Cause No. 46038

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INDIANA UTILITY
REGULATORY COMMISSION

On Behalf of Petitioner,
DUKE ENERGY INDIANA, LLC

VERIFIED DIRECT TESTIMONY OF JOHN D. SWEZ

Petitioner's Exhibit 20

April 4, 2024

DIRECT TESTIMONY OF JOHN D. SWEZ, MANAGING DIRECTOR, TRADING AND DISPATCH DUKE ENERGY CAROLINAS, LLC ON BEHALF OF DUKE ENERGY INDIANA, LLC BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez, and my business address is 525 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC ("Duke Energy Carolinas") as Managing Director, Trading and Dispatch. Duke Energy Carolinas provides various administrative and other services to the regulated affiliated companies within Duke Energy Corporation ("Duke Energy Corp."), including Duke Energy Indiana, LLC., ("Duke Energy Indiana" or "Company").

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Master of Business Administration from the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and have held various engineering positions with the Company or its affiliates in the Power Services, Power Trading, and Fuels and Systems Optimization departments. Though my title has changed in recent years, I assumed my current role on November 1, 2019.

Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGING DIRECTOR, TRADING AND DISPATCH.

A. As Managing Director, Trading and Dispatch, for Duke Energy, I am responsible for Power Trading on behalf of Duke Energy's regulated utilities in the Carolinas and Florida. I am also responsible for Duke Energy's Indiana and Kentucky utilities' generation dispatch, unit commitment, short-term generation maintenance planning, and 24-hour real-time operations as a member of the Midcontinent Independent System Operator, Inc. ("MISO") for Indiana, and PJM Interconnection, L.L.C. ("PJM") for Kentucky and Ohio. My team is also responsible for the submission of the Company's supply offers in MISO's Day-Ahead and Real-Time electric and ancillary services markets and managing the Company's short-term supply position to ensure that the Company has appropriate economic resources committed or available to serve its retail customers' electricity needs.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. On behalf of Duke Energy Indiana, I will provide an overview of MISO, specifically its energy and capacity markets and how Duke Energy Indiana interacts with those markets. I provide background and rationale that supports proposed changes to cost allocation, non-native revenue sharing methodologies, and the scope of transactions related to non-native capacity and energy sales margins captured in Standard Contract Rider No. 70, currently filed as Cause No. 44348 SRA 10, an explanation of the new Special Contract 01-B; and proposed changes to the allocation methodology used to allocate expenses related to Firm Transportation (FT) natural gas pipeline contracts. In addition, I describe recent MISO capacity market changes. The changes proposed in my testimony support and recognize experience gained by Duke Energy Indiana in MISO as energy and capacity markets have matured and evolved since the Company's previous general rate case.

II. OVERVIEW OF MISO

Q. PLEASE BRIEFLY DESCRIBE MISO.

A. MISO is an independent, not for-profit, member-based organization that administers an electric power market covering parts of 15 states and one Canadian province, including Indiana. MISO administers electric energy, capacity, ancillary services, and congestion management markets. As Company witness Mr. Abbott discusses in his testimony, MISO also plans and has functional control of the high voltage transmission system in its footprint.

A. The Capacity Market

Q. PLEASE PROVIDE AN OVERVIEW OF THE MISO PLANNING RESOURCE AUCTION.

A. Resource Adequacy is the general term for the MISO process to ensure sufficient generation resources are in place to meet system requirements across MISO's footprint. MISO's yearly capacity auction is known as the Planning Resource Auction ("PRA"), which is a MISO-administered mechanism where market participants can purchase capacity credits to meet resource adequacy requirements or offer to sell capacity for revenue.

Load Serving Entities ("LSEs"), such as Duke Energy Indiana, are required to provide sufficient capacity to meet a specific load obligation plus a reliability margin as defined by MISO. MISO is a structured market where capacity value is established, through the PRA, for each of the 10 internal zones. The zones represent geographical and transmission system boundaries of Local Balancing Authorities ("LBA") and States. In addition, external resource zones represent additional MISO generation resources external to the MISO footprint.

Generation owners offer capacity, at a price in Dollars per Megawatt Day into the PRA; and the auction clears at the marginal Megawatt of generation that satisfies the load requirement. LSEs are required to purchase sufficient capacity to meet their specific load obligation including a reserve margin, as defined by MISO. The specific market rules that govern the Resource Adequacy process are described in the MISO Open Access Transmission Tariff ("OATT"), Module E-1 and Module E-2 – Resource Adequacy[1] and Business Practice Manual 011 – Resource Adequacy ("BPM011").[2]

Q. PLEASE EXPLAIN HOW DUKE ENERGY INDIANA PARTICIPATES IN THE MISO CAPACITY MARKET.

A. Duke Energy Indiana participates fully in the PRA process described above. As MISO secures capacity for all of Duke Energy Indiana's assigned obligation and Duke Energy Indiana offers all available generation into the capacity market, the Company manages an economic as well as a physical capacity position.

