ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC'S R.M. SCHAHFER GENERATING STATION FIRE AND RELATED IMPACT ON FUEL PROCUREMENT AND FUEL COSTS.

CAUSE NO. 38706 FAC 130 S1

APPROVED: JUN 15 2022

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

In the Order approved on April 28, 2021, in Cause No. 38706 FAC 130, the Commission created this subdocket to examine the prudency of the actions leading to the fire at Northern Indiana Public Service Company LLC's ("NIPSCO") R.M. Schahfer Generating Station ("Schahfer") in July 2020 that resulted in an unplanned forced outage of Units 14 and 15 and, ultimately, the extent to which NIPSCO's fuel costs were impacted.

On May 10, 2021, the NIPSCO Industrial Group ("Industrial Group") filed a Notice of Appearance and Amended "Appendix A" to Petition to Intervene.[1]

On June 10, 2021, Citizens Action Coalition of Indiana, Inc. ("CAC") also petitioned to intervene, with CAC's intervention granted on June 22, 2021.

On August 13, 2021, NIPSCO prefiled the prepared testimony and exhibits constituting its case-in-chief for purposes of this subdocket. This included the direct testimony and exhibits of Patrick N. Augustine, a Vice President in Charles River Associates' Energy Practice and the following NIPSCO employees:

- Ronald E. Talbot, Senior Vice President, Electric Operations
- Kurt W. Sangster, Vice President, Electric Generation and
- Andrew S. Campbell, Director, Regulatory Support and Planning.

On August 13, 2021, NIPSCO also filed a motion requesting confidential treatment for certain information. Confidential treatment was approved on a preliminary basis on August 24, 2021.

[1] The Industrial Group originally petitioned to intervene in Cause No. 38706 FAC 130 on February 22, 2021, and this intervention was granted on March 3, 2021. For purposes of this subdocket, the members of the Industrial Group are Accurate Castings, Inc., BP Products North America, Inc., Cleveland-Cliffs Steel LLC, Jupiter Aluminum Corporation, Linde, Inc., United States Steel Corporation, and USG Corporation.

On November 12, 2021, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of Michael D. Eckert, Assistant Director in the OUCC's Electric Division. That same day, the NIPSCO Industrial Group prefiled the direct testimony and exhibits of Michael P. Gorman, a Managing Principal with Brubaker & Associates, Inc.[2]

On November 23, 2021, NIPSCO filed a second motion requesting confidential treatment for certain information. This relief was granted on a preliminary basis on November 29, 2021.

On December 17, 2021, NIPSCO prefiled the rebuttal testimony and exhibits of Messrs. Talbot, Sangster, Campbell, and Augustine.[3]

On January 19, 2022, NIPSCO filed what it characterized as a hearing exhibit that included the Industrial Group's responses to various data requests. On January 19, 2022, the Industrial Group similarly filed NIPSCO's responses to various data requests as an exhibit to be offered at the evidentiary hearing.

On January 20, 2022, after reviewing the cases-in-chief and rebuttal filed in this proceeding and given the parties' expressed intent to waive cross examination at the evidentiary hearing, the Presiding Officers issued a docket entry eliciting information from the Industrial Group. The Industrial Group filed its response on January 21, 2022.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on January 24, 2022, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, CAC, and the Industrial Group, by counsel, participated in the evidentiary hearing, and their respective testimony and exhibits were admitted without objection. The Industrial Group's docket entry responses were also admitted.

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

1. <u>Commission Jurisdiction and Notice</u>. Notice of the evidentiary hearing in this Cause was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost charge. The Commission, therefore, has jurisdiction over NIPSCO and the matters at issue in this fuel cost adjustment subdocket.

2. <u>NIPSCO's Characteristics</u>. NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service.

3. <u>Petitioner's Case-in-Chief</u>.

[2] The Industrial Group subsequently filed a less redacted version of Mr. Gorman's public direct testimony and attachments on December 1, 2021.

[3] On December 21, 2021, NIPSCO filed a correction to Mr. Campbell's rebuttal testimony.

A. <u>Ronald E. Talbot</u>. Mr. Talbot explained NIPSCO's evaluation and decision-making process to determine what was in its customers' best interest following the fire at Schahfer Unit 14. He also explained how NIPSCO, after reviewing its changing generation portfolio, reduced demand, economics, and reliability, concluded it was in its customers' best interest to retire Units 14 and 15 on October 1, 2021.

Mr. Talbot testified that every three years, NIPSCO undertakes an integrated resource planning ("IRP") process and evaluates the resources needed to serve its electric customers. He stated NIPSCO's 2018 IRP, submitted to the Commission on October 31, 2018, resulted in a Short-Term Action Plan that pointed to retiring all four coal-fired units at Schahfer by May 2023, including Units 14 and 15, and replacing their energy and capacity primarily with wind, solar, and solar plus storage resources. He testified the conclusion to retire the Schahfer units by May 2023 was primarily driven by the estimated economic savings for NIPSCO's customers. Per the 2018 IRP, the retirement of NIPSCO's coal-fired generation and its replacement largely with renewable generation was projected to save NIPSCO's customers $4 billion over 30 years, with retirement of the four Schahfer units accounting for a significant portion of that estimated savings. If economics had been the only relevant factor, he stated the four coal-fired units at Schahfer would have been slated to retire as soon as reasonably possible; however, as relayed in the 2018 IRP, NIPSCO decided that given the need for complex transmission upgrades and the time needed to acquire and commission replacement resources, as well as the need to address related employee and community impacts, a more gradual approach that provided time to execute the Short-Term Action Plan was the best course of action. Consistent with this approach, in its 2018 IRP, NIPSCO proposed to retire the four Schahfer units by May 2023 and Unit 12 at Michigan City in 2028.

Mr. Talbot testified that NIPSCO immediately realized post-fire that instead of assuming Schahfer Units 14 and 15 should continue to run until May 2023, it was appropriate to reassess the timing of their retirements to make the best decision based on the then existing circumstances. He explained there were a few primary factors that needed to be addressed as part of the decision upon the future status of Units 14 and 15. First, the comparative economics associated with restoring the units and then operating them, as compared to an earlier retirement date and reliance on alternative capacity and energy, needed to be considered. This included considering the estimated capital costs associated with restoration and the availability and cost of replacement capacity, as well as the prospective exposure to energy market risk if the units were retired early and how to handle the units' existing coal inventory. Second, reliability was a key factor. He stated retirement of any generation resource can have significant reliability impacts on the bulk electric system and a utility's distribution system. Thus, NIPSCO's decision upon the disposition of Units 14 and 15 had to ensure customers could be reliably served. Finally, resource availability—in terms of both energy and capacity—was also an important factor. This included the potential availability of replacement capacity to serve NIPSCO's customers and ensuring NIPSCO had sufficient resources available to provide economic energy to its customers, as well as considering how the timing of unit retirements could impact NIPSCO's overall NO_x allowances.[4]

Mr. Talbot acknowledged he was not responsible for overseeing the analysis NIPSCO performed as part of the decision-making process. Rather, NIPSCO's senior management relied

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[4] On pages 9-15 of Petitioner's Exhibit 1, Mr. Talbot further explains each of these factors. Because NIPSCO's decision-making process itself was not challenged, all the details he includes are not being recounted.

upon subject matter experts ("SMEs") in particular areas to perform or oversee this work. The results were shared with senior management for evaluation and, ultimately, to decide what was in the best interest of NIPSCO and its customers. As the Senior Vice President of Electric Operations, he was responsible for implementing the decision.

Mr. Talbot stated NIPSCO engaged Charles River Associates ("CRA") following the fire to leverage the work CRA had performed in the 2018 IRP and engage in modeling and analysis to provide economic information regarding NIPSCO's potential alternative action plans. CRA evaluated five alternatives, referred to as "portfolios," that assessed various iterations of restoration and retirement options for Units 14 and 15. While the 2018 IRP results were known, Mr. Talbot stated NIPSCO wanted CRA to consider current information and engage in additional economic analysis to ensure the decision upon the future of Units 14 and 15 was based on the most up-to-date perspective of the market and changes in NIPSCO's demand and resource portfolio. Mr. Talbot testified the results of the economic, reliability, and resource availability considerations were key pieces of information relied on in making the decision.

Mr. Talbot testified the date ultimately chosen for the retirement of Units 14 and 15 was impacted by several factors, all of which pointed to late 2021 as the appropriate retirement date. First, the Attachment Y process under the Midcontinent Independent System Operator, Inc. ("MISO") Tariff requires a 26-week notice of a proposed early retirement date. He stated NIPSCO's Attachment Y notice was submitted in mid-March, and even if it had been submitted earlier in 2021, late summer or early fall were the earliest dates that could be considered. Mr. Talbot stated a decision to retire two coal-fired units was also going to impact NIPSCO's workforce at Schahfer, and NIPSCO needed sufficient time to work with its impacted employees about post-retirement alternatives. Additionally, the necessary transmission upgrades were not expected to be completed until May 2021. As a result, having at least one of the units available through the summer months was determined to be best. This also allowed NIPSCO to address and reduce the coal inventory for Units 14 and 15. He stated it was also determined a retirement in late 2021 would not negatively impact NIPSCO's 2021 Cross-State Air Pollution Rule ("CSAPR") NOx allowances. In addition, NIPSCO had a 300 MW wind generation facility scheduled to come online in late 2021. According to Mr. Talbot, these factors all supported a retirement date in the fall of 2021 as the right decision for customers and NIPSCO.

Mr. Talbot testified that after considering all relevant factors, NIPSCO determined the best option was: (a) Unit 14 remaining in forced outage (beginning in summer 2020); (b) Unit 15 being brought back to service by the end of 2020, and (c) Units 14 and 15 being retired on October 1, 2021.[5] The decision to proceed with retiring Units 14 and 15 in mid-to-late 2021 was made in late January 2021.

After discussing the information and factors NIPSCO considered when deciding the disposition of Units 14 and 15, Mr. Talbot summarized how all the relevant factors led NIPSCO to conclude an October 2021 retirement of both units was in the best interest of NIPSCO's customers. He stated NIPSCO approached this decision in early 2021 knowing adequate capacity had already been procured through two Requests for Proposals ("RFPs") and that NIPSCO would pay the costs associated with this capacity as opposed to seeking recovery from customers. He

[5] Mr. Augustine references this as Portfolio 2a.

testified NIPSCO's significant progress in implementing its Short-Term Action Plan to procure replacement generation capacity also provided assurance that NIPSCO could reliably meet its customers' energy requirements with Units 14 and 15 retired on October 1, 2021. Additionally, historical MISO market data indicated that, to the extent necessary, sufficient and reasonably-priced energy would be available through MISO's Day-Ahead and Real-Time markets.

Mr. Talbot stated that while MISO's review was not complete, NIPSCO knew MISO would be studying any potential reliability concerns and expected none to be identified, in part because of the transmission upgrades NIPSCO was scheduled to complete in May 2021. When considering the expected cost savings for customers, as demonstrated by CRA's analysis, Mr. Talbot testified that retiring Units 14 and 15 in mid-to-late 2021, instead of as late as May 2023, was determined to be the best decision for NIPSCO and its customers.

B. Kurt W. Sangster. Mr. Sangster provided testimony explaining the fire at Schahfer Unit 14 on July 16, 2020, including what occurred at Unit 14 that day and the cause of the fire, as identified by the subsequent root cause analysis ("RCA") NIPSCO performed.

Per Mr. Sangster, NIPSCO's current electric generating fleet is dominated by coal-fired generation, but NIPSCO is in the process of transitioning its generation portfolio such that all coal-fired generation is scheduled to be retired no later than 2028. He stated the capacity of the retiring units is being replaced by a combination of wind, solar, and energy storage technologies. According to Mr. Sangster, over the last several years leading into mid-2020, Units 14 and 15 operated very infrequently. He testified there were often months-long stretches when the units would be offered into the market economically, but MISO would not call for them to be put into service. He stated it has been rare over the last several years for NIPSCO's coal-fired units to be brought on-line when they were offered economically into the MISO market.

Mr. Sangster testified Units 14 and 15 were historically the least reliable of NIPSCO's coal-fired units, and when looking at the equivalent forced outage rate ("EFOR"), Unit 14 had been NIPSCO's least reliable unit, with an EFOR of nearly double the next unit. Unit 15 was consistently NIPSCO's second-worst performing unit in terms of EFOR. When looking at the equivalent availability factor ("EAF"), which measures the percentage of time a unit is available for dispatch, he stated the story was similar, noting that on average from 2014-2019, Michigan City had a slightly worse EAF than any of the Schahfer units, but of the four Schahfer units, Unit 14 had the lowest (or worst) EAF, followed closely by Unit 15.

Mr. Sangster stated that as of July 1, 2020, NIPSCO's 2018 IRP identified retirement of all NIPSCO's coal-fired generation as the most economic option for NIPSCO's customers, but for other reasons—such as reliability, employee impact, community impact, etc.—a transition plan was established to retire the coal-fired units at Schahfer by May 2023.

Before sharing the specifics of what transpired at Unit 14 before the fire, Mr. Sangster described the job responsibilities of a control room operator ("CRO") at Schahfer. He stated CROs are responsible for the overall operations of a particular generating unit. They coordinate the functions of the other production department employees, and each CRO has a dedicated workspace where they have various screens the CRO utilizes to monitor and regulate the operation of one generating unit. When an alarm is issued identifying a potential issue or concern, the CRO receives an alarm or notification on one of their screens and is responsible for directing other personnel (typically a Station Operator) to investigate identified issues. He stated those who apply to become a CRO generally have significant experience and are already very familiar with a unit's operations. Even so, before becoming a CRO, an employee must complete a lengthy, in-depth training course, and NIPSCO also administers ongoing training. Mr. Sangster testified that at Schahfer, there is one CRO for each generating unit that is operating, and these CROs are stationed in the control room; consequently, if Units 14, 15, 17, and 18 are all operating, this means four CROs will be on shift with each CRO responsible for a particular unit.

Mr. Sangster testified July 16, 2020, was a busy day at Schahfer, with all four units operating. Throughout the morning, Unit 14 experienced multiple fuel supply issues. Because the coal coming into the plant was wet from rain, it was plugging up coal chutes and feeders, and this, in turn, was tripping or shutting off the cyclone burners. Mr. Sangster stated the CRO and Station Operators were continuously working to put these systems back into service and keep the unit operating. During this time, hundreds of alarms were coming into the control room. Early in the morning, a general trouble alarm from the unit main transformer came into the control room for Unit 14. Specifically, at 7:56 a.m. an alarm activated associated with the main oil-cooled transformer at Unit 14. This alarm indicated there was a higher than usual temperature in Unit 14's main transformer (the "Transformer") and like many other alarms, "popped up" on the CRO's alarm screen. Mr. Sangster stated that while the CRO for Unit 14 worked with station personnel, including Station Operators, to address Unit 14's fuel supply issues from wet coal, as well as ongoing issues with the cyclone burners, he did not do so concerning the Transformer alarm.

Mr. Sangster testified a high temperature alarm like this one will remain on the alarm screen as an unacknowledged alarm until one of two things happens: (1) it is affirmatively acknowledged by the CRO by manually clicking on the alarm or (2) the condition that activated the alarm resolves itself. In this instance, the CRO indicated he noticed and acknowledged the high temperature alarm and pulled the alarm up on one of his screens to monitor the Transformer's temperature. Mr. Sangster testified that according to NIPSCO's training and procedures, the Unit 14 CRO should have dispatched a Station Operator to investigate the Transformer and verify temperature locally, as well as confirm the cooling systems were operating correctly. At a minimum, when the Unit 14 CRO became aware of the situation, if these actions could not be taken, he should have notified his supervisor of the situation so further actions or a response by other personnel could be evaluated. The CRO, however, did not take either action.

Mr. Sangster testified that to the best of NIPSCO's knowledge, the only person who was aware of the high temperature alarm from 7:56 a.m. until 1:25 p.m. on July 16, 2020, was the Unit 14 CRO. He stated the CRO indicated he did not take immediate action regarding this alarm because the temperature was not extraordinarily high and was not increasing at a significant rate; rather, it was slightly high and slowly increasing. Ultimately, no one was ever dispatched or otherwise informed by the CRO of the rising Transformer temperature before the fire.

Mr. Sangster testified that while what caused the fire cannot be definitively determined because of the extensive damage, to the best of NIPSCO's knowledge, the oil cooling system (either the fans, pumps, or both) tripped off or failed, which caused the Transformer's temperature to increase. Because there was no sudden and significant spike in the Transformer's temperature, it is believed to have increased slowly but steadily throughout the day. Thus, there was a slow but steady rise in temperature over more than five hours for which the CRO dispatched no one to investigate. Mr. Sangster explained that once the oil inside the Transformer reached its boiling point, it turned from a liquid into a gas, setting off the sudden pressure alarm for the Transformer. Unit 14 tripped off-line at approximately 1:25 p.m.[6] Because Unit 14 was actively generating and its turbine was spinning at approximately 3,600 revolutions-per-minute (rpms), the turbine did not immediately stop spinning but began to coast down as Unit 14 began to produce less and less energy, but energy was still being discharged into the Transformer for a few seconds. He stated the protective relay scheme operated properly by isolating the yard, which is the path traveled as energy leaves the Transformer. This created an arc flash[7] that came back toward the Transformer, igniting the gaseous oil then escaping from the Transformer because of the high temperature. In turn, this created the fire.

Mr. Sangster testified the fire caused extensive damage to the Transformer, which was completely destroyed, and significant damage to the 13.8 kV switchgear and other key components of Unit 14 and to some of the common systems Units 14 and 15 shared. This led to Unit 14 and Unit 15 being placed into a forced outage.

Mr. Sangster stated the fire began at 1:25 p.m. and was fully extinguished at approximately 9:00 p.m. He advised that multiple local fire departments came together to work safely and efficiently to extinguish the fire, and their efforts ensured the fire was contained. Mr. Sangster testified the safety of NIPSCO's personnel and the general public is always NIPSCO's top priority, and thankfully, there were no safety incidents or injuries to NIPSCO personnel, the general public, or the first responders extinguishing the fire.

Mr. Sangster sponsored the RCA NIPSCO conducted following the fire (Confidential Attachment 2-A). He stated this was performed under his direction and supervision, and he was responsible for oversight of the post-fire investigation. He also presented the RCA information to NIPSCO leadership.

Mr. Sangster testified that while the extensive damage to the Transformer made a definitive determination of a root cause difficult, NIPSCO concluded the likely cause of the fire was the failure of the cooling system associated with the Unit 14 Transformer. He explained the temperature trend from the control system showed the temperature increased slowly over time, with no instantaneous or rapid temperature increase, which is indicative of a cooling system failure. He testified it is NIPSCO's determination that the cooling system failure led to the Transformer temperature rising. This then led to expulsion of gases from the Transformer and to the conditions where the arc flash from Unit 14 ignited the Transformer's oil, starting the fire.

Mr. Sangster further testified that to the best of his knowledge, there were no problems or concerns with the Transformer's cooling system identified in the past. He stated the cooling system was operating correctly earlier in the day, and historical data indicates the Transformer had been maintaining a normal temperature. He noted the cooling system for the Transformer was periodically inspected and had not been flagged as problematic or needing repair.

[6] When Unit 14 tripped, there was an almost simultaneous but subsequent trip of Unit 15.
[7] An arc flash is a phenomenon where a flashover of electric current leaves its intended path and travels through the air from one conductor to another or to ground.

Mr. Sangster stated that while the cooling system failure appears to be the root cause of the fire, the CRO's failure to adequately or timely respond to the temperature alarm was a contributing factor. He pointed out that according to NIPSCO's procedures and training, the Unit 14 CRO should have dispatched a Station Operator to investigate the temperature alarm. The Station Operator would have checked the Transformer temperature locally and verified whether the cooling systems were working. Additionally, if the abnormal conditions could not be resolved, a discussion among the Station Operator, CRO, and supervisor should have taken place. At that point, a determination would have been made whether to remove Unit 14 from service in accordance with the unit operating procedures.

Mr. Sangster reiterated this was a busy day with several ongoing operational issues at Unit 14 when the high temperature alarm for the Transformer came in, and the CRO was addressing what appeared to be more pressing and problematic issues. He stated it is unfortunate the alarm was not addressed, as this could have potentially prevented the fire. Mr. Sangster acknowledged that given the slow rise in temperature, the CRO had time to act in accordance with NIPSCO's procedures and afford the Station Operator the opportunity to take action to address the Unit 14 Transformer temperature issues. Mr. Sangster testified the CRO on duty and responsible for Unit 14 on July 16, 2020, was an employee with more than 40 years of experience at NIPSCO, including 37 years working in generation-related roles, and he had been a CRO for more than 17 years.

