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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 THE WHOLESALE POWER CAPACITY PURCHASES MADE BY PETITIONER TO MEET ITS RETAIL NATIVE LOAD PEAK REQUIREMENTS; (2) AUTHORITY TO RECOVER VIA RIDER NO. 70 CERTAIN COSTS ASSOCIATED WITH PETITIONER'S POWERSHARE® PROGRAM AND SPECIAL CONTRACT DEMAND RESPONSE PROGRAM (INCLUDING PERMANENT AUTHORITY TO IMPLEMENT AND RECOVER COSTS ASSOCIATED WITH THE POWERSHARE® PROGRAM ON A 12-MONTH BASIS); (3) AUTHORITY TO SHARE NON-NATIVE SALES PROFITS VIA RIDER NO. 70; AND (4) CONFIDENTIAL TREATMENT OF CERTAIN INFORMATION RELATING TO PETITIONER'S POWER PURCHASES AND NON-NATIVE SALES	)	CAUSE NO. 44035 APPROVED: MAY 30 2012

ORDER OF THE COMMISSION

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

On June 3, 2011, Duke Energy Indiana, Inc. ("Petitioner" or "Duke Energy Indiana") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") initiating this Cause. Pursuant to notice, and as provided for in 170 IAC 1-1.1-15, a Prehearing Conference was held on July 26, 2011 at 1:30 PM in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. On July 27, 2011, Duke Energy Indiana and the Indiana Office of Utility Consumer Counselor ("OUCC") filed a Motion for Approval of Procedural Schedule, which the Commission approved by docket entry.

On January 18, 2012, Duke Energy Indiana prefiled testimony, exhibits, verifications and applicable work papers in support of its Petition, including the testimony and exhibits of Duke Energy Business Services LLC employees Ms. Diane L. Jenner, Mr. Wenbin (Michael) Chen, Ms. Yevgeniya Jenny Coston, Mr. Bruce L. Sailers, Mr. Scott A. Burnside and Mr. Roger A. Flick II. Petitioner also filed a Motion for Protection of Confidential and Proprietary Information, on this date, together with supporting affidavits of Ms. Jenner and Mr. Jeffrey R. Bailey. On January 23, 2012, the Commission issued a docket entry finding that the information identified in the Motion should be held as confidential by the Commission on a preliminary basis. On March 21, 2012, the OUCC filed the testimony and exhibit of Ms. Stacie R. Gruca. On April 11, 2012, Petitioner filed the rebuttal testimony of Ms. Jenner.

Pursuant to notice published as required by law, proof of which was incorporated into the record, an evidentiary hearing was held in this Cause on May 9, 2012, at 9:30 AM in Room 224 PNC Center, 101 West Washington Street, Indianapolis, Indiana. Petitioner and the OUCC participated at the hearing. At the evidentiary hearing, Petitioner introduced into evidence its case-in-chief testimony and exhibits, the OUCC introduced into evidence its case-in-chief testimony and exhibits, and Petitioner introduced into evidence its rebuttal testimony.

Based on the applicable law and the evidence herein and being duly advised, the Commission now finds as follows:

1. **<u>Statutory Notice and Commission Jurisdiction</u>.** Due, legal and timely notice of the prehearing conference and evidentiary hearing in this Cause was given and published by the Commission as required by law. Petitioner is a public utility within the meaning of the Public Service Commission Act, as amended, Ind. Code Ch. 8-1-2, and is subject to the jurisdiction of the Commission, in the manner and to the extent provided by the laws of the State of Indiana. The Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **<u>Petitioner's Characteristics</u>.** Petitioner 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. It 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.

3. **<u>Relief Sought</u>.** Petitioner requested the Commission authorize it to: (1) recover the demand-related costs of its forward reliability purchases from October 1, 2010 through September 30, 2011; (2) charge customers with the difference in costs associated with its PowerShare® program and a customer-specific peak load management program for the period of October 1, 2010 through September 30, 2011, compared to the amount included in Duke Energy Indiana's base rates;[1] (3) implement and recover costs associated with the PowerShare® program on a year-round basis permanently; (4) charge customers with 50% of Duke Energy Indiana's net off-system ("non-native") sales profits below the base amount included in Duke Energy Indiana's rates; and (5) approve applicable reconciliation amounts. Petitioner further requested that the Commission find the following be treated as confidential "trade secrets": (1) pricing and vendor information pertaining to purchases made by Duke Energy Indiana for native load purposes; (2) purchase contracts; (3) information related to a customer-specific peak load management contract with Steel Dynamics, Inc.; (4) information from the Generating Availability Data System ("GADS") relating to statistical generation operating data; and (5) certain information relating to Duke Energy Indiana's power purchases and non-native sales. As stated in the direct testimony of Ms. Jenner, Petitioner's total relief requested in this proceeding totals $10,173,636 before adjustment for Utility Receipts Tax via Rider 70 over a twelve-month period. The net impact would be a $0.05 monthly

