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INDIANA UTILITY
REGULATORY COMMISSION

Northern Indiana Public Service Company LLC

Cause No. 45967

VERIFIED DIRECT TESTIMONY OF ORVILLE COCKING

Q1. Please state your name, business address and title.

A1. My name is Orville Cocking. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410. I am employed by Northern Indiana Public Service Company LLC ("NIPSCO") as Senior Vice President of Gas Operations.

Q2. Please describe your educational and employment background.

A2. I received a Bachelor of Science degree in Civil Engineering from Temple University, an MBA from Fordham University and am a licensed Professional Engineer. I began my career at Henkels and McCoy, Inc. in 1997 as a Civil/Structural Engineer with a focus on design of telecommunications facilities until 2001. I then worked at KM Consulting Engineering in a similar capacity until 2003. In 2003 I joined M.G. McLaren, PC as a Senior Structural Engineer until 2005. In 2005 I began working for Consolidated Edison of New York, and I held numerous positions of increasing responsibility for Con Edison of New York and Orange & Rockland Utilities, including Senior Engineer; Manager of Electric

Construction; Manager of Transmission Line Maintenance; Director of Environmental, Health, and Safety; and General Manager of Electric Operations. I was also Vice President of Staten Island Electric Operations and Electric Services for Consolidated Edison Company of New York with responsibility for the electric customers in the borough of Staten Island, Meter and testing operations, and the transformer shop. My most recent past role was Vice President of Operations for Orange & Rockland Utilities, with responsibility for the company's gas and electric operations serving approximately 450,000 customers across six counties in New York and northern New Jersey, ensuring the safe, reliable transmission and distribution of both electricity, and in New York only, natural gas. I joined NIPSCO in my current role as Senior Vice President of Gas Operations in May 2023.

Q3. What are your responsibilities as Senior Vice President of Gas Operations?

A3. As Senior Vice President of Gas Operations, I am responsible for the day-to-day operation of NIPSCO's physical gas transmission, distribution, and storage systems, including operations, maintenance, and damage prevention. In that capacity, I manage a workforce of nearly 650 employees providing safe and reliable delivery of natural gas service to NIPSCO's approximately 859,000 industrial, commercial, and residential customers. This includes NIPSCO's gas construction segment with a labor force of approximately 125 employees, responsible for distribution line extensions, main replacements, and relocations, along with a variety of betterment projects. I also participate in the collaborative process described by NIPSCO Witness Dousias that prioritizes and identifies the capital investment needs for public safety and reliability, compliance requirements, and customer service levels.

Q4. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission") or any other regulatory commission?

A4. No.

Q5. Are you sponsoring any attachments to your testimony in this Cause?

A5. Yes. I am sponsoring <u>Attachment 8-A</u>, which was prepared by me or under my direction and supervision. I also sponsor a portion of the workpapers included in <u>Petitioner's Confidential Exhibit No. 19-S2</u>.

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to (1) provide an overview of NIPSCO's gas operations and maintenance, on system storage, and damage prevention organizations; (2) describe NIPSCO's pipeline safety programs and processes, implementation of its Safety Management System, and the types of pipeline compliance regulations with which NIPSCO must comply; and (3) briefly address NIPSCO's plan to update its communications technology associated with its gas meters. I also sponsor a portion of NIPSCO's Operations and Maintenance (O&M) expense adjustment included in Adjustment OM 2-24.

<u>Overview of NIPSCO's Gas Operations and Maintenance, On System Storage, and Damage Prevention Organizations</u>

Q7. Please provide an overview of NIPSCO's gas operations and maintenance organization.

A7. NIPSCO's gas operations is organized into thirteen Local Operating Areas ("LOAs"). Crews assigned to each LOA are responsible for conducting day to day maintenance activities within a specific geographic area. Within each LOA, crews are designated as either Construction & Maintenance (known as "Street" crews) or as Construction (known as "52G" crews). Street crews are responsible for performing repair and maintenance assignments on NIPSCO's gas transmission and distribution assets, while 52G crews are responsible for the construction of distribution line extensions, facility replacement or relocation, and system improvement projects.

Q8. Please provide an overview of NIPSCO's on system storage organization.