[1] https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/
[2] https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

In addition to the PRA, a bilateral market for capacity also exists. In this market, participants can transact MISO capacity credits directly. If the position is determined to be deficient, or short, Duke Energy Indiana can either engage the bilateral capacity market for PRA eligible capacity credits, or simply allow MISO to secure its capacity in the PRA. If Duke Energy Indiana determines it has an excess capacity, or a long position, it can either sell those capacity credits in the bilateral market or offer them in the PRA. The ability to manage this economic position financially in the short term and physically in the longer term through the Integrated Resource Planning process ("IRP") is one of the advantages of participation in MISO. In MISO, generation assets serve a role as hedges against short-term capacity and energy prices. The capacity markets can be utilized to efficiently fill short gaps and monetize periods of excess capacity. The MISO PRA market is limited to one Planning Year, while the bilateral market can provide capacity price certainty through multiple years.

Q. HAS MISO MADE ANY CHANGES TO ITS CAPACITY MARKET?

A. Yes. After discussions with stakeholders, MISO implemented the Seasonal Accredited Capacity ("SAC") construct starting in Planning Year 2023/2024. There were three significant changes that affect all MISO capacity market participants. The first change is the transition from one annual auction to four simultaneous seasonal auctions (Summer, Fall, Winter, Spring). The second is the method of calculating thermal capacity accreditation for most capacity resources, or what MISO has defined as Schedule 53 Resources (Capacity Resources that are a Generation Resource or Demand Response Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric

Storage Resource, External Resource, or Use Limited Resource). Instead of using forced outage data as previously, generators receive accreditation through calculations weighted toward the time of highest system need. The third change is the implementation of the "31-Day Rule" where a generation unit with a planned outage/derate more than 31 days in length in a season, if cleared in MISO's capacity auction, is now required to replace the capacity for planned outage/derate days in excess of 31 with uncleared capacity or pay a Capacity Replacement Non-Compliance Charge ("CRNCC").

Q. HOW HAVE EACH OF THESE CHANGES IMPACTED HOW THE COMPANY MANAGES CAPACITY?

A. The change to a seasonal structure means that the Company prepares for four auctions instead of one, with four distinct seasonal load forecast peaks, unique seasonal generation capacity accreditation calculations, and differing reliability margins (called the Planning Reserve Margin, or "PRM"). Although this change may seem insignificant at first, even though the Company's highest seasonal peak load still occurs during the summer period, it is now possible for the Company's capacity position to be the tightest during non-summer seasons. Thus, essentially the Company may transition to summer peaking, but non-summer season planning.

For the second change, the method of calculating Schedule 53 Resource capacity accreditation, the SAC construct uses an all-new paradigm to determine the seasonal capacity value of these resources for the MISO capacity auction. Traditionally, the Unforced Capacity ("UCAP") rating of a thermal generator determined its capacity accreditation value. UCAP was previously calculated as the product of the Installed

Capacity ("ICAP") rating of the generator multiplied by one minus the Equivalent Forced Outage Rate in Demand, excluding Outside of Management Control Events ("XEFORd"). XEFORd is a mathematical cousin to Equivalent Forced Outrage Rate ("EFOR"), a standard generation performance metric that the Company tracks for its resources, which is why there has always been synergistic alignment between minimizing EFOR and maximizing UCAP. Under MISO SAC, however, there is a new complex set of rules, separate, distinct, and very different from NERC Generating Availability Data System ("GADS") criteria that define whether any given unavailability state of a thermal generator will be counted against its capacity accreditation value. Unavailability that might be classified as a planned outage or derate, or maintenance outage or derate by NERC GADS, and hence not harmful to EFOR or XEFORd, may now still be detrimental to a generator's SAC value under the new construct. The new terminology under SAC is "exemption". Regardless of its NERC GADS classification, any outage must now meet the new criteria established by MISO for such outage to be "exempt" from impacting the SAC value. Finally, currently under MISO SAC, derates of any kind, including planned derates, are not eligible for exemptions.

The SAC calculation weighs the availability of a unit more heavily in a defined subset of hours known as Reliability Adequacy ("RA") hours, also referred to as Tier 2 hours. MISO targets identifying 65 Tier 2 hours per planning season, or roughly 3% of total hours, to concentrate the capacity accreditation value determination. What all this means is that the Company's generating assets now have two reliability drivers to deliver on; not only EFOR, meaning being generally available across all time, but now being available when the system needs capacity the most, especially in the heavily weighted Tier 2 hours, to maintain thermal unit MISO capacity auction accreditation values for the benefit of customers.