Mr. Sangster testified that he does not believe NIPSCO's actions or inactions caused or led to the cause of the fire at Unit 14. To the best of his knowledge, NIPSCO operated and maintained Unit 14 in a reasonable manner; NIPSCO has properly maintained and operated its generating units, including Unit 14, and NIPSCO has appropriately trained its personnel who work as CROs and System Operators. He testified this was an unfortunate event that, thankfully, did not result in physical injury or loss of life. He stated that ultimately, equipment on older units can fail, and the CRO's human error failed to mitigate that equipment failure, and as a result, the fire occurred.

C. <u>Andrew S. Campbell</u>. Mr. Campbell testified that following the fire at Unit 14, NIPSCO's customers have been provided service at the lowest cost reasonably possible, with Unit 14 never returning to service, and Unit 15 out of service through December 2020. He stated NIPSCO's customers will be reliably and more economically served under Portfolio 2a under which Unit 14 never returns to service and Unit 15 only remains in service through October 2021.

With respect to whether he anticipates NIPSCO's customers will be impacted by NIPSCO's decision to move up the retirement dates for Units 14 and 15 to October 2021, Mr. Campbell testified NIPSCO's 2016 and 2018 IRPs and the analysis CRA undertook following the fire all point to the conclusion that not returning Unit 14 to service and temporarily returning Unit 15 to service will be economically beneficial to NIPSCO's customers. He stated that with Unit 14 remaining in forced outage through October 2021 and then both Units 14 and 15 being retired in October 2021, NIPSCO will have sufficient physical resources to serve its customers. Mr. Campbell testified NIPSCO's customers will not be responsible for the cost of procuring capacity to replace Units 14 and 15 in Planning Years 2021-2022 and 2022-2023 and will receive a revenue credit per the Order in Cause No. 45159[8] that will reduce electricity rates and benefit customers.

In addressing the economics of NIPSCO's coal-fired generating units at Schahfer, Mr. Campbell stated the 2018 IRP, like the 2016 IRP, concluded the more coal-fired generation NIPSCO retires and the earlier it is retired, the more economically NIPSCO will be able to serve its electric customers. He testified that if economics were the only relevant factor in 2018, NIPSCO would have moved to retire its entire coal-fired generation immediately; however, to ensure NIPSCO was able to appropriately plan for retirements, procure replacement generation, and make the necessary upgrades to its transmission system, the 2018 IRP set forth a plan for the transition from coal-fired generation.

Mr. Campbell noted the 2018 IRP resulted in a preferred portfolio for NIPSCO's generation that called for: (a) retirement of 75% of NIPSCO's coal-fired generation by May 2023 and 100% of the coal-fired generation by May 2028;[9] (b) continued operation of NIPSCO's gas-fired Sugar Creek Generating Station ("Sugar Creek"); and (c) replacement of certain retired generation units largely with wind, solar, and solar plus storage projects. It also outlined key steps NIPSCO should take to select and implement resources to replace the 2023 retirement of the Schahfer units.

Mr. Campbell provided an update on where NIPSCO currently stands in executing the Short-Term Action Plan under which NIPSCO replaces higher-cost coal-fired units with lower-cost renewable resources. He stated that upon issuing its 2018 IRP, NIPSCO began implementing the Short-Term Action Plan and issued an RFP to solicit competitive renewable energy projects to add to its portfolio. He stated NIPSCO is pursuing a diversified approach to replacing the retiring coal-fired capacity at Schahfer, with a mix of (a) wind, solar, and solar plus storage projects; (b) power purchase agreements ("PPAs") and project ownership through joint venture structures; (c) geographic or locational diversity; and (d) diversity in the term of the project commitments. He testified that, ultimately, NIPSCO will have a diverse mix of generation resources in terms of fuel source, deal structure, and commitment duration that replaces the retiring Schahfer units.

Mr. Campbell described the renewable generation projects that have reached commercial operation subsequent to the 2018 IRP. He stated that in December 2020, two wind projects reached commercial operation: (1) the Jordan Creek Project, a 400 megawatt ("MW") project for which NIPSCO has a PPA; and (2) the Rosewater Project, a 100 MW project NIPSCO owns as part of a joint venture ("JV"). He stated NIPSCO expects the Indiana Crossroads Wind I Project, a 300 MW wind JV project, to come online in November 2021. Additionally, he shared the names and nameplate capacity of other planned projects.

Mr. Campbell explained that while the least-cost decision in late 2018 would have been to retire all coal generation immediately, considerations such as reliability, the impact on NIPSCO's employees and on local communities, and other factors resulted in a proposed retirement by May

[8] Cause No. 45159 Order dated December 4, 2019 ("45159 Order") at p. 163.
[9] This 75% of NIPSCO's coal-fired generation relates to all four units at Schahfer (Units 14, 15, 17, and 18), and the 25% relates to one unit at the Michigan City Generation Station (Unit 12).

2023. He confirmed the timely execution of the renewable generation projects allowed NIPSCO to consider retirement dates earlier than May 2023 for Units 14 and 15 after the fire in July 2020.

Mr. Campbell also addressed NIPSCO's progress in executing the reliability and transmission upgrades set out in the Short-Term Action Plan before 2023. He stated the Short-Term Action Plan identified six transmission upgrades that were necessary to retire all four coal-fired units at Schahfer (Units 14, 15, 17, and 18). To date, NIPSCO has completed four of these upgrades, and the two remaining are expected to be completed in 2021 and 2022; however, he stated the upgrades required to retire only Units 14 and 15 have been completed, providing NIPSCO with greater flexibility when deciding whether and to what extent Units 14 and 15 should be returned to service.

Mr. Campbell testified that prior to the fire, NIPSCO submitted MISO Attachment Y filings seeking a retirement date of June 1, 2023, for Schahfer Units 14, 15, 17, and 18, and MISO subsequently approved those requests and concluded NIPSCO could retire these assets from commercial operation without any reliability impact. After the fire and after concluding an earlier retirement of Units 14 and 15 was in the best interests of its customers, NIPSCO sought to amend the previously approved retirement date for Units 14 and 15, and in March 2021, he stated NIPSCO submitted a new Attachment Y notice to MISO, seeking a new retirement date of October 1, 2021. NIPSCO has since received MISO approval for an October 1, 2021, retirement date with no reliability concerns identified.

Mr. Campbell provided an overview of NIPSCO's current generation fleet and explained the historical operation and maintenance of NIPSCO's coal-fired units. He also provided confidential testimony explaining how NIPSCO typically offers its thermal generation resources into the MISO market, including NIPSCO's decision-making process for when to offer units as "must run," up to their economic minimum (or "EconMin"), or up to their economic maximum (or "EconMax"). Mr. Campbell also discussed confidential information related to how many of NIPSCO's five coal-fired units are offered at different levels to MISO.

Mr. Campbell stated the fire at Unit 14 changed how NIPSCO offers its coal-fired units into the MISO market. He noted the Unit 14 fire led NIPSCO to put both Units 14 and 15 into forced outage beginning July 16, 2020, with Unit 14 remaining in forced and Unit 15 returning to service on December 1, 2020. Mr. Campbell testified that during the July 16 to December 1, 2020, time period Units 12, 17, and 18 continued to be available, as well as Sugar Creek, the majority of the time. Per Mr. Campbell, having Units 14 and 15 in forced outage did not significantly impact how NIPSCO operated its generation fleet.

Mr. Campbell also described the actions NIPSCO has taken in response to the Unit 14 fire with respect to capacity. He stated that in August 2020 and October 2020, NIPSCO ran two separate RFPs for capacity to probe the market for options to potentially replace the capacity at Units 14 and 15 during MISO's 2021-2022 and 2022-2023 Planning Years. He advised that NIPSCO evaluated these two Planning Years as it was considering options to potentially retire Units 14 and/or 15 sometime between mid-2021 and May 31, 2023. Additionally, in May and June 2021, NIPSCO procured additional capacity for Planning Year 2022-2023. He stated the decision-making process NIPSCO's management undertook was informed by the responses to the RFPs and the capacity NIPSCO was able to procure in 2020. According to Mr. Campbell, NIPSCO is not seeking to recover the costs of these capacity purchases from its customers.

Mr. Campbell explained that after the fire at Unit 14, NIPSCO evaluated whether and to what extent to return Units 14 and 15 to service. To this end, NIPSCO engaged CRA—the consulting group who assisted with NIPSCO's 2016 and 2018 IRPs—to analyze alternative portfolios or options available for Units 14 and 15. He stated the analysis concluded Portfolio 2a had the lowest net present value revenue requirement ("NPVRR") of the five portfolios. He explained that in terms of market volatility risk, the stochastic analysis concluded the portfolios that brought Unit 15 back in-service for a period of time reduced uncertainty and mitigated against high MISO market price risk exposure and low MISO market price risk. He stated Portfolio 2a allowed Unit 14 to remain in forced outage after the fire, temporarily brought Unit 15 back to service by the end of 2020, and retired Units 14 and 15 in mid-2021. Mr. Campbell testified NIPSCO's decision was to pursue Portfolio 2a because it appropriately balanced the cost to NIPSCO's customers and potential market risk.

Mr. Campbell identified what he views as the key factors that allowed for these decisions. He stated NIPSCO was able to secure sufficient, economic capacity through a pair of RFPs that addressed potential capacity concerns, and from the perspective of meeting customers' energy requirements, at least two key factors support the conclusion that NIPSCO will be able to meet its energy requirements without Units 14 and 15. First, subsequent to the 2018 IRP, in January 2020 NIPSCO implemented a new industrial service structure known as Rate 831 that reduced NIPSCO's annual energy requirements by nearly four million megawatt-hours ("MWh"). Second, while the 2018 IRP assumed the timely addition of certain renewable generation facilities, NIPSCO has successfully executed its renewable generation strategy with the addition of Jordan Creek and Rosewater and the addition of Indiana Crossroads Wind I in late 2021 along with the planned addition of several renewable facilities in 2022 and 2023, further supporting the conclusion that NIPSCO can reliably and economically serve its customers without Units 14 and 15. Mr. Campbell sponsored a forecast of NIPSCO's estimated on-peak resources and on-peak demand (Attachment 3-A). This shows the additional renewable generation resources are expected to come online by mid-2023 and estimated on-peak purchases from the MISO market. He stated this graphically demonstrates that without Units 14 and 15, NIPSCO expects to have sufficient resources to cover its on-peak demand and expects to supplement its generation with purchases from the MISO market. He noted the anticipated market purchases are not expected to exceed the historical volumes of purchases observed in NIPSCO's FAC filings in 2019 or 2020, largely due to the Rosewater, Jordan Creek, and Indiana Crossroads Wind I project additions.

Mr. Campbell testified that without Units 14 and 15, NIPSCO will also have sufficient thermal generation available. He stated these resources will continue to serve NIPSCO's customers well, including acting as physical hedges to protect customers from potential volatility in the energy market. Further, in periods when NIPSCO needs to purchase energy through the MISO Day-Ahead and/or Real-Time markets, NIPSCO is confident sufficient energy will be available.

Mr. Campbell stated the Jordan Creek and Rosewater facilities (representing a combined 500 MWs of ICAP) coming online in December 2020 have been beneficial in serving NIPSCO's customers through 2021. He noted the Indiana Crossroads Wind I facility, representing an additional 300 MWs of ICAP, coming online in late 2021[10] also complements the October 2021 retirement of Units 14 and 15. Additionally, beginning in late 2022, NIPSCO has several solar and solar plus storage facilities and one additional wind facility coming online, as shown below.

Table 2[11]

Resource	Fuel	Capacity (ICAP)	In-Service Date
Indiana Crossroads Wind I	Wind	300	November 2021
Greensboro	Solar	100	December 2022
	Storage	30	
Brickyard	Solar	200	December 2022
Dunn's Bridge I	Solar	265	December 2022
Indiana Crossroads Solar	Solar	200	December 2022
Gibson	Solar	280	June 2023
Elliott	Solar	200	June 2023
Green River	Solar	200	June 2023
Fairbanks	Solar	250	October 2023
Dunn's Bridge II	Solar	435	December 2023
	Storage	75	
Cavalry	Solar	200	December 2023
	Storage	60	
Indiana Crossroads Wind II	Wind	200	December 2023

Mr. Campbell testified that by utilizing this increasing number of renewable resources, NIPSCO is confident it will have sufficient capacity and energy to serve its customers' needs. He stated that while NIPSCO anticipates its increased renewable generation will lead to less reliance on MISO market purchases, when there is a need to procure energy in the Day-Ahead or Real-Time market the history of MISO's market and NIPSCO's 2018 IRP demonstrate sufficient and reasonably priced energy will be available.

Mr. Campbell expanded on the cost of NIPSCO's coal-fired generation as compared to other resource options. He provided the average cost for NIPSCO's coal-fired generation in 2020 (noting it varies by unit) and stated the average cost increased in the first few months of 2021. Per Mr. Campbell, if you compare this cost to MISO market purchases, NIPSCO's 2019 average purchase price (looking at all hours) was slightly under $30.00/MWh, and purchases for all of 2020 were less than $22.00/MWh. He stated through June 30, 2021, NIPSCO's MISO market purchases have averaged $25.91/MWh. He testified the average MISO purchase price for each month in 2020 was as low as $16.24/MWh and not more than $27.77/MWh. Thus, to the extent

[10] Per Mr. Talbot's rebuttal testimony (Petitioner's Exhibit 1-R at p. 21, lines 6-8), Indiana Crossroads Wind I went into service in December 2021 (*i.e.*, prior to his testimony being prefiled on December 17, 2021).
[11] As of August 13, 2021, NIPSCO has received Commission approval for each of these projects, with the exception of the Crossroads Wind II Project that remains pending before the Commission in Cause No. 45541.

NIPSCO needs to access the MISO market for some level of energy purchases, NIPSCO expects sufficient, reasonably priced energy to be available.

Mr. Campbell acknowledged that whether it be month-to-month or quarter-to-quarter, between July 2020 and May 2023 there almost certainly will be periods where there are variations in pricing; however, between October 2021 and May 2023, NIPSCO remains confident customers will be served at the lowest reasonable cost by retiring Units 14 and 15 on October 1, 2021.

Mr. Campbell testified there are also other costs associated with having coal-fired generation available that are avoided when making MISO market purchases such as costs to maintain and run the coal-fired units when they are not actively producing energy to serve customers' load. He noted coal-fired generation units are not able to come online quickly or equipped to cycle between high and low MW output on a daily basis. He stated that when offering a coal-fired unit into the MISO market, there are costs to keep the unit ready to be dispatched even if the unit is not actually dispatched by MISO and is not used to produce MWs that will serve NIPSCO's load. Mr. Campbell testified these costs include costs associated with starting up the unit and having it ready if it is dispatched by MISO, as well as the additional operation and maintenance expenses from running the unit.

Mr. Campbell testified that since the fire at Unit 14 on July 16, 2020, NIPSCO has managed its available resources to serve its customers reliably and economically, even with the outages at Units 14 and 15 following the fire. Mr. Campbell reviewed how NIPSCO managed potential market risks and potential economic impacts on its cost to serve customers between July 16 and December 1, 2020, when Unit 15 came back online. He noted that during this period, NIPSCO had two fewer coal units that could act as physical hedges and also had a planned outage at Sugar Creek from October 1 through December 8. He stated that even with these units in outage, NIPSCO did not experience any significant events that drove costs for customers higher. Mr. Campbell stated NIPSCO managed its generation fleet well during this time, even with warmer weather in late July through September.

Mr. Campbell also described how NIPSCO managed potential market risks and economic impacts on its cost to serve customers once the decision was made to leave Unit 14 in a forced outage and return Unit 15 to service. He explained that in Cause No. 38706 FAC 130, which was filed on February 19, 2021, he sponsored an updated Hedge Plan ("2021 Hedge Plan") that contemplated: (a) leaving Unit 14 in a forced outage, (b) Unit 15 having been returned to service, and (c) both units being retired by year-end 2021. He stated the objectives of the 2021 Hedge Plan were to reduce the relative movement in the FAC factor from one period to the next and to limit upside price exposure. Mr. Campbell explained the two types of contracts under the 2021 Hedge Plan that acted as financial, rather than physical, hedges, and he advised the 2021 Hedge Plan was discussed with the OUCC and the Industrial Group before being filed, and NIPSCO incorporated the feedback received. Mr. Campbell testified the Commission approved the 2021 Hedge Plan on April 28, 2021, and NIPSCO began operating under the 2021 Hedge Plan in July 2021 and will continue doing so through June 2023.

Mr. Campbell testified a hypothetical hindsight attempt to resettle the MISO market for a given period requires speculation regarding how a unit might impact economic dispatch in the MISO market, and such an analysis, even if attempted, will not provide definitive conclusions;

however, he noted NIPSCO performed some analysis to provide a reasonable baseline for comparing how a coal unit in forced outage would have performed against the actual market that existed. To provide the comparison for the period when both Units 14 and 15 were offline in 2020 post-fire, he stated NIPSCO undertook a straightforward comparison of its cost to purchase power from the MISO market versus the cost to run Unit 14 or Unit 15 at the "EconMin" level. Mr. Campbell explained what was performed and what assumptions were necessary, and he discussed the results of the comparison. Mr. Campbell testified that for the 169-day period from July 16 through December 31, 2020, the variable cost to run Unit 15 exceeded the actual price of MISO market purchases in 164 of those 169 days. Additionally, for the 5 days where Unit 15's costs were lower than MISO market purchases for the day, the MISO purchase price never exceeded Unit 15's cost by more than $3/MWh. On the other hand, he stated there were numerous days where Unit 15's cost exceeded the MISO purchase price by more than $10/MWh, including days when Unit 15 was more than double the MISO market price. For Unit 14, its variable cost exceeded the actual price of MISO market purchases in 131 of those 169 days. Additionally, for the 38 days when Unit 14's costs were lower than MISO market purchases for the day, the MISO purchase price exceeded Unit 14's cost by more than $5/MWh on only 13 days. On the other hand, there were numerous days where Unit 14's cost exceeded the MISO purchase price by more than $5/MWh.

Mr. Campbell opined that this demonstrates, even under this relatively conservative and simple comparison, NIPSCO customers were placed in a better economic position by NIPSCO purchasing its energy needs from MISO than they would have been had NIPSCO utilized either Unit 14 or 15 to provide these energy needs from July 16 through December 31, 2020. Additionally, while this comparison was performed after CRA performed its market analysis, he noted it supports with real-world data the same conclusion CRA reached—NIPSCO's customers could be more economically served by retiring Units 14 and 15 in October 2021, instead of May 2023. He testified that because (a) NIPSCO was without Units 14 and 15 from July 16 through December 1, 2020; (b) Sugar Creek was in an outage from October 1 through December 8, 2020; (c) the Jordan Creek and Rosewater facilities did not come online until late December 2020; and (d) NIPSCO was still able to economically and reliably serve its customers during this period, he is confident NIPSCO will be able to continue to do so from when Units 14 and 15 retired in October 2021 until May 2023.

Mr. Campbell testified that for July 16 to December 1, 2020, the FAC costs for July through September 2020 were forecast in FAC 127, and actual costs were reconciled in FAC 129. FAC costs for October through December 2020 were forecast in FAC 128, and actual costs were reconciled in FAC 130. He explained that NIPSCO's FAC 127 tracker filing was made in May 2020 a couple months before the Unit 14 fire. Thus, the forecasted cost of fuel for July through September 2020 assumed Unit 14 and Unit 15 would be available. On the other hand, NIPSCO's FAC 128 forecast was filed in August 2020, and the forecasted cost of fuel for October through December of 2020 assumed Units 14 and 15 would not be available for this period.

Mr. Campbell described the differences in forecasted and actual fuel costs for July through September 2020 and October through December 2020. He stated the actual fuel costs for FAC 129 were approximately $700,000 more than forecasted in total dollars and $0.065/kWh less than forecasted on a per kilowatt-hour ($/kWh) basis, resulting in a variance of 0.26%. They were based on NIPSCO utilizing coal-fired generation slightly more than forecasted but, relatedly, utilizing MISO purchases and gas-fired generation slightly less than forecasted.

He stated the actual fuel costs for FAC 130 were approximately $300,000 more than forecasted in total dollars and $0.643/kWh more than forecasted on a $/kWh basis, resulting in a variance of 2.5%, which is well within the typical range of outcomes for most FAC periods. Mr. Campbell testified coal-fired generation was utilized less than forecasted, and Sugar Creek was also in outage, which led to gas-fired generation being utilized less than forecasted as well. Per Mr. Campbell, NIPSCO made more purchases from MISO during this period, and the purchases were made around the expected price, so there was only a small variance for October through December 2020.

Mr. Campbell testified he is confident NIPSCO can serve its customers reliably and economically from the present through May 2023, the latest date by when Units 14 and 15 were originally planned to retire. He stated since the fire at Unit 14, NIPSCO has reliably and economically served its customers and has not encountered any issues that call into question whether NIPSCO will be able to continue doing so after Units 14 and 15 are retired in October 2021. He stated that with respect to economics, both the 2016 and 2018 IRPs concluded the earlier NIPSCO retires its coal-fired generation, the better it is for NIPSCO's customers from the perspective of the lowest cost; consequently, while the fire was unfortunate, it provided NIPSCO with another decision point to evaluate NIPSCO's progress in executing the Short-Term Action Plan and determine the best alternative for NIPSCO's customers.

