ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC SERVICE;(2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; AND (5) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS.	)	CAUSE NO. 43969 APPROVED: DEC 21 2011

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Aaron A. Schmoll, Senior Administrative Law Judge

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INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 43969

INTRODUCTION

On November 19, 2010 Northern Indiana Public Service Company ("Petitioner," "Company" or "NIPSCO") filed its Petition and Notice of Intent to File in Accordance with Minimum Standard Filing Requirements with the Indiana Utility Regulatory Commission ("Commission") for (1) authority to modify its rates and charges for electric utility service; (2) approval of new schedules of rates and charges applicable thereto; (3) approval of revised depreciation accrual rates; (4) inclusion in its basic rates and charges of the costs associated with certain previously approved Qualified Pollution Control Property ("QPCP") projects; and (5) approval of various changes to its Electric Service Tariff including the general rules and regulations.

Petitions to Intervene were filed by NIPSCO Industrial Group ("Industrial Group"),[1] the City of Hammond, Indiana ("Hammond"), Indiana Municipal Utilities Group ("Municipal Utilities"),[2] NLMK Indiana f/k/a Beta Steel Corporation ("NLMK"), Citizens Action Coalition of Indiana, Inc., and the Board of County Commissioners of the County of Jasper (collectively referred to herein as "Intervenors"), all of which were granted, and made parties to this Cause. The Indiana Office of Utility Consumer Counselor ("OUCC") also participated in this proceeding as the statutory representative of the consumers.

On November 19, 2010, NIPSCO filed its prepared testimony and exhibits constituting its case-in-chief and the workpapers required by the Commission's Rules on Minimum Standard Filing Requirements, 170 IAC 1-5-1 ("MSFRs").[3] On December 15, 2010, OUCC filed a Notice Regarding Petitioners' Election on the Minimum Standard Filing Requirements Rules.

A Prehearing Conference was held on December 17, 2010 and a Prehearing Conference Order was issued on January 5, 2011, which established the agreed-to procedural schedule for this proceeding.[4]

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[1] NIPSCO Industrial Group is comprised of Accurate Castings, Inc.; ArcelorMittal USA; BP Energy; Cargill, Inc.; NLMK Indiana; Praxair, Inc.; United States Steel Corporation; USG Corporation; and Weil-McLain.

[2] Municipal Utilities is comprised of Town of Dyer, City of East Chicago, Town of Griffith, Town of Highland, Town of Munster, Town of Schererville, the City of Valparaiso and Town of Winfield.

[3] Petitioner filed Supplemental Information Related to Depreciation Study on November 19, 2010; Submission of Late-Filed Petitioner's Exhibit No. JDS-3 on January 19, 2011; Submission of Corrected Minimum Standard Filing Requirements on January 25, 2011; and Submission of Late-Filed Petitioner's Exhibit No. JDS-2 on February 9, 2011.

[4] 170 IAC 1-5-2(c)(4) provides an exception to complete a case filed under the MSFR beyond the typical 10-month period if exceptional circumstances so warrant. In order for the parties to agree to the schedule proposed, the parties proposed a schedule that provides for a Commission Order to be issued by December 30, 2011, which is beyond 12

During a technical conference held on February 9, 2011 it became apparent that the Commission, OUCC and Intervenors would be aided in their evaluation of NIPSCO's case-in-chief by the provision of additional information related to its cost of service study. NIPSCO agreed, at the Commission staff's request, to rerun the cost of service study to reflect current revenues from all existing rate classes and allocate NIPSCO's current costs to serve those same rate classes.

On February 18, 2011, NIPSCO, OUCC and Industrial Group filed an Agreed Motion for Continuance requesting additional hearing dates for NIPSCO's cost of service and rate design witnesses, which was granted by Docket Entry dated February 22, 2011. NIPSCO filed its Submission of Supplemental Cost of Service Study Information on February 22, 2011 and Additional Supplemental COSS Workpapers on February 24, 2011.

On March 21, 2011, Petitioner filed an Unopposed Motion for Continuation of Hearing, which was granted by Docket Entry dated April 4, 2011. On March 23 and April 1, 2011, Petitioner filed Revised Direct Testimony and Exhibits of its cost of service study and rate design witnesses and Revised Supplemental Cost of Service Study Information.

Pursuant to Ind. Code § 8-1-2-61(b), a public field hearing was held on April 7, 2011 in the City of Hammond, the largest municipality in Petitioner's electric utility service area. At the field hearing, members of the public were afforded the opportunity to make statements on the record or submit written comments to the Commission.[5]

On July 12, 2011, NIPSCO, OUCC, NLMK and Municipal Utilities filed a Notice of Settlement in Principle and Request for Attorneys' Conference. On July 18, 2011, NIPSCO, the OUCC, NLMK, Municipal Utilities and Industrial Group (the "Settling Parties") filed a Stipulation and Settlement Agreement ("Settlement") containing a proposed resolution of the issues in this proceeding. A copy of the Settlement Agreement is attached hereto and incorporated herein by reference.

In accordance with the agreed-to procedural schedule established in the Docket Entry dated July 21, 2011, Petitioner prefiled settlement testimony on July 22, 2011, the remaining Settling Parties filed settlement testimony on July 29, 2011, Hammond filed testimony responding to the Settlement on August 19, 2011, and the Settling Parties filed rebuttal testimony on August 31, 2011. The Commission issued a Docket Entry on June 7, 2011 and August 25, 2011, ordering Petitioner to respond to questions, to which Petitioner responded on July 12, 2011 and September 6, 2011, respectively. Following questioning from the Presiding Officers, Petitioner filed Supplemental Responses to the September 6 Responses on September 14, 2011.

A Settlement Hearing commenced on September 12, 2011. At that time, the direct and rebuttal testimonies and exhibits of the Settling Parties in support of, and Hammond's testimony responding to, the Settlement were admitted into evidence.

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months from the date of Petitioner's prefiling date. The Commission found that exceptional circumstances exist and that the underlying schedule is reasonable. The Commission also authorized the Presiding Officers to make further modifications to the underlying procedural schedule, for good cause shown.

[5] OUCC filed Written Comments of Members of the Public on April 29, 2011.

Having considered the evidence and being duly advised, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed change in its rates and charges for electric service. Due, legal and timely notices of the public hearings in this Cause were given and published as required by law. Petitioner is a public utility as defined in Ind. Code § 8-1-2-1(a) and is subject to the jurisdiction of the Commission in the manner and to the extent provided by the laws of the State of Indiana. This Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Characteristics.** Petitioner is a public utility with its principal place of business located at 801 East 86th Avenue, Merrillville, Indiana, and provides gas ("NIPSCO Gas") and electric service ("NIPSCO Electric") in Indiana. Petitioner is authorized by the Commission to provide electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.

3. **Existing Rates.** The Commission issued an Order in Cause No. 43526 on August 25, 2010 ("43526 Order"), which authorized the modification to NIPSCO's rates and charges for electric service; however, the resulting rates have not been implemented because, at the request of several parties, the Commission ordered a stay of NIPSCO's compliance filing pending this rate case proceeding. As a result, NIPSCO's currently effective basic rates and charges are those approved by the Commission in its Order dated July 15, 1987 in Cause No. 38045.

The 43526 Order also approved new depreciation accrual rates; however, as confirmed by the Docket Entry issued in Cause No. 43526 dated October 22, 2010, those new depreciation accrual rates were not to take effect unless and until the basic rates and charges approved in Cause No. 43526 were implemented. As a result, NIPSCO's currently effective depreciation accrual rates for its electric and common properties are based on a depreciation study prepared in its general rate proceeding in Cause No. 38045.

4. **Test Year and Rate Base Cutoff.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve month period ended June 30, 2010, adjusted for changes that are fixed, known and measurable for ratemaking purposes and that will occur within twelve months following the end of the test year. The Prehearing Conference Order recognized that Petitioner may make proposals regarding rate adjustment mechanisms that are not limited by the 12-month adjustment period. The Prehearing Conference Order provided that the general rate base cutoff shall reflect used and useful property at the end of the test year.

5. **Relief Requested.** In its case-in-chief, NIPSCO sought approval: (1) of changes to its basic rates and charges for electric utility service to provide NIPSCO with the opportunity to earn a fair rate of return on the fair value of its property, (2) of changes to its Electric Service Tariff, including the Series 600 Rate Schedule, revised reconnection charges, standard contracts

and street lighting tariffs and miscellaneous changes to its General Rules and Regulations and (3) to revise its depreciation accrual rates.

In its case-in-chief, NIPSCO also sought approvals in this Cause which are consistent with the findings made by the Commission in its 43526 Order, with respect to:

(1) modifications to its Environmental Expense Recovery Mechanism ("EERM") to track emission allowances purchases and sales;

(2) amortization of deferred depreciation and carrying charges associated with Petitioner's Sugar Creek Generating Station ("Sugar Creek");

(3) the sharing mechanism for off system sales ("OSS") margins;

(4) the Regional Transmission Organization ("RTO") Tracker to track Midwest Independent Transmission System Operator, Inc. ("MISO") non-fuel charges and credits and OSS sharing;

(5) the Resource Adequacy ("RA") Tracker;

(6) modifications to its purchased power benchmark;

(7) modifications to its General Rules and Regulations (except as expressly proposed for further modification in Petitioner's evidence in this Cause); and

(8) reflecting in its basic rates and charges capital costs and operating expenses associated with QPCP projects previously approved by the Commission in Cause Nos. 42150 and 43188 that were completed and in-service at the end of the test year in that Cause and that are currently being recovered through the Environmental Cost Recovery Mechanism ("ECRM"), and adjusting the ECRM to eliminate costs relating to those projects upon the effective date of the new base rates approved herein, subject to any necessary variance reconciliations.

6. Petitioner's Evidence. Prior to the submission of the Settlement, NIPSCO presented extensive evidence, which is briefly summarized here and further considered in the discussion of the Settlement below.

A. Robert C. Skaggs. Robert C. Skaggs, Jr., President and Chief Executive Officer of NiSource Inc. ("NiSource"), provided an overview of NiSource and its corporate structure, and updated the Commission on NiSource's strategic direction. Mr. Skaggs touched on the operation and management of NIPSCO Electric and how it fits into NiSource's strategy. He addressed recent improvements in NiSource's financial health, most notably (i) NiSource's credit profile and the benefits to all stakeholders associated with a continuation of the recent improvement in NiSource's financial outlook and (ii) the recently completed $400 million offering of NiSource common stock.

B. Jimmy D. Staton. Jimmy D. Staton, Executive Vice President and Group Chief Executive Officer for NiSource's Northern Indiana Energy Business Segment, provided an overview of NIPSCO's organizational structure and electric operations. He explained the unique challenges faced by NIPSCO and briefly summarized the relief requested by NIPSCO in its case-in-chief.

C. Frank A. Shambo. Frank A. Shambo, Vice President, Regulatory and Legislative Affairs, provided a brief background of NIPSCO's existing electric rates. He explained why NIPSCO filed this case, including the key drivers and the relationship to NIPSCO's request in Cause No. 43526 and provided an overview of NIPSCO's earnings situation. He explained NIPSCO's approach to this case and its philosophy as it moves forward in this proceeding. He provided an overview of the objectives NIPSCO used in developing the rates proposed in this proceeding and explained key cost allocation and rate design criteria used in the development of rates and how those criteria align with the established objectives. He also provided a summary of NIPSCO's tariff relief. He discussed the appropriate return on its used and useful assets proposed in this proceeding and explained one pro forma adjustment made to test year operating results.

D. Karl E. Stanley. Karl E. Stanley, Vice President, Commercial Operations, described NIPSCO's focus on customer service by (1) conveying NIPSCO's recent success in improving various utility customer satisfaction measurements and metrics and (2) describing projects that the Company has implemented or will implement to further improve customer satisfaction. He also described adjustments that will be made to the revenue requirement due to the purchase or sale of capacity credits. He stated these capacity credits are required to fulfill MISO requirements whereby a Load Serving Entity ("LSE") is required to hold sufficient capacity to serve the needs of its customers.

E. Timothy A. Dehring. Timothy A. Dehring, Senior Vice President, Transmission and Engineering, described NIPSCO's electric transmission and distribution systems. He discussed the Company's customer service and electric reliability programs. He also explained the need for certain pro forma expense adjustments.

F. Philip W. Pack. Philip W. Pack, Director, Generation Support Services and Major Projects, described NIPSCO's generation fleet and the reliability of its coal-fired units. He also provided an explanation of an operation and maintenance ("O&M") expense adjustment for the Bailly gypsum disposal.

G. Linda E. Miller. Linda E. Miller, Executive Director, Rates and Regulatory Finance, presented evidence regarding NIPSCO's net original cost rate base, capital structure and weighted cost of capital. She also presented the results of operations during the test year and on a pro forma basis at both present and proposed rates. She provided an overview of NIPSCO's accounting practices, including its audits, control and processes. She sponsored NIPSCO's per book financial statements for the test year and explained how common costs are allocated between NIPSCO's gas and electric business. She described NIPSCO's request for approval of proposed depreciation rates on an account-by-account basis.

H. Susanne M. Taylor. Susanne M. Taylor, Controller of NiSource Corporate Service Company ("NCSC"), provided background about NCSC and the role it serves within NiSource and provided support for the annualized level of NCSC charges billed to NIPSCO in the historical test year and the amount allocated to NIPSCO Electric. She supported and provided an explanation of each of the pro forma adjustments for fixed, known and measurable changes applicable to NIPSCO Electric occurring during the adjustment period. She provided information pertaining to the types of costs that have been allocated to NIPSCO and the mechanism for billing the NCSC costs to NIPSCO. She sponsored (1) a detailed breakdown of total NCSC contract billings by individual expense line item allocated to NIPSCO and then to NIPSCO Electric and (2) monthly overhead allocation percentages that are billed to NIPSCO.

I. John J. Spanos. John J. Spanos, Vice President, Valuation and Rate Division of Gannett Fleming, Inc., sponsored the results of his depreciation analysis related to NIPSCO's electric and common plant as of June 30, 2010 (the "Depreciation Study"). Mr. Spanos explained the methods and procedures used in the Depreciation Study and proposed new depreciation accrual rates. As part of the Depreciation Study, Mr. Spanos also developed proposed depreciation accrual rates for Sugar Creek.

J. Alberto D. Romero. Alberto D. Romero, Director of Taxes of NCSC, presented and supported NIPSCO's federal and state income tax expense adjustments and the adjustments for taxes other than income included in the cost of service shown in the accounting exhibits of Ms. Miller.

K. Vincent V. Rea. Vincent V. Rea, Assistant Treasurer of NiSource, testified about NIPSCO's debt financing activities, credit ratings and cost of debt.

L. Paul R. Moul. Paul R. Moul, Managing Consultant at the firm P. Moul & Associates, presented evidence, analysis and a recommendation concerning the appropriate cost of common equity for NIPSCO. He also addressed the fair rate of return applicable to NIPSCO's fair value rate base.

M. John P. Kelly. John P. Kelly, Executive Advisor of Concentric Energy Advisors, Inc. ("Concentric"), addressed the fair value of NIPSCO's electric utility assets. He described the valuation study upon which his conclusions were based.

N. Cecelia Largura. Cecelia Largura, Director, Strategic Execution, described the electric load research methodology used in support of NIPSCO witness J. Stephen Gaske's testimony on behalf of NIPSCO's 2010 Allocated Cost of Service Study ("ACOSS") and the methodology used to evaluate load characteristics by class during the test year. She also explained NIPSCO's weather normalization procedures.

O. John D. Taylor. John D. Taylor, Senior Consultant of Concentric, supported the ACOSS. Specifically, he explained the various special studies that were utilized within the ACOSS to apportion the various categories of plant and O&M expenses to the respective customer classes. He also described the general need for, and methodology of, the special studies and provided details on how these studies were conducted for NIPSCO's ACOSS.

P. J. Stephen Gaske. J. Stephen Gaske, Senior Vice President of Concentric, discussed the purpose of an allocated cost of service study and described the Concentric Cost of Service Model used in conducting NIPSCO's electric cost of service study. He described various principals of cost allocation, factors that influence the cost allocation framework, and the underlying methodology and basis used in NIPSCO electric cost of service studies. He described the relative cost studies and other analyses employed to apportion the various categories of plant and O&M expenses to the respective customer classes. He presented the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from NIPSCO's ACOSS for (i) the 800 Series rate classes that were in effect during the test year and (ii) the 600 Series rate classes that are being proposed in this proceeding, including the resulting unit costs by class for customer, demand and energy-related costs within the ACOSS. He also described the method used to allocate NIPSCO's revenue deficiency to the various rate schedules. Finally, he described the process used to design the rates that are being proposed in this proceeding and discussed the customer impacts of the proposed rate increases.

Q. <u>Curt A. Westerhausen</u>. Curt A. Westerhausen, Director of Rates and Contracts, described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 12, including the Schedules of Rates ("Rates"), Riders and General Rules and Regulations ("Rules") (the "Proposed Tariff"). He explained how the Proposed Tariff differs from NIPSCO's IURC Electric Service Tariff, Original Volume No. 10, currently on file with the IURC (the "Current Tariff") and provided support for several proposed changes to NIPSCO's Current Tariff.

7. <u>The Settlement</u>. The Settlement is attached hereto and incorporated herein by reference. The Settlement, which the Settling Parties, i.e., NIPSCO, OUCC, NLMK, Municipal Utilities and Industrial Group, agree is fair, just and reasonable, presents a comprehensive resolution of all matters pending before the Commission in this Cause. The Settlement states that the Settling Parties agree that resolution of the individual issues specified in the Settlement are reasonable for purposes of compromise as part of the overall settlement package. The Settlement provides as follows:

A. <u>Revenue Requirement and Net Operating Income</u>.

(a) <u>Revenue Requirement</u>. The Settling Parties agreed that NIPSCO's base rates will be designed to produce $1.355 billion, which is the Revenue Requirement of $1.401 billion less $46 million of Other Revenues. This Revenue Requirement is a decrease of $68 million from the amount originally requested by the Company. Based on test-year fuel costs, this provides for a margin requirement of $927 million plus $12 million in non-trackable fuel.

(b) <u>Net Operating Income</u>. The Settling Parties agreed that NIPSCO's Revenue Requirement in Paragraph B.6.(a) of the Settlement results in a proposed authorized net operating income ("NOI") of $188.9 million.

B. <u>Fair Value Rate Base, Capital Structure and Fair Return</u>.

(a) <u>Fair Value Rate Base</u>. NIPSCO agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concurred that NIPSCO should be authorized a fair rate of return of 6.98%, yielding an overall return for earnings test purposes of $188.9 million, based upon:

(i) an original cost rate base of $2.7 billion, inclusive of materials, supplies and production fuel, as proposed in NIPSCO's case-in-chief;

(ii) NIPSCO's capital structure; and

(iii) an authorized return on equity ("ROE") of 10.2%.

NIPSCO's sum of the differentials, commonly referred to as the "earnings bank" computed under Ind. Code § 8-1-2-42.3, shall be re-set to $200 million.

(b) Capital Structure and Fair Return. Based on the following capital structure, the 10.2% ROE and cost of debt/zero cost capital as filed, the overall weighted average cost of capital ("WACC") is computed as follows:

	% of Total	Cost	WACC
Common Equity	46.53%	10.20%	4.75%
Long-Term Debt	32.46%	6.42%	2.08%
Customer Deposits	2.32%	4.43%	0.10%
Deferred Income Taxes	13.48%	0.00%	0.00%
Post-Retirement Liability	4.65%	0.00%	0.00%
Post-1970 ITC	0.56%	8.65%	0.05%
Totals	100.0%		6.98%

(c) Environmental Project Financing. The Settling Parties agreed that NIPSCO should finance, in aggregate, the projects for which it receives a Certificate of Public Convenience and Necessity in Cause No. 44012 with at least 60% debt capital.

C. Depreciation and Amortization Expense.

(a) Depreciation Expense. The Settling Parties stipulated that the depreciation accrual rates recommended by Mr. Spanos in the Depreciation Study should be approved, except for changes set forth in Joint Exhibit A that are based upon proposed changes in specified net salvage percents and which will reduce pro forma depreciation expense by $4.9 million. Joint Exhibit A contains a spreadsheet showing the proposed depreciation rates by class of property.

(b) Amortization Expense. The Settling Parties stipulated that annual amortization expense shall be $36.5 million, includingamortization of software and the following items:

(i) Rate case expenses of $0.770 million for this case ($2.3 million amortized over a period of three (3) years). After the completion of the three (3) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(ii) Deferred MISO costs, amortized and recovered over a period of four (4) years. Amounts included in this case were estimated through June 30, 2011. Costs will continue to be deferred until the effective date of new rates. Any difference between the estimate and the actual costs incurred will be included in the RTO tracker approved in Cause No. 43526.

(iii) Deferred Sugar Creek depreciation and carrying charges, through June 30, 2011, amortized and recovered over five (5) years. The Settling Parties agree that Sugar Creek depreciation and carrying charges may continue to be deferred from July 1, 2011 through December 31, 2011 or the implementation of new basic rates and charges, whichever occurs earlier. These amounts will remain as a regulatory asset on NIPSCO's books and records, but shall accrue no additional carrying charges, and NIPSCO may request recovery of the deferred amount in NIPSCO's next general rate case; provided the other Settling Parties reserve the right to contest the recovery of those amounts.

D. Operating Results at Current and Proposed Rates. Joint Exhibit B contains a Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, and with pro forma adjustments at current and proposed rates per NIPSCO's filed request and to reflect the provisions of this Agreement.

E. Cost Allocation and Rate Design. The Settling Parties agreed that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agreed that NIPSCO should generally design its rates using the structure of its existing 800 Series tariffs.

As noted above, the Settling Parties agreed that NIPSCO's settlement base rates in total will be designed to produce $1.355 billion. Joint Exhibit C attached to the Settlement is a table that contains the percentages and dollar amounts of revenue allocatedto the various customer classes. The Settling Parties agreed to the rate design specifics summarized in Joint Exhibit D attached to the Settlement.

The Settling Parties agreed that the proposed cost allocation results in fair and reasonable rates and charges.

F. Demand Allocators. The Settling Parties agreed that NIPSCO's demand allocators for purposes of the RTO Tracker and RA Tracker are set forth in Table 1 of Joint Exhibit E. The demand allocators for purposes of the RA Tracker will be based upon those set forth in Joint Exhibit E modified to reflect the amount of interruptible load contained in Rates 632, 633 and 634.

G. ECRM and EERM Factors. The ECRM and EERM factors are approved after the expenditures have occurred, and therefore, the Settling Parties agreed that the O&M and depreciation expense on the projects being added to rate base in this proceeding will continue to be deferred until the effective date of the rates approved in this Cause, and all such deferred costs will be recovered in the appropriate EERM filing.

H. Interruptible Credit. The Settling Parties agreed that NIPSCO should be authorized to implement Rider 675, which is attached to the Settlement as Joint Exhibit F and that the credits paid under the provisions of Rider 675 should be recovered from ratepayers, with 75% of the costs recovered through NIPSCO's RA Tracker as the demand component and 25% of the costs recovered through NIPSCO's Fuel Adjustment Clause ("FAC") mechanism as the energy component. The Settling Parties further agreed that the limit on megawatt ("MW") eligibility should be 500 MW, and the maximum amount to be paid in any calendar year under Rider 675 is $38 million.

I. Temporary, Backup and Maintenance Service. The Settling Parties agreed that NIPSCO should be authorized to implement Rider 676, which is attached to the Settlement as Joint Exhibit G.

J. The Settling Parties agreed that those facilities:

served under Rate 832 on June 30, 2010;

eligible for Rate 832 on June 30, 2010, but for being on a Special Contract or on Rate 845; or

located behind the meter of a facility eligible under Rate 832 and which facility would have been eligible under Rate 832,

are grandfathered into Rate 632 and those facilities shall remain eligible for Rate Schedule 632, regardless of any change in name, or ownership, or operation.

K. The Settling Parties agreed that a voltage adjusted FAC may be appropriate, and the Parties agreed to work together to determine the appropriate mechanism to be implemented. Upon reaching a resolution of that issue, the Parties will file a separate petition with the Commission.

L. Accounting Reporting. NIPSCO agreed to file separate gas and electric income statements with the Commission annually in April based on the previous calendar year. NIPSCO agreed to ensure that its financial reports are transparent and verifiable for future OUCC financial audits. NIPSCO agreed to work cooperatively with OUCC to facilitate the auditing function.

M. OUCC Audits. NIPSCO agreed in Cause No. 38706-FAC71S1 to fund OUCC actual audit or consulting fees up to an annual maximum of $100,000 per year for the purpose of conducting a review and audit of NIPSCO's hedging program. NIPSCO agreed that the fees may be utilized by OUCC to conduct reviews with respect to any management of fuel, purchased power, off-system sales, use of interruptible resources, or other tracking mechanisms.

N. General Rules and Regulations and Tariffs. The Settling Parties agreed that NIPSCO will make certain modifications to the General Rules and Regulations and Tariffs initially proposed in this proceeding, and the Settling Parties will jointly submit those revised General Rules and Regulations and Tariffs in support of approval of this Agreement. Joint Exhibit H to the Settlement is Rule 10.2 which is included in the General Rules and Regulations.

O. Final True-Up of Customer Credit. Upon the effective date of new rates following the issuance of a Final Order in this proceeding, the revenue credit and the sharing mechanism approved in Cause No. 41746 will cease. After reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month and shall be specifically identified.

Finally, the Commission notes the Settlement states that the Settling Parties agree that the Settlement and each term, condition, amount, methodology and exclusion contained therein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement.

8. Testimony in Support of the Settlement Agreement. NIPSCO witnesses Shambo, Miller, Westerhausen and Spanos presented testimony in support of the Settlement. OUCC witness Tyler E. Bolinger and Industrial Group witnesses James R. Dauphinais and Nicholas Phillips, Jr. also presented testimony in support of the Settlement.

A. NIPSCO's Evidence in Support of Settlement.

(a) Frank A. Shambo. Mr. Shambo (1) provided an overview of why the Settlement is in the public interest, including the regulatory background related to this proceeding; (2) supported the revenue allocation proposed in the Settlement; (3) provided a general description and explanation of the key parts of the Settlement rate design; (4) explained the rationale for interruptible Rider 675; (5) explained why Rider 676 is offered; (6) provided support for the agreed-to ROE, overall return and changes to NIPSCO's earnings bank; and (7) described why the Settlement is in the public interest.

(1) Overview of Settlement. Mr. Shambo testified the Settlement resolves the issues in this proceeding as well as the issues currently pending in Cause No. 43526 in a fashion that balances the needs of NIPSCO's customers, the various parties and NIPSCO while also resolving a number of regulatory matters along the way. He stated the Settling Parties have specifically agreed that the issuance of an order approving the Settlement without any material modification or further condition shall terminate this proceeding, shall supersede the relief approved in the 43526 Order, including its associated compliance filings and shall conclusively resolve both proceedings. The Settlement also will conclude the bridge agreement and settlement with NLMK approved in Cause No. 43866 and the bridge agreement and settlement with BP Products North America, Inc. approved in Cause No. 44046 once new rates become effective.

Mr. Shambo stated that ultimately the Settlement falls within the broader public interest by providing all customer segments with a reasonable outcome and providing NIPSCO the opportunity to earn a fair return so that it can invest in northern Indiana's energy infrastructure, help fuel job creation and economic growth and provide customers with means to manage their energy consumption and bills.

Mr. Shambo noted that this proceeding was filed during a challenging economic period, specifically in NIPSCO's service territory. Northwest Indiana continues to have recession characteristics of high unemployment, under-employment, income challenges, and large industrial customers positioned in an ever more competitive world market. Mr. Shambo stated that the Settlement is the culmination of NIPSCO's efforts to work with its largest customers to develop an appropriate service structure and provide an opportunity to transition to new basic rates and charges. Mr. Shambo noted these industries are important because they not only invest in our state, but they provide a large number of jobs in NIPSCO's service territory as well as tax revenue and property tax base for the region and the state. He testified that jobs are especially critical in Northwest Indiana and that families depend upon a favorable manufacturing environment to retain and attract jobs.

Mr. Shambo stated that the region needs these companies to be competitive to avoid expansion of the ongoing economic downturn. He testified NIPSCO has kept this in mind in this proceeding, and has helped to respond to these drivers in the Settlement, including enhancements to Rider 675 – Interruptible Industrial Service, Rider 676 – Back-Up, Maintenance and Temporary Industrial Service and the introduction of Rate 634 – Industrial Power Service for Air Separation & Hydrogen Production Market Customers. He stated that while the increase for the large industrial customer class is over 20%, they have the ability to mitigate this increase in large part through interruptible options.

Mr. Shambo testified that, in addition to being sensitive to the needs of industrial customers, NIPSCO is also concerned that local poverty levels are high. He stated that, based upon what NIPSCO sees at the local agencies and through requests for assistance, low-income is also a consideration for purposes of evaluating an appropriate outcome to this proceeding. He stated that a related consideration is the ripple effect that can be caused by large residential increases. Low income customers may need further assistance if increases are very large and state agencies are already challenged in meeting the need for assistance.

Mr. Shambo testified that NIPSCO considered all of these factors, and believes that the Settlement reasonably balances (1) the need to retain and attract jobs in the manufacturing industry, (2) the need to mitigate the impact on residential customers and other sectors, and (3) NIPSCO's need to attract capital on reasonable terms to finance ongoing capital programs, including federally mandated environmental compliance facilities that are the subject of Cause No. 44012. He stated that an average $3.33 increase per month is a manageable amount per household. The Settling Parties have agreed that the residential customer charge should only be increased to $11 per month.

In response to questioning from the Presiding Officers, Mr. Shambo further explained the impact of the Settlement on residential customers. He testified the most appropriate way to view the impact is with current fuel costs and various tracker levels. See Petitioner's Exhibit No. 1-S, IURC Set 2-001 Attachment A, page 2 of 2. Assuming the Settlement were approved before the end of calendar year 2011, this analysis reveals that a residential customer using 688 kWh per month would see an increase from $80.43 to $83.10, or $2.67 per month (3.32%).[6]

Mr. Shambo testified the specific objectives addressed in the Settlement include (1) resolution of overall revenue allocation, (2) transitioning industrial customers to full tariffed

6 After implementation of NIPSCO's proposed Demand Side Management Adjustment factor currently pending in Cause No. 43618 DSM 1.

rates from less than tariff rates pursuant to expiring or expired special contracts, (3) concern about residential burden, and (4) mitigating the effect on municipalities and commercial customers.

Mr. Shambo testified the Settlement achieves resolution and compromise to the satisfaction of all customer interests while addressing these key objectives. He stated the Settling Parties represent all classes and some of them represent specific needs within those classes.

Mr. Shambo testified that other customers (not including special contract or economic development rider customers) were receiving a customer credit established as a result of a settlement in the rate investigation in Cause No. 41746. He stated this served as another item for the parties to address while reasonably transitioning customers to full tariff rates. Mr. Shambo testified the customer credit will terminate upon implementation of new rates resulting from this proceeding.

(2) Revenue Allocation. Mr. Shambo testified that the class allocation agreed to in the Settlement is fair and reasonably meets the Settling Parties' key objectives. The revenue increase to residential customers (Rate 611) is 4.788%, the revenue increase to industrial customers (Rates 632, 633 and 634) averages 20.317% and the revenue increase to larger general service classes (Rates 621, 623, and 624) averages 10.586%; the revenue allocation increase was zeroed out to municipalities that utilize NIPSCO's street lighting and traffic lighting rate schedules; and the revenues for no class increased, other than the large industrials, by more than 12%. He stated that while it is true that certain special contract industrial customers will experience a greater increase moving to full tariff rates; the impact is one that they can choose to manage through the utilization of Rider 675 – Interruptible Industrial Service.

