Cause No. 46038

FILED
April 4, 2024
INDIANA UTILITY
REGULATORY COMMISSION

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF WILLIAM C. LUKE

Petitioner's Exhibit 17

April 4, 2024

DIRECT TESTIMONY OF WILLIAM C. LUKE
VICE PRESIDENT OF MIDWEST GENERATION
DUKE ENERGY BUSINESS SERVICES LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William C. Luke, and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

A. I am employed as the Vice President of Midwest Generation by Duke Energy Business Services LLC, a service company subsidiary of Duke Energy Corporation ("Duke Energy"), which provides services to Duke Energy and its subsidiaries, including Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I attended New York Maritime College and graduated with a B.S. in Engineering and also have a United States Coast Guard License. I have also held a New York City High Pressure Boiler Engineer License. I have over 30 years of experience in the power generation industry and have held various roles for public utilities and independent power producers with increasing responsibilities throughout my career. My significant, relevant positions with Duke Energy and its predecessor companies include: the Operations Superintendent at Hines Energy Complex in

Bartow, Florida; the Strategic Initiatives Manager for Progress Energy in St. Petersburg, Florida; the General Manager of Anclote Station in Florida; the General Manager of Bartow Combined Cycle Facility and Suncoast Combustion Turbines in Florida; and General Manager of Cayuga Station in Indiana. I began working for Duke Energy Florida in 2005 and transferred to Duke Energy Indiana in 2015. I assumed my current position in 2022.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES.

A. As Vice President of Midwest Generation, I am responsible for providing safe, compliant and reliable operation of Duke Energy's Midwest generation fleet, which includes four coal, one combined cycle, one combined-heat-and-power, one hydro, six simple cycle combustion turbine, and four solar (two of which include battery storage systems) facilities, serving Indiana, Kentucky, and Ohio, which provide over 8,000 MWs of generation. My primary responsibilities include managing the fleet within design parameters and implementing work practices and procedures that ensure safe and regulatorily compliant operation and maintenance activities.

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

A. The purpose of my testimony in this proceeding is to provide an overview of Duke Energy Indiana's generating fleet; our operating philosophy for the fleet; and the fleet's historical operational performance against industry benchmarks. My testimony will also review significant changes to Duke Energy Indiana's generation fleet since the Company's last base rate case, Cause No. 45253, including generation unit retirements, new generation units in service, and major maintenance activities completed. I will review the 2025 Forward-Looking Test Period ("Test Period") production expenditures for both capital and operation and maintenance ("O&M") costs, as well as more broadly discuss historical O&M expenses and future O&M cost forecasts. I will also discuss historical, Test Period, and future generation planned outage O&M expenses, and provide support for a pro-forma adjustment to the Test Period planned outage O&M expenses. I will address materials and supplies inventory levels. Lastly, I will also address our plans for Gibson Unit 5, which was tentatively scheduled for retirement shortly after the end of the Test Period, in May of 2026. Based on updated information discussed below in this testimony, the Company has decided to continue to operate Gibson Unit 5 into the 2030 timeframe. I will discuss our maintenance plans to ensure the reliability of this unit based on this updated planned retirement date.

II. DUKE ENERGY INDIANA'S GENERATING FACILITIES

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S GENERATING STATIONS AND BATTERY STORAGE SYSTEMS.

A. Attachment 17-A (WCL) shows Duke Energy Indiana's electric generating and storage properties, which consist of: (1) two syngas/natural gas-fired combustion turbines ("CT") and one steam turbine; (2) five solar-powered facilities, two of which have on-site energy storage systems; (3) steam capacity located at two stations comprised of seven coal-fired generation units; (4) combined cycle capacity located at one station comprised of three natural gas-fired CTs and two steam turbine-generators; (5) one CT in a combined heat and power ("CHP") configuration located at Purdue University; (6) a run-of-river hydroelectric generation facility comprised of three units; (7) peaking capacity consisting of four oil-fired diesels and 24 natural gas-fired CTs, one of which is configured with dual natural gas and fuel oil capability; and (8) one distribution-tied energy storage system located at the Nabb substation.

Since the Company's last base rate case, Gallagher Units 2 and 4 (two coal-fired units) were retired. In addition, the Company has constructed generation since the last base rate case: Blue River (solar); and the Purdue University CHP unit. Duke Energy Indiana also completed refurbishment of its Markland hydroelectric facility.

Q. MR. LUKE, PLEASE DISCUSS THE GENERATION RETIREMENTS THAT HAVE OCCURRED SINCE THE COMPANY'S LAST BASE RATE CASE.

A. At the time of the last base rate case, Duke Energy Indiana was planning to retire Gallagher Units 2 and 4 by December 31, 2022, pursuant to the Settlement Agreement approved by the Commission in Cause No. 43114 IGCC-15. Based on the Company's Midcontinent Independent System Operator ("MISO") capacity position and market conditions at the time, the Company ultimately retired the two Gallagher units on June 1, 2021, slightly ahead of plan, in alignment with the start of the MISO plan year. As proposed by the Company and approved by the Commission in the last base rate case, once the units retired, the Company began crediting customers with the depreciation expense for Gallagher Units 2 and 4 through Rider 67, which Company witness Ms. Lilly mentions in her discussion of the Credits Tracker.[1] The Commission's Order also deemed the Gallagher Units 2 and 4 retirements as normal.[2]

Q. PLEASE ELABORATE ON THE COMPANY'S DECISION TO RETIRE GALLAGHER UNITS 2 AND 4 AHEAD OF SCHEDULE.

A. The remaining two units at Gallagher Station, which reliably served our customers with electricity for more than 60 years, were required to retire by the end of 2022. These generating units, however, had been operating at a minimal capacity factor in recent years, and even less due to lower power demand during the pandemic. Due to a COVID-19-influenced lower load forecast, Duke Energy Indiana's generation capacity position for the MISO 2021-2022 plan year was projected to be sufficiently long. Also, based on the most recent Fuel Adjustment Clause ("FAC") modeling at the time, the Gallagher units were forecasted to have near-zero economic dispatch for the remainder of their lives. Due to the Company's longer MISO capacity position during the pandemic, and minimal forecasted energy production of the Gallagher units, their approximately 280 MW of net capacity was not needed for serving customers during the upcoming MISO

[1] Commission Order in Cause No. 45253, at page 21.
[2] *Id*.

2021-2022 plan year. As a result, the Company decided to retire the facility on June 1, 2021.

Q. WHAT IS THE CURRENT STATUS OF THE GALLAGHER STATION?

A. Since its retirement, Gallagher Station was placed in a "safe shutdown" condition, and we have begun to dismantle the plant. The power transmission lines and substation on site will continue to be operational.

Q. PLEASE DESCRIBE THE GENERATING ASSETS DUKE ENERGY INDIANA HAS CONSTRUCTED SINCE THE COMPANY'S LAST BASE RATE CASE.

A. In 2020, in Cause No. 45276, the Commission granted the Company a Certificate of Public Convenience and Necessity ("CPCN") to construct and operate the Purdue University CHP facility, consisting of a 16 megawatt natural gas-fired combustion turbine for electric production, coupled with a heat recovery steam generator for process steam production to serve the steam needs of the Purdue University campus. The unit entered service in December of 2021.

In Cause No. 45145, Duke Energy Indiana was granted authority to undertake a solar services program under an alternative regulatory plan. Subsequently, the Company has constructed the 900-kilowatt Blue River Solar facility, entering service in December 2022. Blue River Solar is a behind-the-meter resource, and is leased to Toray Resin Company, a large manufacturing customer. Though it is governed by an alternative regulatory plan, Blue River

Solar still qualifies for capacity in MISO, and the Company first successfully registered Blue River Solar for the 2023-2024 MISO plan year capacity auction.

Q. WHAT IS THE CURRENT STATE OF CONSTRUCTION OF THE MARKLAND HYDROELECTRIC UPRATE PROJECT?

A. As approved by the Commission in Cause No. 44767, Duke Energy Indiana undertook a three-year uprate project at the Markland Hydroelectric Generating Facility. This project was in progress at the time of the last base rate case. Each of the three generators was successively out of service for approximately one year while the work was performed. A common site outage was required to perform some of the work, such as replacement of the main power transformer for the three units. The project was completed in the spring of 2021, and the station is fully in service once again, providing customers with carbon-free, low-cost energy and capacity.

Q. IN YOUR OPINION, ARE THESE GENERATING FACILITIES USED AND USEFUL IN SUPPLYING ELECTRICAL SERVICE TO DUKE ENERGY INDIANA'S RETAIL CUSTOMERS?

A. Yes. All these facilities were approved by the Commission and supply significant amounts of energy to Duke Energy Indiana customers. As such, it is my opinion that this generation is used and useful in serving our customers.

