TESTIMONY OF J. BRADLEY DANIEL
DIRECTOR, GENERATION DISPATCH AND OPERATIONS
DUKE ENERGY CAROLINAS, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 38707-FAC135 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is J. Bradley Daniel, and my business address is 526 South Church Street, Charlotte, NC 28202.

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

A. I am employed by Duke Energy Carolinas, LLC ("Duke Energy Carolinas") as Director, Generation Dispatch and Operations in the Fuels and Systems Optimization Department. Duke Energy Carolinas is a utility affiliate of Duke Energy Indiana.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Arts degree from the University of Oklahoma in 2000. I received a Master's in Business Administration from Wake Forest University in 2009. I interned as a data analyst with Oklahoma Energy Resources, Inc. in Oklahoma City, OK in the Fall of 1999 and as an energy market research analyst with Cinergy Corporation in Cincinnati, OH in the summer of 2000. From 2001 until 2005, I worked as hourly power scheduler and power trader for Cinergy

Corporation. From 2005 until 2007, I worked as a load forecast analyst and short-term power trader for Cinergy Corporation. In 2007, I transferred to a short-term power trader role for Duke Energy in Charlotte, NC, after the merger of Cinergy Corporation and Duke Power. I worked in that role while completing my MBA from Wake Forest University, with a focus in Economics. From 2010-2012, I managed the Midwest short term trading portfolio, where I took responsibility for power, natural gas, and FTR hedging portfolios covering the Duke Energy Indiana and Kentucky jurisdictions. In 2012, after the Duke Energy and Progress Energy merger, I managed the Southeast Power Trading desk for Duke Energy Carolinas and Duke Energy Florida until 2017. From 2017-2019, I managed the organization's Fuels and Fleet Analytics team, responsible for mid-term production cost modeling, dispatch pricing, fuel burn forecasting, position reporting, budgeting for rates and financial planning, and general analytical support for Fuels Procurement and Hedging, Power and Gas Trading, and Unit Commitment functions for Duke Energy Carolinas (North and South Carolina), Duke Energy Florida, and Duke Energy Midwest (Indiana and Kentucky) within Duke Energy's Fuels and Systems Optimization organization. On December 1, 2019, I assumed my current role of Director, Generation Dispatch and Operations.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS DIRECTOR, GENERATION DISPATCH AND OPERATIONS, AS THEY RELATE TO DUKE ENERGY INDIANA, LLC ("DUKE ENERGY INDIANA" OR "COMPANY").

A. I am responsible for Duke Energy Indiana's and Duke Energy Kentucky's: (i) generating dispatch; (ii) unit commitment; (iii) 24-hour real-time operations; and (iv) short-term generating maintenance. I am also responsible for the submission of the Company's supply offers to the Midcontinent Independent System Operator, Inc. ("MISO") for MISO's day-ahead and real-time electric energy markets ("Energy Markets") and MISO's day-ahead and real-time ancillary services markets ("ASM") in the MISO region (the Energy Markets and ASM collectively referred to as the "MISO Markets"), as well as managing the Company's short term supply position to ensure that the Company has adequate resources committed to serve its retail customers' electricity needs. These markets are often referred to as the "Energy and Operating Reserve Markets."

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. First, I provide an overview of MISO's Energy Markets and discuss economic dispatch in the context of the MISO Markets and how it affects the supply resources that are used to serve Duke Energy Indiana's retail customers' electricity needs. I also describe the actions Duke Energy Indiana takes, subject to operating constraints, to generate or purchase power or both to serve its retail customers at the lowest fuel cost reasonably possible. I provide an update on unit operating issues including an update on the Company's use of a supply offer adjustment. I also provide a summary of outages experienced during the review period. Finally, I generally describe the MISO Markets' charges and credits that are included in the instant fuel cost adjustment filing.

II. OVERVIEW OF MISO'S ENERGY MARKETS

Q. MR. DANIEL, ARE YOU FAMILIAR WITH MISO'S ENERGY MARKETS?

A. Yes. As mentioned above, I manage the team that is responsible for participating in those markets, as well as the ASM, on behalf of the Company.