Mr. Campbell stated that with respect to reliability, because NIPSCO has been successful through 2020 and to date in 2021—including when Units 14 and 15 were offline in late 2020 and Sugar Creek was in a planned outage in late 2020—NIPSCO continues to be confident it can manage a much lower-risk profile through the rest of 2021 and through May 2023.[12] He testified that when combining NIPSCO's performance in the last half of 2020 with the renewable projects that have come online and will be coming online over the next couple years, NIPSCO's available resources will be able to meet firm demand. Ultimately, with the earlier retirements of Units 14 and 15, Mr. Campbell is confident NIPSCO will continue to reliably serve its customers, and NIPSCO's customers will not be financially harmed. He noted NIPSCO will still be subject to the Purchase Power Benchmark where it shares market exposure to the extent purchased power is at high prices, providing an additional level of protection to customers when NIPSCO utilizes the MISO market for energy purchases.

Additionally, Mr. Campbell explained the revenue credit agreed upon as part of the Stipulation and Settlement Agreement approved in the 45159 Order. He stated this credit was originally to begin following the retirement of Schahfer in May 2023, but a credit associated with the earlier retirement of Units 14 and 15 will begin shortly after the units are officially retired. He stated NIPSCO anticipates the revenue credit will be approximately $1 million per month for the first year and will increase over time—all of which will flow directly to NIPSCO's customers through reduced base rates.

[12] This lower-risk profile is demonstrated in Attachment 3-A.

D. Patrick N. Augustine. Mr. Augustine explained the results of CRA's 2020 analysis of the economic implications for the various options for returning Units 14 and 15 to service following the fire in July 2020.

Mr. Augustine testified that prior to 2020, CRA performed modeling analysis for NIPSCO that considered the economics of the four coal-fired units at Schahfer and their future operational life. He stated a key outcome of NIPSCO's 2018 IRP was an analysis of the economics of the existing coal fleet compared to other resource alternatives. From a purely economic perspective, he testified the 2018 IRP concluded that retiring the four coal-fired units at Schahfer and the one coal-fired unit at Michigan City as early as possible was the lowest-cost alternative for NIPSCO's customers. While the most economic choice was clear in 2018, he stated NIPSCO needed time to consider the impacts on its system and to ensure its ability to replace the capacity and energy from these units; therefore, NIPSCO's preferred portfolio called for retirement of all four Schahfer units by 2023.

Mr. Augustine explained why the preferred retirement date for Schahfer Units 14 and 15 was established as 2023 in the 2018 IRP and not earlier. He testified that rather than retire all the coal-fired units as soon as possible, NIPSCO pursued a path to retire all four coal units at Schahfer by 2023 and Unit 12 at Michigan City five years later, in 2028, to allow sufficient time to make required transmission upgrades and secure new resources to maintain reliability during NIPSCO's generation transition. He stated that although NIPSCO found the portfolios that retired its coal units earlier, including a portfolio that retired two units at Schahfer in 2021, were lower cost than the preferred portfolio, the 2018 IRP concluded that leaving time for the transition was important. He testified the preferred portfolio included significant amounts of replacement wind, solar, and solar plus storage capacity and energy over time, plus certain levels of energy efficiency and demand side management peak load savings.

Mr. Augustine described how the economic impact of the preferred portfolio compared with portfolios that had earlier coal retirements. He testified that across NIPSCO's scenario and stochastic-based retirement analysis, it was determined the more coal-fired generation that was retained in the portfolio and the longer it was retained, the more expensive the portfolio was for NIPSCO's customers. He noted this was true across all of NIPSCO's scenarios and the full stochastic distribution of uncertainties that were evaluated. Per Mr. Augustine, the 2018 IRP's economic analysis consistently showed all of NIPSCO's coal-fired generation should be retired as soon as possible.

Mr. Augustine testified that after the July fire placed Units 14 and 15 into forced outage, CRA conducted an additional analysis to assist NIPSCO in evaluating whether and when to repair Units 14 and 15 and restore them to service. He stated NIPSCO asked CRA to evaluate five specific portfolio options associated with near-term restoration decisions at Schahfer Units 14 and 15 within the same modeling framework used in the 2018 IRP. This analysis incorporated major input assumptions associated with NIPSCO's portfolio and the external environment to project customer costs over a 20-year planning horizon and develop estimates of the NPVRR for each of the five portfolio options.

Mr. Augustine testified that based on input from NIPSCO, CRA evaluated the following five portfolio options:

(1) Portfolio 1: Bring both Units 14 and 15 back to service by the end of 2020 and operate both through their original retirement date of May 31, 2023;

(2) Portfolio 2: Allow both Units 14 and 15 to remain in forced outage (beginning in summer 2020) and not return these units to service;

(3) Portfolio 2a: Allow Unit 14 to remain in forced outage (beginning in summer 2020), temporarily bring Unit 15 back to service by the end of 2020 through the middle of 2021, and not have Unit 14 or 15 in service thereafter;

(4) Portfolio 2b: Temporarily bring both Units 14 and 15 back to service by the end of 2020 through the middle of 2021 and remove both from service thereafter; and

(5) Portfolio 2c: Allow Unit 14 to remain in forced outage (beginning in summer 2020) and retire it as soon as reasonably possible, bring Unit 15 back to service by the end of 2020, and operate Unit 15 through its original retirement date of May 31, 2023.

Mr. Augustine described the types of major input assumptions used to develop the NPVRR projections for the five portfolio options and how the assumptions may have changed since 2018. He stated the analysis included assumptions for the following key inputs: (1) unit data on NIPSCO's existing fleet, consistent with NIPSCO's model assumptions at the time of the analysis, including expectations for the specific new wind, solar, and solar plus storage projects NIPSCO is currently integrating into its portfolio over the 2020 through 2023 period; (2) NIPSCO's load forecast at the time of the analysis, which incorporated the impact of implementing Rate 831 after the submission of NIPSCO's 2018 IRP and had the effect of reducing NIPSCO's energy requirements by approximately four million MWhs;[13] (3) commodity prices based on CRA's commodity price outlook and the time of the analysis, along with NIPSCO's specific contract information for its coal fleet; and (4) capital expenditure ("CapEx") and operation and maintenance projections that varied across the five portfolios based on the alternative potential plans at Schahfer.

In describing how the dispatch operations of Units 14 and 15 were modeled, Mr. Augustine stated that as part of the analysis, he evaluated the economic implications associated with NIPSCO's coal inventory. In Portfolio 2, a $32 million cost was assessed in 2021 for the coal inventory and coal contract obligations that would still be owed to suppliers if NIPSCO permanently shut down and ceased burning coal at Units 14 and 15 in 2020. In all other portfolios, at least one unit was brought back online for sufficient time to consume all outstanding coal obligations. Thus, this coal inventory cost was not incorporated in Portfolios 1, 2a, 2b, and 2c. He explained that aside from Portfolio 1, where both Units were assumed to be brought back into service by the end of 2020, replacement capacity purchases were needed to meet minimum reserve

[13] Under new Rate 831, several large industrial customers no longer have their energy and peak demand needs served by NIPSCO; however, while NIPSCO's net energy requirements have fallen with the loss of Rate 831 customer demand, NIPSCO's net capacity position is very similar to what it was before the implementation of Rate 831 because even as peak load requirements have fallen, the interruptible capacity many of the Rate 831 industrial customers previously offered is no longer available.

margin requirements. He stated NIPSCO conducted an RFP in 2020 to assess the quantity and price of capacity available in the market for purchase and to secure capacity for its portfolio.

Mr. Augustine explained how he incorporated replacement capacity costs in the portfolios in CRA's analysis. He testified that although CRA's analysis took the capacity from these purchases into account when assessing the portfolio's supply-demand balance, the costs associated with these purchases were not included in the final revenue requirement calculations because NIPSCO advised CRA to assume that its customers will not be responsible for any replacement capacity costs associated with retiring the Schahfer units before the 2023 retirement date identified in the 2018 IRP. He stated NIPSCO advised CRA that if the units were not returned to service, a credit on the expected return on investment associated with the units will be provided to customers. Thus, an offset to customer costs was incorporated for all portfolios that did not restore and operate both units through May 2023 (Portfolios 2, 2a, 2b, and 2c).

Mr. Augustine described what the analysis concluded with regard to the future NPVRR of the five portfolio options. He testified the economics-focused analysis concluded Portfolio 2a had the lowest NPVRR across the 2020-2040 analysis period. He noted Portfolio 2a is the portfolio that allowed Unit 14 to remain in forced outage and temporarily brought Unit 15 back to service by the end of 2020 through mid-2021.

Mr. Augustine testified he also evaluated market risk exposure for the portfolios beyond this reference case NPVRR analysis. He stated NIPSCO asked CRA to evaluate the exposure of the various portfolio options to commodity price volatility, and CRA performed a short-term stochastic analysis to address this question. Per Mr. Augustine, this exercise was designed to evaluate market risk exposure prior to accounting for any hedging activity NIPSCO could undertake to mitigate market exposure and without regard to the potential for coal prices to change based on contract provisions that tie delivered fuel prices to power market prices. He stated this stochastic analysis varied MISO market power prices through 2025 based on an assessment of historical market volatility, and CRA evaluated 200 different iterations (or potential price paths) in its analysis. He confirmed this assessment did not calculate full revenue requirements, instead focusing on the variable portfolio cost risk associated with NIPSCO's energy position in the MISO market. He testified CRA's stochastic analysis focused on measures of cost variability, recording projected portfolio costs for each of the 200 potential outcomes and measuring the difference between different points on the distribution. For example, one measure of risk is the width of the distribution between the median (or middle point) and the 95th percentile (in this case, the 190th highest cost out of the 200 iterations). If the difference between these two points is wider for one portfolio than another, he advised this is an indication of a riskier portfolio.

Mr. Augustine testified the stochastic analysis found the portfolios that brought Unit 15 back in service for a period of time reduced the range of uncertainty and mitigated against both high MISO market price risk exposure and low MISO market price risk. In other words, having one unit back in service was better than having no units operational under high market price conditions that could expose NIPSCO to higher market purchase costs. He testified the analysis, therefore, suggested that bringing one unit back for a period of time provided a hedge against both low price and high price outcomes and, as a result, Portfolio 2a is both the least cost portfolio and a portfolio that provides lower risk exposure than Portfolios 1 and 2.

Mr. Augustine testified the value of Unit 15 from an energy risk hedge perspective is not the same throughout 2021 through 2023 since NIPSCO's current portfolio will be supplemented by additional wind energy towards the end of 2021 and additional solar energy at the end of 2022. This will minimize market purchases exposure. Thus, the value of retaining Unit 15 is greatest in 2021 because it provides a bridge until this additional renewable energy enters the portfolio. He stated that, overall, given NIPSCO's lower energy requirements after implementing Rate 831 and the expected new renewable additions, the portfolio's total energy production is expected to be close to or above the expected energy demand on a monthly level even after Units 14 and 15 are retired.

Mr. Augustine summarized the key findings from CRA's additional portfolio analysis. He testified the analysis concluded that allowing Unit 14 to remain in forced outage and temporarily restoring Unit 15 back into service in 2020 through mid-2021 resulted in the lowest NPVRR relative to all other portfolio options and mitigated market risk exposure versus portfolio options that did not return either unit to service or returned both units to service. He stated that since the 2018 IRP, NIPSCO's energy requirements have reduced significantly due to implementing Rate 831, and NIPSCO is well advanced in its plan to secure new renewable and storage resources over the 2020 through 2023 period. He noted the economic choice in 2018 was to retire all coal units as soon as possible, but NIPSCO required time to procure replacements and maintain reliability, but circumstances have changed since 2018 with NIPSCO's lower energy requirements and replacement resources added to the portfolio. Thus, economics can guide the decision whether and to what extent to return Units 14 and 15 to service, with Portfolio 2a providing cost savings for customers and confirming the major conclusions from NIPSCO's 2018 IRP.

4. <u>Other Parties' Testimony</u>.

A. <u>Michael D. Eckert</u>. Mr. Eckert provided an overview of the age and planned retirement dates of Units 14 and 15. He then discussed the fire on July 16, 2020, recounting facts similar to those Mr. Sangster shared. Per Mr. Eckert, at approximately 7:56 a.m. on July 16, 2020, Schahfer Unit 14 experienced high Transformer temperatures. No action was taken, and the temperature continued to increase, culminating in the fire several hours later at approximately 1:25 p.m. when the relay triggered and caused an arc flash. Mr. Eckert testified the fire caused extensive damage, leaving Unit 14, Unit 15, and their shared facilities forced out of service and placed on an extended outage. This prompted NIPSCO to perform a portfolio analysis, with NIPSCO ultimately deciding to repair Unit 15 and the shared facilities. NIPSCO operated Unit 15 until the on-site coal inventory was exhausted. As for Unit 14, he stated it remained in an extended forced outage, and Units 14 and 15 were both retired in October 2021. From Mr. Eckert's perspective, the fire resulted in Units 14 and 15 being retired 19 months early.

With respect to the cause of the fire and NIPSCO's responsibility, Mr. Eckert testified that based on the evidence he reviewed, there were several signs there was an issue at Unit 14 that should have been looked at or addressed; therefore, he concluded NIPSCO's actions or inactions contributed to the cause of the fire. Mr. Eckert noted that Unit 14's CRO was aware of the high temperature alarm starting at 7:56 a.m., but he took no responsive action between 7:56 a.m. and 1:25 p.m. No one was dispatched to view Unit 14 or otherwise informed of the rising Transformer temperature shown on the CRO's screen. Mr. Eckert reviewed the actions the CRO should have taken under unit operating procedures that did not occur.

When asked about what contributing events or issues NIPSCO described in its responses to the Industrial Group's discovery, Mr. Eckert cited three NIPSCO discovery responses. Per these responses, the CRO responsible for Unit 14 when the fire occurred was working two consecutive 12 hour shifts that started on July 15, 2021, at 6:00 p.m. through July 16, 2021, at 6:00 p.m.[14] Mr. Eckert also advised that NIPSCO's April 2020 Doble Dissolved Gas Analysis ("DGA") Report, while not recommending any action be taken, scored the Transformer as a "4," meaning the Transformer remained on the transformer watch list.[15] He testified this Transformer had been a level 4 since 1989 and was on NIPSCO's transformer watch list since its implementation a few years ago.[16]

Mr. Eckert testified that NIPSCO's FAC factors have risen since the fire, citing the increase between FAC 127 and FAC 132. Specifically, NIPSCO's approved FAC factor in FAC 127 was ($0.005732) while its most recent approved FAC factor in FAC 132 was $0.009761, representing an increase of approximately 15.493 mills or $15.49 to a customer using 1,000 kw per month. He opined that absent the fire, Units 14 and 15 would be economically dispatched given the current forecasted high natural gas prices and purchased power prices, and NIPSCO's energy prices and FAC factor would be lower.

Mr. Eckert recommended NIPSCO be ordered to calculate the difference between the amount it paid and will pay for purchased power and the cost of power for Units 14 and 15 and provide a credit to customers through May 2023.

B. Michael P. Gorman. In discussing the Schahfer station, as well as other generating units, Mr. Gorman noted Unit 14 is a coal-fired unit, with a capacity of 431 MW, that was placed in service in 1976. Unit 15 is also a coal-fired unit, with a capacity of 472 MW, that was placed in service in 1979. Mr. Gorman stated under NIPSCO's 2018 IRP, the Schahfer station was scheduled for retirement in May 2023. He stated an extended outage in July 2020 followed by retirement in October 2021 for Units 14 and 15 was not consistent with the action plan the 2018 IRP identified. Citing to Mr. Campbell, Mr. Gorman stated NIPSCO planned to replace the capacity of the coal-fired units with new renewable resources and had to complete necessary upgrades to its transmission system to accommodate the planned shift in capacity resources. He testified that as of July 15, 2020, of the planned replacement capacity, NIPSCO had two wind facilities that did not go into operation until December 2020, with most of the projects replacing Schahfer station's coal-fired capacity to be completed by mid-2023.

Mr. Gorman testified the 2018 IRP also identified six transmission upgrades necessary to retire all the coal-fired units at Schahfer. Only four of these six upgrades have been completed, with the other two expected to be completed in late 2021 and 2022. He noted Mr. Campbell testified the upgrades necessary to retire only Units 14 and 15 had been completed as of his August 13, 2021, direct testimony. Citing to testimony Mr. Augustine offered in Cause No. 45159, Mr. Gorman discussed why NIPSCO's preferred portfolio called for retirement of the coal-fired units at Schahfer in 2023 and Michigan City in 2028. He also discussed testimony Michael Hooper provided in Cause No. 45159, stating Mr. Hooper testified NIPSCO invested $86 million in

[14] Cause No. 38706 FAC 130 S1, IG DR 2-005.
[15] Cause No. 38706 FAC 130 S1, IG DR 1-008.
[16] Cause No. 38706 FAC 130 S1, IG DR 1-008.

environmental projects with an in-service date of December 16, 2018, specific to Schahfer Units 14 and 15, plus additional capital projects in 2017-2019. Mr. Gorman testified this level of investment reflects the expectation at the time that Units 14 and 15 would continue in operation another five years or more. Otherwise, this investment level would be a serious lapse in planning if NIPSCO expected the units to have limited or no availability starting in July 2020. Mr. Gorman stated he was unaware of any indication prior to the July 2020 fire that NIPSCO was considering retiring Units 14 and 15 sometime in 2021, noting both units were regularly operating and generating electricity to serve NIPSCO's customers before the fire.

Mr. Gorman discussed his understanding of the circumstances leading to the fire. He generally recounted Mr. Sangster's account, but he was also critical of NIPSCO for not conceding it bears responsibility for the fire since its CRO took no corrective action in response to the high temperature alarm activated in the Unit 14 control room at 7:56 a.m. Mr. Gorman stated Mr. Sangster described the CRO's failure to act as a contributing factor but asserted NIPSCO's actions or inactions did not cause the fire because Unit 14 was maintained and operated in a reasonable manner, and its employees were properly trained. Mr. Gorman disagreed with Mr. Sangster's assessment of NIPSCO's role in the events leading to the fire and absence of accountability. He explained that as a regulated public utility, NIPSCO is charged with a duty to provide safe, reliable service and to devote the resources necessary to maintain and operate its system assets. The CRO whose "human error" NIPSCO describes as a material factor causing the fire was a NIPSCO employee performing his assigned functions in the Unit 14 Control Room; therefore, Mr. Gorman took issue with NIPSCO suggesting it is not responsible for this employee's acts and omissions. Accordingly, Mr. Gorman testified the fire is directly attributable to the failure to take action in response to the high temperature alarm, because five and a half hours is plenty of time to respond to the alarm, monitor the rising temperature, and proceed with an orderly shutdown before the Transformer oil reaches its flash point.

Mr. Gorman continued by discussing additional circumstances he believes support the conclusion that NIPSCO acted imprudently in connection with the factors leading to the fire. Mr. Gorman testified that following the fire, NIPSCO conducted an internal investigation that led to a root cause analysis report and a unit trip/load loss report. He stated the latter document discussed contributing factors to the fire that may have led to the CRO disregarding the high temperature alarm, noting the CRO was working the second half of a 24-hour shift. In a NIPSCO discovery response, NIPSCO stated the CRO worked two 12-hour shifts back to back starting July 15 at 6:00 p.m. and ending at 6:00 p.m. on July 16, the day of the fire. Both days had been scheduled as days off for the CRO, but he completed mandatory safety training during the first 12-hour shift, followed by a 12-hour overtime shift with Control Room duties for Unit 14. Thus, when the high temperature alarm was activated and acknowledged in the Control Room, the CRO had been working for 14 hours, and when the fire broke out, he had been working for 19 ½ hours. Mr. Gorman testified NIPSCO did not take employment action against the CRO arising from the fire, but he voluntarily retired on September 1, 2020. Mr. Gorman claimed the August 7th root cause analysis reached the conclusion that the circumstances cited above were contributing factors to the fire. Per Mr. Gorman, failure to act on a high temperature alarm for a critical piece of equipment for five and a half hours is a dangerous lapse of attention, and the CRO's extended work hours, lack of sleep, and fatigue undoubtedly contributed to that error.

With respect to other factors that may have contributed to the fire, Mr. Gorman discussed the confidential DGA from April 2020. While the DGA results are confidential, Mr. Gorman stated NIPSCO apparently took no responsive actions or special precautions after receiving this analysis because the report did not recommend an action to be taken, but from Mr. Gorman's perspective, it was NIPSCO's responsibility to determine appropriate actions and precautions to take to maintain safe operation of its production assets. Mr. Gorman asserted the DGA and dissolved gas testing from Unit 14's Transformer must have been relevant to the fire because NIPSCO's investigators considered that test report to be significant in including it in the August 7, 2020 Root Cause Analysis. With the issues these reports identified, he stated a high temperature alarm should have been recognized as a potentially dangerous condition; however, NIPSCO did not address the warning signs from the April 2020 DGA during the three-months before the fire. Per Mr. Gorman, longstanding problems with a critical power component, known to be in poor condition, should warrant added care and attention, not less, when a test report warns of potentially hazardous dissolved gas levels.

