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STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

IN THE MATTER OF THE PETITION OF DUKE ENERGY INDIANA, INC., PURSUANT TO THE COMMISSION'S MAY 18, 2004 ORDER IN CAUSE NO. 42359 AND IND. CODE § 8-1-2-42, FOR (1) AUTHORITY TO RECOVER VIA RIDER NO. 70 CERTAIN COSTS ASSOCIATED WITH PETITIONER'S POWERSHARE® PROGRAM AND SPECIAL CONTRACT DEMAND RESPONSE PROGRAM; (2) AUTHORITY TO SHARE NON-NATIVE SALES PROFITS/LOSSES VIA RIDER NO. 70; (3) APPROVAL TO RECOVER MISO MODULE E-1 COSTS VIA RIDER 70; (4) APPROVAL OF THE TREATMENT OF MISO MODULE E-1 REVENUES; AND (5) CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION RELATING TO PETITIONER'S POWER PURCHASES AND SALES AND NON-NATIVE SALES	)	CAUSE NO. 44348 SRA 1 APPROVED: JUN 10 2015

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On January 23, 2015, Duke Energy Indiana, Inc. ("Petitioner" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause.

Also on January 23, 2015, Duke Energy Indiana filed the testimony and exhibits of:

- Mr. Scott Park, Director, IRP & Analytics – Midwest for Duke Energy Business Services LLC
- Mr. Wenbin (Michael) Chen, Manager, Midwest Trading for Duke Energy Business Services LLC
- Mr. Benjamin Passty, Lead Load Forecasting Analyst in Load Forecasting and Fundamentals for Duke Energy Business Services LLC
- Mr. Richard A. Philip, Lead Product & Service Manager for Duke Energy Business Services LLC
- Ms. Suzanne E. Sieferman, Manager Rates and Regulatory Strategy for Duke Energy Business Services LLC
- Mr. Scott A. Burnside, Manager – Post Analysis and Regulatory Support for Duke Energy Carolinas, LLC

On April 2, 2015, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and exhibit of Ms. Stacie R. Gruca, Senior Utility Analyst in the Electric Division of the OUCC.

An evidentiary hearing was held in this Cause on May 6, 2015, at 9:30 a.m. in Room 224 PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the evidentiary hearing, Duke Energy Indiana and the OUCC offered their evidence, which was admitted into the record without objection. No members of the general public appeared or sought to testify at the hearing.

Based on the applicable law and the evidence herein, the Commission finds:

1. **Notice and Commission Jurisdiction.** Due, legal, and timely notice of the evidentiary hearing was given and published by the Commission as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1 and subject to the Commission's jurisdiction for approval of its rates and charges pursuant to Ind. Code § 8-1-2-42. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this Cause.

2. **Petitioner's Characteristics.** Duke Energy Indiana is a public utility organized and existing under the laws of the State of Indiana, and has its principal office at 1000 East Main Street, Plainfield, Indiana 46168. Duke Energy Indiana is engaged in rendering electric utility service in the State of Indiana, and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery, and furnishing of such electric service to the public. Duke Energy Indiana directly supplies electric energy to approximately 810,000 customers located in 69 counties in the central, north central, and southern parts of Indiana.

3. **Relief Requested.** Petitioner requests the Commission find that: (1) Petitioner's PowerShare® and special contract demand response program costs for the period October 1, 2013 through May 31, 2014 are reasonable; (2) Petitioner is authorized to debit (or credit) customers with the difference between its PowerShare® program costs actually incurred and amounts included for the pro forma test period in Cause No. 42359, as modified by an 8/12 factor; (3) Petitioner is authorized to debit (or credit) customers with 50% of Duke Energy Indiana's net off-system or non-native sales profits (or losses) above (or below) the base amount included in Duke Energy Indiana's rates, as modified by an 8/12 factor, including the treatment and recovery of its non-native sales hedging activity; (4) Petitioner's treatment of Midcontinent Independent System Operator ("MISO") Module E-1 revenues is proper; (5) Petitioner is authorized to recover MISO Module E-1 costs and applicable reconciliation amounts.