[1] Pursuant to the Order in Cause No. 43737, in which the Commission approved, among other things, the recovery of Steel Dynamics, Inc. demand response payments via this tracker, Petitioner seeks to recover customer-specific peak load management costs as approved in that proceeding.

bill increase for a typical residential customer from comparable current billings approved in Cause No. 43906.

4. **Prior Applicable Commission Orders**. On May 18, 2004, in Cause No. 42359, Petitioner's 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.

On June 28, 2006, the Commission issued an Order in Cause No. 42870 approving Petitioner's Rider 70 for recovery of summer 2005 purchased power and PowerShare® costs (including revisions to Rider 70 to allow for recovery of year-round PowerShare® program costs on the basis of a two-year pilot program pursuant to a settlement agreement with the OUCC), the sharing of off-system sales profits, and confidential treatment of certain information relating to summer 2005 power purchases and off-system sales. On June 13, 2007, the Commission issued an Order in Cause No. 43074 approving Petitioner's Rider 70 for recovery of summer 2006 purchased power demand and PowerShare® program costs, the sharing of off-system sales profits and revisions to Rider 70 language and formula.

On May 28, 2008, the Commission issued an Order in Cause No. 43302 approving Petitioner's Rider 70 for recovery of summer 2007 purchased power capacity, PowerShare® program costs, and the sharing of off-system sales profits. Additionally, the Order authorized Petitioner to modify Rider 70 to include recovery of reliability power purchases on a year-round basis beginning January 11, 2008 and granted a two-year extension of the annual PowerShare® program through May 31, 2010.

On June 17, 2009, the Commission issued an Order in Cause No. 43505 approving Petitioner's Rider 70 for recovery of summer 2008 purchased power capacity, the sharing of off system sales profits, its fiscal year 2008 PowerShare® costs, its non-native sharing costs, its reconciliation amounts and was authorized to defer, as necessary to effectuate Rider 70, its reliability purchased power capacity costs, PowerShare® costs, and net non-native sales profits (losses). A portion of the recovery of costs was made interim and subject to refund pending a final order in Cause No. 38707 FAC76 S1. The final order in Cause No. 38707 FAC76 S1 was issued on October 21, 2009, with no adjustments required.

On June 23, 2010, the Commission issued an Order in Cause No. 43715 approving PowerShare® for an additional two-year period on a year-round basis, to end on May 31, 2012. The Commission also approved Duke Energy Indiana's proposed treatment of Planning Resource Credits ("PRCs") sold into the Voluntary Capacity Auction ("VCA"), which netted the sale of surplus PRCs purchased for native load reliability against the cost of purchases and was reflected in the Capacity section of Rider 70; as to revenue from PRCs sold in excess of the number purchased for native load reliability or in months without PRC purchases, Petitioner will include this in its non-native load profit calculation in Rider 70, consistent with the treatment of sales of surplus generation not needed to meet native load needs. Finally, the Commission approved the purchase of 8 MW of capacity purchase from Logansport for 2009, but declined to approve it as a long-term capacity purchase.

Most recently, on May 25, 2011, in Cause No. 43906, the Commission approved Petitioner's purchased power capacity costs, including 8 MW capacity purchase from Logansport, for the summer of 2010; its PowerShare® costs, including costs associated with a special contract demand response program; its non-native sales sharing costs; its reconciliation of previously billed amounts; use of deferral accounting treatment, and authorized any sales of PRCs sold through the VCA to be netted monthly against total capacity purchases. The Order also removed the "subject to refund" designation on the recovery approved in Cause No. 43505 and made that recovery final.

