ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED JOINT PETITION OF DUKE ENERGY INDIANA, INC., INDIANAPOLIS POWER & LIGHT COMPANY, NORTHERN INDIANA PUBLIC SERVICE COMPANY AND VECTREN ENERGY DELIVERY OF INDIANA, INC. FOR APPROVAL, IF AND TO THE EXTENT REQUIRED, OF CERTAIN CHANGES IN OPERATIONS THAT ARE LIKELY TO RESULT FROM THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.'S IMPLEMENTATION OF REVISIONS TO ITS OPEN ACCESS TRANSMISSION AND ENERGY MARKETS TARIFF TO ESTABLISH A CO-OPTIMIZED, COMPETITIVE MARKET FOR ENERGY AND ANCILLARY SERVICES MARKET; AND FOR TIMELY RECOVERY OF COSTS ASSOCIATED WITH JOINT PETITIONERS' PARTICIPATION IN SUCH ANCILLARY SERVICES MARKET.	)	CAUSE NO. 43426 PHASE II ORDER APPROVED: JUN 30 2009

BY THE COMMISSION:
David E. Ziegner, Commissioner
Loraine L. Seyfried, Administrative Law Judge

On January 18, 2008, Duke Energy Indiana, Inc. ("Duke Energy Indiana"), Indianapolis Power & Light Company ("IPL"), Northern Indiana Public Service Company ("NIPSCO"), and Vectren Energy Delivery of Indiana, Inc. ("Vectren South") (collectively "Joint Petitioners") filed a Verified Joint Petition with the Indiana Utility Regulatory Commission ("Commission" or "IURC"). The Commission granted intervention to the following parties in this proceeding: Indiana Industrial Group ("IIG"), LaPorte County Board of Commissioners ("LaPorte"), Midwest Independent Transmission System Operator, Inc. ("MISO" or "Midwest ISO"), Nucor Steel, a division of Nucor Corporation ("Nucor"), and Steel Dynamics, Inc. – Engineered Bar Products Division ("SDI").

On February 14, 2008, Joint Petitioners and the Indiana Office of Utility Consumer Counselor ("OUCC") filed a Joint Motion for (a) a Determination of the Extent to which Additional Commission Approval of Operational Changes is Required for Participation in the MISO ASM Market under Ind. Code § 8-1-2-83 and (b) an Interim Order Allowing Utilities to Defer Reasonably Incurred Costs Pending Further Review ("Joint Motion"). In the Joint Motion, Joint Petitioners and the OUCC requested a preliminary order: (1) finding the extent to which additional Commission authority is necessary for the operational changes for the start of the Midwest ISO ancillary services market ("ASM"); (2) to the extent such additional Commission approval is required under Ind. Code § 8-1-2-83 setting a bifurcated procedural schedule to address the separate issues of (a) approval under Ind. Code § 8-1-2-83, and (b) cost recovery; and (3) allowing the Joint Petitioners to defer for future recovery reasonably incurred ASM charges, subject to determination of such recoverability in a final Commission Order on the issue of cost recovery.

On February 14, 2008, the Commission conducted a Prehearing Conference and Preliminary Hearing ("Prehearing Conference") in this Cause. Joint Petitioners, the OUCC and representatives from IIG, LaPorte, Midwest ISO, and Nucor appeared and participated at the Prehearing Conference. At the Prehearing Conference, the Joint Petitioners and the OUCC presented the Joint Motion described above. No party objected to the relief sought in the Joint Motion. Based upon the agreement set forth in the Joint Motion, the parties agreed on a bifurcated schedule to apply (1) with respect to Joint Petitioners' request for Commission approval, if and to the extent required, of operational changes necessary to permit Joint Petitioners to participate in the Midwest ISO's ASM (the Authority of Joint Petitioners Issues) (herein referred to as "Phase I") and (2) with respect to Joint Petitioners' request for a Commission decision determining the manner and timing of recovery or crediting of jurisdictional charges and revenues associated with the Midwest ISO ASM (the Cost and Revenue Recovery Issues) (herein referred to as "Phase II"). On February 27, 2008, the Commission issued its Prehearing Conference Order establishing the schedule and other procedural requirements for this Cause. On August 13, 2008, the Commission issued its Order in Phase I of this proceeding.

To help define the issues to be addressed in Phase II, the Commission held a Technical Conference on July 15, 2008. In accordance with the Prehearing Conference Order and scheduling modifications subsequently approved by the Presiding Officers, Joint Petitioners filed their prepared testimony and exhibits constituting their case-in-chief in Phase II on April 10, 2008. LaPorte, Nucor and SDI,[1] IIG, and the OUCC filed their prepared testimony and exhibits on August 6, 2008. Joint Petitioners prefiled their rebuttal testimony on August 28, 2008.

In a Docket Entry dated September 18, 2008, the Presiding Officers requested Joint Petitioners to respond to three (3) requests. IPL, NIPSCO and Vectren South submitted their response to Request 3 on September 22, 2008; Duke Energy Indiana submitted its responses to Requests 1 and 2 on September 23, 2008. On September 22, 2008, the OUCC filed its response to a separate Docket Entry also issued on September 18, 2008.

On September 22, 2008, Duke Energy Indiana, Vectren South and the OUCC filed a Notice of Settlement in Principal and Joint Motion to Modify Procedural Schedule. The same parties filed their ASM Settlement Terms on September 23, 2008. By Docket Entry dated September 22, 2008, the September 24, 2008 Evidentiary Hearing was converted to an Attorneys' Conference to address the procedural schedule based on the filing of the Notice of Settlement in Principal.

[1] Mr. Higgins' testimony was not offered or admitted into evidence.

In accordance with the procedural schedule set out in a Docket Entry dated September 24, 2008, the Duke Energy Indiana, Vectren South and the OUCC (the "Original Settling Parties") filed a Stipulation and Settlement Agreement ("Original Settlement" or "Original Agreement") and filed testimony and exhibits in support of the Original Settlement on September 29, 2008. Nucor/SDI, and IIG filed prepared testimony and exhibits in opposition to the Original Settlement on November 12, 2008, and Duke Energy Indiana and Vectren South filed prepared rebuttal testimony and exhibits on December 12, 2008.

On December 19, 2008, the Original Settling Parties, IIG and Nucor filed a Joint Motion to Modify Procedural Schedule indicating that they had reached an agreement (the "Settling Parties"). By Docket Entry dated December 22, 2008, the December 22, 2008 Evidentiary Hearing was converted to an Attorneys' Conference to establish a new procedural schedule and hearing date.

In accordance with the procedural schedule set out in the December 22, 2008 Docket Entry, the Settling Parties filed a Modified Stipulation and Agreement, including Modified Settlement Terms ("Modified Settlement") on January 6, 2009 and filed their prepared testimony and exhibits in support of the Modified Settlement on January 9, 2009.

In a Docket Entry dated January 27, 2009, the Presiding Officers requested Intervenors to respond to one (1) request. IIG filed its response on January 30, 2009 and Nucor and LaPorte filed their responses on February 5, 2009.

Pursuant to the Prehearing Conference Order and scheduling modifications approved by the Presiding Officers, and notice of hearing given as provided by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, a public hearing in this Cause on Phase II commenced on February 9, 2009, in Room 222 of the National City Center, Indianapolis, Indiana.

At the evidentiary hearing, the testimony and exhibits prefiled by the Joint Petitioners, the OUCC, LaPorte and the IIG were admitted into the record and certain witnesses were cross-examined. Joint Petitioners submitted a Proposed Order on March 12, 2009. LaPorte and the OUCC submitted Responses on March 27, 2009, and Joint Petitioners submitted their Reply on April 13, 2009.

Having considered the evidence and the applicable law and being duly advised, the Commission now finds as follows:

1. **<u>Notice and Jurisdiction.</u>** Due, legal and timely notice of the commencement of hearings held in this Cause was given and published by the Commission as required by law. Joint Petitioners are public utilities within the meaning of Ind. Code § 8-1-2-1. Ind. Code §§ 8-1-2-42, 8-1-2-61 and 8-1-2-83, among others, are or may be applicable to the subject matter of this proceeding. The Commission has jurisdiction over Joint Petitioners and the subject matter of this proceeding in the manner and to the extent provided by the laws of the State of Indiana.

2. **Joint Petitioners' Characteristics.**

A. **Duke Energy Indiana.** Duke Energy Indiana is an Indiana corporation with its principal office located at 1000 East Main Street, Plainfield, Indiana. Duke Energy Indiana owns, operates, manages and controls plants, properties and equipment used and useful for the production, transmission, distribution and furnishing of electric utility service to the public in the State of Indiana. It directly supplies electric energy to over 770,000 customers located in 69 counties in the central, north central and southern parts of the State of Indiana. It also sells electric energy for resale to municipal utilities, Wabash Valley Power Association, Inc., Indiana Municipal Power Agency, Hoosier Energy Rural Electric Cooperative, Inc., and to other public utilities, which in turn supply electric utility service to numerous customers in areas not served directly by Duke Energy Indiana.

B. **IPL.** IPL is a corporation organized and existing under the laws of the State of Indiana, and has its principal office located at One Monument Circle, Indianapolis, Indiana. IPL renders retail electric utility service to approximately 470,000 retail customers located principally in and near the City of Indianapolis, Indiana, and in portions of the following Indiana counties: Boone, Hamilton, Hancock, Hendricks, Johnson, Marion, Morgan, Owen, Putnam and Shelby Counties. IPL owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power.

C. **NIPSCO.** NIPSCO is a corporation organized and existing under the laws of the State of Indiana, and has its principal office located at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO renders retail electric utility service to approximately 441,000 retail customers in 21 counties in the northern part of Indiana. NIPSCO owns, operates, manages and controls electric generating, transmission and distribution plant, property and equipment and related facilities, which are used and useful for the convenience of the public in the production, transmission, delivery and furnishing of electric energy, heat, light and power.

D. **Vectren South.** Vectren South is a corporation organized and existing under the laws of the State of Indiana, with its principal office located at One Vectren Square, Evansville, Indiana. Vectren has charter power and authority to engage in, and is engaged in the business of rendering electric public 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 service to approximately 140,000 ultimate electric customers in southwestern Indiana.

3. **Background and Introduction.**

A. **Joint Petitioners' Participation in the Midwest ISO.** On February 1, 2002, Joint Petitioners Duke Energy Indiana, IPL and Vectren South transferred functional control of the operation of their respective transmission systems to the Midwest ISO and began taking transmission service under the Midwest ISO Open Access Transmission Tariff ("OATT") to serve their Indiana retail electric customers in accordance with Federal Energy Regulatory

Commission ("FERC") Opinion No. 453 and Opinion No. 453-A.[2] The Commission approved that transfer of functional control on December 17, 2001.[3] As of October 1, 2003, NIPSCO transferred functional control of its transmission operations to the Midwest ISO in compliance with the Commission Order in Cause No. 42349, issued September 24, 2003, and began taking transmission service under the Midwest ISO OATT to serve its Indiana retail electric customers.

On March 31, 2004, the Midwest ISO filed a proposed Open Access Transmission and Energy Markets Tariff ("TEMT") with the FERC in Docket No. ER04-691-000. The Midwest ISO's proposed TEMT set forth rates, charges, terms and conditions for the implementation of a centralized security-constrained economic dispatch platform supported by a day-ahead and real-time energy market design, including locational marginal pricing ("LMP") and financial transmission rights within the Midwest ISO region. On May 26, 2004, the FERC directed the Midwest ISO to implement energy markets (also known as "Day 2") in the Midwest ISO region on March 1, 2005.[4]

On July 9, 2004, Joint Petitioners sought Commission approval for their participation in the real-time and day-ahead energy markets within the Midwest ISO region. On June 1, 2005, in Cause No. 42685, the Commission issued an Order approving the transfer of certain Joint Petitioners' control area operations and their participation in the Day 2 energy markets.

B. <u>Ancillary Services Market Implementation - Relief Granted in Phase I.</u> On January 18, 2008 when their Verified Joint Petition was filed initiating this Cause, Joint Petitioners believed implementation of the Midwest ISO's ASM would take place on June 1, 2008.[5] In a Joint Motion filed on February 14, 2008, the OUCC and Joint Petitioners requested that the state regulatory implications of the Joint Petitioners' participation in the ASM be addressed by this Commission on an expedited basis, in two phases, with Phase I addressing the need for Commission approval of Joint Petitioners' participation in the Midwest ISO's ASM, and Phase II addressing cost recovery issues associated with such participation. Citing to prior orders addressing the Joint Petitioners' participation in the Midwest ISO, Joint Petitioners assert that the Commission has stated a policy of supporting the development of a regional market and a market-based mechanism to manage transmission congestion.[6] Therefore, Joint Petitioners

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2 *Midwest Independent Transmission System Operator, Inc.,* Opinion No. 453, 97 FERC P61,033 (2001); *order on reh'g,* Order No. 453-A, 98 FERC P61,141 (2002).

3 *Hoosier Energy Rural Elec. Cooperative, Inc., et al.,* Cause No. 42027, 2001 Ind. PUC LEXIS 688 (IURC 12/17/2001).

4 *Midwest Independent Transmission System Operator, Inc.*, 107 FERC P61,191 at ¶ 94 (May 26, 2004) ("the Commission directs the Midwest ISO to move the start of the energy market from December 1, 2004 to March 1, 2005"). Following additional testing, the energy markets actually took effect on April 1, 2005.

5 The implementation of ASM was subsequently postponed by the Midwest ISO until September 9, 2008, and then postponed again until January 6, 2009.

6 *See Joint Petitioners' Petition* at p. 12, citing *In re Joint Petition of PSI Energy, Inc. and Vectren Energy Delivery of Ind., Inc.,* Cause Nos. 42257 and 42266, 2002 Ind. PUC LEXIS 571, at *10 (IURC 12/11/2002) and *Hoosier Energy Rural Elec. Cooperative, Inc., et al.,* Cause No. 42027 at p. 9 (IURC 12/17/2001).

requested that the Commission investigate the implications of the Midwest ISO's implementation of the ASM and thereafter issue an order in Phase I of this proceeding.

The Commission issued its Order in Phase I of this proceeding on August 13, 2008 ("Phase I Order"). In the Phase I Order, Joint Petitioners were authorized to: (1) transfer additional balancing authority functions in accordance with the Amended Balancing Authority Agreement and implement the operational changes necessary to permit Joint Petitioners to participate in the Midwest ISO's ASM; (2) seek recovery in their respective fuel adjustment clause ("FAC") or other appropriate proceedings, those items identified as "Modified" in Appendix A, along with the new Non-Excessive Energy Amount and Excessive Energy Amount Charge types. The Commission ruled that the modified charges could continue to be treated for ratemaking purposes as they were currently treated by each of the Joint Petitioners until a final determination by the Commission in this proceeding on the issue of cost recovery; and (3) to defer certain identified ASM costs consistent with Appendix A.[7] The Commission also created a subdocket to allow for further consideration of whether, and to what extent if any, a cost-benefit analysis of the Joint Petitioners' participation in the Midwest ISO or the Midwest ISO ASM should be performed, and whether any additional data concerning ASM costs and benefits should be provided in the Joint Petitioners' respective FAC filings.

4. Relief Requested in Phase II. In Phase II of this proceeding, Joint Petitioners requested approval of the manner and timing of recovery or crediting of jurisdictional charges and revenues associated with the Midwest ISO's ASM.