Further, Petitioner requests the Commission find the following trade secret information is entitled to confidential treatment: (1) all pricing and vendor information pertaining to sales made by Duke Energy Indiana for native load purposes; (2) power sales contracts; (3) information related to a customer-specific peak load management contract with Steel Dynamics, Inc. ("SDI"); (4) information from the Generating Availability Data System ("GADS") relating to statistical generation operating data; and (5) certain information relating to non-native sales.

4. Prior Applicable Commission Orders. On May 18, 2004, in Cause No. 42359, Petitioner's last general retail base rate case, the Commission approved Petitioner's Rider 70, the Summer Reliability Rider, for the recovery of summer purchased power costs, PowerShare® Program costs, and for the sharing of off-system sales profits above and below the level built into base rates. Since issuance of that Order, the Commission has issued Orders in Cause Nos. 42870, 43074, 43302, 43505, 43715, 43906, 44035, 44214 and 44348 addressing Petitioner's requested recovery of costs under Rider 70 and authorizing modifications to the applicable recovery parameters when determined reasonable. For ease of reference, the Commission's most recent Order in Cause No. 44348 directed Petitioner to make future Rider 70 filings under Cause No. 44348 SRA-X.

5. Petitioner's Case-in-Chief.

A. Rider 70 Schedule Realignment. Mr. Park discussed the proposed Rider 70 filing schedule to align the recovery period with the MISO planning year, running June 1 through May 31. He testified that pursuant to the Commission's Order in Cause No. 44348, Duke Energy Indiana met with the OUCC on August 20, 2014, and general agreement was reached for the proposed realignment strategy. He testified that to implement the new schedule, a transitional filing is needed that covers less than a full calendar year. He indicated that the parties agreed this Rider 70 filing would cover only the period October 1, 2013 through May 31, 2014, a truncated eight-month period. The next proceeding will then cover the annual period June 1, 2014 through May 31, 2015, in alignment with the MISO planning year. Petitioner and the OUCC agreed to apply an 8/12 factor to any annualized test period amounts approved in Cause No. 42359. For the non-native load sharing mechanism, Petitioner utilized 8/12 of the annual net credit included in base rates to calculate the amount due from customers. For PowerShare®, Petitioner utilized 8/12 of the test period amount built into base rates, which was deducted from the total costs for the eight-month period in determining the costs in excess of the level built into base rates.

B. Reliability Power Purchases. Mr. Passty testified as to Petitioner's load forecast for the fall of 2012, which projected a peak demand of 6,585 MW. He testified that customers who were served under Duke Energy Indiana's economic development riders totaled eight MWs of incremental load. He indicated the incremental load is very small and already captured in the peak summer load forecast, resulting in no incremental costs related to serving those customers.

Mr. Philip testified as to Petitioner's energy efficiency resources, including its traditional demand-side management and demand response programs, customer-specific contract offerings, and the PowerShare® program.

Mr. Park testified that Petitioner continues to rely on a portfolio approach to meet its native load customers' demand requirements and that renewable resources, purchased power when needed, energy efficiency, PowerShare®, and other demand-side management programs continue to play an important role in Duke Energy Indiana's resource mix.

Mr. Park testified that Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin for the summer of 2013, and as a result, Petitioner made forward capacity sales of 230 Zonal Resource Credits ("ZRCs") in the bilateral market ahead of MISO's Planning Resource Auction ("PRA") and additional net sales of 352.7 ZRCs in the PRA.

Mr. Park testified that Petitioner purchased eight MW of installed capacity ("ICAP") from Logansport Municipal Utilities ("Logansport") under a long-term contract that began in 2009. However, because the unit became unavailable in summer 2011 and has not been repaired, no payments were made to Logansport under the contract for the period October 1, 2013 through May 31, 2014.

