STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC., FOR: (1) APPROVAL OF AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR FEDERALLY MANDATED NATURAL GAS TRANSMISSION AND DISTRIBUTION PROJECTS, AND THE COSTS THEREOF, RELATED TO PETITIONER'S COMPLIANCE WITH VARIOUS FEDERALLY MANDATED REQUIREMENTS RELATING TO NATURAL GAS PIPELINE SAFETY AND INTEGRITY; (2) APPROVAL OF CERTAIN TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM PROJECTS, AND THE COSTS THEREOF, UNDERTAKEN FOR PURPOSES OF SAFETY, RELIABILITY, SYSTEM MODERNIZATION, OR ECONOMIC DEVELOPMENT; (3) APPROVAL OF PETITIONER'S 7-YEAR PLAN FOR TRANSMISSION, DISTRIBUTION AND STORAGE SYSTEM IMPROVEMENTS PURSUANT TO IND. CODE CH. 8-1-39 (AND FOR FEDERALLY MANDATED PROJECTS, IN THE EVENT AND TO THE EXTENT THE COMMISSION CONCLUDES THAT SUCH PROJECTS DO NOT MEET THE REQUIREMENTS OF IND. CODE CH. 8-1-8.4), INCLUDING A PROCESS FOR ANNUAL UPDATES TO THE PLAN; (4) APPROVAL OF A RATE ADJUSTMENT MECHANISM AND RELATED AUTHORITY TO UTILIZE ACCOUNTING DEFERRALS, PURSUANT TO IND. CODE CHAPTERS 8-1-8.4 AND 8-1-39, FOR THE TIMELY RECOVERY AND DEFERRAL OF COSTS RELATED TO SUCH FEDERALLY MANDATED AND TRANSMISSION, DISTRIBUTION AND STORAGE PROJECTS (INCLUDING FINANCING COSTS INCURRED DURING CONSTRUCTION); (5) APPROVAL OF OTHER RELATED RATEMAKING RELIEF AND TARIFF PROPOSALS CONSISTENT WITH IND. CODE CH. 8-1-8.4 AND 8-1-39; (6) IF NECESSARY, GRANTING OF CONFIDENTIAL TREATMENT FOR CERTAIN CONFIDENTIAL AND PROPRIETARY INFORMATION THAT MAY BE SUBMITTED IN THIS CAUSE; AND (7) APPROVAL OF OTHER RELIEF AS MAY BE APPROPRIATE	)	CAUSE NO. 44429

PETITIONER'S SUBMISSION OF DIRECT TESTIMONY AND EXHIBITS OF PETITIONER'S WITNESS JAMES M. FRANCIS

Petitioner Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Petitioner") respectfully submits the Verified Direct Testimony and Exhibits of James M. Francis.

Respectfully submitted,

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.

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CERTIFICATE OF SERVICE

The undersigned certifies that the foregoing Verified Direct Testimony and Exhibits were served this 26th day of November 2013, by email delivery, to the Office of Utility Consumer Counselor, PNC Center, 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204.

Robert H. Heidorn,
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SOUTHERN INDIANA GAS & ELECTRIC COMPANY
d/b/a VECTREN ENERGY DELIVERY OF INDIANA, INC.
(VECTREN SOUTH)

IURC CAUSE NO. 44429

DIRECT TESTIMONY
OF
JAMES M. FRANCIS
DIRECTOR, ENGINEERING AND ASSET MANAGEMENT

ON

FEDERAL MANDATES, COMPLIANCE PROJECTS, AND TDSIC PLAN

SPONSORING PETITIONER'S EXHIBITS JMF-1 THROUGH JMF-50

DIRECT TESTMONY OF JAMES M. FRANCIS

INTRODUCTION

Q. Please state your name, business address and occupation.

A. My name is James M. Francis. My address is One Vectren Square, Evansville, Indiana, and I am Director of Engineering & Asset Management for Vectren Utility Holdings, Inc. ("VUHI"), the parent company of both Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren South" or "the Company") and Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc. ("Vectren North") and of Vectren Energy Delivery of Ohio ("VEDO").

Q. What are your duties in your present position as they relate to Vectren South?

A. My duties include responsibility for engineering and technical support for Vectren South utility operations. My specific responsibilities include Transmission Pipeline Integrity Management, Distribution Integrity Management, System Design and Planning, Corrosion Control, Project Engineering, Compliance, Standards, Asset Management, and Capital Planning and Management.

Q. Please describe your work experience.

A. I have been employed by VUHI since April 8, 2004 when I became the Director of Technical Services. My title has subsequently been changed to Director of Engineering & Asset Management. Prior to my current position, I was employed with VEDO since its purchase of the gas assets of the Dayton Power & Light Company ("DP&L") in 2000. At VEDO, I was the Regional Manager of the Troy Operating Region with responsibility for field operations. I also held other positions at VEDO, including Planning Manager and Measurement Supervisor. Prior to my employment with Vectren, in 1991 I became an employee of DP&L, serving as a Project Engineer, System Planner and Measurement Supervisor.

Q. What is your educational background?

A. I received a Bachelor of Science in mechanical engineering from the University of Dayton in 1993. I received a Masters in Business Administration from The Ohio State University in 2000.

Q. Are you involved in any gas industry association activities?

A. Yes. I am active in the American Gas Association's ("AGA") Operating Section. I am currently a member of the AGA's Distribution and Transmission Engineering Committee.

Q. Have you previously testified before this Commission?

A. Yes. I have provided testimony in support of the recovery of pipeline safety expenses for both Vectren North and Vectren South. I have also testified in Vectren North's most recent general rate case (Cause No. 43298), in Vectren South's most recent general gas rate case (Cause No. 43112) and in Vectren South's most recent general electric rate case (Cause No. 43839).

Q. Does your role include responsibility for Vectren South's gas operation's compliance with Department of Transportation ("DOT") regulations?

A. Yes.

Q. During your tenure, has Vectren South made investment and otherwise taken steps in order to be able to comply with these regulations?

A. Yes. Vectren South has invested in technology that allows us to collect system data, schedule required activities like valve and pipeline surveys, and to evaluate our facilities via a risk modeling process, the outcome of which drives our prioritization of necessary projects to ensure compliance with DOT regulations and enhance system safety and reliability.

In addition, Vectren South has invested in the resources necessary to comply with these regulations and has created a gas compliance team that oversees its processes and works with the rest of operations on compliance actions.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe the investments and expenses for projects that Vectren South will implement to comply with federal regulations ("Compliance Projects") and to meet safety, reliability, or modernization of its gas pipeline systems. My testimony includes investments and expenses that are recoverable pursuant to Ind. Code Ch. 8-1-8.4 ("Compliance Statute") and Ch. 8-1-39 ("TDSIC Statute"), respectively.

Within the Compliance Statute section I will: (1) provide a chronological history of the federal mandates associated with pipeline safety regulations; particularly focusing on the transmission and distribution integrity management regulations, (2) describe in detail what is mandated by the transmission integrity management regulations, and identify the investments and expenses associated with complying with these regulations, and (3) describe in detail what is mandated by the distribution integrity management regulations, and identify the investments and expenses associated with complying with these regulations.

Within the TDSIC Statute section I will describe the investments included in Vectren South's seven year infrastructure plan (the "TDSIC Plan").

I will also describe Vectren South's comprehensive set of Compliance and TDSIC projects that are shown in a seven year plan, including explaining how the projects within that plan were developed, how projects are prioritized and how reasonable cost estimates are developed. Finally, I will explain why the TDSIC Plan may change and how Vectren South proposes to update its TDSIC Plan. While we have chosen to also show the estimated cost of the Compliance projects in the seven year plan presentation so the total amount of infrastructure investment is transparent, to be clear, Vectren South, per the Compliance Statute, is seeking approval of the Compliance Projects as federally mandated and not of the comprehensive seven year "plan"; we are seeking approval of the separate TDSIC Plan.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits which were prepared by me or under my direction:

Petitioner’s Exhibit No. JMF – 2 Table –Transmission Pipeline System Information

Petitioner’s Exhibit No. JMF – 3 Part 192 – Subpart O (TIMP)

Petitioner’s Exhibit No. JMF – 4 ASME B31.8S Standard

Petitioner’s Exhibit No. JMF – 5 PHMSA TIMP Requirement Fact Sheet

Petitioner’s Exhibit No. JMF – 6 PHMSA Advisory Bulletin ADB 11-01

Petitioner’s Exhibit No. JMF – 7 Transmission Risk Model Factor Listing

Petitioner’s Exhibit No. JMF – 8 Transmission Pipe Segment Risk Profile Output

Petitioner’s Exhibit No. JMF – 9 Transmission System Risk Map

Petitioner’s Exhibit No. JMF – 10 Photos – In-line Inspection Modifications

Petitioner’s Exhibit No. JMF – 11 Photos – Pressure Test Modifications

Petitioner’s Exhibit No. JMF – 12 Part 192 – Subpart M (Maintenance)

Petitioner’s Exhibit No. JMF – 13 PHMSA FAQ Excerpts Regarding TIMP Requirements

Petitioner’s Exhibit No. JMF – 14 Vectren’s TIMP section TIMG-08-004

Petitioner’s Exhibit No. JMF – 15 Table – Distribution Pipeline System Information

Petitioner’s Exhibit No. JMF – 16 Part 192 – Subpart P (DIMP)

Petitioner’s Exhibit No. JMF – 17 PHMSA DIMP Requirement Fact Sheet

Petitioner’s Exhibit No. JMF – 18 Vectren’s DIMP Plan

Petitioner’s Exhibit No. JMF – 19 PHMSA Advisory Bulletin ADB 12-05

Petitioner’s Exhibit No. JMF – 20 PHMSA DIMP Enforcement Guidance

Petitioner’s Exhibit No. JMF – 21 Distribution Asset Class and Risk Score Rank Order

Petitioner’s Exhibit No. JMF – 22 Distribution Maps of Aggregate Risk Scores

Petitioner’s Exhibit No. JMF – 23 Calculated Risk Reduction for a Specific BS/CI Project

Petitioner’s Exhibit No. JMF – 24 Calculated Risk Reduction for Overall BS/CI Program

Petitioner’s Exhibit No. JMF – 25 DIMP Mitigating Action Documents

Petitioner’s Exhibit No. JMF – 26 Example Transmission Project Scoping Documents

Petitioner’s Exhibit No. JMF – 27 Compliance Statute TIMP Investments

Petitioner’s Exhibit No. JMF – 28 Compliance Statute TIMP Expenses

Petitioner’s Exhibit No. JMF – 29 Example Distribution Project Scoping Documents

Petitioner's Exhibit No. JMF – 30 Compliance Statute DIMP Investments
Petitioner's Exhibit No. JMF – 31 Compliance Statute DIMP Expenses
Petitioner's Exhibit No. JMF – 32 PHMSA Excavation Damage Excerpt
Petitioner's Exhibit No. JMF – 33 Excavation Damage Improvement Projects Scoping Documents
Petitioner's Exhibit No. JMF – 34 Compliance Statute Expenses from Excavation Damage Improvement Projects
Petitioner's Exhibit No. JMF – 35 Compliance Statute Expenses
Petitioner's Exhibit No. JMF – 36 Compliance Statute TIMP & DIMP Investment Summary
Petitioner's Exhibit No. JMF – 37 EN Engineering Study
Petitioner's Exhibit No. JMF – 38 Example System Improvement Project Scoping Document
Petitioner's Exhibit No. JMF – 39 LP & Storage Project List
Petitioner's Exhibit No. JMF – 40 Risk Avoidance – Equipment Replacement
Petitioner's Exhibit No. JMF – 41 Example Communication Project Scoping Document
Petitioner's Exhibit No. JMF – 42 Risk Avoidance – Communication Equipment Replacement
Petitioner's Exhibit No. JMF – 43 Public Improvement Project List
Petitioner's Exhibit No. JMF – 44 Calculated Risk Avoidance – Public Improvement Project
Petitioner's Exhibit No. JMF – 45 Calculated Risk Reduction - Single Service Line Replacement
Petitioner's Exhibit No. JMF – 46 TDSIC Statute Investment Summary
Petitioner's Exhibit No. JMF – 47 Comprehensive Investment Summary including Compliance Statute and TDSIC Statute Investments
Petitioner's Exhibit No. JMF – 48 Transmission Project Prioritization Model Excerpt
Petitioner's Exhibit No. JMF – 49 Distribution Project Prioritization Model Excerpt
Petitioner's Exhibit No. JMF – 50 BS/CI Project Prioritization List

A. COMPLIANCE STATUTE

I. SUMMARY OF FEDERAL REGULATIONS

Q. Please provide a brief overview of the federal mandates resulting from changing federal pipeline safety regulations over time.

A. The Natural Gas Pipeline Safety Act of 1968 authorized the Federal DOT to implement regulations that established pipeline safety requirements for pipeline operators that transport natural gas and other fuels. DOT 49 Code of Federal Regulations Part 192 ("Part 192") became effective in 1971 and established the minimum safety requirements for pipeline operators that operate a natural gas transmission or distribution system. These regulations established design, construction, testing, inspection, operation, and maintenance requirements that applied to the various pipeline system components (pipelines, valves, odorizers, regulators, etc.). Operators were then required to complete the federally mandated activity on their pipeline system components. Much of the work that pipeline operators perform on their systems today is directly related to the Part 192 requirements.