5. Evidence Presented in Phase II.

A. Joint Petitioners' Evidence. Joint Petitioners' witness, Mr. William L. Jett, Director of Federal Regulatory Policy for Duke Energy Shared Services LLC, provided an overview of key design components of the Midwest ISO ASM. Mr. Jett testified that the primary objectives of ASM are to provide transparent economic signals to value the provision of ancillary services, reconcile operating practices with market incentives so that market participants are compensated for providing reliability, and to appropriately price energy and ancillary services under shortage conditions. A key design element of the ASM is to enable the simultaneous co-optimization of the Energy and Ancillary Services Markets to achieve the least-cost dispatch and ancillary services solution. Mr. Jett explained that simultaneous co-optimization is the key principle by which the Energy and Ancillary Services Markets operate together, with market participants offering each generating resource with an energy component and an ancillary service component. The principle of co-optimization recognizes the trade-off between supplying energy and ancillary services. He stated that simultaneous co-optimization is intended to make resources financially indifferent to providing energy or ancillary services.

Mr. Jett testified that demand curves will be utilized in the clearing and pricing of ancillary services during scarcity conditions. Operating Reserve zones will be established to assess deliverability of contingent reserves and to determine price and settlements. Costs for regulation services will be assigned to load and generator operators will be charged for

[7] Appendix A was attached to the Commission's August 20, 2008 Supplemental Order in this Cause.

regulation if they are operating with deviations outside of tolerance bands. Costs for Contingency Reserves will be assigned to load and exports. Mr. Jett explained that the Midwest ISO is also designed with certain market price caps; energy offers are capped at $1000/MWhr and ancillary services under the Midwest ISO's ASM are capped at $500/MW for Regulating Reserves, $100/MW for Spinning Reserves and $100/MW for Supplemental Reserves.

Mr. Jett explained that resources which may be used for ASM include committed online generation, Demand Response Resources ("DRR") Type I, DRR Type II, available off-line or uncommitted quick start resources and available External Asynchronous Resources ("EAR"). A DRR Type I is a resource hosted by a load serving entity or an energy consumer that is capable of supplying a specific quantity of energy or Contingency Reserve to the market through physical load interruption within 10 minutes of receiving a signal. Such a resource is committable, but not dispatchable, and typically consists of an industrial load. A DRR Type II is a resource hosted by a load serving entity or energy consumer that is capable of supplying energy to the market through behind-the-meter generation or controllable load. A DRR Type II is a committable and dispatchable (capable of responding to dispatch signals) resource, which can provide energy, Regulation and Contingency Reserves, while a DRR Type I can only provide Contingency Reserves. An EAR must be dispatchable on firm transmission service and capable of receiving and responding to dispatch target and setpoint instructions from the Midwest ISO.

Mr. Jett said that the Midwest ISO will set Operating Reserves requirements at two levels: market-wide operating reserves requirements and zonal operating reserves requirements. He stated the goals of reserves zones are to ensure deliverability into identified import constrained areas and to provide a vehicle for electrical dispersion of reserves. For regulation service, the reserve is expected to be about 1% of the Midwest ISO load. Contingency reserve requirements are typically based on the loss of the largest generation or transmission resource.

According to Mr. Jett, resource offers will include resource offer data and operating parameters for both energy and ancillary services. There will be price parameters, including start-up and no load offers, incremental energy offer curves, and reserve availability offers. In addition, there will be non-price parameters, such as resource limits, resource ramp rates and resource dispatch band levels. The components of the Operating Reserves offer data include an availability flag. The operating reserves "Availability Offer" may be submitted with an offer or self-scheduled. The "Availability Offer" may offer to supply a specific type of Operating Reserves (Regulating, Spinning or Supplemental) specified in $/MW. Likewise, for self-scheduled offers, the offer would include the specific type of Operating Reserves specified in MW. Ancillary services offers may vary on an hourly basis.

Mr. Jett testified that locational marginal pricing ("LMP"), covering energy, congestion and losses, will continue under ASM. The prices for Regulating, Spinning and Supplemental Reserves will be quoted as the "market clearing price" ("MCP"). Under ASM, the MCP determined by the Midwest ISO for spinning reserve service will cover the Spinning Reserve offer and opportunity cost from supplying Spinning Reserves rather than energy. Mr. Jett explained that Operating Reserves offers may generally take into account operating costs, compliance risk, and changes in unit efficiency (fuel costs). If Operating Reserves are cleared in the Day Ahead energy market, the resource will receive MCP for the cleared product. If the resource is not called on to provide Operating Reserves in real-time, the cleared availability offer should cover the costs incurred by the unit. The market is designed so that the margin associated with the cleared operating reserves product should always be greater than or equal to the margin associated with energy. If this did not happen, then the resource would clear energy instead of Operating Reserves.

Mr. Jett further testified that all or a portion of a resource offered by a market participant for ASM can be self-scheduled. Deployment of designated self-scheduled reserves will be the responsibility of the Midwest ISO. Self-scheduling has become a common phrase for a number of ways that a generation owner can ensure that a specific unit or units will operate in the Midwest ISO market. There are a variety of valid reasons for a generation owner to "self-schedule" a unit, such as if testing of the unit is necessary. The Midwest ISO will consider self-scheduled generation to be fixed at the self-scheduled level or higher and then will perform an incremental dispatch to meet the remaining demand requirements taking reliability concerns into consideration.

Mr. Jett noted that there is no "one size fits all" approach in submitting a generating unit's Day Ahead Offer status to the Midwest ISO. In making the decision regarding an individual unit's offer status, the generating unit owner considers various factors such as forecasted LMP for energy, MCP for ASM, unit generation production cost, Midwest ISO cost impact, and the capability and economic impact of cycling the generating unit off-line and/or on-line. Before making any generation unit offer, the owner's personnel would engage in a planning process designed to minimize the total customer cost by maximizing each unit's economic value.

Mr. Jett explained that to the extent a Joint Petitioner self-schedules its generation resources to provide reserves, the unit is a price-taker for those self-scheduled reserves and that self-scheduled portion of the unit is unavailable to participate in the Midwest ISO Day Ahead energy market. If the MCP for reserves clears below the cost of the unit, that Joint Petitioner would forego the opportunity to purchase reserves more cheaply for its customers. Also, the self-schedule may remove the ability for the unit to collect lost opportunity costs by removing the self-scheduled portion of the unit from participation in the Day Ahead energy market. Mr. Jett opined that there may, however, be circumstances where it is prudent for a market participant to self-schedule one or more ancillary services.

Finally, Mr. Jett stated that Joint Petitioners (and other market participants) are required to offer their network resources, if available, into the Contingency Reserve market. For the first 180 days of the ASM market operation, the Joint Petitioners (and other market participants) are required to offer their network resources, if capable and available, into the Regulating Reserve market. The Midwest ISO procures all of the necessary reserves (Regulating and Contingency) for the Midwest ISO market footprint in the day-ahead market.

Joint Petitioners' witness Ms. Marlene S. Parsley, Senior Energy Market Analyst for Vectren South, provided an overview of how Joint Petitioners participate in Midwest ISO economic dispatch today and how they will participate in co-optimized economic dispatch under the ASM. She described the economic dispatch process as determining and using the most economical, available resources to meet the needs of the system, taking into consideration the operational characteristics and limitations of the generating units.

Ms. Parsley explained how Operating Reserves are dispatched today. Each Joint Petitioner, as a Balancing Authority, calculates its Operating Reserves needs and ensures or self-certifies that they have sufficient Regulation, Spinning, and Supplemental Reserves to meet North American Electric Reliability Corporation ("NERC") Requirements. Once they have determined the quantity of reserves required to serve their load, they identify those by submitting Day Ahead Offers to MISO reflecting Regulation Minimum and Maximum dispatch limits on individual generators. These Regulation Minimum and Maximum dispatch limits on offered units effectively withhold capacity from the Energy Market to allow the Balancing Authority to meet its Operating Reserves Requirements. Regulation Reserves are used by each Balancing Authority's Automatic Generation Control ("AGC") system to meet changing load requirements and maintain Area Control Error within NERC standards. She explained that the momentary changes can be due to numerous variables, including load fluctuations, changes in generator capability, net interchange, and frequency deviations. Contingency Reserves (Spinning and Supplemental) are used in the event of a sudden loss of generating or transmission capacity, to increase supply quickly to maintain reliable operation of the electrical system.

Ms. Parsley then described how Joint Petitioners will participate in Midwest ISO's Co-Optimized Economic Dispatch once the ASM begins. She explained that in addition to submitting hourly Day Ahead and Real Time Offers for energy, the Joint Petitioners will submit Availability offers for Regulating Reserves and Contingency Reserves (Spinning and Supplemental) for their resources. These offers will be in $/MW and will include physical parameters such as ramp rate, economic minimum and maximum, emergency minimum and maximum, notification and start up times for each resource. The Day Ahead and Real Time offer timing remains the same as in today's Energy-only Market.

Ms. Parsley also explained how Operating Reserves will be deployed in the new ASM. She testified the Midwest ISO's AGC system will calculate the amount of generation required and send a target MW loading to each generator every four (4) seconds. For the set of resources which have cleared Regulating Reserves, this signal may be different at each 4 second interval. The rate of change is determined by the physical parameters, including a bi-directional ramp rate. These regulating resources allow MISO to meet the moment to moment changing needs of the load. Resources which have cleared for Contingency Reserves (Spinning or Supplemental) will receive dispatch targets to increase generation upon the unexpected loss of other resources. The rate these resources are asked to increase is determined by the as-offered ramp rate and the needs of the system. When resources are cleared for Regulation, Spinning, or Supplemental Reserves they are paid the MCP in dollars per megawatt hour for that service. Those MCPs are determined by the least-cost dispatch of the resources to serve load within a reserve zone.

Ms. Parsley testified that even following good utility practice it is reasonable to expect Joint Petitioners to occasionally incur the Regulation and Contingency Reserve charges, which are designed to encourage generator operators to follow the Midwest ISO setpoints. The Midwest ISO tolerance for regulation is four (4) percent of generation with a minimum of 6 MW and maximum of 20 MW. She explained that the unexpected loss of a pulverizer or other equipment, as well as swings in boiler temperature or pressure beyond the generator's reasonable control, may cause a generator to fall outside the tolerance band and incur regulation penalties. Contingency Reserve penalties are incurred when a resource which has cleared Spinning or Supplemental Reserves is deployed and fails to achieve 100 percent of the targeted amount of increase within 10 minutes. For Joint Petitioners, this can occur for many reasons including fluctuations in fuel quality, temperature or pressure swings, sudden loss of equipment, or the inherent operating characteristics of an individual unit.

Ms. Parsley described some of the benefits of the co-optimization of energy and Operating Reserves. Operating Reserves requirements will be met by utilizing Midwest ISO's broad range of resources and the diversified fuel mix. It is anticipated that by turning over additional balancing authority tasks to MISO, as reflected in the Amended Balancing Authority Agreement, the new Local Balancing Authorities, which each of the Joint Petitioners will become, should have lower Operating Reserves requirements. Additionally, there is the potential of increased economic efficiency from Joint Petitioners' generating units because each generator within the Midwest ISO footprint will be dispatched by MISO to supply the product (energy, regulation, spinning reserve, or supplemental reserve) that it is most efficient at producing. It is also anticipated that there will be lower levels of Revenue Sufficiency Guarantee ("RSG") charges assessed against market participants due to the Midwest ISO's inclusion of ancillary services revenues in its calculation of sufficiency payments. Fewer Make Whole Payments should result in lower RSG Distribution Amounts.

Joint Petitioners' witness, Mr. William H. Henley, Vice President Corporate Affairs for IPL, described the costs Joint Petitioners will incur under operation of the Midwest ISO's ASM; described how the same and similar costs are recovered today; and explained why the proposed new charge types that will be assessed once the ASM starts should be recovered through the Joint Petitioners' respective FAC proceedings.

Mr. Henley explained the nature of the changes that are expected when the Midwest ISO implements the ASM. He stated that currently ancillary services are managed and procured locally by 23 Balancing Authorities within the MISO footprint. With the implementation of ASM, MISO will centrally manage ancillary services through simultaneous co-optimization of energy and operating reserve markets. The FERC expects this will yield substantial reliability and efficiency benefits.[8] Mr. Henley stated that each Joint Petitioner, as its own balancing authority, currently manages its ancillary services by "holding back" its own generation to meet Operating Reserves. "Holding back" means a generating unit is not allowed to run at its full operating capability in order to provide reserves for reliability. With the advent of MISO's ASM, each Joint Petitioner will begin purchasing its reserves and will offer both energy and ancillary services into the market. Mr. Henley stated that each Joint Petitioner under ASM will have the benefit of the MISO market to supplement its own generation to make energy purchases and acquire ancillary services, when economic.

Mr. Henley stated that Joint Petitioners incur similar costs today, explaining that when each Joint Petitioner has to "hold back" its own low cost generating unit to provide reserves it

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[8] FERC Order, Docket Nos. ER07-1372-000 and ER07-1372-001 at p. 2.

must run a higher cost unit or purchase from the market to meet its customers' energy needs. This incremental fuel or purchased power cost each Joint Petitioner incurs due to not being able to generate energy at a low cost unit's full operating capability in order to provide reserves for reliability is the cost each Joint Petitioner is incurring today (*i.e.,* prior to ASM). At the evidentiary hearing, Mr. Henley stated that he did not know what those implicit ASM costs were for 2008, did not know what the net cost to customers from the MISO ASM service would be for each Joint Petitioner for 2009, and did not know what the total reduction in fuel costs for customers in 2009 would be as a result of the implementation of the ASM. While he could not quantify the benefits for 2009, he stated that he does believe there will be benefits from ASM.

Mr. Henley stated that today these costs are implicitly recovered from customers through fuel costs, in FAC proceedings, that are higher than they could be if the Joint Petitioners did not maintain their own reserves. Due to operating constraints, portions of these reserves may be maintained on large coal-fired units. The ASM market is expected to free up this low cost generation to serve the Energy Market. He stated that in Indiana, where the low cost generation is first made available to Indiana retail customers, the additional low cost energy is expected to lower the fuel costs customers would otherwise pay.

Mr. Henley explained that generally, Joint Petitioners propose to recover the new charge types as fuel costs recoverable in their respective FAC proceedings, and to recover the modified charge types as currently authorized. He stated that there are certain distinctions between the methodologies proposed by each Joint Petitioner due to the different treatment authorized for each Joint Petitioner's MISO costs from the Energy Market and therefore, each Joint Petitioner is providing individual cost recovery testimony.

Mr. Henley explained that for IPL, these costs and revenues for ancillary services should be recoverable solely through the FAC proceedings, or deferred as currently authorized. Mr. Henley stated that IPL's recovery request is reasonable and consistent with its regulatory framework for recovery of MISO costs in the Energy Market. The recovery of ancillary services as fuel matches the benefits of the market with the recovery mechanism for those benefits. He testified that FERC has determined that MISO's ASM will increase efficiency and opined that IPL's low cost generation freed by the ASM will reduce fuel costs (from the level they would have been absent ASM) for IPL's retail customers. IPL requested that the ASM costs necessary to provide those savings also be flowed through to customers through the FAC. In addition, IPL requested that the ASM revenues it receives be flowed through the FAC to benefit retail customers. The administrative costs for ASM will be bundled with the existing administrative costs in Schedule 17 which are currently deferred for IPL. IPL requested that Schedule 17 costs, including the new ASM administrative costs, continue to be deferred.

