ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Veleta	√		
Ziegner			√

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

APPROVED: DEC 28 2022

ORDER OF THE COMMISSION

Presiding Officers:
Sarah E. Freeman, Commissioner
Greg S. Loyd, Administrative Law Judge

On April 1, 2022, Northern Indiana Public Service Company LLC ("Petitioner," "NIPSCO" or "Company") filed its Verified Petition and case-in-chief, including the prefiled direct testimony and attachments of Alison M. Becker, Manager of Regulatory Policy of NIPSCO; Ryan T. Carr, Manager of Gas TDSIC Engineering and Construction Program of NIPSCO; Steven W. Sylvester, Vice President and General Manager of NIPSCO; Matthew G. Holtz, Director of Asset and Risk Management for NiSource Corporate Services Company ("NCSC"); Brent J. Shuler, Manager Risk Assessment for NCSC; and Elizabeth A. Dousias, Manager of Regulatory for NCSC.

On April 19, 2022, NIPSCO filed corrections to Ms. Becker's and Mr. Holtz's direct testimony. On May 13, 2022, NIPSCO filed corrections to Ms. Becker's, Mr. Carr's, Mr. Holtz's, and Ms. Dousias' direct testimony. On June 21, 2022, NIPSCO filed corrections to Mr. Sylvester's direct testimony. On July 11, 2022, NIPSCO filed corrections to Ms. Becker's direct testimony.

On June 28, 2022, NIPSCO Industrial Group filed its petition to intervene, which was granted by docket entry on July 11, 2022.[1]

On July 18, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed testimony of Mark H. Grosskopf, Senior Utility Analyst at the OUCC, and Brien R. Krieger, Utility Analyst in the OUCC's Natural Gas Division.

On August 1, 2022, NIPSCO filed the rebuttal testimony of Brent. J. Shuler.

On August 9, 2022, the Presiding Officers issued a docket entry with two questions for NIPSCO, to which NIPSCO responded on August 11, 2022.

An evidentiary hearing was held in this matter on August 15, 2022 at 1:30 p.m., in Room 224, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, the prefiled evidence of NIPSCO and the OUCC, along with Industrial Group's Cross Exhibit 1 was admitted into the record without objection.

Based upon the applicable law and the evidence presented, the Commission now finds:

1. Notice and Jurisdiction. Due, legal, and timely notice of the hearing in this Cause was given as required by law. Petitioner is a "public utility" within the meaning of Ind. Code § 8-1-2-1 and an "energy utility" within the meaning of Ind. Code §§ 8-1-2.5-2 and 8-1-8.4-3. NIPSCO is subject to the Commission's jurisdiction for approval of its rates and charges pursuant to Ind. Code § 8-1-2-42. The Commission is authorized by Ind. Code §§ 8-1-8.4-6 and 8-1-8.4-7 to issue a certificate of public convenience and necessity ("CPCN") and to approve cost recovery for projects necessary to comply with federally mandated requirements. Accordingly, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. Petitioner's Characteristics. Petitioner is a public utility organized and existing under the laws of the State of Indiana and having its principal office at 801 East 86th Avenue, Merrillville, Indiana. Petitioner is engaged in rendering electric and gas public utility service in the State of Indiana and owns, operates, manages and controls plant and equipment within the State of Indiana, including Lake County, used for the generation, transmission, distribution and furnishing of such services to the public.

3. Requested Relief. NIPSCO requests (1) approval of a CPCN for a federally mandated Pipeline Safety III Compliance Plan ("Compliance Project"); (2) authority to recover federally mandated costs incurred in connection with the Compliance Project; (3) approval of the estimated federally mandated costs associated with the Compliance Project; (4) authority for the

[1] The companies that comprise the NIPSCO Industrial Group in this Cause are Cargill, Inc., Cleveland-Cliffs Inc., Linde, NLMK Indiana, United States Steel Corporation, and USG Corporation.

timely recovery of 80% of the federally mandated costs through Rider 190 – Federally Mandated Cost Adjustment Rider and Appendix G – FMCA Factors (the "FMCA Mechanism"); (5) authority to defer 20% of the federally mandated costs incurred in connection with the Compliance Project for recovery in NIPSCO's next general rate case; (6) approval of the specific ratemaking and accounting treatment described herein; (7) approval of ongoing review of the Compliance Project; and (8) approval to depreciate the Pipeline Safety III Compliance Plan according to NIPSCO's Commission approved depreciation rates, all pursuant to Ind. Code ch. 8-1-8.4, § 8-1-2-19, § 8-1-2-23 and § 8-1-2-42.

4. <u>Summary of Evidence</u>.

A. <u>Petitioner's Direct Testimony</u>. Ms. Becker provided direct testimony that described NIPSCO's requested relief, the statutory basis for it, and why that relief is in the public interest. She explained that the Compliance Project is a set of 29 projects that together will enable NIPSCO to comply with federally mandated pipeline safety requirements.

Ms. Becker testified NIPSCO is requesting approval to recover the federally mandated capital costs incurred in connection with the Compliance Project, including plan development, engineering, and other costs incurred prior to the commencement of construction. Specifically, NIPSCO is requesting the Commission to approve $228,439,320 as the projected federal mandated project capital costs associated with the Compliance Project, which includes indirect costs but excludes Allowance for Funds Used During Construction ("AFUDC"). However, NIPSCO also seeks approval to record and recover AFUDC associated with the actual Compliance Project based upon the amounts at the time such costs or charges are incurred. Based upon current estimates of AFUDC at the time of the petition filing, the total estimated capital cost, including AFUDC, is $235,292,500. NIPSCO is also requesting approval of federally mandated operation and maintenance ("O&M") costs associated with the Compliance Project totaling $34,072,318 for the period of 2022 through 2026.

Ms. Becker testified NIPSCO typically includes an escalation factor as part of its multi-year compliance and infrastructure plan estimates. She explained that considering the current inflation trends and NIPSCO's recent experience with cost increases, in this proceeding NIPSCO is proposing to apply a 5% annual escalation factor to its base calculations, which is only intended to address expected inflation-based cost increases in material, labor, and other resources – not to address project risk or uncertainty. She explained that escalation is separate and distinct from contingency and addresses different risks (cost increases). She stated that while current inflationary trends are much higher, NIPSCO has included the 5% escalation factor as a reasonable means of accounting for some level of inflation that is now being experienced. She noted that as with all projects, NIPSCO only recovers actual costs, so if the economy stabilizes and costs go down, only actual costs will be included for recovery. The 5% escalation factor is simply NIPSCO's conservative attempt to capture what is foreseeable in terms of the directional increase in the costs of materials and labor. She noted that to the extent inflation continues at higher levels, this escalation will not be sufficient to capture the likely cost increases.

Ms. Becker explained that the Commission approved NIPSCO's FMCA Mechanism on September 19, 2018 in Cause No. 45007, and that pursuant to Ind. Code § 8-1-8.4-7, NIPSCO is requesting approval for the timely recovery of 80% of the Compliance Project costs approved by the Commission in this proceeding and future proceedings through the approved FMCA Mechanism. She provided an overview of the types of costs to be included for recovery as well as an overview of the calculation of the revenue requirement along with the type of information to be provided by NIPSCO in support of each semi-annual FMCA proceeding.

Ms. Becker also provided testimony that the public convenience and necessity will be served by NIPSCO's compliance with the Pipeline and Hazardous Materials Safety Administration ("PHMSA") Rules. The capital investments made in conjunction with the Compliance Project will be used and useful as part of NIPSCO's provision of gas service, and the O&M expenses incurred as part of the Compliance Project will be directly related to the provision of gas service to NIPSCO's gas customers. She explained the Compliance Project is in the public interest since it will enable the Company to comply with the federally mandated PHMSA Rules in an appropriate manner, is consistent with industry best practices, and is within the bounds provided by the General Assembly in the enabling statute.

Mr. Carr provided detailed support for the following six federally mandated projects included in the Compliance Project. Specifically, he sponsored and supported the following projects:

Project No.	Project Name
PSCP3-1	Emergency Valve Installation
PSCP3-2	Isolated Services Installation
PSCP3-3	Pipeline Crossings & Attachments Replacements (Transmission)
PSCP3-4	Pipeline Crossings & Attachments Replacements (Distribution)
PSCP3-5	Regulator Station Remediation
PSCP3-6	Bare Steel Replacement

For each of those projects, he described in detail the work to be performed, how that work would enable compliance with one or more specific provisions of a federal mandate, development of the estimated costs associated with the project, the project alternatives that had been considered to demonstrate the project is reasonable and necessary, and whether each project extended the useful life of an existing facility and the value of any such extension.

Project No. PSCP3-1 – Emergency Valve Installation Project

Mr. Carr described that the Emergency Valve Installation project is to install new emergency valves within pressure systems to create appropriate isolation areas to allow the line to be isolated or to reroute gas as necessary in the event of an emergency. He noted this is generally a continuation of the Emergency Valve Project (Project No. PS17) approved in Cause No. 45007. He testified this project is being undertaken to comply with the provisions of 49 CFR § 192.181(a) requiring valves spaced to reduce the time to shut down a section of main in an emergency, with valve spacing determined by operating pressure, the size of the mains, and the local physical conditions.

Mr. Carr testified NIPSCO projects the federally mandated costs associated with the Emergency Valve Installation project to be $6,072,735 for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained the cost estimate for 2022 was based on proposed Company standards and NIPSCO's previous experience with projects completed through the Emergency Valve Project (Project No. PS17) approved in Cause No. 45007, with the cost estimates for 2023 through 2026 based on the 2022 estimate escalated 5% each year for inflation. Mr. Carr stated that because each system is required to have valves spaced to reduce the time to shut down a section of main in an emergency, it was determined that there was not an alternative for achieving compliance. He stated the Emergency Valve Installation project will not extend the useful life of an existing facility explaining the project involves the replacement and/or new installation of emergency valves as required across NIPSCO's distribution system and is intended to allow NIPSCO to isolate sections of its system to increase safety and reduce risk in the event of an emergency.

Project No. PSCP3-2 – Isolated Services Project

Mr. Carr described that the Isolated Services Installation project is to install new services or replace short sections of distribution main to retire cathodically isolated services to allow NIPSCO to cathodically protect steel lines or replace them as necessary at specific locations. He noted this is generally a continuation of the Isolated Services Project (Project No. PS16) approved in Cause No. 45007. He testified that this project is being undertaken to comply with the provisions of 49 CFR Part 192, Subpart I, that addresses corrosion control. Specifically, 49 CFR § 192.455 and 49 CFR § 192.465 require operators to monitor corrosion on steel pipes appropriate for cathodic protection and promptly remediate any deficiencies, including pipelines isolated from that protection. Isolated services pose increased risk of corrosion and are subject to higher rates of leakage and failure as a result.

Mr. Carr testified NIPSCO projects the federally mandated costs associated with the Isolated Services Installation project to be $7,234,589 for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained the cost estimate for 2022 was based on the costs experienced in 2021, with the cost estimates for 2023 through 2026 based on the 2022 estimate escalated 5% per year for inflation. Mr. Carr testified that NIPSCO considered the best way to replace isolated services and it was determined that the installation of new plastic or cathodically protected steel service lines was the most efficient and cost effective means of achieving compliance. He stated the Isolated Services Installation project could extend the useful life of an existing facility, but it is difficult to determine the extent of any useful life advantage. He explained the primary purpose of the project is to reduce the safety and integrity risk associated with isolated services.

Project No. PSCP3-3 – Pipeline Crossings & Attachments Replacement Project (Transmission) and Project No. PSCP3-4 –Pipeline Crossings & Attachments Replacement Project (Distribution)

Mr. Carr described that the Pipeline Crossings & Attachments Replacement projects will typically involve the replacement of existing gas main which is either above ground or attached to a structure, such as a bridge. He explained that replacement usually involves installation of replacement main through an underground bore, or installation of main and/or regulator stations to replace the function the crossing provides throughout the gas system so the crossing can be retired. He testified that this project is being undertaken to comply with the provisions of 49 CFR § 192.451 through 192.461 (External Corrosion), and 49 CFR § 192.479 and 49 CFR § 192.481 (Atmospheric Corrosion Control), which require the repair or replacement of corroded and or damaged pipe that will directly affect the safe operation of the pipeline system.

Mr. Carr testified NIPSCO projects the federally mandated costs associated with the Pipeline Crossings & Attachments Replacement projects to be $9,694,809 for transmission main crossings and $10,336,876 for distribution main crossings for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained the cost estimate for 2022 was based on NIPSCO's internal estimating program, with the cost estimates for 2023 through 2026 based on the 2022 estimate escalated 5% each year for inflation. Mr. Carr stated that since NIPSCO has determined that replacing crossings and attachments with the installation of new facilities such as direct bore of plastic or steel pipe main, is the most cost-efficient method of replacement, there are no other efficient and equally effective means of achieving compliance. He stated the Pipeline Crossings & Attachments Replacement projects will not extend the useful life of an existing facility. He explained the projects are intended to replace assets, not extend their useful lives.

Project No. PSCP3-5 – Regulator Station Remediation Project

Mr. Carr described that the Regulator Station Remediation project typically involves the complete replacement of an existing regulator station, and/or the installation of pipeline facilities in order to retire the existing regulator station. He explained the stations to be replaced include a regulator in which recommended flow conditions have changed posing a potential risk in their ability to properly regulate pressure. He testified this project is being undertaken to comply with the provisions of 49 CFR § 192.203(b) requiring all materials employed for pipe and components be designed to meet the particular conditions of service and be able to withstand the maximum service pressure and temperature to which it is attached, and 49 CFR § 192.143(a) requiring components of a pipeline to be able to withstand anticipated operating pressures while remaining within the manufacturer's design limitations.

