STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY	))	CAUSE NO. 43526

PREFILED TESTIMONY OF

ANDREW J. SATCHWELL - PUBLIC'S EXHIBIT NO. 5

ON BEHALF OF

THE INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

MAY 8, 2009

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INDIANA UTILITY REGULATORY COMMISSION

TESTIMONY OF ANDREW J. SATCHWELL
CAUSE NO. 43526
NORTHERN INDIANA PUBLIC SERVICE COMPANY

I. Introduction

Q: Please state your name and business address.

A: Andrew J. Satchwell, 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a Utility Analyst in the Resource Planning, Emerging Technologies and Telecommunications Division.

Q: Please describe your educational background and work experience.

A: I received a Bachelor of Arts Degree in Political Science and a Certificate in European Union Studies in 2005 from the University of Pittsburgh. I received a Master of Arts Degree in West European Studies from Indiana University, Bloomington in 2008. My thesis was on regulatory economics and competition policy.

In 2004, I analyzed energy policy as a Legislative Intern for the U.S. Public Interest Research Group. I joined the OUCC as an Intern in the Electric Division in May 2007, and accepted a permanent position as a Utility Analyst in August 2007. I am a member of the American Economic Association ("AEA"). I am also Co-Chair of the Organization of MISO States ("OMS") Resources Work Group.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes.

Q: What have you done to prepare testimony in this proceeding?

A: I reviewed Northern Indiana Public Service Company's ("NIPSCO" or "Petitioner") prefiled application, testimony, workpapers and responses to OUCC and other Intervenor data requests. I participated in informal meetings with Petitioner and OUCC staff members. I am an active participant in Midwest ISO stakeholder meetings, including but not limited to, Ancillary Services Market ("ASM") Design and Implementation meetings and Market Subcommittee meetings. I have also attended numerous training sessions hosted by the Midwest ISO on respective wholesale energy markets and general operations.

Q: Do you specifically focus on certain witnesses and/or issues?

A: Yes. I focused on the witnesses and issues dealing with Petitioner's proposed Reliability Adjustment ("RA") Tracker. A number of Petitioner's witnesses testified regarding the RA Tracker, including Ms. Linda E. Miller, Mr. Frank A. Shambo, Mr. Bradley K. Sweet, and Mr. Curtis A. Crum.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to identify specific concerns with and make adjustments to Petitioner's proposed RA Tracker.

Q: Please summarize your recommendations in this Cause.

A: I recommend the Commission authorize Petitioner to (1) include a portion of the revenues and expenses proposed in the RA Tracker in base rates, (2) recover the remaining revenues and expenses proposed in the RA Tracker, and (3) amend NIPSCO's proposed RA Tracker into two separate trackers as outlined in my testimony.

II. RA Tracker Adjustments

Q: Please describe Petitioner's proposed RA Tracker.

A: Petitioner has proposed a single tracking mechanism with four major components: (1) recovery and credit of Midwest ISO costs and revenues, (2) recovery of purchased power costs, (3) recovery of purchased capacity costs, and (4) the sharing of off-system sales ("OSS") margins. Mr. Crum states in testimony that the RA Tracker should be approved because Midwest ISO costs and revenues and purchased energy and capacity costs are necessary for NIPSCO to provide safe, adequate, and reliable service, and that these costs are variable in amount from year to year.[1]

II.a. Midwest ISO Charges and Revenues

Q: Does the OUCC generally support Petitioner's participation in the Midwest ISO?

A: Yes. In other dockets the OUCC has supported the participation of Indiana investor-owned utilities ("IOUs") in Regional Transmission Organizations ("RTOs") because they are supposed to provide benefits to customers from, among other things, the more efficient use of utility resources, increased

[1] Direct Testimony of Curtis L. Crum, Pages 7-8.

opportunity to sell available generation for a profit, and increased reliability. When one considers the benefits of such participation, however, they must also consider the costs.

Q: What is Petitioner's proposed treatment of Midwest ISO costs and revenues?

A: Petitioner has proposed to recover RTO costs and revenues through the RA Tracker. Mr. Crum explains the costs and revenues specifically proposed to be assigned to the RA Tracker on Page 6, Line 15 through Page 7, Line 14 of his direct testimony. This list of costs and revenues includes "any other amounts billed pursuant to the Midwest ISO's tariff that have been approved for filing at Federal Energy Regulatory Commission ("FERC') and that are not included in NIPSCO's [Fuel Adjustment Clause ("FAC")] proceedings."[2] The OUCC is concerned that this language makes it appear NIPSCO is proposing open-ended approval of all current and future Midwest ISO costs and revenues. Attachment AJS-1 describes NIPSCO's proposed treatment for all Midwest ISO charge types.

Q: How has Petitioner proposed to recover future modified or new Midwest ISO charge types?

A: As stated above, it is unclear how Petitioner proposes to recover any future modified or new Midwest ISO charge types. Evident in Cause No. 43426, changes to the Midwest ISO markets can modify current charge type methodologies and require the implementation of new charge types. The OUCC believes that responsible utility ratemaking protocols require a review of such changes to the charge type structure and a new determination of appropriate

[2] Direct Testimony of Curtis L. Crum, Page 7, Lines 12-14.

recovery.

Q: Do you agree with NIPSCO's proposed treatment of future or new Midwest ISO charge types?

A: No. I recommend any future modified or new charge types be presented for recovery in a separate proceeding. Additionally, I recommend that Petitioner provide a narrative in testimony describing any new or future Midwest ISO charge types, as well as illustrate costs as a separate line item in exhibits and/or schedules.

Q: What is Petitioner's proposed treatment of Midwest ISO administrative charge types?

A: Petitioner has proposed to track all Midwest ISO administrative charge types in its RA Tracker without an amount built into base rates.