III. EDWARDSPORT IGCC 2020 MAJOR OUTAGE

Q. MR. LUKE, PLEASE DISCUSS THE COMPANY'S EXECUTION OF THE EDWARDSPORT IGCC 2020 MAJOR OUTAGE.

A. At the time of the last base rate case, Duke Energy Indiana was planning to execute its first major site outage, to occur every seven years, at Edwardsport IGCC in the spring of 2020. Due to logistical challenges caused by the COVID-19 pandemic, the outage was delayed and extended, taking place over the period May 30, 2020 to August 24, 2020. Within that time, both of the gasifiers and supporting gasification balance of plant equipment, and both combustion turbines, the steam turbine, and supporting power block balance of plant equipment received scheduled maintenance.

The primary maintenance performed on Gasifier 1 included refractory replacement in the sidewall, neck, and dome areas. On Gasifier 2 we performed refractory replacement in the cone, sidewall, neck, and dome areas. With both gasifiers offline, the station also performed necessary maintenance on the flare system, including valves, pilots, and thermocouples. Additionally, the station performed inspections on common gasification equipment, and executed routine summer reliability preparation work.

Both combustion turbines underwent major inspections, comprising inspections of the bearings, the rotor after it was removed, the fits of the blades, the turbine casing and shell, and the compressor. Additionally, each unit received a generator medium/robotic inspection, performed to inspect the generator belly bands and the generator winding without removing the rotor from the generator. Also, each heat recovery steam generator underwent inspection, along with replacement of twelve valves identified with valve seat delamination risk.

The steam turbine rotor was also removed for a major inspection, as well as inspections of the steam turbine main steam, hot reheat, and low-pressure control valves. Also, the steam turbine generator winding was inspected via removal of the generator rotor.

The duration of the outage was extended beyond the originally planned 52 days due to the extensive health and safety protocols put in place during the COVID-19 pandemic. These measures reduced labor productivity and slowed the execution of the work, but were necessary to ensure the health and safety of Duke Energy employees and our contractors. The reduced productivity did manifest in an increased cost of the outage above budget.

Q. WHAT EDWARDSPORT IGCC OUTAGE-RELATED O&M EXPENDITURES WERE EXPECTED IN 2020 AND INCLUDED IN CUSTOMER RATES?

A. The station’s 2020 outage had an O&M budget of $46.4 million. Because it did not make sense to embed this entire expense into base rates, the Company proposed, and the Commission approved, inclusion of one-seventh of the lower of the actual outage expense or the budgeted amount into its base rates in the last base rate case[3] – meaning that the Company would recover the costs of the 2020 outage over the following seven years. The intent was to recover the expense of the 2020 outage before the second seven-year major outage would occur in approximately 2027.

[3] Cause No. 45253 Order at 153.

Q. WHAT WAS THE ACTUAL O&M COST OF THE 2020 OUTAGE?

A. The final actual cost of the Edwardsport IGCC 2020 major outage was $59.5M.

Q. HAS THE COMPANY BEEN RECOVERING THE APPROVED OUTAGE-RELATED O&M EXPENDITURES FROM CUSTOMERS?

A. Yes. It is my understanding that one-seventh of the retail portion of the $46.4M budget is currently being recovered from customers annually. Company witness Ms. Lilly discusses the ratemaking associated with the Edwardsport 2020 outage cost amortization in her testimony in this proceeding.

Q. DO YOU EXPECT EDWARDSPORT WILL CONTINUE TO HAVE MAJOR OUTAGES SUCH AS THE ONE EXECUTED IN 2020 EVERY SEVEN YEARS?

A. Yes. With strong and consistent ongoing operations and dispatch, the primary maintenance interval for Edwardsport continues to track at seven years. That interval is governed predominantly by the life cycle of the combustion turbine parts. However, based on the condition of the unit in the 2020 outage, the Duke Energy Turbine Generator Services group has recommended extension of the steam turbine maintenance interval from seven years to ten years. That will reduce the scope and cost of the next seven-year major outage, tentatively planned for 2027, deferring the steam turbine expenses to a later year, likely in the 2030 timeframe in alignment with a subsequent dual gasifier outage.

Q. HAS ANY OTHER MAJOR MAINTENANCE WORK BEEN PERFORMED AT EDWARDSPORT SINCE 2020?

A. Yes. During the last base rate case, Company witness Mr. Gurganus noted that the next planned dual gasifier outage after 2020 was tentatively scheduled for 2023. That dual gasifier outage did occur in 2023. The main scope of the outage was major maintenance of the gasifiers. While the gasifiers underwent their scheduled maintenance, the power block remained in service on natural gas, providing energy and capacity to customers during the gasifier work. Each combustion turbine underwent shorter routine summer preparation outages. Additionally, as approved in Cause No. 42061 ECR 39, we took the opportunity to load catalyst for the first time into the Unit 1 Selective Catalytic Reduction ("SCR") system during its spring outage. During the 2024 spring outage, hot gas path inspections were performed on both combustion turbines as well as robotic inspections on those generators. We also performed routine gasification maintenance and loaded catalyst for the first time into the Unit 2 SCR.

Q. IS THE COMPANY PROPOSING ANY NEW SPECIAL RECOVERY OF EDWARDSPORT OUTAGE COSTS IN THIS PROCEEDING?

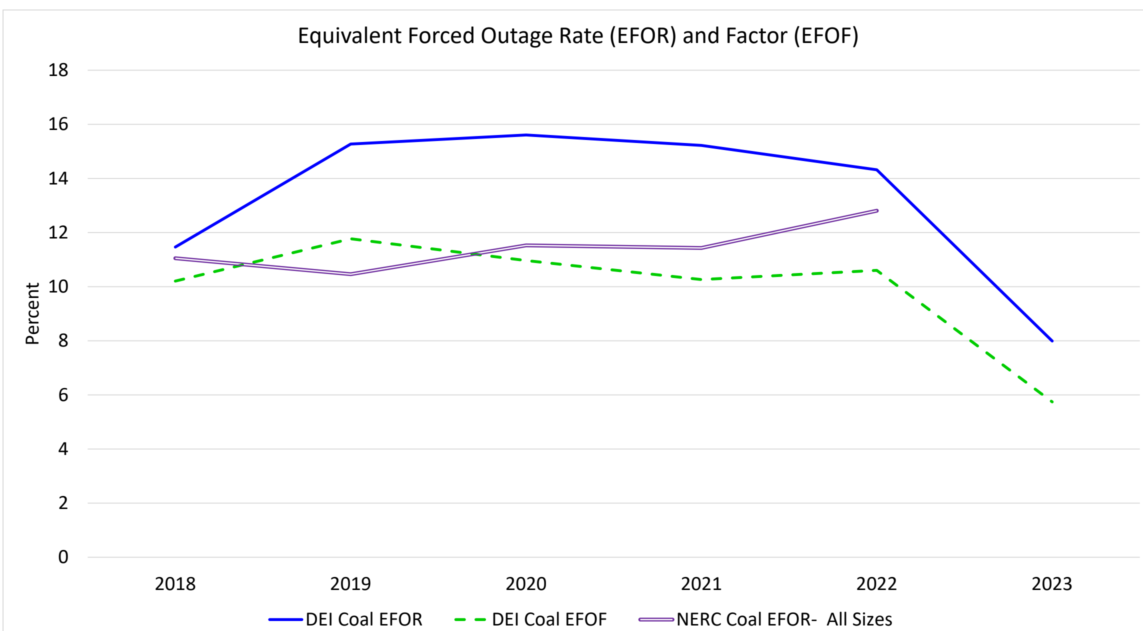
A. No. Besides the completion of the amortization of the remaining balance of the 2020 outage costs from the last base rate case as discussed by Company witness Ms. Lilly, the Company is not seeking any new special provisions for recovery specific to Edwardsport's past or future outage O&M costs in this proceeding.

IV. GENERATION PERFORMANCE

Q. PLEASE SUMMARIZE THE RECENT FORCED UNAVAILABILITY PERFORMANCE OF DUKE ENERGY INDIANA'S COAL-FIRED GENERATING UNITS.

A. The chart below provides a summary of the Equivalent Forced Outage Rate ("EFOR") and Equivalent Forced Outage Factor ("EFOF") for the Company's coal-fired units (Cayuga, Edwardsport, and Gibson), and compares it to the EFOR reported for North American Electric Reliability Corporation ("NERC") coal-fired units over the same period.[4]

Graph 1



Q. PLEASE EXPLAIN HOW EFOR AND EFOF MEASURE UNIT RELIABILITY.

[4] NERC comparison data for 2023 was not available when this testimony was filed.

