	-	25,080	-	-	25,080
Gas General -Transportation Equipment-Heavy Trucks	-	-	-	-	-	279,870	419,443
Gas General -Transportation Equipment-Trailers	-	-	-	381,900	-	-	987,466
Gas Storage-Compressor Station Equipment	29,640	285,585	61,071	209,813	507,531	699,076	10,815,915
Gas Storage-Compressor Station Structures	-	-	-	-	127,680	7,980	191,387
Gas Storage-Lines	-	-	-	-	-	-	(4,031)
Gas Storage-Measuring & Regulat Eq	-	-	-	-	-	-	177,044
Gas Storage-Other Equip	(250)	3,300	81,799	255,213	584,285	473,353	6,532,482
Gas Storage-Other Structures	-	-	-	39,900	-	-	161,900
Gas Storage-Purification Equip	28,500	28,500	-	116,084	-	142,500	2,808,886
Gas Storage-Well Drilling	(833)	(833)	166,767	393,276	649,028	582,330	3,070,173
Gas Storage-Well Equip	-	-	-	-	-	22,409	2,788,027
Gas Transmission-Mains	502,500	2,013,000	1,450,000	1,225,500	1,845,500	3,425,700	17,806,009
Subtotal - Base Rates	**1,863,056**	**3,714,751**	**3,453,987**	**4,412,054**	**5,931,867**	**7,944,291**	**86,523,025**
GLT							
Gas Dist-Mains GLT	900,745	1,049,134	1,687,889	1,672,875	1,685,595	1,783,823	40,038,505
Gas Dist-Services GLT	815,351	694,232	759,884	738,501	823,994	756,161	54,607,830
Gas Transmission-GLT	1,385,463	1,403,958	1,659,137	1,670,539	1,738,279	1,768,546	11,626,209
Subtotal - GLT	**3,101,559**	**3,147,324**	**4,106,910**	**4,081,914**	**4,247,867**	**4,308,529**	**106,272,543**
Total	**4,964,615**	**6,862,076**	**7,560,898**	**8,493,968**	**10,179,734**	**12,252,820**	**192,795,568**

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 258

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q-258. Refer to the testimony of Company witness Bellar at page 4 through the top of page 7 in which Mr. Bellar discusses several gas-specific initiatives which he states are designed to improve efficiency and productivity.

a. For each of the gas-specific initiatives discussed on the referenced pages (including the Asset and Resource Management software system), does the Company anticipate that such initiative will generate costs savings?

b. If the answer to part "a" is "yes", for each gas-specific initiative, identify, quantify and explain the estimated cost savings that LG&E anticipates will be generated. Show detailed calculations.

c. If the answer to part "a" is "yes", state whether such cost savings are reflected in the Company's filing. If so, identify by account and Company schedule where such savings are reflected. If not, explain fully why not.

d. Identify the costs by account of each gas-specific initiative and identify where such costs are reflected in the Company's application.

A-258.

a. Costs savings for these examples are not individually tracked. If net resource savings result those resources are generally deployed to manage ever evolving work such as new regulatory requirements or the next highest priority reliability or safety issue as examples.

b. Not applicable.

c. Not applicable.

d. See attached. The electronic pressure recording devices, FIM replacement, and engine analyzer projects have spending in the forecasted test period. For capital costs in the forecasted test period, see Schedule B-1, Tab 55 of the Filing Requirements. Operating expenses are reflected in Schedule C-2, Tab 56 of the Filing Requirements.

Gas Initiatives

Initiative	Project	Description	Plant Account	Prior to July 2017	July 2017 - June 2018		As of June 2018
Gas Inspection Tracking and Traceability	111LGE16	Gas Tracking and Traceability-LGE16	Common -Misc Intang Plant Software	299,999	-		299,999
Gas Training Tracking (1)			Not applicable - operating expenses	-	-		-
Electronic Pressure Recording Devices (2)	149407	2016 PURCH ELEC RECORD GAUGE	Gas Dist-Meas & Reg Station-Gen	174,887	-		174,887
	149408	2017 PURCH ELEC RECORD GAUGES	Gas Dist-Meas & Reg Station-Gen	-	165,948		165,948
			Not applicable - operating expense		16,393	(4)	16,393
				174,887	182,341		357,228
Gas Stand Alone Data Entry (SADE) Mobile Application	091LGE14	Gas Facility Inspection-LGE14	Common -Misc Intang Plant Software	173,615	-		173,615
	146926	UPGR MAG ANALYZER MA TO PA	Gas Storage-Purification Equip	47,020	-		47,020
Advanced Engine/Compressor Analyzer Technology	CDEFEQ447	Replace Defective Equipment	Gas Storage-Compressor Station Eq	61,001	-		61,001
			Not applicable - operating expense		7,500	(4)	7,500
				108,021	7,500		115,521
Web-based Technology for Gas Transportation Customers	080LGE16	Gas Nomination System-LGE16	Common -Misc Intang Plant Software	285,000	-		285,000
FIM Replacement (3)	158LGE15	FIM Replacement-SER15	Common -Misc Intang Plant Software	1,401,573	-		1,401,573
	158KU15	FIM Replacement-SER15	Intangible-Misc Intangible Plant	1,783,794	-		1,783,794
			Not applicable - operating expense		103,000	(4)	103,000
				3,185,367	103,000		3,288,367

(1) Work on the Gas Training Tracking initiative was completed before the test period. The actual cost was $10,455.
(2) The cost of removal for Electronic Pressure Recording Devices is $8,650.
(3) The FIM replacement supports multiple areas. The costs above represent total project cost, which are allocated between LG&E and KU and between electric and gas for LG&E.
(4) This amount represents annual maintenance applicable to the forecasted test period.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 259

Responding Witness: Lonnie E. Bellar

Q-259. Refer to the testimony of Company witness Bellar. On page 7 (lines 17-19) of his testimony, Mr. Bellar states that at the end of June 2016, LG&E was projected to have 259 full-time employees and that LG&E expects to have 281 employees (an increase of 22) at June 30, 2018.

a. State the actual level of full-time employees as of each of the following dates: (1) December 31, 2015; (2) June 30, 2016, and (3) December 31, 2016.

b. Provide a list of the specific 22 positions that LG&E anticipates adding by June 30, 2018, and identify the annual salary and assumed date of hire for each position.

c. Does the Company's requested revenue requirement reflect the addition of the 22 positions? If so, for each of the 22 positions, quantify the amount of salary and employee benefits that are reflected in the Company's filing.

d. Has the Company filled any of the 22 positions as of December 31, 2016? If so, identify the specific positions that have been filled.

A-259. a.

	Full-Time Employees
12/31/2015	256
6/30/2016	264
12/31/2016	275

b.-d. See attached. In reference to part c, the positions listed may be in support of both O&M and capital functions. Certain information requested is confidential and is being provided under seal pursuant to a petition for confidential protection.

LG&E and KU Energy LLC
Gas Distribution Operations
Headcount between 6/30/16 - 6/30/18 b and d

Confidential Information Redacted

Position Title	Anticipated Hire Date	Annual Rate	Hired by December 31, 2016	Amount Reflected in the Company's Filing
Gas Trouble Tech	Mar-16	[redacted]	Yes	[redacted]
Gas Trouble Tech	Mar-16	[redacted]	Yes	[redacted]
Gas Controller	Oct-17	[redacted]	No	[redacted]
Gas Controller	Jul-17	[redacted]	No	[redacted]
Gas Controller	Jul-17	[redacted]	No	[redacted]
Welder/Fitter	Jan-17	[redacted]	No	[redacted]
Trouble Technician	Jan-18	[redacted]	No	[redacted]
IM&E Technician	Mar-17	[redacted]	No	[redacted]
Corrosion Technician	Mar-18	[redacted]	No	[redacted]
Corrosion Technician	Mar-17	[redacted]	No	[redacted]
Distribution Mechanic	Aug-17	[redacted]	No	[redacted]
Distribution Mechanic	Apr-18	[redacted]	No	[redacted]
Distribution Mechanic	Apr-18	[redacted]	No	[redacted]
Distribution Mechanic	Apr-17	[redacted]	No	[redacted]
CRM SOS Specialist	Dec-17	[redacted]	No	[redacted]
Integrity Management	Sep-17	[redacted]	No	[redacted]
Integrity Management	Sep-17	[redacted]	No	[redacted]
Manager, Gas Service	Mar-17	[redacted]	No	[redacted]
Engineer	Jun-17	[redacted]	No	[redacted]
Engineer	Jun-17	[redacted]	No	[redacted]
IM&E Technician	Mar-18	[redacted]	No	[redacted]
Team Leader - Gas Distribution	Jun-17	[redacted]	No	[redacted]

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 260

Responding Witness: Lonnie E. Bellar

Q-260. Refer to the testimony of Company witness Bellar. On page 8 (lines 6-21) of his testimony, Mr. Bellar states that new pipeline safety regulations are expected to drive LG&E's staffing requirements and other costs. What is the current status of each of the pending and/or proposed areas of regulation that are listed on page 8 (lines 12-21) of Mr. Bellar's testimony.

A-260.

- Safety of Gas Transmission & Gathering Lines – Notice of Proposed Rulemaking issued. PHMSA estimates final rule will be published 12/11/2017.
- Plastic Pipe - Notice of Proposed Rulemaking issued. PHMSA estimates final rule will be published in first quarter 2017.
- Operator Qualification, Cost Recovery, Accident & Incident Notification, and Other Pipeline Safety Changes - Notice of Proposed Rulemaking issued. PHMSA estimates final rule will be published in first quarter 2017.
- Excess Flow Valves Beyond Single Family Homes – Final rule issued
- Underground Storage – Interim final rule issued
- Valve Installation & Rupture Detection - PHMSA estimates notice of proposed rulemaking will be published 5/3/2017.
- State Pipeline Safety Program Certification – Waiting on PHMSA action.
- National Pipeline Mapping System expansion – Final information collection request published.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 261

Responding Witness: Lonnie E. Bellar

Q-261. Refer to the testimony of Company witness Bellar at page 9 (lines 4-14). Mr. Bellar states that many of the Company's long tenured employees will retire before 2020 and that the Company plans to retain these employees' knowledge by hiring new employees prior to their departure.

a. Provide a list of the positions in each year 2015 and 2016 that experienced retirements, and for each retirement identify the length of service of the employee who held the position prior to retirement.

b. Quantify how many employees LG&E expects to retire in each year, 2017 through 2019 (i.e., in each year before 2020). Also identify the length of service of each employee that LG&E anticipates would retire in each year.

c. How many employees LG&E expects to retire from January 1, 2017 to June 30, 2018? Identify the length of service of each employee that LG&E anticipates would retire in that period.

d. For each position that LG&E anticipates would experience a retirement during the period January 1, 2017 to June 30, 2018, identify the annual salary of the current position-holder and the anticipated annual salary of the replacement employee.

e. Does LG&E anticipate that all positions that become vacated or which experience retirements during the period January 1, 2017 to June 30, 2018 will have to be filled upon the retirement of the existing employees? If not, explain fully why not. If so, what differences does LG&E anticipate between (1) the annual salary of the retiring/terminating employee and (2) the annual salary of the new/replacement employee?

A-261.

a. Retirements for 2015 are as follows:

Position Title	Yrs of Service
Gas Trouble Technician A	33
Sr Storage Operator	38
Gas Controller	30
Gas Trouble Technician A	36

Retirements for 2016 are as follows:

Position Title	Yrs of Service
Sys Regulation & Optns Tech A	38
Gas Trouble Technician A	31
Sys Regulation & Optns Tech A	30
Field/Trans&Dist Crew Ldr- Mag	30
Distribution Mechanic A	36

b. Estimated retirements were determined based on employees indicating a potential retirement date and those employees turning age 62 during the time periods specified. See attached.

c-e. Estimated retirements were determined based on employees indicating a potential retirement date and those employees turning age 62 during the time periods specified. Yes, LG&E anticipates all positions which experience retirements during the period January 1, 2017 to June 30, 2018 will have to be filled upon the retirement of the existing employees. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Job Title	Employees Expected to Retire in 2017 - Years of Service
Sr Storage Operator	41
Sr Storage Operator	39
Gas Controller	39
Sys Regulation & Optns Tech A	32
Pipeline Inspector	37
Team Ldr - Gas Distribution	37
Field/Trans&Dist Crew Ldr- Mag	41
Gas Trouble Technician A	40
Sr Storage Operator	41
Pipeline Inspector	32
Gas Trouble Technician A	39
System Operations Specialist	35
Sr Gas Operations Dispatcher	42
Pipeline Inspector	38
Field/Trans&Dist Crew Ldr- Mag	35
Welder/Fitter-Field/Trans&Dist	39
Sr Ime Tech	41
Team Ldr - Gas Distribution	40
Pipeline Inspector	38
Distribution Crew Leader	41
Distribution Crew Leader-Muld	39
Records Coord A - Magnolia	32
Sr Geologist	23
Pipeline Inspector	47
Gas Regulatory Associate III	16
Corrosion Tech A	38

Job Title	Employees Expected to Retire in 2018 - Years of Service
Distribution Mechanic A	42
Sr Storage Maint Mech Operator	41
Gas Trouble Technician A	43
Sr Storage Operator	42
Team Ldr - Gas Distribution	41
Storage Operator A	32
Sr Storage Operator	40
Records Coord A - Muldraugh	38
Corrosion Tech A	40
Sr Corrosion Technician 1	41

Job Title	Employees Expected to Retire in 2019 - Years of Service
Gas Controller	43
Distribution Mechanic A Mul	38
Welder/Fitter-Field/Trans&Dist	43
Distribution Mechanic A Mul	42
Distribution Crew Leader-Muld	42
Sys Regulation & Optns Tech A	38
Grp Ldr - Integrity Management	9
Distribution Crew Leader	43
Distribution Crew Leader-Muld	40
Dir Gas Mgmt Plang & Supply	38
Gas Supply Specialist III	39
Distribution Crew Leader	35
Pipeline Inspector	38
Pipeline Inspector	38
Gas Trouble Technician A	39
Gas Controller	21

Confidential Information Redacted

Job Title	Years of Experience	Current Salary	Replacement Salary
Sr Storage Operator	41	[redacted]	
Sr Storage Operator	39		
Gas Controller	39		
Sys Regulation & Optns Tech A	32		
Pipeline Inspector	37		
Team Ldr - Gas Distribution	37		
Field/Trans&Dist Crew Ldr- Mag	41		
Gas Trouble Technician A	40		
Sr Storage Operator	41		
Pipeline Inspector	32		
Gas Trouble Technician A	39		
System Operations Specialist	35		
Sr Gas Operations Dispatcher	42		
Pipeline Inspector	38		
Field/Trans&Dist Crew Ldr- Mag	35		
Welder/Fitter-Field/Trans&Dist	39		
Sr Ime Tech	41		
Team Ldr - Gas Distribution	40		
Pipeline Inspector	38		
Distribution Crew Leader	41		
Distribution Crew Leader-Muld	39		
Records Coord A - Magnolia	32		
Sr Geologist	23		
Pipeline Inspector	47		
Gas Regulatory Associate III	16		
Distribution Mechanic A	42		
Sr Storage Maint Mech Operator	41		
Sr Storage Operator	42		
Sr Storage Operator	40		
Records Coord A - Muldraugh	38		
Sr Corrosion Technician 1	41		
Distribution Mechanic A Mul	35		
Distribution Mechanic A Mul	39		
Distribution Crew Leader	41		
Storage Operator A	31		
Corrosion Tech A	39		

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

**Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017**

Question No. 262

Responding Witness: Lonnie E. Bellar / Christopher M. Garrett

Q-262. Refer to the testimony of Company witness Bellar at pages 11 and 12 as it relates to the DIMP, which was required by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. Pursuant to that program, Mr. Bellar states that the Company will complete the replacement of all known Aldyl-A early vintage plastic pipe by the end of 2017.

a. Quantify the level of costs that LG&E projects spending pursuant to the replacement of the Aldyl-A plastic pipe by the end of 2017.

b. How much Aldyl-A plastic pipe did LG&E have in its system as of December 31, 2016? Identify the cost and the miles of Aldyl-A pipe.

c. How is the Company's accounting for the costs associated with the replacement of the Aldyl-A plastic pipe?

d. Is any cost for Aldyl-A pipe replacement included in the Company's requested revenue requirement?

e. If the answer to part d is "yes," identify by amount, account and Company schedule where such costs are reflected in LG&E's filing.

A-262.

a. The Aldyl-A investment included in the GLT mechanism is projected to be $5.1 million with $0.2 million in associated cost of removal through 2017. Some of the Aldyl-A piping is being replaced in connection with another project that is requested for recovery in base rates. This project was planned before Aldyl-A was included in GLT. The total investment for this project is projected to be $0.6 million.

b. As of December 31, 2016, LG&E had 10.0 miles of pipe in its system. The cost of this pipe is not available given the age of the pipe and lack of property records as gas pipelines are unitized as mass property. We are tracking the replacement costs in separate property records. See the response to Question No. 263(c).

c. The Company is capitalizing Aldyl-A pipe replacement. The cost associated with removing the existing Aldyl-A pipe or abandoning it in place is recorded as removal. The cost of installing new pipe is recorded as investment.

(d).(e).See the response to Question No. 249(b).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 263

Responding Witness: Christopher M. Garrett

Q-263. Gas Line Tracker Mechanism (GLT). Refer to the testimony of Company witness Bellar. On page 12 (lines 17-18) of his testimony, Mr. Bellar states that the GLT mechanism allows the Company to recover the costs for GLT related plant in service that is not included in gas base rates.

a. In its application for new base rates, has the Company included any costs for GLT related plant in service?

b. If the answer to part a is "yes," identify the amount of cost for GLT related plant in service that the Company has is included in requested gas base rate revenue requirement.

c. Does the Company use separate sub-accounts for GLT related plant to assure that there is no double recovery between base rates and the GLT mechanism? If not, explain fully why not, and identify how the Company assures that GLT plant costs are not included in both the GLT mechanism and in base rates. If so, identify the sub-accounts used.

A-263. a-b. See the response to Question No. 249(b).

c. Yes, the Company uses separate projects, tasks, and plant accounts in its PowerPlan Budgeting and Fixed Asset system to track GLT projects by specific program. As discussed in the testimony of Mr. Garrett, Column 10 of Supporting Schedule B-1.1 for gas operations removes GLT rate base from the Company's gas rate base, and Column E of page 2 of Schedule J-1.1/1.2 for gas operations removes GLT rate base and other mechanism-related rate base from the Company's gas capitalization to prevent any form of double recovery.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 264

Responding Witness: Daniel K. Arbough / Counsel

Q-264. Provide copies of all presentations made to rating agencies and/or investment firms by PPL, and/or Louisville Gas & Electric between January 1, 2015 and the present.

A-264. See the Company's objection filed on January 20, 2017.Without waiver of this objection, see attached. The rating agencies presentations are confidential and proprietary, and are being provided under seal pursuant to a petition for confidential treatment.

The PPL presentation to investment firms can be found at the following link and selecting the desired year.
http://pplweb.investorroom.com/events#past:2017:1

The entire attachment is Confidential and provided separately under seal.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 265

Responding Witness: Daniel K. Arbough

Q-265. Provide copies of all prospectuses for any security issuances by PPL and/or Louisville Gas & Electric between January 1, 2013 and the present.

A-265. Attachments 1-2 are for tax exempt securities issued by LG&E since January 1, 2013. First Mortgage Bonds issued by LG&E and the securities issued by or guaranteed by PPL Corporation can be found by using the links below:

LG&E – November 2013
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=9213730&type=HTML&symbol=0000060549&companyName=LOUISVILLE+GAS+%26+ELECTRIC+CO+%2FKY%2F&formType=424B2&dateFiled=2013-11-07

LG&E – September 2015
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=10494082&type=HTML&symbol=0000060549&companyName=LOUISVILLE+GAS+%26+ELECTRIC+CO+%2FKY%2F&formType=424B2&dateFiled=2015-09-22&cik=0000060549

PPL – March 2013
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=8795891&type=HTML&symbol=PPL&companyName=PPL+Corp.&formType=424B2&dateFiled=2013-03-13

PPL – May 2013
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=8945738&type=HTML&symbol=PPL&companyName=PPL+Corp.&formType=424B2&dateFiled=2013-05-22

PPL – March 2014
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=9449453&type=HTML&symbol=PPL&companyName=PPL+Corp.&formType=424B2&dateFiled=2014-03-06

PPL – February 2015
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=10103763&type=HTML&symbol=PPL&companyName=PPL+Corp.&formType=424B5&dateFiled=2015-02-26&cik=0000922224

PPL – May 2016
http://app.quotemedia.com/data/downloadFiling?webmasterId=101533&ref=10939516&type=HTML&symbol=PPL&companyName=PPL+Corp&formType=424B2&dateFiled=2016-05-13&cik=0000922224

NOT NEW ISSUES **BOOK-ENTRY-ONLY**

On March 22, 2002, the date on which the Bonds were originally issued, Bond Counsel delivered its opinion that stated that, subject to the conditions and exceptions set forth under the caption ''Tax Treatment,'' under then current law, interest on each series of Bonds would be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion was expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a ''substantial user'' of the related Project or a ''related person'' of a substantial user as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the ''Code''). Interest on each series of Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals or corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel was further of the opinion that interest on each series of Bonds would be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under then current law, principal of the Bonds would be exempt from ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel. However, in connection with the conversion of the interest rate mode on each series of Bonds to the Long Term Rate Period, as more fully described in this Reoffering Circular, Bond Counsel will deliver its opinions to the effect that the conversion of the interest rate on each series of Bonds (a) is authorized or permitted by the Act and the related Indenture and (b) will not adversely affect the validity of the Bonds or any exclusion of the interest thereon from the gross income of the owners of the Bonds for federal income tax purposes. See the information under the caption ''Tax Treatment'' in this Reoffering Circular.

$35,000,000
Louisville/Jefferson County Metro Government, Kentucky
Pollution Control Revenue Bonds,
2001 Series B,
(Louisville Gas and Electric Company Project)
Due: November 1, 2027
Mandatory Purchase Date: May 1, 2018
Interest Payment Dates: May 1 and November 1
Interest Rate: 1.35%

$35,000,000
County of Trimble, Kentucky
Pollution Control Revenue Bonds,
2001 Series B,
(Louisville Gas and Electric Company Project)
Due: November 1, 2027
Mandatory Purchase Date: May 1, 2018
Interest Payment Dates: May 1 and November 1
Interest Rate: 1.35%

Conversion Date: December 15, 2014

The Bonds of each issue (individually, the ''Jefferson County Bonds'' and the ''Trimble County Bonds'' and, collectively, the ''Bonds'') are special and limited obligations of the Louisville/Jefferson County Metro Government, Kentucky (as successor in interest to the County of Jefferson) and Trimble County, Kentucky (the ''Issuers''), payable by the respective Issuers solely from and secured by payments to be received by the Issuers pursuant to separate Loan Agreements with Louisville Gas and Electric Company (the ''Company''), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds do not constitute general obligations of the Issuers or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky.

Principal of, and interest on, the Bonds are further secured by the delivery to U.S. Bank National Association, as Trustee, of First Mortgage Bonds of

LOUISVILLE GAS AND ELECTRIC COMPANY

The Bonds of each issue were originally issued on March 22, 2002 and each series currently bears interest at Flexible Rates. Pursuant to the Indentures under which the Bonds were issued, the Company has elected to convert the interest rate mode on each series of Bonds to a Long Term Rate Period, effective as of December 15, 2014 (the ''Conversion Date''). The Bonds are subject to mandatory purchase on the Conversion Date and are being reoffered hereby. Morgan Stanley & Co. LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated will serve as Initial Co-Remarketing Agents for purposes of this conversion and reoffering of the Bonds. Following this conversion and reoffering, Morgan Stanley & Co. LLC will serve as the sole Remarketing Agent for the Bonds.

The Bonds of each issue are separate series, and the sale and delivery of one series is not dependent on the sale and delivery of the other series. The Bonds will accrue interest from the Conversion Date, payable on the interest payment dates listed above. The interest rate period, interest rate and Interest Rate Mode for the Bonds will be subject to change under certain conditions, in whole or in part, as described in this Reoffering Circular. Prior to May 1, 2018, the Bonds will not be subject to optional redemption, but will be subject to extraordinary redemption and mandatory redemption following any determination of taxability prior to maturity as described under the caption ''Summary of the Bonds — Redemptions.'' The Bonds will be subject to mandatory purchase at the end of each Long Term Rate Period.

The Bonds are registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company (''DTC''), New York, New York. DTC will act as securities depository. Except as described in this Reoffering Circular, purchases of beneficial ownership interests in the Bonds will be made in book-entry only form in denominations of $5,000 and integral multiples thereof. Purchasers will not receive certificates representing their beneficial interest in the Bonds. See the information contained under the caption ''Summary of the Bonds — Book-Entry-Only System'' herein. The principal of, premium, if any, and interest on the Bonds will be paid by U.S. Bank National Association, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC Participants and Indirect Participants, as more fully described herein.

PRICE: 100%

The Bonds are reoffered subject to prior sale, withdrawal or modification of the offer without notice (provided, however, that any such notice of withdrawal must be given on the Business Day prior to the Conversion Date) and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois, and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company, and for the Remarketing Agents by their counsel, McGuireWoods LLP, Chicago, Illinois. It is expected that the Bonds will be available for redelivery to DTC in New York, New York on or about December 15, 2014.

Morgan Stanley **BofA Merrill Lynch**

November 24, 2014

No dealer, broker, salesman or other person has been authorized by the Issuers or either of them, the Company or the Remarketing Agents to give any information or to make any representation with respect to the Bonds, other than those contained in this Reoffering Circular, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Remarketing Agents have provided the following sentence for inclusion in this Reoffering Circular. The Remarketing Agents have reviewed the information in this Reoffering Circular in accordance with, and as part of, their responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Remarketing Agents do not guarantee the accuracy or completeness of such information. The information and expressions of opinion herein are subject to change without notice and neither the delivery of this Reoffering Circular nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof. The information set forth herein with respect to the Issuers has been obtained from the respective Issuer, and all other information has been obtained from the Company and from other sources which are believed to be reliable, but it is not guaranteed as to accuracy or completeness by, and is not to be construed as a representation by, the Remarketing Agents.

In connection with the reoffering of the Bonds, the Remarketing Agents may over-allot or effect transactions which stabilize or maintain the market prices of the Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE REOFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

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$35,000,000	**$35,000,000**
Louisville/Jefferson County Metro Government, Kentucky	**County of Trimble, Kentucky**
Pollution Control Revenue Bonds, 2001 Series B	**Pollution Control Revenue Bonds, 2001 Series B**
(Louisville Gas and Electric Company Project)	**(Louisville Gas and Electric Company Project)**

INTRODUCTORY STATEMENT

This Reoffering Circular, including the cover page and Appendices, is provided to furnish information in connection with the reoffering of (i) the Louisville/Jefferson County Metro Government, Kentucky ("Jefferson County") Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), in the aggregate principal amount of $35,000,000 (the "Jefferson County Bonds") issued pursuant to an Indenture of Trust dated as of November 1, 2001, and as amended by Supplemental Indenture No. 1 dated as of September 1, 2010 (collectively, the "Jefferson County Indenture") between Louisville/Jefferson County Metro Government, as successor in interest to the County of Jefferson, and U.S. Bank National Association, as successor trustee (the "Jefferson County Trustee"), and (ii) the County of Trimble, Kentucky ("Trimble County") Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), in the aggregate principal amount of $35,000,000 (the "Trimble County Bonds") issued pursuant to an Indenture of Trust dated as of November 1, 2001 and as amended by Supplemental Indenture No. 1 dated as of September 1, 2010 (collectively, the "Trimble County Indenture") between Trimble County and U.S. Bank National Association, as successor trustee (the "Trimble County Trustee").

Pursuant to separate Loan Agreements by and between Louisville Gas and Electric Company (the "Company") and each of the Issuers, dated as of November 1, 2001, and as amended by Amendment No. 1 dated as of September 1, 2010 (each a "Loan Agreement" and, collectively, the "Loan Agreements"), proceeds from the sale of the Jefferson County Bonds and the Trimble County Bonds were loaned by the applicable Issuer to the Company. The Loan Agreements are separate undertakings by and between the Company and the applicable Issuer.

The proceeds of the Jefferson County Bonds were applied to pay and discharge $35,000,000 in outstanding principal amount of "County of Jefferson, Kentucky, Pollution Control Revenue Bonds, 1997 Series A (Louisville Gas and Electric Company Project)," dated November 13, 1997 (the "1997 Jefferson Bonds") on the date of issuance of the Jefferson County Bonds. The proceeds of the Trimble County Bonds were applied to pay and discharge $35,000,000 in outstanding principal amount of "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 1997 Series A (Louisville Gas and Electric Company Project)," dated November 13, 1997 (the "1997 Trimble Bonds"), on the date of issuance of the Trimble County Bonds. The 1997 Jefferson Bonds and the 1997 Trimble Bonds were issued to refinance the cost of construction of, respectively, the Jefferson County Project and the Trimble County Project (each as described herein).

The Company will continue to repay each loan under the applicable Loan Agreement by making payments to the applicable Trustee in sufficient amount to pay the principal of and interest and any premium on, and purchase price of, the applicable series of Bonds. See "Summary of the Loan Agreement—General." Pursuant to the applicable Indenture, an Issuer's rights under the applicable Loan Agreement (other than with respect to certain indemnification and expense payments) were assigned to the applicable Trustee as security for the applicable series of Bonds.

For the purpose of further securing the Bonds, the Company has issued and delivered to each of the Trustees a separate tranche of the Company's First Mortgage Bonds, Collateral Series 2010 (the "First Mortgage Bonds"). The principal amount, maturity date and interest rate (or method of determining interest rates) of each such tranche of First Mortgage Bonds is identical to the principal amount, maturity date and interest rate (or method of determining interest rates) of the related series of Bonds. The First Mortgage Bonds will only be payable, and interest thereon will only accrue, as described herein. See "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds." The First Mortgage Bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture.

The First Mortgage Bonds have been issued under, and are secured by, an Indenture, dated as of October 1, 2010, as supplemented by a supplemental indenture dated as of October 15, 2010 relating to the Bonds (the "Supplemental Indenture"), (the Indenture, as so supplemented, the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee").

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of PPL Corporation or the Company's other affiliates will be obligated to make any payments due under the Loan Agreement or First Mortgage Bonds or any other payments of principal, interest, premium or purchase price of the Bonds.

The Bonds are being converted to bear interest at the Long Term Rate during a Long Term Rate Period to the respective dates appearing on the cover of this Reoffering Circular, but may be subsequently converted again on the Mandatory Purchase Date of May 1, 2018 for the Jefferson County Bonds and May 1, 2018 for the Trimble County Bonds. This Reoffering Circular pertains only to the Bonds during such period of time that they bear interest at the Long Term Rate established on the Conversion Date of December 15, 2014.

The Bonds are special and limited obligations of the respective Issuer and the respective Issuer's obligation to pay the principal of and interest and any premium on, and purchase price of, its respective series of Bonds is limited solely to the revenues and other amounts received by the Trustee under the applicable Indenture pursuant to the applicable Loan Agreement and amounts payable under the applicable First Mortgage Bonds. The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the respective Issuer, the Commonwealth of Kentucky or any political subdivision thereof.

Morgan Stanley & Co. LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated (each, a "Remarketing Agent" and collectively, the "Remarketing Agents") will be appointed under the Indenture to serve as Initial Co-Remarketing Agents for purposes of this conversion and reoffering of the Bonds. Following this conversion and reoffering, Morgan Stanley & Co.

LLC will serve as the sole Remarketing Agent for the Bonds. Any Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between such Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuers, the Bonds, the Loan Agreements, the Indentures and the First Mortgage Bonds (including the First Mortgage Indenture) are included in this Reoffering Circular. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of accuracy or completeness. All references herein to the documents are qualified in their entirety by reference to such documents, and references herein to a series of Bonds are qualified in their entirety by reference to the definitive form thereof included in the applicable Indenture. Copies of the Loan Agreements and the Indentures will be available for inspection at the principal corporate trust office of the Trustee. The First Mortgage Indenture (including the forms of the First Mortgage Bonds) is available for inspection at the office of the Company in Louisville, Kentucky, and at the corporate trust office of the First Mortgage Trustee, in New York, New York. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. Appendix A to this Reoffering Circular and all information contained under the heading The Projects" has been furnished by the Company. The Issuers and Bond Counsel assume no responsibility for the accuracy or completeness of such Appendix A or such information. Appendix B to this Reoffering Circular contains the opinions of Bond Counsel delivered in connection with the initial issuance and delivery of the Bonds and the proposed forms of opinion of Bond Counsel to be delivered in connection with the conversion of the interest rate mode on the Bonds.

THE ISSUERS

Each Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. Each Issuer is authorized by Section 103.200 to 103.285, inclusive, and, with respect to Jefferson County, Chapter 67C, of the Kentucky Revised Statutes (collectively, the "Act") to (i) convert and reoffer the respective series of Bonds and (ii) continue to perform its obligations under the Loan Agreements and the Indentures. The Issuers, through their respective legislative bodies, the Metro Government Legislative Council or Fiscal Court, have adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS OF EACH ISSUE ARE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY OR ON BEHALF OF THE APPLICABLE ISSUER UNDER THE APPLICABLE LOAN AGREEMENT AND OTHER AMOUNTS RECEIVED FROM PAYMENTS MADE UNDER THE APPLICABLE FIRST MORTGAGE BONDS. THE BONDS OF EACH ISSUE WILL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE RESPECTIVE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE RESPECTIVE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

THE PROJECTS

Jefferson County Project

The Jefferson County Project has been completed and consists of certain air pollution control facilities completed in connection with the Mill Creek and Cane Run Stations of the Company situated in Jefferson County, Kentucky. Major components of the Jefferson County Project include the acquisition, construction, installation and equipping of major reconstructions, and modifications for the sulphur dioxide removal systems serving seven generating units at the two generating stations.

The Department for Natural Resources and Environmental Protection of the Commonwealth of Kentucky and the Air Pollution Control District of Jefferson County, Kentucky, the agencies exercising jurisdiction with respect to the Jefferson County Project, have previously certified that the Jefferson County Project, as designed, was in furtherance of the purposes of controlling atmospheric pollutants or contaminants.

As previously announced, in 2015 the Company intends to retire certain units at the Cane Run Station, including units that include components that are part of the Jefferson County Project.

Trimble County Project

The Trimble County Project has been completed and consists of certain air and water pollution control and solid waste disposal facilities in connection with Unit 1 of the Trimble County Station situated in Trimble County, Kentucky. Major components of the Project include electrostatic precipitators to capture flyash and particulate emissions from the Unit 1 steam-boilers; sulphur dioxide removal systems (scrubbers) to remove sulphur dioxide from flue gases; water pollution control and solid waste disposal facilities, including retention basins, sludge and ash ponds for the receipt of sludge wastes produced by sulphur dioxide removal facilities and by electrostatic precipitators as well as bottom ash; both exterior and interior systems for the collection and transmission to treatment and neutralization facilities of polluted liquids, including coal pile liquid runoffs and fuel oil and other chemical spills; a natural draft cooling tower for the abatement of thermal pollution to the interstate stream (Ohio River); and facilities for the reception, transportation, preparation and holding of reactant chemicals and materials used in sulphur dioxide removal systems, which facilities are functionally related and subordinate to such sulphur dioxide removal systems.

The Department for Natural Resources and Environmental Protection of the Commonwealth of Kentucky, the agency exercising jurisdiction with respect to the Trimble County Project, has previously certified that the Trimble County Project, as designed, was in furtherance of the purposes of controlling atmospheric pollutants or contaminants and water pollution.

SEPARATE SERIES

The Jefferson County Bonds and the Trimble County Bonds will be paid from payments made by or on behalf of the Company, will have substantially the same claim to such source of funds and are treated for federal income tax purposes as a single issue of obligations. However, the Jefferson County Bonds and the Trimble County Bonds are separate series and optional or mandatory redemption of either the Jefferson County Bonds or the Trimble County Bonds may be made in the manner described below without the redemption of the other series. Similarly, a default under one of the series of Bonds or Loan Agreements will not necessarily constitute a default under the other series of Bonds or Loan Agreement. Each series of Bonds can bear interest at an Interest Rate Mode different from the Interest Rate Mode borne by the other series of Bonds. Each series of Bonds is separately secured by a separate tranche of First Mortgage Bonds. Unless specifically otherwise noted, the following discussion under the captions "Summary of the Bonds," "Summary of the Loan Agreement," "Summary of the Indenture," "Summary of the First Mortgage Bonds," "Enforceability of Remedies," "Tax Treatment" and "Continuing Disclosure" applies equally, but separately, to the Jefferson County Bonds and the Trimble County Bonds.

As used under such captions with respect to the Jefferson County Bonds, the term "Issuer" shall mean Jefferson County, the term "Project" shall mean the Jefferson County Project, the term "Generating Station" shall mean the Mill Creek Station or the Cane Run Station, the term "Bonds" shall mean the Jefferson County Bonds, the term "First Mortgage Bonds" shall mean the related tranche of First Mortgage Bonds, the term "1997 Bonds" shall mean the 1997 Jefferson Bonds, the term "Loan Agreement" shall mean the Loan Agreement pursuant to which Jefferson County loaned the proceeds from the sale of the Jefferson County Bonds to the Company, the term "Indenture" shall mean the Jefferson County Indenture, and the term "Trustee" shall mean the Jefferson County Trustee.

As used under such captions with respect to the Trimble County Bonds, the term "County" shall mean Trimble County, the term "Project" shall mean the Trimble County Project, the term "Generating Station" shall mean the Trimble County Station, the term "Bonds" shall mean the Trimble County Bonds, the term "First Mortgage Bonds" shall mean the related tranche of First Mortgage Bonds, the term "1997 Bonds" shall mean the 1997 Trimble Bonds, the term, "Loan Agreement" shall mean the Loan Agreement pursuant to which Trimble County loaned the proceeds from the sale of the Trimble County Bonds to the Company, the term "Indenture" shall mean the Trimble County Indenture, and the term "Trustee" shall mean the Trimble County Trustee.

SUMMARY OF THE BONDS

General

The Bonds will be reoffered in the aggregate principal amount set forth on the cover page of this Reoffering Circular and will mature on November 1, 2027. The Bonds are also subject to redemption prior to maturity as described herein.

The Bonds currently bear interest at Flexible Rates. Pursuant to the terms and provisions of the Indentures summarized below, the Company has exercised its option, effective December 15, 2014 (the "Conversion Date"), to convert the interest rate on the Bonds to a Long Term Rate. The Jefferson County Bonds will bear interest at the Long Term Rate of 1.35% per annum from December 15, 2014 to and including April 30, 2018, and will be subject to mandatory purchase following the initial Long Term Rate Period on May 1, 2018. The Trimble County Bonds will bear interest at the Long Term Rate of 1.35% per annum from December 15 , 2014 to and including April 30, 2018, and will be subject to mandatory purchase following the initial Long Term Rate Period on May 1, 2018. Additional information regarding mandatory purchase is described below under the caption "— Mandatory Purchases of Bonds."

Following the initial Long Term Rate Period, the Bonds will be subject to mandatory purchase, but will continue to bear interest at a Long Term Rate until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. Also, following the initial Long Term Rate Period, the Company may elect to change the Long Term Rate Period to a different Long Term Rate Period. The permitted Interest Rate Modes for the Bonds are (i) the "Flexible Rate," (ii) the "Daily Rate," (iii) the "Weekly Rate," (iv) the "Semi-Annual Rate," (v) the "Annual Rate," (vi) the "Long Term Rate" and (vii) the "Dutch Auction Rate." Changes in the Interest Rate Mode will be effected, and notice of such changes will be given, as described below under the caption "— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods."

This Reoffering Circular does not describe the terms and provisions of the Bonds and the documents related thereto while the Bonds bear interest at a Dutch Auction Rate. Provisions relating to the Bonds if they bear interest at a Dutch Auction Rate will be determined in accordance with auction procedures established at the time of any such conversion to the Dutch Auction Rate pursuant to the provisions of the Indenture.

Interest on the Bonds is payable on each May 1 and November 1, commencing May 1, 2015, (unless any such interest payment date is not a Business Day, in which case interest will be paid on the next succeeding Business Day), to the persons who are the registered owners of the Bonds as of the Record Date preceding such interest payment date. In each case, interest also will be payable on the day following the end of the applicable initial Long Term Rate Period to the persons who are registered owners of the applicable Bonds on the last day of such Long Term Rate Period.

During each Rate Period for an Interest Rate Mode, the interest rate or rates for the Bonds in that Interest Rate Mode, and Flexible Rate Periods for Bonds accruing interest at a Flexible Rate, will be determined by the Remarketing Agent in accordance with the Indenture; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 14% per annum.

Interest on the Bonds which bear interest at a Flexible Rate, Daily Rate or Weekly Rate will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest on the Bonds which bear interest at a Semi-Annual Rate, Annual Rate or Long Term Rate will be computed on the basis of a 360-day year of twelve 30-day months. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment; provided that in the case of Bonds bearing interest at the Flexible Rate, interest will be payable to the registered owner of such Bond on the Interest Payment Date therefor. The Record Date, in the case of interest accrued at a Daily Rate or Weekly Rate, will be the close of business on the Business Day immediately preceding each Interest Payment Date and in the case of interest accrued at a Semi-Annual Rate, Annual Rate or Long Term Rate, will be the close of business on the fifteenth day (whether or not a Business Day) of the month preceding each Interest Payment Date.

The Bonds have been issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Reoffering Circular. See " — Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in (i) denominations of $100,000 and integral multiples thereof, if bearing interest at the Daily Rate or the Weekly Rate; (ii) denominations of $100,000 or any integral multiple of $5,000 in excess of $100,000, if bearing interest at Flexible Rates; or (iii) denominations of $5,000 and integral multiples thereof, if bearing interest at the Semi-Annual Rate, the Annual Rate or the Long Term Rate.

Except as otherwise described below for Bonds held in DTC's book-entry-only system, the principal or redemption price of the Bonds is payable at the designated corporate trust office in New York, New York, of the Trustee, as paying agent (the "Paying Agent"). Except as otherwise described below for Bonds held in DTC's book-entry-only system, interest on the Bonds is payable by check mailed to the owner of record; provided that interest payable on each Bond will be payable in immediately available funds by wire transfer within the continental United States or by deposit into a bank account maintained with the Paying Agent (i) if the Interest Rate Mode is the Daily Rate, the Weekly Rate or the Flexible Rate, or (ii) at the written request of any owner of record holding at least $1,000,000 aggregate principal amount of the Bonds, if the Interest Rate Mode is the Semi-Annual Rate, Annual Rate or Long Term Rate, received by the Trustee, as bond registrar (the "Bond Registrar"), at least one Business Day prior to any Record Date. Except as otherwise described below for Bonds held in DTC's book-entry-only system, if the Interest Rate Mode is the Flexible Rate, interest payable on each Bond will be paid only upon presentation and surrender of such Bond.

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "— Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "— Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Security

Payment of the principal of and interest and any premium on the Bonds is secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company has agreed to pay, among other things, amounts sufficient to pay the aggregate principal amount of and premium, if any, on the Bonds, together with interest thereon as and when the same become due. The Company further has agreed to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal of and interest and any premium on the Bonds is further secured by a separate tranche of the Company's First Mortgage Bonds issued under the First Mortgage Indenture between the Company and the First Mortgage Trustee. The principal amount of the First Mortgage Bonds equals the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds ("Redemption Demand"), or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

Tender Agent

Owners may tender their Bonds, and in certain circumstances will be required to tender their Bonds, to the Tender Agent for purchase at the times and in the manner described herein under "— Summary of Certain Provisions of the Bonds." So long as the Bonds are held in DTC's book-entry-only system, the Trustee will act as Tender Agent under the Indenture. Any successor Tender Agent appointed pursuant to the Indenture will also be a Paying Agent.

Remarketing Agents

Morgan Stanley & Co. LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated will be appointed under the Indenture to serve as Initial Co-Remarketing Agents for purposes of this conversion and reoffering of the Bonds. Following this conversion and reoffering, Morgan Stanley & Co. LLC will serve as the sole Remarketing Agent for the Bonds. The Remarketing Agent may be removed by the Issuer, if so directed by the Company, upon seven days' notice, and may resign in accordance with the Remarketing Agreement upon sixty days' notice.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated:

"*Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Annual Rate and ending on, and including, the day next preceding the second Interest Payment Date thereafter, and each successive twelve-month period (or portion thereof) thereafter until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such upon the systems of DTC and each DTC Participant or the registered holder of such Bonds if such Bond is not then registered in the name of CEDE & Co.

"*Business Day*" means any day other than (i) a Saturday or Sunday or legal holiday or a day on which banking institutions in the city in which the principal office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Company or the Remarketing Agent are located are authorized by law or executive order to close or (ii) a day on which the New York Stock Exchange is closed.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means initially the date of original issuance of the Bonds, and thereafter means the date on which any Conversion becomes effective.

"*Daily Rate Period*" means the period beginning on, and including, the Conversion Date to the Daily Rate and ending on and including the day preceding the next Business Day and each period thereafter beginning on and including a Business Day and ending on and including the day preceding the next succeeding Business Day until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Flexible Rate*" means the Interest Rate Mode for the Bonds in which the interest rate for each Bond is determined with respect to that Bond during each Flexible Rate Period applicable to that Bond, as provided in the Indenture.

"*Flexible Rate Period*" means with respect to any Bond, each period (which may be from one day to 270 days, or such lower maximum number of days as is then permitted under the Indenture) determined for such Bond, as provided in the Indenture.

"*Interest Payment Date*" means (i) if the Interest Rate Mode is the Daily Rate or the Weekly Rate, the first Business Day of each calendar month, (ii) if the Interest Rate Mode is the Flexible Rate, for each Bond the last day of each Flexible Rate Period for such Bond (or if such day is not a Business Day, the next succeeding Business Day), (iii) if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, May 1 and November 1, and, in the case of the Long Term Rate, the effective date of a change to a new Long Term Rate Period; and (iv) any Conversion Date (including the date of a failed Conversion). In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Period*" means for all Bonds (or for any Bond if the Interest Rate Mode is the Flexible Rate) the period from and including each Interest Payment Date to and including the day immediately preceding the next Interest Payment Date, provided, however that the first Interest Period for the Bonds will begin on (and include) the date of issuance of the Bonds and the final Interest Period will end on October 31, 2027.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate and the Long Term Rate.

"*Long Term Rate Period*" means any period established by the Company as hereinafter set forth under "— Determination of Interest Rates for Interest Rate Modes — *Long Term Rates and Long Term Rate Periods*" and beginning on, and including, the Conversion Date to the Long Term Rate and ending on, and including, the day preceding the last Interest Payment Date for such period and, thereafter, each successive period of the same duration as the Long Term Rate Period previously established until the day preceding the earliest of the change to a different Long Term Rate Period, the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Semi-Annual Rate Period*" means the period beginning on, and including, the Conversion Date to the Semi-Annual Rate, and ending on, and including, the day preceding the first Interest Payment Date thereafter and each successive six-month period thereafter beginning on and including an Interest Payment Date and ending on and including the day next preceding the next Interest Payment Date until the day preceding the earlier of the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

"*Weekly Rate Period*" means the period beginning on, and including, the Conversion Date to the Weekly Rate, and ending on, and including, the next Tuesday, and thereafter the period beginning on, and including, each Wednesday and ending on, and including, the earliest of the next Tuesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Summary of Certain Provisions of the Bonds

The following table summarizes, for each of the permitted Interest Rate Modes: the dates on which interest will be paid (*Interest Payment Dates*); the dates on which each interest rate will be determined (*Interest Rate Determination Dates*); the period of time (*Interest Rate Periods*) each interest rate will be in effect (provided that the initial Interest Rate Period for each Interest Rate Mode may begin on a different date from that specified, which date will be the Conversion Date or the date of a change in the Long Term Rate, as applicable); the dates on which registered owners may tender their Bonds for purchase to the Tender Agent and the notice requirements therefor (provided that while the Bonds are held in book-entry-only form, all notices of tender for purchase will be given by Beneficial Owners in the manner described under "— Purchases of Bonds on Demand of Owner — *Notice Required for Purchases*") (*Purchase on Demand of Owner; Required Notice*); the dates on which Bonds are subject to mandatory tender for purchase (*Mandatory Purchase Dates*); the redemption provisions applicable to the Bonds (*Redemption*); the notice requirements for redemption and mandatory tender for purchase (*Notices of Redemption and Mandatory Purchases*); and the manner by which registered owners will receive payments of principal, interest, redemption price and purchase price (*Manner of Payment*). All times stated are New York City time.

	FLEXIBLE RATE	**DAILY RATE**	**WEEKLY RATE**
Interest Payment Dates	With respect to any Bond, the last day of each Flexible Rate Period (or if such day is not a Business Day, the next succeeding Business Day).	The first Business Day of each calendar month.	The first Business Day of each calendar month.
Interest Rate Determination Date	For each Bond, not later than 12:00 noon on the first day of each Flexible Rate Period for such Bond.	Not later than 9:30 a.m. on each Business Day.	Not later than 4:00 p.m. on the day preceding each Weekly Rate Period or, if not a Business Day, on the next preceding Business Day.
Interest Rate Periods	For each Bond, each Flexible Rate Period will be of a duration designated by the Remarketing Agent of one day to 270 days (or lower maximum number as specified in the Indenture); must end on a day immediately prior to a Business Day.	From and including each Business Day to but not including the next Business Day.	From and including each Wednesday to and including the following Tuesday.
Purchase on Demand of Owner; Required Notice*	No purchase on demand of the owner.	Any Business Day; by written or telephonic notice, promptly confirmed in writing, to the Tender Agent by 11:00 a.m. on such Business Day.	Any Business Day; by written notice to the Tender Agent not later than 5:00 p.m. on a Business Day at least seven days prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; and with respect to each Bond, on each Interest Payment Date for such Bond.	Any Conversion Date.	Any Conversion Date.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional, Extraordinary Optional and Mandatory at par on any Business Day.	Optional, Extraordinary Optional and Mandatory at par on any Business Day.
Notices of Redemption and Mandatory Purchases*	No notice of mandatory purchase following the end of each Flexible Rate Period; otherwise not fewer than 15 days (not fewer than 30 days notice of mandatory purchase on a Conversion Date if Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of mandatory purchase if Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.	Not fewer than 15 days (30 days notice of mandatory purchase if Conversion to the Semi-Annual, Annual or Long Term Rate) or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., and payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC. See “— Book-Entry-Only System” below.

	SEMI-ANNUAL	ANNUAL	LONG TERM
Interest Payment Date	Each May 1 and November 1.	Each May 1 and November 1.	Each May 1 and November 1; any Conversion Date; and the effective date of any change to a new Long Term Rate Period.
Interest Rate Determination Dates	Not later than 2:00 p.m. on the Business Day preceding the first day of the Semi-Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Annual Rate Period.	Not later than 12:00 noon on the Business Day preceding the first day of the Long Term Rate Period.
Interest Rate Periods	Each six-month period from and including each May 1 and November 1 to and including the day preceding the next Interest Payment Date.	Each period from and including the Conversion Date to the Annual Rate to and including the day immediately preceding the second Interest Payment Date thereafter and each successive twelve month period thereafter.	Each period designated by the Company of more than one year in duration and which is an integral multiple of six months, from and including the first day of such period (May 1 and November 1) to and including the day immediately preceding the last Interest Payment Date for that period.
Purchase on Demand of Owner; Required Notice*	On any Interest Payment Date; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Annual Rate Period; by written notice to the Tender Agent on any Business Day not later than the fifteenth day prior to the Purchase Date.	On the final Interest Payment Date for the Long Term Rate Period; by written notice to the Tender Agent on a Business Day not later than the fifteenth day prior to the Purchase Date.
Mandatory Purchase Dates	Any Conversion Date; the first Business Day after the end of each Semi-Annual Rate Period.	Any Conversion Date; the first Business Day after the end of each Annual Rate Period.	Any Conversion Date: the first Business Day after the end of each Long Term Rate Period; the effective date of a change of Long Term Rate Period.
Redemption	Optional at par on any Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day (other than extraordinary optional redemption as a result of damage, destruction or condemnation which will be on an Interest Payment Date).	Optional at par on the final Interest Payment Date; Extraordinary Optional and Mandatory at par, on any Business Day.	Optional at times and prices dependent on the length of the Long Term Rate Period; Extraordinary Optional and Mandatory at par, on any Business Day.
Notices of Redemption and Mandatory Purchases*	Not fewer than 30 days or greater than 45 days.	Not fewer than 30 days or greater than 45 days.	Not fewer than 30 days or greater than 45 days.
Manner of Payment*	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner of $1,000,000 or more of an individual issue of Bonds, in immediately available funds: purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.	Principal or redemption price upon surrender of the Bond to the Paying Agent; interest by check mailed to the registered owners or, upon request of registered owner of $1,000,000 or more of an individual issue of Bonds, in immediately available funds; purchase price upon surrender of the Bond to the Tender Agent.

* So long as DTC or its nominee is the registered owner of the Bonds, notices of redemption and mandatory purchases shall be sent to Cede & Co., and payments of principal, redemption and purchase price of and interest on the Bonds will be paid through the facilities of DTC. See "— Book-Entry-Only System" below.

Determination of Interest Rates for Interest Rate Modes

Interest rates shall be established by the Remarketing Agent as follows:

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, the interest rate on the Bonds for any Business Day will be the rate established by the Remarketing Agent no later than 9:30 a.m. (New York City time) on such Business Day as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such Business Day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon. For any day which is not a Business Day or if the Remarketing Agent does not give notice of a change in the interest rate, the interest rate on the Bonds will be the interest rate in effect for the immediately preceding Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, the interest rate on the Bonds for a particular Weekly Rate Period will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon.

Flexible Rates and Flexible Rate Periods. If the Interest Rate Mode for the Bonds is the Flexible Rate, the interest rate on a Bond for a specific Flexible Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the first day of that Flexible Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell such Bond on that day at a price equal to the principal amount thereof. Each Flexible Rate Period applicable for a Bond will be determined separately by the Remarketing Agent on or prior to the first day of such Flexible Rate Period as being the Flexible Rate Period permitted under the Indenture which, in the judgment of the Remarketing Agent, taking into account then Prevailing Market Conditions, will, with respect to such Bond, ultimately produce the lowest overall interest cost on the Bonds while the Interest Rate Mode for the Bonds is the Flexible Rate. Each Flexible Rate Period will be from one day to 270 days in length and will end on a day preceding a Business Day. If the Remarketing Agent fails to set the length of a Flexible Rate Period for any Bond, a new Flexible Rate Period lasting to, but not including, the next Business Day (or until the earlier Conversion or maturity of the Bonds) will be established automatically in accordance with the Indenture.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the interest rate on the Bonds for a particular Semi-Annual Rate Period will be the rate established by the Remarketing Agent no later than 2:00 p.m. (New York City time) on the Business Day immediately preceding the first day of such Semi-Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, the interest rate on the Bonds for a particular Annual Rate Period will be the rate of interest established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Annual Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof.

Long Term Rates and Long Term Rate Periods. If the Interest Rate Mode for the Bonds is the Long Term Rate, the interest rate on the Bonds for a particular Long Term Rate Period will be the rate established by the Remarketing Agent no later than 12:00 noon (New York City time) on the Business Day preceding the first day of such Long Term Rate Period as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof. The Long Term Rate Period will be 3 ½ years with the initial period ending April 30, 2018) for the Jefferson County Bonds and 3 ½ years (with the initial period ending April 30, 2018) for the Trimble County Bonds. Thereafter each successive Long Term Rate Period will be the same as the Long Term Rate Period so established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture (in which case the duration of that Long Term Rate Period will control succeeding Long Term Rate Periods), subject in all cases to the occurrence of a Conversion Date or the maturity of the Bonds. Each Long Term Rate Period will be more than one year in duration, will be for a period which is an integral multiple of six months and will end on the day next preceding an Interest Payment Date; provided that if a Long Term Rate Period commences on a date other than a May 1 or November 1, such Long Term Rate Period may be for a period which is not an integral multiple of six months but will be of a duration as close as possible to (but not in excess of) such Long Term Rate Period established by the Company and will terminate on a day preceding an Interest Payment Date, and each successive Long Term Rate Period thereafter will be for the full period established by the Company until a different Long Term Rate Period is specified by the Company in accordance with the Indenture or until the occurrence of a Conversion Date or the maturity of the Bonds; provided further that no Long Term Rate Period will extend beyond the final maturity date of the Bonds.

Failure to Determine Rate. If for any reason the interest rate for a Bond is not determined by the Remarketing Agent, except as described below under "— Conversion of Interest Rate Modes and Changes of Long Term Rate Periods—_Change of Long Term Rate Period_" and "— _Cancellation of Conversion of Interest Rate Mode_," the interest rate for such Bond for the next succeeding interest rate period will be the interest rate in effect for such Bond for the preceding interest rate period and, pursuant to the terms of the Indenture, there will be no change in the then applicable Long Term Rate Period or any Conversion from the then applicable Interest Rate Mode. Notwithstanding the foregoing, if for any reason the interest rate for a Bond bearing interest at a Flexible Rate is not determined by the Remarketing Agent, the interest rate for such Bond for the next succeeding Interest Period will be equal to The Bond Market Association Municipal Swap Index™ (the "Municipal Index") as defined in the Indenture and the Interest Period for such Bond will extend through the day preceding the next Business Day, until the Trustee is notified of a new Flexible Rate and Flexible Rate Period determined for such Bond by the Remarketing Agent.

Conversion of Interest Rate Modes and Changes of Long Term Rate Periods

Method of Conversion. The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below under "— Limitations on Conversion," at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period.

Limitations on Conversion. Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "— Redemptions — *Optional Redemption*" below); provided that any Conversion from the Daily Rate Period to a Weekly Rate Period or from the Weekly Rate Period to the Daily Rate Period must be on a Wednesday; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; (iii) if the Conversion is from the Flexible Rate, (a) the Conversion Date may be no earlier than the latest Interest Payment Date established prior to the giving of notice to the Remarketing Agent of such proposed Conversion and (b) no further Interest Payment Date may be established while the Interest Rate Mode is then the Flexible Rate if such Interest Payment Date would occur after the effective date of that Conversion; and (iv) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "— Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

Change of Long Term Rate Period. The Company may change from one Long Term Rate Period to another Long Term Rate Period on any Business Day on which the Bonds are subject to optional redemption as described under "— Redemptions — *Optional Redemption*" below upon notice from the Bond Registrar to the owners of Bonds as described below. With any notice of such change, the Company must also deliver an opinion of Bond Counsel stating that such change is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. Notwithstanding the foregoing, the Long Term Rate Period will not be changed to a new Long Term Rate Period if (A) the Remarketing Agent has not determined the interest rate for the new Long Term Rate Period in accordance with the terms of the Indenture or (B) the Bond Registrar receives written notice from Bond Counsel prior to the effective date of the change to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. Upon the occurrence of any of the events described in the preceding sentence, the Bonds will bear interest at the Weekly Rate commencing on the date which would have been the effective date of the proposed change of Long Term Rate Period, subject to the provisions described below under "--*Cancellation of Conversion of Interest Rate Mode*."

Notice to Owners of Conversion of Interest Rate Mode or of Change of Long Term Rate Period. The Bond Registrar will notify each registered owner of the Conversion or change of Long Term Rate Period, as applicable, by first class mail at least 15 days (30 days in the case of

Conversion from or to the Semi-Annual Rate, the Annual Rate or a Long Term Rate or in the case of a change in the Long Term Rate Period) but not more than 45 days before each Conversion Date or each effective date of a change in the Long Term Rate Period. The notice will state those matters required to be set forth therein under the Indenture.

Cancellation of Conversion of Interest Rate Mode. Notwithstanding the foregoing, no Conversion will occur if (A) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (B) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent, or (C) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, the Bonds will automatically be converted to the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Tuesday) at the rate determined by the Remarketing Agent on the failed Conversion Date; provided, that there must be delivered to the Issuer, the Trustee, the Tender Agent, the Company and the Remarketing Agent an opinion of Bond Counsel to the effect that determining the interest rate to be borne by the Bonds at a Weekly Rate is authorized or permitted by the Act and is authorized under the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes. If such opinion is not delivered on the failed Conversion Date, the Bonds will bear interest for a Rate Period of the same type and of substantially the same length as the Rate Period in effect prior to the failed Conversion Date at a rate of interest determined by the Remarketing Agent on the failed Conversion Date (or if shorter, the Rate Period ending on the date before the maturity date); provided that if the Bonds then bear interest at the Long Term Rate, and if such opinion is not delivered on the date which would have been the effective date of a new Long Term Rate Period, the Bonds will bear interest at the Annual Rate, commencing on such date, at an Annual Rate determined by the Remarketing Agent on such date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds on Demand of Owner

The Bonds are subject to purchase on the demand of the owners thereof as described below. If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant. If the Bonds are in certificated form, demands for purchase may be made only by registered owners.

Daily Rate. If the Interest Rate Mode for the Bonds is the Daily Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Daily Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice or telephonic notice to the Tender Agent at its principal office not later than 11:00 a.m. (New York City time) on such Business Day.

Weekly Rate. If the Interest Rate Mode for the Bonds is the Weekly Rate, any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its principal office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Semi-Annual Rate. If the Interest Rate Mode for the Bonds is the Semi-Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on any Interest Payment Date for a Semi-Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Annual Rate. If the Interest Rate Mode for the Bonds is the Annual Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Annual Rate Period at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Long Term Rate. If the Interest Rate Mode for the Bonds is the Long Term Rate, any Bond will be purchased on the demand of the registered owner thereof on the final Interest Payment Date for such Long Term Rate Period (unless such date is the final maturity date) at a purchase price equal to the principal amount thereof upon written notice to the Tender Agent at its principal office on a Business Day not later than the fifteenth day prior to such Purchase Date.

Limitations on Purchases on Demand of Owner. Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing. Also, if the Interest Rate Mode for the Bonds is the Flexible Rate, the Bonds will not be subject to purchase on the demand of the registered owners thereof, but each Bond will be subject to mandatory purchase on each Conversion Date and on the Interest Payment Date with respect to such Bond, as described below under the caption "— Mandatory Purchases of Bonds."

Notice Required for Purchases. Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 11:00 a.m. (1:00 p.m. if a tender during a Daily Rate Period and 12:00 noon if a tender during a Weekly Rate Period) (New York City time) on such Purchase Date.

Mandatory Purchases of Bonds

Mandatory Purchase on Conversion Dates or Change by the Company in Long Term Rate Period. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, plus, if the Interest Rate Mode is the Long Term Rate, the redemption premium, if any, which would be payable as described under "— Redemptions — *Optional Redemption*" below, if the Bonds were redeemed on the Purchase Date (A) on each Conversion

Date and (B) on the effective date of any change by the Company of the Long Term Rate Period. Such tender and purchase will be required even if the change in Long Term Rate Period or the Conversion is canceled pursuant to the Indenture.

Mandatory Purchase on Each Interest Payment Date for Flexible Rate Period. Whenever the Interest Rate Mode for the Bonds is the Flexible Rate, each Bond will be subject to mandatory purchase at a purchase price equal to the principal amount thereof, without premium, on each Interest Payment Date that interest on such Bond is payable at an interest rate determined for the Flexible Rate. Owners of Bonds will receive no notice of such mandatory purchase.

Mandatory Purchase on Day after End of the Semi-Annual Rate Period, the Annual Rate Period or the Long Term Rate Period. Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Annual Rate or the Long Term Rate, such Bonds will be subject to mandatory purchase on the Business Day following the end of each Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period, as the case may be, for such Bond at a purchase price equal to the principal amount thereof plus accrued interest, if any, to such date. Following the end of the initial Long Term Rate Period, the Bonds will be subject to mandatory purchase on May 1, 2018 with respect to the Jefferson County Bonds and May 1, 2018 with respect to the Trimble County Bonds.

Notice to Owners of Mandatory Purchases. Notice to owners of a mandatory purchase of Bonds on a Conversion Date or upon a change in Long Term Rate Period will be given by the Bond Registrar, together with the notice of such Conversion or change of Long Term Rate Period, as applicable, by first class mail at least 15 days (30 days in the case of Conversion from or to the Semi-Annual Rate, the Annual Rate or the Long Term Rate or in the case of a change in the Long Term Rate Period) but not more than 45 days before each Conversion Date or each effective date of a change in the Long Term Rate Period. Notice to owners of a mandatory purchase of Bonds after the end of each Semi-Annual Rate Period, Annual Rate Period and Long Term Rate Period will be given by the Bond Registrar by first class mail at least 30 days prior to the end of such period. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture. No notice of mandatory purchase will be given in connection with a mandatory purchase on an Interest Payment Date for a Flexible Rate Period.

Remarketing and Purchase of Bonds

The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its commercially reasonable best efforts to offer for sale Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

The purchase price of Bonds tendered for purchase will be paid by the Tender Agent from moneys derived from the remarketing of such Bonds by the Remarketing Agent and, if such remarketing proceeds are insufficient, from moneys made available by the Company. The Company is obligated to purchase any Bonds tendered for purchase to the extent such Bonds have not been remarketed. The Company currently maintains lines of credit or other liquidity facilities in amounts determined by it to be sufficient to meet its current needs and expects to continue to maintain such lines of credit or other liquidity facilities from time to time to the extent determined by it to be necessary to meet its then-current needs. The Trustee, any Paying Agent, the Tender Agent and the owners of the Bonds have no right to draw under any line of credit or other liquidity facility maintained by the Company. There is no provision in the Indenture or the Loan Agreement requiring the Company to maintain such financing arrangements which may be discontinued at any time without notice. The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase pursuant to the Indenture.

Any deficiency in purchase price payments resulting from the Remarketing Agent's failure to deliver remarketing proceeds of all Bonds with respect to which the Remarketing Agent notified the Tender Agent were remarketed will not result in an Event of Default under the Indenture until the opening of business on the next succeeding Business Day unless the Company fails to provide sufficient funds to pay such purchase price by the opening of business on such next succeeding Business Day. If sufficient funds are not available for the purchase of all tendered Bonds, no purchase of Bonds will be consummated, but failure to consummate such purchase will not be deemed to be an Event of Default under the Indenture if sufficient funds have been provided in a timely manner by the Company to the Tender Agent for such purpose.

Payment of Purchase Price

When a book-entry-only system is not in effect, payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent: (i) at or prior to 12:00 noon (New York City time), in the case of Bonds delivered for purchase during a Weekly Rate Period or Flexible Rate Period, (ii) at or prior to 1:00 p.m. (New York City time), in the case of Bonds delivered for purchase during a Daily Rate Period or (iii) at or prior to 11:00 a.m. (New York City time), in the case of Bonds delivered for purchase during a Semi-Annual Rate Period, Annual Rate Period or Long Term Rate Period. If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Redemptions

Optional Redemption.

During the initial Long Term Rate Period, the Bonds will not be redeemable at the option of the Company except as described below under the captions "Extraordinary Optional Redemption in Whole," "Extraordinary Optional Redemption in Whole or in Part," or "Mandatory Redemption; Determination of Taxability."

Following the initial Long Term Rate Period, the Bonds will be redeemable at the option of the Company as follows:

(i) Whenever the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

(ii) Whenever the Interest Rate Mode for a Bond is the Flexible Rate, such Bond will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date for that Bond.

(iii) Whenever the Interest Rate Mode for the Bonds is the Semi-Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on any Interest Payment Date.

(iv) Whenever the Interest Rate Mode for the Bonds is the Annual Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof on the final Interest Payment Date for each Annual Rate Period.

(v) Whenever the Interest Rate Mode for the Bonds is the Long Term Rate, the Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the

Company, in whole or in part, (A) on the final Interest Payment Date for the then current Long Term Rate Period at a redemption price of 100% of the principal amount thereof and (B) prior to the end of the then current Long Term Rate Period at any time during the redemption periods and at the redemption prices set forth below, plus in each case interest accrued, if any, to the redemption date:

Original Length of Current Long Term Rate Period (Years)	Commencement of Redemption Period	Redemption Price as Percentage of Principal
More than or equal to 11 years	First Interest Payment Date on or after the tenth anniversary of commencement of Long Term Rate Period	101%, declining by 1% on the next succeeding anniversary of the first day of the redemption period and thereafter 100%
Less than 11 years	Non-callable	Non-callable

Subject to certain conditions, including provision of an opinion of Bond Counsel that a change in the redemption provisions of the Bonds will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, the redemption periods and redemption prices may be revised, effective as of the Conversion Date, the date of a change in the Long Term Rate Period or a Purchase Date on the final Interest Payment Date during a Long Term Rate Period, to reflect Prevailing Market Conditions on such date as determined by the Remarketing Agent in its judgment.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events shall have occurred within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or such other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(ii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iii) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state of federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(iv) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the Generating Station where any of the Project is located to such extent that the Company will be prevented from carrying on its normal operations at such Generating Station for a period of six months.

As a result of a Company Letter Agreement between the Issuer and the Company, to be dated as of December 15, 2014, the Company will agree that it will not, prior to May 1, 2018, exercise the rights under the Loan Agreement it would otherwise have to redeem the Bonds under the following circumstances:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date the Bonds are issued, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project; or

(ii) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the Generating Station where any of the Project is located have occurred, which, in the judgment of the Company, render the continued operation of such Generating Station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or other air and water pollution control requirements or solid waste disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer, the Company or the First Mortgage Trustee in the event of damage, destruction or condemnation of all or a portion of the Project, subject to receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption may occur at any time, provided that if such event occurs while the Interest Rate Mode for the Bonds is the Daily Rate, Weekly Rate, Flexible Rate or Semi-Annual Rate, such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" of the Project or a "related person" of a substantial user within the meaning of Section 147 of Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability shall be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company shall exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" of a substantial user within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. Notice of redemption will be given by mailing a redemption notice by first class mail to the registered owners of the Bonds to be redeemed not less than 30 days (15 days if the Interest Rate Mode for the Bonds is the Flexible Rate, Daily Rate or Weekly Rate) but not more than 45 days prior to the redemption date. Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book-entry-only system have been obtained from DTC. The Issuer, the Company and the Remarketing Agent make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee). One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC, the world's largest securities depository, is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity, corporate and municipal debt issues, and money market instruments from over 100 countries that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners, however, are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry-only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices will be sent to DTC. If less than all of the Bonds within an issue are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such issue to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner will give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and will effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds on DTC's records to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee. The Issuer, at the request of the Company, may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository for the Bonds). Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be printed and delivered as described in the Indenture (see "— *Revision of Book -Entry-Only System; Replacement Bonds*" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture and the Company's obligations under the Loan Agreement and the First Mortgage Bonds, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book-entry-only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Remarketing Agents cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Reoffering Circular.

THE ISSUER, THE COMPANY, THE REMARKETING AGENTS AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds. In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $5,000 and integral multiples thereof, if the Interest Rate Mode is the Semi-Annual Rate, the Annual Rate or the Long Term Rate; in denominations of $100,000 and integral multiples of $5,000 in excess thereof, if the Interest Rate Mode is the Flexible Rate; and in denominations of $100,000 and integral multiples thereof, if the Interest Rate Mode for the Bonds is the Daily Rate or the Weekly Rate. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the principal office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the registered owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "— Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

SUMMARY OF THE LOAN AGREEMENT

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Loan Agreement. Reference is made to the Loan Agreement for the detailed provisions thereof.

General

The term of the Loan Agreement commenced as of its date and will end on the earliest to occur of November 1, 2027, or the date on which all of the Bonds shall have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company has agreed to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal of, premium, if any, and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company has also agreed to pay (a) the reasonable fees and expenses of the Trustee, the Bond Registrar, any Tender Agent and any Paying Agent appointed under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company covenants and agrees with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company shall cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture (see "Summary of the Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar, the Tender Agent and amounts related to indemnification) have been assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer have agreed not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company has executed and delivered to the Trustee the First Mortgage Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee equals the aggregate principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a Redemption Demand, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have been immediately due and payable, such First Mortgage Bonds will bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal of, premium, if any, and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds are registered in the name of the Trustee and are non transferable, except to effect transfers to any successor trustee under the Indenture.

Payment of Taxes

The Company has agreed to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under "Summary of the Bonds — Redemptions — *Extraordinary Optional Redemption in Whole*"). The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain the Project or cause the Project to be maintained in good working condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as air and water pollution control and abatement facilities and solid waste disposal facilities, as applicable, under Section 103(b)(4)(E) and (F) of the Internal Revenue Code of 1954, as amended. However, the Company will have no obligation to maintain, repair, replace or renew any portion of the Project, the maintenance, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements shall be deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 103(b) (4) (E) and (F) of the Internal Revenue Code of 1954, as amended.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer, the Company or the First Mortgage Trustee receives net proceeds from insurance or a condemnation award in connection therewith, the Company shall (i) cause such net proceeds to be used to repair or restore the Project or (ii) take any other action, including the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — *Extraordinary Optional Redemption in Whole or in Part*."

Insurance

The Company has agreed to insure the Project in accordance with the provisions of the First Mortgage Indenture.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, shall not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another corporation, provided the acquirer of the Company's assets or the corporation with which it shall consolidate with or merge into shall be a corporation organized and existing under the laws of one of the states of the United States of America, shall be qualified and admitted to do business in the Commonwealth of Kentucky, and shall assume in writing all of the obligations of the Company under the Loan Agreement.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "event of default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies");

(2) failure by the Company to observe and perform any covenant, condition or agreement, other than as referred to in paragraph (1) above, for a period of thirty days after written notice by the Issuer or Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, it will not constitute an event of default under the Loan Agreement if corrective action with respect thereto is being diligently pursued;

(3) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee;

(4) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company; or

(5) the occurrence of an event of default under the Indenture.

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes, (ii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another corporation unless certain provisions of the Loan Agreement are satisfied; and (iii) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening of an event of default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

Upon the happening of an event of default under the Loan Agreement that results in an event of a default in payment of the principal of, premium, if any, or interest on the Bonds or a default in the payment of the purchase price of the Bonds tendered for purchase, and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such event of default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds" and "Summary of the Indenture —

Defaults and Remedies." Any amounts collected upon the happening of any such event of default will be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay, Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the captions "Summary of the Bonds — Redemptions — *Optional Redemption*," "*Extraordinary Optional Redemption in Whole*" and "*Extraordinary Optional Redemption in Whole or in Part*." Upon the occurrence of the event described under the caption "Summary of the Bonds — Redemptions — *Mandatory Redemption; Determination of Taxability*," the Company shall be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price shall be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to the applicable redemption price plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No amendment or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any amendment or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such amendments, the Loan Agreement may be amended or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see "Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an amendment or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the second paragraph of "Summary of the Indenture — Supplemental Indentures."

SUMMARY OF THE FIRST MORTGAGE BONDS

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the First Mortgage Bonds and the First

Mortgage Indenture. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

The First Mortgage Bonds, in a principal amount equal to the principal amount of the Bonds, were issued as a new tranche from a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of the occurrence of an event of default under the Loan Agreement that has resulted in a default in payment of the principal of, premium, if any, or interest on the Bonds, or a default in payment of the purchase price of any such Bonds tendered for purchase, and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non-negotiable, and will be non-transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the First Mortgage Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to *permitted liens* as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than *excepted property*, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to herein as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business or its natural gas storage, transportation and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities or natural gas storage, transportation and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such permitted liens include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a permitted lien under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. As of September 30, 2014, first mortgage bonds in an aggregate principal amount of $1,359,304,000 were outstanding under the First Mortgage Indenture, of which $574,304,000 were issued to secure the Company's payment obligations with respect to its outstanding pollution control and environmental facilities revenue bonds, including the Bonds.

First mortgage bonds of any series may be issued from time to time in the future on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or
- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts in accordance with U.S. generally accepted accounting principles.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

Future First Mortgage Bonds can be issued on the basis of *property additions*. At August 31, 2014, approximately $1.47 billion of *property additions* were available to be used as the basis for the authentication and delivery of first mortgage bonds.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;
- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);
- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);
- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);
- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released

delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money lien* means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the *cost* or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the *cost* or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company’s request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "event of default" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;

- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;

- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or

- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:

  - all overdue interest;

- the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
- interest on overdue interest to the extent lawful;
- all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and
- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or

- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and

- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of any first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of any first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia, and

- expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture, and

- such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property, including property thereafter acquired by such entity which constitutes an improvement, extension or addition to the Mortgaged Property or a renewal, replacement or substitution thereof;

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;
- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;
- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;
- to add any additional *events of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;
- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;
- to establish the form or terms of any series or tranche of first mortgage bonds;
- to provide for the issuance of bearer securities;
- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;
- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;
- to change any place or places where
    - the Company may pay principal, premium and interest,
    - first mortgage bonds may be surrendered for transfer or exchange, and

— notices and demands to or upon the Company may be served;

- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;
- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or
- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby,

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or the method of calculating such rates) or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;
- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on

all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient,

to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the

First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

SUMMARY OF THE INDENTURE

The following, in addition to the provisions contained elsewhere in this Reoffering Circular, is a brief description of certain provisions of the Indenture. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer has assigned and pledged to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund). The Bonds have been further secured by the First Mortgage Bonds delivered to the Trustee (see “Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds”). The First Mortgage Bonds have been registered in the name of the Trustee and are nontransferable, except to effect a transfer to any successor trustee. The Bonds will not be directly secured by the Project (although the Project is subject to the lien of the First Mortgage Indenture).

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, shall give rise to any pecuniary liability of the Issuer or any charge upon its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the Project and the application of the amounts assigned to payment of the principal of, premium, if any, and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used solely for the payment of the principal of, premium, if any, and interest on the Bonds, for the redemption of Bonds prior to maturity and for the payment of the reasonable and necessary fees and expenses to which the Trustee, Paying Agent and the Issuer are entitled pursuant to the Indenture or the Loan Agreement. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they shall receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture shall become null and void. The Bonds shall be deemed to have been paid and discharged when there shall have been irrevocably deposited with the Trustee moneys sufficient to pay the principal, premium, if any, and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations shall have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Surrender of First Mortgage Bonds

Upon payment of any principal of, premium, if any, and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture (see "Discharge of Indenture" above), First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) Failure to make payment of any installment of interest on any Bond (i) if such Bond bears interest at other than the Long Term Rate, within a period of one Business Day from the due date and (ii) if such Bond bears interest at the Long Term Rate, within a period of five Business Days from the date due;

(b) Failure to make punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable, provided that no event of default shall have occurred in respect of failure to receive such purchase price for any Bond if the Company shall have made the payment on the next Business Day as described in the last paragraph under "Summary of the Bonds — Remarketing and Purchase of Bonds" above;

(c) Failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an event of default under the Indenture if corrective action in respect of such failure is being diligently pursued;

(d) The occurrence of an "event of default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default"); or

(e) All first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under the Indenture, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of Bonds then outstanding and upon receipt of indemnity satisfactory to it shall: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable and (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders. Interest on the Bonds will cease to accrue on the date of issuance of the declaration of acceleration of payment of principal and interest on the Bonds. In exercising such rights, the Trustee shall take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal of, premium, if any, and interest on the Bonds then outstanding and may also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds shall have been declared due and payable, all such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds, and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys shall be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code and (ii) to the payment of principal of and interest then due and unpaid on the Bonds.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding shall have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee shall fail or refuse to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture shall be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment shall be authorized against the general credit of the Issuer.