Q: What is your understanding of Midwest ISO administrative charge types?

A: Administrative charge types are assessed to Midwest ISO members through Midwest ISO Schedules 10, 10-FERC, 16, and 17. The amounts of these charges are non-energy costs that are consistent enough in nature in order to be accurately reflected in base rates.

Q: Do other Indiana electric utilities build Midwest ISO administrative charges and credits into base rates?

A: Yes. See Duke Energy Indiana's (Cause No. 42359) and Vectren's (Cause No. 43111) most recently ordered base rate cases. In addition, PJM administrative charges and credits have been included in base rates per Final Order in Indiana Michigan Power's (I&M) most recent base rate case (Cause No. 43306).

Q: What is your recommendation regarding Midwest ISO administrative charges and credits?

A: I recommend Petitioner include the test year amount of Midwest ISO charges and credits under Schedules 10, 10-FERC, 16, and 17 in base rates and track the variances through an RTO tracking mechanism. Attachment AJS-2 illustrates the $6,502,782 which should be built into base rates. OUCC Witness Mr. Thomas S. Catlin includes this revenue requirement adjustment.

Q: What is Petitioner's proposed treatment of Midwest ISO Schedule 24 charges and credits?

A: Petitioner has proposed to track all Midwest ISO Schedule 24 charges and credits in its RA Tracker without an amount built into base rates.

Q: What is your understanding of Midwest ISO Schedule 24 charges and credits?

A: NIPSCO recovers the costs of performing local balancing authority functions through Schedule 24 charges and credits. This recovery of costs applies to entities that have signed the Midwest ISO Balancing Authority Agreement ("BAA"), of which NIPSCO is a signatory. These costs may "include daily operation and maintenance costs, administrative and general costs, capital costs, costs for systems-in-place, training of personnel, and any costs that result from the performance of obligation imposed by this [Midwest ISO] Tariff on Local Balancing Authorities."[3]

With the launch of the Midwest ISO's ASM on January 6, 2009, an amended BAA was placed in effect. This new BAA identified the Midwest ISO

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[3] Midwest ISO Tariff, Original Sheet No. 2181.

as the Balancing Authority for the entire Midwest-ISO footprint and established Local Balancing Authorities, among them NIPSCO.

Q: Do other Indiana utilities build Schedule 24 charges and credits in base rates?

A: Yes. See Vectren's most recently ordered base rate case (Cause No. 43111).

Q: What is your recommendation regarding Midwest ISO Schedule 24 charges and credits?

A: I recommend Petitioner build the test year amount of Schedule 24 charges and credits into base rates and track the variance through an RTO tracking mechanism. Attachment AJS-2 details the credit amount of $1,287,485 to be built into base rates. Mr. Catlin includes this revenue requirement adjustment.

Q: What is Petitioner's proposed treatment of Midwest ISO Schedule 26 charges?

A: Petitioner has proposed to track all Midwest ISO Schedule 26 charges in its RA Tracker without an amount built into base rates.

Q: What is your understanding of Midwest ISO Schedule 26 charges?

A: The Midwest ISO bills costs associated with transmission expansion projects under the Midwest ISO's Schedule 26 charges. These costs are related to Regional Expansion Criteria and Benefits ("RECB") projects that have been deemed, through an open stakeholder process, the Midwest ISO Transmission Expansion Plan or MTEP, to be transmission projects that yield regional benefits. Schedule 26 charges for NIPSCO will include charges related to its own RECB projects, as well as its allocation of costs related to third-party RECB projects.

Q: Do other Indiana utilities build Schedule 26 charges in base rates?

A: Yes. See Vectren's most recently ordered base rate case (Cause No. 43111).

Q: What is your recommendation regarding Midwest ISO Schedule 26 charges?

A: I recommend Petitioner build the *pro forma* period amount of Schedule 26 charges into base rates and track the variance through an RTO tracking mechanism. The *pro forma* period was chosen as a representative amount, on a going forward basis, after review of OUCC DR 21-009 Attachments A, B, and C that detail NIPSCO's forecasted Schedule 26 charges. These forecasts are significantly higher than the test year amount of $40,268. Attachment AJS-3 details the amount of $111,634 to be built into base rates. Mr. Catlin includes this revenue requirement adjustment.

Q: What is Petitioner's proposed treatment of non-RECB revenues?

A: In a supplemental response to OUCC DR 38-006, Petitioner indicated it is proposing to include non-RECB transmission revenues as a revenue offset in base rates.

Q: Please explain the nature of non-RECB costs and revenues.

A: Non-RECB costs and revenues are recovered in NIPSCO's Attachment O rates charged to wholesale customers using NIPSCO's transmission system. These Attachment O rates are filed at FERC and are not audited and do not undergo a regulatory approval process.

Q: What is your recommendation regarding non-RECB revenues?

A: I accept Petitioner's proposal to include non-RECB transmission revenues as an offset in base rates without tracking a variance in an RTO tracking mechanism.

This represents an appropriate matching of costs and revenues that recognizes the benefit from RTO participation.

Q: What is Petitioner's proposed treatment of its Commission authorized deferred balance of Midwest ISO charges as a result of Commission order in Cause No. 42685?

A: Petitioner has projected the Commission authorized deferral of non-fuel Midwest ISO costs to be $24,768,156 by year-end 2008. Petitioner is requesting this amount be amortized over three years. Any difference between the estimated and actual deferral amount is proposed to be included as an adjustment in the RA Tracker.[4]

Q: Did Petitioner accrue any Midwest ISO transmission revenues during that deferral period?