A. A generating unit's EFOR is equal to the hours of unit forced unavailability (forced outage hours and equivalent forced derated hours) given as a percentage of the total hours of service plus the forced unavailability of that unit (forced outage hours and service hours). For example, if MISO anticipated a unit to run 1,000 hours in a certain year but the unit was unable to run 100 of those hours due to unexpected problems, the unit's EFOR would be 10%. A low EFOR number is desirable. However, EFOR as a metric is most informative for units that run at high-capacity factors (and hence have high service hours). EFOR is less telling on units with lower service hours, such as intermediate and peaking units. EFOR tends to be more volatile on units with low numbers of service hours in the denominator of the calculation. A single forced outage event can result in a large EFOR number, even though total unit availability may be very high. Because of this effect, and because we have been experiencing lower capacity factors on our coal-fired units in recent years, the Company is also now tracking the EFOF of the coal fleet as a metric. EFOF is similar to EFOR, except the denominator now simply contains total period hours, rather than being a function of service hours. Since period hours are constant across any given timeframe, EFOF tends to be more stable, and better reflects the underlying performance of a unit without being affected by its degree of operation. If the coal-fired units do run at high-capacity factors in any given period, EFOR and EFOF will generally converge. Therefore, tracking both metrics on the coal-fired units has improved our ability to monitor the underlying performance. Unfortunately, EFOF is not reported in the NERC Statistical Brochure, so we can only benchmark against the national average performance for EFOR.

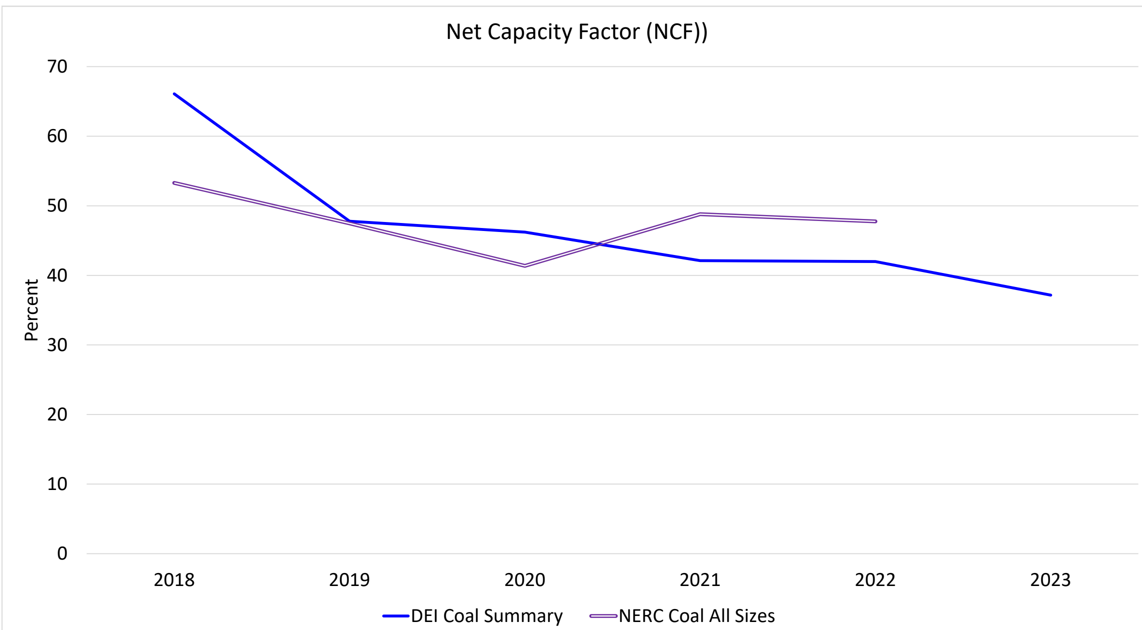
Q. IS THE EFOR FOR DUKE ENERGY INDIANA'S GENERATING UNITS IN LINE WITH INDUSTRY AVERAGES?

A. In general, yes. Duke Energy Indiana's coal unit EFOR trended higher than the NERC national average data over the period 2019-2022 but showed a material improvement in 2023. As can be interpreted from the EFOF trend, which was relatively steady over the same period, the EFOR values of the coal fleet were being more heavily influenced by declining capacity factors (and hence lower service hours in the denominator) that we were experiencing in that time frame. The EFOF demonstrates that the underlying performance of the units held fairly steady over this period. In 2023, though we experienced similar coal unit average capacity factors as in the most recent years, we realized significant improvement in underlying performance as a result of reliability plan execution during several large scheduled maintenance outages that occurred in 2022 and early 2023. That yielded material improvements in both EFOR and EFOF in 2023.

Q. PLEASE DISCUSS THE DECLINING NET CAPACITY FACTORS BEING EXPERIENCED BY DUKE ENERGY INDIANA'S COAL-FIRED GENERATING UNITS.

A. The chart below provides a summary of the net capacity factors ("NCF") for the Company's coal-fired units (Cayuga, Edwardsport, and Gibson), and compares it to the NCF reported for NERC coal-fired units over the same period.[5]

Graph 2



A generating unit's NCF is the ratio of the net electricity generated, for the time considered, to the energy that could have been generated at continuous full-power operation during the same period. A higher NCF number is desirable.

Historically, Duke Energy Indiana's coal-fired units' average NCF has run in the 60% to 70% range. The NCF of the coal-fired units began to decline noticeably in the 2019-2020 timeframe due to load demand reductions caused by the COVID-19 pandemic. To the extent Duke Energy Indiana economically

[5] NERC comparison data for 2023 was not available when this testimony was filed.

commits and dispatches its generators into MISO for the benefit of customers, lower system demands lead to lower MISO energy market prices, making it more economic for customers for the Company's generators to operate less, and instead buy more energy from the MISO market. Post-pandemic, the Company experienced load demand rebound, but became constrained on coal deliveries due to challenges in the supply chain. That constrained the coal-fired units' NCF performance moving out of 2021 into 2022. Those supply chain issues were largely resolved by early 2023. But for several large scheduled maintenance outages that occurred in 2022 and early 2023, the NCF of the coal-fired units may have been even higher. Absent significant changes in market conditions, such as changes in commodity prices or load demand, the Company anticipates more stable levels of operation of the coal-fired units through the Forward-Looking Test Period. Company witness Mr. Swez discusses economic dispatch and MISO market interactions further in his testimony in this proceeding while Company witness Mr. Verderame discusses the coal supply issues in his testimony.

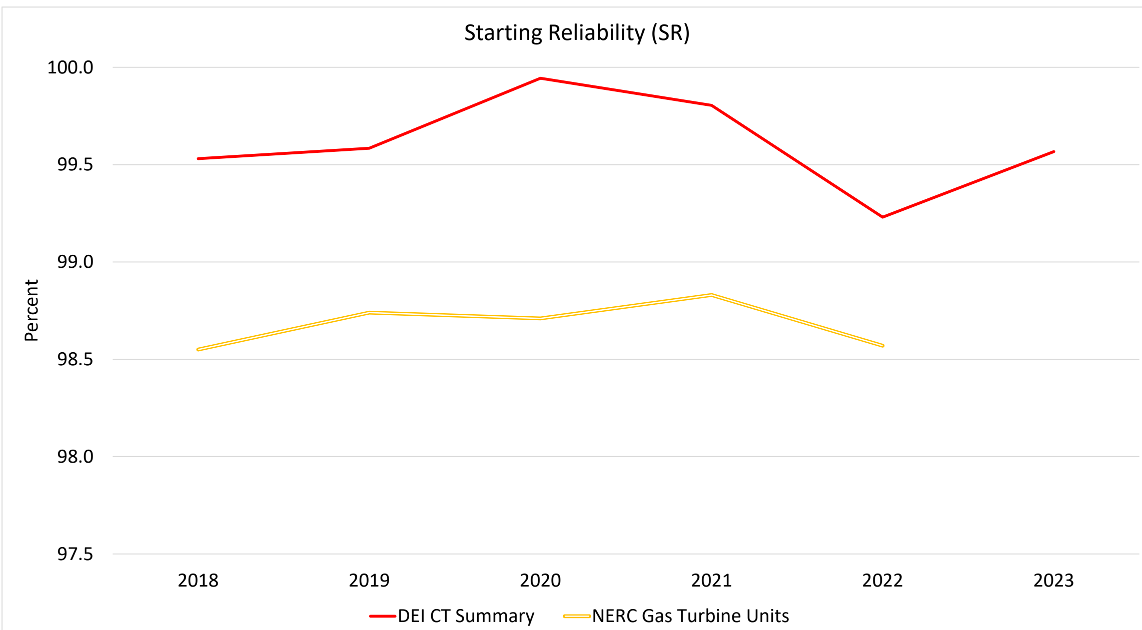
Q. IS THE NCF FOR DUKE ENERGY INDIANA'S GENERATING UNITS IN LINE WITH INDUSTRY AVERAGES?