Without certain special contracts and the PowerShare® impacts, Petitioner's reserve margin on an unforced capacity ("UCAP") basis, as required by MISO, was 9.7%. Mr. Park testified, altogether, the jurisdictional allocation of Rider 70 costs for the period October 1, 2013 through May 31, 2014 results in a request to recover a total of $8,391,102 before adjustment for Utility Receipts Tax via Rider 70 over an eight-month period, which amounts to a decrease of $0.16 on the monthly bill for a typical residential customer. He stated this amount includes a combination of: (1) a charge for the amount of PowerShare® program costs for the eight-month period above that reflected in base rates, (2) a charge for non-native sales profits (reflecting the fact that Duke Energy Indiana did not realize annual non-native sales profits above the level included in base rates for the eight-month period), and (3) a credit resulting from reconciliation for Rider 70 costs approved in Cause No. 44348 to amounts collected.

Mr. Park testified that, beginning with the MISO planning year of June 1, 2009 through May 31, 2010, there is a requirement that the Loss of Load Expectation ("LOLE") due to resource inadequacy cannot exceed one occurrence in ten years. He explained that the MISO Planning Reserve Margin ("PRM") assigned to each load serving entity ("LSE") is on a UCAP basis, such that the PRM on an ICAP basis will be translated to PRM_{UCAP} by multiplying it by one minus the MISO system average equivalent forced outage rate excluding events outside of management control ("$XEFOR_d$"). Each capacity resource is valued at its unforced capacity rating (i.e., installed rating multiplied by one minus the unit-specific $XEFOR_d$). He testified that under the MISO Module E-1 construct, compliance is assessed annually by comparing the amount of ZRCs designated by each LSE with its annual forecasted peak load coincident with the MISO peak multiplied by one plus the PRM_{UCAP}.

With this filing and going forward, Petitioner is aligning to the MISO planning year. For the planning year of October 2013 through May 2014, to satisfy the LOLE requirement, MISO established a minimum 6.2% required reserve margin on an UCAP basis. Mr. Park noted this is the same requirement for the period of June 1, 2013 through September 30, 2013 that was reviewed by the Commission in Cause No. 44348.

Mr. Park described how Petitioner used the MISO Module E-1 Reserve Margin requirements as the minimum for future capacity purchases, as required in Cause No. 43505. He explained Petitioner used the required PRM_{UCAP} of 6.2% in the assessment of its supply vs. demand position. The surplus ZRCs were sold forward and/or offered into the PRA, and that for summer 2013 the resulting actual PRM_{UCAP} was 6.2%. Mr. Park stated that in future years it is unlikely Petitioner would be able to meet the exact required PRM_{UCAP} because the ability to do so is highly dependent on the total number of ZRCs that are purchased, the block sizes available for purchase, and the marketability of any surplus in the PRA. Nevertheless, Petitioner will continue to target the MISO Module E-1 PRM_{UCAP} as the appropriate minimum reserve requirement.

Mr. Park explained that although Petitioner's reserve margin was above the summer 2013 requirement even without taking into account special contracts and PowerShare®, it must take a long-term approach with regard to resource planning. He discussed the true value in the PowerShare® program and special contracts in the long-term avoidance of additional generating capacity.

Mr. Park further explained that meeting the minimum reserve margin requirement does not ensure Petitioner will not need to buy expensive energy from the spot market during the year. Factors like unexpected plant shutdowns, derates, and extreme weather can increase reliance on the spot market at just the time that prices are increasing. He explained buying forward energy or price hedges limits exposure to price spikes. However, all ZRCs are purely capacity products to meet MISO resource adequacy requirements.

Mr. Park testified that Duke Energy Indiana continues to be committed to a portfolio approach to meet its native load peak demand obligations. Mr. Park noted that for summer 2013, Petitioner met native load customers' peak demand requirements through a resource mix consisting of 89.9% through its existing fleet of generating assets, 9.2% through a combination of conservation and demand response products, and 0.9% through renewable resources. Mr. Park testified that hourly spot purchases cannot take the place of firm capacity, but that hourly spot power is utilized when available and to the extent such power purchases are economic to meet short-term needs.

