DUKE ENERGY OHIO EXHIBIT ___

**BEFORE**

**THE PUBLIC UTILITIES COMMISSION OF OHIO**

| | | |
|---|---|---|
| In the Matter of the Application of Duke Energy Ohio, Inc., for a Certificate of Environmental Compatibility and Public Need for the C314V Central Corridor Pipeline Extension Project. | ) ) ) ) ) | Case No. 16-253-GA-BTX |

---

**DIRECT TESTIMONY OF**

**BRUCE L. PASKETT, PE**

**ON BEHALF OF**

**DUKE ENERGY OHIO, INC.**

---

March 26, 2019

**TABLE OF CONTENTS**

**PAGE**

## I. INTRODUCTION AND PURPOSE

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Bruce Paskett. My business address is 10731 E. Easter Avenue, Suite 100, Centennial, Colorado 80112.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am a Senior Associate and Chief Regulatory Engineer at Structural Integrity Associates, Inc.

**Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.**

A. I received a Bachelor of Science Degree in Mechanical Engineering from Oregon State University. I have been a Registered Professional Engineer in the State of Oregon since 1987. From 1983-2014 I was employed at NW Natural Gas (NW Natural), a natural gas transmission and distribution pipeline operator based in Portland, Oregon where I held a number of different positions, including Supervising Engineer-Design, Supervising Engineer-Field, Manager of Engineering, Chief Engineer, Manager of Code Compliance and Principal Compliance Engineer. In these positions, I had responsibility at various times for the design, construction, operation and maintenance and integrity management of the Company's transmission and distribution pipeline systems. During my tenure at NW Natural, I was responsible for ensuring compliance with applicable Federal and State pipeline safety regulations and initiating programs to further improve the safety of the Company's pipeline systems. I was also responsible for the development and distribution of procedures that defined the Company's policies and practices to comply with the requirements of Federal and State pipeline safety regulations.

In September 2014, I joined Structural Integrity Associates, Inc.

**Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS A SENIOR ASSOCIATE AND CHIEF REGULATORY ENGINEER.**

A. In my current practice, I provide consulting services for natural gas transmission and distribution pipeline operators across the nation relative to pipeline safety, pipeline integrity management and compliance with applicable Federal and State pipeline safety regulations.

**Q. PLEASE DESCRIBE YOUR INVOLVEMENT WITH PROFESSIONAL ASSOCIATIONS AND INITIATIVES RELATED TO PIPELINE SAFETY.**

A. During my more than 35 years in the natural gas transmission and distribution industry, I have had the opportunity for significant involvement in natural gas professional associations and pipeline safety initiatives, including:

- American Gas Association (AGA)[1] Loaned Executive (2009-2013). Represented AGA member companies during 2011 congressional pipeline safety reauthorization and various pipeline safety rulemaking initiatives.
- AGA Operations Section Committees for over 30 years, including participation in the Distribution-Transmission Engineering Committee, Security Committee, Operations Safety Regulatory Action Committee and Transmission Integrity Management

[1] The American Gas Association represents over 200 local distribution companies across the nation.

Program Committee. My assignment as a Loaned Executive to AGA and participation in various AGA Operations Committees allowed me to develop an in-depth familiarity with numerous natural gas transmission and distribution pipeline operators across the nation.

- Participated with AGA in the development of the natural gas Transmission Pipeline Integrity Management Program Regulation[2] in 2002- 2003.
- Represented AGA member companies in the American Gas Foundation (AGF) Study on *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure*.[3]
- Represented AGA member companies in the Pipeline and Hazardous Materials Safety Administration (PHMSA) *Integrity Management for Gas Distribution, Report of Phase 1 Investigations*.[4] The Report of Phase 1 Investigations provided recommendations to PHMSA for promulgation of the Distribution Integrity Management Program (DIMP) Regulation.
- Represented the natural gas industry in development of the Gas Piping Technology Committee (GPTC) Guidance for the Distribution Integrity Management Program (DIMP) regulation.[5]

---

[2] 49 CFR, Part 192, Subpart O, Gas Transmission Pipeline Integrity Management, 68 FR, 69817, Dec.15, 2003.
[3] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005.
[4] "Integrity Management for Gas Distribution, Report of Phase 1 Investigations," December 2005.
[5] Gas Piping Technology Committee Z380, "Guide for Gas Transmission and Distribution Piping Systems, Distribution Integrity Management Program," Appendix G-192-8, 2009 Edition.

- Participated with AGA in preparing comments to the docket regarding the Notice of Proposed Rulemaking (NPRM) for the PHMSA DIMP regulation.[6]
- Participated with AGA in preparing comments to the Advance Notice of Proposed Rulemaking (ANPRM) and Notice of Proposed Rulemaking (NPRM) regarding the PHMSA proposed regulation on Safety of Gas Transmission and Gathering Pipelines.[7]

Additionally, I relied on my experience in the following areas:

- Instructor for the Gas Technology Institute (GTI) related to the DIMP regulation and natural gas pipeline safety regulations (49 CFR, Parts 190, 191 & 192) from 2008-2014.
- President of the Board for the Oregon Utility Notification Center (Oregon's One Call Board) for a three-year period during the 1990s.
- Perspectives gained providing pipeline safety and regulatory consulting to natural gas transmission and distribution operators across the nation.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE OHIO POWER SITING BOARD?**

A. No. But I have testified and participated in hearings and matters before the Oregon Public Utilities Commission, Energy Facility Siting Council of the State of Oregon Department of Justice, Washington Utilities and Transportation Commission,

[6] Notice of Proposed Rulemaking, Pipeline Safety: Integrity Management for Gas Distribution Pipelines, FR/ Vol.73, No. 123/ Wednesday, June 25, 2008/ Proposed Rules.
[7] Notice of Proposed Rulemaking, Pipeline Safety: Safety of Gas Transmission and Gathering Pipelines, FR/Vol.81, No.68/ Friday April 8, 2016/Proposed Rules.

Public Utilities Commission of the State of California and Public Service Commission of Utah.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am testifying on behalf of Duke Energy Ohio, Inc. (Duke Energy Ohio or Company).

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

A. The purpose of my testimony is to provide expert testimony related to the differences between the characteristics of liquids pipelines, natural gas transmission pipelines and natural gas distribution pipelines. In addition, my testimony provides expert testimony regarding the Federal pipeline safety regulatory requirements pertaining to gas transmission pipelines and gas distribution pipelines and explains why the Central Corridor Pipeline must be appropriately classified as a gas distribution pipeline. My testimony also addresses the safety of natural gas transmission pipelines and distribution pipelines and provides an overview of recent high-profile pipeline accidents.

## II. DIFFERENTIATION BETWEEN GAS TRANSMISSION PIPELINES AND GAS DISTRIBUTION PIPELINES

**Q. ARE THERE ANY PIPELINE SAFETY REGULATIONS THAT GOVERN THE REQUIREMENTS FOR GAS TRANSMISSION PIPELINES AND GAS DISTRIBUTION PIPELINES?**

A. Yes. The Federal Department of Transportation (DOT) originally issued the Federal pipeline safety regulations as Title 49, Code of Federal Regulations (CFR), Part 192- *Transportation of Natural and Other Gas by Pipeline: Minimum Federal*

*Safety Standards* in August 19, 1970. There have been periodic revisions, updates and additions to Part 192 since that time.