A. Yes. The NERC coal unit national average data for the same period generally trends with the performance of the Duke Energy Indiana coal-fired units. This indicates that many units were similarly impacted by the in-bound and out-bound effects of the pandemic.

Q. PLEASE PROVIDE A COMPARISON OF THE COMPANY'S GAS TURBINES STARTING RELIABILITY WITH INDUSTRY AVERAGES.

A. The chart below provides a summary of the starting reliability of the Company's simple-cycle combustion turbine gas-fired units and compares it to the starting reliability reported for NERC gas turbine units over the same period.[6]

Graph 3



Q. PLEASE EXPLAIN HOW STARTING RELIABILITY FOR GAS UNITS MEASURES UNIT RELIABILITY.

A. As I discussed, EFOR is not an overly informative metric for units with lower service hours. Therefore, we use starting reliability as a more informative metric of peaking unit performance. After all, what really matters for peaking units is that they start-up and serve load reliably when they are needed the most. Starting

[6] NERC comparison data for 2023 was not available when this testimony was filed.

reliability is the ratio of the number of successful startups to the number of attempted startups. A startup is successful if the unit synchronizes to the grid within a certain timeframe. If the unit is unable to start (a start failure) or the startup is delayed, then the unit would be failing in its peaking duty. A high starting reliability is desirable.

Q. IS THE STARTING RELIABILITY FOR DUKE ENERGY INDIANA'S GENERATING UNITS IN LINE WITH INDUSTRY AVERAGES?

A. Yes. Duke Energy Indiana's simple cycle combustion turbine gas-fired unit starting reliability reflects performance that surpasses the starting reliability of comparable NERC combustion turbine unit data for the same time period (see Graph 3 above).

Q. PLEASE DISCUSS THE PERFORMANCE OF THE NEW PURDUE UNIVERSITY COMBINED HEAT AND POWER UNIT.

A. Since entering service in late 2021, the Purdue CHP has performed very well. The capacity factor was ramping up in the first quarter of 2022, and the unit has been running consistently high output since then. Purdue CHP has experienced only minimal forced unavailability. The following table summarizes its NCF and EFOR performance.

Table 1

	NCF	EFOR
2022	72.6%	0.93%
2023	85.3%	0.50%

Q. PLEASE DESCRIBE THE RELIABILITY OF THE COMPANY'S SOLAR GENERATING FACILITIES.

A. For our large solar generating facility Crane Solar (17 MW), the main reliability metrics tracked by the Company are energy yield, which is the percent of energy produced relative to the maximum that could have been produced, considering the actual available solar conditions (daylight hours, sun position, degree of cloudiness, etc.); inverter availability, which is tracked as either on or off during daylight hours only; and net capacity factor. The Crane solar generating facility's performance is as follows:

Table 2

	Energy Yield	Inverter Availability	NCF
2019	92.2%	98.7%	18.2%
2020	98.5%	97.6%	17.9%
2021	84.6%	93.2%	14.3%
2022	97.2%	95.4%	18.6%
2023	98.5%	98.8%	19.5%

For our remaining smaller solar generating facilities including Camp Atterbury (1.9 MW), Tippecanoe (1.6 MW), B-Line Heights (112 KW), and Blue River Solar (900 KW) the tracked reliability metric is Net Capacity Factor as shown below.

Table 3

Net Capacity Factor	2021	2022	2023
Camp Atterbury	21.5%	24.8%	12.9%
Tippecanoe	20.2%	20.2%	20.5%
Blue River	N/A	4.7%	19.7%
B-Line Heights	12.5%	13.0%	12.7%

Q. MR. LUKE, DO YOU EXPECT THE COMPANY'S RELIABILITY METRICS TO REMAIN IN LINE WITH INDUSTRY AVERAGES?

A. Yes, I do. Duke Energy Indiana intends to operate its generating stations in a safe, reliable, and environmentally compliant manner. The ongoing execution of scheduled planned outages helps sustain reliability performance, and controlling variable costs will allow our units to remain competitive in the market, helping to maintain capacity factors.

V. PRODUCTION O&M AND CAPITAL EXPENDITURES

Q. WHAT LEVEL OF OVERALL POWER PRODUCTION O&M AND CAPITAL EXPENDITURES ARE REFLECTED IN THE TEST PERIOD?

A. Duke Energy Indiana's Test Period Power Production O&M and Capital Expenditures are forecasted at $269 million and $198 million, respectively.

Q. ARE YOU SPONSORING THE POWER PRODUCTION O&M AND CAPITAL EXPENDITURES IN THIS FORECAST?

A. Yes. I am sponsoring a portion of the Power Production O&M and Capital Expenditures in this forecast. Company witness Mr. Hill will also be sponsoring a portion of the Power Production O&M and Capital Expenditures forecasts, as it relates directly to his testimony. Please see the tables below for a split of the Test Period Power Production O&M and Capital Expenditures.

Table 4a

Function	O&M Expenditures
Steam Production Plant	$246
Hydro Plant	$2
Other Production Plant	$21
Total (*$ in Millions*)	**$269**

Table 4b

Function	Capital Expenditures
Steam Production Plant	$88
Other Production Plant	$90
General Plant	$20
Total (*$ in Millions*)	**$198**

Q. HOW DOES THE 2025 TEST PERIOD POWER PRODUCTION CAPITAL EXPENDITURES FORECAST COMPARE TO THE 2024 POWER PRODUCTION CAPITAL EXPENDITURES FORECAST AND THE BASE PERIOD ACTUAL POWER PRODUCTION CAPITAL EXPENDITURES?

A. First, as discussed by Company witness Mr. Rutledge, the pertinent historical base reference period is the twelve months ending August of 2023 (“Base Period”). I will present the actual Power Production capital and O&M expenditures from that time period. The forecast for 2024 and the 2025 Test Period are then presented for those calendar years. With that basis established, a comparison of the 2025 Test Period Power Production Capital expenditures to the 2024 Forecast and Base Period Actual Power Production Capital Expenditures is shown in the table below.

Table 5

$ in Millions	**9/2022 - 8/2023 Actual**	**2024 Forecast**	**2025 Forecast**
Power Production Capital Expenditures	$288	$216	$198
YoY Increase / (Decrease)		($72)	($18)

Q. PLEASE DESCRIBE THE MAJOR CHANGES BETWEEN THE BASE PERIOD ACTUAL, 2024 FORECAST, AND 2025 TEST PERIOD POWER PRODUCTION CAPITAL EXPENDITURES, INCLUDING ANY MAJOR ASSUMPTIONS UTILIZED TO ARRIVE AT THE 2025 TEST PERIOD FORECAST.

A. Capital expenditures vary year to year depending on the number of planned outages and equipment maintenance cycles. Referring to Table 5, the major changes between the Base Period Actual and the 2025 Test Period are the completion of larger scale outages at Edwardsport and Gibson during 2023. Over 2024 and 2025, specific work includes Edwardsport Unit 1 and Unit 2 and Wheatland Unit 4 hot gas path inspections, Cayuga Unit 2 High Pressure and Intermediate Pressure ("HP/IP") Steam Turbine, and Noblesville Unit 1 and Unit

2 High Pressure and Low Pressure ("HP/LP") Steam Turbine Blade Replacements.

Q. PLEASE IDENTIFY THE CAPITAL EXPENDITURES THAT ARE INCLUDED IN THE COMPANY'S POWER PRODUCTION 2024 FORECAST AND 2025 TEST PERIOD FORECAST FROM JANUARY 1, 2024 TO DECEMBER 31, 2025 GREATER THAN $4 MILLION.