Finally, due to the "31-Day Rule", for generation units with planned outages/derates over 31 days in length in a season, the Company may no longer offer the units at $0/MW-Day in the capacity auction to make sure they clear in the auction and offset load purchases. With CRNCC, these units will need to include the cost impact of the amount of time a unit exceeds a planned outage/derate of 31 days in its offers and run the risk of not clearing in an auction, causing uncertainties in balancing load/generation capacity positions for each season. Additionally, the Company now must look for better ways to schedule planned outages/derates to avoid or minimize instances of having planned outages/derates lasting longer than 31 days in one season. This adds one more constraint to the complex outage planning process. Despite these three additional challenges, the Company will continue to do its best to optimize the capacity portfolio.

Q. PLEASE PROVIDE A MATHEMATICAL EXAMPLE OF THE DIFFERENCE BETWEEN XEFORd, THE TRADITIONAL UCAP CALCULATION, AND THE NEW MISO SAC VALUE.

A. Using a simple example to demonstrate the potentially divergent behavior between UCAP and SAC, a generator could have a very low 3% XEFORd resulting in a high UCAP value. However, if that 3% of unavailability happened to occur in the 3% of hours that were designated as Tier 2 hours, then that generator's SAC value would be substantially penalized. Conversely, a generator could also have a very high 97%

XEFORd resulting in a very poor UCAP value. However, if the 3% of time the generator was available just happened to occur in the Tier 2 Resource Adequacy Hours when it was needed the most, then the generator could still have a very high SAC value.

Q. HOW IS THE COMPANY MANAGING THE TRANSITION TO THE NEW OUTAGE EXEMPTION RULES UNDER MISO SAC?

A. In response to the new outage exemption criteria, the Company has increased the forward coordination between the generating stations and the dispatch desk by increasing advanced planning, even for short opportunistic maintenance outages, to better optimize the outage timing to now consider longer term capacity market value implications. While we have always taken market conditions into consideration, when possible, in scheduling, moving, and ultimately taking outages, the focus on ensuring availability when needed the most, especially during the Tier 2 hours, has increased significantly. However, since the identification of Tier 2 hours is made after the fact by MISO and is not known in Real-Time, at times needed maintenance can be put at odds with needed availability. For example, say a generator is incurring a derate and needs a short maintenance outage to make a repair to restore full output capability. Taking the outage on short notice would make the outage non-exempt, impacting the unit's future SAC value. However, deferring the outage to a later time when it might be eligible for an exemption exposes the unit to ongoing accumulation of the derated hours, which also affects future SAC value, and could risk the unit still being derated in a future Tier 2 hour when full output capability may be needed by the system. Additionally, the difference in the energy market prices between the two dates would also need to be considered as historically we have done.

There is no simple calculation or predictive method that can easily guide us to a decision in these types of situations. Since we are still early in MISO's new capacity construct, as always, we are continuing to apply what works best and will adjust as we learn more.

Q. WHEN DUKE ENERGY INDIANA IS PLANNING FOR ITS CAPACITY NEEDS, WHAT RESERVE MARGIN IS THE COMPANY REQUIRED TO MAINTAIN?

A. Duke Energy Indiana plans its capacity needs with two different reserve margins, one to meet the near-term one year ahead MISO requirement and another used for the longer-term planning done in the IRP process.

The MISO Planning Reserve Margin affects the capacity that MISO will secure for Duke Energy Indiana load through the PRA. A specific MISO reserve margin is determined for each season of the upcoming planning year. The reserve margins for the 2023/2024 PRA were 7.4% (Summer), 14.9% (Fall), 25.5% (Winter), and 24.5% (Spring). For the upcoming 2024/2025 PRA, MISO has specified reserve margins of 9.0% (Summer), 14.2% (Fall), 27.4% (Winter), and 26.7% (Spring). So as can be seen, the requirements can vary by year, and by season.

For long-term IRP planning purposes, Duke Energy Indiana historically has used a reserve margin of 15% on an installed capacity (or ICAP) definition basis, but more recently has performed IRPs using a UCAP basis with MISO's specified UCAP-based reserve margins. Going forward, the Company has been working with stakeholders to determine a reasonable methodology to include the SAC construct in its IRPs, in both the seasonal capacity accreditation value and seasonal reserve margins. However, these assumptions may change over time. Additionally, modeling some aspects of the SAC construct, such as the 31-Day Rule, is still being explored. Duke Energy Indiana will continue to monitor for future changes and adjust both its prompt-year and long-term planning processes appropriately in response.

Q. WILL THE FORECASTS OF THE COMPANY'S FUTURE PHYSICAL AND FINANCIAL CAPACITY POSITIONS LIKELY CHANGE OVER TIME?

A. Yes. Under the Seasonal Accredited Capacity construct, SAC values for the generators can change over time. In addition, MISO is currently planning on continued use of a vertical demand curve for plan year 2024/2025, but then shifting to a Reliability Based Demand Curve ("RBDC"), which makes the Planning Reserve Margin dependent on the auction clearing price, for plan year 2025/2026 and beyond. Additionally, uncertainties such as load forecast growth from economic development, changes in the Company's generating fleet composition, and from a financial perspective, uncertainties in CRNCC charges and credits, all make the physical and financial positions change over time.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S BI-LATERAL AND MISO CAPACITY MARKET PURCHASES DURING THE 2023/24 AND 2024/2025 PRA AUCTIONS.