**Q. CAN YOU BRIEFLY DESCRIBE THE SCOPE OF THESE FEDERAL PIPELINE SAFETY REGULATIONS?**

A. Yes. The scope of 49 CFR, Part 192 defines the minimum safety standards for the transportation of natural and other gas by pipeline, specifically the transportation of natural gas by transmission, gathering and distribution pipelines. These standards prescribe the minimum requirements for natural gas pipelines regarding acceptable pipeline materials, pipeline design, construction, inspection, post-construction pressure testing, corrosion control, operation, maintenance, personnel qualification and integrity management of gas transmission, gathering and distribution pipelines subject to Part 192.

**Q. DO THE FEDERAL PIPELINE SAFETY REGULATIONS PROVIDE A DEFINITION FOR WHAT CONSTITUTES A NATURAL GAS TRANSMISSION PIPELINE OR GATHERING LINE AS COMPARED TO A NATURAL GAS DISTRIBUTION PIPELINE?**

A. Yes. The Federal pipeline safety regulations define gas transmission pipelines, gathering lines and distribution lines according to the following definitions contained in §192.3:

- *Transmission line* means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS[8]; or transports gas within a storage field.

- *Gathering line* means a pipeline that transports gas from a current production facility to a transmission line or main.
- *Distribution line* means a pipeline other than a gathering or transmission line.

Based on the Federal pipeline safety regulations in Part 192 (§192.3), if a natural gas pipeline does not meet the criteria for either a transmission line or a gathering line, the pipeline must be defined as a distribution line.

**Q. IN SIMPLE TERMS, CAN YOU EXPLAIN THE DIFFERENCES BETWEEN GAS TRANSMISSION LINES AND GAS DISTRIBUTION LINES?**

A. Yes. The differences between natural gas transmission pipelines and distribution pipelines can be summarized by physical and geographical locations, system pressures, size and materials of construction, relative operating stress levels, typical modes of failure, routine operation and maintenance requirements and integrity management requirements.

In simple terms, natural gas transmission pipelines are typically linear systems that transport natural gas over long distances from a production, storage facility or gas processing plant to a city or town. Gas transmission pipelines often include interstate pipelines that traverse long distances across State boundaries. A

[8] Specified Minimum Yield Strength is the minimum strength of the steel pipe material before it begins to "yield"

large percentage of transmission pipelines are located in sparsely populated areas such as farmland and forests (defined in Part 192 as Class 1 or Class 2 Locations).

Nearly 100 % of natural gas transmission lines are constructed of steel material and are typically of larger diameter (up to 48 inches in diameter) than gas distribution lines. Transmission lines typically operate at high pressure levels, between 600 pounds per square inch (psi) and 1,200 psi, and in some cases up to 2,000 psi.[9] And transmission pipelines typically operate at much higher levels of stress in the pipe (ranging from hoop stresses of 20 percent SMYS up to 72 percent of SMYS or even higher) than distribution pipelines. The stress (S) in the pipe caused by the natural gas is based on the operating pressure of the gas (P) compared to the physical characteristics of the pipeline material (wall thickness (t), and pipe diameter (D)) according to the formula $P = 2\,St/D$. The percent of SMYS is a relative percentage of the stress level of the pipeline caused by the gas pressure compared to the stress level (SMYS) at which the steel pipe material will begin to "yield" or "deform". A pipeline may begin to yield at a stress level of 100 percent SMYS.

By comparison, distribution pipelines are typically located in more densely populated urban/ suburban locations where their purpose is to deliver natural gas to end use residential, commercial, industrial and institutional customers within cities and towns. Distribution lines are made of a variety of materials, primarily steel or modern polyethylene plastic, and are of relatively smaller diameters, lower operating pressures and lower stress levels than transmission pipelines. One of the

[9] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005 at page 3-5.

fundamental differences is that distribution pipelines operate at much lower stress levels than transmission pipelines (less than 20 percent of SMYS) whereas transmission lines can operate at stress levels of 72 percent (or more) of SMYS. As a result, distribution pipelines operate with a higher factor of safety than transmission pipelines.

One other critical difference between transmission pipelines and distribution pipelines is the mode of failure. In the unlikely event of a problem with a pipeline, a high-stress transmission pipeline is more likely to result in a rupture, whereas a distribution pipeline (which operates at a much lower stress level) will result in a leak. In §192.941, the Federal pipeline safety regulations define a low stress pipeline as a transmission pipeline that operates below 30 percent of SMYS. Distribution pipelines operate at very low stress levels since they must, by regulation, operate at less than 20 percent of SMYS. In the unlikely event that a distribution pipeline experiences an issue, they will essentially always result in a leak, not a rupture, due to the relatively low operating pressures and relatively low operating stress levels in the pipe. Any leak that does occur can be found by the use of instrumented leak surveys performed by the Company and by the “rotten egg” smell injected into the gas by natural gas operators.

A 2001 study conducted by Battelle Laboratories for the Gas Technology Institute[10] provides further information about the conditions under which ruptures and leaks occur in steel pipelines as referenced in the AGF Study[11] :

---

[10] Leis, B.N.et al, Leak Versus Rupture Considerations for Steel Low-Stress Pipelines, Topical report GRI-00.0232, January 2001

[11] American Gas Foundation, “Safety Performance and Integrity of the Natural Gas Distribution Infrastructure,” January, 2005 at page 3-6.

- *Distribution pipeline incidents typically result in a leak, not a rupture, due to the relatively low operating pressures, and corresponding lower operating stress in the pipe, in distribution systems. A 2001 study conducted by Battelle Laboratories for the Gas Technology Institute provides further information about the conditions under which ruptures and leaks occur in steel pipelines. The exceptional case for distribution systems is rapid crack propagation in certain types of plastic pipe. This was the subject of a 2000 NTSB report and gave rise to an OPS advisory bulletin and the start of a plastic pipe failure data collection project under the oversight of a government-industry group.*

**Q. HOW DOES THE PROPOSED DUKE ENERGY OHIO CENTRAL CORRIDOR PIPELINE COMPARE TO THE INVENTORY OF NATURAL GAS TRANSMISSION PIPELINES? HOW DOES THE CENTRAL CORRIDOR PIPELINE COMPARE TO THE INVENTORY OF GAS DISTRIBUTION PIPELINES?**

A. As noted in the response above, there are some similarities between gas transmission pipelines and gas distribution pipelines, such as the fact that either can be constructed of steel materials. However, there are many more significant differences between gas transmission lines and gas distribution lines. The proposed Central Corridor Pipeline is a 20-inch diameter steel pipeline that is approximately 14 miles long with a pipe wall thickness of 0.438-inches and a Maximum Allowable Operating Pressure (MAOP) of 500 pounds per square inch (psi). The Central

Corridor Pipeline is significantly different from the nation's inventory of gas transmission pipelines in several critical ways:

(1) The Central Corridor Pipeline operates at a lower pressure than most gas transmission pipelines;

(2) The Central Corridor Pipeline operates at a much lower stress level (less than 20 percent of SMYS) than typical transmission pipelines (up to 72 percent of SMYS);

(3) The Central Corridor Pipeline is much shorter than most transmission pipelines; and

(4) The Central Corridor originates and terminates within the "Distribution Center" which serves the greater Cincinnati area.