(3) Description and Explanation of the Key Parts of the Settlement Rate Design. Mr. Shambo explained that NIPSCO simplified its approach by building its service structure from firm services while making few adjustments to determinants overall so that the parties could more easily see the derivation of rates under those services. He testified the Settling Parties have agreed to a treatment of interruptibility (both for its provision of service and recovery of associated credits) that is explicit and clear for customers to understand. He stated this service has also incorporated the input of NIPSCO's large industrial customers, and NIPSCO hopes that it provides a positive working model for years to come.

Mr. Shambo testified Joint Exhibit D to the Settlement serves as the appropriate starting point as a summary of the rate design parameters agreed to by the Settling Parties. He stated that generally speaking, NIPSCO's proposed use of the 600 Series rate structure has been maintained and it closely aligns with the currently-effective 800 Series rate structure with those changes highlighted in Joint Exhibit D.

Mr. Shambo stated the Customer Charge for Rates 611, 612 and 613 would increase to $11.00 per month, consistent with the recently approved gas general base rate case settlement for NIPSCO. The Settling Parties have agreed to a single block rate for energy. Lastly, the Settling Parties have agreed to standardize the breakpoint for a space heating discount to 700 kWh in all of the Rates 611, 612 and 613.

Mr. Shambo stated the Customer Charge for Rates 620, 621 and 622 was changed to $20,with the exception of three phase service to address concerns for low volume commercial customers.

Mr. Shambo stated Rate 625 has been updated and retained and is available for eligible metal melting customers.

Mr. Shambo testified that NIPSCO and the consumer parties have worked since before this proceeding was filed to achieve a rate design and service structure that is satisfactory to all customer classes. He testified that the agreed-to rate design and service structure represent a consensus of all Settling Parties. Specifically, Rates 632, 633 and the addition of 634, along with Riders 675 and 676, are all part of the necessary service structure.

In terms of the specific details for Rate 632, Mr. Shambo explained that this rate is designed to address the needs of lower-load factor, energy intensive customers such as arc furnaces. He stated that when it came time to design rates and implement the agreed-to revenue requirement and allocation, it was apparent that there was a need to grandfather test year customers and/or load migrated to Rate 632. Mr. Shambo explained that Rate 632 was built based upon the assumed load and the Settling Parties have agreed to maintain that foundation. He testified that in order to achieve the agreed-to revenue requirement and allocation while maintaining the features and intent of proposed Rate 632, it became clear that the rate should be available only to customers whose demand is at least 15 MW, but that grandfathering current Rate 832-eligible customers was also necessary and reasonable. The three inclining energy block structure in Rate 632 was specifically designed to maintain the integrity of the relationship between Rates 632 and 633 and avoid unintended migrations of customers. He stated the Settlement continues to apply Riders 675 and 676 to customers under Rate 632.

Mr. Shambo explained that Rate 633 is designed to address the needs of high-load factor customers. He testified that, unlike Rate 632, the Settling Parties are not proposing to increase the minimum demand under Rate 633; instead, it remains at 10 MW. Mr. Shambo stated Rate 633 no longer incorporates hours of energy into the demand charge. Rate 633 incorporates a three declining energy block structure with a smaller demand charge. He stated that the Settlement continues to apply Riders 675 and 676 to customers under Rate 633.

Mr. Shambo testified that Rate 634 is a new rate schedule proposed in the Settlement and it is different from both Rate 632 and Rate 633. He stated that Rate 634 importantly assists in creating greater interruptible capability, provides for operational flexibility and creates the potential for growth in NIPSCO's service territory to the extent it permits the identified customer to increase production of a competitive product at lower marginal cost. He stated that NIPSCO and the identified customer devoted a significant amount of time to develop this rate schedule to help provide for some of the flexibility inherent in the current 800 Series rate structure and special contract while also meeting the objectives in this proceeding. He testified Rate 634 is designed upon the same principles underlying other rates – i.e., upon an allocated revenue requirement and test year determinants, and that the base determinants utilized for the identified customer on Rate 634 are the same as what would be utilized if the customer selected Rate 633. In addition, the allocated revenue requirement is the same as what would be utilized for Rate

633. He explained that the differences rest in the rate structure and are responsive to the specific needs of one of NIPSCO's largest electric customers.

In terms of the specifics of the rate structure for Rate 634, Mr. Shambo testified the notable difference from other large industrial rate schedules is the existence of an overrun energy rate concept. Each hour, the Company will charge the customer an energy rate based upon whether it is above or below its contract demand. He stated that this rate structure allows for a sophisticated, large energy consumer to manage consumption levels around specific breakpoints. He explained that because of this structure and the identified customer's operation, there is no need for surplus or temporary capacity. Moreover, Mr. Shambo stated that the design of the rate structure is based on the fact that the customer will pay a demand charge on a fixed contract demand. The contract demand would only change if the overall average of the customer's on-peak demands exceeds a 12.5% threshold above the existing contract demand. He stated that this provides certainty for both the customer and NIPSCO, and would improve the competiveness of the region for manufacturing.Mr. Shambo explained that the Settling Parties have agreed that NIPSCO should file a petition within two years seeking approval of a revenue neutral transition plan to standard rates for current space heating customers. Mr. Shambo stated the incentive for customers that transition to a natural gas space heating option rather than electric is not being discontinued. He stated that NIPSCO had proposed a one-time incentive of $25 for customers that elected to transition to a natural gas space heating option rather than electric due to the fact that natural gas is more efficient and that the Settlement retains this incentive, and NIPSCO has agreed to provide this incentive from its own funding below-the-line.

(4) Interruptible Rider 675. Mr. Shambo testified Rider 675 balances the needs of all customer groups. He stated that Rider 675 is a key settlement component that is based upon the inputs and compromise from all Settling Parties representing all customer classes. He explained that some of NIPSCO's largest industrial customers are capable of being interrupted, which is beneficial to all customers. He stated that customers willing to guarantee that they will interrupt service on demand, for the benefit of others, should be compensated. He explained that Rider 675 provides these credits to those customers and that the credits are then recovered through the RA and the FAC trackers from all other customers that are receiving the benefit. He stated this is superior to building expected amounts into rates because this mechanism assures that no gap will exist between amounts recovered from customers and the amount of credit provided to industrial customers.

Mr. Shambo testified that Rider 675: (1) caps the overall annual credits to $38 million (in addition to a cap of 500 MW); (2) allows customers with multiple premises to aggregate interruption capability, if they choose Option A, B or C, to help provide customer flexibility; (3) adds a new option; (4) allows market pricing to determine the credits paid under Option A; (5) treats buy-through energy during an Interruption at the Real-Time Locational Marginal Price ("LMP") unless otherwise elected by the customer through prior notice; and (6) includes minimum contract lengths for the various options.

Mr. Shambo testified the interruptible credits are provided for two reasons, reliability and economic, each of which provides value to all customers. He stated that while there is no way to know exactly how much value will result from either, it is clear that reliability is associated with reducing capacity cost and economic will reduce energy costs. He testified the Settling Parties have agreed that 75% of the credits should be recovered through the RA Tracker and the balance through the FAC.

Mr. Shambo explained that reliability is the ability to physically curtail a customer's service in order to maintain system integrity and the credit value is derived from the cost of new capacity. This is beneficial to all customers over time because NIPSCO will be able to avoid purchases of capacity in the market and can delay building new generation capacity. He stated that NIPSCO's current estimated cost of capacity is based on three reference points (1) the price per KW for a new combustion turbine ("CT"), (2) the price per KW for a new combined cycle gas turbine ("CCGT"), and (3) current market price of capacity. He explained that while there exists today a reasonable or excess capacity situation in the broader market, this situation will not continue over time, as environmental laws are likely to take a number of generators off line in the next decade. Mr. Shambo explained that capacity value is a marginal calculation that is likely to be seen in radical terms (very low lows and very high highs) because of the time frame and cost associated with building new generation. Supply change (generating capacity) will move slowly as will demand. Therefore, during periods of clearly excess generation, the price will be low, such as the current market. However, he stated that as capacity becomes tight the price likely will rise sharply. He testified the Settling Parties have distinguished credit pricing based upon the length of contract the customer is willing to sign, and this will help to manage the influence of this radical change on NIPSCO's own supply curve.

Mr. Shambo explained that another distinguishing characteristic of reliability is the ability to change supply / demand. He stated that clearly, quicker responsiveness from resources provides greater value. He explained that newer peaking generation technology can be online and synchronized within 10 to 20 minutes. Most CCGTs can be online within 1 to 4 hours, and the startup time for NIPSCO's existing CTs is roughly one hour. Mr. Shambo stated that MISO rules on load modifying resources require changes within 4 hours. He explained that the interruptible services included as part of the Settlement are also distinguished based upon response time.

Mr. Shambo testified the final distinguishing characteristic is the number of curtailments allowed in a given season. He explained that two of the options follow MISO requirements with limitations on curtailments as opposed to the last two options which are more closely aligned with a physical unit which can start an unlimited number of times.

Mr. Shambo explained that economic interruption is defined separately from reliability events or curtailments. Economic interruptions provide the industrial customer the option to either buy through at market prices or reduce demand. He stated this is beneficial to all customers because it allows NIPSCO to reduce marginally more expensive production (from peaking units) or market purchases, and that these activities generally reduce the cost incurred and recovered through the FAC. He stated the number of economic interruptions allowed in each option is a distinguishing characteristic, where the greater the number, the greater the value.

Mr. Shambo testified that another distinguishing characteristic is the duration of interruption. The greater the duration allowed by the option, the greater the value of that option to customers paying for the credit.

He stated that economic interruptions are triggered by high market prices, which are a function of demand and supply. The major drivers on demand are the general economic state and temperature. He stated that recent events provide some guidance on the value of interruptibility. He explained that NIPSCO has called interruptions on six separate days since May 1, 2011. He stated that while clearly 2011 has been a hot summer, the broader economy has not come close to full recovery. If the economy had fully recovered, the market price per kWh this summer could have been much higher – possibly leading to curtailments.

Mr. Shambo testified reductions in capacity will lead to higher LMPs. He stated that the majority of capacity that will be retired within the near term is coal based and that marginally more expensive production capability will take its place increasing the market price of power, especially if the marginal production is gas based CTs. He explained that if the capacity is not replaced, LMPs could reach very high prices if this is the tool used to bring demand and supply into balance because the marginal value of electricity to most customers far exceeds the costs to produce or the price at which most regulated electric utilities sell power.

Mr. Shambo testified the Settling Parties have agreed to limit availability of Rider 675 for a number of reasons. He explained that there is always some level of uncertainty around how much capacity will be required. Currently, NIPSCO has approximately 200 MW of interruptible resources and has acquired an additional amount of market capacity of 150 MWs.

He explained that the limitation on price is more of a practical limitation to avoid unanticipated consequences. He stated that while the Settling Parties do not know how much interruptible demand participants may provide, establishing a cap of $38 million would allow the Settling Parties to assess the "what if" impact on customers not taking the service.

Mr. Shambo explained the various options and how each option relates to the rationale as follows:

- Option A is a market based product that is only curtailable, not interruptible for economic purposes. This option matches the MISO market place definitions for curtailable capacity and is therefore comparable to short-term capacity bought and sold in the marketplace. Option A has the shortest term contract (1 year), the fewest number of hours curtailable and the greatest limitation in the number of curtailments (5) per summer. Service under Option A is curtailable on 4 hours' notice. The credit is correctly set initially near the market at $1.00. NIPSCO will make a 30-Day Filing to reset this rate every January based upon market prices.

- Option B is one of two middle ground options. The Option B curtailment rules are identical to Option A. The contract term (3 years) is longer than Option A. However, Option B is interruptible for economic reasons. The economic interruptibility is limited, but still significant. Limitations are as follows: one per day, 10 consecutive hours, no more than 2 consecutive days or 3 days in a week and no more than 100 hours per year. The proposed credit of $6.00 for Option B is a function of negotiations but considers both reliability value and economic value.

- Option C is the second middle ground option. The Option C curtailment rules are different from Option B and much more akin to a peaking unit, creating greater value to other customers. Importantly, curtailments are unlimited in number and the notice period is reduced to 1 hour from 4 hours in Options A and B. The contract term (7 years) for Option C is over twice as long as Option B. The economic interruption rules are similar to Option B, with the only difference being the number of consecutive hours of interruptibility is 12 hours versus 10 hours. The proposed credit for Option C is $8.00.

- Option D is the highest value service, providing considerable flexibility for the benefit of all other customers. It is long-term (10 years). There are no constraints on curtailment. Finally, it is curtailable on 10 minutes' notice. Those same rules carry over into economic interruptions, again increasing the value. This service can be economically interrupted up to 3 days per week and 200 hours per year, both considerably greater than Option C. Option D is the closest to the existing Rate 836. For comparison purposes, that rate is currently receiving a credit of approximately $13, considerably more than the $9.00 credit agreed to in this proceeding. The customer currently using Rate 836 has faithfully met every call over the years on this service and has been a welcomed partner.

Mr. Shambo stated it is important to highlight the benefits of Options B, C and D while NIPSCO is also experiencing a summer of intense heat. He explained that the week of July 18 provided the MISO region with a number of consecutive weekdays of heat warnings. It is during this time while businesses and industry work and customers run air conditioners at home that the system sees the greatest amount of stress. He stated the ability to call upon customers to curtail and interrupt with less notice and curtail more often is of benefit to the system and all customers. He stated it is helpful to incent a greater diversity of interruption and curtailment options, not just an economic benefit, but a system reliability benefit that cannot always be measured in dollars per kW. Mr. Shambo testified all of the Rider 675 options provide these benefits, but Options C and D more so.

Mr. Shambo explained that when economic interruptions are called, customers will have the option to "buy-through" into the market. When a customer "buys-through" they will be paying LMP plus an adder. He stated NIPSCO will not be supplying the customer with FAC power during this time; therefore, FAC customers continue to benefit from the bargain.

Mr. Shambo described the allocation of credits if demand exceeds limits (either 500 MW or $38 million annually), as follows.

The Initial Allocation will be as follows:

- First to current interruptible customers up to the amounts in their current agreements. NIPSCO currently has two contracts with interruptible provisions.

- Second to customers under an "open season." Initially, all eligible customers not receiving special pricing or credits at the time new rates go into effect, will make requests for interruptible credits. Customers have the option to exit any such agreement in order to qualify. The effectiveness of the credits would be applied when new rates are implemented. If demand exceeds limits (either 500 MW or $38 million annually) the interruptible credits will be distributed based upon the value of the interruptible credit with the highest demand credit value allocated first.

Allocation will be in 1 MW increments (rounded up). Therefore, if a customer has requested the minimum 1 MW, but the allocation process yields less than that, they will still be allocated 1 MW and other customer volume will be rounded down to stay within the cap.

For future periods, NIPSCO will take requests for any available interruptible credits beginning January 15 and no later than February 1 of each year. NIPSCO will assess availability, allocate interruptible credits based upon the procedures above and provide notice to customers by March 1.

Mr. Shambo stated that while contracts have minimum lengths in accordance with the tariff, a contract expires automatically when new rates (base or interruptible credit) take effect.

In response to questioning from the Presiding Officers, Mr. Shambo explained the impact on residential customer bills from the interruptible credits, assuming full subscription under Rider 675. The same typical residential customer using 688 kWh per month discussed previously would see an additional $2.35 per month. See Petitioner's Exhibit No. 1-S, IURC Set 2-002 Attachment A, page 2 of 2. He explained that full subscription of $38 million is close to double the level which would arise from the current interruptible customers. He further explained that there is a lag between interruptible contract execution and the 6-month RA Tracker filing, and that by the time any material level of interruptible credits would be reflected, the increase would be offset significantly by the "zeroing out" of the currently effective EERM (which would account for $1.42 of this hypothetical customer's monthly bill).

(5) Rider 676. Mr. Shambo explained that Rider 676 provides back-up, maintenance and temporary power to industrial customers served under Rates 632 and 633. These services are provided to industrial customers because the process of converting raw materials into other products is fraught with potential production uncertainties related to the equipment used in the process. He explained that equipment failures can and do occur in the industrial process and that routine maintenance can lessen the risk of an unexpected upset; however, changes in demand for electricity can and will occur due to unexpected non-routine events. He stated that Rider 676 is a relief valve to avoid demand ratchets due to these events.

Mr. Shambo testified NIPSCO has two primary rules embedded in Rider 676. First, the facility must truly be a cogeneration unit, not simply a peaking unit fired to lower demand. Second, the unit must be maintained in a fashion that the outages, covered by back-up, on an annual basis are limited to 45 days. He testified back-up service is for unplanned outages and maintenance service is for planned outages. He explained that the back-up rate is designed to avoid cost shifts to FAC customers due to unexpected load on NIPSCO's system. He stated the rate paid for back-up is a daily demand charge plus LMP plus a non-fuel energy charge of $.0035 per kWh, which is beneficial to the customer in that it does not increase its billing demand due to an unexpected increase caused by equipment failure. Mr. Shambo testified this is reasonable to NIPSCO because the adder does cover variable operating costs and contributes to fixed costs.

Mr. Shambo explained maintenance service is different from back-up service in a few significant ways. First, this service is for planned maintenance of behind the fence generation. Second, maintenance is not available during the summer, whichfurther encourages usage in the off-peak months of February, March, April and October. Third, because maintenance is planned service, the pricing is based on the FAC plus the energy charge in Rate 632 or 633, whichever is applicable. Mr. Shambo stated this service includes a demand charge of \$0.44 per kW per day during the moderately high demand months of December, January and May or \$0.25 per kW per day in the months of February, March, April and October. He explained that as with back-up service, maintenance is curtailable, but not interruptible for economic reasons once it has been granted. Once the service is granted, the customer pays a minimum of 80% of that granted. He stated the service is available for up to 60 days per year per customer.

Mr. Shambo explained how temporary service is different from back-up and maintenance service. He explained that NIPSCO's original filing had only a temporary service designed to cover all unexpected needs for industrial customers. He stated that temporary service continues to be a catch-all for everything from spikes in demand to non-cogeneration equipment failure. For example, this service encourages a customer to take on a marginal order that otherwise might be avoided in order to manage the demand billing determinants to an ongoing run rate level.

Mr. Shambo stated the daily demand rate increases as the number of days increase. He explained that while NIPSCO wants to accommodate incremental projects, if baseline demand is increasing demand billing units should also increase within any rolling 12 month period. He explained that unlike back-up or maintenance, NIPSCO can deny temporary service for economic reasons. However, customers have a "buy-through" option similar to Rider 675. He explained that temporary power can only be interrupted to the extent Rider 675 has previously been interrupted. This higher priority is due to the fact that temporary service under Rider 676 has a daily demand charge.

(6) Discussion of Reasonable Return. Mr. Shambo testified that while the agreed-to ROE of 10.2% is higher than that approved in the 43526 Order (9.9%), it is lower than other comparable electric investor-owned utilities ("IOUs") in Indiana. He noted that Vectren's recent base rate case order approved a rate of return on equity of 10.4%; I&M's (approved 3 years ago) is 10.5%, and Duke's is 10.5%. The ROE is within the range identified in the 43526 Order of 9.9% to 10.5%.

Mr. Shambo stated that as to the agreed-to rate of return of 6.98%, it is lower than the comparable electric IOUs in Indiana. He noted that Vectren's is 7.29%, I&M's is 7.62% and Duke's is 7.30%. He testified that the resulting net operating income of \$188.9 million is an acceptable return on the fair value of NIPSCO's utility plant in service.

Mr. Shambo testified the increase in NIPSCO's ROE relative to the 43526 Order is appropriate because of NIPSCO's service improvements. Pointing to NIPSCO's case-in-chief, Mr. Shambo testified NIPSCO has improved key service metrics for the benefit of customers, including its equivalent forced outage rate ("EFOR"), customer average interruption duration index ("CAIDI"), system average interruption duration index ("SAIDI") and customer perception scores. He stated these improvements all support the agreed-to ROE and also support how NIPSCO needs to remain financially stable to support further investments to provide reasonably adequate service and facilities and to invest in infrastructure to support the local region and jobs and growth.

Mr. Shambo testified that the Settling Parties have agreed to reset the bank of under-earnings calculated according to Ind. Code § 8-1-2-42.3 to $200,000,000. He stated that since its last implemented electric rate case, NIPSCO has amassed more than $1.8 billion in cumulative under-earnings. He explained that in settling the overall issues in this proceeding, the Settling Parties have agreed that $200,000,000 is a reasonable starting point for purposes of the earnings bank calculation upon the implementation of new electric base rates and charges.

(7) Settlement is in the Public Interest. Mr. Shambo testified the Settlement represents a diligent effort by all Settling Parties to reach a comprehensive result. He stated the complexity of the issues and the diversity of the Settling Parties dictated the need for compromise on the part of everyone involved, and the Settlement reflects a delicate balance that accommodates the interests of all Settling Parties in a reasonable way.

Mr. Shambo testified that approval of the Settlement is consistent with the public interest. He noted that in reaching agreement in this case, the Settling Parties have attempted to take previous Commission decisions into account, including the 43526 Order. He opined that the fact that the Settling Parties were able to negotiate a settlement in this proceeding representing all customer segments and diverse interests is strong additional evidence that the Settlement is in the public interest. He also added that the ability to obtain a Commission decision in a more timely and cost effective manner, coupled with certainty about the terms and conditions which have been negotiated, is of the utmost importance in the settlement context. He stated that without such certainty, settlements may not be reached. He testified that the Settlement provides that if following its examination, the Commission finds the Settlement to be in the public interest, the Settlement should be approved in its entirety and without change or condition(s) unacceptable to any Settling Party.

Mr. Shambo testified the Settlement represents a comprehensive resolution of all of the issues in this proceeding and Cause No. 43526. The Settlement resolves complex, divisive, and controversial issues surrounding revenue requirement, revenue allocation, rate design and a number of issues that the parties have been litigating for a number of years. In addition, the Settlement balances the interests of NIPSCO with those of its customers without the expense and risk of continued litigation and potential appeal. He stated the Settlement provides NIPSCO with an opportunity to earn a reasonable return on the investment it has made, balanced with the interests of NIPSCO's customers in receiving reasonable service at a fair cost.

Mr. Shambo explained that time is of the essence and the Settling Parties have agreed to request that the Commission review the Settlement on an expedited basis. He explained that this would finalize years of litigation related to these issues and send a signal of finality and certainty to NIPSCO's customers and the financial marketplace regarding NIPSCO's electric basic rates and service structure.

(b) Linda E. Miller. Ms. Miller addressed each of the revenue requirement settlement changes from NIPSCO's proposal in its filed case-in-chief. She also briefly described the process that will be used to perform a final reconciliation of the customer credits that NIPSCO has been providing to customers in accordance with the Commission's September 23, 2002 Order in Cause No. 41746 ("41746 Order").

Ms. Miller testified that the Settlement modifies NIPSCO's original request and now proposes a gross revenue amount of $1,401,000,000, which reflects a revenue increase of $6,853,718 as compared to test year pro forma results based on current rates. She stated that gross margin requirement is $926,541,944. After adjusting for non-trackable fuel, other revenues and the credit related to emissions allowances, the Settlement provides for approval of base rates to recover revenue of $1,355 million and gross margin of $909 million. Ms. Miller testified this will provide the opportunity to earn net operating income of $188,872,242. She stated the settlement revenue requirement of $1,401,000,000 reflects a reduction of $68,886,481 from the original request of $1,469,886,481 in NIPSCO's filed case-in-chief.

Ms. Miller testified that Joint Exhibit B is the Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, with pro forma adjustments at current and proposed settlement rates. She testified that during the course of the settlement discussions, several expense adjustments were agreed to, which result in differences between the Company's originally filed case and the amounts in the Settlement. Each of the adjustments was discussed in Ms. Miller's settlement testimony. She stated that the settlement adjustments consist of (1) adjustments that reflect new line items that were not shown in the exhibits in the Company's case-in-chief and (2) changes to the amounts of line items that were reflected as adjustments in the Company's case-in-chief. Column I of Joint Exhibit B reflects the settlement adjustments and Column J reflects the settlement pro forma results at proposed rates.

Ms. Miller testified that Petitioner's Exhibit No. LEM-S5 shows the computation of the overall weighted cost of capital for NIPSCO. She stated the only changes to this exhibit from that filed in NIPSCO's case-in-chief are to reflect the settlement return on equity percentage of 10.2% and the resulting overall weighted average cost of capital of 6.98%.

Ms. Miller testified that per the terms of the Settlement, upon the effective date of new rates following the issuance of a Final Order in this proceeding, the customer credit approved in the 41746 Order will cease. She stated that after reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month.

(c) Curt A. Westerhausen. Mr. Westerhausen described NIPSCO's proposed IURC Electric Service Tariff, Original Volume No. 12, including the Rates, Riders and Rules (the "Settlement Tariff," attached to Mr. Westerhausen's testimony in support of the Settlement as Petitioner's Exhibit No. CAW-S2). He also explained how the Settlement Tariff differs from the Proposed Tariff (the tariff originally proposed in Petitioner's case-in-chief). Mr. Westerhausen testified the rates and charges were revised consistent with the agreed-to base rate revenue of $1,355 million and class allocations contained within the Settlement. He provided a summary, in general terms only, of changes to the Rates and Riders. For Rates 611, 612 and 613, (1) the Customer Charge was reduced to $11.00; (2) the declining block energy structure was replaced with a single block energy rate; and (3) the space heating/heat pump rates have been standardized to all start at 700 kWh during the space heating season. For Rates 620 and 622, the Customer Charge was reduced to $20.00 to match the commercial Customer Charge in Rate 621. For Rate 621, (1) the Customer Charge was reduced to $20.00; (2) the declining block energy structure was replaced with a single block energy rate; and (3) the Minimum Monthly Charge was changed to include a $34.00 Minimum Monthly Charge for three-phase service. For Rate 624, clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter. For Rate 625, the hours of service have been modified to include an 8 hour on-peak window, and the customer can choose on an annual basis which five consecutive hours to designate as on-peak and the remaining three hours will be considered as off-peak hours. For Rate 626, clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen testified that for Rate 632, (1) the minimum contract capacity requirement for new customers was increased to 15,000 kilowatts; (2) facilities being served under Rate 832 on June 30, 2010; facilities which would have been eligible for Rate 832 on June 30, 2010 but for being on a Special Contract or on Rate 845; or facilities that would have been eligible for Rate 832 on June 30, 2010, which are located behind the meter of a facility eligible under Rate 632, were grandfathered into Rate 632 and those facilities remain eligible for Rate 632 regardless of any change in name, or ownership, or operation of those facilities; (3) the two tiered demand rate has been collapsed into a single block demand charge; (4) the two tiered energy rate has been modified into a three tiered inclining block energy rate; (5) clarification language was added in determining the billing demand that the customer's half hour demands would be reduced for any back-up, maintenance and temporary service utilized during the month before determining the maximum on-peak and off-peak demands; (6) Surplus Capacity allotted by the Company will not exceed 15% of the Contract Demand; and (7) clarifying language was added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen summarized the changes to Rate 633 as follows: (1) modified to remove all energy from the demand charge; (2) the energy structure is a three tier declining block structure; (3) in the original filing, the first 600 hours of energy was included in the demand charge; now the first 600 hours of energy are in the first energy block; (4) clarification language was added in determining the billing demand that the customer's half hour demands would be reduced for any back-up, maintenance and temporary service utilized during the month before determining the maximum on-peak and off-peak demands; (5) Surplus Capacity allotted by the Company will not exceed 15% of the Contract Demand; and (6) clarifying language has been added such that contracts that have extended beyond the initial term would terminate at the end of any calendar month thereafter.

Mr. Westerhausen explained that Rate 634 is a new rate schedule available to air separation and hydrogen production market customers with a contract minimum of 150 MWs, including aggregation of multiple delivery points to facilitate interruption of load. Customers are required to contract for at least 40 percent of their load as interruptible in accordance with Option D under Rider 675. A Demand Charge is assessed on Contract Demand. There are three block Energy Charges based upon kilowatt hours used. The first block is for all energy on an hourly basis under the Contract Demand, the second block is for all energy on an hourly basis between Contract Demand and 225,000 kilowatts, and the third block is for all energy on an hourly basis over 225,000 kilowatts. Determination of Contract Demand is based upon the Customer's average on-peak demands and is adjusted annually when the average on-peak demands vary by more than 12.5% of the current Contract Demand.

Mr. Westerhausen explained that Rider 670 was modified to include recovery of 25% of costs associated with credits paid for interruptible load. Rider 674 was modified to include recovery of 75% of costs associated with credits paid for interruptible load. Rider 675 was modified to include customers taking service under Rate 634. Rider 675 has a total capacity limit of 500 MW and a total sum of demand credits availability of $38,000,000 in any calendar year.

Mr. Westerhausen testified that Rider 676 was modified to include back-up and maintenance services. Back-up service is available to customers with verified internal electric generation fueled with energy sources such as, but not limited to, process off-gas or waste heat, natural gas, oil, propane, coal and coal by-products and that is capable of meeting the efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission ("FERC") under 16 U.S.C. 824a-3, in effect November 9, 1978 ("Cogeneration Systems"). The Customer may request (including on a pre-qualifying basis) back-up service that may only be available for up to 45 calendar days per Cogeneration System per 12 rolling months. Eligibility for back-up service requires a contract between the customer and the Company that includes information on the Cogeneration System(s). The customer provides initial notice of its request for back-up service within 60 minutes of an event. Back-up service is billed on a daily Demand Charge based on the customer's applicable Rate 632 or 633 Demand Charge divided by the number of days in the month. All kilowatt hours used for back-up service is subject to an Energy Charge equal to Real-Time LMP plus a non-fuel charge of $0.0035 per kWh. A buy-through provision was added to temporary service. To the extent a customer requests temporary service and the Company denies such a request under this Rider, the customer may elect to buy-through subject to an Energy Charge equal to Real-Time LMP plus a non-fuel energy charge of $0.0035 per kWh. The Customer may not elect to buy-through under this Rider if the Company has initiated a curtailment(s) on its system. The Company has the right to deny a request for temporary service if Day Ahead LMPs exceed the Company's current Commission-approved Purchased Power Benchmark that is utilized to develop the Company's fuel cost charge under Rider 670.

Finally, Mr. Westerhausen testified that Rider 677 was modified to include a new eligibility threshold requirement of a minimum of ten (10) full-time equivalent jobs created per project.

Mr. Westerhausen testified the Settling Parties are not proposing any changes to the Purchased Power Benchmark approved in the 43526 Order. He stated that since the Purchased Power Benchmark is being used to trigger economic interruptions of NIPSCO's industrial customers, NIPSCO will make available to its industrial customers who have signed-up for Rider 675, NIPSCO's best estimates of the daily Benchmark as soon as it is available to NIPSCO for the customers' planning purposes.

Mr. Westerhausen also testified that for purposes of Rider 671 (Adjustment of Charges for Regional Transmission Organization) and Rider 674 (Adjustment of Charges for Resource Adequacy), the Settling Parties agreed to utilize the demand allocators set forth in Table 1 of Joint Exhibit E to the Settlement. He stated the demand allocators for purposes of the RA Rider will be based on those set forth in Joint Exhibit E and modified to reflect the amount of interruptible load contained in Rates 632, 633 and 634. At the hearing held in this Cause, Mr. Westerhausen testified that the parties had not specifically stated in the Settlement that the Production Energy Allocation variable in Rider 671 was based upon the percentage allocation of energy used during the test year by the various rate classes. He also explained that the parties had not reached an agreement regarding the allocation of the costs in Rider 672 and 673. He stated that the Settlement does not preclude the Commission from deciding the proper allocation for these two Riders in a subsequent proceeding.