A. For the 2023/2024 MISO PRA and forecasted results for the 2024/2025 MISO PRA, Duke Energy Indiana has either purchased bi-lateral capacity, purchased capacity from MISO, or both depending on the season and year. The amount, cost, and reason for the bi-lateral or MISO capacity purchases are dependent on the forecasted capacity position, bi-lateral capacity price, and resulting MISO auction clearing price for each season. For bi-lateral capacity, Duke Energy Indiana purchased capacity prior to both the MISO

2023/2024 and 2024/2025 MISO PRA capacity auctions. For the 2023/2024 PRA, without the purchase of 398.4 MW Summer and 401.2 MW Spring bi-lateral capacity purchased prior to the auction, the Company would have had insufficient capacity to meet customer load, even at the highest of MISO PRA clearing prices and thus having all Company offered capacity clear the market. For the 2024/2025 PRA, without the purchase of 520 MW bi-lateral capacity for Summer and 550 MW bi-lateral capacity for Fall, Winter, and Spring, plus a 100 MW bi-lateral capacity purchase for Spring only, again the Company has forecasted insufficient capacity present to meet customer load, even at the highest of potential MISO PRA clearing prices and again having all Company offered capacity clear the market. Additionally, for the 2024/2025 PRA, the 100 MW bi-lateral capacity purchase for Spring allowed the Company to meet the threshold 15% market reliance in all seasons established by Indiana Code § 8-1-8.5-13.

Due to the low auction clearing price in the 2023/2024 PRA, Duke Energy Indiana purchased additional capacity from MISO since (1) having generating units with planned outages longer than 31 days in length clear the auction and being charged more for CRNCC is economically disadvantageous, (2) having units clear the auction and then requiring non-exempt outage/derate days may impact capacity accreditation for the next three planning years, and (3) generating unit offers were constructed in such a way to ensure a maximum 15% market reliance in all seasons. At a higher clearing price, Duke Energy Indiana would have purchased less capacity from MISO and at the highest prices, all Duke Energy Indiana generating resources would have cleared in the PRA. Additionally, due to the auction low clearing price and generation that did not clear the auction, the Company sold 112 MW in the bi-lateral capacity replacement market for Summer 2023. Also, as the Commission is aware, the 2024/2025 MISO PRA results are not known at this time since this testimony was prepared prior to the date of the auction.

Finally, it is important to note that the MISO capacity obligation is a short-term requirement, the single pending planning year. In any given year, Duke Energy Indiana's ability to meet the obligation is a function of more transient inputs such as year-to-year customer demand and unit performance factors, while the IRP view of capacity sufficiency is a longer-term planning model. Membership in MISO allows Duke Energy Indiana to manage short-term variations in the net capacity position.

Q. IS DUKE ENERGY INDIANA PROPOSING ANY CHANGES TO THE WAY IT RECOVERS COSTS AND CREDITS REVENUES ASSOCIATED WITH THE MISO CAPACITY MARKET?

A. Yes. As to the recovery of costs and crediting of revenues, Duke Energy Indiana does not propose any changes; the Company proposes to continue to track these items through its Rider 70 filing. This will be discussed in more detail in Company witness Ms. Sieferman's testimony in this proceeding. However, the Company is proposing to change how net margins from sales of excess capacity and energy from certain transactions flow through Rider 70, as will be discussed later in this testimony.

Q. WHAT ADDITIONAL IMPACT HAVE THE RECENT CHANGES TO THE PRA HAD ON DUKE ENERGY INDIANA'S GENERATING UNITS?

A. As discussed by Company witness Mr. Luke, Duke Energy Indiana is planning to continue operations of Gibson Unit 5 beyond its last known expected retirement date of

2026 as a result of the Company's forecasted capacity position, impact of the statutory 15% limit, volume of bi-lateral capacity purchases entered into for the 2023/2024 and 2024/2025 MISO PRA auctions, energy implications, and after discussions with the Joint Owners.

B. MISO Energy Market

Q. PLEASE GENERALLY DESCRIBE MISO'S ENERGY MARKETS.

A. On April 1, 2005, under Federal Energy Regulatory Commission ("FERC") approval, MISO began independently administering both day-ahead and real-time markets ("Energy Markets") for electric energy. The day ahead energy market operates as a planning market for serving anticipated load requirements in the MISO footprint, whereas the real-time energy market functions as a real-time balancing market for electricity. Demand bids in the day-ahead market and supply offers in both markets for energy 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. Along with many other factors or constraints, the forecasted and actual results of these markets determine which Duke Energy Indiana units are committed and dispatched. In addition, MISO administers day ahead and real time ancillary services markets ("ASM") for regulating, ramp capability, short-term, and contingency reserves.