Q. PLEASE GENERALLY DESCRIBE MISO'S ENERGY MARKETS.

A. Beginning April 1, 2005, MISO began independently administering both day-ahead and real-time markets for electric energy pursuant to its Open Access Transmission, Energy Markets Tariff (now known as the Open Access Transmission, Energy and Operating Reserve Markets Tariff or hereinafter "MISO Tariff"), on file with the Federal Energy Regulatory Commission ("FERC"). The real-time energy market functions as a real-time balancing market for electricity. Through the day-ahead energy market, market participants can mitigate their exposure to price risk in the real-time energy market. Demand bids and supply offers for power are submitted to MISO by market participants, including both generator owners (as sellers) and load serving entities (as buyers). Thus, the Company functions as both a seller and buyer in the Energy Markets to serve its retail electric customers in Indiana. Additionally, Duke Energy Indiana can self-schedule certain generating resources in the Energy Markets to ensure that those resources are committed and dispatched.

MISO uses the offers and bids it receives for the sale and purchase of energy from market participants to arrange a security-constrained, economic commitment and dispatch for the entire MISO region for each dispatch interval. The dispatch interval for the day-ahead energy market is hourly; for the real-time energy market, the dispatch interval is every five minutes. Once MISO defines a security-constrained economic dispatch solution for a given dispatch interval, it determines market clearing prices in each energy market using the principles of locational marginal pricing. Finally, MISO administers a system of financial transmission rights ("FTRs") based upon the use of locational marginal pricing for pricing energy to allow parties to hedge their exposure to day-ahead congestion costs.

Q. PLEASE EXPLAIN THE MEANING OF THE TERM "ECONOMIC DISPATCH."

A. Economic dispatch is an operating procedure used by utilities to supply electricity to their customers generally using the most cost-efficient resources available, recognizing and subject to any operational limits, environmental considerations and fuel supply constraints affecting the generation and transmission facilities available to supply that electricity.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY SELF-SCHEDULING.

A. Self-scheduling is a common phrase for ways that a generation owner can ensure that a specific unit or units will either be committed or dispatched at a specific energy output level in the Energy Markets. There are several valid reasons for a generation owner to "self-schedule" a unit. If testing of a unit is necessary, the generation owner would designate the unit as "must-run," usually designating a specific hourly output for the generating unit. Similarly, the Company may frequently designate the commitment status of our most economic generating units and our economic generating units with long start up times as "must-run." MISO, utilizing all self-scheduled generator information as offered, will then perform an incremental dispatch to meet the remaining demand requirements taking into consideration reliability concerns. All of these Company activities described above are generally referred to as self-scheduling. There is no "one size fits all" approach in submitting a generating unit's day-ahead or real-time energy offer to MISO. In making the decision regarding an individual unit's offer status, typically deciding between an Economic and Must Run Commitment Status offer for a unit that is available, the Company considers various factors such as forecasted locational marginal prices ("LMP"), unit generation production costs, MISO settlement impact (such as the ineligibility of revenue sufficiency guarantee make-whole payments when a generating unit is self-committed), and the capability and economic impact from cycling the generating unit off-line and/or on-line. Before making any generation unit offer, Company personnel engage in a planning process designed to minimize the total customer cost by maximizing each unit's economic value.

Q. PLEASE EXPLAIN LOCATIONAL MARGINAL PRICING.

A. Locational marginal pricing defines the marginal cost of energy serving the next increment (*i.e.*, 1 megawatt) of load at each location, based on generation dispatch, transmission constraints, and the offers and bids of sellers and buyers participating in the Energy Markets. Because the locational marginal price is based on the marginal cost of energy to serve the next increment of load, the energy component of the locational marginal price clearing price is the same at each location supplying energy to or withdrawing energy from the market for a given market interval. Additionally, the locational marginal price includes costs for congestion in any market interval when the transmission system is constrained and the lowest price generator available cannot serve the next increment of load at that load zone because of such congestion. The locational marginal price also includes a component to reflect the marginal losses incurred to deliver the energy to the load zone.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONGESTION.

A. All energy activities on the transmission system can potentially result in congestion—when transmission facilities may not be adequate to deliver least-cost available energy to load in a transmission-constrained area. Congestion impacts in RTO markets are reflected in LMP, as mentioned above.