No default under paragraph (c) above shall constitute an Event of Default until actual notice is given to the Issuer and the Company by the Trustee, or to the Issuer, the Company and the Trustee by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding and the Issuer and the Company shall have had thirty days after such notice to correct the default and failed to do so. If the default is such that it cannot be corrected within the applicable period but is capable of being cured, it will not constitute an Event of Default if corrective action is instituted within the applicable period.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and shall do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding shall have been declared to be due and payable and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due shall have been entered, (i) the Company has caused to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which shall have become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) shall have been remedied, then such Event of Default shall be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment shall be binding upon all Bondholders. No such waiver, rescission and annulment shall extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (e) under the subcaption "—Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

Notwithstanding the foregoing, nothing in the Indenture shall affect the right of a registered owner to enforce the payment of principal of, premium, if any, and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Trustee, as holder of the First Mortgage Bonds, shall attend any meeting of holders of first mortgage bonds outstanding under the First Mortgage Indenture as to which it receives due notice. The Trustee shall vote the First Mortgage Bonds held by it, or shall consent with respect thereto, proportionally in the way in which the Trustee reasonably believes will be the vote or consent of all other holders of first mortgage bonds outstanding under the First Mortgage Indenture then eligible to vote or consent.

Notwithstanding the foregoing, the Trustee may not vote the First Mortgage Bonds in favor of, or give consent to, any action which, in the Trustee's opinion, would materially adversely affect the First Mortgage Bonds in a manner not generally shared by all other series of first mortgage bonds, except upon notification by the Trustee to the registered owners of all Bonds then outstanding of such proposal and consent thereto of the registered owners of at least $66^{2/3}$% in aggregate principal amount of all Bonds then outstanding.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture without the consent of or notice to, the Bondholders in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to the Trustee, as may lawfully be granted, additional rights for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights reserved to the Issuer, (vi) to make any modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make amendments to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modification or change to the Indenture necessary to provide liquidity or credit support for the Bonds, or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Exclusive of supplemental indentures for the purposes set forth in the preceding paragraph, the consent of registered owners holding a majority in principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture shall permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the principal amount of the Bonds required for consent to such supplemental indenture, or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer shall request the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice shall set forth the nature of the proposed supplemental indenture and shall state that copies thereof are on file at the principal office of the Trustee for inspection. If, within sixty days (or such longer period as shall be prescribed by the Issuer or the Company) following the mailing of such notice, the registered owners holding the requisite amount of the Bonds outstanding shall have consented to the execution thereof, no Bondholder shall have any right to object or question the execution thereof.

No supplemental indenture shall become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company shall be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the principal office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

ENFORCEABILITY OF REMEDIES

The remedies available to the Trustee, the Issuer and the owners upon an event of default under the Loan Agreement, the Indenture or the First Mortgage Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement, the Indenture and the First Mortgage Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

REOFFERING

Subject to the terms and conditions of the Remarketing and Bond Purchase Agreement dated as of November 24, 2014 (the "Remarketing Agreement"), between the Company and Morgan Stanley & Co. LLC, as Representative of the Initial Co-Remarketing Agents, the Initial Co-Remarketing Agents have agreed to purchase and reoffer the Bonds delivered to the Paying Agent for purchase on December 15, 2014, at a price equal to 100% of the principal amount of the Bonds, plus accrued interest (if any), and in connection therewith will receive compensation in the amount of $227,500, plus reimbursement of certain expenses. Under the terms of the Remarketing Agreement, the Company has agreed to indemnify the Initial Co-Remarketing Agents against certain civil liabilities, including liabilities under federal securities laws.

The Initial Co-Remarketing Agents and their affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. The Initial Co-Remarketing Agents and certain of their affiliates have, from time to time, performed, and may in the future perform, various investment banking and commercial banking services for the Company, for which they received or will receive customary fees and expenses.

In the ordinary course of their various business activities, the Initial Co-Remarketing Agents and their affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (which may include bank loans and/or credit default swaps) for their own account and for the accounts of their customers and may at any time hold long and short positions in such securities and instruments. Such investment and securities activities may involve securities and instruments of the Company.

Morgan Stanley, parent company of Morgan Stanley & Co. LLC, one of the Remarketing Agents of the Bonds, has entered into a retail brokerage joint venture. As part of the joint venture, Morgan Stanley & Co. LLC will distribute municipal securities to retail investors through the financial advisor network of a new broker-dealer, Morgan Stanley Smith Barney LLC. This distribution arrangement became effective on June 1, 2009. As part of this arrangement, Morgan Stanley & Co. LLC will compensate Morgan Stanley Smith Barney LLC for its selling efforts with respect to the Bonds.

TAX TREATMENT

On March 22, 2002, the date on which the Bonds were originally issued, Bond Counsel delivered its opinion that stated that, under existing law, including then current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds would be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion would be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" of a substantial user as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Bond Counsel further opined that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds would be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds would be exempt from all ad valorem taxes in Kentucky. Such opinions have not been updated as of the date hereof and no continuing tax exemption opinions are expressed by Bond Counsel.

Bond Counsel also will deliver opinions in connection with this reoffering to the effect that the conversion of the interest rate on the Bonds to the Long Term Rate (i) is authorized or permitted by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act") and the related Indenture and (ii) will not adversely affect the validity of the Bonds or any exclusion from gross income of interest on the Bonds for federal income tax purposes to which interest on the Bonds would otherwise be entitled.

The opinion of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes was based upon and assumed the accuracy of certain representations of facts and circumstances, including with respect to the Project, which are within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel did not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the opinion and subsequent to the original delivery of the Bonds, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel expressed no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

The Code prescribes a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuer to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer have each covenanted to take all actions required of each to assure that the interest on the Bonds shall be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinion of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds was subject to the following exceptions and qualifications:

(a) The Code also provides for "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel expressed no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

The opinions of Bond Counsel delivered on the date of issuance of the Bonds are attached as Appendix B-1 and B-2. The opinions of Bond Counsel relating to conversion of the Bonds in substantially the forms in which they are expected to be delivered on the Conversion Date, redated to the Conversion Date, are attached as Appendices B-3 and B-4.

LEGAL MATTERS

Certain legal matters in connection with the conversion and reoffering of the Bonds will be passed upon by Stoll Keenon Ogden PLLC, Louisville, Kentucky, Bond Counsel. Certain legal matters pertaining to the Company will be passed upon by Jones Day, Chicago, Illinois, and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company. McGuireWoods LLP, Chicago, Illinois, will pass upon certain legal matters for the Remarketing Agents.

CONTINUING DISCLOSURE

Because the Bonds are special and limited obligations of the Issuers, neither Issuer is an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, or has any continuing obligations thereunder. Accordingly, neither Issuer will provide any continuing disclosure information with respect to the Bonds or such Issuer.

In order to enable the Remarketing Agents to comply with the requirements of the Rule, the Company has covenanted in a continuing disclosure undertaking agreement delivered to the Trustee for the benefit of the holders of the Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of the Bonds. Under its Continuing Disclosure Agreement, the Company has covenanted to take the following actions:

(i) The Company will provide to the Municipal Securities Rulemaking Board ("MSRB") (in electronic format) (a) annual financial information of the type set forth in Appendix A to this Reoffering Circular (including any information incorporated by reference in Appendix A) and (b) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(ii) The Company will file in a timely manner not in excess of 10 business days after the occurrence of the event with the MSRB notice of the occurrence of any of the following events (if applicable) with respect to the Bonds: (a) principal and interest payment delinquencies; (b) non-payment related defaults, if material; (c) any unscheduled draws on debt service reserves reflecting financial difficulties; (d) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (e) substitution of credit or liquidity providers, or their failure to perform; (f) adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds; (g) modifications to rights of the holders of the Bonds, if material; (h) the giving of notice of optional or unscheduled redemption of any Bonds, if material, and tender offers; (i) defeasance of the Bonds or any portion thereof; (j) release, substitution, or sale of property securing repayment of the Bonds, if material; (k) rating changes; (l) bankruptcy, insolvency, receivership or similar event of the Company; (m) the consummation of a merger, consolidation or acquisition involving the Company, or the sale of all or substantially all of the assets of the Company, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and (n) appointment of a successor or additional trustee or a change of name of a trustee, if material.

(iii) The Company will file in a timely manner with the MSRB notice of a failure by the Company to file any of the information referred to in paragraph (i) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit of the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

The Company is a party to continuing disclosure agreements with respect to nine series of pollution control bonds. The MSRB's Electronic Municipal Market Access website reflects that within the past five years (i) for two series of pollution control bonds, the Company did not file certain information in connection with the March 2011 downgrade of the Company's long-term debt and (ii) for one series of bonds, the Company's 2011 annual financial statements were posted to an outdated CUSIP number. The 2011 annual financial statements were posted for that series on May 17, 2012, approximately 17 days after the April 30th deadline. The Company's 2011 annual financial statements had been filed with the SEC on February 28, 2012. The Company has had, and continues to have, procedures in place in order to make material event notices and financial statement filings on an ongoing basis.

This Reoffering Circular has been duly approved, executed and delivered by the Company.

LOUISVILLE GAS AND ELECTRIC COMPANY

By: /s/ Daniel K. Arbough
Daniel K. Arbough
Treasurer

APPENDIX A

THE COMPANY

Louisville Gas and Electric Company (the "Company"), incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of December 31, 2013, the Company provides natural gas to approximately 321,000 customers and electricity to approximately 397,000 customers in Louisville and adjacent areas in Kentucky. The Company's electric service area covers approximately 700 square miles in 9 counties. The Company provides natural gas service in its electric service area and 8 additional counties. The Company's coal-fired electric generating stations, all equipped with systems to reduce sulphur dioxide emissions, produce most of the Company's electricity. The remainder is generated by a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help the Company provide economical and reliable natural gas service to customers.

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's affiliate, Kentucky Utilities Company ("KU"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of KU, PPL Corporation or the Company's other affiliates will be obligated to make any payment on the Loan Agreement or the Bonds.

The Company's executive offices are located at 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

The information above concerning the Company is only a summary and does not purport to be comprehensive. Additional information regarding the Company, including audited financial statements, is available in the documents listed under the caption "Documents Incorporated by Reference," which documents are incorporated by reference herein.

Selected Financial Data
(Dollars in millions)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013	Year Ended December 31, 2013	Year Ended December 31, 2012	Year Ended December 31, 2011
Operating revenues	$ 1,170	$ 1,049	$ 1,410	$ 1,324	$ 1,364
Operating income	$ 251	$ 224	$ 293	$ 237	$ 241
Net income	$ 133	$ 122	$ 163	$ 123	$ 124
Total assets	$ 5,299	$ 4,780	$ 4,934	$ 4,562	$ 4,387
Long-term debt obligations (including amounts due within one year)	$ 1,353	$ 1,112	$ 1,353	$ 1,112	$ 1,112
Ratio of earnings to fixed charges[(1)]	6.4	7.0	8.1	5.4	5.2

Capitalization:

	September 30, 2014	% of Capitalization
Long-term debt and notes payable	$ 1,496	41.8%
Common equity	2,083	58.2%
Total capitalization	$ 3,579	100.00%

(1) For purposes of this ratio, "Earnings" consist of earnings (as defined below) from continuing operations plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes and the mark-to-market impact of derivative instruments.

The selected financial data presented above for the three fiscal years ended December 31, 2013, and as of December 31 for each of those years, have been derived from the Company's audited financial statements. The selected financial data presented above for the nine months ended September 30, 2014 and 2013 have been derived from the Company's unaudited financial statements for the nine months ended September 30, 2014 and 2013. The Company's audited financial statements for the three fiscal years ended December 31, 2013, and as of December 31 for each of those years, are included in the Company's Form 10-K for the year ended December 31, 2013 incorporated by reference herein. The Company's unaudited financial statements for the nine months ended September 30, 2014 are included in the Company's Form 10-Q for the quarter ended September 30, 2014 incorporated by reference herein. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-K for the year ended December 31, 2013 and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-Q for the quarter ended September 30, 2014, as well as the Combined Notes to Financial Statements as of December 31, 2013, 2012 and 2011 and the Combined Notes to Condensed Financial Statements (Unaudited) as of September 30, 2014 and December 31, 2013 and for the nine-month periods ended September 30, 2014 and 2013, should be read in conjunction with the above information. Ernst & Young LLP audited the Company's financial statements for the three fiscal years ended December 31, 2012.

Risk Factors

Investing in the Bonds involves risk. Please see the risk factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2013, which is incorporated by reference in this Appendix A. Before making an investment decision, you should carefully consider these risks as well as the other information contained or incorporated by reference in this Appendix A. Risks and uncertainties not presently known to the Company or that the Company currently deems immaterial may also impair its business operations, its financial results and the value of the Bonds.

Available Information

The Company is subject to the information requirements of the Securities Exchange Act of 1934, as amended, and, accordingly, files reports, proxy statements and other information with the Securities and Exchange Commission (the "SEC"). Such reports, proxy statements and other information, can be inspected and copied at the public reference facilities of the SEC, currently at 100 F Street, N.E., Washington, D.C. 20549; and copies of such material can be obtained from the Public Reference Section of the SEC at its principal office of 100 F Street, N.E., Washington, D.C. 20549 at prescribed rates or from the SEC's Web Site (http://www.sec.gov). Please call the SEC at 1-800-SEC-0330 for further information on the operation of the public reference facilities.

Documents Incorporated By Reference

The following documents, as filed by the Company with the SEC, are incorporated herein by reference:

1. Form 10-K Annual Report of the Company for the year ended December 31, 2013; and

2. Form 10-Q Quarterly Reports of the Company for the quarters ended March 31, 2014, June 30, 2014, and September 30, 2014.

3. Form 8-K Current Report filed with the SEC on August 13, 2014.

All documents filed by the Company with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 subsequent to the date of this Reoffering Circular and prior to the termination of the remarketing of the Bonds shall be deemed to be incorporated by reference in this Appendix and to be made a part hereof from their respective dates of filing. Any statement contained in a document incorporated or deemed to be incorporated by reference in this Reoffering Circular shall be deemed to be modified or superseded for purposes of this Reoffering Circular to the extent that a statement contained in this Reoffering Circular or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Reoffering Circular modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Reoffering Circular.

The Company hereby undertakes to provide without charge to each person (including any beneficial owner) to whom a copy of this Reoffering Circular has been delivered, on the written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated in this Reoffering Circular by reference, other than certain exhibits to such documents. Requests for such copies should be directed to Daniel K. Arbough, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

APPENDIX B-1

(OPINION OF BOND COUNSEL)

HARPER, FERGUSON & DAVIS
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UISVILLE OFFICE
(502) 582-3871
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COVINGTON OFFICE
(606) 491-0712
TELECOPIER (606) 491-0187

March 22, 2002

Re: $35,000,000 County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Trimble, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), dated their date of issuance, in the aggregate principal amount of $35,000,000 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Louisville Gas and Electric Company (the "Company") for the current refunding of $35,000,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 1997 Series A (Louisville Gas and Electric Company Project), dated November 13, 1997 (the "Prior Bonds"), the proceeds of which were loaned to the Company to currently refund a portion of the costs of construction of air and water pollution control facilities and solid waste disposal facilities to serve certain electric generating units of the Company in Trimble County, Kentucky ("the Project") in order to provide for the control, containment, reduction and abatement of atmospheric and liquid pollutants and contaminants and for the disposal of solid wastes, as provided by the Act.

The Bonds mature on November 1, 2027 and bear interest initially at Flexible Rates, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in each of the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of November 1, 2001 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds and the Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of November 1, 2001 (the "Indenture"), by and between the County and Bankers Trust Company, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that all of the proceeds of the Prior Bonds were used to currently refinance certain bonds, all of the proceeds of which were used to currently refinance certain original bonds, not less than 95% of the net proceeds of which original bonds were used to finance air and water pollution control facilities and solid waste disposal facilities qualified for financing under Section 103(b)(4)(E) and (F) of the Internal Revenue Code of 1954, as amended, and permitted by Section 1312(a) of the Tax Reform Act of 1986. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds (or with similar requirements with respect to certain other bonds issued by the County of Jefferson, Kentucky at substantially the same time as the Bonds) subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received and relied upon opinions of John R. McCall, Esq., General Counsel of the Company and Jones, Day, Reavis & Pogue, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. Perry Arnold, County Attorney of the County, and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

HARPER, FERGUSON & DAVIS

By: Spencer E. Harper
SPENCER E. HARPER, JR.

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March 22, 2002

Re: $35,000,000 County of Jefferson, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Jefferson, Kentucky (the "County"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), dated their date of issuance, in the aggregate principal amount of $35,000,000 (the "Bonds"). The Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "Act"), for the purpose of providing funds which will be used, with other funds provided by Louisville Gas and Electric Company (the "Company") for the current refunding of $35,000,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 1997 Series A (Louisville Gas and Electric Company Project), dated November 13, 1997 (the "Prior Bonds"), the proceeds of which were loaned to the Company to currently refund a portion of the costs of construction of air pollution control facilities to serve certain electric generating units of the Company in Jefferson County, Kentucky ("the Project") in order to provide for the control, containment, reduction and abatement of atmospheric pollutants and contaminants, as provided by the Act.

The Bonds mature on November 1, 2027 and bear interest initially at Flexible Rates, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner and upon the terms set forth in each of the Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of November 1, 2001 (the "Loan Agreement"), between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Prior Bonds and the Company has agreed to make Loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on and redemption premium, if any, on the Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed and delivered by the County; and that the Loan Agreement is a legal, valid and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of November 1, 2001 (the "Indenture"), by and between the County and Bankers Trust Company, as trustee (the "Trustee"), securing the Bonds and setting forth the covenants and undertakings of the County in connection with the Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed and delivered by the County; and that the Indenture is a legal, valid and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the Bonds have been validly authorized, executed and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid and binding special obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, interest on the Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, inter alia, that all of the proceeds of the Prior Bonds were used to currently refinance certain bonds, all of the proceeds of which were used to currently refinance certain original bonds, not less than 95% of the net proceeds of which original bonds were used to finance air pollution control facilities qualified for financing under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended, and permitted by Section 1312(a) of the Tax Reform Act of 1986. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with subsequent to the issuance of the Bonds in order that interest on the Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the Bonds (or with similar requirements with respect to certain bonds issued by the County of Trimble, Kentucky at substantially the same time as the Bonds) subsequent to the issuance of the Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. We express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with approval of this firm is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability. We are further of the opinion that interest on the Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds is subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Holders of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income.

We have received and relied upon opinions of John R. McCall, Esq., General Counsel of the Company and Jones, Day, Reavis & Pogue, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. Irv Maze, County Attorney of the County, and relied upon said opinion with respect to the matters therein. Said opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges or encumbrances on, the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the Bonds or the accuracy or completeness of any statements made in connection with any sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

HARPER, FERGUSON & DAVIS

By: Spencer E. Harper
SPENCER E. HARPER, JR.

APPENDIX B-2

(OPINION OF BOND COUNSEL)

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December 15, 2014

County of Trimble, Kentucky
Bedford, Kentucky 40006

U.S. Bank National Association, as Trustee
Louisville, KY 40202

Re: Conversion to Long Term Rate Period of $35,000,000 "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of November 1, 2001, as amended by Supplemental Indenture No. 1 dated as of September 1, 2010 (the "Indenture"), between the County of Trimble, Kentucky (the "Issuer") and U.S. Bank National Association, as successor to Deutsche Bank Trust Company Americas as Trustee (the "Trustee"), pertaining to $35,000,000 principal amount of County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), dated March 22, 2002 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Flexible Rate to a Long Term Rate, for an initial Long Term Rate Period ending April 30, 2018, bearing interest at 1.35%, effective as of December 15, 2014 (the "Conversion Date"). The Bonds mature on November 1, 2027. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the validity of the Bonds or the exclusion from gross income of interest on the Bonds for federal income tax purposes. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated as of November 1, 2001, as amended by Amendment No. 1 to Loan Agreement dated as of September 1, 2010, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

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December 15, 2014

Louisville/Jefferson County Metro Government, Kentucky
Louisville, Kentucky 40202

U.S. Bank National Association, as Trustee
Louisville, KY 40202

Re: Conversion to Long Term Rate Period of $35,000,000 "Louisville/Jefferson County Metro Government, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project)"

Ladies and Gentlemen:

This opinion is being furnished in accordance with the requirements of the Indenture of Trust, dated as of November 1, 2001, as amended by Supplemental Indenture No. 1 dated as of September 1, 2010 (the "Indenture"), between the Louisville/Jefferson County Metro Government, Kentucky (the "Issuer") and U.S. Bank National Association, as successor to Deutsche Bank Trust Company Americas as Trustee (the "Trustee"), pertaining to $35,000,000 principal amount of Louisville/Jefferson County Metro Government, Kentucky, Pollution Control Revenue Bonds, 2001 Series B (Louisville Gas and Electric Company Project), dated March 22, 2002 (the "Bonds"), in order to satisfy certain requirements of Section 2.02(e)(i) of the Indenture. Pursuant to Section 2.02(e)(i) of the Indenture, the interest rate on the Bonds is being converted from a Flexible Rate to a Long Term Rate, for an initial Long Term Rate Period ending April 30, 2018, bearing interest at 1.35%, effective as of December 15, 2014 (the "Conversion Date"). The Bonds mature on November 1, 2027. The terms used herein denoted by initial capitals and not otherwise defined shall have the meanings specified in the Indenture.

We have examined the law and such documents and matters as we have deemed necessary to provide this opinion. As to questions of fact material to the opinions expressed herein, we have relied upon the provisions of the Indenture and related documents, and upon representations made to us without undertaking to verify the same by independent investigation.

Based upon the foregoing, as of the date hereof, we are of the opinion that the conversion of the interest rate on the Bonds as described herein is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the validity of the Bonds or the exclusion from gross income of interest on the Bonds for federal income tax purposes. Interest on the Bonds is not and will not be excluded from gross income during any period when the Bonds are held by the Company or a "related person" of the Company as defined in Section 147(a) of the Internal Revenue Code of 1986, as amended.

In rendering this opinion, we assume, without verifying, that the Issuer and the Company have complied and will comply with all covenants contained in the Indenture, the Loan Agreement between the Issuer and the Company, dated as of November 1, 2001, as amended by Amendment No. 1 to Loan Agreement dated as of September 1, 2010, and other documents relating to the Bonds. We rendered our approving opinion at the time of the issuance of the Bonds relating to, among other things, the validity of the Bonds and the exclusion from federal income taxation of interest on the Bonds. We have not been requested to update or continue such opinion and have not undertaken to do so. Accordingly, we do not express any opinion with respect to the Bonds except as set forth above.

Our opinion represents our legal judgment based upon our review of the law and the facts that we deem relevant to render such opinion and is not a guarantee of a result. This opinion is given as of the date hereof and we assume no obligation to review or supplement this opinion to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We express no opinion herein as to the investment quality of the Bonds or the adequacy, accuracy or completeness of any information furnished to any person in connection with any offer or sale of the Bonds.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

NEW ISSUE **BOOK-ENTRY ONLY**

Subject to the conditions and exceptions set forth under the heading "Tax Treatment," Bond Counsel is of the opinion that, under current law, interest on the Bonds offered hereby will be excludable from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" or a "related person" of the Project as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"). Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. Such interest may be subject to certain federal income taxes imposed on certain corporations, including imposition of the branch profits tax on a portion of such interest. Bond Counsel is further of the opinion that interest on the Bonds will be excludable from the gross income of the recipients thereof for Kentucky income tax purposes and that, under current law, the principal of the Bonds will be exempt from ad valorem taxes in Kentucky. Issuance of the Bonds is subject to receipt of a favorable tax opinion of Bond Counsel as of the date of delivery of the Bonds. See "Tax Treatment" herein.

$125,000,000
County of Trimble, Kentucky
Pollution Control Revenue Refunding Bonds, 2016 Series A, Due September 1, 2044 (Louisville Gas and Electric Company Project)

Dated: Date of Original Issuance

The County of Trimble, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project) (the "Bonds") will be special and limited obligations of the County of Trimble, Kentucky (the "Issuer"), payable by the Issuer solely from and secured by payments to be received by the Issuer pursuant to a Loan Agreement with Louisville Gas and Electric Company (the "Company"), except as payable from proceeds of such Bonds or investment earnings thereon. The Bonds will not constitute general obligations of the Issuer or a charge against the general credit or taxing powers thereof or of the Commonwealth of Kentucky or any other political subdivision of Kentucky.

Principal of, and interest on, the Bonds are further secured by the delivery to U.S. Bank National Association, as Trustee, of First Mortgage Bonds of

LOUISVILLE GAS AND ELECTRIC COMPANY

From and after the date of the issuance and delivery of the Bonds, the Bonds will bear interest at a Weekly Rate, determined by the Remarketing Agent, J.P. Morgan Securities LLC, in accordance with the Indenture, payable on the first Business Day of each calendar month. The interest rate period, interest rate and interest rate mode will be subject to change under certain conditions, as described in this Official Statement. The Bonds will be subject to optional redemption, extraordinary optional redemption and mandatory redemption following a determination of taxability prior to maturity, as described in this Official Statement. The Bonds are subject to optional purchase on the demand of the owner and to mandatory purchase on any date on which the Bonds are converted to a different Interest Rate Mode, in each case as described in this Official Statement.

PRICE: 100%

The Bonds, when issued, will be registered in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company ("DTC"), New York, New York. DTC will act as securities depository. Purchases of beneficial ownership interests in the Bonds will be made in book-entry only form in denominations of $100,000 and multiples thereof. Purchasers will not receive certificates representing their beneficial interests in the Bonds. See the information contained under the heading "Summary of the Bonds — Book-Entry-Only System" in this Official Statement. The principal or redemption price of and interest on the Bonds will be paid by U.S. Bank National Association, as Trustee, to Cede & Co., as long as Cede & Co. is the registered owner of the Bonds. Disbursement of such payments to the DTC Participants is the responsibility of DTC, and disbursement of such payments to the purchasers of beneficial ownership interests is the responsibility of DTC's Direct and Indirect Participants, as more fully described herein.

Liquidity to pay the purchase price of the Bonds that are tendered and not remarketed will be provided by the Company. It is not anticipated that a liquidity or credit facility will be provided by any other party. Prospective purchasers of the Bonds should rely solely on the ability of the Company to provide for the purchase of the Bonds that are tendered and not remarketed. The failure of the Company to pay the purchase price of any Bond tendered by the holder thereof and not remarketed is an Event of Default under the Indenture.

The Bonds are offered when, as and if issued and received by the Underwriter, subject to prior sale, withdrawal or modification of the offer without notice, and to the approval of legality by Stoll Keenon Ogden PLLC, Louisville, Kentucky, as Bond Counsel and upon satisfaction of certain conditions. Certain legal matters will be passed upon for the Company by its counsel, Jones Day, Chicago, Illinois and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and Corporate Secretary of the Company, for the Issuer by its County Attorney, and for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois. It is expected that the Bonds will be available for delivery to DTC in New York, New York on or about September 15, 2016.

J.P. Morgan

September 7, 2016

The Bonds are exempt from registration under the Securities Act of 1933, as amended.

No dealer, broker, salesman or other person has been authorized by the Issuer, the Company or the Underwriter to give any information or to make any representation with respect to the Bonds, other than those contained in this Official Statement, and, if given or made, such other information or representation must not be relied upon as having been authorized by any of the foregoing. The Underwriter has provided the following sentence for inclusion in this Official Statement. The Underwriter has reviewed the information in this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such information. The information and expressions of opinion in this Official Statement are subject to change without notice and neither the delivery of this Official Statement nor any sale made hereunder shall, under any circumstances, create any implication that there has been no change in the affairs of the parties referred to above since the date hereof.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions which stabilize or maintain the market prices of such Bonds at levels above those which might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

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OFFICIAL STATEMENT

$125,000,000
County of Trimble, Kentucky
Pollution Control Revenue Refunding Bonds,
2016 Series A, Due September 1, 2044
(Louisville Gas and Electric
Company Project)

Introductory Statement

This Official Statement, including the cover page and Appendices, is provided to furnish information in connection with the offer and sale by the County of Trimble, Kentucky (the "Issuer") of its Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project), in the aggregate principal amount of $125,000,000 (the "Bonds") to be issued pursuant to an Indenture of Trust dated as of September 1, 2016 (the "Indenture") between the Issuer and U.S. Bank National Association (the "Trustee"), as Trustee, Paying Agent and Bond Registrar.

Pursuant to a Loan Agreement by and between Louisville Gas and Electric Company (the "Company") and the Issuer, dated as of September 1, 2016, (the "Loan Agreement"), proceeds from the sale of the Bonds, other than accrued interest, if any, paid by the initial purchasers thereof, will be loaned by the Issuer to the Company.

The proceeds of the Bonds (other than any accrued interest) will be applied in full, together with other moneys made available by the Company, to pay and discharge (i) $83,335,000 in outstanding principal amount of "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2000 Series A (Louisville Gas and Electric Company Project)," dated August 9, 2000 (the "2000 Bonds") and (ii) $41,665,000 in outstanding principal amount of "County of Trimble, Kentucky, Pollution Control Revenue Bonds, 2002 Series A (Louisville Gas and Electric Company Project)," dated October 23, 2002 (the "2002 Bonds" and, collectively with the 2000 Bonds, the "Prior Bonds"), previously issued by the Issuer to refinance certain pollution control facilities (the "Project") owned by the Company. For information regarding the pollution control facilities, see "The Project."

It is a condition to the Underwriter's obligation to purchase the Bonds that the Company irrevocably instruct the trustees in respect of the Prior Bonds, on or prior to the date of issuance of the Bonds, to call the Prior Bonds for redemption.

The Company will repay the loan under the Loan Agreement by making payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest on the Bonds and will further agree under the Loan Agreement to make payments of the purchase price of the Bonds tendered for purchase to the extent funds are not otherwise available under the Indenture. See "Summary of the Loan Agreement — General." Pursuant to the Indenture, the Issuer's rights under the Loan Agreement (other than with respect to certain rights to indemnification, reimbursement, notice and payment of expenses) will be assigned to the Trustee as security for the Bonds.

For the purpose of further securing the Bonds, the Company will issue and deliver to the Trustee a series of the Company's First Mortgage Bonds, Collateral Series 2016TCA (the "First Mortgage Bonds"). The principal amount, maturity date and interest rate (or method of determining interest rates) of such First Mortgage Bonds will correspond to the principal amount, maturity date and interest rate (or method of determining interest rates) of the Bonds. The First Mortgage Bonds will only be payable, and interest thereon will only accrue, as described herein. See "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds" and "Summary of the First Mortgage Bonds and the First Mortgage Indenture." The First Mortgage Bonds will not provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture.

The First Mortgage Bonds will be issued under, and will be secured by, the Company's Indenture, dated as of October 1, 2010, as previously supplemented and as to be supplemented by a supplemental indenture to be dated as of September 1, 2016 relating to the Bonds (the "First Mortgage Supplemental Indenture" and the Indenture, as so supplemented, the "First Mortgage Indenture"), between the Company and The Bank of New York Mellon, as trustee (the "First Mortgage Trustee").

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of PPL Corporation or the Company's other affiliates will be obligated to make any payments due under the Loan Agreement or First Mortgage Bonds or any other payments of principal, interest, redemption price or purchase price of the Bonds.

The Bonds will be special and limited obligations of the Issuer, and the Issuer's obligation to pay the principal or redemption price of and interest on, and purchase price of, the Bonds will be limited solely to the revenues and other amounts received by the Trustee under the Indenture pursuant to the Loan Agreement, including amounts payable on the First Mortgage Bonds. The Bonds will not constitute an indebtedness, general obligation or pledge of the faith and credit or taxing power of the Issuer, the Commonwealth of Kentucky or any political subdivision thereof.

J.P. Morgan Securities LLC will be appointed in accordance with the Indenture to serve as Remarketing Agent for the Bonds. The Remarketing Agent may resign or be removed and a successor Remarketing Agent may be appointed in accordance with the terms of the Indenture and the Remarketing Agreement for the Bonds between the Remarketing Agent and the Company.

Brief descriptions of the Company, the Issuer, the Bonds, the Loan Agreement, the Indenture, the First Mortgage Bonds and the First Mortgage Indenture are included in this Official Statement. Such descriptions and information do not purport to be complete, comprehensive or definitive and are not to be construed as a representation or a guaranty of completeness. All references in this Official Statement to the documents are qualified in their entirety by reference to such documents, and references in this Official Statement to the Bonds are qualified in their entirety by reference to the definitive form of the Bonds included in the Indenture. Copies of the Loan Agreement and the Indenture will be available for inspection at the principal corporate trust office of the Trustee and, until the issuance of the Bonds, may be obtained from the Underwriter. The First Mortgage Indenture (including the form of the First Mortgage Bonds) is available for inspection at the office of the Company in Louisville, Kentucky, and at the corporate trust office of the First Mortgage Trustee, in Pittsburgh, Pennsylvania. Certain information relating to The Depository Trust Company ("DTC") and the book-entry-only system has been furnished by DTC. Appendix A to this Official Statement and all information contained under the headings "The Project" and "Use of Proceeds" has been furnished by the Company. The Issuer, Bond Counsel and the Remarketing Agent assume no responsibility for the accuracy or completeness of such Appendix A or such information. The Underwriter has reviewed the information in Appendix A to this Official Statement in accordance with, and as part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the completeness of such Appendix A or such information. Appendix B to this Official Statement contains the proposed form of opinion of Bond Counsel to be delivered in connection with the issuance and delivery of the Bonds.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at the Weekly Rate. In the event of a remarketing of the Bonds on or after a Conversion, a supplement to this Official Statement or a new reoffering circular will be prepared describing the new terms and provisions then applicable to such Bonds.

The Issuer

The Issuer is a public body corporate and politic duly created and existing as a county and political subdivision under the Constitution and laws of the Commonwealth of Kentucky. The Issuer is authorized by Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (collectively, the "Act") to (a) issue the Bonds to pay and discharge the Prior Bonds, (b) lend the proceeds from the sale of the Bonds to the Company for such purpose and (c) enter into and perform its obligations under the Loan Agreement and the Indenture. The Issuer, through its legislative body, the Fiscal Court, has adopted one or more ordinances authorizing the issuance of the Bonds and the execution and delivery of the related documents.

THE BONDS WILL BE SPECIAL AND LIMITED OBLIGATIONS PAYABLE SOLELY AND ONLY FROM CERTAIN SOURCES, INCLUDING AMOUNTS TO BE RECEIVED BY OR ON BEHALF OF THE ISSUER UNDER THE LOAN AGREEMENT, INCLUDING AMOUNTS PAYABLE ON THE FIRST MORTGAGE BONDS. THE BONDS WILL NOT CONSTITUTE AN INDEBTEDNESS, GENERAL OBLIGATION OR PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE ISSUER, THE COMMONWEALTH OF KENTUCKY OR ANY POLITICAL SUBDIVISION THEREOF, AND WILL NOT GIVE RISE TO A PECUNIARY LIABILITY OF THE ISSUER OR A CHARGE AGAINST ITS GENERAL CREDIT OR TAXING POWERS.

The Project

The Project being refinanced with the Bonds has been completed and is the property of the Company, subject to the lien of the First Mortgage Indenture. The Project consists of certain air and water pollution control facilities of the Company at the Company's Trimble County Generating Station located in Trimble County, Kentucky (the "Generating Station"), which facilities are an integral component of the comprehensive system of air and water pollution control and solid waste disposal facilities at the Generating Station (the "Project").

The Department for Natural Resources and Environmental Protection of the Commonwealth of Kentucky (now the Energy and Environment Cabinet), the agency exercising jurisdiction with respect to the Project, has certified that the Project, as designed (which includes the facilities constituting the Project), is in furtherance of the purposes of abating and controlling atmospheric and water pollutants or contaminants, as applicable.

Use of Proceeds

The proceeds from the sale of the Bonds (other than any accrued interest) will be used, together with funds to be provided by the Company, to pay and discharge at a redemption price of 100% of the principal amount thereof, plus accrued interest, all of the outstanding Prior Bonds, on the date of the issuance of the Bonds. The Prior Bonds currently bear interest at an auction rate and mature on August 1, 2030 and October 1, 2032. For the twelve months ended June 30, 2016, the weighted average interest rate on the Prior Bonds was 0.486%.

Summary of the Bonds

General

The Bonds will be issued in the aggregate principal amount set forth on the cover page of this Official Statement. The Bonds will mature as to principal on September 1, 2044. The Bonds are also subject to redemption prior to maturity as described in this Official Statement.

The Bonds will bear interest at a Weekly Rate, and interest will be payable on the first Business Day of each calendar month, until a Conversion to another Interest Rate Mode is specified by the Company or until the redemption or maturity of the Bonds. The permitted Interest Rate Modes for the Bonds are (i) the Flexible Rate, (ii) the Daily Rate, (iii) the Weekly Rate, (iv) the Semi-Annual Rate, (v) the Annual Rate, (vi) the Long Term Rate, (vii) the LIBOR Index Rate and (viii) the SIFMA-Based Term Rate.

This Official Statement only describes the terms and provisions applicable to the Bonds while accruing interest at the Weekly Rate. In the event of a remarketing of the Bonds on or after a Conversion to another Interest Rate Mode, a supplement to this Official Statement or a new reoffering circular will be prepared describing the new terms and provisions then applicable to such Bonds.

During each Weekly Rate Period, the interest rate for the Bonds will be the rate established by the Remarketing Agent no later than 4:00 p.m. (New York City time) on the day preceding such Weekly Rate Period or, if such day is not a Business Day, on the next preceding Business Day, as the minimum rate of interest necessary, in the judgment of the Remarketing Agent taking into account then Prevailing Market Conditions (as defined below), and assuming that all Bonds are then available for sale, to enable the Remarketing Agent to sell the Bonds on such first day at a price equal to the principal amount thereof, plus accrued interest, if any, thereon; provided that the interest rate or rates borne by any Bonds may not exceed the lesser of (i) the maximum interest rate permitted by applicable law or (ii) 12% per annum. If for any reason the interest rate for the Bonds is not determined by the Remarketing Agent, except as described below under "Conversion of Interest Rate Modes — Cancellation of Conversion of Interest Rate Mode," the interest rate for the next succeeding interest rate period will be the interest rate in effect for the Bonds for the preceding interest rate period.

Interest on the Bonds will be computed on the basis of a year of 365 or 366 days, as appropriate, and paid for the actual number of days elapsed. Interest payable on any Interest Payment Date will be payable to the registered owner of the Bond as of the Record Date for such payment. The Record Date will be the close of business on the Business Day immediately preceding each Interest Payment Date.

The Bonds initially will be issued solely in book-entry-only form through DTC (or its nominee, Cede & Co.). So long as the Bonds are held in the book-entry-only system, DTC or its nominee will be the registered owner or holder of the Bonds for all purposes of the Indenture, the Bonds and this Official Statement. See "Book-Entry-Only System" below. Individual purchases of book-entry interests in the Bonds will be made in book-entry-only form in denominations of $100,000 and multiples thereof.

So long as the Bonds are held in book-entry-only form, the principal or redemption price of and interest on, and purchase price of, the Bonds will be payable by the Trustee, as paying agent (the "Paying Agent"), through the facilities of DTC (or a successor depository).

Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated office of the Trustee, as bond registrar (the "Bond Registrar"), accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond (i) during the fifteen days before any mailing of a notice of redemption of Bonds, (ii) after such Bond has been called for redemption or (iii) for which a registered owner has submitted a demand for purchase (see "Purchases of Bonds — Purchases of Bonds on Demand of Owner" below), or which has been purchased (see "Purchases of Bonds — Payment of Purchase Price" below). Registration of transfers and exchanges will be made without charge to the registered owners of Bonds, except that the Bond Registrar may require any registered owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Certain Definitions

As used herein, each of the following terms will have the meaning indicated:

"*Beneficial Owner*" means the person in whose name a Bond is recorded as such by the respective systems of DTC and each Participant (as defined herein) or the registered holder of such Bond if such Bond is not then registered in the name of Cede & Co.

"*Business Day*" means any day other than (i) a Saturday or Sunday or legal holiday or a day on which banking institutions in the city in which the designated office of the Trustee, the Bond Registrar, the Tender Agent, the Paying Agent, the Company or the Remarketing Agent is located are authorized by law or executive order to close or (ii) a day on which the New York Stock Exchange is closed.

"*Conversion*" means any conversion from time to time in accordance with the terms of the Indenture of the Bonds from one Interest Rate Mode to another Interest Rate Mode.

"*Conversion Date*" means initially the date of original issuance of the Bonds, and thereafter means the date on which any Conversion becomes effective.

"*Interest Payment Date*" means the first Business Day of each calendar month and any Conversion Date (including the date of a failed Conversion). In any case, the final Interest Payment Date will be the maturity date of the Bonds.

"*Interest Rate Mode*" means the Flexible Rate, the Daily Rate, the Weekly Rate, the Semi-Annual Rate, the Annual Rate, the Long Term Rate, the LIBOR Index Rate and the SIFMA-Based Term Rate.

"*Prevailing Market Conditions*" means, without limitation, the following factors: existing short-term or long-term market rates for securities, the interest on which is excluded from gross income for federal income tax purposes; indexes of such short-term or long-term rates and the existing market supply and demand for securities bearing such short-term or long-term rates; existing yield curves for short-term or long-term securities for obligations of credit quality comparable to the Bonds, the interest on which is excluded from gross income for federal income tax purposes; general economic conditions; industry economic and financial conditions that may affect or be relevant to the Bonds; and such other facts, circumstances and conditions as the Remarketing Agent, in its sole discretion, determines to be relevant.

"*Purchase Date*" means any date on which Bonds are to be purchased on the demand of the registered owners thereof or are subject to mandatory purchase as described in the Indenture.

"*Weekly Rate Period*" means the period beginning on, and including, the date of issuance of the Bonds, and ending on, and including, the next Wednesday, and thereafter the period beginning on, and including, each Thursday and ending on, and including, the earliest of the next Wednesday, the day preceding the Conversion to a different Interest Rate Mode or the maturity of the Bonds.

Conversion of Interest Rate Modes

The Interest Rate Mode for the Bonds is subject to Conversion from time to time, in whole but not in part, on the dates specified below at the option of the Company, upon notice from the Bond Registrar to the registered owners of the Bonds, as described below. With any notice of Conversion, the Company must also deliver to the Bond Registrar an opinion of Bond Counsel stating that such Conversion is authorized or permitted by the Act and is authorized by the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes, other than a Conversion from the Weekly Rate Period to the Daily Rate Period.

Any Conversion of the Interest Rate Mode for the Bonds must be in compliance with the following conditions: (i) the Conversion Date must be a date on which the Bonds are subject to optional redemption (see "Redemptions — Optional Redemption" below); provided that any Conversion from the Weekly Rate Period to the Daily Rate Period must be on a Thursday; (ii) if the proposed Conversion Date would not be an Interest Payment Date but for the Conversion, the Conversion Date must be a Business Day; and (iii) after a determination is made requiring mandatory redemption of all Bonds pursuant to the Indenture (see "Redemptions" below), no change in the Interest Rate Mode may be made prior to such mandatory redemption.

The Bond Registrar will notify each registered owner of the Conversion by first class mail at least 15 days before each Conversion Date. The notice will state those matters required to be set forth therein under the Indenture.

Notwithstanding the foregoing, no Conversion will occur if (A) the Remarketing Agent has not determined the initial interest rate for the new Interest Rate Mode in accordance with the terms of the Indenture, (B) the Bonds that are to be purchased are not remarketed or sold by the Remarketing Agent, or (C) the Bond Registrar receives written notice from Bond Counsel prior to the opening of business on the effective date of Conversion to the effect that the opinion of such Bond Counsel required under the Indenture has been rescinded. If such Conversion fails to occur, the Bonds will remain in the Weekly Rate (with the first period adjusted in length so that the last day of such period will be a Wednesday) at the rate determined by the Remarketing Agent on the failed Conversion Date. If the proposed Conversion of Bonds fails as described herein, any mandatory purchase of such Bonds will remain effective.

Purchases of Bonds

Purchases of Bonds on Demand of Owner. Any Bond will be purchased on the demand of the registered owner thereof on any Business Day during a Weekly Rate Period at a purchase price equal to the principal amount thereof plus accrued interest, if any, to the Purchase Date upon written notice to the Tender Agent at its designated office at or before 5:00 p.m. (New York City time) on a Business Day not later than the seventh day prior to the Purchase Date.

Notwithstanding the foregoing, there will be no purchase of (a) a portion of any Bond unless the portion to be purchased and the portion to be retained each will be in an authorized denomination or (b) any Bond upon the demand of the registered owner if an Event of Default under the Indenture with respect to the payment of principal of, interest on, or purchase price of, the Bonds has occurred and is continuing.

Any written notice delivered to the Tender Agent by an owner demanding the purchase of Bonds must (A) be delivered by the time and dates specified above, (B) state the number and principal amount (or portion thereof) of such Bond to be purchased, (C) state the Purchase Date on which such Bond is to be purchased, (D) irrevocably request such purchase and state that the owner agrees to deliver such Bond, duly endorsed in blank for transfer, with all signatures guaranteed, to the Tender Agent at or prior to 12:00 noon (New York City time) on such Purchase Date.

If the Bonds are in the book-entry-only system, demands for purchase may be made by Beneficial Owners only through such Beneficial Owner's Direct Participant (as defined under the heading "Book-Entry-Only System"). If the Bonds are in certificated form, demands for purchase may be made only by registered owners.

Mandatory Purchase of Bonds. The Bonds will be subject to mandatory purchase at a purchase price equal to the principal amount thereof on each Conversion Date. Such tender and purchase will be required even if the Conversion is canceled pursuant to the Indenture.

Notice to owners of a mandatory purchase of Bonds on a Conversion Date will be given by the Bond Registrar, together with the notice of such Conversion, by first class mail at least 15 days before each Conversion Date. The notice of mandatory purchase will state those matters required to be set forth therein under the Indenture.

Remarketing and Purchase of Bonds. The Indenture provides that, subject to the terms of a Remarketing Agreement with the Company, the Remarketing Agent will use its commercially reasonable best efforts to remarket Bonds purchased upon demand of the owners thereof and, unless otherwise instructed by the Company, upon mandatory purchase, provided that Bonds will not be remarketed upon the occurrence and continuance of certain Events of Default under the Indenture, except in the sole discretion of the Remarketing Agent. Each such sale will be at a price equal to the principal amount thereof, plus interest accrued to the date of sale. The Remarketing Agent, the Trustee, the Paying Agent, the Bond Registrar or the Tender Agent each may purchase any Bonds offered for sale for its own account.

The purchase price of Bonds tendered for purchase will be paid by the Tender Agent from moneys derived from the remarketing of such Bonds by the Remarketing Agent and, if such remarketing proceeds are insufficient, from moneys made available by the Company.

The Company is obligated to purchase any Bonds tendered for purchase to the extent such Bonds have not been remarketed. Any such purchases by the Company will not result in the extinguishment of the purchased Bonds. The Company currently maintains lines of credit or other liquidity facilities in amounts determined by it to be sufficient to meet its current needs and expects to continue to maintain such lines of credit or other liquidity facilities from time to time to the extent determined by it to be necessary to meet its then-current needs. The Trustee, any Paying Agent, the Tender Agent and the owners of the Bonds have no right to draw under any line of credit or other liquidity facility maintained by the Company. There is no provision in the Indenture or the Loan Agreement requiring the Company to maintain such financing arrangements which may be discontinued at any time without notice. The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase pursuant to the Indenture.

Any deficiency in purchase price payments resulting from the Remarketing Agent's failure to deliver remarketing proceeds of all Bonds with respect to which the Remarketing Agent notified the Tender Agent were remarketed will not result in an Event of Default under the Indenture until the opening of business on the next succeeding Business Day unless the Company fails to provide sufficient funds to pay such purchase price by the opening of business on such next succeeding Business Day. If sufficient funds are not available for the purchase of all tendered Bonds, no purchase of Bonds will be consummated, but failure to consummate such purchase will not be deemed to be an Event of Default under the Indenture if sufficient funds have been provided in a timely manner by the Company to the Tender Agent for such purpose.

Payment of Purchase Price. Payment of the purchase price of any Bond will be payable (and delivery of a replacement Bond in exchange for the portion of any Bond not purchased if such Bond is purchased in part will be made) on the Purchase Date upon delivery of such Bond to the Tender Agent on such Purchase Date; provided that such Bond must be delivered to the Tender Agent at or prior to 12:00 noon (New York City time). If the date of such purchase is not a Business Day, the purchase price will be payable on the next succeeding Business Day. When a book-entry-only system is in effect, the requirement for physical delivery of the Bonds will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on the records of DTC to the participant account of the Tender Agent.

Any Bond delivered for payment of the purchase price must be accompanied by an instrument of transfer thereof in form satisfactory to the Tender Agent executed in blank by the registered owner thereof and with all signatures guaranteed. The Tender Agent may refuse to accept delivery of any Bond for which an instrument of transfer satisfactory to it has not been provided and has no obligation to pay the purchase price of such Bond until a satisfactory instrument is delivered.

If the registered owner of any Bond (or portion thereof) that is subject to purchase pursuant to the Indenture fails to deliver such Bond with an appropriate instrument of transfer to the Tender Agent for purchase on the Purchase Date, and if the Tender Agent is in receipt of the purchase price therefor, such Bond (or portion thereof) nevertheless will be deemed purchased on the Purchase Date thereof. Any owner who so fails to deliver such Bond for purchase on (or before) the Purchase Date will have no further rights thereunder, except the right to receive the purchase price thereof from those moneys deposited with the Tender Agent in the Purchase Fund pursuant to the Indenture upon presentation and surrender of such Bond to the Tender Agent properly endorsed for transfer in blank with all signatures guaranteed.

Special Considerations Relating to the Purchase and Remarketing of the Bonds

The Remarketing Agent is Paid by the Company. The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement), all as further described in this Official Statement. The Remarketing Agent has been appointed by the Company and is paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent Routinely Purchases Bonds for its Own Account. The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds May be Offered at Different Prices on Any Date Including an Interest Rate Determination Date. Pursuant to the Indenture, the Remarketing Agent is required to determine the applicable rate of interest that, in its judgment, is the minimum rate necessary, based on Prevailing Market Conditions, and assuming that all Bonds are then available for sale, for the Remarketing Agent to sell the Bonds on the day the rate is set at their principal amount (without regard to accrued interest). The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). The Indenture requires that the Remarketing Agent use its commercially reasonable best efforts to sell tendered Bonds at par, plus accrued interest, if any. There may or may not be Bonds tendered and remarketed on a day that the interest rate on the Bonds is set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third-party buyers for all of the Bonds at the remarketing price.

Secondary Market Transactions. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the interest rate on the Bonds is set, at a discount to par to some investors.

The Ability to Sell the Bonds other than through the Tender Process May Be Limited. The Remarketing Agent may buy and sell Bonds other than in connection with the tender and remarketing process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process set forth in the Indenture.

Under Certain Circumstances, the Remarketing Agent May Be Removed, Resign or Cease Remarketing the Bonds, Without a Successor Being Named. Under certain circumstances, the Remarketing Agent may be removed or have the ability to resign or cease its remarketing efforts, without a successor having been named, subject to the terms of the Remarketing Agreement and the Indenture.

Redemptions

Optional Redemption. The Bonds will be subject to redemption at the option of the Issuer, upon the written direction of the Company, in whole or in part, at a redemption price of 100% of the principal amount thereof, plus interest accrued, if any, to the redemption date, on any Business Day.

Extraordinary Optional Redemption in Whole. The Bonds may be redeemed by the Issuer in whole at any time at 100% of the principal amount thereof plus accrued interest to the redemption date upon the exercise by the Company of an option under the Loan Agreement to prepay the loan if any of the following events occur within 180 days preceding the giving of written notice by the Company to the Trustee of such election:

(i) if in the judgment of the Company, unreasonable burdens or excessive liabilities have been imposed upon the Company after the issuance of the Bonds with respect to the Project or the operation thereof, including without limitation federal, state or other ad valorem property, income or other taxes not imposed on the date of the Loan Agreement, other than ad valorem taxes levied upon privately owned property used for the same general purpose as the Project;

(ii) if the Project or a portion thereof or other property of the Company in connection with which the Project is used has been damaged or destroyed to such an extent so as, in the judgment of the Company, to render the Project or other property of the Company in connection with which the Project is used unsatisfactory to the Company for its intended use, and such condition continues for a period of six months;

(iii) there has occurred condemnation of all or substantially all of the Project or the taking by eminent domain of such use or control of the Project or other property of the Company in connection with which the Project is used so as, in the judgment of the Company, to render the Project or such other property of the Company unsatisfactory to the Company for its intended use;

(iv) in the event changes, which the Company cannot reasonably control, in the economic availability of materials, supplies, labor, equipment or other properties or things necessary for the efficient operation of the Generating Station have occurred, which, in the judgment of the Company, render the continued operation of such Generating Station or any generating unit at such station uneconomical; or changes in circumstances after the issuance of the Bonds, including but not limited to changes in clean air or other air and water pollution control requirements or solid waste disposal requirements, have occurred such that the Company determines that use of the Project is no longer required or desirable;

(v) the Loan Agreement has become void or unenforceable or impossible of performance by reason of any changes in the Constitution of the Commonwealth of Kentucky or the Constitution of the United States of America or by reason of legislative or administrative action (whether state or federal) or any final decree, judgment or order of any court or administrative body, whether state or federal; or

(vi) a final order or decree of any court or administrative body after the issuance of the Bonds requires the Company to cease a substantial part of its operation at the Generating Station to such extent that the Company will be prevented from carrying on its normal operations at such Generating Station for a period of six months.

Extraordinary Optional Redemption in Whole or in Part. The Bonds are also subject to redemption in whole or in part at 100% of the principal amount thereof plus accrued interest to the redemption date at the option of the Company in an amount not to exceed the net proceeds received from insurance or any condemnation award received by the Issuer, the Company or the First Mortgage Trustee in the event of damage, destruction or condemnation of all or a portion of the Project, subject to compliance with the terms of the First Mortgage Indenture and receipt of an opinion of Bond Counsel that such redemption will not adversely affect the exclusion of interest on any of the Bonds from gross income for federal income tax purposes. See "Summary of the Loan Agreement — Maintenance; Damage, Destruction and Condemnation." Such redemption must occur on a date on which the Bonds are otherwise subject to optional redemption as described above.

Mandatory Redemption; Determination of Taxability. The Bonds are required to be redeemed by the Issuer, in whole, or in such part as described below, at a redemption price equal to 100% of the principal amount thereof, without redemption premium, plus accrued interest, if any, to the redemption date, within 180 days following a "Determination of Taxability." As used herein, a "Determination of Taxability" means the receipt by the Trustee of written notice from a current or former registered owner of a Bond or from the Company or the Issuer of (i) the issuance of a published or private ruling or a technical advice memorandum by the Internal Revenue Service in which the Company participated or has been given the opportunity to participate, and which ruling or memorandum the Company, in its discretion, does not contest or from which no further right of administrative or judicial review or appeal exists, or (ii) a final determination from which no further right of appeal exists of any court of competent jurisdiction in the United States in a proceeding in which the Company has participated or has been a party, or has been given the opportunity to participate or be a party, in each case, to the effect that as a result of a failure by the Company to perform or observe any covenant or agreement or the inaccuracy of any representation contained in the Loan Agreement or any other agreement or certificate delivered in connection with the Bonds, the interest on the Bonds is included in the gross income of the owners thereof for federal income tax purposes, other than with respect to a person who is a "substantial user" or a "related person" of a substantial user of the Project within the meaning of Section 147 of the Internal Revenue Code of 1986, as amended (the "Code"); provided, however, that no such Determination of Taxability will be considered to exist as a result of the Trustee receiving notice from a current or former registered owner of a Bond or from the Issuer unless (i) the Issuer or the registered owner or former registered owner of the Bond involved in such proceeding or action (A) gives the Company and the Trustee prompt notice of the commencement thereof, and (B) (if the Company agrees to pay all expenses in connection therewith) offers the Company the opportunity to control unconditionally the defense thereof, and (ii) either (A) the Company does not agree within 30 days of receipt of such offer to pay such expenses and liabilities and to control such defense, or (B) the Company will exhaust or choose not to exhaust all available proceedings for the contest, review, appeal or rehearing of such decree, judgment or action which the Company determines to be appropriate. No Determination of Taxability described above will result from the inclusion of interest on any Bond in the computation of minimum or indirect taxes. All of the Bonds are required to be redeemed upon a Determination of Taxability as described above unless, in the opinion of Bond Counsel, redemption of a portion of such Bonds would have the result that interest payable on the remaining Bonds outstanding after the redemption would not be so included in any such gross income.

In the event any of the Issuer, the Company or the Trustee has been put on notice or becomes aware of the existence or pendency of any inquiry, audit or other proceedings relating to the Bonds being conducted by the Internal Revenue Service, the party so put on notice is required to give immediate written notice to the other parties of such matters. Promptly upon learning of the occurrence of a Determination of Taxability (whether or not the same is being contested), or any of the events described above, the Company is required to give notice thereof to the Trustee and the Issuer.

If the Internal Revenue Service or a court of competent jurisdiction determines that the interest paid or to be paid on any Bond (except to a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) is or was includable in the gross income of the recipient for federal income tax purposes for reasons other than as a result of a failure by the Company to perform or observe any of its covenants, agreements or representations in the Loan Agreement or any other agreement or certificate delivered in connection therewith, the Bonds are not subject to redemption. In such circumstances, Bondholders would continue to hold their Bonds, receiving principal and interest at the applicable rate as and when due, but would be required to include such interest payments in gross income for federal income tax purposes. Also, if the lien of the Indenture is discharged or defeased prior to the occurrence of a final Determination of Taxability, Bonds will not be redeemed as described herein.

General Redemption Terms. Notice of redemption will be given by mailing a redemption notice conforming to the provisions and requirements of the Indenture by first class mail to the registered owners of the Bonds to be redeemed not less than 15 days prior to the redemption date. Any notice mailed as provided in the Indenture will be conclusively presumed to have been given, irrespective of whether the owner receives the notice. Failure to give any such notice by mailing or any defect therein in respect of any Bond will not affect the validity of any proceedings for the redemption of any other Bond. No further interest will accrue on the principal of any Bond called for redemption after the redemption date if funds sufficient for such redemption have been deposited with the Paying Agent as of the redemption date. If the provisions for discharging the Indenture set forth below under the heading "Summary of the Indenture — Discharge of Indenture" have not been complied with, any redemption notice may state that it is conditional on there being sufficient moneys to pay the full redemption price for the Bonds to be redeemed and that if sufficient funds have not been received by the Trustee by the opening of business on the redemption date, such notice shall be of no effect. So long as the Bonds are held in book-entry-only form, all redemption notices will be sent only to Cede & Co.

Security

Payment of the principal or redemption price of and interest on the Bonds will be secured by an assignment by the Issuer to the Trustee of the Issuer's interest in and to the Loan Agreement and all payments to be made pursuant thereto (other than certain indemnification and expense payments). Pursuant to the Loan Agreement, the Company will agree to pay, among other things, amounts sufficient to pay the aggregate principal amount or redemption price of the Bonds, together with interest thereon as and when the same become due. The Company further will agree to make payments of the purchase price of the Bonds tendered for purchase to the extent that funds are not otherwise available therefor under the provisions of the Indenture.

The payment of the principal or redemption price of and interest on the Bonds will be further secured by the First Mortgage Bonds. The principal amount of the First Mortgage Bonds will equal the principal amount of the Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a written demand from the Trustee for redemption of the First Mortgage Bonds ("Redemption Demand"), or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have become immediately due and payable, such First Mortgage Bonds will begin to bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date or dates to which interest on the Bonds has been paid in full, will be payable in accordance with the Supplemental Indenture. See "Summary of the First Mortgage Bonds and the First Mortgage Indenture."

The First Mortgage Bonds are not intended to provide a direct source of liquidity to pay the purchase price of Bonds tendered for purchase in accordance with the Indenture. The Company is not required under the Loan Agreement or Indenture to provide any letter of credit or liquidity support for the Bonds. The First Mortgage Bonds are secured by a lien on certain property owned by the Company. In certain circumstances, the Company is permitted to reduce the aggregate principal amount of its First Mortgage Bonds held by the Trustee, but in no event to an amount lower than the aggregate outstanding principal amount of the Bonds.

Book-Entry-Only System

Portions of the following information concerning DTC and DTC's book-entry-only system have been obtained from DTC. The Issuer, the Company and the Underwriter make no representation as to the accuracy of such information.

Initially, DTC will act as securities depository for the Bonds and the Bonds initially will be issued solely in book-entry-only form to be held under DTC's book-entry-only system, registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully registered bond in the aggregate principal amount of the Bonds will be deposited with DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934 (the "Exchange Act"). DTC holds and provides asset servicing for U.S. and non-U.S. equity issues, corporate and municipal debt issues, and money market instruments that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities certificates. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly ("Indirect Participants" and, together with "Direct Participants," "Participants"). The DTC Rules applicable to its Participants are on file with the SEC. More information about DTC can be found at www.dtcc.com.

Purchases of the Bonds under the DTC system must be made by or through Direct Participants, which will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond ("Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase. Beneficial Owners, however, are expected to receive written confirmations providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in the Bonds, except in the event that use of the book-entry only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co. or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial

Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Redemption notices shall be sent to DTC. If fewer than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's Procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts the Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Principal and interest payments on the Bonds will be made to Cede & Co. or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts, upon DTC's receipt of funds and corresponding detail information from the Issuer or the Trustee on the payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC nor its nominee, the Trustee, the Company or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of principal and interest to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Issuer or the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner may give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Tender Agent, and will effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds on DTC's records to the Tender Agent. The requirement for physical delivery of Bonds in connection with a demand for purchase or a mandatory purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Tender Agent's DTC account.

DTC may discontinue providing its services as securities depository with respect to the Bonds at any time by giving reasonable notice to the Issuer, the Company, the Tender Agent and the Trustee, or the Issuer, at the request of the Company, may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor securities depository for the Bonds). Under such circumstances, in the event that a successor securities depository is not obtained, bond certificates are required to be delivered as described in the Indenture (see "— Revision of Book-Entry-Only System; Replacement Bonds" below). The Beneficial Owner, upon registration of certificates held in the Beneficial Owner's name, will become the registered owner of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, as nominee of DTC, references herein to the registered owners of the Bonds will mean Cede & Co. and will not mean the Beneficial Owners. Under the Indenture, payments made by the Trustee to DTC or its nominee will satisfy the Issuer's obligations under the Indenture and the Company's obligations under the Loan Agreement and the First Mortgage Bonds, to the extent of the payments so made. Beneficial Owners will not be, and will not be considered by the Issuer or the Trustee to be, and will not have any rights as, owners of Bonds under the Indenture.

The Trustee and the Issuer, so long as a book-entry-only system is used for the Bonds, will send any notice of redemption or of proposed document amendments requiring consent of registered owners and any other notices required by the document (including notices of Conversion and mandatory purchase) to be sent to registered owners only to DTC (or any successor securities depository) or its nominee. Any failure of DTC to advise any Direct Participant, or of any Direct Participant or Indirect Participant to notify the Beneficial Owner, of any such notice and its content or effect will not affect the validity of the redemption of the Bonds called for redemption, the document amendment, the Conversion, the mandatory purchase or any other action premised on that notice.

The Issuer, the Company, the Trustee and the Underwriter cannot and do not give any assurances that DTC will distribute payments on the Bonds made to DTC or its nominee as the registered owner or any redemption or other notices, to the Participants, or that the Participants or others will distribute such payments or notices to the Beneficial Owners, or that they will do so on a timely basis, or that DTC will serve and act in the manner described in this Official Statement.

THE ISSUER, THE COMPANY, THE UNDERWRITER, THE REMARKETING AGENT AND THE TRUSTEE WILL HAVE NO RESPONSIBILITY OR OBLIGATION TO ANY DIRECT PARTICIPANT, INDIRECT PARTICIPANT OR ANY BENEFICIAL OWNER OR ANY OTHER PERSON NOT SHOWN ON THE REGISTRATION BOOKS OF THE TRUSTEE AS BEING A REGISTERED OWNER WITH RESPECT TO: (1) THE ACCURACY OF ANY RECORDS MAINTAINED BY DTC OR ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT; (2) THE PAYMENT OF ANY AMOUNT DUE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER IN RESPECT OF THE PRINCIPAL AMOUNT OR REDEMPTION OR PURCHASE PRICE OF OR INTEREST ON THE BONDS; (3) THE DELIVERY OF ANY NOTICE BY DTC TO ANY DIRECT PARTICIPANT OR BY ANY DIRECT PARTICIPANT OR INDIRECT PARTICIPANT TO ANY BENEFICIAL OWNER WHICH IS REQUIRED OR PERMITTED TO BE GIVEN TO REGISTERED OWNERS UNDER THE TERMS OF THE INDENTURE; (4) THE SELECTION OF THE BENEFICIAL OWNERS TO RECEIVE PAYMENT IN THE EVENT OF ANY PARTIAL REDEMPTION OF THE BONDS; OR (5) ANY CONSENT GIVEN OR OTHER ACTION TAKEN BY DTC AS REGISTERED OWNER.

Revision of Book-Entry-Only System; Replacement Bonds

In the event that DTC determines not to continue as securities depository or is removed by the Issuer, at the direction of the Company, as securities depository, the Issuer, at the direction of the Company, may appoint a successor securities depository reasonably acceptable to the Trustee. If the Issuer does not or is unable to appoint a successor securities depository, the Issuer will issue and the Trustee will authenticate and deliver fully registered Bonds, in authorized denominations, to the assignees of DTC or their nominees.

In the event that the book-entry-only system is discontinued, the following provisions will apply. The Bonds may be issued in denominations of $100,000 and multiples thereof. Bonds may be transferred or exchanged for an equal total amount of Bonds of other authorized denominations upon surrender of such Bonds at the designated office of the Bond Registrar, accompanied by a written instrument of transfer or authorization for exchange in form and with guaranty of signature satisfactory to the Bond Registrar, duly executed by the registered owner or the owner's duly authorized attorney. Except as provided in the Indenture, the Bond Registrar will not be required to register the transfer or exchange of any Bond during the fifteen days before any mailing of a notice of redemption, after such Bond has been called for redemption in whole or in part, or after such Bond has been tendered or deemed tendered for optional or mandatory purchase as described under "Purchases of Bonds." Registration of transfers and exchanges will be made without charge to the owners of Bonds, except that the Bond Registrar may require any owner requesting registration of transfer or exchange to pay any required tax or governmental charge.

Summary of the Loan Agreement

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the Loan Agreement. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Loan Agreement , for the detailed provisions thereof.

General

The term of the Loan Agreement will commence as of its date and end on the earliest to occur of September 1, 2044, or the date on which all of the Bonds have been fully paid or provision has been made for such payment pursuant to the Indenture. See "Summary of the Indenture — Discharge of Indenture."

The Company will agree to repay the loan pursuant to the Loan Agreement by making timely payments to the Trustee in sufficient amounts to pay the principal or redemption price of and interest required to be paid on the Bonds on each date upon which any such payments are due. The Company will also agree to pay (a) the agreed upon fees and expenses of the Trustee, the Bond Registrar, the Tender Agent and the Paying Agent and all other amounts which may be payable to the Trustee, the Bond Registrar, the Paying Agent and the Tender Agent, as may be applicable, under the Indenture, (b) the expenses in connection with any redemption of the Bonds and (c) the reasonable expenses of the Issuer.

The Company will covenant and agree with the Issuer that it will cause the purchase of tendered Bonds that are not remarketed in accordance with the Indenture and, to that end, the Company will cause funds to be made available to the Tender Agent at the times and in the manner required to effect such purchases in accordance with the Indenture (see "Summary of the Bonds — Purchases of Bonds — Remarketing and Purchase of Bonds").

All payments to be made by the Company to the Issuer pursuant to the Loan Agreement (except the fees and reasonable out-of-pocket expenses of the Issuer, the Trustee, the Paying Agent, the Bond Registrar and the Tender Agent, and amounts related to indemnification) will be assigned by the Issuer to the Trustee, and the Company will pay such amounts directly to the Trustee. The obligations of the Company to make the payments pursuant to the Loan Agreement are absolute and unconditional.

Maintenance of Tax Exemption

The Company and the Issuer will agree not to take any action that would result in the interest paid on the Bonds being included in gross income of any Bondholder (other than a holder who is a "substantial user" of the Project or a "related person" within the meaning of Section 147(a) of the Code) for federal income tax purposes or that adversely affects the validity of the Bonds.

Issuance and Delivery of First Mortgage Bonds

For the purpose of providing security for the Bonds, the Company will execute and deliver to the Trustee the First Mortgage Bonds on the date of issuance of the Bonds. The principal amount of the First Mortgage Bonds executed and delivered to the Trustee will equal the aggregate principal amount of the

Bonds. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement and upon receipt by the First Mortgage Trustee of a Redemption Demand, or if all first mortgage bonds outstanding under the First Mortgage Indenture shall have become immediately due and payable, such First Mortgage Bonds will then bear interest at the same interest rate or rates borne by the Bonds and the principal of such First Mortgage Bonds, together with interest accrued thereon from the last date to which interest on the Bonds shall have been paid in full, will then be payable. See, however, "Summary of the Indenture — Waiver of Events of Default."

Upon payment of the principal or redemption price of and interest on any of the Bonds, and the surrender to and cancellation thereof by the Trustee, or upon provision for the payment thereof having been made in accordance with the Indenture, First Mortgage Bonds with corresponding principal amounts equal to the aggregate principal amount of the Bonds so surrendered and canceled or for the payment of which provision has been made, will be surrendered by the Trustee to the First Mortgage Trustee and will be canceled by the First Mortgage Trustee. The First Mortgage Bonds will be registered in the name of the Trustee and will be non transferable, except to effect transfers to any successor trustee under the Indenture.

Payment of Taxes

The Company will agree to pay certain taxes and other governmental charges that may be lawfully assessed, levied or charged against or with respect to the Project (see, however, subparagraph (i) under the heading "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole"*)*. The Company may contest such taxes or other governmental charges unless the security provided by the Indenture would be materially endangered.

Maintenance; Damage, Destruction and Condemnation

So long as any Bonds are outstanding, the Company will maintain, preserve and keep the Project or cause the Project to be maintained, preserved and kept in good repair, working order and condition and will make or cause to be made all proper repairs, replacements and renewals necessary to continue to constitute the Project as air and water pollution control and abatement facilities under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended. However, the Company will have no obligation to maintain, preserve, keep, repair, replace or renew any portion of the Project, the maintenance, preservation, keeping, repair, replacement or renewal of which becomes uneconomical to the Company because of certain events, including damage or destruction by a cause not within the Company's control, condemnation of the Project, change in government standards and regulations, economic or other obsolescence or termination of operation of generating facilities to the Project.

The Company, at its own expense, may remodel the Project or make substitutions, modifications and improvements to the Project as it deems desirable, which remodeling, substitutions, modifications and improvements are deemed, under the terms of the Loan Agreement to be a part of the Project. The Company may not, however, change or alter the basic nature of the Project or cause it to lose its status under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended.

If, prior to the payment of all Bonds outstanding, the Project or any portion thereof is destroyed, damaged or taken by the exercise of the power of eminent domain and the Issuer, the Company or the First Mortgage Trustee receives net proceeds from insurance or a condemnation award in connection therewith, the Company must, subject to the requirements of the First Mortgage Indenture, (i) cause such net proceeds to be used to repair or restore the Project or (ii) take any other action, including the redemption of the Bonds in whole or in part at their principal amount, which, by the opinion of Bond Counsel, will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes. See "Summary of the Bonds — Redemptions — Extraordinary Optional Redemption in Whole or in Part."

Project Insurance

The Company will insure the Project in accordance with the provisions of the First Mortgage Indenture.

Assignment, Merger and Release of Obligations of the Company

The Company may assign the Loan Agreement, pursuant to an opinion of Bond Counsel that such assignment will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, without obtaining the consent of either the Issuer or the Trustee. Such assignment, however, will not relieve the Company from primary liability for any of its obligations under the Loan Agreement and performance and observance of the other covenants and agreements to be performed by the Company. The Company may dispose of all or substantially all of its assets or consolidate with or merge into another entity, provided the acquirer of the Company's assets or the entity with which it will consolidate with or merge into is a corporation or other business organization organized and existing under the laws of the United States of America or one of the states of the United States of America or the District of Columbia, is qualified and admitted to do business in the Commonwealth of Kentucky, and assumes in writing all of the obligations and covenants of the Company under the Loan Agreement and delivers a copy of such assumption to the Issuer and the Trustee.

Release and Indemnification Covenant

The Company will indemnify and hold the Issuer harmless against any expense or liability incurred, including attorneys' fees, resulting from any loss or damage to property or any injury to or death of any person occurring on or about or resulting from any defect in the Project or from any action commenced in connection with the financing thereof.

Events of Default

Each of the following events constitutes an "Event of Default" under the Loan Agreement:

(1) failure by the Company to pay the amounts required for payment of the principal of, including purchase price for tendered Bonds and redemption and acceleration prices, and interest accrued, on the Bonds, at the times specified therein taking into account any periods of grace provided in the Indenture and the Bonds for the applicable payment of interest on the Bonds (see "Summary of the Indenture — Defaults and Remedies"), and such failure shall cause an event of default under the Indenture;

(2) failure by the Company to observe and perform any covenant, condition or agreement on its part to be observed or performed, other than as referred to in paragraph (1) above, for a period of 30 days after written notice by the Issuer or Trustee, subject to extension by the Issuer and the Trustee, provided, however, that if such failure is capable of being corrected, but cannot be corrected in such 30-day period, the Issuer and the Trustee will not unreasonably withhold their

consent to an extension of such time if corrective action with respect thereto is instituted within such period and is being diligently pursued;

(3) certain events of bankruptcy, dissolution, liquidation, reorganization or insolvency of the Company;

(4) the occurrence of an Event of Default under the Indenture; or

(5) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee;

Under the Loan Agreement, certain of the Company's obligations (other than the Company's obligations, among others, (i) not to permit any action which would result in interest paid on the Bonds being included in gross income for federal and Kentucky income taxes, (ii) to execute and deliver the First Mortgage Bonds to the Trustee on or before the date of issuance of the Bonds in an amount equal to the principal amount of the Bonds; (iii) to maintain its corporate existence and good standing, and to neither dispose of all or substantially all of its assets or consolidate with or merge into another entity unless certain provisions of the Loan Agreement are satisfied; and (iv) to make loan payments and certain other payments under the provisions of the Loan Agreement) may be suspended if by reason of force majeure (as defined in the Loan Agreement) the Company is unable to carry out such obligations.

Remedies

Upon the happening and continuance of an Event of Default under the Loan Agreement, the Trustee, on behalf of the Issuer, may, among other things, take whatever action at law or in equity may appear necessary or desirable to collect the amounts then due and thereafter to become due, or to enforce performance and observance of any obligation, agreement or covenant of the Company, under the Loan Agreement, including any remedies available in respect of the First Mortgage Bonds.

In the event of a default in payment of the principal or redemption price of or interest on the Bonds and the acceleration of the maturity date of the Bonds (to the extent not already due and payable) as a consequence of such Event of Default, the Trustee may demand redemption of the First Mortgage Bonds. See "Summary of the First Mortgage Bonds and the First Mortgage Indenture" and "Summary of the Indenture — Defaults and Remedies." Any amounts collected upon the happening of any such Event of Default must be applied in accordance with the Indenture or, if the Bonds have been fully paid (or provision for payment thereof has been made in accordance with the Indenture) and all other liabilities of the Company accrued under the Indenture and the Loan Agreement have been paid or satisfied, made available to the Company.

Options to Prepay; Obligation to Prepay

The Company may prepay the loan pursuant to the Loan Agreement, in whole or in part, on certain dates, at the prepayment prices as shown under the headings "Summary of the Bonds — Redemptions — Optional Redemption," "Extraordinary Optional Redemption in Whole" and "Extraordinary Optional Redemption in Whole or in Part." Upon the occurrence of the event described under the heading "Summary of the Bonds — Redemptions — Mandatory Redemption; Determination of Taxability," the Company will be obligated to prepay the loan in an aggregate amount sufficient to redeem the required principal amount of the Bonds.

In each instance, the loan prepayment price must be a sum sufficient, together with other funds deposited with the Trustee and available for such purpose, to redeem the requisite amount of the Bonds at a price equal to 100% of the principal amount plus accrued interest to the redemption date, and to pay all reasonable and necessary fees and expenses of the Trustee, the Paying Agent, the Bond Registrar and the Tender Agent and all other liabilities of the Company under the Loan Agreement accrued to the redemption date.

Amendments and Modifications

No alteration, amendment, change, supplement or modification of the Loan Agreement is permissible without the written consent of the Trustee. The Issuer and the Trustee may, however, without the consent of or notice to any Bondholders, enter into any alteration, amendment, change, supplement or modification of the Loan Agreement (i) which may be required by the provisions of the Loan Agreement or the Indenture, (ii) for the purpose of curing any ambiguity or formal defect or omission, (iii) in connection with any modification or change necessary to conform the Loan Agreement with changes and modifications in the Indenture or (iv) in connection with any other change which, in the judgment of the Trustee, does not adversely affect the Trustee or the Bondholders. Except for such alterations, amendments, changes, supplements or modifications, the Loan Agreement may be altered, amended, changed, supplemented or modified only with the consent of the Bondholders holding a majority in principal amount of the Bonds then outstanding (see "Summary of the Indenture — Supplemental Indentures" for an explanation of the procedures necessary for Bondholder consent); provided, however, that the approval of the Bondholders holding 100% in principal amount of the Bonds then outstanding is necessary to effectuate an alteration, amendment, change, supplement or modification with respect to the Loan Agreement of the type described in clauses (i) through (iv) of the first sentence of the third paragraph of "Summary of the Indenture — Supplemental Indentures."

Summary of the First Mortgage Bonds and the First Mortgage Indenture

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the First Mortgage Bonds and the First Mortgage Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the First Mortgage Indenture and to the form of the First Mortgage Bonds for the detailed provisions thereof.