A: Yes. Attachment AJS-4, which references Petitioner's Response to OUCC DR 30-017 Attachment A, calculates $10,818,454 in transmission revenues accrued by Petitioner for the period August 1, 2006 to year-end 2008. These transmission revenues represent Midwest ISO Schedules 7 and 8. Schedule 7 revenues are associated with firm service point-to-point transmission and Schedule 8 revenues are associated with non-firm service point-to-point transmission. Petitioner recognized Schedule 7 and Schedule 8 transmission revenues in Adjustment REV-10 on Petitioner's Exhibit LEM-2 as a test year amount of $4.7 million. The August 1, 2006 to year-end 2008 amount of $10,818,454 includes the test year transmission revenues.

[4] Direct Testimony of Linda E. Miller, Page 30, Line 13 through Page 31, Line 8.

Q: What is your recommendation regarding the recovery of deferred Midwest ISO charges?

A: I make two recommendations regarding the recovery of deferred Midwest ISO charges: (1) transmission revenues in the amount of $10,818,454 should be netted against the cost balance of $24,768,156 and (2) the balance should be amortized over four years. I recommend transmission revenues be included as an offset to the deferred balance of Midwest ISO costs because it recognizes the benefit of joining the Midwest ISO that would have otherwise not occurred. If ratepayers are expected to pay the costs of Midwest ISO participation they also should enjoy the benefits. My recommendation regarding the four-year amortization period is further described by Mr. Catlin.

Q: What is Petitioner's proposed treatment of fuel-related Midwest ISO charge types?

A: NIPSCO has proposed to include some Midwest ISO charge types that are typically classified as fuel-related in its RA Tracker.

Q: What is your recommendation regarding fuel-related Midwest ISO charge types?

A: The OUCC's recommendation regarding fuel-related Midwest ISO charge types is to track them in the FAC and is further discussed by OUCC Witness Mr. Michael D. Eckert.

Q: What is Petitioner's proposed treatment of modified and new charge types related to the Midwest ISO's Ancillary Services Market ("ASM")?

A: Based on Petitioner's proposal in Cause No. 43426 and review of data requests responses in this case, Petitioner is proposing that all charge types modified as a result of the ASM be included in the proposed RA Tracker, except for Real Time

Asset Energy Amount, which is proposed to be included in the FAC. All new charge types are proposed to be included in either the proposed RA Tracker or FAC, pending a Final Order by the Commission in Cause No. 43426, to determine whether those charge types are fuel or non-fuel.

Q: Would your recommendations supersede or preempt the Commission's Final Order in Cause No. 43426?

A: No.

II.b. Purchased Capacity Costs

Q: What specific proposal has Petitioner made regarding the recovery of purchased capacity costs?

A: Petitioner has proposed to recover "prudently-incurred capacity costs" in its RA Tracker.[5] These capacity purchases are necessary because NIPSCO currently has a "capacity deficiency" and is unable to meet Midwest ISO planning reserve margin requirements without purchasing capacity.

Q: How does Petitioner propose to justify its capacity purchases as "prudently-incurred"?

A: It is not clear how Petitioner would propose that its capacity purchases be reviewed for prudency. While Petitioner must present information regarding its capacity plans during the annual "Summer Reliability Hearings," such proceedings are primarily informational in nature and typically do not include cost data. Since there is no cost recovery action associated with the Summer Reliability Hearings, there would be neither a prudency review nor Commission

[5] Direct Testimony of Curtis L. Crum, Page 6, Line 13.

approval associated with such presentations. I recommend that Petitioner be required to present evidence in each tracker filing as to transactions made in order to comply with the relevant capacity obligations as described below.

Q: Please describe your understanding of Petitioner's resource adequacy needs as determined by the Midwest ISO.

A: Petitioner's resource adequacy is defined by the Midwest ISO's Module E, a long-term resource adequacy construct that was filed at FERC on December 28, 2007 and June 25, 2008. The FERC approved this proposal, which includes bilateral procurement of capacity as well as a voluntary capacity auction for month-by-month capacity needs. Most important was FERC's acceptance of the Midwest ISO's plan to determine capacity obligations, monitor compliance and assess penalties.[6]

The Midwest ISO calculates a Load-Serving Entity's ("LSE")[7] capacity obligation through a Loss of Load Expectation ("LOLE") Study that determines the probability of losing a single load for one occurrence in 10 years. The LOLE is based on loss of firm load after taking into account qualifying demand response resources. The study is statistically computed based on assumptions and inputs provided by Midwest ISO market participants, including NIPSCO. The LOLE Study for the June 1, 2009 to May 31, 2010 planning year determined the minimum generation needed was a 15.4% planning reserve margin for the entire Midwest ISO footprint. Load diversity was taken into account, and it was determined that an individual LSE must carry a minimum planning reserve

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[6] *Midwest Indep. Transmission Sys. Operator, Inc.*, 122 FERC ¶61,283 (2008); *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶61,060 (2008).
[7] NIPSCO is a Midwest ISO LSE.

margin of 12.69%. Individual LSE requirements are also adjusted in order to take into account the unforced capacity ratings of their units. Reductions in the overall planning reserve margin, based on the large amount of diversity across the Midwest ISO footprint, are one of the significant benefits that should result from participation in the Midwest ISO.

The 12.69% planning reserve margin varies greatly from the testimony at hearing of Petitioner's Witness Mr. Sweet who stated, in response to a question asking NIPSCO's targeted planning reserve margin for June 1st, 2009, "I would say June 1st, '09 through May 31st, '10, you would be looking at the 15 percent range, yes."[8]

I believe it is important to clarify Petitioner's planning reserve margin going forward, not only because capacity can be expensive to purchase, but also because the new Midwest ISO Module E includes financial penalty provisions that may be assessed to capacity deficient LSEs.

Q: What is your recommendation regarding the recovery of purchased capacity costs?