A. There are many different capital projects to be completed in 2024 and 2025. Those Power Production projects that involve capital expenditures greater than $4 million include the following:

Table 6

Station	Project	2024 & 2025
Cayuga	Unit 2 Steam Turbine HP/IP Blade Replacement	$ 5
Edwardsport	Unit 1 CT Hot Gas Path Inspection 2	$ 17
	Unit 2 CT Hot Gas Path Inspection 2	$ 17
Gibson	Unit 1 Boiler Platen Superheat Tube Replacement	$ 12
	Unit 2 Boiler Front Wall Tube Panel Replacement	$ 5
Madison	Unit 1 CT Major Inspection	$ 8
	Unit 2 CT Major Inspection	$ 8
	Unit 4 CT Major Inspection	$ 8
	Unit 8 CT Major Inspection	$ 8
Noblesville CT	Unit 1 Steam Turbine HP/LP Blade Replacement	$ 6
	Unit 2 Steam Turbine HP/LP Blade Replacement	$ 6
Wheatland CT	Unit 4 CT Hot Gas Path Inspection 1	$ 16

Q. PLEASE DESCRIBE THE PROJECTS LISTED ABOVE.

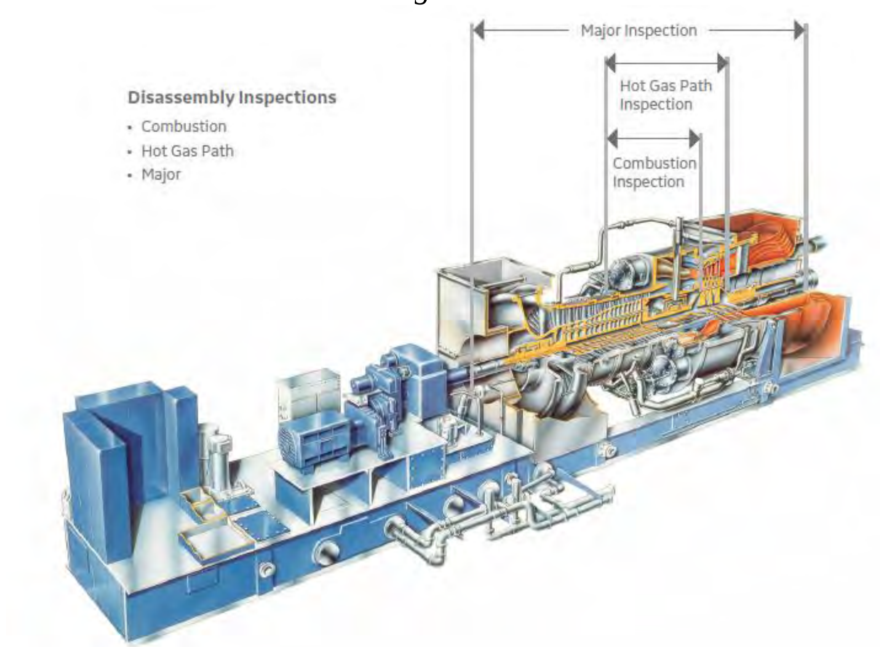
A. These projects are categorized into three main groups; (1) combustion turbine inspections, (2) steam turbine blade projects, and (3) boiler projects.

The first group are combustion turbine inspections based on the original equipment manufacturers ("OEM") recommendations, industry standards and internal engineering assessments. These inspections are essential to maintain both efficiency and reliability of the units. Utilization of the combustion turbines has increased over the last several years due to increasing availability of natural gas supply and market economics, accelerating required maintenance intervals.

There are three notable maintenance events associated with these machines. The most frequent are combustion inspections which involve replacement of the combustion components which have a tendency to wear out the quickest. Next frequent is hot gas path inspections which includes replacing worn turbine components such as blade rows and shrouds. A combustion inspection is typically included in this inspection. Least frequent but most significant are the "Major" inspections which includes replacement of worn compressor components. In addition, this "Major" inspection typically includes the two aforementioned inspections of the combustion and turbine components. All of these inspections are scheduled and performed based on OEM recommendations, industry standards and internal engineering assessments including number of operating hours and starts.

Even though it is industry standard terminology to call these maintenance events "inspections," the OEM-recommended work scope always includes assumed replacement of capital components such as turbine blade/compressor rows and/or combustion components. Final costs for these types of projects can vary from budgeted amounts because the extent of the work is not fully known until the machines are disassembled. Please see the diagram below which is representative of areas addressed by each maintenance event. Without routine inspection and replacement, the stationary and rotating parts of the CT will deteriorate, resulting in loss of efficiency and increased risk of catastrophic mechanical failure.

Figure 1[7]



Similar to the combustion turbine inspections, there are three steam turbine blade projects being executed in this timeframe to note. At both Noblesville and Cayuga Stations, prior inspections of the steam turbines indicate the need for component replacement. The inspections and subsequent

[7] © General Electric Company. Reprinted with Permission from Heavy-Duty Gas Turbine Operating and Maintenance Considerations GER-3620N (10/17) by GE Power, Atlanta, GA for the sole purpose of Duke Energy Indiana Rate Case direct testimony of Mr. William C. Luke submitted as part of a public proceeding to the Indiana Utility Regulatory Commission (IURC).

recommendations to replace specific components are based on internal, industry, and OEM guidance. At Cayuga, the scope includes the high-pressure and intermediate pressure turbine blade replacement, and at Noblesville, the high-pressure and low-pressure blades will be replaced. The need to replace these components is driven by the number of unit starts, services hours, and evaluation of ongoing inspection data.

Lastly there at two boiler projects at Gibson Station to note. Boilers historically can be the highest reliability degrader. These boilers are supercritical and operate above 3,000 PSI pressure. Over the course of time, boiler tubes are subject to normal wear and thinning due to the abrasive properties of the coal, and the corrosive/erosive environment they are subject to inside the boiler. Replacement of these components is based on routine inspections, engineering assessments and reliability impacts to reduce future unplanned forced outages.

Q. IS THE AMOUNT OF CAPITAL TO BE INVESTED IN DUKE ENERGY INDIANA'S GENERATION FLEET REASONABLE AND NECESSARY?

A. Yes. Generating units and their individual components can deteriorate, fail, become obsolete or require additional investment and must be replaced or repaired to maintain safe, reliable, efficient, environmentally compliant service. Additionally, capital investment must be made in response to evolving environmental, safety and regulatory requirements. The amount of investment to be made in 2024 and 2025 represents an appropriate amount based upon the needs of the generating stations to maintain reasonable levels of service.

Q. PLEASE DISCUSS HOW YOU PLAN TO MANAGE MAINTENANCE EXPENSE AND RELIABILITY AS THE GENERATING UNITS APPROACH THEIR RETIREMENT DATES?

A. In its last base rate case, Duke Energy Indiana signaled its first step in a new and significant fleet transition plan, as discussed in detail by Company witness Mr. Pike in that proceeding. That plan was underpinned by a logical reordering and strategic acceleration of planned coal unit retirement dates, as presented in the 2018 Duke Energy Indiana Integrated Resource Plan ("IRP"). Since then, five years have passed, drawing us ever closer to those unit retirements. As units approach their retirement dates, within a given maintenance cycle, the value of any needed maintenance investment is evaluated with consideration of the remaining life of the asset. However, because a unit's capacity value is committed to MISO, of which reliability is a component, the type and amount of maintenance funding is balanced with reliability needs until the unit's last day of operation; with the expectation that safe and compliant operation of a unit is sustained.

As always, good utility engineering and operating practice will continue to guide our behaviors. For example, because of its age and condition, the Gibson Unit 5 flue gas desulfurization ("FGD") system requires ongoing maintenance to ensure stack emissions compliance. With our latest plan to continue to operate Gibson Unit 5 into the 2030 timeframe, we are planning a material maintenance investment in the Gibson Unit 5 FGD in 2025, as that is needed to maintain safe and compliant ongoing operations. Also, Cayuga Unit 2 is currently planned to retire in the 2028-2029 timeframe. However, the maintenance interval on the high HP/IP steam turbine calls for inspection before then. Therefore, we are planning to perform an HP/IP turbine major outage on Cayuga Unit 2 in 2025, as I discussed previously. The HP/IP turbine on Cayuga Unit 1 was similarly inspected in 2022. Additionally, we are planning some boiler tube maintenance on Cayuga Unit 1 in 2024 to alleviate an escalating tube leak issue that needs to be addressed to ensure reliable operation to its planned 2028 retirement date. These are just a few examples of critical maintenance needed for reliability that we are conducting, as governed by condition and/or good utility engineering and operating practice and maintenance intervals, even as these units are approaching their planned retirement dates.

Q. ARE THERE ANY NEW SIGNIFICANT CHANGES IN EXPECTED COAL UNIT RETIREMENT DATES SINCE THE LAST BASE RATE CASE?

A. Yes, but only for Gibson Unit 5. Relative to the degree of changes in planned retirement dates presented in the 2018 Duke Energy Indiana IRP, the 2021 Duke Energy Indiana IRP (taking into account some updated information that impacted the 2021 IRP) yielded fewer changes. For Gibson Station, the planned retirement dates for Gibson Units 1-4 further accelerated slightly in the latest modeling (Gibson Units 1 and 2 from 2038 to 2035, and Gibson Units 3 and 4 from 2034 to the 2031 timeframe), but remain further out in time relative to our near-term maintenance plan. Gibson Units 1 and 2 should experience at least one more full normal maintenance cycle out to 2035. Gibson Units 3 and 4 both underwent major outages in 2023, including an HP/IP turbine major inspection on Unit 4; the Unit 3 HP/IP turbine was last inspected in 2015. Gibson Unit 4 is well positioned for an early 2030s retirement within its current major maintenance cycle, and we will monitor the ongoing accumulation of service time on the Gibson Unit 3 HP/IP turbine and make a determination in the future as to whether another major inspection will be needed before its retirement date.