Mr. Westerhausen testified that the Settlement Tariff also reflects the following Rates and Riders that had been approved since the filing of the Original Tariff: (1) Rate 665 – Feed-In Tariff was approved in Cause No. 43922; (2) Rider 681 – Demand Response Resource Type 1 (DRR 1) – Energy Only and Rider 682 – Emergency Demand Response Resource (EDR) – Energy Only were approved in Cause No. 43566; and (3) Rider 683 – Demand Side Management Adjustment Factor ("DSMA") and Appendix G – Demand Side Management Adjustment Mechanism Factor were approved in Cause No. 43912. He stated that the DSMA also is modified to correct a clerical error that omitted Rate 625 from the applicability section. He noted that all of these additional Rates and Riders were reviewed and revisions were made to implement the tariff layout presented in the 600 Series (i.e., the approved tariff may have referred to language in a rule that is now located in a rate or rider) and any additional corrections noted were made.

Mr. Westerhausen also provided a summary of specific changes to the proposed Rules as follows:

1. Rule 1.2 was revised to remove the reference to a current customer changing to an existing Rate Schedule.

2. Rule 2.1 was modified to state that a copy of the Tariff would be posted on the Company's website.

3. Rule 6.1 governing non-standard service extensions has been modified to incorporate language consistent with that contained in Rule 6.3, which was approved by the Commission as part of the settlement in Cause No. 43706. Rule 6.2 was revised to provide a methodology for service extensions and modification for Transmission and Subtransmission Customers.

4. Rule 7.2 was modified to refer to Rider 679 – Interconnection Standards Rider.

5. Rule 8.1 was modified to clarify that the cost of necessary repairs or replacements shall be paid by the Customer if Company property is destroyed due to Customer's violation of applicable tariffs. Rule 8.5 was revised to insert that an unauthorized user would be responsible for paying out-of-pocket costs for repairs.

Rule 8.6 was revised to provide that the Customer has the right to challenge the Company's determination that it is required or appropriate for the Customer to comply with the standards of outside agencies or duly applicable organizations including FERC, North American Electric Reliability Corporation ("NERC"), Reliability*First*, and MISO.

6. Rule 10.2 was submitted as Joint Exhibit H to the Settlement. It was modified to define the equitable non-discriminatory manner that the Company will use to determine the creditworthiness of both a Customer and an Applicant. As a guarantee against the non-payment of bills, a deposit payable in cash or by letter of credit in an amount equal to the Customer's two (2) highest months usage based upon the most recent twelve (12) months historical usage or two months of projected usage for an Applicant. For Customers with multiple accounts, each account will be treated individually for purposes of this Rule. In the case of a cash deposit as a guarantee against the payment of bills, simple interest thereon at the rate established by the Commission will be paid by the Company for the time such deposit is held by the Company. Upon discontinuance of service, the amount of the final bill will be deducted from the sum of the deposit and interest due, and the balance, if any, will be remitted to the depositor.

7. Rule 12.3 was revised to require the Company to provide no less than 14 days written notice to non-residential customers prior to disconnecting the Customer's service. Rule 12.3.2 was modified to replace the "Customer's failure to allow access" with "Customer's denial of access".

8. Rule 13.2 was revised to modify the calculation for the amount the Demand Charge is reduced because of any disruption, suspension, Reduction or Curtailment of the delivery of Energy, unless due to the fault, neglect or culpability on the part of the Company. For reductions or Curtailments of electric Energy below Customer's Billing Demand, the Demand Charge will be reduced by the amount of the number of kilowatts reduced or Curtailed multiplied by the ratio of the number of hours in which the Curtailment was in force to the total number of hours for the billing period in which the Curtailment was in force.

Mr. Westerhausen also provided a summary of the changes to the Standard Contract originally included in NIPSCO's case-in-chief. He stated that the title of the Standard Contract was revised to show that it also applies to Rate 634 and Rider 676; under Rider 675 Demands, there were four options (Options A, B, C and D) added for the Customer to designate the quantities of Interruptible Contract Demand; a new section for Rider 676 Back-up Service, was added to (1) describe the information to be provided by the Customer to qualify for Back-up Service and (2) describe the requirements for adequate metering or submetering of Cogeneration Systems; and under Paragraph 4, Terms and Conditions, a reference to Commission approval of charges under the contract was added.

Mr. Westerhausen sponsored Revised Petitioner's Exhibit No. CAW-S4, which is a revenue proof incorporating the agreed-to revenue requirement and the modifications in the Rates and Riders.

(d) John J. Spanos. Mr. Spanos supported the Settlement's modifications to the depreciation rates for NIPSCO's electric and common plant as of June 30, 2010 which he recommended in NIPSCO's case-in-chief. He sponsored Petitioner's Exhibit No. JJS-S2 showing the results of his Depreciation Study, as modified to reflect the changes provided by the Settlement.

Mr. Spanos testified the updated pro forma depreciation expense is $4,905,389 less than the original study would have produced. He testified the updated rates are based on the same methods and procedures used in the original study. He stated the only changes relate to net salvage percents for steam production, station equipment and distribution poles. He noted that the calculation of appropriate depreciation accrual rates involves, among other things, the application of informed engineering judgment. He testified the modifications to the accounts are minor and are reasonable in the exercise of that informed engineering judgment and, as a result, he supports them.

B. OUCC's Evidence in Support of Settlement. Tyler E. Bolinger, Director of the Electric Division for OUCC provided testimony in support of the Settlement. Mr. Bolinger testified that, if approved, the Settlement would bring to an end three years of litigation and provide certainty around critical issues, including revenue requirements, authorized return, the earnings bank, and the allocation of revenue requirements among NIPSCO's various rate classes. He stated that the Settlement provides a reasonable balance between utility and ratepayer interests, and provides for the establishment of new base rates for NIPSCO retail electric service for the first time since 1987. Mr. Bolinger explained that the general preference for settlement over litigation is particularly appropriate given the challenges faced in a NIPSCO base electric case. He noted several of the unique challenges presented in this case, including:

- NIPSCO's existing base rates are nearly 25 years old.
- Few, if any, NIPSCO electric ratepayers actually paid NIPSCO's full tariffed rates during the entire test year in this Cause. Thus, evaluation of existing rates is complicated by the need to account for the numerous discounts and credits that customers have received.
- NIPSCO has decided to move away from special contracts with Industrial customers; many Industrial customers were faced with the prospect of both the loss of contract discounts and a move back to increased tariffed rates.
- NIPSCO's service territory is a major global manufacturing center with numerous customers competing in global markets.
- As a global manufacturing center, NIPSCO's territory has been hard hit by the severe global recession, with many persons suffering unemployment and poverty.

- NIPSCO has extraordinary diversity in its customer base, which goes beyond the usual differences between large and small users. *Id.* pp. 4-5.

Mr. Bolinger concluded that absent the Settlement, the Commission (and likely the Courts) would have to grapple with these challenges for an extended period of time, perhaps a number of years of litigation. He described the balance in the Settlement as "delicate," and strongly recommended approval. He supported the Settlement's proposed revenue requirement and emphasized that the Settlement finally brings about a clear resolution of the contentious issue of allocating the revenue requirement between the various rate classes. He testified that the certainty of a mutually agreeable revenue allocation is a major benefit of the Settlement from OUCC's perspective.

Mr. Bolinger testified that Rider 675 (Interruptible Industrial Service) is a key part of the "delicate balance" in the Settlement. He indicated that OUCC supports Rider 675 as a reasonable part of the Settlement. He explained that interruptible service options enable customers to create value for the overall system by agreeing to interruptions to enhance reliability and/or to reduce the need for the utility to purchase energy in the market at times of scarcity and relatively high market prices. This should over time enable the utility to avoid both capacity and purchased energy costs. He also explained OUCC's position that it is reasonable to consider the fact that some customers have made significant investments to enable interruption of their production processes on very short notice.

Mr. Bolinger concluded by summarizing the many benefits of the Settlement and noting that the Settlement "...moves NIPSCO away from the *status quo* of decades-old base rates combined with an amalgamation of special contract discounts and rate credits. This move toward the transparent provision of service through tariffed rates is appropriate for a utility operating in a fully regulated retail electric jurisdiction."

C. Industrial Group's Evidence in Support of Settlement. Industrial Group presented the testimony of Nicholas Phillips, Jr. and James R. Dauphinais, consultants with the firm of Brubaker & Associates, Inc.

(a) Nicholas Phillips, Jr. Mr. Phillips testified regarding the ratemaking and policy issues involved with the Settlement. He recommended approval of the Settlement because it is based on appropriate regulatory policy and sound ratemaking principles. He explained the Settlement is a comprehensive agreement that resolves both revenue and the complex allocation and rate design issues, including the precipitous industrial sales decline due to the economic slowdown, the extraordinary length of time since new base rates were implemented, the proposed elimination of various rates and the expiration of special contracts. He added that the Settlement also terminates issues from NIPSCO's 2008 electric rate case in Cause No. 43526 ("2008 Rate Case") and supersedes other provisions of the 43526 Order. Mr. Phillips stated the Settlement should be approved for the following reasons:

1. The Settlement is fair, reasonable and in the public interest;

2. The Settlement mitigates the increase to the residential class and results in a lower percentage increase to the residential class when compared to the increase resulting from the 43526 Order;

3. The Settlement contains an array of industrial rate offerings that collectively provide a reasonable opportunity for NIPSCO's large customers that are subject to global competition to manage power costs and remain a viable and necessary segment of the Northwest Indiana economy;

4. The Settlement eliminates any rate increase for municipalities that use NIPSCO's street and traffic lighting rate schedules; and

5. The Settlement is forward looking, and in his opinion, should lessen the need for another NIPSCO base rate filing in the near future.

(1) Background of NIPSCO's existing rates and charges. Mr. Phillips provided an overview of the relevant background associated with NIPSCO's rates and charges. He testified NIPSCO's current base rates were established by Order in Cause No. 38045 on July 15, 1987, or 24 years ago and included an interruptible rate. He said NIPSCO has been offering some type of interruptible rate for over 25 years and since the Order in Cause No. 38045, NIPSCO has implemented other rates and charges, including Rate 845 and Rider 846 (real time rates which are non-firm) to offer competitive rate options to its large industrial customers. During the hearing Mr. Phillips testified that in the past NIPSCO has had as much as 600 MWs of interruptible service under Rates 836 and 845. NIPSCO also offered special contract pricing options, which arose out of numerous situations. Mr. Phillips added that many of NIPSCO's industrial customers have or are capable of obtaining customer-owned generating facilities as an alternative to purchasing power from NIPSCO. He noted NIPSCO added Sugar Creek to increase the capacity of its generating portfolio in 2008.

Mr. Phillips also provided a brief background regarding NIPSCO's 2008 Rate Case. He explained that under a settlement agreement in Cause No. 42824, NIPSCO was required to file a base rate case using a 2007 test year by July 2008. Although the Commission issued an Order in Cause No. 43526 on August 25, 2010, the rates approved in that Order have not been implemented, and in a docket entry issued on April 25, 2011, the Commission stayed any further action on the 2008 Rate Case until after an Order in this case. Mr. Phillips added that there were numerous difficulties associated with the compliance rates in Cause No. 43526 including a large residential increase and issues with firm and interruptible industrial rates.

(2) Importance of NIPSCO's industrial customers. Mr. Phillips described the importance of NIPSCO's large industrial customers to the economic viability of both NIPSCO and the NIPSCO service area. He testified that NIPSCO's large industrial customers make up a substantial percentage of NIPSCO's electric load. He added the members of the Industrial Group employ over 18,000 people, not including contractors and others who derive employment from serving Industrial Group member companies and facilities, which results in extensive indirect employment from large industrials. As such, the members of the

Industrial Group are some of the largest employers in the NIPSCO service area and their economic viability has a ripple effect on NIPSCO's commercial and residential customers as well. Mr. Phillips explained that many of the smaller industrial and commercial businesses in NIPSCO's service area are dependent on the viability of NIPSCO's large industrial customers. He said a downturn in the productivity of NIPSCO's large industrial customers has a negative impact on NIPSCO's overall revenues and a downturn in their production also has a significant impact on the unemployment rate in Northwest Indiana and the economic viability of smaller industries and businesses. He said these large customers compete not only nationally but globally for business and sometimes even within their own corporate structure as to other plant locations for the companies. He testified that keeping the large industrial customers' operating costs competitive in Northwest Indiana is vital to keeping the existing customers there and attracting new industry.

(3) Reasonableness of the Settlement. Mr. Phillips said the Settlement resolves the complex issues in this case and provides for the conclusion of the 2008 Rate Case in a reasonable manner and serves the public interest. He testified that absent the Settlement, the Industrial Group would have presented testimony on revenue requirement, cost of service and revenue allocation, rate design and NIPSCO's proposed rules. He emphasized that the Settlement was a result of lengthy and arms-length negotiations between the Settling Parties in order to reach a comprehensive settlement and the Settlement was within the range of outcomes that might reasonably be expected if the case had been fully litigated.

Mr. Phillips explained how the Settlement addresses the needs of NIPSCO's large industrial customers. He noted the Settlement results in an increase in rates for NIPSCO's largest customer classes (632, 633 and 634) of more than 20%, but that the overall settlement package provides tools to allow the large customers to try to mitigate the increased cost. He said both Riders 675 and 676 provide options to allow some of NIPSCO's largest customers to mitigate the increased cost. He explained Rider 675 allows NIPSCO's large customers to assess the level of risk that they are willing to take in receiving non-firm service in exchange for demand credits while, at the same time, increasing the options for interruptible service provides additional flexibility to NIPSCO in managing its capacity needs, resulting in savings to all customers. He said Rider 676 provides back-up, maintenance and temporary service to allow those customers with their own generation to efficiently rely on it, again reducing demand on NIPSCO's system.

Mr. Phillips also described the revenue allocation to classes under the Settlement. He testified the basic starting point of the revenue allocation to classes was an across-the-board approach but modified for various rate class mitigation. He noted an across-the-board approach was proposed by NIPSCO in its case-in-chief filing after large industrial customers were migrated to full firm tariffs.

Mr. Phillips explained that the basis of an across-the-board approach is to allocate an even percent revenue increase to all customer classes, rather than an allocation method based on a cost of service study, and that an across-the-board approach basically preserves existing rate relationships. He added that in some cases mitigation is appropriate to prevent rate shock for some customer classes. He said with regard to NIPSCO's case, the unique facts and circumstances made the use of actual test year load data, which were distorted by the impacts of the most severe recession in a generation, challenging in any cost of service study proposed.

He explained that the information required for the cost of service studies NIPSCO presented, and that would have been presented by the Industrial Group if litigation had continued, was subject to the uncertainties associated with customers operating during a severe recession and from customers operating on rate schedules that were being eliminated or contracts that have or will expire. As an example, he said load data at time of one-hour monthly system peaks during the test year may be based on abnormal data due to the severe economic downturn. He explained another problem is that customers on Rate 845, Rate 836 or a special contract during the test year were migrated to a firm rate under NIPSCO's proposed rate structure and it is difficult to estimate or assume exactly how a customer being migrated from a non-firm rate or special contract would operate under a different rate schedule with different price signals. He added that as in the 2008 Rate Case, NIPSCO had to make various assumptions in migrating special contract customers' loads during the test year to existing tariffs. NIPSCO had to make additional assumptions in migrating those customers' loads currently on Rates 836 and 845, or customers who would have migrated to those rates, to firm rates. He said these various factors created obstacles for any cost of service study. Mr. Phillips testified that although NIPSCO performed various cost of service studies with various sensitivity analyses, the sensitivity analyses were not all inclusive.

With regard to interruptible service, Mr. Phillips testified that customers opting for interruptible options have previously received a credit to firm load for allocation purposes. In this case, NIPSCO proposed to eliminate any interruptible rate schedules and move all customers to firm rates. Consequently, the allocation of credits for interruptible service was not part of NIPSCO's filed cost study. Instead, Mr. Phillips noted that the interruptible service options were being offered through Rider 675. For all of these reasons, Mr. Phillips testified that the Settling Parties utilized an across-the-board approach modified for residential mitigation and other considerations to achieve the revenue allocation and resulting rate increase to classes.

Mr. Phillips testified that the revenue allocation resulting from the Settlement is reasonable in his opinion. He said that, as NIPSCO stated in its case-in-chief, a driving factor for its proposal in this case was to help mitigate the impact on the residential class that would have resulted from implementation of the rates approved in Cause No. 43526. He indicated that concern was also a primary goal in the settlement negotiations and ultimate Settlement.

Mr. Phillips also testified that in his opinion, the rate design agreed to in the Settlement is reasonable. He said that to resolve certain rate design issues that existed in the 2008 Rate Case, NIPSCO utilized the current 800 Series rate structures as guides in this case instead of the completely new rate structure concept that caused many concerns and unexpected levels of increase to some customers in the 2008 Rate Case. He said maintaining the current 800 Series rate structures, with some modifications, avoids the concerns and unexpected results to some customers that existed in the 2008 Rate Case. He testified NIPSCO and the members of the Industrial Group were able to work constructively together to arrive at a rate design that achieved both NIPSCO's revenue requirements and the customers' operating concerns.

Turning to particular rates, Mr. Phillips explained that Rate 625 maintains the basic current structure in Rate 825, which the metal melting customers have operated under for over 20 years. Mr. Phillips also said those members currently on Rate 832 and those likely to move to Rate 632 from special contracts along with current Rate 833 customers and those who will ultimately migrate to Rate 633 were actively involved in the rate design changes for these rates that are part of the Settlement. Specifically, the rate design for Rates 632 and 633 were explicitly designed to work with Riders 675 and 676 to allow those customers to mitigate the impacts of the increase resulting from this rate case to those rate classes and also to provide operating flexibility. The Settlement also maintains the high load factor industrial rate and a lower load factor industrial rate which are present in the 800 Series rates. He explained that the new Rate 634 was also a collaborative effort between NIPSCO and the customer qualifying for that rate to address that customer's unique operations and also is designed to work with Option D in Rider 675.

He testified that while Rate 845, Rider 846 and Rate 836 were being eliminated, the new interruptible rider was being offered in the place of those rate structures. In his opinion, the interruptible rate structure in the Settlement should gain customer acceptance and lessen the need for additional generation on the NIPSCO system in the near future. Mr. Phillips testified the Settlement comprehensively addresses temporary power, back-up and maintenance power, which issues were not fully addressed in the 43526 Order.

He said that while a rate increase to industrial customers is difficult in this economic climate, the rate offerings in the Settlement provide a reasonable opportunity for customers to remain competitive in the global marketplace and remain as a necessary ingredient to the Northwest Indiana economy.

Mr. Phillips added that the Settlement also addresses the ongoing dispute between NIPSCO and the Industrial Group regarding the deposit rule for non-residential customers. He said this issue was raised in the 2008 Rate Case and has also remained unresolved in NIPSCO's gas rate case proceeding. He testified NIPSCO and the Industrial Group were able to reach a consensus on the objective, non-discriminatory criteria for requiring a deposit from an existing non-residential customer and also from a new customer. He added the Industrial Group and NIPSCO were able to reach agreement on other changes to some of NIPSCO's proposed general rules and the standard contract which would have been at issue if this case had been fully litigated.

Mr. Phillips concluded that the Settlement, when taken as a complete package, reasonably resolves the Industrial Group's issues in this rate case and results in a fair and reasonable resolution for all of NIPSCO's customers. He said the Settlement provides for rate mitigation for the residential class, provides rate options that allow NIPSCO's large industrial customers to help mitigate the impact of the increases they will experience as a result of this rate case and movement from special contracts, helps large industrial customers more efficiently operate their production, helps NIPSCO mitigate the need for additional capacity, allows NIPSCO to receive sufficient revenues to efficiently and economically provide service within its service area, and helps maintain the economic stability of NIPSCO's large industrial customers and the economic viability of the entire area. He said the Settlement is a comprehensive agreement and each term within the Settlement is essential to the overall reasonableness of the agreement and therefore he recommended the Commission approve the Settlement without any material changes.

(b) James R. Dauphinais. Mr. Dauphinais testified in support of NIPSCO Riders 675 and 676 under the Settlement. Mr. Dauphinais explained Rider 675 provides for interruptible electric service for large industrial customers and Rider 676 provides for back-up, maintenance and temporary electric service for large industrial customers. He emphasized the two riders are fundamental and critical components of the Settlement in light of the increases for large customers. Mr. Dauphinais noted the percentage base rate increase for large industrial customers of 20.317% on average for Rates 632, 633 and 634 compared to the general service class increase of 10.5864% on average for Rates 621, 623 and 624 and the residential customer class increase of 4.788% for Rate 611. He added that certain special contract industrial customers will be seeing increases well in excess of the 20.317% class average increase for Rates 632, 633 and 634. He stated Riders 675 and 676 are critical toward providing large industrial customers an opportunity to manage and partially mitigate these large base rate increases. Mr. Dauphinais testified the two riders are reasonably based on cost of service but also represent a keystone to the compromises that were arrived at by the Settling Parties in the Settlement. He urged the Commission to consider the Settlement as a complete package rather than isolating particular aspects of the Settlement from other aspects of the Settlement. He recommended the Commission find that Riders 675 and 676 in the Settlement are reasonable and approve the Settlement as filed in its entirety.

(1) Rider 675. Mr. Dauphinais provided an overview of Rider 675. He stated, historically, a number of NIPSCO's largest loads have received service on an interruptible basis, which allowed NIPSCO to avoid building or buying generation capacity to serve those loads. At the hearing, Mr. Dauphinais discussed both Rate 836 and Rate 845, which is a non-firm rate and under which customers pay the highest incremental fuel price. As such, it is basically a self-interrupting rate. He stated with NIPSCO's decision to avoid new special contracts for such loads and to migrate customers to firm tariff rates, addressing the rates, terms and conditions for interruptible service became a central issue that the Settlement comprehensively resolves in Rider 675. Mr. Dauphinais testified that Rider 675 offers a menu of curtailable (reliability) and interruptible (economic) service options that provide substantial value to NIPSCO and its firm service customers. He explained customers that commit to service pursuant to Rider 675 receive varying credits to the demand component of their bill in exchange for a lower quality of service relative to firm customers. He said Rider 675 provides an opportunity for Rate 632, 633 and 634 customers to lower their electric rates through demand charge credits by taking interruptible rather than firm service for all or some of their load, while at the same time providing lower costs to NIPSCO's other customers by lowering NIPSCO's costs for electric generation capacity and lowering NIPSCO's fuel and purchased power costs.

Mr. Dauphinais explained that total participation in Rider 675 is limited to 500 MW of interruptible capacity and that no more than $38.0 million in total demand charge credits will be paid to Rider 675 customers in any calendar year. He compared these limits to NIPSCO's Rider 581 as approved in the 43526 Order, which also was limited to 500 MW of participation, but authorized a higher level of credits to be recovered from firm customers of up to $40.5 million per year rather than the maximum of $38.0 million per year specified in Rider 675.

He also described the four different Rider 675 service options – Options A, B, C and D that provide various levels of demand charge credits based on the level of interruptibility for which an individual customer commits to provide. Mr. Dauphinais testified compensation under Rider 675 can be best thought of as being similar to that under Rider 581 except that, to the benefit of participating customers, they are not forced to try to fit into the "one size fits all" $6.75 per kW-month demand credit and interruptibility provisions of Rider 581, which also benefits NIPSCO and NIPSCO's firm customers.

Mr. Dauphinais described Option A, which requires a participating customer to be subject to reliability curtailments pursuant to the MISO requirements for Demand Resources with the exception that participating customers must be curtailable on four hours of notice rather than the less strict MISO requirement of 12 hours. The minimum contract term for Option A is only one year. He added that participating customers are not subject to economic interruptions under Option A and during reliability curtailments, participating customers curtail their demand down to their firm service level.

Mr. Dauphinais described the value provided to NIPSCO and its firm customers by customers participating in Option A. He explained that due to its short one year minimum commitment, Option A participation cannot be included in NIPSCO's long-term resource planning and, like short-term capacity purchases, cannot be relied upon by NIPSCO to be available year-to-year to maintain reliability and therefore does not provide the same capacity value as a new generation facility. However, he explained Option A participation does provide some benefit in allowing NIPSCO to reduce its near-term need for electric generation capacity and reducing NIPSCO's fuel and purchased power cost during system emergencies when reliability curtailments are called from Rider 675 Option A customers. He said the latter can be significant during a system emergency as it is possible under such conditions that MISO could be inducing scarcity pricing of up to $3,000 per MWh. Consequently, during the curtailment NIPSCO would be avoiding the purchase of any power at this price to serve the interruptible portion of the participating customers' load. He added that during emergencies, the curtailment of Rider 675 Option A customers will reduce the likelihood that NIPSCO's firm service customers will face involuntary curtailments of service.

Mr. Dauphinais testified that a demand charge credit of $1.00 per kW-month will be paid to Option A participants and, starting every subsequent February 1, NIPSCO will update the amount of the credit, subject to Commission approval, to reflect the current annual market price for capacity as determined by NIPSCO from market quotes from candidate bilateral market counterparties received in the preceding January. He explained that the compensation reflects most of the shorter term costs NIPSCO and its firm customers will avoid due to customer participation in Option A. He said the one year is long enough for NIPSCO to avoid the market price for the generation capacity requirement under MISO's resource adequacy requirements due to NIPSCO being able to claim Option A participating customer load as a MISO Demand Resource. He stated the $1.00 per kW-month amount represents NIPSCO's rough estimate of recent prices for short-term electric capacity, which NIPSCO will update every year. He noted that no additional compensation will be provided to Option A participating customers for the fuel and purchased power savings they will provide to NIPSCO and NIPSCO's firm customers when curtailments are called during system emergencies, but when considered in the context of the overall Settlement, the Industrial Group considers the agreed upon level of compensation under Option A to be reasonable for settlement purposes.

Mr. Dauphinais testified that the annual market price for capacity is currently lower than the cost for a new generation facility because of the current size of generation reserve margins in the MISO footprint. He noted, however, that new generation capacity cannot be built overnight and the current annual market price for capacity is a temporary situation. He said experience has shown that short-term market prices for capacity do not reflect the expected long-term cost for generation capacity and that, typically, short-term market prices for capacity significantly understate the long-term value of capacity when excess capacity exists and dramatically overstate the long-term value of capacity when capacity margins are tight. He added there is great uncertainty regarding the future of the large, relatively old coal-fired generation fleet located in the MISO footprint due to the Environmental Protection Agency's ("EPA") recently released Utility Maximum Achievable Control Technology ("MACT") rule for hazardous air pollutants and Cross-State Air Pollution Rule ("CSPAR") for nitrogen and sulfur emissions as well as expected future EPA regulations regarding cooling water. He said if the EPA keeps the tight deadlines it has proposed in its rulemakings, it could rapidly lead to a significant amount of coal-fired generation retirements. As an example, he pointed to a December 2010 study by The Brattle Group identifying 16 to 20 GW of coal-fired generation in the MISO footprint as being vulnerable to retirement by 2020. He said this could result in a rapid reduction in generation planning reserve margins within the MISO footprint and cause the market price of electric capacity to rapidly rise.

He also noted that, as long-term wholesale forward markets for electricity begin to mature, the market price for electric capacity should trend toward the avoided cost of new generation facilities. He cautioned, however, that even in a mature market, the current annual market price for capacity may be substantially lower or substantially higher than the avoided cost for a new generation facility depending on the circumstances present in the year in question.

Mr. Dauphinais also explained Option B. He said like Option A, Option B requires a participating customer to be subject to reliability curtailments pursuant to the MISO requirements for Demand Resources with the exception that participating customers must be curtailable on four hours of notice rather than the less strict requirement of 12 hours under the MISO tariff. Option B participants are also required to provide up to 100 hours per year of economic interruptions within certain restrictions and are required to have a minimum contract term of three years rather than the one year of Option A. He said Option B customers must reduce their load down to a firm service level when reliability curtailments or economic interruptions are called.

Mr. Dauphinais testified that Option B allows NIPSCO to reduce its cost for electric generation facilities and reduces NIPSCO's fuel and purchased power costs when reliability curtailments are called during system emergencies and, more significantly, during the up to 100 hours per year that NIPSCO can call economic interruptions of Option B customer load. He explained that because Option B requires a minimum contract term of three years, NIPSCO can recognize Option B participation in its resource planning decisions. He added the three-year commitment is sufficient to extend past the typical lead time of a simple cycle combustion turbine generation facility (approximately two years) and roughly reaches out to the typical lead time for a new, combined cycle generation facility (approximately three years). He said with Option B participation, NIPSCO can avoid the cost for new generation facilities that are needed to assure reliability and hedge the market cost of electric capacity and energy. He testified the avoidance of such generation facility costs is important because utilities like NIPSCO cannot rely year-to-year on capacity always being available in the short-term markets to maintain reliability.

Mr. Dauphinais stated that Option B provides for a demand charge credit of $6.00 per kW-month to participants. He stated the $6.00 per kW-month credit moves closer to the cost of a new simple cycle combustion turbine generation facility, but noted that it does not provide any additional compensation for the fuel and purchased power cost savings that NIPSCO will see and pass on to ratepayers through lower FAC adjustments as a result of economic interruptions by Option B participants. He added the credit is also $0.75 per kW-month lower than the demand charge credit that would have been paid in Rider 581, under the 43526 Order. He said, because the Settlement also includes Options C and D for Rider 675, which provide the opportunity for greater levels of compensation in exchange for shorter interruption notice, greater interruptibility, and/or longer minimum contract terms, the Industrial Group agrees that the proposed compensation level for Option B is reasonable for settlement purposes.

Mr. Dauphinais testified to the current estimated cost of a new simple cycle combustion turbine generation facility based on the United States Energy Information Administration ("EIA") review of its new generation cost assumptions in 2010. The results of that review identified that the total project cost for a new CCGT in the Indianapolis area would range from $676 per kW to $988 per kW installed in 2010 dollars, excluding finance cost, depending on the size and construction type. *See* Exhibit JRD-2 at 8-4 and 9-3. A review of the same combustion turbines in the Chicago area ranged from $772 to $1,107 per kW installed. Mr. Dauphinais said the estimated fixed O&M cost ran from $6.70 per kW-year to $6.98 per kW-year, which averages to $885.75 per kW installed (without financing cost) with a fixed O&M cost of $6.84 per kW-year. *Id.* at 8-6 and 9-4. He then converted these values into an estimated monthly levelized cost assuming a 50/50 debt to equity ratio and a 10.2% ROE, to yield a levelized amount of $10.79 per kW-month, including income taxes and property taxes.

Mr. Dauphinais added this value needs to be adjusted upward to reflect avoided planning reserve margin requirements and transmission losses. He explained planning reserve margin is an additional amount of generation capacity a LSE, such as NIPSCO, must carry above its forecasted annual system peak load, plus transmission losses, in order to meet resource adequacy requirements. He said typically, planning reserve margins require 12% to 18% more installed generation capacity than a LSE's forecasted annual peak system load, plus transmission losses. He added that in MISO, the situation is a little more complicated because the MISO's resource adequacy requirements are specified in terms of Unforced Capacity ("UCAP") rather than Installed Generation ("IGEN"). He explained UCAP is the rated installed capacity of a generation facility derated down to reflect the expected forced outage rate of that generation facility. UCAP reflects both the size and expected availability of the resource. He stated that in UCAP terms, the MISO's planning reserve margin is currently 3.81%, but when adjusted into IGEN terms by the average forced outage derate of installed capacity, it amounts to approximately 12.06%, citing to MISO Planning Year 2011 LOLE Study Report, December 2010 at page 3.