A: I recommend NIPSCO be allowed to recover prudently-incurred capacity costs through a tracking mechanism. NIPSCO should be required to justify its capacity purchases in testimony filed with each tracker filing, and not at the Commission's Summer Reliability Hearings. Furthermore, while the Midwest ISO Module E does not prohibit an LSE from carrying a higher planning reserve margin, I recommend NIPSCO be required to justify any capacity purchases that yield a

[8] Hearing Transcript at J-33, Lines 15-19.

planning reserve margin *greater than* the Midwest ISO determined capacity obligation.

Q: How does Petitioner propose to recover penalties assessed by the Midwest ISO regarding its Module E compliance?

A: Again, it is unclear from NIPSCO's testimony whether it is proposing to include penalty charges in the RA Tracker.[9] The FERC-approved Midwest ISO Module E makes clear that such charges are intended "to serve as a penalty to encourage LSEs to contract for adequate capacity."[10]

Q: What is your recommendation regarding the recovery of penalties assessed by the Midwest ISO pertaining to Module E compliance?

A: I recommend the Commission not allow the recovery of Midwest ISO Module E penalty charges in any tracking mechanism. Responsible operation of a utility includes planning ahead to assure that adequate capacity is available. The OUCC expects that NIPSCO should not ordinarily find it necessary to incur such penalties and only in extraordinary circumstances should such an event occur. As to such *force majeure* circumstances, it should suffice that NIPSCO could file a separate petition to request recovery of such penalty charges. Petitioner should not be able to use the possibility of such *force majeure* events as a means to absolve it from financial penalties incurred, which result from not planning ahead to provide for its resource adequacy requirements.

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[9] FERC approved the Midwest ISO's calculation of Financial Settlement Charges, to be calculated as a percentage of the Cost of New Entry (CONE), on April 16, 2009 in FERC Docket Nos. ER08-394-007 and ER08-394-009. The Midwest ISO will utilize a CONE value of $80,000 per MW-month. See Midwest ISO Tariff, Module E, Sections 69.3.7 and 69.3.8.

[10] *Midwest Indep. Transmission Sys. Operator, Inc.*, 125 FERC ¶61,060 at para. 101 (2008).

II.c. Purchased Power Costs

Q: What is Petitioner's proposed treatment of purchased power costs (energy)?

A: Petitioner has proposed to recover purchased power costs in the RA Tracker, as opposed to the FAC. Historically, the FAC has been used to recover purchased power costs subject to a "benchmark," which serves to determine the appropriate amount of FAC recoverable fuel costs. NIPSCO has proposed inclusion of purchased power costs in the RA Tracker to be subject to a similar benchmark that is used for the FAC.[11] NIPSCO has made this proposed change in the recovery of purchased power costs because, it believes, the FAC71-S1 Settlement Agreement allows for the recovery of purchased power costs through a tracking mechanism.[12]

Q: What is your recommendation?

A: I recommend purchased power costs be recovered through the FAC subject to Petitioner's proposed benchmark. The testimony of Mr. Eckert describes this recommendation in more detail.

II.d. Off-System Sales Margin Sharing

Q: What is Petitioner's proposed sharing mechanism for off-system sales margins?

A: Petitioner has proposed to pass 100% of off-system sales ("OSS") margins back to consumers up to $15 million annually, and to share OSS margins in excess of

[11] Direct Testimony of Curtis L. Crum, Page 12, Line 18 through Page 13, Line 1.
[12] Direct Testimony of Frank A. Shambo, Page 24, Lines 18-21.

that amount 80% with customers and 20% with the Company.[13] The "dividing line" of $15 million was selected as it was the highest level of OSS margins achieved during the period 2002 through 2006.[14]

Q: How does Petitioner propose to calculate its OSS margins?

A: Petitioner makes no specific detailed calculation for its OSS margins. Ms. Miller makes an adjustment to remove test year margins, including revenues and costs. The specifics of those revenues and costs, however, are not present in Petitioner's case-in-chief. In response to Industrial Group DR 7-002 Attachment A, Petitioner identifies several underlying items for the calculation of OSS revenues and costs. That response is attached as Attachment AJS-5.

Q: What concerns do you have regarding Petitioner's proposed OSS margin sharing?

A: I am concerned that there is no base rate amount for OSS margins. Petitioner has removed all OSS margin from the test year and base rates.[15]

Q: What recommendations do you have regarding Petitioner's proposed OSS margin sharing?

A: I recommend an amount of OSS margins be built into base rates. Consistent with my testimony in Cause No. 43306[16] and consistent with the Commission's final orders in Cause Nos. 42359 and 43111,[17] an OSS tracking mechanism should include a reasonable, historical base rate amount of OSS margins.

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[13] *Ibid*, Page 6, Line 15 through Page 7, Line 2.
[14] *Ibid*, Page 7, Lines 5-8. Petitioner experienced $15.4 million in OSS margins in 2005, which, they propose, establishes the appropriateness of the $15 million "dividing line."
[15] See Adjustments REV-8 and FP-5 on Petitioner's Exhibit LEM-2.
[16] Cause No. 43306, Direct Testimony of Andrew J. Satchwell, Page16, Line 23 through Page 17, Line 21.
[17] Duke Energy Indiana. Cause No. 42359, IURC Final Order, Page 117 and Vectren, Cause No. 43111, IURC Final Order, Page 31.

I agree with Petitioner's recommendation to share all OSS margins 80% with customers and 20% with the company. This sharing would occur above the base rate credit amount recommended in my testimony below.

Q: What do you believe to be a "reasonable, historical amount of OSS margins"?

A: In response to OUCC DR 9-003 Attachment A, Petitioner indicated its OSS margins for the calendar years 2002 through 2007.[18] During that five-year historical period, the smallest margin achieved by NIPSCO was $8,731,000. This amount has been provided to Mr. Catlin in calculating the revenue requirement.