Over the next 30 years, few significant changes were made to Part 192. Those changes addressed improvements in process or technology, clarified requirements, or addressed pipeline safety issues that surfaced over time. A significant change came about a decade ago as a result of the Pipeline Safety Improvement Act of 2002 ("2002 Safety Act").

The 2002 Safety Act was signed into law on December 17, 2002. It mandated significant changes and established new requirements designed to ensure the safety and integrity of natural gas transmission pipelines. The new federal mandates required each pipeline operator to implement an integrity management program for its transmission pipeline system. These regulations are very prescriptive in terms of how operators must comply and established minimum assessment, remediation and mitigation requirements. Other provisions of the 2002 Safety Act include regulations on participation in one-call programs, increases to penalties for pipeline safety violations, public awareness and education requirements, and federal pipeline system mapping requirements. The regulations from the 2002 Safety Act became effective on December 17, 2004, and resulted in the addition to Part 192 of Subpart O - Gas Transmission Pipeline Integrity Management.

The next significant change to Part 192 came as a result of the Pipeline Inspection, Protection, Enforcement, and Safety Act of 2006 ("2006 Safety Act"). The 2006 Safety Act established requirements for reporting of excavation damages, defining state damage prevention standards, and most significantly creating the distribution integrity management program ("DIMP") regulations. On December 4, 2009, Subpart P – Gas Distribution Pipeline Integrity Management was added to Part 192, establishing the DIMP requirements. Each operator's initial DIMP plan, designed to address that operator's system risks, became effective on August 2, 2011.

Currently, the Pipeline Hazardous Materials and Safety Administration ("PHMSA"), the DOT agency responsible for implementing and enforcing pipeline safety standards, is developing regulations in response to the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Safety Act"). The 2011 Safety Act was passed in the aftermath of the 2010 San Bruno, California tragedy, and are expected to result in increased regulations that will expand transmission integrity management requirements, establish pressure testing requirements for pre-1971 pipelines, increase the use of automation technology for valve operation, increase data collection through the national pipeline mapping system, and more. Some advanced notices of proposed rulemaking from the 2011 Safety Act have been drafted and others are expected later in 2013 and into 2014.

The Indiana Utility Regulatory Commission's ("IURC") Pipeline Safety Division ("Pipeline Safety Division") is charged with enforcement of these regulations. The Pipeline Safety Division conducts audits of the Company's operations and has the ability to seek fines for violations. Vectren South endeavors to maintain a collaborative relationship with the Pipeline Safety Division and frequently discusses compliance issues with the Division, seeks guidance on interpretations, and uses feedback from the Division to work on improvements to processes and programs that improve compliance efforts.

II. TRANSMISSION INTEGRITY MANAGEMENT REQUIREMENTS

Q. Please describe Vectren South's transmission pipeline system.

A. Vectren South operates 147 miles of transmission pipeline that reside throughout its service territory. This mileage is made up of 16 distinct pipelines of various diameters (6" through 16") and maximum pressures (260 psi through 1307 psi). Of the 147 miles, approximately 23% resides within a class 3 location (relatively high population density) and 4.5% resides within a high consequence area ("HCA"), as defined by Part 192. Approximately 10% of the transmission system can be inspected with in-line inspection technology currently. Petitioner's Exhibit No. JMF - 2 provides a table with more information about Vectren South's gas transmission pipeline system.

Q. Please provide a summary of the current federal mandates related to transmission integrity management.

A. Petitioner's Exhibit No. JMF-3 is Subpart O of Part 192 that describe the transmission integrity management program ("TIMP") requirements for operators of transmission pipelines. Additionally Petitioner's Exhibit No. JMF-4 is the American Society of Mechanical Engineers ("ASME") B31.8S standard which is incorporated by reference into Subpart O and provides many of the technical and performance requirements associated with TIMP.

In general terms the regulations require that operators do the following:

- Establish a TIMP plan.
- Identify HCAs along transmission pipeline routes.
- Conduct a risk assessment to identify threats to the integrity of its transmission pipeline system.
- Complete a baseline assessment and subsequent reassessments of its transmission pipelines to evaluate threats within HCAs using one of three assessment methods:
    - In-line Inspection

- Hydrostatic Pressure Testing
- Direct Assessment

- Remediate conditions found during an assessment.
- Evaluate and implement preventive and mitigative measures to minimize future threats.
- Evaluate the effectiveness of the integrity management program.

A summary of the TIMP requirements is provided in Petitioner's Exhibit No. JMF-5, which is a fact sheet from PHMSA on the TIMP requirements.

Q. Does Vectren South have a staff that is responsible for the implementation of the TIMP requirements?

A. Yes. Vectren South has a staff of engineering and operations personnel who are dedicated to implementing the TIMP requirements. The staff currently consists of engineers, a field supervisor, inspectors, support technicians, and management staff. This staff is supplemented by a contract workforce and others within Vectren South to aid in the execution of the TIMP requirements.

Q. Please describe what a HCA is and how is it established.

A. A HCA is an area along a transmission pipeline where there is the greatest consequence of loss of life or property in the event of a catastrophic pipeline failure. These are generally in areas where there is high population density near a transmission pipeline (such as a subdivision) or where a structure or site in close proximity to a transmission pipeline may have a substantial congregation of people (such as a school or church). HCAs are the locations along the pipeline route for which integrity assessments are mandated.

HCAs are determined as defined in Part 192.903 and Part 192.905, which involves the calculation of a potential impact radius ("PIR") and the counting of occupied structures or identified sites within the boundary of the PIR. The PIR is a product of the diameter and pressure of each pipeline, and structures and sites within the circle defined by the PIR form the basis of the HCA designation.

Vectren South operates approximately 36 miles of its transmission pipeline system within a HCA, as a HCA is currently defined.

Q. Are there circumstances under which an operator may assess more pipeline mileage than just those pipeline segments within a HCA?

A. Yes. There are several reasons why an operator would assess a pipeline segment beyond the boundary of a HCA. If conditions exist that represent like and similar characteristics to a pipeline residing within a HCA, the operator may choose to extend the assessment beyond the boundary of the HCA. A good example of this is a pressure test.

Generally, when pipeline segments are installed, they are pressure tested through a single, contiguous pressure test over the entire extent of the pipeline segment. If only a portion of the pipeline segment is within a HCA, and the operator has determined that a pressure test is required to assess a particular threat on that pipeline segment, and the operator determines that the same threat is applicable to the entire pipeline segment (both within the HCA and beyond the HCA), then the operator may conduct the pressure test to cover the entirety of the pipeline segment. This type of assessment would fulfill the TIMP requirements and Part 192.619 requirements regarding maximum allowable operating pressure. Additionally, by testing the entire segment, including any portions not within a HCA, the total cost associated with testing the entire segment is significantly less than it would be if tests were performed on each segment independently.

Another example of assessing a pipeline beyond the boundary of a HCA would be an assessment conducted by in-line inspection. Due to the technical requirements of this process, an in-line inspection tool generally runs the full length of a pipeline to allow for installation and removal of the tool without impacting the flow of gas. This is the most efficient means to run these types of tools and therefore an assessment will result in evaluating the entire length of a pipeline, whether or not the pipeline is entirely within a HCA.

Petitioner's Exhibit No. JMF-6 is PHMSA's Advisory Bulletin ADB-11-01 which discusses operator requirements to assess threats and perform risk analysis of **its entire pipeline system** and to use these risk analysis to identify assessment methods and preventive and mitigative ("P&M") measures.

Q. How else are HCAs used in the TIMP?

A. HCAs also drive other requirements such as remediation activities, the evaluation of installing automatic or remote control valves and the application of P&M measures. P&M measures are actions that an operator can take to mitigate risk to its pipelines. Examples of P&M measures include additional patrols, pipeline markers, or pipeline relocations.

Q. What is a risk assessment and how is it conducted?

A. A TIMP risk assessment is a process that evaluates the existence of threats to all pipeline segments within the gas transmission system and allows the operator to choose activities, such as an assessment, replacement, repair, data collection, or P&M measures to mitigate the identified risk. Part 192.917 defines the TIMP requirements for risk assessment.

The risk assessment process begins with the integration of all relevant risk information from a variety of data sources including: prior integrity assessments, inspections, investigations, incidents, design, construction, operational and maintenance, environmental, population density, HCA and more.

Vectren South uses a risk modeling software application to assess its pipeline risks. Vectren South's TIMP risk model contains 70 different factors that are integrated into its model. Petitioner's Exhibit No. JMF-7 is a listing of the factors included in the model. This type of risk model allows Vectren South to prioritize and address interactive threats on its pipeline segments. Petitioner's Exhibit No. JMF-8 is a specific example of the output of a pipeline segment risk profile. Petitioner's Exhibit No. JMF-9 is an overall system map with a high level representation of system risk generated from the Company's risk model. Vectren South continuously imports data specific to its transmission system's assets into the model so that the risk identification process is based on the latest available information.

Q. How is the result of the risk model used?

A. Vectren South uses the results of its risk model to support decisions on the choice of assessment method, the type of tool to use to complete the assessment, to identify P&M measures, to identify segments outside of an HCA that may present relatively higher levels of risk to the pipeline system and to develop mitigating strategies that address the integrity of the entire transmission pipeline system. The risk score associated with a pipeline segment or equipment is used in the prioritization and scheduling of projects to address identified risks. As a result, capital projects are planned, such as those required to conduct assessments, or remediate an issue identified during an assessment, and thereby reduce system risk.

Q. How does Vectren South use the results of the risk assessment process in the identification and prioritization of capital projects?

A. As Vectren South develops both its short term and long term plans for capital investments on its transmission system, it begins with the risk assessment process to evaluate risks associated with its entire transmission pipeline system. The risk factors, as described above, establish risk profiles for each pipeline segment within the transmission system. Vectren South's TIMP engineering staff is then able to evaluate the system's risk profile and identify projects that will reduce system risk. As part of this process, the staff will evaluate previous assessment results, gather feedback from key stakeholders, such as Gas Control or Field Operations, and evaluate industry trends and PHMSA advisory bulletins to develop a list of capital projects. The risk scores for each of the pipeline segments or equipment associated with each capital project is used as a primary factor in the project selection and prioritization model, which will be discussed later in my testimony.

Q. Does the risk assessment process have an impact on the type of assessment that will be performed on a transmission pipeline?

A. Yes. An evaluation of a pipeline's risk profile is conducted as part of the pre-assessment process for a specific pipeline or pipeline segment. The risk profile, which will highlight the applicable threats, is used by the TIMP engineer to select the appropriate assessment method. This approach complies with the TIMP requirements.

Q. Please describe the three types of pipeline assessment methods.

The three types of assessment methods are: direct assessment, pressure testing and in-line inspection.

- Direct Assessment: The direct assessment method is a multi-step assessment process. The process begins by conducting two above ground surveys: a close interval survey detects the condition of the cathodic protection system and a voltage gradient survey detects defects in the pipeline coatings. Once the above ground assessment is completed, a series of excavations are completed, exposing the pipeline so that its condition may be directly observed. Excavations occur where coating defects are suspected and at other locations to prove the extent of the anomalies that may exist. This assessment method is effective when short sections of HCA exist or if corrosion or pipe coating threats are suspected.

- Pressure Testing: The pressure testing method requires taking a pipeline out of service in order to fill it up with water and pressurizing to a level that supports a strength test of the maximum allowable operating pressure ("MAOP") of the pipeline. Typically this method is used to verify the condition of the pipeline to support the MAOP and to verify non-existence of manufacturing or construction defects.

- In-line Inspection: The in-line inspection method is the assessment method that provides the most complete information about the integrity of a pipeline. This method consists of introducing an in-line inspection tool at one end of a pipeline and removing it at the opposite end of the pipeline. The tool will collect data about the pipeline along the entire length and circumference of the pipeline. These readings will then be analyzed to determine the existence of a defect on the pipeline. The tool is also able to capture other information such as the location of welds, the existence of seams and cracks in the pipe, and specific global positioning satellite coordinates for precision mapping. Different tools have varying capabilities to detect and identify different types of anomalies, which may require the use of multiple tools during a single assessment.

Each of these assessment methods provides different information about the integrity of a pipeline. They are all complimentary assessment methods and address different threats.

Q. How does Vectren South decide on which assessment method to use?

A. Vectren South conducts a thorough pre-assessment process, in which it identifies the pipeline to be assessed and the associated threats to be evaluated. Choice of assessment method and tool is an output of this process. Because in-line inspection is the most complete assessment method, if the pipeline is able to be in-line inspected, this method will be chosen. However, depending on other factors, such as threat type, HCA size, pressure test records, pressure and velocity, other methods will be considered.

Q. What are the challenges of each assessment method?

A. Challenges with each assessment method will vary, depending on the characteristics and location of the pipeline being assessed. Some of the challenges typically come in the form of accessibility to the pipeline, pipeline infrastructure and physical constraints, customer demand, and weather. These constraints are considered when selecting the assessment method.

- <u>Direct Assessment</u>: This method is greatly impacted by obstructions, such as fences, access to properties, road crossings, animals and other above or below ground interferences. Because the activity requires walking the pipeline, it is very time and labor intensive. The results of this method are limited to identification of corrosion or pipe coating issues.