5. **Petitioner's Case-in-Chief.**

A. **Reliability Power Purchases.** Ms. Coston, Senior Forecaster in the Load Forecasting group, testified as to Petitioner's load forecast for the summer of 2011, projecting a peak demand of 6,603 MW. Ms. Coston also testified that customers who were served under Duke Energy Indiana's economic development riders totaled 17.85 MWs of incremental load. Because this is under the 50 MW threshold for whether load is considered incremental for purposes of summer capacity and Rider 70, no material incremental costs related to serving those customers resulted.

Mr. Sailers, Manager, Retail Energy Desk, 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.

Ms. Jenner, Director, Regulatory Strategy, testified that, as a result of the return to service of Wabash River Units 2, 3 and 5, no PRC purchases were ultimately necessary. However, before the order to shut down these units was vacated (*i.e.*, April 15, 2011), Petitioner had expected to be 38.3 PRCs short in July and 11.1 PRCs short in August; therefore Petitioner purchased 50 PRCs for July and August. Ms. Jenner explained that Petitioner was able to resell these PRCs at a higher price than the purchase price.

Ms. Jenner testified that Petitioner also purchased 8 MW of installed capacity ("ICAP") (6.6 MW of unforced capacity ("UCAP")) from Logansport under a long-term contract that began in 2009. However, this filing only reflects the costs of June 2011 as Petitioner was informed in July 2011 that the unit was unavailable and payments were suspended. Without these reliability purchases, certain special contracts, and the PowerShare® program, Petitioner's reserve margin on a UCAP basis would have been below the Midwest Independent Transmission System Operator ("MISO") requirement.

Ms. Jenner testified, altogether, the jurisdictional allocation of Rider 70 costs for Fiscal Year 2011 results in a request to recover a total of $10,173,636 before adjustment for Utility Receipts Tax via Rider 70 over a twelve-month period, which amounts to an increase of $0.05 on the monthly bill for a typical residential customer. She stated this amount includes a combination of: (1) the October 1, 2010, through September 30, 2011, forward reliability purchase costs, (2) a charge for the amount of Fiscal Year PowerShare® program costs above that reflected in base rates, (3) a charge for the Fiscal Year 2010 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), and (4) a charge resulting from reconciliation for Rider 70 costs approved in Cause No. 43906 to amounts collected.

Ms. Jenner testified that, beginning with the Planning Year June 1, 2009 - 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. She 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 1 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 1 minus the unit-specific $XEFOR_d$).

For purposes of this filing, there were two different MISO Planning Years. For the period October 2010 through May 2011 (*i.e.*, the portion of the time period covered in this Cause during MISO Planning Year 2010/2011), Duke Energy Indiana was required to meet a PRM_{UCAP} of 4.5%. For the period June 2011 through September 2011 (*i.e.*, the portion of the time period covered in this Cause during MISO Planning Year 2011/2012), Duke Energy Indiana was required to meet a PRM_{UCAP} of 3.81%.

Ms. Jenner testified that due to the volatility of the VCA, Duke Energy Indiana procured all PRCs needed to meet compliance prior to the VCA date. However, in any months that Petitioner had surplus PRCs, an offer was made into the VCA to attempt to sell the surplus and lower the ultimate cost to customers. She provided details of sales and clearing prices for the months of October 2010 through September 2011.

Ms. Jenner described Petitioner's treatment of VCA revenues, as approved in Cause No. 43906. Revenue from the sale of surplus PRCs that have been purchased for native load reliability are netted against the cost of the purchases, effectively reducing the cost of the purchase, and are reflected in the Capacity section of Rider 70. Revenue from PRCs sold in excess of the number purchased for native load reliability or in months without PRC purchases *(i.e.,* PRCs sold due to surplus generating capacity, not surplus purchased PRCs) are included in the non-native load profit calculation in Rider 70, consistent with the treatment of sales of surplus generation not needed to meet native load needs. Ms. Jenner testified that this treatment resulted in partial offsets of the costs of reliability purchases for June 2011.

Ms. Jenner described how Petitioner used the MISO Module E Reserve Margin requirements as the minimum for future capacity purchases, as required in Cause No. 43505. She explained Petitioner used the required PRM_{UCAP} of 3.81% in its determination of the number of PRCs that were necessary to purchase for July and August. These surplus PRCS were offered into the VCA and cleared the VCA. Ms. Jenner stated that in future years it is not likely Petitioner will be able to meet the exact required PRM_{UCAP} because the ability to do so is highly dependent on the total number of PRCs that are purchased, the block sizes available for purchase, and the marketability of any surplus in the VCA. Nevertheless, Petitioner will continue to target the MISO Module E PRM_{UCAP} as the appropriate minimum reserve requirement.

