FILED
July 18, 2022
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) APPROVAL OF AND A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR A FEDERALLY MANDATED PIPELINE SAFETY III COMPLIANCE PLAN; (2) AUTHORITY TO RECOVER FEDERALLY MANDATED COSTS INCURRED IN CONNECTION WITH THE PIPELINE SAFETY III COMPLIANCE PLAN; (3) APPROVAL OF THE ESTIMATED FEDERALLY MANDATED COSTS ASSOCIATED WITH THE PIPELINE SAFETY III COMPLIANCE PLAN; (4) AUTHORITY FOR THE TIMELY RECOVERY OF 80% OF THE FEDERALLY MANDATED COSTS THROUGH RIDER 190 - FEDERALLY MANDATED COST ADJUSTMENT RIDER ("FMCA) MECHANISM"); (5) AUTHORITY TO DEFER 20% OF THE FEDERALLY MANDATED COSTS FOR RECOVERY IN NIPSCO'S NEXT GENERAL RATE CASE; (6) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT; (7) APPROVAL TO DEPRECIATE THE PIPELINE SAFETY III COMPLIANCE PLAN ACCORDING TO NIPSCO'S COMMISSION APPROVED DEPRECIATION RATES; AND (8) APPROVAL OF ONGOING REVIEW OF THE PIPELINE SAFETY III COMPLIANCE PLAN; ALL PURSUANT TO IND. CODE § 8-1-8.4-1 ET SEQ., § 8-1-2-19, § 8-1-2-23, AND § 8-1-2-42; AND, TO THE EXTENT NECESSARY, APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6	)	CAUSE NO. 45703

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR'S

PUBLIC'S EXHIBIT NO. 2 –PUBLIC (REDACTED) TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER

July 18, 2022

Respectfully submitted,

Jeffrey M. Reed
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NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
CAUSE NO. 45703
PUBLIC (REDACTED) TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER

NOTE: [redacted] INDICATES CONFIDENTIAL INFORMATION

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Brien R. Krieger and my business address is 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a utility analyst in the Natural Gas Division. For a summary of my educational and professional experience and general preparation for this case, please see Appendix BRK-1.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to evaluate if Northern Indiana Public Service Company LLC's ("NIPSCO" or "Petitioner") case-in-chief for its Pipeline Safety Compliance Plan III ("Plan III") satisfies Indiana Utility Regulatory Commission ("Commission") requirements to receive a Certificate of Public Convenience and Necessity ("CPCN"). Plan III must contain federally mandated compliance projects as defined under Ind. Code § 8-1-8.4-2, and specifically, Plan III must allow NIPSCO to comply directly or indirectly with Pipeline and Hazardous Materials Safety Administration standards ("PHMSA Rules").

I present my review and analysis for the twenty-two capital projects and the seven Operations & Maintenance ("O&M") projects contained within Plan III.

Some proposed projects are a continuation of prior approved Federally Mandated Compliance Adjustment ("FMCA") Projects in Petitioner's Compliance Plan II, Cause No. 45560 (Order dated December 1, 2021.) Because of specific project continuations, Petitioner removed approved estimates from three projects (PSCP1, PSCP2, and PSCP9) from Cause No. 45560 FMCA-1 and included similar estimates in proposed projects in Cause No. 45703.

Q: What are your recommendations for Plan III?

A: I recommend:

1. the Commission not allow O&M Project PSCP3-29 Repair Grade 3 Leaks as a federally mandated project because Petitioner has existing O&M expenses to repair leaks in base rates and Pipeline Hazardous Materials Safety Administration ("PHMSA") does not require natural gas utilities to repair or accelerate Grade 3 leak repairs; and
2. the Commission approve the remainder of Petitioner's Plan III and issue a CPCN to NIPSCO for its federally mandated compliance Plan III.

II. OVERVIEW OF NIPSCO'S PLAN III

Q: Under what Statutes did Petitioner file its case?

A: NIPSCO requests approval, through its Verified Petition for its Pipeline Safety Compliance Plan III, for a CPCN to implement Plan III, recovery of costs to implement Plan III through a cost adjustment mechanism, and deferral of unrecovered costs to implement Plan III all pursuant to Indiana Code § 8-1-8.4 and §§ 8-1-2-19, -2-23 and -2-42.

Petitioner submits its Plan III as a compliance project under Ind. Code § 8-1-8.4-2 "Compliance Project" and anticipates Plan III will allow NIPSCO to comply directly or indirectly with the PHMSA Rules. Petitioner requests recovery of federally mandated costs incurred in connection with Plan III for capital and O&M expenses. Plan III is a five-year plan, 2022 through 2026, with capital costs and O&M cost estimates.

My analysis determines whether Petitioner has met the requirements for: finding the public convenience and necessity will be served by NIPSCO receiving a CPCN for a federally mandated compliance project; the Pipeline Safety Compliance Plan is a compliance project under Ind. Code § 8-1-8.4-2; and the Pipeline Safety Compliance Plan III will allow NIPSCO to comply directly or indirectly with the PHMSA Rules. NIPSCO also requests approval of other items relating to Plan III, which are discussed in Section V., below

NIPSCO requests recovery of federally mandated costs incurred in connection with Plan III. I considered in my review and analysis if the costs incurred in connection with all Plan III project costs are federally mandated costs under Ind. Code § 8-1-8.4-4.

Q: Please provide an overview of Plan III.

A: Plan III consists of capital and O&M projects ("Compliance Projects") intended to enable the utility to comply with PHMSA Rules. Capital project costs are approximate 85% of Plan III and O&M costs are approximately 15% of Plan III. Three capital project types make up 50% of the total estimated costs: bare steel replacement, fiberglass replacements, and in-line inspection retrofits. Storage wells and underground storage risk assessments make up approximately 15% of capital projects and 25% of O&M projects. The remaining major project types are emergency valve replacements, isolated services, pipeline crossings & attachments, and leak detection projects. Plan III projects start in 2022 and end in 2026.

Q: Are there projects within NIPSCO's Plan III continued from Cause No. 45560, Plan II?

A: Yes. Three (3) Plan III projects are continued from Cause No. 45560 (Order dated December 1, 2021) and Petitioner removed the remaining cost estimates, 2022 through 2026, for these three Projects (PSCP1, PSCP2, and PSCP9) in Cause No. 45560 FMCA-1. (Petitioner's Exhibit No. 1, page 23, line 9 to page 24, line 7.) The majority of the other Plan III projects are similar in scope with cost estimates derived from project experience in Cause No. 45007 and Cause No. 45560.

Projects PSCP1 and PSCP2 are investigative well logging projects at Petitioner's underground storage facility. These two approved and initiated projects are now proposed to be specific well sites based upon requirements in the PHMSA Storage Final Rule. The proposed new projects are Project PSCP3-16 *Well Tubing and Packer Replacement Project – Trenton and Mt. Simon reservoirs* and Project PSCP3-27 *Well Integrity Evaluations – Trenton and Mt. Simon reservoirs.* (Petitioner's Exhibit No. 4, page 8, line 8 to page 9, line 1.)

Project PSCP9 is a prevention and mitigation project focusing on regulator stations. Specifically, Project PSCP9 in Cause No. 45560 was approved for investigating one measure, Station Asset and Equipment. Projects PSCP3-9 *Regulator Station Coating Transmission* and PSCP3-10 *Regulator Station Coating*

Distribution are the continued projects. (Petitioner's Exhibit No. 3, page 9, line 12 – page 12, line 3.)

There are other proposed projects similar to projects in Cause No. 45560 and Cause No. 45007 but are stand-alone projects in this Cause. The similar proposed project types are: isolated services, bare steel replacements, fiberglass replacements, and in-line inspection retrofits.

III. ANALYSIS OF PLAN III FMCA PROJECTS

Q: What support did NIPSCO provide to demonstrate Plan III is consistent with the PHMSA Rule requirements?

A: Petitioner cites specific parts of the Code of Federal Regulations – Title 49 Part 192 (the "Code") as reasons for the Plan III projects. The Code involves both prescriptive and non-prescriptive projects. The non-prescriptive projects provide the structure of on-going risk assessments, continuous improvement, and planning. PHMSA enacted 49 CFR Part 192, Subpart O that mandates creation of a Transmission Integrity Management Program ("TIMP") and 49 CFR Part 192 Subpart P that mandates creation of a Distribution Integrity Management Program ("DIMP"). Much of the planning and risk assessments were completed in Petitioner's prior approved FMCA Causes with Plan III containing specific project implementation.

Petitioner cited various parts of the Code establishing the federal requirements necessary to establish projects as FMCA projects. For example, the Emergency Valve Installation project (PSCP3-1) complies with the provisions of 49 CFR § 192.181(a). Rules 49 CFR § 192.455 and 49 CFR § 192.465 require operators to monitor corrosion on steel pipes and promptly remediate any deficiencies. The Pipeline Crossings & Attachments Replacement projects are being undertaken to comply with the provisions of 49 CFR § 192.451 through 192.461 (External Corrosion), and 49 CFR § 192.481 (Atmospheric Corrosion Control). The Storage Projects are proposed to comply with the Final Rule on Underground Storage that became effective on March 31, 2022. Petitioner included a description of the Final Rule as Attachment B to its Verified Petition. I reviewed Rule references and Petitioner's testimony for my analysis and found one proposed project (PSCP3-29) that my analysis indicates is not covered by federal mandates.

Q: Did you review and analyze Petitioner's twenty-nine (29) proposed FMCA projects.

A: Yes. I reviewed all projects. My analysis focused on Petitioner's pre-filed testimony, and Petitioner's Exhibit Nos. 1-5. I participated in project discussions between the OUCC and NIPSCO on April 21, 2022 and May 20, 2022. On June 17, NIPSCO provided a technical tour for OUCC employees which answered additional questions concerning the use of the Picarro (manufacture name) leak detection mobile unit (PSCP3-22), the fiberglass riser replacement project (PSCP3-14), and regulator station coating projects (PSCP3-9 and PSCP3-10).

For continued or similar projects, I compared Plans by reviewing Petitioner's project workpapers, project cost estimates, and explanations of projects moved forward from Cause No. 45560. I reviewed and analyzed Petitioner's responses to OUCC Data Requests ("DR"), and Petitioner's filed revisions.

Q: Please summarize your analysis of Petitioner's project explanations and project estimates.

A: Petitioner's prior explanations of similar projects from Cause No. 45560 were consistent with Plan III explanations and workpapers. The proposed project workpapers provided additional detail, as compared to Plan I and Plan II, for the 29 proposed projects. Through meetings, Petitioner answered OUCC questions adding clarity into Petitioner's rationale for proposed projects. Petitioner was responsive to OUCC questions during site visits and in the DRs. Petitioner reviewed its risk model (Synergi) results with the OUCC on May 20, 2022. In testimony, Petitioner cited specific PHMSA Rules and provided explanations for each project justification as an FMCA project.

Individual project workpapers are in Excel format and contained multiple tabs such as a summary tab, assumptions tab, material and construction costs tab, and other project costs. The assumptions and costs tabs contained estimates for items such as: feasibility studies, pre-engineering, field verifications, easements, material, internal labor, and contract labor. The assumption tab provided $/unit for the cost items, the counts to be completed, and the estimated annual completion expectations based upon assumptions such as: no environmental issues, no underground rock impediments, or no special easement requirements.

The summary tab compiled the other tabs to arrive at a base year cost and the base year cost was escalated at a 5% annual rate. Project contingency was placed on the base year cost and ranged from 0% to 30%. The highest contingency percentage is on the in-line inspection projects, PSCP3-18, PSCP3-19, PSCP3-20, and PSCP3-21.