Mr. Dauphinais testified that for resource adequacy requirement purposes, LSEs within the MISO footprint are allowed to exclude from their forecasted system peak load plus transmission losses their interruptible load that qualifies as a Demand Resource, along with the transmission losses associated with that Demand Resource. He said as a result, LSEs do not need to carry capacity for the planning reserve margin and transmission losses for that interruptible load and, therefore, every MW of interruptible load is worth the same amount of generation capacity plus the planning reserve margin and transmission losses associated with that interruptible load. As an example, he said if in IGEN terms the planning reserve margin is 12% and the transmission loss factor is 3%, for resource adequacy purposes, 100 MW of interruptible load that qualifies as a MISO Demand Resource is worth the same as 115 MW of installed generation capacity. He testified that adjusting his current estimate of the cost of new CCGTs to reflect planning reserve margin and transmission loss savings results in $12.38 per kW-month using MISO's current IGEN planning reserve margin value of 12.06% and MISO's estimated summer average system transmission loss factor of 2.4%.

Mr. Dauphinais also explained why his current estimated capacity value is higher than his estimated value in Cause No. 43526. He said his testimony in this case reflects more recent estimates from EIA and second, the total demand charge credit he recommended in Cause No. 43526 for curtailments and interruptions that are equivalent to those proposed here for Option B was $8.05 per kW-month. He noted that estimate consisted of a $6.75 per kW-month credit for reliability curtailments and an additional $1.30 per kW-month credit for those customers who elected to participate in economic interruptions. He stated that, in his 2008 Rate Case testimony, he selected a low-end estimate of capacity value of $6.75 per kW-month to be conservative and conservatively used the amortization method NIPSCO uses in its annual avoided cost price filing, which does not fully capture NIPSCO's levelized cost of new generation and does not count the planning reserve margin benefits of curtailments. He said he was conservative in estimating the reliability curtailment credit in that proceeding because he was recommending an additional credit to reflect the value of the economic interruptions being provided. Because the 43526 Order did not approve the additional demand charge credit, he said it is no longer reasonable to use a conservatively low estimate of capacity value for curtailments. He stated a more appropriate approach would be to average the four capacity savings values presented on page 57 of his direct testimony in Cause No. 43526, use the same amortization method he used in Exhibit JRD-3 in this proceeding, adjust the average value up to reflect avoided planning reserve margin costs and then, finally, adjust up the value to reflect losses. He explained the average of those four values is $8.34 per kW-month for capacity only and when adjusted to use his Exhibit JRD-3 amortization method the value is $11.12 per kW-month. *See* Exhibit JRD-4. He added that, with a 12.06% planning reserve margin and 2.4% transmission losses, the adjusted value is $12.52 per kW-month. *Id.*

Mr. Dauphinais went on to explain that his $12.38 per kW-month avoided generation facility capacity cost estimate does not include the fuel and purchased power cost savings NIPSCO and its firm customers will receive from economic interruption of Option B Rider 675 customers. He estimated the additional savings that will be provided to NIPSCO and its firm customers from economic interruption of Rider 675 Option B customers under current fuel and purchased power costs. He examined the cost difference between the economic interruption buy-through rate and the normal Rate 632, 633 and 634 energy rates for the market conditions from July 27, 2010 through July 26, 2011 during periods when economic interruptions would occur.

From that data, he estimated a savings of approximately $0.69 per month for every kW of economic interruptions for Rider 675 Option B customers. *See* Exhibit JRD-5. He noted that estimate is under current fuel and purchased power costs and that the savings provided to NIPSCO and its firm customers from the economic interruption of Option B participants would be greater under higher fuel and purchased power costs.

Mr. Dauphinais explained that Option C, while similar to Option B, differs in three very important ways. He said first, Option C participants must be able to interrupt or curtail their load with a one-hour notice rather than the four-hour notice of Option B; second, Option C participants must commit to a contract term of no less than seven years rather than no less than the three years of Option B; and third, NIPSCO can call an unlimited number of reliability curtailments and those curtailments are not limited in duration. He explained that these features allow Option C curtailments and interruptions to closely approximate, or in some respects exceed, the performance of NIPSCO's existing CCGTs.

Mr. Dauphinais gave an example of how Option C interruptions and curtailments can exceed the performance of NIPSCO's existing CCGTs. He testified that in response to NLMK Data Request 1-3, NIPSCO identified the expected forced outage rates of its Bailly, Mitchell and Schahfer combustion turbines to be no lower than 27% in 2010 (NLMK Cross Exhibit 2). He said in contrast, Option C curtailments, which must be made available within an hour, must be 100% reliable and available when called. If an Option C customer fails to fully perform in response to a curtailment request even one time, Rider 675 requires the customer be disqualified from Rider 675 for three years.

Mr. Dauphinais testified Option C provides a more flexible tool for NIPSCO to deal with reliability issues on its system because if a reliability problem develops, NIPSCO must wait on Option A and B curtailments for four hours, while NIPSCO can call on Option C curtailments in one hour. He added that, unlike with Options A and B, NIPSCO is not limited in regard to the number of Option C reliability curtailments it may call per 12 rolling month period. He said both of these attributes further decrease the likelihood NIPSCO will have to call involuntary curtailments of firm customer load during a system emergency. He added that, if market prices unexpectedly rise above NIPSCO's FAC benchmark price for purchased power, NIPSCO does not have to wait four hours to receive the benefit of economic interruptions from Option C participants because it can start receiving economic interruptions from them in one hour rather than four hours. He said the net effect of these differences is to make Option C participation provide flexibility closer to that of a generator.

Mr. Dauphinais also explained that the minimum term of seven years provides greater reliability and economic value to NIPSCO and its firm customers. He said NIPSCO can consider Option C participation in its resource planning out to a longer planning horizon than it can for Option B participation, and the longer the period covered the greater the likelihood that arrangement will successfully protect against extreme volatility in the capacity market since the likelihood of such volatility increases as the length of time considered increases.

Mr. Dauphinais testified that the demand charge credit of $8.00 per kW-month provided under Option C appropriately moves closer to the full avoided cost of a simple cycle combustion turbine generation facility in light of the reliability, short notice to perform and longer term commitment features he described. He added that, as with Option B, Option C does not provide discrete compensation for economic interruptions, which he estimated for Option C to be an additional $0.94 per kW-month above avoided capacity value under current fuel and purchased power costs. *See* Exhibit JRD-5. He said as a result, the demand charge credit provided by Rider 675 for this level of service is conservative compared to the total benefits provided to NIPSCO and its firm customers.

Mr. Dauphinais testified that Option D incorporates and expands upon all the benefits provided to NIPSCO and its firm customers by Options A, B and C. He explained, Option D is the same as Option C except in regard to four major areas. First, the notice for curtailments and interruptions is only 10 minutes rather than one hour; second, up to 200 hours of economic interruptions can be called versus the 100 hours of Option C; third, a minimum contract term of ten years is required rather than the seven years of Option C; and finally, the curtailments and interruptions under Option D are reductions down by a certain number of MW rather than a reduction down to a firm service level. He testified that these differences provide an even more flexible tool for NIPSCO to deal with reliability issues on its system because with the 10-minute notice under Option D NIPSCO does not need to wait the four hours of Options A and B, or even the one hour of Option C, for curtailments. He said this further reduces the likelihood NIPSCO will have to call involuntary curtailments of firm customer load during a system emergency. He added, the 10-minute notice for economic interruptions builds on Option C and further reduces the delay associated with receiving the benefit of economic interruptions when needed. He said the 10-minute notice combined with the additional 100 hours of economic interruptions required of Option D participants should alone provide additional fuel and purchased power savings for NIPSCO and its firm customers of approximately $0.61 per kW-month of optional interruptible load under current fuel and purchased power costs. He added this value is in addition to the $0.94 per kW-month in fuel and purchased power savings that is estimated from the Option C level of interruptibility.

Mr. Dauphinais explained that because the interruption notice is 10 minutes and interruptions are down by a specified amount of MW rather than down to a specified firm service level, the flexibility provided to NIPSCO under Option D rises to the point where NIPSCO may be able to use, or at least begin to analyze the possibility of using, Option D participation as a MISO Demand Response Resource to provide operating reserves. He said this offers additional potential value to NIPSCO and its firm customers. He added that, the 10 year minimum term for Option D builds further on the greater reliability and economic value benefit provided to NIPSCO and its firm customers from the seven year minimum term of Option C participation.

Mr. Dauphinais testified the combination of additional flexibility, additional economic interruptions and a longer contract commitment makes the demand charge credit of $9.00 per kW-month appropriate. He added the $9.00 per kW-month amount is also significantly less than the approximately $13 per kW-month demand charge credit currently paid under Rate 836, the closest current equivalent to Rider 675 Option D service. He testified that while it could be argued the compensation being provided to Option D customers falls short of the value being provided to NIPSCO and its firm customers, the Industrial Group agrees the proposed compensation is reasonable in the context of the overall Settlement because the customer who would utilize this service would also be able to benefit from the new Rate 634, which works in conjunction with Option D of Rider 675.

(2) Rider 676. Mr. Dauphinais testified Rider 676 as proposed in the Settlement explicitly provides for backup and maintenance service for cogeneration systems serving large industrial customers in addition to general temporary service. He added the proposed terms, rates and conditions for general temporary service have been made much more reasonable than those originally proposed in this proceeding. Rider 676 is only available to Rate 632 and 633 customers.

Mr. Dauphinais stated the federal Public Utility Regulatory Policy Act of 1978 ("PURPA"), as amended by the Energy Policy Act of 2005, was intended to encourage conservation and efficient use of energy resources, including the encouragement of Cogeneration and Small Power Production Facilities. He said the encouragement of cogeneration in particular reduces the amount of capacity utilities such as NIPSCO require to serve their customers and is environmentally friendly due to the very high efficiency of cogeneration facilities such as the Portside Cogeneration Facility.

Mr. Dauphinais explained that PURPA generally requires electric utilities to sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities (collectively, "QFs"). It also generally requires electric utilities to purchase electric energy from QFs. He said PURPA requires that FERC establish rules for just and reasonable rates for sales to QFs that also are in the public interest and do not discriminate against QFs. Similarly, it requires FERC to establish rules for the rates at which purchases are made from QFs such that they are just and reasonable to electric consumers of the electric utility, in the public interest, and do not discriminate against QFs. He noted the FERC's current rules for QFs are contained in of 18 CFR § 292.

Mr. Dauphinais testified the FERC rules, among other things, require the purchase of electric energy and capacity from QFs at a rate no greater than the cost the electric utility avoids by making the purchase. He said this ensures electric consumers do not subsidize QFs. As a result, electric consumers do not pay more for electricity than they would have if the utility had purchased the power elsewhere or generated the power in its own facilities.

He emphasized the FERC rules also require that the rates for Backup and Maintenance Power for QFs reflect the cost of service to provide such power. He said this includes reflecting the non-simultaneous nature of QF forced outages and the low likelihood of such outages during the electric utility's system peak, and includes the recognition of the coordination of QF scheduled maintenance outages with the scheduled outages of the electric utility's own facilities. He stated all of this helps to ensure that these rates are (i) just and reasonable and (ii) do not result in electric consumers subsidizing QFs. Mr. Dauphinais added the IURC's own Rule 4.1, Cogeneration and Alternative Energy Production Facilities, is meant to be consistent with, and expands upon, the FERC rules for QFs.

Mr. Dauphinais stated FERC defines Backup Power as:

> "Electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility." (18 CFR § 829.101(b)(9).)

and Maintenance Power as:

> "Electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility." (*Id.* at (b)(11).)

Mr. Dauphinais testified that there are two reasons why Backup and Maintenance Service is being explicitly provided for in Rider 676 in the Settlement. He said first, outside of defaulting to the applicable firm rate schedule, NIPSCO did not provide a standard tariff for backup and maintenance service in its original rate filing in this proceeding. Second, it resolves a long-standing problem regarding the lack of a standard NIPSCO tariff that is specifically designed for Backup and Maintenance Service. He explained that, previously, such service had to be negotiated on a case-by-case basis or taken as temporary service which NIPSCO only offered on an as-available basis. He said the addition of specific Backup and Maintenance Service provisions reasonably resolves these issues when taken in the context of the overall Settlement.

Mr. Dauphinais provided an overview of the Maintenance Service provisions. He explained Maintenance Service must be requested at least 30 days in advance of need and it may not be requested for days in the months of June, July, August and September. He said it also may not be requested for more than 60 calendar days in any 12-month rolling period. A qualifying request for Maintenance Service cannot be denied by NIPSCO, but Maintenance Service is subject to reliability curtailments prior to other firm customers being curtailed when curtailment of Rider 675 interruptible customer load is insufficient to address a reliability issue. He stated the demand charge for Maintenance Service is $0.44 per kW-day in January, May and December and $0.25 per kW-day in February, March, April, October and November. The energy rate is the same as that for Rate 632 or 633, as applicable. He said customers needing Maintenance Service in June, July, August and/or September or for more than 60 days per rolling 12 months must take such service under the Temporary Service provisions of Rider 676.

Mr. Dauphinais testified that for settlement purposes the Maintenance Service provisions of Rider 676 are reasonable because the provisions provide for standard tariff service specifically designed for maintenance service and the provisions "... take into account the extent to which scheduled outages ... can be usefully coordinated with scheduled outages of the utility's facilities" as required under 18 CFR Ch. I, § 292.305(c). He noted Maintenance Service only can be taken during months of the year when NIPSCO will have spare capacity due to lower loads, and the proposed demand charges reflect the greater amount of spare electric capacity

NIPSCO will likely have in February, March, April, October and November. He added the proposed $0.44 per kW-day and $0.25 per kW-day demand charges are respectively equivalent to pro-rated monthly demand charges of $13.38 per kW-month and $7.60 per kW-month, which represent a reasonable contribution to NIPSCO's fixed costs for a service not driving NIPSCO's generation capacity needs.

Mr. Dauphinais also described the Backup Service provision of Rider 676 in the Settlement. He explained that Backup Service is only available to backup cogeneration systems serving large industrial customers that meet certain minimum efficiency standards. Customers must provide initial notice of a request for Backup Service within 60 minutes of the loss of generation and the customer is required to, on an ongoing basis, provide an update to NIPSCO on the generation outage. He said the Backup Service provisions may only be used for up to 45 calendar days per cogeneration system per 12 rolling months and, like with Maintenance Service, NIPSCO cannot deny a qualifying request for Backup Service, but service is subject to curtailment before other firm service when curtailment of Rider 675 interruptible load is insufficient to address a reliability issue. He stated the daily demand charge for Rider 676 Backup Service is a proration of the Rate 632 or 633 demand charge, as applicable, and the energy charge is equal to the real-time MISO LMP for the NIPSCO load zone, plus a non-fuel energy charge of $0.0035 per kWh.

Mr. Dauphinais testified for settlement purposes the Rider 676 Backup Service provisions are reasonable because the Backup Service provisions provide a significant contribution to NIPSCO's fixed cost and the payment of energy at LMPs plus an adder rather than NIPSCO's Rate 632 and 633 average fuel cost charges. He noted it could be argued the energy charges should be based on something closer to average fuel cost rather than potentially much higher LMPs, but when taken in context of the overall Settlement, including the Maintenance Service and revised Temporary Service provisions of Rider 676, the Industrial Group agrees the Backup Service provisions of Rider 676 are reasonable for settlement purposes.

Mr. Dauphinais also described the Temporary Service provisions of Rider 676 in the Settlement. He testified Temporary Service is available by request from NIPSCO but, unlike with Maintenance Service and Backup Service, NIPSCO can deny a request for Temporary Service if the day-ahead LMP for the NIPSCO load zone exceeds NIPSCO's purchased power benchmark price under its FAC. He added, a customer can elect buy-through Temporary Service if its Temporary Service request is denied, provided NIPSCO has not initiated a reliability curtailment on its system. He noted Temporary Service that is granted by NIPSCO is subject to reliability curtailments before the curtailment of other firm customers when curtailment of Rider 675 interruptible load is insufficient to address a reliability issue. He said there is no limit on the length of time Temporary Service is taken, but the demand charge for granted Temporary Service becomes progressively larger the longer the service is taken in any 12-month rolling period. As an example, he noted the demand charge for the first 30 days of service is $0.58 per kW-day (effectively $17.64 per kW-month prorated), while the demand charge after 90 days of service is $2.32 per kW-day (effectively a very large $70.57 per kW-month prorated). He added the demand charges do not apply to buy-through Temporary Service. He said accepted Temporary Service requests pay the Rate 632 or 633 energy rate, as applicable, while buy-through Temporary Service pays an energy rate equal to the real-time LMP for the NIPSCO load zone plus a non-fuel energy charge of $0.0035 per kWh.

Mr. Dauphinais stated that for settlement purposes the Temporary Service provisions of Rider 676 are reasonable because the proposed provisions reasonably provide a significant contribution to NIPSCO's fixed costs that strongly discourages usage as the length of service taken grows longer, while providing access to energy at average fuel cost when the day-ahead LMP is below NIPSCO's FAC purchased power benchmark price. He said that as such, the provisions are reasonable when taken in the context of the overall Settlement.

Mr. Dauphinais summarized his conclusions and recommendations, stating Rider 675 and 676 as proposed in the Settlement are reasonable in the context of the overall Settlement and are fundamental and critical components to the Settlement that provide large industrial customers, the rate class taking the largest percentage base rate increase under the Settlement, a reasonable opportunity to mitigate that increase. He recommended the Commission accept the Settlement as filed in its entirety.

9. Testimony Opposing the Settlement. Hammond presented the testimony of Reed W. Cearley opposing certain aspects of the Settlement. Mr. Cearley summarized his understanding of Rider 675 and stated that the Commission should not grant NIPSCO any "pre-approval" for the recovery of demand credits under Rider 675. He testified that the amount of interruptible service made available by NIPSCO should not exceed NIPSCO's actual need for capacity or "hedging," and that the value placed on interruptible service in Rider 675 is "overstated and excessive." He testified that the cost for interruptible credits associated with reducing capacity costs should be passed solely through the RA Tracker, and the cost for interruptible credits paid for economic interruptions should be passed solely through the FAC. He offered his opinion that the RA Tracker provides for a prudency review of "all charges related to NIPSCO's capacity purchases," including those costs associated with Rider 675.[7] Mr. Cearley compared NIPSCO's Hedging Plan, approved in Cause No. 43849, and the credits paid pursuant to NIPSCO's Rider 675 tariff offering. He stated that transactions entered into, consistent with the requirements of Rider 675, would be subject to prudency reviews in each RA Tracker and FAC periodic filing, rather than be approved in the rate case. Mr. Cearley noted that the Settling Parties agreed that a division of the Rider 675 credits was appropriate, with 75 percent being recovered in the RA Tracker and 25 percent being recovered in the FAC, but he suggested that credits for Option A should only be recovered in the RA Tracker, while costs associated with economic interruptions, should be passed through the FAC. Mr. Cearley quoted Mr. Dauphinais' testimony from Cause No. 43526, wherein he explained that interruptible service offerings may count as a Load Modifying Resource for purposes of MISO's capacity requirements, and therefore allow NIPSCO to avoid generation capacity or acquisition costs. Mr. Cearley cited NIPSCO's 2009 Integrated Resource Plan ("IRP"), of which the Commission took Administrative Notice. Mr. Cearley noted that in the 2015 to 2018 timeframe, NIPSCO expected to need two additional combustion turbine resources. With regards to economic interruptions, Mr. Cearley testified that because NIPSCO has a plan to hedge 50 percent of its projected MISO purchases, its spot market exposure is limited. He also stated that the rates being paid for the interruptible credits were too high. Mr. Cearley argued that a new CT would offer significantly greater hedging value than Rider 675.

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[7] Intervenor Hammond Exhibit RWC, at 6.

Mr. Cearley noted that the allocation methodology proposed by the Settling Parties for Rider 675 is "unfair and discriminatory." Mr. Cearley suggested that the rate increase for all residential customers be limited to 4.5 percent. Finally, he stated that commercial and industrial customers should have the accrued interest on their deposits applied to their bills "one time per year."

10. Settling Parties Rebuttal Testimony. NIPSCO witness Shambo, OUCC witness Bolinger and Industrial Group witness Dauphinais all presented testimony responding to Mr. Cearley's testimony opposing the Settlement.

A. Frank A. Shambo. In his settlement rebuttal testimony, Mr. Shambo addressed three issues: (1) the appropriateness of Rider 675, (2) cost allocation within Rate 611, and (3) the unreasonableness of a requirement that NIPSCO refund accrued interest on customer deposits on an annual basis.

Mr. Shambo testified that Rider 675 is but one part of the Settlement and should not be considered in isolation from the balance of the agreement. He stated that Mr. Cearley is confusing NIPSCO's purchase of capacity in either the bilateral or MISO market with its offering of a tariff, which includes credits for customers agreeing to a curtailable and/or interruptible service. According to Mr. Shambo, while NIPSCO agrees that the prudence of any capacity purchases should be reviewed in the RA Tracker, the time to undertake a review of recovery of credits paid pursuant to a Commission-approved tariff is in the context of a general rate proceeding.

Mr. Shambo testified that Rider 675 does not give NIPSCO discretion to decide on a case-by-case basis whether to enter into an interruptible contract. If there is room under the $38 million cap, Rider 675 would require NIPSCO to enter into a contract requested by any eligible customer, subject to allocation procedures. He stated that because tracker proceedings are summary in nature, Mr. Cearley's proposal that recovery of the demand credits be dependent on after-the-fact prudence reviews in RA Tracker and FAC Tracker proceedings is not appropriate. Mr. Shambo stated that summary tracker proceedings are not vehicles to review and change tariffs. Further, he contrasted the Settlement's tracker mechanism with the alternative of including a level of credits in base rates as was ordered in Cause No. 43526. Under the 43526 Order methodology, a credit of $6.75 per kW-month for up to 500 megawatts of interruptible load is to be embedded in NIPSCO's basic rates. To the extent it is not fully used, the Commission instructed NIPSCO to credit any remaining amounts through the RA Tracker, and the Commission made an explicit finding that up to 500 megawatts at $6.75 / kw-month was an acceptable level of credits. Mr. Shambo noted that the product of those two variables equates to $40.5 million, an amount that is actually greater than the $38 million maximum amount of credits agreed to in the Settlement. He testified that under the 43526 Order methodology there would be no prudence review. He explained that the result should be no different when the same goal is more accurately accomplished through inclusion in tracking adjustments. Mr. Shambo noted that this is consistent with the treatment of other Indiana electric utilities. For example, the Commission has approved Vectren South's Reliability Cost and Revenue Adjustment that recovers interruptible billing credits without a prudence review.

Mr. Shambo testified that summary tracker proceedings have traditionally been in place to review cost items that change from period to period, which is not the case with the proposed credits within Rider 675. He noted that the Commission has repeatedly stated that FAC proceedings are statutorily required to be summary in nature. According to Mr. Shambo, deferring reasonableness reviews of interruptible rate option credits and participation levels to summary proceedings such as the FAC and RA Trackers would promote further litigation and disputes over these issues. Furthermore, he testified that the Settling Parties have resolved these important items and desire a positive working structure coming out of this rate case. According to Mr. Shambo, the reasonableness of the proposed Rider 675 terms, conditions and credits should be determined as part of the Commission's review of the comprehensive Settlement. He testified that substantial evidence has been presented in this proceeding for the Commission to decide on the prudence of the requested recovery of the demand credits under Rider 675, and that the Settlement is consistent with the 43526 Order. Because of this, Mr. Shambo testified that now is the time to determine the prudence of Rider 675 and the various credits associated with the interruptible options.

Mr. Shambo testified that the methodology proposed by the Settlement is in fact more transparent than the mechanism approved in the 43526 Order because NIPSCO must first provide the credits and then receive recovery. According to Mr. Shambo, the proposal in this proceeding is also more transparent, in that customers are paying for the credits in a separate tracker rather than as a component of basic rates and charges. He testified that it should be apparent that the purpose of the stated limits on Rider 675 service (both total megawatts and total dollars) is to establish a reasonable structure within which NIPSCO can administer the interruptible service program with qualified customers. Consequently, according to Mr. Shambo, an after-the-fact prudence review that Mr. Cearley seeks is unnecessary.

Mr. Shambo testified that post-hoc reviews would also create unnecessary and unreasonable risk for the utility and its customers and that long-term agreements create more certainty for all interested parties. He noted that, while it is true that NIPSCO has no signed contracts regarding future interruptible service, a level of service can be inferred from current customer behavior. Mr. Shambo pointed to two examples: (1) NLMK's agreement to take 90 MWs of interruptible credits in its Bridge Contract approved by the Commission in Cause No. 43866, and (2) NIPSCO's current Rate 836 customer that has a substantial quantity of interruptible load (110 MWs) operating under NIPSCO's currently effective tariff at a credit above what is being offered in this proceeding.

Mr. Shambo testified that the allocation of 75 percent being collected through the RA Tracker and 25 percent being recovered through the FAC Tracker is also reasonable, reflects a careful balancing of the interests of all parties, and is supported by the evidence in this proceeding. He also noted that the dollar cap is reasonable and actually less than the amount approved in the 43526 Order. According to Mr. Shambo, the emphasis on interruptibility and energy efficiency has grown since the 2008 Rate Case, and this explicitly includes the provision of tools for customers to enable them to operate more efficiently and to manage their own electric bills. Mr. Shambo noted that the Commission has subsequently entered orders requiring various Demand Side Management ("DSM") goals to be achieved and the FERC has entered an order requiring MISO to further promote demand response options.

Mr. Shambo explained that the flaw in Mr. Cearley's analysis is his basic premise that everything should be compared to short-term markets. He testified that resource planning performed by any regulated utility bearing an obligation to serve all load must necessarily take a longer term approach that must be capable of accommodating increasing uncertainties. Mr. Shambo stated that Mr. Cearley's argument assumes that NIPSCO should wait until there is a gap that cannot be met easily by the market and then instantly build a new facility with no load costs. He testified that there are substantial risks from failing to be proactive. For example, when the markets move to an environment in which supply is tight, the price will increase dramatically and also present NIPSCO with operational challenges to providing reasonably adequate service to its customers. Mr. Shambo testified that the evidence in support of the Settlement demonstrates that there are continuing risks to this market situation and that the caps were established to limit exposure to non-interruptible customers. He indicated that, while it is uncertain how much demand exists and at what price / service combinations, this was also true when the Commission approved 500 megawatts at $6.75 in the 43526 Order.

Mr. Shambo testified that Mr. Cearley generally ignores imminent events that will reduce capacity, including estimates by the NERC that utilities could retire between 33 to 70 gigawatts of existing generation capacity by 2015 as a result of new EPA rules including, among others, the draft Clean Air Interstate Transport Rule (replaced by the final CSPAR issued by EPA on July 6, 2011) and the Utility MACT standards. North American Electric Reliability Corporation, 2010 *Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulation,* Oct. 2010 at 10. http://www.nerc.com/files/EPA_Scenario_Final.pdf ("NERC Report"). The NERC Report roughly estimates that the MISO footprint could see a 6%-9%+ reduction in adjusted potential capacity resources by 2018. *Id.* at 13. The NERC Report concludes that the estimated retirements of existing capacity across the nation could significantly decrease planning reserve margins and cause "considerable operating challenges." *Id.* at 41.

Mr. Shambo testified that, generally, future curtailments/interruptions cannot be predicted based upon past behavior and that the ability of NIPSCO to interrupt for economic reasons under Rider 675 is different than its ability to call for economic interruptions in the past. Mr. Shambo also noted that there were no buy-through provisions in the special contracts (other than the NLMK Bridge Contract), and, therefore, NIPSCO needed to be conscious of the fact that it was asking customers to drop load when it previously interrupted for economic reasons. Mr. Shambo testified that the Settling Parties have addressed these risks.

Regarding Mr. Cearley's comparison of the Settlement's proposed interruptible service to a hedging program, Mr. Shambo testified that the intent of NIPSCO's hedging program is to mitigate fuel cost volatility and not to shave the hourly price peaks. He noted that under the economic interruption program, if NIPSCO's customers buy through, they will not receive the benefit of pooled resources in the FAC. He stated that NIPSCO's current hedging program models the average on-peak MWhs that will be needed for each month and makes hedge purchases accordingly. Mr. Shambo noted that Rider 675's economic interruptions, however, are different and extremely valuable. He testified that, while Mr. Cearley apparently believes that NIPSCO will only economically interrupt if it is buying in the real-time market (i.e., load exceeds resources), NIPSCO in fact will only be doing so when it is advantageous to do so on behalf of its FAC customers. Mr. Shambo stated that, by giving NIPSCO the ability to essentially remove its interruptible customers from the FAC pool during those high priced hours, the Company will be able to consistently lower its fuel costs to the benefit of all other customers.

Mr. Shambo provided an example of market conditions experienced by NIPSCO in July of 2011 and the role existing interruptible customers played in mitigating the effects of those conditions. During the week of July 18, real-time hourly prices were at a substantially higher level than what had been seen previously. In particular, on July 21, real-time hourly prices reached as high as $454 per MWh with 8 of the 16 on-peak hours over $100 per MWh. According to Mr. Shambo, because NIPSCO was able to interrupt those customers who had an interruptible rate, NIPSCO was able to avoid purchasing power from MISO during these excessively high priced hours and thus lower the overall cost of power to the rest of its customers.

Regarding Mr. Cearley's testimony that the value placed on interruptible service for curtailments and for economic interruptions in Rider 675 is overstated and excessive, Mr. Shambo testified that some price needs to be established before a customer will sign for a service, and specifically, in regard to Option A, some price must be established for the first year to match a contract that a customer would sign. Furthermore, according to Mr. Shambo, NIPSCO must also know the price is recoverable before it is offered. He testified that the credit of $6.75 approved in the 43526 Order was for much more limited interruptions than Options C or D. It is more comparable to Option B, which is priced at $6.00.

In response to Mr. Cearley's argument that the proposed allocation of credits under Rider 675 is unfair and discriminatory, Mr. Shambo testified that customers are migrated to the services that most closely match their existing service. He went on to say that, to the extent NIPSCO is expanding the amount of interruptible service from that currently provided, existing customers should have first access, which is exactly what the Settlement provides. Mr. Shambo also said that limitations on available services frequently exist. For example, under NIPSCO's current 800 Series rates, only air separation facilities are eligible for interruptible service and even then it is limited to 110 megawatts (in combination with Rate 835), and the 43526 Order limited interruptible volumes to 500 megawatts.

The second area Mr. Shambo addressed was the cost allocation within Rate 611. He testified that although Mr. Cearley argues that the revenue requirement for Rate 611 would be better spread among Rate 611 customers so that the base rate increase is limited to 4.5%, it is a rate design issue driven by an increase in customer charge, rather than a cost allocation issue. Mr. Shambo testified that the Settlement includes an $11.00 customer charge, up from $5.95, which is a reasonable customer charge, comparable with other utilities in the state and the same charge to NIPSCO's residential gas customers.

Finally, Mr. Shambo expressed several concerns with Mr. Cearley's proposal that NIPSCO should be required to apply accrued interest on non-residential customer deposits to the customer's bill annually. First, he testified that the non-residential customer is required to timely pay its bill for 24 consecutive months to successfully request a return of its deposit, and to pay the accrued interest on an annual basis might be confusing to customers. Second, Mr. Shambo testified that he is aware of no utility in the State of Indiana that has such a requirement imposed upon them. Because of this, he stated that imposing such a requirement solely on NIPSCO, without any evidence as to why NIPSCO should be treated differently than the other utilities in the State, would be arbitrary and capricious. Finally, Mr. Shambo testified that customer deposits are included in NIPSCO's capital structure and serve to lower NIPSCO's required rate of return. Therefore, it is not correct for Mr. Cearley to say NIPSCO benefits by holding onto the accrued interest for as long as possible. He testified that to require NIPSCO to pay the accrued interest annually would increase the cost of the capital, without an attendant increase in NIPSCO's required rate of return. Mr. Shambo noted that, contrary to Mr. Cearley's testimony, the proposed rule does not provide for customers to request payment of the accrued interest on their deposits on a yearly basis. Mr. Shambo testified that the proposed rule provides that the interest accrues until the customer demonstrates its creditworthiness by having no delinquent bills, disconnections for nonpayment or bankruptcy filings over the last 24 months. The payment of interest is not dependent on an affirmative request by the customer, but it will automatically be paid when the deposit is returned or service is discontinued. Mr. Shambo agreed with Mr. Cearley that the rule provides for payment of simple (not compound) interest, but testified that is not unusual or inappropriate and is in line with the Commission's rules concerning residential customer deposits.