Based on these critical factors, the Central Corridor Pipeline has very little similarity with the nation's inventory of gas transmission lines. Conversely, the Central Corridor Pipeline has significant similarities with typical gas distribution pipelines. These similarities with gas distribution pipelines are explained in greater detail in the responses below.

**Q. CAN YOU EXPLAIN THE SIGNIFICANCE OF THE TERM "SMYS" IN THE FEDERAL DEFINITION OF TRANSMISSION LINE?**

A. Yes. In the Federal pipeline safety regulations, §192.3 defines SMYS as follows:

SMYS means specified minimum yield strength is:

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

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

In simple terms, the SMYS of the pipeline is the minimum yield strength of the steel pipe material that is guaranteed by the pipe manufacturer. The pipe material may begin to yield (deform) if the stresses imposed upon the pipe material exceeds 100 percent of SMYS. The yield strengths of the actual pipe produced are generally much higher than the minimum guaranteed by the manufacturer, which produces an even lower stress level and greater level of safety.

The SMYS of the pipe material is used in the design of pipelines to determine the MAOP for the pipeline based on the Design Formula incorporated into Part 192, Subpart C. Also, the percent of SMYS produced by the gas pressure in the pipe determines the relative safety factor of the pipeline and is also one of the Federal Code criteria that determines whether the pipeline will be classified as a transmission pipeline or a distribution pipeline. Based on the MAOP of the natural gas in the pipeline, if the percent of SMYS is less than 20 percent of the manufacturer's guaranteed minimum yield strength of the steel material (less than 20 percent of SMYS), the pipeline is classified as a distribution pipeline. Conversely, if the gas pressure creates a stress in the pipe material that is 20 percent or more of SMYS, the pipeline would be classified as a transmission pipeline.

**Q. BASED ON THE FEDERAL DEFINITIONS FOR TRANSMISSION LINE AND DISTRIBUTION LINE, IN YOUR EXPERT OPINION, IS THE CENTRAL CORRIDOR PIPELINE PROJECT A TRANSMISSION LINE OR A DISTRIBUTION LINE?**

A. Duke Energy Ohio has specified that the proposed Central Corridor Pipeline will be constructed using 20-inch diameter, 0.438 wall thickness pipe that meets the American Petroleum Institute (API) 5L X-60 specification. The API 5L X-60 pipe specification requires the manufacturer to provide pipe that is tested and certified to have a minimum material yield strength at SMYS to be at least 60,000 psi. Based on the Design Formula for steel pipe contained in Part 192, the stress exerted on the Central Corridor Pipeline pipe material due to the gas pressure at the MAOP is 19.0 percent of SMYS. In different terms, that means there is a safety factor of 5.25 relative to the manufacturer's guaranteed minimum yield strength for the pipe material.

As noted in my response to the question earlier in my testimony, the Federal pipeline safety regulations in Part 192 define whether a pipeline should be classified as a gas transmission line, a gathering line or a gas distribution line based on several criteria. The proposed Central Corridor Pipeline Project is a distribution pipeline because it fails to meet any of the criteria defined for a transmission pipeline, specifically:

(1) The Central Corridor Pipeline will not transport gas from a gathering line or storage facility to a distribution center, storage facility, or

large volume customer that is not down-stream from a distribution center.

(2) The Central Corridor Pipeline will operate at a hoop stress of 19.0 percent SMYS at MAOP and therefore does not meet criteria (2) for transmission lines. Specifically, the Central Corridor Pipeline will not "operate at a hoop stress of 20 percent or more of SMYS."

(3) The Central Corridor Pipeline will not transport gas within a storage field and therefore does not meet criteria (3).

Since the proposed Central Corridor Pipeline does not meet any of the criteria for a gas transmission line, or the definition of a gas gathering line as defined in §192.3, based on my expert opinion, the Central Corridor Pipeline must be classified as a distribution pipeline. Therefore, at a minimum, the Central Corridor Pipeline must be designed, constructed, tested, operated, maintained and have pipeline integrity management performed in accordance with the regulatory requirements for gas distribution pipelines.

## III. REGULATORY REQUIREMENTS FOR MANAGING THE SAFETY AND INTEGRITY OF NATURAL GAS PIPELINES

**Q. DO THE FEDERAL PIPELINE SAFETY REGULATIONS PRESCRIBE THE SAME REQUIREMENTS FOR MANAGING THE SAFETY OF GAS TRANSMISSION PIPELINES AS THEY DO FOR GAS DISTRIBUTION PIPELINES?**

A. No. The Federal regulations prescribe different requirements for natural gas transmission pipelines than for natural gas distribution pipelines.

**Q. PLEASE SUMMARIZE THE MAJOR DIFFERENCES BETWEEN THE FEDERAL REQUIREMENTS FOR MANAGING GAS TRANSMISSION PIPELINES AND GAS DISTRIBUTION PIPELINES.**

A. Federal pipeline safety regulations contained in 49 CFR, Part 192 prescribe the regulatory requirements for the material selection, pipeline design, construction, post-construction pressure testing, corrosion control, operation, maintenance and integrity management of natural gas transmission and distribution pipelines. While there are similarities in some requirements, there are a number of fundamental differences between the requirements for managing gas transmission pipelines and gas distribution pipelines.

The major differences between the regulatory requirements for gas transmission pipelines and gas distribution pipelines include the following:

(1) Transmission pipelines are generally designed to operate at higher pressures and higher percentages of SMYS (greater than or equal to 20 percent of SMYS compared to distribution pipelines (less than 20 percent of SMYS).

(2) Transmission pipelines must be designed to accommodate the passage of in-line inspection tools (*e.g*. "smart pigs"). Distribution pipelines do not.

(3) Federal regulations for transmission pipelines provide prescriptive requirements for the installation of sectionalizing block valves and consideration for installation of automatic shut-off valves (ASVs) or remote-control valves (RCVs). Valve installation requirements for

distribution lines are more general and at the discretion of the operator. ASVs or RCVs are not required on distribution pipelines.

(4) Construction requirements for transmission pipelines are more prescriptive and more stringent than for distribution pipelines.

(5) Post-construction pressure testing requirements are significantly more stringent for transmission pipelines than distribution pipelines.

(6) Federal regulations for transmission pipelines require more frequent, routine O & M inspections than for distribution pipelines.

**Q. PLEASE DESCRIBE THE MAJOR DIFFERENCES BETWEEN THE REQUIREMENTS FOR THE DESIGN AND CONSTRUCTION OF GAS TRANSMISSION PIPELINES AND GAS DISTRIBUTION PIPELINES.**

A. The major differences in Federal pipeline safety regulatory code requirements related to the design and construction of steel gas transmission pipelines compared to gas distribution pipelines are summarized in Table 1 below:

**Table 1**

| Part 192 Code Requirement | Gas Distribution Main Requirement | Gas Transmission Line Requirement |
|---|---|---|
| §192.105 Design formula for steel pipe | Distribution main must be designed to operate at pressures that produce stress levels less than 20% SMYS | Transmission lines can be designed to operate at pressures that create stress levels up to 72% SMYS in Class 1 locations, 60% SMYS in Class 2 locations, 50% SMYS in Class 3 locations and 40% SMYS in Class 4 locations |
| §192.150 Passage of internal inspection devices | There is no requirement for design to accommodate passage of internal inspection devices (e.g. in-line inspection (ILI) tools or "smart pigs") | New and replacement sections of transmission lines must be designed to accommodate internal inspection devices (ILI tools) |
| §192.179-Transmission/ §192.181 Distribution Valve Spacing | No specific valve spacing requirement | Each point in Class 4 locations must be w/in 2 ½ miles of block valve, Class 3 locations must be w/in 4 miles of block valve |
| §192.935(c) Automatic or Remote Valves (ASVs & RCVs) | No regulatory requirement to consider or install ASVs or RCVs | Operator to determine if an ASV or RCV would be an efficient means of adding protection |
| §192.241/ §192.243 Inspection & testing of welds | Non-destructive testing ("x-ray") not required for pipelines with operating pressure that produces a stress level less than 20% SMYS | Girth welds on pipelines with pressure that produces stress level greater than or equal to 20% SMYS must be "x-rayed". In Class 3 & 4 locations, 100% of welds must be inspected unless impracticable, but at least 90% |
| §192.233 Miter joints | Distribution lines with pressure that produces stress level at less than 20.0 % SMYS, but greater than 10% SMYS may have miter joints up to 12 1/2 degrees of misalignment | Transmission lines with pressure that produces stress level of 30% or more of SMYS may not deflect pipe more than 3 degrees of misalignment |
| 192.327 Depth of cover | Each buried main must be installed with at least 24" of cover | Transmission lines must be installed with a minimum 36" depth of cover in normal soil in Class 2, 3 & 4 locations |
| 192.505/ 192.619 **Test requirements.** Testing for hoop stress of 30% or more of SMYS | **N/A- See below** | Lines w/ hoop stress level of 30% or more must be strength tested for at least 8 hours at 1.50 x MAOP in Class 3 or 4 locations |
| 192.507/ 192.619 **Test requirements.** Testing for hoop stress less than 30% SMYS but greater than 100 psi operating pressure | Distribution lines must be leak tested to ensure discovery of all potentially hazardous leaks at 1.5 x MAOP. Test duration not specified | Lines w/ hoop stress level of greater than or equal to 20% SMYS and less than 30% SMYS must be leak tested to ensure discovery of all potentially hazardous leaks at 1.5 x MAOP. Test duration at least one hour. |

**Q. PLEASE DESCRIBE THE MAJOR DIFFERENCES BETWEEN THE REQUIREMENTS FOR ROUTINE INSPECTIONS OF GAS TRANSMISSION PIPELINES AND GAS DISTRIBUTION PIPELINES.**

A. After the initial pipeline construction and pressure testing, Federal pipeline safety regulations require operators of gas transmission pipelines and gas distribution pipelines to have comprehensive written policies and procedures to conduct ongoing operation and maintenance inspections of pipelines to provide ongoing protection throughout the life of the pipelines.

Major differences between the requirements for routine inspections of gas transmission pipelines compared to gas distribution pipelines are summarized in Table 2 below:

**Table 2**

| | Distribution pipelines | Transmission pipelines |
|---|---|---|
| **Pipeline Patrolling** | §192.721- Limited to mains in places or on structures where anticipated physical movement or loading could cause failure or leakage. For those locations, in business districts, the pipeline must be patrolled four times each calendar year, but not more than 4 ½ months between patrols. Outside business districts, the pipeline must be patrolled two times each calendar year, but not more than 7 ½ months between patrols. | §192.705- In Class 3 locations (e.g. subdivisions)- the pipeline must be patrolled two times each calendar year, but not more than 7 ½ months between patrols. In Class 4 locations (e.g. areas where four-story buildings are prevalent) – the pipeline must be patrolled four times each calendar year, but not more than 4 ½ months between patrols. |
| **Leakage Surveys** | §192.723- Pipelines in Business Districts- The pipeline must be surveyed once each calendar year, but not more than 15 months between surveys; outside Business Districts, pipelines must be surveyed once every five calendar years, not more than 63 months between surveys for coated, cathodically protected pipelines. | §192.706- In Class 3 locations- The pipeline must be surveyed two times each calendar year, but not more than 7 ½ months between surveys. In Class 4 locations – the pipeline must be surveyed four time each calendar year, but not more than 4 ½ months between surveys. |
| **Line Markers** | §192.707- Not required in Class 3 and 4 locations where a damage prevention program is in effect. | §192.707 Wherever necessary to identify the location of the line to reduce the possibility of damage or interference. |

**Q. ARE THERE ANY FEDERAL REQUIREMENTS FOR MANAGING THE INTEGRITY OF GAS TRANSMISSION PIPELINES?**

A. Yes. On December 15, 2003, the US Department of Transportation (DOT), PHMSA issued the Final Rule for the integrity management of gas transmission pipelines as mandated by Congress in the 2002 Pipeline Safety Reauthorization. 49 CFR, Part 192, Subpart O *Gas Transmission Pipeline Integrity Management* prescribes the minimum requirements for an integrity management program for gas transmission pipelines.

The Gas Transmission Integrity Management Program (TIMP) Rule required transmission pipeline operators to develop and follow a written integrity management program by December 17, 2004. In simple terms, the gas transmission TIMP Rule requires operators to calculate the "potential impact radius" (PIR) and use the PIR to identify areas where High Consequence Areas (HCAs) are located on a transmission pipeline. The pipeline segments associated with these HCAs are referred to as "covered pipeline segments." Operators must evaluate threats to covered pipeline segment and conduct assessments at least once every seven calendar years to assess and evaluate the integrity of the covered pipeline segments.

**Q. ARE THERE ANY FEDERAL REQUIREMENTS FOR MANAGING THE INTEGRITY OF GAS DISTRIBUTION LINES?**

A. Yes. In March 2005 work began on a study to inform the promulgation of the Distribution Integrity Management Program (DIMP) Regulation. The PHMSA Integrity Management for Gas Distribution, Report of Phase 1 Investigations was authored by a broad range of stakeholders, including representatives from PHMSA

(Federal regulators), National Association of Pipeline Safety Representatives (NAPSR- State regulators), natural gas operators, and the public (National Fire Protection Association (NFPA) and National Association of State Fire Marshals (NASFM)). The Phase 1 Report informed PHMSA and provided the framework for the promulgation of the DIMP regulation. The investigations in the Phase 1 Report were conducted by four multi-stakeholder groups: Strategic Options Group, Risk Control Practices Group, Excavation Damage Prevention Group and Data Group. I served as a member of the Excavation Damage Prevention Group.