A8. As more fully described by NIPSCO Witness Robles, NIPSCO operates the Royal Center Underground Storage facility located near Royal Center, Indiana ("Royal Center"), and the LNG facility located in LaPorte, Indiana. Together these facilities provide NIPSCO with approximately 7.5 billion cubic feet of on system storage capacity. The NIPSCO storage organization consists of approximately 32 employees responsible for the operation and maintenance of these facilities to ensure their availability and performance as required to support NIPSCO's system.

Q9. Please provide an overview of NIPSCO's damage prevention organization.

A9. As more fully described by NIPSCO Witness Smith, NIPSCO's damage prevention organization is responsible for helping to manage and mitigate the risk of damage through a variety of activities including underground facility locating, excavator engagement and outreach, and damage investigation. NIPSCO's damage prevention organization consists of 34 employees charged with working with NIPSCO's locate contractors and with the excavator community to reduce the risk of damage to NIPSCO's underground gas facilities.

<u>**Overview of Pipeline Safety Regulations**</u>

Q10. Please provide an overview of the state and federal pipeline safety regulations applicable to NIPSCO's damage prevention organization.

A10. In 1970, minimum pipeline safety standards were published in the Code of Federal Regulations – Title 49 Part 192 (the "Code"). These mandated rules, and the many amendments and additions that have occurred over 51 years, have defined the minimum standards for the safe construction, operation, and maintenance of natural gas systems. Indiana specifically requires gas utilities to adhere to these requirements.[1] The Code includes detailed sections describing the requirements of things such as corrosion control, pressure testing, pressure rating, operations, and maintenance of gas facilities. As in many jurisdictions, Indiana specifically requires gas utilities

[1] 170 IAC 5-3-1.

to follow these requirements which are subject to audit and enforcement by the Commission's Pipeline Safety Division.[2] Included in the Code are detailed sections describing the requirements for numerous activities including, but not limited to the design, construction, corrosion control, pressure testing, pressure rating, integrity management, and operations and maintenance of gas facilities.

The Code has been amended several times since its inception to create or modify mandatory programs or rules that address various aspects of pipeline and public safety. While the majority of the Code is prescriptive, portions of the Code mandate operators to establish programs that are risk-based. In 2002, Federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration's ("PHMSA") enacted 49 CFR Part 192, Subpart O that mandates the creation of a Transmission Integrity Management Program ("TIMP") covering the higher pressure transmission pipeline and corresponding systems. In 2011, PHMSA enacted 49 CFR Part 192, Subpart P that mandates the creation of a Distribution Integrity Management Program ("DIMP") covering the lower pressure distribution

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[2] *See generally* Ind. Code ch. 8-1-22.5.

system. These programs provide a mandated regulatory structure for the assessment of system risks and progressive implementation of solutions and continuous improvements based upon the severity of those risks over time.

Unlike the other prescriptive provisions of the Code, both the TIMP and DIMP plans are focused on continuous improvement through an ongoing cycle of assessment and remediation whereby risks to transmission and distribution assets must be identified, ranked, and based on risk ranking, be remediated over time (*e.g.*, by program, the more severe risks are addressed first, the lower level risks later after the more severe risks have been addressed). As a result, the TIMP and DIMP plans do not require performance of specific activities but rather mandate that regulated companies diligently undertake a proactive process that identifies, ranks, and then implements measures to remediate the risks identified, based on their relative risk ranking. Attachment 8-A provides additional detail on the federal TIMP and DIMP regulations, as well as NIPSCO's compliance with those regulations.

Q11. Please provide an example of a compliance regulation and how such

regulation can drive NIPSCO's need to invest additional capital to achieve and maintain compliance.

A11. 49 C.F.R. § 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) includes numerous regulations and requirements that NIPSCO, as a gas pipeline operator, must comply with. Under Subpart M (Maintenance), initial and ongoing assessment of pipeline integrity is required for certain transmission pipeline, and in order to comply with these requirements, NIPSCO and other pipeline operators have needed to invest significant capital to allow "in line inspection" (or "ILI") to be performed on certain segments of pipe. NIPSCO has sought and received approval for a few ILI projects under Transmission, Distribution, and Storage Investment Charges ("TDSIC") and Federally Mandated Cost Adjustment ("FMCA") plans totaling tens of millions of dollars. This work is not yet complete, and tens of millions of dollars in additional investments will continue to be required. This is just one example of a federal regulation that NIPSCO must comply with.

Q12. Please explain the PIPES Act of 2020 (the "PIPES Act").