Mr. Chen described the bilateral capacity sales that were made for the eight-month period of October 1, 2013 through May 31, 2014. Mr. Chen testified that there was one bilateral capacity sale within the relevant time period with a counterparty, which had total sale proceeds of $587,965. He stated that Duke Energy Indiana actively participated in MISO's annual PRA, where it purchased capacity from MISO for native load and sold generation capacity to MISO, at the same auction clearing price, resulting in net capacity sales from Petitioner to MISO. Mr. Chen testified that proceeds from sales in the annual auction were $89,989 for this Rider 70 proceeding, which is included in the calculation of non-native sales profits. He further testified as to his belief that the capacity sales were reasonable and only made once it was determined Petitioner had surplus capacity after complying with MISO's resource adequacy requirement. He stated the bilateral sales of ZRCs were the result of arms' length negotiations at then-prevailing market prices.

Mr. Chen stated that Duke Energy Indiana contracted with Logansport in 2009 for the rights to the generating capacity and energy from Logansport Unit #6 for the period July 1, 2009 through December 31, 2018. He explained that although the capacity is available year-round, the payment is prorated from June through September each year of the contract. Because the

Logansport unit became unavailable in July 2011, capacity payments were suspended and the capacity was removed from Petitioner's MISO resource adequacy compliance plans.

Mr. Chen sponsored a confidential exhibit that included the agreement or confirmation supporting the capacity sale.

C. <u>PowerShare® and Customer-Specific Peak Load Management Costs</u>. Mr. Philip described Petitioner's PowerShare® Program. He stated that PowerShare® has been offered under Standard Contract Rider No. 23 since 2000. The program provides financial incentives to industrial and commercial customers to reduce their electric demand during Petitioner's peak load times and has two offerings: CallOption and QuoteOption. Under the CallOption component, customers commit to a pre-selected load reduction at a selected strike price. Mr. Philip explained that CallOption customers are paid a monthly premium for their commitment and an energy credit when they are called upon to reduce their load. Mr. Philip testified that the terms of the CallOption program vary depending on customer-selected parameters that include the contracted for option load, the strike price, the selected duration, and the maximum number of calls.

Mr. Philip explained that QuoteOption customers may elect whether or not to reduce load when called upon. As a result, QuoteOption customers are not paid a monthly premium, but an energy credit is paid when load reductions are made in response to Petitioner's request. The QuoteOption is available year-round, in accordance with the Commission's Order in Cause No. 42870.

Mr. Philip testified that during the winter of 2013/2014, there were 11 PowerShare® CallOption economic events due to the severe cold associated with the "Polar Vortex" weather events during the first quarter of 2014. For the 2013/2014 planning year, Petitioner entered into 104 CallOption contracts.

Mr. Philip described the PowerShare® attributes for the June 2014 through May 2015 planning year. He explained that with changes to MISO's resource adequacy framework the enrollment process will start before the upcoming planning year. Duke Energy Indiana is currently marketing the program for next summer, with a goal for completion of MISO registrations by February 1, 2014. Mr. Philip noted two changes for the 2014/2015 program: (1) event incentives will be paid only for load reduced during an event; and (2) a new PowerShare CallOption option is available that provides flexibility for economic event duration from four to eight hours and shorter notice to customers of events.

Mr. Philip testified regarding Duke Energy Indiana's customer-specific peak load management contract with SDI, which costs are recovered through Rider 70. He provided confidential testimony as to the total expenditures to be charged to customers resulting from the SDI contract. Mr. Philip testified that PowerShare® and any customer-specific peak load management contracts are registered with MISO, as both Load-Modifying Resources ("LMRs") and Emergency Demand Response resources, which allow MISO to call on the programs when MISO declares North American Energy Reliability Corporation's Energy Emergency Alert Level 2 events or higher. However, for the planning year 2014/2015, Duke Energy Indiana will only utilize these programs as LMRs. He also testified that registering the programs as LMRs allows Petitioner to reduce its MISO resource adequacy requirements.