Q: Why have you chosen the smallest OSS margin achieved during the period 2002 to 2007?

A: Consistent with my testimony in Cause No. 43306, I believe it is reasonable to set the base rate amount of OSS margins at a level that is not so high as to be unachievable.[19] Furthermore, a higher than average OSS margin base rate amount might incent the Company to pursue OSS revenue generation using incrementally more risky trading behavior. As the Commission stated in its Final Order in Cause No. 43306:

> The first transactions undertaken by Commercial Operations are likely to be those perceived to have the lowest level of risk associated with them. Subsequent such transactions, with their likely higher levels of risk, should also reflect accompanying greater rewards. This dynamic requires that such transactions be exceptionally disciplined.[20]

The context for the quoted statement refers to a provision in which I&M would be rewarded with a higher share of margins above an established amount of OSS

[18] Petitioner's response to OUCC DR 9-003 is included with this testimony as Attachment AJS-6.
[19] Cause No. 43306, Direct Testimony of Andrew J. Satchwell, Page 16, Line 25 through Page 17, Line 1.
[20] Cause No. 43306, IURC Final Order, Page 50.

margins. I believe the Commission's language points to the inherently greater risk in achieving the next incremental OSS margin dollar. To set a base rate level at the highest amount Petitioner has achieved in the past five years might lead to more risky trading behavior to reach that amount and begin sharing of OSS margins with shareholders.

Q: Do you have any specific concerns regarding how OSS margins will be allocated given Petitioner's proposed RA Tracker mechanics?

A: Yes. I will explain those concerns in Section II.e. of this testimony.

II.e. <u>RA Tracker Mechanics</u>

Q: Please describe Petitioner's proposed mechanics for the RA Tracker.

A: The specific mechanics of Petitioner's proposed RA Tracker are unclear. Mr. Crum states in testimony that, "Ms. Miller explains the mechanics of the RA Tracker."[21] Ms. Miller's testimony, however, only states, "Mr. Crum further describes [the RA Tracker] mechanism."[22] Nevertheless, Ms. Miller does describe the schedules that will be utilized for the RA Tracker. Petitioner's Exhibit LEM-10 shows sample schedules with "hypothetical dollar amounts" for the proposed RA Tracker. NIPSCO has proposed to file the RA Tracker quarterly, concurrent with its quarterly FAC filings. Similar to the FAC filings, the RA Tracker filings will include both a quarterly estimate of future costs and revenues as well as a reconciliation of estimates in subsequent quarters.

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[21] Direct Testimony of Curtis L. Crum, Page 6, Lines 5-6.
[22] Direct Testimony of Linda E. Miller, Page 49, Lines 18-19.

Q: What concerns do you have regarding Petitioner's proposed RA Tracker mechanics?

A: I have two concerns regarding Petitioner's proposed RA Tracker mechanics. First, the quarterly filing schedule will present many challenges for review and auditing by OUCC staff. While I believe concurrent filings with the FAC will yield some auditing resource efficiencies due to the simultaneous reporting of information, the RA Tracker includes many additional complex, data intensive line items that will be difficult to review and audit every quarter.

Second, the proposed RA Tracker appears to be a "catch-all" for the recovery of many costs and revenues. The OUCC is sensitive to issues of transparency and including so many different costs and revenues in a single mechanism may significantly decrease transparency and lead to inaccurate price signals. For example, if Midwest ISO costs increase significantly, but capacity purchase costs decrease by a similar amount, the proposed RA Tracker would appear to be unaffected. Yet, the Commission and ratepayers need to be aware when any area of cost increases or decreases significantly, as it may indicate a change in a utility's operations.

Q: What do you propose for the RA Tracker mechanics?

A: I have three proposals regarding the proposed RA Tracker. First, I recommend the Midwest ISO costs and revenues accepted and adjusted in Section II.a. of this testimony, and the OSS margin sharing accepted and adjusted in Section II.d. of this testimony, be combined into one tracking mechanism. Purchased capacity costs should be combined into a separate tracking mechanism.

Second, I recommend the Midwest ISO costs and revenues and the OSS margins tracking mechanism be titled the RTO Tracker. I further recommend the capacity purchase costs tracking mechanism be titled the Resource Adequacy Tracker.

Third, I recommend the RTO Tracker be a semi-annual tracking mechanism. These filings should be coordinated with the FAC audit process to take advantage of potential regulatory efficiencies. Because of the complexity of Midwest ISO charges and the possibility of future new or modified Midwest ISO charges, I recommend the OUCC and Intervenors have 60 days to audit the RTO Tracker.

Regarding my proposed Resource Adequacy Tracker, I recommend it also be a semi-annual tracking mechanism, subject to a 60 day audit period. This tracker should be coordinated with the Midwest ISO planning year, which runs from June 1 through May 31 of the following year. Because the planning year establishes a new planning reserve margin requirement, tracking costs on a planning-year basis will simplify the auditing process.

Attachment AJS-7 is a set of basic schedules which illustrate my recommended amendments to the tracker mechanisms. I recommend NIPSCO work with the OUCC and Intervenors to develop more detailed templates, as well as a standard audit package to include workpapers that Petitioner will file with each tracker proceeding.

III. Recommendations and Conclusion

Q: Please summarize your recommendations.