Mr. Gorman also discussed a chain of confidential email exchanges discussing operator rounds. Such rounds are visual inspections Station Operators perform during their work shifts. On June 15, 2020, NIPSCO's Operations Superintendent noted there had been no operator rounds sheets submitted in weeks. He followed up a month later on July 15, the day before the fire, indicating the previous week there were only nine round sheets for 22 shifts. In light of all these factors, Mr. Gorman testified he believes NIPSCO bears substantial responsibility for the events leading to the fire.

Mr. Gorman testified about the report NIPSCO provided to the Commission in Cause No. 38706 FAC 129 (Confidential Attachment 4-B to Petitioner's Exhibit 2), noting that while this report was provided to the Commission, the August 7, 2020 Root Cause Analysis was not. He asserted there were significant omissions in the report provided to the Commission, most notably, that a high temperature alarm for the Unit 14 main Transformer was activated more than five hours before the fire and acknowledged in the control room, but no investigation or corrective action was taken as the oil temperature continued to climb. Also, the information NIPSCO shared did not indicate the CRO who failed to act on the high temperature alarm was nearing the end of a 24-hour shift when the fire occurred. Mr. Gorman stated NIPSCO's report to the Commission implied the transformer failure was a spontaneous and unexpected event, failing to disclose material information regarding NIPSCO's lapses and missteps. Per Mr. Gorman, "The document NIPSCO submitted pursuant to the Commission order requiring a root cause analysis stands in stark contrast to NIPSCO's internal assessment of the factors that caused the fire." IG Exhibit 1 at p. 21.

Mr. Gorman also discussed the impact the loss of Units 14 and 15 has had on NIPSCO's FAC costs. He testified there has been a steep increase in NIPSCO's FAC factors since July 2020. Specifically, the last FAC proceeding completed prior to the fire was Cause No. 38706 FAC 127 in which the approved factor was a negative $0.005732 per kWh or a negative 5.732 mills. NIPSCO's next petition, FAC 128, was filed on August 14, 2020, one month after the fire, and the approved factor in that case rose by 5.597 mills. As of the most recently completed proceeding, FAC 132, spanning November 2021 to January 2022, the approved factor has increased to a positive 9.761 mills, which is 15.493 mills higher than the level approved in FAC 127 or an increase to NIPSCO customers of $13.5 million per month. Mr. Gorman stated that to the extent the physical energy hedge value of Units 14 and 15 could have reduced this increase in energy costs, the increase in the FAC charge is higher than it otherwise would have been. He also stated this increase in the FAC charges clearly illustrates the potential benefits to NIPSCO and its customers that can be realized through a physical energy hedge such as Units 14 and 15 provided.

Mr. Gorman noted that NIPSCO acknowledged there are benefits to the system through the operation of Units 14 and 15, including providing capacity resource benefits that help maintain service reliability. He testified the operating benefits of Units 14 and 15 include cost savings from producing energy for system support and/or economic dispatch. He stated energy savings occur when the dispatch cost is lower than the alternative resource dispatch cost or the MISO market purchase energy price. He provided a cost comparison of NIPSCO's coal-fired units in Confidential Attachment MPG-10 and claimed this shows that for system support purposes, there is an economic advantage to using Units 14 and 15 relative to other NIPSCO coal-fired resources for power quality purposes. From an economic dispatch savings basis, Mr. Gorman testified Units 14 and 15 have been able to produce savings for customers to the extent the dispatch cost is below that of alternative higher dispatch cost coal units and/or MISO market energy purchases. He acknowledged that in calendar years 2015-2019, the units' dispatch costs were generally above the market clearing price and, thus, did not typically produce economic dispatch benefits; therefore, in these years the units were seldom dispatched for economic purposes and generally did not produce energy savings; however, as reflected in Confidential Attachment MPG-12, he testified market data shows if Unit 14 had been available in 2021, it could have produced significant energy savings relative to the 2021 MISO energy market prices. Mr. Gorman also stated forward MISO energy prices indicate Units 14 and 15 would have continued to provide economic savings to NIPSCO if they were available to be dispatched through the proposed retirement date of May 2023 and no fire had occurred.

Mr. Gorman testified NIPSCO only partially described the benefits customers could have derived if Units 14 and 15 were available through May 2023. For example, for the last six months of 2020, Mr. Campbell outlined the potential benefits and detriments to NIPSCO from losing Units 14 and 15. He stated one of the primary operating benefits Mr. Campbell noted was that these units could be used as physical hedges to protect customers from potential volatility in the energy market. For the second half of 2020, Mr. Gorman testified it is this hedge value that largely represents the loss to customers through the extended outages and early retirement of these units. He stated that starting in 2021, the energy hedge value of these units increased significantly compared to earlier periods.

Mr. Gorman discussed the economic challenges associated with Units 14 and 15 in recent years, acknowledging the actual output of Units 14 and 15 was limited for economic purposes. He explained, however, that market prices increased through most of 2021, indicating Units 14 and 15 may have been able to act as physical hedges to these higher prices. He also provided Confidential Attachments MPG-12 and MPG-13 which include estimates of the forward MISO prices and compared them with historical dispatch costs for Units 14 and 15. As in 2021, he stated the projections indicate Units 14 and 15 would have produced economic benefits to NIPSCO and its retail customers if they were available to be economically dispatched through May 2023.

With respect to the potential economic savings and proposed refunds, Mr. Gorman utilized a "low end" and "high end" capacity factor (with the high end being exactly double the low end) to provide the Commission with a range of possible outcomes. As developed in Confidential

Attachment MPG-12, he testified that using the low end capacity factor assumption, the amount of energy savings Unit 14 could have produced by operating in calendar year 2021 was estimated to be $17.0 million. This amount increased to $34.0 million under the high-end assumption. He testified if Unit 14 had been available to operate during 2021, he believes NIPSCO's FAC costs would have been lower because the prevailing level of MISO day-ahead prices in 2021 would have supported economic dispatch of Unit 14, thereby displacing NIPSCO's more expensive MISO purchases. Mr. Gorman also asserted Unit 15 could have provided energy savings from its retirement through the end of 2021. Using the low end capacity assumption and looking at November and December 2021, he testified Unit 15 could have produced $5.8 million in savings or $11.5 million under the high end assumption.

Mr. Gorman recommended the Commission direct NIPSCO to provide a rate refund to its customers in the next available FAC proceeding in the amount of $45.5 million ($34.0 million for Unit 14 and $11.5 million for Unit 15). He testified this total reflects the lost savings from reduced MISO purchases if Unit 14 had been available for economic dispatch throughout 2021, combined with the corresponding savings for Unit 15 after it was retired early and not available to operate in November and December 2021. He acknowledged this amount was based on the high end assumption. Under the low end assumption, the amount of the refund he recommended was $22.8 million ($17.0 million for Unit 14 and $5.8 million for Unit 15). Mr. Gorman recommended the Commission direct NIPSCO to provide a credit in successive FAC proceedings, computed on the same basis as he presented for 2021, until FAC costs through May 2023 have been reconciled.

In support of his conclusion that the loss of the energy hedge value of Units 14 and 15 detrimentally impacted 2021 FAC costs, Mr. Gorman shared the following:

> 1. A specific winter event occurred between February 12, 2021, and February 17, 2021, where wholesale market prices increased dramatically relative to historical levels. In February 2021, the ATC price increased $58.27. During this time period, all physical hedge or system generation resources would have been useful to NIPSCO to provide energy savings for its customers.
>
> 2. General wholesale market prices increased after the winter event for many reasons, including a dramatic increase in natural gas prices. As shown in Attachment MPG-14, page 1, ATC power prices increased from a March 2021 price of $24.59 to a projected December 2021 ATC price of $61.89.

Mr. Gorman also discussed NIPSCO's hedging program. He stated the program NIPSCO implemented had the effect of ensuring it has access to market power at MISO market prices, but these hedges do not limit its price of energy based on the energy hedge value of Units 14 and 15. Importantly, Mr. Gorman testified the hedge price does not produce the same physical energy price protection to NIPSCO and its customers that had previously been provided by Units 14 and 15 had they been available to operate in 2021 and through the planned end of their operating lives.

Mr. Gorman also addressed Mr. Augustine's findings that it was economically justifiable to retire Units 14 and 15 in 2021. He testified the energy price projections Mr. Augustine used in the 2020 CRA analysis may have been reasonable at the time of his analysis, but they substantially understated actual MISO energy prices in 2021 and the forward prices through 2023. In these instances, he stated Mr. Augustine's system resource economic studies were based on market prices that were substantially lower than the current market prices. Mr. Gorman concluded the significance of understating market energy prices means Mr. Augustine's economic studies understated the economic benefits to NIPSCO and its customers of operating Units 14 and 15 in lieu of making market purchases over this time period. From his perspective, this change in market circumstances renders Mr. Augustine's economic conclusions concerning the early retirement of Schahfer Units 14 and 15 unreliable and inconsistent with current data.

Mr. Gorman recommended the Commission order NIPSCO to provide a refund to ratepayers, with accrued interest, in the next FAC proceeding, in the amount of $45.5 million, reflecting FAC savings NIPSCO could have achieved through the end of 2021 if Units 14 and 15 had been available. Alternatively, under a more conservative assumption using a lower capacity figure, he recommended the refund amount be no less than $22.8 million. Additionally, for the period from the beginning of 2022 through May 2023, Mr. Gorman recommended each NIPSCO FAC filing reflect an additional credit, if applicable in the given FAC period, computed in the same manner as the 2021 refund amount.

5. <u>NIPSCO's Rebuttal Evidence</u>.

A. <u>Ronald Talbot</u>. Mr. Talbot testified that while the OUCC and the Industrial Group ask the Commission to find NIPSCO's imprudence led to the fire that damaged Units 14 and 15 in July 2020, neither party identified specific actions or inactions by NIPSCO that could have prevented the fire. He stated Mr. Gorman recommends refunds ranging between $22.8 million and $45.5 million for 2021, and between $83.7 million and $167.4 million in total. Additionally, he stated the parties' request for relief focuses on alleged financial harm to customers occurring in 2021 and afterward, but post-fire in 2020, customers likely benefitted financially from NIPSCO not operating these two units as part of its resource portfolio. Mr. Talbot testified that given NIPSCO's intentional, reasoned post-fire decision "to allow"' Unit 14 to remain in forced outage and bring Unit 15 back online through October 2021, the OUCC and the Industrial Group's requests for refunds following October 2021 implicitly challenge the prudence of that post-fire retirement decision. Petitioner's Exhibit 1-R at p. 3.

Mr. Talbot testified that regardless of these prudence arguments related to causation, NIPSCO's 2018 IRP had already identified these units as generally uneconomic and slated for retirement by May 2023. He stated the July 2020 fire and the significant restoration costs logically necessitated NIPSCO assess its execution of the Short-Term Action Plan, as well as other known changes such as the migration of customer demand due to implementing Rate 831, and conduct a reasonable evaluation of the need for Units 14 and 15 going forward. He stated that given the OUCC and Industrial Group's focus on unanticipated market pricing trends in 2021, it is the prudence of CRA's post-fire resource evaluation and NIPSCO's reliance on this evaluation that are the fundamental issues for the Commission to review in determining whether NIPSCO's customers have been harmed due to NIPSCO's imprudent action and whether refunds should be required.

According to Mr. Talbot, if the Commission finds NIPSCO was imprudent with respect to the fire, refunds should not be required unless the OUCC or the Industrial Group demonstrate NIPSCO's retirement decision after the fire was imprudent or unreasonable. He testified if

NIPSCO's actions and decision-making process following the fire were prudent and reasonable NIPSCO should not be required to pay refunds "simply because recent FAC costs have increased." Petitioner's Exhibit 1-R at p. 4. NIPSCO contends it was not imprudent with respect to the fire; however, assuming for the sake of argument the Commission finds otherwise, Mr. Talbot stated no refunds should be required unless NIPSCO's post-fire actions and decision-making process were not prudent and reasonable. He asserted NIPSCO should not be required to pay refunds simply because recent FAC costs have increased—or, as is the case for the overwhelming majority of the refunds Mr. Gorman recommends, because FAC costs are projected to increase based on changes in the broader market. Mr. Talbot testified that to the extent the Commission finds refunds are required, the period over which they are required should not extend past October 1, 2020, when Units 14 and 15 were retired unless NIPSCO's retirement decision is found to be imprudent.

Mr. Talbot stated that while the other parties' testimony primarily focuses on the fire, they gloss over the prudence of the independent, third-party analysis by CRA and decision NIPSCO made regarding the future of the units. He stated that because NIPSCO had the opportunity to operate Unit 15 and possibly operate Unit 14 in 2021 and beyond, this prudence review must focus on the December 2020 decision NIPSCO made based on CRA's updated analysis and the other information NIPSCO had available as part of its evaluation.

Mr. Talbot testified the 2018 IRP led NIPSCO to implement a Short-Term Action Plan under which NIPSCO intended to retire all the Schahfer units by May 2023. He testified NIPSCO viewed May 2023 as a no later than date as opposed to a definitive date on which the units would be retired. Mr. Talbot stated the 2018 IRP indicated retiring NIPSCO's coal-fired generation as early as possible was in the economic best interest of NIPSCO's customers but also identified certain reliability considerations that needed to be addressed as coal-fired units retired. Mr. Talbot noted that to the best of his knowledge, neither the OUCC nor the Industrial Group has challenged the 2018 IRP conclusion that retiring NIPSCO's coal-fired units at Schahfer as soon as reasonably possible is economically in customers' best interest.

In response to Mr. Gorman's view that NIPSCO's retirement of Units 14 and 15 on October 1, 2021, was inconsistent with the 2018 IRP, Mr. Talbot testified that what Mr. Gorman was asked was whether an extended outage at Units 14 and 15 followed by retirement in October 2021 was consistent with the Action Plan identified in the 2018 IRP, and to that question he responds no. Per Mr. Talbot, NIPSCO's Short-Term Action Plan did not call for an outage at Units 14 and 15 in late 2020, but he asserted NIPSCO's decision to retire Units 14 and 15 in October 2021 and continue NIPSCO's transition from coal-fired generation and toward renewable generation was consistent with the 2018 IRP.

Mr. Talbot stated the fire at Unit 14 necessitated that NIPSCO evaluate its overall generation transition and determine the optimal retirement date for Units 14 and 15 based on current circumstances. Because NIPSCO had executed the requisite transmission upgrades needed to retire Units 14 and 15 and successfully procured and implemented renewable generation projects, he testified NIPSCO had by that time already addressed the identified reliability considerations and, thus, made potential retirement dates well before 2023 feasible.

In response to Mr. Gorman's testimony that he is unaware of any indication before the July 2020 fire that NIPSCO was considering retiring Units 14 and/or 15 in 2021, Mr. Talbot testified

NIPSCO was, in fact, considering retirement dates earlier than May 2023 prior to July 16, 2020. He stated that while Mr. Gorman may not have been aware of such discussions, as of July 16, 2020, NIPSCO's management had commenced discussing potential retirement dates for Units 14 and 15 that were much earlier than May 2023. While these discussions had not yet led to a definitive decision, based upon NIPSCO's progress on transmission upgrades and its success in procuring replacement generation capacity, Mr. Talbot testified consideration was being given to retirement dates as early as May 2021. Additionally, he noted NIPSCO's 2021 IRP cycle, which began in late 2020 and concluded in November 2021, would have provided another logical opportunity for NIPSCO to consider the most appropriate retirement date for Units 14 and 15, which would have included the same type of modeling CRA conducted at NIPSCO's request in late 2020 to assess the units' continued operation.

In summarizing NIPSCO's position upon the decisions to return Unit 15 to service, allow Unit 14 to remain in forced outage, and retire both units in October 2021, Mr. Talbot testified the fire at Unit 14 was an unfortunate accident that, thankfully, resulted in no serious injury or loss of life, but it provided NIPSCO with another decision point along its generation transition path. Based on NIPSCO's progress in executing its Short-Term Action Plan as of late 2020, the potential reliability concerns that existed in November 2018 when the 2018 IRP was issued had been mitigated, and NIPSCO was able to consider retiring Units 14 and 15 in 2021. Mr. Talbot testified that based upon information available when the decision was made, including the expert CRA analysis, NIPSCO decided in early 2021 it would be in its customers' best interest to retire Units 14 and 15 in October 2021. Mr. Talbot dismissed as insufficient the other parties' attempt to challenge the prudence of NIPSCO's decision to not bring Unit 14 back in service and retire both units in 2021.

Mr. Talbot stated that while Mr. Augustine substantively responds to Mr. Gorman's criticisms about market pricing, it is telling that neither the OUCC nor the Industrial Group challenged the reasonableness of CRA's analysis or NIPSCO's decision in reliance upon this analysis as of the time when the decision had to be made. While Mr. Gorman engaged in an after-the-fact criticism that Mr. Augustine's assumed market prices were lower than what actually occurred, per Mr. Talbot, he did not argue Mr. Augustine's assumptions in late 2020 were unreasonable or that his analysis was incorrect. Mr. Talbot reiterated that the analysis Mr. Augustine conducted was consistent with the analysis he conducted for the 2018 IRP, and while it reflected certain changes, such as the impact of Rate 831 and the addition of renewable resources in 2020 and 2021, it was the same type of analysis that has served as the foundation for the decisions NIPSCO has made and is making upon the transition of its generation resources.

Mr. Talbot discussed how and when NIPSCO made the decision to retire Units 14 and 15 in October 2021. He stated that after the fire, NIPSCO engaged CRA to analyze what was the most appropriate decision for NIPSCO's customers and NIPSCO. That analysis was based upon the best data available at the time. NIPSCO then took that analysis, considered the available information, and decided retiring Units 14 and 15 in October 2021 was in its customers' best interest.

Mr. Talbot testified Mr. Eckert and Mr. Gorman do not allege NIPSCO made an improper, imprudent, or unreasonable decision in early 2021 when the decision had to be made. According to Mr. Talbot, it is the retirement decision NIPSCO made in January 2021 that led NIPSCO to retire Units 14 and 15—not the fire in July 2020.

In response to Mr. Gorman's discussion of the increase in NIPSCO's FAC factors since July 16, 2020, Mr. Talbot testified that although Mr. Gorman accurately reflects recent NIPSCO FAC factors, he appears to conflate causation and correlation. Per Mr. Talbot, Mr. Gorman notes the fire occurred in July 2020 and that NIPSCO's FAC factors have increased since that time, but Mr. Gorman does not provide evidence demonstrating the fire and subsequent outages actually caused the increased FAC factors. He testified that simply asserting the physical energy hedge's value of Schahfer Units 14 and 15 could have reduced the increase in energy costs does not prove the fire at Unit 14 and subsequent outages increased NIPSCO's FAC factor or that NIPSCO's decision to retire both units in October 2021 was unreasonable or imprudent because the FAC factor increased. He testified it is the unexpected increase in fuel prices that is driving related increases in the price for electricity in the energy markets and ultimately driving the increase to NIPSCO's FAC factors, not the fire or subsequent Units 14 and 15 outages.

Mr. Talbot testified it is not appropriate for the Commission to accept Mr. Gorman's invitation to engage in hindsight review based on changes to energy market prices that were not known or reasonably expected at the time CRA's analysis was performed and NIPSCO's retirement decision was made because the Commission has a long-standing policy not to engage in hindsight or after-the-fact review of a decision and has consistently held the prudency of a decision should be based upon the facts and circumstances that existed at the time the decision was made. In addition, if the Commission were to reverse course and find NIPSCO's retirement decision was imprudent based on unanticipated increases in market pricing, this will put NIPSCO (and other Indiana utilities) in the untenable position of having important decisions second-guessed when they are unable to predict the future.

Mr. Talbot testified that NIPSCO's decision to allow Unit 14 to remain in forced outage, return Unit 15 to service in December 2020, and retire both units in October 2021 was based on a reasonable and prudent evaluation process. He testified that consistent with how NIPSCO approaches important resource decisions, in 2020 following the fire, NIPSCO obtained expert analysis, reviewed pertinent historic data and other information available at the time, and made a reasonable and prudent resource planning decision. Mr. Talbot stated there were three primary factors NIPSCO considered: economics, reliability, and resource availability. He stated that with respect to economics, NIPSCO considered the costs to repair the units, the costs for replacement capacity, the age and condition of these vintage assets, the operating history of these units, including their performance compared to other NIPSCO resources, NIPSCO's energy requirements going forward, and the economic analysis CRA performed. Concerning reliability, he stated all the transmission upgrades necessary to retire Units 14 and 15 were scheduled for completion in May 2021, and NIPSCO knew MISO would be completing a reliability review as part of any retirement approval. Regarding resource availability, he stated NIPSCO was able to procure sufficient capacity for MISO Planning Years 2021-2022 and 2022-2023 and was also progressing well in procuring renewable generation projects. He testified NIPSCO also confirmed that, consistent with prior practice, the energy needs of its customers were covered. Mr. Talbot testified that when all relevant factors were considered and when a reasonable timeframe to pursue retirement was established, retirement of Units 14 and 15 in October 2021 was determined to be in the best interest of NIPSCO's customers and NIPSCO. He stated the analysis supported bringing Unit 15 back on-line as a bridge resource until additional resources were scheduled to be added in late 2021, and this is what NIPSCO did.