For Cayuga Units 1 and 2, the plan remains essentially the same with Cayuga Unit 1 remaining on schedule for an end of May 2028 retirement. However, we are showing Cayuga Unit 2 with a May 2029 retirement date now (delayed one year from the prior expectation) to ensure the availability of capacity and energy for system reliability. It is my understanding that the Company is assessing the potential replacement generation for Cayuga Unit 2 in its 2024 IRP. To the extent replacement generation can be available sooner, we will coordinate the retirement of Cayuga Unit 2 with that earlier date. Performance of the Cayuga Unit 2 HP/IP turbine major inspection in 2025 is necessary in either case.

Attachment 17-B (WCL) summarizes the updated generating unit retirement dates proposed by the Company. Company witness Ms. Graft discusses dates used for depreciation purposes in this proceeding. Please see Company witness Mr. Spanos for the depreciation study.

VI. POWER PRODUCTION O&M

Q. HOW DOES THE 2025 TEST PERIOD POWER PRODUCTION O&M FORECAST COMPARE TO THE 2024 POWER PRODUCTION O&M FORECAST AND THE BASE PERIOD ACTUAL POWER PRODUCTION O&M EXPENDITURES?

A. A comparison of the 2025 Test Period Power Production O&M expenses to the 2024 Forecast and Base Period Actual Power Production O&M expenses is shown in the table below.

Table 7

$ in Millions	9/2022 - 8/2023 Actual	2024 Forecast	2025 Forecast
Power Production O&M	$263	$254	$269
YoY Increase / (Decrease)		($9)	$15

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S MAIN COMPONENTS OF O&M EXPENSES.

A. Fuel cost is a primary component of ongoing O&M for the generation fleet. The testimony of Company witness Mr. Verderame describes the Company's fuel expense, fuel inventory, and fuel purchasing strategy. Non-fuel O&M, outage costs, and non-outage maintenance costs are other main components, which I will discuss below.

Q. WHAT IS NON-FUEL POWER PRODUCTION O&M EXPENSE?

A. Non-fuel O&M expense generally includes the cost associated with the operation, maintenance, administration and support of Duke Energy Indiana's generating units. These costs exclude fuel (which is discussed in Mr. Verderame's testimony), but include labor, materials and supplies, contractor services, process chemicals and reagents, and other miscellaneous expenses for Duke Energy Indiana's generating units.

Q. HOW IS THE TOTAL AMOUNT OF POWER PRODUCTION NON-FUEL O&M DETERMINED?

A. Duke Energy Indiana generally develops its O&M forecast based on the costs necessary to operate and maintain its generating units. Ongoing operations typically include expenses associated with labor (including Company employees and contractors that are required to operate the plants 24 hours a day, seven days a week, as well as the management teams, engineers, maintenance personnel, instrument technicians, electricians, mechanics, etc.); fringe benefits; consumable materials; process chemicals and reagents; mandated fees; and other ongoing expenses. O&M also includes the expense associated with scheduled outages and maintenance at the Company's generating stations. Incremental needs are also evaluated by Duke Energy management, and the available resources are allocated in order of greatest operational benefit.

Q. WHAT ARE THE NON-FUEL O&M EXPENSES FOR THE BASE PERIOD ACTUAL, 2024 FORECAST, AND 2025 TEST PERIOD FORECAST YOU ARE SUPPORTING IN THIS PROCEEDING?

A. Following is a chart showing the O&M from the Base Period, 2024 Forecast, and the 2025 Test Period, separated into outage and non-outage expenses.

Table 8

$ in Millions	9/2022 – 8/2023 Actual	2024 Forecast	2025 Forecast
Non-Outage O&M	$213	$220	$216
YoY Increase / (Decrease)		$7	($4)
Outage O&M	$50	$34	$53
YoY Increase / (Decrease)		($16)	$19
Power Production O&M Total	$263	$254	$269

Q. PLEASE DESCRIBE THE NON-OUTAGE AND OUTAGE POWER PRODUCTION O&M EXPENSE.

A. Non-outage O&M expenses are generally incurred on an ongoing basis. Outage O&M expenses, however, are generally incurred only periodically based the maintenance cycle of the units.

Q. IS THERE A DIFFERENCE BETWEEN THE NON-FUEL POWER PRODUCTION NON-OUTAGE O&M FOR THE BASE PERIOD ACTUAL, 2024 FORECAST, AND 2025 TEST PERIOD FORECAST?

A. Yes. However, the non-outage O&M for the Base Period Actual, 2024 Forecast and 2025 Test Period Forecast is very similar. Inflationary and cost of service increases are partially offset through ongoing cost savings opportunities.

Q. PLEASE DESCRIBE THE NON-FUEL POWER PRODUCTION OUTAGE O&M EXPENSES FOR THE BASE PERIOD ACTUAL, 2024 FORECAST AND 2025 TEST PERIOD FORECAST?

A. Each of Duke Energy Indiana's generating stations has cyclical maintenance and we attempt to schedule that maintenance to occur during off-peak times of the year, and to stagger the outages to prevent the majority of our units from being out for scheduled maintenance at the same time. Previously, predominantly due to past environmental control retrofit tie-in outages, our major outages on the coal units have been compacted together. While, we have been making progress towards re-levelizing the outage schedule, to some extent, taking advantage of lower capacity factors in recent years to extend some maintenance intervals, we continue to see ebb and flow in coal unit planned outage intensity from year to year. Additionally, we are entering a period of more major maintenance outages on the combustion turbine units. Since most of the combustion turbine units were constructed and entered service in the early 2000s, and operate similarly, we tend to see their major maintenance come due around the same time. We try to stagger that maintenance so that only one or two units per facility are in outage in any given outage season. With that, while calendar year 2023 was near-normal in terms of long term average planned outage O&M expense, 2024 is forecast to be a below average year, and 2025 is forecast to be well above average. Table 9 shows the five year trend in planned outage O&M expenses, since the last rate case.

Table 9: Planned Outage O&M Since the Last Rate Case, with 2024 and 2025 Forecast

2021	$34,084,689
2022	$45,592,562
2023	$44,439,847
2024	$33,501,876
2025	$52,739,277
5-Year Average	$42,071,650

Q. IS THE COMPANY PROPOSING ANY SPECIAL CONSIDERATIONS WITH RESPECT TO PLANNED OUTAGE O&M EXPENSES?

A. Yes. Given that 2025 is forecasted to be an above average year for planned outage O&M expenses, the Company is proposing to include a pro-forma adjustment to the 2025 Test Period Forecast O&M expenses to reflect the 2021-2025 5-year average planned outage O&M expense instead. That adjustment is the 5-year average expense of $42.07M, minus the 2025 Test Period Forecast planned outage O&M expense of $52.74M, for a negative adjustment (a reduction) to the 2025 Test Period Forecast of $10.67M. Company witness Ms. Graft addresses this adjustment further in her testimony.

Q. ARE PROCESS CHEMICALS AND REAGENTS INCLUDED IN THE BASE COST OF POWER PRODUCTION O&M?

A. Yes, process chemicals and reagents are included in the base cost of operations.

Q. PLEASE DESCRIBE THE PROCESS CHEMICALS AND REAGENTS USED BY THE COMPANY?

A. Process chemicals and reagents vary in chemical formulation, function, and frequency or degree of usage. Often, a specific chemical formulation from a specific vendor may be discontinued or become more expensive, and the Company may substitute for it a different product from the same or different vendor, but of the same fundamental function. For example, recently the Company has tested the use of lactic acid as the scrubber additive for sulfur dioxide (SO_2) removal on Gibson Unit 5, in lieu of the chemical sodium formate;

so, a different chemical name, but the exact same function and purpose. Some process chemicals and reagents are only used periodically, such as ammonia in the Cayuga Station SCRs, which are only operated for nitrogen oxide (NOx) control during the five-month ozone season. Still other chemicals, such as the Selexol used at Edwardsport to remove sulfur in the acid gas removal system, are separated from their target pollutant and recycled for continued use, and hence only require replenishment. The following table lists the various general process chemicals and reagents used in the generating stations for environmental control, based on the types and quantities included in the 2025 Forward-Looking Test Period Forecast:

Table 10

Reagent	Use
Limestone	SO_2 removal in scrubbers (Cayuga, Gibson)
Selexol	Sulfur removal (Edwardsport)
Pulverized limestone	Additive for arsenic mitigation of SCR catalyst
Lime (or quicklime)	Scrubber and fly ash waste fixation
Hydrated lime	Sulfuric acid mist mitigation (Cayuga)
Sodium bi-sulfate/Soda ash	Sulfuric acid mist mitigation (Gibson)
Ammonia	NOx removal in SCRs
Sodium formate	Scrubber additive for SO_2 removal (Gibson 5)
Mercury re-emission chemical	Scrubber additive for mercury re-emission mitigation
Mercury oxidation chemical	Additive for enhanced mercury oxidation

Q. PLEASE EXPLAIN THE VARIABILITY IN PROCESS CHEMICALS AND REAGENT EXPENSES NECESSARY TO OPERATE THE

COMPANY'S GENERATING STATIONS IN COMPLIANCE WITH ENVIRONMENTAL REGULATIONS.