A12. The PIPES Act was enacted on December 27, 2020 and emphasizes mitigating methane emissions through leak detection and repair. The

PIPES Act focuses on promoting safe operations, including, appropriate identification and ranking of risk under DIMP, mitigation of and appropriate response to over pressurization events, ensuring qualified personnel review construction plans, improved communications during emergencies, facility upgrades, and complete and accessible records.

Q13. Has NIPSCO implemented any additional safety initiatives to address pipeline safety needs and protection of the environment, as emphasized by the PIPES Act?

A13. Yes. In response to the PIPES Act requirements related to use of advanced technologies to mitigate methane emissions, NIPSCO has begun the use of the Picarro platform system to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. The use of the Picarro Leak Detection System serves to advance NIPSCO's leak detection capabilities, as well as estimate leak density and reduce methane emissions across its service territory. Additionally, the Picarro Leak Detection System supports NIPSCO's Operations and Construction departments by aiding in the prioritization of system risk for its ongoing infrastructure replacement program, and by providing quality assurance checks following the installation of new infrastructure.[3]

Q14. Is NIPSCO in compliance with state and federal pipeline safety standards applicable to its distribution system?

A14. Yes. NIPSCO complies with applicable pipeline safety standards promulgated by the Commission's Pipeline Safety Division and PHMSA's Office of Pipeline Safety ("OPS").

Q15. In addition to the PIPES Act discussed above, are there forthcoming regulations that NIPSCO reasonably expects will have compliance obligations?

A15. Yes. NIPSCO monitors proposed and actual changes to applicable pipeline safety standards to ensure it is well-positioned to maintain and achieve compliance on a going-forward basis as well. In response to Congressional directives in the PIPES Act, on May 5, 2023, PHMSA issued a notice of proposed rulemaking entitled "Pipeline Safety: Gas Pipeline Leak Detection and Repair" ("NOPR"). Although a final rule has not been

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[3] As one example, before the end of 2023, NIPSCO intends to utilize Picarro for a quality assurance check for the recently completed project in Kokomo, Indiana to serve an electric vehicle battery plant.

adopted, among other things, the NOPR would: (1) increase the frequency of leakage survey and patrolling requirements; (2) introduce leakage survey and repair requirements for LNG facilities; (3) require grading and repairs of leaks under specific timelines; and (4) expand reporting and record-keeping requirements. To the extent the proposals in the NOPR are adopted, the requirements would increase federal regulations and related compliance requirements and, in all likelihood, require investment of additional capital and expenditure of additional O&M to achieve and maintain compliance.

Q16. Have state and federal pipeline safety regulators advocated adoption of additional initiatives to improve pipeline safety?

A16. Yes. A safety management system ("SMS") is a highly recommended practice endorsed by many federal and state regulatory bodies.[4] And, given the regulations support continuous improvement initiatives, a SMS approach to safety is very responsive to the intent of the regulations. PHMSA's OPS and the National Transportation Safety Board ("NTSB")

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[4] It is worth noting that in May 2019, the American Gas Association (AGA) Board of Directors approved a resolution recommending that all members implement SMS through its endorsement of AmerRP.

have actively encouraged operators at public workshops and industry conferences to voluntarily implement a SMS. In addition, the Commission's Pipeline Safety Division has also discussed the benefits of adopting a SMS at state safety meetings, encouraging Indiana operators to implement a SMS.

Q17. Please describe a SMS.

A17. A SMS is a systematic approach to managing safety, including structures, policies, and procedures used to direct and control activities. SMS has been defined and in place in other industries, especially ones with high risk and low tolerance for failures. In 2015, natural gas operators, industry representatives and state and federal stakeholders collaborated to develop a comprehensive safety management system (SMS) known throughout the natural gas industry as API Recommended Practice 1173 ("RP 1173"). RP 1173 establishes a set of standards and best practices for the oil and natural gas industries based on the successful implementation of similar SMS in the transportation, airline, and nuclear industries. RP 1173 provides guidance to pipeline operators for developing and maintaining a pipeline SMS intended to augment and integrate existing practices while not duplicating any other requirements.

Q18. Has NIPSCO implemented a SMS?

