

**TESTIMONY OF JOHN D. SWEZ
DIRECTOR, GENERATION DISPATCH AND OPERATIONS
DUKE ENERGY CAROLINAS, LLC
ON BEHALF OF DUKE ENERGY INDIANA, LLC
CAUSE NO. 38707-FAC109 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION**

1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is John D. Swez, and my business address is 526 South Church Street,
4 Charlotte, NC 28202.

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

6 A. I am employed by Duke Energy Carolinas, LLC ("Duke Energy Carolinas") as
7 Director, Generation Dispatch and Operations.

8 **Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND
9 AND BUSINESS EXPERIENCE.**

10 A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue
11 University in 1992. I received a Masters of Business Administration degree from
12 the University of Indianapolis in 1995. I joined PSI Energy, Inc. in 1992 and
13 have held various engineering positions with the Company or its affiliates in the
14 Power Services, Power Trading, and Fuels and Systems Optimization
15 departments. Though my title has changed in recent years, I assumed my current
16 role on January 1, 2006.

17 **Q. ARE YOU A REGISTERED PROFESSIONAL ENGINEER LICENSED IN
18 THE STATE OF INDIANA?**

JOHN D. SWEZ

- 1 -

1 A. Yes, I am.

2 **Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS DIRECTOR,**
3 **GENERATION DISPATCH AND OPERATIONS, AS THEY RELATE TO**
4 **DUKE ENERGY INDIANA, LLC (“DUKE ENERGY INDIANA” OR**
5 **“COMPANY”).**

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

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 A. First, I discuss economic dispatch in the context of the MISO Markets and how it
19 affects the supply resources that are used to serve Duke Energy Indiana’s retail
20 customers’ electricity needs. In the course of that discussion, I will describe the
21 actions Duke Energy Indiana takes, subject to operating constraints, to generate or
22 purchase power or both to serve its retail customers at the lowest fuel cost

1 reasonably possible. In addition, I generally describe the MISO Markets' charges
2 and credits that are included in the instant fuel cost adjustment filing. I provide an
3 update on the coal price decrement initiated by the Company in February 2012, a
4 summary of outages experienced during the review period, an update to the recent
5 dispatch of the Company's generating units, an update to the power purchased
6 from Benton County Wind Farm, an update on the Edwardsport IGCC generating
7 station, a change to the operational configuration of Gibson Unit 5, and a
8 discussion of the new MISO ramp capability product.

9 **II. OVERVIEW OF MISO'S ENERGY MARKETS**

10 **Q. MR. SWEZ, ARE YOU FAMILIAR WITH MISO'S ENERGY MARKETS?**

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

13 **Q. PLEASE GENERALLY DESCRIBE MISO'S ENERGY MARKETS.**

14 A. Beginning April 1, 2005, MISO began independently administering both day-
15 ahead and real-time markets for electric energy pursuant to its Open Access
16 Transmission, Energy Markets Tariff (now known as the Open Access
17 Transmission, Energy and Operating Reserve Markets Tariff or hereinafter
18 "MISO Tariff"), on file with the Federal Energy Regulatory Commission
19 ("FERC"). The real-time energy market functions as a real-time balancing market
20 for electricity. Through the day-ahead energy market, market participants can
21 mitigate their exposure to price risk in the real-time energy market. Demand bids
22 and supply offers for power are submitted to MISO by market participants,

1 including both generator owners (as sellers) and load serving entities (as buyers).
2 Thus, the Company functions as both a seller and buyer in the Energy Markets to
3 serve its retail electric customers in Indiana. Additionally, Duke Energy Indiana
4 has the ability to self-schedule certain generating resources in the Energy Markets
5 to ensure that those resources are committed and dispatched.

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

17 **Q. PLEASE EXPLAIN THE MEANING OF THE TERM “ECONOMIC**
18 **DISPATCH.”**

19 A. Economic dispatch is an operating procedure used by utilities to supply electricity
20 to their customers generally using the most cost efficient resources available,
21 recognizing and subject to any operational limits and environmental

1 considerations affecting the generation and transmission facilities available to
2 supply that electricity.