Mr. Henley stated that the relief requested in this case is consistent with the Commission's decision in Cause No. 42685, in which the Commission recognized that there were some MISO charges and credits that should be viewed as a component of the cost of fuel and recovered through the Joint Petitioners' FAC proceedings. In addition, the Commission recognized that the cost components of fuel used to generate electricity are rarely explicitly disclosed.[9]

Mr. Henley explained that MISO's ASM is still under development and providing an estimate of total ASM costs at this juncture would be speculative. He opined that Joint Petitioners' ASM cost recovery proposal addresses costs and revenues that are variable, likely to be substantial and outside the control of Joint Petitioners, but which result from Joint Petitioners taking transmission services under the Midwest ISO TEMT to serve their retail electric customers. As the ASM will result in both new and modified MISO charges, which have previously been determined to be recoverable as fuel under the Commission's Order in Cause No. 42685, and since all charges and credits represent the net cost of providing Operating Reserves, which are required to provide reliable service of energy to retail customers, it is appropriate to include the costs as a cost of fuel in FAC proceedings. Also, administratively and functionally, the ancillary services component cannot be separated out for some charge types from the energy market component on MISO statements. Including all costs, other than administrative costs, in the FAC will ensure neither customers nor Joint Petitioners are harmed by including some of the costs in one tracker and providing for cost recovery for other portions of the net cost of providing reserves through some other mechanism or timing.

Mr. Henley stated that MISO has a mechanism to monitor market participants' behavior in the ASM market so as to ensure there is no market manipulation by generators. He explained that the same Independent Market Monitor that currently reviews market participants' behavior in the Energy Market will review market participants' behavior in the fully co-optimized Energy and Ancillary Services Market.

Joint Petitioners' witness, Mr. James Cutshaw, Revenue Requirements Manager for IPL, reviewed the new and modified charge types Joint Petitioners will be charged or credited on Midwest ISO settlement statements under ASM. He explained that there will be three new charge types on the Day Ahead market settlement statement as a result of the ASM: (1) the Day Ahead Regulation Amount, representing an Asset Owner's compensation for regulation and frequency response reserves cleared by MISO; (2) the Day Ahead Spinning Reserve Amount, representing an Asset Owner's compensation for spinning contingency reserves cleared by MISO; and (3) the Day Ahead Supplemental Reserve Amount, representing an Asset Owner's compensation for supplemental contingency reserves cleared by MISO. He stated that the hourly amount for each charge type will be the product of the cleared megawatts and the Day Ahead MCP for that operating reserve.

Mr. Cutshaw also explained that there will be three comparable new charge types on the Real Time market settlement statement: (1) the Real Time Regulation Amount, which represents an Asset Owner's compensation for regulation reserves cleared in the Real Time market; (2) the Real Time Spinning Reserve Amount, which represents an Asset Owner's compensation for spinning contingency reserves cleared in the Real Time market; and (3) the Real Time Supplemental Reserve Amount, which represents an Asset Owner's compensation for supplemental contingency reserves cleared in the Real Time market. He stated that the hourly

[9] *Verified Joint Petition of PSI Energy, Inc., et. al.*, Cause No. 42685 at p. 36 (IURC 6/1/2005).

amount for each charge type will be the product of the Real Time Net megawatts (difference between the cleared megawatts in Real Time and Day Ahead) and the Real Time MCP for that operating reserve at the offered location.

Mr. Cutshaw further explained that there will be three new charge types on the Real Time market settlement statement related to procurement of Operating Reserves: (1) the Regulation Cost Distribution Amount, which represents the Midwest ISO's allocation by Asset Owner of the total costs of procurement of regulation reserves in the Day Ahead and Real Time markets; (2) the Spinning Reserve Cost Distribution Amount, which represents the Midwest ISO's allocation by Asset Owner of the total cost of procurement of spinning contingency reserves in the Day Ahead and Real Time markets; and (3) the Supplemental Reserve Cost Distribution Amount, which represents the Midwest ISO's allocation by Asset Owner of the total cost of procurement of supplemental contingency reserves in the Day Ahead and Real Time markets. He stated that the total hourly operating reserve product costs (by type) will be calculated separately for each reserve load zone, and will be the product of the operating reserve requirement (in megawatts) and the MCPs for each type of reserve. The product costs (by type) will be allocated on load ratio share to each reserve zone.

Mr. Cutshaw stated that there will be two new charge types on the Real Time market settlement statement resulting from the ASM which were designed as incentives for asset owners to follow dispatch signals. First, the Excessive/Deficient Energy Deployment Charge Amount[10] will be applicable to an Asset Owner with cleared regulation reserves who does not follow MISO set point instructions for three or more consecutive five-minute dispatch intervals within an hour. This aggregate amount will consist of removal of that hour's Day Ahead Regulation Amount and Real Time Regulation Amount and a charge assessed for each megawatt hour of generation in that hour. Second, the Contingency Reserve Deployment Failure Amount[11] will be applicable to an Asset Owner with cleared contingency reserves who fails to follow the MISO deployment instructions for contingency reserves. The amount will consist of the product of LMP and the difference between actual deployment and the instruction amount for that hour. In addition, for the remainder of that operating day, contingency reserves for that asset will be capped at the actually deployed amount and a charge assessed for the product of the shortfall in spinning reserve and the Real Time MCP. Mr. Cutshaw noted that the funds collected from these two charge types will be credited to the Real Time Neutrality Uplift Charge.[12]

Mr. Cutshaw explained that there will be three additional new charge types on the Real Time market settlement statement applicable to generation asset owners. First, the Non-Excessive Energy Amount is a net charge or credit for the portion of actual net energy injections less than or equal to the resource's excessive energy threshold. The excessive energy threshold is the MISO set point plus 4% (with a tolerance minimum of 6 MW and a maximum of 20 MW).

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[10] This charge type was previously named by the Midwest ISO the Regulation Penalty Amount.

[11] This charge type was previously named by the Midwest ISO the Contingency Reserve Deployment Failure Penalty Amount.

[12] In rebuttal, Mr. Cutshaw explained that the treatment of funds collected from the Excessive/Deficient Energy Deployment Charge Amount will now be offset against the Real Time Regulation Cost Distribution Amount.

Net energy injections at or below the threshold will be paid at the Real Time LMP. Second, the Excessive Energy Amount is a net charge or credit for the portion of actual net energy injections greater than the resource's excessive energy threshold. Net energy injections above the threshold will be paid at the lesser of the Real Time LMP or the offer price. And, third, the Net Regulation Adjustment Amount is a charge or credit applicable to an Asset Owner providing deployed regulation service for energy output at levels where the LMP does not match the offer price. The amount will be the product of the megawatt hours of regulation service energy provided and the difference between the Asset Owner's offer price and the LMP. Mr. Cutshaw noted that the Non-Excessive and Excessive Energy charge types will effectively replace the existing Real Time Asset Energy Amount for generation (the Real Time Asset Energy Amount applied to load is discussed below), the existing Real Time Uninstructed Deviation Amount, and the Real Time Uninstructed Deviation Credit (collectively, "UD").

Mr. Cutshaw listed the existing Day 2 charge types that will be modified to include the ASM costs and revenues in their underlying calculations, as follows:

- Day Ahead Market Administration Amount (Schedule 17)
- Day Ahead RSG Distribution Amount
- Day Ahead RSG Make Whole Payment Amount
- Real Time Market Administration Amount (Schedule 17)
- Real Time RSG First Pass Distribution Amount
- Real Time RSG Make Whole Payment Amount

Mr. Cutshaw explained that market participants will not be able to separate the ASM portion from the modified charges. The design of the Energy and Ancillary Services Market includes simultaneous co-optimization of energy and the ancillary services products. A single generator may be dispatched to provide energy alone or may be dispatched to provide a combination of energy and specific ancillary services. MISO will make no distinction or allocation between energy and ancillary services for the above charge types.

Mr. Cutshaw explained that there are three existing Day 2 charge types that will be modified as a result of ASM. First, the Real Time Asset Energy Amount will only be applied to load zones in the ASM. For generation, this charge type will be reflected in the new Non-Excessive Energy Amount and the Excessive Energy Amount charge types. Second, the Real Time Uninstructed Deviation Amount will end with the start of the ASM, but may be reflected on resettlements of prior operating days. Finally, since the Real Time Uninstructed Deviation Amount charge type will no longer continue, the resulting credits from this charge will no longer flow into the Real Time Revenue Neutrality Uplift amount and instead the funds collected from the new Excessive/Deficient Energy Deployment Charge Amount and the new Contingency Reserve Deployment Failure Amount will now be reflected in this charge type.

Mr. Cutshaw stated that the existing Real Time Asset Energy Amount is the means for compensating generators for providing generation in the Real Time market, with the UD providing for real time deviations from MISO dispatch signals. The new Non-Excessive Energy Amount and the Excessive Energy Amount charge types will effectively replace and have similar cost causation characteristics as these three existing charge types and therefore should be treated in the same manner.

Mr. Cutshaw also presented testimony showing how the current MISO Day 2 charge types are recovered by IPL today and explained how IPL proposes to recover the proposed new and modified charge types that will be assessed once the ASM starts. Mr. Cutshaw sponsored Joint Petitioner's Exhibit 7-A, showing how MISO's Day 2 credits and charges are currently treated by IPL. He stated that IPL proposes to recover the new ASM charge types as fuel costs recoverable in its FAC proceedings. He explained that IPL proposes that those items identified as "Modified", along with all other existing charge types which are not affected by the implementation of ASM, would continue to be treated for ratemaking purposes as they are today. This treatment is proposed because the modifications do not impact the previously determined characteristics of these charge types being fuel-like or not. In addition, it will be impossible for IPL to separate these modified charge types into Day 2 and ASM components.

In regards to funds collected from the new Excessive/Deficient Energy Deployment Charge Amount and the new Contingency Reserve Deployment Failure Amount, Mr. Cutshaw stated that to the extent that these credits are specifically identified subcomponents of the Real Time Revenue Neutrality Uplift ("RNU") Amount charge type, IPL proposes to flow such amounts through its FAC proceeding as an offset to recoverable fuel costs. If these credits are not specifically identified subcomponents, IPL proposes to defer such amounts for future recovery as it is authorized to do for existing unspecified RNU amounts. Mr. Cutshaw sponsored Petitioner's Exhibit 7-B to show how IPL proposes to treat each of the new and modified charge types from ASM.

Joint Petitioner Duke Energy Indiana's witness, Ms. Maria Birnbaum, Director, Rates, Indiana Rate Department, agreed with the testimony of Joint Petitioners' witness Mr. William H. Henley and the inclusion of the same new or modified Midwest ISO charge types within future FACs, with exceptions related to ASM revenues and certain modified charge types, which are currently recoverable under Duke Energy Indiana's Rider No. 68, entitled Midwest ISO Management Cost and Revenue Adjustment ("Rider No. 68"). Ms. Birnbaum described the existing charge types that are recovered through Duke Energy Indiana's Rider No. 68 proceedings. She also described which Rider No. 68 charge types will be modified upon the start of the ASM. Further, she explained why the charge types that are recovered through Rider No. 68, but will be modified, should continue to be recovered through Rider No. 68. Finally, she summarized Duke Energy Indiana's proposal for cost recovery of the new and modified MISO charge types by applicable recovery mechanism.

Ms. Birnbaum testified Duke Energy Indiana proposes to include the new and modified charge types identified by Mr. Henley as being fuel-related and allocated to native load in future FAC proceedings and believes it appropriate to do so for the same reasons articulated by Mr. Henley.

Ms. Birnbaum described Duke Energy Indiana-specific cost recovery differences. She stated that to the extent the revenue Duke Energy Indiana receives for certain charge types (namely, Day Ahead Regulation Amount, Day Ahead Spinning Reserve Amount, Day Ahead

Supplemental Reserve Amount, Real Time Regulation Amount, Real Time Spinning Reserve Amount, and Real Time Supplemental Reserve Amount) is greater than the charges to native load for these services from the Regulation Cost Distribution Amount, Spinning Reserve Cost Distribution Amount, and Supplemental Reserve Cost Distribution Amount charge types, Duke Energy Indiana proposes to include those net incremental revenues in Duke Energy Indiana's Standard Contract Rider No. 70 – Summer Reliability Adjustment ("Rider No. 70") as non-native sales profits.[13] Such net incremental ASM revenues allocated to Rider No. 70 would be included with other non-native revenues and costs (including other Midwest ISO ASM allocated costs) in the calculation of non-native sales profits.

Ms. Birnbaum opined this is an equitable proposal for several reasons. First, prior to ASM, Duke Energy Indiana would "hold back" some of its own low cost generating units to provide reserves, which at times required it to run higher cost units or purchase from the market to meet native load requirements. With ASM, Duke Energy Indiana will be able to fully dispatch these units into the Energy Market. Because these units are often low cost, native load customers will benefit as it is expected that much of this low cost freed up generation will be assigned to native load. Second, to the extent ASM revenues are greater than the native load ASM costs as described above, the native load customers are more than made whole in that their ASM costs will be covered by ASM revenues, they will receive the fuel savings referred to above, and they will receive more than 50% of non-native sales profits pursuant to Duke Energy Indiana's Rider No. 70 sharing mechanism.

Ms. Birnbaum testified as to why it is appropriate to include the ASM revenues greater than the native load cost distribution amounts in Rider No. 70. She stated that with the Midwest ISO's simultaneous co-optimization of the energy and operating reserve markets, Duke Energy Indiana should be indifferent to providing ancillary services or energy to the market. She testified that Duke Energy Indiana's generation not needed to meet native load energy requirements will be available to be offered into the market and could result in ASM revenues and/or revenues from non-native energy sales. Today, non-native sales profits are included in Rider No. 70, and Duke Energy Indiana believes that any ASM revenues, above native load costs, should be treated consistently. If Duke Energy Indiana is required to credit customers in the FAC with 100% of the net ASM revenues, the customer would receive the level of non-native sales profits built into base rates (subject to Rider No. 70), plus 100% of the ASM profits. In addition, customers would also benefit from the lower fuel costs that will result from having additional low cost generation available to native load customers due to Duke Energy Indiana not having to hold back generation to maintain its own reserves. Ms. Birnbaum testified that without the Rider No. 70 sharing of ASM net revenues, Duke Energy Indiana would be financially penalized by the fact that its generating units were well suited for use in the ASM, as opposed to being 100% dispatched into the Energy Markets. One of the key principles of the Midwest ISO co-optimized Energy and ASM markets is that generators should be indifferent financially as to whether the generation is used for the ASM or the Energy markets. She stated that under Duke Energy Indiana's proposal, Duke Energy Indiana would generally be financially indifferent as to whether its units are used for ASM products or energy sales.

[13] This proposal was modified in the Original Settlement and the Modified Settlement Duke entered into, which are discussed later in this Order.

Ms. Birnbaum described the costs and transmission revenues recovered under Duke Energy Indiana's Rider No. 68. She testified that pursuant to Rider No. 68, Duke Energy Indiana recovers administrative and other costs billed to Duke Energy Indiana by the Midwest ISO. The Midwest ISO amounts not otherwise recovered in the FAC, and which vary from base rate amounts, are included for recovery in Rider No. 68.

Ms. Birnbaum stated that the Rider No. 68 charge types to be modified as a result of the ASM consist of those under Schedule 17 (referred to as "Day Ahead Market Administration Amount" and "Real Time Market Administration Amount" by Mr. Cutshaw), and the Day Ahead RSG Distribution Amount, the Real Time RSG First Pass Distribution Amount and the RNU. Prior to ASM, Schedule 17 provided for the recovery of all costs incurred by the Midwest ISO to administer the Day 2 markets (except costs recovered by Schedule 16). Such costs include, but are not limited to, costs associated with: (1) market modeling and scheduling functions; (2) market bidding support; (3) LMP support; (4) market settlements and billing; (5) market monitoring functions; and (6) enabling the least-cost, security-constrained commitment and dispatch of generating resources to serve load in the Midwest ISO control areas while also establishing a spot market. Prior to ASM, the RNU was a charge type used by the Midwest ISO as a distribution balancing mechanism for charges and credits, which have no other distribution method, to asset owners. On an hourly basis, all charges and credits that have no other distribution amount are summed, and the subsequent total charge or credit for the hour is distributed to Duke Energy Indiana based on its load ratio share.