Mr. Carr testified NIPSCO projects the federally mandated costs associated with the Regulator Station Remediation project to be $5,880,681 for the period 2022 through 2024, exclusive of indirect capital and AFUDC. He explained the cost estimate for 2022 was based on proposed Company standards and NIPSCO's previous experience with similar projects completed in 2021. As to alternatives, Mr. Carr stated that NIPSCO initially considered the replacement of just the regulator component on the existing station; however, this proved to be impractical for various reasons including the inability to keep customers in service while work was performed, the physical limitation of replacement regulators not being able to fit within existing stations, and updated design standards for regulator stations requiring additional over pressure protection to increase the level of safety provided to NIPSCO's customers. He stated the Regulator Station Remediation project will not extend the useful life of an existing facility because the existing facility is typically retired from service.

Project No. PSCP3-6 – Bare Steel Replacement

Mr. Carr described that the Bare Steel Replacement project is a continuation of the replacement of approximately 30 of the 75 miles of bare steel pipe that is part of NIPSCO's gas distribution system with modern plastic material. He explained the initial focus will be an additional 16 miles of bare steel pipe that still remains to be replaced in the Gary area,[2] with subsequent years focusing on bare steel pipe remaining in Hammond, Crown Point, South Bend, Angola, Monticello and Goshen. He testified that this project is being undertaken specifically to comply with the federal mandates contained in 49 CFR Part 192, Subpart P, which requires NIPSCO to create and implement a Distribution Integrity Management Program ("DIMP") that includes measures to reduce the risks from failure of its gas distribution pipeline. He stated that execution of the Bare Steel Replacement project will primarily remediate risks associated with corrosion and leaks.

Mr. Carr testified NIPSCO projects the federally mandated capital costs associated with the Bare Steel Replacement project to be $34,124,820 for the period 2023 through 2026, exclusive of indirect capital and AFUDC.[3] He explained that the cost estimate was developed using engineering plans for the remaining work and applying contractor rates and costs for replacement of pipe, services, other physical assets, and restoration using the average per foot cost of main. He stated the costs for inspection, project management and other required project support was developed using internal resources based on past experience during the execution of prior work on bare steel projects and applying this experience to the proposed scope of work for the Bare Steel Replacement project. He noted the estimate was also reviewed by an internal stakeholder team. Mr. Carr explained the projected federally mandated cost for 2023 was based on an average installed per foot of main from 2015 through 2021 of $131.00 per foot and an average service replacement cost from 2020 and 2021 of $1,733.00 per service, with the cost estimates for 2024 through 2026 based on the 2023 estimate escalated 5% each year for inflation. As to alternatives, Mr. Carr stated the primary risks are related to corrosion and leaks. He explained that the bare steel pipe was installed without a protective coating, which, over time, produces continuous system degradation and can cause serious and ongoing corrosion leakage, causing reoccurring integrity concerns. He stated that corrosion is the primary threat that drives the difference in risk between bare steel pipe and plastic pipe, and the replacement of the bare steel assets is the only way to eliminate the associated risks and allow for continued service to NIPSCO's customers. He stated that the Bare Steel Replacement project won't extend the useful life of an existing facility

[2] NIPSCO completed approximately 34 miles of bare steel pipe with modern plastic material in the Gary, Indiana area as part of the Gary Bare Steel Project approved in Cause No. 45183. After that program kicked off, NIPSCO discovered an additional 16 miles of bare steel pipe – those are the 16 miles included here in this project.

[3] There is no work being completed in 2022 because the engineering is not complete.

explaining the project is intended to replace assets, not extend their useful lives. He noted the existing assets will be retired.

Mr. Sylvester provided detailed support for the following nine federally mandated projects included in the Compliance Project. Specifically, he sponsored and supported the following projects:

Project No.	Project Name
PSCP3-7	Pipeline Crossings & Attachments Remediation - Transmission
PSCP3-8	Pipeline Crossings & Attachments Remediation - Distribution
PSCP3-9	Regulator Stations Coating - Transmission
PSCP3-10	Regulator Stations Coating - Distribution
PSCP3-11	Storage Plant Coating
PSCP3-12	Install Vehicle Protection Devices - Transmission
PSCP3-13	Install Vehicle Protection Devices - Distribution
PSCP3-14	Fiberglass Riser Replacements
PSCP3-29	Repair Grade 3 Leaks (Distribution)

For each of those projects, he described in detail the work to be performed, how that work would enable compliance with one or more specific provisions of a federal mandate, development of the estimated costs associated with the project, the project alternatives that had been considered to demonstrate the project is reasonable and necessary, and whether each project extended the useful life of an existing facility and the value of any such extension.

Project No. PSCP3-7 – Pipeline Crossings & Attachments Remediation (Transmission) and Project No. PSCP3-8 – Pipeline Crossings & Attachments Remediation (Distribution)

Mr. Sylvester stated the Pipeline Crossings & Attachments Remediation projects will typically involve the repair of existing gas main, which is either above ground or attached to a structure, such as a bridge. He explained that remediation usually involves coating pipe to eliminate localized pitting to prevent pipe wall loss and will prevent additional pitting and the need to replace these pipes in the future. He stated the project also includes repair of any pipeline support structures such as brackets that are attached to a structure, such as a bridge, or pipe/cable supports. He said NIPSCO has identified 140 transmission and distribution pipeline crossings and attachments that need some form of remedial work. He testified that this project is being undertaken to comply with the provisions of 49 CFR Part 192, Subpart I that addresses corrosion control. Specifically, 49 CFR § 192.485(b) and 487(b) requires operators to repair exposed pipelines when localized pitting occurs or when any support structures are deemed to be inadequate to support the pipeline.

Ms. Sylvester testified NIPSCO projects the federally mandated costs associated with the Pipeline Crossings & Attachments Remediation projects to be $1,723,997 for transmission main crossings and $3,978,455 for distribution main crossings for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained the cost estimate for 2022 was developed with the basis that approximately 28 crossings and attachments will be remediated annually, with an estimated 8 transmission mains and 20 distribution mains being remediated each year of the plan. He stated it has been determined that an average crossings and attachments remediation cost is $39,000 per transmission main and $36,000 per distribution main, which includes all material, labor, and work mobilization. He stated the cost estimates for 2023 through 2026 were based on the 2022 estimate escalated 5% each year for inflation. Mr. Sylvester stated NIPSCO has determined that coating pipe to eliminate localized pitting preventing pipe wall loss, additional pitting, and the need to replace these pipes in the future, is the most cost-efficient method of replacement. There are no other efficient and equally effective means of achieving compliance. He stated the Remediate Pipeline Crossings & Attachments – Transmission Project will extend the useful life by providing corrosion protection.

Project No. PSCP3-9 – Regulator Stations Coating (Transmission) and Project No. PSCP3-10 – Regulator Stations Coating (Distribution)

Mr. Sylvester testified that the Regulator Stations Coating projects involve recoating 320 regulator stations over the five-year plan period to prevent atmospheric corrosion from occurring. He stated NIPSCO has a total of 1,692 regulator stations (211 transmission and 1,481 distribution) and to recoat all 1,692 regulatory stations over the next 25 years, NIPSCO needs to coat approximately 68 stations per year. He explained that NIPSCO determines which regulator stations are the highest priority to recoat each year based on an annual inspection that rates the severity of corrosion on the coating at each of the stations; for this reason, it is difficult to determine the exact split between transmission and distribution regulator stations for future years. He stated that for 2022 (based on a prior annual inspection), NIPSCO has determined that the 68 regulator stations will be split 60% transmission and 40% distribution, and that NIPSCO has used that ratio in estimating the costs for the remaining years 2023-2026.[4] He said that once a regulator station has been recoated, recoating will occur on a 25-year cycle to avoid a more costly replacement of the regulator station should atmospheric corrosion occur. He testified that this project is being undertaken to comply with the provisions of 49 CFR § 192.479, which requires operators to coat above ground piping in order to prevent atmospheric corrosion. Atmospheric corrosion can lead to unsafe operating conditions and unreliable operation of stations that regulate the pressure delivered to gas customers.

Mr. Sylvester testified NIPSCO projects the federally mandated costs associated with the Regulator Stations Coating projects to be $4,497,864 for transmission main regulator stations and $3,768,481 for distribution regulator stations for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained that stations vary greatly in size and coating needs so, based on historical averages from the past several years, NIPSCO has determined an average cost of $22,000 per station, which includes coating materials, contracted inspector costs, and contracted labor. He stated the cost estimates for 2023-2026 were based on the 2022 estimate escalated 5% each year for inflation. Mr. Sylvester stated NIPSCO considered the best way to prevent atmospheric corrosion and it was determined that coating was the most efficient and cost effective

[4] In the tracking proceedings, once a year is closed out, a true up occurs so that the allocation between transmission and distribution is accurate.

means of achieving compliance. He stated the coating will extend the useful life by providing corrosion protection.

Project No. PSCP3-11 – Storage Plant Coating Project

Mr. Sylvester said that the Storage Plant Coating project involves recoating plant equipment at NIPSCO's underground storage plant in Royal Center and Liquefied Natural Gas ("LNG") plant in Rolling Prairie. He explained that both plants have above ground pipelines, processing equipment, valves, structural supports, storage vessels, and other related assets, that are periodically inspected for atmospheric corrosion or pitting, which must be remediated. He stated that once the plant equipment has been recoated, recoating will occur on a 25-year cycle to avoid a costlier replacement of the equipment should atmospheric corrosion occur. He testified the project is being undertaken to comply with provisions of 49 CFR § 192.479 for underground storage and 49 CFR §§ 193.2625 and 193.2627 for LNG facilities, both of which require operators to coat above ground piping and other related structures to prevent atmospheric corrosion, which can lead to an unsafe operating condition and unreliable operation of the plant.

Mr. Sylvester testified NIPSCO projects the federally mandated costs associated with the Storage Plant Coating project to be $1,519,549 for the period 2022 through 2026, exclusive of indirect capital and AFUDC. The cost estimate for 2022 was based on historical average from the past several years. The cost estimates for 2023 through 2026 were based on the 2022 estimate escalated 5% each year for inflation. Mr. Sylvester stated NIPSCO has determined that coating the above ground and other related structures to prevent atmospheric corrosion, is the most cost-efficient means of achieving compliance. He stated the Storage Plan Coating project will extend the useful life by providing corrosion protection.

Project No. PSCP3-12 – Install Vehicle Protection Devices (Transmission) and Project No. PSCP3-13 – Install Vehicle Protection Devices (Distribution) Projects

Mr. Sylvester indicated that the Install Vehicle Protection Devices projects will involve the installation of vehicle protection devices on 65 transmission and 492 distribution regulator stations for a total of 557 to prevent damage to NIPSCO's facilities from vehicles, which could cause unsafe gas pressure to its customers. He stated the regulator stations are risk ranked and installation of the vehicle protection devices will be completed in order from highest to lowest risk. He said NIPSCO has determined that installing vehicle protection devices are an industry standard and the most cost-efficient method of achieving compliance. He testified that this project is being undertaken to comply with the provisions of 49 CFR § 192.317(b) requiring that each above-ground transmission line or main, not located offshore or in inland navigable water areas, be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.

Mr. Sylvester testified NIPSCO projects the federally mandated costs associated with the Vehicle Protection Devices Installation projects to be $685,985 for transmission stations and $2,057,955 for distribution stations for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He stated the cost estimate for 2022 was based on an average cost of $4,000 per transmission station and $9,500 per distribution station, which includes materials, contracted inspector costs, and contracted labor. He said that to complete installation of the vehicle protective devices by the end of the five-year period (2026), NIPSCO anticipates installing vehicle protection devices in 112 stations per year (13 transmission and 93 distribution). He explained that the cost estimates for 2023 through 2026 were based on the 2022 estimate escalated 5% each year for inflation. He stated the Vehicle Protection Devices Installation project will not extend the useful life of an existing facility; however, installation of the Vehicle Protection Devices will provide protection and reduce risk.

Project No. PSCP3-14 – Fiberglass Riser Replacements

Mr. Sylvester testified that the Fiberglass Riser Replacements project is intended to replace fiberglass service risers when they are identified on the NIPSCO distribution system.[5] He explained the capital work consists of the replacement of certain components and parts (such as gas meters, regulators, and meter loops) required to be accounted for as capital costs. He explained the number of fiberglass risers is subject to ongoing review, and it is common for additional risers to continue to be identified (sometimes as many as 20 per week). He stated that in recognition of the fluid number of risers that need to be inspected and replaced, NIPSCO has based its estimates on the number of risers it could replace between 2022 and 2026 based on its experience and work capacity. He provided that NIPSCO plans to remediate an estimated 3,400 fiberglass risers per year, for a total of 17,000 fiberglass risers throughout the plan period. He testified the Fiberglass Riser Replacement project is being undertaken to comply with the provisions of 49 CFR § 192.1007(d) requiring NIPSCO to determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline. These measures must include an effective leak management program (unless all leaks are repaired when found). By addressing the known risk of leaks from fiberglass service risers, the Fiberglass Riser Replacement project is intended to reduce the risks from failure associated with its system in compliance with DIMP, 49 CFR Part 192, Subpart O.