Mr. Talbot testified none of the circumstances or fluctuations in the market changed his opinion that this decision was prudently made and consistent with the best interest of NIPSCO's customers. He stated that while there has been some volatility in energy market prices, this post-decision circumstance does not undermine the reasonableness of the evaluation and basis for the retirement decision NIPSCO made. He testified NIPSCO was able to execute the necessary transmission upgrades and also received MISO's approval to retire Units 14 and 15. According to Mr. Talbot, NIPSCO has encountered no reliability issues associated with the outages or retirements, and based on NIPSCO's modified hedge plan and energy procurement strategy, NIPSCO's 2021 energy purchases in the MISO market have actually been at lower volumes than historic levels, demonstrating NIPSCO has not been unreasonably exposed to the market.

Mr. Talbot testified that, as planned, a 300 MW wind farm (Indiana Crossroads Wind I) recently came online, further securing NIPSCO's energy position. He stated that since July 2020 and even after Units 14 and 15 were retired in October 2021, NIPSCO has continued executing its Short-Term Action Plan and moving forward with transitioning its generation fleet from legacy coal-fired units to more affordable and cleaner renewable resources, and NIPSCO has done so without encountering reliability concerns. Mr. Talbot testified the best interest of NIPSCO's customers has always been and will continue to be at the forefront of NIPSCO's decision-making as this transition continues, and NIPSCO is confident its diverse generation portfolio is well-positioned to ensure customers are served at the lowest cost reasonably possible.

Mr. Talbot testified utilities must be able to use information and analysis to assess costs and risks, make sound decisions, and then implement those decisions with confidence. He stated here, with the "only attack" on NIPSCO's resource decision being based on subsequent changes in market prices, an imprudence finding will have to be based on hindsight review and would, therefore, hold NIPSCO responsible for not accurately predicting the future. Petitioner's Exhibit 1-R at p. 22. Mr. Talbot stated this contravenes long-standing precedent and potentially causes utilities to second guess the analysis they conduct in their IRPs by running units longer than economically recommended in case they might be useful in the future if prices rise. He asserted that unless NIPSCO's decision to not restore Unit 14 and to retire Units 14 and 15 in October 2021 is proven to be unreasonable and imprudent, no refunds should be required. Mr. Talbot testified NIPSCO utilized and relied upon analysis from a third-party expert and made a decision that was consistent with NIPSCO's 2018 IRP and expert guidance. He further testified that to require NIPSCO to pay refunds through the FAC for a decision its available data indicates was reasonable and prudent when made will, essentially, tell NIPSCO it should have ignored CRA's analysis and not retired Units 14 and 15 based on the possibility that future market prices increase. He stated this alternative kind of decision-making, which the Industrial Group appears to recommend, is imprudent as opposed to NIPSCO's decision to rely on CRA's analysis.

B. <u>Kurt W. Sangster</u>. In response to Mr. Gorman's analysis for calendar year 2021 of potential energy savings, Mr. Sangster provided context about Unit 14's economics relative to NIPSCO's other coal-fired generation units. He stated NIPSCO's generation fleet is currently heavily coal-reliant, but coming out of the 2018 IRP, NIPSCO is in the midst of transitioning to more renewables and less coal. He stated in recent years, Unit 14 was one of NIPSCO's lowest-cost coal-fired units but was generally also the least-dispatched unit. Looking at the total unit operational hours from July 1, 2015, through July 1, 2020, he noted Unit 14 was by far the least-run of the four units at Schahfer. In explaining why one of NIPSCO's cheapest coal-fired units was also its least dispatched coal-fired unit, Mr. Sangster testified Unit 14 had other factors beyond economics that impacted whether it was put into service. More specifically, NIPSCO operates its electric generation assets as a fleet, and each generating unit is operated based on a number of factors that include economic, reliability, flexibility, and environmental considerations. He stated Unit 14 had the second lowest cost to operate of NIPSCO's coal-fired units, behind only Unit 12 at Michigan City; however, other factors impacting how often it operated included having: (1) one of the longest start-up times; (2) one of the highest minimum loads; (3) very low automatic generation control ("AGC") rates, (4) a high NOx (environmental) emission rate, and (5) an EFOR that was the highest among NIPSCO's coal-fired assets.

Mr. Sangster testified that long start-up times directly impact economics. Unit 14's minimum load was 230 MW (compared to 125 MW for Units 17 and 18), meaning each time the unit operated at a higher cost than the market, there were more uneconomic MWs being forced into the market at a higher cost (*e.g.*, at night) than with other units that could be flexibly ramped down to a lower minimum load. He stated low AGC rates impacted flexibility because Unit 14 could not adjust production quickly, and the unit was used primarily as a base load resource, rather than a resource that was dispatched on the basis of economics to capture economic opportunities in the market. He noted Unit 14 also needed longer expected dispatch durations to operate due to the high level of NOx emissions during start-up to balance the higher start-up emission levels with the relatively lower emission levels when the environmental control systems were in operation. This impacted unit flexibility because the unit should not be started and taken off-line frequently. Additionally, high EFOR is a direct reflection of reliability, indicating that when NIPSCO dispatched Unit 14, it had the highest occurrence of forced outages and was the least reliable. Overall, he stated these factors, in combination, helped explain why Unit 14 was not the preferred coal-fired unit to utilize, though it may have been relatively less expensive in terms of dispatch costs on a per MWh basis.

In response to Mr. Gorman's assertion that the $86 million of environmental investments that went into service in December 2018 reflected the expectation at the time that Units 14 and 15 would continue in operation another five years or more, Mr. Sangster testified Mr. Gorman cites no evidence to support this claim. He claimed the capital investment in question related to a remote ash conveyor system at Schahfer that was necessary for compliance with the Environmental Protection Agency's Coal Combustion Residuals (or "CCR") Rule. Mr. Sangster stated NIPSCO filed for approval of a certificate of public convenience and necessity ("CPCN") for this project in November 2016 in Cause No. 44872, and the Commission issued the CPCN in December 2017 under a settlement agreement to which the Industrial Group was a signatory. He stated that although the investment in question went into service in late 2018, it was part of NIPSCO's plan for compliance with the CCR Rule that was developed a couple years earlier, as reflected by NIPSCO's CPCN request filed more than two years before the in-service date. He testified that without implementation of this CCR Rule compliance project, Units 14 and 15 would have been required to retire much earlier than 2023. Mr. Sangster testified the project Mr. Gorman cites was part of NIPSCO's overall generation transition coming out of the 2016 IRP and was intended to provide flexibility and optionality as NIPSCO proceeded down the path of transitioning from coal-fired generation and towards cleaner, more affordable generation resources.

Mr. Sangster testified how Unit 14 was maintained over the last few years in light of its planned retirement no later than May 2023. He stated that in NIPSCO's most recent electric base rate case, Michael Hooper discussed NIPSCO's plans to retire all four Schahfer units by 2023 and Michigan City Unit 12 by 2028, stating: "With recently announced coal plant retirements, there is the potential for EFOR to move upward over the near to medium term. NIPSCO will continue to operate its facilities in a safe, environmentally compliant manner and with a reasonable level of reliability, while making sound decisions with regard to significant capital investments into facilities with limited operating lives." Petitioner's Exhibit 2-R at p. 8. He stated that while NIPSCO has been operating and maintaining these units in a way that is reliable and environmentally-compliant, NIPSCO's practices have also been informed by the intent to retire the units in the near-term. He stated aging coal units are vulnerable to equipment failure, and as they near the end of life, a balance must be struck between making investments that increase the unit's book value and only extend its life for a short time. He stated the failure of a transformer cooling system can occur at any time and was not the product of the prudent consideration of whether to make investments in replacement equipment. The units had entered a period where everyone knew they could be retired in the near future.

Mr. Sangster provided his understanding of Mr. Gorman's testimony about the fire at Unit 14 on July 16, 2020. He stated Mr. Gorman fairly accurately described the facts and circumstances that led to the fire; however, Mr. Sangster stated that in citing Mr. Sangster's discussion of how the Unit 14 CRO failed to follow procedures and take action to mitigate the failure of the cooling system on the Transformer, Mr. Gorman was somewhat critical of NIPSCO for not conceding it bears full responsibility for the fire. According to Mr. Sangster, Mr. Gorman did not directly testify NIPSCO is 100% responsible for the fire at Unit 14. He stated Mr. Gorman cited circumstances supporting the conclusion that NIPSCO acted imprudently to imply NIPSCO acted imprudently and should be held financially responsible by the Commission.

Mr. Sangster testified that Mr. Gorman contends since NIPSCO's employee failed to act in response to the high temperature alarm on the Transformer caused by the cooling system failure, NIPSCO should be held responsible for the CRO's actions and be found to have acted imprudently; however, Mr. Sangster testified he does not believe NIPSCO acted imprudently in connection with the factors leading to the fire. He stated that following post-fire investigations, NIPSCO concluded the likely root cause of the fire was the failure of the cooling system associated with the Unit 14 Transformer. He testified it was the cooling system failure that led to the Transformer temperature rising, which led to an increase in pressure that caused a failure in the Transformer structure and, ultimately, led to the conditions where the arc flash from Unit 14 tripping offline ignited the Transformer's oil and started the fire.

Mr. Sangster acknowledged NIPSCO has also concluded the CRO's failure to adequately or timely respond to the high temperature alarm was a contributing factor. Per Mr. Sangster, while the CRO was addressing other operational issues he believed were more pressing, if he had followed his training and either dispatched a station operator to inspect the cooling system and Transformer or consulted with a supervisor and notified them of the alarm, the fire likely could have been avoided.

Mr. Sangster testified neither the Industrial Group nor the OUCC cited any evidence demonstrating NIPSCO's training or staffing practices were improper or that NIPSCO did not properly maintain the Unit 14 main Transformer or other equipment. He also contended neither alleged NIPSCO failed to properly train the CRO who failed to respond to the high temperature alarm or that NIPSCO's staffing, operations, or maintenance practices were improper. He stated that in discovery, in response to Mr. Gorman's testimony noting NIPSCO's general duty as a regulated public utility, the Industrial Group was unable to identify any staffing practice, training, procedure deficiency, or other action NIPSCO should or could have taken.

Mr. Sangster stated he reviewed each of the documents Mr. Gorman attached to his testimony, including Confidential Attachment MPG-4, Confidential Attachment MPG-7, and Attachment MPG-8, and he briefly explained what each addressed. He noted Mr. Gorman's discussion of an email chain NIPSCO produced in discovery concerning ongoing lapses in the completion of operator rounds and operating personnel failing to make routine rounds altogether; however, Mr. Sangster testified NIPSCO did not stop completing rounds. Rounds were being substantially completed, although not always consistently and/or in their entirety. He stated the expectation to complete rounds never changed, and the primary issue was that rounds sheets were not being turned in. Mr. Sangster testified operator rounds were actually completed in the days leading up to the fire, and Mr. Gorman and the Industrial Group were aware of this, with Confidential Attachment 2-R-C including copies of this paperwork from July 14 and July 15. Thus, Mr. Sangster stated Mr. Gorman was well aware NIPSCO's operators were completing rounds at Schahfer, as the actual rounds sheets were provided.

Mr. Sangster testified that Mr. Gorman's confidential discussion of the Unit 14 main Transformer and Confidential Attachment MPG-7 are a fair description of the Transformer, but the conclusions Mr. Gorman draws about the Transformer and his categorization of NIPSCO's actions regarding the Transformer are inaccurate. For example, it is accurate to note the Transformer had elevated dissolved gas levels for many years, but it is not accurate to allege NIPSCO did not take any steps to address the warning signs from the April 2020 DGA during the three-months before the fire. First, per Mr. Sangster, there was no significant change in the dissolved gas levels or any red flag identified in the April 2020 report. It reflected the same ongoing issue NIPSCO had been monitoring. Second, in the document attached to Mr. Gorman's testimony as Attachment MPG-6 (NIPSCO's response to Industrials Request 1-008), NIPSCO noted this Transformer was on NIPSCO's transformer watch list and being monitored more frequently than is typical. He noted an additional test was performed on June 20, 2020, (after the April 2020 DGA report), but the results were not received until after July 16, 2020. Finally, Mr. Sangster stated that while Mr. Gorman may allege NIPSCO should have taken some immediate action based on the April 2020 DGA report, no such action was recommended by Doble, the expert who generally performs NIPSCO's transformer testing. Thus, Mr. Sangster testified NIPSCO continued monitoring the Transformer, and operators continued to visually inspect it during their rounds.

Mr. Sangster testified that although Mr. Gorman did not directly aver the dissolved gas levels in the Transformer caused or contributed to the fire, his discussion of this issue implies it is related. For sake of clarity, Mr. Sangster confirmed the dissolved gas levels in the Transformer's oil had no bearing on the fire that occurred on July 16, 2020. He stated while the gases analyzed during the DGA analysis were indicative of electrical activity within the Transformer, the root cause indicated the Transformer failure was due to the oil cooling system not operating properly. This resulted in the Transformer oil temperature rising over the oil's flash point. He stated the cooling system's operation has no link to electrical activity within the Transformer, and the Transformer cooling system is externally powered; therefore, the dissolved gas levels of the oil within the Transformer had nothing to do with the Transformer fire.

Mr. Sangster testified Confidential Attachment MPG-7 and Attachment MPG-8 do not relate to the root cause of the fire. While these documents may generally relate to the Schahfer Station and/or Unit 14 and may have even been referred to in NIPSCO's Root Cause Analysis (Confidential Attachment MPG-4), he stated neither is directly related to the cause of the fire—the failure of the cooling system.

With regard to Confidential Attachment MPG-4, Mr. Sangster explained that as NIPSCO advised the Industrial Group in discovery, the CRO's back-to-back shifts were allowed under NIPSCO's collective bargaining agreement, and it was not unusual for a CRO to work back-to-back shifts. Mr. Sangster stated this CRO was extremely experienced. He also explained that in interviews with the Unit 14 CRO, he confirmed that at 07:56 a.m. on July 16, 2020, he became aware of the high temperature alarm on Unit 14's main Transformer and monitored it all morning; however, because of other issues going on with Unit 14 and because the temperature did not appear to be increasing significantly, the Unit 14 CRO did not take appropriate action.

Mr. Sangster testified the RCA Mr. Gorman included as Confidential Attachment MPG-4 does not indicate there was a failure on NIPSCO's part to operate or maintain the Unit 14 main Transformer or that there was something NIPSCO could have done to avoid the fire. He stated that while it does refer to long-standing dissolved gas issues in the Transformer, this was not the root cause of the fire, as reflected on page 6 of 18 of Confidential Attachment MPG-4. He stated nothing in this document indicates NIPSCO failed to properly maintain or operate Unit 14 generally or the Transformer specifically, and the Industrial Group and the OUCC offered no evidence otherwise.

In response to Mr. Gorman's criticism of NIPSCO for allegedly having significant omissions in the report NIPSCO provided to the Commission, Mr. Sangster testified the DGA report/dissolved gas issue and operator rounds discussion are not relevant to the root cause of the fire; consequently, neither issue was discussed in the Unit Trip/Load Loss Report NIPSCO submitted in the FAC 129 filing. He stated that with respect to Confidential Attachment MPG-4, Mr. Gorman is correct that NIPSCO did not provide the Commission with the entire PowerPoint presentation in its quarterly FAC 129 filing, but NIPSCO provided the Unit Trip/Load Loss Report that was similar to the information traditionally included in quarterly filings when generation outages occur. He testified the information submitted to the Commission in the Unit Trip/Load Loss Report is substantially equivalent to the Executive Summary and discloses the same apparent causes as the PowerPoint. He stated that as part of this incident, an experienced employee failed to timely react to conditions, and had he acted, the fire probably would have been prevented, which could have been added to the Unit Trip/Load Loss Report.

Mr. Sangster testified none of the referenced documents reveal potential or actual concerns with the cooling system on the Unit 14 main Transformer. He stated NIPSCO's RCA and post-fire investigation also did not reveal prior issues with the cooling system and, to the best of his knowledge, none of the documents NIPSCO produced in discovery indicate issues with the cooling system. He reiterated that historically no problems or concerns with the Transformer's cooling system had been identified, and operator rounds sheets indicate it had been operating properly immediately before the apparent failure.

Mr. Sangster testified the documents and testimony or other evidence the OUCC and the Industrial Group provided do not change his conclusion that NIPSCO did not act imprudently. He is confident NIPSCO operated and maintained Unit 14 in a reasonable manner, appropriately trained its personnel who work as CROs and System Operators, and ultimately, the cooling system for Unit 14's main Transformer failed as older equipment sometimes does. He acknowledged human error on the part of the CRO failed to mitigate that equipment failure, and as a result, the fire occurred. Mr. Sangster testified the Industrial Group did not offer testimony that proves NIPSCO did anything improperly. He stated the evidence demonstrates Unit 14's main Transformer was an older piece of equipment NIPSCO had been monitoring/testing more often than usual and had been visually inspecting in the days leading up to the fire. Without any warning, the cooling system failed, and a high temperature alarm was issued notifying the CRO of this rising Transformer oil temperature, but unfortunately, the NIPSCO employee in a position to respond to this alarm and take mitigating actions failed to follow procedures.

Mr. Sangster disagreed that any FAC refund should be required because NIPSCO did not act imprudently or cause the fire. He stated that to the extent the Commission requires a refund, there are costs Mr. Gorman has not reflected that will offset any refund amount. He testified that in addition to the adjustments to the inputs and assumptions Mr. Campbell described, there are additional costs NIPSCO has avoided because of the outages at Units 14 and 15 and retiring the units on October 1, 2021—costs to maintain the units during this time. He explained that while these avoided maintenance costs will not have been collected from customers through the FAC, they are direct, incremental costs NIPSCO would have incurred and recovered from customers had Units 14 and 15 continued to operate normally.

Mr. Sangster provided NIPSCO's best estimate of the avoided capital expenditures to maintain Units 14 and 15 between July 16, 2020, and December 31, 2021.[17] He stated that looking only at the period between July 16, 2020, and December 31, 2021, NIPSCO's decision to retire these units in October 2021 allowed NIPSCO to forego investing approximately $7.7 million of capital in Unit 14 and $7.3 million of capital in Unit 15, or $15 million in total, as compared to its planned investments if the units had continued operation. He testified that had these capital investments been made, they would not have been recovered as fuel costs in NIPSCO's quarterly FAC proceedings, but this $15 million would have been capital additions to the units' book value, and NIPSCO would have recovered the investment and a return on this investment from its customers.

C. <u>Andrew S. Campbell</u>. Mr. Campbell testified that Mr. Gorman does not appear to explicitly state the fire on July 16, 2020, and subsequent generation outages are the primary cause or driver of the FAC increases, but he does testify that to the extent the physical energy hedge's value of Units 14 and 15 could have reduced the increase in energy costs, the increase in this FAC charge is higher than it otherwise would have been. Mr. Campbell stated Mr. Gorman correctly reports NIPSCO's recent FAC factors, and he acknowledged the FAC factors have increased over the last several FAC cycles; however, as reported to the Commission in quarterly FAC cycles, he testified the outages at Units 14 and 15 have not been the primary drivers of these increases.

[17] While Units 14 and 15 were retired on October 1, 2021, NIPSCO's maintenance activities are planned on an annual basis, prompting the date of December 31, 2021, to be used.

Mr. Campbell testified the largest drivers of the increased FAC factors in FAC 132 and FAC 133 are forecasted increases in energy market prices in late 2021 and into early 2022. He stated that while Mr. Gorman does not explicitly tie the forecasted increases in energy market pricing to the increase in FAC factors, he does discuss the relatively higher prices in the MISO market in 2021 and predicted into the future. Mr. Campbell testified he looked at other Indiana electric utilities' FAC factors over the last couple cycles to compare NIPSCO's factors, and although the three-month reconciliation and forecast periods for each utility do not match up with NIPSCO's quarterly FAC cycles exactly, other Indiana electric utilities have also seen increases in their FAC factors over the past few FAC cycles. For example, AES Indiana's FAC 132 (filed in Cause No. 38703 FAC 132 on June 16, 2021) resulted in an 8% increase to the prior factor, and its FAC 133 (filed on September 17, 2021) resulted in an additional 5% increase to the FAC 132 factor. Similarly, he stated Duke's FAC 129 (filed in Cause No. 38707 FAC 129 on July 29, 2021) resulted in a 3% increase to the prior factor, and its FAC 130 (filed on October 29, 2021) resulted in an additional 2% increase to the FAC 129 factor.