Q. DO YOU BELIEVE THE COMPANY'S PARTICIPATION IN THE MISO ENERGY MARKETS CONSTITUTE REASONABLE EFFORTS TO GENERATE

AND/OR PURCHASE POWER TO SERVE ITS RETAIL CUSTOMERS AT THE LOWEST COST REASONABLY POSSIBLE?

A. Yes, I do.

Q. PLEASE EXPLAIN HOW THE COMPANY MODELS THE DISPATCH OF ITS GENERATING STATIONS.

A. The Company utilizes a commercially available production cost model (PowerSimm) to develop the forecast utilized in the Company's quarterly fuel clause filings, as well as its energy, gas, and congestion position management. All the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rate. Other inputs include commitment status, projected dispatch fuel costs for each unit, planned outages, anticipated forced outage rates, the market value for emission allowances, the market price for energy, and the Company's load forecast for native load and other customers. Using a multiple scenario methodology, the PowerSimm model simulates the economic dispatch of the Company's generating fleet and projects market generation sales to MISO and power purchases from MISO to meet the forecasted load and sales for future periods, as well as fuel consumption and emission production. Using the model output, generation is allocated between native load and non-native sales.

III. NON-NATIVE SALES

Q. WHAT TYPE OF WHOLESALE SALES DOES DUKE ENERGY INDIANA ENGAGE IN?

A. Duke Energy Indiana engages in both non-native sales and native load wholesale sales.

Non-native sales refer to the following sales:

- Traditional non-native sales margins from Day Ahead and Real Time generation sales to MISO, which are allocated to non-native load;
- Sales of capacity (Zonal Resource Credits or "ZRCs") in the MISO PRA that do not offset reliability purchases;
- Energy or capacity sales to non-MISO counterparties (*i.e.*, "bilateral sales") that do not offset reliability purchases;
- Non-native sales of emissions allowance realized margins (including profits and losses);
- Realized margin from non-native hedging activity (including profits and losses);
- Non-firm retail sales contracts with Duke Energy Indiana customers; and
- Short-term bundled non-native sales (STBNNS) wholesale contract net margins are included, as approved in Cause No. 45253.

For the remainder of this testimony, only the non-native sales categories of traditional non-native sales margins from Day Ahead and Real Time generation sales and short-term bundled non-native sales contracts are discussed.

Q. PLEASE DEFINE THE TERMS "TRADITIONAL NON-NATIVE SALES", "NATIVE LOAD WHOLESALE SALES", AND "SHORT-TERM BUNDLED NON-NATIVE SALES".

A. Currently, Duke Energy Indiana does not engage in physical energy sales beyond the MISO border. In an RTO construct, non-native energy sales are an accounting concept where hourly loads purchased from MISO are netted with hourly generation sold to MISO. All generation is dispatched into the MISO market and allocated after the fact as either having served native load, including retail load and native load wholesale sales, or non-native load, including non-firm retail sales, traditional non-native sales, or short-term bundled non-native sales ("STBNNS"). Native load customers receive the minimum load energy for long-term commitment generating units such as coal-fired and combined cycle natural gas units and have first call on generating units above minimum load incremental generation. Traditional non-native sales are energy sales that take place in the MISO Energy Markets when generation exceeds native load customer, non-firm retail sales and STBNNS requirements. Native load wholesale sales refer to the historically long-term sales of energy and capacity to wholesale customers. Because these are long-term sales commitments, Duke Energy Indiana plans and builds for these long-term sales. Finally, STBNNS are non-native sales of capacity and energy for a contract term of five years or less. These sales are negotiated and priced competitively to the market.

Q. DO NON-NATIVE SALES PROVIDE BENEFITS TO NATIVE LOAD CUSTOMERS?

A. Yes. By maximizing the value of our generating assets when they are not being used to serve native load customers and by sharing that value with our customers, non-native sales of energy and capacity can reduce costs to customers. Typically, energy sales provide opportunistic energy margins to be shared with customers.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S CURRENT NATIVE LOAD WHOLESALE CONTRACT PORTFOLIO.

A. Duke Energy Indiana currently has four native load wholesale contracts totaling roughly 355 megawatts of traditional wholesale formula rate commitments of capacity and energy, with two of these contracts, or 105 MW, terminating in 2025 and the remaining two expiring in the early 2030s. As previously discussed, without the purchase of bi-lateral capacity the Company has either had or is forecasted to have insufficient capacity, even at the highest of potential MISO PRA clearing prices and having all Company offered capacity clear the market. The expiration of the two contracts in 2025 will help the capacity position starting in the 2025/2026 auction.