Ms. Birnbaum then described how the charges would be modified upon the start of ASM. Schedule 17 will be called "Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder" and the costs of operating the ASM will be allocated under Schedule 17. Therefore, in addition to the current recovery under Day 2, Schedule 17 will provide for the simultaneous co-optimization for the scheduling and enabling of the least-cost security constrained commitment and dispatch of generating resources to serve load and provide Operating Reserves in the Midwest ISO Balancing Authority Areas while also establishing a spot market. Ms. Birnbaum stated that the Midwest ISO estimates there will be an incremental increase to the rate charged of 3.5 cents per megawatt hour attributable to the consolidation of the Balancing Authority functions and the implementation of the ASM, to be charged to market participants based upon their activity in the market. Ms. Birnbaum explained that the Midwest ISO will not segregate Schedule 17 into Day 2 and ASM components, as it is a bundled rate.

Ms. Birnbaum explained that the Day Ahead and Real Time RSG calculations will be modified to include Operating Reserve costs and Operating Reserve revenues along with the energy costs and energy revenues to determine the amount of make whole payments due to generators by the market participants. As a result of the simultaneous co-optimization of the Energy and Ancillary Services Market, the Midwest ISO will evaluate the costs and revenues for the applicable products that are part of the simultaneous co-optimization design to determine the RSG credit amounts due to the generators and the ensuing charge or distribution amounts to be funded by the market participants. Ms. Birnbaum explained that the Midwest ISO will not segregate the Day Ahead RSG Distribution Amount and the Real Time RSG First Pass

Distribution Amount into Day 2 and ASM components on the settlement statements, as these are bundled amounts.

Ms. Birnbaum testified that the Real Time Revenue Neutrality Uplift will be modified to incorporate the addition of the ancillary services products by removing the credit to market participants for revenues collected for Uninstructed Deviation charges. Ms. Birnbaum explained that the Uninstructed Deviation amounts will end with the start of ASM, having been effectively replaced with other charge types. Ms. Birnbaum also explained that the inclusion of the credits to market participants for revenues collected for two new charge types, Contingency Reserve Deployment Failure Amount and Excessive/Deficient Energy Deployment Charge Amount, which are assessed to generators which fail to follow dispatch signals, are expected to be included in the RNU, as described by Mr. Cutshaw. Ms. Birnbaum explained that Duke Energy Indiana proposes that the credits for these two new charges encompassed within the RNU be included in its FAC, consistent both with the treatment being requested by the other Joint Petitioners and with the Order in Cause No. 38707 FAC 70, whereby the Commission authorized Duke Energy Indiana to account for UD in its FAC.

Ms. Birnbaum testified that no adjustments are required to the base rate amounts included in Rider No. 68 filings for Schedule 17, Day Ahead RSG Distribution Amount, Real Time RSG First Pass Distribution Amount, and RNU. She explained that these charge types are incremental amounts to Duke Energy Indiana and the ASM-related modifications were not contemplated during the development of Duke Energy Indiana's base rates in Cause No. 42359. Ms. Birnbaum further stated that Duke Energy Indiana is not able to quantify the dollar impact to Rider No. 68 as a result of the ASM as estimates of overall net savings have only been prepared by the Midwest ISO at a market participant level.

Ms. Birnbaum explained that Duke Energy Indiana currently does not include Schedule 24 and 24a in Rider No. 68 because Duke Energy Indiana's costs for load balancing functions were included in the development of its base rates in Cause No. 42359. Ms. Birnbaum stated that Duke Energy Indiana will monitor revenues and costs associated with both of these schedules after the ASM begins, coincident with several of the load balancing functions transferring to the Midwest ISO. If Duke Energy Indiana were to realize amounts that are significantly different from the amounts built into base rates, Duke Energy Indiana may propose inclusion in a future Rider No. 68 proceeding.

Ms. Birnbaum testified Duke Energy Indiana proposes that the charge types to be modified that are currently recovered through Rider No. 68 should continue to be recovered through Rider No. 68. Ms. Birnbaum opined that the modified charge types are consistent with guidance in the Commission's Order in Cause No. 42685. As described in the testimony of Mr. Jett in this proceeding, the ASM represents the continued evolution of the Day 2 markets and the charge types are the results of decisions by the Midwest ISO, are approved by the FERC, and are included in the Midwest ISO tariff. Ms. Birnbaum stated that there will be variability as to the amount and timing of ASM costs, that the amounts may be substantial, and that the incurrence of such costs is outside the control of Duke Energy Indiana. Ms. Birnbaum concluded that without the incurrence and payment of the administrative and uplift costs by Duke Energy Indiana, Duke Energy Indiana would not be able to realize the benefits of participating in the co-optimized markets. Ms. Birnbaum concluded that it would not be fair for Duke Energy Indiana to bear such costs without recovery, while ultimately the benefits are realized by Duke Energy Indiana's retail electric customers in the form of lower fuel costs and substantial reliability and energy benefits.

Ms. Birnbaum stated that short of withdrawing from the Midwest ISO, which would involve foregoing the benefits of the Midwest ISO Energy Markets, Duke Energy Indiana's participation in the ASM is not optional. Thus, Duke Energy Indiana proposed to include fuel-related costs and credits resulting from the ASM and attributable to native load in its FAC proceedings, with any incremental ASM profits in excess of native load's cost distribution amounts included in Rider No. 70 with other non-native sales margins. Duke Energy Indiana intends to include administrative and other related costs and credits in its Rider No. 68. Joint Petitioner's Exhibit 8-A summarized all Midwest ISO charge types that were either new charge types or modified as a result of the ASM and whether Duke Energy Indiana proposed recovery through the Duke Energy Indiana FAC, Rider No. 68 or Rider No. 70.

Joint Petitioner Vectren South's witness, Mr. Scott E. Albertson, Director of Regulatory Affairs for Vectren Utility Holdings, Inc., agreed with the testimony of Joint Petitioners' witness Mr. Henley and the inclusion of the same new or modified Midwest ISO charge types within future FACs, as described by Mr. Henley, with one exception related to ASM revenues. Mr. Albertson described the existing charge types that are recovered through Vectren South's MISO Cost and Recovery Adjustment ("MCRA") proceedings. He described which MCRA charge types will be modified upon the start of ASM. He also explained why the charge types that are recovered through the MCRA, but will be modified, should continue to be recovered through the MCRA. Finally, he summarized Vectren South's proposal for cost recovery of the new and modified MISO charge types by applicable recovery mechanism.

Mr. Albertson testified Vectren South proposes to include the new and modified charge types identified by Mr. Henley as being fuel-related and allocated to native load in future FAC proceedings and believes it appropriate to do so for the same reasons articulated by Mr. Henley. However, he pointed out that Vectren South proposes to include modified Administrative and RNU costs in its MCRA proceedings.

Mr. Albertson described the company-specific cost recovery differences. He stated that to the extent the revenue Vectren South receives for certain charge types (namely, Day Ahead Regulation Amount, Day Ahead Spinning Reserve Amount, Day Ahead Supplemental Reserve Amount, Real Time Regulation Amount, Real Time Spinning Reserve Amount, and Real Time Supplemental Reserve Amount) is greater than the charges to native load for these services from the Regulation Cost Distribution Amount, Spinning Reserve Cost Distribution Amount, and Supplemental Reserve Cost Distribution Amount charge types, Vectren South proposes to include such net incremental revenues and related costs in its Reliability Cost and Revenue Adjustment ("RCRA") as non-native sales margins. Further, costs in ASM which are associated with non-native load will either (a) be charged to contractual non-native load, or (b) be an offset (reduction) to wholesale power marketing margins. In neither case will such costs attributable to non-native load be borne by native (retail) customers. This treatment is the same as the treatment of MISO-related charges incurred in the Energy-only market currently.

Mr. Albertson testified as to why it is appropriate to include the ASM revenues greater than the native load cost distribution amounts in Vectren South's RCRA. He stated one of the key principles of the Midwest ISO co-optimized Energy and ASM Markets is that generators should be indifferent financially as to whether the generation is used for the ASM or the Energy Markets. He testified that Vectren South's generation not needed to meet native load requirements will be offered into the market and thereafter the Midwest ISO will determine whether the sale is an ASM sale or an energy sale. Currently, Vectren South's nonnative sales margins are included in the RCRA for sharing. If this does not continue, Vectren South would be left in a position where it would not receive its RCRA sharing of excess ASM revenues. Customers would receive 100% of the net ASM revenues, the full level of nonnative sales margins built into base rates and the expected lower fuel costs from having additional low cost generation freed up and not "held back" as reserves. Mr. Albertson testified that as a result, without the RCRA sharing of ASM net revenues, Vectren South would be financially penalized, contrary to the key Midwest ISO principal of the co-optimized energy in ASM markets that generators should be indifferent financially as to whether their generation is used for ASM or energy. However, under Vectren South's proposal, it would remain indifferent as to whether its units are used for ASM products or energy sales.

Mr. Albertson described the costs and transmission revenues recovered under Vectren South's MCRA. He testified that pursuant to the MCRA, the Vectren South recovers administrative and other costs billed by the Midwest ISO. The Midwest ISO amounts not otherwise recovered in the FAC, and which vary from base rate amounts, are included for recovery in the MCRA.

Mr. Albertson described which MCRA charge types will be modified and how they will be modified as a result of the start of the ASM. He stated Schedule 17 will be called "Energy and Operating Reserve Markets Market Support Administrative Service Cost Recovery Adder." The costs for operating the ASM will be allocated under Schedule 17. In addition to the current recovery under Day 2, Schedule 17 also provides for the simultaneous co-optimization for the scheduling and enabling of the least-cost security constrained commitment and dispatch of Generating Resources to serve Load and provide Operating Reserves in the Midwest ISO Balancing Authority Areas while also establishing a spot energy market. The rate will be charged to market participants based upon their activity in the market. The Midwest ISO will not segregate Schedule 17 charges into Day 2 and ASM components, as it is a bundled rate.

He further testified the Day Ahead and Real Time Sufficiency Guarantee calculations will be modified to include Operating Reserve costs and Operating Reserve revenues along with the energy costs and energy revenues to determine the amount of make whole payments due to generators by the market participants. As a result of the simultaneous co-optimization of the Midwest ISO Energy and Ancillary Services Market, the Midwest ISO will evaluate the costs and revenues for the applicable products that are part of the simultaneous co-optimization design to determine the RSG credit amounts due to the generators and the ensuing charge or distribution amounts to be funded by the market participants. The Midwest ISO will not segregate the Day Ahead RSG Distribution Amount and the Real Time RSG First Pass Distribution Amount into Day 2 and ASM components on the settlement statements, as these are bundled amounts.

Mr. Albertson also testified that the RNU will be modified to incorporate the addition of the ancillary services products by removing of the credit to market participants for revenues collected for Uninstructed Deviation charges. Uninstructed Deviation amounts will end with the start of the ASM, having been effectively replaced by other charge types. However, the inclusion of the credits to market participants for revenues collected for two new charge types, Contingency Reserve Deployment Failure Amount and Excessive/Deficient Energy Deployment Charge Amount, are expected to be included in the RNU. These two new charge types are assessed to generators which fail to follow dispatch signals as described in the testimony of Mr. Cutshaw. To the extent that these credits are specifically identified subcomponents of the RNU, Vectren South proposes to flow such amounts through its FAC as an offset to recoverable fuel costs. He stated this is consistent with the Order in Cause No. 38708 FAC 73 whereby the Commission authorized Vectren South to account for UD in its fuel clause filings. The credits from these two new charges will be netted against penalties and included as costs of fuel in future FAC proceedings. The RNU amount which has not been identified as an offset to fuel will be recovered in future MCRA proceedings.

Mr. Albertson testified that no adjustments are required to the base rate amounts included in the MCRA filings as a consequence of modifications to the MCRA charge types. He explained these charge types are incremental amounts to Vectren South. The modifications to accommodate the ASM for Schedule 17, and RNU were not contemplated during the development of base rates in Cause No. 43111.

Thus, Mr. Albertson concluded, Vectren South proposes to include fuel-related costs and credits resulting from the ASM and attributable to native load in its FAC proceedings, with any incremental ASM margins in excess of native load's cost distribution amounts included in the RCRA with other non-native sales margins. Vectren South intends to include non-fuel-related costs and credits in its MCRA. Joint Petitioners' Exhibit 10-A summarizes all Midwest ISO charge types that were either new charge types or modified as a result of the ASM and whether Vectren South proposes recovery through the FAC, RCRA or MCRA.

Joint Petitioners' witness, Ms. Linda E. Miller, Executive Director of Rates and Regulatory Finance for NIPSCO, concurred with the testimony of the other Joint Petitioner witnesses and described how NIPSCO recovers Day 2 energy market costs, and how NIPSCO proposes to recover costs associated with the ASM. Ms. Miller agreed that the ASM is a reasonable approach to serving NIPSCO's retail electric customers. She stated that participation in the ASM is expected to result in lower overall fuel costs for MISO participants and that as a participant in the ASM, NIPSCO will be doing its part to help achieve the expected benefits. Thus, she opined, NIPSCO should be permitted to recover its costs in participating in the ASM. She stated that any efficiencies that result from the operation of the ASM should benefit NIPSCO's ratepayers in the form of lower costs and that it is therefore appropriate that NIPSCO's ratepayers should bear the cost of NIPSCO's participation in the market. She explained that the ASM is a FERC-approved market, which FERC expects will yield substantial reliability and energy benefits. The charges associated with participation in the ASM are outside of NIPSCO's control, but will be allocated in accordance with MISO's FERC-approved TEMT.

Ms. Miller explained that essentially NIPSCO recovers all Day 2 charges through the FAC. She noted that there are a few exceptions, such as the Administrative charges, certain components of the RNU, Schedule 24 costs and credits, and Miscellaneous charge types, which are deferred for recovery in a future rate case.

Ms. Miller stated that NIPSCO proposes to recover ASM charges in the same manner as Day 2 charges. All charges associated with the ASM would be recovered through the FAC, with the exception of Administrative charges, which will be deferred for recovery in a future rate case. She explained that the Modified ASM Charge Types, along with all other existing charge types which are not affected by the implementation of the ASM, would continue to be treated for ratemaking purposes as they are today.

With respect to funds collected from the new Excessive/Deficient Energy Deployment Charge Amount and the new Contingency Reserve Deployment Failure Amount that will be reflected in the RNU, Ms. Miller explained that to the extent these credits are specifically identified subcomponents of the RNU, NIPSCO proposes to flow such amounts through its FAC proceeding as an offset to recoverable fuel costs. She stated that if these credits are not specifically identified subcomponents, NIPSCO proposes to defer such amounts for future recovery.

B. <u>OUCC's Evidence.</u> Mr. Andrew J. Satchwell, Utility Analyst, testified on behalf of the OUCC. He indicated a consideration for the OUCC staff in its review of ASM charges and revenues was determining which ASM costs are related to fuel and which costs should be considered non-fuel. He testified that the costs associated with Operating Reserve activities reflect both operation and maintenance expenses recovered in base rates and charges and fuel expenses recovered in fuel trackers, but that quantifying these amounts is difficult. He testified that determining how to equitably allocate costs and revenues in this ASM presents a challenge for regulators who must not inadvertently incent a utility to craft supply offers based on maximizing shareholder earnings at the expense of ratepayers. Because ratepayers fund the majority of the generating equipment operating expenses through base rates and charges, Mr. Satchwell averred that ratepayers should receive the majority of benefits through the sharing of ASM revenues in addressing the potential for double-recovery of costs. He recommended Vectren South and Duke Energy Indiana follow the same ASM revenue sharing methodology as IPL and NIPSCO. He also recommended that the Commission authorize the Joint Petitioners to recover ASM costs attributable to jurisdictional customers if ASM revenues are equitably allocated between these customers based on recent allocation factors.