Citing to testimony NIPSCO provided in Cause Nos. 38706 FAC 132 and 133, Mr. Campbell stated NIPSCO acknowledges its FAC factors have recently increased and that the increase in natural gas prices and coal and transportation prices, which are primarily responsible for the increasing MISO market and broader energy market prices, are driving the FAC factors—not the fire at Unit 14 and subsequent outages at Units 14 and 15. He testified NIPSCO has taken reasonable actions since July 2020 to protect its customers from increasing market prices, but many factors are outside NIPSCO's control.

Mr. Campbell discussed NIPSCO's actions after the fire to protect its customers. He stated that as of July 2020, NIPSCO had begun discussions about potentially retiring Units 14 and 15 before 2023, and the fire at Unit 14 necessitated that NIPSCO evaluate where it stood in executing the 2018 IRP's Short-Term Action Plan and when Units 14 and 15 could be feasibly retired. He stated NIPSCO engaged CRA to analyze the potential options available with respect to Units 14 and 15 and then followed CRA's recommendations. Mr. Campbell testified NIPSCO has continued to execute its Short-Term Action Plan coming out of the 2018 IRP, and NIPSCO entered into third-party energy transactions during October, November, and December 2020 to address an increase in expected purchased power volumes as a result of the forced outages of Units 14 and 15 and MISO's decision to require many planned outages to be rescheduled to the fall in recognition of COVID-19. He also stated that in Cause No. 38706 FAC 130, NIPSCO proposed changes to its 2020 Hedge Plan that were developed to account for the expected availability of Units 14 and 15 in the latter half of 2021 and going forward. He testified NIPSCO's actions have ensured its customers will continue to be served overwhelmingly from NIPSCO owned or contracted-for-generation resources and will not be unreasonably exposed to the energy market.

In response to Mr. Gorman's discussion of NIPSCO's "2018 IRP Action Plan," including the transmission upgrades included in that Plan, Mr. Campbell explained NIPSCO's execution of the Short-Term Action Plan before and after the fire. He stated Mr. Gorman correctly recounts that all the upgrades necessary to retire Units 14 and 15 were completed before NIPSCO's direct testimony was filed in this subdocket on August 13, 2021. Despite the 2018 IRP's conclusion that retiring NIPSCO's coal-fired units as soon as possible was the best economic decision for NIPSCO's customers, he testified the need to complete certain reliability upgrades prompted NIPSCO to not propose immediately retiring any coal-fired generation assets at Schahfer in the

2018 IRP, but between December 2020 and the present, NIPSCO has brought three wind generation facilities online, totaling 800 MW (ICAP). The expected energy production from these facilities is another reason why NIPSCO was able to consider retiring Units 14 and 15 in October 2021 without concern about its customers being overly-exposed to the energy market.

Mr. Campbell stated NIPSCO is on the path to a balanced, diversified generation mix. He noted some purchases in the MISO energy market have historically been one of the ways NIPSCO served its customers' energy needs, and this continued to be the case coming out of the 2018 IRP. Mr. Campbell stated one of the benefits of being a member of the MISO market is the ability to access its wholesale Real-Time and Day-Ahead energy markets. This allows NIPSCO to access this competitive market when needed. He stated the MISO market allows its load-serving entity members, like NIPSCO, to benefit from broader access to energy and, thus, lower reserve margins as compared to time periods prior to the MISO market.

Mr. Campbell explained the level of NIPSCO's purchases in the MISO market and whether this has changed significantly since July 16, 2020. He demonstrated the number of MWhs NIPSCO has purchased each month in 2021 has been significantly lower than recent years. Important as well, in the warmest summer months of July, August, and September, when energy market prices began to increase, NIPSCO's market purchases in 2021 were significantly less than average and the lowest on average of the last few years—lower even than 2020 when overall demand was generally down because of the COVID-19 pandemic.

Mr. Campbell testified this level of MISO market purchases generally demonstrates that even with the forced outage at Unit 14 through 2021, NIPSCO's customers have not been unreasonably exposed to volatility in the energy market. In fact, based on NIPSCO's execution of the Short-Term Action Plan and available renewable generation, he testified NIPSCO's market exposure has been less in 2021 than it was historically. He explained that not only did NIPSCO plan for an increased amount of available wind energy as part of its portfolio, but the significant reduction in energy requirements due to implementing Rate 831 was also reflected in NIPSCO's planning process. He stated that from a NIPSCO planning perspective, some level of market exposure or market reliance should not be viewed negatively. Mr. Campbell testified market purchases have a place within NIPSCO's diversified resource portfolio, and RTOs were created to provide more efficient transmission investment and improved reliability, as well as access to a broader market to support economic energy purchases. He stated purchases from the market have also served as an economic benefit to customers since MISO's inception as a means of allowing customers to access lower-cost energy. He testified that for years, NIPSCO has benefited from this broader market access through MISO, and while any market will experience periodic volatility, leveraging the ability to purchase some portion of NIPSCO's energy requirements from the wholesale market remains a viable, useful resource alternative. Mr. Campbell stated NIPSCO's limited reliance on MISO purchases in 2021 is consistent with NIPSCO's reasonable planning approach, and customers were protected from purchased power expenses due to NIPSCO's Purchased Power Benchmark.

Mr. Campbell explained how NIPSCO's level of energy purchases in 2021 relates to Mr. Gorman's testimony that refunds should be required. He stated Mr. Gorman discusses the value Units 14 and/or 15 could potentially provide as a hedge against energy market pricing, and his calculations of proposed refunds are premised on the economic hedge value these units provided.

Mr. Campbell acknowledged there is a value associated with having physical generation units to act as a hedge to protect against market volatility but, as best he can tell, Mr. Gorman does not acknowledge NIPSCO has averaged fewer MWhs of MISO market purchases in 2021. Furthermore, he stated that having generation units online and available to be dispatched in the energy market comes at a cost, a cost Mr. Gorman does not discuss, but a cost NIPSCO has avoided by the outages and retirements of Units 14 and 15 as Mr. Sangster discusses.

Mr. Campbell explained how NIPSCO approached its hedge plan following the Unit 14 fire, including discussions with and information presented to the OUCC and the Industrial Group and, ultimately, the Commission's approval of its modified 2021 hedge plan. He testified that as a result of the unexpected outages of Schahfer Units 14 and 15, implementation of the 2020 hedge plan was adjusted for August 2020 through and June 2021 consistent with NIPSCO's past practice of adjusting the hedging plan for material differences in generating unit availability. He stated NIPSCO met with stakeholders in December 2020 and again in March 2021 to update them upon the steps being taken with respect to Units 14 and 15 and the number of hedges they could expect to see in the modified hedge plan. He testified that during the meetings with the OUCC and the Industrial Group, NIPSCO and these parties discussed the proposed hedge plan, and neither took issue with the modified hedge plan in FAC 130 that was approved by the Commission.

Mr. Campbell testified NIPSCO disagrees that any refunds should be required, and he opined that Mr. Sangster and Mr. Talbot have fully addressed the arguments of imprudence related to the root cause of the fire and NIPSCO's resource planning decision-making process using the analysis CRA provided. From Mr. Campbell's perspective, NIPSCO has demonstrated the fire had no detrimental impact on customer fuel costs in 2020 and that NIPSCO prudently covered all capacity needs (at NIPSCO's own cost) and prudently planned for meeting energy requirements in 2021 relying on an appropriate mix of system resources and planned purchases.

Mr. Campbell also reviewed the Industrial Group's refund analysis and the recommended refund amount, as shown in Mr. Gorman's Confidential Attachments MPG-12 and MPG-13. Before directly addressing Mr. Gorman's refund calculations, Mr. Campbell shared the limitations associated with this kind of estimation of market outcomes. He testified all the applicable variables cannot possibly be adequately or accurately accounted for, particularly as you move further from July 2020, with the refund calculations Mr. Gorman performed and the subsequent updates NIPSCO made demonstrating the high variably in these types of analyses.

Mr. Campbell testified that while NIPSCO does not believe any refunds should be required, if the Commission requires refunds to be paid, Mr. Gorman's calculations are not reasonable. He stated these proposed refund estimates are greatly overstated, and if Mr. Gorman's overall methodology were accepted, there are certain adjustments or corrections to his assumptions (data and inputs) that must be made to determine a potentially reasonable refund. Mr. Campbell testified these are necessary to reflect the capabilities of NIPSCO's generation units and the reality of the 2020 and 2021 energy market.

Mr. Campbell stated that after reviewing the data Mr. Gorman utilized in calculating estimated refunds, there are at least three adjustments or corrections that should be made based on the physical capabilities of Units 14 and 15 and what has (or likely would have) actually occurred in the energy market since July 16, 2020. He discussed these as follows:

> First, the maximum capacity for Unit 14 Mr. Gorman used (540 MW) is based on the generator's nameplate rating, which is significantly higher than the boiler-limited and performance-tested physical capabilities for the unit, as well as the interconnection rights of the unit. The appropriate capacity to utilize for Unit 14 is 425 MW,[18] which is the unit's economic maximum (or EconMax) rating. This is the more appropriate number to utilize because, barring an emergency event called by MISO,[19] this would be the maximum output MISO could award for Unit 14. This correction has the effect of reducing the total number of MWhs that Unit 14 can be assumed to be producing energy each day that it may have been dispatched.
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> Second, the dispatch costs Mr. Gorman utilized understated the actual operational costs Unit 14 would have incurred during 2021.[20] For example, while Mr. Gorman mentions (at p. 2, lines 14-16) 'higher [MISO] market prices prevailing in 2021 and projected through 2023[,]' the dispatch costs in his calculations were not updated to reflect significantly higher fuel prices—which is a primary driver of the higher energy market prices—thereby understating the cost to dispatch Unit 14. Utilizing higher, actual dispatch costs based on actual fuel prices have the effect of lessening the delta between MISO energy market prices and Unit 14's dispatch costs, thereby reducing the number of hours in which it is assumed Unit 14 would be economically dispatched. For example, utilizing the actual dispatch cost for Unit 14 (instead of Mr. Gorman's lower figure) results in some months where the MISO market price was *less* than dispatch cost on average for the month.
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> Third, Mr. Gorman did not account for 'delta LMP,' which is a charge or credit associated with the difference between the LMP at a generator's commercial pricing node (where energy is put onto the grid) and the NIPS.NIPS commercial pricing node (where the load is actually served, and predominately is a result of congestion between the two points). Had Unit 14 been dispatched under the assumptions in Mr. Gorman's calculation, delta LMP is a real cost that would have been incurred in the MISO market and therefore paid by customers in the Company's FAC filings. In total for January through September of 2021, the inclusion of delta LMP yields approximately $481,690 that would have been recovered from customers through the FAC. This amount has, thus, been used to reduce the calculations of potential refunds discussed below.

Petitioner's Exhibit 3-R at pp. 19-21 (footnotes in original; not edited).

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[18] This is also the capacity utilized in Mr. Augustine's analysis and included in his work papers.

[19] NIPSCO noted that in 2021, there have been no "Maximum Generation Events" called by MISO. Thus, had Unit 14 been available, it would not have ever been dispatched at greater than its EconMax rating of 425 MW.

[20] For purposes of this calculation, Mr. Campbell utilized actual dispatch costs for the months of July 2020 (the month of the fire) through September of 2021 (the date Units 14 and 15 retired). Because the units retired on October 1, 2021, and because NIPSCO's position is that the maximum time refunds should be due is through retirement, he did not attempt to calculate refunds or actual dispatch costs for later months. However, to the extent energy market prices were assumed to continue to increase in the short-term through 2022 or 2023 (as Mr. Gorman assumed), Mr. Campbell noted it is logical to assume fuel prices and generation dispatch costs would increase at roughly the same rate as well.

Mr. Campbell testified these three items are not potential changes that are a matter of opinion. For example, he stated the assumed maximum capacity Mr. Gorman used is a level at which Unit 14 was not physically capable of performing. Likewise, if Unit 14 had been dispatched at the levels Mr. Gorman assumed under his framework, delta LMP could not have been avoided, and NIPSCO's coal costs (and the cost in the broader market) were significantly elevated for parts of 2021 and should be taken into account when determining actual dispatch costs. Mr. Campbell testified that without challenging the nature of the methodology and the inherent assumptions Mr. Gorman relied upon, these are corrections or adjustments that should be made for Mr. Gorman's calculation to provide any type of accurate estimate that could be used as the basis for a refund.

In responding to the capacity factors Mr. Gorman assumed for his high end and low end refund estimates, Mr. Campbell stated the low end capacity factor Mr. Gorman assumed is a fair proxy for the potential capacity factor of Unit 14 had it not been in forced outage during 2021, as it is based on a historical average for the unit over the past several years. Based on the operational limitations of Unit 14, he stated it is extremely unlikely Unit 14 could have or would have been reliably operated at or near the high end capacity factor (which is double the low end). Mr. Campbell testified that utilizing Mr. Gorman's methodology and only correcting the resulting calculation for the three known items he discussed above, the maximum potential refund for January 1 through September 30, 2021, is approximately \$2,379,146.[21] He sponsored Attachment 3-R-C showing this calculation.

Mr. Campbell also described additional calculations he performed and believes are relevant to the Industrial Group's request for a refund. He stated Mr. Gorman ignores July 16 through December 31, 2020, when requesting refunds, likely due to the relatively low market prices that largely pervaded this time; however, he testified that if Mr. Gorman is going to calculate refunds based on certain assumptions for 2021 when he alleges customers would have benefitted from Unit 14's costs being lower than MISO energy market costs, it is only fair for July to December 2020 to also be considered.

Mr. Campbell testified that using Mr. Gorman's methodology for this period, this analysis revealed that for the overwhelming majority of days, Unit 14's dispatch cost (using actual data) would have exceeded prices in the MISO market. Thus, he stated applying Mr. Gorman's low end assumption and Mr. Campbell's three corrections, customers would have paid \$1,928,190 more to have Unit 14 serve them, as compared to purchasing energy in the MISO market;[22] therefore, for purposes of any refund calculation, it is only fair this amount be used to offset potential periods where Unit 14 was cheaper than MISO energy market prices.

In summary, Mr. Campbell testified that when the \$2,379,146 for 2021 is reduced by \$1,928,190 from 2020, it yields a total potential refund of \$450,955 for July 16, 2020, (the date of the fire) to October 1, 2021 (the date the units retired).[23] He stated this demonstrates that even with the unanticipated increased prices in the energy market in 2021, and ignoring the cost to maintain

[21] Under the high end assumption, this amount would be \$4,758,292.
[22] Under the high end assumption, this amount would be \$3,856,381.
[23] Under the high end assumption, \$4,758,292 for 2021 would be reduced by \$3,856,381 for 2020, resulting in a total refund of \$901,911.

the unit to have it available for this period, at most the fire at Unit 14 had only a negligible impact on NIPSCO's cost to serve its customers.[24]

Mr. Campbell stated his calculation excludes October through December 2021 because NIPSCO's position is that unless it is proven that NIPSCO's decision to retire Units 14 and 15 in October 2021 was unreasonable, no refund should be required. He stated that to the extent the Commission disagrees, NIPSCO believes any refund responsibility should end at the time the units were retired unless NIPSCO's retirement decision is proven unreasonable.

Mr. Campbell testified if refunds were calculated for the post-retirement period for both Units 14 and 15 for October through December 2021, as Mr. Gorman requests, but the corrections discussed above are used, the potential refund amount for these three months using the corrected inputs is approximately $4 million or nearly double the total amount for the first nine months of 2021.

Mr. Campbell testified that when looking at customers' overall best interests, there are at least three factors beyond just the cost to provide energy that are relevant. First, for the period between the fire in July 2020 and May 2023, NIPSCO has already procured replacement capacity for Units 14 and 15 (at a cost of several million dollars) and has committed to not seek recovery of these costs from customers. Second, as Mr. Sangster discussed in his rebuttal, significant expenditures associated with maintaining Units 14 and 15 were avoided when these units were in an outage and will be avoided between the time of their retirement and May 2023. While such costs are not directly recovered through the FAC, he stated NIPSCO avoided capital costs of approximately $15 million between July 2020 and December 2021 that would have been recovered from customers. Finally, beginning with the retirement date, a revenue credit will be provided to customers under the settlement agreement in Cause No. 45159. He stated the credit associated with October-December 2021 will be provided to customers in 2022, and the credit for 2022 and 2023 will be provided in 2023 and 2024, respectively. Mr. Campbell stated the incremental revenue credit associated with retiring Units 14 and 15 in October 2021 instead of May 2023 is subject to adjustment based on year-end closing procedures, but it is currently estimated to be more than $8 million over the first 12 months.

Mr. Campbell testified CRA's analysis in late 2020 was reasonable, and NIPSCO's retirement decision in reliance upon this analysis was prudent and reasonable. He understands the Commission has a long-standing policy that the prudency of utility decision-making should be judged based upon when the decision was made and the information available to the utility at that time. He opined that under this standard, it is clear NIPSCO made reasonable decisions on its customers' behalf. Mr. Campbell noted that even considering the reality of short-term increases in market pricing, NIPSCO has demonstrated it made a decision that is in its customers' best interests when considering all relevant factors.

Mr. Campbell concluded by noting he is confident NIPSCO has served and will serve its customers reliably and economically. He stated NIPSCO was able to do so following the fire at Unit 14 through October 2021 when Units 14 and 15 were retired. Even with these retirements,

[24] As a point of reference, NIPSCO's actual, total fuel cost for the months of July 2020 through September 2021 was more than $424 million, or an average of $28.2 million per month. $2,379,146 is approximately 0.5% (one-half-of-one-percent) of this total amount.

NIPSCO has demonstrated it will continue to reliably serve its customers, and they will be served at the lowest cost reasonably possible.

D. <u>Patrick N. Augustine</u>. Mr. Augustine disagreed with Mr. Gorman that NIPSCO's 2018 IRP identified the planned retirement date of Units 14 and 15 as being in 2023 and that retirement in 2021 was inconsistent with the action plan identified in the 2018 IRP. He stated that although the preferred portfolio from the 2018 IRP was modeled with retirement of all units at Schahfer in 2023, NIPSCO's action plan was designed to be flexible and allow for earlier retirement if reliability concerns associated with replacement capacity and transmission upgrades could be alleviated. He testified the 2018 IRP concluded the earliest possible retirement of coal capacity provided economic benefits for NIPSCO's customers, but time was needed to secure replacement capacity and make required transmission upgrades. He testified this finding was recently confirmed in NIPSCO's 2021 IRP submitted to the Commission on November 15, 2021.

Mr. Augustine stated NIPSCO was able to secure sufficient replacement capacity and significant replacement energy for Units 14 and 15 and completed the transmission upgrades necessary to allow two of the four units at Schahfer to be retired without reliability concerns. In addition, he testified NIPSCO's 2018 IRP preferred plan summary indicated multiple times that retirement of the Schahfer units would occur "by the end of 2023." He stated NIPSCO's 2018 IRP and subsequent planning activities have been heavily focused on allowing for flexibility in resource decisions, with the executive summary of the 2018 IRP specifically noting, "[C]hanges that affect our plan may arise, which is why it's important for us to remain flexible and continually evaluate current market conditions." Petitioner's Exhibit 4-R at p. 4. Thus, although the 2018 IRP's modeled retirement date for Units 14 and 15 was 2023, Mr. Augustine disagreed that retirement in 2021 was inconsistent with the IRP's action plan. He stated the factors limiting early retirement had been alleviated, meaning NIPSCO's decision to retire Units 14 and 15 in October 2021 was still consistent with the findings of the 2018 IRP and the flexibility built into the action plan.

Mr. Augustine testified NIPSCO's decision to retire Units 14 and 15 in October 2021 was also consistent with the findings from the analysis CRA performed in 2020. He stated this CRA analysis evaluated portfolio performance in the same way the 2018 IRP was conducted and concluded the portfolio that allowed Unit 14 to remain in forced outage and temporarily brought Unit 15 back into service represented the lowest net present value of revenue requirements under reference case conditions. He stated the analysis approach and conclusions were presented in detail in his direct testimony and generally were not discussed, let alone challenged, in Mr. Gorman's testimony.

Mr. Augustine explained how he developed the projection of energy market prices used in the 2020 analysis. He testified this analysis used CRA's commodity price outlook at the time the assessment was conducted, and he explained that CRA develops commodity price forecasts using a combination of market forward data and fundamental analysis. Mr. Augustine stated the analysis also included a distribution of stochastic risk around the reference case view based on observed volatility in the MISO power market, consistent with how CRA has provided commodity price forecasts to NIPSCO for the last several years supporting a variety of planning and budgeting activities, and is consistent with industry standards.