Ms. Jenner testified that buying forward cannot completely ensure against expensive energy arising from price spikes in the spot market during limited hours in the operating year. Factors like unexpected plant shutdowns or derates and extreme weather can increase reliance on the spot market at just the time that prices are increasing. She explained buying forward energy or price hedges limits exposure to price spikes. However, all PRCs, including the PRC purchases Petitioner made, are purely capacity products to meet MISO Resource Adequacy requirements, with compliance measured on a forward month-ahead basis.

Ms. Jenner also described the impact on capacity purchases for the summer of 2011 flowing from the New Source Review ("NSR") verdicts and remedy orders. She stated that as a result of the 7th Circuit Court of Appeals vacating the lower court's order to shut down Wabash River Units 2, 3, and 5, all units were returned to service during the summer of 2011 and received capacity credits after returning to service. She also testified that Petitioner's compliance with the Gallagher Consent Decree should have no impact on capacity purchases going forward as a result of replacing 280 MW of Gallagher Units 1 and 3 capacity with 355 MW of Vermillion capacity. She also emphasized that this does not mean that capacity purchases will not be necessary in the future for other reasons, such as load growth or other unit retirements due to age or new environmental regulations.

Ms. Jenner testified that Duke Energy Indiana continues to be committed to a portfolio approach to meet its native load peak demand obligations. Including the purchases needed to meet the required reserve target, Ms. Jenner noted that for summer 2011, Petitioner met native load customers' peak demand requirements through a resource mix consisting of 91% through its existing fleet of generating assets, 8% through a combination of traditional regulated conservation and demand response products, and 1% through renewable resources. Ms. Jenner testified that hourly spot purchases cannot take the place of firm capacity, but hourly spot power is utilized when available and to the extent such power purchases are economic to meet short-term needs.

Mr. Chen, Manager, Portfolio Optimization, described the reliability purchases that were made for the summer of 2011 as identified by Ms. Jenner. Mr. Chen testified as to his belief that the capacity purchases and sales were reasonable, necessary and made in order to comply with MISO's capacity requirement. He stated the Aggregate PRC ("APRC") purchases and sales were the result of arms' length negotiations at then-prevailing market prices. He also stated that the Logansport capacity purchase for the period, until it became unavailable, allowed Duke Energy Indiana to call on this capacity and energy, and that the contracted price was comparable to then-prevailing market prices. 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 until the unit becomes available again in the future.

Mr. Chen further testified as to the continued volatility of the power and natural gas markets. Mr. Chen sponsored a confidential exhibit that included all agreements or confirmations supporting the capacity purchases and sales.

B. <u>PowerShare® and Customer-Specific Peak Load Management Costs</u>. Mr. Sailers described Petitioner's PowerShare® program. He stated that PowerShare® has been offered under Standard Contract Rider No. 23 ("Rider 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. Sailers 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. Sailers 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. Sailers 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. Sailers testified that there were 7 PowerShare® CallOption economic events and 1 PowerShare® QuoteOption event during the summer of 2011 due to relatively hot weather conditions. During the winter of 2010/2011, there were no PowerShare® events. For summer 2011, Petitioner entered into eighty-two CallOption contracts. Fifty-nine of these contracts were also eligible for curtailment over the October 2011 to May 2012 period.

Mr. Sailers described the PowerShare® attributes for summer 2012. At the time of the filing, Duke Energy Indiana planned to extend the emergency portion of PowerShare® CallOption for all program options to an annual requirement and increase the number of potential emergency calls from 5 to 10, which is consistent with MISO's proposed Resource Adequacy changes to have Load-Modifying Resources ("LMRs") available for the entire planning year and available for 10 emergency events. Mr. Sailers testified that participants enrolled in the CallOption 0/5 or 15/5 programs may be called for a system emergency condition during any month of the year and that participants in the CallOption 15/5 program can be called for economic events during any month of the year. The winter program attributes are similar to those for the summer program, with one notable exception: the peak period from November 1 through April 30 is defined as 7:00 a.m. to 1:00 p.m., compared to 12:00 p.m. to 8:00 p.m. during the period of May through October.