Q. PLEASE DESCRIBE DUKE ENERGY INDIANA'S CURRENT STBNNS CONTRACTS.

A. Duke Energy Indiana currently has two STBNNS contracts totaling 310 megawatts of commitments of capacity and energy. The first contract is for **<BEGIN CONFIDENTIAL>**[redacted] **<END CONFIDENTIAL>** with a contract term **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>**. The second contract is for **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>**, with the contract term **<BEGIN CONFIDENTIAL>** [redacted]**<END CONFIDENTIAL>**.

Q. ARE THE STBNNS NON-NATIVE WHOLESALE TRANSACTIONS INCLUDED IN THE CALCULATION OF DUKE ENERGY INDIANA'S NON-NATIVE SALES PROFITS VIA RIDER 70?

A. Yes, beginning with the operating month of August 2020, as approved by the Commission's Order in Cause No. 45253, the Company started calculating and sharing margins on STBNNS.

Q. PLEASE PROVIDE A SUMMARY OF THE NON-NATIVE SALES PROFIT SHARING COMPONENT OF RIDER 70.

A. In Cause No. 45253, the Commission ordered that Duke Energy Indiana should provide 100% credit to retail electric customers for any positive traditional[3] non-native sales margins through the Tracker. Cause No 45253 also stipulated 50/50 sharing of net margins from STBNNS contracts between Duke Energy Indiana's shareholders and retail electric customers with an amount built into base rates. The net margin achieved for STBNNs over the MISO planning year (June through May) is compared to the $11.748 million retail amount built into base rates. If the net margin amount exceeds the $11.748 million level in base rates, 50% of the excess is included as a credit in the rider rate calculation for customers. If the net margin amount is less than what is in base rates, then 50% of the shortfall (with a floor of zero) is included as a charge in the rider rate calculation.

Q. WHAT RATIONALE IS THERE FOR CHANGING THE SHARING REGARDING THE STBNNS AGREEMENTS?

A. As discussed, the Company can't reasonably forecast the overall capacity position (physically or financially) and thus, is unable to forecast the STBNNS capacity sub-position separately. However, the Company does expect generally higher MISO PRA

[3] The term "traditional" refers to the sales of excess generation to MISO and non-firm retail sales.

capacity clearing and bilateral capacity prices and a general ongoing capacity short position, at least through and including the Forward-Looking Test Period, due to general load growth, changes from the MISO SAC, and lack of any substantial capacity build in that timeframe. The same is true for the energy component used to serve STBNNS customers; on a high load day, the Company tends to buy MISO energy to serve native load customers. As a result, due to the STBNNS transactions placement in the stacking process, energy margins from the two STBNNS transactions tend to be negative, especially when MISO energy prices are the highest. By summing the capacity and energy margins, the realized total margin for both transactions, before sharing, was negative $7.618 million for calendar year 2023, with the total margin forecasted to be negative $5.999 million in 2024, negative $5.789 million in 2025, negative $2.438 million in 2026, and negative $1.031 million in 2027. With margins negative in 2023 and forecasted to be negative in the future, the Company proposes that (1) the Company continue to incur all losses below zero net margin, (2) a change to zero for the amount included in base rates, (3) customers receive 100% of any net margins up to a $5 million threshold, and (4) the Company and customers share 50% of positive net margins above $5 million. Creating a threshold amount greater than the highest forecasted margin presents the Company with an incentive to create positive STBNNS margins while benefiting the Customer since all margins return to the Customer up to $5 million and then again through a 50/50 share above $5 million.

Q. PLEASE EXPLAIN NEW SPECIAL CONTRACT 01-B.

A. Special Contract 01-B or "SP01-B," represents the customer's usage above **<BEGIN CONFIDENTIAL>**[redacted] **<END CONFIDENTIAL>**. SP01-A represents the customer usage equal to and below **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>**. The customer's usage under SP01-A is included in the Company's Native Load.

SP01-B is a single customer served by Duke Energy Indiana, but with the customer usage above **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>**. The customer energy usage under SP01-B, called the Supplemental Market Service Energy, is settled under the terms of this special contract. Additionally, the Company may specifically contract for the output from dedicated renewable facilities to serve the customer's load. During time periods where there is insufficient PPA Energy to serve the customer's Supplemental Market Service Energy, the Company will procure the difference from MISO and charge the customer **<BEGIN CONFIDENTIAL>** [redacted] **<END CONFIDENTIAL>**.

Q. WILL THE PPA FACILITY BE A SYSTEM RESOURCE IN DUKE ENERGY INDIANA'S INTEGRATED RESOURCE PLAN ("IRP")?

A. No, because the renewable energy supplied through the PPA facility will be fully subscribed with all the costs and benefits allocated to Customer, the PPA facility will not be added to Duke Energy Indiana's supply portfolio as a typical system resource that provides service to all customers.

Q. WHAT PRODUCTION IMPACTS ARE THERE TO THE EXISTING DUKE ENERGY INDIANA NATIVE LOAD CUSTOMERS AS A RESULT OF THIS AGREEMENT?