A18. Yes. NIPSCO implemented its pipeline SMS program in 2017. The purpose for implementing SMS was to provide an objective framework to pursue a goal of zero incidents. Specifically, NIPSCO's SMS is intended to:

- Promote safety leadership and individual accountability for all employees, including front line, leadership, as well as for executives;
- Build on NIPSCO's strong foundation of safety with a culture of transparency and mutual trust, promoting an inclusive workplace, with a focus on continuous learning and improvement; and
- Add rigor to work practices resulting in the identification and mitigation of risks to protect employees, contractors, customers, and communities. Every NIPSCO employee and contractor is encouraged to report any safety issues to the SMS organization so that risk can be assessed in a consistent manner and the creation of workplans to address identified issues.

NIPSCO's SMS provides a framework for reporting on identified risks and mitigation activities. As NIPSCO's SMS matures, risks, including system reliability and public safety, will be considered in a consistent manner across all asset classes to identify and prioritize projects.

Q19. Why did NIPSCO create a SMS?

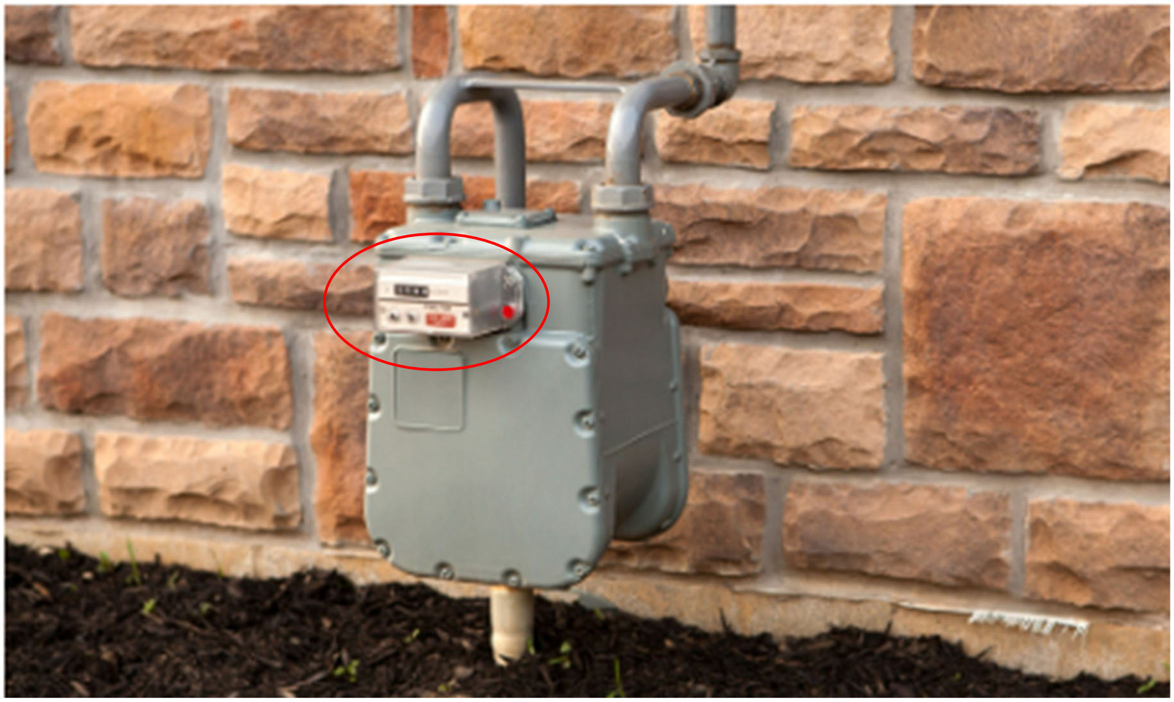
A19. NIPSCO reviewed the results of other industries that had implemented a safety management system as a standard process. In particular, the airline industry in the United States has seen an 83% decline in its fatal accident rate between 1997 and 2007 after implementing a SMS. The pipeline industry has not seen a significant and sustained reduction in reportable incidents, and following some very high profile incidents in the energy industry in 2010, the NTSB issued a recommendation that the pipeline industry develop standards for a safety management system. NIPSCO sees the benefit of a strong, systemic approach to improving pipeline safety. NIPSCO Witness Smith describes how NIPSCO's SMS has improved its damage prevention program.

<u>Gas Meter Communications</u>

Q20. How does NIPSCO currently read its gas meters?