Mr. Sailers supported Petitioner's request to offer its PowerShare® program on a year- round permanent basis. In Cause No. 42870, Petitioner was authorized to implement and recover costs for its PowerShare® program on a year-round basis pursuant to a settlement agreement between Duke Energy Indiana and the OUCC. The initial two-year pilot was originally set to expire in June of 2008. On May 28, 2008, in Cause No. 43302, the Commission approved continuation, implementation and recovery of costs for its PowerShare® program on a year-round basis for an additional two-year period ending on May 31, 2010. Again, in Cause No. 43715, the Commission approved continuation through May 31, 2012. He pointed out that Petitioner has been successful in implementing the PowerShare® program in the non-summer months with some customers and, given that emergency conditions can occur at anytime of the year, that ongoing application of the PowerShare® program on a year-round basis is appropriate. Finally, Mr. Sailers testified that MISO has made a filing at the Federal Energy Regulatory Commission ("FERC") to modify its Resource Adequacy construct to annual rather that monthly requirements beginning with Planning Year 2013/2014, which will make year-round availability of demand response a requirement for using programs to fulfill Resource Adequacy requirements.

Mr. Sailers testified regarding Duke Energy Indiana's customer-specific peak load management contract with Steel Dynamics, Inc. ("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 contract with SDI.

Mr. Sailers testified that PowerShare® and any customer-specific peak load management contracts are registered with MISO, as both LMRs and Emergency Demand Response resources, which allow MISO to call on the programs when MISO declares NERC emergency level of EEA 2 events or higher. He also testified that registering the programs as LMRs allows Petitioner to reduce its MISO Resource Adequacy requirements.

Mr. Sailers also provided an update on Duke Energy Indiana's energy efficiency efforts at the time of the filing.

C. **Sharing of Non-Native Sales Profits.** Ms. Jenner summarized Duke Energy Indiana's non-native sales strategy for the period of October 2010 through September 2011. She explained that Duke Energy Indiana has sold its surplus generation into the MISO markets since the advent of the MISO Day 2 energy markets, in addition to remaining a party to certain pre-Joint Generation Dispatch Agreement legacy power sales contracts.

Mr. Flick, Lead Rates Analyst, explained that in Petitioner's most recent retail electric base rate case, Cause No. 42359, the Commission provided for 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 in that Cause. Mr. Flick testified that 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, Accounting Manager, described the types of non-native sales Petitioner made in the past year, including day ahead and real time sales to MISO, sales of capacity in the MISO VCA that do not offset reliability purchases, energy or capacity sales to non-MISO counterparties, realized margin from non-native sales of emission allowances, realized margin from non-native hedging activity, pre-Joint Generation Dispatch Agreement contracts, and nonfirm retail contracts with special contract customers. Mr. Burnside explained how revenues and expenses allocable to non-native sales are determined.

Mr. Chen explained Petitioner's non-native load power hedging strategy to lock in a margin for the forecasted excess generation not allocated to serve native load. For the period at issue, this power hedging strategy resulted in a gain of approximately $68,169.

Ms. Jenner explained that due to the Commission's Order in Cause No. 43956, Duke Energy Indiana is not allowed to recover the cost of additional SO_2 surrenders required per the Gallagher Consent Decree, so these have not been included in the calculation of the level of non-native sales included in the Rider 70 profit-sharing calculations.

Mr. Burnside stated that gross profits from non-native sales for October 1, 2010, through September 30, 2011, total $2,973,299 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 ($23,192). This adjustment was made to reflect the fact that during the current Rider 70 non-native power sales period (October 1, 2010, through September 30, 2011), Petitioner received updated MISO settlement statements for operating dates impacting prior Rider 70 non-native power sales periods.

D. Rider 70 Calculation and Rate Impact. Mr. Flick 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. He indicated that the period covered by this filing included periods ended September 30, 2011.

Mr. Flick testified that Petitioner made capacity purchases, net of related capacity sales, for the twelve months ended September 2011 in the amount of $1,878 on a retail jurisdictional basis. He stated costs associated with these purchases were for capacity and were appropriate for recovery via Rider 70. Mr. Flick also explained Duke Energy Indiana's treatment of capacity sales included in this filing. Echoing Ms. Jenner's testimony, he stated that, to the extent capacity sales occurred in the periods without capacity purchases or were in excess of capacity purchase values, such amounts were included in the non-native load sharing mechanism.