General

In connection with the issuance of the Bonds, the First Mortgage Bonds will be issued in a principal amount equal to the principal amount of the Bonds and will constitute a new series of first mortgage bonds under the First Mortgage Indenture (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The statements herein made (being for the most part summaries of certain provisions of the First Mortgage Indenture) are subject to the detailed provisions of the First Mortgage Indenture, which is incorporated herein by this reference. Words or phrases italicized are defined in the First Mortgage Indenture.

The First Mortgage Bonds will mature on the same date and bear interest at the same rate or rates as the Bonds; however, the principal of and interest on the First Mortgage Bonds will not be payable other than upon the occurrence of an event of default under the Loan Agreement. If the Bonds become immediately due and payable as a result of a default in payment of the principal or redemption price of or interest on the Bonds, or a default in payment of the purchase price of such Bonds, due to an event of default under the Loan Agreement, and if all first mortgage bonds outstanding under the First Mortgage Indenture shall not have become immediately due and payable following an event of default under the First Mortgage Indenture, the Company will be obligated to redeem the First Mortgage Bonds upon receipt by the First Mortgage Trustee of a Redemption Demand from the Trustee for redemption, at a redemption price equal to the principal amount thereof plus accrued interest at the rates borne by the Bonds from the last date to which interest on the Bonds has been paid.

The First Mortgage Bonds at all times will be in fully registered form registered in the name of the Trustee, will be non negotiable, and will be non transferable except to any successor trustee under the Indenture. Upon payment and cancellation of Bonds by the Trustee or the Paying Agent (other than any Bond or portion thereof that was canceled by the Trustee or the Paying Agent and for which one or more Bonds were delivered and authenticated pursuant to the Indenture), whether at maturity, by redemption or otherwise, or upon provision for the payment of the Bonds having been made in accordance with the Indenture, an equal principal amount of First Mortgage Bonds will be deemed fully paid and the obligations of the Company thereunder will cease.

Security; Lien of the First Mortgage Indenture

General. Except as described below under this heading and under "— Issuance of Additional First Mortgage Bonds," and subject to the exceptions described under "— Satisfaction and Discharge," all first mortgage bonds issued under the First Mortgage Indenture, including the First Mortgage Bonds, will be secured, equally and ratably, by the lien of the First Mortgage Indenture, which constitutes, subject to *permitted liens* and exclusions as described below, a first mortgage lien on substantially all of the Company's real and tangible personal property located in Kentucky and used or to be used in connection with the generation, transmission and distribution of electricity and the storage, transportation and distribution of natural gas (other than property duly released from the lien of the First Mortgage Indenture in accordance with the provisions thereof and other than *excepted property*, as described below). Property that is subject to the lien of the First Mortgage Indenture is referred to below as "Mortgaged Property."

The Company may obtain the release of property from the lien of the First Mortgage Indenture from time to time, upon the bases provided for such release in the First Mortgage Indenture. See "— Release of Property."

The Company may enter into supplemental indentures with the First Mortgage Trustee, without the consent of the holders of the first mortgage bonds, in order to subject additional property (including property that would otherwise be excepted from such lien) to the lien of the First Mortgage Indenture. This property would constitute *property additions* and would be available as a basis for the issuance of additional first mortgage bonds. See "— Issuance of Additional First Mortgage Bonds."

The First Mortgage Indenture provides that after-acquired property (other than *excepted property*) will be subject to the lien of the First Mortgage Indenture. However, in the case of consolidation or merger (whether or not the Company is the surviving company) or transfer of the Mortgaged Property as or substantially as an entirety, the First Mortgage Indenture will not be required to be a lien upon any of the properties either owned or subsequently acquired by the successor company except properties acquired from the Company in or as a result of such transfer, as well as improvements, extensions and additions (as defined in the First Mortgage Indenture) to such properties and renewals, replacements and substitutions of or for any part or parts thereof. See "— Consolidation, Merger and Conveyance of Assets as an Entirety."

Excepted Property. The lien of the First Mortgage Indenture does not cover, among other things, the following types of property: property located outside of Kentucky and not specifically subjected or required to be subjected to the lien of the First Mortgage Indenture; property not used by the Company in its electric generation, transmission and distribution business or its natural gas storage, transportation and distribution business; cash and securities not paid, deposited or held under the First Mortgage Indenture or required so to be; contracts, leases and other agreements of all kinds, contract rights, bills, notes and other instruments, revenues, accounts receivable, claims, demands and judgments; governmental and other licenses, permits, franchises, consents and allowances; intellectual property rights and other general intangibles; vehicles, movable equipment, aircraft and vessels; all goods, stock in trade, wares, merchandise and inventory held for the purpose of sale or lease in the ordinary course of business; materials, supplies, inventory and other personal property consumable in the operation of the Company's business; fuel; tools and equipment; furniture and furnishings; computers and data processing, telecommunications and other facilities used primarily for administrative or clerical purposes or otherwise not used in connection with the operation or maintenance of electric generation, transmission and distribution facilities or natural gas storage, transportation and distribution facilities; coal, ore, gas, oil and other minerals and timber rights; electric energy and capacity, gas, steam, water and other products generated, produced, manufactured, purchased or otherwise acquired; real property and facilities used primarily for the production or gathering of natural gas; property which has been released from the lien of the First Mortgage Indenture; and leasehold interests. Property of the Company not covered by the lien of the First Mortgage Indenture is referred to herein as excepted property. Properties held by any of the Company's subsidiaries, as well as properties leased from others, would not be subject to the lien of the First Mortgage Indenture.

Permitted Liens. The lien of the First Mortgage Indenture is subject to permitted liens described in the First Mortgage Indenture. Such permitted liens include liens existing at the execution date of the First Mortgage Indenture, purchase money liens and other liens placed or otherwise existing on property acquired by the Company after the execution date of the First Mortgage Indenture at the time the Company acquires it, tax liens and other governmental charges which are not delinquent or which are being contested in good faith, mechanics', construction and materialmen's liens, certain judgment liens, easements, reservations and rights of others (including governmental entities) in, and defects of title to, the Company's property, certain leases and leasehold interests, liens to secure public obligations, rights of others to take minerals, timber, electric energy or capacity, gas, water, steam or other products produced by the Company or by others on the Company's property, rights and interests of persons other than the Company arising out of agreements relating to the common ownership or joint use of property, and liens on the interests of such persons in such property and liens which have been bonded or for which other security arrangements have been made.

The First Mortgage Indenture also provides that the First Mortgage Trustee will have a lien, prior to the lien on behalf of the holders of the first mortgage bonds, including the First Mortgage Bonds, upon the Mortgaged Property as security for the Company's payment of its reasonable compensation and expenses and for indemnity against certain liabilities. Any such lien would be a permitted lien under the First Mortgage Indenture.

Issuance of Additional First Mortgage Bonds

The maximum principal amount of first mortgage bonds that may be authenticated and delivered under the First Mortgage Indenture is subject to the issuance restrictions described below; provided, however, that the maximum principal amount of first mortgage bonds outstanding at any one time shall not exceed One Quintillion Dollars ($1,000,000,000,000,000,000), which amount may be changed by supplemental indenture. As of June 30, 2016, first mortgage bonds in an aggregate principal amount of $1,659,304,000 were outstanding under the First Mortgage Indenture, of which $574,304,000 were issued to secure the Company's payment obligations with respect to its outstanding pollution control and environmental facilities revenue bonds, including the Bonds.

First mortgage bonds of any series may be issued from time to time on the basis of, and in an aggregate principal amount not exceeding:

- 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of *property additions* (as described below) which do not constitute *funded property* (generally, *property additions* which have been made the basis of the authentication and delivery of first mortgage bonds, the release of Mortgaged Property or the withdrawal of cash, which have been substituted for retired *funded property* or which have been used for other specified purposes) after certain deductions and additions, primarily including adjustments to offset property retirements;

- the aggregate principal amount of *retired securities* (as described below); or

- an amount of cash deposited with the First Mortgage Trustee.

Property additions generally include any property which is owned by the Company and is subject to the lien of the First Mortgage Indenture except (with certain exceptions) goodwill, going concern value rights or intangible property, or any property the acquisition or construction of which is properly chargeable to one of the Company's operating expense accounts in accordance with U.S. generally accepted accounting principles.

Retired securities means, generally, first mortgage bonds which are no longer outstanding under the First Mortgage Indenture, which have not been retired by the application of *funded cash* and which have not been used as the basis for the authentication and delivery of first mortgage bonds, the release of property or the withdrawal of cash.

At June 30, 2016, approximately $1.3 billion of *property additions* and $250 million of *retired securities* were available to be used as the basis for the authentication and delivery of first mortgage bonds. The Company intends to issue the First Mortgage Bonds on the basis of *retired securities*.

Release of Property

Unless an *event of default* has occurred and is continuing, the Company may obtain the release from the lien of the First Mortgage Indenture of any Mortgaged Property, except for cash held by the First Mortgage Trustee, upon delivery to the First Mortgage Trustee of an amount in cash equal to the amount, if any, by which sixty-six and two-thirds percent (66-2/3%) of the cost of the property to be released (or, if less, the *fair value* to the Company of such property at the time it became *funded property*) exceeds the aggregate of:

- an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property to be released and delivered to the First Mortgage Trustee;

- an amount equal to 66 2/3% of the *cost* or *fair value* to the Company (whichever is less) of certified *property additions* not constituting *funded property* after certain deductions and additions, primarily including adjustments to offset property retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the release);

- the aggregate principal amount of first mortgage bonds the Company would be entitled to issue on the basis of *retired securities* (with such entitlement being waived by operation of such release);

- the aggregate principal amount of first mortgage bonds delivered to the First Mortgage Trustee (with such first mortgage bonds to be canceled by the First Mortgage Trustee);

- any amount of cash and/or an amount equal to 66 2/3% of the aggregate principal amount of obligations secured by *purchase money liens* upon the property released that is delivered to the trustee or other holder of a lien prior to the lien of the First Mortgage Indenture, subject to certain limitations described in the First Mortgage Indenture; and

- any taxes and expenses incidental to any sale, exchange, dedication or other disposition of the property to be released.

As used in the First Mortgage Indenture, the term *purchase money lien* means, generally, a lien on the property being released which is retained by the transferor of such property or granted to one or more other persons in connection with the transfer or release thereof, or granted to or held by a trustee or agent for any such persons, and may include liens which cover property in addition to the property being released and/or which secure indebtedness in addition to indebtedness to the transferor of such property.

Unless an *event of default* has occurred and is continuing, property which is not *funded property* may generally be released from the lien of the First Mortgage Indenture without depositing any cash or property with the First Mortgage Trustee as long as (a) the aggregate amount of *cost* or *fair value* to the Company (whichever is less) of all *property additions* which do not constitute *funded property* (excluding the property to be released) after certain deductions and additions, primarily including adjustments to offset property retirements, is not less than zero or (b) the *cost* or *fair value* (whichever is less) of property to be released does not exceed the aggregate amount of the cost or fair value to the Company (whichever is less) of *property additions* acquired or made within the 90-day period preceding the release.

The First Mortgage Indenture provides simplified procedures for the release of minor properties and property taken by eminent domain, and provides for dispositions of certain obsolete property and grants or surrender of certain rights without any release or consent by the First Mortgage Trustee.

If the Company retains any interest in any property released from the lien of the First Mortgage Indenture, the First Mortgage Indenture will not become a lien on such property or such interest therein or any improvements, extensions or additions to such property or renewals, replacements or substitutions of or for such property or any part or parts thereof.

Withdrawal of Cash

Unless an *event of default* has occurred and is continuing, and subject to certain limitations, cash held by the First Mortgage Trustee may, generally, (1) be withdrawn by the Company (a) to the extent of sixty-six and two-thirds percent (66-2/3%) of the *cost* or *fair value* to the Company (whichever is less) of *property additions* not constituting *funded property*, after certain deductions and additions, primarily including adjustments to offset retirements (except that such adjustments need not be made if such *property additions* were acquired or made within the 90-day period preceding the withdrawal) or (b) in an amount equal to the aggregate principal amount of first mortgage bonds that the Company would be entitled to issue on the basis of *retired securities* (with the entitlement to such issuance being waived by operation of such withdrawal) or (c) in an amount equal to the aggregate principal amount of any outstanding first mortgage bonds delivered to the First Mortgage Trustee; or (2) upon the Company's request, be applied to (a) the purchase of first mortgage bonds in a manner and at a price approved by the Company or (b) the payment (or provision for payment) at stated maturity of any first mortgage bonds or the redemption (or provision for payment) of any first mortgage bonds which are redeemable; provided, however, that cash deposited with the First Mortgage Trustee as the basis for the authentication and delivery of first mortgage bonds may, in addition, be withdrawn in an amount not exceeding the aggregate principal amount of cash delivered to the First Mortgage Trustee for such purpose.

Events of Default

An "event of default" occurs under the First Mortgage Indenture if

- the Company does not pay any interest on any first mortgage bonds within 30 days of the due date;

- the Company does not pay principal or premium, if any, on any first mortgage bonds on the due date;

- the Company remains in breach of any other covenant (excluding covenants specifically dealt with elsewhere in this section) in respect of any first mortgage bonds for 90 days after the Company receives a written notice of default stating the Company is in breach and requiring remedy of the breach; the notice must be sent by either the First Mortgage Trustee or holders of 25% of the principal amount of outstanding first mortgage bonds; the First Mortgage Trustee or such holders can agree to extend the 90-day period and such an agreement to extend will be automatically deemed to occur if the Company initiates corrective action within such 90 day period and the Company is diligently pursuing such action to correct the default; or

- the Company files for bankruptcy or certain other events in bankruptcy, insolvency, receivership or reorganization occur.

Remedies

Acceleration of Maturity. If an event of default occurs and is continuing, then either the First Mortgage Trustee or the holders of not less than 25% in principal amount of the outstanding first mortgage bonds may declare the principal amount of all of the first mortgage bonds to be due and payable immediately.

Rescission of Acceleration. After the declaration of acceleration has been made and before the First Mortgage Trustee has obtained a judgment or decree for payment of the money due, such declaration and its consequences will be rescinded and annulled, if

- the Company pays or deposits with the First Mortgage Trustee a sum sufficient to pay:

  - all overdue interest;
  - the principal of and premium, if any, which have become due otherwise than by such declaration of acceleration and interest thereon;
  - interest on overdue interest to the extent lawful; and
  - all amounts due to the First Mortgage Trustee under the First Mortgage Indenture; and

- all *events of default*, other than the nonpayment of the principal which has become due solely by such declaration of acceleration, have been cured or waived as provided in the First Mortgage Indenture.

For more information as to waiver of defaults, see "— Waiver of Default and of Compliance" below.

Appointment of Receiver and Other Remedies. Subject to the First Mortgage Indenture, under certain circumstances and to the extent permitted by law, if an *event of default* occurs and is continuing, the First Mortgage Trustee has the power to appoint a receiver of the Mortgaged Property, and is entitled to all other remedies available to mortgagees and secured parties under the Uniform Commercial Code or any other applicable law.

Control by Holders; Limitations. Subject to the First Mortgage Indenture, if an *event of default* occurs and is continuing, the holders of a majority in principal amount of the outstanding first mortgage bonds will have the right to

- direct the time, method and place of conducting any proceeding for any remedy available to the First Mortgage Trustee, or

- exercise any trust or power conferred on the First Mortgage Trustee.

The rights of holders to make direction are subject to the following limitations:

- the holders' directions may not conflict with any law or the First Mortgage Indenture; and

- the holders' directions may not involve the First Mortgage Trustee in personal liability where the First Mortgage Trustee believes indemnity is not adequate.

The First Mortgage Trustee may also take any other action it deems proper which is not inconsistent with the holders' direction.

In addition, the First Mortgage Indenture provides that no holder of any first mortgage bond will have any right to institute any proceeding, judicial or otherwise, with respect to the First Mortgage Indenture for the appointment of a receiver or for any other remedy thereunder unless

- that holder has previously given the First Mortgage Trustee written notice of a continuing *event of default*;

- the holders of 25% in aggregate principal amount of the outstanding first mortgage bonds have made written request to the First Mortgage Trustee to institute proceedings in respect of that *event of default* and have offered the First Mortgage Trustee reasonable indemnity against costs, expenses and liabilities incurred in complying with such request; and

- for 60 days after receipt of such notice, request and offer of indemnity, the First Mortgage Trustee has failed to institute any such proceeding and no direction inconsistent with such request has been given to the First Mortgage Trustee during such 60-day period by the holders of a majority in aggregate principal amount of outstanding first mortgage bonds.

Furthermore, no holder of first mortgage bonds will be entitled to institute any such action if and to the extent that such action would disturb or prejudice the rights of other holders of first mortgage bonds.

However, each holder of first mortgage bonds has an absolute and unconditional right to receive payment when due and to bring a suit to enforce that right.

Notice of Default. The First Mortgage Trustee is required to give the holders of the first mortgage bonds notice of any default under the First Mortgage Indenture to the extent required by the Trust Indenture Act, unless such default has been cured or waived; except that in the case of an *event of default* of the character specified in the third bullet point under "— Events of Default" (regarding a breach of certain covenants continuing for 90 days after the receipt of a written notice of default), no such notice shall be given to such holders until at least 60 days after the occurrence thereof. The Trust Indenture Act currently permits the First Mortgage Trustee to withhold notices of default (except for certain payment defaults) if the First Mortgage Trustee in good faith determines the withholding of such notice to be in the interests of the holders of the first mortgage bonds.

The Company will furnish the First Mortgage Trustee with an annual statement as to its compliance with the conditions and covenants in the First Mortgage Indenture.

Waiver of Default and of Compliance. The holders of a majority in aggregate principal amount of the outstanding first mortgage bonds may waive, on behalf of the holders of all outstanding first mortgage bonds, any past default under the First Mortgage Indenture, except a default in the payment of principal, premium or interest, or with respect to compliance with certain provisions of the First Mortgage Indenture that cannot be amended without the consent of the holder of each outstanding first mortgage bond affected.

Compliance with certain covenants in the First Mortgage Indenture or otherwise provided with respect to first mortgage bonds may be waived by the holders of a majority in aggregate principal amount of the affected first mortgage bonds, considered as one class.

Consolidation, Merger and Conveyance of Assets as an Entirety

Subject to the provisions described below, the Company has agreed to preserve its corporate existence.

The Company has agreed not to consolidate with or merge with or into any other entity or convey, transfer or lease the Mortgaged Property as or substantially as an entirety to any entity unless

- the entity formed by such consolidation or into which the Company merges, or the entity which acquires or which leases the Mortgaged Property substantially as an entirety, is an entity organized and existing under the laws of the United States of America or any State or Territory thereof or the District of Columbia; and
    - expressly assumes, by supplemental indenture, the due and punctual payment of the principal of, and premium and interest on, all the outstanding first mortgage bonds and the performance of all of the Company's covenants under the First Mortgage Indenture; and
    - such entity confirms the lien of the First Mortgage Indenture on the Mortgaged Property; and

- in the case of a lease, such lease is made expressly subject to termination by (i) the Company or by the First Mortgage Trustee and (ii) the purchaser of the property so leased at any sale thereof, at any time during the continuance of an *event of default*; and

- immediately after giving effect to such transaction, no *event of default*, and no event which after notice or lapse of time or both would become an *event of default*, will have occurred and be continuing.

In the case of the conveyance or other transfer of the Mortgaged Property as or substantially as an entirety to any other person, upon the satisfaction of all the conditions described above the Company would be released and discharged from all obligations under the First Mortgage Indenture and on the first mortgage bonds then outstanding unless the Company elects to waive such release and discharge.

The First Mortgage Indenture does not prevent or restrict:

- any consolidation or merger after the consummation of which the Company would be the surviving or resulting entity; or

- any conveyance or other transfer, or lease, of any part of the Mortgaged Property which does not constitute the entirety or substantially the entirety thereof.

If following a conveyance or other transfer, or lease, of any part of the Mortgaged Property, the fair value of the Mortgaged Property retained by the Company exceeds an amount equal to three-halves (3/2) of the aggregate principal amount of all outstanding first mortgage bonds, then the part of the Mortgaged Property so conveyed, transferred or leased shall be deemed not to constitute the entirety or substantially the entirety of the Mortgaged Property. This fair value will be determined within 90 days of the conveyance or transfer by an independent expert that the Company selects and that is approved by the First Mortgage Trustee.

Modification of First Mortgage Indenture

Without Holder Consent. Without the consent of any holders of first mortgage bonds, the Company and the First Mortgage Trustee may enter into one or more supplemental indentures for any of the following purposes:

- to evidence the succession of another entity to the Company;

- to add one or more covenants or other provisions for the benefit of the holders of all or any series or tranche of first mortgage bonds, or to surrender any right or power conferred upon the Company;

- to correct or amplify the description of any property at any time subject to the lien of the First Mortgage Indenture; or to better assure, convey and confirm unto the First Mortgage Trustee any property subject or required to be subjected to the lien of the First Mortgage Indenture; or to subject to the lien of the First Mortgage Indenture additional property (including property of others), to specify any additional Permitted Liens with respect to such additional property and to modify the provisions in the First Mortgage Indenture for dispositions of certain types of property without release in order to specify any additional items with respect to such additional property;

- to add any additional *events of default*, which may be stated to remain in effect only so long as the first mortgage bonds of any one more particular series remains outstanding;

- to change or eliminate any provision of the First Mortgage Indenture or to add any new provision to the First Mortgage Indenture that does not adversely affect the interests of the holders in any material respect;

- to establish the form or terms of any series or tranche of first mortgage bonds;

- to provide for the issuance of bearer securities;

- to evidence and provide for the acceptance of appointment of a successor First Mortgage Trustee or by a co-trustee or separate trustee;

- to provide for the procedures required to permit the utilization of a noncertificated system of registration for any series or tranche of first mortgage bonds;

- to change any place or places where

  - the Company may pay principal, premium and interest,

  - first mortgage bonds may be surrendered for transfer or exchange, and

  - notices and demands to or upon the Company may be served;

- to amend and restate the First Mortgage Indenture as originally executed, and as amended from time to time, with such additions, deletions and other changes that do not adversely affect the interest of the holders in any material respect;

- to cure any ambiguity, defect or inconsistency or to make any other changes that do not adversely affect the interests of the holders in any material respect; or

- to increase or decrease the maximum principal amount of first mortgage bonds that may be outstanding at any time.

In addition, if the Trust Indenture Act is amended after the date of the First Mortgage Indenture so as to require changes to the First Mortgage Indenture or so as to permit changes to, or the elimination of, provisions which, at the date of the First Mortgage Indenture or at any time thereafter, were required by the Trust Indenture Act to be contained in the First Mortgage Indenture, the First Mortgage Indenture will be deemed to have been amended so as to conform to such amendment or to effect such changes or elimination, and the Company and the First Mortgage Trustee may, without the consent of any holders, enter into one or more supplemental indentures to effect or evidence such amendment.

With Holder Consent. Except as provided above, the consent of the holders of at least a majority in aggregate principal amount of the first mortgage bonds of all outstanding series, considered as one class, is generally required for the purpose of adding to, or changing or eliminating any of the provisions of, the First Mortgage Indenture pursuant to a supplemental indenture. However, if less than all of the series of outstanding first mortgage bonds are directly affected by a proposed supplemental indenture, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected series, considered as one class. Moreover, if the first mortgage bonds of any series have been issued in more than one tranche and if the proposed supplemental indenture directly affects the rights of the holders of first mortgage bonds of one or more, but less than all, of such tranches, then such proposal only requires the consent of the holders of a majority in aggregate principal amount of the outstanding first mortgage bonds of all directly affected tranches, considered as one class.

However, no amendment or modification may, without the consent of the holder of each outstanding first mortgage bond directly affected thereby:

- change the stated maturity of the principal or interest on any first mortgage bond (other than pursuant to the terms thereof), or reduce the principal amount, interest or premium payable (or the method of calculating such rates) or change the currency in which any first mortgage bond is payable, or impair the right to bring suit to enforce any payment;

- create any lien (not otherwise permitted by the First Mortgage Indenture) ranking prior to the lien of the First Mortgage Indenture with respect to all or substantially all of the Mortgaged Property, or terminate the lien of the First Mortgage Indenture on all or substantially all of the Mortgaged Property (other than in accordance with the terms of the First Mortgage Indenture), or deprive any holder of the benefits of the security of the lien of the First Mortgage Indenture;

- reduce the percentages of holders whose consent is required for any supplemental indenture or waiver of compliance with any provision of the First Mortgage Indenture or of any default thereunder and its consequences, or reduce the requirements for quorum and voting under the First Mortgage Indenture; or

- modify certain of the provisions of the First Mortgage Indenture relating to supplemental indentures, waivers of certain covenants and waivers of past defaults with respect to first mortgage bonds.

A supplemental indenture which changes, modifies or eliminates any provision of the First Mortgage Indenture expressly included solely for the benefit of holders of first mortgage bonds of one or more particular series or tranches will be deemed not to affect the rights under the First Mortgage Indenture of the holders of first mortgage bonds of any other series or tranche.

Satisfaction and Discharge

Any first mortgage bonds or any portion thereof will be deemed to have been paid and no longer outstanding for purposes of the First Mortgage Indenture and, at the Company's election, the Company's entire indebtedness with respect to those securities will be satisfied and discharged, if there shall have been irrevocably deposited with the First Mortgage Trustee or any Paying Agent (other than the Company), in trust:

- money sufficient, or

- in the case of a deposit made prior to the maturity of such first mortgage bonds, non-redeemable *eligible obligations* (as defined in the First Mortgage Indenture) sufficient, or

- a combination of the items listed in the preceding two bullet points, which in total are sufficient, to pay when due the principal of, and any premium, and interest due and to become due on such first mortgage bonds or portions of such first mortgage bonds on and prior to their maturity.

The Company's right to cause its entire indebtedness in respect of the first mortgage bonds of any series to be deemed to be satisfied and discharged as described above will be subject to the satisfaction of any conditions specified in the instrument creating such series.

The First Mortgage Indenture will be deemed satisfied and discharged when no first mortgage bonds remain outstanding and when the Company has paid all other sums payable by it under the First Mortgage Indenture.

All moneys the Company pays to the First Mortgage Trustee or any Paying Agent on First Mortgage Bonds that remain unclaimed at the end of two years after payments have become due may be paid to or upon the Company's order. Thereafter, the holder of such First Mortgage Bond may look only to the Company for payment.

Duties of the First Mortgage Trustee; Resignation and Removal of the First Mortgage Trustee; Deemed Resignation

The First Mortgage Trustee will have, and will be subject to, all the duties and responsibilities specified with respect to an indenture trustee under the Trust Indenture Act. Subject to these provisions, the First Mortgage Trustee will be under no obligation to exercise any of the powers vested in it by the First Mortgage Indenture at the request of any holder of first mortgage bonds, unless offered reasonable indemnity by such holder against the costs, expenses and liabilities which might be incurred thereby. The First Mortgage Trustee will not be required to expend or risk its own funds or otherwise incur financial liability in the performance of its duties if the First Mortgage Trustee reasonably believes that repayment or adequate indemnity is not reasonably assured to it.

The First Mortgage Trustee may resign at any time by giving written notice to the Company.

The First Mortgage Trustee may also be removed by act of the holders of a majority in principal amount of the then outstanding first mortgage bonds.

No resignation or removal of the First Mortgage Trustee and no appointment of a successor trustee will become effective until the acceptance of appointment by a successor trustee in accordance with the requirements of the First Mortgage Indenture.

Under certain circumstances, the Company may appoint a successor trustee and if the successor accepts, the First Mortgage Trustee will be deemed to have resigned.

Evidence to be Furnished to the First Mortgage Trustee

Compliance with First Mortgage Indenture provisions is evidenced by written statements of the Company's officers or persons selected or paid by the Company. In certain cases, opinions of counsel and certifications of an engineer, accountant, appraiser or other expert (who in some cases must be independent) must be furnished. In addition, the First Mortgage Indenture requires the Company to give to the First Mortgage Trustee, not less than annually, a brief statement as to the Company's compliance with the conditions and covenants under the First Mortgage Indenture.

Miscellaneous Provisions

The First Mortgage Indenture provides that certain first mortgage bonds, including those for which payment or redemption money has been deposited or set aside in trust as described under "— Satisfaction and Discharge" above, will not be deemed to be "outstanding" in determining whether the holders of the requisite principal amount of the outstanding first mortgage bonds have given or taken any demand, direction, consent or other action under the First Mortgage Indenture as of any date, or are present at a meeting of holders for quorum purposes.

The Company will be entitled to set any day as a record date for the purpose of determining the holders of outstanding first mortgage bonds of any series entitled to give or take any demand, direction, consent or other action under the First Mortgage Indenture, in the manner and subject to the limitations provided in the First Mortgage Indenture. In certain circumstances, the First Mortgage Trustee also will be entitled to set a record date for action by holders. If such a record date is set for any action to be taken by holders of particular first mortgage bonds, such action may be taken only by persons who are holders of such first mortgage bonds on the record date.

Governing Law

The First Mortgage Indenture and the first mortgage bonds provide that they are to be governed by and construed in accordance with the laws of the State of New York except where the Trust Indenture Act is applicable or where otherwise required by law. The effectiveness of the lien of the First Mortgage Indenture, and the perfection and priority thereof, will be governed by Kentucky law.

Summary of the Indenture

The following, in addition to the provisions contained elsewhere in this Official Statement, is a brief description of certain provisions of the Indenture. This description is only a summary and does not purport to be complete and definitive. Reference is made to the Indenture for the detailed provisions thereof.

Security

Pursuant to the Indenture, the Issuer will assign and pledge to the Trustee its interest in and to the Loan Agreement, including payments and other amounts due the Issuer thereunder, together with all moneys, property and securities from time to time held by the Trustee under the Indenture (with certain exceptions, including moneys held in or earnings on the Rebate Fund and the Purchase Fund).

The Bonds will be further secured by the First Mortgage Bonds to be delivered to the Trustee (see "Summary of the Loan Agreement — Issuance and Delivery of First Mortgage Bonds"). The First Mortgage Bonds will be registered in the name of the Trustee and will be nontransferable, except to effect a transfer to any successor trustee. The Bonds will not be directly secured by the Project (although the Project is subject to the lien of the First Mortgage Indenture).

No Pecuniary Liability of the Issuer

No provision, covenant or agreement contained in the Indenture or in the Loan Agreement, nor any breach thereof, will constitute or give rise to any pecuniary liability of the Issuer or any charge upon any of its assets or its general credit or taxing powers. The Issuer has not obligated itself by making the covenants, agreements or provisions contained in the Indenture or in the Loan Agreement, except with respect to the application of the amounts assigned to payment of the principal or redemption price of and interest on the Bonds.

The Bond Fund

The payments to be made by the Company pursuant to the Loan Agreement to the Issuer and certain other amounts specified in the Indenture will be deposited into a Bond Fund established pursuant to the Indenture (the "Bond Fund") and will be maintained in trust by the Trustee. Moneys in the Bond Fund will be used solely and only for the payment of the principal or redemption price of and interest on the Bonds, and for the payment of the reasonable fees and expenses to which the Trustee, Bond Registrar, Tender Agent, Authenticating Agent, any Paying Agent and the Issuer are entitled pursuant to the Indenture or the Loan Agreement. Any moneys held in the Bond Fund will be invested by the Trustee at the specific written direction of the Company in certain Governmental Obligations, investment-grade corporate obligations and other investments permitted under the Indenture.

The Prior Bond Funds

The proceeds from the issuance of the Bonds will be deposited by the Trustee in (i) the County of Trimble, Kentucky, Pollution Control Revenue Bond Fund, 2000 Series A (Louisville Gas and Electric Company Project) and (ii) the County of Trimble, Kentucky, Pollution Control Revenue Bond Fund, 2002 Series A (Louisville Gas and Electric Company Project), in each case in an amount adequate to pay, together with other moneys to be provided by the Company, all principal of and accrued interest on the respective issue of the Prior Bonds to become due and payable on their scheduled redemption dates.

The Rebate Fund

A Rebate Fund has been created by the Indenture (the "Rebate Fund") and will be maintained as a separate fund free and clear of the lien of the Indenture. The Issuer, the Trustee and the Company have agreed to comply with all rebate requirements of the Code and, in particular, the Company has agreed that if necessary, it will deposit in the Rebate Fund any such amount as is required under the Code. However, the Issuer, the Trustee and the Company may disregard the Rebate Fund provisions to the extent that they receive an opinion of Bond Counsel that such failure to comply will not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes.

Discharge of Indenture

When all the Bonds and all fees and charges accrued and to accrue of the Trustee and the Paying Agent have been paid or provided for, and when proper notice has been given to the Bondholders or the Trustee that the proper amounts have been so paid or provided for, and if the Issuer is not in default in any other respect under the Indenture, the Indenture will become null and void. The Bonds will be deemed to have been paid and discharged when there have been irrevocably deposited with the Trustee moneys sufficient to pay the principal or redemption price of and accrued interest on such Bonds to the due date (whether such date be by reason of maturity or upon redemption) or, in lieu thereof, Governmental Obligations have been deposited which mature in such amounts and at such times as will provide the funds necessary to so pay such Bonds, and when all reasonable and necessary fees and expenses of the Trustee, the Tender Agent, the Authenticating Agent, the Bond Registrar and the Paying Agent have been paid or provided for.

Surrender of First Mortgage Bonds

Upon payment of any principal or redemption price of and interest on any of the Bonds which reduces the principal amount of Bonds outstanding, or upon provision for the payment thereof having been made in accordance with the Indenture (see "Discharge of Indenture" above), First Mortgage Bonds in a principal amount equal to the principal amount of the Bonds so paid, or for the payment of which such provision has been made, shall be surrendered by the Trustee to the First Mortgage Trustee. The First Mortgage Bonds so surrendered shall be deemed fully paid and the obligations of the Company thereunder terminated.

Defaults and Remedies

Each of the following events constitutes an "Event of Default" under the Indenture:

(a) failure to make due and punctual payment of any installment of interest on any Bond within a period of one Business Day from the due date;

(b) failure to make due and punctual payment of the principal of, or premium, if any, on any Bond on the due date, whether at the stated maturity thereof, or upon proceedings for redemption, or upon the maturity thereof by declaration or if payment of the purchase price of any Bond required to be purchased pursuant to the Indenture is not made when such payment has become due and payable, provided that no Event of Default has occurred in respect of failure to receive such purchase price for any Bond if the Company has made the payment at the opening of business on the next Business Day as described in the last paragraph under "Summary of the Bonds — Purchases of Bonds — Remarketing and Purchase of Bonds" above;

(c) failure of the Issuer to perform or observe any other of the covenants, agreements or conditions in the Indenture or in the Bonds which failure continues for a period of 30 days after written notice by the Trustee or by the registered owners holding not less than 25% in aggregate principal amount of all Bonds outstanding, provided, however, that if such failure is capable of being cured, but cannot be cured in such 30-day period, it will not constitute an Event of Default under the Indenture if corrective action in respect of such failure is instituted within such 30-day period and is being diligently pursued;

(d) the occurrence of an "Event of Default" under the Loan Agreement (see "Summary of the Loan Agreement — Events of Default"); or

(e) all first mortgage bonds outstanding under the First Mortgage Indenture, if not already due, shall have become immediately due and payable, whether by declaration or otherwise, and such acceleration shall not have been rescinded by the First Mortgage Trustee.

Upon the occurrence of an Event of Default under the Indenture, the Trustee may, and upon the written request of the registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding and upon receipt of indemnity reasonably satisfactory to it, must: (i) enforce each and every right granted to the Trustee as a holder of the First Mortgage Bonds (see "Summary of the First Mortgage Bonds and the First Mortgage Indenture"), (ii) declare the principal of all Bonds and interest accrued thereon to be immediately due and payable and (iii) declare all payments under the Loan Agreement to be immediately due and payable and enforce each and every other right granted to the Issuer under the Loan Agreement for the benefit of the Bondholders. Interest on the Bonds will cease to accrue on the date of issuance of a declaration of acceleration of payment of the principal and interest on the Bonds.

In exercising such rights, the Trustee will take any action that, in the judgment of the Trustee, would best serve the interests of the registered owners, taking into account the security and remedies afforded to holders of first mortgage bonds under the First Mortgage Indenture. Upon the occurrence of an Event of Default under the Indenture, the Trustee may also proceed to pursue any available remedy by suit at law or in equity to enforce the payment of the principal or redemption price of and interest on the Bonds then outstanding.

If an Event of Default under the Indenture shall occur and be continuing and the maturity date of the Bonds has been accelerated (to the extent the Bonds are not already due and payable) as a consequence of such event of default, the Trustee may, and upon the written request of the registered owners holding not less than 25% in principal amount of all Bonds then outstanding and upon receipt of indemnity satisfactory to it shall, exercise such rights as it shall possess under the First Mortgage Indenture as a holder of the First Mortgage Bonds and shall also issue a Redemption Demand for such First Mortgage Bonds to the First Mortgage Trustee.

If the Trustee recovers any moneys following an Event of Default, unless the principal of the Bonds has been declared due and payable, all such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and the payment of any sums due and payable to the United States pursuant to Section 148(f) of the Code, (ii) to the payment of all interest then due on the Bonds, and (iii) to the payment of unpaid principal and premium, if any, of the Bonds. If the principal of the Bonds has become due or has been accelerated, such moneys will be applied in the following order: (i) to the payment of the fees, expenses, liabilities and advances incurred or made by the Trustee and the Paying Agent and (ii) to the payment of principal of and interest then due and unpaid on the Bonds.

No Bondholder may institute any suit or proceeding in equity or at law for the enforcement of the Indenture unless an Event of Default has occurred of which the Trustee has been notified or is deemed to have notice, and registered owners holding not less than 25% in aggregate principal amount of Bonds then outstanding have made written request to the Trustee to proceed to exercise the powers granted under the Indenture or to institute such action in their own name and the Trustee fails or refuses to exercise its powers within a reasonable time after receipt of indemnity satisfactory to it.

Any judgment against the Issuer pursuant to the exercise of rights under the Indenture will be enforceable only against specific assigned payments, funds and accounts under the Indenture in the hands of the Trustee. No deficiency judgment will be authorized against the general credit of the Issuer.

Waiver of Events of Default

Except as provided below, the Trustee may in its discretion waive any Event of Default under the Indenture and will do so upon the written request of the registered owners holding a majority in principal amount of all Bonds then outstanding. If, after the principal of all Bonds then outstanding have been declared to be due and payable as a result of a default under the Indenture and prior to any judgment or decree for the appointment of a receiver or for the payment of the moneys due has been obtained or entered, (i) the Company causes to be deposited with the Trustee a sum sufficient to pay all matured installments of interest upon all Bonds and the principal of and premium, if any, on any and all Bonds which would become due otherwise than by reason of such declaration (with interest thereon as provided in the Indenture) and the expenses of the Trustee in connection with such default and (ii) all Events of Default under the Indenture (other than nonpayment of the principal of Bonds due by said declaration) have been remedied, then such Event of Default will be deemed waived and such declaration and its consequences rescinded and annulled by the Trustee. Such waiver, rescission and annulment will be binding upon all Bondholders. No such waiver, rescission and annulment will extend to or affect any subsequent Event of Default or impair any right or remedy consequent thereon.

Upon any waiver or rescission as described above or any discontinuance or abandonment of proceedings under the Indenture, the Trustee shall immediately rescind in writing any Redemption Demand of First Mortgage Bonds previously given to the First Mortgage Trustee. The rescission under the First Mortgage Indenture of a declaration that all first mortgage bonds outstanding under the First Mortgage Indenture are immediately due and payable shall also constitute a waiver of an Event of Default described in paragraph (e) under the subheading "Defaults and Remedies" above and a waiver and rescission of its consequences, provided that no such waiver or rescission shall extend to or affect any subsequent or other default or impair any right consequent thereon.

Notwithstanding the foregoing, nothing in the Indenture will affect the right of a registered owner to enforce the payment of principal or redemption price of and interest on the Bonds after the maturity thereof.

Voting of First Mortgage Bonds Held by Trustee

The Indenture provides that the Trustee, as the holder of the First Mortgage Bonds, will be required to attend such meeting or meetings of bondholders under the First Mortgage Indenture or, at its option, deliver its proxy in connection therewith, as relate to matters with respect to which it, as such holder, is entitled to vote or consent. The Trustee, either at any such meeting or meetings or otherwise when the consent of the holders of the First Mortgage Bonds is sought without a meeting, will be required to vote all First Mortgage Bonds then held by it, or consent with respect thereto, proportionately with the vote or consent of the holders of all other securities of the Company then outstanding under the First Mortgage Indenture eligible to vote or consent, as evidenced by, and as to be delivered to the Trustee, a certificate signed by the temporary chairman, the temporary secretary, the permanent chairman, the permanent secretary, or an inspector of votes at any meeting or meetings of security holders under the First Mortgage Indenture, or by the First Mortgage Trustee in the case of consents of such security holders which are sought without a meeting, which states what the signer thereof reasonably believes are the proportionate votes or consents of the holders of all securities (other than the First Mortgage Bonds) outstanding under the First Mortgage Indenture and counted for the purposes of determining whether such security holders have approved or consented to the matter put before them; provided, however, that the Trustee shall not so vote in favor of, or so consent to, any amendment or modification of the First Mortgage Indenture, which, if it were an amendment or modification of the Indenture, would require the consent of the Bondholders as described in the third paragraph under the heading "Summary of the Indenture – Supplemental Indenture," without the prior consent and approval of Bondholders which would be so required; provided further that as a condition to the Trustee voting or giving such consent, the Trustee shall have received a certificate of a Company representative or an opinion of counsel, at its election, stating that such voting or consent is authorized or permitted by the Indenture.

Supplemental Indentures

The Issuer and the Trustee may enter into indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions of the Indenture, without the consent of or notice to the Bondholders, in order (i) to cure any ambiguity or formal defect or omission in the Indenture, (ii) to grant to or confer upon the Trustee, as may lawfully be granted, additional rights, remedies, powers or authorities for the benefit of the Bondholders, (iii) to subject to the Indenture additional revenues, properties or collateral, (iv) to permit qualification of the Indenture under any federal statute or state blue sky law, (v) to add additional covenants and agreements of the Issuer for the protection of the Bondholders or to surrender or limit any rights, powers or authorities reserved to or conferred upon the

Issuer, (vi) to make any other modification or change to the Indenture which, in the sole judgment of the Trustee, does not adversely affect the Trustee or any Bondholder, (vii) to make other amendments not otherwise permitted by (i), (ii), (iii), (iv) or (v) of this paragraph to provisions relating to federal income tax matters under the Code or other relevant provisions if, in the opinion of Bond Counsel, those amendments would not adversely affect the exclusion of the interest on the Bonds from gross income for federal income tax purposes, (viii) to make any modification or change to the Indenture necessary to provide liquidity or credit support for the Bonds, including any modifications necessary to upgrade or maintain the then applicable ratings on the Bonds or (ix) to permit the issuance of the Bonds in other than book-entry-only form or to provide changes to or for the book-entry system.

Notwithstanding the foregoing, the Company, with the consent of the Trustee, may at any time further secure the Bonds by means of a letter of credit, other credit facility or other guarantee or collateral.

Exclusive of supplemental indentures for the purposes set forth in the preceding two paragraphs, the consent of registered owners holding a majority in aggregate principal amount of all Bonds then outstanding is required to approve any supplemental indenture, except no such supplemental indenture may permit, without the consent of all of the registered owners of the Bonds then outstanding, (i) an extension of the maturity of the principal of or the interest on any Bond issued under the Indenture or a reduction in the principal amount of any Bond or the rate of interest or time of redemption or redemption premium thereon, (ii) a privilege or priority of any Bond or Bonds over any other Bond or Bonds, (iii) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or (iv) the deprivation of any registered owners of the lien of the Indenture.

If at any time the Issuer requests the Trustee to enter into any supplemental indenture requiring the consent of the registered owners of the Bonds, the Trustee, upon being satisfactorily indemnified with respect to expenses, must notify all such registered owners. Such notice must set forth the nature of the proposed supplemental indenture and must state that copies thereof are on file at the designated office of the Trustee for inspection. If, within sixty days (or such longer period as prescribed by the Issuer or the Company) following the giving of such notice, the registered owners holding the requisite amount of the Bonds outstanding have consented to the execution thereof, no Bondholder will have any right to object or question the execution thereof.

No supplemental indenture will become effective unless the Company consents to the execution and delivery of such supplemental indenture. The Company will be deemed to have consented to the execution and delivery of any supplemental indenture if the Trustee does not receive a notice of protest or objection signed by the Company on or before 4:30 p.m., local time in the city in which the designated office of the Trustee is located, on the fifteenth day after the mailing to the Company of a notice of the proposed changes and a copy of the proposed supplemental indenture.

Enforceability of Remedies

The remedies available to the Trustee, the Issuer and the owners upon an Event of Default under the Loan Agreement, the Indenture or the First Mortgage Indenture are in many respects dependent upon judicial actions which are often subject to discretion and delay. Under existing constitutional and statutory law and judicial decisions, the remedies specified by the Loan Agreement, the Indenture and the First Mortgage Indenture may not be readily available or may be limited. The various legal opinions to be delivered concurrently with the delivery of the Bonds will be qualified as to the enforceability of the various legal instruments by limitations imposed by principles of equity, bankruptcy, reorganization, insolvency, moratorium or other similar laws affecting the rights of creditors generally.

Tax Treatment

In the opinion of Bond Counsel, under existing law, including current statutes, regulations, administrative rulings and official interpretations, subject to the qualifications and exceptions set forth below, interest on the Bonds will be excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion will be expressed regarding such exclusion from gross income with respect to any Bond during any period in which it is held by a "substantial user" of the Project or a "related person" as such terms are used in Section 147(a) of the Code. Interest on the Bonds will be an item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. It is Bond Counsel's further opinion that, subject to the assumptions stated in the preceding sentence, (i) interest on the Bonds will be excluded from gross income of the owners thereof for Kentucky income tax purposes and (ii) the Bonds will be exempt from all ad valorem taxes in Kentucky.

The opinion of Bond Counsel assumes and is conditioned on the payment and discharge of all of the Prior Bonds on or before the 90th day following the date of issuance of the Bonds. The Company has agreed (i) to apply all of the proceeds of the bonds to the payment and discharge of the Prior Bonds within 90 days following the date of issuance of the Bonds, (ii) to provide additional funds necessary, on or prior to a day within 90 days following the date of issuance of the Bonds, to defease and discharge the Prior Bonds on such day and (iii) to give irrevocable instructions on the date of issuance of the Bonds to the trustee in respect of the Prior Bonds directing the redemption of the Prior Bonds.

The opinion of Bond Counsel as to the excludability of interest from gross income for federal income tax purposes will be based upon and will assume the accuracy of certain representations of facts and circumstances, including with respect to the Project, which are within the knowledge of the Company and compliance by the Company with certain covenants and undertakings set forth in the proceedings authorizing the Bonds which are intended to assure that the Bonds are and will remain obligations the interest on which is not includable in gross income of the recipients thereof under the law in effect on the date of such opinion. Bond Counsel will not independently verify the accuracy of the certifications and representations made by the Company and the Issuer. On the date of the opinion and subsequent to the original delivery of the Bonds, such representations of facts and circumstances must be accurate and such covenants and undertakings must continue to be complied with in order that interest on the Bonds be and remain excludable from gross income of the recipients thereof for federal income tax purposes under existing law. Bond Counsel will express no opinion (i) regarding the exclusion of interest on any Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents other than with the approval of Bond Counsel is taken which adversely affects the tax treatment of the Bonds or (ii) as to the treatment for purposes of federal income taxation of interest on the Bonds upon a Determination of Taxability.

The Code prescribes a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which, including provisions for potential payments by the Issuer to the federal government, require future or continued compliance after issuance of the Bonds in order for the interest to be and to continue to be so excluded from the date of issuance. Noncompliance with certain of these requirements by the Company or the Issuer with respect to the Bonds could cause the interest on the Bonds to be included in gross income for federal income tax purposes and to be subject to federal income taxation retroactively to the date of their issuance. The Company and the Issuer will each covenant to take all actions required of each to assure that the interest on the Bonds will be and remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion.

The opinion of Bond Counsel as to the exclusion of interest on the Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the Bonds will be subject to the following exceptions and qualifications:

(a) The Code also provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, Bond Counsel will express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the Bonds.

Owners of the Bonds should be aware that the ownership of the Bonds may result in collateral federal income tax consequences. For instance, the Code provides that property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income tax credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the Bonds will be taken into account in the calculation of disqualified income. Prospective purchasers of the Bonds should consult their own tax advisors regarding such matters and any other tax consequences of holding the Bonds.

From time to time, there are legislative proposals in Congress which, if enacted, could alter or amend one or more of the federal tax matters referred to above or could adversely affect the market value of the Bonds. It cannot be predicted whether or in what form any such proposal might be enacted or whether, if enacted, it would apply to obligations (such as the Bonds) issued prior to enactment.

A draft of the opinion of Bond Counsel relating to the Bonds in substantially the form in which it is expected to be delivered on the date of issuance of the Bonds is attached as Appendix B to this Official Statement.

Legal Matters

Certain legal matters incident to the authorization, issuance and sale by the Issuer of the Bonds are subject to the approving opinion of Bond Counsel. Bond Counsel has in the past, and may in the future, act as counsel to the Company with respect to certain matters. Certain legal matters will be passed upon for the Issuer by its County Attorney. Certain legal matters will be passed upon for the Company by Jones Day, Chicago, Illinois, and Gerald A. Reynolds, General Counsel, Chief Compliance Officer and

Corporate Secretary for the Company. Certain legal matters will be passed upon for the Underwriter by its counsel, McGuireWoods LLP, Chicago, Illinois.

Underwriting

J.P. Morgan Securities LLC (the "Underwriter") has agreed, subject to the terms of the bond purchase agreement between the Issuer and the Underwriter, to purchase the Bonds from the Issuer at the public offering price set forth on the cover page of this Official Statement. The Underwriter is committed to purchase all the Bonds if any Bonds are purchased. In connection with the underwriting of the Bonds, the Underwriter will be paid by the Company a fee in the amount of $312,500, which excludes reimbursement for certain reasonable out-of-pocket expenses.

The Underwriter may offer and sell the Bonds to certain dealers and others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriter.

In connection with the offering of the Bonds, the Underwriter may over-allot or effect transactions that stabilize or maintain the market prices of such Bonds at levels above those that might otherwise prevail in the open market. Such stabilizing, if commenced, may be discontinued at any time.

Pursuant to an Inducement Letter, the Company has agreed to indemnify the Underwriter and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriter or the Issuer may be required to make in respect thereof.

J.P. Morgan Securities LLC (or its affiliates), the Underwriter of the Bonds, serves as the auction broker-dealer for the 2000 Bonds and owns a substantial portion of the 2000 Bonds that will be refunded with the proceeds of the Bonds.

J.P. Morgan Securities LLC and its affiliates together comprise a full service financial institution engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, principal investment, hedging, financing and brokerage activities. Such activities may involve or relate to assets, securities and/or instruments of the Issuer and/or the Company or its affiliates (whether directly, as collateral securing other obligations or otherwise) and/or persons and entities with relationships with (or that are otherwise involved with transactions by) the Issuer and/or the Company. J.P. Morgan Securities LLC and its affiliates may have, from time to time, engaged, and may in the future engage, in transactions with, and performed and may in the future perform, various investment banking services for the Issuer and/or the Company for which they received or will receive customary fees and expenses. Under certain circumstances, J.P. Morgan Securities LLC and its affiliates may have certain creditor and/or other rights against the Issuer and/or the Company and any affiliates thereof in connection with such transactions and/or services. In addition, J.P. Morgan Securities LLC and its affiliates may currently have and may in the future have investment and commercial banking, trust and other relationships with parties that may relate to assets of, or be involved in the issuance of securities and/or instruments by, the Issuer and/or the Company and any affiliates thereof. J.P. Morgan Securities LLC and its affiliates also may communicate independent investment recommendations, market advice or trading ideas and/or publish or express independent research views in respect of such assets, securities or instruments and at any time may hold, or recommend to clients that they should acquire, long and/or short positions in such assets, securities and instruments.

Continuing Disclosure

Because the Bonds will be special and limited obligations of the Issuer, the Issuer is not an "obligated person" for purposes of Rule 15c2-12 (the "Rule") promulgated by the SEC under the Exchange Act, and does not have any continuing obligations thereunder. Accordingly, the Issuer will not provide any continuing disclosure information with respect to the Bonds or the Issuer.

In order to enable the Underwriter to comply with the requirements of the Rule, the Company will covenant in a continuing disclosure undertaking agreement to be delivered to the Trustee for the benefit of the holders of the Bonds (the "Continuing Disclosure Agreement") to provide certain continuing disclosure for the benefit of the holders of the Bonds. Under its Continuing Disclosure Agreement, the Company will covenant to take the following actions:

(i) The Company will provide to the Municipal Securities Rulemaking Board ("MSRB") (in electronic format) (a) annual financial information of the type set forth in Appendix A to this Official Statement (including any information incorporated by reference in Appendix A) and (b) audited financial statements prepared in accordance with generally accepted accounting principles, in each case not later than 120 days after the end of the Company's fiscal year.

(ii) The Company will file in a timely manner not in excess of 10 business days after the occurrence of the event with the MSRB notice of the occurrence of any of the following events (if applicable) with respect to the Bonds: (a) principal and interest payment delinquencies; (b) non-payment related defaults, if material; (c) any unscheduled draws on debt service reserves reflecting financial difficulties; (d) unscheduled draws on credit enhancement facilities reflecting financial difficulties; (e) substitution of credit or liquidity providers, or their failure to perform; (f) adverse tax opinions, the issuance by the Internal Revenue Service of proposed or final determinations of taxability, Notices of Proposed Issue (IRS Form 5701-TEB) or other material notices or determinations with respect to the tax status of the Bonds, or other material events affecting the tax status of the Bonds; (g) modifications to rights of the holders of the Bonds, if material; (h) the giving of notice of optional or unscheduled redemption of any Bonds, if material, and tender offers; (i) defeasance of the Bonds or any portion thereof; (j) release, substitution, or sale of property securing repayment of the Bonds, if material; (k) rating changes; (l) bankruptcy, insolvency, receivership or similar event of the Company; (m) the consummation of a merger, consolidation or acquisition involving the Company, or the sale of all or substantially all of the assets of the Company, other than in the ordinary course of business, the entry into a definitive agreement to undertake such an action or the termination of a definitive agreement relating to any such actions, other than pursuant to its terms, if material; and (n) appointment of a successor or additional trustee or a change of name of a trustee, if material.

(iii) The Company will file in a timely manner with the MSRB notice of a failure by the Company to file any of the information referred to in paragraph (i) above by the due date.

The Company may amend its Continuing Disclosure Agreement (and the Trustee shall agree to any amendment so requested by the Company that does not change the duties of the Trustee thereunder) or waive any provision thereof, but only with a change in circumstances that arises from a change in legal requirements, change in law, or change in the nature or status of the Company with respect to the Bonds or the type of business conducted by the Company; provided that the undertaking, as amended or following such waiver, would have complied with the requirements of the Rule on the date of issuance of the Bonds, after taking into account any amendments to the Rule as well as any change in circumstances, and the amendment or waiver does not materially impair the interests of the holders of the Bonds to which such undertaking relates, in the opinion of the Trustee or counsel expert in federal securities laws acceptable to both the Company and the Trustee, or is approved by the Beneficial Owners of a majority in aggregate principal amount of the outstanding Bonds. The Company acknowledges that its undertakings pursuant to the Rule described under this heading are intended to be for the benefit of the holders of the Bonds and shall be enforceable by the holders of those Bonds or by the Trustee on behalf of such holders. Any breach by the Company of these undertakings pursuant to the Rule will not constitute an event of default under the Indenture, the Loan Agreement or the Bonds.

The Company is a party to continuing disclosure agreements with respect to nine series of pollution control bonds. The MSRB's Electronic Municipal Market Access ("EMMA") website reflects that, within the past five years, for two series of such bonds, the Company's 2011 annual financial statements were timely posted, but to outdated CUSIP numbers. The 2011 annual financial statements were re-posted to the correct CUSIP numbers for those series in May 2012. With respect to both series of bonds, the Company also failed to file on the MSRB's EMMA website in a timely manner a notice of the Company's failure to file such 2011 financial statements in accordance with the applicable continuing disclosure agreements. The Company has subsequently made all of these corrective filings. The Company's 2011 annual financial statements had been filed with the SEC on February 28, 2012. The Company has had, and continues to have, procedures in place in order to make material event notices and financial statement filings on an ongoing basis.

This Official Statement has been duly approved, executed and delivered by the County Judge/Executive of the Issuer, on behalf of the Issuer. However, the Issuer has not and does not assume any responsibility as to the accuracy or completeness of any of the information in this Official Statement except for information furnished by the Issuer under the heading "The Issuer."

COUNTY OF TRIMBLE, KENTUCKY

By: /s/ Jerry L. Powell
County Judge/Executive

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APPENDIX A

THE COMPANY

Louisville Gas and Electric Company (the "Company"), incorporated in Kentucky in 1913, is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy and the storage, distribution and sale of natural gas. As of December 31, 2015, the Company provides electric service to approximately 403,000 customers in Louisville and adjacent areas in Kentucky, covering approximately 700 square miles in nine counties and provides natural gas service to approximately 322,000 customers in its electric service area and eight additional counties in Kentucky. The Company's coal-fired electric generating stations, all equipped with systems to reduce sulphur dioxide emissions, produce most of the Company's electricity. The remainder is generated by a natural gas combined cycle combustion turbine, a hydroelectric power plant and natural gas and oil fueled combustion turbines. Underground natural gas storage fields help the Company provide economical and reliable natural gas service to customers.

The Company is a wholly-owned subsidiary of LG&E and KU Energy LLC and an indirect wholly-owned subsidiary of PPL Corporation. The Company's affiliate, Kentucky Utilities Company ("KU"), is a regulated public utility engaged in the generation, transmission, distribution and sale of electric energy in Kentucky, Virginia and Tennessee. The Company's obligations under the Loan Agreement are solely its own, and not those of any of its affiliates. None of KU, PPL Corporation or the Company's other affiliates will be obligated to make any payment on the Loan Agreement or the Bonds.

The Company's executive offices are located at 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

The information above concerning the Company is only a summary and does not purport to be comprehensive. Additional information regarding the Company, including audited financial statements, is available in the documents listed under the heading "Documents Incorporated by Reference," which documents are incorporated by reference herein.

Selected Financial Data
(Dollars in millions)

	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015	Year Ended December 31, 2015	Year Ended December 31, 2014	Year Ended December 31, 2013
Operating revenues	$ 709	$ 770	$ 1,444	$ 1,533	$ 1,410
Operating income	$ 195	$ 171	$ 362	$ 324	$ 293
Net income	$ 96	$ 88	$ 185	$ 169	$ 163
Total assets[(1)]	$ 6,157	$ 5,721	$ 6,068	$ 5,654	$ 4,923
Long-term debt obligations (including amounts due within one year)[(1)]	$ 1,642	$ 1,346	$ 1,642	$ 1,345	$ 1,345
Ratio of earnings to fixed charges[(2)]	5.2	6.1	5.9	6.3	8.1

Capitalization:

	June 30, 2016	% of Capitalization
Long-term debt and notes payable	$ 1,752	42%
Common equity	2,412	58%
Total capitalization	$ 4,164	100%

(1) Effective December 31, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of debt issuance costs. The guidance requires certain debt issuance costs to be presented on the balance sheet as a direct deduction from the carrying amount of the associated debt liability. As a result, all periods reported in the December 31, 2015 Form 10-K reflected the retrospective adoption of this guidance. Amounts reported in the table above for June 30, 2015 and December 31, 2013, also reflect retrospective reclassifications from other noncurrent assets to long-term debt of $7 million and $8 million, respectively.

Additionally, effective October 1, 2015, LG&E retrospectively adopted accounting guidance to simplify the presentation of deferred taxes which requires that deferred tax assets and deferred tax liabilities be classified as noncurrent on the balance sheet. As a result, all periods reported in the December 31, 2015 Form 10-K reflected the retrospective adoption of this guidance. Amounts reported in the table above for June 30, 2015 and December 31, 2013, also reflect retrospective reclassifications from other current assets to noncurrent deferred tax liabilities of $17 million and $3 million, respectively.

(2) For purposes of this ratio, "Earnings" consist of earnings (as defined below) from continuing operations plus fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense and the portion of rental expense that represents an imputed interest component. Earnings from continuing operations consist of income before taxes and the mark-to-market impact of derivative instruments.

The selected financial data presented above for the three fiscal years ended December 31, 2015, and as of December 31 for each of those years, have been derived from the Company's audited financial statements. The selected financial data presented above for the six months ended June 30, 2016 and 2015 have been derived from the Company's unaudited financial statements for the six months ended June 30, 2016 and 2015. The Company's audited financial statements for the three fiscal years ended December 31, 2015, and as of December 31 for each of those years, are included in the Company's Form 10-K for the year ended December 31, 2015 incorporated by reference herein. The Company's unaudited financial statements for the six months ended June 30, 2016 are included in the Company's Form 10-Q for the quarter ended June 30, 2016 incorporated by reference herein. "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-K for the year ended December 31, 2015 and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations" in the Company's Form 10-Q for the quarter ended June 30, 2016, as well as the Combined Notes to Financial Statements as of December 31, 2015, 2014 and 2013 and the Combined Notes to Condensed Financial Statements (Unaudited) as of June 30, 2016 and December 31, 2015 and for the six-month periods ended June 30, 2016 and 2015, should be read in conjunction with the above information. Ernst & Young LLP audited the Company's financial statements for the three fiscal years ended December 31, 2015.

Risk Factors

Investing in the Bonds involves risk. Please see the risk factors in the Company's Annual Report on Form 10-K for the year ended December 31, 2015, which is incorporated by reference in this Appendix A. Before making an investment decision, you should carefully consider these risks as well as the other information contained or incorporated by reference in this Appendix A. Risks and uncertainties not presently known to the Company or that the Company currently deems immaterial may also impair its business operations, its financial results and the value of the Bonds.

Available Information

The Company is subject to the information requirements of the Securities Exchange Act of 1934, as amended, and, accordingly, files reports and other information with the Securities and Exchange Commission (the "SEC"). Such reports and other information on file can be inspected and copied at the public reference facilities of the SEC, currently at 100 F Street, N.E., Room 1580, Washington, D.C. 20549; or from the SEC's Web Site (http://www.sec.gov). Please call the SEC at 1-800-SEC-0330 for further information on the public reference room.

Documents Incorporated by Reference

The following documents, as filed by the Company with the SEC, are incorporated herein by reference:

1. Form 10-K Annual Report of the Company for the year ended December 31, 2015;

2. Form 10-Q Quarterly Reports of the Company for the quarters ended March 31, 2016 and June 30, 2016; and

3. Form 8-K Current Reports filed with the SEC on January 12, 2016, February 3, 2016, and June 17, 2016.

All documents filed by the Company with the SEC pursuant to Section 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 subsequent to the date of this Official Statement and prior to the termination of the offering of the Bonds shall be deemed to be incorporated by reference in this Appendix and to be made a part hereof from their respective dates of filing. Any statement contained in a document incorporated or deemed to be incorporated by reference in this Official Statement shall be deemed to be modified or superseded for purposes of this Official Statement to the extent that a statement contained in this Official Statement or in any other subsequently filed document which also is or is deemed to be incorporated by reference in this Official Statement modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this Official Statement.

The Company hereby undertakes to provide without charge to each person (including any beneficial owner) to whom a copy of this Official Statement has been delivered, on the written or oral request of any such person, a copy of any or all of the documents referred to above which have been or may be incorporated in this Official Statement by reference, other than certain exhibits to such documents. Requests for such copies should be directed to Treasurer, Louisville Gas and Electric Company, 220 West Main Street, Louisville, Kentucky 40202, telephone: (502) 627-2000.

APPENDIX B

(FORM OF OPINION OF BOND COUNSEL)

____, 2016

Re: $125,000,000 County of Trimble, Kentucky, Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project)

We hereby certify that we have examined certified copies of the proceedings of record of the County of Trimble, Kentucky (the "**County**"), acting by and through its Fiscal Court as its duly authorized governing body, preliminary to and in connection with the issuance by the County of its Pollution Control Revenue Refunding Bonds, 2016 Series A (Louisville Gas and Electric Company Project), dated their date of issuance, in the aggregate principal amount of $125,000,000 (the "**2016 Series A Bonds**"). The 2016 Series A Bonds are issued under the provisions of Sections 103.200 to 103.285, inclusive, of the Kentucky Revised Statutes (the "**Act**"), for the purpose of providing funds which will be used, with other funds provided by Louisville Gas and Electric Company (the "**Company**") for the current refunding of (i) $83,335,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 2000 Series A (Louisville Gas and Electric Company Project), dated August 9, 2000 (the "**Refunded 2000 Series A Bonds**"), and (ii) $41,665,000 aggregate principal amount of the County's Pollution Control Revenue Bonds, 2002 Series A (Louisville Gas and Electric Company Project), dated October 23, 2002 (the "**Refunded 2002 Series A Bonds"**, and collectively with the Refunded 2000 Series A Bonds, the "**Refunded Bonds**"), which were issued for the purpose of currently refunding a portion of the costs of construction of air and water pollution control facilities serving certain electric generating units of the Company located in Trimble County, Kentucky (the "**Project**"), as provided by the Act.

The 2016 Series A Bonds mature on September 1, 2044 and bear interest initially at the Weekly Rate, as defined in the Indenture, hereinafter described, subject to change as provided in such Indenture. The 2016 Series A Bonds will be subject to optional and mandatory redemption prior to maturity at the times, in the manner, and upon the terms set forth in the 2016 Series A Bonds. From such examination of the proceedings of the Fiscal Court of the County referred to above and from an examination of the Act, we are of the opinion that the County is duly authorized and empowered to issue the 2016 Series A Bonds under the laws of the Commonwealth of Kentucky now in force.

We have examined an executed counterpart of a certain Loan Agreement, dated as of September 1, 2016 (the "**Loan Agreement**"), by and between the County and the Company and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Loan Agreement, pursuant to which the County has agreed to issue the 2016 Series A Bonds and to lend the proceeds thereof to the Company to provide funds to pay and discharge, with other funds provided by the Company, the Refunded Bonds. The Company has agreed to make loan payments to the Trustee at times and in amounts fully adequate to pay maturing principal of, interest on, and redemption premium, if any, on the 2016 Series A Bonds as same become due and payable. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Loan Agreement; that the Loan Agreement has been duly authorized, executed, and delivered by the County; and that the Loan Agreement is a legal, valid, and binding obligation of the County, enforceable in accordance with its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

We have also examined an executed counterpart of a certain Indenture of Trust, dated as of September 1, 2016 (the "**Indenture**"), by and between the County and U.S. Bank National Association, as trustee (the "**Trustee**"), securing the 2016 Series A Bonds and setting forth the covenants and undertakings of the County in connection with the 2016 Series A Bonds and a certified copy of the proceedings of record of the Fiscal Court of the County preliminary to and in connection with the execution and delivery of the Indenture. Pursuant to the Indenture, certain of the County's rights under the Loan Agreement, including the right to receive payments thereunder, and all moneys and securities held by the Trustee in accordance with the Indenture (except moneys and securities in the Rebate Fund created thereby) have been assigned to the Trustee, as security for the holders of the 2016 Series A Bonds. From such examination, we are of the opinion that such proceedings of the Fiscal Court of the County show lawful authority for the execution and delivery of the Indenture; that the Indenture has been duly authorized, executed, and delivered by the County; and that the Indenture is a legal, valid, and binding obligation upon the parties thereto according to its terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought.

In our opinion the 2016 Series A Bonds have been validly authorized, executed, and issued in accordance with the laws of the Commonwealth of Kentucky now in full force and effect, and constitute legal, valid, and binding special and limited obligations of the County entitled to the benefit of the security provided by the Indenture and enforceable in accordance with their terms, subject to the qualification that the enforcement thereof may be limited by laws relating to bankruptcy, insolvency, or other similar laws affecting creditors' rights generally, including equitable provisions where equitable remedies are sought. The 2016 Series A Bonds are payable by the County solely and only from payments and other amounts derived from the Loan Agreement and as provided in the Indenture.

In our opinion, under existing laws, including current statutes, regulations, administrative rulings, and official interpretations by the Internal Revenue Service, subject to the exceptions and qualifications contained in the succeeding paragraphs, (i) interest on the 2016 Series A Bonds is excluded from the gross income of the recipients thereof for federal income tax purposes, except that no opinion is expressed regarding such exclusion from gross income with respect to any 2016 Series A Bond during any period in which it is held by a "substantial user" of the Project or a "related person," as such terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "**Code**"); and (ii) interest on the 2016 Series A Bonds is a separate item of tax preference in determining alternative minimum taxable income for individuals and corporations under the Code. In arriving at this opinion, we have relied upon representations, factual statements, and certifications of the Company with respect to certain material facts which are solely within the Company's knowledge in reaching our conclusion, among other things, that all of the proceeds of the Refunded 2002 Series C Bonds were used to refinance air and water pollution control facilities qualified for financing under Section 103(b)(4)(F) of the Internal Revenue Code of 1954, as amended, and Section 1312(a) of the Tax Reform Act of 1986. Further, in arriving at the opinion set forth in this paragraph as to the exclusion from gross income of interest on the 2016 Series A Bonds, we have assumed and this opinion is conditioned on, the accuracy of and continuing compliance by the Company and the County with representations and covenants set forth in the Loan Agreement and the Indenture which are intended to assure compliance with certain tax-exempt interest provisions of the Code. Such representations and covenants must be accurate and must be complied with after the issuance of the 2016 Series A Bonds in order that interest on the 2016 Series A Bonds be excluded from gross income for federal income tax purposes. Failure to comply with certain of such representations and covenants in respect of the 2016 Series A Bonds after the issuance of the 2016 Series A Bonds could cause the interest thereon to be included in gross income for federal income tax purposes retroactively to the date of issuance of the 2016 Series A Bonds. We express no opinion (i) regarding the exclusion of interest on any 2016 Series A Bond from gross income for federal income tax purposes on or after the date on which any change, including any interest rate conversion, permitted by the documents (other than with approval of this firm) is taken which adversely affects the tax treatment of the 2016 Series A Bonds; or (ii) as to the treatment for purposes of federal income taxation of interest on the 2016 Series A Bonds upon a Determination of Taxability. We are further of the opinion that interest on the 2016 Series A Bonds is excluded from gross income of the recipients thereof for Kentucky income tax purposes and that the 2016 Series A Bonds are exempt from ad valorem taxation by the Commonwealth of Kentucky and all political subdivisions thereof.

Our opinion as to the exclusion of interest on the 2016 Series A Bonds from gross income for federal income tax purposes and federal tax treatment of interest on the 2016 Series A Bonds is further subject to the following exceptions and qualifications:

(a) The Code provides for a "branch profits tax" which subjects to tax, at a rate of 30%, the effectively connected earnings and profits of a foreign corporation which engages in a United States trade or business. Interest on the 2016 Series A Bonds would be includable in the amount of effectively connected earnings and profits and thus would increase the branch profits tax liability.

(b) The Code also provides that passive investment income, including interest on the 2016 Series A Bonds, may be subject to taxation for any S corporation with Subchapter C earnings and profits at the close of its taxable year if greater than 25% of its gross receipts is passive investment income.

Except as stated above, we express no opinion as to any federal or Kentucky tax consequences resulting from the receipt of interest on the 2016 Series A Bonds.

Holders of the 2016 Series A Bonds should be aware that the ownership of the 2016 Series A Bonds may result in collateral federal income tax consequences. For instance, the Code provides that, for taxable years beginning after December 31, 1986, property and casualty insurance companies will be required to reduce their loss reserve deductions by 15% of the tax-exempt interest received on certain obligations, such as the 2016 Series A Bonds, acquired after August 7, 1986. (For purposes of the immediately preceding sentence, a portion of dividends paid to an affiliated insurance company may be treated as tax-exempt interest.) The Code further provides for the disallowance of any deduction for interest expenses incurred by banks and certain other financial institutions allocable to carrying certain tax-exempt obligations, such as the 2016 Series A Bonds, acquired after August 7, 1986. The Code also provides that, with respect to taxpayers other than such financial institutions, such taxpayers will be unable to deduct any portion of the interest expenses incurred or continued to purchase or carry the 2016 Series A Bonds. The Code also provides, with respect to individuals, that interest on tax-exempt obligations, including the 2016 Series A Bonds, is included in modified adjusted gross income for purposes of determining the taxability of social security and railroad retirement benefits. Furthermore, the earned income credit is not allowed for individuals with an aggregate amount of disqualified income within the meaning of Section 32 of the Code, which exceeds $2,200. Interest on the 2016 Series A Bonds will be taken into account in the calculation of disqualified income.

We have received opinions of Gerald A. Reynolds, General Counsel, Chief Compliance Officer, and Corporate Secretary of the Company and Jones Day, Chicago, Illinois, counsel to the Company, of even date herewith. In rendering this opinion, we have relied upon said opinions with respect to the matters therein. We have also received an opinion of even date herewith of Hon. Crystal L. Heinz, County Attorney of Trimble County, Kentucky, and relied upon said opinion with respect to the matters therein. The opinions are in forms satisfactory to us as to both scope and content.

We express no opinion as to the title to, the description of, or the existence or priority of any liens, charges, or encumbrances on the Project.

In rendering the foregoing opinions, we are passing upon only those matters specifically set forth in such opinions and are not passing upon the investment quality of the 2016 Series A Bonds or the accuracy or completeness of any statements made in connection with any offer or sale thereof. The opinions herein are expressed as of the date hereof and we assume no obligation to supplement or update such opinions to reflect any facts or circumstances that may hereafter come to our attention or any changes in law that may hereafter occur.

We are members of the Bar of the Commonwealth of Kentucky and do not purport to be experts on the laws of any jurisdiction other than the Commonwealth of Kentucky and the United States of America, and we express no opinion as to the laws of any jurisdiction other than those specified.

Respectfully submitted,

STOLL KEENON OGDEN PLLC

Mixed Sources
Product group from well managed forests, controlled sources and recycled wood or fiber.

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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 266

Responding Witness: Daniel K. Arbough

Q-266. Provide copies of credit reports for PPL and/or Louisville Gas & Electric between January 1, 2015 and the present from the major credit rating agencies (Moody's, S&P, and Fitch).

A-266. See attached.

FitchRatings

Fitch Withdraws PPL and its U.S. Subsidiaries' Ratings

Ratings Endorsement Policy

09 Jan 2015 3:47 PM (EST)

Fitch Ratings-New York-09 January 2015: Fitch Ratings withdraws the ratings of PPL Corporation and its U.S. subsidiaries for business reasons. A complete list of ratings follows this press release.

For further information, please refer to the Fitch's press release 'Fitch Upgrades PPL Electric to 'BBB+'; PPL Corp's Outlook to Positive; Plans to Withdraw Ratings' dated Dec. 10, 2014.

Fitch withdraws the following ratings:

PPL Corporation
--Long-term Issuer Default Rating (IDR) at 'BBB';
--Short-term IDR at 'F2';
--Rating Outlook Positive.

PPL Capital Funding Inc.
--Senior unsecured debt at 'BBB';
--Junior subordinated notes at 'BB+';
--Rating Outlook Positive.

PPL Electric Utilities Corp.
--Long-term IDR 'BBB+';
--Secured debt at 'A';
--Short-term IDR at 'F2';
--Commercial paper at 'F2';
--Rating Outlook Stable.

LG&E and KU Energy LLC
--Long-term IDR at 'BBB+';
--Senior unsecured debt at 'BBB+';
--Short-term IDR at 'F2';
--Rating Outlook Stable.

Kentucky Utilities Company
--Long-term IDR at 'A-';
--Secured debt at 'A+';
--Secured pollution control bonds at 'A+/F2';
--Senior unsecured debt at 'A';
--Short-term IDR at 'F2';
--Commercial paper at 'F2';
--Rating Outlook Stable.

Louisville Gas and Electric Company
--Long-term IDR at 'A-';
--Secured debt 'A+';
--Secured pollution control bonds at 'A+/F2';
--Senior unsecured debt at 'A';
--Short-term IDR at 'F2';
--Commercial paper at 'F2';
--Rating Outlook Stable.

PPL Energy Supply, LLC.
--Long-term IDR at 'BB';
--Senior unsecured debt at 'BB';
--Short-term IDR at 'B';

--Commercial paper at 'B';
--Rating Watch Negative.

Contact:

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (May 28, 2014);
--'Recovery Ratings and Notching Criteria for Utilities' (Nov. 18, 2014);
--'Parent and Subsidiary Rating Linkage' (Aug. 5, 2013);
--'Rating U.S. Utilities, Power and Gas Companies' (March 11, 2014).

Applicable Criteria and Related Research:
Corporate Rating Methodology - Including Short-Term Ratings and Parent and Subsidiary Linkage
Recovery Ratings and Notching Criteria for Utilities
Parent and Subsidiary Rating Linkage Fitch's Approach to Rating Entities within a Corporate Group Structure
Rating U.S. Utilities, Power and Gas Companies (Sector Credit Factors)

Additional Disclosure
Solicitation Status

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's upgrades PPL Corp. to Baa2 and LKE to Baa1; outlooks stable

Global Credit Research - 11 May 2015

Approximately $ 4.8 billion of debt securities upgraded

New York, May 11, 2015 -- Moody's Investors Service today upgraded the senior unsecured ratings of PPL Corporation (PPL) to Baa2 from Baa3 and its LG&E and KU Energy LLC (LKE) subsidiary to Baa1 from Baa2. At the same time, we have revised PPL Corp and LKE's outlook to stable from positive and revised its PPL Electric Utilities (PPLEU Baa1) subsidiary outlook to positive from stable. The rating actions on PPL and LKE are taken in anticipation that PPL's unregulated subsidiary PPL Energy Supply (Supply; Ba2 stable) will be spun off from PPL on June 1, 2015.

Post spinoff, PPL will have lower business risk because all of its material subsidiaries will be regulated utility companies, leading to an improved credit risk profile. The positive outlook on PPLEU's reflects the continued improvement in Pennsylvania's cost recovery mechanisms as well as the growing share of the transmission operations within PPLEU, which have highly favorable credit characteristics.

Upgrades:

..Issuer: LG&E and KU Energy LLC

.... Issuer Rating, Upgraded to Baa1 from Baa2

....Senior Unsecured Regular Bond/Debenture, Upgraded to Baa1 from Baa2

..Issuer: PPL Capital Funding, Inc.