A20. NIPSCO's gas meters are equipped with automated meter reading ("AMR") technology, which was implemented around 2013. When this was implemented, it increased the efficiency of meter reading, as sending "meter readers" to each home on a regular cadence was no longer required. AMR capability does *not* change how the meter itself functions; instead, NIPSCO is able to collect each meter's usage by having a vehicle drive by in relative proximity to the meter, which requires fewer employees compared to manual meter reading.

This functionality is linked to a communications module called an "ERT," which stands for "encoder receiver transmitter." It is the ERT that transmits the meter's usage to the drive-by vehicle, and the vehicle is fitted with equipment that receives the data transmission from the ERT. The data collected from these drive-by readings is securely uploaded by NIPSCO and utilized to calculate the usage for each customer, based upon the data that was transmitted from the ERT. As pictured below, the meter is the large, grey metal device, and the ERT is the smaller, white plastic device circled in red. Over time, most of the industry has moved to use of AMR technology, and in the last few years, a new generation of technology has been developed with even greater functionality.



Q21. Since NIPSCO installed the ERTs in 2013, how has the technology functioned?

A21. As the ERTs have started to exceed a decade in the field, NIPSCO's metering group has encountered issues in procuring meters equipped with AMR technology and procuring ERTs. NIPSCO has been informed by its meter vendors that they are phasing out production of AMR technology, opting instead to focus on production of advanced metering infrastructure ("AMI") metering solutions, which provide two-way communication capability.

For meters, over the past year or so, NIPSCO has not been able to obtain the traditional meters equipped with AMR. In response, for both new customer installations and existing customers whose meters fail, NIPSCO purchased meters equipped with AMI technology but has installed them in "AMR mode," which enables compatibility with NIPSCO's current capabilities. Again, this is because metering vendors are moving away from AMR technology and focusing production on newer, more advanced technology.

For some customers, the meter itself does not fail, but the ERT device will fail, which may be caused by a mechanical malfunction or the battery for the ERT losing charge. Much like obtaining AMR meters, NIPSCO has also begun to face procurement issues for ERTs. Additionally, NIPSCO is now beginning to see ERT battery failures and expects these failures to increase over the next two to three years.

Q22. What has NIPSCO done in response to this issue?

A22. In response to these procurement issues for AMR assets and the expectation that ERTs will continue to need to be replaced, NIPSCO engaged West Monroe Partners LLC ("West Monroe") in 2023 to assist with an evaluation of potential solutions. This work and NIPSCO's ultimate choice is discussed and supported by NIPSCO Witness Trump.

Q23. What led NIPSCO to engage West Monroe to undertake a formal evaluation of AMI technology options?

A23. First, as noted above, there is the general concern with obsolescence of AMR technology. NIPSCO is already purchasing AMI meters for meter replacements and has begun to see ERTs fail on existing customer meters. Additionally, NIPSCO anticipates a growing number of ERT failures in the next few years based on battery age. Since ERTs are generally not available in the market and it is not practical to replace the ERT batteries, ERT failures have already caused NIPSCO to perform some manual meter reading for customers whose ERTs failed. NIPSCO, therefore, needed to evaluate the alternatives for meter reading as AMR technology is being phased out, and because returning to manual meter reading is not a feasible or efficient option given the magnitude of hiring that would need to occur.

Second, since NIPSCO is in the beginning stages of deployment of its Electric AMI Meter Project, now was the optimal time to evaluate and potentially deploy a future gas metering solution.[5] Approximately half of NIPSCO's gas customers are also NIPSCO electric customers, which presents an opportunity to take advantage of any efficiencies that can be achieved by planning and executing gas and electric projects around the same time, as NIPSCO will already be physically visiting each electric customer's premises.

<u>**Adjustments to Forward Test Year**</u>

Q24. Are you sponsoring any adjustments to the Forward Test Year?

A24. Yes. I am sponsoring the projection of expenses for Gas Operations, which reflects a modest increase of approximately $2 million in the Forward Test Year when compared to the Historic Base Period (the period beginning January 1, 2022 and ending December 31, 2022).

Q25. What categories of expense are included within the overall Gas Operations budget?

A25. Gas Operations expenses in 2022 were approximately $43.9 million and are expected to increase to approximately $45.9 million in 2024, representing a 4.5% total increase over this two-year period. Line Locating expenses are

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[5] NIPSCO's Electric AMI Metering Project was approved as part of NIPSCO's electric TDSIC Plan in Cause No. 45557.

by far the largest category of expense, representing $25.7 million, or more than half of the total Gas Operations expense budget. Materials and Supplies make up about $5 million, and Leak Survey, Repair, Integrity Management, and Emergent Repairs work makes up about another $7 million. Other expense categories in order of relative size include LNG, "other" outside services (not associated with line locating), employee expenses, and "miscellaneous" expenses.