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

4 A. Self-scheduling has become a common phrase for a number of ways that a
5 generation owner can ensure that a specific unit or units will either be committed
6 or operate at or above a specific energy output level in the Energy Markets. There
7 are a variety of valid reasons for a generation owner to “self-schedule” a unit. If
8 testing of a unit is necessary, the generation owner would designate the unit as
9 “must-run,” usually designating a specific hourly output for the generating unit.
10 Similarly, the Company may frequently designate the commitment status of our
11 most economic coal-fired generating units and our economic coal-fired generating
12 units with long start up times as “must-run.” MISO, utilizing all self-scheduled
13 generator information as offered, will then perform an incremental dispatch to
14 meet the remaining demand requirements taking into consideration reliability
15 concerns. All of these activities described above are generally referred to as self-
16 scheduling. It should be noted that there is no “one size fits all” approach in
17 submitting a generating unit’s day-ahead or real-time energy offer to MISO. In
18 making the decision regarding an individual unit’s offer status, the Company
19 considers various factors such as forecasted locational marginal prices (“LMP”),
20 unit generation production cost, MISO cost impact (revenue sufficiency guarantee
21 make-whole payments, real-time price volatility make whole payment amount,
22 real-time revenue sufficiency guarantee first pass distribution, etc.), and the

1 capability and economic impact from cycling the generating unit off-line and/or
2 on-line. Before making any generation unit offer, Company personnel engage in
3 a planning process designed to minimize the total customer cost by maximizing
4 each unit's economic value.

5 **Q. PLEASE EXPLAIN LOCATIONAL MARGINAL PRICING.**

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

19 **Q. PLEASE EXPLAIN WHAT YOU MEAN BY CONGESTION.**

20 A. All energy activities on the transmission system can potentially result in
21 congestion—that is, for a period of time transmission facilities may not be
22 adequate to deliver the least-cost available energy to load in a transmission-

1 constrained area. Congestion can either be managed through methodologies, such
2 as the North American Electric Reliability Corporation's ("NERC") Transmission
3 Loading Relief ("TLR") procedures, or through market-based mechanisms, such
4 as the use of locational marginal pricing and FTRs.

5 **Q. WHAT ARE FINANCIAL TRANSMISSION RIGHTS, OR FTRS?**

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

17 **III. ECONOMIC DISPATCH IN THE ENERGY MARKETS**

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

20 A. The fundamentals of economic dispatch and hedging price risk have not changed.
21 Duke Energy Indiana's retail customers continue to enjoy the benefits of its low
22 cost generation as the Company participates in the Energy Markets. Participation

1 in those markets, however, involves a number of considerations that affect the
2 resources used and the costs incurred to serve retail customers. Those
3 considerations include certain actions within Duke Energy Indiana's control,
4 including decisions regarding self-scheduling of resources, the preparation and
5 submission of generator offer curves in the day-ahead and real-time markets, the
6 amount of retail load bid into the day-ahead market and the acquisition of FTRs,
7 and certain factors outside of the Company's control, such as the actions of other
8 market participants and decisions made by MISO to enhance reliability as well as
9 administer the energy and ancillary services markets.

10 **Q. HOW ARE THE RESPONSIBILITIES FOR DISPATCH IN THE ENERGY**
11 **MARKETS DIVIDED BETWEEN MISO AND LOAD SERVING**
12 **ENTITIES, SUCH AS THE COMPANY?**

13 A. MISO directs the dispatch of all generation connected to the transmission system
14 under its functional control. The Company submits offers for its generation
15 resources, which define the offer prices for a range of outputs, taking into account
16 physical limits. As described above, the Company may also choose to operate a
17 unit at a selected output or higher level by self-scheduling. There are a variety of
18 reasons that Duke Energy Indiana will either offer a generating resource as must-
19 run or self-schedule a unit to ensure the unit is operated as cost efficiently as
20 possible. Although designating the Company's lowest cost units as must-run
21 generally results in the lowest overall fuel costs, this may not be the case for
22 generating units in a middle or lower range of dispatch costs. Again, this depends

1 on the circumstances. For example, if “mid-merit” units are forecast to be on-line
2 for several days in a row but are “sandwiched” by a day in which they are only
3 marginal or slightly uneconomic, it may be prudent to designate such units with a
4 day-ahead offer status of must-run to avoid cycling the unit. Cycling a unit off-
5 line and then back on-line can sometimes result in higher costs during the cycling
6 period and overall.