Mr. Satchwell also provided an update on the Midwest ISO's ASM readiness. He further described the potential for benefits of Joint Petitioners' participation in the ASM, by categorizing a number of potential benefits as to whether they were quantifiable or non-quantifiable. As an example, he pointed to Joint Petitioners' ability to acquire Operating Reserves from the market on an as needed basis rather than holding back capacity as a possible quantifiable benefit. He also explained that a non-quantifiable benefit example would be the effect of co-optimization on LMP. To better understand the potential benefits, he recommended Joint Petitioners work collaboratively with the OUCC and any interested stakeholders to develop an ASM cost benefit study. Finally, Mr. Satchwell described the benefits of stakeholders sharing information and recommended that each Joint Petitioner, individually or on a collective basis, provide information to the OUCC and the Commission six to eight weeks after the start of ASM, and that each Joint Petitioner meet with the OUCC to discuss its confidential bidding and forecasting strategies.

Ms. Stacie R. Gruca, Utility Analyst, also testified on behalf of the OUCC. She described the proposed new and modified Midwest ISO charge types that result from the ASM and why differences in recovery of ASM charge types amongst the Joint Petitioners are appropriate. She explained that Duke Energy Indiana proposes to recover new native load amounts in its FAC, recover new non-native amounts in its Rider No. 70, and recover modified charge types in the same manner they are currently recovered through a combination of its FAC or Rider No. 68 and Rider No. 70. Similarly, she explained that Vectren South proposes to recover all new ASM charge types in its FAC and RCRA proceedings, with native load to be reflected in the FAC and non-native load to be reflected in the RCRA, and recover modified charge types in the same manner they are currently recovered through a combination of its FAC or MCRA and RCRA, with native load amounts in the FAC and MCRA and non-native load amounts to be included in the RCRA. For IPL and NIPSCO, which do not have approved recovery mechanisms such as Rider No. 68, Rider No. 70, RCRA, or MCRA, Ms. Gruca explained that IPL and NIPSCO propose to recover all new ASM charge types within their FAC proceedings. She further explained that they propose to recover modified and existing charge types in the same manner they are currently recovered, *i.e.*, to recover fuel related charge types in the FAC and defer administrative charge types. Ms. Gruca testified that no alternative means of recovery of Schedule 24 and Schedule 24a charges should be pursued until Duke Energy Indiana and Vectren South's next base rate cases.

Ms. Gruca explained that Joint Petitioners propose to recover the replacement charges for UD within their FAC proceedings; in the same manner existing UD is recovered. She also explained that Joint Petitioners currently provide an explanation in support of cost recovery of any Uninstructed Deviation penalty charges which exceed Uninstructed Deviation revenues for any given month, per the Commission's Order in Cause No. 38707 FAC 70 (Duke Energy Indiana) and Commission Orders approving Settlement Agreements in Cause Nos. 38703 FAC 74 (IPL), 38706 FAC 74 (NIPSCO), and 38708 FAC 73 (Vectren South). She recommended that Joint Petitioners work with the OUCC to create similar guidelines for the replacement charges for UD to limit the recovery of future deviations. She suggested Joint Petitioners proactively track operating conditions in which Joint Petitioners' staff suspect units operate outside of accepted bandwidths to aid in understanding ASM operations.

Ms. Gruca explained that Joint Petitioners propose to recover modified RSG charges and credits in the same manner they currently recover RSG charges and credits. She also explained that IPL, NIPSCO, and Vectren South are required to provide supporting documentation establishing the reasonableness of the requested recovery of any RSG amounts above the benchmark through March 31, 2009, per Settlement Agreements in Cause Nos. 43471 (IPL and NIPSCO) and 43475 (Vectren South), unless those settling parties agree otherwise, and notify the Commission prior to March 31, 2009.[14] She recommended that the Commission require Joint Petitioners IPL, NIPSCO, and Vectren South to continue to proactively track RSG amounts above the benchmark and provide support for proposed recovery of such charges as a narrative in testimony filed in each Joint Petitioner's FAC proceeding (or MCRA proceeding with respect to Vectren South), as well as include a narrative in testimony and provide proof as to the reasonableness of "Contestable RSG" amounts in each of such Joint Petitioners' respective recovery mechanisms (unless Joint Petitioners are deferring for future recovery in their next rate case), per Cause Nos. 43471 and 43475.

Ms. Gruca also testified that deferred accounting authority should not be open-ended and should be viewed as a temporary measure to provide relief until necessary rate adjustments can be made. She further testified that after a period of time, deferrals should cease and the utility should propose whatever rate relief it believes necessary to ensure that current rates and revenues reflect the utility's cost of service. She suggested that any deferred accounting authority granted in this Cause should cease after a maximum period of four years. If new basic rates and charges are established during that period, Ms. Gruca testified that deferrals should cease upon the establishment of new basic rates and charges, unless good cause is shown by the utility regarding why deferrals should continue. Finally, she suggested that the parties collaboratively work to create templates to be used in the tracking mechanisms of the utilities in flowing through ASM charges and credits.

C. IIG's Evidence. Mr. James R. Dauphinais testified on behalf of IIG. He testified that each of the Joint Petitioners in their first FAC involving the ASM should provide detailed testimony in regard to how their generation resources were offered into the ASM and why the way they were offered is reasonable. He suggested that the details provided address how the offer parameters of the utilities' resources were developed. Mr. Dauphinais also suggested that until a reasonable level of MISO "penalty" charges can be ascertained, each Joint Petitioner should present detailed testimony and supporting data in their FACs showing the incurrence of such MISO charges was reasonable.

Mr. Dauphinais testified a benchmark for recovery of Operating Reserve purchases would be appropriate. He suggested that each Joint Petitioner with purchases that exceed the purchased energy benchmark of the Joint Petitioner or on average over a month exceed the per unit embedded cost of a new combined cycle combustion turbine generator should be required to provide detailed testimony and supporting data showing such excess amounts were reasonably incurred.

Mr. Dauphinais also recommended that Duke Energy Indiana and Vectren South not be allowed to account for Operating Reserve revenue amounts in excess of Operating Reserve distribution amounts in their respective off-system sales riders. Through this recommendation, 100% of such net Operation Reserve revenue amounts would be used as a credit to retail customers rather than shared in accordance with each utility's approved off-system sales sharing mechanism. Mr. Dauphinais testified that such crediting would account for these revenue

[14] The Commission notes that the settling parties have since notified the Commission and proceedings initiated in Cause No. 43664 (IPL), Cause No. 43665 (NIPSCO), and Cause No. 43672 (Vectren South).

amounts being new revenues that did not exist at the time of the last base rate proceedings of Duke Energy Indiana and Vectren South. He also testified that such crediting would resolve his concern that such revenues are not just off-system sales revenues for Operating Reserves, but rather include both off-system sales revenues for Operating Reserves and payments made by MISO to each utility in lieu of dispatching the utility's generation for energy production that would have been assigned by the utility to its native load. Mr. Dauphinais suggested that this treatment for Duke Energy Indiana and Vectren South's net Operating Reserve revenue amounts would be consistent with the credit proposed by IPL and NIPSCO, which do not have approved off-system sales sharing mechanisms.

Mr. Dauphinais also suggested that in future ratemaking proceedings, it should be considered that ASM will likely provide additional off-system energy sales margins and that IPL and NIPSCO currently do not have any off-system sharing mechanisms of the type approved for Duke Energy Indiana and Vectren South.

D. **LaPorte's Evidence.** LaPorte's witness, Mr. Reed W. Cearley, an independent contractor retained by LaPorte as a special utility consultant, addressed NIPSCO's request to recover from its Indiana retail electric customers the costs incurred as a results of participation in the Midwest ISO ASM. Mr. Cearley opined that NIPSCO cannot recover MISO ASM charges through its FAC. He explained that NIPSCO has not requested recovery of those charges through a tracker mechanism and that the Commission declined to grant NIPSCO's request for a specific MISO tracker in Cause No. 42685, and that NIPSCO has not renewed that request. Mr. Cearley stated that the Commission approved a tracker for purchased power costs of NIPSCO in accordance with a Revised Benchmark established by the settlement in Cause No. 38706 FAC71 S1, but that the settlement provided that "[n]either specifically-identified capacity costs nor non-fuel related MISO costs (as defined in Cause Nos. 42685 and 42962) may be included under the 42(a) costs." The settlement agreement approved in that proceeding allowed NIPSCO to seek recovery of MISO costs pursuant to a Commission order and allowed any other party to the settlement to oppose such recovery. Mr. Cearley stated that NIPSCO seeks the recovery of all MISO charges associated with the ASM through its FAC, with the exception of Administrative charges, which it seeks to defer for recovery in a future rate case and that LaPorte opposes such recovery.

Mr. Cearley opined that not all charges associated with ASM are recoverable through NIPSCO's FAC. He asserted that the ASM charges for which NIPSCO seeks recovery are neither "fuel costs" nor do they involve the generation or purchase of electricity; and that by definition, the ASM charges pertain to reserves, *i.e.,* resources that are available but are not called upon to generate electricity for use by customers. He stated that costs associated with reserves traditionally have not been recovered by NIPSCO through its FAC, but instead are recovered by NIPSCO in its basic rates and charges.

Mr. Cearley disagreed with Joint Petitioners' assertion that ASM costs are implicitly recovered from customers through fuel costs that are higher than they could be if the utilities did not maintain their own reserves. He stated that customers pay "fuel costs" for the fuel used to generate electricity. He opined that since NIPSCO purchased capacity, it was not "holding back" generation. On cross examination, Mr. Cearley admitted that NIPSCO purchases capacity for planning reserve requirements, not Operating Reserve requirements. *See* Tr. B42-B43.

Mr. Cearley opposed NIPSCO's proposal to recover ASM charges in the same manner as Day 2 charges. He asserted that Day 2 charges involve "energy" purchases and that ASM charges involve no fuel and thus include no cost of fuel. He stated that the cost is paid for a resource to be available – the demand and capacity costs that the Commission observed should be removed when determining fuel costs. In Mr. Cearley's opinion, Day 2 charges and ASM charges are not similar and should not be treated similarly in an FAC proceeding.

E. <u>Joint Petitioners' Rebuttal.</u> In rebuttal, Mr. Henley addressed the testimony of IIG witness Mr. Dauphinais, LaPorte witness Mr. Cearley and OUCC witness Mr. Satchwell. First, Joint Petitioners disagreed with Mr. Dauphinais' suggestion that a combustion turbine type benchmark be applied to ASM costs. Mr. Henley noted that if Mr. Dauphinais' recommendation were adopted, it would create a fundamental inconsistency in the treatment of ASM costs and revenues. Mr. Henley pointed out that Mr. Dauphinais appears to be in favor of flowing through revenues received by Joint Petitioners that are attributable to scarcity pricing, but not allowing for the flow through of the costs incurred as a result of scarcity pricing. Mr. Henley stated that if the Commission does not allow for consistent treatment, Joint Petitioners could be in an untenable position of only flowing through revenues but not being able to recover costs.

Next, Joint Petitioners disagreed with Mr. Cearley's assertion that there are no fuel costs in the ASM charges. Mr. Henley stated that ASM costs should be considered fuel or fuel type costs. He explained that the Midwest ISO's ASM is a co-optimized Energy and Ancillary Services Market. When Joint Petitioners offer their generation resources into the Midwest ISO ASM, they will receive a cleared energy component and a cleared amount for each ASM product, if any, in the Day Ahead Market. In Real Time they will receive a set-point instruction for each unit that includes the components of deployed energy and ASM products. However, they will not immediately know which portion of their unit ultimately went to serve energy or an ASM product. This will be determined after the fact based upon the Midwest ISO settlement process. Thus, Joint Petitioners will be operating their generation in response to Midwest ISO instructions and, unless they self-schedule the specific ancillary services, will not have the ability to selectively provide Operating Reserves rather than energy during a given hour. Mr. Henley stated that Joint Petitioners' low cost generation freed up by ASM is expected to reduce fuel costs (from the level they would otherwise be absent ASM) for their retail customers. He further explained that self-scheduling would potentially reduce the benefits of lower cost services. Thus, he concluded, symmetry is served if the ASM costs necessary to provide those savings are recovered from retail customers through the Joint Petitioners' respective FACs. Mr. Henley also noted that FERC addressed this issue in *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶ 61,172, P 392 (2008), finding that ASM costs should be viewed as energy-related costs, not "capacity" type costs.

Mr. Henley also responded to OUCC witness Mr. Satchwell's discussion regarding the issue of treating ASM costs as "fuel" costs. Mr. Henley responded to the OUCC's reference to the Midwest ISO presentation by Richard Doying regarding the non-fuel components of the ASM MCP. Mr. Henley explained that Mr. Doying's statement has to be placed into proper context. "Wear and tear" costs as referenced by Mr. Doying should be considered in the same manner that FERC has considered "facility costs," namely, as part of the marginal cost of energy. Those costs, in both the Energy Market and ASM, are bundled as the total marginal cost of energy. The amount of energy purchased and ancillary services procured is a function of the amount of load being served and should be recovered from retail customers through Joint Petitioners' respective FAC proceedings as a fuel or purchased power cost.

Mr. Henley also addressed Mr. Dauphinais' recommendation that the Commission require each of the Joint Petitioners in their first FAC reconciliation involving the ASM to provide detailed testimony in regard to how their generation resources were offered into the ASM and why the way they were offered is reasonable. He stated that Joint Petitioners were willing to provide such information provided that a preliminary finding of confidentiality could be issued without any impact on the FAC procedural schedule.

Mr. Cutshaw addressed Mr. Cearley's assertion that Joint Petitioners' position that ASM costs were taken into account in fuel costs that were recovered in FAC proceedings is "entirely theoretical." Mr. Cutshaw sponsored Joint Petitioners' Exhibit 15-A, an illustration of how ASM economic dispatch could lower fuel costs.

Second, Mr. Cutshaw addressed Mr. Cearley's assertion that recovery of ASM charges must be dealt with in a "base rate proceeding" and cannot be given deferral treatment. Mr. Cutshaw explained that in Phase I, Joint Petitioners requested deferral of all new MISO ASM charge types (except the new Non-Excessive Energy Amount and Excessive Energy Amount charge types) from the financially-binding testing of the market and continuing until a final determination is made by the Commission on the issue of cost recovery. In addition, Joint Petitioners requested that existing charge types modified by the ASM continue to be treated for ratemaking purposes as they are today by each of the Joint Petitioners until a final determination is made by the Commission in this proceeding. Such current ratemaking treatment includes deferral of certain charge types for two of the Joint Petitioners (IPL and NIPSCO). He noted that the Commission's Phase I Order issued on August 13, 2008, authorized both requests.

Mr. Cutshaw further testified that in Phase II, two of the Joint Petitioners (IPL and NIPSCO) have proposed to continue the deferral of certain existing charge types previously authorized for deferral by the Commission. He opined that it is appropriate for the Commission to authorize the requested continued deferral by IPL and NIPSCO of these certain existing charge types modified by the ASM. He explained that the design of the Energy and Ancillary Services Market includes simultaneous co-optimization of energy and ancillary services products. The Midwest ISO will make no distinction or allocation between energy and ancillary services for these charge types, and therefore it will be impossible for IPL and NIPSCO to separate these modified charges into Day 2 and ASM components. He stated the modifications do not impact the previously determined characteristics of these charge types being fuel-like or not, or the Commission's prior determination that such charge types are appropriately deferred by IPL and NIPSCO for recovery in a future rate case.