Mr. Flick testified that Rider 70 provides for the tracking of actual PowerShare® CallOption premiums and CallOption and QuoteOption energy credits and for costs associated with a customer-specific peak load management contract with SDI. He testified that Petitioner's total peak load management costs included in Rider 70 for October 2010 through September 2011 totaled $4,362,831, which is more than the amount authorized in Cause No. 42359. As such, retail customers will be charged $3,339,831 in this proceeding.

Mr. Flick stated the results of Petitioner's non-native sales for the period October 1, 2010, through September 30, 2011, totals a $2,973,299 profit before applicable prior period adjustments and fixed trading expenses or a $1,002,893 net non-native sales loss after the adjustments. Mr. Flick explained the amount of net non-native sales loss allocated to retail customers is $920,566. He 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 $7,373,500.

Mr. Flick 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. 43715 was made, and Petitioner included a credit to customers of $541,573 from the reconciliation in the determination of the proposed Rider 70 billing factors in this proceeding.

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. Mr. Flick explained that these costs would be recovered over a one-year period, and that Petitioner's request herein would result in an increase of approximately $0.05 in the base bill of a typical residential customer compared to what such customer is paying today (excluding various tracking mechanisms and sales tax).

Mr. Flick 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.

E. **Request for Confidential Treatment.** In addition to the Affidavits of Ms. Jenner and Mr. Bailey filed in support of Duke Energy Indiana's Motion for the Protection of Confidential and Proprietary Information, Ms. Jenner provided additional testimony explaining that certain power purchase information, non-native sales information, 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. **OUCC's Case-In-Chief.** Stacie R. Gruca, Senior Utility Analyst in the Electric Division of the OUCC, testified concerning the OUCC's review of Petitioner's requested relief. Ms. Gruca testified she had no concerns with Petitioner's forward reliability purchase needs for October 1, 2010 through September 30, 2011. She recommended that Petitioner's proposed recovery of capacity purchase costs attributable to Petitioner's contract with Logansport and the MISO PRC transactions for the reconciliation period be approved. She further testified Petitioner complied with the requirement of the Commission's Order in Cause No. 43505 to use MISO Module E reserve margin requirements and she recommended that Petitioner continue to utilize the Module E reserve margin requirements as the appropriate target for future necessary capacity purchases.

Ms. Gruca testified that she had no concerns whether the submitted evidence supports the calculation of proposed recovery of non-native sales profits and that Petitioner's requested recovery seems reasonable.

Ms. Gruca further 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 programs.

She testified the OUCC has concerns with Petitioner's proposal for permanent year-round implementation and cost recovery of its PowerShare® program and stated the OUCC believes that the PowerShare® program should be extended for another two-year pilot. She stated that another two-year term of the pilot program would provide a cumulative eight-year period to evaluate the program on a year-round basis. She testified the concerns expressed by the OUCC in the past continue to exist. She also noted that there have only been two winter CallOption events in the six years in which the pilot program has been in place and that this does not support the necessity of a year-round program. Ms. Gruca further testified against permanent approval of year-round PowerShare® because MISO continues to refine Resource Adequacy rules and has a filing pending at FERC to modify its Resource Adequacy construct (for which she noted the OUCC does not oppose the matching of the PowerShare® program and the associated cost recovery); Petitioner's energy efficiency request involving the CallOption component of PowerShare® was pending at the time she filed her testimony; and it is unknown how the Edwardsport Plant will affect capacity conditions and capacity needs for Petitioner. She further recommended the Commission revisit and reassess the need for the PowerShare® program in Petitioner's next base rate case.

With respect to Petitioner's possibility of refining its hedging philosophy in the future, Ms. Gruca testified the OUCC is willing to meet with Duke Energy Indiana to discuss any changes to its native or non-native hedging. She also indicated the OUCC would like to review and comment on such changes should they occur.

Finally, Ms. Gruca 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, and recommended Petitioner continue to provide such documentation.

7. Petitioner's Rebuttal Testimony. Ms. Jenner responded to the OUCC's concerns with approval for permanent authority to implement PowerShare® on a year-round basis. She disagreed with the OUCC's contention that the unknowns referenced in Ms. Gruca's testimony justify another two-year extension. She stated that there will always be unknowns and allowing unknowns to paralyze decision-making means that nothing will ever get done.