Mr. Philip also provided an update on Duke Energy Indiana's energy efficiency efforts at the time of the filing. He explained that having received clarification from MISO, the applicable incremental impacts from Duke Energy Indiana's energy efficiency portfolio were incorporated in the coincident peak forecast submitted to MISO for the planning year 2014/2015.

D. <u>Sharing of Non-Native Sales Profits</u>. Mr. Burnside summarized Duke Energy Indiana's non-native sales strategy for the period of October 2013 through May 2014.

Ms. Sieferman explained that in Cause No. 42359, the Commission approved a sharing on a 50/50 basis, the differential between net non-native sales profits realized by Petitioner and the $14,747,000 net profit level for non-native sales included in the determination of Duke Energy Indiana's revenue requirement. Ms. Sieferman testified the Commission also found that Petitioner's base rates should reflect a reasonable level of trading expenses required to achieve those non-native sales profits in the amount of $3,953,000.

Mr. Burnside described the types of non-native sales Petitioner made in the past year, including: (1) day ahead and real time sales to MISO; (2) sales of capacity in the MISO PRA that do not offset reliability purchases; (3) energy or capacity sales to non-MISO counterparties; (4) realized margin from non-native sales of emission allowances; (5) realized margin from non-native hedging activity; and (6) non-firm retail contracts with Duke Energy Indiana customers. Mr. Burnside explained how revenues and expenses allocable to non-native sales are determined.

Mr. Chen explained Petitioner's power hedging program and that Duke Energy Indiana also hedges for non-native load with the objective to lock in a margin for the forecasted surplus generation not allocated to serve native load. Mr. Chen testified that he believes Petitioner's power hedging practices are reasonable. For the period at issue, the non-native hedges resulted in a loss of $1,283,245.

Mr. Burnside stated that gross profits from non-native sales for October 1, 2013 through May 31, 2014, total $3,440,325 before trading expense reduction or prior period adjustment amounts. Mr. Burnside explained that due to MISO's settlement cycles, there may be further revisions to non-native sales calculations. Petitioner proposed to include such prior period adjustments in future Rider 70 filings. For this filing, Petitioner calculated a prior period adjustment of $15,061. This adjustment was made to reflect the fact that during the current Rider 70 non-native power sales period (October 1, 2013 – May 31, 2014), Petitioner received updated MISO settlement statements for operating dates impacting prior Rider 70 non-native power sales periods.

Mr. Burnside testified regarding the Post Analysis Cost Evaluator ("PACE") model and that it economically dispatches generating units on an hourly basis, matches the demand (load) with available supply resources (generation or purchases), and allocates those production costs for serving native load and non-native sales. Mr. Burnside testified that starting in late February 2012, a price decrement was applied to the dispatch costs of Gibson 1-5, Wabash River 2-6, and

Cayuga 1-2 generating units to correctly reflect the economics of additional costs associated with avoiding or reducing surplus coal inventories. He explained that the fuel costs used in PACE are undecremented which prevents decremented units with higher actual fuel costs from displacing undecremented units with lower fuel cost in the native stack and that all of Petitioner's resources are included as available resources in this process.

E. Rider 70 Calculation and Rate Impact. Ms. Sieferman explained that Rider 70 was designed to recover the demand or capacity component of summer reliability purchased power costs, the reconciliation of actual and authorized PowerShare® costs, the sharing of non-native sales profits, and the recognition of a standard reconciliation process. She indicated that the period covered by this filing is the eight months ended May 31, 2014.

Ms. Sieferman testified that $1,569,505 in capacity purchases were made in the PRA for native load during the eight months ended May 31, 2014; however, they were offset by revenues received for generating capacity offered in to the PRA, resulting in no net capacity purchases during the eight months ended May 31, 2014. The net capacity sales were $677,954. Ms. Sieferman also explained Duke Energy Indiana's treatment of capacity sales included in this filing. She stated that sales of surplus capacity are from Petitioner's generating capacity or prior capacity purchases, and that capacity sales occurring in periods without capacity purchases, or in excess of capacity purchase values, were included in the non-native load sharing mechanism.