A: I recommend the Commission:

(1) Accept adjustments to the Midwest ISO costs and revenues, including building a test year amount of Midwest ISO administrative charges and Schedule 24 charges and credits into base rates and building an amount of Schedule 26 charges into base rates;

(2) Accept reporting requirements for capacity purchase costs;

(3) Accept the tracking of purchase power costs in the FAC;

(4) Accept adjustments to the OSS margin sharing, including building a base rate amount of OSS margin credit, and the sharing of OSS margins above the base rate amount, 80% to ratepayers and 20% to shareholders; and

(5) Accept amendments to NIPSCO's tracker mechanics, which would instead establish two semi-annual trackers, the RTO Tracker to include Midwest ISO administrative costs and OSS margins, and the Resource Adequacy Tracker to include purchased capacity costs.

Q: Does this conclude your testimony?

A: Yes, it does.

VERIFICATION

STATE OF INDIANA)
) ss:
COUNTY OF MARION)

The undersigned, Andrew J. Satchwell, under penalties of perjury and being first duly sworn on his oath, says that he is an employee for the Indiana Office of Utility Consumer Counselor; that he caused to be prepared and read the foregoing and that the representations set forth therein are true and correct to the best of his knowledge, information and belief.

By: Andrew J. Satchwell
Indiana Office of
Utility Consumer Counselor

Subscribed and sworn to before me, a Notary Public, this 8th day of May, 2009.

Signature

Kimberly D. Remy
Printed Name

My Commission Expires: October 22, 2010

My County of Residence: Johnson

NORTHERN INDIANA PUBLIC SERVICE COMPANY
MISO Charge Types

				2007 Test Year Amounts	
Line No.		**RA Tracker**	**FAC Tracker**	**Total RA Tracker Amount**	**Total FAC Tracker Amount**
1	Day Ahead Market Administration Amount	X		$ 2,569,241	$ -
2	Day Ahead Regulation Amount	*	*	-	-
3	Day Ahead Spinning Reserve Amount	*	*	-	-
4	Day Ahead Supplemental Reserve Amount	*	*	-	-
5	Day Ahead Asset Energy Amount		X	-	189,409,871
6	Day Ahead Financial Bilateral Transaction Congestion Amount	X		-	-
7	Day Ahead Financial Bilateral Transaction Loss Amount	X		-	-
8	Day Ahead Congestion Rebate on Carve-Out Grandfathered Agrmnts			-	-
9	Day Ahead Loss Rebate on Carve-Out Grandfathered Agrmnts	n/a	n/a	-	-
10	Day Ahead Congestion Rebate on Option B Grandfathered Agrmnts			-	-
11	Day Ahead Loss Rebate on Option B Grandfathered Agrmnts			-	-
12	Day Ahead Non-Asset Energy Amount	X		(55,915,295)	-
13	Day Ahead Revenue Sufficiency Guarantee Distribution Amount	X		589,860	-
14	Day Ahead Revenue Sufficiency Guarantee Make Whole Payment Amount		X	-	(178,489)
15	Day Ahead Schedule 24 Allocation	X		421,636	-
16	Day Ahead Virtual Energy Amount	X		(60,021,000)	-
17	Real Time Market Administration Fee Amount	X		246,035	-
18	Real Time Contingency Reserve Deployment Failure Charge Amount	*	*	-	-
19	Real Time Excessive Energy Amount		X	-	-
20	Real Time Excessive/Deficient Energy Deployment Charge Amount	*	*	-	-
21	Real Time Net Regulation Adjustment Amount		X	-	-
22	Real Time Non-Excessive Energy Amount		X	-	-
23	Real Time Regulation Amount	*	*	-	-
24	Real Time Regulation Cost Distribution Amount	*	*	-	-
25	Real Time Spinning Reserve Amount	*	*	-	-
26	Real Time Spinning Reserve Cost Distribution Amount	*	*	-	-
27	Real Time Supplemental Resserve Amount	*	*	-	-
28	Real Time Supplemental Reserve Cost Distribution Amount	*	*	-	-
29	Real Time Asset Energy Amount		X	-	18,157,846
30	Real Time Financial Bilateral Transaction Congestion Amount	X		(18,370)	-
31	Real Time Financial Bilateral Transaction Loss Amount	X		36,251	-
32	Real Time Congestion Rebate on Carve-Out Grandfathered Agrmnts	n/a	n/a	-	-
33	Real Time Loss Rebate on Carve-Out Grandfathered Agrmnts			-	-
34	Real Time Distribution of Losses Amount		X	-	(7,640,082)
35	Real Time Miscellaneous Amount	X		835,513	-
36	Real Time Non-Asset Energy Amount	X		(59,630,859)	-
37	Real Time Net Inadvertent Distribution Amount	X		(129,871)	-
38	Real Time Price Volatility Make Whole		X	-	-
39	Real Time Revenue Neutrality Uplift Amount	X		21,932,376	-
40	Real Time Revenue Sufficiency Guarantee First Pass Distribution Amount	X		(1,259,156)	-
41	Real Time Revenue Sufficiency Guarantee Make Whole Payment Amount		X	-	(2,975,768)
42	Real Time Schedule 24 Allocation	X		38,683	-
43	Real Time Schedule 24 Distribution	X		(1,747,801)	-
44	Real Time Uninstructed Deviation Amount		X	-	21,937
45	Real Time Virtual Energy Amount	X		57,340,638	-
46	Financial Transmission Rights Market Administration Amount	X		239,923	-
47	Financial Transmission Rights Auction Revenue Distribution Amount		X	-	-
48	Financial Transmission Rights Auction Revenue Transaction Amount		X	-	-
49	Financial Transmission Rights Auction Revenue Infeasible Amount		X	-	-
50	Financial Transmission Rights Auction Revenue Excess Distribution Amount		X	-	-
51	Financial Transmission Rights Market Full Funding Guarantee		X	-	-
52	Financial Transmission Rights Market Guarantee Uplift		X	-	-
53	Financial Transmission Rights Hourly Allocation Amount		X	-	(37,762,707)
54	Financial Transmission Rights Monthly Allocation Amount		X	-	(1,692,186)
55	Financial Transmission Rigts Monthly Transaction Amount		X	-	-
56	Financial Transmission Rights Transaction Amount		X	-	407,309
57	Financial Transmission Rights Yearly Allocation Amount		X	-	(2,843,065) **
58	**Total**			**$ (94,472,198)**	**$ 154,904,664**
59	Sch 10 - ISO Cost Recovery Adder	X		2,806,436	
60	Sch 10 - FERC	X		954,020	
61	Sch 11 - Transmission Adjustment	X		202,372	
62	Sch 26 - Network Upgrade Charges fom Transmissin Expnasion Plan (RECB)	X		40,268	
63	**Transmission Charges**			**4,003,096**	
64	Sch 1 - Scheduling, System control & Dispatch Service	X		(324,243)	
65	Sch 2 - Reactive Supply & Voltae control/generation Sources Service	X		(510,959)	
66	Sch 7 & 8 - Long-term/Short-term Firm Point-to-Point Transmission	X		(2,937,029)	
67	Sch 11 - Transmission Adjustment	X		(2,849,873)	
68	**Transmission Revenues**			**(6,622,104)**	