A. None. The existing Duke Energy Indiana customer is not materially impacted from this customer. Company generating resources are not used to serve this customer, either in the MISO Capacity or Energy Markets. For fuel cost assignment purposes in the Fuel Adjustment Clause process, the Company's SUMATRA program will not assign fuel costs to any of this customer's usage other than that assigned to the usage under SP01-A.

IV. PROPOSED COST ALLOCATION OF NATURAL GAS FIRM TRANSPORTATION SUPPLY CONTRACT COSTS

Q. WHAT ARE NATURAL GAS FIRM TRANSPORTATION SUPPLY CONTRACTS?

A. Firm transportation ("FT") natural gas contracts are agreements the Company has completed to ensure a reliable supply of natural gas is available to serve generating stations. As stated by Company witness Mr. Verderame, the Company uses its firm transportation contracts to enhance supply reliability by reducing the risk of gas pipeline capacity curtailments during periods of tighter supply and demand conditions.

Q. WHAT ARE THE CURRENT DUKE ENERGY INDIANA NATURAL GAS FIRM TRANSPORTATION SUPPLY CONTRACTS?

A. Again, as discussed in the testimony of Mr. Verderame, Duke Energy Indiana currently has three FT pipeline agreements: (1) on Panhandle Eastern Pipeline Company ("PEPL") for Noblesville and Cayuga CT Stations, (2) on Midwestern Pipeline for Wheatland

Generation Station, Vermillion Station, and Edwardsport IGCC; and (3) on ANR Pipeline Company for Henry County Station.

Q. WHAT ADDITIONAL FACTORS DID THE COMPANY CONSIDER WHEN ENTERING INTO THESE THREE FT CONTRACTS?

A. The Midwestern FT contract is a longstanding agreement the Company entered into at approximately the same time as the construction of Edwardsport IGCC. This agreement has historically allowed the Company to reliably deliver gas to Edwardsport during times when the stations gasifiers were unavailable, and the unit was burning natural gas. Recently, the Company's experiences during cold weather events when the gas delivery system was stressed helped form the decision regarding additional FT for Henry County Station ("ANR") and Noblesville/Cayuga CT ("PEPL"). Additionally, the lack of back-up fuel oil at Noblesville, Wheatland, Vermillion, Edwardsport IGCC, and Henry County Stations adds to the necessity of these FT agreements.

Q. WHAT ARE THE CURRENT MONTHLY FIXED COSTS ASSOCIATED WITH THESE FT CONTRACTS?

A. For a 31-day month, the PPEL FT fixed costs are $109,091.40, the Midwestern FT fixed costs are $197,838.80, and for ANR the FT fixed costs are $128,574.76, for a total of $435,504.96 per month. These monthly expenses are slightly less for months that contain fewer than 31 days.

Q. DOES THE COMPANY EXPECT THESE FT COSTS TO CHANGE OVER TIME?

A. Yes. As situations change, including the addition of new generating assets, the Company's FT expense will likely change.

Q. HOW DOES THE COMPANY ALLOCATE THE FIXED COSTS OF THESE FT CONTRACTS?

A. Company personnel perform post-dispatch after the fact analysis to allocate these costs between native load and non-native load.

Q. HOW DOES THE COMPANY CURRENTLY DETERMINE ALLOCATION OF THE FT CONTRACT FIXED COSTS TO NATIVE CUSTOMERS AND WHAT COSTS ARE ALLOCATED TO NON-NATIVE CUSTOMERS?

A. Each natural gas FT monthly contract cost is allocated using an energy allocation for the generating station(s) receiving the benefit of the contract based on the percentage of native and non-native load. As an example, in the case of the FT natural gas cost associated with ANR pipeline which serves Henry County Station, if in a month 50% of the energy from Henry County was allocated to native load and 50% of the energy from Henry County was allocated to non-native load, the FT fixed costs in that month would follow the same 50/50 energy allocation. Similarly, FT costs for Midwestern are split using the native and non-native load energy allocation from Wheatland Generation Station, Vermillion Station, and Edwardsport IGCC stations combined. Finally, FT costs for PPEL are split using the native and non-native load energy allocation of Noblesville and Cayuga CT combined.

Q. HOW DOES THE POST-ANALYSIS TEAM PERFORM THESE ANALYSES?

A. The primary tool used is a production costing model, Sumatra, which is jointly supported by Power Costs, Inc. and Duke Energy information technology resources. The model incorporates generator information such as heat rates, emission rates, generating unit fuel costs, emissions allowance costs, and variable operating and maintenance costs. This is the same data used in the Energy Cost Manual, which is also the basis for the supply offers to MISO. Additional model inputs include actual hourly data, native load demand, generating unit output (*i.e.,* megawatt-hour generation) received from MISO, and purchased power agreement billing data.