B. Tyler E. Bolinger. In his settlement rebuttal testimony, Mr. Bolinger addressed the issue of after-the-fact prudence reviews of Rider 675 contracts, as proposed by Mr. Cearley, who argued that recovery of NIPSCO's cost of providing interruptible credits should only occur after a prudence review of each Rider 675 contract transaction. Mr. Bolinger testified that it was not OUCC's intention or expectation that NIPSCO would be subject to a prudence review each time it enters into a contract under Rider 675. He explained that Rider 675 is a tariff offering that enables eligible industrial customers to elect to receive interruptible service in exchange for credits at levels established by Rider 675. Moreover, Rider 675 spells out the terms of eligibility, character of service, and the general terms and conditions of four different options (A through D). Mr. Bolinger testified that if Rider 675 is approved, then OUCC's review of Rider 675 contracts would focus on compliance with the terms of Rider 675. Public's Exhibit No. 1R, pp. 1-2.

Mr. Bolinger testified that, under Mr. Cearley's vision of Rider 675 prudence reviews, a party could challenge a Rider 675 contract as imprudent even if it strictly complied with the terms of Rider 675. Under this scenario, the Commission would be free to disallow costs as imprudent if, for example, it determined that NIPSCO entered into contracts in excess of some optimal or prudent amount even if NIPSCO was in full compliance with the terms of Rider 675, including the 500 MW cap.

Mr. Bolinger testified that OUCC would view contracts that comply with the tariff to be reasonable. OUCC's review of such contracts would focus on compliance with the Rider 675 tariff language. On-going review would focus on quantifying the cost of the credits and how they are recovered and on NIPSCO's management of the interruptible resources. Section B. 18. of the Settlement (p. 9) describes consulting resources available to OUCC to review (among other things) NIPSCO's use of interruptible resources.

Mr. Bolinger concluded that after-the-fact prudence reviews of each Rider 675 contract would inject tremendous uncertainty into the process for NIPSCO and eligible customers, which could undermine the Rider 675 program. Rider 675 is designed to transparently offer an approved tariffed service to eligible customers. If Rider 675 is approved, the Commission should make clear that NIPSCO and its eligible industrial customers can rely on NIPSCO's ability to offer its tariffed services without fear that the provision of tariffed service would later be deemed imprudent. *Id.*, p. 4.

C. James R. Dauphinais. In his settlement rebuttal testimony, Mr. Dauphinais first addressed the implications if Rider 675 under the Settlement was rejected or changed, including the underlying policy considerations for a usable interruptible service. He also addressed the approval procedure for Rider 675 credits, the need for and value placed on interruptible service for reliability curtailments and economic interruptions under Rider 675, and the proposed allocation of credits under Rider 675.

Mr. Dauphinais first noted it was ironic that, in many instances in his settlement testimony, Mr. Cearley referenced Mr. Dauphinais' direct testimony on NIPSCO's interruptible rate from Cause No. 43526. He said although Hammond was an intervenor in Cause No. 43526, at no time did Hammond raise any concerns with either the provisions of Rider 581 or NIPSCO's and the Industrial Group's testimony in that proceeding regarding those provisions. He added it cannot be denied the features for Rider 581 were inferior for firm customers versus comparable provisions in Rider 675. Mr. Dauphinais compared Rider 581 in Cause No. 43526 to Rider 675 under the Settlement. Rider 581 allowed:

- Up to 500 MW of participation with a total of $40.5 million in interruptible credits (versus the lower of 500 MW or $38.0 million in annual demand charge credits under Rider 675);

- A demand charge credit of $6.75 per kW-month for reliability curtailment and economic interruption requirements that are very similar to those under Option B of Rider 675 (versus the $6.00 per kW-month demand charge credit provided under Option B of Rider 675);

- A minimum term of three years (the same as for Option B of Rider 675); and

- Collection of $40.5 million annually in demand charge credits in advance by NIPSCO from customers entirely on a demand basis with unpaid credits refunded to customers through the tracker (versus no collection in advance for Rider 675 credits and recovery from customers of the cost of Rider 675 credits through a tracker on an energy and demand allocation basis).

Mr. Dauphinais testified that beyond these core features, the remainder of Rider 675 differs from Rider 581 primarily in that it reasonably provides greater flexibility in the form of Options A, C and D to allow eligible customers to choose the combination of curtailability, interruptibility and compensation that works best for them. He said the creation of this flexibility within the overall participation and cost limits of Rider 675 was a basic element of compromise among the Settling Parties in framing a comprehensive agreement.

Mr. Dauphinais stated that, conceptually, the addition of such flexibility for interruptible customers cannot be legitimately said to be unreasonable. He said if Rider 675 better meets the needs of interruptible customers, it will better optimize participation in Rider 675 to the benefit of NIPSCO and its firm electric customers. He stated the remaining issue then is whether: (i) the lower demand charge credit of Option A versus B is reasonably commensurate with avoidance of economic interruptions and shorter minimum contract term of Option A versus Option B, and (ii) the higher demand charge credits of Options C and D versus Option B are reasonably commensurate with the additional requirements placed on Option C and D customers versus Option B customers. He testified that both his direct testimony and his rebuttal demonstrate the change in demand charge credits under Options A, C and D versus Option B is in fact reasonably commensurate with the change in customer requirements under Options A, C and D versus Option B.

He added that another important consideration is that Rider 675 is an important part of the overall Settlement and parties comprising a wide variety of interests in this proceeding have worked hard together to produce the Settlement and have jointly asked the Commission to find that the Settlement, when considered in whole, is in the public interest. He noted that within the Industrial Group, there are a variety of interests, including firm customers who will be paying their share of the interruptible credits that Hammond is disputing. He also noted that his silence in regard to any issue raised by Hammond in this proceeding should not be interpreted as agreement with any position taken by Hammond regarding that issue.

He testified that clearly the interruptible service provisions of the Settlement are better for NIPSCO's ratepayers than the compliance rates NIPSCO filed in Cause No. 43526. He stated the total maximum level of interruptible credits recovered from ratepayers is reduced from $40.5 million under Rider 581 to $38 million under Rider 675; recovery of the interruptible credit is not included in base rates but is instead recovered 75% through the RA Tracker and 25% through the FAC; and the residential rate increase is significantly lower under the Settlement than it would have been under the compliance rates in Cause No. 43526, even when adding in the potential cost of full subscription of Rider 675. Rider 675 is more flexible and usable for potential interruptible customers than Rider 581.

Mr. Dauphinais added that Rider 675 is the result of NIPSCO's continuing discussions with its industrial customers, as the Commission directed NIPSCO to do in the 43526 Order. He said Rider 675 is one element of the Settlement through which the Settling Parties developed more narrowly tailored tariffs to meet the needs of both NIPSCO and its industrial customers and that he continues to recommend that the Commission approve the Settlement in its entirety as filed by the Settling Parties.

Mr. Dauphinais testified that while Hammond's testimony is crafted to avoid making specific recommendations, the combination of its prudency review and other arguments undermine the provision of any interruptible service. He said that he has focused his testimony on demonstrating that Hammond's suggestions have no merit because they are based on a flawed view of the capacity cost avoided through interruptible service and the value interruptible service provides to all customers, but that the broader policy implications of having interruptible service offerings should not be ignored.

He noted that scaling back interruptible service is not consistent with the Commission's broad policy objectives. He pointed to various proceedings in recent years on demand response initiatives, of which interruptible service is a part, and said the Commission has consistently supported expansion of such offerings.

(a) Recovery of Rider 675 Demand Charge Credit Costs Through the RA Tracker and FAC. Mr. Dauphinais responded to Mr. Cearley's argument that NIPSCO may not automatically recover any interruptible costs through its RA Tracker and FAC and that NIPSCO's granting of service to customers under Rider 675 should be subject to prudency review in those proceedings. Mr. Dauphinais explained that it was not the intention of the Settlement to require NIPSCO to demonstrate in its RA Tracker and FAC proceedings that it was prudent in its granting of service under Rider 675 to eligible customers for the obvious reason that the reasonableness of the provisions of Rider 675 should be determined at this time in this cause just as the Commission approved the provisions of Rider 581 in Cause No. 43526. He said the RA Tracker, which was approved in Cause No. 43526 for recovery of purchased capacity costs and to refund any unused interruptible credits, and the FAC were selected out of administrative convenience to avoid the need to establish a separate rate tracker for the recovery of the cost of interruptible credits. He explained Rider 675 does not grant NIPSCO the right to deny service to eligible customers until either the 500 MW or annual $38 million cap is reached and, as such, an adverse prudence determination can only be made against a utility when that utility has discretion. NIPSCO has no such discretion under Rider 675.

Mr. Dauphinais also testified that making interruptible service subject to prudency review was not consistent with how interruptible service has been provided in the past. He explained that NIPSCO has had tariffs offering interruptible service for over 25 years. In prior cases, the total amount of interruptible credits was reflected in base rates and not recovered through a rate tracker. Rather, the provision of interruptible service through base rates was considered in the base rate case and not subject to on-going prudency review. He said regardless of whether NIPSCO recovers credits through a tracker or instead includes the recovery of them in base rates, the service offered under the tariff is the same and the granting of that service to customers should not be subject to prudency review.

Mr. Dauphinais added that granting NIPSCO discretion to deny service to eligible customers under Rider 675 such that its decisions could be subject to prudence review in its RA tracker and FAC proceeding would be unprecedented, impractical and unduly discriminatory. He said the time to determine the reasonableness of a standard tariff rate of general applicability is when the rate is being approved by the Commission, as the Commission is doing in this proceeding for Rider 675 and the remainder of the Settlement tariff rates. Mr. Dauphinais stated Mr. Cearley had not identified any precedent in Indiana or any other regulatory jurisdiction where a utility must demonstrate the prudence of its decision to grant interruptible service to customers under a standard tariff rate of general applicability and that Mr. Dauphinais was not aware of any such requirement in any regulatory jurisdiction.

Mr. Dauphinais also explained why it is impractical to require prudence review of a utility's decision to grant interruptible service for an eligible customer under a standard tariff rate. He said first, utilities are not generally given any discretion to deny service to eligible customers under standard tariff rates of general applicability. Under such circumstances, a utility cannot possibly be found imprudent for granting such service. Second, such a prudency review requirement would effectively make the availability of interruptible service under a standard tariff rate very tentative, which would undermine any benefit provided by having a standard tariff for interruptible service. He said such a requirement would have a very chilling effect both in regard to economic development and economic retention in NIPSCO's service territory.

Mr. Dauphinais testified that most large industrial customers would expect an interruptible service offering in a service territory like NIPSCO's, which has one of the largest industrial bases of any utility in the country. He said potential manufacturers could skip over NIPSCO's service territory due to the lack of a true standard tariff rate of general applicability for interruptible service. He added the lack of such a true standard tariff rate also will reduce the attractiveness of continued operation by existing manufacturers in NIPSCO's service territory. He stated NIPSCO's large industrial customers, which are the ones most likely able to meet the interruptible requirements of Rider 675, not only compete globally, but also within their own corporate structure and that those customers evaluate shifting operations or production levels to other company locations with lower energy costs. He said the lack of an available standard interruptible rate could contribute to such a shift of operations or production levels. He testified that NIPSCO should seek to utilize the flexibility of the large industrial base in its service territory, rather than ignore the opportunities provided by it. He said Rider 675 better allows NIPSCO to utilize that flexibility.

Mr. Dauphinais explained that it is unduly discriminatory for a utility to be required to show the prudence of its decisions to grant service to eligible customers under a standard tariff rate for interruptible service because the effect is to have a utility treat captive retail customers that are potentially willing to accept interruptible service similar to sellers in the wholesale market. He stated that, as he has testified in the past before this Commission, industrial end-use customers are not generally in the business of selling interruptions and curtailments. He said industrial end-use customers are principally in the business to profitably produce their core product and when they curtail their energy consumption, these end-users can incur significant lost production costs and other costs they would not otherwise incur. He added these customers may also have to incur capital investments in order to take interruptible service. He said obviously it is not desirable to incur these costs, but if the reduced electricity cost for the customer resulting from agreeing to curtailment and interruption significantly exceeds lost production cost the customer will incur for the curtailment or interruption, the customer will generally be willing to curtail its consumption if it contributes to its goal of profitably producing its core product.

Mr. Dauphinais explained these end-use customers are not the same as merchants in the wholesale electricity market and as a result, the process of obtaining interruptible load cannot work the same way as for purchasing capacity and energy in the wholesale market. He said, instead, there needs to be standard tariff offerings of general applicability along with the option to negotiate customer-specific rates when unique circumstances justify such customer-specific rates. He added that the standard of avoiding undue discrimination requires the standard tariff rate of general applicability recognize differences in customer characteristics and needs. He said just as it would be unduly discriminatory to offer just a single standard tariff rate for all customers, so would it be unduly discriminatory to only offer a firm standard tariff rate to large industrial customers. He explained Rider 675 meets this need within reasonable limitations without making the availability of service tentative under the rate, whereas Hammond's proposal would undermine that availability and unduly discriminate against large customers who are interested in taking interruptible service.

Mr. Dauphinais also testified Hammond presented a very short-sighted view of the need for interruptible service and given the nature of the investments industrial customers need to make in order to sign up for interruptible service, they will tend to do so only in the context of a sustained interruptible service offering. He said Hammond's view that interruptible service might be offered at one level today and another tomorrow creates uncertainty for making these business decisions, and, therefore, increases the likelihood that industrial customers will not elect interruptible service. He said that this, in turn, would make continued operation in NIPSCO's service territory by these customers less viable and could lead to higher electric rates for all customers.

(b) Separation of Compensation for Reliability Curtailments and Economic Interruptions in Rider 675. Regarding Mr. Cearley's argument that the demand charge credit for reliability curtailments and economic interruptions should be separately stated and that participation in economic interruptions should be optional, Mr. Dauphinais testified the 75 percent demand, 25 percent energy allocation for the interruptible credits is part of the overall Settlement, and should not be criticized in isolation. He said when taken in the context of the overall Settlement, including the greater flexibility of the various options offered under Rider 675 versus Rider 581, the Industrial Group considers Rider 675 in the Settlement to be reasonable and it does not, at this time, need to be changed by separating out compensation for economic interruptions from reliability curtailments and making participation in economic interruptions optional. He added that the Settling Parties strived to make the core of Rider 675 (effectively Option B of Rider 675) very similar to Rider 581 in Cause No. 43526. He said in that proceeding, the Commission chose to make the economic interruptions under Rider 581 mandatory with no additional demand charge credit compensation for economic interruptions. He noted that while the Industrial Group does not necessarily agree with that approach, when taken in the context of the overall Settlement, the Industrial Group found it reasonable for settlement purposes to continue that approach in the Rider 675 provisions.

(c) Amount of Reliability Curtailments and Economic Interruptions Needed Under Rider 675.

(1) Reliability Curtailments. Mr. Dauphinais also responded to Mr. Cearley's argument that NIPSCO will need less than 225 MW of interruptible service for reliability purposes in the next few years. Mr. Dauphinais testified that there were a number of flaws with Mr. Cearley's observations, including the fact that NIPSCO's 2009 IRP was filed nearly two years ago on October 29, 2009 and may not reflect NIPSCO's current future needs for capacity. He added it was filed almost 10 months prior to the 43526 Order on August 25, 2010 approving up to 500 MW of interruptible service under Rider 581.

Mr. Dauphinais noted, even if NIPSCO's 2009 IRP remains a reasonable reflection of NIPSCO's future needs and resource plans, it called for the addition of 308 MW of simple cycle combustion turbine generation in 2015, the addition of 127 MW of simple cycle combustion turbine generation in 2020, 225 MW of interruptible load from 2011 through 2020 and approximately 130 MW to 140 MW of DSM from 2014 through 2020. He stated the 435 MW of combustion turbine generation additions could be avoided through additional interruptible load above 225 MW and added that, to the extent the 130 MW to 140 MW DSM goal is not realized, the shortfall could be addressed with yet additional interruptible load.

Mr. Dauphinais testified that NIPSCO is facing compliance with new emission and cooling water rules (e.g., CSPAR and Utility MACT rules) from the EPA that may ultimately dictate that NIPSCO consider early retirement of some of its existing generation capacity. Mr. Dauphinais concluded Mr. Cearley's claim that NIPSCO needs less than 225 MW of interruptible load for reliability purposes was not accurate and that there is substantial evidence of the need for at least 500 MW of interruptible load, as would be provided for under Rider 675.

Mr. Dauphinais also disputed Mr. Cearley's argument that he expects NIPSCO to contract for relatively little interruptible service in the next few years because there is an abundance of capacity in MISO and the current market price for capacity is low. Mr. Dauphinais referenced his direct settlement testimony that the current capacity situation in the MISO footprint is temporary and also noted new EPA rules will be going into effect in the near future that could lead to the early retirement of a large amount of generation in the MISO footprint.

Regarding Mr. Cearley's $0.01 per kW-month claim for the current market price of capacity, Mr. Dauphinais stated it is not an accurate estimate even for the short-term cost of capacity. He explained Mr. Cearley derived his $0.01 per kW-month value from the MISO Voluntary Capacity Auction ("VCA"), which is not a good indicator of the current short-term market price of capacity. Mr. Dauphinais stated the MISO VCA is a very thin and volatile auction for residual capacity and that very little of the total MISO footprint capacity need is traded within the VCA. He also knew of no electric utility that relies upon the VCA to meet its MISO resource adequacy requirements. As an example, Mr. Dauphinais stated that for July through September of 2011, less than 1.5% of MISO's peak footprint load cleared in the VCA.[8] Mr. Dauphinais added that over the period of June 2009 through September 2011, the VCA has had wild monthly swings from as low as $0.01 per MW-month to as high as $10,015.00 per MW-month. He said the VCA product also does not begin to resemble Option A of Rider 675 because Option A requires that a standard contract be executed in advance with a minimum contract term of one year, but the VCA product is residual capacity available for only one month that is cleared in an auction conducted only 40 days before the start of the month of delivery of that capacity. Mr. Dauphinais said this is why the Option A demand charge credit is not updated under Rider 675 using the MISO VCA results and instead will be updated based on the much more reliable surveys of the short-term bilateral capacity market where the vast majority of short-term capacity sales in the MISO footprint are transacted.

Mr. Dauphinais added that NIPSCO cannot heavily rely on short-term capacity purchases to meet its resource adequacy requirements because there is no guarantee such capacity will always be available in abundance in the short-term market. He said even NIPSCO's 2009 IRP recognized this through its very limited use of short-term capacity purchases. He stated that in

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[8] Mr. Dauphinais testified the annual peak demand in the MISO footprint is approximately 100,000 MW (https://www.midwestiso.org/AboutUs/MediaCenter/PressReleases/Pages/NewPeakRecordSetinMISORegion.aspx) and Hammond's Exhibit RWC-5 at page 1 of 3 shows no more than 1,275 MW of capacity cleared in the MISO VCA for any month from June 2011 to September 2011.

contrast, Options B, C and D require progressively longer term commitments of three, seven and 10 years for interruptible service. He said, while the current short-term market price of capacity as determined from the bilateral market is a reasonable basis for updating the demand charge credit for Option A, it is neither an indication of the amount of Option B, C or D interruptible load that NIPSCO could use nor the proper price for demand charge credits under those options.

Addressing Mr. Cearley's observation that the low likelihood of future involuntary reliability curtailment of firm customers further diminishes the value of interruptible load for reliability curtailments, Mr. Dauphinais testified that the future likelihood of involuntary curtailment of firm customers is set at a minimum floor of one day in 10 years (i.e., a 10% likelihood of one day of interruption in any given year) in the loss of load expectation studies performed by MISO to determine the planning reserve margin requirements of load-serving entities like NIPSCO and, consequently, the future likelihood of involuntary curtailments of firm customer load is not a factor that NIPSCO uses to determine its resource adequacy needs. He said, instead, NIPSCO must acquire sufficient generation capacity and interruptible load to meet its planning reserve margin as dictated by MISO regardless of the likelihood of future involuntary curtailments of its firm customers. He noted though that, to the extent NIPSCO has insufficient capacity and interruptible load to meet its planning reserve margin requirement, the likelihood of involuntary curtailment of firm customers increases.

(2) Economic Interruptions. Mr. Dauphinais also addressed Mr. Cearley's fundamental misunderstanding of the purpose of NIPSCO's current hedging plan versus the economic hedging provided by simple cycle combustion turbines and economic interruptions under Options B, C and D of Rider 675. Mr. Dauphinais explained that NIPSCO's Commission-approved initial hedging plan in Cause No. 43849 is designed to manage in aggregate the price risk associated with NIPSCO's projected volume of spot natural gas purchases and spot electric energy purchases for the forthcoming two years and is not focused on purchases of electric energy above NIPSCO's FAC purchased power benchmark price. He noted that the risk or projected frequency of spot electric energy purchases being over the FAC purchased power benchmark is not even an input to the Cause No. 43849 hedging plan.

Mr. Dauphinais testified that NIPSCO's simple cycle combustion turbines and its Rider 675 B, C and D economic interruptions act as a long-term heat rate cap for NIPSCO's fuel and purchased power costs, which is a completely different role than the role played by NIPSCO's initial hedging plan in Cause No. 43849. He said as a result, the Cause No. 43849 hedging plan has no effect on the amount of simple cycle combustion turbine generation and Rider 675 Option B, C and D interruptions that is useful to NIPSCO. He added at most, NIPSCO's simple cycle combustion turbine generation and Rider 675 Option B, C and D economic interruptions influence the Cause No. 43849 hedging plan by shifting how the total volume of hedging is split between natural gas financial instruments and electric energy financial instruments. He said it has no influence on the total volume of hedging under the Cause No. 43849 initial hedge plan.

Mr. Dauphinais testified that NIPSCO needs to operate its system at the lowest reasonable fuel cost and therefore needs to obtain as many MWh of economic interruptions as possible at a cost less than the value provided by those economic interruptions. He pointed to his settlement testimony, which shows all of the demand charge credits that would be paid under Options B, C and D are less than the combined estimated reliability and economic dollar value that would be received by NIPSCO and firm customers. He said thus all of the economic interruptions provided for under Rider 675 are needed by NIPSCO.

(d) Value of Reliability Curtailments and Economic Interruptions Under Rider 675.

(1) Reliability Curtailments. Mr. Dauphinais responded to Mr. Cearley's argument that the initial demand charge credit for Option A should be determined in the first year in the same manner as in subsequent years by noting this is a provision of the overall Settlement that must be taken in context with the rest of the rate structures. He said in the context of the overall Settlement, the Industrial Group is willing to risk the actual short-term market price for capacity being greater than $1 per kW-month for the initial year and the $1 per kW-month demand charge credit is a reasonable initial price for demand charge credits for Option A.

In response to Mr. Cearley's testimony that NIPSCO does not need any Option B load for the next three years and his reliance on the July 2010 long-term market price for capacity, Mr. Dauphinais stated that in addition to the contribution interruptible service could make towards off-setting the additional combustion turbine generation capacity of 435 MW, the July 2010 price estimate Mr. Cearley cited is out of date because it was received prior to the market being aware of the pending pressure on existing capacity resources that will be imposed by the EPA's new emission and cooling water rules. Mr. Dauphinais added that even if Mr. Cearley's estimate was up to date and accurate, the price would not necessarily include the heat rate cap benefit provided by simple cycle combustion turbines and economic interruptions because capacity is usually traded in ISO and RTO markets without any right to call on energy from the traded capacity. Mr. Dauphinais also noted for a very similar level of curtailability, interruptibility and minimum term of service, Option B of Rider 675 pays a lower credit of $6.00 per kW-month versus the $6.75 per kW-month paid by Rider 581 in Cause No. 43526.

Mr. Dauphinais also disputed Mr. Cearley's statements that Options C and D should be rejected because they impose greater costs upon firm customers based on meeting additional curtailment and interruptibility requirements that are unnecessary. Mr. Dauphinais pointed to both NIPSCO witness Frank A. Shambo's and the Industrial Group's extensive evidence regarding the additional value provided to NIPSCO and firm customers by the additional requirements of Option C and D and that the level of compensation provided under these two options is less than the expected cost of a new simple cycle combustion turbine and is reasonably commensurate with the additional value being provided to NIPSCO and its firm customers by those two options.

Addressing Mr. Cearley's argument that the contract expiration term in Rider 675 means Options C and D really do not involve longer contract terms of 7 and 10 years, Mr. Dauphinais explained the purpose of the contract expiration clause. Mr. Dauphinais said if the terms, conditions and rates for curtailments, interruptions and compensation could not be changed by a base rate change during the term of the Option C and D contracts, then the Industrial Group would have no need for such an expiration clause. However, because Rider 675 is not a customer-specific electric service rate, it is subject to change by the Commission in base rate proceedings. Such a base rate change could change the terms, conditions and rates for Rider 675 service such that it is no longer reasonably viable for a particular customer to continue to take service under Option C or D and, thus, there is a strong need for the expiration clause. Mr. Dauphinais added it is not meant to be a means to circumvent the 7- to 10-year minimum term requirements of Options C and D and noted that one of the customers that will likely take service under Option D has been a Rate 836 interruptible service customer of NIPSCO for over 20 years. Mr. Dauphinais also noted that any assumption concerning when new base rates would be filed by NIPSCO, approved by the Commission, and become effective after this current cause is speculative and any customer committing to the terms specified in Options C and D must be prepared to perform as required for the entire stated term of years.

Mr. Dauphinais also addressed Mr. Cearley's testimony that no evidence has been presented that a shorter notice period than four hours is necessary to prevent involuntary curtailments of firm customers. Mr. Dauphinais stated if a system emergency occurs, the additional flexibility will reduce the likelihood that NIPSCO will have to involuntarily curtail firm customers because the notice period is shorter than the four hours required under Options A and B. He added that to the extent this is considered to be of limited value, it is really an argument that the proposed demand charge credit for Option B is too low relative to Options C and D. He also noted that his settlement testimony demonstrated NIPSCO's existing simple cycle combustion turbines (Mitchell 9, Bailly 10, Schahfer 16A and Schahfer 16B) had forced outage rates of no lower than 27% in 2010 and that NIPSCO's response to NLMK Data Request 1-3 shows that these turbines generally operate less than 100 hours per year and require roughly an hour to start (NLMK Cross Exhibit 2). He said in contrast, Option C and D curtailments must be available within an hour (10-minutes for Option D), must be 100% reliable and available when called and again noted that if an Option C or D customer fails to fully perform in response to a curtailment request even one time, the customer shall be disqualified from Rider 675 for three years.

Mr. Dauphinais disputed Mr. Cearley's testimony that the proposed demand charge credits for Options C and D are based on inflated values for a new combustion turbine. Mr. Dauphinais testified the proposed demand charge credits for Options C and D are in fact less than the estimated levelized cost of a new simple cycle combustion turbine generator. He noted again the $6.75 per kW-month value he used in Cause No. 43526 was conservatively low even two years ago and should not be used in this proceeding and pointed to the detailed testimony he provided in his settlement testimony and supporting data for his current estimate of $12.38 per kW-month, which is based on more recent EIA cost estimates. This estimate also reflects the planning reserve benefits of interruptible load that were not reflected in the $6.75 per kW-month estimate filed in Cause No. 43526. Mr. Dauphinais noted that Mr. Cearley's testimony does not directly dispute the: (i) use of up-to-date cost estimates, (ii) levelized cost estimate methodology, or (iii) incorporation of the planning reserve margin benefit provided by interruptible load.

Mr. Dauphinais also noted that while Mr. Cearley points to NIPSCO witness Gaske's direct testimony in this Cause regarding the estimated cost of the avoided cost of a combustion turbine, he neither defends Mr. Gaske's assumptions nor challenges the underpinnings of the calculations that Mr. Dauphinais provided. Mr. Dauphinais stated Mr. Gaske's direct testimony value of $6.58 to $7.00 per kW-month understates the combustion turbine cost avoided by interruptible load. Mr. Dauphinais explained that the overnight installed cost estimates of $610 to $617 per kW that Mr. Gaske used in developing his direct testimony are out of date. Mr. Dauphinais added even if he put more expensive Conventional Combustion Turbine generation aside, the EIA shows the estimated installed cost of an Advanced Combustion Turbine generation to be $676 per kW in the Indianapolis area and $772 per kW in the Chicago area in October 1, 2010 dollars. He said appropriately averaging these two estimates, the estimated cost in NIPSCO's service territory is approximately $724 per kW installed for an Advanced Combustion Turbine generator -- an amount significantly above Mr. Gaske's assumed $610 to $617 per kW values. He added that Mr. Gaske used the amortization method NIPSCO uses in its annual avoided cost price filing, but that method does not fully capture NIPSCO's levelized cost of new generation and does not count the planning reserve margin benefits of curtailments. He said that for the same reasons he identified in his settlement testimony discussing his own Cause No. 43526 cost estimate, Mr. Gaske's estimate is too conservatively low.

As to Mr. Cearley's statement that NIPSCO would pay for new capacity at the lowest cost reasonable option, not the average cost of its options, Mr. Dauphinais testified NIPSCO does not always have all the options available to it. As an example, he said a utility may only have a limited number of brownfield sites available to it and may need to build new generation at a greenfield site rather than a brownfield site. Similarly, a utility may not always be able to use an Advanced Combustion Turbine versus a Conventional Combustion Turbine due to size or other concerns. He stated when new generation is required, it does not necessarily align with the scale economics of standard generating unit sizes and, therefore, it is appropriate to average such cost estimate numbers.

Mr. Dauphinais testified that while he believes the estimate for the avoided cost should be based on an average of costs, if he just used the Advanced Combustion Turbine values from the EIA cost estimates, his $12.38 per kW-month estimate would fall to $10.23 per kW-month. He noted that, even without adding the economic interruption value provided by Option D above the capacity value of a simple cycle combustion turbine, this is substantially above the $8.00 per kW-month and $9.00 per kW-month demand charge credits proposed for Options C and D, respectively.

Mr. Dauphinais strongly disagreed with Mr. Cearley's testimony that interruptible service provided under Options C and D do not provide the benefit to ratepayers as the actual construction of a new combustion turbine. Mr. Dauphinais explained Mr. Cearley based his argument on the faulty premise that a new combustion turbine will be useful for 30 years, but Option C and D last only 7 to 10 years. He said Option C and D customers are only being paid compensation as they provide benefits to NIPSCO and its firm customers, which is very different than a new generator that requires an up front investment for the entire 30-year capital cost of the facility. He said history has shown that customers do not necessarily leave these types of interruptible service options when their contract term is up and noted the existing Rate 836 customer has continuously taken interruptible service for over 20 years with several extensions to its power supply agreement with NIPSCO. He said the reason customers will remain under these rates is that short-term spikes in the short-term market price for capacity cannot be relied upon to confidently predict the electricity cost savings that can be achieved from being interruptible. He stated that, to the extent possible, these customers typically want to build reasonably fixed cost savings estimates into their business forecasts and Options B, C and D reasonably allow for this predictability. He added to be able to be interruptible under Rider 675, customers will need to invest in and maintain infrastructure, incur costs and manage production in ways they would not ordinarily do and customers are likely to want to maximize these investments over an extended time period. He said Options B, C and D are service options that customers will likely remain on even after the expiration of their initial term.