7 In the real-time energy market, MISO sends an instruction every five-
8 minutes, called a set point, to each generating unit connected to the transmission
9 system under its functional control with updates to this instruction occurring
10 every few seconds as ancillary services are deployed on generating units that
11 cleared these same reserves. Under the ASM, Duke Energy Indiana sells
12 regulation and contingency reserve services to MISO as well as purchases these
13 ancillary services from MISO.

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

16 A. Yes. The MISO Tariff encourages the Company (and other market participants)
17 to participate in the day-ahead energy market in a number of ways. First,
18 congestion costs can only be hedged in the day-ahead market. FTRs are not
19 available to offset congestion costs incurred in the real-time market. Moreover, as
20 described below, Duke Energy Indiana is obligated to offer its generation
21 resources in the day-ahead market. Finally, virtual offers and bids can only be

1 submitted in the day-ahead market as a means of hedging certain real-time
2 operations risks.

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

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

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

13 A. Absolutely. Transactions that are scheduled in the day-ahead energy market,
14 including offers to supply generation and bids to purchase energy that are cleared
15 by MISO, create financially binding obligations to sell or purchase energy at the
16 day-ahead locational marginal prices. So, for example, when a utility bids its load
17 forecast in the day-ahead market (a demand bid), the price paid to serve that load
18 will be the day-ahead locational marginal price at the utility's load zone. If the
19 real-time load exceeds the amount of load that was bid in the day-ahead market,
20 the amount underbid will pay real-time locational marginal prices. Conversely, if
21 the real-time load is less than the amount of load that was bid in the day-ahead
22 market, the amount overbid will be sold back to the real-time market at real-time

1 locational marginal prices. Prices paid to suppliers in the real-time market are
2 handled similarly. In other words, only deviations from day-ahead schedules
3 (injections or withdrawals) are exposed to real-time locational marginal prices.

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

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

19 **Q. MR. SWEZ, ARE YOU GENERALLY FAMILIAR WITH THIS**
20 **COMMISSION’S JUNE 1, 2005, ORDER IN CAUSE NO. 42685 (“JUNE 1**
21 **ORDER”)?**

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

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

14 June 1 Order at page 13.

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

19 A. Yes, I do.

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

1 A. Yes, I do.

2 **IV. ASSIGNMENT OF GENERATION RESOURCES**

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

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

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

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

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

6 Day-ahead energy market

- 7 ▪ all expected load will be bid in the day-ahead energy market;
- 8 ▪ all available generation will be made available (offered or self-scheduled) in
9 the day-ahead energy market;
- 10 ▪ native load customers get first call on all available Company generation in the
11 day-ahead energy market; and
- 12 ▪ commitments on generation that clear the day-ahead market in excess of
13 cleared demand bids for native load will be honored in real-time and will be
14 treated as non-native sales, the net profits of which will be shared with retail
15 customers pursuant to Standard Contract Rider No. 70.

16 Real-time energy market

- 17 ▪ native load customers get first call on needed available generation that did not
18 clear the day-ahead energy market;
- 19 ▪ real-time generation in excess of real-time native load will be treated as non-
20 native sales, the net profits of which will be shared with retail customers
21 pursuant to Standard Contract Rider No. 70;

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

8 **Q. PLEASE DESCRIBE THE RAC PROCESSES IN MORE DETAIL.**

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

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

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

9 V. UNIT OPERATING ISSUES

10 Q. ARE THERE ANY NEW DEVELOPMENTS THAT ARE AFFECTING
11 THE DISPATCH OF THE COMPANY'S UNITS?

12 A. Yes. Starting in late February 2012, the Company started applying a coal price
13 decrement to the dispatch costs of Gibson 1-5, Wabash River 2-6, and Cayuga 1-2
14 generating units to correctly reflect the economics of additional costs associated
15 with avoiding or reducing surplus coal inventories. To the extent that the price
16 decrement results in units being dispatched that otherwise would not be, coal
17 coming into the station is consumed, other potential costs are avoided, and
18 customers ultimately benefit because higher cost alternatives to manage the
19 inventory are avoided. With the price decrement in place, the Company initially
20 saw a significant increase in generation output from these units. As the level of
21 the coal price decrement has decreased over time, the impact of the decrement has
22 lessened. In short, the price decrement is working as designed. It should be noted

1 that on specific hours and days, the price decrement will have no impact on the
2 commitment and dispatch of the Company's generating units because the unit in
3 question was already economic without application of the price decrement. In
4 other words, the price decrement does not make a difference under certain
5 circumstances.