On December 4, 2009, PHMSA issued the Final Rule for the Gas DIMP Regulation. 49 CFR, Part 192, Subpart P *Distribution Pipeline Integrity Management (IM)* prescribes the minimum requirements for an IM program for any gas distribution pipeline covered under Part 192. In simple terms, the Distribution IM Rule requires operators to develop and implement a written integrity management plan to manage the integrity of their distribution systems using the following elements:

(a) Knowledge

(b) Identify Threats

(c) Evaluate and rank risk

(d) Identify and implement measures to address risk

(e) Measure performance, monitor results, and evaluate effectiveness

(f) Periodic Evaluation and improvement

(g) Report results

**Q. IN THE RESPONSE TO THE QUESTION ABOVE, YOU MENTIONED THAT THE FEDERAL GAS TRANSMISSION INTEGRITY MANAGEMENT REGULATION REQUIRES OPERATORS OF TRANSMISSION LINES TO CALCULATE THE PIR AND IDENTIFY HCAS. WHY IS THE PIR NOT RELEVANT FOR THE CENTRAL CORRIDOR PIPELINE PROJECT?**

A. The PIR is not relevant for the Central Corridor Pipeline Project because the Central Corridor Pipeline is a distribution pipeline as noted earlier in my testimony. In the PHMSA Phase 1 Report, which formed the foundation of the distribution pipeline Integrity Management Rule, the participants noted that:

> *...distribution pipeline failures almost always involve leaks, rather than ruptures, because the internal gas pressure is much lower than for transmission lines.*[12]

In addition, as previously noted in my testimony, the participants in the American Gas Foundation Study concluded that:

> *Distribution pipeline incidents typically result in a leak, not a rupture, due to the relatively low operating pressures, and correspondingly lower operating stress in the pipe, in distribution systems.*[13]

Because the PHMSA Report of Phase 1 Investigations and the American Gas Foundation Study both acknowledged that the likelihood of a rupture in a distribution pipeline is extremely remote (because distribution pipelines operate at

---

[12] "Integrity Management for Gas Distribution, Report of Phase 1 Investigations," December 2005, Executive Summary at page 4.

[13] American Gas Foundation, "Safety Performance and Integrity of the Natural Gas Distribution Infrastructure," January 2005 at page 3-6.

lower operating pressures and lower stress levels than transmission pipelines), in the Distribution Integrity Management Program Regulation, PHMSA does not require operators to calculate PIRs and identify HCAs for distribution lines. Therefore, the PIR is not a relevant factor for the Central Corridor Pipeline Project.

In addition, it is also important to recognize that the DIMP Regulation requires gas distribution pipeline operators such as Duke Energy Ohio to have a DIMP Program to manage the integrity of all of the Company's distribution pipe system.

**Q. BASED ON YOUR EXPERT KNOWLEDGE OF THE FEDERAL PIPELINE SAFETY REGULATIONS, DO YOU BELIEVE THAT DUKE ENERGY OHIO'S PLANS FOR THE DESIGN, CONSTRUCTION, OPERATION AND MAINTENANCE OF THE CENTRAL CORRIDOR PIPELINE PROJECT COMPLY WITH THE FEDERAL PIPELINE SAFETY REGULATIONS CONTAINED IN PART 192?**

A. Yes. In fact, based on my discussions with Duke Energy Ohio personnel responsible for the Central Corridor Pipeline Project, it is my expert opinion that the Company's plans for the Central Corridor Pipeline regarding the design, construction, post-construction testing and in-line inspection, operations, maintenance and integrity management activities not only comply with Federal regulations contained in Part 192, but that the Company's plans for the Central Corridor Pipeline greatly exceed the regulatory requirements for a natural gas distribution pipeline as mandated by Part 192.

## IV. EVALUATION OF NATURAL GAS PIPELINE SAFETY AND RECENT PIPELINE ACCIDENTS IN THE UNITED STATES

**Q. CAN YOU DISCUSS THE OVERALL SAFETY OF NATURAL GAS TRANSMISSION PIPELINES AND NATURAL GAS DISTRIBUTION LINES?**

A. Yes. Natural gas transmission pipelines and distribution pipelines are a very safe, reliable and efficient means to transport large quantities of energy to serve the needs of the nation. According to the AGA website, the nation's natural gas piping system includes over 2.5 million miles of natural gas pipelines, including 300,000 miles of natural gas transmission pipelines and 2.2 million miles of natural gas distribution pipelines. These natural gas pipelines serve the heating, water heating, cooking, process and power generation needs of the nation's 75 million residential, commercial and industrial natural gas customers.

As mentioned earlier in my testimony, 49 CFR, Part 192 defines the minimum requirements pertaining to acceptable pipeline materials, pipeline design, construction, inspection and post-construction pressure testing to ensure that a new natural gas pipeline has been designed and constructed appropriately. And after a pipeline is constructed, there are ongoing regulatory requirements to ensure the continued safety and reliability of the pipeline. Part 192 includes detailed requirements regarding corrosion control (to prevent "rusting" of buried metallic pipelines), operation, maintenance, personnel qualification and integrity management of natural gas transmission and distribution pipelines. The design and construction requirements combined with the ongoing operations, maintenance and integrity management requirements mandated to be conducted after the pipeline is put into service ensure the continued long-term safety of the pipeline.

Newly promulgated pipeline safety regulations have provided additional safety focused on the long-term integrity management of the natural gas pipeline infrastructure. Since 2000, PHMSA has issued significant new regulations to improve overall pipeline safety, including:

- Transmission Integrity Management Rule[14]- Prescribes the minimum requirements for an integrity management program on any gas transmission pipeline covered under Part 192.
- Distribution Integrity Management Rule[15]- Prescribes the minimum requirements for an integrity management program for any gas distribution pipeline covered under Part 192.

In simple terms, the Transmission Integrity Management Rule and Distribution Integrity Management Rule require pipeline operators to evaluate applicable pipeline segments and take necessary actions to ensure the ongoing safety and integrity of the pipelines. The TIMP Rule and the DIMP Rule have demonstrated substantial benefits to pipeline safety.

But pipeline safety doesn't end with the Part 192 regulations. While Part 192 provides the minimum Federal safety requirements pertaining to the design, construction, operation, maintenance, personnel qualifications and integrity management of natural gas pipelines, operators such as Duke Energy Ohio

---

[14] 49 CFR, Part 192, Subpart O, "Gas Transmission Pipeline Integrity Management", 68 Federal Register, 69817, December 15, 2003

[15] 49 CFR, Part 192, Subpart P, "Gas Distribution Pipeline Integrity Management (IM)", 74 Federal Register, 63934, December 4, 2009

voluntarily take additional actions beyond the requirements of Part 192 to further improve the safety of their pipeline systems. Examples of these additional actions include, but are not limited, to the following;

- Designing and constructing pipelines with thicker and stronger pipe than required by Code;
- Conducting operation and maintenance tasks more frequently than required by Code;
- Implementing aggressive replacement programs of older pipeline infrastructure (such as cast iron or bare steel pipe) with modern materials such as polyethylene plastic;
- Participation in industry "Best Practices" forums to identify and implement creative new practices or approaches to pipeline safety; and
- Participation in industry "Peer-to-Peer Reviews" to identify opportunities for pipeline safety improvements.

In addition, Federal and State regulators perform a valuable role in pipeline safety by overseeing operator's pipeline safety programs. Federal pipeline safety laws provide PHMSA with the authority to oversee the safety of the nation's pipeline infrastructure. And almost all States (with the exception of Alaska and Hawaii) have agreements with PHMSA to oversee and regulate the safety of the State's intrastate pipeline facilities. Federal and State regulators provide significant oversight and an additional layer of safety by conducting periodic inspections of operator's Pipeline Safety Programs to ensure compliance with Federal and applicable State pipeline safety regulations.