In Petitioner's original filing, Petitioner escalated contingency on some projects. In Petitioner's Revision 2, the escalation on contingency was removed from those projects with escalated contingency. Now, none of Petitioner's projects has escalated contingency. Removing escalated contingency from the FMCA projects is consistent with a recent Commission Order not allowing escalated contingency. *In re CEI South, Cause No. 45612* (Ind. Util. Regulatory Comm'n April 20, 2022.) On page 17, the Order states: "Therefore, we find the inclusion of escalation on contingency amounts for Petitioner's Compliance Projects to be unnecessary, and it is not approved."

Q: Do you have any issues with project escalation or escalation on contingency costs handled in the workpapers and project summary tables?

A: No. Petitioner has removed all escalation on contingency.

Q: Does Petitioner's associated PHMSA designation justify each individual project.

A: Yes, except for Project PSCP3-29. I reviewed the CFRs and PHMSA Rules and conclude Plan III meets the CFR requirements, ultimately fulfilling both the TIMP Requirement – 49 CFR 192 Subpart O – Gas Transmission Pipeline Integrity Management, DIMP Requirement – 49 CFR 192 Subpart P – Gas Distribution Pipeline Integrity Management and the Final Rule on Underground Storage.

Q: What is your analysis of the detailed costs analysis?

A: The estimates were detailed and thorough. For the projects similar to or a continuation of prior approved projects, Petitioner used per unit estimates of the same magnitude as prior approved projects. This is the case for replaced services and cost per mile for bare steel for Projects PSCP3-2 Isolated Services and PSCP3-6 Bare Steel Replacement, the installed costs for Project PSCP3-14 Fiberglass Riser

Replacements, and well projects PSCP3-15 and PSCP3-16. The new stand-alone (different location) ILI projects, PSCP3-18 through PSCP3-21 were well documented. The underground storage well projects compare similarly to prior underground storage well projects, PSCP3-15 through PSCP3-17, PSCP3-23, and PSCP3-27. I found no issues with remaining projects except for Project PSCP3-29 Repair Grade 3 Leaks. The remaining proposed projects, other than PSCP3-29, deal with emergency valves, pipeline crossings and attachments, storage plant coatings, vehicle protection devices, underground natural gas storage integrity and geologic validation investigations, and advanced mobile leak detection.

Petitioner's Attachment A contains the proposed FMCA project lists and annual estimates. My assessment of PSCP3-29 Repair Grade 3 Leaks follows.

Q: Please summarize your issues concerning PSCP3-29 Repair Grade 3 Leaks.

A: Petitioner requested authorization of O&M expenses to repair all leaks, including Grade 3 leaks in pending base rates, Cause No. 45621. (Attachment BRK-2, NIPSCO Response to OUCC DR2.9, (a).) PHMSA does not set a required schedule for repairing low level emissions, i.e., non-hazardous natural gas leaks. Petitioner proposes to ramp up the repair of the Grade 3 leaks, by a factor of three and one-half times (3.5x) by 2024 over the average of Grade 3 leaks repaired over the prior four years. (Confidential Attachment BRK-5C; Petitioner's Workpaper PSCP3-29, tab Remediation.) My analysis of these issues follows.

IV. SPECIFIC ANALYSIS OF PROJECT PSCP3-29

Q: What is a Grade 3 natural gas leak?

A: A Grade 3 natural gas leak is the lowest risk category determined by Petitioner to gauge its response to known/discovered leaks. Grade 1 is the highest risk, then Grade 2, with Grade 3 being the lowest leak level. Petitioner has various Gas Standards ("GS") it practices for leak categorization and leak remediation. I reviewed two standards that apply to PSCP3-29: 1) GS 1714.010(IN) *Leakage Classification and Response*, and 2) GS 1010.014(IN) *Natural Gas Emission Reduction Plan*. (Attachment BRK-1, NIPSCO Response to OUCC DR 2.1, Attachment A NIPSCO Gas Standards.)

The first standard addresses severity of leaks and classifies leaks into Grade 1, Grade 2, and Grade 3 with Grade 1 being the most severe. Pages 1, 2, and 3 of the first gas standard contain tables with leak classification definitions and leak remediation response requirements. In part, the first GS states "Grade 3 leaks that are not cleared shall be surveyed at intervals not exceeding 15 months, but at least once each calendar year." In GS 1010.014(IN), Petitioner's gas standard states Petitioner's activity practice is: "For Grade 3 leaks, some repairs are completed within six (6) to twelve (12 months) of discovery." (Attachment BRK-1, page 8, Table 1, Functional Category 5.)

GS 1714.010(IN) *Leakage Classification and Response* has an effective date of January 1, 2015 and the effective date of GS 1010.014(IN) *Natural Gas Emission Reduction Plan* is December 27, 2021. A Grade 3 leak is determined by low level natural gas detection, in NIPSCO's GS, within defined areas such as substructures, around paved areas, and in confined spaces. Please see GS 1714.010(IN), Table 3 Grade 3 Classification and Response for details. (Attachment BRK-1, page 22, Table 3, Grade 3 Classification and Response.)

Q: Is remediation of Grade 3 leaks included in Petitioner's base rates?

A: Yes. I asked a series of questions in OUCC DRs to determine if Grade 3 leak remediation is in base rates and to assist in my analysis to determine if Grade 3 leak remediation is a federally mandated project. Petitioner has Grade 3 leak remediation costs in base rates as part of remediation of Grade 1 and Grade 2 leaks. (Attachment BRK-2, NIPSCO Response to OUCC DR 2.9.) Petitioner describes its Grade 3 leak remediation process in response to OUCC DR 2.1 and estimates 9,789 hours were used in 2021 for remediating Grade 3 leaks. (Attachment BRK-3, NIPSCO Response to OUCC DR 2.1.) Petitioner also provided the quantity of known Grade 3 leaks found each year from 2018 to 2021. (Attachment BRK-4, NIPSCO Response to OUCC DR 2.6.)

Q: Was Petitioner aware of the magnitude of the number of Grade 3 leaks in its most recent rate case, Cause No. 45621?

A: Yes. Cause No. 45621, Petitioner's pending general rate case, was filed September 29, 2021, and Petitioner supplied known Grade 3 leaks back to 2018. Petitioner has steadily increased its Grade 3 leak remediation since 2018. In 2018, Petitioner estimates it remediated approximately <Confidential [redacted] Confidential> (Attachment BRK-5-C, Petitioner's Workpaper PSCP3-29, Remediation tab.) Petitioner states there are more than 50,000 Grade 3 leaks on its system, with 26,510 found in 2021. (Attachment BRK-4, NIPSCO Response to OUCC DR 2.6 (a).) Petitioner states it has $7,927,564 of O&M expense included in the base rate case for repairing all leaks. (Attachment BRK-2, NIPSCO Response to OUCC DR 2.9 (a).)

Q: Does PHMSA require a deadline for remediation of Grade 3 leaks once a Grade 3 leak is discovered?

A: No. In my search of PHMSA codes I did not find where it specifies a time duration for remediating Grade 3 leaks, but Petitioner adheres to the Protecting Infrastructure of Pipelines and Enhancing Safety ("PIPES") to address hazardous leaks and reducing emissions. (Attachment BRK-6; PIPES, and Attachment BRK-7, NIPSCO Response to OUCC DR 2.2.) The PIPES Act does not specifically address the remediation of Grade 1, Grade 2, or Grades 3 but does state in (B) Requirements (iii): "include a schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard, with appropriate deadlines." (Attachment BRK-6; PIPES, page 2.) Petitioner points out there is no PHMSA code for remediation of Grade 3 leaks and NIPSCO's adheres to its own standard, GS 1010.014(IN), for specified remediation timelines for Grade 1 and Grade 2 leaks. (Attachment BRK-7, NIPSCO Response to OUCC DR 2.2, page 1.)

Q: Does Petitioner consider Grade 3 leaks hazardous?

A: No. Petitioner does not initially quantify a discovered Grade 3 leak as hazardous, but recognizes a Grade 3 leak can degrade over time, and therefore adheres to reevaluating Grade 3 leaks within Petitioner's specified schedule. Petitioner recognizes the importance of reinspecting Grade 3 leaks annually, thus determining if remediation is necessary. (Attachment BRK-7, NIPSCO Response to OUCC DR 2.2, and Attachment BRK-8, NIPSCO Response to OUCC DR 2.5.) Petitioner states the PIPES Act is a self-executing mandate. (Attachment BRK-7, NIPSCO

Response to OUCC DR 2.2 (a)). The PIPES Act does not clearly distinguish a Grade 3 leak or require its remediation.

Q: What are some of the existing ways Petitioner remediates or prevents Grade 3 leaks?

A: Petitioner has base rate O&M revenue to remediate Grade 1, Grade 2, and Grade 3 leaks. Separately, Petitioner has a prior approved FMCA project in Cause No. 45007 – Project ID PS8 Fiberglass Riser Replacements for proactively avoiding potential leaks. Additionally, Petitioner requests approval to continue fiberglass riser replacements at different locations in this Cause – Project PSCP3-14. (Attachment BRK-9, NIPSCO Response to OUCC DR 2.8.)

Q: Does Petitioner have fugitive natural emissions greater than Grade 3 Leaks?

A: Yes. I asked Petitioner about the total fugitive natural gas emissions. Petitioner estimates it can eliminate approximately 15-20% of its total emissions with Project PSCP3-29 and Grade 3 leaks makeup 25-30% of all leak emissions. (Attachment BRK-10, NIPSCO Response to OUCC DR 2.7.) To further my analysis of all fugitive leaks versus Grade 3 leaks, I asked a series of questions in DR No. 3. In OUCC DR 3.5, I asked Petitioner to provide sources of remaining leaks, approximately 70% of total leaks, and if other proposed Plan III projects have quantified leak remediations. (Attachment BRK-11, NIPSCO Response to OUCC DR 3.5.)

Q: Please summarize your analysis and recommendation for Project PSCP3-29 Repair Grade 3 Leaks.

A: My analysis indicates Project PSCP3-29 does not meet the requirements of a federally mandated project. I found no specific PHMSA or PIPES Act requirement necessary for the utility to remediate Grade 3 leaks on a specified or immediate time schedule. Petitioner presently has approved O&M expenses to remediate Grade 3 leaks in base rates and indicates a Grade 3 leak is non-hazardous. (Attachment BRK-8, NIPSCO Response to OUCC DR 2.5.)

Remediation of Grade 3 leaks is a normal practice of Petitioner's operations, and Petitioner has available funds in approved O&M expenses in base rates to remediate Grade 3 leaks. My analysis is Project PSCP3-29 is not federally mandated, and Petitioner can continue to remediate Grade 3 leaks with O&M expenses recovered through its base rates.

V. PETITIONER'S REQUESTS FOR COMMISSION APPROVAL

Q: What additional items did Petitioner request in this proceeding?

A: In the petition, Petitioner requested the following items:

- Determining the PHMSA rules are federally mandated requirements as defined by Ind. Code § 8-1-8.4-5;
- Finding that NIPSCO is an energy utility as defined by Ind. Code § 8-1-8.4-3;
- Finding that Plan III is a compliance project under Ind. Code § 8-1-8.4-2;
- Finding that Plan III will allow NIPSCO to comply directly or indirectly with the PHMSA Rules;
- Finding that costs incurred with Plan III are federally mandated costs under Ind. Code § 8-1-8.4-4; and
- Approval of ongoing review of Plan III as part of Petitioner's semi-annual FMCA Mechanism filings.

Per Ind. Code, the PHMSA rules are federally mandated requirements, and Petitioner is an energy utility. Petitioner's Plan III meets Ind. Code requirements for a compliance project, and Petitioner will carry out the federal mandates with specific Plan III projects. My analysis indicates all but one project complies directly or indirectly with PHMSA rules. The associated costs, although the OUCC recommends removal of PSCP3-29, are federally mandated costs and Petitioner provided detailed estimates. If Plan III is approved, my understanding is that Petitioner intends to file a semi-annual update for ongoing review and potential Commission approval.

VI. <u>RECOMMENDATIONS</u>

Q: Please summarize your recommendations.