Mr. Sylvester testified NIPSCO projects the federally mandated costs associated with the Fiberglass Riser Replacement project to be $18,005,773 for the period 2022 through 2026, exclusive of indirect capital and AFUDC. He explained the cost estimate is based on the costs relating to the replacement of fiberglass risers approved in Cause No. 45007 in 2019, with the cost estimates for 2023 through 2026 based on the 2022 estimate escalated at 5% each year for inflation. Mr. Sylvester testified there are no other efficient and equally effective means for achieving compliance. He explained the Fiberglass Riser Replacement Project addresses a known risk with high consequence of failure through its elimination with the cost of replacing the fiberglass risers being very small compared to the consequence of a failure. He explained the alternative to a fiberglass riser replacement program is to replace the risers as they fail and as leaks are reported. He testified the programmatic approach is reasonable and necessary because it will allow for the replacement of all risers within a specified time without the risks associated with a riser failure or leak in very close proximity to the building and that NIPSCO will also be in a position to plan the work and procure the needed materials in an efficient way. With that said, NIPSCO will continue

[5] This project is a continuation of the Fiberglass Riser Replacement Project (Project No. PS8) included in NIPSCO's Pipeline Safety Compliance Plan approved in Cause No. 45007. Replacement of fiberglass risers includes both O&M expenses and capital costs. The O&M expenses were approved in Cause No. 45560 and are being recovered through the FMCA tracker.

to replace risers in the event of a leak or failure at the time of the discovery. He stated the Fiberglass Risers Replacement project is an asset replacement project and as such is not intended to extend the life of the assets being replaced.

Project No. PSCP3-29 – Repair Grade 3 Leaks Project

Mr. Sylvester testified that the Repair Grade 3 Leaks project is intended to increase NIPSCO's response to Grade 3 leaks on its system. NIPSCO defines a Grade 3 Leak in its Leakage Classification and Response (Public Exhibit 2, Attachment BRK-1, page 18 of 34) as "[a] leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous." He stated this project will track the incremental O&M expenses to increase leak remediation above the level that was contemplated when base rates were established. He explained that NIPSCO currently has 51,567 Grade 3 leaks identified on its system, and NIPSCO anticipates that over the next five years the cost to remediate approximately 29,411 of these leaks will be covered through the level of leak repair expense that is included in base rates. He stated that apart from the already identified Grade 3 leaks, NIPSCO estimates that it will identify approximately 20,000 additional leaks per year resulting in a total of 162,629 Grade 3 leaks by 2026. He explained this incremental Repair Grade 3 Leaks project will add approximately 65,519 incremental Grade 3 leak remediations over the next five years for a total Grade 3 leak remediation of approximately 94,930 leaks. He said that over the last four years, NIPSCO has remediated an average of 5,882 Grade 3 leaks per year. He noted that in 2021, NIPSCO spent approximately $69.18 for labor and an additional $7.00 for materials per each Grade 3 leak repair, which amounted to a total amount of $448,075 in 2021. He explained that to address the estimated 94,930 Grade 3 leaks of the total estimated 162,629 leaks over the next five years, NIPSCO will need to repair an additional 65,519 over the five-year period, or approximately 13,104 incremental leaks per year at a cost of $168.09 per repair of O&M labor throughout the plan period. He testified the incremental labor cost per repair is costlier than the base cost to repair leaks because NIPSCO will need to spend additional money on onboarding and training servicemen to adequately repair the incremental Grade 3 leaks. He said that additional O&M expenses will consist of $520,567 in incremental material costs over the five-year program. He testified the total cost to repair the incremental 65,519 Grade 3 leaks over the five-year program is $11,533,592 and that most materials and outside services will fall under capital expenses and are not included in this project. He testified that this project is being undertaken to comply with Section 114 of the Protecting Our Infrastructure of Pipelines and Enhancing Safety ("PIPES") Act requiring all operators of regulated pipeline facilities to update their inspection and maintenance plans to address (1) eliminating hazardous leaks of natural gas, (2) minimizing releases of natural gas, and (3) replacement or remediation of all pipelines that are known to leak. Mr. Sylvester stated that there are no other efficient and equally effective means for achieving compliance. He stated that any replacement or remediation that arises from the leak detection would extend the useful life equivalent to the capital investment.

Mr. Holtz provided detailed support for the following 12 federally mandated projects included in the Compliance Project. Specifically, he sponsored and supported the following projects:

Project No.	Project Name
	Storage Projects
PSCP3-15	Underground Storage Integrity Management - Wellhead Valves and Components Replacement - Trenton and Mt. Simon
PSCP3-16	Underground Storage Integrity Management - Well Tubing and Packer Replacement - Trenton and Mt. Simon
PSCP3-17	Underground Storage Well Site Vehicular Protection and Site Security Project - Trenton and Mt. Simon
PSCP3-23	Underground Storage Integrity Management -Wellhead Material Verification and Annulus Pressure Ports Installation – Trenton and Mt. Simon
PSCP3-24	Underground Storage Reservoir Integrity Risk Assessment – Trenton and Mt. Simon
PSCP3-25	Underground Storage Gas Inventory Assessment – Trenton and Mt. Simon
PSCP3-26	Underground Storage Integrity Management Records Management – Trenton and Mt. Simon
PSCP3-27	Underground Storage Integrity Management – Well Integrity Evaluations – Trenton and Mt. Simon
	In-line Inspection (“ILI”) Projects
PSCP3-18	ILI Retrofit – Kern Road to W Warsaw
PSCP3-19	ILI Retrofit – New Haven to Shellhorn
PSCP3-20	ILI Retrofit – Elder to Cleveland Rd.
PSCP3-21	ILI Retrofit – Mayflower to Grandview

For each of those projects, he described in detail the work to be performed, how that work would enable compliance with one or more specific provisions of a federal mandate, development of the estimated costs associated with the project, the project alternatives that had been considered to demonstrate the project is reasonable and necessary, and whether each project extended the useful life of an existing facility and the value of any such extension.

Project No. PSCP3-15 – Underground Storage Integrity Management – Wellhead Valves and Components Replacement – Trenton and Mt. Simon

Mr. Holtz said that the Underground Storage Integrity Management – Wellhead Valves and Components Replacement - Trenton and Mt. Simon project involves the replacement of the existing above ground wellhead valves/components (otherwise known as the Christmas Tree) that include the master valves, the wellhead pipeline isolation valves (i.e., wing valves), and other associated valves, fittings and hardware to join the equipment together to meet compliance requirements of American Petroleum Institute (“API”) Recommended Practice (“RP”) 1171, Section 9.3.2 to ensure wellhead integrity. He stated this project is proposed to replace the existing above ground wellhead equipment that is unable to be functionally repaired as part of the operator’s valve maintenance program. He explained the valves and components date back to 1962 for Trenton and 1972 for Mt. Simon reservoir wells and the existing valves are currently not standard API 6D valve dimensions, which require the wellhead to be rebuilt to fit in new standard API 6D valves.

Mr. Holtz testified NIPSCO projects the federally mandated direct capital costs associated with this project over the five-year period 2022 through 2026 to be $15,259,485. He stated the costs per site can vary based on the scope of each replacement, including impacts to the transmission piping from the well head to the processing plant. He stated that based on its experience to date, NIPSCO is expecting 75% of the wellheads will require valve and associated component replacement, which equates to 108 well head sites over five years for 21 to 22 sites per year.

He stated that NIPSCO has not identified any alternatives to the proposed replacement program. He stated the Underground Storage Integrity Management – Wellhead Valves and Components Replacement - Trenton and Mt. Simon will extend the useful life of an existing facility and that the value of the replacement equipment will be equal to the capital investment.

Project No. PSCP3-16 – Underground Storage Integrity Management – Well Tubing and Packer Replacement Project – Trenton and Mt. Simon

Mr. Holtz testified that the Underground Storage Integrity Management – Well Tubing and Packer Replacement Project – Trenton and Mt. Simon involves the replacement of the well downhole tubing and packer to meet the compliance requirements of API RP 1171, Sections 8.6 and 9.3.2, to ensure well integrity. NIPSCO's 143 wells have tubing and packer installations as part of the original design basis. First, the tubing and packer acts as a safety barrier between the gas/water flow and the well casing. Second, it is utilized as a siphon string in injection and withdraw wells to draw water out of the well to operate the reservoir. The tubing and packer has been in service for Trenton since 1962 and Mt. Simon since 1972. Over time, the tubing has been observed to undergo corrosion and may no longer have the remaining strength to withstand the gas flow pressure. To ensure well integrity and compliance with API RP 1171 Section 9.3.2 the replacement of the tubing and the associated packer is to be completed.[6] This project is focused on the replacement of the tubing and associated packer on 106 wells (71 at Trenton and 35 at Mt. Simon) of a total of 143 wells being assessed as part of NIPSCO's Well Integrity Evaluation Project, which is expected to be completed by 2025. The remaining 37 wells were inspected and mitigated in 2021. He testified that this project is being undertaken to comply with API RP 1171 Sections 8.6 and 9.3.2, which require preventive and mitigative measures for threat and hazards associated with storage wells. Specifically, Section 9.3.2 states operators should monitor for tubular corrosion and evaluate corrosion impact on well integrity and operating pressure using risk assessment. He explained the well tubing and packer acts as an additional pressure containing barrier to the casing and that if the tubing and packer do not have the integrity to contain pressure, these components are unable to act as a pressure containing barrier to the casing. He stated NIPSCO has conducted a review of the impact of corrosion on well integrity and determined that

[6] Section 8.6 is a section of API 1171 that shows (Table 2) the threats and preventative/mitigation programs to monitor and manage risks. Table 2 specifies how to manage well integrity by directly referencing additional sections of the API 1171. This is the section that brings together all of the other sections of API 1171.

a replacement of the existing material will ensure integrity of the tubing and subsequently the casing.

Mr. Holtz testified that NIPSCO projects the federally mandated direct capital costs associated with this project over the four-year period 2022 through 2025 to be $11,904,047. He explained that the costs are based on completing the remaining 106 wells, which includes the installation of the new tubing and packer, including the reconstruction of well head components as needed. Project management, well supervision, and internal labor costs are included. He stated NIPSCO has not identified any alternatives to this project. He stated the Underground Storage Integrity Management - Well Tubing and Packer Replacement Project - Trenton and Mt. Simon Project will extend the useful life of an existing facility and that the value of the replacement equipment will be equal to the capital investment.

Project No. PSCP3-17 – Underground Storage Site Vehicular Protection and Site Security - Trenton and Mt. Simon

Mr. Holtz stated that the Underground Storage Site Vehicular Protection and Site Security – Trenton and Mt. Simon involves the installation of physical protection site security measures at well sites to reduce potential damage from surface category threats (i.e., threats that occur at ground or above ground level such as third party damage or outside force damage to ground level or above ground level wellhead equipment) related to third party damage (intentional/unintentional damage), with the goal of improving well site security and safety to meet the compliance requirements of API RP 1171, Section 10.2.2. He explained that NIPSCO owns and operates 143 wells and the original design basis from 1962 (Trenton) and 1972 (Mt. Simon) accounted for the potential surface category threat of third-party damage, but the threat landscape and threat awareness regarding vandalism and encroachments has changed. He stated this project will consider additional barriers to entry and safety as required by API RP 1171, Section 10.2.2 on 113 sites over the five-year period 2022 through 2026. The remaining 30 sites were completed as part of the Pipeline Safety I Compliance Plan approved in Cause No. 45007 (Project No. PS10).

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project over the five-year period 2022 through 2026 to be $3,085,272. He stated that with 113 sites remaining, NIPSCO is expecting to complete 23 sites per year, with the costs including material, contract labor, project management, and internal resources to complete the work.

The Site Vehicular Protection and Site Security project is being undertaken to comply with API RP 1171, Section 10.2.2, which requires additional barriers to entry and safety related to the latest Surface category threat of third-party damage (intentional/unintentional damage). Specifically, Section 10.2.2 states that operators should implement and maintain site security and safety measures, should evaluate local and site-specific conditions in developing the security measures, and may include requirements for security check points, barricades such as bollards, jersey barriers, or concrete impediments, industrial-type steel mesh fencing, locking gates, security lighting, security cameras, alarm systems, windsocks, wellhead enclosures, valve handles removed, or valves secured, and other means of preventing unauthorized entry or operation of storage facilities. NIPSCO will conduct wellhead risk assessments in 2022 that will define how it will maintain site security and safety from the above listed requirements.

Mr. Holtz stated that NIPSCO has not identified any alternative safety and security measures to comply with the federal requirement. He stated the Underground Storage Site Vehicular Protection and Site Security Project – Trenton and Mt. Simon project will extend the useful life of an existing facility and the value will be equal to the capital investment.