Mr. Dauphinais stated that Mr. Cearley's argument, that a new combustion turbine provides hedging value far in excess to Options C and D, was flawed. Mr. Dauphinais said first, a new simple cycle combustion turbine will not be dispatched for 8,190 hours per year but will only be dispatched when the energy offer submitted for it to MISO is accepted. He testified, in general, the offer will be accepted by MISO when the LMP at the generator's node is equal to or greater than the offer price and if the offer is cost-based, which is to be expected of a vertically integrated utility such as NIPSCO, the offer will be based on the combustion turbine's expected heat rate, a forecast price for same day natural gas that includes an upward adjustment to address price uncertainty and the combustion turbine's estimated variable O&M costs. He said using an assumed heat rate of 10,300 BTU per kWh,[9] an upward natural gas price uncertainty adjustment of 10%, a variable O&M cost of $12.29 per MWh[10] and generator node LMP that is 2.34%[11] lower than that at NIPSCO's load zone, a typical simple cycle combustion turbine would likely not have been dispatched more than 546 hours during the 12-month period ending July 26, 2011. He noted, however, this assumes the effective forced outage rate of such a turbine is 0%, which it is not. He said assuming an effective forced outage rate of approximately 6.5%, the turbine would typically not be available for 6.5% of the hours in which it would otherwise be dispatched.[12] He concluded the actual likely number of hours that the turbine would have been dispatched in the 12-month period ending July 26, 2011 is 511 hours[13] – a number substantially less than Mr. Cearley's 8,190 hours.

Mr. Dauphinais added the hourly per unit estimated energy cost savings provided by a combustion turbine is not the same as that provided by Rider 675 Option B, C and D economic interruptions. He stated the hourly per unit energy savings provided by a combustion turbine is equal to the LMP at the generator's node less the generator's fuel and variable O&M cost, while the hourly per unit savings provided by Option B, C and D economic interruptions is the LMP at NIPSCO's load zone plus the applicable non-fuel energy adder specified in Rider 675 less the firm energy rate the customer would have paid if it had not been interrupted. He calculated that at an assumed heat rate of 10,300 Btu per kWh, an assumed variable O&M rate of $12.29 per MWh and a generator node LMP that is 2.34% lower than that at NIPSCO's load zone, a typical new simple cycle combustion turbine would provide an estimated $34.93 per MWh of net energy savings for 511 hours for the 12-month period ending July 26, 2011, or a total annual projected energy savings of $17,849 (Exhibit JRD-7) and on a per kW of capacity basis, this is $1.49 per

[9] The average of EIA November 2010 estimates of 10,850 for a Conventional Combustion Turbine and 9,750 for an Advanced Combustion Turbine (Exhibit JRD-2 at pages 8-2 and 9-2).

[10] The average of EIA November 2010 estimates of $14.70 for a Conventional Combustion Turbine and $9.87 for an Advanced Combustion Turbine (Exhibit JRD-2 at pages 8-6 and 9-4).

[11] 2.34% = 100% x [1- (100% / 102.4%)], where 2.4% is the assumed transmission loss factor.

[12] He said NIPSCO cannot control when its generation experiences forced outages. Thus, there is an equal chance for them to occur when the generation would be dispatched as there is when it would not be dispatched.

[13] 511 = 546 x (100% - 6.5%).

kW-month.[14] He said this value compares to his settlement testimony estimated per unit savings of $82.80 per MWh for 100 hours for Option B ($8,280 annually or $0.69 per kW-month), $112.80 per MWh for 100 hours for Option C ($11,280 annually or $0.94 per kW-month) and $93.00 per MWh for 200 hours for Option D ($18,600 annually or $1.55 per kW-month) (Exhibit JRD-5).

Mr. Dauphinais stated that based on these estimates, Option B provides only $0.80 per kW-month less energy value than that of a new simple cycle combustion turbine, and Option C only provides $0.55 per kW-month less energy value than a new simple cycle combustion turbine while Option D is estimated to actually provide $0.06 per kW-month more energy value than a new simple cycle combustion turbine. He concluded Mr. Cearley's argument that a new combustion turbine would provide hedging value far in excess of economic interruptions under Options C and D has no merit.

Mr. Dauphinais demonstrated that if he combined these energy savings estimates versus that of a new simple cycle combustion turbine with his estimated avoided capacity cost of $12.38 per kW-Month for such a turbine, for Option B the net capacity and energy avoided cost would be $11.58 per kW-month; for Option C, it would be $11.83 per kW-month and for Option D, it would be $12.44 per kW-month. He noted these net values are all well in excess of the $6.00 per kW-month, $8.00 per kW-month and $9.00 per kW-month credits respectively provided under Options B, C and D.

Mr. Dauphinais also redid his estimates just using the November 2010 9,750 BTU per kwh heat rate and $9.87 per MWh variable O&M cost estimates for an Advanced Combustion Turbine rather than those for the average of that turbine and of a Conventional Combustion Turbine. He testified that for illustration purposes just using the EIA Advanced Combustion Turbine heat rate and variable O&M estimates, the turbine would be in merit for dispatch for an estimated 693 hours, which would fall to 648 hours due to an assumed forced outage rate of 6.5%. He said the average hourly per unit savings would be $32.81 per MWh that would total to $21,261 annually for 648 hours and amount to a per kW energy value of $1.77 per kW-month. He stated Option B would provide $1.08 per kW-month less energy value, Option C would provide $0.83 per kW-month less value, and Option D would provide $0.22 per kW-month less value. He added that even under such a very conservative assumption, Mr. Cearley's statement that a new combustion turbine would provide hedging value far in excess of economic interruptions under Options C and D would have no merit.

He added that when these particular energy savings estimates versus that of a simple cycle combustion turbine are combined with his $10.23 per kW-month estimate of the avoided capacity value of a combustion turbine based on EIA Advanced Combustion Turbine estimates, the net capacity and energy avoided cost would be $9.15 per kW-month for Option B, $9.40 per kW-month for Option C and $10.01 per kW-month for Option D. He noted that once again, these net values are still all well in excess of the $6.00 per kW-month, $8.00 per kW-month and $9.00 per kW-month credits respectively provided under Options B, C and D.

[14] $1.49 = $17,849 / 12,000.

In response to Mr. Cearley's argument that NIPSCO should be required to receive a certificate of public convenience and necessity ("CPCN") granting service to eligible customers under Rider 675 Options C and D. Mr. Dauphinais testified Mr. Cearley has not identified any precedent in Indiana or any other regulatory jurisdiction where a CPCN is required prior to a utility granting service to eligible customers under a standard interruptible tariff rate of general applicability. Mr. Dauphinais added that, as with the prudence issue, he is not aware of any regulatory jurisdiction where a utility was required to have a CPCN to grant service to an eligible customer under a standard interruptible tariff rate. He also noted that, as with the prudency issue, under Rider 675 NIPSCO does not have the discretion to deny service to any eligible customer until the lower of the 500 MW or $38 million annual demand charge credit cap is met.

Mr. Dauphinais added that, as with the prudency issue, Mr. Cearley's proposed CPCN requirement would effectively make Option C and D service only available on a very tentative case-by-case basis, which undermines the purpose of having a standard tariff rate of general applicability, is unduly discriminatory and could adversely affect economic development and economic retention in NIPSCO's service territory. He said the time for the Commission to determine the reasonableness of a standard tariff rate of general applicability is when it is filed, not in a future proceeding, and that substantial testimony has been presented in this proceeding demonstrating that Rider 675 is reasonable as proposed under the Settlement.

(2) Economic Interruptions. Mr. Dauphinais disputed Mr. Cearley's testimony that the estimated value of economic interruptions is fundamentally flawed. Mr. Dauphinais testified that Mr. Cearley misinterpreted Mr. Dauphinais' estimates on the NIPSCO load zone LMP for the 100 to 200 highest cost hours in conjunction with the LMP price during all above-benchmark hours, as summarized on page 1 of 52 of his Exhibit JRD-5. Mr. Dauphinais explained that for Option B, he did not utilize the per unit value for the 200 most expensive LMP hours of the analysis period, but rather used a blend of the per unit value for all hours over the FAC benchmark during the period and the per unit value for the 100 highest cost LMP hours of the period that was weighted by a factor of two toward the all hours per unit value (Exhibit JRD-5, page 1 of 52, line 4). He explained he did so to appropriately account for the fact that with a four-hour notice and the other limitations of Option B interruptibility, NIPSCO will not be able to perfectly time the Option B economic interruptions to the 100 highest LMP hours of the year.

He added that none of his economic interruption value estimates assumed NIPSCO could perfectly time interruptions to the highest LMP hours of the year but he did recognize that as the notice time grows smaller, NIPSCO's ability to time the interruptions to the highest LMP hours would improve. For Option B, he assumed a 2:1 weight for the per unit value for all hours versus the per unit value for the 100 highest LMP hours and for Option C, which has a one-hour rather than four-hour notice requirement, he assumed a 1:2 weighting on the per unit value for all hours versus the per unit value for the 100 highest LMP hours.

For Option D, which has 200 hours of interpretability versus 100 hours and a notice of 10 minutes rather than one or four hours, he used a 1:4 weighting on the per unit value for all hours versus the per unit value for the 200 highest LMP hours. In his judgment, he has reasonably accounted for the greater likelihood of successful optimization by NIPSCO of the shorter interruption notice of Options C and D while reasonably reflecting NIPSCO will not be able to perfectly time the calling of these economic interruptions.

Mr. Dauphinais addressed Mr. Cearley's claims that actual NIPSCO economic interruptions called during the 12-month period shows NIPSCO will not be able to time the calling of interruptions well. Mr. Dauphinais first noted Rider 675 was not in effect during the 12 months ending July 26, 2011 and the terms and conditions of the interruptible service NIPSCO was providing during that period were likely different than those of Rider 675. He added that under Rate 836, NIPSCO has not necessarily called interruptions when the LMP is over its FAC purchased power benchmark price. Therefore, the call of economic interruptions under NIPSCO's current interruptible service provisions is not an indicator of NIPSCO's future call of economic interruptions under Rider 675. He added the Industrial Group is under no illusion that NIPSCO will not call all of the economic interruptions NIPSCO is entitled to under Rider 675, and the Industrial Group fully expects NIPSCO to completely use the economic interruption hours of Rider 675 and to the greatest extent reasonably possible optimize the call of those economic interruptions in the highest LMP hours of the year.

Mr. Dauphinais also explained why he disagreed with Mr. Cearley's testimony that he incorrectly assumed NIPSCO will interrupt customers to the extent allowed. He said Mr. Cearley bases his argument on the amount of economic interruptions called by NIPSCO under its existing interruptible service provisions during 2011 and as he just discussed, the amount of interruptions under NIPSCO's current interruptible service provisions is not an indicator of the interruptions NIPSCO will call under Rider 675.

Mr. Dauphinais testified that it appears Mr. Cearley also misunderstands how the economic interruption provisions of Rider 675 work and interact with NIPSCO's MISO energy market settlements. Mr. Dauphinais said Mr. Cearley continues to try to incorrectly tie economic interruptions to NIPSCO's Cause No. 43849 initial hedge plan but that the Cause No. 43849 hedging plan performs a different role than NIPSCO's simple cycle combustion turbine generation and economic interruptions under Rider 675 Options B, C and D. He again noted, there is very limited, if any, interaction between the two.

Mr. Dauphinais also testified Rider 675 very clearly allows NIPSCO to call economic interruptions (within the limitations of Options B, C and D) <u>whenever</u> the real-time LMPs for the NIPSCO load zone are reasonably forecast to be in excess of the FAC purchased power benchmark. He said there is no requirement that NIPSCO be a net purchaser of power from MISO in that hour. He added if the customer chooses not to buy-through, the effect in NIPSCO's energy market settlements with MISO will be to avoid clearing that customer's load in the MISO real-time market, which will cause NIPSCO to earn a credit from MISO for the interrupted customer's load equal to the real-time LMP. He said NIPSCO will earn this credit from MISO in real-time settlements whether or not NIPSCO is a net purchaser from MISO during the hour of interruption. Mr. Dauphinais also explained if the Rider 675 customer chooses to buy-through the interruption, the customer pays the same real-time LMP credit to NIPSCO that NIPSCO would have earned in the real-time market from MISO if the customer had actually interrupted its load. Mr. Dauphinais said his economic analysis in Exhibit JRD-5 correctly reflects all of these interactions and is not flawed.

(e) Rider 675 Eligibility Discrimination Issue. Mr. Dauphinais also disagreed with Hammond's claim that Rider 675 is discriminatory. He testified Rider 675 will be a tariff offering available to all customers meeting the eligibility criteria in the tariff and the prioritization Hammond complains about comes into play if, and only if, there is more interest in the tariff than the tariff allows (500 MW or $38 million annually in credits). He said in that scenario, it is reasonable for existing interruptible customers to receive the initial allocation of interruptible capacity since those customers have been providing interruptions for some time and have made significant investments over at least the past 20 years in order to support those interruptions.

In conclusion, Mr. Dauphinais testified the core of Rider 675 is essentially the same as Rider 581 in Cause No. 43526, with the difference being in the options it provides to allow potential interruptible customers to tailor the combination of curtailment requirements, interruption requirements and compensation that works best for them consistent with past suggestions of the Commission. He said the compensation provided under each of these options is commensurate with the curtailment and interruption obligations and that Rider 675 under the Settlement is reasonable in the context of the overall Settlement. He emphasized Rider 675 is a fundamental and critical component to the Settlement that provides large industrial customers, the rate class taking the largest percentage base rate increase under the Settlement, a reasonable opportunity to mitigate the increase. Mr. Dauphinais said he continues to recommend that the Commission accept the Settlement in its entirety.

11. Commission Discussion and Findings. 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). Any settlement agreement that is approved by the Commission "loses its status as a strictly private contract and takes on a public interest gloss." *Id.* (quoting *Citizens Action Coalition v. PSI Energy, Inc.*, 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.*, 582 N.E.2d 330, 331 (Ind. 1991)). Therefore, before the Commission can approve the Settlement, we must determine whether the evidence in this Cause sufficiently supports the conclusion that the Settlement is reasonable, just, and consistent with the purpose of Ind. Code ch. 8-1-2, and that such Settlement serves the public interest. We will discuss the major components of the Settlement.

We have previously discussed our policy with respect to settlements:

> Indiana law strongly favors settlement as a means of resolving contested proceedings. *See, e.g., Manns v. State Department of Highways*, 541 N.E.2d 929, 932 (Ind. 1989); *Klebes* v. *Forest Lake Corp.,* 607 N.E.2d 978, 982 (Ind. Ct. App. 1993); *Harding* v. *State*, 603 N.E.2d 176, 179 (Ind. Ct. App. 1992). A settlement agreement "may be adopted as a resolution *on the merits* if [the Commission] makes an independent finding supported by 'substantial evidence on the record as

a whole' that the proposal will establish 'just and reasonable' rates." *Mobil Oil Corp.* v. *FPC*, 417 U.S. 283, 314 (1974) (emphasis in original).

See, e.g., Indianapolis Power & Light Co., Cause No. 39938, at 7 (IURC 8/24/95); *Commission Investigation of Northern Ind. Pub. Serv. Co.*, Cause No. 41746, at 23 (IURC 9/23/02). This policy is consistent with expressions to the same effect by the Supreme Court of Indiana. *See, e.g., Mendenhall v. Skinner & Broadbent Co.*, 728 N.E.2d 140, 145 (Ind. 2000) ("The policy of the law generally is to discourage litigation and encourage negotiation and settlement of disputes.") (citation omitted); *In re Assignment of Courtrooms, Judge's Offices and Other Facilities of St. Joseph Superior Court*, 715 N.E.2d 372, 376 (Ind. 1999) ("Without question, state judicial policy strongly favors settlement of disputes over litigation.") (citations omitted). Furthermore, we are mindful regarding a settlement which has been entered by representatives of all customer classes, including OUCC (who represents all ratepayers), even though there may be some intervenor or group of intervenors who opposes it. *American Suburban Utils.,* Cause No. 41254, at 4-5 (IURC 4/14/99).

A. Revenue Requirement. The Settlement provides for an agreed-upon revenue requirement that reflects the following original cost rate base, cost of capital and financial results which the Settling Parties agree are reasonable for purposes of compromise and settlement:

Indiana Jurisdictional Rate Base as of June 30, 2010
(000)

Electric Plant In Service	$5,636,770,407
Common Allocated	$207,518,424
Less: Disallowed Plant, Unit 17	$31,733,655
Total Utility Plant	$5,812,555,176
Accumulated Depreciation and Amortization	$(3,165,301,803)
Common Allocated	$(96,045,375)
Less Disallowed Plant: Unit 17	$(30,239,815)
Total Accumulated Depreciation and Amortization	$(3,231,107,364)
Net Utility Plant	$2,581,447,813
Unit 17 Depreciation	$0
Unit 18 Depreciation	$3,277,484
Unit 18 Carrying Charges	$10,132,193

Materials & Supplies	$58,224,978
Production Fuel	$52,823,583
Total Rate Base	$2,705,906,051

Capital Structure as of June 30, 2010

	Balance (000)	% of Total	Cost	WACC
Common Equity	$1,470,831,844	46.53%	10.20%	4.75%
Long-Term Debt	$1,025,792,388	32.46%	6.42%	2.08%
Customer Deposits	$73,318,625	2.32%	4.43%	0.10%
Deferred Income Taxes	$426,048,518	13.48%	0.00%	0.00%
Post-Retirement Liability	$147,029,052	4.65%	0.00%	0.00%
Post-1970 ITC	$17,636,467	0.56%	8.65%	0.05%
Totals	$3,160,656,894	100.0%		6.98%

Pro Forma Proposed Rates

Operating Revenues	$1,401,000,000
Fuel, Purchased Power	$474,458,056
Operating Expenses	
Operations & Maintenance	$363,237,597
Depreciation	$190,392,968
Amortization Expense	$36,500,530
Taxes	$147,538,607
Total Operating Expenses	$737,669,702

Net Operating Income	$188,872,242

No other party to this proceeding has provided any evidence, including evidence opposing the Settling Parties' proposal, with regard to Petitioner's Rate Base, Rate of Return, Operating Income, or Revenue Requirement. The Commission finds that the Petitioner's rate base and rate of return, as agreed to by the Settling Parties, is supported by substantial evidence of record. In addition, we find the proposed depreciation expense and depreciation rates, as supported by Mr. Spanos, are supported by substantial evidence of record. Further, we find the proposed amortization of the rate case expense, deferred MISO costs and the Sugar Creek deferred depreciation and carrying costs, as agreed to by the Settling Parties, is supported by substantial evidence of record. Finally, we find the revenue requirement, as agreed to by the Settling Parties, is supported by substantial evidence of record.

B. Revenue Allocation. While NIPSCO presented a cost of service study prepared by Dr. Gaske, the utility proposed an across-the-board allocation of its requested revenue increase above pro forma adjusted test year revenues. The Settling Parties chose to allocate revenue by class in a manner designed to mitigate the level of increase to any one customer class. As noted by Mr. Shambo, no customer class, other than large industrials, will see an increase to its base rate revenue allocation in excess of 12 percent. We are cognizant of NIPSCO's managerial decision to discontinue the use of special contracts, and that the expiration of those contracts effectively imposes a substantial increase in rates on its energy intensive industrial customers. Given the diverse nature of the Settling Parties, and their willingness to agree to the proposed allocation of revenue, and given that no party to this proceeding provided evidence in opposition to the proposed allocation of revenue, we find that the proposed allocation of revenue is supported by substantial evidence of record and is appropriate for development of NIPSCO's retail rates and charges.

Hammond raised a variety of arguments regarding the revenue allocation method contained in the Settlement in its Exceptions, but Hammond presented no evidence that the proposed revenue allocation was not reasonable, lawful or in the public interest. The Indiana Court of Appeals has found that the Commission need not make a finding regarding cost of service. *Bethlehem Steel v. Northern Ind. Pub. Serv. Co.,* 397 N.E. 2d 623, 633 (Ind. Ct. App. 1997). The Commission has approved rates that were not strictly based on a cost of service study. *See Northern Ind. Pub. Serv. Co.*, Cause No. 38045 (IURC 7/15/87); *Board of Directors for Utils. of the Dep't of Pub. Utils. of the City of Indianapolis*, Cause No. 39066 (IURC 11/1/91); Cause No. 42767 (IURC 10/19/06); Cause No. 43463 (IURC 9/17/08); *Northern Ind. Pub. Serv. Co.*, Cause No. 43984 (IURC 11/4/10). Several cost of service studies were presented to the Commission and showed a variety of outcomes. As discussed by Mr. Bolinger, the revenue requirement, revenue allocation and Rider 675 were interrelated and reflected difficult and painstaking negotiations to reach a balanced outcome and resolution which was acceptable to the Settling Parties.

The determination of NIPSCO's true cost of service for each rate class is complicated by a number of factors, including a substantial amount of interruptible load, disagreement over the allocation methodology (i.e., 12 CP, 4CP, Peak and Average) and the migration of customers from special contracts to firm service. NIPSCO's ACOSS, which was provided to the stakeholders for transparency purposes, created additional complications due to the judgments that were made in migrating customers to rates that were not yet in effect, and assigning revenues based on those migrations without accounting for other changes in customer behavior that could occur based on the revised pricing structures. Accordingly, in its case-in-chief, NIPSCO proposed an equal percentage increase to all customer classes, after adjustments, as an attempt to simplify the rate impacts on the individual customer classes. The Settlement takes that approach one step farther, and modifies the across-the-board increase and attempts to tailor the increases through negotiations with parties.

Revenue allocation was one of the most contentious issues in this case, and in Cause No. 43526. Although not all parties were signatories to the Settlement, the Settling Parties respectively represent every customer class, and negotiated the allocation of costs or revenues to the respective classes. Accordingly, we give substantial weight to the Settling Parties' agreement with respect to revenue allocation. We find that the Settlement revenue allocation constitutes just and reasonable rates under Ind. Code § 8-1-2-4. However, we order NIPSCO, in its next rate case filing, to base its proposed rates on a cost of service analysis.

C. Rate Design. The Commission will first address the contested areas of rate design and then address those areas that were not contested. As we do so, we note the admonition and direction we provided to NIPSCO in Cause No. 43526 regarding the need for collaboration with its largest customers:

> Finally, we must note that despite NIPSCO's assertion to the contrary, it is not evident that NIPSCO endeavored to develop tariff provisions that responded to the requirements of its large industrial customers, to the extent reasonably possible. We were troubled by [NIPSCO's] statement on the first day of the evidentiary hearing that the rate case filing represented the opening round of negotiations between NIPSCO and its industrial customers concerning its new tariff rates. To the Commission, such remarks indicate callous indifference to concerns of a majority of its load and demonstrate a poor management decision. In the absence of special contracts, we would encourage NIPSCO to continue discussions with its industrial customers to develop tariffs that are more narrowly tailored to its industrial customers' needs while furthering NIPSCO interests, resulting in a win-win scenario for both sides.

43526 Order at 113. We have heard considerable evidence concerning the collaborative effort among NIPSCO and representatives of all customer classes to reach accord on all issues in this case, including the development of service structure, tariff provisions and rate design that respond to the needs of the industrial customers. We must keep this level of collaboration in mind as we review the Settlement, especially when it is precisely the type of effort we directed in the 43526 Order.

(a) Rider 675. As explained by several witnesses, Rider 675 is an interruptible service that provides large industrial customers with various options with regard to various amounts of interruptions, on various notice, and various amounts of curtailment and interruptions. This interruptible service allows certain large industrials to mitigate large increases due to termination of special contracts and the elimination of Rates 836 and 845 with concurrent benefits to all customers in the form of avoided capital costs for additional generation and lower fuel costs flowing through the FAC.

We begin our discussion of Rider 675 by comparing it to what was proposed and what was ultimately authorized in Cause No. 43526. There, NIPSCO proposed one category of interruptible service, capped at 250 MW, interruptible or curtailable on 10 minutes' notice, and requiring a 3-year contract. On rebuttal, NIPSCO accepted the proposals of the Industrial Group to increase the amount of interruptible service to 500 MW, to extend the notice requirement to 4 hours, and to provide a demand credit of $6.75 per KW, for a total cap of $40.5 million. We authorized Rider 581 over the Industrial Group's opposition to the single category of service, which mandated interruption for economic purposes. We explained: "[Industrial Group] promoted a construct whereby Rider 581 customers are paying at interruptible rates for nearly firm service." 43526 Order at 114.

The Settlement provides for interruptible service that is based upon what we authorized in Cause No. 43526, keeping the maximum at 500 MWs, but also reducing the total annual cap to $38 million (from $40.5 million approved in Cause No. 43526). The proposed Rider 675 differs from the rider approved in Cause No. 43526 by now providing for four categories of service in an effort to "respond[] to the requirements of [NIPSCO's] large industrial customers . . . to develop tariffs that are more narrowly tailored to [NIPSCO's] industrial customers' needs." *Id.* at 113. These options also serve to address the Commission's concerns regarding economic interruption noted above. Option A responds to the chief objection of the Industrial Group to Rider 581's mandated interruption for economic reasons by eliminating economic interruptions. It also has a much shorter contract term (1 year versus 3 years). In view of these changes, this option offers a lower credit value ($1 versus $6.75), which will be continually adjusted to match the market for short-term capacity. We consider the reduced credit to be reasonable for short-term, reliability only curtailments. Option B is most like the interruptible service we authorized in Cause No. 43526. A three-year contract is required, 4-hours' notice is provided, interruptions for economic reasons are permitted, and the credit is slightly reduced below the level we approved ($6 versus $6.75). Option C is more valuable ($8 credit) than the rate we approved in Cause No. 43526, requiring a 7-year contract term (as compared to 3 years), unlimited duration of curtailments and providing for interruptions or curtailments on one-hour notice. This shorter notice to perform approximates the startup time required for NIPSCO's existing combustion turbine units. Option D requires a 10-year term and interruptions or curtailments on 10 minutes' notice. This category most closely resembles the currently effective Rate 836, and the proposed credit of $9 is less than the approximately $13 credit incorporated into Rate 836.

Hammond invites the Commission to delay deciding the reasonableness of the Settling Parties' proposal in this proceeding and instead to turn every subsequent FAC and RA Tracker proceeding into a prudence review of NIPSCO's contracts, which would be entered into pursuant to Rider 675. Such a result would introduce an untenable level of risk to the FAC and other tracker proceedings.

The decision regarding the prudency of Rider 675 should be made in this proceeding, not reserved for tracker proceedings that already require review of myriad factors beyond cost of fuel. Use of Rider 675 protects all of NIPSCO's customers by potentially avoiding the costs to build new generation that would be ultimately recovered through base rates and the higher energy costs that would need to be paid if NIPSCO could not curtail demand during times of high energy prices or peak usage. At the same time, Rider 675 protects NIPSCO from not recovering reasonably incurred costs through its basic rates and charges. Rider 675 also provides the opportunity for NIPSCO's customers who have invested for interruptibility in their operations to receive credit from firm service customers. Absent a cost-of-service study that accounts for the true cost for NIPSCO to provide interruptible service, Rider 675 provides a reasonable basis for interruptible customers to benefit from the ability to be interrupted. Further, the cap on total dollar amounts and energy available under Rider 675 protects firm service customers from overexposure to interruptible cost. Finally, although the 500 MWs of capacity may exceed NIPSCO's historic interruptible load, we believe that Rider 675 will provide a longer term solution than if the capacity limit of the rider were set at a level consistent with recent load data. Obviously, if neither capacity nor dollar levels expand to the limits of Rider 675, firm service customers will not pay for unused capacity under the rider.

Based upon the evidence presented, the Commission finds that the Settling Parties' proposed Rider 675, including its four options for interruptible service, is reasonable and should be approved. In addition, we find that the Settling Parties' proposed cap of $38 million for credits and/or 500 MWs of capacity are reasonable and should also be approved.

(b) Rate 611. The Settling Parties have agreed that the Customer Charge for Rate 611 should be $11/month and that there should be one block of energy usage. Mr. Cearley recommended that the increase to those customers using minimal amounts of energy would be lessened if NIPSCO instituted an inclining block rate. As noted by Mr. Shambo, the primary cause for the differential in the percentage increase is driven by the increase in the customer charge from $5.95/month to $11/month. In the 43526 Order, we found that NIPSCO had presented sufficient evidence to support its customer charge and single block rate design. In this proceeding, Mr. Cearley presented no probative evidence disputing this finding.

Based upon our review of the evidence, we find that Rate 611, as proposed in the Settlement, is reasonable and should be approved.

(c) Rule 10.2. The Settling Parties have agreed to a revised rule for non-residential customers' deposits. Hammond witness Mr. Cearley proposed that the Rule be revised to provide that NIPSCO will annually credit accrued interest from its non-residential customers to its non-residential customers' bills. No precedent for this proposal was cited, nor was any rationale provided for requiring NIPSCO to undertake such an effort when no other utility in Indiana is required to do so. However, Mr. Westerhausen stated during cross-examination that NIPSCO could credit non-residential customers' bills with accrued interest upon the customer's request. We find that there is sufficient evidence to approve Rule 10.2 as presented in the Settlement, with the qualification that annually, upon a customer's request, NIPSCO would credit any accrued interest to the customer's bill.

(d) RA Tracker. The RA Tracker is a semi-annual tracking mechanism coordinated with the FAC audit process, that recovers prudently incurred capacity costs and 75 percent of costs associated with any credits paid as a result of Rider 675. The allocators for the RA Tracker are set forth in Joint Exhibit E to the Settlement, and will be revised to reflect MWs of interruptible service taken by class. Hammond witness Mr. Cearley disputed the amount of the credits payable under Rider 675, but no party offered evidence in opposition to recovery of 75 percent of the costs associated with any credits for Rider 675, nor did any party offer evidence opposing the allocation of the costs to be recovered by the RA Tracker. We find that there is sufficient evidence to approve the RA Tracker as presented in the Settlement. Due to the lag between payment and recovery of credits, the actual amount of credits paid will be deferred in a balance sheet account until they are recovered in the RA Tracker, or in the case of the 25% portion, in the FAC.

(e) Uncontested Rate Design Issues. Joint Exhibit D to the Settlement provides a summary of the changes agreed to by the Settling Parties regarding various Rates, and the Commission finds that substantial evidence of record exists to support the proposed Rates. Joint Exhibit G is Rider 676, agreed to in the Settlement. No party disputed the Rider 676 terms and the Commission finds that substantial evidence exists to support Rider 676. The RTO Tracker approved in Cause No. 43526 will also be implemented with the basic rates and charges approved in this Cause. The RTO Tracker is a semi-annual mechanism coordinated with the FAC audit process that will recover MISO non-fuel costs and revenues that exceed $5.3 million annually or $2.65 million semi-annually (the amount of MISO non-fuel credits and charges included in base rates) and 50% of any off system sales margins that exceed $7.6 million annually (the amount of off-system sales margins included in base rates). The Settlement is silent as to the allocation of costs in the ECRM and EERM and the Settlement does not preclude the Commission from deciding the proper allocation in a subsequent proceeding. Therefore, for purposes of its compliance filing in this proceeding, NIPSCO should allocate costs for the ECRM and EERM consistent with the way it is currently allocating them, and the Commission finds that in its first ECRM and EERM following issuance of this Order (to be filed in February 2012), NIPSCO shall propose an allocation methodology, which all parties are free to contest.