* Classification Pending the outcome of Cause 43426
** Includes excess congestion charge settled on sch 11

Northern Indiana Public Service Company

Cause No. 43526

December 31, 2007

Midwest ISO Charge Type	Amount ($)
Schedule 10 (1)	2,567,816
Schedule 10 - FERC (1)	880,129
Schedule 16 (2)	239,923
Schedule 17 (3)	2,814,915
Administrative Charge Type Total	6,502,782
Schedule 24 - Day Ahead Allocation (4)	421,635
Schedule 24 - Real Time Allocation (4)	38,682
Schedule 24 - Real Time Distribution (4)	(1,747,802)
Schedule 24 Total	(1,287,485)
Total	5,215,297

(1) OUCC DR 9-006

(2) OUCC DR 9-007

(3) OUCC DR 9-008

(4) OUCC DR 9-001 Attachment A

Northern Indiana Public Service Company

Cause No. 43526

December 31, 2008

Midwest ISO Charge Type	Amount ($)
Schedule 26 - RECB (1)	111,634
Transmission Expansion Type Total	111,634

(1) OUCC DR 35-008 Attachment A

Northern Indiana Public Service Company

Cause No. 43526
For the period
August 1, 2006 through December 31, 2008 (1)

Line No.					
1		Schedule 7 - SFP	Schedule 7 - LFP	Schedule 8 - NF	Total
2	Aug-06	$73,782	$99,322	$118,401	$291,505
3	Sep-06	$57,985	$100,861	$75,418	$234,264
4	Oct-06	$66,355	$109,772	$78,789	$254,915
5	Nov-06	$72,483	$115,567	$118,456	$306,506
6	Dec-06	$95,773	$106,609	$80,390	$282,771
7	Jan-07	$79,013	$98,100	$63,680	$240,794
8	Feb-07	$69,720	$90,062	$53,488	$213,270
9	Mar-07	$137,549	$104,782	$63,048	$305,378
10	Apr-07	$63,168	$95,432	$55,954	$214,554
11	May-07	$75,544	$98,244	$82,573	$256,362
12	Jun-07	$385,613	$107,910	$106,512	$600,035
13	Jul-07	$203,126	$109,826	$134,302	$447,254
14	Aug-07	$107,174	$109,849	$239,460	$456,483
15	Sep-07	$244,850	$127,390	$150,766	$523,006
16	Oct-07	$201,028	$129,933	$144,800	$475,761
17	Nov-07	$234,304	$128,496	$163,762	$526,562
18	Dec-07	$185,568	$140,629	$140,379	$466,575
19	Jan-08	$274,932	$108,988	$177,725	$561,645
20	Feb-08	$280,439	$92,370	$129,438	$502,247
21	Mar-08	$190,075	$104,155	$135,859	$430,089
22	Apr-08	$102,278	$95,416	$166,314	$364,008
23	May-08	$145,403	$97,791	$156,757	$399,951
24	Jun-08	$142,623	$95,876	$165,648	$404,148
25	Jul-08	$172,478	$87,797	$150,272	$410,547
26	Aug-08	$166,271	$88,749	$131,706	$386,726
27	Sep-08	$167,423	$98,362	$80,596	$346,381
28	Oct-08	$100,271	$103,312	$76,983	$280,567
29	Nov-08	$137,096	$97,022	$92,141	$326,260
30	Dec-08	$119,976	$95,003	$94,912	$309,891
31	TOTAL				$10,818,454

(1) OUCC DR 30-017 Attachment A

IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Industrial Group Data Request Set No. 7

Industrial Group Request 7-2:
Please refer to Petitioners' Exhibit No. LEM-2. a. Please identify and provide a complete copy of the workpapers underlying Items REV-8 (off-system sales) and FP-5 (off-system sales) in an electronic format that is readily manipulated, such as Microsoft Excel, with all formulas and links intact. b. For Item REV-8, please identify the MWh of MISO off-system sales, the MWh of non-MISO off-system sales, the total dollar amount of MISO off-system sales revenues and the total dollar amount of non-MISO off-system sales revenues. c. For Item FP-5, please identify the total dollar and MWh amount of MISO energy purchases, the total dollar and MWh amount of non-MISO energy purchases and the total dollar and MWh amount of generation fuel costs. In addition, specifically identify any additional cost components included within Item FP-5.
Objections:
Response:
Please see file attached hereto as Industrials Set 7-002 Attachment A which shows both the MWh and dollar amounts for the REV-8 and FP-5.