Project No. PSCP3-23 – Underground Storage Integrity Management - Wellhead Material Verification and Annulus Pressure Ports Installation Project – Trenton and Mt. Simon

Mr. Holtz testified that the Underground Storage Integrity Management – Wellhead Material Verification and Annulus Pressure Ports Installation Project – Trenton and Mt. Simon project includes the material documentation and verification of the wellhead equipment, as well as the installation and adjustment of annulus pressure ports to meet compliance requirements of API RP 1171, Section 9.3.1. He stated that accurate wellhead material records and verification of existing material are required to conduct accurate mechanical integrity well risk assessments. He explained that this project will provide an as found schematic and material verification report for 101 wellhead sites, including the well head material ratings, sizes, and function, which will be utilized to support the well risk assessment process required by API RP 1171, Section 9.3.1. He said the remaining 42 wellhead sites were completed in 2021. He noted that during this effort, the annulus pressure ports will be moved above the surface and that NIPSCO's annulus pressure ports were historically buried below surface and, therefore, are not accessible to monitor well integrity. He said that once complete, this project will allow NIPSCO to monitor annular pressure in compliance with API RP 1171, Section 9.3.2.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project over the two-year period 2022 through 2023 to be $739,340. He explained that NIPSCO has a total of 143 wells, 42 of the total were completed in 2021 in conjunction with NIPSCO's well logging activities and new integrity management requirements. He said that here, NIPSCO is requesting to fund through this FMCA request the remaining 101 wells to be completed in 2022 and 2023. He testified this project is being undertaken to comply with API RP 1171, Section 6.2, 6.11, 9.3.1, and 9.3.2. He explained the wellhead material verification portion of the project is supported and required by the following sections of API RP 1171 to support well integrity understanding: Section 6.2 defines design requirements for wellhead equipment and valves to ensure functional integrity requirements. Section 6.11 defines records of well completion (as-built) to support ongoing integrity understanding. Section 9.3.1. requires operators to evaluate the mechanical integrity of each active well, including each third-party well, that penetrates the storage reservoir and buffer zone or areas influenced by storage operations. He stated that well integrity evaluation methods typically used by operators include but are not limited to review of design, completion, and well work records, wellhead and downhole inspection, well pressure monitoring and testing, and gas sampling.

Mr. Holtz testified the installation of annulus pressure ports portion of the project is supported and required by API RP 1171, Section 9.3.2, which requires the verification of well integrity through annular gas pressure and flow monitoring based on the following requirement: "The operator shall monitor for presence of annular gas by measuring and recording annular pressure and/or annular gas flow. The operator shall evaluate each annular gas occurrence that exceeds operator – or regulator-defined threshold levels determined from well integrity evaluation and from risk assessment. The operator should test wellhead seals when annulus pressure is detected and where injectable packing and/or test ports are present." Mr. Holtz stated NIPSCO has not identified any alternatives to this project. He stated the Underground Storage Integrity Management – Wellhead Material Verification and Annulus Pressure Ports Installation Project – Trenton and Mt. Simon project will not extend the useful life of an existing facility; rather, the scope of the improvements performed in this project cannot be capitalized and does not extend the useful life.

Project No. PSCP3-24 – Underground Storage Reservoir Integrity Risk Assessment – Trenton and Mt. Simon

Mr. Holtz indicated that the Underground Storage Reservoir Integrity Risk Assessment – Trenton and Mt. Simon project will provide a baseline geological and engineering reservoir characterization along with completion of a reservoir integrity risk assessment utilizing the information generated from these studies to meet the compliance requirements of Pipeline Safety: Safety of Underground Natural Gas Storage Facilities, 85 FR 8104 (Feb. 12, 2020) ("Final Rule"). He stated the baseline reservoir risk assessment is required by the Final Rule no later than March 13, 2024. He explained the Trenton and Mt. Simon fields currently do not have sufficient data and historical records from the design basis regarding geological and engineering reservoir characterization to support the reservoir risk assessment. He testified this project will complete the needed studies to provide the data and information to complete the reservoir risk assessment along with providing a baseline report to continue to review and update over time.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project for 2022 through 2023 to be $1,028,800 and that the costs include outside services, project management, and additional internal resource time to complete the analysis.

Mr. Holtz stated that the Reservoir Integrity Risk Assessment project is being undertaken to comply with API RP 1171, Sections 9.2.2 and 9.4.1 (along with 5.2 and 5.3), which require activities to conduct geological and engineering reservoir characterization to support the reservoir risk assessment to identify and manage threats from geologic uncertainty. Section 9.2.2 requires that risk assessments shall be used as a basis for developing the integrity demonstration, verification, and monitoring tasks and evaluating their frequency requirements. Section 9.4.1 requires operators to review and update reservoir geological characterizations and mapping as new data become available or if there is evidence of changes in the location of gas or in the level of pressure in the reservoir to identify the limits of the gas and any spill points and points to Section 5.2 for additional information on geological reservoir characterization). Section 5.2 states that the goal of the baseline geological reservoir characterization is to develop a practical understanding of the suitability of the reservoir and the adjacent geologic stratigraphic environment prior to storage development or expansion. Section 5.3 states that the engineering characterization expands upon the geological characterization with the goal to understand, prior to storage development or expansion, the probable response of the reservoir and adjacent areas to the proposed pressure cycling and flow rates. Each of these sections support and require NIPSCO to conduct studies to support reservoir risk assessment work for Trenton and Mt. Simon by the Final Rule required date of March 13, 2024. He stated that NIPSCO has not identified any alternatives to this project. He stated the Underground Storage Reservoir Integrity Risk Assessment Project – Trenton and Mt. Simon will not extend the useful life of an existing facility. He stated this project only provides an understanding of risk and that if remedial steps are taken as a result of the risks identified in this project, the remediation could extend the life of the facility but simply identifying the risk does not.

Project No. PSCP3-25 – Underground Storage Gas Inventory Assessment - Trenton and Mt. Simon

Mr. Holtz stated that the Underground Storage Gas Inventory Assessment – Trenton and Mt. Simon project will support reservoir and well integrity management assessments using the attained data to calculate gas inventory on an annual basis. He explained that currently, gas inventory is managed by simple deposits and withdraws on an ongoing basis. He stated this project will conduct a more robust analysis utilizing methods and considerations explained in API RP 1171, Sections 7.3, 9.5, and 9.6 to identify and ultimately manage threats associated with well and reservoir integrity.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project over the five-year period 2022 through 2026 to be $1,859,260. The inventory assessment report along with bottom hole pressure surveys and project management are included in the project costs. The initial report is planned in 2022 with an expectation to complete 60 bottom hole surveys each year starting in 2023.

He testified the Gas Inventory Assessment project is being undertaken to comply with API RP 1171, Sections 7.3, 9.5, and 9.6, which require pressure and inventory assessments to ensure well and reservoir integrity monitoring and material balance management. Section 7.3.1 states the material balance behavior of a storage reservoir shall be monitored relative to the original design and expected reservoir behavior established prior to commissioning and start-up. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss. Monitoring frequency should be based on factors such as reservoir and well fluid loss potential and flow potential. Section 7.3.2 states that average reservoir pressure versus inventory shall be monitored and compared to expected conditions in order to allow for the discovery and correction of any unexpected conditions. Semiannual field shut-in tests, usually occurring at the point of seasonally high and low inventories, should be conducted for inventory verification. Sections 9.5 and 9.6 provide methodologies and guidance for conducting accurate inventory assessments to support threat prevention for well and reservoir integrity. This project intends to attain the proper amount of data to support external engineering services support to analyze inventory levels to identify integrity concerns related to the wells and/or reservoir. He stated that NIPSCO has not identified any alternatives to this project. He stated the Underground Storage Gas Inventory Assessment Project will not extend the useful life of an existing facility noting this project provides information to understand the available gas downhole, but this project itself does not extend the useful life. If deficiencies are identified from this project, and recommended remedial steps are taken beyond this project, those remedial steps may extend useful life.

Project No. PSCP3-26 – Underground Storage Integrity Management Records Management – Trenton and Mt. Simon

Mr. Holtz said the Underground Storage Integrity Management – Records Management Project – Trenton and Mt. Simon. He testified that today, the majority of the records for NIPSCO underground storage are in paper format and stored in local filing cabinets posing the possible threat of loss during fire, flood, or other natural disaster. Additionally, remote access to the records is becoming more important as the workforce becomes more geographically dispersed and centralized under corporate. He stated this project will take paper records for wellhead, downhole, inventory, and reservoir data and convert it into digital record format with associated meta data to support current and future risk assessment and compliance activities. He explained this project will also document the process for digitizing records on an ongoing basis. He noted the records will be stored on a company records management platform as required by NIPSCO's records retention policy. He explained the record types include well and downhole inspection logs, integrity assessments, inventory data, risk assessments, tests, easements, and many more.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project over the two-year period 2022 through 2023 to be $256,000. He stated the costs are based on utilizing an existing IT platform to store records after being digitized and meta data captured, as well as the inclusion of contractor services to create a records management process and organize documents into the digitized platform.

He testified that this project is being undertaken to comply with API RP 1171, Sections 5, 6, 7, 8, and 9, which require actions associated with records retention, management, and ongoing records availability to support threat/risk management and compliance to the Final Rule. Section 5.6 states accurate and comprehensive records of natural gas storage design activities shall be maintained for the life of the facility. Section 6.11.1 states records of well completion (as-built), well construction and well work activities shall be maintained for the life of the facility. Section 6.11.2 states records relating to permitting, procedures, personnel, and equipment shall be retained for a period that meets regulatory requirements, or where no regulatory requirements exist, intervals as determined by the operator. Section 7.5 states records of natural gas storage testing and monitoring activities covered under this section shall be maintained for the life of the facility. Section 8.8 states the operator shall develop a risk management records retention schedule and management plan and define the records retention period. Risk management documentation can include data used during the risk assessment, P&M (preventative and maintenance) measures employed, and the periodic evaluation of performance metrics. Section 9.8.1 states inspections, tests, patrols, or analysis shall be documented according to the operator's procedures. Section 9.8.2 states the operator shall maintain records of storage inventory assessments for the life of the facility. It is these sections to which NIPSCO will comply by transitioning from paper to digital records with associated meta data fields for future query capability.

Mr. Holtz stated NIPSCO has not identified any alternatives that would protect its locally stored paper based records management program from the risk of loss described above. He stated the Underground Storage Integrity Management - Records Management Project – Trenton and Mt. Simon project will not extend the useful life of an existing facility.

Project No. PSCP3-27 – Underground Storage Integrity Management Well Integrity Evaluations – Trenton and Mt. Simon

Mr. Holtz testified that the Underground Storage Integrity Management – Well Integrity Evaluations – Trenton and Mt. Simon project involves completing 100% of baseline well risk assessments for the remaining 106 wells (71 Trenton, 35 Mt. Simon) to ensure well and reservoir integrity to meet the compliance requirements of API RP 1171, Sections 8 and 9 by the Final Rule due date of March 13, 2027, as well as completing 40% of baseline well risk assessments by the Final Rule due date of March 13, 2024. He stated this project will conduct subsurface (downhole) mechanical integrity monitoring and inspection of the casing for corrosion, wellbore cement for isolation, and reservoir integrity. He explained that noise, temperature, and cameras are also sometimes utilized to confirm well and reservoir integrity. He said that once the inspections are completed, that data will be analyzed to identify integrity concerns that can be monitored or require repair. He noted the well risk assessments will be completed, and a future evaluation interval will be determined.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with this project over the four-year period 2022 through 2025 to be $4,319,782. He stated the costs are based on running casing inspection log, wellbore cement isolation, and reservoir integrity gamma ray and neutron log suite, as well as use of contractor services for project management, well supervision, and NIPSCO personnel support.

He testified this project is being undertaken to comply with API RP 1171, Sections 8.6 and 9.3, which require preventative and mitigative assessments to verify well and reservoir threat and hazards associated with mechanical integrity of each active well. Section 8.6 states the P&M (preventative and maintenance) measures include routine condition monitoring activities since the acquisition and analysis of data provides information upon which additional measures can be implemented. Section 9.3 states the operator shall evaluate the mechanical integrity of each active well, including each third-party well, that penetrates the storage reservoir and buffer zone or areas influenced by storage operations. Well integrity evaluation methods typically used by operators include but are not limited to review of design, completion, well work records, wellhead and downhole inspection, well pressure monitoring and testing, and gas sampling. This project will attain the required downhole data to demonstrate and verify mechanical integrity and utilize the data to complete the well risk assessments to support future evaluation intervals. He stated NIPSCO has not identified any alternatives to this project. He stated the Underground Storage Integrity Management - Well Integrity Evaluations Project - Trenton and Mt. Simon project will not extend the useful life of an existing facility.

ILI Retrofit Projects

Mr. Holtz described the ILI Retrofit Projects. He testified the purpose of NIPSCO's ILI Retrofit projects is to make its transmission pipelines ILI compatible through the installation of launchers and receivers for inline inspection tools, commonly known in the industry as "smart pigs," used in the ILI process. He explained this retrofit process will include the modification of the pipeline to accept such devices by replacing fittings and pipeline configurations that allow the insertion and removal of these smart pigs from the pipeline. He noted that when smart pigs are deployed to perform inspections, they need to be able to pass through the various valves, pipe bends, and fittings in the pipe at a well-defined speed range for effective capture of data through the tool sensors. He noted that many older pipes, such as the ones involved in this project, were engineered and built before the advent of this technology and require modification. He testified the targeted projects include: (1) 32 miles of 20" transmission pipeline between Kern Road (Jackson Road Station) and West Warsaw Station in Warsaw, Indiana, (2) 7.5 miles of 16" transmission pipeline between Cleveland Road (Valve Nest) and Elder Road (Station 8903) running north to south on the east side of the South Bend, Mishawaka regional area, (3) 5.0 miles of 16" transmission pipeline between Grandview and South Shore Road (Station 7980) and Mayflower Rd. (Station 7979) on the west side of South Bend, and (4) 4.6 miles of 12" transmission pipeline between Stellhorn Road (Station 8290) and New Haven Ave. (Station 8273) on the east side of Fort Wayne.