Third, Mr. Cutshaw addressed OUCC witness Ms. Gruca's recommendation that Joint Petitioners should provide information concerning the replacement charges for UD. Mr.

Cutshaw stated that Joint Petitioners are willing to work cooperatively to develop guidelines to compare "failure to follow dispatch" costs with associated revenues as proposed by Ms. Gruca, however recovery should not be contingent upon the netting of revenues to costs because revenues may not be specifically identified by the Midwest ISO in all cases. Mr. Cutshaw noted that similar cost-causation does not equal similar transparency on the Midwest ISO settlement statements, so similar guidelines may not be feasible.

Mr. Cutshaw stated that Ms. Gruca's testimony seems to assume that the three new charge types (Excessive Energy Amount, Regulation Penalty Amount, and Contingency Reserve Deployment Failure Charge Amount) will appear on the settlement statements in the same manner as the existing UD. However, he noted, only the Contingency Reserve Deployment Failure Charge Amount will show up like UD on the settlement statements (as a charge on one hand, with the revenues reflected in the RNU). Mr. Cutshaw stated that MISO has made changes to the distribution of the funds from the Excessive/Deficient Energy Deployment Charge Amount (formerly the Regulation Penalty Amount). He explained that initially, the funds collected from the Excessive/Deficient Energy Deployment Charge Amount were to be credited to the RNU, as were the funds collected from the Contingency Reserve Deployment Failure Charge Amount. To the extent such credits were specifically identified subcomponents of RNU, a netting of costs and revenues could occur. However, in its revised Settlements Business Practice Manual issued July 24, 2008, the Midwest ISO changed the distribution of the funds collected from the Excessive/Deficient Energy Deployment Charge Amount and will now include these funds as an offset to the Real Time Regulation Cost Distribution Amount. He stated Joint Petitioners will still receive the effect of the distribution of such funds, but determining the amount will be difficult, if not impossible to do.

Fourth, Mr. Cutshaw addressed Ms. Gruca's recommendations concerning treatment of RSG amounts. He stated that Joint Petitioners believe that the OUCC's recommendation that Joint Petitioners IPL, NIPSCO and Vectren South continue to proactively track RSG Amounts above the benchmark and to provide support for proposed recovery of such charges as a narrative in testimony filed in a particular Joint Petitioner's FAC or MCRA proceeding is consistent with the Settlement Agreements in Cause Nos. 43471 and 43475. Mr. Cutshaw also stated that Joint Petitioners believe that the OUCC's recommendation that Joint Petitioners IPL, NIPSCO and Vectren South include a narrative in testimony filed in a particular Joint Petitioner's respective proceeding for recovery mechanisms of RSG charges and credits, providing proof as to the reasonableness of Contestable RSG amounts (unless deferred for future recovery in their next rate case) is also consistent with the Settlement Agreements in Cause Nos. 43471 and 43475. In addition, Mr. Cutshaw stated that each Joint Petitioner is willing to work separately with the OUCC to aid in understanding ASM operations with respect to a Joint Petitioner's own units to proactively track operating conditions in which Joint Petitioners' staff suspect units operate outside of accepted bandwidths.

Fifth, Mr. Cutshaw addressed Ms. Gruca's suggestion concerning a four year limitation for deferral accounting. Mr. Cutshaw stated that there is currently no time limitation on previously authorized deferral authority. He stated that when the Midwest ISO Day 2 market started, IPL was granted authority to defer certain charge types immediately and NIPSCO was granted authority to begin deferral on August 1, 2006. In Phase II, IPL and NIPSCO have proposed to continue the previously authorized deferral authority for certain existing charge types which have been modified by the ASM, and for which these Joint Petitioners will be unable to separate these modified charge types into Day 2 and ASM components. Mr. Cutshaw stated that customers are currently reaping the benefits of the Day 2 market and are not harmed by the deferral of certain costs for future recovery. Thus, he testified, it is not necessary or appropriate to place a time limitation on these previously authorized deferrals.

Finally, Mr. Cutshaw responded to Ms. Gruca's recommendation concerning the development of templates for future rate tracking proceedings. Mr. Cutshaw stated that Joint Petitioners are willing to work cooperatively to develop such templates for schedules to be filed in future rate tracking proceedings in order to facilitate efficient auditing, as was done in conjunction with the implementation of Day 2. However, in the development of such templates and schedules, consideration should be given to the differences in rate structures among the Joint Petitioners because of different Commission-approved recovery mechanisms that are already in existence for the Energy Market and mechanisms which may be approved in the future for ASM.

Ms. Birnbaum responded to recommendations by Nucor, SDI,[15] the OUCC, and IIG that all revenues attributable to the sale of ancillary services should be booked as a credit against Duke Energy Indiana's fuel cost adjustment, rather than crediting part of such revenues to fuel cost (up to the native load costs for ancillary services) and also utilizing Duke Energy Indiana's revenue sharing proposal for excess revenues. She explained why Duke Energy Indiana believes sharing net ASM revenues in Rider No. 70 strikes an appropriate balance between customer and shareholder interests. Ms. Birnbaum pointed out that the ASM revenue will first be used to offset ASM costs through the FAC. It is only the ASM revenue in excess of ASM costs that would be treated like other non-native energy sales profits subject to the 50/50 sharing, subject to the annual base threshold of assumed net profits of $14,747,000 in Rider No. 70. Duke Energy Indiana is incented to make additional sales, while also benefiting native load customers. Ms. Birnbaum testified that this treatment recognizes the co-optimized nature of the market and provides the same sharing incentive to Duke Energy Indiana's shareholders whether excess generation is used to supply energy or ancillary services, once the new cost distribution amounts charged to native load customers have been offset with the new ASM revenues.

Ms. Birnbaum addressed concerns by Nucor and SDI regarding the cost of ASM and Duke Energy Indiana's proposed sharing mechanism, stating that the Commission found in Phase I of this proceeding that "...ASM is designed to and should result in lower overall market costs" across the Midwest ISO footprint. She noted that the Commission also found that "[w]e expect ASM to result in more efficient unit dispatch as units which can produce energy at the lowest cost will no longer be dispatched below their full capacity when other units are capable of providing Operating Reserves more cost effectively." Ms. Birnbaum addressed Nucor and SDI's concerns that there will be an increased administrative cost burden associated with the ASM that customers will fund and responded that as concluded previously by the Commission, the overall benefits of the ASM market outweigh the costs necessary to achieve those benefits.

[15] Nucor and SDI did not offer Mr. Higgins' testimony into evidence at the hearing.

Ms. Birnbaum also addressed Nucor and SDI's concerns that under Duke Energy Indiana's proposal, customers would only receive 50% of the benefit from incremental ASM revenue. Ms. Birnbaum countered that, under Duke Energy Indiana's proposal, revenues from the sale of ancillary services would be included in the Rider No. 70 sharing mechanism only once they exceed native load's cost for the new ancillary services cost distribution amounts. Below that threshold, customers would receive 100% of the benefit of incremental ancillary services revenue through credits to fuel costs. In addition, although Duke Energy Indiana proposes to include the net ancillary services revenues over this threshold in Rider No. 70 along with its non-native energy sales profits, native customers initially receive credit for at least 100% of the net profits in these markets until the threshold amount built into retail base rates of $14,747,000 is reached. Sharing then takes place for profits above and below this threshold. Ms. Birnbaum stated that because of how this sharing mechanism works, Duke Energy Indiana shareholders never truly receive 50% of total net profits. Moreover, to the extent net profits from non-native energy sales are less than the $14,747,000 threshold, Duke Energy Indiana is only reimbursed by customers a maximum of 50% of the short-fall in non-native energy sales profits.

Ms. Birnbaum testified that given that retail customers are expected to receive the benefit of lower fuel costs resulting from a more efficient market, use of Rider No. 70 for excess ancillary services revenues facilitates the balance that is needed between the interests of customers and shareholders, while encouraging Duke Energy Indiana, consistent with the key principle of simultaneous co-optimization of the Energy and Ancillary Services Markets, to be indifferent to whether it is selling energy or ancillary services.

Ms. Birnbaum also addressed the quantitative example included in the testimony of IIG witness Mr. Dauphinais, explaining that the conditions in the IIG example are expected to be infrequent and that the example did not present hours where customers will benefit from ASM because Duke Energy Indiana will be able to fully utilize its low cost units instead of holding back generation for reserves.

Ms. Birnbaum then responded to the OUCC assertion that ASM revenues should be credited against fuel expense, based in part on its view that some indeterminable portion of ASM costs are currently included in base rates. She testified that Duke Energy Indiana believes that the net benefits of lower market costs from the co-optimized market will translate into lower fuel and purchased power costs for native load customers. She further testified that the 50/50 net ASM revenue sharing proposition based on Duke Energy Indiana's unique rate-making structure, taken in the context of all expected benefits of ASM, creates a fair balance with native load customers such that crediting of jurisdictional ancillary services revenues to customers as a credit to fuel expense is not necessary or appropriate.

Ms. Birnbaum also stated that a "one size fits all approach" for the handling of ASM revenues is not conducive to efficient market results given the different rate structures in place for each of the Joint Petitioners. Ms. Birnbaum supported Exhibit 18-A and Exhibit 18-B, which included proposed modifications to Rider No. 70 calculations and the tariff, respectively.

Ms. Birnbaum addressed the OUCC's recommendation to wait until Duke Energy Indiana's next rate case to pursue alternative means of recovery of load balancing Schedule 24 and 24-A charge types, testifying that Duke Energy Indiana is agreeable to wait until its next rate case to pursue alternative means of recovery of load balancing Schedule 24 and 24a charge types.

Ms. Birnbaum also addressed IIG's proposal to impose an ASM operating reserve purchase benchmark. She stated such a benchmark would be inappropriate for the same reasons described by IPL witness Mr. Henley. Ms. Birnbaum noted that a benchmark, as suggested by the IIG for ancillary service purchases in order to assess the reasonableness of costs, would serve no useful purpose because under the ASM Joint Petitioners must purchase all of their Operating Reserves from the Midwest ISO.

Ms. Parsley responded to recommendations by IIG and the OUCC, that all revenues attributable to the sale of ancillary services should be booked as a credit against Vectren South's FAC, rather than Vectren South's proposal of first using ASM revenues to offset ASM costs and then sharing any excess ASM revenues 50/50 with customers under Vectren South's RCRA as approved in 2007 in Cause No. 43111. Ms. Parsley explained why Vectren South's proposed method of sharing revenues is appropriate under the Midwest ISO's Energy and Ancillary Services Market. She testified that to maximize the benefits to customers, the features of the market design should be used as they are intended. She testified that if there is a regulatory disincentive for the Market Participant to clear either ancillary services in lieu of energy, or energy in lieu of ancillary services, then maximum efficiency may not be achieved. She explained that the resulting tendency would be higher costs for ancillary services than would have occurred from a market which functioned as designed. She further described that being indifferent to whether the resources clear for energy or ancillary services aligns the interests of the customer and utility with the co-optimized market design. Ms. Parsley testified that this alignment results in maximum efficiency for resources in the market.

Mr. Albertson described several reasons why sharing net ASM revenues in the RCRA strikes an appropriate balance between customer and shareholder interests. First, Mr. Albertson pointed out that 100% of ASM revenue will first be used to offset ASM costs. It is only the ASM revenue above ASM costs that is subject to the 50/50 sharing in the RCRA. As discussed by Joint Petitioner's witness Ms. Parsley, absent the 50/50 sharing of net ASM revenue, Vectren South may benefit from the sale of energy but not from the sale of ancillary services. Mr. Albertson further testified that Vectren South's proposal strikes a fair balance and leaves the Company indifferent by treating off system sales and ASM sales in a consistent manner.

Second, Mr. Albertson explained any low cost generation freed up by ASM will be available to serve native retail load. Thus, he testified, customers would receive the resulting fuel savings and in addition receive 50% of any ASM revenue in excess of ASM costs.

Third, Mr. Albertson testified that pursuant to the Commission's Order in Cause No. 43111, Vectren South and its customers share equally in wholesale margins above and below $10.5 million annually. ASM revenue will be a new variable to wholesale performance. He described how other, perhaps more material, variables impacting wholesale sales include the occurrence of planned and unplanned outages, fuel costs, chemical costs, allowance costs, and the market price for power. Because these variables all change from year to year, the sharing mechanism was put in place. Mr. Albertson stated that Vectren South is incented to manage and control these costs under the 50/50 sharing mechanism in the RCRA because the results benefit both the utility and its customers. To the extent variable costs can be managed, more net proceeds remain to be shared. This same sharing proposal under ASM provides Vectren South with the incentive to maximize ASM sales and be completely indifferent as to whether it makes energy sales or ancillary service sales. In fact, if the Company can make ancillary services sales, more revenue will exist to offset ASM costs. Thus, Mr. Albertson concluded, Vectren South's proposal helps further the ASM goal of achieving maximum efficiency in deployment of energy or ancillary service resources across the MISO region while aligning its own goals with those of ASM.

Fourth, Mr. Albertson pointed out that not only would the OUCC and Interveners' proposal to credit 100% of all ASM revenue to the FAC decrease Vectren South's incentive to participate in the ASM, it in fact would penalize Vectren South when its units are called upon for ASM as opposed to being available for off system sales.

Fifth, Mr. Albertson testified that Vectren South's proposal is consistent with the OUCC desire that customers receive the majority of the benefits achievable through the ASM implementation. Vectren South customers will receive the efficiencies resulting from the co-optimization of the Energy and ASM Markets. Under Vectren South's proposal, Mr. Albertson testified that customers further benefit by 100% of ASM revenues being first used to offset ASM costs and by receiving 50% of all ASM revenue in excess of ASM costs. He also testified that customers further benefit from Vectren South retaining the full incentive to maximize off system sales subject to 50/50 sharing regardless of whether its units are used in the ASM or for wholesale sales.

Mr. Albertson also addressed IIG's proposal to impose an ASM Operating Reserve purchase benchmark. He stated such a benchmark would be inappropriate for the same reasons described by IPL witness, Mr. Henley and Duke Energy Indiana witness Ms. Birnbaum. Moreover, Mr. Albertson pointed out that Vectren South and Duke Energy Indiana have RTO trackers, *i.e.,* the MCRA and Rider 70. He testified if there were a benchmark, any above benchmark ASM reserve purchase made in the provision of retail electric service should be recoverable in the RTO trackers.

Finally, Mr. Albertson addressed OUCC witness Ms. Gruca's testimony that Vectren South proposes the option of requesting different ratemaking treatment of Schedule 24 and 24a charges in the future. He testified that currently such costs are included in Vectren South's base rates as part of MISO non-fuel costs. Differences from actual and base rate amounts of MISO non-fuel costs are tracked in the MCRA. He explained that Vectren South did not intend to propose the option of requesting different ratemaking treatment of these charges, but is reserving the right to pursue recovery of non-reimbursable, incremental internal costs in the future.

6. <u>The Modified Settlement of the Original Settling Parties, IIG and Nucor.</u> As stated earlier, Duke Energy Indiana, Vectren South and the OUCC filed the Original Settlement and testimony and exhibits in support thereof in September, 2008. On January 6, 2009, the Original Settling Parties, IIG and Nucor filed the Modified Settlement and subsequently filed their prepared testimony and exhibits in support thereof. The Modified Settlement supersedes the Original Settlement.