6 On July 28, 2015, a non-zero coal price decrement was initiated for
7 Cayuga 1-2 and Gibson 1-5. In addition, the coal price decrement was initiated
8 for Wabash River 6 on November 11, 2015. Due to the planned retirement of
9 Wabash River 2-5 on April 15, 2016, the coal price decrement was not applied to
10 these units.

11 **Q. IN THE COMMISSION'S OCTOBER 30, 2013 ORDER IN CAUSE NO.**
12 **38707 FAC 96, THE COMMISSION ORDERED DUKE ENERGY**
13 **INDIANA TO PRESENT THE INPUTS TO ITS CALCULATION OF THE**
14 **COAL PRICE DECREMENT APPLICABLE TO EACH FAC FILING AS**
15 **SUPPORT FOR THE REASONABLENESS OF ITS PRICING. ARE YOU**
16 **PROVIDING THESE INPUTS WITH YOUR TESTIMONY?**

17 A. Yes. Petitioner's Confidential Exhibit 6-A provides the coal stacks for the time
18 period March through May 2016.

19 **Q. DOES THE COMPANY PLAN TO KEEP THE COAL PRICE**
20 **DECREMENT PROCESS IN PLACE FOR 2016?**

21 A. Yes. The Company continues to forecast its coal inventory position as part of the
22 normal course of business.

1 **Q. ARE THERE ANY OTHER DEVELOPMENTS THAT COULD AFFECT**
2 **THE DISPATCH OF THE COMPANY'S UNITS?**

3 A. On June 29, 2015, the United States Supreme Court remanded, without vacatur,
4 the Environmental Protection Agency's ("EPA") Mercury and Air Toxics
5 Standards ("MATS") back to the D. C. Circuit Court. The D.C. Circuit Court
6 ordered on December 15, 2015 that the MATS rules will remain in effect while
7 the EPA works on a final cost finding. The court noted in the order that the EPA
8 "has represented that it is on track to issue a final finding" to address the Supreme
9 Court's concern that cost was a necessary consideration when deciding to regulate
10 mercury emissions from power plants. The EPA's final supplemental finding was
11 delivered to the D. C. Circuit court on April 15, 2016 and then published in the
12 Federal Register on April 25, 2016. A coal mining company sued the EPA after
13 the supplemental finding was published on April 25. The courts have yet to rule
14 on the lawsuit. Emission allowance prices have not changed materially and
15 continue to constitute a relatively small portion of the overall variable cost of a
16 fossil generation unit.

17 **Q. IN THE COMMISSION'S DECEMBER 28, 2011 ORDER IN CAUSE NO.**
18 **38707 FAC90, THE COMMISSION ORDERED DUKE ENERGY**
19 **INDIANA TO DISCUSS IN FUTURE FAC PROCEEDINGS MAJOR**
20 **FORCED OUTAGES OF UNITS OF 100 MW OR MORE LASTING**
21 **MORE THAN 100 HOURS. WERE THERE ANY SUCH OUTAGES**

1 **OCCURRING DURING THIS REPORTING PERIOD, MARCH**
2 **THROUGH MAY 2016?**

3 A. Yes. An outage occurred at Wabash River 6 starting at April 6, 2016 at 01:46 and
4 ending on April 15, 2016 at 24:00. This outage was associated with the shutdown
5 of this unit as required prior to April 15, 2016.