Mr. Holtz testified NIPSCO projects the federally mandated costs associated with the ILI Retrofit projects for the period 2022 through 2023 to be as follows:

- PSCP3-18 - Kern Road to W Warsaw $26,367,616
- PSCP3-19 - New Haven to Stellhorn $11,621,710
- PSCP3-20 - Elder to Cleveland Rd. $11,702,830
- PSCP3-21 - Mayflower to Grandview $10,840,151

He stated that each of the cost estimates were developed by performing a review of the transmission lines by both an initial feasibility study performed by an external consultant and an outside engineering firm to complete the preliminary scope and cost estimate. He explained the pipeline review considered geographic features that were likely to have an impact (ditches, road crossings, site access) and a review of internal records to identify valves, pipe bends, or fittings that would likely need to be replaced and also considered the location of taps on the line that cannot be conveniently or economically removed from service. He stated the cost estimates include utilizing stopples (temporary devices installed to isolate relatively short sections of the line) to replace valves, pipe bends, or fittings without interrupting customer service. He stated the external engineering firm then utilized this review and experience from projects similar in size and scope to develop an estimate for the project. He stated these estimates are considered Parametric Class 4 estimates, and additional work was performed to assess risks, assumptions, and potential environmental impacts associated with each project. He noted that each estimate also incorporates a 30% contingency (Class 4 estimates can permissibly include up to 40%) and includes the original ILI assessment run as a commissioning verification that the pipeline is effectively ILI compatible.

Mr. Holtz testified the ILI Retrofit projects are being undertaken to comply with the provisions of 49 CFR § 192.917, 49 CFR § 192.919, 49 CFR § 192.921 and 49 CFR § 192.935(a) which are provisions of Transmission Integrity Management Program ("TIMP") promulgated under Subpart O, Gas Transmission Pipeline Integrity Management. These code sections address identifying potential threats, how to apply these threats to the assessment process in developing the plan and what additional steps can be taken to prevent and mitigate these threats from advancing. Sections (a) and (c) of 49 CFR § 192.917 provide the most compelling rationale for the use of ILI assessment for pipelines. Section (a) asks the operator to, "identify and evaluate all potential threats to each covered pipeline segment. Potential threats that an operator must consider include, but are not limited to, the threats listed in American Society of Mechanical Engineers ("ASME")/American National Standards Institute ("ANSI") B31.8S, section 2, which are grouped under the following four categories: (1) Time dependent threats such as internal corrosion, external corrosion, and stress corrosion cracking; (2) Static or resident threats, such as fabrication or construction defects; (3) Time independent threats such as third party damage, mechanical damage, incorrect operational procedure, weather related and outside force damage to include consideration of seismicity, geology, and soil stability of the area; and (4) Human error." Section (c) requires an operation to "conduct a risk assessment that follows ASME/ANSI B31.8S, section 5, and considers the identified threats for each covered segment. An operator must use the risk assessment to prioritize the covered segments for the baseline and continual reassessments (§§ 192.919, 192.921, 192.937), …" in order to fully identify a pipeline's susceptibilities. Also directly from ASME B31.8S, section 6 qualifies the advantage of ILI: "Use of a particular integrity assessment method may find indications of threats other than those that the assessment was intended to address. For example, the third-party damage threat is usually best addressed by implementation of prevention activities; however, an inline inspection tool may indicate a dent in the top half of the pipe."

Mr. Holtz explained that TIMP does not prescriptively require specific measures to be implemented, rather the Code is focused on knowledge of the system being assessed, the most effective assessment method deployed to scrutinize the threat(s) and the remediation of conditions based upon the assessment discovered defect. He stated TIMP does not mandate any particular methodology for the performance of assessments, but ILI assesses the broadest range of threat types identified from the industry standard, ASME B31.8S, the standard incorporated by reference, for the assessment of transmission pipelines. He stated PHMSA has required that operators be able to evaluate the severity of anomalies to better understand operability of these systems and to gage when to re-assess these systems.

Mr. Holtz stated that for an operator to evaluate the effects of metal loss threats like external and internal corrosion as well as mechanical damage, construction or manufacturing threats, two assessment processes would need to be deployed: Pressure Testing and DA. He explained that prior to the advent of ILI, inspections of transmission pipe could only be accomplished either from the outside of the pipe or by taking individual pipe segments out of service and isolating them to inspect using tethered inspection technology or hydrostatic pressure testing, either of which would be more expensive, less effective, and more disruptive to the operation of the system than the proposed ILI Retrofit projects. He testified it is impractical to sectionalize segments of transmission pipeline and utilize these techniques which provide less information for assessing risk compared to an ILI; therefore, this project is required to inspect the pipe in an efficient and cost-effective manner.

Mr. Holtz stated the ILI Retrofit projects will extend the useful life of an existing facility. He explained that completion of the ILI Retrofit projects will enable NIPSCO to more effectively interrogate pipe wall conditions, changes and multiple threat interactions on the pipeline to remediate the most susceptible sections, and monitor the complete range of threat types identified during the assessment toward improving the integrity of the pipeline. He stated it is possible this assessment method will afford NIPSCO operations and TIMP stakeholders various remedial options to extend the useful life of the pipeline. He noted the ability to inspect the pipeline is critical to keeping the line in service, operable and reliable. In addition, the value will be equal to the capital investment.

Mr. Shuler provided detailed support for the following two federally mandated projects included in the Compliance Project. Specifically, he sponsored and supported the following projects:

Project No.	**Project Name**
PSCP3-22	Advanced Mobile Leak Detection (Capital)
PSCP3-28	Advanced Mobile Leak Detection (O&M)

For each of those projects, he described in detail the work to be performed, how that work would enable compliance with one or more specific provisions of a federal mandate, development of the estimated costs associated with the project, the project alternatives that had been considered to demonstrate the project is reasonable and necessary, and whether each project extended the useful life of an existing facility and the value of any such extension.

Mr. Shuler testified that the Advanced Mobile Leak Detection ("AMLD") Project includes the purchase of three Picarro Surveyor units. He stated the Picarro Surveyor enabled units consists of four air inlets that are mounted on the front bumper of a vehicle, an Anemometer and GPS that are mounted on the roof of the vehicle, and an analyzer consisting of a cavity ring down spectroscopy unit that is mounted in the vehicle. A tablet is mounted in the front of the vehicle for the driver to see where they should be driving to ensure they are maximizing the coverage of the area where data collection is taking place. While the vehicle is driving, the inlets will sample the air and send it to the analyzer four times per second to determine concentration of methane in the air. The processing unit will combine the analyzer data with the GPS and wind speed data to determine the most likely location of the indication. The GPS and wind speed information will create a field of view so the user is able to understand the total coverage area of the drives. A driver will perform three drives of the identified area, over three nights. Each drive will consist of two passes of each main segment. Driving at night delivers better results as the sun disperses methane faster, the wind is more steady, and there is less traffic. At the conclusion of the final drive, a leak analyst will generate a report from the three drives that shows the location of all leak indications. Once the leak analyst has generated a report and analyzed the data, they will work with the scheduling team to dispatch a leakage inspector to investigate the indications, which will be prioritized based on Picarro Risk Ranking Analytics.[7]

Mr. Shuler explained that NiSource conducted pilots in Indiana, Pennsylvania, and Ohio. He explained the pilots in Indiana and Pennsylvania focused on surveying distribution mains and services for leaks that have a large flow rate that provided insight into how best to deploy the Picarro Surveyor units for detection of leaks with a large volume of methane emissions. He noted the Ohio pilot focused on surveys of recently completed pipeline replacement projects and

[7] The leakage inspectors will investigate all indications using survey techniques described in GS 1708.070. All leaks found during the investigation will be graded according to the appropriate state level version of GS 1714.010.

compliance surveys where the Picarro unit surveyed an area immediately after a traditional walking leak survey had been completed to help inform processes and procedures for a larger deployment of the Picarro Surveyor technology. He stated that based on these findings, NIPSCO expects to find two to three times the number of leaks using AMLD, when compared to traditional leak inspection. He testified this heightened level of leak detection not only achieves compliance with the PIPES Act but also provides NIPSCO with the improved ability to monitor the condition of its system and address leaks that in the past may not have been detected. He testified the costs associated with this project recognize the level of leaks that have historically been addressed, and therefore are related to the investigation and repair of leaks (Grade 1 and Grade 2) that are above the average number of leaks found through traditional means.

Mr. Shuler stated that in coordination with NIPSCO's pilot project, three separate meetings were held with members of the Commission and the Pipeline Safety Division for the purpose of demonstrating the effectiveness of using the Picarro Surveyor units for compliance leak surveys. He stated that at the conclusion of these meetings, NIPSCO presented the staff of the Pipeline Safety Division with the operating procedure for the Picarro Surveyor units, and NIPSCO received positive feedback from the Pipeline Safety Division on its plan for using the Picarro Surveyor for compliance leak surveys.

Mr. Shuler testified NIPSCO projects the federally mandated capital costs associated with the AMLD Project to be $3,600,000 for the period 2022 through 2024, which is based on a NIPSCO negotiated price of $1,200,000 per vehicle, with one Picarro Surveyor unit being purchased in 2022, one in 2023, and one in 2024.

Mr. Shuler testified NIPSCO projects the federally mandated O&M costs associated with the AMLD Project to be $14,335,544 for the period 2022 through 2026. He stated the cost estimate is based on $60,000 per vehicle per year for service charge, $110,485 per vehicle per year for driver, an average of $109,810 per vehicle per year in additional leakage inspection costs, and an average of $2,128,514 per vehicle per year in incremental leak repair costs. He noted that NIPSCO will begin hiring the internal labor needed to repair the additional leaks in 2022 and expects to have the staff completely hired and trained by the end of 2023. He explained the costs for leak inspection and repair are anticipated to drop in 2026, because NIPSCO expects to see a reduction in the number of leaks, due to AMLD, after one full leak inspection cycle (three years) has been completed. He noted the service charge for the Picarro Surveyor units covers the twice-yearly maintenance, 24-hour support, connection to software interface, and full warranty on replacement or repairs of unit components.

Mr. Shuler testified the PIPES Act of 2020 mandates that the PHMSA create rules to require the use of advanced leak detection technology and requires companies to have a plan in place to address emissions and protect the environment. Section 113 required the PHMSA to create a final rule to require operators to conduct leak detection and repair programs using advanced leak detection technology. Section 114 and ADB-2021-01 requires operators to have inspection and maintenance plans that address eliminating leaks and minimizing the release of natural gas. The AMLD project will provide information that will be used to prioritize leaks for repair/replacement.

As to alternatives, Mr. Shuler testified that NIPSCO has investigated and continues to investigate the use of methane detection satellites for advanced leak detection technology. He stated the initial costs of satellite methane detection are approximately 2 times the costs of using the Picarro Surveyor units, on an annualized basis, but with similar results. He stated that using the advanced leak detection technology mandated by the PIPES Act of 2020 shifts distribution leakage inspection of mains and services from traditional walking surveys. He highlighted that some of the safety aspects of using the Picarro Surveyor units include (1) moving from an asset-based inspection to an area-based inspection, (2) reducing the number of missed leaks due to equipment sensitivity, and (3) surveys can be accomplished more frequently, allowing leaks to be detected sooner. He stated the Picarro Surveyor units deliver on NIPSCO's goals to reduce methane emission by quantifying leak rates, which allows NIPSCO to prioritize highest volume leaks for repair or replacement. He stated the AMLD Project will extend the useful life of an existing facility. He explained that while the leak survey detection itself may not extend the useful life of the pipe, any replacement or remediation that arises from the detection would extend the useful life equivalent to the capital investment.

Ms. Dousias explained NIPSCO's FMCA Mechanism, through which NIPSCO proposes to record and recover federally mandated costs associated with the Compliance Project. She provided a description of the cost recovery provided for under Ind. Code ch. 8-1-8.4 (the "FMCA Statute"); an overview of the FMCA Mechanism; an overview of the ratemaking treatment related to the FMCA Mechanism; an explanation of how the FMCA Mechanism revenue requirement and the related factors are calculated; an explanation of how the deferred federally mandated costs will be reflected in NIPSCO's FMCA Mechanism tracker filings; a description of the proposed allocators NIPSCO uses to allocate the various components of the FMCA Mechanism; and a description of the depreciation rates NIPSCO proposes for the federally mandated projects included in the Compliance Project.

Ms. Dousias testified that NIPSCO's books and records are generally kept in accordance with both the FERC Uniform System of Accounts, and with Generally Accepted Accounting Principles, and explained that NIPSCO first sought authority to implement a periodic retail rate adjustment mechanism through which NIPSCO would recover federally mandated costs associated with federally mandated compliance projects for NIPSCO gas as defined by Ind. Code §§ 8-1-8.4-2 and 8-1-8.4-4 in Cause No. 45007 – which was approved by the Commission in its 45007 Order. She explained that NIPSCO calculates a revenue requirement consisting of two components: (1) a return of capital costs including AFUDC and Post In-Service Carrying Charges ("PISCC"); and (2) recovery of all federally mandated expenses associated with the projects. Then NIPSCO multiplies the total revenue requirement by 80% to establish the FMCA Mechanism revenue requirement. She also explained that Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 requires that such costs include capital, operations and maintenance, depreciation, tax, and financing costs. She added that NIPSCO defers as a regulatory asset the remaining 20% of all federally mandated costs incurred in connection with the Compliance Project and records carrying charges on such amounts based on NIPSCO's Commission-approved overall cost of capital until such amounts are recovered through rates.