Q. WHAT ARE FINANCIAL TRANSMISSION RIGHTS, OR FTRS?

A. FTRs are financial instruments that provide market participants a means to manage the risk of congestion costs they may incur as a result of scheduling energy transactions in the day-ahead energy market. Market participants who own FTRs are provided revenues or allocated costs as an offset to congestion for scheduling injections (*e.g.*, generation, bilateral sales, etc.) at one location, and withdrawals (*e.g.*, load, bilateral purchases) at a different location in the day-ahead energy market. FTR holders are entitled to revenues or costs based on the hourly Day-Ahead congestion price difference across the path. FTRs do not protect market participants from congestion costs that result from scheduling power in the real-time energy market or from deviations between transactions scheduled in the day-ahead energy market and real-time operations.

III. ECONOMIC DISPATCH IN THE ENERGY MARKETS

Q. HOW HAS MISO'S IMPLEMENTATION OF ITS ENERGY MARKETS AFFECTED THE COMPANY'S ECONOMIC DISPATCH?

A. The fundamentals of economic dispatch and hedging price risk have not changed. Duke Energy Indiana's retail customers continue to enjoy the benefits of its low-cost generation as the Company participates in the Energy and Operating Reserve Markets. Participation in those markets involves several considerations that affect the resources used and the costs incurred to serve retail customers. Those considerations include certain actions within Duke Energy Indiana's control, including decisions regarding the determination of a unit's commitment status offer, the preparation and submission of generator offer curves in the day-ahead and real-time markets, the amount of retail load bid into the day-ahead market, fuel procurement, and the acquisition of FTRs. There are also factors that impact economic dispatch which are outside of the Company's control, such as energy market price volatility, fuel inventory supply chain constraints, shifting dynamics in the fuel resource mix, decisions made by MISO to enhance reliability and the actions of other market participants.

Q. HOW ARE THE RESPONSIBILITIES FOR DISPATCH AND COMMITMENT OF GENERATING UNITS IN THE ENERGY MARKETS DIVIDED BETWEEN MISO AND LOAD SERVING ENTITIES, SUCH AS THE COMPANY?

A. MISO directs the dispatch of all generation connected to the transmission system under its functional control. The Company submits offers for its generation resources, which define the offer prices for a range of outputs, while considering the generating unit's physical limits. As described above, the Company may also choose to self-commit a unit with MISO then dispatching the unit between minimum and maximum capability. There are a variety of reasons that Duke Energy Indiana may choose to offer a generating resource as must-run to ensure the unit is operated as cost efficiently as possible. Although designating the Company's lowest cost units as must-run generally results in the lowest overall fuel costs, this may not be the case for generating units in the middle or higher range of dispatch costs. When units are forecast to be on-line for several days in a row but are "sandwiched" by a day in which they are only marginal or slightly uneconomic, it may be prudent to avoid cycling the unit and offer the unit with a day ahead offer status of must run. Cycling a unit off-line and then back on-line can result in higher costs during the cycling period and overall.

In the real-time energy market, MISO sends a dispatch instruction every five-minutes, called a set point, to each generating unit connected to the transmission system under its functional control with updates to this instruction occurring every few seconds as ancillary services are deployed on generating units that cleared these same reserves. Under the ASM, Duke Energy Indiana sells regulation, contingency (spinning and supplemental), short-term reserve, and ramp capability reserve services to MISO as well as purchases these ancillary services from MISO.

Q. DOES THE MISO TARIFF ENCOURAGE PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET?

A. Yes, the MISO Tariff encourages market participants to participate in the day-ahead energy market. Primarily, as described further below, Duke Energy Indiana is obligated to offer its generation resources in the day-ahead market. Also, congestion costs can only be hedged in the day-ahead market. FTRs are not available to offset congestion costs incurred in the real-time market. Finally, virtual offers and bids can only be submitted in the day-ahead market as a means of hedging certain real-time operations risks.

Q. DOES DUKE ENERGY INDIANA UTILIZE MISO'S DAY-AHEAD ENERGY MARKET TO MITIGATE ITS RETAIL CUSTOMERS' EXPOSURE TO REAL-TIME PRICES AND OBTAIN THE BENEFIT OF FTRS?

A. Yes. The Company submits demand bids in the day-ahead market based on its day-ahead load forecasts. Additionally, Duke Energy Indiana offers all available generation resources in the day-ahead market through the submission of unit offers.