Northern Indiana Public Service Company
(Dollars in Thousands)

			Total
Actuals/Forecast:			
Revenue			$50,400
Costs			(21,285)
			29,115
REVENUES			
SALE TO:	MWH		REVENUE
MISO Intersystem Sales	878,873	$	48,482
Financials for Interysytem Sales	58,400		3,375
Duke Energy Ohio	800		51
Excelon	1,600		92
Constellation	1,600		102
DTE Energy Trading	1,700		99
Misc - Sempra, Lmping			12
Misc - Cargill, Lmping	-		43
ARS	-		16
Midwest Contingency Reserve Sharing Group	-		78
	942,973	$	52,350
Greenfield Mills	357		5
Emission Allowance Adjustments			(1,955)
Total Revenue	944,130	**$**	**50,400**
COSTS			
Fuel Cost of Generation Used for Sales	878,873	$	16,111
			-
MISO Other Costs for Resale			-
MISO Delta LMP			2,814
Other MISO Costs			(2,925)
Virtual Activity			392
Subtotal MISO Other Costs for Resale		$	281
Financial Purchases for Intersystem Sales	58,400		4,495
Purchases used in Bilateral Sales	5,700		398
Total Costs	942,973	**$**	**21,285**

IURC Cause No. 43526
Northern Indiana Public Service Company's
Objections and Responses to
Office of Utility Consumer Counselor Ninth Set of Data Requests

OUCC Request 9-003
For the calendar years ending December 31, 2000 through December 31, 2007, please provide the amount (in dollars) of Off-System Sales (OSS) revenues and OSS margins for NIPSCO.
Objections:
Response:
The worksheet attached hereto as OUCC Set 9-003 Attachment A details the 2002 through 2007 Off-System Sales revenues and margins.

Northern Indiana Public Service Company
ELECTRIC Off-System Sales
2002 - 2012 Budget Comparison
(Dollars in Thousands)

	2002 Actual	2003 Actual	2004 Actual	2005 Actual	2006 Actual	2007 Actual
Off-System Revenue	92,204	90,151	46,204	34,218	31,814	50,447
Off-System Cost of Goods Sold	82,554	76,346	37,473	18,781	17,447	21,285
Off-System Margin	9,651	13,805	8,731	15,437	14,367	29,162

<u>Northern Indiana Public Service Company</u>

Determination of RTO Tracker
(page 1 of x)
For the months of
January - June 20xx

Line No.			
1	MISO Costs - Demand Allocated (Page 2 of x)	$	6,000
2	MISO Costs - Energy Allocated (Page 2 of x)		600,000
3	Off System Sales Base Rate Credit - 6-month (Page 3 of x)		(4,365,500)
4	Off System Sales Margin - Customer Share (Page 3 of x)		(1,443,600)
5	Total RTO Tracker Cost (Credit)	$	(5,203,100)

Northern Indiana Public Service Company

Determination of MISO Charges to be included in RTO Tracker
(page 2 of x)
For the months of
January - June 20xx

Line No.			
1	January, 20xx	$ 1,000	
2	February, 20xx	1,000	
3	March, 20xx	1,000	
4	April, 20xx	1,000	
5	May, 20xx	1,000	
6	June, 20xx	1,000	
7	Total MISO Charges - Demand Allocated		$ 6,000
8	January, 20xx	100,000	
9	February, 20xx	100,000	
10	March, 20xx	100,000	
11	April, 20xx	100,000	
12	May, 20xx	100,000	
13	June, 20xx	100,000	
14	Total MISO Charges - Energy Allocated		600,000
15	Total Amount to be included in RTO Tracker		$ 606,000

Northern Indiana Public Service Company

Determination of OSS Margins to be included in RTO Tracker
(page 3 of x)
For the months of
January - June 20xx

Line No.		MWh Sold	Revenues	Costs	Margin	
1	6-month OSS Sales Revenues Embedded in Base Rates (Base Rate Credit / 2)					$ 4,365,500
2	January, 20xx	8,000	$ 1,000,000	$ 200,000	$ 800,000	
3	February, 20xx	6,000	1,200,000	150,000	1,050,000	
4	March, 20xx	10,000	1,500,000	180,000	1,320,000	
5	April, 20xx	5,000	900,000	190,000	710,000	
6	May, 20xx	7,000	1,300,000	210,000	1,090,000	
7	June, 20xx	9,000	1,450,000	250,000	1,200,000	
8	Actual 6-Month Gross Profits from OSS Realized During the Period Jan. 20xx - Jun. 20xx (sum lines 2 through 7)					6,170,000
9	Amount by Which Actual OSS Profits Exceed or are (Less Than) the Net Credit Included in Base Rates (line 1 - line 8)					$ (1,804,500)
10	Sharing Percentage (Customer Share)					80%
11	Amount Due (To) / From Customers (line 9 x 80%)					$ (1,443,600)
12	Sharing Percentage (Company Share)					20%
13	Amount Due (To) / From Company (line 9 x 20%)					$ (360,900)

Northern Indiana Public Service Company

Determination of Resource Adequacy Tracker
(page 1 of x)
For the period
December 1 - May 31, 20xx

Line No.		
1	Capacity Purchases (Page 2 of x)	$ 3,100,000
2	Total Resource Adequacy Tracker Cost (Credit)	$ 3,100,000

Northern Indiana Public Service Company

Determination of Capacity Purchase to be included in Resource Adequacy Tracker
(page 2 of x)
For the period
December 1 - May 31, 20xx

Line No.		MW Purchased	
1	December, 20xx	500	$ 500,000
2	January, 20xx	500	500,000
3	February, 20xx	500	500,000
4	March, 20xx	500	500,000
5	April, 20xx	500	500,000
6	May, 20xx	600	600,000
7	Total Capacity Purchases for the Period Dec. 20xx - May 20xx	3,100	$ 3,100,000