Ms. Dousias detailed the ratemaking treatment approved in the 45007 Order, including Construction Work in Progress ("CWIP") ratemaking treatment whereby financing costs incurred during the construction period attributable to qualifying capital investments are recovered through an adjustment mechanism. She stated that, in connection with CWIP ratemaking, AFUDC accrual ceases the earlier of the date in which such expenditures receive CWIP ratemaking treatment through the FMCA Mechanism or the date the project is placed in service, with any AFUDC recorded in accordance with Generally Accepted Accounting Principles. She added that NIPSCO recovers 80% of all PISCC incurred in connection with approved compliance projects through the FMCA Mechanism and are calculated by multiplying the net book value of completed project costs that have been placed in service, which are not receiving CWIP ratemaking, by NIPSCO's monthly effective weighted average cost of capital ("WACC") rate for the period in which the costs are in-service.

Ms. Dousias testified that the revenue requirement for capital costs included in the FMCA Mechanism is calculated by multiplying the net book value of the associated eligible projects by NIPSCO's monthly effective WACC, which incorporates the Commission-approved return on common equity and capital structure. These capital costs are grossed-up for all applicable taxes.

Ms. Dousias explained that NIPSCO's accounting practice related to all other federally mandated costs, including all capital, depreciation expenses, tax expenses, and financing costs associated with the Compliance Project, is to defer on the balance sheet, as a regulatory asset, all costs incurred until such amounts are included and recovered in rates through the FMCA Mechanism or a rate base proceeding. As amounts are recovered through rates, NIPSCO relieves the regulatory asset and records expense in the income statement to appropriately match the revenues being recorded with the expenses.

Ms. Dousias testified Ind. Code § 8-1-8.4-7 provides for the timely recovery of federally mandated costs as that term is defined in Ind. Code § 8-1-8.4-4; therefore, NIPSCO will include all capital, depreciation, tax, or financing costs related to the Compliance Project in the FMCA semi-annual tracker filings to recover the associated expenses. She testified these expenses are treated consistently with how the expenses approved as part of NIPSCO's Pipeline Safety Compliance Plan in Cause No. 45007, PHMSA Compliance Plan in Cause No. 45183, and Pipeline Safety II Compliance Plan in Cause No. 45560, are treated.

Ms. Dousias further testified that in accordance with Ind. Code § 8-1-8.4-7, NIPSCO defers as a regulatory asset 20% of all federally mandated costs incurred in connection with the Compliance Project. NIPSCO records carrying charges on such amounts based on NIPSCO's Commission-approved overall cost of capital until such amounts are recovered through rates.

Ms. Dousias explained that following the recent approval from Cause No. 45560 basing the Pipeline Safety II Compliance Plan allocators on NIPSCO's Cost of Service Study from NIPSCO's most recent gas base rate case in Cause No. 44988, NIPSCO proposes that all federally mandated costs associated with the Pipeline Safety III Compliance Plan be based on the allocators set forth in the revenue allocation in Paragraph B.8. of the Joint Stipulation and Settlement Agreement dated March 2, 2022 filed in NIPSCO's gas rate case proceeding in Cause No. 45621. Additionally, NIPSCO proposes to continue to adjust its allocation percentages to reflect the significant migration of customers amongst the various rates to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement in its FMCA Mechanism.

Ms. Dousias stated that NIPSCO is proposing to record, defer, and recover depreciation expense related to the Compliance Project according to NIPSCO's Commission-approved depreciation rates.

Ms. Dousias concluded that in accordance with Ind. Code § 8-1-8.4-7(c)(1), NIPSCO will include the operating income associated with the Compliance Project in the total gas Comparison of Gas Operating Income for purposes of the Ind. Code § 8-1-2-42(g) earnings test. She noted this is consistent with the treatment of earnings associated with both NIPSCO's transmission, distribution, and storage system improvement charges in Cause No. 44403 and 45330, NIPSCO's Pipeline Safety Compliance Plan charges in Cause No. 45007, NIPSCO's PHMSA Compliance Plan charges in Cause No. 45183, and NIPSCO's Pipeline Safety II Compliance Plan charges in Cause No. 45560.

B. <u>OUCC's Direct Testimony</u>. Mr. Grosskopf testified regarding the accounting relief requested by NIPSCO related to NIPSCO's proposed Pipeline Safety III Compliance Plan, and how the associated costs ("compliance costs") will be reflected as recoverable costs within the FMCA Mechanism.

Mr. Grosskopf explained what costs are included for recovery in the FMCA mechanism under the FMCA Statute, and stated NIPSCO's proposed FMCA mechanism is modeled from the FMCA mechanism approved by the Commission in Cause No. 45007 on September 19, 2018, as modified by the Commission Order in Cause No. 45183 on September 4, 2019 and again by the Commission Order in Cause No. 45560 on December 1, 2021. He stated this cost recovery model has been used in subsequent filings for Cause No. 45007 FMCA 1 through FMCA 7. He explained how NIPSCO proposes to allocate costs to be recovered through the FMCA mechanism and testified NIPSCO's FMCA cost allocation proposal is appropriate for this Cause, as well as NIPSCO's proposal to adjust allocation percentages to reflect significant migration of customers among the various rate classes, including identification and explanation of any such adjustment in its prefiled testimony. Mr. Grosskopf concluded he had no concerns with NIPSCO's proposed FMCA cost recovery mechanism but did recommend future tracker filings be made in Cause No. 45703-FMCA-X.

Mr. Krieger testified his analysis included a review to determine if NIPSCO has met the requirements for a finding the public convenience and necessity will be served by NIPSCO receiving a CPCN for a federally mandated compliance project; the Pipeline Safety III Compliance Project is a compliance project under Ind. Code § 8-1-8.4-2; and the Compliance Project will allow NIPSCO to comply directly or indirectly with the PHMSA Rules. He considered in his review and analysis if the costs incurred in connection with the Compliance Project are federally mandated costs under Ind. Code § 8-1-8.4-4.

Mr. Krieger provided his review and analysis for the 29 specific projects contained within the Compliance Project. He noted three projects are continued from Cause No. 45560 (PSCP1, PSCP2, and PSCP9), with the majority of the other projects being similar in scope with cost estimates derived from project experience in Cause Nos. 45007 and 45560. He stated NIPSCO cited various parts of the PHMSA Rule establishing the federal requirements necessary to establish projects as FMCA projects. Mr. Krieger testified his analysis found one proposed project (PSCP3-29) indicates it is not covered by federal mandates.

Mr. Krieger testified NIPSCO's associated PHMSA designation justifies each individual project included in the Compliance Project, except for Project PSCP3-29. He concluded the Compliance Project meets the Code of Federal Regulations and PHMSA Rules, ultimately fulfilling both the TIMP and DIMP requirements.

Concerning Project PSCP3-29 – Repair Grade 3 Leaks, Mr. Krieger testified in support of finding that the Repair Grade 3 Leaks project is not a federally mandated project. He stated he found no specific PHMSA or PIPES Act requirement necessary for NIPSCO to remediate Grade 3 leaks on a specified or immediate time schedule. He sponsored Public Exhibit 2, Attachment BRK-7 in which Petitioner admitted in its Data Request responses that there is "no PHMSA code that specifies the duration of time a Grade 3 leak may remain prior to remediation." Mr. Krieger identified language in the PIPES Act stating there is no required schedule for repairing "a pipe with a leak so small that it poses no potential hazard." Public's Exhibit No. 2, page 12, lines 9-16.

Mr. Krieger reviewed two applicable NIPSCO Gas Standards ("GS") for leak categorization and leak remediation. He noted that neither GS 1714.010(IN) *Leakage Classification and Response*, nor GS 1010.014(IN) *Natural Gas Emission Reduction Plan* include a requirement for Grade 3 leak repair. GS 1714.010(IN) only requires such leaks be "surveyed" not less than every 15 months. *Id*., Attachment BRK-1, page 22.

Based on NIPSCO's responses to a series of OUCC Data Requests, Mr. Krieger stated NIPSCO presently has approved annual O&M expenses in base rates in excess of $7.2M to remediate "all" gas leaks, including Grade 3 leaks. He testified NIPSCO has known about, and has been tracking, Grade 3 leak data since at least 2018. Mr. Krieger testified, based on NIPSCO responses to OUCC Data Requests, that NIPSCO does not initially consider a Grade 3 leak hazardous, but reinspects the leaks according to GS 1714.010(IN) and GS 1010.014(IN) to determine if remediation is necessary. *Id*., page 12, lines 18-20.

Mr. Krieger sponsored two NIPSCO responses to OUCC Data Requests, one of which (Public Exhibit 2, Attachment BRK-8) NIPSO stated "[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 of time," which Mr. Krieger noted is performed according to a particular schedule.

Mr. Krieger recognized remediation of Grade 3 leaks is a normal practice of NIPSCO operations. He pointed not only to NIPSCO's O&M expenses, but also to an approved FMCA project in Cause No. 45007 – Project ID PS8 Fiberglass Riser Replacements, which proactively avoids potential leaks. He also noted NIPSCO is requesting approval to continue fiberglass riser replacements at different locations in this Cause via Project PSCP3-14. *Id*., page 13, lines 6-9.

He concluded that his analysis is Repair Grade 3 Leaks project is not federally mandated, and NIPSCO can continue to remediate Grade 3 leaks with O&M expenses recovered through its base rates. *Id*., page 14, lines 4-6. Mr. Krieger recommended the Commission remove Project PSCP3-29 - Repair Grade 3 Leaks from the Compliance Project, approve a modified Compliance Project with his recommended removal of the Repair Grade 3 Leaks project, and issue a CPCN for the Compliance Project. *Id*., page 15, lines 10-13.

C. Petitioner's Rebuttal Testimony. Mr. Shuler testified in response to Mr. Krieger's testimony. Mr. Shuler stated that Project PSCP3-29 is being undertaken to comply with a federally mandated requirement. He said Project PSCP3-29 directly responds to the Advisory Bulletin (86 FR 31002) associated with the PIPES Act, which references the need for operators to "minimize releases of natural gas from pipeline facilities." PIPES Act Section 115, Subsection D (codified in Section 60108 of Title 49). He testified Operators are required to "update their inspection and maintenance plans to identify procedures to prevent and mitigate both vented/intentional and fugitive/unintentional pipeline emissions." 87 FR 4327. Mr. Shuler stated that Project PSCP3-29 explicitly describes a compliance project that allows NIPSCO to comply with the PIPES Act by reducing natural gas emissions from NIPSCO's pipeline facilities through the remediation of Grade 3 leaks through its Methane Reduction Plan. He testified Project PSCP3-29 directly responds to the PIPES Act requirement that NIPSCO update its plans to mitigate pipeline emissions.

Mr. Shuler further stated that with technological advancements in leak detection, the Grade 3 leaks identified on NIPSCO's system have grown dramatically in recent years, and with the addition of the Picarro Surveyor technology, NIPSCO anticipates identifying an increased number of incremental leaks each year. He explained that project PSCP3-29 estimates remediating approximately 65,000 incremental Grade 3 leaks over the project term through 2026 in addition to those Grade 3 leaks remediated in base rates. Without the Commission's approval of the Grade 3 Leaks project here, identification of new Grade 3 leaks will outpace the remediation of monitored leaks.

Mr. Shuler provided that the O&M expenses recovered through NIPSCO's base rates are for remediation and re-inspection of all leaks on NIPSCO's system, which leaves few resources to inspect and remediate Grade 3 leaks that are responsible for a significant percentage of fugitive/unintentional leaks on NIPSCO's system. Project PSCP3-29's federally mandated costs to minimize releases of natural gas associated with Project PSCP3-29 are incremental to the O&M expense included in NIPSCO's most recent rate case (Cause No. 45621).

D. Petitioner's Responses to August 9, 2022 Docket Entry Questions. In response to the Commission's August 9, 2022 docket entry, NIPSCO provided additional clarity regarding the average cost of Grade 3 leak repairs. In addition to explaining the confidential workpaper provided with the filing, NIPSCO explained how the average cost included in this filing included non-productive time for employees, which includes onboarding, training,[8] and other non-productive time, including vacation and sick time. NIPSCO further explained that the $76.18 amount from 2021 would be comparable to an average cost of $86.46 in the proposed plan.

[8] A new serviceman employee is not able to perform Grade 3 leak repair for one full year because of the time of training, qualifications, and experience needed to perform the work on their own. After that first full year, NIPSCO plans for approximately 70% of the employee's time to be spent on actual leak repair and the remaining time will be considered non-productive for meetings and additional training, vacation, sick leave or other items.

Furthermore, NIPSCO explained that all positions included in this Compliance Project for the Grade 3 Leaks project are new positions for the Company.

5. <u>Commission Discussion and Findings</u>.

A. <u>CPCN</u>. Before granting a CPCN under Ind. Code ch. 8-1-8.4, we must (1) find that public convenience and necessity will be served by the proposed compliance project, (2) approve the costs associated with the project, and (3) make a finding on each of the factors in Ind. Code § 8-1-8.4-6(b). Those factors are:

> (A) A description of the federally mandated requirements . . . that the energy utility seeks to comply with through the proposed compliance project.
> (B) A description of the projected federally mandated costs associated with the proposed compliance project . . ..
> (C) A description of how the proposed compliance project allows the energy utility to comply with the federally mandated requirements described by the energy utility under Clause (A).
> (D) Alternative plans that demonstrate that the proposed compliance project is reasonable and necessary.
> (E) Information as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension.