Ms. Sieferman testified that Rider 70 provides for the tracking of actual PowerShare® CallOption premiums, CallOption and QuoteOption energy credits, and costs associated with a customer-specific peak load management contract with SDI. She testified that Petitioner's total peak load management costs included in Rider 70 for the eight-month period ended May 31, 2014, totaled $4,976,111, which is more than the amount authorized in Cause No. 42359. As such, retail customers will be charged $4,294,111 in this proceeding.

Ms. Sieferman stated the results of Petitioner's non-native sales for the eight-month period ended May 31, 2014, total a $3,440,325 gain before applicable prior period adjustments and fixed trading expenses, or a $820,053 net non-native sales gain after the adjustments. Ms. Sieferman explained the amount of net non-native sales profit allocated to retail customers is $752,735. She explained that, when this is compared to the net non-native sales profits currently in base rates, the authorized 50/50 sharing results in a charge to customers of $4,539,299.

Ms. Sieferman explained that Rider 70 includes a standard reconciliation provision in which Duke Energy Indiana determines the difference between Rider 70 amounts approved for recovery and Rider 70 amounts actually billed to customers. Accordingly, a reconciliation of billed Rider 70 amounts corresponding to those authorized for recovery in Cause No. 44214 was made, and the reconciliation results in a $442,308 over-collection, which has been included as a credit to customers.

Ms. Sieferman explained that in Cause 44348, the Commission approved a rate migration adjustment to Petitioner's allocation factors to be used in the development of Rider 70 rates. In that Cause, Duke Energy Indiana committed to continue to monitor the rate migrations between Rate HLF (high load factor) and LLF (low load factor) industrial customers each year and to propose an update to the allocation factors if there was a net change of greater than 10 MW from the 2012 levels. Ms. Sieferman testified that Petitioner completed the 2013 study resulting in an additional migration of approximately 26 MW. This results in a change in the allocation percentages of approximately 2%. Accordingly, Petitioner included this change to the HLF/LLF rate migration adjustment in the development of the Rider 70 rates in this proceeding, which is set forth in Petitioner's Exhibit F-2. Ms. Sieferman also testified that in May 2014, Petitioner completed its transition of certain lighting customers from the area lighting and outdoor lighting rate classes into an unmetered outdoor lighting service class.

In total, the amount to be recovered via Rider 70, including purchased power demand costs, PowerShare® costs, non-native sales profits sharing, and reconciliation is set forth in Petitioner's Exhibit F-2. Ms. Sieferman explained that these costs would be recovered over an eight-month period, and that Petitioner's request herein would result in a decrease of approximately $0.16 in the base bill of a typical residential customer compared to what such customer is paying today (excluding various tracking mechanisms and sales tax).

Ms. Sieferman explained that in order to effectuate Rider 70, Petitioner would defer the jurisdictional component of its purchased power costs until such time as the net purchased power costs are recovered through Rider 70, and that Petitioner would record either a regulatory asset or liability related to the true-up of PowerShare® costs in relation to the give back of PowerShare® costs, the reconciliation of actual Rider 70 billing amounts to amounts approved for recovery, and non-native sales profits subject to sharing.

F. <u>Request for Confidential Treatment</u>. In addition to the Affidavits of Mr. Park and Mr. Bailey filed in support of Duke Energy Indiana's Motion for the Protection of Confidential and Proprietary Information, Mr. Park provided additional testimony explaining that certain pricing and vendor information pertaining to sales, power sale contracts, GADS data relating to statistical generation operating data, and the customer-specific peak load management contract with SDI are "trade secrets" and excepted from the access to public records provisions, consistent with Ind. Code §§ 5-14-3-4(a)(4) and 24-2-3-2.