Q. DOES PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET CREATE FINANCIALLY BINDING OBLIGATIONS?

A. Absolutely. Transactions that are scheduled in the day-ahead energy market, including offers to supply generation and bids to purchase energy that are cleared by MISO, create financially binding obligations to sell or purchase energy at day-ahead locational marginal prices. Deviations from day-ahead schedules (injections or withdrawals) are exposed to real-time locational marginal prices. For example, when a utility bids its load forecast in the day-ahead market (a demand bid), the price paid to serve that load will be the day-ahead locational marginal price at the utility's load zone. If the real-time load exceeds the amount of load that was bid in the day-ahead market, the amount underbid will pay real-time locational marginal prices. Conversely, if the real-time load is less than the amount of load that was bid in the day-ahead market, the amount overbid will be sold back to the real-time market at real-time locational marginal prices. Day ahead generation awards and real time generation deviations are handled in the same manner.

Q. IS THE COMPANY REQUIRED TO OFFER ITS GENERATING RESOURCES IN THE ENERGY MARKETS?

A. Generally, yes. Under the MISO Tariff, Duke Energy Indiana is required to submit offers for Network Resources in the day-ahead energy market to meet its next day forecasted load plus an operating reserve requirement. Additionally, both before and after the day-ahead energy market clears, MISO employs a series of reliability assessment commitment ("RAC") processes to ensure sufficient resources are committed to serve the real-time regional load forecast and to commit units needed to resolve transmission and other operational constraints in real-time. Duke Energy Indiana's Network Resources must also be made available during these RAC processes. All generation resources owned by Duke Energy Indiana and used to serve its retail customers are Network Resources. Consequently, Duke Energy Indiana is required to submit offers for all its generation resources for consideration in the day-ahead market and the RAC processes.

Q. ARE YOU GENERALLY FAMILIAR WITH THIS COMMISSION'S JUNE 1, 2005 ORDER IN CAUSE NO. 42685 ("JUNE 1 ORDER")?

A. Yes. I am generally familiar with that Order. In that Order, the Commission, among other matters, approved the Company's, Indianapolis Power & Light Company's, Vectren Energy Delivery of Indiana, Inc.'s and Northern Indiana Public Service Company's (collectively, the "Joint Petitioners") participation in the Energy Markets. Specifically, the Commission stated:

> Based on the evidence presented, we find that Joint Petitioners should be granted authority to participate in the Midwest ISO Day 2 directed dispatch and Day 2 energy markets as described in their testimony. We find that Joint Petitioners' description of the considerations they will take into account with respect to decisions involving self-scheduling, generation offer curves, demand bidding and the acquisition of FTRs is reasonable.

June 1 Order at page 13.

Q. DO YOU BELIEVE THE COMPANY'S PARTICIPATION IN THE MISO-DIRECTED DISPATCH DURING THE PERIOD AT ISSUE IN THIS PROCEEDING WAS CONSISTENT WITH THE TESTIMONY PRESENTED BY THE JOINT PETITIONERS IN CAUSE NO. 42685?

A. Yes, I do.

Q. DO YOU BELIEVE THE COMPANY'S PARTICIPATION IN THE MISO-DIRECTED DISPATCH DURING THE PERIOD AT ISSUE IN THIS PROCEEDING CONSTITUTED REASONABLE EFFORTS TO GENERATE OR PURCHASE POWER OR BOTH TO SERVE ITS RETAIL CUSTOMERS AT THE LOWEST FUEL COST REASONABLY POSSIBLE?

A. Yes, I do.

IV. ASSIGNMENT OF GENERATION RESOURCES

Q. EARLIER YOU DESCRIBED HOW THE MISO TARIFF ENCOURAGES DUKE ENERGY INDIANA TO PARTICIPATE IN THE DAY-AHEAD ENERGY MARKET. IN YOUR VIEW, DOES THAT AFFECT THE MANNER IN WHICH GENERATING RESOURCES SHOULD BE ASSIGNED?

A. Yes. The fact that participation in the day-ahead energy market is encouraged under the MISO Tariff supports Duke Energy Indiana's proposal to treat the markets as separate and distinct, which they are. In addition, there are a number of other considerations that support Duke Energy Indiana's methodology for assigning generating resources subject to the Energy Markets. Those considerations include:

- because the day-ahead and real-time Energy Markets are separate and distinct markets, participation in the day-ahead energy market creates separate and distinct financially binding obligations;
- day-ahead energy supply offers and demand bids will rarely perfectly match real-time conditions; and
- Duke Energy Indiana retail customers share in the net profits from the Company's non-native sales.