(f) Uncontested Rules. The Settling Parties presented proposed Rules, identified as Petitioner's Exhibit CAW-S2, which the Commission finds are supported by substantial evidence of record and shall be approved.

D. Summary. The Commission has carefully analyzed the evidence and the proposed Settlement, and finds that the resulting rates are reasonable and just and properly balance the interests of NIPSCO, its customers and the overall public interest. Mr. Shambo testified that NIPSCO had as many as 50 meetings with its stakeholders to reach resolution of this matter. Mr. Bolinger testified as to the painstaking negotiations that were held to resolve this complex litigation. While the Commission has expressed its policy goal of moving rates towards a cost of service basis, as noted by Mr. Bolinger, the return from any rate class is calculated consistent with either a 4 CP study, a 12 CP study, or upon a peak and average methodology. While no cost of service study was presented utilizing the agreed upon revenue allocation, NIPSCO's direct testimony did provide both a 4 CP and a 12 CP cost of service study.

In reviewing the rate structure proposed by the Settling Parties, the Commission is guided by Ind. Code § 8-1-2-4 which establishes:

> The charge made by any public utility for any service rendered or to be rendered either directly or in connection therewith shall be reasonable and just . . . .

The Indiana Court of Appeals has found that the Commission need not make a finding regarding cost of service. *See, Bethlehem Steel Corp. v. Northern Indiana Pub. Serv. Co.*, 397 N.E.2d 623 at 633 (Ind. Ct. App. 1979). The Court went on to state:

> Although cost of service may be a factor the Commission could usefully consider in determining the rate design, it is not error for the Commission not to determine the cost of service in its findings. *See, e.g., Boone County Rural Electric Membership Corp. v. Public Service Commission*, 239 Ind. 525, 159 N.E.2d 121 (1959); *Public Service Commission v. City of Indianapolis*, 235 Ind. 70 at 95, 131 N.E.2d at 318 (1956); *Public Service Commission v. Indiana Bell Telephone Co.*, 235 Ind. 1, 130 N.E.2d 467 (1956); *Capital Improvement Board of Managers v. Public Service Commission*, 176 Ind. App. 240, 375 N.E.2d 616 (1978); *L. S. Ayres & Co. v. Indianapolis Power & Light Co.*, 169 Ind. App. 652, 351 N.E.2d 814 (1976).

Id. at 633-634. As shown by substantial evidence of record, the Settlement provides a just and reasonable resolution of all matters pending before the Commission in this case. It reflects the significant collaboration and compromise inherent in serious negotiations among a diverse group of interests. While the Settlement is reasonable as a whole, the evidence in support of the Settlement explains the basis for the proposed rates and other included elements. As a result, the Commission is able to understand how each disputed issue was resolved and to determine that the Settlement is amply supported by the evidence of record, and we so find.

Additionally, as noted above, public policy favor settlements. This public policy is part of the overall public interest. Hence, in the context of settlement, the public interest appropriately includes consideration of the compromise inherent in the negotiation process, particularly where, as here, the Settlement results from a rigorous process and presents a balanced and comprehensive resolution of all the issues among most of the parties. The Commission is particularly mindful of the impact of its decisions. The disparate interests of the Settling Parties provide the Commission some assurance that the interests of all customers have been considered by the Settling Parties. Based upon the evidence of record in this proceeding, the Commission finds that the Settlement is reasonable and in the public interest and should be approved. We further find that the new proposed IURC Electric Service Tariff, Original Volume No. 12, including, but not limited to, the rates and charges set forth therein, is fair, just and reasonable and should be approved subject to the terms and conditions contained in the Settlement. The Commission further finds that for purposes of the earnings test component of the FAC, Petitioner's authorized annual net operating income shall be $188.9 million.

The Settling Parties agreed that the Settlement shall not constitute an admission or a waiver of any position that any of the Settling Parties may take with respect to any or all of the items and issues resolved therein in any future regulatory or other proceedings, except to the extent necessary to enforce its terms. However, with regard to future citation of the Settlement, we find the Settlement and our approval of it should be treated in a manner consistent with our finding in *Richmond Power & Light,* Cause No. 40434 (IURC 3/19/97).

E. Compliance Filing in Cause No. 43526. On April 25, 2011, the Presiding Officers issued a Docket Entry staying the consideration of the Compliance Filing made under

Cause No. 43526 pending an Order in this Cause. The rates proposed in this Cause supersede the rates proposed in Cause No. 43526, and as such, the Compliance Filing in Cause No. 43526 is moot.

12. **Confidentiality.** NIPSCO filed a motion for protective order and NIPSCO and Industrial Group filed a joint motion for protective order, both of which were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4(a)(4) and (9) and Ind. Code § 24-2-3-2. The Presiding Officers issued a Docket Entry finding the information described in NIPSCO's first request to be preliminarily confidential, after which such information was submitted under seal. The information subject to the joint motion was submitted under seal after the presiding officer granted the joint motion on the record. In its Brief, Hammond contests the Commission's preliminary finding of confidentiality with regard to exhibits Hammond CS-48 Confidential, Hammond CS-49 Confidential and related *in camera* testimony, all of which contained specific customer information. Hammond did not appeal the Presiding Officer's decision at the hearing to the full Commission, and thus has waived its opportunity to challenge the ruling. *See* 170 IAC 1-1.1-25(b) (appeals of oral rulings must be made immediately following the ruling). Further, Hammond presented no contradictory evidence at the hearing to suggest that the Commission's preliminary determination should be reversed. Accordingly, we find all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. The Stipulation and Settlement Agreement between Petitioner, OUCC and various Intervenors filed in this Cause on July 18, 2011, and attached hereto, shall be and hereby is accepted, approved and adopted by the Commission.

2. The proposed IURC Electric Service Tariff, Original Volume No. 12 as filed on July 22, 2011, is approved and shall be effective upon its filing and approval with the Commission's Electricity Division.

3. The depreciation accrual rates set forth in Petitioner's Exhibit No. JJS-2 shall be and hereby are approved.

4. Base rates in this case reflect an annual credit of approximately $3.9 million due to sales from emission allowances. This annual credit will remain in base rates for a period of three years and at the end of the three year period, Petitioner shall adjust its base rates to reflect the elimination of this credit.

5. Petitioner shall adjust its base rates to reflect the elimination of the amortization expense for rate case costs, Sugar Creek deferred depreciation and carrying charges, and the MISO deferred costs at the end of the respective amortization periods approved herein by filing revised rate schedules with the Commission's Electricity Division.

6. The information submitted under seal in this Cause pursuant to motions for protective orders is determined to be confidential and exempt from public access and disclosure pursuant to Ind. Code § 24-2-3-2 and § 5-14-3-4.

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

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

APPROVED: DEC 21 2011

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

OFFICIAL
EXHIBITS

IURC
JOINT
EXHIBIT No. 1
9-12-11
DATE REPORTER

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY ("NIPSCO") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES APPLICABLE THERETO; (3) APPROVAL OF REVISED DEPRECIATION ACCRUAL RATES; (4) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY PROJECTS; AND (5) APPROVAL OF VARIOUS CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF INCLUDING WITH RESPECT TO THE GENERAL RULES AND REGULATIONS.	)	CAUSE NO.: 43969

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into as of the 18th day of July, 2011, by and between Northern Indiana Public Service Company ("NIPSCO" or "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC"), the NIPSCO Industrial Group ("Industrials"), NLMK Indiana f/k/a Beta Steel Corporation ("NLMK") and the Indiana Municipal Utilities Group ("Municipals") (collectively the "Settling Parties"), who stipulate and agree for purposes of settling the issues in this Cause that the terms and conditions set forth below represent a fair and reasonable resolution of all issues subject to incorporation into a Final Order of the Indiana Utility Regulatory Commission ("Commission") without any modification or condition that is not acceptable to the Settling Parties.

A. Background.

1. NIPSCO's Current Base Rates and Charges. NIPSCO's currently effective rates and charges for electric utility service were established pursuant to the Commission's Order dated July 15, 1987 in Cause No. 38045. The Commission issued an Order in Cause No.

43526 on August 25, 2010 ("August 25 Order"), which authorized the modification to NIPSCO's rates and charges for electric service. On April 25, 2011 the Commission issued a docket entry granting the Joint Motion to Vacate Remainder of Procedural Schedule in the Compliance Phase, filed by NIPSCO, the OUCC, the City of Hammond and the LaPorte County Board of Commissioners, and suspending the Compliance Filing Schedule. Consequently, the resulting rates have not yet been implemented.

2. NIPSCO's Current Depreciation Accrual Rates. The August 25 Order also approved new depreciation accrual rates; however, as confirmed by the Docket Entry issued in Cause No. 43526 on October 22, 2010, those new depreciation accrual rates will not take effect until new rates and charges take effect. As a result, NIPSCO's currently effective depreciation accrual rates for its electric and common properties were based on a depreciation study prepared in its general rate proceeding in Cause No. 38045.

3. NIPSCO's Fuel Adjustment Clause ("FAC") Proceedings. NIPSCO files a quarterly FAC proceeding in accordance with Ind. Code § 8-1-2-42(d) under Cause No. 38706-FAC-XX to adjust its rates to account for fluctuations in its fuel costs.

4. NIPSCO's Tracking Mechanisms. In Cause No. 42150, the Commission approved two tracking mechanisms for NIPSCO that recover costs associated with Qualified Pollution Control Property ("QPCP") and Clean Coal Technology ("CCT"). Since those approvals, NIPSCO has been recovering a return on its investment in approved QPCP/CCT projects and depreciation expense and operation and maintenance expense relating thereto through its Environmental Cost Recovery Mechanism ("ECRM") and its Environmental Expense Recovery Mechanism ("EERM").

The Commission has also approved three other semi-annual tracking mechanisms:

(a) the Demand Side Management Adjustment Mechanism ("DSMA"), approved by the Commission in Cause No. 43618 that recovers annual costs applicable to NIPSCO's Demand Side Management programs;

(b) the Regional Transmission Organization ("RTO Tracker") approved by the Commission in Cause No. 43526 that recovers net non-fuel Midwest Independent Transmission System Operator, Inc. costs and provides a 50/50 sharing mechanism of annual off-system sale margins above $7,600,638.

(c) the Resource Adequacy ("RA Tracker") approved by the Commission in Cause No. 43526 that recovers the cost of capacity purchases and credits paid for interruptible load.

5. <u>This Proceeding</u>. On November 19, 2010, NIPSCO filed with the Commission its Verified Petition to modify its rates and charges for electric utility service, for approval of new schedules of rates and charges applicable thereto, for approval of revised depreciation accrual rates; for inclusion in its basic rates and charges of the costs associated with certain previously approved QPCP projects; and for approval of certain other requests. NIPSCO also filed its prepared testimony and exhibits constituting its case-in-chief on November 19, 2010. A Prehearing Conference and Preliminary Hearing was conducted on December 17, 2010 and a Prehearing Conference Order was issued on January 5, 2011. A subsequent Docket Entry, issued April 4, 2011 modified the procedural schedule. An evidentiary hearing was held on February 28 through March 4, 2011 and May 16 through 18, 2011 on NIPSCO's Case-in-Chief.

B. Settlement Terms.

6. Revenue Requirement and Net Operating Income.

(a) Revenue Requirement.

The Settling Parties agree that NIPSCO's base rates will be designed to produce \$1.355 billion, which is the Revenue Requirement of \$1.401 billion less \$46 million of Other Revenues. This Revenue Requirement is a decrease of \$68 million from the amount originally requested by the Company. Based on test-year fuel costs, this provides for a margin requirement of \$927 million plus \$12 million in non-trackable fuel.

(b) Net Operating Income.

The Settling Parties agree that NIPSCO's Revenue Requirement in Paragraph B.6.(a) results in a proposed authorized net operating income ("NOI") of \$188.9 million.

7. Fair Value Rate Base, Capital Structure and Fair Return.

(a) Fair Value Rate Base

NIPSCO has agreed that its weighted cost of capital times its original cost rate base yields a fair return for purposes of this case. Based upon this agreement, the Settling Parties concur that NIPSCO should be authorized a fair rate of return of 6.98%, yielding an overall return for earnings test purposes of \$188.9 million, based upon:

(i) an original cost rate base of \$2.7 billion, inclusive of materials, supplies and production fuel, as proposed in NIPSCO's case-in-chief;

(ii) NIPSCO's capital structure; and

(iii) an authorized return on equity ("ROE") of 10.2%.

NIPSCO's sum of the differentials, commonly referred to as the "earnings bank" computed under Ind. Code § 8-1-2-42.3, shall be re-set to $200 million.

(b) Capital Structure and Fair Return.

Based on the following capital structure, the 10.2% ROE and cost of debt/zero cost capital as filed, the overall weighted average cost of capital is computed as follows:

	% of Total	Cost	WACC
Common Equity	46.53%	10.20%	4.75%
Long-Term Debt	32.46%	6.42%	2.08%
Customer Deposits	2.32%	4.43%	0.10%
Deferred Income Taxes	13.48%	0.00%	0.00%
Post-Retirement Liability	4.65%	0.00%	0.00%
Post-1970 ITC	0.56%	8.65%	0.05%
Totals	100.0%		6.98%

(c) Environmental Project Financing.

The Settling Parties agree that NIPSCO should finance, in aggregate, the projects for which it receives a Certificate of Public Convenience and Necessity in Cause No. 44012 with at least 60% debt capital.

8. Depreciation and Amortization Expense.

(a) Depreciation Expense.

The Settling Parties stipulate that the depreciation accrual rates recommended by NIPSCO Witness John Spanos and presented in this proceeding (the "Depreciation Study") should be approved, except that pro-forma depreciation expense should be reduced by $4.9 million due to proposed changes to the net salvage percents for steam production, station equipment, and distribution poles. Joint Exhibit A contains a spreadsheet showing the proposed depreciation rates by class of property.

(b) Amortization Expense.

The Settling Parties stipulate that annual amortization expense shall be $36.5 million that includes amortization of software and the following items:

(i) Rate case expenses of $0.770 million for this case amortized over a period of three (3) years. After the completion of the three (3) year period, NIPSCO agrees to make a tariff filing that will reflect the reduction in amortization expense.

(ii) Deferred MISO costs, amortized and recovered over a period of four (4) years. Amounts included in this case were estimated through June 30, 2011. Costs will continue to be deferred until the effective date of new rates. Any difference between the estimate and the actual costs incurred will be included in the RTO tracker approved in Cause No. 43526.

(iii) Deferred Sugar Creek depreciation and carrying charges, through June 30, 2011, amortized and recovered over five (5) years. The Settling Parties agree that Sugar Creek depreciation and carrying charges may continue to be deferred from July 1, 2011 through December 31, 2011 or the implementation of new basic rates and charges, whichever occurs earlier. These amounts will remain as a regulatory asset on NIPSCO's books and records, but shall accrue no additional carrying charges, and NIPSCO may request recovery of the deferred amount in NIPSCO's next general rate case; provided the other Settling Parties reserve the right to contest the recovery of those amounts.

9. Operating Results at Current and Proposed Rates. Joint Exhibit B contains a Statement of Operating Income for the twelve months ended June 30, 2010 shown on an actual basis, and with pro forma adjustments at current and proposed rates per NIPSCO's filed request and to reflect the provisions of this Agreement.

10. Cost Allocation and Rate Design. The Settling Parties agree that rates should be designed in order to allocate the revenue requirement to and among NIPSCO's customer classes in a fair and reasonable manner. For settlement purposes, the Settling Parties agree that NIPSCO should generally design its rates using the structure of its existing 800 Series tariffs.

The Settling Parties agree that NIPSCO's settlement base rates in total will be designed to produce $1.355 billion. Attached to this Agreement as Joint Exhibit C is a table that contains the allocation revenue and percentages to the various customer classes. The Settling Parties agree to the rate design specifics summarized in Joint Exhibit D.

The Settling Parties agree that the cost allocation herein results in fair and reasonable rates and charges.

11. Demand Allocators. The Settling Parties agree that NIPSCO's demand allocators for purposes of the RTO Tracker and RA Tracker are set forth in Table 1 of Joint Exhibit E. The demand allocators for purposes of the RA Tracker will be based upon those set forth in Joint Exhibit E modified to reflect the amount of interruptible load contained in Rates

632, 633 and 634.

12. ECRM and EERM Factors. The ECRM and EERM factors are approved after the expenditures have occurred, and therefore, the Settling Parties agree that the O&M and depreciation expense on the projects being added to rate base in this proceeding will continue to be deferred until the effective date of the rates, and all such deferred costs will be recovered in the appropriate EERM filing.

13. Interruptible Credit. The Settling Parties agree that NIPSCO should be authorized to implement Rider 675, which is attached hereto as Joint Exhibit F and that the credits paid under the provisions of Rider 675 should be recovered from ratepayers, with 75% of the costs recovered through NIPSCO's RA Tracker as the demand component and 25% of the costs recovered through NIPSCO's FAC mechanism as the energy component. The Settling Parties further agree that the limit on megawatt ("MW") eligibility should be 500 MW, and the maximum amount to be paid in any calendar year under Rider 675 is $38 million.

14. Temporary, Backup and Maintenance Service. The Settling Parties agree that NIPSCO should be authorized to implement Rider 676, which is attached hereto as Joint Exhibit G.

15. The Settling Parties agree that those facilities being served under Rate 832 on June 30, 2010; facilities which would have been eligible for Rate 832 on June 30, 2010, but for being on a Special Contract or on Rate 845; or facilities located behind the meter of a facility eligible under Rate 832 and which facility would have been eligible under Rate 832 are grandfathered into Rate 632 and those facilities shall remain eligible for Rate Schedule 632, regardless of any change in name, or ownership, or operation.

16. The Settling Parties agree that a voltage adjusted FAC may be appropriate, and the Parties agree to work together to determine the appropriate mechanism to be implemented. Upon reaching a resolution of that issue, the Parties will file a separate petition with the Commission.

17. Accounting Reporting. NIPSCO agrees to file separate gas and electric income statements with the Commission annually by April based on the previous calendar year. NIPSCO agrees to insure that its financial reports are transparent and verifiable for future OUCC financial audits. NIPSCO agrees to work cooperatively with the OUCC to facilitate the auditing function.

18. OUCC Audits. NIPSCO agreed in Cause No. 38706-FAC71S1 to fund the OUCC actual audit or consulting fees up to an annual maximum of $100,000 per year for the purpose of conducting a review and audit of NIPSCO's hedging program. NIPSCO agrees that the fees may be utilized by the OUCC to conduct reviews with respect to any management of fuel, purchased power, off-system sales, use of interruptible resources, or other tracking mechanisms.

19. General Rules and Regulations and Tariffs. The Settling Parties agree that NIPSCO will make certain modifications to the General Rules and Regulations and Tariffs initially proposed in this proceeding, and the Settling Parties will jointly submit those revised General Rules and Regulations and Tariffs in support of approval of this Agreement. Included in the General Rules and Regulations is Rule 10.2, which is attached as Joint Exhibit H.

20. Final True-Up of Customer Credit. Upon the effective date of new rates following the issuance of a Final Order in this proceeding, the revenue credit and the sharing mechanism approved in Cause No. 41746 will cease. After reconciliations of the revenue credit have been performed for all billed months, the final balance of any over or under credit will be included in the variance in the FAC filing that follows the final revenue credit reconciliation month and shall be specifically identified.

C. Procedural Aspects and Presentation of the Agreement.

21. The Settling Parties acknowledge that a significant motivation to enter into this Agreement is the expectation that, if the Commission finds the Agreement is reasonable and in the public interest, an order authorizing the increase in NIPSCO's rates and charges will be issued promptly by the Commission following such determination. The Settling Parties have spent many months reviewing data and negotiating this Agreement in an effort to eliminate time consuming and costly litigation. The Settling Parties agree to request that the Commission review the Agreement on an expedited basis and, if it finds the Agreement is reasonable and in the public interest, approve this Agreement without any material changes by December 31, 2011.

22. The Settling Parties agree to jointly present this Agreement to the Commission for its approval in this proceeding, and agree to assist and cooperate in the preparation and presentation of supplemental testimony as necessary to provide an appropriate factual basis for such approval.

23. If the Agreement is not approved in its entirety by the Commission, the Settling Parties agree that the terms herein shall not be admissible in evidence or discussed by any party

in a subsequent proceeding. Moreover, the concurrence of the Settling Parties with the terms of this Agreement is expressly predicated upon the Commission's approval of the Agreement in its entirety without any material modification or any material condition deemed unacceptable by any Party. If the Commission does not approve the Agreement in its entirety, the Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

24. The Settling Parties agree that this Agreement and each term, condition, amount, methodology and exclusion contained herein reflects a fair, just and reasonable resolution and compromise for the purpose of settlement, and is agreed upon without prejudice to the ability of any party to propose a different term, condition, amount, methodology or exclusion in future proceedings. As set forth in the Order in *Re Petition of Richmond Power & Light*, Cause No. 40434, p. 10, the Settling Parties agree and ask the Commission to incorporate as part of its Final Order that this Agreement, or the Order approving it, not be cited as precedent by any person or deemed an admission by any party in any other proceeding except as necessary to enforce its terms before the Commission, or any court of competent jurisdiction on these particular issues. This Agreement is solely the result of compromise in the settlement process. Each of the Settling Parties hereto has entered into this Agreement solely to avoid further disputes and litigation with the attendant inconvenience and expenses.

25. The Settling Parties stipulate that the evidence of record presented in this Cause constitutes substantial evidence sufficient to support this Agreement and provide an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary for the approval of this Agreement, as filed. The Settling Parties agree to the admission into the evidentiary record of this Agreement, along with testimony supporting it without objection.

26. The issuance of a Final Order by the Commission approving this Agreement without any material modification or further condition shall terminate all proceedings in this Cause. The relief requested in this proceeding is associated with but supersedes the relief approved in the August 25 Order, and as a result, upon the issuance of a Final Order approving this Agreement in its entirety without any material modification or further condition unacceptable to any Settling Party, the compliance filings in Cause No. 43526 are moot and no further consideration of those filings are necessary. The Settling Parties further agree to dismiss all pending requests for reconsideration and/or rehearing and all pending appeals of the Commission's August 25 Order.

27. The Settling Parties agree to jointly prepare a press release ("Joint Release") with language agreed upon by them describing the contents and nature of this Agreement, which will be jointly issued to the media. The Settling Parties may respond individually to questions from the public or media, provided that such responses are consistent with the Agreement.

28. The undersigned represent and agree that they are fully authorized to execute this Agreement on behalf of their designated clients who will be bound thereby.

29. The Settling Parties shall not appeal the agreed Final Order or any subsequent Commission order as to any portion of such order that is specifically implementing, without modification, the provisions of this Agreement and the Settling Parties shall not support any appeal of the portion of such order by a person not a party to this Agreement.

30. The provisions of this Agreement shall be enforceable by any Settling Party before the Commission or in any court of competent jurisdiction.

31. The communications and discussions during the negotiations and conferences which produced this Agreement have been conducted on the explicit understanding that they are or relate to offers of settlement and shall therefore be privileged.

ACCEPTED AND AGREED this 18th day of July, 2011.

Northern Indiana Public Service Company

Jimmy D. Staton

Indiana Office of Utility Consumer Counselor

A. David Stippler

NIPSCO Industrial Group

Bette J. Dodd

NLMK Indiana f/k/a Beta Steel Corporation

James W. Brew

Indiana Municipal Utilities Group

Anne E. Becker

ACCEPTED AND AGREED this 18th day of July, 2011.

Northern Indiana Public Service Company

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Indiana Municipal Utilities Group

Anne E. B
____
Anne E. Becker

Joint Exhibit A
Stipulation and Settlement Agreement
Cause No. 43969
Page 1 of 2

Northern Indiana Public Service Company
Calculation of Pro Forma Depreciation Expense - Electric Plant
Twelve Months Ended June 30, 2010
Revised

	Line No.	A/C	Description		Plant In Service A/C 101 & 106	D&A Rates per Study (10/19/2010)		Pro Forma D&A Expense
		B	C		D	E		F =CxD
	1		INTANGIBLE PLANT					
	2							
	3	301	ORGANIZATION	$	-	0.00%	$	-
	4	302	FRANCHISES & CONSENTS	$	1,389	0.00%	$	-
	5	303	MISC INTANGIBLE PLANT	$	33,932,227	0.00%	$	-
	6		TOTAL INTANG PLANT	$	33,933,616		$	-
	7		STEAM PRODUCTION PLANT					
	8	310	LAND AND LAND RIGHTS	$	4,985,072	0.00%	$	-
*	9	311	STRUCTS & IMPRVMNTS	$	464,686,080	1.25%	$	5,808,576
*	10	312.1	BOILER PLANT EQP	$	1,469,132,524	3.25%	$	47,746,807
	11	312.2	MOBILE FUEL HDLG/STRG	$	18,514,564	0.00%	$	-
	12	312.3	UNIT TRAIN COAL CARS	$	4,052,864	0.00%	$	-
*	13	312.4	S02 PLANT EQP	$	138,284,586	4.44%	$	6,139,836
*	14	312.5	COAL PILE BASE	$	5,843,930	0.24%	$	14,025
	15	313	ENGS & ENG-DRVN GENS	$	-	0.00%	$	-
*	16	314	TURBOGENERATOR UNITS	$	462,781,231	2.64%	$	12,217,424
*	17	315	ACCESSORY ELECTRIC EQP	$	251,367,794	1.91%	$	4,801,125
*	18	316	MISC PWR PLNT EQP	$	38,607,867	1.83%	$	706,524
	19		TOAL STEAM PROD PLANT	$	2,858,256,512		$	77,434,317
	20		NUCLEAR PROD PLANT					
	21	321	STRUCTS & IMPRVMNTS	$	-	0.00%	$	-
	22		TOTAL NUC PROD PLANT	$	-		$	-
	23		HYDRO PROD PLANT					
	24	330	LAND AND LAND RIGHTS	$	23,137	0.00%	$	-
	25	331	STRUCTS & IMPRVMNTS	$	3,007,892	6.20%	$	186,489
	26	332	RESIVRS, DAMS, WTR WAYS	$	6,139,608	6.53%	$	400,916
	27	333	WTR WHLS, TURBNS, GENS	$	4,741,205	2.73%	$	129,435
	28	334	ACCESSORY ELECTRIC EQP	$	1,784,733	4.09%	$	72,996
	29	335	MISC PWR PLNT EQP	$	79,710	1.78%	$	1,419
	30	336	ROADS, RRS, AND BRIDGES	$	-	0.00%	$	-
	31		TOTAL HYDRO PROD PLNT	$	15,776,285		$	791,255
	32		OTH PROD PLANT					
	33	340	LAND AND LAND RIGHTS	$	-	0.00%	$	-
	34	341	STRUCTS & IMPRVMNTS	$	2,229,542	0.47%	$	10,479
	35	342	FL HLDRS, PRDCTS, & ACS	$	9,059,763	0.06%	$	5,436
	36	343	PRIME MOVERS	$	26,803,190	2.22%	$	595,031
	37	344	GENERATORS	$	5,384,815	0.24%	$	12,924
	38	345	ACCSRY ELECT EQP	$	3,171,763	2.50%	$	79,294
	39	346	MISC PWR PLNT EQP	$	409,649	0.49%	$	2,007
	40		TOT OTH PROD PLANT	$	47,058,722		$	705,170
	41		TOTAL PROD PLANT	$	2,921,091,519		$	78,930,743
	42		TRANSMISSION PLANT					
	43	350.1	LAND	$	16,659,091	0.00%	$	-
	44	350.2	LAND RIGHTS	$	11,256,804	0.55%	$	61,912
	45	352	STRUCTS & IMPRVMNTS	$	14,253,308	2.61%	$	372,011
*	46	353	STATION EQP	$	386,379,030	2.89%	$	11,166,354
	47	354	TOWERS AND FIXTURES	$	88,019,126	1.99%	$	1,751,581
	48	355	POLES AND FIXTURES	$	111,722,827	2.80%	$	3,128,239
	49	356	OVHD CNDCTRS AND DEV	$	134,393,946	2.30%	$	3,091,061
	50	357	UDGRND CONDUIT	$	213,925	0.40%	$	856
	51	358	UDGRND CNDCTRS & DEV	$	954,006	3.29%	$	31,387
	52	359	ROADS AND TRAILS	$	70,027	0.74%	$	518
	53		TOTAL TRANSM PLANT	$	763,922,090		$	19,603,919
	54		DISTRIBUTION PLANT					
	55	360.1	LAND	$	2,301,782	0.00%	$	-
	56	360.2	LAND RIGHTS	$	691,245	1.21%	$	8,364
	57	361	STRUCTS & IMPRVMNTS	$	11,833,787	2.18%	$	257,977
*	58	362	STATION EQP	$	207,107,251	2.64%	$	5,467,631
	59	363	STORAGE BATTERY EQP	$	-	0.00%	$	-

Northern Indiana Public Service Company
Calculation of Pro Forma Depreciation Expense - Electric Plant
Twelve Months Ended June 30, 2010
Revised

	Line No.	A/C	Description		Plant In Service A/C 101 & 106	D&A Rates per Study (10/19/2010)		Pro Forma D&A Expense
		B	C		D	E		F =CxD
*	60	364.1	CUSTOMER TRANSFORMERS STATIC	$	35,935,640	3.07%	$	1,103,224
*		364.2	POLES, TWRS, AND FXTRS	$	244,737,764	4.55%	$	11,135,568
	61	365	OVHD CNDCTRS AND DEV	$	180,463,041	2.63%	$	4,746,704
	62	366	UGRND CONDUIT	$	3,986,523	1.31%	$	52,223
	63	367	UGRND CNDCTRS & DEV	$	231,528,430	2.60%	$	6,019,739
	64	368	LINE TRANSFORMERS	$	211,942,356	2.00%	$	4,238,847
	65	369.1	OVHD SERVICES	$	37,503,795	0.17%	$	63,756
		369.2	UGRND SERVICES	$	146,092,377	0.84%	$	1,227.176
	66	370.1	CUSTOMER METERING STATIONS	$	12,771,242	2.34%	$	298,847
		370.2	METERS	$	58,884,137	3.71%	$	2,184,601
	67	371	INSTLTS ON CUST PREM	$	7,342,216	5.95%	$	436,862
	68	372	LSD PROP ON CUST PREM	$	-	0.00%	$	-
	69	373	STRT LGHTS & SGNL SYS	$	36,758,790	3.02%	$	1,110,115
	70		TOTAL DISTRIB PLANT	$	1,429,900,376		$	38,351,636
	71		GENERAL PLANT					
	72	389.1	LAND	$	95,891	0.00%	$	-
		389.2	LAND RIGHTS	$	104,242	0.00%	$	-
	73	390	STRUCTS & IMPRVMNTS	$	15,437,742	1.73%	$	267,073
	74	391.1	OFC FURN & EQP	$	7,043,418	7.71%	$	543,048
		391.2	CMPTERS AND PERIPHRAL EQP	$	43,762,460	32.79%	$	14,349,711
	75	392.1	AUTOS	$	42,796	0.00%	$	-
		392.2	TRAILERS	$	2,076,047	0.00%	$	-
		392.3	TRUCKS	$	2,961,028	0.00%	$	-
		392.4	TRUCKS	$	1,074,906	0.00%	$	-
	76	393	STORES EQUIPMENT	$	1,974,880	7.46%	$	147,326
	77	394	TOOLS, SHP, & GRG EQP	$	20,719,098	6.25%	$	1,294,944
	78	395	LAB EQUIPMENT	$	18,291,037	9.36%	$	1,712,041
	79	396	PWR OPERATED EQP	$	22,708,765	0.00%	$	-
	80	397	COMMUNICATION EQUIP	$	21,044,944	11.56%	$	2,432,796
	81	398	MISC EQP	$	2,077,428	6.41%	$	133,163
	82		TOTAL GENERAL PLANT	$	159,416,762		$	20,880,100
	83							
	84	SUSP	SUSPENSE	$	-	0.00%	$	-
	85		DEFERRED-SUGAR CREEK			0.00%	$	-
	86		ELECTRIC PLANT IN SERVICE	$	5,308,264,363		$	157,766,398