A: After analyzing Plan III, I recommend the Commission:

1. Remove Project PSCP3-29 *Repair Grade 3 Leaks* from Plan III.
2. Approve a modified Plan III with my recommended removal of Project PSCP3-29.
3. Issue a CPCN for this federally mandated compliance project, Plan III.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX BRK-1 TO THE TESTIMONY OF
OUCC WITNESS BRIEN R. KRIEGER

I. PROFESSIONAL EXPERIENCE

Q: Please describe your educational background and experience.

A: I graduated from Purdue University in West Lafayette, Indiana with a Bachelor of Science Degree in Mechanical Engineering in May 1986, and a Master of Science Degree in Mechanical Engineering in August 2001 from Purdue University at the IUPUI campus.

From 1986 through mid-1997, I worked for PSI Energy and Cinergy progressing to a Senior Engineer. After the initial four years as a field engineer and industrial representative in Terre Haute, Indiana, I accepted a transfer to corporate offices in Plainfield, Indiana where my focus changed to industrial energy efficiency implementation and power quality. Early Demand Side Management ("DSM") projects included ice storage for Indiana State University, Time of Use rates for industrials, and DSM Verification and Validation reporting to the IURC. I was an Electric Power Research Institute committee member on forums concerning electric vehicle batteries/charging, municipal water/wastewater, and adjustable speed drives. I left Cinergy and worked approximately two years for the energy consultant, ESG, and then worked for the OUCC from mid-1999 to mid-2001.

I completed my Master's in Engineering in 2001, with a focus on power generation, including aerospace turbines, and left the OUCC to gain experience and practice in turbines. I was employed by Rolls-Royce (2001-2008) in Indianapolis working in an engineering capacity for military engines. This work included: fuel-flight regime performance, component failure mode analysis, and military program control account management.

From 2008 to 2016 my employment included substitute teaching in the Plainfield, Indiana school district, grades 3 through 12. I passed the math Praxis exam requirement for teaching secondary school. During this period, I also performed contract engineering work for Duke Energy and Air Analysis. I started working again with the OUCC in 2016.

Over my career I have attended various continuing education workshops at the University of Wisconsin and written technical papers. While previously employed at the OUCC, I completed Week 1 of NARUC's Utility Rate School hosted by the Institute of Public Utilities at Michigan State University. In 2016, I attended two cost-of-service/rate-making courses: Ratemaking Workshop (ISBA Utility Law Section) and Financial Management: Cost of Service Ratemaking (AWWA).

In 2017, I attended the AGA Rate School sponsored by the Center for Business and Regulation in the College of Business & Management at the University of Illinois Springfield and attended Camp NARUC Week 2, Intermediate Course held at Michigan State University. I completed the Fundamentals of Gas Distribution on-line course developed and administered by Gas Technology Institute in 2018. In October 2019, I attended Camp NARUC Week 3, Advanced Regulatory Studies Program held at Michigan State University by the Institute of Public Utilities.

My current responsibilities include reviewing and analyzing Cost of Service Studies ("COSS") relating to cases filed with the Commission by natural gas, electric and water utilities. Additionally, I have taken on engineering responsibilities within the

OUCC's Natural Gas Division, including participation in "Call Before You Dig-811" incident review and natural gas emergency response training.

Q: Have you previously filed testimony with the Commission?

A: Yes. I have provided written testimony concerning COSS in more than thirteen base rate cases filed with the Indiana Utility Regulatory Commission. Additionally, I have provided written testimony for Targeted Economic Development ("TED") projects in 2017/2018/2020 and various Federal Mandate Cost Adjustment ("FMCA") and Transmission, Distribution, and Storage System Improvement Charges ("TDSIC") petitions. I filed testimony or provided analysis in over twelve FMCA or TDSIC 7-Year Plan or Tracker petitions in Indiana.

While previously employed by the OUCC, I wrote testimony concerning the Commission's investigation into merchant power plants, power quality, Midwest Independent System Operator and other procedures. Additionally, I prepared testimony and position papers supporting the OUCC's position on various electric and water rate cases during those same years.

II. BACKGROUND OF TESTIMONY ANALYSIS

Q: Please describe the review you conducted to prepare this testimony.

A: I reviewed NIPSCO's Petition, Testimony, and Attachments for this Cause. I also reviewed Petitioner's prior FMCA cases, Cause Nos. 45007, 45183, and 45560 including the individual FMCA recovery filings and the Commission's Orders for Cause Nos. 45007, 45183, 45560. I participated in OUCC case team meetings concerning Petitioner's case. I reviewed Petitioner's direct testimony of Alison M. Becker, Ryan T. Carr, Steven W.

Sylvester, Matthew G. Holtz, and Brent J. Shuler focusing on PHMSA requirements and estimates for new projects along with project status for those projects continued from Cause No. 45560.

Q: What PHMSA requirement establishes some of the pipeline safety criteria for a natural gas distribution utility?

A: PHMSA establishes standards and policies to improve the safety and integrity of the natural gas system to prevent incidents. Natural gas utilities are required by PHMSA to improve the integrity of natural gas systems in part, as prescribed in 49 CFR 192 Subpart P.

Q: What are some of the Indiana Code sections that apply to FMCA projects?

A: An FMCA project is established in accordance with Indiana Code § 8-1-8.4-5 - "Federally mandated requirements", which states:

> As used in this chapter, "federally mandated requirement" means a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following:
> (1) The federal Clean Air Act (42 U.S.C. 7401 et seq.).
> (2) The federal Water Pollution Control Act (33 U.S.C. 1251 et seq.).
> (3) The federal Resource Conservation and Recovery Act (42 U.S.C. 6901 et seq.).
> (4) The federal Toxic Substances Control Act (15 U.S.C. 2601 et seq.).
> (5) Standards or regulations concerning the integrity, safety, or reliable operation of: (A) transmission; or (B) distribution; pipeline facilities.

and § 8-1-8.4-6(b)(1)(B), which provides:

> A description of the projected federally mandated costs associated with the proposed compliance project, including costs that are allocated to the energy utility: (i) in connection with regional transmission expansion planning and construction; or (ii) under a Federal Energy Regulatory Commission approved tariff, rate schedule, or agreement.

Additionally, new FMCA Projects can be proposed if the new project meets the criteria outlined in the governing PHMSA rule and is a valid federally mandated project in accordance with Indiana Code § 8-1-8.4-2.

Q: Please describe your analysis of the support provided by NIPSCO for project estimates and cost updates in this Cause.

A: I reviewed the testimonial and evidentiary support provided by NIPSCO. I reviewed all projects discussed in Petitioner's testimony and the data contained in Petitioner's attachments. I analyzed Petitioner's testimony and exhibits looking for new projects not continued from Cause Nos. 45007 or 45560, new estimates, PHMSA requirements, and scope. I also validated PHMSA requirements for projects similar to Cause Nos. 45007 or 45560 and looked for any scope changes for these similar projects.

Q: Have you reviewed NIPSCO's Compliance Plan on a project basis?

A: Yes. I reviewed NIPSCO's entire verified petition and testimony. I asked questions of Petitioner to better understand Petitioner's estimated costs, status, and continuation of projects. I participated in informal discussions with Petitioner on April 21, 2022, May 20, 2022, and a site visit on June 17, 2022. I reviewed Petitioner's Revisions 1 through 4 and analyzed Petitioner's responses to OUCC DRs.

NiSource

Distribution Operations

Gas Standard

Effective Date: 12/27/2021	**Natural Gas Emission Reduction Plan**	Standard Number: **GS 1010.014(IN)**
Supersedes: N/A		Page 1 of 17

Companies Affected:

☒ NIPSCO	☐ CKY	☐ CMD
☐ COH	☐ CPA	☐ CVA

REFERENCE Section 114 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020 (PIPES Act of 2020) 49 U.S.C. §§ 60102 and 60108; 49 CFR Part 192.605

1. BACKGROUND

On December 27, 2020, the PIPES Act of 2020 was signed into law. Section 114 of this Act, requires natural gas operators to evaluate and update their existing inspection and maintenance plans by December 27, 2021 to address the following new considerations:

- *Eliminating hazardous leaks and minimizing releases of natural gas from pipeline facilities; and*
- *The extent to which the plan addresses the replacement or remediation of pipelines that are known to leak based on the material (including cast iron, unprotected steel, wrought iron, and historic plastics with known issues), design, or past operating and maintenance history of the pipeline.*

Additionally, an operator's plan "must meet the requirements of any regulations promulgated under section 60102(q)", which includes a congressional mandate for PHMSA to focus on the use of advanced leak detection strategies in order to further reduce methane emissions. PHMSA has recently begun the process of developing a rulemaking to meet the Congressional mandate contained in Section 113 of the PIPES Act. Once any rulemaking implementing Section 113 of the PIPES Act is complete, the Company's O&M Manual of procedures will be updated to meet the new regulatory requirements as necessary.

Finally, inspection and maintenance plans must continue to consider public safety and protection of the environment.

2. OVERVIEW

The Company remains committed to continuous improvement regarding pipeline safety and the reduction of natural gas emissions.

This Standard addresses distribution, transmission, and underground natural gas storage assets and lists activities that addresses the following.

a. Public safety.

b. Eliminating hazardous leaks.

c. Minimizing releases of natural gas from pipeline facilities.

d. Protection of the environment.

e. Pipeline remediation activities.

f. Pipeline replacement programs.

3. EMISSION REDUCTION ACTIVITIES

The existing pipeline safety requirements address not only enhancing public safety and reliability but also seek to prevent leaks from occurring, thereby helping to minimize the release of natural gas into the atmosphere. As required under 49 CFR 192.605, the Company has an O&M Manual of procedures (GS 1010.010 “O&M Manual Administration”) that includes activities to minimize releases of natural gas, as summarized below.

The following are representative activities of existing major programs and plans in place to address the reduction of natural gas emissions. Individual activities aimed at further reducing natural gas emissions, are outlined in Section 4 “Natural Gas Emission Reduction Activity List.”

3.1 Leakage Management Program

The Company’s leak management program includes the following five key elements (“LEAKS”). In part, this program is intended to help eliminate hazardous leaks, minimize release of natural gas from pipeline facilities, help prioritize our pipeline replacement program, and protect the environment through reduction in natural gas emissions.

1. Locate the Leaks.

   a. An effective leak management program includes locating leaks by visual inspection and leak survey equipment, timely response to customer notification of a gas odor, and a variety of other means, which are outlined in the Gas Standard 1708 Series.

   b. Qualified personnel perform leak detection activities, including the selection of appropriate leak detection equipment.

   c. Inspection frequencies vary based on survey type (transmission, business district, areas outside business district, etc.), which are stated in the Gas Standard 1708 Series.

2. Evaluate the Potential Hazards.

   a. The leak management program includes evaluating the severity of leaks according to established classification criteria. These classification criteria take into consideration the safety risk posed by the leak. The determination of leak migration is part of the process.

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b. Leaks are classified in accordance with GS 1714.010 "Leakage Classification and Response."

c. Leak classification is based on the Gas Piping Technology Committee (GPTC) guidance.

3. Act Appropriately.

   a. Once a leak has been located and evaluated, the Company responds consistent with the severity of the leak. This may include temporary or permanent repair, replacement, or other steps that reduce any immediate hazard posed by the leak and thereby reduce natural gas emissions.

   b. Leak repair and monitoring timeframes are based on GPTC guidance.

4. Keep Records.

   a. The Company's leak management program includes the collection and recording of data pertinent to a leak to increase the Company's knowledge of the system, measure its performance and comply with regulatory reporting requirements.

5. Self-Assess.

   a. The Company's leak management program includes a self-assessment of the distribution system by compiling associated performance metrics and by analyzing pertinent information to determine if further risk control practices are needed to enhance the safety of the system.

   b. GS 1714.060 "Leakage Repair Follow-Up Inspections" is an example of assessing leak repairs.