....Junior Subordinated Regular Bond/Debenture, Upgraded to Baa3 from Ba1

....Senior Unsecured Regular Bond/Debenture, Upgraded to Baa2 from Baa3

..Issuer: PPL Corporation

.... Issuer Rating, Upgraded to Baa2 from Baa3

Affirmations:

..Issuer: PPL Electric Utilities Corporation

.... Issuer Rating, Affirmed Baa1

....Senior Secured First Mortgage Bonds, Affirmed A2

....Senior Secured Regular Bond/Debenture, Affirmed A2

....Senior Unsecured Bank Credit Facility, Affirmed Baa1

....Senior Unsecured Commercial Paper, Affirmed P-2

Outlook Actions:

..Issuer: LG&E and KU Energy LLC

....Outlook, Changed To Stable From Positive

..Issuer: PPL Capital Funding, Inc.

....Outlook, Changed To Stable From Positive

..Issuer: PPL Corporation

....Outlook, Changed To Stable From Positive

..Issuer: PPL Electric Utilities Corporation

....Outlook, Changed To Positive From Stable

RATINGS RATIONALE

PPL's Baa2 rating reflects the low business risk of its US and UK regulated utilities, offset by substantial debt leverage at the parent holding company. The regulated business is characterized by credit supportive regulatory environments and a currently large capital expenditure program across all major subsidiaries, resulting in substantial negative free cash flow and depressed key credit metrics. As a fully regulated business after the spinoff, PPL will have 70% of its earnings and cash flows coming from a networks or transmission and distribution (T&D) platform and 30% from integrated utilities buisness, all of which provide good visibility from a recovery, earnings and cash flow perspective.

PPL's consolidated CFO Pre-WC to debt has ranged in the 15% to 16% for the past three years and is expected to decline to the 13% to 14% range going forward after the spin. PPL's retained cash flow (RCF) to debt has been in the 11% to 12% range for the past three years and is expected to fall to about 9% to 10% going forward. These credit metrics position the company reasonably well relative to the range of 11% to 19% for CFO Pre-WC/Debt and 7% to 15% for RCF/debt for the Baa rating category as a lower risk concern under our Regulated Electric and Gas Utility methodology. We consider National Grid Plc (Baa1 stable) as the closest peer comparison to PPL.

Liquidity

PPL's liquidity is marginally adequate, but not a significant concern given its low business risk profile after the spin. Due to a high level of capital expenditure, we expect PPL to have more than $1.5 billion of negative free cash flow after dividends each year, plus about $1.8 billion of debt refinancing needs over the next eighteen months. While PPL has significant amount of cash on hand ($1.3 billion at the end of the first quarter of 2015), we expect most of this cash to be used to fund upcoming negative free cash flow. After the spin, the primary source of liquidity will be mainly comprised of $4 billion of bilateral and syndicated credit facilities issued by various entities throughout the PPL family. As of the end of first quarter 2015, there was about $2.7 billion of availability remaining out of the $4 billion total.

Outlook

PPL's stable outlook is supported by its strong regulated business operations in the US and UK and our expectation that management will maintain its capital structure with equity issuance as needed in the face of large capital expenditures and pressure to increase dividends.

What Could Change the Rating -- Up

The potential for a rating upgrade is low due to the large upcoming capital expenditure program and high level of holding company debt. However, upward pressure could result should its consolidated CFO Pre-WC/debt rise to the high teens and its RCF/debt rises to the mid-teens.

What Could Change the Rating - Down

The potential for a rating downgrade could occur should the company increase its debt level, especially at the holding company level. A downgrade could also result should its consolidated CFO-Pre WC/debt falls to the low-teens range or its RCF/debt falls to mid-single digits.

The principal methodology used in these ratings was Regulated Electric and Gas Utilities published in December 2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

Company Profile

PPL Corporation is a utility holding company headquartered in Allentown, PA. It has three areas of regulated operations: UK regulated, Kentucky regulated, and Pennsylvania regulated. UK regulated is a pure wires business in the United Kingdom with no retail exposure. Kentucky regulated operates under a traditional integrated utility model. Pennsylvania regulated is comprised of a transmission business, mostly regulated by FERC, and a distribution operation regulated by the Pennsylvania Public Utility Commission. After the spin, PPL will control or own about 9,000 MW of generating capacity in the US and sell electricity and natural gas to about 10.3 million customers in the US and UK.

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MOODY'S
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Credit Opinion: Louisville Gas & Electric Company

Global Credit Research - 11 Dec 2015

Louisville, Kentucky, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
Ult Parent: PPL Corporation	
Outlook	Stable
Issuer Rating	Baa2
Parent: LG&E and KU Energy LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1

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Opinion

Rating Drivers

- Supportive regulatory environment

- Large capital expenditure program

- High coal concentration

- Strong and stable financial metrics

Corporate Profile

Louisville Gas and Electric Company (LG&E: A3 stable) is a regulated public utility engaged in the generation, transmission and distribution of electricity and the storage, distribution and sale of natural gas. It provides electricity to approximately 400,000 customers in Louisville and adjacent areas and delivers natural gas service to approximately 321,000 customers in its electric service area and eight additional counties in Kentucky. LG&E's service area covers approximately 700 square miles.

LG&E is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE: Baa1 stable). LG&E and its affiliate, Kentucky Utilities (KU: A3 stable), are the two main operating entities of LKE. LKE, in turn, is wholly owned by PPL Corporation (PPL: Baa2 stable), a diversified energy holding company headquartered in Allentown, PA.

SUMMARY RATING RATIONALE

LG&E's A3 Issuer Rating reflects its sound financial performance and the credit supportive regulatory environment in which it operates, offset in part by a large capital expenditure program and, to a lesser extent, a lack of fuel and geographic diversity.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATION PROVIDES FOR TIMELY COST RECOVERY

We consider the Kentucky Public Service Commission (KPSC) to be supportive of long term credit quality and note that it has approved various tracker mechanisms that provide for timely cost recovery outside of a rate case. LG&E's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR), a Gas Supply Clause (GSC), a Gas Line Tracker (GLT) and a Demand-Side Management Cost Recovery Mechanism (DSM). LG&E does not have a decoupling mechanism in place, which subjects LG&E's net revenue to weather volatilities. The lack of a decoupling mechanism is less of an issue for non-weather related demand fluctuations because LG&E has the DSM and expects to have modest load growth in 2016.

Due to the high level of planned capital expenditures, LG&E and KU filed a rate case in November of 2014, requesting increases in annual base electricity rates of approximately $30 million at LG&E and approximately $153 million at KU and an increase in annual base gas rates of approximately $14 million at LG&E. The rate settlement agreement of LG&E and KU was approved by the KPSC on June 30, 2015. It provided an annual revenue increase for KU's electricity rates of $125 million, as expected, confirming the regulatory credit supportiveness. Although it didn't specify an ROE with respect to the base rates, it authorized a 10% return on equity in Environmental Cost Recovery (ECR) and Gas Line Tracker (GLT). The settlement agreement also provides for deferred cost recovery of a portion of the costs related to pensions and KU's Green River (retired September 30, 2015). The settlement agreement provided no revenue increase for LG&E' electric operations and a $7 million increase in LG&E' gas operations.

LARGE PLANNED CAPITAL EXPENDITURES

Capital expenditures for LG&E are expected to remain at elevated levels from 2015-2019. Total capital expenditures are expected to be $2.7 billion, with $1.1 billion related to environmental. The total estimated amount represents about 57% of the company's net book value of property, plant and equipment, which stood at about $4.7 billion at the end of the third quarter 2015.

The disallowance risk associated with large capital expenditures is meaningfully moderated by Kentucky's supportive regulatory environment especially regarding the environmental expenditures through the ECR. KPSC is also authorized to grant return on construction work in progress (CWIP) in rate case proceedings. Moreover, the ECR virtually eliminates regulatory lag for investments associated with complying with the Clean Air Act and coal combustion waste and byproduct environmental requirements. The terms of the ECR allows LG&E to receive the return of and a return on the investment starting two months after making the investment. This is highly favorable compared to the traditional process where regulatory lag could last a few years due to the length of the construction period plus the rate case proceeding.

HIGH COAL CONCENTRATION

LG&E's current fuel mix is heavily biased towards coal. Of its 2.9 GW of generating capacity, 2.0 GW (69%) is coal-fired which provides almost all (95%) of its electricity generation. The remaining 31% of the generating capacity is comprised mainly of gas- or oil- fired facilities. The fuel concentration, though a credit negative, is acceptable for its rating levels because Kentucky is very supportive of the coal industry. Kentucky is one of the leading coal producing states and the coal industry is very important to the local economy. This support is evidenced by the passage of the ECR, which provides the company with highly favorable terms for its investments in coal-related environmental expenditures.

LG&E's fuel concentration mix recently began to improve. In June 2015, the 640-MW gas-fired combined generating unit Cane Run 7 started commercial operations Cane Run replaces some of the older coal plants totaling 234 MW at Tyrone (retired in 2013) and Green River (retired on September 30, 2015), as well as the 563 MW retirement of Cane Run coal plant in 2015. KU and LG&E had also planned to build a 700-MW gas-fired combined-cycle plant at KU's Green River generating site but the companies withdrew that proposal in August 2014 as a result of municipal contract terminations at KU.

HEALTHY FINANCIAL PROFILE

LG&E's financial metrics have been strong for its rating. As of September 30, 2015, the ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt was 26.6% for the last twelve months and averaged

27.7% for the past three years. Debt to capitalization was 38.9% for the last twelve months and averaged 36.5% for the past three years. LG&E's financial metrics may decline somewhat over the next few years due to the expiration of bonus depreciation in 2014 and the large capital expenditure program. However, we expect LG&E's financial metrics to remain supportive of its rating levels based on the company's targeted capital structure of 52% equity, which is calculated net of goodwill and fully loaded with rating agency adjustments. LG&E's goodwill amounted to $389 million at the end of September 2015 and in comparison total equity, including the goodwill, was $2,259 million.

Liquidity Profile

LG&E has adequate liquidity. As of September 30, 2015, after accounting for all commercial paper and letter of credits issued, LG&E had all its $500 million revolving facility available. For the past twelve months ending September 2015, LG&E had a negative free cash flow of $350 million which is likely to be more sizeable in the coming years given its large capital expenditure program. LG&E's has debt maturities for $25 million in 2016.

LKE manages the liquidity of its Kentucky utility operations on a consolidated basis. LG&E has a $500 million stand-alone revolving credit facility and KU, its sister affiliate, has a $400 million stand-alone credit facility. Both facilities expire in July 2019. LG&E's parent company also has a $75 million syndicated credit facility that expires in October 2018. Each facility contains a financial covenant requiring the companies' debt to total capitalization not to exceed 70%. All entities were in compliance as of September 30, 2015.

Rating Outlook

LG&E's stable outlook reflects its supportive regulatory environment and solid financial performance. LG&E's stable outlook incorporates an expectation of 20%-26% CFO pre-WC to debt and 15-21% RCF to debt.

What Could Change the Rating - Up

The potential for upgrade is constrained by the large upcoming capital expenditure program. However, ratings could be upgraded if the company received more favorable regulatory recovery mechanisms for non-environmental related capital expenditures and maintained its CFO Pre WC/debt ratios at 26% or above.

What Could Change the Rating - Down

LG&E's ratings could be downgraded should the company experience an unfavorable rate case outcome or if unanticipated changes were made to the regulatory compact that currently provides for timely recovery of costs and this were to lead to the company's ratios of CFO pre-WC to debt and retained cash flow to debt dropping below 20% and 15%, respectively for an extended period of time.

Rating Factors

Louisville Gas & Electric Company

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2015		[3]Moody's 12-18 Month Forward ViewAs of 12/8/2015	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				

a) CFO pre-WC + Interest / Interest (3 Year Avg)	10.5x	Aaa	5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	27.7%	A	20% - 26%	A
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	21.0%	A	15% - 21%	A
d) Debt / Capitalization (3 Year Avg)	36.5%	A	34% - 40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching		-		-
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 9/30/2015(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

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CREDIT OPINION
28 October 2016

Update

Rate this Research

RATINGS

Louisville Gas & Electric Company

Domicile	[illegible] United States
Long Term Rating	A3
Type	LT Issuer Rating
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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Louisville Gas & Electric Company

Regulated Vertically Integrated Utility Subsidiary of PPL Corporation

Summary Rating Rationale

Louisville Gas & Electric Company's (LG&E, A3 stable) Issuer Rating reflects its sound financial performance and the credit supportive Kentucky regulatory environment in which it operates, offset in part by a large capital expenditure program and, to a lesser extent, a lack of fuel and geographic diversity.

Exhibit 1
Ratio of CFO pre-WC to Debt Historical Trend

Source: Moody's Investors Service

Credit Strengths

» Supportive regulatory environment in Kentucky

» Strong and stable financial metrics

Credit Challenges

» Large capital expenditure program

» High coal concentration in its generation fuel mix

Rating Outlook

LG&E's stable outlook reflects its supportive regulatory environment in Kentucky and stable financial performance.

Factors that Could Lead to an Upgrade

It is unlikely that LG&E's rating will be upgraded in the near-term, given its large upcoming capital expenditure program and funding needs. However, ratings could be upgraded if the company received more favorable regulatory recovery mechanisms for non-environmental related capital expenditures and maintained its CFO Pre-WC to debt ratio at 26% or above on a sustained basis.

Factors that Could Lead to a Downgrade

LG&E's ratings could be downgraded should there be any materially unfavorable regulatory developments or unanticipated changes are made to the regulatory compact that currently provides for timely recovery of costs, resulting in the company's CFO pre-WC to debt and retained cash flow to debt ratios declining below 20% and 15%, respectively, for an extended period of time.

Key Indicators

Exhibit 2

KEY INDICATORS [1]

Louisville Gas & Electric Company -Private

	6/30/2016(L)	12/31/2015	12/31/2014	12/31/2013	12/31/2012
CFO pre-WC + Interest / Interest	7.5x	8.8x	10.1x	11.9x	8.9x
CFO pre-WC / Debt	24.2%	24.7%	27.1%	28.0%	28.3%
CFO pre-WC – Dividends / Debt	17.7%	18.4%	20.5%	21.0%	22.2%
Debt / Capitalization	36.1%	37.5%	37.0%	35.7%	34.5%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™
Source: Moody's Investors Service

Detailed Rating Considerations

- Supportive regulatory environment provides timely cost recovery

We consider the Kentucky Public Service Commission (KPSC) to be supportive of long-term credit quality and note that it has approved various tracker mechanisms that provide for timely cost recovery outside of a rate case, shortening regulatory lag. LG&E's tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR), a Gas Supply Clause (GSC), a Gas Line Tracker (GLT) and a Demand-Side Management (DSM) Cost Recovery Mechanism. LG&E does not have a decoupling mechanism in place, which subjects LG&E's net revenue to weather volatilities. The lack of a decoupling mechanism is less of an issue for non-weather related demand fluctuations because LG&E has the DSM mechanism and expects to have modest load growth in 2017.

In January 2016, LG&E and affiliate utility Kentucky Utilities (KU, A3 stable) submitted applications to the KPSC, requesting the ECR rate treatment for projects related to the US Environmental Protection Agency's (EPA) regulations addressing the handling of coal and combustion by-products and MATS (mercury and air toxics standards). The projects are expected to commence in the second half of 2016 and are estimated to cost approximately $316 million and $678 million, respectively, for LG&E and KU. On 8 August 2016 the KPSC approved the settlement and authorized a 9.8% return on equity (ROE) for the projects.

LG&E's last general rate case concluded in June 2015 when its case was settled. Although the settlement did not provide any revenue increase for LG&E's electric operations, it authorized a $7 million revenue increase for its gas operations. In addition, the settlement agreed to a 10% ROE for the ECR and GLT riders. It also provided for deferred cost recovery of a portion of the costs related to pensions.

- High capital expenditure planned over the next five years

LG&E's 2016-2020 capital expenditure plan is estimated to be $2.3 billion compared to $2.4 billion spent between 2011 and 2015. Of the $2.3 billion planned capex, approximately $900 million will be related to its environmental investments. The total estimated amount represents about 47% of the company's net book value of property, plant and equipment, which stood at about $4.9 billion at the end of the second quarter of 2016.

We expect the potential disallowance risk associated with large capital expenditures to be meaningfully moderated by Kentucky's supportive regulatory environment, especially regarding the environmental expenditures through the ECR. The KPSC is also authorized to grant return on construction work in progress (CWIP) in rate case proceedings, a credit positive. Moreover, the ECR minimizes regulatory lag for investments associated with complying with the Clean Air Act compliance and coal combustion waste and by-product environmental requirements. The terms of the ECR allows LG&E to receive the return of and a return on the investment starting two months after making the investment. This is more credit supportive compared to the traditional process where there would be longer regulatory lag due to the length of the construction period plus the rate case proceeding.

- High reliance on coal as fuel for generation

LG&E's current generation fuel mix is heavily biased towards coal. Of its 2.9 GW of generating capacity, 2.1 GW (71%) is coal-fired, which provides the majority (89%) of the electricity generation output. The remaining 29% of the generating capacity is comprised mainly of gas- or oil- fired facilities. LG&E's fuel mix improved recently with the addition of a new gas-fired combined-cycle power plant. In June 2015, the 640-MW gas plant at Cane Run started its commercial operations, replacing a retired coal-fired plant at Cane Run.

The fuel concentration in coal, though a credit negative, is acceptable for its rating level because Kentucky is very supportive of the coal industry. This support is evidenced by the passage of the ECR, which provides the company with credit supportive terms and cost recovery for its investments in coal-related environmental expenditures. Kentucky is also one of the 30 states that filed lawsuits to overturn the Clean Power Plan (CPP), which the Supreme Court stayed on 9 February 2016. LG&E has decided not to incorporate its CPP spending in its current capital plan as the issue continues to be litigated.

- Stable financial profile supports robust capex

LG&E's financial metrics have been strong for its rating. As of 30 June 2016, the ratio of consolidated cash flow before changes in working capital (CFO pre-WC) to debt was 24% for the last twelve months and averaged 27% for the past three years. Debt to capitalization was 36% for the last twelve months and averaged 37% for the past three years. We expect LG&E's financial metrics to remain at similar levels over the next few years as it benefits from the extension of bonus depreciation tax credit while the large capital expenditure program continues. We expect LG&E's financial metrics to remain supportive of its rating levels based on the targeted capital structure of 52% equity, which is calculated net of goodwill and Moody's standard adjustments. LG&E's goodwill amounted to $389 million at the end of June 2016 and in comparison total equity, including the goodwill, was $2.4 billion.

Liquidity Analysis

LG&E's short-term rating is P-2 and we expect LG&E to maintain adequate liquidity over the next 12-18 months.

LG&E has a $500 million syndicated credit facility maturing in December 2020. As of 30 June 2016, after accounting for all commercial paper and letter of credits issued, LG&E had $390 million of the revolving facility available. For the past twelve months ending June 2016, LG&E had negative free cash flow of $261 million, which is likely to remain negative in coming years given its large capital expenditure program. LG&E's next debt maturity is $300 million of Secured Notes maturing in 2025.

LG&E and KU Energy LLC (LKE, Baa1 stable), the intermediate parent company of LG&E, manages the liquidity of its Kentucky utility operations on a consolidated basis. In addition to the credit facility at LKE, LG&E and KU have separate stand-alone revolving credit facilities. Also, LKE has its own $75 million of syndicated credit facility that expires in October 2018. Each facility contains a financial covenant requiring the companies' debt to total capitalization not to exceed 70%. All entities were in compliance as of 30 June 2016.

Profile

Louisville Gas and Electric Company (LG&E, A3 stable) is a regulated public utility engaged in the generation, transmission and distribution of electricity and the storage, distribution and sale of natural gas in Kentucky. It provides electricity to approximately 403,000 customers in Louisville and adjacent areas and delivers natural gas service to approximately 322,000 customers in its electric service area and eight additional counties in Kentucky. LG&E's service area covers approximately 700 square miles.

LG&E is a wholly-owned subsidiary of LG&E and KU Energy LLC (LKE, Baa1 stable). LG&E and its affiliate, Kentucky Utilities (KU, A3 stable), are the two main operating entities of LKE. LKE, in turn, is wholly owned by PPL Corporation (PPL, Baa2 stable), a diversified energy holding company headquartered in Allentown, PA.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors

Louisville Gas & Electric Company -Private

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 6/30/2016**		**Moody's 12-18 Month Forward View As of Date Published[3]**	
Factor 1 : Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	A	A	A	A
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Baa	Baa	Baa	Baa
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	9.7x	Aaa	5x - 7x	Aa
b) CFO pre-WC / Debt (3 Year Avg)	28.0%	A	20% - 26%	A
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	21.2%	A	15% - 20%	A
d) Debt / Capitalization (3 Year Avg)	36.0%	A	35% - 40%	A
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A2
HoldCo Structural Subordination Notching		0	0	0
a) Indicated Rating from Grid		A2		A2
b) Actual Rating Assigned		A3		A3

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 6/30/2016(L); Source: Moody's Financial Metrics™
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 4

Category	Moody's Rating
LOUISVILLE GAS & ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
Bkd Other Short Term	P-2
ULT PARENT: PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
PARENT: LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1

Source: Moody's Investors Service

REPORT NUMBER 1038339

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INVESTORS SERVICE

CREDIT OPINION
6 December 2016

Update

RATINGS

PPL Corporation

Domicile	Allentown, Pennsylvania, United States
Long Term Rating	Baa2
	LT Issuer Rating - Dom Curr
Outlook	Stable

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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PPL Corporation

A Regulated Utility Holding Company

Summary Rating Rationale

PPL's Baa2 rating reflects the low business risk of its US and UK regulated utilities, offset by substantial debt leverage at the parent holding company. The regulated business is characterized by credit supportive regulatory environments and a large capital expenditure program across all major subsidiaries, resulting in substantial negative free cash flow. As a fully regulated business PPL generates approximately 70% of its earnings and cash flows from a networks or transmission and distribution (T&D) platform in the US and UK while the remaining 30% comes from integrated utility operation in the US, all of which provide good visibility from a recovery, earnings and cash flow perspective. Prospectively, PPL's CFO Pre-WC to debt is expected to be in the 13% to 15% range and its retained cash flow to debt in the 9% to 10% range, both of which compare well with other low risk Baa holding companies rated under our Regulated Electric and Gas Utility methodology. Although PPL has foreign exchange exposure due to its operations in the UK, we currently do not view the risk as a significant credit driver.

Exhibit 1

Ratio of CFO pre-W/C to Debt Historical Trend

Source: Moody's Investors Service

Credit Strengths

» Mostly low risk, regulated wires-only subsidiaries

» Financial metrics adequate for its rating

» Constructive regulatory environments support rate base growth

Credit Challenges

» Large capital expenditure program

» High level of holding company debt

» Exposure to depreciation of the British Pound

Rating Outlook

PPL's stable outlook is supported by its strong regulated business operations in the US and UK and our expectation that management will maintain an appropriate capital structure during its large capital expenditure cycle as well as credit metrics, such as 13%-15% CFO pre-WC to debt and 9-10% RCF to debt.

Factors that Could Lead to an Upgrade

A rating upgrade could be possible if its consolidated CFO Pre-WC to debt rises to the high teens and its RCF to debt increases to the mid-teens. An upgrade could also occur if PPL lowers its percentage of holding company debt to a level below 20% of total consolidated debt.

Factors that Could Lead to a Downgrade

The potential for a rating downgrade is likely should the company increase its debt level, especially at the holding company level. A downgrade could also result should its consolidated CFO-Pre WC to debt fall to the low-teens or if its RCF to debt falls to mid-single digits. Additional pressure could occur should PPL experience any unexpected negative regulatory developments or concerns about its ability to earn appropriate returns on its investments. Additionally, negative ratings actions could occur if the company fails to properly manage its exposure to a declining foreign exchange rate, following Britain's vote to leave the European Union.

Key Indicators

Exhibit 2

PPL Corporation

	9/30/2016(L)	12/31/2015	12/31/2014	12/31/2013	12/31/2012
CFO pre-WC + Interest / Interest	4.4x	4.4x	4.9x	4.4x	4.1x
CFO pre-WC / Debt	15.3%	14.8%	16.9%	16.0%	14.9%
CFO pre-WC – Dividends / Debt	10.3%	10.0%	12.2%	12.0%	11.0%
Debt / Capitalization	59.9%	60.9%	54.6%	57.1%	59.8%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™
Source: Moody's Investors Service

Detailed Rating Considerations

- Mostly low risk, wires-only utility operations

As a holding company of seven rate regulated utilities, PPL maintains a lower business risk profile when compared to peers in the Baa rating category. Approximately 50% of PPL's cash flow is produced by its UK based T&D operations, which are consolidated under the intermediate holding company Western Power Distribution PLC (WPD, Baa3 stable). The remaining 50% of cash flow is produced in

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the US with about 30% generated at its two Kentucky utilities, Louisville Gas & Electric Company (LG&E, A3 stable) and Kentucky Utilities Company (KU, A3 stable) and 20% from its incumbent utility in Pennsylvania, PPL Electric Utilities Corporation (PPLEU, A3 stable). The two Kentucky utilities are held under an intermediate holding company, LG&E and KU Energy LLC (Baa1 stable).

From a commodity exposure perspective, WPD is considered the least risky, followed by PPLEU and then its utilities in Kentucky. As a distribution network operator (DNO) in the UK, WPD's subsidiaries have no commodity exposure because they do not have any commodity production or procurement responsibilities. PPLEU has more commodity exposure because it functions as the Provider of Last Resort (POLR) for the end-users within its service territory although it is a T&D utility. As the designated POLR entity, PPLEU is the default service provider that produces power for customers who are not served by a competitive retail energy provider. The risk associated with this exposure is very small given the transparent purchased power cost pass-through mechanism that is in place. Additionally, PPLEU mitigates this risk by entering into full-requirement supply agreements to serve its POLR customers.

PPL's Kentucky utilities have the most exposure to commodities as vertically integrated utilities. They own and operate power generation and the output from their power generation is used to serve their customer base. Although LG&E and KU have direct commodity exposure as the primary fuel for their generation fleet is coal, Kentucky allows the cost of fuel used to generate power to be recovered through a fuel adjustment clause within four months.

- Constructive regulatory environment supporting regulated growth

PPL's utilities operate under supportive regulatory environments, which lead to stable and predictable earnings and cash flow generated from roughly $24 billion of rate base. The regulatory environment for WPD subsidiaries is considered to be the strongest, operating under UK's regulatory process, which is among the most transparent globally. As the top performer among its DNO peers, WPD utilities has greatly benefitted from performance-based rate making mechanisms, which results in incentive bonus payments of $35 million annually along with higher authorized returns on equity (ROE) for WPD utilities. Additionally, as the only DNO to qualify for Fast-track incentives, WPD companies are allowed to retain 70% of realized cost efficiencies.

The regulatory environments in Kentucky and Pennsylvania are also considered credit supportive. The Kentucky Public Service Commission (KPSC) has approved various tracker mechanisms that provide for timely cost recovery outside of a general rate case. These tracker mechanisms include a Fuel Adjustment Clause (FAC), an Environmental Cost Recovery Surcharge (ECR), a Gas Supply Clause (GSC), a Gas Line Tracker (GLT), and a Demand-Side Management Cost (DSM) Recovery Mechanism. The last rate case settled in Kentucky in 2015 provided a $125 million annual revenue increase for KU's electricity operations and a $7 million increase for LG&E gas operations. The settlement agreed to no base revenue increase for LG&E's electric operations. Although it didn't specify an allowed ROE with respect to the base rates, a 10% allowed ROE was authorized for the ECR and GLT riders. On 23 November 2016, LG&E and KU filed their most recent rate case. In the filing, LG&E requested a $94 million electric rate increase and a $14 million gas rate increase, while KU filed for a $103 million electric rate increase. The filings are based on a test year of July 2017 through June 2018 and a requested return on equity (ROE) of 10.23%. The KPSC usually processes rate cases in a timely manner as was evident in the 2015 decision, which was settled 7 months after being filed.

In Pennsylvania, PPLEU has historically received reasonable and timely decisions in its rate cases, including the most recent distribution rate case that was concluded in November 2015. In this rate case, the company was allowed to use a forward test year and reached a settlement with interveners in about 5 months. PPLEU requested an 18.5% revenue increase and received about 74% of the request ($124 million versus $167.5 million) in the settlement.

Relative to other electric utilities, a high percentage of PPLEU's rate base is related to FERC regulated transmission assets. PPL expects the rate base contribution from transmission assets to be about 48% in 2017, growing to 55% by 2020. PPLEU's transmission infrastructure is regulated by the FERC under a formula ratemaking mechanism, which we consider to be predictable and thus credit supportive. Based on the formula rate mechanism, PPLEU is currently authorized to earn an 11.68% ROE on its existing transmission assets, while the $650 million Susquehanna-Roseland transmission project is authorized to earn a 12.93% ROE due to incentive-based rate treatments.

- Large capital investment program

PPL's utilities currently have a high level of capital expenditures that could apply pressure on their credit metrics. Based on the its third quarter earnings presentation, the company is projected to spend approximately $15.4 billion in capital expenditures between

2016 and 2020. In comparison, that represents about 64% of the company's rate base worth approximately $23.9 billion in 2016. When a company's capital plans reach these elevated levels there are generally two major credit implications. First, with a large capital expenditure program, the company is more exposed to project completion risk. Second, capital spending tends to place downward pressure on cash flow to debt ratios because debt is used to fund construction but most of the cash flows will only be generated after the project has been placed into service.

In PPL's case we do not view the completion risk to be a major concern because most of the projects are not technically complex and have a moderate to low level of completion risk. In addition the lagging effect on cash flow is less of a concern due to PPL's ability to recover a significant amount of their investments through regulatory recovery mechanisms outside of the traditional base rate case proceedings. For instance in Kentucky, the KPSC has adopted the ECR mechanism and recovery on certain construction work-in-progress, reducing regulatory lag. In Pennsylvania, the FERC transmission formula rate, Distribution System Improvement Charges (DSIC) mechanism and other recovery mechanisms are in place to reduce regulatory lag and provide for a more timely recovery of costs and a return on investments. All together these mechanisms allow PPL to recover approximately 79% of their investments in less than one year with about 71% being recovered in the first 6 months.

- High level of holding company debt

PPL's regulated subsidiaries have an average stand-alone credit profile of A3. However, with approximately $6 billion of holding company debt, which includes debt at the parent holding company and intermediary holding companies in the US and UK, PPL's rating is Baa2, two notches below its operating subsidiaries. PPL's holding company debt accounts for about 33% of total consolidated debt and the two notch treatment is consistent with other utilities that have substantial holding company debt.

[illegible] and stable financial metrics

PPL's consolidated CFO Pre-WC to debt has ranged between 15% to 16% for the past three years and is expected to decline to the 13% to 14% range. PPL's retained cash flow to debt has been in the 10% to 12% range for the past three years and is expected to fall to about 8% to 10% going forward. These credit metrics position the company reasonably well relative to the range of 11% to 19% for CFO Pre-WC to Debt and 7% to 15% for RCF to debt for the Baa rating category as a lower risk company rated under our Regulated Electric and Gas Utility methodology. The declines in cash flow to debt ratios are not considered a credit negative because they were mainly driven by the divestment of the unregulated generation business, which operated with a higher cash flow to debt ratios but also a higher business risk.

- Exposure to foreign currency risk

With a significant portion of earnings and cash flow generated in the UK, PPL must manage its foreign currency risk closely. Despite rapid depreciation of the British Pound (GBP) after the UK voted to leave the European Union, we do not believe there will be a negative impact on credit metrics. Following the vote PPL was able to realize a $310 million dollar increase in cash from hedge gains which they used to pay down debt.Over the next three years, we expect PPL to generate about 45% of its cash flow from its UK operation while about 36% of PPL's debt is either denominated in GBP or has been swapped into GBP. As a result, we do not expect a GBP depreciation to heavily influence the CFO Pre-WC to debt metric. In addition, if depreciation of the pound against other currencies leads to higher import prices in the UK, inflation as measured by the Retail Prices Index (RPI) could increase modestly. Since WPD's revenues and regulatory assets are adjusted annually by RPI, this could lead to higher earning in GBP terms.

Liquidity Analysis

PPL has an adequate liquidity profile supported by stable cash flow generated from its seven low risk utility subsidiaries. In addition to a steady stream of predictable cash flow, PPL has a significant amount of cash on hand totaling $416 million at the end of the third quarter 2016 and approximately $4 billion of bilateral and syndicated credit facilities issued by various entities throughout the PPL family. At the parent level, PPL maintains a $950 million syndicated credit facility expiring in January 2022 and a $300 million syndicated credit facility expiring in November 2018. Drawings under these two revolving credit facilities are not subject to a material adverse change clause. As of 30 September 2016, there were no borrowing against the facilities leaving the full $1.0 billion of capacity available. In January 2016, PPL Capital Funding increased their commercial paper program from $600 million to $1.0 billion to provide additional short-term financing. Additionally, PPL maintains a $150 million bilateral credit facility due in March 2017. The majority of the remaining facilities located at the operating subsidiaries expire between 2020 and 2021. As of the end of the third quarter 2016, there was approximately $2.1 billion of availability reaming out of the $4 billion total.

Over the last twelve month period ending 30 September 2016, PPL generated roughly $3.2 billion of cash flow from operations, spent about $3.1 billion in capital expenditures and paid $1.0 billion in dividends resulting in negative free cash flow of approximately $900 million. Due to the high level of planned capital expenditures we expect PPL to have between $1.0 billion and $1.5 billion of negative free cash flow after dividends going forward. We expect the company will finance the shortfall with a balanced mix of debt and equity and will maintain their current capital structure.

Profile

PPL Corporation is a utility holding company headquartered in Allentown, PA with three areas of regulated operations: UK regulated, Kentucky regulated, and Pennsylvania regulated. UK regulated includes Western Power Distribution PLC , a pure wires business in the United Kingdom with no retail exposure. Kentucky regulated includes Louisville Gas & Electric Company and Kentucky Utilities Company, which operate under a traditional integrated utility model. Pennsylvania regulated is comprised of PPL Electric Utilities Corporation, a transmission business mostly regulated by Federal Energy Regulatory Commission (FERC), and a distribution operation regulated by the Pennsylvania Public Utility Commission. PPL, though its operating subsidiaries, controls or owns about 8,000 MW of generating capacity in the US and sells electricity and natural gas to about 10.4 million customers in the US and UK.

Rating Methodology and Scorecard Factors

Exhibit 3

Exhibit 4

Rating Factors

PPL Corporation

Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 9/30/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Aa	Aa	Aa	Aa
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	3.5x - 4x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	15.3%	Baa	12% - 15%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.7%	Baa	8% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	58.6%	Ba	56% - 60%	Ba
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching	-2	-2	-2	-2
a) Indicated Rating from Grid		Baa2		Baa2
b) Actual Rating Assigned		Baa2		Baa2

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 9/30/2016(L); Source: Moody's Financial Metrics™
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investors Service

Ratings

Exhibit 5

Category	Moody's Rating
PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2

WESTERN POWER DISTRIB (WEST MIDLANDS) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
WESTERN POWER DISTRIB (EAST MIDLANDS) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
PPL CAPITAL FUNDING, INC.	
Outlook	Stable
Bkd Senior Unsecured	Baa2
Bkd Jr Subordinate	Baa3
Bkd Commercial Paper	P-2
WESTERN POWER DISTRIBUTION (SOUTH WEST) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
WESTERN POWER DISTRIBUTION (SOUTH WALES) PLC	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa1
PPL ELECTRIC UTILITIES CORPORATION	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
KENTUCKY UTILITIES CO.	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
LOUISVILLE GAS & ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
PPL WEM HOLDINGS LTD	
Outlook	Stable
Bkd Senior Unsecured	Baa3

Source: Moody's Investors Service

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REPORT NUMBER 1051696

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CREDIT OPINION
23 May 2016

Update

RATINGS

PPL Corporation

Domicile	Allentown, Pennsylvania, United States
Long Term Rating	Baa2
Type	LT Issuer Rating - Dom Curr
Outlook	[illegible]

Please see the ratings section at the end of this report for more information. The ratings and outlook shown reflect information as of the publication date.

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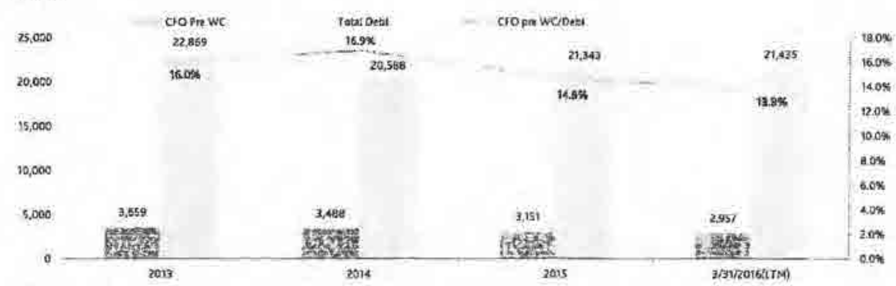
PPL Corporation

A Regulated Utility Holding Company

Summary Rating Rationale

PPL's Baa2 rating reflects the low business risk of its US and UK regulated utilities, offset by substantial debt leverage at the parent holding company. The regulated business is characterized by credit supportive regulatory environments and a large capital expenditure program across all major subsidiaries, resulting in substantial negative free cash flow and depressed key credit metrics. As a fully regulated business PPL has 70% of its earnings and cash flows coming from a networks or transmission and distribution (T&D) platform and the remaining 30% coming from integrated utility operation, all of which provide good visibility from a recovery, earnings and cash flow perspective. Prospectively, PPL's CFO Pre-WC to debt is expected to be in the 13% to 14% range and its retained cash flow (RCF) in the 9% to 10% range, both of which compare well with the Baa category benchmarks for low risk concern under our Regulated Electric and Gas Utility methodology. Although PPL has foreign exchange exposure due to its operation in the UK, we do not view the risk as a significant credit driver. We consider National Grid Plc (Baa1 stable) as the closest peer comparison to PPL.

Exhibit 1



Source: Moody's Investors Service

Credit Strengths

» Low risk, regulated subsidiaries

» Adequate financial metrics

» Compares well with National Grid

Credit Challenges

» Large capital expenditure program

» High level of holding company debt

Rating Outlook

PPL's stable outlook is supported by its strong regulated business operations in the US and UK and our expectation that management will maintain its capital structure with equity issuance as needed in the face of large capital expenditures and pressure to increase dividends. The stable outlook incorporates an expectation of 13%-14% CFO to debt and 9-10% RCF to debt.

Factors that Could Lead to an Upgrade

The potential for a rating upgrade is low due to the large upcoming capital expenditure program and high level of holding company debt. However, upward pressure could result should its consolidated CFO Pre-WC/debt rise to the high teens and its RCF/debt increases to the mid-teens. . An upgrade could also occur if PPL lowers its percentage of holding company debt to a level below 20% of total consolidated debt.

Factors that Could Lead to a Downgrade

The potential for a rating downgrade could occur should the company increase its debt level, especially at the holding company level. A downgrade could also result should its consolidated CFO-Pre WC/debt fall to the low-teens range or if its RCF/debt falls to mid-single digits. Additional pressure could occur should PPL experience any unexpected negative regulatory developments or concerns about its ability to recover its investments.

Key Indicators

Exhibit 2

KEY INDICATORS [1]

PPL Corporation

	3/31/2016(L)	12/31/2015	12/31/2014	12/31/2013	12/31/2012
CFO pre-WC + Interest / Interest	4.1x	4.4x	4.9x	4.4x	4.1x
CFO pre-WC / Debt	13.8%	14.8%	16.9%	16.0%	14.9%
CFO pre-WC – Dividends / Debt	9.0%	10.0%	12.2%	12.0%	11.0%
Debt / Capitalization	61.4%	60.9%	54.6%	57.1%	59.8%

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics™
Source: Moody's Investors Service

Detailed Rating Considerations

Low risk operations

PPL has a low business risk profile because all of its material subsidiaries are regulated utility companies. About 50% of PPL's cash flow and operating income is coming from the UK based utilities consolidated under the intermediate holding company Western Power Distribution Plc (WPD; Baa3 stable), 30% from its two utilities in Kentucky and 20% from its incumbent utility in Pennsylvania, Pennsylvania Electric Utilities (PPLEU; A3 stable).

From a commodity exposure perspective, WPD is considered the least risky, followed by PPLEU and its utilities in Kentucky. As a distribution network operator (DNO) in the UK, WPD subsidiaries have no commodity exposure because they do not have any commodity production or procurement responsibilities. PPLEU has more commodity exposure because it functions as the Provider of Last Resort (POLR) for the end-users within its service territory. As the designated POLR entity, PPLEU is the default service provider that procures power for customers who are not served by a competitive retail energy provider. The risk associated with this exposure is very small given the strong cost pass-through mechanism that has been in place for many years. PPL's two utilities in Kentucky have the most exposure to commodities since they are responsible for supplying their customers mainly with owned generation. The fuel adjustment clause in Kentucky, however, moderates this risk as it usually allows the cost of fuel to generate electricity to be recovered within 4 months.

Supportive regulatory environment

PPL's utilities operate under a supportive regulatory environment. The regulatory environment for WPD subsidiaries is considered the strongest because the UK's regulatory process is highly transparent and formulaic. As the top performer among its distribution network operator (DNO) peers, WPD utilities has greatly benefitted from performance-based rate making mechanism for DNOs, which resulted in incentive bonus payments and higher authorized returns on equity (ROE) for WPD utilities.

The regulatory environments in Kentucky and Pennsylvania are also considered credit supportive. The 2014 Kentucky rate case settlement was approved by the Kentucky Public Service Commission (KPSC) on June 30, 2015. The settlement includes an annual revenue increases for Kentucky Utilities (A3, stable) electricity rates of $125 million and a $7 million annual increase for Louisville Gas & Electric's (A3, stable) base gas rates, which confirms the regulatory credit supportiveness. Although the settlement did not specify an ROE with respect to the base rates, it authorized a 10% return on equity in Environmental Cost Recovery (ECR) and Gas Line Tracker (GLT). PPLEU has historically received reasonable and timely decisions in its T&D rate cases, including the most recent distribution rate case that was filed on March 30, 2015. In this rate case, the company was able use a forward test year and reach a settlement with interveners in about 5 months. PPLEU had requested an 18.5% revenue increase and in the settlement received about 74% of the request ($124 million versus $167.5 million).

Relative to other electric utilities, a high percentage of PPLEU's rate base is related to FERC regulated transmission assets. According to the company's investor presentation in March 2016, the rate base contribution from transmission assets is expected to be about 48% in 2016, growing to 55% by 2020. PPLEU's transmission infrastructure is regulated by the FERC under a formula ratemaking mechanism, which we consider to be predictable and thus credit supportive. Based on the formula rate mechanism, PPLEU is currently authorized to earn an 11.68% ROE on its existing transmission assets, while the $630 million Susquehanna-Roseland transmission project is authorized to earn a 12.93% ROE due to incentive-based rate treatments.

High capital spending

PPL's utilities currently have a high level of capital expenditures that could pressure their credit metrics. Based on its first quarter earnings presentation, the company is projected to spend $16 billion in capital expenditures between 2016 and 2020. In comparison, the company's rate base was worth about $24.3 billion at the end of 2015 and it estimates a rate base of $26.0 billion at the end of 2016. We view the high level of capital spending as having two credit implications. First, with a large capital expenditure program, the company is more exposed to project completion risk. Second, capital spending tends to place downward pressure on debt to cash flow ratios because debt is used to fund construction but most of the cash flows will only be generated after the project has been placed into service.

We do not view the completion risk as a major concern because most of PPL's projects are not technically complex and have moderate to low level of completion risk. The lagging effect on the cash flow, however, can be significant but is moderated by numerous regulatory recovery mechanisms outside of the traditional base rate case proceedings. For instance in Kentucky, the KPSC has adopted the ECR mechanism and recovery on certain construction work-in-progress that reduces regulatory lag. In Pennsylvania, the FERC transmission formula rate, Distribution System Improvement Charges (DSIC) mechanism and other recovery mechanisms are in place to reduce regulatory lag and provide for a more timely recovery of costs and a return on investments.

High level of holding company debt

PPL's regulated subsidiaries have an average stand-alone credit profile of A3. However, with $6.6 billion of holding company debt, which includes debt at the parent holding company and intermediary holding companies in the US and UK, PPL's parent rating is Baa2, two notches below its operating subsidiaries. PPL's holding company debt accounts for about 33% of total consolidated debt and the two notch treatment is consistent with other utilities that have substantial holding company debt.

Adequate financial metrics

PPL's consolidated CFO Pre-WC to debt has ranged between 15% to 16% for the past three years and is expected to decline to the 13% to 14% range. PPL's retained cash flow (RCF) to debt has been in the 10% to 12% range for the past three years and is expected to fall to about 8% to 9% going forward. These credit metrics position the company reasonably well relative to the range of 11% to 19% for CFO Pre-WC/Debt and 7% to 15% for RCF/debt for the Baa rating category as a lower risk concern under our Regulated Electric and Gas Utility methodology. The declines in cash flow to debt ratios are not considered a credit negative because they were mainly driven by the divestment of the unregulated generation business, which operated with a higher cash flow to debt ratios but also a higher business risk.

Compares well with National Grid

We consider National Grid Plc (Baa1 stable) as the closest peer comparison to PPL. Both companies have largely regulated businesses, though National Grid would have a greater share of its business in the networks or T&D platform (90% v. 70% for PPL). National Grid is more than twice the size of PPL using rate base as the measurement and has more of its operation in the United Kingdom (70% versus 50% for PPL). Otherwise, the two companies have similar levels of holding company debt (30% versus 33% of holding company debt to consolidated debt) and on the financial metrics, with both companies' CFO Pre-WC/debt at around 15% and RCF/debt at 12%.

Liquidity Analysis

PPL's liquidity profile appears adequate and supported by a stable cash flow generation from its overall low risk business. Additionally, PPL has a significant amount of cash on hand ($814 million at the end of the first quarter of 2016) and $4 billion of bilateral and syndicated credit facilities issued by various entities throughout the PPL family. Most of the credit facilities expire between 2020 and 2021. As of the end of first quarter 2016, there was about $2.4 billion of availability remaining out of the $4 billion total.

In January 2016, PPL Capital Funding increased their commercial paper program from $600 million to $1.0 billion to provide additional short-term financing. The CP program is back-strapped by a $300 million senior unsecured revolving credit facility expiring in November 2018 and a $700 million senior unsecured revolving credit facility expiring in July 2019. Drawings under these two revolving credit facilities are not subject to a material adverse change clause.

Due to the high level of capital expenditures, which according to the company's first quarter earnings presentation would reach $16 billion for the period 2016-2020, we expect PPL to have more than $1.5 billion of negative free cash flow after dividends each year, plus about $1.75 billion of debt maturity over the next twelve months.

Profile

PPL Corporation is a utility holding company headquartered in Allentown, PA. It has three areas of regulated operations: UK regulated, Kentucky regulated, and Pennsylvania regulated. UK regulated is a pure wires business in the United Kingdom with no retail exposure. Kentucky regulated operates under a traditional integrated utility model. Pennsylvania regulated is comprised of a transmission business, mostly regulated by Federal Energy Regulatory Commission (FERC), and a distribution operation regulated by the Pennsylvania Public Utility Commission. PPL, though its operating subsidiaries, controls or owns about 8,000 MW of generating capacity in the US and sells electricity and natural gas to about 10.3 million customers in the US and UK.

Rating Methodology and Scorecard Factors

Exhibit 3

Rating Factors

PPL Corporation				
Regulated Electric and Gas Utilities Industry Grid [1][2]	Current LTM 3/31/2016		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	Measure	Score	Measure	Score
a) Legislative and Judicial Underpinnings of the Regulatory Framework	Aa	Aa	Aa	Aa
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	A	A	A	A
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	Baa	Baa	Baa	Baa
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.6x	A	3.5x - 3.8x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	15.1%	Baa	12% - 15%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	10.9%	Baa	8% - 11%	Baa
d) Debt / Capitalization (3 Year Avg)	58.3%	Baa	56% - 60%	Ba
Rating:				
Grid-Indicated Rating Before Notching Adjustment		A2		A3
HoldCo Structural Subordination Notching	-2	-2	-2	-2
a) Indicated Rating from Grid		Baa1		Baa2
b) Actual Rating Assigned		Baa2		Baa2

[1]All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2]As of 3/31/2016(L); Source: Moody's Financial Metrics™
[3]This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Investor Service

Ratings

Exhibit 4

Category	Moody's Rating
PPL CORPORATION	
Outlook	Stable
Issuer Rating	Baa2
WESTERN POWER DISTRIB (EAST MIDLANDS) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
WESTERN POWER DISTRIB (WEST MIDLANDS) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
WESTERN POWER DISTRIBUTION (SOUTH WEST) PLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured -Dom Curr	Baa1
WESTERN POWER DISTRIBUTION (SOUTH WALES) PLC	
Outlook	Stable
Senior Unsecured -Dom Curr	Baa1
PPL CAPITAL FUNDING, INC.	

Outlook	Stable
Bkd Senior Unsecured	Baa2
Bkd Jr Subordinate	Baa3
Bkd Commercial Paper	P-2
PPL ELECTRIC UTILITIES CORPORATION	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Senior Secured	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
KENTUCKY UTILITIES CO.	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
LOUISVILLE GAS & ELECTRIC COMPANY	
Outlook	Stable
Issuer Rating	A3
First Mortgage Bonds	A1
Sr Unsec Bank Credit Facility	A3
Commercial Paper	P-2
LG&E AND KU ENERGY LLC	
Outlook	Stable
Issuer Rating	Baa1
Senior Unsecured	Baa1
PPL WEM HOLDINGS LTD	
Outlook	Stable
Bkd Senior Unsecured	Baa3

Source: Moody's Investors Service

REPORT NUMBER 1027960

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PPL Corp.

Business Risk: STRONG

Vulnerable — Excellent

bbb — bbb — bbb

Financial Risk: SIGNIFICANT

Highly leveraged — Minimal

Anchor — Modifiers — Group/Gov't

CORPORATE CREDIT RATING

BBB/Watch Pos/NR

Rationale

Business Risk: Strong	Financial Risk: Significant
• Expected improvement in business risk resulting from planned spin-off of unregulated power generation business, PPL Energy Supply LLC (PPLES) in 2015 • Large and diverse regulated utility operations benefiting from constructive regulatory frameworks • Environmental rules continue to add costs to coal fleet • Merchant generation business benefits from operating diversity, the consistent implementation of a rolling hedging strategy that contributes to cash flow stability, and efficient operations that lead to competitively priced power	• Aggressive financial policies and growth strategy that, historically, included acquisitions and use of hybrid securities • Cash flow variability from exposure to wholesale power prices • Large capital spending program leading to negative discretionary cash flow

CreditWatch

Standard & Poor's Ratings Services' ratings on PPL Corp. are on CreditWatch with positive implications to reflect the potential for higher ratings on the company and its subsidiaries upon the successful spin-off of its merchant generation business. We expect the ratings to remain on CreditWatch until the transaction closes and we will provide periodic updates. Material changes to the projected financial measures in our base case scenario and the cash flow generation capability of the pro forma group could affect the ultimate financial risk profile assessment.

Upside scenario

Upon the close of the transaction, we could raise the issuer credit ratings (ICRs) and issue ratings on PPL Corp., LG&E

and KU Energy LLC, Louisville Gas & Electric Co., Kentucky Utilities Co., and PPL Electric Utilities Corp. by up to two notches depending on the credit measures of the consolidated PPL group, after the spin-off of the merchant business.

Standard & Poor's Base-Case Scenario

Assumptions

- Gross margins grow in the low single digits, benefiting from modest customer growth, the recovery of environmental spending, and transmission and distribution investments.
- Capital spending of about $3.5 billion to $3.75 billion annually
- Merchant generation business is spun off in 2015
- Asset sale proceeds of about $900 million in 2014

Key Metrics

	2014E	2015E	2016E
FFO/total debt (%)	14-15	14-15	13-14
Total debt/EBITDA (x)	4.5-5	4.5-5	4.5-5
CFO/total debt (%)	14-15	14-15	14-15

Standard & Poor's-adjusted figures. A--Actual. E--Estimate.

Company Description

PPL Corp. is an energy and utility holding company serving about 10.5 million mostly electric customers in Kentucky, Pennsylvania, and the U.K. The company also owns approximately 10,500 megawatts (MW) of merchant generation assets that it plans to spin off in 2015.

Business Risk: Strong

We assess PPL Corp.'s business risk profile as "strong," incorporating the company's regulated utility operations, which benefit from constructive regulatory frameworks and serve a large customer base of more than 10 million customers across two states in the U.S. and in the U.K. Our current assessment of business risk also accounts for PPLP's higher-risk merchant generation operations that the company plans to spin-off in 2015.

Subsequent to the spin-off of the merchant generation business, we expect that PPL's business risk profile will improve because it will consist of regulated utilities in the U.S. and U.K., where at least 50% of pro forma EBITDA would be from low-risk distribution and transmission operations. We expect that PPL's business risk profile would fall into the "excellent" category after the divestiture of the higher-risk unregulated generation assets.

Residential and commercial customers contribute the majority of revenue and sales, providing a measure of stability and predictability to cash flow generation. With operations across two states in the U.S., as well as across the U.K., PPL benefits significantly from geographic and regulatory diversity, potentially minimizing the effect of economic conditions in one particular region or the impact of adverse regulatory decisions. The diversity in markets and regulation strengthens credit quality, but the cross-border regulatory jurisdictions also require diligent monitoring and effective management of regulatory relationships.

The U.K. wires-only distribution utilities benefit from predictable, transparent, and credit-supportive regulatory framework along with a lack of commodity exposure since nonaffiliated retail suppliers procure the electricity for retail customers.

S&P Base-Case Operating Scenario

- PPL will complete the spin off its subsidiary PPL Energy Supply in 2015.
- PPL remains focused on expanding its regulated utility operations
- The company continues to effectively manage regulatory risk in all its jurisdictions, ensuring timely investment recovery

Peer comparison

Table 1

PPL Corp. -- Peer Comparison

Industry sector: combo

	PPL Corp.	Consolidated Edison Inc.	Northeast Utilities	Duke Energy Corp.	PEPCO Holdings Inc.
Rating as of Dec. 16, 2014	BBB/Watch Pos/NR	A-/Stable/A-2	A-/Positive/A-2	BBB+/Positive/A-2	BBB+/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	12,294.3	12,493.3	5,910.6	19,583.7	5,168.3
EBITDA	4,619.5	3,555.2	1,934.3	7,222.3	1,188.6
Funds from operations (FFO)	3,284.1	2,416.8	1,502.3	5,501.9	917.2
Net income from cont. oper.	1,384.3	1,088.3	570.8	2,028.3	218.3
Cash flow from operations	3,057.9	3,019.3	1,227.6	5,038.2	633.2
Capital expenditures	3,249.7	2,188.0	1,328.2	5,080.9	1,149.0
Free operating cash flow	(191.7)	831.3	(100.6)	(42.8)	(515.8)
Discretionary cash flow	(1,193.4)	120.8	(445.8)	(1,816.1)	(769.8)
Cash and short-term investments	268.4	143.0	21.6	466.8	13.1
Debt	19,430.0	14,021.0	9,149.4	35,510.5	5,810.3
Equity	13,381.3	11,885.5	7,692.6	35,102.3	4,365.7
Adjusted ratios					
EBITDA margin (%)	37.6	28.5	32.7	36.9	23.0
Return on capital (%)	9.3	7.6	7.6	6.7	6.0
EBITDA interest coverage (x)	4.2	4.2	4.6	4.2	3.8
FFO cash int. cov. (X)	5.0	5.7	5.9	5.5	4.8
Debt/EBITDA (x)	4.2	3.9	4.7	4.9	4.9
FFO/debt (%)	16.9	17.2	16.4	15.5	15.8
Cash flow from operations/debt (%)	15.7	21.5	13.4	14.2	10.9

Table 1

PPL Corp. -- Peer Comparison (cont.)					
Free operating cash flow/debt (%)	(1.0)	5.9	(1.1)	(0.1)	(8.9)
Discretionary cash flow/debt (%)	(6.1)	0.9	(4.9)	(5.1)	(13.2)

Financial Risk: Significant

We assess PPL's financial risk profile as "significant" based on the medial volatility financial ration benchmarks. Under our base case scenario, we expect that credit protection measures will be largely at the lower end of the category with funds from operations (FFO) to debt ranging from 14% to 15% over the next three years and cash flow from operations to debt that ranges between 14% and 15% over the same period. We also expect that debt leverage will remain elevated with debt to EBITDA that ranges from 4.5x and 5x. In light of the company's planned large capital spending program, net cash flow to capital spending will range from 50% to 60% and discretionary cash flow will remain negative.

S&P Base-Case Cash Flow And Capital Structure Scenario

- The financial impact of the spin-off of the merchant generation assets will be largely neutral to credit quality
- Capital spending will remain high to fund system expansion, system maintenance, and environmental spending
- Economic conditions in the company's service territories continue to improve modestly, supporting a gradual increase in load growth.

Financial summary

Table 2

PPL Corp --Financial Summary					
Industry sector: energy					
	--Fiscal year ended Dec. 31--				
	2013	**2012**	**2011**	**2010**	**2009**
Rating history	BBB/Stable/NR	BBB/Stable/NR	BBB/Stable/NR	BBB+/Stable/NR	BBB/Negative/NR
(Mil. $)					
Revenues	11,860.0	12,286.0	12,737.0	8,521.0	3,548.2
EBITDA	4,634.0	4,617.0	4,607.5	2,847.0	657.6
Funds from operations (FFO)	3,258.6	3,313.4	3,280.1	2,007.0	357.8
Net income from continuing operations	1,128.0	1,532.0	1,493.0	955.0	30.2
Cash flow from operations	3,246.1	3,099.9	2,827.9	2,137.9	1,715.4
Capital spending	4,261.0	3,052.0	2,436.0	1,567.0	661.8
Free operating cash flow	(1,014.9)	47.9	391.9	570.9	1,053.6
Discretionary cash flow	(1,975.2)	(1,147.3)	(457.8)	(29.9)	519.9
Cash and short-term investments	275.5	225.3	304.5	272.0	77.8
Debt	21,166.3	19,625.3	17,498.3	13,501.9	4,870.1

Table 2

PPL Corp.--Financial Summary (cont.)					
Equity	13,919.0	12,876.0	13,349.0	9,753.0	2,875.4
Adjusted ratios					
EBITDA margin (%)	39.1	37.6	36.2	33.4	18.5
Return on capital (%)	8.2	9.0	11.0	11.4	4.0
EBITDA interest coverage (x)	4.2	4.3	4.1	3.4	2.0
FFO cash int. cov. (x)	4.5	4.9	5.9	5.8	2.4
Debt/EBITDA (x)	4.6	4.3	3.8	4.7	7.4
FFO/debt (%)	15.4	16.9	18.7	14.9	7.3
Cash flow from operations/debt (%)	15.3	15.8	16.2	15.8	35.2
Free operating cash flow/debt (%)	(4.8)	0.2	2.2	4.2	21.6
Discretionary cash flow/debt (%)	(9.3)	(5.8)	(2.6)	(0.2)	10.7

NR--Not rated.

Liquidity: Adequate

In our opinion, PPL has adequate liquidity to cover its needs over the next 12 to 18 months. We expect that the company's sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria, and the company will also meet our other criteria for such a designation.

PPL has about $7.3 billion in revolving credit facilities, with about $3.3 billion allocated to its merchant generation business, PPL Energy Supply. After the spin off of the merchant business in 2015, we expect that PPL could have about $4 billion in revolving credit facilities.

Principal Liquidity Sources	Principal Liquidity Uses
• FFO of about $2.8 billion to $3 billion • Common equity issuance of $978 million related to mandatory convertible securities • Credit facility availability of about $4 billion	• Debt maturities of about $465 million in 2014 and about $1 billion in 2015 • Maintenance capital spending of about $2.75 billion to $3 billion • Dividends of $950 million to $1 billion

Debt maturities

Table 3

PPL Corp. Debt Maturities	
2014	$314 million
2015	$1.3 billion
2016	$814 million
2017	$104 million
2018	$653 million

Covenant Analysis

Compliance Expectations	Requirements
As of Dec. 31, 2013, PPL Corp. and its subsidiaries were in compliance with the financial covenants in their credit facilities and had sufficient cushion. Under our base case scenario, we expect PPL Corp and its subsidiaries will remain in compliance with these covenants, especially given the stability of its regulated utility operations.	• PPL Corp. and its subsidiaries PPL Electric Utilities Corp., LG&E and KU Energy LLC, Kentucky Utilities Co., and Louisville Electric and Gas Co. are required to maintain a total debt to capitalization ratio of 70% or less • PPL Corp.'s U.K. subsidiaries are required to maintain an EBITDA to interest coverage ratio of not less than 3.0x and a total debt to regulated asset value ratio of 85% or less • The covenant thresholds remain unchanged through the expiration of the credit facilities

Other Modifiers

Our assessment of modifiers does not have any further impact on the anchor score.

Group Influence

Under the group rating methodology criteria, we assess PPL as the parent of the group. We assess PPL's group credit profile (GCP) as 'bbb', leading to an ICR of 'BBB'.

We assess the status of PPL's U.S.-based operating subsidiaries (PPL Electric Utilities Corp., LG&E and KU Energy LLC, Louisville Gas & Electric Co. and Kentucky Utilities Co.) as well as the U.K. regulated operations as core subsidiaries because we view them as integral to the group's identity; they are highly unlikely to be sold and have strong management commitment given the company's emphasis on maintaining the size and scope of the regulated utility business relative to the unregulated operations. Because there are no structural or ring-fencing provisions in place that could restrict PPL's access to the resources of its subsidiaries, the issuer credit rating on each subsidiary is 'BBB', based on PPL's GCP.

Ratings Score Snapshot

Corporate Credit Rating

BBB/Watch Pos/NR

Business risk: Strong

- **Country risk:** Very low

- **Industry risk:** Low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: bbb

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : bbb

- **Group credit profile:** bbb

Reconciliation

Table 4

Reconciliation Of PPL Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

--Fiscal year ended Dec. 31, 2013--										
PPL Corp. reported amounts										
	Debt	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital Spending**
Reported	21,608.0	12,466.0	11,860.0	4,197.0	2,339.0	1,006.0	4,197.0	2,857.0	878.0	4,307.0
Standard & Poor's adjustments										
Interest expense (reported)	--	--	--	--	--	--	(1,006.0)	--	--	--
Interest income (reported)	--	--	--	--	--	--	3.0	--	--	--
Current tax expense (reported)	--	--	--	--	--	--	(107.0)	--	--	--
Operating leases	166.2	--	--	84.0	19.4	19.4	64.6	64.6	--	--
Equity-like hybrids	(978.0)	978.0	--	--	--	(55.5)	55.5	55.5	55.5	--
Intermediate hybrids reported as debt	(475.0)	475.0	--	--	--	(26.7)	26.7	26.7	26.7	--
Postretirement benefit obligations/deferred compensation	981.5	--	--	41.0	41.0	77.8	(206.9)	316.1	--	--
Surplus cash	(826.5)	--	--	--	--	--	--	--	--	--

Table 4

Reconciliation Of PPL Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)										
Capitalized interest	--	--	--	--	--	46.0	(46.0)	(46.0)	--	(46.0)
Share-based compensation expense	--	--	--	52.0	--	--	52.0	--	--	--
Asset retirement obligations	236.0	--	--	38.0	38.0	38.0	10.2	(12.9)	--	--
Non-operating income (expense)	--	--	--	--	(24.0)	--	--	--	--	--
US decommissioning fund contributions	--	--	--	--	--	--	--	(15.0)	--	--
Debt - Accrued interest not included in reported debt	325.0	--	--	--	--	--	--	--	--	--
Debt - Other	129.1	--	--	--	--	--	--	--	--	--
EBITDA - Other	--	--	--	222.0	222.0	--	222.0	--	--	--
D&A - Impairment charges/(reversals)	--	--	--	--	697.0	--	--	--	--	--
D&A - Other	--	--	--	--	(222.0)	--	--	--	--	--
Interest expense - Other	--	--	--	--	--	6.4	(6.4)	--	--	--
Total adjustments	(441.7)	1,453.0	0.0	437.0	771.4	105.3	(938.4)	389.1	82.3	(46.0)

Standard & Poor's adjusted amounts

	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Dividends paid	Capital spending
Adjusted	21,166.3	13,919.0	11,860.0	4,634.0	3,110.4	1,111.3	3,258.6	3,246.1	960.3	4,261.0

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria – Corporates – Industrials: Key Credit Factors For The Unregulated Power And Gas Industry, March 28, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Use of CreditWatch and Outlooks, Sept. 14, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008
- Criteria - Insurance - General: General Criteria: Hybrid Capital Handbook, Sept. 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	**bbb**	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of February 13, 2015)

PPL Corp.	
Corporate Credit Rating	BBB/Watch Pos/NR
Junior Subordinated	BB+/Watch Pos
Senior Unsecured	BBB-/Watch Pos
Corporate Credit Ratings History	
10-Jun-2014	BBB/Watch Pos/NR
15-Apr-2011	BBB/Stable/NR
02-Mar-2011	BBB/Watch Neg/NR
27-Oct-2010	BBB+/Stable/NR
28-Apr-2010	BBB/Watch Pos/NR
Related Entities	
Kentucky Utilities Co.	
Issuer Credit Rating	BBB/Watch Pos/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A-/A-2
Senior Secured	A-/Watch Pos
LG&E and KU Energy LLC	
Issuer Credit Rating	BBB/Watch Pos/--
Senior Unsecured	BBB-/Watch Pos
Louisville Gas & Electric Co.	
Issuer Credit Rating	BBB/Watch Pos/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A-/A-2
Senior Secured	A-/NR
Senior Secured	A-/Watch Pos

Ratings Detail (As Of February 13, 2015) (cont.)	
PPL Electric Utilities Corp.	
Issuer Credit Rating	BBB/Watch Pos/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A-/Watch Pos
Senior Secured	AA-/Stable
PPL Energy Supply LLC	
Issuer Credit Rating	BB/Watch Neg/B
Senior Unsecured	BB/Watch Neg
Western Power Distribution Ltd	
Issuer Credit Rating	BBB/Watch Pos/A-2
Senior Unsecured	BBB-/Watch Pos

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

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Research Update:

PPL Corp. Rating Raised To 'A-' From 'BBB' On Improved Business Risk Profile; Stable Outlook

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Research Update:

PPL Corp. Rating Raised To 'A-' From 'BBB' On Improved Business Risk Profile; Stable Outlook

Overview

- U.S. utility company PPL Corp. (PPL) has completed the spin-off of its merchant generation assets leading to a material improvement to the company's business risk profile.
- PPL will now focus on regulated utility operations in the US and the UK.
- We are raising the issuer credit rating on PPL and its U.S.-based subsidiaries to 'A-' from 'BBB' and removing the ratings from CreditWatch with positive implications. The outlook is stable.

Rating Action

On June 1, 2015, Standard & Poor's Ratings Services raised its issuer credit rating on PPL Corp. and its U.S.-based subsidiaries to 'A-' from 'BBB' and removed the ratings from CreditWatch, where they were placed with positive implications on June 10, 2014 . The outlook is stable.

Rationale

PPL has completed the spin-off of its merchant generation assets resulting in sufficient improvement in business risk to move the company's business risk profile to the "excellent" category from "strong". We are raising the issuer credit rating on PPL and its US-based subsidiaries PPL Electric Utilities Corp. (PPLEU), LG&E and KU Energy LLC (LKE), Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU) to 'A-' from 'BBB'.

PPL's "excellent" business risk profile accounts for the company's ownership of solely regulated utility operations, both integrated as well as lower risk transmission and distribution utilities. PPL's regulated subsidiaries benefit from operations under constructive, transparent and generally stable regulatory frameworks and they take full advantage of all constructs available within the respective regulatory framework to consistently earn returns that are close to or at the authorized levels. Moreover, PPL's business risk profile benefits from scale, serving more than 10 million customers in two countries and and two states, and operating and regulatory diversity, although the service territory demonstrates only modest growth.

We assess PPL's financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that PPL will achieve funds from operations (FFO) to debt of 14% to 15% over the next few years, benefiting from pending rate case decisions and the timely recovery of invested capital, primarily in transmission investments. We anticipate that the company's debt leverage will remain elevated with debt to EBITDA that is close to 5x, in large part influenced by the capitalization of the U.K. subsidiaries.

Liquidity

We assess PPL's liquidity as "adequate" to cover its needs over the next 12 months. We expect the company's liquidity sources to exceed its uses by 1.1x or more, the minimum threshold for regulated utilities under our criteria, and that the company will also meet our other requirements for such a designation. We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

The PPL group has about $4 billion in revolving credit facilities, with $815 million available at the parent, $300 million available at PPLEU, $500 million available at Louisville Gas & Electric, $598 million available at Kentucky Utilities, and about $1.75 billion available at the U.K. operations. The facilities mature from 2016 through 2019.

Principal liquidity sources:

- Revolving credit facilities totaling about $3.3 billion.
- Cash on hand of about $1.5 billion.
- Cash from operations of about $2.5 billion to $2.7 billion.

Principal liquidity uses:

- Debt maturities of about $2.2 billion, including commercial paper.
- Maintenance capital spending averaging about $2.3 billion.
- Dividends of about $1 billion annually.

Outlook

The stable outlook on PPL and its subsidiaries is based on the company's "excellent" business risk profile that we view at the upper end of the range and "significant" financial risk profile, which is at the lower end of the range. Under our base case scenario we expect that FFO to debt will range from 14% to 15% while debt to EBITDA will remain elevated at about 5x.

Downside Scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% and debt to EBITDA exceeds 5x on a consistent basis.

Upside Scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis, while maintaining the current level of business risk.

Ratings Score Snapshot

	To	From
Corporate Credit Rating	A-	BBB
Business Risk	Excellent	Strong
Country Risk	Very Low	Very Low
Industry Risk	Very Low	Low
Competitive Position	Strong	Strong
Financial Risk	Significant	Significant
Cash Flow/Leverage	Significant	Significant
Anchor	a-	bbb
Modifiers		
Diversification/Portfolio effect	Neutral	Neutral
Capital structure	Neutral	Neutral
Financial policy	Neutral	Neutral
Liquidity	Adequate	Adequate
Management and Governance	Satisfactory	Satisfactory
Comparable rating analysis	Neutral	Neutral

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers - December 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry - November 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments - November 19, 2013
- General Criteria: Methodology: Industry Risk - November 19, 2013
- General Criteria: Group Rating Methodology - November 19, 2013
- Criteria - Corporates - General: Corporate Methodology - November 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions - November 19, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property - February 14, 2013

- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers - November 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks - September 14, 2009
- Criteria - Corporates - Utilities: Notching Of U.S. Investment-Grade Investor-Owned Utility Unsecured Debt Now Better Reflects Anticipated Absolute Recovery - November 10, 2008
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue - April 15, 2008

Ratings List

	Ratings	
	To	From
PPL Corp.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/--	BBB/Watch Pos/--
Kentucky Utilities Co.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#1]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#1]	1+	1+
Local Currency [#2]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#2]	1+	1+
Local Currency [#3]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#3]	1+	1+
Local Currency [#4]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#4]	1+	1+
SPUR [#4]	A/A-2	A-/Watch Pos/A-2
Local Currency [#5]	A	A-/Watch Pos
Recovery Rating [#5]	1+	1+
SPUR [#5]	A	A-/Watch Pos
Local Currency [#4]	A	A-/Watch Pos
Recovery Rating [#4]	1+	1+
SPUR [#4]	A	A-/Watch Pos

Ratings List Continued...

Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+
Commercial Paper		
Local Currency	A-2	A-2
LG&E and KU Energy LLC		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/--	BBB/Watch Pos/--
Senior Unsecured		
Local Currency	BBB+	BBB-/Watch Pos
Louisville Gas & Electric Co.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#6]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A	A-/Watch Pos/NR
Recovery Rating [#7]	1+	1+
Local Currency [#6]	A	A-/Watch Pos/NR
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A/A-2	A-/Watch Pos/A-2
Recovery Rating [#7]	1+	1+
Local Currency [#6]	A	A-/Watch Pos
Recovery Rating [#6]	1+	1+
Local Currency [#7]	A	A-/Watch Pos
Recovery Rating [#7]	1+	1+
Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+

Ratings List Continued...

Commercial Paper		
Local Currency	A-2	A-2
PPL Capital Funding Inc		
Senior Unsecured		
Local Currency[1]	BBB+	BBB-/Watch Pos
Junior Subordinated		
Local Currency[1]	BBB	BB+/Watch Pos
PPL Electric Utilities Corp.		
Corporate credit rating		
Foreign and Local Currency	A-/Stable/A-2	BBB/Watch Pos/A-2
Senior Secured		
Local Currency [#8]	A	A-/Watch Pos
Recovery Rating [#8]	1+	1+
Local Currency [#9]	AA-/Stable	AA-/Stable
Recovery Rating [#9]	1+	1+
SPUR [#9]	A	A-/Watch Pos
Local Currency [#10]	AA-/Stable	AA-/Stable
Recovery Rating [#10]	1+	1+
SPUR [#10]	A	A-/Watch Pos
Local Currency[2]	A	A-/Watch Pos
Recovery Rating	1+	1+
SPUR	A	A-/Watch Pos
Local Currency	A	A-/Watch Pos
Recovery Rating	1+	1+
Commercial Paper		
Local Currency	A-2	A-2

[1] Dependent Participant(s): PPL Corp.

[2] Dependent Participant(s): Ambac Assurance Corp.

[#1] Issuer: Carroll Cnty, OBLIGOR: Kentucky Utilities Co.

[#2] Issuer: Mercer Cnty, OBLIGOR: Kentucky Utilities Co.

[#3] Issuer: Muhlenberg Cnty, OBLIGOR: Kentucky Utilities Co.

[#4] Issuer: Carroll Cnty, INSPRO: Ambac Assurance Corp., OBLIGOR: Kentucky Utilities Co.

[#5] Issuer: Trimble Cnty, INSPRO: Ambac Assurance Corp., OBLIGOR: Kentucky Utilities Co.

[#6] Issuer: Louisville & Jefferson Cnty Metro Govt, OBLIGOR: Louisville Gas & Electric Co.

[#7] Issuer: Trimble Cnty, OBLIGOR: Louisville Gas & Electric Co.

[#8] Issuer: Pennsylvania Econ Dev Fing Auth, OBLIGOR: PPL Electric Utilities Corp.

[#9] Issuer: Lehigh Cnty Indl Dev Auth, INSPRO: National Public Finance Guarantee Corp., OBLIGOR: PPL Electric Utilities Corp.

[#10] Issuer: Lehigh Cnty Indl Dev Auth, INSPRO: MBIA Insurance Corp., INSPRO: National Public Finance Guarantee Corp., OBLIGOR: PPL Electric Utilities Corp.

Complete ratings information is available to subscribers of RatingsDirect at www.globalcreditportal.com and at spcapitaliq.com. All ratings referenced herein can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

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Research

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PPL Corp.

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Summary:
PPL Corp.

Business Risk: EXCELLENT

Vulnerable Excellent a- a- a-

Financial Risk: SIGNIFICANT

Highly leveraged Minimal

Anchor Modifiers Group/Gov't

CORPORATE CREDIT RATING

A-/Stable/NR

Rationale

Business Risk: Excellent

- Focus on regulated utility operations in the U.S. and in the U.K. that benefit from constructive regulatory frameworks.
- Large and diverse service territories that demonstrate only modest growth.
- Primarily low operating risk electricity transmission and distribution operations.
- Evolving environmental standards continue to add costs to coal generation fleet.

Financial Risk: Significant

- Core credit ratios are at the lower end of the "significant" financial risk profile category.
- Large capital spending program leading to negative discretionary cash flow.

Outlook: Stable

The stable outlook on PPL Corp. (PPL) and its subsidiaries reflects the company's "excellent" business risk profile that we view at the upper end of the range and "significant" financial risk profile, which is at the lower end of the range. Under our base-case scenario we expect that funds from operations (FFO) to debt will range from 14% to 15% while debt to EBITDA will remain elevated at about 5x.

Downside scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% and debt to EBITDA exceeds 5x on a consistent basis.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis, while maintaining the current level of business risk.

Standard & Poor's Base-Case Scenario

Assumptions

- Gross margins grow in the mid-single digits, primarily benefiting from anticipated base rate increases and the recovery of environmental as well as transmission and distribution investments.
- Capital spending of about $3.6 billion in 2015, $3.3 billion in 2016 and 2017.
- Common dividends grow by an average of about 2% annually.

Key Metrics

	2014A	2015E	2016E
FFO/Debt (%)	15.5	14-15	14-15
Debt/EBITDA (x)	4.5	4.5–5.0	4.5–5.0
OCF/Debt (%)	15.9	12–13	12–13

A--Actual. E—Estimate. FFO—Funds from operations. OCF—operating cash flow.

Business Risk: Excellent

We view PPL's business risk profile as "excellent" incorporating the company's divestment of the merchant generation business and ownership solely of regulated integrated and low-risk transmission and distribution utility operations.

Moreover, PPL's business risk profile benefits from geographic and regulatory diversity, serving more than 10 million customers across two states in the U.S. as well as across the U.K. Although the service territories demonstrate only modest growth, residential and commercial customers contribute the majority of revenue and sales, providing a measure of stability and predictability to cash flow generation.

PPL's regulated utility subsidiaries benefit from operations under constructive, transparent and generally stable regulatory frameworks in the U.S. and the U.K. Moreover, these subsidiaries take full advantage of all constructs available within their respective regulatory frameworks to consistently earn returns that are close to or at the authorized levels.

Financial Risk: Significant

We assess PPL's financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that PPL will achieve FFO to debt of 14% to 15% over the next few years, benefiting from pending rate case decisions and the timely recovery of invested capital, primarily in transmission investments as well as from approved environmental compliance spending in Kentucky. We anticipate that the company's debt leverage will remain elevated with debt to EBITDA that is close to 5x, in large part influenced by the capitalization of the U.K. subsidiaries.

Liquidity: Adequate

We assess PPL's liquidity as "adequate" to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other criteria for such a designation. We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

The PPL group has about $4 billion in revolving credit facilities, with $815 million available at the parent, $300 million available at PPL Electric Utilities Corp., $500 million available at Louisville Gas & Electric Co., $598 million available at Kentucky Utilities Co., and about $1.75 billion available at the U.K. operations. The revolving credit facilities mature from 2016 through 2019.

The 'A-2' short-term rating on the PPL group accounts for the long-term corporate credit rating and our assessment of the group's liquidity as "adequate".

Principal Liquidity Sources	Principal Liquidity Uses
• Revolving credit facilities totaling about $3.5 billion; • Cash on hand of about $1.5 billion; and • Cash from operations of about $2.5 billion to $2.7 billion.	• Debt maturities of about $2.2 billion, including outstanding commercial paper; • Maintenance capital spending averaging about $2.3 billion; and • Dividends of about $1 billion annually.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

Group Influence

Under the group rating methodology criteria, we assess PPL as the parent of the group. We assess PPL's group credit profile (GCP) as 'a-', leading to an issuer credit rating of 'A-'.