Mr. Augustine pointed out that market forward data from spring 2020 was used to calibrate the fuel and power price forecasts for the first few years of the forecast period, which is the same type of data Mr. Gorman uses in his calculations, although he analyzed forward prices as of the time of his analysis in fall 2021. Mr. Augustine stated Mr. Gorman does not claim the energy market pricing used when the 2020 analysis was performed was unreasonable. In fact, Mr. Augustine believes he somewhat concedes the pricing utilized was reasonable but, with the benefit of hindsight, Mr. Gorman testifies the pricing utilized in the analysis was not predictive of the actual market.[25]

Mr. Augustine testified Mr. Gorman's comparison of the energy prices used in CRA's analysis with both historical and forward prices for 2021 and forward prices through 2023 is not an accurate comparison. He explained that while the actual and forward MISO prices are represented reasonably, Mr. Gorman has not correctly presented the reference case market prices used in Mr. Augustine's analysis. Instead of using the monthly MISO market prices summarized in the workpapers provided with Mr. Augustine's direct testimony, Mr. Gorman presented the implied portfolio market purchase price from information NIPSCO provided in response to Industrials Request 7-003. He stated this portfolio purchase price is over \$5/MWh lower on average than the actual market price used in the CRA analysis, with the difference being as high as \$15/MWh in some months. Mr. Augustine explained that in the economic dispatch modeling, market purchases are only expected to occur when the market price is lower than the dispatch costs of NIPSCO's portfolio. In other words, NIPSCO is not expected to simply purchase a fixed amount of energy from MISO during all hours of the year at the prevailing average market price but only during periods when it is more economic to purchase power than operate its own resources; therefore, the market purchase price is more representative of time periods when MISO market prices are lower than average.

Mr. Augustine testified Mr. Gorman's incorrect presentation of the CRA analysis implies a much greater difference in the prices than is actually the case. For example, for the 12-month period from August 2020 (when Mr. Gorman starts his comparison) through July 2021, the average difference between actual MISO market prices and those used in the CRA analysis is just over \$1/MWh, with the actual historical price being higher. This includes February 2021 when prices spiked considerably due to short-term weather events and natural gas price spikes. He stated without this month included, historical market prices over that time period were actually lower than those incorporated in CRA's analysis.

Mr. Augustine clarified that even with this incorrect presentation of the prices from the analysis, Mr. Gorman does not suggest the reference case energy prices used in CRA's analysis performed in 2020 were unreasonable. He stated that while apparently believing the energy prices used in this analysis were on average \$5/MWh lower than those actually used, Mr. Gorman acknowledges they may have been reasonable at the time of the analysis. To emphasize that point, Mr. Augustine provided a graphic showing market forwards from the first trading day of every other month since June 2020, along with the reference case forecast used in CRA's analysis. He testified this shows the forecasted market prices are very similar to market forwards from the

[25] *See* IG Exhibit 1 at p. 33, lines 10-12, where Mr. Gorman states: "These energy prices may have been reasonable at the time of [Mr. Augustine's] analysis, however, they substantially understate actual MISO energy prices in 2021, and the forward prices through 2023."

middle of 2020 and in line with forward market sentiment through the middle of 2021. Mr. Augustine stated that while the graphic indicates MISO market prices have increased since the analysis was performed in mid-2020, prices spiked materially for a short time during a very cold period in February 2021, and they have been materially higher than the prices forecasted in CRA's reference case analysis since summer 2021.

Mr. Augustine testified the CRA analysis in mid-2020 contemplated the potential for higher prices than those presented in the reference case forecast. He explained that CRA performed a stochastic risk analysis to supplement the reference case price and portfolio cost projections, with this analysis designed to evaluate a range of MISO market prices above and below those used in the reference case forecast. He stated this identified market risk exposure tradeoffs associated with bringing both Units 14 and 15 back into service versus keeping both in forced outage and retiring them immediately.

Mr. Augustine testified the analysis found that bringing both units back into service exposed the portfolio to risk under conditions where market prices were lower than expected, while retiring both units immediately exposed the portfolio to risk if market prices were higher than expected. He stated the portfolio that brought one unit (Unit 15) back into service for a time provided a hedge against both low and high price outcomes, a point Mr. Gorman ignores. He asserted that instead of evaluating the reasonableness of the 2020 analysis or the prudence of NIPSCO's decision in reliance on the 2020 analysis at the time it was made, Mr. Gorman engages in hindsight second-guessing based on unanticipated price increases in the energy market.

Mr. Augustine testified the conclusions from the stochastic analysis were consistent with Mr. Gorman's overall position that Units 14 and 15 provided hedge value in the energy market under high market price conditions. In fact, the stochastic analysis included many iterations of potential high market price outcomes where the portfolios that brought both units back into service performed better and provided lower cost outcomes for customers than portfolios that included earlier retirements. Mr. Augustine noted a summary of these conclusions was provided in his direct testimony, including distributions of cost outcomes that estimated potential market exposure ranges associated with the various portfolio strategies; therefore, he agreed with Mr. Gorman's overall premise regarding the energy value of Units 14 and 15 in a high-priced MISO market. He took issue, however, with Mr. Gorman's conclusion that the economic studies understated the economic benefits to NIPSCO and its customers of operating Units 14 and 15 and that the economic conclusions concerning the early retirement of Schahfer Units 14 and 15 are unreliable. Mr. Augustine testified resource planning and generation portfolio decisions must constantly be made in the context of uncertainty using the best information available when the decision is made and with a clear-eyed view of risks and tradeoffs. He stated no single forecast will ever be able to predict the future with precision, but risk analysis can be used to understand the range of potential outcomes to support decision-making. Mr. Augustine testified the CRA analysis incorporated these principles and should be judged based on the information available when the decision was made and not solely on the fact that recent market prices have deviated from the reference case forecast.

Mr. Augustine confirmed that NIPSCO follows the same approach in other planning exercises. He stated CRA and NIPSCO have worked together on resource planning analyses since 2017, implementing a structured process that uses near-term forward market information, fundamental market analysis, and uncertainty assessments that include scenario and stochastic approaches. He stated the Commission has encouraged stochastic analysis as part of the Indiana IRP process, and the Commission's Director of Research, Policy, and Planning complimented NIPSCO's deployment of stochastic risk analysis in its 2018 IRP. He testified that in his experience, NIPSCO's resource planning process is consistent with industry best practice and the Commission's resource planning requirements. Per Mr. Augustine, utilities are unable to accurately predict the future with certainty, so they must make decisions based on the best available information and their understanding of potential risks. He indicated NIPSCO's planning process, including the analysis performed to assess the retirement decision for Units 14 and 15, incorporated all relevant market information and provides a robust view of economic risks. He stated movement of a market driver in a direction unfavorable to a specific resource decision does not suggest the planning process used to reach that decision was imprudent or unreasonable.

Mr. Augustine testified NIPSCO's actions regarding Units 14 and 15 were consistent with the industry standard planning process. He explained the reference case analysis concluded that allowing Unit 14 to remain in forced outage and temporarily restoring Unit 15 back to service resulted in the lowest NPVRR relative to the other portfolio options, while also mitigating market risk exposure relative to portfolios that did not return either unit to service or returned both units to service. Additionally, NIPSCO's actions were consistent with the conclusions and market insights developed through the reference case portfolio analysis and the accompanying 2020 market risk analysis CRA performed.

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

A. <u>Scope of this Subdocket</u>.

Schahfer includes six generating units, two of which, Units 14 and 15, are center stage in this subdocket. Units 14 and 15 are both coal-fired units, with Unit 14 having a capacity of 431 MW. It was placed in service in 1976. Unit 15 has a capacity of 472 MW and was placed in service in 1979. Schahfer includes two additional coal-fired generators, Units 17 and 18, and there are also two smaller gas-fired units, 16A and 16B, that became operational in 1979. IG Exhibit 1 at p. 3. The type of coal burned in Units 14 and 15 differs from the coal Units 17 and 18 burn. Petitioner's Exhibit 1 at p. 12.

Because of the summary nature of FAC proceedings, in Cause No. 38706 FAC 130 ("FAC 130"), the OUCC and the Industrial Group asked the Commission to establish this subdocket to afford additional time to review the actions that led to the fire at Schahfer Unit 14 in July 2020 and to examine NIPSCO's prudence and, potentially, the extent to which NIPSCO's fuel costs were impacted. In granting their joint motion and establishing this subdocket, the Commission in its Order in FAC 130 approved on April 28,2021 ("FAC 130 Order") stated:

> Under the FAC statute, NIPSCO has the burden of demonstrating it has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide its retail customers with electricity at the lowest fuel cost reasonably possible. Ind. Code § 8-1-2-42(d). To this end, the Commission has previously found creation of a subdocket is appropriate where the summary nature of FAC proceedings do not lend themselves to sufficient record development. *Application of Duke Energy Ind., LLC*, Cause No. 38707 FAC 111, 2017 WL

> 1632308, at *8 (IURC April 26, 2017); *see also Application of Duke Energy Ind., LLC*, Cause No. 38706 FAC 76 at pp. 4, 13 (IURC June 25, 2008). Accordingly, the Commission finds a subdocket should be created in this proceeding to examine the prudency of the actions leading to the fire at Schahfer and the actions associated with that fire that led to the unplanned forced outage of Units 14 and 15 and, ultimately, the extent to which fuel costs have been impacted thereby. The subdocket is not to re-examine NIPSCO's 2018 IRP or the planned timeline for retiring Units 14 and 15.

FAC 130 Order at p. 21. The Commission was clear in the FAC 130 Order that in this subdocket we will examine the prudence of NIPSCO's actions leading to the Schahfer fire and, potentially, the extent to which fuel costs were impacted, but we will not re-examine NIPSCO's capacity decisions and choices, including the 2018 IRP or the retirement timeline for Units 14 and 15. Consistent with this focus, in the FAC 130 Order and in each subsequent FAC Order to date issued for NIPSCO, the Commission has approved a fuel cost adjustment on an interim basis, subject to refund based on the outcome of this subdocket. FAC 130 Order, ¶ 14, at p. 19; 38706 FAC 131 Order, ¶ 13, at pp. 13-14 approved on July 28, 2021; 38706 FAC 132 Order, ¶ 13, at p. 15 approved on October 20, 2021; 38706 FAC 133 Order, ¶ 13 at p. 18 approved on January 26, 2022; and 38706 FAC 134 Order, ¶ 14 at p. 22, approved on April 27, 2022. Thus, our threshold focus in this subdocket is upon whether NIPSCO acted reasonably and prudently in connection with the events leading to the fire at Schahfer.

NIPSCO contends the subject fire was caused by an unexpected failure of the Transformer's cooling system, as sometimes happens with older equipment, and NIPSCO did nothing unreasonable or imprudent. The Industrial Group and the OUCC, on the other hand, contend Unit 14's CRO's failure to address the Transformer's high temperature alarm for more than five hours during the second of his two consecutive 12-hour shifts, with the Transformer known to be in poor condition with elevated dissolved gas levels, was imprudent and/or unreasonable as the CRO did not take adequate or appropriate measures for safe operation. While most of the relevant facts are undisputed, the parties dispute whether these facts demonstrate prudent and reasonable operation of Unit 14 leading up to the fire on July 16, 2020.

As an Indiana public utility, NIPSCO is required to provide reasonably adequate service and facilities under Ind. Code § 8-1-2-4 and also has the burden of demonstrating its fuel costs are reasonable to recover these costs from customers. Ind. Code § 8-1-2-42(d). The Commission will, therefore, first review the reasonableness and prudence of NIPSCO's actions leading to the fire.

"[P]rudency is a standard by which a utility's conduct or actions are evaluated. … It is the degree of care required by the circumstances under which the action or conduct is to be exercised and judged by what is known, or could have reasonably been known, at the time of the conduct." *Duke Energy Indiana, Inc.,* Cause No. 43114 IGCC 4S1 (IURC 12/27/2012), p. 111, 2012 WL 6759528; *see also Duke Energy Indiana, Inc.,* Cause No. 38707 FAC 76 S1 (IURC 10/21/2009), pp. 15-16, 2009 WL 3455937. "It is a term often used interchangeably with what is considered 'reasonable' under the circumstances. The Commission must determine whether decisions were made in a reasonable manner in light of the conditions or circumstances that were known or reasonably should have been known when the decision was made." *Id*. at p. 111 (citations omitted). The prudence of an electric utility's actions is not judged with twenty-twenty hindsight. Rather, the Commission will focus on the prudency of the decisions when made, based on the facts and circumstances as they existed at the time. *Northern Ind. Pub. Serv. Co.,* Cause No. 44340 FMCA 12 (IURC 1/29/2020), p. 12, 2020 WL 529286; *see also Northern Ind. Pub. Serv. Co.,* Cause No. 43849 (IURC 7/13/2011), p. 11.

B. <u>NIPSCO's Prudence with Respect to the Fire</u>. The timeline, facts, and key events leading to the fire at Unit 14 on July 16, 2020, are largely not disputed.[26] The same cannot be said of the inferences the parties draw therefrom.

The evidence shows that at Schahfer, there is one CRO for each generating unit that is operating, with each CRO having responsibility for a particular unit, and they are stationed in the control room. Early the morning of July 16, 2020, a general trouble alarm from the Unit 14 Transformer came into the Unit 14 control room. At 7:56 a.m., CST, an alarm was activated indicating there was a higher than usual temperature in Unit 14's Transformer, with this alarm, like many others that morning, popping up on Unit 14's alarm screen. Thus, an alarm indicating an elevated Transformer temperature activated and was issued to the CRO responsible for Unit 14's operations at approximately 7:56 a.m. CST—over five hours before the fire occurred.[27] Based on Mr. Sangster's testimony, this CRO indicated he noticed and acknowledged the high temperature alarm and pulled the alarm up on one of his screens to monitor the Transformer's temperature, Petitioner's Exhibit 2 at p. 10, but he took no immediate action because the temperature was not extraordinarily high and was not increasing at a significant rate. Petitioner's Exhibit 2 at p. 12. Per Mr. Sangster, under NIPSCO's training and procedures, the Unit 14 CRO should have dispatched a Station Operator to investigate the Transformer, verify the temperature locally, and confirm whether the cooling systems were operating correctly. At a minimum, Mr. Sangster stated when the Unit 14 CRO became aware of the situation, if the foregoing actions could not be taken, he should have notified his supervisor of the situation so a response or actions by other personnel could be evaluated. Unit 14's CRO, however, did neither—he did not dispatch a Station Operator or inform anyone of the rising Transformer temperature. Notwithstanding the alarm, the CRO attended to other issues and alarms associated with Unit 14's operations, but he never addressed the Transformer high temperature alarm.

According to Mr. Sangster, Unit 14 experienced additional operational issues throughout the morning of July 16, 2020. The coal coming into the plant was wet and was plugging up coal chutes and feeders. This, in turn, was tripping or shutting off the cyclone burners; consequently, Unit 14's CRO and Station Operators were continuously working to put these systems back into service and keep Unit 14 operating. Meanwhile, although it cannot be definitively determined because of the extensive damage the fire caused, Mr. Sangster testified that since there was no sudden and significant spike in the Transformer's temperature, it is believed the Transformer's oil cooling system, i.e., the fans, pumps, or both, at some point tripped off or failed causing the Transformer's temperature to rise slowly but steadily.[28] The oil inside the Transformer eventually reached its boiling point, turned from a liquid into a gas, and set off a sudden pressure alarm for

[26] While we generally cite to Mr. Sangster's testimony for each relevant fact, Mr. Gorman's testimony, IG Exhibit 1 at pp. 7-8, is consistent with Mr. Sangster's testimony, as is Mr. Eckert's testimony, OUCC Exhibit 1 at p. 3. Thus, the parties provided similar factual scenarios.
[27] Petitioner's Exhibit 2 at p. 9.
[28] *Id*. at pp. 12-13.

the Transformer that led to Unit 14 tripping off-line at approximately 1:25 p.m. CST.[29] Energy continued, however, to be discharged into the Transformer as Unit 14 wound down; consequently, an arc flash came back towards the Transformer, igniting the gaseous oil escaping from the Transformer and creating the fire in question.[30] The fire was not extinguished until approximately 9:00 p.m., CST. It substantially damaged Unit 14, as well as the common equipment Units 14 and 15 shared, resulting in unplanned forced outages of Units 14 and 15. After the fire, Unit 14 was never again in service before its retirement on October 1, 2021. Unit 15 was temporarily returned to service in December 2020 and retired on October 1, 2021.[31]

Mr. Sangster acknowledged that if Unit 14's CRO had followed his training and NIPSCO's procedures by dispatching personnel to locally inspect the cooling system and Transformer or if this CRO had consulted with a supervisor or notified his supervisor of the alarm, the fire likely could have been avoided, but this did not happen. Although the CRO noticed the high temperature alarm and pulled the alarm up on one of his screens to monitor the Transformer's temperature, he never took steps to investigate or remedy the alarm; consequently, Mr. Sangster testified the cooling system failure appears to be the root cause of the fire, but the CRO's failure to adequately or timely respond to the temperature alarm was a contributing factor. Petitioner's Exhibit 2 at p. 17.

As Mr. Gorman testified, the CRO whose human error is described as a contributing factor was NIPSCO's employee. In response to discovery, NIPSCO acknowledged this CRO was scheduled to be off on July 15 and 16, 2020. Instead, he worked two consecutive 12-hour shifts starting on July 15, 2020, at 6:00 p.m. During his first 12-hour shift, the CRO completed mandatory safety training, followed by a 12-hour overtime shift with control room duties for Unit 14. IG Exhibit 1 at p. 11. When the high temperature alarm activated on July 16, 2020, Unit 14's CRO had been working about 14 hours. Mr. Sangster describes this as a particularly busy day at Schahfer, with all four coal-fired units operating and Unit 14 experiencing multiple fuel supply issues upon which its CRO interfaced with Station Operators and station personnel. Petitioner's Exhibit 2 at p. 10. Yet, the CRO never asked a Station Operator to inspect the Transformer or confirm whether the cooling system was operating correctly. The CRO also never brought the alarm to his supervisor's attention so other personnel could evaluate what needed to occur if he was too busy with other Unit 14 matters to resolve the temperature alarm.

Although Mr. Sangster advised in his rebuttal that under NIPSCO's collective bargaining agreement consecutive 12-hour shifts are allowed, Petitioner's Exhibit 2-R at p. 20, the Commission finds that being agreed upon or permitted does not equate to such shifts necessarily being prudent. In this instance, based on the facts the parties presented, the root cause of the fire may have been the cooling system's failure, but the Commission finds it likely the catastrophic fire could have been prevented if the CRO, in the course of his interactions on July 16, 2020, with Station Operators and personnel, asked for the Transformer temperature to be checked locally

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[29] *Id*. at p. 13.
[30] *Id*. at p. 14.
[31] Unit 15 continued in service, burning the coal inventory for Units 14 and 15. Mr. Talbot testified that as of July 16, 2020, there was a coal inventory of approximately 700,000 tons, worth approximately $28 million, and NIPSCO had existing contractual obligations of approximately $4 million that also needed to be addressed. Petitioner's Exhibit 1 at p. 12.

and/or the status of the cooling system verified or if he had brought the alarm to his supervisor's attention so someone could follow up in accordance with NIPSCO's operating procedures.[32]

In support of its prudence, NIPSCO advises that Unit 14's CRO on shift on July 16, 2020, was extremely experienced, with more than 37 years working in generation related roles and more than 17 years as a CRO. As opposed to proving prudence, we find his extensive experience makes it more extraordinary that the CRO ignored the warning alarm for over five hours, heightening the Commission's concern about the wisdom of NIPSCO's two consecutive 12-hour shift practice—in this instance, an overtime second 12-hour shift—and/or whether sufficient personnel were available to address the magnitude of alarms Mr. Sangster described on the day in question.

When all the events and circumstances leading to the fire are considered, the Commission rejects the proposition that this fire occurred simply because mechanical equipment on older units like Unit 14 can fail. Much more transpired. Based on the evidence, this fire also occurred because, over more than five hours, NIPSCO's CRO, while working a second 12-hour shift that was unplanned, took no action in response to the Transformer temperature alarm. The rise in temperature may have been because the cooling equipment failed; it may have been unexpected, but it was not spontaneous.[33] It took several hours for the Transformer oil to reach its flash point; therefore, we agree with the OUCC and the Industrial Group that more than the breakdown in the cooling system caused the fire because activation of the high temperature alarm provided NIPSCO with time to inspect or perform an analysis of the cooling system and, if the alarm could not be resolved, perform an orderly shutdown of Unit 14, but neither the analysis nor the shutdown occurred. Attentiveness and responsiveness to the many moving pieces that occur in a control room are necessary; consequently, the failure to act over the course of several hours on a high temperature alarm for a critical piece of equipment with a potentially dangerous condition presents a scenario the Commission will not countenance by finding NIPSCO's actions leading to the fire were prudent or reasonable. We disagree with Mr. Sangster's rebuttal testimony (Petitioner's Exhibit 2-R at p. 24, lines 3-4) that the Industrial Group offered no testimony and did not prove NIPSCO did anything wrong on the day in question before the fire. This overlooks Mr. Gorman's testimony (IG Exhibit 1 at pp. 7-17) and NIPSCO's discovery responses attached to this testimony.