By way of background, the substantive terms of the Original Settlement provided that on an hourly basis Duke Energy Indiana and Vectren South would first apply all ASM Revenues (revenues from the sale of Day Ahead and Real Time Regulation and Spinning Reserves, and Supplemental Reserves) as an offset to ASM Costs (Cost Distribution Amounts for Regulation, Spinning, and Supplemental Reserves).[16] The utilities would retain 40% of the ASM Excess Revenues and native load customers would receive credit for the 60% balance of ASM Excess Revenues on an hourly basis. Then, on an annual basis, the previous 12 months of historical ASM results would be reviewed. If the annual summation of the 12 months results in an Annual Net Cost to native load customers, then each utility, using its 40% share of Excess Revenues that was initially retained, would reimburse native load customers up to the level of such Annual Net Cost by including a credit to fuel expense in the FAC proceeding. Thus, the utility's 40% share would be at risk and available to offset any net ASM cost to customers. This "annual look back" feature would only serve to reduce fuel costs for customers. The Original Settlement also provided that no benchmark for ASM is needed at this time and that the utilities will support the OUCC's position that alternative means of recovery Schedule 24 and 24(a) charges should not be pursued prior to the utility's next rate case. Finally, the Original Settlement provided for an ASM dialogue with participation by the OUCC and the utilities. The utilities and the OUCC filed supporting testimony, while IIG filed opposing testimony, all of which was admitted into evidence.[17]

Through further negotiations the Original Settling Parties, IIG and Nucor entered into the superseding Modified Settlement. The Modified Settlement is the only settlement in issue before this Commission in this proceeding. Therefore, only the testimony regarding the Modified Settlement is summarized below.

A. <u>Duke Energy Indiana's Testimony in Support of the Modified Settlement.</u> Ms. Birnbaum testified in support of and sponsored the Modified Settlement (Joint Petitioner's Exhibit 24-A) filed on behalf of Duke Energy Indiana, Vectren South, the OUCC, IIG and Nucor on January 6, 2009. Ms. Birnbaum explained that in order to comprehensively resolve issues raised during Phase II between IIG, Nucor, and Duke Energy Indiana, as well as between IIG, Nucor and Vectren South, additional concessions beyond those provided in the Original Settlement with the OUCC were made in the Modified Settlement, whereby IIG and Nucor agreed to join as Settling Parties to the Modified Settlement. The Modified Settlement represents a compromise resolution of issues raised by IIG and Nucor, as well as those raised by the OUCC in this proceeding.

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[16] With respect to Duke Energy Indiana, paragraph 2 of the Original Settlement, as well as the Modified Settlement, recognizes that "...Excess Costs and shared revenues would be allocated between retail and wholesale customer classes along with other fuel costs in accordance with the jurisdictional allocation that applies generally in FAC proceedings (*i.e.*, using updated kwh sales for the historical reconciliation month involved)."

[17] Included in such evidence was Joint Petitioners' Exhibit 19-B, sponsored by Ms. Birnbaum on behalf of Duke, which sets forth in table format the list of various charge and revenue types under ASM and the allocation and recovery mechanism applicable to Duke. This exhibit did not change based on the Modified Settlement.

Ms. Birnbaum summarized the terms of the Modified Settlement.[18] Paragraph 1 provides that the utilities shall net the cost to purchase ancillary services for native load customers (Regulation Cost Distribution Amount, Spinning Reserve Cost Distribution Amount, and Supplemental Reserve Cost Distribution Amount) against revenues from the sale of ancillary services (Day Ahead Regulation Amount, Day Ahead Spinning Reserve Amount, Day Ahead Supplemental Reserve Amount, Real Time Regulation Amount, Real Time Spinning Reserve Amount, and Real Time Supplemental Reserve Amount). The referenced revenues and costs will be netted on a quarterly basis such that in a given quarter, excess revenues may result if revenues exceed costs ("Excess Revenues") or excess costs may result if costs exceed revenues ("Excess Costs"). The quarterly netting results will be included in Duke Energy Indiana's FAC proceedings subject to paragraphs 4 and 5 of the Modified Settlement. Ms. Birnbaum explained that the quarterly netting is a compromise to the hourly netting proposed in the Original Settlement filed on September 29, 2008.

In paragraph 4, the parties recognize that they have not reached agreement as to whether any costs associated with providing ancillary services may be included, or are accurately reflected, in the settling utilities' base rates. Further, the parties recognize that any such costs would be difficult to determine. To address this issue, paragraph 4 provides that each utility's retained share of Excess Revenues will be 30% and the Customers' share of Excess Revenues will be 70%. Paragraph 4 states that actual Excess Revenues and Excess Costs will be determined by quarter. Ms. Birnbaum explained that the increased sharing of 70% of Excess Revenues going to customers is a concession from the proposed sharing of 60% of Excess Revenues going to customers, as provided for in the Original Settlement terms.

Paragraph 5 of the Modified Settlement provides that if the quarterly netting for a given quarter results in Net Excess Costs, the amount is included as native load fuel cost for the respective quarter in the FAC proceeding. If the quarterly netting for a given quarter results in Excess Revenues, the native customer is allocated 70% of the Excess Revenues as a credit to native load fuel costs for the respective quarter in the FAC proceeding and the utility retains the remaining 30%. Ms. Birnbaum stated that due to the quarterly netting provisions and the increase in the excess ASM revenue sharing percentage to customers from 60% to 70%, the annual look-back provision previously included in Paragraph 5 of the Original Settlement was eliminated.

Paragraph 7 of the Modified Settlement provides that the utilities will report the monthly average ASM Cost Distribution Amounts for Regulation, Spinning, and Supplemental Reserves paid by the utilities for each of the ancillary service products in its quarterly FAC proceedings, but that this additional informational will not serve as a benchmark. Ms. Birnbaum stated that this provision represents a compromise with respect to IIG's position regarding an ASM benchmark.

[18] References to paragraph numbers are to the numbered paragraph of the Modified Settlement Terms attached as Exhibit A to the Modified Stipulation and Agreement

Paragraph 8 provides that the terms relating to sharing of net Excess Revenues and the monthly average ASM cost information will expire at the earlier of the utility's next retail electric base rate case order or an IURC order on a proposal to be filed by the utility by January 31, 2012. Paragraph 8 further provides that if this issue is not addressed in the utility's next retail electric base rate order by August 31, 2011, the utilities will meet with the OUCC, the IIG, and Nucor by September 1, 2011 to negotiate a renewal or modify the existing arrangement for sharing of net Excess Revenues with the goal that such agreement be finalized by January 31, 2012. Ms. Birnbaum explained that the addition of IIG and Nucor is a modification to the Original Settlement which had only provided for OUCC involvement in such negotiations.

Paragraph 9 is the utility's commitment to maintain an open dialogue, subject to confidentiality agreements, with the OUCC, the IIG and Nucor, by presenting specific information related to the ASM within two months of the launch of the ASM. Ms. Birnbaum explained that the addition of IIG and Nucor is a modification to the Original Settlement which had only provided for the OUCC's involvement in such dialog.

Paragraph 10 concludes by providing that all issues not identified in the Modified Settlement are approved by the Settling Parties as proposed by the utilities in their Phase II direct and rebuttal testimonies.

Ms. Birnbaum opined that the Modified Settlement results in a negotiated settlement for Phase II of this proceeding for the Settling Parties that preserves the benefits of sharing of Excess Revenues between customers and Duke Energy Indiana and preserves ASM cost recovery for Duke Energy Indiana, subject to requirements applicable to Duke Energy Indiana's tracker proceedings. Ms. Birnbaum testified that the quarterly netting method and excess ASM revenue sharing percentage incents Duke Energy Indiana to provide ancillary services as well as energy consistent with the goal of maximizing the most efficient use of resources in a co-optimized market and negates the need for additional cost mitigation provisions. Ms. Birnbaum noted that Duke Energy Indiana's willingness to share information about the ASM market with the Settling Parties will increase transparency and knowledge of Duke Energy Indiana's ASM activities. For these reasons, Ms. Birnbaum believes that the Modified Settlement is in the public interest, balances both customer and shareholder interests, and should be approved by the Commission without modification.

B. **<u>Vectren South's Testimony in Support of the Modified Settlement.</u>** Ms. Parsley also testified in support of approval of the Modified Settlement. She described the modifications to the Original Agreement and testified that through a process of protracted, good faith, arms length negotiations, the Modified Settlement was agreed upon by the Settling Parties. She stated that achieving this broader settlement required additional concessions on the part of Duke Energy Indiana and Vectren South that form the core of the modifications to the Original Agreement.

Ms. Parsley addressed each of the substantive modifications to the terms of the Original Agreement. She first addressed quarterly netting, as reflected in paragraphs 1, 4, and 5 of the Modified Settlement Terms, by noting the Settling Parties have agreed that the "annual look back" provided for in paragraph 6 of the Original Agreement terms should be replaced with a quarterly netting of "ASM costs" against "ASM revenues." Ms. Parsley explained comparing ASM costs to ASM revenues on a quarterly rather than hourly basis will tend to average out any instances of high ASM costs incurrence and overall make it more likely that there will be excess revenues to be shared with customers. The quarterly netting should provide more benefit to utility customers than the previously proposed hourly netting with the annual look back provision, while still allowing the customers and utility to realize the benefits of the ASM market, thereby maximizing efficiency and minimizing costs through the simultaneously co-optimized deployment of energy and ancillary service resources across the MISO region.

She next addressed the sharing of excess revenues as reflected in paragraphs 4 and 5 of the Modified Settlement Terms, whereby the originally agreed to sharing of excess ASM revenues of 60% to customers and 40% to shareholders has been replaced with 70% to customers and 30% to shareholders. This represents an increased benefit to customers, providing them with 70% of net ASM revenues. She stated that this increase in the customers' share and its quarterly calculation described above is expected to result in additional benefits to customers.

She next addressed average ASM cost information as reflected in paragraph 7 of the Modified Settlement Terms, whereby Duke Energy Indiana and Vectren South will report the monthly average ASM Cost Distribution Amounts for Regulation, Spinning and Supplemental Reserves paid by the utility for each of the ancillary service products in each quarterly FAC proceeding. She further noted that the Modified Settlement clearly states, "This information shall not be a 'benchmark.'"

She next addressed the sunset provisions, initially limiting the agreed time period to the excess revenue sharing provisions. Paragraph 8 of the Modified Settlement reflects that the provision of monthly ASM cost information will be subject to the sunset dates and terms in the Original Agreement. It also now reflects that IIG and Nucor will be invited to meetings and may participate in negotiations with the utilities and the OUCC in conjunction with the future renewal of the agreement on sharing Excess Revenues. Paragraph 8 also now reflects that the interim sharing of ASM revenue agreed upon in the Modified Settlement will not be cited nor used in any manner in determining how to treat such revenues as part of Duke Energy Indiana's and Vectren South's future rate case outcomes.

Ms. Parsley lastly addressed participation in ASM dialogue as reflected in paragraph 9 of the Modified Settlement, whereby the Settling Parties agreed that IIG and Nucor may participate, along with the OUCC, in the ongoing ASM dialogue subject to a reasonable confidentiality agreement and in a manner consistent with anti-trust laws. The confidentiality agreement will include a provision requiring that each recipient of information agrees that it cannot use that information to its competitive advantage in offering resources into the Midwest ISO's markets.

Ms. Parsley testified as to her belief that the Modified Settlement is in the public interest. She stated the Original Agreement was in the public interest and the Modified Settlement increases the benefits to customers and thereby further benefits the public interest. The quarterly calculation of ASM costs and ASM revenues and the quarterly netting of these costs and revenues are expected to provide more financial benefit to customers than the previously agreed to hourly netting with annual look back. Beyond that, the Modified Settlement now provides that customers will receive 70% rather than the previously agreed to 60% of excess ASM net revenues. This also provides additional financial benefits to customers and furthers the public interest. Ms. Parsley testified that she believes the Settling Parties have taken a pro-customer settlement and made it even more favorable to customers. Moreover, the Modified Settlement eliminates all issues that existed between Duke Energy Indiana, Vectren South, the OUCC, IIG and Nucor. The Modified Settlement allows the Settling Parties to avoid the continued and costly litigation of complex issues and to bring this lengthy proceeding to a mutually satisfactory and fair conclusion.

C. <u>OUCC's Testimony in Support of the Modified Settlement.</u> Mr. Satchwell testified as to the five areas in which the Modified Settlement amends the Original Settlement.[19] He described the quarterly netting of ASM costs under the Modified Settlement as opposed to the hourly netting. He described the higher percentage of net ASM revenues to be credited to utility customers. He pointed out that with the addition of those two changes there is no longer an annual "look back" provision. He described the additional benefit of Duke Energy Indiana's and Vectren South's monthly reporting average ASM cost charge types in their quarterly FAC proceedings and the fact that the provision of this information will not be used as a benchmark. He also pointed out that IIG and Nucor will now be allowed to participate in the ASM dialogues. He concluded that the Modified Settlement reduces customer exposure to hours in which they would bear net ASM costs, customers will receive an increased share of excess ASM revenues which helps protect them against uncertainties in the ASM, and the reporting of average ASM costs with the inclusion of IIG and Nucor in the ASM dialogue increases transparency. He recommended that the Commission approve the Modified Settlement in its entirety.

7. <u>Commission Discussion and Findings.</u> Joint Petitioners requested approval to recover ASM related charges, other than administrative charges and other charges currently recoverable in RTO proceedings, as a cost of fuel in their respective FAC proceedings. In reviewing the testimony presented by the Joint Petitioners regarding recovery of fuel costs associated with their participation in the Midwest ISO's ASM, the Commission finds that the resolution of this issue should, to the greatest extent possible, result in a similar approach by each of the Joint Petitioners regarding the type of costs, and the form of filings, that will be made by each utility in their respective FAC proceedings. This approach should result in a consistent framework that will facilitate review by the Commission and all parties in subsequent FAC proceedings.

The Commission previously addressed the issue of fuel costs included in purchased power in Cause No. 41363. In Cause No. 42685, we recognized that under MISO Day 2, we had to broaden our review somewhat to include consideration generally of the "cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity" in order to ensure that we could continue to effectively evaluate fuel costs under Ind. Code § 8-1-2-42(d).

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[19] Mr. Satchwell also testified in support of the Original Settlement citing as benefits: a majority share of net ASM revenues would be provided to customers, the sunset provisions of the settlement, the provisions by which the Original Settling Parties would discuss ASM experiences shortly after the market launches, and continued recovery of Schedule 24 and 24(a) charge types by the utilities in base rates. Mr. Satchwell testified that all of the OUCC's concerns in Phase II of this Cause had been addressed by the utilities and the OUCC believed that the Original Settlement equitably allocated and balanced ASM costs and revenues.

In undertaking our review of the testimony presented in this Cause, the Commission recognizes once again that the cost components of fuel used to generate electricity are rarely explicitly disclosed but, rather, are implicitly included in the cost of purchased power. The charges and credits assigned to the Joint Petitioners in the Midwest ISO ASM are in essence a component of the cost of power to reliably meet the needs of their loads. As we have previously found, utilities should be encouraged to pursue cost-effective means of power acquisition and the ASM should be an integral part of meeting this objective. The charges and credits settled in the ASM are designed to drive such efficiency and reliability. Based on the evidence presented on this issue, we find that certain ASM charges should be treated as fuel costs, recoverable through the individual FAC proceedings of the Joint Petitioners as set forth herein.