We assess the status of PPL's U.S.-based operating subsidiaries (PPL Electric Utilities Corp., LG&E and KU Energy LLC, Louisville Gas & Electric Co. and Kentucky Utilities Co.) as well as the U.K. regulated operations (Western Power Distribution Ltd. and its subsidiaries, Western Power Distribution (West Midlands) PLC, Western Power Distribution (South West) PLC, Western Power Distribution (South Wales) PLC, and Western Power Distribution (East Midlands) PLC) as core subsidiaries because we view them as integral to the group's identity; they are highly unlikely to be sold and have strong management commitment given the company's emphasis on maintaining the size and scope of the regulated utility business relative to the unregulated operations. Because there are no structural or ring-fencing provisions in place that could restrict PPL's access to the resources of its subsidiaries, the issuer credit rating on each subsidiary is 'A-', based on PPL's GCP of 'a-'.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/NR

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-

Issue Ratings

Senior unsecured and junior subordinated debt obligations at PPL Capital Funding are unconditionally guaranteed by PPL Corp. and are effectively obligations of PPL Corp. We rate the senior unsecured debt one notch below the issuer credit rating to reflect the material amount of priority obligations throughout PPL Corp. that encumbers more than 20% of the company's total assets. We rate the junior subordinated debt two notches below the issuer credit rating to reflect the discretionary nature of the dividend payments and the deeply subordinated claim in the event of bankruptcy.

Similarly, we rate PPL Corp.'s commercial paper program 'A-2' to incorporating the issuer credit rating on the company and our assessment of PPL Corp.'s liquidity as "adequate".

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

STANDARD & POOR'S
RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

PPL Corp.

Primary Credit Analyst:
Dimitri Nikas, New York (1) 212-438-7807; dimitri.nikas@standardandpoors.com

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Gerrit W Jepsen, CFA, New York (1) 212-438-2529; gerrit.jepsen@standardandpoors.com

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PPL Corp.

Business Risk: EXCELLENT

Vulnerable — Excellent

Financial Risk: SIGNIFICANT

Highly leveraged — Minimal

Anchor	Modifiers	Group/Gov't
a-	a-	a-

CORPORATE CREDIT RATING

A-/Stable/NR

Rationale

Business Risk: Excellent	Financial Risk: Significant
• Focus on regulated utility operations in the U.S. and in the U.K. that benefit from constructive regulatory frameworks. • Large and diverse service territories that demonstrate only modest growth. • Primarily low operating risk electricity transmission and distribution operations. • Evolving environmental standards continue to add costs to coal generation fleet.	• Core credit ratios are at the lower end of the "significant" financial risk profile category. • Large capital spending program leading to negative discretionary cash flow.

Outlook: Stable

The stable outlook on PPL Corp. (PPL) and its subsidiaries reflects the company's "excellent" business risk profile that we view at the upper end of the range and "significant" financial risk profile, which is at the lower end of the range. Under our base-case scenario we expect that funds from operations (FFO) to debt will range from 14% to 15% while debt to EBITDA will remain elevated at about 5x.

Downside scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% and debt to EBITDA exceeds 5x on a consistent basis.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis, while maintaining the current level of business risk.

Standard & Poor's Base-Case Scenario

Assumptions

- Gross margins grow in the mid-single digits, primarily benefiting from anticipated base rate increases and the recovery of environmental as well as transmission and distribution investments.
- Capital spending of about $3.6 billion in 2015, $3.3 billion in 2016 and 2017.
- Common dividends grow by an average of about 2% annually.

Key Metrics

	2014A	2015E	2016E
FFO/Debt (%)	15.5	14-15	14-15
Debt/EBITDA (x)	4.5	4.5–5.0	4.5–5.0
OCF/Debt (%)	15.9	12–13	12–13

A--Actual. E—Estimate. FFO—Funds from operations. OCF—operating cash flow.

Company Description

PPL Corp. is a utility holding company serving about 10.5 million mostly electric customers in Kentucky, Pennsylvania, and the U.K. The company's operations in Kentucky are fully integrated and are conducted through Louisville Gas & Electric Co. and Kentucky Utilities Co. The company's operations in Pennsylvania, conducted through PPL Electric Utilities Corp., and in the U.K., conducted through the four subsidiaries of Western Power Distribution Ltd., consist solely of electric transmission and distribution operations.

Business Risk: Excellent

We view PPL's business risk profile as "excellent" incorporating the company's divestment of the merchant generation business and ownership solely of regulated integrated and low-risk transmission and distribution utility operations.

Moreover, PPL's business risk profile benefits from geographic and regulatory diversity, serving more than 10 million customers across two states in the U.S. as well as across the U.K. Although the service territories demonstrate only modest growth, residential and commercial customers contribute the majority of revenue and sales, providing a measure of stability and predictability to cash flow generation.

PPL's regulated utility subsidiaries benefit from operations under constructive, transparent and generally stable regulatory frameworks in the U.S. and the U.K. Moreover, these subsidiaries take full advantage of all constructs available within their respective regulatory frameworks to consistently earn returns that are close to or at the authorized levels.

S&P Base-Case Operating Scenario

- PPL consistently and effectively manages regulatory risk across all its jurisdictions
- The company remains focused on the gradual expansion of its regulated utility operations through additions to rate base.

Peer comparison

Table 1

PPL Corp.--Peer Comparison

Industry Sector: Combo

	PPL Corp.	Consolidated Edison Inc.	Eversource Energy	Oncor Electric Delivery Co. LLC	PEPCO Holdings Inc.
Rating as of Aug. 5, 2015	A-/Stable/--	A-/Stable/A-2	A/Stable/A-1	BBB+/Developing/--	BBB+/Stable/A-2
	--Average of past three fiscal years--				
(Mil. $)					
Revenues	11,881.7	12,487.0	7,028.8	3,422.6	4,821.7
EBITDA	4,705.5	3,607.0	2,285.0	1,862.1	1,224.3
Funds from operations (FFO)	3,332.4	2,536.9	1,788.8	1,386.7	1,028.0
Net income from cont. oper.	1,414.3	1,098.3	710.5	410.3	212.3
Cash flow from operations	3,283.9	2,907.9	1,476.0	1,161.7	662.0
Capital expenditures	3,821.3	2,340.3	1,505.9	1,183.3	1,245.0
Free operating cash flow	(537.4)	567.6	(29.9)	(21.6)	(583.0)
Discretionary cash flow	(1,588.0)	(156.4)	(466.4)	(293.9)	(846.3)
Cash and short-term investments	322.8	89.0	15.1	24.3	4.0
Debt	20,951.0	14,453.3	10,817.3	7,060.4	6,119.0

Table 1

PPL Corp.--Peer Comparison (cont.)					
Equity	13,629.3	12,233.0	9,686.2	3,854.3	4,382.5
Adjusted ratios					
EBITDA margin (%)	39.6	28.9	32.5	54.4	25.4
Return on capital (%)	8.5	7.4	7.3	8.7	5.8
EBITDA interest coverage (x)	4.2	4.4	4.9	4.4	3.9
FFO cash int. cov. (X)	4.7	5.9	6.3	5.0	5.1
Debt/EBITDA (x)	4.5	4.0	4.7	3.8	5.0
FFO/debt (%)	15.9	17.6	16.5	19.6	16.8
Cash flow from operations/debt (%)	15.7	20.1	13.6	16.5	10.8
Free operating cash flow/debt (%)	(2.6)	3.9	(0.3)	(0.3)	(9.5)
Discretionary cash flow/debt (%)	(7.6)	(1.1)	(4.3)	(4.2)	(13.8)

Financial Risk: Significant

We assess PPL's financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that PPL will achieve FFO to debt of 14% to 15% over the next few years, benefiting from pending rate case decisions and the timely recovery of invested capital, primarily in transmission investments as well as from approved environmental compliance spending in Kentucky. We anticipate that the company's debt leverage will remain elevated with debt to EBITDA that is close to 5x, in large part influenced by the capitalization of the U.K. subsidiaries.

S&P Base-Case Cash Flow And Capital Structure Scenario

- Capital spending will remain high to fund system expansion, system maintenance, and environmental compliance spending.
- Economic conditions in the company's service territories continue to improve modestly, supporting a gradual increase in load growth.

Financial summary

Table 2

PPL Corp.--Financial Summary					
Industry Sector: Combo					
	--Fiscal year ended Dec. 31--				
	2014	**2013**	**2012**	**2011**	**2010**
Rating history	BBB/Watch Pos/--	BBB/Stable/--	BBB/Stable/--	BBB/Stable/--	BBB+/Stable/--
(Mil. $)					
Revenues	11,499.0	11,860.0	12,286.0	12,737.0	8,521.0

Table 2

PPL Corp.—Financial Summary (cont.)					
EBITDA	4,865.5	4,634.0	4,617.0	4,607.5	2,847.0
Funds from operations (FFO)	3,425.3	3,258.6	3,313.4	3,280.1	2,007.0
Net income from continuing operations	1,583.0	1,128.0	1,532.0	1,493.0	955.0
Cash flow from operations	3,505.7	3,246.1	3,099.9	2,827.9	2,137.9
Capital expenditures	4,151.0	4,261.0	3,052.0	2,436.0	1,567.0
Free operating cash flow	(645.3)	(1,014.9)	47.9	391.9	570.9
Dividends paid	996.3	960.3	1,195.2	849.7	600.8
Discretionary cash flow	(1,641.6)	(1,975.2)	(1,147.3)	(457.8)	(29.9)
Debt	22,061.5	21,166.3	19,625.3	17,498.3	13,501.9
Preferred stock	465.0	1,453.0	2,378.0	2,503.0	1,525.0
Equity	14,093.0	13,919.0	12,876.0	13,349.0	9,753.0
Debt and equity	36,154.5	35,085.3	32,501.3	30,847.3	23,254.9
Adjusted ratios					
EBITDA margin (%)	42.3	39.1	37.6	36.2	33.4
EBITDA interest coverage (x)	4.1	4.2	4.3	4.1	3.4
FFO cash int. cov. (x)	4.6	4.5	4.9	5.9	5.8
Debt/EBITDA (x)	4.5	4.6	4.3	3.8	4.7
FFO/debt (%)	15.5	15.4	16.9	18.7	14.9
Cash flow from operations/debt (%)	15.9	15.3	15.8	16.2	15.8
Free operating cash flow/debt (%)	(2.9)	(4.8)	0.2	2.2	4.2
Discretionary cash flow/debt (%)	(7.4)	(9.3)	(5.8)	(2.6)	(0.2)
Net cash flow/capex (%)	58.5	53.9	69.4	99.8	89.7
Return on capital (%)	8.2	8.2	9.0	11.0	11.4
Return on common equity (%)	11.8	9.3	13.8	15.0	17.0
Common dividend payout ratio (un-adj.) (%)	62.2	79.7	55.2	52.2	63.4

Liquidity: Adequate

We assess PPL's liquidity as "adequate" to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other criteria for such a designation. We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

The PPL group has about $4 billion in revolving credit facilities, with $815 million available at the parent, $300 million available at PPL Electric Utilities Corp., $500 million available at Louisville Gas & Electric Co., $598 million available at Kentucky Utilities Co., and about $1.75 billion available at the U.K. operations. The revolving credit facilities mature from 2016 through 2019.

The 'A-2' short-term rating on the PPL group accounts for the long-term corporate credit rating and our assessment of the group's liquidity as "adequate".

Principal Liquidity Sources	Principal Liquidity Uses
• Revolving credit facilities totaling about $3.5 billion; • Cash on hand of about $1.5 billion; and • Cash from operations of about $2.5 billion to $2.7 billion.	• Debt maturities of about $2.2 billion, including outstanding commercial paper; • Maintenance capital spending averaging about $2.3 billion; and • Dividends of about $1 billion annually.

Debt maturities

As of Dec. 31, 2014 (excludes PPL Energy Supply maturities)

- 2015: $1.0 billion
- 2016: $485 million
- 2017: $294 million
- 2018: $347 million
- 2019: $40 million

Covenant Analysis

Compliance Expectations	Requirements
As of Dec. 31, 2014, PPL Corp. and its subsidiaries were in compliance with the financial covenants in their credit facilities and had sufficient cushion. Under our base case scenario, we expect PPL Corp. and its subsidiaries will remain in compliance with these covenants, especially given the stability of its regulated utility operations.	• PPL Corp. and its subsidiaries PPL Electric Utilities Corp., LG&E and KU Energy LLC, Kentucky Utilities Co., and Louisville Electric and Gas Co. are required to maintain a total debt to capitalization ratio of 70% or less. • PPL Corp.'s U.K. subsidiaries are required to maintain an EBITDA to interest coverage ratio of not less than 3.0x and a total debt to regulated asset value ratio of 85% or less. • The covenant thresholds remain unchanged through the expiration of the credit facilities.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

Group Influence

Under the group rating methodology criteria, we assess PPL as the parent of the group. We assess PPL's group credit profile (GCP) as 'a-', leading to an issuer credit rating of 'A-'.

We assess the status of PPL's U.S.-based operating subsidiaries (PPL Electric Utilities Corp., LG&E and KU Energy LLC, Louisville Gas & Electric Co. and Kentucky Utilities Co.) as well as the U.K. regulated operations (Western Power Distribution Ltd. and its subsidiaries, Western Power Distribution (West Midlands) PLC, Western Power Distribution (South West) PLC, Western Power Distribution (South Wales) PLC, and Western Power Distribution (East Midlands) PLC) as core subsidiaries because we view them as integral to the group's identity; they are highly unlikely to be sold and have strong management commitment given the company's emphasis on maintaining the size and scope of the regulated utility business relative to the unregulated operations. Because there are no structural or ring-fencing provisions in place that could restrict PPL's access to the resources of its subsidiaries, the issuer credit rating on each subsidiary is 'A-', based on PPL's GCP of 'a-'.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/NR

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-

Issue Ratings

Senior unsecured and junior subordinated debt obligations at PPL Capital Funding are unconditionally guaranteed by PPL Corp. and are effectively obligations of PPL Corp. We rate the senior unsecured debt one notch below the issuer credit rating to reflect the material amount of priority obligations throughout PPL Corp. that encumbers more than

20% of the company's total assets. We rate the junior subordinated debt two notches below the issuer credit rating to reflect the discretionary nature of the dividend payments and the deeply subordinated claim in the event of bankruptcy.

Similarly, we rate PPL Corp.'s commercial paper program 'A-2' to incorporating the issuer credit rating on the company and our assessment of PPL Corp.'s liquidity as "adequate"

Reconciliation

Table 3

Reconciliation Of PPL Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2014--								
PPL Corp. reported amounts									
	Debt	**Shareholders' equity**	**EBITDA**	**Operating income**	**Interest expense**	**EBITDA**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	21,857.0	13,628.0	4,492.0	3,272.0	1,024.0	4,492.0	3,403.0	967.0	4,185.0
Standard & Poor's adjustments									
Interest expense (reported)	--	--	--	--	--	(1,024.0)	--	--	--
Interest income (reported)	--	--	--	--	--	5.0	--	--	--
Current tax expense (reported)	--	--	--	--	--	(225.0)	--	--	--
Operating leases	106.0	--	47.5	9.5	9.5	38.0	38.0	--	--
Intermediate hybrids reported as debt	(465.0)	465.0	--	--	(29.3)	29.3	29.3	29.3	--
Postretirement benefit obligations/deferred compensation	1,305.2	--	(31.0)	(31.0)	89.1	(175.7)	103.3	--	--
Surplus cash	(1,403.3)	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	34.0	(34.0)	(34.0)	--	(34.0)
Share-based compensation expense	--	--	64.0	--	--	64.0	--	--	--
Asset retirement obligations	218.4	--	48.0	48.0	48.0	17.2	(17.9)	--	--
Non-operating income (expense)	--	--	--	(3.0)	--	--	--	--	--
US decommissioning fund contributions	--	--	--	--	--	--	(16.0)	--	--
Debt - Accrued interest not included in reported debt	314.0	--	--	--	--	--	--	--	--
Debt - Other	129.1	--	--	--	--	--	--	--	--
EBITDA - Other	--	--	245.0	245.0	--	245.0	--	--	--
D&A - Other	--	--	--	(245.0)	--	--	--	--	--

Table 3

Reconciliation Of PPL Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $) (cont.)									
Interest expense - Other	--	--	--	--	6.4	(6.4)	--	--	--
Total adjustments	204.5	465.0	373.5	23.5	157.8	(1,066.7)	102.7	29.3	(34.0)
Standard & Poor's adjusted amounts									
	Debt	**Equity**	**EBITDA**	**EBIT**	**Interest expense**	**Funds from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Adjusted	22,061.5	14,093.0	4,865.5	3,295.5	1,181.8	3,425.3	3,505.7	996.3	4,151.0

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
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- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
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- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of August 6, 2015)

PPL Corp.	
Corporate Credit Rating	A-/Stable/NR
Junior Subordinated	BBB
Senior Unsecured	BBB+

Ratings Detail (As Of August 6, 2015) (cont.)	
Corporate Credit Ratings History	
01-Jun-2015	A-/Stable/NR
10-Jun-2014	BBB/Watch Pos/NR
15-Apr-2011	BBB/Stable/NR
02-Mar-2011	BBB/Watch Neg/NR
27-Oct-2010	BBB+/Stable/NR
Related Entities	
Kentucky Utilities Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Senior Secured	A/A-2
LG&E and KU Energy LLC	
Issuer Credit Rating	A-/Stable/--
Senior Unsecured	BBB+
Louisville Gas & Electric Co.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Senior Secured	A/A-2
PPL Electric Utilities Corp.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Senior Secured	A
Senior Secured	AA-/Stable
Western Power Distribution Ltd	
Issuer Credit Rating	A-/Stable/A-2
Senior Unsecured	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

STANDARD & POOR'S RATINGS SERVICES
McGRAW HILL FINANCIAL

Research

Summary:
Louisville Gas & Electric Co.

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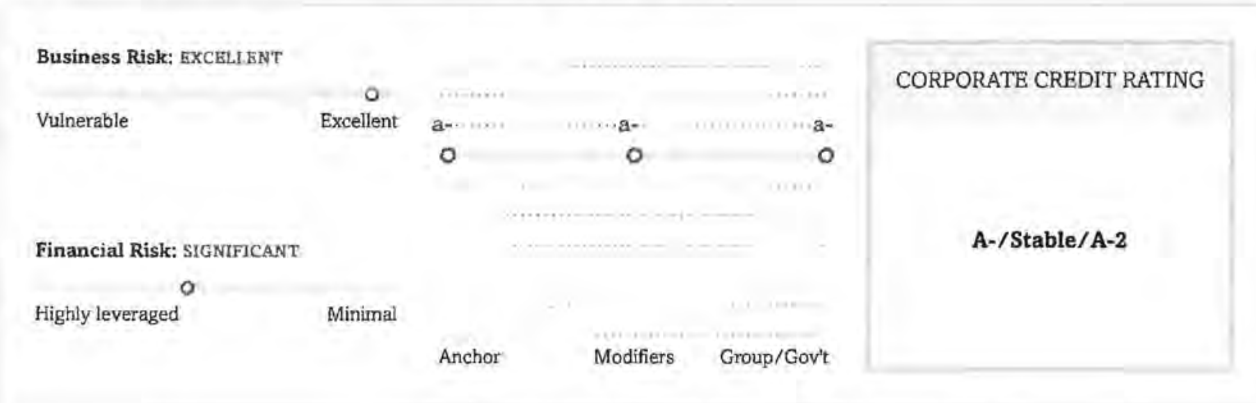
Summary:

Louisville Gas & Electric Co.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Integrated electric utility operations that benefit from a constructive regulatory framework. • Timely recovery of costs through base rates and rate surcharges. • Efficient operations contribute to competitive rates. • Medium-size service territory lacking diversity.	• Core credit ratios support a "significant" financial risk profile assessment. • Large capital expenditure program leading to negative discretionary cash flow. • Balanced capital structure supports overall credit profile.

Outlook: Stable

The outlook on Louisville Gas & Electric Utilities Co. (LG&E) reflects the outlook of its parent, PPL Corp. (PPL), because we view the company as a core subsidiary of PPL. The stable outlook on PPL Corp. (PPL) and its subsidiaries is based on the company's "excellent" business risk profile that we view at the upper end of the range and "significant" financial risk profile which is at the lower end of the range. Under our base-case scenario we expect that funds from operations (FFO) to debt will range from 14% to 15% while debt to EBITDA will remain elevated at about 5x.

Downside scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% and debt to EBITDA exceeds 5x on a consistent basis.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis, while maintaining the current level of business risk.

Standard & Poor's Base-Case Scenario

Assumptions

- Gross margins grow in the mid-single digits, primarily benefiting from anticipated base rate increases and recovery of planned environmental compliance costs.
- Capital spending of about $600 million in 2015 and $500 million in 2016, mainly for environmental compliance.
- Company maintains balanced capital structure, in line with historical trends.

Key Metrics

	2014A	2015E	2016E
FFO/debt (%)	25.5	21–22	21–22
Debt/EBITDA (x)	3.6	3.5-4.0	3.5-4.0
OCF/debt (%)	21	20–21	19-20

A--Actual. E—Estimate. FFO—Funds from operations. OCF—operating cash flow.

Business Risk: Excellent

We assess LG&E's business risk profile as "excellent" accounting primarily for the company's integrated utility operations under a generally constructive regulatory framework in Kentucky that provides for timely recovery of approved capital expenditures. LG&E serves about 720,000 electric and gas customers in Louisville and other service areas in Kentucky. While the customer base has no meaningful exposure to industrial customers, the service territory lacks geographic diversity. Moreover, LG&E has material exposure to coal-fired generation that is only modestly offset by the 640 megawatt natural gas combined-cycle unit that came on-line in mid-2015 and is co-owned with affiliate

Kentucky Utilities Co. At the same time, the company's efficient operations and low-cost coal-fired generation contribute to overall competitive rates for customers.

Financial Risk: Significant

We assess LG&E's financial risk profile as being in the "significant" category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that LG&E's FFO to debt will range from 21% to 22% over the next few years, benefiting from timely recovery of the environmental costs while debt to EBITDA will average about 3.7x.

Liquidity: Adequate

Because we view LG&E as a "core" subsidiary of PPL, we assess its liquidity on a consolidated basis with that of its parent.

We assess PPL's liquidity as "adequate" to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other criteria for such a designation. We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years.

The PPL group has about $4 billion in revolving credit facilities, with $815 million available at the parent, $300 million available at PPL Electric Utilities Corp., $500 million available at Louisville Gas & Electric Co., $598 million available at Kentucky Utilities Co., and about $1.75 billion available at the U.K. operations. The revolving credit facilities mature from 2016 through 2019.

The 'A-2' short-term rating on PPL accounts for its long-term corporate credit rating and our assessment of the company's liquidity as "adequate".

Principal Liquidity Sources	Principal Liquidity Uses
• Revolving credit facilities totaling about $3.5 billion; • Cash on hand of about $1.5 billion; and • Cash from operations of about $2.5 billion to $2.7 billion.	• Debt maturities of about $2.2 billion, including outstanding commercial paper; • Maintenance capital spending averaging about $2.3 billion; and • Dividends of about $1 billion annually.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

Group Influence

LG&E is subject to our group rating methodology criteria. We assess LG&E as a "core" subsidiary of parent PPL Corp. because it is highly unlikely to be sold, is integral to the group's overall strategy, possesses significant management commitment, is a significant contributor to the group and is closely linked to the parent's reputation. Moreover, there are no meaningful insulation measures in place that protect LG&E from its parent. As a result, the issuer credit rating on LG&E is 'A-', in line with PPL's group credit profile of 'a-'.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Recovery Analysis/Issue Ratings

We assign recovery ratings to first-mortgage bonds (FMB), which can result in issue ratings being notched above a corporate credit rating on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage And Issue Notching Rules for '1+' And '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property," published Feb. 14, 2013).

The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.

Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed a utility's CCR by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.

LG&E's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of over 2.6x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

RatingsDirect®

Summary:
PPL Corp.

Primary Credit Analyst:
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Summary:
PPL Corp.

Business Risk: EXCELLENT

Vulnerable Excellent

a- a- a-

Financial Risk: SIGNIFICANT

Highly leveraged Minimal

Anchor Modifiers Group/Gov't

CORPORATE CREDIT RATING

A-/Stable/A-2

Rationale

Business Risk: Excellent

- Focus on regulated utility operations in the U.S. and U.K. that benefit from constructive regulatory frameworks.
- Large and diverse service territories that demonstrate only modest growth.
- Primarily low operating risk electricity transmission and distribution operations.
- Evolving environmental standards continue to add costs to coal generation fleet.

Financial Risk: Significant

- Core credit ratios are at the lower end of the significant financial risk profile category, but are expected to strengthen over time.
- Large capital spending program leading to negative discretionary cash flow.

Outlook: Stable

The stable outlook on PPL Corp. and its subsidiaries is based on our assessments of the company's excellent business risk profile that we view at the upper end of the range and significant financial risk profile, which is at the lower end of the range. Under our base-case scenario we expect that funds from operations (FFO) to debt will range from 13%-14% while debt to EBITDA will remain elevated at over 5x.

Downside scenario

We could lower the ratings on PPL and its subsidiaries if core credit ratios weaken such that FFO to debt is below 13% on a consistent basis while maintaining the current level of business risk.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis while maintaining the current level of business risk.

S&P Global Ratings' Base-Case Scenario

Assumptions

- Gross margins grow by about 4%-6% annually as a result of an increase in base rates and timely recovery of invested capital through mechanisms and transmission formula rates.
- Capital spending of $3 billion to $3.5 billion per year.
- Dividends in line with the company's stated dividend policy over the forecast period, with an expected growth rate of about 3% per year.
- All debt maturities are refinanced.

Key Metrics

	2015A	2016E	2017E
FFO/debt (%)	13.3	13.5-14	13.5-14
Debt/EBITDA (x)	5.4	5-5.5	5-5.5
OCF/debt (%)	13.9	12.5-13	12.5–13

A–Actual. E—Estimate. FFO—Funds from operations. OCF—operating cash flow.

Business Risk: Excellent

We view PPL's business risk profile as excellent incorporating the company's ownership solely of regulated integrated and low-risk transmission and distribution utility operations since the company completed the spin-off of its merchant generation assets in 2015.

Moreover, PPL's business risk profile benefits from geographic and regulatory diversity, serving about 10 million customers across two states in the U.S. as well as across the U.K. Although the service territories demonstrate only modest growth, residential and commercial customers contribute the majority of revenue and sales, providing a measure of stability and predictability to cash flow generation.

PPL's regulated utility subsidiaries benefit from operations under constructive, transparent, and generally stable regulatory frameworks in the U.S. and U.K. Moreover, these subsidiaries take full advantage of various constructs available within their respective regulatory frameworks to consistently earn returns that are close to or at the authorized levels.

Financial Risk: Significant

We assess PPL's financial risk profile as being in the significant category using the medial volatility financial ratio benchmarks. Under our base-case scenario, we project that PPL will achieve FFO to debt of 13%-14% over the next few years. We expect credit measures to improve, benefiting from pending rate case decisions and the timely recovery of invested capital, primarily in transmission investments as well as from approved environmental compliance spending in Kentucky. We anticipate that the company's debt leverage will remain elevated with debt to EBITDA that is close to 5x, in large part influenced by the capitalization of the U.K. subsidiaries.

Liquidity: Adequate

We assess PPL's liquidity as adequate to cover its needs over the next 12 months. We expect the company's liquidity sources to exceed its uses by 1.1x or more, the minimum threshold for regulated utilities under our criteria, and that the company will also meet our other requirements for such a designation.

We expect that PPL's liquidity will benefit from stable cash flow generation, ample availability under the revolving credit facilities, and manageable debt maturities over the next few years. The company's well-established and solid bank relationships, the ability to absorb high-impact, low-probability events without the need for refinancing, and a satisfactory standing in credit markets also support our assessment of its liquidity as adequate.

As of March 31, 2016, PPL Corp. had about $4.3 billion in revolving credit facilities, with $1.15 billion available at the parent, $400 million available at PPL Electric Utilities Corp., $75 million available at LG&E and KU Energy LLC, $500 million available at Louisville Gas & Electric Co., $598 million available at Kentucky Utilities Co. and about $1.55 billion available at the U.K. operations.

The facilities mature from 2017 through 2021.

Principal Liquidity Sources	Principal Liquidity Uses
• Revolving credit facility of approximately $4.3 billion for the next 12 months; • Cash balance of $814 million;and • Cash FFO of $2.7 billion annually;	• Debt maturities are $2.1 billion for the next 12 months; • Capital spending of $3.4 billion in 2016; and • Dividend of more than $1 billion.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral
- **Capital structure:** Neutral
- **Financial policy:** Neutral
- **Liquidity:** Adequate
- **Management and governance:** Satisfactory
- **Comparable rating analysis:** Neutral

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core

Issue Ratings

Senior unsecured and junior subordinated debt obligations at PPL Capital Funding are unconditionally guaranteed by PPL Corp. and are effectively obligations of PPL Corp. We rate the senior unsecured debt one notch below the issuer credit rating to reflect the material amount of priority obligations throughout PPL Corp. that encumbers more than 20% of the company's total assets. We rate the junior subordinated debt two notches below the issuer credit rating to reflect the discretionary nature of the dividend payments and the deeply subordinated claim in the event of bankruptcy.

Similarly, we rate PPL Corp.'s commercial paper program 'A-2' to incorporate the issuer credit rating on the company and our assessment of PPL Corp.'s liquidity as adequate.

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

S&P Global
Ratings

RatingsDirect®

Summary:
Louisville Gas & Electric Co.

Primary Credit Analyst:
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Research Contributor:
Amrita Lokhande, CRISIL Global Analytical Center, an S&P affiliate, Mumbai

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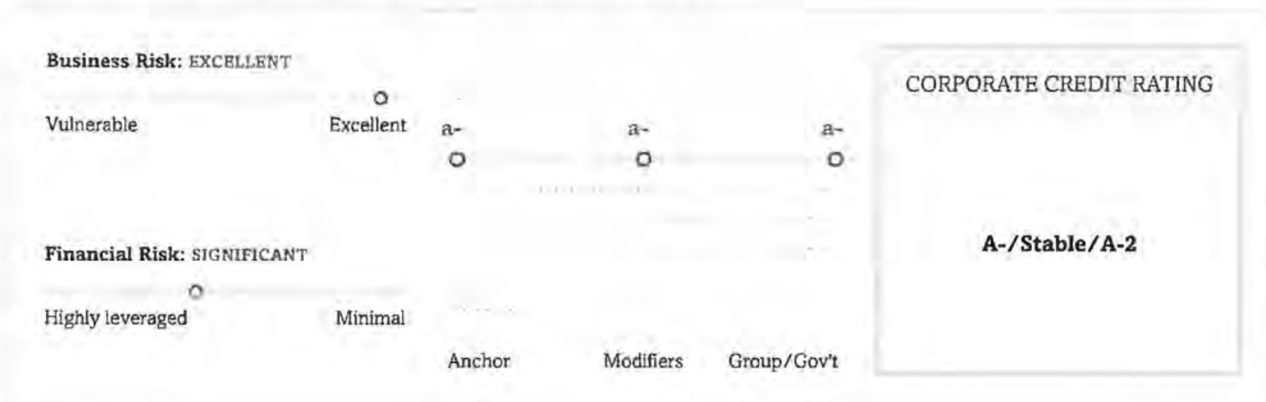
Summary:

Louisville Gas & Electric Co.



Rationale

Business Risk: Excellent	Financial Risk: Significant
• Regulated vertically integrated electric and natural gas distribution utility. • Operations under constructive and credit-supportive regulatory framework in Kentucky. • Medium-size service territory lacking diversity with relatively small customer base.	• Core credit ratios support a significant financial risk profile assessment using medial volatility financial ratio benchmarks. • Elevated capital expenditure program, with focus on environmental compliance spending, leads to negative discretionary cash flow. • Balanced capital structure supports overall credit profile.

Outlook: Stable

The stable rating outlook on Louisville Gas & Electric Co. (LG&E) reflects our rating outlook on its parent, PPL Corp. (PPL), because we view LG&E as a core subsidiary of its parent. The stable outlook on PPL is based on the company's regulated utility strategy that leads to very low business risk and credit metrics on the lower end of the significant financial risk profile range. Under our base-case scenario we expect that funds from operations (FFO) to debt will range from 13%-14% while debt to EBITDA will remain elevated at over 5x.

Downside scenario

We could lower the ratings on PPL and its subsidiaries, including LG&E, if core credit ratios weaken such that FFO to debt is below 13% on a consistent basis over the next 12 to 18 months, while maintaining the current level of business risk.

Upside scenario

Given our assessment of business risk and our base-case scenario for financial performance, we do not anticipate higher ratings during the outlook period. However, higher ratings would largely depend on PPL achieving FFO to debt of more than 18% on a consistent basis over the next 12 to 18 months, while maintaining the current level of business risk.

Our Base-Case Scenario

Assumptions

- Gross margins growth of mid-to-high-single digits, primarily driven by anticipated base rate increases and timely recovery of planned environmental compliance costs.
- Capital spending of about $450 million to $550 million annually, mainly for upgrading generation to comply with environmental regulations.
- Discretionary cash flow to remain negative due to higher capital expenditures and dividends.

Key Metrics

	2015A	2016E	2017E
FFO/debt (%)	23.5	20-22	20-22
Debt/EBITDA (x)	3.8	3.5-4	3.5-4

A--Actual. E—Estimate. FFO—Funds from operations.

Business Risk: Excellent

We assess LG&E's business risk profile based primarily on the company's regulated integrated electric utility and natural gas distribution operations under the generally constructive regulatory framework in Kentucky.

LG&E has limited scale, scope, and diversity, serving a relatively small customer base of about 400,000 electric and about 320,000 natural gas customers in Louisville and surrounding areas. The customer base consists largely of residential and commercial customers, insulating the company from fluctuations in demand and providing stability to the company's cash flows. Our assessment also accounts for the modest operating diversity of the company due to its electric and natural gas operations.

The company has about 3,000 megawatts of generation capacity, which has higher operating risk than T&D operations. The company has been upgrading its coal-fired generation plants to comply with environmental regulations. While the capital costs of these upgrades are significant, spending can be recovered through an environmental cost recovery mechanism which limits regulatory lag and is supportive of the credit profile. Under the regulation of the Kentucky Public Service Commission (PSC), the company benefits from other mechanisms such as a gas line tracker and a pass-through fuel cost mechanism. These mechanisms increase the stability of the company's returns.

Moreover, the company's low-cost coal-fired generation and efficient operations contribute to overall competitive rates for customers.

Financial Risk: Significant

Under our base-case scenario, we project LG&E's core ratios will remain at the higher end of significant category, with FFO to debt ranging from 20%-22% and debt to EBITDA that remains about 3.5x. Over the next few years, we expect credit measures to benefit from use of regulatory mechanisms to recover its invested capital.

We base our assessment of LG&E's financial risk on the medial volatility financial ratio benchmarks, reflecting the company's low-risk regulated electric T&D and natural gas distribution operations, which is partially offset by the relatively higher risk regulated generation.

Liquidity: Adequate

We assess LG&E's liquidity as adequate to cover its needs over the next 12 months. We expect that the company's liquidity sources will exceed its uses by 1.1x or more, the minimum threshold for an adequate designation under our criteria and that the company will also meet our other requirements for such a designation.

We expect that LG&E's liquidity will benefit from stable cash flow generation, a $500 million revolving credit facility, sufficient liquidity support provided by the parent to meet ongoing needs through an intercompany money pool and manageable debt maturities over the next few years.

Other Credit Considerations

Our assessment of modifiers does not affect the anchor score.

Group Influence

LG&E is subject to our group rating methodology criteria. We assess LG&E as a core subsidiary of parent PPL Corp. because it is highly unlikely to be sold, is integral to the group's overall strategy, possesses significant management commitment, is a significant contributor to the group, and is closely linked to the parent's reputation. Moreover, there are no meaningful insulation measures in place that protect LG&E from its parent. As a result, the issuer credit rating on LG&E is 'A-', in line with the group credit profile of 'a-'.

Ratings Score Snapshot

Corporate Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Excellent

Financial risk: Significant

- **Cash flow/Leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/Portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-
- **Entity status within group:** Core (no impact)

Recovery Analysis/Issue Ratings

We assign recovery ratings to first-mortgage bonds (FMB), which can result in issue ratings being notched above an issuer credit rating on a utility depending on the rating category and the extent of the collateral coverage. The FMBs issued by U.S. utilities are a form of "secured utility bond" (SUB) that qualify for a recovery rating as defined in our criteria (see "Collateral Coverage And Issue Notching Rules for '1+' And '1' Recovery Ratings on Senior Bonds Secured by Utility Real Property," published Feb. 14, 2013).

The recovery methodology is supported by the ample historical record of 100% recovery for secured bondholders in utility bankruptcies in the U.S. and our view that the factors that enhanced those recoveries (limited size of the creditor class and the durable value of utility rate-based assets during and after a reorganization given the essential service provided and the high replacement cost) will persist.

Under our SUB criteria, we calculate a ratio of our estimate of the value of the collateral pledged to bondholders relative to the amount of FMBs outstanding. FMB ratings can exceed an issuer credit rating on a utility by up to one notch in the 'A' category, two notches in the 'BBB' category, and three notches in speculative-grade categories, depending on the calculated ratio.

LG&E's FMBs benefit from a first-priority lien on substantially all of the utility's real property owned or subsequently acquired. Collateral coverage of over 1.5x supports a recovery rating of '1+' and an issue rating one notch above the issuer credit rating.

The short-term rating on LG&E is 'A-2', based on its issuer credit rating of 'A-' and assessment of adequate liquidity.

Related Criteria And Research

Related Criteria

- Criteria - Corporates - General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- Criteria - Corporates - General: Corporate Methodology, Nov. 19, 2013
- General Criteria: Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Criteria - Corporates - Utilities: Collateral Coverage And Issue Notching Rules For '1+' And '1' Recovery Ratings On Senior Bonds Secured By Utility Real Property, Feb. 14, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- Use of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Corporates - General: 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	a-	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 267

Responding Witness: Daniel K. Arbough

Q-267. Provide the corporate credit and bond ratings assigned to PPL and Louisville Gas & Electric since the year 2010 by S&P, Moody's, and Fitch. For any change in the credit and/or bond rating, provide a copy of the associated report.

A-267. The corporate credit and bond ratings assigned to LG&E and PPL are provided below. Please see attached for a copy of the associated reports issued prior to January 1, 2015. Please see response to AG 1-266 for a copy of the associated reports issued after January 1, 2015.

LG&E Credit Ratings

Date	Moody's		S&P		Fitch	
	Issuer/Corp. Credit Rating	Secured Debt Rating	Issuer/Corp. Credit Rating	Secured Debt Rating	Issuer/Corp. Credit Rating	Secured Debt Rating
10/25/2010	**Baa1**	N/A	BBB+	N/A	**A-**	**A+**
11/8/2010	Baa1	N/A	BBB+	**A**	A-	A+
11/9/2010	Baa1	**A2**	BBB+	A	A-	A+
3/2/2011	Baa1	A2	**BBB**	**A-**	A-	A+
1/31/2014	**A3**	**A1**	BBB	A-	A-	A+
1/10/2015	A3	A1	BBB	A-	**Ratings Withdrawn**	
6/1/2015	A3	A1	**A-**	**A**		

*Fitch did not provide a rating for LG&E until October 25, 2010.

PPL Corp. Credit Ratings

Date	Issuer/Corp. Credit Rating		
	Moody's	S&P	Fitch
4/28/2010	**Baa3**	BBB	BBB+
10/27/2010	Baa3	**BBB+**	BBB+
3/2/2011	Baa3	**BBB**	BBB+
1/10/2015	Baa3	BBB	**Ratings Withdrawn**
5/1/2015	**Baa2**	BBB	
6/1/2015	Baa2	**A-**	

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's downgrades PPL and PPL Electric, outlook stable

Global Credit Research - 28 Apr 2010

Approximately $1.3 billion of rated instruments affected

New York, April 28, 2010 -- Moody's Investors Service (Moody's) downgraded the long-term unsecured ratings of PPL Corporation (PPL: Issuer Rating to Baa3 from Baa2), and its subsidiaries PPL Electric Utilities Corporation (PPL EU: senior unsecured to Baa2 from Baa1), and PPL Capital Funding, Inc. (PPL Capital: senior unsecured guaranteed by PPL to Baa3 from Baa2); the A3 rating for PPL EU's secured debt, and its Prime-2 rating for commercial paper are affirmed. The outlook for PPL, PPL EU, and PPL Capital is stable. The ratings of PPL's subsidiary PPL Energy Supply (PPL Supply: Baa2 senior unsecured) are affirmed and the outlook remains stable.

The rating actions follow PPL's announced agreement to acquire E.ON U.S. LLC (E.ON U.S.) and its subsidiaries Louisville Gas & Electric Company (LG&E) and Kentucky Utilities Company (KU), and while reflective of the announced transaction, are driven more by weakening financial metrics and the negative outlooks that had been in place for PPL EU and PPL for the past year.

On April 28, 2010, PPL announced that it had reached a definitive agreement with E.ON AG to acquire E.ON U.S, the parent company of LG&E and KU, two regulated utilities with operations principally in Kentucky. The transaction values E.ON U.S. at approximately $7.6 billion, including the assumption of $925 million of existing tax-exempt debt and the repayment of E.ON AG intercompany debt. Permanent financing for the transaction will include a combination of common equity, utility first mortgage bonds, utility holding company bonds, hybrid securities and cash on hand. We anticipate that PPL will arrange the permanent financing in a balanced manner that will be supportive of its Baa3 Issuer Rating.

PPL's Baa3 Issuer Rating considers the additional regulatory scale, diversity and cash flow stability that are likely to result from its planned acquisition of E.ON US. On a pro-forma basis, we anticipate that over 50% of PPL's assets and cash flows would be associated with regulated operations; absent the transaction, we would expect regulated contributions to remain significantly below 50%. The rating also considers the challenges the company is facing as it transitions to a fully competitive market in its Pennsylvania service territory where significant utility investment is needed while its wholesale generation business continues to operate within weakened commodities markets. The rating reflects pro-forma consolidated credit profile and cash flow credit metrics that we anticipate will remain within ranges appropriate for the rating. The Baa3 ratings for PPL and PPL Capital also recognize their structurally subordinate position relative to the Baa2 senior unsecured debt of PPL Supply and PPL EU, and to likely holding company and operating company debt at the Kentucky utilities.

The downgrade for PPL EU reflects our continued expectation that beginning in 2010, the company's cash flow credit metrics will decline dramatically from their recent levels and will remain toward the lower end of the ranges indicated in Moody's August 2009 Rating Methodology for Regulated Electric and Gas Utilities (the Regulated Methodology) rated Baa for the foreseeable future. The expected decline in metrics comes as PPL EU implements market rates for generation while simultaneously incurring increased expenditures for capital investment to support and maintain the reliability of its aging distribution and transmission systems. As a result, PPL EU's debt burden will increase, and cash flow coverage of debt and debt service is expected to be dramatically reduced. For example, for the foreseeable future, the ratio of cash flow from operations excluding changes in working capital (CFO Pre -- WC) to debt, calculated in accordance with Moody's standard analytical adjustments, is expected to remain in the low-to-mid teens, and the ratio of CFO Pre -- WC plus interest to interest is anticipated to remain around three times.

The affirmation of the A3 rating for the senior secured debt at PPL EU reflects its priority position within PPL EU's capital structure and follows Moody's August 2009 implementation of wider notching between the vast majority of ratings for senior secured and senior unsecured debt ratings for investment grade regulated utilities. Issuers with negative outlooks were excluded from the August implementation.

The affirmation of the Baa2 senior unsecured ratings for PPL Supply considers the relatively strong market and competitive position that results from its significant base-load generation portfolio located primarily near load serving entities within the highly liquid and transparent PJM market. The affirmation also recognizes that 2010 is the first year the company is able to sell power produced by its Pennsylvania generation resources at market rates. For 2010 and beyond, we anticipate increased volatility of cash flows, mitigated to some extent by PPL Supply's hedging strategy; however, we also anticipate a strengthening of its cash flow credit metrics commensurate with the company's increased business risk. For example, we anticipate the ratio of CFO Pre-WC to debt (excluding the debt and cash flows associated with its U.K. distribution utilities) to remain above 25%. PPL Supply's published consolidated credit metrics will continue to be impacted by the ownership of its U.K. distribution utilities, which benefit from reasonably stable cash flow, but also employ leverage commensurate with their regulated network activities. We anticipate PPL Supply's consolidated published ratio of CFO Pre-WC to debt will remain above 20%.

The stable outlook for PPL EU reflects our expectation that PPL EU's financial metrics will generally remain within the ranges indicated for electric distribution and transmission utilities rated Baa. The outlook also assumes that PPL EU will finance its significant capital expenditure program in a manner that is consistent with maintaining its current credit profile and that it will continue to successfully manage its regulatory relationships as Pennsylvania continues its statewide transition to market rates.

The stable outlooks for PPL Supply, PPL Capital, and PPL reflect our view that the planned acquisition of E.ON U.S. will be financed in a balanced manner that is consistent with PPL's Baa3 Issuer rating. The stable outlooks also assume that in 2010 and beyond, PPL Supply's low-cost, strategically placed, primarily base load generating assets will generate increased cash flows, and that PPL will continue to seek to mitigate the volatility of these market based cash flow by use of disciplined hedging strategies. In addition, the stable outlooks assume that the transition to the competitive electricity market in Pennsylvania will continue to proceed relatively smoothly and that PPL EU's planned capital expenditures will be financed in a manner that is supportive of its credit quality.

The principal methodology used in rating PPL EU, PPL and PPL Capital was Rating Methodology: Regulated Electric and Gas Utilities, published August 2009 and available on www.moodys.com in the Rating Methodologies sub-directory under the Research and Ratings tab. The principal methodology used in rating PPL Supply was Rating Methodology: Unregulated Utilities and Power Companies, published in August 2009 and also available on www.moodys.com in the Rating Methodologies sub-directory under the Research & Ratings tab. Other methodologies and factors that may have been considered in the process of rating these issuers can also be found in the Rating Methodologies sub-directory on Moody's website.

Moody's last rating action on PPL EU, PPL, PPL Capital and PPL Supply occurred May 11, 2009 the outlooks of PPL EU, PPL and PPL Capital were revised to negative from stable and the ratings of PPL Supply were affirmed with a stable outlook.

PPL is a diversified energy holding company headquartered in Allentown, Pennsylvania. PPL EU is a regulated transmission and distribution utility; PPL Supply is a holding company engaged primarily in non-regulated generation and marketing of power in the U.S. and the regulated delivery of electricity in the U.K., PPL Capital is a financing subsidiary of PPL - its debt is guaranteed by PPL.

Downgrades:

PPL Corporation

Issuer Rating, Downgraded to Baa3 from Baa2

PPL Capital Funding, Inc.

Junior Subordinated Regular Bond/Debenture, Downgraded to Ba1 from Baa3

Multiple Seniority Shelf, Downgraded to (P)Baa3, (P)Ba1 from (P)Baa2, (P)Baa3

Senior Unsecured Regular Bond/Debenture, Downgraded to Baa3 from Baa2

PPL Electric Utilities Corporation

Issuer Rating, Downgraded to Baa2 from Baa1

Multiple Seniority Shelf, Downgraded to (P)Ba1 from (P)Baa3

Preferred Stock, Downgraded to Ba1 from Baa3

Senior Unsecured Bank Credit Facility, Downgraded to Baa2 from Baa1

Senior Unsecured Revenue Bonds (Lehigh County Industrial Development Authority), Downgraded to Baa2 from Baa1

Outlook Actions:

PPL Corporation

Outlook, Changed To Stable From Negative

PPL Capital Funding, Inc.

Outlook, Changed To Stable From Negative

PPL Electric Utilities Corporation

Outlook, Changed To Stable From Negative

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Rating Action: Moody's downgrades the Issuer Ratings for E.ON U.S. and its subsidiaries

Global Credit Research - 25 Oct 2010

New York, October 25, 2010 -- Moody's Investors Service today downgraded the Issuer Rating of E.ON U.S. LLC (E.ON U.S.) to Baa2 from A3 and the Issuer Ratings of its two utility subsidiaries, Kentucky Utilities Company (KU) and Louisville Gas and Electric Company (LG&E), to Baa1 from A2. Moody's also downgraded KU and LG&E's short-term ratings for variable rate demand debt to Prime-2 from Prime-1. These rating actions conclude the review for possible downgrade that commenced on April 29, 2010. The rating outlooks for E.ON U.S., KU and LG&E are stable.

Separately, Moody's confirmed KU and LG&E's outstanding tax-exempt debt at A2. The rating confirmation considers that, in the case of LG&E, the formerly unsecured debt has been secured with first mortgage bonds provided to the trustee and, while KU's bonds are currently unsecured, the utility intends to secure them in a similar manner over the next week. It is Moody's policy to generally rate first mortgage bonds of investment-grade rated utilities two alpha-numeric ratings higher than its Issuer Rating or senior unsecured debt rating.

RATINGS RATIONALE

The downgrade of E.ON U.S., KU and LG&E's Issuer Ratings follows receipt of several regulatory approvals, most notably from the Kentucky Public Service Commission (KPSC), relating to the proposed sale of E.ON U.S. by E.ON AG (E.ON: A2 senior unsecured) to PPL Corp. (PPL: Baa3 senior unsecured) for approximately $7.625 billion.

While approval from the FERC remains outstanding, we believe there is a high probability that it will be received and that the transaction will close in a matter of weeks. Upon closing of the transaction, E.ON U.S. will become a subsidiary of PPL and will be renamed LG&E and KU Energy LLC (LKE), with KU and LG&E remaining as distinct and separate operating entities. In the unlikely scenario that the merger is not consummated, the Issuer Ratings for E.ON U.S., LG&E and KU would likely revert back to their respective prior assigned levels.

"E.ON's ownership of E.ON U.S., KU and LG&E was an important factor supporting their prior respective Issuer Ratings" said Moody's Vice President Scott Solomon. "Specifically, E.ON's size, scale and credit profile provided liquidity and financial flexibility in the form of significant inter-company funding along with a liberal dividend policy that strengthened the related company's respective financial position and provided ratings lift".

Today's downgrades were triggered by the expected near-term transfer of ownership and the elimination of any ratings lift. E.ON U.S., KU and LG&E's ratings, however, are well positioned within their newly assigned rating categories and reflective of sound financial metrics and a generally supportive regulatory environment that provides for above-average cost recovery. Fluctuations in KU and LG&E's cost of fuel and purchased power, for instance, are recoverable with minimal regulatory lag while investments and costs borne by the utilities in order to remain compliant with the Clean Air Act are recoverable through an environmental surcharge mechanism.

KU and LG&E's ratio of consolidated cash flow before changes in working capital (CFO pre W/C) to debt and CFO pre-W/C interest coverage for the twelve months ended June 30, 2010, were each approximately 20% and 5.6 times, respectively. Financial metrics for both utilities are expected to trend modestly upward over the near-term due in large part to rate increases that became effective in August 2010. That being said, both utilities are expected to increase their respective dividend payments under PPL ownership. E.ON U.S. is expected to generate consolidated CFO pre-W/C to debt metrics in the mid-to-upper teens and CFO pre-W/C interest coverage above 4 times, placing it firmly in the mid-Baa rating category.

KU and LG&E, combined, had approximately $2.6 billion of long-term debt outstanding at December 31, 2009. Of this amount, approximately 70% was intercompany debt provided by E.ON affiliates (the remaining 30% is tax-exempt debt that will remain outstanding). While the absolute amount of debt at KU and LGE is not expected to be impacted by the proposed acquisition, PPL anticipates ultimately refinancing the intercompany debt with first mortgage bond debt offerings at KU and LG&E and senior unsecured debt at LKE (the renamed

E.ON U.S.)

Moody's Issuer Ratings are an opinion of the ability of an entity to honor its senior unsecured financial obligations. Specific debt issues may be rated differently and are considered unrated unless rated by Moody's. That being said, it is Moody's expectation that any debt offering by LKE would likely be rated Baa2.

The KPSC's approval of the acquisition included two commitments affecting rates. The first places a moratorium on any base rate increases by KU and LG&E until 1/1/13. The second provision establishes a mechanism under which earnings at the utilities in excess of a 10.75% ROE will be shared equally between ratepayers and shareholders. The agreement has no impact on the utilities' ability to seek rate adjustments through their existing fuel and environmental cost adjustment mechanisms.

The stable outlook considers the modest expected improvement in financial metrics over the near-term and the supportive regulatory environment in which the utilities operate.

Upward pressure may materialize for KU and LG&E if they achieve financial metrics such as CFO pre-WC to debt in excess of 25% and retained cash flow to debt of greater than 17% on a sustainable basis. LKE's rating may be upgraded if it achieves consolidated CFO pre-WC to debt in excess of 19% on a sustainable basis.

KU, LG&E and LKE's ratings could be downgraded should the utilities encounter unexpected problems integrating with PPL or if unexpected changes are made to the regulatory compact that currently provides for timely recovery of costs. Financial metrics that may trigger downward rating pressure include, for KU and LG&E, ratios of CFO pre-WC to debt of below 16% or, in the case of LKE, below 13%.

The principal methodology used in rating E. ON U.S. LLC was Regulated Electric and Gas Utilities rating methodology published in August 2009. Other methodologies and factors that may have been considered in the process of rating this issuer can also be found on Moody's website.

E.ON U.S. LLC is headquartered in Louisville, Kentucky.

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Please see the Credit Policy page on Moodys.com for the methodologies used in determining ratings, further information on the meaning of each rating category and the definition of default and recovery.

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CORRECTION - FITCH ASSIGNS EXPECTED RTGS TO KY UTILITIES CO., LOUISVILLE G&E AND LG&E AND KU ENERGY

Fitch Ratings-New York-04 November 2010: (This is a correction for a release issued on Oct. 25, 2010. It amends the expected senior unsecured ratings for both Louisville Gas and Electric Company and Kentucky Utility Company to 'A'.In addition, the Issuer Default Ratings and short-term IDRs for all entities are now final and the Rating Outlooks Stable.)

Fitch Ratings expects to assign the ratings listed below to Kentucky Utilities Company (KU), Louisville Gas and Electric Company (LG&E), and LG&E and KU Energy LLC (currently E. ON U.S) following the close of PPL Corp.'s (Issuer Default Rating [IDR] 'BBB') acquisition of E.ON U.S. The expected ratings are as follows:

LG&E and KU Energy LLC
--Issuer Default Rating (IDR) 'BBB+';
--Senior unsecured debt 'BBB+';
--Short-term IDR 'F2'.

Kentucky Utilities Co.
--IDR 'A-';
--Secured debt 'A+';
--Senior unsecured debt 'A';
--Short-term IDR 'F2'.

Louisville Gas and Electric Co.
--IDR 'A-';
--Secured debt 'A+';
--Senior unsecured debt 'A';
--Short-term IDR 'F2'.

The proposed ratings reflect the currently sound credit quality of the two regulated utilities, PPL's balanced financing plan for completing the acquisition, constructive regulatory policies in Kentucky and the Kentucky Public Service Commission's (PSC) track record for timely rate decisions. Constructive regulatory policies include a monthly fuel adjustment clause and an environmental cost recovery (ECR) mechanism. The ECR mechanism substantially reduces the environmental risks associated with the companies' coal-fired generating portfolios. Regulatory statutes also include the inclusion of construction work in progress (CWIP) in rate base. Consequently, the utilities' investment in Trimble County unit 2 (TC2), a 760 mw coal plant expected to enter commercial operation by year-end, is already reflected in rate base. Moreover, the majority of its non-fuel operating costs were recognized in rates in the July 2010 rate order, which relied on a test year ended Oct. 31, 2009, at which time TC2 was already in testing mode and fully staffed. In July 2010, the two utilities each received constructive rate decisions from the Kentucky PSC that will enhance earnings and cash flow. The rate decisions were issued six months after the companies' filed their rate increase requests following a settlement agreement with intervenors.

The primary credit concerns, other than exposure to changing environmental regulations, is a provision in the change of control settlement that prohibits the companies from seeking a base rate adjustment that would be effective prior to Jan. 1, 2013 (excluding fuel and ECR adjustments), which will require the company to absorb cost increases in the interim, and the delay in commercial operation of TC2. Burner malfunctions and a transformer failure occurred during commissioning and testing activity of TC2 conducted in the second and third quarter of 2010 causing a delay in TC2 commercial operation. The unit is now expected to enter commercial operation by year end. Because TC2 was constructed with a fixed price contract with liquidated damages, the two utilities are not expected to incur any significant additional capital costs from the start-up delay.

On April 28, 2010, E.ON AG entered into a definitive agreement to sell PPL Corp. (PPL) its equity interests in E.ON U.S. LLC, the parent company of LG&E and KU. The cash purchase price, excluding the assumption of $925 million of pollution control bonds, is approximately $6.7 billion. In June 2010, PPL issued an aggregate of $3.6 billion of common equity and hybrid securities to complete the equity and hybrid security portion of the acquisition financing plan, including $1.15 billion of equity units and $2.484 billion of common equity (net proceeds of $1.116 billion and $2.409 billion, respectively). The remaining cash purchase price of approximately $3.175 billion will be funded with a draw on PPL's existing credit facility, to be repaid with the proceeds of subsidiary debt to be issued after closing the transaction and cash. Management has indicated it plans to issue approximately $2.1 billion of first mortgage bonds at the two utilities and to retire a similar amount of existing inter-company borrowings. Consequently, debt levels should not be meaningfully different from the June 30, 2010 levels and going forward leverage and interest coverage measures should benefit from recently implemented rate increases as well as accessing the capital markets during a period of exceptionally low interest rates. Planned debt financing at LG&E and KU Energy LLC of approximately $800 million is well below the existing parent inter-company borrowings of more than $2 billion.

PPL expects to close the acquisition in the fourth quarter of 2010. On Sept. 2, 2010, PPL reached a settlement agreement with all intervening parties in its change of control application in Kentucky. In the settlement, PPL agreed not to raise base rates before Jan. 1, 2013 (excluding fuel and ECR adjustments). Rate increases that took effect on Aug. 1, 2010 will remain in place. The change of control agreement also provides for 50/50 sharing of any earnings above a 10.75% ROE. On Sept. 30, 2010, the Kentucky PSC approved the proposed acquisition subject to PPL's acceptance of all conditions. State regulators in Tennessee and Virginia have also approved the merger. Other required approvals include the Federal Energy Regulatory Commission (FERC). Pennsylvania Public Utility Commission (PUC) approval is not required.

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Nov. 24, 2009)
--'Credit Rating Guidelines for Regulated utility Companies' (July 31, 2007)
--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines'

(Aug. 22, 2007)

Applicable Criteria and Related Research:
Corporate Rating Methodology
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=546646
Credit Rating Guidelines for Regulated Utility Companies
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=334652
U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=338030

FITCH ASSIGNS EXPECTED RATINGS TO KENTUCKY UTILITIES CO., LOUISVILLE G&E AND LG&E AND KU ENERGY LLC

Fitch Ratings-New York-25 October 2010: Fitch Ratings expects to assign the ratings listed below to Kentucky Utilities Company (KU), Louisville Gas and Electric Company (LG&E), and LG&E and KU Energy LLC (currently E. ON U.S) following the close of PPL Corp.'s (Issuer Default Rating [IDR] 'BBB') acquisition of E.ON U.S. The expected ratings are as follows:

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--Issuer Default Rating (IDR) 'BBB+';
--Senior unsecured debt 'BBB+';
--Short-term IDR 'F2'.

Kentucky Utilities Co.
--IDR 'A-';
--Secured debt 'A+';
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--Short-term IDR 'F2'.

Louisville Gas and Electric Co.
--IDR 'A-';
--Secured debt 'A+';
--Senior unsecured debt 'BBB+';
--Short-term IDR 'F2'.

The proposed ratings reflect the currently sound credit quality of the two regulated utilities, PPL's balanced financing plan for completing the acquisition, constructive regulatory policies in Kentucky and the Kentucky Public Service Commission's (PSC) track record for timely rate decisions. Constructive regulatory policies include a monthly fuel adjustment clause and an environmental cost recovery (ECR) mechanism. The ECR mechanism substantially reduces the environmental risks associated with the companies' coal-fired generating portfolios. Regulatory statutes also include the inclusion of construction work in progress (CWIP) in rate base. Consequently, the utilities' investment in Trimble County unit 2 (TC2), a 760 mw coal plant expected to enter commercial operation by year-end, is already reflected in rate base. Moreover, the majority of its non-fuel operating costs were recognized in rates in the July 2010 rate order, which relied on a test year ended Oct. 31, 2009, at which time TC2 was already in testing mode and fully staffed. In July 2010, the two utilities each received constructive rate decisions from the Kentucky PSC that will enhance earnings and cash flow. The rate decisions were issued six months after the companies' filed their rate increase requests following a settlement agreement with intervenors.

The primary credit concerns, other than exposure to changing environmental regulations, is a provision in the change of control settlement that prohibits the companies from seeking a base rate adjustment that would be effective prior to Jan. 1, 2013 (excluding fuel and ECR adjustments), which will require the company to absorb cost increases in the interim, and the delay in commercial operation of TC2. Burner malfunctions and a transformer failure occurred during commissioning and testing activity of TC2 conducted in the second and third quarter of 2010 causing a delay in TC2 commercial operation. The unit is now expected to enter commercial operation by year end. Because TC2 was constructed with a fixed price contract with liquidated damages, the two utilities are not expected to incur any significant additional capital costs from the start-up delay.

On April 28, 2010, E.ON AG entered into a definitive agreement to sell PPL Corp. (PPL) its equity interests in E.ON U.S. LLC, the parent company of LG&E and KU. The cash purchase price, excluding the assumption of $925 million of pollution control bonds, is approximately $6.7 billion.

In June 2010, PPL issued an aggregate of $3.6 billion of common equity and hybrid securities to complete the equity and hybrid security portion of the acquisition financing plan, including $1.15 billion of equity units and $2.484 billion of common equity (net proceeds of $1.116 billion and $2.409 billion, respectively). The remaining cash purchase price of approximately $3.175 billion will be funded with a draw on PPL's existing credit facility, to be repaid with the proceeds of subsidiary debt to be issued after closing the transaction and cash. Management has indicated it plans to issue approximately $2.1 billion of first mortgage bonds at the two utilities and to retire a similar amount of existing inter-company borrowings. Consequently, debt levels should not be meaningfully different from the June 30, 2010 levels and going forward leverage and interest coverage measures should benefit from recently implemented rate increases as well as accessing the capital markets during a period of exceptionally low interest rates. Planned debt financing at LG&E and KU Energy LLC of approximately $800 million is well below the existing parent inter-company borrowings of more than $2 billion.

PPL expects to close the acquisition in the fourth quarter of 2010. On Sept. 2, 2010, PPL reached a settlement agreement with all intervening parties in its change of control application in Kentucky. In the settlement, PPL agreed not to raise base rates before Jan. 1, 2013 (excluding fuel and ECR adjustments). Rate increases that took effect on Aug. 1, 2010 will remain in place. The change of control agreement also provides for 50/50 sharing of any earnings above a 10.75% ROE. On Sept. 30, 2010, the Kentucky PSC approved the proposed acquisition subject to PPL's acceptance of all conditions. State regulators in Tennessee and Virginia have also approved the merger. Other required approvals include the Federal Energy Regulatory Commission (FERC). Pennsylvania Public Utility Commission (PUC) approval is not required.

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Additional information is available at 'www.fitchratings.com'.

Applicable Criteria and Related Research:
--'Corporate Rating Methodology' (Nov. 24, 2009)
--'Credit Rating Guidelines for Regulated utility Companies' (July 31, 2007)
--'U.S. Power and Gas Comparative Operating Risk (COR) Evaluation and Financial Guidelines' (Aug. 22, 2007)

Applicable Criteria and Related Research:
Corporate Rating Methodology
http://www.fitchratings.com/creditdesk/reports/report_frame.cfm?rpt_id=546646
Credit Rating Guidelines for Regulated Utility Companies

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October 27, 2010

Research Update:

PPL Corp. Upgraded To 'BBB+' And Off CreditWatch On Expected Closing Of E.ON Acquisition

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Research Update:

PPL Corp. Upgraded To 'BBB+' And Off CreditWatch On Expected Closing Of E.ON Acquisition

Overview

- We resolved the CreditWatch listing on diversified energy company PPL Corp. and affiliate PPL Energy Supply LLC (PPL Energy) on the expected Nov. 1, 2010, acquisition of E.ON U.S. LLC and its utility subsidiaries, Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU), for $7.625 billion.
- We are upgrading PPL and PPL Energy to 'BBB+' from 'BBB' to reflect the pro forma consolidated company's expected stronger credit profile due to a reconfigured business strategy that we expect will garner at least two-thirds of the projected operating cash flows from fully regulated utilities. The outlooks are stable.
- We are revising the outlook on utility affiliate PPL Electric Utilities (PPLEU) to stable from negative and affirming the 'A-' corporate credit rating.
- We are affirming the 'BBB+' corporate credit ratings on E.ON, LG&E, and KU. The outlooks are stable.
- We are raising the issue rating to 'A/A-2' from 'BBB+' and assigning a '1+' recovery rating on LG&E's approximately $575 million of outstanding tax-exempt pollution control bonds to reflect the addition of first mortgage bonds as collateral and their secured status.

Rating Action

On Oct. 27, 2010, Standard & Poor's Ratings Services raised the corporate credit ratings on PPL and PPL Energy to 'BBB+' from 'BBB'. At the same time, we removed the ratings from CreditWatch with positive implications, where we put them on April 28, 2010, following the acquisition announcement. The outlooks are stable. We affirmed the 'A-' rating on PPLEU and revised the outlook to stable from negative. In addition, we affirmed the 'BBB+' ratings on LG&E and KU, and their parent, E.ON U.S. The outlooks are stable. Also, we raised the ratings on LG&E's approximately $575 million of tax-exempt pollution control revenue bonds to 'A' from 'BBB+' to reflect the addition of first mortgage bonds as collateral for the duration of the bonds. For these newly collateralized bonds, we are assigning a recovery rating of '1+', reflecting our highest expectation of full recovery of principal (100% recovery) in a default scenario. Following the closing of acquisition, E.ON U.S. will change its name to LG&E and KU Energy LLC.

The upgrade reflects our opinion of an improved credit profile of the consolidated company following the acquisition closing. The inclusion of regulated LG&E and KU into the PPL portfolio is expected to contribute at least two-thirds of overall operating cash flow compared with existing majority of cash flow coming from unregulated operations. In our opinion, the excellent business risk profiles of the regulated utilities will more than offset PPL Energy's satisfactory business risk profile. This results in a pro forma strong consolidated business risk profile. We expect consolidated debt to EBITDA and debt to capital ratios to range in the significant financial risk profile category.

Rationale

For the $6.7 billion cash portion of the $7.625 billion acquisition (excluding $250 million in related transaction expenses/fees), PPL will use cash on hand, approximately $2 billion of LG&E and KU debt, and $800-$900 million of senior unsecured debt at LG&E and KU Energy LLC (intermediate holding company) that will ultimately be issued. In order to complete the acquisition, PPL will draw down its PPL Energy credit facility by about $3 billion after which it is expected to conduct permanent financing that will be used to repay the short-term outstanding debt. PPL has also issued $2.4 billion of common equity and PPL Capital Funding issued $1.1 billion of equity units that receive high equity credit under our rating criteria.

Allentown, Pa.-based PPL has about $4.7 billion of long-term debt excluding debt at PPLEU and the Western Power Distribution (WPD) group of companies. Excluding PPLEU and WPD debt, pro forma PPL debt is expected to be about $9 billion.

LG&E and KU are fully regulated vertically-integrated electric utilities serving customers in Louisville and its surrounding area. The strengths of these utilities include relatively predictable utility operations and associated cash flows, constructive regulatory environment, and competitive rates. The offsetting factor is the reliance on a fleet of mostly coal-fired generation, but the assets are up to date for current environmental requirements and have a significant proportion of future capital spending through 2014 approved in rates.

For PPL Energy, the expiration of PPLEU's long-term provider-of-last-resort (POLR) supply contract, which hitherto provided cash flow stability, has increased volatility of realized margins and liquidity requirements for collateral. While PPL Energy's cash flow is expected to improve because it has contracted much of its 2010 and 2011 generation at substantially higher prices than in 2009, Ratings also reflect a backward-dated EBITDA profile and execution risks associated with PPL Energy's ability to achieve stronger financial metrics and counter the higher business risk that will come attendant with its greater merchant exposure. Market fundamentals also have weakened. The expected tightening of reserve margins in the PJM Interconnection has not materialized because of the economic slowdown. Some drop in demand has depressed RPM prices (rest of RTO price) as well as auctions/RFPs of neighboring utilities (FirstEnergy, Allegheny). We consider PPL's financial risk profile to be significant, with adjusted financial measures expected to be in line for the rating. We expect that financial measures will continue at current levels as full cost recovery following the acquisition. We expect consolidated debt to EBITDA and debt to capital ratios to range in the significant financial risk profile category. Projected FFO to debt in the 22%-23% range is expected to support ratings at the higher end of the 'BBB' category.

Short-term credit factors

The short-term rating on PPL and affiliates is 'A-2'. Standard & Poor's views PPL's liquidity as strong under its corporate liquidity methodology, which categorizes liquidity in five standard descriptors. Projected sources of liquidity, mainly operating cash flow and available bank lines, exceed projected uses, mainly necessary capital expenditures, debt maturities, and common dividends, by more than 1.5x. Sources over uses would be positive even after a 50% EBITDA decline. Additional factors that support the liquidity are PPL's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending, its sound bank relationships, its solid standing in credit markets, and generally prudent risk management. We will assess the pro forma liquidity of newly combined company once bank credit facilities and other short-term financing have been finalized.

Outlook

The stable outlook on PPL and its subsidiaries, and those of LG&E and KU, reflect our expectation that management will maintain a strong business profile by focusing on its regulated utilities and not increase unregulated operations beyond current levels. The outlook also reflects expectations that cash flow protection and debt leverage measures will be in line for the rating. Specifically, our baseline forecast includes FFO to total debt of about 23%, debt to EBITDA under 4x, and debt leverage to total capital of about 52%, consistent with our expectations for the 'BBB+' rating. Given the company's mostly regulated focus, we expect that PPL will avoid any meaningful rise in business risk by reaching constructive regulatory outcomes and not expand its unregulated operations. We could lower the ratings if unregulated cash flow expectations lag due to weaker demand for power in the PJM market or forecasted financial measures are not sustained at expected levels. Although unlikely over the intermediate term, we could raise ratings if the business risk profile moves further towards excellent and financial measures exceed our base line forecast on a consistent basis, including FFO to total debt in excess of 23%, debt to EBITDA below 4x, and debt to total capital around 50%.

Related Criteria And Research

- 2008 Corporate Criteria: Analytical Methodology
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded
- 2008 Corporate Criteria: Ratios And Adjustments
- Methodology And Assumptions: Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers

Ratings List

Upgraded; CreditWatch/Outlook Action

	To	From
PPL Corp.		
PPL Energy Supply LLC		
Corporate Credit Rating	BBB+/Stable/--	BBB/Watch Pos/--
PPL Capital Funding Inc		
Senior Unsecured	BBB	BBB-/Watch Pos
Junior Subordinated	BBB-	BB+/Watch Pos
PPL Capital Funding Trust I		
Preference Stock	BBB-	BB+/Watch Pos
PPL Energy Supply LLC		
Senior Unsecured	BBB+	BBB/Watch Pos

Ratings Affirmed/Outlook Action

	To	From
PPL Electric Utilities Corp		
Corporate Credit Rating	A-/Stable/A-2	A-/Negative/A-2
Senior Secured	A-	
Recovery Rating	1	
Preference Stock	BBB	
Commercial Paper	A-2	

Ratings Affirmed

E.ON U.S. LLC	
Louisville Gas & Electric Co.	
Kentucky Utilities Co.	
Corporate credit rating	BBB+/Stable/--

Upgraded	To	From
Louisville Gas & Electric Co		
$575M tax-exempt pollution control bonds	A/A-2	BBB

Rating Assigned

Louisville Gas & Electric Co.	
Recovery rating	1+

Complete ratings information is available to RatingsDirect subscribers on the Global Credit Portal at www.globalcreditportal.com and RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column

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November 8, 2010

LG&E and KU Energy LLC's Senior Unsecured Debt Rated At 'BBB', Subsidiaries' First Mortgage Bonds Rated At 'A'

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NEW YORK (Standard & Poor's) Nov. 8, 2010--Standard & Poor's Ratings Services assigned its 'BBB' rating to LG&E and KU Energy LLC's $875 million senior unsecured debt offering.

In addition, we assigned our 'A' issue-level ratings and '1+' recovery rating to Kentucky Utilities Co.'s (KU) and Louisville Gas & Electric Co.'s (LG&E) approximately $2 billion first mortgage bond offerings. The issue-level rating and recovery rating reflect our highest expectation of full recovery of principal (100%) in a default scenario since both utilities can issue new secured bonds in an amount not exceeding 66.7% of property additions.

These rating actions follow PPL Corp.'s Nov. 1, 2010, acquisition of E.ON U.S. LLC (now known as LG&E and KU Energy LLC) and utility subsidiaries LG&E and KU. Please see PPL Corp. Upgraded To 'BBB+' And Off CreditWatch On Expected Closing Of E.ON Acquisition.

RELATED CRITERIA AND RESEARCH

- 2008 Corporate Criteria: Analytical Methodology
- Criteria Methodology: Business Risk/Financial Risk Matrix Expanded
- 2008 Corporate Criteria: Ratios And Adjustments
- Methodology And Assumptions: Standard & Poor's Standardizes Liquidity Descriptors For Global Corporate Issuers

RATINGS LIST
LG&E and KU Energy LLC

Corp. credit rating	BBB+/Stable/--
Kentucky Utilities Co.	
Corp. credit rating	BBB+/Stable/A-2
Louisville Gas & Electric Co.	
Corp credit rating	BBB+/Stable/--

Ratings Assigned

LG&E and KU Energy LLC	
Senior unsecured debt due 2015 & 2020	BBB
Kentucky Utilities Co.	
First mortgage bonds due 2015, 2020 & 2040	A
Recovery rating	1+
Louisville Gas & Electric Co.	
First mortgage bonds due 2015 & 2040	A
Recovery rating	1+

Complete ratings information is available to RatingsDirect subscribers on the Global Credit Portal at www.globalcreditportal.com and RatingsDirect subscribers at www.ratingsdirect.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column.

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MOODY'S
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Rating Action: Moody's assigns ratings to LG&E, KU and parent LKE

Global Credit Research - 09 Nov 2010

Approximately $2.9 billion of debt securities affected

New York, November 09, 2010 -- Moody's Investors Service has assigned ratings of A2 to $1,500 million of first mortgage bonds issued by Kentucky Utilities Company (KU: Baa1 Issuer Rating) and $535 million of first mortgage bonds issued by Louisville Gas and Electric Company (LG&E: Baa1 Issuer Rating). Moody's also assigned a Baa2 rating to $875 million of senior unsecured notes issued by their intermediate parent holding company, LG&E and KU Energy LLC (LKE: Baa2 Issuer Rating). The rating outlooks for KU, LG&E and LKE are stable.

Assignments:

..Issuer: Kentucky Utilities Co.

....Senior Secured First Mortgage Bonds, Assigned A2

..Issuer: LG&E and KU Energy LLC

....Senior Unsecured Regular Bond/Debenture, Assigned Baa2

..Issuer: Louisville Gas & Electric Company

....Senior Secured First Mortgage Bonds, Assigned A2

RATINGS RATIONALE

Proceeds from these offerings will be used to repay intercompany debt arising from PPL Corporation's (PPL: Baa3 senior unsecured) acquisition of LKE and its subsidiaries on November 1, 2010 for approximately $7.625 billion.

KU and LG&E's Issuer Ratings are supported by their sound financial performance and the supportive regulatory environment in which they operate offset in part by a lack of fuel diversity and modestly sized service territories. It is Moody's policy to generally rate first mortgage bonds of investment-grade rated utilities two alpha-numeric ratings higher than its Issuer Rating or senior unsecured debt rating. The Baa2 rating assigned to LKE's senior unsecured debt is the same as its Issuer Rating and one-notch below KU and LG&E's Issuer Ratings due to the structural subordination of its debt to the debt issued at its utility subsidiaries.

Please refer to Moodys.com for additional research relating to KU, LG&E and LKE.

The principal methodology used in this rating was Regulated Electric and Gas Utilities published in August 2009.

PPL is a diversified energy holding company headquartered in Allentown, Pennsylvania.

REGULATORY DISCLOSURES

Information sources used to prepare the credit rating are the following: parties involved in the ratings, parties not involved in the ratings, public information, confidential and proprietary Moody's Investors Service information, and confidential and proprietary Moody's Analytics information.

Moody's Investors Service considers the quality of information available on the issuer or obligation satisfactory for the purposes of assigning a credit rating.

Moody's adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources Moody's considers to be reliable including, when appropriate, independent third-party sources. However, Moody's is not an auditor and cannot in every instance independently verify or validate information received in the rating process.

Please see ratings tab on the issuer/entity page on Moodys.com for the last rating action and the rating history.

The date on which some Credit Ratings were first released goes back to a time before Moody's Investors Service's Credit Ratings were fully digitized and accurate data may not be available. Consequently, Moody's Investors Service provides a date that it believes is the most reliable and accurate based on the information that is available to it. Please see the ratings disclosure page on our website www.moodys.com for further information.

Please see the Credit Policy page on Moodys.com for the methodologies used in determining ratings, further information on the meaning of each rating category and the definition of default and recovery.

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March 2, 2011

Research Update:

PPL Corp. Is Lowered To 'BBB' And Placed On CreditWatch Negative After Acquisition Announcement

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Research Update:

PPL Corp. Is Lowered To 'BBB' And Placed On CreditWatch Negative After Acquisition Announcement

Overview

- We lowered our ratings on diversified energy company PPL Corp. (PPL) and its affiliates PPL Energy Supply (PPL Energy), LG&E and KU Energy LLC (LKE), Louisville Gas & Electric Co. (LG&E), and Kentucky Utilities Co. (KU) to 'BBB' from 'BBB+'.
- We lowered the rating on PPL subsidiary PPL Electric Utilities (PPLEU) to 'BBB' from 'A-'.
- At the same, time we placed all the 'BBB' ratings on CreditWatch with negative implications.
- The short-term ratings on Kentucky Utilities, Louisville Gas & Electric, and PPLEU are 'A-3'.
- The downgrades and CreditWatch listing follow PPL's proposed acquisition of E.ON UK's Central Networks West PLC (CNW) and Central Networks East PLC (CNE).