Statistical data strongly supports the fact that natural gas pipelines are a very safe method to transport energy to end use customers and getting safer over time. According to the AGA website:

> *"Natural gas utilities spend $22 billion annually to help enhance the safety of natural gas distribution and transmission systems. U.S. Department of Transportation data shows a continual downward trend in pipeline incidents of approximately 10 percent every three years. The dedicated efforts of natural gas utilities have led to an approximately 50 percent decline in pipeline incidents over the past 30 years: this safe industry continues to get safer."* [16]

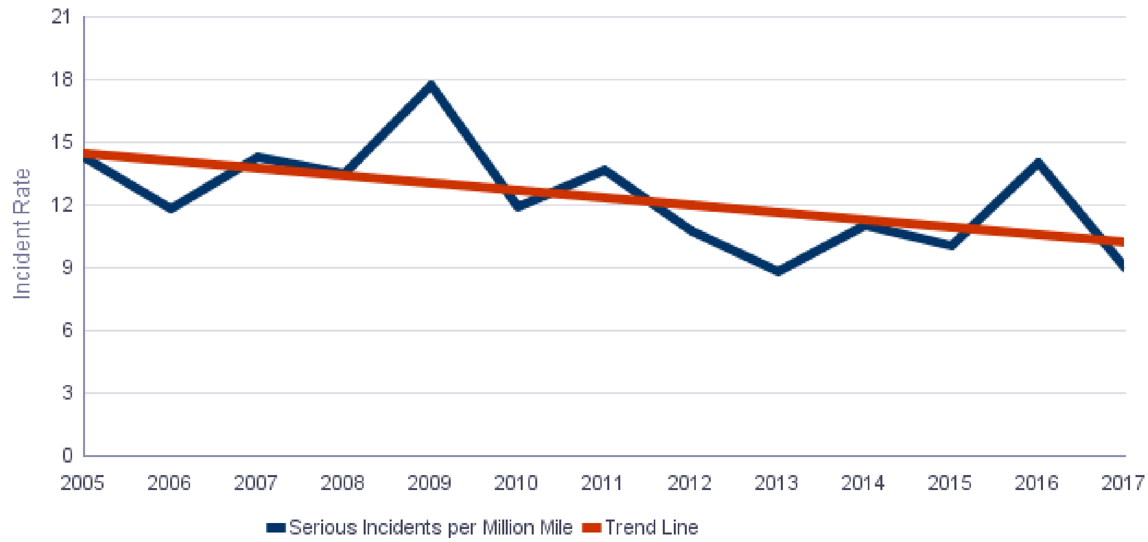
The continued improvement in natural gas pipeline safety is further supported by pipeline safety statistics provided by the U.S. Department of Transportation, PHMSA. Based on PHMSA's data and statistics provided on PHMSA's website, the normalized rate of serious incidents[17] (serious incidents/ million miles of pipeline) for natural gas distribution pipelines has decreased 34% from 2005-2017. This improvement in pipeline safety is shown graphically in Figure 1 below.

---

[16] https://www.aga.org/natural-gas/safe/enhancing-safety/

[17] PHMSA defines a serious incident as an incident that results in a fatality or injury requiring in-patient hospitalization.

Figure 1




**Q. CAN YOU EXPLAIN THE DIFFERENCES BETWEEN A LIQUIDS PIPELINE, A NATURAL GAS TRANSMISSION PIPELINE AND A NATURAL GAS DISTRIBUTION PIPELINE?**

A. Yes. There are significant differences between a liquids pipeline, a natural gas transmission pipeline and a natural gas distribution pipeline. The differences are summarized by the following general characteristics:

(1) Configurations;

(2) Piping materials;

(3) Pipeline operating pressures and operating stress levels;

(4) Locations; and

(5) Typical problem behaviors.

The differences between a liquids pipeline, a natural gas transmission pipeline and a natural gas distribution pipeline are detailed as follows:

Liquids pipelines are typically very long pipelines (interstate liquids pipelines) that transport liquids such as crude oil and refined products such as aviation fuel and gasoline. The liquids transported by these pipelines are "non-compressible fluids" which means the volume cannot be compressed regardless of the operating pressures. Liquids pipelines are typically constructed of steel, are larger diameter (8-inch and larger), operate at very high pressures (600 - 2,000 psi) and very high stress levels (up to 72 percent of SMYS or higher). Liquids pipelines are generally located in sparsely populated areas that have a small number of buildings intended for human occupancy. In the event of a release from a liquids pipeline, the product is generally discharged onto the ground and may present an environmental issue that requires environmental remediation.

Natural gas transmission pipelines are also typically very long pipelines (interstate natural gas pipelines) that transport natural gas from production or storage locations to cities and towns. The natural gas is a "compressible fluid" since the volume can be compressed and reduced under pressure. Gas transmission pipelines are almost always constructed of steel, are larger diameter (6-inch and larger), operate at very high pressures (600 psi - 2,000 psi) and very high stress levels (up to 72 percent of SMYS or higher). Gas transmission lines are generally located in sparsely populated areas (*e.g.* farmland and forests) that have a small number of buildings intended for human occupancy. These sparsely populated locations are defined as Class 1 and Class 2 locations in Part 192. In the event of a release from a natural gas transmission pipeline, the natural gas will typically dissipate into the atmosphere.

Natural gas distribution pipelines are very different from natural gas transmission pipelines. Gas distribution pipelines typically start at City Gate Stations (or other downstream regulator stations) and continue to the meter set located at the customer's home or business. Modern natural gas distribution pipelines are constructed of coated steel pipe, with a corrosion protection system to prevent corrosion ("rusting"), or polyethylene plastic that is not subject to corrosion. Distribution pipelines are smaller in diameter (1/2-inch diameter up to approximately 24-inch in diameter) and operate at much lower pressures (1/4 psi - 600 psi) and much lower stress levels (less than 20 percent of SMYS) than transmission pipelines. Since distribution pipelines operate at much lower stress levels, they inherently have a much higher factor of safety. Since gas distribution lines deliver the natural gas to end use customers, they are located in city streets and on every natural gas customer's property up to the house or business. These more populated locations are defined as Class 3 locations (*e.g.* subdivisions) and Class 4 locations (*e.g.* downtown) in Part 192. In the event of a release from a natural gas distribution pipeline, the natural gas will almost always result in a leak that dissipates into the atmosphere.

**Q. IN THE EVENT OF A PROBLEM WITH A NATURAL GAS PIPELINE, DO TRANSMISSION LINES AND DISTRIBUTION LINES BEHAVE THE SAME?**

A. No. It is important to recognize that it is highly unlikely that there will be a problem with a new natural gas transmission pipeline or new natural gas distribution pipeline constructed in accordance with current Part 192 regulations using modern materials, current construction techniques, and operated and maintained in accordance with Federal pipeline safety regulations.

However, in the highly unlikely event of a problem with a natural gas pipeline, gas transmission lines and gas distribution lines have significantly different failure mechanisms. Transmission pipelines generally operate at much higher operating pressures and at a much higher stress level and percent of SMYS (greater than or equal to 20 percent SMYS up to 72 percent of SMYS) than distribution lines, which are required by Code to operate at less than 20 percent of SMYS. As noted in my testimony above, the regulatory and industry experts involved in both the American Gas Foundation Study and the PHMSA Phase 1 Report concluded that any problems with a gas distribution pipeline will likely result in a leak, not a rupture.

In the unlikely event of a problem with a natural gas transmission pipeline operating between 20 percent SMYS and 30 percent SMYS, the pipeline may either experience a leak or a rupture. Transmission pipelines that operate at greater than 30 percent SMYS are more likely to experience a rupture while pipelines that operate at less than 30 SMYS are more likely to experience a leak.