- <u>Pressure Testing</u>: This method requires that the pipeline be removed from service. This may result in temporary disruption of service or require additional infrastructure modifications to allow for continued service to customers. Additionally, this method may require the removal of fittings that are susceptible to leaking during a hydrostatic pressure test (such as a fitting with a flange joint) prior to conducting the pressure test. The result of this method provides only a pass or fail indicator.

- In-line Inspection: This method requires the modification of the pipeline to allow the inspection tool to be inserted into and removed from the pipeline. Additionally, it requires all constraints or obstructions in the pipeline, such as a tapered core valve, miter bend, or stopple fitting, be removed prior to inspecting the pipeline. Lastly, pipelines need to have sufficient pressure and flow to generate the necessary velocity to move the inspection tool. This method also relies on more sophisticated technology to collect data and the tool can be sensitive to damage or issues with electronics.

Q. What are the advantages of each assessment method?

A. Each assessment method presents some advantage as compared to the other methods. These advantages are considered when selecting the assessment method.

- Direct Assessment: This method is relatively simple and does not impact the flow of gas. Additionally, it does not require investment in infrastructure modifications to complete. It is the only assessment method that identifies where pipe coating failures exist.

- Pressure Testing: This method provides confirmation that the pipeline segment can continue to operate at its defined MAOP. Additionally, if a significant issue is identified during a pressure test, it is done so without the presence of natural gas.

- In-line Inspection: This method provides the most complete information about the integrity of a pipeline. Data is captured through the full extent of the assessment and additional data elements are gathered that are not available through the other assessment methods. Additionally, the in-line inspection process is repeatable which allows data to be compared between different assessments over time. This provides greater ability to trend changes to the condition of the pipeline. Additionally, because this method requires a clean pipeline to move the inspection tool from end to end, older technology or construction practices (such as miter bends and certain fitting types) are removed during the initial setup for in-line inspection, bringing the pipeline to modern design standards.

Q. How often do pipelines need to be reassessed?

A. Per Part 192.939, a confirmatory direct assessment must be conducted at least every seven years. Additionally, depending on the results of an assessment or changes to the threats to a pipeline, such as HCA growth, third party damage, or outside force impact from flooding, reassessment intervals may be less than seven years.

Q. Will Vectren South only use direct assessment to complete the seven year reassessment?

A. No. Particularly if a pipeline is able to be assessed via the in-line inspection method, the reassessment would be conducted with the same method. Results from an in-line inspection are able to be used to more effectively monitor changes in conditions of the pipeline over time by providing data to compare a reassessment to the prior assessment results. Since the mandatory baseline assessment period has passed as of December, 2012, Vectren South, having completed that process, has learned a considerable amount regarding the condition of its pipelines and the value of each assessment method. The more assessments that can be conducted via in-line inspection methods, the better repeatability and greater amount of information can be collected about the pipelines. Additionally, there may be new or additional threats to a pipeline, changes in HCA or other factors that may drive the need for another assessment method.

During the baseline assessment period from 2004 through 2012, Vectren South predominantly performed direct assessments because a majority of the existing system did not have the capability to accommodate in-line inspection or hydrostatic testing, and time constraints in terms of completing the baselines assessments by the compliance deadline were a factor.

As discussed herein, because the other assessment methods are superior in many ways, and because the regulations push operators to engage in the assessment methods that provided the best information related to a pipeline's risk, Vectren South will investment in projects that will make it possible to assess our HCAs using the other methods.

Q. What modifications are necessary to enable Vectren South to conduct an in-line inspection on an existing pipeline?

A. To be able to conduct an in-line inspection, a pipeline must be modified to allow for insertion of an inspection tool, removal of the inspection tool and for passage of the tool between the insertion and removal point. This typically requires the modification at the entry and exit point to install a launcher and receiver and all associated piping, valves, filters, separators and any other related appurtenances and equipment necessary to conduct the inspection. Any tapered core valves along the pipeline route must be replaced with a full port valve, any fittings that may obstruct or damage the inspection tool must be removed, and any short radius, miter or wrinkle bends must be removed to allow for passage of the tool. Petitioner's Exhibit No. JMF-10 includes photographs of various modifications associated with preparing a pipeline for in-line inspection.

Q. Once a pipeline is modified for in-line inspection, will future modifications be required?

A. Not typically. Once a pipeline is modified, the inspection tool may be run through the pipeline without requiring further modification. Any further modification to the pipeline will be as a result of findings from the in-line inspection, including modifications that reduce variation in the pipeline that may impact the quality of the data captured during an inspection.

Q. If Vectren South builds a new transmission pipeline, will the pipeline be designed and constructed to be in-line inspected?

A. Yes. Per Part 192.150, all new transmission pipelines must be designed so that they can be inspected by in-line inspection technology. Vectren South includes launchers and receivers, full port valves, long-radius bends and other appurtenances necessary to allow for in-line inspection and have been doing so since the mid-1990s.

Q. What modifications are necessary to enable Vectren South to conduct a pressure test of an existing pipeline?

A. To be able to conduct a pressure test, a pipeline must be removed from service. Each pressure test presents different challenges and the required modifications will vary with each test. Examples of modifications include the replacement of sections of pipe at the beginning and ending point of the pressure test to allow for the installation of test headers, the installation of valves or valve clusters to allow for segregation of the pipeline or to maintain customers, and the replacement of fittings or bend points susceptible to failure under pressure test. In some cases, this could require the addition of a redundant feed in order to maintain supply to a pipeline system. Petitioner's Exhibit No. JMF-11 provides photographs of various modifications associated with preparing a pipeline for pressure testing.

Q. Are there other modifications that may be made to a pipeline when preparing for a pressure test?

A. Yes. Because most pipelines will be made capable of being inspected by an in-line inspection tool, other modifications will be made while the pipeline segment is inactive to allow for the passage of an in-line inspection tool. These modifications may include replacing valves with full port valves, replacement of fittings that may obstruct or damage an inspection tool or removing short radius, miter or wrinkle bends to allow for passage of the tool.

Q. Is it possible to conduct both a pressure test and an in-line inspection as part of the same assessment?

A. Yes. Certain in-line inspection tools are able to be run through a pipeline filled with water. Because there are circumstances where multiple threats are identified to a pipeline, there may be a need for multiple inspection methods to be used to fully assess the pipeline segment. It is common to conduct both a pressure test and an in-line inspection as part of a single pipeline assessment. However, pressure tests are typically isolated to partial segments of a pipeline. Longer term it is more advantageous to set up the entire pipeline for in-line inspection. Part 192.937 references an operator's need for development of a continual process of evaluation and assessment to maintain a pipeline's integrity and references the requirements for use per the ASME B31.8S standard for internal inspection tools (Part 192.937(c)(2)). These will aid in identifying pipeline changes based on both time dependent (corrosion) and time independent (third party damage) threats. Operators will have better visibility into pipeline asset changes with the availability of internal inspection tool's evaluation of the pipeline characteristics.

Q. What are the requirements when a condition is identified either through an assessment or surfaced through other means, and remediation is required?

A. Part 192.933, Part 192.935 of Subpart O and various sections of Part 192 Subpart M (Maintenance) describe the requirements for remediation of defects identified on a transmission pipeline. <u>Petitioner's Exhibit No. JMF-12</u> is Subpart M of Part 192. Generally the requirements describe the expectation of the operator to take actions to remediate conditions found during an assessment or additional measures to mitigate the likelihood or consequence of a failure and establishes certain timeframes and minimum parameters around those responses.

Q. Please describe the types of conditions that may exist that could require Vectren South to take remedial action?

A. There are a variety of conditions that may be discovered during an assessment or during other inspection or maintenance activity that require action to be taken to remediate. Examples of issues that require remedial actions include, but are not limited, to: poor or damaged coating, dents and gouges, puddle welds, corrosion, wall thinning, shallow or exposed pipe, obsolete equipment, miter or wrinkle bends, retired fittings, cracked pipe or appurtenances, poor welds, and fittings or weld material protruding into the pipeline.

Q. What types of remedial or mitigative actions does Vectren South implement to

address the conditions described above?

A. Typical remedial or mitigating actions result in either repairing or replacing the pipeline or equipment where the condition exists. The TIMP engineering staff will evaluate the condition identified, consider the extent of the condition, determine if it is isolated to a specific location or if it applies more broadly to the pipeline segment or entire pipeline and then make a recommendation on the action to be taken. Specific requirements and actions are defined in Part 192.933, Part 192.935 and Subpart M. Examples of remedial or mitigative actions include but are not limited to: pressure reduction, coating repair, grinding and recoating, repair sleeve installation, replacement of a fitting, equipment, or appurtenance, replacement of a section of pipe or the replacement of an entire pipeline.

Q. When Vectren South finds conditions within a HCA, does it have to assess whether the same condition may exist on segments not within a HCA and implement remedial measures to address?

A. Yes. Per Part 192.917(e)(5), operators who identify corrosion in a HCA that could affect the integrity of the pipeline must evaluate and remediate all pipeline segments. In particular, because some assessments, especially when conducted by in-line inspection, result in assessing pipeline segments not within a HCA, conditions may be discovered along the entire extent of the assessment and those conditions must be remediated per the requirements in Part 192.485, 192.703(b), 192.711, 192.713, 192.715, 192.717, and 192.719 as applicable. <u>Petitioner's Exhibit No. JMF-13</u> contains excerpts from PHMSA's frequently asked questions regarding the TIMP requirements.

Q. Is Vectren South required to implement preventive and mitigative measures?

A. Yes. Per Part 192.935, Vectren South must evaluate and implement P&M measures.

Q. What is a P&M measure?

A. A P&M measure is an action that the operator will implement to prevent the occurrence of or mitigate the likelihood of a threat to the integrity of a pipeline, pipeline segment, equipment or appurtenances. An example of a P&M measure is conducting additional surveys or patrols of the pipeline to mitigate the threat of third party damage. Another example of a P&M measure is installing a parallel pipeline under a river to mitigate loss of service in the event of a failure of the existing pipeline under the river. A third example of a P&M measure is the replacement of a pipeline, pipe segment or equipment.

Q. Please describe the requirements defined in Part 192.935

A. Part 192.935 generally describes that operators must take additional measures beyond those described in Part 192 to prevent a pipeline failure and to mitigate the consequences of a failure. There are specific requirements that all operators must evaluate as it pertains to third party damage, outside force damage, the use of automatic shut-off or remotely controlled valves and pipelines operating below 30% of the specified minimum yield strength of the pipeline. Mitigative measures include but are not limited to: installing remote controlled valves, replacing pipe segments with heavier wall, conducting training, conducting emergency drills and more.

Q. How does Vectren South decide on the P&M measure to implement?

A. Vectren South uses a variety of data sources to determine the P&M measure, including but not limited to: Vectren South's risk model, Vectren South's Baseline Assessment Plan, Long Range Assessment Calendar, the Threat Analysis included in Vectren South's TIMP plan and other sources of threat data, a thorough review of the identified threats are performed for each HCA to determine the significant contributors leading to the threat. An evaluation is then performed to consider what action will effectively prevent and mitigate the threat identified. This is all clearly spelled out in Vectren South's TIMP plan in section TIMG-08-004, which is presented in Petitioner's Exhibit No. JMF-14.

Q. Are P&M measures only operations and maintenance activities?

A. No. As described in Part 192.935, P&M measures may be both operations and maintenance ("O&M") activities and capital projects. Because the threats to a pipeline vary significantly and the extent of conditions discovered may range from moderate, which needs monitoring, to severe, which needs remediated, all types of P&M measures must be considered to mitigate the threat and improve the integrity of the pipeline, including the replacement of an asset or the installation of a new asset.

Q. What are some of the P&M measures Vectren South has implemented?

A. Vectren South has replaced pipelines, replaced pipeline segments, installed a new pipeline to allow for derating an existing pipeline, installed valves, replaced fittings, repaired pipelines and appurtenances, relocated facilities, reclaimed rights-of-way, re-negotiated easements, conducted monthly aerial patrols, conducted additional leak surveys, rehabilitated a station, replaced supports that cause atmospheric corrosion, improved security and signage at stations, enhanced public awareness program messaging to property owners where transmission pipelines reside, increased information provided to emergency responders, painted above ground facilities, removed encroachments, added pipeline markers and made improvements to cathodic protection systems.

Q. How does Vectren South measure the effectiveness of its TIMP?

A. Performance measures, as defined in Vectren South's TIMP plan, measure the effectiveness of Vectren's overall TIMP. This is a collaborative process between the TIMP engineering staff and other internal stakeholders. It is performed annually and reviewed at all levels of Energy Delivery management and reported to PHMSA. Examples of metrics reported to PHMSA include: mileage of transmission pipeline inspected by in-line inspection, number of conditions repaired, total assessment mileage, and more. Additionally, a review of threat specific performance measures is performed by the TIMP engineering staff with our operating personnel subject matter experts. Trending and analysis of certain metrics will assess the effectiveness of expected inspection results and additional P&M measures. Examples of these supplemental metrics include the number of leaks by threat type, number of corrosion indications, number of pressure test failures, and more.

Q. Having completed the baseline assessment of the transmission system within HCAs, why is there a need to now invest in additional infrastructure replacement/modernization in order to comply with TIMP?