Rating Action

On March 2, 2011, Standard & Poor's Ratings Services lowered the corporate credit ratings on PPL Corp. (PPL) and its affiliates PPL Energy Supply (PPL Energy), LG&E and KU Energy LLC (LKE), Louisville Gas & Electric Co. (LG&E), and Kentucky Utilities Co. (KU) to 'BBB' from 'BBB+' and placed these ratings on CreditWatch with negative implications. We also lowered the rating on PPL subsidiary PPL Electric Utilities (PPLEU) to 'BBB' from 'A-'. The ratings actions follow PPL's planned acquisition of E.ON UK's Central Networks West PLC (CNW) and Central Networks East PLC (CNE), two distribution networks in the United Kingdom. The CreditWatch listing is directly related to the execution of the financing plan for the acquisition, which includes a commitment by the company for a substantial issuance of equity. Resolution of the CreditWatch will depend on the ability of the company to complete its financing activities consistent with our expectations for the 'BBB' ratings. Allentown, Pa.-based PPL has about $12.7 billion of long-term debt, including $1.63 billion of junior subordinated notes.

The CreditWatch listing will remain until demonstrated progress on the permanent financing plan has been executed in line with our expectations. The acquisition requires large permanent financing that has attendant execution risks, and we will monitor PPL's ability to finalize this permanent financing We could remove the CreditWatch listing and assign a stable outlook if financing is consistent with our expectation. We could lower the ratings if PPL is unable to fully execute its permanent financing plan in a credit-supportive manner consistent with our expectations for 'BBB' ratings.

Rationale

PPL's purchase price of E.ON UK's Central Networks utilities includes the assumption of $800 million of public debt and cash of $5.6 billion (excluding related transaction expenses and fees) that will be funded through a combination of cash, common equity issuance at PPL, unsecured debt at CNW and CNE, and unsecured debt at an intermediate holding company (generically called UK Holdings) that will own CNW and CNE. In addition, PPL will issue equity units at PPL Capital Funding, which will likely receive high equity credit under our rating criteria. This acquisition will raise PPL's regulated cash flows to approximately 75% from the current level of 60%. Before PPL bought the Kentucky utilities, its regulated cash flows comprised less than 30%. The ratings change reflects our revisions, in accordance with our criteria, of PPL's business risk profile to excellent from strong and the company's financial risk profile to aggressive from significant.

Our revision of the business profile to exnellent reflects the addition of fully regulated distribution utilities that have credit-supportive U.K. regulation and no commodity exposure, since power for retail customers is procured by nonaffiliated retail suppliers. The Central Networks utilities are contiguous to PPL's existing U.K. utilities. After the acquisition of CNE and CNW, we expect U.K. operations to be about 30% of PPL's consolidated cash flow. With this transaction, we are viewing all of PPL's utility assets as part of a consolidated entity, whereas previously we considered only the quality of the utility's dividends to its parent. The stability of CNE and CNW along with existing utility assets in the U.K., Kentucky, and Pennsylvania, which we assess as excellent, will more than offset the business risk profile, which we assess as satisfactory, of PPL Energy's merchant generation, resulting in an excellent business profile. We expect the merchant generation business to comprise less than 25% of pro forma consolidated cash flows.

Our revision of the financial risk profile to aggressive reflects in part the company's financial policies toward acquisitions, including funding with aggressive levels of hybrid securities. Furthermore, due to the company's strategy to focus on fully regulated operations and also expand its U.K. presence, we are incorporating consolidated financial measures for PPL in our analysis. When reviewing the financial metrics, we are now including all cash flows and debt obligations from the U.K. utilities and PPLEU in PPL's financial measures. We expect consolidated financial measures, including ratios of debt to EBITDA, funds from operations (FFO) to total debt, and debt to capital, to range in the aggressive category of our financial risk profile. Debt to EBITDA should range between 4x and 5x, while we expect the percentage of FFO to debt to be in the mid-teens. These measures will support ratings at the 'BBB' level on successful completion of the permanent financing.

Short-term credit factors

Standard & Poor's currently views PPL's liquidity as strong under its corporate liquidity methodology, which categorizes liquidity in five standard descriptors. Our assessment of liquidity as strong supports PPL's 'BBB' issuer credit rating. Projected sources of liquidity--mainly operating cash flow and available bank lines--exceed projected uses--mainly necessary capital expenditures, debt maturities, and common dividends--by more than 1.5x. The ratio of sources over uses would be positive even after a 50% EBITDA decline. Additional factors that support the liquidity are PPL's ability to absorb high-impact, low-probability events with limited need for refinancing, its flexibility to lower capital spending, its sound bank relationships, its solid standing in credit markets, and its generally prudent risk management.

CreditWatch

The CreditWatch listing will remain until demonstrated progress on the permanent financing plan has been executed in line with our expectations. The acquisition requires large permanent financing that has attendant execution risks, and we will monitor PPL's ability to finalize this permanent financing We could remove the CreditWatch listing and assign a stable outlook if financing is consistent with our expectation. We could lower the ratings if PPL is unable to fully execute its permanent financing plan in a credit-supportive manner consistent with our expectations for 'BBB' ratings.

Related Criteria And Research

- "Criteria Methodology: Business Risk/Financial Risk Matrix Expanded," May 27, 2009
- "2008 Corporate Criteria: Analytical Methodology," April 15, 2008
- "2008 Corporate Criteria: Ratios And Adjustments," April 15, 2008

Ratings List

Downgraded; CreditWatch Action

	To	From
PPL Corp.		
Corporate Credit Rating	BBB/Watch Neg/--	BBB+/Stable/--
PPL Capital Funding Inc		
Senior Unsecured	BBB-/Watch Neg	BBB
Junior Subordinated	BB+/Watch Neg	BBB-
PPL Energy Supply LLC		
Corporate Credit Rating	BBB/Watch Neg/--	BBB+/Stable/--
Senior Unsecured	BBB/Watch Neg	BBB+
PPL Electric Utilities Corp.		
Corporate Credit Rating	BBB/Watch Neg/A-3	A-/Stable/A-2

Senior Secured	BBB+/Watch Neg	A-
Recovery Rating	1	1
Preference Stock	BB+/Watch Neg	BBB
Commercial Paper	A-3/Watch Neg	A-2
LG&E and KU Energy LLC		
Corporate Credit Rating	BBB/Watch Neg/--	BBB+/Stable/--
Senior Unsecured	BBB-/Watch Neg	BBB
Louisville Gas & Electric Co.		
Corporate Credit Rating	BBB/Watch Neg/--	BBB+/Stable/--
Senior Secured	A-/Watch Neg	A
Recovery Rating	1+	1+
Kentucky Utilities Co		
Corporate Credit Rating	BBB/Watch Neg/A-3	BBB+/Stable/A-2
Senior Secured	A-/Watch Neg	A
Recovery Rating	1+	1+

Complete ratings information is available to subscribers of RatingsDirect on the Global Credit Portal at www.globalcreditportal.com. All ratings affected by this rating action can be found on Standard & Poor's public Web site at www.standardandpoors.com. Use the Ratings search box located in the left column

MOODY'S
INVESTORS SERVICE

Rating Action: Moody's upgrades the ratings of PPL US utility subsidiaries and confirms the rating of PPL Corp. and LKE; rating outlook stable.

Global Credit Research - 31 Jan 2014

Approximately $10.8 Billion of Debt Affected

New York, January 31, 2014 -- Moody's Investors Service today upgraded the ratings of PPL Corporation's US utility operating subsidiaries: the rating of PPL Electric Utilities (PPLEU) was upgraded to Baa1 from Baa2 and the ratings of Louisville Gas & Electric Company (LGE) and Kentucky Utilities (KU) were upgraded to A3 from Baa1. Moody's confirmed the senior unsecured ratings of PPL Corporation (PPL) at Baa3 and of LG&E and KU Energy LLC (LKE) at Baa2. This rating action completes our review of PPL and its regulated operations initiated on November 8, 2013. The outlook for all PPL entities is stable.

The primary driver of today's positive rating action on PPL's US utility operating companies was Moody's more favorable view of the relative credit supportiveness of the US regulatory environment, as detailed in our September 2013 Request for Comment titled "Proposed Refinements to the Regulated Utilities Rating Methodology and our Evolving View of US Utility Regulation."

The review, however, did not result in a corresponding upgrade for the parent holding company PPL because the upgrades of PPL's US regulated utilities, which represent 31% of earnings, did not shift PPL's consolidated credit profile sufficiently. PPL's consolidated financial metrics are also weak for its rating category. LKE did not receive an upgrade because of the high debt level at LKE relative to the consolidated LKE. Moreover, because there is free movement of cash between PPL and LKE, PPL has a constraining effect on LKE's ratings.

RATINGS RATIONALE

The ratings of PPL and its utility subsidiaries are underpinned by regulatory environments that, while they may vary somewhat from jurisdiction to jurisdiction, are generally supportive of utility credit quality and by an energy commodity market that has alleviated some of the pressure on rates generally. Additionally, PPL's rating is reflective of the consolidated credit profile which has been transformed from a heavily merchant commodity driven and regionally focused operation, to a more diversified and mostly rate regulated platform. These positive factors are balanced against financial metrics on a consolidated basis that have been on the lower end of the range for benchmarks established for regulated utilities. As of end of third quarter 2013, PPL's CFO Pre-WC/debt averaged over the past three years is 15.5%, while the benchmark for regulated utilities in the Baa category is between 13% and 22%.

Rating Outlook

The stable outlook for PPL reflects our view that PPL's credit quality has been fortified through the growing share of its regulated business. The stable outlook also incorporates a view that the company's large capital investment will be prudently financed, to include if needed, the issuance of common equity. The unregulated generation assets' cash flow generating capacity is expected to be lower over the next several years but further downsides are moderated by hedging and its declining share to the consolidated cash flow.

What Could Change the Rating -- Up

Potential for upgrade is currently limited by its financial metrics which are weak for its ratings. Upgrade is possible if exposure to unregulated activity continue to decline while cash flow to debt ratio improves 20% or above on a sustained basis.

What Could Change the Rating - Down

While we do not foresee any particular event that would result in a negative rating action, the company's cash flow to debt credit metrics are expected to be weaker going forward due to the declining cash flow coming from its unregulated operations. As a result, the company has a smaller margin of error for a negative rating action.

The principal methodology used in this rating was Regulated Electric and Gas Utilities published in December

2013. Please see the Credit Policy page on www.moodys.com for a copy of this methodology.

Issuer: PPL Corporation

Outlook revised to stable from RUR-UP

Confirmed:

LT Issuer Rating: Baa3

Pref. Shelf ratings: (P)Ba2

Issuer: PPL Electric Utilities Corporation

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to Baa1 from Baa2

Senior unsecured to Baa1 from Baa2

Senior secured to A2 from A3

First Mortgage Bonds to A2 from A3

Preference Shelf to (P)Baa3 from (P)Ba1

Senior Secured Shelf to (P)A2 from (P)A3

Affirmed:

Commercial paper rating of P-2

Issuer: LG&E and KU Energy LLC

Outlook revised to stable from RUR-UP

Confirmed:

LT Issuer Rating: Baa2

Senior unsecured: Baa2

Senior unsecured Self: (P)Baa2

Issuer: Louisville Gas & Electric Company

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to A3 from Baa1

Senior unsecured to A3 from Baa1

Senior secured to A1 from A2

Senior secured Shelf to (P)A1 from (P)A2

Affirmed:

Commercial Paper ratings: P-2

Issuer: Kentucky Utilities Co.

Outlook revised to stable from RUR-UP

Upgraded:

LT Issuer Rating to A3 from Baa1

Senior unsecured to A3 from Baa1

Senior secured to A1 from A2

Senior secured Shelf to (P)A1 from (P)A2

Affirmed:

Commercial Paper rating: P-2

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LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 268

Responding Witness: Daniel K. Arbough

Q-268. Provide the breakdown in the expected return on pension plan assets for Louisville Gas & Electric. Specifically, provide the expected return on different assets classes (bonds, US stocks, international stocks, etc) used in determining the expected return on plan assets. Provide all associated source documents and work papers.

A-268. See the attachment to the response to Question No. 108.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 269

Responding Witness: Daniel K. Arbough

Q-269. For the past five years, provide the dates and amount of: (1) cash dividend payments made to PPL by Louisville Gas & Electric; and (2) cash equity infusions made by PPL into Louisville Gas & Electric.

A-269. See the response to PSC 2-46(b).

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 270

Responding Witness: Daniel K. Arbough

Q-270. Provide the Company's authorized and earned return on common equity for Louisville Gas & Electric over the past five years. Provide copies of all associated work papers and source documents. Provide copies of the source documents, work papers, and data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-270. See attachment 1 being provided in Excel format for the calculation of the Return on Equity (ROE) and attachments 2 and 3 for the source documents. The ROE percentage calculation is based on net income and total equity as presented in the monthly KPSC financial statements. 2016 information is not available as of the date of this response.

Attachment 1 is being provided in a separate file in Excel format.

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2011

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,059,750,303.49	$ 1,015,611,566.97	$ 44,138,736.52	4.35
Gas Operating Revenues..	304,574,421.82	302,947,355.88	1,627,065.94	0.54
Total Operating Revenues..	1,364,324,725.31	1,318,558,922.85	45,765,802.46	3.47
Fuel for Electric Generation...	360,968,393.36	368,556,326.34	(7,587,932.98)	(2.06)
Power Purchased...	74,894,547.12	54,379,718.69	20,514,828.43	37.73
Gas Supply Expenses..	161,235,625.70	169,003,608.05	(7,767,982.35)	(4.60)
Other Operation Expenses...	236,277,354.89	226,813,004.57	9,464,350.32	4.17
Maintenance..	116,359,068.55	111,701,105.08	4,657,963.47	4.17
Depreciation..	141,998,214.92	131,210,003.27	10,788,211.65	8.22
Amortization Expense...	8,133,464.03	7,726,988.90	406,475.13	5.26
Regulatory Credits...	(5,730,085.69)	(4,269,731.45)	(1,460,354.24)	(34.20)
Taxes				
Federal Income...	11,962,850.45	28,874,607.18	(16,911,756.73)	(58.57)
State Income...	8,265,532.67	6,047,167.43	2,218,365.24	36.68
Deferred Federal Income - Net...................................	52,223,724.36	27,667,005.00	24,556,719.36	88.76
Deferred State Income - Net.......................................	2,011,675.35	2,370,024.44	(358,349.09)	(15.12)
Property and Other...	28,121,583.64	22,571,623.82	5,549,959.82	24.59
Amortization of Investment Tax Credit......................	(2,805,732.00)	(2,501,774.00)	(303,958.00)	(12.15)
Loss (Gain) from Disposition of Allowances.................	(2,577.94)	(34,460.14)	31,882.20	92.52
Accretion Expense...	2,644,484.62	3,284,105.63	(639,621.01)	(19.48)
Total Operating Expenses...	1,196,558,124.03	1,153,399,322.81	43,158,801.22	3.74
Net Operating Income...	167,766,601.28	165,159,600.04	2,607,001.24	1.58
Other Income Less Deductions...................................	1,079,397.77	10,717,472.34	(9,638,074.57)	(89.93)
Income Before Interest Charges.................................	168,845,999.05	175,877,072.38	(7,031,073.33)	(4.00)
Interest on Long-Term Debt..	38,809,735.79	43,895,047.17	(5,085,311.38)	(11.59)
Amortization of Debt Expense - Net.............................	3,311,473.23	1,664,625.74	1,646,847.49	98.93
Other Interest Expenses..	2,538,484.60	2,603,013.75	(64,529.15)	(2.48)
Total Interest Charges..	44,659,693.62	48,162,686.66	(3,502,993.04)	(7.27)
Net Income..	$ 124,186,305.43	$ 127,714,385.72	$ (3,528,080.29)	(2.76)

January 26, 2012

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2012

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,069,346,402.37	$ 1,059,750,303.49	$ 9,596,098.88	0.91
Gas Operating Revenues...	254,278,399.37	304,574,421.82	(50,296,022.45)	(16.51)
Total Operating Revenues..	1,323,624,801.74	1,364,324,725.31	(40,699,923.57)	(2.98)
Fuel for Electric Generation..	385,916,157.30	360,968,393.36	24,947,763.94	6.91
Power Purchased..	52,477,768.07	74,894,547.12	(22,416,779.05)	(29.93)
Gas Supply Expenses..	114,891,748.83	161,235,625.70	(46,343,876.87)	(28.74)
Other Operation Expenses..	231,092,051.74	236,277,354.89	(5,185,303.15)	(2.19)
Maintenance...	118,770,588.91	116,359,068.55	2,411,520.36	2.07
Depreciation...	146,291,263.74	141,998,214.92	4,293,048.82	3.02
Amortization Expense...	8,836,853.38	8,133,464.03	703,389.35	8.65
Regulatory Credits..	(5,915,936.88)	(5,730,085.69)	(185,851.19)	(3.24)
Taxes				
Federal Income...	(596,880.01)	11,962,850.45	(12,559,730.46)	(104.99)
State Income...	2,588,533.28	8,265,532.67	(5,676,999.39)	(68.68)
Deferred Federal Income - Net..................................	65,478,279.30	52,223,724.36	13,254,554.94	25.38
Deferred State Income - Net......................................	5,491,332.09	2,011,675.35	3,479,656.74	172.97
Property and Other...	31,025,991.29	28,121,583.64	2,904,407.65	10.33
Amortization of Investment Tax Credit.....................	(2,847,617.48)	(2,805,732.00)	(41,885.48)	(1.49)
Loss (Gain) from Disposition of Allowances................	(693.97)	(2,577.94)	1,883.97	73.08
Accretion Expense...	2,928,135.80	2,644,484.62	283,651.18	10.73
Total Operating Expenses..	1,156,427,575.39	1,196,558,124.03	(40,130,548.64)	(3.35)
Net Operating Income...	167,197,226.35	167,766,601.28	(569,374.93)	(0.34)
Other Income Less Deductions..................................	(2,051,782.46)	1,079,397.77	(3,131,180.23)	(290.09)
Income Before Interest Charges.................................	165,145,443.89	168,845,999.05	(3,700,555.16)	(2.19)
Interest on Long-Term Debt..	36,998,262.52	38,809,735.79	(1,811,473.27)	(4.67)
Amortization of Debt Expense - Net.............................	3,302,414.80	3,311,473.23	(9,058.43)	(0.27)
Other Interest Expenses..	1,921,988.34	2,538,484.60	(616,496.26)	(24.29)
Total Interest Charges..	42,222,665.66	44,659,693.62	(2,437,027.96)	(5.46)
Net Income...	$ 122,922,778.23	$ 124,186,305.43	$ (1,263,527.20)	(1.02)

January 25, 2013

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2013

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,096,596,441.56	$ 1,069,346,402.37	$ 27,250,039.19	2.55
Gas Operating Revenues..	324,221,273.80	254,278,399.37	69,942,874.43	27.51
Total Operating Revenues..	1,420,817,715.36	1,323,624,801.74	97,192,913.62	7.34
Fuel for Electric Generation...	379,035,048.52	385,916,157.30	(6,881,108.78)	(1.78)
Power Purchased...	48,124,183.55	52,477,768.07	(4,353,584.52)	(8.30)
Gas Supply Expenses..	159,274,580.38	115,461,797.85	43,812,782.53	37.95
Other Operation Expenses...	245,282,973.20	230,522,002.72	14,760,970.48	6.40
Maintenance..	113,413,020.83	118,770,588.91	(5,357,568.08)	(4.51)
Depreciation..	139,714,329.28	146,291,263.74	(6,576,934.46)	(4.50)
Amortization Expense...	7,948,702.52	8,836,853.38	(888,150.86)	(10.05)
Regulatory Credits...	-	(5,915,936.88)	5,915,936.88	100.00
Taxes				
Federal Income...	53,107,973.69	(596,880.01)	53,704,853.70	8,997.60
State Income..	16,078,249.40	2,588,533.28	13,489,716.12	521.13
Deferred Federal Income - Net...................................	27,433,268.07	65,478,279.30	(38,045,011.23)	(58.10)
Deferred State Income - Net.......................................	(2,365,803.36)	5,491,332.09	(7,857,135.45)	(143.08)
Property and Other...	32,517,048.48	31,025,991.29	1,491,057.19	4.81
Amortization of Investment Tax Credit......................	(2,100,342.00)	(2,847,617.48)	747,275.48	26.24
Loss (Gain) from Disposition of Allowances.................	(281.66)	(693.97)	412.31	59.41
Accretion Expense...	-	2,928,135.80	(2,928,135.80)	(100.00)
Total Operating Expenses..	1,217,462,950.90	1,156,427,575.39	61,035,375.51	5.28
Net Operating Income...	203,354,764.46	167,197,226.35	36,157,538.11	21.63
Other Income Less Deductions...................................	(2,656,845.89)	(2,051,782.46)	(605,063.43)	(29.49)
Income Before Interest Charges.................................	200,697,918.57	165,145,443.89	35,552,474.68	21.53
Interest on Long-Term Debt..	36,512,116.83	36,998,262.52	(486,145.69)	(1.31)
Amortization of Debt Expense - Net.............................	3,954,651.55	3,302,414.80	652,236.75	19.75
Other Interest Expenses..	1,530,547.08	1,921,988.34	(391,441.26)	(20.37)
Total Interest Charges..	41,997,315.46	42,222,665.66	(225,350.20)	(0.53)
Net Income..	$ 158,700,603.11	$ 122,922,778.23	$ 35,777,824.88	29.11

January 27, 2014

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2014

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues	$ 1,177,644,420.47	$ 1,096,596,441.56	$ 81,047,978.91	7.39
Gas Operating Revenues	360,282,965.53	324,221,273.80	36,061,691.73	11.12
Total Operating Revenues	1,537,927,386.00	1,420,817,715.36	117,109,670.64	8.24
Fuel for Electric Generation	415,537,575.06	379,035,048.52	36,502,526.54	9.63
Power Purchased	47,842,269.20	48,124,183.55	(281,914.35)	(0.59)
Gas Supply Expenses	194,255,410.39	159,274,580.38	34,980,830.01	21.96
Other Operation Expenses	254,080,283.39	245,282,973.20	8,797,310.19	3.59
Maintenance	111,790,202.46	113,413,020.83	(1,622,818.37)	(1.43)
Depreciation	147,126,108.59	139,714,329.28	7,411,779.31	5.31
Amortization Expense	9,488,708.66	7,948,702.52	1,540,006.14	19.37
Regulatory Credits	-	-	-	-
Taxes				
Federal Income	(24,215,205.07)	53,107,973.69	(77,323,178.76)	(145.60)
State Income	9,909,705.72	16,078,249.40	(6,168,543.68)	(38.37)
Deferred Federal Income - Net	114,376,711.98	27,433,268.07	86,943,443.91	316.93
Deferred State Income - Net	5,579,077.67	(2,365,803.36)	7,944,881.03	335.82
Property and Other	34,200,411.41	32,517,048.48	1,683,362.93	5.18
Amortization of Investment Tax Credit	(1,788,780.00)	(2,100,342.00)	311,562.00	14.83
Loss (Gain) from Disposition of Allowances	(427.27)	(281.66)	(145.61)	(51.70)
Accretion Expense	-	-	-	-
Total Operating Expenses	1,318,182,052.19	1,217,462,950.90	100,719,101.29	8.27
Net Operating Income	219,745,333.81	203,354,764.46	16,390,569.35	8.06
Other Income Less Deductions	(2,494,255.41)	(2,656,845.89)	162,590.48	6.12
Income Before Interest Charges	217,251,078.40	200,697,918.57	16,553,159.83	8.25
Interest on Long-Term Debt	44,191,487.60	36,512,116.83	7,679,370.77	21.03
Amortization of Debt Expense - Net	3,417,263.90	3,954,651.55	(537,387.65)	(13.59)
Other Interest Expenses	1,510,376.49	1,530,547.08	(20,170.59)	(1.32)
Total Interest Charges	49,119,127.99	41,997,315.46	7,121,812.53	16.96
Net Income	$ 168,131,950.41	$ 158,700,603.11	$ 9,431,347.30	5.94

January 27, 2015

Louisville Gas and Electric Company
Comparative Statement of Income
December 31, 2015

	Year to Date			
	This Year Amount	Last Year Amount	Increase or Decrease Amount	%
Electric Operating Revenues...	$ 1,146,077,403.04	$ 1,177,644,420.47	$ (31,567,017.43)	(2.68)
Gas Operating Revenues..	319,521,344.26	360,282,965.53	(40,761,621.27)	(11.31)
Total Operating Revenues..	1,465,598,747.30	1,537,927,386.00	(72,328,638.70)	(4.70)
Fuel for Electric Generation...	339,561,703.42	415,537,575.06	(75,975,871.64)	(18.28)
Power Purchased...	59,903,875.93	47,842,269.20	12,061,606.73	25.21
Gas Supply Expenses..	142,271,053.03	194,255,410.39	(51,984,357.36)	(26.76)
Other Operation Expenses...	248,995,045.05	254,080,283.39	(5,085,238.34)	(2.00)
Maintenance..	114,048,757.77	111,790,202.46	2,258,555.31	2.02
Depreciation..	151,308,950.75	147,126,108.59	4,182,842.16	2.84
Amortization Expense...	10,664,306.59	9,488,708.66	1,175,597.93	12.39
Regulatory Credits...	-	-	-	-
Taxes				
Federal Income...	(13,679,234.83)	(24,215,205.07)	10,535,970.24	43.51
State Income...	3,659,700.36	9,909,705.72	(6,250,005.36)	(63.07)
Deferred Federal Income - Net...................................	113,800,565.01	114,376,711.97	(576,146.96)	(0.50)
Deferred State Income - Net.......................................	13,718,209.44	5,579,077.68	8,139,131.76	145.89
Property and Other...	37,400,046.64	34,200,411.41	3,199,635.23	9.36
Amortization of Investment Tax Credit......................	(1,338,634.00)	(1,788,780.00)	450,146.00	25.17
Loss (Gain) from Disposition of Allowances.................	(122.56)	(427.27)	304.71	71.32
Accretion Expense...	-	-	-	-
Total Operating Expenses...	1,220,314,222.60	1,318,182,052.19	(97,867,829.59)	(7.42)
Net Operating Income...	245,284,524.70	219,745,333.81	25,539,190.89	11.62
Other Income Less Deductions...................................	(3,419,679.86)	(2,494,255.41)	(925,424.45)	(37.10)
Income Before Interest Charges.................................	241,864,844.84	217,251,078.40	24,613,766.44	11.33
Interest on Long-Term Debt..	50,718,552.20	44,191,487.60	6,527,064.60	14.77
Amortization of Debt Expense - Net.............................	3,637,668.92	3,417,263.90	220,405.02	6.45
Other Interest Expenses..	2,089,050.15	1,510,376.49	578,673.66	38.31
Total Interest Charges..	56,445,271.27	49,119,127.99	7,326,143.28	14.92
Net Income..	$ 185,419,573.57	$ 168,131,950.41	$ 17,287,623.16	10.28

January 27, 2016

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2010 and 2009

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,748,839,654.01	$ 4,541,632,947.41
Less Reserves for Depreciation and Amortization......	2,043,099,789.34	1,961,838,754.75
Total...	2,705,739,864.67	2,579,794,192.66
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	18,763,173.33	17,082,757.84
Total...	19,369,338.53	17,688,923.04
Current and Accrued Assets		
Cash...	2,025,606.25	5,195,366.67
Special Deposits..	3,511,014.88	761,176.30
Temporary Cash Investments..................................	100,405.59	119.71
Accounts Receivable - Less Reserve........................	163,630,222.30	143,019,717.17
Accounts Receivable from Associated Companies.....	29,799,791.23	53,063,384.59
Materials and Supplies - At Average Cost................		
Fuel...	68,043,290.05	60,492,689.12
Plant Materials and Operating Supplies.................	29,326,915.51	29,060,730.75
Stores Expense...	4,943,153.44	4,173,782.87
Gas Stored Underground.....................................	59,956,180.78	56,183,317.06
Emission Allowances...	2,728.96	4,171.00
Prepayments..	6,832,694.11	7,825,624.32
Miscellaneous Current and Accrued Assets..............	137,908.13	1,599,269.09
Total...	368,309,911.23	361,379,348.65
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,116,651.27	3,854,161.59
Unamortized Loss on Bonds...................................	21,934,649.45	23,119,333.51
Accumulated Deferred Income Taxes......................	38,744,526.28	58,267,127.60
Deferred Regulatory Assets.....................................	344,036,363.17	319,990,094.71
Other Deferred Debits..	1,127,060.49	3,844,266.75
Total...	418,959,250.66	409,074,984.16
Total Assets...	$ 3,512,378,365.09	$ 3,367,937,448.51

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(10,454,765.91)
Retained Earnings..	827,993,251.96	755,278,866.24
Total Proprietary Capital...	1,335,909,286.41	1,252,740,134.78
Pollution Control Bonds - Net of Reacquired Bonds.	411,104,000.00	411,104,000.00
First Mortgage Bonds..	531,051,682.50	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	942,155,682.50	896,104,000.00
Total Capitalization..	2,278,064,968.91	2,148,844,134.78
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	11,876,000.00	170,400,400.00
Notes Payable...	163,000,000.00	-
Accounts Payable..	104,974,357.13	97,284,355.93
Accounts Payable to Associated Companies.............	19,944,791.03	27,731,236.27
Customer Deposits..	23,237,608.55	22,459,554.36
Taxes Accrued..	9,598,152.76	26,729,807.13
Interest Accrued..	5,235,853.08	3,358,755.82
Miscellaneous Current and Accrued Liabilities..........	24,850,419.60	24,518,757.88
Total...	362,717,182.15	372,482,867.39
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	458,393,362.16	427,458,362.10
Investment Tax Credit...	45,524,576.13	48,026,350.13
Regulatory Liabilities...	51,426,348.46	84,907,208.58
Customer Advances for Construction......................	8,580,930.08	9,555,185.09
Asset Retirement Obligations..................................	52,650,788.91	33,043,629.14
Other Deferred Credits...	5,677,069.75	8,161,865.35
Miscellaneous Long-Term Liabilities.......................	35,751,188.04	33,921,654.80
Accum Provision for Postretirement Benefits...........	213,591,950.50	201,536,191.15
Total...	871,596,214.03	846,610,446.34
Total Liabilities and Stockholders' Equity......................	$ 3,512,378,365.09	$ 3,367,937,448.51

January 31, 2011

Attachment 3 to Response to AG-1 Question No. 270
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Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,750,777,974.71	$ 4,547,506,200.76
Less Reserves for Depreciation and Amortization......	2,049,262,226.20	1,972,299,586.33
Total...	2,701,515,748.51	2,575,206,614.43
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	16,266,282.58	14,724,565.77
Total...	16,872,447.78	15,330,730.97
Current and Accrued Assets		
Cash...	10,946,085.86	4,973,847.06
Special Deposits..	3,590,045.06	755,066.07
Temporary Cash Investments..................................	1,861.08	119.71
Accounts Receivable - Less Reserve........................	172,877,770.06	155,240,458.08
Accounts Receivable from Associated Companies.....	18,031,905.66	10,909,282.44
Materials and Supplies - At Average Cost................		
Fuel...	63,040,020.16	63,263,325.62
Plant Materials and Operating Supplies.................	29,472,535.23	29,427,375.18
Stores Expense...	4,987,130.53	4,238,253.24
Gas Stored Underground.....................................	43,600,442.97	41,531,671.17
Emission Allowances...	2,624.91	4,103.41
Prepayments..	6,932,677.50	8,867,721.64
Miscellaneous Current and Accrued Assets..............	453,145.30	2,269,808.57
Total...	353,936,244.32	321,481,032.19
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,553,077.84	3,838,643.28
Unamortized Loss on Bonds...................................	21,833,646.50	23,018,562.36
Accumulated Deferred Income Taxes......................	53,869,965.22	56,726,770.90
Deferred Regulatory Assets.....................................	353,138,961.12	325,096,765.91
Other Deferred Debits..	901,719.66	1,149,330.63
Total...	443,297,370.34	409,830,073.08
Total Assets...	$ 3,515,621,810.95	$ 3,321,848,450.67

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income................................	-	(10,963,295.75)
Retained Earnings..	846,905,423.78	764,289,058.43
Total Proprietary Capital...	1,354,821,458.23	1,261,241,797.13
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,075,004.16	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,379,004.16	896,104,000.00
Total Capitalization..	2,460,200,462.39	2,157,345,797.13
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	39,801,000.00	131,982,400.00
Accounts Payable..	95,342,791.32	94,675,668.19
Accounts Payable to Associated Companies.............	16,395,004.37	33,460,583.90
Customer Deposits..	23,571,825.06	22,862,521.85
Taxes Accrued..	11,594,182.53	33,322,970.74
Interest Accrued..	7,648,967.20	3,043,132.52
Miscellaneous Current and Accrued Liabilities..........	26,764,921.93	28,849,916.80
Total...	221,118,692.41	348,197,194.00
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	473,518,807.92	427,458,362.10
Investment Tax Credit...	45,315,209.13	47,807,192.13
Regulatory Liabilities...	65,743,017.64	74,415,259.97
Customer Advances for Construction......................	8,492,300.89	9,543,581.56
Asset Retirement Obligations..................................	52,869,451.55	33,208,192.55
Other Deferred Credits...	6,909,404.21	8,163,617.99
Miscellaneous Long-Term Liabilities.......................	33,228,101.47	35,538,871.79
Accum Provision for Postretirement Benefits...........	148,226,363.34	180,170,381.45
Total...	834,302,656.15	816,305,459.54
Total Liabilities and Stockholders' Equity......................	$ 3,515,621,810.95	$ 3,321,848,450.67

February 25, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 28, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,755,964,845.70	$ 4,552,654,928.95
Less Reserves for Depreciation and Amortization......	2,058,736,206.02	1,981,307,560.30
Total...	2,697,228,639.68	2,571,347,368.65
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	15,268,536.90	14,725,914.75
Total...	15,874,702.10	15,332,079.95
Current and Accrued Assets		
Cash...	16,211,302.24	6,682,158.33
Special Deposits..	1,618,654.10	755,066.07
Temporary Cash Investments..................................	1,872.19	119.71
Accounts Receivable - Less Reserve........................	154,061,012.70	174,880,549.88
Accounts Receivable from Associated Companies.....	9,427,052.69	14,403,080.19
Materials and Supplies - At Average Cost................		
Fuel...	66,707,850.08	67,263,983.95
Plant Materials and Operating Supplies.................	29,621,208.53	29,699,506.78
Stores Expense...	5,077,532.37	4,489,199.51
Gas Stored Underground.....................................	29,403,684.34	27,252,753.26
Emission Allowances...	2,482.89	4,030.42
Prepayments..	6,421,800.81	8,329,947.40
Miscellaneous Current and Accrued Assets..............	1,725,982.95	3,464,844.53
Total...	320,280,435.89	337,225,240.03
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,480,018.81	3,823,124.97
Unamortized Loss on Bonds...................................	21,732,643.55	22,944,264.17
Accumulated Deferred Income Taxes......................	53,869,965.22	56,645,657.80
Deferred Regulatory Assets.....................................	353,942,206.87	325,383,079.97
Other Deferred Debits..	(99,098.81)	754,242.56
Total...	442,925,735.64	409,550,369.47
Total Assets...	$ 3,476,309,513.31	$ 3,333,455,058.10

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(10,855,676.09)
Retained Earnings..	842,546,810.76	789,099,827.24
Total Proprietary Capital...	1,350,462,845.21	1,286,160,185.60
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,098,325.82	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,402,325.82	896,104,000.00
Total Capitalization..	2,455,865,171.03	2,182,264,185.60
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	5,664,000.00	129,748,400.00
Accounts Payable..	69,841,267.94	96,961,734.14
Accounts Payable to Associated Companies.............	9,519,697.55	6,825,999.35
Customer Deposits..	23,753,770.99	23,419,274.95
Taxes Accrued..	21,091,839.71	49,795,698.78
Dividends Declared...	17,250,000.00	-
Interest Accrued..	9,153,672.60	2,800,377.17
Miscellaneous Current and Accrued Liabilities..........	28,798,384.87	36,050,042.18
Total...	185,072,633.66	345,601,526.57
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	473,518,807.92	427,215,539.38
Investment Tax Credit...	45,079,175.13	47,609,386.13
Regulatory Liabilities...	65,182,295.26	61,466,915.77
Customer Advances for Construction......................	8,441,333.51	9,398,607.27
Asset Retirement Obligations..................................	53,089,053.69	33,373,579.17
Other Deferred Credits...	8,625,923.25	10,662,007.14
Miscellaneous Long-Term Liabilities.......................	33,222,865.65	35,707,243.79
Accum Provision for Postretirement Benefits...........	148,212,254.21	180,156,067.28
Total...	835,371,708.62	805,589,345.93
Total Liabilities and Stockholders' Equity......................	$ 3,476,309,513.31	$ 3,333,455,058.10

March 28, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,770,490,279.22	$ 4,553,812,856.77
Less Reserves for Depreciation and Amortization......	2,068,083,714.02	1,982,617,156.88
Total...	2,702,406,565.20	2,571,195,699.89
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	20,180,403.81	14,727,362.80
Total...	20,786,569.01	15,333,528.00
Current and Accrued Assets		
Cash...	28,355,866.45	4,581,700.41
Special Deposits..	4,098,610.17	755,272.54
Temporary Cash Investments..................................	2,431.80	119.71
Accounts Receivable - Less Reserve........................	133,817,500.02	133,999,184.50
Accounts Receivable from Associated Companies.....	24,396,918.17	15,709,235.55
Materials and Supplies - At Average Cost................		
Fuel..	67,368,406.54	68,540,274.67
Plant Materials and Operating Supplies.................	30,050,637.73	29,661,158.50
Stores Expense...	5,108,104.12	4,581,464.86
Gas Stored Underground.....................................	19,475,230.55	19,702,551.38
Emission Allowances...	2,444.82	3,979.99
Prepayments..	6,469,399.17	7,494,347.38
Miscellaneous Current and Accrued Assets..............	941,878.08	7,403,197.91
Total...	320,087,427.62	292,432,487.40
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,460,450.73	3,807,606.66
Unamortized Loss on Bonds...................................	21,631,640.60	22,843,399.48
Accumulated Deferred Income Taxes......................	53,426,611.12	51,562,119.86
Deferred Regulatory Assets.....................................	357,236,196.73	318,835,262.63
Other Deferred Debits..	1,328,343.09	2,115,572.23
Total...	447,083,242.27	399,163,960.86
Total Assets...	$ 3,490,363,804.10	$ 3,278,125,676.15

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(10,559,983.29)
Retained Earnings..	849,838,699.75	757,728,567.29
Total Proprietary Capital...	1,357,754,734.20	1,255,084,618.45
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,121,647.48	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,425,647.48	896,104,000.00
Total Capitalization..	2,463,180,381.68	2,151,188,618.45
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	123,592,400.00
Accounts Payable..	75,673,663.92	75,243,599.29
Accounts Payable to Associated Companies.............	14,546,268.31	38,887,982.75
Customer Deposits..	23,240,672.59	23,505,026.21
Taxes Accrued..	18,309,170.54	21,251,712.73
Interest Accrued..	11,708,678.03	3,542,330.75
Miscellaneous Current and Accrued Liabilities..........	32,140,201.55	39,807,477.66
Total...	175,618,654.94	325,830,529.39
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,780,888.27	427,056,738.37
Investment Tax Credit...	44,843,141.13	47,400,905.13
Regulatory Liabilities...	62,145,912.07	58,220,051.36
Customer Advances for Construction......................	8,163,578.28	9,391,871.62
Asset Retirement Obligations..................................	53,309,599.51	33,539,793.09
Other Deferred Credits...	12,660,924.88	12,024,479.23
Miscellaneous Long-Term Liabilities.......................	34,448,469.13	33,345,166.16
Accum Provision for Postretirement Benefits...........	148,212,254.21	180,127,523.35
Total...	851,564,767.48	801,106,528.31
Total Liabilities and Stockholders' Equity......................	$ 3,490,363,804.10	$ 3,278,125,676.15

April 26, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,782,878,078.55	$ 4,564,494,960.09
Less Reserves for Depreciation and Amortization......	2,077,990,172.73	1,991,374,248.54
Total...	2,704,887,905.82	2,573,120,711.55
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	20,392,613.99	14,729,449.18
Total...	20,998,779.19	15,335,614.38
Current and Accrued Assets		
Cash...	32,004,651.77	5,847,850.51
Special Deposits..	5,336,432.10	755,355.97
Temporary Cash Investments..................................	32,004,573.78	119.71
Accounts Receivable - Less Reserve........................	116,387,007.31	118,456,375.85
Accounts Receivable from Associated Companies.....	11,414,595.15	12,314,747.96
Materials and Supplies - At Average Cost................		
Fuel...	64,634,046.64	73,203,744.22
Plant Materials and Operating Supplies.................	29,834,678.95	29,387,046.33
Stores Expense...	5,079,805.34	4,653,117.81
Gas Stored Underground.....................................	14,392,608.85	14,842,906.51
Emission Allowances...	2,409.88	3,916.15
Prepayments..	7,049,940.71	6,542,096.80
Miscellaneous Current and Accrued Assets..............	724,075.07	5,801,250.84
Total...	318,864,825.55	271,808,528.66
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,309,465.49	3,792,088.35
Unamortized Loss on Bonds...................................	21,530,637.65	22,742,534.79
Accumulated Deferred Income Taxes......................	53,426,611.12	51,895,455.16
Deferred Regulatory Assets.....................................	361,306,009.06	320,567,422.64
Other Deferred Debits..	1,251,973.01	2,095,968.23
Total...	450,824,696.33	401,093,469.17
Total Assets...	$ 3,495,576,206.89	$ 3,261,358,323.76

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(11,094,243.55)
Retained Earnings..	852,322,196.36	757,127,061.99
Total Proprietary Capital...	1,360,238,230.81	1,253,948,852.89
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,144,969.14	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,448,969.14	896,104,000.00
Total Capitalization..	2,465,687,199.95	2,150,052,852.89
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	133,491,400.00
Accounts Payable..	72,770,225.00	68,051,345.04
Accounts Payable to Associated Companies.............	27,020,672.69	30,812,887.97
Customer Deposits..	23,394,006.56	23,941,242.89
Taxes Accrued..	7,782,784.18	13,407,762.97
Interest Accrued..	13,874,035.61	4,315,904.54
Miscellaneous Current and Accrued Liabilities..........	29,874,305.15	34,238,967.29
Total...	174,716,029.19	308,259,510.70
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,780,888.27	425,917,166.76
Investment Tax Credit...	44,607,107.13	47,192,424.13
Regulatory Liabilities...	61,508,554.02	56,089,200.04
Customer Advances for Construction......................	8,115,146.29	9,395,487.39
Asset Retirement Obligations..................................	53,172,083.34	33,706,838.44
Other Deferred Credits...	15,198,179.97	15,483,167.15
Miscellaneous Long-Term Liabilities.......................	36,567,706.97	36,593,225.16
Accum Provision for Postretirement Benefits...........	148,223,311.76	178,668,451.10
Total...	855,172,977.75	803,045,960.17
Total Liabilities and Stockholders' Equity......................	$ 3,495,576,206.89	$ 3,261,358,323.76

May 26, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,792,382,669.03	$ 4,576,411,472.76
Less: Reserves for Depreciation and Amortization.....	2,086,932,887.81	2,001,192,563.45
Total...	2,705,449,781.22	2,575,218,909.31
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	21,674,314.80	16,102,047.29
Total...	22,280,480.00	16,708,212.49
Current and Accrued Assets		
Cash...	42,642,184.10	4,093,386.56
Special Deposits..	6,103,356.02	755,688.09
Temporary Cash Investments..................................	16,607,994.23	119.71
Accounts Receivable - Less Reserve........................	117,302,831.48	122,964,056.28
Accounts Receivable from Associated Companies.....	17,220,727.53	13,089,862.47
Materials and Supplies - At Average Cost................		
Fuel...	64,042,394.78	74,024,035.18
Plant Materials and Operating Supplies.................	29,638,442.60	29,814,569.11
Stores Expense...	5,123,126.75	4,770,116.70
Gas Stored Underground.....................................	12,379,663.46	10,720,154.28
Emission Allowances...	2,331.27	3,823.11
Prepayments..	6,486,268.51	5,557,672.61
Miscellaneous Current and Accrued Assets..............	681,197.76	2,805,844.80
Total...	318,230,518.49	268,599,328.90
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,330,061.12	3,776,570.04
Unamortized Loss on Bonds...................................	21,429,634.70	22,641,670.10
Accumulated Deferred Income Taxes......................	55,739,575.24	52,035,131.46
Deferred Regulatory Assets.....................................	358,597,038.27	320,150,845.07
Other Deferred Debits..	1,033,868.72	1,356,503.81
Total...	450,130,178.05	399,960,720.48
Total Assets...	$ 3,496,090,957.76	$ 3,260,487,171.18

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(11,313,632.31)
Retained Earnings..	831,803,763.59	759,575,375.78
Total Proprietary Capital...	1,339,719,798.04	1,256,177,777.92
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,168,290.80	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,472,290.80	896,104,000.00
Total Capitalization..	2,445,192,088.84	2,152,281,777.92
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	140,750,400.00
Accounts Payable..	83,744,950.28	76,031,950.00
Accounts Payable to Associated Companies.............	13,185,424.92	15,645,927.12
Customer Deposits..	22,522,323.63	24,161,270.63
Taxes Accrued..	10,625,328.89	16,134,690.53
Interest Accrued..	6,438,420.39	4,194,617.12
Dividends Declared...	25,000,000.00	-
Miscellaneous Current and Accrued Liabilities.........	28,264,294.97	23,498,823.08
Total...	189,780,743.08	300,417,678.48
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	492,983,143.27	425,917,166.76
Investment Tax Credit...	44,371,073.13	46,983,943.13
Regulatory Liabilities...	59,210,182.72	54,737,886.15
Customer Advances for Construction......................	8,092,132.24	9,284,085.81
Asset Retirement Obligations..................................	51,902,235.56	33,874,719.43
Other Deferred Credits..	18,472,668.22	18,309,202.24
Miscellaneous Long-Term Liabilities.......................	39,234,121.95	40,012,260.16
Accum Provision for Postretirement Benefits...........	146,852,568.75	178,668,451.10
Total...	861,118,125.84	807,787,714.78
Total Liabilities and Stockholders' Equity......................	$ 3,496,090,957.76	$ 3,260,487,171.18

June 21, 2011

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Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,802,348,313.16	$ 4,586,733,561.50
Less: Reserves for Depreciation and Amortization	2,092,493,560.06	2,011,388,361.15
Total	2,709,854,753.10	2,575,345,200.35
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	22,505,965.16	17,054,543.60
Total	23,112,130.36	17,660,708.80
Current and Accrued Assets		
Cash	41,156,614.54	5,546,990.55
Special Deposits	4,626,601.12	693,958.65
Temporary Cash Investments	10,763.48	119.71
Accounts Receivable - Less Reserve	126,976,576.30	154,587,253.55
Accounts Receivable from Associated Companies	12,749,748.11	17,787,025.30
Materials and Supplies - At Average Cost		
Fuel	67,711,396.61	69,073,218.18
Plant Materials and Operating Supplies	29,950,707.42	29,037,290.76
Stores Expense	5,157,847.02	4,733,941.15
Gas Stored Underground	19,007,070.36	19,129,762.47
Emission Allowances	2,233.53	3,713.56
Prepayments	7,798,435.51	4,924,681.40
Miscellaneous Current and Accrued Assets	605,541.52	1,882,811.38
Total	315,753,535.52	307,400,766.66
Deferred Debits and Other		
Unamortized Debt Expense	13,247,160.62	3,761,023.23
Unamortized Loss on Bonds	21,328,631.75	22,540,667.15
Accumulated Deferred Income Taxes	55,536,998.05	50,944,309.61
Deferred Regulatory Assets	355,709,240.35	319,055,168.65
Other Deferred Debits	1,478,646.74	1,202,822.23
Total	447,300,677.51	397,503,990.87
Total Assets	$ 3,496,021,096.49	$ 3,297,910,666.68

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	(12,554,675.38)
Retained Earnings	844,832,315.17	771,804,572.18
Total Proprietary Capital	1,352,748,349.62	1,267,165,931.25
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,191,612.46	-
LT Notes Payable to Associated Companies	-	485,000,000.00
Total Long-Term Debt	1,105,495,612.46	896,104,000.00
Total Capitalization	2,458,243,962.08	2,163,269,931.25
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	137,358,400.00
Accounts Payable	85,621,470.31	79,568,208.23
Accounts Payable to Associated Companies	13,004,765.06	27,944,985.02
Customer Deposits	22,604,581.72	24,032,890.71
Taxes Accrued	10,103,469.64	8,213,597.22
Interest Accrued	5,332,202.80	2,307,571.20
Dividends Declared	-	-
Miscellaneous Current and Accrued Liabilities	25,114,319.95	22,705,173.97
Total	161,780,809.48	302,130,826.35
Deferred Credits and Other		
Accumulated Deferred Income Taxes	506,075,924.63	442,371,641.52
Investment Tax Credit	44,135,039.13	46,775,462.13
Regulatory Liabilities	59,639,476.44	54,630,645.87
Customer Advances for Construction	8,117,149.39	8,624,175.20
Asset Retirement Obligations	52,117,276.38	34,043,440.31
Other Deferred Credits	21,631,372.89	21,536,826.65
Miscellaneous Long-Term Liabilities	37,441,515.45	45,873,512.45
Accum Provision for Postretirement Benefits	146,838,570.62	178,654,204.95
Total	875,996,324.93	832,509,909.08
Total Liabilities and Stockholders' Equity	$ 3,496,021,096.49	$ 3,297,910,666.68

July 27, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,813,897,037.14	$ 4,596,155,723.91
Less: Reserves for Depreciation and Amortization.....	2,103,467,014.13	2,020,431,818.86
Total...	2,710,430,023.01	2,575,723,905.05
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	22,357,645.64	17,816,924.04
Total...	22,963,810.84	18,423,089.24
Current and Accrued Assets		
Cash...	38,334,376.50	2,458,207.79
Special Deposits..	3,151,789.21	694,039.76
Temporary Cash Investments..................................	18,512,047.18	119.71
Accounts Receivable - Less Reserve........................	148,476,351.97	152,615,048.85
Accounts Receivable from Associated Companies.....	11,752,654.76	31,743,790.61
Materials and Supplies - At Average Cost................		
Fuel...	58,266,316.48	67,057,622.92
Plant Materials and Operating Supplies.................	30,252,113.88	28,948,754.37
Stores Expense...	5,282,243.47	4,880,898.47
Gas Stored Underground.....................................	32,199,333.75	34,640,844.19
Emission Allowances...	2,114.63	3,467.86
Prepayments..	6,527,553.62	6,107,360.76
Miscellaneous Current and Accrued Assets..............	642,063.90	1,786,668.84
Total...	353,398,959.35	330,936,824.13
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,272,796.01	3,745,476.42
Unamortized Loss on Bonds...................................	21,227,628.80	22,439,664.20
Accumulated Deferred Income Taxes......................	55,536,998.05	51,350,160.00
Deferred Regulatory Assets.....................................	359,022,573.48	318,009,867.49
Other Deferred Debits..	1,307,123.49	554,607.97
Total...	450,367,119.83	396,099,776.08
Total Assets...	$ 3,537,159,913.03	$ 3,321,183,594.50

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(13,202,834.60)
Retained Earnings..	865,073,836.64	787,479,070.96
Total Proprietary Capital...	1,372,989,871.09	1,282,192,270.81
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,214,934.12	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt..	1,105,518,934.12	896,104,000.00
Total Capitalization..	2,478,508,805.21	2,178,296,270.81
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	135,048,400.00
Accounts Payable..	85,729,649.67	87,363,988.88
Accounts Payable to Associated Companies.............	12,602,066.24	20,164,038.85
Customer Deposits..	22,714,988.20	24,236,689.44
Taxes Accrued..	23,590,209.81	18,333,431.49
Interest Accrued..	7,939,349.46	3,078,318.40
Dividends Declared...	-	-
Miscellaneous Current and Accrued Liabilities.........	23,212,684.00	20,436,721.44
Total...	175,788,947.38	308,661,588.50
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	506,075,924.63	442,364,833.95
Investment Tax Credit...	43,899,005.13	46,566,981.13
Regulatory Liabilities...	60,756,940.33	54,864,073.23
Customer Advances for Construction......................	8,075,464.10	8,678,961.61
Asset Retirement Obligations..................................	52,226,757.13	34,213,005.28
Other Deferred Credits..	23,912,823.90	22,956,121.09
Miscellaneous Long-Term Liabilities.......................	42,351,120.43	47,399,984.45
Accum Provision for Postretirement Benefits...........	145,564,124.79	177,181,774.45
Total...	882,862,160.44	834,225,735.19
Total Liabilities and Stockholders' Equity......................	$ 3,537,159,913.03	$ 3,321,183,594.50

August 19, 2011

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Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,815,048,867.20	$ 4,606,776,233.47
Less: Reserves for Depreciation and Amortization.....	2,099,822,626.80	2,029,983,137.15
Total...	2,715,226,240.40	2,576,793,096.32
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	26,739,003.13	20,609,773.64
Total...	27,345,168.33	21,215,938.84
Current and Accrued Assets		
Cash...	41,235,356.47	6,526,467.04
Special Deposits..	2,204,705.90	694,352.78
Temporary Cash Investments..................................	42,115,568.00	119.71
Accounts Receivable - Less Reserve........................	133,715,904.02	157,954,307.83
Accounts Receivable from Associated Companies.....	14,603,137.03	22,334,304.00
Materials and Supplies - At Average Cost................		
Fuel...	51,087,714.21	62,977,241.54
Plant Materials and Operating Supplies.................	30,417,147.49	29,209,716.40
Stores Expense...	5,422,256.65	4,798,275.05
Gas Stored Underground.....................................	45,030,809.18	48,929,595.86
Emission Allowances...	2,005.06	3,240.25
Prepayments..	6,575,036.00	5,872,425.02
Miscellaneous Current and Accrued Assets..............	951,689.47	2,274,436.12
Total...	373,361,329.48	341,574,481.60
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,117,553.69	3,729,929.61
Unamortized Loss on Bonds...................................	21,126,625.85	22,338,661.25
Accumulated Deferred Income Taxes......................	56,272,700.06	52,250,170.26
Deferred Regulatory Assets.....................................	369,108,007.04	328,198,136.08
Other Deferred Debits...	1,352,515.52	575,187.76
Total...	460,977,402.16	407,092,084.96
Total Assets...	$ 3,576,910,140.37	$ 3,346,675,601.72

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	(14,616,475.40)
Retained Earnings..	863,429,950.41	810,873,011.74
Total Proprietary Capital...	1,371,345,984.86	1,304,172,570.79
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,238,255.78	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,542,255.78	896,104,000.00
Total Capitalization..	2,476,888,240.64	2,200,276,570.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	118,326,400.00
Accounts Payable..	87,601,078.61	84,988,459.47
Accounts Payable to Associated Companies.............	17,443,956.77	18,509,327.38
Customer Deposits..	22,667,140.95	24,270,260.87
Taxes Accrued..	31,834,314.50	34,501,171.40
Interest Accrued..	9,378,075.45	2,386,121.71
Dividends Declared...	13,000,000.00	-
Miscellaneous Current and Accrued Liabilities.........	23,121,809.92	19,448,952.37
Total...	205,046,376.20	302,430,693.20
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	504,554,359.26	442,364,833.95
Investment Tax Credit...	43,662,971.13	46,358,500.13
Regulatory Liabilities...	62,515,471.19	51,689,278.97
Customer Advances for Construction......................	8,059,948.10	8,623,967.39
Asset Retirement Obligations..................................	52,443,159.11	34,383,418.56
Other Deferred Credits...	26,770,314.68	26,842,521.07
Miscellaneous Long-Term Liabilities.......................	51,419,138.37	56,538,247.45
Accum Provision for Postretirement Benefits...........	145,550,161.69	177,167,570.21
Total...	894,975,523.53	843,968,337.73
Total Liabilities and Stockholders' Equity......................	$ 3,576,910,140.37	$ 3,346,675,601.72

September 22, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,834,755,063.44	$ 4,644,050,008.98
Less: Reserves for Depreciation and Amortization.....	2,109,448,034.24	2,023,632,803.62
Total...	2,725,307,029.20	2,620,417,205.36
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds...	29,511,083.19	21,152,872.82
Total...	30,117,248.39	21,759,038.02
Current and Accrued Assets		
Cash...	36,121,124.88	3,904,029.96
Special Deposits..	1,203,174.45	694,666.13
Temporary Cash Investments..................................	38,421,281.63	119.71
Accounts Receivable - Less Reserve........................	115,617,416.71	131,282,221.86
Accounts Receivable from Associated Companies.....	10,903,711.10	16,943,535.45
Materials and Supplies - At Average Cost................		
Fuel..	52,528,086.41	65,769,984.00
Plant Materials and Operating Supplies.................	30,797,037.86	29,786,478.70
Stores Expense..	5,476,575.61	4,860,767.32
Gas Stored Underground.....................................	56,853,462.78	60,652,456.09
Emission Allowances...	2,772.88	3,007.09
Prepayments..	6,339,120.25	4,911,746.03
Miscellaneous Current and Accrued Assets..............	761,979.55	1,807,657.91
Total...	355,025,744.11	320,616,670.25
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,044,553.50	3,714,382.80
Unamortized Loss on Bonds...................................	21,025,622.90	22,237,658.30
Accumulated Deferred Income Taxes......................	26,152,975.69	46,431,887.66
Deferred Regulatory Assets.....................................	383,199,682.64	378,525,174.50
Other Deferred Debits...	1,330,450.74	1,197,806.18
Total...	444,753,285.47	452,106,909.44
Total Assets...	$ 3,555,203,307.17	$ 3,414,899,823.07

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	-
Retained Earnings..	874,925,832.17	807,159,675.10
Total Proprietary Capital...	1,382,841,866.62	1,315,075,709.55
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds...	531,261,577.46	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt...	1,105,565,577.46	896,104,000.00
Total Capitalization..	2,488,407,444.08	2,211,179,709.55
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	121,885,400.00
Accounts Payable..	81,366,680.34	83,374,445.21
Accounts Payable to Associated Companies.............	21,152,123.73	38,853,764.01
Customer Deposits..	22,546,494.46	24,435,083.96
Taxes Accrued..	18,953,407.93	20,358,882.40
Interest Accrued..	12,029,932.24	3,555,639.55
Dividends Declared...	-	-
Miscellaneous Current and Accrued Liabilities..........	21,917,601.45	20,902,601.42
Total...	177,966,240.15	313,365,816.55
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,104,353.22	459,200,169.51
Investment Tax Credit...	43,426,937.13	46,150,019.13
Regulatory Liabilities...	60,890,790.21	51,562,025.10
Customer Advances for Construction......................	8,049,779.58	8,229,472.91
Asset Retirement Obligations..................................	55,794,013.83	64,974,252.91
Other Deferred Credits...	29,396,986.25	28,608,492.59
Miscellaneous Long-Term Liabilities.......................	58,630,593.68	54,476,525.20
Accum Provision for Postretirement Benefits............	145,536,169.04	177,153,339.62
Total...	888,829,622.94	890,354,296.97
Total Liabilities and Stockholders' Equity......................	$ 3,555,203,307.17	$ 3,414,899,823.07

October 26, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,854,087,312.73	$ 4,689,347,414.37
Less: Reserves for Depreciation and Amortization.....	2,119,839,274.24	2,030,781,175.75
Total...	2,734,248,038.49	2,658,566,238.62
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	29,513,085.39	21,156,261.72
Total...	30,119,250.59	21,762,426.92
Current and Accrued Assets		
Cash...	42,810,271.73	3,825,761.11
Special Deposits..	557,339.76	694,647.22
Temporary Cash Investments..................................	31,125,914.89	119.71
Accounts Receivable - Less Reserve........................	105,912,233.14	120,885,025.11
Accounts Receivable from Associated Companies.....	11,234,858.52	15,918,666.44
Materials and Supplies - At Average Cost................		
Fuel..	59,220,758.36	69,001,447.80
Plant Materials and Operating Supplies.................	30,813,805.38	29,262,178.89
Stores Expense..	5,577,590.22	4,866,562.11
Gas Stored Underground.....................................	66,152,494.75	69,292,419.44
Emission Allowances...	24,614.20	2,936.23
Prepayments..	5,460,672.11	4,620,700.76
Miscellaneous Current and Accrued Assets..............	607,780.56	1,053,692.59
Total...	359,498,333.62	319,424,157.41
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,557,379.65	3,698,835.99
Unamortized Loss on Bonds...................................	20,924,619.95	22,136,655.35
Accumulated Deferred Income Taxes......................	26,434,331.06	49,392,552.07
Deferred Regulatory Assets.....................................	376,302,783.78	398,998,957.42
Other Deferred Debits...	1,365,988.12	2,639,042.93
Total...	438,585,102.56	476,866,043.76
Total Assets...	$ 3,562,450,725.26	$ 3,476,618,866.71

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	-
Retained Earnings..	877,862,183.07	808,946,891.52
Total Proprietary Capital...	1,385,778,217.52	1,316,862,925.97
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,284,899.12	-
LT Notes Payable to Associated Companies............	-	485,000,000.00
Total Long-Term Debt..	1,105,588,899.12	896,104,000.00
Total Capitalization..	2,491,367,116.64	2,212,966,925.97
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies.............	-	142,309,400.00
Accounts Payable..	91,057,684.20	108,349,293.44
Accounts Payable to Associated Companies.............	13,798,613.52	51,218,385.36
Customer Deposits..	22,425,873.82	23,673,139.66
Taxes Accrued..	23,483,954.44	12,074,347.15
Interest Accrued..	13,345,579.80	4,316,975.16
Dividends Declared...	-	-
Miscellaneous Current and Accrued Liabilities..........	19,943,526.53	16,881,002.06
Total...	184,055,232.31	358,822,542.83
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,243,920.69	454,586,900.11
Investment Tax Credit..	43,190,903.13	45,941,538.13
Regulatory Liabilities...	61,440,578.69	51,659,503.79
Customer Advances for Construction......................	8,022,178.51	8,451,907.43
Asset Retirement Obligations..................................	55,792,039.70	65,149,934.69
Other Deferred Credits...	32,850,657.34	5,955,456.28
Miscellaneous Long-Term Liabilities.......................	54,212,429.21	49,962,421.48
Accum Provision for Postretirement Benefits...........	144,275,669.04	223,121,736.00
Total...	887,028,376.31	904,829,397.91
Total Liabilities and Stockholders' Equity......................	$ 3,562,450,725.26	$ 3,476,618,866.71

November 21, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 4,872,997,987.35	$ 4,725,820,363.00
Less: Reserves for Depreciation and Amortization.....	2,126,828,778.97	2,038,048,102.91
Total...	2,746,169,208.38	2,687,772,260.09
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve...........................	11,879.20	11,879.20
Special Funds..	28,514,787.39	21,159,746.63
Total...	29,120,952.59	21,765,911.83
Current and Accrued Assets		
Cash...	34,195,977.48	8,943,622.67
Special Deposits..	-	694,907.86
Temporary Cash Investments..................................	29,029,898.75	257.35
Accounts Receivable - Less Reserve........................	114,669,412.44	120,611,707.66
Accounts Receivable from Associated Companies.....	11,548,437.29	12,503,081.78
Materials and Supplies - At Average Cost................		
Fuel...	55,707,094.47	72,766,804.02
Plant Materials and Operating Supplies.................	30,482,076.24	29,408,708.50
Stores Expense...	5,550,219.41	4,916,530.71
Gas Stored Underground....................................	62,658,874.27	69,206,931.68
Emission Allowances...	26,604.68	2,872.24
Prepayments..	4,982,269.92	12,611,917.95
Miscellaneous Current and Accrued Assets..............	-	455,865.92
Total...	348,850,864.95	332,123,208.34
Deferred Debits and Other		
Unamortized Debt Expense.....................................	13,447,248.44	11,959,147.13
Unamortized Loss on Bonds...................................	20,823,617.00	22,035,652.40
Accumulated Deferred Income Taxes......................	26,355,404.03	49,259,820.29
Deferred Regulatory Assets.....................................	379,199,955.06	367,782,479.06
Other Deferred Debits...	1,649,265.49	1,205,148.42
Total...	441,475,490.02	452,242,247.30
Total Assets..	$ 3,565,616,515.94	$ 3,493,903,627.56

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income.................................	-	-
Retained Earnings..	856,776,505.55	813,953,056.34
Total Proprietary Capital...	1,364,692,540.00	1,321,869,090.79
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds..	531,308,220.78	531,028,360.84
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt...	1,105,612,220.78	942,132,360.84
Total Capitalization..	2,470,304,760.78	2,264,001,451.63
Current and Accrued Liabilities		
Notes Payable...	-	163,000,000.00
Accounts Payable..	81,283,596.90	93,382,514.42
Accounts Payable to Associated Companies.............	16,784,036.42	20,131,634.53
Customer Deposits..	22,388,530.85	23,813,630.54
Taxes Accrued..	29,529,563.22	12,466,240.58
Interest Accrued..	5,951,860.54	2,515,610.98
Dividends Declared...	28,000,000.00	-
Miscellaneous Current and Accrued Liabilities..........	19,807,279.09	18,067,321.29
Total...	203,744,867.02	333,376,952.34
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	487,425,528.06	454,586,900.11
Investment Tax Credit..	42,954,869.13	45,733,057.13
Regulatory Liabilities...	60,622,974.76	51,586,279.37
Customer Advances for Construction......................	7,247,002.77	8,466,567.41
Asset Retirement Obligations..................................	56,022,754.36	52,433,061.81
Other Deferred Credits...	35,534,880.32	35,528,957.25
Miscellaneous Long-Term Liabilities.......................	57,497,148.14	45,581,269.32
Accum Provision for Postretirement Benefits...........	144,261,730.60	202,609,131.19
Total...	891,566,888.14	896,525,223.59
Total Liabilities and Stockholders' Equity......................	$ 3,565,616,515.94	$ 3,493,903,627.56

December 22, 2011

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2011 and 2010

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,897,295,931.52	$ 4,748,839,654.01
Less: Reserves for Depreciation and Amortization	2,117,873,452.51	2,043,099,789.34
Total	2,779,422,479.01	2,705,739,864.67
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	28,846,730.20	18,763,173.33
Total	29,452,895.40	19,369,338.53
Current and Accrued Assets		
Cash	24,920,484.53	2,025,606.25
Special Deposits	12,277.00	3,511,014.88
Temporary Cash Investments	33,063.99	100,405.59
Accounts Receivable - Less Reserve	137,419,594.66	163,630,222.30
Accounts Receivable from Associated Companies	10,916,898.01	29,799,791.23
Materials and Supplies - At Average Cost		
Fuel	52,502,546.26	68,043,290.05
Plant Materials and Operating Supplies	30,625,941.68	29,326,915.51
Stores Expense	5,596,505.54	4,943,153.44
Gas Stored Underground	53,287,604.59	59,956,180.78
Emission Allowances	2,511.67	2,728.96
Prepayments	5,472,353.44	6,832,694.11
Miscellaneous Current and Accrued Assets	-	137,908.13
Total	320,789,781.37	368,309,911.23
Deferred Debits and Other		
Unamortized Debt Expense	13,326,195.59	13,116,651.27
Unamortized Loss on Bonds	20,963,862.78	21,934,649.45
Accumulated Deferred Income Taxes	23,826,072.01	38,744,526.28
Deferred Regulatory Assets	397,110,901.24	344,036,363.17
Other Deferred Debits	1,480,708.22	1,127,060.49
Total	456,707,739.84	418,959,250.66
Total Assets	$ 3,586,372,895.62	$ 3,512,378,365.09

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	868,929,557.39	827,993,251.96
Total Proprietary Capital	1,376,845,591.84	1,335,909,286.41
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	411,104,000.00
First Mortgage Bonds	531,331,542.44	531,051,682.50
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,635,542.44	942,155,682.50
Total Capitalization	2,482,481,134.28	2,278,064,968.91
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	11,876,000.00
Notes Payable	-	163,000,000.00
Accounts Payable	97,848,807.56	104,974,357.13
Accounts Payable to Associated Companies	25,528,425.55	19,944,791.03
Customer Deposits	22,361,041.85	23,237,608.55
Taxes Accrued	13,284,849.56	9,598,152.76
Interest Accrued	5,825,755.42	5,235,853.08
Miscellaneous Current and Accrued Liabilities	22,176,210.30	24,850,419.60
Total	187,025,090.24	362,717,182.15
Deferred Credits and Other		
Accumulated Deferred Income Taxes	499,655,847.56	458,393,362.16
Investment Tax Credit	42,718,844.13	45,524,576.13
Regulatory Liabilities	58,617,596.40	51,426,348.46
Customer Advances for Construction	7,307,168.56	8,580,930.08
Asset Retirement Obligations	58,606,350.25	52,650,788.91
Other Deferred Credits	5,120,367.14	5,677,069.75
Miscellaneous Long-Term Liabilities	60,707,001.86	35,751,188.04
Accum Provision for Postretirement Benefits	184,133,495.20	213,591,950.50
Total	916,866,671.10	871,596,214.03
Total Liabilities and Stockholders' Equity	$ 3,586,372,895.62	$ 3,512,378,365.09

January 26, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.....................................	$ 4,909,056,549.82	$ 4,750,777,974.71
Less: Reserves for Depreciation and Amortization....	2,129,469,771.92	2,049,262,226.20
Total..	2,779,586,777.90	2,701,515,748.51
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	11,879.20	11,879.20
Special Funds...	29,788,557.01	16,266,282.58
Total..	30,394,722.21	16,872,447.78
Current and Accrued Assets		
Cash..	22,562,167.83	10,946,085.86
Special Deposits...	12,277.00	3,590,045.06
Temporary Cash Investments....................................	33,199.87	1,861.08
Accounts Receivable - Less Reserve..........................	143,404,574.12	172,877,770.06
Accounts Receivable from Associated Companies....	12,419,799.02	18,031,905.66
Materials and Supplies - At Average Cost................		
Fuel..	50,199,426.27	63,040,020.16
Plant Materials and Operating Supplies.................	30,878,565.61	29,472,535.23
Stores Expense...	5,639,880.99	4,987,130.53
Gas Stored Underground..	41,005,070.14	43,600,442.97
Emission Allowances..	19,936.74	2,624.91
Prepayments..	5,317,036.50	6,932,677.50
Miscellaneous Current and Accrued Assets..............	-	453,145.30
Total..	311,491,934.09	353,936,244.32
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,189,647.53	13,553,077.84
Unamortized Loss on Bonds......................................	20,885,609.22	21,833,646.50
Accumulated Deferred Income Taxes.......................	23,749,922.01	53,869,965.22
Deferred Regulatory Assets.......................................	399,361,510.17	353,138,961.12
Other Deferred Debits...	1,259,355.16	901,719.66
Total..	458,446,044.09	443,297,370.34
Total Assets...	$ 3,579,919,478.29	$ 3,515,621,810.95

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	882,491,644.40	846,905,423.78
Total Proprietary Capital...	1,390,407,678.85	1,354,821,458.23
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,354,864.10	531,075,004.16
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt..	1,105,658,864.10	1,105,379,004.16
Total Capitalization...	2,496,066,542.95	2,460,200,462.39
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	39,801,000.00
Notes Payable..	-	-
Accounts Payable..	90,067,704.18	95,342,791.32
Accounts Payable to Associated Companies............	15,168,942.65	16,395,004.37
Customer Deposits..	22,478,501.90	23,571,825.06
Taxes Accrued...	19,172,547.29	11,594,182.53
Interest Accrued..	8,169,288.22	7,648,967.20
Miscellaneous Current and Accrued Liabilities.........	27,349,223.25	26,764,921.93
Total..	182,406,207.49	221,118,692.41
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	499,655,847.55	473,518,807.92
Investment Tax Credit...	42,495,488.13	45,315,209.13
Regulatory Liabilities..	60,785,846.15	65,743,017.64
Customer Advances for Construction.......................	7,319,187.89	8,492,300.89
Asset Retirement Obligations...................................	58,847,147.60	52,869,451.55
Other Deferred Credits..	8,612,478.80	6,909,404.21
Miscellaneous Long-Term Liabilities.......................	61,995,072.79	33,228,101.47
Accum Provision for Postretirement Benefits...........	161,735,658.94	148,226,363.34
Total..	901,446,727.85	834,302,656.15
Total Liabilities and Stockholders' Equity.....................	$ 3,579,919,478.29	$ 3,515,621,810.95

February 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 29, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,919,723,457.68	$ 4,755,964,845.70
Less: Reserves for Depreciation and Amortization	2,137,988,703.28	2,058,736,206.02
Total	2,781,734,754.40	2,697,228,639.68
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	30,310,548.45	15,268,536.90
Total	30,916,713.65	15,874,702.10
Current and Accrued Assets		
Cash	38,370,592.06	16,211,302.24
Special Deposits	-	1,618,654.10
Temporary Cash Investments	16,534,761.64	1,872.19
Accounts Receivable - Less Reserve	129,860,629.76	154,061,012.70
Accounts Receivable from Associated Companies	15,190,151.03	9,427,052.69
Materials and Supplies - At Average Cost		
Fuel	57,383,128.29	66,707,850.08
Plant Materials and Operating Supplies	30,831,292.12	29,621,208.53
Stores Expense	5,538,432.48	5,077,532.37
Gas Stored Underground	27,251,651.60	29,403,684.34
Emission Allowances	18,675.79	2,482.89
Prepayments	5,872,637.42	6,421,800.81
Miscellaneous Current and Accrued Assets	-	1,725,982.95
Total	326,851,952.19	320,280,435.89
Deferred Debits and Other		
Unamortized Debt Expense	13,053,099.47	13,480,018.81
Unamortized Loss on Bonds	20,784,542.53	21,732,643.55
Accumulated Deferred Income Taxes	23,749,922.01	53,869,965.22
Deferred Regulatory Assets	396,075,506.26	353,942,206.87
Other Deferred Debits	1,224,882.41	(99,098.81)
Total	454,887,952.68	442,925,735.64
Total Assets	$ 3,594,391,372.92	$ 3,476,309,513.31

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	872,702,746.19	842,546,810.76
Total Proprietary Capital	1,380,618,780.64	1,350,462,845.21
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,378,185.76	531,098,325.82
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,682,185.76	1,105,402,325.82
Total Capitalization	2,486,300,966.40	2,455,865,171.03
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	5,664,000.00
Notes Payable	-	-
Accounts Payable	96,978,222.55	69,841,267.94
Accounts Payable to Associated Companies	13,291,277.31	9,519,697.55
Customer Deposits	22,518,161.40	23,753,770.99
Taxes Accrued	23,830,129.23	21,091,839.71
Dividends Declared	15,000,000.00	17,250,000.00
Interest Accrued	9,522,801.62	9,153,672.60
Miscellaneous Current and Accrued Liabilities	27,524,482.90	28,798,384.87
Total	208,665,075.01	185,072,633.66
Deferred Credits and Other		
Accumulated Deferred Income Taxes	499,655,847.55	473,518,807.92
Investment Tax Credit	42,272,132.13	45,079,175.13
Regulatory Liabilities	59,483,304.96	65,182,295.26
Customer Advances for Construction	7,342,362.81	8,441,333.51
Asset Retirement Obligations	59,088,992.03	53,089,053.69
Other Deferred Credits	10,978,950.12	8,625,923.25
Miscellaneous Long-Term Liabilities	58,881,944.50	33,222,865.65
Accum Provision for Postretirement Benefits	161,721,797.41	148,212,254.21
Total	899,425,331.51	835,371,708.62
Total Liabilities and Stockholders' Equity	$ 3,594,391,372.92	$ 3,476,309,513.31

March 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,933,705,788.03	$ 4,770,490,279.22
Less: Reserves for Depreciation and Amortization	2,144,260,445.77	2,068,083,714.02
Total	2,789,445,342.26	2,702,406,565.20
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	26,812,546.91	20,180,403.81
Total	27,418,712.11	20,786,569.01
Current and Accrued Assets		
Cash	37,944,606.65	28,355,866.45
Special Deposits	-	4,098,610.17
Temporary Cash Investments	16,338,854.02	2,431.80
Accounts Receivable - Less Reserve	121,482,082.46	133,817,500.02
Accounts Receivable from Associated Companies	20,097,723.37	24,396,918.17
Materials and Supplies - At Average Cost		
Fuel	66,393,015.44	67,368,406.54
Plant Materials and Operating Supplies	30,964,056.64	30,050,637.73
Stores Expense	5,553,099.47	5,108,104.12
Gas Stored Underground	20,184,889.10	19,475,230.55
Emission Allowances	17,221.12	2,444.82
Prepayments	4,804,662.67	6,469,399.17
Miscellaneous Current and Accrued Assets	693.97	941,878.08
Total	323,780,904.91	320,087,427.62
Deferred Debits and Other		
Unamortized Debt Expense	12,916,551.41	13,460,450.73
Unamortized Loss on Bonds	20,682,089.39	21,631,640.60
Accumulated Deferred Income Taxes	22,116,906.94	53,426,611.12
Deferred Regulatory Assets	388,800,142.12	357,236,196.73
Other Deferred Debits	1,804,929.40	1,328,343.09
Total	446,320,619.26	447,083,242.27
Total Assets	$ 3,586,965,578.54	$ 3,490,363,804.10

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	879,118,652.63	849,838,699.75
Total Proprietary Capital	1,387,034,687.08	1,357,754,734.20
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,401,507.42	531,121,647.48
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,705,507.42	1,105,425,647.48
Total Capitalization	2,492,740,194.50	2,463,180,381.68
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	-
Accounts Payable	92,234,601.80	75,673,663.92
Accounts Payable to Associated Companies	15,938,027.00	14,546,268.31
Customer Deposits	22,435,650.26	23,240,672.59
Taxes Accrued	17,874,000.30	18,309,170.54
Dividends Declared	-	-
Interest Accrued	12,083,404.23	11,708,678.03
Miscellaneous Current and Accrued Liabilities	28,854,345.46	32,140,201.55
Total	189,420,029.05	175,618,654.94
Deferred Credits and Other		
Accumulated Deferred Income Taxes	515,319,247.11	487,780,888.27
Investment Tax Credit	42,048,774.66	44,843,141.13
Regulatory Liabilities	58,003,499.13	62,145,912.07
Customer Advances for Construction	7,329,863.59	8,163,578.28
Asset Retirement Obligations	59,331,864.27	53,309,599.51
Other Deferred Credits	8,148,016.44	12,660,924.88
Miscellaneous Long-Term Liabilities	53,954,916.00	34,448,469.13
Accum Provision for Postretirement Benefits	160,669,173.79	148,212,254.21
Total	904,805,354.99	851,564,767.48
Total Liabilities and Stockholders' Equity	$ 3,586,965,578.54	$ 3,490,363,804.10