Q. HOW DOES THE COMPANY ASSIGN GENERATION RESOURCES IN LIGHT OF ITS PARTICIPATION IN THE DAY-AHEAD ENERGY MARKET?

A. The Company observes the following general rules to govern assignment of its generation resources in the Energy Markets:

<u>Day-ahead energy market</u>

- all expected load will be bid in the day-ahead energy market;
- all available generation will be made available (offered or self-scheduled) in the day-ahead energy market;

<u>Real-time energy market</u>

- native load customers get first call on needed available generation;
- real-time metered (real-time meter = day ahead award +/- real time true-up) generation in excess of native load will be treated as non-native sales, the net

profits of which will be shared with retail customers pursuant to Standard Contract Rider No. 70. In addition, note that there were changes approved in the Commission's Order in Cause No. 45253 with the sharing of net profits from non-native sales;

- native load customers will pay actual fuel costs for Company generation that is assigned to serve them in real-time, including all generating units subject to unit testing, inspections or similar operational reasons related to reliability, plus other applicable charges and credits imposed under the MISO Tariff; and
- non-native sales will pay actual fuel costs for generation that is assigned to non-native sales plus other applicable charges and credits imposed under the MISO Tariff.

Q. PLEASE DESCRIBE THE RAC PROCESSES IN MORE DETAIL.

A. Reliability Assessment Commitment ("RAC") processes are intended to enhance reliability. There are three separate RAC processes that MISO may utilize to commit and schedule a unit for purposes of reliability: (1) prior to the submission of day-ahead energy offers, if MISO believes a unit will be required for reliability purposes; (2) after the day-ahead energy market clears, if MISO believes sufficient capacity has not been committed to meet its load forecast, taking operational limitations of the transmission system into account; and (3) during real-time energy operations, if MISO believes a unit is required for reliability purposes. MISO's RAC processes employ a security-constrained unit commitment algorithm intended to minimize the cost of committing the required capacity, including start-up, no-load and cost to operate at dispatch minimum. MISO guarantees that units committed by MISO during the RAC processes will receive at least their start-up, no-load and incremental costs (based on their offers).

Q. HOW ARE THE COSTS FOR UNITS COMMITTED AS A RESULT OF THE RAC PROCESSES ALLOCATED FOR PURPOSES OF FAC PROCEEDINGS?

A. The Company proposed to economically stack units selected as a part of the RAC processes in Cause No. 38707-FAC69 S1, with the Make Whole payments associated with the units following the allocation of energy of the units. The Company implemented that proposal in Cause No. 38707-FAC70 and this revised cost allocation procedure is ongoing.

V. <u>UNIT OPERATING ISSUES</u>

Q. PLEASE PROVIDE AN UPDATE ON THE COMPANY'S USE OF A SUPPLY OFFER ADJUSTMENT.

A. The Company continued the use of supply offer adjustments through the FAC 135 period to maintain a reliable level of coal inventory at Gibson units 1-5 and Cayuga units 1-2. Constraints in the coal supply and transportation market moderately improved and spot and future natural gas and power prices declined. This resulted in a decrease in the supply offer adjustments over the course of the FAC period.

Q. WHAT FACTORS INFLUENCED THE SUPPLY OFFER ADJUSTMENT, THROUGHOUT THE FAC PERIOD?

A. Constraints in the coal supply and transportation chain as well as volatility of power and natural gas prices continued to influence the supply offer adjustment, throughout the FAC period. Even though constraints in the coal supply and transportation chain improved throughout the FAC period, supply offer adjustments remained necessary to achieve the Company's objective function of providing reliable station fuel inventory targets for the upcoming winter season. Absent use of a supply offer adjustment, coal consumption was projected to exceed the amount of coal that can be physically delivered putting the Company's objective function of supplying reliable fuel inventory at risk.

Q. WHAT OFFER ADJUSTMENTS WERE MADE TO THE COMPANY'S SUPPLY OFFERS AT GIBSON UNITS 1-5 AND CAYUGA 1 AND 2?

A. During the FAC period, the offer adjustment declined from **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** to **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** at Gibson units 1-4 and from **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** to **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** at Gibson unit 5. The offer adjustment declined from **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** to **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** at Cayuga units 1-2.