A. Just like fuel cost, the cost of consumption of these various environmental control process chemicals and reagents varies directly with generation output of the units. The more coal is consumed, the more limestone is needed to remove SO_2 in the scrubbers, the more ammonia is needed to remove NOx in the SCRs, the more quicklime is needed to fixate FGD waste product, and so on. Because of this variability, we include process chemicals and environmental control reagent costs as variable costs in our MISO offers. But even beyond variation with generation, process chemical and reagent consumption rates also vary with coal quality. For example, coals with higher sulfur contents require more limestone usage in the scrubbers. Also, the commodity and delivery transportation prices of the process chemicals and reagents themselves can show volatility. Ammonia prices, for example, can increase significantly during farming season. Delivery costs can also move with the cost of oil, due to the fuel cost of transportation.

Q. HOW DOES THE COMPANY PROPOSE TO MANAGE THE VARIABLE NATURE OF THESE PROCESS CHEMICALS AND REAGENTS?

A. As the Commission approved in the Company's last base rate case,[8] the Company is proposing to continue to build into its base rates a representative level of cost, and then track the actual expense, both up and down, through the Company's Environmental Cost Recovery ("ECR") Rider 62. Company witness Ms. Lilly

[8] 45253 Order at 140.

discusses this further. The fundamental variable nature of these expenditures has not changed in the last five years. In fact, in the last base rate case, the Company placed $48.5M per year of reagent expense into base rates based on its 2020 forecast, but through the use of the tracking mechanism has credited retail customers on average $18.1M per year up through December 2023. Clearly, customers have benefited from the tracking of these variable costs in this time of declining coal-fired unit capacity factors that we have recently experienced. Just as fuel expense is treated through the FAC, process chemical and reagent usage is heavily dependent on generation levels. Therefore, the Company is proposing to continue to treat them in the same manner.

VII. INVENTORY LEVELS

Q. PLEASE DESCRIBE THE MATERIALS AND SUPPLIES THE COMPANY KEEPS AS INVENTORY FOR ITS GENERATING STATIONS.

A. Materials and supplies inventory consists of items that are required to maintain the generating stations' equipment in a safe and reliable manner. That may include spare parts (ranging from nuts-and-bolts to pumps, motors, piping and tubing, values, turbine and compressor blades, burners, wire, measurement instruments, computer cards, etc.) and other products such as cleaning agents and refractory. Other common items in inventory include personnel health and safety products, such as hard hats, respirators, and arc-flash protective clothing. Inventory is required to be on site for rapid response, due to lead times of materials based on vendor availability, domestic and foreign supplier fabrication, shipping, handling, and freight which can be associated with repair or replacement of critical plant equipment. The amount of production inventory included in the 2025 Test Period Forecast is $251.9M.

Q. IS THIS LEVEL OF INVENTORY REASONABLE AND NECESSARY FOR THE OPERATION OF THE GENERATING STATIONS?

A. Yes, it is. It is critical that we have replacement parts available for unplanned maintenance and planned maintenance work. Many of our vendors are overseas and lead times are longer. Additionally, requesting on demand material and supplies when they are needed would likely add increased cost. So, to be ready to provide reliable service, we need spare parts on hand. The level of inventory we target to carry has worked well to ensure we can timely repair and replace worn or broken materials and supplies.

Q. WAS THERE A REMAINING MATERIALS AND SUPPLIES INVENTORY LEVEL AT GALLAGHER STATION WHEN UNITS 2 AND 4 RETIRED IN 2021?

A. Yes. We continued to carry a reasonable and necessary spare parts inventory at Gallagher Station up until its retirement in 2021.

Q. WHAT WAS DONE WITH THE GALLAGHER STATION REMAINING INVENTORY LEADING UP TO AND AFTER UNITS 2 AND 4 RETIRED?

A. Leading up to the Gallagher Units 2 and 4 retirements, we sought to consume as much inventory as practical at the station. That predominantly addressed chemicals and other such materials that are consumed as the units would operate. However, as I mentioned earlier, depleting those materials perfectly was challenged by the limited operating time of the Gallagher units in the years leading up to retirement. As the retirement date drew closer and after the actual retirement, we assessed the remaining inventory, and relocated common consumable items (standard nuts-and-bolts type items) to other generating facilities. That then predominantly left spare parts specific to the Gallagher Units themselves. To the extent there are no units left in service in the entire Duke Energy system similar to Gallagher, we attempted to market these parts to the broader utility industry. However, similarly, the industry demand for parts for units such as this is also quite limited. We were mainly successful in marketing general high-value metals items, such as stainless-steel boiler tubes and copper generator windings.

Q. WHAT VALUE OF GALLAGHER STATION INVENTORY REMAINED AFTER THE COMPANY'S EFFORTS TO REUSE OR MONETIZE IT?

A. After the Company's concerted efforts to minimize the remaining inventory from Gallagher Station, there was approximately $7.6M of value left unmonetized.

Q. WHAT REGULATORY TREATMENT IS THE COMPANY REQUESTING FOR THIS REMAINING GALLAGHER STATION INVENTORY?

A. Consistent with the Commission's order in the last rate case,[9] the Company placed the remaining Gallagher Station inventory into a regulatory asset. The Company undertook reasonable and concerted actions to minimize this remaining inventory amount and is requesting to amortize this regulatory asset in rates. Company witness Ms. Lilly discusses this treatment in more detail in her testimony in this proceeding.

Q. DID YOU PROVIDE THE 2025 POWER PRODUCTION O&M AND CAPITAL EXPENDITURES REFLECTED ABOVE, TO COMPANY WITNESS MR. RUTLEDGE FOR INCLUSION IN THE COMPANY'S TEST PERIOD FOR THIS PROCEEDING?

A. Yes.

VIII. GIBSON UNIT 5

Q. HAS DUKE ENERGY INDIANA CHANGED ITS RETIREMENT PLAN FOR GIBSON UNIT 5 SINCE THE LAST RATE CASE?

A. Yes. While the Company had previously been planning to retire Gibson Unit 5 in either the 2025 or 2026 timeframe, due to some changes in circumstances, Duke Energy Indiana is currently planning to operate Gibson Unit 5 until the 2030 timeframe.

First and foremost, it is important to note that Gibson Unit 5 is jointly owned with Wabash Valley Power Alliance ("WVPA") and the Indiana Municipal Power Agency ("IMPA"). Duke Energy Indiana owns 50.05% of the

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[9] Cause No. 45253 Order at 91.

unit, WVPA 25.00%, and IMPA 24.95% (separately, “Owner”, or all together, the “Joint Owners”). Each Owner is entitled to its ownership share of the capacity and energy output of the unit, while also responsible for its ownership share of the costs of the unit. As majority Owner, Duke Energy Indiana has generally governed the maintenance decisions for the unit. However, under the Joint Ownership Agreement, all three Joint Owners must unanimously agree to cease operations. Therefore, all three Joint Owners must be ready and willing to take this action, and getting to that readiness requires significant cooperation and planning among the Joint Owners.

Second, as discussed by Company witness Mr. Swez, the transition to the MISO SAC construct and other ongoing capacity auction redesign work currently underway at MISO have already caused Duke Energy Indiana to become shorter in capacity, prompting Duke Energy Indiana to make significant capacity purchases in recent years. Duke Energy Indiana reasonably believes that continued operation of Gibson Unit 5 is prudent in the short term to promote reliability in balancing supply and demand on the system for the benefit of customers.

Q. AT THIS POINT, WHEN DOES THE COMPANY EXPECT GIBSON UNIT 5 TO RETIRE?

A. Based on our discussions with the Joint Owners, the Company currently expects Gibson Unit 5 to operate past 2026, likely until 2030. However, any one of the three Joint Owners could require ongoing operations based on customer need. We will continue to cooperate and find a balance that works for everyone. Therefore, for purposes of depreciation in this proceeding, the Company is proposing to use a date of May 2030, as the current best estimate of the retirement of Gibson Unit 5. This represents a balance of these risks and constraints.