Ind. Code § 8-1-8.4-6(b); *See also Northern Ind. Pub. Serv. Co.*, Cause No. 45560, at 16-17 (IURC 12/01/2021) (consideration of Pipeline Safety II Compliance Project); *Northern Ind. Pub. Serv. Co.*, Cause No. 45183, at 17 (IURC 09/04/2019) (consideration of PHMSA Compliance Project); *Northern Ind. Pub. Serv. Co.*, Cause No. 45007, at 11 (IURC 09/19/2018) (consideration of Pipeline Safety Compliance Plan); *Northern Ind. Pub. Serv. Co.*, Cause No. 44340, at 5 (IURC 01/29/2014) (consideration of Critical Infrastructure Protection Compliance Plan); *Northern Ind. Pub. Serv. Co.*, Cause No. 44889, at 5 (IURC 07/12/2017) (consideration of North American Electric Reliability Corporation Compliance Project); and *Northern Ind. Pub. Serv. Co.*, Cause No. 44872, at 31 (IURC 12/13/2017) (consideration of Environmental Compliance Project).

i. <u>Federally Mandated Requirements</u>. The term "federally mandated requirement" is defined as "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with any of the following: . . . (5) Standards or regulations concerning the integrity, safety, or reliable operation of: (A) transmission; or (B) distribution; pipeline facilities[ ]" as well as "(7) [a]ny other law, order, or regulation administered or issued by the United States Environmental Protection Agency, the United States Department of Transportation, the Federal Energy Regulatory Commission, or the United States Department of Energy." Ind. Code § 8-1-8.4-5.

As stated above, NIPSCO is an "energy utility" as defined by Ind. Code § 8-1-8.4-3. Ms. Becker sponsored Attachment 1-A, Attachment B providing a detailed and comprehensive explanation of both the history of pipeline safety regulation and the origin and intent of the current federal regulatory scheme including the introduction of proactive, risk-based regulatory initiatives such as DIMP and TIMP embodied in the provisions of the performance standards promulgated by PHMSA, a branch of the U.S. Department of Transportation, pursuant to their statutory authority.

No party has disputed that the PHMSA Rules are a federally mandated requirement as defined in the FMCA Statute. Based on our review of the evidence, the applicable federal pipeline safety performance standards codified generally under 49 CFR Part 192 and consistent with previous determinations of the Commission, we find that federal pipeline safety performance standards promulgated by PHMSA are federally mandated requirements under Ind. Code § 8-1-8.4-5 and NIPSCO has satisfied the requirement of Ind. Code § 8-1-8.4-6(b)(1)(A). *See Northern Ind. Pub. Serv. Co.*, Cause No. 45560, at 17 (IURC 12/01/2021); *Northern Ind. Pub. Serv. Co.*, Cause No. 45183, at 18 (IURC 09/04/2019); *Northern Ind. Pub. Serv. Co.*, Cause No. 45007, at 12 (IURC 07/12/2017) and *Southern Indiana Gas & Elec. Co.*, Cause No. 44429, at 14 (IURC 08/27/17).

ii. <u>Projected Federally Mandated Costs</u>. Ms. Becker testified that NIPSCO's total projected capital cost estimate for the Compliance Project is $235,292,500 (inclusive of direct, indirect, and AFUDC) and that an additional $34,072,318 of O&M costs (exclusive of depreciation expense, property tax expense, and other taxes) should be eligible for ratemaking treatment and tracker recovery according to the provisions of the FMCA Statute. NIPSCO provided detailed information about the process used to develop cost projections for each project included in the Compliance Project and provided year-by-year estimated expenditures by project in its testimony and exhibits.

In its response to the Commission's August 9, 2022 docket entry, NIPSCO explained how the estimate for the Grade 3 leaks project was developed and provided a direct comparison to the 2021 costs. This provided the Commission with a more meaningful comparison related to expected costs of the project.

The evidence presented describes the projected federally mandated costs associated with the Compliance Project and demonstrates that the cost estimates are based on multiple sources of information. The evidence also adequately identifies the factors that could cause the cost estimates to change. Based on our review of the evidence, we find that NIPSCO's cost estimates for the Compliance Project, as depicted in Petitioner's Exhibit No. 1, Attachment 1-A, Third Revised Attachment A, are reasonable. Therefore, we approve the projected federally mandated costs associated with the Compliance Project as required by Ind. Code §8-1-8.4-7(b)(2). In addition, we find that NIPSCO has satisfied the requirement of Ind. Code § 8-1-8.4-6(b)(1)(B).

iii. <u>Compliance Project</u>. Mr. Carr, Mr. Sylvester, Mr. Holtz, and Mr. Shuler testified that each of the projects included in the Compliance Project are each driven by federal pipeline safety standards and explained how each is intended to permit NIPSCO to comply directly or indirectly with those standards. With the exception of Project No. PSCP3-29 – Repair Grade 3 Leaks, no party disputes that the Compliance Project will allow NIPSCO to achieve compliance with a federally mandated requirement (*i.e.*, the PHMSA Rules). We therefore turn our attention to Project No. PSCP3-29 and whether it qualifies as a Compliance Project.

A "Compliance Project" is defined in Ind. Code 8-1-8.4-2 as a project that is:

> (1) undertaken by an energy utility; and
> (2) related to the direct or indirect compliance by the energy utility with one (1) or more federally mandated requirements.
>
> (b) The term includes:
> (1) an addition; or
> (2) an integrity, enhancement, or a replacement project;
>
> undertaken by an energy utility to comply with a federally mandated requirement . . .

Ind. Code § 8-1-8.4-5 defines a "federally mandated requirement" as "a requirement that the commission determines is imposed on an energy utility by the federal government in connection with . . . [s]tandards or regulations concerning the integrity, safety, or reliable operation of: (A) transmission; or (B) distribution[] pipeline facilities."

49 U.S.C. § 60108(a) requires the following:

> (1) Each person owning or operating a gas pipeline facility[9] or hazardous liquid pipeline facility[10] shall carry out a current written plan (including any changes) for inspection and maintenance of each facility used in the transportation and owned or operated by the person.
>
> (2) . . . A plan required under paragraph (1) must be practicable and designed to meet the need for pipeline safety, must meet the requirements of any regulations promulgated under [49 U.S.C. § 60102(q)] . . . In deciding on the adequacy of a plan, the Secretary or authority shall consider . . .
>
> **(D)** the extent to which the plan will contribute to--
> > **(i)** public safety;
> > **(ii)** eliminating hazardous leaks and minimizing releases of natural gas from pipeline facilities; and
> > **(iii)** the protection of the environment; and
>
> **(E)** the extent to which the plan addresses the replacement or remediation of pipelines that are known to leak based on . . . past operating and maintenance history of the pipeline.

The PHMSA noted in an advisory bulletin the obligatory nature of minimizing releases of natural gas and the protection of the environment requirements. Here, PHMSA stated the "PIPES Act of 2020 contains self-executing provisions **requiring** pipeline facility operators to update their inspection and maintenance plans to address the elimination of hazardous leaks and minimization

[9] 49 U.S.C § 60101(a)(3) states that a "'gas pipeline facility' includes a pipeline, a right of way, a facility, a building, or equipment used in transporting gas or treating gas during its transportation."
[10] 49 U.S.C. § 60101(a)(5) states that "'hazardous liquid pipeline facility' includes a pipeline, a right of way, a facility, a building, or equipment used or intended to be used in transporting hazardous liquid."

of releases of natural gas . . . from their pipeline facilities" (emphasis added). Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities, 86 Fed. Reg. 31002, 31002 (June 10, 2021). Further, PHMSA stated in this advisory that "Operators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history." *Id*.

Pertinent to the protection of the environment, PHMSA notes in its advisory bulletin that "Natural gas is composed primarily of methane, therefore leaks and other releases of natural gas emit methane gas into the atmosphere. According to the U.S. Environmental Protection Agency (EPA), methane is a potent greenhouse gas with a global warming potential (GWP) of 28–36 over 100 years" (internal citation omitted). *Id*. at 31002.

We therefore find that NIPSCO is under a federally mandated requirement to update its inspection and maintenance plans to minimize releases of natural gas from its pipeline facilities and to protect the environment.

As to whether NIPSCO is under a federal requirement to implement its revised inspection and maintenance plans, 49 U.S.C. § 60801(a)(2)(E) states that operators' updated plans will be evaluated regarding "the extent to which the plan addresses the replacement or remediation of pipelines that are known to leak based on . . . past operating and maintenance history of the pipeline." Further, 49 U.S.C. § 60801(a)(1) states operators "shall **carry out** a current written plan . . . for inspection and maintenance" (emphasis added). NIPSCO provided a PHMSA advisory bulletin, in which PHMSA stated, in part, that "[d]eveloping and **implementing** comprehensive written O&M plans is an effective way to eliminate hazardous leaks and minimize the release of natural gas from pipeline systems.[11] PHMSA anticipates these self-executing statutory mandates will result in enhanced public safety and reductions in pipeline emissions thereby reducing impact on the environment" (emphasis added). Pipeline Safety: Statutory Mandate to Update Inspection and Maintenance Plans to Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas from Pipeline Facilities, 88 FR 31002 (June 10, 2021). This statutory language and PHMSA guidance all indicate that operators are required to implement their revised inspection and maintenance plans.

The OUCC and the Industrial Group contend that neither PHMSA nor the Pipes Act of 2020 require NIPSCO to repair Grade 3 leaks. They assert that operators are merely required to update their inspection and maintenance plans, not actually implement those plans due to the lower risk associated with Grade 3 leaks. NIPSCO defines a Grade 3 leak in its Leakage Classification and Response as "[a] leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous." As support, they reference the requirement under 49 U.S.C. § 60102(q)(3)(A)(iii) ("Subsection (iii)") that the Secretary of Transportation promulgate final regulations that " 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" (emphasis added).

[11] The Commission notes that Petitioner did not submit this bulletin until its rebuttal evidence. Petitioner is reminded to submit supporting documentation as part of its case-in-chief.

In response, NIPSCO argues that pursuant to 49 U.S.C. § 60108(a)(2)(D), NIPSCO is required to eliminate hazardous leaks in addition to minimizing releases of natural gas. NIPSCO therefore submits that the OUCC and the Industrial Group's argument does not account for this second requirement. Additionally, we note that Subsection (iii) does not state that a repair is not required, it only states that a final regulation does not need to include a repair schedule for small leaks that pose no potential hazard. Subsection (iii) does not impact the mandatory implementation requirements discussed above.

We therefore find that NIPSCO is under a federally mandated requirement to update and implement its inspection and maintenance plans to minimize releases of natural gas from its pipeline facilities and to protect the environment.

NIPSCO argues that Project PSCP3-29 implements its Natural Gas Emission Reduction Plan (Public Exhibit 2, Attachment BRK-1) ("Reduction Plan") to comply with the Pipes Act. The Reduction Plan's Overview section states that the plan addresses public safety, eliminating hazardous leaks, minimizing releases of natural gas from pipeline facilities, protection of the environment, pipeline remediation activities, and pipeline replacement programs. The Reduction Plan includes a leak management program. The Reduction Plan further sets forth in Table 1 a list of 35 emission reduction activities that, according to the Reduction Plan, "reduce natural gas emissions."

The OUCC and Industrial Group argue that NIPSCO's existing plans do not require repairs of Grade 3 leaks. They state that NIPSCO's Reduction Plan merely references NIPSCO's Leak Classification and Response to evaluate potential hazards, rather than require repairs. They note the Leak Classification and Response plan states the following regarding Grade 3 leaks:

> 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.

NIPSCO replied to these counterarguments in stating that the question is not whether the Reduction Plan requires repairs, but rather, whether such repairs are federally mandated. We note that Project PSCP3-29, through the repair of Grade 3 leaks, will minimize releases of natural gas from pipeline facilities and protect the environment, two of the activities referenced in the Reduction Plan Overview.

The OUCC and the Industrial Group further argue that the Leak Classification and Response language "suggest that a Grade 3 leak may resolve itself without further action, and if that occurs, periodic inspections would no longer be required." No evidence was presented as to the likelihood of this possibility nor how long such a process may take. Regardless, the federal mandate above requires NIPSCO to take affirmative action.

Based on our review of the evidence, and our determination that the Repair Grade 3 Leaks project should be approved, we find that the Compliance Project constitutes a federally mandated "compliance project" under Ind. Code § 8-1-8.4-2 because each component project will be undertaken by an energy utility (NIPSCO) and is related to the direct or indirect compliance with federal pipeline safety standards – federally mandated requirements. Therefore, we find that NIPSCO has satisfied the requirement of Ind. Code § 8-1-8.4-6(b)(1)(C).

iv. Alternative Plans. Mr. Carr, Mr. Sylvester, Mr. Holtz, and Mr. Shuler provided testimony about the availability of alternative approaches for compliance with respect to the Compliance Project. The record demonstrates how the proposed projects were considered against other approaches but that the other approaches would not address the risks associated as effectively as would the Compliance Project. Based on our review of the evidence, we find that NIPSCO considered alternative plans for compliance with the PHMSA Rules. The evidence shows that the Compliance Project is reasonable and necessary. Therefore, we find that NIPSCO has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(D).

v. Useful Life of Facilities. Mr. Carr, Mr. Sylvester, Mr. Holtz, and Mr. Shuler described how each project within the proposed Compliance Project could impact the useful lives of facilities on its system. The record evidence shows that the Compliance Project is intended to either replace NIPSCO assets, not extend their useful lives, or will have no impact on the useful life of a facility but will provide a benefit by increasing safety and reducing risk. Based on the evidence presented, we find that NIPSCO has satisfied the requirements of Ind. Code § 8-1-8.4-6(b)(1)(E).[12]

vi. Conclusion. The evidence presented demonstrates that the amended Compliance Project will allow NIPSCO to comply directly or indirectly with the PHMSA Rules – a federally mandated requirement. We have made a finding on each of the factors described in Ind. Code § 8-1-8.4-6(b) and approved the projected federally mandated costs associated with the amended Compliance Project. Therefore, we approve the amended Compliance Project and issue NIPSCO a CPCN for the project under Ind. Code 8-1-8.4-7(b).