3.2 Damage Prevention Program

Excavating damages continue to be a leading cause of pipeline incidents and are a significant contributing factor for natural gas leaks. The Company has in place a program to protect the Company's natural gas pipelines from external damage; to prevent injury to the public, excavators, and employees; to safeguard property; and to streamline communication related to proposed excavations or demolition work near Company facilities. In part, this program is intended to contribute to public safety, help eliminate hazardous leaks, minimize release of natural gas from pipeline facilities, and protect the environment through reduction in natural gas emissions.

The details of the program are described in a written plan, titled Damage Prevention Plan and state-specific Strategic Plans.

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3.3 Infrastructure Replacement Programs

The Company has an infrastructure replacement program where leakage and other infrastructure information are evaluated to identify replacement candidates. In part, this program is intended to contribute to public safety, minimize release of natural gas from pipeline facilities, and protect the environment through reduction in natural gas emissions.

This evaluation and identification is performed on a continuing basis by the Field Engineering Department as new system information is presented. The identification and evaluation is supported by Field Operations personnel and associated field information along with a software application.

Active corrosion review meetings (refer to GS 1430.030 “Active Corrosion”) will review the corrosion indicator maps to see any new leaks that have occurred on coated steel piping systems, and review bare steel and cast iron systems to determine additional candidates for replacements that are not already identified on the proposed replacement lists derived from the software application. New leaks, historical leaks, pipeline condition as well as local knowledge of the system are considered in determining potential leakage candidates. The active corrosion meetings include representatives from Field Engineering, Field Operations, and System Operations.

3.4 Cross Bore Remediation Program

This remediation program is designed to investigate and eliminate all legacy cross bores in the Company’s systems and to prevent new cross bores from occurring. In 2021, an incentive program for licensed plumbers was implemented to reward plumbers who utilize camera equipment prior to clearing blockages and reporting suspected gas cross bores to the Company for investigation.

In part, this program is intended to contribute to public safety, help eliminate hazardous leaks, minimize release of natural gas from pipeline facilities, and protect the environment through reduction in natural gas emissions.

3.5 Distribution Integrity Management Program (DIMP)

The DIMP Plan was developed in accordance with the requirements of 49 CFR Part 192 Subpart P and applies to all operating units involved in the operation, maintenance, scheduling, or control of its distribution pipeline systems.

The DIMP plan requires the Company to develop and implement a program that addresses the following elements.

a. Knowledge of System.

b. Identify Threats.

c. Evaluate and Rank Risks.

d. Identify and Implement Measures to Address Risks.

e. Measure Performance, Monitor Results and Evaluate Effectiveness.

f. Periodic Evaluation and Improvement.

g. Report Results.

The DIMP Plan applies to all gas distribution pipelines operated by the Company that include the associated mains, services, service regulators, customer meters, valves and other appurtenances attached to the pipe such as metering stations, regulator stations, and fabricated assemblies.

The DIMP Plan captures and trends leak data on system pipe materials, such as bare steel and cast/wrought iron, to help drive the necessary program changes to reduce pipeline leakage. Tracking and trending of data associated with other assets is also captured in the various appendices of the DIMP Plan.

In part, this program is intended to contribute to public safety, help eliminate hazardous leaks, minimize release of natural gas from pipeline facilities, help prioritize our pipeline replacement program, and protect the environment through reduction in natural gas emissions.

3.6 Transmission Integrity Management Program (TIMP)

The Transmission Integrity Management Program (TIMP) is a comprehensive systematic approach to maintain and improve the safety of the Company's transmission pipeline system.

The TIMP Plan was developed in accordance with the requirements of 49 CFR Part 192 Subpart O and applies to all operating units involved in the operation, maintenance, scheduling, or control of its natural gas transmission pipeline systems.

The Company's TIMP goals and objectives include the following activities.

a. Ensures the operational integrity of its natural gas transmission pipeline system meets or exceeds the requirements as detailed in 49 CFR Part 192 Subpart O Pipeline Integrity Management.

b. Provides for the safety of the general public, customers, employees, contractors and other third parties that may be impacted by the operation of the pipeline system.

c. Reveals and manages risk, and makes risk reduction routine.

d. Enables dependent and interrelated functions within the organization to share information and work to achieve stated policies and objectives.

e. Complies with all environmental and safety regulatory requirements.

In part, this program is intended to contribute to public safety, help eliminate hazardous leaks, minimize release of natural gas from pipeline facilities, help prioritize our pipeline replacement program and protect the environment through reduction in natural gas emissions.

3.7 Natural Gas Underground Storage Integrity Management Program (SIMP)

The U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an interim final rule (IFR), effective January 18, 2018, and subsequent Final Rule (FR), effective March 13, 2020, revising the Federal Pipeline Safety Regulations, Code of Federal Regulations (CFR 49) § 192.12. The FR put critical safety standards in place for underground storage facilities and incorporated Sections 8, 9, 10, and 11 of the American Petroleum Institute's Recommended Practices (API RP) 1171, "Functional Integrity of Natural Gas Storage in Depleted Hydrocarbon Reservoirs and Aquifer Reservoirs," by reference.

The Natural Gas Underground Storage Integrity Management Program (SIMP) procedures describes the risk processes involved in assessing wells and reservoirs and complies with requirements of Section 8, API 1171 and includes discussion of the following.

a. Data collection and integration.
b. Threat and hazard identification and analysis.
c. Likelihood of failure estimates, event scenarios, and consequence of failure estimates.
d. Risk evaluation and treatment decision making.
e. Preventive and mitigative measures.
f. Periodic review and reassessment.

The Company has developed a framework of underground gas storage standards (UGS 5700 Series) that include procedures for how well and reservoir storage integrity management will be conducted. The SIMP framework document describes how the network of UGS standards and other Company or site-specific operating procedures ensure compliance with regulations and work toward continual improvement in underground gas storage safety.

4. EMISSION REDUCTION ACTIVITY LIST

The following is a list of activities that reduce natural gas emissions.

Table 1 List of Emission Reduction Activities				
Functional Category		**Activity**	**Description**	**Reference**
1	Leak Management	Centralized Database of Leaks	Open leaks are stored within the Company's work management system and the data managed to ensure follow up work is scheduled for re-evaluation, repair and/or elimination by asset (e.g., main, service line) replacement in accordance with the Company procedure timeframe. Clearance of open leaks eliminates fugitive emissions.	GS 1714.010(IN); DIMP Plan
2	Leak Management	Mobile Advanced Leak Detection: Picarro Pilot	The purpose of the pilot is to evaluate and develop an implementation plan to use the Picarro units as a Company recognized compliance leak survey method. The Picarro system identifies the characteristic signatures of natural gas leaks by analyzing the methane plumes as they propagate in the atmosphere and intersect with the path of the vehicle. This can lead to quicker and more accurate identification of large volume gas leaks. The pilot includes performing large volume leak surveys in certain targeted areas that detects leaks with a volume flow rate of 10scfh or greater (fugitive emissions).	ON 21-03; IURC agreement
3	Leak Management	Distribution System Leakage Survey Frequency	49 CFR Part 192.723 requires plastic and cathodically-protected steel pipelines outside of business districts to be surveyed for leakage at least once every 5 calendar years at intervals not exceeding 63 months. The Company surveys all pipelines outside of business districts at least once every 3 calendar years at intervals not exceeding 39 months.	Practice; Maximo

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Table 1 List of Emission Reduction Activities				
Functional Category		Activity	Description	Reference
			Frequent leakage surveys can lead to earlier discovery and subsequent clearance of leaks, e.g., repair, replacement, abandonment (fugitive emissions).	
4	Leak Management	Leak Classification and Response	The Company establishes leak classifications to prioritize the clearance of leaks.	GS 1714.010(IN)
5	Leak Management	Above Ground Leaks on Outside Meter Set Assemblies	Above ground leaks found on outside meter set assemblies are classified in accordance with GS 1714.010(IN) "Leakage Classification and Response." For GR2 classified leaks, most repairs are completed within approximately three (3) to six (6) months of discovery. For GR3 classified leaks, some repairs are completed within six (6) to twelve (12) months of discovery.	Company Practice
6	Damage Prevention	Cross Bore Remediation	Remediation program proactively investigates systems to discover and remediate legacy cross bores as well as preventing new cross bores from occurring. The identification and remediation of cross bores contributes to public safety and eliminates fugitive emissions.	Program; GS 1100.050(IN)
7	Damage Prevention	Gold Shovel Standard Certification	Gold Shovel Standard (GSS) is a certification program focused on reducing risks and damages to the Company's underground assets. The Company achieved GSS Certification in 2020 and required Company contractors to achieve GSS Certification by March 2021.	Practice

Table 1 List of Emission Reduction Activities

Functional Category		Activity	Description	Reference
			Participation in this program can result in a decrease in excavation damages thus reducing fugitive emissions.	
8	Damage Prevention	Reward Program for Licensed Plumbers	An incentive program for licensed plumbers was implemented to reward plumbers who utilize camera equipment prior to clearing blockages and reporting suspected gas cross bores to NiSource for investigation. The identification and remediation of cross bores contributes to public safety and reduces fugitive emissions.	Program; Company Website
9	Damage Prevention	Jameson Live Tracer	For difficult to locate plastic pipe (e.g., broken tracer wire) this tool enables vertical insertion of a tracer rod into plastic pipe and is used with a transmitter and receiver to locate the asset. With the use of the tool, difficult to locate plastic pipe can be accurately located to prevent hazardous leaks resulting from excavation damages (fugitive emissions).	Practice
10	Damage Prevention	Mapping Service Lines	Service line mapping supports our safety and compliance programs by providing employees and contractors with accurate documentation. Service Lines mapped in GIS improves the accuracy of performing service line locates to prevent hazardous leaks caused by excavation damage (fugitive emissions).	Program

Table 1 List of Emission Reduction Activities				
Functional Category		Activity	Description	Reference
11	Damage Prevention	Locating Near Vacant Lot or Inconsistent Addresses	When a vacant lot or inconsistent address (e.g., existing building that is not in the Company's customer information system) is identified during a locate, the locate technician is directed to review service line records to determine if a service line stub might be active. If service records indicate an active stub, the stub must be located. A record of an active service line stub can be located in the field. This reduces excavator damages, which reduces fugitive emissions.	GS 1100.010(IN)
12	Damage Prevention	Transmission Lines	If a locate request for 3rd party excavation is planned to cross, parallel, or is located within 50 feet of a Company-owned transmission line, the Company communicates with the excavator and often arranges to monitor the excavation. Damage prevention efforts reduce fugitive emissions.	GS 1100.010(IN)
13	Damage Prevention	Low Pressure (LP) Pressure Regulating Stations	For all locate requests within a 250 foot radius of a LP pressure regulating station, the planned excavation is reviewed in the field, and depending upon its proximity to the station and the station's completed safety actions (e.g., control lines and taps protected, additional overpressure protection has been installed), onsite monitoring of the excavation and onsite monitoring of the LP pressure regulating station is completed. Damage prevention efforts reduce excavator damages, which reduces fugitive emissions.	GS 1100.010 (IN); ON 19-02

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Table 1 List of Emission Reduction Activities

Functional Category		Activity	Description	Reference
14	Damage Prevention	Mapping Stubs of Abandoned Service Lines	When abandoning a service line, employees are directed to disconnect the service line as close as practical to the supplying pipeline. After the abandonment of the service line, if the service line stub that remains attached to an in-service main extends beyond 18" from the edge of the main, employees are directed to install an electronic marker to enable future locating and to submit a map revision request to map the stub and electronic marker. The service line record is updated to show a sketch of the service line stub, regardless of length, and the location of the tapping tee remaining in-service after service line abandonment. Mapped service line stubs can be located in the field and marked thereby reducing excavator damages (fugitive emissions).	GS 1740.010, SOP 1740.010-1
15	Damage Prevention	Identification of Suspected Encroachments	Identification and remediation of encroachments reduces potential damages (fugitive emissions).	GS 1100.010(IN), GS 1704.010, GS 1708.020(IN), GS 1782.010, GS 2650.010
16	Damage Prevention	Flush-Mounted Line Markers	When conventional line markers (e.g., post-style) are not required and are not feasible in urban areas or practical in some residential areas, flush-mounted line markers may be used to indicate the presence of gas facilities.	GS 1720.010