6. <u>OUCC's Case-In-Chief</u>. Ms. Gruca testified concerning the OUCC's review of Petitioner's requested relief. She testified that an agreement was reached between the OUCC and Petitioner with respect to the proper methodology to be used for the netting of capacity purchases and sales under MISO's Module E-1 annual resource adequacy construct. She testified that in this transitional filing and the future, there will only be one set of reserve margin requirements at a time, which makes it reasonable and straightforward to net the Module E-1 capacity purchase costs and capacity sales revenues annually. She explained that should capacity sales occur, then sales revenues are first netted against any capacity purchases to offset purchase costs before any excess profits are shared 50/50 (50% with ratepayers and 50% retained by Petitioner) through the non-native profit sharing computation.

Ms. Gruca testified that her calculations of the jurisdictional allocation of Rider 70 costs for the period of October 1, 2013 through May 31, 2014 match the amount that Petitioner is requesting to recover and recommends the Commission approve recovery of such costs.

Ms. Gruca testified that Duke Energy Indiana complied with the Commission's Order in Cause No. 44348 by using the required PRM_{UCAP} of 6.2% and that Duke Energy Indiana's capacity position was adequate to meet the minimum required reserve margin for summer 2013 and no forward capacity purchases were necessary. She testified that Duke Energy Indiana's actual summer 2013 PRM_{UCAP} was 6.2%. She further stated that the OUCC continues to recommend that the Module E-1 reserve margin requirements be utilized as the target for future necessary capacity purchases to fully capture the benefit of participating in MISO.

Ms. Gruca explained Duke Energy Indiana's continued use of special contracts and PowerShare® resources when it had already exceeded the MISO reserve margin requirements and that the OUCC agreed with Mr. Park's testimony that it is appropriate to take a longer-term view by considering future compliance needs that may impact resource planning. She testified that it seems reasonable to continue the use of special contracts and PowerShare® resources until it is known how retirement, shut down, or suspension of Duke Energy Indiana's units will affect capacity conditions and capacity needs.

Ms. Gruca testified that Duke Energy Indiana provided an update regarding the status of its contract with Logansport, with no capacity payments being made to Logansport for summer 2013, and that this capacity was not included in Duke Energy Indiana's supply vs. demand balance to meet its resource adequacy requirements. She recommended that Duke Energy Indiana continue to keep the Commission informed of the status of the Logansport contract and unit in future Rider 70 proceedings.

Ms. Gruca discussed the capacity purchases and sales made during the October 2013 through May 2014 period. She stated that capacity sales were netted against capacity purchases resulting in net proceeds of $677,954 for inclusion in non-native profit sharing.

Ms. Gruca testified that her audit corroborates Duke Energy Indiana's calculation of off-system sales profits and that Petitioner's requested recovery seems reasonable.

Ms. Gruca recommended that Duke Energy Indiana continue to update the Commission in future Rider 70 proceedings regarding its coal inventory, including the development of alternatives to its decrement pricing.

Ms. Gruca testified she had no concerns regarding Petitioner's proposed recovery of PowerShare® Program costs or customer-specific peak load management costs. She testified that Petitioner's PowerShare® activity log shows a quantified benefit to customers who participate in the program.

With respect to Petitioner's hedging philosophy, Ms. Gruca testified that Petitioner indicated in testimony that in June 2014, Duke Energy Indiana switched from its Commercial Business Model ("CBM") to a vendor-provided economic model called GenTrader to perform the economic dispatch simulations. Ms. Gruca testified that based on the testimony of Duke Energy Indiana witness Mr. Chen, it appears that the fundamentals of what GenTrader does is virtually identical to Petitioner's previous CBM. Ms. Gruca further testified with respect to

Petitioner's native hedging philosophy, indicating that Duke Energy Indiana and the OUCC have entered into a settlement agreement to meet annually to discuss the matter.

Ms. Gruca also testified that Duke Energy Indiana provided documentation consistent with its obligation pursuant to the Settlement Agreement approved in Cause No. 42870 and modified as agreed to by the OUCC in Cause No. 43906.