Q26. Please describe Petitioner's Exhibit No. 3, Attachment 3-C-S2, Adjustment OM 2-24, as it relates to Materials and Supplies.

A26. A portion of Adjustment OM 2-24 reflects the Forward Test Year operating expenses in the amount of $5,029,712 for Materials and Supplies, a decrease of $1,092,584 compared to the Historic Base Period. This decrease can be attributed to improved time recording business practices, which reduced the associated scope of work and therefore, the materials and supplies needed to complete that work.

Q27. Please describe Petitioner's Exhibit No. 3, Attachment 3-C-S2, Adjustment OM 2-24, as it relates to Miscellaneous Direct.

A27. A portion of Adjustment OM 2-24 reflects the Forward Test Year operating expenses in the amount of $148,000 for Miscellaneous Direct, a decrease of $303,529 compared to the Historic Base Period. This decrease can be attributed to a reduction in the number of active PHMSA storage facilities upon which the Department of Transportation's Pipeline Safety User Fee is based.

Q28. Please describe Petitioner's Exhibit No. 3, Attachment 3-C-S2, Adjustment OM 2-24, as it relates to Outside Services – Leak Survey, Repair, Integrity Management, and Emergent Repair.

A28. A portion of Adjustment OM 2-24 reflects the Forward Test Year operating expenses in the amount of $6,820,391 for Outside Services – Leak Survey, Repair, Integrity Management, and Emergent Repair, a decrease of $2,638,472 compared to the Historic Base Period. This decrease can be attributed to several factors. For example, in lieu of attempting to repair aging infrastructure (an O&M cost), NIPSCO is conducting more replacements (a capital cost) to bring its aging assets up to current standards. Another example is that leak survey expense is calculated per mile and is expected to decrease in 2024 as compared to the number of miles surveyed during the Historic Base Period.

Q29. Please describe Petitioner's Exhibit No. 3, Attachment 3-C-S2, Adjustment OM 2-24, as it relates to Outside Services – Other.

A29. A portion of Adjustment OM 2-24 reflects the Forward Test Year operating expenses in the amount of $2,985,308 for Outside Services – Other, a decrease of $3,360,637 compared to the Historic Base Period. This decrease is attributable to continuous improvement in determining when to use outside services to perform various leak repair functions and instead using internal labor to conduct that work.

Q30. Please describe Petitioner's Exhibit No. 3, Attachment 3-C-S2, Adjustment OM 2-24, as it relates to LNG.

A30. A portion of Adjustment OM 2-24 reflects the Forward Test Year operating expenses in the amount of $3,991,060 for LNG, an increase of $2,386,482 compared to the Historic Base Period. Electrification costs were updated to reflect the increase to NIPSCO interdepartmental rates from NIPSCO's most recent electric base rate case (Cause No. 45772). NIPSCO also expects to conduct more liquefaction during the Forward Test Year than the Historic Base Period, as a maintenance outage drove a reduction in liquefaction in the Historic Base Period.

Q31. Does this conclude your prefiled direct testimony?

A31. Yes.

VERIFICATION

I, Orville Cocking, Senior Vice President of Gas Operations for Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Orville Cocking

Dated: October 25, 2023

Federal Transmission Integrity Management Program ("TIMP" Regulations

In 2002, the American Society of Mechanical Engineers ("ASME") published a standard to ensure the integrity of pipelines. PHMSA's Office of Pipeline Safety ("OPS") subsequently adopted regulations that incorporated the results of the ASME B31.8S standard. These standards define a formal gas pipeline integrity program in accordance with the Pipeline Safety Improvement Act of 2002 enacted on December 17, 2002.[1]

The intent of the TIMP regulations is to identify potential threats to the transmission system, assess the severity of those threats with a risk analysis process, rank the risks identified, complete an assessment method interrogating the threat and remediate or monitor the risks as appropriate. Operators address potential threats by either repairing defects, replacing pipeline sections, or implementing preventive and mitigating measures to preemptively identify changes in threats. The TIMP regulations also specify how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate, through comprehensive analyses, the integrity of gas transmission pipelines that, in the event of a leak or failure, could affect certain populated and occupied areas or

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1 *See* 49 CFR Part 192 Subpart O (Amdt 192-95).