Table 1 List of Emission Reduction Activities				
Functional Category		Activity	Description	Reference
			Line markers indicating the presence of gas facilities reduces excavator damages (fugitive emissions).	
17	Public Awareness	Excavator Education Campaign	A Public Awareness excavator education outreach that specifically targets proper excavation within the tolerance zone. The campaign is a combination approach of email blasts, digital advertising, and social media posts designed to decrease excavation damages to Company assets (and thereby reduce fugitive emissions).	Program
18	Public Awareness	Customer Education: Know Your Home	A plan to educate our customers on gas safety inside and outside their home and encourage customers to take steps to protect themselves, their families and their property from unsafe natural gas situations and practices such as calling 811 before digging. Information is provided via bill messaging, website content and customer care center on-hold messaging. This reduces fugitive emissions by reducing excavation damages and outside force damages to the piping that serve customers.	Public Awareness Plan
19	Engineering	Monitor Regulators for Overpressure Protection	49 CFR Part 192.195 requires protection against accidental overpressuring by using pressure relieving or pressure limiting devices. The Company's pressure regulating station designs specify monitor regulation as the primary overpressure protection device.	GS 2300.010, GS 2300.020

Table 1 List of Emission Reduction Activities

Functional Category		Activity	Description	Reference
			The use of a monitor regulator instead of a full-capacity relief valve for overpressure protection reduces venting natural gas to the atmosphere.	
20	Engineering and Construction	Low Pressure Regulator System Work Requirements	Protocols were implemented to allow work on LP systems that include verifying location of control lines, updating control line isometric drawings, and requiring M&R personnel to be onsite at impacted LP stations for all LP system tie-ins and abandonments. These protocols help to prevent damages to control lines and mitigate consequences that would lead to fugitive emissions.	ON 19-02
21	Engineering and Construction	Cross Compression Pilot	The Company is piloting Zero Emissions Vacuum and Compression (ZEVAC®) technology, which captures natural gas before maintenance, inspection, or abandonment so it can be recycled for use. The use of a ZEVAC unit can reduce the amount of natural gas vented to the atmosphere.	Pilot
22	Construction	Installation of Excess Flow Valves	An Excess Flow Valve (EFV) is a cartridge valve inside the pipe that immediately closes when the flow exceeds its designed limit at a certain pressure. EFVs are installed on new and replaced 2-inch and less service lines in accordance with GS 3020.100. The intent of an EFV is to stop the flow when a service line is damaged, normally severed by an excavator thereby eliminating gas release and a potentially hazardous leak (fugitive emissions).	GS 3020.100
23	Construction	Sewer Locate Process	Prior to the use of trenchless technology to install gas facilities, construction personnel are required to complete a thorough site	GS 1100.050(IN)

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Table 1 List of Emission Reduction Activities

Functional Category		Activity	Description	Reference
			investigation to identify all known facilities to avoid a cross bore of another facility. The site investigation is documented and enables planning a bore path that avoids a potential cross bore. Cross bore avoidance reduces fugitive emissions.	
24	Construction	Camera Inspection of Sewer Facilities	Prior to the use of trenchless technology to install transmission line or distribution main, camera inspection of sewer lines are completed to ensure that sewers within the project area are located and free from any existing cross bores. Potholes are monitored during the use of trenchless technology to ensure the bore is proceeding as planned. After the use of trenchless technology, a post-construction camera inspection of the sewers within the project area are completed to confirm that no cross bores were created during the bore process and pipeline installation. Cross bore avoidance reduces fugitive emissions.	GS 1100.050(IN)
25	Construction	Use of a Pull-Back Camera	After a thorough site investigation of a property, a service line may be installed by the use of trenchless technology (e.g., directional drill, pneumatic punch tool) if a pull-back camera is used to inspect the bore hole for a cross bore of other underground facilities. Pull-back cameras were implemented throughout the Company in 2016. Cross bore avoidance reduces fugitive emissions.	GS 1100.050(IN)

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Table 1 List of Emission Reduction Activities

Functional Category		Activity	Description	Reference
26	Construction	Service Line Insertions and Reconnections – Camera Inspection of Sewer Facilities	The installation of a new or replacement service line through an abandoned service line and the reconnection of an existing service line to a new main requires the verification of no cross bores by a pre-construction or post-construction camera inspection of the sewer facilities in the project area. Identifying and remediating cross bores reduces fugitive emissions.	1100.050(IN)
27	Construction	No Blind Bores	Trenchless technology shall not be used if any known underground facility location and depth crossing the proposed bore path cannot be determined. Cross bore avoidance reduces fugitive emissions.	GS 1100.050(IN)
28	Construction	Flaring Procedures for Pipeline Blowdown	The Company encourages the use of flaring when possible during pipeline blowdown to reduce natural gas emissions. GS 1690.012 “Flaring” was developed to provide guidance for planning and notification of flaring operations and procedures for safe flaring operations.	GS 1690.012
29	Operations	Temporary Repair Clamps on Polyethylene Pipe	A full encirclement clamp may be used to slow down or eliminate gas flow to more safely enable a permanent repair or pipeline replacement to occur.	GS 1714.020
30	DIMP	Facility Failure Reporting and Investigation	This program establishes a method for analyzing material and equipment failures associated with an in-service pipeline and for determining the apparent cause of the failure and where	DIMP Plan; GS 1652.010

Table 1 List of Emission Reduction Activities				
Functional Category		Activity	Description	Reference
			appropriate to take action to minimize the possibility of a recurrence. Each year the results of failed material and equipment is reviewed by the Company's DIMP Team to determine if mitigative actions are needed to address material and equipment issues (fugitive emissions).	
31	DIMP	Kerotest Kerotite Valve and Kerogrip Fittings	This involves the opportunistic replacement of the Kerotest Kerotite valves and the Kerotest Kerogrip fittings when they are discovered during the course of other maintenance or construction activities. Replacing these fittings reduces fugitive emissions.	ON 16-12
32	TIMP	Retrofit for ILI Readiness	Only some of NiSource's transmission system accommodates running gas driven ILI tools and a program is underway to evaluate and make 'inspection-able' the remaining pipe in the system. Inspection of gas transmission pipelines using in-line inspection tools incorporates one of the primary means used to detect and therefore mitigate potential threats on the system. Identifying and remediating threats prior to failure eliminates fugitive emissions.	TIMP Plan
33	Replacement Program	Cast Iron and Bare Steel Replacement Program	The focused replacement of known cast iron and bare steel distribution mains will reduce hazardous and non-hazardous natural gas fugitive emissions.	DIMP Plan

Table 1 List of Emission Reduction Activities				
Functional Category		**Activity**	**Description**	**Reference**
34	Replacement Program	Prone to Fail Riser Identification and Replacement	Risers are used to bring underground gas service lines above ground for customer access. Where identified, the Company is prioritizing elimination of riser models that are known to fail. Proactively replacing these risers with today's materials will reduce fugitive emissions.	DIMP Plan
35	Equipment	Pietro Fiorentini FE 25 Service Regulator	The Pietro Fiorentini FE 25 service regulator is an option to address existing service lines with meter set assemblies (MSAs) located in which the regulator vent terminal is in close proximity to building openings and potential sources of ignition. The Pietro Fiorentini FE 25 regulators are equipped with an over pressure shut-off (OPSO) device, designed to shut the gas off when the downstream pressure reaches the set point and thereby eliminating full relief venting.	ON 16-09

NiSource
Distribution Operations

Gas Standard

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Companies Affected:

☒ NIPSCO	☐ CVA	☐ CMD
	☐ CKY	☐ COH
		☐ CPA

REFERENCE 49 CFR Part 192.706, 192.709, 192.723; IN 170 IAC 5-3-4

1. GENERAL

The following establishes procedures for classifying and responding to leaks on both transmission lines and distribution systems.

Each segment of the Company's pipeline that becomes unsafe must be replaced, repaired, or abandoned.

The examples of each leak classification provided in this procedure may not cover all possible conditions found in the field. The judgment of the qualified person at the scene is of primary importance in determining the classification assigned to a leak.

Leak survey contractors working for the Company have been trained in leak classification in accordance with this procedure. All leaks found are classified and reported to local operations. Grade 1 leaks are called in immediately.

Company personnel will classify leaks in accordance with Section 2 of this procedure. All leak reports will be investigated and hazardous leaks shall be repaired promptly. If conditions warrant, leaks considered non-hazardous shall be repaired as quickly as practical. Scheduling of the repairs of leakage on underground piping is the responsibility of the local operating area involved. The detailed response procedure in the "Gas Systems Emergency Operating Plan" will be followed when responding to a report of gas odor.

2. LEAKAGE CLASSIFICATION AND RESPONSE

All leaks shall be classified as either a Grade 1, 2, or 3. Evaluating leaks and determining the leak grade may require equipment capable of indicating the concentration of gas. When evaluating any gas leak indication, the initial step is to determine the perimeter of the leak area. When this perimeter extends to a building wall, the investigation should continue into the building.

Responding employees shall take all necessary actions directed toward protecting people first and then property.

After initial classification, any leak may be reclassified based on further evaluation by a person qualified in leak classification.

A classified leak shall be cleared only after an on-site evaluation is performed by a person qualified in leak classification. Normally leakage within a leakage area shall be completely eliminated before the classified leak is cleared. If leakage cannot be completely eliminated by the action taken the leak shall remain active. If action taken has reduced the hazard level, the leak may be reclassified.

Cleared as used in this procedure means a repaired leak, the leaking facility has been replaced, or the leak has been reclassified.

The following Tables provide the definition of each leak classification, response criteria, and examples of conditions for each classification. When a leak is re-evaluated, a qualified person shall classify the leak being re-evaluated using the classification criteria listed in the Tables below. Examples of conditions listed for each classification in the Tables below are not all inclusive.

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Table 1

Grade 1 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**
A leak that represents an existing or probable hazard to persons or property, and requires immediate repair or continuous action until the conditions are no longer hazardous.	Requires prompt action* to protect life and property, and continuous action until the conditions are no longer hazardous. *The prompt action in some instances may require one or more of the following. a. Implementation of Company's emergency plan. b. Evacuating premises. c. Blocking off an area. d. Rerouting traffic. e. Eliminating sources of ignition. f. Venting the area by removing manhole covers, barholing, installing vent holes, or other means. g. Stopping the flow of gas by closing valves or other means. h. Notifying police and fire departments. Where there is residual gas in the ground after the repair of a Grade 1 leak, a follow-up inspection shall be conducted as soon as practical after allowing the soil atmosphere to vent and stabilize, but in no case later than the last day of the next calendar month following the repair date.	Examples of classification criteria that indicate a Grade 1 are: a. Blowing gas which creates a serious operating problem or hazard, such as the possibility of ignition. b. Combustible gas indicator (CGI) reading which indicates that gas had migrated into or under a building. c. CGI reading which indicates the presence of gas up to and against a foundation or wall of a building. d. Sustained reading of 3.2% gas or greater in a manhole, conduit, catch basin or tunnel, other than a gas substructure. e. CGI readings which detect gas in consecutive inter-connected manholes, catch basins or substructures. f. Leakage which, in the judgment of the person performing the evaluation, is serious enough to warrant immediate action.