7. **Commission Discussion and Findings.** Based on the evidence presented, we find Petitioner continues to use a portfolio of diverse options to serve its customers' capacity needs. In addition, Petitioner should continue to use the MISO Module E-1 reserve margin requirements as the appropriate target for future necessary capacity purchases and update the Commission on any additional changes to MISO's resource adequacy construct. We further find that Petitioner should keep the Commission informed of the status of the Logansport contract and unit in future Rider 70 proceedings.

We also find that Petitioner's PowerShare® Program and customer-specific peak load management costs for October 1, 2013 through May 31, 2014 were reasonable, the expenses were accurately calculated, and are approved. As we stated in the final Order in Cause No. 43074, the PowerShare® program is an important component in Petitioner's summer preparedness.

We further find that Petitioner has accurately calculated the amount of non-native sales profits that should be shared with customers under Rider 70, as approved by the Commission in Cause No. 42359. Mr. Burnside explained how Petitioner calculated its non-native sales amount, including adjustments for expense reduction and prior period amounts. Additionally, we find that Petitioner should continue to update the Commission on its coal inventory, including the development of alternatives to its decrement pricing.

We also find that the calculations of the Rider 70 billing factors as outlined in the exhibits and testimony of Ms. Sieferman are accurate, appropriate, and approved, including the adjustments made to the allocations for the industrial class rate migrations. We further direct Duke Energy Indiana to include such adjustment factors in the Rider 70 filed with the Commission in compliance with this Order.

As to netting of capacity purchases and sales under the MISO Module E-1 construct, we find that the methodology agreed to by Petitioner and the OUCC is reasonable and approved. The methodology nets capacity purchase costs for the planning year against capacity sales revenues for the planning year, and any excess annual net revenues that result from the annual netting calculation is then included in the non-native sales profit sharing computation to be shared 50/50 between ratepayers and shareholders.

We also find that Rider 70 filings should be aligned with the MISO planning year, running June through May. Petitioner's next Rider 70 proceeding will be filed in mid-September 2015 and cover the annual period June 1, 2014 through May 31, 2015. The Commission further approves the transitional filing schedule for this proceeding which covers a truncated eight-month period of October 1, 2013 to May 31, 2014.

Finally, Petitioner demonstrated a need for confidential treatment of certain information associated with its pricing and vendor information pertaining to sales made by Duke Energy Indiana for native load purposes, power sales contracts, GADS data relating to statistical generation operating data, and the customer-specific peak load management contract with SDI, and no party objected to the request for confidential treatment. Accordingly, pursuant to Ind. Code § 5-14-3-4(a)(4), we find that this information, as identified in Duke Energy Indiana's redacted testimony and exhibits, constitutes "trade secrets" and shall continue to be held as confidential.

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

1. Petitioner is authorized to recover, through Rider 70, its PowerShare® and customer-specific peak load management program costs consistent with Petitioner's testimony and exhibits.

2. Petitioner is authorized to recover, through Rider 70, its non-native sale sharing costs consistent with Petitioner's testimony and exhibits.

3. Petitioner is authorized to recover, through Rider 70, its calculated reconciliation amounts.

4. Petitioner is authorized to recover its MISO Module E-1 costs consistent with Petitioner's testimony and exhibits.

5. Petitioner shall file with the Commission's Electricity Division its Rider 70, with the rates therein reflecting the provisions of this Order. Rider 70 shall be effective for all bills rendered on and after the first billing cycle of July 2015 or the date of the Commission Order, if later.

6. Petitioner's confidential information identified herein shall continue to be held as confidential pursuant to Ind. Code §§ 8-1-2-29 and 5-14-3-4(a)(4).

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

<u>MAYS-MEDLEY, HUSTON AND ZIEGNER CONCUR; STEPHAN AND WEBER ABSENT:</u>

JUN 10 2015

I hereby certify that the above is a true and correct copy of the Order as approved.

Brenda A. Howe

Brenda A. Howe,
Secretary to the Commission