April 26, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 4,949,339,993.11	$ 4,782,878,078.55
Less: Reserves for Depreciation and Amortization	2,156,178,006.63	2,077,990,172.73
Total	2,793,161,986.48	2,704,887,905.82
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	11,879.20	11,879.20
Special Funds	27,925,671.53	20,392,613.99
Total	28,531,836.73	20,998,779.19
Current and Accrued Assets		
Cash	10,016,906.74	32,004,651.77
Special Deposits	-	5,336,432.10
Temporary Cash Investments	52,355,142.71	32,004,573.78
Accounts Receivable - Less Reserve	104,780,703.45	116,387,007.31
Accounts Receivable from Associated Companies	25,088,585.14	11,414,595.15
Materials and Supplies - At Average Cost		
Fuel	72,777,150.72	64,634,046.64
Plant Materials and Operating Supplies	30,871,620.53	29,834,678.95
Stores Expense	5,607,672.47	5,079,805.34
Gas Stored Underground	15,614,287.22	14,392,608.85
Emission Allowances	17,030.85	2,409.88
Prepayments	7,947,391.08	7,049,940.71
Miscellaneous Current and Accrued Assets	-	724,075.07
Total	325,076,490.91	318,864,825.55
Deferred Debits and Other		
Unamortized Debt Expense	13,372,967.21	13,309,465.49
Unamortized Loss on Bonds	20,579,912.22	21,530,637.65
Accumulated Deferred Income Taxes	22,116,906.94	53,426,611.12
Deferred Regulatory Assets	390,498,248.98	361,306,009.06
Other Deferred Debits	1,607,565.38	1,251,973.01
Total	448,175,600.73	450,824,696.33
Total Assets	$ 3,594,945,914.85	$ 3,495,576,206.89

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	880,877,328.94	852,322,196.36
Total Proprietary Capital	1,388,793,363.39	1,360,238,230.81
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,424,829.08	531,144,969.14
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,728,829.08	1,105,448,969.14
Total Capitalization	2,494,522,192.47	2,465,687,199.95
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	-
Accounts Payable	92,726,583.06	72,770,225.00
Accounts Payable to Associated Companies	15,978,347.55	27,020,672.69
Customer Deposits	22,664,278.75	23,394,006.56
Taxes Accrued	20,723,795.10	7,782,784.18
Dividends Declared	-	-
Interest Accrued	13,286,065.56	13,874,035.61
Miscellaneous Current and Accrued Liabilities	24,826,978.40	29,874,305.15
Total	190,206,048.42	174,716,029.19
Deferred Credits and Other		
Accumulated Deferred Income Taxes	515,319,247.11	487,780,888.27
Investment Tax Credit	41,825,418.66	44,607,107.13
Regulatory Liabilities	58,100,239.91	61,508,554.02
Customer Advances for Construction	7,260,539.35	8,115,146.29
Asset Retirement Obligations	59,575,768.76	53,172,083.34
Other Deferred Credits	8,766,043.62	15,198,179.97
Miscellaneous Long-Term Liabilities	58,676,959.72	36,567,706.97
Accum Provision for Postretirement Benefits	160,693,456.83	148,223,311.76
Total	910,217,673.96	855,172,977.75
Total Liabilities and Stockholders' Equity	$ 3,594,945,914.85	$ 3,495,576,206.89

May 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.....................................	$ 4,955,335,855.52	$ 4,792,382,669.03
Less: Reserves for Depreciation and Amortization....	2,154,314,007.40	2,086,932,887.81
Total..	2,801,021,848.12	2,705,449,781.22
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	489,420.24	11,879.20
Special Funds...	30,038,647.44	21,674,314.80
Total..	31,122,353.68	22,280,480.00
Current and Accrued Assets		
Cash..	2,723,379.80	42,642,184.10
Special Deposits...	-	6,103,356.02
Temporary Cash Investments....................................	56,789,553.88	16,607,994.23
Accounts Receivable - Less Reserve..........................	115,726,428.88	117,302,831.48
Accounts Receivable from Associated Companies....	18,516,220.52	17,220,727.53
Materials and Supplies - At Average Cost................		
Fuel..	77,965,508.21	64,042,394.78
Plant Materials and Operating Supplies.................	31,139,888.40	29,638,442.60
Stores Expense..	5,618,419.13	5,123,126.75
Gas Stored Underground.......................................	12,963,890.70	12,379,663.46
Emission Allowances..	14,818.81	2,331.27
Prepayments..	6,961,549.16	6,486,268.51
Miscellaneous Current and Accrued Assets..............	-	681,197.76
Total..	328,419,657.49	318,230,518.49
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,274,962.75	13,330,061.12
Unamortized Loss on Bonds......................................	20,477,457.55	21,429,634.70
Accumulated Deferred Income Taxes.......................	22,116,906.94	55,739,575.24
Deferred Regulatory Assets.......................................	394,427,029.43	358,597,038.27
Other Deferred Debits...	1,520,049.20	1,033,868.72
Total..	451,816,405.87	450,130,178.05
Total Assets...	$ 3,612,380,265.16	$ 3,496,090,957.76

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	875,545,328.22	831,803,763.59
Total Proprietary Capital...	1,383,461,362.67	1,339,719,798.04
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,448,150.74	531,168,290.80
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt..	1,105,752,150.74	1,105,472,290.80
Total Capitalization...	2,489,213,513.41	2,445,192,088.84
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	-
Notes Payable..	-	-
Accounts Payable..	99,605,780.92	83,744,950.28
Accounts Payable to Associated Companies............	13,538,755.10	13,185,424.92
Customer Deposits..	22,829,665.41	22,522,323.63
Taxes Accrued...	28,061,310.06	10,625,328.89
Dividends Declared..	16,000,000.00	25,000,000.00
Interest Accrued..	6,407,705.65	6,438,420.39
Miscellaneous Current and Accrued Liabilities.........	22,489,064.63	28,264,294.97
Total..	208,932,281.77	189,780,743.08
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	515,319,247.11	492,983,143.27
Investment Tax Credit...	41,602,062.66	44,371,073.13
Regulatory Liabilities..	55,477,787.65	59,210,182.72
Customer Advances for Construction.......................	7,054,434.77	8,092,132.24
Asset Retirement Obligations..................................	59,820,710.04	51,902,235.56
Other Deferred Credits...	9,845,612.27	18,472,668.22
Miscellaneous Long-Term Liabilities.......................	64,434,986.68	39,234,121.95
Accum Provision for Postretirement Benefits...........	160,679,628.80	146,852,568.75
Total..	914,234,469.98	861,118,125.84
Total Liabilities and Stockholders' Equity.....................	$ 3,612,380,265.16	$ 3,496,090,957.76

June 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.....................................	$ 4,974,883,424.55	$ 4,802,348,313.16
Less: Reserves for Depreciation and Amortization....	2,165,621,133.29	2,092,493,560.06
Total..	2,809,262,291.26	2,709,854,753.10
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	489,420.24	11,879.20
Special Funds...	31,222,671.10	22,505,965.16
Total..	32,306,377.34	23,112,130.36
Current and Accrued Assets		
Cash...	1,760,996.05	41,156,614.54
Special Deposits..	-	4,626,601.12
Temporary Cash Investments....................................	23,340,652.93	10,763.48
Accounts Receivable - Less Reserve.........................	129,522,191.56	126,976,576.30
Notes Receivable from Associated Companies.........	6,336,000.00	-
Accounts Receivable from Associated Companies....	20,911,591.65	12,749,748.11
Materials and Supplies - At Average Cost................		
Fuel..	81,713,136.72	67,711,396.61
Plant Materials and Operating Supplies.................	31,497,096.89	29,950,707.42
Stores Expense...	5,757,071.63	5,157,847.02
Gas Stored Underground..	17,134,671.17	19,007,070.36
Emission Allowances..	12,781.82	2,233.53
Prepayments..	8,474,255.83	7,798,435.51
Miscellaneous Current and Accrued Assets..............	28,664.30	605,541.52
Total..	326,489,110.55	315,753,535.52
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,435,346.42	13,247,160.62
Unamortized Loss on Bonds......................................	20,375,002.88	21,328,631.75
Accumulated Deferred Income Taxes.......................	20,590,827.55	55,536,998.05
Deferred Regulatory Assets.......................................	391,327,323.63	355,709,240.35
Other Deferred Debits...	1,519,555.11	1,478,646.74
Total..	447,248,055.59	447,300,677.51
Total Assets...	$ 3,615,305,834.74	$ 3,496,021,096.49

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	888,274,232.93	844,832,315.17
Total Proprietary Capital...	1,396,190,267.38	1,352,748,349.62
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,471,472.40	531,191,612.46
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt..	1,105,775,472.40	1,105,495,612.46
Total Capitalization...	2,501,965,739.78	2,458,243,962.08
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	-
Notes Payable..	-	-
Accounts Payable..	96,664,918.41	85,621,470.31
Accounts Payable to Associated Companies............	16,094,052.20	13,004,765.06
Customer Deposits..	22,941,224.37	22,604,581.72
Taxes Accrued...	28,344,767.32	10,103,469.64
Dividends Declared...	-	-
Interest Accrued..	5,549,087.36	5,332,202.80
Miscellaneous Current and Accrued Liabilities.........	22,622,779.87	25,114,319.95
Total..	192,216,829.53	161,780,809.48
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	527,001,372.70	506,075,924.63
Investment Tax Credit...	41,378,705.16	44,135,039.13
Regulatory Liabilities..	53,918,978.47	59,639,476.44
Customer Advances for Construction.......................	6,986,694.49	8,117,149.39
Asset Retirement Obligations...................................	59,316,628.51	52,117,276.38
Other Deferred Credits..	10,593,268.77	21,631,372.89
Miscellaneous Long-Term Liabilities.......................	62,460,773.32	37,441,515.45
Accum Provision for Postretirement Benefits...........	159,466,844.01	146,838,570.62
Total..	921,123,265.43	875,996,324.93
Total Liabilities and Stockholders' Equity......................	$ 3,615,305,834.74	$ 3,496,021,096.49

July 26, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 5,014,081,528.26	$ 4,813,897,037.14
Less: Reserves for Depreciation and Amortization....	2,176,953,369.14	2,103,467,014.13
Total...	2,837,128,159.12	2,710,430,023.01
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	489,420.24	11,879.20
Special Funds...	32,726,937.42	22,357,645.64
Total...	33,810,643.66	22,963,810.84
Current and Accrued Assets		
Cash..	12,005,288.42	38,334,376.50
Special Deposits...	-	3,151,789.21
Temporary Cash Investments....................................	39,024,144.73	18,512,047.18
Accounts Receivable - Less Reserve.........................	132,734,286.93	148,476,351.97
Notes Receivable from Associated Companies.........	1,479,000.00	-
Accounts Receivable from Associated Companies....	6,790,508.67	11,752,654.76
Materials and Supplies - At Average Cost................		
Fuel..	78,713,060.54	58,266,316.48
Plant Materials and Operating Supplies.................	31,950,402.21	30,252,113.88
Stores Expense..	5,834,577.23	5,282,243.47
Gas Stored Underground.......................................	24,611,086.84	32,199,333.75
Emission Allowances...	10,342.09	2,114.63
Prepayments...	7,725,383.83	6,527,553.62
Miscellaneous Current and Accrued Assets..............	28,664.30	642,063.90
Total...	340,906,745.79	353,398,959.35
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,340,316.65	13,272,796.01
Unamortized Loss on Bonds......................................	20,272,548.21	21,227,628.80
Accumulated Deferred Income Taxes.......................	20,590,827.53	55,536,998.05
Deferred Regulatory Assets.......................................	393,815,311.30	359,022,573.48
Other Deferred Debits..	1,555,265.33	1,307,123.49
Total...	449,574,269.02	450,367,119.83
Total Assets..	$ 3,661,419,817.59	$ 3,537,159,913.03

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings..	905,514,927.36	865,073,836.64
Total Proprietary Capital...	1,413,430,961.81	1,372,989,871.09
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,494,794.06	531,214,934.12
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt...	1,105,798,794.06	1,105,518,934.12
Total Capitalization..	2,519,229,755.87	2,478,508,805.21
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	-
Notes Payable...	-	-
Accounts Payable...	110,014,239.75	85,729,649.67
Accounts Payable to Associated Companies............	13,270,628.64	12,602,066.24
Customer Deposits...	23,052,350.61	22,714,988.20
Taxes Accrued..	40,485,132.50	23,590,209.81
Dividends Declared..	-	-
Interest Accrued...	7,470,803.71	7,939,349.46
Miscellaneous Current and Accrued Liabilities.........	21,624,281.77	23,212,684.00
Total...	215,917,436.98	175,788,947.38
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	527,001,372.71	506,075,924.63
Investment Tax Credit..	41,155,349.16	43,899,005.13
Regulatory Liabilities...	54,392,800.83	60,756,940.33
Customer Advances for Construction.......................	6,994,094.45	8,075,464.10
Asset Retirement Obligations..................................	59,560,218.98	52,226,757.13
Other Deferred Credits...	11,590,486.36	23,912,823.90
Miscellaneous Long-Term Liabilities.......................	66,125,249.06	42,351,120.43
Accum Provision for Postretirement Benefits..........	159,453,053.19	145,564,124.79
Total...	926,272,624.74	882,862,160.44
Total Liabilities and Stockholders' Equity.....................	$ 3,661,419,817.59	$ 3,537,159,913.03

August 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,027,591,244.87	$ 4,815,048,867.20
Less: Reserves for Depreciation and Amortization	2,179,786,041.44	2,099,822,626.80
Total	2,847,805,203.43	2,715,226,240.40
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	11,879.20
Special Funds	32,731,165.22	26,739,003.13
Total	33,814,871.46	27,345,168.33
Current and Accrued Assets		
Cash	4,535,999.33	41,235,356.47
Special Deposits	-	2,204,705.90
Temporary Cash Investments	44,534,395.43	42,115,568.00
Accounts Receivable - Less Reserve	129,119,558.61	133,715,904.02
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	12,586,629.53	14,603,137.03
Materials and Supplies - At Average Cost		
Fuel	73,755,685.60	51,087,714.21
Plant Materials and Operating Supplies	31,954,956.95	30,417,147.49
Stores Expense	5,890,452.07	5,422,256.65
Gas Stored Underground	34,297,757.43	45,030,809.18
Emission Allowances	8,417.59	2,005.06
Prepayments	6,196,010.61	6,575,036.00
Miscellaneous Current and Accrued Assets	55,054.73	951,689.47
Total	342,934,917.88	373,361,329.48
Deferred Debits and Other		
Unamortized Debt Expense	13,205,466.82	13,117,553.69
Unamortized Loss on Bonds	20,170,093.54	21,126,625.85
Accumulated Deferred Income Taxes	20,590,827.53	56,272,700.06
Deferred Regulatory Assets	391,229,041.18	369,108,007.04
Other Deferred Debits	1,622,696.20	1,352,515.52
Total	446,818,125.27	460,977,402.16
Total Assets	$ 3,671,373,118.04	$ 3,576,910,140.37

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	905,451,395.08	863,429,950.41
Total Proprietary Capital	1,413,367,429.53	1,371,345,984.86
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,518,115.72	531,238,255.78
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,822,115.72	1,105,542,255.78
Total Capitalization	2,519,189,545.25	2,476,888,240.64
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	-	-
Accounts Payable	91,562,468.16	87,601,078.61
Accounts Payable to Associated Companies	14,115,468.89	17,443,956.77
Customer Deposits	23,041,114.99	22,667,140.95
Taxes Accrued	50,670,314.40	31,834,314.50
Dividends Declared	16,250,000.00	13,000,000.00
Interest Accrued	8,756,470.55	9,378,075.45
Miscellaneous Current and Accrued Liabilities	22,359,783.68	23,121,809.92
Total	226,755,620.67	205,046,376.20
Deferred Credits and Other		
Accumulated Deferred Income Taxes	527,001,372.71	504,554,359.26
Investment Tax Credit	40,931,993.16	43,662,971.13
Regulatory Liabilities	53,929,760.21	62,515,471.19
Customer Advances for Construction	6,999,243.15	8,059,948.10
Asset Retirement Obligations	59,582,063.96	52,443,159.11
Other Deferred Credits	13,292,154.95	26,770,314.68
Miscellaneous Long-Term Liabilities	64,252,063.42	51,419,138.37
Accum Provision for Postretirement Benefits	159,439,300.56	145,550,161.69
Total	925,427,952.12	894,975,523.53
Total Liabilities and Stockholders' Equity	$ 3,671,373,118.04	$ 3,576,910,140.37

September 24, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 5,038,451,961.90	$ 4,834,755,063.44
Less: Reserves for Depreciation and Amortization....	2,189,489,496.18	2,109,448,034.24
Total...	2,848,962,465.72	2,725,307,029.20
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	529,399.03	11,879.20
Special Funds..	32,235,216.00	29,511,083.19
Total...	33,358,901.03	30,117,248.39
Current and Accrued Assets		
Cash...	6,447,044.04	36,121,124.88
Special Deposits..	-	1,203,174.45
Temporary Cash Investments....................................	41,089,237.10	38,421,281.63
Accounts Receivable - Less Reserve.........................	121,917,865.73	115,617,416.71
Notes Receivable from Associated Companies.........	-	-
Accounts Receivable from Associated Companies....	12,268,738.68	10,903,711.10
Materials and Supplies - At Average Cost................		
Fuel..	70,658,087.85	52,528,086.41
Plant Materials and Operating Supplies.................	31,982,438.44	30,797,037.86
Stores Expense...	5,825,571.88	5,476,575.61
Gas Stored Underground..	43,171,101.97	56,853,462.78
Emission Allowances..	6,142.14	2,772.88
Prepayments..	5,986,499.65	6,339,120.25
Miscellaneous Current and Accrued Assets..............	-	761,979.55
Total...	339,352,727.48	355,025,744.11
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,109,416.74	13,044,553.50
Unamortized Loss on Bonds......................................	20,067,638.87	21,025,622.90
Accumulated Deferred Income Taxes.......................	19,781,210.52	26,152,975.69
Deferred Regulatory Assets.......................................	389,889,081.35	383,199,682.64
Other Deferred Debits...	1,736,802.60	1,330,450.74
Total...	444,584,150.08	444,753,285.47
Total Assets..	$ 3,666,258,244.31	$ 3,555,203,307.17

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	915,074,377.72	874,925,832.17
Total Proprietary Capital...	1,422,990,412.17	1,382,841,866.62
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,541,437.38	531,261,577.46
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt..	1,105,845,437.38	1,105,565,577.46
Total Capitalization...	2,528,835,849.55	2,488,407,444.08
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	-
Notes Payable..	-	-
Accounts Payable..	95,601,507.96	81,366,680.34
Accounts Payable to Associated Companies............	23,509,748.16	21,152,123.73
Customer Deposits..	22,994,495.65	22,546,494.46
Taxes Accrued...	33,871,908.20	18,953,407.93
Dividends Declared...	-	-
Interest Accrued..	10,965,648.79	12,029,932.24
Miscellaneous Current and Accrued Liabilities.........	22,223,302.18	21,917,601.45
Total...	209,166,610.94	177,966,240.15
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	540,233,826.23	487,104,353.22
Investment Tax Credit...	40,708,635.66	43,426,937.13
Regulatory Liabilities..	51,575,729.21	60,890,790.21
Customer Advances for Construction.......................	6,890,680.89	8,049,779.58
Asset Retirement Obligations...................................	59,720,626.70	55,794,013.83
Other Deferred Credits..	9,132,291.82	29,396,986.25
Miscellaneous Long-Term Liabilities.......................	61,685,599.38	58,630,593.68
Accum Provision for Postretirement Benefits...........	158,308,393.93	145,536,169.04
Total...	928,255,783.82	888,829,622.94
Total Liabilities and Stockholders' Equity......................	$ 3,666,258,244.31	$ 3,555,203,307.17

October 24, 2012

Attachment 3 to Response to AG-1 Question No. 270
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Arbough

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost....................................	$ 5,072,415,973.89	$ 4,854,087,312.73
Less: Reserves for Depreciation and Amortization....	2,198,815,952.28	2,119,839,274.24
Total...	2,873,600,021.61	2,734,248,038.49
Investments		
Ohio Valley Electric Corporation.............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	528,727.07	11,879.20
Special Funds...	31,738,777.33	29,513,085.39
Total...	32,861,790.40	30,119,250.59
Current and Accrued Assets		
Cash..	4,229,699.86	42,810,271.73
Special Deposits..	-	557,339.76
Temporary Cash Investments....................................	37,224,301.98	31,125,914.89
Accounts Receivable - Less Reserve.........................	111,441,066.03	105,912,233.14
Notes Receivable from Associated Companies.........	-	-
Accounts Receivable from Associated Companies....	13,107,960.96	11,234,858.52
Materials and Supplies - At Average Cost................		
Fuel..	68,476,162.63	59,220,758.36
Plant Materials and Operating Supplies.................	31,821,287.16	30,813,805.38
Stores Expense...	5,799,417.86	5,577,590.22
Gas Stored Underground..	51,815,567.01	66,152,494.75
Emission Allowances..	4,433.73	24,614.20
Prepayments..	5,376,103.15	5,460,672.11
Miscellaneous Current and Accrued Assets..............	-	607,780.56
Total...	329,296,000.37	359,498,333.62
Deferred Debits and Other		
Unamortized Debt Expense.......................................	12,968,666.66	13,557,379.65
Unamortized Loss on Bonds......................................	19,965,184.20	20,924,619.95
Accumulated Deferred Income Taxes.......................	20,181,843.17	26,434,331.06
Deferred Regulatory Assets.......................................	384,311,220.22	376,302,783.78
Other Deferred Debits...	1,879,355.74	1,365,988.12
Total...	439,306,269.99	438,585,102.56
Total Assets..	$ 3,675,064,082.37	$ 3,562,450,725.26

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	83,581,499.00	83,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings..	919,980,877.70	877,862,183.07
Total Proprietary Capital...	1,427,896,912.15	1,385,778,217.52
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,564,759.04	531,284,899.12
LT Notes Payable to Associated Companies............	-	-
Total Long-Term Debt...	1,105,868,759.04	1,105,588,899.12
Total Capitalization..	2,533,765,671.19	2,491,367,116.64
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies............	-	-
Notes Payable...	-	-
Accounts Payable...	104,244,188.17	91,057,684.20
Accounts Payable to Associated Companies............	15,954,240.75	13,798,613.52
Customer Deposits...	23,160,507.46	22,425,873.82
Taxes Accrued..	28,747,564.06	23,483,954.44
Dividends Declared..	-	-
Interest Accrued..	12,347,285.91	13,345,579.80
Miscellaneous Current and Accrued Liabilities.........	23,215,765.19	19,943,526.53
Total...	207,669,551.54	184,055,232.31
Deferred Credits and Other		
Accumulated Deferred Income Taxes......................	545,563,011.90	487,243,920.69
Investment Tax Credit..	40,485,279.66	43,190,903.13
Regulatory Liabilities...	51,115,164.33	61,440,578.69
Customer Advances for Construction.......................	6,776,700.92	8,022,178.51
Asset Retirement Obligations..................................	59,489,283.35	55,792,039.70
Other Deferred Credits...	10,338,677.38	32,850,657.34
Miscellaneous Long-Term Liabilities.......................	61,565,964.78	54,212,429.21
Accum Provision for Postretirement Benefits..........	158,294,777.32	144,275,669.04
Total...	933,628,859.64	887,028,376.31
Total Liabilities and Stockholders' Equity.....................	$ 3,675,064,082.37	$ 3,562,450,725.26

November 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,089,281,905.69	$ 4,872,997,987.35
Less: Reserves for Depreciation and Amortization	2,195,394,384.85	2,126,828,778.97
Total	2,893,887,520.84	2,746,169,208.38
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	527,721.95	11,879.20
Special Funds	31,743,108.24	28,514,787.39
Total	32,865,116.19	29,120,952.59
Current and Accrued Assets		
Cash	1,767,229.44	34,195,977.48
Special Deposits	-	-
Temporary Cash Investments	24,256,181.41	29,029,898.75
Accounts Receivable - Less Reserve	126,039,216.73	114,669,412.44
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	14,468,670.16	11,548,437.29
Materials and Supplies - At Average Cost		
Fuel	65,493,205.88	55,707,094.47
Plant Materials and Operating Supplies	32,475,982.80	30,482,076.24
Stores Expense	5,824,485.57	5,550,219.41
Gas Stored Underground	49,302,196.90	62,658,874.27
Emission Allowances	2,271.75	26,604.68
Prepayments	4,197,223.54	4,982,269.92
Miscellaneous Current and Accrued Assets	191,189.92	-
Total	324,017,854.10	348,850,864.95
Deferred Debits and Other		
Unamortized Debt Expense	12,777,429.70	13,447,248.44
Unamortized Loss on Bonds	19,862,729.53	20,823,617.00
Accumulated Deferred Income Taxes	20,181,843.18	26,355,404.03
Deferred Regulatory Assets	384,389,779.28	379,199,955.06
Other Deferred Debits	2,468,920.19	1,649,265.49
Total	439,680,701.88	441,475,490.02
Total Assets	$ 3,690,451,193.01	$ 3,565,616,515.94

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	900,600,053.15	856,776,505.55
Total Proprietary Capital	1,408,516,087.60	1,364,692,540.00
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,588,080.70	531,308,220.78
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,105,892,080.70	1,105,612,220.78
Total Capitalization	2,514,408,168.30	2,470,304,760.78
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	9,999,683.34	-
Accounts Payable	109,469,936.19	81,283,596.90
Accounts Payable to Associated Companies	15,271,102.39	16,784,036.42
Customer Deposits	23,279,184.37	22,388,530.85
Taxes Accrued	25,219,842.07	29,529,563.22
Dividends Declared	28,000,000.00	28,000,000.00
Interest Accrued	5,390,338.93	5,951,860.54
Miscellaneous Current and Accrued Liabilities	25,079,425.89	19,807,279.09
Total	241,709,513.18	203,744,867.02
Deferred Credits and Other		
Accumulated Deferred Income Taxes	545,563,011.90	487,425,528.06
Investment Tax Credit	40,261,923.17	42,954,869.13
Regulatory Liabilities	50,731,141.32	60,622,974.76
Customer Advances for Construction	6,738,520.31	7,247,002.77
Asset Retirement Obligations	59,733,563.53	56,022,754.36
Other Deferred Credits	11,566,373.85	35,534,880.32
Miscellaneous Long-Term Liabilities	62,635,802.67	57,497,148.14
Accum Provision for Postretirement Benefits	157,103,174.78	144,261,730.60
Total	934,333,511.53	891,566,888.14
Total Liabilities and Stockholders' Equity	$ 3,690,451,193.01	$ 3,565,616,515.94

December 21, 2012

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2012 and 2011

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,142,141,435.14	$ 4,897,295,931.52
Less: Reserves for Depreciation and Amortization	2,201,756,056.71	2,117,873,452.51
Total	2,940,385,378.43	2,779,422,479.01
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	527,049.99	11,879.20
Special Funds	31,747,623.54	28,846,730.20
Total	32,868,959.53	29,452,895.40
Current and Accrued Assets		
Cash	7,372,093.05	24,920,484.53
Special Deposits	-	12,277.00
Temporary Cash Investments	14,316,601.29	33,063.99
Accounts Receivable - Less Reserve	147,774,702.72	137,419,594.66
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	13,662,417.99	10,916,898.01
Materials and Supplies - At Average Cost		
Fuel	61,099,619.31	52,502,546.26
Plant Materials and Operating Supplies	32,727,609.51	30,625,941.68
Stores Expense	5,860,024.37	5,596,505.54
Gas Stored Underground	42,010,154.00	53,287,604.59
Emission Allowances	1,771.39	2,511.67
Prepayments	6,976,760.79	5,472,353.44
Miscellaneous Current and Accrued Assets	7,142,276.04	-
Total	338,944,030.46	320,789,781.37
Deferred Debits and Other		
Unamortized Debt Expense	13,126,319.25	13,326,195.59
Unamortized Loss on Bonds	19,968,045.28	20,963,862.78
Accumulated Deferred Income Taxes	106,846,805.72	23,826,072.01
Deferred Regulatory Assets	408,462,227.05	397,110,901.24
Other Deferred Debits	1,942,008.43	1,480,708.22
Total	550,345,405.73	456,707,739.84
Total Assets	$ 3,862,543,774.15	$ 3,586,372,895.62

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	916,602,335.62	868,929,557.39
Total Proprietary Capital	1,424,518,370.07	1,376,845,591.84
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,611,402.36	531,331,542.44
Total Long-Term Debt	1,105,915,402.36	1,105,635,542.44
Total Capitalization	2,530,433,772.43	2,482,481,134.28
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	54,992,669.46	-
Accounts Payable	121,578,265.62	97,848,807.56
Accounts Payable to Associated Companies	22,801,659.30	25,528,425.55
Customer Deposits	23,464,189.08	22,361,041.85
Taxes Accrued	1,735,494.84	13,284,849.56
Dividends Declared	-	-
Interest Accrued	5,118,488.31	5,825,755.42
Miscellaneous Current and Accrued Liabilities	25,492,408.81	22,176,210.30
Total	255,183,175.42	187,025,090.24
Deferred Credits and Other		
Accumulated Deferred Income Taxes	657,001,051.36	499,655,847.56
Investment Tax Credit	39,871,226.65	42,718,844.13
Regulatory Liabilities	56,225,013.57	58,617,596.40
Customer Advances for Construction	6,709,975.18	7,307,168.56
Asset Retirement Obligations	64,684,737.37	58,606,350.25
Other Deferred Credits	7,409,316.48	5,120,367.14
Miscellaneous Long-Term Liabilities	58,713,172.11	60,707,001.86
Accum Provision for Postretirement Benefits	186,312,333.58	184,133,495.20
Total	1,076,926,826.30	916,866,671.10
Total Liabilities and Stockholders' Equity	$ 3,862,543,774.15	$ 3,586,372,895.62

January 25, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,167,479,536.50	$ 4,909,056,549.82
Less: Reserves for Depreciation and Amortization	2,212,595,282.35	2,129,469,771.92
Total	2,954,884,254.15	2,779,586,777.90
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	526,378.03	11,879.20
Special Funds	30,251,930.44	29,788,557.01
Total	31,372,594.47	30,394,722.21
Current and Accrued Assets		
Cash	5,030,414.68	22,562,167.83
Special Deposits	1,897.82	12,277.00
Temporary Cash Investments	21,145,805.00	33,199.87
Accounts Receivable - Less Reserve	182,018,031.74	143,404,574.12
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	15,701,111.16	12,419,799.02
Materials and Supplies - At Average Cost		
Fuel	55,186,491.79	50,199,426.27
Plant Materials and Operating Supplies	34,044,336.81	30,878,565.61
Stores Expense	5,660,118.60	5,639,880.99
Gas Stored Underground	30,073,532.84	41,005,070.14
Emission Allowances	(705.19)	19,936.74
Prepayments	7,061,717.26	5,317,036.50
Miscellaneous Current and Accrued Assets	12,847,239.85	-
Total	368,769,992.36	311,491,934.09
Deferred Debits and Other		
Unamortized Debt Expense	12,991,495.50	13,189,647.53
Unamortized Loss on Bonds	19,891,987.34	20,885,609.22
Accumulated Deferred Income Taxes	106,846,805.72	23,749,922.01
Deferred Regulatory Assets	402,665,333.71	399,361,510.17
Other Deferred Debits	1,613,170.75	1,259,355.16
Total	544,008,793.02	458,446,044.09
Total Assets	$ 3,899,035,634.00	$ 3,579,919,478.29

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	83,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	932,554,302.72	882,491,644.40
Total Proprietary Capital	1,440,470,337.17	1,390,407,678.85
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,634,724.02	531,354,864.10
Total Long-Term Debt	1,105,938,724.02	1,105,658,864.10
Total Capitalization	2,546,409,061.19	2,496,066,542.95
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	114,991,594.45	-
Accounts Payable	123,960,910.00	90,067,704.18
Accounts Payable to Associated Companies	13,113,858.27	15,168,942.65
Customer Deposits	23,484,456.67	22,478,501.90
Taxes Accrued	6,130,384.39	19,172,547.29
Dividends Declared	-	-
Interest Accrued	7,232,237.99	8,169,288.22
Miscellaneous Current and Accrued Liabilities	25,819,342.34	27,349,223.25
Total	314,732,784.11	182,406,207.49
Deferred Credits and Other		
Accumulated Deferred Income Taxes	657,001,051.36	499,655,847.55
Investment Tax Credit	39,742,902.65	42,495,488.13
Regulatory Liabilities	60,951,140.88	60,785,846.15
Customer Advances for Construction	6,756,993.26	7,319,187.89
Asset Retirement Obligations	64,920,825.85	58,847,147.60
Other Deferred Credits	9,409,962.23	8,612,478.80
Miscellaneous Long-Term Liabilities	54,312,108.09	61,995,072.79
Accum Provision for Postretirement Benefits	144,798,804.38	161,735,658.94
Total	1,037,893,788.70	901,446,727.85
Total Liabilities and Stockholders' Equity	$ 3,899,035,634.00	$ 3,579,919,478.29

February 21, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 28, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,203,508,033.24	$ 4,919,723,457.68
Less: Reserves for Depreciation and Amortization	2,222,944,323.21	2,137,988,703.28
Total	2,980,563,710.03	2,781,734,754.40
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	525,706.07	11,879.20
Special Funds	27,853,318.97	30,310,548.45
Total	28,973,311.04	30,916,713.65
Current and Accrued Assets		
Cash	5,406,414.77	38,370,592.06
Temporary Cash Investments	25,386,862.99	16,534,761.64
Accounts Receivable - Less Reserve	181,114,088.81	129,860,629.76
Accounts Receivable from Associated Companies	35,298,621.92	15,190,151.03
Materials and Supplies - At Average Cost		
Fuel	53,584,247.86	57,383,128.29
Plant Materials and Operating Supplies	34,369,732.02	30,831,292.12
Stores Expense	5,716,710.78	5,538,432.48
Gas Stored Underground	19,553,217.95	27,251,651.60
Emission Allowances	8,211.08	18,675.79
Prepayments	7,850,382.49	5,872,637.42
Miscellaneous Current and Accrued Assets	10,850,015.35	-
Total	379,138,506.02	326,851,952.19
Deferred Debits and Other		
Unamortized Debt Expense	12,856,710.29	13,053,099.47
Unamortized Loss on Bonds	19,821,272.26	20,784,542.53
Accumulated Deferred Income Taxes	107,462,562.43	23,749,922.01
Deferred Regulatory Assets	401,922,192.81	396,075,506.26
Other Deferred Debits	1,492,282.60	1,224,882.41
Total	543,555,020.39	454,887,952.68
Total Assets	$ 3,932,230,547.48	$ 3,594,391,372.92

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	108,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	927,981,204.69	872,702,746.19
Total Proprietary Capital	1,460,897,239.14	1,380,618,780.64
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,658,045.68	531,378,185.76
Total Long-Term Debt	1,105,962,045.68	1,105,682,185.76
Total Capitalization	2,566,859,284.82	2,486,300,966.40
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	94,989,974.98	-
Accounts Payable	121,657,647.50	96,978,222.55
Accounts Payable to Associated Companies	14,716,564.81	13,291,277.31
Customer Deposits	23,625,632.91	22,518,161.40
Taxes Accrued	16,227,214.04	23,830,129.23
Dividends Declared	19,000,000.00	15,000,000.00
Interest Accrued	8,334,450.93	9,522,801.62
Miscellaneous Current and Accrued Liabilities	27,538,157.13	27,524,482.90
Total	326,089,642.30	208,665,075.01
Deferred Credits and Other		
Accumulated Deferred Income Taxes	657,616,808.47	499,655,847.55
Investment Tax Credit	39,607,273.65	42,272,132.13
Regulatory Liabilities	59,285,491.84	59,483,304.96
Customer Advances for Construction	6,704,841.60	7,342,362.81
Asset Retirement Obligations	65,011,482.41	59,088,992.03
Other Deferred Credits	11,115,141.56	10,978,950.12
Miscellaneous Long-Term Liabilities	55,155,396.82	58,881,944.50
Accum Provision for Postretirement Benefits	144,785,184.01	161,721,797.41
Total	1,039,281,620.36	899,425,331.51
Total Liabilities and Stockholders' Equity	$ 3,932,230,547.48	$ 3,594,391,372.92

March 21, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,240,543,201.82	$ 4,933,705,788.03
Less: Reserves for Depreciation and Amortization	2,232,492,243.42	2,144,260,445.77
Total	3,008,050,958.40	2,789,445,342.26
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	525,034.11	11,879.20
Special Funds	27,356,493.29	26,812,546.91
Total	28,475,813.40	27,418,712.11
Current and Accrued Assets		
Cash	13,358,033.75	37,944,606.65
Temporary Cash Investments	20,537,988.63	16,338,854.02
Accounts Receivable - Less Reserve	176,498,356.08	121,482,082.46
Accounts Receivable from Associated Companies	12,261,257.01	20,097,723.37
Materials and Supplies - At Average Cost		
Fuel	51,990,437.53	66,393,015.44
Plant Materials and Operating Supplies	34,245,776.81	30,964,056.64
Stores Expense	5,733,638.24	5,553,099.47
Gas Stored Underground	12,790,124.32	20,184,889.10
Emission Allowances	7,289.18	17,221.12
Prepayments	7,035,150.93	4,804,662.67
Miscellaneous Current and Accrued Assets	11,947,786.86	693.97
Total	346,405,839.34	323,780,904.91
Deferred Debits and Other		
Unamortized Debt Expense	12,721,931.60	12,916,551.41
Unamortized Loss on Bonds	19,717,723.31	20,682,089.39
Accumulated Deferred Income Taxes	105,600,953.75	22,116,906.94
Deferred Regulatory Assets	398,753,301.39	388,800,142.12
Other Deferred Debits	2,071,241.05	1,804,929.40
Total	538,865,151.10	446,320,619.26
Total Assets	$ 3,921,797,762.24	$ 3,586,965,578.54

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	108,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	941,920,995.41	879,118,652.63
Total Proprietary Capital	1,474,837,029.86	1,387,034,687.08
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,681,367.34	531,401,507.42
Total Long-Term Debt	1,105,985,367.34	1,105,705,507.42
Total Capitalization	2,580,822,397.20	2,492,740,194.50
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	69,994,680.53	-
Accounts Payable	126,432,156.04	92,234,601.80
Accounts Payable to Associated Companies	16,044,323.15	15,938,027.00
Customer Deposits	23,859,840.87	22,435,650.26
Taxes Accrued	18,612,357.30	17,874,000.30
Dividends Declared	-	-
Interest Accrued	10,622,408.79	12,083,404.23
Miscellaneous Current and Accrued Liabilities	29,585,242.10	28,854,345.46
Total	295,151,008.78	189,420,029.05
Deferred Credits and Other		
Accumulated Deferred Income Taxes	666,905,987.64	515,319,247.11
Investment Tax Credit	39,471,644.65	42,048,774.66
Regulatory Liabilities	59,379,429.27	58,003,499.13
Customer Advances for Construction	6,675,322.68	7,329,863.59
Asset Retirement Obligations	66,165,250.85	59,331,864.27
Other Deferred Credits	9,754,305.37	8,148,016.44
Miscellaneous Long-Term Liabilities	53,818,113.37	53,954,916.00
Accum Provision for Postretirement Benefits	143,654,302.43	160,669,173.79
Total	1,045,824,356.26	904,805,354.99
Total Liabilities and Stockholders' Equity	$ 3,921,797,762.24	$ 3,586,965,578.54

April 24, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 5,284,282,587.16	$ 4,949,339,993.11
Less: Reserves for Depreciation and Amortization......	2,240,867,369.38	2,156,178,006.63
Total..	3,043,415,217.78	2,793,161,986.48
Investments		
Ohio Valley Electric Corporation................................	594,286.00	594,286.00
Nonutility Property - Less Reserve..............................	524,362.15	11,879.20
Special Funds...	27,759,880.69	27,925,671.53
Total..	28,878,528.84	28,531,836.73
Current and Accrued Assets		
Cash...	8,553,583.33	10,016,906.74
Temporary Cash Investments......................................	26,390,246.29	52,355,142.71
Accounts Receivable - Less Reserve...........................	147,956,584.39	104,780,703.45
Accounts Receivable from Associated Companies.....	9,509,326.41	25,088,585.14
Materials and Supplies - At Average Cost..................		
Fuel...	61,288,516.31	72,777,150.72
Plant Materials and Operating Supplies...................	34,563,046.74	30,871,620.53
Stores Expense...	5,818,678.03	5,607,672.47
Gas Stored Underground..	9,589,099.05	15,614,287.22
Emission Allowances..	6,549.64	17,030.85
Prepayments..	9,807,241.06	7,947,391.08
Miscellaneous Current and Accrued Assets................	6,322,137.30	-
Total..	319,805,008.55	325,076,490.91
Deferred Debits and Other		
Unamortized Debt Expense...	12,587,106.99	13,372,967.21
Unamortized Loss on Bonds..	19,631,104.11	20,579,912.22
Accumulated Deferred Income Taxes.........................	105,600,953.75	22,116,906.94
Deferred Regulatory Assets...	400,618,874.29	390,498,248.98
Other Deferred Debits..	1,788,127.03	1,607,565.38
Total..	540,226,166.17	448,175,600.73
Total Assets..	$ 3,932,324,921.34	$ 3,594,945,914.85

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense....................................	835,888.64	835,888.64
Paid-In Capital..	108,581,499.00	83,581,499.00
Other Comprehensive Income.....................................	-	-
Retained Earnings..	944,015,648.47	880,877,328.94
Total Proprietary Capital...	1,476,931,682.92	1,388,793,363.39
Pollution Control Bonds - Net of Reacquired Bonds..	574,304,000.00	574,304,000.00
First Mortgage Bonds..	531,704,689.00	531,424,829.08
Total Long-Term Debt...	1,106,008,689.00	1,105,728,829.08
Total Capitalization...	2,582,940,371.92	2,494,522,192.47
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies..............	-	-
Notes Payable..	49,994,470.81	-
Accounts Payable..	148,611,961.51	92,726,583.06
Accounts Payable to Associated Companies..............	29,396,914.55	15,978,347.55
Customer Deposits..	24,100,589.15	22,664,278.75
Taxes Accrued...	11,415,566.56	20,723,795.10
Dividends Declared...	-	-
Interest Accrued...	11,739,603.29	13,286,065.56
Miscellaneous Current and Accrued Liabilities..........	29,346,999.98	24,826,978.40
Total..	304,606,105.85	190,206,048.42
Deferred Credits and Other		
Accumulated Deferred Income Taxes.........................	666,905,987.64	515,319,247.11
Investment Tax Credit...	39,282,670.65	41,825,418.66
Regulatory Liabilities..	54,079,671.82	58,100,239.91
Customer Advances for Construction.........................	6,630,314.66	7,260,539.35
Asset Retirement Obligations.....................................	66,404,615.07	59,575,768.76
Other Deferred Credits..	10,860,188.92	8,766,043.62
Miscellaneous Long-Term Liabilities.........................	56,974,227.08	58,676,959.72
Accum Provision for Postretirement Benefits............	143,640,767.73	160,693,456.83
Total..	1,044,778,443.57	910,217,673.96
Total Liabilities and Stockholders' Equity........................	$ 3,932,324,921.34	$ 3,594,945,914.85

May 21, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,334,168,672.32	$ 4,955,335,855.52
Less: Reserves for Depreciation and Amortization	2,249,964,605.91	2,154,314,007.40
Total	3,084,204,066.41	2,801,021,848.12
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	489,420.24
Special Funds	25,262,989.42	30,038,647.44
Total	26,346,695.66	31,122,353.68
Current and Accrued Assets		
Cash	3,063,433.86	2,723,379.80
Temporary Cash Investments	10,820,016.50	56,789,553.88
Accounts Receivable - Less Reserve	145,340,381.35	115,726,428.88
Accounts Receivable from Associated Companies	33,412,514.86	18,516,220.52
Materials and Supplies - At Average Cost		
Fuel	63,670,490.98	77,965,508.21
Plant Materials and Operating Supplies	35,151,353.66	31,139,888.40
Stores Expense	5,833,709.11	5,618,419.13
Gas Stored Underground	8,472,755.53	12,963,890.70
Emission Allowances	5,710.10	14,818.81
Prepayments	8,731,338.35	6,961,549.16
Miscellaneous Current and Accrued Assets	25,975,791.61	-
Total	340,477,495.91	328,419,657.49
Deferred Debits and Other		
Unamortized Debt Expense	12,452,282.38	13,274,962.75
Unamortized Loss on Bonds	19,527,484.91	20,477,457.55
Accumulated Deferred Income Taxes	105,600,953.75	22,116,906.94
Deferred Regulatory Assets	392,448,302.41	394,427,029.43
Other Deferred Debits	1,761,489.32	1,520,049.20
Total	531,790,512.77	451,816,405.87
Total Assets	$ 3,982,818,770.75	$ 3,612,380,265.16

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	925,552,953.35	875,545,328.22
Total Proprietary Capital	1,487,468,987.80	1,383,461,362.67
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,728,010.66	531,448,150.74
Total Long-Term Debt	1,106,032,010.66	1,105,752,150.74
Total Capitalization	2,593,500,998.46	2,489,213,513.41
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	69,991,055.52	-
Accounts Payable	141,692,072.25	99,605,780.92
Accounts Payable to Associated Companies	15,816,566.80	13,538,755.10
Customer Deposits	23,942,701.78	22,829,665.41
Taxes Accrued	19,418,066.43	28,061,310.06
Dividends Declared	29,000,000.00	16,000,000.00
Interest Accrued	4,695,144.36	6,407,705.65
Miscellaneous Current and Accrued Liabilities	25,960,777.07	22,489,064.63
Total	330,516,384.21	208,932,281.77
Deferred Credits and Other		
Accumulated Deferred Income Taxes	666,905,987.64	515,319,247.11
Investment Tax Credit	39,093,696.65	41,602,062.66
Regulatory Liabilities	74,265,475.41	55,477,787.65
Customer Advances for Construction	6,639,598.96	7,054,434.77
Asset Retirement Obligations	66,638,965.96	59,820,710.04
Other Deferred Credits	12,410,503.50	9,845,612.27
Miscellaneous Long-Term Liabilities	49,219,909.26	64,434,986.68
Accum Provision for Postretirement Benefits	143,627,250.70	160,679,628.80
Total	1,058,801,388.08	914,234,469.98
Total Liabilities and Stockholders' Equity	$ 3,982,818,770.75	$ 3,612,380,265.16

June 21, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,378,994,655.84	$ 4,974,883,424.55
Less: Reserves for Depreciation and Amortization	2,260,073,132.03	2,165,621,133.29
Total	3,118,921,523.81	2,809,262,291.26
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	489,420.24
Special Funds	22,045,681.83	31,222,671.10
Total	23,129,388.07	32,306,377.34
Current and Accrued Assets		
Cash	5,599,679.48	1,760,996.05
Temporary Cash Investments	7,242,477.71	23,340,652.93
Accounts Receivable - Less Reserve	163,656,401.51	129,522,191.56
Accounts Receivable from Associated Companies	7,616,227.86	20,911,591.65
Materials and Supplies - At Average Cost		
Fuel	59,663,659.02	81,713,136.72
Plant Materials and Operating Supplies	35,651,188.45	31,497,096.89
Stores Expense	5,979,073.71	5,757,071.63
Gas Stored Underground	15,053,205.64	17,134,671.17
Emission Allowances	4,872.66	12,781.82
Prepayments	7,765,787.00	8,474,255.83
Miscellaneous Current and Accrued Assets	35,686,873.54	28,664.30
Total	343,919,446.58	326,489,110.55
Deferred Debits and Other		
Unamortized Debt Expense	12,317,457.77	13,435,346.42
Unamortized Loss on Bonds	19,423,865.71	20,375,002.88
Accumulated Deferred Income Taxes	106,027,258.96	20,590,827.55
Deferred Regulatory Assets	380,164,522.91	391,327,323.63
Other Deferred Debits	2,613,805.77	1,519,555.11
Total	520,546,911.12	447,248,055.59
Total Assets	$ 4,006,517,269.58	$ 3,615,305,834.74

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	941,395,957.72	888,274,232.93
Total Proprietary Capital	1,503,311,992.17	1,396,190,267.38
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,751,332.32	531,471,472.40
Total Long-Term Debt	1,106,055,332.32	1,105,775,472.40
Total Capitalization	2,609,367,324.49	2,501,965,739.78
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	80,490,016.63	-
Accounts Payable	153,721,284.77	96,664,918.41
Accounts Payable to Associated Companies	21,410,861.34	16,094,052.20
Customer Deposits	24,004,564.12	22,941,224.37
Taxes Accrued	13,775,204.13	28,344,767.32
Dividends Declared	-	-
Interest Accrued	4,914,356.01	5,549,087.36
Miscellaneous Current and Accrued Liabilities	25,649,962.66	22,622,779.87
Total	323,966,249.66	192,216,829.53
Deferred Credits and Other		
Accumulated Deferred Income Taxes	679,454,571.88	527,001,372.70
Investment Tax Credit	38,904,724.65	41,378,705.16
Regulatory Liabilities	83,857,243.68	53,918,978.47
Customer Advances for Construction	6,602,754.40	6,986,694.49
Asset Retirement Obligations	66,867,668.89	59,316,628.51
Other Deferred Credits	11,149,320.97	10,593,268.77
Miscellaneous Long-Term Liabilities	43,838,978.79	62,460,773.32
Accum Provision for Postretirement Benefits	142,508,432.17	159,466,844.01
Total	1,073,183,695.43	921,123,265.43
Total Liabilities and Stockholders' Equity	$ 4,006,517,269.58	$ 3,615,305,834.74

July 25, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,417,778,559.16	$ 5,014,081,528.26
Less: Reserves for Depreciation and Amortization	2,267,769,629.19	2,176,953,369.14
Total	3,150,008,929.97	2,837,128,159.12
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	489,420.24
Special Funds	22,517,484.69	32,726,937.42
Total	23,601,190.93	33,810,643.66
Current and Accrued Assets		
Cash	4,129,030.97	12,005,288.42
Temporary Cash Investments	5,143,876.66	39,024,144.73
Accounts Receivable - Less Reserve	170,866,336.46	132,734,286.93
Notes Receivable from Associated Companies	-	1,479,000.00
Accounts Receivable from Associated Companies	7,008,016.48	6,790,508.67
Materials and Supplies - At Average Cost		
Fuel	49,277,963.91	78,713,060.54
Plant Materials and Operating Supplies	35,812,476.23	31,950,402.21
Stores Expense	6,074,120.29	5,834,577.23
Gas Stored Underground	26,540,270.99	24,611,086.84
Emission Allowances	3,932.98	10,342.09
Prepayments	9,257,511.38	7,725,383.83
Miscellaneous Current and Accrued Assets	42,620,881.45	28,664.30
Total	356,734,417.80	340,906,745.79
Deferred Debits and Other		
Unamortized Debt Expense	12,183,111.77	13,340,316.65
Unamortized Loss on Bonds	19,320,218.84	20,272,548.21
Accumulated Deferred Income Taxes	106,027,258.96	20,590,827.53
Deferred Regulatory Assets	372,233,233.38	393,815,311.30
Other Deferred Debits	2,389,911.57	1,555,265.33
Total	512,153,734.52	449,574,269.02
Total Assets	$ 4,042,498,273.22	$ 3,661,419,817.59

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	958,126,111.15	905,514,927.36
Total Proprietary Capital	1,520,042,145.60	1,413,430,961.81
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,774,653.98	531,494,794.06
Total Long-Term Debt	1,106,078,653.98	1,105,798,794.06
Total Capitalization	2,626,120,799.58	2,519,229,755.87
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	89,996,058.29	-
Accounts Payable	150,299,043.73	110,014,239.75
Accounts Payable to Associated Companies	13,773,865.49	13,270,628.64
Customer Deposits	24,000,794.42	23,052,350.61
Taxes Accrued	25,667,135.38	40,485,132.50
Dividends Declared	-	-
Interest Accrued	7,198,100.91	7,470,803.71
Miscellaneous Current and Accrued Liabilities	22,823,787.79	21,624,281.77
Total	333,758,786.01	215,917,436.98
Deferred Credits and Other		
Accumulated Deferred Income Taxes	679,454,571.88	527,001,372.71
Investment Tax Credit	38,715,750.65	41,155,349.16
Regulatory Liabilities	92,643,281.99	54,392,800.83
Customer Advances for Construction	6,601,492.53	6,994,094.45
Asset Retirement Obligations	67,104,569.25	59,560,218.98
Other Deferred Credits	13,186,866.63	11,590,486.36
Miscellaneous Long-Term Liabilities	42,417,272.88	66,125,249.06
Accum Provision for Postretirement Benefits	142,494,881.82	159,453,053.19
Total	1,082,618,687.63	926,272,624.74
Total Liabilities and Stockholders' Equity	$ 4,042,498,273.22	$ 3,661,419,817.59

August 21, 2013

Attachment 3 to Response to AG-1 Question No. 270
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Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,461,187,625.01	$ 5,027,591,244.87
Less: Reserves for Depreciation and Amortization	2,275,759,687.58	2,179,786,041.44
Total	3,185,427,937.43	2,847,805,203.43
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	489,420.24
Special Funds	21,419,279.83	32,731,165.22
Total	22,502,986.07	33,814,871.46
Current and Accrued Assets		
Cash	4,206,681.35	4,535,999.33
Temporary Cash Investments	4,110,197.03	44,534,395.43
Accounts Receivable - Less Reserve	169,394,183.28	129,119,558.61
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	11,944,969.35	12,586,629.53
Materials and Supplies - At Average Cost	-	-
Fuel	46,249,565.57	73,755,685.60
Plant Materials and Operating Supplies	35,795,504.65	31,954,956.95
Stores Expense	6,119,187.55	5,890,452.07
Gas Stored Underground	37,298,719.86	34,297,757.43
Emission Allowances	2,921.23	8,417.59
Prepayments	8,181,970.27	6,196,010.61
Miscellaneous Current and Accrued Assets	45,987,773.40	55,054.73
Total	369,291,673.54	342,934,917.88
Deferred Debits and Other		
Unamortized Debt Expense	12,051,841.19	13,205,466.82
Unamortized Loss on Bonds	19,218,425.64	20,170,093.54
Accumulated Deferred Income Taxes	112,014,231.33	20,590,827.53
Deferred Regulatory Assets	367,286,446.45	391,229,041.18
Other Deferred Debits	1,811,678.56	1,622,696.20
Total	512,382,623.17	446,818,125.27
Total Assets	$ 4,089,605,220.21	$ 3,671,373,118.04

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	956,642,521.73	905,451,395.08
Total Proprietary Capital	1,518,558,556.18	1,413,367,429.53
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,797,975.64	531,518,115.72
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,106,101,975.64	1,105,822,115.72
Total Capitalization	2,624,660,531.82	2,519,189,545.25
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	84,994,776.35	-
Accounts Payable	157,856,399.10	91,562,468.16
Accounts Payable to Associated Companies	13,888,821.43	14,115,468.89
Customer Deposits	24,002,871.50	23,041,114.99
Taxes Accrued	35,901,713.40	50,670,314.40
Dividends Declared	19,000,000.00	16,250,000.00
Interest Accrued	8,318,971.18	8,756,470.55
Miscellaneous Current and Accrued Liabilities	22,785,228.84	22,359,783.68
Total	366,748,781.80	226,755,620.67
Deferred Credits and Other		
Accumulated Deferred Income Taxes	691,457,419.08	527,001,372.71
Investment Tax Credit	38,526,776.65	40,931,993.16
Regulatory Liabilities	96,945,129.21	53,929,760.21
Customer Advances for Construction	6,578,662.65	6,999,243.15
Asset Retirement Obligations	66,660,519.88	59,582,063.96
Other Deferred Credits	15,157,834.18	13,292,154.95
Miscellaneous Long-Term Liabilities	40,388,307.23	64,252,063.42
Accum Provision for Postretirement Benefits	142,481,257.71	159,439,300.56
Total	1,098,195,906.59	925,427,952.12
Total Liabilities and Stockholders' Equity	$ 4,089,605,220.21	$ 3,671,373,118.04

September 26, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,519,804,889.37	$ 5,038,451,961.90
Less: Reserves for Depreciation and Amortization	2,285,480,642.61	2,189,489,496.18
Total	3,234,324,246.76	2,848,962,465.72
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	529,399.03
Special Funds	21,880,914.00	32,235,216.00
Total	22,964,620.24	33,358,901.03
Current and Accrued Assets		
Cash	7,803,894.68	6,447,044.04
Temporary Cash Investments	3,910,528.84	41,089,237.10
Accounts Receivable - Less Reserve	163,166,562.46	121,917,865.73
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	7,973,069.04	12,268,738.68
Materials and Supplies - At Average Cost		
Fuel	50,180,346.34	70,658,087.85
Plant Materials and Operating Supplies	35,559,936.23	31,982,438.44
Stores Expense	6,158,552.20	5,825,571.88
Gas Stored Underground	48,416,877.19	43,171,101.97
Emission Allowances	1,973.11	6,142.14
Prepayments	7,672,710.03	5,986,499.65
Miscellaneous Current and Accrued Assets	-	-
Total	330,844,450.12	339,352,727.48
Deferred Debits and Other		
Unamortized Debt Expense	11,916,935.92	13,109,416.74
Unamortized Loss on Bonds	19,116,632.44	20,067,638.87
Accumulated Deferred Income Taxes	125,563,664.46	19,781,210.52
Deferred Regulatory Assets	367,930,073.55	389,889,081.35
Other Deferred Debits	2,085,668.23	1,736,802.60
Total	526,612,974.60	444,584,150.08
Total Assets	$ 4,114,746,291.72	$ 3,666,258,244.31

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	971,446,656.07	915,074,377.72
Total Proprietary Capital	1,533,362,690.52	1,422,990,412.17
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,821,297.30	531,541,437.38
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,106,125,297.30	1,105,845,437.38
Total Capitalization	2,639,487,987.82	2,528,835,849.55
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	71,994,903.58	-
Accounts Payable	154,290,014.02	95,601,507.96
Accounts Payable to Associated Companies	29,505,269.14	23,509,748.16
Customer Deposits	23,957,081.85	22,994,495.65
Taxes Accrued	33,588,446.87	33,871,908.20
Dividends Declared	-	-
Interest Accrued	10,454,073.85	10,965,648.79
Miscellaneous Current and Accrued Liabilities	32,287,655.00	22,223,302.18
Total	356,077,444.31	209,166,610.94
Deferred Credits and Other		
Accumulated Deferred Income Taxes	701,712,186.50	540,233,826.23
Investment Tax Credit	38,337,804.65	40,708,635.66
Regulatory Liabilities	93,429,374.35	51,575,729.21
Customer Advances for Construction	6,526,703.37	6,890,680.89
Asset Retirement Obligations	82,771,557.38	59,720,626.70
Other Deferred Credits	13,869,481.81	9,132,291.82
Miscellaneous Long-Term Liabilities	41,172,493.82	61,685,599.38
Accum Provision for Postretirement Benefits	141,361,257.71	158,308,393.93
Total	1,119,180,859.59	928,255,783.82
Total Liabilities and Stockholders' Equity	$ 4,114,746,291.72	$ 3,666,258,244.31

October 24, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,587,939,337.42	$ 5,072,415,973.89
Less: Reserves for Depreciation and Amortization	2,294,580,139.72	2,198,815,952.28
Total	3,293,359,197.70	2,873,600,021.61
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	528,727.07
Special Funds	22,222,263.26	31,738,777.33
Total	23,305,969.50	32,861,790.40
Current and Accrued Assets		
Cash	3,009,061.91	4,229,699.86
Temporary Cash Investments	2,370,674.98	37,224,301.98
Accounts Receivable - Less Reserve	143,840,241.66	111,441,066.03
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	5,123,219.43	13,107,960.96
Materials and Supplies - At Average Cost	-	-
Fuel	62,657,855.24	68,476,162.63
Plant Materials and Operating Supplies	35,385,184.42	31,821,287.16
Stores Expense	6,056,945.28	5,799,417.86
Gas Stored Underground	57,473,519.98	51,815,567.01
Emission Allowances	1,119.56	4,433.73
Prepayments	6,775,755.77	5,376,103.15
Miscellaneous Current and Accrued Assets	-	-
Total	322,693,578.23	329,296,000.37
Deferred Debits and Other		
Unamortized Debt Expense	11,782,030.65	12,968,666.66
Unamortized Loss on Bonds	19,014,839.24	19,965,184.20
Accumulated Deferred Income Taxes	125,563,664.54	20,181,843.17
Deferred Regulatory Assets	366,547,862.23	384,311,220.22
Other Deferred Debits	2,888,683.81	1,879,355.74
Total	525,797,080.47	439,306,269.99
Total Assets	$ 4,165,155,825.90	$ 3,675,064,082.37

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	978,835,580.07	919,980,877.70
Total Proprietary Capital	1,540,751,614.52	1,427,896,912.15
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	531,844,618.96	531,564,759.04
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,106,148,618.96	1,105,868,759.04
Total Capitalization	2,646,900,233.48	2,533,765,671.19
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	88,993,522.47	-
Accounts Payable	188,990,657.33	104,244,188.17
Accounts Payable to Associated Companies	17,332,336.62	15,954,240.75
Customer Deposits	23,970,028.99	23,160,507.46
Taxes Accrued	33,999,090.19	28,747,564.06
Dividends Declared	-	-
Interest Accrued	11,691,768.07	12,347,285.91
Miscellaneous Current and Accrued Liabilities	32,804,845.98	23,215,765.19
Total	397,782,249.65	207,669,551.54
Deferred Credits and Other		
Accumulated Deferred Income Taxes	701,712,186.50	545,563,011.90
Investment Tax Credit	38,148,830.65	40,485,279.66
Regulatory Liabilities	88,631,729.60	51,115,164.33
Customer Advances for Construction	6,862,030.82	6,776,700.92
Asset Retirement Obligations	83,085,321.44	59,489,283.35
Other Deferred Credits	17,783,957.28	10,338,677.38
Miscellaneous Long-Term Liabilities	42,915,064.13	61,565,964.78
Accum Provision for Postretirement Benefits	141,334,222.35	158,294,777.32
Total	1,120,473,342.77	933,628,859.64
Total Liabilities and Stockholders' Equity	$ 4,165,155,825.90	$ 3,675,064,082.37

November 21, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,642,170,100.76	$ 5,089,281,905.69
Less: Reserves for Depreciation and Amortization	2,296,532,370.26	2,195,394,384.85
Total	3,345,637,730.50	2,893,887,520.84
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	527,721.95
Special Funds	22,223,907.27	31,743,108.24
Total	23,307,613.51	32,865,116.19
Current and Accrued Assets		
Cash	2,877,130.15	1,767,229.44
Temporary Cash Investments	89,760,344.95	24,256,181.41
Accounts Receivable - Less Reserve	168,241,920.65	126,039,216.73
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	6,579,830.37	14,468,670.16
Materials and Supplies - At Average Cost	-	-
Fuel	66,754,580.34	65,493,205.88
Plant Materials and Operating Supplies	35,353,533.48	32,475,982.80
Stores Expense	6,168,991.97	5,824,485.57
Gas Stored Underground	55,531,157.29	49,302,196.90
Emission Allowances	18,344.65	2,271.75
Prepayments	5,794,365.17	4,197,223.54
Miscellaneous Current and Accrued Assets	-	191,189.92
Total	437,080,199.02	324,017,854.10
Deferred Debits and Other		
Unamortized Debt Expense	13,909,860.69	12,777,429.70
Unamortized Loss on Bonds	18,913,046.04	19,862,729.53
Accumulated Deferred Income Taxes	125,563,664.54	20,181,843.18
Deferred Regulatory Assets	360,117,539.29	384,389,779.28
Other Deferred Debits	2,980,731.33	2,468,920.19
Total	521,484,841.89	439,680,701.88
Total Assets	$ 4,327,510,384.92	$ 3,690,451,193.01

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	137,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	959,452,137.61	900,600,053.15
Total Proprietary Capital	1,521,368,172.06	1,408,516,087.60
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	780,070,440.62	531,588,080.70
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,354,374,440.62	1,105,892,080.70
Total Capitalization	2,875,742,612.68	2,514,408,168.30
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	(0.03)	9,999,683.34
Accounts Payable	187,701,495.70	109,469,936.19
Accounts Payable to Associated Companies	14,855,793.17	15,271,102.39
Customer Deposits	24,023,891.63	23,279,184.37
Taxes Accrued	41,724,577.23	25,219,842.07
Dividends Declared	32,000,000.00	28,000,000.00
Interest Accrued	5,132,089.14	5,390,338.93
Miscellaneous Current and Accrued Liabilities	24,420,687.01	25,079,425.89
Total	329,858,533.85	241,709,513.18
Deferred Credits and Other		
Accumulated Deferred Income Taxes	701,712,186.50	545,563,011.90
Investment Tax Credit	37,959,856.65	40,261,923.17
Regulatory Liabilities	93,166,537.60	50,731,141.32
Customer Advances for Construction	6,888,798.87	6,738,520.31
Asset Retirement Obligations	81,931,392.45	59,733,563.53
Other Deferred Credits	18,144,596.09	11,566,373.85
Miscellaneous Long-Term Liabilities	40,785,059.35	62,635,802.67
Accum Provision for Postretirement Benefits	141,320,810.88	157,103,174.78
Total	1,121,909,238.39	934,333,511.53
Total Liabilities and Stockholders' Equity	$ 4,327,510,384.92	$ 3,690,451,193.01

December 20, 2013

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2013 and 2012

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,721,485,380.08	$ 5,142,141,435.14
Less: Reserves for Depreciation and Amortization	2,304,132,232.43	2,201,756,056.71
Total	3,417,353,147.65	2,940,385,378.43
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	527,049.99
Special Funds	22,225,512.33	31,747,623.54
Total	23,309,218.57	32,868,959.53
Current and Accrued Assets		
Cash	3,467,771.27	7,372,093.05
Temporary Cash Investments	4,534,363.17	14,316,601.29
Accounts Receivable - Less Reserve	196,537,992.03	147,774,702.72
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	108,734.54	13,662,417.99
Materials and Supplies - At Average Cost	-	-
Fuel	64,191,758.19	61,099,619.31
Plant Materials and Operating Supplies	35,816,744.57	32,727,609.51
Stores Expense	6,186,831.58	5,860,024.37
Gas Stored Underground	47,546,888.01	42,010,154.00
Emission Allowances	41,738.64	1,771.39
Prepayments	5,125,670.28	6,976,760.79
Miscellaneous Current and Accrued Assets	-	7,142,276.04
Total	363,558,492.28	338,944,030.46
Deferred Debits and Other		
Unamortized Debt Expense	13,965,458.39	13,126,319.25
Unamortized Loss on Bonds	18,442,649.35	19,968,045.28
Accumulated Deferred Income Taxes	130,998,531.38	106,846,805.72
Deferred Regulatory Assets	312,656,792.93	408,462,227.05
Other Deferred Debits	1,493,995.45	1,942,008.43
Total	477,557,427.50	550,345,405.73
Total Assets	$ 4,281,778,286.00	$ 3,862,543,774.15

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	169,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	976,302,938.73	916,602,335.62
Total Proprietary Capital	1,570,218,973.18	1,424,518,370.07
Pollution Control Bonds - Net of Reacquired Bonds.	574,304,000.00	574,304,000.00
First Mortgage Bonds	780,098,769.24	531,611,402.36
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,354,402,769.24	1,105,915,402.36
Total Capitalization	2,924,621,742.42	2,530,433,772.43
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	19,996,777.75	54,992,669.46
Accounts Payable	170,850,242.83	121,578,265.62
Accounts Payable to Associated Companies	24,294,740.78	22,801,659.30
Customer Deposits	24,075,548.94	23,464,189.08
Taxes Accrued	11,474,665.55	1,735,494.84
Dividends Declared	-	-
Interest Accrued	5,580,257.90	5,118,488.31
Miscellaneous Current and Accrued Liabilities	24,038,771.27	25,492,408.81
Total	280,311,005.02	255,183,175.42
Deferred Credits and Other		
Accumulated Deferred Income Taxes	708,811,163.39	657,001,051.36
Investment Tax Credit	37,770,884.65	39,871,226.65
Regulatory Liabilities	92,564,168.25	56,225,013.57
Customer Advances for Construction	6,748,025.17	6,709,975.18
Asset Retirement Obligations	82,196,215.38	64,684,737.37
Other Deferred Credits	17,117,635.73	7,409,316.48
Miscellaneous Long-Term Liabilities	36,535,511.45	58,713,172.11
Accum Provision for Postretirement Benefits	95,101,934.54	186,312,333.58
Total	1,076,845,538.56	1,076,926,826.30
Total Liabilities and Stockholders' Equity	$ 4,281,778,286.00	$ 3,862,543,774.15

January 27, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,752,452,480.55	$ 5,167,479,536.50
Less: Reserves for Depreciation and Amortization	2,314,875,211.10	2,212,595,282.35
Total	3,437,577,269.45	2,954,884,254.15
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	526,378.03
Special Funds	20,927,142.20	30,251,930.44
Total	22,010,848.44	31,372,594.47
Current and Accrued Assets		
Cash	8,164,120.69	5,030,414.68
Special Deposits	-	1,897.82
Temporary Cash Investments	3,525,712.11	21,145,805.00
Accounts Receivable - Less Reserve	231,584,264.49	182,018,031.74
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	24,919,004.32	15,701,111.16
Materials and Supplies - At Average Cost	-	-
Fuel	55,632,627.98	55,186,491.79
Plant Materials and Operating Supplies	35,927,175.09	34,044,336.81
Stores Expense	6,203,562.58	5,660,118.60
Gas Stored Underground	32,656,552.78	30,073,532.84
Emission Allowances	36,357.58	(705.19)
Prepayments	7,039,588.11	7,061,717.26
Miscellaneous Current and Accrued Assets	-	12,847,239.85
Total	405,688,965.73	368,769,992.36
Deferred Debits and Other		
Unamortized Debt Expense	13,901,263.13	12,991,495.50
Unamortized Loss on Bonds	18,352,820.24	19,891,987.34
Accumulated Deferred Income Taxes	130,998,531.39	106,846,805.72
Deferred Regulatory Assets	314,829,587.33	402,665,333.71
Other Deferred Debits	2,122,297.15	1,613,170.75
Total	480,204,499.24	544,008,793.02
Total Assets	$ 4,345,481,582.86	$ 3,899,035,634.00

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	169,581,499.00	83,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,002,292,495.37	932,554,302.72
Total Proprietary Capital	1,596,208,529.82	1,440,470,337.17
Other Long-Term Debt	-	-
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	780,127,097.86	531,634,724.02
LT Notes Payable to Associated Companies	-	-
Total Long-Term Debt	1,354,431,097.86	1,105,938,724.02
Total Capitalization	2,950,639,627.68	2,546,409,061.19
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	24,997,712.47	114,991,594.45
Accounts Payable	189,989,777.38	123,960,910.00
Accounts Payable to Associated Companies	15,100,972.15	13,113,858.27
Customer Deposits	24,078,344.11	23,484,456.67
Taxes Accrued	29,727,725.65	6,130,384.39
Dividends Declared	-	-
Interest Accrued	8,674,736.74	7,232,237.99
Miscellaneous Current and Accrued Liabilities	27,062,643.72	25,819,342.34
Total	319,631,912.22	314,732,784.11
Deferred Credits and Other		
Accumulated Deferred Income Taxes	708,811,163.41	657,001,051.36
Investment Tax Credit	37,621,818.65	39,742,902.65
Regulatory Liabilities	92,051,390.75	60,951,140.88
Customer Advances for Construction	6,730,515.63	6,756,993.26
Asset Retirement Obligations	83,299,042.89	64,920,825.85
Other Deferred Credits	19,589,236.56	9,409,962.23
Miscellaneous Long-Term Liabilities	40,218,297.25	54,312,108.09
Accum Provision for Postretirement Benefits	86,888,577.82	144,798,804.38
Total	1,075,210,042.96	1,037,893,788.70
Total Liabilities and Stockholders' Equity	$ 4,345,481,582.86	$ 3,899,035,634.00

February 21, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 28, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,793,632,284.43	$ 5,203,508,033.24
Less: Reserves for Depreciation and Amortization	2,323,820,737.02	2,222,944,323.21
Total	3,469,811,547.41	2,980,563,710.03
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	525,706.07
Special Funds	20,928,465.17	27,853,318.97
Total	22,012,171.41	28,973,311.04
Current and Accrued Assets		
Cash	6,145,135.70	5,406,414.77
Temporary Cash Investments	22,306,514.03	25,386,862.99
Accounts Receivable - Less Reserve	216,354,629.51	181,114,088.81
Accounts Receivable from Associated Companies	11,842,219.45	35,298,621.92
Materials and Supplies - At Average Cost	-	-
Fuel	53,156,325.11	53,584,247.86
Plant Materials and Operating Supplies	35,848,978.44	34,369,732.02
Stores Expense	6,242,519.14	5,716,710.78
Gas Stored Underground	24,226,844.36	19,553,217.95
Emission Allowances	31,547.72	8,211.08
Prepayments	8,222,453.95	7,850,382.49
Miscellaneous Current and Accrued Assets	-	10,850,015.35
Total	384,377,167.41	379,138,506.02
Deferred Debits and Other		
Unamortized Debt Expense	13,866,161.93	12,856,710.29
Unamortized Loss on Bonds	18,262,991.13	19,821,272.26
Accumulated Deferred Income Taxes	130,998,531.39	107,462,562.43
Deferred Regulatory Assets	319,048,090.06	401,922,192.81
Other Deferred Debits	1,985,662.19	1,492,282.60
Total	484,161,436.70	543,555,020.39
Total Assets	$ 4,360,362,322.93	$ 3,932,230,547.48

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	169,581,499.00	108,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	990,073,656.40	927,981,204.69
Total Proprietary Capital	1,583,989,690.85	1,460,897,239.14
Other Long-Term Debt	-	-
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	780,155,426.48	531,658,045.68
Total Long-Term Debt	1,354,459,426.48	1,105,962,045.68
Total Capitalization	2,938,449,117.33	2,566,859,284.82
Current and Accrued Liabilities		
Notes Payable	14,999,566.63	94,989,974.98
Accounts Payable	178,924,743.58	121,657,647.50
Accounts Payable to Associated Companies	16,258,307.06	14,716,564.81
Customer Deposits	24,070,289.69	23,625,632.91
Taxes Accrued	40,772,865.09	16,227,214.04
Dividends Declared	27,000,000.00	19,000,000.00
Interest Accrued	11,602,313.00	8,334,450.93
Miscellaneous Current and Accrued Liabilities	29,661,555.59	27,538,157.13
Total	343,289,640.64	326,089,642.30
Deferred Credits and Other		
Accumulated Deferred Income Taxes	708,811,163.41	657,616,808.47
Investment Tax Credit	37,472,752.65	39,607,273.65
Regulatory Liabilities	91,772,297.20	59,285,491.84
Customer Advances for Construction	6,711,207.70	6,704,841.60
Asset Retirement Obligations	83,495,504.84	65,011,482.41
Other Deferred Credits	23,064,043.85	11,115,141.56
Miscellaneous Long-Term Liabilities	40,421,360.35	55,155,396.82
Accum Provision for Postretirement Benefits	86,875,234.96	144,785,184.01
Total	1,078,623,564.96	1,039,281,620.36
Total Liabilities and Stockholders' Equity	$ 4,360,362,322.93	$ 3,932,230,547.48

March 21, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 5,838,356,857.81	$ 5,240,543,201.82
Less: Reserves for Depreciation and Amortization	2,334,756,488.27	2,232,492,243.42
Total	3,503,600,369.54	3,008,050,958.40
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	489,420.24	525,034.11
Special Funds	20,929,534.85	27,356,493.29
Total	22,013,241.09	28,475,813.40
Current and Accrued Assets		
Cash	6,148,903.35	13,358,033.75
Temporary Cash Investments	3,093,566.78	20,537,988.63
Accounts Receivable - Less Reserve	189,098,626.70	176,498,356.08
Accounts Receivable from Associated Companies	22,567,694.68	12,261,257.01
Materials and Supplies - At Average Cost	-	-
Fuel	52,267,758.99	51,990,437.53
Plant Materials and Operating Supplies	35,828,626.54	34,245,776.81
Stores Expense	6,325,909.69	5,733,638.24
Gas Stored Underground	16,010,966.83	12,790,124.32
Emission Allowances	25,999.97	7,289.18
Prepayments	6,581,637.40	7,035,150.93
Miscellaneous Current and Accrued Assets	427.22	11,947,786.86
Total	337,950,118.15	346,405,839.34
Deferred Debits and Other		
Unamortized Debt Expense	13,698,381.58	12,721,931.60
Unamortized Loss on Bonds	18,173,162.02	19,717,723.31
Accumulated Deferred Income Taxes	129,178,487.65	105,600,953.75
Deferred Regulatory Assets	317,364,932.38	398,753,301.39
Other Deferred Debits	2,435,355.11	2,071,241.05
Total	480,850,318.74	538,865,151.10
Total Assets	$ 4,344,414,047.52	$ 3,921,797,762.24

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	169,581,499.00	108,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,000,658,673.50	941,920,995.41
Total Proprietary Capital	1,594,574,707.95	1,474,837,029.86
Other Long-Term Debt	-	-
Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00	574,304,000.00
First Mortgage Bonds	780,183,755.10	531,681,367.34
Total Long-Term Debt	1,354,487,755.10	1,105,985,367.34
Total Capitalization	2,949,062,463.05	2,580,822,397.20
Current and Accrued Liabilities		
Notes Payable	14,999,051.21	69,994,680.53
Accounts Payable	182,815,970.27	126,432,156.04
Accounts Payable to Associated Companies	17,259,546.28	16,044,323.15
Customer Deposits	23,927,076.62	23,859,840.87
Taxes Accrued	31,998,367.95	18,612,357.30
Dividends Declared	-	-
Interest Accrued	14,641,456.30	10,622,408.79
Miscellaneous Current and Accrued Liabilities	31,319,750.73	29,585,242.10
Total	316,961,219.36	295,151,008.78
Deferred Credits and Other		
Accumulated Deferred Income Taxes	713,697,360.68	666,905,987.64
Investment Tax Credit	37,323,689.65	39,471,644.65
Regulatory Liabilities	90,704,475.94	59,379,429.27
Customer Advances for Construction	6,714,733.28	6,675,322.68
Asset Retirement Obligations	83,813,179.35	66,165,250.85
Other Deferred Credits	20,551,432.31	9,754,305.37
Miscellaneous Long-Term Liabilities	39,783,845.85	53,818,113.37
Accum Provision for Postretirement Benefits	85,801,648.05	143,654,302.43
Total	1,078,390,365.11	1,045,824,356.26
Total Liabilities and Stockholders' Equity	$ 4,344,414,047.52	$ 3,921,797,762.24