In the unlikely event of a problem with a distribution pipeline, which by definition must operate at less than 20 percent of SMYS, the distribution pipeline almost always experience a leak, not a rupture. Since Part 192 requires all distribution pipelines to operate at a MAOP of less than 20% SMYS, it is virtually impossible for a distribution pipeline to experience a rupture.

Since any problems with a distribution pipeline are extremely likely to result in a leak, the leak will be detected by instrumented leak investigations required by Part 192, or by the odor injected into the natural gas pipeline. Federal pipeline safety regulations require operators to inject a pipeline odorant into the gas system to alert operating personnel and the public of the existence of any leak so it may be detected, evaluated and repaired before it can cause a safety issue.

**Q. THERE WAS A NATURAL GAS PIPELINE ACCIDENT IN SAN BRUNO, CALIFORNIA ON SEPTEMBER 9, 2010. CAN YOU SUMMARIZE THE FACTS ASSOCIATED WITH THE SAN BRUNO ACCIDENT AND EXPLAIN THE DIFFERENCES BETWEEN THE PIPELINE INVOLVED IN THE SAN BRUNO ACCIDENT AND THE CENTRAL CORRIDOR PIPELINE PROJECT?**

A. Yes. The pipeline involved in the San Bruno accident was a gas transmission pipeline. The original pipeline was installed in 1948. The section that failed was relocated in 1956. The pipeline was a 30-inch diameter line with a Maximum Allowable Operating Pressure (MAOP) that was based on the "Grandfather Clause" (§192.619(c))[18] when the original Federal pipeline safety regulations (49 CFR, Part 192) were promulgated in 1970. An MAOP based on the Grandfather Clause typically means that the operator is unable to locate complete documentation of original pipeline material records and/ or a post-construction pressure test. With the exception of the 28-foot section of the pipeline that failed, the pipeline was

[18] In the original 49 CFR, Part 192 regulation (issued August 1970) the "Grandfather clause" allowed operators to establish the Maximum Allowable Operating Pressure based on the highest recorded operating pressure in the five years preceding July 1, 1970

constructed of 0.375-inch wall thickness, American Petroleum Institute (API) 5L X-52 grade (52,000 psi yield strength) steel pipe to the north of the accident site and 0.312-inch wall thickness, API 5L X-52 grade pipe to the south of the accident site. The 0.312-inch thick portion of the pipeline to the south of the accident site operated at a stress level of up to 37 percent of SMYS.

The failed section of the pipeline was 28 feet long and was originally constructed in 1956 from six pipe "pups" (short sections of pipe), ranging in length from 3.5-4.7 feet in length. The long seam weld on the inside diameter (ID) of one of the pipe pups was not welded completely. In addition, the material properties (yield strength) of some of the pups did not meet the operator's specifications for the pipeline or industry specifications for pipeline material at the time of construction. This type of defect is typically referred to as a "manufacturing and construction defect." On September 9, 2010, the incorrectly welded pipeline segment failed, resulting in a pipeline rupture and ignition. Based on the effective weld area of the pups, and the pipe material properties, the short sections of pipe operated at approximately 100% SMYS or higher. This is beyond the design specifications of the pipe material and current Federal pipeline safety regulations.

The National Transportation Safety Board (NTSB) investigated the San Bruno Accident.[19] The NTSB identified the Probable Cause of the accident as follows:

[19] NTSB Accident Report NTSB/PAR-11/01, PB2011-916501, Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire, San Bruno, California, September 9, 2010

*Probable Cause*

*The National Transportation Safety Board determines that the probable cause of the accident was the Pacific Gas and Electric Company's (PG&E) (1) inadequate quality assurance and quality control in 1956 during its Line 132 relocation project, which allowed the installation of a substandard and poorly welded pipe section with a visible seam weld flaw that, over time grew to a critical size, causing the pipeline to rupture during a pressure increase stemming from poorly planned electrical work at the Milpitas Terminal; and (2) inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section.*

*Contributing to the accident were the California Public Utilities Commission's (CPUC) and the U.S. Department of Transportation's exemptions of existing pipelines from the regulatory requirement for pressure testing, which likely would have detected the installation defects. Also contributing to the accident was the CPUC's failure to detect the inadequacies of PG&E's pipeline integrity management program.*

*Contributing to the severity of the accident were the lack of either automatic shutoff valves or remote-control valves on the line and PG&E's flawed emergency response procedures and delay in isolating the rupture to stop the flow of gas.*

There are significant differences between the pipeline involved in the San Bruno accident and the Central Corridor Pipeline Project which are detailed as follows:

(1) The San Bruno Pipeline was installed in 1948 and relocated in 1956, prior to the promulgation of the first Federal pipeline safety regulation in 1970. The MAOP of the San Bruno transmission pipeline was based on the “Grandfather Clause”. The Central Corridor Pipeline will be designed, constructed, operated and maintained, and integrity managed in full compliance with the requirements of Part 192.

(2) The San Bruno Pipeline was a gas transmission line operating at up to 37 percent SMYS (37 percent of yield strength) for much of the pipeline. Conversely, the Central Corridor Pipeline will be a distribution pipeline that will operate at a maximum stress level of 19.0 percent SMYS at MAOP.

(3) The San Bruno Pipeline was not subjected to a post-construction hydro-static pressure/ strength test to establish MAOP and detect “manufacturing and construction defects”, such as the defective weld seam on the short pipe section that failed. The Central Corridor Pipeline will be subjected to a post-construction hydro-static pressure/ strength test of at least 150% of MAOP. The pressure that will be applied to the Central Corridor Pipeline is far greater than the pipeline will experience at any time in its service life and ensures that no critical manufacturing and/or construction defects remain in the pipeline when it is placed in service.

(4) The defective pipe pup in the San Bruno pipeline operated at approximately 100 percent SMYS. The Central Corridor project is designed to operate at a maximum of 19.0 percent of SMYS and will have a comprehensive Quality Assurance Plan to ensure the quality of all pipe and related appurtenances that will be installed during construction of the pipeline, resulting in Traceable, Verifiable and Complete material records and construction records that document conformance with design specifications.

(5) After construction, the San Bruno Pipeline was never subjected to inspection by an in-line inspection tool (ILI or "smart pig"). Although the Federal pipeline safety regulations and Distribution Integrity Management Program Regulation does not require that operators inspect distribution lines using in-line inspection (ILI) tools, Duke Energy Ohio will voluntarily inspect the Central Corridor Pipeline using smart pigs to assess and evaluate the integrity of the pipeline.

(6) The San Bruno Pipeline did not include any automated, sectionalizing shut-off valves to accelerate timely pipeline shut-down. Although the Federal pipeline safety regulations do not require operators of distribution lines to evaluate or install Automatic Shut-off Valves (ASVs) or Remote-Control Valves (RCVs), Duke Energy has voluntarily elected to install RCVs on the proposed Central Corridor Pipeline. In the highly unlikely event of

a problem with the Central Corridor Pipeline, these RCVs will allow the Duke Energy Ohio Gas Control Room to close the valves rapidly to shut off the flow of gas. The Gas Control Room will have remote telemetry sensors on the pipeline to monitor pipeline operating pressures and flow conditions 24 hours per day/ 7 days per week.