Sumatra then "economically dispatches" or matches, on an hourly basis, the demand (load) with available supply resources (*i.e.*, generation or purchases) that are economically stacked. Except for generation online for testing or reliability, certain joint owner agreements, and power purchased or produced specifically from renewable resources, the unit stacking is prioritized based on average production costs, ranked lowest cost to highest cost. The resulting energy allocation between native and non-native load is then calculated and used to allocate the FT expense as described.

Q. IS THIS ALLOCATION METHODOLOGY FAIR?

A. No. Based on the principals of cost causation, although the results of this allocation are accurate, it is not fair. The FT agreements are entered into for reliability to ensure natural gas is available at times of peak demand. During peak periods typically most or all Company generating units, including the natural gas units that have FT contracts, are operating and serving native load. Even with these generating units operating, typically all generating units are being allocated to serving native load and there are no non-native sales. Non-native sales typically occur during off-peak hours when the value of energy is lower, and the FT contracts are not needed to secure natural gas. In addition, the Company does not include fixed costs in its energy offers to MISO; only variable costs are included in an energy offer since these are the only costs that change as a function of the amount of energy being generated. If a unit is dispatched up (increased in output) for an hour, allocating fixed costs that are not needed to make this energy sale makes no sense.

If a simplistic example is used where a unit operates at the same output during two hours of a month, one hour during the valley and one hour at peak, the mismatch using the current allocation methodology can be easily seen. Suppose that the variable cost offer of the unit during the valley (off-peak) hour is made to MISO at $30/MWh. If LMP in that hour is $31/MWh, the resulting energy margin is $1/MWh. In that same month, if the unit ran during one peak hour, using the same variable cost offer of the unit at $30/MWh, if LMP in that hour is $100/MWh, the resulting energy margin is $70/MWh. Since the FT had no value and was not needed for the unit to operate in the hour when the energy margin was $1/MWh and was only valuable to the unit during the peak hour, allocating the FT expense using 50% native and 50% non-native in this month makes no sense. Allocation to 100% native load is appropriate since that the FT agreement was utilized to operate the natural gas generating unit across the peak hour. It is possible that non-native load be allocated FT expenses even though non-native energy sales are occurring during times where the FT contract is not needed.

Q. WHAT ALLOCATION METHODOLOGY CORRECTLY ASSIGNS COSTS TO THE PARTY ACTUALLY CAUSING THE INCURRENCE OF THE COST?

A. The allocation of 100% of natural gas FT contract expense to native load is appropriate for the reasons previously stated. This allocation methodology is more equitable and appropriately allocates fixed expense to the group that was using the service provided by that expense. Note that the allocation of variable costs, or costs associated with the amount of natural gas consumed, does not change. Finally, these contracts were entered into to ensure a reliable supply of natural gas was available to operate units for native load, not to ensure supply of natural gas for non-native sales, and thus should be assigned to native load.

Q. WHAT IS THE EXPECTED RESULT OF THIS PROPOSED ALLOCATION?

A. Today, the vast majority of FT expense is ultimately allocated to native load. Since traditional non-native profits are returned to customers, any FT gas expense allocated to traditional non-native load is ultimately paid for by the native customer, since 100% of non-native profits are returned to the customer. This calculation does impact STBNNS margins, however, but due to the Company's predominant short position, the majority of energy serving the STBNNS customers is from the MISO energy market and thus, the amount of FT expenses allocated to these sales is low.

V. CONCLUSION

Q. IN YOUR OPINION, ARE THE PROPOSALS PRESENTED IN YOUR DIRECT TESTIMONY REASONABLE AND IN THE PUBLIC INTEREST?

A. Yes. Duke Energy Indiana has several proposals that it believes are both reasonable and in the public interest. These proposals are in response to the evolution of energy and capacity markets since its last general base rate case.

First, as to the recovery of costs and crediting of capacity market revenues, Duke Energy Indiana does not propose any changes; the Company proposes to continue to track these items through its Rider 70 filing. However, the Company is proposing to change how net margins from sales of excess capacity and energy from STBNNS transactions flow through Rider 70. Specifically, the Company proposes that (1) the Company incurs all losses below zero net margin, (2) the customer receive 100% of any net margins up to $5 million, and (3) the Company and customer sharing 50% of positive net margins above $5 million.

Second, the Company proposes to allocate 100% of natural gas FT contract expenses to native load. This change is appropriate since the FT contract is utilized to operate the natural gas generating unit across peak hours, when the energy is most likely being allocated to native load. These contracts were entered into to ensure a reliable supply of natural gas was available to operate units for native load, not to ensure supply of natural gas for non-native sales.

In conclusion, the Company's proposals modernize the partnership between customers and the Company and addresses significant changes that have occurred in energy markets since its last base rate case. I believe that these proposals will create an equitable framework for future years.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

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: ______________________
John D. Swez

Dated: April 4, 2024