Q. DO YOU CONSIDER THE COMPANY'S STRATEGY TO MAINTAIN GIBSON UNIT 5 IN SERVICE PAST 2026 TO BE REASONABLE?

A. Yes, I do.

IX. CONCLUSION

Q. WERE ATTACHMENTS 17-A (WCL) AND 17-B (WCL) PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

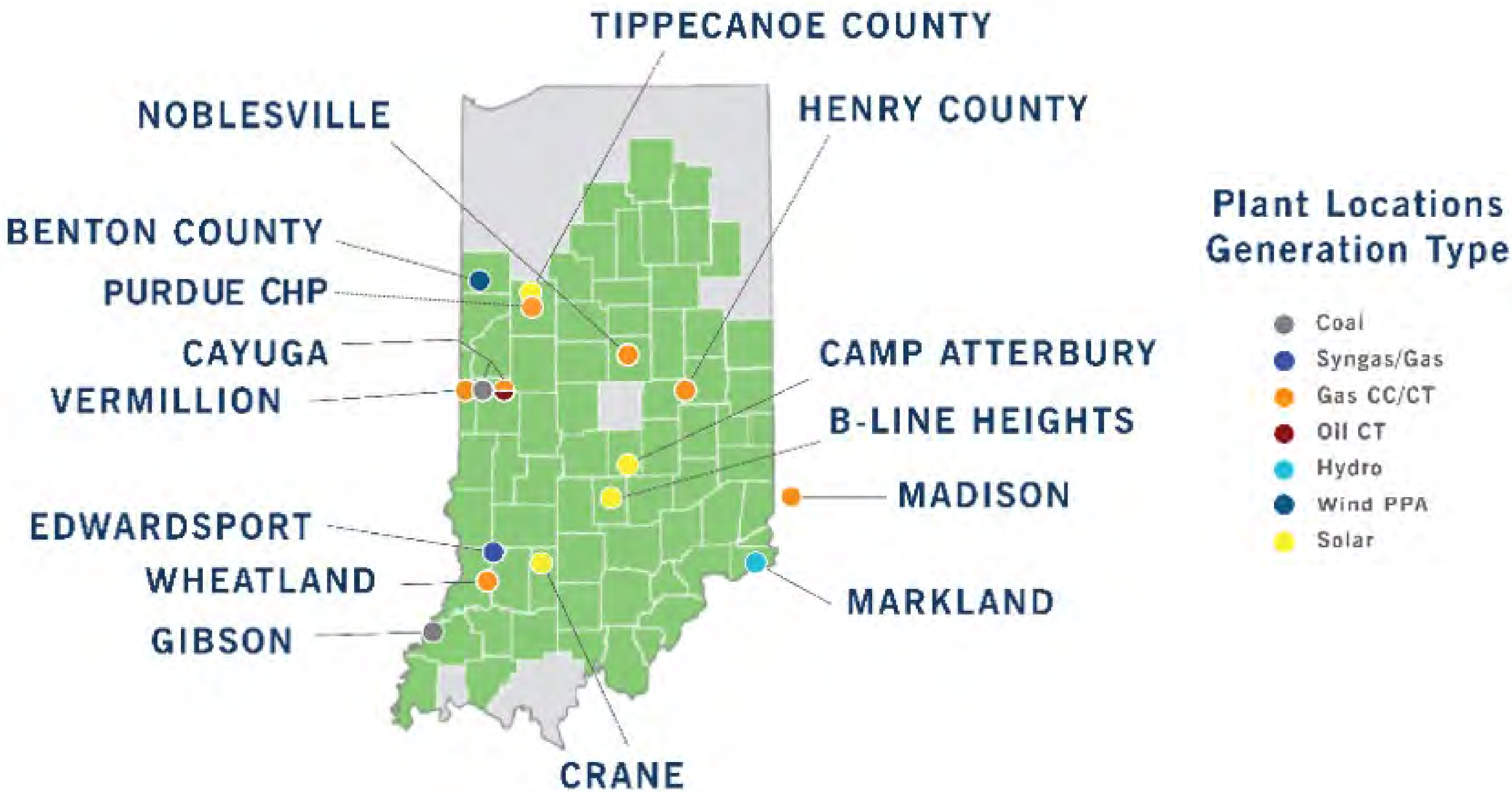
A. Yes, it does.

Cause No. 46038

VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: ______________________ Dated: April 4, 2024
William C. Luke


TIPPECANOE COUNTY
NOBLESVILLE
HENRY COUNTY
BENTON COUNTY
PURDUE CHP
CAYUGA
VERMILLION
CAMP ATTERBURY
B-LINE HEIGHTS
MADISON
EDWARDSPORT
WHEATLAND
GIBSON
MARKLAND
CRANE
Plant Locations
Generation Type
Coal
Syngas/Gas
Gas CC/CT
Oil CT
Hydro
Wind PPA
Solar

Remaining Life As Of 3/28/2024

			2019 Rate Case Cause 45253			2024 Rate Case		
Unit	**Type**	**In Service Date**	**Assumed * Retire Date**	**Age at Retirement**	**Remaining Life**	**Assumed * Retire Date**	**Age at Retirement**	**Remaining Life**
Cayuga 1	Coal	10/4/1970	5/31/2028	57.7	4.2	5/31/2028	57.7	4.2
Cayuga 2	Coal	6/22/1972	5/31/2028	55.9	4.2	5/31/2029	56.9	5.2
Edwardsport IGCC	Syngas CC	6/7/2013	5/31/2045	32.0	21.2	5/31/2045	32.0	21.2
Gibson 1	Coal	5/3/1976	5/31/2038	62.1	14.2	5/31/2035	59.1	11.2
Gibson 2	Coal	4/16/1975	5/31/2038	63.1	14.2	5/31/2035	60.1	11.2
Gibson 3	Coal	3/28/1978	5/31/2034	56.2	10.2	5/31/2031	53.2	7.2
Gibson 4	Coal	3/27/1979	5/31/2034	55.2	10.2	5/31/2031	52.2	7.2
Gibson 5	Coal	10/1/1982	5/31/2026	43.7	2.2	5/31/2030	47.7	6.2
Noblesville ST 1-2	CC	1/1/1950	5/31/2034	84.4	10.2	5/31/2035	85.4	11.2
Noblesville CT3-5	CT	4/1/2003	5/31/2034	31.2	10.2	5/31/2035	32.2	11.2
Purdue CHP	CT	12/10/2021				3/16/2057	35.3	33.0
Cayuga CT4	CT	6/29/1993	5/31/2028	34.9	4.2	5/31/2036	42.9	12.2
Cayuga Diesel 3a-d	IC	6/1/1972	5/31/2028	56.0	4.2	5/31/2029	57.0	5.2
Henry County CT1	CT	7/31/2001	5/31/2038	36.8	14.2	5/31/2038	36.8	14.2
Henry County CT2	CT	8/11/2001	5/31/2038	36.8	14.2	5/31/2038	36.8	14.2
Henry County CT3	CT	8/25/2001	5/31/2038	36.8	14.2	5/31/2038	36.8	14.2
Madison CT1	CT	5/29/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT2	CT	5/29/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT3	CT	5/29/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT4	CT	5/29/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT5	CT	6/15/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT6	CT	6/29/2000	5/31/2041	40.9	17.2	5/31/2041	40.9	17.2
Madison CT7	CT	6/15/2000	5/31/2041	41.0	17.2	5/31/2041	41.0	17.2
Madison CT8	CT	6/29/2000	5/31/2041	40.9	17.2	5/31/2041	40.9	17.2
Vermillion CT1	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT2	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT3	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT4	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT5	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT6	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT7	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Vermillion CT8	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Wheatland CT1	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Wheatland CT2	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Wheatland CT3	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Wheatland CT4	CT	6/1/2000	5/31/2043	43.0	19.2	5/31/2043	43.0	19.2
Markland 1-3	Hydro	1/1/1967	4/30/2061	94.3	37.1	4/30/2061	94.3	37.1
Crane	Solar	1/31/2017	5/31/2047	30.3	23.2	5/31/2047	30.3	23.2
B-Line Heights Solar	Solar	11/19/2019				5/31/2050	30.5	26.2
Tippecanoe Solar	Solar	12/18/2019				5/31/2050	30.5	26.2
Camp Atterbury Microg	Solar+Stor	11/22/2019	5/31/2045	25.5	21.2	5/31/2045	25.5	21.2
Nabb Battery	Storage	12/21/2020				5/31/2046	25.4	22.2
Crane Battery	Storage	12/22/2020				5/31/2046	25.4	22.2
			*As of 7/2/2019 Rate Case Filing			*As of 4/4/2024 Rate Case Filing		
	Average Lives							
	Coal			56.3	8.5		55.3	7.5
	CT			40.8	17.0		40.9	17.9
	Coal	Change From Prior					-1.0	-11.8%
	CT	Change From Prior					0.1	5.7%