B. Cost Recovery. Ind. Code § 8-1-8.4-7(c) states:

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
>
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
>
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service

12 This section of the FMCA Statute only requires that the energy utility provide "[i]nformation as to whether the proposed compliance project will extend the useful life of an existing energy utility facility and, if so, the value of that extension."

> carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the commission.
>
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

i. <u>FMCA Mechanism</u>. NIPSCO requested authority to utilize its existing FMCA Mechanism, for the timely and periodic recovery of 80% of the federally mandated costs. Ind. Code § 8-1-8.4-7 provides that an energy utility may, in a timely manner, recover 80% of all federally mandated costs through a periodic rate adjustment mechanism. Ind. Code §§ 8-1-8.4-4 and 8-1-8.4-7 provide that such costs include capital, O&M, depreciation, tax, and financing costs through a periodic rate adjustment mechanism.

Ms. Dousias described how capital costs are incorporated into the FMCA Mechanism. She testified the revenue requirement for capital costs included in the FMCA Mechanism are calculated by multiplying the net book value of the eligible projects by NIPSCO's WACC, which incorporates the Commission-approved return on common equity and capital structure, grossed-up for all applicable taxes.

Ms. Dousias described how all other federally mandated costs (including O&M, depreciation expenses, tax expenses, and financing costs) are incorporated into the FMCA Mechanism. She testified that NIPSCO's accounting practice related to these costs is to defer on the balance sheet, as a regulatory asset, all costs incurred until such amounts are included and recovered in rates through the FMCA Mechanism or a rate base proceeding. As amounts are recovered through rates, NIPSCO relieves the regulatory asset and records expense in the income statement in order to appropriately match the revenues being recorded with the expenses. These expenses would be treated consistently with how the expenses were treated and approved as part of the Pipeline Safety Compliance Plan in the 45007 Order, the PHMSA Compliance Plan in the 45183 Order, and the Pipeline Safety II Compliance Plan in the 45560 Order.

Ms. Dousias described how the FMCA Mechanism revenue requirement is calculated. She stated that, in each semi-annual filing, NIPSCO calculates a revenue requirement which consists of two components: (1) a return of capital costs including AFUDC and PISCC, and (2) recovery of all federally mandated expenses associated with the projects. Then NIPSCO multiplies the total revenue requirement by 80% to establish the FMCA Mechanism revenue requirement.

Based on the evidence presented, NIPSCO's request for authority for the timely recovery of 80% of the federally mandated costs incurred in connection with the Compliance Project through its currently approved FMCA Mechanism is approved.

ii. <u>Ratemaking and Accounting Treatment for the FMCA</u>. With respect to the treatment of operating income, Ms. Dousias testified that, in accordance with Ind.

Code § 8-1-8.4-7(c)(1), NIPSCO will include the operating income associated with the Compliance Project in the total gas Comparison of Gas Operating Income for purposes of the Ind. Code § 8-1-2-42(g) earnings test. She stated this is consistent with the treatment of earnings associated with both NIPSCO's transmission, distribution, and storage system improvement charges in Cause Nos. 44403 and 45330, NIPSCO's Pipeline Safety Compliance Plan charges in Cause No. 45007, NIPSCO's PHMSA Compliance Plan charges in Cause No. 45183, and NIPSCO's Pipeline Safety II Compliance Plan charges in Cause No. 45560.

Ms. Dousias explained NIPSCO's ratemaking treatment under the proposed FMCA Mechanism would include (1) implementing CWIP ratemaking treatment associated with the Compliance Project until such costs receive either CWIP ratemaking treatment through the FMCA Mechanism, are placed in service, or are otherwise reflected in NIPSCO's base rates; and (2) recovering through the FMCA Mechanism 80% of all PISCC incurred in connection with approved compliance projects.

Ms. Dousias testified that in addition to the recovery of these capital costs, NIPSCO requests the timely recovery through the FMCA Mechanism of reasonably incurred O&M, depreciation expenses, tax expenses, and financing costs associated with each approved project included in the Compliance Project. She stated this ratemaking treatment is consistent with the ratemaking treatment authorized by the Commission in its 45007 Order.

With respect to cost allocation, no party disputed that all federally mandated costs associated with the Pipeline Safety III Compliance Plan will be based on the allocators set forth in the revenue allocation in Paragraph B.8. of the Joint Stipulation and Settlement Agreement dated March 2, 2022 in NIPSCO's most recent gas rate case proceeding approved in Cause No. 45621. Industrial Group's Cross Exhibit 1 reflects the following allocators:

Rate Code	Compliance Project Allocation %
111	65.5%
115	0.5%
121 / 134	20.5%
125	2.7%
128 DP	2.4%
128 HP	7.3%
138	1.1%

Ms. Dousias testified that NIPSCO proposes to continue to adjust its allocation percentages to reflect the significant migration of customers amongst the various rates to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement in its FMCA Mechanism.

Based on the evidence presented, the Commission finds that NIPSCO is authorized to defer (until captured within the FMCA Mechanism) and recover 80% of the approved federally mandated costs incurred in connection with the Compliance Project through the FMCA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including O&M, capital, depreciation, taxes, financing, and AFUDC based on the current month overall WACC. NIPSCO is authorized to utilize CWIP ratemaking treatment for the Compliance Project through its the FMCA Mechanism. NIPSCO is authorized to accrue AFUDC and PISCC relating to the Compliance Project until such time as all of the projects included in the Compliance Project are placed into service or receive ratemaking treatment. Consistent with Ind. Code § 8-1-8.4-7(c)(3), actual costs that exceed NIPSCO's estimated costs by 25% or more will require specific justification and specific approval by the Commission before being authorized in NIPSCO's next general rate case. Subject to this limitation, NIPSCO is authorized to defer and recover through the FMCA Mechanism any federally mandated costs, including, but not limited to, federally mandated costs incurred prior to and after approval of a final order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Compliance Project described in NIPSCO's evidence.

NIPSCO's proposed ratemaking and accounting treatment is approved. Petitioner is authorized to allocate the costs of the Compliance Project based on the allocators set forth above.

iii. Accounting and Ratemaking Treatment for Deferred Costs. Ind. Code § 8-1-8.4-7 provides that 20% of the approved federally mandated costs, including depreciation, AFUDC, and PISCC, based on the overall cost of capital most recently approved by the Commission, shall be deferred and recovered by the energy utility as part of the next general rate case filed by the energy utility with the Commission. Ms. Dousias testified NIPSCO proposes to defer as a regulatory asset 20% of all federally mandated costs incurred in connection with the Compliance Project. She testified that NIPSCO proposes to record carrying charges on such amounts based on NIPSCO's overall cost of capital until such amounts are recovered through rates.

Based on the evidence presented, we find NIPSCO is authorized to defer 20% of the federally mandated costs incurred in connection with the Compliance Project, and NIPSCO may recover the deferred costs in its next general rate case as allowed by Ind. Code § 8-1-8.4-7(c)(2). NIPSCO is also authorized to record ongoing carrying charges based on the monthly effective WACC on the deferred federally mandated costs, including deferred depreciation and O&M expenses, until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case. NIPSCO will not gross up for taxes any amounts associated with the 20% deferral but will gross up for taxes the 20% deferral in the revenue requirements of its next base rate case.

iv. Depreciation Treatment. NIPSCO requests authority to record, defer, and recover depreciation expense related to the Compliance Project according to the depreciation rates approved in its most recent base rate Order. Based on the evidence presented, we find that NIPSCO's proposal to record, defer, and recover depreciation expense related to the Compliance Project according to NIPSCO's Commission approved depreciation rates is reasonable and is approved.

C. Ongoing Review. NIPSCO requests ongoing review of the Compliance Project as part of its FMCA Mechanism semi-annual filings. NIPSCO proposes to include: (1) information supporting proposed revised FMCA Mechanism factors including actual capital expenditures and forecast expenses during the relevant period, and a reconciliation of prior period revenues and costs; and (2) updated information regarding project list or scope, schedules and costs for the individual projects, for purposes of explaining the progress of its Compliance Project.

The CPCN approved herein provides for the execution of projects necessary to comply with the PHMSA Rules. We believe the Commission and stakeholders should be kept informed as to the status of the Compliance Project. While the FMCA Statute does not contain an explicit provision for ongoing review, we find that the ongoing review regarding NIPSCO's existing gas FMCA approved in Cause No. 45007, Cause No. 45183, and Cause No. 45560 is reasonable and will provide useful information to the Commission and the OUCC. We find that NIPSCO should include updated information regarding project list or scope, schedules and costs for the individual projects included in the Compliance Project in its FMCA Mechanism semi-annual filings is an appropriate way to accomplish this requirement. NIPSCO should make all future semi-annual filings in Cause No. 45703 FMCA X.

D. <u>Confidentiality</u>. On April 1, 2022, Petitioner filed its Motion for Protection and Nondisclosure of Confidential and Proprietary Information with a supporting affidavit asserting that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. A Docket Entry was issued on April 11, 2022, wherein the Presiding Officers determined the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavit, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held confidential and protected from public access and disclosure by the Commission.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. Petitioner is issued a Certificate of Public Convenience and Necessity pursuant to Ind. Code ch. 8-1-8.4. This Order constitutes the Certificate.

2. The provisions of federal pipeline safety standards promulgated by PHMSA and codified as 49 C.F.R. Part 192 are determined to constitute federally mandated requirements as defined by Ind. Code § 8-1-8.4-5.

3. The Compliance Project is determined to constitute "federally mandated compliance projects," and the costs incurred in connection with the Compliance Project are determined to be "federally mandated costs" under Ind. Code ch. 8-1-8.4 and are therefore eligible for the ratemaking treatment described in Ind. Code § 8-1-8.4-7.

4. The cost estimates for the Compliance Project set forth in Section 5.A.ii. above are approved.

5. Petitioner is authorized to implement its FMCA Mechanism pursuant to Ind. Code §§ 8-1-8.4-7 and 8-1-2-42 to effectuate the timely and periodic recovery of 80% of the federally mandated costs.

6. Petitioner is authorized to recover 80% of the approved federally mandated costs incurred in connection with the Compliance Project through the proposed FMCA Mechanism pursuant to Ind. Code § 8-1-8.4-7, including capital, O&M, depreciation, taxes, financing and carrying costs based on its current month overall WACC and AFUDC as described herein.

7. Petitioner is authorized to utilize CWIP ratemaking treatment for the Compliance Project through the proposed FMCA Mechanism.

8. Petitioner is authorized to accrue AFUDC relating to the Compliance Project until such time as the Compliance Project is placed into service or receive ratemaking treatment.

9. Petitioner is authorized to defer post-in service costs of the Compliance Project, including carrying costs based on its current month overall WACC, depreciation and tax expenses on an interim basis until such costs are recognized for ratemaking purposes through Petitioner's proposed FMCA Mechanism or otherwise included for recovery in NIPSCO's base rates in its next general rate case.

10. Petitioner is authorized to defer and recover through Petitioner's proposed FMCA Mechanism any federally mandated costs, including but not limited to federally mandated costs incurred prior to and after approval of a final Order in this proceeding to the extent that such costs are reasonable and consistent with the scope of the Compliance Project described in Petitioner's evidence.

11. Petitioner is authorized to adjust its authorized net operating income to reflect any approved earnings associated with the Compliance Project for purposes of Ind. Code § 8-1-2-42(g)(3) pursuant to Ind. Code § 8-1-8.4-7.

12. Petitioner is authorized to allocate the costs of the Compliance Project based on the allocators set forth in Section 5.B.ii. above.

13. Petitioner is authorized to defer 20% of the federally mandated costs incurred in connection with the Compliance Project and is authorized to recover in NIPSCO's next general rate case the deferred federally mandated costs pursuant to Ind. Code § 8-1-8.4-7.

14. Petitioner is authorized to record ongoing carrying charges based on NIPSCO's overall cost of capital, on all deferred federally mandated costs including deferred depreciation and tax expenses until the deferred federally mandated costs are included for recovery in NIPSCO's base rates in its next general rate case.

15. Petitioner's request for ongoing review of the Compliance Project as part of Petitioner's proposed FMCA Mechanism semi-annual filings is approved. As set forth in Section 5.C., future filings shall be made under Cause No. 45703 FMCA X.

16. The information submitted under seal in this Cause pursuant to Petitioner's request for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29.

17. This Order shall be effective on and after the date of its approval.

HUSTON, FREEMAN, KREVDA, AND VELETA CONCUR; ZIEGNER ABSENT:

APPROVED: DEC 28 2022

I hereby certify that the above is a true and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco Date: 2022.12.28 10:23:52 -05'00'

Dana Kosco
Secretary of the Commission