A. Based on the discoveries made during the baseline assessment processes and the direct examinations of the pipelines, it is apparent that legacy first or second party construction practices or third party interactions with the pipelines have contributed to the considerable majority of anomalies encountered. The corrosion pitting anomalies discovered generally were not actively advancing due to implementation of the cathodic protection systems. The best assessment tool for visibility into the range of possible threats resulting in pipeline characteristic changes is the use of in-line inspection tools that can easily identify geometry changes as well as pipeline wall changes. Pipelines having identified legacy manufacturing and construction threats will be evaluated for the proper strength characteristics especially where pressure test records do not persist through the pressure test process. However, internal inspection tools will provide Vectren South the widest range of awareness of threat changes to its pipelines.

Q. Has Vectren South been audited on its TIMP since the completion of the baseline assessment period in 2012?

A. Yes. Vectren South has been audited by both PHMSA and the Pipeline Safety Division on its completion of the baseline assessments. Both audits were completed with no findings of non-compliance. Both audit teams reviewed Vectren South's risk assessment process, choices of assessment method, results of the assessments, remedial actions taken to address issues identified during assessment, choice and implementation of P&M measures and all other aspects of Vectren South's TIMP. These audits were thorough reviews of Vectren South's program and the results support the robustness of the program and the quality of the processes that Vectren South uses to execute its program.

III. DISTRIBUTION INTEGRITY MANAGEMENT REQUIREMENTS

Q. Please describe Vectren South's distribution pipeline system.

A. Vectren South operates approximately 3,000 miles of distribution pipeline throughout its service territory. This mileage is made up of pipelines of various material types (bare steel, coated steel, cast iron, plastic, and ductile iron) and operating pressures. Operating within the system are numerous other components such as regulators, valves, odorizers, service lines, meters, cathodic protection system components, and fittings. Petitioner's Exhibit No. JMF-15 provides a table with more information about Vectren South's gas distribution pipeline system.

Q. Please provide a summary of the federal mandates for distribution integrity management.

A. Petitioner's Exhibit No. JMF-16 is the code requirements from Subpart P of Part 192 that describes the DIMP requirements for operators of distribution pipelines.

In general terms the regulations require that operators do the following:

- Establish a DIMP plan.
- Demonstrate understanding of their gas distribution system.
- Identify the threats to its distribution system.
- Evaluate risk to its distribution system.
- Identify and implement measures to address risks.
- Measure performance, monitor results and evaluate effectiveness.
- Evaluate the effectiveness of the integrity management program.

A summary of the DIMP requirements is provided in Petitioner's Exhibit No. JMF-17, which is a fact sheet from PHMSA on the DIMP requirements.

Q. Does Vectren South have a staff that is responsible for the implementation of the DIMP requirements?

A. Yes. Vectren South has a staff of engineering personnel who are dedicated to implementing the DIMP requirements. The staff currently consists of engineers and management staff. This staff is supplemented by a contract workforce and others within Vectren South to aid in the execution of the DIMP requirements.

Q. Did Vectren South develop and implement a DIMP plan?

A. Yes. Vectren South's DIMP plan can be found in Petitioner's Exhibit No. JMF-18. The DIMP plan was reviewed with regulators and then implemented in August of 2011.

Q. How does Vectren South develop an understanding of its gas distribution system?

A. Vectren South gathers information about its gas distribution system through a variety of means. Vectren South has a geographic information system ("GIS") that provides much of the data about its pipeline facilities, including location of the facilities and various attributes about each of them. Vectren South uses other information such as historical design and construction data, historical operating data (system pressures), historical maintenance records (inspection, survey, patrol, and repair data), historical system performance records (leaks, corrosion read history, pipe examinations, etc.), and excavation activity records. Section 2.0- "Knowledge of Distribution System" of Petitioner's Exhibit No. JMF-18 provides a more detailed explanation on how Vectren South develops an understanding of its gas distribution system.

Q. Does Vectren South continue to collect additional information about its gas distribution system?

A. Yes. Particularly with DIMP being a relatively new program, Vectren South is continuously learning more about its system and identifying other data to collect. Work is constantly being done on the gas distribution system and the DIMP process must take into consideration the new data elements that arise. Additionally, data collection opportunities may be generated out of a specific issue that arises, such as locating or facility damages, or, more broadly, industry issues, such as a comprehensive review of cast iron distribution systems and replacement programs to accelerate repair, rehabilitation and replacement of aging and high-risk pipe (as was described in PHMSA advisory bulletin ADB-12-05 found in Petitioner's Exhibit No. JMF-19). Collection of additional data elements will enhance Vectren South's DIMP and allow for a more refined and detailed analysis of the threats to its gas distribution system. This will provide opportunities to enhance the integrity of the gas distribution system and reduce risk. PHMSA's enforcement guidance reinforces this requirement (see guidance for Code Section 192.1007(a)). PHMSA's DIMP enforcement guidance can be found in Petitioner's Exhibit No. JMF-20.

Q. What are the threats that Vectren South must consider in its DIMP plan?

A. There are eight primary threats that Vectren South must consider in its DIMP plan. Those threats are: corrosion, excavation damage, other outside force damage, material, weld or joint failures, natural forces, equipment malfunctions, inappropriate operations, or other concerns. Each of these threats is defined in Vectren South's

DIMP plan in Petitioner's Exhibit No. JMF-18, section 3.0 Threat Identification.

Q. How does Vectren South assess whether these threats apply to Vectren South distribution assets?

A. Vectren South has reviewed each asset class against the threats to the gas distribution system to determine if the threats apply. Vectren South's DIMP engineering staff will then review system data, failure codes, and performance trends to analyze the presence of these threats and the impact on the various assets. These findings are reviewed with Vectren South's subject matter experts to validate the results from the threat evaluation. Additional input from field operations personnel are obtained in the process. The results of this evaluation are used in the evaluation of risk to the gas distribution system.

Q. How are the threats to Vectren South's gas distribution system used in the evaluation of risk?

A. Vectren South conducts the risk evaluation in a multi-step process. Vectren South first evaluates the relative risk of each asset class by assessing the applicability of the threat type against the asset class. To determine the relative risk of the asset classes, Vectren South's DIMP engineering staff worked with Vectren South subject matter experts ("SMEs") to determine the likelihood of each threat and the consequence of a failure caused by each threat that was applicable to each asset class. SMEs are experienced operations and engineering personnel, with others being included as the risk assessment pertains to their particular area of expertise. The SME based consequence is a product of various factors including health, environmental and cost (such as outage, property damage, gas loss, and repair costs). The likelihood and consequence factors are then multiplied to establish an asset class risk score. Petitioner's Exhibit No. JMF-21 is a table showing each asset class and its associated risk score, in rank order.

The next part of the risk evaluation is to assess risk based on the performance of the assets. This process allows Vectren South to assess risk from a geographic perspective and incorporate factors such as threat driven leak data and population density, with the SME based consequence factors in the evaluation of risk. The risk equation establishes the probability of a failure through historical leak records associated with each threat type as a factor of asset density. Vectren South then evaluates the consequences of these failures for each threat type based on a subject matter evaluation, as a product of the asset class risk results, and population density. The leak based probably, SME based consequences and population density based consequence is then multiplied to establish geographically based risk scores. These risk results can then be viewed in aggregate as a sum of all threat types or viewed by each threat independently. Petitioner's Exhibit No. JMF-22 is a thematic map of the aggregate risk score, by operating center.

Section 4.0 of Vectren South's DIMP plan (see Petitioner's Exhibit No. JMF-18), describes the process in more detail.

Q. How does Vectren South use the results of its risk model?

A. Vectren South uses the results of the risk model to identify mitigating actions to reduce risk. The results allow the DIMP engineering staff to evaluate the threats driving the higher risk results, the higher risk asset classes, and the higher risk geographical areas to determine appropriate risk mitigating activities. The risk mitigating actions may broadly apply to address a specific threat (such as excavation damage or corrosion of steel pipe), may broadly address an asset class (such as bare steel or cast iron pipe), or may be more targeted to address threats in a geographical area (such as specific project to mitigate an exposure or difficult to locate facilities). The risk model results allow the DIMP engineering staff to select mitigating actions that address the threats that drive the risk scores and project whether the mitigating action will drive a change in risk for those specific assets in which the mitigating action is being executed against.

An example of this is the replacement of a segment of bare steel pipe with plastic pipe. The primary threat that drives the difference in risk between a bare steel pipe and a plastic pipe is corrosion. The mitigating action to address this threat could either be replacement of the asset or making improvements to the cathodic protection system. While cathodic protection could be applied to the bare steel pipe segment, it would not mitigate prior degradation of that segment nor would it fully eliminate the threat of corrosion on that segment, thus replacement is a better option. From the asset class risk assessment, the resulting reduction of risk for this segment by replacing it with plastic pipe would be a minimum of 21%. This means that the Vectren South system, where the new pipeline infrastructure resides, will be 21% less likely to experience a failure as a result of one of the applicable system threats as compared to the existing infrastructure. A comparison of the threats associated with metallic pipe as compared to plastic pipe (from Petitioner’s Exhibit No. JMF-20) demonstrates the drivers of the difference in risk between the asset classes. Petitioner’s Exhibit No. JMF-23 further provides an example of the change in risk, using the risk equation from Vectren South’s DIMP plan (see Appendix B section 16.5 of Petitioner’s Exhibit No. JMF-18 for the equation). As described previously, this formula uses a combination of actual experience (such as leaks, pipe length, service density) with SME based risk factors depending on the asset class types to calculate a geographically based risk score. Petitioner’s Exhibit No. JMF-23 provides the calculated difference for an actual bare steel replacement projects completed in 2012. In this example, the resulting difference in risk between the existing bare steel main that had active leaks and the new plastic pipe was 24%. Likewise, Petitioner’s Exhibit No. JMF-24 is a calculation of the risk associated with the remaining bare steel and cast iron pipe mileage as compared to the projected mileage of new plastic pipe, with what the bare steel and cast iron pipe will be replaced. This calculation reflects a reduction of risk of 23% at the end of the replacement program. While these calculations are static based on the current system and performance levels, they provide directional expectations of change in risk.

Section 5.0 of Vectren South’s DIMP plan (see Petitioner’s Exhibit No. JMF-18) provides more details about how Vectren South uses risk assessment results.

Vectren South documents the recommended mitigating action for each one it chooses to implement. These mitigating actions are in the form of infrastructure replacements, additional O&M activities (inspections, surveys, patrols, repairs, etc.), communication and education programs, training and qualification improvements or others as deemed appropriate to mitigate risk. Examples of Vectren South’s mitigating action documents can be found in Petitioner's Exhibit No. JMF-25.

In addition to using the risk results in the evaluation and selection of mitigating actions, Vectren South also uses this data as an input into its project identification and prioritization process that will be discussed later in my testimony.

Q. Does Vectren South have to take action to mitigate every threat to its distribution system?

A. No. At a minimum, Vectren South has to establish a threshold level of risk that it must evaluate and consider implementing mitigating actions to address the threats in particular areas. Vectren South can and does implement other mitigating actions to address other threats outside of the risk threshold. This is a common approach that Vectren South takes to broadly address threats associated with a higher risk asset class, such as the replacement of bare steel or cast iron infrastructure, or when needed to address a specific issue, such as a pipeline exposure or odorizer replacement.

Q. Once Vectren South has identified a mitigating action, is it mandated to implement the mitigating measure?

A. Yes. Part 192.1007(d) requires the operator to determine and implement measures to reduce risk. This is further reinforced by PHMSA's enforcement guidelines ("DIMP Enforcement Guidance"). See guidelines described in Code Section 192.1007(d) of Petitioner's Exhibit No. JMF-20. The DIMP Enforcement Guidance sets forth explanations of how DIMP regulations shall be applied and the consequences of failing to act in conformity with those regulations. The DIMP Enforcement Guidance makes it clear that the DIMP regulations prescribe "minimum requirements" each gas pipeline operator must meet. Essentially, once mitigation actions are identified, Vectren South is charged with moving forward with program implementation.

Q. Can the mitigating action change?

A. Yes. As Vectren South measures the effectiveness of the mitigating action, the results may require modifications to the action as it is currently defined. An example of this may be to further accelerate the replacement of assets, to implement a different measure such as conducting additional inspections, or to stop implementing that measure altogether. The risk modeling under Vectren South's DIMP Plan is continuous. As information regarding additional regulations or findings from new evaluations is input into our system, additional mitigating measures will be identified.

Specifically, PHMSA states that operators must follow their procedures as set forth in the DIMP plan. More specifically, once Vectren South identifies threats and determines the level of significance of a given threat, Vectren South must proceed to determine required actions over and above normal practices. The greatest risks must be dealt with first. As a result, PHMSA has urged operators to accelerate the repair and replacement of aging pipes (see pp. 21-27 of DIMP Enforcement Guidance). In terms of DIMP plan requirements, PHMSA states that the operator must "determine and implement measures designed to reduce the risks from failure of its gas distribution," and, "must provide a schedule of when measures to reduce risk will be taken, and…act as quickly as practical" to deal with identified risks. To the extent the operator's DIMP program does not provide for implementation of mitigative measures, including a schedule, designed to remediate risk factors, a probable violation will have occurred. (DIMP Enforcement Guidance, pp. 29-30). Finally, the process is ongoing. Risks must be periodically reevaluated, including a review of the effectiveness of mitigating actions. Absent such evaluation, a violation will occur. (DIMP Enforcement Guidance, pp. 37-38). This leads to an allocation of resources directed at the prioritized system risks. (DIMP Enforcement Guidance, p. 49).