6 **Q. WERE THERE ANY ISSUES THAT AFFECTED THE DISPATCH OF**
7 **WABASH RIVER 2-5 UP UNTIL THE RETIREMENT OF THE UNITS IN**
8 **APRIL 2016?**

9 A. As we have previously indicated, Wabash River Units 2-5 were retired on April
10 15, 2016. These units were granted a one-year extension of the April 2015 MATS
11 rule compliance date due to the need for at least two of the four units to operate at
12 any given time for transmission system reliability (in addition to Wabash River
13 Unit 6, which also has a one-year MATS rule extension of time). In consideration
14 of the minimization of MATS-related emissions during the extension period and
15 the operational complexities of units at this point in the lifecycle, Duke Energy
16 Indiana employed a MISO offer strategy that prioritized availability and operation
17 of the units to solve transmission reliability constraints. As a result, Duke Energy
18 Indiana generally held two of the four of Wabash River Units 2-5 in reserve
19 shutdown available for emergency operation only. The number of units in reserve
20 versus operation varied depending on unit availability, the needs of the
21 transmission system, and energy prices in the MISO market. Additionally, offer
22 prices on these units were adjusted to reflect these considerations. The

1 Company's goal was to maintain the availability of the generating units primarily
2 for transmission reliability support, and specifically to maintain availability
3 during peak demand times such as summer and winter periods when transmission
4 related events and/or energy prices had the highest customer impact.

5 Because these units were not available for the full MISO capacity
6 planning year, Duke Energy Indiana sought and was granted a FERC waiver so
7 that it was not required to offer the units into the MISO resource adequacy
8 capacity market for planning year 2015/2016.

9 **Q. PLEASE PROVIDE AN UPDATE ON THE CURRENT OPERATION OF**
10 **WABASH RIVER 6.**

11 A. As discussed, Wabash River Unit 6 had a one-year MATS rule extension until
12 April 15, 2016, after which time the unit suspended operation. As the
13 Commission is aware, Duke Energy Indiana has been evaluating the potential to
14 convert Wabash River 6 to natural gas fuel. The Company has decided not to
15 pursue this, and on June 7, 2016, Duke Energy Indiana submitted an Attachment
16 Y notification to MISO requesting a decommissioning and retirement date of
17 December 7, 2016 for Wabash River 6 (318 MW) as well as the Wabash River 7
18 (8 MW) diesel units. MISO is studying the decommissioning request and has not
19 provided the conclusion to date.

20 **Q. IN THE COMMISSION'S SEPTEMBER 26, 2012 ORDER IN CAUSE NO.**
21 **38707 FAC93, THE COMMISSION ORDERED DUKE ENERGY**
22 **INDIANA TO PROVIDE AN UPDATE IN THIS PROCEEDING ON THE**

1 **NEGATIVE LMP SITUATION WITH BENTON COUNTY WIND FARM.**
2 **WILL YOU PLEASE DESCRIBE THIS SITUATION AND PROVIDE THE**
3 **REQUESTED UPDATE?**

4 A. Starting in 2012, during various times primarily in the spring, fall, and winter
5 seasons, Benton County Wind Farm (“BCWF”) received persistent negative day-
6 ahead and real-time LMP’s at the generator node. During this time, BCWF was
7 registered at MISO as an Intermittent Resource, which means it had no ability to
8 be committed or decommitted by, or follow the setpoint instructions of, MISO
9 during normal energy market operations. MISO did have the ability to curtail the
10 output of the units, however, through manual curtailment. Due to the nature of
11 the contractual arrangement between the Company and BCWF and the way MISO
12 treated offers from Intermittent Resources, the offer made by the Company to
13 MISO for this generator was equal to the day-ahead forecast of the anticipated
14 energy from the facility. The Company set the unit minimum and maximum
15 loading equal to the forecasted generation amount, and, in addition, used a
16 commitment status of must-run, meaning that MISO cleared the generator at any
17 LMP, positive or negative, in the day-ahead market. As a result, negative revenue
18 (meaning that payments must be made to send the power into the MISO system)
19 was sometimes received by this generator in the day-ahead markets. Because the
20 unit was an intermittent unit, the unit had no ability to be dispatched up or down
21 and, as a result, no offer was made in the real-time market. Thus, it was possible

1 to receive negative revenue in the real-time market as well if generation from the
2 unit was greater than the day-ahead award and real-time LMPs were negative.