Ms. Jenner stated that looking to past usage of the PowerShare® program is not relevant because the current request is founded on Petitioner's need to position this program to meet future year-round Resource Adequacy requirements. She stated that if FERC approves MISO's pending request for annual requirements, Petitioner needs to be well-positioned to move to an annual construct beginning with Planning Year 2013/2014, which will require LMRs to be available for the entire planning year. Ms Jenner explained that if FERC approves MISO's request, it would result in another request for permanent authority to offer PowerShare® on a year-round basis, resulting in an inefficient use of resources for the Commission and parties to this proceeding. She also testified that Petitioner's 2011 Integrated Resource Plan included the Edwardsport IGCC plant going into service later this year. Further, she stated, due to the combination of impending environmental regulations and the lack of new capacity additions before 2015, Duke Energy Indiana needs PowerShare® to meet the reserve margin requirements. Finally, she explained the risks associated with Petitioner discontinuing the PowerShare® program and then trying to restart it at a later time.

8. Commission Discussion and Findings. Based upon the evidence presented, we find Petitioner has adequately demonstrated that its forward reliability purchases at issue in this proceeding were necessary and reasonable in order to reliably and efficiently meet its native load customers' projected peak demand requirements. Ms. Jenner provided supporting testimony regarding the reserve margin requirements for the summer of 2011, including the MISO requirement of 4.5% for the period October 2010 through May 2011 and 3.81% for the period June 2011 through September 2011. As stated by Mr. Chen, Petitioner's forward purchases and sales were necessary to comply with this calculated reserve margin, taking into account known outages and derates. We also approve the inclusion of the contract costs for Logansport for the month of June 2011.

The Commission notes that Petitioner continues to use a portfolio of diverse options to serve its customers' capacity needs. Even with alternatives to purchases in place like Petitioner's demand side resources, Petitioner's purchases and sales were necessary to achieve a reasonable level of reserve margin as required by MISO. Accordingly, we approve the recovery of the costs associated with such purchases, net of related capacity sales, via Petitioner's Standard Contract Rider No. 70.

We also find that Petitioner's PowerShare® program and customer specific peak load management costs for October 1, 2010, through September 30, 2011, were reasonable, and the expenses were accurately calculated and should be approved. As we stated in the final Order in Cause No. 43074, the PowerShare® program is an important component in Petitioner's summer preparedness.

With respect to Petitioner's request to offer PowerShare® permanently on a year-round basis, we find it should be approved. The program has been a pilot program for six years and is reasonably likely to offer benefits to all customers as well as program participants. The Commission also recognizes Petitioner's desire to avoid any disruptions in offering the program. We agree with Petitioner that there is little to be gained by extending the pilot status of the program for another two years, particularly in light of MISO's pending request for annual Resource Adequacy requirements. And, although we are approving Petitioner's request, the OUCC may certainly request the Commission revisit approval of the PowerShare® program in Petitioner's next base rate case (or at any other time).

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, and we authorize Petitioner to charge retail customers accordingly. We also find that Petitioner's non-native hedging strategy is reasonable and that Petitioner's recovery of its calculated reconciliation amount is appropriate.

Finally, Petitioner demonstrated a need for confidential treatment of certain information associated with its power purchase arrangements, non-native sales, GADS data relating to statistical generation operating data, forward-looking data regarding Petitioner's supply and demand balance, 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 §§ 8-1-2-29 and 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 hereby authorized to recover, through Standard Contract Rider No. 70, its retail purchased power capacity costs, net of related capacity sales, consistent with Petitioner's testimony and exhibits.

2. Petitioner is hereby authorized to recover, through Standard Contract Rider No. 70, its PowerShare® program and customer-specific peak load management program costs consistent with Petitioner's testimony and exhibits.

3. Petitioner is hereby authorized to recover, through Standard Contract Rider No. 70, its non-native sales sharing costs consistent with Petitioner's testimony and exhibits.

4. Petitioner is hereby authorized to recover, through Standard Contract Rider No. 70, its calculated reconciliation amounts.

5. Petitioner is hereby authorized to defer, as necessary to effectuate Rider 70, its reliability purchased power capacity costs, PowerShare® and other peak load management costs, and net non-native sales profits (losses).

6. Petitioner is hereby granted permanent authority to offer its PowerShare® program on a year-round basis.

7. Petitioner shall file with the Commission's Electricity Division its Standard Contract Rider No. 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 2012 or the date of such filing, if later, and shall continue for a twelve-month period.

8. 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).

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

ATTERHOLT, BENNETT, LANDIS AND MAYS CONCUR; ZIEGNER ABSENT:

APPROVED: MAY 30 2012

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