Vectren South's DIMP plan does what PHMSA states is required—the mitigating actions designed to address identified and prioritized risks are identified, scheduled and to be funded.

Q. How does Vectren South measure the effectiveness of its DIMP?

A. Vectren South measures the effectiveness of its DIMP through a review of program level metrics, such a leak tracking and trending, excavation damage rates, and one-call ticket activity. Additional measures related to the mitigation actions being implemented are reviewed to determine the effectiveness of the actions taken. In addition to specific metrics, Vectren South gauges effectiveness through discussion with Vectren South SMEs.

IV. <u>Compliance Projects: Investments and Expenses to comply with TIMP and DIMP Federal Mandates</u>

Q. Describe the Investments Vectren South will be making as a result of the TIMP federal mandates?

A. Vectren South will be making a number of investments over the foreseeable future to meet the requirements of the TIMP regulations that will allow it to either complete the necessary assessments of its transmission pipeline system, remediate issues identified during the assessment process, reduce overall risk to the integrity of its pipeline system by addressing specific threats, high risk segments or equipment or through the implementation of P&M measures. Vectren South will be making investments in the following types of projects: in-line inspection modifications, pressure tests, eliminating exposures and shallow segments of pipe, remediating encroachments, replacing obsolete equipment, eliminating casings, addressing gas quality, valve isolation and automation, odorizer replacements, electronic monitoring and SCADA improvements, rehabilitating regulator stations, and relocating or replacing segments. Examples of the scope of various projects are included in <u>Petitioner's Exhibit No. JMF-26</u>.

Q. Has Vectren South made similar investments in the past to comply with the TIMP requirements?

A. Yes. Vectren South has been making investments in its transmission pipeline system to allow it to comply with the TIMP regulations. The investments that have been made have been similar to those described above. However, as Vectren South's TIMP has matured, Vectren South has developed a more sophisticated and comprehensive risk assessment process that addresses the interactive threats to its pipeline integrity, has significantly increased its knowledge of its transmission pipeline system and equipment, has seen the advancement of technology that will allow for the better understanding of pipeline system integrity, and has matured its decision making process. These improvements now allow Vectren South to develop and implement long term capital plans that address the threats to its transmission pipeline system in an efficient manner.

Q. Does Vectren South expect that it will be making investments to comply with the TIMP requirements beyond the seven year period included in this proceeding?

A. Yes. Because of the different risks being evaluated, different assessment methods used to assess these risks, HCAs changing over time, new segments of the pipeline system being assessed and new conditions being identified, Vectren South will be making similar investments beyond the seven year period defined in its current plan (described later in my testimony). This is particularly impacted by the choice of a pressure test or an in-line inspection assessment. In cases where a pressure test is required for the assessment, Vectren South will implement that type of project during the next reassessment period and then the in-line inspection modification during the following reassessment period. As discussed previously, where there are opportunities to modify the pipeline for in-line inspection in the long term, those synergies will be considered.

Q. When Vectren South designs the capital projects to meet the TIMP requirements, does it consider opportunities to combine multiple projects into a single project to gain synergies and economies of scope and scale?

A. Yes. Because Vectren South's risk model allows it to evaluate multiple threats on a pipeline and it can understand the interactive nature of these threats, Vectren South is then able to plan projects that meet both the assessment requirements and also implement measures to mitigate other threats to the pipeline system. Examples of this type of synergistic planning include replacing an exposure while modifying a pipeline for in-line inspection, removing wrinkle bends or plug valves when preparing a pipeline for pressure testing to allow for future in-line inspections, or installing a valve actuator, upgrading SCADA equipment and adding sensors during a station modification to install launchers and receivers. These types of synergies allow Vectren South to utilize its resources, both physical and capital, in a more efficient manner than when working each project independently.

Q. Has Vectren South established a long term plan for the investments related to

the TIMP requirements?

A. Yes. Petitioner's Exhibit No. JMF-27 is a summary of the expected TIMP investments over a seven year period based on the current regulations and the currently known conditions. These investments will continue beyond the seven years depicted in this plan and are of course subject to change depending on changes to the regulations, new information that may change the risk model, new conditions identified during assessments or as a result of other changes in the pipeline system.

Q. What O&M expenses will Vectren South incur as a result of the TIMP federal mandates?

A. Since the inception of the TIMP requirements, Vectren South has incurred expenses to comply with these mandates. Vectren South has incurred these costs pursuant to the 2002 Safety Act and Subpart O, and has historically recovered these costs through the Pipeline Safety Adjustment ("PSA") mechanism. Over the past 5 years, Vectren South has incurred annual average TIMP expenses of approximately $1,425,000. These expenses have been incurred to execute the TIMP requirements so that Vectren South could perform the necessary pipeline and station assessments, gather and integrate data, implement P&M measures, update processes, procedures, standards and records, remediate conditions identified during assessment, train personnel, implement public awareness programs and engage in other activities necessary to manage the program. Since compliance with the TIMP requirements is an on-going process, with reassessments reoccurring at least every seven years, these types of expenses will continue on through the foreseeable future. Vectren South's current plan estimates that it will incur on average annual expenses of approximately $1,550,000. Petitioner's Exhibit No. JMF-28 is a summary of these projected expenses over the next seven years. Once again, this level of expense may vary depending on new findings during assessments, results of the risk models, changes to HCAs and class locations, new threats surfacing, additional data needing to be gathered and other factors. This level of expense does not reflect any additional cost that may come as a result of new or modified pipeline safety regulations being developed by PHMSA.

Q. Describe the investments Vectren South will be making as a result of the DIMP

federal mandates?

A. Vectren South will be making a number of investments over the foreseeable future to meet the requirements of the DIMP federal mandates that will allow it to address the risks identified through its DIMP process as described previously. The most significant investment will be the continued replacement of the bare steel and cast iron infrastructure. Additionally investments will be made to address risks associated with ineffectively coated steel pipe, vintage plastic pipe, obsolete equipment, exposures and shallow pipe, bridge crossings, non-commercially available pipe, station rehabilitation, additional valves and sectionalization, inside meters, encroachments, pressure monitoring and other investments as identified through the DIMP. Examples of the scope of various projects are included in Petitioner's Exhibit No. JMF-29.

Q. Has Vectren South established a long term plan for the investments related to the DIMP requirements?

A. Yes. Petitioner's Exhibit No. JMF-30 is a summary of the expected DIMP investments over a seven year period based on the current regulations and the currently known conditions. These investments will continue beyond the seven years depicted in this plan and are of course subject to change depending on changes to the regulations, new information that may change the risk model results, new conditions identified in the pipeline system, new information regarding industry-wide material issues or as a result of other changes in the pipeline system.

Q. Has Vectren South made similar investments in the past to comply with the DIMP requirements?

A. Yes. Vectren South has been making investments in its distribution pipeline system that comply with the DIMP regulations. The investments that have been made have been similar to those described above. However, as Vectren South has formalized its DIMP processes, it has identified and established a more programmatic approach to planning these investments throughout its entire system, which will produce greater benefits to distribution pipeline integrity, capital utilization, customer service, and public and pipeline safety. As previously stated, through our modeling Vectren South ranks its areas of risk, identifies mitigating strategies to reduce risk and therefore directs our resources to those projects that provide the greatest risk reductions. This is in line with PHMSA's DIMP Enforcement Guidance.

Q. Does Vectren South expect that it will be making investments to comply with the DIMP requirements beyond the seven year period included in this proceeding?

A. Yes. Because DIMP is a perpetual process, new or changing risks are going to surface that require Vectren South to implement mitigation measures, including infrastructure additions or replacement, to address. Because of the amount of certain infrastructure currently active in its distribution system, Vectren South will be making investments beyond the years shown in its plan. A primary example is the investment in the replacement of bare steel and cast iron. Due to the age and quantity of active bare steel and cast iron facilities, Vectren South currently plans to replace the remainder of these assets over the next 10 years.

Q. When Vectren South engineers the capital projects to meet the DIMP requirements, does it consider opportunities to combine multiple projects into a single project to gain synergies and economies of scope and scale?

A. Yes. As planning for individual projects occur, Vectren South engineers will evaluate opportunities to group projects into a single capital project and achieve the goals of multiple DIMP mitigating actions. An example of this is when Vectren South completes a bare steel replacement project, it will also move meters outside, replace vintage plastic service lines, replace ineffectively coated steel service lines, and increase system pressures to allow it to retire an obsolete regulator. These opportunities are refined and evaluated in more detail during the design phase of each project.

Q. What O&M expenses will Vectren South incur as a result of the DIMP federal mandates?

A. Since the inception of the DIMP requirements, Vectren South has incurred expenses to comply with these mandates. Vectren South has historically recovered these costs through the PSA mechanism. Over the first 2 years of DIMP, Vectren South has incurred annual average expenses of approximately $175,000. Vectren South has recently added additional DIMP staff and is executing additional data gathering and other accelerated actions. Since DIMP is a perpetual process, these types of expenses will be on-going but will vary depending on the risks identified, the amount and type of data being gathered, the type of mitigating action being implemented and the duration of these activities. Vectren South's current plan estimates that it will incur on average, annual DIMP expenses of approximately $815,000. Petitioner's Exhibit No. JMF-31 is a summary of these expenses over the next seven years.

Q. Are other DIMP mitigating actions being proposed as part of the Federally Mandated Projects that will increase O&M expenses above the expenses mentioned above?

A. Yes. Vectren South is including as a separate item in its plan, the investment and expenses associated with reducing risk of excavation damages. Nationally, excavation damages are the leading cause of serious pipeline safety incidents (see Petitioner's Exhibit No. JMF-32 for an excerpt from PHMSA on excavation damage). This is evidenced by both TIMP and DIMP evaluating excavation damages as one of the major threat categories. Vectren South has taken additional steps through its TIMP program to implement P&M measures on the transmission pipeline system. However, these same measures are not practical on its distribution system. Vectren South has also implemented a very effective public awareness program. However, excavation damages still remain a high risk threat to our gas distribution system. Additionally, all gas distribution system operators have seen an increased amount of activity at the state level with the implementation of the Indiana 811 laws and Underground Plant Protection Advisory Council, which provides the IURC with the ability to assess penalties as a result of excavation damage. After discussion with the Pipeline Safety Division, Vectren South has assessed opportunities to improve the facility locating and damage prevention programs and will be implementing a number of improvements.

Vectren South has identified three primary areas of focus for these improvements: maps and records, locating, and excavator inspections, monitoring and education.

- Maps and records: Improvement in this area will involve imaging many of

Vectren South's historical documents (include as-built work order packets and other maintenance records) and providing a means to share this data with locators, operating personnel, engineers and other stakeholders. There will be a focus on records research to identify and map service stubs, improve the quality of service record cards, collect additional attribution data to enhance searching and mapping capabilities, populate additional attributes and enhance facility location information either through better measurements or through GPS surveys.

- Locating: Improvement in this area include field investigations and adding pipeline markers, exposing difficult to locate facilities to validate locations and update location records, replacement of infrastructure as needed, development of new processes to conduct records research, pre-locates and exposures for certain types of public improvement projects, additional training for locators and other activities as necessary to address a difficult to locate facility.

- Monitoring and education: Improvement in this area will involve establishing a notification system for certain excavation types and contractors and having personnel available for education, pre-construction conferences, project risk assessment, and inspections and monitoring.

The projects associated with reducing excavation damages are found in Petitioner's Exhibit No. JMF-33. The annual expenses associated with these projects are included in Petitioner's Exhibit No. JMF-34.

Q. Please provide a summary of the O&M expenses associated with Vectren South's compliance plan.

A. Vectren South's O&M plan to comply with the TIMP and DIMP requirements and to implement new projects associated with reducing excavation damages, as described above, can be found in Petitioner's Exhibit No. JMF-35.

Q. Is Vectren South requesting recovery of these federally mandated O&M

expenses?

A. Yes. Vectren South is requesting that these expenses be recovered pursuant to the Compliance Statute. As discussed previously, the current TIMP and DIMP costs are tracked and recovered through the PSA. Vectren South Witness Scott E. Albertson discusses recovery of these expenses in his direct testimony.

Q. Please provide a summary of Vectren South's Compliance Projects.

A. Vectren South's capital investments to comply with TIMP and DIMP federal mandates is found in Petitioner's Exhibit No. JMF-36.

Q. Will the Compliance Projects identified by Vectren South allow it to comply with the federal mandates described in your testimony?

A. Yes. The Vectren South's Compliance Projects will allow it to comply with the TIMP and DIMP federal mandates.

Q. Please summarize Vectren South's request specific to the Compliance Projects.

A. Vectren South requests that the Commission approve and grant a certificate of public convenience and necessity ("CPCN") for the Compliance Projects, and find that the Compliance Projects are reasonable and necessary for the utility in order to achieve compliance with the stated federal mandates. Additionally, Vectren South requests that the Commission approve the requested ratemaking and accounting treatment for these ongoing investments and expenses, as described by Vectren South Witnesses Albertson, M. Susan Hardwick, and J. Cas Swiz.