April 25, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 5,894,590,703.79	$ 5,284,282,587.16
Less: Reserves for Depreciation and Amortization.....	2,345,809,627.70	2,240,867,369.38
Total..	3,548,781,076.09	3,043,415,217.78
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	489,420.24	524,362.15
Special Funds..	20,930,872.01	27,759,880.69
Total..	22,014,578.25	28,878,528.84
Current and Accrued Assets		
Cash..	4,361,468.48	8,553,583.33
Special Deposits...	-	-
Temporary Cash Investments.....................................	2,313,860.30	26,390,246.29
Accounts Receivable - Less Reserve..........................	161,903,327.31	147,956,584.39
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	22,163,025.13	9,509,326.41
Materials and Supplies - At Average Cost..................		
Fuel..	55,194,917.68	61,288,516.31
Plant Materials and Operating Supplies..................	35,276,840.30	34,563,046.74
Stores Expense...	6,301,408.30	5,818,678.03
Gas Stored Underground..	11,545,086.36	9,589,099.05
Emission Allowances..	107,143.32	6,549.64
Prepayments..	5,429,609.18	9,807,241.06
Miscellaneous Current and Accrued Assets................	-	6,322,137.30
Total..	304,596,686.36	319,805,008.55
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,529,214.32	12,587,106.99
Unamortized Loss on Bonds......................................	18,083,332.91	19,631,104.11
Accumulated Deferred Income Taxes........................	129,178,487.65	105,600,953.75
Deferred Regulatory Assets.......................................	320,332,380.22	400,618,874.29
Other Deferred Debits..	2,702,582.16	1,788,127.03
Total..	483,825,997.26	540,226,166.17
Total Assets..	$ 4,359,218,337.96	$ 3,932,324,921.34

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	169,581,499.00	108,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	1,005,259,270.55	944,015,648.47
Total Proprietary Capital...	1,599,175,305.00	1,476,931,682.92
Other Long-Term Debt...	-	-
Pollution Control Bonds - Net of Reacquired Bonds..	574,304,000.00	574,304,000.00
First Mortgage Bonds...	780,212,083.72	531,704,689.00
Advances from Associated Companies.....................	-	-
Total Long-Term Debt..	1,354,516,083.72	1,106,008,689.00
Total Capitalization...	2,953,691,388.72	2,582,940,371.92
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies..............	-	-
Notes Payable...	19,999,305.52	49,994,470.81
Accounts Payable..	198,567,964.04	148,611,961.51
Accounts Payable to Associated Companies..............	16,440,682.45	29,396,914.55
Customer Deposits..	23,924,787.34	24,100,589.15
Taxes Accrued..	23,533,399.12	11,415,566.56
Dividends Declared..	-	-
Interest Accrued..	16,704,715.50	11,739,603.29
Miscellaneous Current and Accrued Liabilities..........	27,153,752.99	29,346,999.98
Total..	326,324,606.96	304,606,105.85
Deferred Credits and Other		
Accumulated Deferred Income Taxes........................	713,697,360.68	666,905,987.64
Investment Tax Credit..	37,174,623.65	39,282,670.65
Regulatory Liabilities..	90,619,714.71	54,079,671.82
Customer Advances for Construction........................	6,703,799.16	6,630,314.66
Asset Retirement Obligations....................................	84,040,447.01	66,404,615.07
Other Deferred Credits...	20,091,783.17	10,860,188.92
Miscellaneous Long-Term Liabilities.........................	41,086,348.44	56,974,227.08
Accum Provision for Postretirement Benefits............	85,788,265.46	143,640,767.73
Total..	1,079,202,342.28	1,044,778,443.57
Total Liabilities and Stockholders' Equity.......................	$ 4,359,218,337.96	$ 3,932,324,921.34

May 21, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 5,946,114,085.30	$ 5,334,168,672.32
Less: Reserves for Depreciation and Amortization.....	2,354,493,158.62	2,249,964,605.91
Total..	3,591,620,926.68	3,084,204,066.41
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	489,420.24	489,420.24
Special Funds..	21,202,447.64	25,262,989.42
Total..	22,286,153.88	26,346,695.66
Current and Accrued Assets		
Cash..	3,512,004.83	3,063,433.86
Special Deposits...	-	-
Temporary Cash Investments.....................................	859,242.43	10,820,016.50
Accounts Receivable - Less Reserve..........................	163,912,893.46	145,340,381.35
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	22,465,454.72	33,412,514.86
Materials and Supplies - At Average Cost..................		
Fuel..	56,257,478.86	63,670,490.98
Plant Materials and Operating Supplies..................	35,779,701.59	35,151,353.66
Stores Expense...	6,398,228.05	5,833,709.11
Gas Stored Underground..	9,899,197.98	8,472,755.53
Emission Allowances..	87,435.53	5,710.10
Prepayments..	8,280,103.56	8,731,338.35
Miscellaneous Current and Accrued Assets................	-	25,975,791.61
Total..	307,451,741.01	340,477,495.91
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,360,047.06	12,452,282.38
Unamortized Loss on Bonds......................................	17,993,503.80	19,527,484.91
Accumulated Deferred Income Taxes........................	129,178,487.65	105,600,953.75
Deferred Regulatory Assets.......................................	320,348,922.62	392,448,302.41
Other Deferred Debits..	2,644,221.18	1,761,489.32
Total..	483,525,182.31	531,790,512.77
Total Assets..	$ 4,404,884,003.88	$ 3,982,818,770.75

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...................................	835,888.64	835,888.64
Paid-In Capital..	169,581,499.00	137,581,499.00
Other Comprehensive Income...................................	-	-
Retained Earnings...	985,065,888.15	925,552,953.35
Total Proprietary Capital...	1,578,981,922.60	1,487,468,987.80
Other Long-Term Debt...	-	-
Pollution Control Bonds - Net of Reacquired Bonds..	574,304,000.00	574,304,000.00
First Mortgage Bonds...	780,240,412.34	531,728,010.66
Advances from Associated Companies.....................	-	-
Total Long-Term Debt..	1,354,544,412.34	1,106,032,010.66
Total Capitalization...	2,933,526,334.94	2,593,500,998.46
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies..............	-	-
Notes Payable...	49,996,662.46	69,991,055.52
Accounts Payable..	202,509,083.28	141,692,072.25
Accounts Payable to Associated Companies..............	20,057,830.92	15,816,566.80
Customer Deposits..	23,980,131.07	23,942,701.78
Taxes Accrued..	33,438,222.55	19,418,066.43
Dividends Declared..	33,000,000.00	29,000,000.00
Interest Accrued..	4,619,437.25	4,695,144.36
Miscellaneous Current and Accrued Liabilities..........	23,567,265.87	25,960,777.07
Total..	391,168,633.40	330,516,384.21
Deferred Credits and Other		
Accumulated Deferred Income Taxes........................	713,697,360.68	666,905,987.64
Investment Tax Credit..	37,025,557.65	39,093,696.65
Regulatory Liabilities..	90,098,620.06	74,265,475.41
Customer Advances for Construction........................	6,628,645.72	6,639,598.96
Asset Retirement Obligations...................................	84,262,780.57	66,638,965.96
Other Deferred Credits...	20,590,080.54	12,410,503.50
Miscellaneous Long-Term Liabilities.........................	43,335,591.17	49,219,909.26
Accum Provision for Postretirement Benefits............	84,550,399.15	143,627,250.70
Total..	1,080,189,035.54	1,058,801,388.08
Total Liabilities and Stockholders' Equity.......................	$ 4,404,884,003.88	$ 3,982,818,770.75

June 20, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 5,993,948,101.36	$ 5,378,994,655.84
Less: Reserves for Depreciation and Amortization.....	2,364,797,528.58	2,260,073,132.03
Total..	3,629,150,572.78	3,118,921,523.81
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	539,420.24	489,420.24
Special Funds..	21,204,065.89	22,045,681.83
Total..	22,337,772.13	23,129,388.07
Current and Accrued Assets		
Cash..	4,067,696.37	5,599,679.48
Special Deposits..	-	-
Temporary Cash Investments....................................	754,594.90	7,242,477.71
Accounts Receivable - Less Reserve..........................	177,233,790.69	163,656,401.51
Notes Receivable from Associated Companies..........	-	-
Accounts Receivable from Associated Companies.....	22,210,361.71	7,616,227.86
Materials and Supplies - At Average Cost..................		
Fuel..	51,698,565.63	59,663,659.02
Plant Materials and Operating Supplies..................	35,618,766.83	35,651,188.45
Stores Expense...	6,262,881.93	5,979,073.71
Gas Stored Underground..	16,771,949.95	15,053,205.64
Emission Allowances..	67,674.47	4,872.66
Prepayments..	7,323,392.95	7,765,787.00
Miscellaneous Current and Accrued Assets...............	-	35,686,873.54
Total..	322,009,675.43	343,919,446.58
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,194,870.32	12,317,457.77
Unamortized Loss on Bonds......................................	17,904,942.43	19,423,865.71
Accumulated Deferred Income Taxes........................	126,247,168.09	106,027,258.96
Deferred Regulatory Assets.......................................	322,499,065.88	380,164,522.91
Other Deferred Debits..	4,600,781.13	2,613,805.77
Total..	484,446,827.85	520,546,911.12
Total Assets..	$ 4,457,944,848.19	$ 4,006,517,269.58

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..................................	835,888.64	835,888.64
Paid-In Capital..	222,581,499.00	137,581,499.00
Other Comprehensive Income..................................	-	-
Retained Earnings...	1,003,304,674.81	941,395,957.72
Total Proprietary Capital...	1,650,220,709.26	1,503,311,992.17
Other Long-Term Debt...	27,924.66	-
Pollution Control Bonds - Net of Reacquired Bonds..	574,304,000.00	574,304,000.00
First Mortgage Bonds...	780,240,412.34	531,751,332.32
Advances from Associated Companies.....................	-	-
Total Long-Term Debt..	1,354,572,337.00	1,106,055,332.32
Total Capitalization...	3,004,793,046.26	2,609,367,324.49
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies..............	-	-
Notes Payable...	69,992,485.52	80,490,016.63
Accounts Payable..	202,767,972.89	153,721,284.77
Accounts Payable to Associated Companies..............	20,042,122.31	21,410,861.34
Customer Deposits..	23,985,321.70	24,004,564.12
Taxes Accrued..	12,748,569.46	13,775,204.13
Dividends Declared..	-	-
Interest Accrued..	5,829,204.32	4,914,356.01
Miscellaneous Current and Accrued Liabilities..........	23,832,770.27	25,649,962.66
Total..	359,198,446.47	323,966,249.66
Deferred Credits and Other		
Accumulated Deferred Income Taxes........................	726,121,824.04	679,454,571.88
Investment Tax Credit..	36,876,494.65	38,904,724.65
Regulatory Liabilities..	89,636,180.41	83,857,243.68
Customer Advances for Construction........................	7,275,246.78	6,602,754.40
Asset Retirement Obligations....................................	84,348,366.27	66,867,668.89
Other Deferred Credits...	17,766,201.39	11,149,320.97
Miscellaneous Long-Term Liabilities.........................	42,355,613.56	43,838,978.79
Accum Provision for Postretirement Benefits............	89,573,428.36	142,508,432.17
Total..	1,093,953,355.46	1,073,183,695.43
Total Liabilities and Stockholders' Equity.......................	$ 4,457,944,848.19	$ 4,006,517,269.58

July 25, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,059,693,508.40	$ 5,417,778,559.16
Less: Reserves for Depreciation and Amortization.....	2,375,296,839.18	2,267,769,629.19
Total..	3,684,396,669.22	3,150,008,929.97
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	539,420.24	489,420.24
Special Funds..	21,205,709.21	22,517,484.69
Total..	22,339,415.45	23,601,190.93
Current and Accrued Assets		
Cash..	4,396,756.98	4,129,030.97
Special Deposits...	-	-
Temporary Cash Investments.....................................	4,742,868.79	5,143,876.66
Accounts Receivable - Less Reserve..........................	169,859,908.75	170,866,336.46
Notes Receivable from Associated Companies..........	-	-
Accounts Receivable from Associated Companies.....	12,703,358.98	7,008,016.48
Materials and Supplies - At Average Cost..................		
Fuel..	49,559,924.55	49,277,963.91
Plant Materials and Operating Supplies..................	35,522,957.84	35,812,476.23
Stores Expense...	6,318,520.22	6,074,120.29
Gas Stored Underground..	29,591,164.87	26,540,270.99
Emission Allowances..	171,339.92	3,932.98
Prepayments..	9,194,729.57	9,257,511.38
Miscellaneous Current and Accrued Assets...............	867,901.15	42,620,881.45
Total..	322,929,431.62	356,734,417.80
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,617,457.54	12,183,111.77
Unamortized Loss on Bonds......................................	18,098,611.89	19,320,218.84
Accumulated Deferred Income Taxes........................	126,247,168.09	106,027,258.96
Deferred Regulatory Assets..	319,764,899.83	372,233,233.38
Other Deferred Debits..	4,828,761.77	2,389,911.57
Total..	482,556,899.12	512,153,734.52
Total Assets..	$ 4,512,222,415.41	$ 4,042,498,273.22

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital...	222,581,499.00	137,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,018,313,508.29	958,126,111.15
Total Proprietary Capital...	1,665,229,542.74	1,520,042,145.60
Other Long-Term Debt...	1,354,601,169.95	1,106,078,653.98
Pollution Control Bonds - Net of Reacquired Bonds...........	-	-
First Mortgage Bonds...	-	-
Advances from Associated Companies..............................	-	-
Total Long-Term Debt..	1,354,601,169.95	1,106,078,653.98
Total Capitalization..	3,019,830,712.69	2,626,120,799.58
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable..	80,995,314.40	89,996,058.29
Accounts Payable...	225,905,652.32	150,299,043.73
Accounts Payable to Associated Companies........................	15,843,144.95	13,773,865.49
Customer Deposits..	24,004,851.61	24,000,794.42
Taxes Accrued...	18,891,476.67	25,667,135.38
Dividends Declared...	-	-
Interest Accrued..	9,283,522.81	7,198,100.91
Miscellaneous Current and Accrued Liabilities...................	44,891,816.20	29,196,116.61
Total..	419,815,778.96	340,131,114.83
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	726,121,824.04	679,454,571.88
Investment Tax Credit..	36,727,428.65	38,715,750.65
Regulatory Liabilities..	90,194,572.67	92,643,281.99
Customer Advances for Construction..................................	7,868,967.40	6,601,492.53
Asset Retirement Obligations...	84,669,336.44	67,104,569.25
Other Deferred Credits...	19,214,151.84	13,186,866.63
Miscellaneous Long-Term Liabilities..................................	18,219,604.11	36,044,944.06
Accum Provision for Pension & Postretirement Benefits.....	89,560,038.61	142,494,881.82
Total..	1,072,575,923.76	1,076,246,358.81
Total Liabilities and Stockholders' Equity.................................	$ 4,512,222,415.41	$ 4,042,498,273.22

August 21, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,124,709,957.40	$ 5,461,187,625.01
Less: Reserves for Depreciation and Amortization	2,385,294,963.27	2,275,759,687.58
Total	3,739,414,994.13	3,185,427,937.43
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	539,420.24	489,420.24
Special Funds	21,207,370.32	21,419,279.83
Total	22,341,076.56	22,502,986.07
Current and Accrued Assets		
Cash	6,795,124.97	4,206,681.35
Special Deposits	-	-
Temporary Cash Investments	15,160,259.71	4,110,197.03
Accounts Receivable - Less Reserve	171,620,834.19	169,394,183.28
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	13,902,270.03	11,944,969.35
Materials and Supplies - At Average Cost		
Fuel	45,152,960.84	46,249,565.57
Plant Materials and Operating Supplies	35,170,059.40	35,795,504.65
Stores Expense	6,277,557.18	6,119,187.55
Gas Stored Underground	41,769,807.04	37,298,719.86
Emission Allowances	136,170.06	2,921.23
Prepayments	7,919,876.81	8,181,970.27
Miscellaneous Current and Accrued Assets	23,617.75	45,987,773.40
Total	343,928,537.98	369,291,673.54
Deferred Debits and Other		
Unamortized Debt Expense	13,494,597.16	12,051,841.19
Unamortized Loss on Bonds	18,002,246.90	19,218,425.64
Accumulated Deferred Income Taxes	125,509,564.69	112,014,231.33
Deferred Regulatory Assets	320,954,164.31	367,286,446.45
Other Deferred Debits	3,360,861.05	1,811,678.56
Total	481,321,434.11	512,382,623.17
Total Assets	$ 4,587,006,042.78	$ 4,089,605,220.21

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	222,581,499.00	137,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,013,474,521.07	956,642,521.73
Total Proprietary Capital	1,660,390,555.52	1,518,558,556.18
Other Long-Term Debt	1,354,630,025.44	1,106,101,975.64
Pollution Control Bonds - Net of Reacquired Bonds	-	-
First Mortgage Bonds	-	-
Advances from Associated Companies	-	-
Total Long-Term Debt	1,354,630,025.44	1,106,101,975.64
Total Capitalization	3,015,020,580.96	2,624,660,531.82
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	104,992,899.99	84,994,776.35
Accounts Payable	241,299,605.28	157,856,399.10
Accounts Payable to Associated Companies	14,836,332.67	13,888,821.43
Customer Deposits	24,000,006.56	24,002,871.50
Taxes Accrued	36,956,840.98	35,901,713.40
Dividends Declared	23,000,000.00	19,000,000.00
Interest Accrued	11,558,616.60	8,318,971.18
Miscellaneous Current and Accrued Liabilities	52,300,689.34	28,772,692.41
Total	508,944,991.42	372,736,245.37
Deferred Credits and Other		
Accumulated Deferred Income Taxes	722,645,905.36	691,457,419.08
Investment Tax Credit	36,578,363.65	38,526,776.65
Regulatory Liabilities	84,074,311.07	96,945,129.21
Customer Advances for Construction	7,841,390.40	6,578,662.65
Asset Retirement Obligations	84,898,331.36	66,660,519.88
Other Deferred Credits	17,650,945.71	15,157,834.18
Miscellaneous Long-Term Liabilities	19,804,549.89	34,400,843.66
Accum Provision for Pension & Postretirement Benefits	89,546,672.96	142,481,257.71
Total	1,063,040,470.40	1,092,208,443.02
Total Liabilities and Stockholders' Equity	$ 4,587,006,042.78	$ 4,089,605,220.21

September 22, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,196,387,956.02	$ 5,519,804,889.37
Less: Reserves for Depreciation and Amortization.....	2,397,029,582.13	2,285,480,642.61
Total..	3,799,358,373.89	3,234,324,246.76
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	539,420.24	489,420.24
Special Funds..	19,709,019.78	21,880,914.00
Total..	20,842,726.02	22,964,620.24
Current and Accrued Assets		
Cash..	6,526,816.56	7,803,894.68
Special Deposits...	-	-
Temporary Cash Investments.....................................	18,026,531.83	3,910,528.84
Accounts Receivable - Less Reserve..........................	160,429,793.14	163,166,562.46
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	11,397,202.77	7,973,069.04
Materials and Supplies - At Average Cost..................		
Fuel..	54,011,575.82	50,180,346.34
Plant Materials and Operating Supplies..................	35,234,229.18	35,559,936.23
Stores Expense...	6,188,502.49	6,158,552.20
Gas Stored Underground..	53,224,450.20	48,416,877.19
Emission Allowances..	103,610.44	1,973.11
Prepayments..	7,618,415.49	7,672,710.03
Miscellaneous Current and Accrued Assets................	2,804,902.73	-
Total..	355,566,030.65	330,844,450.12
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,339,706.42	11,916,935.92
Unamortized Loss on Bonds......................................	17,908,990.43	19,116,632.44
Accumulated Deferred Income Taxes.........................	119,748,320.87	125,563,664.46
Deferred Regulatory Assets..	321,039,417.54	367,930,073.55
Other Deferred Debits..	4,414,459.18	2,085,668.23
Total..	476,450,894.44	526,612,974.60
Total Assets..	$ 4,652,218,025.00	$ 4,114,746,291.72

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital..	242,581,499.00	137,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,025,427,505.22	971,446,656.07
Total Proprietary Capital...	1,692,343,539.67	1,533,362,690.52
Other Long-Term Debt...	1,354,657,950.12	1,106,125,297.30
Pollution Control Bonds - Net of Reacquired Bonds...........	-	-
First Mortgage Bonds...	-	-
Advances from Associated Companies..............................	-	-
Total Long-Term Debt..	1,354,657,950.12	1,106,125,297.30
Total Capitalization...	3,047,001,489.79	2,639,487,987.82
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable...	142,992,686.68	71,994,903.58
Accounts Payable...	258,419,677.93	154,290,014.02
Accounts Payable to Associated Companies........................	19,717,400.65	29,505,269.14
Customer Deposits..	24,037,240.94	23,957,081.85
Taxes Accrued...	20,485,102.24	33,588,446.87
Dividends Declared..	-	-
Interest Accrued..	14,594,255.13	10,454,073.85
Miscellaneous Current and Accrued Liabilities...................	49,104,144.83	38,592,765.02
Total..	529,350,508.40	362,382,554.33
Deferred Credits and Other		
Accumulated Deferred Income Taxes................................	731,219,440.14	701,712,186.50
Investment Tax Credit..	36,429,299.65	38,337,804.65
Regulatory Liabilities..	92,071,568.65	93,429,374.35
Customer Advances for Construction..................................	7,968,468.03	6,526,703.37
Asset Retirement Obligations..	85,221,471.06	82,771,557.38
Other Deferred Credits...	15,673,384.37	13,869,481.81
Miscellaneous Long-Term Liabilities.................................	18,891,311.79	34,867,383.80
Accum Provision for Pension & Postretirement Benefits.....	88,391,083.12	141,361,257.71
Total..	1,075,866,026.81	1,112,875,749.57
Total Liabilities and Stockholders' Equity................................	$ 4,652,218,025.00	$ 4,114,746,291.72

October 24, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,268,420,953.90	$ 5,587,939,337.42
Less: Reserves for Depreciation and Amortization.....	2,406,013,060.80	2,294,580,139.72
Total..	3,862,407,893.10	3,293,359,197.70
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	539,420.24	489,420.24
Special Funds..	20,870,491.01	22,222,263.26
Total..	22,004,197.25	23,305,969.50
Current and Accrued Assets		
Cash..	3,612,757.57	3,029,151.91
Special Deposits...	-	-
Temporary Cash Investments.....................................	3,783,792.60	2,370,674.98
Accounts Receivable - Less Reserve..........................	145,561,838.49	143,820,151.66
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	9,554,317.60	5,123,219.43
Materials and Supplies - At Average Cost..................		
Fuel..	57,430,662.25	62,657,855.24
Plant Materials and Operating Supplies..................	35,029,626.81	35,385,184.42
Stores Expense..	6,206,129.26	6,056,945.28
Gas Stored Underground..	63,098,990.85	57,473,519.98
Emission Allowances..	72,839.58	1,119.56
Prepayments..	6,456,387.83	6,775,755.77
Miscellaneous Current and Accrued Assets...............	2,359,144.20	-
Total..	333,166,487.04	322,693,578.23
Deferred Debits and Other		
Unamortized Debt Expense.......................................	13,179,066.37	11,782,030.65
Unamortized Loss on Bonds......................................	17,812,625.42	19,014,839.24
Accumulated Deferred Income Taxes........................	119,748,320.87	125,563,664.54
Deferred Regulatory Assets..	328,466,862.17	366,547,862.23
Other Deferred Debits..	3,198,532.87	2,888,683.81
Total..	482,405,407.70	525,797,080.47
Total Assets..	$ 4,699,983,985.09	$ 4,165,155,825.90

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital..	242,581,499.00	137,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,033,479,336.84	978,835,580.07
Total Proprietary Capital...	1,700,395,371.29	1,540,751,614.52
Other Long-Term Debt...	1,354,686,805.61	1,106,148,618.96
Pollution Control Bonds - Net of Reacquired Bonds...........	-	-
First Mortgage Bonds...	-	-
Advances from Associated Companies..............................	-	-
Total Long-Term Debt..	1,354,686,805.61	1,106,148,618.96
Total Capitalization...	3,055,082,176.90	2,646,900,233.48
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable...	184,987,468.05	88,993,522.47
Accounts Payable...	243,227,816.46	188,990,657.33
Accounts Payable to Associated Companies........................	16,720,482.07	17,332,336.62
Customer Deposits..	24,047,757.12	23,970,028.99
Taxes Accrued...	25,622,548.09	33,999,090.19
Dividends Declared..	-	-
Interest Accrued...	16,659,969.34	11,691,768.07
Miscellaneous Current and Accrued Liabilities...................	56,444,493.32	39,371,163.74
Total..	567,710,534.45	404,348,567.41
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	731,219,440.14	701,712,186.50
Investment Tax Credit..	36,280,233.65	38,148,830.65
Regulatory Liabilities...	92,676,316.97	88,631,729.60
Customer Advances for Construction..................................	8,221,981.62	6,862,030.82
Asset Retirement Obligations..	85,507,845.22	83,085,321.44
Other Deferred Credits..	14,910,378.40	17,783,957.28
Miscellaneous Long-Term Liabilities..................................	19,997,262.86	36,348,746.37
Accum Provision for Pension & Postretirement Benefits.....	88,377,814.88	141,334,222.35
Total..	1,077,191,273.74	1,113,907,025.01
Total Liabilities and Stockholders' Equity.................................	$ 4,699,983,985.09	$ 4,165,155,825.90

November 21, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,324,429,544.89	$ 5,642,170,100.76
Less: Reserves for Depreciation and Amortization	2,406,359,001.15	2,296,532,370.26
Total	3,918,070,543.74	3,345,637,730.50
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	568,051.84	489,420.24
Special Funds	20,872,130.81	22,223,907.27
Total	22,034,468.65	23,307,613.51
Current and Accrued Assets		
Cash	10,996,971.09	2,897,220.15
Special Deposits	-	-
Temporary Cash Investments	42,606,470.40	89,760,344.95
Accounts Receivable - Less Reserve	176,686,859.29	168,221,830.65
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	15,403,059.38	6,579,830.37
Materials and Supplies - At Average Cost		
Fuel	57,783,784.82	66,754,580.34
Plant Materials and Operating Supplies	35,383,368.00	35,353,533.48
Stores Expense	6,269,025.10	6,168,991.97
Gas Stored Underground	62,615,775.94	55,531,157.29
Emission Allowances	36,483.02	18,344.65
Prepayments	5,884,434.02	5,794,365.17
Miscellaneous Current and Accrued Assets	311,056.62	-
Total	413,977,287.68	437,080,199.02
Deferred Debits and Other		
Unamortized Debt Expense	13,023,556.62	13,909,860.69
Unamortized Loss on Bonds	17,719,368.96	18,913,046.04
Accumulated Deferred Income Taxes	119,748,320.87	125,563,664.54
Deferred Regulatory Assets	342,088,110.62	360,117,539.29
Other Deferred Debits	4,071,667.80	2,980,731.33
Total	496,651,024.87	521,484,841.89
Total Assets	$ 4,850,733,324.94	$ 4,327,510,384.92

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	242,581,499.00	137,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,017,845,296.56	959,452,137.61
Total Proprietary Capital	1,684,761,331.01	1,521,368,172.06
Other Long-Term Debt	1,104,714,730.28	1,354,374,440.62
Total Long-Term Debt	1,104,714,730.28	1,354,374,440.62
Total Capitalization	2,789,476,061.29	2,875,742,612.68
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	558,930,984.72	(0.03)
Accounts Payable	254,457,376.67	187,701,495.70
Accounts Payable to Associated Companies	12,200,574.75	14,855,793.17
Customer Deposits	24,296,403.83	24,023,891.63
Taxes Accrued	28,857,448.43	41,724,577.23
Dividends Declared	29,000,000.00	32,000,000.00
Interest Accrued	4,517,681.31	5,132,089.14
Miscellaneous Current and Accrued Liabilities	73,066,750.71	30,441,270.71
Total	985,327,220.42	335,879,117.55
Deferred Credits and Other		
Accumulated Deferred Income Taxes	731,219,440.14	701,712,186.50
Investment Tax Credit	36,131,167.65	37,959,856.65
Regulatory Liabilities	90,704,452.86	93,166,537.60
Customer Advances for Construction	8,216,098.13	6,888,798.87
Asset Retirement Obligations	85,052,191.06	81,931,392.45
Other Deferred Credits	15,101,993.04	18,144,596.09
Miscellaneous Long-Term Liabilities	21,140,088.82	34,764,475.65
Accum Provision for Pension & Postretirement Benefits	88,364,611.53	141,320,810.88
Total	1,075,930,043.23	1,115,888,654.69
Total Liabilities and Stockholders' Equity	$ 4,850,733,324.94	$ 4,327,510,384.92

December 19, 2014

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2014 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,382,762,019.87	$ 5,721,485,380.08
Less: Reserves for Depreciation and Amortization	2,416,826,219.77	2,304,132,232.43
Total	3,965,935,800.10	3,417,353,147.65
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	568,051.84	489,420.24
Special Funds	20,873,649.84	22,225,512.33
Total	22,035,987.68	23,309,218.57
Current and Accrued Assets		
Cash	4,471,662.22	3,487,861.27
Special Deposits	-	-
Temporary Cash Investments	5,476,947.62	4,534,363.17
Accounts Receivable - Less Reserve	193,836,265.11	196,517,902.03
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	97,209,024.27	108,734.54
Materials and Supplies - At Average Cost		
Fuel	66,567,148.57	64,191,758.19
Plant Materials and Operating Supplies	35,430,432.09	35,816,744.57
Stores Expense	6,352,862.07	6,186,831.58
Gas Stored Underground	54,151,379.40	47,546,888.01
Emission Allowances	6,328.97	41,738.64
Prepayments	7,636,886.04	5,125,670.28
Miscellaneous Current and Accrued Assets	-	-
Total	471,138,936.36	363,558,492.28
Deferred Debits and Other		
Unamortized Debt Expense	12,997,479.51	13,965,458.39
Unamortized Loss on Bonds	18,031,262.30	18,442,649.35
Accumulated Deferred Income Taxes	157,876,610.00	130,998,531.38
Deferred Regulatory Assets	410,620,298.44	312,656,792.93
Other Deferred Debits	3,752,217.02	1,493,995.45
Total	603,277,867.27	477,557,427.50
Total Assets	$ 5,062,388,591.41	$ 4,281,778,286.00

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	327,081,499.00	169,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,032,434,889.14	976,302,938.73
Total Proprietary Capital	1,783,850,923.59	1,570,218,973.18
Other Long-Term Debt	1,354,743,585.78	1,354,402,769.24
Total Long-Term Debt	1,354,743,585.78	1,354,402,769.24
Total Capitalization	3,138,594,509.37	2,924,621,742.42
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	263,956,483.33	19,996,777.75
Accounts Payable	245,177,038.42	170,850,242.83
Accounts Payable to Associated Companies	20,016,015.43	24,294,740.78
Customer Deposits	24,498,183.30	24,075,548.94
Taxes Accrued	18,869,564.99	11,474,665.55
Dividends Declared	-	-
Interest Accrued	5,870,902.91	5,580,257.90
Miscellaneous Current and Accrued Liabilities	89,656,314.87	46,216,861.60
Total	668,044,503.25	302,489,095.35
Deferred Credits and Other		
Accumulated Deferred Income Taxes	857,528,991.76	708,811,163.39
Investment Tax Credit	35,982,104.65	37,770,884.65
Regulatory Liabilities	89,485,208.96	92,564,168.25
Customer Advances for Construction	8,234,051.24	6,748,025.17
Asset Retirement Obligations	85,375,725.04	82,196,215.38
Other Deferred Credits	14,609,362.50	17,117,635.73
Miscellaneous Long-Term Liabilities	22,159,359.96	14,357,421.12
Accum Provision for Pension & Postretirement Benefits	142,374,774.68	95,101,934.54
Total	1,255,749,578.79	1,054,667,448.23
Total Liabilities and Stockholders' Equity	$ 5,062,388,591.41	$ 4,281,778,286.00

January 27, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of January 31, 2015 and 2013

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,354,300,842.21	$ 5,752,452,480.55
Less: Reserves for Depreciation and Amortization	2,348,362,652.38	2,314,875,211.10
Total	4,005,938,189.83	3,437,577,269.45
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	568,051.84	489,420.24
Special Funds	22,895,887.96	20,927,142.20
Total	24,058,225.80	22,010,848.44
Current and Accrued Assets		
Cash	4,133,972.30	8,184,210.69
Special Deposits	-	-
Temporary Cash Investments	3,719,099.14	3,525,712.11
Accounts Receivable - Less Reserve	222,089,244.19	231,564,174.49
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	76,750,146.39	24,919,004.32
Materials and Supplies - At Average Cost		
Fuel	55,893,880.61	55,632,627.98
Plant Materials and Operating Supplies	35,581,591.23	35,927,175.09
Stores Expense	6,418,591.64	6,203,562.58
Gas Stored Underground	37,535,703.58	32,656,552.78
Emission Allowances	6,324.22	36,357.58
Prepayments	8,983,876.21	7,039,588.11
Miscellaneous Current and Accrued Assets	-	-
Total	451,112,429.51	405,688,965.73
Deferred Debits and Other		
Unamortized Debt Expense	12,826,426.85	13,901,263.13
Unamortized Loss on Bonds	17,932,113.23	18,352,820.24
Accumulated Deferred Income Taxes	157,876,610.00	130,998,531.39
Deferred Regulatory Assets	458,234,887.13	314,829,587.33
Other Deferred Debits	3,960,941.01	2,122,297.15
Total	650,830,978.22	480,204,499.24
Total Assets	$ 5,131,939,823.36	$ 4,345,481,582.86

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	327,081,499.00	169,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,054,325,447.75	1,002,292,495.37
Total Proprietary Capital	1,805,741,482.20	1,596,208,529.82
Other Long-Term Debt	1,354,772,441.27	1,354,431,097.86
Total Long-Term Debt	1,354,772,441.27	1,354,431,097.86
Total Capitalization	3,160,513,923.47	2,950,639,627.68
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	308,449,698.45	24,997,712.47
Accounts Payable	220,502,638.96	189,989,777.38
Accounts Payable to Associated Companies	17,350,751.47	15,100,972.15
Customer Deposits	24,606,838.10	24,078,344.11
Taxes Accrued	8,224,210.78	29,727,725.65
Dividends Declared	-	-
Interest Accrued	9,024,986.40	8,674,736.74
Miscellaneous Current and Accrued Liabilities	141,536,687.07	50,900,530.12
Total	729,695,811.23	343,469,798.62
Deferred Credits and Other		
Accumulated Deferred Income Taxes	857,528,991.77	708,811,163.41
Investment Tax Credit	35,870,551.65	37,621,818.65
Regulatory Liabilities	91,371,508.39	92,051,390.75
Customer Advances for Construction	7,997,834.97	6,730,515.63
Asset Retirement Obligations	85,700,538.28	83,299,042.89
Other Deferred Credits	15,845,284.28	19,589,236.56
Miscellaneous Long-Term Liabilities	26,271,747.37	16,380,410.85
Accum Provision for Pension & Postretirement Benefits	121,143,631.95	86,888,577.82
Total	1,241,730,088.66	1,051,372,156.56
Total Liabilities and Stockholders' Equity	$ 5,131,939,823.36	$ 4,345,481,582.86

February 20, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of February 28, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,384,557,974.92	$ 5,793,632,284.43
Less: Reserves for Depreciation and Amortization.....	2,343,810,620.29	2,323,820,737.02
Total..	4,040,747,354.63	3,469,811,547.41
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	567,535.13	489,420.24
Special Funds..	23,097,938.47	20,928,465.17
Total..	24,259,759.60	22,012,171.41
Current and Accrued Assets		
Cash..	9,210,820.78	6,165,225.70
Special Deposits..	-	-
Temporary Cash Investments.....................................	3,660,446.40	22,306,514.03
Accounts Receivable - Less Reserve..........................	234,618,432.74	216,334,539.51
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	83,334,101.87	11,842,219.45
Materials and Supplies - At Average Cost..................		
Fuel...	50,210,452.70	53,156,325.11
Plant Materials and Operating Supplies..................	35,464,229.70	35,848,978.44
Stores Expense...	6,428,534.54	6,242,519.14
Gas Stored Underground..	24,366,912.13	24,226,844.36
Emission Allowances..	6,319.97	31,547.72
Prepayments..	7,393,433.69	8,222,453.95
Miscellaneous Current and Accrued Assets................	-	-
Total..	454,693,684.52	384,377,167.41
Deferred Debits and Other		
Unamortized Debt Expense.......................................	12,686,210.91	13,866,161.93
Unamortized Loss on Bonds......................................	17,842,559.17	18,262,991.13
Accumulated Deferred Income Taxes.........................	165,010,035.38	130,998,531.39
Deferred Regulatory Assets..	419,900,836.01	319,048,090.06
Other Deferred Debits..	4,764,071.69	1,985,662.19
Total..	620,203,713.16	484,161,436.70
Total Assets..	$ 5,139,904,511.91	$ 4,360,362,322.93

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..	835,888.64	835,888.64
Paid-In Capital..	327,081,499.00	169,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,053,170,518.71	990,073,656.40
Total Proprietary Capital...	1,804,586,553.16	1,583,989,690.85
Other Long-Term Debt...	1,354,798,504.29	1,354,459,426.48
Total Long-Term Debt..	1,354,798,504.29	1,354,459,426.48
Total Capitalization...	3,159,385,057.45	2,938,449,117.33
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable...	294,981,079.17	14,999,566.63
Accounts Payable..	226,174,917.51	178,924,743.58
Accounts Payable to Associated Companies........................	13,768,731.02	16,258,307.06
Customer Deposits...	24,824,334.83	24,070,289.69
Taxes Accrued..	11,592,728.01	40,772,865.09
Dividends Declared..	23,000,000.00	27,000,000.00
Interest Accrued...	11,786,458.38	11,602,313.00
Miscellaneous Current and Accrued Liabilities...................	129,793,447.02	53,475,267.03
Total..	735,921,695.94	367,103,352.08
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	880,219,726.57	708,811,163.41
Investment Tax Credit..	35,758,998.65	37,472,752.65
Regulatory Liabilities..	92,852,683.82	91,772,297.20
Customer Advances for Construction..................................	7,758,016.39	6,711,207.70
Asset Retirement Obligations..	85,988,289.21	83,495,504.84
Other Deferred Credits..	16,635,067.25	23,064,043.85
Miscellaneous Long-Term Liabilities..................................	4,272,804.90	16,607,648.91
Accum Provision for Pension & Postretirement Benefits.....	121,112,171.73	86,875,234.96
Total..	1,244,597,758.52	1,054,809,853.52
Total Liabilities and Stockholders' Equity.................................	$ 5,139,904,511.91	$ 4,360,362,322.93

March 20, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of March 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,308,800,844.46	$ 5,838,356,857.81
Less: Reserves for Depreciation and Amortization	2,215,855,873.16	2,334,756,488.27
Total	4,092,944,971.30	3,503,600,369.54
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	567,536.63	489,420.24
Special Funds	21,699,755.24	20,929,534.85
Total	22,861,577.87	22,013,241.09
Current and Accrued Assets		
Cash	9,312,458.15	6,168,993.35
Special Deposits	-	-
Temporary Cash Investments	7,664,032.42	3,093,566.78
Accounts Receivable - Less Reserve	187,962,802.98	189,078,536.70
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	12,530,233.52	22,567,694.68
Materials and Supplies - At Average Cost		
Fuel	47,534,803.25	52,267,758.99
Plant Materials and Operating Supplies	34,102,528.16	35,828,626.54
Stores Expense	6,283,018.71	6,325,909.69
Gas Stored Underground	17,309,800.73	16,010,966.83
Emission Allowances	6,316.40	25,999.97
Prepayments	6,771,296.90	6,581,637.40
Miscellaneous Current and Accrued Assets	119.97	427.22
Total	329,477,411.19	337,950,118.15
Deferred Debits and Other		
Unamortized Debt Expense	12,576,508.50	13,698,381.58
Unamortized Loss on Bonds	17,743,410.05	18,173,162.02
Accumulated Deferred Income Taxes	167,577,445.23	129,178,487.65
Deferred Regulatory Assets	427,357,285.01	317,364,932.38
Other Deferred Debits	6,139,935.06	2,435,355.11
Total	631,394,583.85	480,850,318.74
Total Assets	$ 5,076,678,544.21	$ 4,344,414,047.52

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	327,081,499.00	169,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,062,994,137.55	1,000,658,673.50
Total Proprietary Capital	1,814,410,172.00	1,594,574,707.95
Other Long-Term Debt	1,354,827,359.79	1,354,487,755.10
Total Long-Term Debt	1,354,827,359.79	1,354,487,755.10
Total Capitalization	3,169,237,531.79	2,949,062,463.05
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	215,644,111.06	14,999,051.21
Accounts Payable	219,917,147.20	182,815,970.27
Accounts Payable to Associated Companies	19,939,696.64	17,259,546.28
Customer Deposits	24,833,561.35	23,927,076.62
Taxes Accrued	12,045,083.83	31,998,367.95
Dividends Declared	-	-
Interest Accrued	14,955,545.11	14,641,456.30
Miscellaneous Current and Accrued Liabilities	141,264,317.57	66,908,237.64
Total	648,599,462.76	352,549,706.27
Deferred Credits and Other		
Accumulated Deferred Income Taxes	898,758,763.56	713,697,360.68
Investment Tax Credit	35,647,445.65	37,323,689.65
Regulatory Liabilities	91,738,914.37	90,704,475.94
Customer Advances for Construction	7,590,237.65	6,714,733.28
Asset Retirement Obligations	86,274,724.96	83,813,179.35
Other Deferred Credits	14,601,675.24	20,551,432.31
Miscellaneous Long-Term Liabilities	4,331,074.54	4,195,358.94
Accum Provision for Pension & Postretirement Benefits	119,898,713.69	85,801,648.05
Total	1,258,841,549.66	1,042,801,878.20
Total Liabilities and Stockholders' Equity	$ 5,076,678,544.21	$ 4,344,414,047.52

April 27, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of April 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,367,812,651.30	$ 5,894,590,703.79
Less: Reserves for Depreciation and Amortization.....	2,223,536,024.40	2,345,809,627.70
Total..	4,144,276,626.90	3,548,781,076.09
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	567,535.13	489,420.24
Special Funds..	21,701,718.11	20,930,872.01
Total..	22,863,539.24	22,014,578.25
Current and Accrued Assets		
Cash..	4,100,705.62	4,381,558.48
Special Deposits...	-	-
Temporary Cash Investments.....................................	1,206,483.79	2,313,860.30
Accounts Receivable - Less Reserve..........................	159,451,716.70	161,883,237.31
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	18,862,699.60	22,163,025.13
Materials and Supplies - At Average Cost..................		
Fuel..	51,038,673.68	55,194,917.68
Plant Materials and Operating Supplies..................	34,889,876.00	35,276,840.30
Stores Expense..	6,480,786.65	6,301,408.30
Gas Stored Underground..	12,896,168.34	11,545,086.36
Emission Allowances..	6,314.25	107,143.32
Prepayments..	9,757,866.83	5,429,609.18
Miscellaneous Current and Accrued Assets................	-	-
Total..	298,691,291.46	304,596,686.36
Deferred Debits and Other		
Unamortized Debt Expense.......................................	12,419,551.61	13,529,214.32
Unamortized Loss on Bonds......................................	17,647,459.29	18,083,332.91
Accumulated Deferred Income Taxes........................	167,577,445.23	129,178,487.65
Deferred Regulatory Assets..	414,842,323.64	320,332,380.22
Other Deferred Debits..	5,992,876.54	2,702,582.16
Total..	618,479,656.31	483,825,997.26
Total Assets..	$ 5,084,311,113.91	$ 4,359,218,337.96

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital..	327,081,499.00	169,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,071,439,251.96	1,005,259,270.55
Total Proprietary Capital...	1,822,855,286.41	1,599,175,305.00
Other Long-Term Debt...	1,354,855,284.45	1,354,516,083.72
Total Long-Term Debt..	1,354,855,284.45	1,354,516,083.72
Total Capitalization...	3,177,710,570.86	2,953,691,388.72
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable...	207,952,894.99	19,999,305.52
Accounts Payable..	225,521,644.77	198,567,964.04
Accounts Payable to Associated Companies........................	22,839,034.81	16,440,682.45
Customer Deposits...	24,783,100.25	23,924,787.34
Taxes Accrued..	23,236,071.51	23,533,399.12
Dividends Declared..	-	-
Interest Accrued...	17,101,366.74	16,704,715.50
Miscellaneous Current and Accrued Liabilities...................	124,914,560.67	63,911,053.44
Total..	646,348,673.74	363,081,907.41
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	898,758,763.56	713,697,360.68
Investment Tax Credit..	35,535,892.65	37,174,623.65
Regulatory Liabilities..	92,499,496.91	90,619,714.71
Customer Advances for Construction..................................	7,466,748.69	6,703,799.16
Asset Retirement Obligations..	86,582,646.00	84,040,447.01
Other Deferred Credits..	15,268,076.93	20,091,783.17
Miscellaneous Long-Term Liabilities..................................	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits.....	119,867,439.67	85,788,265.46
Total..	1,260,251,869.31	1,042,445,041.83
	$ 5,084,311,113.91	$ 4,359,218,337.96

May 21, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of May 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,335,919,741.41	$ 5,946,114,085.30
Less: Reserves for Depreciation and Amortization.....	2,155,620,139.08	2,354,493,158.62
Total..	4,180,299,602.33	3,591,620,926.68
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve............................	567,535.13	489,420.24
Special Funds..	20,803,848.01	21,202,447.64
Total..	21,965,669.14	22,286,153.88
Current and Accrued Assets		
Cash..	4,025,608.25	3,532,094.83
Special Deposits...	-	-
Temporary Cash Investments.....................................	711,699.53	859,242.43
Accounts Receivable - Less Reserve..........................	160,136,379.05	163,892,803.46
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	16,539,052.81	22,465,454.72
Materials and Supplies - At Average Cost..................		
Fuel..	50,856,723.20	56,257,478.86
Plant Materials and Operating Supplies..................	34,925,949.28	35,779,701.59
Stores Expense...	6,533,041.08	6,398,228.05
Gas Stored Underground..	11,377,475.59	9,899,197.98
Emission Allowances...	6,312.43	87,435.53
Prepayments...	7,672,934.34	8,280,103.56
Miscellaneous Current and Accrued Assets................	-	-
Total..	292,785,175.56	307,451,741.01
Deferred Debits and Other		
Unamortized Debt Expense.......................................	12,246,865.77	13,360,047.06
Unamortized Loss on Bonds......................................	17,548,310.17	17,993,503.80
Accumulated Deferred Income Taxes.........................	167,577,445.23	129,178,487.65
Deferred Regulatory Assets..	404,311,907.11	320,348,922.62
Other Deferred Debits..	6,272,213.64	2,644,221.18
Total..	607,956,741.92	483,525,182.31
Total Assets..	$ 5,103,007,188.95	$ 4,404,884,003.88

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock...	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense..	835,888.64	835,888.64
Paid-In Capital..	327,081,499.00	169,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings..	1,050,807,556.95	985,065,888.15
Total Proprietary Capital...	1,802,223,591.40	1,578,981,922.60
Other Long-Term Debt..	1,354,884,139.95	1,354,544,412.34
Total Long-Term Debt...	1,354,884,139.95	1,354,544,412.34
Total Capitalization...	3,157,107,731.35	2,933,526,334.94
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable..	245,946,033.60	49,996,662.46
Accounts Payable..	211,310,163.63	202,509,083.28
Accounts Payable to Associated Companies........................	14,212,243.95	20,057,830.92
Customer Deposits...	24,835,127.62	23,980,131.07
Taxes Accrued..	33,949,702.34	33,438,222.55
Dividends Declared...	35,000,000.00	33,000,000.00
Interest Accrued..	4,729,207.19	4,619,437.25
Miscellaneous Current and Accrued Liabilities...................	113,236,908.99	62,573,809.05
Total..	683,219,387.32	430,175,176.58
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	898,758,763.56	713,697,360.68
Investment Tax Credit...	35,424,339.65	37,025,557.65
Regulatory Liabilities..	92,865,354.92	90,098,620.06
Customer Advances for Construction..................................	7,523,356.03	6,628,645.72
Asset Retirement Obligations..	86,676,004.45	84,262,780.57
Other Deferred Credits..	18,496,007.56	20,590,080.54
Miscellaneous Long-Term Liabilities..................................	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits.....	118,663,439.21	84,550,399.15
Total..	1,262,680,070.28	1,041,182,492.36
Total Liabilities and Stockholders' Equity.................................	$ 5,103,007,188.95	$ 4,404,884,003.88

June 19, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of June 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,243,932,144.37	$ 5,993,948,101.36
Less: Reserves for Depreciation and Amortization	1,986,590,406.63	2,364,797,528.58
Total	4,257,341,737.74	3,629,150,572.78
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	567,535.13	539,420.24
Special Funds	9,005,379.40	21,204,065.89
Total	10,167,200.53	22,337,772.13
Current and Accrued Assets		
Cash	6,606,484.72	4,087,486.37
Special Deposits	-	-
Temporary Cash Investments	243,993.78	754,594.90
Accounts Receivable - Less Reserve	171,353,555.27	177,214,000.69
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	16,077,313.04	22,210,361.71
Materials and Supplies - At Average Cost		
Fuel	51,966,230.70	51,698,565.63
Plant Materials and Operating Supplies	29,469,243.73	35,618,766.83
Stores Expense	5,563,405.67	6,262,881.93
Gas Stored Underground	15,858,495.03	16,771,949.95
Emission Allowances	6,310.96	67,674.47
Prepayments	9,160,028.25	7,323,392.95
Miscellaneous Current and Accrued Assets	132,969.39	-
Total	306,438,030.54	322,009,675.43
Deferred Debits and Other		
Unamortized Debt Expense	12,079,681.73	13,194,870.32
Unamortized Loss on Bonds	17,452,359.46	17,904,942.43
Accumulated Deferred Income Taxes	173,535,037.32	126,247,168.09
Deferred Regulatory Assets	374,351,256.72	322,499,065.88
Other Deferred Debits	8,395,473.40	4,600,781.13
Total	585,813,808.63	484,446,827.85
Total Assets	$ 5,159,760,777.44	$ 4,457,944,848.19

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	347,081,499.00	222,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,063,027,168.78	1,003,304,674.81
Total Proprietary Capital	1,834,443,203.23	1,650,220,709.26
Other Long-Term Debt	1,354,912,064.61	1,354,572,337.00
Total Long-Term Debt	1,354,912,064.61	1,354,572,337.00
Total Capitalization	3,189,355,267.84	3,004,793,046.26
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	258,939,995.27	69,992,485.52
Accounts Payable	217,423,312.95	202,767,972.89
Accounts Payable to Associated Companies	16,355,690.24	20,042,122.31
Customer Deposits	24,880,997.80	23,985,321.70
Taxes Accrued	27,599,441.50	12,748,569.46
Dividends Declared	-	-
Interest Accrued	6,045,446.48	5,829,204.32
Miscellaneous Current and Accrued Liabilities	88,856,943.69	62,032,527.12
Total	640,101,827.93	397,398,203.32
Deferred Credits and Other		
Accumulated Deferred Income Taxes	933,242,229.26	726,121,824.04
Investment Tax Credit	35,312,786.65	36,876,494.65
Regulatory Liabilities	91,833,397.25	89,636,180.41
Customer Advances for Construction	7,392,383.39	7,275,246.78
Asset Retirement Obligations	133,057,703.93	84,348,366.27
Other Deferred Credits	5,848,532.70	17,766,201.39
Miscellaneous Long-Term Liabilities	4,706,580.40	4,155,856.71
Accum Provision for Pension & Postretirement Benefits	118,910,068.09	89,573,428.36
Total	1,330,303,681.67	1,055,753,598.61
Total Liabilities and Stockholders' Equity	$ 5,159,760,777.44	$ 4,457,944,848.19

July 27, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of July 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,286,884,784.65	$ 6,059,693,508.40
Less: Reserves for Depreciation and Amortization	1,997,770,250.63	2,375,296,839.18
Total	4,289,114,534.02	3,684,396,669.22
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	567,535.13	539,420.24
Special Funds	9,006,492.09	21,205,709.21
Total	10,168,313.22	22,339,415.45
Current and Accrued Assets		
Cash	4,389,467.90	4,416,546.98
Special Deposits	-	-
Temporary Cash Investments	2,223,137.19	4,742,868.79
Accounts Receivable - Less Reserve	176,547,901.80	169,840,118.75
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	12,205,322.35	12,703,358.98
Materials and Supplies - At Average Cost		
Fuel	48,482,833.73	49,559,924.55
Plant Materials and Operating Supplies	31,262,065.81	35,522,957.84
Stores Expense	5,492,733.95	6,318,520.22
Gas Stored Underground	24,762,952.38	29,591,164.87
Emission Allowances	166.88	171,339.92
Prepayments	8,180,413.20	9,194,729.57
Miscellaneous Current and Accrued Assets	-	867,901.15
Total	313,546,995.19	322,929,431.62
Deferred Debits and Other		
Unamortized Debt Expense	11,790,694.76	13,617,457.54
Unamortized Loss on Bonds	17,353,210.28	18,098,611.89
Accumulated Deferred Income Taxes	173,535,037.32	126,247,168.09
Deferred Regulatory Assets	395,808,993.68	319,764,899.83
Other Deferred Debits	6,841,671.38	4,828,761.77
Total	605,329,607.42	482,556,899.12
Total Assets	$ 5,218,159,449.85	$ 4,512,222,415.41

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	347,081,499.00	222,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,083,722,761.14	1,018,313,508.29
Total Proprietary Capital	1,855,138,795.59	1,665,229,542.74
Other Long-Term Debt	1,354,940,920.12	1,354,601,169.95
Total Long-Term Debt	1,354,940,920.12	1,354,601,169.95
Total Capitalization	3,210,079,715.71	3,019,830,712.69
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	264,208,566.31	80,995,314.40
Accounts Payable	213,333,222.43	225,905,652.32
Accounts Payable to Associated Companies	14,221,393.45	15,843,144.95
Customer Deposits	24,830,151.48	24,004,851.61
Taxes Accrued	42,772,007.39	18,891,476.67
Dividends Declared	-	-
Interest Accrued	9,237,313.58	9,283,522.81
Miscellaneous Current and Accrued Liabilities	108,012,290.81	58,782,372.32
Total	676,614,945.45	433,706,335.08
Deferred Credits and Other		
Accumulated Deferred Income Taxes	933,242,229.26	726,121,824.04
Investment Tax Credit	35,201,233.65	36,727,428.65
Regulatory Liabilities	92,346,768.25	90,194,572.67
Customer Advances for Construction	7,456,825.63	7,868,967.40
Asset Retirement Obligations	133,179,690.83	84,669,336.44
Other Deferred Credits	6,887,632.87	19,214,151.84
Miscellaneous Long-Term Liabilities	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits	118,877,603.30	89,560,038.61
Total	1,331,464,788.69	1,058,685,367.64
Total Liabilities and Stockholders' Equity	$ 5,218,159,449.85	$ 4,512,222,415.41

August 21, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of August 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,317,360,481.00	$ 6,124,709,957.40
Less: Reserves for Depreciation and Amortization	1,993,322,632.66	2,385,294,963.27
Total	4,324,037,848.34	3,739,414,994.13
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	567,535.13	539,420.24
Special Funds	9,397,542.92	21,207,370.32
Total	10,559,364.05	22,341,076.56
Current and Accrued Assets		
Cash	11,968,185.49	6,814,914.97
Special Deposits	-	-
Temporary Cash Investments	3,846,324.34	15,160,259.71
Accounts Receivable - Less Reserve	175,557,739.07	171,601,044.19
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	6,088,965.28	13,902,270.03
Materials and Supplies - At Average Cost		
Fuel	48,506,844.20	45,152,960.84
Plant Materials and Operating Supplies	31,559,894.45	35,170,059.40
Stores Expense	5,737,824.75	6,277,557.18
Gas Stored Underground	34,310,851.88	41,769,807.04
Emission Allowances	165.13	136,170.06
Prepayments	7,407,104.58	7,919,876.81
Miscellaneous Current and Accrued Assets	-	23,617.75
Total	324,983,899.17	343,928,537.98
Deferred Debits and Other		
Unamortized Debt Expense	11,624,239.04	13,494,597.16
Unamortized Loss on Bonds	17,254,061.19	18,002,246.90
Accumulated Deferred Income Taxes	174,891,325.03	125,509,564.69
Deferred Regulatory Assets	394,153,017.69	320,954,164.31
Other Deferred Debits	6,890,695.20	3,360,861.05
Total	604,813,338.15	481,321,434.11
Total Assets	$ 5,264,394,449.71	$ 4,587,006,042.78

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	347,081,499.00	222,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,080,312,749.01	1,013,474,521.07
Total Proprietary Capital	1,851,728,783.46	1,660,390,555.52
Other Long-Term Debt	1,354,969,775.61	1,354,630,025.44
Total Long-Term Debt	1,354,969,775.61	1,354,630,025.44
Total Capitalization	3,206,698,559.07	3,015,020,580.96
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	282,182,025.52	104,992,899.99
Accounts Payable	202,083,446.20	241,299,605.28
Accounts Payable to Associated Companies	17,206,808.86	14,836,332.67
Customer Deposits	24,898,636.14	24,000,006.56
Taxes Accrued	58,474,350.51	36,956,840.98
Dividends Declared	23,000,000.00	23,000,000.00
Interest Accrued	11,937,515.12	11,558,616.60
Miscellaneous Current and Accrued Liabilities	107,455,726.20	67,776,191.24
Total	727,238,508.55	524,420,493.32
Deferred Credits and Other		
Accumulated Deferred Income Taxes	933,712,106.24	722,645,905.36
Investment Tax Credit	35,089,680.65	36,578,363.65
Regulatory Liabilities	92,004,422.18	84,074,311.07
Customer Advances for Construction	7,551,642.88	7,841,390.40
Asset Retirement Obligations	133,595,095.22	84,898,331.36
Other Deferred Credits	6,474,641.06	17,650,945.71
Miscellaneous Long-Term Liabilities	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits	117,756,988.96	89,546,672.96
Total	1,330,457,382.09	1,047,564,968.50
Total Liabilities and Stockholders' Equity	$ 5,264,394,449.71	$ 4,587,006,042.78

September 22, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of September 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,401,878,898.09	$ 6,196,387,956.02
Less: Reserves for Depreciation and Amortization.....	2,004,810,068.24	2,397,029,582.13
Total..	4,397,068,829.85	3,799,358,373.89
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	567,535.13	539,420.24
Special Funds..	9,608,582.89	19,709,019.78
Total..	10,770,404.02	20,842,726.02
Current and Accrued Assets		
Cash..	4,132,567.35	6,546,606.56
Special Deposits...	-	-
Temporary Cash Investments.....................................	175,299,804.48	18,026,531.83
Accounts Receivable - Less Reserve..........................	169,112,258.77	160,410,003.14
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	18,795,304.47	11,397,202.77
Materials and Supplies - At Average Cost..................		
Fuel..	53,523,746.00	54,011,575.82
Plant Materials and Operating Supplies..................	31,550,520.01	35,234,229.18
Stores Expense...	5,541,295.11	6,188,502.49
Gas Stored Underground..	42,748,459.15	53,224,450.20
Emission Allowances..	163.61	103,610.44
Prepayments..	6,460,629.33	7,618,415.49
Miscellaneous Current and Accrued Assets................	-	2,804,902.73
Total..	507,164,748.28	355,566,030.65
Deferred Debits and Other		
Unamortized Debt Expense.......................................	15,897,418.55	13,339,706.42
Unamortized Loss on Bonds......................................	17,158,110.45	17,908,990.43
Accumulated Deferred Income Taxes........................	194,209,814.28	119,748,320.87
Deferred Regulatory Assets..	401,093,009.86	321,039,417.54
Other Deferred Debits..	9,327,081.36	4,414,459.18
Total..	637,685,434.50	476,450,894.44
Total Assets..	$ 5,552,689,416.65	$ 4,652,218,025.00

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital..	347,081,499.00	242,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings..	1,098,281,415.07	1,025,427,505.22
Total Proprietary Capital..	1,869,697,449.52	1,692,343,539.67
Other Long-Term Debt..	1,904,661,362.88	1,354,657,950.12
Total Long-Term Debt...	1,904,661,362.88	1,354,657,950.12
Total Capitalization..	3,774,358,812.40	3,047,001,489.79
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable..	-	142,992,686.68
Accounts Payable..	206,860,492.18	258,419,677.93
Accounts Payable to Associated Companies........................	19,875,477.86	19,717,400.65
Customer Deposits..	25,018,785.13	24,037,240.94
Taxes Accrued...	18,000,861.29	20,485,102.24
Dividends Declared...	-	-
Interest Accrued..	15,189,551.35	14,594,255.13
Miscellaneous Current and Accrued Liabilities...................	71,468,189.35	63,625,614.70
Total..	356,413,357.16	543,871,978.27
Deferred Credits and Other		
Accumulated Deferred Income Taxes................................	989,128,001.08	731,219,440.14
Investment Tax Credit...	34,978,127.65	36,429,299.65
Regulatory Liabilities...	91,612,276.83	92,071,568.65
Customer Advances for Construction.................................	7,613,919.34	7,968,468.03
Asset Retirement Obligations...	170,704,405.25	85,221,471.06
Other Deferred Credits...	5,614,672.69	15,673,384.37
Miscellaneous Long-Term Liabilities.................................	4,542,792.03	4,369,841.92
Accum Provision for Pension & Postretirement Benefits.....	117,723,052.22	88,391,083.12
Total..	1,421,917,247.09	1,061,344,556.94
Total Liabilities and Stockholders' Equity.................................	$ 5,552,689,416.65	$ 4,652,218,025.00

October 26, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of October 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost......................................	$ 6,439,967,117.10	$ 6,268,420,953.90
Less: Reserves for Depreciation and Amortization.....	2,007,867,650.11	2,406,013,060.80
Total...	4,432,099,466.99	3,862,407,893.10
Investments		
Ohio Valley Electric Corporation...............................	594,286.00	594,286.00
Nonutility Property - Less Reserve.............................	567,535.13	539,420.24
Special Funds...	9,609,648.54	20,870,491.01
Total...	10,771,469.67	22,004,197.25
Current and Accrued Assets		
Cash...	2,940,675.58	3,612,757.57
Special Deposits...	-	-
Temporary Cash Investments.....................................	159,384,688.55	3,783,792.60
Accounts Receivable - Less Reserve..........................	152,620,261.39	145,561,838.49
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies.....	23,254,511.03	9,554,317.60
Materials and Supplies - At Average Cost..................		
Fuel..	59,687,698.87	57,430,662.25
Plant Materials and Operating Supplies..................	30,915,324.60	35,029,626.81
Stores Expense...	5,467,461.29	6,206,129.26
Gas Stored Underground..	48,111,034.14	63,098,990.85
Emission Allowances..	162.20	72,839.58
Prepayments...	5,656,737.03	6,456,387.83
Miscellaneous Current and Accrued Assets...............	-	2,359,144.20
Total...	488,038,554.68	333,166,487.04
Deferred Debits and Other		
Unamortized Debt Expense.......................................	15,790,858.16	13,179,066.37
Unamortized Loss on Bonds......................................	17,058,961.32	17,812,625.42
Accumulated Deferred Income Taxes........................	194,209,814.28	119,748,320.87
Deferred Regulatory Assets..	402,385,728.22	328,466,862.17
Other Deferred Debits...	6,872,671.44	3,198,532.87
Total...	636,318,033.42	482,405,407.70
Total Assets..	$ 5,567,227,524.76	$ 4,699,983,985.09

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital...	347,081,499.00	242,581,499.00
Other Comprehensive Income..	-	-
Retained Earnings...	1,107,509,965.23	1,033,479,336.84
Total Proprietary Capital...	1,878,925,999.68	1,700,395,371.29
Other Long-Term Debt...	1,904,691,945.27	1,354,686,805.61
Total Long-Term Debt..	1,904,691,945.27	1,354,686,805.61
Total Capitalization..	3,783,617,944.95	3,055,082,176.90
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable...	-	184,987,468.05
Accounts Payable...	201,495,393.24	243,227,816.46
Accounts Payable to Associated Companies........................	18,973,659.68	16,720,482.07
Customer Deposits...	25,132,712.92	24,047,757.12
Taxes Accrued..	25,801,171.72	25,622,548.09
Dividends Declared..	-	-
Interest Accrued..	19,080,896.30	16,659,969.34
Miscellaneous Current and Accrued Liabilities...................	70,311,790.09	72,112,708.19
Total..	360,795,623.95	583,378,749.32
Deferred Credits and Other		
Accumulated Deferred Income Taxes.................................	989,128,001.08	731,219,440.14
Investment Tax Credit...	34,866,574.65	36,280,233.65
Regulatory Liabilities..	92,585,845.19	92,676,316.97
Customer Advances for Construction..................................	7,612,506.86	8,221,981.62
Asset Retirement Obligations...	170,506,422.60	85,507,845.22
Other Deferred Credits...	6,152,881.54	14,910,378.40
Miscellaneous Long-Term Liabilities..................................	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits.....	117,688,919.04	88,377,814.88
Total..	1,422,813,955.86	1,061,523,058.87
Total Liabilities and Stockholders' Equity.................................	$ 5,567,227,524.76	$ 4,699,983,985.09

November 20, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of November 30, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost	$ 6,477,326,640.66	$ 6,324,429,544.89
Less: Reserves for Depreciation and Amortization	2,015,507,295.34	2,406,359,001.15
Total	4,461,819,345.32	3,918,070,543.74
Investments		
Ohio Valley Electric Corporation	594,286.00	594,286.00
Nonutility Property - Less Reserve	567,535.13	568,051.84
Special Funds	9,610,689.65	20,872,130.81
Total	10,772,510.78	22,034,468.65
Current and Accrued Assets		
Cash	3,839,227.38	10,996,971.09
Special Deposits	-	-
Temporary Cash Investments	1,108,221.74	42,606,470.40
Accounts Receivable - Less Reserve	156,816,404.42	176,686,859.29
Notes Receivable from Associated Companies	-	-
Accounts Receivable from Associated Companies	21,478,413.53	15,403,059.38
Materials and Supplies - At Average Cost		
Fuel	66,108,449.64	57,783,784.82
Plant Materials and Operating Supplies	31,874,624.26	35,383,368.00
Stores Expense	5,584,464.30	6,269,025.10
Gas Stored Underground	48,195,621.99	62,615,775.94
Emission Allowances	160.48	36,483.02
Prepayments	5,310,777.41	5,884,434.02
Miscellaneous Current and Accrued Assets	-	311,056.62
Total	340,316,365.15	413,977,287.68
Deferred Debits and Other		
Unamortized Debt Expense	15,750,527.85	13,023,556.62
Unamortized Loss on Bonds	16,963,010.57	17,719,368.96
Accumulated Deferred Income Taxes	194,209,814.28	119,748,320.87
Deferred Regulatory Assets	418,818,391.42	342,088,110.62
Other Deferred Debits	7,265,837.02	4,071,667.80
Total	653,007,581.14	496,651,024.87
Total Assets	$ 5,465,915,802.39	$ 4,850,733,324.94

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense	835,888.64	835,888.64
Paid-In Capital	347,081,499.00	242,581,499.00
Other Comprehensive Income	-	-
Retained Earnings	1,082,807,092.94	1,017,845,296.56
Total Proprietary Capital	1,854,223,127.39	1,684,761,331.01
Other Long-Term Debt	1,654,713,921.91	1,104,714,730.28
Total Long-Term Debt	1,654,713,921.91	1,104,714,730.28
Total Capitalization	3,508,937,049.30	2,789,476,061.29
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies	-	-
Notes Payable	127,990,549.94	558,930,984.72
Accounts Payable	195,200,342.12	254,457,376.67
Accounts Payable to Associated Companies	19,922,700.51	12,200,574.75
Customer Deposits	25,302,606.20	24,296,403.83
Taxes Accrued	36,518,244.29	28,857,448.43
Dividends Declared	38,000,000.00	29,000,000.00
Interest Accrued	8,178,564.25	4,517,681.31
Miscellaneous Current and Accrued Liabilities	70,944,269.84	89,877,791.54
Total	522,057,277.15	1,002,138,261.25
Deferred Credits and Other		
Accumulated Deferred Income Taxes	989,128,001.08	731,219,440.14
Investment Tax Credit	34,755,021.65	36,131,167.65
Regulatory Liabilities	93,267,703.15	90,704,452.86
Customer Advances for Construction	7,764,277.97	8,216,098.13
Asset Retirement Obligations	181,006,065.04	85,052,191.06
Other Deferred Credits	8,159,690.00	15,101,993.04
Miscellaneous Long-Term Liabilities	4,272,804.90	4,329,047.99
Accum Provision for Pension & Postretirement Benefits	116,567,912.15	88,364,611.53
Total	1,434,921,475.94	1,059,119,002.40
Total Liabilities and Stockholders' Equity	$ 5,465,915,802.39	$ 4,850,733,324.94

December 21, 2015

Louisville Gas and Electric Company
Comparative Balance Sheets as of December 31, 2015 and 2014

Assets	This Year	Last Year
Utility Plant		
Utility Plant at Original Cost.......................................	$ 6,523,426,436.56	$ 6,382,762,019.87
Less: Reserves for Depreciation and Amortization......	2,015,937,460.48	2,416,826,219.77
Total..	4,507,488,976.08	3,965,935,800.10
Investments		
Ohio Valley Electric Corporation................................	594,286.00	594,286.00
Nonutility Property - Less Reserve..............................	567,535.13	568,051.84
Special Funds...	9,111,613.40	20,873,649.84
Total..	10,273,434.53	22,035,987.68
Current and Accrued Assets		
Cash...	2,749,464.21	4,471,662.22
Special Deposits...	-	-
Temporary Cash Investments......................................	16,031,631.89	5,476,947.62
Accounts Receivable - Less Reserve...........................	165,958,510.51	193,836,265.11
Notes Receivable from Associated Companies...........	-	-
Accounts Receivable from Associated Companies......	16,375,433.66	97,209,024.27
Materials and Supplies - At Average Cost..................		
Fuel..	71,040,238.38	66,567,148.57
Plant Materials and Operating Supplies...................	32,048,293.29	35,430,432.09
Stores Expense...	5,546,727.58	6,352,862.07
Gas Stored Underground..	42,068,559.83	54,151,379.40
Emission Allowances..	159.09	6,328.97
Prepayments..	6,472,536.96	7,636,886.04
Miscellaneous Current and Accrued Assets................	411.87	-
Total..	358,291,967.27	471,138,936.36
Deferred Debits and Other		
Unamortized Debt Expense...	15,881,934.90	12,997,479.51
Unamortized Loss on Bonds..	16,863,861.47	18,031,262.30
Accumulated Deferred Income Taxes.........................	261,142,312.27	157,876,610.00
Deferred Regulatory Assets...	434,413,096.84	410,620,298.44
Other Deferred Debits..	6,585,818.64	3,752,217.02
Total..	734,887,024.12	603,277,867.27
Total Assets..	$ 5,610,941,402.00	$ 5,062,388,591.41

Liabilities and Proprietary Capital	This Year	Last Year
Proprietary Capital		
Common Stock..	$ 425,170,424.09	$ 425,170,424.09
Less: Common Stock Expense...	835,888.64	835,888.64
Paid-In Capital...	417,081,499.00	327,081,499.00
Other Comprehensive Income..	-	-
Retained Earnings..	1,098,854,462.71	1,032,434,889.14
Total Proprietary Capital..	1,940,270,497.16	1,783,850,923.59
Other Long-Term Debt...	1,654,729,467.65	1,354,743,585.78
Total Long-Term Debt..	1,654,729,467.65	1,354,743,585.78
Total Capitalization..	3,594,999,964.81	3,138,594,509.37
Current and Accrued Liabilities		
ST Notes Payable to Associated Companies........................	-	-
Notes Payable..	141,969,180.01	263,956,483.33
Accounts Payable...	172,152,825.79	245,177,038.42
Accounts Payable to Associated Companies........................	24,563,440.46	20,016,015.43
Customer Deposits...	25,405,487.76	24,498,183.30
Taxes Accrued...	19,925,518.88	18,869,564.99
Dividends Declared..	-	-
Interest Accrued...	10,946,603.47	5,870,902.91
Miscellaneous Current and Accrued Liabilities....................	70,058,014.62	107,542,869.93
Total...	465,021,070.99	685,931,058.31
Deferred Credits and Other		
Accumulated Deferred Income Taxes...................................	1,089,626,416.50	857,528,991.76
Investment Tax Credit..	34,643,470.65	35,982,104.65
Regulatory Liabilities...	89,547,280.36	89,485,208.96
Customer Advances for Construction...................................	7,428,646.39	8,234,051.24
Asset Retirement Obligations..	189,099,814.48	85,375,725.04
Other Deferred Credits..	4,017,629.15	14,609,362.50
Miscellaneous Long-Term Liabilities...................................	4,249,577.64	4,272,804.90
Accum Provision for Pension & Postretirement Benefits.....	132,307,531.03	142,374,774.68
Total...	1,550,920,366.20	1,237,863,023.73
Total Liabilities and Stockholders' Equity..................................	$ 5,610,941,402.00	$ 5,062,388,591.41

January 27, 2016

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 271

Responding Witness: Valerie L. Scott

Q-271. Provide copies of the financial statements (balance sheet, income statement, statement of cash flows, and the notes to the financial statements) for PPL and Louisville Gas & Electric for 2014, 2015, and 2016 (when available). Provide copies of the financial statements in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-271. See Filing Requirement 807 KAR 5:001 Section 16(7)(p) for the integrated 2014 and 2015 Forms 10-K. These documents contain both PPL Corporation's and Louisville Gas and Electric Company's notes to the financial statements beginning on page 159 of the 2014 Form 10-K and page 123 of the 2015 Form 10-K. The 2015 Form 10-K contains both PPL Corporation's (beginning on page 93) and LG&E's (beginning on page 112) financial statements for the past two years. The 2016 Form-K will be provided upon its filing with the Securities and Exchange Commission. The Companies do not maintain these statements in Excel.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 272

Responding Witness: Daniel K. Arbough

Q-272. Provide the working electronic copies of all pages of Schedule J – Cost of capital. Provide the copies of the data in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-272. See the attachment to PSC 1-54.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 273

Responding Witness: Daniel K. Arbough

Q-273. With regard to Schedule J: (1) provide copies of all data, source documents, calculations and work papers associated with development of the short-term and long-term debt costs; (2) detail all assumptions and show calculations for projected amounts and costs of short and long-term debt; (3) provide copies of prospectuses and inter-company loan agreements for all debt issuances; and (4) provide the data and work papers in (1) and (2) in both hard copy and electronic (Microsoft Excel) formats, with all data and formulas intact.

A-273.

(1) Please see Section 11 of the Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) –Item A for the description of the development of the amounts of short-term and long-term debt.

(2) See the attachment to this question for the assumptions related to the cost of short-term and long-term debt which is being provided in Excel format.

(3) LG&E used a forecasted test year, therefore, there are no prospectuses and inter-company loan agreements for future debt issuances.

(4) See the attachment to PSC 1-54 for the electronic version of Schedule J.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 274

Responding Witness: Daniel K. Arbough

Q-274. Provide copies of all data, source documents, calculations and work papers associated with development of the proposed capital structure set forth in Schedule J. Provide copies of the source documents, work papers, and data in both hard copy and working electronic (Microsoft Excel) formats, with all data and formulas intact.

A-274. See Section 11 of the Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) – Item A for description of the development of the capital structure. The attachment to the response to PSC 1-54 contains Schedule J in Excel format.

Also, see pages 8-11 of Mr. Arbough's testimony for additional details surrounding the determination of the target capital structure of the Company.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 275

Responding Witness: Robert M. Conroy

Q-275. Provide a copy of Mr. Arbough's testimony in Microsoft Word.

A-275. See the response to Question No. 6.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 276

Responding Witness: Daniel K. Arbough

Q-276. Provide copies of all source documents, articles, cited documents listed in footnotes, regulatory decisions, work papers, and other sources used in the development and preparation of pages 8-13 in the testimony of Mr. Arbough.

A-276. See the response to KIUC 1-42.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 277

Responding Witness: Daniel K. Arbough

Q-277. With reference to the Arbough testimony, page 8, lines 9-13, provide the quarterly capitalization amounts and ratios for Louisville Gas and Electric and PPL Corporation for the years 2014 – 2016. Provide the data and work papers in both hard copy and electronic formats (Microsoft Excel), with all data and formulas intact. Also include electronic copies (Microsoft Excel) of the Exhibit, leaving all data and formulas intact.

A-277. See the response to KIUC 1-42.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 278

Responding Witness: Daniel K. Arbough

Q-278. With reference to the Arbough testimony page 9, lines 8-16, provide the data, source documents and calculations detailing the Moody's debt percentage ratios. Provide the data and work papers in both hard copy and electronic formats (Microsoft Excel), with all data and formulas intact. Also include electronic copies (Microsoft Excel) of the Exhibit, leaving all data and formulas intact.

A-278. See the response to KIUC 1-42.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information Dated January 11, 2017

Question No. 279

Responding Witness: Daniel K. Arbough

Q-279. With reference to the Arbough testimony page 10, lines 15-21, provide the data, source documents and calculations detailing the S&P debt percentage ratios. Provide the data and work papers in both hard copy and electronic formats (Microsoft Excel), with all data and formulas intact. Also include electronic copies (Microsoft Excel) of the Exhibit, leaving all data and formulas intact.

A-279. See the response to KIUC 1-42.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 280

Responding Witness: Robert M. Conroy

Q-280. Provide a copy of Mr. McKenzie's testimony in Microsoft Word.

A-280. See the response to Question No. 6.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2016-00371

Response to Attorney General's Initial Data Requests for Information
Dated January 11, 2017

Question No. 281

Responding Witness: Adrien M. McKenzie

Q-281. Provide copies of Mr. McKenzie's Exhibit Nos. 2 through 11 in Microsoft Excel, with data and formulas intact.

A-281. See the response to PSC 1-54.