Q. HOW DOES THE COMPANY DETERMINE THE AMOUNT OF ADJUSTMENT TO USE?

A. To alleviate a potential steep decline in inventory and to retain fuel security for the winter season, the objective function of the modeling process is set to achieve reliable coal inventory levels for the upcoming winter. To determine the amount of adjustment necessary, Company personnel utilizes its production cost model to determine the amount of adjustment to unit offers needed to meet reliable inventory levels. The model utilizes up-to-date spot and future commodity and power prices, along with actual and expected coal deliveries and actual and targeted station coal inventory. The model then runs scenarios at different adjustment levels and selects the optimal adjustment level needed to meet the Company's inventory targets most economically.

Q. WERE THERE ANY CHANGES TO MINIMUM OR MAXIMUM INVENTORY LEVELS USED AS INPUTS TO THE MODELING PROCESS?

A. No. Company personnel continue to bound coal inventory levels between a minimum of **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** days and maximum of **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** days full load burn inventory at Gibson and Cayuga stations for modeling purposes.

Q. WHY DOES THE COMPANY USE THESE INVENTORY RANGES AS INPUTS TO THE MODELING PROCESS?

A. The Company uses these inventory ranges for fuel inventory planning and procurement purposes and therefore utilizes the same approach in its modeling and analysis with respect to an offer adjustment.

Q. PLEASE DESCRIBE THE APPLICATION OF THE ADJUSTMENT TO THE COMPANY'S OFFERS.

A. Supply offers continue to be calculated just as they are normally. Offers are determined by both the amount and availability of generation and the generator's offer price. The offer price of a generator is largely determined by the input price of the commodity used to produce power, which includes the price of fuel, emission allowances, and variable O&M. In the case of the adjustment to the Company's supply offers at Gibson 1-5 and Cayuga 1-2, offers are calculated as they would be normally and then adjusted by the necessary $/MWh supply offer adjustment amount.

Q. DOES THE COMPANY EXPECT TO CONTINUE TO ADJUST ITS SUPPLY OFFERS AT GIBSON UNITS 1-5 AND CAYUGA UNITS 1-2?

A. Yes, based on all the factors described, the Company expects the need to continue to adjust its supply offers at Gibson 1-5 and Cayuga 1-2.

Q. IS THE PRICE ADJUSTMENT EXPECTED TO CHANGE OVER TIME?

A. Yes, power prices and natural gas prices are dynamic and in a sustained period of volatility. Coal supply chain issues have improved but continue to be unpredictable and portfolio fuel mixes continue to evolve across the energy markets. Based on these elements, coal inventories can fluctuate significantly over short periods of time and therefore the associated adjustment level to the Company’s offers will change to best respond to current market conditions and expectations in the best interest of Duke Energy Indiana customers.

Q. HOW OFTEN WILL THIS ADJUSTMENT BE UPDATED?

A. The Company monitors commodity prices and coal inventories within its normal course of business and is currently updating the $/MWh adjustment to offers at Gibson and Cayuga stations on a weekly basis.

Q. DOES THE USE OF AN OFFER ADJUSTMENT CONTINUE TO BE IN THE BEST INTEREST OF THE COMPANY’S CUSTOMERS?

A. Yes. The Company continues to respond prudently to volatility in energy markets and coal commodity and transportation market supply chain constraints that impact fuel inventory reliability. Over the course of the FAC period, if the Company took no action, coal inventories would have decreased to unreliable levels, putting fuel security at risk for the upcoming winter season. Without an offer adjustment, coal purchased at a lower cost would have been consumed at a rate the coal supply chain could not have supported, resulting in unacceptable reliability and market price exposure risks to customers going into the winter months. Using an offer adjustment enabled some coal to be conserved at a cost less expensive and less risky than future mitigation steps might otherwise be. Had the Company not implemented an offer adjustment, fuel inventory was projected to drop to unreliable levels going into the winter.

The offer adjustment methodology also allows Company personnel to manage inventory at reliable levels throughout the year. As energy market price volatility, fuel inventory supply chain constraints, and shifting dynamics in the market fuel resource mix continue to impact fuel inventories and fuel reliability, utilizing a price offer adjustment is an established methodology that allows the Company to proactively protect customers from otherwise larger swings in fuel inventories over time. Utilizing the use of the price offer adjustment process gives the Company a tool to use to avoid more expensive and higher risk options to solve fuel inventory challenges over time. The Company has implemented a reasonable and objective modeling solution to account for these constraints and to best balance dispatch economics in a volatile energy market environment while also accounting for retaining a reliable amount of coal inventory for future periods. This is in the best interest of customers from a fuel security standpoint as well as an economic standpoint.