This particular Transformer had been placed on a watch list as a result of many years of elevated levels of combustible gases. It was described as being in poor overall condition, with both ethane and acetylene at elevated levels that could possibly have signaled "a worsening problem." Attachment MPG-7 at p. 3. While its excessive dissolved gas levels were not shown to have caused the Transformer's cooling system to fail or breakdown, the Commission would have expected the Transformer's history, degradation, and watch list status to prompt more CRO attention instead of minimal attention. Accordingly, based on the evidence, the Commission finds NIPSCO's actions leading to and associated with the fire were imprudent and not reasonable given all the circumstances. We do not, however, find, as the OUCC and the Industrial Group suggest, that

[32] NIPSCO took no employment action with respect to Unit 14's CRO as a result of the fire, but he retired on September 1, 2020.

[33] Per Attachment MPG-7 at p. 3, "The transformer temperature went into alarm at approximately 0700 and remain[ed] in alarm while climbing in temperature until the time of the failure (approximately 5 hours). The temperature was approximately 139 degrees C at the time of the failure. Mineral oil flash point is 140 degrees C."

lapses in completing operator rounds and deficient recordkeeping at Schahfer were also contributing factors, but these are deficiencies NIPSCO must rectify.

Although the Commission finds a direct nexus was not established between this fire and lapses in completing operator rounds at Schahfer and submitting rounds sheets, we would be remiss to not instruct NIPSCO to assure operator rounds are prospectively conducted with regularity and diligent recordkeeping is timely maintained. In this instance, in the week before the fire, the Industrial Group showed lapses in completing operator rounds of equipment and ongoing recordkeeping deficiencies. NIPSCO contends rounds were being "substantially" completed, "although not always consistently and/or in their entirety," Petitioner's Exhibit 2-R at p.15, and characterizes the problem as more the failure to turn in rounds sheets as opposed to performing rounds. The Operations Superintendent, however, issued an email on July 23, 2020, a week after the fire, that stated:

> We have now had a catastrophe at the plant due to the unit 14 main power transformer failure. The RCA team is now requesting the rounds for the outside operators for July 15th and 16th days and nights. These rounds contain the info that is needed to see what if anything we observed while comp[l]eting the rounds. As of this time [July 23, 2020] there are no round sheets or electronic rounds shown to be completed on these days. So we have no evidence that we completed any rounds. Therefore by not completing the paperwork or electronic rounds it shows complete disregard for our primary job and the emails I sent [earlier about completing rounds] went unheeded. All of us will have to answer for our failure in ensuring these rounds were completed.

Attachment MPG-8 at p. 1. Diligently performing rounds for operating equipment and compliance with associated recordkeeping requirements can be critical in identifying existing or potential equipment concerns and fostering safe practices. While the Commission finds their absence was not *shown* to be a material factor with respect to this fire, the evidence does show a troubling, ongoing failure to perform these important practices that the Commission directs NIPSCO to promptly resolve.

Having determined NIPSCO's actions leading up to the fire at Unit 14 that ravaged this unit and damaged its common facilities with Unit 15 were not prudent and reasonable, the Commission must also determine the extent to which NIPSCO's fuel costs have been impacted by the forced outages of Units 14 and 15 after the fire. FAC 130 Order at p. 21.

C. <u>Impact on Customers' Fuel Costs</u>. Prior to the Unit 14 fire, the planned retirement of Units 14 and 15, as reflected in NIPSCO's 2018 IRP, was by May 2023. Petitioner's Exhibits 1 at p. 4; 1-R at p. 7; 4-R at p. 3. Thus, as opposed to May 2023 being the units' retirement date, a retirement window was left ajar. Under the settlement agreement the Commission approved in Cause No. 45159 on December 4, 2019, the revenue credit originally to begin following the retirement of Schahfer in May 2023 will begin earlier if Units 14 and 15 are retired earlier, Petitioner's Exhibits 3 at p. 36 and 3-R at p. 27,[34] evidencing, from the Commission's perspective, a recognition by the parties to that agreement, who included NIPSCO, the OUCC, and the Industrial Group, that these Schahfer units might be retired before 2023.

After the fire, Unit 14 was placed in forced outage for the remainder of 2020 and all of 2021 until its retirement on October 1, 2021. Unit 15 was similarly in forced outage for most of the remainder of 2020 while repairs were performed that enabled Unit 15 to be brought back into service before year-end 2020 until its retirement on October 1, 2021. The Commission advised in the FAC 130 Order that this subdocket will examine the extent to which customers' fuel costs were negatively impacted by the fire leading to the unplanned forced outages, not re-examine NIPSCO's 2018 IRP or the planned timeline for retiring Units 14 and 15 which, by the time this subdocket was requested, was forecasted to be late summer or early fall of 2021—not May 2023. FAC 130 Order at p. 16. The Commission, therefore, declines to re-examine the propriety of retiring Units 14 and 15 on October 1, 2021, in this FAC subdocket. Our focus, having reviewed the prudency of NIPSCO's actions leading to the fire, turns now to the fuel cost impact and related refunds.

On the propriety and level of refunds, the parties diverge. NIPSCO's position is that no refunds are required because the fire was the result of aged equipment malfunctioning, not NIPSCO's imprudence. Alternatively, to the extent refunds are required, NIPSCO contends the potential refund period is the time between the date of the fire and the Units' retirement, i.e., July 16, 2020, through October 1, 2021.

Until the fire, the record shows NIPSCO routinely operated Units 14 and 15 as capacity resources to help maintain system reliability and also as physical energy hedges available when market conditions supported economic dispatch. Industrial Group witness Gorman explained that energy savings occur when a unit's dispatch cost is lower than the alternative resource dispatch cost or the MISO market purchase energy price. IG Exhibit 1 at p. 23. Per Mr. Gorman, during the five-year period before the fire, Units 14 and 15 were operated primarily for system support and power quality purposes because prevailing energy prices in the MISO market were generally lower than the dispatch costs of Units 14 and 15. Those units were seldom dispatched for economic purposes because their dispatch costs were generally above the market clearing prices. IG Exhibit 1 at p. 23. MISO market energy prices, however, increased in 2021 and were above the dispatch cost of Units 14 and 15. With this increase, the Commission finds the unavailability of Unit 14 resulted in higher fuel costs because NIPSCO made incremental purchases in the more expensive MISO market when it could have achieved energy savings through economic dispatch until October 1, 2021. The same cannot be said for Unit 15 because it was in service.

With respect to the period from January 1 to October 1, 2021, if refunds are required, NIPSCO initially contends any 2021 refund amounts attributable to MISO market pricing being above Unit 14's dispatch cost should be offset by periods in 2020 when most MISO market pricing was well below Unit 14 or Unit 15's dispatch costs. The Commission disagrees. Before the fire, Units 14 and 15 served two distinct purposes, i.e., as physical hedges against MISO price risk and

[34] Per Mr. Campbell, the incremental revenue credit associated with retiring Units 14 and 15 in October 2021 instead of May 2023 is currently estimated to be more than $8 million over the first 12 months, all of which will flow directly to NIPSCO's customers.

as capacity resources. When Unit 14 and Unit 15's dispatch costs were higher than MISO prices, as in the latter half of 2020, the units would have run, had they been available, for system support and reliability purposes, but NIPSCO utilized different capacity resources. NIPSCO's FAC charges for that time period reflected the costs associated with the resources actually utilized. The credit NIPSCO proposes will, effectively, require ratepayers to pay redundant costs for the hypothetical operation of Units 14 and 15 in 2020 and the capacity resources that actually provided reliability. The Commission finds this would be improper because the offset NIPSCO proposes amounts to double-counting for the same function. Units 14 and 15 were not dispatched or used as capacity resources while in forced outage in 2020 and did not yield an offsetting credit. The evidence also shows that in 2020 economic dispatch of Units 14 and 15, had they been available, would not have produced measurable cost savings. It was not until 2021 that MISO market prices measurably increased, so our analysis of the fuel cost impact of the fire will commence with January 2021 when it is reasonable to assume Units 14 and 15 would have begun being economically dispatched.

NIPSCO also contends that to the extent refunds are warranted, the Commission should take into account the millions of dollars of capacity coverage NIPSCO secured after the fire to replace the loss of capacity from Units 14 and 15 through 2023. These capacity costs are separate and distinct from the energy prices and fuel cost impact at issue. NIPSCO's decision to forego cost recovery for replacement capacity does not properly offset or factor into our determination in this subdocket of any excess fuel costs NIPSCO incurred due to the unavailability of Units 14 and/or 15. Finally, NIPSCO also claims $15 million in capital improvements to Units 14 and 15 were not made between July 16, 2020, and December 31, 2021, which NIPSCO would have recovered along with a return on this investment from its customers. As Mr. Sangster acknowledges, such capital expenditures are not an FAC cost and not recoverable in fuel costs. (Petitioner's Exhibit 2-R at p. 26). Accordingly, the Commission finds such expenditures are not properly considered in determining the extent to which NIPSCO's fuel costs were impacted by the fire.

In contrast to NIPSCO's position that no refunds are warranted because its actions leading to the fire were prudent and reasonable or that relatively limited refunds (between $450,955 and $901,911) should be ordered as a result of the above offsetting considerations, the refund analysis Mr. Gorman presented focused on lost fuel cost savings from the unavailability of Units 14 and 15 during periods when economic dispatch would have produced measurable cost savings. He proposed a range with a low-end that was based on Unit 14's historical operation in the five years prior to the fire when the units were typically operated for reliability purposes but seldom dispatched economically and a high-end based on the actual operation of Unit 15 in 2021 during the period of rising MISO prices. By comparing Unit 14 and Unit 15 dispatch costs with prevailing MISO market energy prices, Mr. Gorman computed refunds in the range of $17 million on the low-end and $34 million on the high-end for January through December 2021, before making the adjustment the Industrial Group accepted in its docket entry response. He viewed this as representing the fuel cost savings NIPSCO reasonably could have achieved through reduced purchases in the MISO market if Units 14 and 15 were not unavailable due to the fire.[35]

[35] Mr. Gorman's complete analysis includes refund dollars beyond the October 1, 2021, retirement date for Units 14 and 15. We will not input generation beyond the units' retirement when determining the fuel cost impact.

While not conceding the accuracy of Mr. Gorman's methodology, Mr. Campbell in his rebuttal testimony proposed the following three adjustments to Mr. Gorman's refund computation that he opined are needed based on the physical capabilities of Units 14 and 15 and what has occurred in the energy market since July 16, 2020: (1) a limit on the units' maximum capacity; (2) an update to dispatch costs; and (3) a correction for price differences between distinct nodes. Petitioner's Exhibit 3-R at pp. 19-21. Of these three adjustments, the Industrial Group in its response to the docket entry issued on January 20, 2022, agreed with the third adjustment Mr. Campbell proposed.

Mr. Campbell's first adjustment to Mr. Gorman's calculations concerns the methodology and result of Mr. Gorman's estimated energy generation output (MWhs) from Units 14 and 15 if the fire had not occurred and these units had been available to provide service. Mr. Campbell takes issue with Mr. Gorman utilizing a maximum capacity of 540 MW based on Unit 14 and Unit 15's generator nameplate ratings. Per Mr. Campbell, this is significantly higher than the units' physical capability of 425 MW and 440 MW, respectively. He recommends using 425 MW for Unit 14 and 440 MW for Unit 15 which reflects each unit's economic maximum or EconMax rating. Per Mr. Campbell, this correction reduces the total number of MWhs Unit 14 can be assumed to be producing energy each day it may have been dispatched. In contrast, for his output estimates, Mr. Gorman relied on the actual energy generation for the units in the five-year historical period prior to the fire while Mr. Campbell's suggested revision substitutes figures that are substantially lower than the actual history of past operations. NIPSCO asserts that Mr. Campbell's assumed total MWhs of generation are more reasonable and representative of what may have occurred in 2021 because of the additional renewable generation that came online in late 2020 which would have displaced some amount of more expensive coal-fired generation.

According to the Industrial Group's docket entry response filed on January 21, 2022, changing the capacity rating as Mr. Campbell proposes will change the forecasted capacity factor but does not change Mr. Gorman's estimate of the energy output of the units in the forecast period. From the Industrial Group's perspective, Mr. Campbell's analysis understates energy generation in the forecast period relative to past operations and is, therefore, an unreasonable adjustment. The Commission finds the proposed maximum limit adjustment NIPSCO proposes is inconsistent with the actual operating history for Units 14 and 15, and Mr. Campbell did not establish its reasonableness simply because new renewable generation came online in late 2020. Mr. Gorman's estimated energy output for Unit 14 is between 79,000 MWh and 158,000 MWh based on his low-end and high-end estimates and compares to the five-year average actual energy output for Unit 14 of 83,336 MWh. Mr. Campbell's low-end estimate is, however, substantially lower than the actual historical energy output and appears understated. Given the evidence, the Commission finds Mr. Gorman's use of the units' historical output is reasonable, and we reject Mr. Campbell's first proposed adjustment. In doing so, it is noted Mr. Gorman opined that his assumed capacity factor ranges were conservative because he anticipates the capacity factor of Units 14 and 15 would have been higher than historic averages due to market conditions in 2021, a position he supports based on NIPSCO's discovery responses. That said, we find it appropriate to utilize Mr. Gorman's low-end estimate, as opposed to his high-end estimate, due to its closer proximity to the five-year average output.

In his second proposed adjustment Mr. Campbell seeks to increase the dispatch costs for Units 14 and 15 to reflect higher fuel prices. Per Mr. Campbell, the dispatch costs Mr. Gorman utilized understate the actual operational costs Unit 14 would have incurred during 2021. Mr. Gorman took issue with this adjustment because "the coal supply for Units 14 and 15 that existed before the fire was under contract that shielded these units' delivered coal price from changes in spot coal prices during 2021 through 2023." IG Exhibit 3 at p. 4. According to Mr. Gorman, while the dispatch offering price for these units to MISO may have tracked spot prices, NIPSCO's actual cost of fuel, which is the relevant issue in establishing recoverable fuel costs, was not tied to changes in spot market fuel prices. "The cost of fuel for these units would have been based on contract pricing structures and not changes in short-term or spot coal market price factors." IG Exhibit 3 at p. 4. We find Mr. Gorman's testimony more consistent with our understanding that Unit 15 was returned to service to exhaust the existing coal inventory and coal contract commitments for Units 14 and 15, with the prices for these coal deliveries generally fixed in most supply contracts. The Commission finds NIPSCO did not adequately support its alternative projection of dispatch costs.

The third adjustment Mr. Campbell identified deals with delta LMP prices. Mr. Campbell stated that Mr. Gorman did not account for delta LMP, i.e., a charge or credit associated with the difference between the LMP at a generator's commercial pricing node where energy is put onto the grid and the NIPS commercial pricing node where the load is actually served and is, predominately, a result of congestion between the two points. Petitioner's Exhibit 3-R at p. 21. Per Mr. Campbell, if Unit 14 had been dispatched under the assumptions in Mr. Gorman's calculation, delta LMP is a real cost that would have been incurred in the MISO market and paid by NIPSCO's customers in its FAC fillings. Mr. Campbell testified that in total, for January through September 2021, the inclusion of delta LMP yields approximately $481,690 that NIPSCO would have recovered from customers through the FAC and, thus, Mr. Gorman's calculation of potential refunds should be reduced by this amount. Per the Industrial Group's responses to the Commission's docket entry, Mr. Gorman agrees with the propriety of this adjustment. He, however, computed the reduction for calendar year 2021 as opposed to the October 1, 2021, retirement date the Commission acknowledged above.

Consistent with the foregoing, the Commission finds the computation methodology Mr. Gorman used reasonably measures the adverse impact on NIPSCO's fuel costs resulting from the fire and that the appropriate refund period is January 1, 2021, until the units' planned and actual retirement on October 1, 2021. After reviewing Mr. Gorman's calculations, the adjustments NIPSCO proposed and the Commission rejected, and the LMP delta adjustment the Commission found appropriate, when the low-end calculation is applied to the Industrial Group's confidential workpaper submitted in response to the docket entry, the Commission computes the refund amount to be $7,986,115.

The Commission finds the unavailability of Unit 14 after the fire until its retirement on October 1, 2021, had an adverse effect on NIPSCO's fuel costs that the refund directed above reasonably measures. Considering the adjustment the Commission found appropriate to Mr. Gorman's calculation and utilizing his low-end capacity factor which, as discussed above, the Commission finds most appropriate, NIPSCO is instructed to refund and/or credit the full refund amount in its first FAC filing following the issuance of this Order. We find it is unnecessary to spread the refund amount over multiple FAC filings since this amount is only around ten percent of NIPSCO's typical quarterly fuel costs.

D. NIPSCO's Absence of Candor with the Commission. When the Commission orders a public utility to file a report, it is paramount the report be candid and complete, without material omissions. The requirement to file a root cause analysis report in NIPSCO's FACs facilitates the Commission's review, assessment, and knowledge associated with the incident or reported outage. It affords the Commission information we need to help assure safe and reliable utility service. The purpose behind sharing such an analysis is undermined when the utility's regulatory disclosure fails to provide material facts that relate to utility responsiveness with respect to safely operating its facilities or selective disclosure of related facts and circumstances. The Commission finds the Unit Trip/Load Loss Report NIPSCO confidentially submitted in Cause No. 38706 FAC 129 ("FAC 129") on December 2, 2020, was materially deficient and inferred the fire at Unit 14 was simply attributable to an equipment failure, an inference NIPSCO knew, or should have known, to be incomplete.

Mr. Sangster acknowledges that following the fire, NIPSCO conducted an internal investigation leading to a root cause analysis report dated August 7, 2020. This report was not shared with the Commission in FAC 129 nor was the Commission apprised of its contents. This analysis surfaced in response to discovery in this subdocket and discloses circumstances NIPSCO's investigators considered contributing factors leading to the fire such as fatigue and the CRO being on the second half of a 24-hour shift when the fire occurred. In contrast, what NIPSCO provided in FAC 129 was a form Unit Trip/Load Loss Report that omits key information found in the August 7, 2020, root cause analysis, including how long the high temperature alarm went unaddressed after being activated and data regarding the condition of the Transformer. The root cause analysis report and NIPSCO's discovery responses stand in stark contrast to what NIPSCO shared with the Commission before this subdocket commenced.

The Commission finds NIPSCO did not provide the root cause analysis report upon the Unit 14 fire as previously ordered with respect to major forced outages and exhibited a lack of candor in what seems to have been selectively shared. This is troubling, contradicts prior Commission Orders, and evidences what we have found to be ill-advised and imprudent actions after the fire that NIPSCO shall prospectively assure are not repeated. The root cause analysis report shall be prospectively shared in NIPSCO's FACs, as previously ordered, to facilitate informative review.

7. Interim Rate Disposition. As set forth above, the Commission finds refunds are appropriate as a result of this subdocket. Accordingly, the potential refund obligations recognized by the Commission's Orders in Cause Nos. 38706 FAC 130 through FAC 133 related to this subdocket proceeding are triggered, and the ordered refund shall be effectuated in NIPSCO's first FAC filing after the date of this subdocket Order.

8. Confidential Information. On August 13, 2021, NIPSCO filed a motion for protective order which was supported by an affidavit showing certain information to be submitted to the Commission contained trade secrets within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In an August 24, 2021 docket entry, such information was found to preliminarily be confidential. On November 23, 2021, NIPSCO filed a second motion for protection and nondisclosure that was supported by an affidavit showing certain documents to be submitted to the Commission by the Industrial Group also contained trade secrets within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In a November 29, 2021 docket entry, such information was preliminarily found to be confidential. The Commission finds such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. Consistent with the Commission's discussion and findings above, the Commission finds NIPSCO acted unreasonably and imprudently with respect to the events that gave rise to the fire at Schahfer Units 14 and 15 on July 16, 2020, and as a result of such imprudence, ratepayers have incurred greater fuel costs between the date of the fire and the retirement of Units 14 and 15 on October 1, 2021, in the amount of $7,986,115 that NIPSCO shall refund.

2. NIPSCO shall effectuate the ordered refund in the amount of $7,986,115 with the first FAC quarterly filing NIPSCO makes after the date of this Order in accordance with Finding No. 6.C. above. Such implementation of the ordered refund in NIPSCO's next FAC proceeding shall not be an opportunity to relitigate the merits of the findings in this Order.

3. NIPSCO shall promptly take those actions necessary to assure employee rounds are diligently and regularly performed and associated recordkeeping timely maintained consistent with Finding No. 6.B. above.

4. NIPSCO shall continue to provide the Commission with the root cause analysis report in its FACs for major forced outages as previously ordered and shall promptly take those actions necessary to assure the Commission is prospectively fully and completely apprised of the circumstances leading to and associated with such outages per Finding No. 6.D. above.

5. The information filed in this Cause pursuant to NIPSCO's motions for confidential treatment is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

<u>HUSTON, FREEMAN, KREVDA, OBER, AND ZIEGNER CONCUR</u>:

APPROVED: JUN 15 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: 2022.06.15 10:41:10
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Dana Kosco
Secretary of the Commission