3 MISO's creation of the Dispatchable Intermittent Resource ("DIR")
4 construct was designed to allow MISO to better manage the output of intermittent
5 resources, thereby allowing for better management of congestion in certain areas,
6 such as where Benton County Wind Farm is located. On March 1, 2013, Benton
7 County Wind Farm began operation as a DIR, as required by MISO. Although it
8 appears that the DIR construct is giving MISO additional tools to manage
9 congestion at Benton County Wind Farm, negative LMPs at times do continue to
10 be observed.

11 On June 17, 2013, the Company received an invoice for payment from
12 Benton County Wind Farm for March, April, and May 2013 liquidated damages
13 for production that was not generated. The Company disputed this invoice and, as
14 a result, did not issue payment or include the invoice in any FAC proceeding. In
15 accordance with provisions of the contract, the Company and Benton County
16 Wind Farm had negotiations regarding this invoice and other issues pertaining to
17 operation under the MISO DIR. On December 16, 2013, Benton County Wind
18 Farm filed a lawsuit against Duke Energy Indiana in United States District Court
19 for the Southern District of Indiana, alleging that Duke Energy Indiana breached
20 its contract with the wind farm (Case No. 113CV1984SEBTAB). A trial was
21 scheduled for August 2015, however, in early July the court entered summary
22 judgment on behalf of Duke Energy Indiana in the case, meaning that the Court

1 found the PPA was not a take or pay contract and that the Company's supply offer
2 was found to be reasonable. Because the Court entered judgment in the
3 Company's favor on all remaining claims, no payment is owed to Benton County
4 Wind Farm for power not actually generated and delivered. As a result, the
5 Company is not required to nor has plans to pay the invoice (discussed above)
6 from Benton County Wind Farm for March, April, and May 2013 liquidated
7 damages for production that was not generated. On July 30, 2015, Benton County
8 Wind Farm filed a notice of appeal. As required in the appeal process, both
9 parties participated in a court-ordered settlement conference. No settlement was
10 reached as a result of this effort. The appeal was then fully briefed and oral
11 argument was heard in the 7th Circuit Court on February 26, 2016. No decision
12 has been issued at this time.

13 **Q. PLEASE PROVIDE AN UPDATE ON THE EDWARDSPORT IGCC**
14 **GENERATING STATION.**

15 A. During March 2016, the station produced the 5th most generation in any month
16 since being declared commercial. During periods of April and May 2016, the
17 station underwent its spring maintenance outage. During June, the station
18 rebounded with the 4th most generation in any month.

19 **Q. PLEASE DESCRIBE THE OFFER THAT IS BEING MADE FOR**
20 **EDWARDSPORT IGCC.**

21 A. When the unit's gasifiers are available or operating, Edwardsport is being offered
22 with a commitment status of must-run with the unit's parameters outlined for

1 MISO, as is typically the case with other Duke Energy Indiana large coal
2 generating units. Edwardsport has followed MISO's dispatch direction between
3 the minimum and maximum capability of the unit during this time. In addition,
4 during times when syngas is not available and the station is available on natural
5 gas operation, the unit will typically be offered to MISO with a commitment
6 status of economic and can be committed and dispatched at MISO's discretion.

7 **Q. PLEASE DESCRIBE THE OPERATIONAL CONFIGURATION CHANGE**
8 **THAT OCCURRED ON MARCH 1, 2016 FOR GIBSON UNIT 5.**

9 A. Prior to March 1, 2016 Gibson Unit 5, although owned 50.05% by Duke Energy
10 Indiana, 25% by Wabash Valley Power Association ("WVPA"), and 24.95% by
11 Indiana Municipal Power Agency ("IMPA"), was offered to MISO by Duke
12 Energy Indiana as a whole (100%) unit. Thus, the Company offered the entire
13 unit to MISO, and MISO settled the charges and credits as if Duke Energy
14 Indiana owned 100% of the unit. Outside of the MISO market, the Company then
15 sent the WVPA and IMPA share of the energy and related charges and credits,
16 through various billing mechanisms and market instruments, to each owner
17 respectively. At WVPA's request, on March 1, 2016, the WVPA share of Gibson
18 5 was successfully pseudo-tied to PJM. Thus, the WVPA share of Gibson 5
19 became part of the PJM market on this date. The remaining Duke Energy Indiana
20 and IMPA share of Gibson 5 remains in MISO. This transition occurred smoothly
21 and accurately, and there has been minimal change to the Company's customers

1 because only the Duke Energy Indiana share of Gibson 5 served Duke Energy
2 Indiana customers before and after this change.