Q. IS THE USE OF A SUPPLY OFFER ADJUSTMENT HAVING THE INTENDED EFFECT ON COAL INVENTORIES?

A. Yes. Over the course of the FAC period, Duke Energy Indiana coal inventories increased from 33 Full Load Burn ("FLB") Days on May 31, 2022 to 42 FLB Days as of November 30, 2022, as referenced in the testimony of Mr. Verderame. Had the Company taken no action with respect to supply offer adjustments, coal inventories at Gibson and Cayuga station likely would have dropped below **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>** days of FLB inventory during the FAC period and would have also negatively impacted the Company's ability to meet its objective function of building coal inventory to reliable levels for the upcoming winter. Based on this, the supply offer adjustments at Gibson and Cayuga stations are working to the benefit of the customer as intended.

Q. IN THE COMMISSION'S DECEMBER 28, 2021 ORDER IN CAUSE NO. 38707 FAC 130, THE COMMISSION ORDERED DUKE ENERGY INDIANA TO PRESENT SUPPORT FOR THE REASONABLENESS OF ANY SUPPLY OFFER ADJUSTMENT. ARE YOU PROVIDING THIS INFORMATION?

A. Yes. Petitioner's Confidential Attachment 4-A (JBD) provides support for the reasonableness of supply offer adjustments for the time-period September through November 2022.

Q. IS THERE ANY UPDATE ON DISPATCH OF THE COMPANY'S WHEATLAND UNITS?

A. Wheatland CT station's air permit allows for a rolling 12-month NOx tons emissions of 241 tons. The rolling 12-month permit limit is not currently an immediate constraint. The Company uses a variable $/MWh adjustment to its economic offers to optimize its rolling 12-month permit allowance.

Q. HOW IS THE EPA'S CROSS STATE AIR POLLUTION RULE AFFECTING DISPATCH OF THE COMPANY'S UNITS?

A. Emission costs are variable costs that are included in the Company's Day Ahead and Real-Time offers into the MISO energy market. Because the market price in $/ton cost of NOx emissions is included in those emissions costs, emissions allowance market prices impact the $/MWh cost of a generating unit in the Company's offer to MISO. As the market price of seasonal NOx allowances has increased, the Company's $/MWh NOx component of its offers has also increased. This can impact the dispatch of the Company's units in MISO during ozone season, depending on how marginal coal units are compared to the market power price. Ozone season runs from May 1 to September 30. The Company monitors actual and forecasted plant emissions, seasonal NOx allocations and market prices as part of its normal course of business.

Q. IN THE COMMISSION'S DECEMBER 28, 2011, ORDER IN CAUSE NO. 38707 FAC90, THE COMMISSION ORDERED DUKE ENERGY INDIANA TO DISCUSS IN FUTURE FAC PROCEEDINGS MAJOR FORCED OUTAGES OF UNITS OF 100 MW OR MORE LASTING MORE THAN 100 HOURS. WERE THERE ANY SUCH OUTAGES OCCURRING DURING THIS REPORTING PERIOD, SEPTEMBER THROUGH NOVEMBER 2022?

A. Yes, there were two outages that met these criteria during this FAC reconciliation period.

The first outage during this period that met these criteria occurred at Cayuga 1, beginning at 08:43 on October 13 when the unit came offline for a superheater tube leak. The resulting repairs were completed, and the unit returned to service on October 22 at 18:00. The second outage occurred at Gibson 5, which began at 14:41 EST on November 4 due to a waterwall tube leak. The issue was repaired, and the unit was returned to service at 08:55 EST on November 11.

Q. IN THE SETTLEMENT IN FAC 111-S1, APPROVED ON APRIL 11, 2018, DUKE ENERGY INDIANA AGREED TO PROVIDE A ROOT CAUSE ANALYSIS IF PERFORMED. DID THE COMPANY PERFORM A ROOT CAUSE ANALYSIS FOR ANY OF THESE OUTAGES?

A. No.

Q. AS PART OF THE BENTON COUNTY SETTLEMENT PREVIOUSLY DISCUSSED IN FAC 113, THE CONCEPT OF DEEMED GENERATION WAS INTRODUCED. PLEASE EXPLAIN DEEMED GENERATION.