Q. Would the Compliance Projects also qualify for recovery under the TDSIC Statute?

A. Yes. Vectren South recognizes that the Compliance Statute does not require the presentation of a seven year plan. However, while these investments are based upon Vectren South's TIMP and DIMP to comply with federal mandates, these investments also meet the criteria established under the TDSIC Statute. The purpose of the TIMP and DIMP regulations is to improve pipeline safety and reliability, and inherent in replacing infrastructure is the opportunity to modernize the pipeline system. All of Vectren South's compliance projects align with one or all of the safety, reliability or system modernization categories under the TDSIC Statute. As such, Vectren South is presenting a comprehensive seven year plan that includes both its Compliance Statute and TDSIC Statute investments and expenses. In this manner, all investment and cost impact can be reviewed at the same time. The Compliance Projects are the output of the Company's rigorous planning and modeling process and must proceed as planned so that when audited by regulators the Company can demonstrate that it diligently implemented all appropriate measures and assessments in response to the mandates and have taken a proactive approach to addressing risks to the system as required by the regulations. TDSIC projects, even in the absence of a federal mandate, should be undertaken to further improve reliability and safety of the Company's pipeline system, as contemplated by the TDSIC Statute.

Q. If any of the Compliance Projects being proposed by Vectren South is for some reason found to not be a mandated project, would Vectren South propose to proceed to implement any such project as part of its TDSIC Plan?

A. Yes. While Vectren South believes that its planning processes have shown the need for such projects as responsive to federal mandates, even if some aspect of these projects is determined to not be required to meet regulatory mandates, such projects, having been identified as beneficial to reliability and safety by the Company's planning processes and therefore should be implemented, and the costs of those project(s) should be determined to be recoverable pursuant to the TDSIC Statute.

Q. Did Vectren South engage a third party to review its TIMP and DIMP plans and processes to assess whether the approach Vectren South is using to identify and select projects is reasonable?

A. Yes. Vectren South engaged EN Engineering to review its processes for identifying and prioritizing projects. EN has particular experience in this area and has previously authored reports through the American Gas Association, regarding particular areas of the integrity management programs. Their review verified that Vectren South's TIMP and DIMP programs based on risk modeling reasonably address the risks associated with its system and are used to derive projects that enhance system integrity and improve pipeline and public safety. EN Engineering's study can be found in Petitioner's Exhibit No. JMF-37. EN Engineering found that Vectren South's approach and application of the integrity management requirements and principles were consistent with the requirements and were comparable to others in the industry. Additionally, EN Engineering found that the projects initiated by Vectren South as a result of its TIMP and DIMP were consistent with PHMSA's goal of improving pipeline safety and similar to projects being undertaken by other utilities in the industry.

Q. Has Vectren South reviewed the Gas Infrastructure Study that EN Engineering developed for NIPSCO as part of NIPSCO's TDSIC filing?, If so, are there differences between what Vectren South sought from EN compared to NIPSCO?

A. Yes, Vectren South reviewed the Gas Infrastructure Study that EN Engineering developed for NIPSCO as part of NIPSCO's TDSIC filing. The risk based approach developed by NIPSCO and EN Engineering is essentially the same approach Vectren South applies to identifying its Compliance Projects. The primary difference between risk equations will be the number factors and amount of data that will be included in the risk algorithm and impact the results. Both approaches are appropriate and both adhere to the same basic risk formula. However, Vectren South's existing risk models related to its TIMP and DIMP programs, as described previously, already provide Vectren South with the ability to model risks associated with its pipeline systems and Vectren South is able to use these models to evaluate and identify risk mitigation activities. In particular, because of the nature of Vectren South's TIMP risk model, which is very robust, it is able to dynamically evaluate risk and address interactive threats that are present on all pipelines. This provides Vectren South with the ability to evaluate mitigating actions that address the overall risk to a specific pipeline. As such, Vectren South did not require EN Engineering's assistance in evaluating risk or identifying risk mitigating projects. The types of risk mitigating projects identified by NIPSCO are very similar to those Compliance Projects identified by Vectren South as a result of its risk assessment process. While EN Engineering did evaluate Vectren South's risk models and found them to be appropriate, EN Engineering's primary task was to evaluate Vectren South's use of its risk models in determining Compliance Projects.

Q. A significant portion of NIPSCO's TDSIC plan, particularly investments on its transmission system, is a result of PHMSA's Integrity Verification Process ("IVP"). In this proceeding is Vectren South addressing how it will respond to the anticipated IVP?

A. No, not directly. PHMSA's IVP is a draft at this time. Vectren South expects that PHMSA will memorialize this process into regulation in the near future. Additionally, Vectren South expects that PHMSA will implement additional regulations that will expand the integrity management requirements and require the assessment of more of the transmission pipeline mileage by increasing the mileage of transmission pipelines within HCAs. Vectren South's current risk model has the capability and contains the data, where already collected, to conduct the necessary engineering critical assessment and already identifies areas of "medium consequence areas" (a new term introduced by PHMSA as part of its IVP). Vectren South understands these expectations and contemplates them when considering Compliance Projects. As such, a significant portion of Vectren South's Compliance Projects will include retrofitting pipelines for in-line inspection and pressure testing pipelines within current HCAs. These types of projects meet compliance with the current regulations and have the added benefit of allowing Vectren South to also comply with the anticipated IVP, for the pipelines currently within HCAs, once it becomes applicable regulation. When PHMSA issues new regulations, including the integrity verification process, Vectren South will assess the impact of all of the new requirements and, as necessary, and adjust its Compliance Projects. At that time, to the extent necessary, Vectren South will request additional authority from the Commission to engage in further compliance projects.

B. <u>TDSIC STATUTE</u>

Q. Please describe the TDSIC investments Vectren South is proposing as it relates to safety, reliability or system modernization and provide a summary of its TDSIC Plan.

A. A majority of Vectren South's planned capital investment over the next seven years is associated with investments necessary to comply with the federal TIMP and DIMP mandates. As stated previously, the Compliance Statute investments are being undertaken to meet federal regulations, but will also result in enhancements to safety, reliability and system modernization as required under the TDSIC Statute. In evaluating its system, Vectren South has identified additional investments that, although not directly required as a result of a federal mandate, will provide beneficial improvements in terms of safety or reliability, or result in system modernization.

Vectren South's TDSIC capital investments will fall into the following categories: System and Pressure Improvements, Storage Operations, Instrumentation and Communication Equipment, Public Improvement Projects, and Service Replacements.

Q. Please describe types of System and Pressure Improvement projects.

A. These investments require the replacement or addition of pipelines to allow for continued delivery of reliable service to Vectren South customers. Projects may be a result of needing to provide additional gas service to an isolated area of the Vectren South gas system or providing an additional feed into a broader distribution system to maintain deliverability and allow for future expansion. Additional system improvement projects may be driven from an emergent need, such as repairing a leak, remediating water in the main or addressing an emergent pressure problem. System and pressure improvement projects are a combination of planned projects and emergent projects. Projects may be as simple as replacing a regulator to increase capacity or as complicated as building a new transmission pipeline to provide additional supply to a system. Vectren South will include specific planned projects to address longer term reliability and deliverability as Vectren South's system planning models identify a need. Additional investment will be reflective of historical investments to address emergent projects.

Q. How does Vectren South identify System and Pressure Improvement projects?

A. There are multiple ways in which these types of projects are initiated however, generally, they could be categorized as either a project driven from an emergent need or a project driven from long term system planning models.

Emergent projects are generally a result of an experience in our pipeline system that results in temporary loss of service to a portion of that system or a reduction in system pressure from increased load or expansion or change of a system. Depending on the severity of the pressure reduction and the impact to customers, resolution of these issues will either require immediate repairs or a near term improvement to be made prior to the next heating season. These types of projects are generally not known until after the heating season or at the moment an issue occurs. As such, Vectren South will budget a certain amount for these types of projects annually based on experience, without having specific projects identified until the pressure problem occurs or system analysis and modeling can be completed.

Vectren South's operations staff monitors systems suspected of having pressure issues through charts and other recording devices. Vectren South's system planning department receives notifications from operations and engineering personnel when they witness pressure reductions, specific issues, or suspect potential gas deliverability issues. Additionally, Vectren South's system planning department receives notifications when commercial and industrial customers are either being added to our system or are increasing their load, which allows them to analyze whether the pipeline system can supply the increased load. The system planning staff recommends improvement projects accordingly.

Longer term system improvement projects are generated from Vectren South's system planning department. Vectren South maintains detailed pipeline system models that use pipeline infrastructure data from its GIS, customer usage data from its customer information system, and pressure data from its SCADA system, pressure recording devices, meter readings, and pressure charts. Vectren South then models current system performance at various temperatures, but in particular at projected peak loads. Vectren South is then able to project changes in system loads to evaluate if additional pipeline infrastructure is needed, either through adding infrastructure (such as a pipeline or regulator station), or replacing existing infrastructure to increase capacity. This type of analysis typically generates larger projects to add supply points to the system. Examples of projects are the addition of a supply point from a large transmission pipeline (such as Texas Gas Transmission Company or Panhandle Eastern Pipeline Company), or a transmission pipeline to provide additional supply to an existing distribution system. Solutions may also be less complicated and of smaller magnitude, such as replacing regulators.

Examples of system and pressure improvement projects that will be implemented as part of Vectren South's TDSIC Plan can be found in Petitioner's Exhibit No. JMF-38.

Q. Please describe types of Storage Operations projects.

A. These investments will require the replacement or addition of equipment required to maintain or improve the reliability of Vectren South's storage field operations. Much of the equipment at these facilities has been in service for many decades. These projects generally involve upgrading equipment to maintain reliable service. These types of projects typically surface following the maintenance cycle conducted annually or based on experience during winter operations. Vectren South projects expected investments in this area based on historical investment amounts and identifies specific projects as it continually reevaluates its system.

Q. How does Vectren South identify Storage projects?

A. Storage operations are very seasonal. These facilities are generally operated throughout the heating season to either provide peaking delivery during short periods of time during the winter months or provide broader system supply throughout the heating season. Many of the projects that are needed to maintain reliable operations of these facilities surface during the winter operations period. However, given the criticality of these facilities to heating season operations, replacement or upgrades are not typically undertaken until the non-heating season months, particularly throughout the summer. These projects will be executed during the maintenance cycle. Additional projects may be uncovered during annual maintenance and will be scheduled accordingly. As such, much of the budgeted investment is earmarked for emergent or near term projects. However, Vectren South will also identify other planned projects that consider the age of the facilities, their general performance, the ability to perform maintenance and other factors. These projects will be included in the longer term plan and then evaluated after each heating season to reevaluate the scope, need and timing of such a project. The longer term projects are typically larger projects that require more planning, such as the replacement or upgrade of a compressor. See Petitioner's Exhibit No. JMF-39 for a list of Storage projects.

Q. Will the replacement or upgrade of Storage equipment result in an avoidance of risk to Vectren South's system?

A. Yes. While these projects are primarily driven out of operational and maintenance needs, the continued operation of this equipment is important to provide reliable service to our customers. As such, the replacement or upgrade of equipment reduces the threat of an equipment failure. While the threat would exist on either an existing or replaced piece of equipment performing the same function, the likelihood of a failure due to fatigue of the equipment will be less for the newer equipment. Petitioner's Exhibit No. JMF-40 provides an example of the risk avoidance associated with the replacement of storage equipment.

Q. Please describe types of Instrumentation and Communication projects.

A. These investments will require the replacement of various instrumentation and communication equipment, such as a remote terminal unit, radios or other equipment related to Vectren South's SCADA system, which is used to provide its Gas Control department with visibility into how its transmission and distribution system is operating and provide controls for certain equipment to respond to safety and reliability needs. Vectren South will project expected investments in this area based on historical investment amounts and will support with specific projects as identified.

Q. How does Vectren South identify Instrumentation and Communication projects?

A. Vectren South's instrumentation and communication equipment are electronic devices that reside at various locations within its pipeline system. Primarily these devices are at regulator stations and are used to provide information back to Vectren South's gas control department, who monitors its pipeline system. The devices used in Vectren South's SCADA system will monitor and communicate pressures, regulator set points, valve positions, odorizer flow rates, gas flow rates, and security alarms. Their operations are critical to the safe and reliable operation of Vectren South's gas systems. Because these devices are exposed to the elements and because of the nature of electronic devices, they are susceptible to failures of components, such as a communication board, or of the entire device. Manual systems are in place to allow for contingency in the event of a partial or total loss of instrumentation or communication devices. The instrumentation and communication devices are inspected annually. Projects to replace or upgrade instrumentation and communication equipment are generated from failures that are identified through daily operations or issues that are identified during the annual inspection cycle. Vectren South will monitor performance of these devices in order to assess whether a planned replacement approach is necessary; otherwise projects are undertaken to address an immediate need. An example of a communication equipment project that will be implemented as part of Vectren South's TDSIC Plan can be found in Petitioner's Exhibit No. JMF-41.

Q. Will the replacement or upgrade of Instrumentation and Communication equipment result in an avoidance of risk to Vectren South's system?

A. Yes. While these projects are primarily driven out of operational and maintenance needs, their continued operation is important to provide safe and reliable service to our customers. As such, the replacement or upgrade of instrumentation and communication equipment reduces the threat of an equipment failure. While the threat would exist on either an existing or replaced piece of equipment performing the same function, the likelihood of a failure of the equipment will be less for the newer equipment. Petitioner's Exhibit No. JMF-42 provides an example of the risk avoidance associated with the replacement of communication equipment.