3 **VI. ENERGY AND ANCILLARY SERVICES MARKETS CHARGES AND**
4 **CREDITS**

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

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

- 19 ▪ FTR congestion costs;
- 20 ▪ FTR congestion credits;
- 21 ▪ FTR auction settlements;

- 1 ▪ virtual bids and offers in the day-ahead market which are used for hedging
- 2 jurisdictional load;
- 3 ▪ day-ahead recovery of unit commitment costs;
- 4 ▪ excess congestion charge fund credit;
- 5 ▪ real-time marginal losses surplus credit;
- 6 ▪ RAC recovery of unit commitment costs;
- 7 ▪ marginal losses surplus credit; and
- 8 ▪ inadvertent energy charge or credit.

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

12 A. Consistent with the June 1 Order, Duke Energy Indiana has included in this filing
13 the Energy Markets charges and credits that are incurred as a cost of reliably
14 meeting the power needs of Duke Energy Indiana's load, including: (1) Energy
15 Markets charges and credits associated with Duke Energy Indiana's own
16 generation and bilateral purchases that were used to serve retail load;
17 (2) purchases from MISO at the full LMP at Duke Energy Indiana's load zone; (3)
18 other Energy Markets charges and credits included in the list on page 37 of the
19 June 1 Order; and (4) credits and charges related to auction revenue rights
20 ("ARRs") and Schedule 27 and 27-A.

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

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

9 **Q. WERE THERE ANY NEW MISO CHARGES OR CREDITS**
10 **INTRODUCED DURING THIS FAC PERIOD?**

11 A. Yes. MISO implemented the ramp capability product on May 1, 2016.

12 **Q. WHAT IS THE PURPOSE OF THE RAMP CAPABILITY PRODUCT?**

13 A. MISO created the ramp capability product as a market-based approach to better
14 position resources with the ability to move (ramp) in order to manage net load
15 variations and uncertainties such as those created by additional renewable energy
16 resources.

17 **Q. WHAT IS DUKE ENERGY INDIANA PROPOSING FOR THE**
18 **TREATMENT OF THE RAMP CAPABILITY CREDITS AND CHARGES?**

19 A. Similar to the ancillary services products, two additional charge types, the Day-
20 Ahead and Real-Time Ramp Capability Amount, were created that represent an
21 asset owners compensation for up and/or down ramp capability in the Day-Ahead
22 and/or Real-Time markets. In addition, the corresponding cost of supplying ramp

1 capability, the Ramp Capability Distribution Uplift Amount, was added as one of
2 the components that comprise the existing Real-Time Revenue Neutrality Uplift
3 Amount. Given that the Real-Time Revenue Neutrality Uplift Amount is
4 recovered in the RTO filing, this creates a mismatch between the credit and
5 charge for the ramp capability product. Duke Energy Indiana proposes to include
6 both the charge types that represent the assets compensation for providing this
7 service, the Day-Ahead and Real-Time Ramp Capability Amount, as well as the
8 corresponding cost component for these new charge types from the Real-Time
9 Revenue Neutrality Uplift Amount, the Ramp Capability Distribution Uplift
10 Amount, in the Fuel Adjustment Clause.

11 **Q. WHAT HAS BEEN THE IMPACT OF THE RAMP CAPABILITY**
12 **PRODUCT ON DUKE ENERGY INDIANA?**

13 A. At times, Duke Energy Indiana generating units are both clearing and/or being
14 deployed as ramp capability in both the Day-Ahead and Real-Time markets.

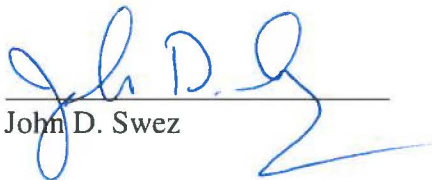
15 **VII. CONCLUSION**

16 **Q. DOES THIS CONCLUDE YOUR PREPARED DIRECT TESTIMONY?**

17 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: 7/27/2016

PETITIONER'S EXHIBIT 6-A IS CONFIDENTIAL