A. During only those hours when the output of Benton County is curtailed by MISO, Deemed Generation is the hourly amount of generation that would have been produced had the units not been dispatched down by MISO, calculated using the hourly recorded wind speed at the Benton County site and adjusted for factors such as turbine availability. For each hourly amount of Deemed Generation, Benton County receives payment equal to the applicable Power Purchase Agreement ("PPA") price.

Q. ARE THERE ANY NOTABLE ISSUES IMPACTING THE OPERATION OF BENTON COUNTY WIND FARM?

A. No. There were no notable issues impacting the operation of Benton County Wind Farm during the FAC period. The Company began submitting a modified incremental cost offer on June 1, 2017, in accordance with the settlement agreement discussed in Cause No. 38707 FAC 113 and continues to make an offer that meets the terms of the settlement agreement.

Q. ARE THERE ANY NOTABLE UPDATES ON THE COMPANY'S NEW BATTERY RESOURCES.

A. No. The 5 MW batteries at Camp Atterbury, Nabb and Crane are fully operational. The Company is making unit offers for each battery resource within its normal unit offer process and the units receive settlement charges and credits within normal course of business.

VI. ENERGY & ANCILLARY SERVICES MARKETS CHARGES & CREDITS

Q. PLEASE EXPLAIN YOUR UNDERSTANDING OF THE JUNE 1 ORDER AS IT RELATES TO THE CHARGES AND CREDITS OF THE ENERGY MARKETS THAT CAN BE INCLUDED IN FUEL COST ADJUSTMENT PROCEEDINGS.

A. On page 34 of the June 1 Order, the Commission found that costs incurred as a result of participating in the Energy Markets, including charges and credits imposed under the MISO Tariff, fall into two broad categories: fuel costs and non-fuel costs. With respect to fuel costs, the Commission stated on page 36, "[t]he charges and credits assigned to the Joint Petitioners in the Midwest ISO Day-ahead and Real-time markets are in essence the cost of power to reliably meet the needs of their loads." On page 37 of the June 1 Order, the Commission further delineated certain Energy Markets charges and credits imposed under the MISO Tariff that should be included in the cost of fuel in quarterly fuel cost proceedings as follows:

- FTR congestion costs;
- FTR congestion credits;
- FTR auction settlements;
- virtual bids and offers in the day-ahead market which are used for hedging jurisdictional load;
- day-ahead recovery of unit commitment costs;
- excess congestion charge fund credit;
- real-time marginal losses surplus credit;
- RAC recovery of unit commitment costs;
- marginal losses surplus credit; and
- inadvertent energy charge or credit.

Q. WHAT ENERGY MARKETS CHARGES AND CREDITS HAS THE COMPANY INCLUDED IN ITS CURRENT FUEL COST ADJUSTMENT FILING?

A. Consistent with the June 1 Order, Duke Energy Indiana has included in this filing the Energy Markets charges and credits that are incurred as a cost of reliably meeting the power needs of Duke Energy Indiana's load, including: (1) Energy Markets charges and credits associated with Duke Energy Indiana's own generation and bilateral purchases that were used to serve retail load; (2) purchases from MISO at the full LMP at Duke Energy Indiana's load zone; (3) other Energy Markets charges and credits included in the list on page 37 of the June 1 Order; (4) credits and charges related to auction revenue rights ("ARRs") and Schedule 27 and 27-A; and (5) fuel related charges and credits received from PJM Interconnection LLC ("PJM") that result from the operation of Madison Generation Station, as approved by the Commission's Final Order in the Duke Energy Indiana rate case, Cause No. 45253.

Q. IN THE COMPANY'S PRIOR FAC PROCEEDINGS YOU DISCUSSED THE NEW AND MODIFIED CHARGE TYPES UNDER ASM. ARE ASM CHARGES OR CREDITS INCLUDED IN THIS PROCEEDING?

A. Yes. The Commission authorized the Company and the other Joint Petitioners in its Phase II Order issued on June 30, 2009 in Cause No. 43426 to recover its costs and credit revenues related to ASM. Accordingly, the Company has included various ASM charges and credits in this proceeding, consistent with that order, as well as appropriate period adjustments.

VII. <u>CONCLUSION</u>

Q. WAS PETITIONER'S CONFIDENTIAL ATTACHMENT 4-A (JBD) PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?

A. Yes, it does.

PETITIONER'S ATTACHMENT 4-A IS CONFIDENTIAL

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: ______________________
J. Bradley Daniel

Dated: January 31, 2023