**Q. THERE WAS ALSO A CRUDE OIL PIPELINE ACCIDENT IN MARSHALL, MICHIGAN ON JULY 25, 2010 THAT RELEASED OIL INTO THE ENVIRONMENT. CAN YOU PLEASE EXPLAIN THE FACTS OF THE MARSHALL, MICHIGAN PIPELINE ACCIDENT AND CONTRAST THE DIFFERENCES BETWEEN THE PIPELINE INVOLVED IN THAT ACCIDENT AND THE CENTRAL CORRIDOR PIPELINE EXTENSION PROJECT?**

A. Yes. On July 25, 2010, a 30-inch liquids pipeline carrying crude oil ruptured in Marshall, Michigan and released approximately 844,000 gallons of crude oil into the surrounding wetlands and the Kalamazoo River. There was no ignition and no injuries or fatalities, but there was environmental damage from the release of crude oil and environmental remediation required. The pipeline was constructed in 1969 using 0.250 wall thickness, API 5L X-52 steel pipe (52,000 psi yield strength). The Maximum Operating Pressure (MOP) of the pipeline was 624 pounds per square inch (psi). The pressure at 100% SMYS was 867 psi. At MOP, the pipeline operated at a very high stress level (72 percent of SMYS).

The National Transportation Safety Board (NTSB) investigated the Marshall Michigan incident and issued the Accident Report on July 10, 2012.[20]

The NTSB identified the Probable Cause of the accident as follows:

> *The National Transportation Safety Board (NTSB) determines that the probable cause of the pipeline rupture was corrosion fatigue cracks that grew and coalesced from crack and corrosion defects under disbonded polyethylene tape coating, producing a substantial crude oil release that went undetected by the control center for over 17 hours. The rupture and prolonged release were made possible by pervasive organizational failures at Enbridge Incorporated (Enbridge) that included the following:*
>
> - *Deficient integrity management procedures, which allowed well-documented crack defects in corroded areas to propagate until the pipeline failed.*
> - *Inadequate training of control center personnel, which allowed the rupture to remain undetected for 17 hours and through two startups of the pipeline.*
> - *Insufficient public awareness and education, which allowed the release to continue for nearly 14 hours after the first notification of an odor to local emergency response agencies.*
>
> *Contributing to the accident was the Pipeline and Hazardous Materials Safety Administration's (PHMSA) weak regulation for assessing and repairing crack indications, as well as PHMSA's ineffective oversight*

[20] NTSB Accident Report NTSB/PAR-12/01, PB2012-916501, Enbridge Incorporated, Hazardous Liquid Pipeline Rupture and Release, Marshall, Michigan, July 25, 2010.

*of pipeline integrity management programs, control center procedures, and public awareness.*

*Contributing to the severity of the environmental consequences were (1) Enbridge's failure to identify and ensure the availability of well-trained emergency responders with sufficient response resources, (2) PHMSA's lack of regulatory guidance for pipeline facility response planning, and (3) PHMSA's limited oversight of pipeline emergency preparedness that led to the approval of a deficient facility response plan.*

There are significant differences between the liquids pipeline involved in the Marshall, Michigan pipeline accident and the proposed Central Corridor Pipeline Project, which are detailed as follows:

(1) The Marshall, Michigan pipeline was a liquids pipeline that transported crude oil which is an "incompressible fluids". Liquids pipelines are much more susceptible to cyclic fatigue and cracking. The proposed Central Corridor Pipeline will transport natural gas which is a compressible fluid. The Central Corridor Pipeline is generally not subject to cyclic fatigue stresses.

(2) A critical NTSB finding associated with the Marshall, Michigan pipeline failure was "corrosion fatigue cracks that grew and coalesced from crack and corrosion defects under disbonded polyethylene tape coating." The Central Corridor Pipeline will have Fusion Bond Epoxy (FBE) coating installed on the pipe. FBE coating has been the state-of-the-art pipeline coating for many years

and is vastly superior to polyethylene tape coating relative to pipe adhesion and corrosion protection properties.

(3) The Marshall, Michigan Pipeline was a liquids transmission line that operated at a very high stress level (up to 72 percent of SMYS). Conversely, the Central Corridor Pipeline is a natural gas distribution pipeline that will operate at much lower pressures and at a relatively low stress level (19.0 percent of SMYS). Therefore, the Central Corridor Pipeline will operate with a much higher factor of safety than the Marshall, Michigan pipeline.

(4) Because the Marshall, Michigan pipeline was a liquids transmission pipeline that operated at a high stress level, when the problem occurred the pipeline was susceptible to a rupture. Conversely, in the highly unlikely event of a problem with the Central Corridor Pipeline, it will very likely result in a leak that can be detected, evaluated and repaired as necessary with no harm to people, property or the environment.

## V. <u>CENTRAL CORRIDOR ENHANCED SAFETY CRITERIA</u>

**Q. HAVE YOU REVIEWED THE DESIGN, CONSTRUCTION, OPERATION AND ASSESSMENT CRITERIA THAT DUKE ENERGY OHIO HAS APPLIED TO THE PROPOSED CENTRAL CORRIDOR PROJECT.**

A. Yes. Duke Energy Ohio will apply several enhanced criteria that goes above and beyond Federal pipeline safety regulatory requirements in order to ensure the long-term safety and reliability of the Central Corridor pipeline. For example, the Central Corridor will be constructed of pipe having a wall thickness equal or greater than

0.438 inches.  Although the Central Corridor pipeline is a distribution line, this wall thickness design is more than twice the wall thickness required for a transmission line in a Class 4 location. The Central Corridor pipeline will have shut off valves at five-mile spacings, which is consistent with the Class 4 transmission line criterion. In addition, Duke Energy Ohio designed the Central Corridor pipeline with facilities to enable in-line assessments by ILI devices. Finally, as an added protection, the proposed pipeline is designed with RCVs at the beginning and end points and also at intermediate block valve locations.

As far as enhanced construction criteria, the Company will install the pipeline at a depth of approximately 48 inches of cover. This depth is twice that required for distribution lines and a full foot deeper than required for natural gas transmission lines. During construction, the pipeline will be installed and tested in accordance with transmission line requirements, which are more stringent than distribution line requirements. This will include x-rays of pipe girth welds and inspections by qualified personnel.

Duke Energy Ohio also will perform hydro-static pressure testing, consistent with transmission line requirements after installing the pipe in the ditch. The pipeline will be strength-tested for a minimum of eight hours at a minimum pressure of 1.5 times the MAOP.

Finally, Duke Energy Ohio will perform an in-line assessment utilizing an ILI device prior to placing the pipeline in service, then again within ten years, and then every seven years thereafter.

**Q. WHAT IS YOUR OPINION REGARDING THE DESIGN, CONSTRUCTION AND PROPOSED OPERATION OF THE PROPOSED PIPELINE?**

A. The proposed pipeline demonstrates Duke Energy Ohio's commitment to provide safe and reliable natural gas services to its customers. The Company has gone above and beyond the Federal regulatory requirements for a gas distribution pipeline and designed this pipeline system with safety as a priority. This commitment to safety is clear from my discussion with Company personnel regarding the overall design, the selection of high quality pipeline materials, the construction plan, x-ray inspections, enhanced pressure testing, lower operating pressure, low operating stress and low percent of SMYS, and the commitment to conduct integrity inspections using ILI tools in the future. All of these factors contribute to my expert opinion that the proposed pipeline will be a safe and reliable replacement for the propane-air facilities and will provide essential system supply flexibility for the life of the pipeline.

## VI. CONCLUSION

**Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?**

A. Yes.