Table 2

Grade 2 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**
A leak that is recognized as being non-hazardous at the time of detection, but justifies scheduled repair based on probable future hazard.	Grade "2" leaks not cleared shall be reevaluated* at least once every six months until cleared; and either: a. repaired not later than the last day of the following calendar year from the date discovered, not to exceed fifteen (15) months; or b. eliminated by replacing the pipeline containing the leak within twenty-four months from the date the leak is discovered. *When a leak is to be reevaluated, it shall be classified in accordance with the criteria listed in this procedure.	Examples of classification criteria that indicate a Grade 2 are: a. Sustained CGI readings in a valve box or meter box other than a gas substructure. b. Sustained CGI barhole readings in an area of wall-to-wall pavement. c. Leakage that has spread to both sides of a paved driveway and/or shows indications of migrating along the driveway toward a building. d. Sustained CGI barhole readings on both sides of a street or corners of an intersection. e. Leakage which, in the judgment of the person performing the evaluation, would become potentially hazardous if left unrepaired until the next scheduled reevaluation.

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Table 3

Grade 3 Classification and Response		
Definition	**Response Criteria**	**Examples of Classification Criteria**
A leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous.	Grade “3” leaks not cleared shall be surveyed at intervals not exceeding 15 months, but at least once each calendar year. Any leak detected during the survey shall be reevaluated*. Open Grade 3 leaks that no longer produce a detectable reading during the survey do not require reevaluation and shall remain open until cleared. *Reevaluated means classifying the leak in accordance with this procedure.	Examples of classification criteria that indicate a Grade 3 are: a. Any reading of less than 3.2% gas in small gas associated substructures. b. Any reading under a street in areas without wall-to-wall paving where it is unlikely the gas could migrate to the outside wall of a building. c. Any reading of less than 0.8% gas in a confined space.

3. RESPONSES INVOLVING REPAIRS, REPLACEMENT OR ABANDONMENT

Leaks that are eliminated by repair, replacement, or abandonment shall be done in accordance with the Company’s gas standards for repair, replacement, or abandonment.

For repair guidance see GS 1714.020 “Leakage: Distribution Pipe Repair” and GS 1730.010 “Transmission Line Field Repair”.

The Company’s construction gas standards address replacement and abandonment requirements.

4. RECORDS

Leakage information is to be documented on the applicable Company forms or in the work management system.

The Company shall retain leakage records for at least the life of the pipeline, but not less than five (5) years from the cleared date. Exceptions include records of leaks with negative indications after a reevaluation, which may be discarded after five (5) years from the cleared date.

Effective Date: 01/01/2015	Leakage Classification and Response	Standard Number: GS 1714.010(IN)
Supersedes: N/A		Page 6 of 6

5. INDIANA SPECIFIC REQUIREMENTS

The Company shall submit to the pipeline safety division of the Commission two (2) annual leak repair reports which shall show (1) for the distribution system of the operator and (2) for the transmission system of the operator as follows:

a. number of unrepaired leak reports on January 1st of the preceding year,

b. number of leak reports received during the preceding year,

c. number of leaks repaired during the preceding year, and

d. number of unrepaired leak reports at the end of the preceding year.

These reports shall include all known leak reports regardless of classification, on the respective systems, up to and including the meter outlet. These reports shall be filed with the pipeline safety division of the Commission by March 1st for the preceding calendar year.

NiSource
Distribution Operations

Gas Standard

Effective Date: 04/22/2019	**Leakage: Distribution Pipe Repair**	Standard Number: **GS 1714.020**
Supersedes: 01/01/2016		Page 1 of 11

Companies Affected:

☒ NIPSCO	☐ CVA	☒ CMD
	☒ CKY	☒ COH
		☒ CPA

REFERENCE 49 CFR Part 192.703, 192.720

1. GENERAL

When repairing gas pipelines, all applicable Company safety procedures shall be followed to protect personnel and the public from hazards. Only those directly involved with the repair work should be in the work area. Care shall be taken when excavating around the pipeline and pipe exposure should be limited so that additional damage does not occur. The pipe on both sides of the known defect shall be assessed to determine if additional defects are present.

Each segment of pipeline that becomes unsafe, i.e., it has been found to be damaged or deteriorated to the extent that its serviceability is impaired (see guidance in sections below) or it has developed leakage classified as Grade 1, must be replaced, repaired, or removed from service. Refer to the applicable GS 1714.010 "Leakage Classification and Response" for leakage response requirements for all leak classifications.

Defect as used in this gas standard includes leaks, dents, gouges, and defective welds.

If temporary measures or repairs were made, as soon as practical, the pipe shall be repaired using a permanent method.

Consider taking the pipeline out of service or reducing the operating pressure as low as practical/feasible before attempting to uncover the pipeline. Whenever the repair requires interrupting the pressure in the line, gauges shall be installed and monitored to ensure that adequate pressure is maintained.

The pressure rating of a permanent repair device shall meet or exceed the Maximum Allowable Operating Pressure (MAOP) of the pipeline. The pressure rating of a temporary repair device shall meet or exceed the operating pressure of the pipeline during the period of time that the repair device is in-service. A temporary repair device that does not meet or exceed the MAOP of the pipeline may remain, only if it is encapsulated with a repair device that meets or exceeds the MAOP of the pipeline.

See GS 1730.010 “Transmission Line Field Repair” and GS 1714.030 “Pinpointing” for additional guidance.

2. REPAIRS ON METALLIC PIPES

Generally repairs on a metallic system are performed by the use of an external repair clamp. Common types of leaks can be repaired with band and saddle clamps, collar clamps, split repair clamps (mechanical or weld), bell joint clamps, and screw fitting clamps. Other approved repair methods, such as anaerobic injection (e.g., Permabond gaseal) and encapsulation, can also be used.

Refer to manufacturer's instructions for the pressure ratings and limitations for the selected repair method.

2.1 Preliminary Assessment

When exposing pipe where restraint style couplings can't be verified or the method of joining is unknown, only one joint of pipe should be exposed at a time. This joint should be treated and backfilled prior to exposing additional pipe. The intent is to limit the number of couplings exposed at any one time.

2.1.1 Mechanical Couplings

The following additional precautions are recommended to help prevent coupling pullout when repairing elevated pressure or large diameter pipelines joined by mechanical couplings.

When repairing existing pipelines, consider the possibility that couplings could exist in the pipeline and could potentially separate when soil, that provides passive restraint, is removed. Maps and records may identify the presence of couplings as well as the lengths of pipe joints used.

To reduce the possibility of coupling pull-out, consider blocking offset fittings which were not strapped or blocked, with concrete by encasing the pipeline. Contact Engineering for recommended blocking sizing. Also, plan for protection of the pipeline from damage due to the concrete, e.g., installation of coating and tape wrap, installation of rock shield, etc. Contact the Corrosion department prior to encasing the pipe for corrosion recommendations.

Refer to GS 1320.010 "Mechanical Coupling Connections" for additional guidelines.

When tying-in while making repairs, refer to GS 1680.010 "Tie-ins and Tapping Pressurized Pipelines."

2.1.2 Evaluate the Defect

Consider the age of the pipeline and type of the defect. Take caution when evaluating defects on higher pressure pipelines such as sharp mechanical damage, dents, old defects, and/or defects that have been in service for an unknown length of time. Defects such as sharp or deep gouges and dents may have cracked during service and need to be handled with caution.

2.2 Defects Involving Corrosion

2.2.1 Localized Corrosion

Localized corrosion pitting is an area on the pipe surface that contains corrosion pits over a non-contiguous area. Localized corrosion does not always affect a pipe's serviceability.

Defects involving leaks in areas of localized corrosion can generally be repaired using an appropriate leak clamp.

2.2.2 General Corrosion

General corrosion is considered corrosion pitting so closely grouped as to affect the overall strength of the pipe and should be considered as affecting the pipeline's serviceability.

Defects involving leaks in areas of general corrosion can be temporarily repaired using an appropriate leak clamp. Supervision should be notified to arrange for permanent repair.

NOTE: Supervision should be notified of defects involving general corrosion prior to backfilling.

2.3 Cast Iron and Ductile Iron Considerations

2.3.1 Graphitization

Graphitization is the process where the ferrous (iron) portion of the cast-iron or ductile iron pipe is dissolved into the surrounding electrolyte (soil) and leaves behind graphite and other non-corroding elements of the metal.

Localized graphitization occurs as a penetrating attack confined to a few small locations (pitting). Each segment of cast-iron or ductile iron pipe on which localized graphitization is found to a degree where leakage exists or might result shall be replaced or repaired with an appropriate repair device.

General graphitization occurs as a pipe wall loss over a large area. Each segment of cast-iron or ductile iron pipe on which general graphitization is found to a degree where a fracture or leakage exists or might result shall be replaced.

Both types of graphitization can occur on any segment of pipe.

2.3.2 Joints

Each cast-iron caulked bell and spigot joint that is exposed for any reason shall be sealed. Acceptable means of sealing are: mechanical bell joint clamps, encapsulation, or anaerobic sealants. Sealing methods shall be done in accordance with manufacturer's pressure limitations and instructions.

2.3.3 Backfilling

When routine maintenance, such as leak repairs, bell-joint clamping, or replacement of service connections, occurs on cast-iron pipe, care shall be taken to bed the pipe properly to prevent pipe settlement. If the bottom of the cast-iron pipe has been exposed, precautions shall be taken when backfilling to assure that the pipe rests upon a well compacted base that is as free of voids as possible. A flowable (controlled density) backfill may be used.

2.4 Dents, Grooves, Scratches, Gouges, and Other Defects

The depth of dents, grooves, scratches, and other defects can be measured by placing a straight edge along the undisturbed contour of the pipe and measuring the deepest point of the gap. A pit depth gage will usually work for this purpose.

3. METALLIC PIPELINE EXPOSURE EXAMINATION REQUIREMENTS

GS 1410.010 "Metallic Pipeline Exposures" provides the requirements for examination of the external condition of an exposed pipeline for evidence of corrosion (or **graphitization** on cast iron) or physical damage. Additional guidance for the excavation of a pipeline is provided below.

The excavation of a leaking pipeline should be planned by using the guidance provided within GS 1714.030 "Leakage Pinpointing." As the excavation exposes the pipeline, a visual examination of the pipeline should be ongoing to determine the extent of the excavation based on the condition of the pipeline.

Once the pipeline is exposed and the original leak is repaired, perform an investigation by examining the pipeline along the entire pipeline surface (i.e. circumferentially and longitudinally) to determine the extent of corrosion and/or damage. The examination shall extend beyond the original exposed portion by means of one of the following methods.

a. Direct Examination – Expose at least 12 inches* of additional pipeline on each end of the excavation, if conditions warrant, and examine the newly exposed pipeline along the entire pipeline surface (i.e., circumferentially and longitudinally). Conditions that warrant extending the excavation include visual observations that pitting continues into the bank of the original excavation, site conditions (e.g., traffic flow, soil conditions, weather) that allow for continued safe excavation, etc. Extend the excavation* until no corrosion that requiring repair or replacement is found.

b. Indirect Method – Examine the unexposed pipeline by making sidebar holes, prior to backfilling the original excavation, at 3, 6, 9, and 12 o'clock approximate positions around the pipe as it enters the earth on both sides of the excavation and test with a combustible gas indicator for leakage.

*If the excavation continues to require extension beyond typical repair limits, consider performing spot checks along the existing pipeline to determine the extent of corrosion and/or if the pipeline segment should be a candidate for replacement. Contact local field operations leadership and/or field engineering personnel for guidance, if necessary.

If no leakage requiring repair or replacement is found, a pipe-to-soil potential measurement should be obtained. Install anode (if required), and coating according to GS 1460.010 “Corrosion Remedial Measures – Distribution,” and then backfill the excavation. If additional leakage exists, investigate according to GS 1708.070 “Outside Leak Investigation,” GS 1714.030 “Leakage Pinpointing,” and other applicable leakage gas standards.

4. ADDITIONAL REMEDIAL MEASURES FOR REPAIRS ON METALLIC PIPE

4.1 Steel Pipeline

Whenever a corrosion leak is repaired on a steel pipeline, a pipe-to-soil potential measurement (refer to GS 1430.110 “Pipe-to-Soil Potential Measurements”) should be obtained after the repair, but prior to other remedial actions being performed.