Q. Please describe types of Public Improvement projects.

A. These investments require the replacement or relocation of gas mains and service lines to allow for continued safe and reliable service to customers. The investments require relocation of pipeline facilities to avoid conflicts with third party utilities and with public road or other construction in public right-of-way during construction and after new utilities are installed, thus avoiding a safety risk from excavation damage during third party construction activities while maintaining reliable service delivery for Vectren South's customers. The TDSIC Plan does not include the cost of any portion of such projects for which Vectren South is reimbursed by a third party. Relocations are necessary to avoid excavation damage during the third parties' construction activities. Vectren South will project expected investments in this area based on history and will account for unique differences to the plan in any given year as they are known.

Q. How does Vectren South identify Public Improvement projects?

A. Public improvement projects are generated from a third party. Typically entities such as the Indiana Department of Transportation ("INDOT") or county and city governments will initiate projects to improve their utilities. The projects may be as simple as a resurfacing of an asphalt surface or the replacement of a catch basis or may be more complicated, such as the replacement of storm drains, sanitary sewer and a complete reconstruction or relocation of the roadway from the subsurface layer on up. These projects are typically communicated to Vectren South's engineering staff during the planning phase of the project, but may be later depending on the project type and entity. These third parties may have projects in the design phase for many years or for only a few months. Once Vectren South receives sufficiently completed plans from the third party, it will evaluate what if any conflicts it has with the proposed project. Once a known conflict is determined, Vectren South will initiate a project to relocate the facilities in conflict in accordance with the third party's schedule. These projects are generally developed in the year they are constructed due to the typical process in which third parties release their projects. On some occasions, Vectren South will be provided with more advanced notice of project plans and can project changes in its budgets to reflect the level of investment that may be different than the current forecast. Petitioner's Exhibit No. JMF-43 provides a listing of currently known public improvement projects that Vectren South will undertake as part of its plan. The timing and completion of these projects is dependent upon the third party's schedule. Some projects may be scheduled at a different time or cancelled altogether. This list contains only the projects of which Vectren South is currently aware.

Q. Will the relocation of pipeline facilities as a result of a public improvement project result in an avoidance of risk to Vectren South's system?

A. Yes. While these projects are completed as a result of a third party, the relocation of facilities results in the avoidance of excavation damages. As was described previously in my testimony, excavation damages are the leading cause of pipeline safety incidents, largely as a result of these types of projects. Moving facilities during third party construction activity reduces the threat of excavation damage. Petitioner's Exhibit No. JMF-44 provides an example of the risk avoidance associated with the relocation of a pipeline as a result of a public improvement project. The resulting risk avoidance assumes that one excavation damage event would occur on the existing pipeline and provides the least case risk avoidance. Further damages would be likely if the entirety of pipeline facilities being impacted were not relocated and would thus result in a higher risk avoidance score.

Q. Please describe types of Service Replacement projects.

A. These investments involve the replacement of a service line as a result of the condition of the service line (such as a leak or corrosion), to resolve a deliverability issue for a customer, or as a result of a relocation to avoid a conflict or encroachment with a third party. Service replacements are typically emergent projects constructed within the year they are identified as needing to be replaced. Thus, Vectren South will project expected investments in this area based on history and will account for unique differences to the TDSIC Plan in any given year as they are known. These investments are generally undertaken for safety or reliability purposes but will also modernize the pipeline system through the use of modern materials. The service line replacements included in the TDSIC Plan do not include those performed as part of Vectren South's bare steel and cast iron replacement program.

Q. How does Vectren South identify Service Replacement projects?

A. Most of the service replacements are identified through daily operations as a result of an event that requires the replacement of the service line. The most common reason is the identification of a leak, sufficient corrosion, water or blockage of the service line, or other similar issues. These types of issues surface from customer calls, through annual leak surveys and patrols, and through other operational work. Replacements projects may be performed immediately upon discovery of the problem or be scheduled for a near term, planned replacement.

Customer load additions may also require a service replacement. This may be common as a building changes function, such as moving from an office with only space heating requirements to a restaurant with heavy cooking load in addition to heating needs. These replacements are only completed upon request and typically occur in the year they are requested.

Vectren South replaces approximately 325 services each year.

Q. Will the replacement of service lines result in a reduction of risk to Vectren South's system?

A. In most cases, yes. As described above, most service replacements are a result of an event occurring on that service line that requires that it be replaced. The resulting reduction of risk can be attributed to the use of modern materials (such a plastic) and modern safety equipment, such as an excess flow valve (assuming one is able to be installed). Petitioner's Exhibit No. JMF-45 provides an example of the risk reduction associated with the replacement of a leaking service line.

Q. Apart from risk reductions, do the projects set forth in the TDSIC Plan provide other benefits?

A. Yes. Service reliability is a significant benefit derived from the projects. The reliability benefits may be specific to a single customer or may broadly apply to a larger portion of the customer base. Moreover, broad system modernization compliments the compliance projects because we are improving our system facilities as needed, which is consistent with the spirit of the regulations, allows us to update records and know more about our system and avoid system breakdowns which take our time and focus away from safety initiatives.

Q. Please provide a summary of Vectren South's TDSIC Plan.

A. Petitioner's Exhibit No. JMF-46 provides a summary of the seven year TDSIC Plan. This exhibit also includes annual investments for the purpose of economic development, which will be discussed in more detail by Vectren South Witness Thomas L. Bailey.

Q. Please summarize Vectren South's request specific to its TDSIC Plan.

A. Vectren South requests that the Commission approve its TDSIC Plan, including the cost estimates of the Plan and the process used to identify projects going forward, and find that the Plan serves the public convenience and necessity. Additionally, Vectren South requests that the Commission determine the TDSIC Plan is justified by the incremental benefits supported by the TDSIC Plan. Finally, Vectren South requests that the Commission approve the requested ratemaking and accounting treatment, as described by other witnesses.

C. Comprehensive Investment Program

Q. Please provide a summary of Vectren South's comprehensive seven year capital investment program, including both Compliance Projects and the TDSIC Plan.

A. Petitioner's Exhibit No. JMF-47 is the comprehensive investment program, which for presentation purposes includes investments pursuant to the Compliance Statute and the TDSIC Statute.

Q. Please describe how Vectren South developed its program.

A. As it relates to Compliance Statute investments, Vectren South identified Compliance Projects through its TIMP and DIMP programs respectively. These processes were described in more detail previously in my testimony. Once projects are identified, the scope of the project is defined and a budgetary estimate is developed for inclusion in the investment plan. Petitioner's Exhibit No. JMF-26 and Petitioner's Exhibit No. JMF-29 contain examples of scope documents for different types of projects. Vectren South uses a process to prioritize the projects and determine the appropriate timing and schedule in order to establish the investment for each year of the program. There are factors that can impact the extent and timing of any project. Factors will include, but are not limited to, things such as: assessment timing, operational and system constraints, resource availability, impact on a community, risk, or budget constraints. Vectren South evaluates these factors for each project in determining when that project will fit into the long term schedule and also establishes a level of investment that is achievable without overly burdening resources (ex. engineering, materials and construction) and stakeholders (ex. customers or communities). As the near term projects are more fully designed or as current year projects are executed, updates to the program will be made annually to reflect changes to the timing of projects being completed, the project scope, costs estimates and the budget.

As it relates to TDSIC Statute investments in the TDSIC Plan, Vectren South identifies projected investment levels based on a combination of historical investment levels, known specific projects and projected projects based on system modeling. This was described more fully previously in my testimony for each investment category. The investment amounts are established for each year over the seven year planning period and refined for the near term budget year as more specific details about projects are known. As the near term projects are more fully designed or as current year projects are executed, updates to the TDSIC Plan will be made annually to reflect changes to timing of projects being completed, the project scope and costs estimates.

Q. Please describe Vectren South's project selection and prioritization process.

A. Through its TIMP or DIMP process, Vectren South identifies projects and develops a scope of work around each project. Vectren South then creates a budgetary estimate based on the defined scope of the project. All of the projects, with defined scope and budget are added to a prioritization model. The prioritization model calculates a score for each project that is a combination of factors including the asset risk score from the TIMP or DIMP risk models, and other factors such as compliance requirements, SME input, class location, HCA, asset type, and more. The additional factors are intended to establish project specific prioritization with heavy weighting from the risk score. The prioritization model needs to consider aspects of timing, such as when a reassessment needs to be completed or when a project needs to be done in conjunction with a public improvement project. The prioritization score allows the engineering staff to establish a preliminary priority to establish a schedule as to when each project may be constructed. Vectren South then reviews the prioritized project list with key stakeholders, such as operations, engineering, gas control and others, to obtain agreement on the prioritized list of projects. Petitioner's Exhibit No. JMF-48 is a list of projects excerpt from Vectren South's transmission project prioritization model. Petitioner's Exhibit No. JMF-49 is a list of projects excerpt from the project prioritization model. Due to the nature of the projects and the size of the program, Vectren South evaluates bare steel or cast iron replacement projects independently to include more specific performance factors, particularly leaks, associated with those project types. Petitioner's Exhibit No. JMF-50 is a BSCI project list excerpt from the project prioritization model.

For the types of investments described in the TDSIC statute section, a long term investment plan is projected using a combination of historical investment levels and project specific investments, as described previously, to generate a budgetary estimate for the TDSIC Plan.

Q. Please describe the process that Vectren South uses to establish reasonable estimates for the projects in its program?

A. When Vectren South identifies a project, it develops a preliminary scope of work and a preliminary cost estimate for that project. The preliminary estimate will be a high level estimate contemplating certain expectations about the project but recognizing that certain unknowns will exist until a more detailed design is developed. A good example is the preliminary scoping of a project to modify a pipeline to be capable of in-line inspection. The preliminary scope for this project will contemplate the expectation that the pipeline will require a launcher at one end of the pipeline and a receiver at the other end of the pipeline. The cost to install the launcher and receiver will be approximately $750,000 each. Because of the experience Vectren South has had with similar in-line inspection modification projects, the scope would contemplate some number of additional modifications for the replacement of certain obstructions, such as plug valves, which may cost approximately $200,000 each. The preliminary estimate will include these expected costs and then have additional contingencies added to the project to account for some expected unknowns (such as the removal miter bends and other unknown obstructions). Because Vectren South has experience performing all of the types of projects in its program, it is able to use its experience to develop reasonable estimates. However, until more detailed research is completed to refine the scope of the project, these estimates remain in the planning (-30% to +50%) or scoping quality (-20% to +30%), depending on the level of detail understood at the time the initial project scope is developed. However, Vectren South has generally presented estimates for purposes of its plan that are more reflective of a scoping level estimate because of its experience with similar projects, and thus more likely to fall within the more narrow estimation range.

Generally, Vectren South is able to define the initial scope of work with more certainty because Vectren South has experience with all of the projects included in its plan and has regularly performed this type of work. Thus Vectren South expects that preliminary estimates will typically be in the scoping range (-20 to +30%). Vectren South uses this experience and understanding of the types and magnitude of costs associated with these projects to develop its preliminary cost estimates. The historical investments provide a solid basis for future project costs. This is best illustrated by Vectren South's estimates of projects to replace bare steel or cast iron pipelines. Vectren South has been performing these types of projects over the past five years in towns throughout its service territory. At the beginning of this program, Vectren South had minimal experience designing and estimating projects of this magnitude and thus the preliminary estimates varied more from the actual costs as a simple average was used to develop preliminary estimates. Vectren South's preliminary estimates in this area have improved over time. This was a conclusion that EN Engineering reached in its evaluation of Vectren South's estimates over time.

Vectren South has completed or has in process more than 50 bare steel and cast iron replacement projects, from which to draw on for developing estimates of future costs. Additionally, Vectren South is able to use similar projects performed in

Vectren North and VEDO as further experience of these types of projects. As a result of an in-depth understanding of the actual costs and the factors that influence these costs, such as footage of pipe, number of below ground crossings per foot of pipe, number of services, permitting fees, and restoration requirements, Vectren South has been able to develop an estimating model that recognizes unique differences in its service territory. This allows Vectren South to contemplate challenges, such as the existence of rock or the density of homes and other underground utilities, in its preliminary estimates. Thus, Vectren South's preliminary estimates for its bare steel and cast iron replacement projects are at a minimum representative of a scoping level estimate but more likely representative of a design level estimate (-15% to + 20%). However, since these projects are bid and design estimates are not completed until after the bidding process, the estimates are recognized as a scoping level estimate. Additionally, because pipe replacement is similar, whether a bare steel and cast iron replacement project, public improvement project, or system improvement project, the same tool can be used to estimate other project types, provided the new infrastructure is similar.

Once a project is moved to the detailed design phase, a more refined estimate will be developed based on the further refinement of the scope of the project. As an example, using the in-line inspection modification project example discussed previously, during the detailed design phase, the project engineer will research the locations of all possible obstruction. This research may include excavating the existing pipeline to confirm the existence of such obstructions. Additional concerns will be contemplated such as maintaining service to a customer tapped off of the pipeline being modified, adding distribution pipelines to create an additional connection to allow for the temporary removal of a regulator station, or the purchasing of additional easements to accommodate station modifications. For many projects, once the project has been refined and a detailed design completed, the project will be bid for construction or estimated against a blanket bid contract. The design estimate will be completed with all current material costs, construction labor costs, and other costs (such as crop damage, restoration, easements, permitting, inspection, x-ray testing, and other related costs).