A. <u>Modified Settlement of the Original Settling Parties, IIG and Nucor.</u> Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy*, 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement." *Citizens Action Coalition*, 664 N.E.2d at 406.

Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 583 N.E.2d 330, 331 (Ind. 1991)). The Commission's own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Modified Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Modified Settlement is reasonable, just and consistent with the purpose of Ind. Code § 8-1-2, and that such agreement serves the public interest.

In the Modified Settlement, both Duke Energy Indiana and Vectren South proposed that "Excess Revenues" resulting from the netting of the utilities' "ASM costs" with "ASM revenues" would be subject to sharing between each of these utilities' customers and their shareholders. In its case-in-chief, IIG recommended that the Commission require Duke Energy Indiana and Vectren South credit such "Excess Revenues" in their entirety back to ratepayers, as proposed by IPL and NIPSCO. IIG stated that the excess operating reserve revenues are not solely incremental off-system sales margins, but instead also include payments made by MISO to each utility in lieu of dispatching the utility's generation for energy production that would have been assigned by the utility to its native load. Furthermore, IIG noted that these ancillary service revenues are new revenues that did not exist at the time of either utility's last base rate proceeding.

The Commission recognizes that at the time of each utility's last rate case, the costs of providing ancillary service to retail customers did exist and were included in the development of base rates. However, such costs were not transparent. With the start of the Midwest ISO ASM, the ancillary service revenues and costs are newly transparent revenues and costs. The

Commission also notes, as the Modified Settlement acknowledges, that the costs of providing ancillary services included in base rates is difficult to determine and that the terms of the Modified Settlement are an attempt by the parties to allocate such reasonably. However, we find the record lacks sufficient evidence to support the underlying allocation, as well as the materiality of the potential excess revenues to be shared. Accordingly, the Commission finds that based on the evidence presented the Modified Settlement is unreasonable and not in the public interest, and should be rejected. Further, the Commission finds that the public interest is better served by requiring a consistent recovery methodology for ASM charges to the greatest extent possible as this will allow for a better overall understanding of ASM costs over time.

B. **Recovery of ASM Charges.** In approving the operational changes necessary to permit Joint Petitioners to accommodate the Midwest ISO's ASM, we found in Phase I of this proceeding that the ASM "should have a positive impact on efficiency and rates." Phase I Order at p. 11. The Phase II testimony presented by Joint Petitioners has indicated that participation in the ASM is expected to free up lower cost generation to serve Indiana retail customers, lowering the fuel costs retail customers would otherwise pay. As IPL witness Mr. Henley explained, the recovery of ancillary services as fuel matches the benefits of the market with the recovery mechanism for those benefits. Treating certain ASM charges as fuel costs will promote consistency in how the costs and benefits of participation in the ASM are allocated among jurisdictional customers.

As explained by Joint Petitioners, the Midwest ISO's ASM is a co-optimized Energy and Ancillary Services Market. IPL witness Mr. Cutshaw testified that for the existing Day 2 charge types that are being modified to include the ASM costs and revenues, MISO will make no distinction or allocation between energy and ancillary services. Because of the functional and practical inability of Joint Petitioners to separately identify and track the ancillary services component for these charge types, treating the entire charge commonly will also be consistent with how these charge types have been treated for ratemaking purposes in the past.

The Commission declines to accept LaPorte's contention that all ASM charges are not fuel-related or energy type charges. In addition to ignoring the functional inability of the Joint Petitioners to offer their generation into MISO as "energy only" or "ASM only," treating these charges distinctly would be inconsistent with FERC's treatment of these charges.

Based on the evidence presented in this Cause, the Commission finds that the following Midwest ISO charges and credits assigned to the Joint Petitioners, and attributable to their Indiana retail customers, should be included in the cost of fuel for purposes of our review in subsequent FAC proceedings:

a. Day Ahead Regulation Amount;
b. Day Ahead Spinning Reserve Amount;
c. Day Ahead Supplemental Reserve Amount;
d. Real Time Regulation Amount;
e. Real Time Spinning Reserve Amount;
f. Real Time Supplemental Reserve Amount;
g. Regulation Cost Distribution Amount (Day Ahead & Real Time);

h. Spinning Reserve Cost Distribution Amount (Day Ahead & Real Time);
i. Supplemental Reserve Cost Distribution Amount (Day Ahead & Real Time);
j. Excessive/Deficient Energy Deployment Charge Amount;
k. Contingency Reserve Deployment Failure Charge Amount;
l. Net Regulation Adjustment Amount;
m. Non-Excessive Energy Amount; and
n. Excessive Energy Amount.

The Commission further finds that the following modified charges types should also be included in the cost of fuel for purposes of our review in subsequent FAC proceedings:

a. Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amount;
b. Day Ahead RSG Make Whole Payment Amount;
c. Real Time RSG First Pass Distribution Amount; and
d. Real Time RSG Make Whole Payment Amount.

The Commission finds that the reporting requirements, as described below, coupled with the Commission's review during each FAC proceeding will provide sufficient safeguards. Additionally, we observe that the Joint Petitioners in future fuel cost proceedings will continue to be required to make the showings required under Ind. Code § 8-1-2-42(d)(1).

With respect to Day Ahead RSG Distribution Amounts and Real Time RSG First Pass Distribution Amounts, the Commission notes that these charges are collected under different rate adjustment mechanisms by the Joint Petitioners. Duke Energy Indiana utilizes its Rider No. 68 which allocates cost to rate class on a demand basis while the other Joint Petitioners utilize their respective FACs which allocate cost based entirely on an energy basis. As noted above, the Commission favors consistent cost treatment when possible. Joint Petitioners, in their response to a September 18, 2008 Docket Entry, stated that these credits or charges are assigned to market participants for their participation in the Day Ahead and Real Time markets and are not a socialized or uplift charge. These amounts include the recovery of fuel-related costs by other market participants for running generation committed by MISO to ensure adequate capacity is available to meet demand and reserve obligations and to ensure system reliability. This generation would provide additional supply and creates downward pressure on LMPs, which would also lower overall purchased power costs reconciled through the FAC. Both the OUCC and LaPorte also agreed that these amounts were properly considered fuel related charges. Although IIG did not specifically agree that these amounts were fuel related, they did not object to them being treated as fuel charges. Consequently, the Commission finds that these amounts should be included in the cost of fuel in each of the Joint Petitioners' future FAC proceedings.

In addition to the above charges and credits, the Commission finds that the following modified charge types, along with all other existing charge types which are not affected by the implementation of ASM, should continue to be treated for ratemaking purposes as they are today by each of the Joint Petitioners:

a. Real Time Asset Energy Amount; and
b. Real Time Revenue Neutrality Uplift.

The Commission hereby authorizes each of the Joint Petitioners to continue to treat these modified charges as they have done previously for ratemaking purposes, and as described in their testimony in this proceeding.

C. Reporting Requirements. The parties discussed various reporting requirements throughout the proceeding which should serve to provide information to the Commission and all parties concerning operation of the Midwest ISO ASM as it matures. We find that the specific agreement of IPL and NISPCO as discussed below to be reasonable and appropriate. In addition, we find the application of such reporting requirements to Duke Energy Indiana and Vectren South to be in the public interest and in accord with the Commission's preference for consistency to aid in the review of ASM costs and a general understanding of the operation of the ASM. Consequently, Joint Petitioners shall report the monthly average ASM Cost Distribution Amounts for Regulation, Spinning and Supplemental Reserves paid by the utility for each of the ancillary service products in each quarterly FAC proceeding. However, this information shall not be a benchmark. Although IIG recommended using the per unit embedded cost of a new combined cycle combustion turbine generator CT as a benchmark, it is unclear from the evidence presented whether this is an appropriate benchmark, or if a benchmark is even necessary. Therefore, we decline to establish a benchmark at this time.

In addition, Joint Petitioners should meet with the OUCC and the IIG, in an ongoing ASM dialogue, beginning within one month from the date of this Order, to provide information related to the ASM, including general observations about the ASM, operational experiences, bidding and forecasting strategies, and actual (preliminary) costs and revenue information (including Excessive/Deficient Energy Deployment Charge Amount, Contingency Reserve Deployment Failure Amount, Excessive Energy Amount), in a manner consistent with anti-trust laws and subject to a reasonable confidentiality agreement, which will include a provision requiring that each recipient of such information agrees that it cannot use that information to its competitive advantage in terms of offering resources into the Midwest ISO's markets.

D. Cost Recovery of Administrative Costs. As a result of the ASM, two existing administration amounts will be modified to include ASM costs: (1) the Day Ahead Market Administration Amount; and (2) the Real Time Market Administration Amount. Because each of the Joint Petitioners has a slightly different history with respect to the recovery and/or deferral of non-fuel related Midwest ISO charges, our discussion of cost recovery for ASM related non-fuel Midwest ISO charges will be set forth individually for each utility.

1. Duke Energy Indiana. Duke Energy Indiana's Rider No. 68, its Midwest ISO cost tracker, was approved by the Commission in Duke Energy Indiana's last retail rate case, Cause No. 42359. As we did with MISO Day 2 non-fuel costs, we find that this mechanism shall continue to provide for non-fuel related MISO cost recovery under ASM operations. We note Duke Energy Indiana's ongoing obligation to demonstrate the amount and reasonableness of any costs recovered under Rider No. 68, other than administrative charges imposed by the Midwest ISO under Schedules 10, 10-FERC, 16 and 17 of its tariff.

2. Vectren South. In Vectren South's most recent electric rate Order, Cause No. 43111 dated August 15, 2007, the Commission approved a MCRA procedure. Vectren South is

authorized, on a semi-annual basis, to recover the difference between certain Midwest ISO charges, including administrative costs, and the base rate amount of those charges. Certain transmission revenues are then applied to reduce the recoverable Midwest ISO charges. Vectren South is authorized to recover its Midwest ISO administrative costs, including those modified by the ASM, through its MCRA mechanism.

3. IPL. When the Midwest ISO Day 2 market started, IPL was granted authority to defer certain non-fuel charge types immediately, for consideration and review as part of IPL's next base rate case proceeding. *See, PSI Energy, Inc. et al.*, Cause No. 42685 (IURC 6/01/2005), p. 39. In Phase I of this proceeding, IPL sought and was granted, approval to continue to defer these charges that were modified by the ASM pending the outcome of Phase II. Based on the evidence presented, the Commission finds that IPL should be permitted to continue deferral of these non-fuel Midwest ISO costs until IPL's next base rate case. The Commission declines to accept the OUCC's proposal that such deferral be limited to four years, as IPL has been previously authorized to defer these costs and is unable to separate the modified charge types into Day 2 and ASM components. Based on the evidence presented by Joint Petitioners, the Midwest ISO will make no distinction or allocation between energy and ancillary services for these charges. In proposing that the Commission limit the deferral period for certain ASM costs, the OUCC offered no proposal to separate ASM and Day 2 expenses. We also note that the lack of carrying charges on the deferred costs, in and of itself, presents a disincentive to prolonged deferral of these costs.

4. NIPSCO. Similar to IPL, NIPSCO was granted authority to defer certain Midwest ISO charges as part of its implementation of the Day 2 market. Unlike IPL, however, NIPSCO was not authorized to begin deferral until after August 1, 2006, consistent with NIPSCO's rate freeze and settlement agreement in Cause No. 41746. Our August 13, 2008 Order in Phase I of this cause authorized NIPSCO to defer, for subsequent recovery through rates, the costs associated with participation in the Midwest ISO ASM until a final determination by the Commission of cost recovery in Phase II. Phase I Order at p. 22. Notwithstanding opposition by LaPorte to continuation of the deferral of these costs, the evidence presented in Phase II has persuaded us that NIPSCO should be authorized to continue the use of deferred accounting treatment for the identified non-fuel related ASM amounts.

Our rejection of objections raised to the continued deferral of the Midwest ISO charges associated with the ASM market begins with the practical impossibility of separating ASM charges from Midwest ISO Day 2 charges. We have previously authorized the deferral of Midwest ISO Day 2 charges for NIPSCO (and other utilities). *PSI Energy, Inc. et al.*, Cause No. 42685 (IURC 06/01/2005). The direct evidence submitted by the Joint Petitioners explained that the design of the Energy and Ancillary Services Market includes simultaneous co-optimization of energy and the ancillary services products. Joint Petitioner's Exhibit 7 at p. 7. The result of this "co-optimization" is that the Midwest ISO will make no distinction or allocation between energy and ancillary services for several of the charges that will be impacted by the ASM. *Id.* and Joint Petitioner's Exhibit 15 at p. 5. In proposing that the Commission not allow deferral of NIPSCO's ASM costs, LaPorte offered no proposal to separate ASM and Day 2 expenses. The simple rejection of deferred accounting treatment proposed by LaPorte would lead to undue (and unnecessary) litigation over the proper theoretical division among Day 2 and ASM charges. Our authorization of deferral of the non-fuel related ASM charges resolves this concern and, as we explain further below, we find no reason to change our conclusion that deferral of such charges is appropriate. For this same reason, we reject the OUCC's proposal to limit NIPSCO's ability to defer these costs to a period of four years. As stated earlier, the Midwest ISO will make no distinction or allocation between energy and ancillary services for these charges. In proposing that the Commission limit the deferral period for certain ASM costs, the OUCC offered no proposal to separate ASM and Day 2 expenses. We also note that the lack of carrying charges on the deferred costs, in and of itself, presents a disincentive to prolonged deferral of these costs.

LaPorte also contends we grant deferred accounting authority when a utility would otherwise face significant earnings erosion but that significant earnings erosion will not occur as a result of the ASM because LaPorte alleges that the Joint Petitioners' evidence indicates ASM revenues will likely exceed expenses. LaPorte Exhibit RWC at p. 8. However, the portion of Joint Petitioners' testimony cited by LaPorte includes no discussion of the likelihood that revenues will exceed expenses. Rather, the Joint Petitioners' evidence was that the ASM costs could not be estimated at the time the testimony was prepared because the market was still under development. Joint Petitioners' Exhibit 6 at p. 9. The Joint Petitioners' could not assert that revenues are likely to exceed costs if the costs could not be estimated. Neither our Phase I Order nor our June 1, 2005 Order in Cause No. 42685 authorizing deferral of Day 2 charges required a showing of significant earnings erosions to authorize deferred accounting treatment.

E. **ASM Implementation.** As indicated by the evidence presented in this Cause, there are many uncertainties associated with the implementation of the ASM. Further, the Commission recognizes that the Midwest ISO ASM development is likely to be dynamic and that changing conditions or learned results may dictate a re-examination of our decisions herein. We believe that the reporting requirements discussed above will provide an ongoing means to monitor these developments and the opportunity to address any issues or conduct any re-examination when reasonably necessary.

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

1. Joint Petitioners Duke Energy Indiana, Vectren South, IPL and NIPSCO are hereby granted authority to recover through their retail electric rates the respective jurisdictional costs incurred by them in connection with their participation in the Midwest ISO ASM, as described in this Order. This authorization is in addition to any recovery of Midwest ISO costs previously authorized by the Commission for any of the Joint Petitioners.

2. Joint Petitioners Duke Energy Indiana, Vectren South, IPL and NIPSCO are hereby authorized to implement subsequent FAC filings in the manner specified in this Order.

3. IPL and NIPSCO may continue to defer non-fuel MISO costs, including those costs deferred pursuant to the Phase I Order issued in this Cause, for recovery as part of their next base rate case, provided that they may not seek recovery of any interest or other carrying charges on such costs.

4. The Modified Settlement shall be and hereby is rejected.

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

<u>HARDY, ATTERHOLT, GOLC, LANDIS, AND ZIEGNER CONCUR:</u>

APPROVED: JUN 3 0 2009

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