Corrosion leak repairs on steel pipeline require the installation of an anode (if the pipe-to-soil potential measurement is less negative than -1.000 V in reference to a copper-copper sulfate electrode) and the application of an approved coating.

Refer to GS 1460.010 “Corrosion Remedial Measures – Distribution” for detailed guidance.

4.2 Coated Steel Pipeline

In addition to the general requirements in Section 4.1 above, the installation of a test station is also required for corrosion leak repairs on coated steel pipeline.

Also, before a leak repair on coated steel pipeline is backfilled, field personnel should notify the local corrosion personnel so that investigative tests can be performed near or at the pipeline to help determine the root cause of the leak if the pipeline is cathodically protected.

4.3 Cast Iron or Wrought Iron

When a repair fitting is installed, apply an approved coating and install an anode, where required.

5. REPAIRS ON POLYETHYLENE AND PVC PIPES

In all cases, care must be exercised to prevent a static charge from igniting a combustible mixture of air and gas. The pipe shall be wrapped with wet soapy burlap or cotton rags or other approved static reducing material contacting the earth to protect against static charge.

When it is necessary to squeeze off polyethylene pipe, the squeeze off shall be done in a separate bellhole remote to the leak whenever possible.

Permanent repairs on polyethylene pipe that has been severed in half, gouged or punctured and is leaking, require cutting out and replacing the damaged pipe. The pipe must be isolated by operating a valve(s) or squeezed off and a pre-tested section installed using mechanical, electrofusion, socket fusion, butt fusion, or a combination of these methods.

The installation of electrically isolated metallic fittings within plastic pipelines should be avoided when possible. However, when electrically isolated metallic fittings are installed in a plastic pipeline, the installation of an anode, the installation of a test station, and the application of an approved coating is required, with the following exception. If the isolated metallic component can be bonded to an adjacent cathodic protection system, then only the application of an approved coating is required.

5.1 Working in Excavations with Blowing Gas

Because static electricity charges can build up on any non-conductor such as polyethylene and PVC pipe, there is a possibility of a spark discharge of sufficient energy to cause ignition if the proper air/gas mixture is present. It is also possible for repair crew members to receive shocks even though ignition does not occur. Before personnel are permitted in the excavation where live gas is escaping, static electricity control measures shall be applied. Refer to GS 1770.010 “Prevention of Accidental Ignition” for guidelines.

The objective is to provide a path to ground for any static discharge.

5.1.1 Temporary Repair Clamps on Polyethylene Pipe

The installation of a mechanical stainless steel or carbon steel leak repair clamp as a temporary or permanent repair on polyethylene pipe is prohibited.

A full encirclement clamp may be used to slow down or eliminate gas flow to more safely enable a permanent repair or pipeline replacement to occur. However, in no case shall the installation of this clamp be buried or left unattended on an in-service pipeline.

5.1.2 Installing Squeeze-Off Units on Polyethylene Pipe

Squeezing the pipe creates an increase in velocity of flowing gas and possible increase in static charge.

Refer to GS 1680.040 “Squeeze-Off Procedure for Plastic Pipe” for guidelines.

5.2 Ten Percent Rule

Polyethylene pipe that has been gouged, nicked or cut to a depth of more than 10% of its wall thickness must be replaced. PVC pipe with the same defects may either be replaced or repaired with an all stainless steel band type clamp. Damages resulting in wall loss of less than 10% require no remedial action.

5.3 Use of Fusion Equipment in Gaseous Atmosphere

Heat fusion tools can be used in the presence of gas provided they are unplugged from their power source. Never enter a gaseous atmosphere with a heating tool that is plugged into a generator or standard current source. Electrofusion equipment and generators are considered potential sources of ignition and shall be kept outside of any gaseous atmosphere.

5.4 Faulty Butt Fusion Joints and Cracks

Faulty butt fusion joints and cracks should be repaired by installing a new section of pipe. In some instances a faulty butt fusion can be repaired by cutting through the joint and connecting the ends with an approved mechanical or electrofusion fitting.

6. REPAIR METHODS

Approved repair methods for dents, grooves, scratches, gouges, and other defects are provided in Table 1.

Approved repair methods for various conditions in steel and wrought iron pipe are provided in Table 2.

Approved repair methods for various conditions in cast iron and ductile iron pipe are provided in Table 3.

Approved repair methods for various defects in polyethylene and PVC pipe are provided in Table 4.

TABLE 1

Repair Methods for Dents, Grooves, Scratches, Gouges, and Other Defects on Steel Pipe*	
Type of Defect	**Type of Repair**
Dent with stress concentrator such as scratch, gouge, groove or arc burn **or** Dent that affects a seam or girth weld	• Install an appropriate type bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) greater than 2% of nominal O.D. on greater than 12.75" O.D. pipe or greater than ¼" deep on pipe less than or equal to 12.75" O.D. pipe	• Install an appropriate type bolt-on clamp or sleeve **or** • Install a welded split sleeve of the appropriate design **or** • Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. **or** • Remove by cutting out and replacing the pipe as a cylinder
Dent (no metal loss) less than 2% of nominal O.D. on greater than12.75" O.D. pipe or less than ¼" deep on pipe less than or equal to 12.75" .D.	• Re-coat
Grooves, Scratches, Gouges, and other defects with less than 12.5% metal loss	• Recoat • Grind/Sand
Grooves, Scratches, Gouges, and other defects with 12.5% and greater metal loss	• Install an appropriate bolt-on clamp **or** • Install a welded split sleeve of the appropriate design **or** • Remove by cutting out and replacing the pipe as a cylinder

***GENERAL NOTE:**
See GS 1730.010 "Transmission Line Field Repair" for repair methods for Transmission Lines.

TABLE 2

REPAIR DEVICE(S)[1] FOR STEEL OR WROUGHT IRON PIPE*			
TYPE OF DEFECT	**125 PSIG OR LESS**	**GREATER THAN 125 PSIG TO 175 PSIG**	**GREATER THAN 175 PSIG**
CORROSION LOCAL PITTING	BAND TYPE CLAMP or PIT HOLE CLAMP		BAND TYPE CLAMP or WELDED SPLIT SLEEVE
LENGTHY PITTING	LONG BAND TYPE CLAMP		WELDED SPLIT SLEEVE OR REPLACE
GENERAL CORROSION	MECHANICAL SPLIT SLEEVE[2] or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP or REPLACE		WELDED SPLIT SLEEVE OR REPLACE
FAILURES RUPTURE (caused by internal pressure)	REPLACE		
PUNCTURE, BREAK or TEAR (caused by external force)	BAND TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	WELDED SPLIT SLEEVE OR REPLACE
CRACK IN PIPE	MECHANICAL SPLIT SLEEVE[2]	WELDED SPLIT SLEEVE	REPLACE
JOINT FAILURES COUPLING: GASKET	RETIGHTEN or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
BARREL	J TYPE CLAMP or MECHANICAL SPLIT SLEEVE[2]		WELDED SPLIT SLEEVE OR REPLACE
CRACK IN WELD	WELDED SPLIT SLEEVE OR REPLACE		
SCREW FITTING	COLLAR LEAK or PIPE JOINT TYPE CLAMP		NA
OTHER BAG OR PURGE HOLES	BAND TYPE CLAMP or SERVICE SADDLE	NA	
LONGITUDINAL SEAM	LONG BAND TYPE CLAMP	WELDED SPLIT SLEEVE OR REPLACE	

*GENERAL NOTES:

a. The repair techniques for higher pressure steel mains are acceptable for lower operating pressure steel mains.
b. Mechanical or welded split sleeves are acceptable alternatives for any mechanical clamp device installation.
c. Refer to manufacturer's instructions for additional pressure limitations for certain repair fittings.

[1] Non-mechanical repair devices (e.g., Trident Seal, Clock Spring, Armor Plate) may also be used subject to pressure limitations of the product and if appropriate for the application per the manufacturer's intended use of such products.

[2] Welded split sleeves may be substituted for mechanical split sleeves.

TABLE 3

TYPE OF DEFECT	REPAIR DEVICE(S) FOR CAST IRON PIPE*
GRAPHITIZATION GENERAL	REPLACE
LOCALIZED	BAND TYPE CLAMP OR REPLACE
FAILURES CRACK IN PIPE	FULL SEAL TYPE CLAMP
JOINT FAILURES COUPLING: GASKET OR BARREL	MECHANICAL SPLIT SLEEVE or ENCAPSULATION
BELL JOINT LEAK	BELL JOINT CLAMP[3], ENCAPSULATION, or ANAEROBIC GASEAL
OTHER BAG OR PURGE HOLES	BAND TYPE CLAMP

*GENERAL NOTES:

a. Mechanical split sleeves are acceptable alternatives for any mechanical clamp device installation.
b. The pipe may be repaired by a clamp or sleeve, provided that the repair clamp or sleeve will cover the graphitized area and the ends of the repair clamp or sleeve are over sound, non-graphitized pipe.

[3] Bell joint leak repair devices are subject to pressure limitations.

Effective Date: 04/22/2019	Leakage: Distribution Pipe Repair	Standard Number: GS 1714.020
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TABLE 4

REPAIR DEVICE(S) FOR POLYETHYLENE OR PVC PIPE		
TYPE OF DEFECT	**POLYETHELENE**	**PVC**
RUPTURE (caused by internal pressure)	REPLACE	
PUNCTURE, BREAK or TEAR (caused by external force)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE
CRACK IN PIPE	REPLACE	
LEAK AT FUSIONS (BUTT, SOCKET, SADDLE OR ELECTROFUSION)	REPLACE	NA
NON-LEAKING DAMAGES (deeper than 10% of wall thickness)	REPLACE	ALL STAINLESS STEEL BAND TYPE CLAMP[4] OR REPLACE

[4] Repairs on PVC pipe using an all stainless steel band clamp require the gasket to extend 2 ½ inches beyond the damage and holes must be less than one third (1/3) the pipe diameter.

Cause No. 45703
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor Data Request Set No. 2

OUCC Request 2-009:
Referring to NIPSCO's pending rate case in Cause No. 45621: a. What amount of operation and maintenance expense was included in the future test year ending of December 31, 2022 for Grade 3 leak remediation? b. What amount of Grade 3 leaks did NIPSCO plan to remediate during the future test year ending December 31, 2022. c. If NIPSCO included Grade 3 leak remediation in Cause No. 45621 for the future test year ending December 31, 2022, please explain why NIPSCO also included amounts in the Cause No. 45703 FMCA Plan for Grade 3 leak remediation.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a. The O&M expense for the future test year ending December 31, 2022 in NIPSCO's pending gas rate case in Cause No. 45621 was not prepared specifically isolating Grade 3 Leak Repairs but rather included an amount of $7,927,564 for O&M for ALL leak repairs and re-inspections. b. The amount of Grade 3 Leak Repairs was not itemized in the future test year ending December 31, 2022 in NIPSCO's pending gas rate case in Cause No. 45621. c. Generally, in this Cause, NIPSCO is requesting recovery of federally mandated costs to address Grade 3 leaks that are in addition to those that were included in base rates. In addition, the Company anticipates identifying additional leaks per year than it has previously. Please see NIPSCO Witness Sylvester's testimony, Questions / Answers 35 and 36 for a description of how NIPSCO determined the incremental O&M expenses

Cause No. 45703
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for inclusion in the Repair Grade 3 Leaks project. Please see Confidential Attachment 3-A for the workpapers that support the incremental costs associated with the Repair Grade 3 Leaks project.