High Consequence Areas ("HCAs").

Revisions to the Code published on October 1, 2019 with an effective date of July 1, 2020 were designed to improve the safety of onshore gas transmission pipelines and addresses several congressional mandates, National Transportation Safety Board ("NTSB") recommendations and responds to public input. These amendments focus on expansion of TIMP requirements to areas outside of HCAs, reconfirmation of maximum allowable operation pressure ("MAOP") for certain transmission pipeline facilities, additional recordkeeping requirements for newly constructed transmission pipeline facilities, and various other safety improvements and recordkeeping provisions.

NIPSCO operates 690.11 miles of transmission-class natural gas pipelines, 122.94 miles of which are located in HCAs. The pipelines in HCAs are assessed and ranked on a seven year cycle using a relative risk model in conjunction with subject matter experts' input to identify threats, potential threats, or variability in known threats. Based on the results of the inspections and assessments, excavations are performed to directly examine the pipe and make appropriate remediation as necessary. Further, it should be noted that NIPSCO exceeds the minimum standards in that it uses In-Line-Inspection ("ILI") tools in all ILI compatible transmission lines, without regard to which of the line sections are HCAs. In addition, NIPSCO plans to continue to expand its inventory of ILI compatible transmission lines across its transmission footprint.

NIPSCO's TIMP baseline assessments began in 2004 and were completed by 2010 with 42 assessment projects using Direct Assessment ("DA") methods in the form of External Corrosion Direct Assessment ("ECDA") and Internal Corrosion Direct Assessment ("ICDA"). There were 442 excavations, known as direct examinations, performed within the HCAs of the pipelines. These inspections identified coating deficiencies and anomalies based on the ECDA and ICDA techniques deployed, including some from mechanical damage stemming from third party damage by other excavators. The majority of corrosion related anomalies were from original coating techniques used during installation. NIPSCO discovered and corrected 25 external corrosion defects during its initial assessments.

TIMP re-assessments of the HCA pipelines began in 2010 completing another 75 assessments of HCA pipeline to date, incorporating an additional 4,175 direct examinations. The assessment methods used for the reassessments were 64 DA methods, four hydrostatically pressure tested methods, and seven ILI methods. The re-assessments discovered more material damage to the pipe wall in the form of six gouges from third party damages requiring repair; laminations within the pipe wall due to process deficiencies in the original manufacturing requiring cut out and replacement; and internal corrosion issues in transmission class pipeline requiring installation of a pipeline liner to provide further protection against corrosive constituents within the gas stream. ILI has proven to be a far superior pipeline assessment method – discovering defects with higher probabilities for future failures if not appropriately addressed. Similar to DIMP discussed below, the TIMP requirements continue to evolve based on new federal pipeline safety regulations.

Federal Distribution Integrity Management Program ("DIMP") regulations

PHMSA's OPS adopted rules imposing integrity management requirements for gas distribution pipeline systems on December 4, 2009. *See* Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines, 74 Fed. Reg. 63906 (Dec. 4, 2009). The effective date of the rules was February 12, 2010. The DIMP regulations require operators to develop, write, and implement a program with the following elements:

- Distribution system knowledge;
- Identification of threats;
- Evaluation of risks;
- Implementation of measures to address risks;
- Measurement of performance, monitoring of results and evaluation of effectiveness;
- Periodic evaluation and improvement of program; and
- Reporting of results.

The focus areas of NIPSCO's distribution integrity execution are damage prevention, leak management, public awareness, operator qualification programs and corrosion. A centerpiece of NIPSCO's DIMP has been the priority pipe replacement effort addressing cast iron pipe and corrosion threats. As NIPSCO has matured its DIMP, it has worked to continually improve its DIMP to reduce the various DIMP risks that have been identified and to create effective programs to reduce those risks.

Yes. The Commission has previously determined that compliance with DIMP and TIMP are federally mandated and has authorized recovery of associated costs as part of its Pipeline Safety Compliance Project in Cause No. 45007, PHMSA Compliance Project in Cause No. 45183, Pipeline Safety II Compliance Project in Cause No. 45560, and Pipeline Safety III Compliance Project in Cause No. 45703.