Depending on the type of project or program being implemented, projects will be estimated against a pre-determined bid price (such as service replacements and installing main as part of a public improvement project), will be bid as a package of projects (such as all bare steel and cast iron replacement projects) or will be bid as a single project (such as an in-line inspection retrofit project). The timing of development of the design estimate will also vary depending on the type of project. As an example, Vectren South has pre-determined bid prices for certain type of construction activity that is updated annually. Vectren South bids its packages of bare steel and cast iron projects in November of each year and finalizes cost estimates after the bid packages are analyzed and awarded. Vectren South bids transmission projects prior to construction so detailed estimates are typically available just prior to the work commencing.

There still exists the possibility of unknowns being encountered during a project, and estimates will often contain contingencies to account for any unexpected issues. Minor modifications to projects, such re-routing a pipeline to avoid buried, un-locatable obstructions, or installing additional footage to tie the new pipeline into an existing pipeline of better condition will often happen, particularly on a distribution replacement project. As more significant job changes are encountered, which happens on occasion, additional scope to a project could occur that would require modification of the estimate.

As projects progress through their lifecycles, more refinement of the estimates occur as more information is learned about the scope of the project and the specific issues associated with each project. Vectren South's estimating practices are similar to AACE International's recommended practice on cost estimating. As Vectren South continues to perform more of this work, it will use the results of the more recently completed projects to review its estimates and adjust them as necessary.

Q. Did Vectren South have a third party review its cost estimate-methodology for reasonableness?

A. Yes. Vectren South contracted with EN Engineering to review estimates for subset of projects included in the seven year investment plan. Vectren South has experience with all of the project types in its program and used this experience to develop the estimated investment amounts included in its program. EN Engineering has reviewed various project types and has concluded that the estimating approach and the resulting estimates Vectren South provided are reasonable and consistent with accepted practices. The results of EN Engineering's review is provided in Petitioner's Exhibit No. JMF-37.

As another comparison, NIPSCO's estimates for its TDSIC Plan were designed to an AACE class 3 estimate level, which represents an accuracy range of -20% to +30%, with a maturity range of 10% to 40%, according to the standard. These estimate levels and ranges are comparable to Vectren South's estimating practices. With the level of detail described on each project, NIPSCO appears to have a very solid understanding of the scope of their projects and thus I would expect that their estimates would meet the AACE class 3 estimate accuracy ranges. Vectren South uses a similar approach to establish expected levels of accuracy for its preliminary, scoping and detailed design estimates. As described previously, Vectren South has a lot of recent project experience on a variety of project types and is able to use this experience to develop reasonable estimates during the various stages of the lifecycle of a project.

Q. Would it be reasonable to expect that Vectren South would have detailed estimates for all projects at this point in time?

A. No. As described above, Vectren South has experience performing the type of work it has included in its program. The estimates performed were reasonable and adhere to AACE recommended practices. Vectren South focuses its detailed engineering efforts on the near term projects. Projects identified for completion much later in the program period will be estimated based on past experience with similar projects. Expending considerable time developing detailed estimates for projects that will not be constructed for some time would be an inefficient use of resources and result in additional and unnecessary costs.

Q. How will Vectren South manage its overall budget and cost estimates for the Compliance Projects and the TDSIC Plan?

A. We will manage the budget and cost estimate for the Compliance Projects on an aggregate basis, and similarly, we will manage the budget and cost estimate for the TDSIC Plan on an aggregate basis. The Company is seeking Commission approval of an overall aggregate cost estimate for the Compliance Projects, and similar approval of the programs and associated costs, on an aggregated basis, as set forth in the TDSIC Plan. Assuming those approvals are received, we will manage the individual projects within those two categories toward meeting the overall aggregate budget for each category. Thus, individual project cost overages can be offset by savings on other individual projects. As is discussed below, we will annually update the Commission with respect to cost estimates. In the event necessary, we will seek approval of changes to the overall cost estimate for the Compliance Projects that exceed the specified statutory 25% overage, and we will through the update process seek approval of any changes to the overall cost estimate for the TDSIC Plan.

Q. Please describe the benefits associated with Vectren South's Compliance Projects and TDSIC Plan.

A. The benefits from the projects performed as part of Vectren South's Compliance Projects and TDSIC Plan can be categorized into operational benefits, customer benefits and cost benefits.

Operationally, the benefits of performing the projects will allow Vectren South to comply with the TIMP and DIMP requirements. The projects will improve the integrity of the pipeline systems, which will have an impact on safety and reliability. System risk will be reduced through the replacement of poorer performing assets, improved reliability by replacing obsolete equipment, increase the knowledge of the pipeline systems, which will further improve assessment and mitigation capabilities, address specific threats to reduce the likelihood of failure such as excavation damages, increase visibility for emergency response and remote operational control and more. The projects being executed will introduce modern materials and equipment, which eliminate certain threats that may exist with older infrastructure. The projects will eliminate certain challenges faced by Vectren South employees that impact employee safety.

Customers will benefit through the implementation of projects that will improve system integrity, reduce threats to the pipeline system to reduce the likelihood of a failure, reduce the impact to specific customers, such as moving meters outside, improve emergency response capabilities, improve customer education and awareness opportunities by learning more about our system, and reduce excavation damages caused by customers through improved processes in record keeping and locating. Continued reliable service delivery to the customers will be enhanced through these system improvements and by implementing a long term planning process.

Executing a long term program will result in better utilization of capital dollars than if executed in an independent and unplanned manner. There are opportunities for Vectren South to gain economies of scope by combining projects to address multiple issues at one time. This should result in a lower overall cost for the projects by minimizing costs related to mobilization, materials management, and design. Additionally, Vectren South will be able to work with key material suppliers and service providers to develop strategic partnerships that allow Vectren South to complete the projects at a lower overall cost. By implementing a long term approach, coordination with other stakeholders, particularly the various communities Vectren South serves, will aid them in their planning efforts.

Q. Does Vectren South expect that it will have to update its Compliance Projects and TDSIC Plan?

A. Yes, but each separately and in accordance with the provisions of each statute. TIMP and DIMP are fluid and perpetual processes that require continual evaluation and surfacing of new information that drives decisions that will require the projects to be modified. Other external factors will drive timing of certain Compliance Projects.

PHMSA is on the verge of implementing new regulations as a result of the 2011 Safety Act. This is most evident from their draft of the Integrity Verification Process, where they initiated the concept of a medium consequence area. Utilities across the country will be making more investment in projects similar to those proposed by Vectren South, creating increased competition for materials and resources. New technologies, materials, service providers, and process will be developed that will have to be considered when planning for and designing future projects. The influences that can change the program are considerably more than identified here. Regardless, there has to be allowance for changes to the program to meet the changing environment. The new PHMSA rules will likely result in new program costs for which Vectren South will need to separately seek approval for in the future under the Compliance Statute. Notably, our Compliance Projects and TDSIC Plan provides for investments that modernize the system and will provide the indirect benefit of providing new or modified facilities that are more likely to meet the safety and reliability requirements of these increasingly expansive regulations.

With respect to the TDSIC Plan, Vectren South will need to maintain flexibility in managing its projects in order to address the various influences that may cause changes to them. As described throughout my testimony, there are many things that may cause an emergent need to be addressed, and, as such, Vectren South will have to accommodate these changes. Vectren South will generally be able to manage these changes within the Plan but will need the flexibility to move investment amounts between the various categories of work. This will allow for situations where project scopes are modified due to findings during detailed designs, for emergent issues identified during normal operations and assessments, and to otherwise respond to changes identified through risk modeling and the capture of new data.

Q. How does Vectren South propose to update its TDSIC Plan?

A. Vectren South proposes that each September, it file an update of its TDSIC Plan, including any changes in cost estimates or changes in individual projects. The updated Plan will provide more detail regarding the proposed investments and expenses for the following year and update the out years as needed. The September timing allows Vectren South to complete its planning and budgeting cycle and coincides with the preparation of bid packages for the following year's work. Vectren South will be able to further refine its cost estimates in the Plan, especially for projects slated for the next year, as many of the projects will be through or in the more detailed design phase. Additionally, other projects will be better known as third parties' plans are better defined and as Vectren South has completed much of its inspection and maintenance cycles. Any significant changes to the Plan will be identified and explanation provided to support the change. During the September update, Vectren South will formally request approval of any changes to the TDSIC Plan, including if necessary any adjustments to the overall cost estimate for the TDSIC Plan.

Q. The Compliance Statute does not explicitly provide for an update process. Does Vectren South have a proposal with respect to any such updates?

A. Vectren South will report on Compliance Projects progress and costs in its periodic rate adjustment filings. The Company will endeavor to manage costs within the 25% threshold amount provided for in the Compliance Statute. To the extent that cost level is exceeded, Vectren South will follow the prescribed requirement of demonstrating the reasonableness of its costs in order to obtain subsequent recovery of such amounts. As stated previously, as new regulations take effect, the Company anticipates the need to file another proceeding, separate and apart from the rate adjustment filings, to obtain additional authority to expand or implement new compliance projects required to comply with federal mandates.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

I affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

James M. Francis

Transmission Natural Gas Pipelines Information (2013)	
Detail	**VEDI-S (c)**
Total Miles of Transmission Pipeline	148
Mileage in HCA	7
Mileage in Class 1	96
Mileage in Class 2	18
Mileage in Class 3	34
Mileage Inspectable by In Line Technology	15
Mileage Pre-1970 Vintage	68
Number of Pipelines	16
Total Number of HCAs	53

ELECTRONIC CODE OF FEDERAL REGULATIONS

e-CFR Data is current as of November 5, 2013

Title 49: Transportation
PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS

Subpart O—Gas Transmission Pipeline Integrity Management

Contents

SOURCE: 68 FR 69817, Dec. 15, 2003, unless otherwise noted.

§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.

§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 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 with a distance of 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 × (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) 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004; Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-103, 72 FR 4657, Feb. 1, 2007]

§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.

§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.

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 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.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

§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.

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18231, Apr. 6, 2004]

§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.

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18232, Apr. 6, 2004]

§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) ASME/ANSI B31.8S (incorporated by reference, *see* §192.7), section 6.4; NACE SP0502-2008 (incorporated by reference, *see* §192.7); and §192.925 if addressing external corrosion (ECDA).

(2) ASME/ANSI B31.8S, section 6.4 and appendix B2, and §192.927 if addressing internal corrosion (ICDA).

(3) ASME/ANSI B31.8S, appendix A3, and §192.929 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-114, 75 FR 48604, Aug. 11, 2010]

§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 preassessment, indirect 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 SP0502-2008, 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 SP0502-2008, the operator must demonstrate the applicability, validation basis, equipment used, application procedure, and utilization of data for the inspection method.

(2) *Indirect 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 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 SP0502-2008, 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 SP0502-2008), or

(B) Root cause analysis reveals conditions for which ECDA is not suitable (Section 5.6.2 of NACE SP0502-2008);

(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 SP0502-2008.

(4) *Post assessment and continuing evaluation.* In addition to the requirements in ASME/ANSI B31.8S section 6.4 and NACE SP0502-2008, 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 SP0502-2008.)

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-114, 75 FR 48604, Aug. 11, 2010]

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18232, Apr. 6, 2004]

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18233, Apr. 6, 2004]

§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 SP0502-2008 (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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-114, 75 FR 48604, Aug. 11, 2010]

§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) or AGA Pipeline Research Committee Project PR-3-805 ("RSTRENG," incorporated by reference, *see* §192.7) or reduce the operating pressure to a level not exceeding 80 percent of the level at the time the condition was discovered. (See appendix A to this part for information on availability of incorporation by reference information.) 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 temporary reduction in operating pressure or other 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; RSTRENG; or an alternative equivalent method of remaining strength calculation. These documents are incorporated by reference and available at the addresses listed in appendix A to part 192.

(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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18233, Apr. 6, 2004; Amdt. 192-104, 72 FR 39016, July 17, 2007]

§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 SP0502-2008 (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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18233, Apr. 6, 2004; Amdt. 192-95, 69 FR 29904, May 26, 2004; Amdt. 192-114, 75 FR 48604, Aug. 11, 2010]

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004]

§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, 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 SP0502-2008 (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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004; 192-114, 75 FR 48604, Aug. 11, 2010]

§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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004; 75 FR 72906, 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.

[68 FR 69817, Dec. 15, 2003, as amended by Amdt. 192-95, 69 FR 18234, Apr. 6, 2004]

§192.949 How does an operator notify PHMSA?

An operator must provide any notification required by this subpart by—

(a) Sending the notification to the Office of Pipeline Safety, Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation, Information Resources Manager, PHP-10, 1200 New Jersey Avenue, SE., Washington, DC 20590-0001;

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

(c) Entering the information directly on the Integrity Management Database (IMDB) Web site at *http://primis.rspa.dot.gov/gasimp/.*

[68 FR 69817, Dec. 15, 2003, as amended at 70 FR 11139, Mar. 8, 2005; Amdt. 192-103, 72 FR 4657, Feb. 1, 2007; 73 FR 16570, Mar. 28, 2008; 74 FR 2894, Jan. 16, 2009]

§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. No. 192-115, 75 FR 72906, Nov. 26, 2010]