Cause No. 45703
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor Data Request Set No. 2

OUCC Request 2-001:
For O&M Project No. PSCP3-29 Repair Grade 3 Leaks, please answer the following relating to Petitioner's existing process for remediating Grade 3 leaks and the associated cost of remediating Grade 3 leaks in base rates. a. Please explain the existing process of identifying Grade 3 leaks from discovery to remediation of the Grade 3 leak. b. Please provide data from 2018, 2019, 2020, and 2021 that substantiates the time duration from identification to remediation of the Grade 3 leaks in Petitioner's present remediation process. c. Please provide the title, wages, and number of employees presently dedicated (100% of billable time) to remediation of Grade 3 leaks. d. For employees who dedicate some, but less than 100% of their time for Grade 3 leak remediation, please provide the number of employees working on Grade 3 remediation and their percentage of total time separated into their various work responsibilities. e. Does NIPSCO use contractors to remediate Grade 3 leaks? If so, please provide the number of contractors working on Grade 3 remediation and total amount spent by year for contractor labor for Grade 3 leaks.
Objections:
NIPSCO objects to subparts (b) and (d) of this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a. The gas leak survey field technicians investigate and grade the leaks in the field in accordance with Gas Standard 1010.014(IN) (OUCC Request 2-001 Attachment A). Upon the investigation the technicians electronically document and record the leak finding in ESRI Field Maps. This is an application-based platform that is located on the technician's iPad. That electronically recorded leakage data is then pulled into the system within two to five days of entry using a robotic process automation process where a bot pulls the leakage data into the

Cause No. 45703
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necessary systems. The bot pulls the leaks in the Customer Information System and Ventyx, which then creates a leak investigation which is tracked in the Maximo system. NIPSCO continues to monitor the leak until remediated using the Company's standard practices. Please see OUCC Request 2-001 Attachment B for Leakage Classification and Response and OUCC Request 2-001 Attachment C for Leakage: Distribution Pipe Repair, Gas Standard 1714.020.

b. NIPSCO does not track the duration from identification to remediation of Grade 3 leaks since there is no requirement to repair Grade 3 leaks within a certain time period. Some leaks are repaired immediately upon identification and others are inspected annually until remediation is complete.

c. NIPSCO does not have any employees who work on Grade 3 leak remediation full time.

d. NIPSCO does not track the number of employees who work on Grade 3 leak remediation. However, the Company does track the number of hours of gas service work completed each year. For Grade 3 leak remediation, 9,789 hours were spent in 2021, which equates to 4% of gas service work. Through June 13, 2022, 4,462 hours, or 5% of gas service work, have been spent on Grade 3 leak remediation.

e. NIPSCO does not currently utilize contractors to remediate Grade 3 leaks.

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Objections and Responses to
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OUCC Request 2-006:

For O&M Project No. PSCP3-29, and referencing Petitioner's workpaper PSCP3-29_Repair Grade 3 Leaks Estimate and Workpaper_03312022 (Excel file), please answer the following

a. Considering the two tables, Historical Remediation and G3 Leaks Found, on the Remediation tab, please explain why NIPSCO considers it necessary to approximately triple its remediation of Grade 3 leaks from 8,483 remediated leaks in 2020 to 25,902 remediated leaks in 2024.
b. Please explain NIPSCO's process of identification to remediation of Grade 3 leaks as proposed in O&M Project No. PSCP3-29.

Objections:

Response:

a. Improved leak survey technology has driven a significant increase in the number of Grade 3 leaks identified since 2018. The number of leaks that have been discovered but not addressed is currently more than 50,000. Without additional remediation, as you can see from the table below, the number of leaks found has increased year over year in excess of the number that have been remediated each year, and the number of leaks found will continue to grow. In addition, each of those found leaks need to be reinspected annually, which requires resources that could be used for other activities.

Year	Number of Leaks Found
2018	10,514
2019	17,624
2020	21,563
2021	26,510

b. Please see NIPSCO's response to OUCC Request 2-001, subpart a.

Note: Attachment BRK-5, Page 1 is Confidential.

Note: Attachment BRK-5, Page 2 is Confidential.

Note: Attachment BRK-5, Page 3 is Confidential.

SEC. 114. LEAK DETECTION AND REPAIR.

Section 60102 of title 49, United States Code, is amended by adding at the end the following:

"(q) GAS PIPELINE LEAK DETECTION AND REPAIR.—

"(1) IN GENERAL.—Not later than 1 year after the date of enactment of this subsection, the Secretary shall promulgate final regulations that require operators of regulated gathering lines (as defined pursuant to subsection (b) of section 60101 for purposes of subsection (a)(21) of that section) in a Class 2 location, Class 3 location, or Class 4 location, as determined under section 192.5 of title 49, Code of Federal Regulations, operators of new and existing gas transmission pipeline facilities, and operators of new and existing gas distribution pipeline facilities to conduct leak detection and repair programs—

"(A) to meet the need for gas pipeline safety, as determined by the Secretary; and

"(B) to protect the environment.

"(2) LEAK DETECTION AND REPAIR PROGRAMS.—

"(A) MINIMUM PERFORMANCE STANDARDS.—The final regulations promulgated under paragraph (1) shall include, for the leak detection and repair programs described in that paragraph, minimum performance standards that reflect the capabilities of commercially available advanced technologies that, with respect to each pipeline covered by the programs, are appropriate for—

"(i) the type of pipeline;

"(ii) the location of the pipeline;

"(iii) the material of which the pipeline is constructed; and

"(iv) the materials transported by the pipeline.

"(B) REQUIREMENT.—The leak detection and repair programs described in paragraph (1) shall be able to identify, locate, and categorize all leaks that—

"(i) are hazardous to human safety or the environment; or

"(ii) have the potential to become explosive or otherwise hazardous to human safety.

"(3) ADVANCED LEAK DETECTION TECHNOLOGIES AND PRACTICES.—

"(A) IN GENERAL.—The final regulations promulgated under paragraph (1) shall—

"(i) require the use of advanced leak detection technologies and practices described in subparagraph (B);

"(ii) identify any scenarios where operators may use leak detection practices that depend on human senses; and

"(iii) include a schedule for repairing or replacing each leaking pipe, except a pipe with a leak so small that it poses no potential hazard, with appropriate deadlines.

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Northern Indiana Public Service Company LLC's
Objections and Responses to
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OUCC Request 2-002:
Please provide the PHMSA code and associated language Petitioner is using that specifies duration of time a Grade 3 leak may remain prior to remediation.
Objections:
Response:
There is no PHMSA code that specifies the duration of time a Grade 3 leak may remain prior to remediation. However, the Protecting our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act is a self-executing mandate that requires pipeline operators to address the elimination of hazardous leaks and minimize releases of natural gas from pipeline facilities. See the description of the PIPES Act of 2020 starting on page 9 of Attachment B to the Verified Petition. See also Page 22 of NIPSCO Witness Sylvester's testimony. NIPSCO follows the Gas Piping and Technology Committee standards for grading of natural gas leaks, which also specifies the timeline for repair. Grade 1 leaks require immediate repair or continuous action until the conditions are no longer hazardous. Grade 2 leaks require scheduled repair based on probably future hazard. Grade 3 leaks must be inspected annually, but there is no specific timeframe for repair. Please see OUCC Request 2-001 Attachment A for NIPSCO's GS 1010.014(N), which provides NIPSCO's emission reduction activities to comply with the PIPES Act. For Above Ground Leaks on Outside Meter Set Assemblies, Company Practices indicates that some repairs are completed within six to 12 months of discovery.

Cause No. 45703
Northern Indiana Public Service Company LLC's
Objections and Responses to
Indiana Office of Utility Consumer Counselor Data Request Set No. 2

OUCC Request 2-005:
Is a Grade 3 leak hazardous? Please explain your answer.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request is vague and ambiguous as the term "hazardous" is undefined.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: A Grade 3 leak is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. However, a Grade 3 leak can change over time, which is why they are reinspected annually. Given that the number of Grade 3 leaks is currently more than 50,000 and that number continues to grow, it is important to implement a plan to repair Grade 3 leaks before they become more significant and to decrease the number of Grade 3 leaks that need to be reinspected annually. In addition, any fugitive gas emissions, no matter how small, can be harmful to the environment.

Cause No. 45703
Northern Indiana Public Service Company LLC's
Objections and Responses to
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OUCC Request 2-008:
Was the remediation of NIPSCO's Grade 3 leaks included in any prior FMCA Plan? If yes, please provide the Cause No. and Project No. in which those Grade 3 leak remediations were included.
Objections:
Response:
No. Although some leaks may have been addressed as a result of the Fiberglass Riser replacement program, which was included as Project ID PSCP3-14 in this Cause and Project ID PS 8 in Cause No. 45007, there was no specific project for remediating Grade 3 leaks. Please note, these may have been addressed because the riser was replaced, not at the same time the riser was being replaced. In other words, the riser replacement may have had the added benefit of remediating the leak. But, if a leak was present that could not be remediated through the replacement of the riser, it was not also remediated during that work.

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OUCC Request 2-007:
In part, NIPSCO Gas Standard 1010.014-in specifically outlines adherence to some PHMSA requirements. Section 4, Item 5 of this gas standard highlights the practices NIPSCO is using/implementing to address fugitive leaks. Please answer the following questions. a. What percentage, on a volumetric basis, of emission possibilities listed in Table 1, List of Emission Reduction Activities, does Petitioner expect to eliminate with the completion of proposed O&M Project No. PSCP3-29? b. What percentage, on a volumetric basis, of emissions listed in Table 1, List of Emission Reduction Activities, are Grade 3 leaks?
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a. NIPSCO has not historically tracked leaks on a volumetric basis, however the Company is in the process of implementing advanced mobile leak detection ("AMLD") technology, using the Picarro Surveyor. AMLD is the only technology that has been proven in the industry to measure methane emissions at scale. Without having performed a leakage survey over the totality of NIPSCO's system with AMLD, it is challenging to estimate with a high degree of certainty, what percentage reduction Grade 3 leak repair would attribute to emissions reduction. As NIPSCO starts to implement AMLD, direct measurement of methane emissions will allow it to have a better understanding of which leaks account for the most amount of methane emissions. If NIPSCO were to use the initial information that has been gathered to date and try to extrapolate based on initial AMLD trials with the Picarro Surveyor unit, the Company could expect to eliminate approximately 15-20% of its emissions with the Grade 3 leak remediation project.

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b. As part of the initial information gathered through the Picarro implementation, NIPSCO has gathered some volumetric flow rate on Grade 3 leaks. Using this information, NIPSCO estimates that Grade 3 leaks make up 25-30% of all leak emissions.

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OUCC Request 3-005:
Referencing NIPSCO's response to OUCC DR 2-007 which states in part (a): "…the Company could expect to eliminate approximately 15-20% of its emissions with the Grade 3 leak remediation project." The response to part (b) of the same DR states: "…NIPSCO estimates that Grade 3 leaks make up 25-30% of all leak emissions." Please answer the following. a. Has NIPSCO determined the sources of the remaining 70% to 75% of leak emissions? Please explain your answer and provide the sources if available. b. Has NIPSCO determined the magnitude of leak emissions represented by all FMCA projects of Plan III? Please explain your answer. c. Has NIPSCO determined the magnitude of leak emissions that will be remediated by all FMCA projects of Plan III? Please explain your answer and provide the percentage magnitude of reduced emissions per FMCA project if such data is available.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: a. NIPSCO expects Grade 1 and 2 leaks to make up an even split of the remaining 70-75% of leak emissions. These projections are based on preliminary findings through NIPSCOs Picarro pilot. The sources of these leaks vary from meter sets to below ground fittings. NIPSCO does not currently possess enough data to determine which source is most likely to be the source of methane emissions.

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b. NIPSCO has not determined the magnitude of leak emissions represented by all FMCA projects of Plan III because these projects are being implemented to address other federal requirements and may not include emission abatement.

c. NIPSCO has not determined the magnitude of leak emissions that will be remediated by all FMCA projects of Plan III because these projects are being implemented to address other federal requirements and may not include emission abatement.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Brien R. Krieger

Brien R. Krieger
Utility Analyst II
Indiana Office of
Utility Consumer Counselor
Cause No. 45703
Northern Indiana Public Service Co.

July 18, 2022
Date

CERTIFICATE OF SERVICE

This is to certify that a copy of the foregoing has been served upon the following parties of record in the captioned proceeding by electronic service on July 18, 2022.

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