ELECTRIC DEPRECIATION	$	157,766,398
COMMON DEPRECIATION	$	21,048,318
SUGAR CREEK DEPRECIATION	$	11,578,252
TOTAL PLANT IN SERVICE DEPRECIATION	$	190,392,968

* Rates changed from filed Case-in-Chief

IURC JOINT EXHIBIT No. Exhibit B
9-12-11
DATE REPORTER

Northern Indiana Public Service Company
Statement of Operating Income
Actual, Pro Forma, Proposed and Settlement
For the Twelve Month Period Ending June 30, 2010

Line No.	Description	Actual	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Filed Pro Forma Results Based on Proposed Rates	Settlement Adjustments	Settlement Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J
1	Operating Revenue									
2	Revenue	$ 1,290,077,061			$ 1,394,146,282	75,740,199	PF-1	$ 1,469,886,481	$ (68,886,481)	$ 1,401,000,000 (1)
3	Abnormal Weather		15,693,447	REV - 1						
4	Interdepartmental Sales - LNG Liquefaction		293,468	REV - 2						
5	Aggregate Planning Resource Credits		(937,500)	REV - 3						
6	Special Contracts		32,792,263	REV - 4						
7	EDR Rates		1,116,049	REV - 5						
8	Interest - FAC71 Legal Fees		(30,111)	REV - 6						
9	MISO Transmission Revenue		(3,205,777)	REV - 7						
10	Expiration of Customer Credit		58,789,378	REV - 8						
11	FAC 80 S1 Settlement Adjustment		(800,000)	REV - 9						
12	Fuel Costs Recovery - Lighting Tarriffs		499,611	REV - 10						
13	Capacity Sales Adjustment		(141,607)	REV - 11						
14	Total Operating Revenue	$ 1,290,077,061	$ 104,069,221		$ 1,394,146,282	$ 75,740,199		$ 1,469,886,481	$ (68,886,481)	$ 1,401,000,000
15	Fuel and Purchased Power	$ 473,066,869			$ 474,458,056			$ 474,458,056	$ -	$ 474,458,056
16	Abnormal Weather		4,661,013	FP - 1						
17	Interdepartmental Sales - LNG Liquefaction - Fuel		194,246	FP - 2						
18	Aggregate Planning Resource Credits - Costs		(337,500)	FP - 3						
19	Gas & Diesel - Gen Stations		18,335	FP - 4						
20	Capacity Purchases		(3,375,000)	FP - 5						
21	Accounting Accrual Adjustment		230,093	FP - 6						
22	Total Fuel and Purchased Power	$ 473,066,869	$ 1,391,187		$ 474,458,056	$ -		$ 474,458,056	$ -	$ 474,458,056
23	Gross Margin	$ 817,010,192	$ 102,678,034		$ 919,688,226	$ 75,740,199		$ 995,428,425	$ (68,886,481)	$ 926,541,944
24	Operations and Maintenance Expenses	$ 382,060,512			$ 389,318,655	203,687	PF - 2	$ 389,522,342	$ (185,256)	$ 363,237,597
25	Line Locates		(259,417)	OM - 1						
26	Vegetation Management		3,437,162	OM - 2						
27	Gas & Diesel		10,385	OM - 3						
28	Wage Increase		5,465,525	OM - 4						
28a	Pension								(17,151,702)	
29	Incentive Adjustment		1,283,166	OM - 5						
30	Environmental Expense Adjustment		(668,000)	OM - 6						
31	Labor Adjustment		(3,249,936)	OM - 7						
32	BU Signing Bonus		(22,400)	OM - 8						
33	Corp Services - NCSC		(1,248,857)	OM - 9						
34	Gary Business Office Relocation		(125,640)	OM - 10						
35	Lobbying / EEI		(78,183)	OM - 11						
36	Institutional Goodwill Advertising		(12,449)	OM - 12						
37	Advertising		(1,854,005)	OM - 13						
38	Selected Payments		(45,055)	OM - 14						
39	Excess / Obsolete Material		(2,023,458)	OM - 15						
40	Insurance Reimbursement		445,774	OM - 16						
41	MISO Administrative Fee		5,326,931	OM - 17						
42	Gypsum Expense Adjustment		876,600	OM - 18						
43	Settlement Adjustment								(8,947,786)	
44	Total Operations and Maintenance	$ 382,060,512	$ 7,258,143		$ 389,318,655	$ 203,687		$ 389,522,342	$ (26,284,745)	$ 363,237,597

(1) NIPSCO's base rates will be designed to produce $1.355 billion, which is the revenue requirement of $1.401 billion less approximately $42m of other revenue and $4m emission allowance credit as ordered in Cause 43526.

Northern Indiana Public Service Company
Statement of Operating Income
Actual, Pro Forma, Proposed and Settlement
For the Twelve Month Period Ending June 30, 2010

Line No.	Description	Actual	Pro Forma Adjustments Increases (Decreases)	Ref.	Pro Forma Results Based on Current Rates	Pro Forma Adjustments Increases (Decreases)	Ref	Filed Pro Forma Results Based on Proposed Rates	Settlement Adjustments	Settlement Pro Forma Results Based on Proposed Rates
	A	B	C	D	E	F	G	H	I	J
45	<u>Depreciation Expense</u>	$ 193,896,526			$ 195,298,357			$ 195,298,357	$ (4,905,389)	$ 190,392,968
46	Depreciation Expense - New Rates		1,401,831	DA - 1						
47	**Total Depreciation Expense**	$ 193,896,526	$ 1,401,831		$ 195,298,357	$ -		$ 195,298,357	$ (4,905,389)	$ 190,392,968
48	Amortization Expense	$ 12,850,263			$ 37,688,102			$ 37,688,102		$ 36,500,530
49	Amortization Expense (Reg Assets) - MISO (4 yr)		3,876,018	DA - 2						
50	Amortization Expense (Reg Assets) - MISO Cause No. 43526 (4 yr)		5,732,141	DA - 2A						
51	Amortization Expense (Reg Assets) - Rate Case (3 yr)		770,162	DA - 3						
52	Amortization Expense (Reg Assets) - Rate Case Cause No. 43526 (5 yr)		1,187,572	DA - 3A					(1,187,572)	
53	Amortization Expense - Deferred Sugar Creek Depreciation (5 yr)		2,029,113	DA - 4						
54	Amortization Expense - Deferred Sugar Creek Depreciation Cause No. 43526 (5 yr)		1,459,652	DA - 4A						
55	Amortization Expense - Deferred Sugar Carrying Charges (5 yr)		6,287,705	DA - 5						
56	Amortization Expense - Deferred Sugar Carrying Charges Cause No. 43526 (5 yr)		4,541,120	DA - 5A						
57	Amortization Expense - RM Schahfer Unit 17 Deferred Depreciation		(193,544)	DA - 6						
58	Amortization Expense - RM Schahfer Unit 17 Carrying Charges		(852,000)	DA - 7						
59	**Total Amortization Expense**	$ 12,850,263	$ 24,837,839		$ 37,688,102	$ -		$ 37,688,102	$ (1,187,572)	$ 36,500,530
60	<u>Taxes</u>									
61	<u>Taxes Other than Income</u>	$ 54,999,209			$ 60,334,582			$ 60,334,582		$ 57,719,217
62	Real Estate Taxes		3,084,954	OTX - 1					(2,615,365)	
63	Payroll Tax		456,104	OTX - 2						
64	Indiana Utility Receipts Tax		1,602,321	OTX - 3		1,060,363	PF - 3	1,060,363	(964,411)	95,952
65	Public Utility Fee		192,994	OTX - 4		90,055	PF - 4	90,055	(81,906)	8,149
66	Total Taxes Other Than Income	$ 54,999,209	$ 5,335,373		$ 60,334,582	$ 1,150,418		$ 61,485,000	$ (3,661,682)	$ 57,823,318
67	<u>Income Taxes</u>									
68	Federal and State Taxes	$ 57,557,401	$ 15,318,907	ITX - 1	$ 72,876,308	$ 30,203,550	PF - 5	$ 103,079,858	$ (13,364,569)	$ 89,715,289
69	Total Taxes	$ 112,556,610	$ 20,654,280		$ 133,210,890	$ 31,353,967		$ 164,564,857	$ (17,026,250)	$ 147,538,607
70	Total Operating Expenses	$ 701,363,911	$ 54,152,093		$ 755,516,004	$ 31,557,654		$ 787,073,659	$ (49,403,957)	$ 737,669,702
71	**Required Net Operating Income**	$ 115,646,281	$ 48,525,941		$ 164,172,222	$ 44,182,544		$ 208,354,766	$ (19,482,524)	$ 188,872,242

(1) NIPSCO's base rates will be designed to produce $1,355 billion, which is the revenue requirement of $1,401 billion less approximately $42m of other revenue and $4m emission allowance credit as ordered in Cause 43526.

Joint Exhibit C
Stipulation and Settlement Agreement
Cause No. 43969

Allocation of Base Rate Revenue Requirement

	Base Rate Revenue Requirement		% of Total
Rate 611	$	377,800,682	27.882%
Rate 612	$	5,160,037	0.381%
Rate 613	$	1,225,658	0.090%
Rate 617	$	79,874	0.006%
Rate 620	$	629,024	0.046%
Rate 621	$	179,174,263	13.223%
Rate 622	$	1,198,071	0.088%
Rate 623	$	156,979,496	11.585%
Rate 624	$	192,453,641	14.203%
Rate 625	$	3,187,081	0.235%
Rate 626	$	59,229,608	4.371%
Rate 632	$	140,914,919	10.400%
Rate 633	$	121,519,285	8.968%
Rate 634	$	94,742,567	6.992%
Rate 641	$	2,356,647	0.174%
Rate 642	$	83,773	0.006%
Rate 644	$	1,862,949	0.137%
Rate 650 -Street Lighting	$	8,864,654	0.654%
Rate 655 - Traffic Lighting	$	917,431	0.068%
Rate 660 - Dusk-to-Dawn	$	2,221,152	0.164%
Interdepartmental	$	4,399,188	0.325%
Total	$	1,355,000,000	100.000%

Generally applicable:

- Rates and charges revised consistent with agreed base rate revenue of $1,355 million and class allocations contained within Settlement Agreement
- Subject to agreeable language for all tariffs, general terms and conditions of service, and standard contract applicable to certain industrial tariffs.

Rates 611 (Residential), 612 (Single Family Residential – Heat Pump) and 613 (Multiple Family Residential Housing – Heat Pump):

- $11 customer charge
- Single energy block (i.e., no declining blocks)
- Standardize spaceheating kilowatt breakpoint with spaceheating/heat pump rates at 700 kWh

Discontinuation of Spaceheating/Heat Pump Rates:

- Gas heating incentive ($25) below-the-line
- NIPSCO agrees to file for the Commission's consideration within two years of an Order in this Cause a rate design analysis for its residential space heating rates that provides revenue neutral transition plans to discontinue discounts from standard rates for space heating customers and any required alterations to the rates of the standard customers on these rate schedules.

Rates 620 (Commercial and General Service – Heat Pump) and 622 (Commercial Spaceheating):

- $20 customer charge

Rate 621 (General Service – Small):

- $20 customer charge, with the exception of a $34 customer charge for three-phase service customers
- Single energy block (i.e., no declining block)

Rate 625 (Metal Melting Service)

- Current tariff structure (peak and off-peak hours) is generally retained.

Rate 632 (Industrial Power Service):

- Grandfather test year customers and/or load as migrated
- Increase minimum threshold to 15 MW
- Single demand charge rate

- Three inclining energy blocks

Rate 633 (High Load Factor Industrial Power Service):

- Grandfather test year customers and/or load as migrated
- Three declining energy blocks
- No embedded energy/hours in the demand component

Rate 634 (Industrial Power Service for Air Separation & Hydrogen Production Market Customers)

- New rate schedule available to air separation and hydrogen production market customers with contract minimum of 150 MW, including aggregation of multiple delivery points to facilitate interruption of load
- Customer required to contract for at least 40 percent (40%) as interruptible in accordance with Option D under Rider 675
- Demand Charge assessed on Contract Demand
- Three block Energy Charges based upon kilowatt hours used under Contract Demand, between Contract Demand and 225,000 KW and kilowatt hours used over 225,000 KW.
- Determination of Contract Demand based upon average of on-peak demands and subject to 12.5% bandwidth

Rider 670 (Adjustment of Charges for Cost of Fuel Rider)

- Modified to include recovery of 25% of costs associated with credits paid for interruptible load

Rider 674 (Adjustment of Charges for Resource Adequacy)

- Modified to include recovery of 75% of costs associated with credits paid for interruptible load

Rider 675 (Interruptible Industrial Service Rider)

- *See* Joint Exhibit F

Rider 676 (Back-up, Maintenance and Temporary Industrial Service Rider)

- *See* Joint Exhibit G

Rider 677 (Economic Development Rider)

- Modified to include new eligibility threshold requirement of a minimum of 10 full-time equivalent jobs created per project

Joint Exhibit E
Stipulation and Settlement Agreement
Cause No. 43969

Demand Allocators

Table 1

	Demand Allocators - Production Rate Base	% of Total
Rate 611	$ 874,364,266	27.03%
Rate 612	$ 11,568,405	0.36%
Rate 613	$ 2,491,423	0.08%
Rate 617	$ 567,352	0.02%
Rate 620	$ 2,460,930	0.08%
Rate 621	$ 321,313,655	9.93%
Rate 622	$ 3,167,196	0.10%
Rate 623	$ 352,718,755	10.90%
Rate 624	$ 381,527,692	11.80%
Rate 625	$ 10,357,175	0.32%
Rate 626	$ 149,042,043	4.61%
Rate 632	$ 486,895,971	15.05%
Rate 633	$ 359,680,007	11.12%
Rate 634	$ 258,398,965	7.99%
Rate 641	$ 4,083,935	0.13%
Rate 642	$ 40,353	0.00%
Rate 644	$ 3,382,779	0.10%
Rate 650 - Street Lighting	$ 3,183,659	0.10%
Rate 655 - Traffic Lighting	$ 1,792,941	0.06%
Rate 660 - Dusk-to-Dawn	$ 873,080	0.03%
Interdepartmental	$ 6,685,997	0.21%
Total	$ 3,234,596,580	100.0%

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

TO WHOM AVAILABLE

Available to Customers taking service under either Rate 632, Rate 633 or Rate 634 whose facilities are located adjacent to existing electric facilities having capacity sufficient to meet the Customer's requirements, subject to the conditions set forth in this Rider and the Company Rules. The total capacity to be made available under this Rider is limited to 500 MW and the total sum of demand credits available under this Rider shall not exceed $38,000,000 in any calendar year. If initial requests for capacity exceed the 500 MW cap, the priority of allocation will be first to existing interruptible customers and then the remaining capacity will be allocated on a pro rata share.

Customers shall contract for and specify an Interruptible Contract Demand of 1,000 kW or greater under this Rider. The Company shall not be obligated to supply interruptible capacity in excess of the Interruptible Contract Demand specified in the contract. Interruptible Contract Demand is the demand (kW) that the Customer intends to make available for Interruptions and/or Curtailments from one or more of Customer's premises taking service under Rate 632, Rate 633 or Rate 634. Customers electing service under this Rider shall specify a Firm Contract Demand that the Customer intends to exclude from Interruptions and Curtailments. The Firm Contract Demand amount shall be specified in the customer's agreement. The Interruptible Contract Demand shall not exceed the Rate 632, Rate 633 or Rate 634 Demand.

For Options A, B, and C, if Customer elects to provide Interruptible Contract Demand from more than one premise, Customer shall indicate the Interruptible Contract Demand and Firm Contract Demand that applies in aggregate to its premises as well as by each premise or facility. In these instances, Company shall have the right to call Customer for the Interruptible Contract Demand quantity in aggregate from Customer, and Customer shall indicate from which facility or premise it will utilize to satisfy the obligations under this Rider.

Customers electing this rider shall be required to have the ability of Curtailment or Interruption at the stated notice by the Company and the provisions of service under this Rider to Customers shall also meet the applicable Load Modifying Resource requirements pursuant to Midwest ISO Tariff Module E or any successor. Customers electing this Rider shall provide information necessary to satisfy these requirements, including information demonstrating to Company's satisfaction that the Customer has the ability to reduce load to the level of curtailability and/or interruptibility for which they contract.

CHARACTER OF SERVICE

There are four options of interruptible service. The Customer shall contract for the interruptible option which shall remain in effect for the duration of the contract.

The Company shall dispatch customers for the Curtailments or Interruptions at its own discretion in accordance within the limitations specified under this Rider and the Company's General Rules and Regulations Applicable to Electric Service.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Option A – Curtailments only

Curtailments shall be limited to the following:

1. No more than one (1) per day;
2. No more than four (4) hours per day;
3. No more than five (5) days during the summer (May – September).

The Company shall provide at least four (4) hours advanced notice before a Curtailment. This service will be billed as second through the meter.

Option B – Curtailment and Limited Interruptions

1. Customer will be subject to the Curtailments defined in Option A plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than ten (10) consecutive hours,
   c. No more than two (2) consecutive days,
   d. No more than three (3) in any seven (7) days of the week, and
   e. No more than 100 hours per rolling 365 days.

The Company shall provide at least four (4) hours advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of four (4) hour notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as second through the meter.

Option C – Curtailment and Interruptions

1. Customer will be subject to Curtailments unlimited as to quantity and duration plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than 12 consecutive hours,
   c. No more than two (2) consecutive days,
   d. No more than three (3) in any seven (7) days of the week, and
   e. No more than 100 hours per rolling 365 days.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

The Company shall provide at least one (1) hour advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of one (1) hour notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as second through the meter.

Option D – Curtailment and Short notice Interruptions

1. Customer will be subject to Curtailments unlimited as to quantity and duration plus
2. Interruptions shall be limited as follows:
   a. No more than one (1) per day,
   b. No more than 12 consecutive hours,
   c. No more than three (3) consecutive days during weekdays (Monday – Friday), and
   d. No more than 200 hours per rolling 365 days.

The Company shall provide at least ten (10) minute advanced notice before an Interruption or Curtailment. Adjustments to the requested Interruptible demand may be increased with a minimum of ten (10) minutes notice during the Interruption. Once notice is given to a Customer, an Interruption of a minimum of at least four (4) consecutive hours in length will be deemed to have occurred for purposes of the above limits even if the Company subsequently provides a notice of cancellation of such Interruption. This service will be billed as first through the meter.

INTERRUPTIONS

Company may call an Interruption when the applicable real-time LMPs for the Company's load zone are reasonably forecasted by the Company to be in excess of the Company's current Commission-approved purchased power benchmark that is utilized to develop the Company's fuel cost charge under Rider 670. Company shall provide a good faith estimate of the duration of an Interruption based upon the information available to Company.

Customers may elect to buy-through an Interruption subject to the Energy rate provided in this Rider.

RATE

Demand Credit

Option A

On the effective date of this Rider:	$1.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Starting every subsequent February 1: The annual market price per kilowatt per month for capacity deliverable to the NIPSCO load zone as determined by the Company through an average of quotes taken from candidate bilateral counterparties in the wholesale market (or reasonably similar information available to Company) during the preceding January.

Option B

$6.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Option C

$8.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Option D

$9.00 per kilowatt per Interruptible Billing Demand per month will be applied to the Rate 632, Rate 633 or Rate 634 bill.

Energy

During Interruptions, all kilowatt hours used above the Interruptible Contract Demand plus the firm Contract Demand less the amount requested for Interruption shall be subject to an energy charge equal to the Real-Time LMP for the Company's load zone plus a non-fuel energy charge as follows:

Rate 632:	$0.005702 per kilowatt hour
Rate 633:	$0.005108 per kilowatt hour
Rate 634:	$0.003009 per kilowatt hour.

Prior to 9 AM CST day-ahead, a Customer may elect in writing to Company to pay the Day-Ahead LMP for the Company's load zone in place of the Company's Real-Time LMP for the Company's load zone for any energy taken by the Customer pursuant to this Rider during any Interruptions that occur for that operating day.

DETERMINATION OF INTERRUPTIBLE BILLING DEMAND

Interruptible billing demand shall be calculated as follows:

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

Options A, B & C:

The lessor of:

(1) the Interruptible Contract Demand, or
(2) Billing demand of the either Rate 632, Rate 633 or Rate 634 less firm Contract Demand.

Option D:

The lessor of:

(1) the Interruptible Contract Demand, or
(2) Billing demand of either Rate 632, Rate 633 or Rate 634.

The customer's monthly Rate 632, Rate 633 or Rate 634 Billing Demand shall be calculated in accordance with Rate 632, Rate 633 or Rate 634.

The interruptible demand credit will not apply to Back-up, Maintenance or Temporary Service demands taken under Rider 676.

CUSTOMER'S FAILURE TO COMPLY WITH REQUESTED INTERRUPTIONS OR CURTAILMENT

A Customer is deemed to have failed to comply with a Curtailment or Interruption when the Customer's current integrated Demand, as measured by the meters installed by the Company, has not decreased to a level equal to or less than its Firm Contract Demand plus its Interruptible Contract Demand less the amount requested within the applicable notification period of the option for Interruptions and/or Curtailments.

If a Customer fails to comply with a Curtailment, the Customer shall be immediately disqualified and removed from service under this Rider and shall not be eligible for this Rider for a period of three (3) years. In addition, a Customer failing to comply with a Curtailment shall be subject to the above energy charge during a Curtailment and, the Customer shall be liable for any charges and/or penalties from any outside agency(ies) or duly applicable organization including Midwest ISO, FERC and Reliability*First* Corporation for failure to comply with a Curtailment. Penalties and charges may be, but are not limited to, penalties associated with disqualification as a Load Modifying Resource.

For Interruptions, the only consequence of such compliance failure will be that the Customer will be deemed to have elected to buy-through its Interruption pursuant to the Energy charge under this Rider to the extent the Customer failed to interrupt its demand.

RIDER 675
INTERRUPTIBLE INDUSTRIAL SERVICE RIDER

GENERAL TERMS AND CONDITIONS OF SERVICE - CONTRACT

Any Customer requesting service under this rate shall enter into a written contract for an initial period of:

Option A:	Not less than one (1) year.
Option B:	Not less than three (3) years.
Option C:	Not less than seven (7) years.
Option D:	Not less than 10 years.

Customers electing Options B, C or D under this Rider shall have the option once each year by February 15 to modify its Interruptible Contract Demand by plus or minus 10 percent (10%), subject to the overall availability under this Rider. A Customer electing to modify its Interruptible Contract Demand shall also agree to make corresponding changes to its Firm Contract Demand and other provisions in its contract impacted by such modification.

To the extent Customers electing Options B, C or D experience a material change in plant operations and provide Company at least 60 days' advance notice, the contract under this Rider, including the Interruptible Contract Demand and Firm Contract Demand, may be modified to accommodate such change upon mutual agreement of Customer and Company.

In such contract, it shall also be proper to include such provisions, if any, as may be agreed upon between the Company and the Customer with respect to special terms and conditions under which service is to be furnished hereunder, including but not limited to, amount of Contract Demand, voltage to be supplied, and facilities to be provided by each party in accordance with the Company Rules.

Notwithstanding the above, contracts under this Rider shall expire upon the date of Company's implementation of new electric basic rates and charges resulting from a general rate proceeding.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

TO WHOM AVAILABLE

Available to Customers taking service under either Rate 632 or Rate 633 who desire to take service from the Company on a temporary basis, including for back-up or maintenance purposes, subject to Curtailments. Back-up, Maintenance, and Temporary Services under this Rider shall be subject to Curtailments when curtailment of the Company's interruptible service customers under Rider 675 is insufficient.

CHARACTER OF SERVICE

Subject to the provisions applicable to Back-up, Maintenance or Temporary Service under this Rider, Customer shall request in writing, which can be via electronic mail, an amount of capacity and the duration said capacity shall be needed. The Company shall by written notice, which can be via electronic mail, confirm the amount of capacity it is willing to accept as load on its system and the duration said capacity shall be available to the Customer.

Back-up Service
Subject to the requirements of Back-up Service in this Rider, a Customer with verified internal electric generation fueled with energy sources such as, but not limited to, process off-gas or waste heat, natural gas, oil, propane, coal and coal by-products and that is capable of meeting the efficiency standards established for a cogeneration facility by the Federal Energy Regulatory Commission under 16 U. S. C. 824a-3, in effect November 9, 1978 ("Cogeneration Systems") may request (including on a pre-qualifying basis) Back-up Service that may only be available for up to 45 calendar days per Cogeneration System per 12 rolling months. Eligibility for Back-Up Service requires a contract between the Customer and Company that shall include information on the Cogeneration System(s). Customer shall provide initial notice of request of Back-up Service within 60 minutes of event, including (i) information reasonably verifying such event, (ii) expected outage schedule, and (iii) daily notice to Company thereafter during and throughout the conclusion of an event.

Maintenance Service
Subject to the requirements of Maintenance Service in this Rider, the amount confirmed by Company shall be deemed firm load, subject to Curtailments.

Temporary Service
Subject to the requirements of Temporary Service in this Rider, the amount confirmed by Company shall be deemed firm load, subject to Curtailments. To the extent Customer requests Temporary Service and Company denies such a request under this Rider, Customer may elect to buy-through subject to the Demand and Energy Charges during Buy-through provided in this Rider. Customer may not elect to buy-through under this Rider if Company has initiated a Curtailment(s) on its system. The Company has the right to deny a request if Day Ahead LMPs exceed the Company's current Commission-approved purchased power benchmark that is utilized to develop the Company's fuel cost charge under Rider 670.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

RATE

Back-up Service

For Back-up service, the following charges shall apply:

Demand Charge:

The demand charge shall be the applicable Rate 632 or Rate 633 demand charge, divided by the number of calendar days within the applicable calendar month, per kilowatt per day.

Energy Charge

All kilowatt hours used for Back-up service shall be subject to an energy charge equal to Real-Time LMP plus a non-fuel energy charge of $0.0035 per kilowatt hour.

All energy for Back-up Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the confirmed Back-up Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Back-up Service capacity was taken by the Customer.

Maintenance Service

For Customers (i) requesting service in writing at least 30 days in advance of the need for maintenance service, (ii) requesting service for days not including June, July, August and September, and (iii) maintaining such requested daily schedule without material change, the following charges shall apply for up to a maximum of 60 calendar days in any 12 month rolling period:

Demand Charge

For Customers requesting service for January, May and/or December, the Demand Charge shall be $0.44 per kilowatt per day.

For Customers requesting service for February, March, April, October and/or November, the Demand Charge shall be $0.25 per kilowatt per day.

Energy Charge

The energy charge for all kilowatt hours shall be the applicable energy charge in Rate 632 or Rate 633.

To the extent Customer seeks to recall the amount of Maintenance Service confirmed by Company, Customer shall provide at least 48 hours prior notice. In such instance, Company shall confirm to Customer the amount recalled within 24 hours of notice of recall and such recalled amounts shall not contribute towards the maximum days permitted under this Rider.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

Temporary Service
For Temporary service, the following charges shall apply:

Demand Charge (except as defined for buy-through described below)
$0.58 per kilowatt per day for the first 30 calendar days of temporary demand take in any 12 month rolling period;
$0.87 per kilowatt per day for the second 30 calendar days of temporary demand take in any 12 month rolling period;
$1.16 per kilowatt per day for the third 30 calendar days of temporary demand take in any 12 month rolling period; and
$2.32 per kilowatt per day for all calendar days in excess of 90 of temporary demand take in any 12 month rolling period.

Energy Charge (except as defined for buy-through described below)
The energy charge for all kilowatt hours shall be the applicable energy charge in Rate 632 or Rate 633.

All energy for Temporary Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the confirmed Temporary Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Temporary Service capacity was taken by the Customer.

Buy-Through Temporary Service

Demand Charge (during buy-through)
There shall be no demand charge for Temporary Service during a buy-through event.

Energy Charges (during buy-through)
All kilowatt hours used for Temporary service during buy-through shall be subject to an energy charge equal to Real-Time LMP plus a non-fuel energy charge of $0.0035 per kilowatt hour.

All energy for Temporary Service shall be billed on an hourly basis at the lower of: (i) 100% load factor for the requested Temporary Service capacity or (ii) the total energy consumed by the Customer under this Rider and either Rate 632 or Rate 633, as applicable, during the period in which Temporary Service capacity was taken with buy-through by the Customer.

Subject to the amount requested by Customer, during a buy-through event there is no cap on kWh's imported or duration of buy-through for that applicable operating day. Buy-through days do not count toward the number of days of Temporary Service during any rolling 12 month period.

This Rider is subject to the Midwest ISO charges or credits associated with the service.

RIDER 676
BACK-UP, MAINTENANCE AND TEMPORARY INDUSTRIAL SERVICE RIDER

DETERMINATION OF BILLING DEMAND

The billing demand for the day for Maintenance Service shall be the greater of (i) the granted Maintenance Service capacity times 80% or (ii) the actual amount of Maintenance Service taken by Customer above the billing demand under Rate 632 or Rate 633. To the extent Company has confirmed a recall of Maintenance Service under the provisions of this Rider, Customer shall not be charged for the amount recalled.

The billing demand for the day for Back-up and Temporary Service shall be the confirmed amount of Back-up and Temporary Service.

RULES AND REGULATIONS

Service hereunder shall be subject to the Company Rules and IURC Rules.

Rule 10.2 Non-Residential Customers

The Company shall determine the creditworthiness of an Applicant or Customer in an equitable non-discriminatory manner.

A Customer shall be deemed creditworthy if it has no delinquent bills to the Company for electric service within the last twenty-four (24) months and, within the last two (2) years has not: (a) had service disconnected for nonpayment or (b) filed a voluntary petition, has a pending petition, or has an involuntary petition filed against it, under any bankruptcy or insolvency law. For purposes of this determination a contested bill shall not be considered delinquent.

In determining the creditworthiness of Applicants, the Company shall consider the size of the credit exposure and the availability of objective and verifiable information about the Applicant. The Company may consider the Applicant's payment history from other utilities and verifiable conditions such as, but not limited to: Applicant 's independently audited annual and quarterly financial statements, including an analysis of its leverage, liquidity, profitability and cash flows; and credit rating agency information.

The Company may require from any uncreditworthy Applicant or Customer, as a guarantee against the non-payment of bills, a deposit payable in cash or by letter of credit in an amount equal to the Customer's two (2) highest months usage based upon the most recent twelve (12) months historical usage or two months of projected usage for an Applicant. For Customers with multiple accounts, each account will be treated individually for purposes of this Rule.

If the Company requires a deposit as a condition of providing service, upon request of the Customer or Applicant, the Company must: (a) provide written explanation of the facts upon which the utility based its decision; and (b) provide the Applicant or Customer with an opportunity to rebut the facts and show other facts demonstrating its creditworthiness.

Upon the request of the Customer, but no more than once every twenty four (24) consecutive months, the Company will conduct a reevaluation of Customer's creditworthiness with repayment of the security deposit or portion thereof as appropriate, within 60 days and with written notice identifying the basis for any continued deposit.

In the case of a cash deposit as a guarantee against the payment of bills, simple interest thereon at the rate established by the Indiana Utility Regulatory Commission shall be paid by the Company for the time such deposit is held by the Company. Upon discontinuance of service, the amount of the final bill will be deducted from the sum of the deposit and interest due, and the balance, if any, shall be remitted to the depositor.